## 1.4    MARKET ANALYSIS

## 1.4.1    Introduction and Executive Summary

### 1.4.1.1    Introduction

This section examines petroleum markets, analyzes how they would be affected by the proposed Project, and assesses whether conclusions from previous market analyses should be altered in light of recent developments. It builds upon and updates the Final Environmental Impact Statement (EIS) published on August 26, 2011, and the Draft Supplemental EIS published on March 1, 2013.

The scope and content of the market analysis that was conducted for the Supplemental EIS were informed by public and interagency comments and new information that was not previously available. Among the notable updates to this analysis are revised modeling to incorporate evolving market conditions, more extensive information on the logistics and economics of crude by rail, and a more detailed analysis of supply costs to inform conclusions about production implications.

The updated market analysis in the Supplemental EIS, similar to the market analysis sections in the 2011 Final EIS and Draft Supplemental EIS concludes that the proposed Project is unlikely to significantly affect the rate of extraction in oil sands areas (based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios). The Department conducted this analysis, drawing on a wide variety of data and leveraging external expertise. The analysis reflects inputs from other U.S. government agencies and was reviewed through an interagency process.

### 1.4.1.2    Methodological Overview

The subsections of this analysis examine individual market issues relevant to the proposed Project, which are then integrated to draw conclusions about its potential impact on oil sands production. Section 1.4.2, Oil Market Conditions, provides context on the global oil market, North American upstream and downstream oil industries, supply costs, and recent market developments. Section 1.4.3, Crude Oil Transportation, describes current, planned, or potential midstream crude oil transportation infrastructure, particularly pipelines and rail, which could affect crude oil movements. Section 1.4.4, Updated Modeling, describes key findings from external modeling to indicate how oil trade, refining activities, and price differentials might respond to selected supply-demand and pipeline scenarios.

Conclusions about production impacts of the proposed Project are developed in Section 1.4.5, Conclusions. First, prices from the model results were compared to the long-term supply costs of representative oil sands projects. Second, the difference between modeled prices and oil sands supply costs was examined to approximate how far benchmark oil prices might have to fall before selected oil sands projects would become uneconomic. Third, current and potential transportation options between western Canada and the U.S. Gulf Coast were explored to assess how modeled transportation costs, which affect the prices received by oil sands producers, could vary by mode. The results of these analytical approaches were combined in Section 1.4.5.4, Implications for Production, to draw general conclusions about the production impacts of the proposed Project under various conditions.

### 1.4.1.3    Summary of Analysis

The 2011 Final EIS was developed contemporaneously with the start of strong growth in domestic light crude oil supply from tight oil formations. Domestic production of crude oil has increased significantly, from approximately 5.5 million barrels per day (bpd) in 2010 to 6.5 million bpd in 2012 and 7.5 million bpd by mid-2013. Rising domestic crude production is predominantly light crude, and it has replaced foreign imports of light crude oil. However, the demand persists for imported heavy crude oil by U.S. refineries optimized to process heavy crude slates. Meanwhile, Canadian production of bitumen from the oil sands continues to grow, the vast majority of which is currently exported to the United States to be processed by U.S. refineries. North American production growth and logistics constraints have contributed to significant discounts on the price of landlocked crude and led to growing volumes of crude shipped by rail in the United States and, more recently, Canada.

The Draft Supplemental EIS (2013) and Final EIS (2011) discussed the transportation of Canadian crude by rail as a future possibility. Due to market developments since then, this Final Supplemental EIS notes that the transportation of Canadian crude by rail is already occurring in substantial volumes. It is estimated that approximately 180,000 bpd of Canadian crude oil already travel by rail (see Figure 1.4.1-1).
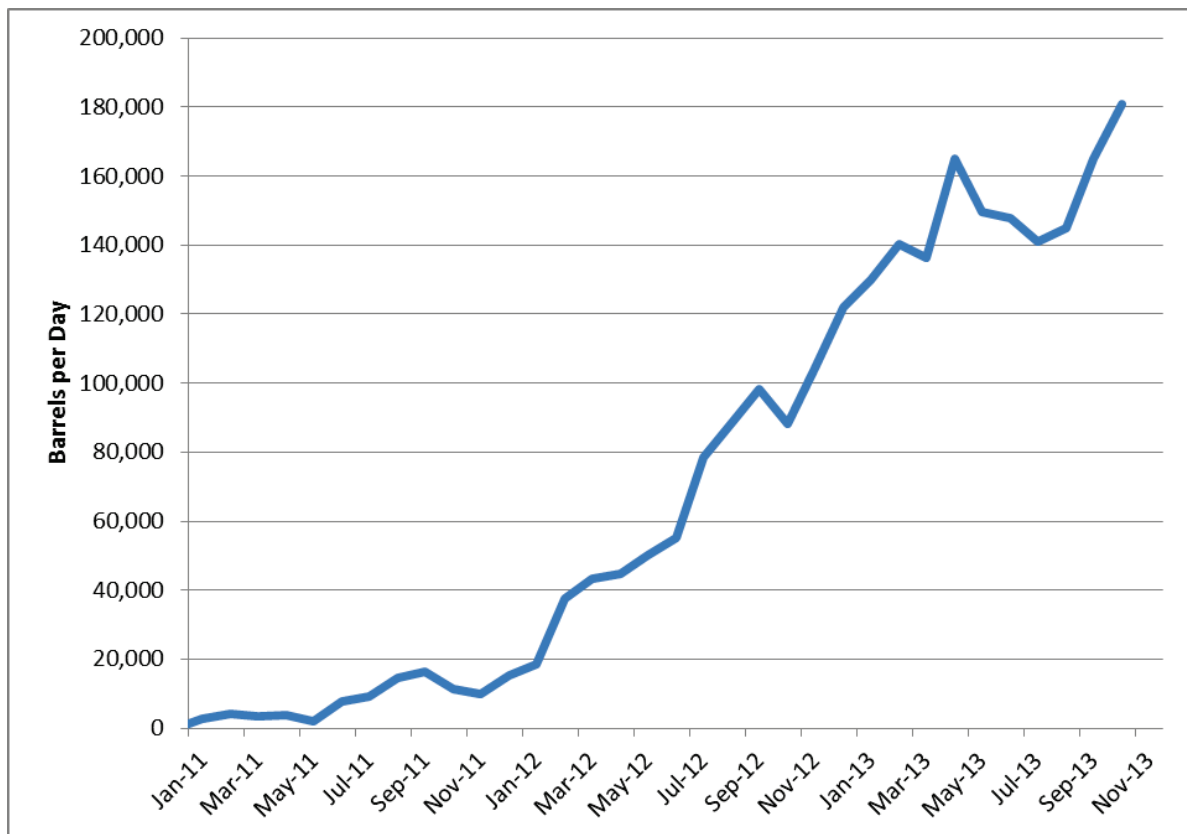


Source: Statistics Canada 2013, U.S. Department of Transportation Bureau of Transportation Statistics 2013, Peters and Co. 2013, IHS Cambridge Energy Research Associates, Inc. (IHS CERA) 2013, and company information.

**Figure 1.4.1-1         Estimated Crude Oil Transported by Rail from WCSB, bpd**

The industry has been making significant investments in increasing rail transport capacity for crude oil out of the Western Canadian Sedimentary Basin (WCSB). Figure 1.4.1-2 illustrates the increase in rail loading and unloading terminals between 2010 and 2013. Rail-loading facilities in the WCSB are estimated to have a capacity of approximately 700,000 bpd of crude oil, and by the end of 2014, this will likely increase to more than 1.1 million bpd. Most of this capacity (approximately 900,000 to 1 million bpd) is in areas that produce primarily heavy crude oil (both conventional and oil sands), or is being connected by pipelines to those areas.

Various uncertainties underlie the projections upon which the Supplemental EIS partially relies. In recognition of the uncertainty of future market conditions, the analysis included updated modeling about the sensitivity of the market to some of these elements.

Updated information on rail transportation and oil market trends, particularly rising U.S. oil production, was incorporated in oil market modeling. This modeling was developed in response to comments received on the Draft Supplemental EIS. To help account for key uncertainties about oil production, consumption, and transportation, the modeling examined 16 different scenarios that combine various supply-demand assumptions and pipeline constraints. Modeled cases test supply and demand projections based on the official energy forecasts of the independent U.S. Energy Information Administration's (EIA's) 2013 Annual Energy Outlook (AEO) that correspond to uncertainties raised in public comments, including potential higher-than-expected U.S. supply, lower-than-expected U.S. demand, and higher-than-expected oil production in Latin America.

The supply-demand cases were paired with four pipeline configuration scenarios: an unconstrained scenario, which allows pipelines to be built without restrictions; a scenario in which no new cross-border pipeline capacity to U.S. markets is permitted but pipelines from the WSCB to Canada's east and west coasts are built; a scenario where new cross-border capacity between the United States and Canada is permitted but Canadian authorities do not permit new east-west pipelines; and a constrained scenario that assumes no new or expanded pipelines carrying WCSB crude are built in any direction.

Updated model results indicated that cross-border pipeline constraints have a limited impact on crude flows and prices. If additional east-west pipelines were built to the Canadian coasts, such pipelines would be heavily utilized to export oil sands crude due to relatively low shipping costs to reach growing Asian markets. If new east-west and cross-border pipelines were both completely constrained, oil sands crude could reach U.S. and Canadian refineries by rail. Varying pipeline availability has little impact on the prices U.S. consumers pay for refined products such as gasoline or for heavy crude demand in the Gulf Coast. When this demand is not met by heavy Canadian supplies, it is met by heavy crude from Latin America and the Middle East.

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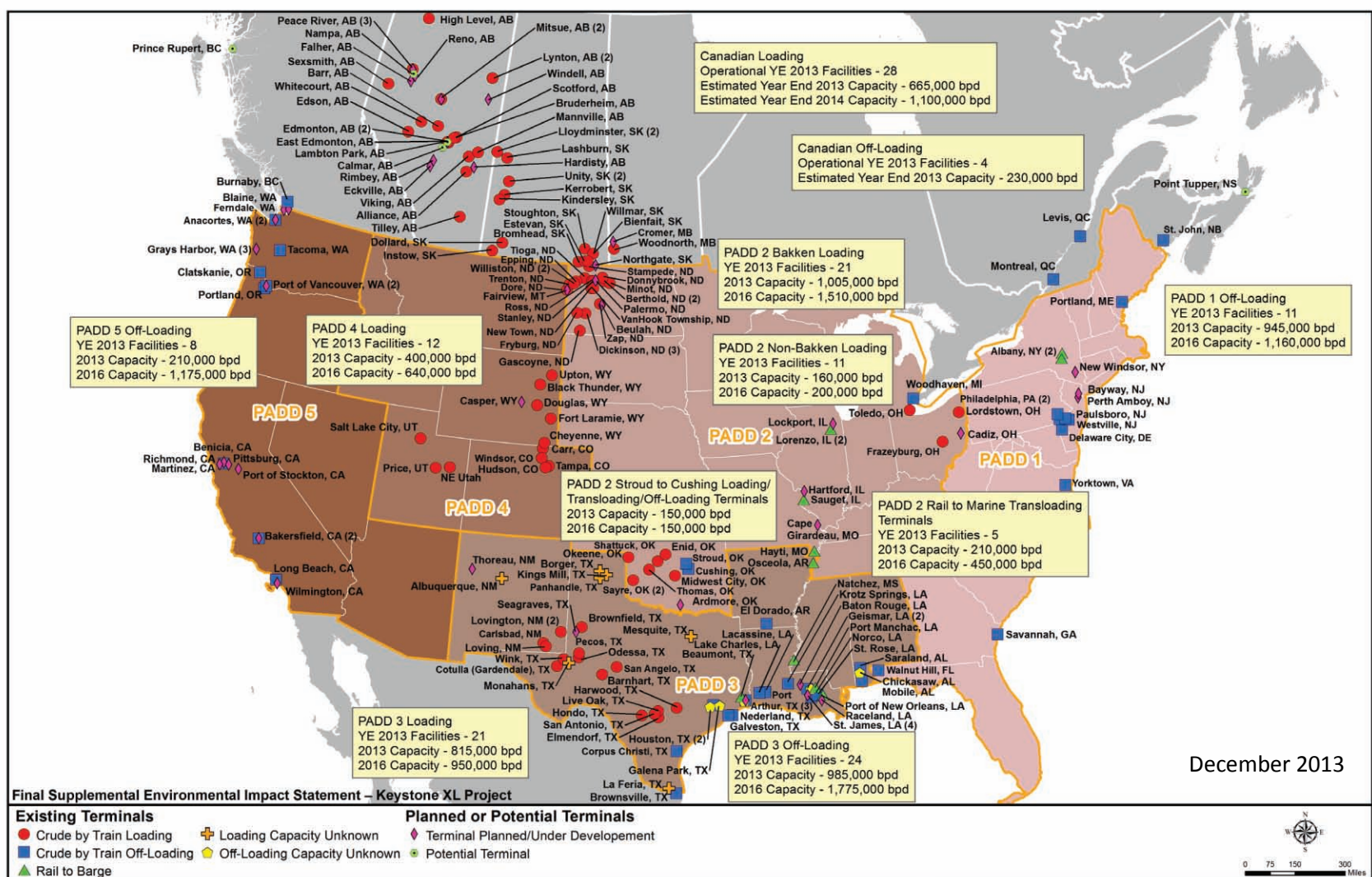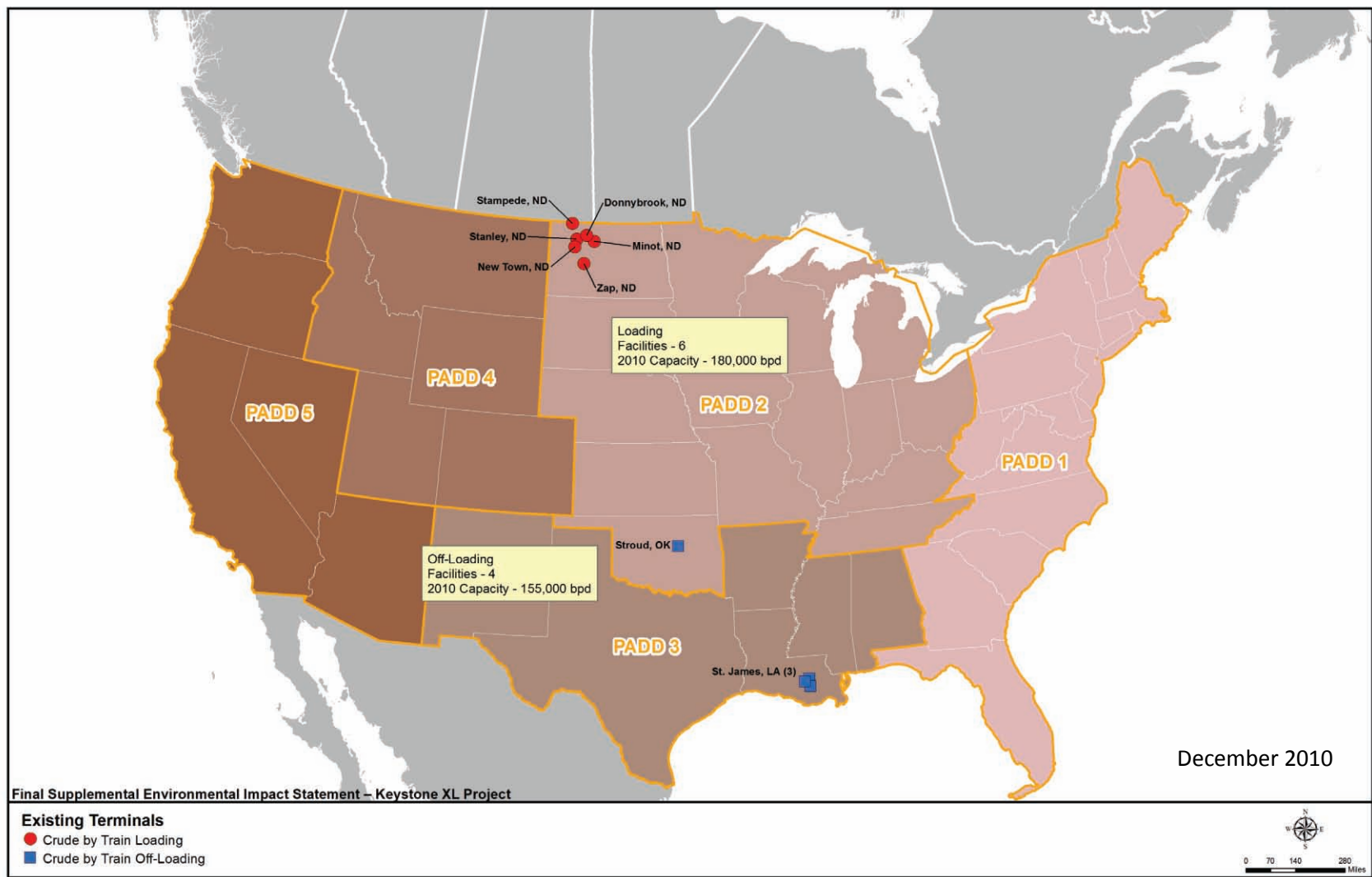
Source: Esri 2013. Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

Note: These estimates do not include a facility being constructed in Edmonton, Alberta, with a design capacity of 250,000 bpd (100,000 bpd expected to be operational by the end of 2014) that was announced immediately before the Final Supplemental EIS was completed.

**Figure 1.4.1-2      Crude by Train Loading and Off-Loading Facilities in 2010 (top map) and 2013 (bottom map)**

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Conclusions about the potential effects of pipeline constraints on production levels were informed by comparing modeled oil prices to the prices that would be required to support expected levels of oil sands capacity growth. Figure 1.4.1-3 illustrates existing oil sands capacity, the estimated supply costs of announced capacity, and the capacity growth that will be required to meet EIA and Canadian Association of Petroleum Producers (CAPP) production projections. Projected prices generally exceed supply costs for the projects responsible for future oil sands production growth. Modeling results indicate that severe pipeline constraints reduce the prices received by bitumen producers by up to $8 per barrel, but not enough to curtail most oil sands growth plans or to shut in existing production (based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios). These conclusions are based on conservative assumptions about rail costs, which likely overstate the cost penalty producers pay for shipping by rail if more economical methods currently under consideration to ship bitumen by rail are utilized.
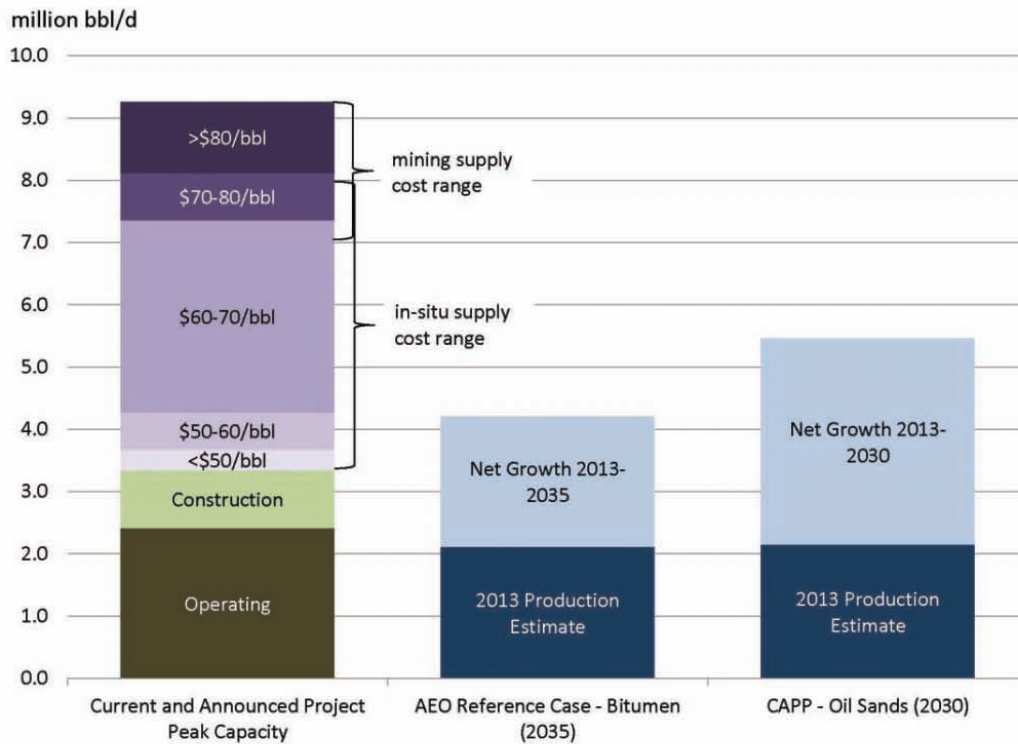


Source: EIA 2013a, CAPP 2013a, Oil Sands Developers Group (OSDG) 2013, internal analysis

Notes: WTI = West Texas Intermediate, $/bbl = dollars per barrel

**Figure 1.4.1-3        Oil Sands Supply Costs (WTI-Equivalent $/bbl), Project Capacity, and Production Projections**

Several analysts and financial institutions have stated that denying the proposed Project would have significant impacts on oil sands production. To the extent that other assessments appear to differ from the analysis in this report, they typically do so because they have different focuses, near-term time scales, production expectations, and/or include less detailed data and analysis about rail than this report. While short-term physical transportation constraints introduce uncertainty to industry outlooks over the next decade, new data and analysis in the market analysis section indicate that rail will likely be able to accommodate new production if new pipelines are delayed or not constructed.

Over the long term, lower-than-expected oil prices could affect the outlook for oil sands production, and in certain scenarios higher transportation costs resulting from pipeline constraints could exacerbate the impacts of low prices. The primary assumptions required to create conditions under which production growth would slow due to transportation constraints include: that prices persist below current or most projected levels in the long run; and all new and expanded Canadian and cross-border pipeline capacity, beyond just the proposed Project, is not constructed.

Above approximately $75 per barrel (West Texas Intermediate [WTI]-equivalent), revenues to oil sands producers are likely to remain above the long-run supply costs of most projects responsible for expected levels of oil sands production growth. Transport penalties could reduce the returns to producers and, as with any increase in supply costs, potentially affect investment decisions about individual projects on the margins. However, at these prices, enough relatively low-cost in situ projects are under development that baseline production projections would likely be met even with constraints on new pipeline capacity. Oil sands production is expected to be most sensitive to increased transport costs in a range of prices around $65 to 75 per barrel. Assuming prices fell in this range, higher transportation costs could have a substantial impact on oil sands production levels—possibly in excess of the capacity of the proposed Project—because many in situ projects are estimated to break even around these levels. Prices below this range would challenge the supply costs of many projects, regardless of pipeline constraints, but higher transport costs could further curtail production.

Oil prices are volatile, particularly over the short term, and long-term trends, which drive investment decisions, are difficult to predict. Specific supply cost thresholds, Canadian production growth forecasts, and the amount of new capacity needed to meet them are uncertain. As a result, the price threshold above which pipeline constraints are likely to have a limited impact on future production levels could change if supply costs or production expectations prove different than estimated in this analysis.

The dominant drivers of oil sands development are more global than any single infrastructural project. Oil sands production and investment could slow or accelerate depending on oil price trends, regulations, and technological developments, but the potential effects of those factors on the industry's rate of expansion should not be conflated with the more limited effects of individual pipelines.

### 1.4.1.4    Previous Analysis

The assessment of the potential market impact of the previously proposed Keystone XL Project was released in the August 26, 2011, Final EIS document. That assessment of the petroleum market drew on several studies, including one commissioned by the U.S. Department of Energy (USDOE) Office of Policy and International Affairs. The USDOE contracted with EnSys Energy and Systems, Inc. (EnSys) to develop a study of different North American crude oil pipeline scenarios through 2030 using EnSys's World Oil Refining Logistics & Demand (WORLD) model.[1] The conclusions included the following:

- There was commercial demand for WCSB heavy crude oil in the Gulf Coast. The demand identified by the EnSys 2010 Assessment was sufficiently high that were a permit for the Keystone XL pipeline, as then proposed, denied, the market would likely respond by adding broadly comparable transport capacity over time. The EnSys 2010 Assessment forecasted that the demand for WCSB heavy crude from the oil sands would be such that irrespective of whether a permit for the Keystone XL pipeline, as then proposed, was granted, transport capacity in excess of the Keystone XL pipeline would likely be built.

- In a situation in which the industry and market react based on normal commercial incentives, neither the production rate in the oil sands nor refining activities in the Gulf Coast would change substantially based on whether Keystone XL, as then proposed, was built.

- The 2010 EnSys report found the production rate in the oil sands was only substantially reduced in scenarios that assumed all pipeline transport capacity was frozen at 2010 levels through 2030. The scenario also assumed that incremental non-pipeline transport capacity (such as rail or tanker) was not available. The EnSys 2010 report concluded that a *No Expansion* scenario had a low probability of occurring. Nonetheless, to better assess the No Expansion scenario analyzed by EnSys in 2010, the Department and the USDOE commissioned EnSys to further examine the likelihood of the No Expansion scenario, including assessing in greater detail the potential of non-pipeline transportation of crude oil. In the 2011 No Expansion Update, EnSys concluded that even if there were no new pipelines added beyond those existing in 2010, rail supported by barge and tanker, as well as expansions to refining/upgrading in Canada, could accommodate projected oil sands production.

Other sources consulted in preparing the 2011 Final EIS included input from experts at the USDOE, information from industry associations (CAPP) and private consulting companies such as Purvin & Gertz, IHS Cambridge Energy Research Associates, Inc. (IHS CERA), Hart Energy, and ICF International, as well as the numerous comments received from the public. Taking account of all of the relevant information, the 2011 Final EIS concluded that the proposed Project is unlikely to significantly affect the rate of extraction in the oil sands or in U.S. refining

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[1] EnSys's WORLD model provides an integrated analysis and projection of the global petroleum industry that encompasses total liquids, captures the effects of developments, changes, and interactions between regions, and projects the economics and activities of refining crude oils and products. WORLD has been used for DOE's Office of Strategic Petroleum Reserve since 1987, and has been applied in analyses for many organizations, including the EIA, U.S. Environmental Protection Agency, the American Petroleum Institute (API), the World Bank, the Organization of the Petroleum Exporting Countries (OPEC) Secretariat, the International Maritime Organization, Bloomberg, and major and specialty oil and chemical companies.

activities. The Final EIS nonetheless, as a matter of policy, included information about the environmental impacts associated with extraction of crude oil in the oil sands, particularly an extensive analysis of the fact that on a lifecycle basis, transportation fuels produced from oil sands crudes emit more greenhouse gases than most conventional crude oils.[2]

The March 1, 2013, Draft Supplemental EIS examined petroleum market changes since the 2011 Final EIS was issued and whether these changes alter the conclusion of the 2011 Final EIS. It took into account increases for domestic oil production, decreases in expected demand, and changes in infrastructure, particularly the increase in oil transport by rail and found the following:

- While the increase in U.S. production of crude oil and the reduced U.S. demand for transportation fuels will likely reduce the demand for total U.S. crude oil imports, it is unlikely to reduce demand for heavy sour crude at Gulf Coast refineries. Additionally, as was projected in the 2011 Final EIS, the midstream industry is showing it is capable of developing alternative capacity to move WCSB (and Bakken and Midcontinent) crudes to markets in the event the proposed Project is not built. Specifically, alternative pipeline capacity is being developed that would support WCSB crude oil movements to U.S. and foreign markets, and also that rail was available to transport large volumes of crude oil to East, West, and Gulf Coast markets as a viable alternative to pipelines. In addition, projected crude oil prices are sufficient to support production of oil sands (and U.S. tight oil[3]). Rail and supporting non-pipeline modes should be capable, as was projected in 2011, of providing the capacity needed to transport all incremental western Canadian and Bakken crude oil production to markets if there were no additional pipeline projects approved.

- Approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the United States. Limitations on pipeline transport would force more crude oil to be transported via other modes of transportation, such as rail, which would probably (but not certainly) be more expensive. Longer term limitations also depend upon whether pipeline projects that are located exclusively in Canada proceed (such as the proposed Northern Gateway, the Trans Mountain expansion, and the TransCanada Corporation [TransCanada] proposal to ship crude oil east to Ontario on a converted natural gas pipeline). The Draft Supplemental EIS estimated that if all such pipeline capacity were restricted in the medium-to-long term, the incremental increase in cost of the non-pipeline transport options could result in a decrease in production from the oil sands, perhaps 90,000 to 210,000 bpd (approximately 2 to 4 percent) by 2030. The Draft Supplemental EIS also estimated that if the proposed Project were denied but other proposed new and expanded pipelines go forward, the incremental decrease in production could be approximately 20,000 to 30,000 bpd (from 0.4 to 0.6 percent of total WCSB production) by 2030.

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[2] This information and analysis is updated in this Final Supplemental EIS in Section 4.14, Greenhouse Gases and Climate Change.

[3] Tight oil or shale oil refers to oil found in low-permeability and low-porosity reservoirs, typically shale. Bakken crude from the Williston Basin in North Dakota and Montana is considered tight oil. The technology of extracting crude oil from tight rock formations has only recently been exploited at scale, but produces and supplies large quantities of crude oil into the domestic market.

As in 2011, the analysis in the Draft Supplemental EIS again was informed by consultation with experts from USDOE and information from industry associations such as CAPP and private consulting companies such as EnSys, Hart Energy, and ICF International. The Draft Supplemental EIS also relied on a January 2013 memorandum from the Administrator of the EIA (see Appendix C, Supplemental Information to Market Analysis) that analyzed some of the key issues also presented in this section.

In response to public and agency comments on the Draft Supplemental EIS, this Final Supplemental EIS has updated and expanded its analysis, including on oil sands supply costs, rail transport costs, the EnSys modeling, and expected impacts on production.

## 1.4.2    Oil Market Conditions[4]

### 1.4.2.1    Global Oil Market Context

The United States is part of a globally integrated oil market. Crude oil makes up roughly 75 million bpd out of a roughly 90 million bpd total oil market.[5] More than 60 percent of the world's oil is traded internationally.[6] In 2012, the United States accounted for 20 percent of global oil consumption. Expectations for oil market growth vary, with many projecting that global consumption will grow to 100 million bpd or more by 2035.

Supply and demand trends will drive long-term prices in this global market. Due to the integrated nature of the global oil market, oil prices tend to move together. Nonetheless, benchmark prices may differ due to quality discounts and transportation costs. The supply and demand for oil are relatively price inelastic (unresponsive to price changes), at least in the short run. Exogenous shocks to demand and/or supply will therefore translate into relatively large price changes.

The United States and other members of the Organization for Economic Cooperation and Development (OECD), a group of the world's advanced economies, consumed just over half of the world's liquid fuels in 2012.[7] OECD consumption is not anticipated to grow substantially, if at all, over the foreseeable future due to efficiency policies, modest economic growth driven by non-industrial sectors, and generally because many of the energy-intensive needs of OECD consumers are already being met.

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[4] This section describes oil market conditions using historical data and projections available as of November 15, 2013. The Early Release of the Reference Case from the 2014 AEO occurred after this section was prepared. AEO2014 Reference Case projections update the AEO2013 projections referenced here, but remain substantially similar with regard to the issues considered. AEO2014 Reference Case projections generally fall within the range of the AEO2013 cases assessed in this report. The full version of the AEO2014 will not be released until Spring 2014.

[5] Global crude oil supply in 2012 was roughly 75 million bpd according to the International Energy Agency (IEA) Monthly Oil Market Report (IEA 2012a). That crude must be refined into fuels, which can then be consumed as is discussed below. A volumetric increase that occurs as crudes are broken down into fuels means that 75 million barrels of crude corresponds with a slightly greater amount of liquid fuels. Apart from crude-based fuels, other liquid fuels that help meet global oil demand include natural gas liquids, biofuels, and coal or gas transformed into liquid fuels.

[6] Globally traded oil amounted to 62 percent of global consumption in 2012, according to the BP Statistical Review of World Energy (BP 2013).

[7] These global trends and those discussed below reflect widely held expectations, including in the EIA AEO and International Energy Outlook, the IEA World Energy Outlook (WEO), and other long-term oil market projections.

Most oil consumption growth going forward is likely to come from rapid economic development in non-OECD regions. Key economies driving energy demand growth include China, India, and the countries of the Middle East.

Supply to meet this rising demand will come from a diverse set of resources around the world. Some of the largest sources of additional supply through 2035, according to many analysts, include unconventional oil resources—such as those trapped in U.S. shale or the offshore subsalt in Brazil—as well as the large conventional oil resources of the Middle East. Many analysts also expect substantial growth in Canada's oil sands. The prospects for this are discussed more fully throughout this document.

### 1.4.2.2    U.S. Oil Market Overview

The subsection provides context and background on U.S. oil market conditions as of 2013. In general, U.S. domestic crude oil and related liquid fuels production has increased in recent years. Consumption fell from 2007 to 2009 and has averaged between 18.5 to 19.2 million bpd since then. The United States consumed 18.6 million bpd of liquid fuels in 2012, primarily fuels refined from crude oil (see Table 1.4.1). This demand was met through a combination of domestic crude production, other domestic liquid fuels production, crude imports, and imports of non-crude liquids (including refined products). Of the imported crude, 2.4 million bpd came from Canada.

For data collection and analysis, the 50 U.S. states and the District of Columbia are divided into five regions called Petroleum Administration for Defense Districts (PADDs) (see Figure 1.4.2-1).[8] The supply and refining profiles of the PADDs differ significantly. For example, PADD 3 and PADD 1 both import significant amounts of crude oil. PADD 3 imports a wider variety of crude oils, including over 2 million bpd of heavy crude oil, whereas PADD 1 imports are almost entirely of light and medium crude oils. Refiners in different PADDs largely serve the market for transportation fuels and other products in that PADD, but there are inter-PADD transfers and refiners in the different PADDs are in competition with one another. In particular, PADD 3 refiners ship refined products to both PADD 1 and PADD 2. Additional information about the PADDs, including their refining and supply profiles, is included in Section 2.0 of Appendix C, Supplemental Information to Market Analysis.

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[8] The origin of PADDs dates from World War II when it was necessary to allocate domestic petroleum supplies. The boundaries between the different PADDs do not reflect either a regulatory or a business requirement, but provide the EIA with a mechanism to consistently report the key attributes of the petroleum industry (inventory, crude processing levels, prices, consumption, etc.) over various time periods.

**Table 1.4-1    U.S. Liquid Fuel Supply-Demand Balance, 2012 (million bpd)**

| | |
|---|---|
| **U.S. Liquid Fuels Consumption** | **18.6** |
| Gasoline | 8.7 |
| Distillate Fuel Oil/Diesel | 3.7 |
| Other | 6.1 |
| **Crude Oil Supply** | **14.9** |
| Domestic crude production | 6.5 |
| Net crude imports | 8.4 |
| Gross Crude Imports | 8.5 |
| from Canada | 2.4 |
| from Other | 6.1 |
| Exports to Canada | -0.1 |
| **Other Supply** | **3.4** |
| Natural Gas Liquids Production | 2.4 |
| Refinery Processing Gain[a] | 1.1 |
| Renewables and Oxygenates Production | 1.0 |
| Net Petroleum Product Imports | -1.0 |
| Gross Imports | 2.1 |
| Imports from Canada | 0.5 |
| Imports from Others | 1.6 |
| Gross Exports | -3.1 |
| Exports to Canada | -0.3 |
| Exports to Others | -2.8 |

Source: EIA 2013a.

Notes: May not sum due to rounding. Inventory withdrawal and adjustments amounting to 0.3 million bpd are not listed. Exports are listed as negative values. U.S. origin crude is only exported to Canada.

[a] Refinery processing gain is the volumetric amount by which total output (refined products) is greater than input (crude oil) for a given period of time. According to EIA's definition, "this difference is due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed".
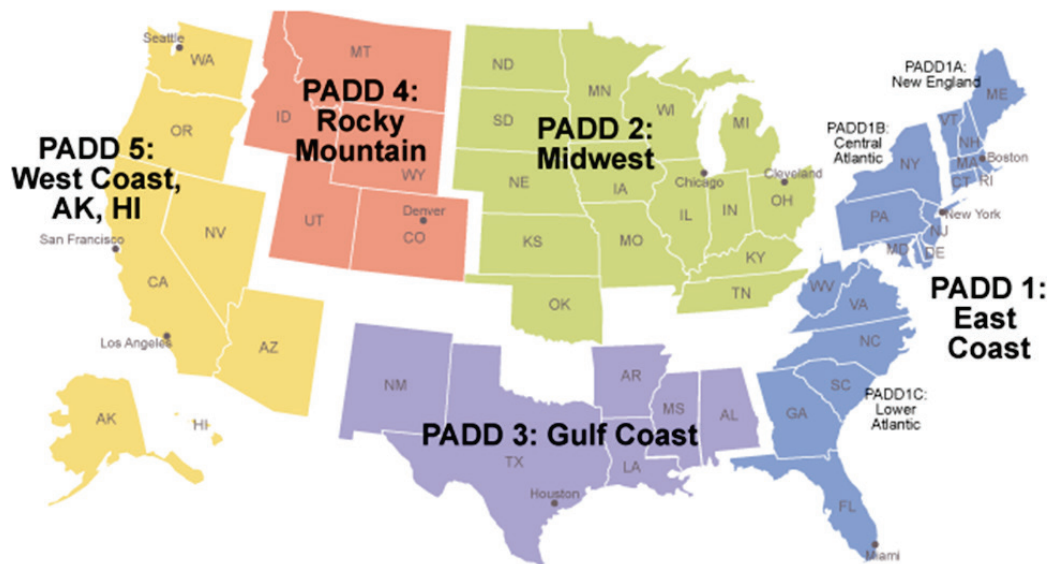


Source: EIA 2012b

**Figure 1.4.2-1        Petroleum Administration for Defense Districts (PADD) Locations**
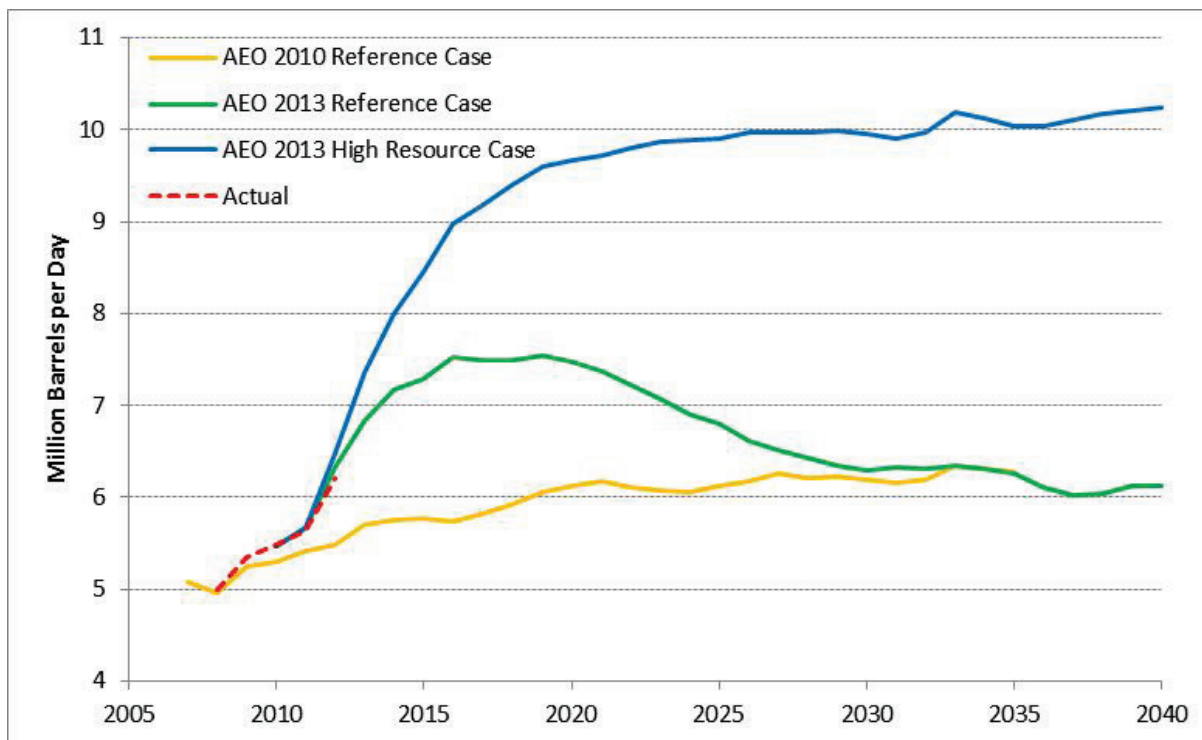
### *1.4.2.3    U.S. Crude Oil Production*

The 2011 Final EIS was developed contemporaneously with the beginnings of strong growth in domestic light crude oil supply from shale, or tight oil, formations.[9] Domestic production of crude oil has increased significantly, from approximately 5.5 million bpd in 2010 to 6.5 million bpd in 2012 and 7.5 million bpd by mid-2013. In addition to contributing to significant discounts on the price of inland crude because of logistics constraints,[10] there has been a sharp reduction in U.S. imports of crude oil, particularly light sweet crude oil.

Domestic crude production is expected to grow further in the coming years, but there is uncertainty about how high supplies will go and how long they will remain elevated. The 2013 EIA AEO Reference Case projects domestic crude output will peak at 7.5 million bpd in 2019 and then decline to 6 million bpd by 2035 (see Figure 1.4.2-2). EIA's High Oil and Gas Resources case, which assumes higher recovery rates from tight oil resources, projects crude production rises to 10 million bpd by 2025 and remains at that level through 2035.[11]

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[9] U.S. tight oil sources include the Bakken in the Williston Basin of North Dakota and Montana; the Eagle Ford in South Texas; the Permian in West Texas and New Mexico; the Mississippian Lime in Oklahoma and Kansas; the Tuscaloosa Marine Shale in Louisiana; the Monterey and Kreyenhagen in California; the Avalon, Bone Springs, and Wolfberry in the Permian Basin of Texas and New Mexico; the Niobrara in Colorado and Wyoming; and the Utica shale in Ohio and Pennsylvania. Among these, the Bakken and Eagle Ford have been the main sources of supply growth to date.

[10] The discount for PADD 2 crude did not translate to a discount for refined products in PADD 2. The discount for PADD 2 crude was due to infrastructure bottlenecks for crude transport from PADD 2 to PADD 3 and elsewhere. Inter-regional refined products movements kept prices for gasoline and other refined products in PADD 2 in line with their historic relationship with products prices elsewhere in the United States. The resulting widened differential between PADD 2 crude and products prices benefited PADD 2 refiners. See Section 1.4.6.1, Crude Price Differences and Gasoline Prices.

[11] "In the High Oil and Gas Resources case, resource assumptions are adjusted to give continued increase in domestic crude oil production after 2020, reaching over 10 million barrels per day. This case includes:
(1) 100 percent higher EUR [estimated ultimate recovery] per tight oil, tight gas, and shale gas well than in the Reference case and a maximum well spacing of 40 acres, to reflect the possibility that additional layers of low-permeability zones are identified and developed, compared with well spacing that ranges from 20 to 406 acres with an average of 100 acres in the Reference case; (2) kerogen development reaching 135,000 barrels per day in 2025; (3) tight oil development in Alaska increasing the total Alaska TRR [technically recoverable resources] by 1.9 billion barrels; and (4) 50 percent higher technically recoverable undiscovered resources in Alaska and the offshore lower 48 states than in the Reference case. Additionally, a few offshore Alaska fields are assumed to be discovered and thus developed earlier than in the Reference case. Given the higher natural gas resource in this case, the maximum penetration rate for GTL [gas-to-liquids] was increased to 10 percent per year, compared to a rate of 5 percent per year in the Reference case." (EIA 2013a).

Source: EIA 2013a

**Figure 1.4.2-2       AEO Forecasts for Domestic Crude and Condensate Production**

Other forecasts also reflect a wide range of expectations. The 2013 International Energy Agency (IEA) World Energy Outlook (WEO) expects U.S. crude oil production to climb until 2025, reaching 8.8 million bpd before falling to 8.6 million bpd by 2035.[12] Oil industry consultant PIRA Energy Group expects U.S. crude oil production to rise to 11.6 million bpd by 2025 before starting to decline, reaching 11.4 million bpd by 2030.[13] Investment research firm Sanford C. Bernstein expects crude production to reach 8.1 million bpd in 2019 and then decline to 5.6 million bpd by 2030.[14]

While expected peak output levels and years vary, most other forecasts—like the Reference Case—expect U.S. production growth to be driven by light, tight oil and to peak between 2019 and 2025 before starting to decline. In contrast, EIA's High Resource Case projects relatively flat production at elevated levels after 2020. Uncertainty about future technology, geology, development costs, oil prices, policy, and other factors drive differences in expectations.

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[12] Data from IEA analysis for the 2012 WEO. Timur Gould, personal communication, December 5, 2013.

[13] Victoria Watkins, personal communication, 2013.

[14] Helin Shiah, personal communication, December 2013.

### 1.4.2.4     U.S. Oil Consumption

U.S. liquid fuels consumption averaged 18.6 million bpd in 2012, down from a peak of 20.8 million bpd in 2005. As shown in Table 1.4-2, consumption declined across fuels, including gasoline. Economic weakness and efficiency improvements have contributed to the decline.

**Table 1.4-2     Fuels Consumption by Product (million bpd)**

| Product | 2005 | 2010 | 2012 |
|---------|------|------|------|
| NGLs and LRGs | 2.15 | 2.27 | 2.32 |
| Finished Motor Gasoline | 9.16 | 8.99 | 8.70 |
| Distillate Fuel Oil | 4.12 | 3.80 | 3.74 |
| Kerosene—Type Jet Fuel | 1.68 | 1.43 | 1.40 |
| Finished Aviation Gasoline | 0.02 | 0.02 | 0.01 |
| Residual Fuel Oil | 0.92 | 0.54 | 0.35 |
| Other Liquids | 0.01 | 0.01 | 0.08 |

Source: EIA 2013a

In EIA's Reference Case (EIA 2013a), consumption is expected to rise to 19.8 million bpd in 2019 and then fall, leveling off at 18.9 million bpd after 2030 (see Figure 1.4.2-3). Divergent trends across fuels would underlie aggregate consumption near today's levels: A 1.7 million bpd decline in gasoline consumption by 2035 is offset by rising demand for distillate fuel oil (primarily diesel), liquefied petroleum gases, and jet fuel (see Figures 1.4.2-4, 1.4.2-5, and 1.4.2-6). The Reference Case projections reflect improving efficiency, such as the Corporate Average Fuel Economy (CAFE) standards for model years 2012 through 2025, and slowing growth in vehicle miles traveled as a result of demographic changes. For an expanded discussion on efficiency improvements, see Section 2.2, Description of Alternatives.

In its Low/No Net Imports case, where the EIA makes assumptions that lead to lower oil demand,[15] EIA projects a smaller increase in consumption in this decade and then a decline after 2020, with consumption falling to around 17 million bpd by 2035. Most of the difference with the Reference Case is accounted for by lower projected gasoline and distillate fuel oil consumption due in large part to the Low/No Net Imports case assumption that vehicle miles traveled continually decline.

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[15] "In the Low/No Net Imports case, changes were made to various NEMS [National Energy Modeling System] modeling assumptions that, in comparison with the AEO 2013 reference case, resulted in higher domestic production of crude oil and natural gas, lower domestic liquid fuels demand, and higher domestic production of nonpetroleum liquids. The methodology used to achieve higher domestic crude production is the same as that used in the High Oil and Gas Resource case (described in the "Oil and gas supply cases" section above). Domestic liquid fuels demand was reduced by changes made in the Transportation Demand Module. As described in the "Transportation sector cases" section, this included the use of more optimistic assumptions about improvements in LDV [light-duty vehicle] fuel economy and reductions in LDV technology costs; lower VMT [vehicle miles travelled] due to changes in consumer behavior; an extension of the LDV CAFE standards beyond 2025 at an average annual rate of 1.4 percent through 2040; expanded market availability of LNG [liquified natural gas]/CNG [compressed natural gas] fuels for heavy-duty trucks, rail, and marine; and use of assumptions from the optimistic battery case (EIA 2012a) for electric vehicle battery and drivetrain costs. Within the LFMM [Liquid Fuels Market Module], the assumption for market penetration of biomass pyrolysis oils, CTL [carbon-to-liquids], and BTL [biomass-to-liquids] production was more optimistic. Also, initial assumptions associated with E85 availability and maximum penetration of E15 were set to be more optimistic, such that E85 availability was nearly three times the Reference case level in 2040, and E15 penetration was about 15 percent higher by 2040." (EIA 2013a).
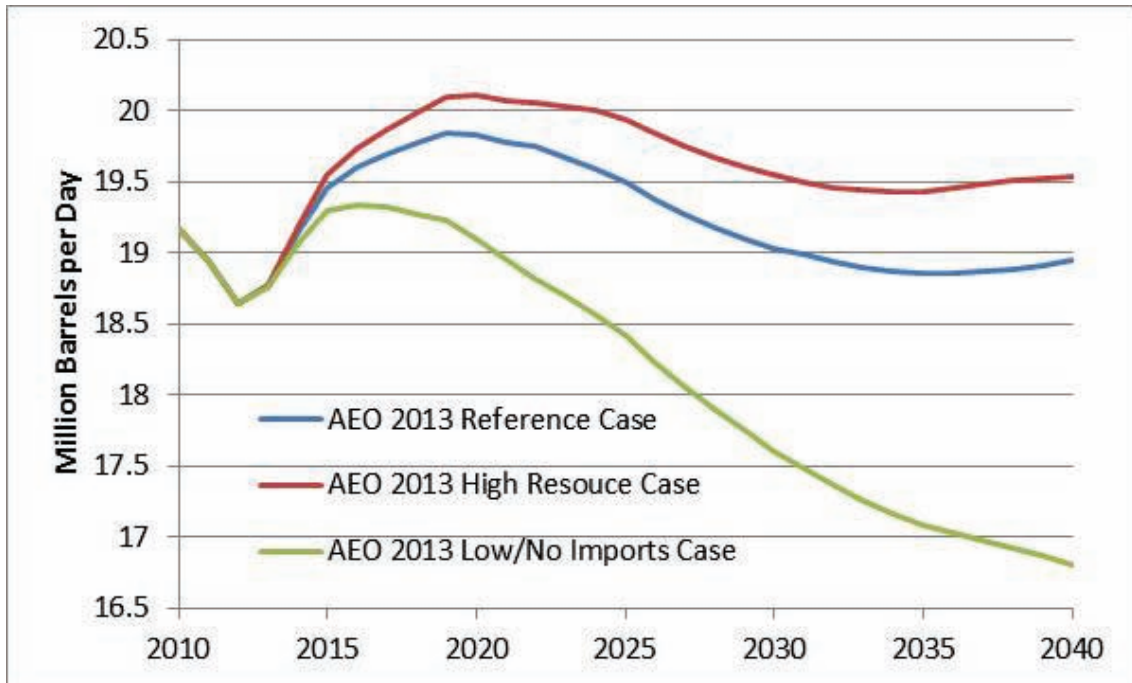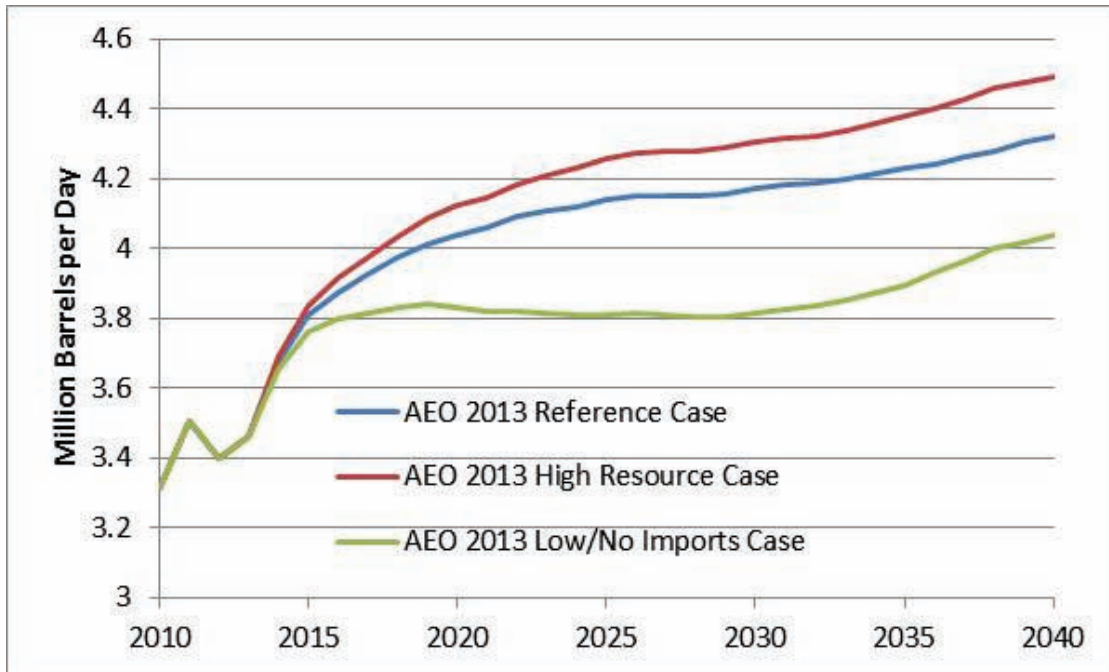
Source: EIA 2013a

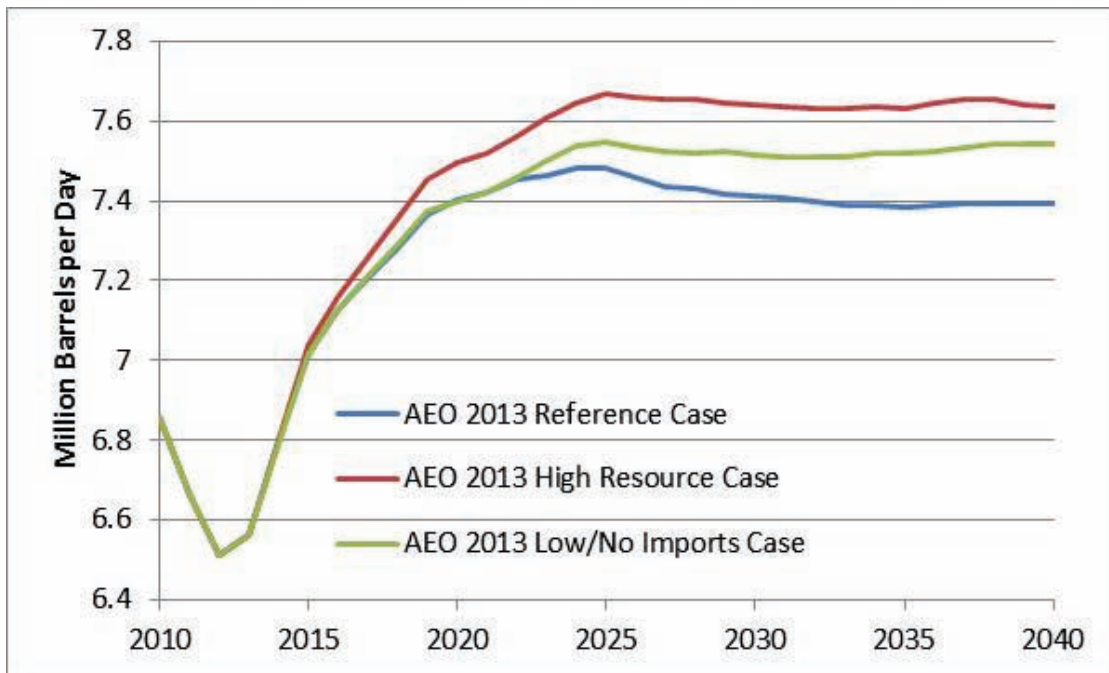**Figure 1.4.2-3          AEO Forecasts for U.S. Liquid Fuels Consumption**
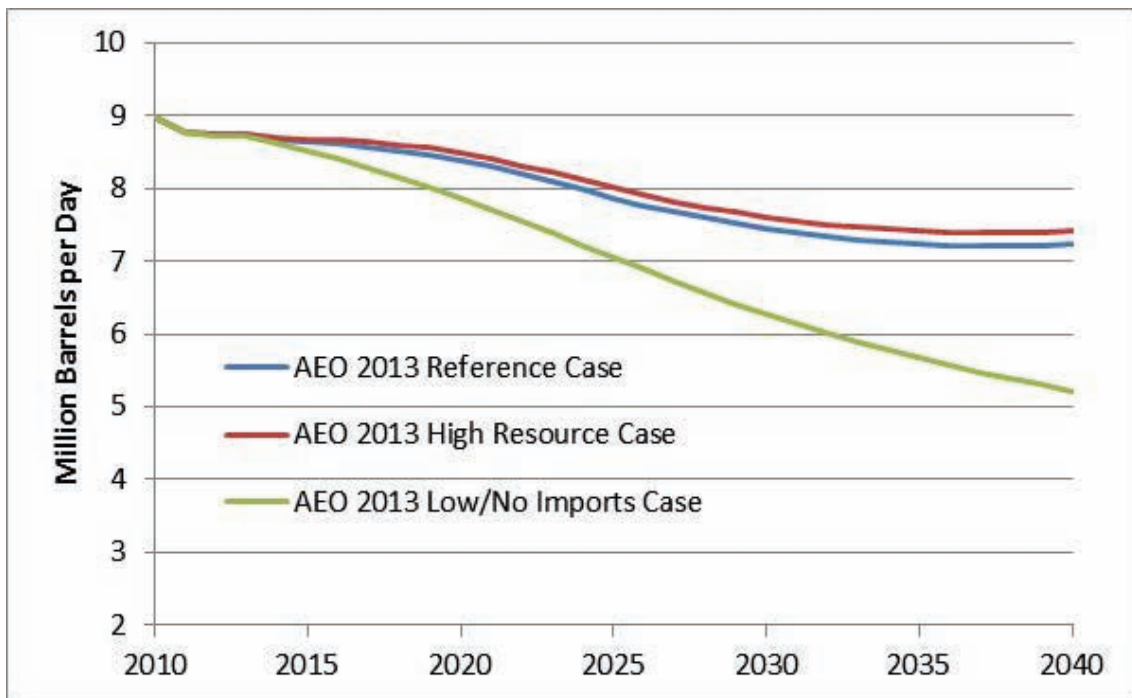


Source: EIA 2013a

**Figure 1.4.2-4          AEO Gasoline/E85 Consumption**

Source: EIA 2013a

**Figure 1.4.2-5            AEO Diesel Consumption**



Source: EIA 2013a

Note: Consumption of liquid fuels excluding gasoline, E85, and diesel is higher in the Low/No Imports Case than the Reference Case due primarily to differing assumptions about oil and natural gas production, which contributes to greater use of liquefied petroleum gases.

**Figure 1.4.2-6            Other Liquids Fuels Consumption (excluding Gas/E85, and Diesel)**

### 1.4.2.5    U.S. Refining

The petroleum products that make up the vast majority of U.S. and global oil consumption must be processed from crude oil in a refinery. Refineries break crude oil down into its various components, which then are selectively reconfigured into products. In 2012, the United States had 19.0 million bpd of crude distillation capacity, the simplest form of crude refining.[16] Crude distillation units (CDU) separate crude oil into fractions. These are then further processed and treated to produce finished fuels, some of which also contain blending components. Some U.S. refineries integrate CDUs with more complex processing units that can upgrade heavier fractions of crude oil coming from the CDU into more valuable fuels. More complex refining capacity such as catalytic cracking and coking units are concentrated in PADD 3 (see Table 1.4-3, Figures 1.4.2-7, and 1.4.2-8 below), which has traditionally imported heavy crude from sources including Venezuela and Mexico.

Cokers are the downstream processing unit necessary to process the heaviest fractions from crude oils, called residuum. The United States has over half of the world's coking[17] capacity, and the majority of this capacity is at Gulf Coast refineries (1.6 million bpd capacity in PADD 3 out of 2.85 million bpd nationwide in 2012), according to EIA data.

Refineries build units in configurations and combinations that run optimally with certain kinds of crudes. Lighter crudes, or those with higher American Petroleum Institute (API) gravity[18], yield historically more valuable products, such as gasoline and diesel, with less processing than heavier crudes. Heavier crudes yield relatively more low-value products through distillation, which can then be upgraded to lighter, more valuable products through more complex refining processes described briefly above. As a result of processing costs and/or the value of product yields, heavier crudes trade at a discount to lighter crudes. A refinery can be built to process a heavier slate of crudes depending on what units are built and how they are configured to run together. A refiner can also invest in units which can remove sulfur from oil, allowing a refinery to process higher sulfur crude oils and still produce fuels that meet U.S. sulfur limits. The configuration of a refinery is an integrated system which has some flexibility to alter the types of crudes run with regard to API gravity, sulfur content, and other characteristics. However, large changes in the crude slate require investment in new units and the reconfiguration of existing operations; hence refiners have an incentive to process the crude oil slate for which they are configured.

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[16] For data availability reasons, this figure and the data in Table 1.4-3 are based on "barrels per stream day," which according to EIA is "The maximum number of barrels of input that a distillation facility can process within a 24-hour period when running at full capacity under optimal crude and product slate conditions." The United States had 17.3 million bpd of atmospheric crude distillation capacity in terms of barrels per calendar day, or the amount of input that a distillation facility can process under usual operating conditions.

[17] Coking is a refinery operation that is used to process heavy crude oil. The process upgrades material into higher value products and produces petroleum coke (EIA 2013b).

[18] API gravity is the API's scale for expressing the gravity or density of crude oil (among other liquids). Water has an API gravity of 10. There is a range of cutoff points that are used to specify heavy crude oil. Generally, an API gravity of around 28 is considered the cutoff for the lightest heavy crude that is suited to processing in a *deep conversion* refinery, one that usually in the United States has a coker to upgrade the heaviest residuum fractions to light products. Nonetheless, a common cutoff is 25 API and that is what is used in this analysis. For comparison, Brent crude has an API gravity of about 38 and WTI has an API gravity of around 40. Crude oils from shale range from an API gravity of around 38 (Bakken crude) to 45 (Eagle Ford crude). Diluted bitumen, or dilbit, has API gravity of around 20.

**Table 1.4-3     Refining Charge Capacity by Unit and PADD**

| (Barrels per Stream Day) | Atmospheric Distillation Capacity[a] | Vacuum Distillation[b] | Coking/ Thermal Cracking[c] | Catalytic Cracking[d] | Catalytic Reforming[e] | Hydrotreating/ Desulfurization[f] | Fuels Solvent Deasphalting[g] |
|---|---|---|---|---|---|---|---|
| PADD 1 | 1,361,700 | 586,400 | 81,500 | 573,500 | 263,950 | 1,092,500 | 22,000 |
| PADD 2 | 4,063,188 | 1,703,312 | 502,276 | 1,322,501 | 906,807 | 3,601,746 | 17,850 |
| PADD 3 | 9,664,455 | 4,781,775 | 1,608,880 | 3,169,105 | 1,845,790 | 9,030,080 | 241,400 |
| PADD 4 | 672,300 | 240,600 | 89,300 | 205,350 | 133,600 | 563,660 | 6,000 |
| PADD 5 | 3,210,000 | 1,626,006 | 595,500 | 903,300 | 608,200 | 2,572,200 | 80,300 |
| Total | 18,971,643 | 8,938,093 | 2,877,456 | 6,173,756 | 3,758,347 | 16,860,186 | 367,550 |

Source: EIA 2013d

[a] The refining process of separating crude oil components at atmospheric pressure by heating to temperatures of about 600 degrees to 750 degrees Fahrenheit (depending on the nature of the crude oil and desired products) and subsequent condensing of the fractions by cooling.
[b] Distillation under reduced pressure (less the atmospheric), which lowers the boiling temperature of the liquid being distilled. This technique with its relatively low temperatures prevents cracking or decomposition of the charge stock.
[c] Thermal cracking is a refining process in which heat and pressure are used to break down, rearrange, or combine hydrocarbon molecules. Thermal cracking includes gas oil, visbreaking, fluid coking, delayed coking, and other thermal cracking processes. Coking describes a thermal refining processes used to produce fuel gas, gasoline blendstocks, distillates, and petroleum coke from the heavier products of atmospheric and vacuum distillation. This category is primarily coking units with 26,600 bpd of other units included.
[d] The refining process of breaking down the larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules. Catalytic cracking is accomplished by the use of a catalytic agent and is an effective process for increasing the yield of gasoline from crude oil. Catalytic cracking processes fresh feeds and recycled feeds. Includes fresh feed and recycle feed.
[e] A refining process using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules, thereby converting paraffinic and naphthenic type hydrocarbons (e.g., low octane gasoline boiling range fractions) into petrochemical feedstocks and higher octane stocks suitable for blending into finished gasoline.
[f] A refining process for treating petroleum fractions from atmospheric or vacuum distillation units (e.g., naphthas, middle distillates, reformer feeds, residual fuel oil, and heavy gas oil) and other petroleum (e.g., cat cracked naphtha, coker naphtha, gas oil, etc.) in the presence of catalysts and substantial quantities of hydrogen. Hydrotreating includes desulfurization, removal of substances (e.g., nitrogen compounds) that deactivate catalysts, conversion of olefins to paraffins to reduce gum formation in gasoline, and other processes to upgrade the quality of the fractions.
[g] A refining process for removing asphalt compounds from petroleum fractions, such as reduced crude oil. The recovered stream from this process is used to produce fuel products.
Note: Reference to total refining capacity is typically based on atmospheric distillation capacity. Definitions above from the EIA Glossary.
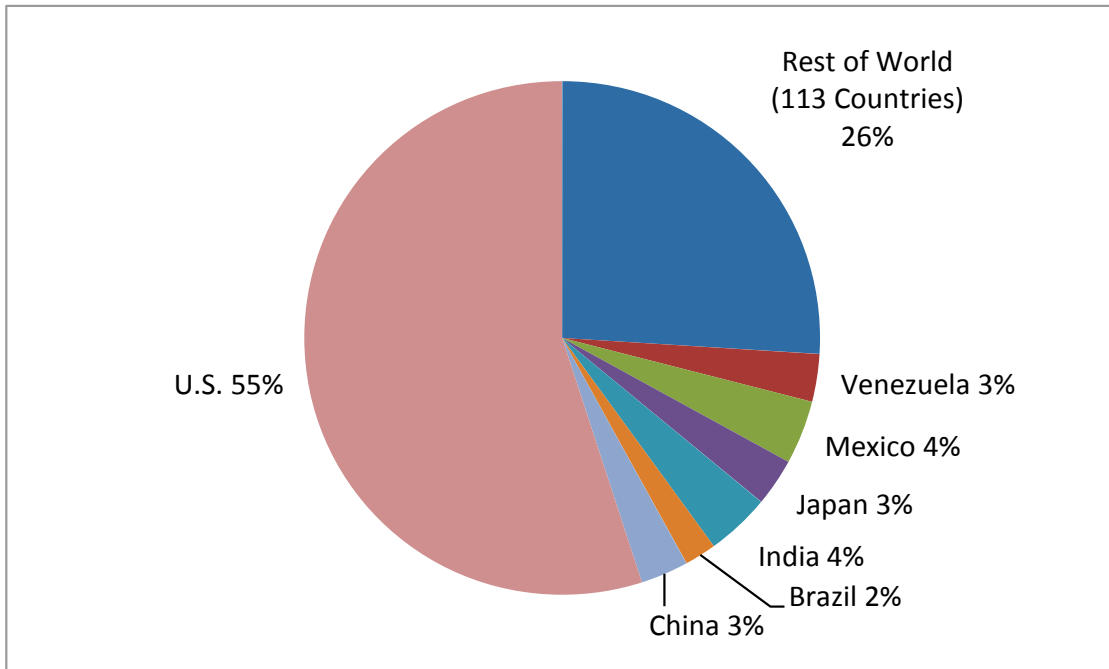
Source: Canadian Imperial Bank of Commerce (CIBC) 2012

**Figure 1.4.2-7        Distribution of Global Coking Capacity**
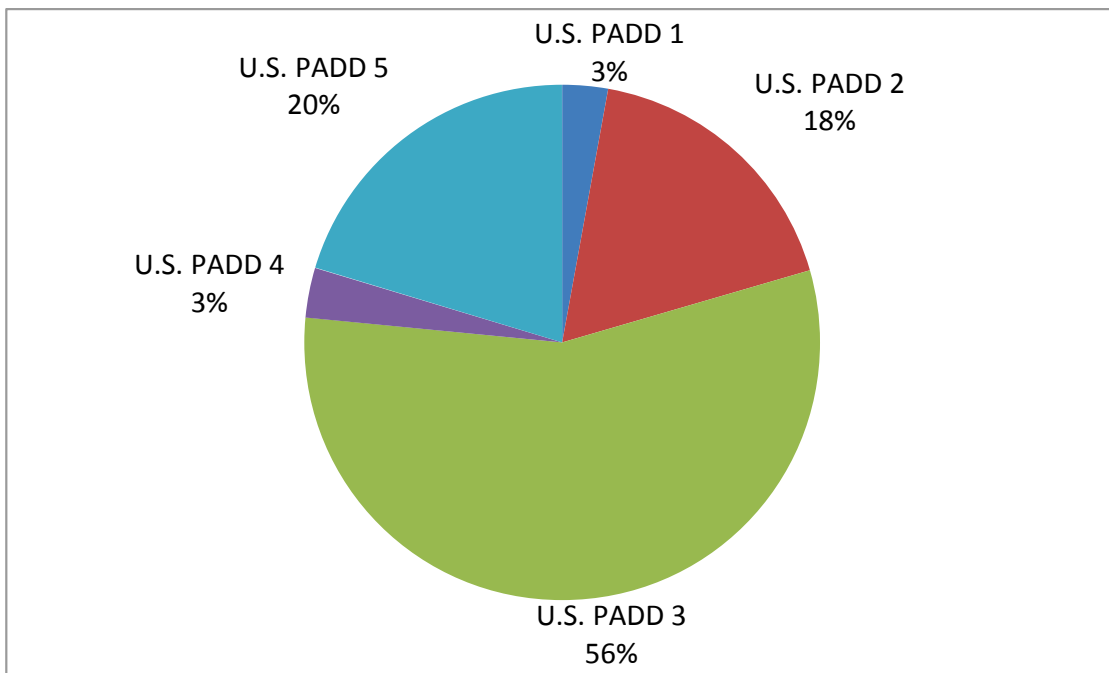


Source: EIA 2013a

**Figure 1.4.2-8        Distribution of U.S. Coking Capacity**

### *1.4.2.6    Demand for Heavy Imported Crude*

Table 1.4-4 shows heavy crude imports (25 API gravity and below) in the first half of 2013 for Gulf Coast area refiners that are in the immediate anticipated destination market for the proposed Project.[19] This table indicates that there are about 1.4 million bpd of heavy crude imports into refineries along the Gulf Coast area through Lake Charles, Louisiana. Actual heavy crude processing capacity is higher than current levels of heavy crude imports.

**Table 1.4-4    Proposed Project Destination Area Refiners Heavy Crude Processing, January to June 2013[a]**

| Refiner | Heavy Crude Imports (bpd) | Number of Refineries | Top 2 Import Sources of Heavy Crude |
|---|---|---|---|
| Valero Refining Co Texas LP | 315,022 | 3 | Mexico, Venezuela |
| CITGO Petroleum Corp | 255,376 | 2 | Venezuela, Angola |
| Houston Refining LP | 192,122 | 1 | Colombia, Venezuela |
| Phillips 66 Company | 175,260 | 2 | Venezuela, Mexico |
| Deer Park Refining LTD Partnership | 144,039 | 1 | Mexico, Venezuela |
| ExxonMobil Refining & Supply Co | 143,133 | 2 | Mexico, Colombia |
| Motiva Enterprises LLC | 80,923 | 1 | Venezuela, Brazil |
| Total Petrochemicals & Refining USA | 73,448 | 1 | Venezuela, Mexico |
| Marathon Petroleum Co LLC | 31,293 | 2 | Kuwait, Mexico |
| Pasadena Refining Systems Inc. | 5,309 | 1 | Angola |
| Total | 1,415,923 | 16 | |

Source: EIA Refinery Capacity Report (EIA 2013d). Data as of January 1, 2013; EIA Company Level Imports (EIA 2013c).

Note: Although Flint Hill Resources LP has a small coker and has imported heavy crude from Brazil from January to June, the coker is currently idling.

[a] This table includes all refineries importing heavy crude (<25 API) between Corpus Christi, Texas, and Lake Charles, Louisiana. In the eastern Gulf Coast area (New Orleans and Baton Rouge areas), over the same time period (January to June 2013) there were 17 refineries with combined total refining capacity of 3.01 million bpd, and these refineries imported 513,773 bpd of heavy crude.

Over the last five years, the average quality of crudes processed in U.S. refineries stopped declining, moving up slightly from 30.4 degrees API gravity in 2007 to 31.0 degrees API gravity in 2012 (see Figure 1.4.2-9).

Underlying this is a shift in sourcing for light versus heavy crudes. Rising domestic light crude production has backed out foreign imports of light crude oil. However, refiners optimized for crude slates that use heavy crudes still have demand for heavy crude and continue to meet that demand through imports. Figure 1.4.2-10 shows decreasing volumes of light crude imports while heavy crude imports remain robust. Refiners' preferences for heavier crudes appear to be enduring despite rising domestic light supplies. This reflects refinery optimization for certain kinds of crudes. Consequently, growing domestic light crude production is backing out (reducing) light imports, and may be blended with heavier crudes to back out medium grade imports.

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[19] Includes refineries importing heavy crude in the first half of 2013 between Corpus Christi and Lake Charles (i.e., not the New Orleans refinery sector).
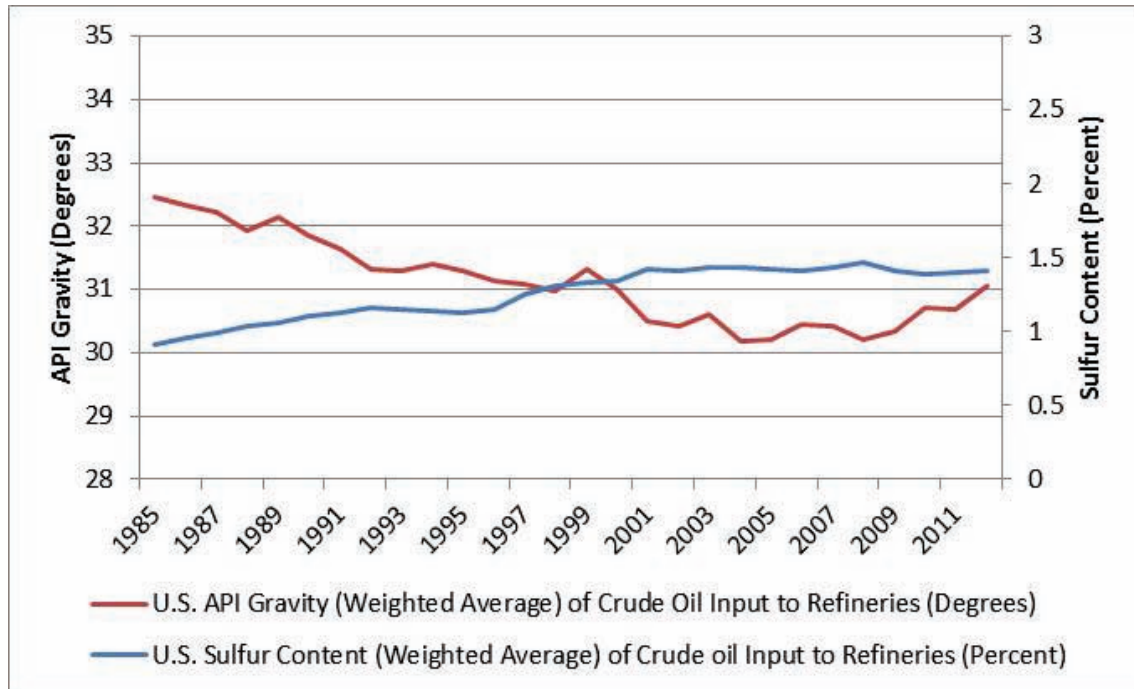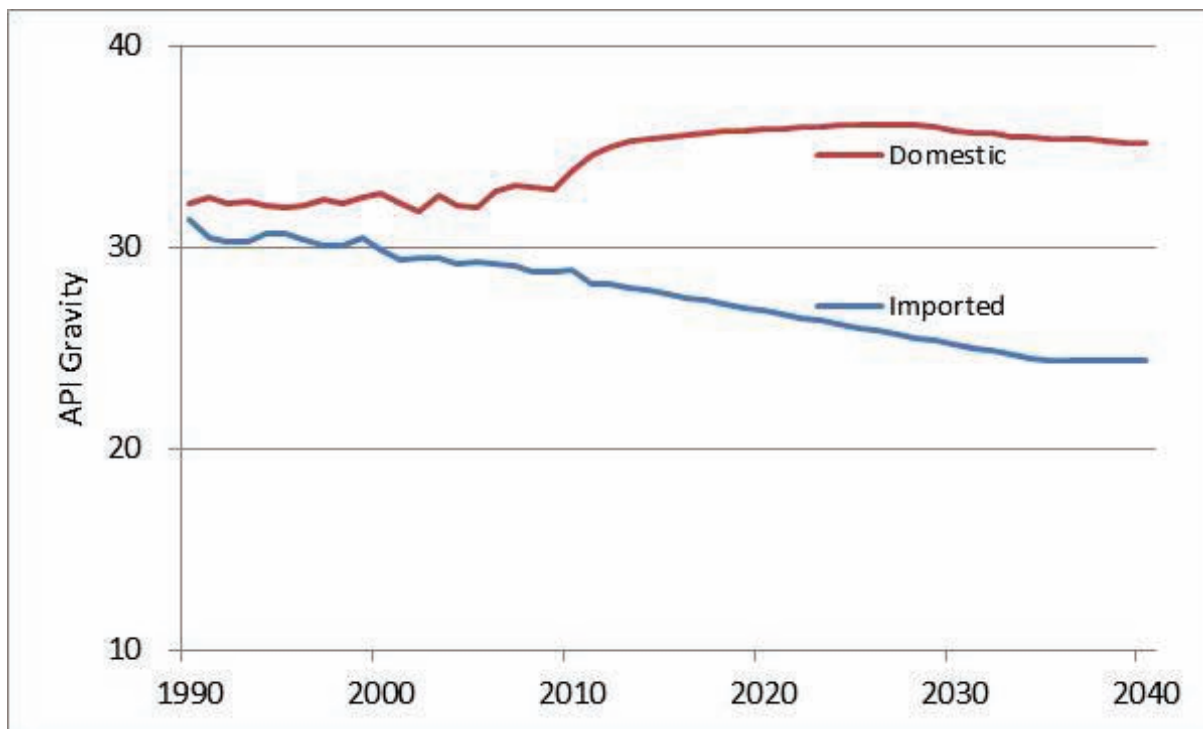
Source: EIA 2013a

**Figure 1.4.2-9          Average Quality of Crude Oil Input to Refineries**
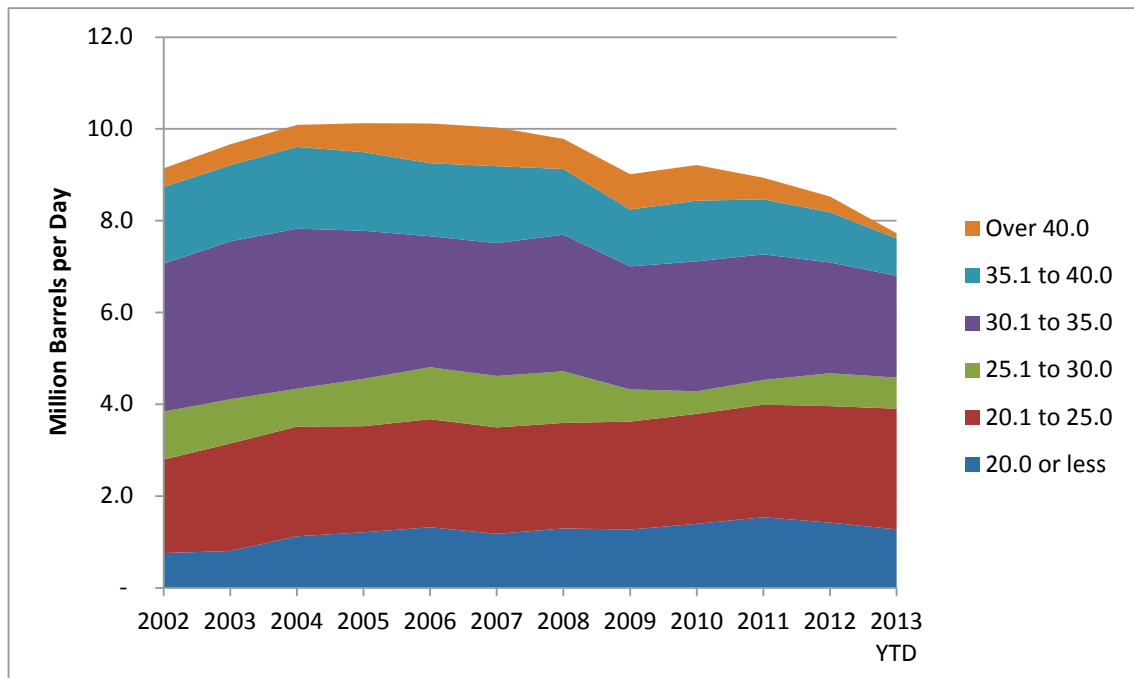


Source: EIA 2013a

**Figure 1.4.2-10          Average Annual Imports by API Gravity, thousand bpd**

As a result, the average quality of crude imports is growing heavier (see Figure 1.4.2-11). The EIA AEO explicitly forecasts that U.S. imports will continue growing heavier on average in its Reference Case.



Source: EIA 2013a

**Figure 1.4.2-11        Quality of Domestic and Imported Crude Processed by U.S. Refiners**

While EIA does not explicitly forecast the quality of crude imports in other cases, it is likely that the average gravity of imported crude would be even heavier in the High Resource and Low/No Net Imports cases. The High Resource Case projects the United States continues gross crude oil imports of 3.4 million bpd or more through 2035. Because the additional domestic crude supply in the High Resource versus the Reference Case is largely light, tight oil, it is likely that what crude is imported is even heavier on average than in the Reference Case. Even in the Low/No Net Imports case—which is built on top of the domestic production assumptions in the High Resource Case—the United States is expected to continue gross imports of crude at 3.1 million bpd or higher and again it is likely that these trend even heavier than in the Reference Case on average.

The EIA notes, "AEO2013, AEO2012, and AEO2011 all project continued strong demand for heavy sour crudes from Gulf Coast refiners that are optimized to process such oil" (see the EIA January 2013 memo in Appendix C, Supplemental Information to Market Analysis). A main driver for this is that although refiners can be expected to make adjustments in their operations to take advantage of the increased supply of light crudes on the markets, shutting down their heavy crude upgrading units would likely be an inefficient and expensive option. Given the

concentration of upgrading units in PADD 3 and the economic incentives to run heavy crudes given light-heavy oil price differentials, this region will likely remain a key source of heavy crude demand. However, options for refinery reconfiguration were included in the modeling described in Section 1.4.4, Updated Modeling, to test how heavy crude demand might change due to increased supplies of light crude.

### 1.4.2.7    Oil Trade

U.S. net imports of crude and petroleum product averaged 7.4 million bpd in 2012 (see Table 1.4-5). This is 5.1 million bpd lower than its peak in 2005 due to supply and demand changes described above. These developments have manifested as both a decline in gross imports of crude and petroleum products and an increase in exports of petroleum products.

**Table 1.4-5    Gross Imports and Exports of Crude Oil and Petroleum Products (thousand bpd)**

|  | Gross Imports | | | Gross Exports | | | Net Imports | | |
|---|---|---|---|---|---|---|---|---|---|
|  | 2005 | 2010 | 2012 | 2005 | 2010 | 2012 | 2005 | 2010 | 2012 |
| Crude Oil | 10,126 | 9,213 | 8,491 | 32 | 42 | 60 | 10,094 | 9,171 | 8,431 |
| Petroleum Products | 3,588 | 2,580 | 2,105 | 1,133 | 2,311 | 3,124 | 2,455 | 269 | -1,019 |
| Total | 13,714 | 11,793 | 10,596 | 1,165 | 2,353 | 3,184 | 12,549 | 9,440 | 7,412 |

Source: EIA 2013a

### Crude Oil Trade

Gross crude oil imports fell from 10.1 million bpd in 2005 to about 8.5 million bpd in 2012. Imports fell in all PADDs except PADD 2, and to a lesser extent PADD 5, where imports from Canada have increased (see Table 1.4-6 and Table 1.4-7).

**Table 1.4-6    Crude Imports by Processing PADD (thousand bpd)**

|  | 2005 | 2010 | 2012 |
|---|---|---|---|
| PADD 1 | 1,602 | 1,093 | 859 |
| PADD 2 | 1,516 | 1,377 | 1,720 |
| PADD 3 | 5,650 | 5,329 | 4,467 |
| >= 25 API | 3,378 | 2,985 | 2,285 |
| < 25 API | 2,272 | 2,343 | 2,194 |
| PADD 4 | 271 | 225 | 234 |
| PADD 5 | 1,056 | 1,139 | 1,145 |
| Total | 10,096 | 9,163 | 8,424 |

Source: EIA 2013c (Company Level Imports)

**Table 1.4-7      Crude Imports by Port PADD (thousand bpd)**

|              | 2005   | 2010  | 2012  |
|--------------|--------|-------|-------|
| PADD 1       | 1,602  | 1,092 | 854   |
| PADD 2       | 1,006  | 1,207 | 1,726 |
| PADD 3       | 6,099  | 5,400 | 4,385 |
| >= 25 API    | 3,785  | 3,149 | 2,315 |
| < 25 API     | 2,314  | 2,251 | 2,069 |
| PADD 4       | 332    | 325   | 315   |
| PADD 5       | 1,056  | 1,139 | 1,146 |
| Total        | 10,096 | 9,163 | 8,424 |

Source: EIA 2013c (Company Level Imports)

Rising domestic light crude supplies, the configuration of domestic refineries, and production trends abroad have shaped where U.S. imports come from, as shown in Figure 1.4.2-12. For instance, imports from West Africa, which has traditionally supplied light crude oil to the United States, have been backed out by rising U.S. light crude oil production.
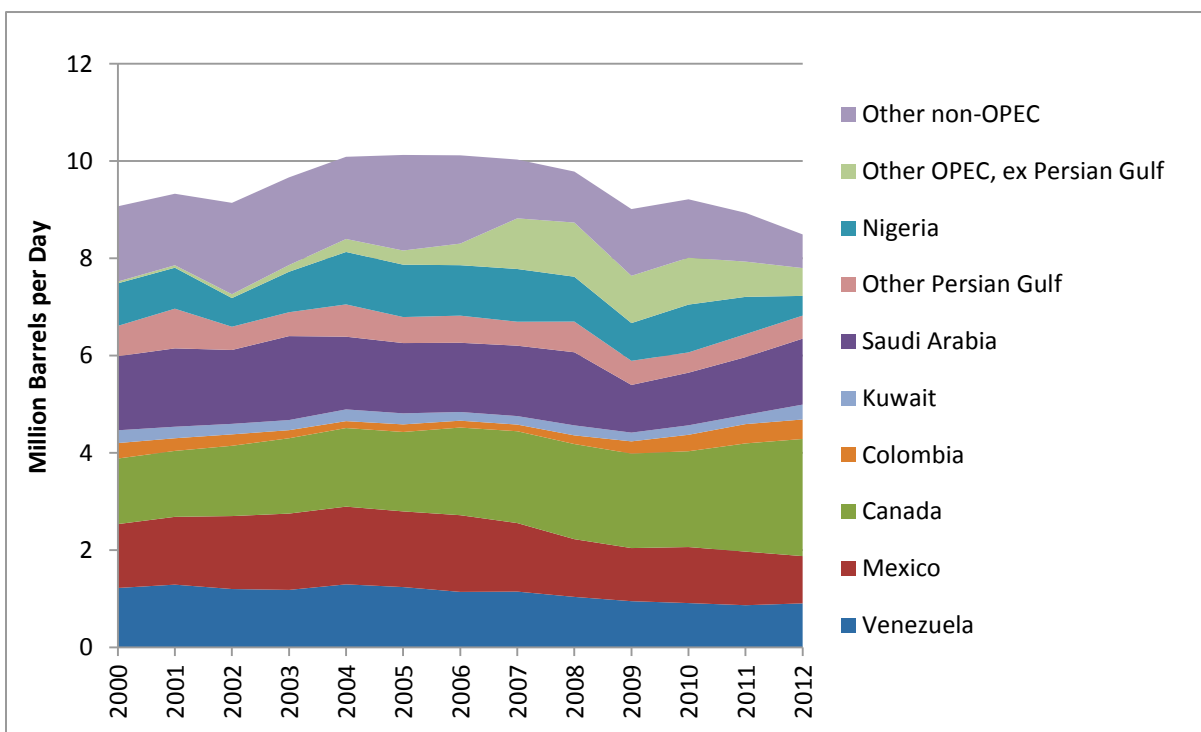


Source: EIA 2013a

**Figure 1.4.2-12      Gross U.S. Crude Oil Imports by Major Foreign Sources[20]**

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[20] The United States primarily imports crude comparable in quality to dilbit from five countries: Canada, Mexico, Venezuela, Colombia, and Kuwait.

Imports from Mexico and Venezuela, traditional heavy oil suppliers, fell during the 2000s as production from those countries declined. EIA's forecast implies that net oil exports from these countries will continue to decline.[21] There is uncertainty about how production levels will develop and both countries are looking to alter the trend, which are explored further in Section 1.4.4, Updated Modeling. However, even if this trend changes, Mexican production is becoming lighter on average as new supplies are relatively lighter than those in decline,[22] and Venezuela is actively trying to market its crudes to non-U.S. buyers.[23] Meanwhile, as discussed above, U.S. demand for imported crude is expected to grow heavier. Declining supplies from Mexico and Venezuela were partially offset by greater imports from Canada as well as small volumes from Colombia and Brazil, which are heavy crude producers where oil production has been growing.

U.S. refinery demand for WCSB heavy crude imports is likely to remain robust given expected global trends (see Table 1.4-8). Apart from WCSB, heavy crude supply from some traditional sources may decline. In addition, some countries that produce heavy crude oil are attempting to expand domestic refining and upgrading capacity to process more of their heavy crudes at home, and are either reducing their refined products imports, increasing products exports, and/or exporting a greater share of the higher-value light crudes that they produce.[24] This includes some of the world's largest oil producers, including Russia and Saudi Arabia.[25] EIA notes that "While the AEO does not identify specific sources for imported crude used by U.S. refineries, Canada is certainly a likely source for heavy grades" (2013 EIA Memo included in Appendix C, Supplemental Information to Market Analysis).

**Table 1.4-8       U.S. Heavy and Canadian Heavy Crude Oil Refined (thousand bpd)**

|                                                  | 2011  | 2015  | 2020  | 2025  | 2030  | 2035  |
|--------------------------------------------------|-------|-------|-------|-------|-------|-------|
| Total U.S. Heavy Crude Refined                   | 2,611 | 3,134 | 3,987 | 4,030 | 4,022 | 4,183 |
| Canadian Heavy Crude Refined in United States    | 1,242 | 1,769 | 3,277 | 3,535 | 3,690 | 3,900 |

Source: Hart 2012

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[21] Though it does not break out individually Mexican and Venezuelan production, consumption, and thus net exports, it aggregates them in ways that the trend is relatively clear. For both production and consumption, Mexico is aggregated with Chile, the other OECD country in Latin America which produces negligible amounts of oil. Production for the grouping falls by 1 million bpd by 2020 to 2 million bpd and remains near that level for the rest of the forecast. Meanwhile consumption for the group grows steadily. Venezuela's production is grouped with Ecuador, the other OPEC country in Latin American, and the grouping's production is roughly flat in the range of 2.9 to 3.2 million bpd throughout the forecast. Venezuela's consumption is more difficult to identify as it is grouped with all of Central and South America except Brazil. That group's consumption rises from 3.4 to 3.9 million bpd.

[22] Pemex 2013

[23] EIA 2012c

[24] OPEC 2012

[25] Saudi Arabia is building four refineries with a combined capacity of 1.2 million bpd that will mostly run Arab Heavy and Arab Medium crude (EIA 2013e; Saudi Aramco, "Company Refineries," website). Companies in Russia, a major fuel oil exporter, are also planning to add substantial upgrading capacity to process heavy fuels domestically (Fattouh and Henderson 2012).

**Petroleum Products Trade**

Along with crude, U.S. net imports of petroleum products have also fallen. Lower domestic demand and available refining capacity reduced the need for refined fuels from abroad (see Table 1.4-5). These factors also contributed to an increase in petroleum products exports. U.S. petroleum products exports have increased from around 1.2 million bpd in 2005 to 3.2 million bpd in 2012. The largest increase has been in middle distillates such as diesel fuel. Contributing factors include strong demand for imported diesel, particularly in the nearby markets of Latin America, and available refining capacity which is fueled by relatively low cost natural gas.[26]

In its Reference Case, EIA projects U.S. gross product imports will be 2.47 million bpd by 2035, but net product exports will increase to 0.37 million bpd (i.e., gross product exports are higher than gross imports; see Table 1.4-9). In scenarios with higher domestic supply and lower demand, net imports fall further. However, in all scenarios, EIA still expects U.S. refineries to import some crude oil on a gross basis, even in the Low/No Net Imports scenario where it makes supply and demand assumptions that would cause the United States to be a net oil exporter. Given that the increased crude supplies in the High Resource and Low/No Net Imports Cases are likely to be light crudes, refiners are likely to demand heavier crude imports (as mentioned above). The option to reconfigure refineries to run more light crudes was also tested in the modeling described in Section 1.4.4, Updated Modeling.

**Table 1.4-9       AEO U.S. Oil Trade Projections (million bpd)**

| | Gross Imports | | | Gross Exports | | | Net Imports | | |
|---|---|---|---|---|---|---|---|---|---|
| | **2010** | **2020** | **2035** | **2010** | **2020** | **2035** | **2010** | **2020** | **2035** |
| AEO 2013 Reference | | | | | | | | | |
| Crude | 9.21 | 6.82 | 7.37 | 0.04 | 0.00 | 0.00 | 9.17 | 6.82 | 7.37 |
| Petroleum Products | 2.58 | 2.66 | 2.47 | 2.29 | 2.79 | 2.84 | 0.29 | -0.13 | -0.37 |
| AEO 2013 High Resource | | | | | | | | | |
| Crude | 9.21 | 4.57 | 3.48 | 0.04 | 0.00 | 0.00 | 9.17 | 4.57 | 3.48 |
| Petroleum Products | 2.58 | 2.62 | 2.19 | 2.29 | 3.30 | 3.75 | 0.29 | -0.68 | -1.56 |
| AEO 2013 Low/No Imports | | | | | | | | | |
| Crude | 9.21 | 3.69 | 3.30 | 0.04 | 0.00 | 0.00 | 9.17 | 3.69 | 3.30 |
| Petroleum Products | 2.58 | 2.61 | 2.22 | 2.29 | 3.24 | 5.73 | 0.29 | -0.63 | -3.52 |

Source: EIA 2013a

### 1.4.2.8     Canadian Oil Production

Canada is the world's fifth largest oil producer (behind Russia, Saudi Arabia, United States, and China), and almost all of its crude oil exports are directed to U.S. refineries. Canada's largest crude resource is the oil sands of the WCSB, which are primarily located in the province of Alberta as well as portions of British Columbia, Northwest Territories, Manitoba, and Saskatchewan.

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[26] Foreign refineries frequently fuel their processes with oil.

**Oil Sands**

The Athabasca, Cold Lake, and Peace River deposits are the main oil sands deposits within the WCSB, which are largely concentrated in north-central Alberta and extend to east-central Alberta and western Saskatchewan. According to CAPP (2013a), approximately 1.8 million bpd of WCSB oil sands crude were produced in 2012, equal to about 2 percent of global supply.

WCSB oil sands are primarily composed of bitumen, a form of petroleum in a solid or semi-solid state that is typically associated with a mixture of sand, clay, and water. Bitumen is generated from crude that was formerly light (such as crude from the Bakken region in North Dakota, for example), but has undergone further bacterial degradation over geologic time, resulting in the loss of its light hydrocarbon components. WCSB oil sands crude is a heavy crude and is more viscous than light crude.

In general, two different methods are used to extract WCSB oil sands. One method involves pit mining, utilizing heavy equipment to shovel bitumen onto trucks for transport to processing facilities. Approximately 80 percent of remaining oil sands reserves cannot be mined due to the depth of the underground bitumen deposit, and can only be extracted using in situ techniques. In situ extraction involves injecting steam and/or solvents into underground formations to decrease the viscosity of the bitumen which allows it to be pumped to the surface through wells. Steam-assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS) are the most commonly used in situ extraction techniques.[27]

WCSB oil sands crude is brought to market by either pipeline or rail transport. Due to its viscosity, bitumen cannot be transported by pipeline on its own. It first must be mixed with a petroleum-based product (called a diluent) such as naphtha (refined or partially refined light distillates) or natural gas condensate, to make a less viscous liquid referred to as *dilbit*. Dilbit is composed of approximately 30 percent diluent and 70 percent bitumen, although the proportions vary depending upon the type of bitumen and the time of year. Alternatively, producers may upgrade, or partially refine, bitumen to a medium weight crude oil called *synthetic crude oil* (SCO) to meet pipeline specifications. Producers can also use SCO as the diluent to create a product called *synbit*.

Bitumen can also be transported to market by rail in undiluted form (undiluted bitumen transported by rail is referred to as *rawbit* in this report). Rawbit transport by rail requires using coiled and insulated tank cars that enable the crude to be steam-heated (to reduce viscosity) prior to unloading at destination facilities. *Railbit*, or bitumen that has been diluted with approximately 15 percent diluent, is also transported by rail (railbit does not meet pipeline specifications). As explained further in Section 1.4.3, Crude Oil Transportation, dilbit can also be transported in rail cars, but doing so results in different transport economics than if rawbit were delivered via rail.[28]

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[27] SAGD extraction typically involves installing two horizontal wells parallel to one another but at different depths, usually one near the bottom of the formation, and the other above it. The top well is injected with steam which, over a period of weeks to months, allows the bitumen to flow to the bottom well where it is then pumped to the surface. In CSS extraction, a vertical well is installed and pressurized steam is injected into the formation over a period of several weeks. Once filled with steam, the reservoir is left to soak for another several weeks, which softens the bitumen enough to allow it to be pumped to the surface through the same well.

[28] Oil sands bitumen is often mixed with diluent prior to transportation beyond the production facility, as *process diluent* is used to facilitate the separation and removal of water, sediment, and other impurities from bitumen.

Crude oil transported by rail may be transported by unit trains or manifest trains. A *unit train* carries only one commodity and transits from origin point to one destination point. A crude-oil unit train is typically 100 to 120 (or more) cars long. Unit trains have been utilized for many years to transport other bulk commodities, such as coal or grain. Manifest trains have mixed car and cargo types and may have various destinations for each of the different products transported. As discussed in more detail in Section 1.4.3, Crude Oil Transportation, unit train transport typically allows for better economics (and shorter delivery times) than manifest transport options.

**Oil Production Growth**

The production of Canadian crude oil is anticipated to increase substantially through 2030. The EIA (2013) projects total Canadian oil production rises from 2.3 million bpd in 2012 to 5.9 million bpd in 2030 and 6.1 million bpd in 2035. The majority of the growth comes from oil sands crudes, which rise from 1.9 million bpd to 4.2 million bpd. EIA projections of Canadian oil sands production represent the total volumes of any bitumen derived product—i.e., the sum of all raw bitumen, dilbit, synbit, and syncrude. The projection is based on information about investment plans in the oil sands as well as economic conditions in Canada and the global oil market. Growth averages roughly 100,000 bpd per year to 2035, in line with the rate of supply growth over the last decade.[29]

Other forecasts similarly show a substantial increase in Canadian production from the oil sands. The IEA (2013) WEO expects Canadian supply to increase to 5.0 million bpd in 2020 and 6.1 million bpd in 2035 in the New Policies scenario, of which 4.3 is oil sands.[30] Canada's National Energy Board (NEB), a Canadian governmental agency, issued a report in 2012 projecting 6 million bpd of oil production in 2035 of which 5.1 million bpd were oil sands (NEB 2012). According to its 2013 forecast, CAPP expects total Canadian oil production to reach 6.7 million bpd in 2030, of which 5.2 million bpd is oil sands crude. This is up from CAPP's 2012 forecast of 6.1 million bpd by 2030 (CAPP 2012a).[31] While the specifics of each forecast differ,

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[29] Over the last decade, more projects have been announced than upstream development constraints permitted to come online. Consequently, forecasts have sometimes overestimated supply growth. For example, the 2007 CAPP forecast expected oil sands production to reach 2.5 million bpd by 2012. The industry has been able to deliver roughly 100,000 bpd annual average supply growth over the last decade given upstream development constraints such as the availability of labor and specialized equipment within the oil sands industry. As the level of oil sands production grows, more resources will be required to operate and maintain the base of projects, which may make it challenging to accelerate the rate of growth regardless of midstream constraints.

[30] The IEA implies that this projection is consistent with current conditions and suggests "if the controversies over the Keystone XL pipeline and the pipelines from Alberta to the British Columbia coast were to be resolved quickly, oil sands production could easily grow 1 million b/d higher than we project [by 2035]." However, the methodology used to arrive at that estimate is unknown; the WEO model does not account for transportation considerations and the agency did not state its assumptions regarding the growth of crude-by-rail.

[31] CAPP is at the high end of the forecast range and has been criticized because it tends to overestimate production growth. According to the Natural Resources Defense Council "In estimating the need for additional pipeline capacity to transport WSCB crudes across the Canadian border, the SEIS should not rely on the Canadian Association of Petroleum Producer's ("CAPP") forecasts, which have consistently overestimated actual Canadian exports…Therefore, these results make the CAPP forecast methodology inappropriate for use in long-term need or cost/benefit analyses. That CAPP's supply forecasts are overly optimistic and unreliable is also indicated by the fact that Enbridge does not use the CAPP forecasts in its business analysis" (Natural Resource Defense Council 2012).

they point to substantial and sustained increase in Canadian oil production driven by oil sands supply.[32]

### 1.4.2.9    *Oil Sands Supply Costs*

Many authorities have estimated or published oil supply cost or breakeven price estimates, including for projects in the Canadian oil sands. Oil sands supply cost estimates employ different methodologies and assumptions, and are often expressed in inconsistent ways. In order to better understand supply cost estimates, incorporate new information about them, and respond to public comments regarding their treatment in the Draft Supplemental EIS or their applicability to projections for oil sands production volumes, credible estimates of oil sands production costs and supporting documentation were reviewed and compared.[33] Findings from these studies were used to expand upon the analysis in the Draft Supplemental EIS and to develop a notional oil sands supply curve that depicts the ranges and averages of supply cost estimates for announced oil sands projects.

Supply cost estimates are typically generated through complex discounted cash flow models that account for financial streams over a project's lifetime.[34] The present value of capital costs, operating costs, fiscal costs, and other costs are balanced with the present value of revenues at a given rate of return. Supply cost estimates are not static snapshots of the present, nor are they certain. Instead, they include assumptions about the future, which will inevitably evolve as market conditions change and new insights about the industry's cost structure emerge.

Supply cost studies indicate that capital expenditures account for the largest share of total oil sands supply costs.[35] Oil sands projects are generally capital-intensive, and integrated and mining projects generally require more upfront capital investment than in situ projects. On the other hand, in situ projects are more energy-intensive.[36] Oil sands projects also have large labor requirements at the construction stage, particularly mining or upgrading projects.[37] Beyond the

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[32] According to information contained in these reports, growth in production will occur primarily from oil sands development as well as from Canadian tight oil development, including at formations in the Cardium, Viking, Lower Shaunavon, Montney/Doig, Lower Ameranth, Pekisko, Bakken/Three Forks, Exshaw, Duvernay/Muskwa, Slave Point, and Beaverhill Lake.

[33] Sources employed include BMO Capital Markets 2012, Canadian Energy Research Institute (CERI) 2012 and 2013, CIBC 2012 and 2013, Energy Resources Conservation Board (ERCB) 2013, Goldman Sachs 2013a, NEB 2011, and Rodgers 2012.

[34] Most reports assume an average oil sands project life of 30 to 35 years.

[35] CERI (2013) data indicate how different types of costs factor into to total supply cost estimates. SAGD (fixed capital is 41.8 percent of total costs) is less capital intensive than mining (46.9 percent) or mining with upgrading (51.5 percent). Operating costs (i.e., labor and maintenance costs, not including fuel) account for 24 to 25 percent of total costs for all project types. Operating costs for SAGD are higher early in the project, and lower thereafter, because it takes time (a few months to two years) for injected steam to sufficiently heat the bitumen and for production to ramp up to capacity. Royalties are responsible for 19 percent of costs for SAGD and mining operations, or 13 percent for integrated upgraders. Other costs include income taxes, operating working capital, emission compliance, and abandonment costs.

[36] According to CERI (2013), fuel accounts for 6.8 percent of SAGD costs, relative to 2 to 3 percent for mining or integrated mining and upgrading.

[37] CIBC (2012) quantifies the labor requirements of typical oil sands projects: "The oil sands is a massively labor intensive project type. A typical 100,000 bpd non-upgraded mine requires peak labor of approximately 5,000 workers. A typical upgraded mine can require anywhere from 5,000 to 10,000 peak labor force depending on pace of construction (historically peak was 10,000 but more companies are planning to stretch construction to have better
*(footnote continued on the following page)*

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capital and operating expenditures associated with supplying bitumen, oil sands producers must generally contend with the costs associated with dilution in order to process, transport, and market bitumen beyond the plant gate.[38]

The implication of supply cost estimates is that sustained prices above the breakeven would make these projects economic, while prices below could make these projects uneconomic. The terms *supply cost* and *breakeven price* are commonly used interchangeably, including in this report, but they are often used in different ways.[39] Some supply cost estimates calculate and compare internal rates of return (IRR) for projects based on fixed assumptions about current or projected prices and input costs.[40] Narrower production cost estimates focus on operating costs of existing projects. Another approach is to estimate breakeven prices, or the prices at which a given project recoups its cost of capital. These models solve for the price that would cause revenues and costs to balance at a given rate of return, which means that higher required rates of return would translate into higher supply costs.[41]

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work force control). SAGD is less labor intensive but, even still, a typical 35,000 bpd SAGD project still requires a peak labor force of approximately 700 workers over a two- to three-year construction period (smaller projects at shorter end of scale)" (page 88).

[38] Diluent costs are incorporated into referenced oil sands supply cost estimates, but sources employ different methodologies to model their price (e.g., the size of diluent's premium relative to light sweet crude oil) and account for their purchase. For example, CIBC explicitly accounts for the fact that some of the costs associated with purchasing diluent are at least partially recovered in revenues from their sale in a heavy oil blend, while some other sources treat diluent as an input cost and do not separately model the revenues attributable to it in the sale of the resulting blend.

[39] CERI (2013) supply cost definition: "the constant dollar price needed to recover all capital expenditures, operating costs, royalties and taxes and earn a specified return on investment. Supply costs in this study are calculated using an annual discount rate of 10 percent (real), which is equivalent to an annual return on investment of 12.5 percent (nominal) based on the assumed inflation rate of 2.5 percent per annum" (pg. xiii) . ERCB (2013) supply cost definition: "The supply cost for a resource or project can be defined as the minimum constant dollar price required to recover all capital expenditures, operating costs, royalties, and taxes, as well as earn a specified return on investment. This price can then be compared with current market prices to assess whether a project or resource is economically attractive. It can also be used for comparative project economics." (pg. 3-23) NEB (2011) definition of supply cost: "All costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return." BMO Capital Markets' (2012) definition of breakeven oil price is "the oil-equivalent price that is required to recover all reported costs, plus provide a 10% return on capital. Essentially, this represents the industry's average supply cost. We then translate the breakeven oil price into a 'required WTI price,' that is, breakeven oil price plus a differential reflecting the difference in the quality of the production base relative to WTI." (page A1-A2, A55) Goldman Sachs (2013a) defines the breakeven price as: "The oil price required for a project to generate what we consider to be a commercial rate of nominal IRR [internal rates of return] (i.e. cost of capital). We assume geography determines this rate of return with projects in the OECD requiring 11% up to a maximum of 15% in countries which we deem to be higher risk" (page 131). Goldman Sachs assumes that investments in Canada, as an OECD country, require the lower rate of return.

[40] Supply cost estimates based on fixed assumptions about current or projected oil prices or input costs are commonly employed to compare the IRR across projects and inform investment decisions.

[41] IRR are commonly assumed to be 10 to 15 percent, depending upon the criteria employed. CIBC (2013) notes that 10 percent after-tax IRR is a rough proxy for "economic break-even" but that "most producers indicate that '15%' is the threshold IRR to sanction a project" (page 69). If higher IRR thresholds are required to sanction a project, some of the supply cost estimates used in this section could change. However, higher IRR thresholds would also raise the supply costs of other projects with which the oil sands compete for capital. The required internal rate of return for Canadian oil sands projects could arguably be lower than for projects in other countries that would have higher political or geologic risk.

Supply cost estimates vary across the oil sands (see Table 1.4-10). They are generally expressed in one of two ways: as estimates for actual individual projects or as generic estimates by project type (e.g., mining, integrated mining and upgrading, in situ, SAGD).[42] Generic averages obscure considerable variation with respect to the supply costs of individual projects, which can be above or below the average due to reservoir quality, the type of technology applied, and other factors. Many general supply cost estimates for generic projects are based on the construction of hypothetical new greenfield SAGD, mining, and integrated mining and upgrading facilities.[43] Actual breakeven prices could be lower than greenfield supply cost estimates because most oil sands projects are developed in stages. Brownfield expansions of existing projects are less expensive than greenfield projects because they can take advantage of existing infrastructure.[44] Consequently, references to individual supply cost estimates should be considered in their original context and may not be applicable to all current or planned oil sands projects.

**Table 1.4-10      Oil Sands Supply Cost Estimates (WTI[a]-Equivalent, \$/bbl[b])**

| Source | In Situ/SAGD | Mining (no upgrader) | Integrated mining and upgrading |
|---|---|---|---|
| BMO Capital Markets (2012) | 30-100 (range of project estimates, all types) | | |
| CERI[c] (2013) | 78 | 99 | 103 |
| CIBC (2012)[d] | 43-82 | 67-76 | 83-93 |
| Energy Resources Conservation Board (ERCB 2013) | 50-80 | 70-85 | N/A |
| Goldman Sachs (2013a)[e] | 40-136 (range of project estimates, all types) | | |
| NEB (2013a)[f] | 50-80 | 70-100 | 80-100 |

[a] WTI = West Texas Intermediate
[b] bbl = barrel
[c] CERI = Canadian Energy Research Institute
[d] CIBC's (2012) ranges are for different levels of Western Canadian Select (WCS) discounts (15 to 25 percent) and SCO discounts (0 to 10 percent) to WTI. Its SAGD ranges include low, average, and high cost SAGD projects. The range for average SAGD projects was \$56.02 to \$63.49. Its 2013 report omitted the smaller discounts and the integrated projects; the remaining estimates were largely the same.
[e] Goldman Sachs (2013a) published supply cost estimates in terms of Brent equivalency. They have been converted to WTI here using Goldman Sach's assumed differential of \$14 per barrel.
[f] NEB (2013) supply cost estimates derive from a survey of other studies. The numbers reflect 2012 \$US. It also includes a supply cost estimate for standalone upgrading of \$55 to \$65 per barrel.

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[42] Most supply costs are expressed in real dollars, though differences in base years or the use of nominal dollars can explain some differences in supply cost estimates.

[43] For example, CERI's cost estimates are for greenfield projects.

[44] The range of supply costs estimated by ERCB (2011) reflect how costs can differ significantly between new projects and expansions of existing projects: "The wide range in SAGD capital costs represents the current economic environment in which producers are pursuing additional phases, as well as greenfield development, with the lower range of the capital cost being applicable to phased additions where portions of the infrastructure are already in place" (page 3-25).

Most reports express supply costs in terms of equivalence to an oil price benchmark—usually WTI, sometimes Brent—for purposes of comparison with market prices and the costs of other projects around the world.[45] Supply costs for oil sands projects that are expressed in terms of WTI include implicit assumptions about quality differentials, transportation costs, and other market factors that contribute to the discount between bitumen in Western Canada and light sweet crude in Cushing, Oklahoma. Therefore, supply cost estimates and project rates of return will change as spreads between WTI and Canadian benchmark prices change over the long-run.[46]

Supply cost estimates for known oil sands projects are plotted against actual or planned project capacities in Figure 1.4.2-13.[47] The red line is a notional supply curve that depicts the cumulative production capacity of currently operational, under construction, and announced projects (horizontal axis) and their estimated supply costs (vertical axis, expressed in terms of WTI).[48] The supply costs for individual projects were estimated by averaging secondary supply cost estimates for specific projects, where available.[49] For projects without publicly available project-specific supply costs, the supply cost estimates underlying the curve represent the average supply cost estimates for the type of project under consideration (e.g., in situ, mining, etc.). Like similar supply curves, it presents the total volume of current and future announced capacity that may be economic at a corresponding price point.[50] The brackets around the curve illustrate the range of commonly referenced supply costs for any given project type and acknowledge the uncertainty

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[45] Goldman Sachs (2013a) expressed supply costs in terms of Brent. The near-term Brent-WTI differential estimated in their recent reports ($14 per barrel) was used to convert from their Brent-equivalent breakeven prices to WTI-equivalent breakeven prices.

[46] Transportation cost is one factor that explains the project economics calculation for supply costs expressed in terms of benchmark oil prices. For example, according to CERI (2013), increasing transportation costs by $5 per barrel "lowers a typical project's IRR from 15% to 13% and net present value (NPV) (10%) from $800 million to $570 million, a 28% reduction" (pg. 6).

[47] The projects analyzed derive from a comprehensive oil sands project database published by the Oil Sands Developers Group (OSDG 2013), which includes information on project ownership, operatorship, production capacity, production technology, status (e.g., operating, construction, approved, announced), planned start date, and other relevant data points for nearly 300 announced projects and project phases.

[48] While the curve plots aggregated data about actual projects, the identities of those projects have been suppressed to avoid making public claims about individual companies. The curve depicts current and announced capacity, which will not necessarily equal production levels at any particular point in time or price level. The supply costs for existing projects reflect costs across the project's lifetime (including previously sunk capital costs). Operational costs are lower than lifetime supply costs, and current production is unlikely to be shut-in unless marginal revenues fall below marginal costs from existing operations. For that reason, existing production and projects already under construction are removed from the supply cost curves later in this section.

[49] The averages favor project-specific estimates to reflect an assumption that those calculations reflect a project's unique characteristics and more closely approximate true project supply costs than general industry estimates. Project-specific estimates derive from BMO Capital Markets (2012), Goldman Sachs (2013a), and individual company reports. For the many projects that lack individual project-specific estimates, the average breakeven price is the average of the generic estimates applicable to the technology embodied in the project. Most sources do not publish estimates of breakeven prices for the relatively few CSS projects that are due to come online. For purposes of this analysis, we assume that CSS breakeven price estimates are comparable with SAGD breakeven prices (both are in situ technologies).

[50] Many investment banks publish similar types of curves. The vertical (y-axis) value of a point on the curve represents the estimated supply cost of the marginal (or next least-expensive) project. The horizontal (x-axis) value of that same point represents the summed capacity of all projects less expensive than that marginal project, plus the capacity of the marginal project. Each in situ project averages about 30,000 bpd of capacity, though actual capacity varies by project. Mining projects are usually larger and average about 100,000 bpd of capacity per project.

inherent in net present value calculations that include many variables extending far into the future.[51] Caveats aside, the curve facilitates a more reasoned discussion of how prices could relate to production volumes by attaching supply cost estimates to actual current and future oil sands project capacities.
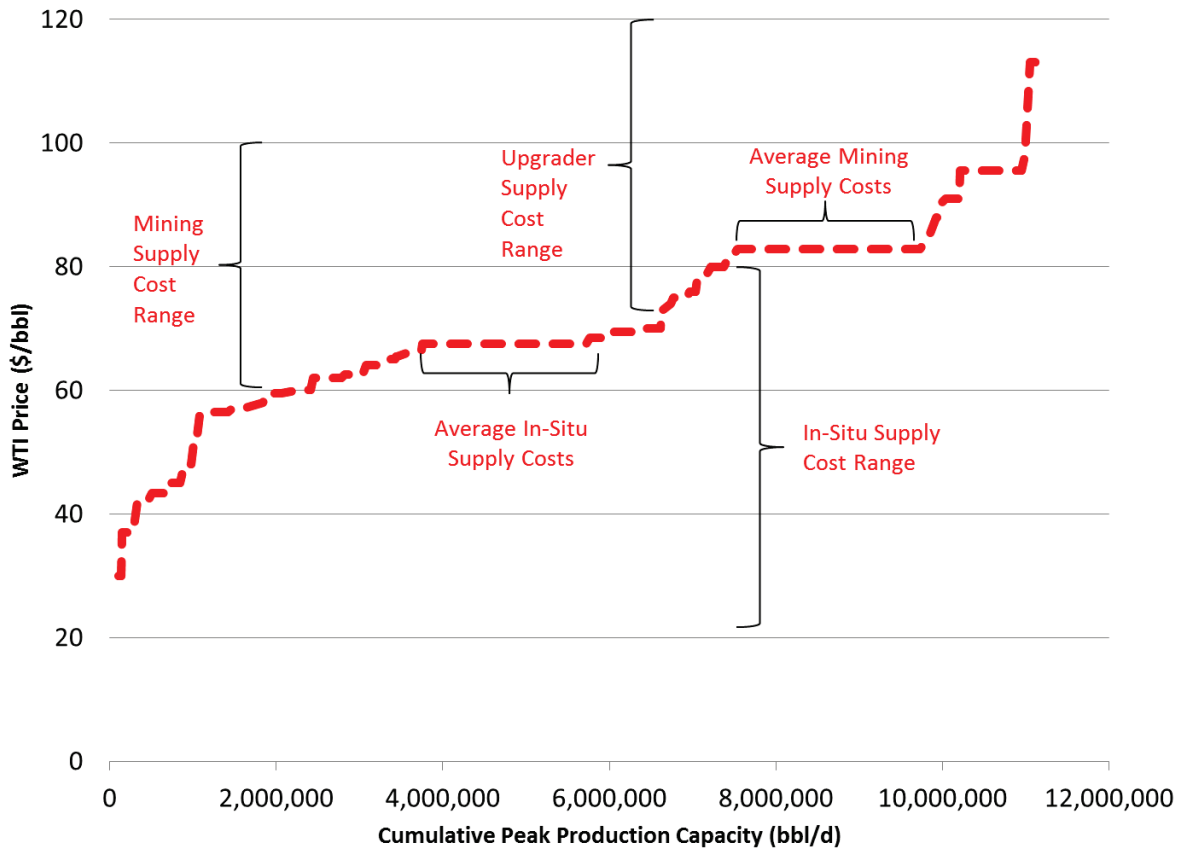


**Figure 1.4.2-13      Estimated WTI-Equivalent Supply Costs for all Oil Sands Projects**

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[51] Many supply cost estimates implicit in the curve or the bracket ranges around the curve are illustrative and are not necessarily relevant for all projects. Points on the curve and the bounds of the brackets should not necessarily be treated equally, as some of the high and low values represent extreme assumptions about costs or market factors that are unlikely to be widely applicable.

The total capacity of current and announced projects exceeds forecasts of Canadian oil sands production growth because not all projects will ultimately be developed.[52] Forecasts typically account for the volumes implied by announced projects, but adjust total supply to eliminate high-cost projects and incorporate project risk, industry project development capacity constraints such as labor and capital, and general oil market conditions and uncertainty. It is expected and it would be normal for some announced projects to not proceed. Project rationalization always occurs, whether in the oil sands or in other prospective producing regions.[53]

The concentration of projects with average supply costs of $65 to $75 per barrel (in WTI terms) reflects the large number of existing and announced in situ projects. Many in situ projects lack individualized, publicly available supply cost estimates, in which case the estimates reflect the average supply cost estimates for generic in situ projects. The projects with estimated supply costs below $65 per barrel reflect project-specific estimates—mostly for relatively low-cost in situ projects—that fall below average levels due to easily exploited reservoirs, technological advantages, or other factors. Alternatively, some supply cost estimates above $70 reflect in situ projects that were assessed to be more expensive than industry averages. The second plateau around $80 to 85 per barrel reflects average supply costs for generic mining projects; above and below that level are project-specific estimates for relatively more or less expensive mining and some in situ projects. The third plateau around $90 to $100 per barrel mostly consists of upgraders.[54] The few projects with breakeven estimates exceeding $100 per barrel denote integrated upgraders that analysts deemed to be particularly expensive.

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[52] CIBC (2013): "According to our detailed oil sands project database, in aggregate, oil sands producers have independent plans that would lead to oil sands production reaching 5 MMbbl/d by 2020 (vs. CAPP forecasts of 3.2 million bpd)—a completely unrealistic scenario. As no producer willingly gives up the quest for growth, some degree of project rationalization will be required and will be dictated by market forces in the form of inflation, lower pricing (due to transportation bottlenecks), inability to finance or some combination of all these factors. This continues to highlight a competitive backdrop in the oil sands." (page 5)

[53] As BMO Capital Markets (2012) notes, "the arrival of relatively lower cost tight oil as the new marginal source of supply means that oil sands are now the next marginal source of supply, pushing off the need for some projects." CIBC (2013): "Clearly, it is unrealistic to consider that oil sands production will reach 5 MMbbl/d by 2020; there are a number of projects in this estimate that are wildly optimistic and completely unfunded. However, when we risk each project in our project database according to financing ability and project quality, we still reach a risked level of 4 MMbbl/d by 2020, which comprises production from high-quality resources from high-quality developers. This growth level is only achievable to the extent that adequate cost-effective transportation is built (pipeline or reasonable-cost rail) and inflation is held in check. To the extent that infrastructure bottlenecks continue and/or hyper-inflation emerges, growth would be restrained. Our downside view (i.e., infrastructure constraints and inflation forcing cancellation of some reasonable-quality projects) still forecasts growth in the 3.0 to 3.5 million barrels per day range by 2020 (which is in line with CAPP's base-case view)" (page 5). "After applying our detailed risking, we still generate very aggressive oil sands growth projections. The CIBC risked case forecasts oil sands production increasing from 1.8 MMbbl/d in 2012 to 4.2 MMbbl/d in 2020 (297,000 bbls/d) per year growth. Despite a more detailed approach to risking, our current forecasts are in line with our forecasts a year ago. Compared to CAPP's forecasts, the risked production potential we foresee is ~383,000 Bbls/d higher in 2016 and 1 MMbbl/d higher in 2020" (page 46). CIBC (2012) notes that project rationalization happened before and will happen again, for the oil sands and other parts of the oil industry: "In an efficient market, price or costs will rationalize the supply/demand balance—and oil sands is no exception. As recently as the 2005-2008 cycle, we saw inflating costs substantially rationalize the pace of planned oil sands development—and we will see that again" (page 90).

[54] OSDG (2013) data separate upgraders from associated mining projects that are components of integrated mining and upgrader projects. Most upgrader supply costs are expressed in terms of integrated projects. In this report, supply costs for integrated projects are applied only to the upgraders; associated but separately reported mining projects are assigned mining supply costs. The peak project capacity reported by OSDG is not necessarily the same *(footnote continued on the following page)*

The volumes depicted in Figure 1.4.2-13 represent operating, under construction, and planned projects. However, the upfront capital costs for operational projects are already sunk or amortized. Production from these existing projects would presumably be shut in only if revenues fell below current operating costs, which are much lower than total supply costs ($20 to $40 per barrel according to most estimates).[55] Figure 1.4.2-14, alternatively, presents the WTI-equivalent supply costs of future projects.[56] If prices were consistently below those supply costs over the long term, investments into some projects that underpin future production growth could potentially be delayed, deferred, or canceled altogether. The supply curve for future projects (see Figure 1.4.2-14) has a higher concentration of projects with comparatively low supply costs than the supply curve for all current and future projects since more expensive mining projects were responsible for much of the industry's initial expansion and existing capacity. An estimated 4 million bpd of potential future production from announced projects has supply costs that average below $75 per barrel because much of the growth in oil sands output is expected to derive from in situ projects, which are low cost relative to other parts of the industry.

Most supply cost estimates are expressed in WTI-equivalent terms, which vary as WTI-Western Canadian Select (WCS) differentials change. In order to assess upstream fundamentals in the oil sands industry, WTI-equivalent supply costs were converted to bitumen supply costs at the plant gate by applying assumptions about intermediate transportation costs, diluent costs, and quality differentials.[57]

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concept as streams to market; aggregating peak capacity from all projects double counts mined volumes of raw bitumen and upgraded volumes of SCO produced from that bitumen feedstock.

[55] CERI (2013) estimates that operating working capital, fuel, royalties, income taxes, emissions compliance costs, and other operating costs amount to approximately $28 per barrel for SAGD projects, $36 per barrel for mining projects, and $48 per barrel for integrated mining and upgrading projects ( pg. xiv). Husky Energy's (2012) annual report provides an example of one operator's operating cost trends. It states that operating costs for its oil sands bitumen projects were $48.75 per barrel of oil equivalent (boe) in 2010, $25.13 per boe in 2011, and $21.61 per boe in 2012. Suncor expects cash operating costs in the oil sands of C$31.50 to C$34.50 a barrel in 2014, down from an estimated range of C$34.50 to C$36.50 in last year's forecast. The willingness to shut-in existing production from any given project may vary for geological reasons or due to reservoir engineering requirements associated with in situ as opposed to mining techniques.

[56] Future projects were defined as announced projects that are not currently operational or under construction, and which have not been previously cancelled or considered to be on hold.

[57] Where possible, to maintain internal consistency, the individual supply cost estimates were converted from "WTI-equivalence" to bitumen supply costs using analysts' original assumptions. Bitumen supply costs in western Canada are lower than WTI supply costs in Cushing because they are upstream of the costs that must be applied to blend bitumen (diluent acquisition costs), ship it (transportation costs of pipeline or rail), and compare the blend to a crude that is lighter and sweeter (quality differential). Diluent is commonly assumed to trade at a slight premium (0 to 10 percent) to the price of light crude, such as Edmonton Light or WTI. Most analysts assume $0.50 to $2 per barrel in transportation costs from field to Hardisty or Edmonton. Referenced supply costs typically use pipeline tariffs to estimate transportation costs from western Canada to Cushing, where WTI is traded.
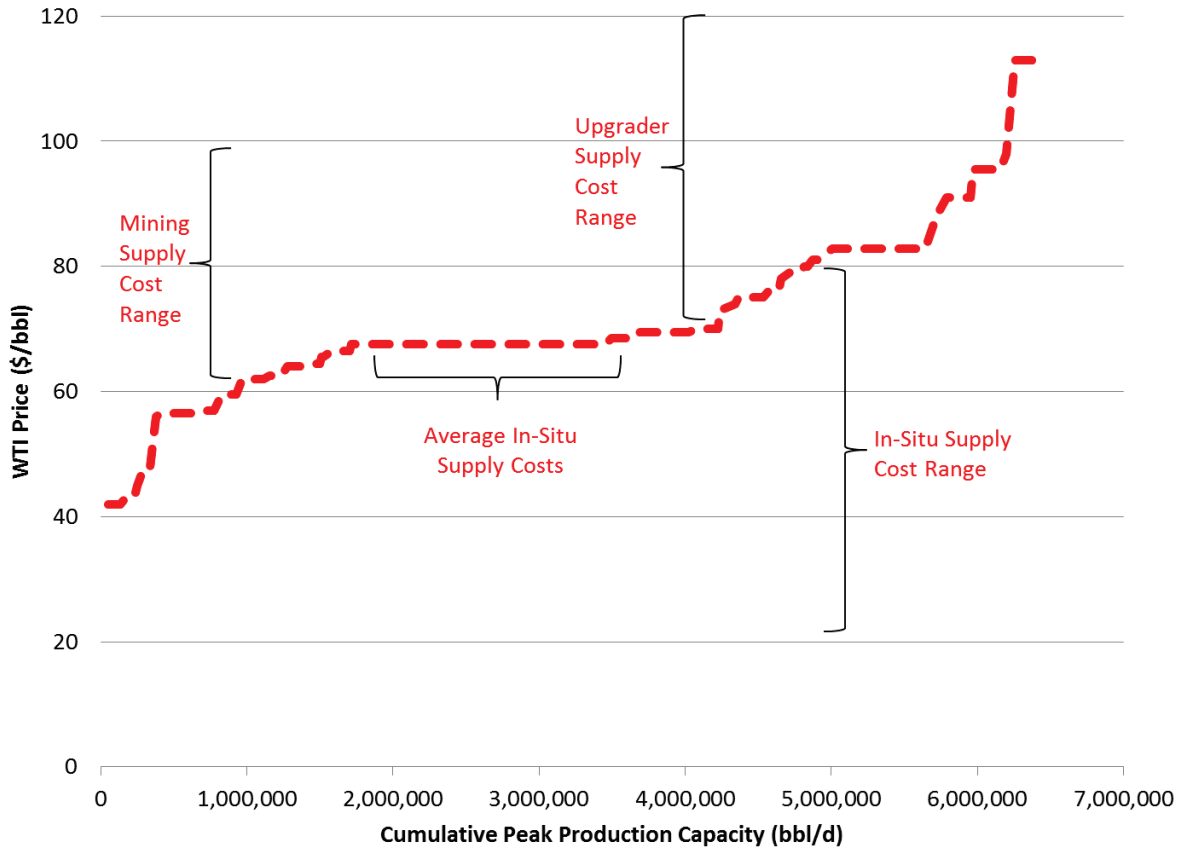
**Figure 1.4.2-14          Estimated WTI-Equivalent Supply Costs for Future Oil Sands Projects**

Bitumen supply costs were then converted to supply costs for different bitumen blends, which are consistent with the prices generated by the EnSys WORLD model in Section 1.4.4.3, Results. The supply costs for dilbit, railbit, and rawbit were calculated from bitumen supply costs presented in Figure 1.4.2-15 by adjusting for 1) the assumed cost of transportation from the plant gate to a Canadian trading hub; 2) the costs of using diluent recovery units (DRUs) to convert dilbit blends to railbit or rawbit; and 3) the net diluent savings for railbit and rawbit.[58] The

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[58] SCO from upgraders was excluded from the conversion because it is a light sweet crude oil that does not require diluents or other alterations to flow through pipelines. It was assumed that most oil sands projects must ship production as diluted bitumen (dilbit) from the plant gate to Canadian trading hubs, given the transportation infrastructure available from the field. A basic assumption for the cost of transportation from the field to Hardisty or Edmonton is $1 per barrel (CERI 2013). Some diluent is procured to aid bitumen recovery (process diluent); additional diluent is added so that it can flow in a pipeline (dilbit). An ICF International analysis provided cost assumptions for DRUs: "Assuming a midstream company may charge a fee of $2.00 per barrel of dilbit processed for the DRU operation (storage, processing, railbit quality assurance, etc.), this would amount to a cost of $2.35 per barrel of railbit or $2.87 per barrel of bitumen." Canadian National (CN) used a similar estimate of the likely processing cost ($2 per barrel) for a DRU (Cairns 2013). Alternatively, operators could truck railbit or raw bitumen from the plant gate to a rail terminal, and there are several smaller producers currently doing this. The diluent price was assumed to trade at a 10 percent premium to corresponding WTI breakeven price.

differences between the supply costs for dilbit, railbit, and rawbit in Figure 1.4.2-15 reflect the purchase or sale of diluent for each blend, but do not depict transportation costs out of western Canada.[59] These transportation costs for various bitumen blends are discussed in greater detail in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail, and Section 1.4.5.3, Transportation Cost Sensitivities.
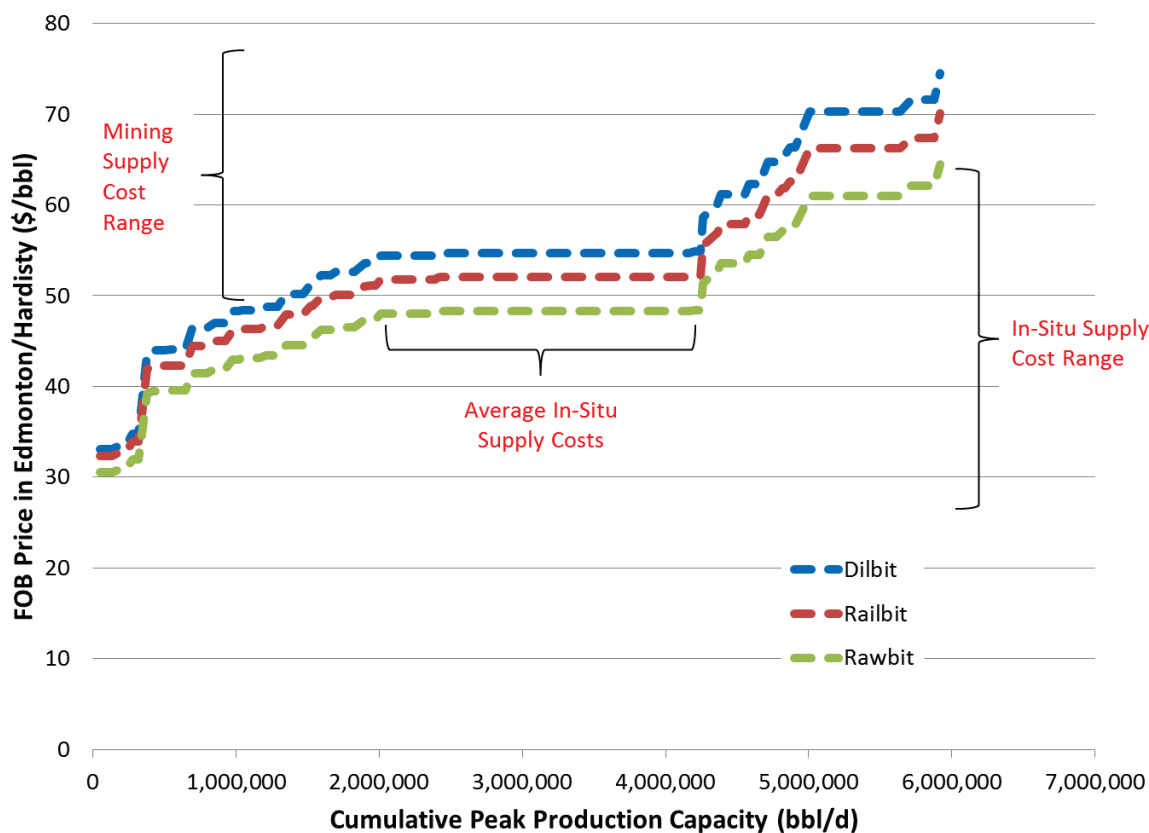


Note: FOB = free on board, i.e., prior to transport to markets.

**Figure 1.4.2-15      Dilbit, Railbit, Rawbit Supply Costs in Western Canada ($/bbl)[60]**

**Cost Inflation**

The estimates depicted above should not be misconstrued as static representations of current supply costs, or as costs that do not consider or incorporate assessments of how costs could change over time. Discounted cash flow models include estimates of capital and operating costs for each year of a project's lifetime. Therefore, individual studies' judgments regarding potential drivers of oil sands cost inflation or deflation—such as different assumptions about energy

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[59] The supply cost differences between dilbit, railbit, and rawbit widen at higher breakeven price levels as the assumed cost of diluent rises.

[60] Figure excludes upgrader projects, which yield light sweet SCO rather than heavy bitumen blends.

prices, labor costs, transportation costs, or the potential for technological advancements—are already internalized in most supply cost estimates.[61]

Studies differ in their assessments of the likely direction and magnitude of inflation for supply cost components. The general ranges of uncertainty in the supply cost estimates for a given project type were illustrated in the preceding figures. Actual cost inflation will depend on a complicated interplay of internal and external factors that is impossible to predict, and evidence suggests that costs can both rise or fall.[62]

Heavy levels of investment, labor constraints, and other factors increased supply costs in the oil sands over the first half of the last decade.[63] However, oil sands supply costs fell as oil prices collapsed in 2008 to 2009 and investment slowed.[64] Most reports indicate that costs have risen slightly since then, but not at the rapid rates experienced earlier in the last decade due to a combination of more efficient internal practices and the effects of external economic factors on industry costs. Historical data are limited and it is difficult to draw conclusions about how the oil sands industry's cost structure and broader measures of its competitiveness will evolve under different market conditions. There are few transparent measures of oil sands cost trends, which requires analysts to use proxy measures and underscores the uncertain nature of oil sands supply costs.[65]

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[61] For example, BMO Capital Markets (2012) and Rodgers (2012) assume operating cost inflation of 2 percent per year.

[62] Jaffe et. al 2011 found that "nominal cost estimates for breakeven in the Athabasca oil sands of Canada have fluctuated significantly since the 1990s, ranging from as low as $15/bbl in the late 1990s to current estimates of around $50/bbl."

[63] According to BMO Capital Markets (2012), "More than $125 billion of capital has been invested in the Canadian oil sands over the last decade. This heavy level of investment coupled with labour market constraints dramatically drove up the supply costs for oil sands from $20/bbl in 1999 to more than $90/bbl by 2008" (page A32). According to Goldman Sachs (2013c), the entire cost curve for the oil sands rose dramatically from 2003 to 2008, which was partly attributable to high mining costs and decreases in labor productivity.

[64] BMO Capital Markets (2012): "the slowdown in oil sands spending following the oil price collapse in 2008–2009 coupled with a shift in focus from integrated mining projects to smaller in situ developments has helped reduce the overall weighted average to $70/bbl, with several projects economic at prices as low as $40/bbl" (page A32).

[65] CERI (2013) appropriates costs trends in proxy indices to model future cost inflation in the oil sands. For example, CERI applies the Nelson-Farrar Inflation Refinery Construction Cost Index as a method to estimate future oil sands construction cost inflation and the Nelson-Farrar Refinery Operating Cost Index to account for inflation in future operating costs: "The average annual construction cost inflation rate, forecasted between October 2012 and October 2046, is 1.9 percent, which is lower than the assumed annual inflation rate of 2.5 percent…This forecast of the annual inflation rate in refinery construction costs (used to proxy the oil sands construction cost inflation) is used to inflate the projected initial and sustaining capital costs in the oil sands industry…While the operating costs of an oil refinery do not mirror those of an oil sands project exactly, the two facilities are similar in that each consists of very energy-intensive processing units…The [Nelson-Farrar Refinery Operating Cost Index] accounts for the following refinery operating costs: fuel, power, labour, investment, maintenance, and chemicals. The historical data implies that the refinery operating costs have decreased by 1.0 percent, year-over-year (October 2011-October 2012). The annual average operating cost inflation rate forecasted between October 2012 and October 2046 is 2.03 percent, which is lower than the annual inflation rate of 2.5 percent. This forecast of the annual inflation rate in refinery operating costs (used to proxy the oil sands operating cost inflation) is used to inflate the projected operating costs in the oil sands industry" (pgs. 95-97).

Some prominent reports point to a more challenging operating environment for the oil sands due to higher operating costs and/or steep oil price differentials.[66] Pipeline infrastructure has been cited by some experts as a key determinant of the competitiveness of the oil sands and the oil prices suppliers receive, as bottlenecks could limit takeaway capacity and/or higher transportation costs could cause supply costs to rise.[67] Inflation of labor costs and construction costs, while currently manageable, are often cited as key risks to industry outlooks and expectations for capital or operating expenditures.[68] Historical experience shows that input

[66] CERI's 2013 report describes inflation in supply cost estimates: "A cost comparison with last year's estimates indicate that the cost for a SAGD producer had risen by 6.3 percent, 10.9 percent for an integrated mine, and by 13.2 percent for a stand-alone mine…The initial capital costs have increased for SAGD producers by 1.7 percent from 2011 to $32,482/bbl per day of capacity; and for mining by 4.4 percent, to $76,122/bbl per day of capacity. The sustaining capital costs have doubled across all producers, indicating a stronger cost inflation and the fact that a large number of projects are mature and in need of more maintenance. The greenfield projects might exhibit lower sustaining capital requirements, however, the cost inflation will be present for all new and existing projects, and hence this assumption of higher sustaining capital costs is applied to new projects as well. The non-energy total operating costs have increased to $9.60/bbl of production for SAGD producers and mining saw an increase to $16.80/bbl of produced bitumen. These costs reflect the fact that ongoing labour, materials and equipment costs have seen the greatest escalation in recent years." (pg. xiii, 19) Goldman Sachs (2013a) states that higher costs have made some oil sands projects less competitive: "Data points that indicate higher costs for SAGD greenfields (such as Japex's Hangingstone, sanctioned in 2012 for an implied US$70,000 per flowing barrel) as well as our assumptions for higher maintenance capex [capital expenditure] have led to deterioration in the curve from last year's report. If we run the curve taking into account 2012 Brent-heavy spreads, the picture becomes even more worrying" (page 36, Top 380). However, according to Goldman Sachs (2013c), many of the drivers of inflation have since abated and there haven't been significant changes in oil sands supply costs since 2008.

[67] Goldman Sachs (2013a) specifically points to infrastructure constraints as key determinants of differentials and a key risk to their oil sands supply and price forecasts. Goldman Sachs's *Getting Oil out of Canada* report (2013b) was widely cited as a negative bellwether for the industry and as evidence that infrastructure delays would limit Canadian oil sands production: "While we see significant demand for Canadian heavy crude oil in the United States, in particular in the Gulf Coast region, the main question at this time is whether sufficient pipeline takeaway capacity will exist that crosses the Canada/U.S. border, with Keystone XL (TransCanada) and Alberta Clipper (Enbridge) the key projects to watch, in our view (Exhibits 1-4). In the event that either the Keystone XL newbuild or Alberta Clipper expansion (or both) encounter further delays, we believe risk would grow that Canadian heavy oil/oil sands supply would remain trapped in the province of Alberta, putting downward pressure on WCS pricing on both an absolute basis and versus WTI" (page 2). However, in subsequent correspondence a representative of Goldman Sachs clarified that they were referring to shorter-term impacts and, "to the risk of project delays/deferrals until alternate transportation modes are built (i.e., a different pipeline or new rail capacity). The word 'trapped' was meant as a shorter-term consideration. We believe crude oil production in Canada will grow for many years/decades into the future given the size of the resource and expected resource development economics. However, if Keystone XL and other key near-term pipeline projects face further delay, there is a risk some projects could get pushed out in time."

[68] NEB (2011 and 2013) cites relatively low construction and labor costs, but acknowledges them as key uncertainties in their outlook: "While the current outlook for cost inflation is relatively low, there are a number of large oil sands projects in the construction and planning stages. These projects will be competing for labour and materials from conventional oil and gas projects, as well as other large projects. Although companies have taken steps to control construction costs, cost inflation does have the potential to slow the pace of expansion. A shortage of skilled workers is developing as the workforce ages and overall demand for labour increases. According to the Petroleum Human Resources Council of Canada (PHRCC) the oil and gas industry needs to fill 36,000 job openings between 2013 and 2015, as a result of industry activity levels as well as age-related attrition. In the longer term, under a scenario of higher oil and gas prices, the PHRCC is predicting a requirement of 84,000 new hires by 2022. This challenge is being addressed through a number of government and industry initiatives, but a potential labour shortage may increase construction costs and slow the pace of oil development" (2013, page 48). CIBC (2012) estimated the growth in the labor market that would be required to meet the needs of announced projects: "with so

*(footnote continued on the following page)*

scarcity can materially affect supply costs in the short term, but systemic bottlenecks are likely to be relieved over time as markets and infrastructure adjust.[69]

There is also support for assertions that oil sands supply costs could fall, rather than rise, particularly in a low-price environment. Some companies have reported that oil sands supply costs have risen at moderate, manageable levels or even fallen over the last few years.[70] Trends in the application of technology could reduce oil sands supply costs in the future, as the industry shifts from more expensive mining or integrated upgrading processes, which have high upfront capital and labor costs, to in situ projects that have lower labor requirements and increasingly efficient production processes.[71] There is room for considerable technological learning and innovation in the oil sands—much like innovation unlocked the potential of North American tight oil—which could lower the supply costs of existing production methods ones.[72] Moreover,

many projects in the queue, the labor needs are still massive…The key takeaway is that to meet industry growth forecasts to the 2016/17 time frame, the available labor force in the oil sands would need to expand approximately 80% from 2012 levels" (page 88-89).

[69] "Costs have recently been much higher than they will be in the long run since they reflect scarcity of inputs such as skilled labor, rigs, and steel generated by the exceptionally rapid expansion of the industry and the strong demand for commodities in general spurred by high economic growth in Asia. Costs will likely return to a more moderate level once scarcity of the various inputs is alleviated" (Jaffe et. al. 2011, page 19).

[70] Cenovus (2013a) reports that, between 2010 and 2013, supply costs fell by $10 per barrel for one of its projects (Christina Lake, from $45 to $55 per barrel to $35 to $45 per barrel), $5 per barrel for another project (Foster Creek, from $40 to $50 per barrel to $35 to $45 per barrel), and remained unchanged for three of its projects ($45 to $55 per barrel for Narrows Lake and $55 to $65 per barrel for Grand Rapids and Telephone Lake). According to Goldman Sachs (2013c), one big variable in the reduction of some supply costs is reservoir quality, particularly for SAGD projects. SAGD is not as labor-intensive as mining and especially upgrading, which explains why some cost pressure has disappeared. CIBC (2013) notes that while "there has been record oil sands spending over the past two years, particularly for SAGD projects, inflation appears to be running <5% (which is line with our forecast) and a level that would still allow very robust oil sands growth" (page 46).

[71] Relatively lower-cost in situ production accounts for 70 percent of CIBC's (2013) risked production growth. BMO Capital Markets (2012): "We estimate that supply cost for most oil sands projects is in the range of $50 to $90 per barrel with in situ developments tending to fall at the lower end of the range while mining projects are toward the high end of the range because of their higher upfront capital requirements. In situ extraction of bitumen remains in its relative infancy overall, and rapid advancements in technology and production processes could greatly improve the cost structures of high quality projects, in some cases we estimate supply costs as low as $30/bbl are possible…The shift in focus to in-situ projects is the most significant change as their smaller scale allows for more efficient management of capital and scheduling to match the availability of key inputs such as skilled labour. Moreover, the smaller-scale in-situ processing facilities are more easily modularized and can be outsourced to equipment fabrication shops. New technology and approaches are also helping to reduce costs. The primary in-situ development techniques include Steam Assisted Gravity Drainage (SAGD) and Cyclic Steam Stimulation (CSS); however, the oil sands industry is rapidly evolving, bringing with it inevitable advancement in technology that we believe could help to further reduce the industry's cost structure and reduce the breakeven price for the average in situ oil sands to $50/bbl from roughly $60/bbl currently." (page A9, A32).

[72] For example, the NEB (2011) is optimistic about increased energy efficiency in the oil sands and incorporates assumptions about reduced gas requirements in its outlooks: "New technologies and efficiency enhancements are expected to decrease the intensity of gas use over time. As well, as operators gain experience with their projects they are able to make them more energy-efficient. For the Reference Case, gas use intensity is assumed to improve by 0.5 per cent annually for mining-only, integrated mining and upgrading projects. For in situ projects, intensity is assumed to improve by 1.5 per cent annually" (page 20). NEB also acknowledges the potential for larger technological change: "Over the 25-year outlook period, it is possible that technological breakthroughs will occur that accelerate the pace of development in conventional and/or oil sands resources" (page 26). CIBC makes a similar point in its 2012 report: "There is unprecedented R&D going on in the oil sands, aimed at improving the economics and environmental footprint. Technologies range from evolutionary to revolutionary and any success could have a *(footnote continued on the following page)*

many supply cost elements are endogenous to oil prices and may naturally adjust as oil prices rise or fall, including diluent prices, the cost of energy inputs, royalties, or even labor costs.[73] Similarly, there is considerable uncertainty about how responsive other input costs are to changes in cost pressures as projects are rationalized.

**Supply Cost Comparisons**

Statements about the supply costs or competitiveness of the oil sands vis-à-vis other parts of the oil industry can be somewhat misleading. Oil sands projects are not homogenous and are sanctioned on an individual basis rather than an industry-wide one. Consequently, generalizations about the oil sands are difficult, as the supply costs for individual projects can be significantly higher or lower than other marginal sources of supply due to their reservoir quality and production techniques.

A common finding is that in situ projects compete well with other marginal sources of supply, including U.S. light tight oil.[74] Integrated oil sands projects, which have relatively high costs and must compete directly against growing, cheaper sources of light sweet crude, will be challenged.[75] Oil sands supply costs, widely divergent as they may be, are within the range of most other new sources of oil supply. Tight oil supply costs vary widely, with many estimates falling between $60 and $80 per barrel (IEA 2013).[76]

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meaningful impact on supply costs—similar to how frac technology changed the game for tight oil. Oil sands continue to offer a significant 'free option' on technology" (page 6).

[73] Jaffe et al (2011) found generally that "upstream costs tend to cycle with the price of oil" (page 20). More specifically, the relationship between supply costs and oil prices can be illustrated by examining the costs of specific inputs. Diluents such as condensate, pentanes plus, or SCO are currently priced at a slight premium to light sweet crude oil prices and are closely correlated with their movements. As oil prices fall to the breakeven level implied by supply costs, diluent costs will decrease accordingly, and vice-versa. Alberta's royalty rates also increase along with oil prices. Some terms of certain labor contracts are also related to the price of oil. In 2011, press reported that the Building Trades of Alberta union, which represents provincial construction unions (including those with members who build oil refineries, bitumen upgraders, and other energy infrastructure), signed an agreement with employers that ties wages to average WTI prices as well as the Consumer Price Index (CPI). The agreement represents an attempt to avoid the problems encountered in late 2008, when the province's economic fortunes and demand for construction fell along with the price of oil, but labor costs rose (Gilbert 2011).

[74] BMO Capital Markets (2012): Breakeven prices for in situ oil sands projects are slightly lower than the worldwide average breakeven price and comparable with tight oil breakeven prices, while the costs for integrated oil sands projects are higher (Chart 8, page A8). According to CIBC (2013), "high quality oil sands resources can easily compete with LTO [light tight oil]". CIBC goes on to say that "The oil sands are often considered a fairly homogenous resource, but that really couldn't be further from the truth—particularly in the world of in-situ oil sands where there are vast differences in terms of quality. The challenges facing oil sands will no doubt impact some growth plans (as we noted earlier, corporate expectations are wildly optimistic), but by way of natural selection they will hit the lowest-quality and most underfunded resources the hardest. High-quality in-situ resources compete very well in rate of return with even the most economic LTO plays and have the advantage of resource longevity" (page 51). See Figure 13.17, IEA (2013).

[75] There has been a trend away from integrated oil sands projects and upgrading projects in recent years.

[76] According to the IEA, most estimates for the breakeven cost to produce U.S. shale resources range from $60 to $80 per barrel (IEA 2013). According to reports, energy consultant IHS-PFC Energy estimates breakeven prices range from $40 to beyond $100 a barrel (Denning 2013). Breakeven supply costs for most North American unconventional liquids plays fall in a range of approximately $50 to $100 per barrel (in Brent-equivalent terms), according to Goldman Sachs (2013a). Ranges reflect the differences in geology and ease of production within and between plays.

In certain respects, investments in the oil sands are of a fundamentally different nature than investments in U.S. tight oil. The oil sands are large projects that require long-term investments with payoffs that span decades, while light tight oil developments occur on the basis of individual wells with time horizons measured in months or at most a few years.[77] While the short-term nature of tight oil developments are often attractive because they require less commitment, oil sands developments have the advantage of long lifetimes and do not suffer significant decline rates in the near term like conventional or tight oil developments. Moreover, there is very little uncertainty about the resource potential in the oil sands, which is significant because the usual geologic risks and associated reserve replacement costs are almost entirely absent from the oil sands. The long lead times of oil sands projects mean they can be more difficult to sanction in uncertain or adverse macroeconomic environments, but also that projects under development are less likely to be canceled in response to temporary setbacks.[78] In other words, the price elasticity of supply for the oil sands is likely to be lower than for other, smaller projects, at least in the short term.

## 1.4.3    Crude Oil Transportation

This subsection reviews developments over the past three years in the expansion of pipeline and rail transport. Pipelines have long been the preferred method of transportation for crude oil producers and shippers for long-term, relatively stable commitments. Nonetheless, there has been rapid growth in the use of rail to transport crude oil throughout North America over the past three years.

The nameplate capacity of pipelines exiting western Canada is 3.7 million bpd, almost all of which crosses the U.S. border (total also includes the existing Kinder Morgan Trans Mountain pipeline to Vancouver). Nameplate capacity exceeds actual available capacity due to operational constraints, and capacity utilization fluctuates due to market issues. Effective cross-border pipeline capacity is estimated to be approximately 3.3 million bpd, though some of that capacity is used by petroleum products or Bakken production.

As noted in Section 1.4.2.8, Canadian Oil Production, the production of Canadian crude oil is anticipated to increase substantially through 2030. The EIA 2013 projects total production rises from 2.3 million bpd in 2012 to 5.9 million bpd in 2030 and 6.1 million bpd in 2035. The increment is oil sands crudes, which rise from 1.9 million bpd to 4.2 million bpd. The analysis in the August 2011 Final EIS, including the 2010 and 2011 EnSys analysis, examined estimates of then existing pipeline capacity relative to increases in production as estimated in CAPP forecasts.

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[77] CIBC (2013): "For investors, capital spending profiles (particularly for small- and mid-cap players) are important considerations. Being a mid-cap oil sands producer facing a $1 billion-$2 billion sanction decision is far different than an equivalent-sized LTO producer sanctioning next month's drilling activity. The shorter cycle times and smaller capital exposures give LTO producers a big advantage, particularly in a volatile pricing environment" (page 53).

[78] Goldman Sachs (2013a) makes this point for projects within the oil sands, but the same argument could be made when comparing large-scale, long-term oil sands projects with smaller, short-term projects (e.g., drilling in tight oil plays): "In the event WCS prices come under pressure, in particular in our bear case scenario, we would expect project delays/deferrals in the out years. While it can be difficult to delay/cancel mining oil sands projects mid-development given the large-scale, long lead time nature of oil sands mining, SAGD projects could more easily get pushed out as individual projects are typically smaller scale than mining, with CAPEX [capital expenditure] more easily adjusted." (Goldman Sachs 2013b).

The EnSys 2010 analysis estimated that existing cross-border pipeline capacity could be filled by shortly after 2020, and the EnSys 2011 update noted that it could likely be filled before 2020 based on increased production projections. Since the 2011 EnSys study, the CAPP projection of total western Canadian crude oil supply to market has increased from 3.8 million bpd to 5.2 million bpd by 2020 (and 7.8 million bpd by 2030)[79], implying that existing capacity would be taken up sooner. The IEA 2012b WEO noted existing pipeline capacity could be fully utilized by 2016.[80]

Transportation constraints can have significant impacts on crude oil prices. In late 2012 and early 2013, there were transportation constraints substantially impacting the prices of WCSB crude oils. These constraints were largely within the United States and related primarily to a shortage of pipeline capacity to move crude from PADD 2 to PADD 3, as well as to maintenance on the Enbridge pipeline system and delay in the BP Whiting refinery starting its new heavy crude processing units. The benchmark heavy Canadian crude, WCS, has traded between $9 and $43 per barrel under Maya crude in 2013 through November, and $24 per barrel under Maya on average. This average is in the range of transport costs explained in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail. WCS has also traded at a similar sized discount to WTI. While WTI is lighter, and thus more valuable, than both WCS and Maya, it is the focal point of recent bottlenecks for crude movement from PADD 2 to PADD 3.

There are other proposed WCSB export pipeline projects, including the Enbridge Northern Gateway project to Kitimat, British Columbia, and the Kinder Morgan Trans Mountain pipeline expansions to the Canadian West Coast. These projects are being reviewed, but face significant opposition from various groups, and they may continue to be delayed. Enbridge has stated in investor presentations that the Northern Gateway pipeline (525,000 bpd, expandable to 800,000 bpd) may be operational by "2017+". Kinder Morgan has continued to state in investor presentations that the expansion of the existing Trans Mountain capacity (from 300,000 bpd today to 890,000 bpd capacity based on shipper commitments of 708,000 bpd) is expected to be in service in 2017 (Persily 2013). TransCanada has also proposed an export pipeline to the Canadian East Coast, called Energy East, with a stated proposed capacity of 1.1 million bpd. Because this project involves converting an existing natural gas pipeline for much of the distance (rather than being all-new construction) it may face fewer permitting obstacles than the Canadian West Coast pipelines. Nonetheless, all of the proposed pipeline projects within Canada have faced stringent political opposition and substantial regulatory uncertainty.

Industry has been making significant investments in increasing rail transport capacity for crude oil out of the WCSB. In September 2013, one Canadian investment bank estimated that $5 to $6 billion would be spent in 2013 and 2014 on crude by rail export capacity from the WCSB (Platts 2013)[81]. To assess the crude by rail loading capacity in the WCSB, the Department conducted a comprehensive survey of rail loading facilities in the WCSB, based on company reports, analyst commentary, conference presentations, and interviews with industry operators.

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[79] In the CAPP forecasts (CAPP 2013a) "Western Canadian Oil Supply" is greater than "Western Canadian Oil Production" because the supply numbers include imported diluent necessary to dilute bitumen or heavy crude to pipeline specifications.
[80] Recent private analyst reports indicate existing pipeline capacity could be fully utilized by 2014 or 2015 (Goldman Sachs 2013b).
[81] Citing a September 2013 Peters and Co. report.

Based on this survey, this analysis estimates that by end of 2013 there will be facilities in the WCSB with a nameplate loading capacity of approximately 700,000 bpd of crude oil, and that by the end of 2014 this will increase to just over 1.1 million bpd. Of this capacity, approximately 900,000 bpd is located in (and/or being connected by pipeline to) areas that primarily produce heavy crude oil, both conventional and oil sands, and just over 200,000 bpd is located in the Bakken oil formation where predominantly light sweet crude oil is produced.

Whether transporting heavy crude or light, the transportation of crude by rail in Canada frees up pipeline capacity for other supplies, including oil sands production growth. This added rail transport capacity helps alleviate the transport constraints identified in the analyses cited above. For similar reasons, the EIA noted in mid-2012 that transportation constraints had not appeared to result in production being shut in in the United States, including in the Bakken:

> The phrase "transportation constraints" refers to a broad range of logistic issues, with inadequate pipeline capacity being the most common issue. EIA is not aware of any crude oil production capacity being shut in because of a lack of capacity to move the oil. (EIA 2012a)

### 1.4.3.1    Increases in Pipeline Capacity

Since August 2011, when the Final EIS was published, there have been a significant number of projects that would directly support the export of WCSB crudes and/or move WCSB and Bakken crudes to destination markets.

Enbridge has made regulatory filings[82] to expand one of its heavy crude pipelines, Line 67 (also known as Alberta Clipper), from Hardisty, Alberta, to Superior, Wisconsin, by 120,000 bpd (to 570,000 bpd, with potential to go to 800,000 bpd). The company has also announced that it has shipper support to add a new pipeline from Edmonton to Hardisty with stated initial capacity of 570,000 bpd, expandable to 800,000 bpd, and a potential 2015 in-service date.

In addition, as summarized in Table 1.4-11 and shown in Figure 1.4.3-1, there is substantial pipeline capacity coming online to take WCSB crude oils through the U.S. heartland and out to markets in both the Gulf Coast and eastern Canada. Most of these projects would also support taking Bakken, Rocky Mountain, or Midcontinent U.S. crudes to these same markets. These projects are, for the most part, in addition to those known during the development of the 2011 Final EIS.

Plains All American and Enbridge have projects that will take Bakken crude either north (back up into Canada) or east, in all cases connecting in to the Enbridge Mainline system that runs cross border into northern PADD 2. Enbridge, and also Kinder Morgan, are expanding capacity to bring crude oils from northern PADD 2 (Chicago area) and PADD 4 south to Cushing, which continues to be expanded as a crude oil hub. Expansions are also being made to pipelines from West Texas, Oklahoma, and Kansas into Cushing or directly to refining markets to bring in growing production from those regions.

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[82] This includes an application for a new Presidential Permit currently under review by the Department.

**Table 1.4-11    Selected New Crude Oil Transportation Expansion Projects, Late 2011 to Current**

| Pipeline | Crude type | Route | Date In Service | New Capacity/ Expansion (bpd) | Capacity after Expansion(s) (bpd) |
|---|---|---|---|---|---|
| **Cross Border** | | | | | |
| Enbridge Alberta Clipper/Line 67 Expansion Phase 1 | WCSB | From Hardisty, Alberta to Superior, Wisconsin | 2014 | 120,000 | 570,000 |
| Enbridge Alberta Clipper/Line 67 Expansion Phase 2 | WCSB | From Hardisty, Alberta to Superior, Wisconsin | 2014 | 230,000 | 800,000 |
| Enbridge Bakken Pipeline | Bakken | From Berthold, North Dakota, to Cromer, Manitoba | 2013 | 120,000 | 145,000 |
| Plains All American Bakken North | Bakken | From Trenton, North Dakota, to Regina, Saskatchewan | 2013 | 50,000 | 50,000 |
| Plains All American Wascana Pipeline Reversal | Bakken | Outlook, Montana to Regina, Saskatchewan | 2013 | 50,000 | 50,000 |
| **United States** | | | | | |
| Enbridge/Energy Transfer Partners Natural Gas to Crude Conversion | WCSB, Bakken | Patoka, Illinois to Gulf Coast area | 2015 | 660,000 | 660,000 |
| Enbridge/Enterprise/Seaway Reversal and Expansion Phase I | Midcontinent, WCSB, Bakken | Cushing, Oklahoma to Gulf Coast area | 2012 | 150,000 | 150,000 |
| Enbridge/Enterprise/Seaway Reversal Phase II | Midcontinent, WCSB, Bakken | Cushing, Oklahoma to Gulf Coast area | 2013 | 250,000 | 400,000 |
| Enbridge/Enterprise/Seaway Reversal Phase III | Midcontinent, WCSB, Bakken | Cushing, Oklahoma to Gulf Coast area | 2014 | 450,000 | 850,000 |
| Enbridge Flanagan South | WCSB and Bakken | Flanagan, Illinois to Cushing, Oklahoma | 2014 | 585,000 | 585,000 |
| Enbridge Line 5 Expansion[a] | WCSB and Bakken | Superior, Wisconsin to Sarnia, Ontario | 2013 | 50,000 | 540,000 |
| Enbridge Sandpiper Pipeline | Bakken | Beaver Lodge, North Dakota, to Superior, Wisconsin | 2015 | To Clearbrook: 225,000 Clearbrook to Superior: 375,000 | 375,000 |
| Enbridge Southern Access Expansion/Line 61 Enhancement Phase 1 | WCSB and Bakken | From Superior, Wisconsin to Flanagan, Illinois | 2014 | 160,000 | 560,000 |
| Enbridge Southern Access Expansion/Line 61 Enhancement Phase 2 | WCSB and Bakken | From Superior, Wisconsin to Flanagan, Illinois | 2015 | 640,000 | 1,200,000 |
| Enbridge Spearhead North Twin | WCSB, Bakken | Flanagan, Illinois to Griffith, Indiana | 2015 | 100,000 | 235,000 |
| Hiland Crude Double H Project | Bakken | Dover, North Dakota to Guernsey, Wyoming | 2014 | 50,000 | 50,000 |
| Kinder Morgan Pony Express | Niobrara, Bakken | Guernsey, Wyoming to Cushing, Oklahoma | 2014 | 220,000 | 220,000 |
| Koch Pipeline Co Dakota Express Pipeline | Bakken | Western, North Dakota to Patoka, Illinois | 2016 | 250,000 | 250,000 |
| TransCanada Bakken Marketlink | Bakken | Baker, Montana to Cushing, Oklahoma | 2014 | 100,000 | 100,000 |
| TransCanada Gulf Coast Project | Midcontinent, WCSB, Bakken | Cushing, Oklahoma to Gulf Coast area | 2013 | 830,000 | 830,000 |
| **Canada Export** | | | | | |
| Enbridge Line 6B Replacement and Expansion[a] | WCSB and Bakken | Griffith/Hartsdale, Indiana to Sarnia, Ontario | 2013 | 260,000 | 500,000 |
| Enbridge Line 9B Reversal and Line 9 Capacity Expansion[a] | WCSB and Bakken | From North Westover, Ontario to Montreal, Quebec | 2014 | 60,000 | 300,000 |
| Enbridge Northern Gateway Bitumen and Condensate Pipeline | WCSB | Edmonton, Alberta to Kitimat, British Columbia | 2018 | 525,000 | 525,000 |
| Kinder Morgan Canada Trans Mountain Pipeline Expansion | WCSB | Edmonton, Alberta to Burnaby, British Columbia | 2017 | 590,000 | 890,000 |
| TransCanada Energy East Pipeline | WCSB | Hardisty, Alberta to Saint John, New Brunswick | 2017 | 1,100,000 | 1,100,000 |

Source: Ellerd 2012; Enbridge 2010; Enbridge 2011a; Enbridge 2011b; Enbridge 2012a; Enbridge 2012b; Enbridge 2012c; Enbridge 2012d; Industrial Commission of North Dakota 2012; Smith 2012; TransCanada 2012; Reuters 2013; Pipeline companies' websites and industry press announcements.

[a] Enbridge Line 5, 6B, and Line 9/9B are components of their Eastern Access project.

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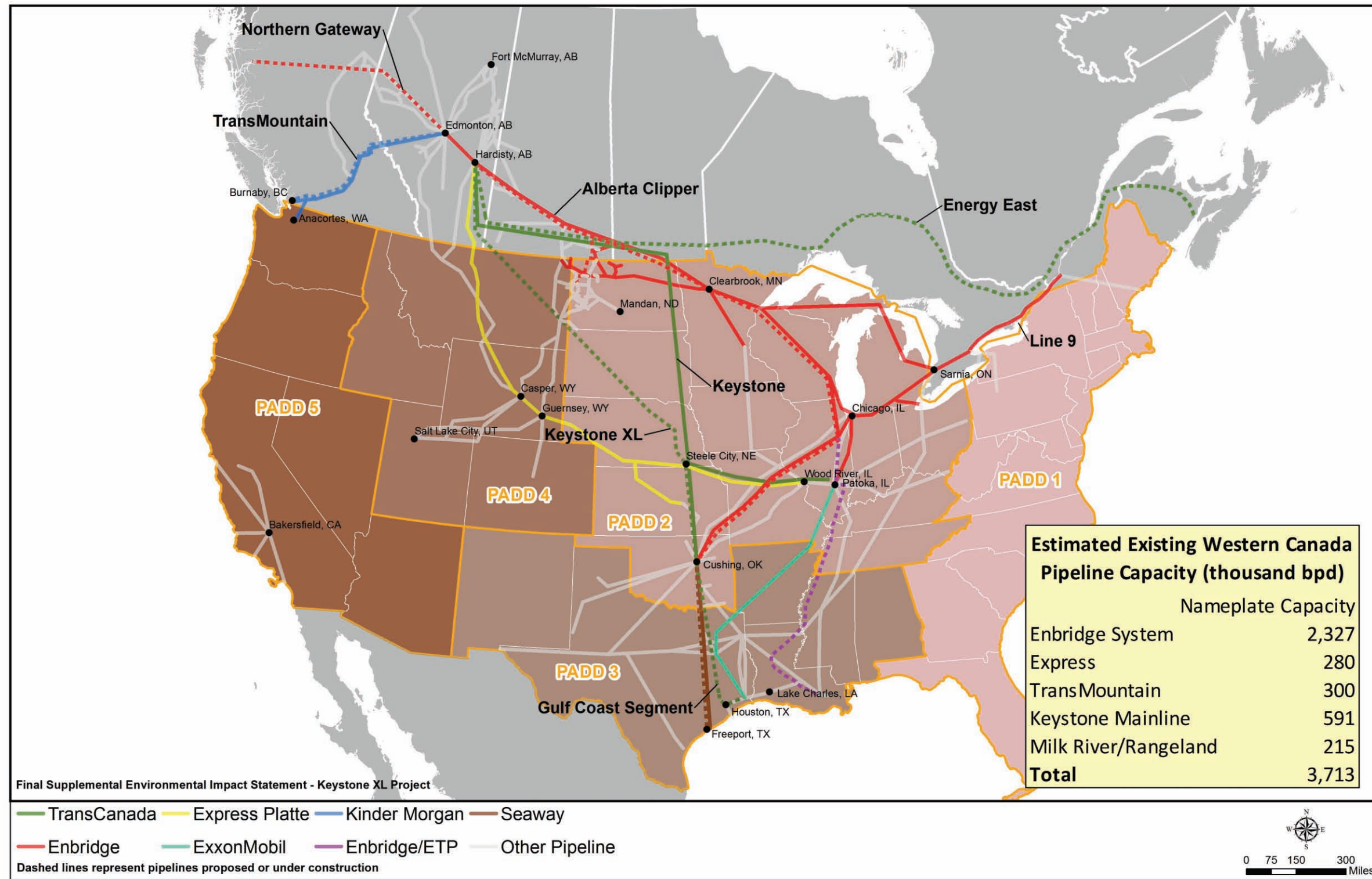
Source: CAPP 2013a; Esri 2013

**Figure 1.4.3-1        Selected Current and Proposed Crude Oil Pipelines**

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Enbridge has an array of projects under the heading *Eastern Access* to increase capacity to take WCSB, and also potentially Bakken, crudes to refineries in eastern PADD 2 but primarily in Sarnia, Ontario, and potentially Quebec and Montreal.

There are several projects that have been developed, and are under development, that would substantially increase the capacity to transfer crude oil from PADD 2 south to PADD 3, and to redirect crude oil that would have been delivered into PADD 2 directly to PADD 3. Until mid-2012, there was only one pipeline, the 93,000 bpd Pegasus line, carrying crude oil from PADD 2 to PADD 3 (the Gulf Coast). That pipeline has been out of service since March 2013, after a substantial spill in Mayflower, Arkansas. In 2012, reversal of the existing Seaway pipeline was completed so that it now runs south from Cushing to the Gulf Coast. Initial capacity of 150,000 bpd in the reversed direction was increased to 400,000 bpd in January 2013 by adding pumping capacity. The owners of the pipeline are also twinning it, adding another 450,000 bpd of capacity for a total of 850,000 bpd. Construction on TransCanada's Gulf Coast Project is completed,[83] which would add up to 830,000 bpd of transport capacity between those locations. Enbridge and Energy Transfer Partners, LP, announced plans to convert one of three pipelines of the Trunkline system from natural gas transmission to crude oil service, which would allow transport of up to 660,000 bpd from Patoka, Illinois, to the Gulf Coast area. These combined projects add a total of 2.34 million bpd of new pipeline capacity between PADD 2 and PADD 3 that did not exist when the Final EIS was published.

In general, the projects listed in Table 1.4-11 have entered service or are expected to be in service in 2013 or 2014. They constitute a subset of the total array of pipeline projects currently underway.

In addition to these projects, substantial additional capacity is also coming on stream to move Eagle Ford crude to the Gulf Coast and, as noted, to take expanding West Texas and Midcontinent crude production to Cushing, and thence onward to inland destinations and the Gulf Coast.

The Final EIS and EnSys 2011 had noted that projects for interstate petroleum pipelines that do not cross an international border face less regulatory review, especially when they entail modifications to existing lines or rights of way. The development of these projects supports that assessment, and supports the view that, in general and absent larger regulatory changes, one can expect infrastructure developments to follow market patterns of supply and demand, which EnSys had described as business as usual.

The next sections address how rail capacity has increased in the WCSB and elsewhere to accommodate the changing production patterns and ends with a discussion regarding how the price discounts noted here are creating overriding incentives to use alternate modes of transport.

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[83] The TransCanada Gulf Coast Project is the renamed southern segment of the previous Keystone XL pipeline project. In February 2012, Keystone advised the Department that it considered the Gulf Coast Project to have independent utility and that it was proceeding with construction of the Gulf Coast Project.

### 1.4.3.2      Increases in Canadian Crude by Rail

While no new pipeline capacity has been added since 2011 across the Canada-United States border or to the Canadian West Coast, the development of rail as a viable, large-scale transport option for crude oil is adding significant transport capacity along these and other routes.[84] Although crude oil was being shipped by train prior to 2010, it was not being done in significant quantities. Many refineries and terminals had facilities to handle crude oil and refined products by rail, but there were very few (if any) facilities dedicated to shipping crude by rail prior to 2010. The Williston Basin region in North Dakota has seen the most rapid development of crude by rail transport (moving over 700,000 bpd at one point in the summer of 2013), but crude by rail has been expanding throughout North America, including from western Canada.

Although this section focuses on rail, rail is also being used in combination with pipelines as well as barges and tankers to deliver crude oil to refineries.

**Current Crude by Rail in the WCSB**

There are two major rail operators in Canada, Canadian National (CN) and Canadian Pacific Railway System (CPRS). Before 2011, the two rail carriers did not transport significant volumes of crude oil (although CN had been promoting the option of crude by rail for a few years before 2011). Beginning in 2011, each operator began increasing the amount of crude oil it transported. Based on statements in the earnings calls for CN and CPRS, it is estimated that in the first half of 2013 they transported just under 70,000 carloads of crude oil, and are expected to transport more than 150,000 carloads in 2013 (see Figure 1.4.3-2).

The total carloads in Figure 1.4.3-2 include CN's and CPRS's loadings in the United States. While almost all of CN's carload originations are in Canada, CPRS serves several large loading facilities in North Dakota. The American Association of Railroads collects quarterly statistics on carloads of various commodities originated in the Unites States. CN and CPRS reported a combined total crude oil carloadings in the United States of 11,837 and 12,020 carloads in the first and second quarters of 2013, respectively (Surface Transportation Board 2013). Based on these reports, it is estimated that in the first half of 2013, approximately 36 percent of CN's and CPRS's crude carloadings were in the United States and 64 percent in Canada. If this proportion stayed the same in the second half of 2013, then CN and CPRS total crude carloads loaded in western Canada in 2013 would be approximately 95,000.

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[84] For example, the Express Pipeline, terminating in Casper, Wyoming, with a capacity of 280,000 bpd, is underutilized because the Platte Pipeline to which it connects has a capacity of approximately 150,000 bpd. The Draft Supplements EIS had noted there were proposed rail facilities that could provide onward delivery for additional quantities of WCSB heavy crude delivered to Casper. In September 2013, the Express Pipeline owner announced that it had signed new, long-term contracts for 225,000 bpd of committed capacity on the pipeline. They noted that some of the crude transported by the pipeline would be loaded for onward delivery to refineries at the new crude-by-rail facilities being developed in Wyoming.
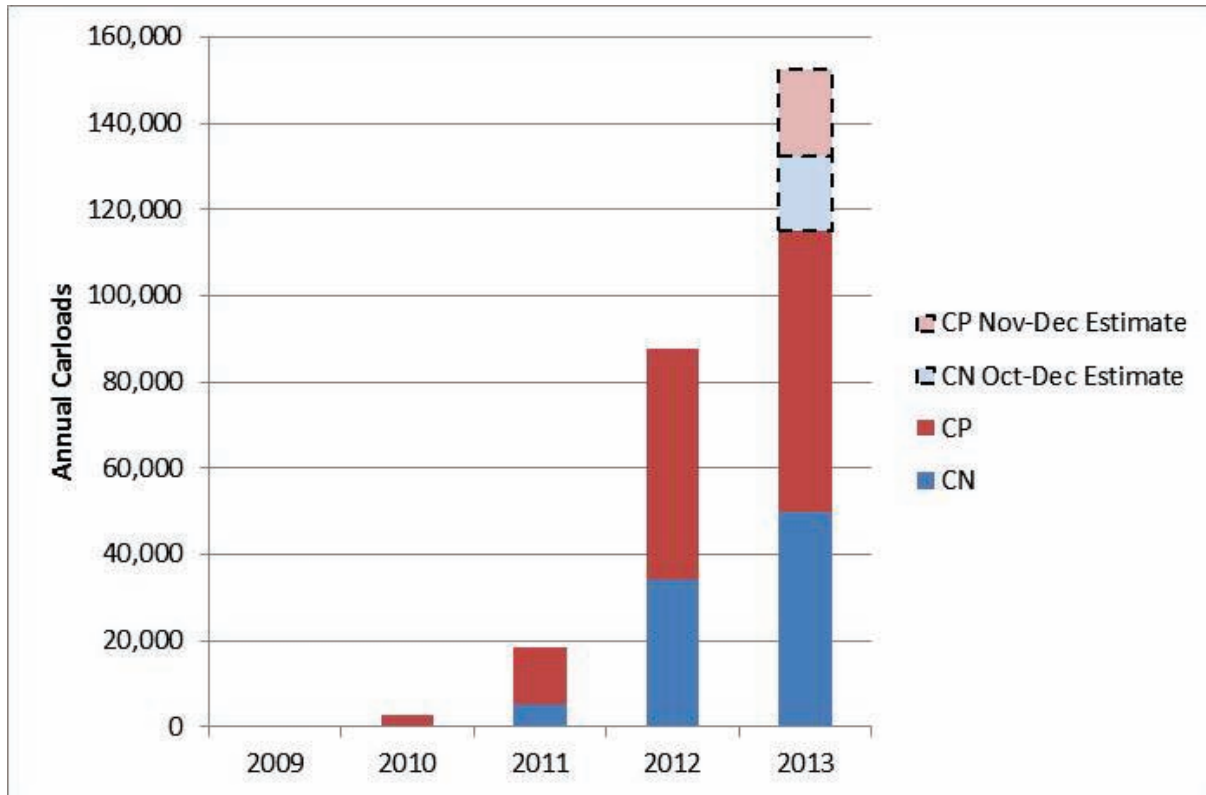
Source: CN and CPRS earnings calls and company reports.

**Figure 1.4.3-2        CPRS and CN Reported Crude Oil Transport—Carloads**

The limiting factor for a given load in a tank car is typically the weight limits, rather than volume limits. Because crude oils vary in density, this means that there is a range of barrels contained in a carload of crude oil. Depending upon the density of crude oil and the size of the rail car, one carload could range from approximately 500 barrels (for raw bitumen in the smaller coiled and insulated tank cars) to just over 700 barrels (for light crude oil in the largest size general purpose tank car) (see Table 1.4-12).

**Table 1.4-12     Estimates of Barrels per Carload of Different Crude Oils**

| Crude Type | Raw Bitumen (0% diluent) | Railbit (15% diluent) | Dilbit (30% diluent) | Light Crude |
|---|---|---|---|---|
| API Gravity | 8.5 | 14 | 21 | 42 |
| Estimated barrels per Carload | 525-550 | 550-575 | 600-625 | 675-700 |

Note: The low end of the estimate is based on a tank car with total gross weight limit of 268,000 pounds; the high end is for a tank car with total gross weight limit of 286,000 pounds.

The estimates that follow in this section generally assume a mix of light and heavy crude oils are transported in 268,000 pound gross weight limit tank cars, resulting in an average volume of 600 barrels per carload.[85]

The quarterly reports of crude carloadings from CN and CPRS were cross-referenced with monthly data from Statistics Canada (2013) on crude and fuel oil carloadings in Western Canada to develop a month-by-month estimate of crude by rail loadings.[86] This estimate was then compared with estimates from industry analysts (in particular Peters and Co. 2013 estimates, as well as estimates from IHS CERA 2013, and Energy Policy Research Foundation Inc. [EPRINC] 2013). The results are presented in Figure 1.4.3-3 below, which indicates the crude by rail increasing from nominal amounts in early 2011, to approximately 160,000 bpd by April 2013, then declining back to around 150,000 bpd before recovering back to approximately 160,000 bpd in September.[87]

Not all of the crude oil loaded by rail in western Canada is necessarily exported to the United States. The Canadian NEB reports exports of crude oil by rail on an annual basis, but also provided statistics by quarter for the first half of 2012 and the first half of 2013 (NEB 2013b). The NEB statistics reflect a similar trend in increasing rail transport from 2011 to 2013, and indicate approximately 70 percent to 80 percent of the crude by rail loaded in western Canada was exported to the United States[88] (see Figure 1.4.3-4).

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[85] An average of 600 barrels per carload is derived from an assumed mix of 1/3 railbit; 1/3 dilbit; and 1/3 light crude being transported from Western Canada. This is consistent with company reports and NEB export statistics. The mix of crudes being loaded in western Canada is discussed further below.

[86] To estimate the portion of crude oil in 2011, 2012, and 2013 in the Statistics Canada aggregated data on crude oil and fuel oil loadings, the monthly estimates in those years were compared to the average monthly loadings from 2005 to 2010 when almost no crude oil was loaded.

[87] This is consistent with estimates from Peters & Co. that in early 2013 there were 120,000 bpd of being transported by rail from the WCSB (Peters & Co. Limited 2013), growing to 175,000 bpd by mid-2013 (Healing 2013). IHS CERA indicated that by the end of the first quarter 2013, about 150,000 bpd of crude was leaving western Canada by rail (IHS CERA 2013); and EPRINC estimated 120,000 bpd in October (EPRINC 2013).

[88] This would mean that in 2013 25,000 to 40,000 bpd of crude oil are being exported via rail from the WCSB to other locations in Canada. There have been news reports that refineries on the Canadian West Coast and Canadian East Coast are receiving crude oil shipments from the WCSB by rail. CBC 2013a; Penty 2012.
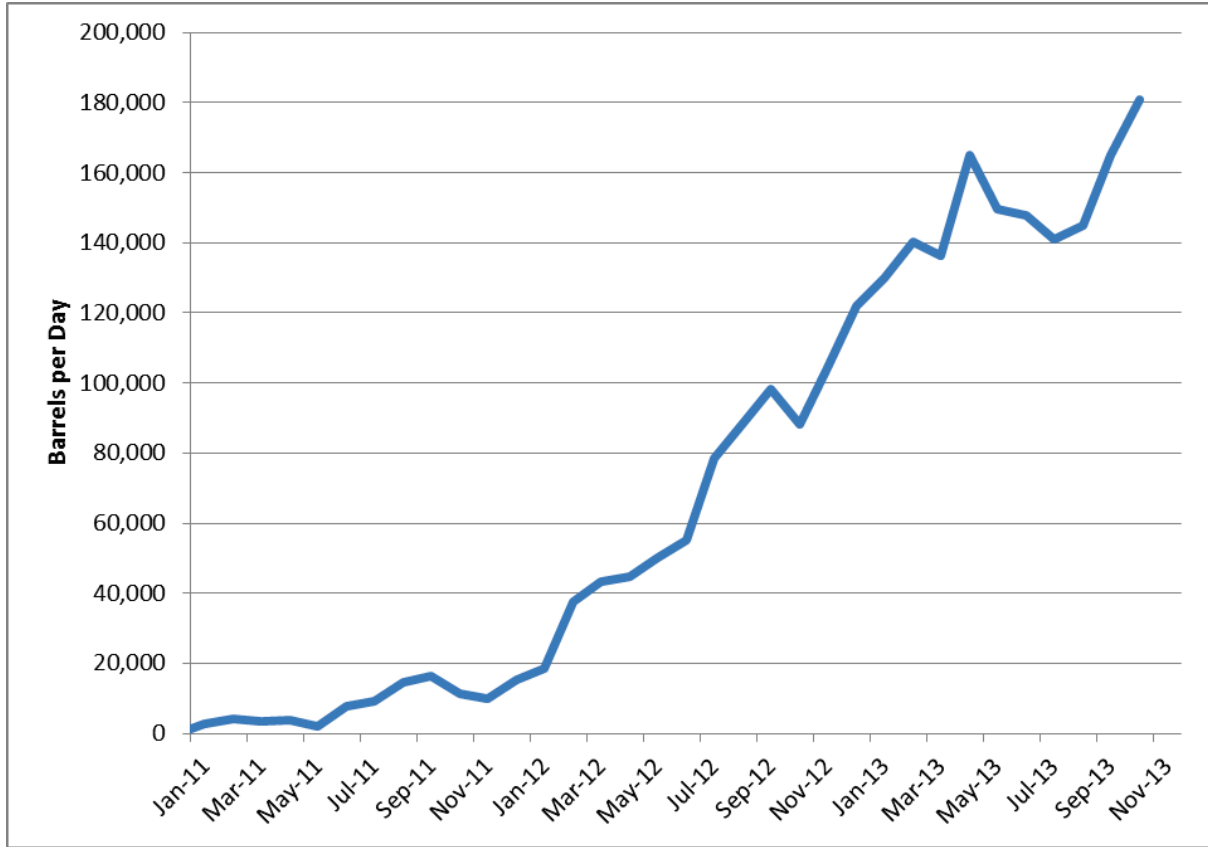
Source: Statistics Canada 2013, U.S. Department of Transportation Bureau of Transportation Statistics 2013, Peters and Co. 2013, IHS CERA 2013, and company information.

**Figure 1.4.3-3          Estimated Crude Oil Transported by Rail from WCSB, bpd**
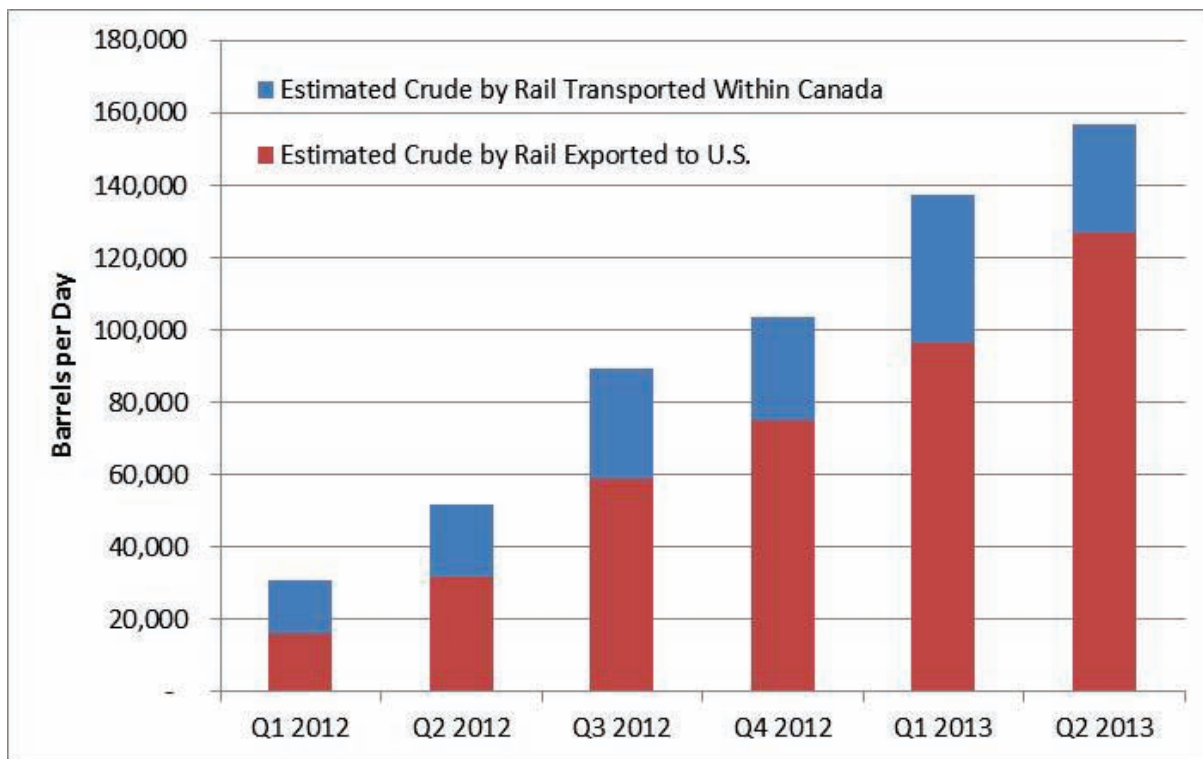
Source: NEB 2012 (exports by transportation mode), Statistics Canada 2013, U.S. Department of Transportation Bureau of Transportation Statistics 2013, Peters and Co. 2013, IHS CERA 2013, and company information.

**Figure 1.4.3-4     Estimated Crude Rail Loadings in WCSB Compared to NEB Crude by Rail Exports to the United States**

In January 2013, Peters and Co. estimated that approximately half of the crude oil hauled by rail in western Canada was light, and half was heavy. In 2012, approximately 50 percent of the Canadian crude-by-rail exports went to PADD 3 (Gulf Coast), and approximately 40 percent went to PADD 1 (East Coast) (NEB 2012). The relative volume of light and heavy crude oils hauled by rail was estimated by employing the following methodology. First, it was assumed that the volumes shipped within Canada were almost all light grades.[89] Second, the NEB crude by rail export statistics were compared with NEB statistics regarding qualities of crude exported to the United States. By correlating those data sets, it is estimated that in the second quarter of 2013, as much as 90,000 to 100,000 bpd of heavy Canadian crude (both oil sands bitumen blends and conventional heavy) were exported by rail to the United States, almost all to PADDs 1 and 3.[90] This is consistent with reports from midstream companies involved in crude by rail in

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[89] The refineries reportedly receiving crude-by-rail shipments in Canada, primarily the Irving refinery in St. John, New Brunswick and the Chevron refinery in Burnaby, British Columbia, process predominantly light sweet crude oil, but there could be some heavy grades hauled by rail within Alberta.

[90] In 2012, over 90 percent of the crude-by-rail exports are to PADDs 3 (50 percent) and 1 (40 percent). If those percentages were similar for the second quarter of 2013 then crude by rail exports to PADD 3 would have been approximately 62,000 bpd, and PADD 1 would have been approximately 50,000 bpd. In 2012 and the first half of 2013, PADD 3 imported an average of 130,000 bpd of Canadian crude, of which only 12,000 bpd was light or
*(footnote continued on the following page)*

Alberta.[91] If accurate, this would indicate that in the second quarter of 2013, the mix of heavy crude had increased to approximately two-thirds of the total crude-by-rail shipments loaded in western Canada, and 70 to 80 percent of western Canadian crude exported to the United State by rail. Based on the locations and focus of the crude by rail facilities currently being constructed, it is likely that the relative proportion of heavy crude oil will grow.

**Canadian Crude-by-Rail Loading Capacity**

Transporting large volumes of crude oil by rail requires the construction of specialized facilities (or modification of existing terminal facilities) to load crude oil into rail cars. Western Canada is in the midst of a significant build out of such facilities. At the end of 2011, crude oil loading facilities had an estimated capacity to load approximately 60,000 bpd, with most of that capacity being in the Canadian Bakken area that produces almost exclusively light crude oil. This loading capacity had grown to approximately 200,000 bpd at the end of 2012, with approximately 55 percent of the loading capacity in areas of the WCSB that produce primarily heavy crude oil and 45 percent in the Canadian Bakken. In mid-2013 crude-by-rail loading capacity began to increase substantially, particularly in the portions of the WCSB that produce primarily heavy crude oil. By the end of 2014, the total crude-by-rail loading capacity is expected to be approximately 1.1 million bpd (75 percent in the WCSB and 25 percent in the Canadian Bakken), as shown in Figure 1.4.3-5. These estimates do not include a facility being constructed in Edmonton, Alberta, with a design capacity of 250,000 bpd (100,000 bpd expected to be operational by the end of 2014) that was announced shortly before the Supplemental Final EIS was completed.[92]

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medium crude. If all of that light or medium crude were delivered by rail in the second quarter of 2013, then the remainder of the rail shipments to PADD 3 would be approximately 50,000 bpd of heavy crude delivered to PADD 3. Before 2012, the only western Canadian crude delivered to PADD 1 was via the Enbridge pipeline system delivered almost entirely to a single refinery in Warren, Pennsylvania (CAPP 2013a). During 2011, the average volume of heavy Canadian crude exported to PADD 1, according to NEB, was 35,000 bpd. In 2012 NuStar began shipping heavy Canadian crude by rail to its asphalt refinery, and in early 2013 PBF Energy also began shipping heavy Canadian crude by rail to its refinery in Delaware City. In the first half of 2013 NEB data indicate that heavy Canadian crude exports to PADD I averaged 78,000 bpd. If all of the incremental heavy crude were crude delivered by rail (a reasonable assumption since the refinery in Warren, Pennsylvania has not been reconfigured to run entirely on heavy crude) then in the second quarter of 2013 PADD I may have been receiving approximately 40,000 bpd of heavy Canadian crude.

[91] Altex Energy, Torq Transloading, and Canexus were the three largest operators of crude-by-rail facilities in western Canada in 2013. Altex and Canexus state that they load almost exclusively heavy crude oil. Torq estimates that its loadings are 80 percent heavy crude oil. According to statements of those companies, at the end of the second quarter, beginning of the third quarter of 2013 they were cumulatively loading approximately 90,000 to 100,000 bpd, of which approximately 85,000 to 90,000 bpd were likely heavy crude.

[92] On December 20, 2013, Kinder Morgan and Imperial Oil announced they were building a new unit-train facility in Edmonton that would have 100,000 bpd of loading capacity by the end of 2014, and a top capacity of 250,000 bpd (Kinder Morgan 2013).
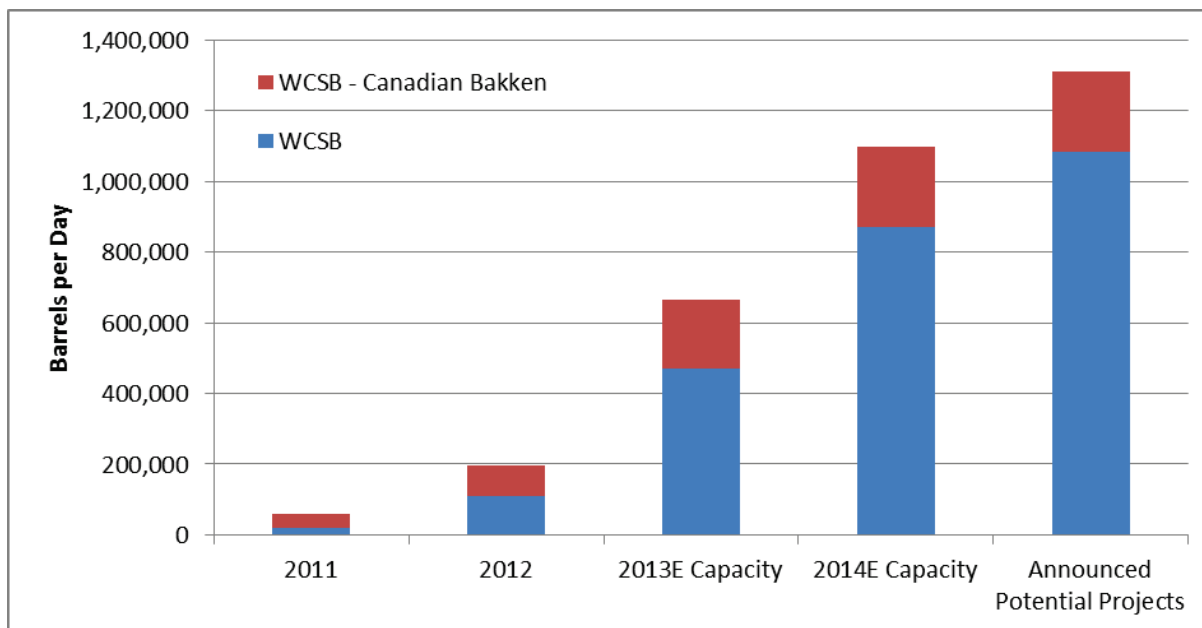
Note: WCSB is used to refer to the primarily heavy crude loading areas. Canadian Bakken is primarily light crude loading areas. Western Canada refers to both areas. A complete list of these facilities is presented in Table 1.4-13 below. Sources for each facility are presented in Appendix C, Supplemental Information to Market Analysis. These estimates do not include a facility being constructed in Edmonton with a design capacity of 250,000 bpd (100,000 bpd expected to be operational by the end of 2014) that was announced immediately before the Supplemental Final EIS was completed. Adding this facility to the figure would increase the 2014 year-end capacity to 1.2 million bpd, and the Announced Potential Projects to approximately 1.5 million bpd.

**Figure 1.4.3-5        Estimated Western Canada Crude Oil Rail Loading Nameplate Capacity (Year End)**

This substantial increase in WCSB crude-by-rail loading capacity is being driven by a shift to building larger loading facilities, including unit train facilities. Unit train facilities can load an entire 100 to 120 tank-car train in 1 or 2 days. The entire train travels as one unit from a single origin point to a single destination point (and back). This provides faster and less expensive transport than manifest shipments, where a smaller number of tank cars are added to trains carrying a variety of goods. The increased crude-by-rail shipments from western Canada shown in Figure 1.4.3-3 were almost exclusively accomplished from manifest train loading facilities.[93] By the end of 2013 there are expected to be four unit-train facilities in operation in the WCSB focused on transporting heavy crude oil (a combination of bitumen blends and conventional heavy crude).[94] In addition, in 2014, three additional unit-train facilities are scheduled for

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[93] Pembina Pipeline stated that it loaded a unit train of crude oil from its Nexus facility in September 2013. There was also a report of a unit train of heavy Canadian crude delivered to Port Arthur, Texas, in July of 2013. Canexus announced in mid-December 2013 that they had begun of unit-train operations.

[94] These facilities are the Altex Energy facility at Lashburn, Saskatchewan, the Canexus facility at Bruderheim, Alberta; the Pembina Pipeline facility at its Nexus terminal (which reportedly loaded its first unit train at the end of the third quarter of 2013); the Torq Transloading facility at Unity, Saskatchewan. The first two facilities are focused on transporting pipeline-delivered dilbit by rail, while the second two are focused on transporting conventional heavy crude oil.

completion (and one of the existing facilities is expanding). If these various projects are completed on schedule, there would be seven unit train facilities in the WCSB that could load up to nine trains per day.[95]

Table 1.4-13 below lists the known operating, under construction, and planned western Canada crude-by-rail loading facilities. It lists those facilities in operation by the third quarter of 2013, and then specifies expected start dates for facilities beginning operation after the third quarter of 2013. The table distinguishes between facilities in the WCSB areas that produce primarily heavy crude oil and those facilities located in the Canadian Bakken.

**Table 1.4-13    Canadian Crude by Rail Loading Facilities**

| Facility/Owner Operator | Capacity (bpd) | In-Service Date | WCSB or Canadian Bakken[a] |
|---|---|---|---|
| Altex Energy, Falher (Peace River), AB | 20,000 | 2013 | WCSB |
| Altex Energy, Lashburn, SK | 30,000 | Operational | WCSB |
| Altex Energy, Lashburn, SK (expansion) | 30,000 | 2013 | WCSB |
| Altex Energy, Lloydminster, SK | 3,000 | Operational | WCSB |
| Altex Energy, Lynton, AB (expansion) | 8,000 | 2013 | WCSB |
| Altex Energy, Lynton, AB | 12,000 | Operational | WCSB |
| Altex Energy, Peace River, AB | na | Potential | WCSB |
| Altex Energy, Reno, AB | 22,000 | 2014 | WCSB |
| Altex Energy, Reno, AB | 38,000 | Under development | WCSB |
| Altex Energy, Unity, SK | 19,000 | Operational | WCSB |
| Altex Energy, Wainwright, AB | 6,000 | 2013 | WCSB |
| Arrow Reload Systems, Kerrobert, SK | 6,000 | Operational | WCSB |
| Canexus Corp, Bruderheim, AB | 30,000 | Operational | WCSB |
| Canexus Corp, Bruderheim, AB (Phase 1) | 30,000 | 2013 | WCSB |
| Canexus Corp, Bruderheim, AB (Phase 2) | 60,000 | 2014 | WCSB |
| Ceres Global Ag. Corp, Northgate, SK | 70,000 | 2013 | Canadian Bakken |
| CN, Barr, AB | 8,000[b] | Operational | WCSB |
| CN, Eckville, AB | na | Under development | WCSB |
| CN, Edson, AB | 6,000 | Operational | WCSB |
| CN, High Level, AB | 3,000[b] | Operational | WCSB |
| CN, Lynton, AB | 8,000[b] | Operational | WCSB |
| CN/PetroGas, Wilmar, SK | 14,000 | Operational | Canadian Bakken |
| CN, Scotford, AB | 8,000[b] | Operational | WCSB |
| CN/Watco, Bienfait, SK | 8000[b] | Operational | Canadian Bakken |
| CN/Watco, Woodnorth, SK | 8,000[b] | Operational | Canadian Bakken |
| CP, Calmar, AB | na | | WCSB |
| CP, Estevan, SK | 10,000 | Operation | Canadian Bakken |
| CP, Lambton Park, AB | na | Operational | WCSB |
| Crescent Point, Alliance, AB | 3,000 | Operational | WCSB |
| Crescent Point, Dollard, SK | 12,000 | Operational | WCSB |
| Crescent Point, Stoughton, SK | 45,000 | Operational | Canadian Bakken |

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[95] Facility-trains per day at end 2014: Altex Energy, Lashburn—1; Canexus, Bruderheim—2; Gibson Energy/U.S. Development Group, Hardisty—2; Keyera/Kinder Morgan, Edmonton—0.5; Pembina Pipeline, Edmonton—0.5; Torq Transloading, Kerrobert—2; Torq Transloading, Unity—1. Adding the Kinder Morgan/Imperial, Edmonton facility announced on December 20, 2013, would increase this to 10 to 11 unit trains per day that could be loaded in the WCSB by the end of 2014. There are two additional unit-train facilities under development in the Bakken area of Canada: Tundra Energy, Cromer—1; Ceres Global Ag, Northgate—2.

| Facility/Owner Operator | Capacity (bpd) | In-Service Date | WCSB or Canadian Bakken[a] |
|---|---|---|---|
| Elbow River, Nampa, AB | na | Potential | WCSB |
| Elbow River/Roma, Peace River, AB | 10,000 | Operational | WCSB |
| Gibson, East Edmonton, AB | 8,000[b] | Operational | WCSB |
| Gibson Energy, Edmonton, AB | 20,000 | 2015 | WCSB |
| Gibson Energy, Rimbey, AB | na | 2013 | WCSB |
| Gibson Energy, Sexsmith, AB | 6,000 | Operational | WCSB |
| Gibson Energy, U.S. Dev., Hardisty, AB | 140,000 | 2014 | WCSB |
| Grizzly Oil Sands, Windell, AB | na | Under development | WCSB |
| Keyera/Enbridge, South Cheecham, Wood Buffalo, AB | 32,000 | 2013 | WCSB |
| KM/Keyera, Edmonton, AB (initial phase) | 40,000 | 2014 | WCSB |
| KM/Keyera, Edmonton, AB (potential expansion) | 125,000 | Potential | WCSB |
| Pembina Pipeline, Edmonton, AB | 40,000 | 2013 | WCSB |
| Plains Midstream, Mitsue, AB | 30,000 | 2015 | WCSB |
| Predator Oil, Alliance, AB | 8,000[b] | Operational | WCSB |
| Predator Oil, Mannville, AB | 8,000[b] | Operational | WCSB |
| Private Owner, Kindersley | na | Operational | WCSB |
| Savage Services, Peace River, AB | na | Under development | WCSB |
| Torq Transloading, Bromhead, Southall, SK | 13,000 | Operational | Canadian Bakken |
| Torq Transloading, Instow, SK | 15,000 | Operational | WCSB |
| Torq Transloading, Kerrobert | 140,000 | 2014 | WCSB |
| Torq Transloading, Lloydminster, SK | 10,000 | Operational | WCSB |
| Torq Transloading, Tilley, AB | 8,000 | Operational | WCSB |
| Torq Transloading, Unity, SK | 20,000 | Operational | WCSB |
| Torq Transloading, Unity, SK | 50,000 | 2013 | WCSB |
| Torq Transloading, Whitecourt, AB | 3,500 | Operational | WCSB |
| Tundra Energy, Cromer, MB (Phase 1) | 30,000 | 2013 | Canadian Bakken |
| Tundra Energy, Cromer, MB (Phase 2) | 30,000 | 2014 | Canadian Bakken |
| Unknown Operator, Mitsue, AB | 8,000[b] | Operational | WCSB |

| Potential Project Totals | | | |
|---|---|---|---|
| | WCSB | Canadian Bakken | Total |
| 2013 Estimated Capacity | 468,500 | 198,000 | 666,500 |
| 2014 Estimated Capacity | 870,500 | 228,000 | 1,098,500 |
| Announced Potential Projects | 1,084,000 | 228,000 | 1,312,000 |

Source: Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

[a] WCSB is used to refer to the primarily heavy crude loading areas. Canadian Bakken is primarily light crude loading areas. This table does not include a facility being constructed in Edmonton with a design capacity of 250,000 bpd (100,000 bpd expected to be operational by the end of 2014) that was announced shortly before the Final Supplemental EIS was completed. In addition, Altex Energy has plans for a 55,000 bpd loading facility in Vermillion, Alberta (Altex Energy, n.d.). Adding these facilities would increase the WCSB estimated capacity to 970,500 bpd for 2014, and 1.3 million bpd of capacity of announced potential projects.

[b] These facilities are listed on Canadian National Railway presentations but capacities could not be confirmed. Estimated capacity of 8,000 bpd is based on the average capacity of other manifest facilities (with capacities of less than 20,000 bpd), except for High Level, which is assumed to be 3,000 bpd (the lowest reported capacity for any facility) because it is not in a large production region.

[c] na = not available

Although it appears that the shippers report the capacities of these facilities in a variety of ways, it is assumed that the capacities listed in Table 1.4-13 are nameplate capacities. Based on industry reports and statistics from North Dakota, it appears a reasonable estimate of effective capacity is approximately 80 percent of nameplate capacity (Industrial Commission of North Dakota 2013). This means the effective capacity of the crude-by-rail loading facilities in western

Canada at the end of 2014 would be approximately 720,000 bpd in the WCSB,[96] and 190,000 bpd in the Bakken.

Figure 1.4.3-6 below maps the western Canada crude-by-rail loading facilities listed in the table above (see Table 1.4-13).

There are potential expansions to many of these facilities and additional facilities in earlier permitting/planning stages that could add several additional unit trains of capacity by the end of 2015, if supported by market conditions. As noted above, the large, unit-train facilities have been developed near existing pipeline-connected oil hubs in the Edmonton and Hardisty areas (as well as farther southeast in areas of conventional heavy crude production). Some of the facilities where the operators have noted the possibility of expanding are north of those areas, farther into the oil sand production areas.[97] The CN tracks into that area are currently weight restricted and would require investment before handling significant increases in rail traffic.

**Canadian Crude by Rail Compared to North Dakota Crude by Rail**

The development of crude loading facilities in western Canada is part of a broader trend in remaking the crude oil logistics map in North America to respond to new and expanding crude oil production. This includes new and modified pipelines (described above in Table 1.4-11), but also the build out of crude-by-rail loading facilities in every major new (or expanding) production area in North America. Crude by rail is developing to serve production areas that do not have adequate pipeline capacity and/or to connect production areas to additional markets beyond those served by pipeline.

The leading production area that has developed crude by rail is in the Bakken in North Dakota and Montana. When the Final EIS (and the 2010 and 2011EnSys Reports) were prepared, rail shipments were just beginning to occur in large quantities from the Bakken. When EnSys 2010 was completed in December 2010, only approximately 50,000 bpd of crude oil were being shipped by rail. There was capacity at rail facilities to load approximately 115,000 bpd of crude oil. When the Final EIS was released in August 2011, there were approximately 80,000 bpd of crude oil being shipped by rail and capacity to load approximately 275,000 bpd of crude oil. In mid-2013, approximately 700,000 bpd was shipped from the Bakken, with a capacity to load over 900,000 bpd.

Figure 1.4.3-7 below compares the trend in crude-by-rail shipments in North Dakota to that in western Canada. The upward trend in crude-by-rail shipments from North Dakota began in January 2010, when the first unit train loading facility in North Dakota began operation. The increase in crude-by-rail shipments from western Canada began approximately 18 months later, in June 2011.

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[96] This would be 776,000 bpd including the unit-train facility announced on December 20, 2013, being constructed in Edmonton.

[97] Altex Energy has noted that the Lynton, Alberta, facility could be expanded to unit-train scale if economics warrant. Grizzly Oil Sands has noted they expect to expand their loading facility in Windell, Alberta, as their production increases. Keyera has noted its facility at Wood Buffalo, Alberta, could be expanded.
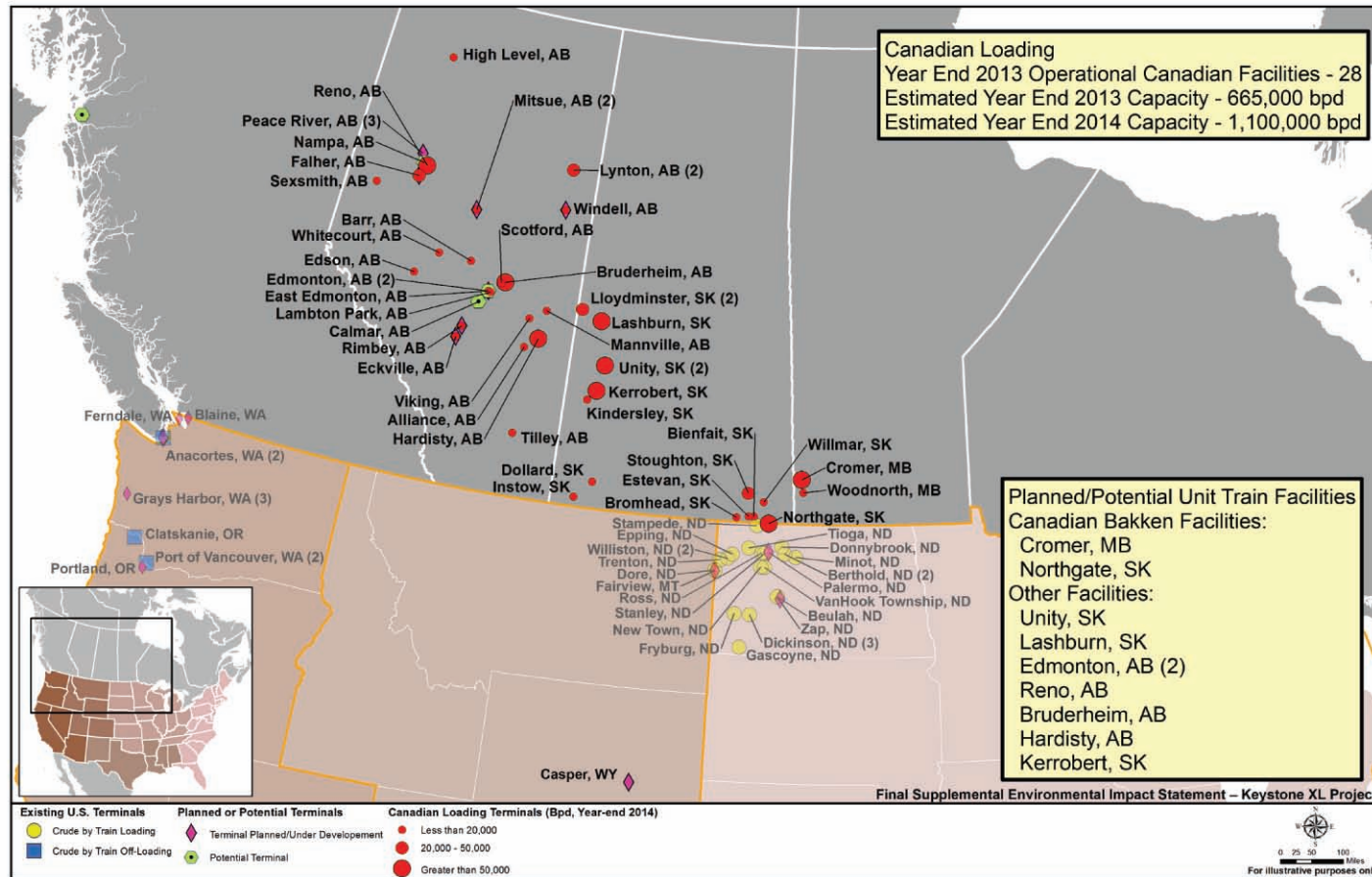
Source: Companies' websites and industry press announcements; Esri 2013. Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-6    Existing, Planned, and Potential Rail Facilities in Western Canada for Crude Loading[98]**

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[98] The Casper, Wyoming, terminal is included as a western Canadian loading terminal because Spectra Energy (operator of the Express Pipeline) and the rail terminal operator have both announced that contracts have been signed for western Canadian crude oil to be delivered to the rail terminal by the Express pipeline for onward delivery by rail.
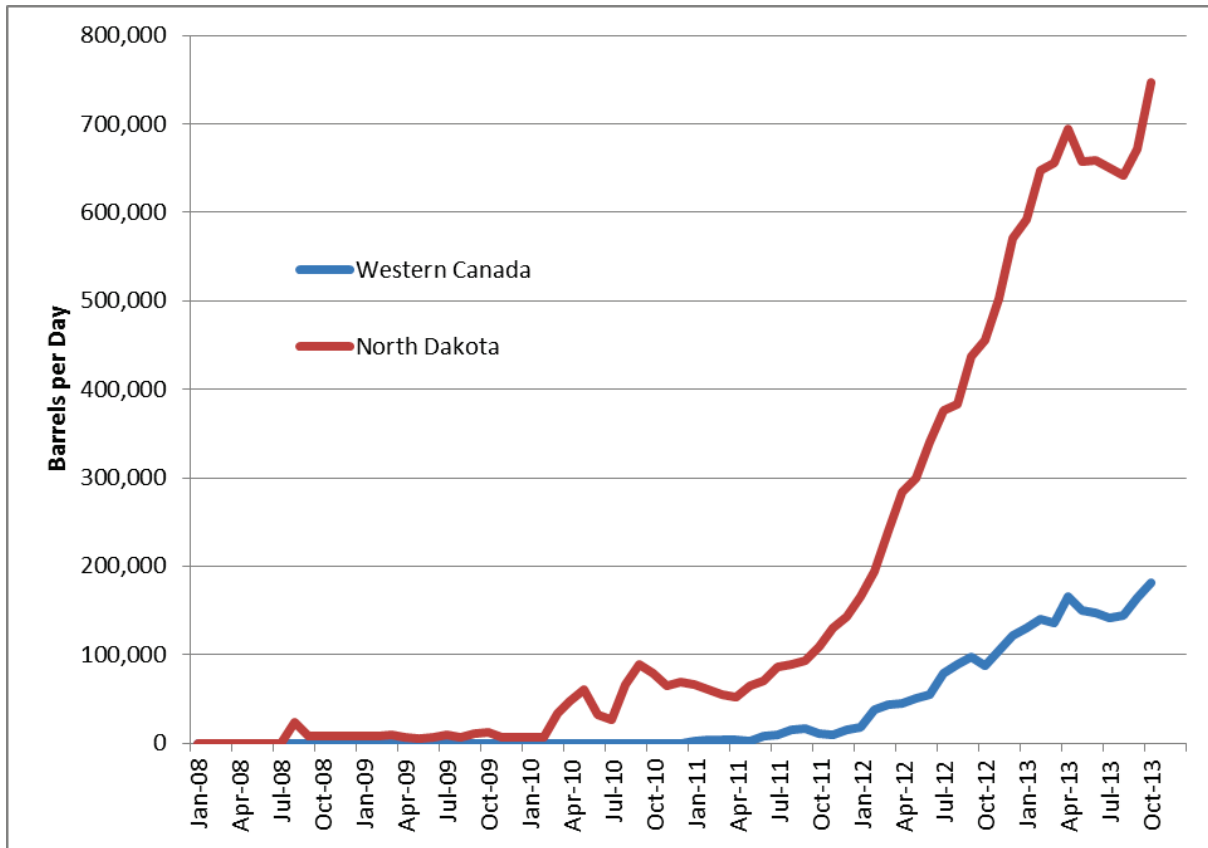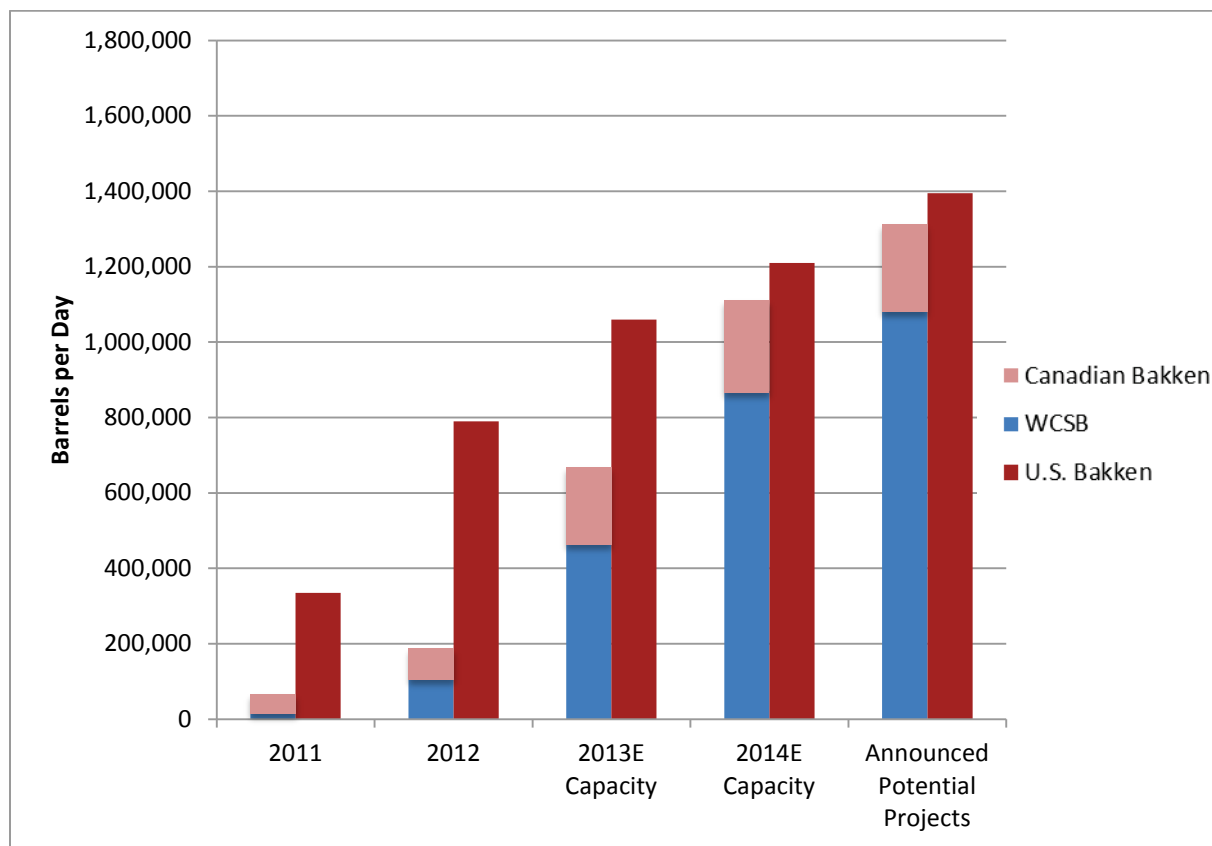
Source: Industrial Commission of North Dakota 2013, CN reports, CPRS reports, Statistics Canada 2013, and additional sources included in Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-7        Western Canada Crude by Rail Shipments Compared to North Dakota**

A better illustration of the rail trends in western Canada and North Dakota is to compare growth in each from the respective months when there was first an uptick in crude-by-rail shipments. In North Dakota this was January 2010. In western Canada it was June 2011. Although they followed different trend lines, total shipments in each area increased to roughly 150,000 bpd over the first 24 months of their respective crude-by-rail growth periods (see Figure 1.4.3-8). The increases in North Dakota began when the first unit train facility began operation. In contrast, the first unit-train facilities in western Canada were not completed until last quarter of 2013. The increases in western Canadian crude-by-rail shipping to date have been achieved without the benefit of the cheaper shipping costs of unit trains.
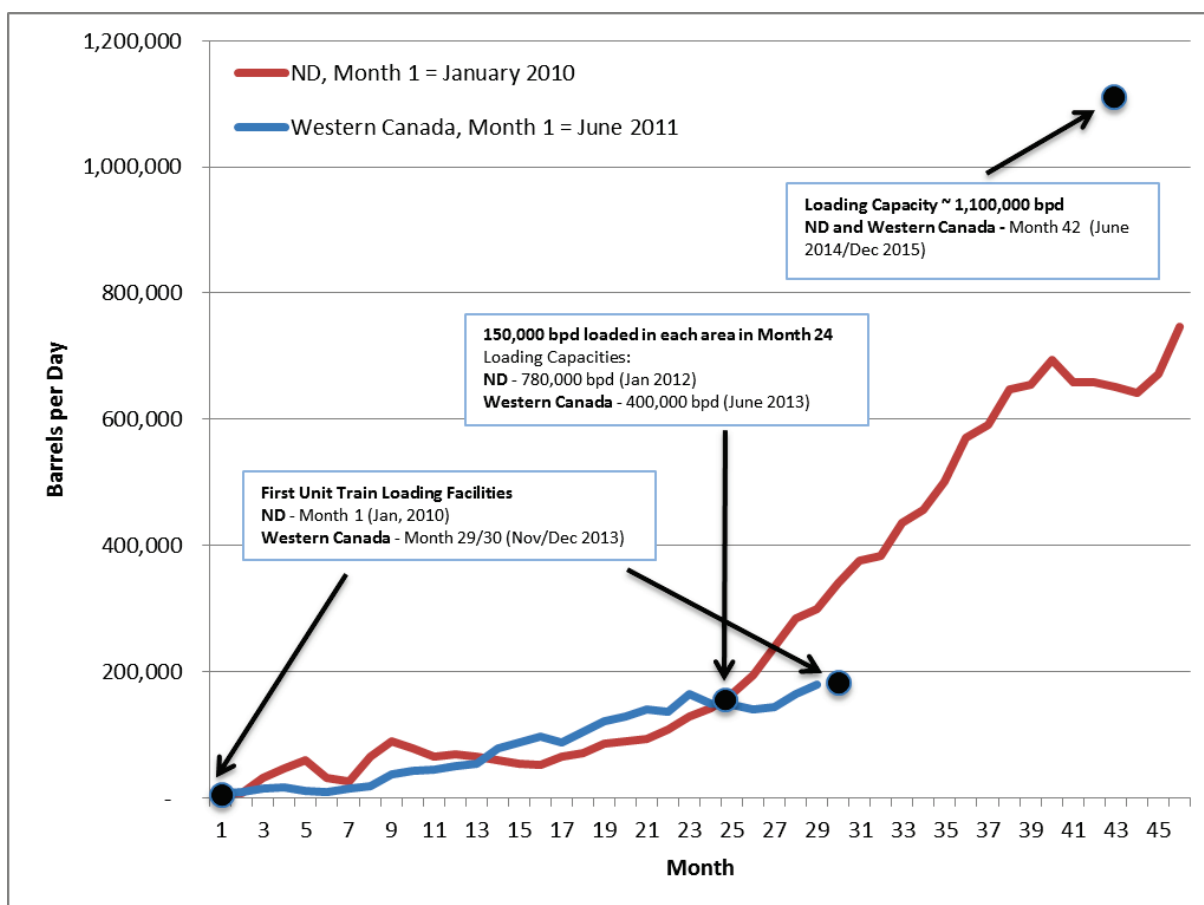


Source: Industrial Commission of North Dakota 2013, CN reports, CPRS reports, Statistics Canada 2013, and additional sources included in Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-8          Western Canada Compared to North Dakota**

At the 24-month point, the North Dakota trend was at an inflection point starting a sharp increase in volumes transported of approximately 50,000 bpd per month over the next 10 months. Based on the number and capacities of facilities recently completed and under development in the WCSB, crude by rail could also be at an inflection point in that area. It remains to be seen, however, whether crude by rail from the WCSB will increase at a similar rate—or will need to, given production growth rates and other available infrastructure.

The development of loading facilities in western Canada has also lagged the development in North Dakota—at least in part due to available pipeline capacity in the former—but there has been a steady increase in both the number of facilities and the capacity of the facilities there. With the development of the multiple unit-train facilities in 2013 and 2014 underway in western Canada, the total loading capacity is expected to nearly match that in North Dakota by the end of 2014 (see Figure 1.4.3-9). Although just over 200,000 bpd of this western Canadian loading capacity is in the Canadian portion of the Bakken formation, just across the border form North Dakota, over 900,000 bpd of the capacity will be farther north in the WCSB, where the increasing production is primarily from oil sands.



Source: Industrial Commission of North Dakota 2013, Company Reports, Table 1.4-13 (above), Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-9    Western Canada Crude Rail Loading Capacity Compared to North Dakota**

## Gulf Coast Crude-by-Rail Off-Loading

As noted above, the crude-by-rail exports to the United States have been split predominantly between PADD 1 and PADD 3. Going forward the primary market for additional quantities of heavy Canadian crude would be in PADD 3 as it has much more refining capacity and demand for heavy crudes than PADD 1. Contracted volumes on the proposed Project, as well as other proposed pipeline projects providing access for Canadian crude to the Gulf Coast, are indicators of this demand.

There are considerable crude-by-rail offloading facilities that provide access to PADD 3 refiners, and additional facilities are being developed in PADD 3. Figure 1.4.3-10 shows the locations of those facilities relative to the different refining centers along the Gulf Coast in PADD 3. Although the refineries and terminals in this area have long been served by railroads, they have primarily utilized railroads to transport part of their refined products away from the refinery. At the beginning of 2011, there was less than 100,000 bpd of crude by rail offloading capacity in this region.

Initially, these facilities have been focused on receiving light sweet crude oil from the Bakken and other new domestic tight oil production areas. More recently, there is a trend for operators and developers of these facilities to improve their ability to receive heavy sour crude from western Canada, including installing the specialized equipment to receive bitumen or conventional heavy crudes that do not have the necessary amount of diluent to meet pipeline specifications. Such underdiluted bitumen or heavy crude requires specialized steam heating equipment and insulated tanks because, as described above, it does not readily flow at ambient temperatures.[99] Table 1.4-14 outlines the off-loading facilities that provide access to PADD 3 refineries, and categorizes them by those that have announced they have installed, or are installing, the equipment to handle underdiluted bitumen; those facilities that have announced they are considering adding such equipment; and the other facilities.[100]

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[99] Pipeline specification dilbit can be transported in standard crude oil tank cars, although shippers may elect to use coiled and insulated cars to facilitate faster offloading and to prevent potential problems in cold weather.

[100] In addition to the Gulf Coast facilities that have installed equipment to handle underdiluted bitumen, there are also facilities on the East and West Coasts. Both PBF Energy and NuStar have installed steam heating to handle railbit and rawbit at their refineries in Delaware City, Delaware, and Paulsboro, New Jersey, respectively. Global Partners has filed permit applications to add steam heating capacity to its heavily used facility in Albany, New York. Finally, Buckeye Partners has announced it is exploring using its under-construction facility at Perth Amboy, New Jersey, to transfer heavy Canadian crude from rail to tanker for export to its Bahamas Oil Refining Company (BORCO) terminal in the Bahamas. On the West Coast, the following proposed rail facilities include the necessary steam heating equipment to handle railbit and rawbit: Alon Refining, Bakersfield, California; Phillips 66, Arroyo Grande, California; Tesoro/Savage Services, Vancouver, Washington.
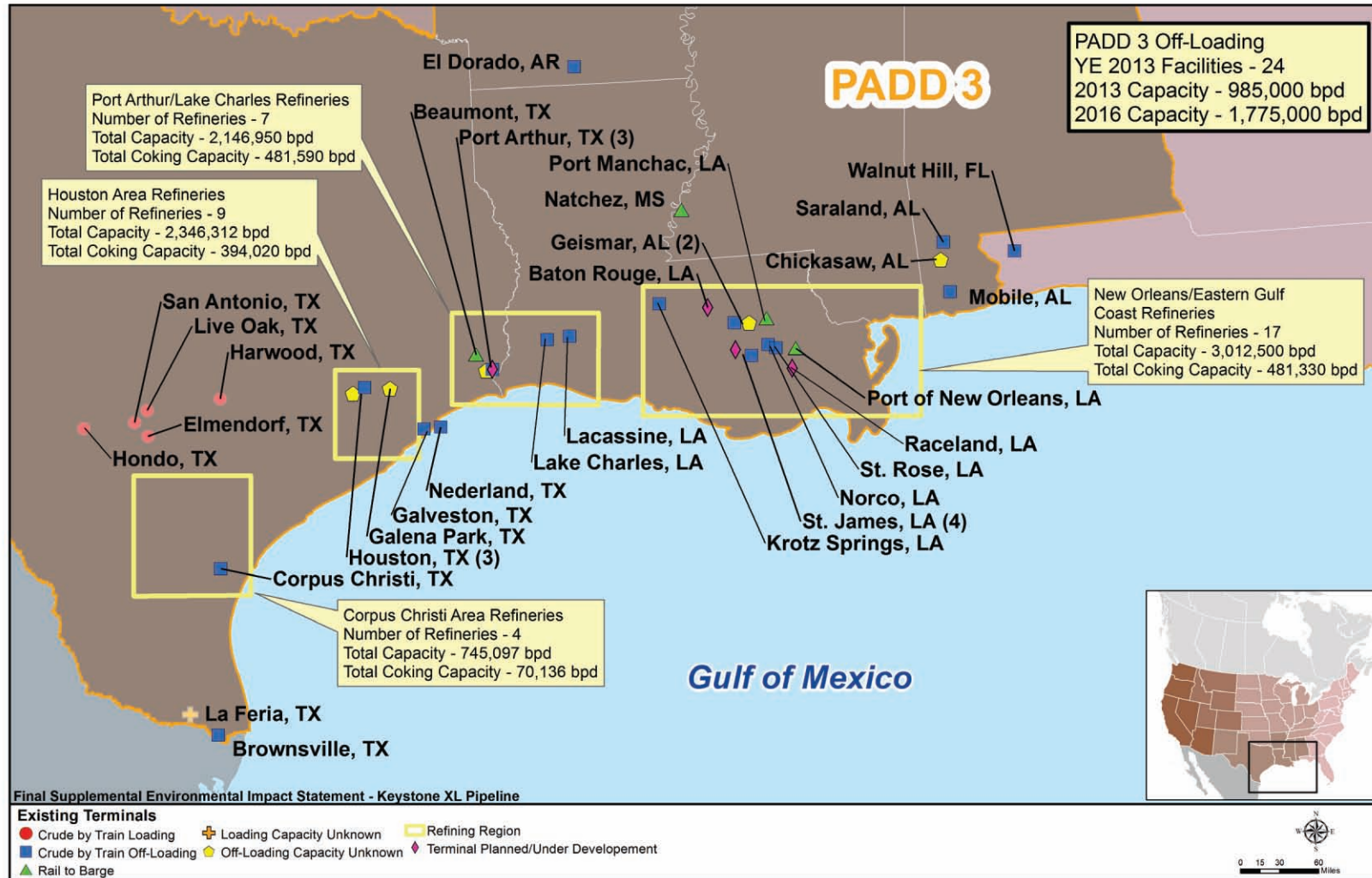
Source: Companies' websites and industry press announcements; Esri 2013. Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-10    Gulf Coast Area Crude by Rail Destination Facilities and Refinery Sector Capacities**

## Table 1.4-14     Rail Off-Loading Projects Providing Access to Gulf Coast Refineries

| Gulf Coast Area Destination Terminals | Estimated Year End 2014 Capacity, bpd |
|---|---|
| **Facilities with Steam Heat Capabilities** | |
| Wolverine Terminals/Paulina Terminal, St. James, LA | 10,000 |
| Genesis Energy, Natchez, MS—Phases I and II | 50,000 |
| Jefferson Refinery LLC/Orange County Terminal, Beaumont, TX | 60,000 |
| Arc Terminals LP, Mobile, AL | 70,000 |
| LBC Tank Terminals, Geismar, LA | na[a] |
| Seacor Holdings/Gateway Terminals, Sauget, IL (PADD 2 rail to barge) | 65,000 |
| LBC Terminal, Bayport, TX | na |
| International Matex Tank Terminals (IMTT), St. Rose, LA | 20,000 |
| **Other Facilities** | |
| Marquis Energy[b], Hayti, MO | 150,000 |
| KW Express/Mercuria Energy, TX[b] | 210,000 |
| GT Logistics/GT Omni Port, Port Arthur, TX[b] | 100,000 |
| Nustar/EOG, St. James, LA[b] | 140,000 |
| Valero, St. Charles Refinery, Norco, LA[b] | 30,000 |
| Plains All American, St. James, LA | 140,000 |
| Trafigura, Corpus Christi, TX | 30,000 |
| Crosstex Energy, Geismar, LA | 15,000 |
| Sunoco, Nederland, TX | 15,000 |
| Genesis Energy, Baton Rouge, LA | 65,000 |
| Genesis Energy, Raceland, LA | 120,000 |
| JW Stone Oil Distributors, Port Manchac, LA | 15,000 |
| Alon USA, Krotz Springs, LA | 9,000 |
| Magellan Midstream Partners/Galena Park, TX | na |
| Arc Terminals LP, Saraland, AL | 75,000 |
| Bulk Resources/Murex/SGS Petroleum Services—Port of New Orleans, LA | 70,000 |
| BioFuels Development International/ Channel Biorefinery & Terminals/ Houston, TX | na |
| Canal Refining, Lacassine, LA | 5,000 |
| Texas International Terminals, Galveston, TX | 60,000 |
| Citgo, Lake Charles, LA | 20,000 |
| **Total** | **1,524,000** |

Source: Company public disclosures, media reports, Fielden 2013. Source: Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

[a] na = not available
[b] Operator has stated that they are exploring improving ability to receive heavy crudes.

Crude-by-rail loading and off-loading facilities are being operated and constructed throughout North America. Loading facilities have been or are being constructed in virtually every new production area of the United States to transport crude oil where there is not sufficient pipeline capacity to accommodate the new production, including the Eagle Ford shale in Texas, the Permian basin in Texas, the Woodford/Anadarko area in Oklahoma, the Utica shale in Ohio, and the Niobrara shale in Colorado and Wyoming. The extent to which these facilities are utilized, including those in western Canada, will depend upon many factors, including the availability of cheaper pipeline transport options from the respective production areas, the rate of production growth in emerging plays, demand from refineries that may be better served by rail from these sources, general discounts between the price of oil paid in the production areas and the price of oil paid at the refinery markets (particularly on the coasts), and temporary arbitrage opportunities that may better be taken advantage of through faster rail-based transport.

Rail off-loading facilities are being developed along the inland waterways, on the Gulf Coast, and on the East and West Coasts (see Table 1.4-14). Rail off-loading capacity to serve U.S. East Coast refineries is developing rapidly. Capacity bpd is expected to grow to over 800,000 bpd by the end of 2013. This does not include around 70,000 bpd of rail off-loading capacity at the Irving refinery in St. John, New Brunswick, or the other off-loading capacity at refineries in eastern Canada. Off-loading capacity on the West Coast is currently approximately 195,000 bpd and is projected to increase to as much as 950,000 bpd.

Figure 1.4.3-11 shows estimated crude by rail loading and offloading in 2010; Figure 1.4.3-12 shows the estimated crude by rail loading, off-loading, and transloading facilities throughout North America and their estimated capacities in 2013 and 2016. The map includes rail to barge or tanker transloading facilities.

Nearly all of these facilities have been constructed since 2010. At the end of 2010, it is estimated that there were six dedicated crude-by-rail loading facilities (all in the Bakken in North Dakota), and four dedicated crude-by-rail offloading facilities. By year-end 2013, it is estimated that there will be 53 total loading facilities, and 64 total offloading facilities.[101]
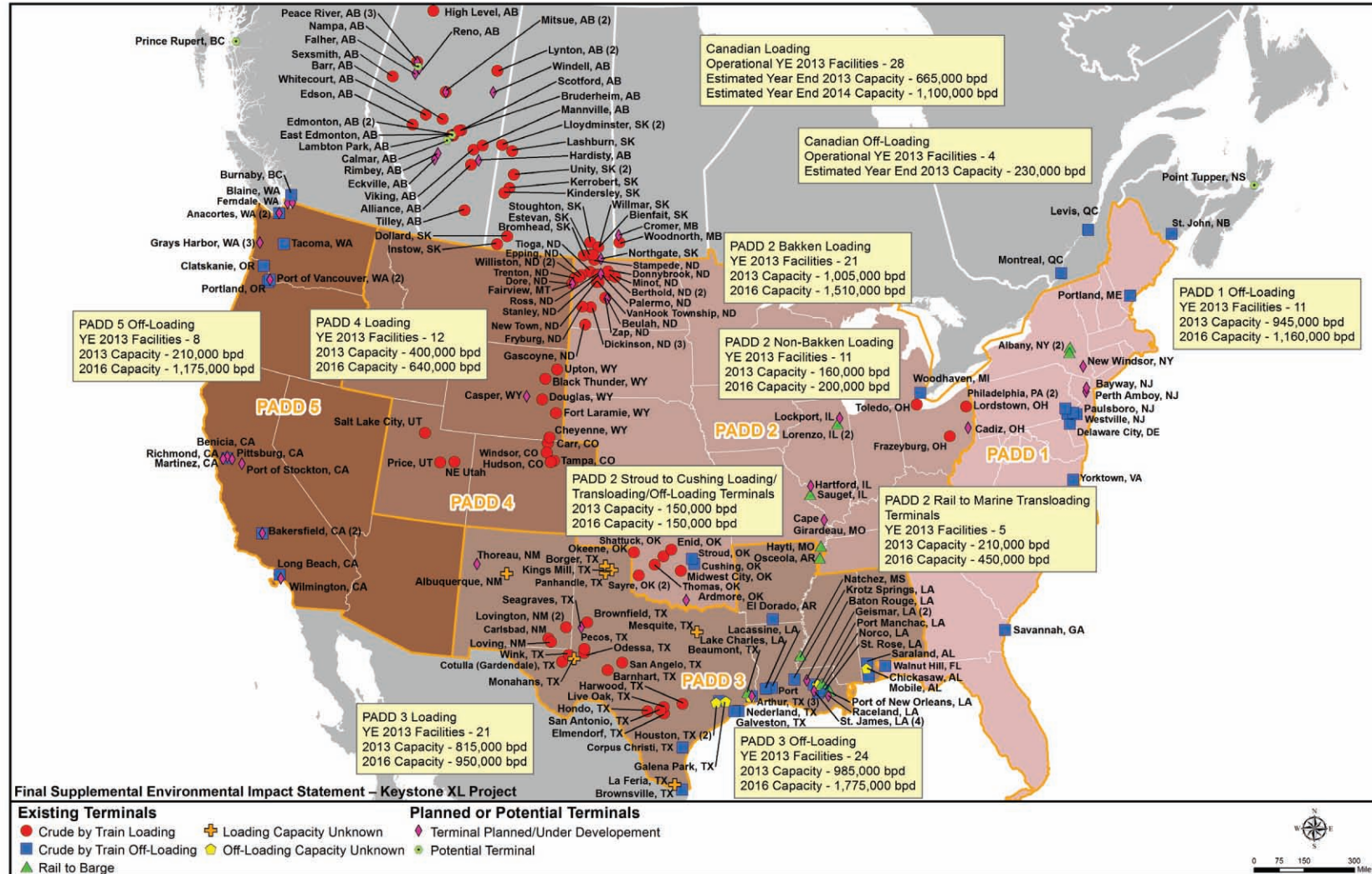
Appendix C, Supplemental Information to Market Analysis, provides additional information related to these facilities and their estimated capacities and start-up dates.

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[101] A complete list of facilities and sources is presented in Appendix C, Supplemental Information to Market Analysis.
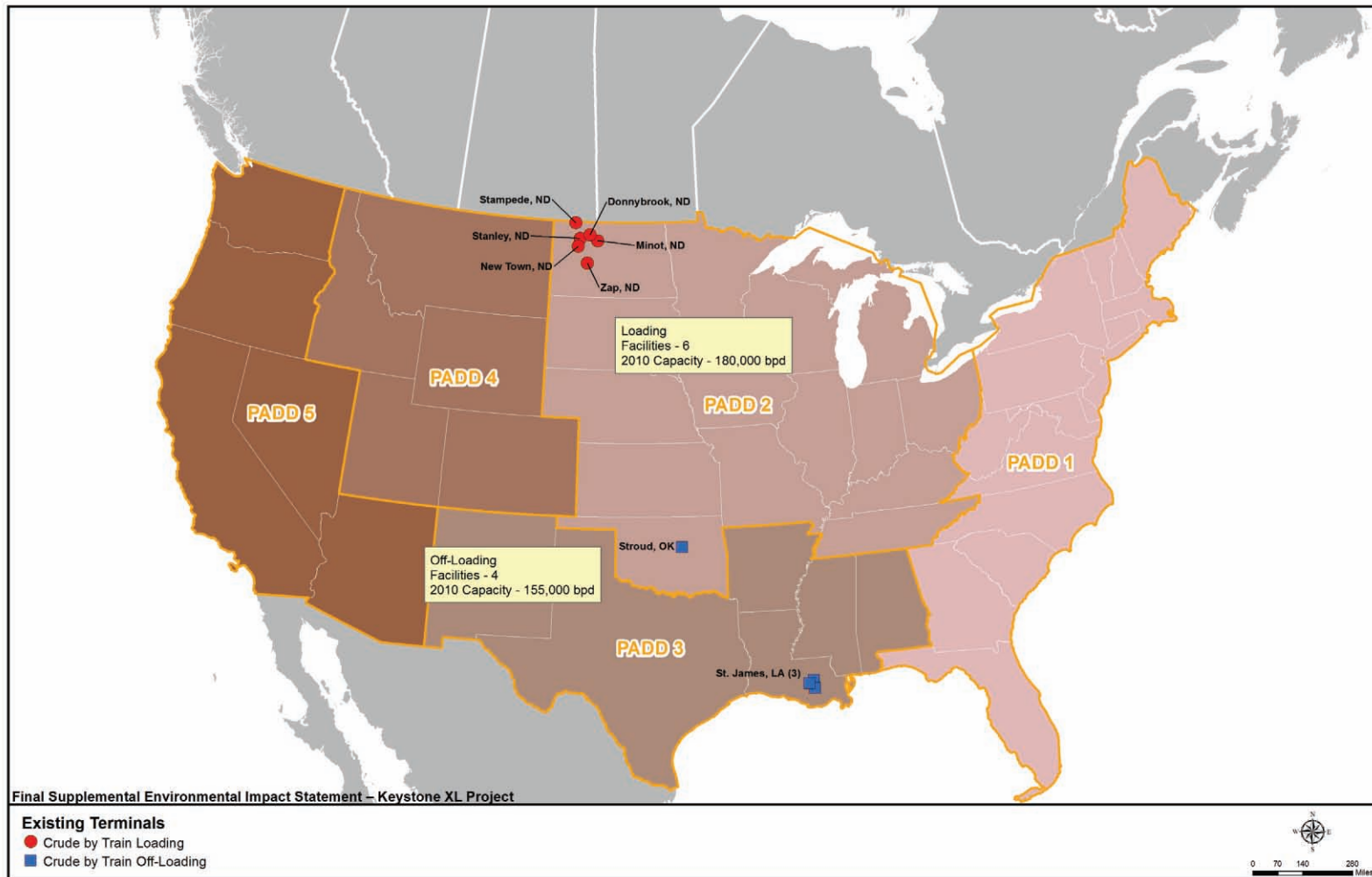
Source: Esri 2013; Walton 2010; Fielden 2013; NuStar Energy L.P. 2010; North Dakota Petroleum Council 2010; company and media reports

**Figure 1.4.3-11     Crude by Train Loading and Off-Loading Facilities in 2010, Estimated Capacities**

Source: Esri 2013; company and media reports. Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-12    Crude by Train Loading and Off-Loading Facilities in 2013 (Current and Planned), Estimated Capacities**

### 1.4.3.3    *Potential to Increase WCSB Crude by Rail*

This section assesses the potential for rail to transport the increases in WCSB production through 2030, as projected in the 2013 CAPP outlook (CAPP 2013a), even if no further pipeline capacity is added out of the WCSB. In this sense it considers a situation different than just a typical *No Action* alternative, as it assumes all proposals for pipeline expansions (beyond those already under construction) do not occur. It assesses the logistics of increasing crude-by-rail transport, which includes the build out of specialized loading and off-loading facilities, the capacity of the existing rail network and/or ability of it to increase capacity, and the availability of tank cars. The cost issues associated with crude by rail are assessed in the Pipeline Transport Costs Compared to Rail Transport Costs subsection below.

In assessing rail capacity compared to pipeline capacity, one must account for the fact that rail capacity and pipeline capacity cannot necessarily be compared on a one-to-one basis because rail can transport not only the same dilbit transported by pipeline, but also railbit or rawbit. As noted in Section 1.4.3.1, Increases in Pipeline Capacity, any given tank car (or unit train) cannot transport as many barrels of rawbit or railbit as it can of dilbit. But on a net barrel of bitumen basis, every barrel of rawbit or railbit transported is the equivalent of transporting 1.2 to 1.4 barrels of dilbit. This means that although a unit train of rawbit has a lower total volume than a unit train of dilbit, the rawbit train is hauling more bitumen. For example, a 100 car unit train might only be able to carry 50,000 to 63,000 barrels of raw bitumen. But it would take 70,000 to 90,000 barrels of dilbit transported by pipeline to transport an equivalent amount of raw bitumen. This is illustrated in Table 1.4-15. The estimated capacity of the proposed Project is 830,000 bpd of heavy crude. That volume of dilbit is equivalent to 581,000 bpd of bitumen.

**Table 1.4-15    Comparison of Volume of Oil Sands Crude Transported on Unit Train to Equivalent Pipeline Volume**

| Crude Type | Raw Bitumen | Railbit | Dilbit |
|---|---|---|---|
| Barrels per Unit Train[a] | 50,000–63,000 | 55,000–69,000 | 60,000–75,000 |
| Equivalent Pipeline Capacity for Dilbit | 71,000–90,000 | 66,000–83,000 | 60,000–75,000 |

[a] The range of unit train capacities are based on 100-car trains of 268,000 pound gross weight limit tank cars on the low end, to 120-car trains of 286,000 pound gross weight limit tanks cars on the high end.

As noted in Section 1.4.2.8, Canadian Oil Production, above, the production of Canadian crude oil is anticipated to increase substantially through 2030. The EIA 2013 (EIA 2013a) projects total production rises from 2.3 million bpd in 2012 to 5.9 million bpd in 2030 and 6.1 million bpd in 2035. The increment is oil sands crudes, which rise from 1.9 million bpd to 4.2 million bpd. The analysis in the August 2011 Final EIS, including the 2010 and 2011 EnSys analysis, examined estimates of then-existing pipeline capacity relative to increases in production as estimated in CAPP forecasts. The EnSys 2010 analysis estimated that existing cross-border pipeline capacity could be filled by shortly after 2020, and the EnSys 2011 update noted that it could likely be filled before 2020 based on increased production projections. Since the 2011 EnSys study, the CAPP projection of total western Canadian crude oil supply to market has

increased from 3.8 million bpd to 5.2 million bpd by 2020 (and 7.8 million bpd by 2030)[102], implying that existing capacity would be taken up sooner. The IEA 2012 noted existing pipeline capacity could be fully utilized by 2016.[103]

Whereas the updated modeling (described below) utilized the EIA production outlook, the following assessment of logistics capabilities is based on the CAPP forecasts because it would be more challenging for crude by rail (combined with other non-pipeline transport options) to keep pace with CAPP production growth rates. Based on the CAPP 2012 (CAPP 2012a) outlook for Canadian production, the Draft Supplemental EIS estimated that if no new pipeline capacity were added, crude by rail would need to be capable of transporting that annual expansion of approximately 175,000 bpd each year in order to keep up with (and prevent shut in of) the increases in western Canadian crude supplies.[104] Taking account of the higher estimates in CAPP 2013 (CAPP 2013a), and of the facilities that have been constructed (or are under development) in the western Canada, crude by rail and other transport modes would have to increase by an average of 210,000 bpd per year beginning in 2016.

**Expansion of Loading and Offloading Capacity**

A key question is whether rail capacity could grow at a sufficiently fast rate to support projected increases in oil sands production.[105] In order to do so from a logistics perspective, there would need to be development of loading and unloading facilities, of existing track capacity to accommodate additional traffic, and in rail tank car availability. These capacity additions would need to be capable of being sustained year after year to match WCSB crude supply increases.

As noted above, shippers in the WCSB (excluding the Canadian Bakken) are in the process of adding 400,000 bpd of rail loading capacity in 2013, and have undertaken projects that would add more than 500,000 bpd in 2014 (see Table 1.4-13). Rail on- and off-loading facilities have been constructed at a similar pace over the past 2 years throughout the United States. In 2012 and 2013, over 700,000 bpd of loading capacity was added in the Bakken, and over 800,000 bpd of offloading capacity was added on the East Coast. Offloading capacity on the Gulf Coast will have increased to an estimated 1.125 million bpd by the end of 2013. Approximately 255,000 bpd of offloading facilities have been added on the West Coast in recent years, but some of the current developments there are proceeding slower than developers initially indicated as a result of permitting issues.[106]

From a logistics standpoint, the ability to construct the necessary crude-by-rail loading and offloading facilities at a rate that could support WCSB production growth in the long term does not appear to be a substantial impediment. As described further below, the most economical way

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[102] In the CAPP forecasts, "Western Canadian Oil Supply" is greater than "Western Canadian Oil Production" because the supply numbers include imported diluent necessary to dilute bitumen or heavy crude to pipeline specifications.

[103] IEA 2012b; Recent private analyst reports indicate existing pipeline capacity could be fully utilized by 2014 or 2015 (Goldman Sachs 2013b).

[104] This estimate is based on rail capacity being 200,000 bpd in 2013 and increasing from that amount. Total WCSB export pipeline capacities are based on the CAPP 2012 outlook (CAPP 2012a).

[105] In preparing this section, the Department consulted with several rail experts, including experts at the Department of Transportation (including the Federal Railroad Administration) regarding the analysis of rail network capacity.

[106] A complete list of facilities and sources are presented in Appendix C, Supplemental Information to Market Analysis.

to transport oil-sands bitumen by rail is as underdiluted railbit or raw bitumen, and additional specialized equipment is required to load those products (including insulated storage tanks, heating equipment, heated pipelines, etc.). Such specialized facilities have been recently constructed, and are under development, to both load and off-load shipments of railbit and/or bitumen. These types of facilities, however, would have to be constructed at a much larger scale to accommodate all projected oil sands growth. This would require substantial capital investments on the order of hundreds of millions of dollars, or even billions of dollars, over several years. But that level of investment would be consistent with what has occurred over the past several years.[107]

**Rail Network Capacity**

The next logistics question would be whether the rail network itself has the capacity to accommodate a substantial increase in crude by rail traffic from the WCSB. Depending upon the product transported (dilbit, railbit, or rawbit), and the number of cars in each unit train (100 to 120 cars), it would require approximately 9 to 14 loaded unit trains per day (and an equal number of empty trains returning each day for a total of 18 to 28 trains) to equal the capacity of the proposed Project.[108] To transport the projected increase in oil sands production from the CAPP outlook (CAPP 2013a) in a scenario where no additional pipeline capacity were added would require an increase of between 48 to 75 loaded unit trains per day, and an equal number of empty unit trains returning, for a total of 96 to 150 total crude oil trains on the rail network by 2030.[109] In assessing system capacity, it was assumed that trains replacing the capacity of the proposed Project would travel from Western Canada (and the Bakken in the United States) predominantly to the U.S. Gulf Coast. In the scenario where no pipeline capacity was added, it was assumed that WCSB crude would be transported to a variety of destinations in North America—not only the U.S. Gulf Coast, but also the U.S. West and East Coasts, and the Canadian West and East Coasts.[110]

There are seven rail crossings from Canada to the United States on the CN and CPRS networks between Washington state and Minnesota that can handle crude by rail shipments, and there are two primary rail crossings that are the most likely points to accommodate increased shipments

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[107] There are examples of very large-scale facilities (with storage capacities of up to 16 million barrels) designed to load, offload, blend, and store large volumes of petroleum products (fuel oil) that must be heated to be handled on the U.S. Gulf Coast. The Houston Fuel Oil Terminal has 13 million barrels of storage for fuel oil that is all insulated and steam heated to keep the fuel oil in a liquid state, enabling handling. The Bostco terminal is nearing completion of its first phase, which will also have several million barrels of heated/insulated storage for handling fuel oil. Neither of those terminals is currently equipped to handle heavy crudes that require heating for handling. Construction of such specialized facilities would appear to be within the capabilities of the industry if the economics justified it.

[108] Also affecting the total number of trains would be the size of the tank cars used—268,000 pound gross weight limit or 286,000 pound gross weight limit. Rawbit, transported in 286,000 pound gross weight limited tank cars in 120 car unit trains would require approximately 9 trains per day, while dilbit transported in 268,000 pound gross weight limited tank cars in 100 car unit trains would require approximately 14 trains per day. This would be split between Western Canada (7 to 11 trains per day) and the Bakken in the United States (2 to 3 trains per day).

[109] Rawbit, transported in 286,000 pound gross weight limited tank cars in 120 car unit trains would require approximately 48 loaded (96 total) trains per day, while dilbit transported in 268,000 pound gross weight limited tank cars in 100 car unit trains would require approximately 75 loaded (150 total) trains per day.

[110] See Appendix C, Supplemental Information to Market Analysis, for a further explanation of the assumptions used in the network capacity assessment.

from the WCSB to the Gulf Coast (and the U.S. West Coast). In addition, rail lines exist to ports on the British Columbia coast (notably Prince Rupert, Kitimat, and Vancouver) and the Canadian East Coast, which could be used for export of western Canadian crudes.[111] In 2012 and the first four months of 2013, there were an average of 32 trains per day crossing into the United States at those ports of entry (between two and 11 trains per day crossing into the United States at each of those seven border crossings).

A single rail line with a single track and the most sophisticated signaling system can accommodate up to 30 trains per day. Putting a double track along that line, which can be done without need for regulatory approval from the Surface Transportation Board, expands the potential capacity to 75 trains per day (Cambridge Systematics 2007). This type of expansion can, in effect, be done incrementally over time as sidings (a parallel set of tracks put in for trains to stop on or to pass oncoming trains) for specific areas are added and expanded until they connect into long sections of double tracks where trains can move in both directions simultaneously.[112]

The Cambridge Systematics study assessed possible investment needs in rail infrastructure to accommodate economic growth and increased rail traffic (for all goods and commodities) through 2035. The report concluded that with adequate capital investment, the rail system could accommodate increased rail traffic without encountering capacity issues. A subsequent report prepared for the Surface Transportation Board concluded that the economic growth outlook relied on by the Cambridge Systematics study may have overstated the potential additional rail traffic (Christensen 2009). For example, the forecast relied on by the Cambridge Systematics study had projected coal rail tonnage in the western United States to increase by more than 200 percent by 2030. More recent EIA forecasts have coal production in the western United States growing by less than 20 percent over that same time period (Christensen 2009; EIA 2012a). For grains, the Cambridge Systematics study relied upon a projected growth in transport of approximately 80 percent by 2035, whereas subsequent U.S. Department of Agriculture production forecasts showed less than a 40 percent increase over that period (Christensen 2009). The Christensen report concluded that the rail system would require lower levels of capital investment to accommodate projected growth in rail traffic than had been indicated by the Cambridge Systematics study.

Recent trends in the movements of commodities by railroads are consistent with the more conservative growth forecasts for rail traffic noted in the Christensen report. Movements of the railroads' primary freight product, coal, have been dropping as abundant and low-priced natural gas has been increasingly adopted in the power generation sector (see Figure 1.4.3-13).

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[111] Nexen Inc. is exploring moving oil by rail to Prince Rupert, British Columbia, to export crude onto tankers for delivery to Asia markets (Vanderklippe 2013).

[112] Most of the seven identified ports of entry have two tracks (a main track and a siding) at the border. Although these border crossings are not part of long, double-tracked corridors, it would appear that the border crossings may be able to be incorporated to a future double-tracked corridor (if justified by rail traffic) without substantial modification of the facilities at the border.
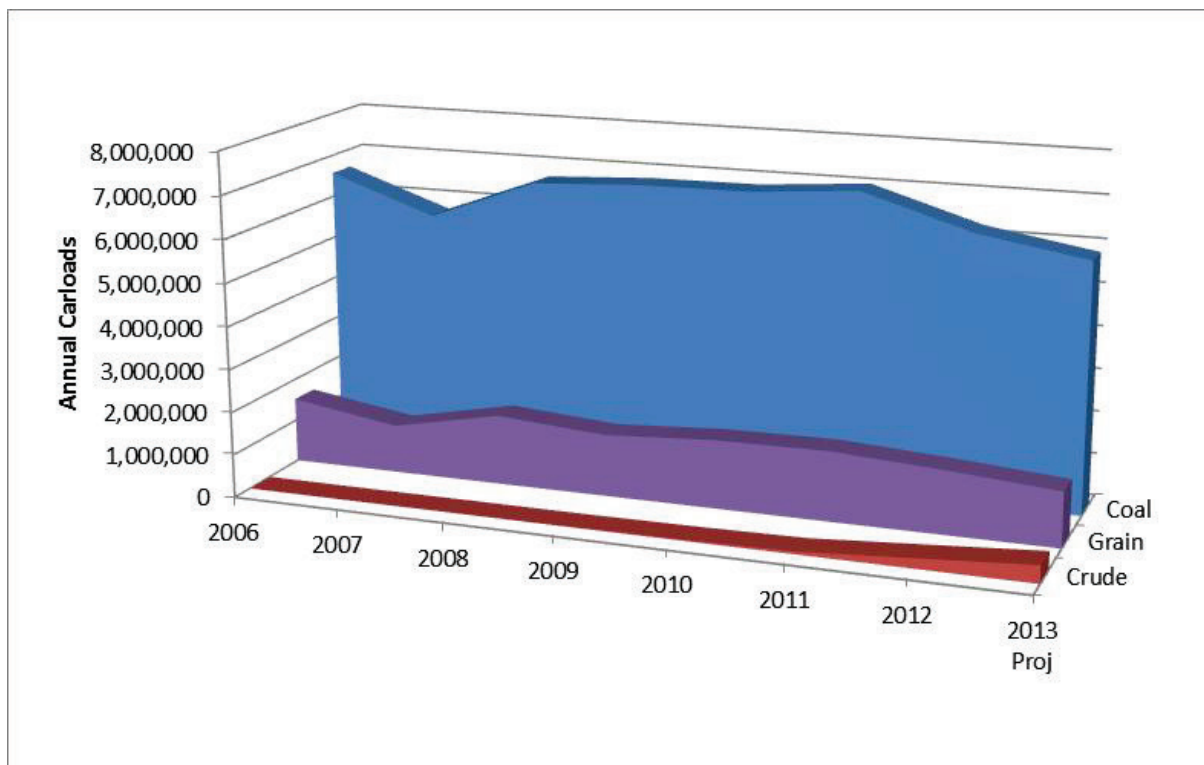
Source: Surface Transportation Board 2013

**Figure 1.4.3-13       Annual Carloads by Commodity for Major U.S. Railroads**

The major rail carriers engage in annual capital expenditure programs, some of which is devoted to improving or expanding capacity on their existing network. In the past 2 years, many of the major carriers have noted they are devoting a portion of that capital spending specifically to accommodate increases in crude-by-rail traffic. Other carriers have noted it is not possible to accurately designate capital spending on network improvements to one specific commodity, as the network improvements support improved movements of all products.

As noted above, the Bakken has experienced the largest increase in crude-by-rail traffic. The volume of crude oil transported out of the Bakken by rail has grown at a rate similar to that of the development of loading capacity, allowing for loading terminals to run below full utilization. In 2012, BNSF Railway Company (BNSF) stated that its network had the capacity to transport up to 750,000 bpd from the Bakken. After making upgrades during 2012, BNSF announced at the beginning in 2013 that it could accommodate up to 1,000,000 bpd of crude-by-rail traffic from the Bakken (BNSF 2012). This means BNSF made improvements in the rail network to accommodate an additional 3 to 3.5 unit trains per day from the Bakken in 2012.

Appendix C, Supplemental Information to Market Analysis, includes a report regarding an assessment of rail system capacity (*Potential Rail Logistics Constraints for Crude Oil Movements from Canada to U.S. Destinations*). The assessment considered the most challenging scenario for transporting WCSB crudes by unit train—the smallest tank cars, smaller unit trains (100 cars instead of 120 cars), and transporting dilbit instead of railbit or rawbit. Particularly in the scenario where no pipeline capacity is added, the increase in rail traffic on the system would

be substantial, equivalent to (or greater than) the largest example of network capacity growth in North America (the increase in rail traffic from the Powder River Basin Coal mines in Wyoming and Montana, discussed further below). The assessment concluded that this level of growth could be done if the economics warranted it, particularly because of the long time period over which it would need to be done.[113] In the shorter term, there could very well be temporary capacity constraints if investment in system capacity lagged increasing demand, but no long term logistics constraints on capacity were identified.

Another factor in concluding that the network system capacity could be expanded to accommodate that increase in rail traffic in the scenario where no pipeline capacity is added is the fact that the locations where the increased traffic would be most pronounced, and thus where the greatest amount of investment would be required, is a relatively discrete geographic area. The assessment noted:

> South and west of Edmonton and east of Winnipeg the number of additional trains on any segment drops off considerably as trains head in five different directions to the US Gulf Coast, US East Coast, US West Coast, Eastern Canada and Vancouver/Prince Rupert, BC. There are multiple railroads and rail routes to all of these regions so the impact on any one line would be relatively small.

Since the crude-by-rail phenomenon is relatively new, other historic examples of rail network expansion at a similar or greater rate to transport a commodity from a discrete geographic origination point over a long period of time could provide useful insights. One example, the largest example found, is coal transport from the Powder River Basin in Wyoming and Montana.[114]

The Powder River basin produces approximately 40 percent of the nation's coal, nearly 500 million short tons per year, almost all of which is transported by rail (see Figure 1.4.3-14). According to the IEA, total U.S. crude oil production in 2012 was 387 million metric tons (approximately 440 million short tons). In other words, the rail network out of the Powder River basin hauls the equivalent of more than the total 2012 U.S. crude oil production of 6.5 million bpd.

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[113] "However, it is unlikely that all of the new production would come on stream at the same time. Therefore, the railroad would have time to plan for and make the required investments in additional track, traffic control systems, locomotives and other assets. Depending on the rate of increase in train volume there could be temporary capacity constraints; but the railroads would make investments to handle the projected volume." Potential Rail Logistics Constraints for Crude Oil Movements from Canada to U.S. Destinations Report in Appendix C, Supplemental Information to Market Analysis.

[114] The analysis of rail network capacity was informed by, among other things, consultation with rail experts, including experts at the Department of Transportation (including the Federal Railroad Administration). Rail experts consulted did not identify any logistics constraints on the ability of railroads to increase the capacity of their networks over time to accommodate the number of trains that would be necessary transport all future WCSB oil sands growth under the CAPP forecast if the economics justified such growth.
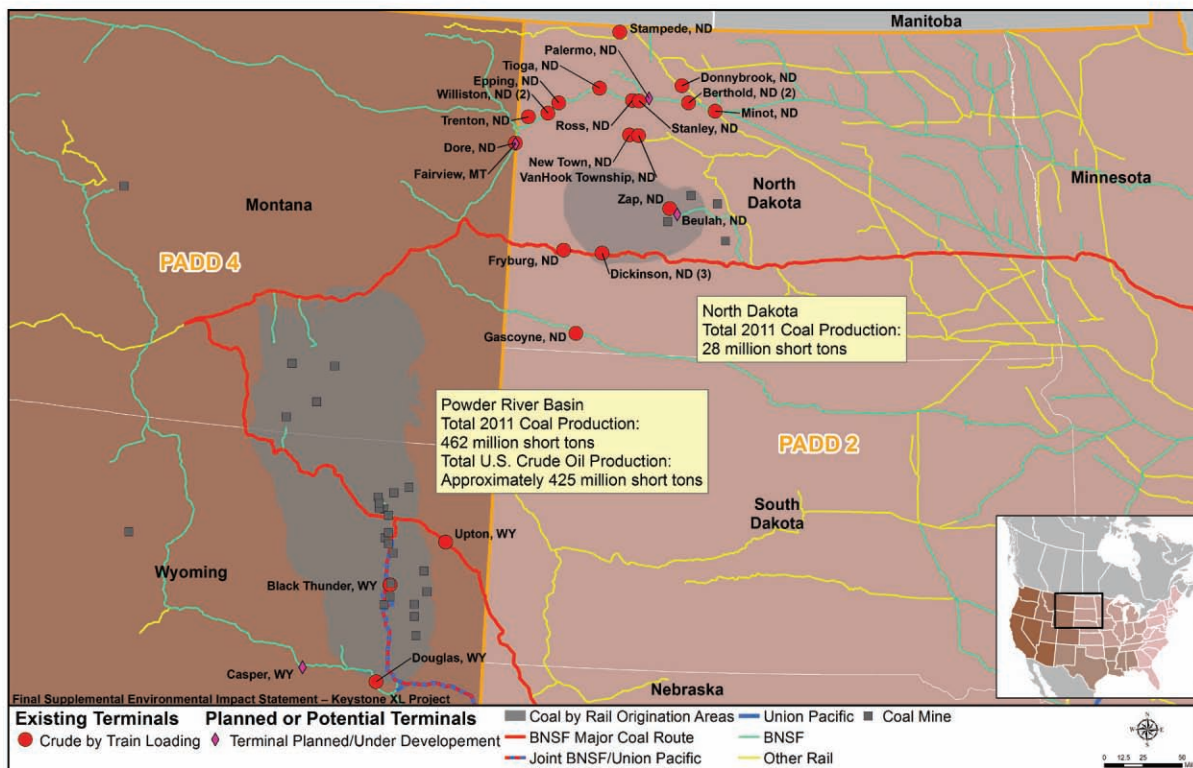
Sources: Esri 2013. Sources for all facilities are presented in Appendix C, Supplemental Information to Market Analysis.

**Figure 1.4.3-14        Powder River Basin Major Coal Rail Lines[115]**

This increase in Powder River basin rail network capacity was achieved over a 25-year period, a similar timeframe to the current EIA outlook for crude production (the current CAPP forecast only goes to 2030). The first truly large-scale surface mines in the Powder River basin began operating in the 1970s. By 1980, approximately 99 million short tons of coal were transported out of the Powder River Basin. By 2008, this had increased to approximately 500 million short tons. The rail network was able to accommodate an increase in capacity of, on average, 14 million short tons per year every year for 28 years. This is equivalent to an increase of approximately 240,000 bpd of heavy crude (approximately 22 API) per year, or a 6.7 million bpd cumulative increase over the 28 years. Figure 1.4.3-15 below compares the annual increase in rail transport of crude oil (expressed in short tons) that would be necessary to accommodate projected western Canada production from 2016 to 2030 (based on the CAPP and EIA outlooks) to the annual increase in tons of coal hauled from the Powder River Basin from 1993 to 2008, when the most significant expansion in production occurred. It also compares the annual

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[115] Comments were received regarding whether the scale-up in crude-by-rail capacity from North Dakota since 2010 was possible because it benefited from under-utilized infrastructure associated with the decrease in coal transport. As indicated in Figure 1.4.3-14 above, the primary rail lines utilized for the increase in Bakken crude by rail shipping (indicated by the number of crude-by-rail loading facilities on the different rail lines) are different from the major coal routes that have hauled coal from Wyoming and Montana.

increases expressed in terms of the increase in the number of 120-car unit trains per day for both rawbit and dilbit. The overall assessment of network capacity for transporting WCSB production increases was based on an assumption of 100-car unit trains to assess the most conservative scenario for capacity increase, but this direct comparison to the Powder River Basin assumes the same number of cars per unit train to present a more apples-to-apples comparison.
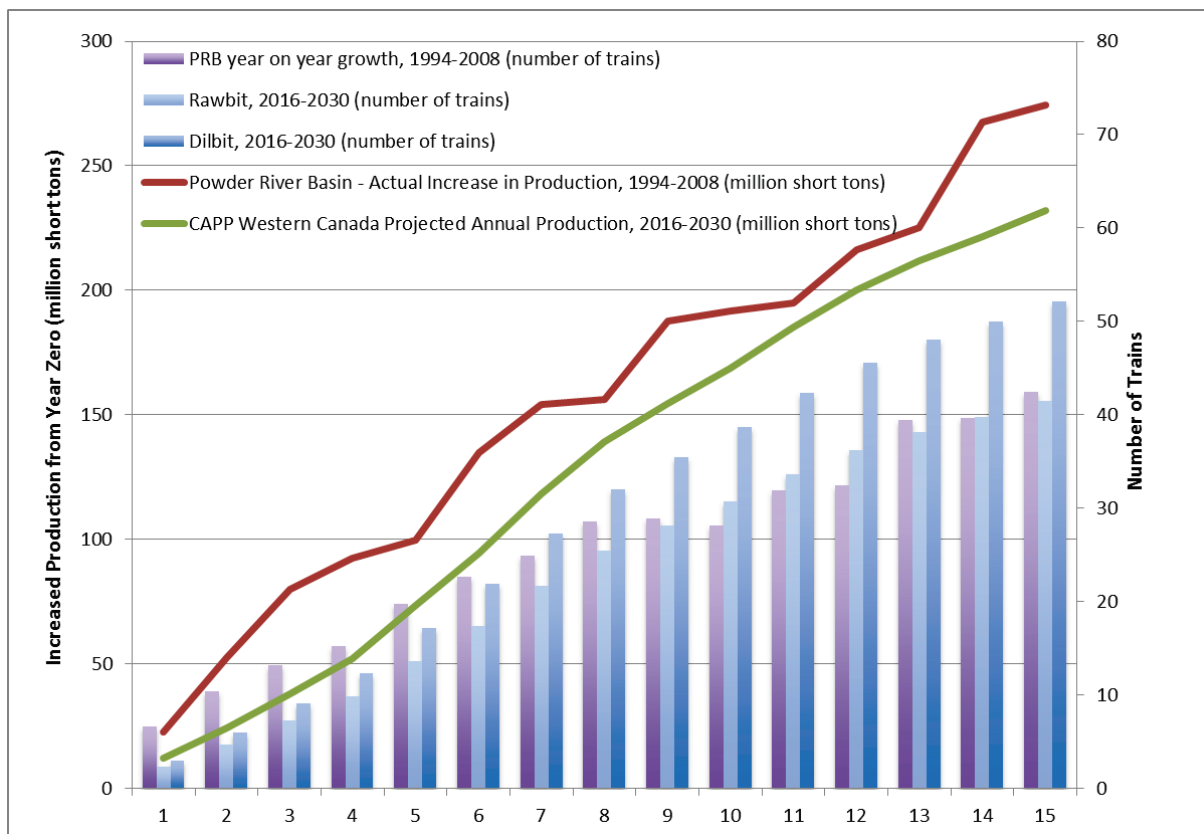


Source: CAPP 2013a; Hellerworx, Inc. 2013.

**Figure 1.4.3-15      Annual Increases in Rail Transport to Accommodate WSCB Production Compared to Coal**

Although the year-on-year increase in short tons of coal hauled from the Powder River Basin is greater than what would be required to haul WCSB production (as dilbit), the total number of coal unit trains is less because a 120-car coal unit train can haul approximately 25 percent more net tons than a crude oil unit train.[116] Thus, if the WCSB production were hauled as dilbit, it would require a greater increase per day of unit trains than the Powder River Basin example. Hauling WCSB production as rawbit would require an increase of a similar number of unit trains per day as the Powder River Basin example.

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[116] The coal unit trains can haul more tons of commodity than crude oil unit trains because coal hopper cars weigh less than crude oil tank cars.

In summary, in a scenario in which no new pipelines were built, potential demand for rail service could exceed 150 additional trains per day (75 loaded trains and 75 returning trains), which would be split between Fort McMurray and Edmonton on CN and between Lloydminster and Edmonton or Winnipeg, on both CN and CPRS. A more realistic scenario of growth where shippers and railroads utilize more efficient 120-car unit trains would reduce the total number of trains needed to just under 100 per day. In either scenario, accommodating this volume of traffic would require several years of substantial capital investment. In all western Canada production projections, this volume of crude oil would come online over a couple of decades, which would provide railroads time to plan for and make the required investments in additional track, traffic control systems, locomotives and other assets, if the economics warranted. [117] Depending on the rate of increase in train volume there could be temporary capacity constraints (as there was in the Powder River Basin increase), but this volume of rail growth (originating from a discrete geographic area), and capital investments, is consistent with growth in the Powder River Basin example.

**Capacity of Crude-by-Rail Tank Car Fleet**

The remaining potential logistics constraint on the expansion of crude oil movement by rail is the ability of the rail car industry to manufacture the necessary additional tank cars to accommodate this growth in crude by rail. There were numerous press reports in early 2013 identifying the shortage of tank cars as a constraint on crude by rail growth, but it appears this constraint has eased.

When the Draft Supplemental EIS was released, it noted there was a backlog of tank car orders of approximately 47,000 tank cars. It was estimated that it would take until 2015 to clear this backlog. In the first three quarters of 2013, there were 19,000, 6,900, and 5,100 tank cars ordered, respectively. In those three quarters, 6,100, 6,900, and 7,580 tank cars were delivered, respectively. This means that as of the fourth quarter of 2013, the backlog of tank car orders stood at 59,000 and would take until the end of 2015 to clear at current production rates.

Information indicates that at the end of the first quarter of 2013 there were an estimated 30,000 tank cars in the North American crude-by-rail fleet. Industry and analyst statements indicate that the natural replacement rate for the overall North American tank car fleet of just over 300,000 tank cars was approximately 9,000 cars per year, and that the orders above that amount were likely devoted to meeting the increasing crude-by-rail demand. Based on those estimates, the North American tank car fleet devoted to crude by rail could increase from the 30,000 tank cars in March 2013 to nearly 80,000 by the beginning of 2016.

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[117] "Portions of the capital costs and return on investment for these items are included in the long run variable cost (LRVC) estimates for each example movement. Major upgrades to infrastructure such as traffic control systems and the addition of main line tracks would also add to the fixed cost for each railroad. Over the past three years all of the Class I railroads in the US and Canada have made similar investments in main line track, traffic control systems and locomotives to handle the projected growth in crude oil indicating that they anticipate earning a return sufficient to justify these investments." (Hellerworx rail logistics constraints report footnote 3, included in Appendix C Supplemental Information to Market Analysis.

Figure 1.4.3-16 compares the estimated total capacity of the North American crude by rail fleet of tank cars to high estimates of potential crude by rail demand in North America. This comparison indicates that going forward the availability of tank cars does not appear likely to be a substantial constraint on growth, and that the manufacturing industry has the capability to deliver tank cars at rates well exceeding what would be necessary to accommodate oil sands production increases along with increasing crude by rail throughout North America. There could be constraints on tank car availability in particular regions, such as the WCSB, or of a particular type (coiled insulated cars as discussed below), but at current manufacturing rates, such constraints are likely to be short term.
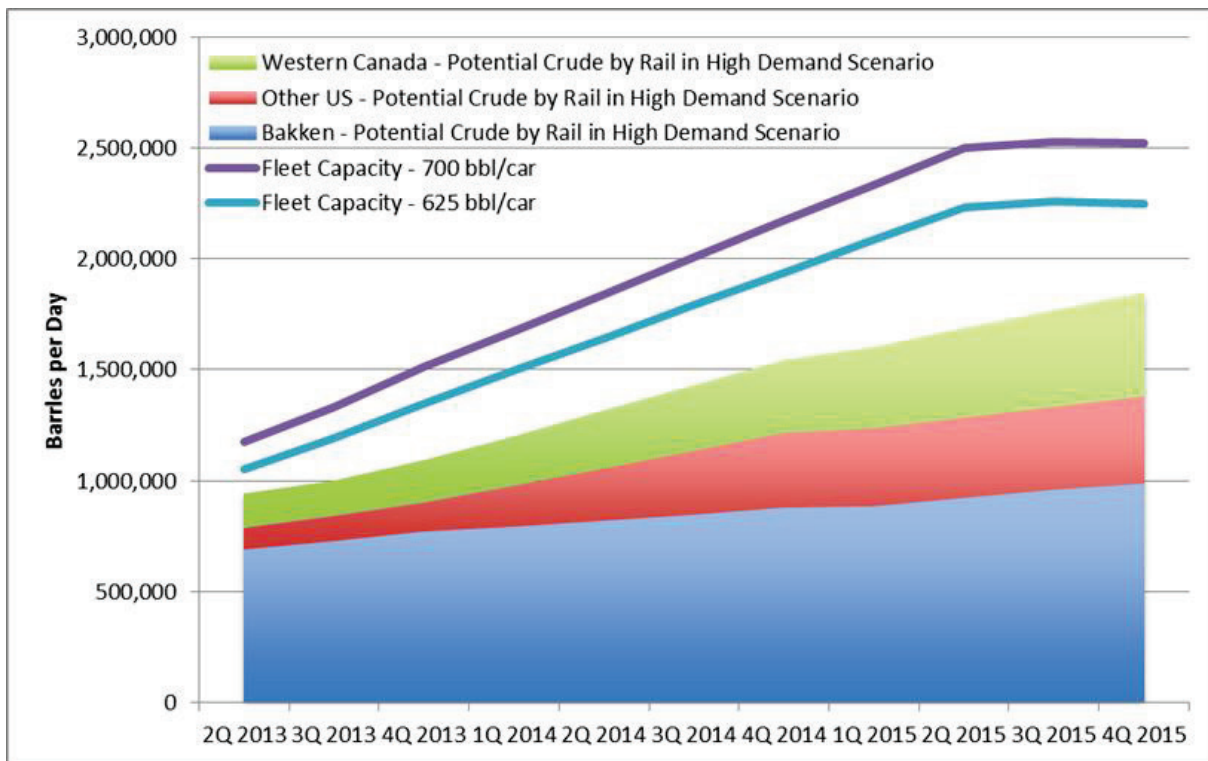


Source: Rail Energy Transportation Advisory Committee 2013, Bowen 2013, PLG Consulting 2013, Titterton 2013

Note: Total cars in crude fleet based on reports of 30,000 cars in fleet at the end of the first quarter of 2013. Additions to fleet per quarter are based on the assumption that tank car deliveries above the natural replacement rate for overall tank car fleet (2,250 per quarter/9,000 per year) are destined for crude service. Production rate per quarter based on the average of tank car deliveries in the second and third quarters of 2013. This also assumes a ninety percent utilization rate for tank cars in the crude oil fleet, and attrition in the crude-by-rail fleet of approximately 3 percent annually of the existing 30,000 cars in the fleet at end of the first quarter of 2013.

**Figure 1.4.3-16        Estimated Tank Car Capacity Compared to Potential Crude-by-Rail Demand**

Reports in early 2013 estimated that 60 percent of the tank cars then on backorder, or being manufactured, are of the coiled/insulated type (Torq Transloading 2012). No information indicating any break down of the types of tank cars that were ordered in 2013 was located. A high percentage of coiled and insulated cars on order would indicate that a substantial amount of the tank cars on order are specifically intended to carry heavy oil sands crude that is in the form of railbit and rawbit, or to give carriers the flexibility to do so. Crude oil grades that can be transported by pipeline (light crude oils through to heavy crude oils such as dilbit) can generally be transported in standard tank cars (although moving dilbit in cold weather can require insulated cars). As explained below, the most economical way to transport oil sands crude by rail is not as dilbit (which comprises around 67 to 75 percent bitumen with 33 to 25 percent diluent) but rather as either railbit (around 15 to 20 percent diluent) or as undiluted bitumen (zero diluent). Railbit and raw bitumen would be transported in rail cars that are insulated and contain steam coils for re-heating the bitumen as necessary at destination. If the report were correct that coiled and insulated tank cars accounted for roughly 60 percent of the early 2013 backlog in tank car orders, there would be enough new insulated rail tank cars available by late 2014 to transport approximately 400,000 to 450,000 bpd of bitumen or railbit per day.[118]

The CAPP projections for crude supplied to market are based on produced bitumen being moved either after upgrading to SCO, or as synbit or dilbit blends, with the latter being predominant. Despite the fact that there is a reduction in carrying capacity per car when moving undiluted bitumen, the ability for rail to reduce or eliminate diluent has the potential to decrease the total blended heavy crude volumes that must be shipped out from western Canada and (increasingly) returned as diluent. For example, 400,000 bpd of raw bitumen or railbit would be equivalent to just over 570,000 bpd of dilbit in terms of the volume of bitumen shipped.

One current uncertainty in the future availability of tank cars is in the current proposed rule-making on the safety of DOT-111 tank cars. DOT-111 tank cars are the class of tank car used in crude-by-rail service, as well as in transporting several other flammable products. Comments on the proposed rulemaking have noted that there are approximately 90,000 DOT-111 tank cars that could be impacted by a requirement to retrofit or retire existing cars that do not meet certain new safety requirements. The notice of proposed rulemaking issued in September 2013 did not recommend the possibility of retrofitting or retiring existing tank cars, but comments were received suggesting existing cars be retrofitted or retired, including comments from the American Association of Railroads.

It is early in the rulemaking process, and it is too speculative to project what a final rule may look like, much less how a final rule might impact the availability of tank cars for crude-by-rail or other flammable liquids service. Based on the notice of proposed rulemaking and comments made on it, a few observations can be made. First, if the measures outlined in the notice of proposed rulemaking were implemented, and were applied to existing tank cars, the long-term cost of complying with those measures per barrel of oil transported could be approximately

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[118] Using the Gulf Coast as a typical destination, with a transit time of around 15 days for the complete trip, each daily loading would require a total of around 20 unit train sets (one loading, nine in transit laden, one off-loading, eight returning empty [or carrying diluent]), assuming a conservative 10 percent underutilization rate. Since each unit train comprises around 100 to 120 cars, the capacity to move incrementally approximately 200,000 bpd of western Canadian crude each year would require adding approximately 6,000 rail tank cars per year (each year an additional three daily loading × 20 train sets × 100 cars per train). More crude oil could be transported each day if the destination were the Canadian or U.S. West Coast as those journeys are shorter.

$0.30.[119] Shorter-term cost impacts (on the order of a few years) could be an order of magnitude greater than that if removing cars from service for retirement or retrofitting causes a shortage of tank cars. This estimate is based on the impact on short-term tank car lease rates over the past 2 years of the crude-by-rail expansion.[120] Also, removing significant amounts of cars from service for retrofitting or retirement could constrain crude-by-rail shipments in the short term if there simply were insufficient cars to handle crude-by-rail demand. Factors that would tend to ameliorate such potential impacts on tank car supply are the current apparent oversupply of tank cars being constructed, improvements in the efficient use of the tank cars in the crude-by-rail fleet,[121] and the demonstrated ability of tank car manufacturers to increase production in response to increased demand. For example, fewer than 10,000 tank cars were produced in 2010 and 2011, compared to 17,700 in 2012 and 28,000+ in 2013.

To summarize, as with the other aspects of logistics growth (loading and off-loading capacity, and rail network capacity) there could be short-term capacity constraints in the availability of rail tank cars, particularly specialized tank cars such as coiled and insulated tank cars necessary to transport railbit or rawbit. Such capacity constraints could be exacerbated by regulatory changes regarding DOT-111 tank cars. Over the medium to long term, however, the tank-car manufacturing industry has demonstrated an ability to substantially increase production of tank cars in response to demand, and could produce cars at a greater rate than that necessary to accommodate additional crude-by-rail transport in North America.

**Pipeline Transport Costs Compared to Rail Transport Costs**

Although crude oil transport by rail predates that via pipeline, one of the primary reasons that pipelines have been preferentially used over many years is because the cost of rail transport of crude oil has generally been higher than pipeline. There are no published tariffs yet available for the proposed Project, but based on existing tariffs, transporting dilbit from Hardisty, Alberta, to the Gulf Coast by pipeline under a long-term contract is estimated to cost between $8 and $10 per barrel.[122]

To estimate the per-barrel cost of transporting oil sands crude by rail from the WCSB to the Gulf Coast, this analysis examined a variety of published sources including company reports and investor presentations and publications by analysts. A summary of these estimates for the cost is presented in Table 1.4-16.

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[119] This estimate is based on the estimates of cost of compliance submitted in comments by the Rail Supply Institute, and the assumptions regarding tank car usage, lifespan, turn times, etc. used in estimating the crude-by-rail rates.

[120] The typical long-term (7-year) lease rate (and long-term cost of ownership) of a general service tank car in recent years has been approximately $1,200 per month. Industry reports indicate that over the past 2 years short-term lease rates for tank cars in crude-by-rail service have been two to three times that rate (or more).

[121] In July 2013, GATX Corporation estimated that there were then approximately 30,000 tank cars in crude-by-rail service (20,000 in the Bakken and 10,000 in Canada), but that as efficiency improved the then-transported volumes would only require 20,000 total cars (Titterton 2013).

[122] On December 2, 2013, TransCanada filed a letter with Federal Energy Regulatory Commission proposing committed pipeline tariffs for delivery of heavy crude oil from Hardisty, Alberta, to Port Arthur via the original Keystone Pipeline and the Gulf Coast Project of $8.10 per barrel.

**Table 1.4-16    Rail Cost References**

| Source | Date | Origin/Destination | Cost/Barrel |
|---|---|---|---|
| | | Oil Sands to: | |
| | | Gulf Coast | $14–$21 |
| | | East Coast | $13–$20 |
| Devon Energy | October 2013 | West Coast | $8–$14 |
| | | Western Canada to | |
| Peters and Co. Limited | January 2013 | U.S. markets | $15–$20 |
| | | Oil Sands to: | |
| | | Gulf Coast | $15–$16 |
| LyondellBasell | 2013 | East Coast | $16–$18 |
| | | Hardisty, AB to: | |
| | | U.S. Gulf Coast | $14–$21 |
| | | U.S. West Coast | $13–$20 |
| Gibson Energy | June 2013 | Canadian East Coast | $13–$20 |
| | | Kerrobert, SK to: | |
| | | U.S. Gulf Coast | |
| Torq Transloading | September 2013 | (Raw Bitumen, Unit Train) | $16–$22 |
| | | Oil Sands to U.S. Gulf Coast or | |
| Cenovus Energy | April 2013(b) | East Coast | $12–$15 |
| Canadian Natural Resources | June 2013 | Edmonton, AB to Houston, TX | $20 |
| Platts—New Crudes, New Markets | March 2013 | Western Canada to East Coast | $15 |
| | | Lynton, AB to Gulf Coast | |
| | | (Natchez, MS) (manifest, railbit | |
| Southern Pacific Resource Corp | November 2012 | or rawbit) | $31 |
| | | Oil sands to: | |
| | | Gulf Coast | $24 |
| | | U.S. East Coast | $23 |
| PLG Consulting | July 2013 | U.S. Northwest | $17 |
| Gulfport Energy/Grizzly Oil Sands | November 2013 | Windell, AB to U.S. Gulf Coast | $21–$22 |
| EY | 2013 | Hardisty, AB to U.S. Gulf Coast | $14–$21 |

The cost estimates generally range from $12 to $24 per barrel from western Canada to the U.S. Gulf Coast, with one example of a stated transportation cost of $31 per barrel. There are several main reasons there is such a wide range. First, the sources cover a variety of origin points in western Canada, from as far south as Kerrobert, Saskatchewan, to as far north as Fort McMurray (Lynton), Alberta. The rail distance between those origin points is over 600 miles. Second, the transport costs are different depending upon whether the product is shipped on manifest train or a unit train. Unit trains are $3 to $4 cheaper per barrel. Third, oil sands crude can be transported as a variety of products (rawbit, railbit, or dilbit) that have different densities and thus different freight costs per barrel. Fourth, different estimates may include different types of costs, including storage costs, capital carrying costs during transport, and/or gathering costs to transport the product from the production field to a terminal. Fifth, rail transport rates are not based on published tariffs, as are pipelines, but are based on private contractual negotiations. Therefore, not every shipper pays the same price.

Taking account of these factors, examining the details of the sources identified above, as well as specific cost estimates (made as described below) reveals some patterns that help explain the range in cost estimates. Table 1.4-17 below outlines several guidelines that help explain the range in cost estimates, building from the lowest cost per barrel estimates, which are unit train shipments from the Edmonton/Hardisty area.[123]

**Table 1.4-17     Estimates of Cost per Barrel Impacts of Different Rail Options**

| Unit Train Dilbit Origin: Edmonton/Hardisty | Manifest Train | Railbit or Rawbit | Origin: North of Edmonton |
|---|---|---|---|
| $14–$17 | + $3–$4 | + $2–$3 | + $1–$4 |

Note: Cost increase for railbit and rawbit compared to dilbit does not take into account any penalty for transporting diluent.

In addition to reviewing the sources, rail rates were estimated for transporting crude by rail from the WCSB to the Gulf Coast (as well as a variety of other origin and destination points). These estimates are based on estimating crude loading/offloading fees based on recent industry/analyst reports, calculating the long-term cost of leasing or owning the necessary tank cars, calculating rail freight rates, and calculating the cost of transport from the destination rail terminal to a local refinery (typically by barge). The rail freight rates are calculated based on adding a contribution margin of 46 percent to long-run variable costs. The 46 percent contribution margin (i.e., total revenue minus variable costs) is consistent with recent industry statistics, and would provide a sufficient return to the railroads to allow them to make the capital spending necessary to accommodate increasing amounts of crude by rail traffic (additional improvements and signaling systems, additional sidings, and/or constructing double tracks where necessary) if there were demand for such capacity increases. A summary of those cost estimates is provided in Table 1.4-18, and the complete list of cost estimates for different destinations is provided in Appendix C, Supplemental Information to Market Analysis. These estimates are consistent with the estimates reviewed above.

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[123] Applying these guidelines to the list of sources above can help explain the range of estimates. For example, Cenovus Energy, according to company announcements, is planning to ship dilbit by rail from the Canexus facility near Hardisty to the U.S. Gulf Coast. In April 2013, they noted their estimated cost for crude by rail movements was from $12 to $15 per barrel, which is consistent with unit train estimates for dilbit for that route (albeit on the low end of estimates). On the other hand, Southern Pacific Resources has stated the total cost of transporting railbit or rawbit in manifest shipments from Fort McMurray (Lynton) to the Gulf Coast at a much higher $31 per barrel. This estimate is consistent with adding up the high end of the estimates for the guidelines ($17 + $4 + $3 + $4 = $28) and taking account that from company statements their estimate appears to include gathering fees from the field and barge fees for final shipment to refiners along the Gulf Coast. Finally, Grizzly Oil Sands has stated that their estimated cost for shipping railbit in manifest shipments from Windell, Alberta (near Fort McMurray), to the Gulf Coast is $21 to $22 per barrel. This would be consistent with taking the low end of estimates for the guidelines ($14 + $3 + $2 + $3).

**Table 1.4-18    Estimates of Rail Cost For Transport from Western Canada to Port Arthur, Texas**

| Origin | Origin Province | Product | Railcar Loading | Rail Freight | Railcar | Off-Loading | Movement to Refinery | Total[a] |
|--------|------|---------|--------|--------|--------|--------|--------|--------|
| Fort McMurray | AB | Dilbit | $1.50 | $14.88 | $1.02 | $1.50 | $0.52 | $19.45 |
| Fort McMurray | AB | Railbit | $1.75 | $16.39 | $1.22 | $1.75 | $0.57 | $21.70 |
| Fort McMurray | AB | Bitumen | $1.75 | $17.07 | $1.28 | $1.75 | $0.60 | $22.45 |
| Lloydminster | SK | Dilbit | $1.50 | $10.88 | $0.89 | $1.50 | $0.52 | $15.25 |
| Lloydminster | SK | Railbit | $1.75 | $11.95 | $1.08 | $1.75 | $0.57 | $17.10 |
| Lloydminster | SK | Bitumen | $1.75 | $12.44 | $1.13 | $1.75 | $0.60 | $17.70 |

a Total cost estimates rounded to the nearest nickel.

To compare the costs of shipping by rail to pipeline costs, it is important to ensure the costs cover equivalent services. The most direct comparison to pipeline tolls from Hardisty to Port Arthur would be for dilbit costs from Lloydminster to Port Arthur. (Lloydminster was selected as the origin point for calculating rates because it has access to both CN and CPRS and is a similar rail distance to the Gulf Coast to Hardisty.) The difference between the $8 to $10 pipeline toll and $15.25 is $5.25 to $7.25 (comparing the low estimate of pipeline tolls, $8, to the high estimate of unit-train dilbit costs from the company reports, $17, is a $9 difference). This comparison would tend to overstate the true difference in cost between pipeline and rail shipping of oil sands crude because on a net per barrel of bitumen basis, it is more economical to ship oil sands crude on rail not as dilbit, but as railbit or rawbit.

To better assess the respective costs of pipeline versus rail transport, the cost of shipping a barrel of bitumen by pipeline (as dilbit) was compared to the cost of shipping a barrel of bitumen by rail as railbit or rawbit. To ship bitumen by pipeline, producers must either dilute it or upgrade it to a lighter crude oil. The producer must acquire diluent to transport bitumen to market by pipeline, so the cost of purchasing the diluent and transporting is effectively part of the transportation cost of the bitumen. This means that the net cost per barrel of bitumen transported by pipeline is greater than just the stated pipeline toll.

Figure 1.4.3-17 estimates the net cost per barrel of bitumen transported by pipeline. This figure is based on an estimated tariff from transporting crude on the original Keystone pipeline to Cushing, Oklahoma, and then onward to the Gulf Coast on the Seaway pipeline. The tariffs quoted are per barrel of dilbit transported. To transport a barrel of bitumen actually requires 0.4 barrels of diluent for a total of 1.4 barrels of dilbit. This is captured in the figure by showing the cost of shipping the 0.4 barrels of diluent south with the bitumen, and of then shipping 0.4 barrels of diluent back to Alberta where it could be combined again with bitumen to make more dilbit. It also includes the *line fill* cost, which is the cost attributed to the amount of time it takes to transport the product down the pipeline, and costs for the final transport from the delivery terminal to the refinery. It does not include any gathering or storage costs. Adding these costs in indicates that the net cost of transporting a barrel of bitumen from Alberta to the Gulf Coast is approximately $18 based on a long-term committed pipeline tariff, or just over $24 with an uncommitted tariff.
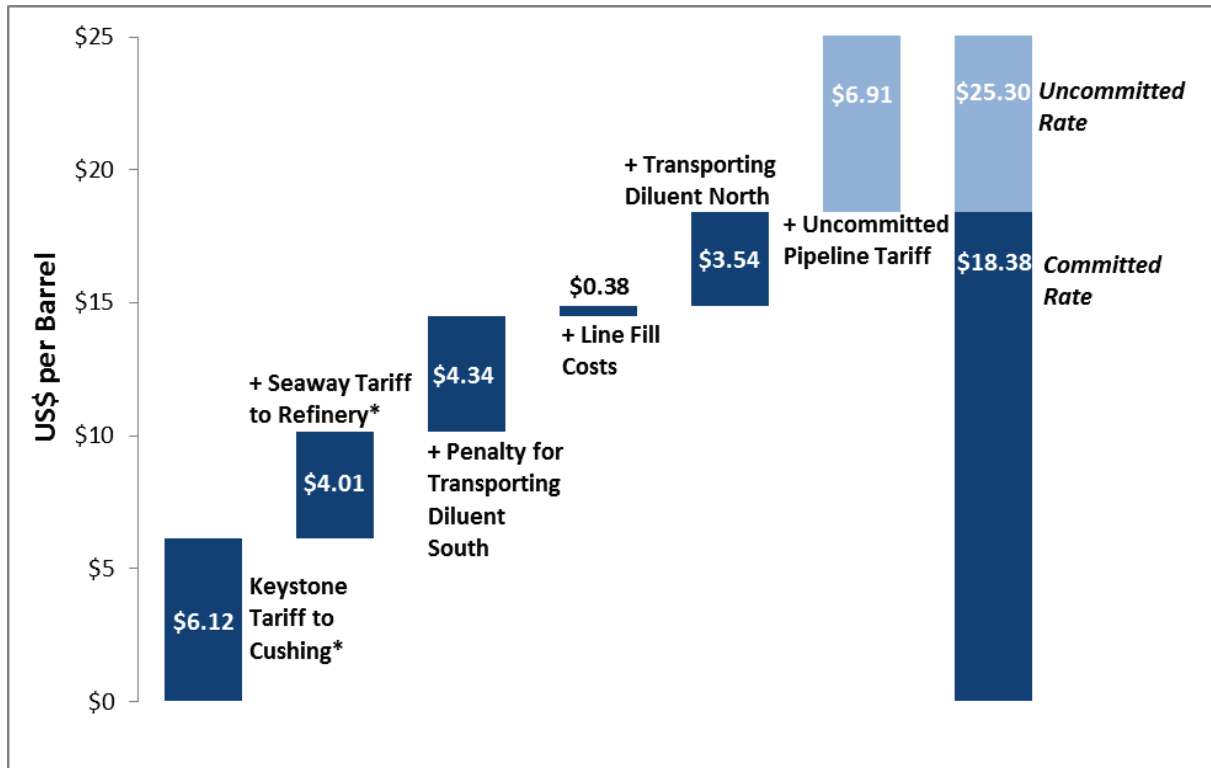
**Figure 1.4.3-17     Pipeline Economics Net Per Barrel of Bitumen (Western Canada to the U.S. Gulf Coast Area), US$**

When transporting bitumen by rail, producers and shippers can ship pipeline specification dilbit, in which case no specialized equipment is necessary beyond what is required to transport any sour crude oil, or they can ship railbit or rawbit. Shipping railbit or raw bitumen allows the shippers to avoid the cost of acquiring and shipping all (or a portion of) the diluent, but requires coiled and insulated tank cars and additional equipment at the loading and offloading facilities. The cost of transporting a barrel of railbit or bitumen is more expensive than transporting a barrel of dilbit by rail, but rawbit or railbit are less expensive on a net per barrel of bitumen basis, even accounting for the additional expense of shipping those products, special equipment, and slightly longer loading and unloading times. Figures 1.4.3-18 and 1.4.3-19 show the calculations of the total cost per barrel of bitumen for shipping railbit and raw bitumen.
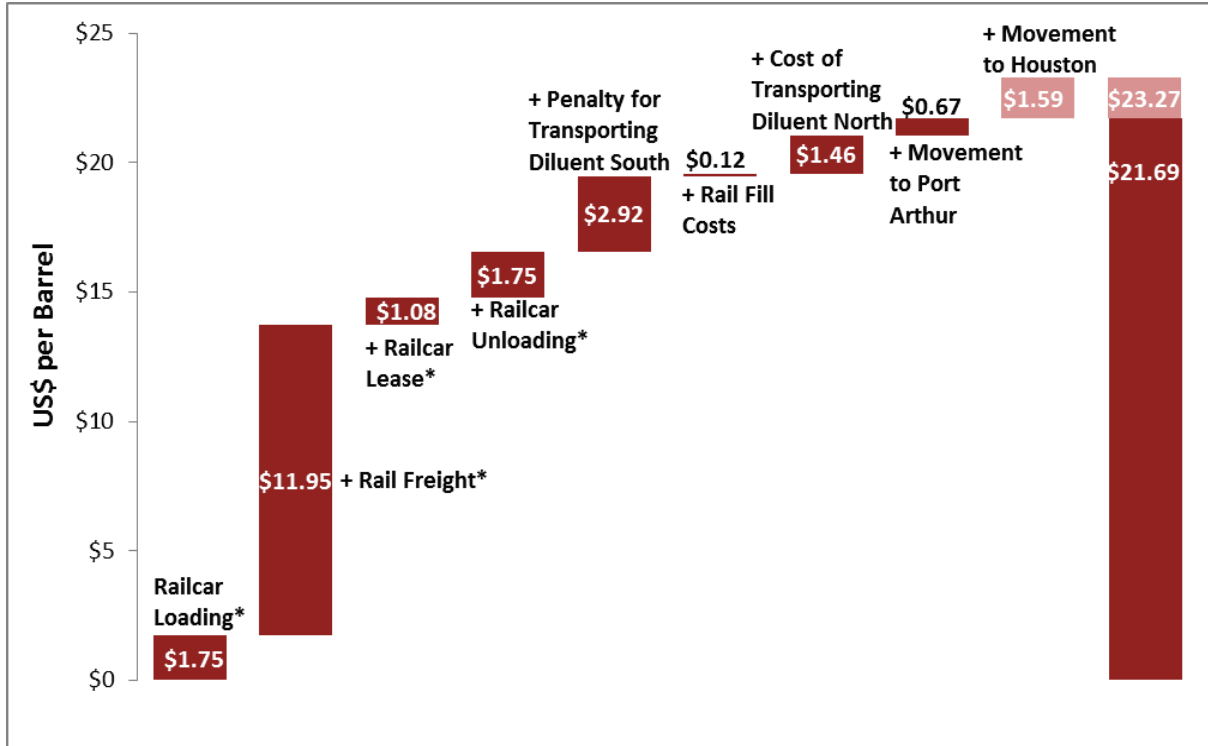
Notes: Although the calculation in this figure is net cost per barrel of bitumen, the rail freight per barrel portion of the cost build-up is different than the rail freight portion per barrel of bitumen in Figure 1.4.3-19 This is because the per-barrel calculation of rail freight here is for one barrel of railbit which is less dense, and thus slightly cheaper to transport, than one barrel of bitumen. The total cost in the right column reflects the total net cost per barrel of bitumen. Costs may not sum due to rounding. * = Cost is shown in $ per dilbit barrel. See "Comparative Transportation Costs For Pipelines and Rail" report in Appendix C, Supplemental Information to Market Analysis, for additional information.

**Figure 1.4.3-18      Railbit by Rail Economics Net per Barrel of Bitumen (Western Canada to the U.S. Gulf Coast Area), US$/bbl**
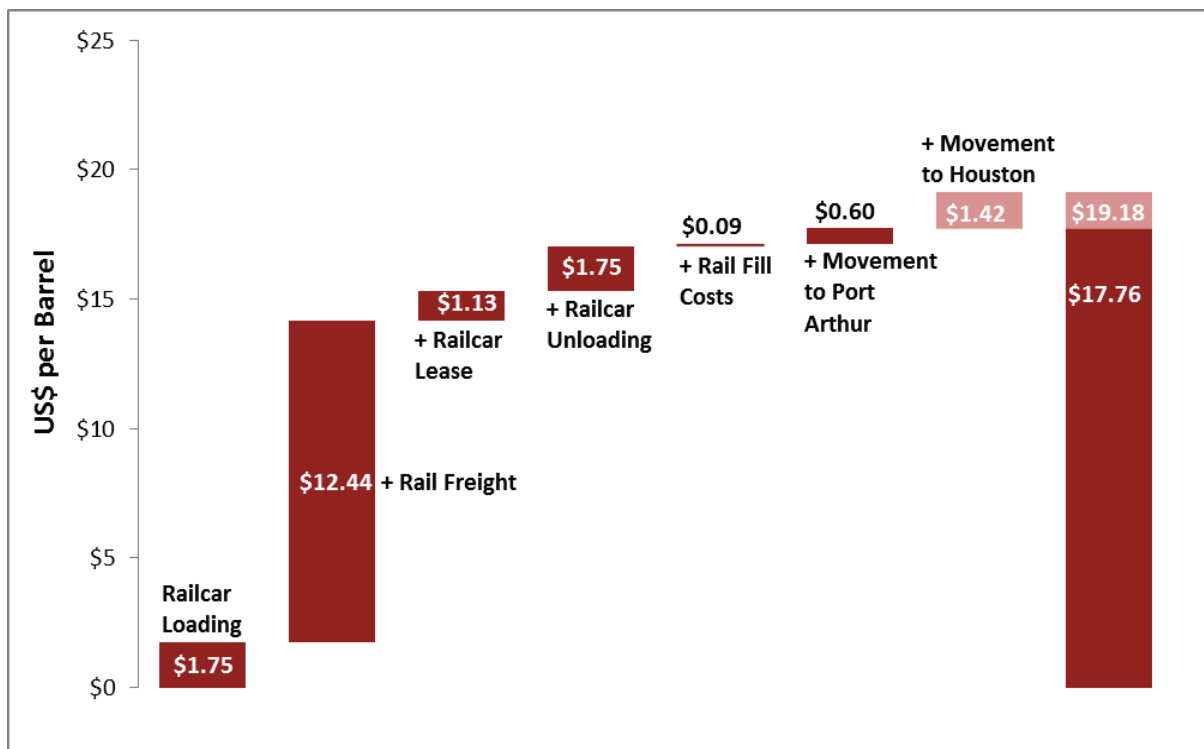
Note: Costs may not sum due to rounding. See "Comparative Transportation Costs For Pipelines and Rail" report in Appendix C, Supplemental Information to Market Analysis, for additional information.

**Figure 1.4.3-19        Bitumen by Rail Economics
(Western Canada to the U.S. Gulf Coast Area), US$/bbl**

The above estimates are based on specific cost estimates of rail and pipeline transport. Changing those underlying cost estimates would impact these calculations regarding the net cost per barrel of bitumen. For example, the pipeline toll used in these calculations was based on combining tolls between two existing pipelines operated by different operators, and is at the higher end of the range for estimated pipeline tolls for committed volumes. Shortly before this Final Supplemental EIS was completed, TransCanada proposed a tariff for transporting heavy crude oil to the Gulf Coast from Hardisty utilizing the existing Keystone pipeline combined with the Keystone Gulf Coast segment. This proposed tariff for long-term committed volumes is approximately $8.09 to the end terminal in Nederland, Texas. Using TransCanada's proposed tariffs (for both the committed and uncommitted volumes) in the calculations shown in Figure 1.4.3-17 would lower the net per barrel of bitumen costs to $16.14 and $24.78, respectively.

Also, the above estimates do not account for potential additional savings associated with backhauling diluent on a unit-train's return journey. Many shippers and commentators have noted the additional savings that could be achieved. CN has estimated that taking advantage of the opportunity to backhaul diluent could improve netbacks of transporting rawbit by as much as an additional $2 to $5 per barrel. Two recent independent analyses have concluded that shipping raw bitumen by rail may actually be cheaper than shipping dilbit by pipeline, and may increase a

producer's netbacks by $4 to $10 per barrel compared to shipping it as dilbit in a pipeline (Fielden 2013, Genscape 2013).

Based on the above, one can consider a reasonable range of estimates of the transport penalty, relative to committed pipeline tariffs, associated with transporting oil sands crude by rail from Alberta to the Gulf Coast as follows: rawbit less than $3.00 per barrel (perhaps even more economic than dilbit by pipeline); railbit $5 to $7 per barrel; and dilbit $7 to $9 per barrel. The transport penalty would be lower if rail costs were compared to uncommitted pipeline tariffs, or if diluent were backhauled.

These estimates of shipping costs could change as markets evolve, but are consistent with producer behavior that has been observed in recent years. The first adopters of crude by rail in the oil sands have been smaller producers (such as Baytex Energy, Southern Pacific Resources, Grizzly Oil Sands, Connacher Oil Sands, Black Pearl Resources, and Laricina Energy) that do not produce enough bitumen and/or do not have enough capital to enable them to obtain long-term committed rates on pipelines. Shipping railbit (which has been primarily from conventional heavy crude production) or raw bitumen on trains may very well be a more economic choice than having to pay uncommitted pipeline tolls and/or selling into the local Alberta market.

By the middle of 2013, larger producers such as Cenovus, Canadian Natural, Suncor, MEG Energy, Statoil, and Imperial Oil had announced plans to utilize more crude by rail as a hedge against pipeline constraints and price volatility in western Canada. Based on the initial announcements of the unit-train rail facilities that are pipeline connected to the producing areas, it appears that in the short term many of these producers may be planning on shipping oil sands crude, via midstream operators, in the form of dilbit. In December 2013, MEG Energy became the first oil sands producer to announce plans to invest in a large DRU at its terminal near Hardisty. This will enable it to ship bitumen as dilbit by pipeline from the production field to the terminal, then remove the diluent and ship the bitumen by rail as rawbit.

As explained below, for the updated modeling, the assumption was that most incremental volumes of crude by rail were transported as dilbit. After the section discussing the modeling, the estimates of the potential transport penalty are further assessed by taking into account the quality discounts of the different products shipped.

## 1.4.4    Updated Modeling

In response to public comment, modeling that supplied insights used in the Final EIS and Draft Supplemental EIS was updated for the Final Supplemental EIS to reflect evolving market factors, particularly higher U.S. oil production. The Final EIS incorporated modeling by EnSys that was commissioned by the U.S. Department of Energy Office of Policy and International Affairs to assist in the analysis of petroleum markets and how the proposed Project may impact them. EnSys used its WORLD model.[124]

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[124] The WORLD model simulates the global petroleum liquids downstream industry, capturing the interactions of crude and non-crudes supply, product demand, refining, trade, investment and regulation (EnSys 2009). By marrying top-down scenarios with bottom-up detail, WORLD generates near-term and long-term projections of the industry's activity. EnSys maintains bottom-up databases of global crudes, crude oil and product transportation routes, pipelines, refining capacity and future developments. Shipping rates are based on the World Scale system. The Refining Technology (RTEC) module of WORLD simulates the technology and economics of refining. *(footnote continued on the following page)*

WORLD is run with supply and demand forecasts from the EIA AEO (2013a) discussed above to project refinery operations, global crude flows, and North American and other regional crude prices.[125] To account for uncertainties, the model was run over several different supply-demand projections and pipeline configurations. The resulting 16 scenarios provide insight into how the U.S. need for imported heavy crude oil may evolve and how this may change depending on the availability of pipelines.

As with the EnSys 2010 modeling, a key result is that when westbound pipelines in Canada are available, they are the preferred route for WCSB crudes. Due to attractive netbacks from Asian markets, these westbound pipelines divert WCSB crudes towards Asia and away from the United States, which is then left importing more crudes from Latin America and the Middle East, regardless of cross-border pipeline availability.

Rising U.S. light crude production reduces imports of light and medium crudes. Refiners continue to demand heavy crude, meeting this demand with crudes from Canada, Latin America, and the Middle East. The amount of crude from each region varies depending on pipeline assumptions.

In any scenario, some WCSB crudes are likely to travel to the United States by rail. This reflects the considerable rail capacity being developed in the WCSB described above. After 2020, the amount of crude traveling by rail varies substantially depending on the availability of cross-border pipelines, rising to as much as 1.5 million bpd in 2035 in some scenarios.

### 1.4.4.1    *Introduction to Model Updates*

As described above, the Final EIS and Draft Supplemental EIS incorporated findings from a modeling analysis of the oil market which examined the impact of the proposed Project. The 2010/2011 modeling, carried out by EnSys on its WORLD model, included the potential impacts of constructing or not constructing the proposed Project on U.S. refining, oil imports, and on Canadian crude oil market destinations. The Draft Supplemental EIS explained how subsequent changes in U.S. oil supply and demand did not fundamentally alter its findings. WORLD scenarios were run using EIA AEO 2010 and 2011a supply and demand projections. While these differed from AEO 2013 projects, the EIA noted:

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By combining this bottom-up detail in WORLD with upstream liquids production, downstream fuels consumption, and world crude oil (Brent) price outlooks from a range of EIA AEO 2013 cases, EnSys projected strategic industry parameters, notably, global refining activities, investments and economics, crude and product pricing/differentials, trade flows and logistics through to 2035. For more details, see "WORLD Model Overview and Results" in Appendix C, Supplemental Information to Market Analysis.

[125] The WORLD model was run on projections from the EIA AEO 2013, published May 2, 2013 (EIA 2013a). The Early Release of the AEO2014 Reference Case occurred December 16, 2013. AEO Early Release editions only have a Reference Case, which may be revised before a final edition and other cases are published sometime in 2014. While projections in the AEO2014 Early Release Reference Case differ from the AEO 2013 Reference Case, the issues considered are similar and the projections generally fall within the range of AEO2013 cases used here. U.S. crude oil production is higher in the AEO2014 Reference Case than in the AEO2013 Reference Case, but generally lower than in the AEO2013 High Resource Case and Low/No Net Imports Case. Reference Case crude oil production retains its former profile, peaking later this decade and then declining, but it now peaks at 9.6 million bpd in 2019 and falls to 7.9 million bpd by 2035. AEO2014 projections for U.S. total liquid fuel consumption and Canadian liquid fuels production are nearly unchanged. U.S. petroleum product exports are higher in the AEO2014, moving closer to the levels projected by WORLD.

"The AEO Reference case reflects some important updates, including more rapid near-term growth in U.S. tight oil production, a lower near-term trajectory for oil prices, and reduced U.S. gasoline demand due to higher vehicle efficiency. However, these updates do not alter some of the major implications of earlier projections, including continued U.S. dependence on imported crude oil supplies, growing global demand, long-term rising oil prices, growth in Canadian oil sands production, and continued demand for heavy crude by U.S. Gulf Coast refiners even as traditional sources from Mexico and Venezuela continue their recent declines." (EIA January 2013 Memo, see Appendix C, Supplemental Information to Market Analysis)

However, in response to comments from the public and other agencies, the Department commissioned an update of the EnSys modeling to explicitly incorporate recent developments. Scenarios reflecting key uncertainties raised in comments from the public and other government agencies were incorporated into this effort. As a result 16 different scenarios were modeled with updated data and supported by additional analysis such as the transportation information in Section 1.4.3, Crude Oil Transportation. Questions examined in various scenarios include the impact of shifting oil production and consumption trends, the markets for WCSB crudes, the impact on U.S. oil imports, and the implications for crude transport by rail.

### 1.4.4.2    Scenarios

In response to comments and to assess key uncertainties regarding supply, demand, and pipeline availability, the EnSys WORLD model was applied to four supply-demand cases and four sets of pipeline configurations. Each supply-demand case was modeled against each pipeline configuration to yield the 16 scenarios as shown in Table 1.4-19. The WORLD model generated projections through 2035 in each scenario. The supply-demand cases modeled are as follows:

- The Reference Case projection, in which U.S. crude production reaches 7.5 million bpd by 2016 to 2020 and thereafter gradually declines to 6.3 million bpd by 2035.

- The EIA AEO High Oil and Gas Resource Case projections, where U.S. crude oil production reaches 10 million bpd by 2020 and remains around that level thereafter (natural gas production is also elevated in this case, keeping natural gas prices lower than in the Reference Case).

- The EIA AEO Low/No Net Imports Case projections, a supplement to the High Resource Scenario that also assumes U.S. oil consumption falls a further 2.8 million bpd by 2035 relative to the High Resource Case and the United States becomes a net oil exporter.

- A supply-demand case which assumes higher than expected oil production in Latin America. The High Latin America case assumes the region produces 2.5 million bpd more oil than the Reference Case by 2020 and 3.5 million bpd by 2035. This would result in total Latin American liquids supply of 14.3 million bpd in 2020 and 18.4 million bpd in 2035. This scenario does not represent a forecast, but rather a hypothetical scenario to understand the implications of uncertainty.

**Table 1.4-19    Supply-Demand and Pipeline Cases, and the Resulting Scenarios**

|  | **EIA AEO Reference Case:** U.S. crude oil production peaks at 7.5 million bpd in 2019 and then declines | **EIA AEO High Resource Case:** Larger recoverable oil and gas resource assumptions result in U.S. crude oil output reaching 10 million bpd by 2020 and then remaining flat | **EIA Low/No Imports Case:** Assumes High Resource supply plus greater demand-side efficiency, leaving United States a net oil exporter by 2035 | **High Latin American Supply Case:** Assumes higher Latin American production with Reference Case |
|---|---|---|---|---|
| **Unconstrained:** Allow all cross-border and Canadian east/west pipelines | *Reference Unconstrained Scenario* | *High Resource Unconstrained Scenario* | *Low/No Imports Case Unconstrained Scenario* | *Higher Latin American Unconstrained Scenario* |
| **No East-West Pipelines:** Allow cross-border pipelines but no new Canadian east/west pipelines or rail to Canadian West Coast | *Reference No East-West Scenario* | *High Resource No East-West Scenario* | *Low/No Imports No East-West Scenario* | *Higher Latin American No East-West Scenario* |
| **No Cross-Border Pipelines:** No cross-border pipelines but allow Canadian east/west pipelines[a] | *Reference No Cross-Border Scenario* | *High Resource No Cross-Border Scenario* | *Low/No Imports No Cross-Border Scenario* | *High Latin American No Cross-Border Scenario* |
| **All Constrained:** No new cross-border, east-west Canadian pipelines, or rail to Canadian West Coast | *Reference Constrained Scenario* | *High Resource Constrained Scenario* | *Low/No Imports Constrained Scenario* | *High Latin American Constrained Scenario* |

[a] Where permitted, planned pipelines begin after several years, including the northern leg of TransCanada Keystone XL (2017), TransCanada Energy East (2018), expansion of Kinder Morgan Trans Mountain (2020), and Enbridge Northern Gateway (2025).

Key aspects of the AEO cases were described above.[126] The additional Latin America scenario was included to examine uncertainty that this region, traditionally the source for heavy crude oil imports into PADD 3, would produce more heavy oil than expected in the Reference Case.

Each of these supply-demand cases was paired with four pipeline configurations:

- An *Unconstrained* pipeline scenario, where pipelines are assumed to be built as warranted by market conditions.

- A *No East-West Pipelines* scenario, where new pipelines capacities between the United States and Canada are permitted as dictated by market need but no new pipelines from Canada's oil sands region to Canada's East or West Coast are permitted by Canadian

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[126] Additional details are available in the AEO (EIA 2013a).

authorities. Crude by rail to the Canadian West Coast for onward overseas shipment by tanker to Asia is also not permitted.

- A *No Cross-Border Pipelines* scenario, where pipelines within Canada are assumed to be built as dictated by market conditions but no new cross-border pipeline capacity into the United States is permitted.

- A *Constrained Pipelines* scenario, which assumes that no new pipelines carrying WCSB crude are built. Like the No East-West Pipelines scenario, no additional crude by rail to the Canadian West Coast is permitted.

In scenarios where pipelines were constrained, increased crude shipment by rail was allowed subject to the constraints described above.[127] The WORLD model projections for oil sands crude by rail are for rail shipments of dilbit, which contains approximately 30 percent diluent. This is the least economic means of transporting oil sands crude by rail, as discussed in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail.

In reality, growing volumes of bitumen by rail may be shipped as railbit or rawbit, which requires less or no diluent. The model does provide prices for railbit and dilbit in the Gulf of Mexico based on refiner demand for comparable crudes. The economics of railbit and rawbit are considered in Section 1.4.5.3, Transportation Cost Sensitivities. Rail transport costs in WORLD rise over time as diesel costs rise with global oil prices.

Two previous scenarios—denying the proposed Project but allowing other new cross-border pipeline capacity and not allowing any new transport capacity out of the WCSB—did not need to be updated because results from the EnSys 2010/2011 modeling would be unaffected by recent changes:

- In a scenario where the proposed Project is not built but other new cross-border capacity is permitted, then other, broadly similar pipeline capacity is likely to be built between the WCSB and PADD 2 and PADD 3. This has been borne out in recent pipeline proposals, in particular the Alberta Clipper Expansion and Flanagan South proposals.

- In a scenario where it is assumed that all transportation options are frozen at current levels, little additional production from the WCSB would be possible (production would be capped at current export capacity). This scenario remains unrealistic, and is contrary to the ongoing trends in increasing rail capacity that have been developing since the middle of 2011. Any assumption that rail capacity remains at current levels would be inconsistent with the developments described above, including projects currently under construction.

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[127] In all scenarios, rail transport of crude oil was permitted with two exceptions. As outlined in Table 1.4-14, rail to the Canadian West Coast is constrained in scenarios where new pipelines from the WCSB to the Canadian West Coast are not permitted. Due to relatively low costs to reach markets in Asia whether by rail or pipeline results allowing westbound rail transport where westbound pipelines were not allowed appeared substantially similar to permitting westbound pipelines. This overwhelms the impacts of changing other variables. Rail transport to Eastern Canada for export was not as similar to pipeline transport and does occur in some scenarios, but not others. Also, potential rail shipments to the U.S. West Coast for export were constrained to 0.1 million bpd or less.

## *1.4.4.3 Results*

**Summary**

The WORLD model projects sustained demand for imported heavy crude oil in the United States, particularly in PADD 3. This reflects how rising domestic crude supply is primarily light crude oil while many PADD 3 refiners are optimized to take heavy crude. As a result, rising light crude supply primarily backs out light and medium crudes across all scenarios. How much U.S. demand for imported heavy crude oil is met by WCSB heavy crudes depends primarily on if pipelines connecting the WCSB to the Canadian coasts are built. If they are built, they are utilized ahead of cross-border options. Shipping distances to Asia are relatively short. Asian oil demand is rising, and the region is projected to account for roughly 40 percent of global deep conversion capacity additions through 2035.[128] When these pipelines are available, PADD 3 refiners are left importing more crude from Latin America and the Middle East. If these pipelines are not available, more Latin American and Middle Eastern crude flows to Asia. This is consistent with findings in the EnSys 2010 study and reflects shipping costs to Asia shown in Table 1.4-20.

**Table 1.4-20      Comparison of Transport Costs for Routes to Asian Markets**

|  | Pipeline/Rail Cost | Marine Transport (Suezmax) | Marine Transport (VLCCᵃ) | Total Transport Cost |
|---|---|---|---|---|
| Canadian West Coast (via pipeline) to Asia | $4–$5 | $3 | $2 | $6–$8 |
| Canadian West Coast (via rail) to Asia | $8–$9 | $3 | $2 | $10–$12 |
| U.S. Pacific Northwest (via rail) to Asia | $10–$11 | $4 | $3 | $13–$15 |
| U.S. Gulf Coast (via pipeline) to Asia | $8–$10 | $7 | $5 | $13–$17 |

Source: Poten and Partners 2013.

ᵃ VLCC = very large crude carrier

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[128] Deep conversion capacity refers to coking as well as fluidized catalitic cracking and hydrocracking units. There is already a significant capability in Asia to process heavy Canadian type crudes and this is being substantially increased. WORLD projects that in any scenario, Asian refiners will by 2020 have added more than 3.5 million bpd of new crude unit capacity, together with 3 million bpd each of deep conversion and desulfurization capacity—the bulk of these additions being firm projects. These additions will substantially increase the region's ability to handle additional heavy and sour crudes by 2020. These additions are on top of capability today to process mainly heavy Canadian crude oils that was assessed in 2012 as being 2.2 million bpd across northeast Asia (China, Japan, South Korea and Taiwan), to which should be added capabilities in India (the Reliance and Essar complexes for example) and in other countries in Asia (Muse 2012).

In contrast, refining capacity increases on the Canadian West Coast are generally considered possible but not probable. Currently, there is only one small coastal refinery, the 55,000 bpd Chevron refinery at Burnaby, a suburb of Vancouver. There are no known plans to expand this. A project has, however, been put forward. Kitimat Clean, Ltd. would build a 550,000 bpd diluted bitumen refinery at Kitimat, British Columbia (the same port as for Enbridge's proposed Northern Gateway pipeline). The total estimated cost has been reported at $26 billion, to entail both the refinery—which would apparently use patented hydrogen addition technology to reduce its carbon footprint—a pipeline from Alberta similar to Northern Gateway to bring in diluted bitumen, a gas supply pipeline, and dedicated tankers. Rail is stated as the alternative mode for crude supply if a pipeline is not approved. Financial support up to $16 billion has reportedly been agreed with a leading Chinese bank and Kitimat Clean Ltd. has requested that the Canadian federal government provide the balance. The refinery's products would be shipped to Asia. The project timetable indicates 3 years for environmental assessments and permitting and a further 5 years for refinery and pipeline construction. (Cattaneo 2013).

Higher U.S. crude supply and lower demand is balanced throughout the scenarios primarily with lower light and medium imports and an increase in refined product exports. Supply-demand cases with higher oil supply also have higher natural gas supply and natural gas prices that are substantially lower than natural gas prices outside of North America or global oil prices on an energy-equivalent basis. U.S. refiners use natural gas as a process fuel and in recent years low natural gas prices have given U.S. refiners a competitive advantage against foreign refiners, who primarily use oil to fuel refining processes. The even lower projected prices for natural gas in the higher oil supply and lower oil demand cases further increase the competitiveness of U.S. refiners in those cases. Coupled with their advantaged access to growing crude supplies, U.S. refiners are a competitive source to supply rising refined products demand in emerging economies such as those of Latin America and Africa. Competitiveness in the export market helps sustain U.S. throughputs even when U.S. consumption is falling.

The availability of pipelines affects how WCSB reaches U.S. markets. Where additional cross-border pipeline capacity is not available, rail is able to carry crudes to the United States and eastern Canada. As discussed above, rail as a transport option for WCSB is already developing rapidly. Some crude is likely to travel by rail regardless of the availability of pipelines. Currently committed crude-by-rail plans, coupled with existing pipeline capacity, appear sufficient to carry projected oil sands production through 2020, based on the EIA (2013a) outlook. After this point, rail capacity must grow substantially to accommodate rising WCSB supplies. WCSB crude-by-rail flows reach as high as 1.5 million bpd depending on the scenarios. When more crude travels by rail, as dilbit in the WORLD projections, the higher cost relative to pipeline reduces the price of oil sands crudes in Alberta (represented below as WCS, an oil sands crude benchmark). However, the impact is limited, in line with the limited difference in costs for dilbit transport for pipeline versus rail as discussed in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail.[129]

When Latin American oil production is expected to be greater than that projected in the Reference Case, the incremental volumes flow to the United States, Asia, and elsewhere. In the United States, higher Latin American imports primarily displace imports from more distant sources such as Africa and the Middle East. The impact on demand for heavy crude from Canada is limited.

Within a given supply-demand case, varying pipeline availability has little impact on the price of U.S. refined products such as gasoline. This is because global crude prices vary little within a given supply-demand case and these crude prices drive products prices. Inland crude prices, such as those for WCS, do vary by pipeline scenario. However, products prices continue to be set by global crude prices. Products prices vary between supply-demand cases but this is due to changes in global production and consumption outlooks, or global oil prices, rather than the availability of pipelines.

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[129] WORLD models crude by rail as dilbit, and not as railbit or rawbit. However, it does provide landed prices for crude with the qualities of railbit and rawbit, as well as dilbit, in the Gulf Coast. The economics of railbit, rawbit, and dilbit crude by rail is discussed in Section 1.4.5.3, Transportation Cost Sensitivities.

**Reference Case Scenarios**

A key determinant for the disposition of WCSB crude is the availability of westbound pipelines within Canada. The WORLD model projects not only that flows to Asia are viable, but that they are preferred in scenarios where westbound pipelines (or rail) are available due to short shipping distances to Asia and growing Asian demand (see Table 1.4-20). This is the case in all pipeline scenarios under the Reference Case, and it leaves U.S. refiners importing more crudes from Latin America and the Middle East. Where westbound pipelines are not available and growing WCSB crude flows predominantly to the United States, the global market rebalances by Asian refiners taking in heavy crudes from the Middle East or Latin America that might otherwise have come to the United States (see Figure 1.4.4-1).
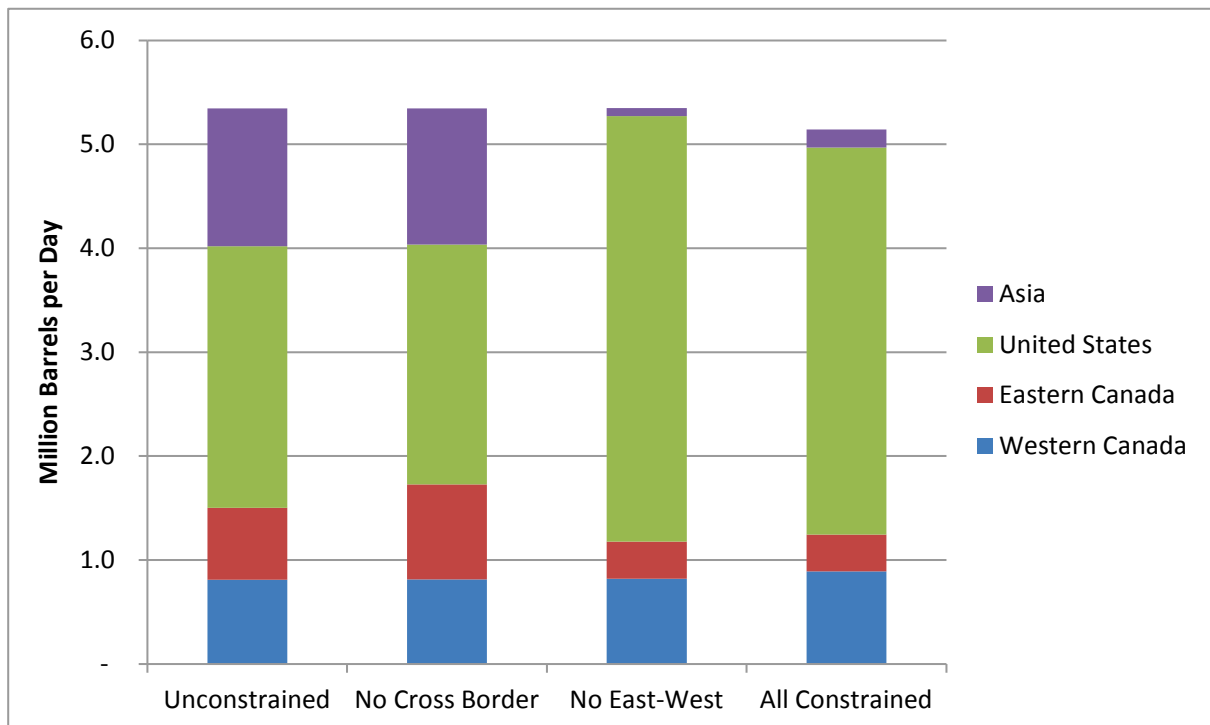


**Figure 1.4.4-1          Reference Case WCSB Crude to Markets in 2035**

When westbound Canadian pipelines are not available, about 70 percent or more of WCSB crudes come to U.S. markets regardless of whether new cross-border pipeline capacity is permitted (most of the remainder is consumed inside Canada, with small amounts flowing to Asia). This drops to less than 50 percent when Canadian pipelines are available (see Figure 1.4.4-2).
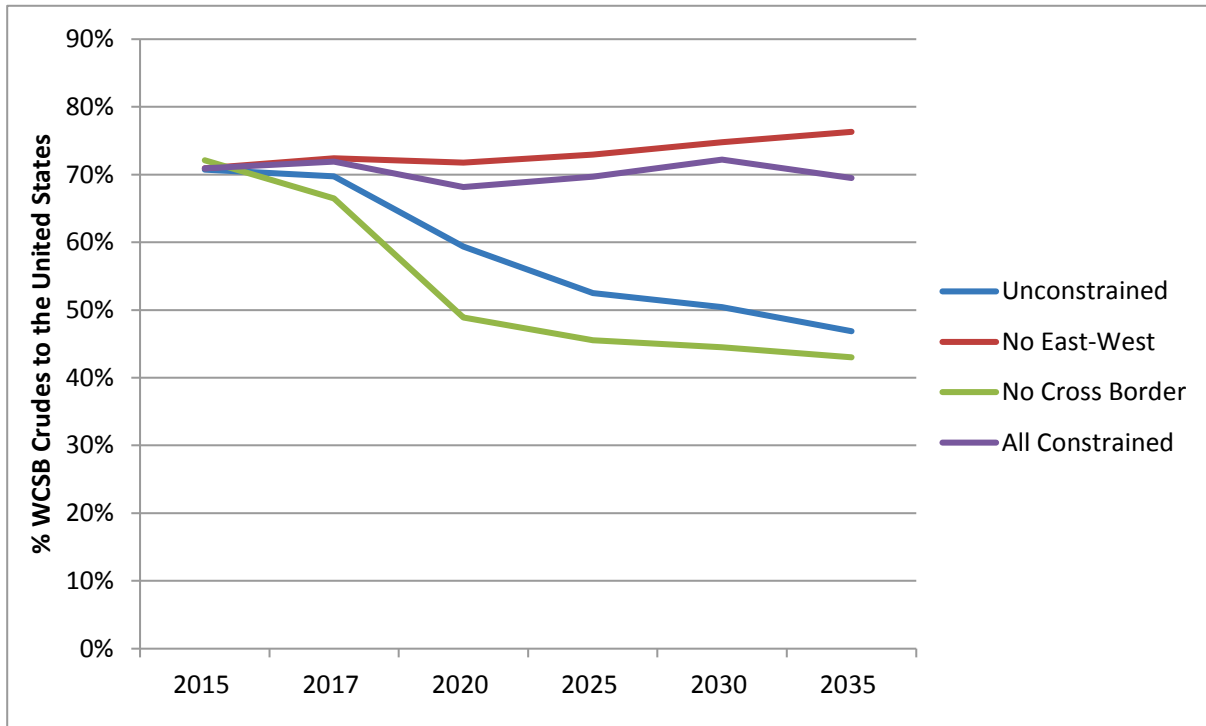


**Figure 1.4.4-2        Share of WCSB Crude to the United States**

U.S. heavy crude demand remains robust regardless of pipeline availability.[130] Heavy crude demand by 2035 varies from 4.8 to 5.7 million bpd in WORLD projections, with the fluctuation largely occurring in PADD 2 depending on whether Canadian westbound pipelines are built (see Figure 1.4.4-3). Where they are not, PADD 2 refiners take greater advantage of their proximity to WCSB crudes, expanding deep conversion capacity to process additional heavy WCSB crudes.[131] Sitting closer to western Canada than competitors in PADD 3, transport costs are lower to PADD 2 refiners. In all scenarios, the level of demand for heavy crude in PADD 3 is relatively stable, varying between 2.4 and 2.7 million bpd depending on pipeline options.
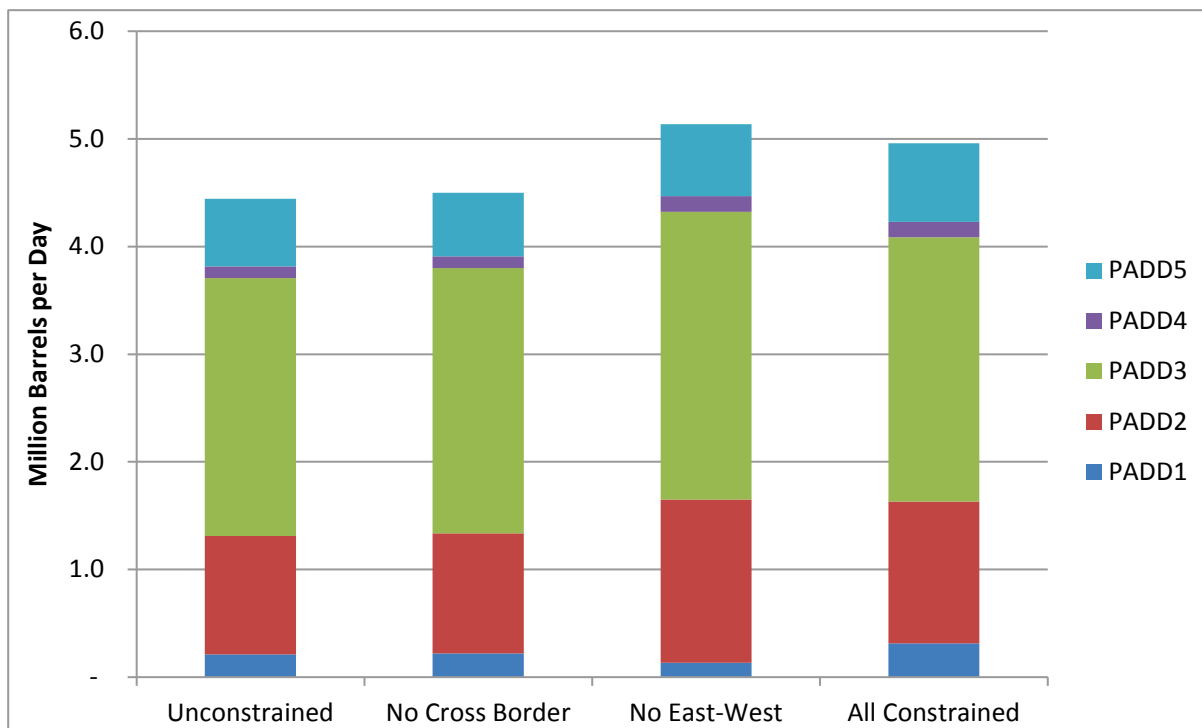


**Figure 1.4.4-3**      **Reference Case Heavy Crude Demand in 2035 by PADD and Pipeline Case**

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[130] EnSys 2013 WORLD defines heavy crude as crude with API gravity of 29 degrees API gravity or less as this is the generally the lightest crude that would be used to provide feedstock for a coker, which is the primary deep upgrading unit used in U.S. refineries.
[131] For instance, BP's recent expansion of deep conversion capacity at their PADD 2 Whiting refinery was based in part on the location advantage versus PADD 3 refiners (Laasby 2011). By being closer to WCSB, transport costs to Whiting would be lower than transport costs to other deep conversion refineries in PADD 3. Lower transport costs amount to lower feedstock costs versus PADD 3 refiners that sell some products into the PADD 3 market.

PADD 3 refinery crude throughputs remain similar and relatively stable between the scenarios. They range from 8.1 to 8.4 million bpd through 2035 (see Figure 1.4.4-4). Rising throughputs through 2025 reflect rising U.S. fuel demand and petroleum product exports; they decline slightly afterwards under the Reference Case with moderating domestic demand. The changing availability of pipelines from the WCSB has limited impact on PADD 3 throughputs.
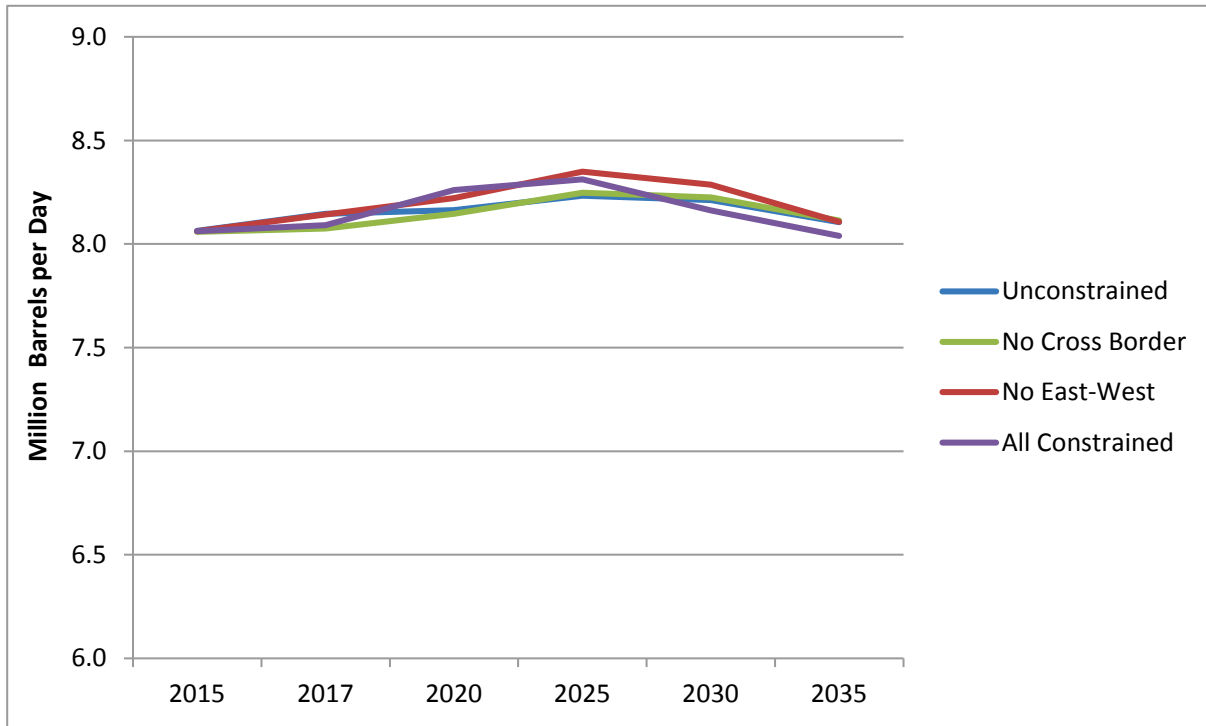


**Figure 1.4.4-4          Reference Case PADD 3 Throughputs by Pipeline Case, million bpd**

How PADD 3 heavy crude demand is met varies by pipeline scenario. Where more WCSB crude is shipped to Asia, PADD 3 imports more heavy crude from the Middle East and Latin America. Where more WCSB crudes come into U.S. markets instead, WORLD projects that on an economic basis they could displace waterborne imported crudes, particularly crudes from the Middle East (see Figure 1.4.4-5).[132]
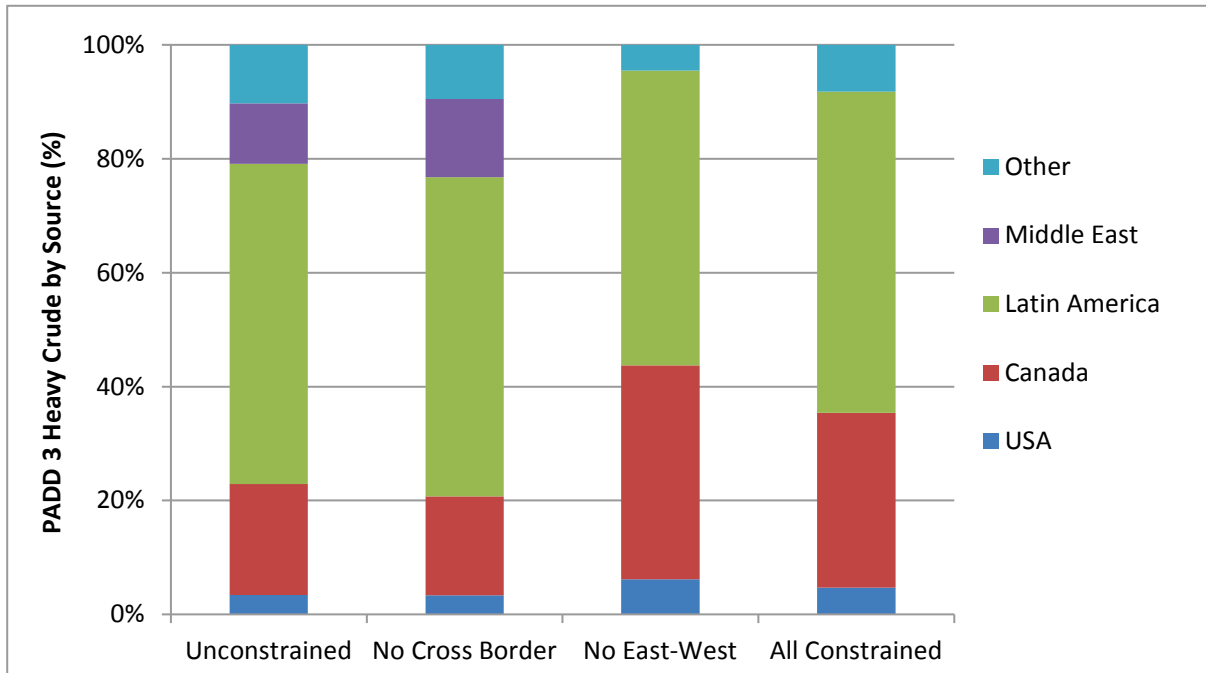


**Figure 1.4.4-5**              **Reference Case Share of PADD 3 Heavy Crude Supply in 2035 by Source**

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[132] This analysis was conducted without imposing a floor to these flows. It could be argued that some producers might intentionally discount crudes to keep some flows into the United States despite economics favoring Asian destinations. In particular, some argue that Saudi Aramco may continue some exports to the PADD 3 Motiva refinery, which it co-owns.

While volumes of crudes shipped from WCSB to the United States look similar in the No East-West and Constrained Pipeline scenarios, their mode of transport differs substantially between the two cases after 2020. Given rail terminals in development with shipper commitments, up to 500,000 bpd of WCSB crude by rail is expected by 2015 regardless of pipeline availability.[133] This will likely result in available capacity on existing pipelines after 2020. After that point, growing WCSB supplies will require growth in crude-by-rail flows if more pipeline capacity is not available. In the absence of additional pipeline capacity, WORLD projects the market would bring more than 1 million bpd to the United States by rail (see Figure 1.4.4-6). The largest volumes are projected to flow to PADD 3; crude by rail also reaches eastern Canada, PADD 1, and PADD 5. After 2020, the Constrained scenario diverges substantially as basically all supply growth from WCSB would have to be carried by rail. WORLD projects a rapid increase in WSCB crude projected to be moved by rail after 2025. The lower pipeline flows in the Reference Case No Cross Border scenario reflect assumptions that some currently announced plans to rail crude to the West Coast for export by tanker are not permitted. The ability of rail transport capacity to meet these demands is discussed in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail, above. Note that crude-by-rail volumes in the Unconstrained and No Cross Border scenarios in Figure 1.4.4-6 below are essentially identical. This reflects how, when west-bound pipelines are available as they are in both these scenarios, they carry the bulk of growing oil sands output regardless of whether cross-border pipeline capacity is available. This results in the same need for rail in either scenario.

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[133] Rail plans are being developed now in part because rail can more effectively reach certain refineries (e.g., PBF Energy's Delaware City Refinery expects to import 70,000 to 80,000 bpd of WCSB heavy crude by the fourth quarter of 2014) and due to uncertainty in future pipeline availability. Shippers can commit to 5 to 7 year rail contracts, shorter commitments than is required for pipelines. Several large new crude-by-rail terminals with shipper commitments are already in development and coming online in 2013 to 2014. This includes the Canexus, whose unit-train rail terminal begins shipments of crude by rail in late 2013. It has stated it has up to 150,000 bpd of transport commitments under contract. Pembina Pipeline Corporation has agreements to ship 40,000 bpd from its Nexus terminal. Gibson Energy has approximately 100,000 bpd under contract for its 140,000 bpd Hardisty unit-train loading terminal. Kinder Morgan and Keyera have announced that their 40,000 bpd terminal due for completion in the second quarter of 2014 is underpinned by a contract with a refiner and they are considering expansion to 125,000 bpd along with a potential DRU. In addition, roughly 100,000 bpd are currently being carried by rail and a number of smaller producers are developing capacity. Consequently, it appears that around 500,000 bpd of crude is likely to be carried by rail by 2015. For more detail see Section 1.4.3.3, Potential to Increase WCSB Crude by Rail.
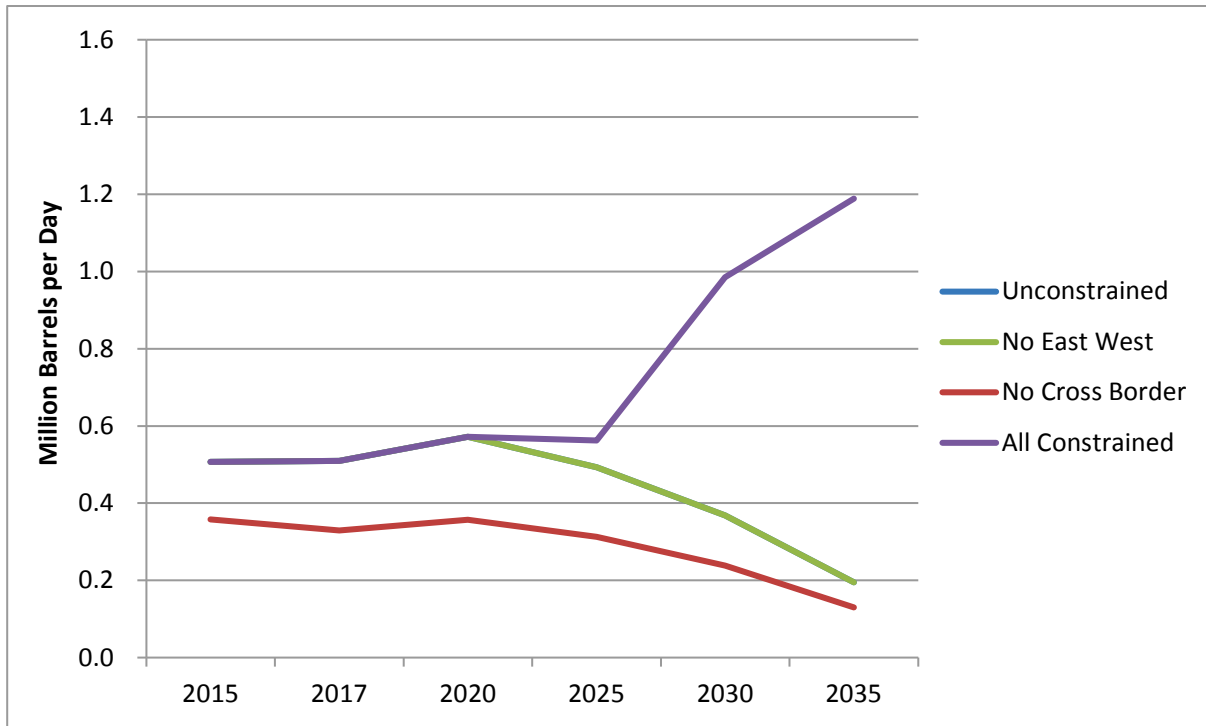
**Figure 1.4.4-6**     **Reference Case Rail Shipments of WCSB Crudes to U.S. and Canadian Destinations[134]**

Crude by rail to the United States in the Reference Case Constrained scenario are carried to PADD 3 as well as PADD 1 and PADD 5 (see Figure 1.4.4-7).[135] PADD 3 is the center of U.S. refining activity and has the largest concentration of deep conversion capacity. PADD 5 refineries are geared toward heavy crude as well due to heavy indigenous supply from California and Alaska, which is in decline. WORLD projects that PADD 5 would receive conventional and oil sands crudes via rail from WCSB.[136] From 2030 to 2035, WORLD projects that rising crude-by-rail volumes flow to eastern Canada, increasing from 30,000 bpd to 220,000 bpd.[137] Given available pipeline capacity, WORLD does not project that rail will carry crude to PADD 2 and PADD 4.

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[134] Crude by rail in the Unconstrained and No Cross Border scenarios overlap in the Reference Case and other cases.

[135] Roughly 220,000 bpd, of WCSB crude in Figure 1.4.4-7 is shipped via rail to eastern Canada in this scenario.

[136] Because the details of how California's Low Carbon Fuels Standard would treat oil sands crude was not yet clear when the modeling was done, the modeling assumes it is not possible to send oil sands crudes to California. Heavy WCSB crudes sent via rail to Canada are conventional heavy grades similar to the Californian crudes that are declining.

[137] EnSys advises that WORLD is relatively uncertain on this estimate of crude-by-rail to eastern Canada, and it is possible these volumes could instead flow to PADD 1.
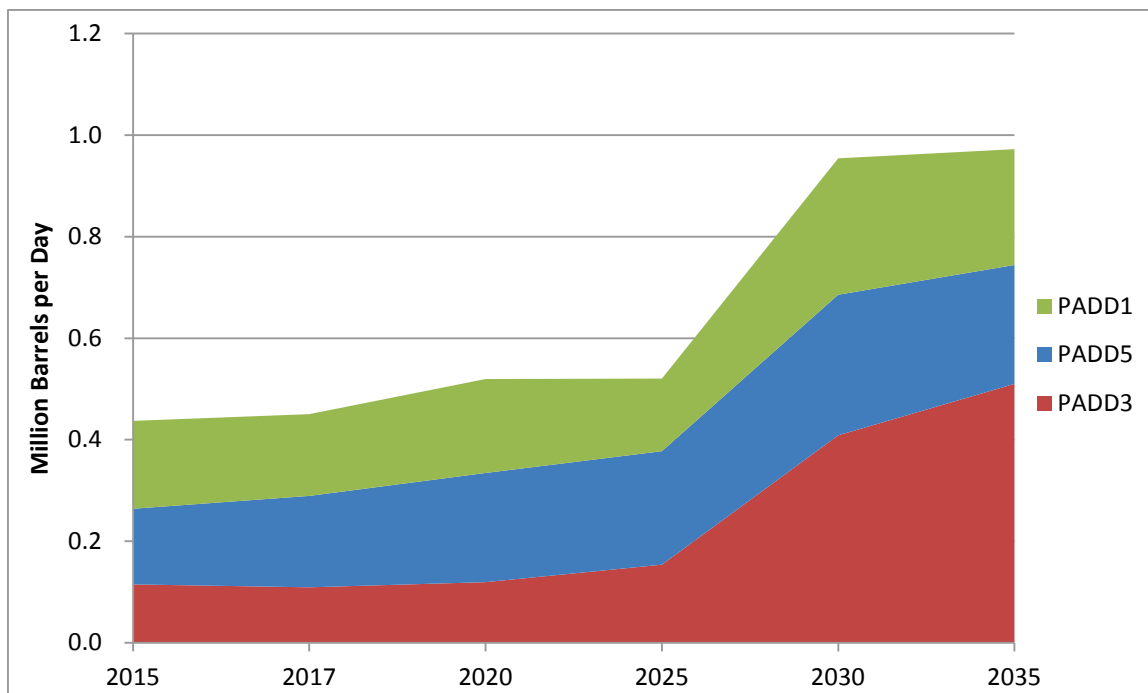
**Figure 1.4.4-7          Reference Case Constrained Scenario WCSB Crude Shipments by Rail to the United States**

Crude by rail can be more expensive than shipping by pipeline, particularly when shipped as dilbit as is assumed in WORLD, and the uptick in rail transport after 2020 corresponds to divergence in projected WCS prices, particularly in the all constrained scenario. Greater crude by rail reduces revenues to oil sands producers; however the reduction is limited, reflecting the limited difference between pipeline and rail transport costs in general as described in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail. The price for WCS, the benchmark price for oil sands crude, is discounted to the U.S. benchmark WTI primarily due to crude quality and location. As heavier, more sulfurous crude, WCS is priced lower than WTI. The degree to which this occurs depends on the relative supply of heavy and sour crudes as well as the availability of various kinds of refining capacity as described in Section 1.4.2.5, U.S. Refining. WTI's price is also higher due to closer proximity to markets. As transport costs to reach market increase, the discount for WCS increases.

Based on AEO benchmark price projections, the WORLD model projects that oil sands prices generally follow global oil prices. WCS follows WTI with a discount. The discount for quality expands in dollar terms as oil prices increase.[138] In addition, there is a discount related to

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[138] The price of WTI itself disconnected from global oil markets in early 2011. WTI traded at a large discount due to bottlenecks in domestic U.S. pipeline capacity. Recent experience in the Bakken shows that rail has helped alleviate such inland domestic discounts for crude. These bottlenecks are being resolved, especially with the startup of new crude pipeline capacity from PADD2 to PADD3. Discounts have compressed and WTI is reconnecting with global prices. The issue is discussed in more detail in Section 1.4.6.1, Crude Price Differences and Gasoline Prices. The *(footnote continued on the following page)*

transport options. Where pipeline capacity is unconstrained, or at least unconstrained to reach Asian markets, WCS prices remain relatively higher. Prices are lower in scenarios where growing oil sands crude supplies are largely restricted to U.S. markets and lowest in the Constrained scenario where progressively greater volumes must be transported by rail (see Figure 1.4.4-8).
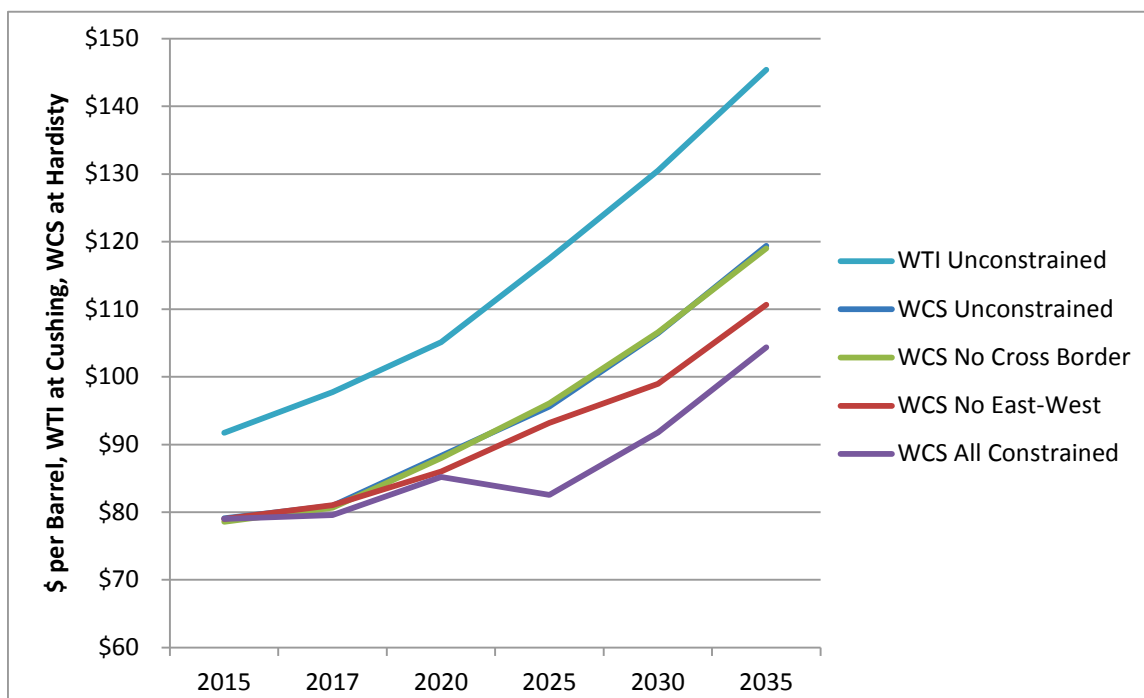


**Figure 1.4.4-8          Reference Case WCS Prices by Pipeline Scenario**

Different pipeline scenarios have little impact on WORLD projections gasoline prices, as shown in Table 1.4-21. Wholesale gasoline prices follow the global crude prices.

**Table 1.4-21     U.S. Average Wholesale Regular Gasoline Prices, Reference Case, $ per gallon**

|  | 2015 | 2017 | 2020 | 2025 | 2030 | 2035 |
|---|---|---|---|---|---|---|
| Unconstrained | 2.51 | 2.61 | 2.76 | 2.94 | 3.17 | 3.53 |
| No Cross Border | 2.51 | 2.60 | 2.75 | 2.94 | 3.16 | 3.53 |
| No East-West | 2.51 | 2.61 | 2.75 | 2.94 | 3.16 | 3.52 |
| Constrained | 2.51 | 2.62 | 2.75 | 2.94 | 3.16 | 3.52 |

Notes: Does not include distribution costs or taxes. Unweighted average of WORLD projections for East Coast and Gulf Coast regular gasoline and West Coast reformulated gasoline.

WORLD model predicts that rail will continue to play an important role in helping crude from the Bakken reach markets.

**Higher Oil Production**

The possibility of significantly higher U.S. oil domestic production was a key uncertainty identified in public comments and in Section 1.4.2.3, U.S. Crude Oil Production. To explore this possibility, WORLD was run with supply and demand projections from the AEO High Resource Case. The key difference versus the Reference Case is that U.S. crude oil production grows higher and remains level at approximately 10 million bpd through 2035, at which point it is roughly 60 percent higher than in the Reference Case (see Figure 1.4.4-9). This is primarily balanced out through reduced crude oil import needs. Also, U.S. refinery throughputs are projected to be higher under the High Resource case, driven by the combination of increased supply of domestic crudes (which in this study were not allowed to be exported except to Canada), slightly higher domestic demand resulting from lower oil prices, and low natural gas prices which strengthen U.S. oil refineries' competitive advantage against foreign competitors. This yielded higher exports of refined products as described below.
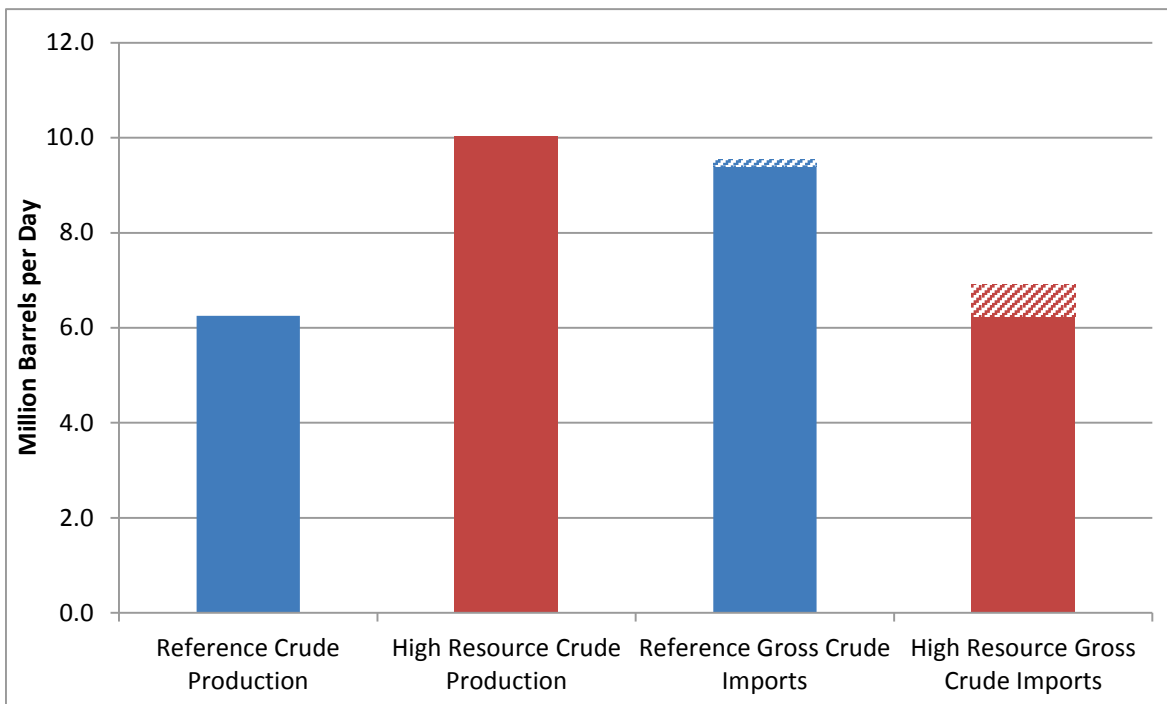


Note: Shaded regions represent ranges of crude imports in the different pipeline cases.

**Figure 1.4.4-9         Reference and High Resource Case Crude Production and Imports in 2035**

Because the increase in domestic crude production in the High Resource Case comes from light crude, it is light and medium crude imports that decline most. This is in line with EIA expectations as shown in Figure 1.4.2-11 that crude imports grow progressively heavier on average. WORLD projects that refinery demand for heavy crudes remains similar between the two cases (see Figure 1.4.4-10). There is not sufficient domestic crude volume in the High Resource Case to displace heavy grades as well as light and medium grades. This is especially so as low natural gas prices in the High Resource Case sustain the competitive advantage for U.S. refiners to maintain high throughputs and export some refined products (as well as natural gas liquids). Also there are costs for refiners to move to processing lighter crudes, both in terms of refinery adaptation and refinery yields and economics.
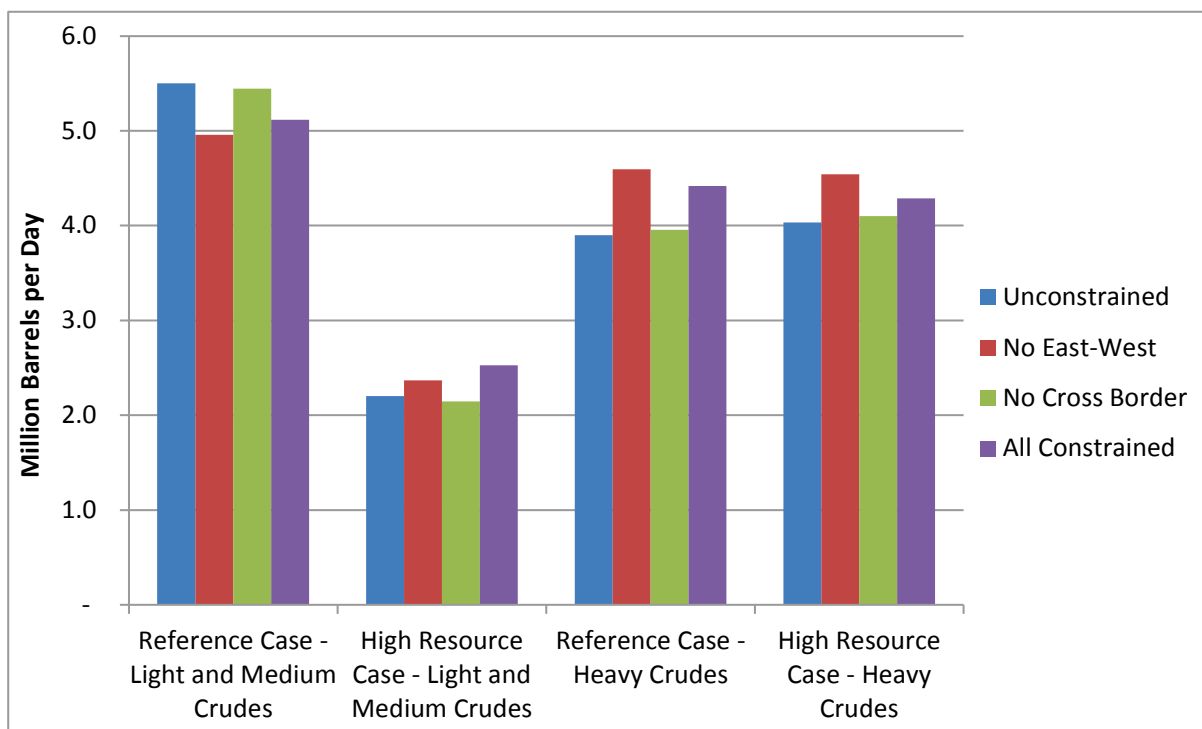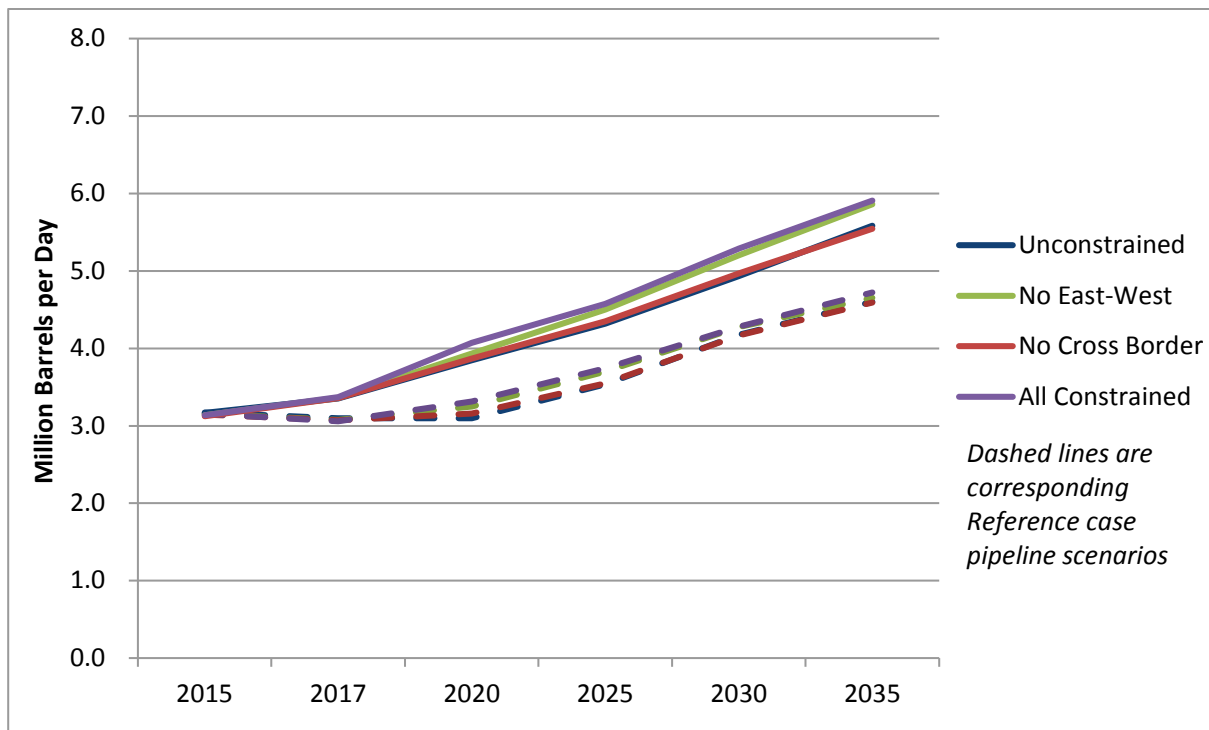


**Figure 1.4.4-10       Reference and High Resource Case Light/Medium and Heavy Crude Imports in 2035**

Apart from lower crude imports, the other way that WORLD projects the market balancing higher domestic supply is through higher petroleum product exports. Refinery throughputs are higher in the High Resource scenario: 15.6 to 16.1 million bpd versus 15.6 to 16.6 million bpd depending on pipeline scenarios. Apart from advantaged access to WCSB crudes in scenarios where Canadian West Coast pipelines are constrained, a key driver elevating throughputs in the United States is lower natural gas costs. The AEO High Resource scenario assumes higher oil and natural gas resources, which also raises natural gas production and keeps natural gas prices significantly lower. Gas prices rise to $6.32 per million British thermal units in 2035 in the Reference Case versus the High Resource Case where at $3.77 per million British thermal units they remain near current levels. Oil prices continue to rise and the gulf between oil and natural

gas prices widens. As a result, U.S. refiners maintain the competitive advantage that has raised refined products exports as described in Section 1.4.2.5, U.S. Refining, and U.S. demand for crude remains higher than is needed to process fuels for domestic consumption alone. Higher natural gas production in the High Resource Case also contributes to greater liquid petroleum gases (LPGs, e.g., propane and butane) production. LPG exports are approximately 1.2 million bpd of the total petroleum liquids exports in 2035 shown in Figure 1.4.4-11 below, roughly twice the level of LPG exports in the Reference Case LPG exports—LPG exports account for most of the difference between Reference Case and High Resource Case product exports.



Note: Data are net of product imports from approximately 0.4 to 0.6 million bpd.

**Figure 1.4.4-11      High Resource Case and Reference Case Net Petroleum Product Exports in 2035**

Where heavy crude is imported from in the High Resource Case pipeline scenarios remains similar to the corresponding Reference Case scenarios. In cases where westbound Canadian pipelines are permitted, they are utilized, which sends more Canadian crude to Asia and leaves the United States importing relatively more crude from Latin America and the Middle East. How this crude reaches U.S. markets does change. Greater U.S. production fills more of the U.S. pipeline system and meets more domestic demand, particularly in PADD 2, forcing more WSCB crude oil to reach markets by rail in the All Constrained scenario (see Figure 1.4.4-12).
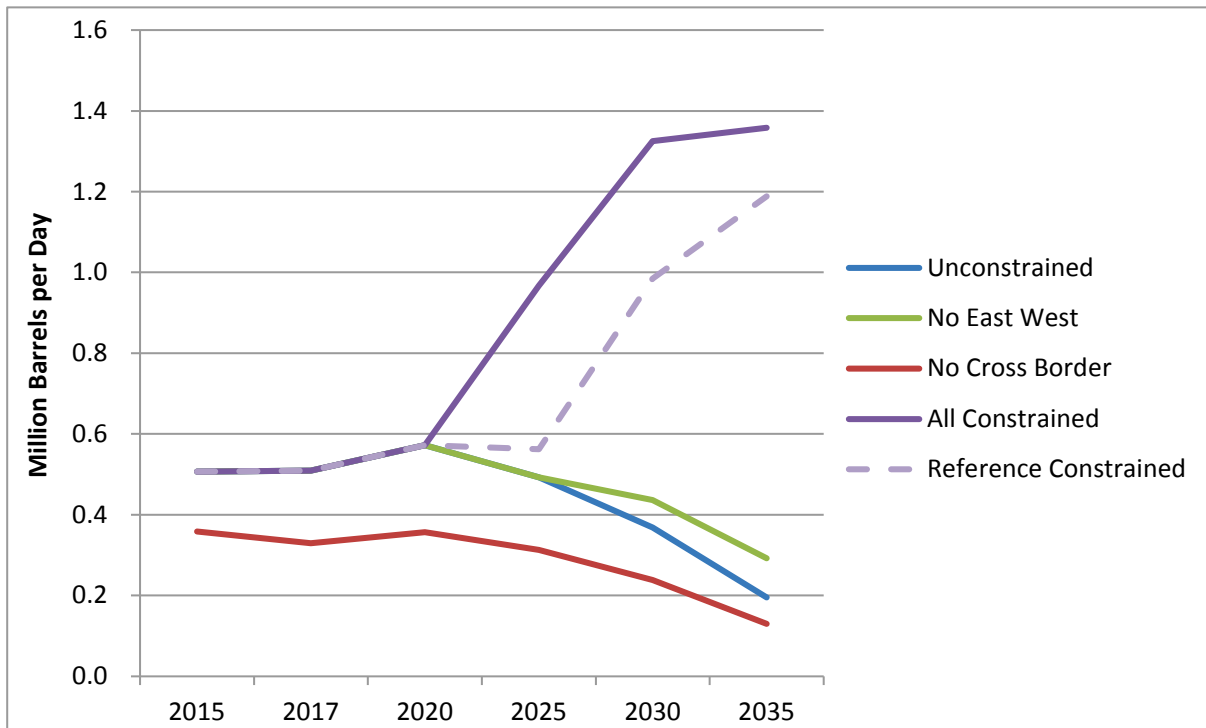


**Figure 1.4.4-12          High Resource Case Rail Shipments of WCSB Crudes**

The increment in crude by rail is to markets in eastern Canada and PADD 5. Crude to eastern Canada rises to as much as 370,000 bpd in this scenario, some of which could be used by the region's refineries or could be exported via the proposed Canaport terminal or other similar facilities. As with the Reference Case, major growth in crude by rail occurs after 2020. Existing pipeline capacity and crude likely to be traveling by rail by 2015—an estimated 500,000 bpd—leave sufficient capacity until then (see Figure 1.4.4-13). Most of the growth after 2020 is to U.S. refineries, but some is projected to move to eastern Canada for export.[139]
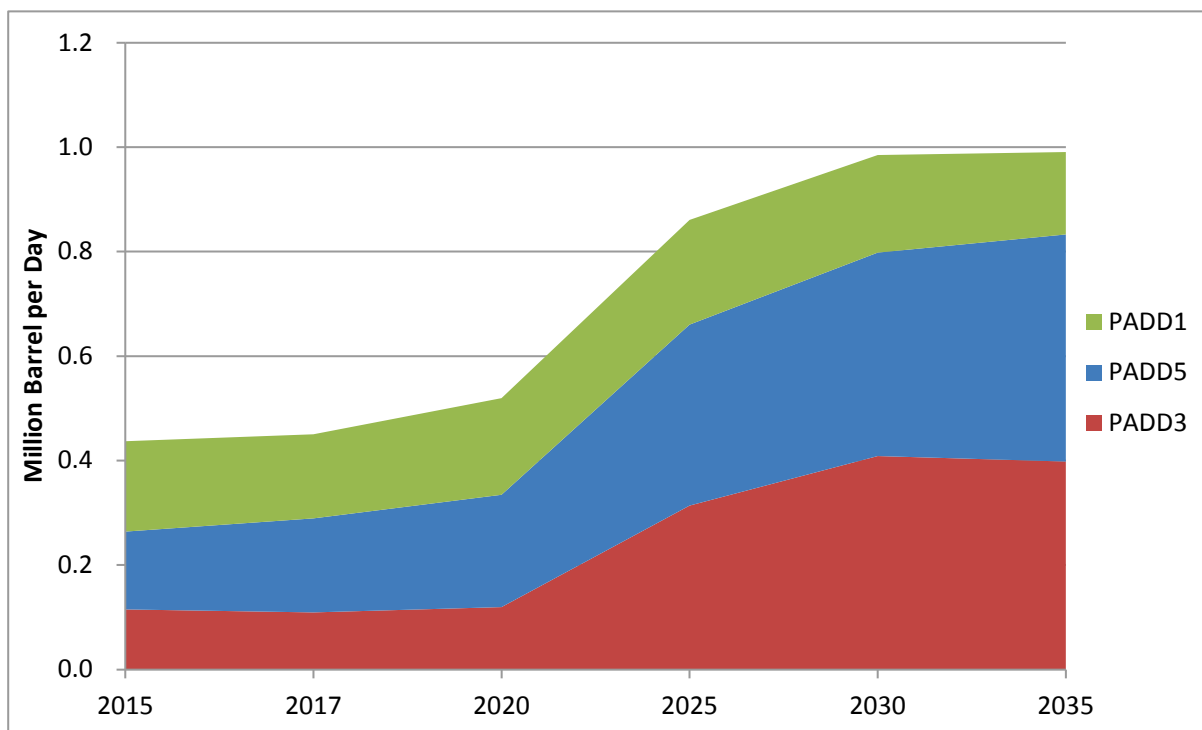


**Figure 1.4.4-13     High Resource Case Constrained Scenario Rail Shipments of WCSB Crudes to the United States by PADD**

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[139] As with the Reference Case results, EnSys advises that it is possible some of these volumes could instead be sent to PADD 1. However, Irving Oil, which has a 300,000 bpd complex refinery at St. John, New Brunswick, is already actively bringing in both Bakken and WCSB crudes via rail and is actively involved in developing a large, deep water, crude oil export terminal at nearby Canaport (Penty 2013).

The WCS price is lower in the High Resource Case than the Reference Case (see Figure 1.4.4-14). This is largely due to lower global crude oil prices, a result of higher U.S. crude production. In part this is also due to the larger required crude flows by rail in pipeline constrained scenarios, which further depress the price available to oil sands producers. The impact is partially mitigated by the light-heavy spread compressing at lower levels of oil prices. Combined, these factors leave 2035 WCS prices 15 to 16 percent lower in the High Resource Case than the Reference Case versus a 14 percent lower WTI price.
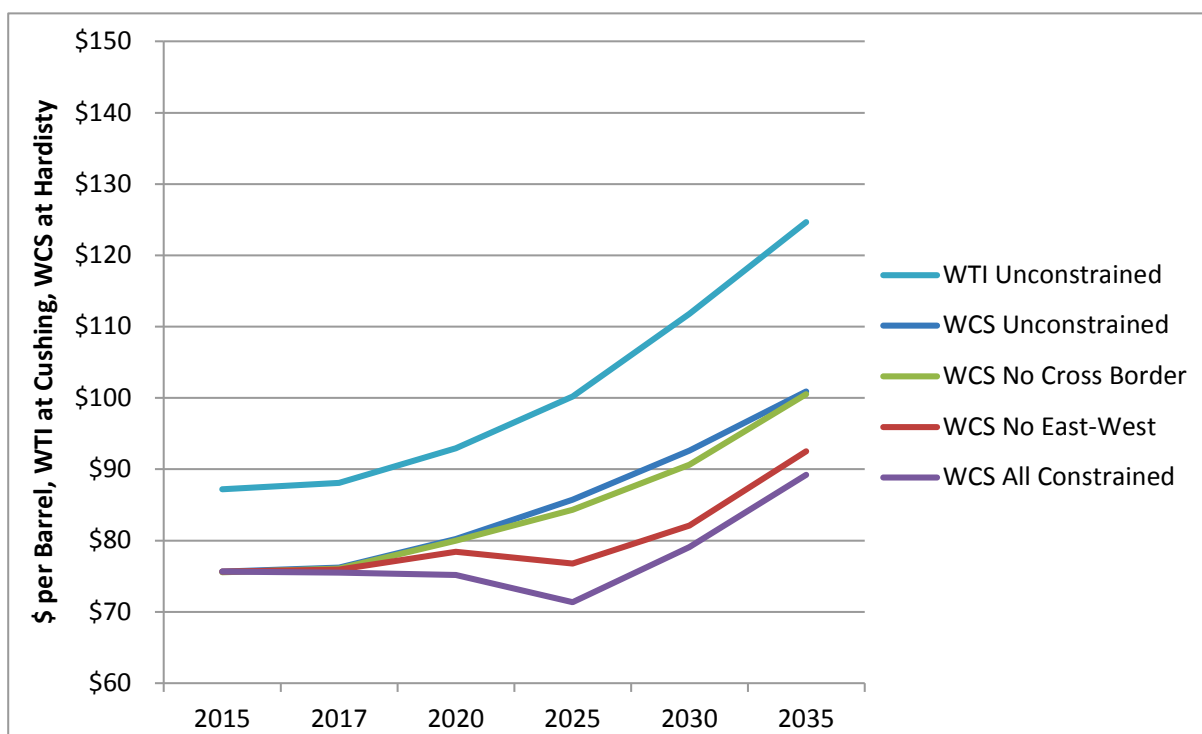


**Figure 1.4.4-14        High Resource Case WCS Prices by Pipeline Scenario, $/bbl**

Like the Reference Case projections, there is little difference among the various High Resource Case pipeline scenarios for projected wholesale gasoline costs (see Table 1.4-22). They primarily follow global oil prices.

**Table 1.4-22      U.S. Average Wholesale Regular Gasoline Prices, High Resource Case, $ per gallon**

|                  | 2015 | 2017 | 2020 | 2025 | 2030 | 2035 |
|------------------|------|------|------|------|------|------|
| Unconstrained    | 2.41 | 2.45 | 2.54 | 2.67 | 2.87 | 3.16 |
| No Cross Border  | 2.40 | 2.45 | 2.54 | 2.68 | 2.87 | 3.16 |
| No East-West     | 2.41 | 2.46 | 2.53 | 2.67 | 2.86 | 3.16 |
| Constrained      | 2.41 | 2.46 | 2.53 | 2.67 | 2.86 | 3.16 |

**Higher Oil Production and Lower Consumption**

Higher domestic production of crude oil and other liquid fuels in the Reference and High Resource Cases, as well as WORLD projections based on supply and demand figures from those cases, would still leave the United States a net importer (see Figure 1.4.4-15). The assumptions in the Low/No Net Imports Case illustrate the magnitude and type of changes that would be required for the United States to become a net exporter of liquid fuels.[140] The Low/No Net Imports Case combines the High Resource Case with a series of demand-side assumptions that reduce consumption and make the United States a net oil exporter by 2034. To address uncertainty about U.S. demand and respond to public comments, WORLD projections were also developed using the production and consumption figures from the Low/No Net Imports case.
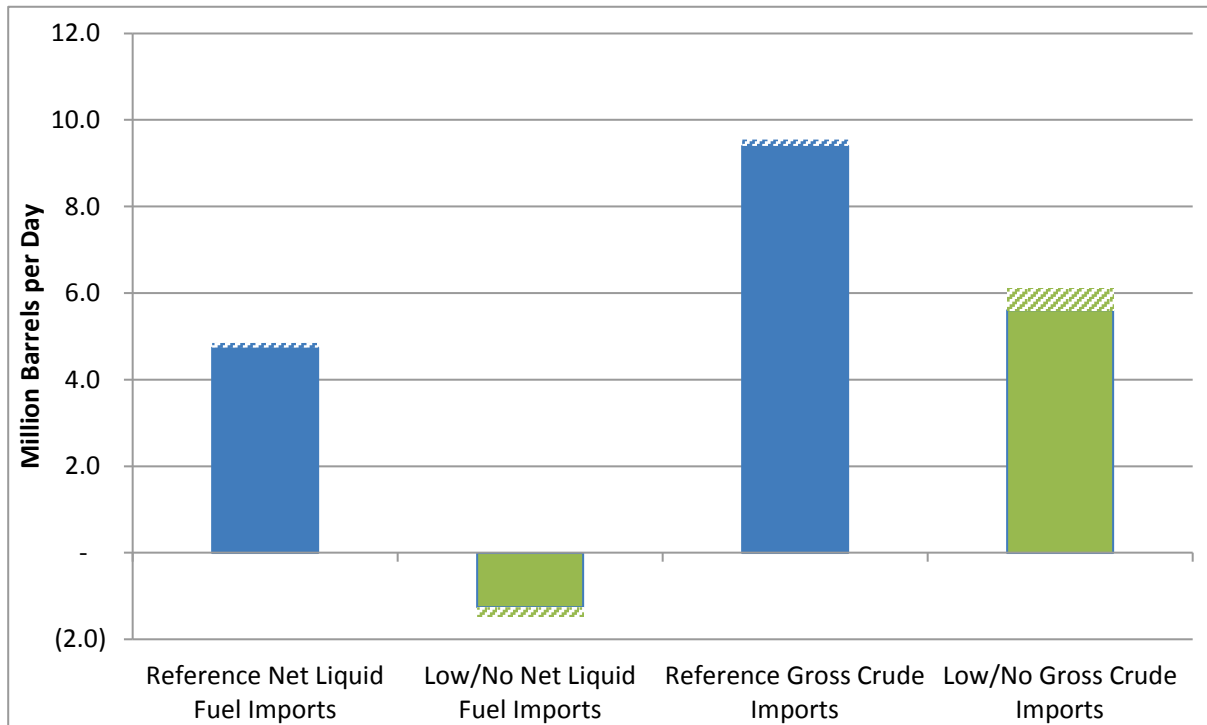


Note: Shaded regions represent ranges between different pipeline cases

**Figure 1.4.4-15      Reference and Low/No Imports Case Liquid Fuels Net Liquids Imports and Gross Crude Imports in 2035**

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[140] Assumptions are described above in Footnote 15.

In the Low/No Net Imports Case, U.S. consumption falls to 17.1 million bpd in 2035 versus 18.9 million bpd in the Reference Case. On a gross basis, however, both WORLD and the AEO project that the United States continues to import crude oil in the Low/No Net Imports Case (but exporting more refined products than it imports crude).

The Low/No Net Imports Case shared supply-side assumptions with the High Resource Case, so the increase in domestic supply is again light crude. And so like the High Resource Case, the lower gross imports in the Low/No Net Imports Case are in the form of lower light and medium crude imports, albeit the trend is more pronounced (see Figure 1.4.4-16). Versus the Reference Case, the decline in heavy crude imports in the Low/No Net Imports Case is limited. Demand for heavy crude remains robust, particularly in PADD 3.
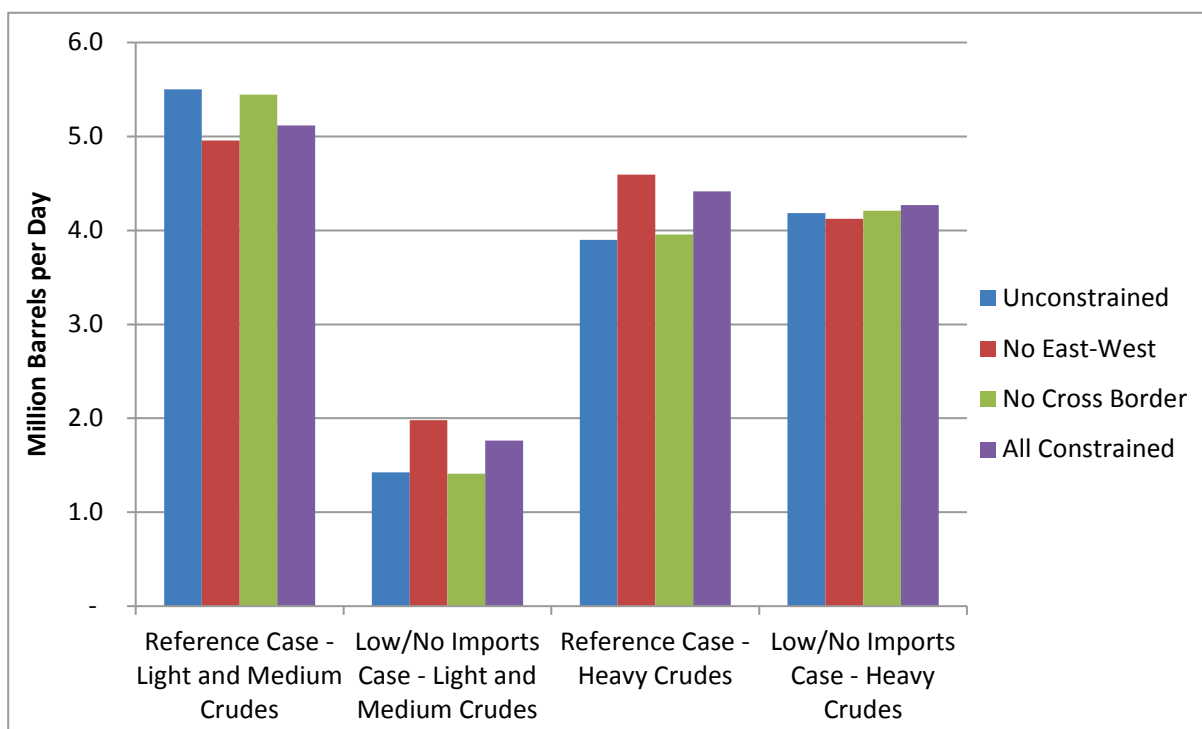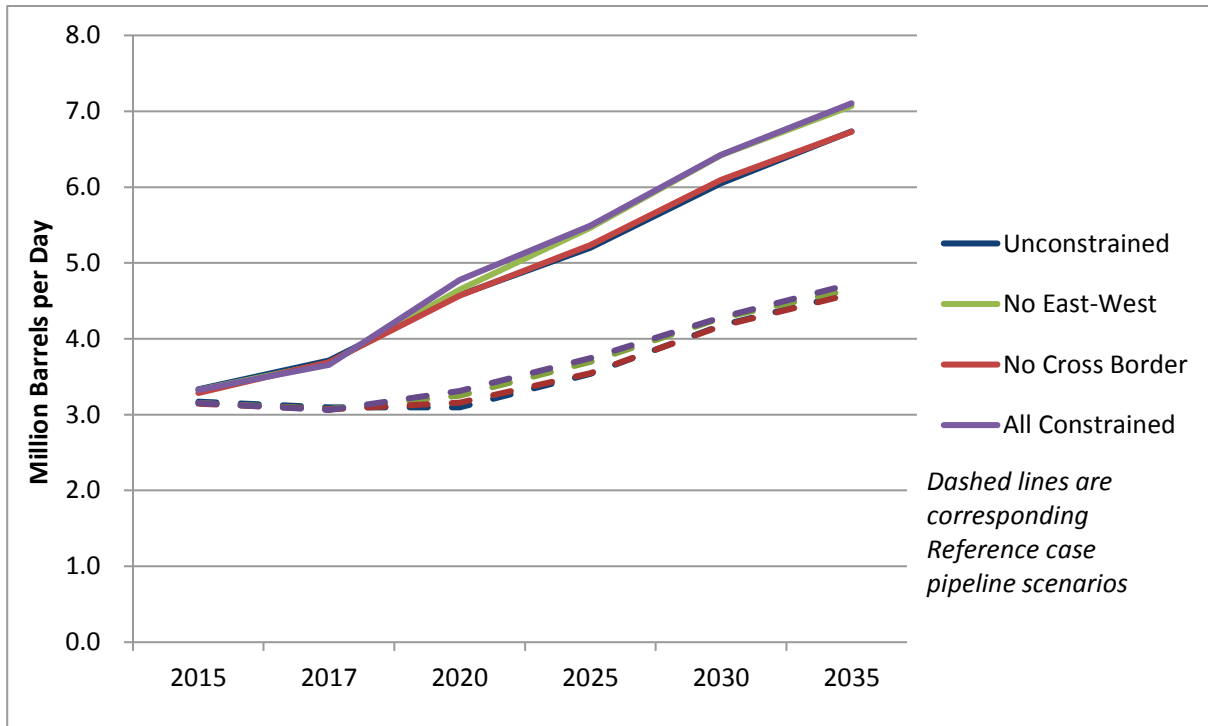


**Figure 1.4.4-16       Reference and Low/No Case Light/Medium and Heavy Crude Imports in 2035**

In addition to lower crude imports, WORLD projects the market balances lower U.S. demand and higher supply through increased refined products exports. This in some ways reflects recent history, where falling U.S. consumption, low natural gas prices, and available refining capacity have contributed to rising refined product exports since 2005. Total petroleum liquids exports are approximately 2 million bpd higher than the Reference Case and 1 million bpd higher than the High Resource Case (see Figure 1.4.4-17). LPG exports increase to 1.4 to 1.5 million bpd.

Note: Data are net of product imports from approximately 0.4 to 0.6 million bpd.

**Figure 1.4.4-17      Reference and Low/No Case Net Petroleum Product Exports in 2035**

In a pipeline constrained scenario, the Low/No Net Imports Case requires substantially more WCSB crude to be carried by rail than the Reference Case and slightly more than the High Resource Case (see Figure 1.4.4-18). Rail requirements are slightly higher here than in the High Resource Case because lower demand in PADD 2 requires more crude to reach more distant markets, including PADD 1, PADD 5, and eastern Canada by rail (see Figure 1.4.4-19). Of the 3.7 million bpd of WCSB crude projected to be exported to the United States in 2035 in this scenario, 1.1 million bpd is expected to be carried by rail. Rail shipments to eastern Canada, from which point they can be exported, reach 425,000 bpd.
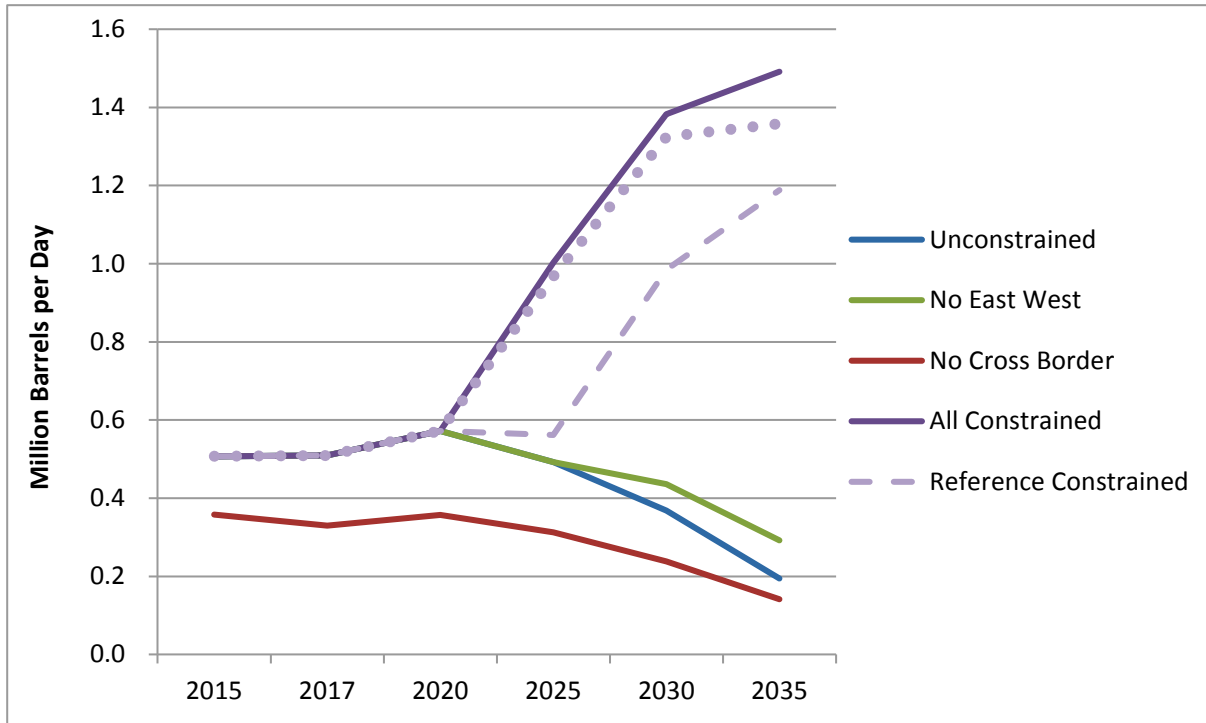


**Figure 1.4.4-18      Low/No Imports Case Rail shipments of WCSB Crudes to U.S. and Canadian Destinations**
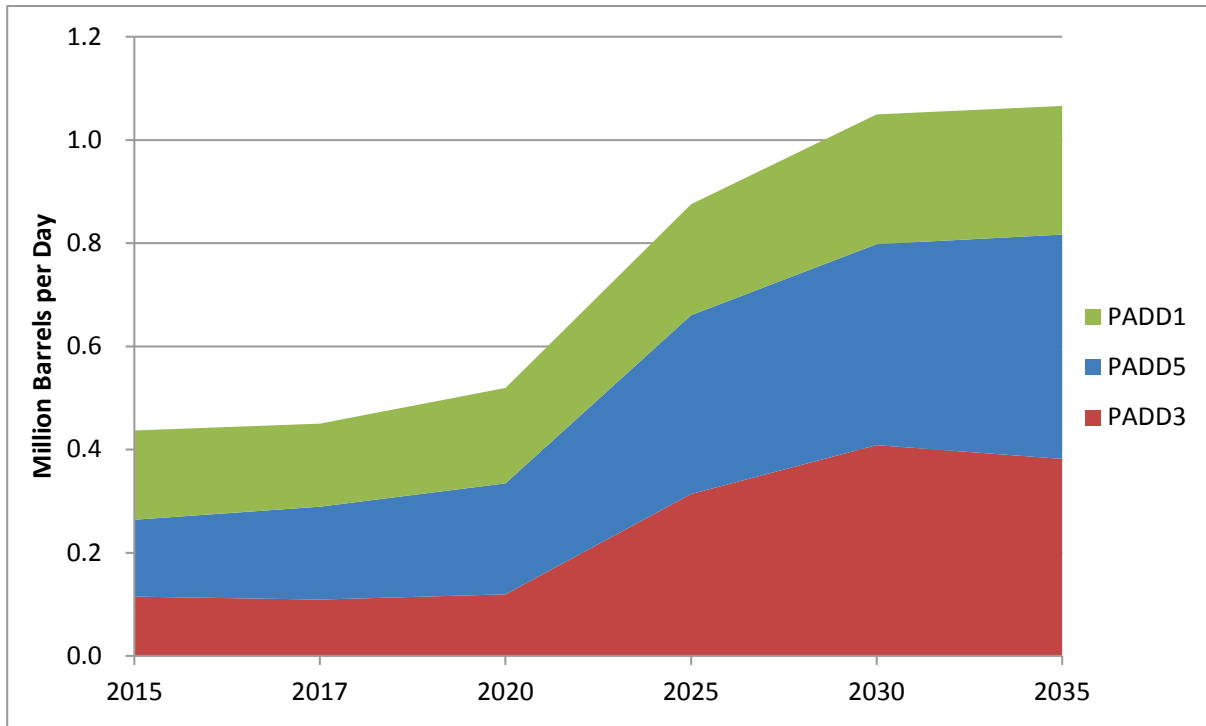
**Figure 1.4.4-19    Low/No Imports Constrained Scenario Rail Shipments of WCSB Crudes to the United States by PADD**

WCS is lower in the Low/No Imports scenarios due primarily to the lower global crude prices in this supply-demand case (see Figure 1.4.4-20). The higher transport cost of carrying crude by rail in the model versus other supply-demand cases may be slightly offset by a smaller discount for heavy crudes.[141] This nets out to WCS being 22 to 23 percent below Reference Case levels while WTI is only 20 percent lower.

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[141] The tight light-heavy differential in dollar terms is due to two factors. First, the abundance of light crudes in North America is even more acute in the Low/No Imports Case as demand is lower and more light imports are backed out. Second, as the general price level or the benchmark gets lower, the light-heavy differential has a tendency to compress in dollar terms even if it stays the same in percentage terms. So the absolute difference in dollars between light crude and heavy crude prices is likely to be less when the benchmark light crude price is $120 per barrel than $150 per barrel.
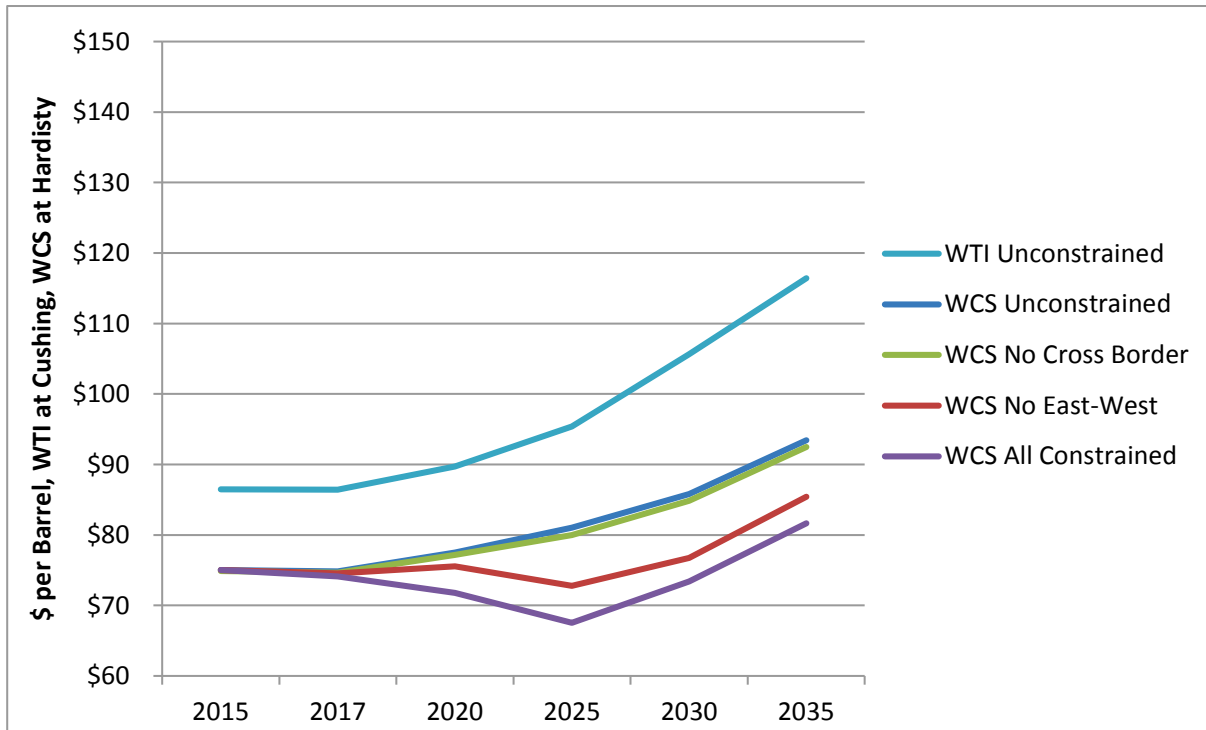
**Figure 1.4.4-20    Low/No Imports Case WCS Prices by Pipeline Scenario**

As before, there is little difference among the various pipeline scenarios for implications on wholesale gasoline costs as shown in Table 1.4-23.

**Table 1.4-23    Low/No Imports Case U.S. Average Wholesale Regular Gasoline Prices, $ per gallon**

|                  | 2015 | 2017 | 2020 | 2025 | 2030 | 2035 |
|------------------|------|------|------|------|------|------|
| Unconstrained    | 2.37 | 2.37 | 2.41 | 2.50 | 2.63 | 2.87 |
| No Cross Border  | 2.37 | 2.37 | 2.41 | 2.50 | 2.63 | 2.87 |
| No East-West     | 2.38 | 2.37 | 2.41 | 2.50 | 2.63 | 2.88 |
| Constrained      | 2.38 | 2.37 | 2.41 | 2.50 | 2.63 | 2.87 |

**Higher Latin American Production**

Latin America is the traditional source for heavy crude oil into PADD 3. The region has substantial resource potential but also policy and regulatory challenges that may limit supply growth. Taking resources and existing policies into account, the EIA's Reference Case projects that total Latin American liquids supply will rise to 15.0 million bpd in 2035 (see Figure 1.4.4-21). In response to uncertainty around factors driving production and potential reform efforts throughout the region, the EnSys WORLD model was run with a High Latin America Case, which assumes the region's oil production exceeds Reference Case projections by 3.5 million bpd by 2035. This would result in total Latin American liquids supply of 18.4 million bpd in 2035. This is not a forecast or projection, but rather a set of assumptions used as a plausible alternative supply-demand case to test the impacts on how U.S. demand for WCSB heavy crudes may change under various pipeline scenarios.
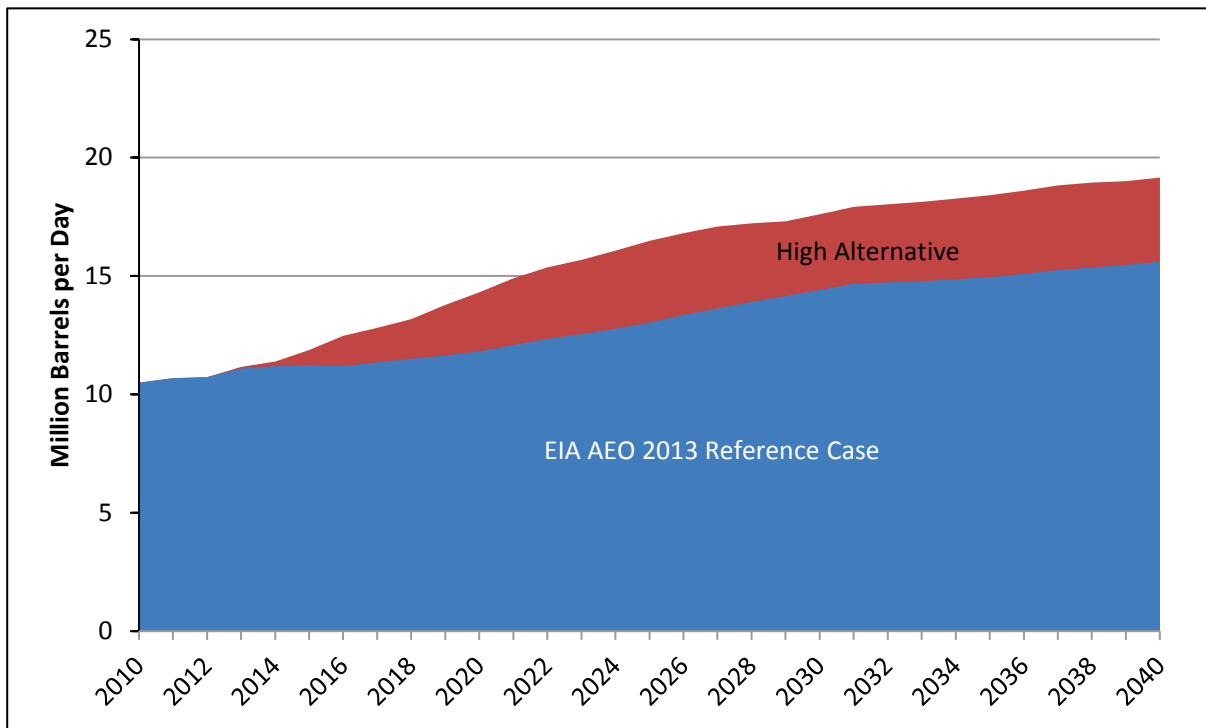


**Figure 1.4.4-21     Latin American Oil Production in the Reference and High Latin America Case, million bpd**

There is little change in where WCSB crude goes in the High Latin America scenarios (see Figure 1.4.4-22). According to WORLD projections, the disposition of WCSB crudes is similar to that seen in the Reference Case (see Figure 1.4.4-5 above).
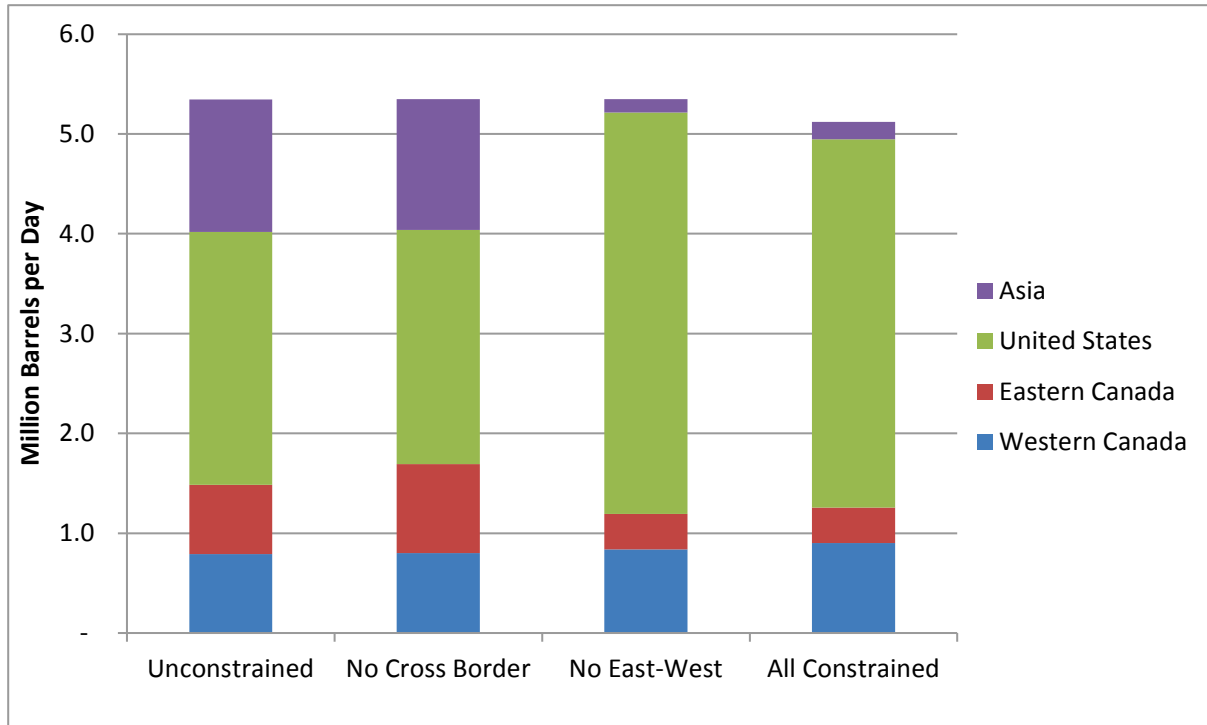


**Figure 1.4.4-22      High Latin America Case WCSB Crude Supply to Refineries in 2035 by Major Market**

Latin American crude exports to other countries/regions are 3.2 to 3.4 million bpd higher than in the Reference Case as shown in Table 1.4-24. Depending on the pipeline scenario, between 45 percent and 54 percent of the increase is destined for the United States, with the remainder going primarily to Asia.

**Table 1.4-24     Incremental Latin American Crude Exports, Difference between High Latin America and Reference Cases, million bpd**

|                 | United States | Europe | Asia | Total |
|-----------------|---------------|--------|------|-------|
| Unconstrained   | 1.8           | 0.5    | 1.0  | 3.3   |
| No Cross Border | 1.8           | 0.5    | 1.0  | 3.4   |
| No East-West    | 1.4           | 0.8    | 1.0  | 3.2   |
| Constrained     | 1.6           | 0.7    | 0.9  | 3.2   |

The volumes that come to the United States primarily displace crudes from the Middle East and Africa. The result is in part due to an operating assumption of the WORLD model that exogenous increases in crude supply elsewhere are balanced out by lower production from the Middle East (as the balancing crude supply region).[142] African crudes are forced elsewhere, primarily to Asia. The impact on PADD 3 heavy crude imports can be seen in the difference between Figures 1.4.4-23 and 1.4.4-24 below. Middle Eastern and African imports are lower in the High Latin America Case. There is a small decline in imports of Canadian heavy crude into PADD 3 in all scenarios. Total heavy imports are higher as heavy Latin American crudes displace medium crudes from elsewhere.
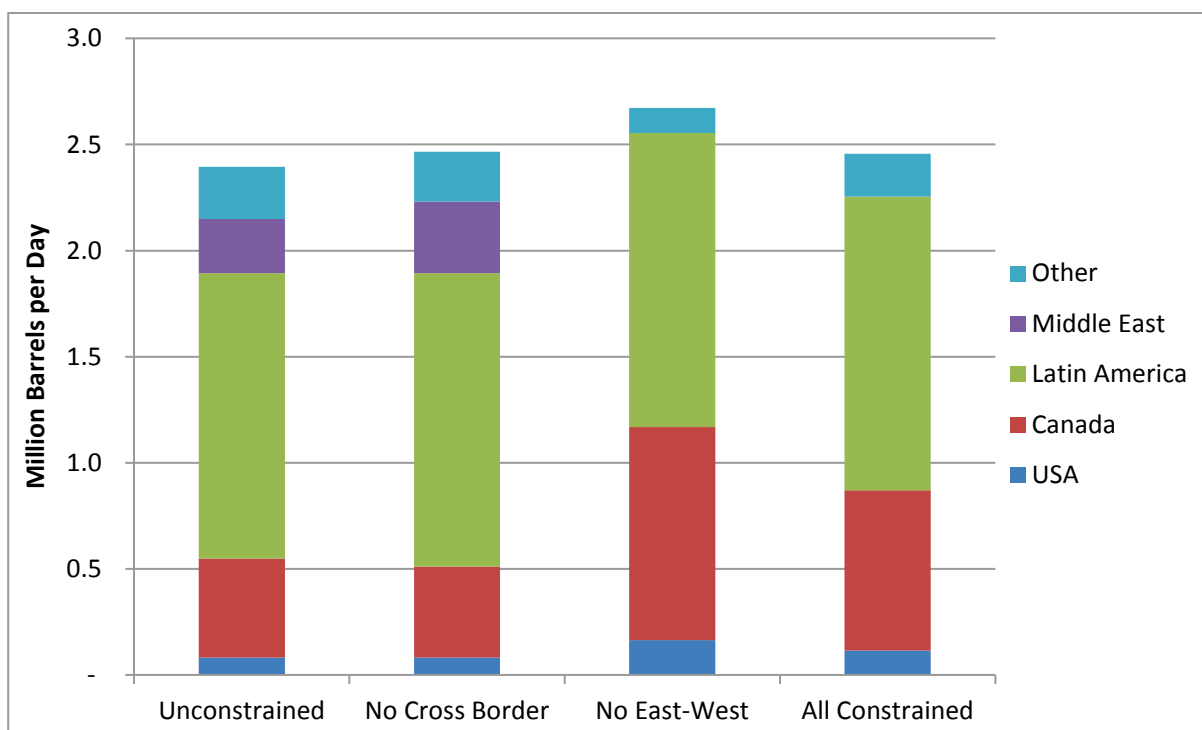


**Figure 1.4.4-23     Reference Case PADD 3 Heavy Crude Supply in 2035 by Source**

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[142] As mentioned above, there are no required minimum imports from the Middle East and imports from the Middle East drop to zero an economic basis. Some analysts may argue that Saudi Aramco may send its own crude to its Motiva refinery in the PADD 3 on strategic grounds, regardless of the economics. Separately, it is also possible for other foreign oil exporters to the United States that own U.S. refining capacity to see their U.S. crude exports decline. Mexico's Pemex has an equity stake in the Deer Park Refinery. Citgo, a subsidiary of Venezuela's Petróleos de Venezuela, S.A. (PDVSA), operates three U.S. refineries, with equity in a fourth. Mexican production and exports to the United States have been falling, as have those from Venezuela, which is trying to diversify PDVSA's markets away from the United States. PDVSA's exports to its U.S. refineries are falling, in some cases with those refineries running more Canadian crude (Parraga 2013). WORLD scenarios project Middle Eastern crudes into PADD 3 being phased out through the medium to long term, especially in the High Resource scenarios. (Some volume of Middle Eastern crude is projected as continuing to flow into PADD 5, although at smaller volumes than today in the High Resource Cases.) The same model cases indicate flows of Latin American crude into PADD 3 are dependent on both the AEO Scenario (Reference versus High Resource) and on the logistics scenario and that they can range between 1.5 and 3.8 million bpd depending on the horizon and the case.
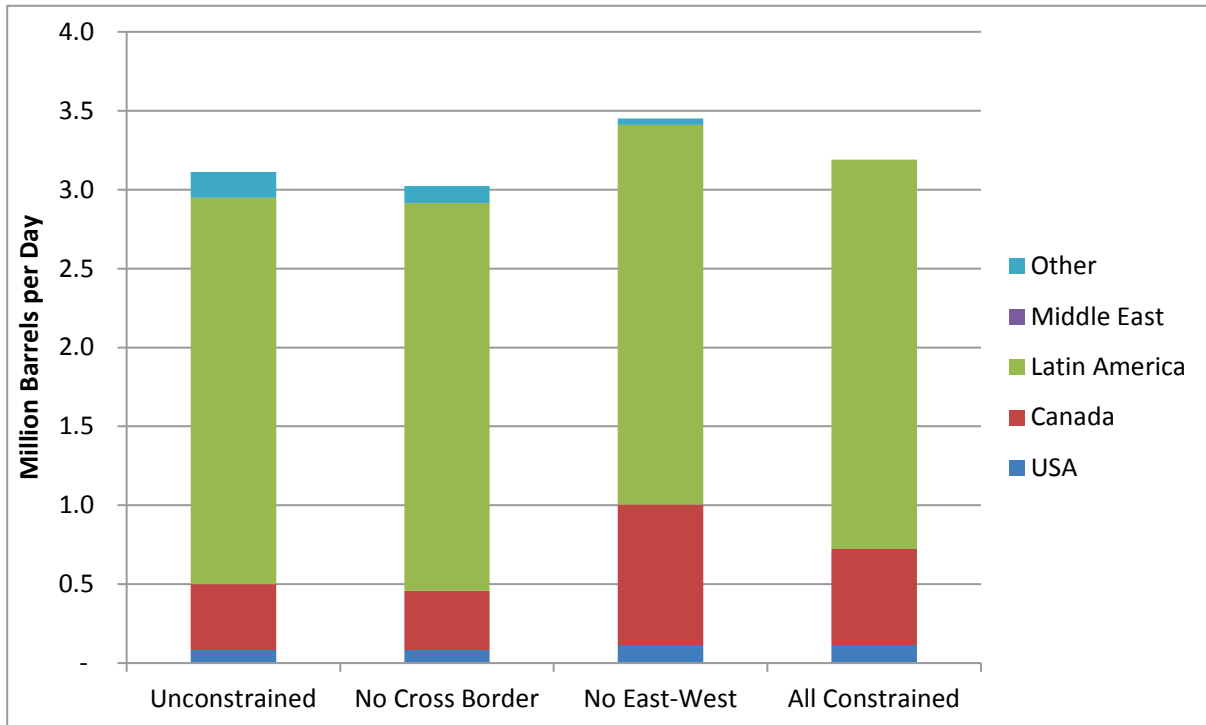
**Figure 1.4.4-24      High Latin America Case PADD 3 Heavy Crude Supply in 2035 by Source**

With little change in the disposition of WCSB in the United States, the need for rail transport in the various pipeline scenarios under the Latin America case resemble the need for rail transport in the Reference Case (see Figure 1.4.4-25).
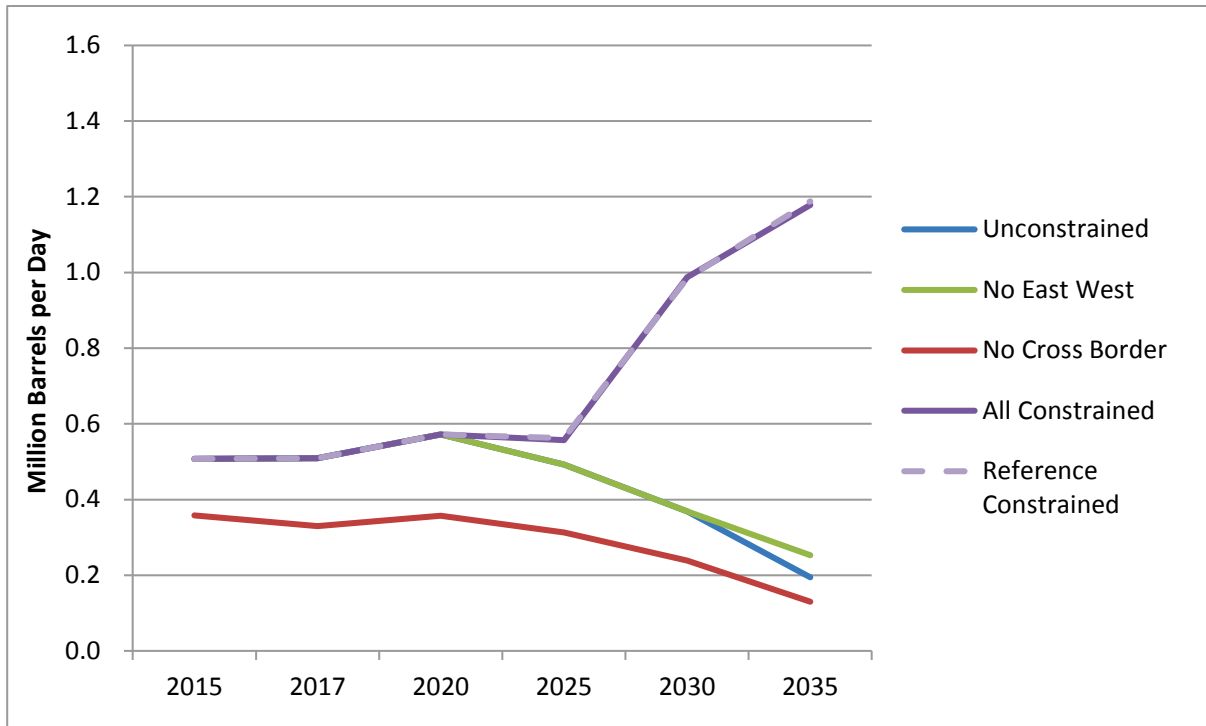
**Figure 1.4.4-25        High Latin America Case Shipments of WCSB Crudes to U.S. and Canadian Destinations**

The impact on prices received by oil sands producers is also minimal. Netbacks in corresponding pipeline scenarios vary from roughly the same to $1.40 per barrel lower than in the corresponding Reference Case (see Figure 1.4.4-26). With little change in crude prices, the wholesale price of gasoline is also very similar to the Reference Case results.
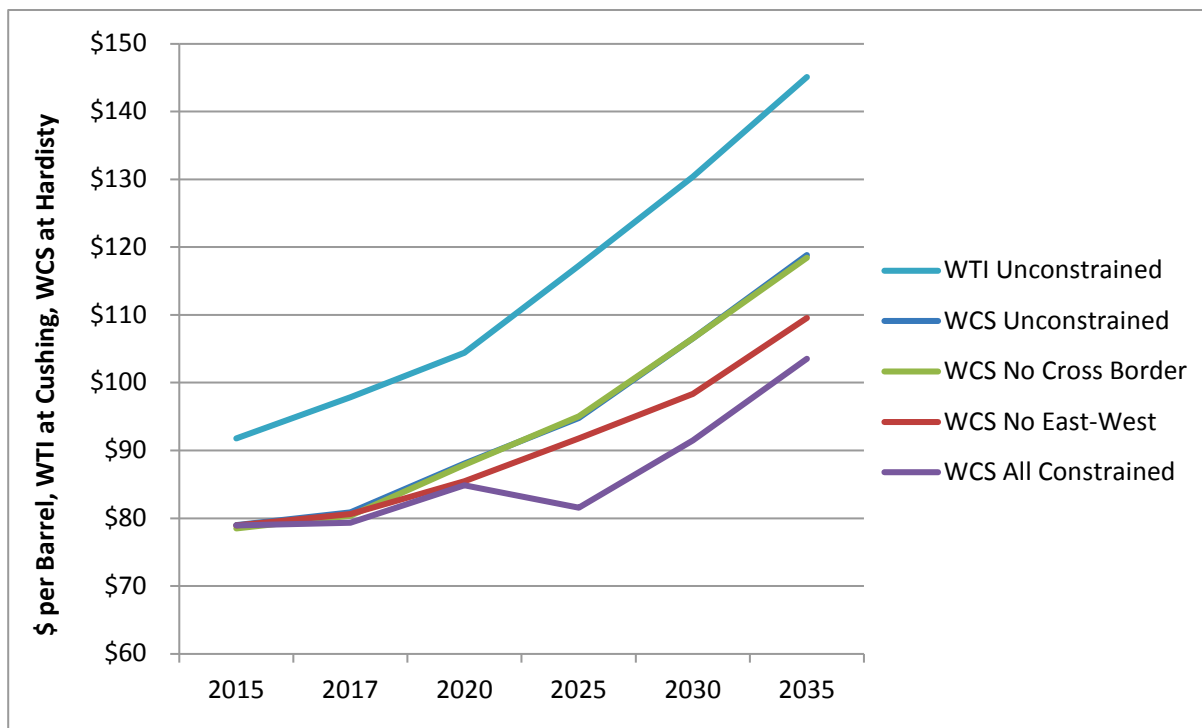
**Figure 1.4.4-26      High Latin America Case WCS Prices by Pipeline Scenario**

## 1.4.5      Conclusions

### *1.4.5.1      Prices vs. Supply Costs*

Comments on the Draft Supplemental EIS indicate that many assertions about the proposed Project center upon the extent to which it would or would not contribute to increased oil sands production levels. To respond to this interest and concern, the modeling results from Section 1.4.4, Updated Modeling, were combined with the supply cost information from Section 1.4.2.8, Canadian Oil Production, to assess how changes to the prices received by oil sands operators under various scenarios might or might not affect investment and production in the oil sands.

Analyses of the potential production impacts of the proposed Project are, as with all projections about the future, to some extent uncertain. Nonetheless, a unified approach that compares modeled prices and estimated supply costs provides a more robust basis for assessing possible production impacts than previous approaches.

The EnSys WORLD model results presented in Section 1.4.4, Updated Modeling, included prices received by producers for dilbit in western Canada.[143] Dilbit prices vary from benchmark crude prices in any given scenario due to marginal transport costs and quality differentials.

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[143] This subsection focuses on dilbit because most future oil sands production growth is expected to reach markets in blends of raw bitumen mixed with diluent. Less additional SCO is expected due to the higher cost of upgraders and the increase in competing light tight oil supplies. Dilbit specifications are assumed to be 70 percent bitumen and 30 percent diluent, though exact proportions will vary by project and operator. Railbit and rawbit prices were not comprehensively modeled, though the economics of transporting those blends by rail could be more economically *(footnote continued on the following page)*

Across scenarios, modeled prices remain above the average supply costs of all but the most expensive in situ projects (see Table 1.4-25).[144] In situ projects are expected to be responsible for most future oil sands production growth. Pipeline constraints affect the prices received by producers, but the prices received do not fall below relevant in situ supply cost thresholds.

**Table 1.4-25     Dilbit Free-on-Board Prices[a] Versus Dilbit Supply Costs**

| | Average Dilbit Price in Western Canada (FOB)[a] | | | | Supply Cost (FOB)[a] |
| | Unconstrained | No Cross-Border Pipelines | No East-West Pipelines | Constrained | Marginal Capacity |
|---|---|---|---|---|---|
| Reference | $90.96 | $90.76 | $87.19 | $82.83 | |
| High Resource | $81.08 | $80.37 | $75.81 | $73.34 | $46–$54 |
| Low/No Net Imports | $77.25 | $76.67 | $72.31 | $69.56 | |
| High Latin America | $90.70 | $90.36 | $86.42 | $82.33 | |

[a] FOB = free-on-board (i.e., prior to transport to markets). Prices reflect the long-term average real prices across time for each modeled case.

Between alternative pipeline configurations, cross-border pipeline constraints are relatively inconsequential for the prices received by producers in western Canada if east-west pipelines are allowed to expand. Constraints on both east-west and cross-border pipelines bind transportation options further and faster than constraints on only east-west pipelines, and the average prices for dilbit fall by approximately $8 per barrel relative to the corresponding unconstrained case.

Between supply-demand cases, netbacks to producers are further pressured in the High Resource and Low/No Net Imports Case, largely due to assumptions about lower benchmark price paths. Again, prices received by oil sands producers fall when all pipelines are constrained—by almost $20 per barrel relative to the unconstrained reference case scenario.

Even in the most challenging supply-demand and pipeline scenario for oil sands crude oil—when all new pipelines are constrained, U.S. supply growth is high, and U.S. demand is low—prices remain higher than supply costs of the average in situ projects required to meet EIA, IEA, and CAPP oil sands supply projection levels. This conclusion is reached even though the model used in Section 1.4.4, Updated Modeling, cannot separately model diluent flows or utilize the more economic option of transporting marginal barrels of bitumen as railbit or rawbit. Consequently it may overstate the price penalty of pipeline constraints because it does not reflect rail's full economic possibilities as described in Section 1.4.3, Crude Oil Transportation.

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attractive than transporting dilbit by rail as described in Sections 1.4.3, Crude Oil Transportation, and 1.4.4.2, Scenarios.

[144] The supply costs of marginal projects were determined from the supply curves in Section 1.4.2.8, Canadian Oil Production.

### 1.4.5.2    Low Oil Prices Scenario

Comments on the Draft Supplemental EIS suggested the Department analyze the impacts of sustained low oil prices and the proposed Project on oil sands production. In response, model outputs and supply cost findings were compared to assess the conditions under which low prices and pipeline conditions could impact oil sands production. An important caveat when assessing the results of this exercise and assigning probabilities to any scenario is that prices are difficult to predict and could also evolve in the other direction.[145]

The results of Section 1.4.5.1, Prices vs. Supply Costs, can be used to estimate how much further benchmark oil prices would have to fall, all else equal, before marginal in situ supply costs could be threatened (see Table 1.4-26).[146] If long-run oil prices fell consistently below $65 to $75 per barrel (over $40 per barrel less than in the Reference Case average, $30 per barrel lower than the High Resource Case, or $25 per barrel lower than the Low/No Net Imports Case), then the threshold supply costs for marginal oil sands capacity could be tested and production impacted even without pipeline constraints. This price threshold could increase by up to $8 per barrel if all new pipelines and West Coast rail shipments are constrained. Cross-border pipeline constraints do not significantly affect the amount by which prices would need to fall if other east-west pipelines and/or rail to the West Coast are allowed to proceed in Canada.

**Table 1.4-26    WTI Price Paths and Implied Breakeven Prices[147]**

| | WTI Average (2013–2035) | Implied WTI Breakeven Price for Marginal Supply | | | |
| --- | --- | --- | --- | --- | --- |
| | | Unconstrained | No Cross-Border Pipelines | No East-West Pipelines | Constrained |
| Reference | $113 | | | | |
| High Resource | $104 | $68–$77 | $68–$78 | $72–$82 | $76–$85 |
| Low/No Net Imports | $100 | | | | |
| High Latin America | $113 | | | | |

The sensitivity case in this section must make simplifying assumptions about other market factors, or the oil market conditions that would lead to lower oil prices, which may or may not be realistic and are different than those used in the AEO projections or the EnSys modeling. Another approach, the results of which are described in Section 1.4.5.4, Implications for Production, is to shift up a notional supply curve to reflect the potential for higher transportation costs, and then to identify the price points at which there may not be enough economically viable new capacity to meet EIA or CAPP production projections.

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[145] For example, EIA AEO (EIA 2013a) has scenarios where oil prices fall to $70 per barrel (discussed below) or rise to $237 per barrel in real 2011 dollars.

[146] In reality, as explained further below, quality differentials and some transportation costs compress as prices fall, and vice-versa as prices rise.

[147] The WTI average price in the first column of Table 1.4-26 is the long-term average (2013 to 2035) of the price paths in each modeled EIA case: Reference, High Resource, and Low/No Net Imports. The High Latin America case is a supply-side modification of the Reference Case, and the benchmark WTI price is assumed to be the same. The implied benchmark breakeven price was generated by 1) finding the margin between modeled free-on-board (FOB) prices and marginal supply costs and 2) applying that difference to average price paths, using the conservative assumption that benchmark prices and differentials fall on a dollar-for-dollar basis. The resulting implied breakevens differ by pipeline constraint, but do not significantly differ across supply-demand scenario.

This analysis is based on the supply cost of new marginal in situ supply capacity, a sufficient amount of which has been announced to meet projections for oil sands production growth. While these reflect the best-available supply cost estimates, and generate novel insights when combined with detailed capacity expansion plans, they should be interpreted in terms of ranges of possible impacts. Supply costs for other types of projects could be different:

- Plans for the most expensive projects, integrated upgraders, have mostly been canceled and are the most likely to be further rationalized (i.e. delayed, cancelled, or revised) going forward.

- Supply costs for new mining capacity would be approximately $5 to $25 per barrel higher (in dilbit free-on-board (FOB) terms, depending on the project) than average in situ capacity, which suggests that complete pipeline constraints could affect breakeven thresholds for some announced mining projects in adverse supply-demand or lower oil price scenarios.

Operating costs, estimated to be $20 to $40 per barrel for existing in situ and mining projects, are much lower than long-run supply costs that include fixed capital investment.[148] Therefore, prices would have to fall to very low and very unlikely levels before existing production would be shut in. The foregoing analysis conservatively assumes that oil sands supply costs, quality differentials, and other economic factors remain constant in dollar terms at lower benchmark oil prices. In reality, several factors would shift with lower benchmark oil prices, including the following:

- Oil sands supply costs are likely to fall along with oil prices due to cheaper diluent prices, cheaper energy inputs, labor contracts and royalties tied to the price of oil, and efficiency measures (though some of these assumptions are already intrinsic in long-run supply cost estimates).

- Light-heavy crude price differentials are typically a function of percentage differences in price and, thus, may compress in absolute dollar terms as prices fall. Consequently, the analysis in this section about how changes to benchmark oil prices might translate to equivalent changes in the prices received by oil sands producers is likely to be conservative.

- Midstream transportation costs are also likely to fall with the price of oil, especially for shipment of crude on rail cars using diesel fuel.[149]

- Apart from certain rawbit and railbit flows that reflect already announced plans, the WORLD model assumes that additional crude-by-rail travels as dilbit with 30 percent diluent per barrel. Especially in a pipeline-constrained world, it is likely that much of these additional volumes would instead travel as railbit or rawbit, which have progressively superior economics to railed dilbit in any scenario due to their lower diluent requirements (see Section 1.4.3, Crude Oil Transportation). Railbit or rawbit may become particularly attractive if oil prices decline to a level that challenges dilbit-by-rail economics.

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[148] CERI (2013) and company reports. See Section 1.4.2.8, Canadian Oil Production.
[149] Current rail freight rates include a fuel surcharge that is closely linked to the price of diesel. An analysis of the effects of diesel fuel price changes on freight rates indicated that a 50 cent increase in fuel prices, as measured by the U.S. Average Retail On Highway Diesel Fuel Index published by the EIA, would increase rail freight rates by about 3.74 percent. A 50 cent per gallon decrease would reduce rail freight rates by about 3.8 percent.

A low oil price world is not necessarily incompatible with rising oil sands production if, for instance, supply costs declined.[150] For example, WTI averages just over $70 per barrel (real 2011 dollars) in EIA's Low Oil Price Case, which is below the supply cost thresholds for the announced capacity needed to meet production projections in certain scenarios (see Table 1.4-26). However, the projections for Canadian and bitumen production levels are actually higher in EIA's Low Oil Price Case than in EIA's Reference Case over most of the forecast period (see Figure 1.4.5-1). EIA's Low Oil Price Case achieves its lower price in part through an assumption that oil production costs fall in the oil sands and elsewhere.
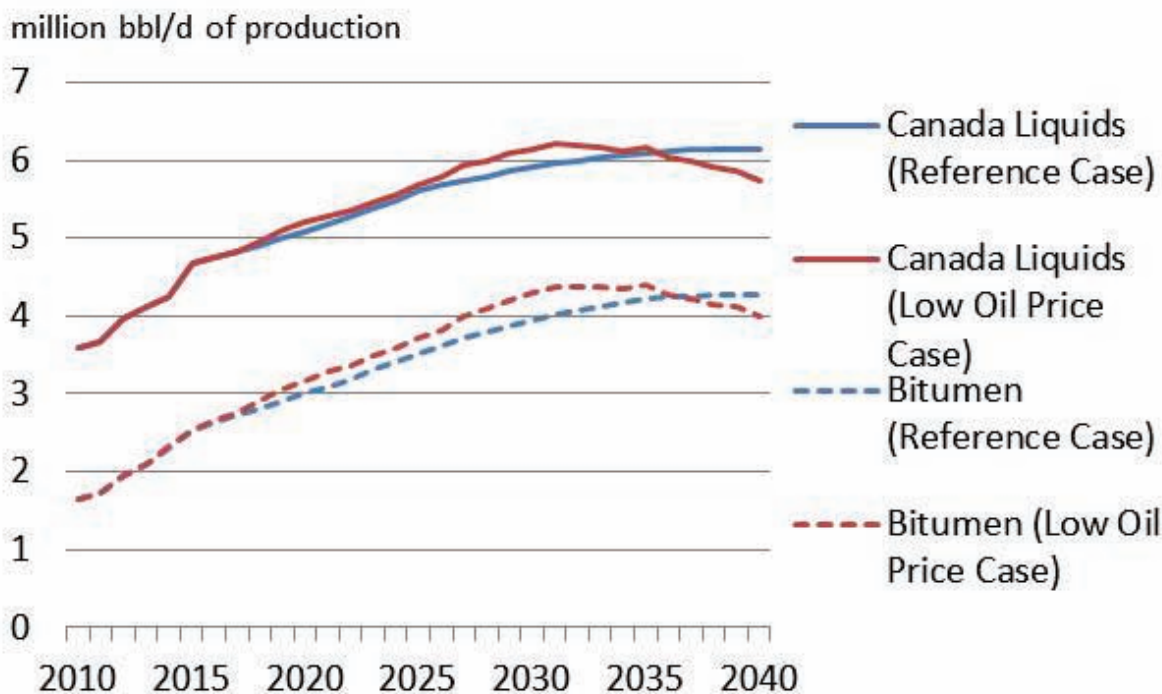


Source: EIA 2013a

**Figure 1.4.5-1        Reference and Low Oil Price Case Projections for Canadian and Bitumen Production**

Finally, on a related note, if WTI fell below $80 per barrel, it could begin to threaten production outlooks from other marginal sources of supply as well as from the oil sands. The potential

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[150] Oil production, consumption, and prices are endogenous variables, and the causation between changes in prices and changes in quantities runs in both directions. Instead of lower prices causing a supply response in which oil sands production falls, lower prices could be caused by higher Canadian supplies. According to the 2012 AEO (EIA 2012a), "the Low Oil Price case assumes that technologies for producing biofuels, bitumen, CTL [carbon-to-liquids], BTL [biomass-to-liquids], GTL [gas-to-liquids] and extra-heavy oils achieve much lower costs than in the Reference case. As a result, production of those liquids increases to 16 million barrels per day in 2035 despite significantly lower oil prices."

curtailment of production could in turn make sustained price decreases for any substantial length of time unlikely, at least without additional assumptions about supply costs or oil demand.[151]

### 1.4.5.3    *Transportation Cost Sensitivities*

Transportation costs affect the oil price and supply cost thresholds of the sensitivity analyses presented above. The EnSys WORLD model described in Section 1.4.4, Updated Modeling, does not separately model diluent flows or include an option to economically transport marginal barrels of bitumen as railbit or rawbit. Therefore, conclusions drawn from its results may not reflect rail's full economic possibilities as described in Section 1.4.3, Crude Oil Transportation, and may overstate the penalty of pipeline constraints or the potential production impacts thereof. To complement the preceding analysis, this section briefly examines the transportation costs and breakeven impacts of different options for connecting oil sands producers in western Canada with refiners on the Gulf Coast.

The economics of dilbit by pipeline, dilbit by rail, railbit by rail, and rawbit by rail differ due to transportation costs, quality differentials that reflect refiner demand for bitumen blends, and supply costs that reflect various diluent acquisition requirements. The transport costs assessment in Section 1.4.3.3, Potential to Increase WCSB Crude by Rail, concluded that the transport penalty for shipping oil sands crude oil to the Gulf Coast resulting from pipeline constraints could be from $0 to $8 per barrel. The low end of this estimate was based on shipping rawbit by rail, the high end was based on shipping dilbit by rail, and railbit by rail fell in between. These cost estimates did not factor in the potential impact of the quality differentials for those respective products.[152]

Table 1.4-27 presents the range of estimates for the costs of transporting bitumen blends from western Canada to the Gulf Coast as assessed in Section 1.4.3, Crude Oil Transportation, but also incorporates the information on quality discounts for bitumen blends at the Gulf Coast from the model results presented in Section 1.4.4, Updated Modeling, and the marginal supply costs for different bitumen blends as described in Section 1.4.2.9, Oil Sands Supply Costs. These figures are then used to calculate hypothetical breakeven benchmark price points to illustrate the relative economics of different bitumen delivery options. If rail or pipeline is more or less expensive than currently estimated, or if the estimated quality differentials were different than indicated from the modeling, the implied breakeven prices would change accordingly.

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[151] See Section 1.4.2.9, Oil Sands Supply Costs. Current breakeven costs for U.S. shale oil or ultra-deepwater production are around $60 to $90 per barrel. It is possible that these costs could decline with improved technology or deflation for labor and material inputs needed for upstream development (e.g., engineers, geologists, steel, cement, etc.). It is also possible that future oil resources prove to be more technically challenging, or that input costs increase.

[152] The cost estimates of transporting railbit and rawbit by rail versus transporting dilbit by pipeline in Section 1.4.3, Crude Oil Transportation, were based on the assumption that bitumen is ultimately what the receiving refiners processed. This assumption eliminated the need to explicitly calculate the quality differentials for the different products, because the refineries would be processing the same product, regardless of the form in which it was transported. These assumptions were based on the configuration of at least one Midwestern refiner that has been upgraded to process substantial quantities of oil sands crude oil. Rather than removing the diluent in a processing unit before the dilbit or railbit is sent through a crude distillation unit, a refiner may be configured to process the entire barrel. In that instance, to capture the relative economics of transporting rawbit or railbit by rail versus dilbit by pipeline, one must also take account of the quality differential between those products.

**Table 1.4-27    Supply Costs, Transport Costs, Modeled Quality Discounts, and Implied Breakevens**

| | Dilbit | Dilbit | Dilbit | Railbit | Rawbit | |
|---|---|---|---|---|---|---|
| Blend | Dilbit | Dilbit | Dilbit | Railbit | Rawbit | Dilbit is 70% bitumen/30% diluent. Railbit is 85% bitumen. Rawbit is 100% bitumen. |
| Transport Mode | Pipeline (Committed) | Pipeline (Uncommitted) | Rail | Rail | Rail | Dilbit can travel by pipeline or rail. Railbit and rawbit can only be transported by rail. |
| Plant Gate Supply Cost ($/bbl) | $45.00 | $45.00 | $45.00 | $45.00 | $45.00 | Hypothetical supply cost of a barrel of bitumen at the producing facility. Value is close to average lifetime in situ supply cost. |
| Diluent Price ($/bbl) | $100.00 | $100.00 | $100.00 | $100.00 | $100.00 | Assumed price for diluent (such as condensate) in western Canada. Trades near the price of light sweet crude. |
| Diluent Acquisition Cost ($/bbl) | $43.00 | $43.00 | $43.00 | $43.00 | $43.00 | Assume all producers must dilute bitumen to use pipelines from producing facility to trading hub. Acquisition cost reflects the price of diluent times the amount (.43 barrel) added to a barrel of bitumen to make a dilbit blend. |
| Blend Supply Cost at Plant Gate ($/1.43 bbl) | $88.00 | $88.00 | $88.00 | $88.00 | $88.00 | Supply cost plus diluent acquisition cost. Reflects total supply cost at the plant gate for 1.43 barrels of bitumen and diluent. |
| Transportation to Hardisty ($/1.43 bbl) | $1.43 | $1.43 | $1.43 | $1.43 | $1.43 | Assumption for cost of transportation of 1.43 barrels of dilbit from producing facility to trading hub (e.g., Hardisty, Edmonton, Lloydminster). |
| DRU Processing Cost ($/bbl)[a] | $0.00 | $0.00 | $0.00 | $2.35 | $2.87 | Assessed cost to use a DRU to separate diluent from dilbit blend. Cost is higher for conversion to rawbit because more diluent is recovered. |
| Diluent Revenue ($/bbl) | $0.00 | $0.00 | $0.00 | $24.85 | $42.14 | Revenue from reselling diluent recovered from DRU. Assume some conversion loss and that the resale price of diluent equals purchase price. |
| Blend Supply Cost in Western Canada ($/bbl) | $62.54 | $62.54 | $62.54 | $56.89 | $50.16 | Supply cost for one barrel of blend at trading hub. |
| Transport Cost to Gulf Coast ($/bbl) | $8.10–$10.51 | $14.52–$16.93 | $15.00–$21.00 | $17.00–$24.00 | $17.50–$24.50 | The range in estimated costs to transport one barrel of blend from western Canada to the Gulf Coast. The upper end of the pipeline cost range reflects the uncommitted and committed tariffs estimated in Figure 1.4.3-17, while the lower end of the range reflects lower potential tariffs on certain routes. The rail cost ranges reflect the rates for transporting a given barrel on unit trains (low end) as opposed in manifest trains (high end), as well as the differences in freight rates across blends. These rail cost ranges include the rail cost estimates presented in Figure 1.4.3-18 and Figure 1.4.3-19. |
| Landed Supply Cost in Gulf Cost ($/bbl) | $70.64–$73.05 | $77.06–$79.47 | $77.54–$83.54 | $73.89–$80.89 | $67.66–$74.66 | Blend supply cost plus transport cost to Gulf Coast. |
| Average Price Discount to Maya Crude (%) | 92% | 92% | 92% | 89% | 87% | Modeled average quality discount for each blend relative to Maya, an imported Mexican heavy crude, at the Gulf Coast. Railbit and rawbit have larger discounts because they are heavier blends. In reality, some refiners could prefer barrels with more bitumen feedstock. |
| Required Maya CIF[b] Price ($/bbl) | $76.78–$79.40 | $83.76–$86.38 | $84.28–$90.80 | $83.03–$90.89 | $77.77–$85.82 | Notional heavy crude breakeven prices at the Gulf Coast, taking into account landed supply costs (including transportation) and quality discounts. |

[a] This estimate was based on the assumption that bitumen is diluted to dilbit and transported to hubs in Edmonton/Hardisty/Lloydminster areas, and is then processed through a DRU to produce either railbit or rawbit. This is consistent with recently announced projects. Some producers may be able to save on these costs by accessing rail facilities much closer to their production area.

[b] CIF = cost, insurance, and freight

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The most cost-effective way to move dilbit from western Canada to the Gulf Coast is by pipeline through a committed tariff. Rail shipments of dilbit are generally costlier than shipments of dilbit by pipeline, which explain why netbacks were lower in pipeline constrained scenarios of the modeling, when marginal barrels of dilbit were moved by rail to PADD 3 (Sections 1.4.4.3, Results). Railbit is also more expensive than dilbit by pipeline with a committed tariff, but less expensive than dilbit by rail. Rawbit by rail rivals dilbit by pipeline as an economic mode for moving bitumen to market according to this calculation, and as found in other studies.[153] Rail is particularly attractive compared to uncommitted pipeline tariffs, which is what most small producers unable to secure long-term pipeline capacity must pay. The cost advantages of transporting bitumen as railbit or rawbit, as opposed to dilbit, suggest that the penalty producers pay for pipeline constraints is likely to be smaller than the estimates in Sections 1.4.4.3, Results; Section 1.4.5.1, Prices vs. Supply Costs; and Section 1.4.5.2, Low Oil Prices Scenario.

### 1.4.5.4    Implications for Production

The Draft Supplemental EIS had concluded that approval or denial of any one crude oil transport project, including the proposed Project, remains unlikely to significantly impact the rate of extraction in the oil sands, or the continued demand for heavy crude oil at refineries in the United States. This basic conclusion, which is based on current market forecasts, modeling analysis, and the prevailing regulatory framework, remains the same (based on expected oil prices, oil-sands supply costs, transport costs, and supply-demand scenarios). However, the additional information obtained and analysis conducted for this Final Supplemental EIS provides more insights.

Long-run average supply costs for the in situ projects that will drive oil sands production growth are estimated to be appreciably below the average prices that oil sands producers can expect to receive according to modeling of several supply-demand and pipeline scenarios. Certain pipeline constraints reduce the prices received by bitumen producers, but not enough to curtail most oil sands growth plans or shut in existing production. There are enough announced projects with sufficiently high cumulative capacity and sufficiently low supply costs to meet or exceed production growth forecasts under most market conditions (see Figure 1.4.5-2). This section further explains the Final Supplemental EIS's general conclusions about the production implications of the proposed Project, examines some of the uncertainties that could impact this analysis, and describes the conditions under which oil sands production could conceivably slow.[154]

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[153] This conclusion is supported by other external studies that have found that raw bitumen by rail could provide better netbacks than dilbit by pipeline (Fielden 2013; Genscape 2013). Dedicated rail cars, DRUs, and/or rail terminal equipment are needed to effectively transport rawbit, which explains why most producers opt for pipelines given current infrastructure. There are increasing reports of producers doing increased testing of the potential to ship rawbit (MEG Energy third quarter earnings call; Cenovus third quarter earnings call).

[154] The methodology used to draw conclusions about production implications is similar to the one employed in a recent report published by Carbon Tracker Initiative (2013). However, that report's conclusions were different due to various analytical issues.
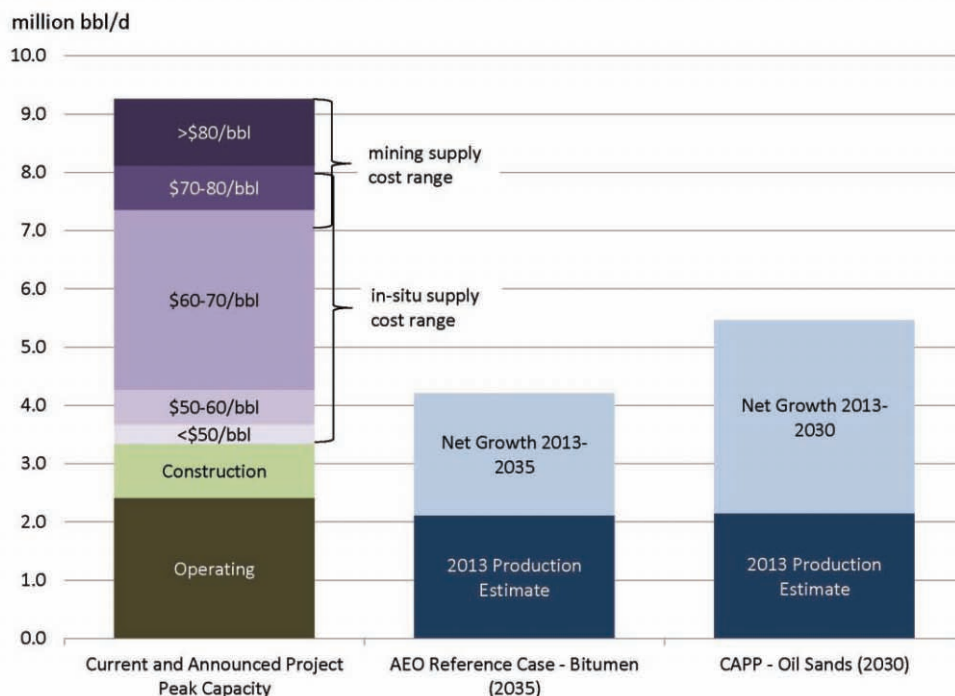
**Figure 1.4.5-2**        **Oil Sands Supply Costs (WTI-Equivalent $/bbl), Project Capacity, and Production Projections**

**Production Implications of Model Results and Supply Costs**

Permitting or denying one particular pipeline project alone, such as Keystone XL, is unlikely to have a significant impact on oil sands economics if similar new pipelines are permitted in the future or if existing cross-border pipelines are allowed to expand. Previous modeling analysis showed that, in the absence of the proposed pipeline, demand exists for other similar cross-border capacity. Recent experience and myriad new pipeline and expansion plans announced since 2010 provide practical support for these results of the model outputs, as explained in Section 1.4.3.1, Increases in Pipeline Capacity. The market provides an incentive for pipeline operators to construct or expand cross-border capacity, regulations permitting.

If all future new cross-border pipelines and capacity expansions on existing pipelines are prohibited but additional crude transportation infrastructure in Canada is developed, then oil sands production is still unlikely to slow significantly. Pipeline permitting decisions for pipelines to the East and West Coasts of Canada are determined by its federal and provincial governments. Model results indicate that if additional pipelines to Canada's West Coast are constructed, they would most likely be utilized regardless of the availability of cross-border pipelines due to the economic attractiveness of the relatively short seaborne shipping distances from Canadian export terminals to refineries in Asia. Aside from domestic east-west pipelines in Canada, crude-by-rail to the Canadian West Coast is an economically viable alternative for WCSB crude if export

facilities on the coast are developed.[155] Consequently, imposing a constraint exclusively on future cross-border pipeline capacity does not cause a significant reduction in the modeled prices of oil sands blends or the returns to oil sands producers.

The absence of the proposed Project and all other new and expanded cross-border pipelines, east-west pipelines, and rail shipments to the Canadian West Coast for export is still unlikely to have a significant effect on the level of oil sands production due to the economic feasibility of crude-by-rail shipments. According to the modeling analysis described in Section 1.4.4.3, Results, if pipelines are completely constrained then roughly 1.2 to 1.5 million bpd of crude would need to be transported by rail to U.S. and Canadian refineries under the EIA outlook.[156] The analysis in Section 1.4.3, Crude Oil Transportation, indicates that this level of rail transport is achievable; indeed, 1.2 million bpd of crude by rail loading projects are already available or under development, even with uncertainty about whether cross-border and Canadian pipelines will get built. Greater use of rail could lower the prices received by upstream Canadian oil producers, particularly if they shipped dilbit by rail rather than moving to shipping railbit or rawbit.

Certain supply-demand cases lower the returns to oil sands production, particularly when combined with pipeline constraints, but the model outputs indicated resulting prices would not be low enough to challenge average in situ supply costs. Scenarios including EIA's Reference Case projections, higher forecasts for domestic oil production, higher-than-expected supplies from competing Latin American heavy oil producers, and/or lower-than-expected U.S. demand were modeled in response to public and interagency comments. Despite reducing the prices received by oil sands producers, in part due to lower benchmark oil price assumptions, most announced oil sands projects are still economic even in the most adverse supply-demand and pipeline scenarios. A hypothetical situation in which no additional cross-border and Canadian capacity is permitted and markets evolve towards EIA's High Resource or Low/No Net Imports Cases reduces the prices received by producers, but not enough to undermine the capacity needed to meet most forecasts.[157]

This analysis is based on an assumption that the most economic oil sands projects, in terms of the estimated supply costs of announced capacity, would be used to meet Canadian production projections.[158] In situ projects have the lowest supply costs on average. Units that integrate mining projects with upgrading to light sweet crude oil are generally the most expensive oil

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[155] There are also favorable economics for rail transport of oil sands crude oil to the U.S. West Coast for export (see Section 1.4.4.3, Results, and Table 1.4-20).

[156] Rail could also accommodate the volumes required to meet CAPP (2013a) production forecasts as explained in Section 1.4.3.2, Increases in Canadian Crude by Rail.

[157] These conclusions are based on the price paths in EIA's Reference, High Resource, and Low/No Net Import Cases, as well as EIA's baseline projections for Canadian bitumen production. Most conclusions would remain the same when applied to production projections from other leading authorities, such as CAPP, IEA, NEB, Canadian Energy Research Institute, or the Alberta Energy Regulator.

[158] Higher production projections would necessitate increasingly more expensive oil sands projects, such as more surface mines and more expensive in situ projects. However, a large number of in situ projects have been announced, the supply costs of which are estimated to be low enough to meet most production projections under most price forecasts and market conditions. This assessment is not based on any evaluation of the fates of individual companies or projects, and does not imply that all announced projects will proceed on schedule. On the contrary, most production projections are risked forecasts that account for project rationalization due to company risk, industry constraints, and oil market conditions and uncertainty.

sands projects and many of them have already been canceled.[159] The supply costs for surface mines are usually higher than the supply costs for in situ projects. CAPP projections include 900,000 bpd in gradual growth of mined bitumen through 2030.[160] These projects could be the first to be rationalized if prices fall below mining supply costs, even if the companies behind those projects tend to be mature operators with financially sound balance sheets.[161] Regardless, constraints on the proposed Project and other infrastructure would only impact the margin between prices and supply costs by $0 to $8 per barrel depending on the assumptions made about the development of other cross-border and/or east-west capacity.

**Short-Term Production Implications and Other Assessments of Pipeline Constraints**

Several analysts and financial institutions have stated that denying the proposed Project would have significant impacts on oil sands production (CIBC 2012, Goldman Sachs 2013a, Pembina Institute 2013, RBC 2013, IEA 2013). To the extent that other assessments appear to differ from the analysis in this report, they typically do so because they have different focuses, near-term time scales, or production expectations, and/or include little direct assessment of rail capacity and basic assumptions or limited data about rail's growth potential.

Most of this analysis focuses on the possibility for long run impacts because they are more relevant to the potential environmental impacts of the proposed Project. However, this subsection also reviews other assertions that approval or denial of the proposed Project would have an impact on production in the oil sands, particularly in the short to medium term. Unlike the studies referenced in this report, the extensive rail data in Section 1.4.3, Crude Oil Transportation, indicate that pipeline constraints are unlikely to significantly affect oil sands production in the short run. Some financial reports that make production claims about the proposed Project focus on short-run, temporary production impacts, whereas most of the analysis in this report focuses on long-run production impacts. Assertions that transportation constraints could affect producers in the next couple of years unless the proposed Project is approved do not necessarily conflict with this document's long-run production conclusions or the forecasts upon which they rely. Some analysts think certain projects could be temporarily delayed due in part to transportation constraints, but that oil sands projects would still be developed in later years and production will catch up to previously forecasted levels by the end of the decade.[162]

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[159] It is worth noting that upgraders are a secondary process and don't add to the supply of raw bitumen, which is produced from mines or in situ projects.

[160] EIA does not publish a distinction between in situ and mined bitumen in its projections.

[161] The companies pursuing surface mining projects are among the industry's largest and most established. Their integrated operations and access to financial resources means they may be more able to endure narrow margins between prices and supply or operating costs than small independents, at least temporarily. The October 2013 decision by Suncor and partners to develop the Fort Hills mine indicates that even surface mines can be attractive investments given their supply costs, current and project prices, and long lifetime: "On October 30, 2013, Suncor announced that the project co-owners voted unanimously to proceed with the Fort Hills oil sands mining project. Suncor has a 40.8% interest and is the developer and operator of the project. The project is scheduled to produce first oil as early as the fourth quarter of 2017 and achieve 90% of its planned production capacity of 180,000 bbls/d within twelve months. With best estimate contingent resources of approximately 3.3 billion barrels, the mine life is expected to be in excess of 50 years at the current planned production rate" (Suncor Energy 2013).

[162] Goldman Sachs's *Getting Oil out of Canada* report (Goldman Sachs 2013b) was widely cited as a negative bellwether for the industry and as evidence that infrastructure delays would limit Canadian oil sands production. However, in subsequent correspondence, a representative of Goldman Sachs (Goldman Sachs 2013c) clarified that *(footnote continued on the following page)*

Moreover, many investment-oriented reports are focused on the financial performance of individual companies rather than total oil sands production levels, which are the focus of this analysis. Transportation constraints could impact more marginal companies or projects without challenging expected production increases, because the production from those more marginal companies and projects are already risked out of long-term forecasts. Some of the reports that have made assertions about the proposed Project's short-term production impacts are published by financial institutions, whose partial objective is to guide individual investment decisions about specific companies. Short-term fluctuations in price differentials are very relevant considerations for those investment decisions because they could affect the timing, profile, and profits of individual projects. However, they are less indicative of the industry's general outlook than broader macroeconomic forces.[163]

Differences in publication dates, or in the amount of data available at the time of analysis, could also explain why the conclusions of other reports might diverge from this one. Some analyst reports predated public announcements of large-scale unit train facilities. Loading facilities in the oil sands region are now scheduled to have approximately 1.2 million bpd of crude by rail capacity in operation by the end of 2014—greater than the capacity of the proposed Project. As analysts have become aware of crude-by-rail transport capacity, they have typically moderated their estimates of the impact of pipeline constraints.[164]

The extent to which the analysts' understanding of the potential of crude-by-rail has changed over time is illustrated by the evolution of this market analysis section. The Final EIS (August 2011) and Draft Supplemental EIS (March 2013) anticipated the potential for increased rail transport capacity. Since the Draft Supplemental EIS was released, over 700,000 bpd of additional crude-by-rail loading capacity in Western Canada has been publicly announced that is expected to be operational by the end of 2014 (this does not include the recently announced Kinder Morgan-Imperial Oil terminal with an expected capacity of 100,000 bpd by the end of

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the production impacts they described were not expected to be permanent (see Appendix C, Supplemental Information to Market Analysis). RBC noted that up to 300,000 bpd of production which would be deferred to later years, but not necessarily stopped.

[163] The long-term industry projections referenced throughout this report, like EIA's and CIBC's, do not predict that all projects will go forward as scheduled. Instead, those production forecasts already discount the size and speed of announced expansion plans because of the risk that projects do not proceed on time or at all due to company-specific or industry-wide constraints. The comparison of long-run supply costs with long-run prices, which focuses on the industry's aggregate outlook rather than its temporary vagaries, is the best way to examine oil sands production levels and associated environmental impacts.

[164] For example, in one widely cited report from August 2012, one group of investment analysts had concluded that pipeline constraints would lead to major rationalizations of oil sands projects. In their update to that report in June 2013, they noted that the biggest change from the previous year was higher confidence that rail could accommodate the growth in the oil sands (but they noted that their estimated higher rail costs of $5 to $10 per barrel could still impact their growth outlook, which is substantially higher than that of EIA or CAPP) (CIBC 2013). In another example, a group of analysts estimated in February of 2013 that denial of the proposed Project could lead to 450,000 bpd of deferred growth in the 2014 and 2015 timeframe. In an updated report in September of 2013, they had revised this number down to 300,000 bpd and noted that it could be even less "as crude-by-rail marketing has increased in significance and should significantly bridge the export capacity gap" (RBC 2013).

[164] Unlike its natural gas modeling, the IEA WEO model does not actually incorporate midstream constraints for oil (IEA 2013b). Pembina briefly considers rail, stating "While shipping by rail is in the pilot stages, in 2011, only 20,000 barrels of crude oil per day left western Canada on rail. This volume may well grow in the future, but relative to large diameter pipelines, rail's contributions to total exports will remain very small," dismissing the potential for rail transport without additional data or analysis.

2014, and an ultimate capacity of 250,000 bpd). These rail facilities are being developed even in the face of uncertainty around future pipeline capacity.

Some analysts assessing a production impact from pipeline constraints appear to have based their conclusions on fixed assumptions about rail.[165] At the time the Final Supplemental EIS was completed, there were no known reports of companies delaying start dates for new projects due to impending transportation constraints. While short-term physical transportation constraints introduce uncertainty to industry outlooks,[166] data and analysis in Section 1.4.3, Crude Oil Transportation, indicate that rail will likely be able to accommodate new production if new pipelines are delayed or not constructed. The data and analysis in this section are generally more comprehensive than the information used in other referenced reports to draw conclusions about rail's potential growth.

**Long-Term Production Implications of Lower Oil Prices**

As shown in the Production Implications of Model Results section above, pipeline constraints are unlikely to impact production given expected supply-demand scenarios, prices, and supply costs. Over the long term, lower-than-expected oil prices could affect the outlook for oil sands production, and in certain scenarios higher transportation costs resulting from pipeline constraints could exacerbate the impacts of low prices.[167] The primary assumptions required to create conditions under which production growth would slow due to transportation constraints include that prices persist below current or most projected levels in the long run and all new and expanded Canadian and cross-border pipeline capacity, beyond just the proposed Project, is not constructed.[168]

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[165] For example, Pembina (2013) briefly considers rail, stating "While shipping by rail is in the pilot stages, in 2011, only 20,000 barrels of crude oil per day left western Canada on rail. This volume may well grow in the future, but relative to large diameter pipelines, rail's contributions to total exports will remain very small." dismissing the potential for rail transport without additional data or analysis. IEA (2013) claimed, "if the controversies over the Keystone XL pipeline and the pipelines from Alberta to the British Columbia coast were to be resolved quickly, oil sands production could easily grow 1 million b/d higher than we project [by 2035]." However, the methodology used to arrive at that estimate is unclear; the WEO model does not account for midstream transportation considerations for oil (as opposed to natural gas and biofuels) and the agency did not state its assumptions regarding the growth of crude by rail.

[166] For example, in December 2013, it was reported that Statoil stated that it may have to choose between investing in increasing production in Alberta or investing increasing production in Canadian offshore discoveries. One of the uncertainties the company cited contributing to a reluctance to invest in increasing Alberta production (by Statoil and other companies) was the uncertainty about the status of new pipelines (Lewis 2013, CBC 2013b).

[167] Rail cost penalties are likely to fall in a range of $0 to $8 per barrel, according to the analysis in Sections 1.4.3, Crude Oil Transportation, and 1.4.4, Updated Modeling. Higher rail cost estimates and potential production impacts are conditional on an assumption that bitumen by rail travels as dilbit, despite the apparent availability of more economic options. If the industry moved to the more economic rail option of railbit or rawbit by rail, then prices could fall to a level more comparable to dilbit by pipeline due to the cost savings explained in Section 1.4.3, Crude Oil Transportation, and Section 1.4.5.3, Transportation Cost Sensitivities.

[168] Oil prices would have to be substantially lower than current oil prices or those projected for WTI in the Reference, High Resource, and Low/No Net Imports Cases, which average between $100 to $113 per barrel in real terms through 2035. This analysis also assumes that other costs and differentials do not fall along with oil prices. Some deflation in oil sands supply costs could be expected to occur in a low-price scenario, as upstream, midstream transportation, and downstream costs all fall to a certain extent along with oil prices. As some projects are canceled or deferred due to low oil prices, it would free labor and other resources to develop remaining projects at a lower cost. Oil price differentials in dollar terms, such as those between Canadian heavy oil and light sweet domestic
*(footnote continued on the following page)*

Above approximately $75 per barrel (WTI-equivalent), revenues to oil sands producers are likely to remain above the long-run supply costs of most projects responsible for expected levels of oil sands production growth. Transport penalties could reduce the returns to producers and, as with any increase in supply costs, potentially affect investment decisions about individual mining and in situ projects on the margins. However, at these prices, enough relatively low-cost in situ projects are under development that baseline EIA and CAPP production projections would likely be met even with constraints on new pipeline capacity.

Current and most projections for future WTI-equivalent oil prices exceed $75 per barrel. Oil prices are volatile, particularly over the short-term, and long-term trends, which drive investment decisions, are difficult to predict. Specific supply cost thresholds, Canadian production growth forecasts, and the amount of new capacity needed to meet them are uncertain. As a result, the price threshold above which pipeline constraints are likely to have a limited impact on future production levels could change if supply costs or production expectations prove different than estimated in this analysis.

Oil sands production is expected to be most sensitive to increased transport costs in a range of prices around $65 to 75 per barrel. Assuming prices fell in this range, higher transportation costs could have a substantial impact on oil sands production levels—possibly in excess of the capacity of the proposed Project—because many in situ projects are estimated to break even around these levels. EIA and CAPP production projections would likely not be met under such circumstances. However, the marginal production impact of pipeline constraints cannot be accurately quantified in part because benchmark EIA and CAPP production projections were conditioned on higher oil prices. Prices below this range would challenge the supply costs of many projects needed to meet EIA and especially CAPP production projections, regardless of pipeline constraints, but higher transport costs could further curtail production.

These assessments derive from the breakeven prices needed to make investments in new in-situ capacity financially attractive, given external estimates of total project costs (capital and operating). Breakeven prices are then compared to the points at which higher transportation costs could affect the amount of future capacity that would be able to come online versus the amount that would be required to meet production growth forecasts. Once online, the operating costs for existing projects are relatively low ($20 to $40 per barrel according to most estimates), so prices for oil sands crudes would have to fall much further before existing production would be shut in. Note that some low-oil-price projections achieve low prices in part due to assumptions about higher, rather than lower, oil sands production.[169]

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production, are also likely to compress along with benchmark price levels. U.S. tight oil and other marginal sources of supply could be uneconomic at lower assumed oil price levels, such that prices could not fall that far without other assumed changes to supply and demand. To achieve a low-price world, one would have to make other assumptions about demand and/or assume that supply from other high cost resources, such as from shale or deepwater, is not affected by lower prices.

[169] Low oil prices are not necessarily incompatible with oil sands economics. EIA's Low Oil Price case, which averages $70 per barrel, projects higher Canadian oil production than the baseline Reference Case for much of the forecast period. This illustrates that many visions of a low oil price world depend in part on increasing levels of efficiency in oil production. Absent the implied improvements for oil sands and other sources of oil production, it may not be possible for oil prices to drift as low as they do in the AEO low price case.

Ultimately, one must distinguish between the influence of the proposed Project and the influence of other mitigating factors when drawing conclusions about oil sands production rates. The dominant drivers of oil sands development are more global than any single infrastructural project. There are possible scenarios in which production and investment in the oil sands could abate due to extremely low oil prices, regulatory changes, or the development of new technologies or energy sources, but the effects of those factors should not be conflated with the effects of constraints on an individual pipeline or other cross-border pipeline capacity growth.

## 1.4.6      Additional Issues in Market Outlook

### 1.4.6.1     Crude Price Differences and Gasoline Prices

Comments were received throughout the review process leading up to the Final EIS about whether the steep discounts in Midwestern crude prices were resulting in lower gasoline prices for Midwest consumers, and, conversely, whether approving the proposed Project would relieve the crude bottleneck at Cushing and could thereby raise gasoline prices in the Midwest. Several pipelines, including the Seaway pipeline and the Gulf Coast Project, are already adding more pipeline transport capacity from Cushing, Oklahoma, to the Gulf Coast and will compress the discount for inland crudes with or without the proposed Project. Consequently, this issue is not solely related to the proposed Project.

Since early 2011 there has been a glut of crude oil at the Cushing, Oklahoma, oil hub where WTI crude oil is priced. This glut was caused by a variety of factors including growth in domestic light crude production, displacement of light crude by several refiners bringing on-line heavy crude upgrading projects in the Midwest to process heavy WCSB crude oils, and constraints in the transportation capacity out of Cushing because of the change in production areas and associated crude flows. With no viable options to move light crude to coastal refineries, notably on the Gulf Coast, the crude at Cushing and further north to the Bakken region became heavily discounted by producers relative to traditional markers such as Louisiana Light Sweet (LLS) or Brent. This led to the prevailing and highly unusual market situation where a Gulf Coast refiner processing LLS would have had to pay as much as $20 to $25 per barrel more (at various times) for a light crude than a refiner in the Midwest would pay for a crude with similar yields (WTI). This situation gave refiners in the Midcontinent region that purchase crude oil based on the WTI price a significant crude oil cost advantage over Gulf Coast (or East or West Coast) refiners that rely on purchases of foreign crude oils since those are priced off of Brent or other international markers.

The steep discounts in crude prices in the Midcontinent and upper Midwest/Chicago regions compared to Gulf Coast crude prices have not, however, resulted in lower wholesale gasoline prices in those regions compared to the Gulf Coast. According to market data (see Figure 1.4.6-1), despite the discounts in WTI and hence regional crude prices, wholesale product prices in the Chicago and Group 3 markets—for the most part—did not follow crude price discounts.[170] Figure 1.4.6-1 shows that during the period that WTI crude was steeply discounted to similar crude oils on the Gulf Coast (shown by the blue line in Figure 1.4.6-1), the wholesale price of gasoline in the Midwest (Chicago and Group 3) has remained generally higher

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[170] See Appendix C, Supplemental Information to Market Analysis, for an explanation of the relationship of PADD regions to the U.S. crude oil market and an explanation of Chicago and Group markets.

than that on the Gulf Coast (shown by the green and red lines in Figure 1.4.6-1). This is because there is an active flow of gasoline, and other clean products, from the Gulf Coast into the Midwest, mainly via the Explorer and Magellen pipelines. As a consequence, Midwest product prices are derived from Gulf Coast prices, both of which are in turn driven by international (rather than U.S. inland) crude oil prices. Enabling (additional volumes of) WCSB crudes to flow to the Gulf Coast would not change this dynamic. Rising refining runs in the Midwest have left the region balanced or net long gasoline during certain parts of the year, but because it remains tied via transport capacity to the national (and international) market for refined products, product prices remain in line with other regions, adjusted for the cost of transportation.
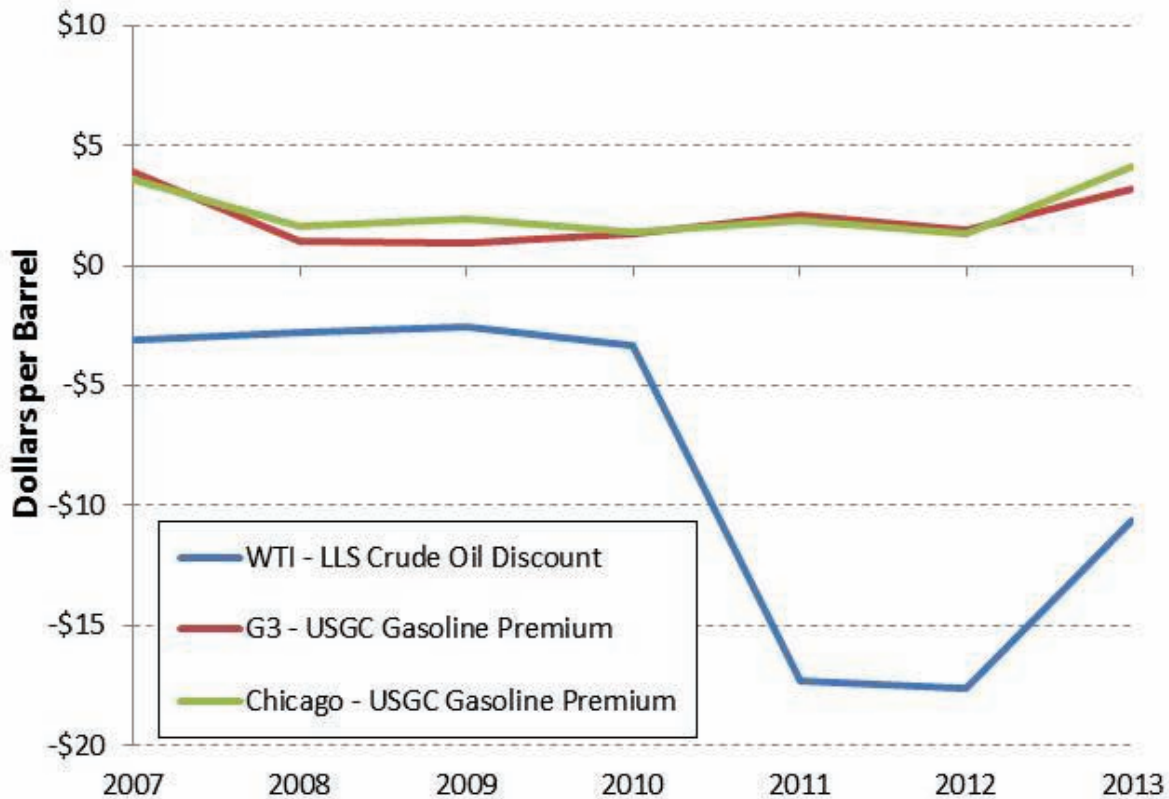


Source: Bloomberg 2013

Notes: Bloomberg WTI pricing (ticker symbol: USCRWTIC Index). Bloomberg LLS pricing (ticker symbol: USCRLLSS Index). Danaher Oil Midcontinent Unleaded Gas pricing (ticker symbol: G3OR87PC Index). Bloomberg U.S. Gulf Coast Reformulated Blendstock for Oxygenate Blending pricing (ticker symbol: RBOBG87P Index). Bloomberg Chicago Conventional Blendstock for Oxygenate Blending pricing (ticker symbol: CHOR87PC Index).

**Figure 1.4.6-1          Average Crude Oil and Gasoline Price Spreads**

### 1.4.6.2    Oil Exports from Keystone XL

Comments were received throughout the review process speculating that WCSB heavy crude oil supplies carried on the proposed Project would pass through the United States and be loaded onto vessels for ultimate sale in markets such as Asia. As crude of foreign origin, Canadian crude is eligible for crude export license as long as it is not comingled with domestic crude.[171] However, such an option appears unlikely to be economically justified for any significant durable trade given transport costs and market conditions.

Once WCSB crude oil arrives at the Gulf Coast, Gulf Coast refiners have a significant competitive advantage in processing it compared to foreign refiners because the foreign refiners would have to incur additional transportation charges to have the crude oil delivered from the Gulf Coast to their location. The pipeline or rail-delivered crude oil would compete with seaborne crude from elsewhere that has already undergone costs of loading onto seagoing tankers and may be delivered to other countries more competitively.

Gulf Coast refiners' traditional sources of heavy crudes, particularly Mexico and Venezuela, are declining and are expected to continue to decline. This results in a situation where the refiners have significant incentive to obtain heavy crude from the oil sands. Both the EIA's 2013 AEO (EIA 2013a) and EnSys WORLD model indicate that this demand for heavy crude in the Gulf Coast refineries is likely to persist. Gulf Coast refineries have the potential to absorb volumes of WCSB crude that go well beyond those that would be delivered via the proposed Project. On this basis, the likelihood that WCSB crudes will be exported in volume from the Gulf Coast is considered low.

Further, given transport costs, if WCSB crude was to move to Asia, it would be more economical to move it via pipeline to the Canadian West Coast and ship by tanker from there rather than first moving it to the U.S. Gulf Coast. The EnSys modeling results above suggest that westbound routes to Asia offer such attractive netbacks that they may be preferred to U.S. destinations. Even if westbound pipelines from the WCSB were not to be built/expanded, it is still cheaper to move via rail to the West Coast and then by crude tanker, as shown in Table 1.4-20. WCSB crudes would then be refined in Asia versus in the United States. In such a scenario, as per Section 1.4.4.3, Results, the United States would be left importing more crude from Latin America and the Middle East to refine here.

EnSys modeling shows no export of light or heavy crude oil carried on Keystone XL or any other pipeline into PADD 3 onward to overseas markets, confirming the barriers that PADD 3 heavy crude demand and transport costs would be to such export activity. Further, given the increase of light crude supplies within the United States, were such export activity to occur, they would be more likely to be Canadian light crude rather than heavy.

In short, while it is possible that some cargos of heavy WSCB crude could be exported, it is unlikely for a range of economic factors that any such trade flows would be significant or durable in the long run.

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[171] 15 Code of Federal Regulations 754.2

Finally, according to the modeling analysis above, U.S. product exports are not sensitive to different scenarios of pipeline development. It is possible that WCSB heavy crude may be refined in the United States and processed into petroleum products that are exported. Where less WCSB crudes are used in the United States, U.S. refined product exports remain elevated, in part with crudes from Latin America and the Middle East substituting WCSB crudes. Refined product export levels have already increased and some of the crude used is from foreign sources. As this may already be occurring, it may continue with or without the proposed Project. Exports are made possible at least in part due to available sophisticated U.S. refining capacity; proximity to markets that import refined fuels, particularly in Latin America, where most of these exports go; and low natural gas costs for U.S. refiners.[172] The prospects for refined product exports will be affected by domestic demand versus domestic refining capacity, the cost of natural gas, and refining capacity abroad, including in foreign markets currently importing U.S. refined products such as Mexico, Brazil, Chile, and Europe. The economic viability of exports does increase the demand for crudes in the United States, particularly in PADD 3, the source of most U.S. exports. But this demand does not depend on the proposed Project.

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[172] Both for operating expenses and feedstocks, abundant U.S. natural gas supplies and low natural gas prices create a competitive advantage for U.S. refiners. For process fuel, refineries elsewhere generally use higher cost oil to fuel refinery process (Valero 2013).

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Additional references are included in Appendix C, Supplemental Information to Market Analysis.

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