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PACIFIC BASIN HEAVY OIL REFINING CAPACITY‡

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SUMMARY

The United States today is Canada's largest customer for oil and refined oil products. However, this relationship may be strained due to physical, economic and political influences. Pipeline capacity is approaching its limits; Canadian oil is selling at substantive discounts to world market prices; and U.S. demand for crude oil and finished products (such as gasoline), has begun to flatten significantly relative to historical rates. Lower demand, combined with increased shale oil production, means U.S. demand for Canadian oil is expected to continue to decline. Under these circumstances, gaining access to new markets such as those in the Asia-Pacific region is becoming more and more important for the Canadian economy.

However, expanding pipeline capacity to the Pacific via the proposed Northern Gateway pipeline and the planned Trans Mountain pipeline expansion is only feasible when there is sufficient demand and processing capacity to support Canadian crude blends. Canadian heavy oil requires more refining and produces less valuable end products than other lighter and sweeter blends. Canadian producers must compete with lighter, sweeter oils from the Middle East, and elsewhere, for a place in the Pacific Basin refineries built to handle heavy crude blends.

Canadian oil sands producers are currently expanding production capacity. Once complete, the Northern Gateway pipeline and the Trans Mountain expansion are expected to deliver an additional 500,000 to 1.1 million barrels a day to tankers on the Pacific coast. Through this survey of the capacity of Pacific Basin refineries, including existing and proposed facilities, we have concluded that there is sufficient technical capacity in the Pacific Basin to refine the additional Canadian volume; however, there may be some modifications required to certain refineries to allow them to process Western Canadian crude. Any additional capacity for Canadian oil would require refinery modifications or additional refineries, both of which are not expected, given the volume of lighter and more valuable crude from the Middle East finding its way to Pacific Basin markets.

Consequently, any new refinery capacity is not likely to be dedicated to Canadian crude shipments. This places increasing importance on the need to enter into long-term contracts to supply Pacific Basin refineries, backed up by evidence of adequate transportation capacity. Canadians will have to show first, and quickly, that we are committed to building pipelines that will bring sufficient volumes of oil to the Pacific coast necessary to give the refiners the certainty they need to invest in infrastructure for refining Canadian oil.

Access to this crucial market will depend critically on the outcome of the pipeline approval process, and also the cost to ship from Canada. If Canada does not approve of the Pacific coast pipeline expansions, or takes too long in doing so, it could find its crude unable to effectively penetrate the world's most promising oil export market.

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CAPACITÉ DE RAFFINAGE DU PÉTROLE LOURD DANS LE BASSIN DU PACIFIQUE‡

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RÉSUMÉ

À l'heure actuelle, les États-Unis sont le plus gros consommateur de pétrole et de produits pétroliers raffinés du Canada. Toutefois, certaines influences physiques, économiques et politiques pèsent sur cette relation et pourraient lui nuire. Les pipelines seront bientôt utilisés à pleine capacité; le pétrole canadien se vend à des prix considérablement réduits sur le marché mondial; et la demande des États-Unis pour le pétrole brut et les produits finis (notamment l'essence) a commencé à fléchir substantiellement en raison des taux historiques. Compte tenu de la faiblesse de la demande et de l'accroissement de la production du pétrole de schiste, la demande moyenne de pétrole canadien par les É.-U. devrait continuer de décliner. Dans ces circonstances, il est de plus en plus important pour l'économie canadienne d'obtenir l'accès à de nouveaux marchés, par exemple ceux de la région Asie-Pacifique.

Toutefois, on ne peut augmenter la capacité de transport du pétrole vers le Pacifique au moyen du prolongement de l'oléoduc Northern Gateway et du pipeline Trans Mountain que si la demande est suffisante et que l'on dispose des moyens pour effectuer le traitement des mélanges de brut canadien, qui exige davantage de raffinage et donne des produits finaux de moins grande valeur que d'autres mélanges; ainsi, les producteurs canadiens doivent concurrencer les pétroles plus légers, moins acides du Moyen-Orient et d'un peu partout pour se faire une place dans les raffineries du bassin du Pacifique qui peuvent assumer le traitement des mélanges de brut lourd.

Les producteurs des sables bitumineux canadiens augmentent actuellement leur capacité de production. Une fois terminés, le pipeline Northern Gateway ainsi que le prolongement du pipeline Trans Mountain devraient livrer 500 000 à 1,1 million de barils supplémentaires par jour aux pétroliers de la côte du Pacifique. Cette étude sur la capacité des raffineries du bassin du Pacifique, y compris les installations existantes et proposées, nous a permis de conclure que le potentiel technique y est suffisant pour le raffinage du volume supplémentaire de pétrole canadien; toutefois, il se peut qu'il faille apporter des changements à certaines raffineries. Si la quantité du brut canadien venait à augmenter, on devrait modifier les installations existantes ou en créer de nouvelles, ce qui n'est pas prévu étant donné le volume de pétrole léger et de plus grande valeur du Moyen-Orient qui pénètre les marchés du bassin du Pacifique.

Par conséquent, il est peu probable que de nouvelles capacités de raffinage soient réservées aux cargaisons de pétrole brut canadien. Il est donc d'autant plus important de conclure des contrats à long terme pour alimenter les raffineries du bassin du Pacifique, et de les appuyer par les preuves d'un potentiel de transport avéré. Les Canadiens devront avant tout démontrer sans tarder qu'ils sont déterminés à construire des pipelines qui transporteront des volumes suffisants de pétrole vers la côte du Pacifique, afin que les raffineurs aient l'assurance dont ils ont besoin pour investir dans l'infrastructure de raffinage du pétrole canadien.

L'accès aux marchés essentiels dépendra d'abord et avant tout du processus d'approbation des pipelines et du prix du transport du pétrole depuis le Canada. Si le pays n'approuve pas le prolongement des pipelines vers la côte du Pacifique, ou s'il est trop lent à se décider, il se peut que son pétrole brut ne puisse plus se faire une place sur le marché mondial le plus prometteur.

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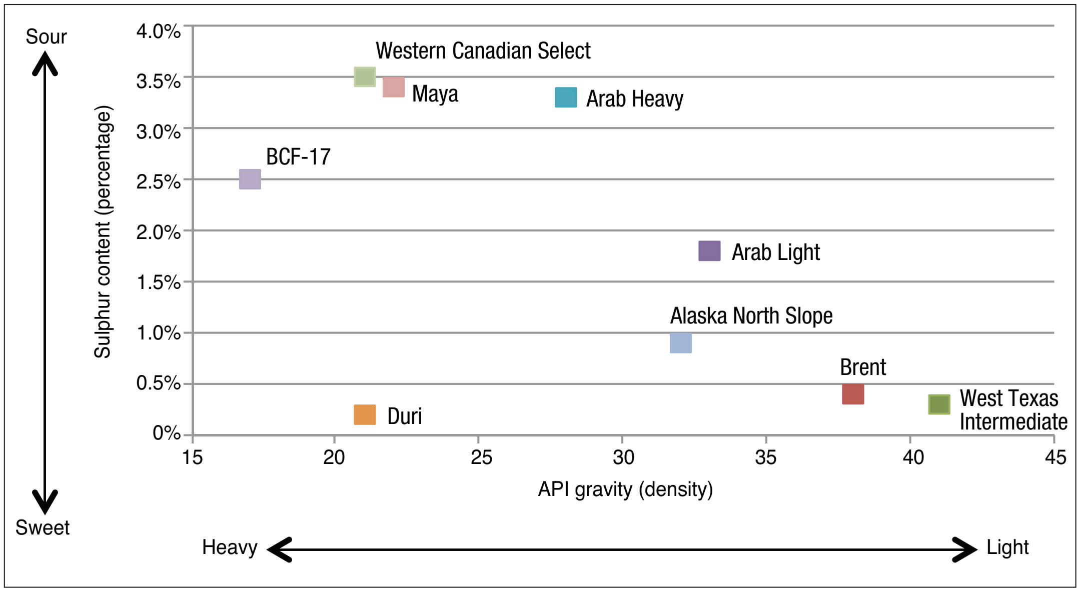
I. OVERVIEW

Canada is rich in primary resources ranging from timber and fish, to oil and gas reserves and hydroelectric power. Each province has a share of this resource wealth, but none match the hydrocarbon wealth of Alberta, which includes conventional oil and gas reserves, unconventional reserves such as tight oil and gas, and abundant coal. The oil reserves of Alberta, contained largely in the oil sands region, provide a technical challenge for acquisition, as well as for delivery to appropriate markets. Once produced, the oil itself requires specialized refining capability, given the very low API (American Petroleum Institute) gravity and high sulphur content and levels of residual metals. Western Canadian Select (WCS) is classified as "heavy sour."[1] As a consequence, the price of this product is discounted, relative to other grades, as a function of the distance to refineries as well as the inherent physical properties.

Figure 1 displays the relative properties of a variety of globally traded crude oils. The most highly valued crude oils are those that are low in sulphur and have a high API gravity (light). By gravity, crude oils are typically classified as light, medium or heavy. "Sweet" crude oils are naturally low in sulphur and require less refining, while "sour" crudes are high in sulphur. See Appendix A for additional details.

FIGURE 1: DENSITY AND SULPHUR CONTENT OF CRUDE OILS



Flat and declining demand in some regions, such as the United States, coupled with price discounts in the U.S. market, has encouraged Canadian producers to begin exploring other markets for future growth. Increased competition in the principal market (the U.S.), from production in areas such as the Bakken Formation, combined with limited tidewater access and export pipeline capacity constraints for oil from Alberta, make growing markets such as those in the Asia-Pacific region very attractive.

[1] "Heavy" refers to the API gravity, while "sour" refers to the sulphur content.

Previous reports[2] have discussed the issue of market prices for upgraded and finished products in the Pacific Basin, but none so far have analyzed refining capability throughout the Pacific Basin as a functional element of demand for heavy oil products.[3] We address this by providing an estimate of the physical and economic capacity within the Basin to absorb a substantial volume of future Canadian heavy oil products. Our proxy for this capacity is the heavy oil upgrading capability/capacity in existing refineries in the region, and planned capacity in new refineries, over the next 20 years.

We take the existing output of the oil sands region as the basis for estimating the future volume of Western Canadian Select (WCS) and as the driver for Canadian, but not global, heavy oil supplies. We assume that the refineries throughout the Pacific Basin make an economic as well as a physical choice when bidding for a range of oil inputs for the refinery. Their decision is based on their own demand combined with domestic capability, as well as demand in alternative markets and the ability to acquire lighter, sweeter products, or even upgraded distillates at competitive prices. In the time period assumed in this report (through to 2020) we do not assume a change in production from Canadian sources, but we do assume higher volumes reaching coastal shipping points.[4] Similarly, we do not assume a change in quality from Canadian producers during this period and we assume the price discount will continue to reflect quality and distance characteristics.

In this research we have assumed enough coastal access to accommodate future flows up to three million barrels per day (3 mmbd). Currently, the majority of Canadian production is sent to the U.S. Midwest, and the balance (in excess of stock destined for domestic consumption) is sent to the Pacific. The limit of transfer to the Pacific Basin is set through a combination of processing capacity within the oil sands operations and full pipeline utilization (approximately 1.1 mmbd) to Vancouver and Kitimat, on the Canadian Pacific coast. Based on this volume assumption, we have estimated the upgrading capacity that is available, or is likely to be available, over the period to 2020 to serve heavy crude supplies exported to markets in the Pacific Basin.

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2 M.C. Moore et al.,"Catching the Brass Ring: Oil Market Diversification Potential for Canada," University of Calgary School of Public Policy (December 2011); "Market Prospects and Benefits Analysis for the Northern Gateway Project," Muse Stancil (January 2010); and Harold York, "A Netback Impact Analysis of West Coast Export Capacity," Wood Mackenzie (December 2011).

3 For purposes of this report, the product we have used as a proxy for heavy oil is that oil transported without extensive upgrading: essentially synthetic crude oil (SCO), diluted bitumen (dilbit) and synthetic bitumen (synbit) destined for refineries with the next level of upgrading capacity.

4 The Northern Gateway pipeline is intended to move 525,000 barrels a day (525 kbd) from Alberta to Kitimat, B.C. The current capacity of Kinder Morgan's Trans Mountain pipeline to Vancouver is 300 kbd. Kinder Morgan has plans to expand the capacity of Trans Mountain to 890 kbd. This analysis assumes that the two pipelines have the incremental capacity to move approximately 1.1 million barrels a day (1.1 mmbd) from Alberta to the Pacific Coast.

II. BACKGROUND

Alberta's economy depends to a large degree on distant markets for crude oil and processed crude oil products. However, Alberta's access to these markets is limited by available transportation infrastructure facilities (pipelines and railroads) that make it possible to economically move the crude oil to distant world markets, notably either the Pacific Basin or the U.S. Gulf Coast. Alberta's current outlets are through Vancouver and pipelines accessing PADDs (Petroleum Administration for Defense Districts) II and III in the U.S. As a result, Alberta crude oil production is priced at a significant location discount relative to other globally traded crude oils.[5] That location discount is essentially the cost to move crude by the least economic transportation alternative — truck — which is the transportation method by which the "last barrel" of Canadian crude moves to the current major market, the U.S. Gulf Coast.

Developing access to these distant markets is requisite to diversify the market for Alberta crude. However, market access is not sufficient to create "security of demand"[6] for Alberta crude. Creating "security of demand," or long-term successful disposition of Canadian crude oil into different or new distant markets, requires that Canadian crude be a "fit" for those markets, matching refining capability and product demand. It also requires that Canadian crude be competitive with other crude oils supplied to the market from the standpoint of relative value, where value is a function of relative price, but also supplier preference, based on political or trade relationships.

For Alberta crude to satisfy crude oil demand in distant markets, crude oil refining facilities in those markets must have the capability — the refinery hardware — to process Canadian crude oil, notably the heavy oil/diluted bitumen/synthetic bitumen from current and expected future production in the oil sands region of Alberta. SCO (synthetic crude oil) is bitumen or very heavy crude oil that is processed in upgraders to produce a lighter crude oil blend. Bitumen is the heavy asphalt-like material that is recovered from or produced with enhanced production methods in Alberta's oil sands. Dilbit (diluted bitumen) is bitumen that is diluted with lighter oil, usually a condensate, so that the properties of the blend are compatible with conventional crude oil transport systems. Synbit (synthetic bitumen) is bitumen blended with SCO so that the properties of the blend are compatible with conventional crude oil transport systems. Details about crude oil types and properties can be found in Appendix A.

Canadian crude oil must also be a suitable feedstock from which the refineries can manufacture the particular mix of refined petroleum products that satisfy demand in the destination market.[7] Even with this match between crude oil quality, refining hardware and product demand, there must also be sufficient volume/quantity of crude processing capacity in these distant markets to support Canadian investment in the transportation infrastructure needed to reach these markets. Lastly, while demand for crude oil in these markets is expected to increase — in some cases dramatically — production is competitive, and other crude oil producers, some with longstanding relationships with and investment in Asia, have a strong interest in preserving their market share.

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[5] Prices for Canadian crude oil are also adjusted for quality differences that affect the cost to refine the crude and the value of the products produced from the crude.

[6] Gorden Houlden et al, "Building a Long Term Energy Relationship between Alberta and China," University of Alberta's China Institute (December 2011).

[7] Different qualities of crude oil produce different mixes of refined products. This is discussed in more detail in Appendices A and B.

We assume the most promising prospective markets for Canadian crude oil are likely to be a collection of markets in the Pacific Basin and the U.S. West Coast. The Pacific Basin includes markets in Asia where the demand for petroleum products is expected to increase significantly. The U.S. West Coast has a large concentration of refineries with heavy sour crude processing capability, and indigenous production of heavy crude oil is declining.[8, 9] These markets in Asia and on the U.S. West Coast can be accessed from the Pacific coast of Canada.

Earlier studies on prospective markets for Canadian crude oil have concluded that there is a potential market in the near term (2016 to 2018) in the U.S. and Asia for as much as 2,300 kbd of a mix of Canadian synthetic crude oil, dilbit and synbit.[10] Wood Mackenzie estimated the likely Asian market for Canadian crude oil at 300 to 600 kbd of heavy oil and zero to 300 kbd of SCO with only the Northern Gateway pipeline in operation.

These earlier studies[11] have focused on the economic benefit and have looked at aggregate demand in the U.S. and Asia, notably on the exploding demand for energy in China. However, they have not presented or discussed in detail the nature of that demand or the competitive supply of crude oil to Asia.

We consider the expected nature of crude oil demand in prospective markets by examining current and future refining capabilities, capacities and feedstock preferences, as well as product demand and details of competitive crude supply to these markets. An understanding of these issues is critical for long-range planning by oil producers, government agencies that regulate pipelines, transfer and storage facilities, and ultimately agencies that depend on oil-related tax and revenue streams for budget purposes. We turn first to a discussion of demand, followed by an analysis of processing capability and implications for Canadian producers.

III. DEMAND FOR PETROLEUM PRODUCTS

Crude oil demand is driven by subsidiary markets, or demand for refined products, including gasoline, diesel fuel, heating oil, jet fuel and heavy fuel oil.

Demand for liquid fuel products varies widely depending on region and economic conditions. For instance, in the U.S., gasoline makes up almost half of total petroleum product demand. In much of the rest of the world, demand for diesel fuel, kerosene and other middle distillates exceeds the demand for gasoline. This is most evident in Table 1 below, which illustrates regional differences in demand. Of particular interest is the far lower use of motor fuel in China compared to the U.S., implying strong growth in future demand as car ownership increases in Asia.[12]

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[8] This is true in spite of California's Assembly Bill 32 (the Global Warming Solutions Act) and the Low Carbon Fuel Standard, which could place regulatory constraints on heavy oil processing capability.

[9] The U.S. Gulf Coast, where there is also substantial capability to process heavy sour crude, has also been identified as a prospective market, but it is not discussed in this paper as it was addressed in a previous paper: M.C. Moore et al., "Catching the Brass Ring" (December 2011).

[10] SCO is considered a high-quality crude since it has been processed to remove the negative properties of bitumen. Dilbit and synbit are diluted bitumen and retain the negative properties of bitumen.

[11] Harold York, "A Netback Impact Analysis of West Coast Export Capacity" Wood Mackenzie (December 2011); and "Market Prospects and Benefits Analysis for the Northern Gateway Project," Muse Stancil (January 2010).

[12] The Chinese government's 12th Five-Year Plan emphasizes new electric vehicle demand as a commitment to cleaner energy use in China; this is not expected to significantly diminish overall crude oil demand growth patterns.

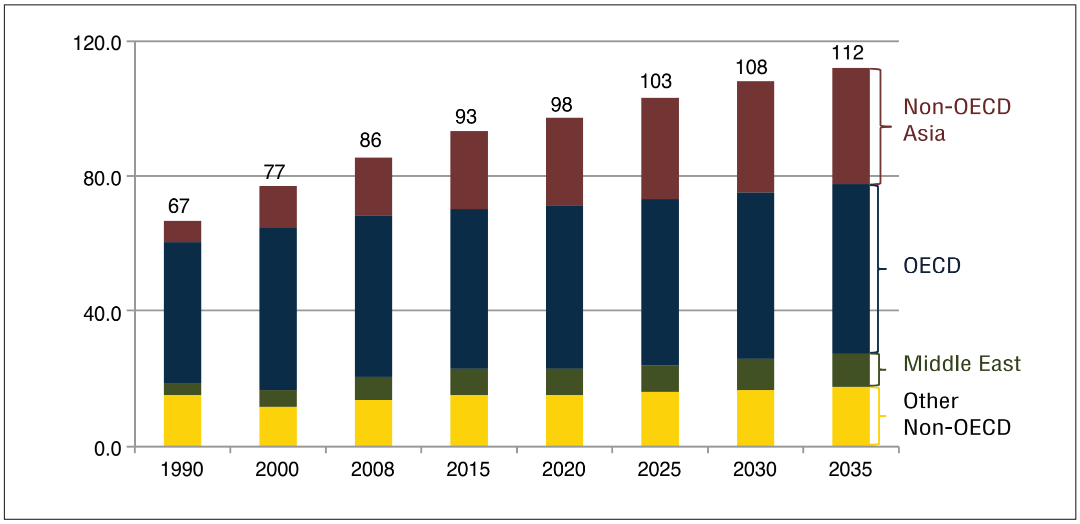
TABLE 1: LIQUID FUELS CONSUMPTION SHARE BY TYPE
(Per cent of 2010 petroleum product demand)

	Motor and aviation gasolines	Jet fuel, heating oil and kerosene, and diesel fuels	Marine bunker fuel and crude oil used as fuel	Total transportation fuel demand
U.S.	48.6%	28.5%	2.9%	80.0%
Europe	22.4%	50.5%	8.1%	81.0%
Latin America	30.1%	36.1%	12.4%	78.6%
Africa	24.4%	45.2%	13.6%	83.2%
Asia/Oceania	30.6%	36.1%	11.6%	78.3%
China	27.1%	39.5%	7.4%	74.0%
Japan	39.1%	31.1%	10.0%	80.2%

Source: BP plc. BP Statistical Review of World Energy, 2011.

In 2008, global demand for liquid fuels was 86 million barrels per day (mmbd). The U.S. Energy Information Administration (U.S. EIA) projects liquid fuels demand will reach 112.2 mmbd by 2035, an increase of 30 per cent.

FIGURE 2: WORLD LIQUID FUEL CONSUMPTION BY REGION 1990 - 2035 IN MMBD



Source: U.S. EIA International Energy Outlook (September 2011).

Historically, the U.S. has been the largest consumer of liquid fuels in the world, consuming 20 mmbd of liquid fuels in 2008, about 23 per cent of total global consumption. U.S. demand has been fairly static for much of the last decade and the EIA projects that U.S. demand will reach only 21.9 mmbd by 2035 or 19.5 per cent of total global consumption.

Conversely, liquid fuel demand in non-OECD Asia,[13] which totaled 16.2 mmbd in 2008, is projected to more than double to 34.4 mmbd by 2035. As previous studies have highlighted,[14] most of this new demand for liquid fuels will be in China. It has been projected that by 2035, China will consume 16.9 mmbd of liquid fuels, accounting for 15 per cent of total global consumption.

Chinese demand for diesel and gasoline will be primarily to support domestic use. Some of the growth in China's demand for gasoline is likely to be tempered by efforts to promote the use of electric cars as a substitute for traditional gasoline-powered automobiles. If electric use increases, the most likely scenario is that residual demand for transportation fuels will be dominated by diesel.[15]

A. Product Demand, Oil Quality and Refinery Configuration

Product demand profiles directly affect/determine refinery configuration and hardware. Refineries are typically designed to manufacture products to supply local or regional markets. For example, in the U.S., refinery configuration and technology has favoured gasoline production, reflecting product demand in the U.S. In Asia, refinery configuration and technology has developed to favour diesel and petrochemical production, reflecting final product demand in Asia.[16]

Crude oil quality affects product yields and refinery configuration as well. Crude oil is typically and most simply classified based on gravity and sulphur content. Both characteristics, as well as the presence of additional compounds, among many others, affect the required refinery technology capability. Crude oil quality and the refining technology mix will define the mix of products that a crude oil can be refined into. Higher sulphur, higher viscosity crude oils, such as Western Canadian Select (WCS), yield more potential residual fuel oil in a refinery that lacks upgrading hardware, such as catalytic crackers, hydrocrackers, cokers and other residual upgrading necessary for heavy oil refining. In more sophisticated refineries, WCS is further processed — e.g. "coked" and "cracked" — in order to shift from fuel oil production to greater yields of higher-value products, such as gasoline and diesel fuel. The number of steps involved, taking a heavier and higher sulphur crude to the highest-value slate of products, reflects the higher cost of processing and the lower aggregate value of the entire delivered product mix. For a more detailed discussion of crude oil quality and refining please see Appendices A and B.

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[13] The major non-OECD economies include China, India, and Indonesia. Appendix C includes a complete list of EIA regional definitions.

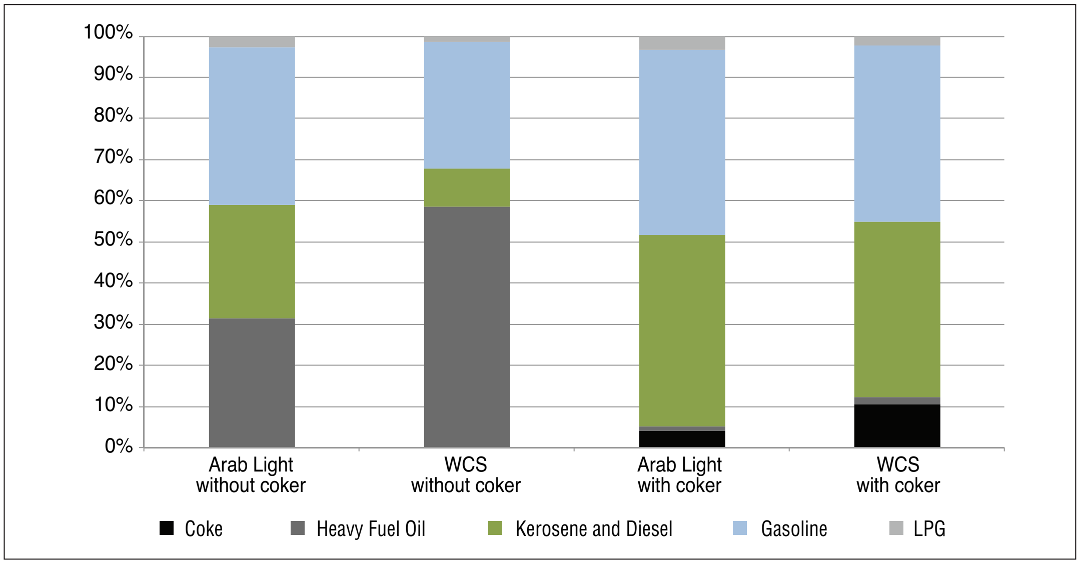
[14] M.C. Moore et al.,"Catching the Brass Ring" (December 2011); "Market Prospects and Benefits Analysis for the Northern Gateway Project," Muse Stancil (January 2010); and Harold York, "A Netback Impact Analysis of West Coast Export Capacity" Wood Mackenzie (December 2011).

[15] Alan Troner, *The Rise of China and Its Energy Implications: China's Oil Sector: Trends and Uncertainties*, Energy Forum of the James A. Baker III Institute for Public Policy at Rice University (Houston, Texas: 2011).

[16] In Asia, generally, petrochemicals are produced from liquids that might otherwise be gasoline. In the U.S., a large portion of petrochemicals tend to be produced from natural gas liquids (ethane, propane, etc.), which diminishes the demand for petrochemicals from crude oil.

Refinery yield is a convenient proxy for the efficiency of the processing facility and the suite of distillate products that it yields. This is not only a function of the processing technology but the raw product characteristics; thus, the addition of coking capacity changes the yield to a more useful, valuable and competitive suite of products, from the same volume of input crude supplies. Figure 3 below illustrates the estimated product percentage yields for WCS and Arabian Light for refineries of different configurations.[17] The relationship of additional coking capacity with higher value-added products such as gasoline, kerosene and diesel is apparent in the representative share fractions of the final yields.

FIGURE 3: ESTIMATED REFINERY YIELDS



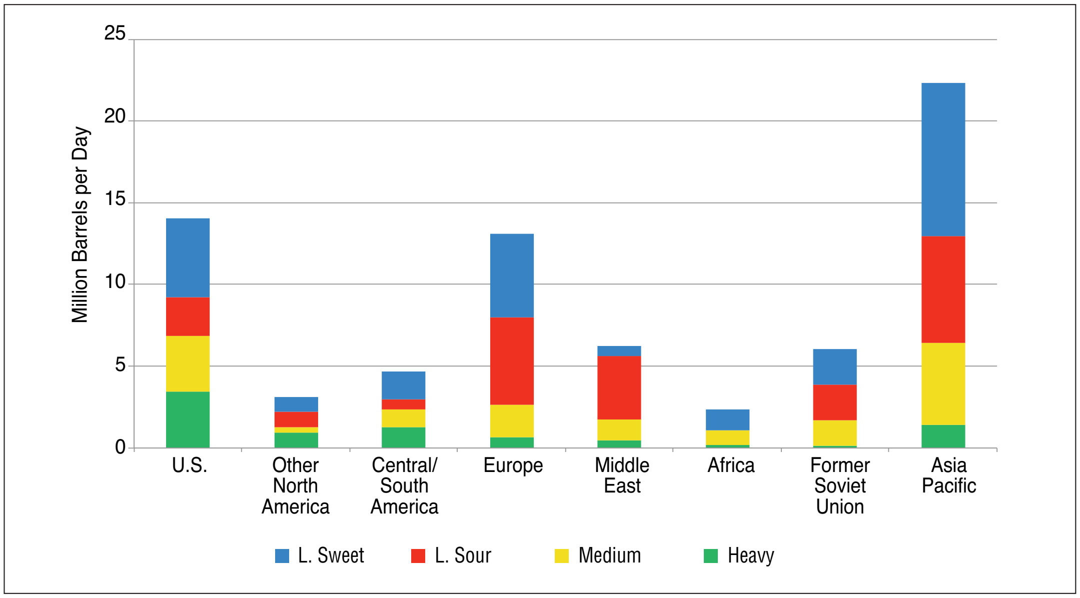
Source: Stillwater estimates.

U.S. refineries, especially in PADD III, have made significant investments in complex refining hardware to support processing heavier, higher sulphur crude into gasoline and other refined distillates. Similar investment has been pursued less vigorously outside the U.S.,[18] in part because of higher capital costs as well as higher residual fuel demand. The following chart illustrates this trend; about 75 per cent of crude processed in Europe in 2010 was comprised of light sweet and light sour grades. In the Asia-Pacific region, light sweet and sour crudes accounted for about two-thirds of total crude inputs.

[17] The refineries chosen are intended to represent average characteristics for the two oil blends, Arabian Light (light API) and WCS (heavy API), with similar sulphur content.

[18] This trend is not entirely consistent. For instance, India, China and Brazil have been particularly aggressive in adding upgrading capacity. These investments were made: 1) because of diminishing demand and price for residual fuel oils, 2) because of prospects to reduce raw material costs, and 3) as a function of the scale of refineries and refinery activities.

FIGURE 4: WORLD REFINING CAPACITY BY GRADE



Source: Lynn Westfall, "The Oil Refinery Buildout," Turner, Mason and Company. Presented at the Midstream Summit, Houston, Texas (March 2, 2011).

In articles in the popular and academic press, there are strong indications that there is significant interest in and investment directed at expanding heavy crude processing capacity outside the U.S., notably in China and India, including investment in coking, fluid catalytic cracking (FCCU) and hydrocracking capability. Investment in heavy upgrading capacity creates flexibility for a refinery, increasing the range of crude qualities that can be processed.

A recent forecast[19] anticipated that investment in expanding heavy crude processing capacity would continue and that crude slates worldwide would shift toward heavy, higher sulphur crude oils. However, global crude production balances are shifting dramatically with the identification and development of tight oil formations, which produce lighter, lower sulphur crudes. This development may slow additional investment in heavy crude oil processing capacity.

B. Production Characteristics

The U.S. EIA's International Energy Outlook (2011) reference case projects that the increase in liquid fuels demand will be supplied by an increase in both conventional and unconventional liquids. The EIA defines crude oil, lease condensate and natural gas plant liquids as conventional liquids, and biofuels, oil sands, extra-heavy oil, coal-to-liquids (CTL), gas-to-liquids (GTL) and oil from shale formations as unconventional liquids. The EIA projects that OPEC's share of liquids production will remain at 42 per cent as OPEC producers opt to limit investment in production capacity below a level justified by high oil prices. This suggests a conservative outlook for demand, even though the EIA reference case forecasts sustained high world oil prices.

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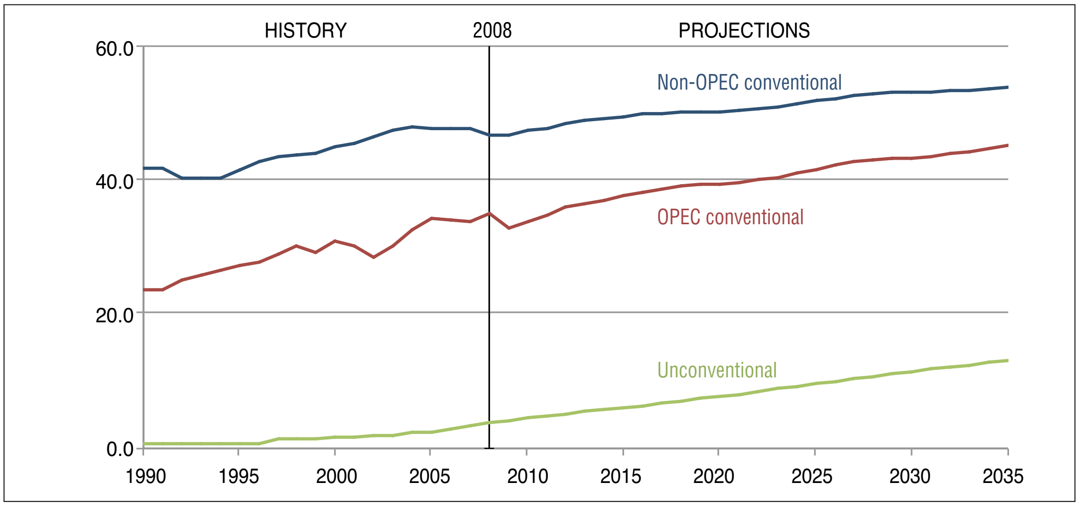
[19] Lynn Westfall, "The Oil Refinery Buildout," Turner, Mason and Company. Presented at the Midstream Summit, Houston, Texas (March 2, 2011).

FIGURE 5: WORLD LIQUID FUELS PRODUCTION IN MMBD

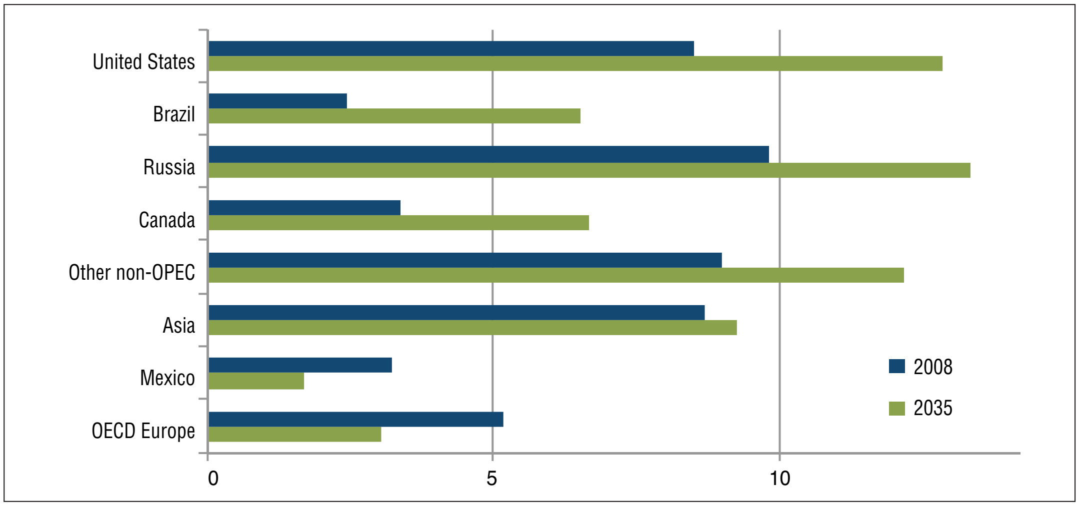


Source: U.S. EIA International Energy Outlook (September 2011).

In contrast, the BP Energy Outlook 2030[20] projects that the majority of the growth in global liquid fuels production will come from increases in OPEC production from Saudi Arabia and Iraq. BP projects OPEC's market share will increase to 45 per cent, its highest level since the 1970s.

The high oil prices in the EIA reference case support the development of production from high-cost areas such as ultra-deep water formations, the Arctic and the oil sands. The U.S. EIA projects that non-OPEC liquids production, mainly from Russia, the United States, Brazil, and Canada, will contribute up to 57 per cent of the total increase in liquids production by 2035. BP is less optimistic about the non-OPEC share of increased production. The difference in outlook confirms the uncertainty in global growth trends, recovery from the lingering recession, and ultimately, the shift in shares of liquid versus gaseous fuels in the future.

FIGURE 6: NON-OPEC LIQUIDS PRODUCTION BY REGION, 2008 AND 2035, IN MMBD



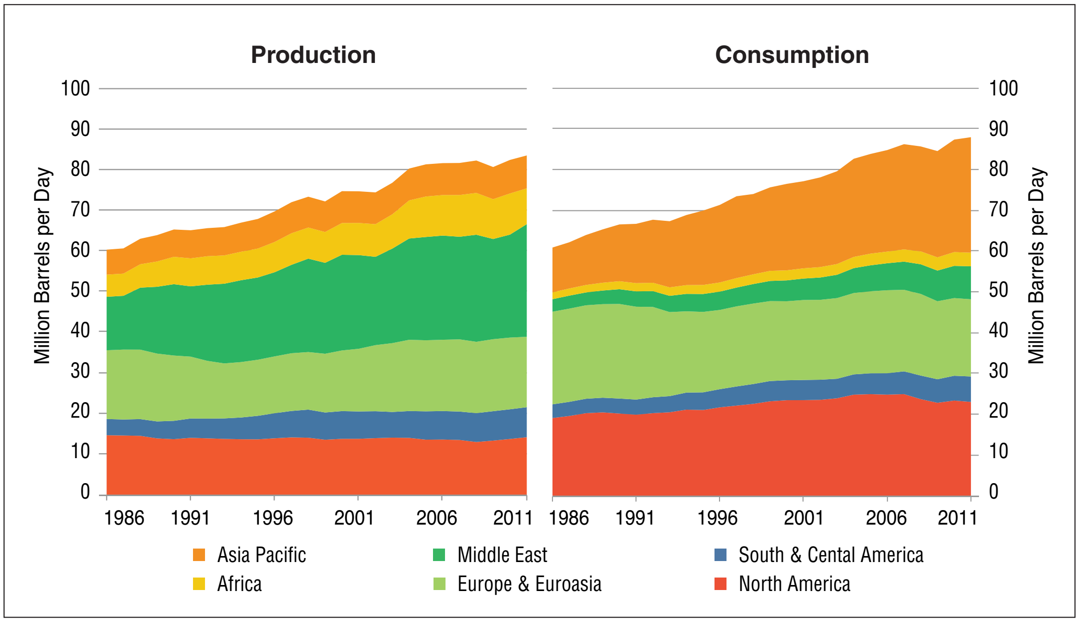
Source: BP plc. BP Statistical Review of World Energy (June 2012).

[20] BP plc. *BP Energy Outlook 2030* (January 2012). http://www.bp.com/sectiongenericarticle800.do?categoryId=9037134&contentId=7068677

The U.S. EIA projects unconventional resources will become increasingly competitive going forward, with the potential to become the dominant production source in the future. However, the EIA notes that development of unconventional crude oils depends on the resolution of environmental and investment concerns.[21] The EIA also notes that production of biofuels, CTL, and GTL, requires sustained high prices and country-specific programs or mandates. The EIA projects that by 2035 global production of unconventional liquids will reach approximately 13.1 mmbd.

Crude oil production and demand for non-upgraded products do not balance regionally. Additionally, in terms of refined products, North America, the Asia-Pacific region and Europe and Eurasia all consume more than is produced regionally. This is clear from Figure 7, which highlights an increasing imbalance in regional distribution. In Asia, the imbalance is more evident as demand is forecast to increase in the near term. Changes in existing inventory and short-term storage patterns are showing signs of change — for instance where Singapore has encountered space restrictions, and both PetroChina and Sinopec have begun acquiring storage facility capacity in Indonesia and Malaysia.[22]

FIGURE 7: DISTRIBUTION OF OIL BY REGION IN MMBD



Source: BP Statistical Review of World Energy (June 2012).

[21] Environmental concerns in the case of Canada's oil sands projects, and hydraulic fracturing (fracking) in North America. Investment concerns are due to investment restrictions in the case of Venezuela's extra-heavy oil projects.

[22] Reuters, "China's Sinopec to Build $850M Oil Storage in Indonesia," October 10, 2012. http://www.reuters.com/article/2012/10/10/energy-sinopec-indonesia-idUSL3E8LA0VK20121010

TABLE 2: PETROLEUM PRODUCTION AND CONSUMPTION IN THE PACIFIC BASIN IN KBD

Thousand barrels daily	**Oil: Production**[1] 2011	**Oil: Consumption**[2] 2011	**Net Oil Production** NET
Total North America West Coast *(3)*	**1,186**	**2,623**	**(1,437)**
West Coast South America			
Chile	–	327	(327)
Ecuador	509	226	282
Peru	153	203	(50)
Total West Coast South America	**661**	**756**	**(95)**
Australia and New Zealand			
Australia	484	1,003	(519)
New Zealand	–	148	(148)
Total Australia and New Zealand	**484**	**1,151**	**(667)**
South West Asia			
Bangladesh	–	104	(104)
India 858	3,473	(2,614)	
Pakistan	–	408	(408)
Total South West Asia	**858**	**3,985**	**(3,126)**
South East Asia			
Brunei	166	–	166
Indonesia	942	1,430	(489)
Malaysia	573	608	(35)
Philippines	–	256	(256)
Singapore	–	1,192	(1,192)
Thailand	345	1,080	(735)
Vietnam	328	358	(30)
Total South East Asia	**2,354**	**4,925**	**(2,571)**
East Asia			
China	4,090	9,758	(5,668)
China Hong Kong SAR	–	363	(363)
Japan	–	4,418	(4,418)
South Korea	–	2,397	(2,397)
Taiwan	–	951	(951)
Total East Asia	**4,090**	**17,887**	**(13,798)**
Other Asia-Pacific	**300**	**353**	**(53)**
TOTAL PACIFIC RIM	**9,933**	**31,680**	**(21,747)**

Source: BP Statistical Review 2012, Historical Data (http://www.bp.com/sectionbodycopy.do?categoryId=7500&contentId=7068481).

(1) Includes crude oil, shale oil, oil sands and natural gas liquids (NGLS – the liquid content of natural gas, where this is recovered separately). Excludes liquid fuels from other sources such as biomass and coal derivatives.

(2) Oil consumption data includes inland demand plus international aviation, marine bunkers and oil products consumed in the refining process. Consumption of fuel additives and substitute fuels, and unavoidable disparities in the definition, measurement or conversion of ethanol and biodiesel is also included.

(3) British Columbia, Alaska, Washington, Oregon and California. EIA and Canadian Centre for Energy Information (2010 data).

In 2011, Westfall noted that previously announced world refining capacity expansions and upgrades through 2017 overwhelmingly favoured medium and heavy crude oils, especially in North America and Asia, often at the expense of light crudes.[23] Westfall also noted that projected increases in world crude oil production out to 2021 were mostly light sweet and light sour grades of crudes. This mismatch between the quality of crude production and the quality of crude demand could become significant given the more aggressive projections for production of tight oil from shale formations in the U.S. and Canada.[24] The mismatch ultimately will affect the price relationship between light and heavy crudes by reducing the premium for lighter crudes, favouring not only refineries with light sweet capacity, but also affecting investment and planning for future heavy crude refining capacity expansion. As shown in Table 3 below, the production/demand balance[25] in the Western Canadian Sedimentary Basin is influenced by the range and diversity of demand sources, each of which addresses not only different markets, but also different processing and treatment technologies.

TABLE 3: 2011 PRODUCTION/DEMAND BALANCE

	2011 kbd
Alberta Production	
Oil Sands	1,039
Conventional Heavy	269
SCO	835
Conventional Light	561
Other Western Canada Production	151
Total Production	**2,855**
Demand	
Canada	
Alberta	424
Ontario	298
Quebec	3
Atlantic	0
Rest of Canada	152
PADD II (Midwest)	1,430
PADD III (Gulf Coast)	129
PADD IV (Rockies)	234
PADD V (West Coast)	175
Asia-Pacific	10
Total Demand	**2,855**

Source: Wood Mackenzie, Statistics Canada, National Energy Board, EIA.

23 Lynn Westfall, "The Oil Refinery Buildout" (March 2, 2011).

24 The recent ERCB report, "Summary of Alberta's Shale- and Silicone-Hosted Hydrocarbon Resource Potential," estimates there are 423.6 billion barrels of shale oil. The ERCB report notes the 2011 EIA report on shale oil estimates 24 billion barrels of oil in the U.S.

25 Production and supply/demand balance is a broad and variable characteristic that reflects average conditions of equilibrium between production and demand regionally, within the entire market.

Production totaled about 2,855 kbd in 2011. Note that demand for Canada in Table 3 represents demand for *Western Canadian crude*, as statistics detailing demand for the full range of Alberta crude are not available. In 2011, Canadian refineries processed 877 kbd of Western Canadian crude, with about 2,000 kbd directed to U.S. refineries and 10 kbd exported to the Asia-Pacific region. The Trans Mountain pipeline, operating at its maximum capacity of 300 kbd, supplies west coast exports to Asian markets and PADD V. We note that in order for crude oil production to grow, future growth must be matched with growth in take-away capacity.

C. Production Logistics

Shipments from Canada's Pacific Coast ports[26] will be governed by the key issues of suitability, logistics and politics. This section examines logistics from the perspective of competitive costs.

There are two proposed Pacific Basin pipeline projects: the Trans Mountain expansion through Burnaby, B.C., which would effectively triple current capacity, and the Northern Gateway project, which would provide a twin oil-export/condensate-import pipeline between Alberta and the northern B.C. coast. If both pipeline projects are developed, it is likely that shipments out of Kitimat would go long distances on large-capacity ships. Movement of crude supplies originating in Vancouver should satisfy U.S. West Coast demand before the first barrel crosses the Pacific to Asia.

The Northern Gateway pipeline is planned to deliver 525 kbd of oil from Alberta to Kitimat by 2017.[27] The Trans Mountain pipeline's current capacity is 300 kbd to Burnaby. From there, the oil travels via pipeline and rail to Anacortes and by ship to Pacific Basin refineries. TMPL has plans to expand the capacity to 890 kbd. This analysis assumes that the two lines have the incremental capacity to move about 1.1 million barrels a day from Alberta to the Pacific Coast.

From a logistics perspective, these issues are best described using a comparison of ton/miles in transport. Simply put, a large tanker can deliver more tons of crude oil than a small tanker, and a long distance is more expensive to travel than a shorter distance.

Relative to ship size, Kitimat has an advantage over Vancouver because Kitimat will be able to load Very Large Crude Carriers (VLCC) with capacities of 2.0 mmbd or greater. Kinder Morgan's Westridge terminal at Port Metro Vancouver will not be able to load VLCCs because of draft (water depth) restrictions. Loadings at Westridge are restricted to 120,000 deadweight tons or about 0.9 mmbd, as a function of individual tanker configuration.[28] Kinder Morgan has announced plans to expand the Westridge terminal.[29]

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[26] Currently, the only access to the Pacific coast is through the Kinder Morgan pipeline (to Port Metro Vancouver) or by rail. If approved in 2013, the Enbridge Northern Gateway pipeline to Kitimat could be online as soon as 2017. U.S. West Coast refineries have technology that is suitable to process heavy Canadian crude oil and are close to Vancouver and Kitimat. Refineries in Korea, Taiwan, and China could have an appetite for WCS barrels as well.

[27] See Enbridge's timeline (http://www.northerngateway.ca/project-details/timeline/) for details.

[28] "Market Access through Canada's West Coast for Natural Gas and Crude Oil," Canadian Association of Petroleum Producers (November 2011), p. 25.

[29] "Trans Mountain Expansion Receives Strong Binding Commercial Support," Kinder Morgan press release (April 12, 2012). http://www.businesswire.com/news/home/20120412006258/en/Trans-Mountain-Expansion-Receives-Strong-Binding-Commercial.

The mile portion of the concept can be expressed as the distance between the load port and the discharge port. Table 4 (below) illustrates the distance between the B.C. load ports and potential discharge ports. Also illustrated are the distances from the load ports of competitive crude oil sources in Saudi Arabia and Venezuela. In the rightmost columns, we calculate the difference in distance between Kitimat and the refining centres, relative to movements from Saudi Arabia and Venezuela. This illustrates, for example, that Guangzhou is approximately equidistant from Saudi Arabia and the west coast of Canada.

TABLE 4: TRANSPORT DISTANCE

Discharge Port	Load Port to Discharge Port Distance (Nautical Miles)				Kitimat vs.	
	Vancouver, B.C.	Kitimat, B.C.	Ras Tanura, Saudi Arabia	Puerto la Cruz, Venezuela	Ras Tanura, Saudi Arabia	Puerto la Cruz, Venezuela
Martinez, California	855	1,052	11,392	4,216	(10,340)	(3,164)
Los Angeles, California	1,174	1,387	11,672	3,894	(10,285)	(2,507)
Tokyo, Japan	4,283	3,933	6,929	8,699	(2,996)	(4,766)
Ulsan, Korea	4,644	4,697	6,532	9,076	(1,835)	(4,379)
Dalian, China	5,170	5,057	6,607	9,608	(1,550)	(4,551)
Guangzhou, China	5,843	5,526	5,483	10,213	43	(4,687)
Kaoshung, Taiwan	5,545	5,526	5,674	9,961	(148)	(4,435)

Sources: Searates.com, Portworld.com

It is worth noting that Kitimat is about 10,000 nautical miles closer to California than Ras Tanura, Saudi Arabia, and 3,000 miles closer to California than Venezuela. The California refineries all have draft restriction such that, for short distances, it is more economical to use tankers smaller than VLCCs. California refiners today do move crude from Ras Tanura on VLCCs, but these ships draw too much water to get into the ports in Los Angeles or San Francisco Bay. The cargo on these ships is shuttled ashore in smaller tankers via an operation known as lightering.

FIGURE 8: DISTANCES FROM LOAD PORTS TO SOUTHERN CHINA

Figure 8 illustrates that the distance from B.C. to Southern China is about the same as from Saudi Arabia and roughly half of the distance from Venezuela to Southern China. Movements from Saudi Arabia and Kitimat would be made by VLCCs. In this illustration, the Venezuelan crude is tankered to Panama, moved by pipeline across the isthmus, and then loaded onto a VLCC for the voyage to Asia. Shipments on smaller tankers from Vancouver to Asia would be less competitive than large ships from Kitimat because of the distance.

Wood Mackenzie estimates the shipping cost from B.C. to the U.S. West Coast at $1.60 per barrel, and the cost to China at $3.00 per barrel.[30] The cost to tanker crude from Venezuela to Asia is likely more than twice the cost of shipping from Canada because of the distance and the complexity of the movement. It is useful to note that while these costs are a small percentage of current crude oil prices, companies are constantly looking to reduce these costs as much as they can, consistent with good operating policy and safety.

D. Demand Summary

The Pacific Basin offers a valuable prospective market for Canadian crude oil over the next 20 years, according to available data and forecasts. Oil demand in the region is growing and refinery capacity is growing to meet anticipated demand. However, this market will attract a significant level of competition from alternative crude oil suppliers, many with crude oils that require less upgrading than the WCS blend. Supplying the Pacific Basin will entail a varying range of discounts in order to remain competitive, reflecting the increased cost of shipping in addition to the quality discount inherent in the heavy oil itself.

In the following section we consider the regions and countries in the Pacific Basin from the standpoint of potential demand for Canadian crude oil, represented by Western Canadian Select.

IV. THE PACIFIC BASIN

The Pacific Basin, including India and Bangladesh, has more than 24 million barrels of refining capacity and approximately 28 per cent of the world's total refining capacity of 88 million barrels.

Eastern Asia, which includes China, Taiwan, South Korea, North Korea and Japan, has the largest concentration of refineries and two-thirds of total Pacific Basin refining capacity. Table 5 lists refining capacities for the Pacific Basin countries by region and by country.

[30] Harold York, "A Netback Impact Analysis of West Coast Export Capacity," Wood Mackenzie (December 2011), p. 15.

TABLE 5: PACIFIC RIM REFINERY CAPACITIES (2012, BARRELS PER DAY)

Region	Number	Capacity	Coking	FCCU/ RFCC	Hydrocracking
South America West Coast	25	693,650	13,860	158,540	50,400
Mexico & Central America West Coast	4	396,000	50,000	80,000	0
Canada & U.S. West Coast	29	3,260,225	539,390	836,170	570,250
Australasia	8	867,148	0	235,043	48,407
Southeast Asia	27	3,937,157	56,580	335,140	308,153
East Asia	96	15,736,390	349,400	2,106,880	718,190
TOTAL PACIFIC BASIN	**189**	**24,890,570**	**1,009,230**	**3,751,773**	**1,695,400**
SOUTH ASIA	**25**	**4,114,761**	**174,825**	**531,305**	**166,800**
TOTAL WORLD	**655**	**88,055,552**	**4,681,023**	**14,693,328**	**5,488,694**

Source: "Worldwide Refineries – Capacities as of January 1, 2012," Oil and Gas Journal, Dec. 5, 2011.

FCCU is fluid catalytic cracking units and RFCC is residual fluid catalytic cracking.

The data is derived from the *Oil and Gas Journal*'s Annual Refining Survey.[31] This survey is one of the most widely used and is a well-respected source of refining industry capacity data; however, we note that the quality of the statistical data from non-OECD countries is often problematic. The survey depends on self-reporting of capacity information by refiners. Not all countries have effective mechanisms and procedures in place for collecting and vetting the data. This is particularly true for China, which has the largest refining base in Asia and the largest refining base outside the U.S.[32]

The attractiveness of heavy crude oil to refiners in the Pacific Basin varies and depends on several factors. As we noted earlier, refinery configuration is key to processing heavy, high sulphur crude oil, especially heavy crudes with the high sulphur, high trace metals and high acid number that characterize Western Canadian Select (WCS). Please refer to Appendices A and B for additional information on crude refining and Western Canadian Select crude.

Extracting full value from any heavy oil such as WCS requires coking or other residual upgrading that is compatible with the high metals content.[33] In addition, a variety of technologies, including fluid catalytic cracking and hydrocracking, desulphurization capability, and ancillary sulphur recovery and hydrogen production capacity, will be required to upgrade the other products of the crude and the liquid products of the coker. Without these processes, production of low-value residual fuel oil will be high, product quality will be low, and the resultant products likely unmarketable or priced at a significant discount. In addition, without the proper metallurgy, refinery hardware could be affected by high levels of corrosion in pipes, containment vessels, pumps and other equipment.

Coking is usually the preferred process for upgrading poor-quality residuals. As residuals are not distilled overhead as vapour during distillation, the non-volatile materials such as trace metals and asphaltenes remain in this bottom cut, which is used as the coker feedstock. Coking is a non-catalytic process that uses thermal cracking to convert a portion of the residual to

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31 In addition to the Oil and Gas Journal survey data, the website "A Barrel Full" (http://abarrelfull.wikidot.com/home) and company websites were used as a reference in developing refinery data.

32 As noted in the discussion of Chinese refinery capacity below, there is a large discrepancy between this data and data from analysts who cover the sector.

33 A high concentration of trace metals will poison conventional catalytic processes.

liquid streams that can be further processed in the refinery, leaving behind solid residual coke in "coke drums" that are regularly taken off-line to remove the coke. In the drums, the oil and asphaltene components are cracked to lighter liquids and gases, or they are converted to coke, and almost all of the metals are deposited with the coke. The yield of coke depends on the properties of the coker feedstock and normally varies from 20 to 40 by weight per cent solution (wt%) on the base.

The attractiveness of a given type of crude to a refinery is also a function of proximity. In countries that produce crude for export or domestic use, refineries have typically been configured to process local crude types because they are readily available and their use minimizes transportation costs. To access crudes from distant supply regions, refineries must have access to ports that can receive the crudes, either directly from large tankers or indirectly by transfer mechanisms such as pipes or rail systems.

Occasionally, a refinery's crude selection decision is dictated by owner preference. Refineries that are owned, wholly or partially, by crude producers are often specifically configured to process the producer's crude, sometimes to the exclusion of other crudes. In addition, crude selection decisions are often affected by overriding political or economic partnerships between producers, owners and regional or national governments. Lastly, and as noted previously, product demand profiles affect crude selection decisions.

An assessment of attractiveness of Western Canadian Select crude oil to each of the Pacific Basin regions characterized in Table 5 (above) follows. We evaluate *attractiveness* based on refinery configuration, product demand, refining capacity, shipping considerations and preference dictated by ownership and relationships, as appropriate.

Projecting refining capability from aggregate data covering numerous refineries in many locations with widely varied configurations has inherent inaccuracies. It is far more accurate to project the capability of a few refineries of similar configuration that are geographically clustered. Every refinery has bottlenecks in its processing configuration, or ancillary processes such as hydrogen or sulphur recovery that defines its capabilities. Aggregated data obscures the bottlenecks of each individual refinery by combining capacities with other refineries' capacities that are not bottlenecked in those processes. In this way, aggregate data can overestimate capability or underestimate the need for investment. Without detailed information on each refinery in some regions, we couple aggregated refining data with publicly available information on specific refineries to draw our conclusions.

Finally, the so-called elephant in the room is the increase in conventional and unconventional oil in previously shut-in basins in the U.S. Midwest and Southwest, and production from the Bakken formation in the upper Midwest. These production sources have the potential to displace a significant fraction of Canadian heavy oil supplies, forcing a deeper discount in current markets, or potentially stranding some current production. Displaced Canadian oil may ultimately be processed in North American sites on the West Coast if regulatory standards are relaxed, or may be added to exports from Canadian ports serving Asian markets.[34] However, significant market challenges from these continental sources can disrupt the overall market balance and destination pricing. Long-term agreements on shipping standards, new pipeline or storage facility approvals, and U.S. market access must be factored in when assessing the nature of the entire market, not simply those markets reached through Pacific tidewater ports.

[34] There is also potential for processing in Eastern Canada if Enbridge's proposal to reverse Line 9 or TransCanada's suggested changeover of its mainline from gas to oil are approved.

A. Regional Evaluations

The regions of the Pacific Basin will be examined in turn, beginning with the Eastern Pacific Basin, before continuing to the Western Pacific Basin. Each side of the Pacific will be taken south to north.

I. SOUTH AMERICAN PACIFIC COAST: CHILE, COLOMBIA, ECUADOR AND PERU

Prospects for WCS in refineries on the West Coast of South America are poor due to refinery configurations. The only coker in the region is Chile's Empresa Nacional del Petróleo (ENAP) Biobio refinery; ENAP Biobio has minimal desulphurization capacity to allow for processing of high-sulphur crude oil, such as WCS. In addition, while some refinery expansions have been announced for this region, these new refineries will target local or regional crude production that would otherwise be destined for export.

II. MEXICO AND CENTRAL AMERICAN PACIFIC COAST: COSTA RICA, EL SALVADOR, SALINA CRUZ (MEXICO) AND NICARAGUA

Refineries in this region predominantly lack upgrading capacity (except for Mexico's Pemex Salina Cruz refinery), making WCS a poor crude choice. WCS is also a poor choice for the Salina Cruz refinery as it processes heavy crude oil from the Bay of Campeche, supplied by pipeline across the isthmus of Mexico. We note that Pemex has recently installed a large coking unit at Salina Cruz to upgrade residual fuel oil.

The Recope refinery in Costa Rica will be expanded in 2015 from a 25 kbd capacity to 60 kbd in a project funded by the China Development Bank, with some participation from the China National Petroleum Corporation (CNPC).[35] After the expansion, the refinery will be able to process heavy crudes; however, WCS is not a good fit given the proximity of heavy crude production from South America (where CNPC has producing assets), and from Mexico.

III. CANADA AND THE U.S. WEST COAST

Refineries in California and Washington have considerable coking capacity and even those refineries without coking capacity may be interested in processing small amounts of WCS to make asphalt or fuel oil. Refineries in Washington are supplied partially with crude oil from Western Canada via the Trans Mountain pipeline system. Two of the five refineries in Washington state — BP's Cherry Point and Shell's Anacortes refineries — are refineries with available coking capacity. Historically, both have processed North Slope crude from Alaska, along with Canadian and other imported crudes, and are expected to continue processing North Slope crude as long as it is available. The refineries are configured to process a medium gravity crude mixture and could process WCS as part of a mix with higher quality grades. Recent studies by Muse Stancil and Wood Mackenzie estimated an appetite for about 50 kbd of heavy Canadian crudes in Washington refineries, which can be delivered by the existing Trans Mountain pipeline system. As the logistics to deliver already exist, any demand for WCS from the Washington refineries should not be considered as an incremental heavy crude market.

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[35] "China to Fund Costa Rica Refinery Revamp," Reuters (http://www.reuters.com/article/2011/12/06/costarica-idUSN1E7B41JZ20111206), December 5, 2011.

The California refining system is specifically tailored to process heavy, high-metals, high-acid crude oils where the key product is primarily gasoline. Historically, California has processed a limited amount of Canadian crude oil, shipped from West Coast ports. However, new opportunities for future deliveries of WCS to California refineries may emerge as the production of heavy crude in California in the Kern River Basin declines. The immediate prospects for continuing to refine WCS-type crudes in California are nevertheless uncertain because, at least on paper, California's Low Carbon Fuel Standard (LCFS) penalizes crude oil production methods with higher carbon intensity relative to conventional production methods.

However, while final regulations for high carbon-intensity crude oils have not yet been adopted, a final ruling and final language from the California Air Resources Board are expected in 2013; further implementation may be delayed indefinitely with the likelihood of a future court appeal. Should this standard be modified and made more permissive in the future, WCS would be a good fit for California refineries. We estimate that 300 kbd of WCS could be supplied to California, ultimately displacing other crude oil.[36] We note that Muse Stancil is more optimistic about potential supply to California, having estimated that California could refine 450 kbd of WCS. However, we believe that the actual capability will be lower due to logistical and capacity constraints not comprehended in the Muse Stancil methodology. We expect that WCS volume could increase over time with a continued decline of California heavy crude oil production from the Kern River Basin.

The refineries in British Columbia, Alaska and Hawaii have technology that generally excludes WCS as a competitive or price-effective production source. Moreover, few future refinery expansion projects have been announced for the U.S. West Coast. Instead, it is expected that refinery capacity in California may decrease as refineries in California are faced with declining demand due to displacement by renewable or alternate fuels required by the LCSF regulation.[37]

IV. AUSTRALASIA: AUSTRALIA AND NEW ZEALAND

There are eight refineries in this region. These refineries are designed to process light crudes and condensates that are indigenous to the region. There is no coking capacity, and future plans focus on processing condensates associated with natural gas production to produce liquid natural gas (LNG). The prospects are very poor for expanding WCS-type crudes sales in this region.

V. SOUTHEAST ASIA: INDONESIA, MALAYSIA, PAPUA NEW GUINEA, THE PHILIPPINES, SINGAPORE, THAILAND AND VIETNAM

The Southeast Asian region has refining capacity of just under 4 million barrels per day. The region has significant local crude production and easy access to crude imports from Africa and the Middle East. In addition, there is a total of only 57 kbd of coking capacity in two refineries: the Petromin Dumai refinery and the Petronas/Conoco Malaka II refinery. The Dumai refinery processes indigenous sweet Sumatran crudes, since it is located at the export terminal in Sumatra. The Malaka II refinery processes primarily medium gravity, high sulphur crudes from the Middle East.

[36] Analysis of the EIA company-level import data reveals that, in 2010, imports of crude oil heavier than 25 API into California totaled 373 kbd, of which 52 kbd was Canadian and 321 kbd was from other countries.

[37] "Understanding the impact of AB 32" The Boston Consulting Group (June 19, 2012). Accessed December 5, 2012 at http:// www.cafuelfacts.com/wp-content/uploads/2012/07/BCG_report.pdf.

Most refineries in the region process locally produced low sulphur crudes as well as condensates and crudes imported from the Middle East and Africa, and use residual fluid catalytic cracking (RFCC). RFCC is an alternative to coking for converting the heaviest part of the barrel when the crude quality is high. RFCC technology is not appropriate for crude oil with high metals (nickel and vanadium) content, as the metals will render the catalyst ineffective. RFCC is an effective technology for heavy and light crude oils with low to medium sulphur content and low metals content. RFCC technology is sometimes coupled with residual oil hydrotreaters to process crude oils with medium metals and sulphur content. The metals levels of WCS and similar crudes are too high to process using conventional residual hydrotreating, and coking is preferred since the metals are rejected in the solid coke product.

A number of refinery expansions and new refinery projects in the region have been announced, although most have not yet secured funding for construction. Two new projects that appear to be proceeding are the Pengerang Johor refinery in Johor, Malaysia, and the Nghi Son Refinery in Vietnam. The Pengerang refinery is part of a new 300 kbd refining and petrochemical complex being undertaken by Petronas. The Pengerang refinery has been designed to process imported crudes and is scheduled to be completed in 2016. The Nghi Son Refinery is a joint venture between Vietnam Oil and Gas Group, Kuwait Petroleum International, Idemitsu Kosan Co., Ltd. and Mitsui Chemicals Inc. The 200 kbd refinery is scheduled for completion in 2015 with Kuwait Petroleum International committed to supplying the refinery's crude needs.

Given the minimal existing coking capacity, the refining/upgrading technologies in place, the RFCC technology and residual oil hydrotreating capacity available, and the preference for local and Middle Eastern crudes, the prospects in the region for WCS-type crudes are limited in the short term. If inexpensive, very heavy crudes become available, new refineries or refinery modifications may be initiated to take advantage of the heavy crude processing opportunity, but there is no indication of this currently.

VI. SOUTH ASIA: INDIA AND BANGLADESH

The refining capacity of South Asia, primarily in India, is substantial at over 4 million barrels per day and it is growing rapidly. India's crude production, which is mostly light and sweet, falls well short of meeting domestic demand, and historically India has imported substantial amounts of crude oil (2.2 mmbd in 2010) primarily from the Middle East, and mostly from Saudi Arabia. As refineries in this region are a long sailing distance from Canada's Pacific Coast — especially relative to their distances from sources of crude production in the Middle East — they are not considered good candidates for Canadian crudes. We do note, however, that the Indian refining system is employing technology that supports processing heavy, high sulphur, high metals crude in its crude mix.

VII. EAST ASIA: CHINA, TAIWAN, SOUTH KOREA, NORTH KOREA AND JAPAN

East Asia provides the most promising markets for WCS because of its proximity to the Western Canadian production point and because of the hardware configuration of its refineries. Almost all of the refining capacity in the region is located in China, Japan, South Korea and Taiwan, and we focus our discussion primarily on those countries. There are a few refineries in North Korea and on Russia's East Coast, but little information about their characteristics is publicly available. As a consequence, the remainder of this discussion is focused primarily on the high-demand areas of China, Japan, South Korea and Taiwan.

a. Japan

Japanese refining capacity totals 4.7 mmbd. Japan's refineries process light crude that is on average 35.7 degrees API.[38] The configuration of the Japanese refineries, however, could support some processing of heavy, sour, high metals crude oil. According to the *Oil and Gas Journal*, four refineries in Japan do have coking units, and a fifth coker is under construction. However, the refineries are much better suited to refining light and medium crudes in the coking mode. Technically, some small amount (less than 50 kbd) of heavy, high sulphur, high metals crude could be processed if it were attractively priced. However, processing of WCS-type crudes would de-rate (lower the rated capabilities of) effective crude processing capacity and may require modifications to the refineries. As a result, the general prospects for processing WCS-type crude with low API gravity, high sulphur content and high concentration of metals is poor — though as noted in prior studies, Japan could offer a good market for Canadian SCO.[39]

b. South Korea

The refining industry in South Korea is characterized by five large-capacity refineries and one small refinery. Several of the refineries are coupled with petrochemical complexes and the refineries supply petrochemical feedstock and take receipt of by-product streams.

Of the six refineries in South Korea, one is a small lube oil refinery. The average capacity of the five other refineries is 550 kbd. As South Korea has no domestic petroleum reserves, it imports 100 per cent of its crude oil supplies. Historically, supplies have come principally from the Middle East: in 2011, 87 per cent of South Korea's crude oil demand was supplied from the Middle East, primarily from Saudi Arabia. The remaining crude oil refined is sweet crude sourced primarily from Asia. Given South Korea's reliance on imported crude oil, the Korea Petroleum Association formed the Korea-Oil Producing Nations Exchange (KOPEX) to foster good relations with suppliers.

In February 2012, one of the five refineries, the 669 kbd S-Oil refinery in Onsan, signed a 20-year crude production agreement with Saudi Aramco. Under the terms of the agreement, Saudi Aramco will supply 100 per cent of the refinery's crude oil requirements. Saudi Aramco has been a partial owner of S-Oil since 1991.

Of the four remaining refineries, the SK refinery at Inchon and the Hyundai Oil refinery at Deasan are poor candidates for processing heavy, WCS-type crudes. Inchon has a simple configuration and no upgrading facilities, and Deasan has a small coker relative to the total capacity of the refinery.

The two largest refineries in South Korea, GS Caltex at Yeosu and SK at Ulsan, have residual processing/upgrading capability and could process heavy, high sulphur, heavy metals crudes as a portion of their crude slate. GS Caltex has made, and is continuing to make, major investments to upgrade the processing capability of the Yeosu refinery. Recently, GS Caltex installed a 60 kbd LC-Fining[40] residual hydrocracker to expand existing heavy oil capability.

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[38] According to Cosmo Oil, the average API gravity for oil processed by Japan's refineries from 2005 through 2009 averaged 35.7 degrees.

[39] "Market Prospects and Benefits Analysis for the Northern Gateway Project," Muse Stancil (January 2010) and Harold York, "A Netback Impact Analysis of West Coast Export Capacity" Wood Mackenzie (December 2011).

[40] LC-Fining is a residual hydrocracking technology that uses an ebullated catalyst bed which allows depleted catalyst to be regularly withdrawn and fresh catalyst added as the metals and other poisons accumulate on the catalyst.

The LC-Fining catalytic technology is suitable for processing WCS-type crude oils. The maximum technical potential for WCS-type crude in these two refineries is estimated at about 260 kbd, and the likely processing potential may average 100,000 to 200,000 barrels per day.

c. Taiwan

Taiwan has 1,310 kbd of refining capacity in four refineries with an average capacity per refinery of 327,500 barrels per day. Chinese Petroleum Corporation (CPC), the state-owned petroleum, natural gas, and gasoline company, and the core of the Taiwanese petrochemicals industry, owns three of the four refineries. The CPC refineries (Kaohsiung, Dalin and Taoyuan) have limited conversion capacity, although Kaohsiung does have a small coker. The Dalin refinery is being upgraded with a RFCC unit and the Taoyuan is slated for a similar upgrade. The upgraded CPC refineries will have a limited potential for WCS-type crudes since they will use the RFCC technology to upgrade residual fuel oil. The fourth refinery, Formosa Petrochemical at Mailiao, has the best potential for heavy high sulphur crudes. The refinery has large feed hydrotreaters, a large RFCC unit to process most residual fuels, and a delayed coker. The coking capacity is expected be available for processing heavy high sulphur crudes. The technical capability to process WCS-type crude oils in Taiwan is about 100 kbd.

d. China

China represented about 35 per cent of 2011 Asia-Pacific petroleum demand and is a key element of economic growth in the region. Since 2000, China's petroleum demand has grown 105 per cent while demand in Asia-Pacific as whole grew 33.5 per cent.[41] The rate of petroleum demand growth in China has not gone unnoticed, and is addressed in the government's 12th Five-Year Plan.

The 12th Five-Year Plan[42] is the latest in the series of five-year guidelines for social and economic development initiatives in the People's Republic of China. Planning is a key characteristic of centralized, communist economies, where the one plan established for the entire country normally contains detailed economic development guidelines for all its regions.

The 12th Five-Year Plan was developed in 2010, for the period 2011 to 2015. The plan is dominated by goals of creating new wealth and a more equitable distribution of economic gains. The Plan, in part, recognizes the need to rebalance the economy, moving the emphasis from investment towards consumption, and encouraging development in the interior regions. Many of the objectives for enhancing environmental protection and expanding energy production in the previous Five-Year Plan were maintained.

Some of the highlights of the Plan are:

- Urbanization rate will approach 51.5 per cent.
- Value-added output of emerging strategic industries should account for eight per cent of GDP.
- Developing coastal regions into hubs of research and development, high-end manufacturing, and services.

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[41] BP plc., *BP Statistical Review of World Energy* (June 2012).

[42] China develops a Five-Year Plan every five years. Based on the Soviet approach to centralized planning, the first plan covered the years 1953 to 1957. The last plan, the 11th, was completed in 2005 and covered 2006 to 2010.

- More efficient development of nuclear power.
- Increase incentives for large-scale hydropower plants in Southwest China.
- Increasing the length of high-speed railways to reach 45,000 km.
- Increasing the length of highway networks to reach 83,000 km.

Specific targets in the area of energy during this period are:

- A 16 per cent reduction in overall energy use per unit of GDP in 2015, relative to the previous plan.
- A 17 per cent reduction in overall CO2 emissions per unit of GDP in 2015.
- A RMB 5.3 trillion investment in the power industry.
- Non-fossil fuels comprise an 11.4 per cent share of fuel use by 2015, and a 15 per cent share by 2020.

With the emphasis on energy use in the plan, it is expected that China's rate of growth in petroleum demand will continue to be significant, but will slow below the rate experienced over the past decade.

With its size and growth rate, mainland China represents a substantial new and continuing worldwide market for crude oil of a wide range of qualities. However, given information and data constraints, assessing the market or the capacity for refining and upgrading is subject to a considerable range of variance and uncertainty depending on the source.[43] The *Oil and Gas Journal (OGJ)* refining survey reports total Chinese refining capacity as of 2012 at 6.9 million barrels per day based on individual refinery information. The *OGJ* survey data lacks information on the capacity of downstream distillation processing of crude such as cracking, hydrotreating and coking. Other sources of information on Chinese refining capacity report considerably higher capacities. Kang Wu of the East-West Center, writing for the *Oil and Gas Journal* in 2011, reported an aggregate crude capacity of 11.4 mmbd, with much higher capacities for downstream processing than reported by the *OGJ* refining survey.[44] If one were to solely use the *OGJ* survey data, which includes capacities for the two large state-owned companies, one would draw the conclusion that there is little WCS processing capability in China. For our assessment of China, we have not used the *Oil and Gas Journal* data. Instead we have relied on Wu's article, information provided by the refining companies on their websites, and other sources. The ambiguity of the refinery capacity data expressed is reflected in Table 6 (below).

Another major issue with Chinese refinery statistics concerns the so-called "teapot" refineries that are not formally recognized by the state. These small, locally owned and operated refineries do not consistently report operating data. Wu estimates that the "teapots" have aggregate crude processing capacity of as much as 2.4 million barrels per day that is often excluded or missed in reported statistics.

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[43] There is a good explanation of the quality of Chinese oil-related statistics in: Alan Troner, *The Rise of China and Its Energy Implications: China's Oil Sector: Trends and Uncertainties* (2011).

[44] Kang Wu, "Special Report: Capacity, Complexity Expansions Characterize China's Refining Industry, Past, Present and Future," *Oil and Gas Journal*, March 7, 2011. http://www.ogj.com/articles/print/volume-109/issue-10/processing/special-report-capacity-complexity-expansions.html.

Published information from Wu in the *Oil and Gas Journal* special report[45] provides a more complete and thorough picture of the aggregate Chinese refining system. The information in the article is used as the reference for aggregate Chinese refining capacity and capability.

B. China in Detail

Due to its size and growth rate, we believe China is an important continuing and potential market for Canadian crude oils. As such, we provide additional details on China's current and expected future capacity for WCS-type crude oils.

The majority of the refining capacity in China belongs to two state-owned oil companies, PetroChina (of which China National Petroleum Corporation (CNPC) is the controlling shareholder) and Sinopec. Together PetroChina and Sinopec control over eight mmbd of refining capacity. The PetroChina/CNPC refineries are located primarily in northwestern and northeastern China. CNPC's new refinery, Guangxi Petrochemical, is located in southern China, where product demand reflects continuing high-growth potential. The Sinopec refineries are located in the central northern, southern and eastern regions of China.

China National Offshore Oil Company (CNOOC) and Sinochem operate refineries as well. CNOOC operates 800 kbd of refining capacity, including the 240 kbd Huizhou refinery in Guangdong province. Sinochem has an equity position, along with CNPC and Total, in the Dalian West Pacific Petro-Chemical Co. (WEPEC) refinery.[46] Table 6 provides a comparison of Chinese refinery capacity by region, to put this in perspective.

TABLE 6: CHINESE REFINING CAPACITY AND OWNERSHIP IN KBD (2011)

Region	Sinopec	CNPC	CNOOC	Local	Total
Northeast	–	1,975	–	229	2,204
Northeast	1,762	254	400	1,090	3,506
Mid Yangtze	546	–	–	–	546
Lower Yangtze	1,658	–	160	33	1,851
South	1,046	220	240	109	1,615
Southwest	–	22	–	22	44
Northwest	50	605	–	376	1,031
West	100	506	–	3	609
Total	**5,162**	**3,582**	**800**	**1,862**	**11,406**

Source: Kang Wu, "Special Report: Capacity, Complexity Expansions Characterize China's Refining Industry, Past, Present and Future," Oil and Gas Journal, March 7, 2011.

In addition to its large capacity, the Chinese refining system is complex, with cracking- and coking-to-crude ratios that approach those in the U.S. Table 7 provides aggregate data on unit capacities, comparing China to the broader Pacific region.

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45 ibid.

46 A similarly named port — Dalin — exists in Taiwan.

TABLE 7: COMPARATIVE COKING CAPACITY IN THE PACIFIC BASIN MID-2010

	China	Japan	India	Asia-Pacific	U.S. (1)
Crude Distillation	10,984	4,454	3,752	28,771	17,763
FCC/RCC	2,598	905	734	5,395	5,663
Hydrocracking	1,021	146	332	2,063	1,680
Visbreaking/Thermal Cracking	260	–	174	806	34
Coking	1,321	119	387	1,945	2,419
Cat reforming	789	752	282	3,055	3,583
Hydrotreating, hydrorefining (2)	3,168	2,573	1,264	9,319	13,929

Source: Table 2, Kang Wu, "Special Report: Capacity, Complexity Expansions Characterize China's Refining Industry, Past, Present and Future," Oil and Gas Journal, March 7, 2011.

1) Start of 2010 data

2) HDT = hydrotreating. In China this includes gasoline, kerosene and middle distillates, other countries typically do not include gasoline hydrotreating.

I. CHINESE REFINING SYSTEM CHARACTERISTICS

China's legacy refining system was developed based on indigenous crude oils, produced mainly in the northeast, eastern and central parts of the country. These crudes were primarily sweet, waxy and heavy, which fit with the use of RFCC technology. In the 1990s, China began to develop its refining system by expanding and upgrading its coastal refineries into large complexes that could process imported sour crude oils. This policy developed when China's demand for crude oil was projected to exceed Chinese domestic production. Most of the subsequent expansion of capacity has been in the coastal areas that have access to imported crudes. The exceptions have been the relatively small, landlocked "teapot" refineries and the refineries in the north and west with access to local and pipeline crude from Russia and Kazakhstan.

The large coastal refiners are the key to supplying WCS-type crudes to China. There are 19 refineries with capacity of at least 200 kbd per refinery, 17 of which could accommodate waterborne imports. Table 8 tabulates these refineries and their capacities, by region, and, where available, the refinery's sour and high-acid crude capacities. These 19 refineries represent over 40 per cent of Chinese refining capacity. Excluding the two refineries in western China, which are not logistically capable of receiving waterborne imports, these appear to be the most likely refineries with the capacity and access to process Western Canadian crudes.

Processing capacity data beyond crude capacity for these refineries is not publicly available. The lack of detailed information consequently reduces our confidence in forecasting the volume of WCS that any given refinery has the technical capability to refine. However, by reviewing the information available in the various sources and the tables included here, defensible overall, aggregate conclusions can be drawn regarding coking as a proxy for heavy oil demand. Table 8, below, provides the basis for this proxy relationship.

TABLE 8: CHINESE LARGE-SCALE PROCESSING CAPABILITY AND CAPACITY IN KBD

Company	Refinery	Region	Capacities kbd		
			crude (4) (5)	high sulphur (4)	high acid
Sinopec	Zhenhai	East	460	300	80
CNPC	Dalian	Northeast	410	(3)	(3)
Sinopec	Jinling	East	270	160	40
Sinopec	Maoming	South	270	160	40
Sinopec	Guangzhou	South	264	160	40
Sinopec	Shanghai Gaoqiao	East	250	120	
Sinopec	Tianjin	North	250	250	
(1)	Fujian	South	240	160	
CNOOC	Huizhou	South	240	240	240
Sinopec	Shanghai Petrochemical	East	230	160	
CNPC	Fushun	Northeast	230	(3)	(3)
Sinopec	Beijing Yanshan	North	220	(3)	(3)
Sinopec	Qilu	East	210	210	210
Sinopec	Qingdao	East	200	200	
(2)	Dalian West Pacific	Northeast	200	(3)	(3)
CNPC	Dushanzi	West	200	(3)	(3)
CNPC	Guangxi	South	200	(3)	(3)
CNPC	Jilin	Northeast	200	(3)	(3)
CNPC	Lanzhou	West	200	(3)	(3)

Source: Sinopec and CNPC websites

(1) Sinopec, ExxonMobil, Saudi Aramco, local.
(2) CNPC, Total, Sinochem.
(3) Value not specified.
(4) Values from Sinopec Website.
(5) It has been reported by Wu that Sinopec and CNPC have a combined 3.3 million barrels of capacity for processing imported sour crudes.

With 1.3 million barrels per day of coking capacity (12 per cent of crude capacity), per Wu, and given the more than 2 million barrels of high sulphur crude capability for Sinopec alone, there should be ample basic technical processing capability in the Sinopec refineries to process at least 500 kbd of WCS-type crudes. There will probably be modifications required — including increased hydrotreating, sulphur recovery capacity, and other unit modifications — to realize this WCS capability. In addition, lighter crudes may be necessary to add to the crude slate as a way to mitigate the high residual yield of the heavy crude and not de-rate the refinery capacity.

II. STATE FIVE-YEAR PLANS AND REFINING CAPACITY

The newest Five-Year Plan for China contemplates a four million barrel per day increase in refining capacity in the years 2011 to 2015. To meet this growth plan, new refineries have been built, are being built or are in the planning stages. This is reflected in Table 9 below, and represents a fairly aggressive view, even for China, in terms of demand growth for the plan period.

TABLE 9: PLANNED NEW REFINERY PROJECTS AND UPGRADES IN CHINA

Planned New Refinery Projects and Upgrades in China				
Owner	**Location**	**Capacity**	**Planned start-date**	**Notes**
Sinopec	Maoming	240,000	2015	Upgrade
	Guangdong / Zhanjiang	300,000	2013	Developing with Kuwait Petroleum
	Nanjing/Jinling	100,000	2012	Expansion
	Shanghai (Caojing)	240,000	2015	Preparing Environmental Impact Statement
	Zhenhai/Zhejiang	300,000	2015	Expansion
CNPC/PetroChina	Qinzhou/Guangxi	200,000	TBD	Expansion
	Qinzhou/ Yunnan	200,000	2013	Saudi Aramco signed MOU to jointly develop
	Tianjin	260,000	2015	Feasibility stage; JV with Rosneft
	Guangdong/ Jieyang	400,000	2013	New: developed with Petroleos de Venezuela, S.A.
	Lanzhou	200,000	2015	Expansion
	Huabei	100,000	2013	Expansion
	Changzhou	200,000	2015	Feasibility study
	Pengzhou	200,000	2012	Construction
	Ningxia/Yinchuan	100,000	2011+	Construction
	Jiangsu/ Taizhou	400,000	2015+	Waiting approval
CNOOC	Huizhou	200,000 / 400,000	2015 / 2020	Various Plant Expansions
Sinochem	Quanzhou	240,000	2013	Preliminary approval
	Ningbo	240,000	TBD	Pending approval

Sources: Global Insight and FACTS Global Energy, "Country Analysis Brief — China," May 2011, U.S. Energy Information Administration

III. PARTICIPATION BY FOREIGN PARTNERS

A number of these new refineries include participation by foreign companies and Chinese national oil companies that are also crude producers. Table 10 lists new refineries with foreign participation in China that have been built and are scheduled to be built within the current Five-Year Plan period.

TABLE 10: REFINERIES IN CHINA WITH FOREIGN PARTNERS

Location	Region	Company	Partner	Capacity in kbd	Startup date
Dalian West Pacific	NE	CNPC	Total, Sinochem	200	In operation since 1996
Fujian	South	Sinopec	Saudi Aramco, XOM	240	In operation since 2009
Zhangjiang	South	Sinopec	KPC	300	2015
Jieyang	South	CNPC	PDVSA	400	2015
Tiajin	North	CNPC	Rosneft	300	2015
Yunnan	Central	CNPC	Saudi Aramco	200	2015
Jiangsu/ Taizhou	North	CNPC	Qatar and Shell	400	2015+

Sources: Global Insight and FACTS Global Energy, Country Analysis Brief – China May 2011, U.S. Energy Information Administration

And

"Asian Refineries in Operation", A Barrel Full, http://abarrelfull.wikidot.com/asian-refineries

By investing in these refineries, foreign producers of crude oil can ensure a rateable market for some share of their crude oil production. If all these projects are completed, over 2,000 kbd of Chinese crude refining capacity will include participation by foreign producers. This will represent about 130 per cent of China's total refinery capacity and a larger share of sour and heavy crude capacity. This capacity will likely exhibit a preference to process crudes from the foreign-producer partner, which may, in turn, diminish some of the attraction of WCS in the future.

IV. CHINA SUMMARY

China has the capability of processing at least 500 kbd of WCS-type crudes. With the planned new refineries and expansions, this capability is expected to grow. Since WCS has higher sulphur, higher total acidic number (TAN), higher residual yields, and higher metals compared to most other crudes imported by China, it is expected that refiners would require modifications to compensate for these qualities. Since China has been modifying its refineries to improve product quality, some modifications for WCS could be incorporated. The Chinese oil companies should be motivated to modify their refineries for WCS-type crudes to ensure a market for WCS, as they have been aggressively growing their position in Western Canadian heavy oil production.

V. SUMMARY OF PACIFIC BASIN REFINING CAPABILITY FOR WCS-TYPE CRUDES

The Pacific Basin represents, and includes, a substantial, diversified and growing future market for Canadian oil supplies, including heavy crudes typified by WCS blends. Current planning for accessing Pacific tidewater ports and boosting transport capacity by over one million barrels per day is aligned with growing and forecasted processing capability throughout the Asia-Pacific region, including the California market as its existing heavy oil reserves decline.

New and planned coking capacity, especially in China, should be sufficient to absorb the expected increases in Canadian products that can be shipped into the Pacific Basin, up to the limit of the proposed new pipeline capacity, though there will be a discount to world price levels as a variety of other producers vie for long- and short-term contractual arrangements with Chinese refiners. The current and projected heavy oil processing capacity in China and other East Asian countries is expected to be sufficient to handle Canadian export supplies, with the caveat of discounted quality and shipping charges. Consequently, Canadian crudes (WCS) will satisfy a clear market demand, albeit one in which the demand mix will change dynamically over time.

The quality and shipping discount is likely to be challenged by competition from lighter and sweeter conventional and unconventional supplies on the market (tight oil), which may cause re-examination of proposed heavy oil processing investments in China's next Five-Year Plan. The Chinese Five-Year Plan, especially given the focus on rebuilding existing, inefficient capacity, will provide an opportunity, but not necessarily the incentive, to build new coking capacity. Coking capacity is likely to be a major negotiating point in new contract developments.

In summary, given the published values, supplemented by the interviews incorporated in this report, there is sufficient technical refining capability in the Pacific Rim to process WCS-type crudes for at least the 500 to 1,115 kbd expected to be available for shipping after pipeline expansions, though some modifications may be necessary to compensate for the physical characteristics and yield pattern of WCS. We expect the majority of WCS-type crudes would be absorbed by China and Korea, due to the capacity and configuration of current and planned refineries. This estimate reflects some degree of uncertainty. This is due in part to the limited ability of some Asian nations, especially China, to quickly adjust refinery investment plans as the available crude blends and pricing schedules change. The uncertainty is influenced primarily by decisions in China, the largest consumer in the Pacific Basin.

Actual capacity for processing WCS-type crudes in the Pacific Basin will also depend on the view from refiners about the certainty of the pipeline(s) to the Canadian Pacific coast and the potential discount of the crude relative to other production sources. From the refiners' perspective, they may wish to initiate projects such as pipeline extensions or upgrading, or even change business plans, so that they can process WCS crude in North America or in Asia. Thus, the outcome of the pipeline approval proceedings currently underway will influence investment decisions on heavy oil refining capability in the Pacific Basin. In this process, there is a significant risk implied in the nature and timing of the capital investment necessary to support not only supply chain expansion, but the offshore processing capacity needed to process increasing volumes of heavy oil. Pipeline owners will demand commitments from shippers and, in turn, oil producers will want assurances from refiners that long-term arrangements will be honoured. We anticipate few current political barriers, or market impediments to the expansion of refining capacity in Asia, or to increasing production in Alberta. While there may be uncertainty over individual pipeline expansion capacity, in the long term, this is likely to pose less risk than the market impacts on product demand.

VI. CONCLUSIONS, POLICY ISSUES AND IMPLICATIONS

When looking out at the investment horizon, resource markets are notoriously unstable, affected not only by demand shifts, but also by shifts in geopolitical alliances, market preferences, taxes, tariffs and access to transportation or shipping mediums. This is particularly true of oil markets, especially those associated with products that can be displaced by more accessible or more competitively priced alternatives. While oil is a fungible product, changes in worldwide supply can impact the competitive opportunities for supplies such as WCS, especially when supply-line capacity is limited.

In this report, we have examined the capability of coking capacity in the context of increased supplies of Canadian heavy oil competing for market share in the Pacific Basin. This scenario is subject to a host of variables, including political and regulatory approvals for new Canadian tidewater access, continued expansion of unconventional oil facilities, and agreements for new pipeline rights of way in Canada. As a consequence, it is worth mentioning other policy and market scenarios that could affect the balance of production forces and processing capability within the Basin.

These include the delay of export-transfer capability within Canada, an event that would find Asian refiners seeking contracts with other producers, many of whom would offer products of better quality. This outcome would represent a replacement rather than displacement of Canadian supplies, and would have a tendency to reinforce the status quo in terms of overall coking capacity in Asia, where refiners would have diminished interest in the high capital costs of investing in new processing capacity tailored to Canadian heavy oil. An alternative scenario could involve a near-term shift in focus for Canadian producers, where heavy oil shipments would continue to be directed to the U.S. PADD III facilities in the Midwest via existing pipelines, augmented by rail transport, and medium gravity oils would be targeted to the Asia-Pacific market. This outcome would support the paradigm described above and allow direct competition with lighter, sweeter Middle Eastern oil supplies that can be processed by existing and less-specialized refineries in Asia.

Ultimately, the capacity available for processing heavy oil in Asia will reflect the desire and capability of Canadian oil producers to create transportation and contractual pathways from new or expanded tidewater ports to refineries capable of processing heavy oil. This, in turn, will depend on continued Canadian oil market competitiveness versus internationally competitive alternatives and performance standards. Other factors include changing market demand in North America, based on variables such as the relaxation or delay of the California low carbon fuel standard, or increased substitution by alternative fuels in the transportation sector.

As the market for unconventional oil evolves, this dynamic will be revisited both in terms of market dynamics, but also in future public policy analysis that will concentrate on market structure and performance in the face of dramatic changes in both market supply and demand.

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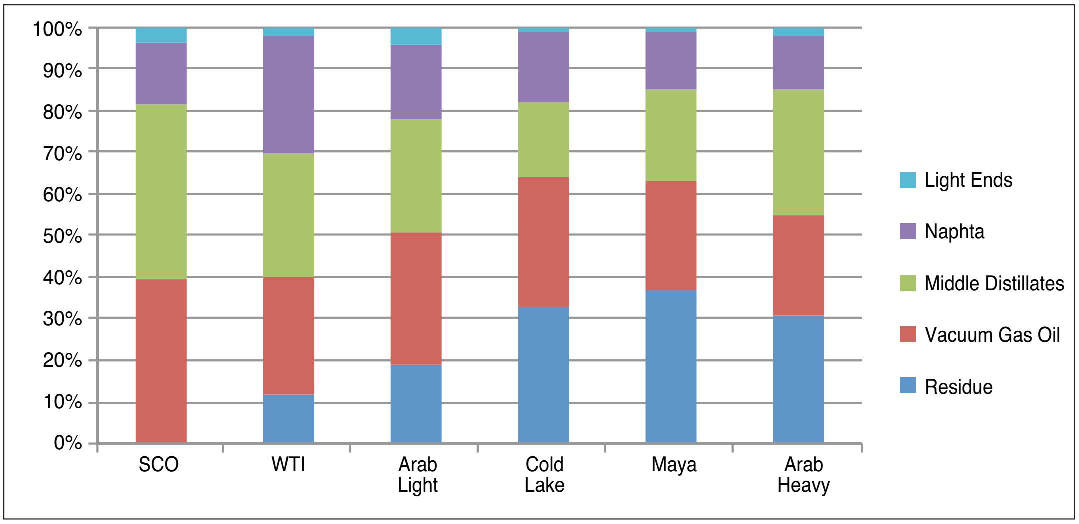
APPENDIX A: CRUDE OIL TYPES AND PROPERTIES

Crude oils are a complex mixture of hydrocarbons that must be "refined" to produce products of particular qualities and specified volumes. As a general rule, different qualities of crude oil from the same region of the world have similar properties in one or more dimensions. For example: Middle Eastern crudes are usually sour; California crudes are usually heavy, high-sulphur and asphaltenic; Asian crudes are usually sweet; Brazilian crudes are usually sweet and heavy; etc. These generalities are useful as a guide, however, numerous exceptions do exist. Figure A1 displays the comparative products from light crude oils (SCO, WTI and Arab Light) and heavy crude oils (Cold Lake, Maya and Arab Heavy).

FIGURE A1: COMPARISON OF REFINED PRODUCTS BY SOURCE CRUDE



Source: "A Netback Analysis of West Coast Export Capacity," Wood Mackenzie (December 2011),

The suitability and desirability (economic value) of a particular type of crude oil to a particular refinery depends on a number of factors. Suitability is a function of how the properties and yields of the crude oil fit within the equipment and configuration (the technology employed and capacity of each technology), and the capability of the refinery to produce the desired products from the crude oil. The value of a crude oil in a refinery that can process that crude oil depends on the yield of products, the product prices, and the refinery's costs to process the crude. Relative value, i.e. value compared to that of other crudes, determines what crudes will be processed.

Refineries that are designed to produce products (such as petrochemical blends, petrochemical feedstocks, lubricants, anode coke and metallurgical-grade calcined coke) are designed around supplies of suitable crude oils for production of these final products. The local and export markets for the refinery will determine the desirable products and their price. The major fuel products with prices at a premium to crude oil prices are: gasoline, kerosene and diesel, or light products. The heaviest product from crude, residual fuel, is usually discounted below crude oil prices. These price characteristics drive the refining industry to minimize residual fuel production and maximize light products.

The crude oil properties that are most discussed to distinguish value on the first level are API gravity and sulphur content. A higher API gravity (lower specific gravity or less dense) normally correlates with a higher natural yield of higher-valued products naturally occurring in the crude oil. Lower sulphur content (sweet) is an indication that the natural products are closer to product specifications for sulphur content and will require less intensive (lower cost) refining. Thus light, sweet crude would be highly valued and heavy, high sulphur crude would be of lower value. The potential market for light, sweet crudes is vastly greater than that for heavy, sour crudes since the number of refineries with the proper configuration for processing a crude oil decreases as its quality decreases. Effectively, for the lowest quality crudes, the focus must be on refineries that have the specialized capability to handle those crudes.

Table A.1 exemplifies the wide range of available crude oils, including Western Canadian Select, with some of their key properties for refining.

TABLE A.1: CRUDE OIL TYPES AND PROPERTIES

	Bonny Light[1]	**Brent[1]**	**West Texas Intermediate[2]**	**Arab Light[3]**	**Arab Heavy[3]**	**Duri[3]**	**Alaska North Slope[3]**	**Maya[2]**	**Western Canadian Select[4]**	**BCF-17[3]**
Country of Origin	Nigeria	U.K.	U.S. Texas	Saudi Arabia	Saudi Arabia	Indonesia	U.S. Alaska	Mexico	Canada	Venezuela
Classification	Light sweet	Light sweet	Light sweet	Light sour	Medium sour	Heavy sweet	Light sour	Heavy sour	Heavy sour	Heavy sour
API Gravity	35	38	41	33	28	21	32	22	21	17
Sulphur, wt%	0.2%	0.4%	0.3%	1.8%	3.3%	0.2%	0.9%	3.4%	3.5%	2.5%
TAN, mg KOH/gm	0.25	0.1	0.1			1.3	0.1	0.4	0.9	2.5
Vanadium, ppm	0	7		16	58	1	25		143	360
Nickel, ppm	3	1		4	19	32	11		58	49
Yield on Crude, vol%										
Gasoline & lighter	28%	27%	35%	19%	18%	2%	25%	0%	19%	5%
Diesel & Kerosene	46%	40%	32%	34%	29%	21%	29%	0%	18%	23%
650+ Residual	26%	33%	33%	47%	53%	77%	51%	1%	63%	72%
Residual	6%	11%	9%			N/A		0%	37%	
Gasoline Octane RON	77	70	56	70	74	75		51		
Diesel Cetane										
Index or Number	46	54		50	47	40	45	54		40

Sources:

(1) TOTSA Total Oil Trading SA, http://www.totsa.com/pub/crude/crude_oil_home.php

(2) Oil and Gas Journal

(3) Petroleum Intelligence Weekly

(4) "Canadian Crude Quick Reference Guide," Crude Quality Inc., June 2, 2012.

Western Canadian Select (WCS) is a heavy, high sulphur crude oil with moderately high acid content and high metals. In reviewing Table A1, it can be seen that Western Canadian Select has some of the highest values for sulphur, TAN, vanadium and nickel, compared to other crude oils available from other regions. In addition, it has one of the lower yields of diesel of any of the crudes. In the Pacific Rim, the low diesel yield would be a disadvantage compared to other crudes. This disadvantage will be reflected in the pricing.

The crude oil characteristics/properties beyond API Gravity and sulphur that impact a refinery are:

- **Volume percentage of gasoline and distillates:** Higher yields of these products are normally positive for a refinery since the refining to products will be less intensive. The yield of each product is important as it relates to the capacities of the downstream processes that improve product quality.
- **Volume percentage of 650° F+ Residual:** The portion of the barrel with boiling points over 650° F which requires conversion (cracking, coking, etc.) to light products for the production of residual fuel. The conversion processes represent the most complex parts of a crude oil refinery. Crudes with higher 650° F+ percentages require higher initial refinery investment and operating costs. This material is distilled under a vacuum and the distillate portion called gas oil becomes feedstock for fluid catalytic cracking or hydrocracking processes.
- **Volume residual:** Normally measured as the amount boiling at more than 950° F or 1000° F, this represents the vacuum residual or asphalt portion of the crude. Since this material is not distilled overhead, the non-volatile materials, such as metal and asphaltenes, remain in this cut. If this material is of high quality with low metals and asphaltenes, it can be converted to light products in a residual fluid catalytic cracker unit (RFCC). This is the portion that is used to make asphalt or blended with light oils to make heavy fuel oils, if there is a market for these products. In heavy oil refineries (as well as upgraders) this material is fed to a coker, where it is thermally cracked to lighter liquid products leaving behind a solid residual coke. The asphaltenes are cracked or converted to coke and almost all of the metals are deposited with the coke. The yield of coke depends on the properties of the coker feed and can vary from 20 to 40 per cent, by weight (wt %) on feed. Processes such as residual hydrocracking and solvent de-asphalting are also used in a few refineries to convert residuals from heavy, high sulphur crude oil.
- **Gasoline Octane:** The octane of the naturally occurring gasoline is an indicator of the difficulty in making gasoline of octane quality.
- **Diesel Cetane:** With diesel’s continually growing demand as a fuel, particularly outside North America, diesel quality has grown in importance. Higher cetane quality from the diesel in the crude lessens the need for additional processing or blending materials to meet cetane specifications.
- **TAN:** This is an acronym for total acid number, which measures the organic acid number of the crude. The organic acids will cause corrosion in the hotter parts of the crude distillation process that do not have the properly alloyed metallurgy. A refinery without proper alloy will experience high corrosion rates resulting in equipment damage and extended downtime to make repairs.
- **Vanadium and Nickel:** Vanadium and nickel are trace metals found in crude oils. When crude is distilled, almost all of these metals remain in the residual portion. If the content of these metals is low, the material can be feed to an RFCC unit for conversion. If the metals content is high, the material must go to a coker or specialized hydrocracker for conversion. If the material is not converted, the metals remain in the residual product. If the product is residual fuel, there are vanadium specifications that must be met.

Other crude oil properties that are important relate to logistical considerations or specialty products, and include hydrogen sulfide content, lubricant quality, and pour point.

Crude oils such as WCS are unusual, but not unique, in that they are a blend of a light oil portion and a heavy bitumen portion, such that the resulting blend has properties that enable the blend to be transported using conventional crude oil systems. In other countries where heavy oils and bitumen occur, blending with lighter crude oils is common to facilitate transport of the blend. In Venezuela, bitumen from the Orinoco is blended with synthetic light oil.

In Canada, the blends are achieved either through blending or diluting the bitumen with condensate (a very light oil produced with natural gas) to create dilbit, or blending with synthetic oil (a light oil without residual produced by refining bitumen to a light oil without residual) to create synbit. The lighter cuts of the resulting blend that directly make light products primarily have the properties of the light oil, and the heaviest residual (coker feed) cut has the properties of the bitumen. The bitumen has high sulphur, high TAN and high metals properties. The gas oil or cracking feedstock cuts are a blend from the relative cuts from the light oil and the bitumen.[47]

Blends such as WCS exhibit "dumbbell" characteristics to a refiner, in that the light distillates, which are primarily from the condensate or synthetic oils, are "premium" (easier to refine than that from most conventional crude oils), and the heaviest or residual portions are "low grade" (more difficult to refine than that from traditional crude oils, because they have the high sulphur, high TAN and high metals properties). The properties of the residual, which is from the bitumen, define the refinery configurations that are candidates for WCS processing. The yields of the light products, a function of the condensate or synthetic oil yields, would be important to a refiner relative to his desired mix of light products.

Table A.2 contains Canadian crude property data that illustrates the range of properties of Canadian crudes and blends. WCS is used as representative of the proposed pipeline heavy crude.

[47] "Western Canadian Select is a Hardisty-based blend of conventional and oil sands production managed by Canadian Natural Resources, Cenovus Energy, Suncor Energy, and Talisman Energy. Argus has launched daily, volume-weighted average price indexes for Western Canadian Select and will publish this index in the daily Argus Crude and Argus Americas Crude publications." – *Crude Quality Inc., www.crudemoinotor.ca*

TABLE A.2: CANADIAN CRUDE OILS AND PROPERTIES

	Western Canadian Select (WCS)	Mixed Sweet Blend	Light Sour Blend	Mixed Sour Blend	Western Canadian Blend	Cold Lake (Dilbit)	Suncor Synthetic A	Syncrude Synthetic
Crude Type	Dilbit	Conven-tional	Conven-tional	Conven-tional	Conven-tional	Dilbit	Synthetic	Synthetic
Classification	Heavy sour	Light sweet	Light sour	Medium sour	Heavy sour	Heavy sour	Light sweet	Light sweet
API Gravity	21	40	37	31	21	21	33	32
Sulphur, wt%	3.5%	0.5%	1.1%	1.6%	3.1%	3.8%	0.2%	0.2%
TAN, mg KOH/gm	0.9(1)	na	0.2	0.4	0.7	1.0	na	na
Vanadium, ppm	143	9	9	33	97	170	nd	nd
Nickel, ppm	58	4	6	17	44	64	nd	nd
Yield on Crude, vol%								
Gasoline and lighter	19%	40%	39%	27%	17%	22%	27%	23%
Diesel and Kerosene	18%	30%	29%	22%	22%	15%	37%	39%
650+ Residual	63%	34%	31%	21%	61%	63%	36%	38%
Residual	37%	11%	11%	23%	39%	40%	na	na
Gasoline Octane RON	(2)	na	na	na	na	(2)	na	na
Diesel Cetane Index or Number	(2)	na	na	na	na	(2)	33-40+ (3)	

Source unless otherwise noted: "Canadian Crude Quick Reference Guide", Crude Quality Inc, June 2, 2012.

(1) Other dilbit crudes have TAN as high as 2.49 mg KOH/g.

(2) Gasoline octane and diesel cetane will vary with the diluent. In the case of synthetic crude, the diluent properties will depend on the process used in the upgraders.

(3) Gary R. Brierley, Visnja A. Gembicki and Tim M. Cowan, "Changing Refinery Configuration For Heavy And Synthetic Crude Processing," UOP LLC, Des Plaines, Illinois, U.S.A.

(4) Petroleum Intelligence Weekly.

Table A.2 illustrates that WCS is representative of other heavy Canadian crudes and heavy blends. This table also illustrates that the synthetic crudes have a much better diesel yield than WCS, which will be attractive to the Far East markets.

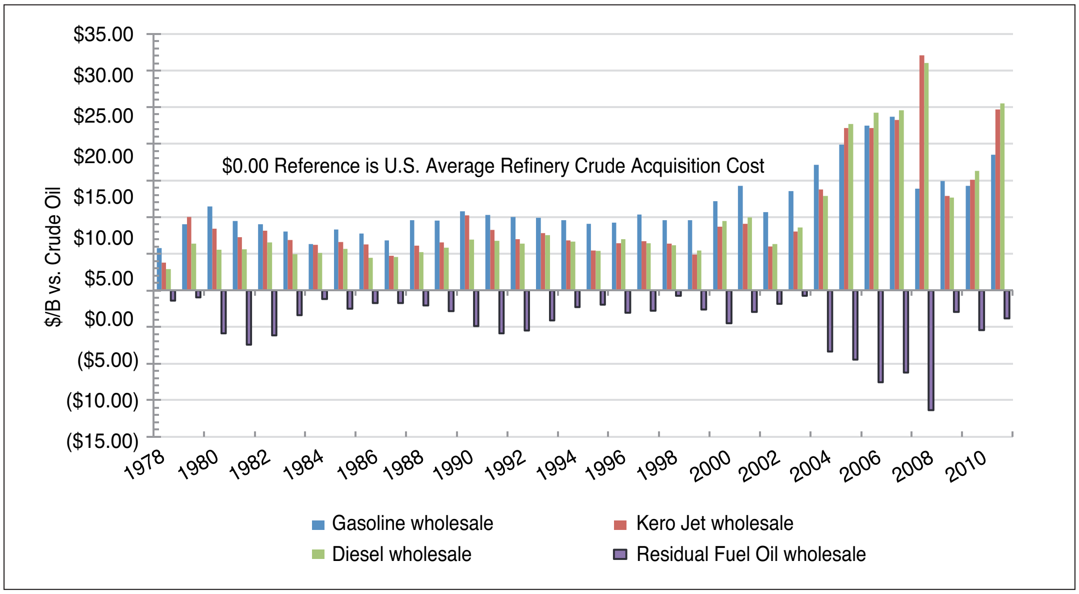
Refining of WCS

The properties of WCS make it particularly challenging crude to refine because of its high sulphur, high metals and TAN. The high residual yield requires refineries with robust coking-based residual conversion capacity. The high metals content minimizes catalytic conversion technologies that can be used. Candidate refineries for processing significant amounts of WCS will have coker capacity that is designed for high yield of coke; fluid catalytic cracking and/or hydrocracking capacity to process the gas oil from the crude and coker; adequate hydro-desulphurization capacity to process all of the light product and gas-oil streams; and adequate sulphur recovery capacity to recover the resulting sulphur yielded from processing the crude. Unless a refinery is designated as a WCS refinery for long-term supply, it is expected that the WCS will be processed along with other crude oils.

APPENDIX B: REFINERY CRUDE OIL SELECTION

The purpose of the refining industry in its simplest form is to convert crude oils to products that can be sold to the consumer for use as fuel or as a raw material input for another industry. The basic economic driver for refining is the margin between the mix of products and the cost of the crude oil input plus operating costs. Figure B.1 illustrates the value over time for the major products and the cost of crude in the U.S.

FIGURE B.1: PRICES OF PRODUCTS VS. CRUDE OIL



Source: U.S. Total Refiner Acquisition Cost of Crude, http://www.eia.gov/dnav/pet/pet_pri_rac2_dcu_nus_a.htm.
U.S. Total Refiner Petroleum Product Prices, Sales for Resale, http://www.eia.gov/dnav/pet/pet_pri_rac2_dcu_nus_a.htm.

As illustrated, gasoline, jet fuel and diesel prices exceed that of crude oil, and residual fuel oil, the heaviest part of the barrel, has a price less than crude oil. The reason that residual fuel has a low price is that a far greater amount of it exists in crude oil than is required by the market. A major portion of the complexity and investment in refining is employed to convert the heaviest part of the crude barrel to gasoline, jet fuel or diesel products. The simplest refineries do not have such capability to convert the heaviest part of the crude barrel. The most complex refineries essentially eliminate all of the heaviest part of the crude barrel.

Crude selection for a refinery is a very complex analysis, often using a technique called linear programming, which involves complex mathematical models of the refinery with the capacity and processing limits, product specifications and expected prices. A successful refiner, in order to be profitable, selects feedstock, usually a mix of crude oils, which will give it the best profit within the refinery's technical and capacity constraints, and according to market prices and constraints. Among the constraints faced by the refiner are the ability to convert the heaviest part of the barrel, the yield profile to fit the various processing capacities, the ability to remove and recover sulphur, the corrosiveness of the crude oil, and the quality of the products yielded from the crude oil.

Most refineries with access to deep-water berthing for tankers used in international trade refine a mix of crudes, not an individual crude oil. This is because most have multiple crude units and select mixes of crudes that best fit the units, and a mix of crudes can use the beneficial properties or yields from one crude to offset the detrimental qualities or yields of others. It is usually a special circumstance where a large, complex refinery will have one crude oil as the majority of its feedstock.

The crude oil refining industry in different parts of the world developed according to types of crude oils available locally and available for import to the refining location; local and export product demand; and the product quality requirements of the local and export markets. These factors are the primary reasons refinery size and the refining technology mix employed differs in different areas of the world. In addition to these market and technical factors, financial, economic and political factors influenced the pattern of refinery development. These include the availability of capital to invest in refining, and the economic and political motives of the resident country. Exogenous factors contribute to the lack of refining in countries where demand exists, or the locating of refineries where they refine volumes in excess of local product demand and, hence, depend on export markets.

Some examples: The Singapore refining centre is geared to produce residual fuel, as Singapore is a major shipping hub and export centre. China is not geared to produce residual fuel since it has been national policy to not use residual fuel for power generation (that sector is reserved for coal). Asian refineries are geared to produce diesel over gasoline, reflecting regional demand, and North America has been geared to produce gasoline, reflecting North American demand.

As individual refineries differ in the technology employed, the most economically advantageous crude mix to an individual refinery differs. To a specific refinery, the optimal crude mix has the greatest margin between aggregate product value and the aggregate crude cost plus operating costs that meets the technology and capacity constraints of the refinery.

APPENDIX C: EIA REGIONAL DEFINITIONS

The six basic country groupings used in this report (Figure C.1) are defined as follows:

1. OECD (18 per cent of the 2011 world population):

A. **OECD Americas**—United States, Canada, Chile, and Mexico;

B. **OECD Europe**—Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom;

C. **OECD Asia**—Japan, South Korea, Australia, and New Zealand.

2. Non-OECD (82 per cent of the 2011 world population):

A. **Non-OECD Europe and Eurasia (five per cent of the 2011 world population)**—Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Russia, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

B. **Non-OECD Asia (53 per cent of the 2011 world population)**—Afghanistan, American Samoa, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), China, Cook Islands, Fiji, French Polynesia, Guam, Hong Kong, India, Indonesia, Kiribati, Laos, Macau, Malaysia, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Timor-Leste (East Timor), Tonga, U.S. Pacific Islands, Vanuatu, Vietnam, and Wake Islands.

C. **Middle East (three per cent of the 2011 world population)**—Bahrain, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syria, the United Arab Emirates, and Yemen.

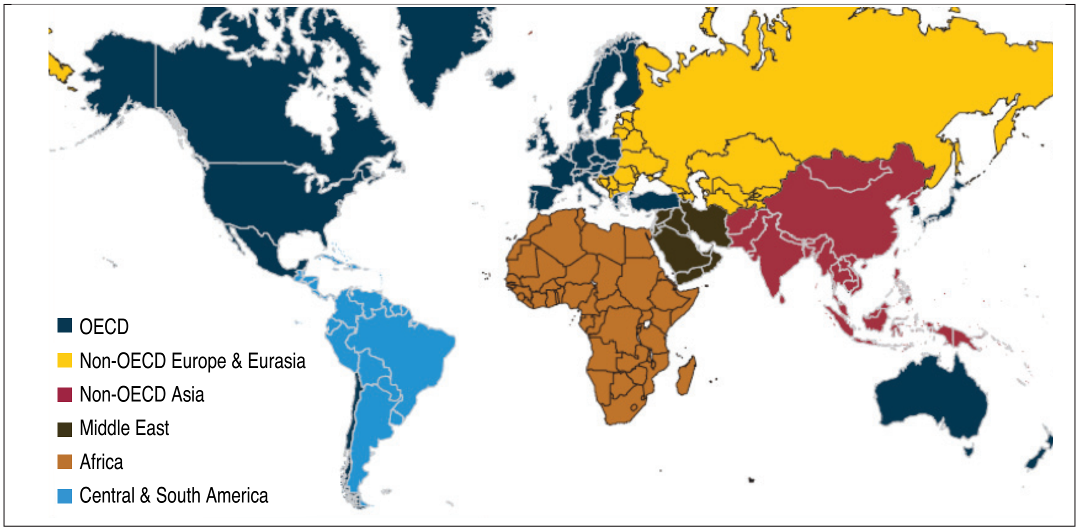
D. **Africa (15 per cent of the 2011 world population)**—Algeria, Angola, Benin, Botswana, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Congo (Brazzaville), Congo (Kinshasa), Côte d'Ivoire, Djibouti, Egypt, Equatorial Guinea, Eritrea, Ethiopia, Gabon, The Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Libya, Madagascar, Malawi, Mali, Mauritania, Mauritius, Morocco, Mozambique, Namibia, Niger, Nigeria, Reunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, St. Helena, Sudan, Swaziland, Tanzania, Togo, Tunisia, Uganda, Western Sahara, Zambia, and Zimbabwe.

E. **Central and South America (seven per cent of the 2011 world population)**—Antarctica, Antigua and Barbuda, Argentina, Aruba, The Bahamas, Barbados, Belize, Bolivia, Brazil, British Virgin Islands, Cayman Islands, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, Falkland Islands, French Guiana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Montserrat, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Puerto Rico, St. Kitts-Nevis, St. Lucia, St. Vincent/Grenadines, Suriname, Trinidad and Tobago, Turks and Caicos Islands, Uruguay, U.S. Virgin Islands, and Venezuela.

In addition, the following commonly used country groupings are referenced in this report:

- **Annex I Countries participating in the Kyoto Climate Change Protocol on Greenhouse Gas Emissions**: Australia, Austria, Belarus, Belgium, Bulgaria, Canada, Croatia, Czech Republic, Denmark, Estonia, European Community, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Japan, Latvia, Liechtenstein, Lithuania, Luxembourg, Monaco, the Netherlands, New Zealand, Norway, Poland, Portugal, Romania, Russia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Ukraine, and the United Kingdom.
- **European Union (EU):** Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, the Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, and the United Kingdom.
- **Organization of the Petroleum Exporting Countries (OPEC):** Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
- **Persian Gulf Countries:** Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia, and the United Arab Emirates.
- **Natural Gas Arabian Producers:** Bahrain, Kuwait, Oman, United Arab Emirates, and Yemen.

FIGURE C.1: EIA COUNTRY REGIONS



Source: EIA International Energy Outlook 2011.

TABLE C1: WORLD TOTAL PRIMARY ENERGY CONSUMPTION BY REGION (QUADRILLION BTU)

Region/Country	History			Projections					Average annual percent change, 2008-2035
	2006	2007	2008	2015	2020	2025	2030	2035	
OECD									
OECD North America	**122.3**	**124.3**	**122.9**	**126.1**	**131.0**	**135.9**	**141.6**	**147.7**	**0.7**
United States	99.8	101.7	100.1	102.0	104.9	108.0	111.0	114.2	0.5
Canada	14.0	14.3	14.3	14.6	15.7	16.4	17.6	18.8	1.0
Mexico/Chile	8.5	8.3	8.5	9.5	10.4	11.5	13.0	14.7	2.1
OECD Europe	**82.8**	**82.3**	**82.2**	**83.6**	**86.9**	**89.7**	**91.8**	**93.8**	**0.5**
OECD Asia	**39.2**	**39.4**	**39.2**	**40.7**	**42.7**	**44.2**	**45.4**	**46.7**	**0.7**
Japan	23.3	23.0	22.4	22.2	23.2	23.7	23.7	23.8	0.2
South Korea	9.4	9.8	10.0	11.1	11.6	12.4	13.1	13.9	1.2
Australia/New Zealand	6.5	6.6	6.8	7.4	7.8	8.1	8.5	8.9	1.0
Total OECD	**244.3**	**246.1**	**244.3**	**250.4**	**260.6**	**269.8**	**278.7**	**288.2**	**0.6**
Non-OECD									
Non-OECD Europe and Eurasia	**48.9**	**49.6**	**50.5**	**51.4**	**52.3**	**54.0**	**56.0**	**58.4**	**0.5**
Russia	29.1	29.7	30.6	31.1	31.3	32.3	33.7	35.5	0.6
Other	19.8	19.9	19.9	20.4	21.0	21.7	22.3	22.9	0.5
Non-OECD Asia	**121.0**	**128.6**	**137.9**	**188.1**	**215.0**	**246.4**	**274.3**	**298.8**	**2.9**
China	73.4	78.9	86.2	124.2	140.6	160.9	177.9	191.4	3.0
India	18.8	20.0	21.1	27.8	33.1	38.9	44.3	49.2	3.2
Other Non-OECD Asia	28.8	29.7	30.7	36.2	41.3	46.7	52.1	58.2	2.4
Middle East	**24.0**	**24.0**	**25.6**	**31.0**	**33.9**	**37.3**	**41.3**	**45.3**	**2.1**
Africa	**17.2**	**17.8**	**18.8**	**21.5**	**23.6**	**25.9**	**28.5**	**31.4**	**1.9**
Central and South America	**25.9**	**26.5**	**27.7**	**31.0**	**34.2**	**38.0**	**42.6**	**47.8**	**2.0**
Brazil	11.5	12.1	12.7	15.5	17.3	19.9	23.2	26.9	2.8
Other Central and South America	14.4	14.5	15.0	15.6	16.9	18.1	19.5	20.8	1.2
Total Non-OECD	**237.0**	**246.5**	**260.5**	**323.1**	**358.9**	**401.7**	**442.8**	**481.6**	**2.3**
TOTAL WORLD	**481.3**	**492.6**	**504.7**	**573.5**	**619.5**	**671.5**	**721.5**	**769.8**	**1.6**

Source: Table A1, U.S. EIA International Energy Outlook 2011

TABLE C2: WORLD LIQUIDS CONSUMPTION BY REGION (MMBD)

Region/Country	History			Projections					Average annual percent change, 2008-2035
	2006	2007	2008	2015	2020	2025	2030	2035	
OECD									
OECD North America	**25.3**	**25.4**	**24.2**	**25.2**	**25.5**	**25.8**	**26.4**	**27.2**	**0.4**
United States	20.7	20.6	19.5	20.4	20.7	21.0	21.4	21.9	0.4
Canada	2.3	2.3	2.2	2.3	2.3	2.3	2.3	2.4	0.2
Mexico/Chile	2.4	2.5	2.4	2.5	2.6	2.6	2.7	2.9	0.7
OECD Europe	**15.7**	**15.6**	**15.6**	**14.4**	**14.6**	**14.8**	**14.8**	**14.9**	**-0.2**
OECD Asia	**8.6**	**8.5**	**8.3**	**7.8**	**8.2**	**8.3**	**8.3**	**8.4**	**0.1**
Japan	5.3	5.2	5.0	4.3	4.6	4.7	4.6	4.5	-0.4
South Korea	2.2	2.2	2.1	2.3	2.4	2.4	2.5	2.6	0.7
Australia/New Zealand	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.3	0.5
Total OECD	**49.6**	**49.6**	**48.0**	**47.5**	**48.3**	**48.9**	**49.5**	**50.4**	**0.2**
Non-OECD									
Non-OECD Europe and Eurasia	**4.9**	**4.6**	**5.0**	**5.3**	**5.2**	**5.2**	**5.4**	**5.6**	**0.4**
Russia	2.8	2.6	2.8	2.9	2.8	2.7	2.8	2.9	0.1
Other	2.1	2.1	2.1	2.3	2.4	2.5	2.6	2.6	0.8
Non-OECD Asia	**16.2**	**16.6**	**17.1**	**23.0**	**26.2**	**30.2**	**32.6**	**34.4**	**2.6**
China	7.3	7.5	7.8	12.1	13.6	15.6	16.4	16.9	2.9
India	2.7	2.8	3.0	3.8	4.6	5.7	6.8	7.5	3.5
Other Non-OECD Asia	6.2	6.3	6.3	7.1	7.9	8.8	9.4	9.9	1.7
Middle East	**6.0**	**6.3**	**6.6**	**7.7**	**7.7**	**8.1**	**9.0**	**9.5**	**1.4**
Africa	**3.0**	**3.1**	**3.2**	**3.3**	**3.4**	**3.5**	**3.7**	**4.0**	**0.9**
Central and South America	**5.5**	**5.6**	**5.8**	**6.6**	**6.9**	**7.2**	**7.8**	**8.3**	**1.4**
Brazil	2.3	2.4	2.5	2.9	3.1	3.3	3.6	3.9	1.7
Other Central and South America	3.2	3.3	3.3	3.7	3.9	4.0	4.2	4.4	1.1
Total Non-OECD	**35.7**	**36.3**	**37.7**	**45.9**	**49.3**	**54.3**	**58.4**	**61.8**	**1.9**
Total World	**85.3**	**85.9**	**85.7**	**93.3**	**97.6**	**103.2**	**108.0**	**112.2**	**1.0**

Source: Table A5, U.S. EIA International Energy Outlook 2011

APPENDIX D: DEFINITIONS AND GLOSSARY

API Gravity	A specific gravity scale developed by the American Petroleum Institute (API) for measuring the relative density or viscosity of various petroleum liquids.
Barrel	A standard oil barrel is approximately equal to 35 imperial gallons (42 U.S. gallons) or approximately 159 litres.
Bitumen	A heavy, viscous oil that must be processed extensively to convert it into a crude oil before it can be used by refineries to produce gasoline and other petroleum products.
Capability	The technical ability or capacity of a refinery to process a crude oil or produce a product.
Coker	The processing unit in which bitumen is cracked into lighter fractions and withdrawn to start the conversion of bitumen into upgraded crude oil.
Condensate	A mixture of mainly pentanes and heavier hydrocarbons. It may be gaseous in its reservoir state but is liquid at the conditions under which its volume is measured or estimated.
Crude Input/Crude Demand/Crude Runs	The volumes and/or types of crude oils that are chosen or are expected to be used by a refinery or group of refineries.
Crude Oil (Conventional)	A mixture of pentanes and heavier hydrocarbons that is recovered or is recoverable at a well from an underground reservoir. It is liquid at the conditions under which its volume is measured or estimated and includes all other hydrocarbon mixtures so recovered or recoverable, except for raw gas, condensate, or bitumen.
Crude Oil (Heavy)	Crude oils that include blended oils with higher density and low natural gasoline and distillate content; typically have higher levels of sulphur and other impurities; and are difficult to refine into petroleum products for the market. For this report, crude oils are heavy if they have an API gravity less than 22.3°.
Crude Oil (Light)	Liquid petroleum that has a low density (for this report, an API gravity greater than 31.1°) and flows freely at room temperature.
Crude Oil (Medium)	Crude oil is deemed, in this report, to be medium crude oil if it has an API greater than 22.3° but less than 31.1°. No differentiation is made between sweet and sour crude oil that falls in the medium category because medium crude oil is generally sour.
Crude Oil (Sour)	Crude oil with high amounts of sulphur, increasing the processing cost. Typically crude oils that are over 0.5% sulphur by weight are defined as “sour.”
Crude Oil (Sweet)	Crude oil with small amounts of sulphur and carbon. Typically defined as crude oil with 0.42% or less sulphur by weight.
Crude Oil (Synthetic)/ SCO	A mixture of hydrocarbons, similar to crude oil, derived by upgrading bitumen from the oil sands.
Density	The mass of matter per unit volume.
Dilbit	Bitumen that has been reduced in viscosity through the addition of a diluent (or solvent) such as condensate or naphtha.
Diluent	Lighter viscosity petroleum products that are used to dilute bitumen for transportation in pipelines.
Feedstock	The raw material supplied to a refinery or oil sands upgrader.
Fluid catalytic cracking unit (FCCU)	An FCCU takes long chain hydrocarbons and breaks them into smaller value-added products in a heating and chemical process called hydro-cracking.
Oil	Condensate, crude oil, or a constituent of raw gas, condensate, or crude oil that is recovered in processing and is liquid at the conditions under which its volume is measured or estimated.

Oil sands	Refers to a mixture of sand and other rock materials containing crude bitumen or the crude bitumen contained in those sands.
Pentanes Plus	A mixture mainly of pentanes and heavier hydrocarbons that ordinarily may contain some butanes and is obtained from the processing of raw gas, condensate or crude oil.
PADD	Petroleum Administration for Defense District. Defines a market area for crude oil in the U.S.
Refined Petroleum Products	End products in the refining process (e.g. gasoline).
Residual fluid catalytic cracking (RFCC)	An alternative to coking for converting the heaviest part of the barrel when the crude quality is high, i.e., low sulphur and low metals content.
Synthetic bitumen (Synbit)	A blend of bitumen and synthetic crude oil that has similar properties to medium sour crude oil.
Upgrading	The process that converts bitumen or heavy crude oil into a product with a lower density and viscosity.
Western Canadian Select (WCS)	WCS is comprised of existing Canadian heavy conventional and bitumen crude oils blended with sweet synthetic and condensate diluents.
West Texas Intermediate (WTI)	WTI is a light, sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

ABBREVIATIONS

API	American Petroleum Institute
BP	British Petroleum
CAPP	Canadian Association of Petroleum Producers
EIA	U.S. Energy Information Administration
IEA	International Energy Agency
PADD	Petroleum Administration for Defense District
WCS	Western Canadian Select
WTI	West Texas Intermediate

UNITS

kbd	Thousand barrels per day
mmbd	Million barrels per day
BTU	British thermal units

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