WESTERN CANADIAN PROPANE, HEAVY OIL AND DILUENT SUPPLY AND DEMAND

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I. INTRODUCTION

Purvin & Gertz, Inc. (Purvin & Gertz or PGI), an IHS company (IHS), was engaged by Bennett Jones LLP to provide market analysis services in connection with the anticipated application to the National Energy Board (NEB) by Kinder Morgan Cochin ULC (Kinder Morgan) for approval to reverse the product flow on a portion of the Cochin Pipeline System in Canada (Cochin).

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II. EXECUTIVE SUMMARY

In this report, Purvin & Gertz, Inc., (Purvin & Gertz or PGI) an IHS company (IHS) provides a discussion of propane and diluent supply and demand in North America, in connection with the anticipated reversal of the product flow on a portion of the Cochin Pipeline System (Cochin). Reversing Cochin would take the line out of propane export service and put it into diluent import service. The first part of the report (Sections III and IV) discusses propane supply and demand and the impact on Western Canadian propane markets of taking Cochin out of propane export service. The second part of the report (Sections V and VI) discusses the demand for diluent material in Western Canada.

Approximately 85 percent of Canada's propane supply is derived from processing natural gas in Western Canada. Consequently, forecasts of propane supply are largely dependent upon the outlook for natural gas supply and processing. In the last decade, Western Canadian natural gas markets have been characterized by declining production coupled with rising domestic demand, especially in Alberta. The decline in Western Canadian production has been driven primarily by a low price environment, which resulted from a rapid increase of unconventional natural gas reserves and production in the U.S. The growth of unconventional gas supply has turned North America into a demand constrained market with low prices. PGI expects Western Canadian natural gas supply to decline steadily until the later part of this decade. At that point, natural gas production is expected to begin to increase largely driven by increased demand for Liquified Natural Gas (LNG) exports. Natural gas exports to the U.S. are also expected to decline for the balance of this decade.

PGI anticipates that a relatively high gas processing margin environment will persist through 2020. Consequently, producers will continue to pursue rich gas prospects and all available Natural Gas Liquids (NGL) will be recovered. Nevertheless, propane supply is expected to decline with natural gas supply, at least until the later part of the decade. PGI expects domestic propane demand will increase, which, combined with declining supply, implies that propane exports to the U.S. will decline similar to natural gas.

If Cochin is reversed, the displaced propane volumes would have several alternative routes to export markets, including other pipelines and rail. PGI believes that the combination of declining propane supply, increasing domestic demand and incremental pipeline and/or rail exports means that the market impact of taking Cochin out of propane service would be minimal. If natural gas and propane production were to be much higher than expected, PGI believes that there would still be adequate pipeline and rail capacity to export the higher volumes even if there were no incremental domestic demand.

Western Canadian crude oil production is growing, led by increases in production from the vast oil sands deposits in Alberta. Partly offsetting this trend has been a slow decline in conventional crude production, although tight oil developments may slow, or even reverse, the decline in conventional light crude production. A comparison of available crude production forecasts confirms a general consensus that the growth rate for bitumen will exceed that of synthetic crude oil (SCO) due to cancellation of upgrading projects. At present, most in-situ bitumen is produced from the Cold Lake area. However, future production growth from the Athabasca region will surpass other oil sands regions.

The outlook for growing bitumen production will increase the requirement for diluent, which is needed to meet export pipeline specifications for density and viscosity. Diluent demand far outstrips the available supplies in Western Canada, and future growth in bitumen production will exacerbate this situation. Pentanes plus (C5+) includes gas plant recovery and segregated condensate production. There has been considerable interest in sourcing alternative diluents, including imported and recycled streams, as well as SCO. The Enbridge Southern Lights pipeline from Chicago to Edmonton started up in 2010, and other diluent pipelines are proposed. Additional imported condensate supplies or SCO blending will be required. However, the supply of segregated SCO is likely to be limited. PGI concludes that the condensate volume available for delivery by a reversed Cochin Pipeline could be readily accommodated in Western Canada.

III. WESTERN CANADIAN NATURAL GAS

Approximately 85 percent of Canada's propane supply is derived from processing natural gas in Western Canada. The balance of Canada's propane supply is recovered across the country primarily in refineries, petrochemical plants and heavy oil upgraders.

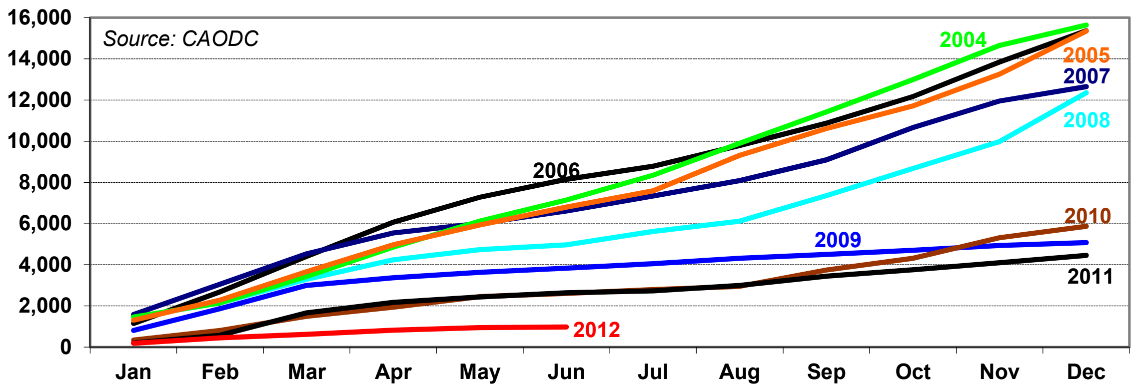
The distribution of propane production implies that forecasts of propane supply are largely dependent upon the outlook for natural gas supply and processing. The following discussion of gas supply and flow forecasts is provided as the basis for the propane outlook in this report.

WESTERN CANADIAN NATURAL GAS SUPPLY OVERVIEW

Over the last decade, Western Canadian natural gas markets have been characterized by flat to declining production coupled with rising domestic demand, especially in Alberta. In the Western Canada Sedimentary Basin (WCSB), natural gas directed drilling surged in the 2003 through 2007 period in response to higher demand and prices. Drilling and production costs surged as well. Natural gas well completions exceeded 15,000 wells per year in each of 2004, 2005 and 2006. Production remained relatively flat through the period of increased drilling activity indicating that high levels of drilling activity are required to maintain the productive capacity of the basin.

In the 2007/08 period, drilling declined as a result of relatively weak prices and high costs. There were approximately 12,000 gas well completions in each of 2007 and 2008. Natural gas production and exports declined in 2008. In the fall and winter of 2008/09, natural gas directed drilling throughout North America declined sharply as a result of very weak natural gas prices and the worsening economic conditions. Low natural gas prices have persisted and the low level of drilling activity continued in Western Canada throughout 2009 (5,082 completions), 2010 (5,868 completions) and 2011 (4,452 completions). Completions in the first half of 2012 were at roughly 37 percent of the 2011 rate. The following chart illustrates the recent decline in drilling activity.

FIGURE III-1
CUMULATIVE GAS WELLS COMPLETED IN WESTERN CANADA



The outlook for 2012/13 is for continued low drilling rates and low gas production as a result of very weak natural gas prices.

The development of unconventional gas resources in North America has been a significant contributing factor to the decline in gas directed drilling in Western Canada. The rapid increase in shale gas reserves and production in recent years has been described as a "Game Changer" for the entire North American natural gas business. A combination of innovative drilling techniques including horizontal wells and hydraulic fracturing as well as seismic imaging technologies helped to drive very large reserves and production increases in unconventional areas throughout North America. Expectations are that there will be adequate natural gas supplies close to the large demand centers in North America for many years to come. These areas are traditional markets for Western Canadian natural gas exports and therefore, demand for Western Canadian natural gas is expected to decline in these areas.

The rapid growth of reserves and production has turned North America into a demand constrained market. The implication is that North American natural gas prices should stay relatively low for the foreseeable future. This does not bode well for natural gas in Western Canada. Since Western Canadian prices are typically priced at a discount from U.S. prices, then low prices in the U.S. means lower prices in Western Canada. The low price environment has been a major factor in the decline in natural gas drilling in Western Canada since 2007. Furthermore, natural gas directed drilling activity is expected to remain relatively low over the next several years.

One consequence of lower drilling activity is that conventional natural gas production is now clearly in decline in Alberta and the prospects for long-term conventional production from the WCSB look less promising than once thought. However, the outlook for unconventional gas production is more encouraging, similar to the U.S. Production of shale gas in Western Canada is growing in the Montney and Horn River shale gas plays in Northeastern B.C as well as the Duvernay shale in Alberta. The limited history makes forecasting production from these plays difficult. Nevertheless, unconventional gas production is expected to increase fairly rapidly over the next decade. This should slow, but not reverse, the overall production decline in Western Canada at least until the middle or latter part of this decade.

One positive factor affecting the outlook for natural gas is increased average well productivity. As drilling numbers decline, producers pursue higher potential targets. This high-grading of drilling prospects combined with improved drilling techniques has led to an increase in average well productivities in Western Canada in recent years. On the other hand, if drilling numbers increase in the future, then the recent productivity gains may be moderated somewhat as less promising targets are drilled. Nevertheless, Purvin & Gertz expects that fewer wells will be required in the future to replace production declines.

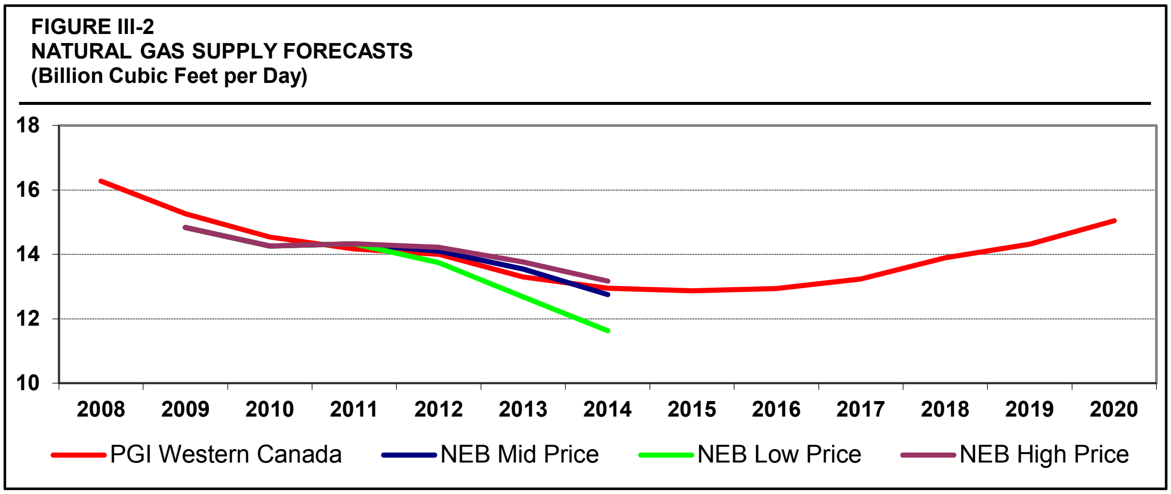
The outlook for Canadian gas supply depends to a large extent on the outlook for drilling activity and estimates of the average productivity of future wells. The resumption of drilling activity depends on higher market prices and the ability of producers to control costs and improve netbacks. While costs have declined from the peaks in 2006 and 2007, in general Western Canada remains a relatively high cost area.

For many years, Arctic gas was considered to be a large source of future gas supply in Western Canada. As a result of the large increases in unconventional gas reserves in North America as well as cost and regulatory issues, Purvin & Gertz does not expect that Arctic gas production will be delivered to Western Canada prior to 2020.

The resolution of all these factors is that Purvin & Gertz' outlook for Western Canadian natural gas supply is a steady decline until the 2015/16 period when increased drilling activity, improved productivity and increasing unconventional production eventually overcomes the overall decline. It should be noted that there is some downside risk in this outlook. If economic conditions worsen or North American demand falters, then it is likely that gas prices will remain very low which could further constrain drilling activity and production in Western Canada.

Figure III-2 illustrates gas supply forecasts from Purvin & Gertz and the National Energy Board[1]. It must be noted that these forecasts are based on different forecasting methodologies and assumptions and therefore the forecasts are not directly comparable. Nevertheless, similar trends are apparent in the forecasts, especially the expectation that Western Canadian natural gas production will decline over the short term.

[1] Short-term Canadian Natural Gas Deliverability 2012 – 2014, National Energy Board, April 2012, Appendix C



WESTERN CANADA NATURAL GAS DEMAND

Purvin & Gertz expects that domestic demand for natural gas in Western Canada will continue to grow over the next decade. Low prices will make natural gas a very competitive fuel.

Residential and commercial sector gas demand is primarily for space and water heating. The main short-term driver is weather-related whereas the principal long-term determinant is population growth. Purvin & Gertz expects relatively slow, but steady, growth in residential and commercial demand in Western Canada.

Many factors impact natural gas demand in the industrial sector. The market share of natural gas is determined by its relative competitiveness to other fuels. Natural gas consumption is expected to grow substantially in the industrial sector over the next decade especially in the production of oil sands bitumen. The production, extraction and upgrading of bitumen is a very energy-intensive process requiring large amounts of steam for thermal production, hot water for oil sands extraction and hydrogen for upgrading. To date, natural gas had been the uncontested fuel of choice for oil sands projects and we believe that natural gas will continue to be the fuel of choice for many of the future oil sands and upgrader operations. The gas consumption potential from future oil sands and upgrader operations is likely to be a significant contributor to future incremental gas demand in Western Canada.

The other industrial components of Western Canada natural demand grow at different rates. The primary driver is based on economic activity with some consideration given to conservation/efficiency gains. The overall outlook for industrial demand growth in Western Canada remains strong.

EXPORT GAS FLOWS

Exports of natural gas from Western Canada have declined in recent years. Shale gas development in the U.S., particularly in the Appalachian Basin of the U.S. Northeast, is displacing WCSB natural gas from traditional markets in the Upper Midwest and New England, causing exports flows to decline. The decline is expected to continue over the near and medium term. Purvin & Gertz estimates that declining gas supplies and increasing demand in Western Canada combined with unconventional gas developments in the U.S. will further reduce gas exports. As gas exports decline, the volumes available for processing at the export straddle plant system[2] are also expected to decrease and consequently, Natural Gas Liquids (NGL) production volumes, including propane, will decrease.

In addition, developments in the Liquified Natural Gas (LNG) business will have an influence on gas exports from Western Canada. Notable projects include the Apache, Encana and EOG Kitimat LNG Project, the BC LNG Export Co-operative project, the Shell, Mitsubishi, CNPC and KOGAS project and the PETRONAS/Progress project as well as several others. Purvin & Gertz does not expect that all these LNG export projects will proceed. Nevertheless, the majority of the gas supply for these LNG export projects is expected to come from unconventional sources in Western Canada. Purvin & Gertz anticipates that LNG exports will spur production growth in Western Canada beginning late in this decade.

GAS QUALITY

Since most of Western Canada's propane supply is derived from processing natural gas, it follows that knowledge of the composition of natural gas is required in order to determine the potential supply of NGL, including propane, in Western Canada. Two aspects of gas quality are important in this discussion. First, in recent years, throughout North America, NGL prices have been relatively high and natural gas prices have been relatively low. Therefore, gas processing margins (often called "frac spreads") have been high, which has encouraged industry participants to target rich gas plays and to recover all available NGL. Although NGL prices have fallen sharply in recent months, Purvin & Gertz anticipates that a relatively high frac spread environment will persist for the balance of this decade. Consequently, producers will continue to pursue rich gas prospects and all available NGL will be recovered.

The second important factor is that the growth of unconventional production and the decline of conventional production will influence overall gas quality. The limited production history of Western Canadian shale gas provides an element of uncertainty regarding its quality. Horn River gas appears to be quite lean but with high CO_2 content while the Montney and Duvernay plays appear to have regions with significant amounts of recoverable NGL. The resolution of these issues is that Purvin & Gertz expects Western Canadian gas composition to increase slowly over the forecast period leading to increased NGL recovery per unit of gas processed.

[2] The straddle plants are large deep cut gas processing facilities that "straddle" gas export pipelines and process gas leaving Alberta. The largest straddle plants are located at Empress on the Alberta/Saskatchewan border and at Cochrane which straddles gas destined for export to California and the Pacific Northwest. Smaller straddle plants are located in Edmonton and at Joffre and process gas consumed within Alberta.

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IV. CANADIAN PROPANE SUPPLY, DEMAND & LOGISTICS

There is a well-developed propane infrastructure in Canada. The propane supply situation is relatively straightforward, being dominated by Western Canadian gas plant production. Smaller volumes are also produced in Canadian refineries. Propane demand is seen across all the provinces, with consumption dominated by conventional and industrial customers. Exports serve to balance supply and demand. Propane is moved by truck, rail and pipeline across Canada and for export to the United States.

PROPANE SUPPLY

The majority of Canadian propane supply comes from natural gas processing in Western Canada. The balance of Canadian propane supply is recovered primarily in refineries, petrochemical plants and heavy oil upgraders.

Conventional natural gas production in Western Canada is expected to decline. Natural Gas Liquids (NGL) production is forecast to decline correspondingly however, increases in gas composition and recovery levels will offset some of the decline in conventional production. PGI expects that there will be a significant excess of gas processing capacity for existing conventional production while new capacity is developed for new unconventional gas production. This will lead to a period of consolidation among existing facilities over the next several years. Nevertheless, there will be adequate economic incentive to ensure that virtually all Western Canadian natural gas will be processed for liquids recovery.

Canadian refinery propane production is expected to remain relatively stable in the next 10 years at roughly 15 percent of total supply. Refinery NGL production excludes volumes which are utilized within the refinery to produce other products, but are not recovered in segregated form for sale or storage.

Upgrader or refinery offgas streams represent a potentially significant new source of NGL volumes in Western Canada. However, these volumes are dependent on future upgrader developments and may be very costly to recover. The offgas streams contain mixed paraffinic and olefinic products. Williams Energy (Canada), Inc. currently extracts an olefinic propane plus NGL mix at the Suncor facility in Fort McMurray and processes the mix at a fractionation facility in Redwater near Edmonton to produce roughly 7,000 barrels per day (B/D) of propane and a similar amount of other products. Williams has built a new ethane plus NGL pipeline from Fort McMurray to the Redwater processing facility. The majority of incremental volumes expected to be moved on the line will be an ethane/ethylene mix, however total propane volumes could be in the 15,000 to 20,000 B/D range.

The Alliance gas pipeline reduces the availability of propane in Western Canada. The Alliance pipeline typically exports about 16,000 to 20,000 B/D of propane with natural gas. This propane volume is not available for recovery in Canada. In the past, when market conditions were favourable, propane injection onto the Alliance system occurred. However, we expect minimal propane injections into Alliance in the future.

PROPANE DEMAND

EXPORTS

The largest propane demand segment is exports, which account for approximately 60 percent of the overall market. Virtually all propane exports are destined for the United States. There is a large seasonal component to propane exports with the majority moving in late summer and fall in anticipation of crop drying and fall/winter heating demand. Propane exports to the United States are transported primarily by pipeline and rail.

The combination of declining natural gas supply and processing with increasing domestic demand leads to the expectation that propane exports will also decline over the next several years.

CONVENTIONAL / DOMESTIC MARKETS

Conventional domestic demand is the next largest segment of the propane market in Canada. In order of consumption, the major domestic propane demand sectors are conventional markets, auto propane, solvent flood, and petrochemical feedstock.

The major conventional use of propane in Canada is for residential and commercial consumption as a space heating, water heating and cooking fuel. Propane usage in the residential and commercial sector is primarily for consumers who are not on local natural gas distribution systems. The residential sector includes a large seasonal housing component. Compared to natural gas and electricity, propane retains a relatively small share of the home heating fuel market. Propane has a higher market share in rural markets and a lower share in urban markets.

One of the largest demand categories is the mining and oil and gas extraction industry. Much of the demand in this sector is for lease fuel and space heating. Industrial construction and manufacturing demand includes paving applications, construction heating, heavy industrial use, food processing, etc. Agricultural demand is primarily for crop drying and space heating.

Annual conventional demand for propane is expected to continue to increase slowly with a growing population and economy.

ENGINE FUEL / AUTO PROPANE

Propane use as engine fuel for automobile transportation was promoted for several years by the Government of Canada, by some provincial governments (particularly Ontario), and by propane distributors. Initially, provincial and federal governments viewed the concept as a means of reducing crude oil imports by the substitution of domestically produced alternative liquid fuels. Because Canada has surplus LPG, incentives to increase domestic LPG use were viewed by governments to be consistent with public policy. To a significant extent, these efforts were successful.

In the 1990s favourable government policies and legislation in both the U.S. and Canada contributed to a significant growth in the number of propane fuelled vehicles. However, in the last decade, the increased availability of biofuels and hybrid electric vehicles has increased the market share of alternative fuelled fleet vehicles. In addition, the development of more complicated, fuel-efficient gasoline engines increases the conversion cost thereby limiting the number of propane fuelled vehicles. In recent years, few OEM propane-fueled vehicles and fewer emissions compliant conversion kits were available in the marketplace. As older propane-fueled vehicles are retired, they are being replaced by other alternative-fueled vehicles. In the future, environmental or clean air initiatives may provide some renewed stimulus for auto propane in Canada. Fleet vehicles currently represent the major market for propane as a transportation fuel, and propane is widely available at a broad network of retail outlets across the country. Some of the more significant applications are light-duty and heavy-duty trucks, taxicabs, buses, delivery and service vehicles. Forklifts and riding lawn mowers are also growing markets for propane as an internal combustion engine fuel. However, without manufacture of propane-fuelled vehicles, and without government incentives, the automobile fuel market is expected to continue to decline.

SOLVENT FLOOD

NGLs are used in hydrocarbon solvent miscible flood enhanced oil recovery projects in Alberta. These projects utilize an ethane plus mix and most of the NGLs are recovered toward the end of these projects. Several projects were developed in the 1980s on the basis of relatively low solvent costs and deferred royalties. No new projects are anticipated and propane requirements for solvent floods in particular are expected to decline.

In the future, some propane may be used as a solvent to enhance in-situ recovery of heavy oil. Other potential uses of propane include use as a diluent material for pipeline shipments of heavy oil and bitumen. An important constraint on these alternative uses is that any significant increase in propane demand in Western Canada would be expected to raise propane prices. This could undermine the economics of solvent type processes or a diluent application.

REFINERY FUEL / INDUSTRY USE

Modest quantities of propane are used within certain Canadian refineries as fuel. Refinery consumption of propane as fuel remains at about one percent of total domestic propane disposition. The largest regional consumption occurs in the Atlantic Provinces where refineries do not have access to seasonal storage or an alternative disposition.

PROPANE PRICE-SENSITIVE DEMAND

In Canada, propane is a relatively small component of the petrochemical feedstock slate and is largely price driven. Two ethylene plants in Eastern Canada consume some propane and/or butane. Actual consumption is seasonal and is generally higher in the summer than in the winter due to relatively lower prices in the summer. Propane consumption in these facilities is expected to decline as they convert to crack cheaper ethane sourced from the Marcellus area in the U.S.

The Western Canadian petrochemical industry may consume increased amounts of propane in the future as their traditional ethane feedstock supplies fall with declining natural gas supplies. The Western Canadian petrochemical facilities were designed to crack ethane; however the facilities can crack relatively small amounts of propane and/or butane. PGI estimates that, in total, the facilities could crack up to approximately 30,000 B/D. The capacity is limited by byproduct handling capacity. PGI does not anticipate that significant quantities of propane or butane will be cracked in Western Canada over the forecast period because Western Canadian propane and butane markets are expected to tighten with declining gas production and steady demand in most of the traditional propane market areas. Thus, propane and butane are likely to be relatively high cost feedstocks. Any material increase in Western Canadian petrochemical consumption would likely raise prices which would tend to dampen petrochemical demand. Nevertheless, PGI expects that some propane and butane cracking will occur on an opportunistic basis when pricing is favorable.

In July 2012, Williams Energy (Canada), Inc. announced that it is exploring the possibility of building a propane dehydrogenation facility in Alberta to capture the expected price premium of propylene over propane. The 1 billion pounds per year facility would consume roughly 20,000 B/D of propane which would be sourced from Williams' offgas extraction facilities. As discussed above, such a material increase in propane consumption will tend to raise prices and dampen demand. If built, the increased domestic propane consumption would reduce exports.

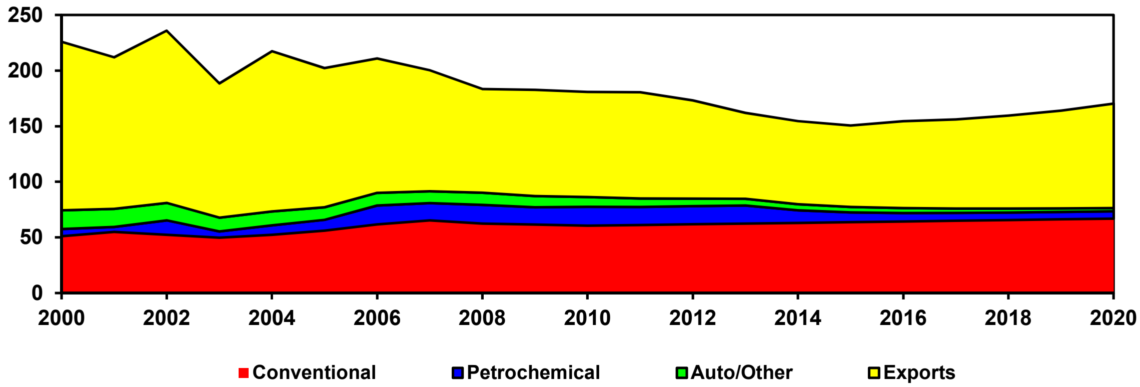
PROPANE SUPPLY / DEMAND BALANCE

As with the other NGLs in Canada, propane supply is closely tied to natural gas production. Western Canada still has a significant surplus of propane. Exports from Western Canada are approximately evenly split between Eastern Canada and the U.S. In Alberta, not all of the propane is segregated. Large volumes of propane move to Sarnia/Marysville in the Enbridge NGL Mix. Segregated propane is exported from Alberta by truck, rail and the Cochin Pipeline.

Canadian propane markets are expected to tighten with declining gas production and steady markets in most of the traditional propane demand areas. Solvent flooding in Alberta is expected to decline. Conventional usage is expected to see gradual growth. Petrochemical usage is expected to be variable and exports should decline until the later part of the decade.

The following figure presents the Canadian propane supply and demand outlook. Exports serve to balance supply and demand. PGI does not include material demand increases from the petrochemical industry or solvent use in the heavy oil business in this outlook. If these demands were to materialize, then propane exports would be reduced correspondingly.

FIGURE IV-1
CANADA PROPANE SUPPLY/DEMAND
(Thousand Barrels per Day)



WESTERN CANADIAN PROPANE LOGISTICS

Propane is transported by truck, rail and pipeline to markets across Canada and in the U.S. In Western Canada, there are three principal pipelines (with associated storage systems), which ship NGL from major western production sources to end-use markets in eastern Canada and the U.S. The Enbridge System ships NGL mixes from Alberta to the Canadian border, where it connects to its affiliated pipeline in the U.S., the Lakehead System, operated by Enbridge Energy Partners L.P. The majority of volumes on the Enbridge system are delivered to Sarnia, Ontario. Relatively small amounts are also delivered to Superior, Wisconsin. The second major Canadian NGL line, the Cochin Pipeline[3] transports specification grade products to markets in the U.S. Midwest and eastern Canada. Finally, the Petroleum Transmission Company (PTC) pipeline operated by Spectra Energy extends about 600 miles from the Empress, Alberta straddle plants to Fort Whyte, Manitoba (near Winnipeg) where most of the propane volumes are exported to the U.S. via rail with the remainder being sold locally. None of the three pipelines are currently operating at or near capacity.

The Alliance Pipeline also provides options to Canadian producers to move NGL to the U.S. market. The pipeline system was constructed to move “wet” natural gas from northeastern British Columbia and northwestern Alberta to the Chicago area. The pipeline operates under high-pressure, allowing it to move ethane, propane and some heavier natural gas liquids to U.S. markets as a component of the rich gas. The Aux Sable straddle plant was built in the Chicago area to extract the entrained liquids. The Alliance system is expected to remain full at least through 2015 and will likely continue to remove significant volumes of NGL from Western Canada for the balance of this decade and into the next.

[3] Owned by Kinder Morgan Energy Partners; operated in Canada by Kinder Morgan Cochin ULC; operated in the U.S. by Kinder Morgan Cochin LLC

COCHIN PIPELINE REVERSAL

The Cochin Pipeline commenced operation in 1979, and is 100 percent owned by Kinder Morgan subsequent to purchasing BP's 50 percent interest in the first quarter of 2007. This 1,902-mile, 12-inch light hydrocarbon pipeline extends from salt cavern storage at Fort Saskatchewan, Alberta, through the U.S. south of the Great Lakes and back into Canada at Windsor, Ontario. The Cochin Pipeline mainly transports specification-grade propane to the U.S. Midwest and eastern Canadian markets. Ethylene was shipped on the Cochin Pipeline until March 2006, when a voluntary pipeline pressure restriction precluded the transport of ethylene. Ethane shipments were stopped in mid-2007. The line is operating at well below full capacity. Propane volumes averaged around 30,000 B/D from 2006 through 2009, fell to around 20,000 B/D in 2010 and rose to approximately 26,500 B/D in 2011.

Kinder Morgan has investigated several options to improve utilization of the Cochin pipeline including moving crude oil from Western Canada to U.S. markets and moving ethane from the Marcellus shale play to Sarnia and the Chicago area. Kinder Morgan is currently proposing to reverse the Cochin Pipeline to import condensate material for the heavy oil diluent market in Western Canada. As a consequence of reversing the line, it would be taken out of propane export service.

PROPANE IMPLICATIONS OF COCHIN REVERSAL PROJECT

Taking the Cochin Pipeline out of propane export service is not expected to have a material impact on propane markets in Western Canada. Most, if not all, of the shippers on Cochin are already active participants in export propane markets either via rail, other pipelines or both. There is sufficient excess capacity between the Enbridge, PTC and Alliance systems to accommodate all the propane volumes that would come off the Cochin Pipeline. Alternatively, the volume could be moved by rail. Assuming the displaced Cochin propane volume remained at 2011 levels (26,500 B/D), then approximately 37 rail cars per day would be required to move all the volumes. While this is not a trivial amount, it is also not a particularly large number of rail cars. PGI believes that the combination of declining propane supply, increasing domestic demand and incremental pipeline and/or rail exports means that the market impact of taking the Cochin Pipeline out of propane service will be minimal.

V. HEAVY CRUDE / BITUMEN PRODUCTION

This section presents the current Purvin & Gertz outlook for production of heavy crude and bitumen in Western Canada. The future potential for crude production in Western Canada is focused on the vast oil sands deposits in Alberta. A discussion of the Purvin & Gertz outlook for bitumen and synthetic crude oil (SCO) production is provided. This section also presents our forecast of the production of pentanes plus (C5+) or condensate in Western Canada.

WESTERN CANADIAN CRUDE OIL PRODUCTION

Crude oil production in Western Canada includes crude produced from both conventional and oil sands resources. Conventional crude oil production includes light crude oil in Alberta, British Columbia, Saskatchewan, Manitoba and the Northwest Territories; heavy crude oil in Alberta and Saskatchewan; and, C5+ or condensate in the western provinces. Oil sands crude includes bitumen and SCO, which is produced by any of a number of processes referred to as upgrading. The forecast is summarized by crude type in the following table.

WESTERN CANADA CRUDE OIL PRODUCTION
(Thousand Barrels per Day)

	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Conventional Light	686	530	528	573	668	709	731	744	747	753	757	759	747
Synthetic (1)	428	676	812	891	962	989	1,007	1,042	1,086	1,117	1,152	1,168	1,196
Pentanes Plus (2)	165	171	146	145	136	125	118	114	114	114	116	118	122
Conventional Heavy (1)(3)	460	428	391	394	400	401	390	373	357	343	332	321	309
Bitumen (1)(3)	255	393	664	714	805	933	1,059	1,149	1,318	1,476	1,605	1,733	1,849
Total	1,995	2,198	2,541	2,717	2,972	3,156	3,305	3,422	3,622	3,803	3,961	4,100	4,222

Notes:
(1) Net production after upgrading to synthetic crude. Includes synthetic crude produced for diluent.
(2) Includes C5+ used as diluent
(3) Net heavy crude and bitumen after upgrading; excludes diluent

In 2011, total crude oil production in Western Canada was approximately 2.7 million B/D. Of this, conventional crude oil and C5+ or condensate production was estimated at 1.1 million B/D, while oil sands production was estimated at 1.6 million B/D.

FORECAST COMPARISON

Purvin & Gertz forecasts total crude production in Western Canada. The Purvin & Gertz forecast for this report was prepared in March 2012. Refer to Figure V-1, where the Purvin & Gertz March 2012 forecast is compared with forecasts from the Canadian Association of Petroleum Producers (CAPP). The CAPP 2012 forecast is presented in the CAPP 2012 forecast report[4]. The CAPP 2011 Growth forecast is presented in the CAPP 2011 forecast report[5]. Both are shown in Figure V-1 for comparison purposes.

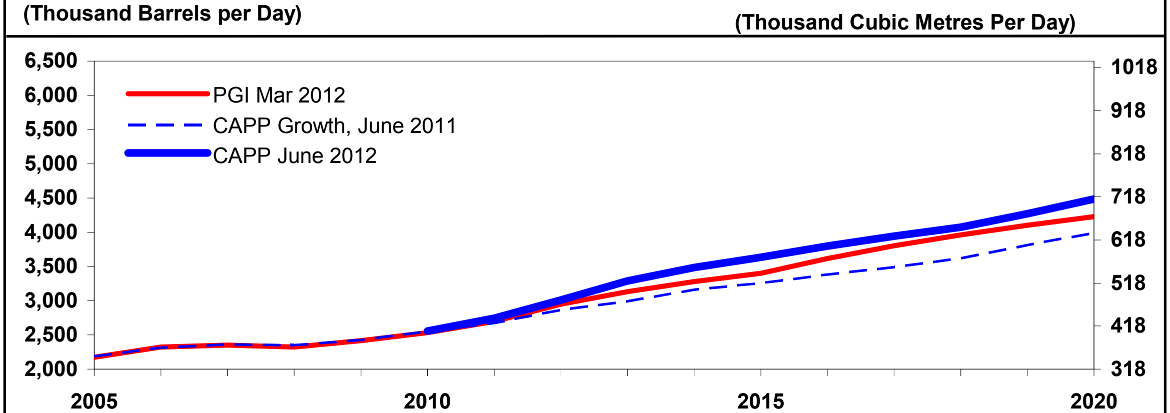
[4] CAPP, "Crude Oil Forecast, Markets & Pipelines", June 2012

[5] CAPP, "Crude Oil Forecast, Markets & Pipelines", June 2011

All forecasts include production increases for Western Canadian crude for the forecast period. The Purvin & Gertz March 2012 forecast shows an increase in Western Canada crude production of about 1.28 million B/D between 2012 and 2020, to reach 4.23 million B/D.

The CAPP 2012 production forecast includes a trend of increasing total Western Canada production. For 2020, the CAPP 2012 forecast is higher by 496,000 B/D compared to the CAPP 2011 Growth forecast. The CAPP 2012 forecast shows an absolute increase of 1.47 million B/D between 2012 and 2020, to reach 4.49 million B/D of production. This is about 250,000 B/D above the current Purvin & Gertz forecast.

FIGURE V-1
TOTAL WESTERN CANADIAN CRUDE PRODUCTION
(Thousand Barrels per Day)



OVERVIEW OF CANADIAN OIL SANDS PRODUCTION

Oil sands production forecasts are adjusted to reflect Purvin & Gertz views of current and future developments. Total Canadian crude oil production is growing, led by increases in bitumen and SCO from the oil sands. Partly offsetting the growth in bitumen and SCO has been a slow decline in Western Canadian conventional crude production. However, tight oil developments have the potential to slow, or even reverse, this decline.

The resource base in Western Canada's oil sands deposits is recognized to be vast. This huge resource potential has encouraged the interest of a wide group of companies to increase production from the oil sands. Many projects have been announced to commence new production of bitumen. Some are underway, while others are in various stages of planning and/or regulatory review.

BITUMEN

Bitumen is found in large reserves in several areas of Northern Alberta. The Alberta Energy Resources Conservation Board (ERCB) has deemed the hydrocarbon resources found in certain regions of the province to be oil sands. The Athabasca, Cold Lake, and Peace River Oil Sands Areas are delineated for this purpose.

Bitumen is the heavy (8^o to 12^o API gravity) viscous material that is generally recovered by in-situ techniques such as steam stimulation in its various forms, or by mining and extraction from the oil sands. Bitumen production includes commercial projects, projects with primary (cold) recovery, conventional non-project production, and experimental production. Bitumen is also extracted from mining operations before upgrading to SCO at several facilities.

The Purvin & Gertz bitumen forecast is summarized in the following table. Bitumen that is produced and upgraded as part of an integrated resource project is excluded.

ALBERTA BITUMEN PRODUCTION (1) (2)
(Thousand Barrels per Day)

	Actual		Estimate		Forecast								
	2000	**2005**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Athabasca, In-Situ	9	64	146	164	251	288	370	445	538	653	769	879	977
Mining	0	0	0	0	4	84	103	106	157	189	189	195	211
Subtotal	9	64	146	164	255	372	473	550	695	843	958	1,074	1,188
Cold Lake/Primrose	181	268	426	467	456	457	477	491	516	533	547	556	564
Lindbergh	54	41	26	24	23	22	22	21	20	20	19	18	18
Peace River	4	25	39	36	39	42	46	49	58	63	69	76	80
Wabasca	44	50	56	54	65	74	79	84	94	92	86	82	81
Total	292	448	693	746	838	968	1,096	1,196	1,383	1,551	1,679	1,807	1,930
Memo: Total In-Situ	292	448	693	746	834	884	993	1,090	1,225	1,361	1,490	1,613	1,719

Notes: (1) Bitumen does not include production which is upgraded as part of integrated projects (in-situ or mining).
(2) Includes experimental and conventional production.

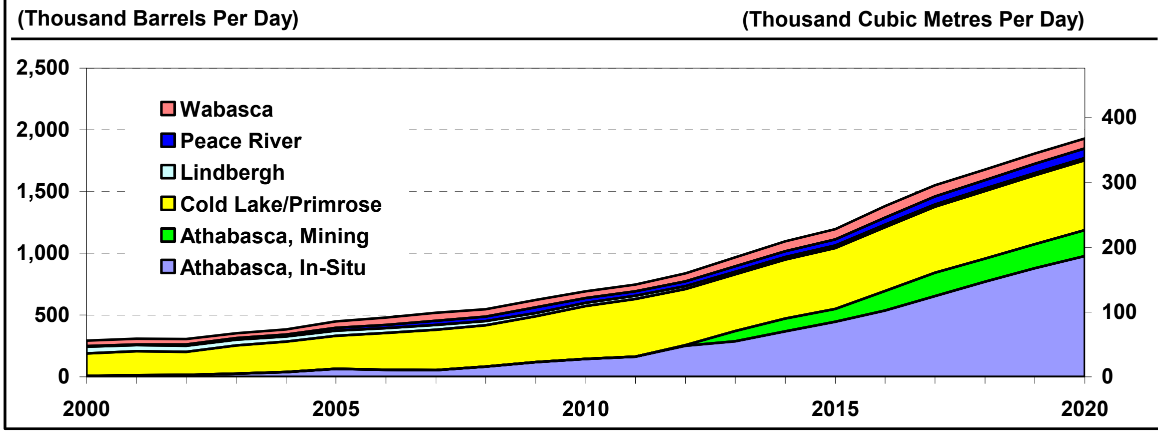
In-Situ Bitumen

We have classified in-situ bitumen production according to five specific areas, specifically Cold Lake, Lindbergh, Athabasca, Wabasca, and Peace River. Bitumen production has risen steadily for two decades and it exceeded 500,000 B/D by 2007, excluding bitumen which is upgraded at integrated resource projects. Production has continued to increase, reaching approximately 750,000 B/D in 2011.

At present, most in-situ bitumen is produced from the Cold Lake area. There has also been significant production from the Lindbergh, Peace River, and Wabasca regions. However, production from the Athabasca region has grown and now exceeds the other regions except Cold Lake.

Figure V-2 presents the history and forecast for bitumen production by major region in Alberta. The figure also indicates production in the Athabasca region from in-situ as well as mining operations. It does not include bitumen which is upgraded to SCO as part of integrated oil sands projects.

FIGURE V-2
ALBERTA BITUMEN PRODUCTION BY REGION



Mined Bitumen

Most bitumen produced at oil sands mining operations is upgraded to SCO. There are currently four commercial mining operations that produce bitumen with subsequent upgrading. These are Suncor, Syncrude, the Athabasca Oil Sands Project (AOSP) and Canadian Natural Resources Limited (CNRL) Horizon. Imperial Oil and ExxonMobil are nearing completion of the construction of the Kearl Lake mine and extraction facility.

If mined bitumen is blended for pipeline movement to refineries, it would have to be adequately treated at the source to minimize solids content. Unlike the current mining operations, Kearl Lake will use paraffinic froth treatment technology so that the bitumen blend quality will be suitable for blending, pipelines and refining.

UPGRADING

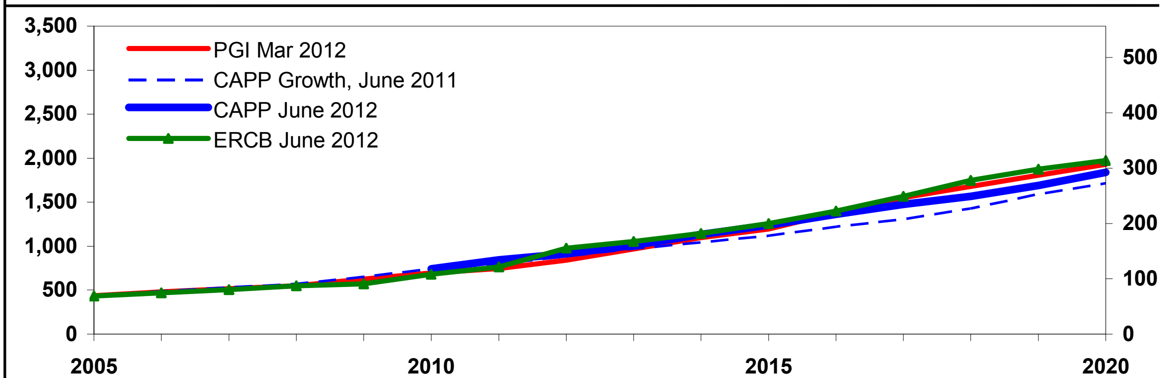
Upgrading projects that produce SCO may be differentiated based on whether the upgrading facility is integrated with crude production or is a standalone facility. Integrated facilities upgrade bitumen to SCO, while midstream upgraders receive heavy oils as feedstock and produce SCO.

SCO production from Western Canada has increased in recent years. SCO production is estimated at around 890,000 B/D in 2011, including production from standalone upgraders, and before use as diluent. Potential capacity for SCO could increase, based on current projects and expansions. However, many planned upgrading projects have been cancelled or decisions deferred, in response to concerns about high capital costs and narrow light/heavy crude price differentials. North West Upgrading (NWU) is planning to construct a standalone bitumen upgrading refinery near Redwater, AB with an initial capacity of 50,000 B/D of bitumen. The initial phase is scheduled to start up in 2015 and produce diluent, diesel and gas oil instead of a blended SCO product. Two additional upgrader phases are also planned.

OIL SANDS PRODUCTION FORECAST COMPARISON

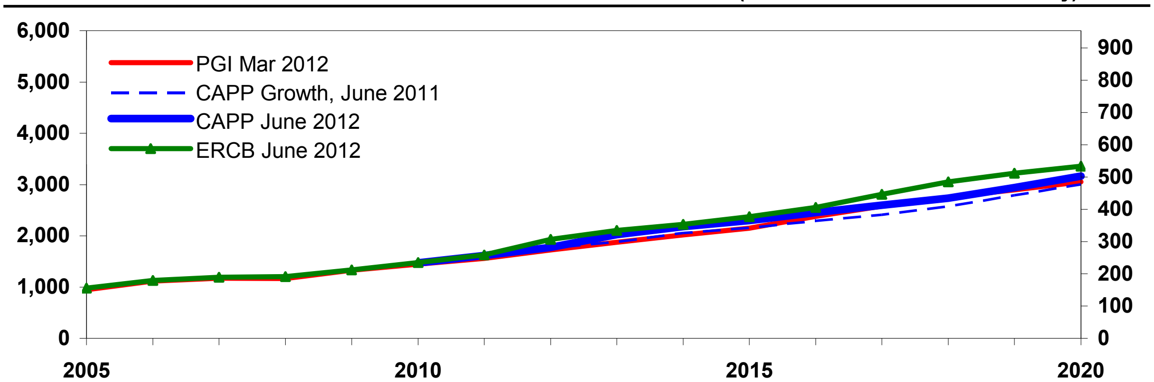
Bitumen production forecasts (excluding diluent) are compared in Figure V-3. The ERCB 2012 forecast is shown in Figure V-3, in addition to the CAPP and PGI forecasts. The CAPP forecasts exclude upgrading. For oil sands projects where bitumen production is integrated with upgrading, PGI considers this to be SCO production rather than bitumen. Any difference in volume is primarily due to the yield loss for upgrading. The Purvin & Gertz forecast is comparable to the CAPP 2012 forecast through 2020, and lower than the ERCB 2012 forecast.

FIGURE V-3
BITUMEN PRODUCTION
(Thousand Barrels per Day) **(Thousand Cubic Metres Per Day)**



Total oil sands production forecasts (excluding diluent) are shown in Figure V-4. Oil sands production includes in-situ and mining production of bitumen.

FIGURE V-4
TOTAL OIL SANDS CRUDE PRODUCTION
(Thousand Barrels per Day) **(Thousand Cubic Metres Per Day)**



By 2015, the Purvin & Gertz March 2012 forecast has oil sands production increasing by about 420,000 B/D over 2012, to reach 2.15 million B/D. This is somewhat less than the CAPP 2012 Forecast for 2015 (2.3 million B/D). Figure V-4 also presents the 2012 oil sands production forecast prepared by the ERCB.[6] The ERCB forecast is the highest of the available forecasts, at 2.37 million B/D for 2015, including an estimate of yield losses for upgrading. The ERCB forecast for 2015 is about 225,000 B/D above PGI's forecast.

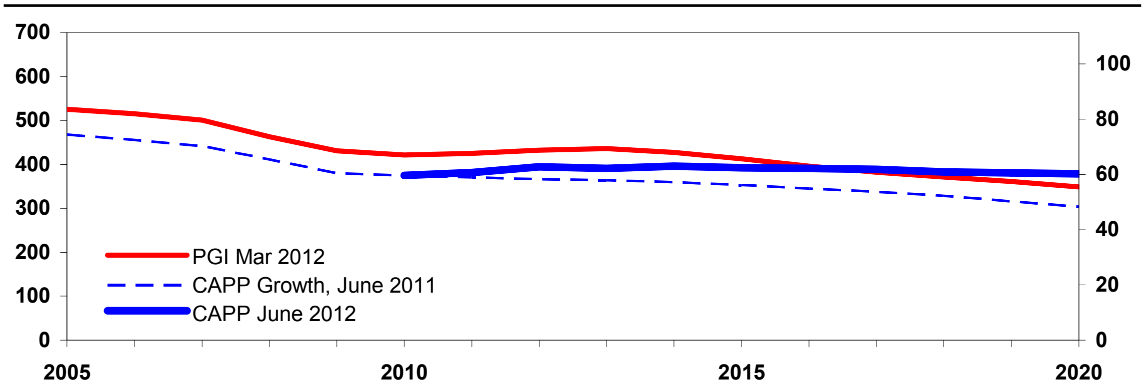
By 2020, the Purvin & Gertz March 2012 forecast of oil sands production reaches 3.18 million B/D, which is 200,000 B/D lower than the CAPP 2012 forecast, and 270,000 B/D lower than the ERCB forecast. Among the forecasts considered, there is a consensus that crude oil supply from Western Canada will continue to grow due to growth in oil sands production.

CONVENTIONAL HEAVY CRUDE PRODUCTION

Conventional heavy crude is produced in both Alberta and Saskatchewan. Production has been in decline, and further declines are anticipated. Conventional heavy crude production experiences relatively high decline rates unless new wells are drilled and brought on stream. Conventional heavy crude production is highly sensitive to price and light/heavy price differentials.

Figure V-5 shows general agreement on the conventional heavy crude outlook between the Purvin & Gertz March 2012 forecast and the CAPP 2011 Growth forecast. However, the CAPP 2012 forecast includes a much stronger forecast for conventional heavy crude. As a result, the CAPP 2012 forecast is above the Purvin & Gertz forecast after 2017. A modest decline of around 20,000 B/D in conventional heavy crude production is forecast by PGI between 2012 and 2015. CAPP is projecting conventional crude to be essentially flat over this period, although their prior forecast (2011 Growth) had production declining.

FIGURE V-5
CONVENTIONAL HEAVY PRODUCTION
(Thousand Barrels per Day) **(Thousand Cubic Metres Per Day)**

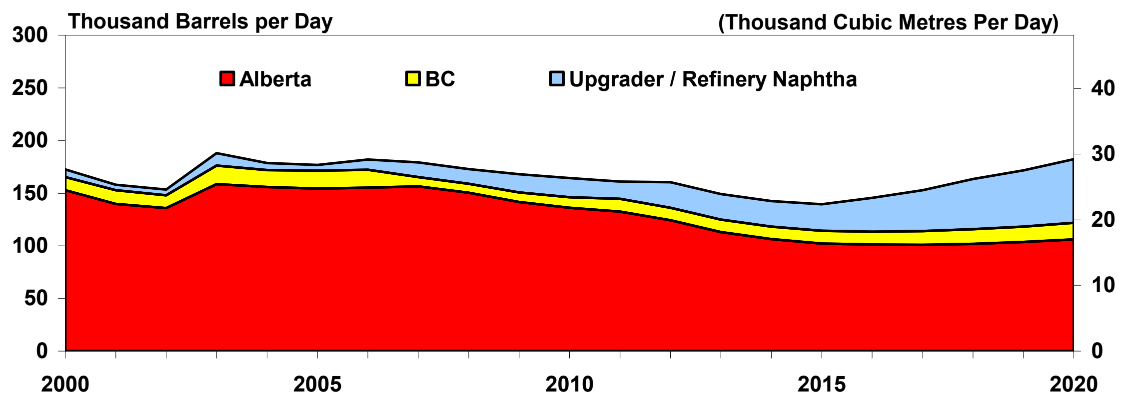


[6] Alberta Energy Resources Conservation Board ST98-2012, "Alberta's Energy Reserves 2011 and Supply/Demand Outlook 2011-2021"

PENTANES PLUS SUPPLY

The Purvin & Gertz production forecast for C5+ and naphtha is developed from forecasts of natural gas production in Alberta, British Columbia, Saskatchewan and Northwest Territories. The natural gas production forecast is presented in Section III. Total Western Canadian C5+/condensate supply was approximately 160,000 B/D in 2011. The supply of C5+ is forecast to decline with natural gas production through 2015.

FIGURE V-6
CONDENSATE AND NAPHTHA PRODUCTION



Other potential sources of C5+ supply in Western Canada include upgrader and refinery naphtha. The quantity of naphtha available from these facilities is price-sensitive. Our forecast for the post-2015 period includes the contribution from the North West Upgrading facility, which is expected to produce naphtha specifically for the diluent market.

In the later part of the decade, domestic condensate volumes are expected to begin to increase with natural gas and upgrader/refinery volume growth.

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VI. DILUENT REQUIREMENTS FOR HEAVY CRUDE/BITUMEN

Diluent is a general term for any hydrocarbon stream which is used to reduce the viscosity and density of heavy crude for transportation by major trunklines. Pentanes plus (C5+) or condensate is utilized as a diluent for heavy crude and bitumen. This section presents our forecast for the balance in C5+ supply, based on availability of suitable diluent streams that are either produced or transferred into Western Canada. Other sources of diluent are considered, to meet the balance of the growth in diluent demand. The supply of bitumen blends and segregated SCO depends on diluent availability and selection.

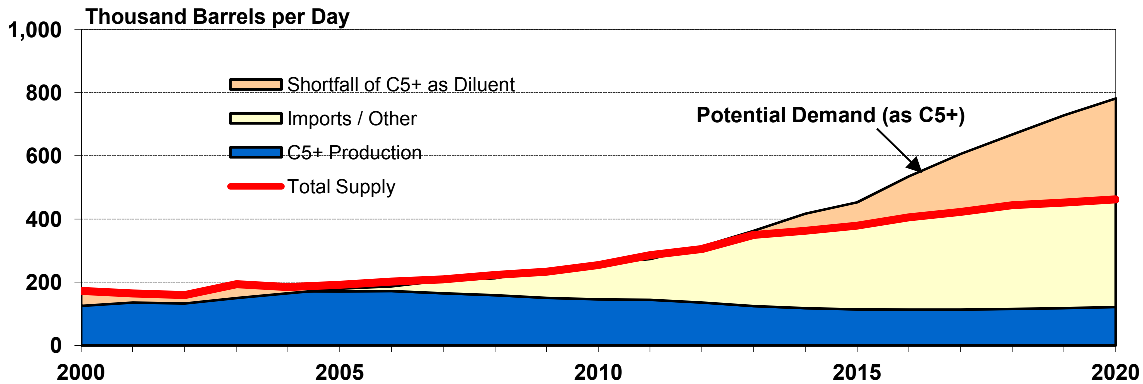
DILUENT SUPPLY AND DEMAND

Diluent demand far outstrips the available supplies in Western Canada, and future growth in bitumen production will exacerbate this situation. C5+ supply includes gas plant recovery and segregated condensate production. Most of the C5+ available in Western Canada is produced in Alberta, and essentially all sources of C5+ supply in Western Canada are currently being captured.

Since C5+ supply is already less than diluent demand, there has been considerable interest in sourcing alternative diluents. Imports and transfers into the region have increased in recent years. Enbridge started its Southern Lights Pipeline from Chicago to Edmonton in 2010, so imports of C5+ and recycle of refinery naphtha have increased. More condensate imports are expected to reach Alberta from Southern Lights and potentially other pipelines, as well as by rail. The role of SCO as a diluent is expected to be limited until after other sources of supply are absorbed.

The forecast diluent requirements for conventional heavy crude and bitumen are presented in Table VI-1. As indicated in the table, and summarized in Figure VI-1, there will not be sufficient C5+ to meet the anticipated increasing demand for diluent to blend with bitumen. Currently, the supply/demand balance is tight and incremental production will require other diluent sources. To blend projected bitumen production with C5+ would require around 450,000 B/D of supply by 2015. Without other diluent available, the demand for C5+ could rise as high as 780,000 B/D by 2020. Supply is not forecast to be sufficient, even with pipeline development for more imports and recycle.

FIGURE VI-1
CONDENSATE AND NAPHTHA SUPPLY/DEMAND



DILUENT IMPORTS/RECYCLE

The import of hydrocarbon streams of suitable quality for diluent is the most expedient short term option to increase supply. Condensate premiums in Alberta have been high enough to support rail imports since about 2005. PGI estimates that imports have increased to over 100,000 B/D in 2011, of which 65,000 B/D was shipped in the Southern Lights Pipeline. However, current data on imports is limited by the quality of available statistics.

Condensate and natural gasoline are now being imported by rail for use as diluent. Natural gasoline is being sourced in the U.S. Rocky Mountains and Midcontinent to various offloading terminals in Alberta. Since early 2006, Cenovus has been importing Pacific Rim condensate to Kitimat, British Columbia with rail deliveries to an Edmonton terminal. This movement is typically about 10,000 B/D.

Larger volumes of diluent imports are expected by pipeline. Projects are described below. Enbridge's Southern Lights Pipeline has capacity for up to 180,000 B/D of diluent components to be shipped from Chicago to Edmonton. Condensate could be delivered to Chicago from the Gulf Coast for the Southern Lights Pipeline.

Natural gasoline is primarily produced from natural gas processing. Therefore, supply is strongly linked to natural gas production. U.S. production is approximately 300,000 B/D and is growing with natural gas production. U.S. imports vary widely on a monthly basis, but are estimated to be in the 40,000-50,000 B/D range in recent years. Imports will balance supply with demand. Most U.S. natural gasoline is produced from associated gas in the Petroleum Administration for Defense District (PADD) III region, including the deepwater Gulf of Mexico. Texas is the largest producer within PADD III due to an abundance of fractionation capacity.

Natural gasoline is a poor gasoline blendstock, yet refineries are the largest end users. Refinery demand is for both gasoline blending and isomerization feed. Petrochemical demand for natural gasoline feedstocks is price sensitive, and depends to a large extent on revenues from byproduct streams from ethylene production. Petrochemical demand is expected to be limited in the future, as many U.S. petrochemical facilities shift to crack cheaper ethane. All U.S. chemical feedstock demand for natural gasoline is located in PADD III. Other demand includes diluent for heavy crude blending, denaturant for ethanol production and splash blending into gasoline. Natural gasoline would be available for the diluent market in Western Canada, assuming that the price is high enough to bid supplies away from gasoline blenders and petrochemical producers in the source region.

DILUENT DEMAND FOR SCO

As described above, the traditional diluent for bitumen blending has been pentanes plus or condensate. SCO is a potential source of diluent. Some use of SCO as diluent began in the winter of 2002-2003. Without more C5+ or equivalent supply, SCO could become an increasingly important diluent because of its availability in the Athabasca region.

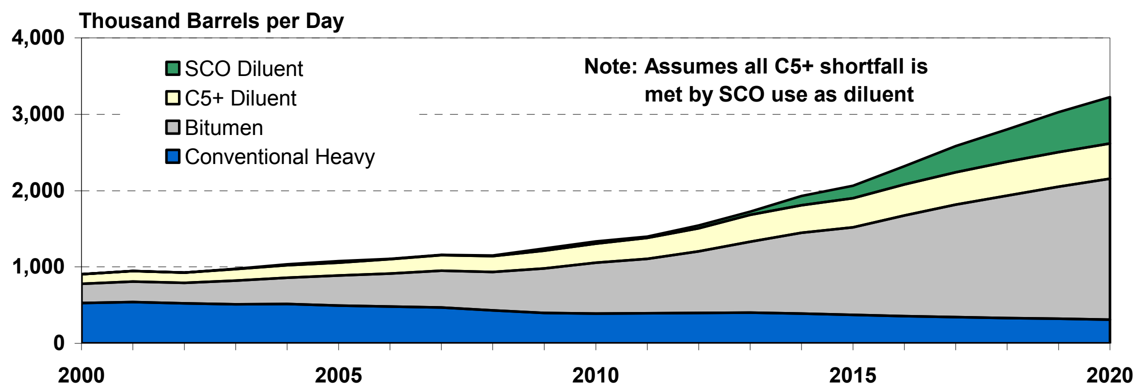
Some bitumen projects have used SCO as diluent, although the resulting blend (SynBit) is generally reblended with other heavy crude blends into the Western Canadian Select (WCS) stream. Our supply/demand balance forecasts that there will be a growing demand for SCO, even as condensate imports increase.

For Athabasca bitumen, a “DilBit” blend of C5+ requires approximately 33 percent diluent, while a SynBit blend of SCO requires approximately 49 percent SCO. On this basis, one barrel of Athabasca bitumen can be blended to yield approximately 1.5 barrels of DilBit or 2 barrels of SynBit.

The shortfall for C5+ should continue to increase, consistent with current developments for new and expanded bitumen production. At Edmonton, either C5+ or SCO could be blended with heavy crude streams. Without more pipeline infrastructure for C5+, the Athabasca bitumen producers have fewer options for diluent so they tend to use SCO.

Figure VI-2 presents the historical and forecast heavy oil and bitumen supply, based on the individual components which comprise the blended streams. Diluent streams include C5+ and SCO. The use of SCO has been limited thus far, but SCO demand for diluent grows after 2015 in the forecast. For illustration, the figure shows the amount of SCO that would be required to meet the shortfall of C5+ for diluent. Without more C5+, SCO use as diluent would be forecast to increase to about 140,000 B/D by 2015, and over 610,000 B/D by 2020.

FIGURE VI-2
HEAVY CRUDE SUPPLY BY COMPONENT



As noted, the heavy crude supply shown in Figure VI-2 assumes that the shortfall of C5+ as diluent can be made up by SCO. However, PGI notes that SCO is currently being marketed to refineries in Canada and the U.S., and that the ability to divert SCO to the diluent pool may be limited. For illustrative purposes, Table VI-1 includes a limitation of SCO supply to the diluent pool, equal to 30 percent of the total SCO supply. On this premise, a growing shortfall of SCO compared to the call on supply as diluent would be projected to occur by 2017. This suggests that an increase in external supplies of condensate would be needed by that time.

The forecast of a diluent shortfall is premised on current blend ratios for C5+ applying in the future. Quality changes may occur in the pooled diluent stream, due to import of refinery naphtha, natural gasoline or imported condensate. The quality of available SCO products used as diluent may also change, which would potentially change the required blend ratio compared to the current situation. Regardless, the greater quantity of SCO needed as diluent compared to C5+ means the resulting net supply of bitumen blend would grow more rapidly if using SCO than if using C5+.

OTHER NAPHTHA / CONDENSATE SUPPLIES

Suncor produces a small amount of naphtha for diluent from its upgrading operation (the OSN stream). Future upgrader projects may be considering production of naphtha for use as diluent. In some cases, this would be a co-product with low sulfur diesel fuel. In our forecast, we have allowed for synthetic naphtha to reach 14,000 B/D before 2015, increasing further to about 30,000 B/D by 2020.

The Suncor refinery at Edmonton also produces some naphtha for use as diluent, depending on gasoline needs. We assume that this naphtha production will continue at around 10,000 B/D.

IMPACT OF DILUENT QUALITY

A wide range of hydrocarbon streams may be suitable for diluent. This may include light refinery naphtha, natural gasoline, as well as Gulf Coast and Midcontinent condensates. The composition of the pooled Alberta diluent stream may be expected to vary, depending on the source and type of the constituent streams. For example, significant quantities of light virgin naphtha from refineries would lighten the pooled diluent stream, and reduce the amount of diluent needed to blend a barrel of bitumen. This would potentially improve the efficiency of mainline transportation systems. Midwest refineries have a large pool of light hydrocarbons to draw on for this purpose. Natural gasoline from sources like the NGL fractionation facilities at Conway, Kansas and/or Mt. Belvieu, Texas may also be imported to Western Canada. Imported condensate may be of different quality, depending on its origin.

In addition to changing the quality of the pooled diluent, the availability of different streams for diluent use may be expected to have significant impact on the volume and quality of the resulting bitumen blends. PGI has not evaluated the impact of changes in diluent quality for this report.

DILUENT IMPORT PIPELINES

ENBRIDGE SOUTHERN LIGHTS PIPELINE

Enbridge's Southern Lights Pipeline allows up to 180,000 B/D of potential diluent components to be shipped from Chicago back to Edmonton. The Southern Lights project started up in July 2010. We understand that committed volumes are 77,000 B/D between two shippers. The Southern Lights Pipeline is expandable to more than 300,000 B/D, if justified. In May 2012, Enbridge announced plans to hold an open season for 85,000 B/D of capacity on the pipeline.

In support of the Enbridge Southern Lights Pipeline, Chicap (Patoka to Chicago) and Capline (St. James to Patoka) Pipeline have made modifications to transport light hydrocarbons like condensates and light naphtha from the Gulf Coast to Chicago. Materials as light as 85 API gravity and 13.5 RVP could be shipped.

The Southern Lights Pipeline might allow natural gasoline from sources like the NGL fractionation facilities at Conway, Kansas and/or Mt. Belvieu, Texas delivered to Chicago. Such a system would potentially have the flexibility to adjust the volume and composition of the diluent stream to meet seasonal blending requirements as well as the long term pace of heavy oil development in Canada.

ENBRIDGE NORTHERN GATEWAY PIPELINE

The proposed Enbridge Northern Gateway Pipeline would include twin pipelines from Edmonton to a new marine terminal at Kitimat on the west coast of British Columbia. One pipeline would be used for crude oil exports, and the second pipeline would be used for diluent imports. The eastbound import line would be a 20 inch diluent line capable of bringing up to 193,000 B/D of waterborne supplies of condensate or other diluents from Kitimat to Edmonton. Wharfage and terminal facilities at Kitimat would be designed to handle up to Suezmax class (1.1 million barrels) vessels for condensate deliveries. Enbridge estimates an in-service date of 2017. PGI does not expect the line to be available until after 2020.

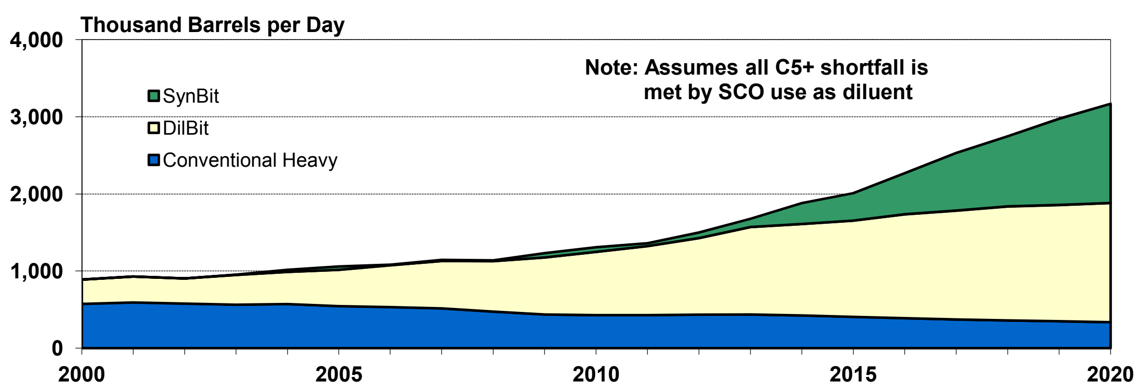
COCHIN REVERSAL

Kinder Morgan announced an open season in April 2012 seeking interest for its Cochin Reversal Project. The Cochin Pipeline currently moves LPG streams from Fort Saskatchewan, AB to Windsor, ON. The reversal project would involve modifying the western leg of the pipeline to connect with the Explorer Pipeline in Kankakee County, IL and reverse the flow to move condensate to Fort Saskatchewan. Available capacity would be approximately 95,000 B/D. The project could be available by July 2014. Explorer Pipeline transports refined petroleum products, feedstocks and diluent from the U.S. Gulf Coast to various points in the Midwest. The project would therefore provide access to imported condensate supplies for delivery to Western Canada.

MARKETABLE BITUMEN BLEND AND SCO

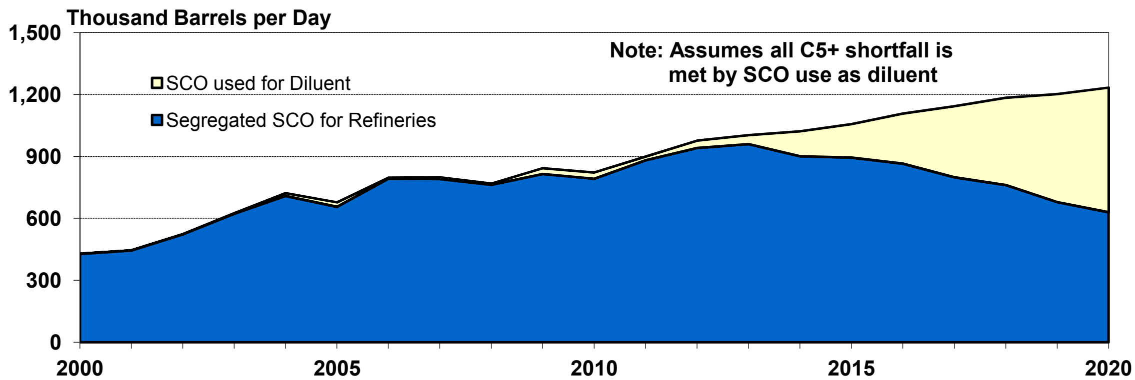
The marketable heavy blends resulting from the above blending forecast are shown in Figure VI-3. Conventional heavy crude blends are forecast to decline whereas DilBit grows with the supply of C5+ as diluent. SynBit supply grows slowly until after 2015. The demand for diluent is dependent on the production rate of bitumen and the amount that is upgraded, so diluent demand could be higher or lower.

FIGURE VI-3
HEAVY BLEND SUPPLY BY TYPE



In addition to impacting the amount of diluent required, these factors will also affect the availability of segregated SCO for refineries. Even allowing for use as diluent, the availability of segregated light and heavy SCO is forecast to increase this year, to 916,000 B/D from 879,000 B/D in 2011 (Figure VI-4). Because of diluent demand and imports, it is forecast to remain close to this level throughout the forecast period.

FIGURE VI-4
NET SUPPLY OF LIGHT SWEET SCO



DILUENT IMPLICATIONS OF COCHIN REVERSAL PROJECT

PGI concludes that the diluent volumes proposed to be delivered by the Cochin Pipeline could be readily accommodated in Western Canada. As illustrated above, currently available sources of C5+ diluent are inadequate to meet expected demand, based on bitumen production and upgrading in Alberta. Other sources of diluent will be required to meet the projected shortfall, including additional imported supplies of condensate, refinery naphtha or natural gasoline, or SCO blending for SynBit. The proposed capacity of the Cochin Pipeline (operating in condensate service) is up to 95,000 B/D. The projected shortfall of C5+ exceeds this capacity before 2020.

TABLE VI-1
CANADA DEMAND FOR HEAVY CRUDE DILUENT
(Thousand Barrels Per Day)

	Actual			Estimate	Forecast								
	2000	2005	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Conventional Heavy Crude Production													
Lloydminster	248	273	205	200	201	203	202	199	193	188	183	178	173
Bow River	135	104	91	86	82	78	74	70	67	63	60	57	54
Other	178	149	127	125	124	123	121	119	117	114	112	109	107
Total	560	526	422	411	407	403	397	388	376	365	354	345	334
Alberta Bitumen Production													
Lindbergh	54	41	26	24	23	22	22	21	20	20	19	18	18
Cold Lake and Primrose	182	268	426	467	456	457	477	491	516	533	547	556	564
Athabasca	9	52	148	164	255	372	473	550	695	843	958	1,074	1,188
Wabasca	44	50	56	54	65	74	79	84	94	92	86	82	81
Peace River	4	25	39	36	39	42	46	49	58	63	69	76	80
Gross Bitumen Supply	293	436	694	746	838	968	1,096	1,196	1,383	1,551	1,679	1,807	1,930
Diluent Requirements - Conventional Crude													
Lloydminster Production	248	273	205	200	201	203	202	199	193	188	183	178	173
Less: Field Upgrader Feed	34	32	31	32	33	35	38	40	40	40	40	40	40
Less: Refinery Demand for Raw Lloydminster	12	15	17	17	18	18	18	18	18	19	19	19	19
Net Lloydminster Requiring Diluent	202	226	157	150	151	150	147	140	135	129	124	119	114
Diluent Requirements - Bitumen													
Gross Bitumen Production	293	436	694	746	838	968	1,096	1,196	1,383	1,551	1,679	1,807	1,930
Less: Refinery/Upgrader Demand for Bitumen	37	43	31	32	33	35	38	47	65	75	75	75	82
Net Bitumen Requiring Diluent	255	393	663	714	805	932	1,058	1,148	1,318	1,476	1,604	1,733	1,848
Diluent Requirements - as C5+													
Diluent for Lloydminster	42	47	33	32	32	31	31	29	28	27	26	25	24
Diluent for Bow River	5	4	4	3	3	3	3	3	3	3	2	2	2
Diluent for Bitumen	77	129	223	239	278	328	383	421	504	577	639	701	756
Total Diluent Requirement	125	180	259	274	313	363	417	453	535	606	668	729	782
C5+ Supply													
Production	165	171	146	145	136	125	118	114	114	114	116	118	122
Pipeline Import (1)	-	-	22	65	125	180	180	180	180	180	180	180	180
Other Import (2)	-	15	68	60	20	20	40	60	80	90	100	100	100
Other Supplies (3)	7	6	18	16	24	24	24	25	32	39	47	53	60
Total	173	192	254	286	305	349	363	379	406	423	443	452	462
Surplus / (Shortfall) of C5+ as Bitumen Diluent	47	12	(5)	12	(8)	(14)	(54)	(74)	(130)	(183)	(224)	(277)	(319)
Required SCO Use as Diluent	-	-	10	-	15	26	104	141	250	352	432	533	614
Total SCO Supply	428	676	812	891	962	989	1,007	1,042	1,086	1,117	1,152	1,168	1,196
Available SCO for Diluent (4)	-	-	10	-	15	26	104	141	250	335	346	350	359
Surplus / (Shortfall) of SCO as Bitumen Diluent	-	-	-	-	-	-	-	-	-	(17)	(86)	(182)	(255)

Notes:
(1) Assumes operation of Enbridge Southern Lights Pipeline at 180,000 B/D.
(2) Rail and/or other pipeline imports. Purvin & Gertz estimates.
(3) Production from refineries and upgraders. Purvin & Gertz estimates.
(4) Limited to 30% of total SCO supply.