WORKSHOP WORKING REPORT

DRAFT

Oil Sands Experts Group Workshop
Houston, Texas
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Acknowledgements

President Bush, Prime Minister Martin and President Fox officially announced the Security and Prosperity Partnership of North America (SPP) agreement in March 2005. Through the SPP, Canada, the United States and Mexico agreed to collaborate on the development of oil sands resources, and an Experts Group was formed. The workshop for the Oil Sands Experts Group, held in Houston, Texas, January 24th to 25th, 2006, was jointly sponsored by The U.S. Department of Energy (USDOE) and National Resources, Canada (NRCan). The Energy Department of Alberta (ADOE) was also involved with the workshop planning. Representatives from Mexico's Secretariat of Energy participated as observers.

Kevin Cliffe (NRCan) and Ann Ducca (USDOE) led the workshop planning. Special thanks go to Robert Donovan and Lori Krause of the U.S. Energy Association for making the meeting arrangements.

Four working groups were held each day. The sponsors thank the discussion facilitators and recorders for their work. Facilitators were Kathy Stirling (USDOE) and Art Hartstein (USDOE), Kevin Cliffe (NRCan) and Carol Fairbrother (NRCan). Recorders of the working group discussions were Kathy Bergman (ADOE), Castlen Moore (USDOE), Diane Simsovic (Consulate of Canada in Houston) and Sarah Ladislaw (USDOE).

The sponsors also thank the three plenary session speakers and their organizations for their efforts to develop and deliver presentations that helped set the tone and content for the working group discussions. They were Mike Ekelund, Assistant Deputy Minister-Oil Development, of the Alberta Department of Energy, Gerald Bruce, Upgrading Manager for Jacobs Engineering in Canada and Thomas Boslett, Commercial Director for B.P. North America.

Len Flint of LENEF Consulting (1994) Limited, from Calgary, Alberta was the general workshop facilitator and author of this report.

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Section 1: EXECUTIVE SUMMARY

Introduction

President Bush, Prime Minister Martin and President Fox officially announced the Security and Prosperity Partnership of North American (SPP) agreement in March 2005. The energy activities of the SPP encompass a trilateral effort among Mexico, the United States and Canada, to create a sustainable energy economy for North America. The Canadian oil sands are one of the world's largest hydrocarbon resources and will be a significant contributor to energy supply and security for the continent. As such, the three countries agreed to collaborate through the SPP on the sustainable development of the oil sands resources and an ad hoc Oil Sands Experts Group was formed that includes the U.S., Canadian and Alberta Government representatives.

The first deliverable for the Group consisted of the following: "By January 2006, building on joint discussions with key stakeholders and scientific experts, issue a report that discusses the mid- to long-term aspects of the oil sands product market development and the infrastructure and refinery implications for increased oil sands market penetration". To meet this deliverable, the Group convened a workshop in Houston, Texas, on January 24-25, 2006, that was jointly sponsored by the U.S. Department of Energy (USDOE) and Natural Resources Canada (NRCan). The Alberta Department of Energy, (ADOE) also participated in the workshop planning and delivery. Representatives from Mexico's Secretariat of Energy participated as observers. This report summarizes the results of the workshop discussions.

The goal of the workshop was: "To identify and develop options to address the infrastructure, market access and market capacity issues in North America associated with the value-added development in Canada of the oil sands". The workshop brought together experts representing the oil sands industry, refiners, marketers, pipeline companies, and government.

Delegates participated in the following working groups to examine the challenges associated with oil sands market development and propose potential actions:

- Upgrading & Refining
- Kicking the Natural Gas Habit
- Markets
- Pipeline Infrastructure

The most important challenges and proposed actions are summarized in the following sections.

Upgrading and Refining

The oil sands industry currently produces two types of product, synthetic crude and diluted bitumen.

The highest value products are sweet synthetic crudes (SCO) characterized by zero residue and low sulphur. However, while SCO commands a premium price and is in many ways comparable to light sweet crude, the high aromaticity of bitumen from which it is derived limits its penetration into refineries that are not specially equipped to handle it. A typical refinery is limited to between 10-20% of SCO in its crude slate. Part of the solution lies in additional technical/infrastructure capability in existing or new refineries and another lies in producing a higher quality light sweet synthetic crude, something being planned by a few of the new oil sands projects.

Unprocessed bitumen is also marketed, but for pipeline transportation reasons must be shipped in diluted form. It sells at a considerable discount to synthetic crude as can be explained by the light-heavy differential: because heavy oil is worth less to a refiner, it typically sells at a discount to light oil. This difference in price is referred to as the differential. When the differential widens, it means that heavy oil is trading at a larger discount to light oil and it fetches a lower price. Bitumen is discounted yet again with respect to heavy oil.

The low price, or netback, that the bitumen producer currently receives is due not only to the fact that there is a ready supply of this less valuable commodity, but also to the high cost of diluent. In fact, after accounting for the costs of diluent (condensate or synthetic crude), operations, transportation, and capital recovery, the netback for dilbit, syn-bit, and syn-dil-bit[1] producers is greatly reduced and often in the single digits, despite a high price for light sweet crude oil.

Upgraders or refineries with upgrading capability are able to capture value using bitumen as a feedstock, which is why a sustained and sufficiently large differential will, in time, prompt more upgrading in Canada. Both the Canadian and Alberta governments would like to see more value-added activities in Canada. For Alberta, this potentially means more upgrading to synthetic crudes, as well as more refined petroleum products, including specification transportation fuels and petrochemicals. Such investments could help to address the refining capacity shortage in the U.S.

The working groups also discussed the possible use of other refining centres, including Mexico, to help extract value from the oil sands resource.

Potential Actions:

It is the responsibility of the producers and upgraders to continue the dialogue with future refinery markets in the U.S. to ensure a broad understanding of the oil sands industry.

[1] **dilbit** = 20-30% condensate + bitumen; **syn-bit** = 50% synthetic crude + bitumen; **syn-dil-bit** = condensate + synthetic crude + bitumen

In the short to medium term, continued bitumen supply may require commercial deals between producers and refiners that more equitably share the risks and benefits. In the longer term, there may need to be a more stable, open pricing mechanism for diluted blends.

Government needs to be informed and ensure the flow of information amongst themselves and the various stakeholders. One example of this is the work being done for the Alberta government and industry through the Hydrocarbon Upgrading Task Force to develop a long-term business case for more upgrading and value added products in Alberta.

Kicking the Natural Gas Habit

Discussion of the energy sources used in recovery and upgrading are not directly related to expanding the market opportunities for oil sands products. However, there are indirect relationships in terms of the overall economics, and in facilitating the production of higher quality synthetic crudes. There are also links to the third SPP deliverable for the Oil Sands Experts Group, examining the long-term prospects for enhanced oil recovery in Canada and the U.S. using CO_2 from oil sands operations.

Both production and upgrading of oil sands bitumen require significant energy inputs which are largely met by natural gas today. Such dependence on natural gas is believed to be unsustainable as the industry expands. Energy sources such as coal, nuclear, and internally generated residues or upgrader by-product coke have been suggested and some reviewed as alternatives. Some commercial projects are already responding to the challenge of "kicking the natural gas habit" by the use of processing schemes that replace natural gas with their own internal residues. In fact, such processing schemes create a special advantage. Firstly, the residues, or the least valuable and heaviest portion of the bitumen, are consumed. Secondly, the remaining lighter portions are more easily upgraded. Thirdly, using such schemes ultimately provides more options for the operator to produce higher quality synthetics.

A key enabling technology in these processing schemes is gasification. However, while gasification is well established in some refineries and power production worldwide, there may be special challenges in adapting it for wide scale use in oil sands. As such, it needs to be further studied, and demonstration scale prototypes may be required to advance the development of technology.

In addition, using coal or residues to replace natural gas results in a higher CO_2 emission intensity. Participants discussed the need to investigate the capture and distribution of CO_2 to other users, such as enhanced oil recovery projects, as well as the long term need to provide for hydrogen and CO_2 pipeline networks to connect to key industry hubs and potential users.

Potential Actions

The Canadian and Alberta governments need to confirm the likely position on future natural gas supplies, and develop an understanding with industry on future expectations regarding energy for oil sands development. The Oil Sands and Natural Gas Expert Groups under the SPP will continue to exchange information on this issue.

Governments and industry have a mutual interest to assess alternatives to using natural gas in oil sands operations. In addition, they have a strong vested interest in demonstrating the viability of gasification for residues and coal. Consideration should be given to tailored incentive programs and/or part funding of studies and demonstration-scale technologies.

In the opinion of many workshop participants, a study of CO_2 emissions and associated infrastructure, currently scheduled under the SPP for review in 2007, should be considered for more immediate action.

Markets for Oil Sands Products.

The key market issues largely concern increasing and diversifying the market; evaluating the impact of products in the marketplace; understanding the entire value chain; and determining what exactly would be involved in refining bitumen to transportation fuels.

Canadian and U.S. refiners are the preferred markets for oil sands derived products. However, as already mentioned in the section on Upgrading and Refining, given current refinery configurations and capacity, there is a limit to the amount of synthetic crude and bitumen that the market can absorb. If oil sands production is to realize its full potential, new markets must be developed in the U.S. and possibly offshore, via the west coast.

Not only must new markets be created, but also the impact of products in the marketplace must be considered. Is the current marketing model sustainable for the future? Oil sands producers and U.S. refiners have made considerable progress in a common understanding of the characteristics of individual synthetics. However, as more “unique” products emerge (from new projects) there is a danger of creating confusion in the marketplace. In addition, pipelines will be asked to handle an increasing number of individual crudes with associated batching problems.

Finally, there is a need to understand the entire value chain and determine what exactly would be involved in refining to transportation fuels. What is the long-term view for such fuels in North America? The current strategy of re-configuration and refinery creep is insufficient to respond to demand for transportation fuels. New build will be required. Furthermore, the U.S. leadership in fuel emissions regulations has led to more technically demanding fuel chemistry or “boutique fuels” and more complex refineries. Internal combustion engine research is also underway which has the potential to transform engine technology.

Potential Actions

It will be necessary to look at options and plan for a smooth transition towards bitumen production that could be as high as 5 million barrels per day as was envisioned by the Oil Sands Technology Roadmap. A better understanding is needed of the future mix of unprocessed diluted bitumen, synthetic crudes, finished products and petrochemical feedstocks to meet optimum value-added potential. In addition, producers and refiners need to ensure that refinery capacity is available and that the risks of constructing and operating facilities can be shared. Producers could consider pooling production into a few market crudes in consultation with major market regions.

The US and Canadian federal governments may need to be involved in ensuring that refinery capacity is adequate and that future fuel specifications and trends are well understood. A structural and incremental approach to fuel specification changes would help to ease the burden on refineries from having to constantly tweak their operations to meet ever changing specifications. In the long-term, governments and industry may need to work towards developing stable, standardized sets of specifications for high quality, clean fuels to provide greater flexibility and certainty to the market.

Addressing the issue of transportation fuels and further study of fuels quality in relation to oil sands products is the second SPP deliverable for the Oil Sands Experts Group.

Pipeline Infrastructure

The geography of North America requires integrated long distance pipelines that transport crudes and finished products. New pipelines and pipeline expansion plans are already in place to meet the certain doubling of oil sands production to two million barrels per day by 2010 to 2012 timeframe. This includes extensions of the market va a west coast port, and more deeply into the U.S. However, pursuing new markets beyond then will necessitate an expansion in delivery systems. The fivefold expansion anticipated for oil sands products in a relatively short time span will represent many challenges for the pipeline industry. New and expanded pipelines will move more volume into existing and expanding interior U.S. markets, and offer shipments to California via the Canadian West Coast.

The workshop addressed the major pipeline issues including the size of the investment, permitting, and handling an increasing variety of products.

There are risks with pipeline investment decisions, particularly as they relate to determining pipeline capacity, and who should bear the cost in the event of temporary excess capacity.

Regulatory and permitting issues were cited as a concern on both sides of the Canada/U.S. border, as they impact the overall risk and timing of pipeline investments. In the United States, pipeline companies face an often complicated and “patchwork” collection of local, state, or federal regulations as well as potential obligations to Native American groups.

The Canadian and US Governments already cooperate and share information with respect to pipeline regulation.

As many new synthetic crude variants come on to the market, pipelines will be required to handle increasing numbers of separate batches. While this is technically feasible, this does place certain operational constraints on the system. Fewer product types in the medium to long term may help to reduce these constraints as could basic research and development in new ways to ship bitumen.

Potential Actions

Ultimately, the market will determine the investment decisions related to pipeline build and capacity. Timely information on oil sands projects, start up dates and expansion plans are key to coordinated construction of pipelines.

Governments are encouraged to streamline the regulatory approval process and better manage the risk to both pipeline and energy projects. Canadian governments have already gone a long way to coordinating and streamlining the environmental and regulatory approvals, but more needs to be done.

Providing process mapping and a one-stop-shop for projects would help to ease the complexity, facilitate coordination and reduce the time required for regulatory approval and permitting.

The Labour and Infrastructure Challenges

Although they were not a separate topic of discussion during the workshop, labour issues and infrastructure challenges in North America were raised in each of the four working groups. The rapid pace of development in Alberta and in other parts of North America has contributed to escalating demands for in skilled trades people and professional engineers that have placed pressure on their availability as well as the cost of their services. These pressures could affect development plans and time lines for oil sands projects, pipelines, upgraders and refineries. Construction materials also face similar pressures. Several of the groups also discussed the infrastructure limitations in the fast growing region of Fort McMurray.

Potential Actions

This issue is being addressed at the federal and provincial levels of the Canadian government, and by professional organizations in their respective areas of jurisdiction. Efforts are on going.

Conclusion

While there are significant challenges in the long-term expansion and market acceptance of oil sands products, industry and governments have a vested interest to work together to ensure the successful expansion of this important North American energy resource. All market challenges associated with this expansion can be successfully addressed so that the oil sands can make a truly significant contribution to North America's energy supply and security.

Section 2: BACKGROUND

2.1 The Security and Prosperity Partnership

President Bush, Prime Minister Martin and President Fox officially announced the Security and Prosperity Partnership (SPP) agreement in March 2005. The energy activities of the SPP encompass a trilateral effort among Mexico, the United States and Canada, to create a sustainable energy economy for North America. Through the SPP, Canada and the US, with Mexico as an observer, will collaborate on identifying market, infrastructure and refining capacity issues needs, and developing technologies to reduce costs and environmental impacts of oil sands production, to promote optimal sustainable development of these resources. For more information about the SPP, reference can be made to the following website (www.fac-aec.gc.ca/spp/spp-menu-en.asp or http://www.spp.gov/)

Under the Oil Sands Experts Group of the SPP, the three countries have agreed to three deliverables:

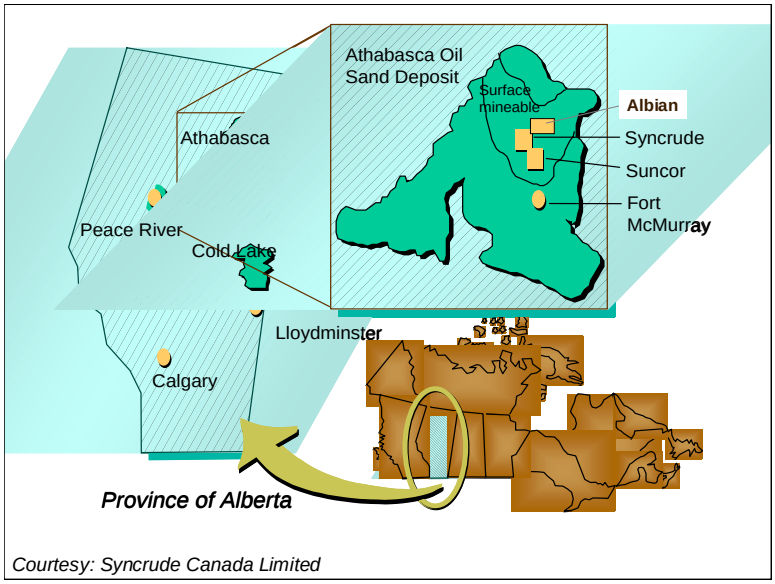
- By January 2006, building on joint discussions with key stakeholders and scientific experts, issue a report that discusses the mid- to long-term challenges to increased production from oil sands, associated product mix, distribution infrastructure, and refinery implications for increased oil sands market penetration.
- By June 2006, working from the results of the June 2005 Oil Sands Chemistry and Engine Emissions Roadmap Workshop, issue a paper that discusses future fuel options for North America, the market implications for oil sands production, and the impact on refiners and infrastructure.
- By June 2007, produce a paper examining the long-term prospects for enhanced oil recovery in Canada and the U.S. using CO_2 from oil sands operations.

This is a report of the Oil Sands Workshop held in Houston, Texas on January 24-25, 2006, under the auspices of the Oil Sands Experts Group of the Security and Prosperity Partnership (SPP) for North America. A separate synopsis of this report will fulfill the deliverable under the SPP.

2.2 The Oil Sands Industry Today and the Vision for the Future

The Canadian oil sands are one of the world's largest hydrocarbon resources. As a result of the development of new technology over an extended period, and the firming up of oil prices in the last ten years, oil sands production now exceeds one million barrels per day. Continued development of these resources will be a significant contributor to energy supply and security in North America. Figure 2.1 shows the geographic location of the three main production regions.

Figure 2.1: Major Geographic Regions of Oil Sands Deposits



Even greater production is anticipated in the future. Announcements already made by various companies include close to $100 Billion dollars of investment to 2020 on new oil sands projects and sustaining capital, with production well ahead of the five million barrel per day vision to 2030 advanced by the Oil Sands Technology Roadmap (See References).

The size of the resource is not likely an issue for the foreseeable future. The oft-quoted 175 billion barrel recoverable number may now be low, as it was made before recent price increases. However, at reserves of 175 billion, and a production level of 5 million barrels per day, the reserves to production ratio would be close to 100 years.

Figure 2.2 is drawn from the Roadmap and illustrates the anticipated long-term shift from the two products that dominate the oil sands market today – whole bitumen and synthetic crude – to multiple energy products such as finished transportation fuels and petrochemicals.

Additional multi-billion dollar investments may be made in the same timeframe as part of the value-added opportunities (refined petroleum products or petrochemicals) in Alberta.

The vision also anticipated the growing use of oil sands derived residues to provide internal energy needs and hydrogen production, that is now largely met by natural gas.

Figure 2.2: Oil Sands Technology Roadmap Vision

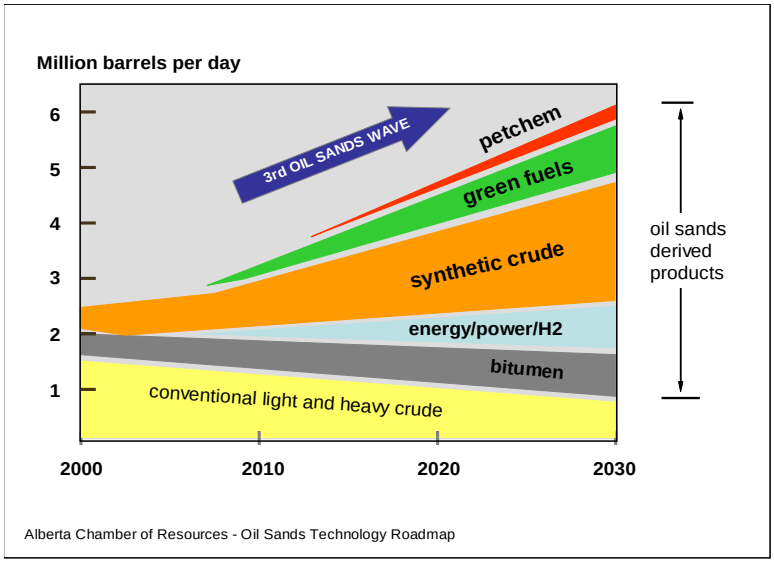
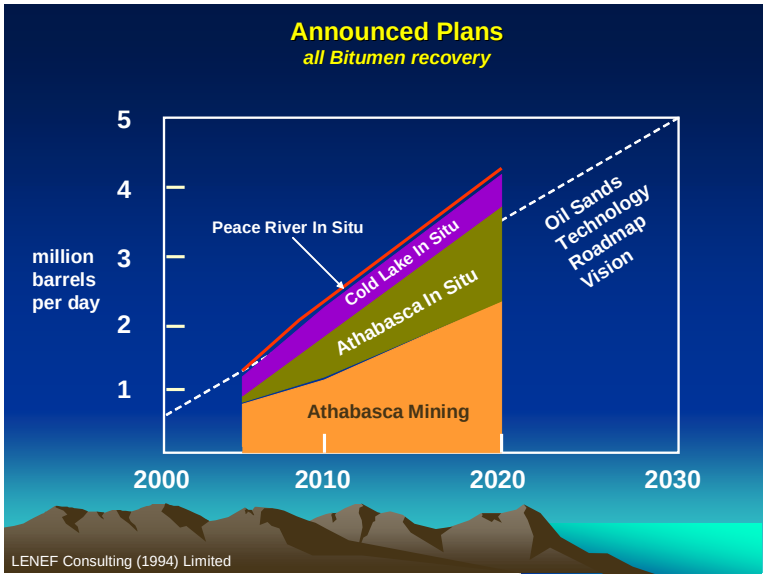


Figure 2.3 summarizes the announced plans for production spread over the three principle deposits in Athabasca, Cold Lake and Peace River, and the current division in those plans between bitumen for shipping to markets unprocessed and for upgrading to synthetic crudes.

Figure 2.3: Plans to 2020 for Bitumen Production

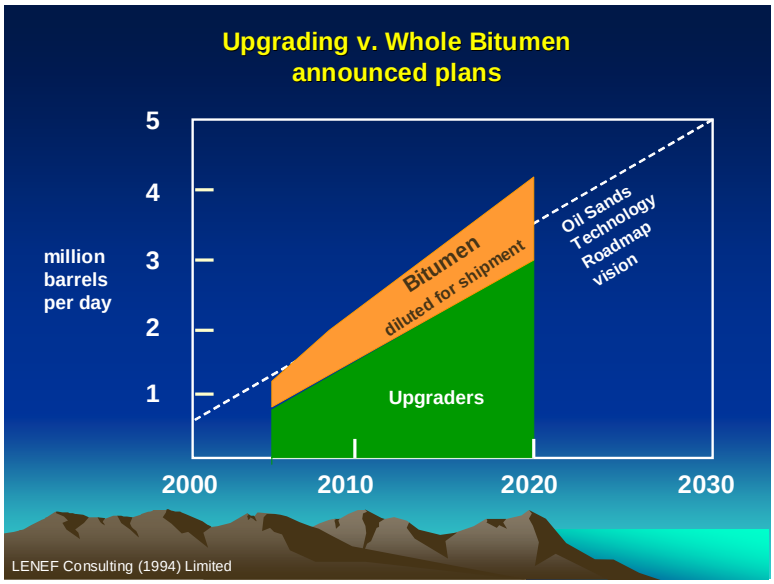


Bitumen production is dominated today by two approaches. The first approach, open pit mining is practiced where the overburden is less than about 150 feet (50 metres). The second approach, *in situ* thermal recovery is practiced in deeper reserves. At this time, incremental and step-change recovery technology development has reduced operating and capital recovery costs to around $12 U.S. per barrel. In recent years, this figure has been increasing because of higher natural gas prices.

The main intent of the workshop was to review the mid- to long-term challenges to oil sands product mix, distribution infrastructure, the workforce and refining industry implications for increased market penetration. It was decided not to include a detailed review of the challenges associated with production in this Workshop, except where the issues might directly impact the main intent. More information on recovery can be found in the Oil Sands Technology Roadmap.

Figure 2.4 depicts the total production plans from Figure 2.3 in a different way. These are the current plans for the shipment of whole bitumen (largely to export markets) versus plans for upgrading to synthetics. However, these plans are subject to change as the future unfolds.

Figure 2.4: Plans to 2020 for Whole Bitumen v. Upgrading



Background information specific to the workshop working groups, dealing with upgrading and refining, and market and pipelines is provided in later sections of this report.

2.3 Workshop Goal

A number of factors could constrain the increased development of oil sands. There is a need to identify those factors related to production or market acceptance, and evaluate the options

for ensuring the sustainable and value-added development of the oil sands resources. This workshop brought stakeholders together to discuss the issues.

The goal of the Oil Sands Workshop was:

> ***To identify and develop options to address the infrastructure, market access and market capacity issues in North America associated with the value-added development in Canada of the oil sands.***

2.4 Organization of the Workshop

The following are the challenges that will need to be managed to ensure sustainable and steady growth:

- **Upgrading & Refining:** the cost structure, the stress on available skilled construction and operating labour in remote areas, and the growing mix of products
- **Kicking the Natural Gas Habit:** alternatives to heavy reliance on natural gas for recovery energy and for hydrogen generation for upgrading
- **Markets:** the integration of products and the refinery markets served
- **Pipelines:** the timely provision of pipelines to expand to multiple products

Working groups were established to address these topics in relation to the overall aims of the workshop. Prior to the working groups deliberations, three presentations were made by industry experts to provide background and provoke questions.

Mike Ekelund, Assistant Deputy Minister, Oil Development, Alberta Department of Energy (representing the owners of the resource) provided an overview of the oil sands resource, and Alberta's determination to encourage long-term value-added development. Gerald Bruce, Upgrading Manager for Jacobs Engineering in Canada, provided an overview of the linkage between the oil sands products and quality, and the pros and cons for the major target market in the U.S. Thomas Boslett, Commercial Director for B.P. North America, elaborated on the challenges faced by the U.S. refiners in accepting more heavy crudes from Canada and synthetic crudes with some currently challenging quality attributes.

These presentations can be found in Appendix 2. After the presentations, the three speakers participated in a panel discussion with questions from the floor, where some of the issues raised and cross cutting challenges were further explored.

Central to the success of the workshop were the four working groups, held each day with the mandate to review issues under the four topics listed above. On the first day, delegates were assigned to the working groups based on the need to obtain a cross section of opinion from industry and government experts present. On the second day, delegates were allowed to participate in the workshop of their choice. On this second day, the working groups used the output from the first day, and refined the identification of the issues and challenges. The output from the working groups was used to provide the summaries in sections 3 through 6 in this report.

2.5 Exclusions from Consideration in this Report

While important to Canada, issues related to bitumen production, internal infrastructure, societal challenges from rapid growth, and the environmental footprint were not a focus of this workshop. The resolution of these issues are essential to the long-term sustainable development of the oil sands industry, but are the responsibility of industry and Canadian and Alberta governments to address. Unless closely linked to the objectives of this workshop, they were not included in the final report.

Section 3: UPGRADING & REFINING

3.1 Backgound

Figure 2.4 in Section 2 summarized the announced production plans to 2020 from the perspective of upgrading versus the production of unprocessed bitumen. The term "**upgrading**" conventionally refers to the conversion of bitumen to synthetic products, typically in closely coupled large scale upgrading plants. "**Refining**" is normally used to represent the use of crudes in conventional refineries, where the objective is the production of finished products, largely transportation fuels: gasoline, jet and diesel. However, upgrading and refining are a continuum to convert bitumen to finished products, and some future upgrading plans are proposing the full conversion to finished products, as was anticipated in the Oil Sands Technology Roadmap (refer to Figure 2.2 in Section 2).

Prior to 2003, all mined bitumen was upgraded to light, sweet synthetic crude by Syncrude, and a range of light sweet and medium sour crudes by Suncor. All these products target suitable downstream refineries. The Husky, Lloydminster and the Newgrade, Regina upgraders (both in Saskatchewan) add some further marketed synthetics (about 10% of the total) but from lighter bitumen and heavy oil sources. Shell *et al* (Athabasca Oil Sands Project (AOSP)) and now Petro-Canada (both major integrated oil companies in Canada) are linking large scale upgrading with their own refineries, further blurring the distinction between upgrading and refining.

Oil Sands Products Today

The oil sands industry ships two types of products today. The first of these is bitumen blends, which are blends of the produced bitumen and a diluent stream to reduce viscosity to facilitate pipelining to markets. The original type of blend called "dilbit" utilizes approximately 20-30% by volume light condensate (primarily naphtha but with some light distillate). These are the so called "dumb-bell" blends, consisting largely of naphtha and heavy residues, with low volume in the distillate range.

Owing to tight condensate supply, two other variants have recently gained market access. The first is "synbit" whereby the diluent is synthetic crude at approximately 50% of the blend. The second variant, and a recent addition to the market place, can be referred to as "syn-dil-bit" that is marketed under the name Western Canada Select ("WCS") that uses both condensate and synthetic crude as co-diluents. All of these products are blended to approximately 20°API gravity, contain substantial volumes of residue, and are high in sulphur. In all, blends consume some 350,000 barrels per day of bitumen (this figure does not include the associated diluent). The principal market for these products is refineries equipped with high residue conversion capacity, such as coking.

The second class of product is synthetic crude, the principal one being a light, sweet product resembling light conventional crudes. However, some unique characteristics described more fully in Section 5 affect current refinery acceptance. One upgrading company (Suncor) also offers a range of other synthetics that approximate medium sour crudes. Synthetic crudes

currently total about 700,000 barrels per day, but this includes 150,000 barrels per day from the Shell *et al* (AOSP) upgrader, a large portion of which is feed for the adjacent Shell Scotford refinery. Only some 50,000 barrels per day of the AOSP volume are openly marketed.

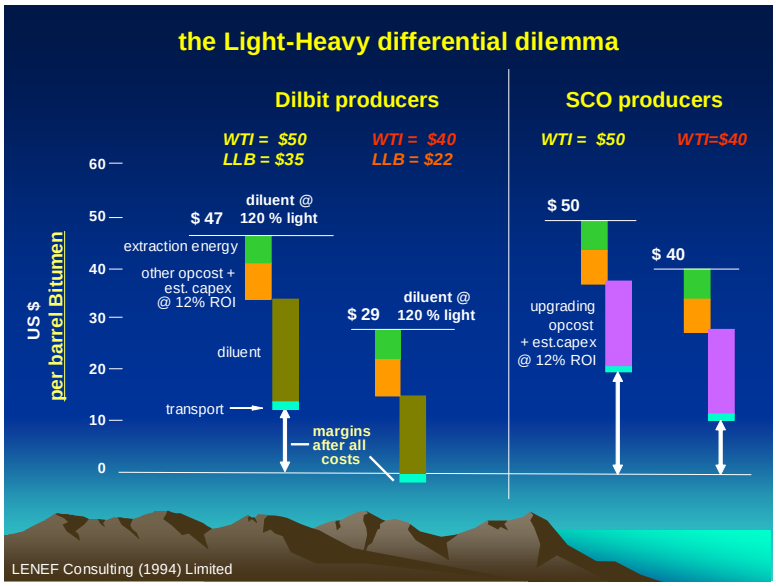
Economic Considerations of Upgrading

The economic consideration for upgrading partially depends on the target market for the products. Some aspects of economics are therefore linked to markets, as discussed below.

The key incentive driving upgrading is the light-heavy differential. This is defined as the value of WTI in Cushing, Oklahoma minus the value of the current "marker" dilbit, LLB (this is a blend based on Lloydminster heavy crude from Saskatchewan) at Hardisty, Alberta. Cold Lake Blend based on Cold Lake bitumen (CLB) is also a significant dilbit and is typically priced slightly below LLB. Dilbits contain from 20-30% light condensate to allow transport in common carrier pipelines.

Prior to the recent light crude price run up, the long-term average LLB value was approximately 65% of WTI (35% differential), but has always been characterized by significant fluctuations. In recent months, as light crude value has increased, the LLB value has been trending down relative to WTI (in recent months it has been around 50 – 55% of WTI). The market dynamic causing this situation has been increased production moving into an essentially single market with a fixed residue conversion capacity. Figure 3.4 is a graphic example of how this pricing dynamic affects the bitumen and synthetic crude marketers. The cost bars for SAGD recovery and upgrading are only illustrative of the many varying options. They also include an estimated capital recovery portion.

Figure 3.1: Influence of Light-Heavy Differential on Bitumen Netbacks



On the left of Figure 3.4, it is evident that a drop of light crude from $50 per barrel to $40, and a large light-heavy differential can combine to seriously erode or even eliminate bitumen netbacks for the producer, even in what is in historical terms a healthy crude pricing regime. By contrast, the synthetic crude producer (represented by the bars to the right hand side of Figure 3.1) enjoys more robust margins at this point in time. Such differences may have implications for secure supply of bitumen to those U.S. refineries suitably equipped to handle the heavy material.

While not shown, the relatively small step from upgrading (to synthetic crudes) towards finished products will show even greater returns.

3.2 Issues and Recommended Actions

The working group considering upgrading and downstream refining identified more than 20 topics in the two sessions. In any such discussion, however, there are many similarities in the underlying themes. The discussions have been regrouped in the sub-sections below, without loss of the original substance.

One issue discussed at length in this working group was the long-term view of the transportation fuel mix in North America. This was also discussed in the market working group, and the combined output of those discussions has been summarized in Section 5, Markets for Oil Sands Products. However, it should not be forgotten that any major changes in the fuel mix may influence upgrading in future. One of the inherent advantages of the need to upgrade will be the ability to adjust to changing engine fuel and refinery market trends.

As a foreword to the summaries, the job of upgrading the bitumen produced to finished products is a role shared by two linked industries. The first group is the producers themselves, or raw bitumen purchasers, choosing to upgrade bitumen within Canada (and most notably Alberta). The second group is U.S. and Canadian refiners who have invested in additional refining equipment to handle the raw bitumen and the synthetic crudes that are marketed today.

In reviewing the topics discussed below it may seem that some of the positions are potentially at variance. For example, Alberta's interest to upgrade the bitumen in Canada could seemingly conflict with U.S. interest to have access to unprocessed product in the short-and long-tersm. However, such topics need to be reviewed in the context of long-term industry development, where strategy may vary over time. It is to be expected that the free market will continue to drive future expansions, but that intra-government knowledge and regulatory powers can be marshalled to assist rapid but orderly sustainable development.

3.2.1 Understanding Costs and Challenges Associated with the Oil Sands Resource

At an industry level there has been significant discussion between producers and potential new markets in the U.S.

Upgrader operators and refiners on both sides of the border remember the low margins of previous decades, that to a large degree have led to the reduced ability of U.S. refiners to meet their own domestic demand for petroleum products.

Many refiners are also well versed in the cost-benefit relationship between various levels of hydrogen addition inherent in upgrading bitumen. For refineries which are not well equipped to handle the aromatic nature of this crude, the relatively poor distillate and heavy gas oil quality can limit refinery intake to anywhere from 10-20% by volume. However, some upgrading projects scheduled for start up within the next 5-6 years, are addressing these quality deficiencies, but at an associated higher cost for the increased hydrogen addition.

In addition, current depressed light-heavy differentials (and low cost access to unprocessed bitumen in the U.S. market) may not persist if market diversification allows oil sands products to move from North America. Other topics summarized below also dealt with these factors in more detail. A more common, high-level understanding of the industry is needed to help smooth future expansion to target markets in the U.S.

On another level, the relatively recent enthusiasm for expanded oil sands development was partly due to a more favourable royalty regime from the Alberta government. This regime reduces royalty payments to 1% of gross revenue in the pre-payout period, that is, prior to the recovery of upfront investments by the developers. In the post-payment period, the royalties are the greater of 25% of net revenue or 1% of gross revenue. In this way, the province effectively shares in some of the up-front risk of development. This is one example of enlightened government action. However, given higher crude oil prices, companies are recovering capital costs more quickly than might have been anticipated and will thus be reverting to the standard royalty regime more quickly. The investment community needs to be assured that such benefits will not be the subject of government rethink when high industry profits arise.

Proposed Actions:

It is the responsibility of the producers and upgraders to continue the dialogue with future refinery markets in the U.S. to ensure a broad understanding of the oil sands industry in Canada's largest market. Governments in all jurisdictions need to be kept in the consultative and enabling role, and recognize the need for long-term stability in the regulatory regimes for such high cost projects.

3.2.2 Sharing Risks and Rewards between Producers and Downstream Processors

The discussions in this group also addressed the concept of "managing the economic risk". The decision to upgrade within Canada is largely governed by the producers' long-term perception of the light to heavy price differential. In the oil sands market orbit, this is the difference between WTI priced in Cushing, Oklahoma and the traditional "marker" dilbit Lloydminster blend (LLB). Other blends, such as diluted Cold Lake and Christina Lake bitumens are becoming increasingly available. Synthetic crude has been priced at a level similar to light conventional crude, but blends have tracked at a significant discount.

However, the differential has varied widely, and has historically been anywhere from 35-40% of WTI, but in more recent times has grown to as much as 50% discount against light crude. A major reason for this increased devaluation is access to a single market with a fixed heavy oil conversion capability, as well as increasing dilbit supplies in the last two years. If wide light-heavy differentials with low netbacks for diluted blends persist, more Canadian producers will favour the upgrading route, albeit with higher capital investment. In addition, these conditions will encourage market diversification, for example, the development of offshore markets.

While large differentials may benefit U.S. refineries with residue conversion capacity in the near term, those same refiners might risk a long-term shortage of these feedstocks, or need to pay higher prices. Producers willing to provide blends over the long-term need to be assured of a fair share of the value added opportunities from bitumen to synthetics, or to finished transportation fuels. This issue is also addressed in Section 5, Markets for Oil Sands Products.

Proposed Actions:

Some of the ways to promote an equitable sharing of the value added opportunities from oil sands might include:

- Developing a commercial framework for producers and upgraders or refiners to share the risks and benefits;
- Investigating the opportunity for U.S. refiners to take advantage of tax credits proposed in the recent Energy bill to diversify transportation fuel sources;
- Initiating a study of a more stable pricing mechanism for openly traded diluted blends which reflects acceptable long-term discounts required for processing to transportation fuels.

3.2.3 Alberta's Opportunity to Add Value in Canada and U.S. Links

Alberta is looking for ways to provide more upgrading capacity in the province, to produce more synthetic crudes, and together with industry is studying the economic and technical feasibilities of producing finished transportation fuels and petrochemicals. This opportunity is in some ways in direct competition to expanded upgrading capacity in U.S. refineries.

Nonetheless, this trend could benefit the U.S., which is currently approximately 2 million barrels a day short of refining capacity. While the development of more upgrading on a large scale will take at least five years, in the meantime, there is an opportunity to understand how the extension of upgrading to finished products can be of strategic benefit to the U.S. market, and avoid major refinery expansions or new construction.

Proposed Actions:

Industry and the Alberta government need to pursue a long-term business case for more upgrading in Alberta. (This is currently being pursued through the Hydrocarbon Upgrading

Task Force). See also the link to Section 5.2.3, Long Term View of Transportation Fuels in North America.

3.2.4 Niche Opportunities for Supplier/Customer Deals

The marketing models of the first major upgrading projects - Syncrude and Suncor - have represented two extremes. Syncrude has largely operated under the philosophy of a single quality synthetic crude. Suncor has based much of its marketing effort on individual refinery deals, where oil sands virgin and upgraded streams could be custom blended. The latter marketing philosophy needs to be explored by future upgraders, working together or alone. Greater synthetic crude diversity inherent in custom blending may assist the industry to expand its market reach. On the other hand, smaller volumes of custom crudes to markets do impose more limitations on transportation infrastructure.

Proposed Actions:

There is an opportunity for individual oil sands companies to pursue the feasibility of custom blending.

3.2.5 New Technology versus Older Processes in New Roles

Is there a "magic bullet" to the upgrading challenge? Upgrading today is based almost exclusively on mature technology adapted from standard refinery practices. In essence, upgraders choose their processes based on established and reliable performance, in large part due to the very high investment costs. There are many new technologies that have been advanced over the years which may offer improved cost effectiveness, but which have suffered from a lack of established facilities for large scale demonstration.

In terms of supporting processes to upgrading, special attention is now being focused on gasification. Gasification is a well established technology, with many commercial projects in existence world wide. It is gaining prominence in the oil sands industry as an effective way to reduce or eliminate reliance on natural gas for recovery energy and hydrogen production. The Nexen/OPTI project is destined to be the first oil sands plant to utilize this technology. Two of four newly announced high severity upgrading projects are also including gasification in their plans. Energy substitution aspects, and potential links to dealing with CO_2 emissions are discussed in Section 4, Kicking the Natural Gas Habit. This technology may also be attractive in the long-term to refiners, who face similar challenges from rising natural gas prices and its declining availability.

Gasifying the least valuable portions of bitumen provides an additional benefit to integrated upgraders. By removing the heaviest bitumen components processes used for upgrading, the balance of the barrel can be selected in a way that inherently promotes higher quality synthetic crude. This trend will partly address some of the concerns expressed for current quality synthetic crudes, as discussed above.

Proposed Actions:

Governments may need to consider joint funding of promising new technologies applicable to residue upgrading, where developers of the processes are unable to find funding alone.

3.2.6 Construction costs in Alberta and Labour Availability Issues

While not directly related to market availability issues, strained availability of trained construction personnel in Alberta, coupled with the relatively remote locations of many of the projects, have led to significant capital cost overruns in recent major projects. Low initial estimates likely also contributed to this situation. The combination of these factors was responsible for the scaling down of plans for another major project. Canadian governments are already aware of the need to review immigration rules to allow a faster influx of skilled trades and professionals from outside of Canada. This could include trained personnel from the U.S.

Proposed Actions:

Industry and construction associations in Alberta need to pursue this issue of availability of skilled labour at both the federal and provincial levels of the Canadian government.

3.2.7 Collaboration With Other Refining Centres and Markets

It is recognized that the growing Chinese economy is placing added pressure on crude oil supplies worldwide. At least two Chinese companies have already invested in planned oil sands projects, with a view to using planned new pipeline capacity between Alberta and the West Coast. Plans for their share of output are unclear at this time, but if not used directly by Chinese refineries, may be subject to trading into the U.S.

In another development the working group discussed the possible processing of oil sands products in new Mexican refineries, to replace future declines in Mexican heavy crude supply.

Proposed Actions:

No action is proposed at this time. Industry and government need to keep abreast of the opportunities for refining outside the U.S. and Canada.

The upgrading and refining working groups also discussed a number of environmental issues in bitumen recovery and upgrading, and infrastructure limitations in the fast growing region of Fort McMurray. While these challenges are important in the overall development of the resource, they are considered outside the scope of this workshop's focus on market expansion and related initiatives.

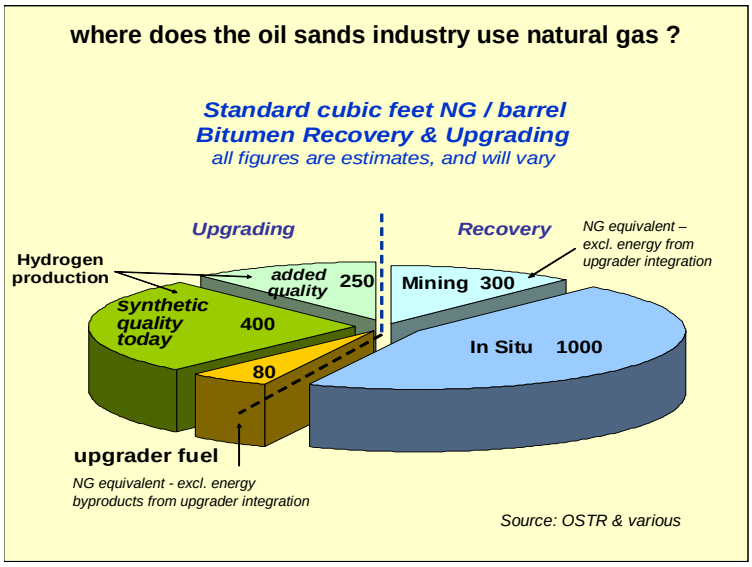
Section 4: KICKING THE NATURAL GAS HABIT

4.1 Backgound

Discussion of the energy sources used in recovery and upgrading are not directly related to expanding the market opportunities for oil sands products. However, there are indirect relationships in terms of overall economics, and in facilitating the production of higher quality synthetic crudes. There are also links to the third SPP deliverable, opportunities for value added uses for CO2 emissions from oil sands operations.

There is a high energy component to bitumen recovery, especially for SAGD and other *in situ* operations. While many mining operations are linked to upgraders, and can benefit from upgrader by-products for some of the recovery energy needs, *in situ* production currently relies exclusively on natural gas firing to generate steam. The other major energy requirement in the oil sands industry is for upgrader hydrogen. The current hydrogen generation process of choice is steam methane reforming, also based on natural gas feed. Figure 4.1 summarizes the combined energy and hydrogen demand, based on natural gas feed. The right hand side includes the two options for recovery—mining or *in situ*. On the left hand side, energy demand includes two levels of hydrogen consumption; the lower level is for the predominant light sweet synthetic crude quality today (about 33 ^{o}API) and added requirement to raise the product to around 40 ^{o}API, similar to the quality targeted by the Nexen-OPTI project.

Figure 4.1: Natural Gas Demand for Bitumen Recovery and Upgrading



In summary, the most extreme case (*in situ* recovery combined with a high level of upgrading) would consume around 1700 standard cubic feet of natural gas per barrel of product. This is equivalent to about 28 % of the energy content of the barrel.

Canadian Gas Supply

The Oil Sands Technology Roadmap indicated that at 5 million barrels per day, continued reliance on natural gas could consume as much as 60% of natural gas available in western Canada in 2030. While, there is admittedly some uncertainty in projecting natural gas supply to the year 2030, this level of consumption for oil sands development is, nonetheless, unsustainable and uneconomical.

Alternative energy sources, including coal, nuclear, and internally generated residues or upgrader by-product coke have all been reviewed as alternatives to natural gas. Where *recovery energy* is the principal objective, any are capable of supplying energy.

With respect to energy (including hydrogen) for upgrading, especially where closely linked to production, there are reasons why internal residues have a special advantage. In consuming the least valuable and heaviest portions of the bitumen, the remaining lighter portions of the bitumen barrel are more easily upgraded, and promote upgrader process options that inherently lead to higher quality synthetics.

While combustion of residues or coal is an alternative to natural gas for recovery energy, the only known technology to replace steam methane reforming for upgrader hydrogen is gasification. Increasingly the industry is studying integrated gasification for hydrogen production. While gasification is an established technology, oil sands residues are possibly more difficult to handle, and there is currently no commercial operating experience. The Nexen-OPTI project will be the first commercial oil sands plant to gasify the asphaltene residue to produce fuel gas and hydrogen.

However, given what is likely an unsustainable dependence on natural gas as the industry expands, the question may well be not ***if*** alternatives will have to be used, but ***when***.

4.2 Issues and Recommended Actions

Between mining and in situ recovery and full upgrading, the energy consumption per barrel of bitumen derived synthetic crude is equivalent to 18-28% of the original barrel.

As noted at the start of this section, energy sources used in recovery and upgrading are not directly related to expanding the market opportunities for oil sands products. However, there are indirect relationships in terms of overall economics, and in facilitating the production of higher quality synthetic crudes. The working groups covered eighteen individual topics, but in several cases similar underlying themes emerged. This report covers these working group discussions under six themes.

4.2.1 Is the Concern for Natural Gas Supply Justified?

Current production of natural gas in Canada is approximately 17 billion cubic feet (bcf) per day. To place this in perspective, on an energy basis this is equivalent to 3 million barrels of oil per day. One half of Canada's current gas supply (about 8 bcf per day) is exported to the U.S.

In Canada, various organizations forecast Canadian natural gas production. An average of eight recent forecasts surveyed by NRCan in 2005 (see References) suggests Canadian natural gas supply would rise very slightly to 17.5 bcf per day by 2020. A similar average of demand forecasts suggests a Canadian natural gas demand of about 11 bcf per day by 2020. This demand outlook includes considerable natural gas use by the oil sands projects in Canada. Currently, oil sands projects in Canada consume about 0.5 bcf per day. The National Energy Board has projected that by 2015 this could rise to 1.6 bcf per day, while the Alberta Energy and Utilities Board project 1.2 bcf per day by 2014. During the Oil Sands Technology Roadmap work, it was noted that considerably higher natural gas use by oil sands could be possible depending on the assumptions used.

Proposed Actions:

Canadian and Alberta governments need to confirm the likely position on future natural gas supplies, and develop an understanding with industry on future expectations regarding energy for oil sands developments. The two SPP Expert Groups will continue to exchange information on this issue.

4.2.2 Alternative Energy Sources

In the last two years there have been a number of studies in Canada related directly or indirectly to alternatives to natural gas to fuel the oil sands industry.

The growing interest in clean coal technology in both the U.S. and Canada is another possible approach to energy supply. This interest is exemplified by the recently published Clean Coal Technology Roadmap (see References). Replacing natural gas for recovery is clearly an established technology worthy of further consideration. Additionally, the WCSB contains reserves of low sulphur coal that rival oil sands bitumen reserves.

A study by Canadian Energy Research Institute (CERI) reviewed the possible use of small scale nuclear plants to generate steam for SAGD operations (see References). While the study showed scope economics that are competitive with natural gas prices of $5 Cdn per gigajoule, to be effective, the scale of operation would still require a number of 30,000 barrel per day production sites, connected by long distance steam pipelines. Hydrogen supply using nuclear energy would need to be via electrolysis, a relatively inefficient and expensive energy conversion route. On the one hand, a known advantage of nuclear energy is its near absence of CO_2 emissions, on the other hand, it has an historical image to overcome.

A less developed alternative may be the use of geothermal bedrock to reduce natural gas intensity, again at the recovery stage.

Proposed Actions:

Industry and governments need to assess alternatives to using natural gas in oil sands operations.

4.2.3 Gasification Technology

Gasification, and its potential for hydrogen production, was discussed in Section 3 in relation to linkages with upgrading. Gasification is a process that can be applied to any hydrocarbon, with the first step being the production of "syngas", a mixture of hydrogen and carbon monoxide. The syngas can be used directly as a fuel, or further reformed with steam to produce hydrogen. When gasification is used for multiple energy products it is sometimes referred to as "polygeneration".

The Oil Sands Technology Roadmap reviewed the benefits of gasification and concluded that it is rapidly becoming competitive with alternatives fueled by gas for higher value added end uses, such as hydrogen and power. For combustion alone the economics are less compelling because of the high capital cost of gasification compared with combustion and flue gas desulphurization. However, if the decision is made to invest in gasification for hydrogen, it is then relatively cost effective to include power and energy production via syngas. In the long-term, conversion of syngas to high quality hydrocarbons by Fischer-Tropsch synthesis will also benefit from gasification plants constructed for multiple uses.

There are some potential drawbacks to alternative fuels and hydrogen via gasification. The first is the lack of experience with the technology using oil sands derived residues. The second is the higher generation of carbon dioxide relative to clean burning natural gas. The third is the current onstream factor for gasifier reactors, which requires sparing, and therefore added capital, to allow onstream factors acceptable to upgraders and refiners. A fourth factor is the current requirement for oxygen separation units prior to the gasifier. However, all of these factors are under review as part of the decision making process for future upgraders and the general development of the technology.

The capital intensity of gasification, and its relative departure from standard upgrading and refining technologies is leading to consideration of centralized utility style facilities owned and operated by third parties.

Proposed Actions:

Gasification licensors have a vested interest to address the potential drawbacks of gasification, and they are in a position to advise projects accordingly. In particular, the onstream factor needs to be addressed, and more cost effective ways to separate oxygen are desired.

Governments and society have a strong vested interest in demonstrating the viability of gasification for residues and coal, as its successful application has the potential to significantly reduce industrial use of natural gas. Consideration should be given to tailored incentive programs and/or part funding of studies and demonstration scale technologies.

4.2.4 CO_2 Emission Considerations

While natural gas burning or conversion to hydrogen produces CO_2 emissions, the use of residues or coal on an equivalent energy basis will raise these emissions by an additional 40-

50%. Because of this, consideration of alternative fuels for oil sands development is often accompanied by consideration of CO_2 concentration, capture and use or disposal. This is also the topic of the third deliverable for the Oil Sands Expert Group.

The working group identified a number of possible actions in the handling of CO_2. There have also been a number of studies completed in the last few years. In addition, as CO_2 is captured other emissions can be reduced. This impact on multiple emissions should be explored.

The federal and Alberta regulators are attempting to coordinate their initiatives to meet Kyoto commitments. In general terms, both are promoting a "fuel neutral" approach to setting greenhouse gas emission intensity targets for new oil sands industrial emitters. Currently, the federal government proposes that new facilities be subject to a "best available technology economically achievable" standard ("BATEA"). The federal government is further proposing that the BATEA standard be based on natural gas as the fuel source. Emissions for any alternative fuel beyond the natural gas standard would then be subject to action, including capture and storage or purchasing of credits for any excess.

Proposed Actions:

Confirm CO_2 emissions from alternative fuels as compared to natural gas and for various end uses (e.g. fuel, power and hydrogen).

The U.S. DOE, Canada and Alberta need to pool existing information on prospects for EOR and other value-added recovery uses for CO_2, the subject of the third deliverable in SPP directive under oil sands. In the opinion of many workshop participants, this deliverable should be considered for more immediate action.

The Alberta and federal governments need to determine future regulations on emissions for new projects.

4.2.5 Utility Pipelines

The consideration of central utility style hubs for gasification complexes described in Section 4.2.3 leads to consideration of pipeline hubs for supply and distribution of hydrogen and CO_2 to end users.

Proposed Actions:

There should be strong government sponsorship of studies to facilitate the development of pipeline hubs for the future to supply and distribute hydrogen and CO_2. In particular, a CO_2 distribution network is necessary if EOR or enhanced coalbed methane application is to be practiced, as these production sites are often inherently distant from the likely oil sands production and upgrading sites.

Section 5: MARKETS FOR OIL SANDS PRODUCTS

5.1 Backgound

The target markets for oil sands products to date have been Canadian refineries as far east as Sarnia, Ontario and northern tier U.S. refineries, particularly in PADD II. PADD IV and V (Washington State) are additional but smaller markets. Oil sands producers are currently connected to approximately 5 million barrels per day of refining capacity. If oil sands production is to realize its full potential, new markets must be developed in the U.S. and possibly offshore, via the west coast. A better understanding is needed of the future mix of unprocessed diluted bitumen, synthetic crudes and possibly finished products and petrochemical feedstocks to meet optimum value-added potential.

Oil Sands Products

Unprocessed bitumen shipped in diluted form is a known commodity in the U.S. Refiners are able to handle this material technically, but within the constraints of existing conversion unit capacities. As concerns for diluent supply have gained ground, some producers have evaluated small scale field upgrading to reduce or eliminate diluent, but no such operations currently exist.

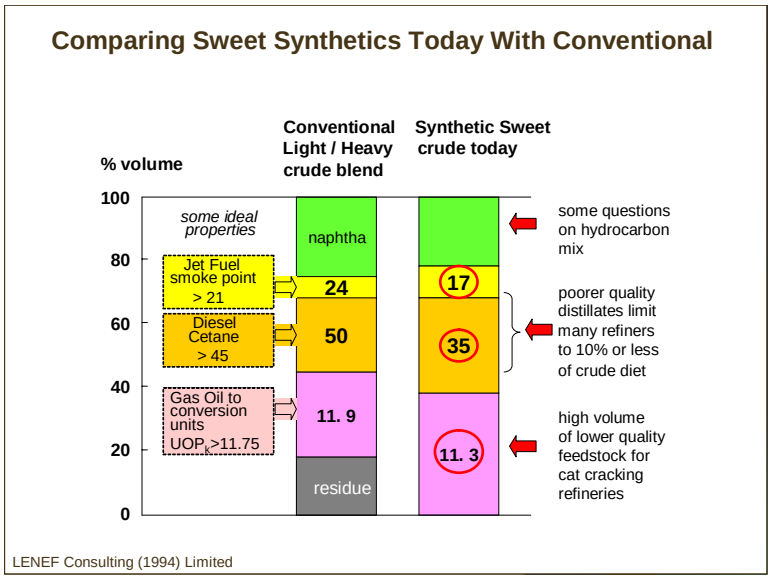
On the other hand, the synthetic crudes that predominate today have special characteristics that limit their penetration into refineries that are not specially equipped to handle them. Advantages in some markets are zero residue and low sulphur, but the key characteristics that give rise to the greatest difficulties are:

- The high aromatic content of the distillate streams, requiring more extensive hydro processing or “blending off” with lighter higher quality conventional crudes.
- The high volume and poly-aromatic nature of the heavy gas oil stream. This can lead to lower conversion in key refinery processes such as fluid catalytic cracking, which is commonly the sole gas oil conversion unit in U.S. refineries

Figure 5.1 is a summary depiction of the quality limitations. In combination, these factors impose significant limits on their contribution to crude diets in many U.S. (and Canadian) refineries. Syncrude’s recent expansion, and some of the newer projects planned have recognized this limitation and are planning for higher quality light sweet synthetic crude.

The residual sulphur in distillate fractions is another quality attribute that needs to be considered by refiners wishing to expand processing of synthetic crudes. While synthetic crudes are generally low in total sulphur, the sulphur that remains is captured in species most difficult to process. Confirming the ability of conventional hydrotreaters in refineries to further treat these cuts for future ultra-low sulphur fuels is essential, and may require added technical capability.

Figure 5.1: Key Quality Limitations of Most Current Synthetic Crudes



The following drivers that require careful long-term industry and market management include:

- Establishing a balance between the long-term value for unprocessed bitumen that will provide a fair return to the producer and ensure U.S. refinery-based conversion capacity is satisfied;
- Ensuring that the medium to long-term demand for lighter synthetic crudes and the desired quality attributes are consistent with changing transportation fuels specifications;
- Establishing the economic and technical merits of central upgraders and refineries in Alberta to produce specification products.

5.2 Issues and Recommended Actions

The Markets working group did spend a significant amount of time on a vision for the future and recognized that there was a need to develop a critical path to affect utilization of the anticipated 4 - 5 million barrels per day of production over the next 25 years.

The following sections are a summary of the points raised, some of which are cross cutting challenges also covered in Section 3, Upgrading and Refining and Section 6, Pipelines.

5.2.1 Is Today's Marketing Model Sustainable for the Future?

The first major upgraders were Suncor (originally Great Canadian Oil Sands, GCOS) and Syncrude. From its inception, Syncrude adopted a market strategy based upon a single light

sweet synthetic crude. Suncor, however, evolved into a marketing model based on custom blending of virgin and synthetic cuts into a number of synthetic crude types. In this way, Suncor has been able to satisfy individual refiners based on their varied needs. The Husky upgrader in Lloydminster, Saskatchewan, produces a single synthetic similar to the Syncrude product, but at a much lower volume. The Shell led upgrading project in Fort Saskatchewan, Alberta produces two grades of synthetic crude but only openly markets approximately 50,000 barrels per day. In all, the industry is now approaching 600,000 barrels per day of marketed synthetics, with as many as eight variations.

Of the next two upgraders expected to start up, CNRL's Horizon project is currently expected to produce a light sweet synthetic crude similar to Syncrude's product. The Nexen-OPTI Long Lake project will produce a higher quality synthetic crude partly as a result of its different process unit configuration.

In the short to medium term it is anticipated that individual producers will market their synthetics independently, but as new entrants become operational, there is danger of creating confusion in the market place. In addition, pipelines will be asked to handle an increasing number of individual crudes with associated batching problems.

Proposed Actions:

There is a need for industry and refiners to partner to ensure strategic alignments, that is, that refinery capacity is available, that there are markets for synthetic crude and that the risks of constructing and operating facilities can be shared.

5.2.2 Arguments for Oil Sands Industry Standard Marker Crudes

The variety of upgrader processes being used today, and anticipated in the future, will continue to add synthetic crudes which differ in individual quality of cuts, even while overall distribution of cuts and sulphur levels appear very similar. While conventional crudes have historically been differentiated on the basis of sulphur level and API gravity, the complexity of upgrading does not lend itself to such a simple approach. As the industry expands to even more players, and starts to exceed two million barrels daily, it may be advantageous to considering pooling of production into a few marker crudes, with defined quality bands.

In the last year just such an approach has been initiated in the creation of the new heavy sour blend called Western Canada Select (WCS). This crude type is produced from multiple bitumen sources, by blending with synthetic crude and condensate to meet a range of key specifications, each with a limited target range. It is too soon to gauge the success of this initiative. However, producers of light synthetics and markets may benefit from an extension of this approach in the medium to long-term. What may emerge is a fewer number of light synthetic crudes, with contribution of blending streams from several producers, and which become recognized as marker crudes with defined value bands.

Proposed Actions:

Over the long-term the industry needs to consider the value of pooling production into a few marker crudes, in consultation with major market regions.

5.2.3 Long-term View of Transportation Fuels in North America

North America, and the U.S. in particular, have a gasoline-oriented transportation fuel system. In other parts of the world, diesel is much more prominent as a transportation fuel. There are a number of reasons for preferring gasoline over diesel for private car transport in North America. For example, diesel fuels are less convenient in colder regions of this large continent. In addition, early attempts (during the 1970s) by U.S. car manufacturers to develop and supply diesel engine vehicles created a poor impression in the minds of the consumer. However, the long-term nature of the oil sands industry development cannot ignore the possibility that diesel-fueled vehicles will gain more interest because of their more attractive fuel economy.

In addition, to the fact that the future ratio between gasoline and diesel fuel demand is uncertain, tail pipe emission regulations are tightening, and forcing the market to ultra low sulphur fuels. These concerns have led to the emergence of a number of "boutique" fuels for specific market segments. Linked to both these trends, new engine technology is being researched which is designed to facilitate both lower tailpipe emissions and higher engine efficiency. A class of engines based upon low temperature combustion is under active long-term development, and, at this time, there is no clear indication as to which form of technology will prevail. There is also no clear direction on the preferred future fuel for these engines. For example, the ideal fuel may turn out to be something in between gasoline and diesel, as we know them today. This general topic is the subject of a second deliverable of the Oil Sands Expert Group and builds on the results of a workshop held in June 2005 on Oil Sands Chemistry and Fuel Emissions Roadmap Workshop (see References).

All these factors need to be addressed over the long-term by the oil sands industry and refining market together. In particular, there are strong links with future upgrading and synthetic crudes, which unlike conventional crudes are able to adjust as requirements change.

Proposed Actions:

The U.S. and Canadian federal governments may need to be involved in ensuring future fuel specifications and trends that are well understood in Canada. This will facilitate production of specification fuels destined for markets in the U.S.

There is a need for governments and industry to work towards a more limited range of cleaner fuels to provide greater flexibility and certainty to the market.

Addressing the issue of transportation fuels has already been identified as the next deliverable for the Oil Sands Expert Group.

5.2.4 Refinery Capacity and Location

Refining capacity in the U.S. is approximately 2 million barrels per day short of demand. Industry memories of persistent low netbacks over several decades are partly responsible for significant refinery rationalization in the 1980's and 1990's. "Capacity creep" in the remaining refineries has not kept pace with demand increases.

In the short term, added refinery capacity, through expansions in the preferred markets for oil sands products, will help to absorb the growing production base. This is in combination with planned expansion into newer markets.

In the long-term, and assuming continuing need for product imports into the U.S., the industry and U.S. fuel marketers should assess the value of large scale centralized upgrading in Alberta to finished specification fuels. This was also discussed in Section 3.2.3. The proposed action however, is repeated here.

Proposed Action:

Industry and the Alberta government need to pursue a long-term business case for more upgrading in Alberta. The U.S. and Canadian federal governments may need to be involved in ensuring future fuel specifications and trends are well understood in Canada. This will facilitate production of specification fuels destined for markets in the U.S.

5.2.5 Synthetic Crude Quality Challenges to Refiners

Refineries, technology licensors and consulting engineering companies need to use available information to address the key limitations in current quality synthetics summarized in Section 5.1. The main challenges are concerned with gas oil conversion unit performance and diesel pool cetane, and the ability to meet increasingly stringent sulphur specifications.

This also needs to take into account the generally increasing synthetic crude quality in some upgraders.

Proposed Action:

The fit between synthetic crude quality and refinery modifications are the responsibility of technology licensors and consulting engineering companies who will exercise process engineering due diligence.

Section 6: PIPELINE INFRASTRUCTURE

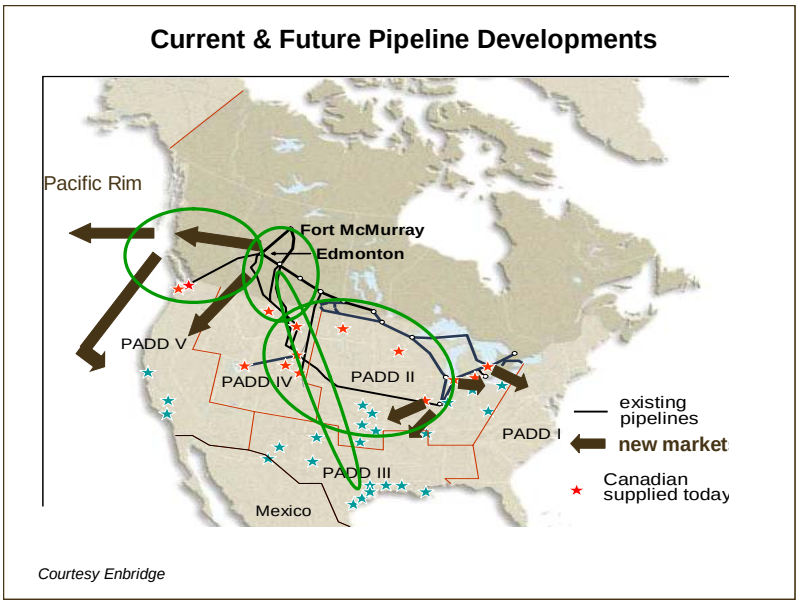
6.1 Background

The geography of North America requires integrated long distance pipelines to transport crudes and finished products. The fivefold expansion anticipated for oil sands products in a relatively short time span will represent many challenges for the pipeline industry.

Plans are in place to provide the necessary additional pipeline to significantly increase capacity by 2010 beyond the current 2 million barrels daily. Figure 6.1 identifies three key regions where pipeline capacity increases represent logical extensions. These four regions are:

- internally within Alberta
- from Alberta to the West Coast (offshore and California)
- from Alberta to the Midwest and selected Southern States
- from Edmonton to PADD III

Figure 6.1: Areas with Significant Pipeline Infrastructure Development Plans for Oil Sands



Beyond 2010, consideration may need to be given to central upgrading in Alberta that products specification light oil products, and could result in the consequent need for clean product pipelines to strategic U.S. markets.

6.2 Issues and Recommended Actions

In the initial working group, some concerns were raised concerning the technical operation of the pipeline as well as market and economic decisions. At the end of the second session, many of the participants dismissed these as major concerns for pipelines.

For example, with respect to the technical operations, pipeline companies already have specifications, mechanisms or pricing structures in place to move various crudes or petroleum products, including those from the oil sands.

Similarly, participants felt confident that the industry or the marketplace would be able to adequately handle investment decisions. This included other pipelines such as for CO2, hydrogen or clean refined petroleum products, that is, it was more an issue of first establishing the market before it was a pipeline issue.

The four remaining issues identified by the pipelines working group dealt with the size of the investments, permitting issues, lead times and resource constraints, handling increasing numbers of different products and bitumen shipping technology.

6.2.1 Size of the Investments

There are risks with pipeline investment decisions, particularly as they relate to determining initial pipeline capacity and who should bear the cost should there be initial excess capacity. One solution is increased tolling that spreads the costs to all users. Another is having an association or government help to spread the costs. The Canadian Association of Petroleum Producers (CAPP) has entered into agreements to guarantee sufficient commitments. Participants pointed to the Mackenzie Valley Gas Project where the Canadian Government has used creative means to ensure a capacity commitment on the natural gas pipeline through the funding of the Aboriginal Pipeline Group. Another example cited was the Alberta Government's commitment of royalty volumes in 1999 on the Express Pipeline.

Proposed Actions:

Ultimately, the market will determine the appropriate investment decisions. Continued communication among governments, associations, and pipeline companies and their clients is necessary. Governments can help to ensure that issues are raised and discussed, such as at the Oil Sands Experts Working Group Workshop.

6.2.2 Permitting Issues

Regulatory issues were cited as a major concern on both sides of the Canada/U.S. border. This applies not only to new construction but also to expansion or reversal of existing pipelines. Regulatory issues impact the overall risk of a pipeline and extend the length of time for approval.

The Canadian and US Governments already cooperate and share information with respect to pipeline regulation. In May 2004, the National Energy Board (NEB) and the Federal Energy Regulatory Commission (FERC) signed a Memorandum of Understanding (MOU) for natural gas pipelines. In November 2005, as part of the SPP, the NEB and the U.S. Pipeline

and Hazardous Materials Safety Administration signed an MOU that set the stage for increased compliance data sharing as well as staff exchanges and joint training opportunities.

Canadian governments have already gone a long way to coordinating and streamlining the environmental and regulatory approvals, but more needs to be done.

In the United States, pipeline companies face an often complicated and "patchwork" collection of local, state, or federal regulations as well as potential native obligations. There is no one single federal agency that handles all aspects for interstate liquid petroleum pipelines or which expedites permitting, such as is done for natural gas pipelines under the Natural Gas Act.

Proposed Actions:

Governments need to streamline regulatory approval and better manage the risk to both pipeline and energy projects. Providing process mapping and a one-stop-shop for proponents would help to ease the complexity, facilitate coordination and reduce the time required for regulatory approval and permitting.

Expanding the planning horizon and including all stakeholders such as government, producers, NGO's, First Nations, and private landowners, could help to identify and resolve the environmental and accommodation concerns in a more timely manner.

6.2.3 Lead Times and Construction Constraints

Along with permitting issues, two other factors can combine to affect the smooth delivery of appropriate pipeline capacity. The first is timely information on oil sands projects, start up dates and expansion plans. The second is related to infrastructure and resource constraints such as labour and pipe mill capacity. As discussed in previous sections, this also impacts oil sands developments themselves.

Proposed Actions:

Governments can help to ensure that information about projects is collected and disseminated, and that issues are raised and discussed, such as at the workshop. With respect to infrastructure and workforce issues, government needs to take the lead with policy issues dealing with immigration and infrastructure while greater industry transparency would aid with long-term planning.

6.2.4 Handling Increased Variety of Products

As many new synthetic crude variants come on to the market, pipelines will be required to handle increasing numbers of separate batches. While this is technically feasible, and done today, this does place certain operational constraints, potentially leading to increased tariffs. The industry would, for example, be handling more breakout tankage and interface batches. Fewer product types in the medium to long-term may help to reduce these constraints.

It was the consensus opinion within the working group that technically the pipeline companies already deal with this kind of challenge on a daily basis. However, simplification from handling fewer products may help overall pipeline efficiency and reduce costs.

There are no proposed actions at this time.

6.2.5 Bitumen Shipping Technology

Bitumen represents the more difficult product for pipeline shipments. The working group discussed the need for more basic research and development in new ways to ship bitumen.

Proposed Actions:

As more basic research and development in new ways to ship bitumen was deemed to be a public good issue, it was felt that this could be a government/industry focus that involved many research organizations such as the Alberta Energy Research Institute, the Alberta Research Council, the National Research Council, universities, or the Canadian Oil Sands Network for Research and Development (CONRAD).

Section 7: REFERENCES

1. **Alberta Chamber of Resources, (2004). "Oil Sands Technology Roadmap: Unlocking the Potential".**
   http://www.acr-alberta.com/Projects/Oil_Sands_Technology_Roadmap/OSTR_report.pdf

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5. **NRCan, (2006). "Canadian Natural Gas"**
   http://www2.nrcan.gc.ca/es/erb/CMFiles/CANADIAN_GAS_REVIEW_AND_OUTLOOK_ENGLISH209IEP-26012006-7427.pdf

Section 8: APPENDICES

Appendix 1: Questions from the Pre-Workshop Reading Material

Appendix 2: Plenary Session Presentations

- Mike Ekelund, Alberta Energy
- Gerald Bruce, Jacobs Canada Inc.
- Tom Boslett, BP Refining

Appendix 3: List of Participants

Security & Prosperity Partnership
Oil Sands Experts Group Workshop
Houston, January 24-25, 2006

Appendix 1: QUESTIONS FROM THE PRE-WORKSHOP BRIEFING MATERIAL

Appendix 1 contains the questions from the Pre-Workshop Briefing Material that were not otherwise incorporated into the Final Report.

Upgrading and Refining:

1. *Is there sufficient dialogue between the oil sands producers and the downstream refiners - particularly in the US - on long-term needs ?*
2. *Do "economics" indicate a favoured location to upgrading…large scale standalone upgraders providing a suite of synthetic crudes, or individual refinery revamps ?*
3. *What are the opportunities and challenges for increasing upgrading, refining and petrochemical production capacity in Alberta?*
4. *The US currently imports approximately 2 million barrels daily of finished transportation fuels. Does this represent a "niche" target for large scale Alberta upgrader complexes to fully finished products ?*
5. *Are there special issues for oil sands derived crudes in the light of increasingly stringent fuel quality requirements ?*
6. *How to address what might seem to be a mismatch in risk-reward for bitumen and synthetic crude producers, and ensure long-term supplies of both commodities.*
7. *How is it best to incorporate energy self-sufficiency or other alternatives to natural gas use ? (see also the next section)*

Some of these questions are closely tied to the discussion on "markets".

Kicking the Natural Gas Habit

1. *At the level of 5 million barrels by 2030 and current natural gas use, the industry would consume as much as 25-50% of the available natural gas from the Western Canada Sedimentary Basin…is this sustainable ?*
2. *There are integration benefits to using internally generated residues as an alternative energy and hydrogen source. The countervailing impact is higher CO_2 emissions. Workshop comments?*
3. *What is the current level of comfort in the industry with residue combustion, and how can that be improved?*
4. *What is the current level of comfort in the industry with gasification, and how can that be improved?*
5. *Nuclear energy has been cited as an alternative energy source, with potential for drastic reduction in CO_2 emissions. Workshop comments?*
6. *What role might coal play?*
7. *What comments does the Workshop have on dealing with CO_2 emissions, and available technologies?*

Markets:

1. *Is the oil sands industry comfortable that they have a good handle on US regional refinery needs in terms of synthetics and bitumens to replace declining or other offshore products, and in an expanded market orbit ?*
2. *Does the planned scale of oil sands product increases, and the need to address the future mix of products and quality, favour and industry-wide strategy that still keeps producers and uses "at arms length" or are producer/refiner deals more effective?*
3. *What are the opportunities and challenges to building increased upgrading, and refining to finished products and petrochemicals in Alberta?*

Pipelines:

1. *What lead time is needed for a major new pipeline installation ?*
2. *Should we plan now for the long-term vision of 5 million barrels per day ?*
3. *What are the issues in pipeline permitting in the US and in Canada ?*
4. *Are there issues with multiple new synthetic crude products into existing pipeline systems.*

Security & Prosperity Partnership
Oil Sands Experts Group Workshop
Houston, January 24-25, 2006

Appendix 2: PLENARY SESSION PRESENTATIONS

Security & Prosperity Partnership

Oil Sands Experts Group Workshop
Houston, January 24-25, 2006

Alberta's Oil Sands Opportunity

Oil Sands Workshop
Houston, TX
January 24-25

Alberta Government

Alberta's Oil Sands Regions

Oil Sands Reserves

Initial Established Reserves:

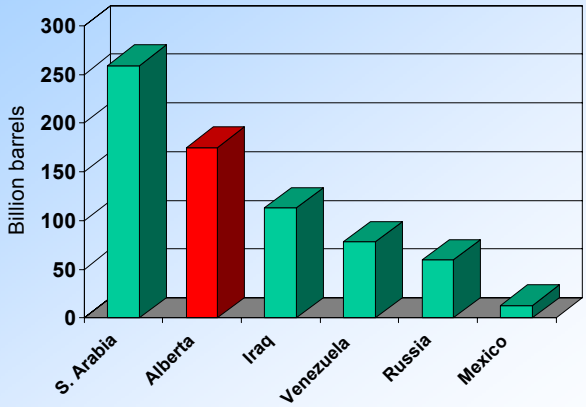
179 billion barrels

Remaining Established Reserves:

175 billion barrels

Source: *Energy and Utilities Board Report 2004-98*
Rounded to nearest 1 billion barrels

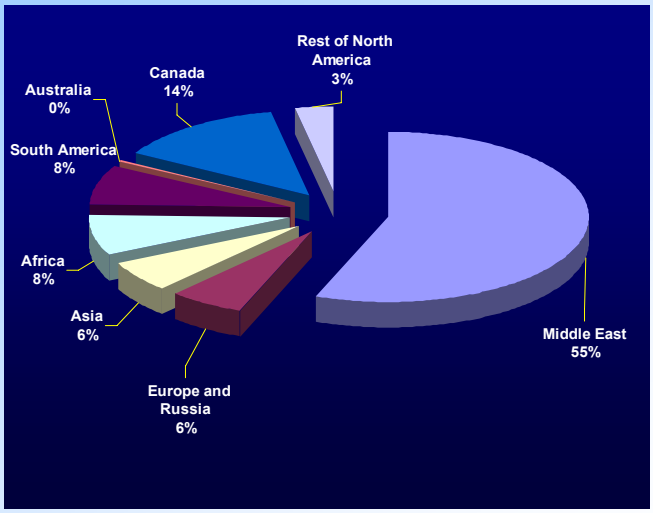
Alberta Oil Reserves



Source: *Energy Information Agency Report*

Alberta Government

World Proven Oil Reserves



Source: *Energy Information Agency Report*

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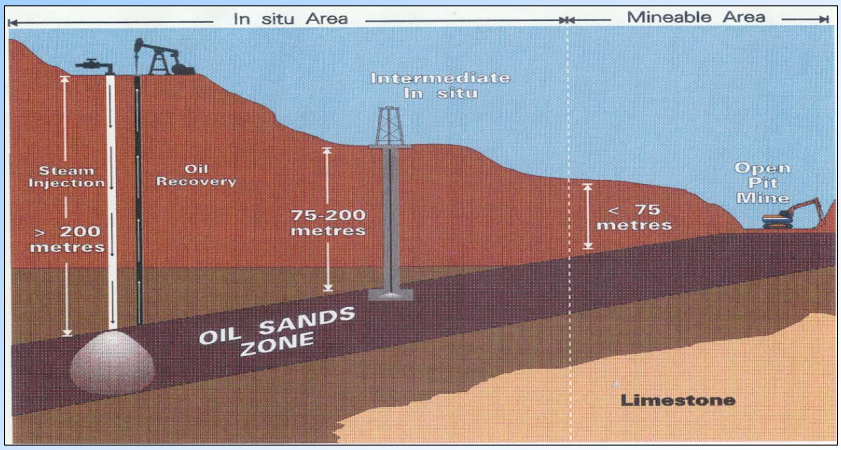
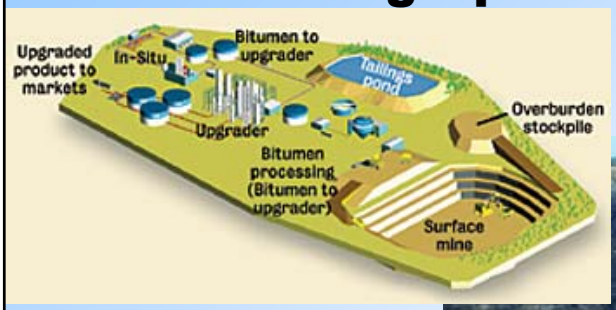
Resource and Recovery Methods



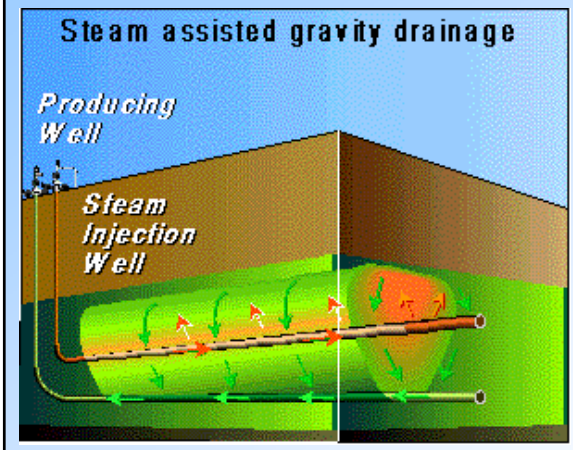
Alberta Government

Mining Operations



Alberta Government

In Situ Operations

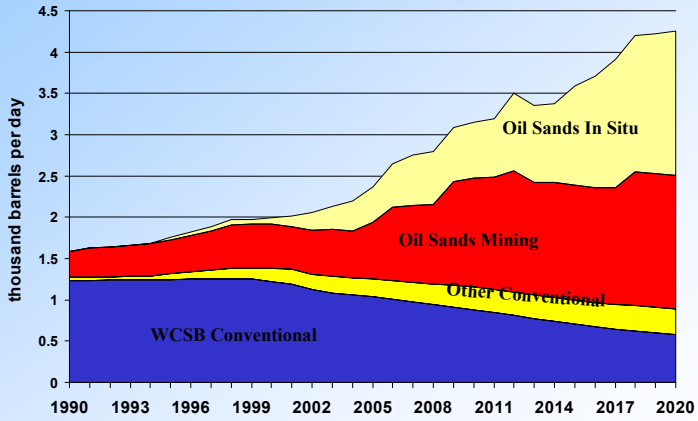


- 80% of current reserves
- Multiple Technologies
  - Cold pumping
  - Cyclic steam stimulation
  - SAGD
  - Vapex
  - THAI

SAGD Operations Example

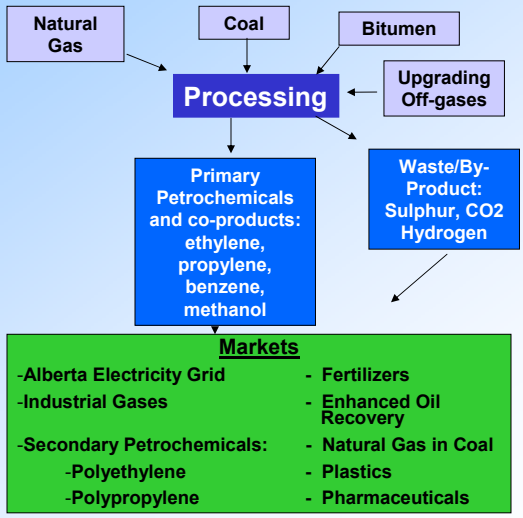
Alberta Government

Projected Canadian Oil Supply



Sources Conventional Production - CAPP 2005-2015 forecast
Oil Sands Bitumen Production and trend extrapolation beyond 2015 - ADOE

Alberta – Resources and Markets



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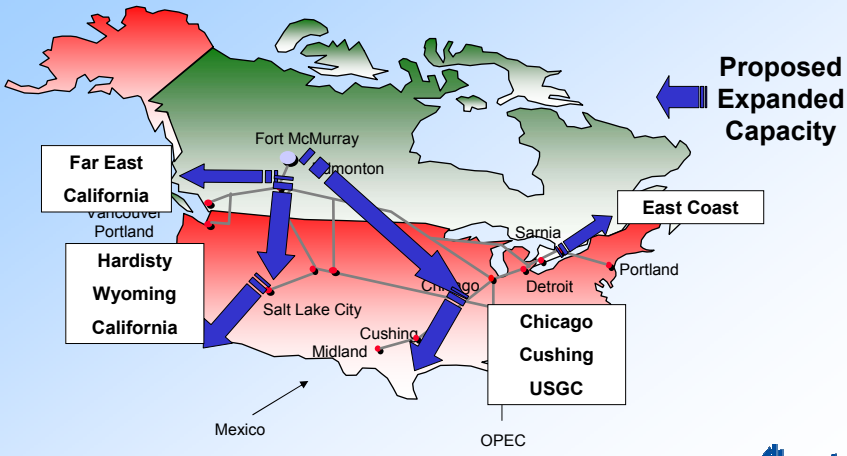
Markets for Alberta Crude



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Alberta Upgrading

(Barrels per Day)

	2003	2006	2010+	2020
Alberta Heavy Oil Forecast	**1,041,000**	**1,300,000**	**2,000,000**	**3,000,000**
	Upgrading Capacity			
Company:				
Suncor	225,000	260,000	550,000	POTENTIAL
Syncrude	245,000	350,000	500,000	
Shell	155,000	200,000	300,000	
Husky	75,000	82,000	150,000	
Other*	--	--	190,000	
Total Upgrading Capacity	**700,000**	**892,000**	**1,690,000**	**2,000,000**
Heavy Available for Upgrading	***341,000***	***408,000***	***310,000***	***1,000,000***

Alberta Refining

(Barrels per Day)

Company	Location	Capacity 2003	Capacity 2020
Husky Oil	Lloydminster	25,000	POTENTIAL
Imperial Oil	Edmonton	180,000	
PetroCanada	Edmonton	130,000	
Shell	Ft Saskatchewan	100,000	
Other*	*To be Announced*	--	
Total Refining Capacity		**430,000**	**1,200,000**

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Advantages of Refining at Source

- Inexpensive/standardized feedstock
- Zoned sites for infrastructure and support services
- Integration with upgraders and petrochemicals
- Low transportation costs
- Access to major markets – not locked to one market
- Other Alberta Advantages:
  - Efficient and Effective Regulatory Processes
  - Integration With Complementary Plants:

Alberta Government

Alberta Advantage

- Located near largest consumer of energy- U.S.A.
- Access to growing East Asian markets
- Stable political system and competitive fiscal regime – no public debt
- Outstanding, skilled work force
- World-class transportation infrastructure
- Proven record of applied innovation
- Strong investment climate

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Alberta Hydrocarbon Upgrading Task Force (HUTF)

- HUTF established in February 2004
- Consists of over 70 members from government and industry collaborating on achieving the Vision
- Objective to maximize the value-added potential of our massive oil sands resource
- Demonstrating the business case for further upgrading and refining of bitumen within Alberta
- Joint initiative of Industry, Alberta Energy and Economic Development

Alberta Government

HUTF Action Plan

- Business Case: Advantages of an eco-industrial complex, value of integration, product market supply/demand
- Create an environment that supports technology processes for an integrated complex
- Propose options to Government policies and regulations that would foster development of an eco-industrial complex
- Benchmark successful jurisdictions (Singapore, Marl, Houston)
- Identify challenges (labour, infrastructure)
- Investment Promotion Strategy

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Purvin & Gertz Asian Study

- SCO and SCO/bitumen blends are suitable substitutes for Middle East imports
- High TAN and sulphur values may limit the amount of bitumen blend that Asia refineries can process.
- Diesel produced in Edmonton could be competitive in Asia, and particularly in China
- An Alberta upgrader could export gasoline to the U.S. and diesel to Asia, as these are the products each area prefers
- Requires competitive pipeline infrastructure
- Study focused on price competitiveness and did not address market volume issues

Alberta Government

Purvin & Gertz North American Market Studies

- Rather than upgrade bitumen to synthetic crude, incremental economics of producing refined products and petrochemicals are slightly more favourable than standalone upgrading.
- Large capital investments would be required. The potential to reduce capital costs has a very positive impact on the overall economics.
- Both California and Midwest markets appear to be good outlets for product exports from Canada, with California appearing to be slightly more favourable.

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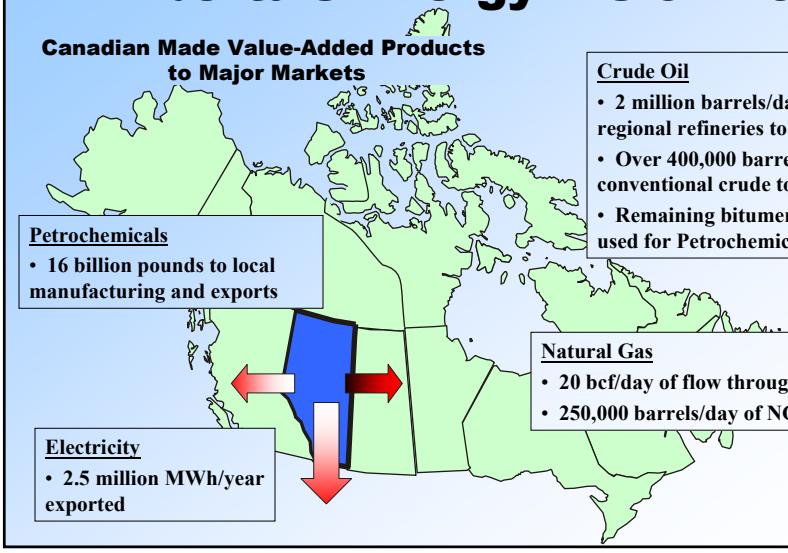
Alberta's Energy Vision 2020

Canadian Made Value-Added Products to Major Markets



Crude Oil
- 2 million barrels/day of SCO to regional refineries to produce RPPs
- Over 400,000 barrels/day of conventional crude to refineries
- Remaining bitumen volumes are used for Petrochemical feedstock

Petrochemicals
- 16 billion pounds to local manufacturing and exports

Natural Gas
- 20 bcf/day of flow through Alberta
- 250,000 barrels/day of NGLs produced

Electricity
- 2.5 million MWh/year exported

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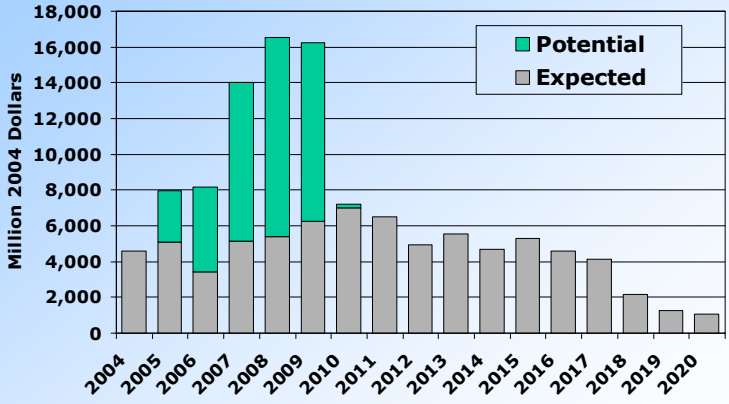
CERI Projected Investment



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Oil Sands Benefits Forecast

CERI Report (2005) Forecasts 2000 -2020		
Production	3.4 million bopd (sales) by 2020	
Increased Expenditures	$100 billion capital over period (2004$) $46 billion/yr operating by 2020 (2004$)	
Added GDP	3.0% (all of Canada in 2020)	
	Alberta	Rest of Canada
Employment (direct, indirect, induced)	3.6 million PY over period 244,000 permanent jobs in 2020	1.8 million PY over period 114,000 permanent jobs in 2020
Added Revenue Royalty & Tax (1994$)	$42 billion over period	$51 billion (Federal) over period ($29 billion other Provinces/Municipalities)

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Prospects for the Future Oil Sands Production

Presented by:

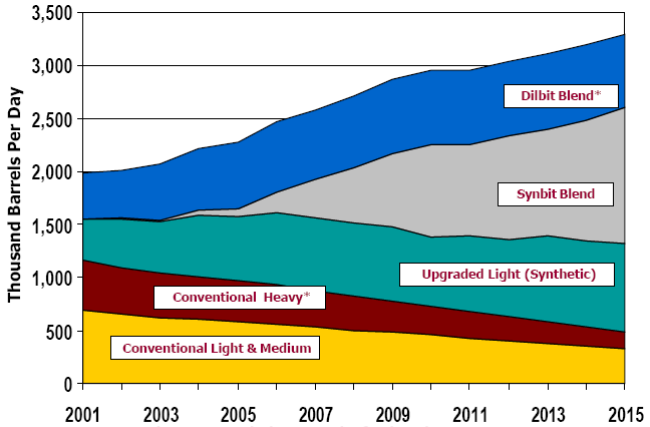
Gerald W. Bruce
Jacobs Canada Inc.

SPP Oil Sands Workshop, Houston, January 24, 2006

Overview

- Oil Sands
  - *Growth projection*
  - *Processing chain*
- Upgrading and refining
  - *Adding value to bitumen*
- Synthetic Crude Oil vs Bitumen Blends
  - *Processing challenges*
- Typical US refinery configurations
  - *Complexity range*
- Market Reach
- Issues and challenges
- Conclusions

Anticipated Production Growth



- Conventional Heavy– excludes upgrader feedstock
- Dil Bit Blend includes Upgraded Heavy

Source: CAPP

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Oil Sands … Visualization

Source: Syncrude

4

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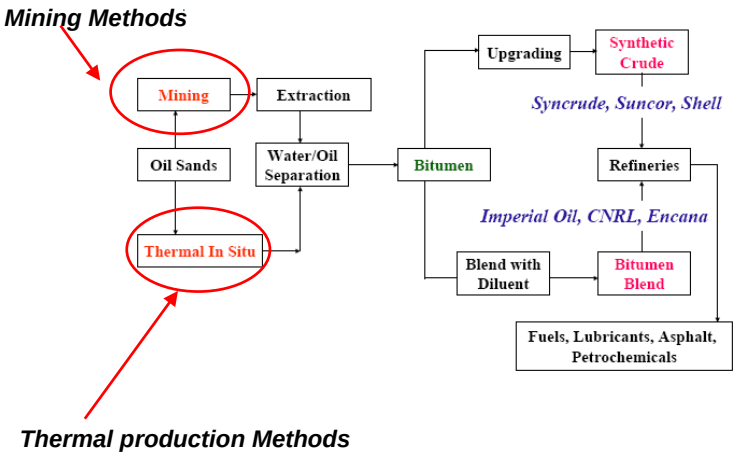
Oil Sands Processing Chain



Source: TD Securities

5

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Bitumen can be Upgraded (or not)

Bitumen

Synthetic Crude Oil

Or…. Bitumen Blends

6

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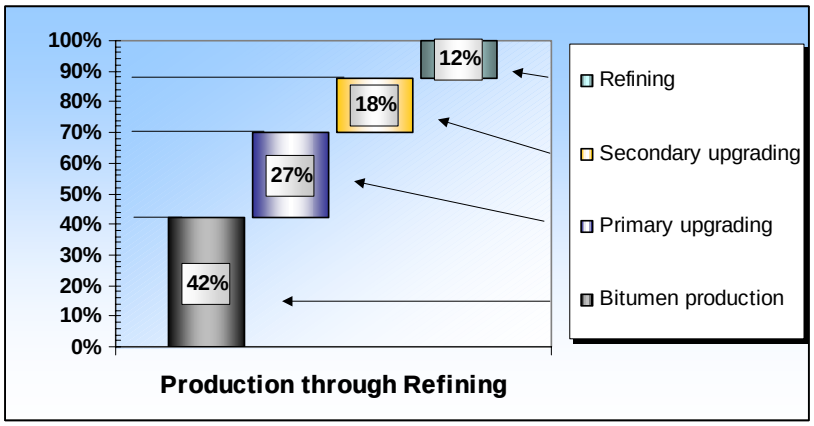
Adding Value to Bitumen

Production through refining



Source: Petro-Canada

7

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Adding Value to Bitumen

- Dilute bitumen and ship
  - *Dilute with naphtha (Dilbit)*
  - *Dilute with Synthetic Crude Oil (Synbit)*
  - *A heavy, sour feed for processing "somewhere else"*
- Upgrade to premium Synthetic Crude Oil
  - *Like Syncrude, Suncor, Shell today*
  - *Multiple players plan to do this in the future*
- Complete transformation to finished products and petro-chemicals

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Investment Planned

- Mining (reserves close to the surface)
  - *Truck and shovel, extraction facilities*
- Thermal Production (reserves too deep to mine)
  - *Steam Assisted Gravity Drainage*
  - *Cyclical Steam Stimulation*
- Upgrading/refining
- Infrastructure
  - *Pipelines to new markets*

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Planned Investment in Alberta

Inventory of Major Alberta Projects Summary, December 2005		
Sector	**# Total Projects**	**Value of Projects ($millions)**
Agriculture & Related	25	$ 585.0
Chemicals & Petrochemicals	8	$ 609.2
Commercial/Retail	110	$ 3,556.4
Commercial/Retail and Residential	7	$ 1,176.0
Forestry & Related	8	$ 934.0
Infrastructure	346	$ 11,440.8
Institutional	214	$ 7,808.1
Manufacturing	3	$ 26.0
Mining	6	$ 319.8
Oil & Gas	25	$ 5,030.5
Oil Sands	48	$ 73,804.7
Other Industrial	30	$ 509.3
Pipelines	45	$ 5,439.1
Power	21	$ 4,162.5
Residential	97	$ 1,792.3
Tourism/Recreation	155	$ 5,898.0
Total	**1148**	**$123,091.7**

>$C123 billion

Source: Alberta Economic Development

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Degree of Processing

- Minimal
  - *Dilute and ship*
- Full
  - *Finished products*
- Today:
  - *Premium Synthetic Crude Oil*
- Tomorrow:
  - *Tailor processing to match refining*

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New Facilities

- All In
  - *Close to the resource (Alberta)*
  - *Upgrading to finished products*
  - *Integration with petro-chemicals*
  - *Gasification of residue for hydrogen*
  - *CO2 capture and sequestration*
  - *Integration with SAGD production*
  - *Global market reach*

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In Reality

- Upgrading to synthetic crude oil
  - *Premium*
  - *others*
- Local market is satisfied
- Limited refineries dedicated to handle synthetics
- Cheap feedstocks are attractive to refiners
  - *Light / heavy differential in their pocket*
  - *US market, existing refineries*
- Producers looking for a home for bitumen blends
- New markets opening up

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Thus….

- More than one opinion on the "best way" to handle oil sands production
- New facilities planning to upgrade bitumen
  - *Into synthetic crude oil*
    - Range of quality
  - *Some have refineries for finished product*
- Merchant upgrading
- Upstream producers link with downstream refiners
- US refineries investing to process new feedstocks
- New markets opening up

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Incentives to Invest in Processing

- Capturing the Light/Heavy differential
  - *Requires significant investment to become "bitumen friendly"… remember bitumen is cheap for a reason!*
  - *Will have to deal with the diluent in the bitumen*
    - Dilbit vs Synbit
  - *Do I want to look like a bitumen upgrader?*
- Processing Synthetic Crude Oil
  - *Is premium sweet SCO a good fit?*
  - *What are all these new variations of SCO coming ion the market?*
  - *Difficult processing is already done*
    - Residue stays in Alberta
- Security of feedstock supply

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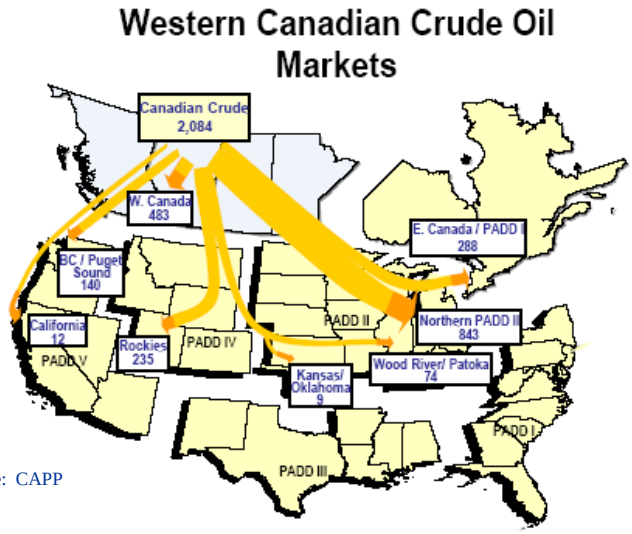
Existing Markets - Relative Volumes



Source: CAPP

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Bitumen Characteristics

- Heavy, high viscosity, high sulphur
  - *requires diluent blending for pipeline transport*
- High residual (high boiling fraction) content
  - *requires conversion (coking or Hydrocracking), asphalt or heavy fuel oil outlets*
- Quality Challenges
  - *Total Acid Number >1 requires metallurgy upgrade on crude, vacuum unit*
  - *metals,sulphur, salts required treating*
  - *High aromatics, naphthenes*

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SCO Characteristics

- Range of qualities
  - *Depends on upgrading process and objectives*
- Premium SCO
  - *Bottomless, refined product*
- Sour Synthetic
  - *Partially upgraded*
  - *With or without bottoms*
- Other
  - *New formulations planned with new projects*

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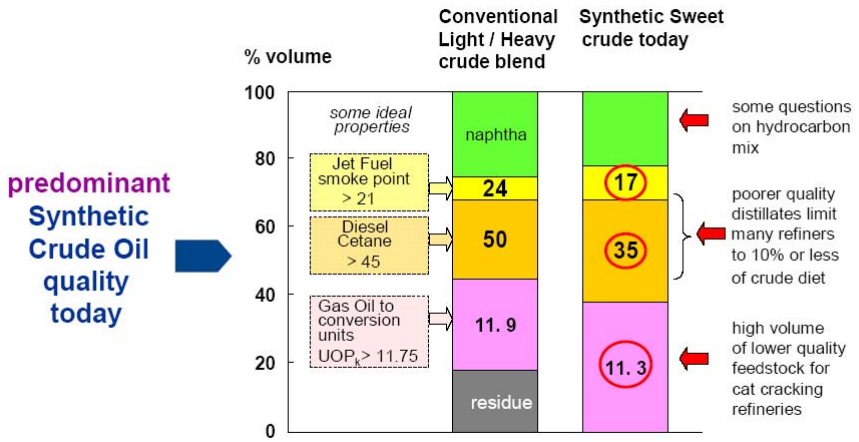
SCO Comparison



Source: Len Flint

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Comparison

	Bitumen		Bitumen Derived		
	Athabasca Bitumen	Cold Lake Bitumen	Cold Lake Blend	Syncrude Sweet Blend	West Texas Intermediate
Gravity, API	7.9	11.0	23.1	31.8	40.8
Specific gravity	1.0151	0.9928	0.915	0.8663	0.8212
Sulphur, wt%	4.9	4.6	3.5	0.1	0.3
Nitrogen, ppm	4000	3740	3230	630	800
CCR, wt%	13.4	12.9	11.0	0.0	1.08
Vanadium, ppmw	222	182	152	<0.4	1.6
Nickel, ppmw	87	65	57	<0.4	1.6
Asphaltenes, wt%	17.5	16.0	13.4		0.1
TAN	3	1	0.8		
Salt, lb/1000 bbl	40	20	15-20		

Message: Bitumen derived feedstocks are very different than Medium Sweet Crude

Source: NCUT

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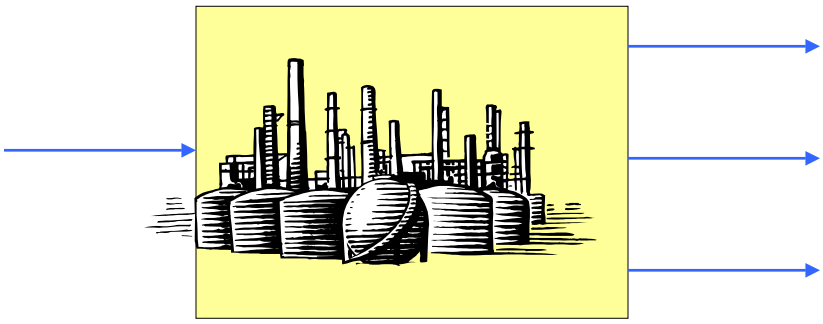
US Refinery Configurations



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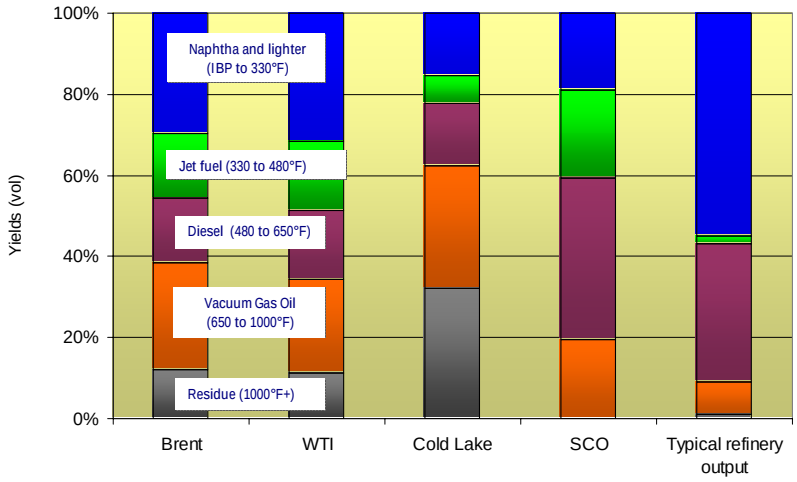
Fitting the Pipes - Typical Yields



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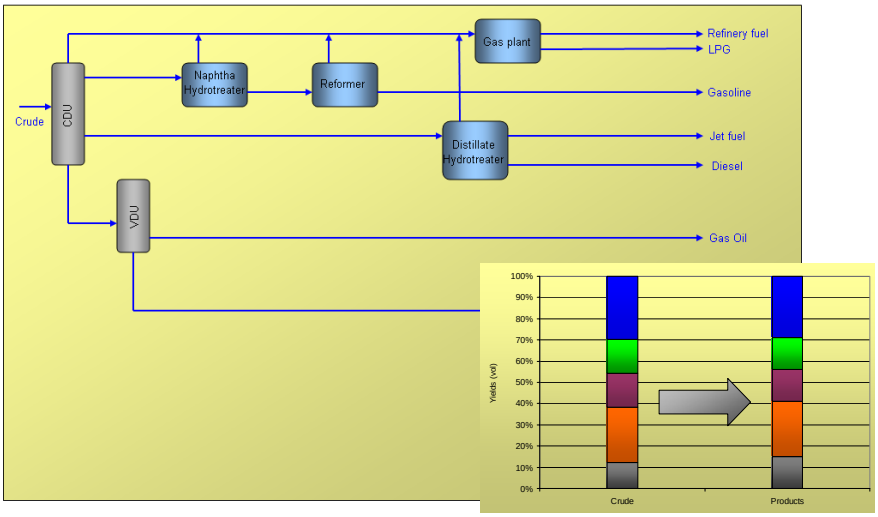
Low Complexity Refinery



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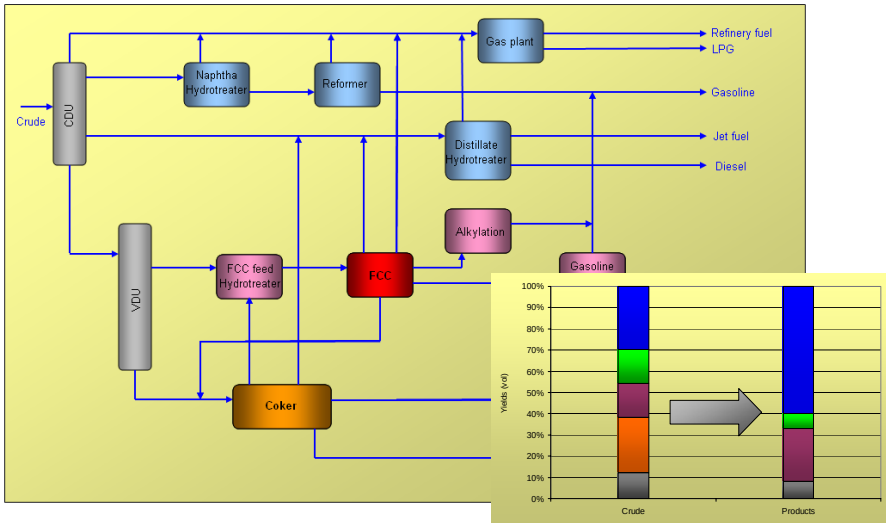
High Complexity Coking Refinery



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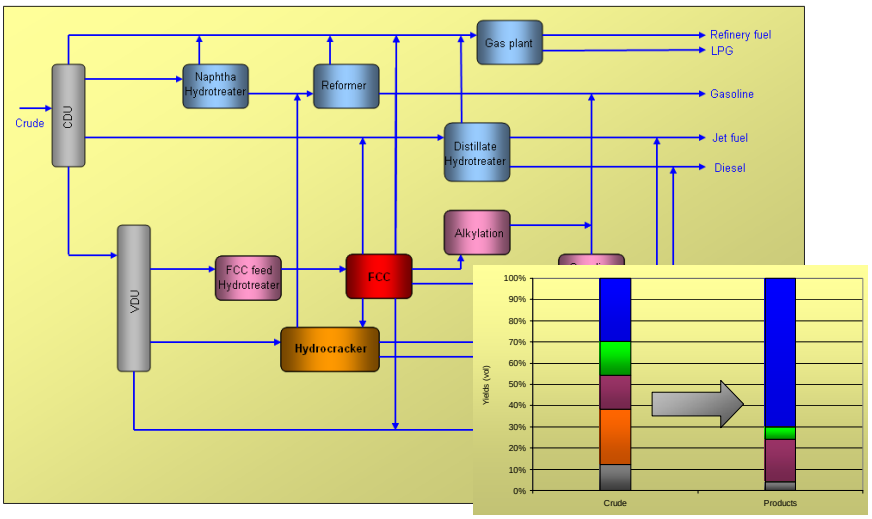
High Complexity Cracking Refinery



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Processing Bitumen Blends

- Not a good fit with refineries designed for light sweet crudes
- Need “conversion” capacity to handle bottoms
- Significant hydroprocessing of converted material
  - *Bitumen is H2 deficient*
  - *Never seems to be enough H2 around*
- Byproducts are plentiful and nasty
  - *Sulphur, Coke*

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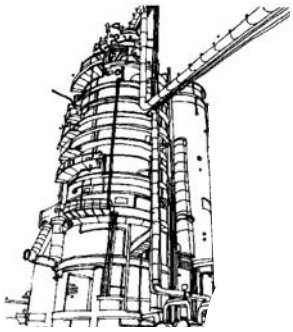
Processing SCO in Refineries

- Current SCO quality
  - *Low Hydrogen content*
  - *FCCU conversion issues*
  - *Diesel cetane issues*
  - *Making jet fuel*



- Co processing with conventional crudes provides some blending flexibility

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All Bitumen Really Needs:

- Conversion of heavy molecules
- Significant hydrogen addition
- A home for the by-products
  - *Residue (coke, asphaltenes)*
  - *sulphur*

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All SCO Really Needs

- A “matched” refinery
  - *to take advantage of the work that has already been done in the upgrader*
- Inexpensive upgrader = expensive refinery
- Expensive upgrader = “less expensive” refinery

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Future Product Formulation

- Blended bitumen
- Premium SCO
- Partially upgraded SCO
- Custom blending – customer specific
  - *Matched with a refinery*
- Finished products – motor fuels
- Petro-chemicals

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Future Product Formulation

- Something that looks like “WTI”
  - *West Texas Intermediate*
  - *Medium sour, with bottoms*
- Something that look like “ANS”
  - *Alaska North Slope*
  - *With bottoms that can make “good” coke*

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Issues and Challenges

- Following through with investment plans
  - *Labour , engineering, equipment constraints*
- Deciding where the value gets added
  - *Upgrading investment vs refinery investment*
- Capitalizing on the unique qualities of bitumen
  - *More than just a refinery feed*
- Market Access
- Environmental responsibility
  - *Natural gas, CO2, byproduct management*

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Target Markets

- Current
  - *US Midwest (PADD II)*
  - *US Rocky Mountain Region (PADD IV)*
- Extended and New Markets
  - *US West Coast (PADD V)*
  - *US Gulf Coast (PADD III)*
  - *Offshore (Export from Kitimat BC Terminal)*

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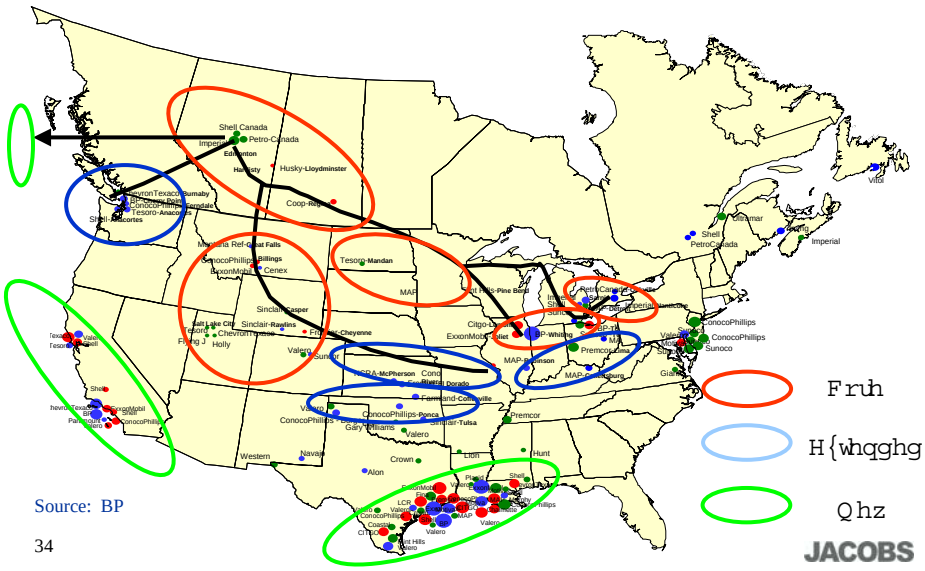
Existing and New Markets are Key



Source: BP

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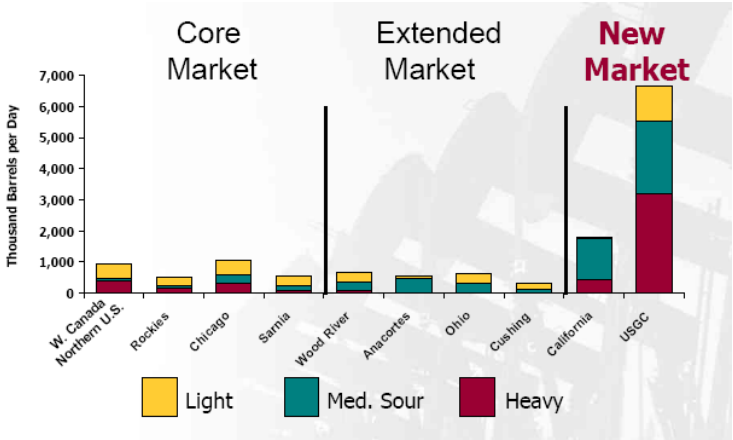
New Markets - Comparison



Source: CAPP

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Conclusions

- The time is right for significant oil sands development.
- Upgrading or not….. Depends on the market
- Security of supply will fuel the expansion of bitumen derived feedstocks in current and extended US markets.
- Refineries need to be "reconfigured" to make them bitumen friendly.
  - *Start to look much like an upgrader*
- New markets provide the opportunity to "tailor" production to meet market needs.

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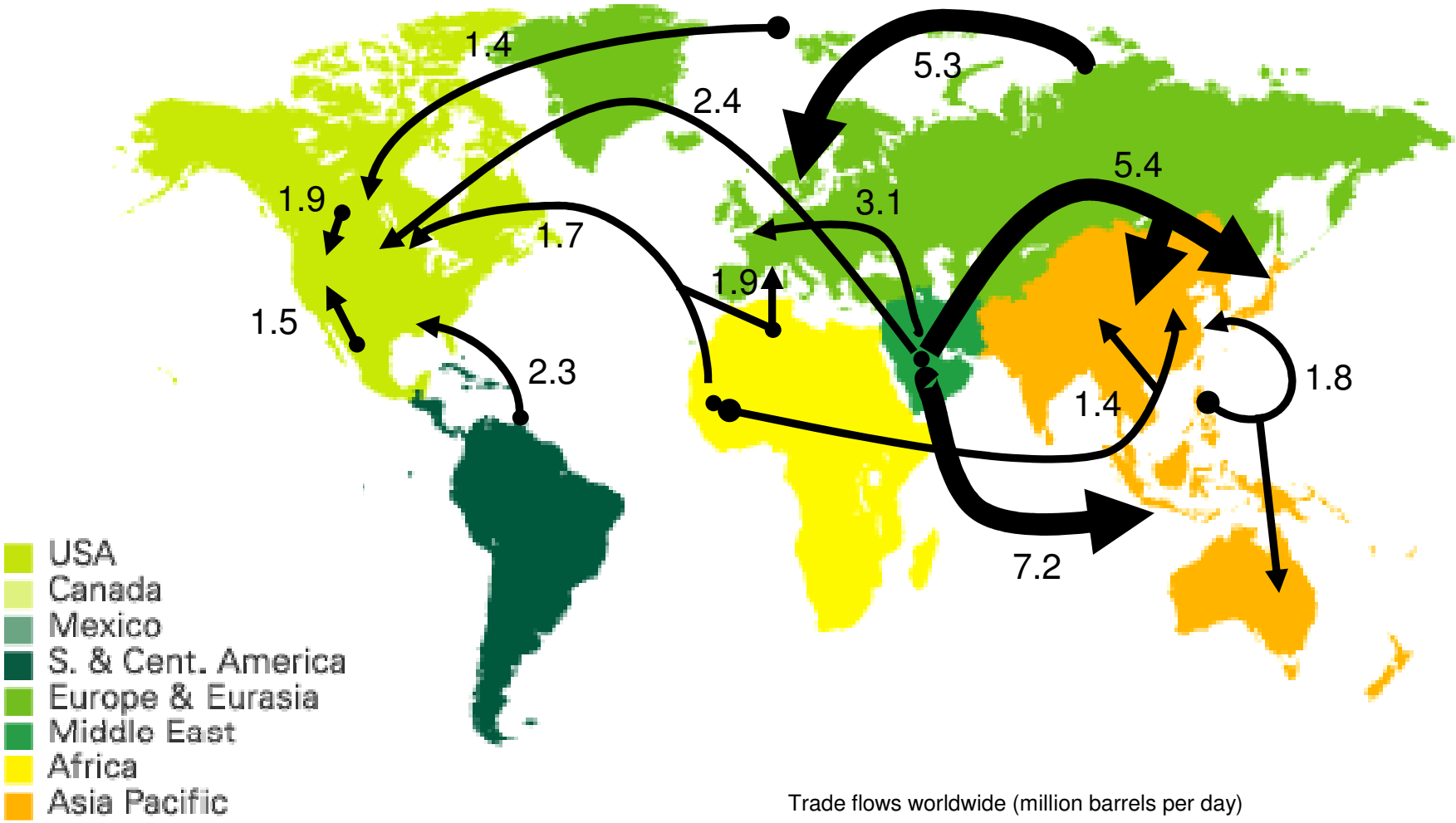
Oil Sands : A Customer's View

USEA Oil Sands Workshop

January 24-25, 2006

A global supply view

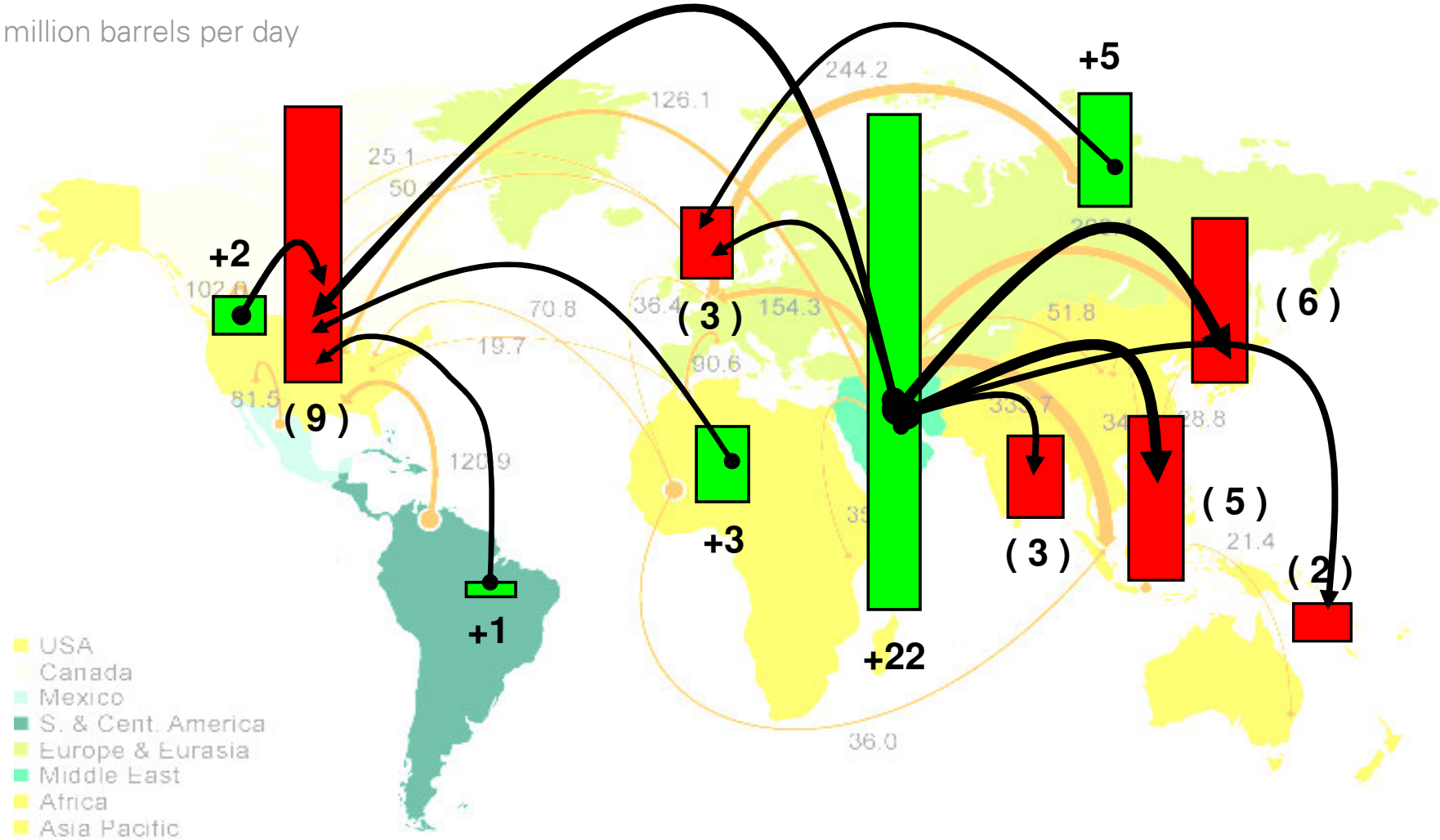
Major oil trade movements



Trade flows worldwide (million barrels per day)

A global supply view

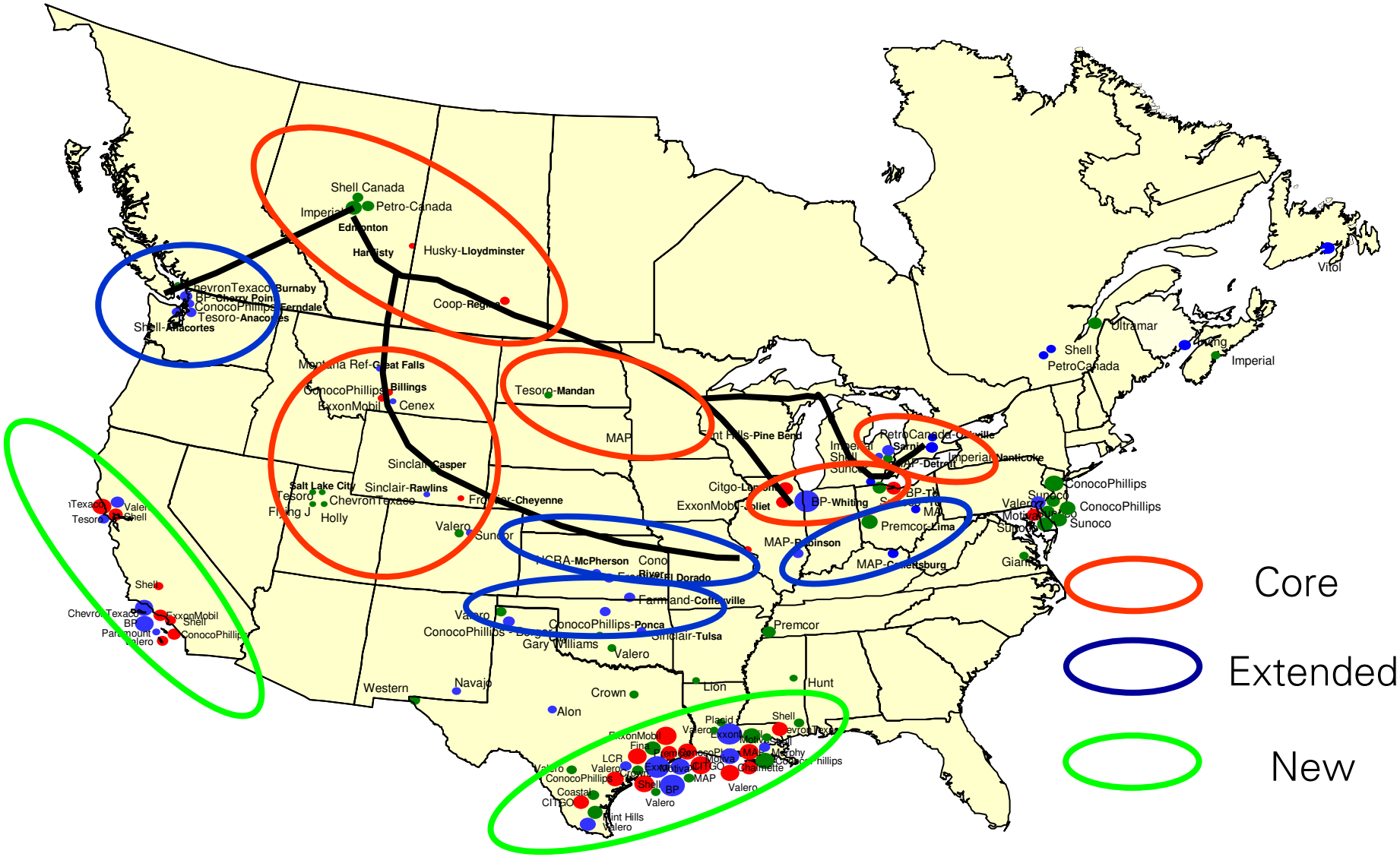
Developments in oil trade movements to 2025



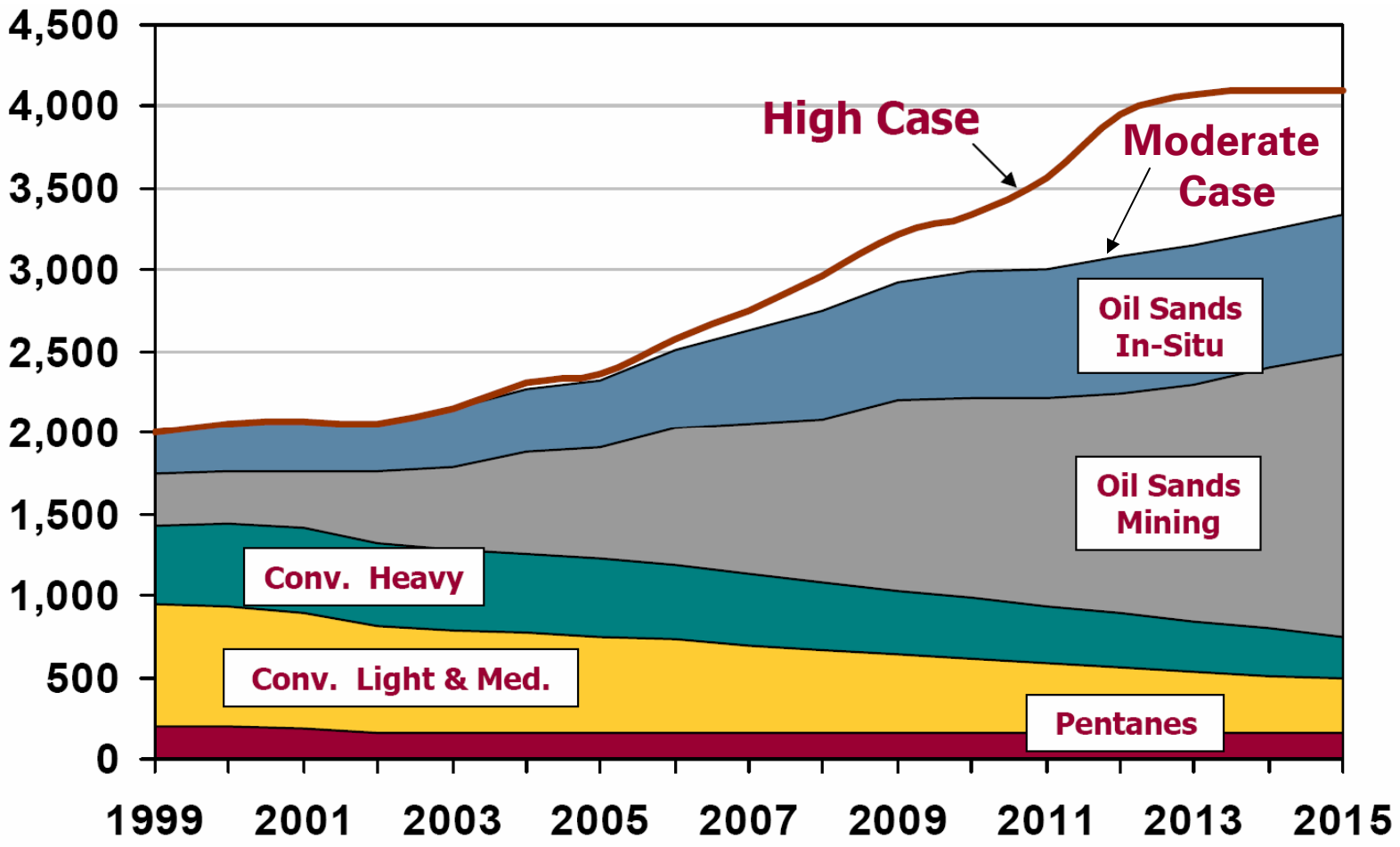
Energy Information Administration / International Energy Outlook 2004

Market Development

Existing and New markets are key



What is the Canadian potential



Canadian Association of Petroleum Producers
2004-2015 Crude Oil Forecast, July 2004

Summary

- **Primary demand is increasing**
- **Oil Sands have competing products**
- **Core, Extended and Gulf markets are the most attractive – but access must expand**
- **Challenges remain – Pipelines & Diluent**
- **BP plans to participate as a key customer**

Oil Sands : A Customer's View

USEA Oil Sands Workshop

January 24-25, 2006

Appendix 3: LIST OF PARTICIPANTS

Participant List - Oil Sands SPP Workshop, Houston, Texas, January 24-25, 2006

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