

FINAL DRAFT

**TYPICAL
HEAVY CRUDE AND BITUMEN
DERIVATIVE
GREENHOUSE GAS LIFE CYCLES
IN 2007**

prepared for

**REGIONAL INFRASTRUCTURE
WORKING GROUP**

by

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McC+A



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Preamble

Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles in 2007.

Attached is the original draft report written by T. J. McCann and Associates in November of 2001, entitled "***Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles in 2007.***"

This report was commissioned by The Oil Sands Developers Group, (then called The Regional Infrastructure Working Group) The report attached to this preamble is a broader continuation of a previous report that was issued in 1998 for an individual member of the Oil Sands Developers Group.

In this report, McCann attempted to generalize what the oil sands products would look like in 2007 and contrast them with other crudes around the world. The total Green House Gases (GHGs) produced during the entire life cycle of each product was calculated and presented. The overall process is shown in the picture diagram on page 5 of the report. The Chicago Area Refinery demonstrated in the picture diagram is a theoretical model that would notionally process products from oil sands as there was no typical refinery in operation at the time that would handle products from the oil sands. The methodology of the calculations is explained in the report.

On page 10, table 5-1 shows the results of the calculation in the various stages of the life cycle of the oil sands product. The stages listed are: Production, Transport, Refining, Transport Fuel Combustion and Byproduct Combustion.

Figure 1-1 (page 2) illustrates the comparison of the various crudes and their respective Green House Gas emissions during the life cycle. Each crude's total emissions are shown at 100% and are placed along side each other to show differences in GHG generation throughout respective life cycles. One notable observation was that any product, once consumed, generates nearly the exact same amount of GHGs, regardless of wherever the product originated. (Refer to table 5-1 comments, page 10, Transport Fuel Combustion)

Tom McCann passed away before the attached Final Draft could be issued as a Final Copy. However, the attached final draft report has been reviewed and the general thrust of his analysis is supported by many of his peers today. Given the interest in this report and that it has been publicly referenced by others despite its Final Draft status, the Oil Sands Developers Group believes that it should be recognized, officially supported and placed in the public domain.

The Oil Sands Developers Group is in the process of reviewing related work being undertaken elsewhere, and may consider updating this report.

TABLE OF CONTENTS

	PAGE
1.0 EXECUTIVE SUMMARY	1
2.0 INTRODUCTION	3
2.1 General.....	3
2.2 Canadian Heavy Crude/Bitumen Derivative GHG Profile	3
2.3 Reference Crudes Profiling.....	4
2.4 1998 to 2007 Refinery/Market Changes	6
2.5 Upgrading Versus Refining.....	7
3.0 SPECTRUM OF PRODUCTS.....	7
4.0 SPECIAL ATTRIBUTES OF ALBERTA OIL SAND INDUSTRY	9
4.1 Starting From World's Largest Hydrocarbon Reservoir – Bigger than Saudi's	9
4.2 Broad Spectrum of Product Forms	9
4.3 More or Less Coke (And Sulphur) Left in Alberta	9
4.4 Industry Committed to Greenhouse Gas Reduction Per Unit of Product	9
4.5 Cogeneration Excellent Match at All Oil Sands Production	9
4.6 Integrated Oil Sands Regional Environmental and Social Quality Monitoring and Control	10
5.0 LIFE CYCLE RESULTS	10

1.0 EXECUTIVE SUMMARY

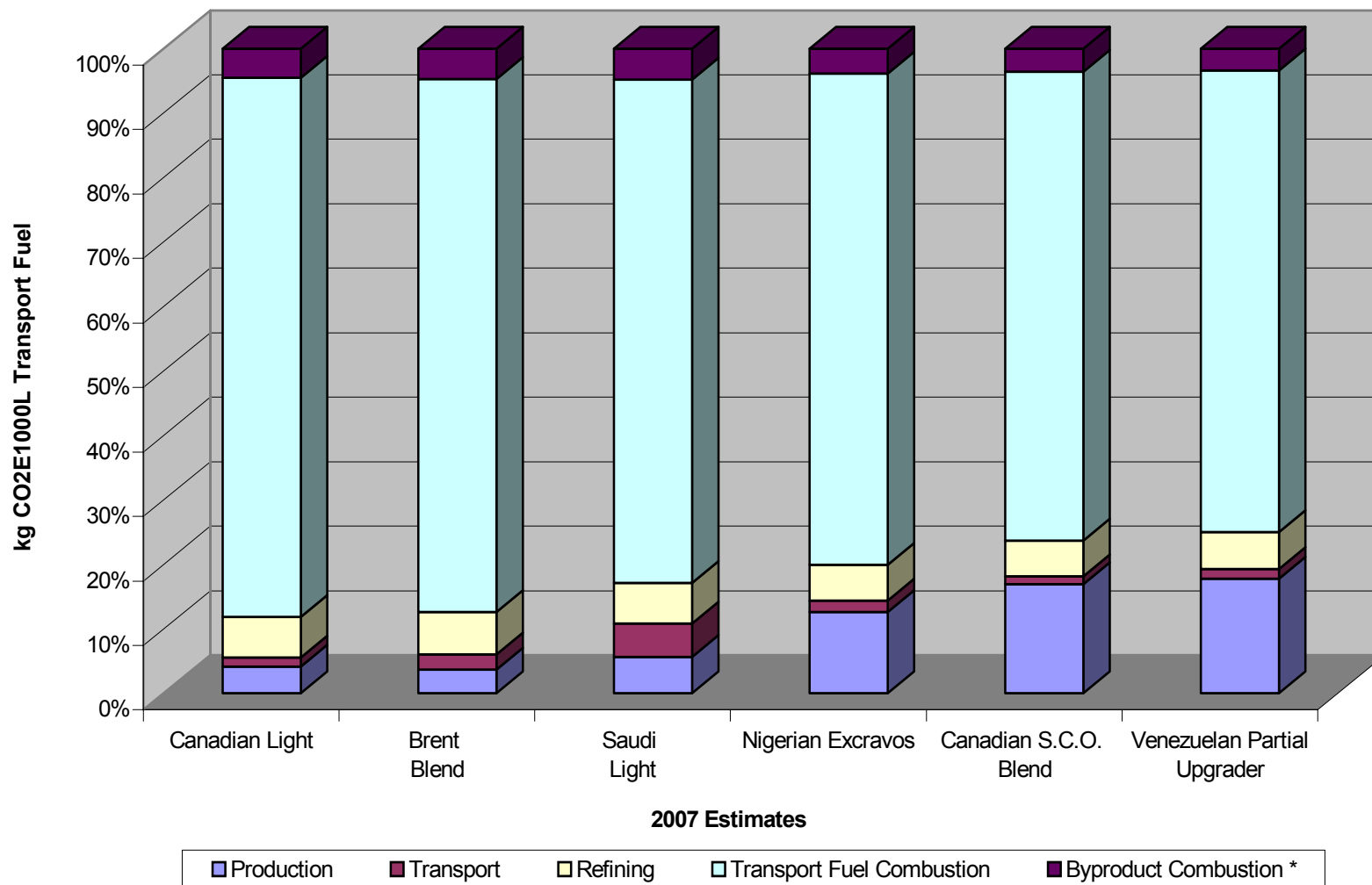
A new analysis of greenhouse gas attributions of various Canadian heavy crude/bitumen derivatives and their overall life cycles, assuming 2007 Chicago area refining and refined product has been developed. Foreign reference crudes were also considered with new production end greenhouse gas (GHG) emission forecasts.

The 2007 refinery/product scenario reflects increasing importance of jet fuels and diesels in the U.S. Midwest (despite the surge to SUV's and light trucks) and much decreased sulphur specifications for gasolines and diesels and an assumed parallel decline in jet fuel sulphur levels.

Unlike conventional crude oils, the 2000's will see a broad spectrum of new derivatives coming available tailored to match specific U.S. refinery targets, to replace declining western Canadian and U.S. light and medium crude production.

Figure 1-1 provides a quick summary of the GHG life cycles of the various foreign crudes compared to a blend of Canadian 2007 synthetic crude oils predicted to be approximately 750,000-BPD, up from the mid 2001 rate of about 325,000-BPD. Major diluted crude/bitumen blends, with significant residual contents is only to be noticed. Again, the Canadian composite stands up well against foreign competitors, although in two cases their field emissions have declined appreciably and in the case of Nigeria at least further reduction will continue.

Figure 1-1. Greenhouse Gas Life Cycles



2.0 INTRODUCTION

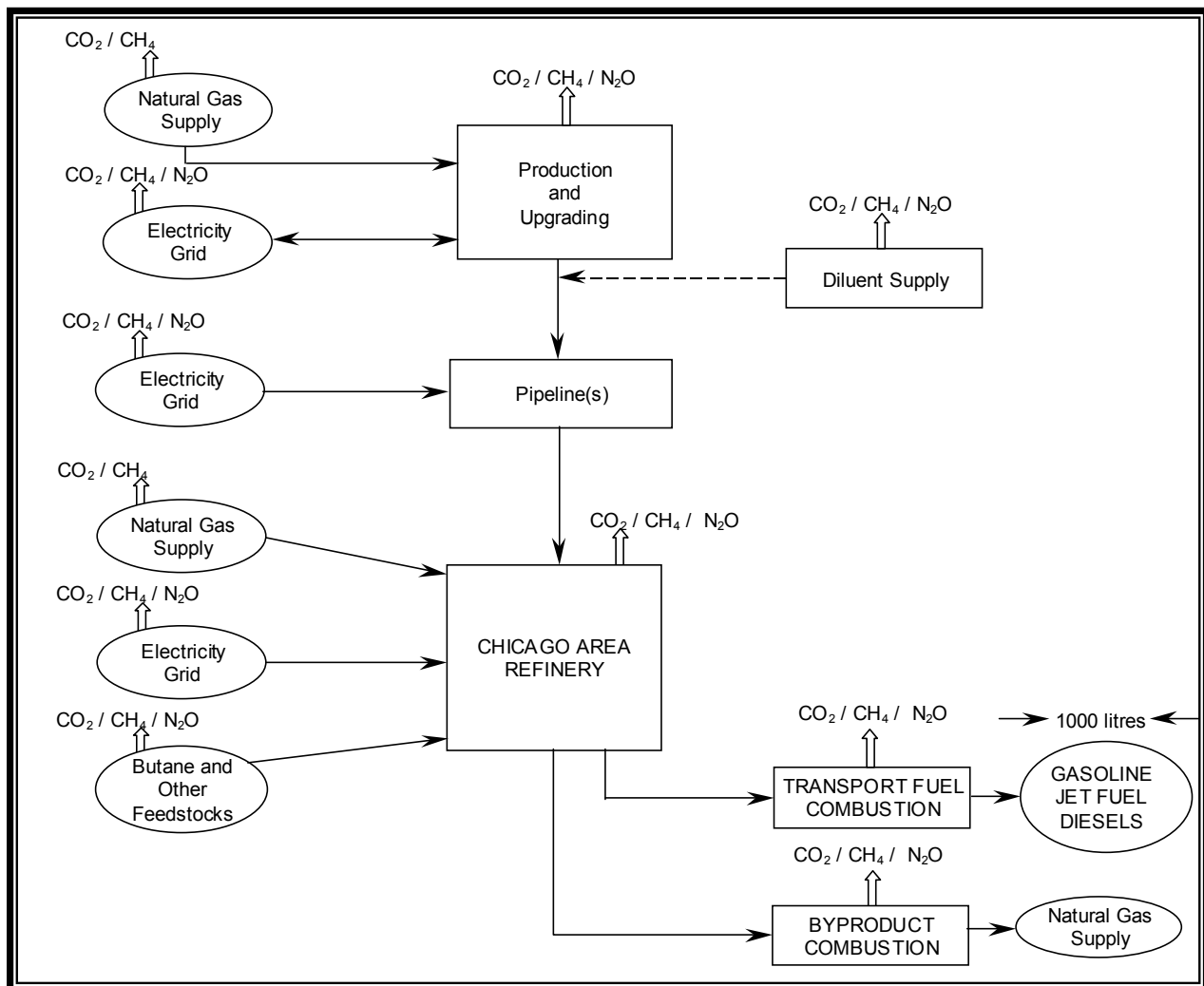
2.1 General

RIWG have used prior synthetic crude oil GHG life cycle analyses to illustrate the small differences from conventional light crudes and from a selected foreign partially upgraded crude. A new set of calculations was appropriate in late 2001 to illustrate the range of new heavy crude/bitumen derivatives in what is largely a new market setting.

A broad spectrum of derivatives is now planned to fit Canadian and U.S. refinery markets, with premium S.C.O. increasing to 750,000-BPD by 2007 (from current 325,000). Environmental pressures on refined product specifications are at the same time changing the U.S. refining scene and product demand patterns are also changing.

As most Canadian heavy crudes, bitumen, and derivatives are and will continue to be used in U.S. Midwest refineries, this study has again considered Chicago as the refining and end product use point. A 2007 context has been assumed to match readily forecastable quantities and Canadian plant site GHG's, as well as now foreseeable changes in U.S. product demands and specifications.

2.2 Canadian Heavy Crude/Bitumen Derivative GHG Profile



The above figure outlines the envelopes considered for the various Canadian derived GHG products. Producers have provided production and upgrading emissions and utility inputs and product assays. McC+A correlations and models have been used to develop GHG gases through the rest of the overall system.

In the case of electricity, many bitumen production sites are now producing a surplus of electricity and this has been credited to bitumen production, assuming Alberta average electricity generation in 2007, appropriate fuel supply GHG's and line losses to a central nul point in the Alberta grid. Electricity purchases are charged with a lesser line loss due to the perceived regional surplus.

The refinery sees the form of the crude received and the analysis is done on the actual feed, including diluent when applicable. No GHG emissions due to capital or off plot activities other than specific to natural gas or electricity supply were considered.

The pseudo Chicago area refinery will produce some propane and often fuel grade coke byproducts, in addition to gasoline, jet fuels and diesels – transportation fuels being the refinery's raison d'être. The byproducts are assumed burned in the Chicago area backing out an equivalent quantity of natural gas. An apparent excess of refinery fuel gas was indicated in certain cases – then was credited to the refinery as it would be used for other oil refinery operations such as petrochemical production.

But no petrochemicals asphalt, lube oils and other specialty products are assumed produced from the crudes under study.

The life cycle GHG total is based on 1000 litres of transport fuel and yields and sectorial GHG emissions are adjusted to that basis.

2.3 Reference Crudes Profiling

Despite location, the Chicago area refineries run significant non-North American crudes, although Canadian crudes compete (marginally) as far south as St. Louis. Western Canadian and U.S. light crude supplies are declining and declines largely partly balanced by new Canadian heavy crude/bitumen and derivatives.

Canadian high quality S.C.O. production appears likely to be about 750,000 BPD by 2007 – up from the current 325,000. Foreign light crudes are seen as the competition in this study for these S.C.O.'s.

Prior GHG life cycles have used North Sea Brent (blends) as a key reference and that is repeated here. Saudi Arabian light has also been repeated. For Nigerian an Escravos blend has been assumed – a lighter crude than the previous Forcados selection, considered better suited to Chicago area light crude needs. A Venezuelan partially upgraded crude has again been selected.

Published assay data have been used for each of these foreign crudes, with U.S. DOE and McC+A estimates of production related emissions. Pronounced reductions from prior studies in production GHG emissions in Saudi Arabia and Nigeria were noted and in the latter, at least, the trend will continue as more LNG, LPG and gas-based generation projects come on line.

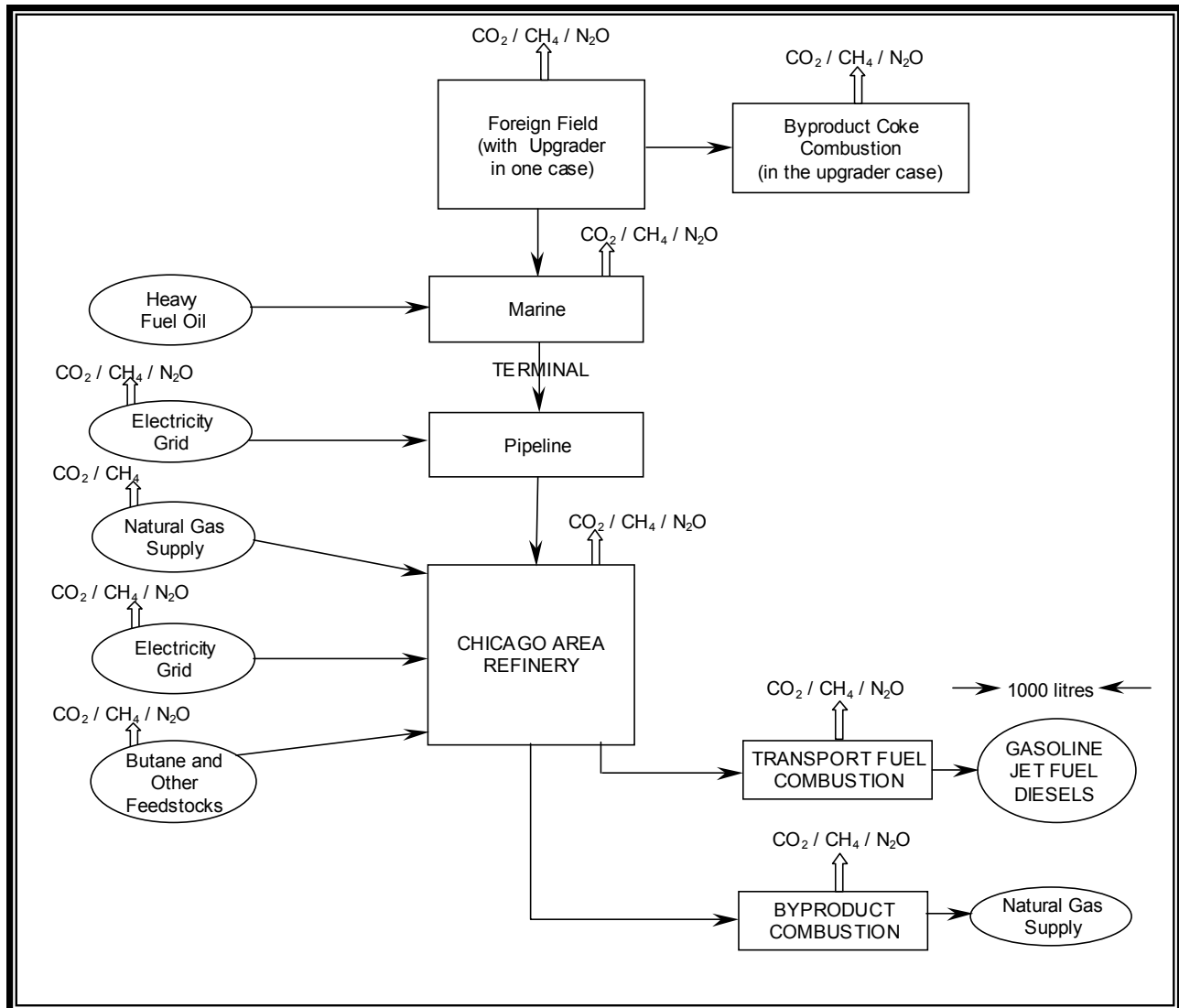
Oil Field Emissions Note:

Flaring appears to have dramatically reduced in the North Sea, Saudi, Nigeria and Canada; but as Alberta data show this does not necessarily indicate reduced venting and other methane emissions. Also capture of previously flared gas requires energy and, hence, increased field energy and related GHG's have increased.

Nigeria flaring is especially important due to its very magnitude Shell, Chevron and others have mega projects – e.g., LNG, LPG, and Gas to Liquids – underway, which will dramatically reduce

flaring and hopefully venting. McC+A's judgements have been used to estimate 2007 conventional oil field GHG emissions; Alberta producers, current and prospective have provided estimates, which were reviewed and adjusted by McC+A for electricity and gas external emissions.

The Canadian heavy crude/bitumen products will be competing with imported crudes (as U.S. crude production is expected to continue its decline along with western Canadian light crudes).



The GHG profiling is essentially the same as that for the Canadian heavy crude/bitumen derivatives except as follows:

a) Field Emissions

- While prior CAPP studies are available here, U.S. DOE CO_2 1998 countrywide estimates have provided clues to significant flaring reduction in many areas. Generally, the fields are self-contained, hence, no natural gas or electricity exchanges are considered.

- In the one (Venezuela) case with an upgrader McC+A modelling of the Petro Zuata project was used for the upgrader with a field balance provided by a (early) participant in the project.
- b) Marine
- All foreign crudes were assumed moved by ship to a U.S. Gulf Coast port, using appropriate McC+A tankers emission models.
- c) Pipeline and U.S. Gulf Coast Processing.
- From the U.S. Gulf Coast, all but the partially upgraded crude is assumed pipelined to the pseudo Chicago area refinery.
 - The partially upgraded crude was assumed processed in a specific U.S. Gulf Coast refinery, with products pipelined to the Chicago area.

2.4 1998 to 2007 Refinery/Market Changes

This study is based on McC+A estimates of transport fuel demand ratios and product specifications for 2007. Since the earlier studies there have been significant changes in demand ratios and by 2007 all transport fuels are expected to have much lower sulphur specifications – gasoline and diesel by regulation and jet fuel to avoid major product pipeline interface challenges when diesels are down below 15-ppm. (No other by 2007 changes in specification are apparent at this time.)

The pseudo refinery has been assumed to have:

- a) Either a deep catalytic cracking unit feed hydrodesulphurizer or, with low sulphur crudes, a catalytic cracked gasoline hydrodesulphurizer to achieve 25-ppm overall gasoline sulphur.
- b) Added depth in diesel hydrodesulphurization to reach a very difficult 10-ppm level.
- c) New or enhanced jet fuel hydrodesulphurization to reach the same level.
- d) Enough process flexibility to meet projected gasoline to jet plus diesel demand ratios.
- e) Enough octane capacity to meet gasoline octane specifications without oxygenates.

Analysis of recent year trends in gasoline/diesel indicates a falling ratio despite the surge in SUV's and light trucks. Conversely, jet fuel demands may be lower than previously anticipated. For this study, a gasoline/diesel ratio of 1.6 has been assumed, down significantly from the 1.8 plus ratio of the mid/late 1990's (but still well above the 1 ratio in western Canada and adjacent states).

Earlier life cycles had assumed use of MTBE, but that is expected to be ruled out shortly. A recent Chicago refinery fire knocked out most low vapour pressure base stock, essential for ethanol/gasoline blends, a special vapour pressure waiver was given such blends. This appeared to indicate other refineries were providing primarily ethanol free gasoline. Thus, this study has neglected the use of ethanol.

The pseudo refinery has been assumed to have all necessary process units for the range of crudes considered in the study, but such units are used only to the extent needed for each crude. It is important to note that all crudes in this study were evaluated based on their addition to a base crude – in effect, their marginal impact on refinery GHG's and yields is presented.

2.5 Upgrading Versus Refining

In this study the following assumptions were made:

- a) Consumers Co-operative/New Grade is a refinery and excluded from consideration (although it does sell some intermediates as a S.C.O. equivalent derived from heavy crudes).
- b) Petro-Canada's proposed Edmonton upgrader was also considered part of a refinery as most or all of its product will be used in the existing refinery.
- c) The Albian upgrader however has been included to the extent that it will produce an S.C.O. for sale to remote refineries. The portions applicable to the existing Scotford refinery have not been included. (It is recognized that the split is somewhat arbitrary.)
- d) Suncor's merchant diesel production is only 10% or so of the total and the entire Tar Island area Suncor operation has been included as S.C.O.
- e) The Shell Peace River operation produces some asphalt, hence, inclusion under a separate product category. The two prairie asphalt refineries were excluded.

3.0 SPECTRUM OF PRODUCTS

Table 3-1 illustrates the broadening of the types of heavy crude/bitumen derivatives expected over the next few years. It is quite likely that more grades and blends will emerge to best fit specific U.S. crude markets. In some cases, there may be changes from this study's expectations.

By 2007, Syncrude and Suncor standard S.C.O.'s are expected to have close to jet fuel smoke and diesel cetane specification fractional qualities. But Suncor's multi tailored blend approach is to be noted along with the use of some premium Suncor S.C.O. in the PanCanadian and Petro-Canada SynBit blends.

The asphalt quality of residual fractions is very important at many U.S. refineries – at least during the asphalt season, hence, the diluted bitumens are also of major importance.

Table 3-1
Spectrum of Canadian Bitumen & Derivative Products



	Condensate Diluted Bitumen	Condensate Diluted Bitumen with some Asphalt Demand	Diluted Partly Deasphalted Bitumen	S.C.O. Diluted Bitumen	S.C.O. with some Residue	Unhydrotreated Distillates	Varying Qualities of Synthetic Crude Oils	Diesel to Market
Today								
	Imperial	Shell (P.R.)		Suncor		Suncor X	Syncrude XX	Suncor † XX
AEC							Suncor XX	
CNRL							(wide variety of blends)	
Etc.							Husky	
Etc.								
Tomorrow								
	Jacos		True North (Albian*)	PanCanadian Petro-Canada	Albian		Opti/Nexen	
<p>Decisions to be made: Gulf, CNRL, AEC (future), SynEnCo.</p> <p>Legend:</p> <ul style="list-style-type: none"> * For feed to Upgrader † Also selling propylene/propylene mix and some coke. X Expanding XX Expanding, with quality increases. <p>Note that bitumen processing in refineries without major ongoing S.C.O. sales not included.</p>								

4.0 SPECIAL ATTRIBUTES OF ALBERTA OIL SAND INDUSTRY

4.1 Starting From World's Largest Hydrocarbon Reservoir – Bigger than Saudi's

- Only detailed coring needed for facility planning and operation.
- Large Schemes
 - Smallest commercial scheme at one site 30,000-BPD.
 - Next two mining schemes over 150,00-BPD each. In-situ schemes generally at/over 60,000-BPD.
 - Two largest commercial schemes have each operator recovery at 2 or 3 nearby sites and single central processing.
 - Big, technically sophisticated, efficient operations.
- Overall Product
 - Synthetic crude oil output now near 325,000-BPD to, over 750,000 by 2007.
 - Diluted bitumen and miscellaneous products now at 400,000-BPD level and rising in several versions to over 800,000-BPD over next 5 to 10 years.
 - In effect, outputs rising from 1% of world's crude supply to 2%, with reserves for much more in future.

Need
Bill's
Figures.

LARGE NATURAL GAS SUPPLY SUPPORTING BASE

4.2 Broad Spectrum of Product Forms

- To match individual refinery needs.
- Diluted bitumens (especially during asphalt season) all the way to bottomless premium very low sulphur synthetic crude oils.
- Special blends available.

4.3 More or Less Coke (And Sulphur) Left in Alberta

- Two largest operations put large portion of coke (from production of synthetic - bottomless crude) back in mine.
- Two large upcoming operations will return part of asphaltenes to mine.
- Reduced refinery end and coke product CO₂, SO₂ and particulate emissions.

4.4 Industry Committed to Greenhouse Gas Reduction Per Unit of Product

(consistent with changing refinery industry feedstock need) – e.g.:

- Major propylene/propane to petrochemical product being replaced in fuel gas with natural gas.
- Lower temperature extraction needing less heat and further improving cogeneration efficiencies.
- Internal diesel production to serve new more energy efficient mining operations.
- Scale of operations permit large-scale energy integration such as distillation condensers heating extraction water.
- Note that refinery and ultimate byproduct GHG emissions are reduced due to use of Canadian S.C.O.'s.

4.5 Cogeneration Excellent Match at All Oil Sands Production

- Oil sand area now more than self sufficient in electricity through cogeneration.
- By 2010, minimum of 1950-MW of sales outside the region is projected - electricity produced at 70 to 80% thermal efficiency, very largely from natural gas, although in one place case gases from coke gasification and in another fixed quantity of coke. Overall, at 20% to 25% of GHG/kWh of conventional coal base generation.

- Cogeneration ideal due to thermal needs in extraction and current in-situ processes.
- Very high efficiency Δ fuels.
 - 70 to 80% efficiency depending on process - 1950-MW minimum estimate
- Only partially some gasification of pitch (1 case in S.C.O.)
- Portions of coke/coke formers back to mine.
 - Extraction DA in 2 cases (1 in S.C.O. case).
 - Excess coke to mine (equal in 2 cases in S.C.O.)

4.6 Integrated Oil Sands Regional Environmental and Social Quality Monitoring and Control

- Same group as sponsoring these life cycles has over 300 people on local committees to further all aspects of regional quality of life and environment - AND companies ALL COMMITTED.
- Indigenous populous and their own organizations are very deeply involved in oil sands industry.

PROVEN SECURE SUPPLIES OF TAILORED CRUDES

5.0 LIFE CYCLE RESULTS

Table 5-1 below sets out the comparison of a blend of approximately 750,000-BPD of Canadian S.C.O.'s, with selected competitive crude types in a Chicago 2007 refining and refined product scenario. A Canadian light crude is also shown to largely provide a link to the past.

Table 5-1 Greenhouse Gas Total - kg of CO₂E per 1000 litres of Transport Fuel <i>(Consumed in Chicago Area)</i>						
	Canadian Light	Brent Blend	Saudi Light	Nigerian Extravos	Canadian S.C.O. Blend	Venezuelan Partial Upgrader
Production	128	116	186	430	606	651
Transport	45	71	167	61	42	55
Refining	193	205	204	188	199	211
Transport Fuel Combustion	2580	2572	2537	2591	2590	2619
Byproduct Combustion *	139	146	158	133	130	124
LIFE CYCLE TOTAL	3085	3110	3252	3403	3567	3660
* Net of displaced natural gas. Numbers are rounded.						

Differences between cases are considered significant when over 5% - say 150-kg CO₂E per 1000 litres of transport fuel. This table indicates the S.C.O. case overall GHG's roughly 18% above those of Brent blend; but the emissions in the U.S. will be the same. (Indeed, the same appears true for all crudes.)

As noted above, Canadian producers are very actively pursuing approaches to reducing production end emissions, added cogeneration integration is noted in all new projects, with its inherent net GHG reductions that trend will continue narrowing the North Sea/S.C.O. differential.

FINAL DRAFT

The Canadian Voluntary Challenge and Registry's October 2001 "Champion News" notes a major Canadian trucking company achieving a 25% reduction in unit fuel consumption between 1996 and 1999. Such user end reduction potentials are generally significantly higher than the differences between the various conventional and synthetic crudes noted in Table 5-1.