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Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions

Final Report

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Disclaimer

This report has not undergone an independent technical review.

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Executive Summary

When comparing alternative transportation fuel greenhouse gas (GHG) emissions, it has become customary to consider not only the tailpipe or tank-to-wheel (TTW) emissions, but also the upstream or well-to-tank (WTT) emissions. California is in the process of adopting and finalizing its Low Carbon Fuel Standard in which the full fuel cycle, well-to-wheel (WTW) greenhouse gas (GHG) emissions of all transportation fuels sold must be reduced by 10% from baseline levels by 2020. At the federal level, U.S. EPA has also considered the WTW emissions of transportation fuels in its recent Renewable Fuels Standard 2 (RFS2) rulemaking.

The tool employed by both regulatory agencies in their rule development efforts is the "Greenhouse Gases, Regulated Emissions, and Energy in Transportation" (GREET) model developed and maintained by Argonne National Laboratory. The default inputs in the GREET model for gasoline and diesel derived from conventional crude oil are based on U.S. average values for crude oil recovery energy, flaring/venting emissions, and refining energy. For oil sands, two default recovery pathways are provided (both with onsite upgrading), with the resulting synthetic crude oil (SCO) sent to the refinery.

Because there is a wide range of energy used to recover and refine different crude oils, there is a concern that utilizing average values is not optimum for regulatory/policy making purposes. The objective of this project is to provide a transparent quantification of WTT GHG emissions for specific Canadian crude oils and other major crude oils utilized in the United States.

We found that:

- There is a wide range of WTW emissions for the conventional crude oil pathways.

- The SCO-Mining pathway WTW emissions are within the range of those for the conventional crude oils. However, the mining pathway likely has direct land use change emissions that are not accounted for here.

- On average, the synbit/dilbit pathway emissions considered here are 10% higher than the average conventional crude oil pathways considered. However, there is overlap between the conventional and synbit/dilbit emissions.

- In general, the level of uncertainty associated with the pathways within the sensitivity bounds does not significantly change their relative WTT GHG emissions rankings and suggests that the analysis values offer a reasonable estimate of the GHG emissions for the different crude oils.

- This analysis is based entirely on publicly available data. The benefit is that the results are transparent and may be utilized for transportation policy and regulation if desired. On the other hand, the analysis could be improved with the availability of more data from oil sands operations.

- Although the GREET default values for the conventional crude oil pathways are within the range of our results, the range is quite large (20 g/MJ range). For regulatory purposes, it may

be appropriate to monitor the quantities of different crude oils being utilized relative to baseline quantities to ensure that carbon reductions are actually achieved.

Acknowledgement

TIAX would like to thank Surindar Singh, Alberta Energy Research Institute (AERI) for his efforts as Project Manager. Dr. Singh formed and coordinated a Steering Committee to provide input and feedback to this analysis. We thank the members of the Steering Committee for sharing their experience and time with us:

Alberta Energy Research Institute:	Eddy Isaacs, Donna Kostuik
Shell Canada Limited:	Edward Brost, Raman Narayanan
Nexen Inc.:	Anand Gohil, Mark Ewanchyna
University of Calgary:	Joule Bergerson, David Keith
Pembina Institute:	Greg Powell
California Energy Commission:	Pierre DuVair, McKinley Addy

Additionally, in January of this year, a Workshop was held to review the analysis methodology and preliminary data for crude recovery and refining. We would like to thank Pierre DuVair and the California Energy Commission for providing the meeting room for the California participants and Brent Stuart of Suncor Energy for providing the meeting room for the Alberta participants. The workshop was well attended with many written comments provided. The workshop attendees and a summary of their written comments and our responses are provided in Appendix.

1. Introduction

When comparing alternative transportation fuel greenhouse gas (GHG) emissions, it has become customary to consider not only the tailpipe or tank-to-wheel (TTW) emissions, but also the upstream or well-to-tank (WTT) emissions. Comparing fuels on a WTT basis is necessary to because some fuels, like electricity and hydrogen, have no TTW component but significant WTT emissions. California is in the process of adopting and finalizing its Low Carbon Fuel Standard in which the full fuel cycle, well-to-wheel (WTW) greenhouse gas emissions of all transportation fuels sold must be reduced by 10% from baseline levels by 2020. At the federal level, U.S. EPA has also considered the WTW emissions of transportation fuels in its recent Renewable Fuels Standard 2 (RFS2) rulemaking.

The tool employed by both regulatory agencies in their rule development efforts is the "Greenhouse Gases, Regulated Emissions, and Energy in Transportation" or GREET model developed and maintained by Argonne National Laboratory. The default inputs in the GREET model for gasoline and diesel derived from conventional crude oil are based on U.S. average values for crude oil recovery energy, flaring/venting emissions, and refining energy. For oil sands, two default recovery pathways are provided (both with onsite upgrading), with the resulting synthetic crude oil (SCO) sent to the refinery.

While these average cases are important, it is clear that there is wide variety in the energy needed to recover different crude oils. Moreover, oilfield venting and flaring emissions from some countries are extremely high. At the refinery, it is known that heavy and sour crude oils require significantly more energy to refine than a premium crude oil such as SCO. Over the past 30 years, the quality of crude oils refined in the U.S. has steadily declined (API gravity decreasing and sulfur content increasing). At present, the effects of these variations on GHG emissions are not captured by the U.S. average GREET defaults for crude recovery and refining. Because transportation fuels will be regulated based on WTW carbon potential in the near future, it is of interest to determine the range of WTT GHG emissions among different petroleum feedstocks. If there is a wide variation in conventional crude oil WTT GHG emissions, it may be appropriate from a regulatory standpoint to determine the volumes of each crude oil consumed to more accurately quantify petroleum fuel WTW GHG emissions. A better understanding of the energy required by a range of oil sands recovery methods and the energy required to refine oil sands derived products delivered to the refinery will also be important.

In this project, we have estimated the actual WTT energy and emissions for a variety of conventional and oil sands derived crude oils. Section 2 provides an overview of the project scope and approach. Section 3 describes the crude oil recovery energy data utilized to generate GREET inputs for both the conventional crude oils and the oil sands pathways. A description of the refinery modeling effort is provided in Section 4 along with the model results used to generate GREET inputs for refining. Section 5 describes how the data are utilized to create GREET inputs for each of the pathways considered. The GREET greenhouse gas emissions results are presented in Section 6. Well to Tank (WTT) results are provided indicating relative contributions from recovery activities, venting and flaring, crude transportation, refining and fuel transportation. For perspective, the results are also shown on a Well to Wheels (WTW) basis. Section 7 provides the results of sensitivity and uncertainty analyses. Finally, our conclusions are provided in Section 8.

2. Project Objective and Approach

The objective of this project is to estimate and compare WTT GHG emissions of Canadian crude oils, especially oil sands, and other major crude oils used in the United States. Because the TTW emissions are invariant among the different pathways, we focus here on the WTT emissions. To accomplish this objective, a number of technical tasks were structured as indicated in Figure 2-1. Once the important crude oils were identified and agreed upon with the Steering Committee, the crude recovery and refining tasks were launched. The objective for each of these tasks was to determine the amount of energy consumed in each process and the division of this energy among process fuel types.

In the crude recovery task, the dominant recovery methods employed for each crude oil were determined, and the corresponding energy requirements determined through engineering estimates. The oilfield flaring and venting quantities are based on published data. In the refining task, MathPro Inc utilized their ARMS refinery linear programming model to determine the impact of each crude oil on refinery energy consumption by fuel type. Once the recovery and refining tasks were completed, the data were recast into GREET inputs, and the GREET model was run. The resulting GHG emission estimates for crude recovery, oilfield venting/flaring, crude transportation, refining, and finished fuel transportation are provided in this report.

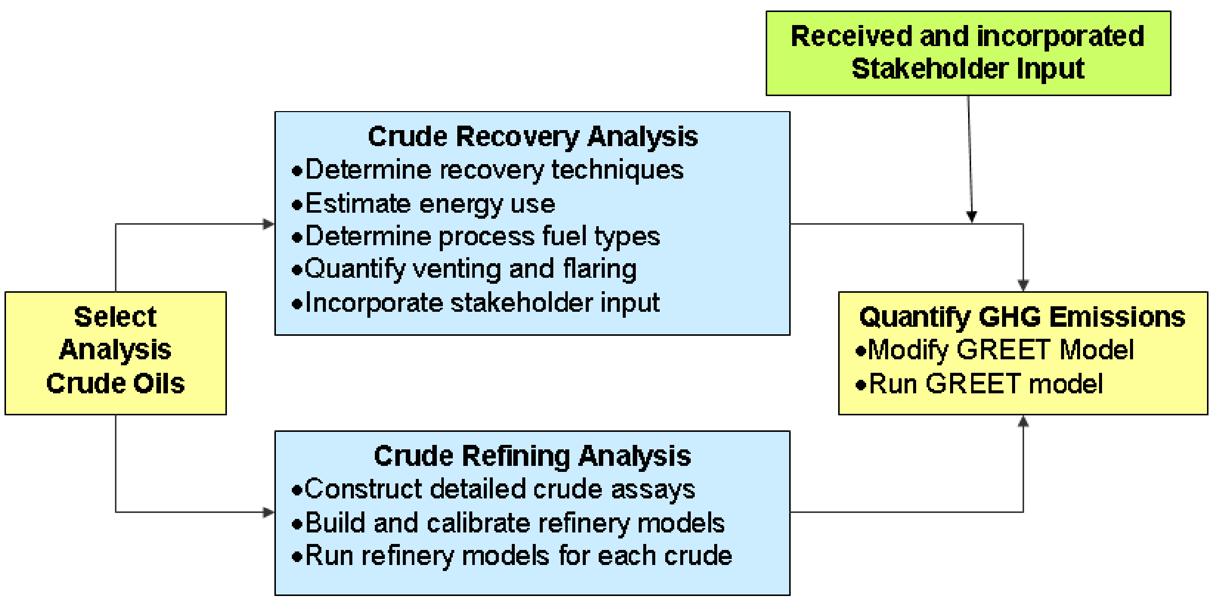

Figure 2-1. Technical Approach

An overarching requirement for this project was transparency. All data used to develop emissions estimates are publicly available. All calculations using these data are provided. The modified GREET model with the GREET inputs is provided. The benefit of this approach is that the results can be utilized in the policy/regulatory arena. The shortcoming of this approach is that it may not be as accurate or complete as an analysis that employs proprietary data.

3. Crude Oil Recovery Data

The amount of energy expended to recover crude oil and the resulting GHG emissions vary depending upon the crude characteristics and the extraction method employed. WTT energy consumption and emissions for gasoline and diesel are highly sensitive to assumed crude oil recovery energy consumption. Unfortunately, the fuel cycle models commonly employed today (GREET and GHGenius) do not differentiate between different crude oils and recovery methods when assigning energy consumption and emissions for recovery.

To provide more specificity relative to crude petroleum received by U.S. refineries, the energy required to recover a variety of conventional crude oils and oil sands derived petroleum was estimated. This section of the report describes: the predominant recovery techniques for each analysis crude oil; total process energy consumed per barrel of product sent to U.S. refineries; and estimates of flared and vented associated gas quantities.

3.1 Conventional Crude Oils

As indicated in Section 2, a variety of conventional crude oils commonly used in U.S. refineries was considered. Table 3-1 summarizes the conventional crude oils considered.

Table 3-1. Conventional Crude Oils Considered

Source	Analysis Crude
U.S. Alaska	Alaska North Slope
U.S. California	Kern County Heavy Oil (Midway-Sunset)
U.S. Gulf Coast	West Texas Intermediate (Permian Basin)
Canada	Bow River Heavy Oil
Saudi Arabia	Medium
Iraq	Basrah Medium
Nigeria	Escravos
Mexico	Maya Heavy
Venezuela	Bachaquero 17

To estimate GHG emissions, the energy necessary to recover each crude oil and transport it to its refinery locations was estimated. TIAX used a combination of publicly-available professional publications and government data to determine the energy consumed and process fuel types for each pathway. The next two sections summarize the data gathered to quantify recovery energy, recovery energy fuel types, and quantities associated gas venting and flaring for conventional crude oils.

3.1.1 Conventional Crude Oil Recovery Energy

This section documents the data used to quantify the recovery energy necessary for each crude pathway. For each pathway, a brief description of the crude oil and its dominant recovery technique is provided. A process flow diagram and table with the recovery energy consumed per barrel of crude produced is also provided. The calculations performed to produce the numbers in the tables may be found in Appendix A. The recent "Development of Baseline Data and Analysis of Life Cycle GHG Emissions of Petroleum Based Fuels" report from the National Energy Technology Laboratory (NETL)[1] that was used to estimate the share of electricity consumption from the local grid for several of the crude oils is referred to in the following paragraphs as the "NETL report."

Alaska

Because 97% of Alaska's total production comes from the North Slope,[2] the analysis crude for Alaska is Alaska North Slope (ANS). The remainder of Alaska production comes from Cook Inlet in Southern Alaska. ANS is an intermediate API (32°) sweet (0.5% wt sulfur) crude oil, with most of the production coming from the Prudhoe Bay region.

The representative enhanced oil recovery pathway for Alaska is Water-Alternating-Gas (WAG). WAG is an enhanced oil recovery technique in which alternating injections of water and gas are used to maintain reservoir pressure and push the crude toward the production wells. The WAG technique maintains the reservoir pressure and allows for natural drive production. WAG is used extensively in Alaska because there is an ample supply of water to pump into the reservoirs and because there are limited transportation options from the North Slope to Southern Alaska or the lower 48 states for the produced gas. This results in significant reservoir re-injection (91% in 2006).[3]

Figure 3-1 is a schematic representation of the Alaska North Slope crude oil recovery process. The production gas and injection ratios are from the Alaska 2007 Division of Oil and Gas Report[4] data for total natural gas produced and total crude oil produced. The water injection rate is from State of Alaska Oil and Gas Conservation Commission.[5] Produced gas is assumed to be consumed in a simple cycle gas turbine. The remaining produced gas that is neither consumed nor injected into the reservoir is exported from the production well.

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[1] "Development of Baseline Data and Analysis of Life Cycle GHG Emissions of Petroleum Based Fuels", NETL, Nov 2008

[2] EIA on-line database

[3] ADOG, "Division of Oil and Gas 2007 Annual Report," Alaska Division of Oil and Gas, July 2007

[4] *Ibid*

[5] AOGCC, "Order and Decisions – Area Injection Orders," Alaska Oil and Gas Conservation Commission, Updated May 2006, <http://www.state.ak.us/admin/ogc/orders/aio/aioindex.htm>

Per Barrel of Crude	
Injection Gas (scf)	10,500
Injection Water (bbl)	2.6
Electricity (kWh)	20
Total Produced Gas (scf)	11,400
Produced Gas Consumed (scf)	220
Produced Gas Exported (scf)	680

For detailed calculations see Appendix A

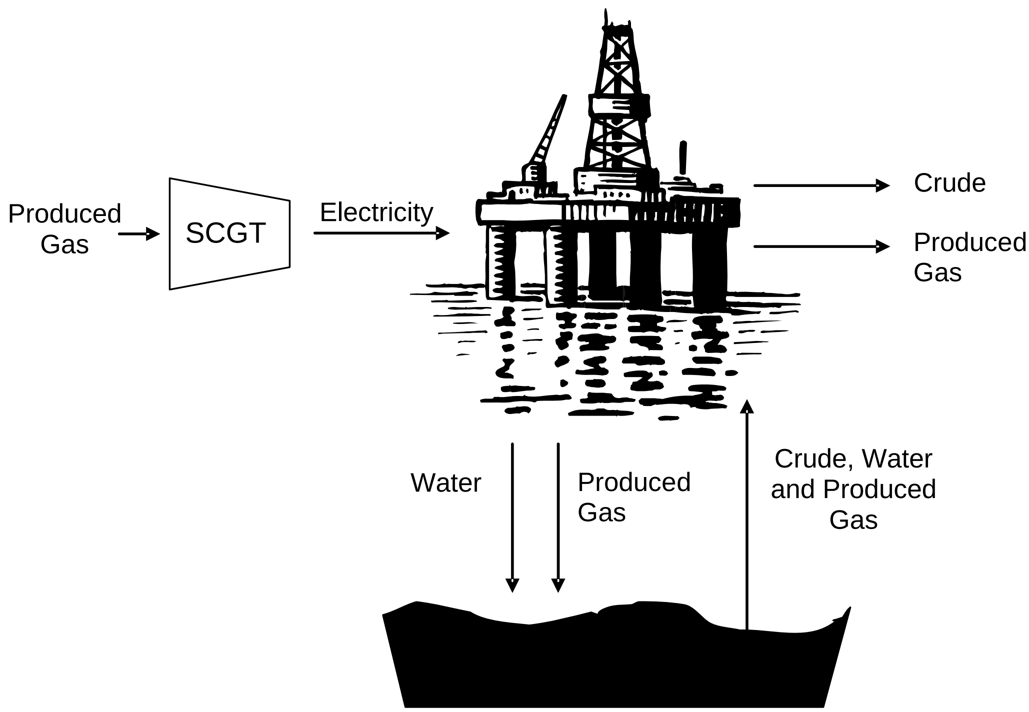

Figure 3-1. Alaska North Slope Process Flow Diagram

California Heavy Crude Oil

For the California Heavy Crude, Kern County crude oil was selected as the analysis crude. Kern County is a heavy (~14° API) sour (~1.4%wt sulfur) crude oil. Steam drive is used as the enhanced oil recovery technique. Steam is injected into the reservoir to heat the oil to reduce its viscosity and drive it towards the production wells. Sucker rod pumps are employed to pull the oil out of the reservoir.

Figure 3-2 shows the process flows for Kern County heavy crude oil, based on data[6] for the Midway-Sunset field, the largest historical producing field in the State of California. Pipeline natural gas is consumed at the cogeneration plant that tilts its production heavily towards steam. The steam is injected into the reservoirs, and electricity from the cogeneration plant is used to pump the crude oil from the ground. Excess electricity is exported to the local grid. Kern County recovers just over 1,000 scf of produced gas for every barrel of crude oil recovered.

Per Barrel of Crude	
Natural Gas Consumed (scf)	3,778
Steam Produced & Consumed(bbl)	4.9
Electricity Produced (kWh)	319
Electricity Consumed (kWh)	7.4
Produced Gas Exported (scf)	1,003

For detailed calculations see Appendix A

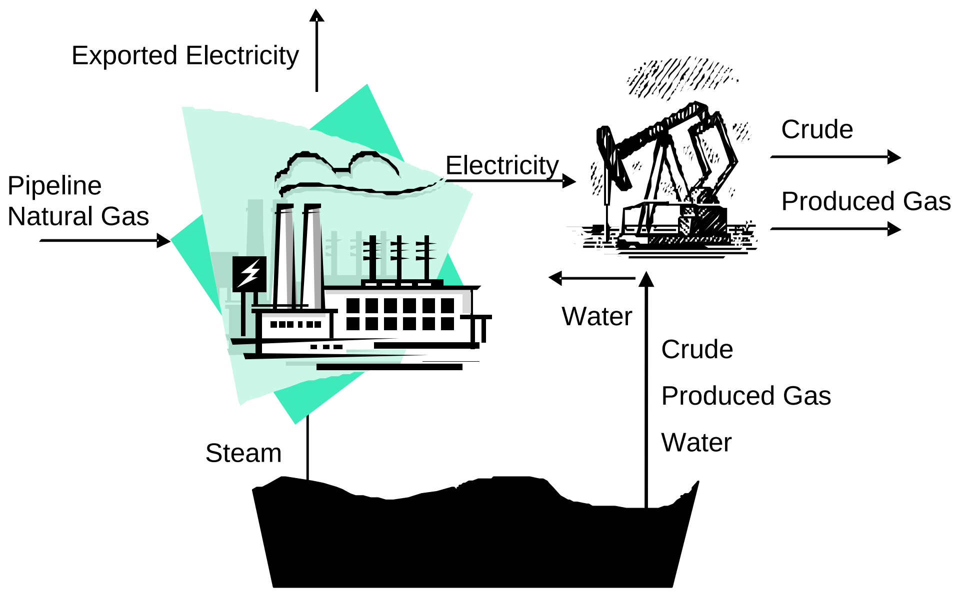

Figure 3-2. Process Flow Diagram for California Heavy Crude

[6] California Department of Conservation, "2006 Annual Report of the State Oil and Gas Supervisor," Division of Oil, Gas and Geothermal Resources, Sacramento: 2007.

Gulf Coast Crude Oil

The Federal Offshore region in the Gulf of Mexico was chosen as the representative recovery location for the Gulf Coast analysis crude. Waterflooding is the predominant recovery method in the offshore region; water is used to maintain reservoir pressure, ensuring continued natural drive recovery. The crude oil assay selected for analysis is West Texas Intermediate (WTI). Although WTI is not produced specifically in the offshore region of the Gulf of Mexico, its properties were selected for refinery analysis because it is a key crude oil in the United States. WTI is a light (~40° API) sweet (~0.5% wt sulfur) crude oil.

Figure 3-3 provides the process flows for WTI crude recovery. Produced gas is used in a simple cycle turbine to create the electricity used to pump the water into the reservoir. The balance of the produced gas is exported.

Per Barrel of Crude	
Water (bbl)	8
Electricity (kWh)	2.5
Total Produced Gas (scf)	3,966
Produced Gas Consumed (scf)	26
Produced Gas Exported (scf)	3,940

For detailed calculations see Appendix A

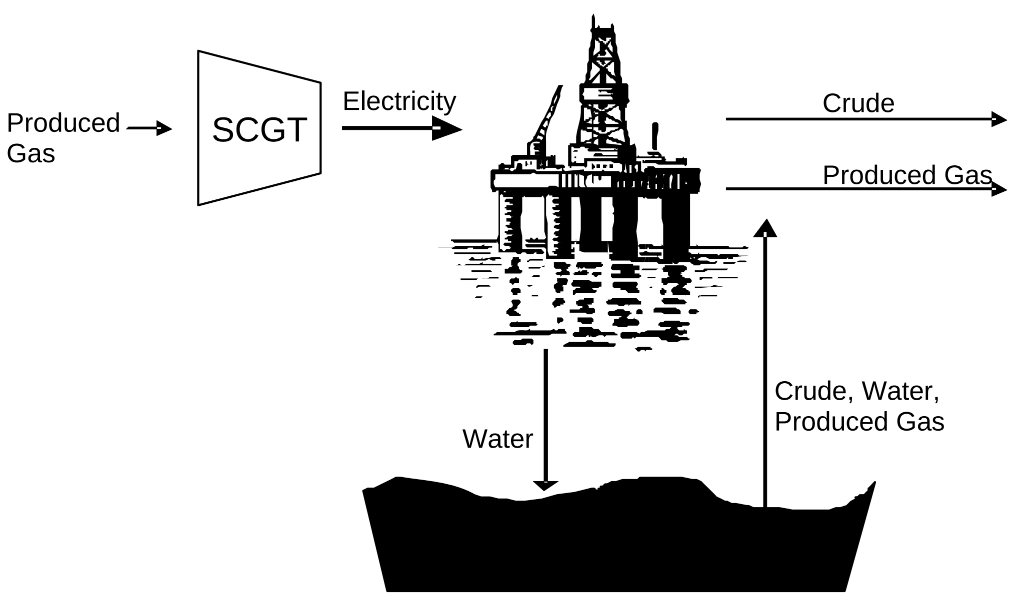

Figure 3-3. West Texas Intermediate Crude Process Flow Diagram

__Canadian Heavy Crude Oil__

Bow River crude from the southeastern region of Alberta was selected as the analysis crude for Canadian heavy oil. Bow River is a heavy (~21° API) sour (~2.9% wt sulfur) crude oil recovered with progressive cavity pumps (PCPs) and waterflooding. PCPs are used because Bow River crude is very viscous and can have high quantities of sand. Waterflooding significantly enhances PCP recovery and helps prevent subsidence after the removal of oil and sand by the pumps.

The diagram in Figure 3-4 shows the process flows for Bow River crude recovery. Electricity used to pump the water into the reservoir and pump the crude out of the ground is taken from the Alberta electricity grid. The excess produced gas is assumed exported from the field.

Per Barrel of Crude	
Water (bbl)	13
Electricity Consumed (kWh)	13
Total Produced Gas (scf)	1,860
Produced Gas Consumed (scf)	132
Produced Gas Exported (scf)	1,728

For detailed calculations see Appendix A

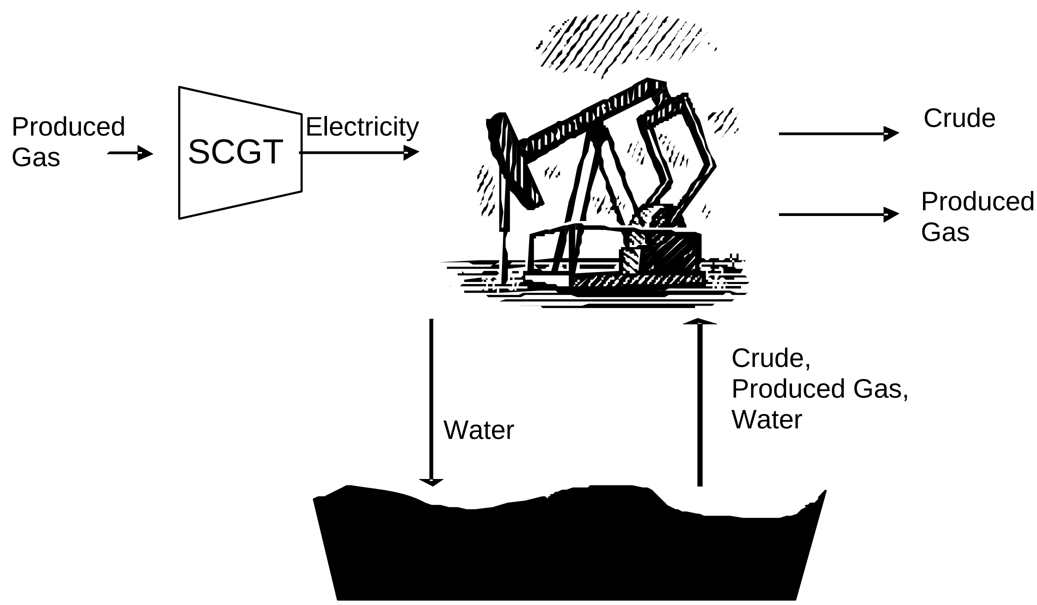

Figure 3-4. Canadian Heavy Oil (Bow River) Process Flow Diagram

Saudi Arabia

For the Saudi Arabian crude oil, TIAX selected Saudi Medium crude oil, which has become the predominant crude oil imported to the United States from Saudi Arabia.[7] Saudi Medium is a 30° API sour (~2.6% wt sulfur) crude extracted from the onshore/offshore Northeastern region of the country. The main recovery method is waterflooding with natural drive producing the crude oil.

Figure 3-5 shows the process flows for recovery of Saudi Medium. Electricity used to pump the water into the reservoir is created both by onsite generation from a simple cycle turbine and from the Saudi electricity grid. The proportion of onsite production to grid is taken from the NETL report. The remaining produced gas is assumed to be exported.

Per Barrel of Crude	
Water (bbl)	2.9
Total Electricity Consumed (kWh)	0.88
Total Produced Gas (scf)	800
Produced Gas Consumed (scf)	8.0
Produced Gas Exported (scf)	792

For detailed calculations see Appendix A

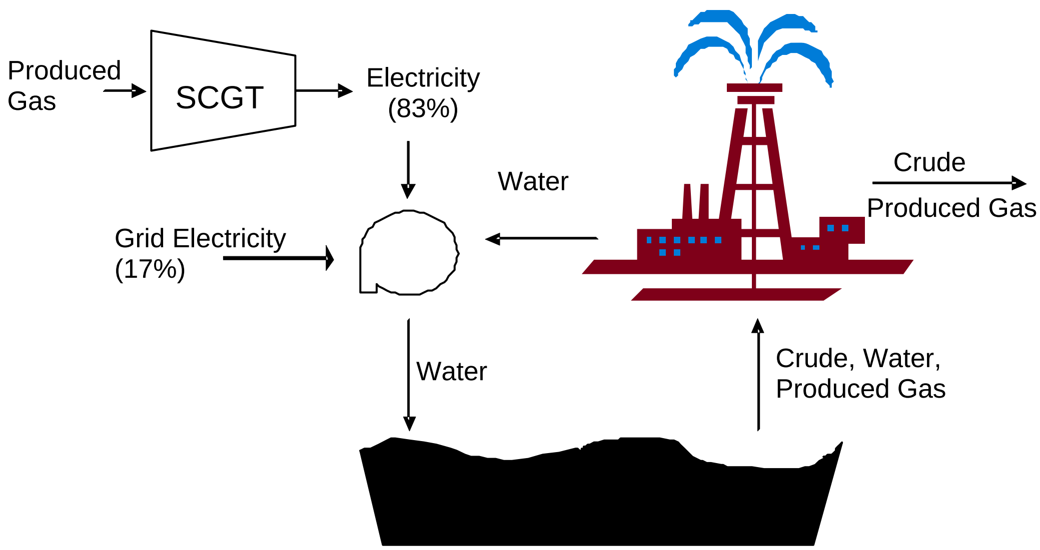

Figure 3-5. Process Flow Diagram for Saudi Medium Crude Oil

[7] EPA Database of Petroleum Imports

Mexico Crude Oil

Maya crude produced from the Cantarell oil field was chosen as the Mexico analysis crude oil. Cantarell is the largest producing field in Mexico and one of the largest fields in the world. Maya is a heavy (~21° API) sour (~3.4% wt sulfur) crude oil. The current recovery methods utilized at Cantarell are nitrogen flooding for reservoir pressure maintenance and gas lift to assist in crude oil recovery. A 1.2 billion scf/day nitrogen plant operates at the Cantarell oil field.[8]

The diagram in Figure 3-6 illustrates the process flows for Maya Crude recovery. The electricity used to produce and compress nitrogen is supplied by an onsite natural gas combined cycle power plant. Electricity used to pressurize and pump gas for the gas lift process is from onsite electricity generation using produced gas and from the grid. The proportion of onsite production to grid is taken from the NETL report. The excess produced gas is assumed to be exported from the field.

Per Barrel of Crude	
Gas (for gas lift, scf)	400
Nitrogen Gas (scf)	667
Electricity for Recovery (kWh)	0.63
Electricity for N_2 Plant (kWh)	14.0
Natural Gas Consumed in N_2 Plant (scf)	92
Total Produced Gas (scf)	372
Produced Gas Consumed (scf)	4.4
Produced Gas Exported (scf)	367

For detailed calculations see Appendix A

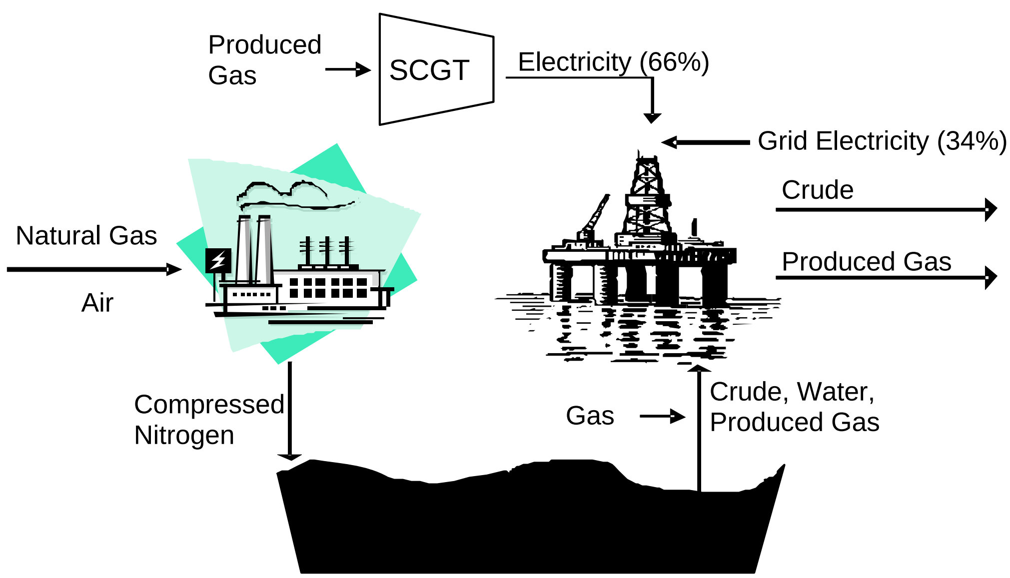

Figure 3-6. Mexican Maya Crude Process Flow Diagram

[8] http://www.ipsi.com/Tech_papers/cantarell2.pdf

Iraq Crude

The predominant Iraqi crude oil imported to the United States is Basrah Medium,[9] produced in the southeastern region of Iraq. Basrah Medium has an API gravity of 31° API and is sour with a sulfur content of 2.6% by weight. The recovery method for Basrah Medium is mainly waterflooding with natural drive producing the crude oil.

Figure 3-7 illustrates the process flows for recovery of Basrah Medium. Electricity used to pump the water into the reservoir comes from both onsite electricity generation from a simple cycle turbine and from the Iraqi electricity grid. The proportion of onsite production to grid is taken from the NETL report. The excess produced gas is assumed to be exported from the field.

Per Barrel of Crude	
Water (bbl)	5
Electricity (kWh)	1.5
Total Produced Gas (scf)	490
Produced Gas Consumed (scf)	13
Produced Gas Exported (scf)	477

For detailed calculations see Appendix A

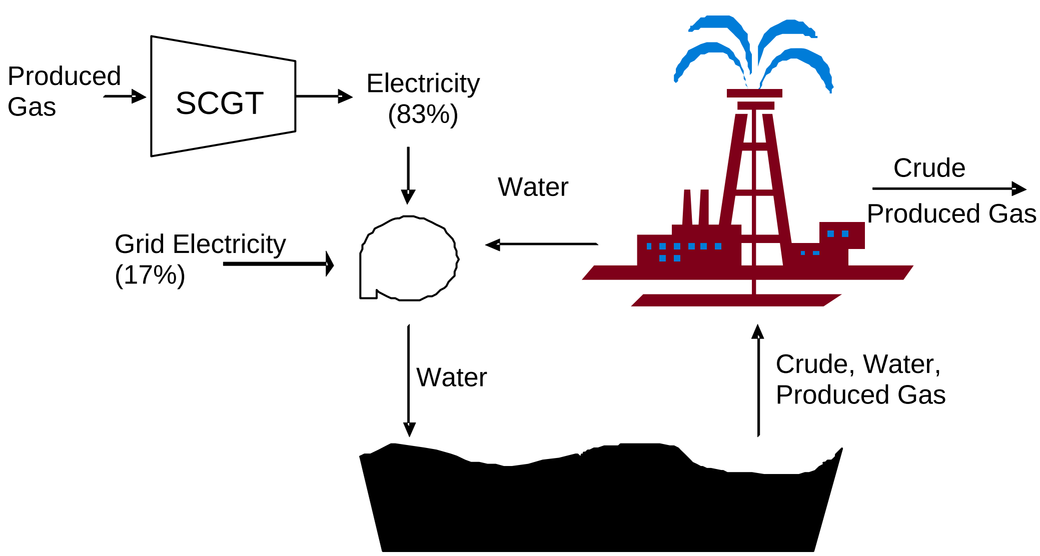

Figure 3-7. Basrah Medium (Iraq) Crude Recovery Process Flow Diagram

[9] EPA Database of Petroleum Imports

Venezuela Crude Oil

Bachaquero 17 produced from Venezuela's Lake Maracaibo field was selected as the representative crude oil from Venezuela. Bachaquero 17 is heavy (~17° API) sour (~2.4% wt sulfur) crude oil. The predominant recovery method is thermal recovery with cyclic steam stimulation (CSS) and sucker rod pumping. CSS is a batch process in which steam is injected into the reservoir at the wellhead. The steam is allowed to soak to reduce the viscosity of the crude oil, so it can be pumped to the surface (along with the water) more easily.

The process flow diagram provided in Figure 3-8 shows the energy flows to recover Bachaquero Crude from the Lake Maracaibo field. The steam is produced through a combination of produced and natural gas in a steam generator. The electricity is produced onsite with a simple cycle turbine using pipeline natural gas. All of the produced gas is combusted at the field.

Per Barrel of Crude	
Steam Produced and Consumed (bbl)	1.7
Electricity Produced and Consumed (kWh)	2.35
Natural Gas Consumed for Electricity (scf)	25
Natural Gas Consumed for Steam Production (scf)	246
Total Produced Gas (scf)	495
Produced Gas Consumed (scf)	495
Produced Gas Exported (scf)	0

For detailed calculations see Appendix A

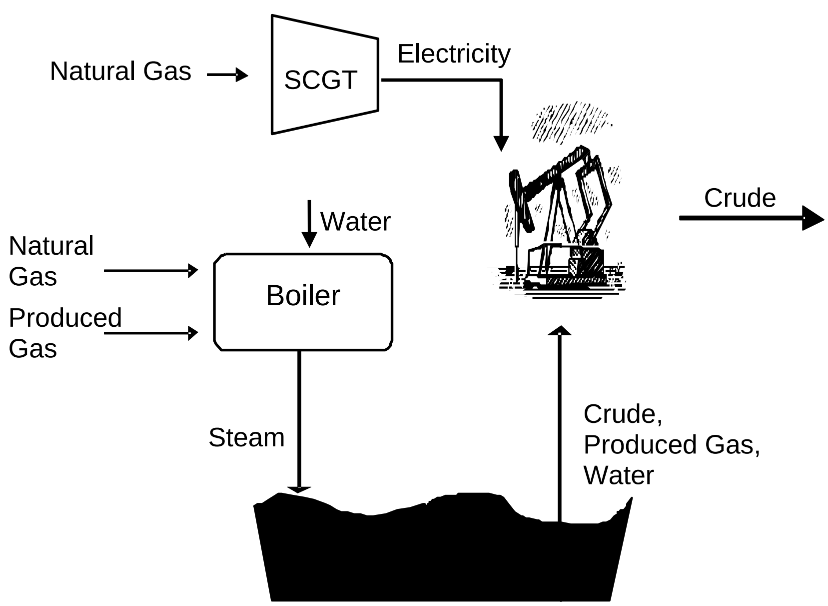

Figure 3-8. Process Flow Diagram for Bachaquero 17 (Venezuela) Recovery

Nigeria

Escravos crude oil was chosen as the analysis crude oil for Nigeria. Escravos is produced offshore and is a light (~35° API) sweet (0.16% wt sulfur) crude oil. The dominant recovery method for Nigerian crude oil is waterflooding to maintain reservoir pressure and gas lift to assist in crude oil recovery.

Figure 3-9 illustrates the process flows for Escravos crude recovery from the offshore oil fields. Electricity used to pressurize and pump gas for the gas lift process and to pump water into the reservoir comes from both onsite electricity generation from a simple cycle turbine and from Nigeria's electricity grid. The proportion of onsite production to grid is taken from the NETL report. The excess produced gas is assumed to be exported from the field.

Per Barrel of Crude	
Gas Injected for Gas Lift (scf)	416
Water Injected (bbl)	2.3
Electricity Consumed (kWh)	1.5
Total Produced Gas (scf)	1734
Produced Gas Consumed (scf)	11
Produced Gas Exported (scf)	1,723

For detailed calculations see Appendix A

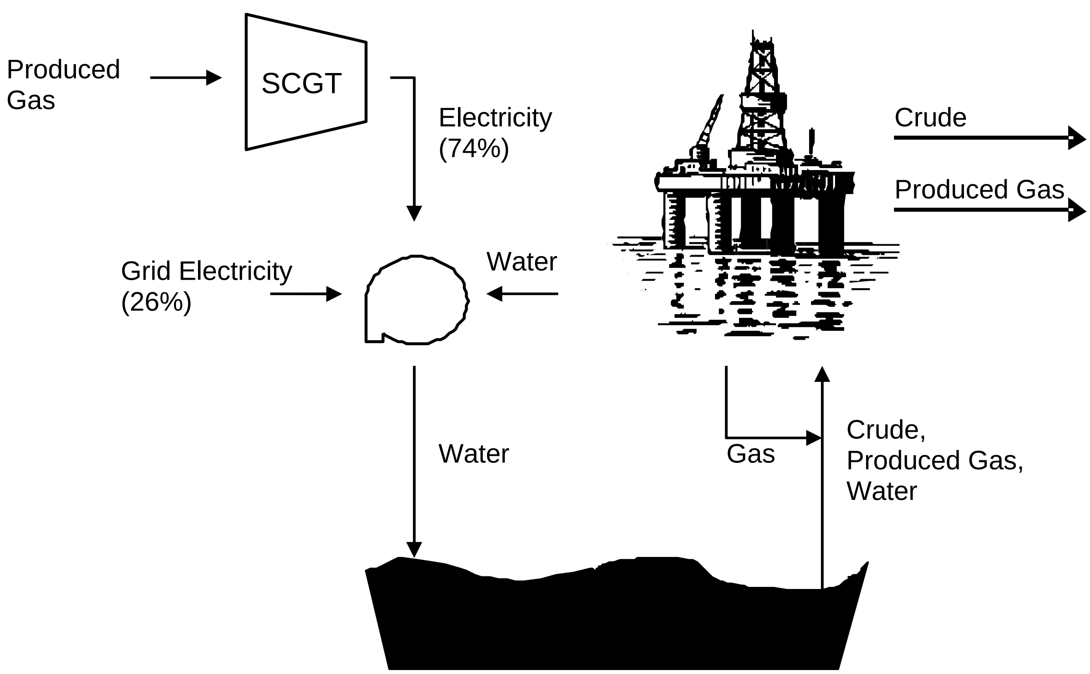

Figure 3-9. Process Flow Diagram for Escravos (Nigeria) Crude Recovery

3.1.2 Venting and Flaring

Natural gas is in liquid form at reservoir pressures. As the crude oil-natural gas liquid mixture is pumped to the surface, the pressure drops, and the natural gas liquids change to the gas phase. A major GHG emission source in the production of conventional crude is the amount of this associated gas that is vented and flared in the field. Therefore, one of the goals of this study was to determine the quantity and fate of the associated gas for each crude oil pathway. A variety of data sources were utilized; no venting and flaring data were found for specific reservoirs, but the highest resolution data for each pathway were used (i.e. country, region, state or province-wide data). The main data sources utilized were:

- DOE EIA International Energy Annual, 2005
- World Bank Global Gas Flaring Reduction, "Reported Flaring Data, 2004-2005"
- NETL Petroleum Fuels LCA Report[10]

These are referred to as the EIA data, World Bank data, and NETL report, respectively, in the following discussion. Our analysis values were developed from these and other sources noted as footnotes to the data in Tables 3-2 and 3-3. Discrepancies among the values are considered in our sensitivity analysis to determine the impact of uncertainty in flaring and venting emissions on pathway GHG emissions.

The majority of the venting and flaring data is reported as total gas volumes vented and flared. TIAX normalized these volumes to mass of total fossil fuel produced (natural gas, natural gas liquids (NGLs), and petroleum) based on the most recent data available (2006). The resulting ratios of mass of vented gas and mass of flared natural gas per mass of total fossil fuel production are used as inputs to the GREET model. The underlying assumption of this methodology is that the same amount of methane is vented or flared for every mass of fossil fuel produced (natural gas, NGLs, or petroleum).

Table 3-2 provides a summary of the flaring emissions in billion cubic feet (bcf) gathered for each country/region of interest. Note that the World Bank data consists of both reported emissions and data produced from satellite photographs. Table 3-3 provides a summary of venting emissions for each country/region of interest. As is evident from the table, there is much less published data on venting than on flaring with essentially only one data point on venting per region.

Table 3-4 provides the total fossil fuel production values used to normalize the venting and flaring volumes to mass of fossil fuel production. Tables 3-5 and 3-6 provide the normalized flaring and venting data, respectively.

[10] "Development of Baseline Data and Analysis of Life Cycle GHG Emissions of Petroleum Based Fuels", NETL, Nov 2008

Table 3-2. Flaring Data in Billion Cubic Feet (bcf)

	EIA International Energy Annual[11]		World Bank Data					Other Data Sources			
			Reported Data[12]		Satellite Data[13]						
	2005	2006	2004	2005	2005	2006	2007	2004	2005	2006	2007
United States	133.0	146.1	98.9	120.1	70.6	67.1	67.1	113.1[14]	135.4[15]	129.0[16]	—
California Heavy	—	—	—	—	—	—	—	—	—	0.7[17]	—
Alaska - NS	—	—	—	—	—	—	—	4.6[18]	—	—	—
Gulf of Mexico	—	—	—	—	—	—	—	2.7[19]/5.2[20]	—	—	—
Canada	63	68	—	—	42	57	63	—	—	—	—
Alberta	—	—	—	—	—	—	—	—	—	—	11[21]
Mexico	57	83	53	88	32	42	60	—	—	—	—
Venezuela	118	105	191	191	74	71	74	—	—	—	—
Iraq	259	252	304	254	251	261	247	—	—	—	—
Saudi Arabia	6.6	2.3	—	—	106	117	120	—	—	—	—
Nigeria	750	731	851	901	752	682	593	805[22]	—	—	—

Note: Alaska and Gulf Coast venting and flaring data reported as one value. The venting and flaring values shown have been divided per Table 3-8.

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[11] EIA International Energy Annual 2005, Table H3co2.
[12] "Reported Flaring Data—2004-2005," World Bank Global Gas Flaring Reduction, http://go.worldbank.org/GVAZH50WY0
[13] "A Twelve Year Record of National and Global Gas: Flaring Volumes Estimated Using Satellite Data," NOAA, http://siteresources.worldbank.org/INTGGFR /Resources/DMSP_flares_20070530_b-sm.pdf
[14] US EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006," US EPA, April 15, 2008, EPA 430-R-08-005
[15] *Ibid*
[16] *Ibid*
[17] Email communication and "District 4 Flaring Data" provided by Jim Campion, California Department of Conservation, Jan 23, 2009.
[18] State of Alaska, "Alaska Oil and Gas Conservation Commission 2004 Annual Report: Gas Disposition," Alaska Oil and Gas Conservation Commission, http://www.state.ak.us/admin/ogc/annual/2004/2004_Gas_Disposition_Final.pdf.
[19] EIA, "Natural Gas Gross Withdrawals and Production: Federal Offshore Gulf of Mexico" Energy Information Administration, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_r3fm_a.htm.
[20] US EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004," US EPA, EPA 430-R-06-005
[21] ERBC, "Upstream Petroleum Industry Flaring and Venting Report 2007," ERCB June 2008, ST60B-2008.
[22] Hart Resources, Ltd, "Nigeria Extractive Industries Transparency Initiative," Hart Resources Ltd., November 2006.

Table 3-3. Venting Data in Billion Cubic Feet (bcf)

	EIA[23,24]		Other Data Sources			
	2005	2006	2004	2005	2006	2007
United States	—	—	23.8[25]	23.4[26]	23.5[27]	—
California Heavy	—	—	—	—	1.3[28]	—
Alaska - NS	—	—	0.8[29]	—	—	—
Gulf of Mexico	—	—	7.6[30] / 15[31]	—	—	—
Canada	—	5.7	—	—	—	—
Alberta	—	—	—	—	—	4.1[32]
Mexico	—	5.4	—	—	—	—
Venezuela	9.2	—	—	—	—	—
Iraq	20.1	—	—	—	—	—
Saudi Arabia	0.5	—	—	—	—	—
Nigeria	58.2	—	—	—	—	—

Note: Alaska and Gulf Coast venting and flaring data reported as one value. The venting and flaring values shown have been divided per Table 3-8.

[23] EIA International Energy Annual 2006, Table H3co2.

[24] EIA, "International Energy Annual 2006: Country Energy Balances," http://www.eia.doe.gov/emeu/world/country/countrybal.html.

[25] US EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006," US EPA, April 15, 2008, EPA 430-R-08-005

[26] *Ibid*

[27] *Ibid*

[28] Draft Documentation of California's GHG Inventory, Fugitive Emissions From Oil and Gas Extraction, www.arb.ca.gov/cc/inventory/docs/docs1/1B2_oil&gasextraction

[29] State of Alaska, "Alaska Oil and Gas Conservation Commission 2004 Annual Report: Gas Disposition," Alaska Oil and Gas Conservation Commission, http://www.state.ak.us/admin/ogc/annual/2004/2004_Gas_Disposition_Final.pdf.

[30] EIA, "Natural Gas Gross Withdrawals and Production: Federal Offshore Gulf of Mexico" Energy Information Administration, http://tonto.eia.doe.gov/dnav/ng/ng_prod_sum_dcu_r3fm_a.htm.

[31] US EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004," US EPA, EPA 430-R-06-005

[32] ERBC, "Upstream Petroleum Industry Flaring and Venting Report 2007," ERCB June 2008, ST60B-2008

Table 3-4. Total Annual Hydrocarbon Production

	Total Hydrocarbon Production (Gg)[33]			
	2004	2005	2006	2007
United States	688,000	668,000	670,000	—
California Heavy	—	—	29,000	—
Alaska - NS	111,000	—	—	—
Gulf of Mexico	158,000	—	—	—
Canada	273,000	273,000	283,000	—
Alberta	—	—	—	34,000
Mexico	218,000	216,000	217,000	—
Venezuela	164,000	171,000	166,000	—
Iraq	101,000	95,000	100,000	—
Saudi Arabia	542,000	574,000	554,000	—
Nigeria	130,000	146,000	141,000	—

[33] EIA International Energy Annual 2006.

Table 3-5. Mass Ratio of Flared to Produced (g/g fossil production)

	EIA International Energy Annual		World Bank Data					Other Data Sources			
			Reported Data		Satellite Data						
	2005	2006	2004	2005	2005	2006	2007	2004	2005	2006	2007
United States	0.0039	0.0043	0.0028	0.0035	0.0021	0.0020	0.0020	0.0032	0.0040	0.0038	—
California Heavy	—	—	—	—	—	—	—	—	—	0.00057	—
Alaska - NS	—	—	—	—	—	—	—	0.00081	—	—	—
Gulf of Mexico	—	—	—	—	—	—	—	0.00033 / 0.00065	—	—	—
Canada	0.0046	0.0048	—	—	0.0030	0.0040	0.0044	—	—	—	—
Alberta	—	—	—	—	—	—	—	—	—	—	0.0064
Mexico	0.0055	0.0079	0.0050	0.0084	0.0030	0.0040	0.0057	—	—	—	—
Venezuela	0.016	0.014	0.027	0.026	0.010	0.0098	0.010	—	—	—	—
Iraq	0.055	0.051	0.061	0.054	0.053	0.053	0.050	—	—	—	—
Saudi Arabia	0.00023	0.000084	—	—	0.0037	0.0042	0.0044	—	—	—	—
Nigeria	0.10	0.10	0.13	0.12	0.10	0.098	0.085	0.12	—	—	—

Table 3-6. Mass Ratio of Vented to Produced (g/g fossil production)

	EIA		Other Data Sources			
	2005	2006	2004	2005	2006	2007
United States	—	—	0.00067	0.00069	0.00069	
California Heavy	—	—			0.00099	
Alaska - NS	—	—	0.00014			
Gulf of Mexico	—	—	0.00095 / 0.0018	—	—	—
Canada	—	0.00040	—	—	—	—
Alberta	—		—	—	—	0.0024
Mexico	—	0.00052	—	—	—	—
Venezuela	0.0012	—	—	—	—	—
Iraq	0.0043	—	—	—	—	—
Saudi Arabia	0.000018	—	—	—	—	—
Nigeria	0.0081	—	—	—	—	—

As mentioned, NETL recently published a report on oilfield venting and flaring emissions. Their results are also provided as ratios of mass of flared/vented gas to total fossil production and are based on a database of reported values.[34] Table 3-7 below shows the comparison of the NETL numbers and the values chosen for use in this analysis. Figures 3-10 and 3-11 provide the comparison graphically. Table 3-8 summarizes how the TIAX analysis values were determined.

Table 3-7. Comparison of NETL and TIAX Analysis Values

	NETL		TIAX Analysis	
	Flared	Vented	Flared	Vented
United States	0.0037	0.00094		
California Heavy			0.00057	0.00099
Alaska - NS			0.00081	0.00014
Gulf of Mexico			0.00049	0.0014
Canada	0.0072	0.0043		
Alberta			0.0064	0.0024
Mexico	0.022	0.0055	0.0056	0.0030
Venezuela	0.013	0.0016	0.016	0.0014
Iraq	0.0059	0.0017	0.054	0.0030
Saudi Arabia	0.00032	0.000092	0.0025	0.000055
Nigeria	0.10	0.029	0.11	0.019

[34] Centre International d'Information Sur le Gaz Naturel et Tous Hydrocarvures Gazeux (CEDIGAZ), "Natural Gas in the World" Trends and Figures in 2007 as of July 2008 Electronic Database.

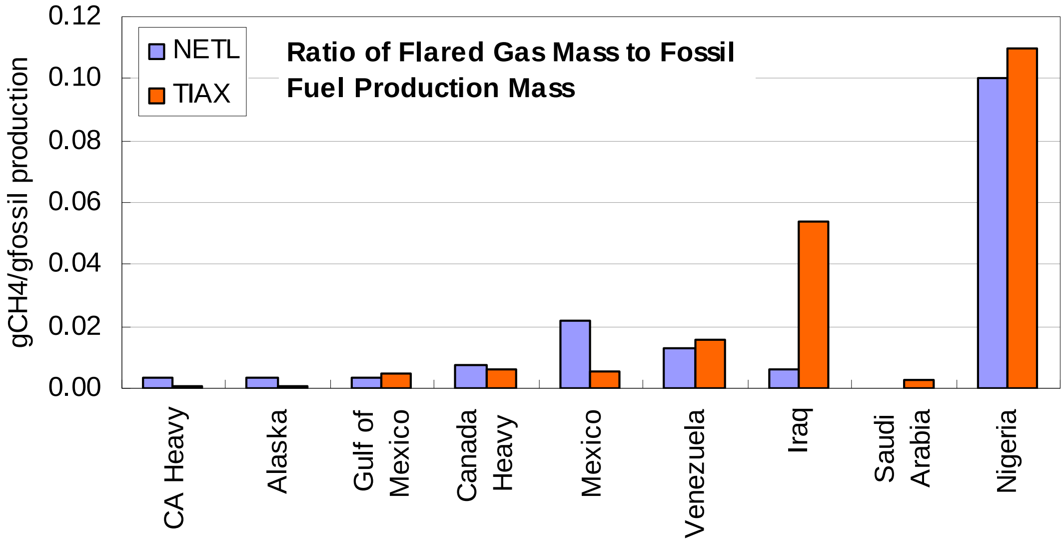


Figure 3-10. Comparison of TIAX Analysis Value and NETL Values for Flared Gas

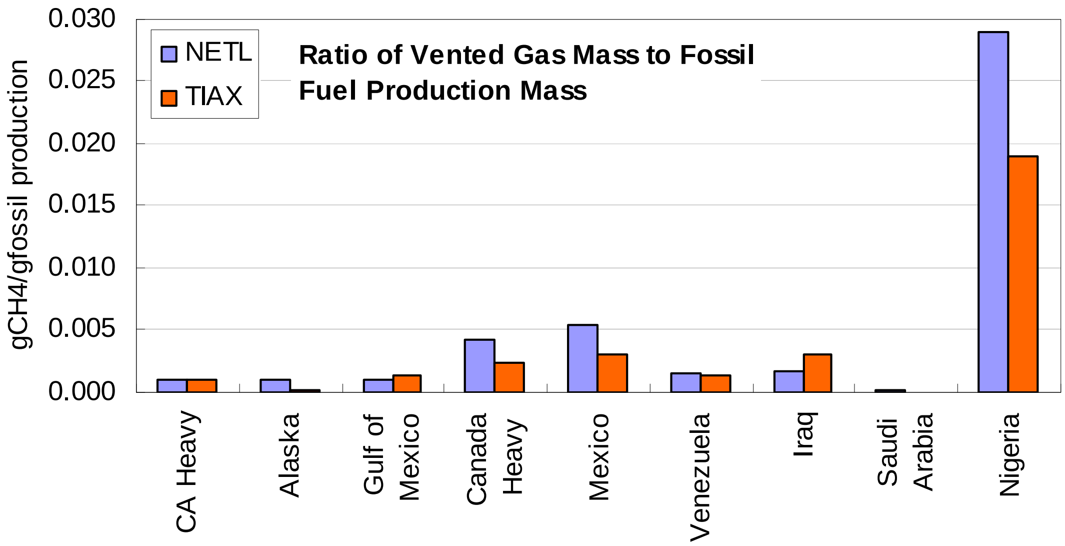


Figure 3-11. Comparison of TIAX Analysis Value and NETL Values for Vented Gas

Table 3-8. Basis for TIAX Analysis Venting and Flaring Emissions

Anaylsis Crude	Basis for Analysis Values
California Heavy	The venting and flaring values are based on actual data from the California Department of Conservation, the only data source found for California emissions.
Alaska - NS	The combined venting and flaring value is based on data from the State of Alaska Oil and Gas Conservation Commission. The total amount was split according to the U.S. average values[35] for amount flared over total vented and flared (85%).
Gulf of Mexico	The combined venting and flaring values from the USEPA and EIA were averaged. The total amount was split according to the Gulf of Mexico values[36] for amount flared over total vented and flared (26%).
Canada Heavy	The ERCB values for Alberta venting and flaring were used as they were the only Alberta specific values found
Mexico	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Venezuela	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Iraq	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Saudi Arabia	For flaring, an average of the EIA and World Bank data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.
Nigeria	For flaring, an average of the EIA, World Bank and HART data is used. These values are consistent. For venting, an average of the NETL and EIA values is used.

[35] US EPA, "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006," US EPA, April 15, 2008, EPA 430-R-08-005

[36] *Ibid*

3.2 Crude Oil Derived from Oil Sands

This section outlines the data collection for the analysis of Canadian oil sands recovery and upgrading. The pathways and projects used to represent the oil sands operations are discussed, and the energy and material balances for the projects are presented. The data collected here for the oil sands projects are subsequently input into the GREET model to determine the full WTW GHG emissions.

3.2.1 Oil Sands Pathways

Bitumen from oil sands, an alternative to the conventional crude oil that is currently used to produce the majority of the world's petroleum products, represents a significant energy resource. By some estimates, the volume of oil sands in Canada alone makes the country second only to Saudi Arabia in proven oil reserves in the world.[37] Some of the largest reserves of oil sands are found in northeastern Alberta, primarily in the Athabasca, Cold Lake, and Peace River regions (Figure 3-12).

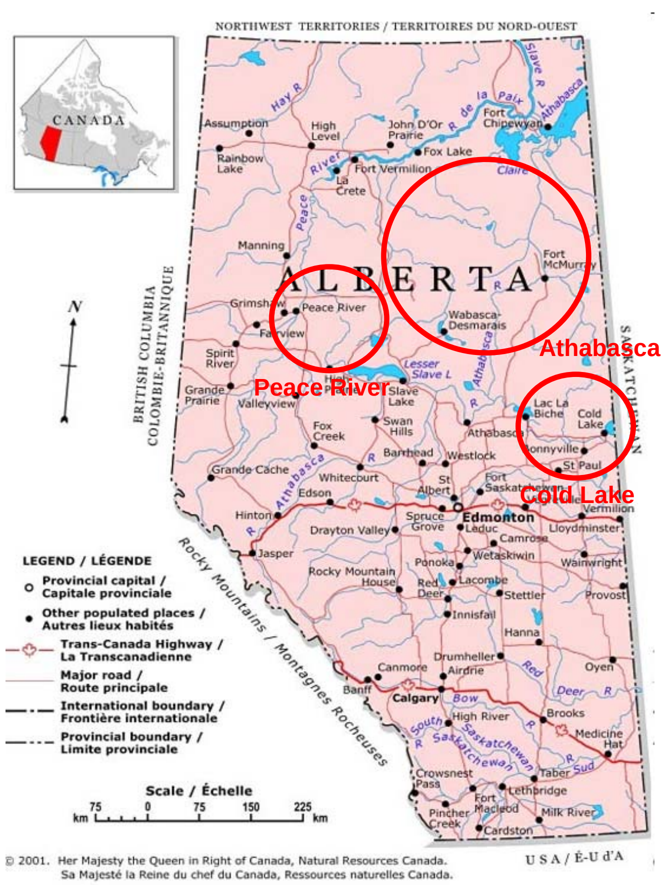


Figure 3-12. Oil Sands Regions in Alberta, Canada

[37] Isaacs, E. "Canadian Oil Sands: Development and Future Outlook", Alberta Energy Research Institute, 2005

Two different recovery techniques are utilized to recover Canadian oil sands: mining and in-situ thermal recovery. Currently, mining and in-situ techniques produce approximately equal quantities of bitumen. When bitumen deposits are close to the surface, mining is used for recovery. In surface mining, large earthmoving equipment is utilized to first remove the overburden and then excavate and load the oil sands onto large trucks for transport to a processing facility. At the processing facility, the bitumen is separated from the sand with hot water. The sand, water and residual bitumen are deposited in a tailings pond.

For deposits that are too deep to reach with surface mining, in-situ thermal recovery techniques are utilized in which steam is injected to reduce the bitumen's viscosity to such a degree that it flows to the surface. Two main in-situ methods are employed: steam assisted gravity drainage (SAGD) and cycle steam stimulation (CSS). In SAGD recovery, a pair of horizontal wells is installed. The upper well is used to inject steam. The heated bitumen flows into the lower well by gravity and is subsequently pumped to the surface. The CSS recovery process involves vertical wells used in three cyclic stages: 1) steam injection, 2) soaking, and 3) bitumen production.

Oil sands derived crude is delivered to the refinery as either bitumen or upgraded synthetic crude oil (SCO). Because bitumen is too viscous to flow through a pipeline to the refinery on its own, it is generally blended with SCO or a diluent (typically natural gas condensate) and delivered as synbit or dilbit to the refinery. With input from the Steering Committee, four bitumen recovery pathways were selected to characterize the range of methods utilized to recover and deliver oil sands derived crude oil to refineries. The recovery pathways are summarized in Table 3-9. Recognizing that a number of different oil sands pathways are possible, our analysis focused on these four pathways to bracket the range of operation.

Table 3-9. Oil Sands Analysis Recovery Pathways

Recovery Pathway	Bitumen Recovery Method	Upgrading?	Product Delivered to Refinery	Refinery Products
1	Surface Mining	Yes, On-site	SCO	Reformulated Gasoline Blendstock and Low Sulfur Diesel
2	In-Situ SAGD	Yes, On-site	SCO	
3	In-Situ SAGD	No	Synbit, Dilbit	
4	In-Situ CSS	No	Synbit, Dilbit	

SCO = Synthetic Crude Oil
Synbit is assumed to be a 50/50 volume blend of SCO and Bitumen
Dilbit is assumed to be a 25/75 volume blend of diluent (natural gas condensate) and Bitumen

3.2.2 Selection of Representative Projects

Once the bitumen recovery analysis pathways were identified, TIAX sought data that could be used to formulate energy balances for each. From the projects listed in Appendix A, six projects from the Athabasca and Cold Lake regions of Alberta were ultimately selected and approved by the Steering Committee to form the foundation of our oil sands energy balances. The selection criteria were:

- Availability of detailed and public/releasable energy and material balance data
- As close to currently producing as possible
- High production capacity relative to other projects of its type

The first criterion reflected our overarching goal of a transparent analysis, relying on the use of public and releasable operation data. Furthermore, to achieve the granularity required for our bottom-up analysis approach, these public data were required to contain detailed energy and material balances. Unfortunately, certain large and established projects that likely best represent oil sands operations were not able to provide public data. This criterion, therefore, led to the selection of somewhat smaller or less established projects. In addition, some data are derived from permit applications that are several years old, and energy and material balances are likely to have changed since the applications were approved. In an effort to update these data as much as possible, the operators of the selected projects were given the opportunity to review the data gathered for this analysis; two operators provided updates to the application data.

The second criterion of current production, as directed by the Steering Committee, was aimed at representing the *near-term* emissions of crude oil from oil sands. While detailed data were publicly available through permit applications from many oil sands projects, a large number of these projects would not be fully operational for several years. The selected projects were either currently producing or the closest in its operation type to coming online that also provided public data.

The third criterion focused on selecting the largest projects to represent each operation type, subject to the first two criteria. Although the actual production of crude oil product from a project in any given year may be affected by a myriad of unpredictable factors, the determination of the largest projects was based on design capacity.

The projects utilized as the basis for our energy balances based on the selection criteria are presented in Table 3-10. Combined, these projects represent 34% of the total current oil sands production capacity in Alberta. The data were derived from a combination of original applications to the Energy and Utilities Board (EUB) and Alberta Environment (AENV), recent reports to the Energy Resources Conservation Board (ERCB), and updates provided by the operators.

Table 3-10. Selected Oil Sands Projects

Pathway	Project	2007 Status	Capacity (bpd)	References
Mining & Upgrading	CNRL Horizon	In start-up	Design: 110,000	EUB/AENV Supplemental Info (2003)[38]
SAGD & Upgrading	Nexen/OPTI Long Lake	In start-up	Design: 58,000	EUB/AENV EIA (2000)[39] Supplemental Information (2002)[40] Application for Amendment (2006)[41] Nexen/OPTI (2009)[42]
SAGD	Petro-Canada MacKay River	Producing	Design: 33,000 2007: 22,000	EUB/AENV Application (2005)[43] In-Situ Progress Report to ERCB (2008)[44]
	EnCana Christina Lake	Producing	Design: 60,000 2007: 6,000	EUB/AENV Application, EIA[45], [46] Supplemental Information (1998)[47] In-Situ Progress Report to ERCB (2008)[48]
CSS	Imperial Oil Cold Lake	Producing	2007: 160,000	EUB/AENV Application (2002)[49] EUB/AENV Supplemental Information (2003)[50] In-Situ Progress Report to ERCB (2008)[51]
	CNRL Primrose	Producing	Design: 80,000 2007: 62,000	EUB/AENV Supplemental Information (2001)[52] EUB/AENV EIA (2000)[53] In-Situ Progress Report to ERCB (2008)[54] CNRL (2008)[55]

[38] CNRL Horizon. "Application to Energy and Utilities Board/Alberta Environment, Supplemental Information."2003.
[39] Nexen/OPTI Long Lake. "Application for Amendment to Energy and Utilities Board/Alberta Environment." 2006.
[40] Nexen/OPTI Long Lake. "Application to Energy and Utilities Board/Alberta Environment." 2000
[41] Nexen/OPTI Long Lake. "Application to Energy and Utilities Board/Alberta Environment, Supplemental Information." 2002
[42] Nexen/OPTI Long Lake. TIAX communication with Anand Gohil. 2009
[43] Petro-Canada MacKay River. "Application to Energy and Utilities Board/Alberta Environment." 2005.
[44] Petro-Canada MacKay River. "In-Situ Progress Report to Energy Resources Conservation Board." 2008
[45] EnCana Christina Lake. "Application to Energy and Utilities Board/Alberta Environment." 1998.
[46] EnCana Christina Lake. "Application to Energy and Utilities Board/Alberta Environment, Environmental Impact Assessment." 1998
[47] EnCana Christina Lake. "Application to Energy and Utilities Board/Alberta Environment, Supplemental Information." 1998
[48] EnCana Christina Lake. "In-Situ Progress Report to Energy Resources Conservation Board." 2008
[49] Imperial Oil Cold Lake. "Application to Energy and Utilities Board/Alberta Environment." 2002.
[50] Imperial Oil Cold Lake. "Application to Energy and Utilities Board/Alberta Environment, Supplemental Information." 2003
[51] Imperial Oil Cold Lake. "In-Situ Progress Report to Energy Resources Conservation Board." 2008
[52] CNRL Primrose. "Application to Energy and Utilities Board/Alberta Environment, Environmental Impact Assessment." 2000.
[53] CNRL Primrose. "Application to Energy and Utilities Board/Alberta Environment, Supplemental Information." 2001.
[54] CNRL Primrose. "In-Situ Progress Report to Energy Resources Conservation Board." 2008.
[55] CNRL Primrose. TIAX communication with Christa Seaman. 2008

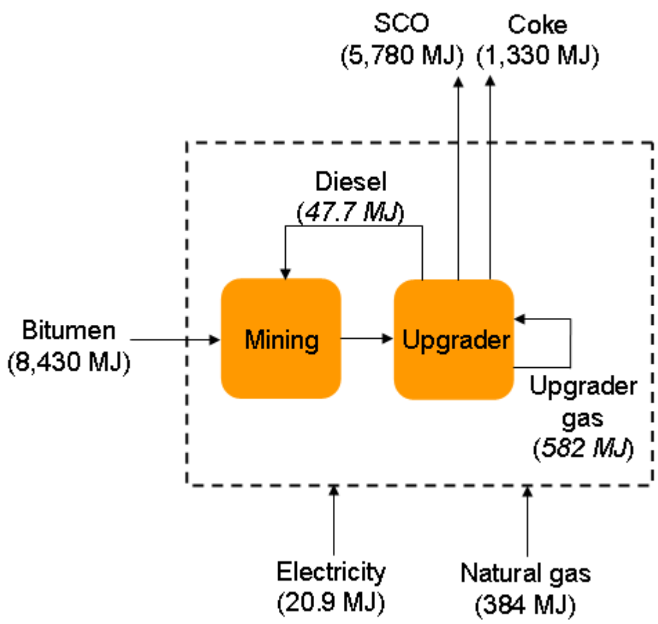
3.2.3 Energy Balance Data

From these publicly available and releasable data, the key energy and material flows for each project are detailed below. Except for standard conversions, the data are presented as they are given in the original references. Italicized values indicate where, in the absence of information in the original reference, a conversion factor has been assumed for data comparison purposes; the assumed conversion factors are listed in Appendix C.

Mining/Upgrading: CNRL Horizon

The Horizon project consists of bitumen recovery through mining and upgrading to SCO at the integrated, onsite upgrader. In addition to the input of mined bitumen, the project purchases pipeline natural gas and electricity and produces SCO and coke, which is subsequently stockpiled. The project includes cogeneration capabilities but currently does not produce excess electricity for export. Gas produced during the upgrading process is used internally as fuel, and diesel produced during the upgrading process is used internally to power the mining fleet. The material and energy flows are presented in Figure 3-12.

	Per barrel SCO:	**CNRL Horizon**	
IN	Bitumen	1.34	bbl
	Natural gas	11.7	m^3
	Electricity import	20.9	MJ
OUT	SCO	1	bbl
	Coke, stockpiled	40.3	kg
INTERNAL	Upgrader gas	13.5	m^3
	Diesel	0.008	bbl



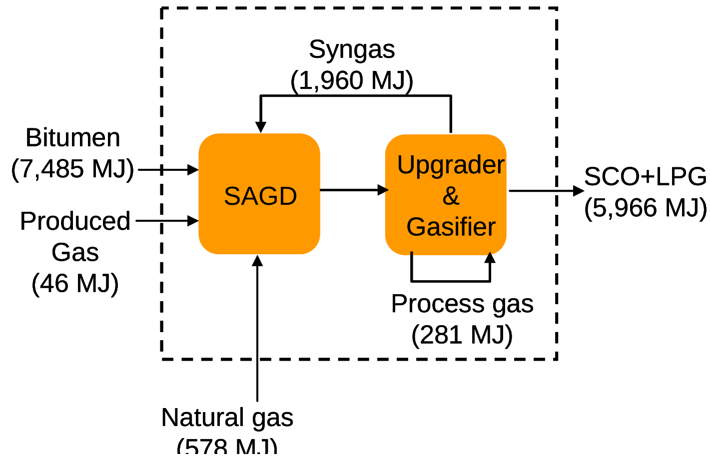
Italicized values are estimates for comparison purposes

Figure 3-12. Material and Energy Flows for Mining/Upgrading Operations

SAGD/Upgrading: Nexen/OPTI Long Lake

The Long Lake project utilizes SAGD to recover bitumen which is upgraded to SCO onsite. A small amount of liquid petroleum gas (LPG) is also produced. The distinguishing feature of the Long Lake project is that the coke produced in the upgrader is gasified; the resulting syngas produced is used along with the produced gas and pipeline natural gas to cogenerate steam and electricity used in the recovery process. Although earlier application data provided by Nexen indicated higher pipeline natural gas consumption coupled with electricity exports, the most recent process flow diagram provided shows lower pipeline natural gas consumption, and no excess electricity is exported to the grid. The material and energy flows are presented in Figure 3-13.

	Per barrel SCO+LPG:	**Nexen/OPTI Long Lake** (CSOR = 3)	
IN	Bitumen	1.18	bbl
	Produced gas	*46.25*	*MJ*
	Natural gas	*577.5*	*MJ*
OUT	SCO + LPG	1	bbl
	Electricity Exports	0	MJ
INTER-NAL	Syngas	1260	MJ
	Upgrader Process Gas	281	MJ



Italicized values are estimates for comparison purposes

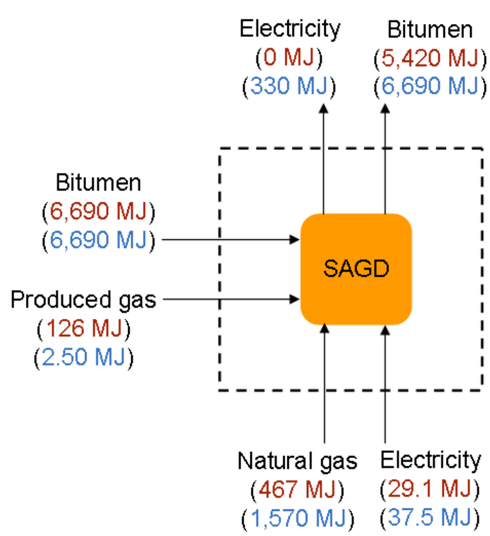
Figure 3-13. Material and Energy Flows for SAGD/Upgrading Operations

SAGD: EnCana Christina Lake and Petro-Canada MacKay River

The Christina Lake project consists of bitumen recovery through SAGD with no upgrading. The project purchases grid electricity and pipeline natural gas for steam production.

The MacKay River project is similar to the Christina Lake project, except that the steam is produced onsite with a cogeneration plant, and excess electricity is exported to the grid. The material and energy flows of both SAGD projects are presented in Figure 3-14 (values in red are for Christina Lake, blue values are for MacKay River).

	Per barrel bitumen:	**EnCana Christina Lake** (CSOR = 2.5)		**Petro-Canada MacKay River** (CSOR = 2.5)	
IN	Natural gas	*14.2*	*m^3*	*43.4*	*m^3*
	Produced gas	3.97	m^3	*0.069*	*m^3*
	Electricity import	29.1	MJ	37.5	MJ
OUT	Bitumen	1	bbl	1	bbl
	Electricity sales	0	MJ	330	MJ



Italicized values are estimates for comparison purposes

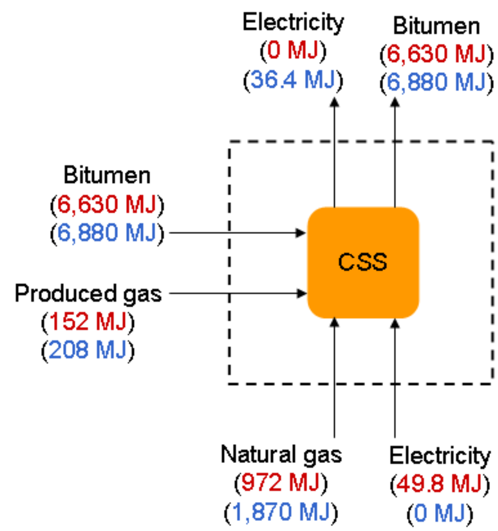
Figure 3-14. Material and Energy Flows for SAGD Operations

CSS: Imperial Oil Cold Lake and CNRL Primrose

The Cold Lake project consists of bitumen recovery through CSS with no upgrading. The project consumes pipeline natural gas to generate steam for CSS and, although the addition of cogeneration capability has been proposed, currently purchases grid electricity.

The Primrose project is similar to the Cold Lake project, except that the steam is produced onsite with a cogeneration plant, and excess electricity is exported to the grid. The material and energy flows of both CSS projects are presented in Figure 3-15 (Cold Lake in red and Primrose in blue).

	Per barrel bitumen:	Imperial Oil Cold Lake (CSOR = 3.35)		CNRL Primrose (CSOR = 4.81)	
IN	Natural gas	26.1	m^3	*51.6*	*m^3*
IN	Produced gas	4.65	m^3	*5.73*	*m^3*
IN	Electricity import	49.8	MJ	0	MJ
OUT	Bitumen	1	bbl	1	bbl
OUT	Electricity	0	MJ	36.4	MJ



Italicized values are estimates for comparison purposes

Figure 3-15. Material and Energy Flows for CSS Operations

3.2.4 Flaring, Venting, and Fugitive Emissions

Flaring, venting, and fugitive emissions also contribute to total GHG emissions for oil sands recovery. For the mining and upgrading operation, the CNRL Horizon application provides flaring and fugitive emission values, presented in Table 3-11.

Table 3-11. Fugitive and Flaring Emissions from Mining/Upgrading Operations

	CO (g/MMBtu)	VOC (g/MMBtu)
Mine face fugitives	—	13.7
Tailings pond fugitives	—	0-226
Plant fugitives	—	6.70
Flaring	0.114	0.016

Source: CNRL Horizon, "EUB/AENV Supplemental Information," 2003.

Although the flaring emissions of carbon monoxide (CO) and volatile organic compounds (VOCs)[56] can be entered directly into the GREET model, other flaring pollutants need to be accounted for. To estimate emissions of each pollutant, the given emission rates of CO and VOC are used to back-calculate the gas flaring volumes. The flaring volume is then used as a direct GREET input; flare emission factors for VOC, CO, NO_x, PM_{10}, SO_2, N_2O, CH_4 and CO_2 are applied to the estimated amount of gas flared.

For the in-situ operations (SAGD and CSS), ERCB provides flaring and venting emission values, presented in Table 3-12.

Table 3-12. Flaring and Venting Emissions from In-Situ Operations

	m^3/bbl bitumen	GREET units
Flaring	0.099	542 Btu/MMBtu bitumen
Venting	1.15	138 g/MMBtu bitumen

Source: ERCB[57]

The report gives these values as total volumes of gas flared and vented for the entire volume of bitumen produced in Alberta, and the conversion to GREET units below assumes that the gases can be approximated by natural gas. An additional assumption is that the ERCB values, which are reported for all bitumen projects collectively, including mining, are a good representation of in-situ operation. The report indicates that the most significant source of venting, which accounts for more than ten times the volume of flaring, is the production casing annulus at wells, which applies only to in-situ, not mining, operations. Thus, the assumption that the ERCB values provide a good estimate of in-situ flaring and venting emissions appears to be reasonable.

[56] VOCs in the CNRL Horizon application do not include methane.

[57] Energy Resources Conservation Board. "Upstream Petroleum Industry Flaring and Venting Report: Industry Performance for Year Ending December 31, 2007." June 2008

4. Refinery Modeling

Crude oil refining represents a significant portion of gasoline/diesel WTT GHG emissions. The objective of this task was to determine the amount of energy required to refine each crude oil into gasoline and diesel, and to differentiate among process fuel types. Each crude oil has unique properties that influence the amount of energy needed to refine it. Some of these properties include: specific gravity, sulfur content, distillation yield curve, naphthene and aromatic content of the naphtha, cracking characteristics, and coke yield. Figure 4-1 provides the specific gravity and sulfur content of the crude oils analyzed here.

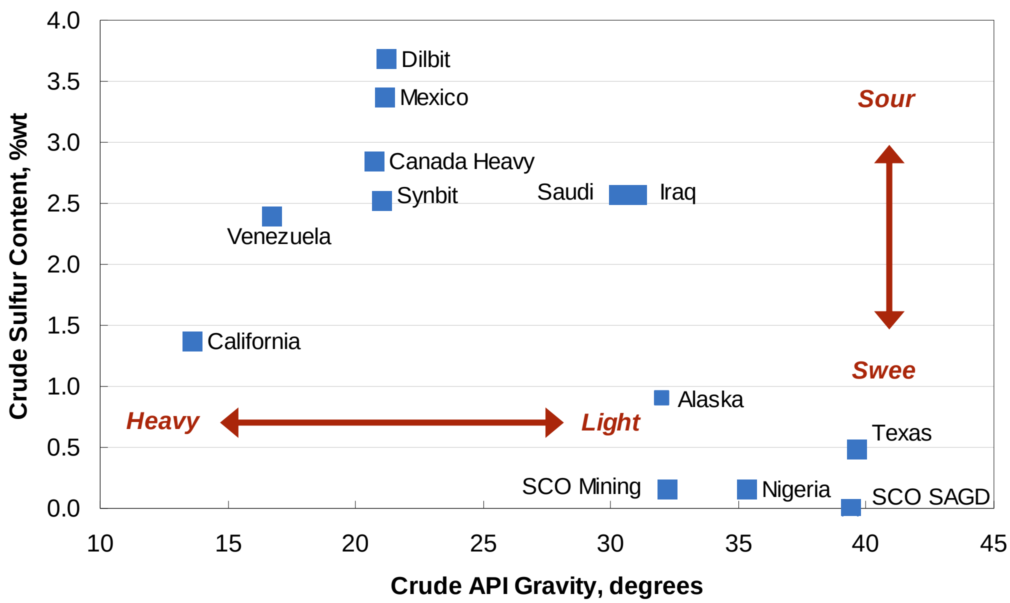


Figure 4-1. Specific Gravity and Sulfur Content of Analysis Crude Oils

Petroleum refineries are extremely complex; a simplistic flow chart representation of a U.S. deep conversion refinery[58] is provided in Figure 4-2. Converting the crude oil into refined products requires energy which is supplied by:

- Pipeline natural gas
- Electricity (grid and/or self-generated)
- Refinery produced still gas
- Catalyst coke (produced in the FCC units)

[58]Deep conversion refineries convert vacuum gas oils and resid into lighter products through cracking/coking.

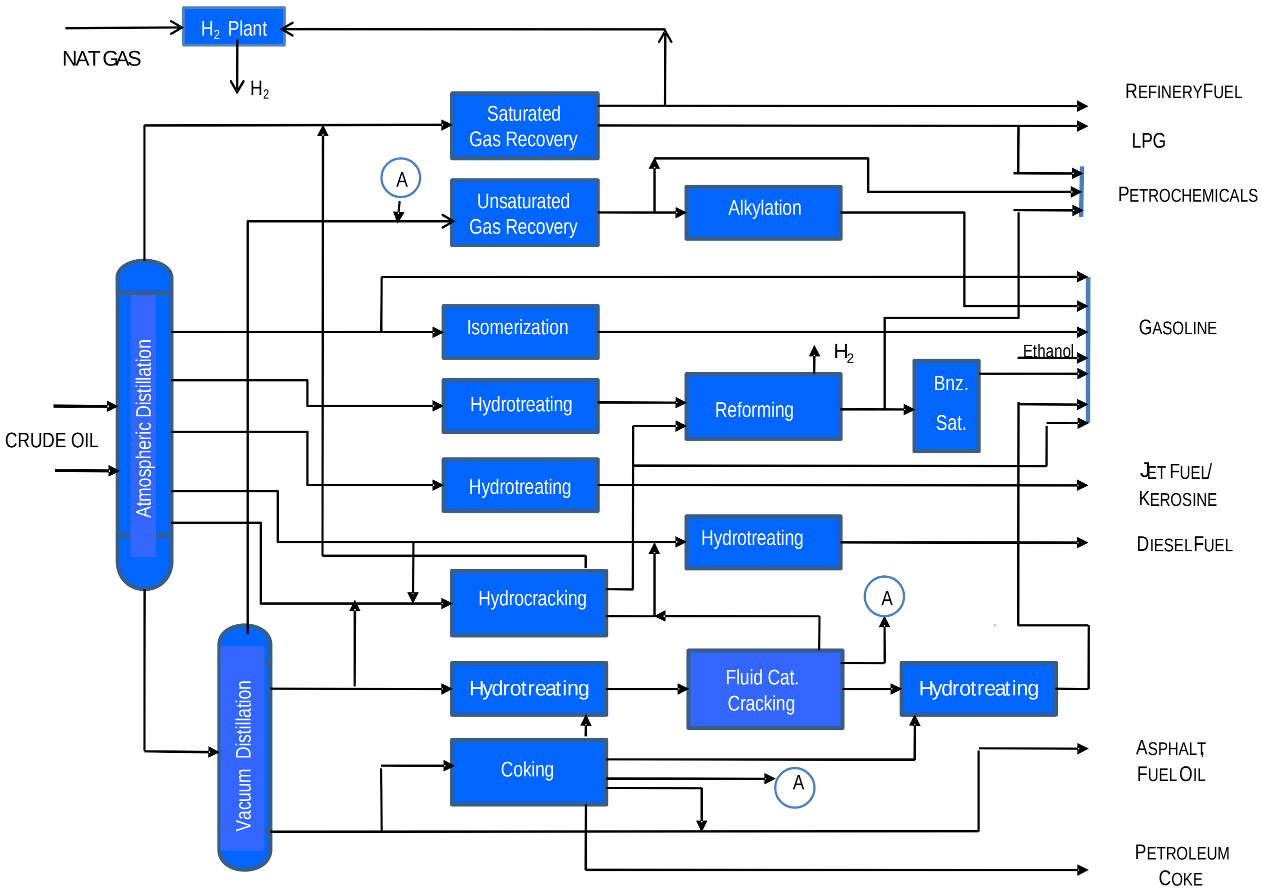


Figure 4-2. Simplified Flow Chart of a U.S. Deep Conversion Refinery (MathPro, Inc).

Crude oil properties influence the amount of energy consumed to produce finished fuels. The properties that have the largest impact are crude distillation curve, sulfur content, and chemical composition.

- Heavier crude oils tend to use less energy in the distillation process than lighter crude oils. In contrast, the heavier crude oils have higher yields of vacuum gas oil and residual fractions, requiring more energy for catalytic cracking (FCC), coking and hydrocracking.
- Refinery energy use is proportional to crude oil sulfur content. Sulfur is removed by hydrotreating the FCC feed, product hydrotreating, and hydrocracking. Sulfur removal required direct fuel consumption and indirect through production of hydrogen from natural gas reforming.
- Composition of the fractions fed to the conversion and upgrading units influence the yields and operating severity required for the desired product slate.

While crude characteristics are important, a number of other factors also influence the amount of energy and resulting GHG emissions associated with refining a specific crude oil, including:

- Properties of the other crude oils being refined at the same time
- Refined products slate
- Refinery configuration/processes employed
- Local electricity grid mix

Therefore, energy required for refining is not an intrinsic property of each specific crude oil; it depends on its refining environment. Because there are regional differences in the refinery crude mixes, product slates, and refinery configuration, a regional approach has been employed to estimate the amount of energy needed to refine a given crude oil. Table 4-1 provides the analysis matrix. The refining regions selected for each crude oil are reflective of where the crude oils are currently refined and where they are likely to be refined in the near future. A total of 26 crude/region combinations were considered.

Table 4-1. Analysis Crude Oils and Corresponding Refinery Regions

Source	Analysis Crude	Refinery Region		
		PADD 2	PADD 3	California
U.S. Alaska	Alaska North Slope			X
U.S. California	Kern County Heavy Oil			X
U.S. Gulf Coast	West Texas Intermediate	X	X	
Canada	Bow River Heavy Oil	X		
Saudi Arabia	Medium	X	X	X
Iraq	Basrah Medium		X	X
Nigeria	Escravos		X	
Mexico	Maya Heavy		X	X
Venezuela	Bachaquero 17		X	
Canada	SCO (mined bitumen)	X	X	X
Canada	SCO (in situ bitumen)	X	X	X
Canada	Synbit (SCO and insitu bitumen)	X	X	X
Canada	Dilbit (condensate and insitu bitumen)	X	X	X

PADD 2 is the MidWest; PADD 3 is the Gulf Coast

The objective of this task was to estimate the amount of energy required to produced gasoline and diesel from each of the analysis crude oils considered. Further, the total energy for each crude oil needed to be differentiated by process fuel type. MathPro Inc performed this analysis utilizing their ARMS modeling system. In the paragraphs below we summarize MathPro's approach and results. For a detailed description of the modeling effort, please refer to MathPro's report in Appendix D.

4.1 Modeling Methodology

As mentioned above, four models were constructed: a national composite refinery model as well as regional models for PADD 2, PADD 3, and California. Each regional model represents aggregate refining capacity of that region, including a composite crude oil slate and producing a composite slate of refined products. Each model also reflects the regional capacity of each refining process (e.g. cat cracking capacity). The models were calibrated against 2006 data and then modified to take into account adopted fuel standards mostly implemented currently, but fully implemented in 2015.[59]

The models estimate total refinery energy use, process-by-process. The direct energy input to each refining process is determined by energy source (natural gas, still gas, catalyst coke, electricity). It was assumed that all hydrogen needed was produced onsite from purchased natural gas; this puts the refinery control volume around merchant hydrogen suppliers. Refinery natural gas consumption and electricity purchases reflect refinery co-generation reported by EIA. The model was calibrated against numerous data sources for the year 2006.

Two key results were required from the refinery modeling estimate:

- Allocation factors to allocate total refinery energy consumption to the four product groups (gasoline, diesel, jet fuel, and all other refined products)
- Total refinery energy consumption by fuel type to refine each analysis crude oil in each of the regions it flows to.

To develop allocation factors, MathPro used the national refining model since these factors were to be applied to the results from each of the refining regions. Once the national model was calibrated and baseline values established, the energy use associated with gasoline was determined by reducing the amount of gasoline products by 1%, holding all other refinery inputs and outputs constant. The resulting decreases in each process fuel type are entirely attributable to the decrease in the volume of gasoline. This process was repeated for diesel, jet fuel and all other refinery products. The result is the energy required to refine a barrel of each product group.

To estimate the impact of each crude oil on total refinery energy consumption, first the regional models were calibrated and baseline values established. Next, the region's composite crude slate was reduced by 100 K bbl/day and replaced with 100 K bbl/day of the analysis crude oil. The value for total refinery energy use returned by the model was compared to the baseline value. The difference (higher or lower) is entirely attributable to the analysis crude oil. A model run was performed for each crude/region combination to determine total energy required (by fuel type) to refine a barrel of the analysis crude oil.

[59] This includes the Tier 2 National Gasoline sulfur standard, MSAT2, ULSD Standard, CARB3, RFS2)

4.2 Modeling Results

The results of the allocation modeling exercise (U.S. Average) are presented in Figure 4-3. The results are in terms of energy per volume of each product produced. As can be seen, gasoline is the most energy intensive product. Producing the gasoline volumes demanded in the United States (relative to other products) combined with stringent requirements requires extensive conversion and upgrading of heavy crude fractions to gasoline. The next most energy intensive product is jet fuel. The diesel fuel energy allocation is approximately a third of the energy required to produce gasoline. The energy requirements for diesel are low because the volumes are low relative to gasoline. Most of the diesel produced is a by-product of the conversion processes producing gasoline.

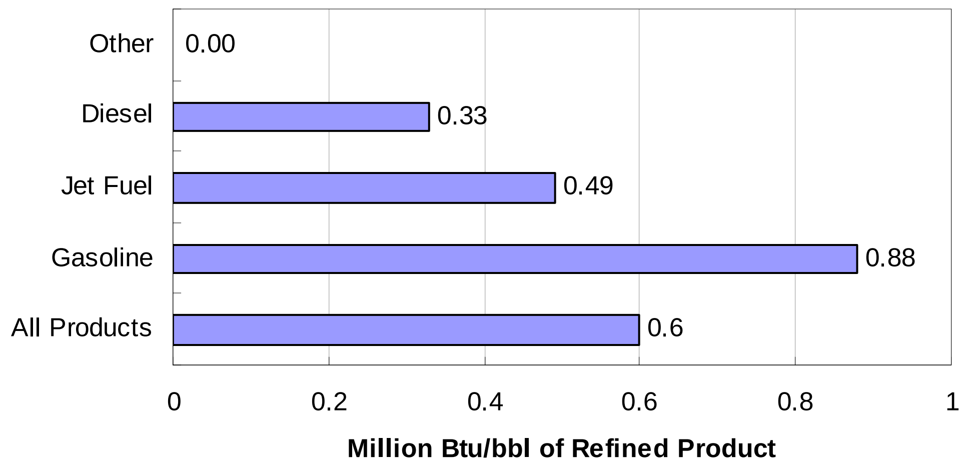


Figure 4-3. Allocation of Refinery Energy Use to Refined Products (U.S. Average)

The results for the refinery energy use by crude/region combination exercise are presented in Figures 4-4 through 4-6. From the plots we see:

- Refinery energy use in PADD 3 and California is higher than in PADD 2 mainly because the crude slates in PADD 3 and California have higher proportions of heavy sour crude oils.
- Refinery energy use for light sweet crude oils is approximately 2/3 of the energy used by the heavier crude oils.
- For a given crude oil, refinery energy varies by region. These differences reflect the impact of regional crude slate and refinery equipment
- Refinery energy use for synbit and dilbit is comparable to the conventional heavy sour crude oils.
- The refinery energy for SCO is significantly lower than the other crude oils.

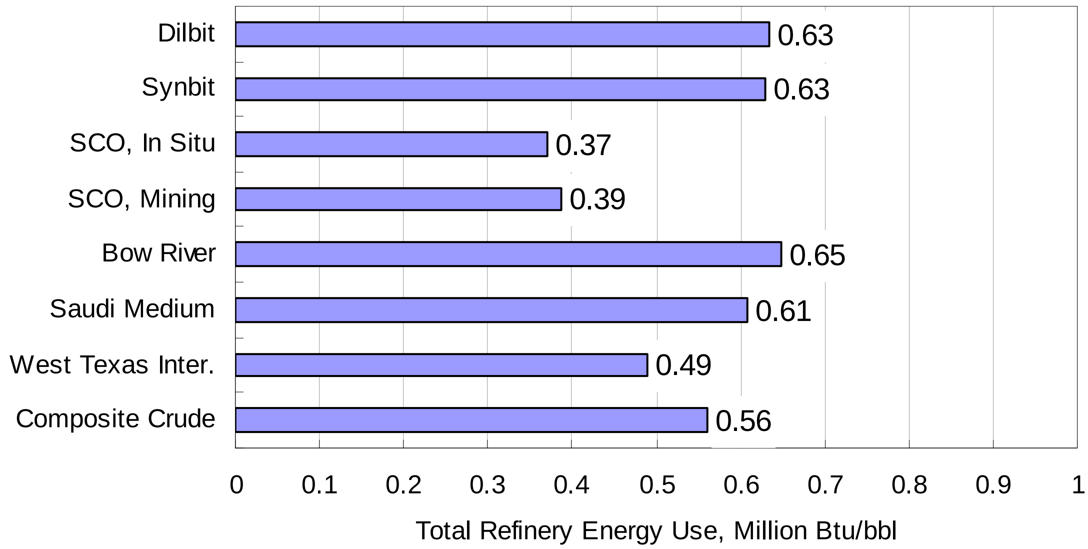


Figure 4-4. Estimated Refinery Energy Use by Crude Oil, PADD 2

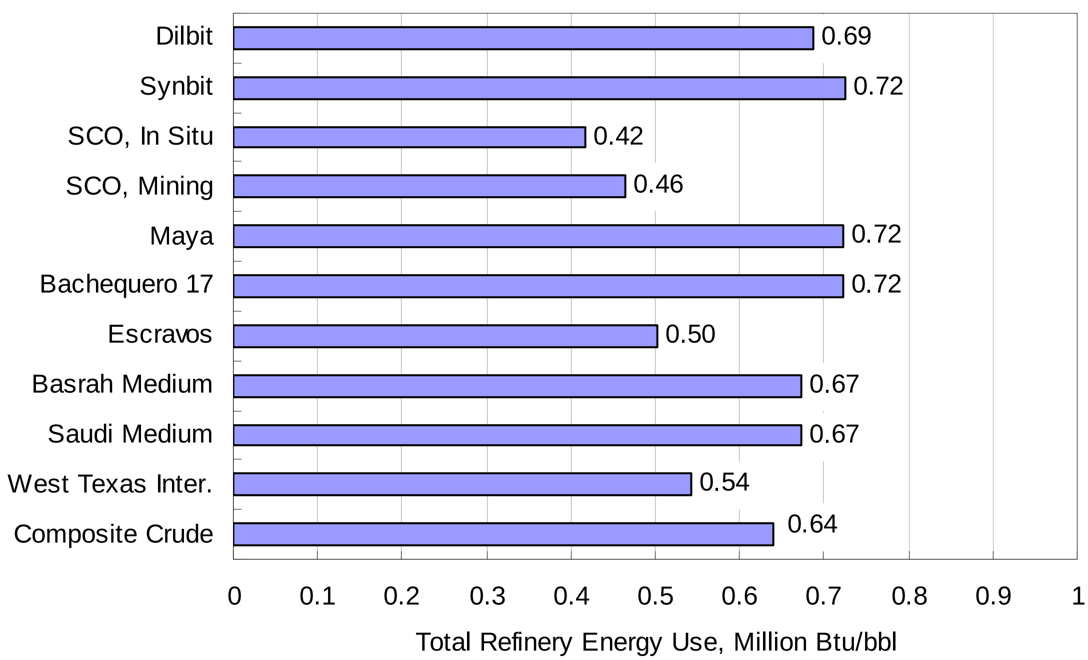


Figure 4-5. Estimated Refinery Energy Use by Crude Oil, PADD 3

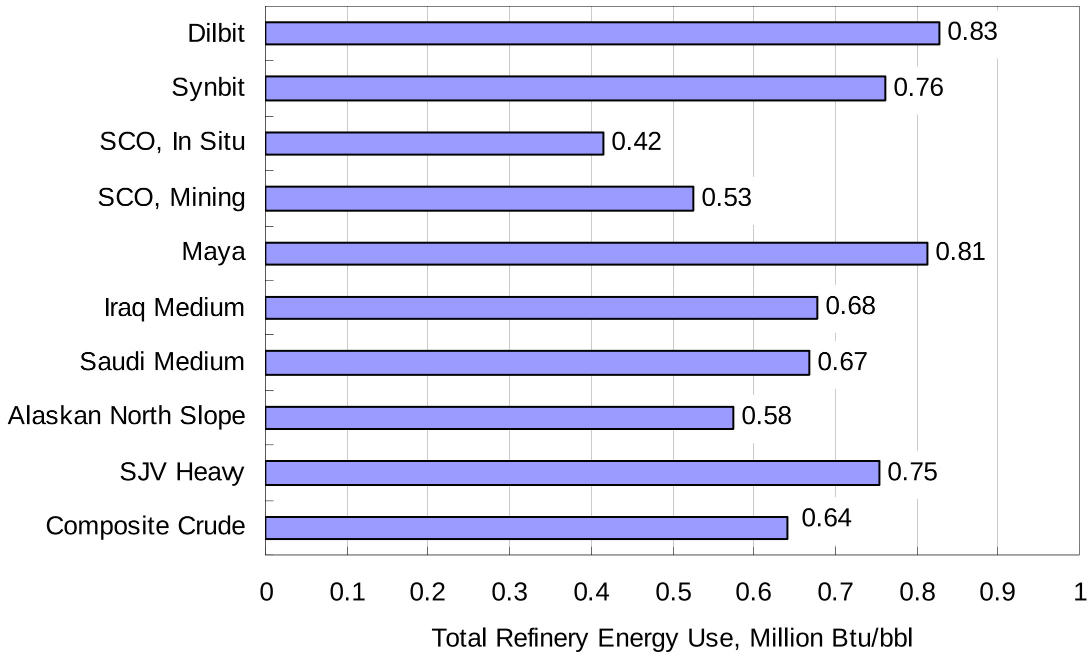


Figure 4-6. Estimated Refinery Energy Use by Crude Oil, California

Finally, Tables 4-2 through 4-4 provide the total energy use by process fuel type for each of the crude/region combinations considered.

Table 4-2. Estimated Fuel Use by Crude Oil and Fuel Type, PADD 2

Fuel	Units	Reference Case	West Texas Int.	Saudi Medium	Bow River	SCO Mining	SCO SAGD	Synbit	Dilbit
Pipeline Natural Gas	foeb/bbl	0.023	0.024	0.031	0.026	0.009	0.013	0.024	0.030
Refinery Still Gas	foeb/bbl	0.038	0.034	0.045	0.037	0.013	0.020	0.035	0.043
Catalyst Coke	bbl/bbl	0.013	0.008	0.004	0.020	0.028	0.016	0.024	0.009
Purchased Electricity	K kwh/ bbl	0.009	0.007	0.010	0.012	0.008	0.006	0.011	0.011

foeb is fuel oil equivalent barrels, 6.3 million Btu/foeb

Table 4-3. Estimated Fuel Use by Crude Oil and Fuel Type, PADD 3

Fuel	Units	Reference Case	West Texas Int.	Saudi Medium	Iraq Medium	Nigeria	Mexico	Venezuela	SCO Mining	SCO SAGD	Synbit	Dilbit
Pipeline NG	foeb/ bbl	0.028	0.024	0.029	0.029	0.019	0.025	0.031	0.010	0.014	0.025	0.028
Refinery Still Gas	foeb/ bbl	0.041	0.035	0.042	0.042	0.027	0.037	0.045	0.015	0.020	0.037	0.041
Catalyst Coke	bbl/ bbl	0.016	0.013	0.017	0.017	0.022	0.032	0.018	0.037	0.022	0.033	0.023
Purchased Electricity	K kwh/ bbl	0.008	0.006	0.008	0.008	0.005	0.010	0.010	0.006	0.005	0.009	0.008

foeb is fuel oil equivalent barrels, 6.3 million Btu/foeb

Table 4-4. Estimated Fuel Use by Crude Oil and Fuel Type, California

Fuel	Units	Reference Case	California Heavy	Alaska	Saudi Medium	Iraq Medium	Mexico	SCO Mining	SCO SAGD	Synbit	Dilbit
Pipeline NG	foeb/ bbl	0.018	0.019	0.016	0.019	0.019	0.025	0.011	0.011	0.021	0.024
Refinery Still Gas	foeb/ bbl	0.053	0.055	0.047	0.054	0.056	0.072	0.033	0.032	0.060	0.068
Catalyst Coke	bbl/bbl	0.016	0.030	0.015	0.016	0.016	0.012	0.028	0.012	0.024	0.020
Purchased Electricity	K kwh/ bbl	0.005	0.005	0.004	0.005	0.005	0.006	0.004	0.003	0.005	0.006

5. GREET Integration

Once the energy balances are established for each pathway considered, the pathways need to be recast in GREET terms. The GREET model quantifies energy consumption and emissions associated with production of transportation fuels. For petroleum products, the modeling is broken down into four distinct parts:

- Crude/Bitumen Recovery (and upgrading if applicable)
- Crude/Bitumen Transportation to Refinery
- Refining into Finished Fuels
- Finished Fuel Transport and Distribution

For the crude recovery and refining portions, the emissions are calculated according to Figure 5-1. Total direct fuel consumption is calculated from a user specified process efficiency value. From here, the process fuel is divided by fuel type and equipment type. To estimate direct emissions (g/MMBtu product), the fuel consumption is multiplied by the appropriate fuel/equipment emission factors. We have used only GREET default emission factors.

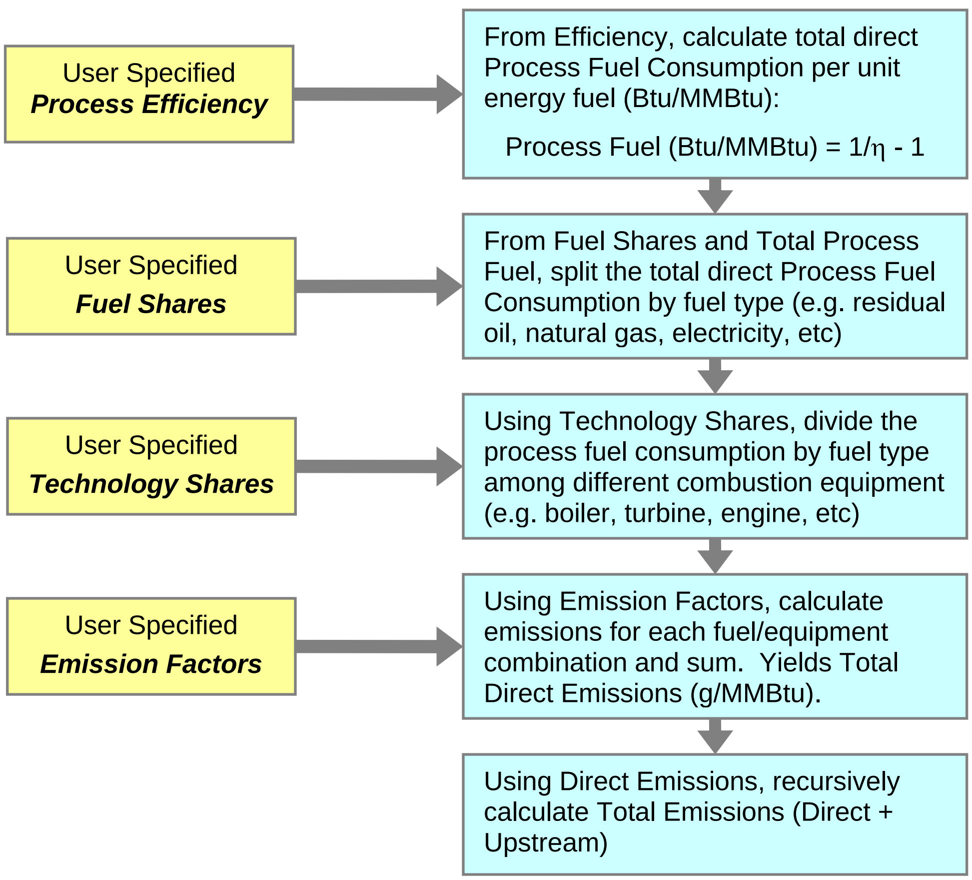


Figure 5-1. GREET Emission Calculation Methodology.

The transportation pieces are straightforward: the distance traveled by each transportation mode (cargo ship, rail, barge, truck) are determined. In all cases, we have used GREET default values for transport energy consumed per ton-mile traveled. The amount of energy consumed in each transport mode is combined with fuel/equipment appropriate emission factors to determine emissions per unit fuel transported.

For each segment in the fuel production pathway, once the direct fuel consumption and emissions are calculated, recursive formulas are employed to add in the upstream energy and emissions associated with recovery, refining, and transporting the fuels being directly utilized.

The objective of this task is to recast the energy flows presented in Section 3 above in GREET efficiency terms so that the model will correctly calculate the process fuel use values that are subsequently utilized to calculate GHG emissions. In the GREET model, the efficiency is defined as the total amount of energy in divided by total energy outputs:

$$GREET\_Efficiency \equiv \frac{Total\_Outputs}{Total\_Inputs}$$

GREET uses the specified efficiency to calculate total process fuel consumption per MMBtu of fuel produced:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1$$

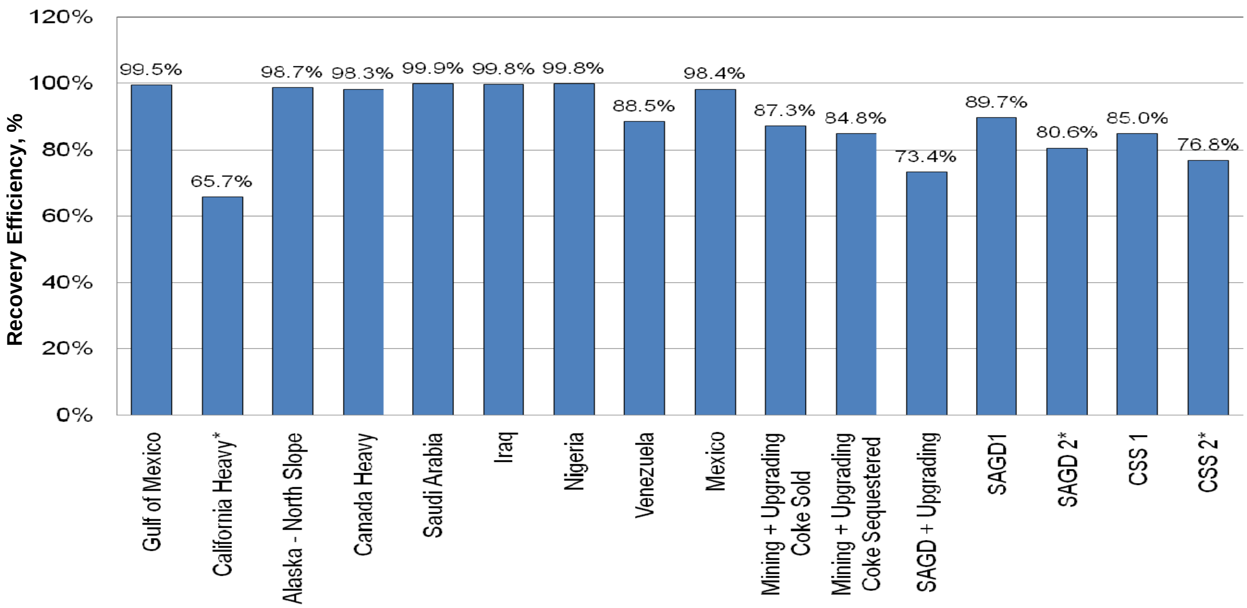
Because our data gathering exercise yielded the amount of each process fuel utilized per amount of crude/bitumen/SCO produced, we use the process fuel to back calculate GREET efficiency. This is the value input into the GREET model to ensure that the process fuel consumption values used in the emission calculations are consistent with the values shown in Sections 3 and 4 of this report. Therefore, the efficiency is calculated from process fuel consumption and energy output as follows:

$$\eta = \frac{Energy\_Output}{Process\_Fuel + Energy\_Output}$$

The following sections provide: the recovery efficiencies and process fuel shares; refining efficiencies and process fuel shares; philosophy on treatment of byproduct coke, transportation modes and distances, and electricity grid mixes for recovery and refining electricity consumption. This information comprises the inputs/modifications made to the GREET model to estimate GHG emissions for each of the analysis crude pathways.

5.1 GREET Inputs for Crude/Bitumen Recovery

The first step in the GREET calculation is resource recovery. Figure 5-2 presents the GREET recovery efficiencies for each of the pathways considered. Table 5-1 provides the efficiencies and process fuel shares for each crude pathway.



*Pathway receives a credit for electricity export not reflected in efficiency value

Figure 5-2. GREET Efficiency for each Crude/Bitumen Recovery Pathway Considered.

Table 5-1. GREET Efficiency and Process Fuel Shares for each Pathway Considered

Pathway	Product	Recovery Efficiency	Electricity Credit	Process Fuel Shares					
			Btu/MMBtu	Produced Gas	Pipeline Gas	Grid Electr.	Upgrader Gas	Syngas	Diesel
CA Kern County	Heavy Crude	63.4%	195,089	0%	100%	0%	0%	0%	0%
Alaska	Medium Crude	98.8%	0	100%	0%	0%	0%	0%	0%
US Gulf Coast	Medium Crude	99.7%	0	100%	0%	0%	0%	0%	0%
Saudi	Medium Crude	99.9%	0	94%	0%	6%	0%	0%	0%
Mexico	Heavy Crude	98.4%	0	5%	95%	1%	0%	0%	0%
Venezuela	Heavy Crude	87.9%	0	65%	35%	0%	0%	0%	0%
Nigeria	Light Crude	99.8%	0	90%	0%	10%	0%	0%	0%
Iraq	Medium Crude	99.8%	0	94%	0%	6%	0%	0%	0%
Canada	Heavy Crude	98.2%	0	100%	0%	0%	0%	0%	0%
Mining+Upgrading Coke Sold	SCO + Coke	87.3%	0	0%	37%	2%	56%	0%	5%
Mining+Upgrading Sequester Coke	SCO	84.8%	0	0%	37%	2%	56%	0%	5%
SAGD + Upgrading	SCO	73.4%	0	2%	27%	0%	13%	58%	0%
SAGD 1	Bitumen	91.5%	0	20%	75%	5%	0%	0%	0%
SAGD 2	Bitumen	80.6%	49,327	0%	98%	2%	0%	0%	0%
CSS 1	Bitumen	85.0%	0	13%	83%	4%	0%	0%	0%
CSS 2	Bitumen	76.8%	5,291	10%	90%	0%	0%	0%	0%

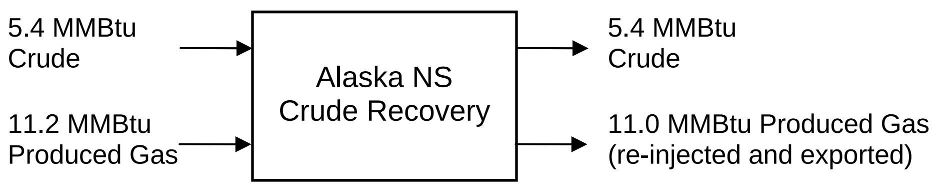
Note: The electricity credit is not included in the efficiency value

For this analysis we have added three process fuels to the GREET model: produced gas, upgrader gas, and syngas. For produced gas, we could have substituted pipeline natural gas, but pipeline natural gas has upstream emissions (recovery, processing, transmission and distribution) that are not appropriate for oil field produced gas. For the pathways with onsite bitumen upgrading, upgrader process gas is burned; this composition is sufficiently different from natural gas to warrant a separate upgrader process gas fuel. For the SAGD-Upgrading case, the syngas produced from coke gasification (less most of the hydrogen) is burned.

The following paragraphs step through the efficiency calculation for each of the crude/bitumen recovery pathways considered.

Alaska North Slope

As described in Section 3, the only process fuel consumed in Alaska North Slope crude recovery is produced gas. The produced gas is used to generate electricity in a simple cycle turbine. The diagram below illustrates the energy flows used to calculate GREET efficiency.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.4+11}{0.2+5.4+11} = 98.8\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9876} - 1 = 0.012536 Btu / Btu = 12{,}536 Btu / MMBtu$$

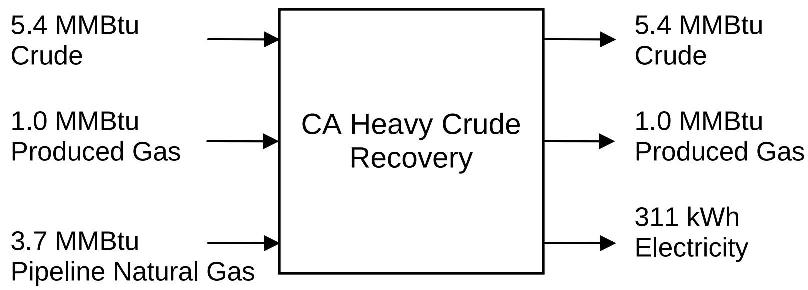
Check:

0.206 mmBtu produced gas used to generate electricity. Total energy out is 16.446 MMBtu.

Process Fuel = 0.206*1,000,000 / 16.446 = 12,536 Btu/MMBtu

California Kern County Heavy

As discussed in Section 3, steam drive is utilized to recover Kern County heavy crude. A turbine with a heat recovery steam generator (HRSG) is utilized to generate electricity and injection steam. Excess electricity is exported to the grid. Only pipeline natural gas is consumed in the turbine/HRSG; no produced gas is combusted onsite. The diagram below illustrates the energy flows used to calculate GREET efficiency.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.4+1}{3.7+5.4+1} = 63.4\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.634} - 1 = 0.5774 Btu / Btu = 577{,}391 Btu / MMBtu$$

Check:

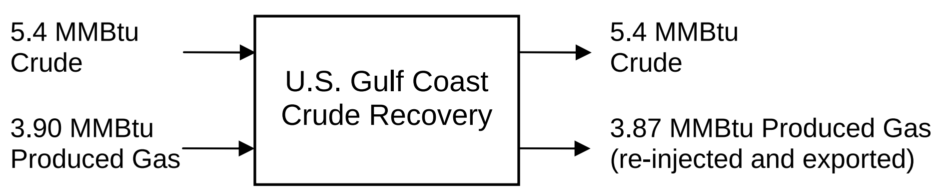
3.714 mmBtu pipeline gas used to generate electricity/steam. Total energy out is 6.432 MMBtu.

Process Fuel = 3.714*1,000,000 / 6.432 = 577,391 Btu/MMBtu

Note that this pathway also receives an emissions credit for exporting 311 kWh electricity per bbl of oil produced. The emissions credit is equal to 311 kWh/bbl of marginal electricity production which is assumed to be natural gas combined cycle generators.

U.S. Gulf Coast

The U.S. Gulf Coast recovery efficiency calculation is similar to the Alaska calculation. The only process fuel consumed in U.S. Gulf Coast crude recovery is produced gas. The produced gas is used to generate electricity in a simple cycle turbine. The diagram below illustrates the energy flows used to calculate GREET efficiency.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.45 + 3.87}{0.03 + 5.45 + 3.87} = 99.7\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9973} - 1 = 0.002725 Btu / Btu = 2{,}725 Btu / MMBtu$$

Check:

0.025 mmBtu produced gas used to generate electricity. Total energy out is 9.319 MMBtu.

Process Fuel = 0.025*1,000,000 / 9.319 = 2,725 Btu/MMBtu

Canada Bow River

The Canada heavy crude recovery efficiency calculation is similar to the Alaska calculation. The only process fuel consumed in Canadian crude recovery is produced gas. The produced gas is used to generate electricity in a simple cycle turbine. The diagram below illustrates the energy flows used to calculate GREET efficiency.

$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.45 + 1.7}{0.13 + 5.45 + 1.7} = 98.2\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9821} - 1 = 0.018179 Btu / Btu = 18{,}179 Btu / MMBtu$$

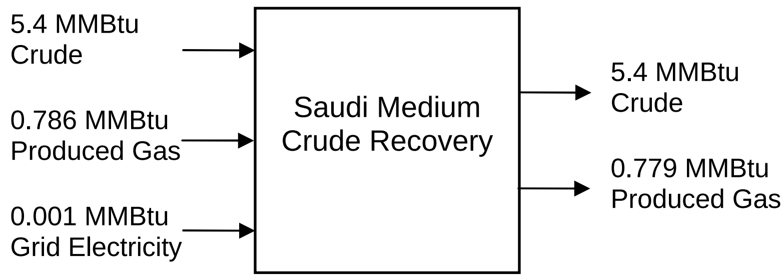
Check:

0.130 mmBtu produced gas used to generate electricity. Total energy out is 7.145 MMBtu.

Process Fuel = 0.130*1,000,000 / 7.145 = 18,179 Btu/MMBtu

Saudi Arabia Medium

The Saudi medium crude recovery efficiency calculation is similar to the Alaska calculation except that a small amount of its electricity needs come from the grid. Some of the produced gas is used to generate electricity in a simple cycle turbine. The diagram below illustrates the energy flows used to calculate GREET efficiency.



$$\eta \equiv \frac{Energy\_Output}{Process\_Fuel + Energy\_Output} = \frac{5.45 + 0.779}{0.007 + 0.001 + 5.45 + 0.779} = 99.87\%$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9987} - 1 = 0.001291 Btu / Btu = 1{,}291 Btu / MMBtu$$

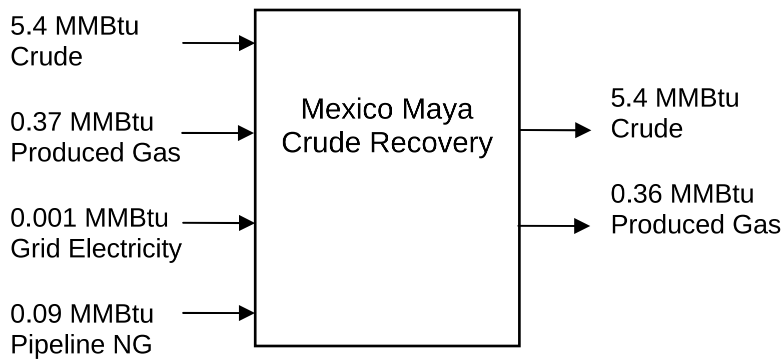
Check:

0.008 mmBtu produced gas and electricity consumed. Total energy out is 6.225 MMBtu.

Process Fuel = 0.008*1,000,000 / 6.225 = 1,291 Btu/MMBtu

Mexico Maya

For the Mexican Maya crude, pipeline natural gas is consumed to generate electricity for the nitrogen plant. A portion of the produced gas is used in simple cycle turbines to generate electricity on site, with the balance exported. Approximately 1/3 of the electricity consumed onsite is grid electricity.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.446 + 0.361}{0.095 + 5.446 + 0.361} = 98.39\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9839} - 1 = 0.016397\,Btu/Btu = 16{,}397\,Btu/MMBtu$$

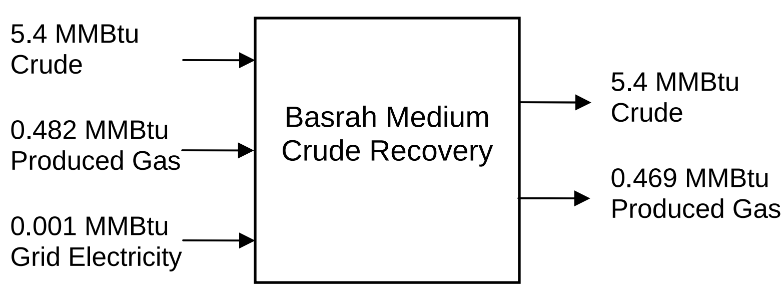
Check:

0.0952 MMBtu produced gas, pipeline gas and electricity consumed. Total energy out is 5.807 MMBtu.

Process Fuel = 0.0952*1,000,000 / 5.807 = 16,397 Btu/MMBtu

Iraq Basrah Medium

The Iraq Basrah medium crude recovery efficiency calculation is similar to the Saudi Medium calculation. Some of the electricity used is generated onsite in simple cycle turbines using produced gas; the balance comes from the grid. The diagram below illustrates the energy flows used to calculate GREET efficiency.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.446 + 0.469}{0.014 + 5.446 + 0.469} = 99.76\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9976} - 1 = 0.002379\, Btu / Btu = 2{,}379\, Btu / MMBtu$$

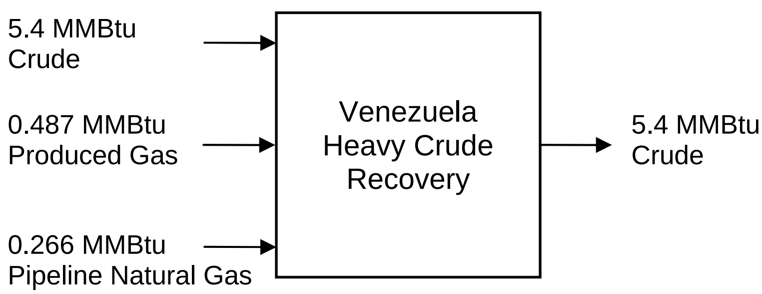
Check:

0.0141 mmBtu produced gas and electricity consumed. Total energy out is 5.915 MMBtu.

Process Fuel = 0.0141*1,000,000 / 5.915 = 2,379 Btu/MMBtu

Venezuela Bachaquero

For Bachaquero crude, cyclic steam injection is utilized. All of the produced gas and some pipeline gas are consumed in a boiler to generate steam. Additional pipeline natural gas is consumed to generate electricity with a simple cycle turbine.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.446}{0.266 + 0.487 + 5.446} = 87.86\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.8786} - 1 = 0.138228\, Btu / Btu = 138{,}228\, Btu / MMBtu$$

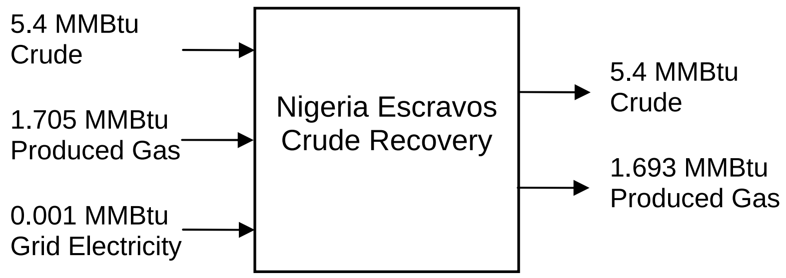
Check:

0.7528 MMBtu pipeline and produced gas used to generate electricity/steam. Total energy out is 5.446 MMBtu.

Process Fuel = 0.7528*1,000,000 / 5.446 = 138,228 Btu/MMBtu

Nigeria Escravos

The Nigerian crude recovery efficiency calculation is similar to the Saudi Medium calculation. Some of the electricity used is generated onsite in simple cycle turbines using produced gas; the balance comes from the grid. The diagram below illustrates the energy flows used to calculate GREET efficiency.



$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5.446 + 1.693}{0.012 + 0.001 + 5.446 + 1.693} = 99.82\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.9982} - 1 = 0.001756 Btu / Btu = 1{,}756 Btu / MMBtu$$

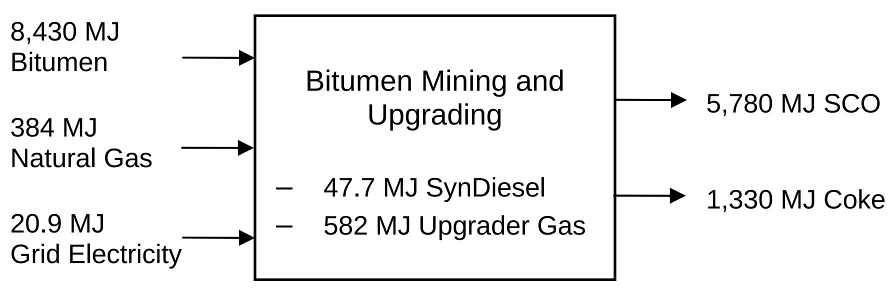
Check:

0.0125 mmBtu produced gas and electricity consumed. Total energy out is 7.139 MMBtu.

Process Fuel = 0.0125*1,000,000 / 7.139 = 1,756 Btu/MMBtu

Bitumen Mining and Upgrading

The diagram below illustrates the energy flows used to calculate GREET efficiency for the Mining and Upgrading pathway. Recall that the process fuels consumed are pipeline natural gas, grid electricity, upgrader process gas, and synthetic diesel produced in the upgrading process.



There are two different ways to account for the coke produced. In the first method, we assume that coke is a marketable product and it is ultimately sold. It is therefore appropriate to allocate some of the recovery energy to the coke. To allocate based on energy value, then the coke must be included in the "energy output" value:

$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5780+1330}{384+20.9+47.7+582+5780+1330} = 87.3\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.87297} - 1 = 0.145513 Btu/Btu = 145{,}513 Btu/MMBtu$$

Check:

1034.6 MJ process fuel consumed. Total energy out is 7110 MJ.

Process Fuel = 1034.6*1,000,000 / 7110 = 145,513 Btu/MMBtu

If the coke is subsequently burned in a utility boiler, it's share of the recovery emissions plus the emissions to transport the coke to the power plant and the boiler emissions would result. However, these would be offset by the emissions associated with coal mining, transport and combustion. It could also be argued that the coke fired boiler emissions would be offset by natural gas fired combustion turbine emissions, a net disbenefit. We do not consider these secondary effects in this analysis. Once we have allocated recovery energy to the coke, we do not consider it further.

The other way to consider the coke is to assume that it is "sequestered". If the coke is never sold as a product, it can not be considered in the "energy output" value and efficiency with sequestered coke is:

$$\eta \equiv \frac{Energy\_Output}{\Pr ocess\_Fuel + Energy\_Output} = \frac{5780}{384+20.9+47.7+582+5780} = 84.8\%$$

$$\frac{\Pr ocess\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.8482} - 1 = 0.179 Btu/Btu = 179{,}000 Btu/MMBtu$$

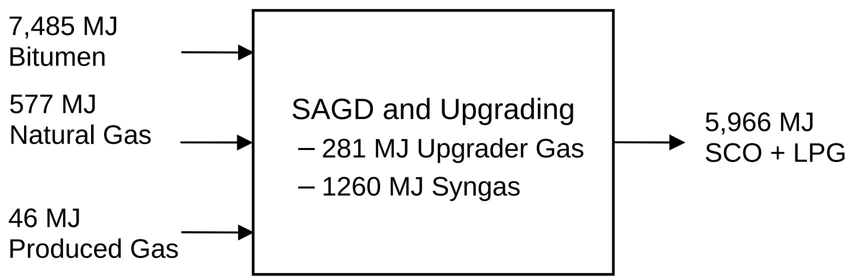
Check:

1034.6 MJ process fuel consumed. Total energy out is 5780 MJ.

Process Fuel = 1034.6*1,000,000 / 5780 = 179,000 Btu/MMBtu

SAGD and Upgrading

The diagram below illustrates the energy flows used to calculate GREET efficiency. In this pathway, the coke produced in the upgrading process is gasified to make hydrogen and syngas which is used to generate steam. The process fuels consumed are pipeline natural gas, produced gas, syngas, upgrader process gas. The most recent energy balance provided by Nexen indicates reduced pipeline natural gas consumption and no electricity exports. Because the output is SCO and a very small amount of LPG consolidated into one value, the resulting efficiency is for total outputs. In this analysis, we allocate the recovery energy between the SCO and LPG on an energy basis, so the resulting efficiency is applicable to SCO alone (or LPG alone).



$$\eta \equiv \frac{Energy\_Output}{Process\_Fuel + Energy\_Output} = \frac{5966}{577+46+281+1260+5966} = 73.4\%$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.7338} - 1 = 0.362\,Btu/Btu = 362{,}700\,Btu/MMBtu$$

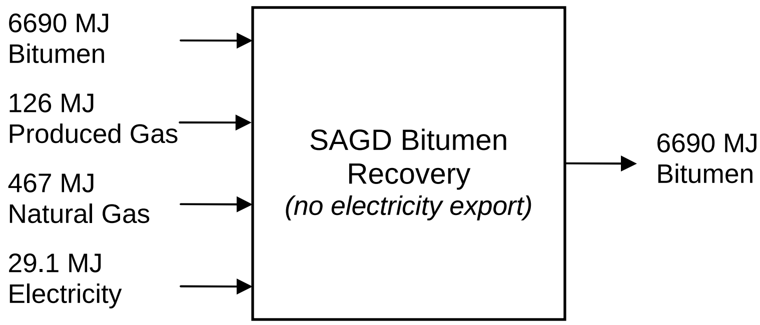
Check:

2164 MJ process fuel consumed. Total energy out is 5966 MJ.

Process Fuel = 2164*1,000,000 / 5966 = 362,700 Btu/MMBtu

SAGD Bitumen Recovery

Two different SAGD bitumen recovery projects were considered: Christina Lake and MacKay River. Christina Lake has lower pipeline natural gas consumption and no exported electricity. The MacKay River project has higher natural gas consumption and electricity exports. The diagram below illustrates the energy flows used to calculate GREET efficiency for the Christina Lake project which does not export electricity. When modeling exported electricity in GREET, we specify an efficiency that reflects the correct amount of process fuels consumed. Therefore, we do not include electricity in the efficiency calculation since it would improve the efficiency and reduce the amount of process fuels below what is actually consumed. Instead of including the exported electricity in the efficiency calculation, we apply a credit equal to the amount of electricity exported. For exported electricity, we assume that the displaced electricity is marginal supply (natural gas combined cycle turbines).



$$\eta \equiv \frac{Energy\_Output}{Process\_Fuel + Energy\_Output} = \frac{6690}{126+467+29+6690} = 91.5\%$$

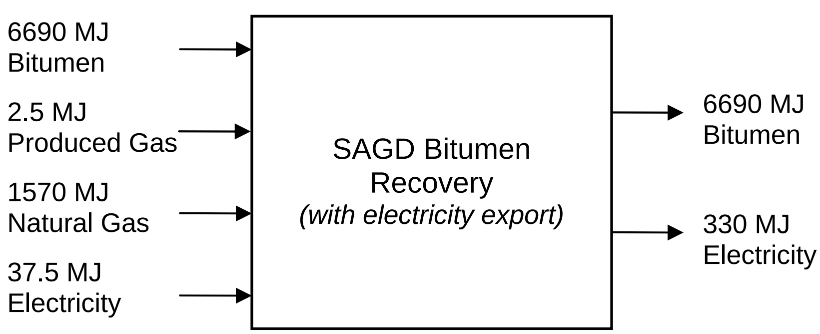
$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.915} - 1 = 0.0929\, Btu/Btu = 92{,}900\, Btu/MMBtu$$

Check:

622 MJ process fuel consumed. Total energy out is 6690 MJ.

Process Fuel = 622*1,000,000 / 6690 = 92,900 Btu/MMBtu

The diagram below illustrates the energy flows used to calculate GREET efficiency for the MacKay River project which cogenerates steam and electricity. Excess electricity is exported to the grid (but not included in the efficiency calculation).



$$\eta \equiv \frac{Energy\_Output}{Process\_Fuel + Energy\_Output} = \frac{6690}{2+1570+38+6690} = 80.6\%$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.806} - 1 = 0.2407\, Btu/Btu = 240{,}700\, Btu/MMBtu$$

Check:

1610 MJ process fuel consumed. Total energy out is 6690 MJ.

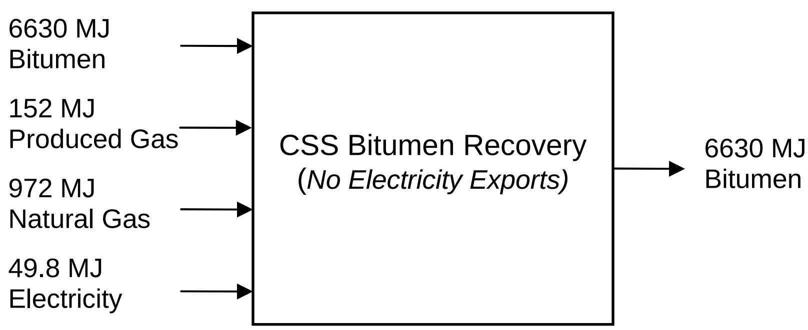
Process Fuel = 1610*1,000,000 / 6690 = 240,700 Btu/MMBtu

The value of the electricity credit is:

Electricity Credit = 330 / 6690 * 1,000,000 = 49,327 Btu/MMBtu

CSS Bitumen Recovery

The final pathways are bitumen recovery using cyclic steam stimulation. One of the pathways (Cold Lake) generates only enough electricity for use in recovery while the other pathway (Primrose)consumes more natural gas and exports electricity to the grid. It is important to note that the Primrose project also has a higher steam oil ratio than Cold Lake, resulting in higher natural gas consumption for steam generation. The diagram below illustrates the energy flows used to calculate GREET efficiency for the Cold Lake project.



$$\eta \equiv \frac{Energy\_Output}{Process\_Fuel + Energy\_Output} = \frac{6630}{152 + 972 + 50 + 6630} = 85.0\%$$

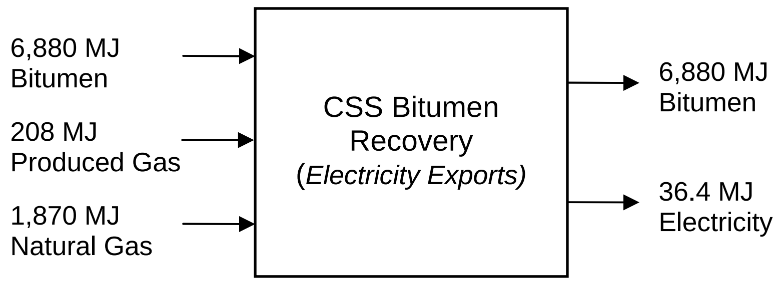
$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.8496} - 1 = 0.2407\,Btu/Btu = 177{,}000\,Btu/MMBtu$$

Check:

1174 MJ process fuel consumed. Total energy out is 6630 MJ.

Process Fuel = 1174*1,000,000 / 6630 = 177,000 Btu/MMBtu

The diagram below illustrates the energy flows used to calculate GREET efficiency for the Primrose project which cogenerates steam and electricity. Excess electricity is exported.



$$\eta \equiv \frac{Energy\_Output}{Process\_Fuel + Energy\_Output} = \frac{6880}{1870 + 208 + 6880} = 76.8\%$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.768} - 1 = 0.302\, Btu / Btu = 302{,}000\, Btu / MMBtu$$

Check:

2078 MJ process fuel consumed. Total energy out is 6880 MJ.

Process Fuel = 2078*1,000,000 / 6880 = 302,000 Btu/MMBtu

The value of the electricity credit is:

Electricity Credit = 36.4 / 6880 * 1,000,000 = 5,291 Btu/MMBtu

5.2 GREET Inputs for Refining

Based on MathPro's estimate of the overall energy use in refining per barrel of crude and the allocation of this energy among refined products, values for GREET refining efficiency and process fuel shares were estimated. Specifically, values for the GREET efficiency for gasoline and diesel refining and fuel allocations in the refinery between fuel gas, still gas, catalyst coke, electricity and hydrogen were determined for each crude/PADD combination considered.

We proportionately allocates the process energy for each case between gasoline blendstock and diesel using the process energy for each of the refined products from the US Average model run, the quantity of crude and refined products for each specific model run, and total refinery process energy consumed for each crude oil pathway. The results for the U.S. Average and Regional Reference Cases are provided in Table 5-2. Figures 5-3 through 5-5 present the GREET refinery efficiencies for each crude/PADD combination. Tables 5-3 through 5-5 provide the results for PADD 2, PADD 3, and California for each crude oil. In addition to the GREET inputs (efficiency and fuel shares), the tables also provides the percentage of process energy allocated between refined products. Please refer to Appendix E for the detailed calculations.

Table 5-2. GREET Refinery Inputs for US Average and Regional Reference Cases

		US Average	PADD 2	PADD 3	California	GREET Default
GREET Efficiency	Gasoline	86.3%	87.3%	85.6%	85.8%	87.2%
	Diesel	92.5%	92.7%	92.0%	90.4%	89.3%
Process Energy (Btu/MMBtu)	Gasoline	158,480	146,087	167,947	165,405	146,789
	Diesel	81,590	78,247	86,574	105,750	119,821
Gasoline Blendstock Fuel Shares	Natural Gas	22.7%	25.0%	26.5%	15.6%	30.0%
	Still Gas	39.8%	40.3%	38.5%	44.7%	50.0%
	Coke	22.6%	19.8%	23.8%	18.3%	13.0%
	Electricity	8.1%	8.0%	5.8%	2.8%	4.0%
	Hydrogen	6.9%	6.9%	5.5%	18.6%	0.0%
Diesel Fuel Shares	Natural Gas	30.4%	32.3%	35.4%	16.8%	30.0%
	Still Gas	53.4%	52.0%	51.6%	48.3%	50.0%
	Coke	0.0%	0.0%	0.0%	0.0%	13.0%
	Electricity	0.2%	0.2%	0.2%	0.1%	4.0%
	Hydrogen	15.9%	15.5%	12.8%	34.8%	0.0%
% Process Energy	Gasoline	66.7%	69.4%	64.8%	64.4%	60.0%
	Jet Fuel	9.5%	5.7%	10.3%	15.8%	-
	Diesel	23.1%	24.2%	24.2%	19.3%	25.0%
	Other	0.7%	0.8%	0.7%	0.4%	15.0%

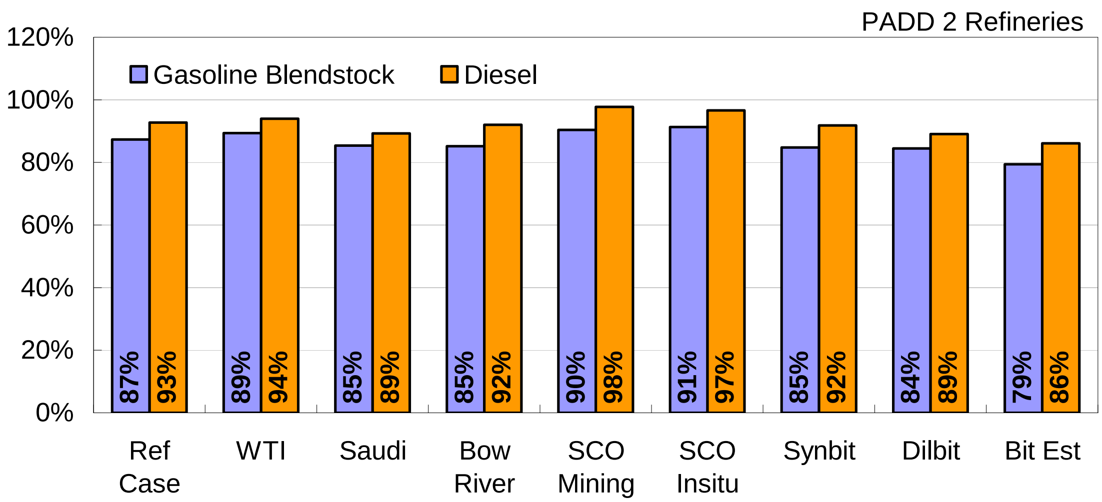


Figure 5-3. GREET Refinery Efficiency for PADD 2

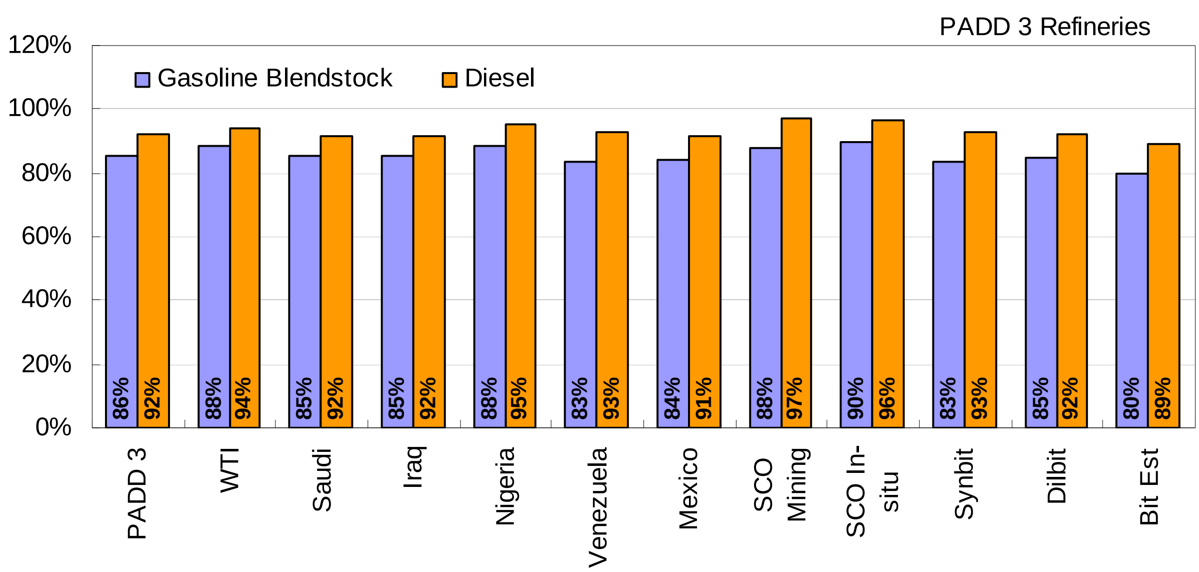


Figure 5-4. GREET Refinery Efficiency for PADD 3

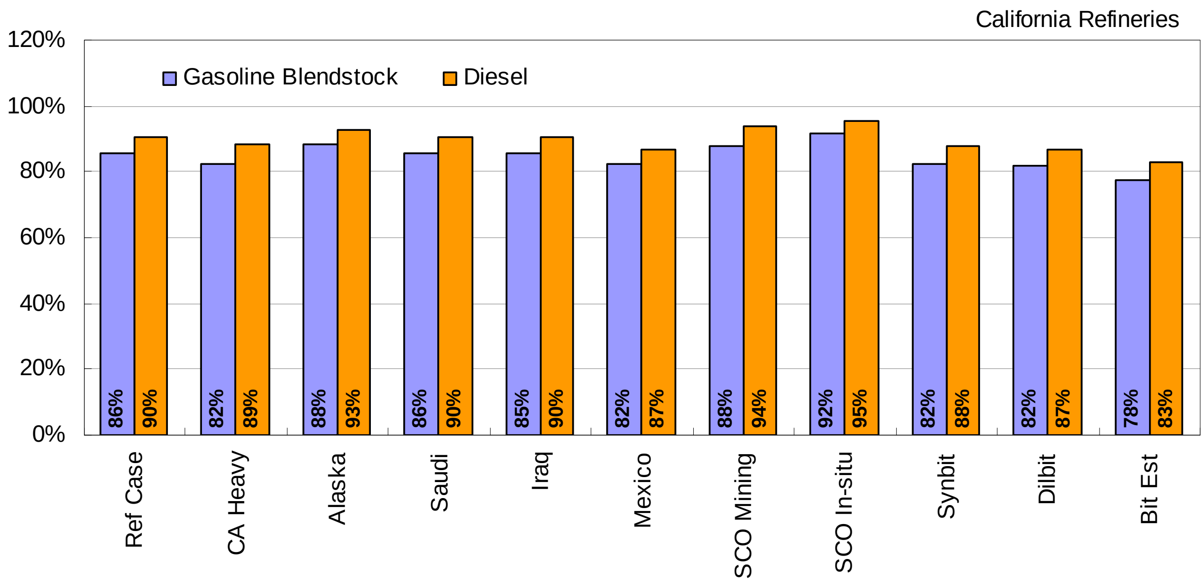


Figure 5-5. GREET Refinery Efficiency for California Refineries.

One interesting result of our analysis is that the U.S. Average refinery efficiency value for RFG Blendstock (86.3%) is slightly lower than the GREET default value (87.2%). In contrast, our estimate for diesel refinery efficiency (92.5%) is significantly higher than the GREET default value (89.3%). This is a result of differences between our energy allocation approach and the GREET allocation method. Section 4 describes how MathPro divided/allocated refinery process fuel consumption among the refinery products. The resulting percentages for each regional model are indicated in Table 5-2. The GREET allocation methodology is a rule of thumb in which 60% of the energy is allocated to gasoline and 25% is allocated to diesel.

For the U.S. Average case, MathPro estimates that 67% (Table 5-2) of the total process fuel use is attributed to gasoline production; this is more than the GREET estimate, resulting in a lower refining efficiency. For diesel, the MathPro estimate is lower than the GREET estimate, resulting in a higher refining efficiency. Since the process energy for diesel is normalized to a much smaller product volume than in the gasoline case, the percentage difference in diesel allocation has a larger impact on refinery efficiency for diesel than gasoline.

Table 5-3. GREET Refinery Inputs for PADD 2

		Ref Case	WTI	Saudi Arabia	Bow River	SCO Mining	SCO Insitu	Synbit	Dilbit	Bitumen Est[1]
GREET Efficiency	Gasoline	87.3%	89.3%	85.3%	85.1%	90.4%	91.3%	84.7%	84.4%	79.4%
	Diesel	92.7%	93.9%	89.2%	92.0%	97.7%	96.6%	91.7%	89.1%	86.1%
Process Energy (Btu/MMBtu)	Gasoline	146,087	119,661	171,983	174,851	106,533	95,158	180,812	184,825	259,036
	Diesel	78,247	64,927	121,247	86,753	23,440	35,700	90,012	122,641	161,312
Gasoline Blendstock Fuel Shares	NG	25.0%	30.7%	28.0%	22.8%	12.9%	22.0%	20.7%	25.2%	23.6%
	Still	40.3%	44.7%	40.7%	33.2%	18.7%	32.0%	30.1%	36.7%	34.3%
	Coke	19.8%	15.5%	4.6%	26.3%	59.4%	37.8%	29.5%	11.1%	16.7%
	Elec	8.0%	7.5%	7.6%	8.7%	9.0%	8.2%	7.6%	7.5%	6.9%
	H2	6.9%	1.7%	19.1%	8.9%	0.0%	0.0%	12.1%	19.5%	18.4%
Diesel Fuel Shares	NG	32.3%	39.1%	27.4%	31.9%	40.5%	40.6%	28.7%	26.3%	26.2%
	Still	52.0%	56.9%	39.9%	46.4%	58.9%	59.1%	41.8%	38.3%	38.1%
	Coke	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Elec	0.2%	0.2%	0.2%	0.3%	0.6%	0.3%	0.2%	0.2%	0.2%
	H2	15.5%	3.7%	32.5%	21.5%	0.0%	0.0%	29.2%	35.2%	35.5%
% Process Energy	Gasoline	69.4%	69.4%	63.1%	70.7%	83.9%	76.3%	70.5%	64.3%	65.7%
	Jet Fuel	5.7%	5.1%	7.2%	5.8%	3.7%	4.3%	6.0%	7.2%	7.0%
	Diesel	24.2%	24.5%	29.0%	22.9%	12.0%	18.7%	22.9%	27.8%	26.7%
	Other	0.8%	0.9%	0.7%	0.7%	0.4%	0.7%	0.6%	0.7%	0.6%

Notes:

1 – Bitumen Estimate is a linear estimated using SCO mining and synbit which is a combination SCO mining and bitumen

Table 5-4. GREET Refinery Inputs for PADD 3

		Ref Case	WTI	Saudi Arabia	Iraq	Nigeria	Venezuela	Mexico	SCO Mining	SCO In-Situ	Synbit	Dilbit	Bitumen Est[1]
GREET Efficiency	Gasoline	85.6%	88.2%	85.2%	85.2%	88.2%	83.5%	84.4%	88.0%	89.8%	83.3%	84.5%	79.7%
	Diesel	92.0%	93.8%	91.8%	91.8%	95.2%	92.6%	91.4%	97.4%	96.4%	92.6%	92.1%	89.2%
Process Energy (Btu/MMBtu)	Gasoline	167,947	133,595	174,270	174,347	133,880	197,988	184,838	136,297	113,867	200,422	183,215	255,206
	Diesel	86,574	65,571	89,615	89,522	50,447	79,824	93,621	26,938	36,917	79,383	86,115	120,652
Gasoline Blendstock Fuel Shares	NG	26.5%	28.9%	26.5%	26.5%	22.2%	20.4%	26.3%	11.6%	19.1%	20.0%	24.1%	25.3%
	Still	38.5%	42.1%	38.6%	38.5%	32.3%	29.7%	38.2%	16.9%	27.8%	29.1%	35.0%	36.7%
	Coke	23.8%	23.1%	23.4%	23.5%	40.4%	39.0%	23.7%	65.7%	47.7%	40.3%	29.9%	28.2%
	Elec	5.8%	6.0%	6.2%	6.2%	5.2%	6.2%	6.8%	5.8%	5.5%	5.9%	5.9%	6.2%
	H2	5.5%	0.0%	5.4%	5.4%	0.0%	4.7%	5.1%	0.0%	0.0%	4.7%	5.1%	3.7%
Diesel Fuel Shares	NG	35.4%	40.7%	35.6%	35.6%	40.6%	34.9%	35.8%	40.5%	40.6%	34.9%	35.4%	36.9%
	Still	51.6%	59.2%	51.8%	51.8%	59.1%	50.8%	52.1%	59.0%	59.1%	50.8%	51.5%	53.7%
	Coke	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Elec	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.2%	0.4%	0.3%	0.2%	0.2%	0.2%
	H2	12.8%	0.0%	12.5%	12.5%	0.0%	14.0%	11.9%	0.0%	0.0%	14.1%	13.0%	9.3%
% Process Energy	Gasoline	64.8%	66.5%	64.8%	64.9%	71.6%	69.6%	65.2%	81.3%	74.2%	70.0%	66.7%	66.7%
	Jet Fuel	10.3%	9.1%	10.3%	10.3%	8.2%	9.5%	10.2%	6.7%	7.8%	9.4%	9.9%	9.7%
	Diesel	24.2%	23.6%	24.2%	24.1%	19.5%	20.3%	23.9%	11.6%	17.4%	20.1%	22.7%	22.9%
	Other	0.7%	0.8%	0.7%	0.7%	0.7%	0.6%	0.7%	0.4%	0.6%	0.6%	0.7%	0.7%

Notes:
1 – Bitumen Estimate is a linear estimated using SCO mining and synbit which is a combination SCO mining and bitumen

Table 5-5. GREET Refinery Inputs for California

		Ref Case	SJV Heavy	Alaska	Saudi Arabia	Iraq	Mexico	SCO Mining	SCO In-Situ	Synbit	Dilbit	Bitumen Est[1]
GREET Efficiency	Gasoline	85.8%	82.3%	88.2%	85.6%	85.4%	82.3%	87.6%	91.5%	82.3%	81.6%	77.5%
	Diesel	90.4%	88.5%	92.9%	90.4%	90.3%	86.7%	93.6%	95.5%	87.8%	86.9%	82.7%
Process Energy (Btu/MMBtu)	Gasoline	165,405	215,229	134,313	168,878	170,808	214,887	141,257	92,645	215,567	226,094	289,877
	Diesel	105,750	129,726	76,671	106,613	107,408	153,795	68,084	47,384	138,318	151,284	208,551
Gasoline Fuel Shares	NG	15.6%	12.5%	17.1%	15.8%	16.0%	16.4%	11.3%	17.0%	13.6%	14.7%	14.7%
	Still	44.7%	36.1%	49.2%	45.4%	46.1%	47.2%	32.4%	48.9%	39.0%	42.3%	42.1%
	Coke	18.3%	26.8%	21.2%	18.4%	18.2%	10.5%	38.6%	26.1%	21.9%	17.3%	13.7%
	Elec	2.8%	2.3%	3.1%	3.0%	3.0%	2.9%	2.6%	3.4%	2.3%	2.7%	2.2%
	H2	18.6%	22.3%	9.3%	17.3%	16.6%	23.0%	15.0%	4.6%	23.3%	22.9%	27.3%
Diesel Fuel Shares	NG	16.8%	14.4%	20.7%	17.3%	17.6%	15.9%	16.2%	23.0%	14.6%	15.2%	14.1%
	Still	48.3%	41.3%	59.6%	49.7%	50.7%	45.6%	46.5%	66.1%	41.9%	43.7%	40.5%
	Coke	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Elec	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.0%
	H2	34.8%	44.2%	19.6%	32.9%	31.6%	38.5%	37.2%	10.8%	43.4%	41.0%	45.4%
% Process Energy	Gasoline	64.4%	65.0%	67.8%	64.8%	64.7%	61.7%	69.9%	70.5%	63.7%	63.0%	61.1%
	Jet Fuel	15.8%	16.3%	13.5%	15.6%	15.5%	17.1%	14.0%	12.1%	16.7%	16.8%	17.9%
	Diesel	19.3%	18.4%	18.2%	19.2%	19.3%	20.7%	15.8%	16.9%	19.2%	19.8%	20.6%
	Other	0.4%	0.4%	0.5%	0.5%	0.5%	0.4%	0.3%	0.5%	0.4%	0.4%	0.4%

Notes:
1 – Bitumen Estimate is a linear estimated using SCO mining and synbit which is a combination SCO mining and bitumen

5.3 Treatment of Byproduct Coke

One unintentional byproduct of upgrading and refining oil sands and conventional crude oil is petroleum coke. An important issue in WTT GHG estimates of petroleum based transportation fuels is whether and how to allocate upgrading and refining process energy consumption to production of coke. It can be argued that since coke is a not on purpose byproduct, that none of the refining/upgrading energy should be allocated to it; all of the energy should instead be allocated to the on purpose products such as gasoline, diesel, jet fuel, residual oil etc.

On the other hand, if the coke is actually utilized, some of the refining/upgrading energy could be allocated to it. If energy is allocated to byproduct coke, there are many different allocation methodologies that might be employed: by mass, by economic value, or by energy content. In general, if it is not clear how much of each process fuel should be allocated to each co-product, the preferred allocation methodology is the substitution method. In the substitution method, all of the energy is allocated to the main product, and then a credit is given equal to the emissions associated with production of the product for which the byproduct is substituting. In this case, all of the upgrading/refining energy would be allocated to the products of interest, and a credit would be given equal to the production of what the coke substitutes for. If we assume that petroleum coke is used in a utility boiler in place of coal, then there would be a slight increase in boiler emissions per MWh since coke has a higher carbon content than coal. This would be offset by the avoided coal mining and transport emissions. The resulting credit, if any would likely be small.

In our analysis, we have allocated energy to all refinery products except coke as described in Section 4 and Section 5.2 above. Essentially, the refinery model was utilized to determine the impact of reducing each product of interest by a small amount on process fuel consumption. We have shown for the mining operation what the result would be if process energy were allocated by energy content to coke (SCO Mining – sell coke), but it is our belief that this underestimates emissions that should be allocated to the SCO and eventually to the gasoline and diesel transportation fuels. Therefore we believe that the mining case “SCO Mining – Bury Coke” is the more representative pathway for SCO mining emissions. If allocation to coke is done, it should be done via the substitution method.

5.4 Crude and Finished Fuel Transportation

The emissions due to crude transport to the refinery and finished fuel (gasoline blendstock and low sulfur diesel) transport to refueling stations are based on:

- Travel mode shares and
- Distance traveled by mode
- Energy intensity of transport mode (Btu/ton-mile)
- Fuel type for transport mode
- Emission factors for each transport mode/fuel type

In all cases we have utilized GREET default values for energy intensity, transportation fuel types and transport emission factors. We have adjusted travel mode shares and distance traveled by mode as shown in Tables 5-6 and 5-7 for crude oil and finished fuel transport. For crude transport, shipping miles were estimated using Portworld's online shipping route distance calculator. For pipeline miles, estimates are based on pipeline maps. For finished fuel transport modes and miles, we have assumed U.S. default values for PADD 2 and PADD 3 except we have set ship miles to zero. For California, we have used the GREET default California finished fuel transport values.

Table 5-6. Assumed Crude Oil Transport Modes and Distances

Crude Source	PADD 2			PADD 3			California		
	Foreign Pipeline	Cargo Ship	U.S. Pipeline	Foreign Pipeline	Cargo Ship	U.S. Pipeline	Foreign Pipeline	Cargo Ship	U.S. Pipeline
WTI	0	0	950	0	0	50			
CA Heavy							0	0	120
Alaska							800	2,250	50
Saudi	0	9,790	950	0	9,790	50	0	11,420	50
Iraq				65	9,920	50	65	11,550	50
Canada	0	0	1,400						
Nigeria				0	6,300	50			
Venezuela				0	1,820	50			
Mexico				0	700	50	150	1,780	50
Oil Sands	0	0	1,800	0	0	2,700	900	1,100	50

Table 5-7. Assumed Finished Fuel Transport Modes and Distances

	Units	U.S. Default	PADD 2	PADD 3	California
Cargo Ship					
Mode Share	%	16 (20)	0	0	0
Distance	Miles	1450 (1665)	0	0	0
Barge					
Mode Share	%	6 (4)	6 (4)	6 (4)	0
Distance	Miles	520	520	520	0
Pipeline					
Mode Share	%	75 (73)	75 (73)	75 (73)	95
Distance	Miles	400 (405)	400 (405)	400 (405)	150
Rail					
Mode Share	%	7	7	7	5
Distance	Miles	800	800	800	250
Heavy Duty Truck					
Mode Share	%	100	100	100	100
Distance	Miles	30	30	30	30

Values in parenthesis are gasoline blendstock when different from diesel.

5.5 Electricity Grid Mixes

Electricity is used as a process fuel in the refinery and in some cases at the oil field. For this analysis, we have modified GREET slightly to allow for different electricity mixes to be used at the oil field and in the refinery for the same pathway. The following crude oils utilize grid electricity during resource recovery: Saudi Arabia, Mexico, Nigeria, Iraq, and some of the oil sands pathways. For Canada, the 2006 Alberta grid mix is used.[60] For the other countries, the data were taken from the IEA.[61] The "other" category is non-combustion sources such as solar, hydro, and wind.

Table 5-8. Electricity Grid Mixes for Crude Recovery

	Saudi Arabia	Iraq	Nigeria	Mexico	Oil Sands
Residual Oil	50.0%	98.5%	10.4%	29.8%	0.2%
Natural Gas	50.0%	0.0%	54.2%	36.2%	12.5%
Coal	0.0%	0.0%	0.0%	12.8%	84.0%
Biomass	0.0%	0.0%	0.0%	0.4%	0.0%
Nuclear	0.0%	0.0%	0.0%	4.3%	0.0%
Other	0.0%	1.5%	35.4%	16.6%	3.3%

We also needed local grid mixes for the three refinery locations: PADD 2, PADD 3, and California. The grid mixes for the three refinery locations are summarized in Table 5-9. For the California mix, we simply used the GREET default values. For the PADD 2 and PADD 3 values we calculated a crude production weighted average based on the states located in each PADD, the state refinery capacity, and the state electricity mix for 2006. A map indicating which states belong to each PADD is provided in Figure 5-6. Table 5-10 provides the electricity mix and refining data utilized to calculate the weighted averages.

Table 5-9. Electricity Grid Mixes for the Refining Regions

	PADD 2	PADD 3	California
Residual Oil	1%	2%	1%
Natural Gas	9%	46%	42%
Coal	68%	34%	15%
Biomass	1%	1%	2%
Nuclear	20%	13%	19%
Other	1%	4%	23%

[60] "National Inventory Report: GHG Sources and Sinks in Canada, 1990-2006.

[61] International Energy Agency, http://www.iea.org/Textbase/stats/index.asp

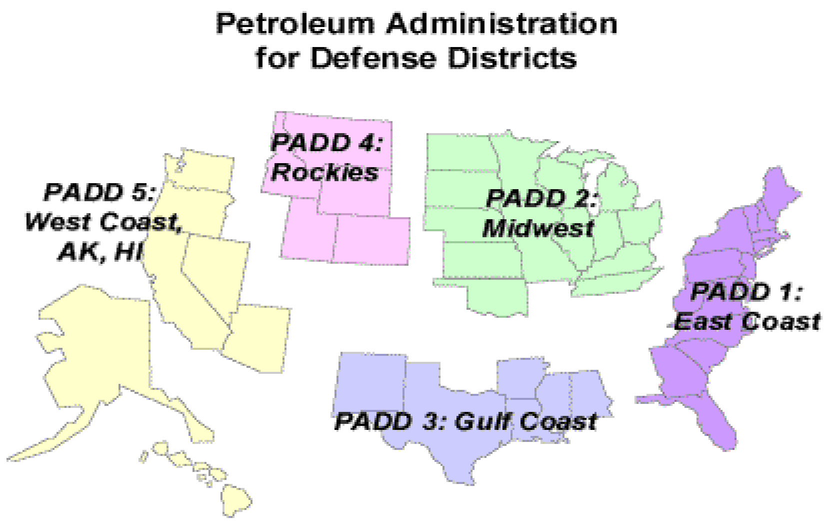


Figure 5-6. Map of PADD Regions (EIA)

Table 5-10. Calculation of Production Weighted Electricity Grid Mixes for PADD2 and PADD3

PADD	State	Capacity, bbl/day	% of PADD	2005 Electricity Resource Mix State Level, % (eGRID2007, Jan 2009)										
				Coal	Oil	NG	Nuclear	Hydro	Biomass	Wind	Solar	Geo-thermal	Other Fossil	Other
2	Illinois	915,600	25%	47.5	0.2	3.7	48.0	0.1	0.4	0.1	0.0	0.0	0.1	0.0
2	Indiana	433,000	12%	94.2	0.2	2.8	0.0	0.3	0.1	0.0	0.0	0.0	2.1	0.3
2	Kansas	305,900	8%	75.2	2.2	2.5	19.2	0.0	0.0	0.9	0.0	0.0	0.0	0.0
2	Kentucky	231,500	6%	91.1	3.8	1.7	0.0	3.0	0.4	0.0	0.0	0.0	0.0	0.0
2	Michigan	102,000	3%	57.8	0.7	11.2	27.0	0.3	2.1	0.0	0.0	0.0	0.8	0.0
2	Minnesota	362,150	10%	62.1	1.5	5.1	24.3	1.5	1.9	3.0	0.0	0.0	0.6	0.1
2	North Dakota	58,000	2%	94.8	0.1	0.0	0.0	4.2	0.0	0.7	0.0	0.0	0.2	0.0
2	Ohio	515,200	14%	87.2	0.9	1.7	9.4	0.3	0.2	0.0	0.0	0.0	0.2	0.0
2	Oklahoma	520,400	14%	51.7	0.1	43.0	0.0	3.5	0.4	1.2	0.0	0.0	0.0	0.0
2	Tennessee	180,000	5%	61.0	0.2	0.5	28.7	9.0	0.6	0.0	0.0	0.0	0.0	0.0
2	Wisconsin	34,300	1%	67.3	1.1	10.5	16.0	2.8	1.9	0.1	0.0	0.0	0.1	0.1
PADD 2 Production Weighted Average				**68%**	**1%**	**9%**	**20%**	**1%**	**1%**	**1%**	**0%**	**0%**	**0%**	**0%**
3	Alabama	124,600	1%	56.9	0.1	10.1	23.1	7.4	2.3	0.0	0.0	0.0	0.1	0.0
3	Arkansas	77,500	1%	48.2	0.4	12.6	28.6	6.5	3.6	0.0	0.0	0.0	0.0	0.0
3	Louisiana	2,976,383	35%	24.9	3.8	47.3	16.9	0.9	2.9	0.0	0.0	0.0	3.0	0.3
3	Mississippi	364,000	4%	36.9	3.2	34.0	22.4	0.0	3.5	0.0	0.0	0.0	0.0	0.0
3	New Mexico	121,600	1%	85.2	0.1	11.9	0.0	0.5	0.0	2.3	0.0	0.0	0.0	0.0
3	Texas	4,751,746	56%	37.3	0.6	49.3	9.6	0.3	0.3	1.1	0.0	0.0	1.3	0.2
PADD 3 Production Weighted Average				**34%**	**2%**	**46%**	**13%**	**1%**	**1%**	**1%**	**0%**	**0%**	**2%**	**0%**

Capacity is Atmospheric Distillation Capacity

6. Results

The recovery and refining process efficiencies, process fuel shares, electricity grid mixes, and transport modes/distances presented in Section 5 were coded into GREET1.8b and results were generated. The following sections provide recovery, refining, well-to-tank (WTT), and well-to-wheel (WTW) GHG emission estimates. For convenience, Tables 6-1 and 6-2 provide a brief description of each pathway name used in the figures and tables.

Table 6-1. Conventional Crude Oil Pathway Descriptor Key

Label	Crude Name	Recovery Methods
Alaska	Alaska North Slope	Water Alternating Gas (WAG) and Natural Drive
California Heavy	Kern County Heavy Oil	Steam Injection, Sucker Rod Pumps
Texas	West Texas Intermediate	Water Flooding, Natural Drive
Canada Heavy	Bow River Heavy Oil	Water Flooding, Progressive Cavity Pumps
Iraq	Basrah Medium	Water Flooding, Natural Drive
Mexico	Maya (Canterell)	Nitrogen Flooding, Gas Lift
Nigeria	Escravos	Water Flooding, Gas Lift
Saudi	Saudi Medium	Water Flooding, Natural Drive
Venezuela	Bachaquero (Maracaibo)	Cyclic Steam Stimulation, Sucker Rod Pumps

Table 6-2. Oil Sands Pathway Descriptor Key

Label	Description
SCO Mining, Sell Coke	Bitumen recovery through mining, onsite upgrading. Assume that the coke is ultimately utilized as a fuel (some of the recovery energy is allocated to the coke).
SCO Mining, Bury Coke	Bitumen recovery through mining, onsite upgrading. Assume that the coke is never utilized as a fuel (none of the recovery energy is allocated to the coke).
SCO SAGD, Use Coke	Bitumen recovery through SAGD, onsite upgrading. All coke is gasified with resulting syngas utilized as a process fuel.
SCO SAGD, Use NG	Bitumen recovery through SAGD, onsite upgrading. Assume that the carbon rich syngas is replaced with natural gas.
Bitumen, SAGD 1	Bitumen recovery through SAGD, SOR of 2.5, no electricity exports
Bitumen, SAGD 2	Bitumen recovery through SAGD, SOR of 2.5, with electricity exports
Bitumen, CSS 1	Bitumen recovery through CSS, SOR of 3.4, no electricity exports
Bitumen, CSS 2	Bitumen recovery through CSS, SOR of 4.8, with electricity exports

6.1 Recovery Emissions

The recovery emissions include emissions from recovering the crude/bitumen, oilfield flaring and venting, and transport to the refinery. The GHG emissions associated with crude/bitumen recovery, flaring, and venting are provided in Figure 6-1 and Table 6-3. The GREET default values are also provided for comparison. The figure demonstrates that the recovery GHG emissions associated with the range of products sold to refineries is highly variable. Some of the conventional crude oils (California, Nigeria and Venezuela) have recovery emissions roughly equivalent to the oil sands pathways (with the exception of the SAGD-SCO pathway).

For the conventional crude oils considered, the recovery emissions (not including transport) range from 0.3 to 12.2 g/MJ. The GREET default value is within this range at 5.0 g/MJ.

For the SCO pathways, the SCO-Mining emissions range from 10.6 to 12.8 g/MJ depending upon how the coke is treated. The GREET default value for SCO-Mining is just over 15 g/MJ. The availability of more public data would help verify/refine our result for this pathway.

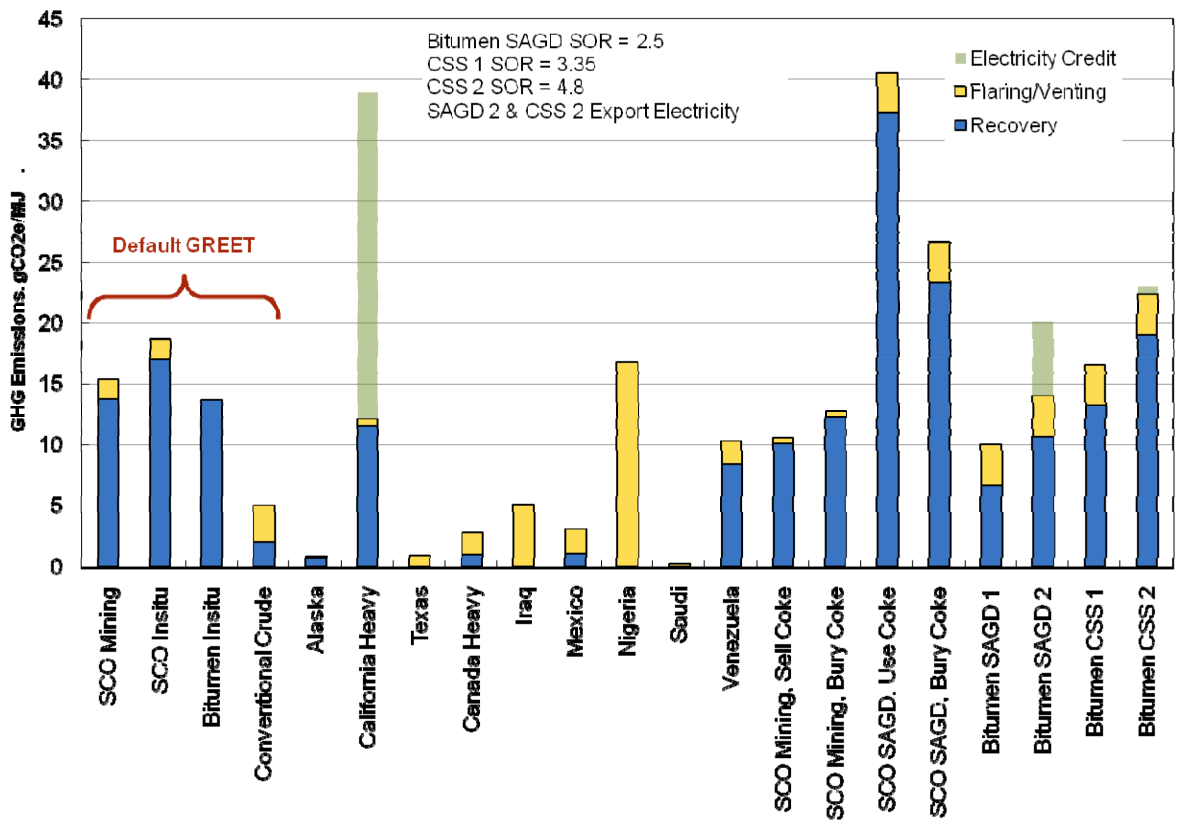


Figure 6-1. Recovery and Venting Emissions for Analysis Pathways

Table 6-3. Recovery and Venting Emissions

Crude Oil	Recovery Emissions gCO2e/MJ	Venting/Flaring Emissions gCO2e/MJ	Recovery Total gCO2e/MJ
GREET Default SCO Mining	13.7	1.6	15.4
GREET Default SCO Insitu	17.1	1.6	18.7
GREET Default Bitumen Insitu	13.6	0.0	13.6
GREET Default Conventional Crude	2.1	2.9	5.0
Alaska North Slope	0.7	0.1	0.9
California Heavy	11.6*	0.6	12.2
West Texas Intermediate	0.2	0.8	1.0
Canada Heavy	1.1	1.8	2.8
Iraq	0.2	4.9	5.1
Mexico	1.1	2.0	3.1
Nigeria	0.1	16.7	16.8
Saudi	0.1	0.2	0.3
Venezuela	8.5	1.8	10.3
SCO Mining, Sell Coke	10.1	0.5	10.6
SCO Mining, Bury Coke	12.4	0.5	12.8
SCO SAGD, Use All Coke	37.3	3.3	40.6
SCO SAGD, Use No Coke	23.4	3.3	26.7
Bitumen SAGD 1 (no electricity export)	6.7	3.3	10.0
Bitumen SAGD 2 (w/ electricity export)	10.7*	3.3	14.0
Bitumen CSS 1 (no electricity export)	13.3	3.3	16.6
Bitumen CSS 2 (w/ electricity export)	19.1*	3.3	22.4

*-net recovery emissions when accounting for electricity credits

The SAGD and upgrading pathway in which all of the coke is gasified and the resulting syngas is used to raise steam has the highest recovery GHG emissions of all pathways at 40 g/MJ. To determine the impact of the syngas use relative to natural gas use, we replaced the syngas energy with natural gas, and the recovery emissions drop to 27 g/MJ. As will be seen in the next section, the high recovery emissions are somewhat offset by lower emissions from the refinery for the premium SCO produced. The GREET default SCO In-situ value is significantly lower at 19 g/MJ.

For the bitumen pathways (no onsite upgrading) there is variability depending upon the steam oil ratio (SOR) and whether or not steam is produced through cogeneration plants with export of excess electricity. For the electricity export cases, an emission credit is given equivalent to the emissions from a natural gas combined cycle electricity generator. Because SAGD 1 (no electricity export) and SAGD 2 (electricity export) have the same SOR, the difference between the two indicates that consuming extra natural gas onsite results in slightly higher GHG emissions. The differential between CSS 1 (no exports) and CSS 2 (exports) is larger than the difference between the two SAGD cases because the CSS 2 SOR is much higher than the CSS 1 SOR. The recovery GHG emissions for the bitumen pathways range from 10 to 22 g/MJ. The GREET default value for bitumen recovery (14 g/MJ) is on the low side of this range.

Figure 6-2 and Table 6-4 provide the transportation emissions from the oil fields to the various refinery locations considered. Transport emissions are relatively small, less than 2 g/MJ.

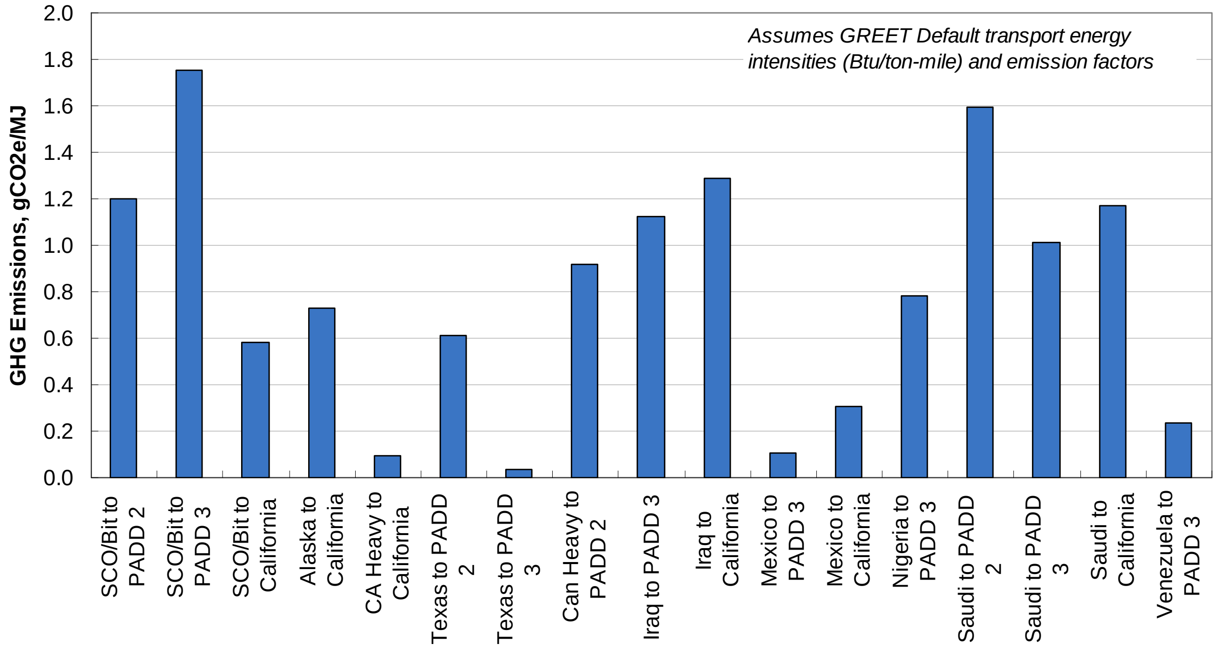


Figure 6-2. Emissions due to Crude and Bitumen Transport to the Refinery

Table 6-4. Emissions Due to Crude/Bitumen Transport

Crude Oil	Destination	Transport Emissions gCO2e/MJ
SCO/Bit	PADD 2	1.20
SCO/Bit to PADD 3	PADD 3	1.75
SCO/Bit to California	California	0.58
Alaska	California	0.73
California Heavy	California	0.10
Texas	PADD 2	0.61
Texas	PADD 3	0.04
Canada Heavy	PADD 2	0.92
Iraq	PADD 3	1.12
Iraq	California	1.29
Mexico	PADD 3	0.11
Mexico	California	0.30
Nigeria	PADD 3	0.78
Saudi	PADD 2	1.60
Saudi	PADD 3	1.01
Saudi	California	1.17
Venezuela	PADD 3	0.24

6.2 Refining Emissions

Recall that in Task 4 MathPro estimated a refinery efficiency for each crude oil product (conventional, SCO, synbit, dilbit) entering each regional refinery (PADD 2, PADD 3, California). This crude/region specific efficiency value combined with estimated process fuel shares dictates the refining GHG emissions. Figures 6-3 and 6-4 and Table 6-5 provide the GHG emission estimates for refining reformulated gasoline (RFG) blendstock and ultra low sulfur diesel, respectively. The figures also show transport emissions from the refinery to refueling stations (small). For each refining region, we have also estimated the energy required to refine pure bitumen as opposed to the actual delivered fuels (synbit, dilbit, SCO).

The GREET default refining value is also indicated in the Figure. Note that the un-modified GREET model only considers SCO or conventional crude refining (no synbit or dilbit). As a result, the GREET default refining emissions are independent of crude oil properties and are therefore compared to our estimates for refining emissions from both conventional and oil sands derived crudes.

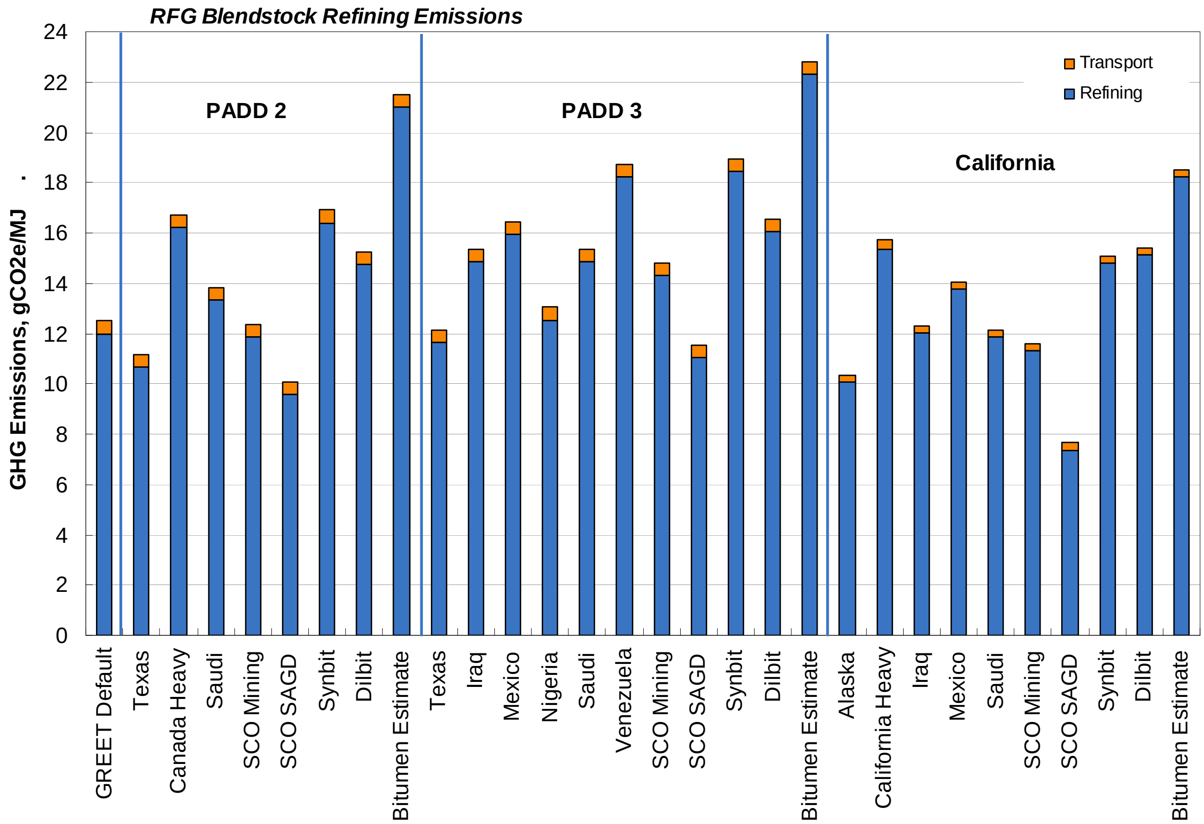


Figure 6-3. RFG Blendstock Refining and Transport Emissions

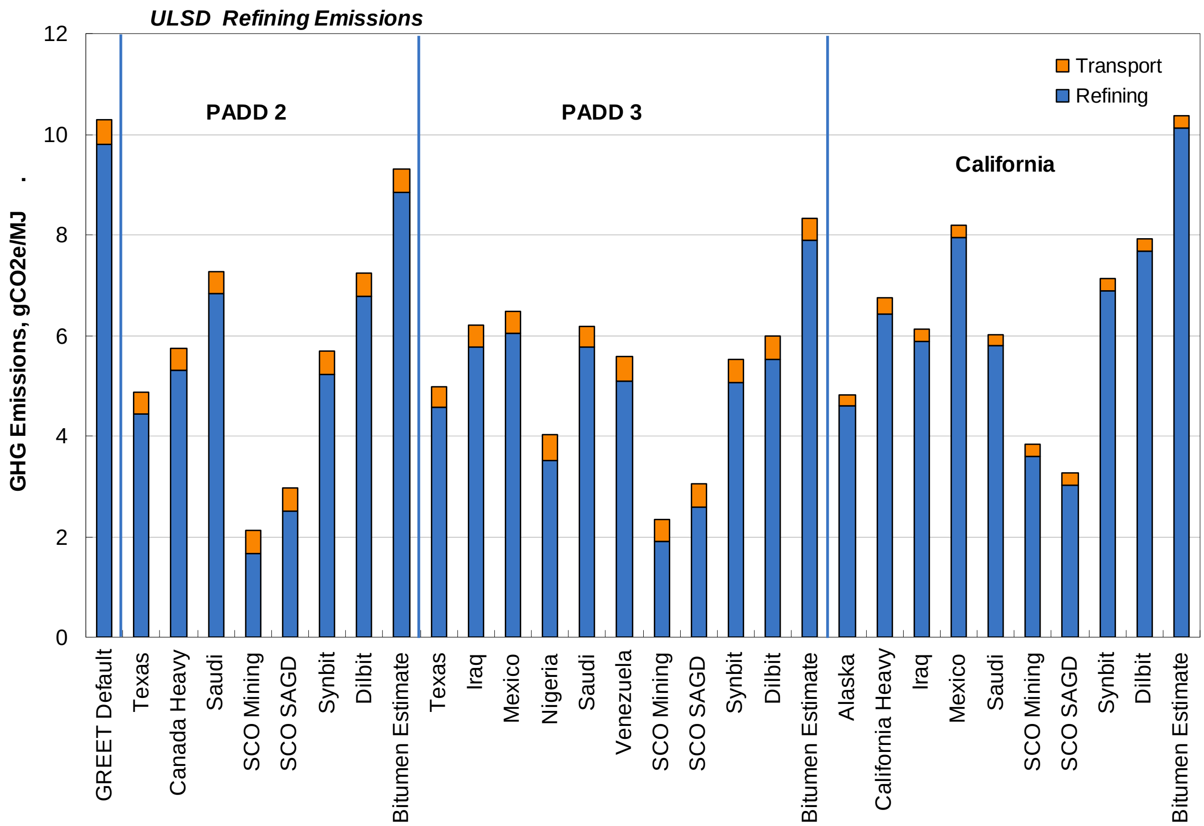


Figure 6-4. ULSD Refining and Transport Emissions

Table 6-5. Emissions Due to Refining and Transport

Crude Oil	Refinery Location	RFG Blendstock Emissions gCO2e/MJ	ULSD Emissions gCO2e/MJ
GREET Default	US Ave	12.5	10.3
Reference Case	PADD 2	13.6	5.4
Texas	PADD 2	11.1	4.9
Canada Heavy	PADD 2	16.7	5.8
Saudi	PADD 2	13.8	7.3
SCO Mining	PADD 2	12.4	2.1
SCO SAGD	PADD 2	10.1	3.0
Synbit	PADD 2	16.9	5.7
Dilbit	PADD 2	15.2	7.2
Bitumen Estimate	PADD 2	21.5	9.3
Reference Case	PADD 3	14.7	6.0
Texas	PADD 3	12.1	5.0
Iraq	PADD 3	15.4	6.2
Mexico	PADD 3	16.4	6.5
Nigeria	PADD 3	13.1	4.0

Table 6-5. Emissions Due to Refining and Transport (concluded)

Crude Oil	Refinery Location	RFG Blendstock Emissions gCO2e/MJ	ULSD Emissions gCO2e/MJ
Saudi	PADD 3	15.3	6.2
Venezuela	PADD 3	18.7	5.6
SCO Mining	PADD 3	14.8	2.3
SCO SAGD	PADD 3	11.6	3.0
Synbit	PADD 3	19.0	5.5
Dilbit	PADD 3	16.5	6.0
Bitumen Estimate	PADD 3	22.8	8.3
Reference Case	CA	11.8	5.9
Alaska	CA	10.4	4.8
California Heavy	CA	15.7	6.8
Iraq	CA	12.3	6.1
Mexico	CA	14.0	8.2
Saudi	CA	12.1	6.0
SCO Mining	CA	11.6	3.8
SCO SAGD	CA	7.7	3.3
Synbit	CA	15.1	7.1
Dilbit	CA	15.4	7.9
Bitumen Estimate	CA	18.5	10.4

For RFG blendstock refining, the GREET value (12.5 g/MJ) is within the range of values we estimate for the crude oils considered (10 to 19 g/MJ). For ULSD refining, the GREET value (10.3 g/MJ) is significantly higher than our results (2 to 8 g/MJ). The difference is due to two factors. First, our ULSD refining efficiencies are higher than the GREET default refining efficiency (Table 5-2). Second, GREET assumes the same process fuel shares for gasoline and diesel, including catalyst coke. GREET assumes that 13% of the process fuel consumed for diesel refining is catalyst coke – we have allocated all of the catalyst coke to gasoline since it comes from the FCC units which are utilized to produce gasoline.

For RFG blendstock refining, the heavy conventional crude oils (California, Canada, Mexico, and Venezuela) have similar refining emissions to synbit and dilbit. For ULSD refining, the conventional crude oils have similar refining emissions to synbit and dilbit. With the exception of Texas, SCO has much lower refining emissions than the other crude oils.

The variations in emissions of a given crude oil from region to region are complex, and are due to the local grid mix, the quality of the other crude oils being co-processed, the product slate, and the refinery configuration.

6.3 Well-to-Tank Emissions

In this section we summarize the foregoing results into WTT emissions. This includes recovery, crude transport, refining, and transport of finished fuels to refueling stations. Note that for the synbit and dilbit cases, the recovery values presented in Section 6.1 are on a per MMBtu bitumen basis. The values presented here for dilbit and synbit are on a per MMBtu delivered fuel basis. For dilbits, it has been assumed that the bitumen is blended with natural gas condensates at 25% diluent and 75% bitumen (volume basis). To approximate the upstream emissions associated with natural gas condensates, we have assumed the WTT emissions for pipeline natural gas.

For synbits, it has been assumed that the bitumen is blended with SCO on a 50/50 volume basis. The upstream emissions for the SCO component are taken from the SCO mining with buried coke case. It was assumed that SCO from mining is currently the most likely blending SCO. Had we chosen to blend with the SCO-SAGD case, the emissions would be higher for the synbit cases.

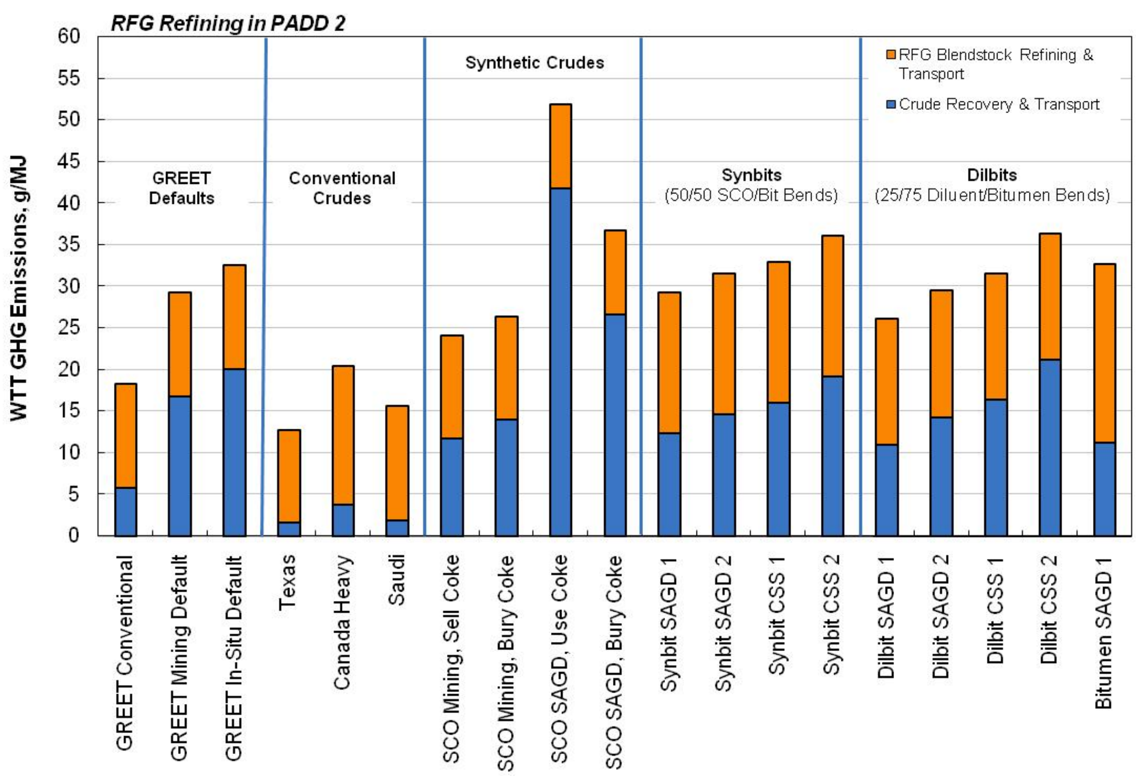


Figure 6-5. RFG Blendstock WTT Emissions (PADD 2 Refining)

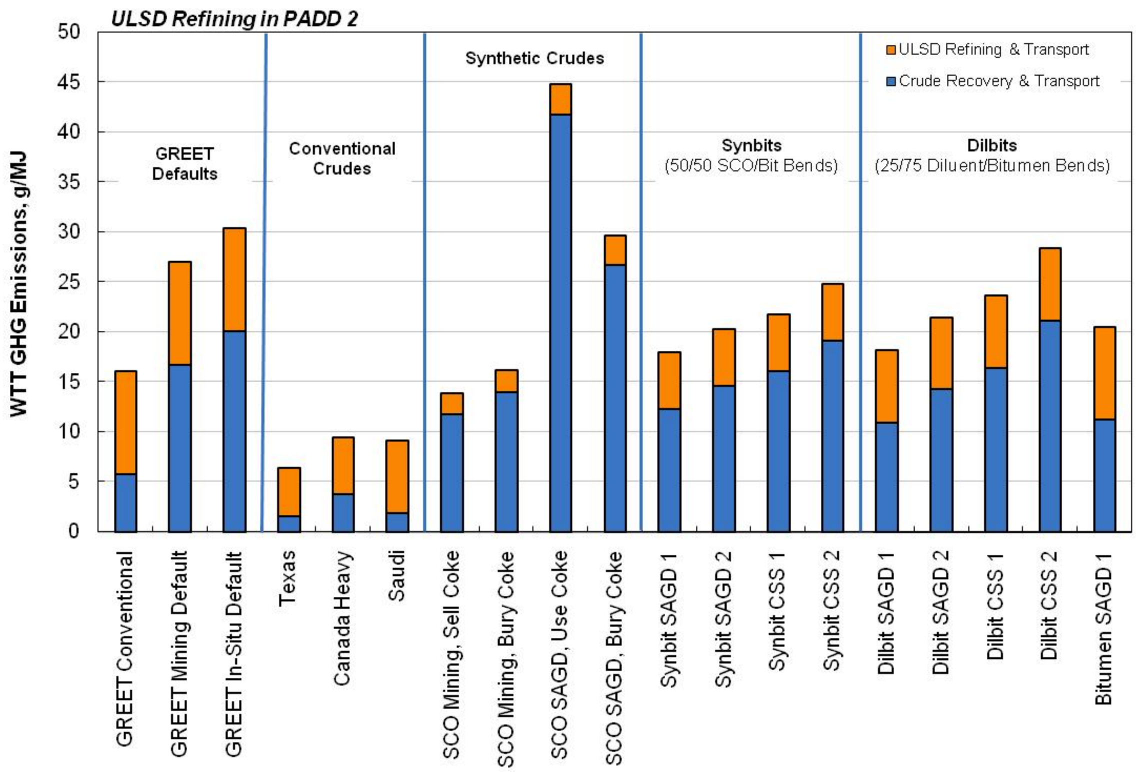


Figure 6-6. ULSD WTT Emissions (PADD 2 Refining)

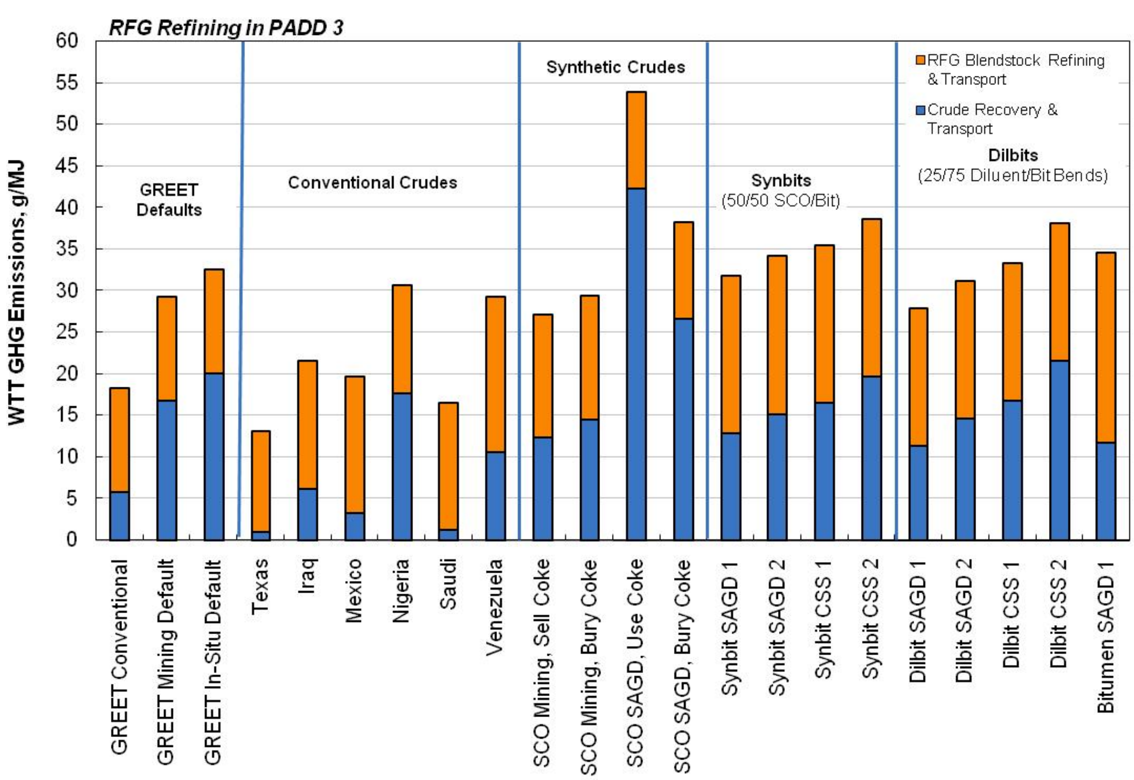


Figure 6-7. RFG Blendstock WTT Emissions (PADD 3 Refining)

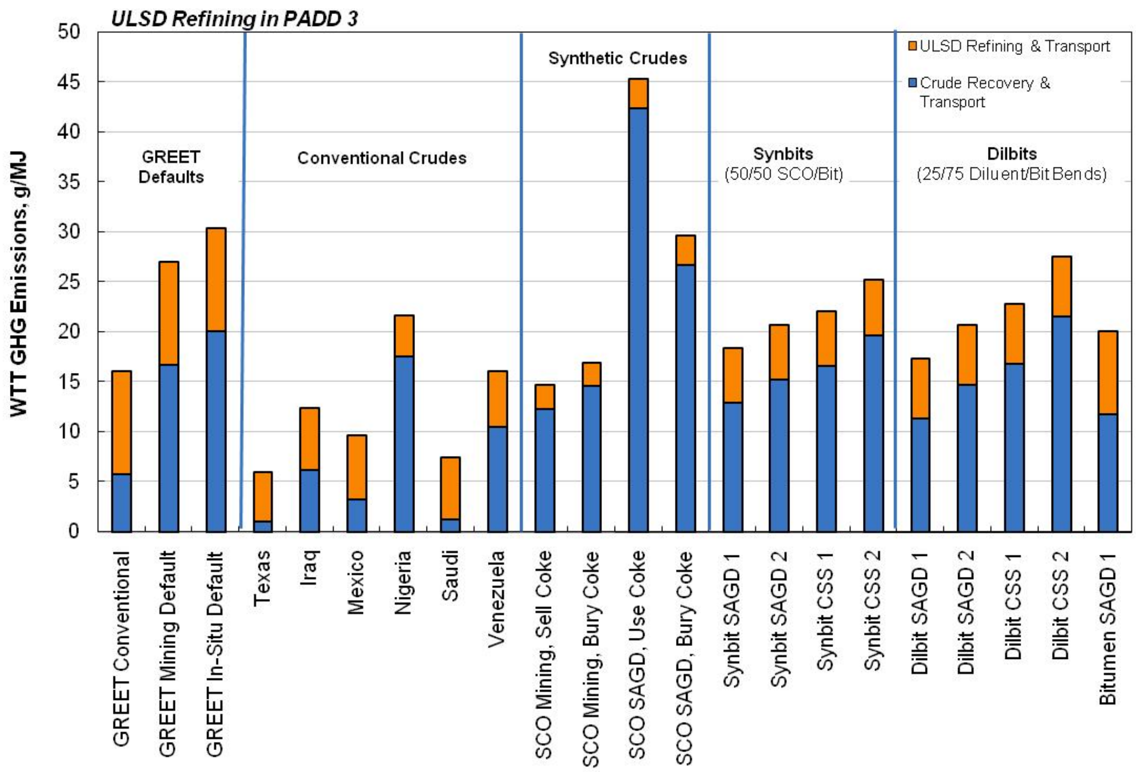


Figure 6-8. ULSD WTT Emissions (PADD 3 Refining)

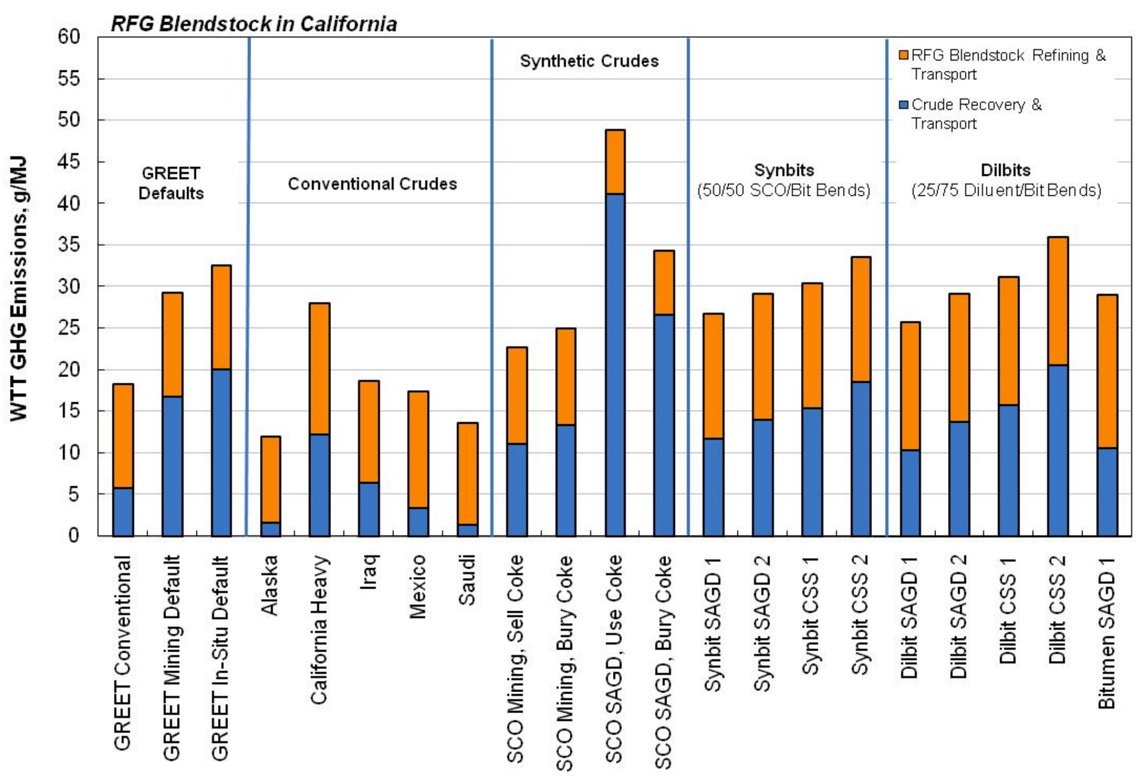


Figure 6-9. RFG Blendstock WTT Emissions (CA Refining)

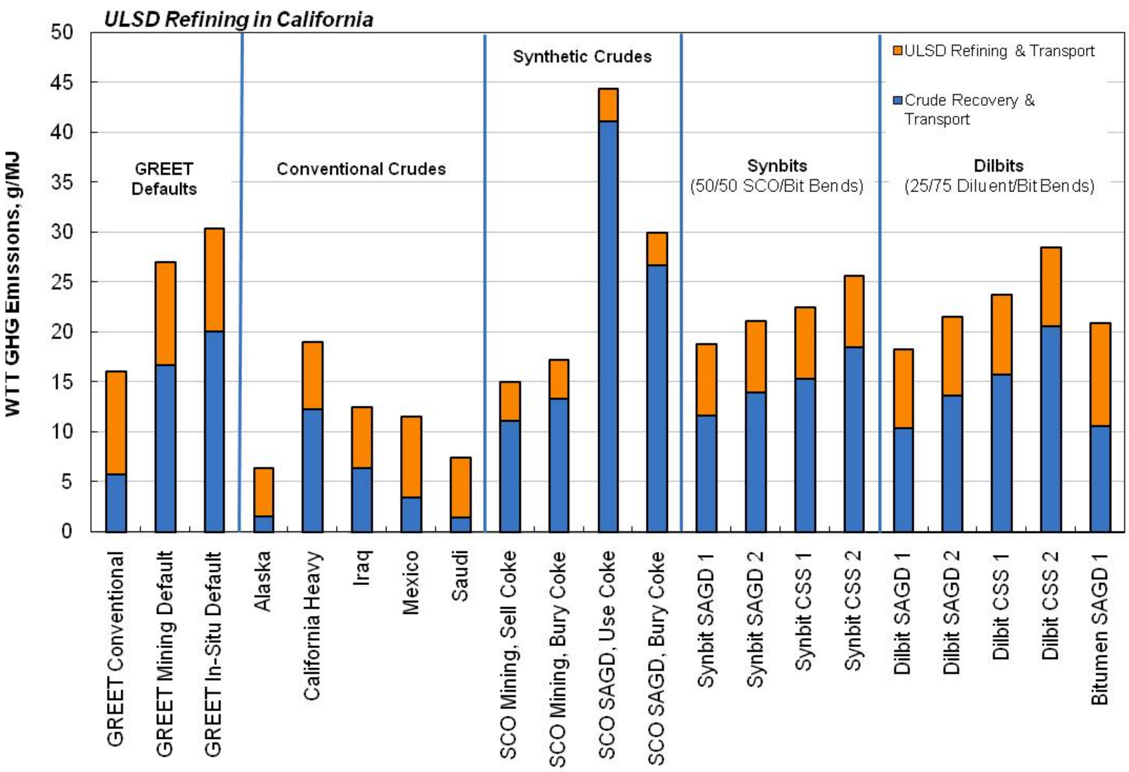


Figure 6-10. ULSD WTT Emissions (CA Refining)

6.4 Well-to-Wheel Results

Finally, to keep the importance of variations in WTT emissions in perspective, the WTW emissions estimates for each pathway are provided in Figures 6-11, 6-12 and 6-13 for PADD 2, PADD 3, and California refining. Figures 6-14 and 6-15 summarize these results with bars representing the range of results for each category.

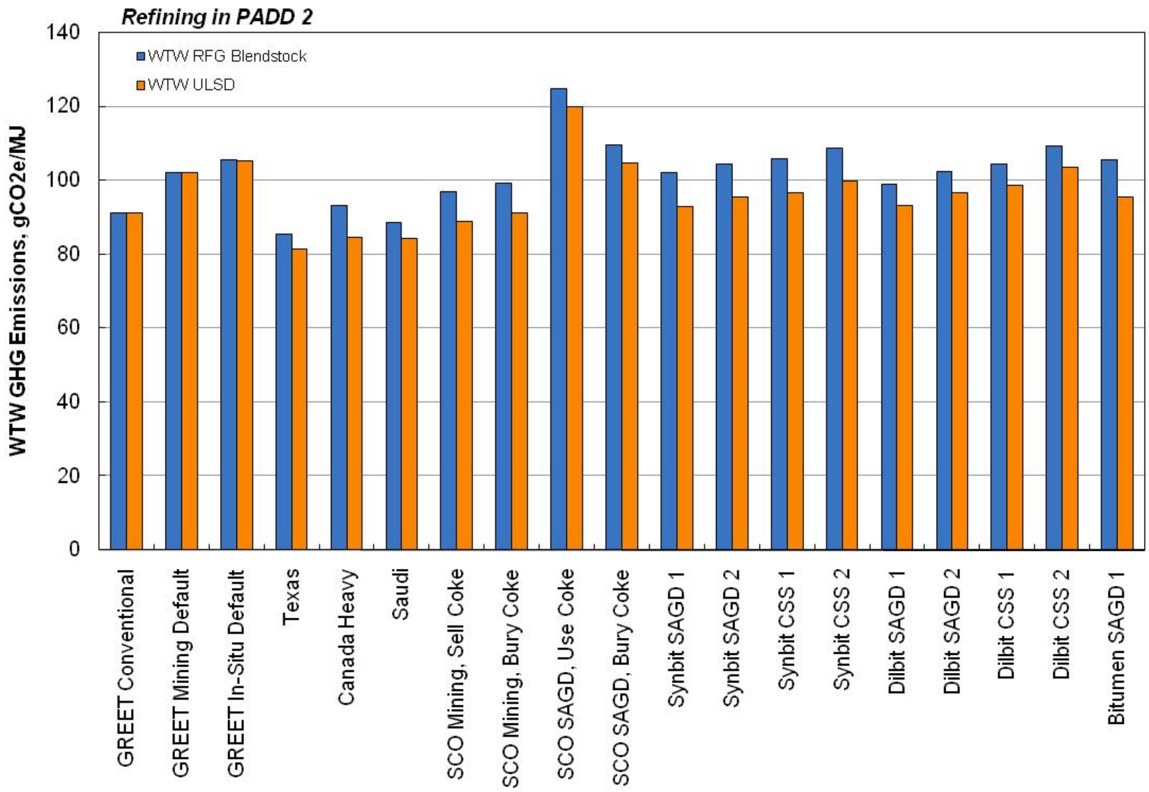


Figure 6-11. WTW GHG Emissions for Analysis Crudes Refined in PADD 2

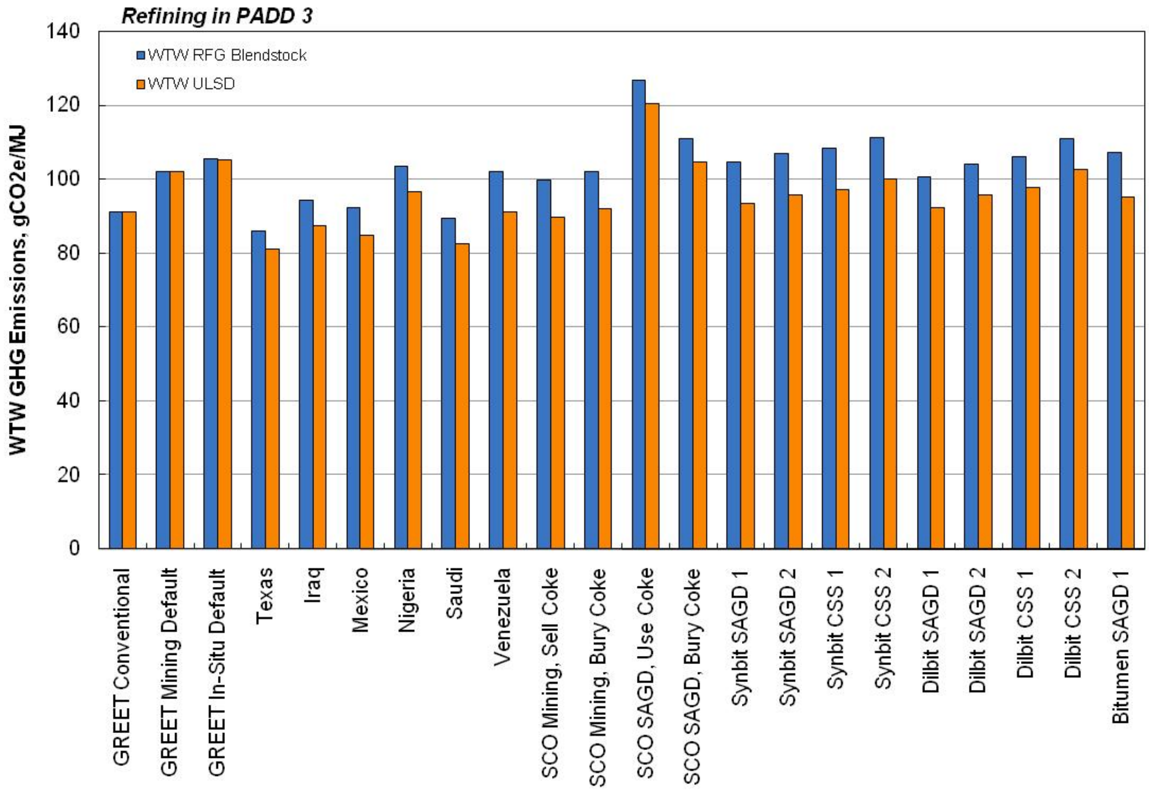


Figure 6-12. WTW GHG Emissions for Analysis Crudes Refined in PADD 3.

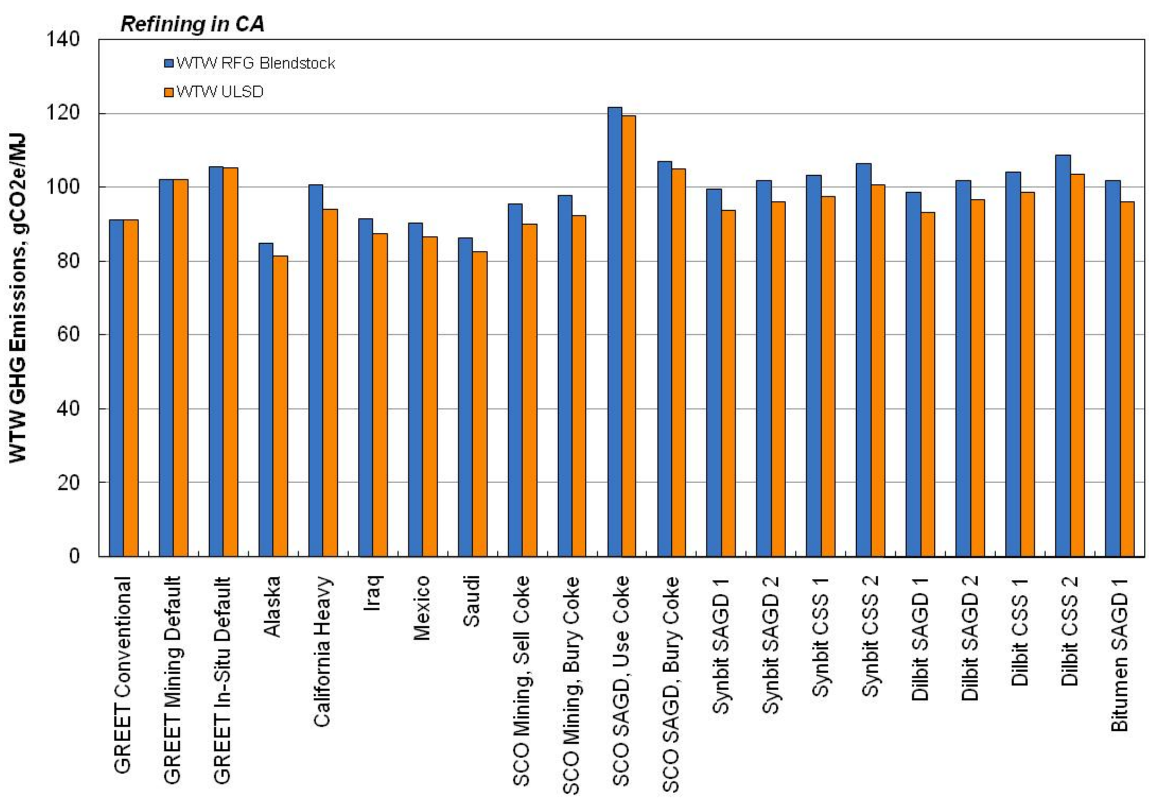


Figure 6-13. WTW GHG Emissions for Analysis Crudes Refined in California

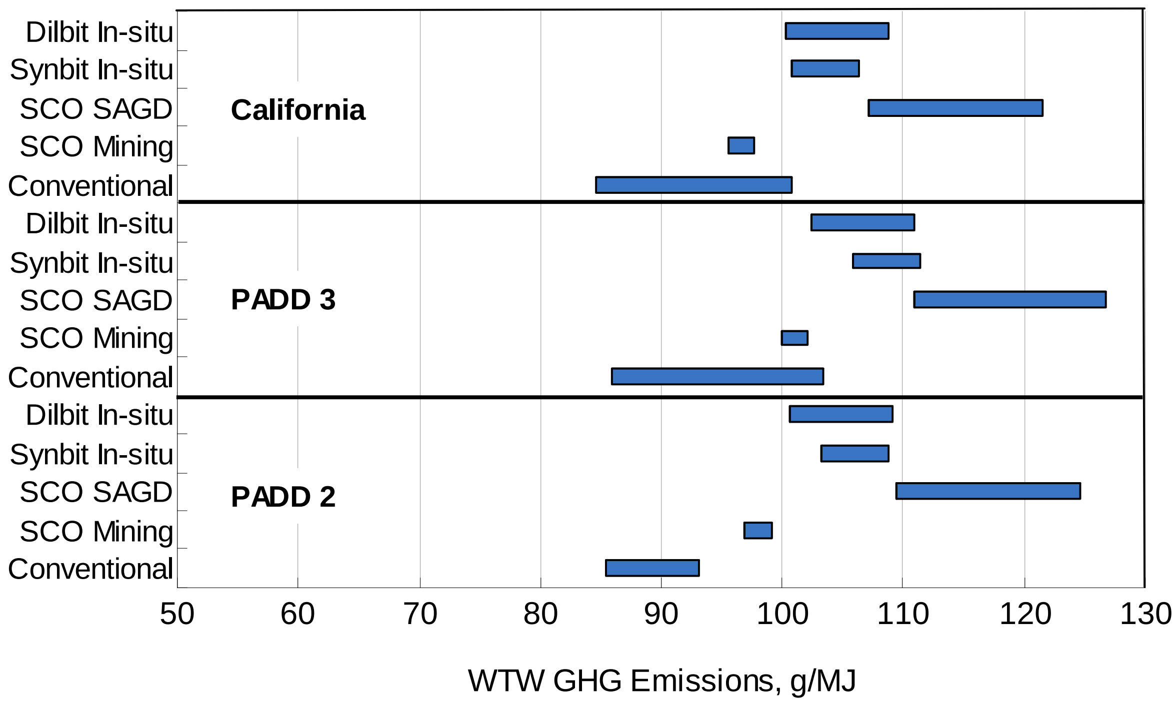


Figure 6-144. Ranges of RFG Blendstock WTW GHG Emissions

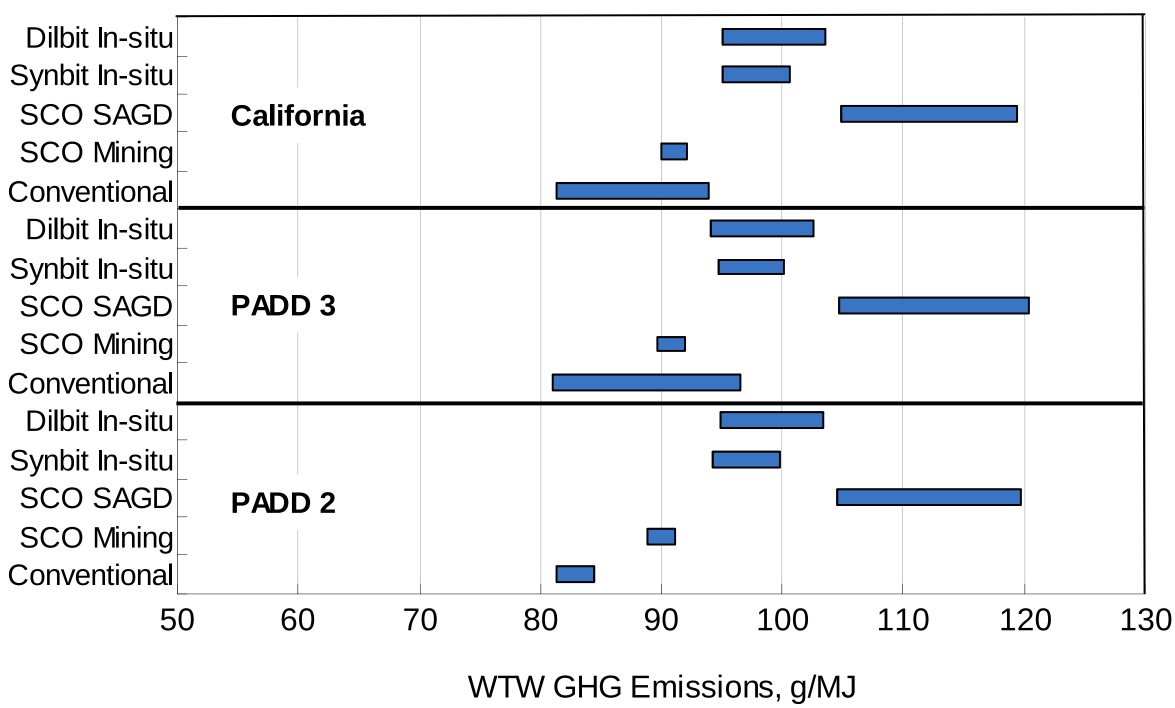


Figure 6-15. Ranges of ULSD WTW GHG Emissions

7. Sensitivity and Uncertainty

To better understand the impact of the quality of our assumptions on the emission estimates made here, we have performed both a sensitivity analysis and an uncertainty analysis. The objective of the sensitivity analysis is to identify which uncertain parameters have the largest impact on the final result. The objective of the uncertainty analysis is to determine confidence intervals for our results using the GREET stochastic simulation tool.

7.1 Sensitivity Analysis

TIAX performed a sensitivity analysis on the major assumptions and parameters that were used to determine the WTT GHG emissions using the GREET model. Each of the parameters was modeled separately to determine the individual effect. The parameters analyzed in the sensitivity and how they were determined are:

- Refining efficiency
  - TIAX took the refinery efficiency value determined in Section 5.2 for both gasoline and diesel ± 2% and ± 50% of the refinery energy use for traditional crude
- Crude recovery efficiency
  - TIAX took the GREET efficiency value for oil sands recovery ± 2%
- Associated gas venting
  - Minimum and maximum values from the venting data in Section 3.1.2
- Associated gas flaring
  - Minimum and maximum values from the flaring data in Section 3.1.2
- Gas Oil Ratio
  - TIAX took ± 50% of the analysis GOR
- Fugitive VOCs (SCO Mining Only)
  - TIAX used the range of values for fugitive VOCs from Section 3.2.1

Tables 7-1 to 7-4 below show the analysis values for the each of the parameters listed above and those values used for the sensitivity.

Table 7-1. Refinery Efficiency Sensitivity Values

Crude Pathways	Refinery Efficiency					
	Gasoline			Diesel		
	Analysis	Min	Max	Analysis	Min	Max
Alaska North Slope	88.2%	86.2%	90.2%	92.9%	90.9%	94.9%
California Heavy	82.3%	80.3%	84.3%	88.5%	86.5%	90.5%
Gulf of Mexico	88.2%	86.2%	90.2%	93.8%	91.8%	95.8%
Alberta Conventional	85.1%	83.1%	87.1%	92.0%	90.0%	94.0%
Saudi Arabia	85.6%	83.6%	87.6%	90.4%	88.4%	92.4%
Mexico	82.3%	80.3%	84.3%	86.7%	84.7%	88.7%
Iraq	85.4%	83.4%	87.4%	90.3%	88.3%	92.3%
Venezuela	83.5%	81.5%	85.5%	92.6%	90.6%	94.6%
Nigeria	88.2%	86.2%	90.2%	95.2%	93.2%	97.2%
SCO Mining	87.6%	85.6%	89.6%	93.6%	91.6%	95.6%
SCO Insitu	91.5%	89.5%	93.5%	95.5%	93.5%	97.5%
Synbit	82.3%	80.3%	84.3%	87.8%	85.8%	89.8%
Dilbit	81.6%	79.6%	83.6%	86.9%	84.9%	88.9%
Bitumen Estimate	77.5%	75.5%	79.5%	82.7%	80.7%	84.7%

Table 7-2. Recovery Efficiency and GOR Sensitivity Values

Crude Pathway	Crude Recovery Efficiency			Gas Oil Ratio (scf/bbl)		
	Analysis	Min	Max	Analysis	Min	Max
Alaska North Slope	98.8%	99.4%	98.1%	11,400	5,700	17,100
California Heavy	63.4%	77.6%	53.6%	1,003	502	1,505
Gulf of Mexico	99.7%	99.9%	99.6%	3,966	1,983	5,949
Alberta Conventional	98.2%	99.1%	97.3%	1,860	930	2,790
Saudi Arabia	99.9%	99.9%	99.8%	800	400	1,200
Mexico	98.4%	99.2%	97.6%	372	186	557
Iraq	99.8%	99.9%	99.6%	490	245	735
Venezuela	87.9%	93.5%	82.8%	495	248	743
Nigeria	99.8%	99.9%	99.7%	1,734	867	2,601
SCO Mining	84.8%	86.8%	82.8%	—	—	—
SCO Insitu	73.4%	75.4%	71.4%	—	—	—
Synbit	80.6%	82.6%	78.6%	—	—	—
Dilbit	85.0%	87.0%	83.0%	—	—	—
Bitumen Estimate	89.7%	91.7%	87.7%	—	—	—

Table 7-3. Associated Gas Venting and Flaring Sensitivity Values

Crude Pathway	Gas Venting (g/mmBtu)			Gas Flaring (Btu/mmBtu)		
	Analysis	Min	Max	Analysis	Min	Max
Alaska North Slope	3.4	1.7	5.0	866	433	1,299
California Heavy	23.2	11.6	34.8	607	303	910
Gulf of Mexico	32.8	22.3	43.2	525	358	692
Alberta Conventional	57.4	28.7	86.1	6,942	3,471	10,413
Saudi Arabia	1.3	0.4	2.2	2,639	90	4,687
Mexico	70.7	12.1	129.3	6,045	3,244	9,012
Iraq	69.3	40.0	100.7	56,920	53,394	65,186
Venezuela	34.5	28.9	37.6	17,889	10,462	28,608
Nigeria	426	190	682	91,268	141,215	31
SCO Mining	6.7	3.4	10.1	5,392	2,696	8,088
SCO Insitu	138	69	207	542	271	813
Synbit	138	69	207	542	271	813
Dilbit	138	69	207	542	271	813
Bitumen Estimate	138	69	207	542	271	813

Table 7-4. Fugitive VOC Sensitivity Values

Crude Pathway	Fugitive VOCs (g/mmBtu)		
	Analysis	Min	Max
SCO Mining	127	14	240

Figures 7-1 and 7-2 below show the resulting sensitivity plots after modeling each of the individual parameters for the gasoline (Figure 7-1) and diesel (Figure 7-2) found in the tables above.

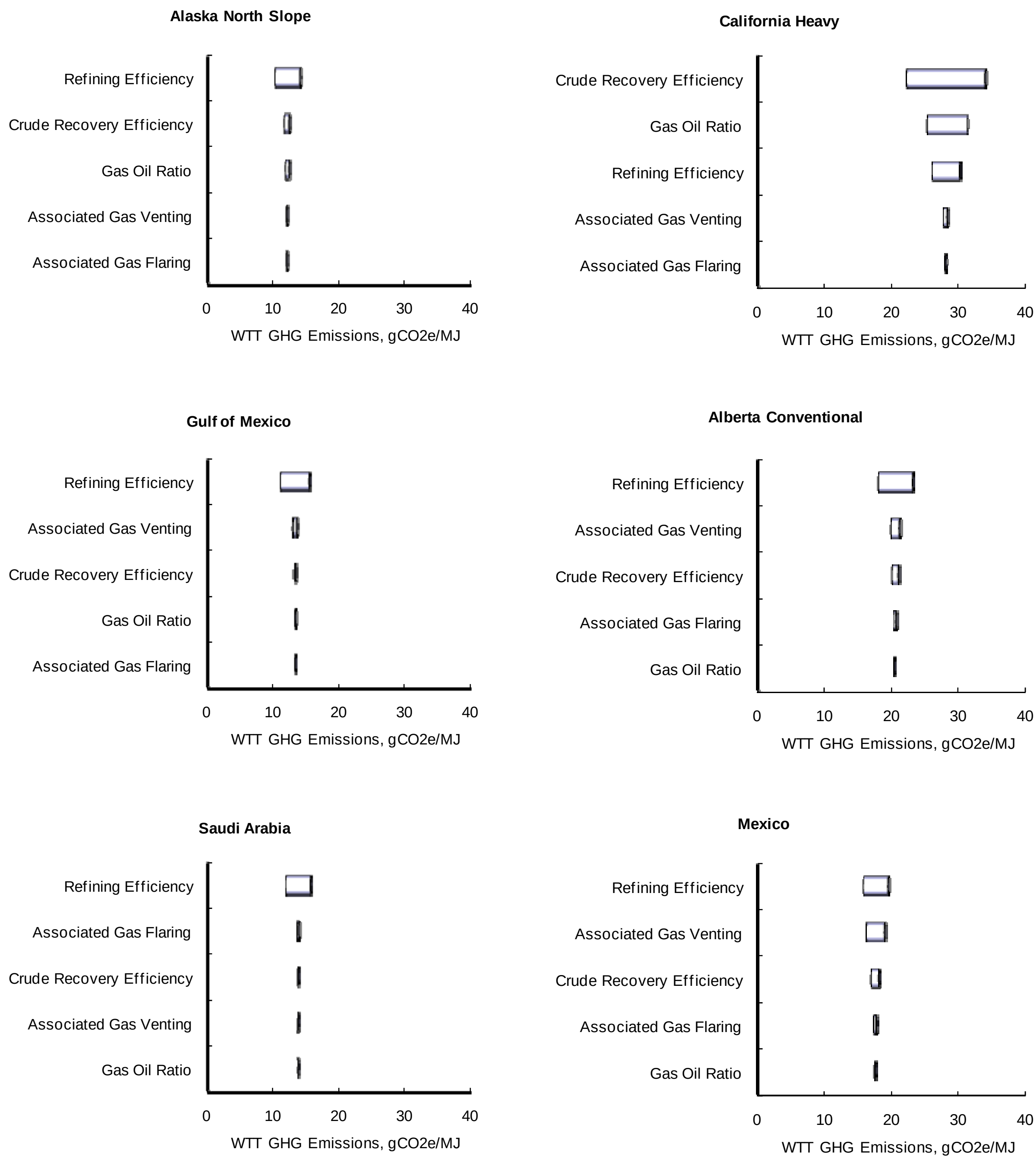


Figure 7-1. Gasoline Crude Pathways Sensitivity Plots

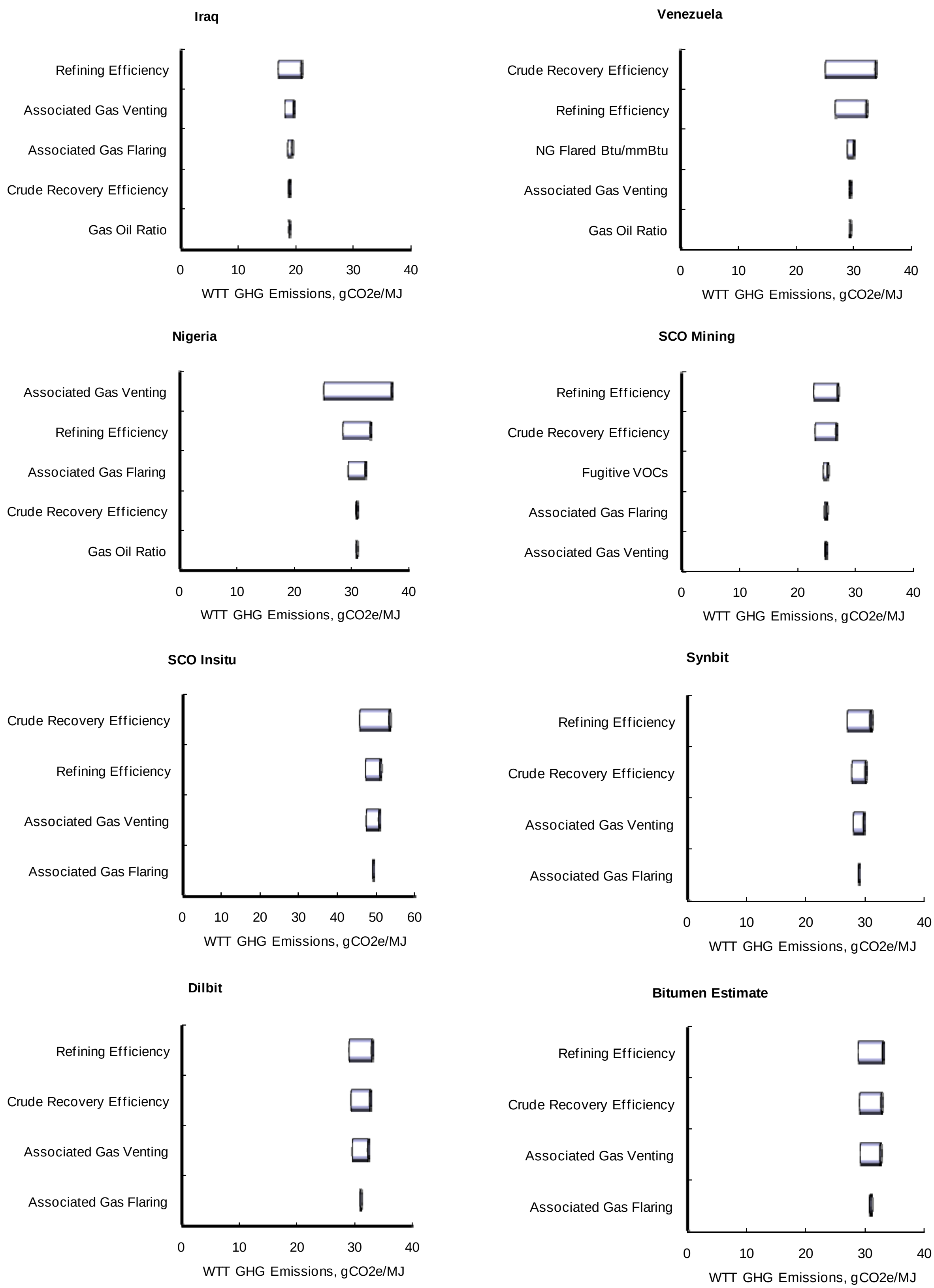


Figure 7-1. Gasoline Crude Pathways Sensitivity Plots (concluded)

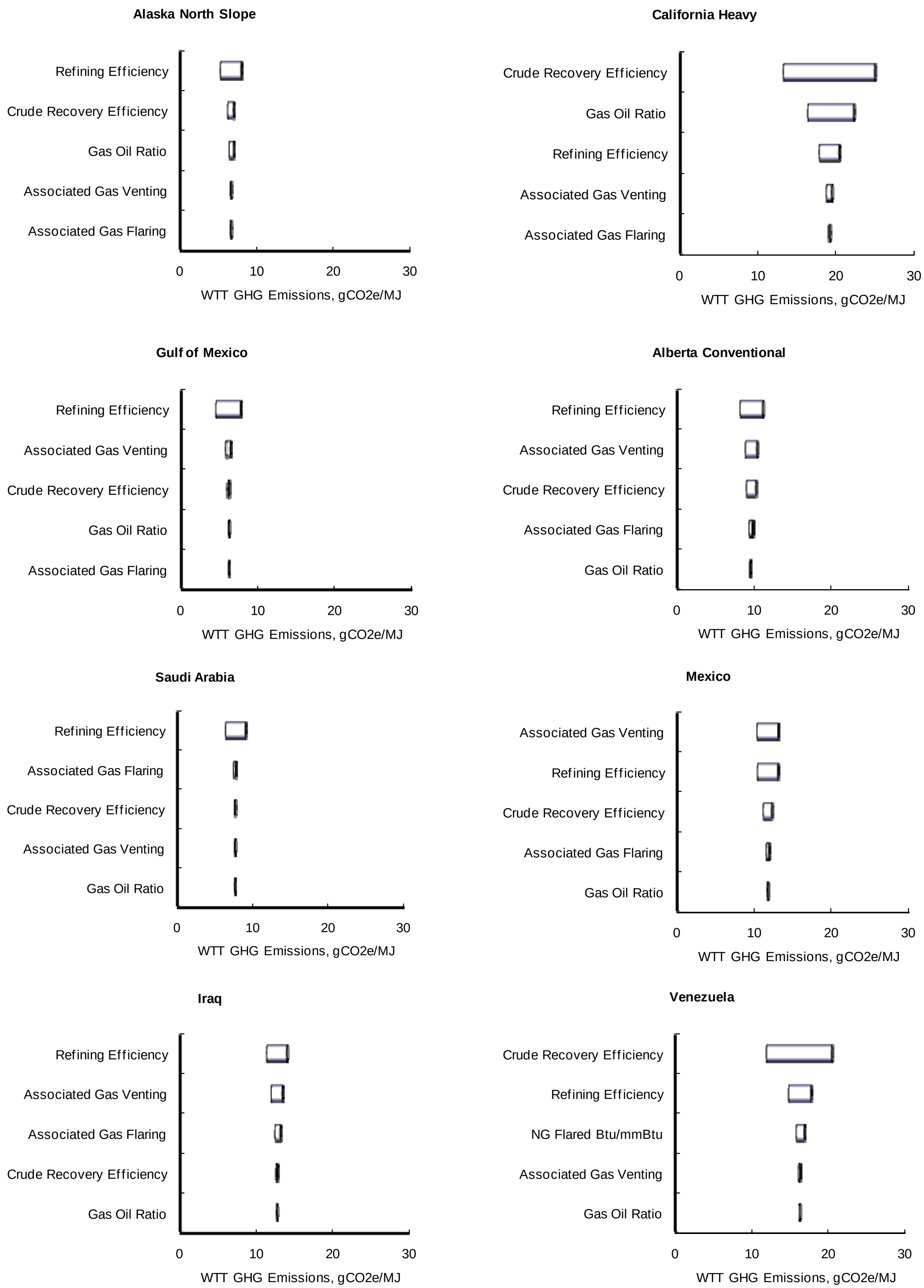


Figure 7-2. Diesel Crude Pathways Sensitivity Plots

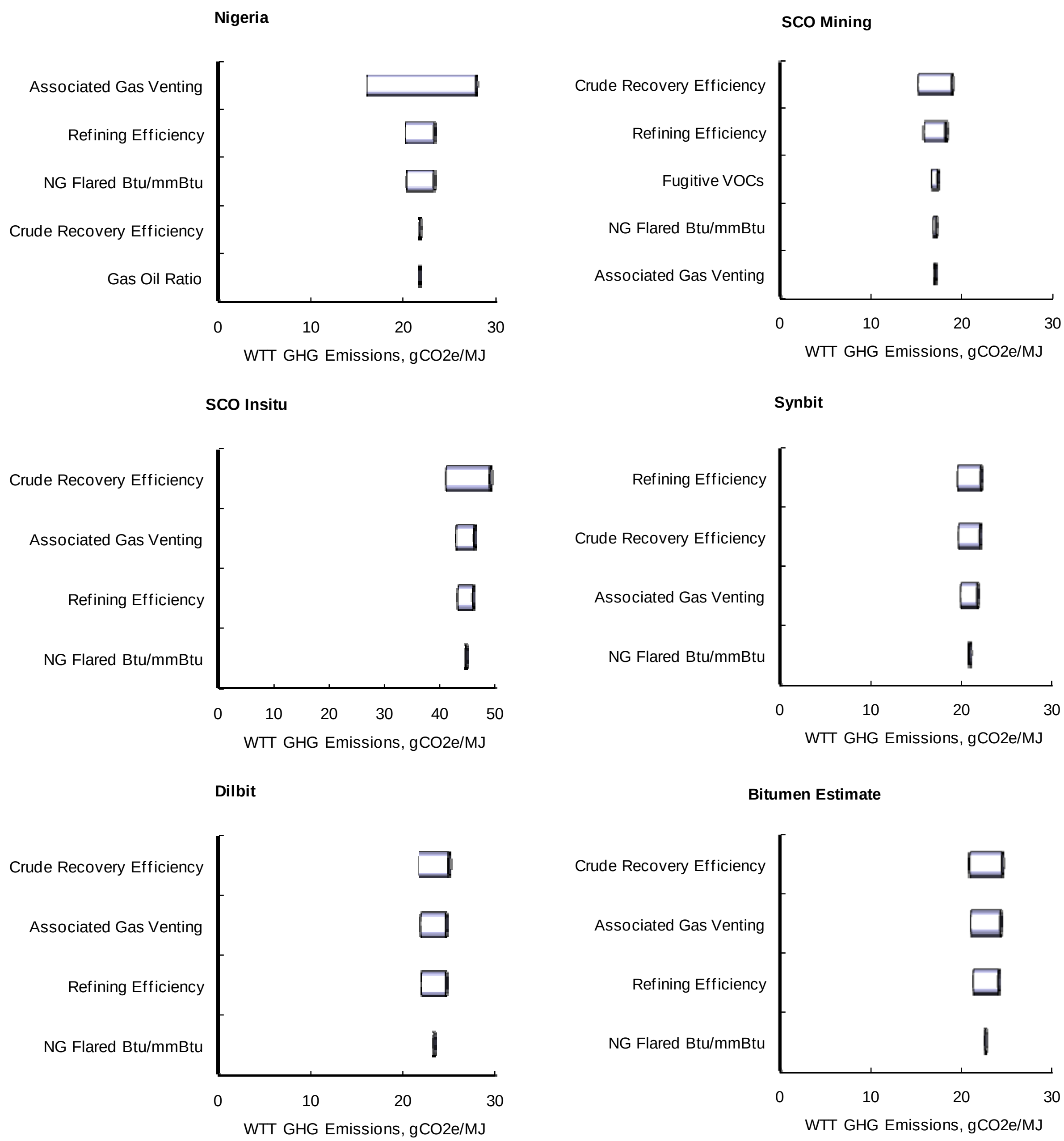


Figure 7-2. Diesel Crude Pathways Sensitivity Plots (concluded)

The figures above show the importance of variations in specific parameter values on emissions between pathways. From this analysis, it can be determined which parameters are more important to investigate further and gather more detailed and specific information.

7.2 Uncertainty Analysis

To quantify the uncertainty in our GHG estimates, the GREET stochastic simulation tool was employed. The GREET model contains hundreds of built-in distribution profiles to quantify uncertainty. The parameters with built-in profiles include fuel properties, emission factors, process efficiencies, and use rates of various non-fuel substances, such as fertilizer and solvents. In our analysis, we adjusted the recovery and refining distribution profiles to match the ranges of our data and added profiles for venting and flaring.

The stochastic tool was run once for each crude pathway using the GREET default Hammersley Sequence Sampling technique. For each case, 500 samples were run, producing a mean value and probability values. Figure 7-3 and Figure 7-4 show the mean WTT GHG emissions and error bars indicating p20 and p80 values for each pathway. The p20 and p80 values represent values in the range for which there is 20% and 80% chance, respectively, that the true value is lower than this value in the range and indicate the level of uncertainty in the GHG emissions estimates.

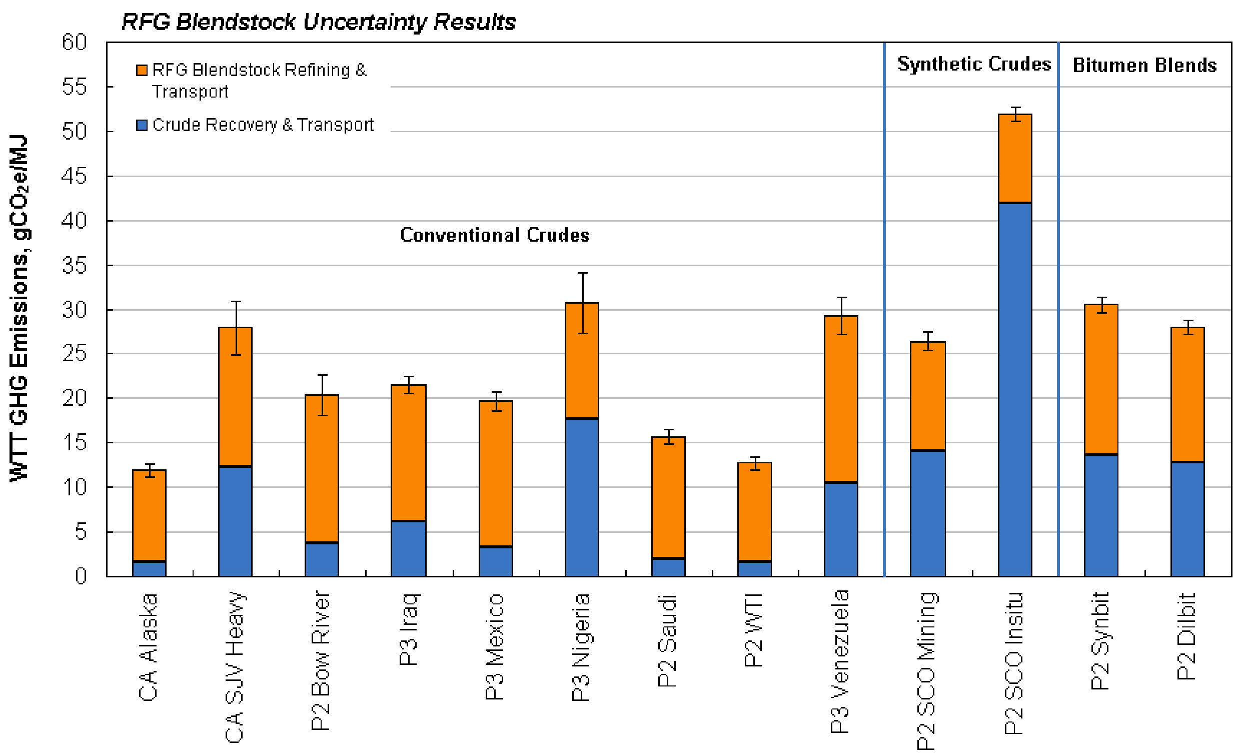


Figure 7-3. RFG Blendstock WTT GHG Uncertainty

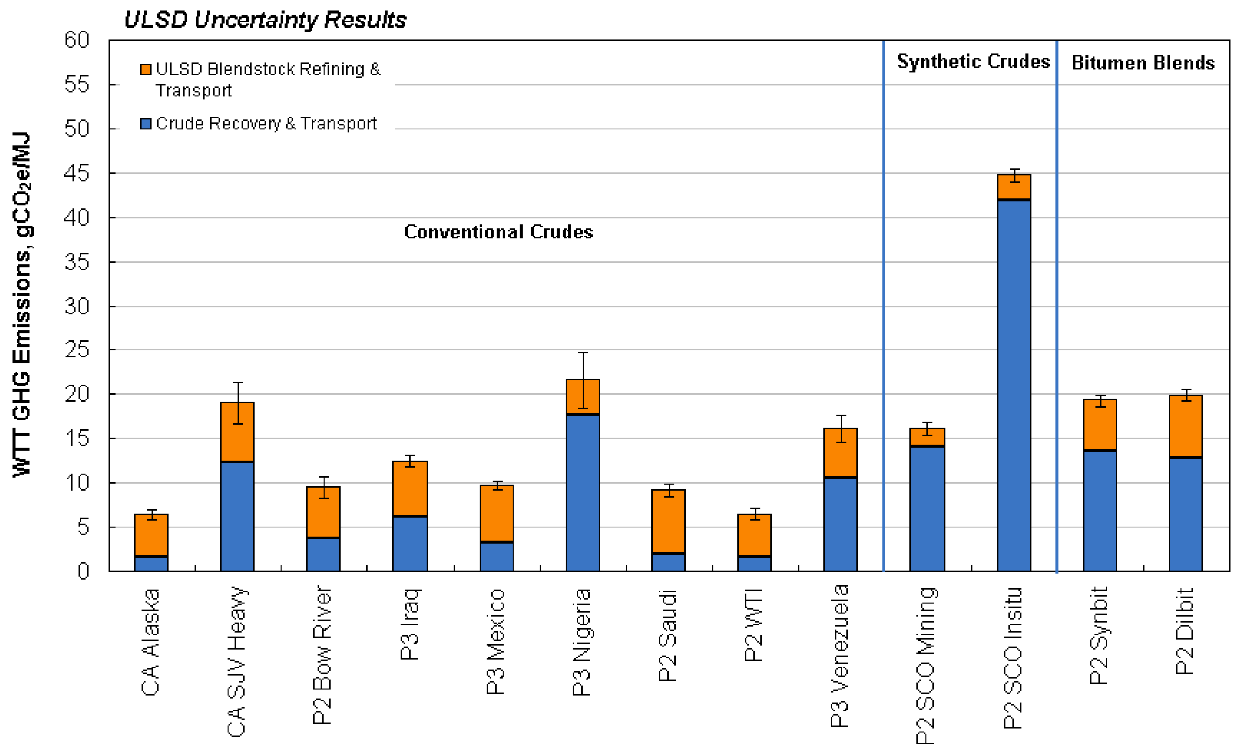


Figure 7-4. ULSD WTT GHG Uncertainty

Based on the results of the stochastic simulation, the level of uncertainty in WTT GHG estimates does not significantly change the relative rankings of the various crude pathways. The Venezuela, Nigeria, and California crude pathways show the largest ranges of uncertainty, which can be attributed to the uncertainty in their recovery emissions specifically and the scaling effect from the magnitude of these emissions. However, the ranges for these three pathways change their rankings only slightly relative to the oil sands pathways with roughly the same WTT emissions. While RFG blendstock shows greater total emissions than ULSD due to extra emissions associated with additional refining requirements, the error bars are similar for the two final products. In general, the level of uncertainty associated with the pathways within the sensitivity bounds suggests that the analysis values offer a reasonable estimate of the GHG emissions for the different crude oils.

8. Conclusions

Looking at the results provided in Sections 6 and 7, we draw the following conclusions:

Recovery Emissions

- There is a wide variation in recovery emissions among the conventional crude oils. This is due to both crude oil recovery technique and variations in vented/flared gas quantities.
- The conventional crude oil with the highest recovery emissions is Nigeria due to its venting and flaring emissions.
- SCO-Mining recovery and upgrading emissions are significantly lower than the SCO-SAGD cases, even if NG is used instead of gasified coke. This may indicate the difference between mining and SAGD recovery emissions.
- Several conventional crude oils (California, Venezuela and Nigeria) have similar recovery emissions to SCO-Mining and the Bitumen pathways (except for the Bitumen CSS 2 pathway with high SOR).
- Except for Nigeria and Iraq, venting and flaring emissions are of the same order as crude transport
- The GREET default emissions for conventional crude recovery are within the range of our results
- The GREET default value for SCO-Mining is 30% higher than our result (again, we are not confident we have accounted for all of the process fuel consumption in our SCO-Mining case)
- The GREET default value for SCO-SAGD is approximately half of our result
- The GREET default value for Bitumen In-situ recovery is similar to our SAGD value and lower than our CSS value.

Refining Emissions

- Emissions from refining light sweet crudes into RFG Blendstock is ~ 2/3 of the emissions from refining heavy sour crudes
- Emissions from refining synbit and dilbit into RFG Blendstock is comparable to that of conventional heavy sour crudes
- Emissions from refining synbit and dilbit into ULSD is comparable to the conventional crude oils
- Emissions from refining SCO are the lowest of any crude oil
- Emissions for a given crude oil vary from region to region, reflecting impact of crude slate, product slate, refinery configuration, local grid mix
- RFG Blendstock and ULSD transport emissions are relatively small
- For RFG Blendstock, the GREET refining GHG emission estimate is at the low end of the range for PADD 2 and PADD 3, but at the mid-point of the range for California refining

- For ULSD, the GREET default refining GHG emission estimate is approximately twice our average value for the crude oils considered.

WTT Emissions

- Refinery emissions are more significant for RFG blendstock than ULSD
- The SCO-Mining cases have consistently lower GHG emissions than the other oil sands pathways
- The SCO-SAGD cases consistently had the highest GHG emissions, though when the syngas derived from coke is replace with natural gas, the emissions are similar to the synbit and dilbit cases
- The heavy conventional crudes have similar emissions to the oil sands pathways
- For RFG Blendstock, the synbit pathways are slightly higher than the dilbit pathways. Had the SCO-SAGD pathway been used as the blending agent for the synbit pathways, the emissions would have been proportionately higher.
- The GREET Default RFG Blendstock emissions for conventional crudes is within the range of our estimates for the pathways considered.
- The GREET Default ULSD emissions for conventional crudes is consistent with the higher side of our range of values for the pathways considered
- The GREET Default RFG Blendstock emissions for oil sands mining and in-situ are comparable to our mining and in-situ results, respectively. Our recovery emission estimates are generally lower than the GREET estimates, while our refining emission estimates are generally higher.
- The GREET Default ULSD WTT emissions for oil sands mining and in-situ are much higher than our ULSD values. Both our recovery and refining estimates are lower than the GREET estimates.

WTW Emissions:

- There is a wide range of WTW emissions for the conventional crude oils refined in PADD 3 and California.
- The SCO-Mining pathway WTW emissions are within the range of those for the conventional crude oils refined in PADD 3 and California. However, the mining pathway likely has direct land use change emissions that are not accounted for here.
- In general, the lower end of the synbit and dilbit emissions range is at the high end of the conventional crude oil emission range. On average, the synbit/dilbit pathway emissions considered here are 10% higher than the average conventional crude oil pathways considered.
- Synbit/dilbit pathway emissions are higher than SCO-mining because in-situ recovery is inherently more energy intensive than mining.

- The SCO-SAGD pathway is higher than the in-situ dilbit pathway, suggesting that onsite upgrading results in higher emissions than upgrading at the oil refinery.

- The GREET Default values for RFG blendstock and ULSD derived from conventional crude oil are within the range of results found here (except we estimate a significantly lower ULSD value for the crude oils refined in PADD 2).

- The GREET Default values for RFG blendstock and ULSD derived from oil sands mining are higher than our estimates (particularly for ULSD)

- The GREET Default value for RFG blendstock derived from in-situ recovery of oil sands is consistent with our synbit and dilbit pathways, but lower than our SCO-SAGD pathway.

- The GREET Default value for ULSD derived from in-situ recovery of oil sands is higher than our synbit and dilbit pathways, and similar to our SCO-SAGD pathway if natural gas is used rather than gasified coke.

General Observations

- In general, the level of uncertainty associated with the pathways within the sensitivity bounds does not significantly change their relative GHG emissions rankings and suggests that the analysis values offer a reasonable estimate of the GHG emissions for the different crude oils.

- This analysis is based entirely on publicly available data. The benefit is that the results are transparent and may be utilized for transportation policy and regulation if desired. On the other hand, the analysis could be improved with the availability of more data from oil sands operations to verify our results and provide a more defensible and operationally accurate result.

- Although the GREET default values for the conventional crude oil pathways are within the range of our results, the range is quite large (20 g/MJ range). For regulatory purposes, it may be appropriate to monitor the quantities of different crude oils being utilized relative to baseline quantities to ensure that carbon reductions are actually achieved.

Suggested Next Steps:

- Add Technology Pathways: because individual recovery pathways have different WTT emissions, it would be of interest to quantify emissions for more pathways.

- Evaluate CO2 Mitigation Options: because the California LCFS will allow CO2 mitigation to count against oil sands recovery emissions, it will be important to identify technologies that are feasible, defensible, and cost effective.

- Expand Boundary Conditions: TIAX believes that all transportation fuels should be analyzed and compared using the same boundary conditions. Therefore, if indirect land use change emissions are levied on biofuels, then the emissions from land clearing for mining and in-situ operations should be taken into account. Moreover, other indirect effects associated with crude oil originating in the Middle East should be considered.

Appendices

A. Conventional Crude Recovery Supplemental Information

B. Oil Sands Projects Considered

C. Oil Sands Conversion Factors

D. MathPro Refinery Modeling Report

E. Calculating GREET Refinery Inputs from Refinery Modeling Data

F. Distribution Profiles for Uncertainty Analysis

G. Stakeholder Workshop (Attendees, Comments, Responses)

H. Comments and Responses From Final Presentation

Appendix A. Conventional Crude Oil Recovery Data

General Correlations and Factors

Waterflood Injection Energy Requirement:

29,000 bbl water/day injected; 500 hp pumps[62]

$$\frac{1\,\text{day}}{29{,}000\,\text{bbl}} * 500\,\text{hp} * \frac{0.746\,\text{kW}}{1\text{hp}} * \frac{24\,\text{hr}}{1\,\text{day}} = 0.309\,\text{kWh/bbl}$$

Gas Re-injection Energy Requirement[63]*:*

$$\text{kWh/scf} = 2.78 * 10^{-4} * \frac{k}{k-1} * p_1 \left(\frac{p_2}{p_1}\right)^{\frac{k-1}{k}}$$

Where k for methane is 1.3, P2 is assumed to be 4000 psi and P1 is 14.7 psi.

Electricity to Pump Water/Crude from Resevoir

29,000bbl water/day; 6,502 bbl oil/day recovered; 2200 hp pumps[64]

$$\frac{1\,\text{day}}{29{,}000\,\text{bbl} + 6{,}502\,\text{bbl}} * 2200\,\text{hp} * \frac{0.746\,\text{kW}}{1\text{hp}} * \frac{24\,\text{hr}}{1\,\text{day}} = 1.109\,\text{kWh/bbl}$$

[62] Paik, M.E., "Reducing Electric Power Costs in Old Oil Fields," 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery Tulsa, OK, 21-24 April 1996, SPE/DOE 35408.

[63] “Perrys Chemical Engineering Handbook.”

[64] Paik, M.E., "Reducing Electric Power Costs in Old Oil Fields," 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery Tulsa, OK, 21-24 April 1996, SPE/DOE 35408.

Alaskan Crude Oil Production Data

North Slope 2006 Production[65]

- 264.252 MMBO
- 3,026.496 BCF Produced Gas = 11,400 scf/bbl
- 2,768.902 BCF Produced Gas Injected = 10,500 scf/bbl
- Injection Water – 2.6 bbl water/bbl oil [66]

Injection Energy

- 0.308 kWh/bbl water injected
- 0.0018 kWh/scf injected (p1 = 14.7 psi; p2 = 4000 psi)[67]
- 2.6 * 0.308 + 0.0018 * 10,500 = 20 kWh/bbl oil

Produced Gas Consumed

33.1% conversion efficiency in a simple cycle combustion turbine[68]

$$\frac{20kWh}{bbl} * \frac{3412Btu}{kWh} * \frac{1Btu_{NG}}{0.331Btu_{elec}} * \frac{scf}{983Btu} = 210scf_{NG}$$

[65] ADOG, "Division of Oil and Gas 2007 Annual Report," Alaska Division of Oil and Gas, July 2007

[66] *Ibid*

[67] AOGCC, "Order and Decisions – Area Injection Orders," Alaska Oil and Gas Conservation Commission, Updated May 2006, <http://www.state.ak.us/admin/ogc/orders/aio/aioindex.htm>

[68] GREET 1.8b, "GREET 1, Version 1.8b," UChicago Argonne, LLC, 1999.

Kern County California Heavy Oil Production Data

2006 Production in California District 4[69]

- 170,164,866 Total BO produced
- 170,738,952 Total Mcf Associated Gas
- 426,530,299 Total bbls of steam injected
- 86,189,000 Total BO from Thermal EOR
- 85% WC

$$\frac{ProducedGas}{bbl_{oil}} = \frac{170{,}738{,}952 Mcf}{170{,}164{,}866 bbl_{oil}} = \frac{1{,}003 cf}{bbl_{oil}}$$

$$\text{Steam Oil Ratio (SOR)} = \frac{426{,}530{,}299 bbl_{steam}}{86{,}189{,}000 bbl_{oil}} = \frac{4.9 bbl_{steam}}{bbl_{oil}}$$

Midway-Sunset Cogeneration Plant

- 225 MW Net Plant
- 234 MW Gross
- 1,222,000 lbs steam/hr
- 64.0 MMcf Natural Gas/day

Conversion Factor – 8.33 lbs Water/gallon * 42 gallons/bbl = 349.86 lbs water/bbl

$$\frac{1{,}222{,}000 lbsWater}{hr} * \frac{1 bblWater}{349.86 lbsWater} * \frac{1 bblSteam}{1 bblWater} = \frac{3493 bblsSteam}{hr}$$

$$\frac{64.0 MMcfNG}{day} * \frac{1 day}{24 hrs} * \frac{1 hr}{3493 bblsSteam} * 10\hat{}6 = \frac{763 cfNG}{bblsteam} * \frac{4.9 bblsteam}{bbloil} = \frac{3778 cfNG}{bbloil}$$

$$225 MW * \frac{1 hr}{3493 bblsSteam} * \frac{4.9 bblSteam}{bbloil} * \frac{1000 kW}{MW} = \frac{318.8 kWh Produced}{bbloil}$$

$$\text{Pumping Energy} = \frac{1.109 kWh}{bblfluid} * \frac{1 bblfluid}{0.15 bbloil} = \frac{7.39 kWh}{bbloil}$$

[69] California Department of Conservation, "2006 Annual Report of the State Oil and Gas Supervisor," Division of Oil, Gas and Geothermal Resources, Sacramento: 2007.

US Gulf of Mexico Crude Oil Production Data

Recovery Data

- 75% WC[70]
- 3,966 scf/bbl produced gas[71]
- 2 bbl water injected/bbl fluid extracted[72]

Injection Water and Energy

$$\frac{2\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{fluid out}}} * \frac{1\,\text{bbl}_{\text{fluid out}}}{0.25\,\text{bbl}_{\text{oil}}} = \frac{8\,\text{bbl}_{\text{water in}}}{1\text{bbl}_{\text{oil}}}$$

$$\frac{8\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{oil}}} * \frac{0.308\,\text{kWh}}{1\,\text{bbl}_{\text{water in}}} = \frac{2.5\,\text{kWh}}{1\text{bbl}_{\text{oil}}}$$

Produced Gas Consumed

33.1% conversion efficiency in a simple cycle combustion turbine[73]

$$\frac{2.5\,\text{kWh}}{1\,\text{bbl}_{\text{oilt}}} * \frac{3412\,\text{Btu}}{\text{kWh}} * \frac{1\,\text{Btu}_{\text{NG}}}{0.331\,\text{Btu}_{\text{elec}}} * \frac{1\,\text{scf}_{\text{NG}}}{983\,\text{Btu}_{\text{NG}}} = \frac{26\,\text{scf}_{\text{NG}}}{1\text{bbl}_{\text{oil}}}$$

[70] Al-Kindi, Azhar, et al., “Challenges for Waterflooding in a Deepwater Environment,” SPE Productions and Operations, August 2008, Vol. 23 #3, pgs 404-410.

[71] Okuma, A.F., et al., "Baldplate Field Exploration History, Garden Banks 260, Gulf of Mexico," GCSSEPM Foundation 20th Annual Research Conference Deep Water Reserviors of the World, 3-6 December 2000.

[72] Bibars, O.A., et al., "Waterflood Strategy - Challenges and Innovations," 11th Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, U.A.E 10-13 October 2004, SPE 88774.

[73] GREET 1.8b, “GREET 1, Version 1.8b,” UChicago Argonne, LLC, 1999.

Canadian Heavy Crude Oil Production Data

Recovery Data

- 85% WC[74]
- From ERCB Report[75]:
- Crude Oil in 2007: 305e06 m^3 vented; 115e06 m^3 flared; 420e06 m^3 total
- Crude Oil and Bitumen: Total 667.6e06 m^3 vented and flared
- Crude Oil and Bitumen Sol'n gas: 16,043,671,100 m^3
- Crude Oil Produced in Alberta[76]: 191,625,000 bbl/yr

Injection Water and Energy

$$\frac{2\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{fluid out}}} * \frac{1\,\text{bbl}_{\text{fluid out}}}{0.15\,\text{bbl}_{\text{oil}}} = \frac{13\,\text{bbl}_{\text{water in}}}{1\text{bbl}_{\text{oil}}} * \frac{0.308\,\text{kWh}}{1\,\text{bbl}_{\text{water in}}} = \frac{4.1\,\text{kWh}}{1\text{bbl}_{\text{oil}}}$$

Pumping Energy

1.274 kWh/bbl removed with PCP[77]

$$\frac{1.274\,\text{kWh}}{1\,\text{bbl}_{\text{fluid out}}} * \frac{1\,\text{bbl}_{\text{fluid out}}}{0.15\,\text{bbl}_{\text{oil}}} = \frac{8.5\,\text{bbl}_{\text{water in}}}{1\text{bbl}_{\text{oil}}}$$

Produced Gas

Assume ratio of Crude oil Vented and Flared to Crude plus Bitumen Vented and Flared the same as Crude Solution Gas to Total Crude plus Bitumen Solution Gas.

$$\frac{420 * 10^6\ \text{m}^3_{\text{V+F}}}{667.6 * 10^6\ \text{m}^3_{\text{V+F}}} * 16{,}043{,}671{,}100\,\text{m}^3_{\text{soln gas}} = 10{,}092{,}851{,}000\,\text{m}^3_{\text{soln gas}}$$

$$\frac{10{,}092{,}851{,}000\,\text{m}^3_{\text{soln gas}}}{191{,}625{,}000\,\text{bbl}_{\text{crude}}} * \frac{\text{ft}^3}{0.0283168\,\text{m}^3} = \frac{1{,}860\,\text{scf}_{\text{soln gas}}}{\text{bbl}_{\text{crude}}}$$

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[74] Paik, M.E., " Reducing Electric Power Costs in Old Oil Fields," 1996 SPE/DOE Tenth Symposium on Improved Oil Recovery Tulsa, OK, 21-24 April 1996, SPE/DOE 35408.

[75] ERBC, "Upstream Petroleum Industry Flaring and Venting Report 2007," ERCB June 2008, ST60B-2008

[76] http://www.capp.ca/default.asp?V_DOC_ID=675

[77] He, L. et al., "Successful Application of 2000 PCP Wells in Daqing Oilfield," International Petroleum Technology Conference, Doha, Qatar 21-23 November 2005, IPTC 10032.

Saudi Arabia Crude Oil Production Data

Recovery Data

- 30% WC[78]
- Produced oil Ratio: 800 scf/bbl[79]
- 17% Electricity from Grid[80]
- 83% Electricity produced onsite from Produced Gas

Injection Water and Energy

$$\frac{2\ \text{bbl}_{\text{water in}}}{1\ \text{bbl}_{\text{fluid out}}} * \frac{1\ \text{bbl}_{\text{fluid out}}}{0.70\ \text{bbl}_{\text{oil}}} = \frac{2.9\ \text{bbl}_{\text{water in}}}{1\text{bbl}_{\text{oil}}}$$

$$\frac{2.9\ \text{bbl}_{\text{water in}}}{1\ \text{bbl}_{\text{oil}}} * \frac{0.308\ \text{kWh}}{1\ \text{bbl}_{\text{water in}}} = \frac{0.88\ \text{kWh}}{1\text{bbl}_{\text{oil}}}$$

$$\frac{0.88\ \text{kWh}}{1\text{bbl}_{\text{oil}}} * 17\% = \frac{0.15\ \text{kWh}_{\text{Grid}}}{1\text{bbl}_{\text{oil}}}$$

Produced Gas Consumed

33.1% conversion efficiency[81]

$$83\% * \frac{0.88\ \text{kWh}}{1\ \text{bbl}_{\text{oilt}}} * \frac{3412\ \text{Btu}}{\text{kWh}} * \frac{1\ \text{Btu}_{\text{NG}}}{0.331\ \text{Btu}_{\text{elec}}} * \frac{1\ \text{scf}_{\text{NG}}}{983\ \text{Btu}_{\text{NG}}} = \frac{7.7\ \text{scf}_{\text{NG}}}{1\text{bbl}_{\text{oil}}}$$

[78] Kokal, Sunil and Abdullah Al-Ghamdi, "Oil-Water Separtion Experience From a Large Oil Field," SPE Production and Operations, Vol 21 #3, August 2006.

[79] *Ibid*

[80] NETL, "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," NETL, November 26, 2008.

[81] GREET 1.8b, "GREET 1, Version 1.8b," UChicago Argonne, LLC, 1999.

Mexico Crude Oil Production Data

Crude Oil Recovery Data

- 1.8 Million bbl/day production[82]
- 1.2 Billion scf/day Nitrogen produced[83]
- 21 kWh/1000 scf N_2 for the Nitrogen Plant[84]
- 400 scf for gas lift/bbl oil produced[85]
- 34% Electricity from Grid for Gas lift[86]
- 66% Electricity produced onsite from Produced Gas
- 371.6 Produced Gas to Oil ratio[87] (this gas is in excess of the 400 scf used for gas lift)

Injected Nitrogen Energy

$$\frac{NitrogenGas}{bbl_{oil}} = \frac{1{,}200{,}000{,}000\,scf}{1{,}800{,}000\,bbl_{oil}} = \frac{667\,scf}{bbl_{oil}} * \frac{21\,kWh}{1000\,scf} = \frac{14\,kWh}{bbl_{oil}}$$

53% conversion efficiency for combined cycle turbine[88]

$$\frac{14\ \text{kWh}}{\text{bbl}_{\text{oil}}} * \frac{3412\ \text{Btu}}{\text{kWh}} * \frac{1\ \text{Btu}_{\text{NG}}}{0.53\ \text{Btu}_{\text{elec}}} * \frac{1\ \text{scf}_{\text{NG}}}{983\ \text{Btu}_{\text{NG}}} = \frac{92\ \text{scf}_{\text{NG}}}{\text{bbl}_{\text{oil}}}$$

Gas Lift Energy

$$\frac{400\ \text{scf}_{\text{gas in}}}{\text{bbl}_{\text{oil}}} * \frac{0.0016\ \text{kWh}}{\text{bbl}_{\text{water in}}} = \frac{0.63\ \text{kWh}}{\text{bbl}_{\text{oil}}} * 34\% = \frac{0.2\ \text{kWh}_{\text{Grid}}}{\text{bbl}_{\text{oil}}}$$

Produced Gas Consumed

33.1% conversion efficiency[89]

$$66\% * \frac{0.63\ \text{kWh}}{1\ \text{bbl}_{\text{oilt}}} * \frac{3412\ \text{Btu}}{\text{kWh}} * \frac{1\ \text{Btu}_{\text{NG}}}{0.331\ \text{Btu}_{\text{elec}}} * \frac{1\ \text{scf}_{\text{NG}}}{983\ \text{Btu}_{\text{NG}}} = \frac{4\ \text{scf}_{\text{NG}}}{1\text{bbl}_{\text{oil}}}$$

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82 EIA "Mexico," EIA Country Analysis Briefs, December 2007

83 http://www.ipsi.com/Tech_papers/cantarell2.pdf

84 Email communications with Praxair that helps run the Cantarell Oil Field Nitrogen Plant.

85 Guerrero-Sarabia, I., et al., "Stability Analysis of Gas Lift Wells Used for Deepwater Oil Production," First International Oil Conference and Exhibition in Mexico, 31-August - 2 September 2008, SPE 104037.

86 NETL, "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels," NETL, November 26, 2008.

87 Limon-Hernandez, T., "Overview of Cantarell Field Development Offshore Mexico," World Oil, July 1999.

88 GREET 1.8b, "GREET 1, Version 1.8b," UChicago Argonne, LLC, 1999.

89 *Ibid*

Iraq Crude Oil Production Data

Crude Oil Recovery Data

- 60% WC[90]
- Produced oil Ration: 490 scf/bbl[91]
- 17% Electricity from Grid[92]
- 83% Electricity produced onsite from Produced Gas

Water Injection Energy

$$\frac{2\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{fluid out}}} * \frac{1\,\text{bbl}_{\text{fluid out}}}{0.40\,\text{bbl}_{\text{oil}}} = \frac{5\,\text{bbl}_{\text{water in}}}{1\text{bbl}_{\text{oil}}}$$

$$\frac{5\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{oil}}} * \frac{0.308\,\text{kWh}}{1\,\text{bbl}_{\text{water in}}} = \frac{1.54\,\text{kWh}}{1\text{bbl}_{\text{oil}}}$$

$$\frac{1.54\,\text{kWh}}{1\text{bbl}_{\text{oil}}} * 17\% = \frac{0.26\,\text{kWh}_{\text{Grid}}}{1\text{bbl}_{\text{oil}}}$$

Produced Gas Consumed

33.1% conversion efficiency[93]

$$83\% * \frac{1.54\,\text{kWh}}{1\,\text{bbl}_{\text{oilt}}} * \frac{3412\,\text{Btu}}{\text{kWh}} * \frac{1\,\text{Btu}_{\text{NG}}}{0.331\,\text{Btu}_{\text{elec}}} * \frac{1\,\text{scf}_{\text{NG}}}{983\,\text{Btu}_{\text{NG}}} = \frac{13.4\,\text{scf}_{\text{NG}}}{1\text{bbl}_{\text{oil}}}$$

[90] Kabir, C.S., et al., "Lessons Learned From Energy Models: Iraq's South Rumaila Case Study," SPE Reservior Evaluation and Engineering, Vol. 11 #4, August 2008.

[91] *Ibid*

[92] NETL, “Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels,” NETL, November 26, 2008.

[93] GREET 1.8b, “GREET 1, Version 1.8b,” UChicago Argonne, LLC, 1999.

Venezuela Heavy Oil Production Data

Crude Recovery Data

- 39% WC[94]
- 1.7 Steam Oil Ratio[95]
- Produced Gas oil ratio – 495 scf/bbl[96,97]
- Steam Oil Field Boiler[98]:
- 62.5 MMBtu/hr heat input
- 50.0 MMBtu/hr heat output
- 3,500 bbl steam/day
- Electricity requirement: 320,000kWh/yr
- Annual average steam: 1,022,000 bbl/yr

Pumping Energy

$$\frac{1.109\,\mathrm{kWh}}{\mathrm{bbl}_{\mathrm{fluid}}} * \frac{\mathrm{bbl}_{\mathrm{fluid}}}{0.61\,\mathrm{bbl}_{\mathrm{oil}}} = \frac{1.82\,\mathrm{kWh}}{1\mathrm{bbl}_{\mathrm{oil}}}$$

Steam Generator Parasitic Electricity Consumption

$$\frac{320{,}000\,\mathrm{kWh}}{1{,}022{,}000\,\mathrm{bbl}_{\mathrm{steam}}} * \frac{1.7\,\mathrm{bbl}_{\mathrm{steam}}}{\mathrm{bbl}_{\mathrm{oil}}} = \frac{0.53\,\mathrm{kWh}}{1\mathrm{bbl}_{\mathrm{oil}}}$$

Natural Gas Consumed for Electricity Production via Simple Cycle Turbine

$$\frac{2.4\,\mathrm{kWh}}{1\,\mathrm{bbl}_{\mathrm{oilt}}} * \frac{3412\,\mathrm{Btu}}{\mathrm{kWh}} * \frac{1\,\mathrm{Btu}_{\mathrm{NG}}}{0.331\,\mathrm{Btu}_{\mathrm{elec}}} * \frac{1\,\mathrm{scf}_{\mathrm{NG}}}{930\,\mathrm{Btu}_{\mathrm{NG}}} = \frac{27\,\mathrm{scf}_{\mathrm{NG}}}{1\mathrm{bbl}_{\mathrm{oil}}}$$

Natural Gas + Produced Gas Consumed for Steam

$$\frac{1.7\,\mathrm{bbl}_{\mathrm{steam}}}{1\,\mathrm{bbl}_{\mathrm{oilt}}} * \frac{1\,\mathrm{day}}{3{,}500\,\mathrm{bbl}_{\mathrm{steam}}} * \frac{24\,\mathrm{hours}}{1\,\mathrm{day}} * \frac{62.5 * 10^{6}\ \mathrm{Btu}_{\mathrm{NG}}}{1\,\mathrm{hr}} * \frac{1\,\mathrm{scf}_{\mathrm{NG}}}{983\,\mathrm{Btu}_{\mathrm{NG}}} = \frac{741\,\mathrm{scf}_{\mathrm{NG}}}{1\mathrm{bbl}_{\mathrm{oil}}}$$

94

95 de Haan, H. J., et al., "Perfomrance Analysis of a Major Steam Drive Project in the Tia Juana Field, Western Venzuela," Journal Journal of Petroleum Technology, Vol. 21 No 1, January 1969, pgs 111-119.

96 Pizzarelli, S.G., et al., "Results of Thermal Horizontal Completions with Sand Control in Lake Maracaibo, Venezuela: Case Histories of Horizontal Gravel Packs in Bachaquero-01 Reservior," SPE/Ps-CIM/CHOA International Thermal Operations and HEavy Oil symposium and International Horizontal Well Technology Conference, Calgary, Alberta Canada, 4-7 November 2002.

97 Dou, Hong'en, et al., " Decline Analysis for Horizontal Wells of Intercampo Field, Venezuela," 2007 Production and Operations Symposium Oklahoma City, OK, 31 March - 3 April 2007, SPE 106440.

98 Sarathi, Partha S. and David K Olsen, "Practical Aspects of Steam Injection Processes: A Handbook for Independent Operators," National Institute for Petroleum and Energy Research for US DOE, October 1992, No. DE-FC22-83FE60149.

Nigeria Crude Oil Production Data

Crude Recovery Data

- 416 scf/bbl Gas lift rate[99]
- 13% WC[100]
- Produced Gas Oil Ratio – 1734 scf/bbl[101]
- 26% Electricity from Grid[102]
- 74% Electricity produced onsite from Produced Gas

Injection Water and Energy

$$\frac{2\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{fluid out}}} * \frac{1\,\text{bbl}_{\text{fluid out}}}{0.87\,\text{bbl}_{\text{oil}}} = \frac{2.3\,\text{bbl}_{\text{water in}}}{1\text{bbl}_{\text{oil}}}$$

$$\frac{2.3\,\text{bbl}_{\text{water in}}}{1\,\text{bbl}_{\text{oil}}} * \frac{0.308\,\text{kWh}}{1\,\text{bbl}_{\text{water in}}} = \frac{0.71\,\text{kWh}}{1\text{bbl}_{\text{oil}}}$$

Gas Lift Energy

$$\frac{416\,\text{scf}_{\text{gas in}}}{\text{bbl}_{\text{oil}}} * \frac{0.0016\,\text{kWh}}{\text{bbl}_{\text{water in}}} = \frac{0.76\,\text{kWh}}{\text{bbl}_{\text{oil}}}$$

$$\frac{1.47\,\text{kWh}}{\text{bbl}_{\text{oil}}} * 26\% = \frac{0.38\,\text{kWh}_{\text{Grid}}}{\text{bbl}_{\text{oil}}}$$

Produced Gas Consumed

33.1% conversion efficiency[103]

$$74\% * \frac{1.47\,\text{kWh}}{1\,\text{bbl}_{\text{oilt}}} * \frac{3412\,\text{Btu}}{\text{kWh}} * \frac{1\,\text{Btu}_{\text{NG}}}{0.331\,\text{Btu}_{\text{elec}}} * \frac{1\,\text{scf}_{\text{NG}}}{983\,\text{Btu}_{\text{NG}}} = \frac{11.4\,\text{scf}_{\text{NG}}}{1\text{bbl}_{\text{oil}}}$$

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99 Ghoniem, E.Q., "Dynamic Production Optimization in Khafji Offshore Field," 2006 Abu Dhabi International Petroleum Exhibition and Conference, Abu Dhabi, U.A.E., 5-8 November 2006, SPE 101388.

100 Hart Resources, Ltd, “Nigeria Extractive Industries Transparency Initiative,” Hart Resources Ltd., November 2006.

101 *Ibid*

102 NETL, “Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels,” NETL, November 26, 2008.

103 GREET 1.8b, “GREET 1, Version 1.8b,” UChicago Argonne, LLC, 1999.

Appendix B. Oil Sands Projects Considered

The oil sands projects considered for this analysis were derived from the following list of projects in the government of Alberta's semi-annual update.[104] The projects selected to represent the four oil sands pathways (in blue) met the three criteria set by the Steering Committee:

- Availability of detailed and public/releasable energy and material balance data
- As close to currently producing as possible
- High production capacity relative to other projects of its type

Project Name	Operator	Type	Status	Design Capacity (thousand bpd)
Cold Lake	CNRL	Cold	Producing	75
Orion Hilda Lake	Shell Canada	Cold	Under construction	10
Peace River Oil Sands	Penn West Energy Trust	Cold	Producing	5
Pelican Lake	CNRL	Cold	Producing	35
Pelican Lake	EnCana Energy, ConocoPhillips	Cold	Producing	24
Carmon Creek	Shell Canada	CSS	Application filed	100
Cold Lake	Imperial Oil	CSS	Producing	160
Cold Lake Nabiye Expansion	Imperial Oil	CSS	Application approved	30
Primrose	CNRL	CSS	Producing	80
Primrose Expansion	CNRL	CSS	Application approved	40
Peace River	Shell Canada	CSS, cold production	Producing	30
Black Gold	Korea National Oil Corporation	*In situ*	Resource delineation underway	30
Fort Hills	Petro-Canada	Mining	Under construction	190
Jackpine Mine	AOSP	Mining	Under construction	200
Jackpine Mine Expansion	Shell Canada	Mining	Application filed	100
Joslyn Mine	Total E&P	Mining	Application filed	100
Kearl	Imperial Oil, Exxon Mobil	Mining	Application approved	300
Lease 14/Lease 311	UTS Energy, Teck Cominco	Mining	Resource delineation underway	50
Muskeg River Mine	AOSP	Mining	Producing	150
Muskeg River Mine Expansion	AOSP	Mining	Under construction	120

[104] Alberta Employment, Immigration and Industry. "Alberta Oil Sands Industry Update." December 2007

Project Name	Operator	Type	Status	Design Capacity (thousand bpd)
Northern Lights Phases 1 and 2	Synenco Energy	Mining	Application filed	100
Pierre River Mine	Shell Canada	Mining	Application filed	200
Voyageur South	Suncor	Mining	Application filed	120
Horizon	CNRL	Mining/upgrading	In start-up	110
Horizon Phases 2 and 3	CNRL	Mining/upgrading	Application approved	122
Horizon Phases 4 and 5	CNRL	Mining/upgrading	Publicly discussed	500
Steepbank/Millennium	Suncor	Mining/upgrading	Producing	239
Syncrude	Syncrude	Mining/upgrading	Producing	304
Algar	Connacher Oil and Gas	SAGD	Application filed	10
Borealis	EnCana Energy, ConocoPhillips	SAGD	Application filed	100
Christina Lake	MEG Energy	SAGD	Application filed	210
Christina Lake	EnCana Energy, ConocoPhillips	SAGD	Producing	60
Christina Lake	MEG Energy	SAGD	Under construction	3
Christina Lake Expansion	EnCana Energy, ConocoPhillips	SAGD	Publicly discussed	90
Ells River	Chevron, Shell, Marathon	SAGD	Resource delineation underway	100
Foster Creek	EnCana Energy, ConocoPhillips	SAGD	Producing	60
Great Divide	Connacher Oil and Gas	SAGD	Producing	10
Hangingstone	JACOS	SAGD	Disclosed	30
Hangingstone Pilot	JACOS	SAGD	Pilot	9
Jackfish	Devon Energy	SAGD	Under construction	35
Jackfish 2	Devon Energy	SAGD	Application filed	35
Joslyn Phase 3	Total E&P Canada, Enerplus Resources Fund	SAGD	Application filed	15
Joslyn Phases 1 and 2	Total E&P Canada, Enerplus Resources Fund	SAGD	Producing	12
Kai Kos Dehseh	Statoil Canada, North American Oil Sands Corporation	SAGD	Application filed	220
Kirby	CNRL	SAGD	Application filed	45
MacKay River	Petro-Canada	SAGD	Producing	33
MacKay River Expansion	Petro-Canada	SAGD	Application filed	40
May River	Petrobank Energy & Resources	SAGD	Disclosed	100
Meadow Creek	Petro-Canada	SAGD	Application approved	80

Project Name	Operator	Type	Status	Design Capacity (thousand bpd)
Saleski and Caribou	Husky Energy, BP	SAGD	Application filed for pilot	1
Sunrise	Husky Energy, BP	SAGD	Under construction	200
Surmont	MEG Energy	SAGD	Application in progress	50
Tucker	Husky Energy	SAGD	Producing	35
Terre de Grace	The Value Creation Group	SAGD/upgrader	Application in progress	300
Long Lake	Nexen, OPTI	SAGD/upgrading	In start-up	58
Surmont	ConocoPhillips	SAGD/upgrading	Producing	25
White Sands	Petrobank Energy & Resources	THAI	Pilot	18
Alberta Heartland Upgrader	BA Energy	Upgrader	Under construction	160
North American Upgrader	Statoil Canada, North American Oil Sands Corporation	Upgrader	Application filed	250
North West Upgrader	North West Upgrading	Upgrader	Under construction	150
Northern Lights Upgrader	Synenco Energy	Upgrader	On hold	100
Scotford Upgrader	AOSP	Upgrader	Producing	136
Scotford Upgrader Expansion 1	Shell Canada	Upgrader	Under construction	90
Scotford Upgrader Expansion 2	Shell Canada	Upgrader	Application filed	400
Sturgeon Upgrader	Petro-Canada, UTS Energy, Teck Cominco	Upgrader	Application filed	340
Syncrude 21, Stage 3	Syncrude	Upgrader	Under construction	40
Total Upgrader	Total E&P Canada Ltd	Upgrader	Application filed	200

Appendix C. Oil Sands Conversion Factors

The following conversion factors are assumed in absence of specified data from the original references.

Bitumen	6,315 MJ/bbl
SCO	5,800 MJ/bbl
Diesel	5,682 MJ/bbl
LPG	4,737 MJ/bbl
Natural gas	36.2 MJ/m^3
Upgrader gas	43.2 MJ/m^3

Appendix D. MathPro Refinery Modeling Final Report

DRAFT

A LIFECYCLE ASSESSMENT (LCA) OF

NORTH AMERICAN AND IMPORTED CRUDES

FINAL REPORT:

ESTIMATING REFINERY ENERGY CONSUMPTION

AND CO_2 EMISSIONS FOR SELECTED CRUDE OILS

IN THE U.S. REFINING SECTOR

Prepared for

ALBERTA ENERGY RESEARCH INSTITUTE

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TABLE OF CONTENTS

1. INTRODUCTION

The analysis in Task 4 has two objectives:

- Estimate the U.S. refining sector's per-barrel energy use in producing each of the four primary co-products of the refining process: gasoline, jet fuel, diesel fuel and other distillate products (such as heating oil), and all other refined products.

- Estimate the U.S. refining sector's per-barrel energy use and the resulting CO_2 emissions in refining each of thirteen specified crude oils in various U.S. refining regions.

These estimates are intended to support life cycle analysis – sometimes called "well-to-wheels" analysis – of refined product supply pathways by means of LCA models, such as GREET 1.7.[1]

The analysis considered twenty-six (26) crude oil/region combinations, shown in **Exhibit 1.1**.

Exhibit 1.1: Crude Oil / U.S. Refining Region Combinations Analyzed

Origin	Crude Oil	Refining Region		
		PADD 2	PADD 3	Calif.
U.S.				
Gulf Coast	West Texas Inter. (WTI)	x	x	
California	SJV Heavy			x
Alaska	ANS			x
Imports (ex Canada)				
Saudi Arabia	Saudi Medium	x	x	x
Iraq	Basrah Medium		x	x
Nigeria	Escravos		x	
Venezuela	Bachaquero 17		x	
Mexico	Maya		x	x
Canada				
Conventional Heavy	Bow River	x		
SCO	SCO *(mined bitumen)*	x	x	x
SCO	SCO *(in situ bitumen)*	x	x	x
Synbit	SCO / in situ bitumen	x	x	x
Dilbit	Conden. / in situ bitumen	x	x	x

[1] *Operating Manual for GREET: Version 1.7*; Center for Transportation Research, Argonne National Laboratory; ANL/ESD/05-3; February 2007; http://www.transportation.anl.gov/modeling_simulation/GREET/publications.html#intro

The eight U.S. and imported (ex Canada) crude oils, along with Bow River crude, are large-volume, conventional crudes ranging in quality from light, low-sulfur (WTI, Escravos) to very heavy, high-sulfur (SJV Heavy, Maya). The Canadian crudes (ex Bow River) are representative of the crudes being produced from Alberta oil sands and entering U.S. markets in increasing volumes. The refining regions associated with each crude oil are those to which the crude oil now flows and those to which it would likely flow in the future. For example, future volumes of the oil sands crudes would most likely go to PADD 2 (the Midwest), PADD 3 (the Gulf Coast), and California, for economic and logistical reasons.[2]

We developed estimates of refinery energy use by means of detailed, process-oriented modeling of regional refining operations. In particular, we used linear programming (LP) modeling, implemented in MathPro's proprietary refinery modeling system (called **ARMS**), to develop and operate a *national* U.S. refining model and three *regional* refining models.

The national model represents aggregate refining capacity and refining operations in the U.S. in 2006. We used the this model to estimate the refining sector's per-barrel energy use attributable to the production of gasoline, jet fuel, diesel fuel and other distillate products, and all other refined products.

Each regional model represents aggregate refining capacity in one of the regions of interest, processing a mixed crude oil slate and producing a slate of refined products meeting all U.S. specifications and regulatory requirements. We used the regional models to estimate refinery energy use and resulting CO_2 emissions associated with processing the various crude oils in the specified refining regions combination.

This report discusses the technical foundation, methodology, and results of Task 4 and comprises eight sections, including this one.

1. Introduction
2. Essentials of crude oils, refining, and refinery energy use
3. Crude oil assays used in the analysis
4. Energy use in U.S. refineries
5. The refinery energy and CO_2 accounting framework used in the analysis
6. Overview of the analytical approach
7. Key results and findings
8. Comments on the results

[2] Some Alberta crude oil flows to U.S. PADD 4 (the Mountain states) and that volume is likely to increase. We did not consider PADD 4 in this analysis because it is small, accounting for less than 4% of U.S. refining capacity.

2. Some Essentials of Crude Oil Characterization, Refining, and Refinery Energy Use

To facilitate the subsequent discussion of the technical approach and results of Task 4, this section offers an overview of basic concepts regarding crude oils, refining operations, and refinery energy use. Detailed discussion of refining operations in general and the U.S. refining sector in particular is well beyond the scope of this study.[3]

2.1 Crude Oil and Its Constituents

Hundreds of crude oils (usually identified by geographic origin) are processed, in greater or lesser volumes, in the world's refineries. Each crude oil is a unique mixture of thousands of compounds, mainly hydrocarbons.[4] Some hydrocarbon compounds contain small (but important) amounts of other ("hetero"-) elements, most notably sulfur, nitrogen, and certain metals (e.g., nickel, vanadium, etc.). The compounds that make up crude oil range from the smallest and simplest hydrocarbon molecule – CH_4 (methane) – to large, complex molecules containing up to 50 or more carbon atoms (as well hydrogen and hetero-elements).

In general, the more carbon atoms in a hydrocarbon molecule, the heavier and more dense the material and the higher the boiling temperature.[5] This characteristic of hydrocarbons enables the separation of crude oils into distinct boiling range constituents, or fractions, by *distillation* (or *fractionation*), a standard refining process that is the starting point for all other refining processes and operations.

The physical and chemical properties of any given crude oil fraction or refinery-produced stream depends on the molecular composition of the stream – not only the number of carbon atoms in each component but also the nature of the chemical bonds between them. Carbon atoms readily bond with one another (and with hydrogen and hetero-atoms) in various ways – single bonds, double bonds, and triple bonds – to form different classes of hydrocarbons, as illustrated in **Exhibit 2.1** Paraffins, aromatics, and naphthenes are natural constituents of crude oil; but are produced in various refining operations as well. Olefins are not present in crude oil; they are produced in certain refining operations dedicated mainly to gasoline production.

The proportions of these hydrocarbon classes, their carbon number distribution, and the concentration of hetero-elements in a given crude oil influence the yields and qualities of the

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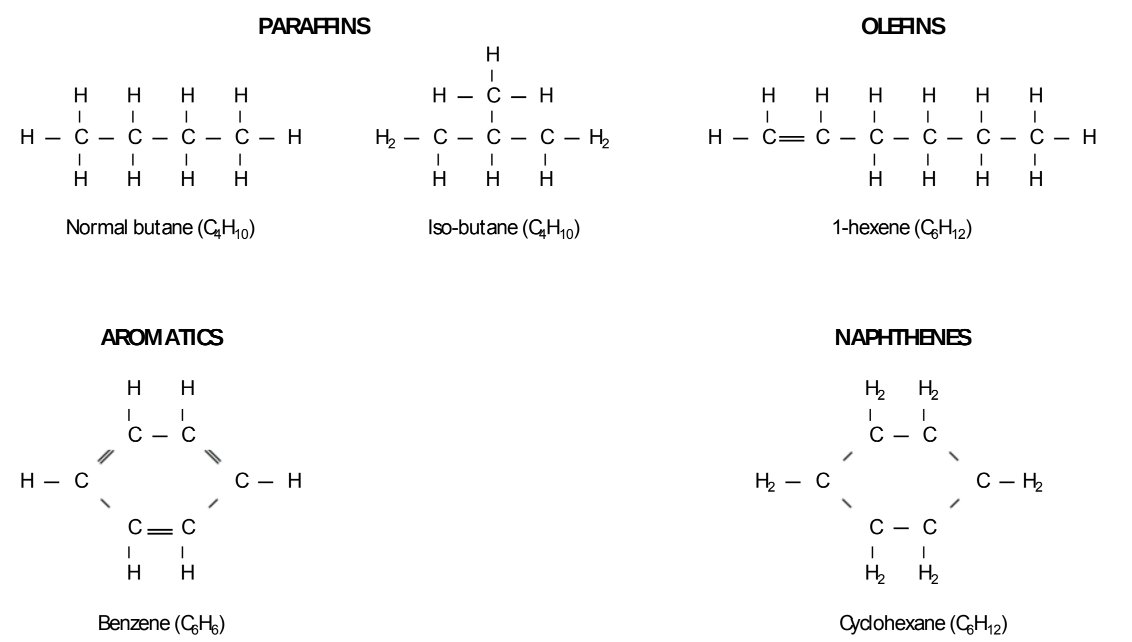
[3] For a particularly useful discussion of the fundamentals of refining operations in the U.S. refining sector, see Appendix C of "U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels"; June 2000; National Petroleum Council; www.npc.org

[4] Hydrocarbons are organic compounds composed of carbon and hydrogen.

[5] Gasoline, for example, consists of molecules in the C_4–C_{12} range, and has a boiling range of ≈ 60°–375°F; diesel fuel consists of molecules in the C_{15}–C_{20} range, and has a boiling range of ≈ 425°–625°F.

refined products that a given refinery can produce from that crude, and hence the economic value of the crude.

Exhibit 2.1: Important Classes of Hydrocarbon Compounds in Refining



For example, the volume of gasoline that a given refinery can produce depends in part on the fraction of the crude oil that is in the gasoline boiling range. In that boiling range, aromatic and naphthenic compounds contribute more octane to the gasoline pool than do paraffinic compounds. (In the U.S., refiners must control the aromatics content of gasoline in order to meet emissions standards.) In the distillate (jet fuel and diesel fuel) boiling range, aromatics content adversely affects product quality (cetane number, smoke point); hence, the processing severity required to meet jet fuel and diesel fuel specifications increases with the aromatics content of the crude fractions in the distillate boiling range.

As Figure 2.1 indicates, aromatic compounds have higher carbon-to-hydrogen ratios than paraffins and naphthenes. Due to the chemistry of oil refining, the higher the aromatics content of a crude oil, the higher the coke[6] yield and the more hydrogen is required in the refining process (all else equal). Through mechanisms such as these, the chemical make-up of a crude oil and its various boiling range fractions influence refinery energy use and the CO_2 emissions associated with refining the crude to produce a given slate of refined products.

[6] Petroleum coke is ≈ 95 wt% carbon.

2.2 Crude Oil Characterization

A *crude oil assay* is a detailed characterization of the chemical and physical properties of a crude oil and its boiling range fractions, developed from an extensive set of analyses performed by petroleum testing laboratories. A crude assay includes a characterization of the crude oil as a whole and more detailed characterizations of each boiling range fraction. Every crude oil has a unique assay; no two are the same.[7]

Detailed assays for all crudes in commerce are maintained in proprietary assay libraries. Many assays are placed in the public domain, in varying levels of detail and varying vintage. For many crudes – particularly those that have been in commerce for some time – assays of recent vintage and sufficient detail for most analytical purposes are available in the public domain.

Exhibit 2.2 shows an extract of the physical and chemical properties reported in a typical crude assay. The properties shown in Exhibit 2.2 are those that we usually use in assessing the economic values of crude oils.

Crude assay yields – the volumetric yields of the various crude oil fractions – often are presented graphically as a *crude oil distillation curve*, a plot of cumulative volume distilled off as a function of boiling temperature.

The indicated properties of the whole crude – API gravity (a common industry measure of density) and sulfur content – are widely used to classify crude oils as heavy, medium, or light (denoting specific gravity) and as sweet or sour (denoting sulfur content). All else equal, light crudes yield higher proportions of the more valuable light products (gasoline, jet fuel, diesel fuel); sweet crudes tend to incur lower refining costs than sour crudes of the same density (because of the costs associated with removing sulfur from refined products and refinery effluents to meet environmental standards).

The most common crude oil classifications are:

- Synthetic crude oil (SCO), such as that produced by upgrading Alberta bitumens
- Light sweet crude
- Light sour crude
- Medium sweet crude
- Medium sour crude
- Heavy sour crude

However, simple classifications based on properties of the whole crude are insufficient for assessing the refining economics of crude oils or estimating the refinery energy required to process crude oils. For these tasks, techno-economic assessments of crude oils are based on the volumes and properties (such as those shown in Exhibit 2.2) of their various boiling range

[7] The assay for a given crude may change over time as a result of changes in the method used to produce the crude from its reservoir, changes in analytical procedures, or unintended commingling with other crude oils.

fractions. The volumetric yields and the properties of the crude oil fractions exert significant influence on crude oil values, refining operations, and refinery energy use.

Exhibit 2.2: Representative Subset of Crude Oil Properties Provided in a Crude Assay

Crude Oil Fraction		Boiling Range (°F)	Physical Property							
			Yield (vol%)	RON	N + 2A (vol%)	Sulfur (ppmw)	Cetane No	Sp. Grav (° API)	K Factor	Con Carb.
	Notes	----->	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Whole crude						✓		✓		
Light ends		C_4^-	✓							
Naphtha	Straight run	C5-160	✓	✓				✓		
	Light	160-250	✓		✓			✓		
	Medium	250-325	✓		✓			✓		
	Heavy	325-375	✓		✓			✓		
Distillate	Kerosene	375-500	✓			✓		✓		
	Diesel	500-620	✓			✓	✓	✓		
Vacuum gas oil	Light	620-800	✓			✓		✓	✓	
	Heavy	800-1050	✓			✓		✓	✓	
Vacuum resid	Residual oil	1050+	✓			✓		✓		✓

Notes:

1 **Yield** is the volume percent of the whole crude in the indicated boiling range.
2 **RON** is Research Octane Number, a standard measure of anti-knock quality.
3 **N + 2A**, an indicator of reformer feed quality, is the vol. % Naphthenes plus 2 x the vol % Aromatics in the naphtha.
4 **Sulfur** is the sulfur content of the fraction, in weight parts per million or in weight %.,
5 **Cetane** is Cetane Number, a measure of diesel fuel performance.
6 **Sp Grav** is the specific gravity, or density, of the crude fraction, usually expressed in *API degrees*. (° API = (141.5/Sp.Gr.) - 131.5).
7 **K Factor** is the Characterization, a function of the crude fraction's specific gravity and distillation curve, is an indicator of the gas oil's susceptibility to cracking.
8 **Con Carbon** is Conradson Carbon, an indicator of the coke yield of the crude fraction when it is subjected to cat cracking or coking.

2.3 U.S. Refining Operations

Petroleum refineries are large, complex, continuous-flow plants that process crude oils and other input streams into a large number of refined (co-)products, most notably LPG, gasoline, jet fuel, diesel fuel, petrochemical feedstocks, home heating oil, fuel oil, and asphalt. Each refinery has a unique configuration and operating characteristics, determined primarily by its location, vintage, preferred crude oil slate, and market requirements for refined products.

The U.S. refining sector is the world's largest. It produces mainly high-value, "light" products – primarily transportation fuels (gasoline, jet fuel, diesel fuel) and petrochemical feedstocks – that meet stringent U.S. performance specifications and environmental standards. U.S. refineries are among the world's most complex and technically advanced, embodying extensive processing and upgrading of crude oil fractions and "conversion" of the heaviest crude oil fractions into lighter, higher-valued products (mainly transportation fuels).

Virtually all U.S. refineries process multiple crude oils simultaneously. Some refineries are designed to process mostly light, low-sulfur (sweet) crudes; others are configured and equipped to process heavy, high sulfur (sour) crudes. Heavy, sour crudes are more difficult to process into transportation fuels, but consequently are less expensive than light, sweet crudes.

Almost all U.S. refineries are either *conversion* ("cracking") or *deep conversion* ("coking/ cracking") refineries, designed to maximize production of light products (mainly transportation fuels) by converting ("cracking") the high boiling range fractions of the crudes to lighter fractions in the gasoline and diesel fuel boiling ranges. Conversion refineries convert vacuum gas oils into lighter products; deep conversion refineries convert not only vacuum gas oils but also vacuum resid, the heaviest crude fraction, into lighter products.

Exhibit 2.3 is a highly simplified flow chart of a notional U.S. deep conversion refinery, illustrating a typical flow pattern of crude oil fractions from the crude oil distillation units to the various downstream processing units and ultimately to product blending. Vacuum resid, the heaviest product of vacuum distillation, goes to the coker (in a deep conversion refinery), where it is converted (cracked) to lighter streams for further processing to higher-valued products, or (in a conversion refinery) to the refinery's residual oil or asphalt product pool (low value). The other products of vacuum distillation, the vacuum gas oil fractions, go to the fluid cat cracking (FCC) unit and/or to the hydrocracker, where they are cracked to lighter streams that ultimately find their way into the gasoline and distillate product pools. In many conversion refineries, vacuum gas oils fed to the FCC unit go first to an FCC feed hydrotreater, which removes sulfur and other impurities and increases the hydrogen content of the FCC feed (which in turn increases the FCC's gasoline yield).

Straight run distillate, the heaviest product of atmospheric distillation, goes either to hydrotreating and then blending to distillate products (e.g., diesel fuel) or to hydrocracking, where it is converted to gasoline and jet fuel blendstocks. Straight run kerosene, the next lighter product of atmospheric distillation, goes to hydrotreating and then blending to kerosene and jet or diesel fuel products. Finally, the straight run naphthas go to various processes in which they are treated and upgraded for gasoline blending or (for the heaviest naphthas) jet fuel blending.

For purposes of this discussion, the important aspect of Exhibit 2.3 is not any of its details, but the overall picture it conveys of the complexity of refining operations in general and U.S. refining in particular. As the flow chart suggests, U.S. refineries comprise many specialized refining processes. However, these processes can be thought of in terms of a few broad classes, shown in **Exhibit 2.4**.

Exhibit 2.3: Simplified Flow Chart of a U.S. Deep Conversion Refinery

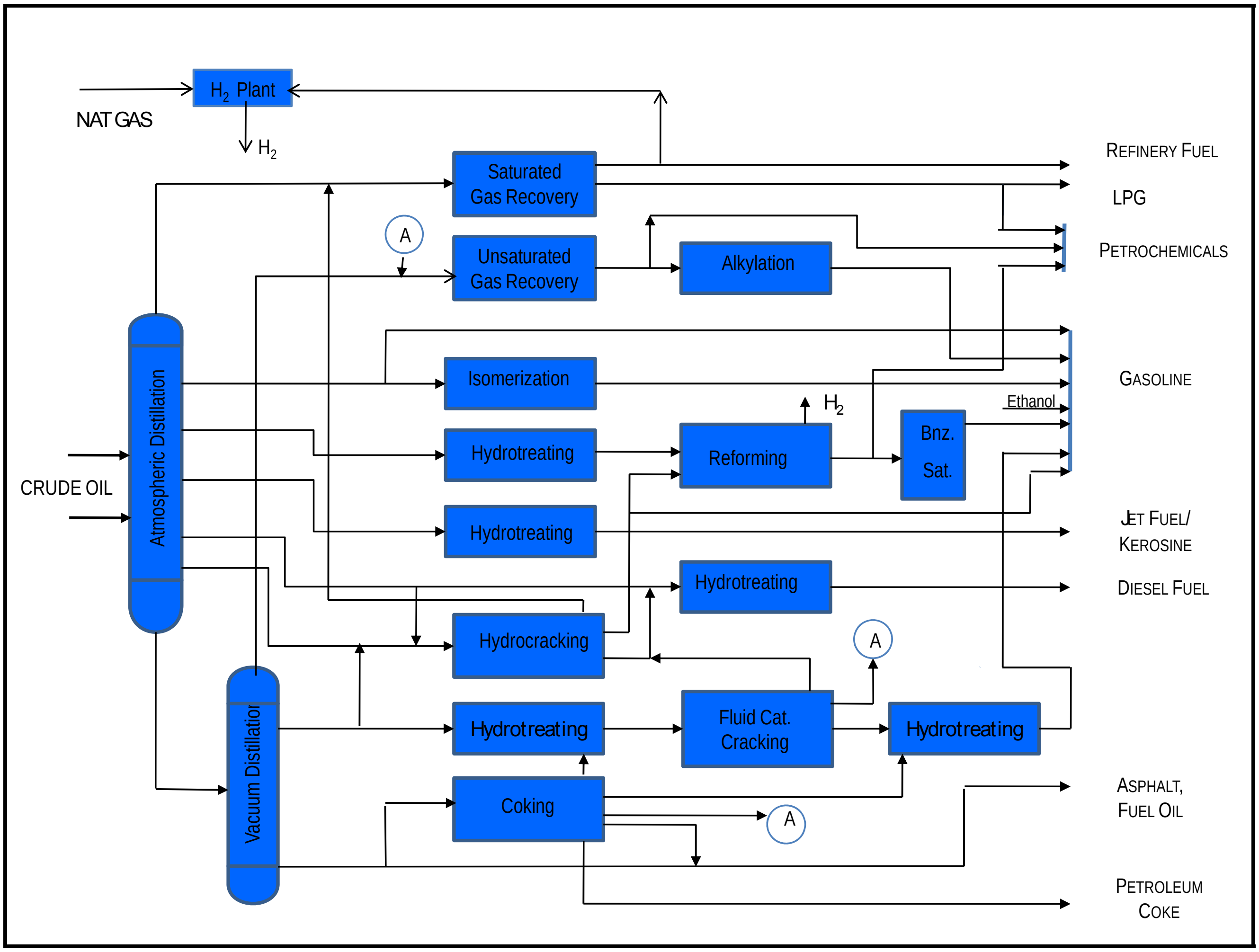


Exhibit 2.4: Important Classes of Refining Processes in U.S. Refineries

Class	Function	Examples
Crude distillation	Separate crude oil charge into boiling range fractions for further processing	Atmospheric distillation Vacuum distillation
Conversion	Break down ("crack") heavy crude fractions into lighter, higher-valued streams for further processing	Fluid cat cracking Coking, Hydrocracking
Upgrading	Enhance the blending properties (e.g., octane) and value of gasoline and diesel blendstocks	Reforming Alkylation, Isomerization
Treating	Remove hetero-atom impurities from refinery streams and blendstocks	Hydrotreating Caustic treating
Separation	Separate, by physical or chemical means, constituents of refinery streams for further processing	Fractionation Extraction
Blending	Combine blendstocks to produce finished products that meet product specifications and environmental standards	
Utilities	Supply refinery fuel, power, steam, oil movements, storage, emissions control, etc.	Power generation Sulfur recovery

Exhibits 2.3 and 2.4 illustrate three aspects of refining operations that merit comment in the context of this study.

- Refinery operations are extremely complex.

  Exhibit 2.3 only hints at the actual complexity of a conversion refinery – with respect to the physical facilities of the refinery, the interaction of these facilities with one another, and the range of operations of which they are capable.

- Refineries produce a wide range (or “slate”) of products – actually co-products.

  The light products are more valuable than the other products (residual oil, asphalt, etc.). Hence, in general, U.S. conversion refineries seek to maximize production of light products, to the extent their process capabilities allow. Refineries have some ability to change their product slate in response to market conditions and to maintain their product slate in the face of changes in the slate of crude oils that they process. This flexibility is centered in the refineries' conversion units, which convert vacuum gas oil and resid fractions into lighter fractions that can be upgraded and blended into gasoline, jet fuel, and diesel fuels.

Refiners can change the operations of their conversion units to accommodate changes in crude and product slates, but only within physical limits defined by the characteristics of these units and the properties of the crude oils. To exceed these limits requires capital investment in new or expanded process capacity. For example, a U.S. refinery may have to install coking capacity and additional FCC capacity to accommodate Canadian dilbits in its crude slate.

- Refinery energy use is (1) distributed, not concentrated, and (2) increases with increasing refining severity.[8]

  Essentially all refining processes consume energy, primarily in the form of process heat (from the combustion of natural gas and various refinery-generated fuels) and electricity. A few processes are net producers of energy, primarily in the form of steam generated from process waste heat.[9]

  In general, the severity of refining operations needed to produce a given product slate is a function of the physical and chemical properties of the crude oil slate (as discussed below) and the design of the refinery's conversion and upgrading processes.

2.4 Crude Oil Properties and Their Effect on Refining Operations

The various properties of a crude oil affect the operations and performance of any given refinery, and indeed determine the technical and economic feasibility of running the crude in that refinery. Some of the manifold ways in which crude oil properties affect operations in a U.S. light products refinery are listed below (with reference to Exhibits 2.3 and 2.4):

- The volumetric **yields** of the various crude fractions determine the relative feed rates to the primary refinery process units and the amount of conversion and treating capacity needed to produce the required volumes of light products;

- The **RON** and **N + 2A** content of the naphtha streams influence the extent and severity of upgrading process operations (primarily reforming) needed to meet gasoline volume and octane requirements;

[8] "Severity" is a term of art denoting the thermodynamic intensity of refinery processing. For example, a refiner might increase the severity of a refinery process by increasing the temperature at which the process operates, so as to accelerate a chemical reaction.

[9] In addition, many refineries have co-generation units, which produce electricity and steam for process heat. Some refineries sell a portion of their co-generated electricity to the local grid.

- The volumetric **yield** and the **vapor pressure** (not shown in Exhibit 2.2) of the light straight run naphtha influences the extent of the separation (fractionation) operations required to meet industry and regulatory standards for gasoline volatility.

- The **Sulfur** levels of the various crude fractions determine the required treating capacity for desulfurization, the severity and cost of these operations, and the associated hydrogen consumption;

- The **Con Carbon** content and **K Factor** of the heavy crude fractions are indicators of the carbon/hydrogen ratio and the aromatics content in these fractions.

  The carbon/hydrogen ratio of a crude fraction or refinery stream determines the extent to which these fractions can be converted to lighter components in the **Conversion** processes; the volumes of petroleum coke and catalyst coke produced in coking and cat cracking, respectively; the yield patterns in coking and cat cracking and coking; refinery hydrogen consumption; the aromatics content of the various light products; and the throughput capacity of given process units.

  For example, the yield of gasoline blendstocks in cat cracking and coking is a strong increasing function of the hydrogen content of the feed.

Crude oil properties affect refining operations and performance in many other ways as well, too numerous to mention here. They also determine in large measure the design and materials of construction of the various process units.

2.5 Crude Oil Properties and Their Effects on Refinery Energy Use and CO_2 Emissions

The conversion of crude oil into refined products in a refinery requires the expenditure of energy, which is provided in U.S. refineries by the combustion of natural gas and of by-product streams (primarily catalyst coke and still gas) produced in the refinery and by electricity (either purchased or produced in the refinery by co-generation units fueled by natural gas). Because crude oil properties affect the nature and severity of refinery operations, they also affect refinery energy use and the consequent CO_2 emissions.

2.5.1 Effects on Refinery Energy Use

- The crude distillation curve has two primary effects on refinery energy use.

  - Crude distillation (**Atmospheric Distillation** and V**acuum Distillation** in Exhibit 2.3) – which separates the crude oil charge into its boiling range fractions – is the most energy-intensive refining process. In general, the lighter the crude oil (i.e., the greater the proportion of low-boiling fractions: distillates and lighter), the higher the energy (fuel) use in crude distillation.

Alone among crude oils, synthetic crude oil (SCO) contains essentially no vacuum resid (boiling range: 1050^o F +). Vacuum resid is separated from the next lightest fractions, the light and heavy vacuum gas oils, in the **Vacuum Distillation** unit. Hence, if SCO is segregated from conventional crudes in shipment and in crude distillation (as we assume in this study), it incurs no energy expenditure for vacuum distillation.

- The heavier the crude oil the higher the volumetric yields of vacuum gas oil and resid fractions, the higher the through-put and/or the operating severity in the conversion units (cat cracking (FCC), coking, and hydrocracking) needed to produce a given product slate, and hence the higher the refinery energy consumption.

  The conversion units all consume energy directly. Hydrocracking also consumes energy indirectly, due to its requirements for large volumes of hydrogen. (Hydrogen production is highly energy-intensive).

- The higher the sulfur content (and hetero-atom content) of the various crude fractions, the higher the refinery energy use.

  - Essentially all of the sulfur, except that in the heaviest fraction (vacuum resid) must be removed, primarily by FCC feed hydrotreating, product hydrotreating, and hydrocracking.

  - Essentially all hetero-molecules (which poison process catalysts) in heavy naphtha, distillates, and vacuum gas oil must be removed by hydrotreating: FCC feed hydrotreating and naphtha hydrotreating.

  Hydrotreating and hydrocracking use energy both directly and indirectly, in quantities that increase with increasing sulfur and hetero-molecule content. The indirect energy use is primarily in hydrogen production.

  For example, the sulfur content of FCC products – which constitute large fractions of the gasoline and diesel fuel pools – is directly correlated with the sulfur content of the FCC feed. FCC feed hydrotreating and hydrocracking, processes needed for meeting stringent U.S. specifications on gasoline and diesel fuel sulfur content, are two of the largest energy consumers in U.S. refineries.

- The chemical composition (such as aromatics content, hetero-atom content) and properties of crude oil fractions fed to the conversion units, as well as to the upgrading units (such as reforming) and treating units (naphtha hydrotreating, distillate hydrotreating), influence the product yields and the required operating severity in the various refinery units that process the crude oil fractions.

  For example, in cat cracking, conversion and gasoline yield tend to decrease with increasing aromatics content and sulfur content in the cat cracking feed (all else equal). Cat crackers and cokers "over-crack" some feed material (that is, reduce it to coke and light-gas by-products), and over-cracking increases with increasing severity. Hydrocrackers consume hydrogen, in amounts that increase with increasing severity.

Refinery energy use in these units increases with increasing severity because:

- Increasing severity usually means higher operating temperatures and/or pressures, achievement of which calls for additional energy.

- Increasing severity entails some loss in product yield (with a corresponding increase in low-valued by-product yield), meaning that the refinery must process more crude oil and expend more energy to produce a given product slate.

Each crude oil has a unique set of properties. Hence, energy use in any given refinery is a function of the refinery's crude oil slate (all else equal).

2.5.2 Effects on Refinery CO_2 Emissions

Refinery CO_2 emissions are primarily a consequence of refinery energy use. The volumetric yields and properties of a crude oil's fractions affect refinery energy use because influence the extent of processing they partially determine the operating severity needed in various process units to meet product volume and quality requirements.

The sources of energy used in the refinery (natural gas, still gas, FCC catalyst coke, electricity) also influence CO_2 emissions to some extent. Refineries that rely most on the more-carbon-intensive sources (catalyst coke, coal-sourced electricity) will tend to have higher CO_2 emissions per barrel of crude throughput than refineries that rely more on less-carbon-intensive sources (natural gas, still gas, natural gas- or nuclear-sourced electricity).

3. Assay Properties of the Crude Oils Considered in the Analysis

3.1 Sources of the Crude Oil Assays

We used assays in MathPro's library for the three U.S. crudes and the five Import crudes. These assays come from public and private sources. We updated three of these assays – for ANS, SJV Heavy, and Bow River – in the course of this study.

We developed assay data for the four Canadian bitumen crudes (Exhibit 1.1) from bitumen and dilbit assays obtained in the course of this study from industry sources.

The assay for *SCO from mined bitumen* is a composite assay representing SCOs produced by Syncrude Canada and Suncor; we prepared the composite assay from individual assays provided by the companies.

The assay for *SCO from in situ bitumen* represents Long Lake SCO and was provided by its producer, OPTI/Nexen.[10]

The assay for *Dilbit* (25% condensate/75% in situ bitumen) represents Cold Lake Dilbit and was provided by its producer, ExxonMobil Canada.

We had no assay for *Synbit* (50% SCO/50% in situ bitumen) so we derived one, starting from the Cold Lake Dilbit assay. First, we estimated assay properties for the bitumen by a volume-weighted "subtraction" of 25 vol% diluent from the Dilbit assay. Then, we combined the derived bitumen assay with the composite assay for SCO from mined bitumen, on a 50/50 volume-weighted basis, to obtain the Synbit assay.

3.2 Properties of the Whole Crudes and Boiling Range Fractions

Exhibit 3.1 shows the API gravity, sulfur content, and classification of the thirteen crude oils considered in this study.

As the exhibit indicates, the U.S. and imported (ex Canada) crude oils span the range from light sweet to heavy sour; Bow River, Synbit, and Dilbit are heavy sour crudes. Collectively, the crude oils are reasonably representative of the larger set of conventional crude oils processed by U.S. refineries. The aggregate crude slate processed by the U.S. refining sector has an average API gravity of about 30.4^o and average sulfur content of about 1.4 wt%.[11]

[10] OPTI/Nexen considers the Long Lake assay to be confidential. Hence, the exhibits show minimal assay information for the SCO from in situ bitumen.

[11] The aggregate U.S. crude slate is growing gradually heavier and higher in sulfur. This trend has persisted over many years.

Exhibit 3.1: API Gravity and Sulfur Content of the Study's Crude Oils

Crude Oil	API Gravity (°)	Sulfur Content (wt%)	Classification
U.S.			
West Texas Inter. (WTI)	39.6	0.49	Light sweet
SJV Heavy	13.6	1.38	Heavy sour
ANS	32.0	0.90	Medium sweet
Imports (ex Canada)			
Saudi Medium	30.3	2.57	Medium sour
Basrah Medium	31.0	2.58	Medium sour
Escravos	35.3	0.16	Light sweet
Bachaquero 17	16.7	2.40	Heavy sour
Maya	21.1	3.38	Heavy sour
Canada			
Bow River	20.7	2.85	Heavy sour
SCO (*mined bitumen*)	32.2	0.16	Synthetic crude
SCO *(in situ bitumen)*	39.4	0.001	Synthetic crude
Synbit	21.0	2.53	Heavy sour
Dilbit	21.2	3.69	Heavy sour

Exhibit 3.2 shows in tabular form each crude oil's volumetric yields of the various boiling range fractions.

Exhibits 3.3a, 3.3b, and 3.3c show the distillation curves for the U.S., imported, and Canadian crudes, respectively. The distillation curves are graphs of the boiling range yields tabulated in Exhibit 3.2.

Exhibit 3.4 shows some key properties of the various boiling range fractions for each crude oil.[12]
The properties shown in Exhibit 3.4 are all incorporated in the regional refining models used in the study.

[12] These properties correspond to those indicated in Exhibit 2.2.

Exhibit 3.2: Crude Oil API Gravity, Sulfur Content, and Boiling Range Yields

			U.S. Crudes			Imported Crudes					Canadian Crudes				
		Boiling Range (°F)	West Texas Inter	SJV Heavy	Alaskan North Slope	Saudi Medium	Iraq Basrah Medium	Nigerian Escravos	Venez. Bach 17	Mexican Maya	Bow River	Mining SCO	In Situ SCO	Synbit	Dilbit with Diluent
Whole Crude	API Gravity		39.6	13.6	32.0	30.3	31.0	35.3	16.7	21.1	20.7	32.2	39.4	21.0	21.2
	Sulfur (wt%)		0.49	1.38	0.90	2.57	2.58	0.16	2.40	3.38	2.85	0.16	0.00	2.53	3.69
Gases	C3-		0.5	0.0	0.4	0.7	0.7	0.4	0.3	0.0	0.1	0.1		0.1	0.0
	C4		1.6	0.0	3.1	2.0	1.5	1.2	0.5	0.0	1.0	1.9		0.9	0.9
Naphthas	Straight Run	C5-160	6.0	0.0	5.2	4.8	5.4	4.5	1.8	3.2	4.5	5.1		2.6	13.4
	Light	160-250	11.6	0.3	8.5	7.1	7.8	8.1	2.3	5.3	4.0	6.0		3.1	5.5
	Medium	250-325	9.8	0.7	9.2	6.9	6.9	7.8	2.6	5.0	3.5	5.6		2.9	3.0
	Heavy	325-375	5.6	1.1	4.3	4.9	4.6	8.8	2.0	3.5	3.1	3.8		2.0	1.5
Distillate	Kerosene	375-500	13.7	7.5	11.0	11.3	11.5	17.1	6.7	10.0	9.7	12.0		8.6	5.0
	Diesel	500-620	12.2	11.9	11.5	10.9	11.3	15.1	10.4	9.3	9.2	19.7		15.0	8.0
Vacuum Gas Oil	Light	620-800	15.5	21.9	15.5	14.3	15.1	18.2	18.1	13.2	13.9	29.7		22.8	12.0
	Heavy	800-1050	14.3	26.2	16.5	16.1	16.1	13.0	22.5	16.5	19.8	16.3		19.4	16.9
Vacuum Resid	Residual Oil	1050+	9.2	30.5	14.8	20.8	19.1	5.7	32.8	34.0	31.1	0.0		22.5	33.8
Total			100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Exhibit 3.3a: Distillation Curves for U.S. Crudes

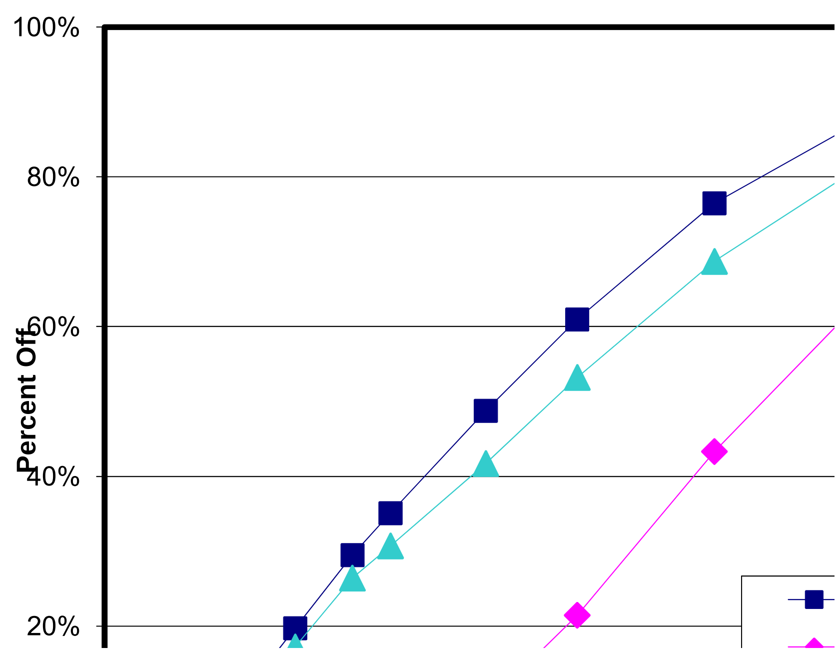


Exhibit 3.3b: Distillation Curves for Imported Crudes

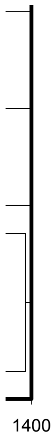


Exhibit 3.3c: Distillation Curves for Canadian Crudes

Exhibit 3.4: Key Properties of Crude Oil Boiling Range Fractions

			U.S. Crudes			Imported Crudes					Canadian Crudes				
		Boiling Range (°F)	West Texas Inter	SJV Heavy	Alaskan North Slope	Saudi Medium	Iraq Basrah Medium	Nigerian Escravos	Venez. Bach 17	Mexican Maya	Bow River	Mining SCO	In Situ SCO	Synbit	Dilbit with Diluent
Whole Crude	API Gravity		39.6	13.6	32.0	30.3	31.0	35.3	16.7	21.1	20.7	32.2	39.4	21.0	21.2
	Sulfur (wt%)		0.49	1.38	0.90	2.57	2.58	0.16	2.40	3.38	2.85	0.16	0.00	2.53	3.69
Napthas	Straight Run	C5-160													
	RON		65.6	75.5	69.0	70.5	66.7	78.5	73.6	63.7	73.1	73.4		73.4	71.9
	Light	160-250													
	N + 2A (vol%)		61.2	72.0	59.0	25.4	31.7	90.0	83.5	42.0	43.7	46.5		45.5	60.1
	Medium	250-325													
	N + 2A (vol%)		66.4	82.0	75.6	45.3	46.6	77.0	87.7	55.0	70.6	71.9		71.3	74.3
	Heavy	325-375													
	N + 2A (vol%)		65.9	79.0	79.0	64.8	63.1	65.5	87.6	66.4	71.2	93.6		93.3	72.9
Distillate	Kerosene	375-500													
	Sulfur (ppm)		1,800	3,300	1,100	3,200	3,700	600	4,700	10,000	7,000	200		4,200	10,620
	Cetane No.		46.8	33.0	41.5	49.0	47.9	40.0	37.5	46.0	40.2	35.0		32.4	27.8
	Diesel	500-620													
	API Gravity		36.6	25.0	31.0	35.2	35.1	32.3	28.3	33.0	27.0	27.7		27.4	27.2
	Sulfur (ppm)		3,400	7,200	5,000	13,900	15,800	1,100	10,600	21,000	15,000	700		7,300	19,000
	Cetane No.		56.7	32.0	46.0	51.2	40.1	49.7	43.1	47.0	43.1	38.8		36.4	33.2
Vacuum Gas Oil	Light	620-800													
	API Gravity		30.6	18.2	24.0	26.5	26.0	27.6	20.0	25.5	21.0	21.6		20.9	19.6
	Sulfur (ppm)		5,700	11,700	10,500	25,500	23,700	2,300	20,400	28,000	21,000	2,500		11,000	26,550
	K factor		12.1	11.2	11.6	11.8	11.7	11.8	11.3	11.7	11.4	11.4		11.4	11.3
	Heavy	800-1050													
	API Gravity		22.2	12.2	17.5	19.1	15.6	17.2	15.5	17.5	13.5	16.4		13.9	12.1
	Sulfur (ppm)		8,400	15,200	13,500	31,900	38,100	4,200	25,200	36,000	31,000	3,800		26,900	43,140
	K factor		12.1	11.3	11.7	11.9	11.6	11.7	11.6	11.6	11.4	11.6		11.5	11.3
Vacuum Resid	Residual Oil	1050+													
	API Gravity		13.3	1.0	5.5	4.1	4.1	10.1	2.6	-1.4	3.0			2.0	2.0
	Sulfur (ppm)		13,300	18,800	23,500	53,500	57,200	5,500	36,600	54,000	49,000			61,000	61,000
	Con Carbon (wt%)		14.0	22.3	22.0	25.1	26.1	17.0	26.6	31.4	25.0			26.2	26.2
Utilities Used in Crude Distillat'n	Fuel Use (foeb/b)		0.016	0.013	0.015	0.014	0.014	0.016	0.012	0.012	0.012	0.010	0.012	0.014	0.012
	Steam (lbs/b)		34.2	31.2	33.3	32.2	32.6	34.8	30.6	30.0	30.6	18.7	24.2	32.4	30.0
	Power (kWh/b)		0.82	0.94	0.84	0.85	0.85	0.81	0.92	0.89	0.89	0.70	0.70	0.89	0.89

3.3 Observations on Crude Properties and Refining Operations

The U.S. and imported crudes have *vacuum resid* (coker feed) yields ranging from about 9 vol% to more than 34 vol%. Synbit and Dilbit have vacuum resid yields of about 22 vol% and 34% vol%, respectively. SCOs contain no vacuum resid by virtue of the field upgrading processes that produce them.

Most of the U.S. and imported crudes have *vacuum gas oil* (FCC feed) yields in the range of about 30 vol%, with a few heavy outliers (e.g., SJV Heavy, Maya), which have yields of 40 vol% and higher. Dilbit has a vacuum gas oil yield in the 30 vol% range. Synbit and straight SCO have unusually high vacuum gas oil yields – well above 40 vol%.

> (As Exhibit 2.3 indicates, vacuum resid goes either to the coker, where it is converted (cracked) to lighter streams for further processing to higher-valued products, or else to the refinery's residual oil product pool (low value). Vacuum gas oil goes to the FCC unit (which in many refineries is preceded by an FCC feed hydrotreater) and to the hydrocracker, in both of which it is converted to lighter streams processed into gasoline and diesel blend stocks.)

Some crude oils – including Dilbit, Synbit, and SCO – are high in aromatics content.[13] All else equal, high aromatics content has adverse effects on the quality of jet fuel and diesel fuel. Counteracting these effects requires more severe hydrotreating and increased hydrogen consumption. SCO vacuum gas oil is very low in sulfur and hence does not require FCC feed hydrotreating before going to the FCC unit. SCO offers higher-than-average yields of vacuum gas oil. However, taking advantage of these SCO characteristics requires segregating the SCOs from the conventional crude oils. Some refineries are configured so as to be able to segregate different crude types; others are not.

As these comments suggest, the properties of Dilbit, Synbit, and SCO affect their disposition in the U.S. refining sector and their refinery energy use. Dilbit is suitable for many U.S. deep conversion refineries – having both a coker and an FCC unit – because Dilbit has vacuum resid and vacuum gas oil fractions with yields comparable to the U.S. average. Straight SCO (uncontaminated by conventional crude oil or bitumen) is best suited for processing in conversion refineries – having an FCC unit but no coker – because SCO contains no vacuum resid. For the same reason, SCO does not require processing in the refinery's vacuum distillation unit (which separates vacuum resid from vacuum gas oil, as indicated in Exhibit 2.3).

[13] A good indicator of a crude's aromatics is the **K factor** of the vacuum gas oil (Exhibit 3.4). Aromatics content is inversely related to K factor. A K factor in the range of (≈ 11.2–11.5 indicates high aromatic content.

4. Energy Use in U.S. Refineries

U.S. refineries account for about 3% of total U.S. energy consumption. In general, refinery energy consumption, both total and per barrel of crude through-put, has tended to increase slowly over time. This trend reflects U.S. refiners' gradual shift to a heavier, higher sulfur crude slate, coupled with increasingly stringent specifications on refined products, particularly the sulfur standards for gasoline and diesel fuel.

Exhibits 4.1, 4.2, 4.3, and 4.4 show information on energy consumption in the U.S. refining sector in 2005, 2006, and 2007. Most of this information was obtained from Energy Information Administration (EIA) *Petroleum Supply Annuals* and the EIA website.

4.1 Total Refinery Energy Use

Exhibit 4.1 shows total annual refinery energy consumption, crude throughput, and average energy consumption per barrel of crude through-put, by PADD.[14]

Exhibit 4.1: Reported U.S. Refinery Energy Use, By Region, 2005-2007

Region	Refinery Energy Use (Quads/Year)			Crude Throughput (1) (Million Bbl/Day)			Avg. Energy Use per Bbl Crude (Million BTU/Bbl Crude)		
	2005	2006	2007	2005	2006	2007	2005	2006	2007
U.S.	3.019	3.123	3.090	15.220	15.242	15.156	0.543	0.561	0.559
PADD 2	0.582	0.588	0.585	3.298	3.297	3.226	0.483	0.489	0.497
PADD 3	1.478	1.600	1.557	7.098	7.260	7.315	0.570	0.604	0.583
PADD 5	0.572	0.565	0.574	2.638	2.621	2.560	0.594	0.591	0.614

Source: *Petroleum Supply Annuals* for 2005, 2006, and 2007; Energy Information Administration

(1) **Crude Throughput** volumes include unfinished oils

(2) California accounts for about 80% of PADD 5 refinery energy use

PADD 5 generally shows the highest per-barrel energy use, reflecting primarily the refining operations in California, where the aggregate crude slate is particularly heavy and the product specifications are the most stringent in the U.S.

[14] Our analysis considers PADD 2, PADD 3, and California (but not PADD 5, which includes California). Exhibits 4.1 and 4.2 show values for PADD 5 rather than for California because the *Petroleum Supply Annuals* provide data on refining operations by PADD, not by state. However, California accounts for about 80% of the refining capacity and crude runs in PADD 5.

4.2 Sources of Refinery Energy

The energy consumed in refining comes from various sources; some from outside the refinery – such as purchased natural gas and electricity – and some generated within the refinery by the destruction of crude oil – such as still gas and catalyst coke.

> *Still gas* is a mixture of light gases (methane, ethane, etc.) produced as by-products in various refining processes. These light gas streams are collected, treated, and sent to the refinery fuel system.
>
> *Catalyst coke* – coke laid down on the cracking catalyst – is a by-product of the cracking reactions that occur in the FCC reactor. The coke is burned off the catalyst in the FCC regenerator. The heat of combustion is used to provide process energy for the FCC unit and to generate refinery steam.
>
> (*Petroleum coke* (or *marketable coke*) – which is not used as a refinery fuel – is the primary by-product of refinery coking units (cokers). Coke usually constitutes ≈ 25%–35% of coker output and has various uses outside the refining industry.)

Exhibit 4.2 shows annual U.S. refinery energy use (quads/year), by energy source (fuel type) and by PADD, in 2005, 2006, and 2007.

The values in Exhibit 4.2 are derived from various EIA sources[15] and the EIA website. As the exhibit indicates, EIA tracks and reports essentially all sources of refinery energy, large and small. However, four sources – still gas and catalyst coke (refinery-produced) and natural gas and electricity (purchased) – account for about 95% of reported U.S. refinery energy consumption.

> (EIA does not treat natural gas used in refinery hydrogen production as a fuel use. Nor does EIA include in its reporting the natural gas used as fuel by merchant hydrogen plants supplying hydrogen to the refining sector.)

Exhibit 4.3 shows annual refinery energy use (2005-2006), by energy source for California (only). EIA reports refinery energy use by PADD, but not by state. We developed Exhibit 4.2 using data provided by the California Energy Commission (CEC). We revised the petroleum coke and natural gas values provided by CEC to make them consistent with EIA's reported values for PADD 5.

[15] *Petroleum Supply Annual*; *Table 47*; Department of Energy/ Energy Information Administration
More references needed

Exhibit 4.2: Refinery Fuel Use Reported by EIA (2005-2007), by PADD and Source

Region	Type of Fuel	Unit of Measure	MM btu/ fuel unit	Refinery Fuel/Energy Use 2005	2006	2007
U.S.	**Energy Use**	Quads		**3.231**	**3.352**	**3.338**
	LPGs	K Bbl	3.8	4,175	2,656	2,663
	Distillate	K Bbl	5.8	755	434	420
	Residual Fuel	K Bbl	6.3	2,207	2,018	1,844
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	238,236	249,358	247,106
	Marketable Petroleum Coke	K Bbl	6.02	2,242	458	648
	Catalyst Petroleum Coke	K Bbl	6.02	87,410	90,034	87,367
	Other Products	K Bbl	5.25	5,329	6,327	3,704
	Natural Gas	Mcf	1.1	682,919	697,593	667,986
	Coal	K tons	21	41	34	39
	Purchased Electricity	MM Kwh	9.977	36,594	39,353	41,829
	Purchased Steam	MM lbs	1.3	63,591	70,769	99,022
PADD 2	**Energy Use**	Quads		**0.641**	**0.651**	**0.649**
	LPGs	K Bbl	3.8	779	567	842
	Distillate	K Bbl	5.8	50	45	47
	Residual Fuel	K Bbl	6.3	163	206	189
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	50,213	49,585	49,429
	Marketable Petroleum Coke	K Bbl	6.02	0	0	0
	Catalyst Petroleum Coke	K Bbl	6.02	17,342	16,502	15,701
	Other Products	K Bbl	5.25	1,686	1,961	395
	Natural Gas	Mcf	1.1	106,480	114,721	120,047
	Coal	K tons	21	8	3	7
	Purchased Electricity	MM Kwh	9.977	9,875	10,488	10,555
	Purchased Steam	MM lbs	1.3	5,033	7,298	10,738
PADD 3	**Energy Use**	Quads		**1.575**	**1.708**	**1.678**
	LPGs	K Bbl	3.8	359	277	208
	Distillate	K Bbl	5.8	86	111	115
	Residual Fuel	K Bbl	6.3	4	1	3
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	111,798	125,046	120,930
	Marketable Petroleum Coke	K Bbl	6.02	29	194	58
	Catalyst Petroleum Coke	K Bbl	6.02	41,270	45,395	42,690
	Other Products	K Bbl	5.25	1,300	1,971	1,510
	Natural Gas	Mcf	1.1	395,980	395,627	363,004
	Coal	K tons	21	0	0	0
	Purchased Electricity	MM Kwh	9.977	16,620	18,612	20,433
	Purchased Steam	MM lbs	1.3	34,738	38,999	63,471
PADD 5	**Energy Use**	Quads		**0.599**	**0.593**	**0.602**
	LPGs	K Bbl	3.8	2,291	1,468	1,415
	Distillate	K Bbl	5.8	253	255	236
	Residual Fuel	K Bbl	6.3	727	770	743
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	45,700	44,999	45,553
	Marketable Petroleum Coke	K Bbl	6.02	970	110	117
	Catalyst Petroleum Coke	K Bbl	6.02	14,401	14,440	14,404
	Other Products	K Bbl	5.25	1,700	2,199	1,716
	Natural Gas	Mcf	1.1	123,271	126,190	133,713
	Coal	K tons	21	0	0	0
	Purchased Electricity	MM Kwh	9.977	4,978	4,973	5,113
	Purchased Steam	MM lbs	1.3	17,956	17,999	17,838

Note: Electricity conversion factor represents btu's in delivered power adjusted for generation efficiency and transmission loss.
Source: Derived from EIA Website.

Exhibit 4.3: Refinery Fuel Use (2005-2006) in California, by Source

Region	Type of Fuel	Unit of Unit of Measure	MM btu/ fuel unit	Refinery Fuel/ Energy Use 2005	Refinery Fuel/ Energy Use 2006	Note
California	**Energy Use**	Quads		**0.495**	**0.483**	
	LPGs	K Bbl	3.8	1,706	1,015	
	Distillate	K Bbl	5.8	155	78	
	Residual Fuel	K Bbl	6.3	0	0	
	Still Gas (@ 6.0MM btu/foeb)	K foeb	6	40,795	39,824	
	Marketable Petroleum Coke	K Bbl	6.02	776	88	X
	Catalyst Petroleum Coke	K Bbl	6.02	11,675	11,704	
	Other Products	K Bbl	5.25	4	6	
	Natural Gas	Mcf	1.1	109,407	108,895	X
	Coal	K tons	21	0	0	
	Purchased Electricity	MM Kwh	9.977	3,096	3,244	
	Purchased Steam	MM lbs	1.3	12,508	12,712	

Note: Electricity conversion factor represents btu's in delivered power adjusted for generation efficiency and transmission loss.
"X" indicates data provided by CEC were revised to be consistent with data reported by EIA for PADD 5.
Source: Derived from from data provided by CEC and from EIA Website.

4.3 Refinery Generation of Electricity

Exhibit 4.4, derived from the EIA-906 and EIA-920 surveys, summarizes U.S. refinery electricity generation, by region, for 2006.

Exhibit 4.4: Power Generation in U.S. Refineries, 2006

Region	Gross Power Generation (1)		Sales to Grid (1)		Share of Gross Power Sold to Grid	Net Power Generation (2)	
	(M Kwh)	(M Kwh/day)	(M Kwh)	(M Kwh/day)		(M Kwh)	(M Kwh/day)
PADD 1	1310.0	3.6	157.4	0.4	12.0%	1152.5	3.2
PADD 2	814.0	2.2	0.0	0.0	0.0%	814.0	2.2
PADD 3	12004.0	32.9	2398.8	6.6	20.0%	9605.2	26.3
PADD 4	206.8	0.6	198.7	0.5	96.1%	8.2	0.0
PADD 5	8593.1	23.5	3794.7	10.4	44.2%	4798.4	13.1
California	8313.1	22.8	3783.4	10.4	45.5%	4529.7	12.4
Total	**22927.8**	**62.8**	**6549.6**	**17.9**	**28.6%**	**16378.3**	**44.9**

(1) Derived from *Annual Sources and Disposition of Electricity for Non-Utility Generators, 2006;*
EIA-906 and EIA-920 Surveys; EIA Website
(2) **Gross Power Generation** minus **Sales to Grid**

Exhibit 4.4 indicates that gross electricity generation in U.S. refineries averaged about 2½ gigawatts (63 gigawatt-hours per day) in 2006. Most of the refinery-generated electricity came from gas-fired co-generation units. U.S. refineries sold about 29% of gross electricity output to the grid. The indicated net electricity generation for internal use in U.S. refineries (after sales to the grid) was about 1.9 gigawatts.

It appears that the refinery purchases of natural gas reported by EIA (as shown in Exhibit 4.2) include natural gas used for power generation, without adjustment for refinery sales of electricity to the grid. Refinery purchases of electricity natural reported by EIA reflect purchases from the grid and do not include refinery-generated electricity. We adjusted the EIA data to reflect their reporting framework in our analysis of refinery energy use.

5. The Energy and CO_2 Accounting Framework in the Regional Refining Models

5.1 Background

In principle, one can envision at least two approaches for estimating refinery use and CO_2 emissions as a function of a refinery's crude oil slate.

The more rigorous approach is to develop complete energy, material, and carbon balances around the refinery. The difference between the energy embodied in all refinery outputs and inputs equals the energy expended in the refinery. Similarly, the difference between the total carbon content of all refinery outputs and inputs equals the refinery's carbon emissions, some of which will be in the form of CO_2. At first glance, this approach is appealing because it rests on the fundamental chemical engineering principles of heat and material balance. In practice, the approach is unworkable. It requires (1) complete and tight material and energy balances for the refinery (including not only all refinery feed and product streams but also waste streams and losses, such as furnace exhaust, flare gas, fugitive emissions, waste water, etc.) and (2) precise estimates or measurements of the energy and carbon content of each refinery input and output. Such measurements are subject to day-to-day fluctuation and, in many cases, are simply unavailable. Moreover, because the desired results of the analysis – refinery energy use and CO_2 emissions – are residuals, the inevitable gaps in refinery material balances and inaccuracies in energy and carbon content – even small ones – would render the results useless.

The more practical approach focuses on energy consumption within the refinery battery limits. This approach involves

- Estimating total refinery energy use, process-by-process – that is, by summing the direct energy inputs to each refining process, by energy source (natural gas, refinery-generated fuel, petroleum coke, electricity); and then

- Estimating refinery CO_2 emissions by applying standard carbon emission factors to each of the refinery energy sources.

The latter approach is the standard one and the one followed in this study. In theory, it is less rigorous than the first approach, but it is practical and adequate to the purpose. It does not require precise (and indeed unattainable) material and energy balances, and it can be implemented through refinery LP models.

5.2 Refinery Energy Accounting in the Regional Refining Models

The engineering representation of each refining process in our refinery LP models includes the process's consumption (or production) of refinery fuel, steam, and electricity, as functions of operating conditions and feeds. In the models, the energy flows are expressed as foeb (fuel oil equivalent barrels) of fuel, K lbs (thousand pounds) of steam, and Kwh (kilowatt-hours) of electricity per barrel of process throughput. The energy input/output coefficients for each process reflect information provided by technology providers (i.e., process developers and licensors) in public sources and, in some cases, private communications.

The models sum energy consumption (net of energy production) across all processes and set aggregate refinery energy consumption equal to refinery energy supply, by energy source:

- Purchased natural gas, for use as refinery fuel (and as feed to hydrogen production)
- Refinery fuel gas streams (e.g., still gas) generated as co-products or waste products in certain processes
- Catalyst coke produced generated in the fluid catalytic cracking (FCC) unit
- Purchased electricity

These sums capture the various effects of crude oil properties on refinery energy use represented in the models, examples of which are discussed in Section 2.6. Hence, changes in crude slate, product slate, and/or product specifications (e.g., sulfur content) will, in general, lead to corresponding changes in the refinery energy use returned by the regional refining models used in this study.

The refining models represent all on-purpose hydrogen used by refineries as being produced in the refinery (rather than some being produced by merchant hydrogen plants[16]) and all electricity used by refineries as being purchased (rather than some being internally generated). Hence, refinery energy use in the models includes natural gas used as fuel in the production of hydrogen purchased from merchant plants (located outside the refinery battery limits). We adjusted refinery natural gas consumption and electricity purchases to account for the refinery co-generation reported by EIA.[17]

The refinery energy use in the models does not include (1) energy used in production and transport of ethanol blended into gasoline downstream of the refinery; (2) energy used in production and supply of unfinished oils (refinery inputs other than crude oil) blended into gasoline and distillate fuels in the refinery, but not otherwise processed in the refinery; (3) electricity used in non-process or off-site activities (such as oil movements in and out of storage, product blending, lighting, etc.); and (4) energy losses due to flaring, fugitive emissions, etc.

[16] Merchant hydrogen plants are not in the refinery proper, but the energy they use and the CO_2 they generate in producing hydrogen for refinery use are directly connected with refinery operations. In effect, the refinery models treat purchased hydrogen as though the merchant hydrogen plants were integral parts of the refining sector.

[17] *Annual Source and Disposition of Electricity for Non-Utility Generators, 2006*; EIA Report 906 and 920 Surveys; Energy Information Administration

5.3 Normalization to EIA Reporting of U.S. Refinery Energy Use

The energy accounting framework described above should tend to produce estimates of regional refinery energy use somewhat lower than the "actual" values shown in the EIA reports, for three reasons. First, the refining models do not explicitly represent some auxiliary refinery process units (such as certain distillation and other separation processes), whose operation consumes some energy. Second, the models do not capture the energy that real refineries use in non-process or off-site activities (described above). We assume that refineries include such energy use in their reporting to EIA. Third, the refining models' representation of energy use in the individual refining processes is based on information provided by technology providers (i.e., process developers and licensors). In our view, such information usually reflects best-practice operation of new process units at design conditions, and therefore probably understates actual energy consumption of the existing refinery capital stock in day-to-day refining operations.

Without adjustment for these factors, the energy accounting framework in the refining models still produce reasonable estimates of regional refinery energy use. Unadjusted estimates of total refinery energy use in the U.S. developed with our refinery modeling system for year 2006 were within 20% of that reported by EIA for that year (Exhibit 4.1).

However, given the objective of this analysis, we chose to normalize the estimates of refinery energy use returned by the regional refining models such they matched the total refinery energy use reported by EIA, by region, for a base year: 2006. That is, we developed a computational procedure to adjust the refinery energy use values returned by the regional refining models applied to 2006 so that these results matched the adjusted values reported by EIA, by region, for 2006. Then, we applied this procedure to the results returned by the models in the various study cases to estimate refinery energy use for each of the thirteen crude oils.

Normalizing to EIA-reported values was complicated by several factors.

First, the energy accounting framework in the regional refining models differs in some ways from that used by EIA in gathering and reporting data on U.S. refinery energy use. For example, as Exhibit 4.2 indicates, EIA tracks and reports more sources of refinery energy than the four explicitly represented in our refinery models.[18] As noted earlier, the four primary sources account for about 95% of reported U.S. refinery energy consumption. In effect, the refining models treat the refinery energy provided by the other sources (e.g., residual fuel, coal, purchased steam, etc.) as though it came from purchased natural gas.

Second, EIA's reporting framework for refinery energy does not include natural gas used as either feed or fuel in merchant hydrogen plants. Hence, without suitable adjustment, EIA's reporting of refinery energy use would lead to estimates of CO_2 emissions that did not include emissions resulting from hydrogen production. The total amount of natural gas used in all hydrogen production – both refinery and merchant plants – is relatively small, but in the context of this study it is a significant contributor to total refinery energy use and CO_2 generation.

[18] Some of the small-volume energy sources reported by EIA may reflect losses (due to spillage, leaks, etc.) rather energy production.

Finally, as noted in Section 4, refinery purchases of natural gas reported by EIA include natural gas used for power generation, without adjustment for refinery sales of electricity to the grid, and refinery purchases of electricity natural reported by EIA reflect purchases from the grid and do not include refinery-generated electricity.

5.4 Refinery CO_2 Emissions Accounting

We used standard CO_2 emissions factors, shown in **Exhibit 5.4**, to convert computed volumes of purchased natural gas, refinery fuel gas streams, FCC catalyst coke, and purchased electricity to refinery emissions of CO_2. The emissions factors are drawn from an American Petroleum Institute publication[19] and are similar to factors published by the IPCC.

The estimates of refinery CO_2 generation returned by the regional refining models reflect fuel consumption in all refining processes, as well as the natural gas used as feed for all on-purpose hydrogen production.

Exhibit 5.4: CO2 Emission Factors in the Regional Refining Models

Refinery Energy Source	CO_2 Emission Factor (Me Tons/MM BTU)
Natural gas	0.0531
Still gas	0.0642
Petroleum coke	0.1020
Electricity (purchased)	0.0639
Electricity (refinery-generated)	0.0531

Note:
Purchased electricity factor reflects 50%/30%/20% sourcing from coal, natural gas, and nuclear + renewables, respectively.

[19] Source: "*Toward a Consistent Methodology for Estimating GHG Emissions*"; American Petroleum Institute

6. Overview of the Refinery Modeling Methodology

This section briefly discusses the development and application of the methodology for estimating refinery energy use and CO_2 emissions for the specified crude oils. The discussion covers eight topics.

1. Refinery LP models
2. Data sources for the analysis
3. Developing the models
4. Calibrating the models (*calibration* cases)
5. Normalizing refinery energy use factors
6. Establishing baseline values for the analysis (*reference* cases)
7. Allocating refinery energy use and CO_2 emissions to refined products (*study* cases)
8. Estimating refinery energy use and CO_2 emissions, by crude oil and region (*study* cases)

6.1 Refinery LP Models

We conducted the analysis of refinery energy use and CO_2 emissions using linear programming (LP) models of aggregate refining operations: one national refining model and three regional refining models, representing the refining centers in the Midwest (PADD 2), the Gulf Coast (PADD 3), and California. Each model is an analytical construct representing aggregate refining capacity in a region of interest, processing a composite crude oil slate and producing a slate of refined products. We used the national refining model to estimate the shares of refinery energy use attributable to the various refined product categories. We used the regional refining models to estimate refinery energy use and CO_2 emissions for each specified crude oil/refining region combination.

Linear programming (LP) is a rigorous mathematical modeling technique for obtaining optimal (e.g., cost-minimizing) solutions to technical and economic problems. Refinery LP models are detailed, engineering representations of the primary refinery process operations and the material flows between processes. Since the mid-1950's, LP modeling has been the method of choice for refinery operations and investment planning, as well as techno-economic analysis of refining operations in general. LP modeling has achieved this status because it is uniquely suited to capturing the technical and economic essentials of refining operations.

With respect to this study, refinery LP modeling captures the key analytical elements of refining operations discussed in Section 2.3: complexity, co-product production, and distributed energy use.

We constructed the four refining models using MathPro's proprietary refinery modeling system (**ARMS**), which includes a library of crude assay data, technical characterizations of refining processes, and blendstock properties. Though developed from a common data base, the models are distinct in terms of aggregate refining process capacity, composite crude oil slate, refinery inputs and outputs, refined product specifications, and, in some instances, representations of individual refining processes.

Finally, we developed and applied the national model and each regional model through a sequence of *calibration*, *reference*, and *study* cases.

6.2 Primary Data Sources

In developing the various data elements in the models, we relied on the following published sources of U.S. refining data.

- Refining process capacity
  - "*2006 Worldwide Refinery Survey*"; Oil & Gas Journal; Dec. 18, 2006
  - "*2006 Refinery Capacity Survey*"; Energy Information Administration (EIA) website
  - "*2007 California Refinery Survey*"; California Energy Commission

- Crude oil slate
  - "*2006 Company-Level Import Data*"; EIA Website
  - "*2006 Petroleum Supply Annual, Table 17*"; EIA website
  - "*2007 California Refinery Survey*"; CEC
  - "*Crude Oil Production Data*"; State-Level, Monthly; EIA Website;

- Refinery inputs and outputs
  - "*Petroleum Supply Annuals, Tables 17 and 18*"; EIA website
  - "*Petroleum Industry Information Reporting Act (PIRA) Data,2006*"; CEC website;
  - "*Weekly Fuels Watch Reports*" for 2006; CEC website

- Refined product specifications
  - "*RFG Area Surveys for 2006*"; Environmental Protection Agency (EPA) website
  - "*Average Conventional and Reformulated Gasoline Properties for 2006*"; provided by EPA
  - ASTM Standard D4814-06; "*Table 1: Vapor Pressure and Distillation Class Requirements*" and "*Table 4: Schedule of Seasonal and Geographical Volatility Classes*"
  - "*2007 California Refinery Survey*"; CEC
  - "*1996 API/NPRA Survey of Refining Operations and Product Quality*"; American Petroleum Institute and National Petroleum Refiners Association; July 1997

- Refinery fuel use

    - "*Refinery Fuel Use, 2006*"; EIA website
    - "*California Refinery Fuel Use for 2006*"; provided by California Energy Commission;
    - "*Annual Sources and Disposition of Electricity for Non-utility Generators, 2006*"; EIA website

Exhibits A-1 to A-4 (in Appendix A) show the data we developed in the first four categories for the regional refining models, for the year 2006. Exhibit A-1 shows aggregate refining process capacity. Exhibit A-2 shows derived distillation curves and properties for the regional composite crude slates. Exhibit A-3 shows regional refinery input and output volumes. Exhibit A-4 shows product specifications for gasoline and diesel fuel. (Exhibits 4.2 and 4.3 show our estimates of refinery fuel use, by region and fuel type.) All of these data elements appear, in one form or another, in the refining models used in the study.

6.3 Model Development: Year 2006

Initially, we developed the national model and the regional refining models to represent annual average refining operations (in particular, refining process capacity, crude oil slate, refinery inputs and outputs, and product specifications) in 2006. Development of these models involved the following steps.

- Endow each model with the total refining process capacity reported for each region, process by process (e.g., cat cracking, alkylation, etc.), as of 1 January 2007.

- Set the volume shares of desulfurized and untreated FCC feed to conform to the reported process capacities of gas oil (FCC feed) hydrotreating and FCC units.

  We constrained the sulfur content of the gas oil feeds to the FCC feed hydrotreater so as to match our estimates of the average sulfur content of gas oils processed by refineries with FCC feed hydrotreaters in each region. In the California model, we required desulfurization of all FCC feed, because all California refineries have FCC feed hydrotreaters. We split the hydrotreating capacity between conventional hydrotreating and deep hydrotreating (in effect, mild hydrocracking) on the basis of our estimates of the relative volumes of these types of FCC feed hydrotreating in the California refining sector.

- Set the volume shares of coker gas oil sent to cat cracking (constrained via hydrotreating) and to hydrocracking on the basis of various survey data.

- Limit the crude oil inputs to each regional model to regional composite crude oils, which we developed using the data sources cited above.

  Each regional composite crude oil is a volume-weighted average of the imported and domestic crudes that comprise the region's crude oil slate, according to our estimates.

Hence, the composition and properties of the crude oil slate represented in each regional model are invariant with respect to the volume processed.

- Set the volumes of the refinery inputs of unfinished oils and certain gasoline blendstocks (MTBE, pentanes, alkylate, iso-octane, pyrolysis gas, and toluene) at the reported (or, where necessary, estimated) volumes.

- Set prices of the refinery inputs of crude oil, n-butane, and iso-butane and allow the input volumes to vary (subject to upper limits corresponding to reported input volumes).

- Set the volumes of ethanol use as follows.

  - For ethanol used in conventional gasoline (CG), set an upper limit on volume equal to the sum of (1) the volume of ethanol reported by refineries for producing finished, ethanol-blended conventional gasoline on-site (i.e., at the refinery) and (2) the volume of ethanol commensurate with 10 vol% ethanol blending with CBOBs.[20]

  - For ethanol used in reformulated gasoline (RFG), set an upper limit equal to the sum of: (1) the volume of ethanol reported by refineries to make finished, ethanol-blended RFG on-site and (2) the volume of ethanol commensurate with 10 vol% ethanol blending with RBOBs (except in California where the ethanol blending rate was 5.7 vol% in CaRFG).[21]

- Set the volumes of purchased MTBE at the reported volumes.

- Fix the volumes of most refined product outputs at the reported (or, where necessary, estimated) volumes.

- Set prices of two refinery outputs – propane (for LPG) and petroleum coke – and allow the output volumes returned by models to vary in response to the specified prices.

- Specify the product specifications for conventional gasoline, RFG, jet fuel, diesel fuel (on- and off- road and CARB), and residual oil using the above cited data sources.

All of these elements represented annual operations (averages of summer and winter operations).

[20] The refining models were set up to produce all finished gasoline, rather than the mixture of gasoline products – finished gasoline, RBOB (Reformulated Blendstock for Oxygenate Blending), and CBOB (Conventional Blendstock for Oxygenate Blending) – reported by EIA.

RBOB and CBOB are base gasoline blends to which ethanol is added at terminals, downstream of the refinery, to produce, respectively, finished federal reformulated gasoline and conventional gasoline.

[21] CaRFG stands for California reformulated gasoline (which differs from federal RFG). The base gasoline for CaRFG is called CARBOB.

6.4 Calibrating the Models to 2006 Refining Operations

Consistent with our standard practice in studies of refining operations, our first step in applying the regional models was to *calibrate* each model to the corresponding regional refining operations in a prior time period – in this instance, 2006. Well-calibrated models provide assurance that subsequent uses of the models will adequately represent refining operations under alternative sets of requirements, such as refined product standards, and/or with different crude and product slates.

Calibrating a refining model involves adjusting some of the model's internal technical coefficients – such as yields from refining processes, blending properties of refinery streams, or process capacity utilization rates – as needed so that solutions returned by the model closely approximate reported refining operations. In calibrating the regional refining models this study, we modified the initial specification of the models (discussed above) in various ways, including:

- Allowing the model to represent additions of new capacity in (1) various separation (splitting) processes, (2) FCC naphtha desulfurization, and (3) benzene saturation, to facilitate meeting refined product specifications or shifting the boiling range cut points of distillate products

- Adding additional hydrogen plant capacity to simulate production of hydrogen purchased from merchant plants

- Changing the boiling range cut points for vacuum gas oils to better match reported feed rates to coking and fluid cat cracking

- Allowing the retrofitting (at a cost) of existing conventional distillate desulfurization units to meet the new ULSD standard ($\leq$ 15 ppm) for the sulfur content of diesel fuel

- Modifying the yields of petroleum coke (in the coker) and catalyst coke (in the FCC unit) to better approximate reported volumes of marketable and catalyst coke; and

- Modifying a few refined product specifications, primarily distillation temperature and cetane number (for diesel fuel), when these specifications constrained the model from making certain refined products.

The reported refining operations to which we calibrated included crude oil throughput; feed rates to fluid cat cracking, delayed coking, and fluid coking; production volumes of marketable (petroleum) coke and of catalyst coke; and (importantly) the marginal costs (shadow values) of producing the major refined product categories (gasoline, jet fuel, diesel fuel, and residual fuel).

Regarding the marginal costs of production returned by the models, the objective of the calibration was to ensure that (1) the marginal costs of the various refined products bear the same general relationship as do the reported market prices for these products, (2) the marginal costs of meeting various product specifications are reasonable, and (3) the marginal value of various intermediate refinery streams and blendstocks are reasonable in relation to product prices. Meeting these criteria is essential even when, as in this study, the refining analysis does not focus primarily on refining economics.

Exhibits B-1 and B-2 (Appendix B) show, respectively, refinery inputs and outputs and refinery process capacity, by unit, for the calibrated regional models.

6.5 Normalizing Refinery Energy Use Estimates Returned by the Models

As discussed in Section 5, we expected raw (unadjusted) estimates of aggregate refinery energy use returned by our refinery models to be somewhat lower than the values reported by EIA (as adjusted for refinery-generated power sold to the grid). The models do not represent certain auxiliary refining processes. The energy use factors for the various refining processes represented in ARMS reflect recent information published by refining technology providers. This information most likely represents best-practice energy use in new process units, rather than average energy use across actual units of various vintages. Finally, the refining models represent fuel and power consumption only for direct refinery processing, not for ancillary operations (e.g., oil movement, storage, blending, effluent treating, etc.).

To deal with this situation, we developed a post-model *regional normalization procedure* for refinery energy use. The normalization procedure transforms the estimates of refinery energy use, by energy source, returned by the national and regional refining models into estimates consistent with those reported by EIA and CEC. We developed the normalization procedure by conforming the refinery energy use values returned by the national and regional models in the calibration cases (representing year 2006) to corresponding refinery energy use estimates for 2006 developed from EIA and CEC reports.

Exhibits C-1a and C-1b (Appendix C) show the normalization factors derived for the national and regional models, respectively. In developing the normalization factors, we made several adjustments to the values reported by EIA and CEC.

As noted in Section 4, the EIA (and CEC) reports on refinery energy use include refinery purchases of natural gas for generating power, whether for internal use or sale to the grid. Using an EIA database of non-utility power generators, we estimated regional refinery-based power generation and the percentage of such power sold to the grid (shown in Exhibit 4.4). We then

- Subtracted from reported refinery purchases of natural gas for fuel our estimate of the volume of natural gas used for all refinery-based power generation; and

- Added to the reported refinery purchases of power our estimate of the amount of refinery-generated power that was used internally.

This procedure essentially (1) removes from the refineries' energy balance sheet the energy (from natural gas) used to generate power sold to the grid – energy that is not used in processing crude oil into refined products – and (2) shifts the natural gas used to generate power for internal use into an equivalent amount of purchased electricity. The latter adjustment reflects our practice of representing refineries as purchasing all of the electricity they use.

We applied the normalization factors uniformly to the refinery energy use estimates returned by the refining models in the reference and study cases.

6.6 Establishing Baseline Values for the Analysis (*Reference* Cases)

Developing the regional refining models, calibrating them, and normalizing the estimates of refinery energy use returned by the calibrated models are prerequisite steps to the methodology that we used to allocate refinery energy use to refined product categories and to estimate refinery energy use and CO_2 emissions for each crude oil/refining region combination and.

The first step in the methodology was to establish national and regional baselines. In this instance, the baseline values are the solutions returned by models for the *reference* cases. We developed reference cases, rather than simply using the 2006 calibration cases as the baseline cases, because significant changes in the regulatory landscape bearing on fuel quality and ethanol blending have occurred since 2006 and others will occur over the next several years. The new (i.e., post-2006) regulatory programs and standards include:

- National Tier 2 gasoline sulfur standards (average sulfur level in gasoline < 30 ppm)
- National MSAT 2 standards on toxic emissions from gasoline (average benzene levels in gasoline < 0.62 vol%)
- National Ultra-Low Sulfur Diesel (ULSD) standard (maximum sulfur level in on-road and off-road diesel < 15 ppm)
- National roll-out of the new Renewable Fuel Standard (RFS2) in the Energy Independence and Security Act of 2007 (requiring 10 vol% ethanol blending in all RFG and conventional gasoline, along with increased E85 volumes by 2015, most likely in the Midwest) [22]
- California's revisions to the state's reformulated gasoline program (CARB 3) and amendments to its Predictive Model (PM-3) for certifying CARB 3 gasoline batches (to facilitate ethanol blending at 10 vol% and to account for the permeation emissions associated with ethanol blending)

These regulatory developments will be fully implemented by 2015.

In addition, we assumed that the main regulatory programs affecting gasoline properties that were in full effect in 2006 would continue. In particular, we assumed that the 1 psi RVP waiver

[22] The RFS2 standard mandates annual increases in renewable fuels volumes through 2022.

for ethanol blending in the summer would remain in effect in its present form, covering all gasoline types except for federal RFG and California RFG.

We incorporated the impending new regulatory requirements in the national and regional refining models by suitably modifying the refined product standards and requiring 10 vol% ethanol blending in all gasoline, both conventional and reformulated.

In establishing the reference cases, we used projections of U.S. refinery inputs and outputs for 2015 drawn from EIA's most recent *Annual Energy Outlook* [23] for the national model and allocated these inputs and outputs proportionately for the regional models, except that we allocated all projected E85 use to PADD 2 and adjusted gasoline volumes in other regions accordingly. The reference cases embody the same crude slates as the calibration cases, because we assumed that the regional crude oil slates would not change significantly between 2006 and 2015.

Exhibits A-3c and A-3d, respectively, show reference case projections of 2015 refinery inputs and outputs for the U.S. and for the refining regions. **Exhibit 6.1** shows the projected volumes (K Bbl/day) and volume shares (vol%) of each product category in the projected 2015 U.S. refined product slate.

Exhibit 6.1: Projected Volumes of Refined Product Categories (2015)

Refined Product Category	Projected 2015 Volume (K Bbl/day)	Projected 2015 Volume (Vol%)	Notes
Gasoline	7267	48.6	(1)
Jet Fuel	1366	9.1	
Diesel Fuel	4142	27.7	(2)
All Other	2165	14.5	(3)
Total	14940	100	(4)

Notes:

1 **Gasoline** volumes are net of ethanol and other purchased blendstocks.
2 **Diesel fuel** volumes include other distillate products, such as No. 2 heating oil.
3 **All other** includes LPG, petrochemical feedstocks, unfinished oils, residual fuel, asphalt, and lubes and waxes.
4 **Total** excludes marketable coke.

[23] *Annual Energy Outlook, 2009 (Early Release)*; EIA website

We selected 2015 as the target year for the analysis because the regulatory developments discussed above will be fully implemented by then. With these regulations in place, the choice of year for the reference cases will, in our judgment, have only negligible effects on the estimates of per barrel energy use and CO_2 emissions obtained with the methodology described here.

6.7 Estimating Refinery Energy Use and CO_2 Emissions (*Study* Cases)

With the national and regional baselines established via the reference cases, the next step in the modeling methodology involved developing and analyzing a set of *study* cases.

The study cases for allocating refinery energy use to refined product classes represented the U.S. refining sector as a whole and were analyzed with the national refining model.

The study cases for estimating refinery energy use and CO_2 emissions by crude oil and refining region each represented a particular crude oil/region combination and were analyzed with the appropriate regional refining model. Exhibit 1.1 shows the crude oil/region combinations analyzed in these study cases.

6.7.1 Allocating Refinery Energy Use and CO_2 Emissions to Refined Products

Each of the four study cases in this part of the analysis pertained to one product category: *gasoline*, *jet fuel*, *diesel fuel* (and other distillate products), and *all other refined products*.

The analysis produced estimates of U.S. refinery energy use associated with each product category (in MBTU/Bbl) and of the corresponding CO_2 emissions (in MeTons/Bbl), for use in the Life Cycle Analysis framework of choice (e.g., GREET). We used the national refining model, rather than the regional models, for this analysis because the results were to be applicable to all U.S. refining regions.

The analysis employed an incremental refined product substitution procedure, comprising the following steps.

1. Estimate baseline values of U.S. aggregate energy use and CO_2 emissions (as discussed in Section 6.6).

2. For each product category in turn, estimate the change in aggregate energy use associated with a small (1%) reduction in its production volume; holding all other refinery outputs and all refinery inputs constant.

   The values of total refinery energy use and calculated CO_2 emissions in this case are lower than the baseline values, with the differences entirely attributable to the specified decrement in the volume of the specified product.

3. Calculate refinery energy use per barrel of refined product, for each refined product category.

The computation involves (1) calculating energy allocation factors for each product category equal to the reduction in energy use for a given product category (returned in Step 2) divided by the sum of the reductions in energy use across all product categories; (2) calculating per barrel energy use for each product category equal to the product category's allocation factor times total refinery energy use in the study case divided by the specified volume of the product category.

4. Calculate CO_2 emissions per barrel of refined product, for each refined product category.

   The computation involves (1) calculating per barrel fuel use (by fuel type) for each product category as energy use is calculated in Step 3; (2) multiplying per barrel fuel use by the corresponding CO_2 emission factors (Exhibit 5.4); and (3) calculating CO_2 emissions per barrel of each product category as the sum of CO_2 emissions for each fuel type, for that category.

Exhibit C-2 provides additional detail on this procedure, in numerical form.

6.7.2 Estimating Refinery Energy Use and CO2 Emissions for Each Crude Oil, by Refining Region

We developed two study cases for each crude oil/region combination, which we called *FIX* and *FLOAT*. In the FIX cases, which were the primary cases (and which we discuss first), we held essentially all refinery inputs and outputs constant at their baseline values. In the FLOAT cases, we allowed refinery outputs to vary within relatively narrow limits.

FIX Cases

The analysis of the FIX cases employed an incremental crude oil substitution procedure, consisting of the following steps.

1. Estimate baseline values of regional energy use and CO_2 emissions (as discussed in Section 6.6)

2. Develop, for each crude oil/refining region combination, a study case incorporating an incremental change in the regional refining model's crude slate: a 100 K Bbl/day reduction in the volume of the region's composite crude and a corresponding increase in the volume of a specified crude oil (e.g., Escravos or Dilbit).

   In the study case, we allowed (1) refinery purchases of butanes (to augment refinery-produced butanes) [24] and (2) investment in new refining capacity, if needed to produce the specified product slate with the amended crude slate. We allowed refinery production of

[24] Butanes include n-butane (for direct blending to gasoline) in PADD 2 and i-butane (for feed to alkylation units) in PADD 3 and California.

marketable coke and propane to vary (so as not to over-constrain the models). We held essentially all other model elements and inputs constant.

We allowed the volume of purchased butanes to vary because we found that an added degree of freedom was necessary to avoid large excursions in the marginal values of the various refinery inputs and outputs from their baseline levels. Such excursions indicate that the regional refinery model is employing unrealistic processing options. We allowed the volumes of marketable coke and propane production to vary because (1) holding all product volumes constant would likely have precluded a feasible solution to the model, and (2) propane and petroleum coke are pure refinery by-products (that is, they are not produced on purpose).

The values of total refinery energy use and CO_2 emissions returned by the regional models were different (higher or lower) than the baseline values. The differences were entirely attributable to the introduction of the given crude oil into the refinery crude slate.

3. Compute, for each crude oil/refining region combination, the refinery energy use and CO_2 emissions per unit (e.g., MM BTU and Bbl) of the given crude oil.

   The computation involves (1) calculating the normalized fuel use, by fuel type, for the modified crude slate in the study case; (2) calculating per-barrel energy use, by fuel type, for the specified crude as total fuel use in the study case minus total fuel use associated with the composite crude slate (the latter being equal to the volume of the composite crude time the baseline per-barrel fuel use for the composite crude); (3) calculating per-barrel fuel use of the specified crude as the sum of the per-barrel energy use from each type of fuel times its energy conversion factor; and (4) calculate per-barrel CO_2 emissions for the specified crude as the sum of the per-barrel use of each fuel type times its CO_2 emissions factor.

This phase of the analysis produced estimates of the incremental refinery energy use and CO_2 emissions attributable to each crude oil in refineries characteristic of each refining region, with the other refinery inputs and outputs product slate essentially constant. Consistent with the discussion in Section 2, these estimates (1) reflect the effects of crude oil properties on refinery energy use (and the consequent CO_2 emissions) required to produce a given product slate to given product specifications and standards and (2) indicate the effects on a given crude's refinery energy use and CO_2 emissions of regional differences in refinery configuration (i.e., process capacity profile) and product slate.

FLOAT Cases

We used a similar methodology in the FLOAT cases, except that we allowed the volumes of gasoline, jet fuel, and diesel production to vary from their baseline values, within the narrow ranges shown below.

- PADD 2: +/- 1%
- PADD 3: +/- ½%
- California: +/- 1½%

In the FLOAT cases, we specified prices for the refined products equal to the marginal production costs ("shadow values") for the products returned in the baseline cases.

The FIX and FLOAT cases were otherwise identical.

We established the FLOAT cases, with their variable product volumes, to more closely simulate the prospective behavior of the refining sector, which would seek to use its crude oil slate in an economically optimal manner – even if the economic optimum were to involve some change in product slate. For purposes of this analysis, we assumed that any changes (up or down) in product volumes would be off-set by corresponding changes in product imports or in the product out-turns of other refining regions. Accordingly, for each FLOAT case, we adjusted the computed refinery energy use to include the delta energy use associated with the off-setting changes in product volumes outside of the region of interest. For this purpose, we used the refinery energy use and CO_2 emissions estimates for each refined product category from the earlier analysis employing the national model (discussed in Section 6.7.1 above).

Exhibits C-3a, C-3b, C-4a, C-4b, C-5a, and C-5b provides additional detail on this procedure, in numerical form, for PADD 2, PADD 3, and California, respectively, and for each region's FIX and FLOAT cases.

7. Results of the Analysis

This section presents and briefly discusses the primary results of the analysis:

- Estimates of the aggregate U.S. refining sector's per-barrel energy use in producing each of the four primary product categories

- Estimates of the U.S. regional refining sectors' per-barrel energy use and the resulting CO_2 emissions for each crude oil/refining region combination considered

7.1 Allocation of Refinery Energy Use and CO_2 Emissions to Refined Products

Exhibits 7.1a and 7.1b, respectively, show the estimated allocation of (a) refinery energy use (in MBTU/Bbl) and (b) refinery CO_2 emissions (in MeT CO_2/Bbl) to the primary refined product categories – *gasoline*, *jet fuel*, *diesel fuel*, and *all other* – and to refined products as a whole – designated as *all refined products*.

The product-specific estimates denote changes in refinery energy use and CO_2 emissions per incremental barrel of product volume (with all other product volumes held constant). The all-refined-products estimates reflect average refinery energy use and CO_2 emissions across all refined products.

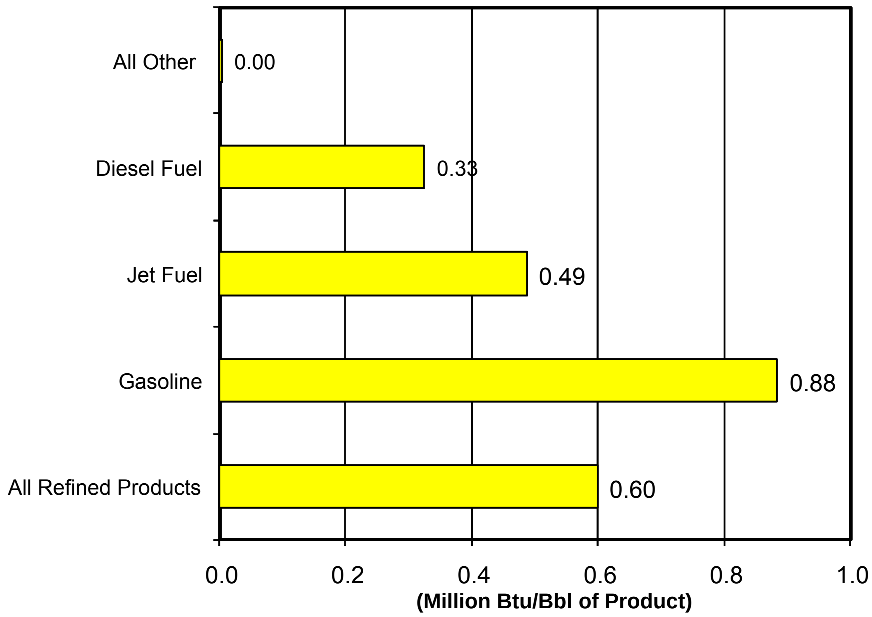
These estimates apply to the U.S. refining sector as a whole, and not necessarily to a particular region (or individual refinery) whose process capacity profile, product slate, and product specifications may differ from the national aggregate.

Gasoline is the most energy-intensive of the four product categories and, correspondingly, the associated refinery CO_2 emissions are the highest of the four. Producing the gasoline volumes demanded in the U.S. calls for extensive conversion of heavy crude fractions to gasoline components, and stringent U.S. gasoline specifications call for extensive upgrading operations. These operations are large consumers of refinery energy.

Jet fuel is the second most energy-intensive product category; its per-barrel energy allocation is a little over half that of gasoline. Like gasoline, jet fuel contains substantial volumes of refinery streams produced by upgrading and conversion processes. However, the specifications that jet fuel must meet do not require as much refinery processing as those for gasoline (or diesel fuel).

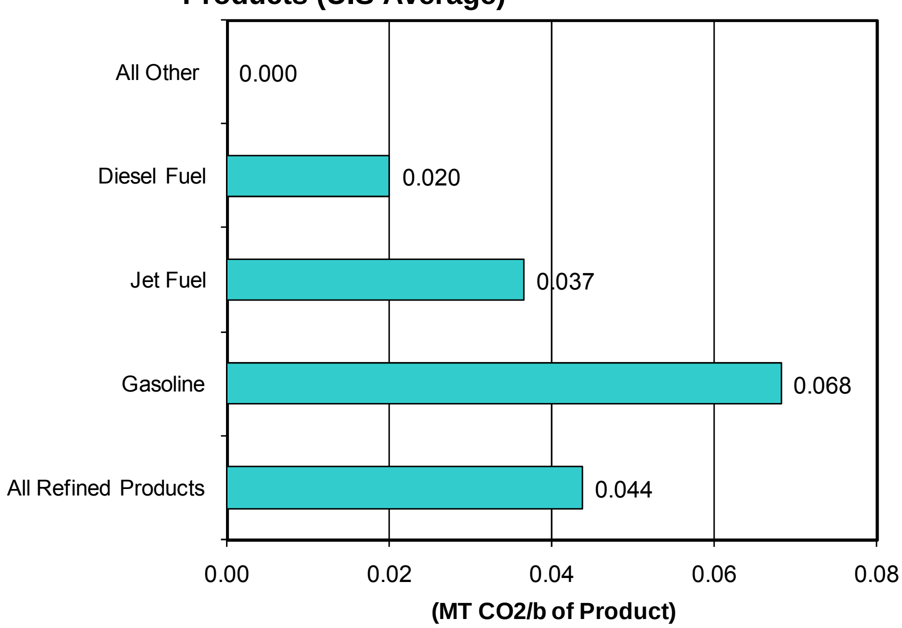
Diesel fuel's energy allocation is a little over one-third that of gasoline (and about two-thirds that of jet fuel). Diesel fuel specifications, especially the stringent sulfur specification (< 15 ppm), call for extensive hydrotreating of diesel fuel blendstocks. However, only a relatively small portion of the diesel fuel volume in U.S. refineries is produced on-purpose (as opposed to being a by-product of conversion operations aimed at producing gasoline blendstocks).

Exhibit 7.1a: Allocation of Refinery Energy Use to Refined Products (U.S Average)



Note: Gasoline includes BTX, propylene, naphthas, aviation gasoline, CBOBs, and RBOBs; excludes purchased gasoline blendstocks (e.g., ethanol). Diesel fuel includes lube oils.

Exhibit 7.1b: Allocation of Refinery CO2 Emissions to Refined Products (U.S Average)



7.2 Estimated Refinery Energy Use and CO2 Emissions, by Crude Oil and Region

Exhibits 7.2, 7.3, 7.4, and 7.5 show estimated refinery energy use (in MBTU/Bbl) and refinery CO_2 emissions (in MeT CO_2/Bbl) for all of the crude oil/region combinations considered. All the exhibits show estimates for both the FIX and the FLOAT cases analyzed for each crude oil/region combination, as well as baseline estimates corresponding to the baseline composite crude oil in region.

Exhibit 7.2 summarizes in tabular form the estimates for the composite crude oil in each region and for all crude oil/region combinations. **Exhibits 7.3, 7.4, and 7.5** show the same results in graphical form for PADD 2, PADD 3, and California, respectively.

Exhibit 7.2: Estimated Refinery Energy Use and CO2 Emissions by Crude Oil, Region, and Case

	PADD 2		PADD 3		California	
	Fix	Float	Fix	Float	Fix	Float
Energy Use (MM Btu/Bbl)						
Composite Crude	0.561	0.561	0.641	0.641	0.641	0.641
West Texas Inter.	0.489	0.507	0.543	0.552		
SJV Heavy					0.754	0.765
Alaskan North Slope					0.576	0.577
Saudi Medium	0.608	0.590	0.673	0.681	0.669	0.650
Basrah Medium			0.673	0.681	0.677	0.655
Escravos			0.501	0.523		
Bachequero 17			0.723	0.732		
Maya			0.722	0.716	0.814	0.716
Bow River	0.647	0.643				
SCO, Mining	0.386	0.357	0.465	0.480	0.526	0.527
SCO, In Situ	0.370	0.396	0.417	0.436	0.415	0.386
Synbit	0.630	0.616	0.724	0.735	0.761	0.770
Dilbit	0.633	0.642	0.687	0.697	0.829	0.748
CO2 Emissions (MeT/Bbl)						
Composite Crude	0.041	0.041	0.046	0.046	0.055	0.055
West Texas Inter.	0.032	0.032	0.033	0.032		
SJV Heavy					0.073	0.074
Alaskan North Slope					0.043	0.044
Saudi Medium	0.048	0.047	0.048	0.049	0.057	0.054
Basrah Medium			0.048	0.049	0.057	0.056
Escravos			0.031	0.031		
Bachequero 17			0.056	0.057		
Maya			0.052	0.053	0.073	0.063
Bow River	0.051	0.053				
SCO, Mining	0.030	0.027	0.033	0.035	0.048	0.044
SCO, In Situ	0.023	0.024	0.023	0.023	0.030	0.028
Synbit	0.053	0.052	0.056	0.057	0.073	0.075
Dilbit	0.053	0.054	0.051	0.053	0.078	0.065

Exhibit 7.3a: Estimated Refinery Energy Use by Crude Oil, PADD 2

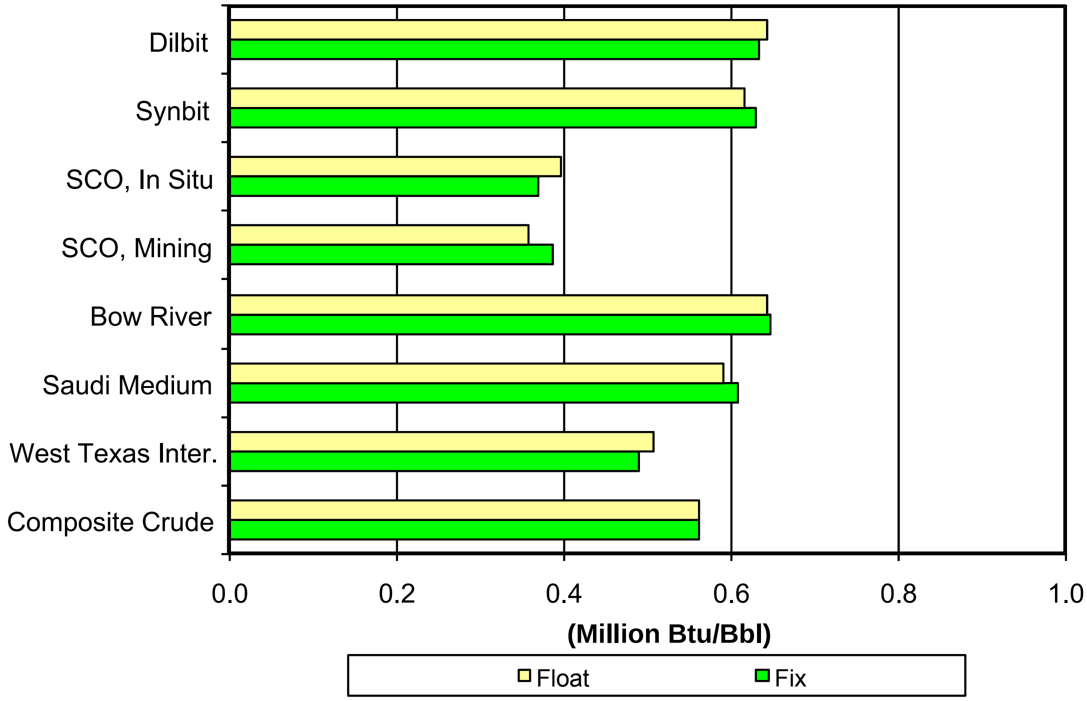


Exhibit 7.3b: Estimated Refinery CO2 Emissions by Crude Oil, PADD 2

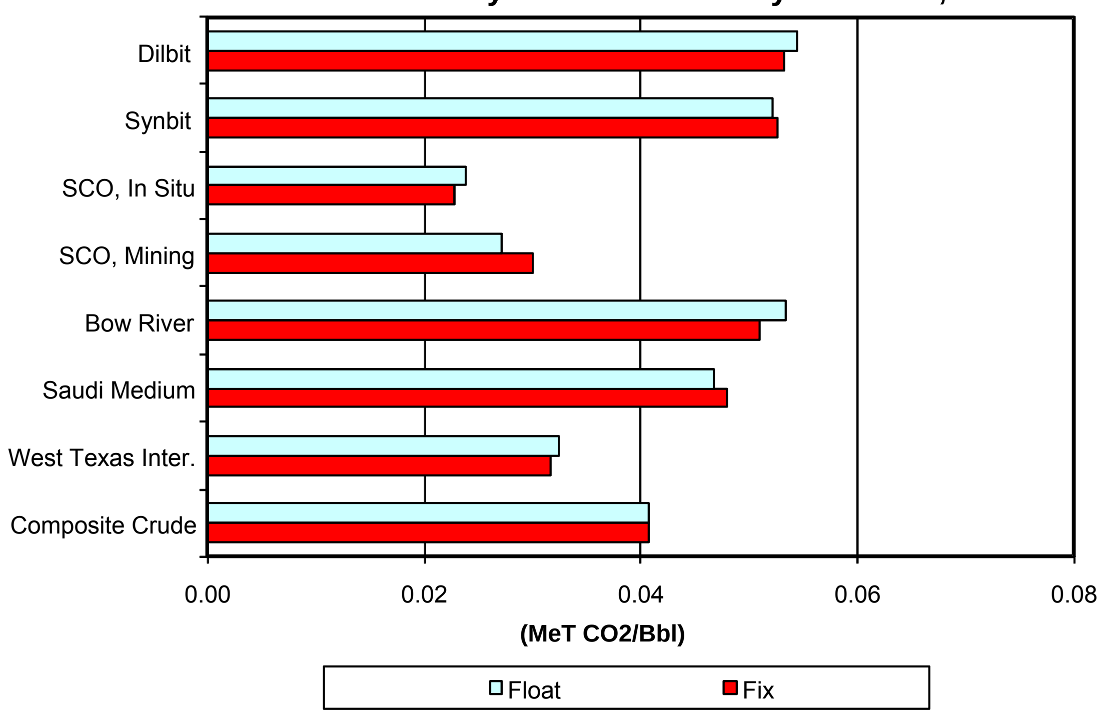


Exhibit 7.4a: Estimated Refinery Energy Use by Crude Oil, PADD 3

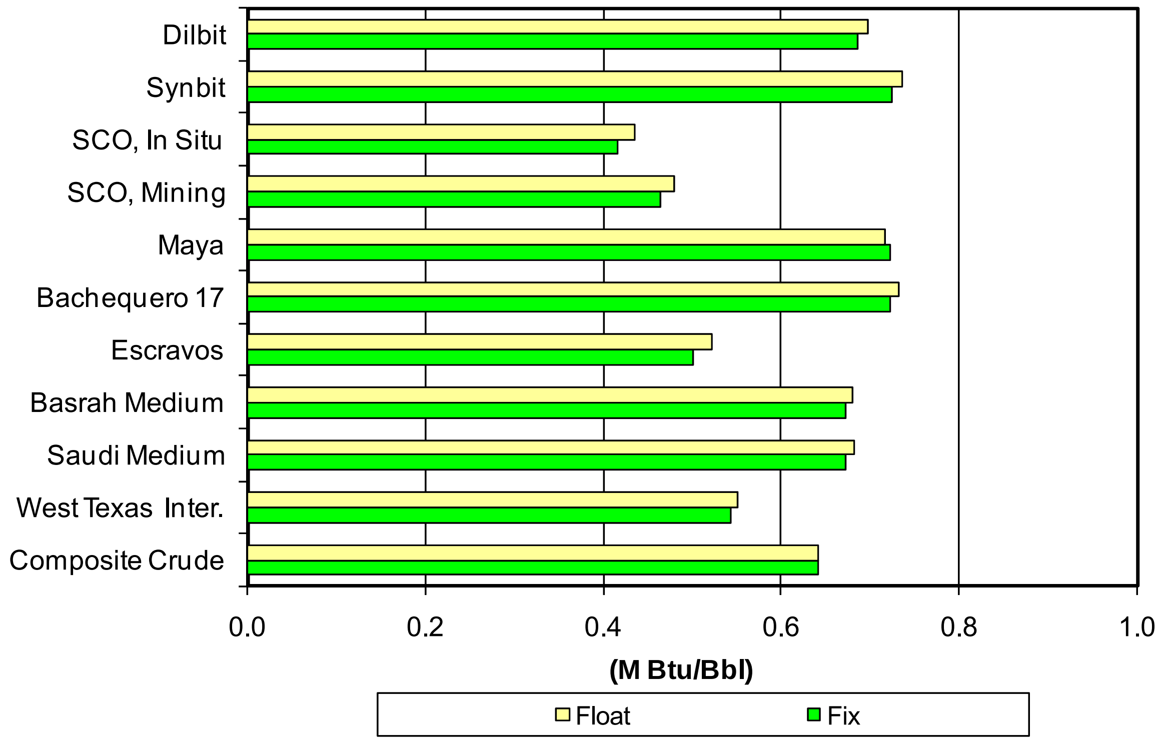


Exhibit 7.4b: Estimated Refinery CO2 Emissions by Crude Oil, PADD 3

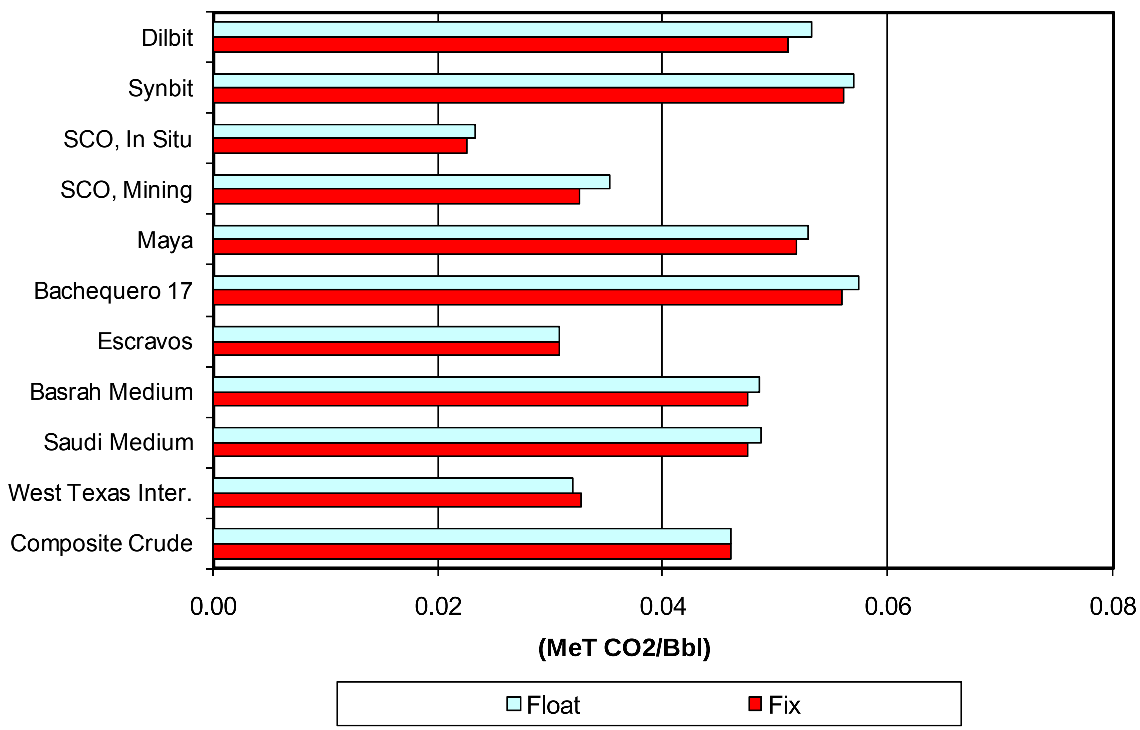


Exhibit 7.5a: Estimated Refinery Energy Use by Crude Oil, California

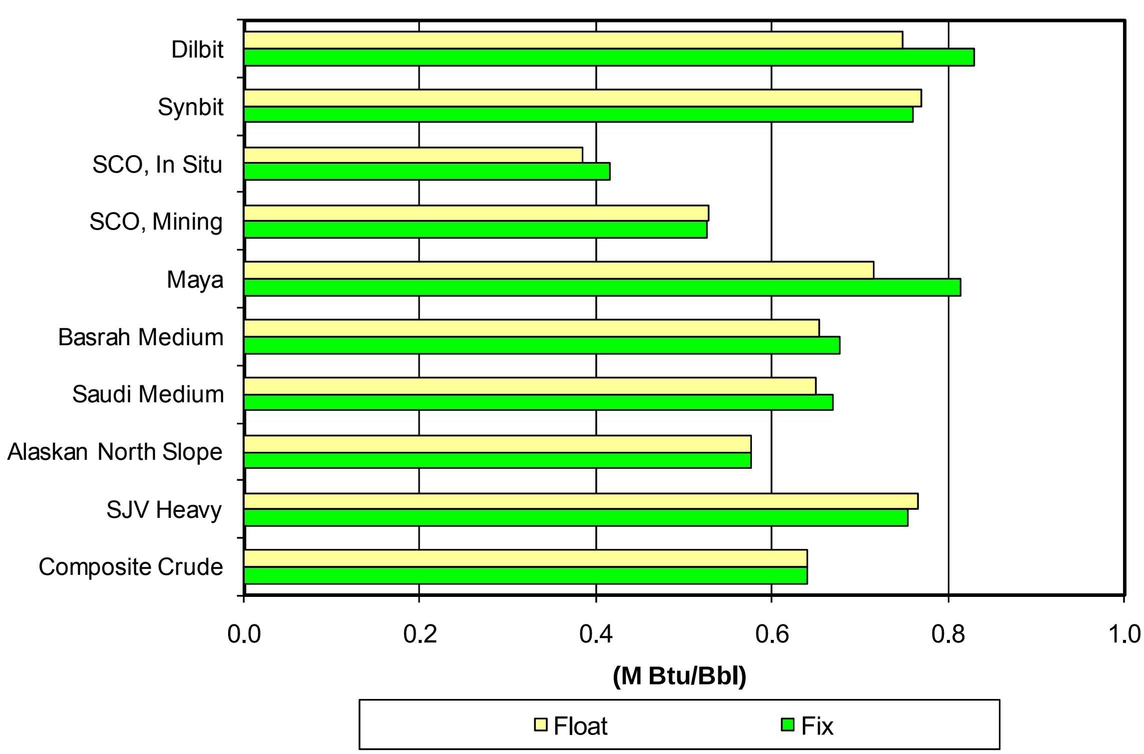
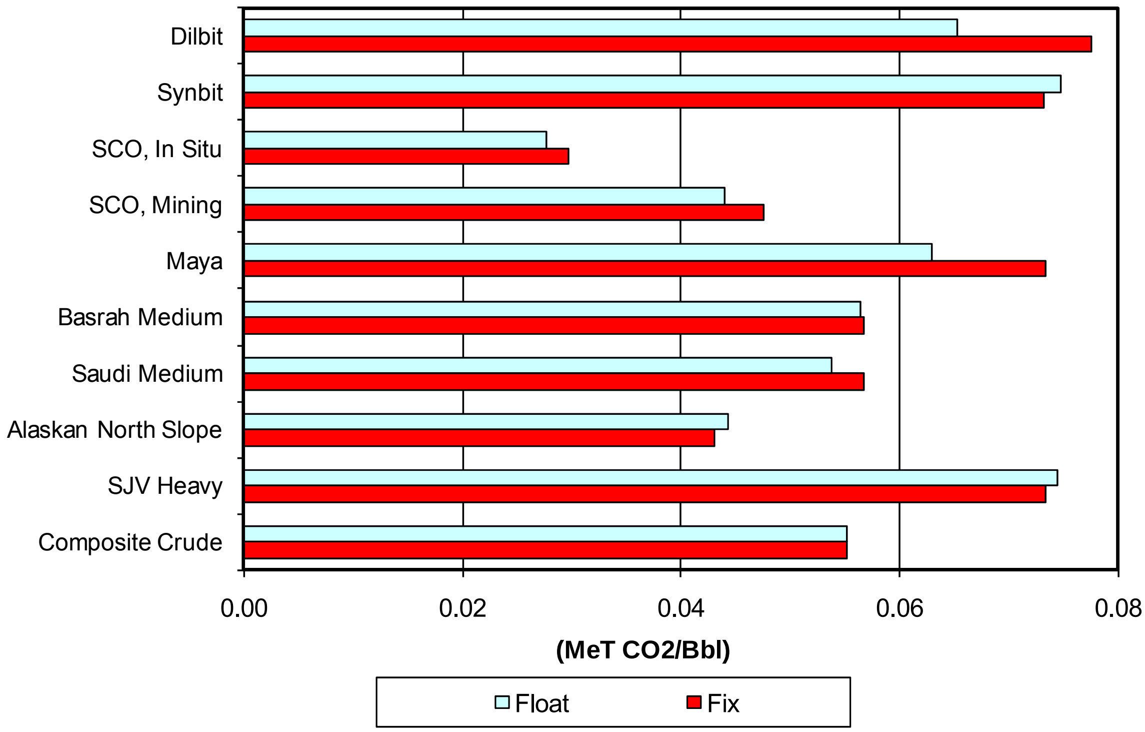


Exhibit 7.5b: Estimated Refinery CO2 Emissions by Crude Oil, California



7.2.1 Estimated Refinery Energy Use, by Crude Oil and Region

The estimates shown in these exhibits indicate that:

- For a given crude oil/region combination, the FIX and FLOAT cases yield similar (but not identical) results. The differences between FIX and FLOAT pairs vary, in both magnitude and direction, from one crude oil/region combination to another. See, for example, the estimates for Maya and Dilbit in Exhibit 7.2.

  Differences between FIX and FLOAT pairs for a given crude oil indicate different region-to-region differences in the optimal refinery processing response to an incremental volume of the given crude in the overall crude slate.

- Current refinery energy use in the U.S., indicated by the *Composite Crude* estimates (obtained from the baseline cases) is in the range of 0.56–0.64 M BTU/Bbl, or about 9½–11% of the energy content of the crude oil.

  Refinery energy use is higher in PADD 3 and California than in PADD 2, primarily because the crude slates in PADD 3 and California contain proportionately more heavy, sour crude (such as Bachaquero 17, Maya, and SJV Heavy) than the crude slate in PADD 2. Correspondingly, PADD 2 refineries are less complex (that is, have relatively less conversion process capacity) than PADD 3 and California refineries. PADD 2 refineries also produce a product slate with relatively less jet fuel, lube oils, and petrochemical feedstocks.

- The refinery energy use associated with conventional light, sweet crudes (WTI, Escravos) is roughly 2/3 the energy use associated with the heaviest conventional sour crudes (SJV Heavy, Maya, Bachaquero 17). For example, in PADD 3, estimated refinery energy use is 0.50–0.54 M BTU/Bbl for Escravos and WTI and 0.72–0.73 M BTU/Bbl for Maya and Bachaquero 17.

  These intra-regional differences indicate the effects of crude oil properties on refinery energy use (all else equal).

- For a given crude oil, refinery energy use varies from region to region. For example, the refinery energy use for Saudi Medium ranges from about 0.59–0.61 M BTU/Bbl in PADD 2 to about 0.67–0.68 BTU/Bbl in PADD 3; the refinery energy use for SCO (in situ) ranges from 0.36–0.39 MM BTU/Bbl in PADD 2 to 0.42– 0.44 M BTU/Bbl in PADD 3.

  These inter-regional differences for a given crude oil indicate the effects on refinery energy use of baseline crude slate, refinery capital stock, and (to a lesser extent) regional standards on refined product emissions performance.

- In general, the estimated refinery energy use associated with the Canadian Synbit and Dilbit crudes is comparable to that of the conventional heavy, sour crudes (e.g., Maya, Bachaquero 17, and SJV Heavy).
  The estimated refinery energy use for SCO (from both mined and in situ bitumen) is less than that for any conventional crude oil considered, primarily because (by virtue of the upgrading processes that produce them) the SCOs have low sulfur content and no vacuum resid fraction. We assumed in the analysis that refineries running SCO would use processing schemes that fully exploit these properties.

7.2.2 Estimated Refinery CO_2 Emissions, by Crude Oil and Region

The estimates shown in Exhibits 7.2–7.5 indicate that:

- The differences in estimated refinery CO_2 emissions between FIX and FLOAT pairs track the differences in estimated refinery energy use between the same pairs.

- Current refinery CO_2 emissions in the U.S., indicated by the *Composite Crude* estimates (obtained from the baseline cases) are in the range of 0.041–0.055 MeT/Bbl.

  Refinery CO_2 emissions are highest in California, because of the high proportion of heavy, sour crude in the California crude slate, the unusual product slate in California (little or no residual oil production), and the state's stringent standards on gasoline and diesel quality.

- For the various crude oil/region combinations, estimated refinery CO_2 emissions track estimated refinery energy use.

  Crude oils with the highest refinery energy use have the highest refinery CO_2 emissions (SJV Heavy, Maya, Bachaquero 17, Synbit, and Dilbit). The SCOs have the lowest refinery CO_2 emissions.

- In general, the estimated refinery CO_2 emissions associated with Canadian Synbit and Dilbit crudes is comparable to those of the conventional heavy, sour crudes (e.g., Maya, Bachaquero 17, and SJV Heavy). The estimated refinery CO_2 emissions for SCO (from both mined and in situ bitumen) are lower than those for any conventional crude oil considered.

8. Additional Comments

8.1 Interpreting the Refinery Energy Use and CO_2 Emissions Estimates

The results of our analysis should be interpreted as estimates of the refinery energy use and CO_2 emissions associated with a given crude oil when a small volume of it is introduced into a particular refining region's crude slate.

The energy required to refine a crude oil is not a fixed, intrinsic property of the crude. In practice, a crude oil's refinery energy use and the resulting CO_2 emissions depend not only on the crude's properties but also, to some degree, on the specific refining environment in which the crude is processed.

Our analytical approach recognizes differences in the regional refining environments in which the various crudes are used (i.e., the rest of the crude slate, refinery configuration, product slate, etc.). Accordingly, for a given crude oil, the analysis yields somewhat different results from region to region, as well as different results in corresponding pairs of FIX and FLOAT cases (as shown in Exhibit 7.2).

The methodology produces such estimates because, through its use of refinery LP modeling, it recognizes the (albeit limited) flexibility in regional refining operations to accommodate changes in crude slate and respond to economic driving forces.

8.2 Refinery Energy Use in the U.S. and Elsewhere

The U.S. refining sector is unlike any other, and its special characteristics exert a strong influence on the results. Hence, the results apply specifically to the U.S. refining sector.

U.S. refineries turn out a product slate with the world's highest proportion of transportation fuels – and of gasoline in particular. The gasoline output of U.S. refineries is about 50 vol% on crude, more than double the world average, and gasoline is the main "on purpose" product of U.S. refineries. Accordingly, U.S. refineries perform extensive processing and upgrading of crude oil fractions and conversion of the heaviest crude oil fractions into lighter, higher-valued products (of which gasoline is the largest component).

European refineries, by contrast, turn out less gasoline, more diesel fuel, and more resid per barrel of crude than U.S. refineries. The main "on purpose" product of European refineries is diesel fuel; gasoline is in large measure a co-product. (Indeed, much of the gasoline output of European refineries is surplus to local demand and is exported.) European refineries have much less conversion capacity, relative to crude throughput, than U.S. refineries. Consequently, we expect that this analysis would yield different results if were applied to the European refining sector.

8.3 Assumed Primary Fuels Mix for Purchased Power

As indicated in Section 5, we assumed that the primary fuel sourcing for purchased electricity was 50% coal/30% natural gas/20% nuclear and renewables– approximately the U.S. average – for all regions. Changes in this assumption would affect the results of the analysis: a higher (lower) coal share would lead to higher (lower) estimates of refinery energy use and CO_2 emissions. However, the effect of any such change on the results of the analysis would be small because purchased electricity constitutes a relatively small share of total refinery energy use.

Appendix E. GREET Refinery Input

This appendix covers the conversion of MathPro's modeling results into GREET inputs for gasoline and diesel refining efficiencies and fuel allocations. This appendix contains example calculations of these values using the results from the US average model run, this is also the same scenario used when performing the individual output model runs for process fuel allocations, and the California heavy crude examples. Tables E-1 through E-8 are for the US Average Refinery results and Tables E-9 through E-15 are for California Heavy Crude Oil Refinery Results.

E.1 US Average

Table E-1 provides the MathPro modeling results for the US Average refinery.

Table E-1. US Average Energy Contents of Refinery Inputs and Outputs (LHV)

Inputs	Energy Content (MM Btu/Bbl)	Reference Case (k Bbl/d)
Crude Oil	5.45	14,345
Iso-butane	3.88	
Butane	4.04	
Gas Oils	5.60	400
Residuum	5.82	142
Outputs[1]		
Aromatics	5.60	232
Ethane	2.86	19
Propane	3.57	270
Propylene	3.07	232
Aviation Gas	4.73	18
Naphthas	4.91	31
CBOBs & RBOBs	4.76	7,255
Jet Fuel	5.28	1,366
Diesel Fuel	5.35	4,142
Unfinished Oils	5.35	208
Residual Oil	5.81	520
Asphalt	6.24	455
Lubes & Waxes	5.57	198
Marketable Coke	5.72	597

Below are the modeling results for the U.S. Average case and process energy for each of the refined products.

Table E-2. US Average Refinery Energy Use per Barrel of Crude and Product

	Natural Gas & Still Gas			Catalyst Coke (bbl/bbl)	Power (K kwh/ bbl)	Hydrogen (K scf/ bbl)
	Total (foeb/bbl)	Natural Gas (foeb/bbl)	Still Gas (foeb/bbl)			
Crude Oil	0.064	0.023	0.041	0.016	0.010	0.213
Refined Product						
Gasoline	0.077	0.028	0.049	0.030	0.018	0.207
Jet Fuel	0.059	0.021	0.038	0.005	0.013	0.541
Diesel	0.060	0.022	0.038	-0.001	0.000	0.279
Other	0.008	0.003	0.005	-0.002	-0.002	-0.259

foeb = fuel oil equivalent barrels (6.05 MMBTU/bbl LHV)

TIAX used the results found in Table E-2 to estimate the energy use by combining the individual process energies and compared that to the results for the overall crude oil. The individual energies of the products were then used to allocate the actual crude oil refinery energy between the products.

Table E-3. US Average Estimated and Actual Refinery Energy Use per Day

US Total Case	Production kbbl/d	Total Gas kfoeb/d	Natural Gas kfoeb/d	Still Gas kfoeb/d	Coke kbbl/d	Power kMWh/d	Hydrogen MMscf/ day
Crude Oil	14,345						
Gasoline Blendstock	7,255	562.07	205.12	356.96	216.17	130.77	1,500.22
Jet Fuel	1,366	80.86	29.51	51.35	7.24	18.09	738.53
Diesel Fuel, Lubes & Waxes	4,340	261.87	95.56	166.31	-4.55	1.35	1,211.18
Other (Unfinished Oils, Resid Oil, Asphalt)	1,183	9.22	3.37	5.86	-2.21	-2.92	-306.75
Estimated Total		914.02	333.55	580.47	216.64	147.28	3,143.19
Actual Total		918.31	333.56	584.75	222.80	150.09	3,057.68

Based upon the sum of the estimated individual energy uses, TIAX proportioned the actual energy use between the individual categories based upon the individual estimated energy uses. TIAX ignored negative values in these calculates. Below is an example calculation and all the results are below in Table E-4.

Example Calculation: $Jet\_Fuel\_Hydrogen = \frac{738.53}{1500.55 + 738.53 + 1211.18} = 21.4\%$

Table E-4. US Average Percent Energy Use for each Process Energy Source

	Total Gas	Natural Gas	Still Gas	Catalyst Coke	Power	Hydrogen
Gasoline Blendstock	61.5%	61.5%	61.5%	96.8%	87.1%	43.5%
Jet Fuel	8.8%	8.8%	8.8%	3.2%	12.0%	21.4%
Diesel Fuel	28.7%	28.7%	28.7%	0.0%	0.9%	35.1%
Other	1.0%	1.0%	1.0%	0.0%	0.0%	0.0%

TIAX then utilized the percentages in the above Table and the energy content in Table E-5 below to determine total process energy shown in Table E-6.

Table E-5. Energy Content of Process Fuels

	Unit	MMBTU/Unit (LHV)
Gas (Total, Natural, Still)	foeb	6.05
Catalyst Coke	bbl	5.72
Electricity	k kwh	3.412
Hydrogen	k scf	0.282

Table E-6. Itemized and Total Process Energy By Refined Product Category

	Total Gas (foeb/ bbl)	Natural Gas (foeb/ bbl)	Still Gas (foeb/ bbl)	Catalyst Coke (bbl/bbl)	Power (Kkwh/ bbl)	Hydrogen (K scf/ bbl)	Total Process Energy (MMBTU/ bbl)
Gasoline Blendstock	0.039	0.014	0.025	0.015	0.0091	0.093	5471.03
Jet Fuel	0.0057	0.0021	0.0036	0.00050	0.0013	0.046	779.01
Diesel Fuel	0.018	0.0067	0.012	0	0.000094	0.075	1899.06
Other	0.00065	0.00023	0.00041	0	0	0	56.06

Once total process energy is determined, a GREET efficiency must be determined to force GREET to back-calculate the necessary energy values. The formula below was used to determine the GREET efficiencies shown in Table E-7.

$$GREET\_Efficiency = \frac{Output\_Energy}{Output\_Energy + \Pr ocess\_Energy}$$

Table E-7. GREET Efficiency by Refined Product

	Output (k bbls)	Output Energy (k MMBTU)	Process Energy (k MMBTU)	GREET Efficiency
Gasoline Blendstock	7,255	34,521.96	5,471.03	86.32%
Jet Fuel	1,366	7,216.58	779.01	90.26%
Diesel Fuel	4,340	23,275.69	1,899.06	92.46%
Other	1,183	6,973.11	56.06	99.20%

To finish the GREET inputs, process fuel allocations must be determined to divide the process energy accurately for gasoline (CBOB & RBOB) and diesel. The example formula below was used to determine the values in Table E-8.

$$Diesel\_Still\_Gas = \frac{Still\_Gas}{Natural\_Gas + Still\_Gas + Coke + Electricity + Hydrogen} = 53.4\%$$

Table E-8. Process Fuel Allocation Percentages

	Gasoline	Diesel
Natural Gas	22.68%	30.45%
Still Gas	39.76%	53.37%
Catalyst Coke	22.55%	0.00%
Electricity	8.15%	0.24%
Hydrogen	6.85%	15.94%

E.2 Example Calculation for California Heavy Crude Oil

Below are the example calculations for the California heavy crude oil refined in California using the same methodology as above.

Table E-9. Energy Contents of Refinery Inputs and Outputs (LHV)

Inputs	Energy Content (MMBtu/Bbl)	Reference Case
Crude Oil	5.45	1695
Iso-butane	3.88	23
Butane	4.04	
Gas Oils	5.60	86
Residuum	5.82	2
Outputs[1]		
Aromatics	5.60	
Ethane	2.86	
Propane	3.57	28
Propylene	3.07	7
Aviation Gas	4.73	
Naphthas	4.91	
CBOBs & RBOBs	4.76	1004
Jet Fuel	5.28	247
Diesel Fuel	5.35	399
Unfinished Oils	5.35	20
Residual Oil	5.81	56
Asphalt	6.24	38
Lubes & Waxes	5.57	19
Marketable Coke	5.72	

Table E-10. California Heavy Crude Refinery Energy Use per Barrel of Crude

	Natural Gas & Still Gas			Catalyst Coke (bbl/bbl)	Power (K kwh/ bbl)	Hydrogen (K scf/ bbl)
	Total (foeb/ bbl)	Natural Gas (foeb/ bbl)	Still Gas (foeb/ bbl)			
Crude Oil	0.074	0.019	0.055	0.030	0.005	1.056
Refined Product						
Gasoline Blendstock	0.077	0.028	0.049	0.030	0.018	0.207
Jet Fuel	0.059	0.021	0.038	0.005	0.013	0.541
Diesel	0.060	0.022	0.038	-0.001	0.000	0.279
Other	0.008	0.003	0.005	-0.002	-0.002	-0.259

foeb = fuel oil equivalent barrels (6.05 MMBTU/bbl LHV)
Note: Product specific results here are for US Average

Table E-11. California Heavy Crude Estimated and Actual Refinery Energy Use per Day

California Heavy Crude Case	Production kbbl/d	Total Gas kfeob/d	Natural Gas kfeob/d	Still Gas kfoeb/d	Coke kbbl/d	Power kMWh/d	Hydrogen MMscf/day
Crude Oil	1695						
Gasoline Blendstock	1004	77.81	28.40	49.42	29.93	18.10	207.68
Jet Fuel	247	14.62	5.34	9.28	1.31	3.27	133.54
Diesel Fuel, Lubes, Waxes	399	25.22	9.20	16.02	-0.44	0.13	116.65
Other (Unfinished Oils, Residual Oil, Asphalt)	19	0.89	0.32	0.56	-0.21	-0.28	-29.56
Estimated Total		118.54	43.26	75.28	30.58	21.22	428.32
Actual Total		125.89	32.50	93.38	50.30	8.33	1789.85

Based upon the sum of the estimated individual energy uses, TIAX proportioned actual energy use between the individual categories based upon the individual estimated energy uses. TIAX ignored negative values in these calculates. Below is an example calculation and all the results are below in Table E-12.

$$Jet\_Fuel\_Hydrogen = \frac{133.54}{207.68 + 133.54 + 116.65} = 29.2\%$$

Table E-12. California Heavy Crude Percent Process Energy Use by Product

	Total Gas	Natural Gas	Still Gas	Catalyst Coke	Power	Hydrogen
Gasoline Blendstock	65.6%	65.6%	65.6%	95.8%	84.2%	45.4%
Jet Fuel	12.3%	12.3%	12.3%	4.2%	15.2%	29.2%
Diesel Fuel	21.3%	21.3%	21.3%	0.0%	0.6%	25.5%
Other	0.7%	0.7%	0.7%	0.0%	0.0%	0.0%

Table E-13. California Heavy Crude Process Energy By Refined Product Category

	Total Gas (foeb/ bbl)	Natural Gas (foeb/ bbl)	Still Gas (foeb/ bbl)	Catalyst Coke (bbl/bbl)	Power (Kkwh/ bbl)	Hydrogen (K scf/ bbl)	Total Process Energy (MMBtu/ bbl)
Gasoline Blendstock	0.049	0.013	0.036	0.028	0.0041	0.48	1028.59
Jet Fuel	0.0092	0.0024	0.0068	0.0012	0.00075	0.31	257.52
Diesel Fuel	0.016	0.0041	0.012	0	0.000030	0.27	290.81
Other	0.00056	0.00014	0.00041	0	0	0	5.71

Once total process energy is determined, a GREET efficiency must be determined to force GREET to back-calculate the necessary energy values. The formula below was used to determine the GREET efficiencies shown in Table B-14.

$$GREET\_Efficiency = \frac{Output\_Energy}{Output\_Energy + \Pr ocess\_Energy}$$

Table E-14. California Heavy Crude GREET Efficiency by Refined Product

	Output (k bbls)	Output Energy (k MMBTU)	Process Energy (k MMBTU)	GREET Efficiency
Gasoline Blendstock	1004	4779.06	1028.59	82.3%
Jet Fuel	247	1304.90	257.52	83.5%
Diesel Fuel	418	2241.74	290.81	88.5%
Other	114	669.52	5.71	99.2%

To finish the GREET inputs, process fuel allocations must be determined to divide the process energy accurately for gasoline (CBOB & RBOB) and diesel. The example formula below was used to determine the values in Table E-15.

Example Calculation:

$$Diesel\_Still\_Gas = \frac{Still\_Gas}{Natural\_Gas + Still\_Gas + Coke + Electricity + Hydrogen} = 41.34\%$$

Table E-15. California Heavy Crude Process Fuel Shares

	Gasoline	**Diesel**
Natural Gas	12.55%	14.39%
Still Gas	36.05%	41.34%
Catalyst Coke	26.81%	0.00%
Electricity	2.33%	0.06%
Hydrogen	22.26%	44.22%

Appendix F. Distribution Functions for Uncertainty Analysis

This appendix details the distribution profiles used in the stochastic simulation of WTT GHG emissions. The Hammersley Sequence Sampling technique was used to generate confidence intervals for the emissions of each crude oil pathway.

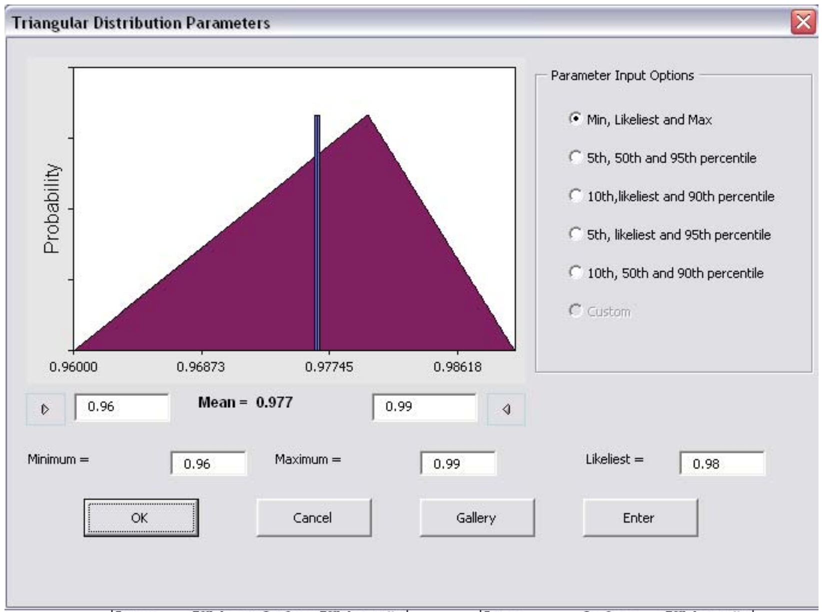


Figure F-1. Default Crude Recovery Efficiency Distribution Profile

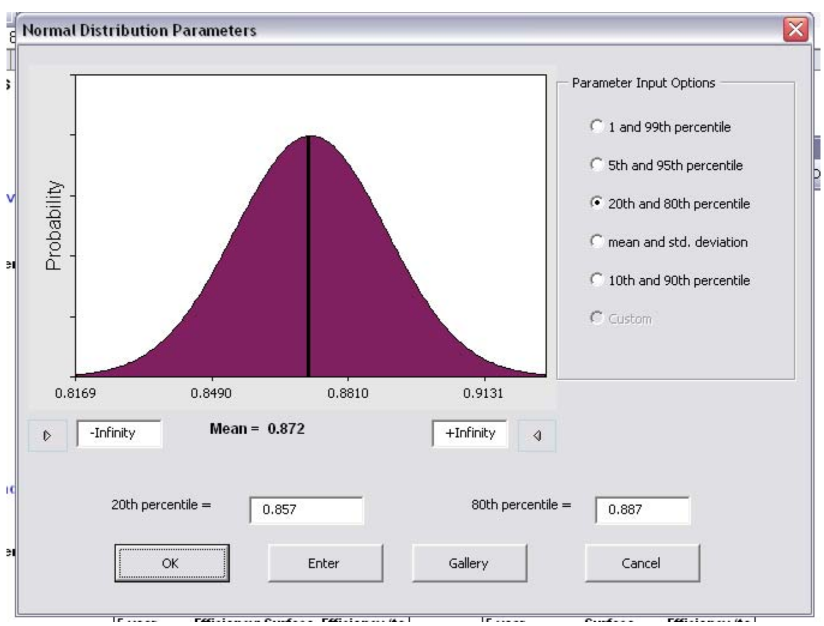


Figure F-2. Default Reformulated Gasoline Refining Efficiency Distribution Profile

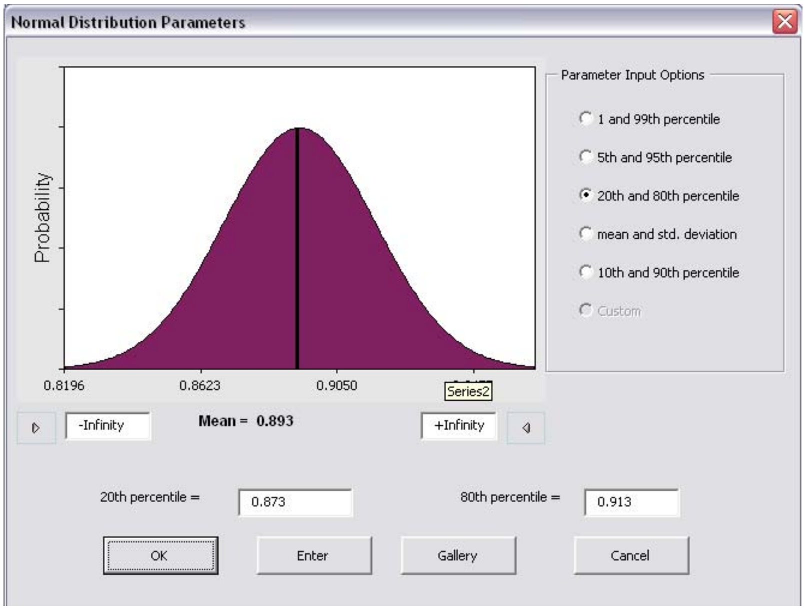


Figure F-3. Default ULSD Refining Efficiency Distribution Profile

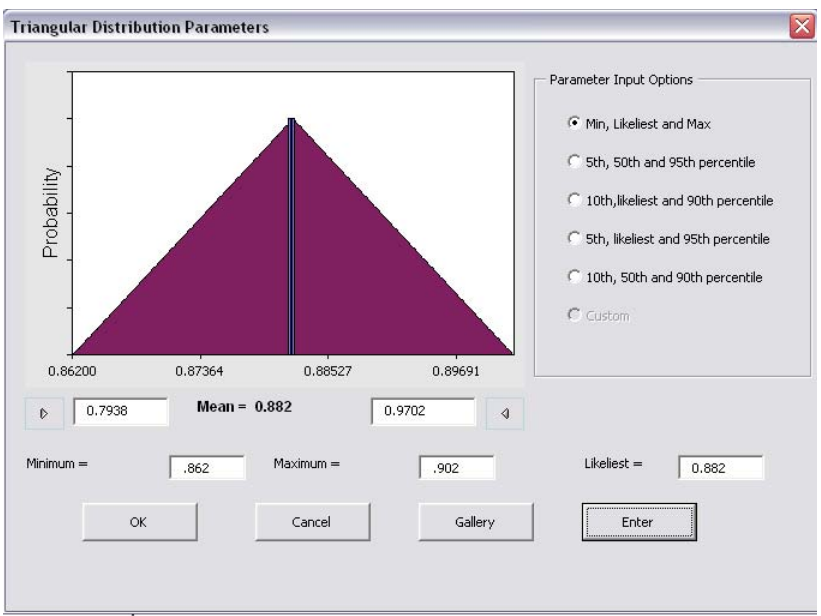


Figure F-4. Distribution profile for Alaska Recovery Efficiency

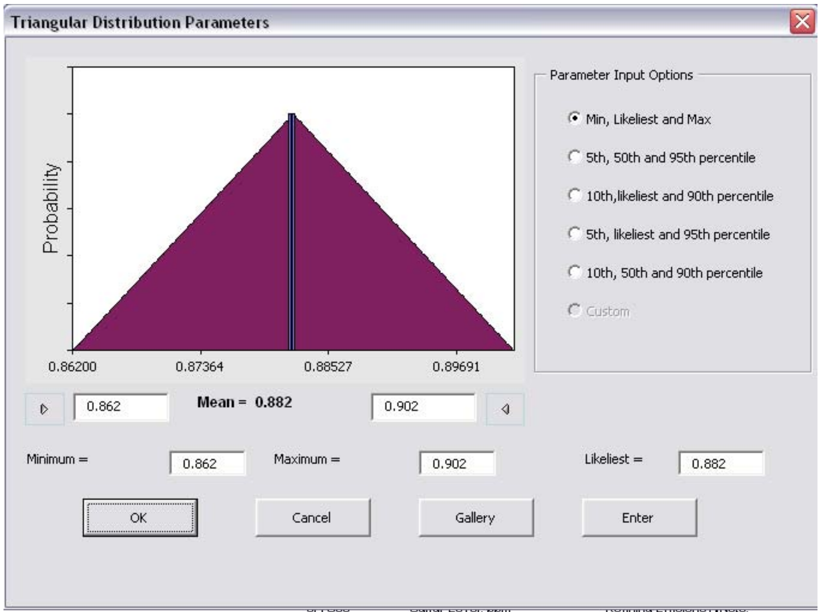


Figure F-5. Distribution profile for Alaska REF Blendstock Refining Efficiency

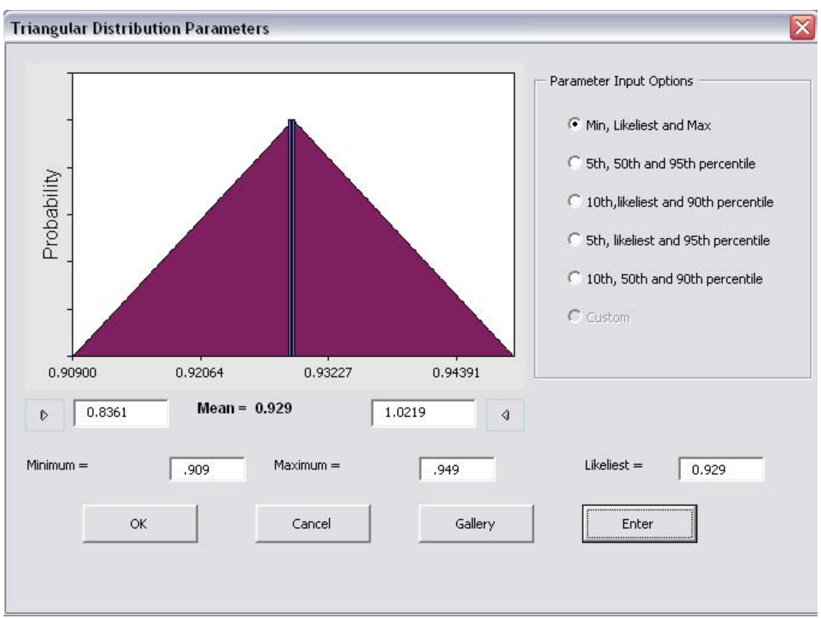


Figure F-6. Distribution Profile for ULSD Refining of Alaska North Slope

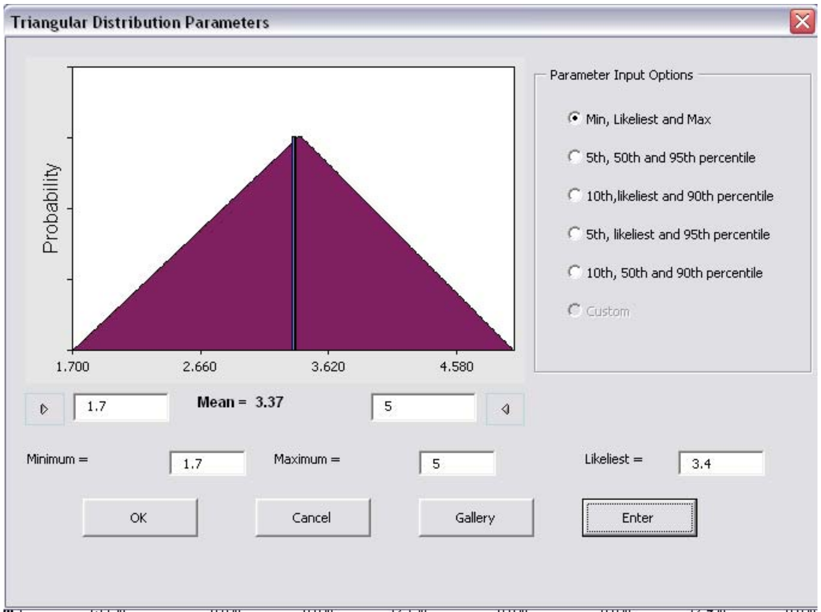


Figure F-7. Distribution Profile for oil field methane venting, Alaska NS

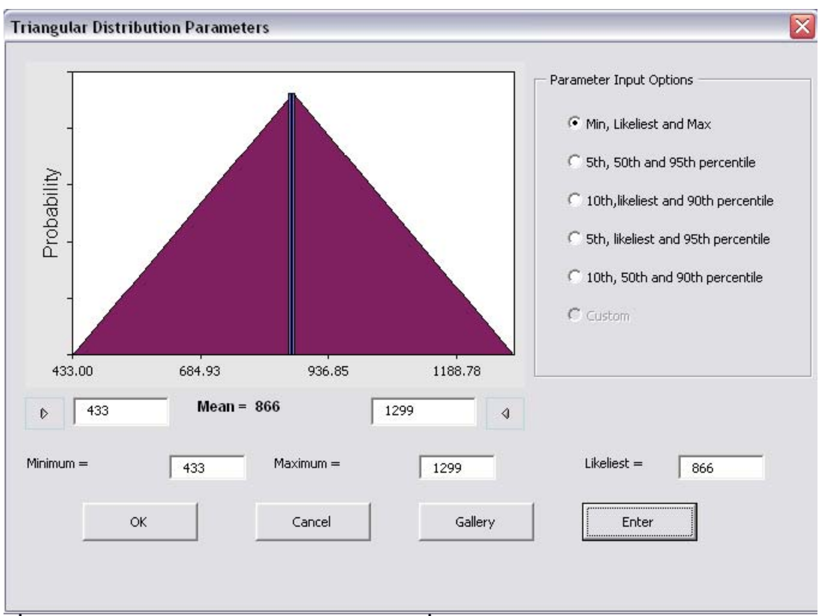


Figure F-8. Distribution Profile for oil field flaring, Alaska NS

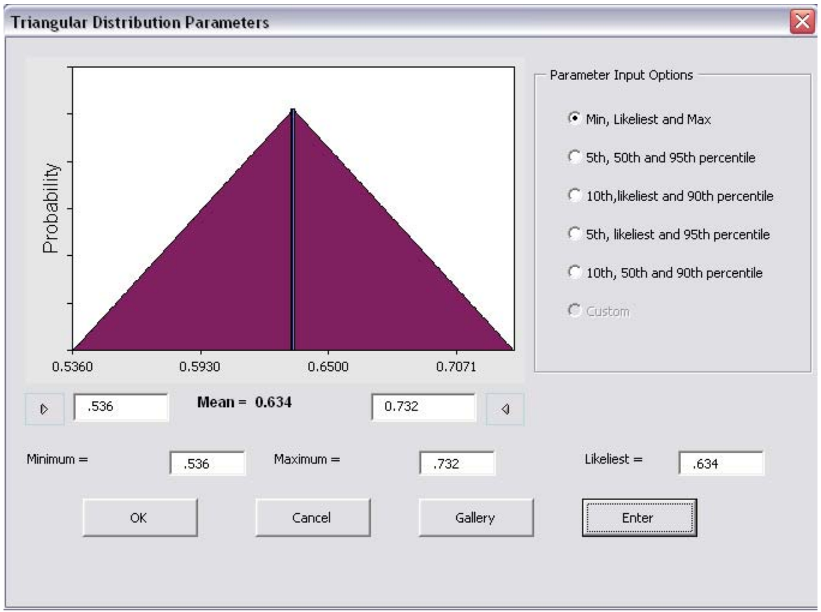


Figure F-9. Distribution Profile for California Heavy Recovery Efficiency

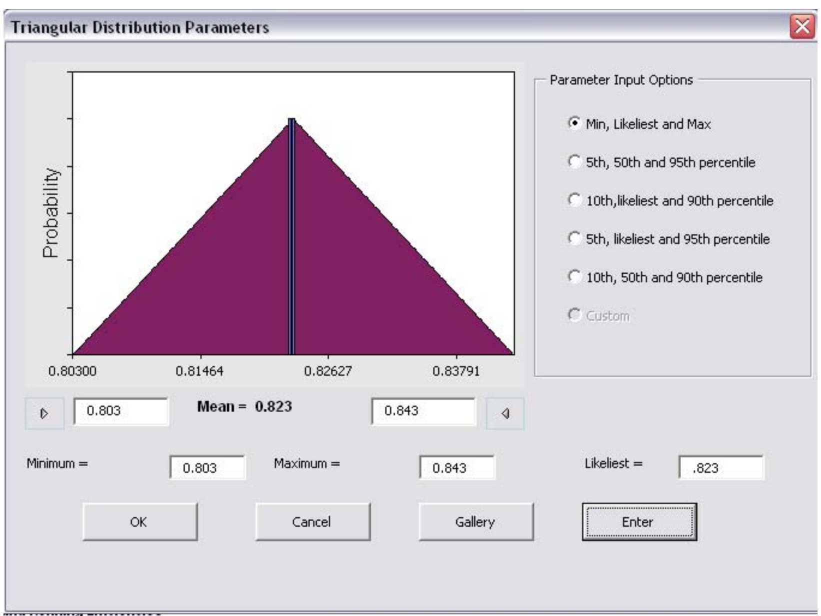


Figure F-10. Distribution Profile for RFG Blendstock Refining, California Heavy

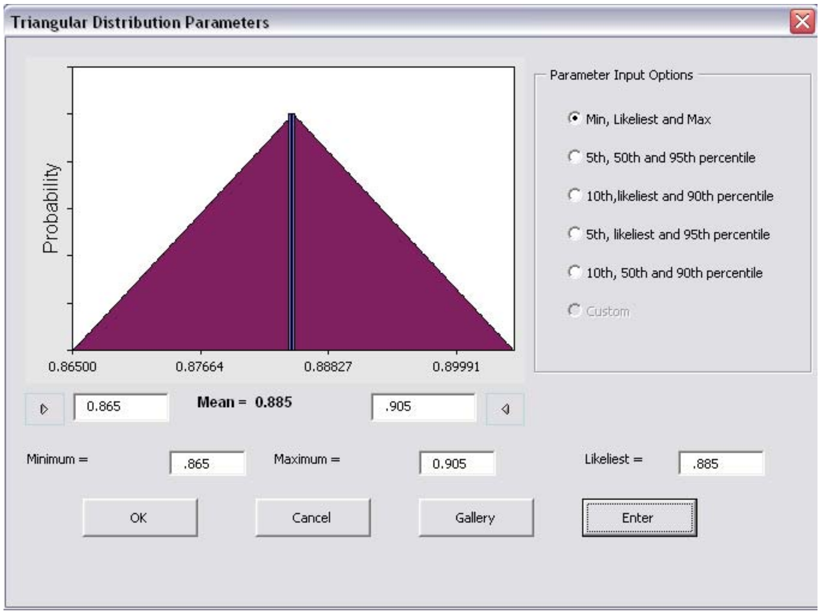


Figure F-11. Distribution Profile for ULSD Refining, California Heavy

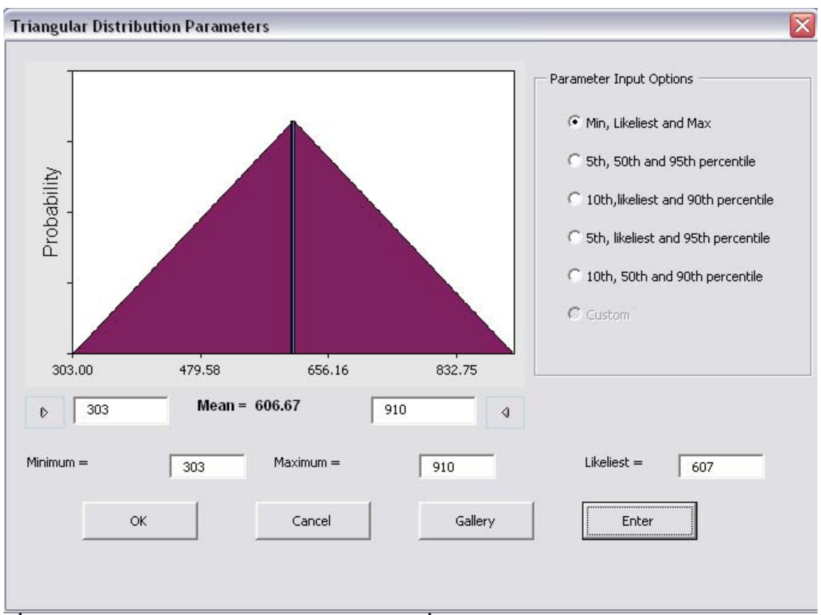


Figure F-12. Distribution Profile for oil field flaring, California Heavy

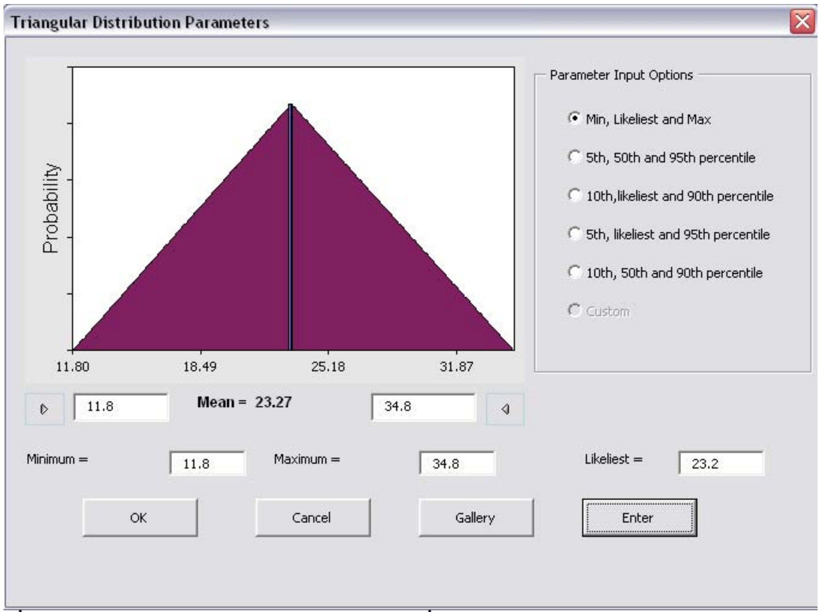


Figure F-13. Distribution Profile for oil field venting, California Heavy

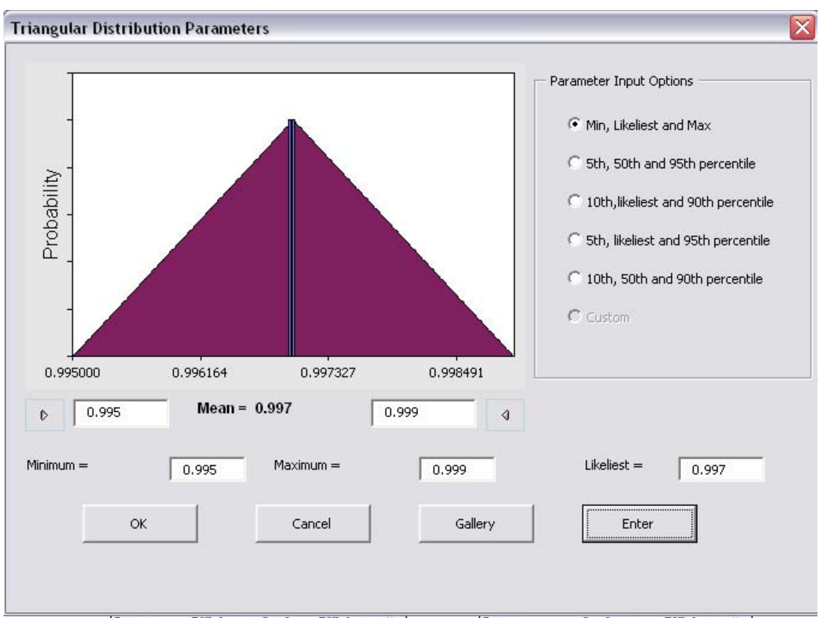


Figure F-14. Distribution Profile for West Texas Recovery Efficiency

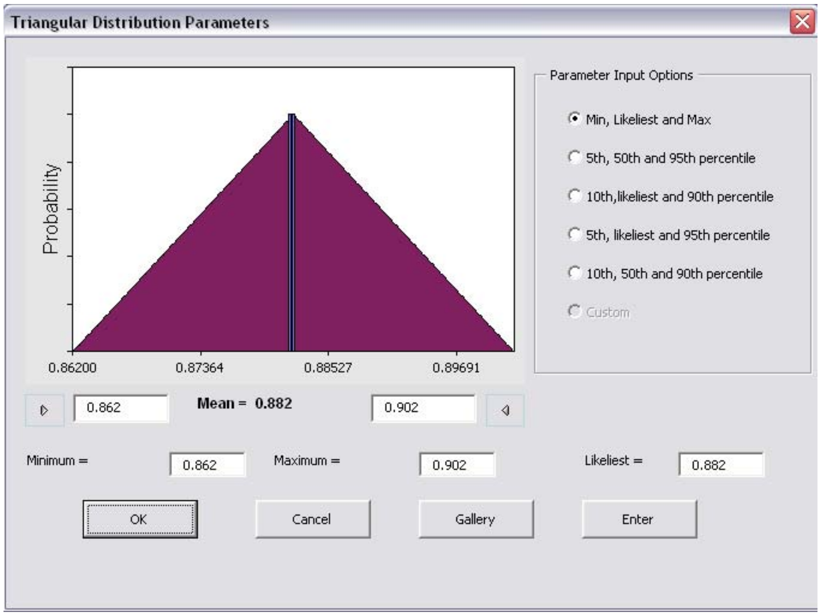


Figure F-15. Distribution Profile for RFG Blendstock Refining, West Texas

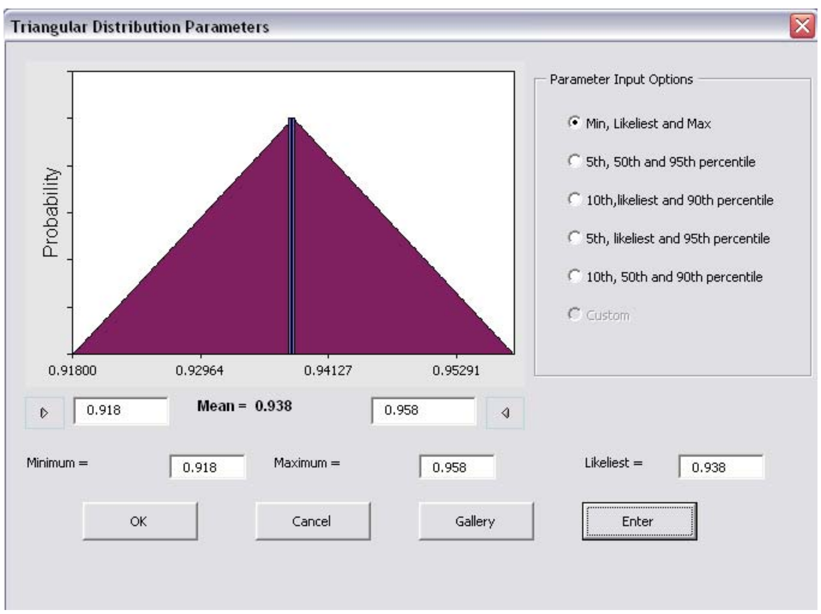


Figure F-16. Distribution Profile for ULSD Refining, West Texas

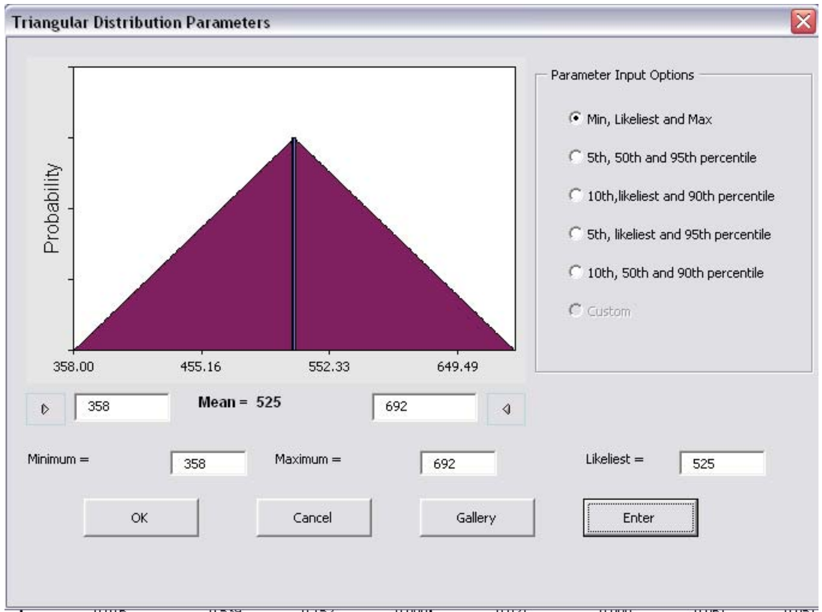


Figure F-17. Distribution Profile for oil field flaring, West Texas

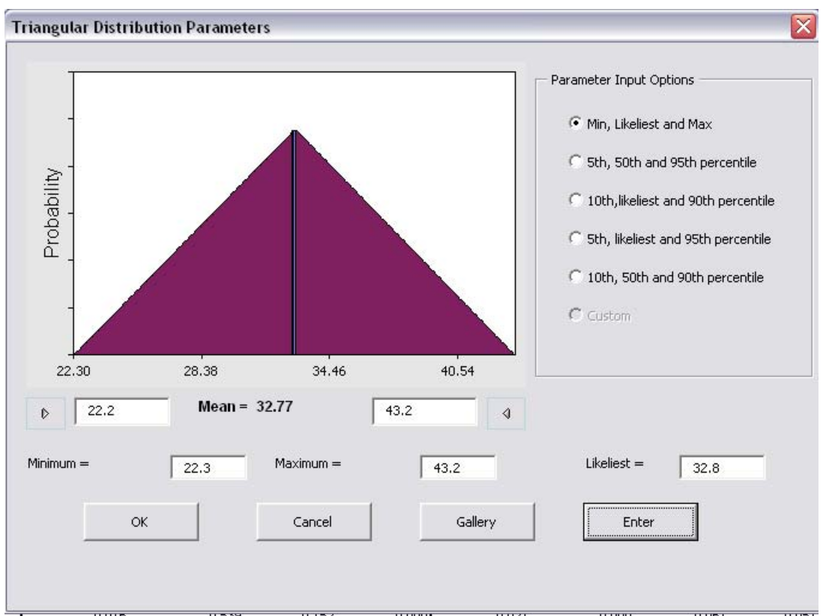


Figure F-18. Distribution Profile for oil field venting, West Texas

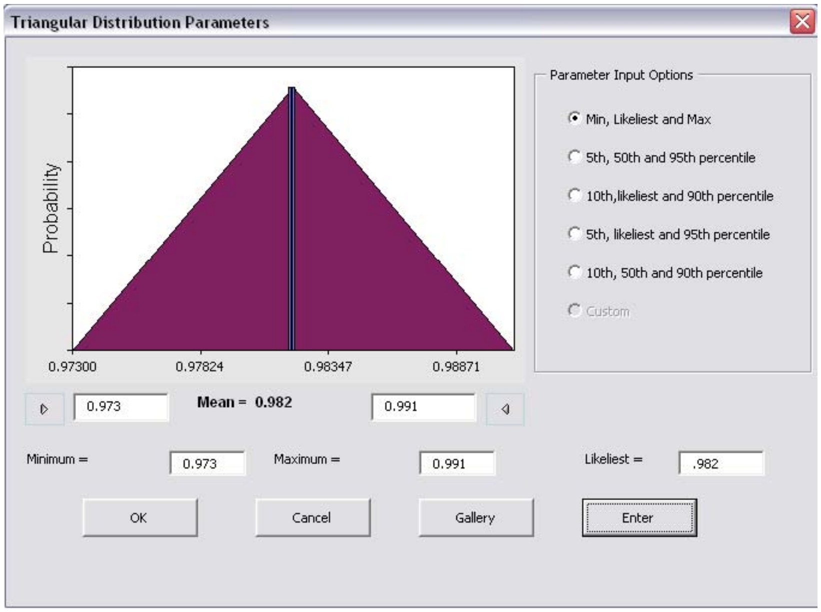


Figure F-19. Distribution Profile for Canada Heavy Recovery Efficiency

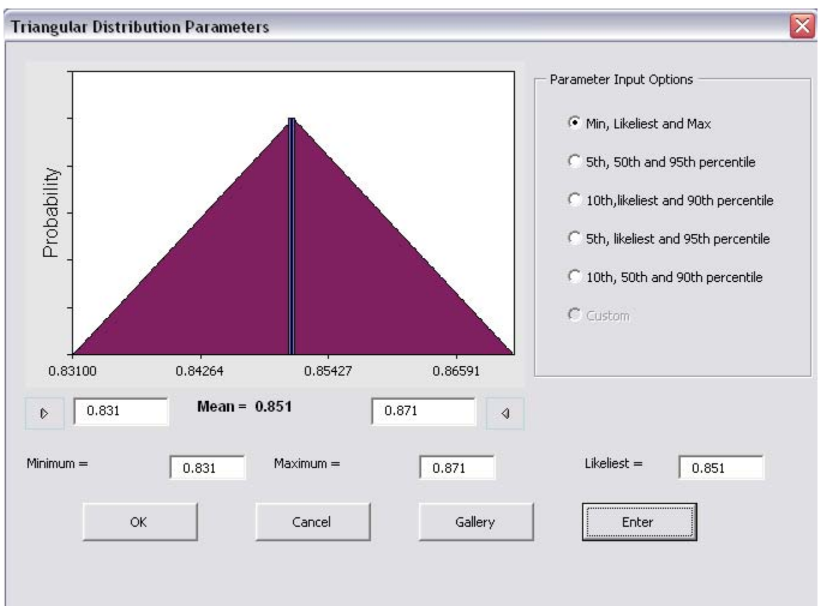


Figure F-20. Distribution Profile for RFG Blendstock Refining, Canada Heavy

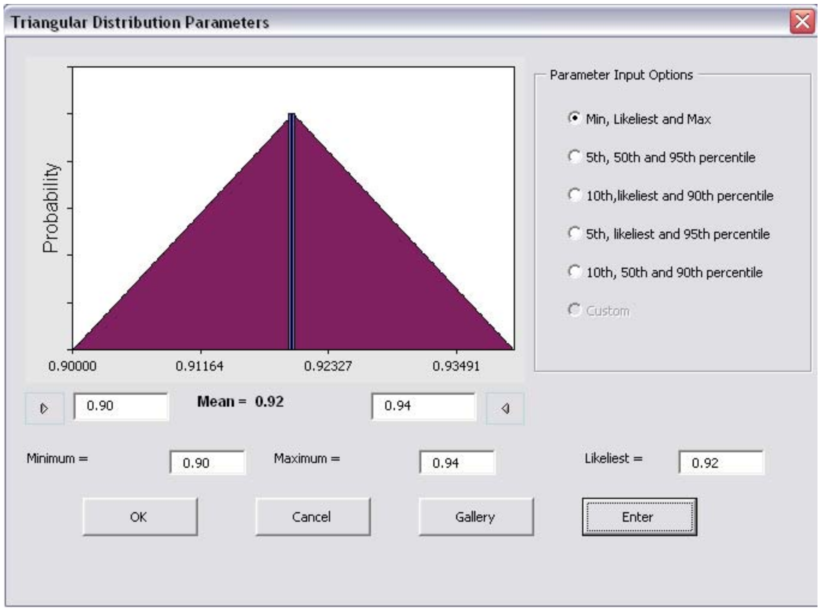


Figure F-21. Distribution Profile for ULSD Refining, Canada Heavy

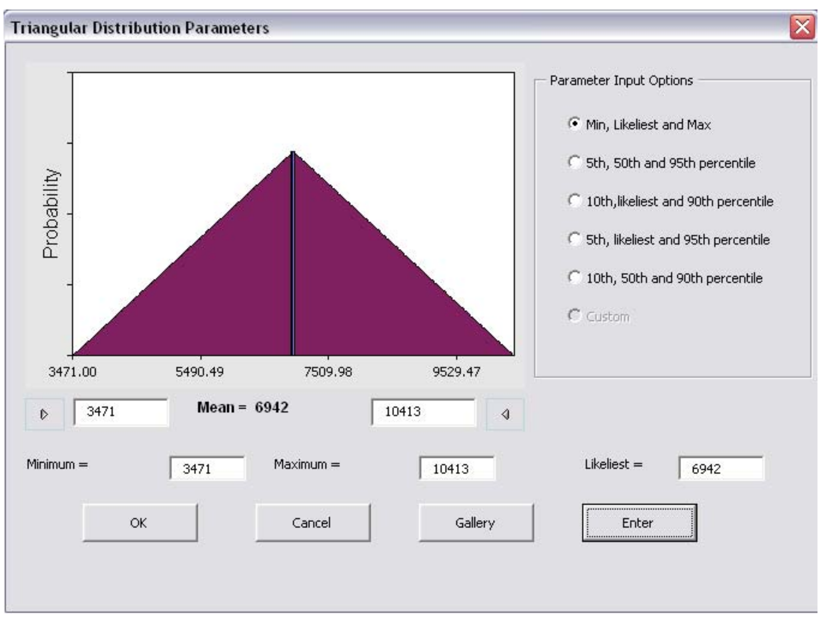


Figure F-22. Distribution Profile for oil field flaring, Canada Heavy

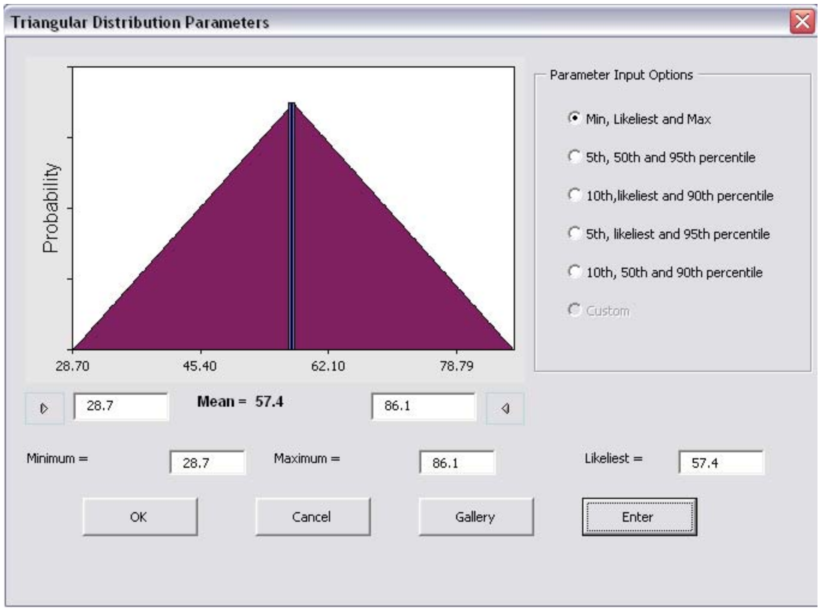


Figure F-23. Distribution Profile for oil field venting, Canada Heavy

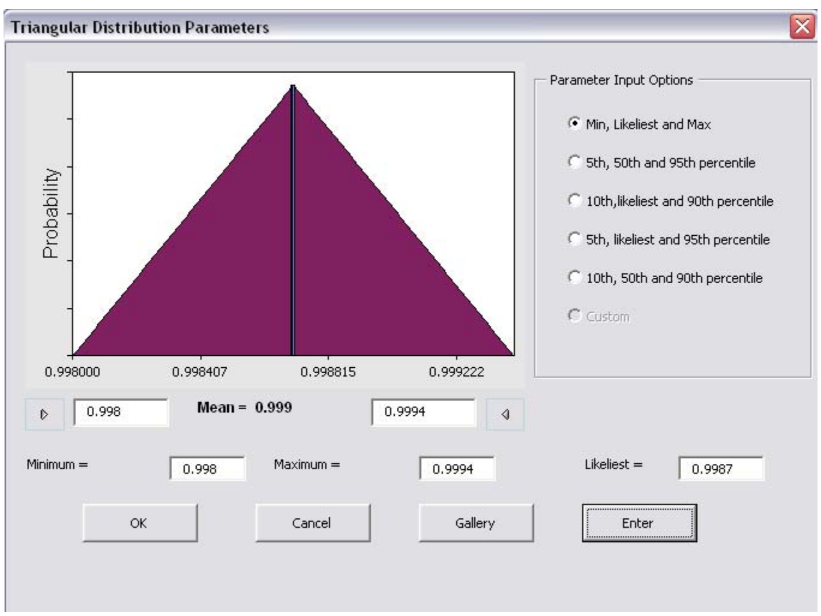


Figure F-24. Distribution Profile for Saudi Recovery Efficiency

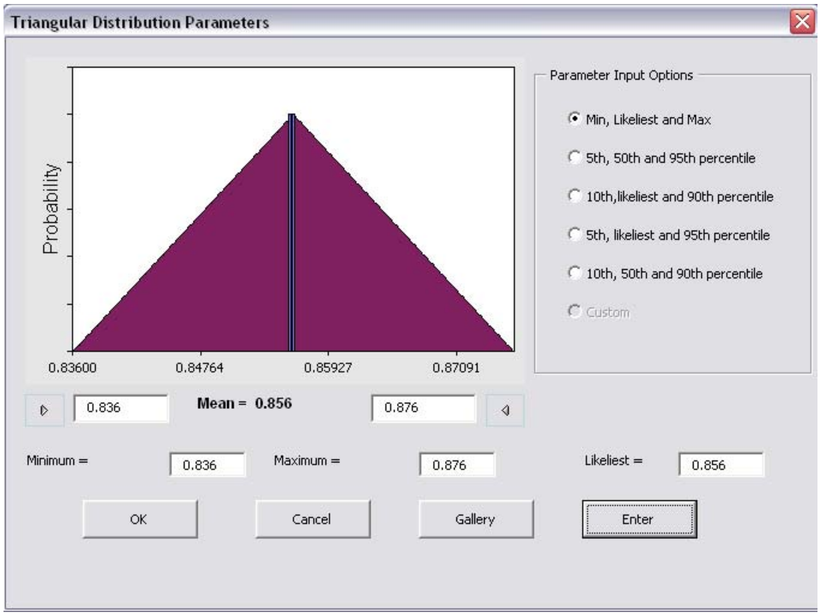


Figure F-25. Distribution Profile for RFG Blendstock Refining, Saudi

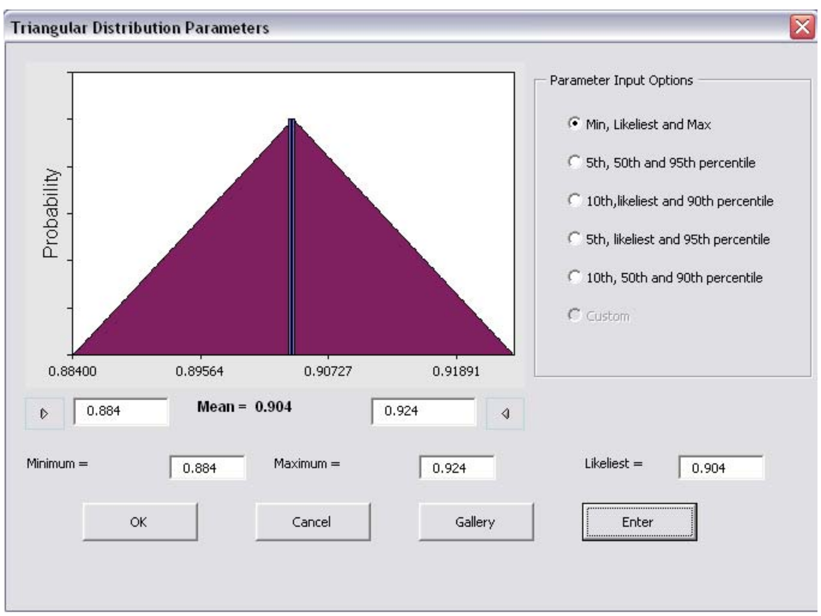


Figure F-26. Distribution Profile for ULSD Refining, Saudi

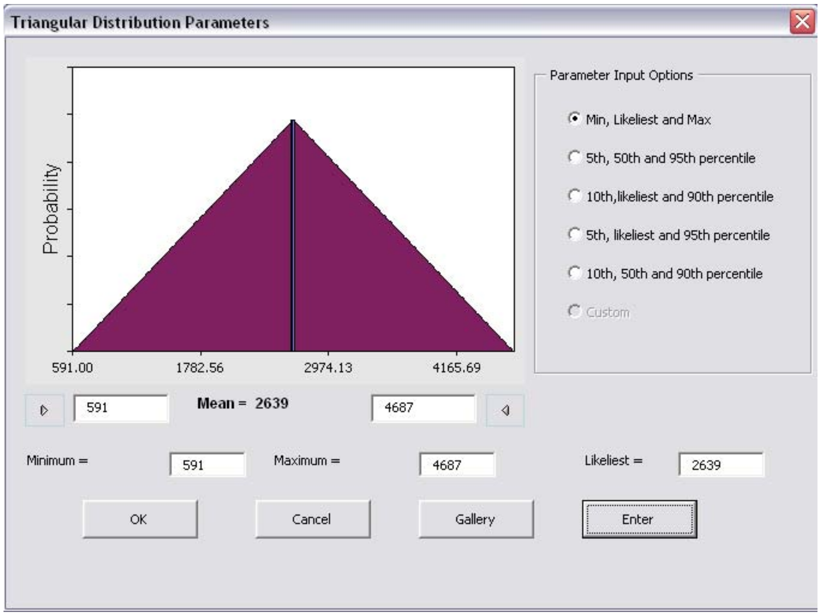


Figure F-27. Distribution Profile for oil field flaring, Saudi

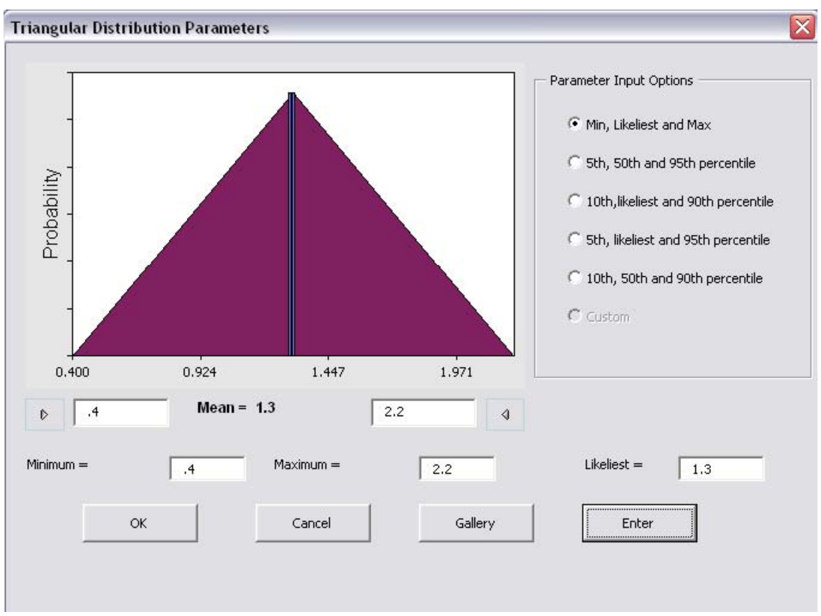


Figure F-28. Distribution Profile for oil field venting, Saudi

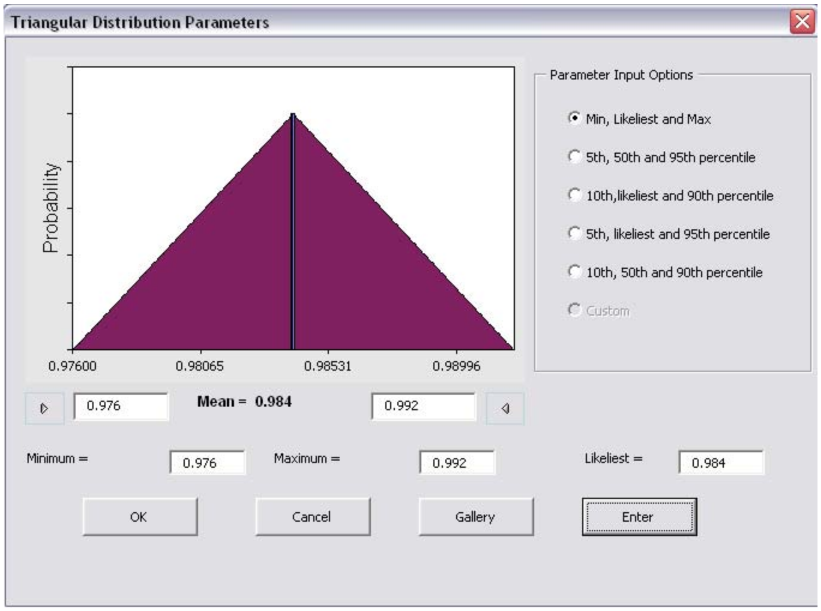


Figure F-29. Distribution Profile for Mexico Heavy Recovery Efficiency

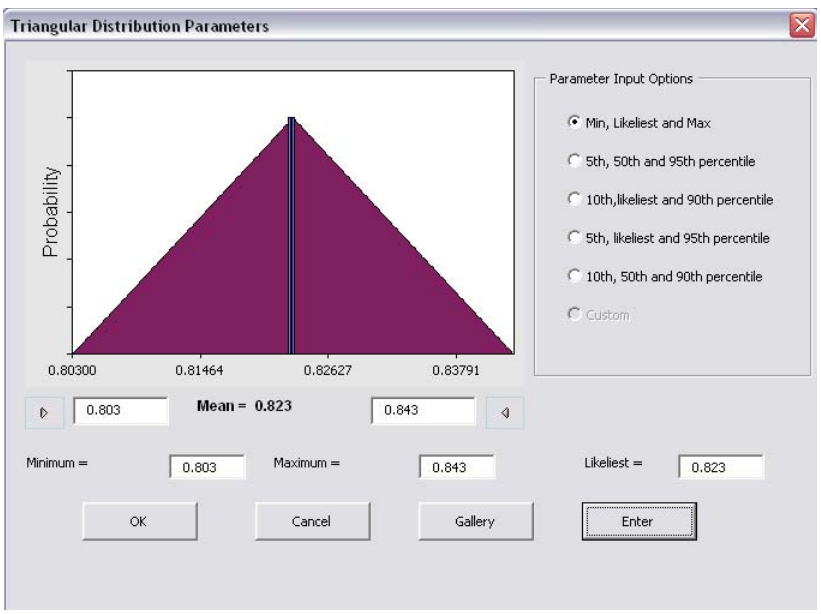


Figure F-30. Distribution Profile for RFG Blendstock Refining, Mexico Heavy

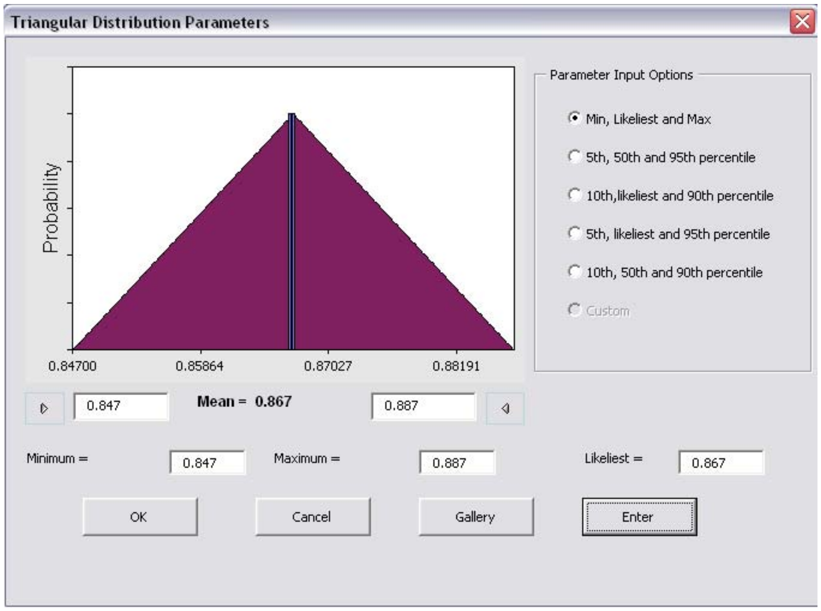


Figure F-31. Distribution Profile for ULSD Refining, Mexico Heavy

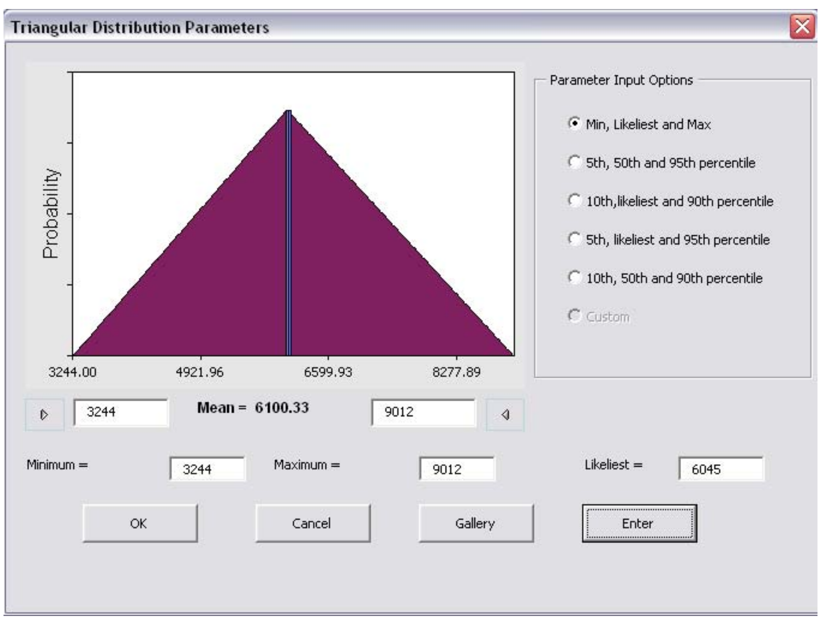


Figure F-32. Distribution Profile for oil field flaring, Mexico Heavy

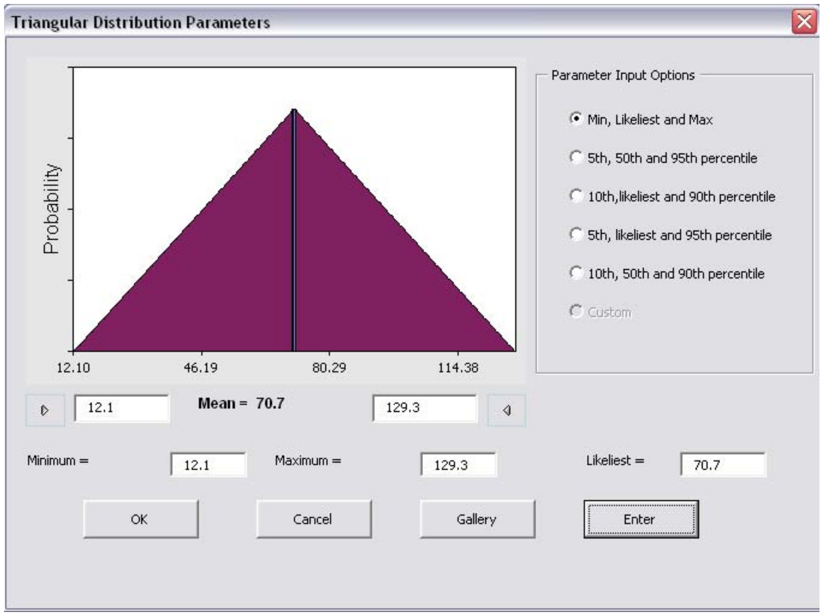


Figure F-33. Distribution Profile for oil field venting, Mexico Heavy

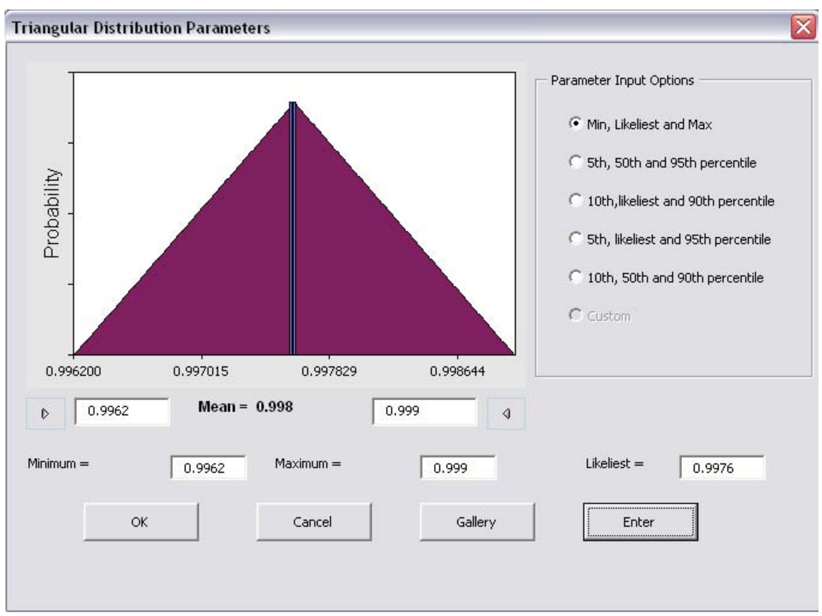


Figure F-34. Distribution Profile for Iraq Recovery Efficiency

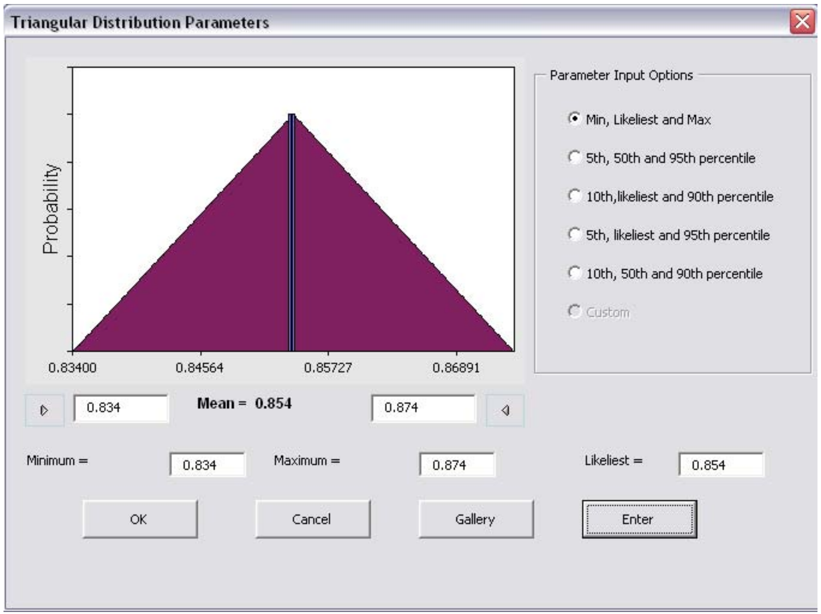


Figure F-35. Distribution Profile for RFG Blendstock Refining, Iraq

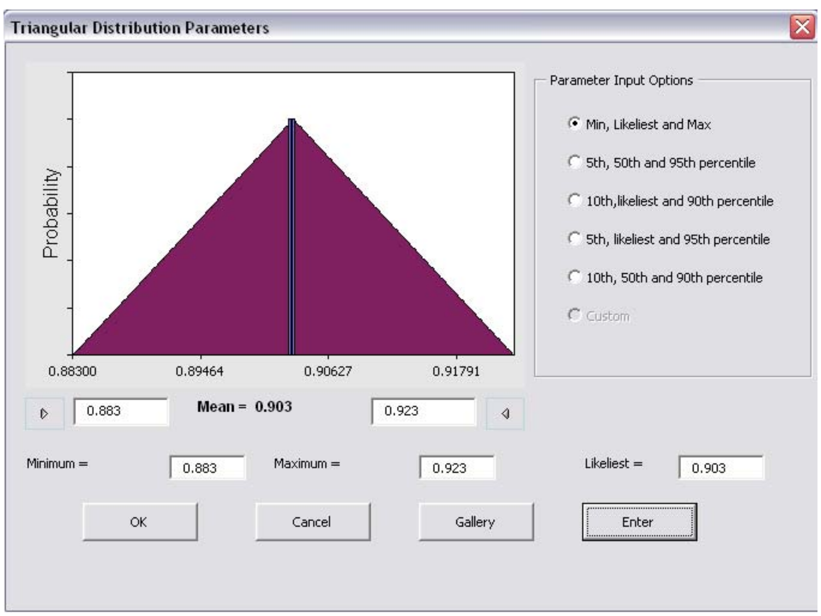


Figure F-36. Distribution Profile for ULSD Refining, Iraq

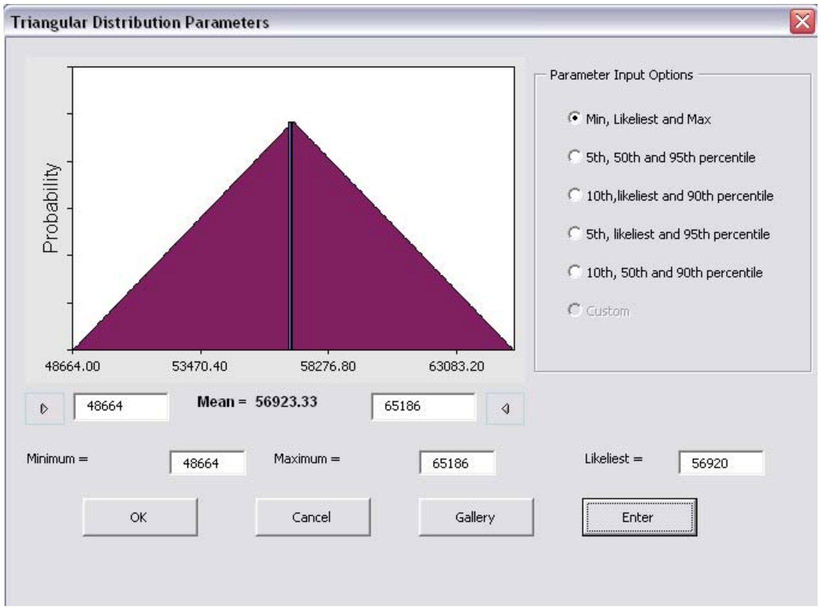


Figure F-37. Distribution Profile for oil field flaring, Iraq

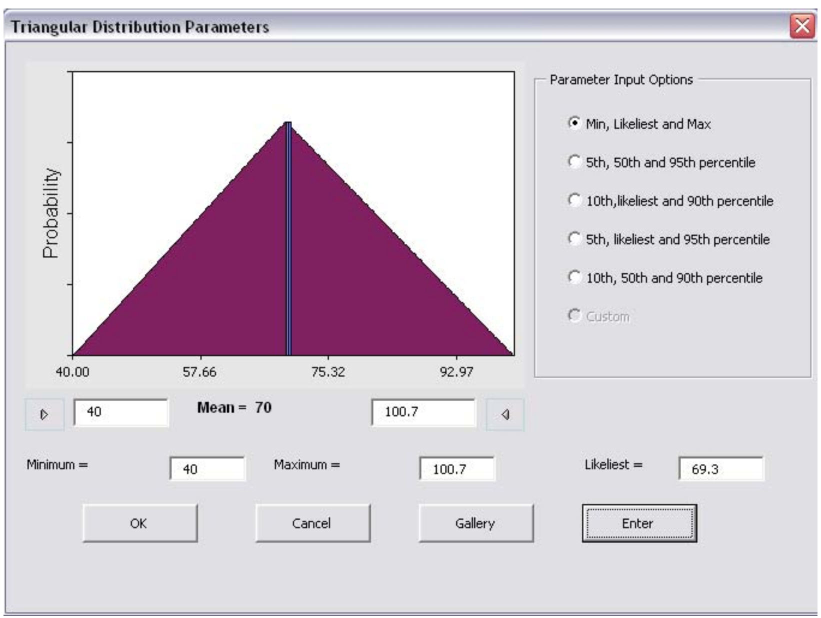


Figure F-38. Distribution Profile for oil field venting, Iraq

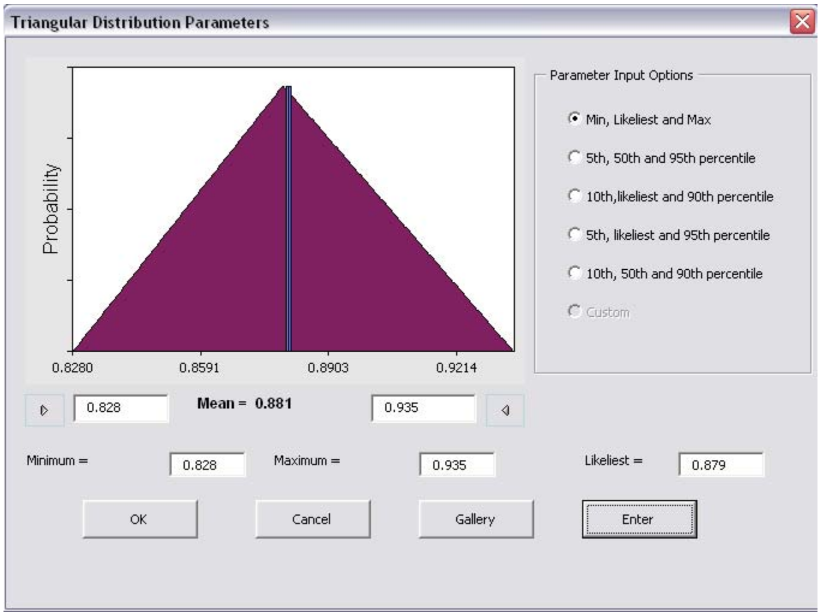


Figure F-39. Distribution Profile for Venezuela Recovery Efficiency

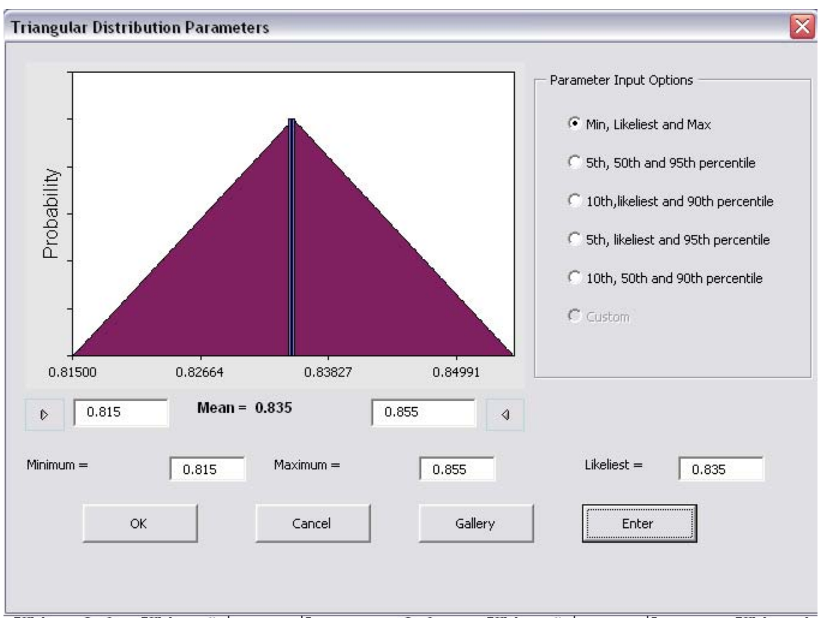


Figure F-40. Distribution Profile for RFG Blendstock Refining, Venezuela

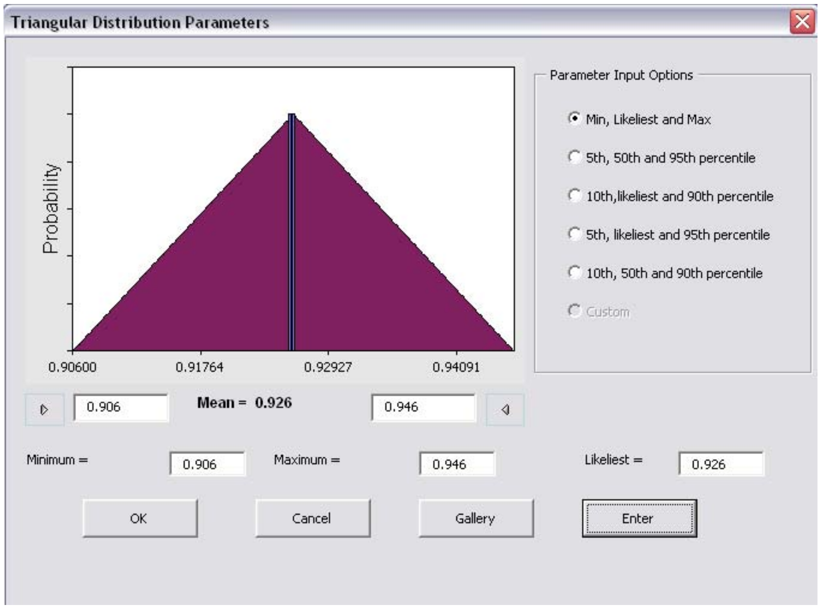


Figure F-41. Distribution Profile for ULSD Refining, Venezuela

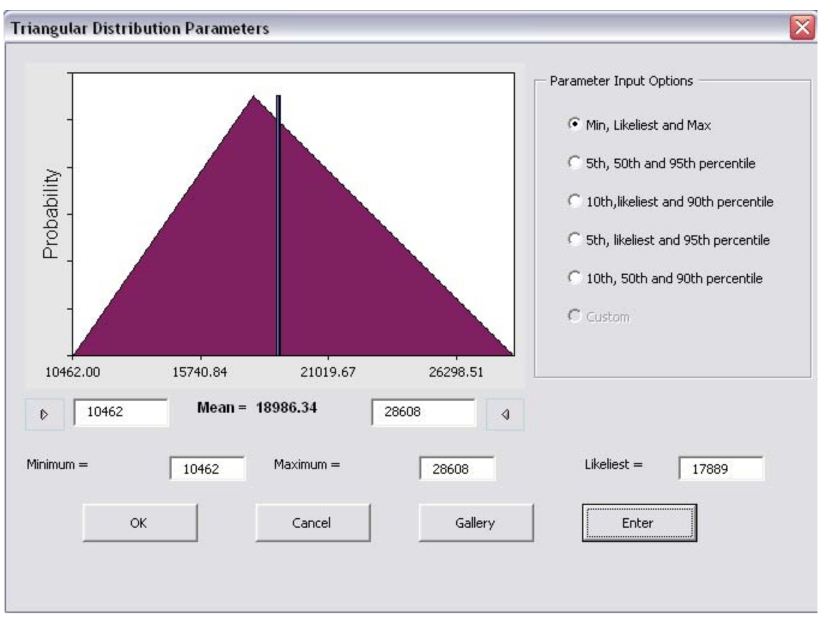


Figure F-42. Distribution Profile for oil field flaring, Venezuela

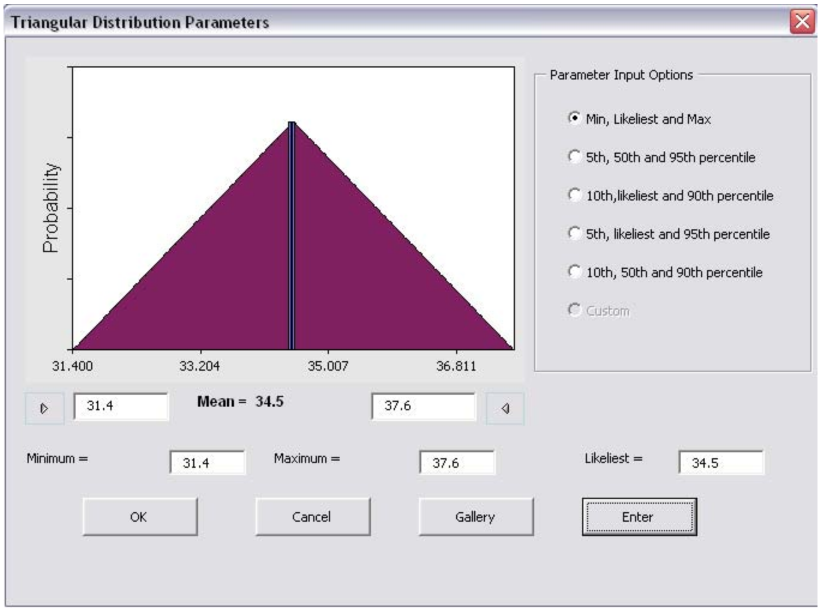


Figure F-43. Distribution Profile for oil field venting, Venezuela

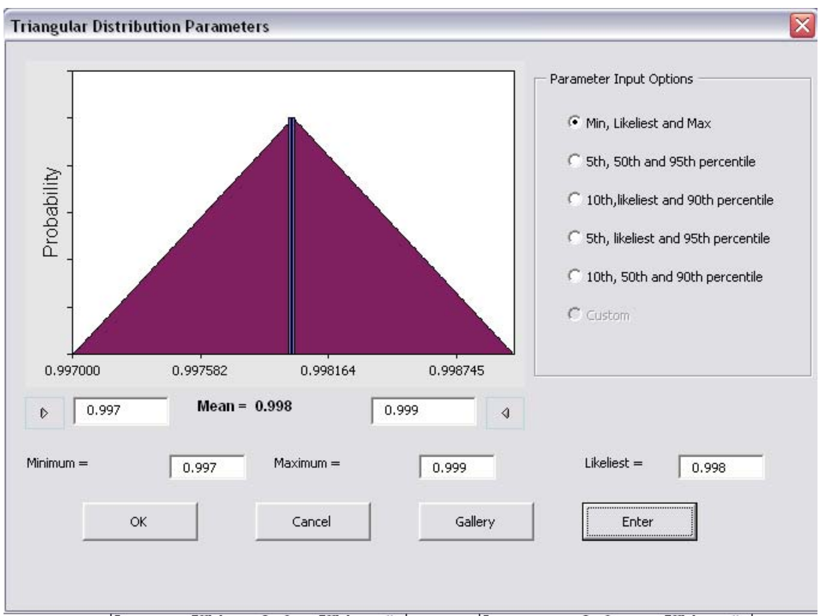


Figure F-44. Distribution Profile for Nigeria Recovery Efficiency

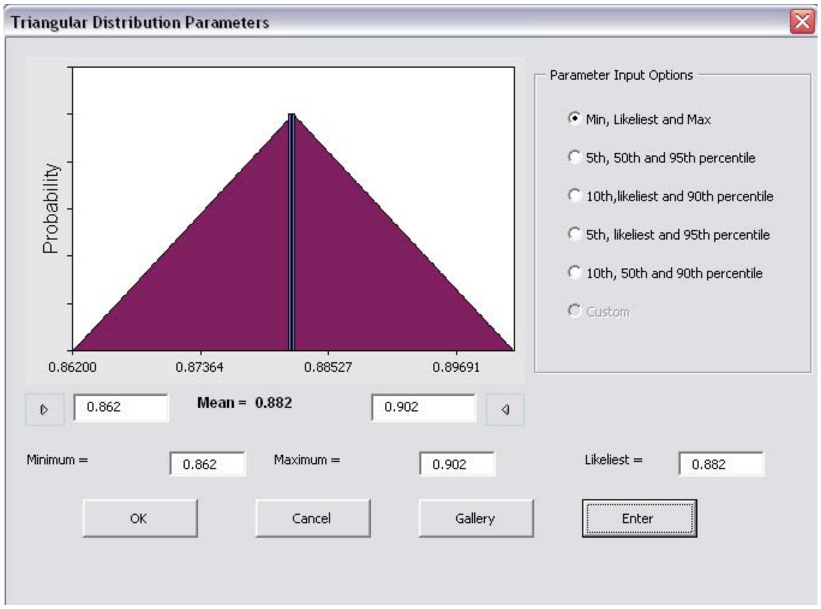


Figure F-45. Distribution Profile for RFG Blendstock Refining, Nigeria

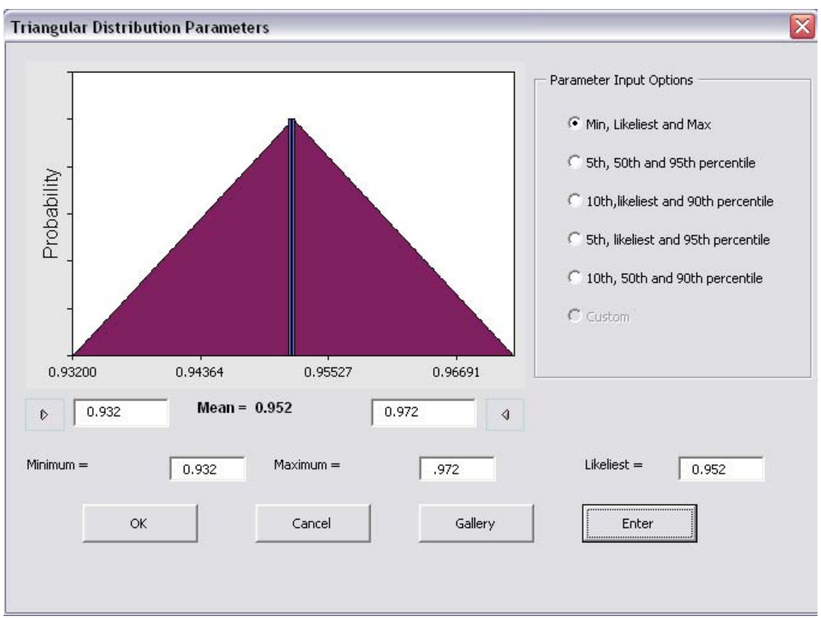


Figure F-46. Distribution Profile for ULSD Refining, Nigeria

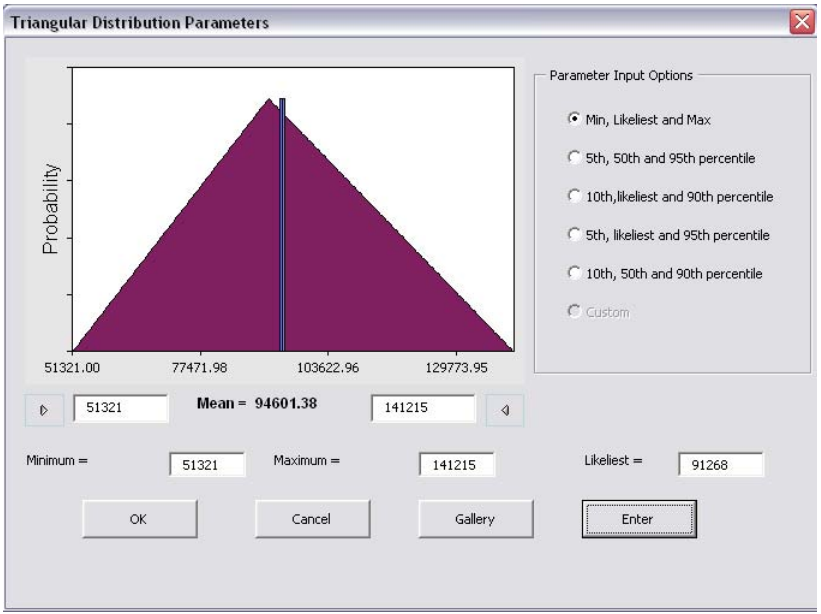


Figure F-47. Distribution Profile for oil field flaring, Nigeria

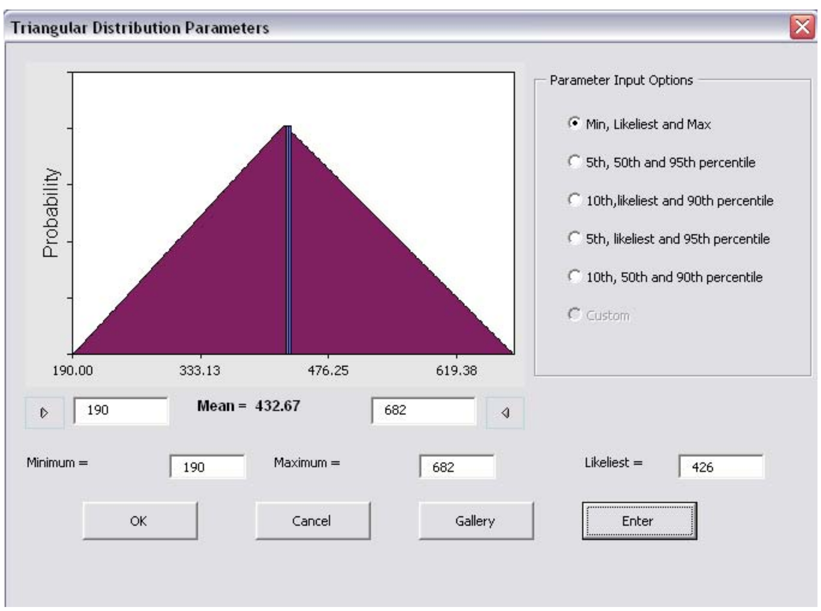


Figure F-48. Distribution Profile for oil field venting, Nigeria

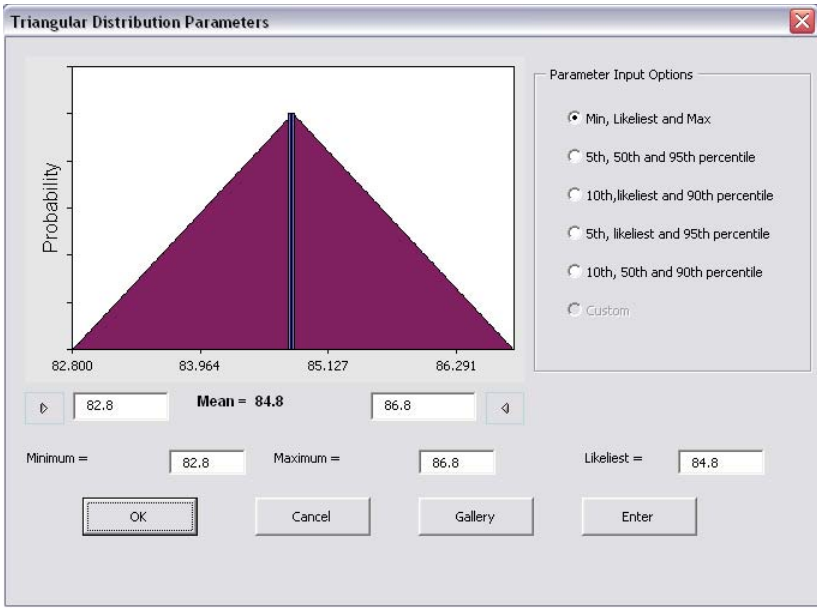


Figure F-49. Distribution Profile for Oil Sands Mining Recovery & Upgrading Efficiency

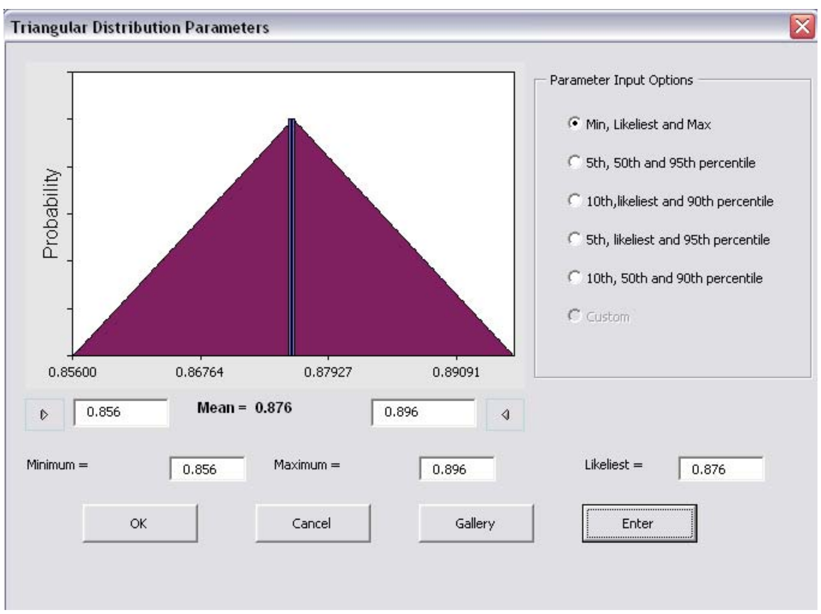


Figure F-50. Distribution Profile for Oil Sands Mining SCO RFG Blendstock Refining Efficiency

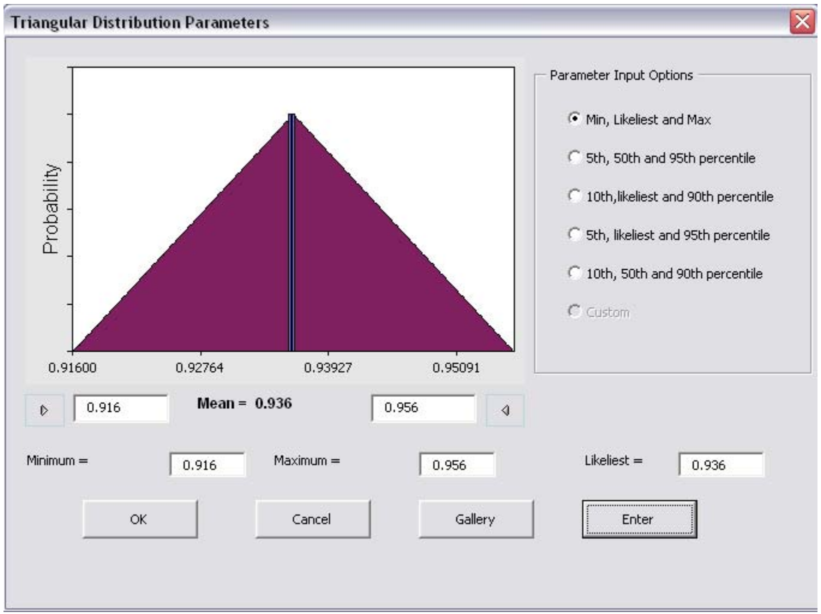


Figure F-51. Distribution Profile for Oil Sands Mining SCO ULSD Refining Efficiency

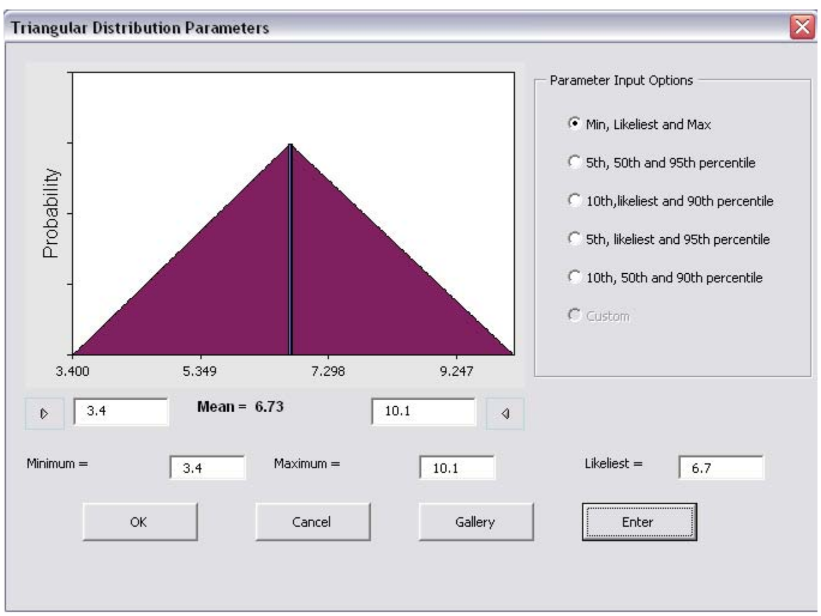


Figure F-52. Distribution Profile for Oil Sands Mining & Upgrading Venting Emissions

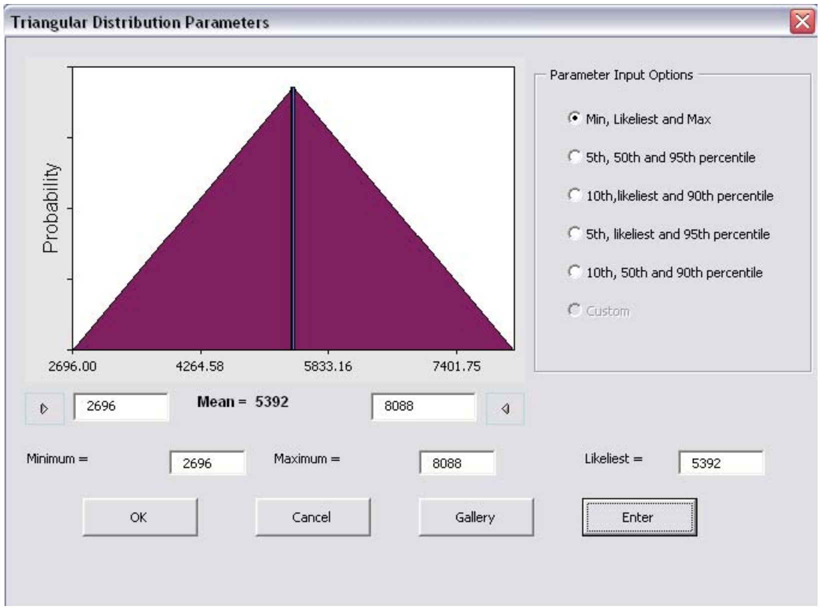


Figure F-53. Distribution Profile for Oil Sands Mining & Upgrading Flaring Emissions

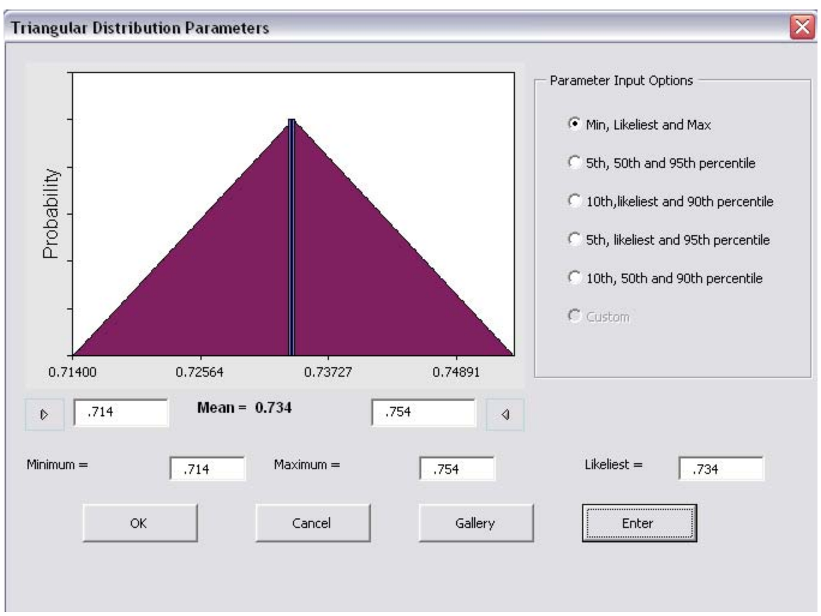


Figure F-54. Distribution Profile for Oil Sands SAGD Recovery & Upgrading Efficiency

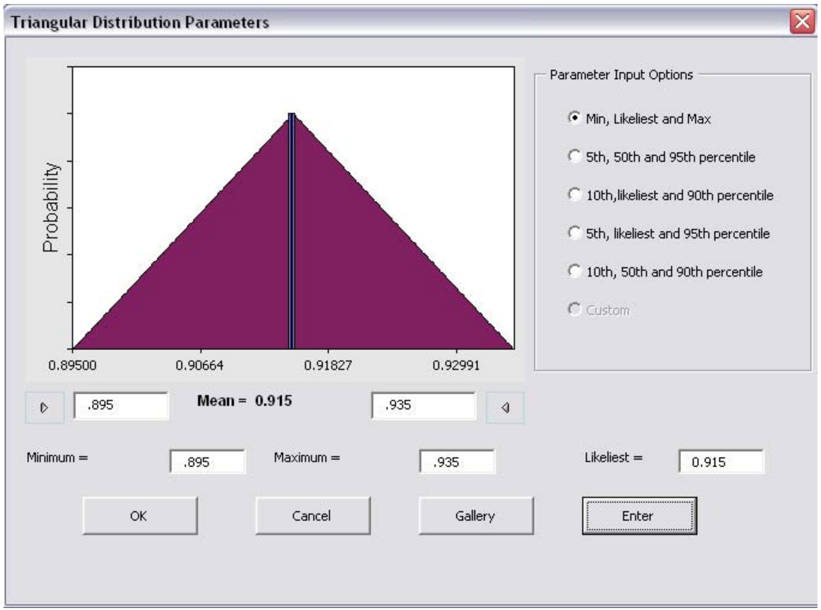


Figure F-55. Distribution Profile for Oil Sands SAGD SCO RFG Blendstock Refining Efficiency

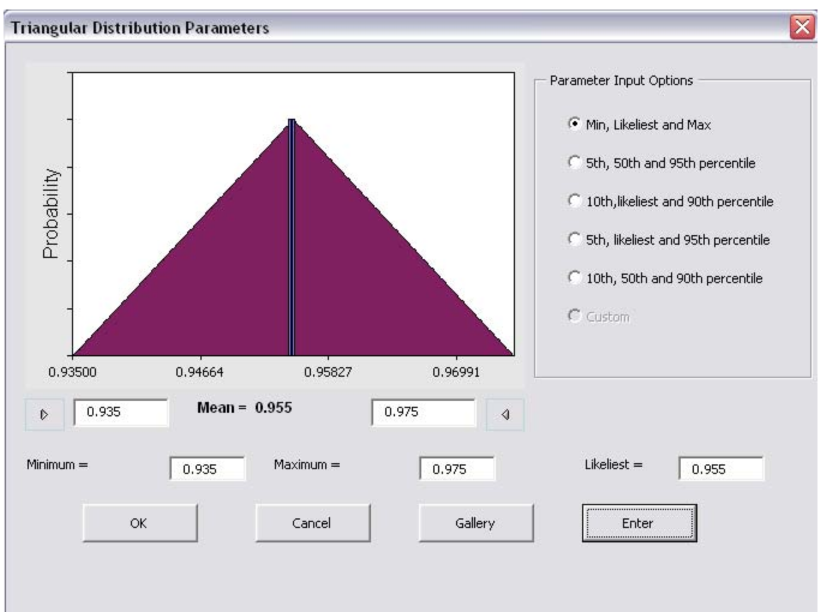


Figure F-56. Distribution Profile for Oil Sands SAGD SCO ULSD Refining Efficiency

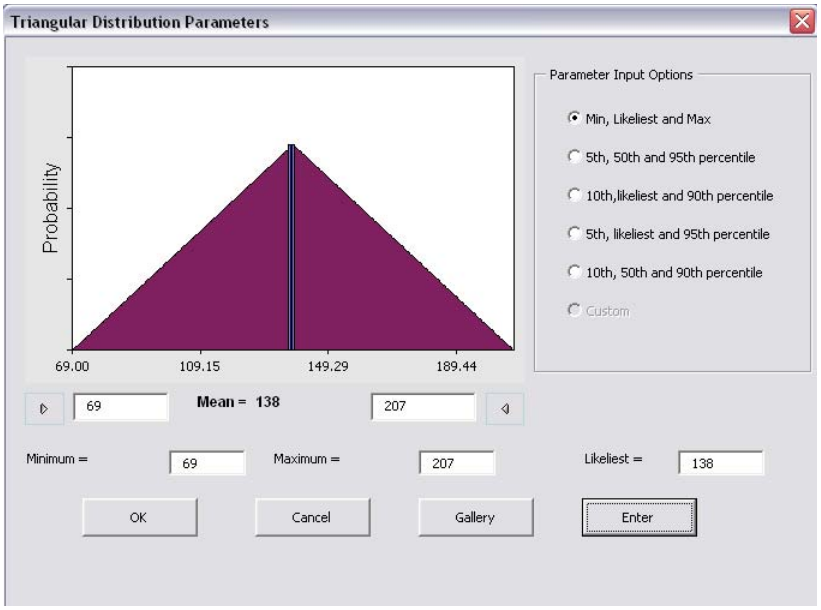


Figure F-57. Distribution Profile for Oil Sands Mining & Upgrading, SAGD & Upgrading Venting Emissions

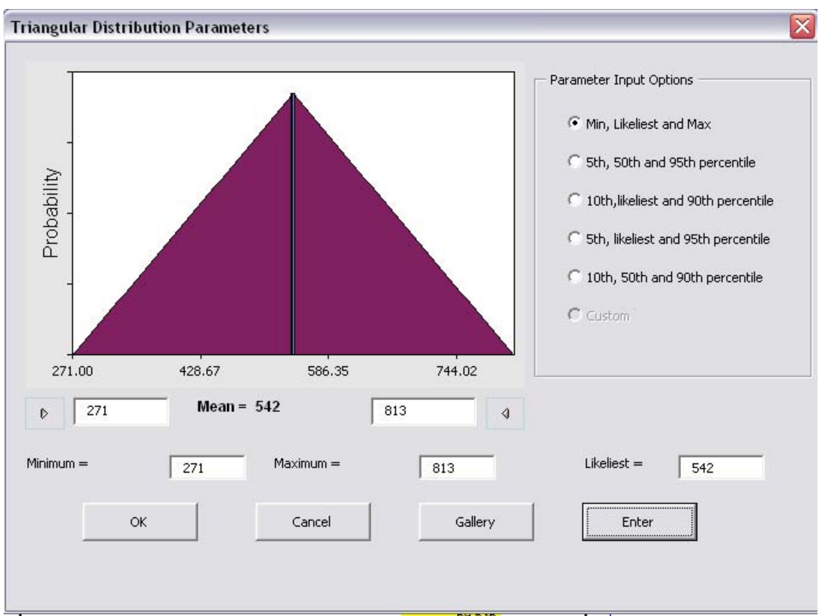


Figure F-58. Distribution Profile for Oil Sands Mining & Upgrading, SAGD & Upgrading Flaring Emissions

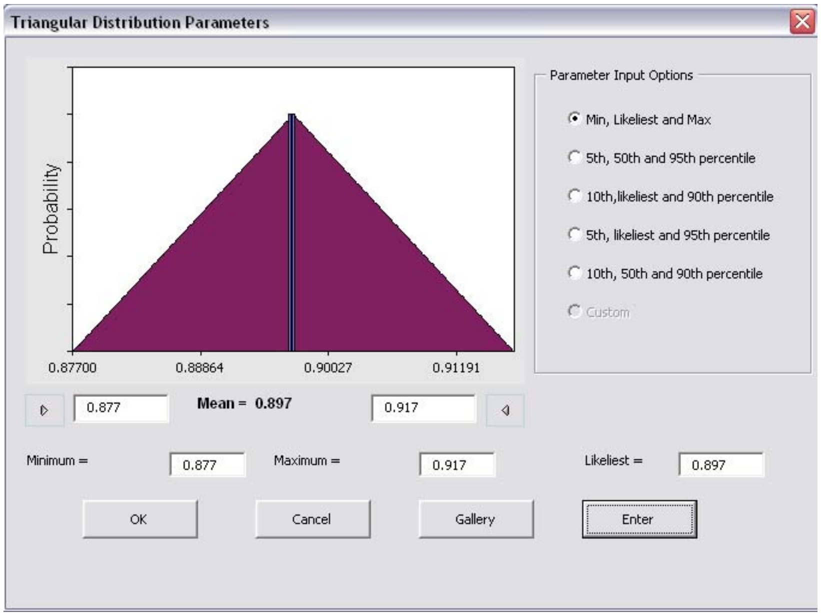


Figure F-59. Distribution Profile for Oil Sands SAGD Bitumen Recovery Efficiency

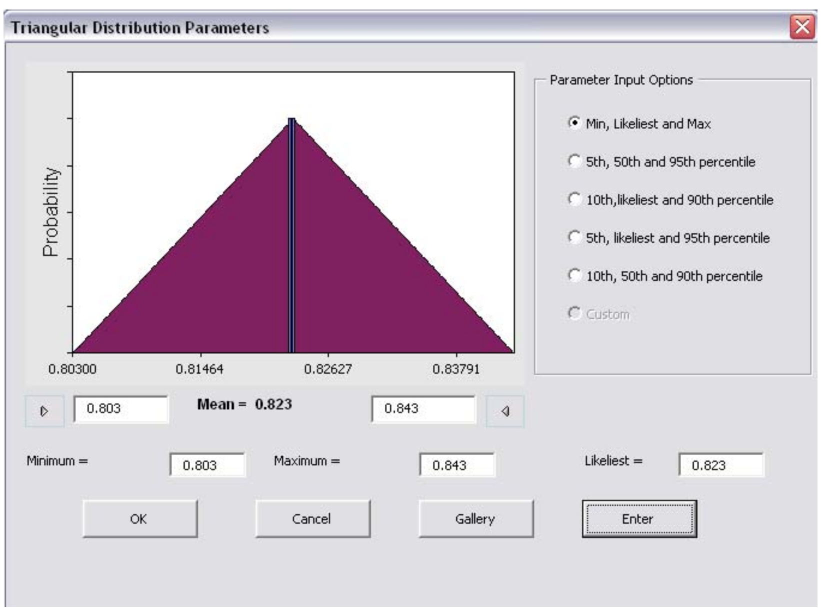


Figure F-60. Distribution Profile for Synbit RFG Blendstock Refining Efficiency

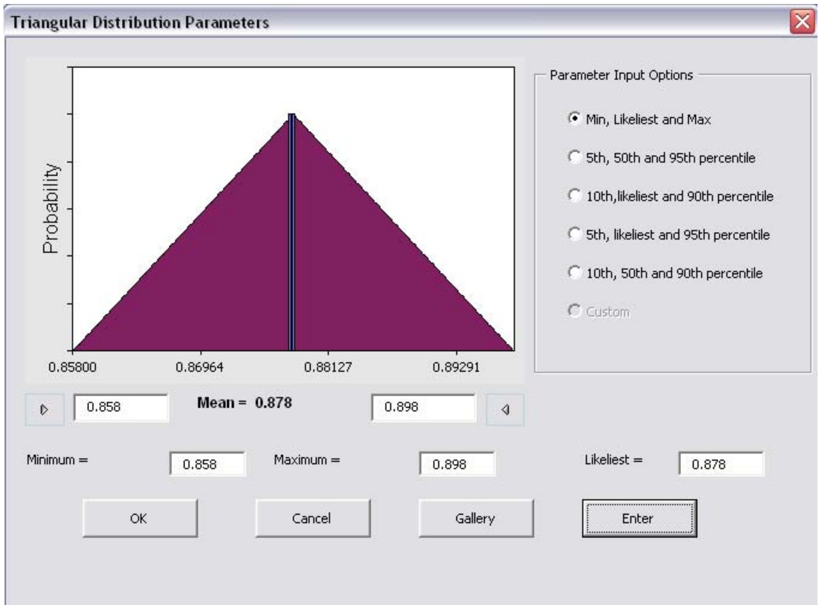


Figure F-61. Distribution Profile for Oil Sands Synbit ULSD Refining Efficiency

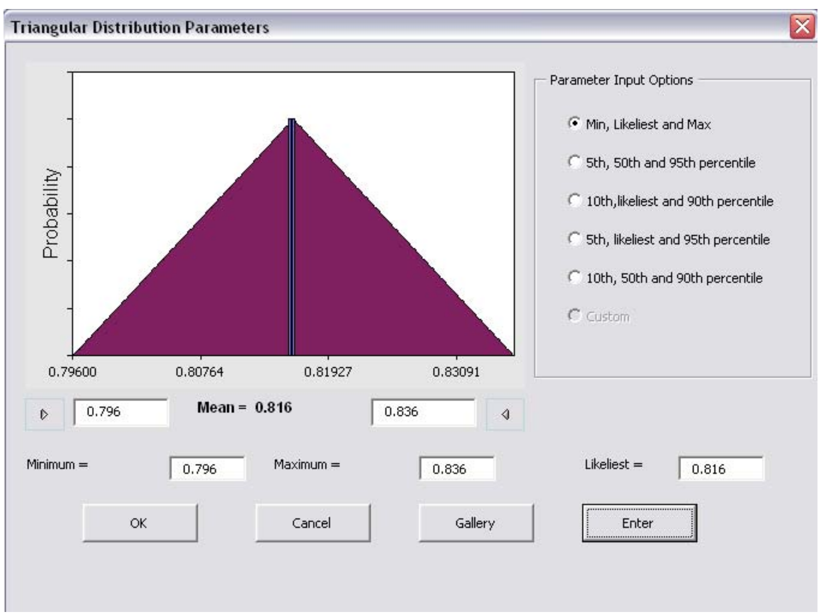


Figure F-62. Distribution Profile for Dilbit RFG Blendstock Refining Efficiency

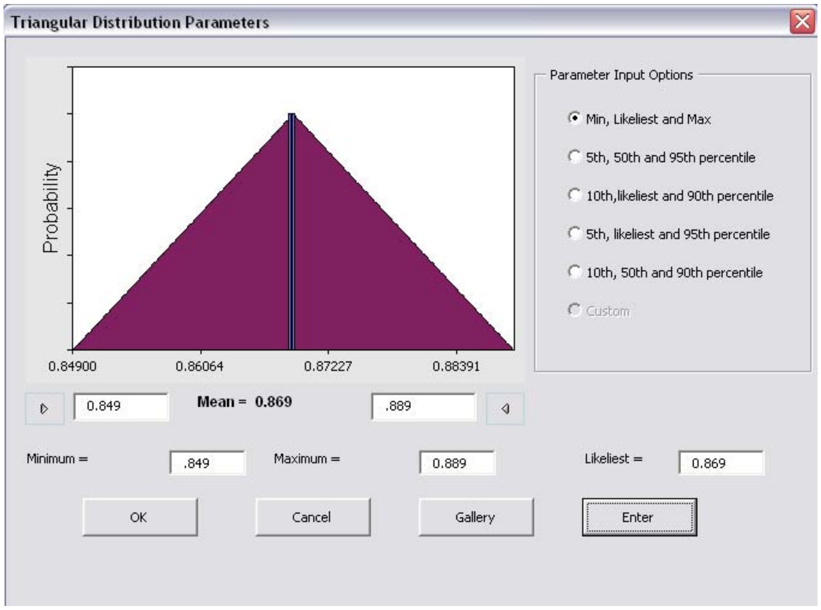


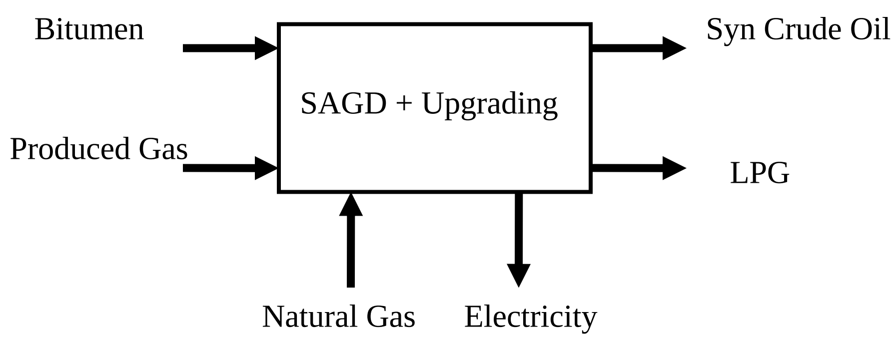
Figure F-63.Distribution Profile for Oil Sands Mining SCO ULSD Refining Efficiency

Appendix G. Stakeholder Workshop

A Workshop was held on January 16, 2009 to provide an opportunity for stakeholders to review our interim progress. The Workshop Attendees asked many good questions and provided instructive comments. The following is a summary of the questions/comments received and TIAX responses. The comments have been divided into the following categories: GREET Efficiency, Treatment of Coke, Conventional Crude Data, Oil Sands Data, Venting and Flaring Data, General Comments. We appreciate the time/effort to review the interim data, attend the workshop, and provide comments.

GREET Efficiency Explanation

At the workshop there was general confusion about the term efficiency as used in the GREET model. We use the following energy flows as an example:



Anand Gohil of Nexen has clarified that the petroleum industry definition of plant efficiency is how much additional energy is required to make petroleum products. Therefore, the industry defines efficiency as:

$$Efficiency = 1 - \frac{Net\_Inputs}{Petroleum\_Outputs}$$

$$Efficiency = 1 - \frac{516 - 70.2}{6170 + 65.4} = 93\%$$

In the GREET model, the efficiency is defined as the total amount of energy consumed in making all energy outputs. Therefore, the energy in the bitumen that is used as process fuel is also considered. The process efficiency is defined in GREET as:

$$GREET\_Efficiency \equiv \frac{Total\_Outputs}{Total\_Inputs}$$

For our example, the GREET efficiency would therefore be:

$$GREET\_\eta = \frac{SCO + LPG + Electricity}{Bitumen + ProducedGas + NaturalGas} = \frac{6170 + 65.4 + 70.2}{8570 + 44.8 + 516} = 69\%$$

This definition of efficiency includes the energy in the bitumen and produced gas that are utilized to make SCO. In the GREET model, this value for efficiency is utilized to determine the amount of process fuels consumed to produce SCO, LPG and electricity:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.69} - 1 = 0.448$$

Check:

$$Process\_Fuels = Prod\_Gas + NG + (Bitumen - SCO - LPG - Elec) = 2825MJ$$

$$Energy\_Output = SCO + LPG + Electricity = 6305.6MJ$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{2825MJ}{6305.6MJ} = 0.448$$

The next step is to split this energy consumption (448,000 Btu/mmBtu SCO) among process fuel types. In this case, the process fuels are produced gas (44.8 MJ), natural gas (516 MJ) and the balance is syngas produced from gasification of coke. Note that care needs to be taken here with the syngas composition since a portion of the syngas hydrogen is utilized in upgrading. Once the share of each fuel type is estimated the appropriate GHG emission factors are applied (depends on assumed combustion equipment split for each fuel type) to arrive at total GHG emissions per mmBtu SCO.

In this example, the exported electricity is produced by burning a mixture of natural gas, produced gas and syngas. This electricity has a lower GHG footprint than the average grid mix (which includes a significant portion of coal). It could be argued therefore that the process should get a credit equivalent to the difference between the CO2e/MWh generated onsite and CO2e/MWh that it displaces. A variety of things could be selected as the electricity displaced: provincial mix, NG combined cycle turbines, etc. The mix selected will be clearly noted along with the results. If time and budget are available, TIAX will vary this and show the impact on CO2 emissions.

To capture the credit, we need to take the electricity export out of the efficiency calculation (increase natural gas fuel consumption) and then subtract out the electricity energy as a line item. The model will automatically subtract out the GHG emissions associated with the specified grid mix electricity.

With the electricity credit method, the GREET efficiency is:

$$GREET\_\eta'' = \frac{SCO + LPG}{Bitumen + ProducedGas + NaturalGas} = \frac{6170 + 65.4}{8570 + 44.8 + 516} = 68.3\%$$

The process fuel consumption is higher, but there is an electricity credit (70.2 MJ) that will more than offset the increased NG combustion emissions.

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.683} - 1 = 0.464$$

Comments on Treatment of Coke

There were many comments regarding the accounting of coke. We present a list of comments followed by a detailed explanation of how we anticipate treating coke production.

Ivanhoe Energy:

TIAX needs to make sure it handles coke consistently for oil sands operations with and without integrated upgraders. For the oil sands without upgraders, the coke is produced in the refineries and sold, not stockpiled. If this coke use is not accounted for, it will unfairly bias the results towards U.S. refining.

LENEF Consulting:

Oil sands mining/integrated coker upgraders in the Fort McMurray area could (and do) deliberately "sequester" their coke in the mines, and can in the long term include this in their land remediation. Should such operators be able to claim "Credit" for this deliberate act? If the coke is assumed to be burned in a powerplant, then is a credit granted for the mining, transport, and burning of coal?

Suncor:

Different oil sands companies manage coke differently. At Suncor, 34% of the coke is consumed in the production of SCO with the balance stockpiled or sold. Each company has a different approach to coke and the CO2 profiles will be different.

TIAX Methodology for Handling Coke

For each of the oil sands pathways, coke will be produced. For the two onsite upgrading pathways, the coke is produced onsite. For the other two pathways, the coke is produced at the refinery. Regardless of where the coke is produced, it will be treated consistently. The key issue is whether to assign a portion of the recovery and upgrading energy (and therefore emissions) to the coke or to assign all of the energy (and emissions) to the SCO. Further, if some energy is allocated to the coke, what allocation methodology would be employed. In this study we are analyzing two pathways with onsite upgrading:

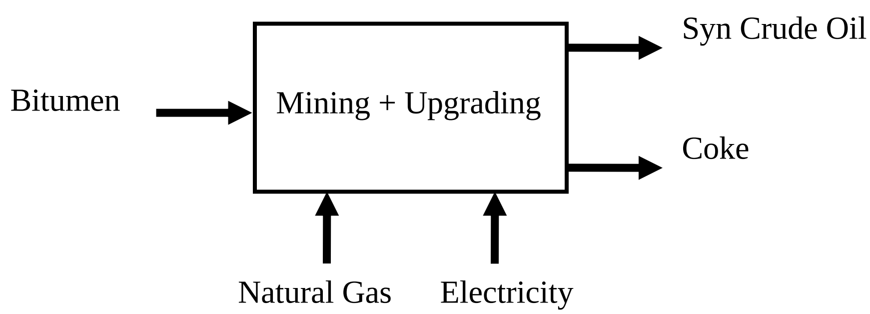
Pathway 1: SAGD+Upgrading: All of the coke is utilized onsite, reducing the quantity of imported NG for steam production

Pathway 2: Mining+Upgrading: The product coke is not consumed onsite

The first pathway is based on the Nexen process. Coke does not exit the control volume, so we do not need to worry about allocating recovery/upgrading energy and emissions to it. Because this pathway utilizes coke to generate steam rather than natural gas, the CO2 emissions will be slightly higher since coke has a higher carbon content per unit energy than natural gas.

The second pathway, mining+upgrading, does not consume any of the coke onsite, so we need to decide whether a portion of the recovery/upgrading energy and emissions should be allocated to it and if so, by what method. We recognize that other pathways are possible (e.g. Suncor utilizes a portion of their coke onsite and stockpiles the balance), however the pathway we are analyzing here does not use the coke onsite.

The Mining+Upgrading pathway is depicted below:



To determine how to split or allocate the recovery energy/emissions between the SCO and the coke, we need to consider the fate of the coke. There are two possible fates:

1. The coke is sold for use as a fuel (or stockpiled for future use as a fuel)
2. The coke is buried and considered sequestered

The manner in which these scenarios will be modeled in this project is described below.

Scenario 1: Coke is Sold for Use as a Fuel (or stockpiled for use at a later time)

If the coke is sold (or will be sold in the future), then it is a useful product and it is appropriate to assign some of the recovery/upgrading energy to it. There are many ways to allocate energy among co-products. One way would be proportionally by energy flows, mass, or economic value. The following shows allocation by energy flows. With this approach, we would first we calculate GREET Efficiency with coke in the numerator since it is a useful output:

$$GREET\_\eta \equiv \frac{Total\_Outputs}{Total\_Inputs} = \frac{SCO + Coke}{Bitumen + NG + Electricity} = \frac{5780 + 1330}{8430 + 384 + 20.9} = 80.48\%$$

This efficiency is utilized in the model to calculate total energy consumption as follows:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1 = \frac{1}{0.8048} - 1 = 0.243$$

Let's check this value:

$$Process\_Fuels = NG + Electricity + (Bitumen - SCO - Coke) = 1725MJ$$

$$Energy\_Output = SCO + Coke = 7110MJ$$

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1725MJ}{7110MJ} = 0.243 \quad \text{OK}$$

If we assume that the recovery energy is allocated by energy content to the SCO and Coke, then the SCO recovery efficiency is also 80.48%. When this efficiency is utilized in GREET, the total process energy calculated will be 0.243 Btu/MMBtu SCO produced.

An alternative allocation methodology is the substitution/displacement method. The substitution/displacement method is essentially giving a credit for an avoided emission associated with the product that the co-product is displacing. In this method, all of the energy/emissions are assigned to the main product (SCO), but a credit is applied that is equivalent to the avoided energy/emissions to produce the product that is being displaced. For example, pet coke can be utilized in place of coal in utility boilers. Use of pet coke in the boiler instead of coke would reduce the amount of coal being mined. The substitution method would then credit the SCO energy/emissions with the energy and emissions associated with coal mining. Note that coal mining energy and emissions are not being used as a surrogate for coke production – the coal mining energy/emissions are avoided if the coke is sold for use in place of coal.

The substitution/displacement allocation method is generally preferred to other allocation methodologies as allocating by energy content, mass or economic value can be rather arbitrary. TIAX will clearly document the allocation methodology employed in the analysis. If budget and time allow, we will likely look at both an energy and displacement methodology.

Scenario 2: Coke is Considered Sequestered

In this scenario, the total process fuel consumption is the same as in Scenario 1.

$$Process\_Fuels = NG + Electricity + (Bitumen - SCO - Coke) = 1725MJ$$

However, since the coke is not a useful product, all of this process fuel must be allocated to the SCO. Therefore we can back-calculate the GREET process efficiency from the process fuel and SCO:

$$\frac{Process\_Fuels}{Energy\_Output} = \frac{1}{\eta} - 1$$

$$\frac{1}{\eta} = \frac{Process\_Fuels}{Energy\_Output} + 1 = \frac{Bitument - SCO - Coke + NG + Electricity}{SCO} + 1 = \frac{1725}{5780} + 1 = 1.2984$$

$$GREET\_\eta = \frac{1}{1.2984} = 77\%$$

When this process efficiency is utilized in GREET, the calculated process fuel consumption will be 0.298 Btu/Btu SCO produced. This is higher than Scenario 1 because we are allocating all of the process energy to the SCO rather than to the SCO+Coke.

Carbon Content of the Coke

At the workshop one topic discussed was whether emissions associated with burning the produced coke downstream are considered. If these emissions are included, then a credit would have to be applied equivalent to the combustion that is being displaced. If the coke is utilized in a coal fired boiler to generate electricity, then the credit would be the lifecycle emissions associated with electricity produced from a coal fired boiler or perhaps the average grid mix. TIAX will not consider the emissions from combustion of the product coke. Once we have allocated energy between the SCO and the coke, we have finished considering coke.

Comments on Conventional Crude Recovery Data

<u>EnCana</u>:

The Alaska North Slope diagram indicates pipeline NG and associated gas used to generate electricity. No pipeline natural gas is used in Alaska – only associated gas.

TIAX calculated the amount of fuel needed to generate the estimated amount of electricity to recover ANS crude. Based on our GOR, supplemental fuel was needed. It is true, however, that almost 85% of the produced gas is re-injected, confirming that no pipeline gas is needed. Our preliminary GOR estimate may be low – we will look into this further. We will use data from the State of Alaska Gas Disposition for 2004 which details associated gas produced and the quantity reinjected.

<u>Shell</u>:

For Saudi Arabian Crude, TIAX is not showing any energy use for desalination

TIAX is aware that some of the recovered water is desalinated and used elsewhere. However, a contact at Saudi Aramco has informed us that the water used for recovery is not desalinated prior to injection. Therefore, the desalination process is outside of our control volume and the associated energy use is not considered.

Unknown:

In Saudi Arabia, excess associated gas is used for space heating – is this accounted for?

Any associated gas that is not used for crude recovery exits the recovery control volume and is included in the numerator of the GREET Efficiency calculation.

Ivanhoe Energy:

Mexico Maya utilizes N2 flood – is TIAX accounting for this?

This will be added to the Mexican crude energy balance. Thank you for providing the DOE EIA nitrogen consumption information as well as the Praxair data on nitrogen production energy use.

Pembina:

Is the energy use associated with cleanup of sour associated gas prior to utilization in CTs taken into account?

TIAX contacted Sulfatreat, a company selling skid mounted H2S removal equipment. Their process is used around the world. Their sales rep for Bakersfield California says that no heating or electricity is required. Typically the pressure of the associated gas is sufficient for flow through the reactor. The gas flows from the reactor directly to steam and electricity generators. We are therefore assuming no additional energy needs to clean the associated gas.

Laricina Energy:

The Alaska water oil ratio seems too high – I would verify through other sources.

TIAX has since found detailed information from the State of Alaska on water production.

Laricina Energy:

Canadian heavy oil electricity supply: power is supplied by the Alberta grid rather than directly by natural gas fired generation.

Thank you – we had not found any specific data on the source of conventional oil recovery electricity and had assumed electricity was self-generated. Joule Bergerson has provided sources indicating that most oil sands/upgrading operators are net electricity exporters to the grid. However, this is not necessarily true for conventional heavy oil recovery.

Unknown:

The GOR for Mexico Maya seems high – could this be gas cap production?

Cantarell Oil Field data for 1996 indicates the produced oil ratio is 372 scf/bbl.

Comments on the Oil Sands Pathways

<u>Unknown</u>:

TIAX is analyzing SAGD+upgrading and SAGD recovery with transport as a synbit. SAGD recovery and transport as Dilbit is also a significant pathway. Why was the SAGD+Dilbit pathway not considered here?

There are many different projects and variations for oil sands operations. The scope of this project originally included analysis of only two oil sands pathways. We have increased this to four in consultation with the Steering Committee. Given this constraint, we do consider SAGD recovery and Dilbit refining, so it may be possible to piece these together to create a SAGD+Dilbit pathway in GREET. We will add this as a GREET pathway if we have resources remaining at the end of the project.

<u>Unknown</u>:

Why did TIAX choose the projects it did for the study? CNRL Horizon's last EIA update was in 2003. Long Lake is the only integrated in-situ/gasifier/cogen/upgrader plant in operation. MacKay River and Christina Lake are the two best SAGD projects currently in operation.

One of the overarching requirements for this analysis is that all of the data utilized be publicly available or releasable so that a high level of transparency is achieved. At the start of the project, TIAX and the Steering Committee decided to evaluate the four oil sands pathway indicated in the Table below based on current and future importance. For these pathways, all of the projects with publicly releasable data were considered. Contact was made with other operators, but no public data was made available

Oil Sands Pathways Considered and Corresponding Projects with Public Data

Pathway	Projects Utilized
Mining to SCO	CNRL Horizon
SAGD to SCO	Nexen/OPTI Long Lake
SAGD to Synbit	MacKay River, Christina Lake
CCS to Dilbit	Cold Lake, Primrose

<u>Unknown</u>:

For the CNRL Horizon project, the value reported for coke stockpiled (4,540 kg/bbl) appears to be much higher than Syncrude and Suncor.

Because the Syncrude and Suncor data are not public, we do not have access to it, nor could we consider it. The value utilized is from the EUB/AENV Supplemental Info, 2003. If this number is inaccurate, it may be in the interest of other operators to provide publishable data supporting a more accurate number.

Unknown:

For the Christina Lake project, the natural gas input seems low (TIAX assumes electricity import = 0 and EnCana runs a cogen plant at Christina Lake).

TIAX went back to our data source (EUB/AENV Application, EIA Supplemental Info, 1998) and found that Christina Lake does import a small amount of electricity. The comparison project, MacKay River, consumes ~29 cubic meters (1100 MJ) more of natural gas than the Christina Lake project and exports 330 MJ of electricity. This corresponds to a turbine efficiency at MacKay River of 30%. Since the CSOR values are equivalent for the two projects, TIAX believes that the natural gas consumption and electricity export values of the two projects are consistent.

Unknown:

For the Imperial Oil Cold Lake project, the natural gas input seems low considering the cumulative SOR is 3.35. In addition, Imperial Oil was the first in situ producer to add cogen (170 MW). It seems unlikely that they are importing electricity from the grid.

Our process data is from the EUB/AENV Application in 2002 and supplemental information in 2003. The CSOR is from a progress report to ERCB in 2008. It is possible that the reported 2008 CSOR is not consistent with the natural gas consumption data in the application. The CSOR is not utilized in the calculations. The Cold Lake application data does not include a cogen unit – is it possible that this was added after 2003?

Laricina Energy:

I believe that a fifth oil sands pathway (dil-bit from SAGD production) should be included as it represents the most promising pathway for reducing the GHG footprint of oil sands production through the use of solvent aided processes, which reduce steam injection requirements. Modeling this pathway should lay the foundation for future evaluations.

Please see response to the first comment in the Oil Sands section.

Laricina Energy:

During the seminar, the issue of bias and data acquisition was raised. To appear unbiased, the project was to source only public data. In the case of oil sands mining, this has lead to the utilization of hypothetical information from projects that are not yet currently operating. The omission of Syncrude and Suncor in the data set, because … the data are not publicly available will result in an inaccurate view of oil sands mining operations. I would recommend obtaining private data from these companies to provide a complete and credible data set for oil sands mining.

TIAX understands this frustration, but the overarching requirement for this project is transparency, so the underlying data must not be secret.

Laricina Energy:

Much of the product shipped to the USA from Canada is blended with other conventional crudes to create a more marketable product that is known as Western Canada Select (WCS) rather than shipped as separately as dilbit, synbit, or SCO. This blending will serve to reduce the emissions footprint on a barrel shipped to the USA. Please ensure that the shipped oil volumes are characterized by the correct oil assay.

The intent of the project is to accurately characterize each oil sands pathway deliverable, not a single composite WCS. We are utilizing representative assays for each (SCO, dil-bit and synbit) crude delivered to the refinery.

Ivanhoe Energy:

On Slide 51, the 2500 mile transport distance from Edmonton to PADD 3 ends in west Texas. Shouldn't this be extended to the Gulf Coast?

TIAX agrees and we will adjust this distance to reflect the increased pipeline distance to the Gulf Coast.

Comments on Venting and Flaring Data

API:

Consult December 2008 World Bank report on venting and flaring emissions.

TIAX was unable to find this report on the World Bank website, but we are utilizing 2007 satellite data to complement the EIA/IEA data.

NRCan:

Use World Bank venting and flaring data with caution

TIAX will utilize World Bank data with caution.

Unknown:

Determine how NETL venting and flaring data (EIA/IEA data) were obtained to better understand the data validity.

TIAX is currently going through the source data utilized in the NETL report and will provide the origin of the venting/flaring in the final report. TIAX has contacted EIA for the specific references for international venting and flaring.

API:

It is not accurate to use U.S. average venting/flaring values for Alaska, CA and Gulf Coast.

TIAX agrees and will try to provide more granularity. So far we have:

- *For California, we obtained California District 4 (Kern County) flare volumes from the California Department of Conservation. Venting is prohibited in San Joaquin Valley by the local air district, however it is not zero. Venting emissions will be taken from the California GHG inventory.*
- *For Alaska, venting and flaring data were obtained from the Alaska OGCC Gas disposition reports for 2004.*
- *For Texas, the Texas Railroad Commission has been contacted for gas disposition data. If this cannot be obtained TIAX will use USEPA estimates for federal offshore Gulf of Mexico venting and flaring.*

<u>API</u>:

What is the source of flare emission factors in GREET? The flare emission factors in the API compendium are more accurate.

The GREET documentation does not source the emission factors other than that they are natural gas combustion factors. Unless the flare gas composition is known, the API flare emission estimation methodology is: assume flare gas composition (80% methane, 15% ethane, 5% propane), 98% combustion efficiency (2% of methane is emitted as methane). Using this methodology, the GREET and API CO2 factors agree fairly well. The GREET N2O factor is higher than the API factor, but the GREET CH4 factor is lower than the API factor. We have elected not to modify the GREET emission factors for this analysis.

General Crude Recovery Comments

<u>Suncor</u>:

The energy efficiency shown on slides 30 & 31 are confusing.

Please see discussion of GREET process efficiency at the beginning of this document.

<u>Unknown</u>:

TIAX compares calculated efficiencies to GREET values but not to GHGenius values.

TIAX will compare values to both GREET and GHGenius default values.

<u>Suncor</u>:

We export 190 MW of electricity to the grid. How is this accounted for?

For this operation, the process fuel consumption would be higher than a non-electricity exporter, but a credit would be given equal to the emissions associated with generating 190MW. The offset emissions assumed would be consistent with the grid mix that the exported electricity is displacing. If we have time, it would be nice to build an algorithm in GREET allowing the user to adjust the amount of cogen done (onsite fuel consumption would increase and exports would *increase). Alternatively, we will address this by running cases that bracket the range (time and budget allowing). As mentioned above, the grid mix that is assumed for the credit will be clearly stated (Alberta mix, National mix, natural gas combined cycle, etc).*

<u>Ontario Ministry of Energy</u>:

Oil Sands operations run continuously. Although Alberta is a net importer, in off-peak hours, Alberta exports electricity to British Columbia. This would displace BC hydro generation. However, by exporting to BC in off-peak hours, Alberta can import more hydro from BC in peak hours. Is TIAX considering imports/exports in determining the electricity credit?

The grid mix used for electricity credit is always a complicated issue. In an ideal world, a dispatch model would need to be run to capture what the net effect is of adding a generating unit at an upgrader. This is beyond the scope of the project, and as you point out reduced hydro use at night will result in increased hydro use in the daytime, possibly making it a wash. TIAX plans to use the Alberta annual average grid mix reflecting total consumption by fuel type (including imports and exports).

<u>LENEF Consulting</u>:

I do not see any factors or information on pipelining based emissions.

TIAX will use the GREET default values for pipeline transport energy consumption. Pipeline transport energy and emissions are a relatively small part of the total.

<u>LENEF Consulting</u>:

I believe that comparisons of CO_2 lifecycle emissions between crude sources should be based on a "unit of liquid refinery products" produced not at the "unit of crude" level.

TIAX agrees – the final results will be in g/mmBtu gasoline and g/mmBtu diesel.

<u>Suncor:</u>

Although the TTW portion of the analysis will be a constant added to each crude, it is important for policy-makers and the public to understand the relative CO_2 contribution during fuel combustion in the engine.

TIAX agrees – the WTT portion of the WTW emissions is small. While not all of the results will be presented as WTW, we will be sure to emphasize this point.

<u>Laricina Energy</u>:

The characterization of conventional crudes is not as rigorous as for Canadian oil sands production. A more rigorous evaluation of only some crude oils could result in a higher GHG emission footprint compared to those with less rigorous evaluations, leading policy makers to invoke less effective policy and regulation. I would recommend that experts for each country or crude oil be engaged to help characterize each crude oil.

We do not agree that the oil sands characterization is more rigorous than the conventional crude characterization. Moreover, a more rigorous evaluation does not necessarily result in higher GHG emissions. This project is not meant to be the final statement on crude oil recovery emissions for each country. It is simply meant to be an improvement over what has been utilized to date in GREET (U.S. average crude recovery and refining energy and emissions).

Laricina Energy:

It is not apparent what the final deliverable will look like. I assume that an evaluation of the emissions from wells-to-wheels for each crude and refining location combination will be part of the final deliverable. In addition, I would also suggest that the average emissions for production from each country be determined. Developing such modeling capabilities will serve to enable the evaluation of changing crude oil properties, production mixes and refining markets over time in the future.

The final deliverable will provide for each crude/refining region option WTT and WTW energy consumption and GHG emissions. In addition, the composite results will be broken down into components (recovery, crude transport, refining, finished fuel transport). Finally, sensitivity and uncertainty analyses will be done so that error bars can be shown on the plots.

Comments on Refinery Modeling

Ivanhoe Energy:

We encourage the “Fix” case rather than the “Float case” because we are trying to count carbon and not attempting to optimize the refinery. We suggest that you assume the market needs be met for all crudes and vary the crude rates to meet the production of refined products to the greatest extent possible.

This question may pertain to the refinery modeling results to be submitted to the forthcoming GREET-based lifecycle analysis. We expect that the life-cycle analysis will use results from the Fix cases. However, the question calls for a broader answer.

The energy used in refining a given crude oil is not an immutable attribute of the crude oil; it depends not only on the crude’s properties but also, to some degree, on the specific refining environment in which the crude is processed. All of our estimates of refinery energy use for specified crudes are in fact estimates of the change in refinery energy use resulting from the optimal introduction of a specified crude into a baseline crude slate being processed in a particular refining configuration. Whether or not that optimal introduction would involve a change in product out-turns would depend on market conditions at the time – which is unknowable now.

We did not suggest that the results of either the Fix cases or the Float cases be taken as the preferred estimates of refinery energy use. Rather, we presented both sets of results to indicate the sensitivity of our results (and of refinery energy use estimates in general) to assumptions regarding the way in which refining sector would accommodate a change in crude slate.

Recognize that we are "counting carbon" in both sets of cases; but under different premises regarding the refining sector's behavior. In practice, each refiner indeed seeks to "optimize the refinery" every day; if that means adjusting the product slate to make the best economic use of a specific crude slate, so be it.

<u>LENEF Consulting</u>:

There is no obvious allowance for iso-butane purchases. I have found that light-med conventional crudes need 2% by vol purchased isobutane, but a bitumen barrel needs about 7% volume b/c of the high per unit FCCU feed from virgin VGO and the coker.

In our analysis, we recognize iso-butane purchases, but we hold the purchase volume constant for all study crudes as we displace some of the composite crude slate with a like volume of a study crude (e.g., synbit, Escravos, etc.). We do the analysis that way because (1) the substitution volume is small relative to the total regional crude volume, (2) the refinery model uses the flexibility in regional refining operations to meet the specified product slate without increasing purchases of iso-butane or any other non-crude input, and (3) our objective is to estimate, for each study crude, the change in regional refinery energy use resulting from the introduction of a specified volume of the study crude into the regional crude slate.

Item (3) is particularly important. By contrast, Mr. Flint's note seems to imply that his analysis treats refinery energy as an intrinsic property of a study crude, regardless of the refinery setting. I think that his analysis showed large crude-to-crude swings in iso-butane purchases because his refinery model handled only one crude at a time and did not capture sufficient flexibility in refining operations.

Finally, because we hold iso-butane purchases constant from crude to crude, TIAX need not worry about the energy input to field iso-butane production and transport.

<u>LENEF Consulting</u>:

With respect to refinery coke, how is the "clearing market" issue handled in the event of coke make excess to North America demand?

As the question suggests, introducing certain heavy crudes (e.g., Maya, SJV Heavy, Synbit, etc.) into the baseline crude slate leads to production of petroleum coke in excess of the reference case volume (which we estimate from EIA projections of future U.S. refined product demand). We assume in this analysis that the regional refining sectors can dispose of all of the pet coke they produce, in all cases, without regard to price.

Coke is a low-value product, and coke sales constitute only a small share of refinery revenues. Moreover, pet coke is a refinery by-product. Real refineries – and certainly our refinery models – do not produce pet coke on-purpose, nor do they have any direct means of controlling pet coke production without affecting other product rates. In general, refineries tend to price coke as needed to sell their production in the available markets, and they use various means to dispose of coke in excess of what the markets will take. These means can include refinery-based gasification and co-generation, stockpiling, or even paying to have the coke hauled away.

<u>UC Davis</u>:

There is a discrepancy between the timeframes of the crude oil analysis (as recent as possible) and the refinery modeling (2015).

The only aspect of the refinery modeling that reflects the year 2015 is the finished fuel formulations. Current fuel formulations are very close to the 2015 standards. Rather than model an intermediate situation, we have chosen to use 2015 standards as these will remain useful longer. Since the early 90's, formulation standards have been changing almost yearly in the areas of sulfur and compatibility with ethanol for refinery produced gasoline. Although more energy will be required to meet increasingly stringent sulfur regulations, the introduction of larger quantities of ethanol into reformulated gasoline will also reduce the refinery energy necessary to produce the refinery gasoline that will be mixed with ethanol. This is due to the estimated 105+ octane of ethanol and reduced refining necessary to meet the requirements of combined refinery gasoline + octane (reformulated gasoline) of 87 (regular) and 92/93 (premium).

Appendix H. Phase I Final Presentation

The final presentation for Phase I of this project was held on June 15, 2009 in Calgary, Alberta to provide an opportunity for stakeholders to understand our methodology and findings. The following is a summary of the questions/comments received and TIAX responses.

How good is publicly-available data for conventional crude and oil sands?

We recognize the limitations of using publicly-available data and have attempted to use credible sources. Our data are derived from peer-reviewed, published reports and applications reviewed by the EUB and AENV. Because applications may be several years old and current operations may differ, oil sands operators were given the opportunity to comment on our GREET inputs.

Did TIAX consider emissions associated with diluent production?

Yes, diluent production emissions were considered, along with other upstream energy requirements.

Did TIAX distinguish among different SCO qualities?

Yes, our refining analysis examined the properties of each crude oil. (See API gravity/sulfur graph in Figure 4-1.)

Did TIAX account for upstream emissions, e.g. to produce natural gas used in steam generation?

Yes, one of GREET's main functions is to track upstream emissions, and model inputs were adapted to each specific crude oil pathway.

Were default GREET values used for upstream emissions?

Yes, default emission factors were used, and we specified inputs such as electricity grid mix at the PADD-level for the United States, state/province-level for Alberta and California, and country-level for foreign crude pathways.

Why is a SAGD-dilbit result shown when it is not one of the four selected oil sands pathways?

We list four main oil sands recovery pathways but actually also ran variations of these pathways. The SAGD-dilbit pathway was created by combining SAGD recovery with dilbit transport and refining.

Was there an attempt to "ground truth" recovery emissions from conventional crudes?

No reports on specific processes were available to make this comparison, which was one motivation for conducting this analysis of different crude pathways.

Where did TIAX find the names of the crude oils corresponding to each country?

MathPro matched the crude properties (API gravity/sulfur content) reported for each country to specific, known assays.

How is refinery coke handled?

No energy and non GHG emissions are allocated to coke produced at the refinery since this is not an on-purpose product.

How is refinery LPG handled?

LPG is part of the product slate, listed under the "Other Products" category.

How did TIAX distinguish among different refineries and seasonal differences, e.g. high vs. medium conversion?

We held the refinery slate constant for an annualized average refinery within the refinery region (California, PADD 2, PADD 3).

California refineries seem to be the most inefficient. Is this erroneously taking into account high conversions?

California has a high percentage of gasoline in its product slate in addition to a heavy crude slate, which makes the refineries look less efficient. In this analysis aimed at understanding the emissions of different crude oils, it is more important to compare across different crude oils in the same region rather than the same crude oil in different regions.

Where are the estimated refinery energy use data from?

Section 4 of Appendix D details the sources of refinery energy use data, including the U.S. Department of Energy and the Energy Information Administration.

What is the range of gasoline-to-distillate ratio in the three refining regions?

Diesel is fairly constant across the regions. Gasoline varies and is highest for California.

Where is the graph in slide 28 (estimated refinery energy use) in the TIAX report?

This graph is aggregated from multiple graphs in the report.

Are the SCOs from SAGD and mining different?

Yes, synthetic crude oils from the two pathways are associated with different properties in the analysis. (See API gravity/sulfur graph in Figure 4-1.)

Does refinery energy use account for and normalize to natural gas and electricity?

Yes, the energy use is reported per barrel of crude oil entering the refinery and includes energy from natural gas and electricity.

How do refineries change to accommodate different crude oils?

The refinery modeling accounts for caps (e.g. hydrogen) that are present for each PADD, and the crude oils and products must conform to what is needed for consumers.

Is unconstrained coke burning allowed in the catalytic cracker?

Yes, coke burning is not constrained. The model accounts from more steam as a result of more coke.

Refineries are not optimized in real operation. Does it make sense to analyze an optimized refinery?

Although real operations may not necessarily be specifically optimized for energy use, they can be expected to be nearly optimized economically. For the purposes of this analysis, optimized refineries offer a way to compare different pathways, since un-optimized refineries have an infinite number of variations to compare, which can lead to misleading results.

TIAX calculates approximately 12 gCO_2e/MJ for the mining pathways, while Suncor and Syncrude have reported 16 and 21 gCO_2e/MJ for their operations. What is the reason for this discrepancy?

Because the Suncor and Syncrude numbers do not include explanations of how these total emissions were derived, it is difficult to pinpoint the reason for this discrepancy. It is possible that these numbers include partial coke use rather than 100% natural gas as in the CNRL Horizon operation which was used to represent the mining pathway.

Are refinery byproducts not allocated to products?

Coke is not considered a product, but other products such as bunker fuel are included in the "Other Products" category.

Did TIAX include non-combustion emission factors?

We included venting and flaring, and non-combustion factors were incorporated into MathPro's emissions.

Is residual oil accounted for?

Our focus was on the lighter end of the product slate, and residual oil was included in the "Other Products" category. Residual oil and other products were held constant, and coke was allowed to float.

Coke was not combusted, so its energy cannot be included in the GREET efficiency calculation.

True, and as such, the SAGD-upgrading process has no coke output in the efficiency calculation.

The treatment of coke in the analysis is not fair to operations that have integrated coke use.

From an emissions standpoint, it is true that internal coke use is penalized because coke has a higher carbon per energy content than the alternative fuel, natural gas.

Gasoline and diesel refining are equivalent today, driven by the ULSD specifications. Gasoline does not take more energy to refine than diesel.

The difference in relative energy is shown by the refinery modeling. The ULSD standard does not increase the refinery energy requirement by a large amount because the hydrogen required is not as much as is needed for hydrocracking.

ULSD from SCO-SAGD should not need much refining and should show the lowest emissions.

While upgrading creates a lighter product, the gains in upgrading do not directly translate into less energy required in refining because upgrading and refining create different molecules.

Dilbit looks better than synbit from an emissions perspective because not all material comes from oil sands (dilbit has condensates).

True, and with limited diluent supply, the incorporation of new elements to the pathway, such as a diluent return pipeline, will change the emissions of the dilbit pathway.

Does CNRL Horizon use cogeneration?

According to CNRL Horizon's March 2003 application to the EUB and AENV, the project has cogeneration capability but will not apply to the EUB to export electricity in its first three phases.

The Christina Lake bitumen heating value in the TIAX report is incorrect and should be the same as that of MacKay River.

The heating value in the draft version of this report was based on the EnCana Christina Lake EUB Supplemental Responses, August 2005. However, as we allowed operators of the representative projects to provide feedback on how the current processes may deviate from the original applications, we have assumed for this final report that the bitumen heating values are the same for Christina Lake and MacKay River, both of which are located in the Athabasca region.