NATIONAL ENERGY TECHNOLOGY LABORATORY

An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact on Life Cycle Greenhouse Gas Emissions

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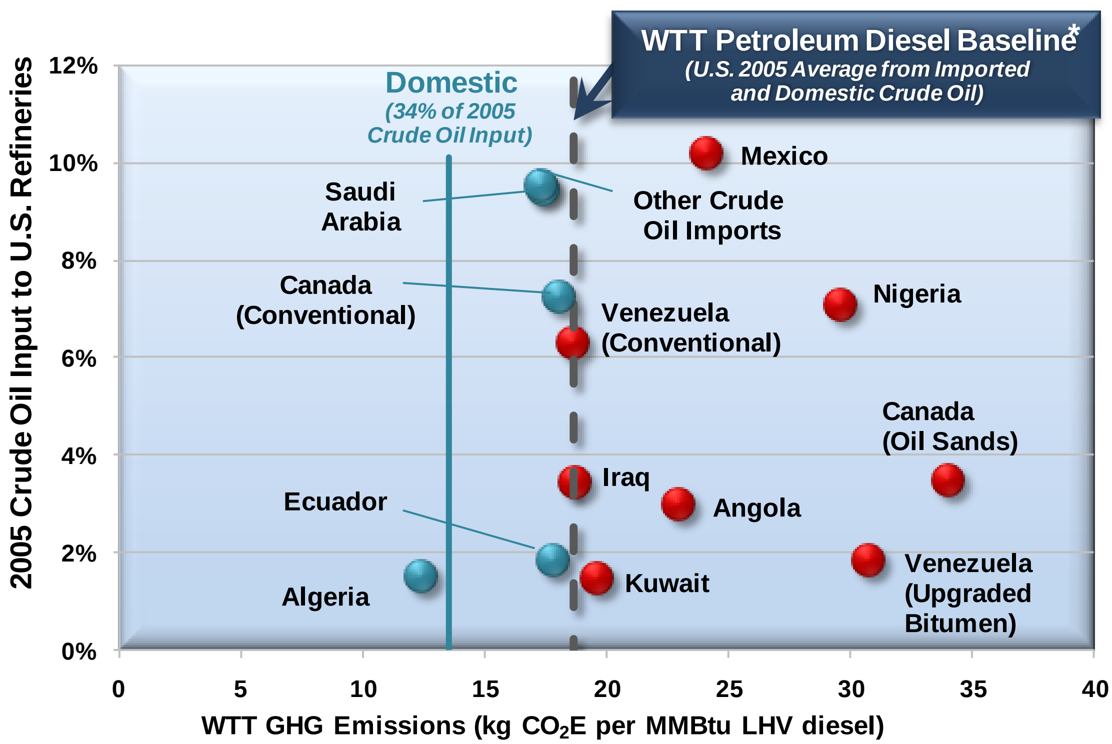
Executive Summary

The National Energy Technology Laboratory (NETL) has analyzed the full life cycle greenhouse gas (GHG) emissions of transportation fuels derived from domestic crude oil and crude oil imported from specific countries. Estimates of the well-to-tank (WTT) [1] GHG emissions associated with producing diesel fuel for each source are shown in Figure ES-1.

This analysis reveals that producing diesel fuel from imported crude oil results in WTT GHG emissions that are, on average, 59% higher than diesel from domestic crude oil (21.4 vs. 13.5 kg CO_2E/MMBtu LHV[2]). Imported crude oils are on average heavier and contain higher levels of sulfur, and the controls on venting and flaring during crude oil production are not as good as in domestic operations. Figure ES-1 also shows that Venezuela bitumen, Canada oil sands, and Nigeria stand out as having high GHG emissions compared to other sources. Acquisition costs of the crude oil from these three sources are estimated at $62 billion for 2008.[3]

Figure ES-1. Crude Oil Source-Specific GHG Emissions for Diesel



* Source: NETL report, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008

1 The WTT profile excludes the emissions associated with vehicle operation which is approximately 80% of the GHG emissions well-to-wheels (WTW) profile. For this analysis, comparisons are made on a WTT basis as the GHG emissions from combustion of petroleum-based fuels are not expected to be impacted by crude oil source. For alternative liquid transportation fuels, the GHG emissions for combustion may vary from that of petroleum-based fuels depending on the carbon content relative to the energy content of the fuel.

2 Kilograms carbon dioxide equivalents (kg CO_2E) per million British Thermal Units (MMBtu) on a lower heating value (LHV) basis.

3 Average refiner acquisition cost of crude oil in 2008 was $95/bbl. While crude oil price has fallen to $39/bbl for February 2009, the Energy Information Administration Annual Energy Outlook 2009 Early Release projects a 2030 imported crude oil price of $124/bbl.

The following activities were addressed in evaluating the impact of crude oil source on WTT GHG emissions:

- Flaring and/or venting of associated natural gas during the crude oil extraction process
- Alternative crude oil extraction techniques and pre-processing requirements required for oil sands and bitumen
- Ocean transport distances for delivery of crude oil.
- Varying processing requirements within the refinery for crude oils of different quality

Table ES-1 provides the resulting WTT GHG emissions for diesel production divided into the key activities that are influenced by crude oil source. Differences between crude oil extraction practices have the greatest upward impact on the WTT GHG emissions by crude oil source with less variation due to refining and transport requirements.

Table ES-1. Crude Oil Source-Specific GHG Emissions for Diesel

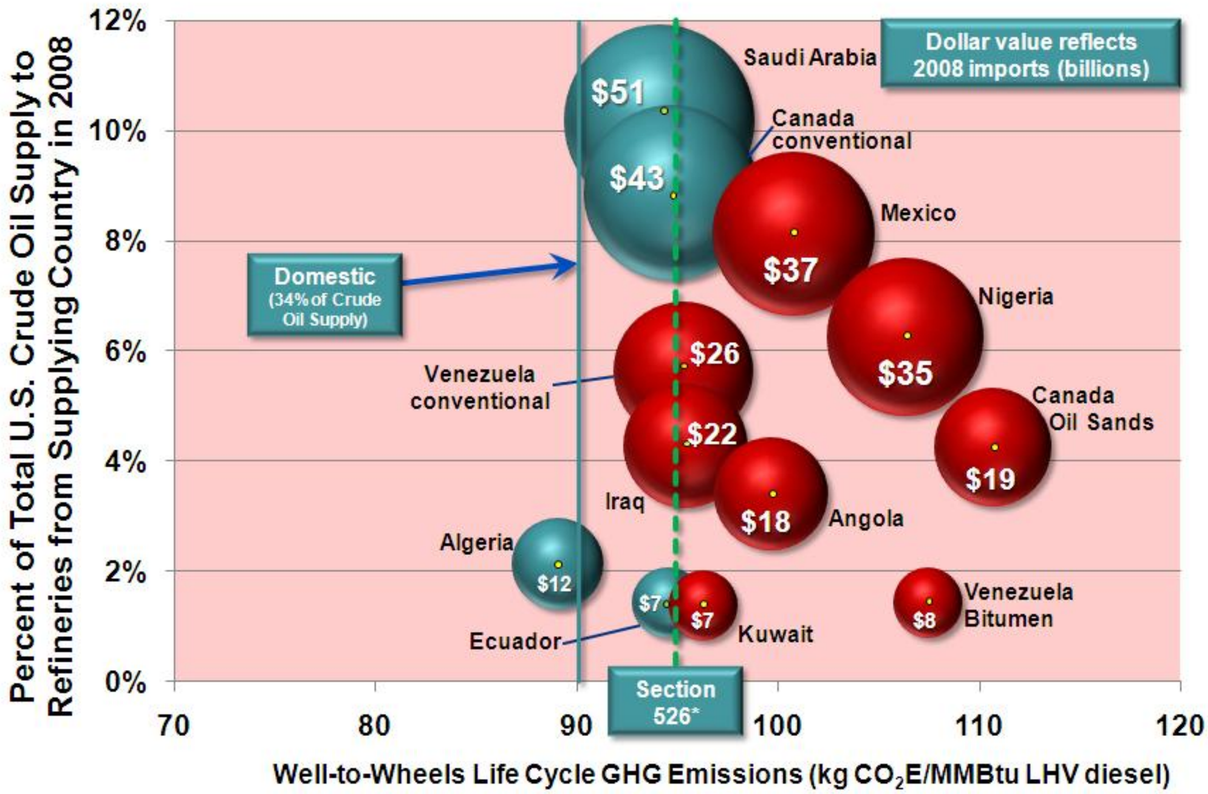
Crude Oil Source	Crude Oil Extraction and Pre-Processing	Crude Oil Transport	Diesel Refining Operations	Finished Fuel Transport	Total Well-to-Tank
	kg CO_2E/MMBtu LHV diesel				
Canada Oil Sands	19.0	0.9	13.2	0.8	34.0
Venezuela Bitumen	16.3[1]	1.1	12.5	0.8	30.8[1]
Nigeria	22.0	1.7	5.1	0.8	29.7
Mexico	6.6	1.0	15.7	0.8	24.1
Angola	14.0	1.9	6.3	0.8	23.0
Kuwait	2.8	2.7	13.2	0.8	19.6
Iraq	3.3	2.7	11.8	0.8	18.7
Venezuela Conventional	4.1	1.1	12.5	0.8	18.6
Baseline WTT[2]	**6.6**	**1.3**	**9.5**	**0.9**	**18.4**
Canada Conventional	6.0	0.9	10.3	0.8	18.0
Ecuador	5.3	1.7	9.9	0.8	17.8
Saudi Arabia	2.3	2.7	11.6	0.8	17.4
Domestic	4.2	0.7	7.7	0.8	13.5
Algeria	6.0	1.5	4.0	0.8	12.4

[1] The GHG emissions estimate for extraction and pre-processing of Venezuela bitumen has greater uncertainty that other crude sources due to limited data availability. Uncertainty analysis provides a 90% confidence interval of 11 to 20 kg CO_2E/MMBtu LHV diesel for extraction and pre-processing and 25 to 35 kg CO_2E/MMBtu LHV of diesel for the WTT GHG emissions. The total effect of this uncertainty on the baseline WTT is approximately 1%.

[2] The baseline value is based on the NETL report, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008. The analysis in that report is consistent with the definition of "baseline lifecycle greenhouse gas emissions" for the production and use of transportation fuels for the baseline year 2005 in the Energy Independence and Security Act (EISA) of 2007. The baseline here includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile that has been determined in this analysis.

Evaluating the acquisition cost of imported crude oil provides an understanding of the magnitude of U.S. dollars that are spent on foreign crude oil relative to the resulting GHG emissions profile for transportation fuels from that crude oil. Figure ES-2 shows the 2008 crude oil acquisition costs by source relative to its contribution to the 2005 baseline GHG emissions profile for diesel fuel. $171 billion[1] was spent in 2008 on imported crude oil which results in GHG emissions greater than the 2005 U.S. average baseline for production of diesel. The top GHG emitters equate to import costs of $62 billion[1] which result in WTT GHG emissions more than twice that of production of diesel from domestic crude oil.

Figure ES-2. Crude Oil Source-Specific GHG Emissions for Diesel Relative to 2008 Acquisition Cost[1]



* Source: NETL report, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008
NETL Petroleum Baseline "Section 526" value is a proxy pending designation by the EPA Administrator according to EISA 2007

Changes to the GHG emissions profiles specific to each country's crude oil will occur over time. Since 2005, crude oil imports to the U.S. have become heavier and more sour increasing the gap between domestic crude oil and imported crude oil refining requirements. However, efficiency improvements in oil sands upgrading and start-up of liquified natural gas operations in Africa (which will reduce the flaring and venting of associated natural gas) could result in a future reduction of upstream GHG emissions for imported crude oil.

[1] Average refiner acquisition cost of crude oil in 2008 was $95/bbl. While crude oil price has fallen to $39/bbl for February 2009, the Energy Information Administration Annual Energy Outlook 2009 Early Release projects a 2030 imported crude oil price of $124/bbl.

1.0 Introduction

1.1 NETL Petroleum Baseline

The National Energy Technology Laboratory (NETL) has presented development and analysis of the life cycle greenhouse gas (GHG) emissions for U.S. consumption of petroleum-based fuels for the baseline year 2005 (NETL 2008). That report (herein referred to as the NETL Petroleum Baseline) describes the methodology utilized to determine the individual well-to-wheels (WTW) GHG emissions profiles for the fuels of interest: conventional gasoline (excludes oxygenates), conventional diesel (<500 ppm Sulfur) and kerosene-type jet fuel.

The study goal and scope were aligned to meet the definition of "baseline life cycle greenhouse has emissions" in the Energy Independence and Security Act (EISA) of 2007.

Figure 1-1 depicts the life cycle (LC) stages used in the NETL Petroleum Baseline analysis and in this report. LC stages 1-4 make up the well-to-tank (WTT) profile and includes both domestic and foreign extraction of refinery feedstock and fuels, transport to U.S. and foreign refineries (for imported finished fuels), processing of petroleum to produce transportation fuels, and transport to refueling stations. The WTW profile adds LC stage 5 – the fuel consumption in either a light-duty passenger vehicle or a jet aircraft.

Table 1-1 shows the GHG emissions for each fuel by LC stage as produced in the U.S. in terms of carbon dioxide equivalents (CO_2E) per million British thermal units (MMBtu) lower heating value (LHV). The WTT profile makes up 20% or less of the full life cycle WTW profile for each fuel.

Figure 1-1. Life Cycle System Boundary

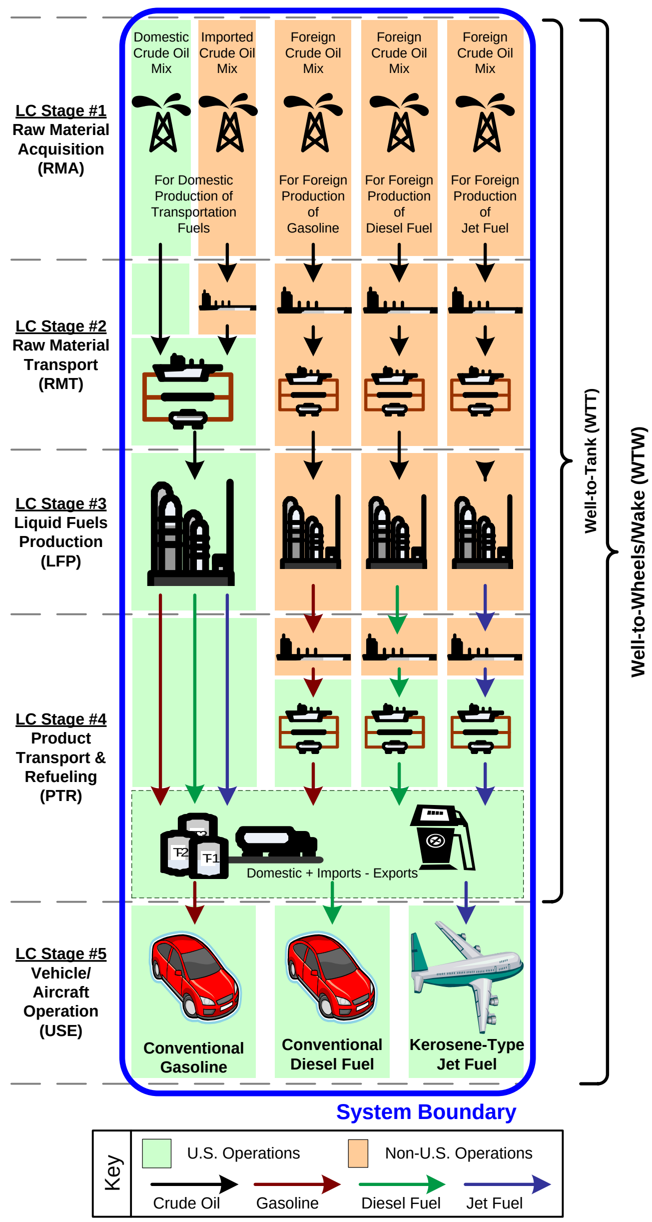


Table 1-1. Baseline Life Cycle Greenhouse Gas Emissions for Petroleum Transportation Fuels Consumed in the U.S. in the Year 2005

Life Cycle Stage	Conventional Gasoline	Conventional Diesel	Kerosene-Type Jet Fuel
	GHG Emissions (kg CO_2E per MMBtu LHV)		
#1: RMA	7.3	6.6	6.8
#2: RMT	1.4	1.3	1.3
#3: LFP	9.8	9.5	6.0
#4: PTR	1.1	0.9	1.0
#5: Use	76.6	76.7	77.7
Total: WTT	19.6	18.4	15.1
Total: WTW	96.3	95.0	92.9

1.2 Goal of Study

This analysis estimates the contribution of the crude oil sources (primarily by country of origin) to the 2005 baseline GHG emissions profile for each transportation fuel. Crude oil extraction and pre-processing needs, transport distances, and refining requirements (based on API gravity and sulfur content) were evaluated to determine their impact on the GHG emissions profiles for each transportation fuel.

1.3 Scope of Analysis

The NETL Petroleum Baseline analysis estimates the industry average GHG emissions associated with each fuel for 2005. Primary data on the industry in the time frame desired was extracted from a variety of published, respected and verified sources to depict the activities and associated GHG emissions of the industry. This subsequent analysis breaks down that baseline life cycle GHG emissions estimate by crude oil source, thus estimating the contribution of each source to the industry average. This analysis does not attempt to model or provide the GHG emissions associated with the marginal production of each transportation fuel.

The life cycle boundary extends from raw material extraction from the earth to combustion of the fuel in a vehicle or aircraft. Data excluded from the system boundary include construction related emissions, humans involved in the system boundary, and low frequency, high magnitude environmental events (e.g. accidental releases).

This life cycle inventory is limited to GHG emissions and considers only the global warming potential (GWP). Carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) were identified as the three forms of GHG emissions that have environmental relevance to the total life cycle of petroleum-derived transportation fuels. The 2007 IPCC 100-year GWPs in CO_2E for each greenhouse gas shown in Table 1-2 were used for this study.

Table 1-2. GHG Emissions Included in Study Boundary and their 100-year GWP

Emissions to Air	Abbreviation	2007 IPCC (GWP CO_2E)
Carbon Dioxide	CO_2	1
Methane	CH_4	25
Nitrous Oxide	N_2O	298

This analysis conform to the International Standards Organization (ISO) 14040 and 14044 life cycle assessment standards. ISO standards, where appropriate, are used as guidelines in performing data reductions and allocation procedures. In determining the GHG emissions associated with each of the various petroleum refining co-products, unit process division and system expansion were used to the extent possible prior to allocation as recommended within ISO 14044 (ISO 2006).

2.0 Modeling Methodology and Assumptions

The modeling conducted for the NETL Petroleum Baseline analysis was used as a basis for this study. LC Stages #1, 2 and 3 were evaluated individually to determine the impact of feedstock source while LC Stage #4 (product transport and refueling) and LC Stage #5 (vehicle/aircraft use) were assumed to have GHG emissions independent of the source of the crude oil.

2.1 Petroleum Feedstock Sources

U.S. petroleum refineries had a 2005 feedstock mix of 62% imported crude oil, 32% domestic crude oil and 6% natural gas liquids (NGL) and unfinished oils as reported by refiners to the Department of Energy (DOE) Energy Information Administration (EIA). Table 2-1 shows the quantities in thousand barrels per day (MBPD) of crude oil imported by the U.S. from each of the top ten countries as well as the other inputs to U.S. refineries in 2005.

Table 2-1. Source and Quantity of Feedstock Input to U.S. Refineries in 2005 (EIA 2008)

Feedstock Source	Input to U.S. Refineries (MBPD)
Canada	1,629
Mexico	1,551
Other Imports	1,452
Saudi Arabia	1,436
Venezuela	1,235
Nigeria	1,075
Iraq	522
Angola	455
Ecuador	276
Algeria	228
Kuwait	222
Domestic Crude Oil	5,140
NGL and Unfinished Oils	1,001
Total	16,221

2.2 LC Stage #1: Raw Material Acquisition

Country-specific crude oil extraction emissions profiles for the U.S. and top ten countries importing crude oil to the U.S. in 2005 were purchased from PE International for incorporation into GaBi 4 (2007) and utilized in the NETL Petroleum Baseline analysis (excluding Canada). Additional analysis was conducted to provide an estimate for the GHG emissions associated with NGL and unfinished oils production, extraction of conventional Canadian crude oil and production of blended or synthetic crude oil from Canadian oil sands. This prior analysis provides a ready breakdown of the emissions associated with raw material acquisition by country. Further analysis in this study refines the Venezuelan profile.

The following two factors significantly impact these profiles: 1) flaring and venting associated with crude oil extraction; and 2) extraction and pre-processing requirements of crude bitumen/oil sands prior to receipt at U.S. refineries.

2.2.1 Associated Natural Gas Flaring and Venting

The CO_2 and methane emissions profiles are highly dependent on the venting and flaring of associated hydrocarbons during crude oil extraction as shown in Figure 2-1 and Figure 2-2. This is especially apparent in the African countries of Nigeria and Angola. Angola flares and vents 75% of its natural gas production while the World Bank estimates that Nigeria accounts for 12.5% of all natural gas flared or vented in the world. While plans have existed in both countries to develop or expand liquefied natural gas (LNG) production, little reduction in flaring and venting has occurred in recent years. In contrast, the African country of Algeria, with a much lower GHG emissions profile, is the fourth highest LNG exporter in the world (EIA 2009a).

Figure 2-1. Country-Specific CO_2 Emissions Associated with Crude Oil Extraction Relative to Flaring of Hydrocarbons (NETL 2008)

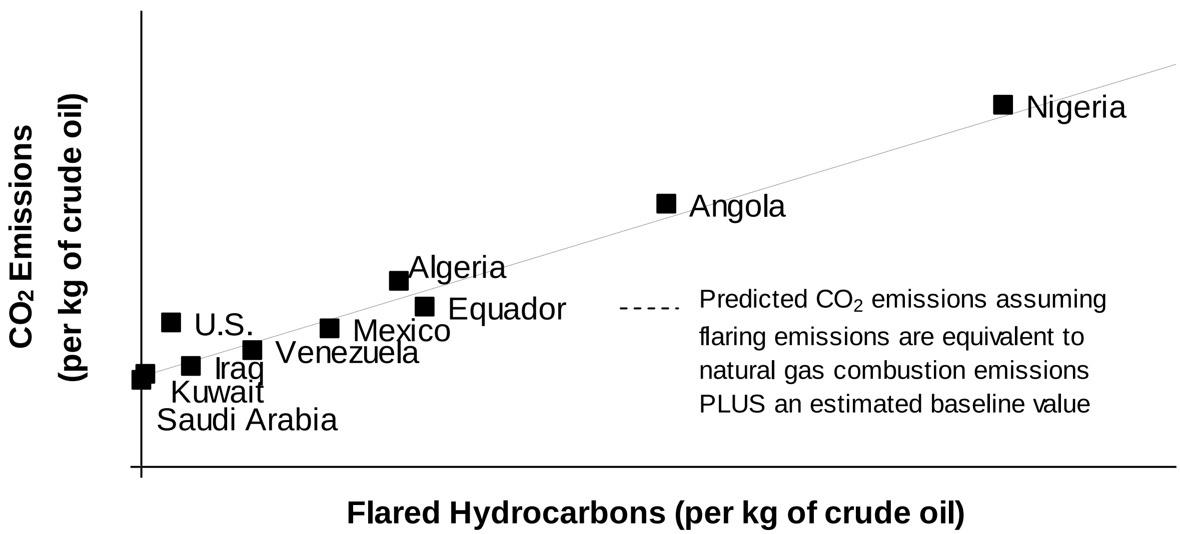
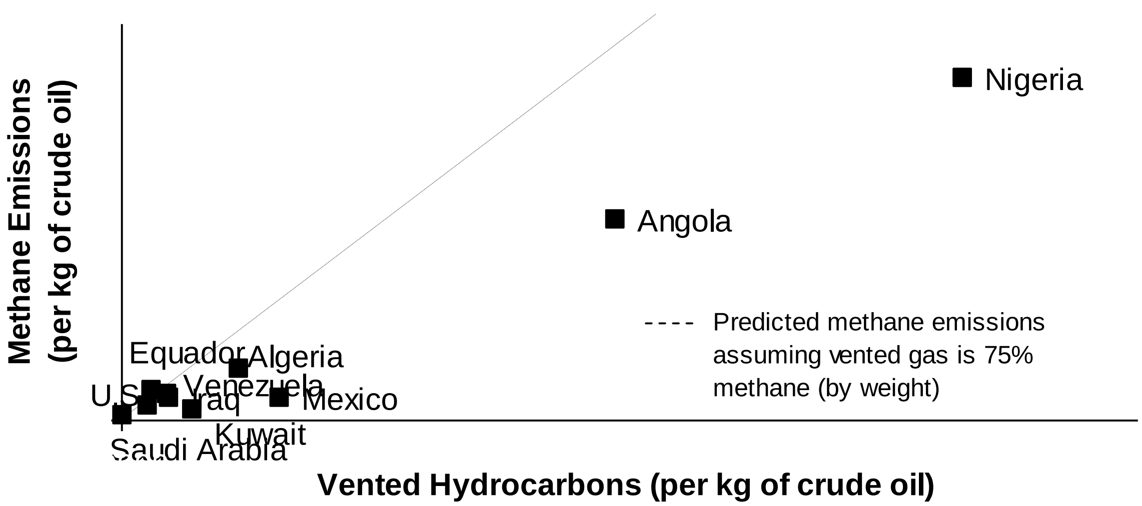


Figure 2-2. Country-Specific Methane Emissions Associated with Crude Oil Extraction Relative to Venting of Hydrocarbons (NETL 2008)



2.2.2 Bitumen Extraction and Upgrading

Hydrocarbon deposits called bitumen are located in Venezuela and Canada and U.S. refineries are key destinations to refine the oils that are produced from these resources. This dense tar-like material is also referred to as oil sands in Canada and extra- or ultra-heavy crude oil in Venezuela. The bitumen must be mined, separated from the sand and other minerals and either blended with a light oil or upgraded to create a synthetic crude (using heat, pressure, hydrogen and/or catalysts to crack the larger molecules into smaller molecules) so that it can be transported and processed by existing refineries. The GHG emissions associated with the entire process are significantly higher than for extraction of conventional crude oil (where venting and flaring of associated gas is minimized).

Canada Oil Sands

Estimates of 2005 emissions associated with Canadian oil sands production and volumes received by the U.S. as reported in the NETL Petroleum Baseline are shown in Table 2-2. The original 7º to 10º API bitumen has been blended or upgraded to the delivered refinery feedstock which is 20º to 33º API (CM.ca 2009).

Table 2-2. 2005 Quantity to the U.S. and GHG Emissions Associated with Extraction and Processing of Canadian Oil Sands (NETL 2008)

	Input to U.S. Refineries (MBPD)	Emissions (kg CO_2E/barrel upgraded bitumen)
Crude Bitumen	227	81
Light Synthetic Crude from Oil Sands	187	134
Heavy Synthetic Crude from Oil Sands	113	
Total/Weighted Average	**528**	**111**

Venezuela Heavy Oils

In the NETL Petroleum Baseline study, it was noted that the Venezuela crude oil GHG emissions profile as purchased from PE International did not appear to be consistent with the expected emissions associated with bitumen upgrading occurring in that country. While Canadian oil sands data is readily available, similar information for Venezuela is limited. For the NETL Petroleum Baseline, the extraction profile was used as provided from PE International, but a sensitivity analysis was conducted to determine the impact if 25% of the Venezuelan crude oil had a profile similar to that of the Canadian oil sands mix consumed in the U.S. The result of the sensitivity analysis was within the appropriate bounds for the *baseline* value.

Further analysis has been completed as part of the study to estimate the volume of Venezuelan heavy-oil production that was received by the U.S. in 2005 and the associated GHG emissions. Table 2-3 shows the production capacity and other quality data for the four strategic associations which have been charged with developing these resources in Venezuela. EIA estimates Venezuela's 2005 total crude oil production at 2.6 million barrels per day (includes upgraded bitumen); therefore the blended bitumen and synthetic crude oil represent roughly 20% of Venezuela's crude oil production. Venezuela has the capacity to refine a significant portion of its own crude oil with a refining capacity in 2005 of 1.28 million barrels (OGJ 2005). At the same time, imports to the U.S. of Venezuelan crude oil in 2005 were 1.24 million barrels per day or nearly half of the Venezuelan production. As many U.S. Gulf Coast refineries are specifically configured to handle Venezuelan heavy crude varieties (EIA 2009a), it is expected that at least a proportional quantity (20%) of the U.S. imports from Venezuela is upgraded bitumen.

Table 2-3. Venezuelan Bitumen Mining and Upgrading Association Data (EIA 2009a)

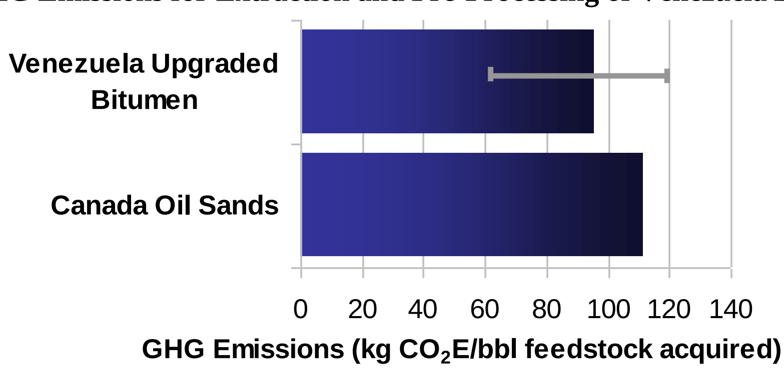
		Orinoco Belt Strategic Associations			
		Petrozuata	**Cerro Negro**	**Sincor**	**Hamaca**
Partners (percent)		PdVSA (100)	PdVSA (83), BP (16)	PdVSA (60), Total (30), Statoil (10)	PdVSA (70), Chevron (30)
Startup Date		Oct 1998	Nov 1999	Dec 2000	Oct 2001
Extra-Heavy Crude Production	MBPD	120	120	200	200
	API	9.3º	8.5º	8º-8.5º	8.7º
Synthetic Crude Production	MBPD	104	105	180	190
	API	19º-25º	16º	32º	26º

Published analysis on Venezuelan bitumen mining and upgrading operations and associated GHG emissions is limited; however, there is enough information available to indicate that the process is not identical to Canada's. While Canada and Venezuela bitumen have similar API gravity (7º-10º), Venezuela's bitumen has a much lower viscosity and a greater reservoir temperature than does Canada's. This means that mining in Canada often requires heating of the reservoir using steam to make the bitumen flow while Venezuela can use lower-energy-intensive-cold production (Total 2002). At the same time, environmental policy and performance for Venezuela are generally lower than for Canada. The 2005 Energy Sustainability Index ranks Venezuela 82nd with the U.S. at 45th and Canada at 6th. Relative to Canada, Venezuela ranks lower in the categories of environmental governance, efficiency and private sector responsiveness, all of which could impact the efficiency and environmental consciousness of bitumen mining and upgrading operations (Yale 2005).

Published data that does compare the GHG emissions of the two processes lacks the transparency and detail to evaluate the quality and methodology. In a 2002 presentation file, Total, which has a 30% stake in the Venezuela SINCOR strategic association, indicated that, with "current technology," the CO_2 emissions for mining and upgrading of Venezuela bitumen would be 40 to 60% of that for Canadian bitumen (no data on other greenhouse gases). Countering this data, in a 2001 report to the Canadian Regional Infrastructure Working Group, McCann reports that the upstream GHG emissions associated with producing synthetic crude are roughly 7% higher with Venezuela bitumen relative to Canadian bitumen. His Venezuelan analysis was based on modeling of the Petro Zuata project with a field balance conducted by an early participant in the project.

Uncertainty analysis determined the 90% confidence interval (CI) for the Venezuelan upgraded bitumen extraction profile shown in Figure 2-3. Similar analysis was used to determine the fraction of the crude oil received by the U.S. that is conventional crude oil. These analyses are detailed in Appendix B.

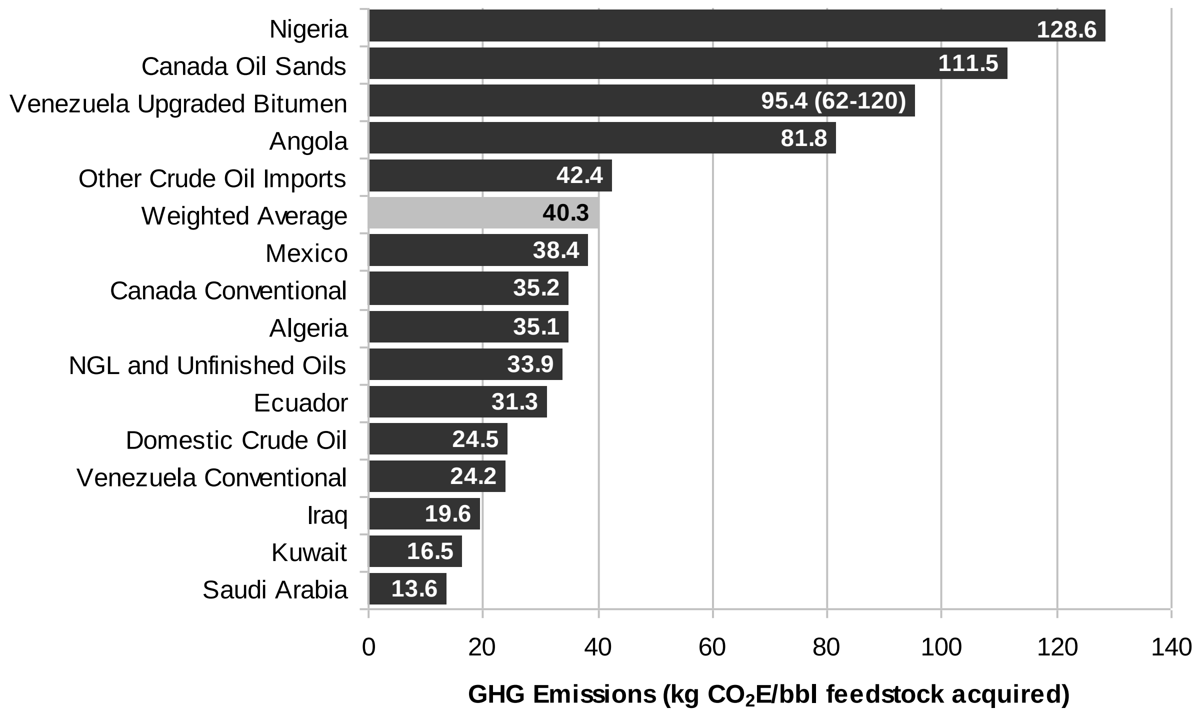
Figure 2-3. GHG Emissions for Extraction and Pre-Processing of Venezuela Bitumen (90% CI)



2.2.3 LC Stage #1 Emissions by Feedstock Source

Utilizing the emissions profiles from the original NETL Petroleum Baseline analysis and the updated Venezuelan bitumen profile, the GHG emissions profiles for raw material acquisition by feedstock source are shown below. The average Venezuela upgraded bitumen profile is shown with the 90% CI in parentheses, the conventional Venezuelan crude oil is assumed to have a profile equivalent to that provided by PE International, and the weighted average includes the impact of the new Venezuelan profile.

Figure 2-4. GHG Emissions Profiles for Refinery Feedstock Extraction and Pre-Processing by Source



2.3 LC Stage #2: Raw Material Transport

In the NETL Petroleum Baseline analysis, crude oil transport was divided into the three categories below:

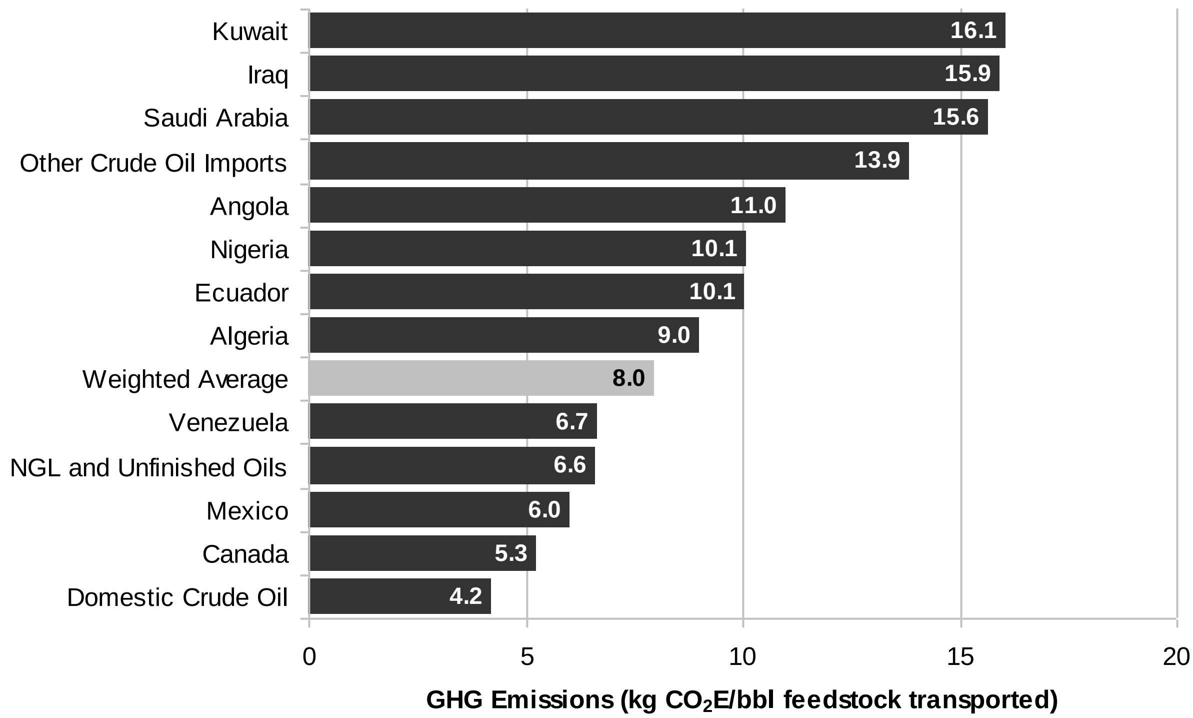
- Transport from point of extraction to port or border was assumed to be by pipeline for 100 miles.
- Transport from foreign port to U.S. port was by ocean tanker with transport distances determined by Portworld.com with no travel allowed through the Panama and Suez canals.
- Transport from U.S. port to refineries and transport of domestic crude oil within the country by a mix of water, rail, truck and pipeline were equally weighted.

Table 2-4 shows the average GHG emissions per barrel transported to the U.S. For this study, it is assumed that the in-country transport (both foreign and domestic) GHG emissions are independent of the country of origin. The original ocean tanker transport distances and emissions factors for each country were added to the in-country transport emissions resulting in the individual profiles shown in Figure 2-5.

Table 2-4. GHG Emissions Associated with Crude Oil Transport (NETL 2008)

Emissions Source	Emissions (kg CO_2E/barrel transported by this mode)
Transport Within Exporting Country	0.89
Ocean Tanker Transport to U.S. Port	5.61
Transport Within U.S.	4.20
Weighted Total for All Crude Oil Input to U.S. Refineries	**8.08**

Figure 2-5. GHG Emissions Profiles for Refinery Feedstock Transport by Source



2.4 LC Stage #3: Liquid Fuels Production

Crude oil properties impact the amount of processing and energy input required and the resulting GHG emissions from refining operations. For this analysis, heuristics were developed to approximate the relationship between crude oil properties and certain refinery processing steps. This section addresses development, application and limitation of these heuristics. Note that no process modeling was conducted as part of this analysis to try to simulate a refinery that would process 100% of a given crude oil type and the results of this analysis are not intended to estimate the refinery GHG emissions should such a refinery exist.

The crude oil properties and refinery processes for which the impact is modeled are shown in Table 2-5. The portion of the LC Stage #3 GHG emissions that these processes account for in the NETL Petroleum Baseline by product type is also provided. This table shows that, for diesel, 35% of the GHG emissions are due to the operations that process and upgrade the heavy portion of the crude oil and 43% of the GHG emissions are due to the sulfur removal processes.

Table 2-5. Refinery Processes Modeled to be Impacted by Variations in Crude Oil Properties and Percentage of LC Stage #3 GHG Emissions Attributable to Each Process

Crude Oil Property	Impacted Refinery Process	Percentage of Each Fuel's LC Stage #3 GHG Emissions Attributable to Process		
		Gasoline	Diesel	Jet Fuel
API Gravity	Vacuum Distillation	9%	8%	3%
	Coking	1%	7%	3%
	Fluid Catalytic Cracking	19%	11%	4%
	Hydrocracking	2%	2%	3%
	Production of Hydrogen for Hydrocracking	6%	7%	10%
Sulfur	Hydrotreating	7%	11%	12%
	Production of Hydrogen for Hydrotreating	18%	32%	28%

API gravity and sulfur content are elementary indicators of crude oil quality, but were selected for use in this analysis because they are readily available for U.S. refining operations. Crude oil grades with the same API gravity and sulfur will in reality have different refinery processing requirements as they will have a different volume distribution between each fraction (i.e. naphtha, distillate, gas oil, residuum) and will have sulfur that is more or less difficult to remove.

2.4.1 Properties of Crude Oil to U.S. Refineries

EIA collects and reports the country of origin, volume, API gravity and sulfur content for each shipment of crude oil imported into the U.S. (EIA 2009b). Table 2-6 shows the average of these qualities for the crude oil received from each country in 2005. The annual average API gravity and sulfur content of the crude oil fed to U.S. refineries reported by EIA along with the import data was used to estimate the properties of domestic crude oil processed by U.S. refineries in 2005.

The properties of upgraded Canadian oil sands were estimated separately (CM.ca 2009) and the Canadian conventional crude oil properties were then calculated based on the average properties for all Canadian crude oil received. Venezuelan upgraded bitumen was assumed to have the same average properties of conventional Venezuelan crude oil. While the Venezuelan bitumen itself is heavier and may have higher sulfur, the API gravity and sulfur content of the upgraded bitumen is expected to be similar to the overall average properties of Venezuelan crude oil received by the U.S. in 2005.

Table 2-6. Average API Gravity and Sulfur Content of Crude Oil As Received by U.S. Refineries in 2005 by Country of Origin

Crude Oil Source	Crude Oil Input to U.S. Refineries (MBPD)	Average API Gravity	Specific Gravity	Average Sulfur Content (wt%)
Canada Conventional	1,101	28.7	0.88	1.56
Canada Oil Sands	528	24.5	0.91	2.25
Mexico	1,551	23.8	0.91	3.01
Saudi Arabia	1,436	31.6	0.87	2.23
Venezuela	1,235	22.6	0.92	1.86
Nigeria	1,075	35.7	0.85	0.22
Iraq	522	30.9	0.87	2.25
Angola	455	32.0	0.87	0.40
Ecuador	276	22.8	0.92	1.03
Algeria	228	44.8	0.80	0.12
Kuwait	222	29.6	0.88	2.63
Other Crude Oil Imports	1,452	31.8	0.87	0.60
Domestic Crude Oil	5,140	32.8	0.86	0.96
Overall	15,220	30.2	0.88	1.42

2.4.2 Specific Gravity Heuristics

Density of the crude oil will impact the energy requirements for processing of the crude oil. Catalytic cracking, hydrocracking, coking and vacuum distillation were anticipated to be the primary processing units impacted by the specific gravity of the crude oil. The hydrogen production associated with hydrocracking was also included.

Figure 2-6 shows the relationship between coking throughput and catalytic cracking and hydrocracking throughput (relative to crude oil input quantity) and the specific gravity of crude oil. Each point represents a monthly average for a major refining district in the U.S. since 2000 (EIA 2009b). Catalytic cracking and hydrocracking were combined as refineries often use one or the other as their primary gas oil fraction upgrader. It is assumed in this analysis that hydrocracking is only for conversion purposes and is not being used for sulfur removal. This is noted as a limitation of the analysis.

Figure 2-7 shows the relationship between vacuum distillation capacity (actual throughput is not available) relative to the crude oil input and specific gravity of crude oil input. Each point represents an annual average for PADDs 1, 3, and 5 in the U.S. since 1998 (EIA 2009b).

The slope of the linear regression lines on the figures represents the ratio of the throughput as a percentage of crude oil input to the specific gravity. The resulting heuristic, for example, is that for every one-hundredth specific gravity point above the 2005 average, the coking throughput relative to crude oil input will be 3.4 percentage points higher. These three heuristics were combined with the modeled fraction of the LC stage #3 emissions attributable to each processing unit (Table 2-5) to determine the total percentage difference between the baseline and the country-specific profile. For Algeria, the heuristic resulted in a negative coking capacity. This was adjusted to zero.

Figure 2-6. Relationship Between Refinery Upgrader Throughput and Specific Gravity

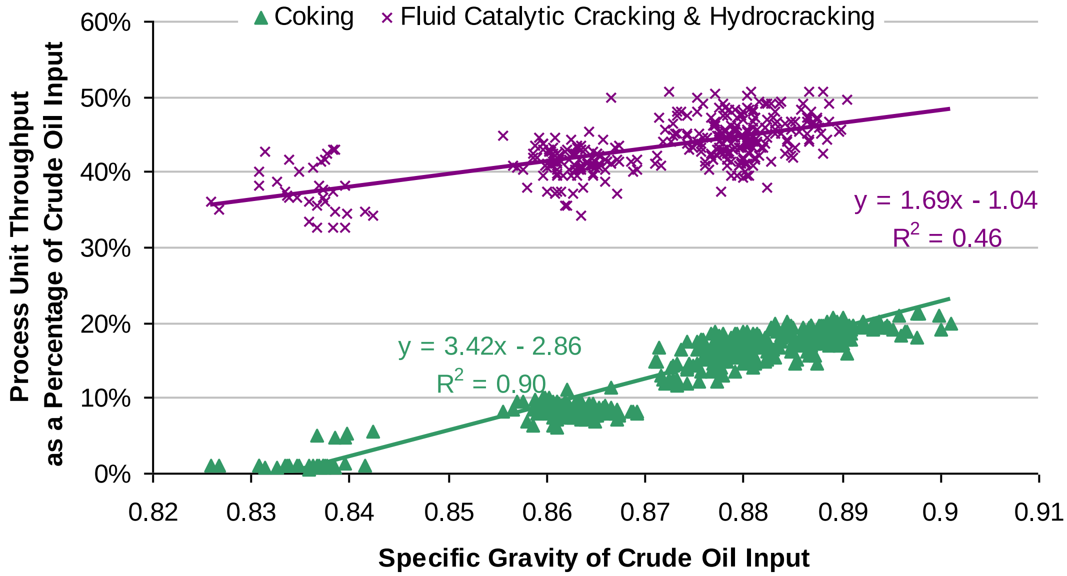
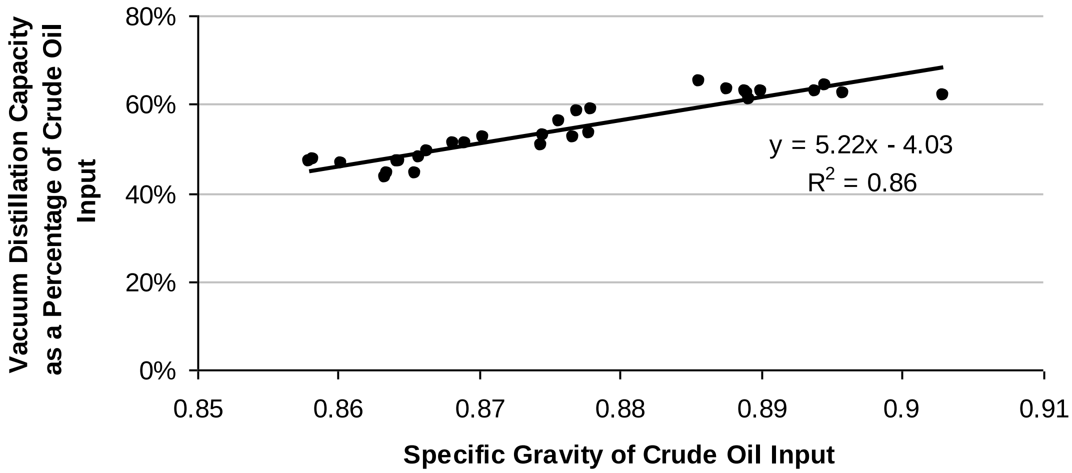


Figure 2-7. Relationship Between Vacuum Distillation Capacity and API Gravity

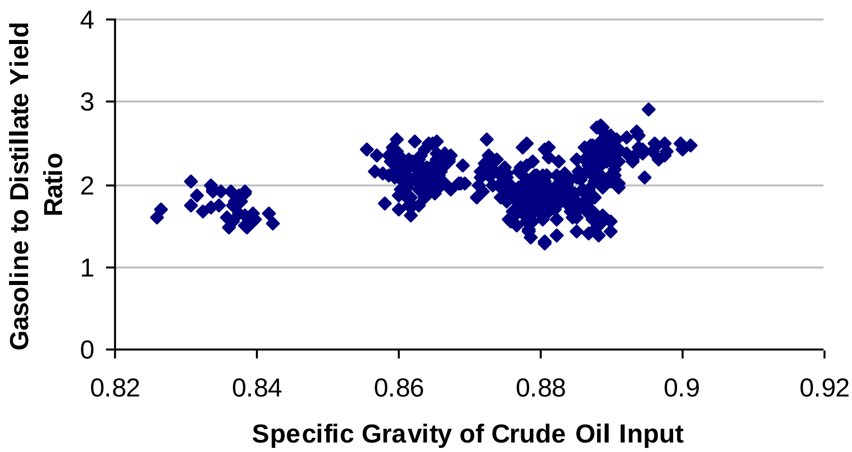


Key assumptions and limitations in this modeling approach are as follows:

- As previously noted, the average density of the crude oil provides no information on the specific distillation of the crude oil. For blended synthetic crude oils in particular, it is likely that there is a significantly larger fraction of a residuum (which would be sent to a coker) and a large fraction of lighter molecules originating as condensate. In contrast, synthetic crude oil may have very little residuum or light ends. The impact of this was not evaluated.
- The API gravity range for developing the heuristics was between 25 and 40 (smaller range for vacuum distillation). Several countries fall outside of this range thus increasing the uncertainty of this process for those countries.

- As in the original NETL Petroleum Baseline analysis, refinery GHG emissions exist in a "pool." No attempt is made to determine what the source of fuel and the associated upstream and combustion emissions are for each refinery process unit.
- A linear relationship is assumed between the volumetric throughput and the energy requirement for a process unit. If a particular crude grade only uses 10% of the vacuum distillation capacity compared to the baseline average, the energy usage and associated emissions are exactly 10% of the vacuum distillation baseline average energy usage and associated emissions.
- No adjustment was made for atmospheric distillation operations. For varying crude oil densities, more or less energy may be required for this initial separation that occurs in this process.
- The ratio between transportation fuels and other heavy products (coke, fuel oil, other heavy ends) will vary with crude oil density. Estimates using historical data indicate a ~1% yield shift to the heavier products for each API degree shift downward. However, the impact on the profile due to this new mix of products going through each processing unit will not significantly impact the LC stage #3 results. Analysis showed that even for countries with very heavy and very light crude oil, the impact would be <2% of the LC stage #3 profile.
- It was assumed that the ratios between gasoline/diesel/jet fuel will not vary significantly with the crude oil density. Figure 2-8 shows the relationship between specific gravity of the crude oil input and the gasoline to distillate yield ratio. The spread of the data for varying specific gravities suggests that this assumption is reasonable.

Figure 2-8. Relationship Between API Gravity and the Gasoline to Distillate Yield Ratio



2.4.3 Sulfur Heuristics

Sulfur content of the crude oil will impact the requirements for hydrotreating and the associated production of hydrogen at refineries. A simplistic approach was used for this analysis. The ratio between the average amount of sulfur in the country-specific crude oil to the 2005 average sulfur content was used to determine the relative increase in hydrotreating and associated hydrogen production. For example, if the sulfur content for a source of crude oil is two times higher than the average, then the hydrotreating and hydrogen requirements (and associated emissions) are twice as high. This information was then combined with the modeled fraction of the LC stage #3 emissions attributable to the hydrotreating and hydrogen production (Table 2-5) to determine the total percentage difference between the baseline and the country-specific profile.

This simplification does not consider the following two trends:

- Heavier hydrocarbons will contain sulfurs that are more difficult to remove and will consume more hydrogen relative to the sulfur content due to hydrogenation and require higher pressure and temperature hydrotreating (and thus more energy).
- A higher concentration of the sulfur will exist in heavier fractions of a given crude oil, thus some will leave the system in the coke/fuel oil and will not require hydrogen or processing to remove it.

These two items have the opposite effect, but are by no means equal. The level of this analysis and availability of information did not allow these two factors to be quantified.

2.4.4 LC Stage #3 Emissions by Feedstock Source

Figure 2-10 shows the resulting feedstock-source-specific GHG emissions profiles for LC Stage #3 activities. The gasoline profiles are more dependent on the density of the crude oil quality due to gasoline's lower reliance on hydrotreating, and diesel has the greatest variability (+64%) as 78% of its LC Stage #3 emissions are attributable to the modeled upgrading and hydrotreating activities.

Mexico, which exports heavy, high sulfur crude oil to the U.S., has the highest GHG emissions associated with refining operations. Persian Gulf crude oil grades, Canadian oil sands and Venezuela crude oil make up the next highest contributors to LC Stage #3 emissions. The order in which they appear vary between the fuels based on the fuel's upgrading and sulfur removal requirements. Persian Gulf crude oil grades have a mid-level density, but have relativity high sulfur content. Canadian Oil Sands are heavier and have similar sulfur content to Saudi and Iraqi crude oil grades, but lower sulfur than Kuwait crude oil. Venezuela imports to the U.S. are the heaviest of any source, but the average sulfur content is lower than the Persian Gulf crude oils. Domestic crude oil falls lower than the baseline value and the other end of the spectrum is represented by the African crude oil grades which are both light and have the lowest sulfur content.

Figure 2-9 shows the impact of density and sulfur content on the LC Stage #3 GHG emissions for representative light-sweet crude oil (Algeria) and heavy-sour crude oil (Mexico) relative to the U.S. average. The base activities represent those refining operations that are not part of sulfur removal or upgrading heavy fractions of oil.

Figure 2-9. LC Stage #3 GHG Emissions for Representative Light, Low Sulfur and Heavy, High Sulfur Crude Oil

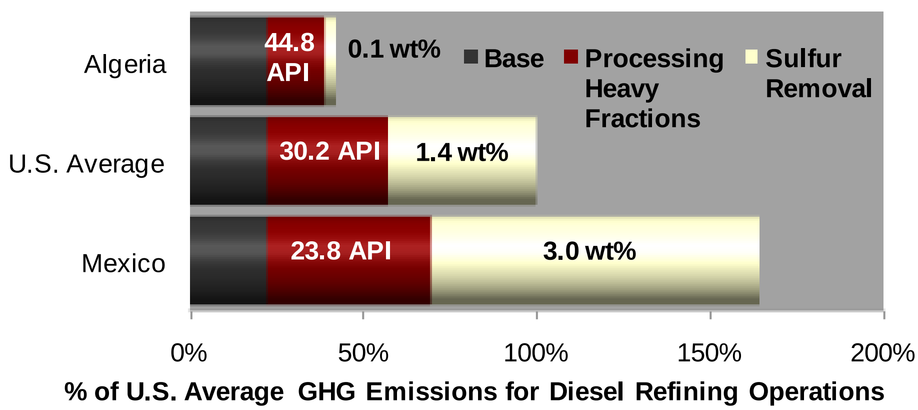
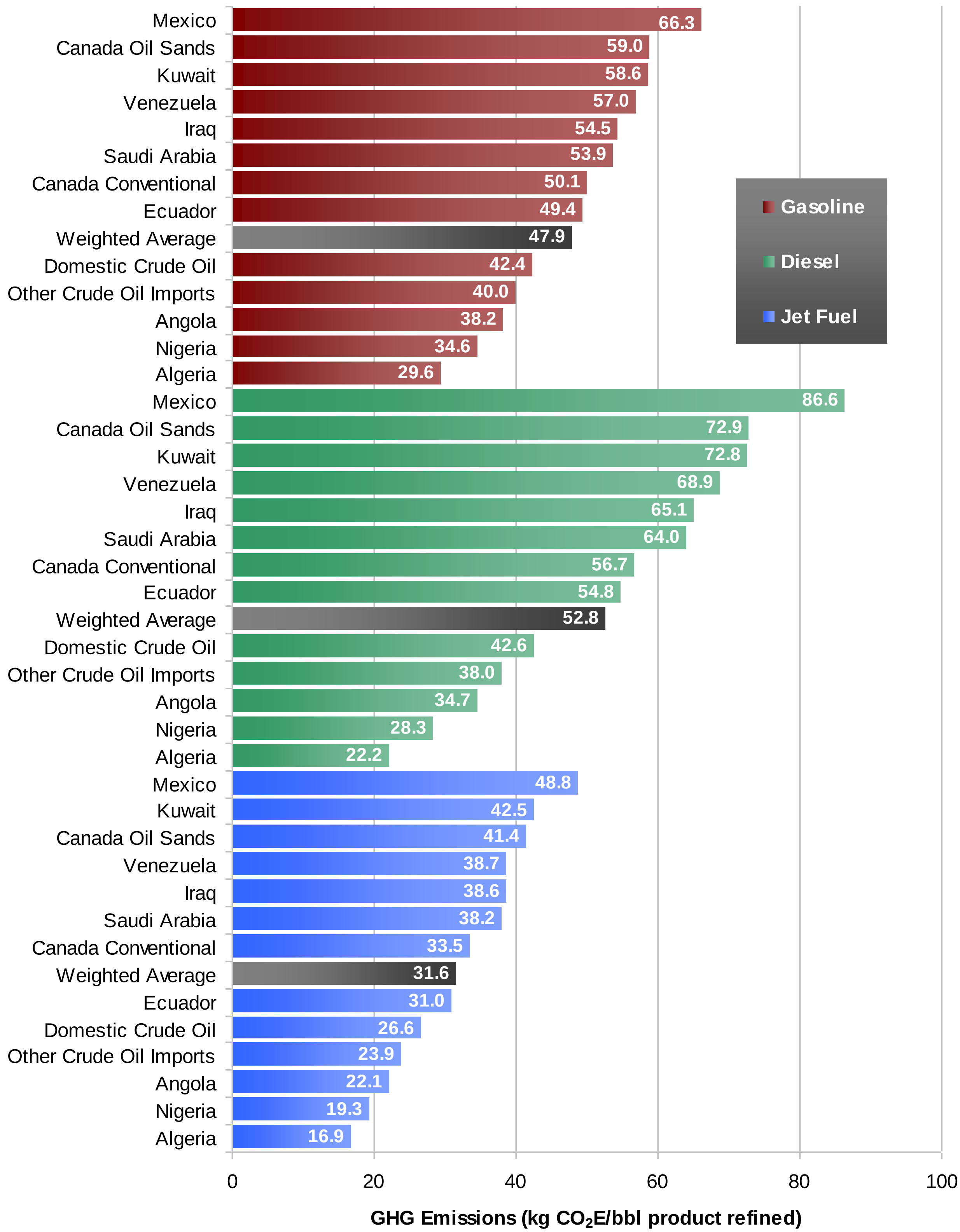


Figure 2-10. GHG Emissions Profiles for Liquid Fuels Production by Feedstock Source



3.0 Results and Discussion

The feedstock-source-specific GHG emissions profiles for LC Stages #1 through #3 presented in subsequent sections are converted to MMBtu LHV of fuel consumed using the refining feedstock conversion factors, loss factors and heating values presented in the NETL Petroleum Baseline analysis. LC Stage #4, product transport, and refueling and LC Stage #5, fuel use, are considered constant.

The contribution of each feedstock source to the WTT profile for conventional diesel fuel is shown in Figure 3-1 and Table 3-1 by LC stage and in Table 3-2 by GHG component. Raw material extraction has the greatest upward impact on the GHG emissions with upgraded bitumen operations in Canada and Venezuela at the top followed by countries that have greater flaring and venting associated with their crude oil extraction (Nigeria and Angola). While Algeria and Mexico have similar LC Stage #1 GHG emissions, they fall at the opposite ends of the figure as Mexico's heavy sour crude oils require more processing than do Algeria's light, sweet crude oils. Imported crude oil on average has a profile that is 59% greater than the domestic crude oil WTT GHG emissions profile for production of diesel fuel. Figure 3-2 shows the WTT profiles relative to their input to U.S. refineries.

The WTT profile has been examined as the variability for feedstock source will not be apparent in the combustion of the fuel. However, the WTT profile makes up only 20% of the baseline full life cycle profile. Figure 3-3 shows the full WTW feedstock-source-specific GHG emissions profile for diesel fuel by LC stage incorporating the LC Stage #5 value of 76.7 kg CO_2E/MMBtu LHV of diesel.

Results for conventional gasoline and kerosene-type jet fuel are provided in Appendix A.

Figure 3-1. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Diesel

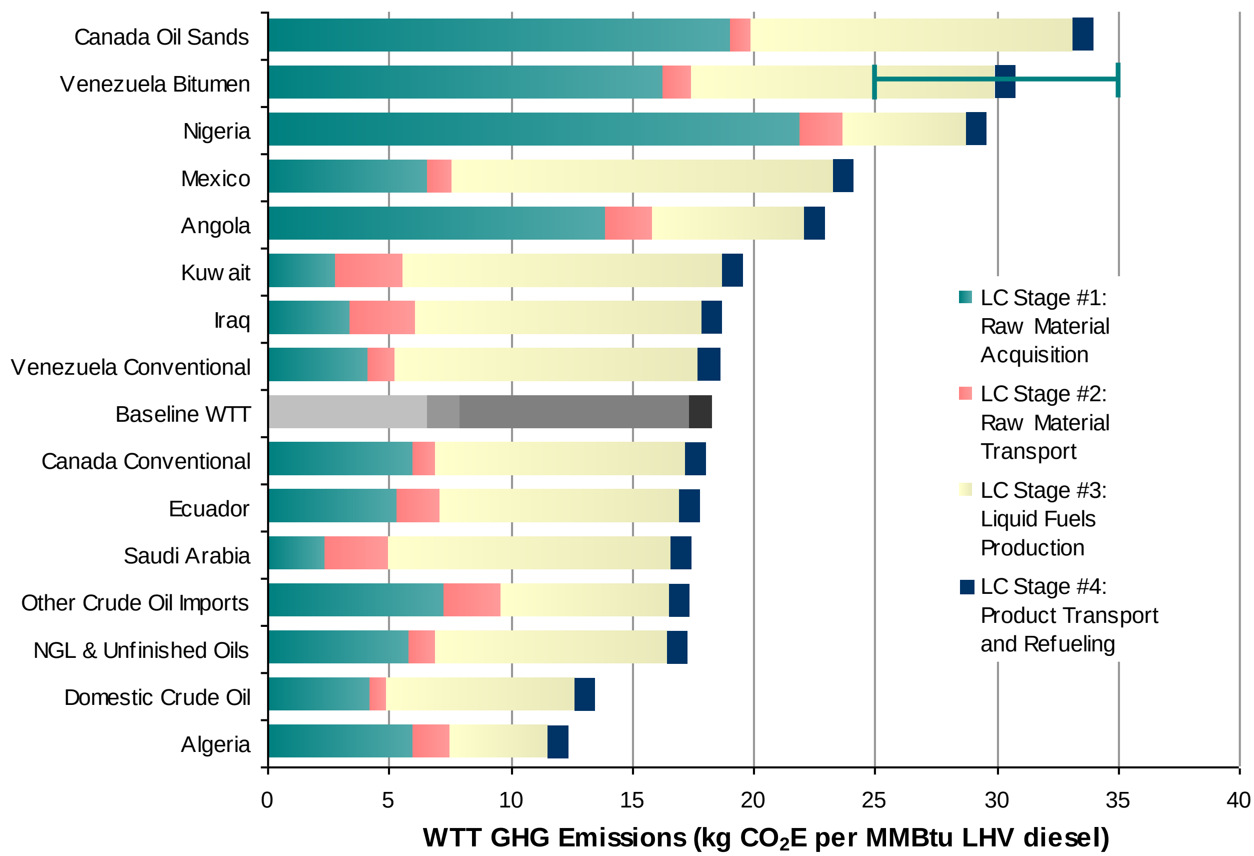


Figure 3-2. Contribution of Feedstock Source to the 2005 Baseline GHG Emissions for Diesel Relative to 2005 Input to U.S. Refineries

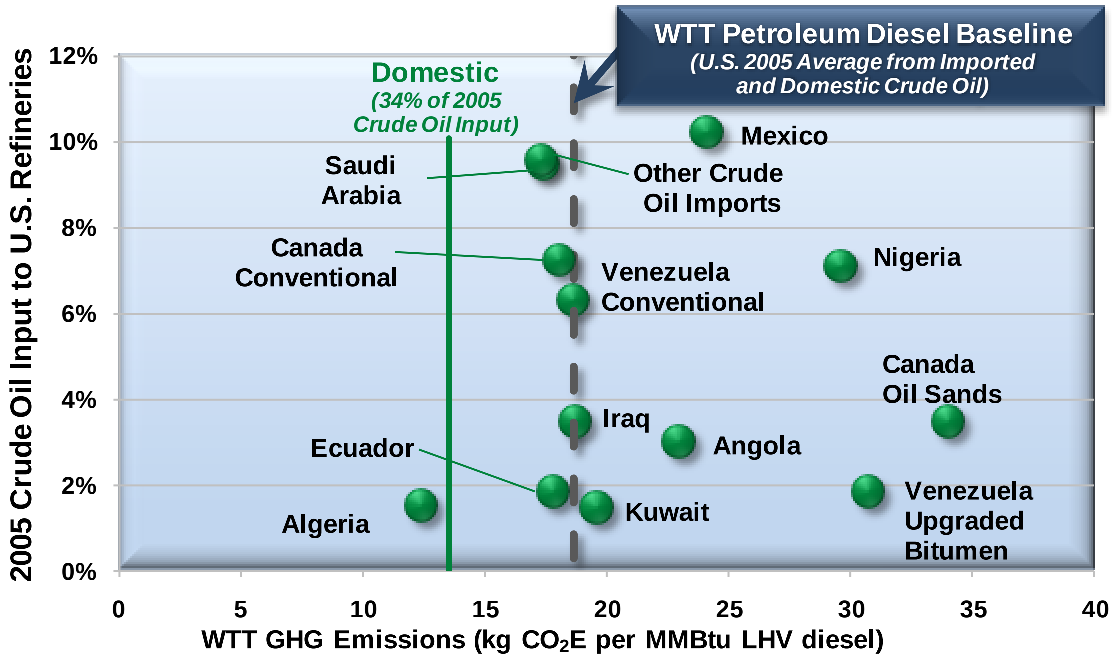


Figure 3-3. Contribution of Feedstock Source to the 2005 Baseline WTW GHG Emissions for Diesel

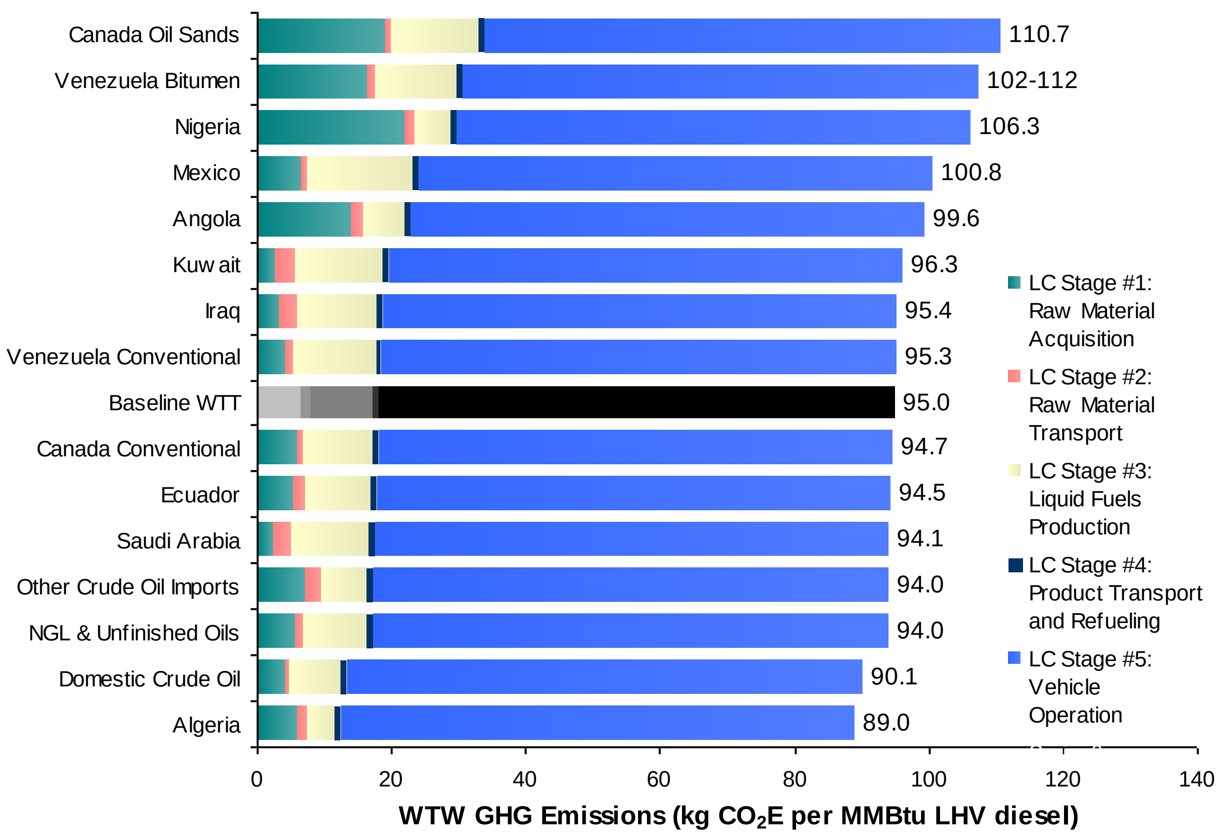


Table 3-1. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Diesel (by Stage)

Feedstock Source	2005 Input to U.S. Refineries	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	Total WTT	Percent of Baseline WTT
	Mbpd	kg CO_2E per MMBtu LHV of diesel dispensed					
Imported Crude Oil	10,080	8.4	1.7	10.5	0.8	21.4	115%
Canada	2,987	10.2	0.9	11.2	0.8	23.2	125%
Conventional	1,101	6.0	0.9	10.3	0.8	18.0	97%
Oil Sands	528	19.0	0.9	13.2	0.8	34.0	183%
Mexico	1,551	6.6	1.0	15.7	0.8	24.1	129%
Saudi Arabia	1,436	2.3	2.7	11.6	0.8	17.4	94%
Venezuela[1]	1,235	6.9 (5-10)	1.1	12.5	0.8	21.3 (19-25)	115%
Conventional[1]	957 (774-1,135)	4.1	1.1	12.5	0.8	18.6	100%
Upgraded Bitumen[1]	278 (100-461)	16.3 (11-20)	1.1	12.5	0.8	30.8 (25-35)	165%
Nigeria	1,075	22.0	1.7	5.1	0.8	29.7	159%
Iraq	522	3.3	2.7	11.8	0.8	18.7	100%
Angola	455	14.0	1.9	6.3	0.8	23.0	123%
Ecuador	276	5.3	1.7	9.9	0.8	17.8	96%
Algeria	228	6.0	1.5	4.0	0.8	12.4	66%
Kuwait	222	2.8	2.7	13.2	0.8	19.6	105%
Other Crude Imports	1,452	7.2	2.4	6.9	0.8	17.3	93%
Domestic Crude Oil	5,140	4.2	0.7	7.7	0.8	13.5	72%
Natural Gas Liquids and Unfinished Oils	1,001	5.8	1.1	9.6	0.8	17.3	93%
Weighted Average (U.S. Production Only)[1]	**16,221**	**6.9** (6.7-7.1)	**1.4**	**9.6**	**0.8**	**18.7** (18.5-18.9)	**100%**
Baseline[2]		**6.6**	**1.3**	**9.5**	**0.9**	**18.4**	**100%**

[1] Mean value from uncertainty analysis on the Venezuela upgraded bitumen is shown with 90% confidence interval in parentheses.

[2] The baseline includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile.

Table 3-2. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Diesel (by GHG Component)

Feedstock Source	Well-to-Tank GHG Emissions in kg CO_2E per MMBtu LHV of diesel dispensed			
	CO_2	CH_4	N_2O	Total GWP
Imported Crude Oil	17.9	3.4	0.1	21.4
Canada	21.0	2.1	0.1	23.2
Conventional	15.6	2.3	0.1	18.0
Oil Sands	32.3	1.5	0.2	34.0
Mexico	20.7	3.3	0.1	24.1
Saudi Arabia	16.9	0.5	0.1	17.4
Venezuela[1]	19.9	1.4	0.1	21.3
Conventional	17.2	1.4	0.1	18.6
Upgraded Bitumen[1]	29.2	1.4	0.2	30.8
Nigeria	16.7	12.8	0.1	29.7
Iraq	17.5	1.2	0.1	18.7
Angola	15.4	7.5	0.1	23.0
Ecuador	16.3	1.5	0.1	17.8
Algeria	10.5	1.9	0.1	12.4
Kuwait	18.7	0.8	0.1	19.6
Other Crude Imports	14.0	3.2	0.1	17.3
Domestic Crude Oil	12.7	0.7	0.1	13.5
Natural Gas Liquids and Unfinished Oils	15.4	1.8	0.1	17.3
Weighted Average (U.S. Production Only)[1]	**16.1**	**2.5**	**0.1**	**18.7**
Baseline[2]	**15.8**	**2.5**	**0.1**	**18.4**

1 Mean value from uncertainty analysis is shown here.

2 The baseline includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile.

4.0 Crude Oil Trends to 2008

The GHG emissions profile presented in the NETL Petroleum Baseline is representative of 2005 production of transportation fuels in the U.S., particularly with regards to refining operations. However, evaluating the crude oil quality trends through 2008 can provide a qualitative understanding of the increase or decrease in energy requirements and associated GHG emissions of processing crude oil from various sources.

Figure 4-1 trends the average API gravity of crude oil imported to the U.S. or domestic oil processed by U.S. refineries from 2000 to 2008 calculated from data available through EIA. Domestic crude oil, all imports and the top four countries supplying crude oil to the U.S. are shown. Canadian and Venezuelan crude oil properties are for the combined mix of upgraded bitumen and conventional crude oil. Domestic and Saudi crude oil are slightly lighter while the average of all imports, Canada and Mexico have become heavier. Venezuelan crude oil imports to the U.S. have changed in density from year-to-year, but the average is close in 2008 to what it was in 2000.

Figure 4-1. API Gravity Trends for U.S. and Imported Crude Oil (EIA 2009b)

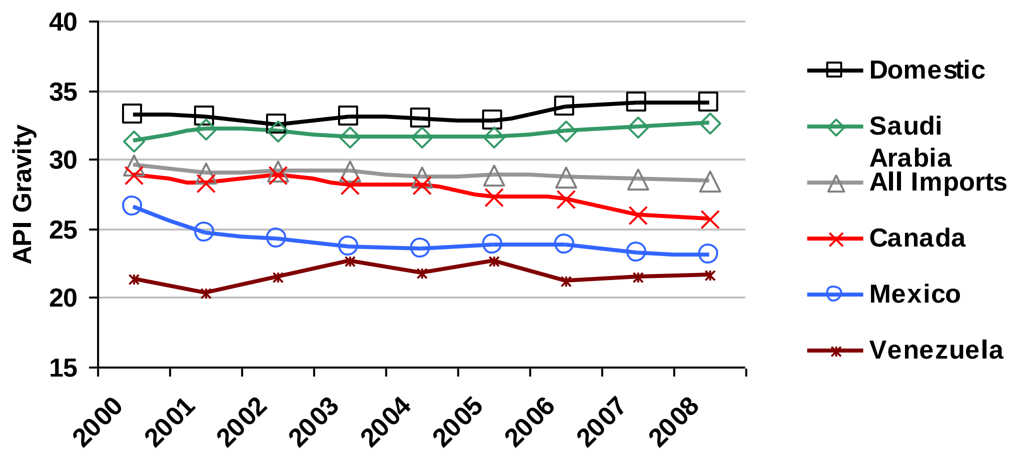


Figure 4-2 trends the average sulfur content of crude oil imported to the U.S. or domestic oil processed by U.S. refineries from 2000 to 2008 calculated from data available from EIA. Sulfur content in domestic crude oil processed by U.S. refineries has trended down since 2003 while imports have risen slightly in the same time period. Saudi Arabia and Venezuela crude oil sulfurs have dropped slightly while Canadian and Mexican crude oils have both become more sour. Table 4-1 provides a more detailed review of the crude oil properties in 2005 and 2008 as well as the mix to U.S. refineries for the top ten imported crude oil sources.

From this data, it can be generalized that imported Mexican and Canadian crude oil mixes have become more difficult to process and that the gap has widened slightly between domestic and imported crude oil, with domestic crude oil being the easier to process. These data can only qualitatively show potential shifts for LC Stage #3 refinery emissions.

For example, one may jump to the conclusion that the Canadian imports which are heavier and more sour in 2008 contain a greater volume of oil sands and that the LC Stage #1 and LC Stage #3 profile for Canada would be higher for 2008. It is possible, however, that the upgraded bitumen from Canada has undergone less processing in Canada and is thus arriving at U.S. refineries heavier and more sour. This would mean a marginally lower LC Stage #1 profile would counter the increase in the LC Stage #3 profile. In another scenario, marginal increases in Canadian oil sands in 2008 may be processed in new refinery equipment that is specifically designed to upgrade this oil and is less energy and GHG intensive.

Figure 4-2. Sulfur Content Trends for U.S. and Imported Crude Oil (EIA 2009b)

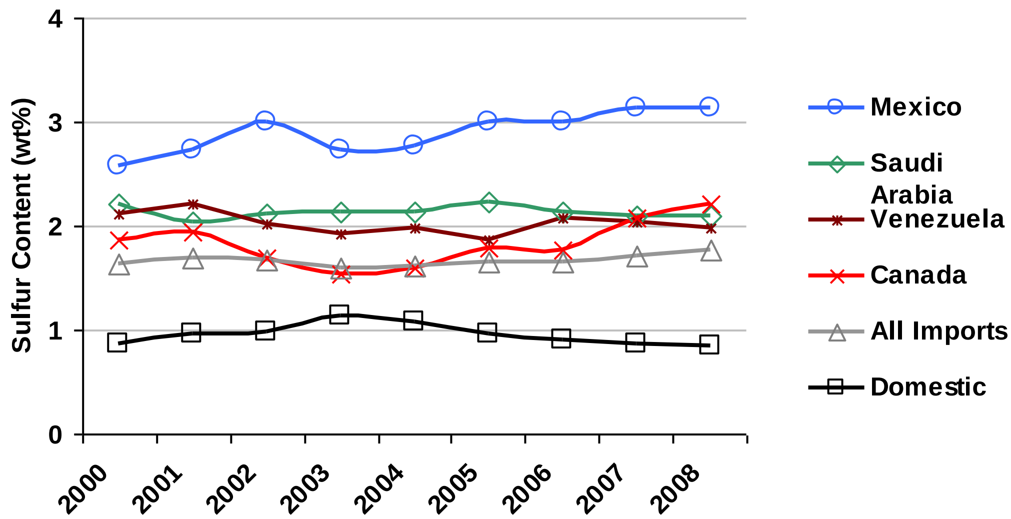


Table 4-1. Shifts in Crude Oil Quantity and Quality from 2005 to 2008 by Feedstock Source to U.S. Refineries (EIA 2009b)

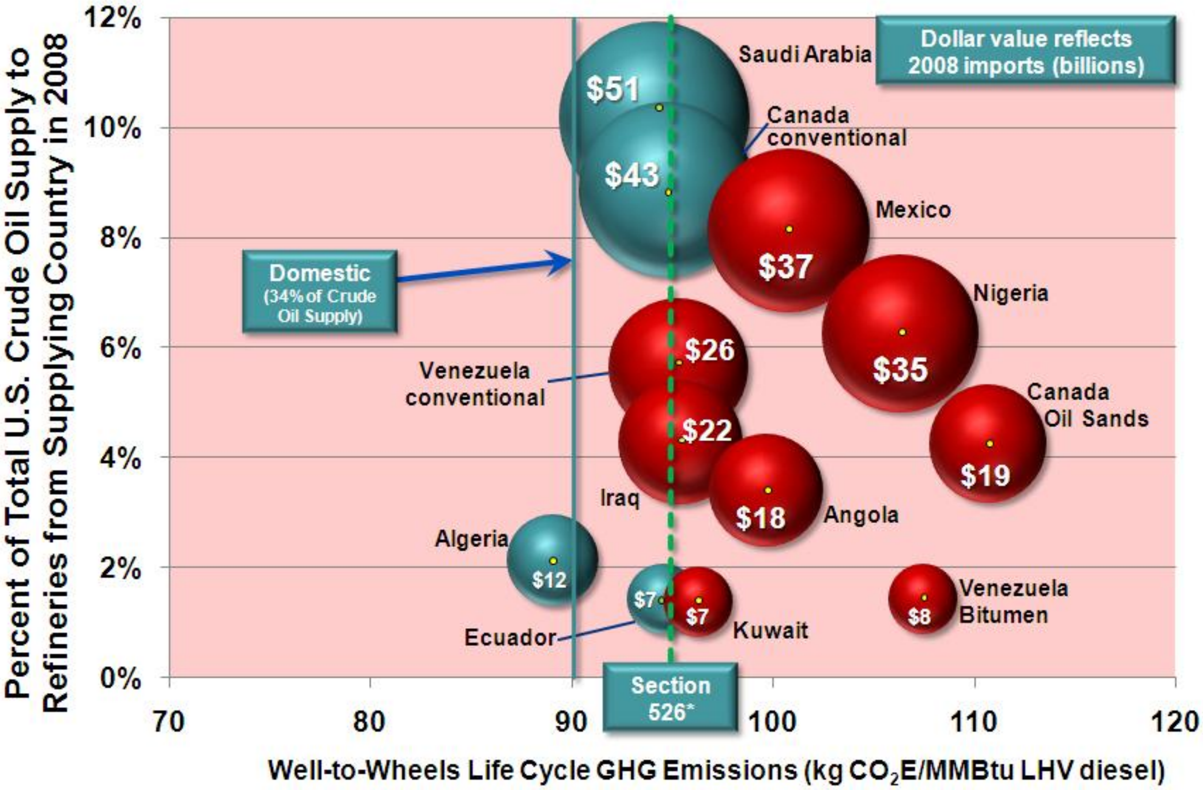
Feedstock Source	% of Volumetric Input to U.S. Refineries		Average API Gravity		Average Sulfur Content (wt%)		Description of Change
	2005	2008	2005	2008	2005	2008	
Canada	10%	12%	27.3	25.7	1.8	2.2	Heavier, higher S
Mexico	10%	7%	23.8	23.2	3.0	3.1	Heavier, higher S
Saudi Arabia	9%	9%	31.6	32.6	2.2	2.1	Lighter, lower S
Venezuela	8%	6%	22.6	21.5	1.9	2.0	Heavier, higher S
Nigeria	7%	6%	35.7	34.9	0.2	0.2	Heavier, same S
Iraq	3%	4%	30.9	30.5	2.3	2.3	Minimal change
Angola	3%	3%	32.0	31.3	0.4	0.4	Heavier, higher S
Ecuador	2%	1%	22.8	21.1	1.0	1.8	Heavier, higher S
Algeria	1%	2%	44.8	43.0	0.1	0.2	Heavier, higher S
Kuwait	1%	1%	29.6	27.6	2.6	3.1	Heavier, higher S
Other Crude Oil Imports	9%	8%	31.8	30.0	0.6	0.6	Heavier, same S
Domestic Crude Oil	32%	31%	32.9	33.9	1.0	0.9	Lighter, lower S
NGL & Unfinished Oils	6%	8%					
Overall	**100%**	**100%**	**30.2**	**30.2**	**1.42**	**1.47**	**Minimal change**

5.0 2008 Crude Oil Import Costs

Evaluating the costs of imported crude oil in conjunction with the feedstock acquisition profiles provides an understanding of the magnitude of U.S. dollars that are spent on foreign crude oil relative to the resulting GHG emissions profile for production of transportation fuels. Figure 5-1 shows the 2008 crude oil acquisition costs by feedstock source (derived from EIA data) relative to its contribution to the 2005 baseline GHG emissions profile for diesel fuel.

$171 billion[1] was spent in 2008 on imported crude oil which results in GHG emissions greater than the 2005 U.S. average baseline for production of diesel. The top GHG emitters equate to import costs of $62 billion[1] which result in WTT GHG emissions more than twice that of production of diesel from domestic crude oil.

Figure 5-1. Contribution of Feedstock Source to the WTW GHG Emissions Baseline Profile Relative to Crude Oil Acquisition Cost for Production of Diesel Fuel[1]



* Source: NETL report, *Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels*, November 26, 2008
NETL Petroleum Baseline "Section 526" value is a proxy pending designation by the EPA Administrator according to EISA 2007

Table 5-1 shows the same cost data in tabular form for the countries of interest with the addition of the average cost per barrel (BBL). Crude oil input and acquisition costs are as reported by EIA. The variability by country in landed cost per barrel of crude oil is based on a number of factors including

[1] Average refiner acquisition cost of crude oil in 2008 was $95/bbl. While crude oil price has fallen to $39/bbl for February 2009, the Energy Information Administration Annual Energy Outlook 2009 Early Release projects a 2030 imported crude oil price of $124/bbl.

transportation costs, quality of the crude oil and supply and demand relationships. In 2008, crude oil imported from Mexico, Canada and Venezuela was at least $10/bbl less than the estimated cost for domestic crude oil. Some of this discount is due to the quality of the crude oil which means one or more of the following may be true: 1) refiners may not be able to produce as many valuable products from the crude oil; 2) refiners will have higher operating costs to process the crude oil to make valuable products; or 3) the number of refiners who can process the type of crude oil into valuable product is limited, thus limited demand drives the price down. When the discounted price is due to limited demand, those refiners who can process the heavier and/or higher sulfur crude oil will choose to do so because the profit associated with processing this feedstock is superior to other options.

Table 5-1. 2008 Crude Oil Input and Acquisition Cost (EIA 2009b)

Crude Oil Source	Crude Oil Input to U.S. Refineries (MBPD)	Crude Oil Acquisition Cost ($/BBL)	Crude Oil Acquisition Cost (B$)	EIA Cost Source
Canada Conventional	1,301	$90	$43	Canada Landed Cost Adjusted for Quality Differences
Canada Oil Sands	623	$85	$19	
Saudi Arabia	1,491	$94	$51	Saudi Arabia Landed Cost
Mexico	1,182	$86	$37	Mexico Landed Cost
Venezuela Conventional	801	$90	$26	Venezuela Landed Cost
Venezuela Upgraded Bitumen	233	$90	$8	Venezuela Landed Cost
Nigeria	915	$104	$35	Nigeria Landed Cost
Iraq	622	$95	$22	Persian Gulf Landed Cost
Angola	500	$98	$18	Angola Landed Cost
Algeria	305	$104	$12	Nigeria Landed Cost
Ecuador	212	$91	$7	Colombia Landed Cost
Kuwait	198	$91	$7	Persian Gulf Landed Cost
Other Crude Oil Imports	1,284	$92	$43	Balance of All Imports Landed Cost
Domestic Crude Oil	5,018	$99	$181	Balance
Overall	**14,686**	**$95**	**$508**	**Refiner Acquisition Cost**

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Appendix A: Life Cycle GHG Results for Gasoline and Jet Fuel

Conventional Gasoline

The contribution of each feedstock source to the WTT profile for conventional gasoline is shown in Figure A-1 and Table A-1 by LC stage and Table A-2 by GHG component. Figure A-2 shows the WTT profiles relative to their input to U.S. refineries. Figure A-3 adds LC Stage #5 to show the WTW profile.

Figure A-1. Contribution of Feedstock Source to the WTT GHG Emissions Baseline Profile for Gasoline

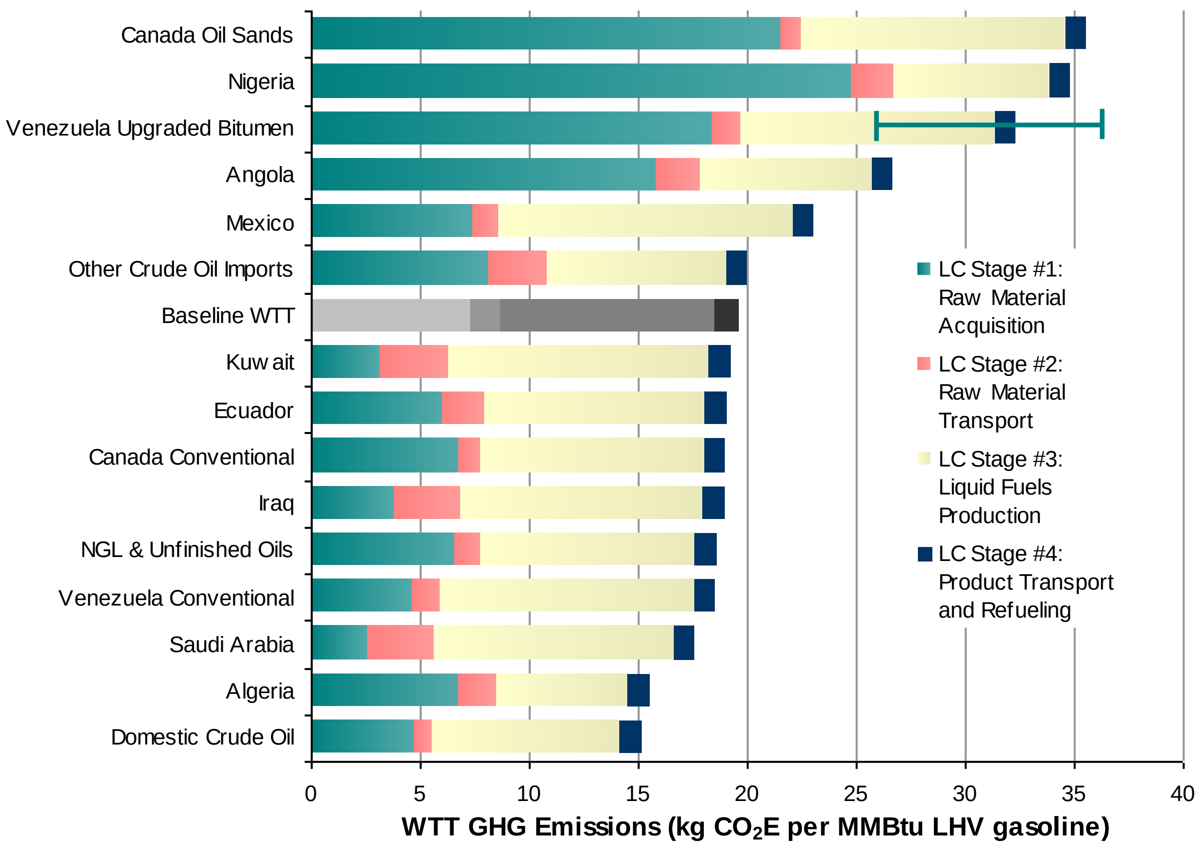


Figure A-2. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Gasoline Relative to 2005 Input to U.S. Refineries

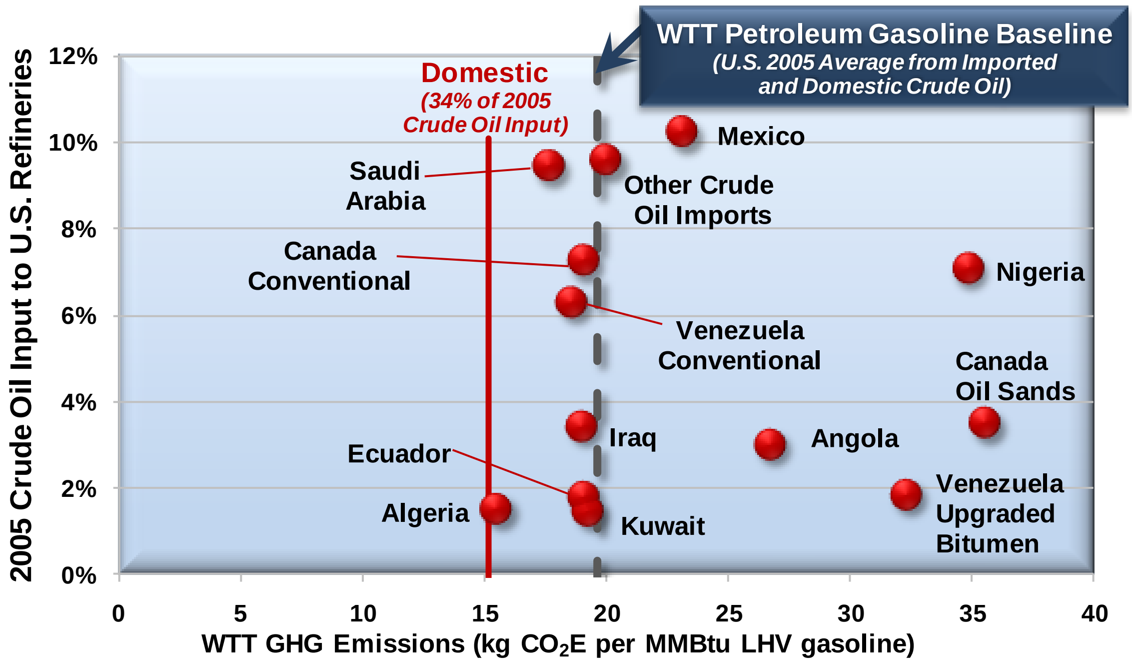


Figure A-3. Contribution of Feedstock Source to the 2005 Baseline WTW GHG Emissions for Gasoline

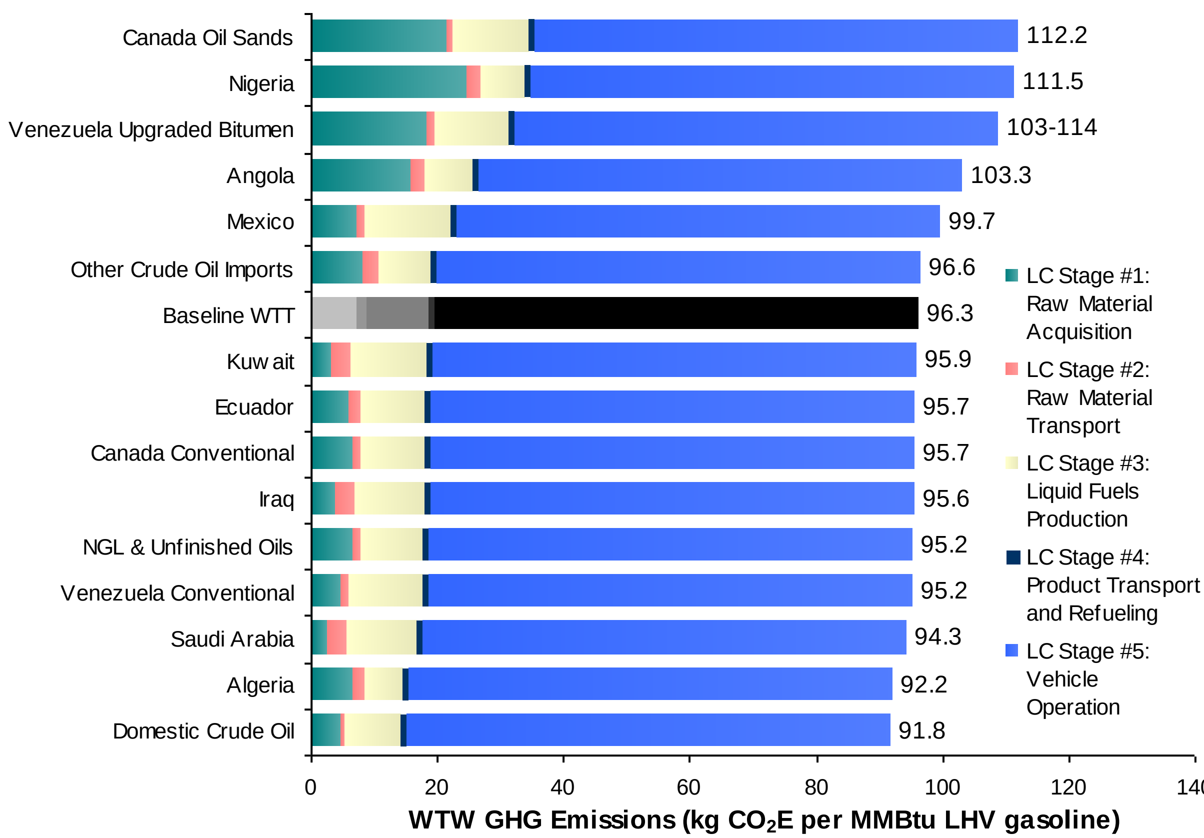


Table A-1. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Gasoline (by Stage)

Feedstock Source	2005 Input to U.S. Refineries	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	Total WTT	Percent of Baseline WTT
	Mbpd	kg CO_2E per MMBtu LHV of gasoline dispensed					
Imported Crude Oil	10,080	9.5	1.9	10.4	1.0	22.7	114%
Canada	1,629	11.6	1.0	10.8	1.0	24.4	122%
Conventional	1,101	6.8	1.0	10.2	1.0	19.0	95%
Oil Sands	528	21.5	1.0		1.0	35.6	179%
Mexico	1,551	7.4	1.2	13.6	1.0	23.1	116%
Saudi Arabia	1,436	2.6	3.0	11.0	1.0	17.6	88%
Venezuela[1]	1,235	7.8 (5-12)	1.3	11.6	1.0	21.6 (19-25)	109%
Conventional[1]	957 (774-1,135)	4.7	1.3	11.6	1.0	18.6	93%
Upgraded Bitumen[1]	278 (100-461)	18.4 (12-23)	1.3	11.6	1.0	32.3 (26-37)	162%
Nigeria	1,075	24.8	1.9	7.1	1.0	34.8	175%
Iraq	522	3.8	3.1	11.1	1.0	19.0	95%
Angola	455	15.8	2.1	7.8	1.0	26.7	134%
Ecuador	276	6.0	1.9	10.1	1.0	19.0	96%
Algeria	228	6.8	1.7	6.0	1.0	15.5	78%
Kuwait	222	3.2	3.1	12.0	1.0	19.2	97%
Other Crude Imports	1,452	8.2	2.7	8.2	1.0	20.0	100%
Domestic Crude Oil	5,140	4.7	0.8	8.7	1.0	15.2	76%
Natural Gas Liquids and Unfinished Oils	1,001	6.6	1.3	9.8	1.0	18.6	93%
Weighted Average (U.S. Production Only)[1]	**16,221**	**7.8** (7.6-8.1)	**1.5**	**9.8**	**1.0**	**20.1** (19.9-20.4)	**101%**
Baseline[2]		**7.3**	**1.4**	**9.8**	**1.1**	**19.6**	**100%**

[1] Mean value from uncertainty analysis on the Venezuela upgraded bitumen is shown with 90% confidence interval in parentheses.

[2] The baseline includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile.

Table A-2. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Gasoline (by GHG Component)

Feedstock Source	Well-to-Tank GHG Emissions in kg CO_2E per MMBtu LHV of gasoline dispensed			
	CO_2	CH_4	N_2O	Total GWP
Imported Crude Oil	18.8	3.8	0.1	22.7
Canada	22.0	2.3	0.1	24.4
Conventional	16.3	2.6	0.1	19.0
Oil Sands	33.8	1.6	0.2	35.6
Mexico	19.3	3.7	0.1	23.1
Saudi Arabia	17.0	0.5	0.1	17.6
Venezuela[1]	20.1	1.5	0.1	21.6
Conventional	17.0	1.5	0.1	18.6
Upgraded Bitumen[1]	30.6	1.5	0.2	32.3
Nigeria	20.2	14.5	0.1	34.8
Iraq	17.6	1.3	0.1	19.0
Angola	18.0	8.5	0.1	26.7
Ecuador	17.3	1.6	0.1	19.0
Algeria	13.3	2.1	0.1	15.5
Kuwait	18.3	0.8	0.1	19.2
Other Crude Imports	16.2	3.7	0.1	20.0
Domestic Crude Oil	14.2	0.8	0.1	15.2
Natural Gas Liquids and Unfinished Oils	16.4	2.0	0.1	18.6
Weighted Average (U.S. Production Only)[1]	**17.2**	**2.8**	**0.1**	**20.1**
Baseline[2]	**16.8**	**2.7**	**0.1**	**19.6**

[1] Mean value from uncertainty analysis on Venezuela upgraded bitumen profile is shown here.

[2] The baseline includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile.

Kerosene-Type Jet Fuel

The contribution of feedstock source to the WTT profile for kerosene-based jet fuel is shown in Figure A-4 and Table A-3 by LC stage and Table A-4 by GHG component. Figure A-5 shows the WTT profiles relative to their input to U.S. refineries. Figure A-6 adds LC Stage #5 to show the WTW profile.

Figure A-4. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Jet Fuel

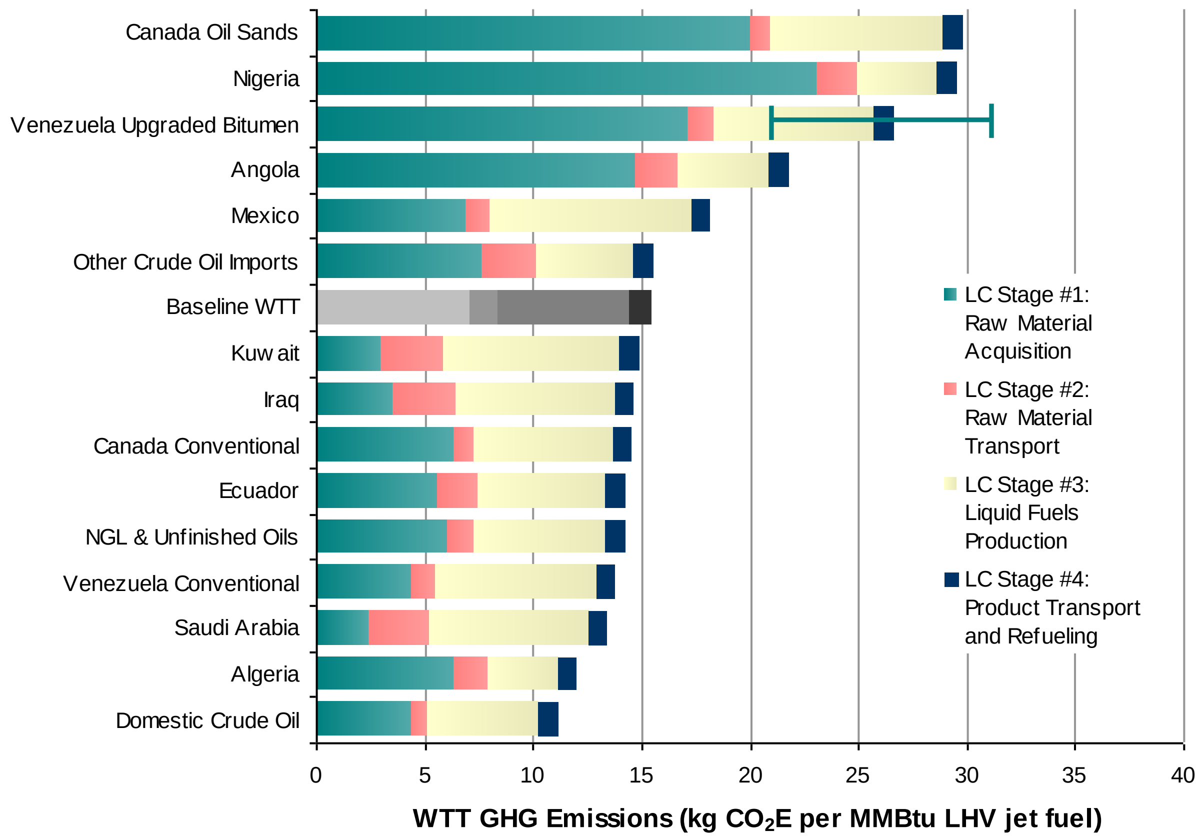


Figure A-5. Contribution of Feedstock Source to the 2005 Baseline GHG Emissions for Jet Fuel Relative to 2005 Input to U.S. Refineries

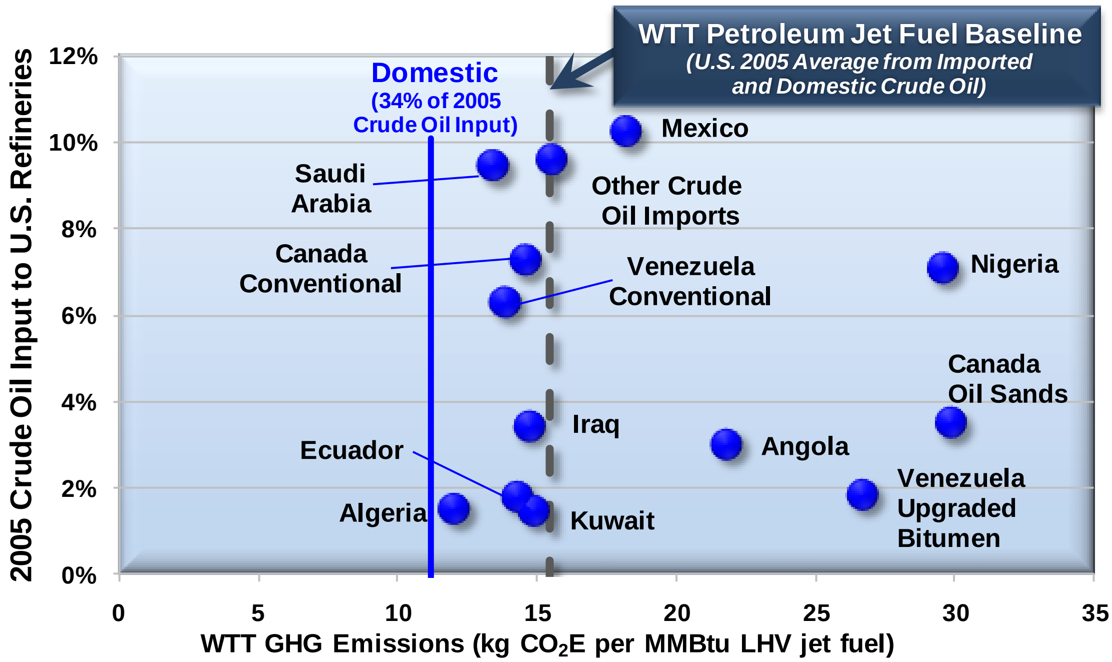


Figure A-6. Contribution of Feedstock Source to the 2005 Baseline WTW GHG Emissions for Jet Fuel

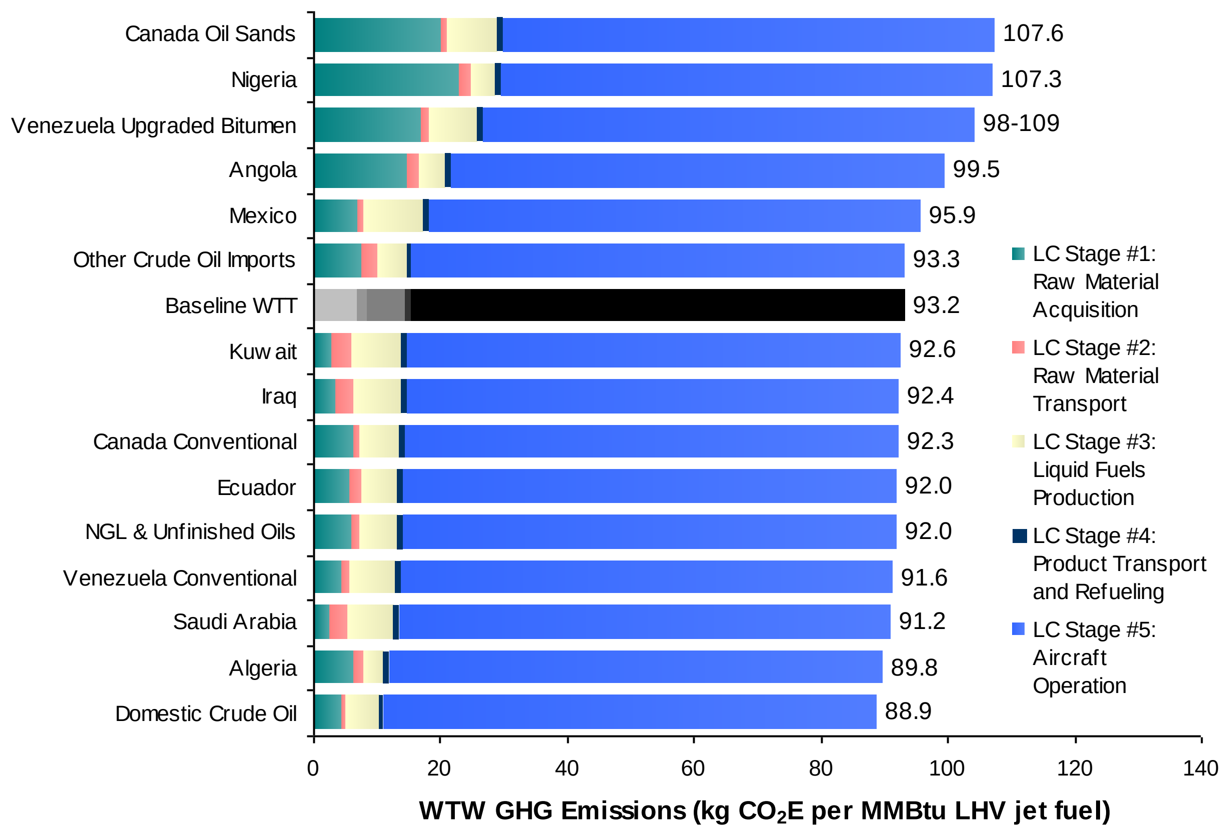


Table A-3. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Jet Fuel (by Stage)

Feedstock Source	2005 Input to U.S. Refineries	LC Stage #1: Raw Material Acquisition	LC Stage #2: Raw Material Transport	LC Stage #3: Liquid Fuels Production	LC Stage #4: Product Transport and Refueling	Total WTT	Percent of Baseline WTT
	Mbpd	kg CO_2E per MMBtu LHV of jet fuel dispensed					
Imported Crude Oil	10,080	8.8	1.8	6.5	0.9	18.0	117%
Canada	1,629	10.8	0.9	6.9	0.9	19.5	126%
Conventional	1,101	6.3	0.9	6.4	0.9	14.6	94%
Oil Sands	528	20.1	0.9	7.9	0.9	29.8	193%
Mexico	1,551	6.9	1.1	9.3	0.9	18.2	118%
Saudi Arabia	1,436	2.4	2.8	7.3	0.9	13.4	87%
Venezuela[1]	1,235	7.2 (5-11)	1.2	7.4	0.9	16.7 (14-20)	108%
Conventional[1]	957 (774-1135)	4.3	1.2	7.4	0.9	13.8	90%
Upgraded Bitumen[1]	278 (100-461)	17.2 (11-22)	1.2	7.4	0.9	26.7 (21-31)	173%
Nigeria	1,075	23.1	1.8	3.7	0.9	29.5	191%
Iraq	522	3.5	2.9	7.4	0.9	14.7	95%
Angola	455	14.7	2.0	4.2	0.9	21.8	141%
Ecuador	276	5.6	1.8	5.9	0.9	14.3	92%
Algeria	228	6.3	1.6	3.2	0.9	12.0	78%
Kuwait	222	3.0	2.9	8.1	0.9	14.9	96%
Other Crude Imports	1,452	7.6	2.5	4.6	0.9	15.6	101%
Domestic Crude Oil	5,140	4.4	0.8	5.1	0.9	11.1	72%
Natural Gas Liquids and Unfinished Oils	1,001	6.1	1.2	6.0	0.9	14.2	92%
Weighted Average (U.S. Production Only)[1]	**16,221**	**7.3** (7.1-7.5)	**1.4**	**6.0**	**0.9**	**15.6** (15.4-15.9)	**101%**
Baseline[2]		**6.8**	**1.3**	**6.0**	**1.0**	**15.1**	**100%**

[1] Mean value from uncertainty analysis on the Venezuela upgraded bitumen is shown with 90% confidence interval in parentheses.

[2] The baseline includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile.

Table A-4. Contribution of Feedstock Source to the 2005 Baseline WTT GHG Emissions for Diesel (by GHG Component)

Feedstock Source	Well-to-Tank GHG Emissions in kg CO_2E per MMBtu LHV of jet fuel dispensed			
	CO_2	CH_4	N_2O	Total GWP
Imported Crude Oil	14.5	3.5	0.1	18.0
Canada	17.4	2.0	0.1	19.5
Conventional	12.2	2.3	0.1	14.6
Oil Sands	28.2	1.4	0.2	29.8
Mexico	14.8	3.3	0.1	18.2
Saudi Arabia	13.0	0.4	0.1	13.4
Venezuela[1]	15.4	1.3	0.1	16.7
Conventional	12.5	1.3	0.1	13.8
Upgraded Bitumen[1]	25.2	1.3	0.2	26.7
Nigeria	16.0	13.4	0.1	29.5
Iraq	13.5	1.1	0.1	14.7
Angola	13.8	7.9	0.1	21.8
Ecuador	12.8	1.4	0.1	14.3
Algeria	10.1	1.9	0.1	12.0
Kuwait	14.1	0.7	0.1	14.9
Other Crude Imports	12.2	3.3	0.1	15.6
Domestic Crude Oil	10.4	0.7	0.1	11.1
Natural Gas Liquids and Unfinished Oils	12.3	1.8	0.1	14.2
Weighted Average (U.S. Production Only)[1]	**13.1**	**2.5**	**0.1**	**15.6**
Baseline[2]	**12.7**	**2.4**	**0.1**	**15.1**

[1] Mean value from uncertainty analysis on Venezuela upgraded bitumen profile is shown here.

[2] The baseline includes imported transportation fuels to the U.S. in 2005 and does not include the new Venezuelan upgraded bitumen acquisition profile.

Appendix B: Uncertainty Analysis for Venezuela Bitumen

Due to limited availability of public data, the GHG emissions profile for extraction and pre-processing of Venezuela's ultra-heavy oil/bitumen was bounded using uncertainty analysis. Several variables were used and varied for development of a 90% confidence interval for the extraction profile. Description and use of these variables is provided here with input and output values from the uncertainty analysis shown in Table B-1.

- Ratio of Venezuela bitumen GHG profile to Canada oil sands profiles: The Canada oil sands profiles for both upgraded synthetic oil and blended bitumen served as a baseline (Table 2-2). The Total 2002 and McCann 2001 comparisons of the two processes were used as guides in setting boundaries for the comparison.
- Mix of Venezuela upgraded bitumen that is upgraded synthetic oil vs. blended bitumen: Data available from EIA on API gravity and production volume of the upgraded bitumen for the four Venezuela strategic associations was used to predict this mix (Table 2-3).
- Mix of Venezuela imports to the U.S. that are conventional vs. upgraded bitumen: EIA data on the production volumes of upgraded bitumen and export volumes for all Venezuela crude oil sources served as a guide for setting uncertainty analysis bounds. Note that this factor will not impact the GHG emissions profile for the Venezuela's ultra-heavy oil/bitumen, only the composite mix for all Venezuela imports.

The equation used to provide the range of results for the Venezuela bitumen extraction GHG emissions is shown in Equation 1. Uncertainty analysis input variables are identified in ***red***.

$$Ven\_Bit = (F_{BB} * Can\_BlendBit + (1 - F_{BB}) * Can\_UpBit) * \boldsymbol{\mathit{Ven\_Can\_Ratio}} \quad (1)$$

Where,

Ven_Bit = Venezuela bitumen extraction GHG emissions profile

F_{BB} = Fraction of Venezuela bitumen that is blended bitumen (versus upgraded bitumen/synthetic crude oil), calculated by Equation 2

Can_BlendBit = Canadian blended bitumen extraction GHG emissions profile (Table 2-2)

Can_UpBit = Canadian synthetic crude oil/upgraded bitumen extraction GHG emissions profile (Table 2-2)

Ven_Can_Ratio = Ratio of Venezuela Bitumen GHG profile to Canadian oil sand profile

$$F_{BB} = \sum (\boldsymbol{F_{BB\text{-}i}} * Cap_i) / Total\_Capacity \quad (2)$$

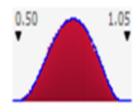
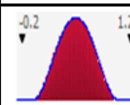
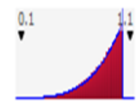
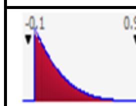
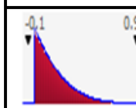
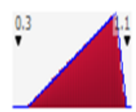
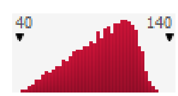
Where,

$F_{BB\text{-}i}$ = The fraction of the Venezuela bitumen that is blended bitumen for each of the strategic associations: Petrozuata, Cerro Negro, Sincor, and Hamaca

Cap_i = The production capacity for each of the strategic associations: Petrozuata, Cerro Negro, Sincor, and Hamaca (Table 2-3)

Total Capacity = The total capacity for all of the Venezuela strategic associations

Table B-1. Uncertainty Analysis Inputs and Outputs for Life Cycle Stage #1 Venezuela Upgraded Bitumen

Parameter	Inputs					Outputs			
	Function	Min	Max	Most Likely	References	Graph	Mean	5%	95%
Ratio of Venezuela bitumen GHG profile to Canada oil sands profiles	Pert	0.4	1.07	1	Min based on Total 2002; Max based on McCann 2001		0.82	0.54	1.02
Petrozuata: portion blended bitumen	Pert	0%	100%	50%	Expected based on API gravity of upgraded bitumen from each strategic association (Table 2-3; EIA 2009b); lower API is indicative of blended bitumen; higher API is indicative of synthetic/upgraded bitumen		50%	19%	81%
Cerro Negro: portion blended bitumen	Pert	0%	100%	100%			83%	55%	99%
Sincor: portion blended bitumen	Pert	0%	100%	0%			17%	1%	45%
Hamaca: portion blended bitumen	Pert	0%	100%	0%			17%	1%	45%
Conventional portion of Venezuela imports	Triangle	53%	100%	78%	Min represents 100% of Venezuela bitumen to U.S.; Max represents no Venezuela bitumen to U.S.; Expected represents proportional volume to U.S. (EIA 2009b)		78%	63%	92%
Venezuela bitumen extraction GHG emissions (kg CO_2E/bbl crude oil)					Uncertainty Analysis Result		95.4	62.2	119.9