

Detailed California-Modified GREET Pathway for Ultra Low Sulfur Diesel (ULSD) from Average Crude Refined in California

Stationary Source Division
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Commission, TIAX and Life Cycle Associates during the
development of this document)*

When reviewing this document, please submit comments directly to:

Anil Prabhu: aprabhu@arb.ca.gov

Chan Pham: cpham@arb.ca.gov

Alan Glabe: aglab@arb.ca.gov

James Duffy: jduffy@arb.ca.gov

These comments will be compiled, reviewed, and posted to the LCFS
website in a timely manner.

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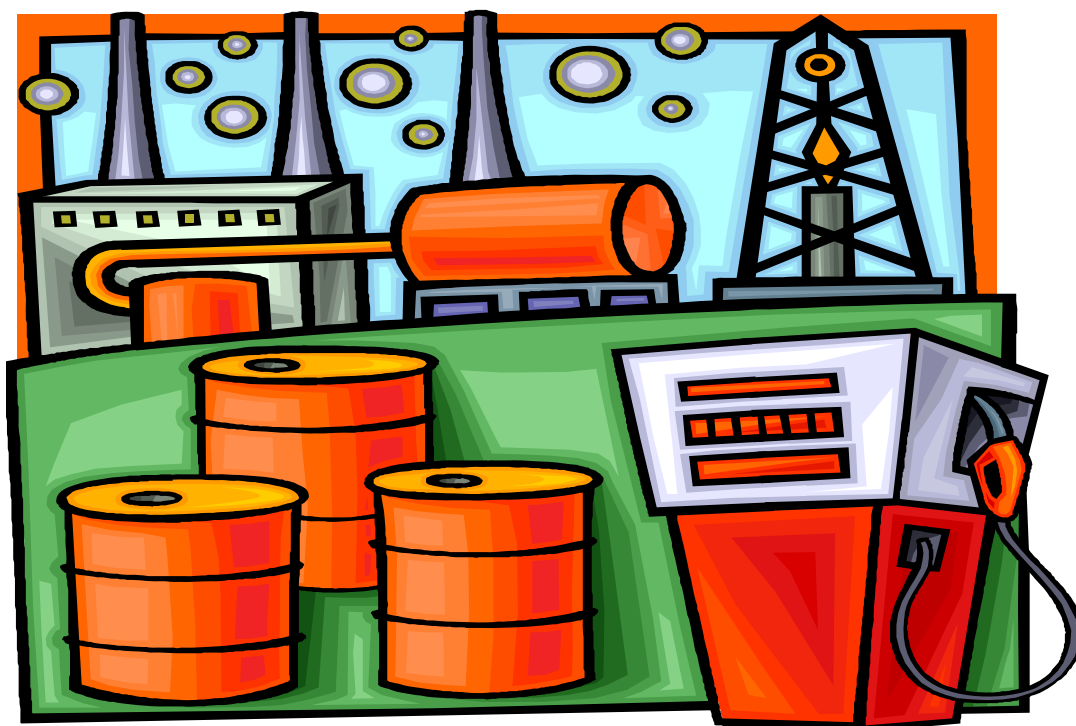
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SUMMARY



CA-GREET Model Pathway for ULSD from Average Crude Refined In California

Well-To-Tank (WTT) Life Cycle Analysis of a petroleum based fuel pathway includes all steps from crude oil recovery to final finished fuel. Tank-To-Wheel (TTW) analysis includes actual combustion of fuel in a motor vehicle for motive power. WTT and TTW analysis are combined to provide a total Well-To-Wheel (WTW) analysis.

A Life Cycle Analysis Model called the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) [1] developed by Argonne National Laboratory and modified by TIAx during the AB 1007 process [2] was used to calculate the energy use and greenhouse gas (GHG) emissions generated during the process of transforming crude to produce Ultra Low Sulfur Diesel (ULSD). Using this model, staff developed a pathway document for ULSD which was made available in mid-2008 on the Low Carbon Fuel Standard (LCFS) website (<http://www.arb.ca.gov/fuels/lcfs/lcfs.htm>). Subsequent to this, the Argonne Model was updated in September 2008. To reflect the update and to incorporate other changes, staff contracted with Life Cycle Associates to update the CA-GREET model. This updated California modified GREET model (v1.8b) (released December 2008) forms the basis of this document. It has been used to calculate the energy use and greenhouse gas (GHG) emissions associated with the production and use of ULSD.

The pathway includes crude recovery, transport, refining of crude in a typical California refinery and transport of finished product (ULSD). Figure 1 show below details the discrete components that form the ULSD pathway, from crude recovery through final finished fuel. Utilizing the energy and GHG emissions from each component, a total for the entire ULSD pathway is then calculated.

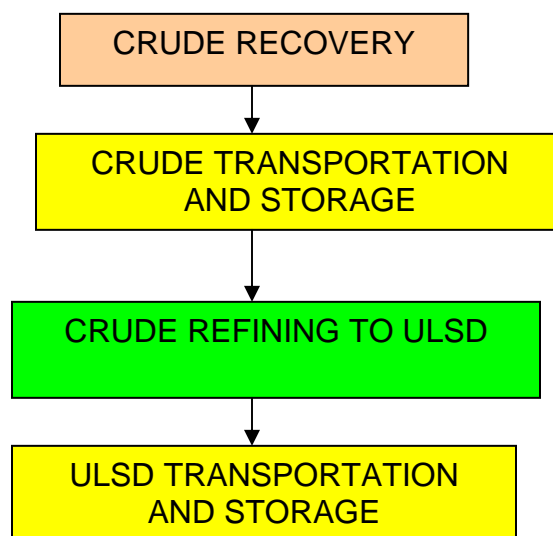


Figure 1. Discrete Components of Crude to ULSD Pathway

This document provides detailed calculations, assumptions, input values and other information required to calculate the energy use and GHG emissions for the ULSD pathway. Although the original GREET model developed by Argonne National Laboratory forms the core basis of this analysis, it has been appropriately modified to reflect California specific conditions. Examples include electricity generation factors, crude transportation distances, etc. which have been used to replace to the original GREET input values. A detailed list of all input values is provided in Appendix B.

Table A provides a summary of the Well-To-Tank (WTT) and Tank-To-Wheel (TTW) energy use and GHG emissions for this pathway. Energy use is presented as Btu/mmBtu and GHG emissions are reported as g CO_{2e}/MJ, where non-CO₂ gasses (i.e., methane and nitrous oxide) are converted into CO₂ equivalents. Details of converting non-CO₂ gasses to CO₂ equivalents are detailed in Appendix A in this document. Note: The energy inputs are presented in mmBtu because the calculations in the GREET model use mmBtu.

Table A. Summary Energy and GHG Values for the ULSD Pathway

	Energy Required (Btu/mmBtu)	% Energy Contribution	Emissions (gCO_{2e}/MJ)	% Emissions Contribution
Crude Recovery	101,615	7.84%	8.76	9.19%
Crude Transport	16,420	1.27%	1.14	1.20%
Crude Refining	173,766	13.41%	10.31	10.82%
ULSD Transport	4,293	0.33%	0.22	0.23%
Total (WTT)	296,094	22.8%	20.43	21.43%
Tank to Wheel	1,000,000	77.15%	74.9	78.57%
Total (WTW)	1,296,094	100%	95.3	100%

Note: percentages may not add due to rounding

From Table A above, the WTW analysis of ULSD indicates that **1,296,094** Btu of energy is required to produce 1 (one) mmBtu of available fuel energy delivered to the vehicle. From a GHG perspective, **95.3** gCO_{2e} of GHG are released during the production and use of 1 (one) MJ of ULSD. Note that this analysis uses average crude recovery which takes into consideration crude extracted in California as well as crude recovered overseas. The transportation of crude via ocean tanker from overseas locations and pipeline from Alaska is also weighted to reflect average crude available in California.

The values in Table A are pictorially represented in Figure 2, showing specific contributions of each of the discrete components of the fuel pathway. The charts are shown separately for energy use and GHG emissions. From an energy use viewpoint, energy in fuel (77.1%) and crude refining (13.4%) dominate the WTW energy use. From a GHG perspective, carbon in fuel (78.6%), crude refining

(10.80%), and crude recovery (9.2%) dominate the GHG emissions for this pathway.

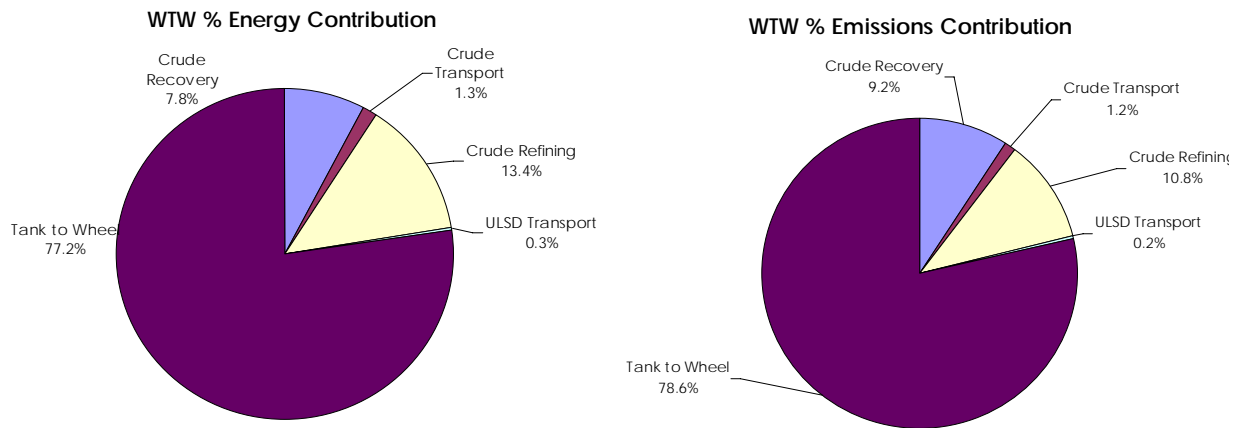


Figure 2. Percent Energy Contribution and Emissions Contribution from Well-to-Wheel (WTW)

WTT Details-Crude Recovery

Table B provides a breakdown of energy use for crude recovery. Crude recovery utilizes process energy which CA-GREET depicts as being derived from a combination of several fuel types including crude itself, residual oil, diesel, gasoline, natural gas and electricity. As an example, natural gas used as a fuel is combusted in a boiler to generate heat which then runs a turbine to generate electricity. This feature is captured in the electricity fuel share part of the energy mix. The table indicates that 101,615 Btu of energy is required, on average, to recover crude containing 1 mmBtu of energy. Detailed calculations are provided in Appendix A.

Table B. Total Energy use for Crude Recovery

Fuel Type	Btu/mmBtu
Crude oil	521
Residual oil	563
Diesel fuel	8,419
Gasoline	1,112
Natural gas	60,775
Coke (Pet. Coke)	322
Electricity	29,825
Feed Loss	79
Total energy for crude recovery	101,615

In a similar manner, GHG emissions associated with the transformation of fuel sources to useful process energy for crude recovery are shown in Table C below.

Additional details are provided in Appendix A. GHG emissions from all crude supplied to CA refineries produces 8.76 gCO₂e/MJ of GHG emissions.

Table C. Total GHG Emissions from Crude Recovery

	gCO₂e/MJ
CO ₂	6.54
CH ₄	2.13
N ₂ O	0.03
CO	0.04
VOC	0.01
Total GHG emissions	8.76

WTT Details-Crude Transport and Storage

Table D shows the energy necessary for transporting crude via ocean tanker and pipeline to California refineries. The proportional split between these two modes of transport is calculated from the average crude mix arriving in California, both from within the state as well as from overseas. Detailed breakdown of proportions utilized in the calculations are provided in Appendix A. A small energy loss attributable to feed losses is also captured in this analysis. As shown in the Table below, crude transport utilizes an average of 16,420 Btu of energy for every 1 mmBtu of crude transported.

Table D. Energy Consumed for Crude Transport

	Btu/mmBtu
Feed Loss	62
Ocean Tanker	7,240
Pipeline	9,091
Barge	90
Total Crude Recovery	16,420

Table E captures GHG emissions from crude transport in ocean tankers and pipelines. The fuel consumption and other specifics necessary for this calculation are detailed in the Appendix A. Crude transport generates 1.14 gCO₂e GHG emissions for every 1 MJ of crude transported.

Table E. Total GHG Emissions Crude Transport and Distribution

GHG	g CO₂e/MJ
CO ₂	1.08
CH ₄	0.05
N ₂ O	0.01
CO	0.00
VOC	0.00
Total GHG emissions	1.14

WTT Details-Crude Refining

Table F provides energy source mix used in refining of California average crude mix to ULSD. This is similar to the energy mix analysis presented in crude recovery earlier. As can be seen in the Table below, 173,766 Btu of energy is required to produce 1 mmBtu of finished CARBOB. Again here, each source of fuel has associated GHG emissions in its transformation into useful energy and these are shown in Table G below. The refining process generates 10.31 grams of CO₂e per MJ of finished fuel. Details of all the calculations are presented in Appendix A.

Table F. Energy Required for Crude Refining to ULSD

Fuel Type	Btu/mmBtu
Residual Oil	5,437
Natural Gas	49,211
Coal	20,344
Electricity	13,967
Refinery still gas	84,807
Total energy for refining	173,766

Table G. GHG Emissions from Crude Refining to ULSD

GHG	g CO₂e/MJ
CO ₂	10.01
CH ₄ (combustion)	0.26
N ₂ O	0.03
CO	0.01
VOC	0.00
Total	10.31

WTT Details-ULSD Transport and Storage

Table H provides a summary of the energy used to transport finished ULSD via pipeline and Heavy Duty Diesel (HDD) truck from refineries to a blending station. From Table H, this component of the pathway utilizes 4,293 Btu of energy for every 1 mmBtu of ULSD transported. The transportation through pipeline and HDD truck generates GHG emissions which are shown in Table I below. A total

of 0.22 gCO₂e GHG emissions are generated for every 1 MJ of ULSD transported.

Table H. Energy Use for ULSD Transportation and Distribution

Transport mode	Btu/mmBtu
Feed Loss	49
ULSD transported by pipeline	561
ULSD Transport by HDD truck	617
ULSD Distribution by HDD truck	3,066
Total	4,293

Table I. GHG Emissions from Transporting and Distributing ULSD

GHG	gCO₂e/MJ
CO ₂	0.21
CH ₄	<0.01
N ₂ O	<0.01
CO	<0.01
VOC	<0.01
Total	0.22

TTW - Tank to Wheel Energy and GHG Emissions Summary

Table J below provides a summary of the carbon dioxide equivalent emissions generated during combustion in a passenger vehicle. A total of 74.9 gCO₂e GHG emissions are generated from the TTW portion of the ULSD pathway.

Table J. Tank To Wheel Summary for ULSD

Parameter	GHG (gCO₂e/MJ)
CO ₂	74.10
N ₂ O	0.735
CH ₄	0.045
Total	74.9

APPENDIX A

Section 1. CRUDE RECOVERY



1.1 Energy Use for Crude Recovery

California crude is derived from various countries. Table 1.01 provides a breakdown of the sources for California. The data was obtained from the California Energy Commission website. This document utilized the 2006 supply to calculate the appropriate weightings for crude recovery and crude transport.

Table 1.01 Crude Oil Sources for California Refineries (barrels/year)

Feedstock Location	2005 CEC	2006 CEC	2007 CEC
Alaska, Valdez	135,906,000	105,684,000	100,900,000
Saudi Arabia	95,507,000	86,976,000	72,296,000
Ecuador	67,705,000	71,174,000	55,456,000
Iraq	34,160,000	56,163,000	57,788,000
Brazil	12,474,000	17,938,000	22,453,000
Mexico	19,316,000	15,473,000	9,214,000
Angola	12,912,000	14,979,000	21,038,000
Columbia	4,180,000	9,362,000	11,813,000
Oman	2,985,000	6,326,000	
Venezuela		4,120,000	4,706,000
Argentina	6,213,000	3,484,000	
Nigeria			5,447,000
Others	13,707,000	9,311,000	21,313,000
Canada	4,942,000		5,320,000
California	266,052,000	254,498,000	251,445,000
Total	676,059,000	655,488,000	639,189,000

Energy requirements in CA-GREET for crude recovery utilizes a recovery efficiency which is used to calculate energy needs for this process. The default value in GREET is 98%, which reflects an average of crudes processed in the U.S. The crude recovery efficiency (92.7%) used here however, is a weighted average and takes into consideration crude extracted in California, crude transported from Alaska as well as worldwide crude that is imported into California. The 92.7% value represents an estimate of a mix of conventional oil recovery and Thermally Enhanced Oil Recovery (TEOR). Approximately 38.9% of total crude for CA is produced in the state and 38.3% of CA crude is produced using thermally enhanced oil recovery (TEOR) methods, which use steam injection to recover heavier oil products. Since TEOR requires steam to be injected into the oil reserves it uses more energy than conventional oil recovery. Some TEOR sites also cogenerate electricity, which is used to provide power for the oil recovery operations, other oil recovery sites, and export to the grid. In California, 95% of the power generation capacity for TEOR sites is natural gas derived with the balance coal fired (DOGGR).

Of the 38.3% crude produced using TEOR, 40% is produced with cogenerated electricity. An electricity credit is calculated for electricity exported to the grid based on CEC data for TEOR cogeneration projects. However, calculating the

electricity co-product credit separately complicates analysis for other fuel pathway analyses because nearly all fuels rely on petroleum throughout their production pathways. To avoid using an electricity co-product credit for TEOR, the electricity produced is subtracted from the average electricity required for all crude production. The co-product electricity generated is 0.003 Btu electricity/Btu crude produced and is calculated outside of CA-GREET based on CA crude data. The calculation for the TEOR electricity co-product applied to all crude is all follows:

$$(0.003 \text{ Btu electricity/Btu crude}) = (38.9\% \text{ CA crude share of total crude}) * (38.3\% \text{ TEOR share of total CA crude}) * (-0.020 \text{ Btu/Btu cogen TEOR electricity credit}) * (10^9 \text{ Btu/mmBtu}) = - 3,023 \text{ Btu electricity/mmBtu crude}$$

Table 1.02 shows details of the types and proportion of various fuels used in crude recovery. The values in Table 1.02 are adjusted to account for the WTT energy used to produce each fuel. Table 1.03 depicts the adjustments to the values from the table above for each fuel type, accounting for loss factors associated with the WTT energy for each fuel used during crude recovery operations. Table 1.04 provides values and descriptions for the formulas used in Table 1.03.

Table 1.02 Details on How Efficiency is Used to Calculate Energy Consumption for Crude Recovery

Fuel Type	Fuel Shares	Relationship of Recovery Efficiency (0.927) and Fuel Shares	Default Direct Energy (Btu/mmBtu)	Direct Energy including Electricity Credit for CA TEOR* (Btu/mmBtu)
Crude oil	0.6%	$(10^6)(1/0.927 - 1)(0.006) = 472$	472	472
Residual oil	0.6%	$(10^6)(1/0.927 - 1)(0.006) = 472$	472	472
Diesel fuel	8.6%	$(10^6)(1/0.927 - 1)(0.086) = 6,772$	6,772	6,772
Gasoline	1.1%	$(10^6)(1/0.927 - 1)(0.011) = 886$	886	886
Natural gas	72.1%	$(10^6)(1/0.927 - 1)(0.721) = 56,778$	56,778	56,778
Coke (Pet. Coke)	0.4%	$(10^6)(1/0.927 - 1)(0.004) = 315$	315	315
Electricity	16.5%	$(10^6)(1/0.927 - 1)(0.165) = 12,994$	12,994	9,971*
Feed Loss	0.1%	$(10^6)(1/0.927 - 1)(0.001) = 79$	79	79
Natural Gas Flared		Weighted average for worldwide crude for CA refineries	13,181	13,181

*Includes 3,023 Btu/mmBtu credit for electricity co-produced during TEOR.

Table 1.03 Adjustment to Crude Recovery Energy to Account for Losses and WTT Energy Inputs

Fuel Type	Formula	Btu/mmBtu
Crude oil	$472 (1 + A/10^6)$	521
Residual oil	$472 (1 + (B \cdot D + C)/10^6)$	563
Diesel fuel	$6,772 (1 + (B \cdot F + E)/10^6)$	8,419
Gasoline	$886 (1 + (B \cdot H + G)/10^6)$	1,112
Natural gas	$56,778 (1 + I/10^6)$	60,775
Coke (Pet. Coke)	$315 (1 + J/10^6)$	322
Electricity	$9,971 (K + L)/10^6$	29,825
Feed Loss	79	79
Total WTT energy for crude recovery		101,615

Table 1.04 Details for Formulas in Table 1.03

Quantity	Description
A = 101,615	WTT energy in Btu for crude recovery at the oil field. This value calculated as the total WTT energy for crude recovery in Table 1.02 above. It is also an input the total WTT energy calculation This is one instance of a “recursive” calculation in CA-GREET.
B = 113,262	WTT energy of crude in Btu consumed to recover one million Btu as feedstock used in US refineries. This is a CA-GREET calculation that includes losses and delivery to the oil refinery.
C = 77,970	WTT energy in Btu required to produce 1 million Btu of residual oil. This is calculated from the WTT analysis of residual oil similar to the CARBOB calculations being detailed in this document.
D = 1.0000	Loss factor for Residual Oil which is a CA-GREET default value.
E = 129,882	WTT energy required in Btu to produce one million Btu of diesel. This value is calculated from the WTT analysis of diesel from CA-GREET similar to the CARBOB calculations being detailed in this document.
F = 1.0000	Loss factor ¹ for diesel fuel which is default CA-GREET value.
G = 170,877	WTT energy in Btu to produce one million Btu of gasoline. This value is calculated from the WTT analysis of gasoline from CA-GREET similar to the CARBOB calculations being detailed in this document.
H = 1.00008	Loss factor ¹ for gasoline which is default CA-GREET value.
I = 70,394	WTT energy in Btu used to produce natural gas as stationary fuel. This is a CA-GREET calculated value.
J = 20,113	WTT energy in Btu used to produce coal as stationary fuel. This is a CA-GREET calculated value.
K = 2,793,243	Total energy required in Btu to produce one million Btu of electricity. This is derived from the electricity analysis by CA-GREET.
L = 198,043	Total energy required Btu to produce one million Btu of electricity feedstock. This is derived from the electricity analysis by CA-GREET.

¹ Loss factors for petroleum fuels include refueling spillage plus evaporative losses from vehicle fueling and fuel transfer operations.

1.2 GHG Emissions from Crude Recovery

For all greenhouse gas (GHG) emissions, CA-GREET accounts for only three GHGs: CO₂, CH₄ and N₂O. For CO and VOCs, the model calculates the CO₂ when these components are oxidized in the atmosphere. The Global Warming Potentials (GWP) for all gases are default CA-GREET values and listed in Table 1.05. Information on VOC and CO conversion calculations is provided as a note below.

Table 1.05 Global Warming Potentials for Gases (GREET Default per IPCC)

Species	GWP (relative to CO ₂)
CO ₂	1
CH ₄	25
N ₂ O	298

Note: values from mmBtu to MJ have been calculated using 1 mmBtu = 1055 MJ

Carbon ratio of VOC = 0.85 which is converted to gCO₂e/MJ = grams VOC*(0.85 gC/gVOC)*(44 gCO₂/12 gC)

Carbon ratio of CO = 0.43 which is converted to gCO₂e/MJ = grams CO*(0.43 gC/gCO)*(44 gCO₂/12 gC)

The transformation of various fuel types into energy generates emissions, specific to each type of fuel and the equipment used in the transformation. An example is natural gas being combusted to generate electricity in turbines. Table 1.06 details only CO₂ emissions for each fuel type used in crude recovery. CH₄, N₂O, VOC and CO contributions to total GHG emissions are detailed later in this section. Additional details for each specific fuel type are provided in sections to follow. The table provides GHG values both in g CO₂/mmBtu and g CO₂/MJ. As an example, the use of diesel fuel in crude recovery generates 0.61 g CO₂/MJ.

Table 1.06 CO₂ Emissions by Fuel Type (does not include other GHGs)

Fuel Type	g-CO ₂ /mmBtu	g-CO ₂ /MJ
Crude oil	40	0.04
Residual oil	46	0.04
Diesel fuel	641	0.61
Gasoline	61	0.06
Natural Gas	3,550	3.36
Coke (Pet. Coke)	31	0.03
Electricity	1,764	1.67
Natural Gas (flared)	765	0.73
Total	6,867	6.54

Table 1.07 utilizes the energy use by fuel type from Table 1.02 and calculates GHG emissions utilizing emission factors which are provided in Table 1.08. The CO₂ emission factors represent the carbon in fuel minus carbon emissions associated with VOC and CO emissions. Thus, the emission factor is different among equipment types such as engines and turbines. The carbon in fuel factors are CA-GREET default values, except for natural gas, which is slightly

different based on the AB 1007 analysis. However, the calculations in the fuel cycle reflect the estimated direct emissions of CO₂ from the different equipment types excluding the carbon in VOC and CO. Note that energy use is used from Table 1.02 of this document (as an example, the value 472 is from Table 1.02 for crude oil). Table 1.07 essentially provides details on how CO₂ emissions were calculated and provided in Table 1.06.

Table 1.07 Specific Fuel Shares Contributing to CO₂ Emissions (see Table 1.06)

Fuel	Calculations	CO₂ emissions (g CO₂/mmBtu)
Crude Oil	$472 * (\text{crude oil emissions factor} + \text{total CO}_2 \text{ emissions from crude recovery}) / 10^6$	40
Residual Oil	$472 * (\text{Fraction of residual oil consumed in a commercial boiler} * \text{emissions factor of a commercial boiler} + \text{emissions from crude} * \text{loss factor for emissions from crude} + \text{total emissions from residual oil}) / 10^6$	46
Diesel fuel	$6,772 * (\text{percentage from diesel boiler} * \text{emission factor for diesel boiler} + \text{percentage from stationary diesel engine} * \text{emissions factor for diesel engine} + \text{percentage from stationary diesel turbine} * \text{emission factor of diesel turbine} + \text{emissions from crude} * \text{loss factor} + \text{total emissions from diesel}) / 10^6$ (see Table 1.08A for further details)	641
Gasoline	$866 * (\text{emissions factor of reciprocating engine} + \text{crude emissions} * \text{loss factor} + \text{emissions from conventional gasoline}) / 10^6$	61
Natural Gas	$56,778 * (\text{percentage of natural gas used in an engine} * \text{emissions factor for natural gas engine} + \text{percentage of natural gas used in a small industrial boiler} * \text{emissions factor for small industrial boiler} + \text{emissions from natural gas as a stationary fuel}) / 10^6$ (see Table 1.09B for further details)	3,550
Coal	$315 * (\text{emission factor for coal boiler} + \text{WTT emissions for coal})$	31
Electricity	$9,971 * (\text{emissions from producing feedstock} + \text{emissions from consuming feedstock}) / 10^6$	1,764
Natural Gas (flared)	$13,181 * (\text{emissions factor for natural gas flaring}) / 10^6$	765

Table 1.08 Values Used in Table 1.07

Fuel	Calculations
Crude Oil	Crude oil emission factor = 77,264 (g CO ₂ /mmBtu) which is a CA-GREET default.
	CO ₂ emissions from crude recovery = 6,865 (g CO ₂ /mmBtu) which is recursively calculated from Table 1.06.
Residual Oil	Fraction of residual oil consumed in a commercial boiler = 1.00 which is a GREET default value.
	Emission factor of a commercial boiler = 85,049 in g CO ₂ /mmBtu which is a GREET calculated value.
	WTT Emission for crude = 7,853 in g CO ₂ /mmBtu which is a CA-GREET calculated value.
	Loss factor for emissions from crude = 1.0000 also a CA-GREET default value.
	WTT emissions from residual oil = 5,437 a CA-GREET calculated value.
Diesel fuel	Percentage from diesel boiler = 25.0% a default value from CA-GREET.
	Emission factor for diesel boiler = 78,167 g CO ₂ /mmBtu, a CA-GREET calculated value.
	Percentage from stationary diesel engine = 50.0%, a CA-GREET default value.
	Emission factor for diesel engine = 77,349 g CO ₂ /mmBtu, a calculated value from CA-GREET.
	Percentage from stationary diesel turbine = 25.0% a default CA-GREET value.
	Emission factor of diesel turbine = 78,179 g CO ₂ /mmBtu, a CA-GREET calculated value.
	Emissions from crude = 7,853 g CO ₂ /mmBtu, calculated from CA-GREET.
	Loss factor for emissions from crude = 1.0000, a default value from CA-GREET.
	Total emissions from diesel = 9,048 g CO ₂ /mmBtu, a CA-GREET calculated value.
Gasoline	Emission factor of reciprocating engine = 50,480 g CO ₂ /mmBtu a CA-GREET default value.
	Emissions from crude = 7,853 g CO ₂ /mmBtu, a CA-GREET calculated value.
	Loss factor for emissions from crude = 1.0000, a CA-GREET default value.
	Emissions from conventional gasoline = 11,678 g CO ₂ /mmBtu, CA-GREET calculated value.
Natural Gas	Percentage of natural gas used in an engine = 50.0%, CA-GREET default.
	Emission factor for natural gas engine = 56,551 g CO ₂ /mmBtu, a CA-GREET calculated value
	Percentage of natural gas used in a small industrial boiler = 50.0%, a CA-GREET default.
	Emissions factor for small industrial boiler = 58,176 g CO ₂ /mmBtu, a CA-GREET calculated value
	Emissions from natural gas as a stationary fuel = 5,161 g CO ₂ /mmBtu, a CA-GREET calculated value.
Coke (Pet. Coke)	Emission factor for coal boiler = 96,299 g/mmBtu, a CA-GREET calculated value
	Emissions from natural gas a processing fuel = 1,505 g/mmBtu

Electricity	Emissions from producing feedstock = 14,305 g CO ₂ /mmBtu, a CA-GREET calculated value from electricity pathway.
	Emissions from consuming feedstock = 162,627 g CO ₂ /mmBtu, a CA-GREET calculated from electricity pathway.
Natural Gas (flared)	Emissions factor for natural gas flaring =58,048 g CO ₂ /mmBtu, a CA-GREET default value.

Tables 1.09A and 1.09B provide additional details on emissions resulting from use of diesel, natural gas and electricity generation. CO₂ emissions from crude oil, residual oil, and gasoline combustion cannot be further broken down according to equipment type because they are used in only one equipment type: industrial boilers (crude oil and residual oil) and reciprocating engines (gasoline). The values from crude oil, residual oil, and gasoline combustion are provided by the emission factors for these fuels as detailed in Tables 1.07 and 1.08. In Tables 1.09A and 1.09B, details for CO₂ emissions are provided for diesel and natural gas used as a fuel in crude recovery operations. All values in Tables 1.09A and 1.09B are CA-GREET default values and subsequent CA-GREET calculated values. Note that Tables 1.09A and 1.09B detail how values reported in Table 1.07 for diesel and natural gas are calculated.

Table 1.09A CO₂ Emissions from Diesel

Equipment Type	Equipment Shares	Emissions Factor (g/mmBtu)	g CO₂/mmBtu
Commercial Boiler	25%	78,167	132
Stationary Reciprocating Engine	50%	77,349	262
Turbine	25%	78,179	132
Crude Oil and Diesel Production			114
Total			641

Table 1.09B CO₂ Emissions from Natural Gas

Equipment Type	Equipment Shares	Emissions Factor	g CO₂/mmBtu
Stationary Reciprocating Engine	50%	56,551	1,605
Small Industrial Boiler	50%	58,176	1,652
As Stationary Fuel		5,349	293
Total			3,550

Tables 1.10 through 1.13 detail CO₂ emissions from electricity generation. The emissions factor are CA-GREET calculations. For electricity, it is broken down into emissions from feedstock production (recovering feedstock such as coal from mines and transporting to a facility) and feedstock consumption (actual use in a boiler). Table 1.10 details the net and individual equipment generation efficiencies and upstream energy for natural gas based electricity.

Table 1.10 Energy Breakdown from Electricity (Feedstock Consumption)

Fuel	Conv. Efficiency	Generation Mix	Relationship of Conversion Efficiency and Energy Use	Energy Use (Btu/mmBtu)	Description
Natural Gas	39.0%	100%	$(10^6/0.394)*(1/1-0.081)$	2,793,243	Energy used as natural gas (Btu/mmBtu), a CA-GREET calculation.

Table 1.11 summarizes upstream CO₂ emissions from feedstock production related to electricity

Table 1.11 Detailed CO₂ Emissions from Feedstock Production

Feedstock	Calculation	g CO₂/mmBtu
Natural Gas	$9,971*(2,793,243*5,084)/10^6/10^6$	142
Total		

Where 9,971 Btu/mmBtu is the electricity input, 2,793,243 Btu/mmBtu is the fuel cycle electricity energy and 5,084 g CO₂/mmBtu electricity is the fuel cycle CO₂ emissions for natural gas destined for electricity production.

Table 1.12 provides details on CH₄, N₂O, VOC and CO emissions generated during the combustion of the different fuels listed in these tables. These values

are calculated from default CA-GREET values for sources that are used in crude recovery.

Table 1.12 CH₄, N₂O, VOC and CO Emissions from Crude Recovery

	CH₄ emissions	N₂O Emissions	VOC Emissions	CO Emissions
Fuel Type	(g CH ₄ /mmBtu)	(g N ₂ O/mmBtu)	(g VOC/mmBtu)	(g CO/mmBtu)
Crude oil	0.012	0.001	0.002	0.023
Residual oil	0.054	0.000	0.005	0.023
Diesel fuel	0.809	0.012	0.359	1.493
Gasoline	0.187	0.002	1.564	11.360
Natural gas	17.823	0.055	1.593	11.192
Electricity	4.814	0.036	0.226	0.934
Natural gas (flared)	0.646	0.014	0.033	0.343
Total (without non- combustion)	24.344	0.122	3.783	25.369
Non- combustion	11.0		0.702	
Vented	54.6			
Total	89.944	0.122	4.485	25.369

Table 1.13 summarizes the total GHG emissions for crude recovery. The total is calculated as g CO₂e where non-CO₂ GHG gasses have been converted to CO₂ equivalents using their GWP detailed earlier. It also shows how CA-GREET accounts for CO and VOC emissions in its calculation of pathway GHG emissions.

Table 1.13 Total GHG emissions from Crude Recovery

	(g/mmBtu)	Formula	gCO ₂ e/mmBtu	gCO ₂ e/MJ
CO ₂	6,898	6,898*1	6,898	6.54
CH ₄	89.944	89.944*25	2249	2.13
N ₂ O	0.122	0.122*298	36	0.03
CO	25.369	25.369*0.43*(44/12)	40	0.04
VOC	4.485	4.485*0.85*(44/12)	14	0.01
Total GHG emissions			9,237	8.76

Section 2. CRUDE TRANSPORT



2.1 Energy Use for Crude Transport

Crude transportation energy use is based on the weighted mix for crude recovery (average CA crude) and the corresponding transport mode. Table 2.01 provides details on the various modes of transport for crude used in CA refineries. The electricity mix is assumed to be 100% NG-based, since the majority of the crude is foreign and produced off-grid. The transport distances have been calculated to be 442 miles via pipeline, 7,063 miles via oil tanker, and 200 miles via barge.

Table 2.01 Crude Oil Transport Details

Crude Supply (2005)	Mix	Crude Pipeline			Ocean Tanker			Barge		
		Dest.	Share	miles	Dest.	Share	miles	Dest.	Share	miles
Alaska	16.1 %	Valdez	100%	870	SF	100%	1,974			
Domestic	38.9 %	Refineries	100%	200	-		-	CA	5.0%	200
Foreign	45.0 %	Weighted Calc.	100%	498	Weighted Calc.	100%	8,884			
Annual Total		Weighted Average		442	Weighted Average		7,063	Weighted Average	1.9%	200

Transport distance for imported foreign oil is based on CEC's summary of EIA data for crude oil sources combined with transport distances determined from e-ship's (<http://www.e-ship.com>) on-line calculator.

The average pipeline and ocean tanker distances and average barge share were calculated using the weighted consumption data in Table 2.01 and shown below:

- Average Pipeline Distance: 442 mi = $(870 \times 16.1\%) + (200 \times 38.9\%) + (498 \times 45.0\%)$
- Average Ocean Tanker Distance: 7,063 mi = $[(1,974 \times 16.1\%) + (8,884 \times 45.0\%)] / (16.1\% + 45.0\%)$
- Average Barge Distance: 200 mi = $(38.9\% \times 5.0\% \times 200) / (38.9\% \times 5\%)$
 - Average Barge Average Share: 1.9% = $(38.9\%) \times (5.0\%)$

Note: The average barge share must be calculated separately and input into CA-GREET as one number because GREET only has one input for barge share.

The three modes of transport are utilized to transport crude to California refineries. Details of how energy use is calculated for both types of modes of transport appear in Table 2.02 below with values used in the calculation provided in Table 2.03. Both modes utilize common factors such as lower heating values (LHV) and density of crude, and transport mode specific factors such as energy consumed per mile of transport to calculate energy use for specific distances transported.

Table 2.02 Details of Energy Consumed for Crude Transport

	Detailed Calculations	Btu/mmBtu
Feed Loss	CA-GREET default	62
Ocean Tanker	(% Fuel Transported by Ocean Tanker)*(Density of crude/LHV of crude)*(Energy Intensity Origin to Destination plus Return Trip)*(Average Miles Traveled)* (1/454)* (1/2000)*(1+0.191)*10 ⁶	7,240
Pipeline	(% Fuel Transported by Pipeline)*(Density of crude/LHV of crude)*(Energy consumed)*(miles traveled)*(1/454) *(1/2000)*(2.991))*10 ⁶	9,091
Barge	(% Fuel Transported by Barge)*(Density of crude/LHV of crude)*(Energy Intensity Origin to Destination plus Return Trip)*(miles traveled)*(1/454)*(1/2000)*(1+0.191)*10 ⁶	90
Total		16,420

Table 2.03 Values for formulas in Table 2.02

Description	Value	Source
Weighted average distance traveled by ocean tanker (mi)	7,063	Table 2.01
Weighted average distance traveled by pipeline (mi)	442	Table 2.01
Distance traveled by Barge (mi)	200	Table 2.01
Density of crude (grams/gallon)	3,205	CA-GREET default
Lower heating value (LHV) of crude (Btu/gallon)	129,670	CA-GREET default
Ocean tanker energy intensity (Btu/ton-mile)	27 24 (return trip)	CA-GREET calculation based on tanker size
Pipeline energy intensity (Btu/ton-mile)	253	CA-GREET default
Barge energy intensity (Btu/ton-mile)	403 307 (return trip)	CA-GREET default
Conversion from pounds to grams	454	
Conversion from tons to pounds	2,000	
WTT Energy Factor for Residual Oil (Btu/Btu)	0.191	CA-GREET calculation
WTT Energy Factor for Electricity including electricity (Btu/Btu)	2.991	CA-GREET calculation

2.2 GHG Emissions for Crude Transportation

Table 2.04 details CO₂ emissions related to crude transport and distribution. These calculations assume 7,063 miles for ocean tankers and 442 miles for pipelines, as detailed in section 2.1. Table 2.05 provides values for various terms used in Table 2.04.

Table 2.04 Crude Transport CO₂ Emissions

Mode	Formula	gCO ₂ /mmBtu	gCO ₂ /MJ
Ocean Tanker	(Density of crude/LHV of crude)*(miles traveled) *(1/454)*(1/2000)*[(Energy intensity on trip from origin to destination*(emission factor for residual oil+ WTT CO ₂ for residual oil)) + (Energy intensity on return trip*(emission factor for residual oil + WTT CO ₂ for residual oil)]	594	0.56
Pipeline	(Density of crude/LHV of crude)*(Energy intensity of pipeline)*(miles traveled)*(1/454)*(1/2000) *(CO ₂ emissions factor for electricity +WTT emissions for electricity)	538	0.51
Barge	(Density of crude/LHV of crude)*(miles traveled) *(1/454)*(1/2000)*[(Energy intensity on trip from origin to destination*(emission factor for residual oil + WTT residual oil CO ₂)) + (Energy intensity on return trip*(emission factor for residual oil + WTT residual oil CO ₂)]	7	0.01
	Total	1,139	1.08

Table 2.05 Values of Properties Used in Table 2.04

Parameters	Values	Sources
Miles traveled by Ocean Tanker (miles)	7,063	Table 2.01
Pipeline transport (miles)	442	Table 2.01
Density of crude (grams/gallon)	3,205	CA-GREET default
Lower heating value (LHV) of crude (Btu/gallon)	129,670	CA-GREET default
Energy intensity of Ocean Tanker on trip to destination (Btu/ton-mile)	27	CA-GREET default
Energy intensity of Ocean Tanker on return trip (Btu/ton-mile)	24	CA-GREET default
Energy intensity of Pipeline (Btu/ton-mile)	253	CA-GREET default
Energy intensity of Barge on trip to destination (Btu/ton-mile)	403	CA-GREET default
Energy intensity of Barge on trip to destination (Btu/ton-mile)	307	CA-GREET default
Conversion from pounds to grams	454	
Conversion from tons to pounds	2,000	
Conversion from MJ to mmBtu	1055	
CO ₂ EF for residual oil in barge (g/mmBtu fuel burned)	84,792 (both trips)	CA-GREET default
WTT electricity CO ₂ emissions (g/mmBtu)	176,933	CA-GREET calculated
WTT Emission factor for Residual Oil (g/mmBtu)	13,538	CA-GREET default
CO ₂ EF for Electricity (g/mmBtu)	162,627	CA-GREET default

Table 2.06 details CH₄ emissions for crude transport and distribution utilizing ocean tanker and pipeline transport modes. The emissions are CA-GREET defaults. VOC, CO, and N₂O emissions are small for this group and not detailed, but are included in the total GHG emissions calculations for this part and shown in Table 2.07.

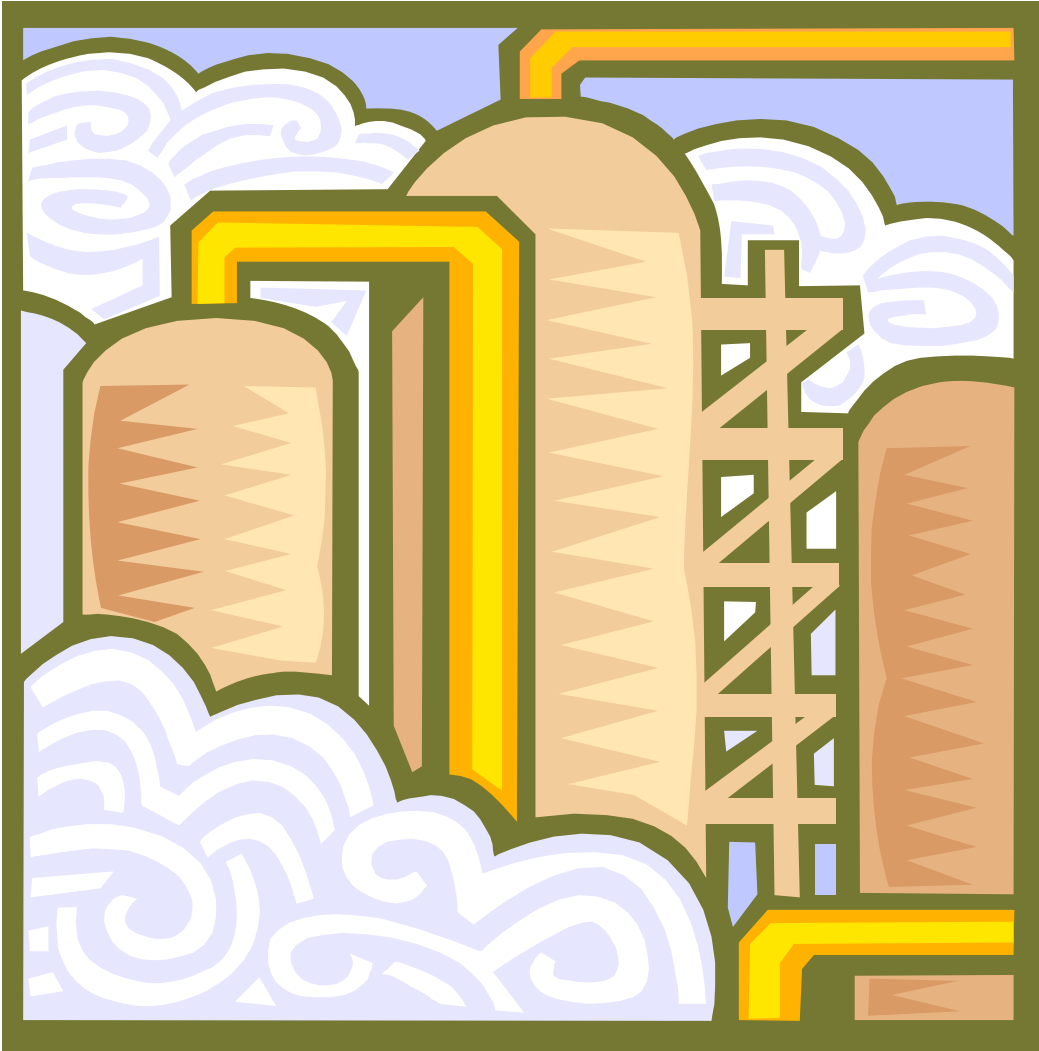
Table 2.06 Crude Transport CH₄ Emissions

	g CH₄/mmBtu
Ocean Tanker (residual oil)	0.708
Pipeline (electricity)	1.467
Barge	0.009
Total	2.184

Table 2.07 Total GHG Emissions Crude Transport and Distribution

GHG	(g/mmBtu)	Formula to convert to CO₂e	g CO₂e/mmBtu	g CO₂e/MJ
CO ₂	1,139	1,139*1	1,139	1.08
CH ₄	2.184	2.184*25	55	0.05
N ₂ O	0.025	0.025*298	7	0.01
CO	1.647	1.647*0.43*(44/ 12)	3	<0.001
VOC	0.626	0.626*0.85*(44/ 12)	2	<0.001
Total GHG emissions			1,206	1.14

Section 3. CRUDE REFINING



3.1 Energy Use for Crude Refining

Wang et al. [3] analyzed refining efficiency on a process allocation basis and, based on this analysis, calculated energy efficiency for the various fuels produced from a crude refining facility. The refinery efficiency is based on a model refinery result combined with EIA data for petroleum production. The 86.7% refinery efficiency value for ULSD is based on the AB 1007 report and is consistent with other well to wheel studies. This refinery efficiency takes into account additional energy and additional hydrogen required for sulfur removal. Figure 3 is from Wang et al. [3] and provides refining efficiencies for the various streams exiting a modern refinery and the refining for ULSD was adjusted from this to be 86.7% (see AB 1007 report).

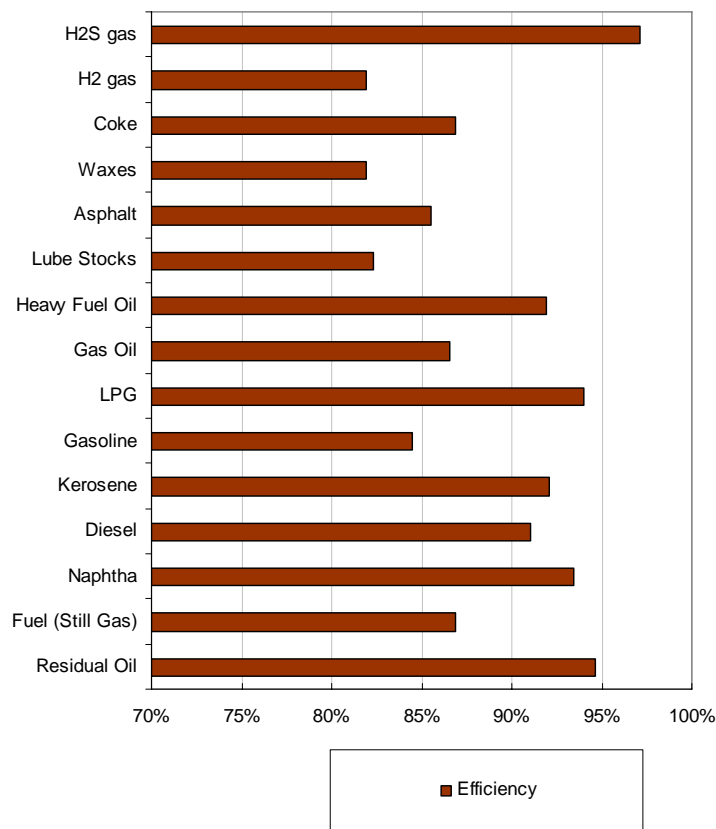


Figure 3. Efficiency of various fuel productions

The AB 1007 study used an average ULSD refining efficiency of 86.7% from the study above which is for average CA crude. This value is used to calculate the energy inputs necessary for ULSD as detailed in Table 3.01. The CA average electricity mix defined in the AB1007 analysis is assumed for refining.

Table 3.01 Details on How Efficiency is Used to Calculate Energy Needs for Crude Refining

Fuel Type	Fuel Shares	Relationship of Refinery Efficiency (0.867) and Fuel Shares	Btu/mmBtu Fuel
Residual Oil	3%	$(1,000,000)(1/0.867 - 1)(0.03)$	4,602
Natural Gas	30%	$(1,000,000)(1/0.867 - 1)(0.30)$	46,021
Coal	13%	$(1,000,000)(1/0.867 - 1)(0.13)$	19,942
Electricity	4%	$(1,000,000)(1/0.867 - 1)(0.04)$	6,136
Refinery Still Gas	50%	$(1,000,000)(1/0.867 - 1)(0.50)$	76,701
Total	100%		153,403

The values in Table 3.01 are adjusted to account for upstream WTT energy use. Table 3.02 depicts the adjustments to the values from the table above for each fuel type accounting for loss factors associated with the WTT energy for each fuel used during crude refining operations. Table 3.03 details the values and descriptions for the formulas presented in Table 3.02.

Table 3.02 Adjustment to Crude Refining to Account for Loss Factors and Other Factors

Fuel Type	Formula	Btu/mmBtu
Residual Oil	$4,602 * (1 + (A * B + C / 10^6))$	5,437
Natural Gas	$46,021 * (1 + D / 10^6)$	49,211
Coal	$19,942 * (1 + E / 10^6)$	20,344
Electricity	$6,136 * ((F + G) / 10^6)$	13,967
Refinery still gas	$76,701 * (1 + (A / 10^6))$	84,807
Total energy for refining		173,766

Table 3.03 Details for Entries in Table 3.02

Quantity	Description
A = 105,677	Energy required to produce crude as feedstock for use in US refineries, a CA-GREET calculated value. (Btu/mmBtu)
B = 1.0000	Loss factor, a CA-GREET default.
C = 75,834	Energy in Btu required to produce 1 million Btu of residual oil, a CA-GREET calculated value.
D = 69,327	Energy required to produce natural gas as a stationary fuel, a CA-GREET calculated value.
E = 20,117	Total energy required to produce coal for refining.
F = 103,008	Total energy required to produce feedstock for power generation, calculated in CA-GREET electricity analysis.
G = 2,173,222	Energy required in Btu to produce one million Btu of electricity which is calculated in CA-GREET electricity analysis.

3.2 GHG Emissions from Crude Refining

The transformation of energy from the various fuels above to useful energy required in the processing of crude to ULSD generates equipment specific GHG emissions. GHG emissions include CO₂ as well as non-CO₂ GHG gases. This document first presents the CO₂ emissions, followed by non-CO₂ emissions, which are then converted to CO₂ equivalents and summarized at the end of this section (3.2).

Table 3.04 lists CO₂ emissions by fuel type generated during the refining of crude to ULSD. Tables 3.05 and 3.06 provide details of CO₂ emissions related to use of residual oil in refineries for processing crude to ULSD.

Table 3.04 CO₂ Emissions by Fuel Type

Fuel Type	(g CO₂/mmBtu)	(g CO_{2e}/MJ)
Residual oil	450	0.43
Natural gas	2,912	2.76
Coal	1,951	1.85
Electricity	789	0.75
Refinery Still Gas	4,463	4.23
Total	10,565	10.01

Table 3.05 CO₂ Emissions from Residual Oil Use in Refineries from Table 3.04

Calculation Details	g CO₂/mmBtu	Reference
4,602*(emissions factor for an industrial residual oil boiler*Loss Factor + emissions from residual oil + emissions from crude oil)/10 ⁶	450	CA-GREET default

Table 3.06 Values for use in Table 3.05

Factor	Value	Reference
Emissions factor for an industrial residual oil boiler	85,045 g CO ₂ /mmBtu	CA-GREET default
Residual oil loss factor	1.0000	CA-GREET default
Emissions from residual oil	5,308 grams CO ₂ /mmBtu	CA-GREET default
Emissions from crude oil	7,340 grams CO ₂ /mmBtu	CA-GREET default

Tables 3.07 and 3.08 provide details on CO₂ emissions from natural gas use in crude refining to ULSD.

Table 3.07 CO₂ Emissions from Natural Gas from Table 3.04

Calculation details	g CO₂/mmBtu	Reference
46,021*(share from NG engine*emission factor for NG engine)+(share from large turbine*emission factor for large turbine +(share from large industrial boiler*emission factor for large industrial boiler) + (share from small industrial boiler *emission factor for small industrial boiler) + Emissions from natural gas as a stationary fuel/10 ⁶	2,912	CA-GREET default

Table 3.08 Details of Values Used in Table 3.07

	Shares	Emissions factor (g CO ₂ /mmBtu)	Reference
Share from natural gas engine	0%	56,551	CA-GREET default
Share from large turbine	25%	58,179	CA-GREET default
Share from large industrial boiler	60%	58,198	CA-GREET default
Share from small industrial boiler	15%	58,176	CA-GREET default
Emissions from natural gas as a stationary fuel		3,482	CA-GREET default

Electricity contributions to GHG emissions are provided in Tables 3.09 to 3.15, both for feedstock production and feedstock consumption.

Table 3.09 CO₂ Emissions from Electricity from Table 3.04

	Details Calculation	g CO ₂ /mmBtu
Electricity as feedstock	$6,136 \times 7,135 / 10^6$	44
Electricity as fuels	$6,136 \times 121,444 / 10^6$	745
Total		789

Note: 6,136 Btu/mmBtu is energy of electricity used in ULSD refining (see table 3.01)

To calculate CO₂ emissions above:

CO₂ emission from power plant + VOC and CO emissions conversion from power plant, where:

- CO₂ from power plant = $6,136 \times (\text{Specific Power Plant Emission Factor}) \times \% \text{ of generation mix} / (1 - \% \text{ assumed loss in transmission}) / 10^6$, then convert from g/kWh to gCO₂e/mmBtu by multiplying g/kWh by $(10^6/3412)$.
- VOC and CO conversion are from CA-GREET defaults.

Table 3.10 Type of Power Generation Plant and Associated Emission Factors

Power Plant Type	Generation Mix	CO₂ Emission Factor (g/kWhr)	Loss in transmission
Oil-fired	0.1%	907	8.1%
Nat. Gas-fired	43.1%	554	8.1%
Coal-fired	15.4%	1,050	8.1%
Nuclear	14.8%	0	8.1%
Biomass	1.1%	0	8.1%
Renewables	25.6%	0	8.1%

Table 3.11 provides a breakdown of CO₂ emissions from electricity generation into feedstock production and feedstock consumption (as fuels). Production refers to mining or other methods to actually procure the feedstock necessary for use in electricity generation. Feedstock production accounts for about 5.7% of the total emissions and feedstock consumption to generate electricity accounts for the balance of 94.3%.

Table 3.11 CO₂ Emissions from Electricity

	gCO₂/mmBtu	% share
Feedstock Production	7,135	5.7%
Feedstock Consumption	121,444	94.3%
Total	128,579	

ULSD refining also results in CO₂ emissions from vented sources (non-combustion), as shown in Table 3.12.

Table 3.12 CO₂ Emissions from Non-Combustion Sources

	gCO₂/mmBtu	gCO₂e/MJ
Non-combustion	1,477	1.40

Table 3.13 and 3.14 provide details of CO₂ emissions related to feedstock electricity production.

Table 3.13 CO₂ Emissions from Electricity (feedstock production)

Fuel Share	Relationship of Energy Use and CO₂ Emissions	Energy Use Emissions g CO₂/mmBtu
Residual oil	$1,563 * (\text{crude emission factor} * \text{crude loss factor} + \text{residual oil emission factor}) / 10^6$	19
Natural gas	$1,203,887 * (\text{natural gas emission factor}) / 10^6$	6,038
Coal	$491,417 * (\text{coal emission factor}) / 10^6$	739
Biomass	$37,288 * (\text{biomass emission factor}) / \text{farmed trees heating value}$	-160
Nuclear	$161,044 * (\text{uranium emission factor}) / (\text{conversion factor for nuclear power plants} * 1000 * 3412)$	435
Other*	$\text{VOC emissions} * \text{Carbon ration of VOC} / \text{Carbon ratio of CO}_2 + \text{CO emissions} * \text{Carbon ration of CO} / \text{Carbon ratio of CO}_2$	64
Total		7,135

* "Other" is a combination of hydro, wind, geothermal, etc.

The numerical values used in the table above are the direct energies from feedstocks used at power plants to generate one mmBtu of electricity at the use site (see Table 1.10).

Table 3.14 Factors and Values for Use in Table 3.13

Description		REET default
Crude WTT emissions (to U.S refineries)	(Petroleum worksheet)	7,458 g CO ₂ /mmBtu
Crude loss factor		1.000
Residual oil WTT emissions	(Petroleum worksheet)	5,308 g CO ₂ /mmBtu
Natural gas WTT emissions	(NG worksheet)	5,015 g CO ₂ /mmBtu
Coal WTT emissions	(Coal worksheet)	1,505 g CO ₂ /mmBtu
Biomass WTT emissions (Farmed Trees) (sum of factors for trees farming, fertilizer, pesticides, and trees T&D)	EtOH worksheet	-10,527 g CO ₂ /mmBtu
Farmed trees heating value (LHV, Btu/ton)	Fuel_Specs worksheet	16,811,000 Btu/ton
Uranium WTT CO ₂ emissions	Uranium worksheet	63,765 g CO ₂ /mmBtu
Conversion factor for nuclear power plants		6.926 MWh/g of U-235
Carbon Ratio of VOC		0.85
Carbon Ratio of CO		0.43
Carbon Ratio of CO ₂ (12/44)		0.27

Table 3.15 shows the relationship between the energies used from feedstocks at a power plant (to produce one mmBtu of electricity to the use site) and the conversion efficiencies of electrical generation for each feedstock used, after taking into account the loss (8.1%) from the transmission of electricity.

Table 3.15 Energy Breakdown from Electricity (Feedstock Consumption)

Fuel Shares	Conversion Efficiency	Generation Mix	Relationship of Conversion Efficiency and Energy Use	Energy Use (Btu/mmBtu)
Residual oil	34.8%	0.05%	$(10^6/0.348)*(1/1-0.081)*0.0005$	1,563
Natural gas	39.0%	43.1%	$(10^6/0.390)*(1/1-0.081)*0.431$	1,203,888
Coal	34.1%	15.4%	$(10^6/0.341)*(1/1-0.081)*0.154$	491,418
Biomass	32.1%	1.1%	$(10^6/0.321)*(1/1-0.081)*0.011$	37,288
Nuclear	100%	14.8%	$(10^6/1.00)*(1/1-0.081)*0.148$	161,045
Other*	100%	25.6%	$(10^6/1.00)*(1/1-0.081)*0.255$	278,020
Total				2,173,222

* "Other" is a combination of hydro, wind, geothermal, etc.

Tables 3.16 and 3.17 detail CO₂ emissions from use of refinery still gas in crude refining operations.

Table 3.16 CO₂ Emissions from Use of Refinery Still Gas

Calculation	Value (g CO ₂ /mmBtu)	Reference
Emissions from refinery still gas as a stationary fuel* (share from engine*natural gas engine emission factor) + (share from large turbine*emission factor for large natural gas turbine) + (share from large industrial boiler*emission factor for large industrial boiler) + (share from small industrial boiler *emission factor for small industrial boiler) + (Emissions from natural gas as a stationary fuel)/10 ⁶	4,463	CA-GREET default calculation

Table 3.17 Values Used in Table 3.16

Description	Shares	Emission Factor (g CO ₂ /mmBtu)	Reference
Natural Gas, engine	0	56,551	CA-GREET default
Natural Gas, large turbine	25%	58,179	CA-GREET default
Natural Gas, large Industrial boiler	60%	58,198	CA-GREET default
Natural Gas, small Industrial boiler	15%	58,176	CA-GREET default
Emissions from natural gas as a stationary fuel		5,088	CA-GREET default

CH₄ emissions and N₂O emissions from crude refining are shown in Tables 3.18 and 3.19. VOC and CO contributions are small and not further detailed here. They are however included in Table 3.20 below.

Table 3.18 CH₄ Emissions Converted to CO₂e

Fuel	g CH₄/mmBtu	g CO₂e/MJ
Residual oil	0.517	0.01
Natural gas	6.015	0.14
Coal	2.469	0.06
Electricity	1.652	0.04
Refinery Still Gas	0.145	0.00
Total	10.799	0.26

Table 3.19 N₂O Emissions

Fuel	g N₂O/mmBtu	g CO₂e/MJ
Residual oil	0.002	0.00
Natural gas	0.031	0.01
Coal	0.012	0.00
Electricity	0.013	0.00
Refinery Still Gas	0.047	0.01
Total	0.106	0.03

Table 3.20 summarizes the total GHG emissions from crude refining. Note that non-CO₂ gases have been converted to CO₂ equivalents using conversion factors detailed earlier in this document.

Table 3.20 GHG Emissions from Crude Refining

GHG	(g/mmBtu)	Conversion to CO₂e	g CO₂e/mmBtu	g CO₂e/MJ
CO ₂	10,565	10,565 *1	10,565	10.01
CH ₄ (combustion)	10.799	10.799*25	270	0.26
N ₂ O	0.106	0.106*298	31	0.03
CO	5.413	5.413*0.43 *(44/12)	9	0.01
VOC	0.814	0.814*0.85*(44/12)	3	0.00
Total			10,877	10.31

Section 4. ULSD TRANSPORT AND DISTRIBUTION



4.1 Energy Use for Transport and Distribution of ULSD

Table 4.01 shows the energy inputs used in transporting ULSD to trucking terminals. The energy intensity of 253 Btu/ton-mi is a default CA-GREET value based on a composite of natural gas compressor prime movers. The 50 mile distance is based on an average for California pipeline delivery and is documented in the AB 1007 report. The fuel shares input assumption is 100% electric motors based on the AB 1007 analysis of petroleum infrastructure in California. The energy intensity is multiplied by an adjustment factor for each type of pipeline motor. In this case the electric motor adjustment factor is 100% (a CA-GREET default value). The total energy is then calculated, including the WTT energy to produce electricity.

Table 4.02 shows the energy inputs for truck transport. The calculation is based on a tanker truck capacity of 9,000 gallons (25 metric tons) and a transport distance of 50 miles. The 50 mile distance is based on a survey of California fuel delivery trucks and is documented in the AB 1007 report. CA-GREET calculates the diesel energy per ton-mile based on the cargo capacity of the truck and its fuel economy.

Table 4.03 shows the total energy calculations used in CA-GREET. Here the pipeline and truck values are weighted by the fraction of fuel delivered by each mode. 80% of the gasoline is assumed to be piped to a blending terminal because some refineries fill trucks at the loading rack adjacent to the refinery. 99.4% of the gasoline is assumed to be transported to fueling stations by delivery trucks. The remaining 0.6% corresponds to the few fueling stations where gasoline is provided directly by pipeline. Table 4.04 details the values used in the formulas presented in Table 4.03. The total transport energy for ULSD shown in Table 4.03 includes energy associated with feed loss, which is calculated based on the VOC emissions (g/mmBtu) from the bulk terminal and refinery stations (see note below Table 4.03).

Table 4.01 Energy use for Transport and Distribution via Pipeline

	Energy Intensity (Btu/ton-mile)	Distance from Origin to Destination (miles)	Type of Power Generation	Shares of the type of turbine used	Distributed by pipeline
Pipeline	253	50	Electric Motor	100 %	80%*

*Assumed 20% transported directly from refinery terminal rack

Table 4.02 Energy use for Transportation and Distribution ULSD via HDD Truck

	Energy Intensity (Btu/ton-mile)	Distance from Origin to Dest. (miles)	Capacity (tons)	Fuel used (miles/gal)	Energy use of HDD truck (Btu/mile)	Shares of Diesel used	Transport/Distribution by truck
HDD Truck Transport	1,028	50	25	5	25,690	100%	20%
HDD Truck Distribution	1,028	50	25	5	25,690	100%	99.4%*

* Assumed 0.6% CARBOB is transported directly by pipeline to about 50 stations

Table 4.03 Details of Energy Uses for ULSD Transportation and Distribution

Transport mode	Details Calculations	Btu/mmBtu
Feed Loss	$(\text{Loss Factor} - 1) \times 10^6$	49
ULSD transported by pipeline	$(\text{Density of ULSD/LHV of ULSD}) \times (1/454) \times (1/2000) \times (\text{energy consumed by pipeline}) \times (\text{miles transported one-way}) \times 100\% \times 100\% \times (2.276) \times 80\% \times 10^6 = [(2819/127464)/(454 \times 2000)] \times 253 \times 50 \times 100\% \times 100\% \times (2.276 \times 80\% \times 10^6) = 561$	561
ULSD Transport by HDD truck	$(\text{Density of ULSD/LHV of ULSD}) \times (1/454) \times (1/2000) \times (\text{energy consumed by HDD truck}) \times (\text{miles transported one-way} + \text{miles transported one-way backhaul}) \times 100\% \times (1 + 0.232) \times 20\% \times 10^6$	617
ULSD Distribution by HDD truck	$(\text{Density of ULSD/LHV of ULSD}) \times (1/454) \times (1/2000) \times (\text{energy consumed by HDD truck}) \times (\text{miles transported one-way} + \text{miles transported one-way backhaul}) \times 100\% \times (1 + 0.232) \times 99.4\% \times 10^6$	3,066
Total		4,293

Note: Loss factor = $[(\text{VOC from bulk terminal} + \text{VOC from refinery stations})/\text{ULSD Density}] \times (\text{ULSD LHV}/10^6) + 1$

Table 4.04 Values of Properties Used in Table 4.03

Properties	Values	Source
Feed loss (Btu/mmBtu)	44	CA-GREET calculation
Lower heating value of ULSD (Btu/gallon)	127,464	AB 1007 value
Density of ULSD (grams/gallon)	2,819	CA-GREET default
Energy consumed by Pipeline (Btu/ton-mile)	253	CA-GREET default
Conversion from pounds to grams	454	
Conversion from tons to pounds	2,000	
Energy intensity of ULSD transported by HDD truck (Btu/ton-mile)	1,028	AB 1007 value
ULSD transport one-way (mile)	50	AB 1007 value
Energy consumed in electricity used as transportation fuel in ULSD Production (Btu/Btu)	2.276	CA-GREET calculation
Energy consumed in diesel used as transportation fuel in ULSD Production (Btu/Btu)	0.232	CA-GREET calculation
VOC from bulk terminal (g/mmBtu)	0.207	CA-GREET Default
VOC from refinery stations (g/mmBtu)	0.880	CA-GREET Default

Note:

- 2.276 is the WTT energy for electricity calculated in CA-GREET = (energy consumed to produce feedstock + Energy consumed to produce electricity)/106 = (2,173,222+102,959)/10⁶
- 0.228 is the diesel adjustment factor = energy of crude oil transported to the US refineries*loss factor of diesel + WTT energy of conventional diesel.

4.2 GHG Emissions for Transportation and Distribution of CARBOB

Table 4.05 details only CO₂ emissions for the transport and distribution of finished ULSD.

Table 4.05 CO₂ from ULSD Transportation and Distribution

	Miles traveled 1-way	Energy Intensity (Btu/mile-ton)	Assumed % usage	CO₂ (g/mmBtu)	CO₂e (g/MJ)
Transported by Pipeline	50	253	80%	35	0.03
Transport by HDD Truck	50	1028	20%	31	0.03
Distributed by HDD Truck	50	1028	99.4%	156	0.15
Total				223	0.21

Note:

- For pipeline: assumed shares of power generation are divided as following: turbine 55%, current NG engine 33%, and 12% future NG engine (CA-GREET defaults)
- For HDD Truck: assumed energy consumption at 25,690 Btu/mile, average speed at 5 mph, and 25 tons capacity load of ULSD.
for delivery to a blending station after taking consideration of 80% and 99.4% mode shares of pipeline

Table 4.06 provides details for all GHG emissions for ULSD transport and distribution. This includes CH₄, N₂O, VOC combined with CO₂.

Table 4.06 Details of GHG from ULSD Transportation and Distribution

	g/mmBtu		g/MJ		Total (g/MJ)
	Transp.	Distr.	Transp.	Distr.	
CO ₂	66	156	0.06	0.15	0.21
CH ₄	3	5	<0.01	<0.01	<0.01
N ₂ O	0.405	1.148	<0.01	<0.01	<0.01
CO	0.139	0.487	<0.01	<0.01	<0.01
VOC	0.055	0.211	<0.01	<0.01	<0.01
Total	70.1	163.0	0.07	0.15	0.22

Section 5. CARBON EMISSIONS FROM ULSD COMBUSTION



5.1 Combustion Emissions from Fuel

GHG emissions from the fuel occur during vehicle operation. The engine burns fuel which primarily forms CO₂. A small fraction of the fuel is emitted as CO, hydrocarbons, methane, or particulate matter. Since CO and hydrocarbon emissions are converted to CO₂ in the atmosphere within a few days, the carbon emissions are treated as CO₂. CA-GREET uses the carbon content in the fuel to calculate GHG emissions. In the CA-GREET model, these fuel CO₂ emissions are shown in a per mile basis and are embedded in the tank to wheel calculations. The calculations below show the CO₂ emissions per MMBtu and MJ of fuel. The carbon in fuel is calculated from the carbon content in the fuel and fuel density. Table 5.01 provides input values and sources of these values used in calculating carbon emissions from fuel. The average carbon ratio in ULSD is 86.5% (by weight) which translates to about 78,179 grams of CO₂ per mmBtu of fuel (74.10 g CO₂/MJ).

Table 5.01 Inputs and Assumptions used for Calculating Combustion GHG Emissions

Description	Value	Reference
Lower Heating Value of ULSD	127,464 Btu/gal	CA-GREET
Density of ULSD	3,142 g/gal	CA-GREET
Molecular weight of CO ₂	44 g/mole	
Atomic weight of C	12 g/mole	
C factor	12/44 = 0.27	
Carbon ratio in ULSD	86.5 % (by weight)	CA-GREET
MJ to mmBtu conversion	1,055	
Fossil carbon in gasoline: $3,142 \times 86.5\% \times 44 / 12 / 127,464 \times 10^6 = 78,179$ g CO ₂ /MMBtu = 74.10 g CO ₂ /MJ CO ₂ from fuel = Density * carbon ratio in gasoline / (C factor * LHV)		

Table 5.02 CH₄ and N₂O Combustion Emissions for HDVs

Description	Value	Reference
Lower heating value of ULSD	127,464 Btu/gal	CA-GREET
Density of ULSD	3,142 g/gal	CA-GREET
CH ₄ emission factor (g/mi)	0.035 g/mi	EMFAC Calculation
N ₂ O emission factor (g/mi)	0.048 g/mi	EMFAC Calculation
Vehicle Energy Use	6.1 mpg	EMFAC parameter
CH ₄ emissions (g-CO ₂ e/MJ)	0.045	EMFAC Calculation
N ₂ O emissions (g-CO ₂ e/MJ)	0.735	EMFAC Calculation

GHG emissions from Tables 5.01 and 5.02 are combined to provide a total TTW GHG emissions of 79.27 gCO₂e for ULSD and is provided in Table 5.03

Table 5.03 Total TTW GHG Emissions for ULSD

Parameter	GHG (gCO₂e/MJ)
CO ₂	74.10
N ₂ O	0.735
CH ₄	0.045
Total	74.9

APPENDIX B

ULSD Pathway Input Values

Scenario: Average Crude Oil to California refineries to make ULSD

Parameters	Units	Values	Note
GHG Equivalent			
CO ₂		1	
CH ₄		25	
N ₂ O		298	
VOC		3.1	
CO		1.6	
Crude Recovery			
Efficiency		92.7%	
Process Shares			
Crude		0.6%	
Residual Oil		0.6%	
Conventional Diesel		8.6%	
Pet. Coke		0.4%	
Conventional Gasoline		1.1%	
Natural Gas		72.1%	
Electricity		16.5%	
Feed Loss crude recovery		0.1%	
Equipment Shares			
Commercial Boiler - Diesel		25%	
CO ₂ Emission Factor	gCO ₂ /mmBtu	78,167	
Stationary Reciprocating Eng. - Diesel		50%	
CO ₂ Emission Factor	gCO ₂ /mmBtu	77,349	
Turbine - Diesel		25%	
CO ₂ Emission Factor	gCO ₂ /mmBtu	78,179	
Stationary Reciprocating Eng. - NG		50%	
CO ₂ Emission Factor	gCO ₂ /mmBtu	56,551	
Small Industrial Boiler - NG		50%	
CO ₂ Emission Factor	gCO ₂ /mmBtu	58,176	
Transportation to CA refineries			
Pipeline shares		42%	
Pipeline distance	miles	150	One way
Pipeline Energy Intensity	Btu/mile-ton	253	
Transportation to US refineries			
Pipeline distance	miles	266	One way
Pipeline Energy Intensity	Btu/mile-ton	253	
Ocean Tanker distance traveled	miles	3,550	One way
Ocean Tanker Energy Intensity	Btu/mile-ton	27	24 Btu/mile-ton for return trip
Loss Factor in Crude T&D		1.000062	
CARBOB Refining			
Efficiency		84.5%	
Process Shares			
Residual Oil		3%	
Natural Gas		30%	
Pet. Coke		13%	
Electricity		4%	
Still Gas		50%	
Equipment shares			
Large Turbine - Natural Gas		25%	
CO ₂ Emission Factor	gCO ₂ /mmBtu	58,179	
Large Industrial Boiler - Natural Gas		60%	

Parameters	Units	Values	Note
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	58,198	
Small Industrial Boiler - Natural Gas		15%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	58,176	
Industrial Boiler - Residual Oil		100%	
<i>CO₂ Emission Factor</i>	gCO ₂ /mmBtu	85,045	
Transportation			
Transportation by pipeline		80%	20% directly from refinery terminal rack
<i>Distance</i>	miles	50	
<i>Energy Intensity</i>	Btu/ton-mile	253	
<i>Transportation by truck</i>		20%	
<i>Distance</i>	miles	50	
<i>Energy Intensity</i>	Btu/ton-mile	1028	
Distribution by truck		99.4%	0.6% directly supplied by pipeline
<i>Distance</i>	miles	50	
<i>Energy Intensity</i>	Btu/ton-mile	1,028	
<i>Loss Factor in CARBOB T&D</i>		1.000201	
Fuels Properties	LHV (Btu/gal)	Density (g/gal)	
<i>Crude</i>	129,670	3,205	
<i>Residual Oil</i>	140,353	3,752	
<i>Conventional Diesel</i>	128,450	3,167	
<i>Conventional Gasoline</i>	116,090	2,819	
<i>CaRFG</i>	111,289	2,828	
<i>CARBOB</i>	113,300	2,767	
<i>Natural Gas</i>	83,686	2,651	NG Liquids
<i>Ethanol</i>	76,330	2,988	
<i>Still Gas</i>	128,590		
Transportation Mode			
<i>Ocean Tanker</i>	tons	250,000	Crude Oil
	tons	150,000	Gasoline
<i>Heavy Duty Truck</i>	tons	25	Crude Oil
	tons	25	Gasoline

References

¹ <http://www.transportation.anl.gov/software/GREET/>

² AB 1007 Study: <http://www.energy.ca.gov/ab1007>

³ Refinery Energy Efficiency Allocation Analysis based on: Wang, M., et al. (2004) Allocation of Energy Use in Petroleum Refineries to Petroleum Products Implications for Life-Cycle Energy Use and Emission Inventory of Petroleum Transportation Fuels. LCA Case Studies.