California Environmental Protection Agency
Air Resources Board

Detailed California-Modified GREET Pathway for Compressed Natural Gas (CNG) from North American Natural Gas

Stationary Source Division

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Version 2.1

The Staff of the Air Resources Board developed this preliminary draft version as part of the Low Carbon Fuel Standard Regulatory Process

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

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SUMMARY


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CA-GREET Model Pathway for CNG from North American Natural Gas

Well-To-Tank (WTT) Life Cycle Analysis of a 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. Together, WTT and TTW analysis are combined to provide a total Well-To-Wheel (WTW) analysis.

A Life Cycle Analysis Model called the **G**reenhouse gases, **R**egulated **E**missions, and **E**nergy use in **T**ransportation (GREET)[1] developed by Argonne National Laboratory forms the core basis of the methodology used in this document. The model however, was modified by TIAX under contract to the California Energy Commission during the AB 1007 process[2]. Using this model, staff developed a pathway document for compressed natural gas (CNG) 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 February 2009) forms the basis of this document. It has been used to calculate the energy use and greenhouse gas (GHG) emissions generated during the process of producing and using compressed natural gas (CNG) from North American natural gas (NA NG) in an internal combustion engine.

The pathway includes natural gas recovery, processing, transport & distribution, compression at a CNG refueling station and use in an internal combustion vehicle. Figure 1 shows the discrete components that form the CNG from NA NG pathway. This document presents all assumptions, and step by step calculations of energy consumption and GHG emissions for this CNG pathway. Several general descriptions and clarification of terminology used throughout this document are:

- CA-GREET employs a recursive methodology to calculate energy consumption and emissions. To calculate WTT energy and emissions, the values being calculated are often utilized in the calculation. For example, crude oil is used as a process fuel to recover crude oil. The total crude oil recovery energy consumption includes the direct crude oil consumption AND the energy associated with crude recovery (which is the value being calculated).

- Btu/mmBtu is the energy input necessary in Btu to produce or transport one million Btu of a finished (or intermediate) product. This description is used consistently in CA-GREET for all energy calculations. There are 1,055 MJ in one mmBtu of energy, so in order to convert one million Btu into MJ, divide the million Btu by 1055.

- gCO_2e/MJ provides the total greenhouse gas emissions on a CO_2 equivalent basis per unit of energy (MJ) for a given fuel. Methane (CH_4) and nitrous oxide (N_2O) are converted to a CO_2 equivalent basis using IPCC global warming potential values and included in the total.

- CA-GREET assumes that VOC and CO are converted to CO_2 in the atmosphere and includes these pollutants in the total CO_2 value using ratios of the appropriate molecular weights.

- Process Efficiency for any step in CA-GREET is defined as:

Efficiency = energy output / (energy output + energy consumed)

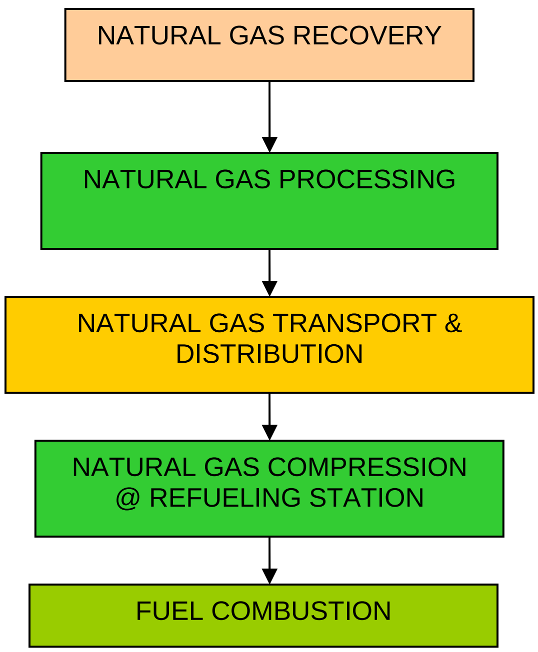

Figure 1. Discrete Components of the North American Natural Gas to CNG Pathway.

Table A below provides a summary of the results for this CNG pathway. The WTW analysis for CNG results in **1,113,153** Btu of energy required to produce 1 (one) mmBtu of available fuel energy. From a GHG perspective, **68.0** gCO_2e/MJ of GHG emissions are generated during the production and use of CNG in **a heavy duty vehicle**.

Note that rounding of values has not been performed in several tables in this document. This is to allow stakeholders executing runs with the GREET model to compare actual output values from the CA-modified model with values in this document.

Table A. Summary of Energy Consumption and GHG Emissions per mmBtu of CNG Produced from NA NG

	Energy Required (Btu/mmBtu)	**% Energy Contribution**	**GHG Emissions (gCO_2e/MJ)**	**%Emissions Contribution**
Well-to-Tank				
Natural Gas Recovery	31,207	2.8%	3.5	5.1%
Natural Gas Processing	31,862	2.9%	3.7	5.5%
Transport & Distribution	9,348	0.8%	0.97	1.4%
Compression at Station	40,736	3.7%	2.14	3.1%
Total Well-to-Tank	**113,153**	**10.2%**	**10.31**	**15.1%**
Tank-to-Wheel				
Carbon in Fuel	1,000,000	89.8%	55.2	81.1%
Vehicle CH_4 and N_2O			2.5	3.8%
Total Tank-to-Wheel	**1,000,000**	**89.8%**	**57.7**	**84.9%**
Total Well-to-Wheel	**1,113,153**	**100%**	**68.0***	**100%**

Note: percentages may not add to 100 due to rounding

*** Note: For NG from California, the WTW GHG emissions are calculated to be 67.7 gCO_2e/MJ.**

For this pathway it is assumed that except for the NG to CNG compression, all other use of electricity is U. S. Average electricity and appropriate energy and emissions factors for this mix have been used for this pathway document. For compression of NG to CNG in California, energy is provided by marginal California electricity, which is based on natural gas and renewable power.

The values in Table A are used to show pictorially in Figure 2 the relative contributions of each of the discrete components of this pathway. The charts are shown separately for energy use and GHG emissions. From an energy viewpoint, energy in fuel as carbon (89.8%) makes up the bulk of the WTW analysis. From a GHG perspective, carbon in fuel (81.1%) is the dominant source for GHG emissions for this pathway.

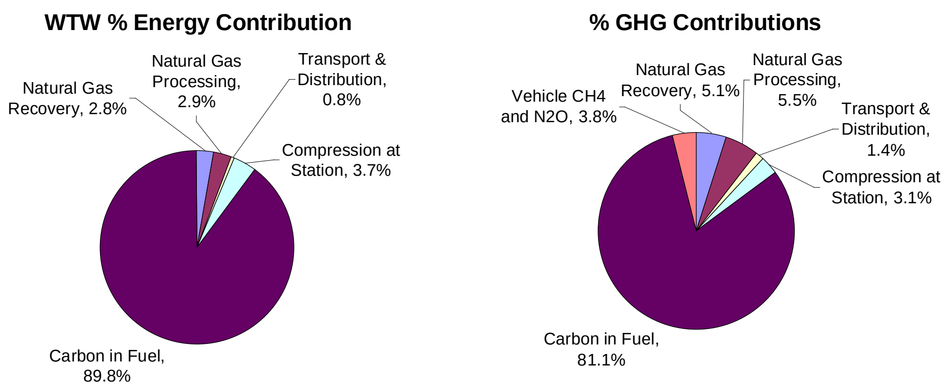

Figure 2. Energy and GHG Contributions of CNG

The following sections provide summaries of each of the four WTT components as well as the TTW values. Expanded details are provided in Appendix A. A table of all input values is provided in Appendix B.

Natural Gas Recovery

Tables B and C provide a summary of the energy consumption and associated GHG emissions from natural gas recovery. Calculation details are provided in Appendix A.

Table B. Total Energy Consumption by Fuel Type for Natural Gas Recovery

Fuel Type	Btu/mmBtu
Residual Oil	288
Diesel Fuel	3,313
Gasoline	311
Natural gas	23,328
Electricity	676
NG Leaks	3,290
Total	**31,207**

Table C. Total GHG Emissions from Natural Gas Recovery

	GHG gCO_2e/MJ
Residual Oil	0.023
Diesel	0.260
Gasoline	0.024
Natural Gas	1.40
Electricity	0.06
NG Leakage	1.71
Total	**3.5**

Natural Gas-Processing

Tables D and E provide the energy consumption and associated GHG emissions from natural gas processing. Calculation details are provided in Appendix A.

Table D. Total Energy Consumption for the Natural Gas Processing Step

Fuel Type	**Btu/mmBtu**
Diesel Fuel	323
Natural gas	27,889
Electricity	2,172
NG Leaks	1,479
Total Energy	**31,862**

Table E. Total GHG Emissions from Natural Gas Processing

	GHG gCO_2e/MJ
Diesel	0.02
Natural Gas	1.57
Electricity	0.18
NG Leakage	0.77
Non-Combustion Processing	1.18
Total	**3.7**

Natural Gas Transport

Tables F and G summarize energy consumption and GHG emissions from natural gas transport. Calculation details are provided in Appendix A.

Table F. Energy Use for NG Transport

Total T&D Energy Use = 9,348 Btu/mmBtu

Table G. GHG Emissions from Natural Gas Transport to Refueling Station

	CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Total	**532**	**19.64**	**0.015**	**1,028**	**0.97**

Natural Gas Compression

Tables H and I provide a summary of energy consumption and GHG emissions from natural gas compression at the refueling station. Calculation details are provided in Appendix A.

Table H. Energy Use for NG Compression, Btu/mmBtu

Total electricity use for compression is 40,736 Btu/mmBtu

Table I. Total GHG Emissions Associated with Natural Gas Compression

	CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Total	**2,136**	**4.22**	**0.053**	**2257**	**2.14**

Natural Gas Tank to Wheel

This section provides a summary of GHG emissions from combusting NG in an engine. Details of calculations are provided in Appendix A. Table J provides details of WTT GHG emissions from combusting NG in a Heavy Duty vehicle.

Table J. Well to Tank GHG Emissions for NG

TTW = Vehicle GHG = 57.7 gCO_2e/MJ

APPENDIX A

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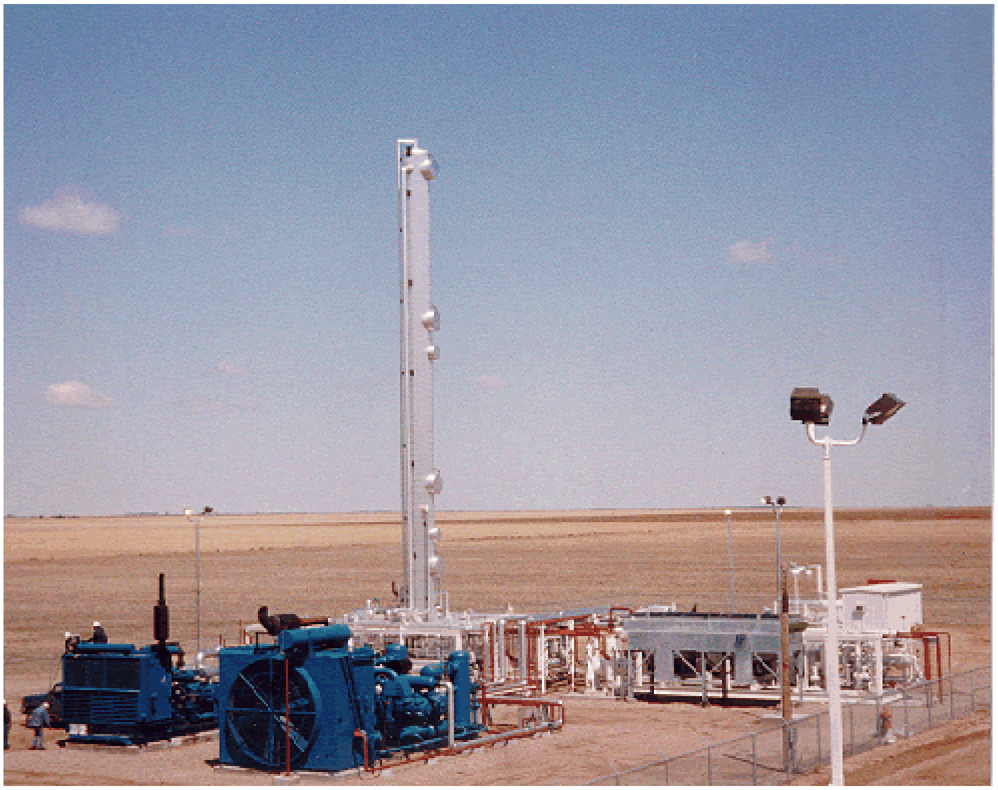
SECTION 1. NATURAL GAS RECOVERY



1.1 Energy Use for Natural Gas Recovery

The first step in the NG pathway is natural gas recovery. There are three key assumptions made to calculate direct energy consumption for natural gas recovery:

- Process efficiency (97.2%, CA-GREET Default)
- Fuel Shares (split of total energy consumed by fuel type, CA-GREET Default)
- Natural Gas Leak Rate (0.35%, CA-GREET Default)

The assumed process efficiency of 97.2% means that it takes 0.028 mmBtu of energy to recover 1 mmBtu of NG. The efficiency assumption is coupled with an assumed split of fuels used in natural gas recovery to arrive at direct energy use by fuel to recover NA NG. The results of this calculation are provided in Table 1.01

Table 1.01. Calculation of Direct Energy Consumption (Btu/mmBtu) to Recover Natural Gas from Assumed Values for NG Recovery Efficiency and Fuel Shares

Process Fuel Type	Fuel Shares	Relationship of Recovery Efficiency (0.972) and Fuel Shares	Direct Energy Consumption, Btu/mmBtu
Residual oil	0.9%	$(10^6)(1/0.972 – 1)$ (0.009)	255
Diesel fuel	9.7%	$(10^6)(1/0.972 – 1)$ (0.097)	2,807
Gasoline	0.9%	$(10^6)(1/0.972 – 1)(0.009)$	255
Natural gas	76.2%	$(10^6)(1/0.972 – 1)(0.762)$	21,944
Electricity	0.9%	$(10^6)(1/0.972 – 1)(0.009)$	255
Feed Loss (Leak)	11.4%	$(10^6)(1/0.972 – 1)(0.114)$	3,290
Total Direct Energy Consumption for NG recovery			**28,807**

The feed loss (leak) share of 11.4% is back calculated from an assumed leak fraction of 0.35% (0.0035 g methane leaks per g natural gas). This is converted to g/mmBtu using the natural gas density and heating value.

The values provided in Table 1.01 are direct energy consumption per for the natural gas recovery step. This is not the total energy required however, since CA-GREET accounts for the "upstream" energy associated with each of the fuels utilized to recover natural gas. For example, 255 Btu of residual oil are required to recover each mmBtu of natural gas. The total energy associated with the 255 Btu of residual oil includes the energy to recover the crude and refine it to residual oil.

Table 1.02 demonstrates how the direct energy values shown in Table 1.01 are utilized to calculate total energy required to recover natural gas. Table 1.03 provides details on the values used in Table 1.02. Table 1.04 details values used in Table 1.03.

Table 1.02. Total Energy Consumption from Direct Energy Consumption for NG Recovery

Fuel Type	Formula	Btu/mmBtu
Residual Oil	$(A + A*(B*D + C)/ 10^6) * L1*L2$	288
Diesel Fuel	$(E + E* (F*G + H)/ 10^6)* L1 * L2$	3,313
Gasoline	$(I + I* (J*K + L)/ 10^6) * L1 * L2$	311
Natural gas	$(M + M*(N + O) /10^6) * L1 * L2$	23,328
Electricity	$(P (Q + R)/ 10^6) * L1 * L2$	676
NG Leaks	3,227 * L1 * L2	3,290
Total energy for natural gas recovery		**31,207**

Table 1.03. Values Used in Table 1.02

Fuel Type	Description
A	255 Btu of direct residual oil used per mmBtu NG recovered. (see Table 1.01)
B	55,561 Btu are required to recover 1mmBtu crude for US refineries.
C	74,866 Btu are required to produce 1 mmBtu residual oil (not including crude recovery & transport).
D	1.0000 is the loss factor for residual oil. This is a CA-GREET default.
E	2,807 Btu of direct conventional diesel used per mmBtu NG recovered. (see Table 1.01)
F	The energy to recover crude is 55,561 Btu /mmBtu crude.
G	The conventional diesel fuel loss factor is 1.0000. This is a CA-GREET default.
H	The energy to produce conventional diesel fuel is 124,812 Btu/mmBtu (not including crude recovery & transport).
I	255 Btu of direct conventional gasoline used per mmBtu NG recovered. (see Table 1.01)
J	The energy to recover crude is 55,561 Btu/mmBtu crude.
K	1.0008 is the loss factor for conventional gasoline and is a CA-GREET default
L	To refine & transport conventional gasoline, 164,227 Btu/mmBtu gasoline is used.
M	21,944 Btu of direct NG fuel used per mmBtu NG recovered. (see Table 1.01)
N	Total energy to recover NG is 31,207 Btu/mmBtu NG. (Note that 31,207 is the total energy we are calculating – this is an example of the iterative nature of the calculations.)
O	31,862 Btu are used to process 1 mmBtu NG.
P	255 Btu of direct electricity used to recover 1 mmBtu NG. (see Table 1.01)
Q	87,352 Btu of energy used to recover and transport sufficient feedstock to generate 1 mmBtu electricity.
R	2,561,534 Btu used to produce 1 mmBtu electricity.
L1	Loss Factor For North American Natural gas processing, 1.001 which is a CA-GREET default
L2	Loss Factor for North American Natural gas transmission, 1.001 which is a CA-GREET default

Table 1.04. WTT and Specific Energy Calculations

	E:WTT energy (Btu input/Btu product)	**S: Specific Energy (Btu input/Btu product)**
Residual Oil	$E_{ResOil} = 74{,}866$	$S_{Res\ Oil} = 1+(E_C*\text{Loss Factor}_{Crude}+E_{ResOil})/10^6$
Conventional Diesel	$E_{diesel} = 124{,}812$	$S_{Diesel} = 1+(E_C*\text{Loss Factor}_{diesel}+E_{diesel})/10^6$
Conventional Gasoline	$E_{Gasoline} = 164{,}227$	$S_{Gasoline} = 1+(E_C*\text{Loss Factor}_{Gasoline}+E_{Gasoline})/10^6 =$
NG	$E_{NG}=(E_{NG\ Rec}+E_{NG\ Procss})*\text{Loss Factor}+E_{T\&D} = 72{,}522$	$S_{NG} = 1+E_{NG}/10^6$
NG Recovery	$E_{NG\ Rec} = 31{,}207$	
NG Processing	$E_{NG\ Procss} = 31{,}862$	
NG T&D	$E_{NG\ T\&D} = 9{,}452$	
Electricity		$S_{Electricity} = (E_{efeedstock}+E_{efuel})/10^6$
as Feedstock	$E_{efeedstock} = 87{,}352$	
as Fuel	$E_{efuel} = 2{,}561{,}534$	

1.2 GHG Emissions from Natural Gas Recovery

The emission calculation methodology is analogous to the energy calculations. First the direct emissions are calculated and then the upstream emissions (due to recovery and processing of each direct fuel used) are added. To calculate the direct emissions, direct energy by fuel type (provided in detail above) is multiplied by the technology share (% fired in turbine, boiler, engine etc) and then multiplied by the appropriate emission factor. Emissions of CO_2, N_2O and methane due to combustion are quantified. In addition, emissions of VOC and CO are quantified and assumed to convert to CO_2 in the atmosphere. The conversions are calculated as follows:

CO (g/mmBtu) * 44 gCO_2/gmole / 28 gCO/gmole

VOC (g/mmBtu) * 44 gCO_2/gmole / 12 gC/gmole * 0.85 gC/ gVOC

Because the same emission factors are used in all steps, Tables 1.05, 1.06, 1.07, 1.08, and 1.09 provide the emission factors for CO_2, CH_4 (due to combustion), N_2O, VOC and CO, respectively. While CA-GREET has emission factors for each fuel and piece of combustion equipment, only emission factors used in this pathway are shown for clarity. The emission factors shown here are based on assuming marginal CNG production. The following points summarize the emission factor assumptions:

- All CO_2 emission factors are CA-GREET default values.
- All gasoline engine emission factors for CH_4, VOC, and CO are from the ARB off-road inventory
- The diesel engine CH_4 and VOC emission factors are based on the ARB offroad model
- Natural gas CH_4 factors are from U.S EPA's Emission Inventory AP-42[3] and are slightly higher than the CA-GREET defaults
- The N_2O factor for natural gas boilers is based on AP-42 and is lower than the CA-GREET default (1.1)
- The NOx and VOC values for NG combustion are set to 0 to reflect the marginal assumption that results in no net emission increase (new emissions are offset).
- CO emissions from NG fired equipment are assumed to be BACT (Best Available Control Technology) levels.

Table 1.05. CO_2 Emission Factors, g/mmBtu

Fuel	Large Boiler	Small Boiler	Engine	Turbine
Residual Oil		85,049		
Diesel		78,167	77,349	78,179
Gasoline			50,480	
Natural Gas	58,198	58,176	56,551	58,179

Table 1.06. CH_4 (due to combustion) Emission Factors, g/mmBtu

Fuel	Large Boiler	Small Boiler	Engine	Turbine
Residual Oil		1.538		
Diesel		0.760	7.526	0.844
Gasoline			98.158	
Natural Gas	1.100	1.100	368.940	4.260

Table 1.07. N_2O Emission Factors, g/mmBtu

Fuel	Large Boiler	Small Boiler	Engine	Turbine
Residual Oil		0.357		
Diesel		0.390	2.000	2.000
Gasoline			2.400	
Natural Gas	0.315	0.315	1.500	1.500

Table 1.08. VOC Emission Factors, g/mmBtu

Fuel	Large Boiler	Small Boiler	Engine	Turbine
Residual Oil		0.907		
Diesel		1.173	83.407	1.335
Gasoline			1,776.169	
Natural Gas	1.557	2.417	41.120	1.000

Table 1.09. CO Emission Factors, g/mmBtu

Fuel	Large Boiler	Small Boiler	Engine	Turbine
Residual Oil		15.764		
Diesel		16.686	362.100	8.714
Gasoline			13,079.562	
Natural Gas	16.419	28.822	342.445	24.000

The direct emissions from natural gas recovery are based on the direct energy (see Table 1.01) and the assumed equipment shares shown in Table 1.10. The equipment shares are CA-GREET defaults. Multiplying the direct energy shown by the corresponding emission factors in Tables 1.05 through 1.09 and summing the equipment share results yields the direct emissions provided in Tables 1.11.

Table 1.10. NG Recovery Direct Energy (Btu/mmBtu) and Equipment Shares

	Residual Oil	Diesel	Gasoline	Natural Gas
Direct Energy	255	2,807	255	21,944
By Equipment Shares				
Small Boiler	100%	25%		50%
Engine		50%	100%	50%
Turbine		25%		
By Equipment				
Small Boiler	255	702		10,972
Engine		1,403	255	10,972
Turbine		702		

Similar to total energy, the total emissions include direct emissions plus the emissions associated with recovery and processing/refining the fuels used to recover natural gas. Table 1.12 provides the upstream CO_2 emission for natural gas recovery. Table 1.13 details the values used in Table 1.12. Table 1.14 further illuminates the values in Table 1.13.

Table 1.11. Direct Emissions from NG Recovery, g/mmBtu

	CO_2	VOC	CO	CH_4	N_2O
Residual Oil	22	0.000	0.004	0.000	0.000
Diesel	218	0.119	0.526	0.012	0.004
Gasoline	13	0.453	3.337	0.025	0.001
Natural Gas	1,259	0.478	4.074	4.060	0.020
Electricity	1,512	1.050	7.941	4.097	0.025

Table 1.12. Calculation of Upstream CO_2 Emissions from Direct Energy Consumption for NG Recovery

Fuel Type	Formula	g/mmBtu
Residual Oil	$A^* (B+ C)/ 10^6$	3
Diesel	$D * (E*F +G) / 10^6$	41
Gasoline	$H * (I * J+ K) / 10^6$	4
Natural gas	$L*(M)/10^6$	106
Electricity	$N (O + P)/ 10^6$	56

Table 1.13. Values Used to Calculate Upstream CO_2 Emissions for NG Recovery

Fuel Type	Description
A	255 Btu of direct residual oil used per mmBtu NG recovered.
B	The crude recovery CO_2 emissions are 5,230 g/mmBtu.
C	The CO_2 emissions from producing residual oil is 5,623 g/mmBtu.
D	2,807 Btu of direct diesel used per mmBtu NG recovered.
E	The crude recovery CO_2 emissions are 5,230 g/mmBtu.
F	The Loss Factor for diesel refining is 1.0000. This is a CA-GREET default.
G	The diesel refining CO_2 emissions are 9,395 g/mmBtu.
H	255 Btu of direct gasoline used per mmBtu NG recovered.
I	The crude recovery CO_2 emissions are 5,230 g/mmBtu.
J	The Loss Factor for gasoline refining is 1.0008. This is a CA-GREET default.
K	The gasoline refining CO_2 emissions are 12,131 g/mmBtu.
L	21,944 Btu of direct NG fuel used per mmBtu NG recovered.
M	Total CO_2 emissions to recover and process NG is 1,722 + 1,859 + 1237.
N	255 Btu of direct electricity used to recover 1 mmBtu NG.
O	6,980 g/mmBtu CO_2 to produce & transport feedstock.
P	213,458 gCO_2 to produce 1 mmBtu electricity.

Table 1.14. WTT and Specific CO_2 Emission Calculations by Fuel Type

	EF:WTT CO_2 Emission Factor (gCO_2 /mmBtu fuel output)	**SE: Specific Emission (gCO_2/mmBtu fuel output)**
Residual Oil	EF_{ResOil} = 5,623	$SE_{Res\ Oil} = 1+(EF_C*Loss\ Factor_{Crude}+ EF_{ResOil}) /10^6$
Conventional Diesel	EF_{Diesel} = 9,395	$SE_{Diesel} = 1+(EF_C*Loss\ Factor_{diesel}+EF_{diesel})/ 10^6$
Conventional Gasoline	$EF_{Gasoline}$ = 12,131	$SE_{Gasoline} = 1+(EF_C*Loss\ Factor_{Gasoline}+EF_{Gasoline})/ 10^6$
NG	$EF_{NG}=(EF_{NG\ Rec} + EF_{NG\ Procss})$ *Loss Factor + $E_{T\&D}$ + $EF_{Non-combustion}$+ (VOC, CO conversion)= 5,214	$SE_{NG} = 1+EF_{NG}/10^6$
NG Recovery	$E_{NG\ Rec}$ = 1,722	
NG Processing	$E_{NG\ Procss}$ = 1,859	
NG T&D	$E_{NG\ T\&D} =$ 528	
NG non-combustion	$E_{NG\ non\text{-}combustion}$ = 1,237	
Loss Factor	Loss Factor = 1.001	
Electricity		$SE_{Electricity} = (EF_{efeedstock}+EF_{efuel})/ 10^6$
as Feedstock	$EF_{efeedstock}$ = 6,980	
as Fuel	EF_{efuel} = 213,458	

Table 1.15 summarizes the upstream emissions for each GHG contributor. Note that there are no direct emissions from electricity, only indirect. The direct and indirect emissions are summed and presented in Table 1.16. The total emissions are presented in Table 1.17; the CO and VOC values are converted to CO_2 and two loss factors are applied: 1.001 (processing) and 1.001 (T&D).

Table 1.15. Upstream GHG Emissions (emissions associated with recovery & production of direct fuels used) for Natural Gas Recovery, g/mmBtu

	CO_2	VOC	CO	CH_4	N_2O
Residual Oil	3	0.002	0.004	0.025	0.000
Diesel	41	0.023	0.053	0.280	0.000
Gasoline	4	0.007	0.005	0.026	0.000
Natural Gas	106	0.128	0.230	0.111	0.001
Electricity	56	0.005	0.049	0.069	0.001
Total	**210**	**0.165**	**0.342**	**0.511**	**0.002**

Table 1.16. Direct and Upstream GHG Emissions from Natural Gas Recovery, g/mmBtu

	CO_2	VOC	CO	CH_4 (combustion)	N_2O	CH_4 (leak)
Residual Oil	24	0.002	0.008	0.025	0.000	
Diesel	259	0.142	0.579	0.292	0.005	
Gasoline	17	0.460	3.343	0.051	0.001	
Natural Gas	1,365	0.606	4.304	4.171	0.021	72.166
Electricity	1,568	1.055	7.991	4.166	0.026	
Total	**210**	**0.165**	**0.342**	**0.511**	**0.002**	**72.166**

Table 1.17. Total GHG Emissions from Natural Gas Recovery, g/mmBtu

	CO_2	CH_4	N_2O	GHG $gCO_2e/mmBtu$	GHG gCO_2e/MJ
Residual Oil	24	0.025	0.000	25	0.02
Diesel	260	0.292	0.005	269	0.26
Gasoline	19	0.051	0.001	20	0.02
Natural Gas	1,366	4.171	0.021	1,477	1.40
Electricity	56	0.069	0.001	58	0.06
NG Leakage		72.166		1,804	1.71
Total	**1,726**	**4.608**	**0.027**	**1,849**	**3.5**

SECTION 2. NATURAL GAS PROCESSING

2.1 Energy use for Natural Gas Processing

The next step in the CNG pathway is processing of the natural gas. The methodology to calculate direct and total energy for natural gas processing is the same as that to calculate direct and total energy for natural gas recovery. The key assumptions are:

- Process efficiency (97.2%, CA-GREET Default)
- Fuel Shares (split of total energy consumed by fuel type, CA-GREET Default)
- Natural Gas Leak Rate (0.15%)

Table 2.01 provides details of direct energy consumption to process natural gas.

Table 2.01. Calculation of Direct Energy Consumption for NG Processing

Process Fuel Type	Fuel Shares	Relationship of Recovery Efficiency (0.972) and Fuel Shares	Direct Energy Consumption, Btu/mmBtu
Diesel fuel	0.9%	$(10^6)(1/0.972 - 1)(0.09) = 273$	273
Natural gas	91.1%	$(10^6)(1/0.972 - 1)(0.911) = 26{,}234$	26,234
Electricity	2.8%	$(10^6)(1/0.972 - 1)(0.028) = 820$	820
Feed Loss (Leak)	5.1%	$(10^6)(1/0.972 - 1)(0.051) = 1{,}479$	1,479
Direct Energy Consumption for NG Processing			**28,807**

The Feed Loss share (5.1%) is back calculated from an assumed leak fraction of 0.15% (0.0015 g methane leaks per g natural gas processed). The leak fraction is converted to g/MMBtu using the natural gas density and heating value:

CH_4 Leakage (g/mmBtu) = 0.0015 g CH_4/g NG * 20.4 g NG/930 Btu * 10^6 Btu/mmBtu – Combustion CH_4 (0.464 g/mmBtu) = 32.44 g/MMBtu

The leakage is then converted to a Feed Loss Share of total energy consumptions (shown in Table 2.02) as follows:

Feed Loss (%) = 32.45 g leak/mmBtu / 20.4 g/scf * 930 Btu/scf / 10^6 Btu/mmBtu * 0.972 / (1-0.972) = 5.14%

The values provided in Table 2.01 are direct energy consumption per Btu for the natural gas processing step. This is not the total energy required however, since CA-GREET accounts for the “upstream” energy associated with each of the fuels utilized to recover natural gas. Table 2.02 demonstrates how the direct energy consumption values shown in Table 2.01 and values in Table 2.03 are utilized to calculate total energy required to process natural gas.

Table 2.02. Total Energy Consumption from Direct Energy Consumption for NG Processing

Fuel Type	Formula	Btu/mmBtu
Diesel Fuel	A + A* (B*C + D)/ 10^6 * L2	323
Natural gas	E + E*(F + G)/10^6 * L2	27,889
Electricity	H (I + J)/ 10^6 * L2	2,172
NG Leaks	1,479 * L2	1,479
Total Energy Consumption for NG Processing		**31,862**

Table 2.03. Values Used in Table 2.02

Fuel Type	Description
A	273 Btu of direct conventional diesel used per mmBtu NG recovered.
B	The energy to recover crude is 55,561 Btu/mmBtu crude.
C	The conventional diesel fuel loss factor is 1.0000 and is a CA-GREET default.
D	The energy to produce conventional diesel fuel is 124,812 Btu/mmBtu (not including crude recovery & transport).
E	26,234 Btu of direct NG fuel used per mmBtu NG recovered.
F	Total energy to recover NG is 31,207 Btu/mmBtu NG.
G	31,862 Btu used to process 1 mmBtu NG. (This is an example of the iterative nature of the calculations.)
H	820 Btu of direct electricity used to recover 1 mmBtu NG.
I	87,352 Btu of energy used to recover and transport sufficient feedstock to generate 1 mmBtu electricity.
J	2,561,534 Btu used to produce 1 mmBtu electricity.
L2	Loss factor for North American natural gas transmission, 1.001 a CA-GREET default

2.2 GHG Emissions from Natural Gas Processing

The direct emissions from natural gas recovery are based on the direct energy (see section 1) and the assumed equipment shares shown in Table 2.04. The equipment shares are CA-GREET defaults. Multiplying the direct energy shown by the corresponding emission factors in Tables 1.05 through 1.09 and summing the individual equipment results yields the direct emissions provided in Tables 2.05.

Table 2.04. NG Processing Direct Energy (Btu/mmBtu) and Equipment Shares

	Diesel	Natural Gas
Direct Energy	273	26,234
Equipment Shares		
Large Boiler		50%
Small Boiler	33%	
Engine	33%	
Turbine	34%	50%
Direct Energy		
Large Boiler		13,117
Small Boiler	90.2	
Engine	90.2	
Turbine	92.9	13,117

Table 2.05. Direct Emissions from Natural Gas Processing, g/mmBtu

	CO_2	VOC	CO	CH_4	N_2O
Diesel	21	0.008	0.035	0.001	0.000
Natural Gas	1,527	0.034	0.530	0.070	0.024
Total	**1,548**	**0.041**	**0.565**	**0.453**	**0.024**

Similar to total energy, the total emissions include direct emissions plus the emissions associated with recovery and processing/refining the fuels used to recover natural gas. Table 2.06 provides the upstream CO_2 emission calculations and Table 2.07 details the values for natural gas processing used in Table 2.06. Table 2.08 provides the upstream emissions associated with recovery & production of direct fuels used.

Note that there are no direct emissions from electricity, only indirect. Table 2.09 combines the upstream and direct GHG emissions.

Table 2.06. Calculation of Upstream CO_2 Emissions from Direct Energy Consumption for NG Processing

Fuel Type	Formula	g/mmBtu
Diesel	$A *(B * C + D) / 10^6$	4
Natural gas	$E *(F + G + H)/10^6$	126
Electricity	$I *(J + K)/ 10^6$	181

Table 2.07. Values Used in Table 2.06

Fuel Type	Description
A	273 Btu of direct diesel used per mmBtu NG processed
B	The crude recovery CO_2 emissions are 5,230 g/mmBtu
C	The Loss Factor for diesel refining is 1.0000
D	diesel refining CO_2 emissions are 9,395 g/mmBtu
E	26,234 Btu of direct NG fuel used per mmBtu NG recovered
F,G,H	Total CO_2 emissions to recover and process NG = 1722 + 1859 + 1237
I	820 Btu of direct electricity used to recover 1 mmBtu NG
J	6,980 g/mmBtu CO_2 to produce & transport feedstock
K	213,458 g CO_2 to produce 1 mmBtu electricity.

Table 2.08. Upstream GHG Emissions for NG Processing, g/mmBtu

	CO_2	VOC	CO	CH_4	N_2O
Diesel	4	0.002	0.005	0.027	0.000
Natural Gas	126	0.153	0.275	0.133	0.001
Electricity	181	0.016	0.159	0.222	0.002

Table 2.09. Total Direct and Upstream GHG Emissions for NG Processing, g/mmBtu

	CO_2	VOC	CO	CH_4 (comb.)	N_2O	CH_4 (leak)
Diesel	25	0.010	0.040	0.028	0.000	
Natural Gas	1,653	0.186	0.805	0.203	0.025	32.450
Electricity	181	0.016	0.159	0.222	0.002	
Total	**1,859**	**0.213**	**1.004**	**0.453**	**0.027**	**32.450**

At this point, a third category of emissions are added in: non-combustion processing emissions. These consist of 1,237 g/mmBtu CO_2, 4.4 g/mmBtu VOC and 1.2 g/mmBtu CO. These values are CA-GREET defaults (no calculations, simply an input number). The VOC and CO are combined with CO_2 to result in 1,253 g/mmBtu CO_2. Finally, the direct, indirect and non-combustion emissions are summed and multiplied by the loss factor (1.001) and presented in Table 2.10.

Table 2.10. Total GHG Emissions from NG Processing

	CO_2 g/mmBtu	CH_4 g/mmBtu	N_2O g/mmBtu	GHG gCO_2e/mmBtu	GHG gCO_2e/MJ
Diesel	25	0.028	0.000	26	0.02
Natural Gas	1,654	0.203	0.025	1,666	1.57
Electricity	181	0.222	0.002	187	0.18
NG Leakage	1,253	32.450		811	0.77
Non-combustion Processing Emissions				1,253	1.18
Total	**3,112**	**32.903**	**0.027**	**2,690**	**3.7**

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SECTION 3. NATURAL GAS TRANSPORTATION AND DISTRIBUTION

3.1 Energy Use for NG Transport and Distribution

The third step in the CNG from NA NG pathway is transport and distribution of the natural gas by pipeline from the processing plant to the CNG refueling station. The energy consumption for T&D consists of:

- T&D Feedstock Loss (0.08%)
- T&D Pipeline Energy Consumption

The feedstock loss factor is based on specification of a leak rate along the transmission & distribution pipelines. The CA-GREET default value is 0.45% however in the AB1007 analysis, Southern California Gas Company (SoCal)[4] provided a report documenting unaccounted for gas losses. This report indicates that pipeline leak rates are 0.08%. (871,900 MCF leakage over 1,052,280,216 MCF system throughput). Therefore the loss factor utilized is lower than the CA-GREET default. The leak rate is calculated as follows:

> CH_4 Leak Rate = 0.0008 g CH_4/gNG * 20.4 g/930 Btu * 10^6 Btu/mmBtu = 17.548 g/mmBtu

The default CA-GREET version divides the methane leakage value by 600 miles to yield a per mile value because the 0.45% unaccounted NG (0.27% + 0.18%) corresponds with 600 mile transport distance. This per mile leak rate is then multiplied by the distance to yield the methane leakage. No distance is applied in this analysis because the 0.08% leak rate occurs over the entire SoCal Gas system.

The leak rate is then used to calculate the Loss Factor (1.0008) as follows:

> Loss Factor = 17.548 g/mmBtu * 930 Btu / 20.4 g / 10^6 Btu/mmBtu + 1 = 1.0008

Finally, the feedstock loss can be calculated:

> T&D Feedstock Loss = (1.0008 – 1) * 10^6 = 800 Btu/mmBtu

The pipeline energy consumption is the energy associated with moving the natural gas through the pipeline. The main assumptions are:

- Fuel Shares (94% natural gas, 6% electricity)
- Energy Intensity (405 Btu/ton-mile, CA-GREET default)
- Distance (CA-GREET default is 750 miles)
- Heating value (930 Btu/scf)
- Density (20.4 g/scf)

The T&D pipeline energy consumption is calculated as follows:

Pipeline Energy (Btu/mmBtu) = ((20.4 grams/scf)/ (930 Btu/scf))*(750 miles) * (405 Btu/ton-mile) * (1 pound/454 grams) * (1 ton/2,000 pound) *(0.94*1.070+0.06*2.649) * 1,000,000 = 8,548 Btu/mmBtu

As illustrated in Table 3.01, the total T&D energy is the sum of the feedstock loss and pipeline energy consumption.

Table 3.01 Energy Use for NG Transport to Refueling Station

Total T&D Energy Use = 8,548 + 800 = 9,348 Btu/mmBtu

3.2 GHG Emissions from Natural Gas Transport to the Refueling Station

The pipeline transport emissions are composed of methane leaks and emissions associated with moving the natural gas through the pipeline. As discussed in the energy section, an assumed leak fraction dictates CH_4 leakage emissions of 17.5 g/mmBtu (see discussion in Section 3.1 above regarding the leak rate and transmission distance calculation.

The pipeline combustion emissions are set by the CA-GREET default energy intensity of 344 Btu/ton-mile and the assumed transport distance of 750 miles. The direct energy (excluding electricity) use is 6,900 Btu/mmBtu. The fuel split is 94% natural gas, 6% electricity. Table 3.02 provides the direct energy consumption and equipment shares. Direct emissions are calculated by multiplying the direct energy for each fuel type in Table 3.02 by the emission factors in Table 3.03. The upstream emissions are shown in Table 3.04.

Table 3.02. NG Transport Direct Energy Consumption (Btu/mmBtu) and Equipment Shares (NG fuel)

	Natural Gas
Direct Energy	8,067
Equipment Shares	
Turbine	55%
Engine	36%
Advanced Engine	9%
Direct Energy	
Turbine	3,795
Engine	2,484
Advanced Engine	621

Table 3.03. Emission Factors for NG Fired Equipment, g/mmBtu

	CO_2	VOC	CO	CH_4 (comb.)	N_2O
Turbine	58,044	0.908	77.180	23.154	2.000
Engine	56,013	230.400	379.847	328.393	2.000
Adv Eng	56,725	61.29	331.42	289.047	2.000

Table 3.04. Upstream Emissions from NG and Electricity use, g/mmBtu

	CO_2	VOC	CO	CH_4 (comb.)	N_2O
Natural Gas	36	0.043	0.080	0.889	0.000
Electricity	97	0.009	0.085	0.119	0.001

Table 3.05 provides the total direct and upstream emissions associated with natural gas combustion to transport natural gas along the pipeline. Table 3.06 combines these with the upstream electricity emissions and the methane leakage, yielding total T&D emissions.

Table 3.05. Direct and Upstream Emissions from NG Combustion (g/mmBtu)

	CO_2	VOC	CO	CH_4 (comb.)	N_2O
Natural Gas	431	0.657	1.522	1.972	0.014
Electricity	97	0.009	0.085	0.119	0.001
Methane Leakage				17.548	
Total	**528**	**0.666**	**1.608**	**19.640**	**0.015**

Table 3.06. Total GHG Emissions Associated with NG Transport to Refueling Station

	CO_2 g/mmBtu	CH_4 g/mmBtu	N_2O g/mmBtu	GHG gCO_2e/mmBtu	GHG gCO_2e/MJ
Total	**532**	**19.640**	**0.015**	**1,028**	**0.97**

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SECTION 4. NATURAL GAS COMPRESSION TO CNG

4.1 CNG Compression Energy Use

The final step in CNG production is compression at the refueling station. The two assumptions for this part of the analysis are:

- Compression Efficiency (98%)
- Compression Fuel (electric)
- Electricity mix is marginal California mix (NG + renewables, 100% combined-cycle)

The CA-GREET default value for compression efficiency is 97%. For the AB1007 analysis, Clean Energy Fuels provided data indicating that compressor efficiency in California is 98.046%. Using this:

Direct electricity use = 10^6 * (1/98.0% -1) * 100% = 20,408 Btu/mmBtu

Total electricity use = 20,408 * (111,058 + 1,884,989)/10^6 = 40,736 Btu/mmBtu

The direct and total electricity use for compression are therefore 20,408 Btu/mmBtu and 40,736 Btu/mmBtu, respectively.

4.2 GHG Emissions from Natural Gas Compression to CNG

As stated above, this pathway assumes that only electric compressors are used to compress the natural gas. The direct energy use is 20,408 Btu/mmBtu CNG (see section 4.1 above). There are no direct emissions from electricity, only upstream emissions. The upstream emissions associated with electricity production are provided in Table 4.01. These emissions are calculated by multiplying direct energy use in NG compression by CO_2 (shown in table 2.07), VOC, CO, CH4 and N_2O emission factors. Table 4.02 provides final values (CO and VOC converted to CO_2).

Table 4.01. Upstream Emissions From Electricity Production for Compression, g/mmBtu

	CO_2*	VOC	CO	CH_4 (comb.)	N_2O
Total	**2,133**	**0.324**	**1.187**	**4.220**	**0.053**

* CO_2 calculation: ((20,408 Btu/MmmBtu)*(8,278 + 96,250) g/mmBtu)/10^6 = 2,133 CO_2 g/mmBtu where CO_2 emission factor of electricity as feedstock is 8,278 g/mmBtu and as fuels is 96,250 g/mmBtu (see table 2.07 CO_2 emission factor)

Table 4.02. Total GHG Emissions Associated with Natural Gas Compression

	CO_2 g/mmBtu	CH_4 g/mmBtu	N_2O g/mmBtu	GHG gCO_2e/mmBtu	GHG gCO_2e/MJ
Total	**2,136**	**4.220**	**0.053**	**2,257**	**2.14**

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Section 5. GHG EMISSIONS FROM VEHICLE

5.1 GHG Emissions from Vehicles

The vehicle GHG emissions consist of:

- Tailpipe CO_2 (100% of carbon in fuel goes to CO_2)
- Tailpipe N_2O (combustion product)
- Tailpipe CH_4 (product of incomplete combustion, evaporative losses)

The CO_2 may be directly calculated from finished fuel properties as follows:

Vehicle CO_2 (g/MJ) = (20.4 g NG/scf) * (0.724 g C/g NG) * (1/930 Btu/scf) * (44 g CO_2 / 12 g C) * (Btu/1.055kJ) * (1000kJ/MJ) = **55.2** g/MJ

Here, 20.4 g/scf is the density of NG (CA-GREET default), 0.724 is the Carbon in NG (CA-GREET default) and the LHV of NG is 930 Btu/scf. 1.055 is a factor to convert from Btu to kJ.

For CH_4 and N_2O emissions, California Climate Action Registry (CCAR)[5] g/mile values are used. The CCAR emission factors for CH_4 and N_2O for CNG vehicles are both set at 0.0375 g/mi.

Note: CH_4 and N_2O emission factors for tailpipe emissions have been used as place holder since staff is investigating the availability of appropriate tailpipe emissions data for heavy duty CNG vehicles. When available, staff will adjust contributions from tailpipe emissions CH_4 and N_2O appropriately.

(Note: In a study on CNG use in urban buses[6], calculations for tailpipe CH_4 and N_2O emissions were approximately 2.82 g/MJ, close to the value **2.53** g/MJ calculated below).

To convert this to a g/MJ basis, we need to assume a vehicle fuel economy. For the AB1007 analysis, CNG vehicles were assumed to have a fuel economy of 4.8 MJ/mi. Using this value, the vehicle emissions are:

Vehicle GHG = 55.2 gCO_2/MJ + (0.0375 gN_2O/mi * 298 + 0.0375 gCH_4/mi * 25)/4.8 MJ/mi = 55.2 gCO_2e/MJ + 2.53 gCO_2e/MJ = **57.73** gCO_2e/MJ

APPENDIX B

COMPRESSED NATURAL GAS (CNG) FROM NORTH AMERICAN NATURAL GAS PATHWAY INPUT VALUES

Parameters	Units	Values	Note
GHG Equivalent			
CO_2		1	CA-GREET Default
CH_4		25	CA-GREET Default
N_2O		298	CA-GREET Default
VOC		3.1	CA-GREET Default
CO		1.6	CA-GREET Default
Natural Gas Recovery			
Process Efficiency		97.2%	CA-GREET Default
Natural Gas Leak Rate		0.35%	CA-GREET Default
Fuel Shares			
Residual Oil		0.9%	CA-GREET Default
Conventional Diesel		9.8%	CA-GREET Default
Conventional Gasoline		0.9%	CA-GREET Default
Natural Gas		76.2%	CA-GREET Default
Electricity		0.9%	CA-GREET Default
Feed Loss (Leak)		11.4%	CA-GREET Default
Equipment Shares			
Small Boiler - Residual Oil		100%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	85,049	CA-GREET Default
Commercial Boiler - Diesel		25%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,167	CA-GREET Default
Stationary Reciprocating Eng. - Diesel		50%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	77,349	CA-GREET Default
Turbine - Diesel		25%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,179	CA-GREET Default
Stationary Reciprocating Eng. - Gasoline			
CO_2 Emission Factor	gCO_2/mmBtu	50,480	CA-GREET Default
Small Boiler - NG		50%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,215	CA-GREET Default
Stationary Reciprocating Eng. - NG		50%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	56,388	CA-GREET Default
Natural Gas Processing			
Process Efficiency		97.2%	CA-GREET Default
Natural Gas Leak Rate		0.15%	CA-GREET Default
Fuel Shares			
Conventional Diesel		0.9%	CA-GREET Default
Natural Gas		91.1%	CA-GREET Default
Electricity		2.8%	CA-GREET Default
Feed Loss (Leak)		5.1%	CA-GREET Default
Equipment Shares			
Commercial Boiler - Diesel		33%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,167	CA-GREET Default
Stationary Reciprocating Eng. - Diesel		33%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	77,349	CA-GREET Default
Turbine - Diesel		34%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,179	CA-GREET Default
Large Boiler - NG		50%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,215	CA-GREET Default

Parameters	Units	Values	Note
Large Turbine - NG		50%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,196	CA-GREET Default
Feed Loss		1.001	CA-GREET Default
CNG Compression			
Efficiency		98.0%	Based on Data Provided by Clean Energy Fuels
Process Shares			
Electricity		100%	AB 1007 Assumption
CNG Transportation and Distribution			
Leak Rate		0.08%	Based on Data Provided by SoCal Gas Ab1007
Transportation by pipeline		100%	CA-GREET Default
Distance	miles	1,000	AB1007 Assumption
Energy Intensity	Btu/ton-mile	344	CA-GREET Default
Fuel Shares			
Natural Gas		94%	CA-GREET Default
Electricity		6%	CA-GREET Default
Equipment Shares			
Turbine - NG		55%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,196	CA-GREET Default
Engine - NG		36%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	56,013	CA-GREET Default
Advanced Engine - NG		9%	CA-GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	56,388	CA-GREET Default
Loss Factor of CNG by T&D		1.00122	CA-GREET Default
Fuels Specifications	**LHV (Btu/gal)**	**Density (g/gal)**	
Crude	129,670	3,205	CA-GREET Default
Residual Oil	140,353	3,752	CA-GREET Default
Conventional Diesel	128,450	3,167	CA-GREET Default
Conventional Gasoline	116,090	2,819	CA-GREET Default
Natural Gas	83,686	2,651	as liquid - for gaseous LHV: 930 Btu/SCF, 20.4 g/SCF

[1] GREET Model: Argonne National Laboratory: http://www.transportation.anl.gov/modeling_simulation/GREET/index.html

[2] California Assembly Bill AB 1007 Study: http://www.energy.ca.gov/ab1007

[3] AP 42 Compilation of Air Pollutant Emission Factors from U.S. EPA: www.epa.gov/otaq/ap42.htm

[4] S. Meshkati J. Groot D. Aquin B. Beloat B. Epps (Aug 1993). *"A Study of the 1991 Unaccounted for Gas Volume At the Southern California Gas Company"* – Southern California Gas Company

[5] California Climate Action Registry (CCAR): http://www.climateregistry.org/PROTOCOLS/; January 2009, page 98

[6] Australian Report: "*Life-cycle Emissions Analysis of Alternative Fuels for Heavy Vehicles*" Mar 2000 by T. Beer et al. http://www.cleanairnet.org/infopool/1411/articles-59987_resource_1.pdf - page 56 for CH_4 and N_2O calculation of CNG vehicles