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

Release Date: April 21, 2008

Version 1.0

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

The ARB acknowledges contributions from the California Energy Commission, TIAX, and Life Cycle Associates during the development of this document

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

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

SUMMARY


THIS SALE
THIS SALE
Driving for a Cleaner Future
NGV
EMERGENCY
STOP
BUTTON

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]. This California-modified GREET model 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 compressed natural gas (CNG) from North American natural gas (NA NG).

The pathway includes natural gas recovery, processing, transport & distribution, compression at a CNG refueling station and use in an internal combustion vehicle. The values, assumptions, and equations used in this document are from the CA modified GREET model (greet1.7ca_v98.xls). This model is available for download from the Low Carbon Fuel Standard website at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. The values shown in this document are preliminary draft values and staff is in the process of evaluating them. The areas that staff may revise include emission factors, energy intensity factors, % fuel shares, transport modes and their shares, agricultural chemical use factors, co-product credit methodologies, etc. 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:

- 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 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.

[1] http://www.transportation.anl.gov/software/GREET/
[2] http://www.energy.ca.gov/ab1007/

- 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.

- 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 GREET is defined as:

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

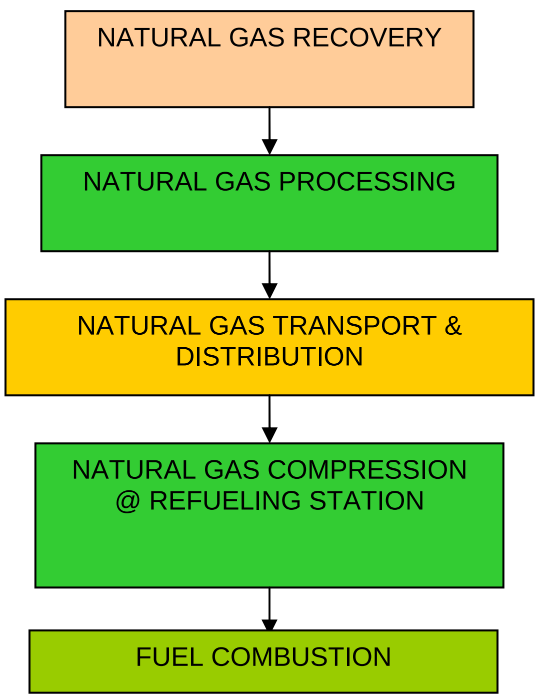

Figure 1. Discrete Components of the North American Natural Gas to CNG Pathway.

Table A below provides a summary of the results for this CNG pathway. The WTW analysis for CNG results in 1,113,032 Btu of energy required to produce 1 (one) mmBtu of available fuel energy. From a GHG perspective, 67.9 gCO_2e/MJ of GHG emissions are generated during the production and use of CNG in a passenger 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**
Natural Gas Recovery	31,091	2.8%	3.3	4.8%
Natural Gas Processing	31,353	2.8%	3.6	5.3%
Transport & Distribution	10,596	1.0%	1.2	1.7%
Compression at Station	39,992	3.6%	2.1	3.1%
Total (WTT)	**113,032 (see note below)**	**10.2%**	**10.2 (see note below)**	**15.0%**
Carbon in Fuel	1,000,000	89.8%	55.2	81.4%
Vehicle CH_4 and N_2O			2.5	3.7%
Total WTW	**1,113,032**	**100%**	**67.9** (see note below)	**100%**

Note: percentages may not add to 100 due to rounding

For this pathway it is assumed that compression energy is provided by marginal California electricity, which is based on natural gas and renewable power. If the California average electricity mix (please refer to the companion electricity document) is assumed for electrical energy consumption and not marginal electricity, then the WTT energy use would be 118,902 Btu/mmBtu and the WTT GHG emissions would be 11.4 gCO_2e/MJ. The WTW GHG emissions would increase to 69.3 gCO_2e/MJ.

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, CO_2 in fuel (81.4%) is the dominant source for GHG emissions for this pathway.

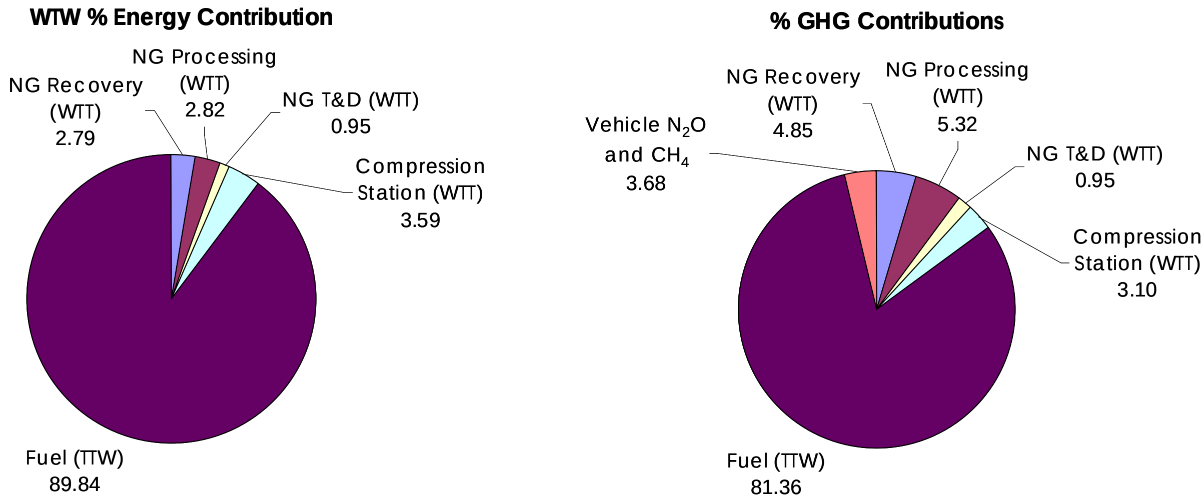

Figure 2. Energy and GHG Contributions of CNG

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	283
Diesel Fuel	3,313
Gasoline	312
Natural gas	23,432
Electricity	515
NG Leaks	3,236
Total	**31,091**

Table C. Total GHG Emissions from Natural Gas Recovery

	CO_2 g/mmBtu	CH_4 g/mmBtu	N_2O g/mmBtu	GHG gCO_2e/mmBtu	GHG gCO_2e/MJ
Residual Oil	24	0.025	0.000	24.370	0.023
Diesel	256	0.295	0.005	263.839	0.250
Gasoline	24	0.052	0.001	25.289	0.024
Natural Gas	1,374	76.549	0.021	3,140.417	2.977
Electricity	27	0.061	0.001	28.573	0.027
Total	1,703.725	76.982	0.028	3,482.487	**3.301**

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	321
Natural gas	27,903
Electricity	1,647
NG Leaks	1,481
Total Energy	**31,353**

Table E. Total GHG Emissions from Natural Gas 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			
Natural Gas	1,653	32.720	0.025		
Electricity	86	0.195	0.002		
Total	3,018.4	32.943	0.028	**3784**	**3.59**

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 = 10,596 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	**544.799**	**29.247**	**0.015**	**1222**	**1.158**

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 39,992 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	**2,095.682**	**4.73**	**0.052**	**2220**	**2.10**

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 light duty vehicle.

Table J. Well to Tank GHG Emissions for NG

TTW = Vehicle = 57.7g CO_2e/MJ

Table K below provides an expanded summary of all the GHG species and their emissions in each of the discrete steps of the NG pathway. Please note that pursuant to the discussion in section 3.1 in Appendix A regarding the distance over which the T&D leakage occurs, the value for CH_4 leakage due to T&D may be reduced. The proposed modification will reduce pathway GHG emissions from 10.15 to ~9.7 gCO_2e/MJ.

Table K. GHG Emissions by Pathway Step for CNG from North American Natural Gas

	Units	Recovery	Processing	T&D	Compression	Total
CO_2	g/mmBtu	1,704	3,018	555	2,096	7,363
CH_4 (combustion)	g/mmBtu	6.2	0.5	2.5	4.7	13.9
CH_4 (leak)	g/mmBtu	70.8	32.4	26.8		130.0
N_2O	g/mmBtu	0.028	0.028	0.015	0.052	0.123
CH_4 (comb)	gCO_2e/mmBtu	142.5	11.6	57.3	108.8	320.1
CH_4 (leak)	gCO_2e/mmBtu	1,628	746	615		2,990
N_2O	gCO_2e/mmBtu	0.64	0.64	0.35	1.20	2.82
Total GHGs	**gCO_2e/mmBtu**	**3,482**	**3,784**	**1,222**	**2,220**	**10,708**
Total GHGs	**gCO_2e/MJ**	**3.30**	**3.59**	**1.16**	**2.10**	**10.15**

APPENDIX A

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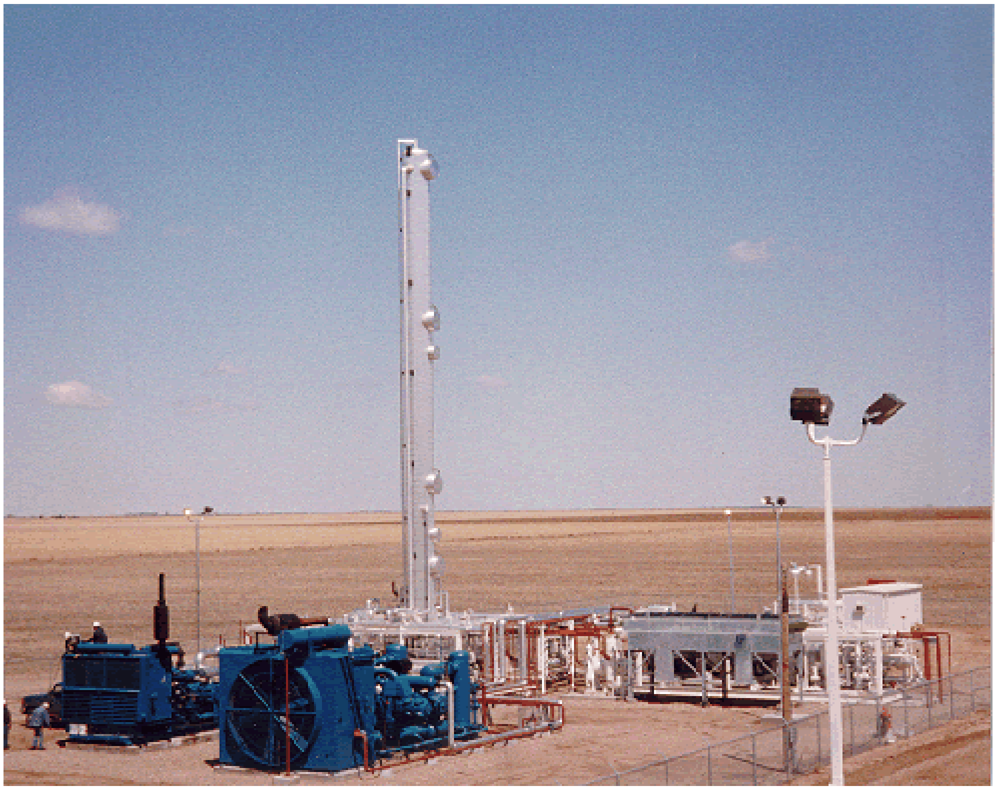
SECTION 1. NATURAL GAS RECOVERY



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%, GREET Default)
- Fuel Shares (split of total energy consumed by fuel type, GREET Default)
- Natural Gas Leak Rate (0.35%, 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%	$(10^6)(1/0.972 – 1)(0.009)$	256
Diesel fuel	9.8%	$(10^6)(1/0.972 – 1)(0.098)$	2,814
Gasoline	0.9%	$(10^6)(1/0.972 – 1)(0.009)$	256
Natural gas	76.4%	$(10^6)(1/0.972 – 1)(0.764)$	21,998
Electricity	0.9%	$(10^6)(1/0.972 – 1)(0.009)$	256
Feed Loss (Leak)	11.2%	$(10^6)(1/0.972 – 1)(0.112)$	3,227
Total Direct Energy Consumption for NG recovery			**28,807**

The feed loss (leak) share of 11.2% 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 GREET accounts for the "upstream" energy associated with each of the fuels utilized to recover natural gas. For example, 256 Btu of residual oil are required to recover each mmBtu of natural gas. The total energy associated with the 256 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	$(A + A*(B*D + C)/ 10^6) * L1*L2$	283
Diesel Fuel	$(E + E* (F*G + H)/ 10^6)* L1 * L2$	3,313
Gasoline	$(I + I* (J*K + L)/ 10^6) * L1 * L2$	312
Natural gas	$(M + M*(N + O) /10^6) * L1 * L2$	23,432
Electricity	$(P (Q + R)/ 10^6) * L1 * L2$	515
NG Leaks	3,227 * L1 * L2	3,236
Total energy for natural gas recovery		**31,091**

Table 1.03 Values Used in Table 1.02

Fuel Type	Description
A	256 Btu of direct residual oil used per mmBtu NG recovered. (see Table 1.01)
B	32,050 Btu are required to recover 1 mmBtu crude for US refineries.
C	70,292 Btu are required to produce 1 mmBtu residual oil (not including crude recovery & transport).
D	1.0 is the loss factor for residual oil. This is a GREET default.
E	2,814 Btu of direct conventional diesel used per mmBtu NG recovered. (see Table 1.01)
F	The energy to recover crude is 32,050 Btu /mmBtu crude.
G	The conventional diesel fuel loss factor is 1.00002. This is a GREET default.
H	The energy to produce conventional diesel fuel is 142,368 Btu/mmBtu (not including crude recovery & transport).
I	256 Btu of direct conventional gasoline used per mmBtu NG recovered. (see Table 1.01)
J	The energy to recover crude is 32,050 Btu/mmBtu crude.
K	1.0002 is the loss factor for conventional gasoline and is a GREET default
L	To refine & transport conventional gasoline, 182,504 Btu/mmBtu gasoline is used.
M	21,998 Btu of direct NG fuel used per mmBtu NG recovered. (see Table 1.01)
N	Total energy to recover NG is 31,007 Btu/mmBtu NG. (Note that 31,007 is the total energy we are calculating – this is an example of the iterative nature of the calculations.)
O	31,315 Btu are used to process 1 mmBtu NG.
P	256 Btu of direct electricity used to recover 1 mmBtu NG. (see Table 1.01)
Q	120,830 Btu of energy used to recover and transport sufficient feedstock to generate 1 mmBtu electricity.
R	1,886,091 Btu used to produce 1 mmBtu electricity.
L1	Loss Factor For North American Natural Gas processing, 1.001 which is a GREET default
L2	Loss Factor for North American Natural gas transmission, 1.001 which is a GREET default

Table 1.04 WTT and Specific Energy Calculations

	E:WTT energy (Btu input/Btu product)	**S: Specific Energy (Btu input/Btu product)**
Res Oil	$E_{ResOil} = 70{,}292$	$S_{Res\ Oil} = 1+(E_C$*Loss $Factor_{Crude}+E_{ResOil})/10^6$
Conventional Diesel	$E_{diesel} = 142{,}368$	$S_{Diesel} = 1+(E_C$*Loss $Factor_{diesel}+E_{diesel})/10^6$
Conventional Gasoline	$E_{Gasoline} = 182{,}504$	$S_{Gasoline} = 1+(E_C$*Loss $Factor_{Gasoline}+E_{Gasoline})/10^6 =$
NG	$E_{NG}=(E_{NG\ Rec} + E_{NG\ Procss})$ *Loss Factor + $E_{T\&D} = 73{,}039$	$S_{NG} = 1+E_{NG}/10^6$
NG Recovery	$E_{NG\ Rec} = 31{,}007$	
NG Processing	$E_{NG\ Procss} = 31{,}315$	
NG T&D	$E_{NG\ T\&D} = 10{,}596$	
Electricity		$S_{Electricity} = (E_{efeedstock}+E_{efuel})/10^6$
as Feedstock	$E_{efeedstock} = 120{,}830$	
as Fuel	$E_{efuel} = 1{,}886{,}091$	

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 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 the AB1007 analysis assuming marginal CNG production. The following points summarize the AB1007 emission factor assumptions:

- All CO_2 emission factors are GREET default values.
- All gasoline engine emission factors for CH_4, VOC, and CO are from the ARB offroad inventory
- The diesel engine CH_4 and VOC emission factors are based on the ARB offroad model
- Natural gas CH_4 factors are from EPA's AP-42 and are slightly higher than the GREET defaults
- The N_2O factor for natural gas boilers is based on AP-42 and is lower than the 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). The engine emissions are assumed to be below the offset size threshold. The NG engine emission factor assumes 11 ppm (converted to g/mmBtu assuming a MW of 16).
- CO emissions from NG fired equipment are assumed to be BACT 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	58,215	58,215	56,388	58,196

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	1.133	1.133	491	4.322

Table 1.07 N_2O Emission Factors, g/mmBtu

Fuel	Large Boiler	Small Boiler	Engine	Turbine
Residual Oil		0.357		
Diesel		0.390	2	2
Gasoline			2.4	
Natural Gas	0.315	0.315	1.5	1.508

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	0	0	81.4	0

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			13,079.56	
Natural Gas	8.5	8.5	152.2	15.07

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 GREET defaults. Multiplying the direct energy shown by the corresponding emission factors in Tables 1.05 through 1.09 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	256	2,814	256	21,995
By Equipment Shares				
Small Boiler	*100%*	*25%*		*50%*
Engine		*50%*	*100%*	*50%*
Turbine		*25%*		
By Equipment				
Small Boiler	*256*	*703.5*		*10,998*
Engine		*1,407*	*256*	*10,998*
Turbine		*703.5*		

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

	Small Boiler	Engine	Turbine	Total
CO_2 Emissions				
Residual Oil	21.755			21.755
Diesel	54.986	108.821	54.994	218.800
Gasoline		12.912		12.912
Natural Gas	640.317	620.225		1,260.542
VOC Emissions				
Residual Oil				
Diesel	0.001	0.117	0.001	0.119
Gasoline		0.454		0.454
Natural Gas		0.895		0.895
CO Emissions				
Residual Oil	0.004			0.004
Diesel	0.012	0.509	0.006	0.527
Gasoline		3.346		3.346
Natural Gas	0.093	1.674		1.768
CH_4 Emissions				
Residual Oil				
Diesel	0.001	0.011	0.001	0.012
Gasoline		0.025		0.025
Natural Gas	0.012	5.401		5.413
N_2O Emissions				
Residual Oil				
Diesel		0.003	0.001	0.004
Gasoline		0.001		0.001
Natural Gas	0.003	0.016		0.020

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

Fuel Type	Formula	g/mmBtu
Residual Oil	$A^* (B+ C)/ 10^6$	1.9
Diesel	$D * (E * F +G) / 10^6$	35
Gasoline	$H * (I * J+ K) / 10^6$	4
Natural gas	$L^*(M)/10^6$	103
Electricity	$N (O + P)/ 10^6$	27

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

Fuel Type	Description
A	256 Btu of direct residual oil used per mmBtu NG recovered.
B	The crude recovery CO_2 emissions are 2,987 g/mmBtu.
C	The CO_2 emissions from producing residual oil is 4,552 g/mmBtu.
D	2,814 Btu of direct diesel used per mmBtu NG recovered.
E	The crude recovery CO_2 emissions are 2,987 g/mmBtu.
F	The Loss Factor for diesel refining is 1.00002. This is a GREET default.
G	The diesel refining CO_2 emissions are 9,370 g/mmBtu.
H	256 Btu of direct gasoline used per mmBtu NG recovered.
I	The crude recovery CO_2 emissions are 2,987 g/mmBtu.
J	The Loss Factor for gasoline refining is 1.00002. This is a GREET default.
K	The diesel refining CO_2 emissions are 9,370 g/mmBtu.
L	21,998 Btu of direct NG fuel used per mmBtu NG recovered.
M	Total CO_2 emissions to recover and process NG is 1685 + 1761 + 1237.
N	256 Btu of direct electricity used to recover 1 mmBtu NG.
O	8,773 g/mmBtu CO_2 to produce & transport feedstock.
P	96,314 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} = 4,522	$SE_{Res\ Oil} = 1+(EF_C{*}Loss\ Factor_{Crude} + EF_{ResOil})/10^6$
Conventional Diesel	EF_{Diesel} = 9,370	$SE_{Diesel} = 1+(EF_C{*}Loss\ Factor_{diesel}+EF_{diesel})/10^6$
Conventional Gasoline	$EF_{Gasoline}$ = 13,591	$SE_{Gasoline} = 1+(EF_C{*}Loss\ Factor_{Gasoline}+EF_{Gasoline})/10^6$
NG	$EF_{NG}=(EF_{NG\ Rec} + EF_{NG\ Procss})$ *Loss Factor + $E_{T\&D}$ + $EF_{Non\text{-}combustion}$+ (VOC, CO conversion)= 5,267	$SE_{NG} = 1+EF_{NG}/10^6$
NG Recovery	$E_{NG\ Rec}$ = 1,685	
NG Processing	$E_{NG\ Procss}$ = 1,761	
NG T&D	$E_{NG\ T\&D}$ = 540	
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	$EF_{efeedstock}$ = 8,733	
as Fuel	EF_{efuel} = 96,314	

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	0.009	0.024	0.000
Diesel	47	0.029	0.101	0.282	0.001
Gasoline	5	0.004	0.010	0.026	0.000
Natural Gas	104	0.128	0.229	0.110	0.001
Electricity	37	0.004	0.025	0.059	0.001

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	25	0.003	0.013	0.025	0.000	
Diesel	265	0.148	0.627	0.294	0.005	
Gasoline	18	0.457	3.347	0.051	0.001	
Natural Gas	1,363	0.606	4.303	4.170	0.021	72.175
Electricity	37	0.004	0.025	0.059	0.001	
Total	**1,707**	**1.217**	**8.315**	**4.599**	**0.028**	**72.175**

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	24.370	0.023
Diesel	256	0.295	0.005	263.839	0.250
Gasoline	24	0.052	0.001	25.289	0.024
Natural Gas	1,374	76.549	0.021	3,140.417	2.977
Electricity	27	0.061	0.001	28.573	0.027
Total	**1,703.725**	**76.982**	**0.028**	**3,482.487**	**3.301**

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

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%	$(10^6)(1/0.972 – 1) (0.09) = 2{,}814$	273
Natural gas	91.1%	$(10^6)(1/0.972 – 1)(0.911) = 21{,}998$	26,235
Electricity	2.8%	$(10^6)(1/0.972 – 1)(0.028) = 256$	820
Feed Loss (Leak)	5.1%	$(10^6)(1/0.972 – 1)(0.051) = 3{,}227$	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 (%) = 32.44 g leak/mmBtu / 20.4 g/scf * 930 Btu/scf / 10^6 Btu/mmBtu * 0.972 / (1-0.972) = 5.13%

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 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	321
Natural gas	E + E*(F + G)/10^6 * L2	27,903
Electricity	H (I + J)/ 10^6 * L2	1,647
NG Leaks	1,479 * L2	1,481
Total Energy Consumption for NG Processing		**31,353**

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 32,050 Btu/mmBtu crude.
C	The conventional diesel fuel loss factor is 1.00002 and is a GREET default.
D	The energy to produce conventional diesel fuel is 142,368 Btu/mmBtu (not including crude recovery & transport).
E	26,235 Btu of direct NG fuel used per mmBtu NG recovered.
F	Total energy to recover NG is 31,007 Btu/mmBtu NG.
G	31,315 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	120,830 Btu of energy used to recover and transport sufficient feedstock to generate 1 mmBtu electricity.
J	1,886,091 Btu used to produce 1 mmBtu electricity.
L2	Loss factor for North American natural gas transmission, 1.001 a 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 GREET defaults. Multiplying the direct energy shown by the corresponding emission factors in Tables 1.05 through 1.09 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	26,235
Equipment Shares		
Large Boiler		50%
Small Boiler	33%	
Engine	33%	
Turbine	34%	50%
Direct Energy		
Large Boiler		13,118
Small Boiler	90.2	
Engine	90.2	
Turbine	92.9	13,118

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

	Large Boiler	Small Boiler	Engine	Turbine	Total
CO_2 Emissions					
Diesel		7.049	6.975	7.264	21.289
Natural Gas	763.623			763.372	1,526.995
VOC Emissions					
Diesel			0.008		0.008
Natural Gas					
CO Emissions					
Diesel		0.002	0.033	0.001	0.035
Natural Gas	0.111			0.198	0.309
CH_4 Emissions					
Diesel			0.001		0.001
Natural Gas	0.015			0.057	0.072
N_2O Emissions					
Diesel					
Natural Gas	0.004			0.020	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	$A * (B * C + D) / 10^6$	3
Natural gas	$E *(F + G + H)/10^6$	123
Electricity	$I (J + 96{,}314)/ 10^6$	86

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 2,987 g/mmBtu.
C	The Loss Factor for diesel refining is 1.00002
D	diesel refining CO_2 emissions are 9,370 g/mmBtu.
E	26,233 Btu of direct NG fuel used per mmBtu NG recovered
F,G,H	Total CO_2 emissions to recover and process NG = 1685 + 1761 + 1237
I	820 Btu of direct electricity used to recover 1 mmBtu NG.
J	8,773 g/mmBtu CO_2 to produce & transport feedstock.
K	96,314 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	3	0.002	0.004	0.027	0.000
Natural Gas	123	0.163	0.200	0.169	0.001
Electricity	86	0.009	0.024	0.195	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	0.038	0.028	0.000	
Natural Gas	1,650	0.163	0.509	0.241	0.025	32.440
Electricity	86					
Total	**1,760.65**	**0.182**	**0.572**	**0.464**	**0.028**	**32.44**

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 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		25.570	
Natural Gas	1,653	32.720	0.025	2,413.245	
Electricity	86	0.195	0.002	91.441	
Total	**3,018.4**	**32.943**	**0.028**	**3,784.383**	**3.59**

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SECTION 3: NATURAL GAS TRANSPORT & 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
- T&D Pipeline Energy Consumption

The feedstock loss factor is based on specification of a leak rate along the transmission & distribution pipelines. The GREET default value is 0.15% however in the AB1007 analysis, SoCal [3] gas 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 significantly lower than the 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 / 600 * 1000 mi - 2.5 g/mmBtu (CH_4 from combustion)
> = 26.756 g/mmBtu

According to conversations with Argonne National Laboratory, the "600" value in the denominator is the length associated with the default 0.15% leakage value. In the AB1007 analysis, only the value for leak rate was altered, not the 600 miles value. Because the 0.08% leak rate occurs over the entire SoCal Gas system, the 600 value should be changed to the SoCal Gas pipeline value. Also, it is not clear why the combustion emissions are subtracted from the leak value. A proposed revised formula shown for illustration (and used for calculation here) is:

> CH_4 Leak Rate = % leak/mile * 20.4 g/930 Btu * 106 Btu/mmBtu * 1000 miles
>
> Where 1,000 miles is the distance from NG processing to CNG station (assumed)

The leak rate is then used to calculate the Loss Factor (1.00122) as follows:

> Loss Factor = 26.756 g/mmBtu * 930 Btu / 20.4 g / 10^6 Btu/mmBtu + 1 = 1.00122

Finally, the feedstock loss can be calculated:

> T&D Feedstock Loss = (1.00122 – 1) * 10^6 = 1,220 Btu/mmBtu

[3] "A Study of the 1991 Unaccounted for Gas Volume At the Southern California Gas Company", Aug 1993.

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 (344 Btu/ton-mile, GREET default)
- Distance (1000 miles, 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))*(1000 miles) * (344 Btu/ton-mile) * (1 pound/454 grams) * (1 ton/2,000 pound) *(0.94*1.073+0.06*2.007) * 1,000,000
= 9,376 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 = 1220 + 9376 = 10,596 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 26.8 g/mmBtu (see discussion in Section 3.1 above regarding the leak rate and transmission distance calculation. The proposed modification will reduce CH_4 leakage emissions).

The pipeline combustion emissions are set by the GREET default energy intensity of 344 Btu/ton-mile and the assumed transport distance of 1000 miles. The direct energy use is 9,376 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

	Natural Gas
Direct Energy	8,813
Equipment Shares	
Turbine	55%
Engine	36%
Advanced Engine	9%
Direct Energy	
Turbine	4,847
Engine	3,173
Advanced Engine	793

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

	CO_2	VOC	CO	CH_4 (comb.)	N_2O
Turbine	58,196	0.00	15.07	4.32	1.51
Engine	56,013	230.4	379.8	328.4	2.00
Adv Eng	56,388	81.4	152.2	491.0	1.5

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

	CO_2	VOC	CO	CH_4 (comb.)	N_2O
Natural Gas	5,267	6.992	8.976	139.2	0.071
Electricity	105,086	11.57	28.91	237.4	2.612

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
Turbine	272.459	0.030	0.103	0.616	0.007
Engine	172.204	0.667	1.093	1.314	0.006
Adv Eng	43.314	0.062	0.113	0.443	0.001
Total	**487.977**	**0.759**	**1.309**	**2.373**	**0.014**

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	**544.799**	**29.247**	**0.015**	**1,221.93**	**1.158**

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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)

The 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 * (1/98.046% -1) * 100% = 19,927 Btu/mmBtu

Total electricity use = 19,927 * (120,830 + 1,886,091)/10^6 = 39,992 Btu/mmBtu (see table 1.04 for energy required for electricity).

The direct and total electricity use for compression are therefore 19,927 Btu/mmBtu and 39,992 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 19,927 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	**2,094.059**	**0.231**	**0.576**	**4.730**	**0.052**

* CO_2 calculation: ((19,927 Btu/MmmBtu)*(8,773 + 96,314) g/mmBtu)/10^6 = 2,094 CO_2 g/mmBtu where CO_2 emission factor of electricity as feedstock is 8,773 g/mmBtu and as fuels is 96,314 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	**2,095.682**	**4.73**	**0.052**	**2220**	**2.10**

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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) * (0.72 g C/g NG) * (1/930 Btu/scf) * (44 g CO_2 / 12 g C) * (Btu/1.055kJ) * (1000kJ/MJ)
= 54.9 g/MJ

Here, 20.4 g/scf is the density of NG (GREET default), 0.72 is the Carbon in NG (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)[4] g/mile values are used. The CCAR emission factors for CH_4 and N_2O for CNG vehicles are both set at 0.04 g/mi.

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 4.728 MJ/mi. Using this value, the vehicle emissions would are:

Vehicle GHG = 54.9 gCO_2/MJ + (0.04 gN_2O/mi * 296 + 0.04 gCH_4/mi * 23)/4.728 MJ/mi
= 57.7 gCO_2e/MJ

[4] http://www.climateregistry.org/PROTOCOLS/

APPENDIX B

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

Parameters	Units	Values	Note
GHG Equivalent			
CO_2		1	GREET Default
CH_4		23	GREET Default
N_2O		296	GREET Default
VOC		3.1	GREET Default
CO		1.6	GREET Default
Natural Gas Recovery			
Process Efficiency		97.2%	GREET Default
Natural Gas Leak Rate		0.35%	GREET Default
Fuel Shares			
Residual Oil		0.9%	GREET Default
Conventional Diesel		9.8%	GREET Default
Conventional Gasoline		0.9%	GREET Default
Natural Gas		76.4%	GREET Default
Electricity		0.9%	GREET Default
Feed Loss (Leak)		11.2%	GREET Default
Equipment Shares			
Small Boiler - Residual Oil		100%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	85,049	GREET Default
Commercial Boiler - Diesel		25%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,167	GREET Default
Stationary Reciprocating Eng. - Diesel		50%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	77,349	GREET Default
Turbine - Diesel		25%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,179	GREET Default
Stationary Reciprocating Eng. - Gasoline			
CO_2 Emission Factor	gCO_2/mmBtu	50,480	GREET Default
Small Boiler - NG		50%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,215	GREET Default
Stationary Reciprocating Eng. - NG		50%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	56,388	GREET Default
Natural Gas Processing			
Process Efficiency		97.2%	GREET Default
Natural Gas Leak Rate		0.15%	GREET Default
Fuel Shares			
Conventional Diesel		0.9%	GREET Default
Natural Gas		91.1%	GREET Default
Electricity		2.8%	GREET Default
Feed Loss (Leak)		5.1%	GREET Default
Equipment Shares			
Commercial Boiler - Diesel		33%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,167	GREET Default
Stationary Reciprocating Eng. - Diesel		33%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	77,349	GREET Default
Turbine - Diesel		34%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	78,179	GREET Default
Large Boiler - NG		50%	GREET Default
CO_2 Emission Factor	gCO_2/mmBtu	58,215	GREET Default

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