Technical Report

Technical Review of CA-GREET 2.0 Model

October 24, 2014

Submitted to:
California Natural Gas Vehicle Coalition
NGVAmerica
Coalition for Renewable Natural Gas

Prepared by
ICF International
620 Folsom Street, Suite 200
San Francisco, CA 94107
415.677.7100

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1 Key Findings

The California Air Resources Board (CARB) released a draft version of the California modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model on October 10, 2014, referred to as CA-GREET 2.0. ICF staff reviewed the CA-GREET 2.0 model, with a particular focus on changes made to natural gas pathways. ICF identified an array of issues and concerns associated with the CA-GREET 2.0 model, as highlighted in Table 1 below; the table includes the following information:

- A brief description of the issue or relevant stage in the lifecycle of natural gas
- The carbon intensity (CI) impact of CARB assumptions, which includes a) the CI of the corresponding stage of the fuel cycle (in units of grams CO_2 equivalents per megajoule, gCO2e/MJ) reported in the CA-GREET 2.0 model, b) ICF's estimate for the carbon intensity based on our initial assessment of available data, and c) the difference between the current version of the CA-GREET 2.0 model and ICF's estimates.
- ICF recommendations to remedy the issue identified

Note that in some cases, ICF was unable to estimate the CI impact of the issue identified. The subsequent sections of this memo describe these issues in more detail.

Table 1. Summary of ICF Findings and Recommendations Based on Review of CA-GREET 2.0 Model

Issue / Stage of Fuel Cycle	Brief Description	CI Impact (gCO_2eq/MJ)			ICF Recommendation
		CA-GREET 2.0	ICF Analysis	Impact	
MD/HD CNG Vehicles Tailpipe CH_4& N_2O	• Incorrect vehicle type used to estimate emissions • Incorrect use of emissions factor • Emission factors and methodology are outdated and unrepresentative of current NGV technology	12.21	1.11–9.36	2.85–11.10	• Consider emissions testing data from WVU study for SCAQMD • Review certification data from Cummins Westport on ISL G • Review literature for additional emission factors that represent current suite of available vehicles • Differentiate emission factors e.g., spark vs compression ignition and light-/medium-duty vs heavy-duty
MD/HD LNG Vehicles Tailpipe CH_4& N_2O	• Incorrect vehicle type used to estimate emissions • Incorrect use of emissions factor • Emission factors and methodology are outdated and unrepresentative of current NGV technology	12.62	1.11–9.36	3.26–11.51	• Consider emissions testing data from WVU study for SCAQMD • Review certification data from Cummins Westport on ISX12 G • Review literature for additional emission factors that represent current suite of available vehicles • Differentiate emission factors e.g., spark vs compression ignition and light-/medium-duty vs heavy-duty
RNG 2% Leakage at Landfill	• Incorrect application of on-site leakage rate for gas capture and processing for landfills • The data provided are based on anaerobic digestion facilities	8.85–8.90	0	8.85–8.90	• Modify leakage rate for landfill gas facilities to zero • Incorporate research on leakage rates specific to landfill facilities as it is available
LCNG Regasification	• Duplicate storage emissions and gasification occurs in an atmospheric temperature vaporizer	4.2	0	4.2	• Remove duplicate storage emissions from model

Issue / Stage of Fuel Cycle	Brief Description	CI Impact (gCO_2eq/MJ)			ICF Recommendation
		CA-GREET 2.0	ICF Analysis	Impact	
LCNG Compression	• Incorrect assumption regarding LNG-to-CNG; model assumes that LNG is gasified to atmospheric pressure and then compressed • LNG is compressed as a liquid	3.22	0.41	2.81	• Update assumptions regarding LNG to CNG steps to reflect that LNG is compressed as a liquid • Consult with L/CNG companies as needed to confirm process as described
Multiple pathways Compression	• Unclear why there is methane loss at compression • Compression efficiency is different for LFG than NA NG	3.71	2.14	1.57	• Eliminate methane loss at compression unless references available to indicate this is real • Normalize compression efficiency for natural gas, regardless of feedstock
LNG Liquefaction	• Model appears to be internally inconsistent; the values used for liquefaction are different for NA NG and RNG	n/a	n/a	n/a	• Ensure that the model is internally consistent regarding liquefaction efficiencies regardless of feed gas
Multiple pathways	• Many parts of the model include incorrect calculations • Multiple cells in the model include “fixed” calculations	n/a	n/a	n/a	• Conduct a thorough quality assurance and quality check (QA/QC) of the CA-GREET 2.0 model to ensure the model is developed accurately
Fugitive methane emissions	• Fugitive methane emissions do not represent California pipelines • Unclear why CARB is using national-level numbers for fugitive emissions, but assuming a pipeline distance of 750 mi • Unclear if CARB is apportioning emissions amongst oil and gas production properly	n/a	n/a	n/a	• Review GREET input values to ensure they are representative of the California industry • Consider delaying update of CA-GREET 2.0 until updated studies, which included California utility participation, are published • Consider OPGEE-type model for natural gas to improve characterization of CI for natural gas specific to California
Updates to electricity and hydrogen pathways	• It is unclear how other pathways, including electricity and hydrogen, will be impacted by natural gas updates • Unclear why CARB is selectively updating pathways	n/a	n/a	n/a	• Update all fuel pathways simultaneously to maintain fuel neutrality and innovation-driving aspects of LCFS

2 Review of Tailpipe Emissions: Methane (CH_4) and Nitrous Oxide (N_2O)

Methane (CH_4) and nitrous oxide (N_2O) are greenhouse gases (GHGs) with global warming potentials (GWPs) much higher than carbon dioxide (CO_2). Both CH_4 and N_2O are emitted directly from vehicles at the tailpipe as a result of combusting fuel.

The carbon intensity values for compressed natural gas (CNG) and liquefied natural gas (LNG) in Table 1: Tailpipe Emission Factors of the document entitled *Draft: Comparison of CA-GREET 1.8B, GREET1 2013, and CA-GREET 2.0* (hereafter referred to as Draft Comparison Document) do not match the values referenced in the draft CA-GREET 2.0 model distributed for review. Table 2 below highlights the inconsistencies between these two source documents.

Table 2. Comparison of Draft Comparison Document and CA-GREET 2.0 Model

Fuel Type	Unit	Table 1, Draft Comparison Document	'NG' Spreadsheet (Cell reference)
LNG	g CO_2/MJ	56.55	56.55 (Q123)
	g CH_4/MJ	0.162	0.245 calculated based on Q121
	g N_2O/MJ	0.014	0.022 calculated based on Q122
	gCO_2e/MJ	64.89	69.17 (Q125)
CNG	g CO_2/MJ	55.19	55.19 (F123)
	g CH_4/MJ	0.111	0.237 calculated based on F121
	g N_2O/MJ	0.009	0.021 calculated based on F122
	gCO_2e/MJ	60.74	67.41 (F125)

In the following discussion, ICF uses the values in the draft model provided by CARB rather than the values in the Draft Comparison Document.

The tailpipe CH_4 and N_2O emission values calculated in the spreadsheet model are linked to an emissions factor from the US Environmental Protection Agency (EPA).[1] The values in the spreadsheet are shown in Table 3 below.

[1] United States Environmental Protection Agency, "ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories", pg. A-150, Table-A106, http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2014-Annex-3-Additional-Source-or-Sink-Categories.pdf

Table 3. Emission Factors for Natural Gas Vehicles from CA-GREET 2.0 model

GHG	Emissions factor (g/mile)
CH_4	1.966
N_2O	0.175

The CA-GREET 2.0 model uses these values to estimate the tailpipe emissions of CH_4 and N_2O attributable to medium- and heavy-duty trucks using CNG and LNG. In cells E121:E122 and of the NG tab, the g/mile emission factors are converted to g/MMBtu using fuel economy values linked to a MY2005 LDT2 running on gasoline or diesel, with a fuel economy of 14.70 (LDT2_TS, Cell C10) or 17.65 (LDT2_TS, Cell C23) and adjusted for the efficiency of a dedicated CNG vehicle (LDT2_TS , C119) or LNG vehicle (LDT2_TS, C132). These parameters are shown in Table 4 below.

Table 4. Adjusted Fuel Economy Values for NGVs in CA-GREET 2.0

Vehicle Type	Linked Vehicle Type	Fuel Economy (mpg)	Adjustment factor	Adj Fuel Economy (mpg)
CNG Vehicle	MY2005, LDT2, Gasoline	14.70	95%	13.9650 (mpgge)
LNG Vehicle	MY2005, LDT2, Diesel	17.65	95%	16.7675 (mpdge)

It is inaccurate to use the grams per mile emissions from one data set with the fuel economy of another data set to determine grams per unit of energy consumed. When emission factors are provided on a grams/mile basis, it is critical that the vehicle or fleet mix used to determine the emissions factor is known. ICF looked into the EPA inventory from which CARB obtained the CH_4 and N_2O emissions factor. Those emissions factors are calculated in a different way and for a different type of vehicle than the vehicles used by CARB.

The EPA emissions factors are originally from tests performed on heavy-duty gasoline vehicles, with adjustment factors applied to alternative fuel vehicles based on values from the literature. The heavy-duty gasoline vehicles tested utilized Tier 1 control technologies (typically a three-way catalyst, TWC) and are a mix of MY1996 and MY1997 vehicles (see Table 5 below), with an average fuel economy of 11.27 miles per gallon.

Table 5. Heavy-Duty Gasoline Vehicles for FTP Tests with Tier 1 Control Technology

MY	Company	Make	Model	MPG	MY	Company	Make	Model	MPG
1996	ISUZU	ISUZU	PICK	10.1	1997	GM	CHEVROLET	SUPR	10.64
1996	ISUZU	ISUZU	PICK	8.79	1997	GM	CHEVROLET	SUPR	11.25
1996	ISUZU	ISUZU	PICK	6.82	1997	GM	CHEVROLET	SUPR	11.39
1996	ISUZU	ISUZU	PICK	9.97	1997	GM	CHEVROLET	SUPR	11.21
1997	CHRYSLER	DODGE	RAMC 2500	12.84	1997	GM	CHEVROLET	SUPR	11.12
1997	CHRYSLER	DODGE	RAMC	10.99	1997	GM	CHEVROLET	SUPR	10.52
1997	CHRYSLER	DODGE	RAMC	12.67	1997	GM	CHEVROLET	SILV	12.19
1997	CHRYSLER	DODGE	RAMC	12.55	1997	GM	CHEVROLET	SILV	11.03
1997	CHRYSLER	DODGE	RAMC	12.59	1997	GM	CHEVROLET	SILV	10.61
1997	CHRYSLER	DODGE	RAMC	12.05	1997	GM	CHEVROLET	SILV	11.97
1997	CHRYSLER	DODGE	RAMC	13.1	1997	GM	CHEVROLET	SILV	12.27
1996	CHRYSLER	DODGE	RAM 3500	13.32	1997	FORD	FORD	CLUBWAGON XLT	10.37
1996	CHRYSLER	DODGE	RAM 3500	11.06	1997	FORD	FORD	CLUBWAGON XLT	9.37
1996	CHRYSLER	DODGE	RAM 3500	13.49	1997	FORD	FORD	CLUBWAGON XLT	10.84
1996	GM	CHEVROLET	2500	12.37	1997	FORD	FORD	CLUBWAGON	12.19
1996	GM	CHEVROLET	2500	11.05	1997	FORD	FORD	CLUBWAGON	10.91
1996	GM	CHEVROLET	2500	12.65	1997	FORD	FORD	CLUBWAGON	12.73
1996	FORD	FORD	F-350 PU	9.66					
1996	FORD	FORD	F-350 PU	9.08					

Furthermore, the adjustment factors are based on a 2002 study by Lipman and Delucchi regarding N_2O and CH_4 emission factors.[2] Lipman and Delucchi reference over 100 tested vehicles; however, none of the studies are post-1998. The medium- and heavy-duty natural gas vehicles referenced in Lipman and Delucchi are shown in Table 6 below.

[2] Lipman and M.A. Delucchi, "Emissions of Nitrous Oxide and Methane from Conventional and Alternative Motor Vehicles," *Climatic Change* 53: 477–516, 2002.

Table 6. NGVs Referenced by Lipman and Delucchi to Develop CH_4 and N_2O Emission Factor Multiplier

Vehicle Class	Vehicle Type	Reference
Natural Gas Dual-fuel MDVs	1989 Ford Club Wagon	1
	1990 Ford F-350 XLT	1
Natural Gas HDVs	Diesel dual-fuel pilot	2
	GMC 454 CID V-8 bus engine	3
	GMC 454 CID V-8 bus, non-control tech engine	4
	Cummins L-10 lean-burn engine	5
	1992 DDC 6V-92TA DDEC II 2-stroke (high-pressure DI)	6
1. California Air Resources Board: 1991, Alternative Fuel and Advanced Technology Vehicle Fleet Test Program Eleventh Interim Report, Mobile Sources Division, July, El Monte, California.		
2. BC Research: 1986, Exhaust Emission Measurements of Natural Gas Fuelled Vehicles, prepared for the Department of Energy, Mines, and Resources of Canada, January, Vancouver.		
3. Jones, W. M., Goetz, W. A., Canning, H., and Voodg, A. D.: 1988, Closed Loop Fuel System and Low Emissions for a Natural Gas Engine, NGV Conference – The New Direction in Transportation, October 27–30, Sydney, Australia.		
4. Alson, J. A., Adler, J. M., and Baines, T. M.: 1989, 'Motor Vehicle Emission Characteristics and Air Quality Impacts', in Sperling, D. (ed.), Alternative Transportation Fuels, an Environmental and Energy Solution, Quorum Books, Westport, pp. 109–144.		
5. Lawson, A.: 1988, Development of a Cummins L10 Natural Gas Bus Engine, NGV Conference –The New Direction in Transportation, October 27–30, Sydney, Australia.		
6. Douville, B., Ouellette, P., and Touchette, A.: 1998, 'Performance and Emissions of a Two-Stroke Engine Fueled Using High-Pressure Direct Injection of Natural Gas', SAE Tech. Paper Series (#981160), Warrendale, Pennsylvania, pp. 1–8.		

ICF's assessment of the emissions factor employed by CARB in the CA-GREET 2.0 model revealed the following:

- The current version of the CA-GREET 2.0 model uses the wrong vehicle types to calculate the tailpipe emissions of CH_4 and N_2O from natural gas vehicles. It is unclear why CARB staff is using LDT2 fuel economies for medium- and heavy-duty trucks that run on CNG and LNG, considering that the fuel economies for these vehicles are vastly different. Furthermore, LCFS reporting is performed jointly for LD and MD applications, while it is separate for HD applications. It seems that the methodology in the CA-GREET 2.0 model should reflect the LCFS reporting requirements.
- It is inaccurate to use the fuel economy from one data source and emission factors from another data source to determine grams per unit of energy consumed (whether it be MMBtu or MJ). The fuel economy values used in the CA-GREET 2.0 model lead to the emissions factor for CH_4 and N_2O being over-estimated by 30%-35%.
- The studies used to develop the emissions factors referenced by CARB are outdated and it is highly unlikely that these emissions factors reflect the operation of today's natural gas vehicles.
- CARB should consider the diversity of natural gas vehicles when developing CI values, recognizing vehicle class (light-, medium-, and heavy-duty) and engine type (compression ignition and spark ignition). There are emission testing data available on all of these vehicle combinations and these should be accounted for to the extent feasible in an updated version of CA-GREET 2.0

Regarding the last point, ICF reviewed more recent studies to understand the most current research regarding CH_4 and N_2O emissions from medium- and heavy-duty natural gas vehicles. Our review focuses on the following information:

- In July 2014, the West Virginia University (WVU) Center for Alternative Fuels, Engines & Emissions (CAFEE) prepared a report for the South Coast Air Quality Management District (SCAQMD) entitled the "In-Use Emissions Testing and Demonstration of Retrofit Technology for Control of On-Road Heavy-Duty Engines." The study measured CO_2, CH_4, and N_2O emissions for three heavy-duty natural gas vehicles: a goods movement vehicle with a three-way catalyst (TWC), a goods movement vehicle with a high pressure direct injection (HPDI) dual fuel engine with a diesel particulate filter (DPF) and selective catalytic reduction (SCR), and a refuse truck with a TWC.
- Cummins Westport has submitted engine certification data as part of EPA/NHTSA rules. ICF extracted engine certification data for the ISL G and ISX12 G

ICF converted the emissions factors reported in the WVU study and those reported in the EPA certification data for Cummins Westport into gCO_2e/MJ using reported fuel economies and the corresponding GWP of each GHG. The values are shown in the table below, and are compared to the numbers reported in the CA-GREET 2.0 model for reference.

Table 7. Emission Factors for NGVs

Source	Vehicle Type	Emissions Factor (gCO_2e/MJ)		
		CH_4	N_2O	Total
CA-GREET 2.0	MD and HD CNGVs	5.93	6.29	12.21
Re-calculated CA-GREET 2.0, using correct fuel economy	MD and HD CNGVs	4.54	4.82	9.36
WVU / SCAQMD	NG Stoichiometric (TWC)	1.04	0.07	1.11
	HPDI	1.67	0.64	2.31
	Refuse	3.73	0.20	3.93
Cummins Westport Certification Data	ISL G	5.87	2.27	8.15
	ISX12 G	2.89	0.98	3.87

The minimum carbon intensity difference between the value reported by CARB in the CA-GREET 2.0 model and the literature values calculated by ICF is 4.06 gCO_2e/MJ. Even if CARB employed the correct fuel economy values to convert the emissions factors for CH_4 and N_2O reported by EPA, the values reported in CA-GREET 2.0 are still more than 1 gCO_2e/MJ higher than the highest emissions factor for CNG vehicles reported in the most current literature.

The information presented in Table 7 helps to reiterate an earlier point: It is critical that the CA-GREET 2.0 model recognize the differences in emissions from compression and spark ignition engines (including more advanced engine technologies like the HDPI NG engine from Westport Innovations), the differences across vehicle class, and the differences across duty cycles. The ANL-developed GREET model, on which the CA-GREET model is based, is not ideally suited to calculate the CI of fuels used in medium- and heavy-duty vehicles. If CARB is going to apply some adjustment factors for NGVs, it is important that these adjustments reflect the most updated information available. ICF is not suggesting that CARB staff select a single value (e.g., from Table 7) and apply that value across the board; rather ICF urges CARB staff to recognize that there is additional work and time required to develop more precise CI values for natural gas used in different vehicles.

3 Fugitive Methane Emissions

A detailed analysis of methane emissions from various stages of natural gas pathways resulted from the need to understand the implications that development of the shale gas production has in the GHG footprint of natural gas. Most of the analysis has been based on the U.S. EPA's GHG inventory. The EPA 2011 inventory was the first to incorporate shale gas and included significant revisions to its liquid unloading leakage estimates (EPA 2011[3]). The EPA inventory is a bottom-up analysis based on type of equipment and emission factors. In 2013, the EPA emission factors were reviewed based on recent studies, and CH_4 leakage estimates were reduced significantly (e.g., liquid uploading estimate in conventional GREET1_2012 changed from 247.1 g CH_4/million Btu NG to 10.2 g CH_4/million Btu[4]). EPA's updated 2013 inventory used the American Petroleum Institute (API) and the American Natural Gas Association (ANGA) survey of natural gas industry to improve bottom-up emission factors and activity data for shale gas well completions and liquid unloadings.[5] An independent study that examined well completions and other production emissions using direct measurements at 150 sites indicated completion emission factors to be much lower while pneumatic controller and other equipment emissions to be higher than the EPA inventory. However, as a whole, the aggregated emissions for the sources measured were similar.[6] Technical literature published on natural gas CH_4 emissions have shown that there is a discrepancy between the estimates of leakage from individual devices or facilities (bottom up analysis) and atmospheric measurements (top-down analysis). National scale atmospheric measurements[7] suggest EPA's total CH_4 inventory undercounts emissions by 50% (+/- 25%) and evidence at multiple scales suggests that the natural gas and oil sectors are important contributors. However, recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical natural gas system leakage rates; a small number of "super-emitters" could be responsible for a large fraction of leakage.[8] The GREET life cycle inventory continues to rely on EPA inventory considering it as the best data source that provides detailed emissions by specific activities, and it is consistent data source. ANL researchers will continue monitoring work in this area and update estimates accordingly.

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3 U.S. EPA. 2011. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2009, EPA 430-R-11-005; U.S. EPA: Washington, DC.

4 Burnham el al 2013. Updated Fugitive Greenhouse Gas Emissions for Natural Gas Pathways in the GREETTM Model. Systems Assessment Group. Energy Systems Division, Argonne National Laboratory. October 2013.

5 Shires et al. 2012. Characterizing Pivotal Sources of Methane Emissions from Unconventional Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses; Prepared for the American Petroleum Institute and the American Natural Gas Association.

6 Allen et al. 2013. Measurements of Methane Emissions at Natural Gas Production Sites in the United States, Proceedings of the National Academy of Sciences, September, 16.

7 Miller et al. 2013. "Anthropogenic Emissions of Methane in the United States," Proceedings of the National Academy of Sciences, Vol. 110, No. 50.

8 Brandt el al. 2014. Methane Leaks from North American Natural Gas Systems. Policy Forum of Journal Science. Energy and Environment. October 15, 2014.

CA-GREET 2.0 updates include changes in input values due to updates in the GREET model as well as changes specific to model California market. Modifications specific to updates in GREET natural gas pathway include the examination and update of three different types of input values:

- Input 4.3) CH_4 leakage rate for each stage in conventional NG and shale gas pathways
- Input 4.4) Flaring energy and CO_2 emission rate for recovery and processing in conventional NG and shale gas pathways
- Input 7) in tab tilted ”T&D”: Energy Intensity of Pipeline Transportation

Modifications due to California market include two types of changes

- Use of California fuel specification (e.g., natural gas density and heating content)
- Electricity source disaggregated from regional data (GREET default modelling option) to sub-regional data

The table below shows the updated values for both inputs. The table illustrates that the CA-GREET 2.0 model relies on CH_4 leakage rate data inputs from GREET 2014 (EPA, 2014 and EIA, 2013a and 2014 data for calendar year 2012) and flaring energy and CO_2 emission rate data inputs from GREET 2013 (EPA 2013 for calendar year 2011). Changes in CA-GREET 2.0 input values compared to those on CA-GREET 1.8b are shown to be significant only for three inputs:

- Transmission and Storage - CH_4 Venting and Leakage.
- Distribution- CH_4 Venting and Leakage
- Energy Intensity of Natural Gas Pipeline Transportation

For the sake of comparison, the table also includes:

- A fugitive emissions rate for distribution calculated based on an internal Southern California Gas Company engineering analysis. ICF’s understanding is that this calculation is based on a mass-balance approach; Southern California Gas Company’s findings are that the emissions rate have decreased over time and are approaching this calculated value. The current value that Southern California Gas Company estimates for its system is 0.12%, using recently collected data. Reported (EPA and CARB) methane leakage rates have been higher (0.31%) because these were based on much older emission factors from the 1990s.
- A fugitive emissions rate for distribution calculated by an unpublished CARB/GTI report.

Table 8. Comparison of Fugitive Methane Emissions for various GREET Models

	Units/mmBtu NG	GREET 2013		GREET 2014		CA-GREET 1.8b		CA-GREET 2.0	
		Emission	vol. % of CH_4 over NG throughput	Emission	vol. % of CH_4 over NG throughput	Emission	vol. % of CH_4 over NG throughput	Emission	vol.% of CH_4 over NG throughput
Input 4.3) CH4 leakage rate for each stage in conventional NG and shale gas pathways									
Recovery - Completion CH_4 Venting	g CH_4/	0.549	0.0027%	0.543	0.00%	n.a.	0.35%	0.543	0.0025%
Recovery - Workover CH_4 Venting	g CH_4	0.008	0.000037%	0.008	0.00%	n.a.		0.008	0.000035%
Recovery - Liquid Unloading CH_4 Venting	g CH_4	10.194	0.049%	10.357	0.049%	n.a.		10.357	0.05%
Well Equipment - CH_4 Venting and Leakage	g CH_4	59.097	0.29%	51.345	0.25%	n.a.		51.345	0.23%
Processing - CH_4 Venting and Leakage	g CH_4	36.982	0.18%	26.710	0.13%	n.a.	0.15%	26.710	0.12%
Transmission and Storage - CH_4 Venting and Leakage	g CH_4/680 miles	87.401	0.42%	81.189	0.39%	n.a.	0.08%	81.189	0.37%
Distribution - CH_4 Venting and Leakage	g CH_4	70.667	0.34%	63.635	0.31%	n.a.	0.08%	63.635	0.29%
		Total	1.28%	Total	1.14%	Total	0.58%	Total	1.06%
Distribution – Calculated by SoCalGas	*g CH_4*				*0.053%*				
Distribution – Based on GTI Study	*g CH_4*				*0.23%*				
Input 4.4) Flaring energy and CO2 emission rate for recovery and processing in conventional NG and shale gas pathways									
Recovery - Flaring	Btu NG	6,870		8,370		"Natural gas flared" 0		6,870	
Recovery - Venting	g CO_2	21		13		no included		21	
Processing - Acid Gas Removal Equipment Venting	g CO_2	849		810		1,237		849	
Input T&D Tab 7) Energy Intensity of Pipeline Transportation									
NG pipeline	Btu/ton-mile	1,641		1,641		405		1,641	
Fuel Specifications									
NG Heating Content (LHV)	Btu/scf	983		983		930		923.7	
NG density	g/scf	22		22		20.4		20.4	

These inputs values have been adopted by GREET to represent average methane emissions and energy use for these activities. To calculate methane leakage emissions from natural gas transmission and storage and distribution sectors, ANL researchers divided the average methane emissions from these sectors by the average production of natural gas for the same time period; [9,10,11] starting with GREET 2013, the data was changed to represent natural gas throughput by each stage. [12] To determine energy intensity of natural gas pipeline transportation, ANL researches change the estimated compression energy intensity based on electric motor efficiency, compressor adiabatic efficiency, inlet and outlet pressure, inlet temperature, and compression ratio assumptions. [13] Energy intensity values are now derived from natural gas use in pipelines reported by EIA 2012 data, [14] electricity use in pipelines from U.S. DOE and Oakridge National Laboratory, [15] and natural gas transported reported by U.S. DOT's Bureau of Transportation Statistics. The update was conducted in GREET 2013. [16]

California should review these input values to represent the California industry more specifically. Although changes in CA-GREET 2.0 regarding energy intensity of natural gas pipeline transportation are derived from a new GREET calculation approach, the changes in transmission, storage, and distribution for CH_4 venting and leakage are derived from early review of CA-GREET 1.8b. CH_4 transmission and storage as well as distribution values have been in the same order of magnitude since CA-GREET 1.8b. The CA-GREET 1.8b file includes a comment that states that the input value used of 0.08% was based on data from PG&E and SoCal Gas, and that the default CA-GREET 1.8b value was 0.27%+0.18%. The current Draft Comparison Document does not discuss this issue. [17]

There are two updates that could be expected in the future regarding natural gas pathways. First, ANL continuously updates the fugitive emissions in GREET. In particular, an update is expected based on the analysis of associated natural gas production. As of now, it is unknown whether the emissions resulting from co-production of natural gas through petroleum production have been appropriately accounted/allocated between the two systems. The second item is related to natural gas pathway

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9 U.S. EPA. 2013. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011, EPA 430- R-13-001; U.S. EPA: Washington, DC.

10 U.S. EIA. 2013a. U.S. Natural Gas Summary: Natural Gas Gross Withdrawals and Production, http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_a.htm. (accessed September 9, 2013).

11 U.S. EIA. 2013c. Natural Gas Annual Respondent Query System (EIA-176 Data through 2011), http://www.eia.gov/cfapps/ngqs/ngqs.cfm. (accessed September 24, 2013).

12 Using EIA data for 2007 through 2011, Argonne National Laboratory researchers estimated the amount of natural gas delivered to end users by transmission pipelines (37%) as compared to distribution pipelines (63%) (EIA 2013b)

13 Dunn et al. 2013. Update to Transportation Parameters in GREET™. Systems Assessment Group, Energy Systems Division, Argonne National Laboratory. October 7, 2013.

14 U.S. Energy Information Administration (EIA). 2012. Annual Energy Outlook 2012. Appendix A. Table A2: Energy Consumption by Sector and Source. June 2012. http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf. Last accessed September 23, 2013.

15 U.S. DOE and Oakridge National Laboratory (ORNL). Transportation Energy Data Book. Edition 32. Appendix A. Table A.12: Pipeline Fuel Use (2009). July 2013. http://cta.ornl.gov/data/index.shtml. Last accessed September 23, 2013.

16 Dunn et al. 2013. Update to Transportation Parameters in GREET™. Systems Assessment Group, Energy Systems Division, Argonne National Laboratory. October 7, 2013.

17 California Air Resources Board DRAFT Comparison of CA-GREET 1.8B, GREET1 2013, and CA-GREET 2.0.

process energy shares. CARB draft documentation indicates that Natural Gas Recovery Energy Efficiency and Process Fuel Shares data have been reviewed from sources other than GREET 2013 and 2014 for inclusion in the CA-GREET 2.0 model. While there is no information regarding the type of review being conducted by CARB, it is expected that the review will address a formula and logic calculation issue currently in GREET. The GREET default calculation to determine the electricity used is based on the energy efficiency measured and the contribution of other energy sources including gas feed losses (i.e., electricity share= 100%-% natural gas as process fuel - % natural gas as feed loss; electricity use = energy efficiency x electricity share). As a result, electricity energy use estimates change whenever assumptions in CH_4 leaks change. There have not been updates on Natural Gas Recovery and Natural Gas Processing Energy Efficiency inputs in GREET. As a result, any modification to the carbon intensity of electricity for a specific pathway may impact the emission estimates for natural gas recovery and natural gas processing. The table below illustrates differences in calculated electricity shares and feed losses among models.

In previous meetings with CARB, potential allocation issues have been raised about the emissions from natural gas production and processing that comes from associated gas wells. There is no indication in the CA-GREET model and accompanying documentation that these issues have been addressed or how they will be addressed. There is concern that energy and emissions are being allocated to natural gas from associated gas recovery when these emissions should be allocated to oil production.

There is an impending report on energy and emissions associated with the natural gas section including natural gas recovery, processing, transportation and distribution. The main California natural gas utilities have participated in the study and it will contain information specific to the California distribution systems. It is the most recent and relevant information to model the most scientifically accurate carbon intensities for natural gas used for transportation. For the most scientifically accurate results, the natural gas pathways will need the use of this information.

Table 9. Natural gas assumptions in different versions of GREET models

Stage	GREET 2013	GREET 2014	CA-GREET 1.8b	CA-GREET 2.0
Gas Recovery Electricity Share	0.90%	2.20%	0.90%	2.80%
Gas Recovery Feed Losses	11.70%	10.40%	11.40%	9.80%
Gas Processing Natural Gas Share	90.1	90.1	91.1	90.1
Gas Processing Electricity Share	2.80%	4.50%	2.80%	4.80%
Gas Processing Feed Losses	6.20%	4.50%	5.10%	4.20%
Loss Factor in NG Processing	1.001793	1.001295	1.0015	1.001793
Loss Factor in NG Transmission and Distribution	1.004	1.004	1.00100	1.004

Finally, ICF notes the disproportionate amount of resources dedicated to characterizing the carbon intensity of crude oils used by California refiners (e.g., via OPGEE model development and expansion) compared to the natural gas used in California. For instance, the distribution between conventional and shale gas is based on national-level estimates. Similarly, the fugitive emission rates are based on data from national-level inventories. The pipeline distance of 750 miles used in the CA-GREET 2.0 model for the NA NG pathways demonstrates that gas consumed within California is not necessarily the same as the “average” unit of natural gas consumed in the United States. Rather, it is likely natural gas produced in the Western United States within and west of the Rocky Mountains. The natural gas recovery and processing emissions should reflect the characteristics of this natural gas.

4 Methane Leakage for Landfill Gas Facilities

The CA-GREET 2.0 model includes 2% leakage rate at facilities that capture landfill gas. The source of this leakage rate is included in Argonne National Laboratory’s (ANL) Waste-to-Wheel study[18] and reads:

> CH_4 vented or leaked from equipment during AD [anaerobic digestion], NG [natural gas] production or upgrading is a major source of GHG emissions. On the basis of several Swedish reports, Börjesson and Berglund (2006) estimate that 2% of the biogas produced is vented or leaked during these stages. This value is significantly larger than the 0.15% emission rate for conventional NG upgrading facilities, but could be attributed to differences in scale (Burnham et al., 2011). Therefore, this study assumes that 2% of the produced renewable gas is leaked. As indicated by Börjesson and Berglund (2006), more research on CH_4 emissions from anaerobic digesters and small-scale NG processing facilities is warranted for a more comprehensive understanding of biogas-based pathways.

The 2006 Börjesson and Berglund study is cited by ANL as the basis for adoption their 2% “vented or leaked” assumption. The study reads:

> Losses of methane may occur during the upgrading and pressurisation of the biogas. These losses are reported normally to correspond to less than 2% of the biogas purified, but may vary between 0.2% and 11–13%. These differences depend mainly on the upgrading technology used, the required methane content of the upgraded gas, and occasional uncontrolled leakages. Uncontrolled losses of methane may also occur in other parts of the biogas system. However, due to the difficulties in measuring and quantifying net losses of methane from biogas production, such data are uncertain and limited.

According to Energigas Sverige (The Swedish Gas Association) Sweden has no stand-alone landfill operation upgrading its biogas to pipeline or transportation fuel quality.[19] No landfill is attached to their national transmission grid. In other words, the Börjesson and Berglund study is limited to anaerobic digestion (AD) facilities.

The 2013 Swedish Gas Technology Report[20] indicates the following:

> Measurements conducted within the Swedish programme Voluntary Agreement, set up by the Swedish Waste Management Society in 2007 to study losses and emissions from biogas

18 Han, Mintz & Wang. *Waste-to-Wheel Analysis of Anaerobic-Digestion-Based Renewable Natural Gas Pathways with the GREET Model*, Argon National Laboratory, Center for Transportation Research, Energy Systems Division, September 2011, 15-16. (ANL Waste-to-Wheels).

19 Email communication between David Cox and Ben Bock, Helena Gyrulf, Agnetha Petterson at Energigas Sverige, October 2014.

20 Bauer, F., Hulteberg, C., Persson, T., Tamm, D., 2013. Swedish Gas Technology Centre Rapport. Description of the available upgrading technologies. Membrane separation, 28-31.

> production, show low emissions of me- thane. Losses from the PSA upgrading units measured within this programme loss were 1.8% in median, whereas the average value was 2.5% due to a single unit with relatively high losses. Units with end-of-pipe treatment, i.e. combustion or catalytic oxidation of methane, showed even lower methane losses with a median of 0.7% and an average value of 1.0% (Holmgren et al. 2010).

In other words, the technologies that are currently employed to minimize methane losses at landfill gas sites in the U.S. are reporting much lower methane losses than those without.

It is difficult to make comparisons between the Swedish market for natural gas from anaerobic digestion and the US market for captured landfill gas. For instance, the application of anaerobic digestion at farms is largely unregulated (as it is in the United States). Conversely, U.S. landfill gas systems are subject to landfill New Source Performance Standard (NSPS), which regulates operational standards for collection and control systems. California's landfill methane rule is even more stringent, requiring leak testing of any components that contain landfill gas under pressure (including the entire upgrading and treatment system). Based on ICF's understanding, all U.S. landfill gas-to-energy facilities utilize a thermal oxidizer or flare to combust and destroy unused waste gas and all vent pipes are run to the thermal oxidizer or flared. Given the stringency of regulations applied to landfill operators in the US, it seems highly unlikely that any landfill gas system is losing 2% of methane via leaks as the CA-GREET 2.0 model suggests.

In a paper submitted to Environmental Research Letters,[21] ANL staff make note of the same 2% leakage rate, based on the following information:

> We performed a literature search for information concerning unintended methane emissions from AD and from biogas clean-up. Two studies measured methane loss at eleven AD facilities (Flesch *et al* 2011, Liebetrau *et al* 2010). Two other studies considered methane loss in biogas pathways when used for transportation (Moller *et al* 2009, Borjesson and Berglund 2006). Flesch reported 3.1% total loss of CH_4 from AD at a state of the art facility. This fell to 1.7% after redesigning the biomass loading hopper. Liebetrau reported similar total emissions, but commented that the digestate can yield up to an additional 10% of the total AD CH_4 during digestate storage (field application is seasonal), which might be leaked depending upon the storage method. Liebetrau also observed substantial losses from previously undiscovered equipment failures, e.g., leaking service openings.

It appears that a significant percentage of the methane leakage occurs during the biomass handling and anaerobic digestion stages and is not relevant for landfill gas pathways. For landfill gas pathways, these processes (e.g., depositing waste in the landfill; and digestion under the landfill cap) are occurring under the landfill cap whether or not the landfill to energy facility is installed.

ICF conducted outreach to landfill gas operators in conjunction with the Coalition for Renewable Natural Gas as part of our research for this technical report. The summary of our findings and research on this particular issue are:

21 Frank, E.D., Han, J., Palou-Rivera, I., Elgowainy, A., and Wang, M. Methane and nitrous oxide emissions affect the life-cycle analysis of algal biofuels, Environ. Res. Lett. 7 (2012).

- Landfill gas to biomethane facilities are small, closed systems. Safety and economics demand that these facilities do not have any leaks.
- All waste gas is incinerated, and there is a flare to back up waste gas incineration.
- Landfill gas to biomethane facilities are constantly monitored for leaks.
- SCS Engineers, in conjunction with several facility owners/operators, will be conducting an analysis of landfill gas to LNG, CNG and pipeline quality processing operations in order to definitively evaluate the methane leakage rate (if any). This analysis should be complete and available for review within the next four-to-six months
- Absent data, ICF recommends incorporating a methane leak factor of zero for landfills.

5 Review of Formulas, Constants, and Engineering Calculations

ICF reviewed the formulas, constants, and calculations for natural gas pathways to the maximum extent feasible in the time allotted. ICF staff found several issues associated with each pathway. These are highlighted in the text below.

5.1 Pathway: LCNG

Storage values: ICF found a duplication of storage values for LCNG. Both LNG and LCNG follow the same process and supply chain steps except at the refueling station, where LNG as a transportation fuel is dispensed from the LNG storage tank to the vehicle as LNG and LCNG is converted from LNG to CNG and dispensed to the vehicle. There are no additional supply chain or storage steps for LCNG. ICF found that the "LNG Regasification" process ("NG" tab, Cells AJ21–AJ74) duplicates LNG storage that already occurs during the *LNG Storage: As a Transportation Fuel* stage on the "NG" tab cells AI22–AI67 and computed to CI in cells AD107–AD114 on the "NG" tab. Furthermore, the incorrect value is being used within the "LNG Regasification" stage for storage boil-off emissions. Value in cell AJ65 on the "NG" tab (which takes into account the control efficiency) should be utilized in the carbon intensity calculation (cell AE107 on the "NG" tab) and not cell AJ67 on the "NG" tab.

Regasification: LCNG stations pump and compress LNG as a fluid before being vaporized into a compressed storage system for refueling. Compression occurs as a liquid, which requires much less power than compression as a gas. Heat for regasification comes mainly from ambient temperature, with relatively minor heat input from the heat of pumping and friction. The regasification step included in the CA-GREET 2.0 model that requires use of natural gas as a thermal heat source is not applicable to LCNG stations in California.

Compression: ICF is confused by the introduction of methane loss during the conversion and compression of LNG to CNG. Furthermore, there are several issues with calculations and assumptions, namely:

- There is an error in a calculation related to the LNG to CNG energy efficiency calculation, cell F1346 on the "TI Calculator" tab; the formula reads:

"=F1340*Fuel_Specs!$B$53/(F1343*F1340+F1344*F1340+F1339*Fuel_Specs!B53***)*0+97%***". The last element of the equation negates the entire calculation and calculates the efficiency, no matter what values are inputted, at 97%.

- Cells F1339 and F1340 on the "TI Calculator" tab show a loss of 9% (5000 scf vs 5500 scf). This inaccuracy calculates incorrect energy efficiencies. For example, currently under the LNG to CNG compression stage, when the above error is corrected, the energy efficiency is 90.88%. If cell F1340 on the "TI Calculator" tab is correctly changed to 5,500 scf, the energy efficiency is 99.96%.
- Based on engineering calculations from NorthStar, Inc., the estimated electricity consumption at LCNG stations is 0.00102 kWh/scf. When you correct for CARB's natural gas density, (20.4 g/scf = 0.04497 lb/scf vs 0.04242 lb/scf used by NorthStar), the electricity consumption is adjusted to 0.00108 kWh/scf. This equates to 1.167 kWh/MMBtu using the CA-GREET 2.0 energy density of natural gas, 923.7 btu/scf. When you correctly make the adjustment to the energy efficiency calculation as discussed above and make F1339=F1340=1082.6 scf (scf/ 1 MMBtu) and 1.167 kWh in cell F1342 on the "TI Calculator" tab; then the resulting energy efficiency is 99.60% which results in a carbon intensity, when using the CAMX grid mix, of 0.41 g/MJ (Cell AF114 from "NG" tab).

5.2 Pathway: LNG

Storage: CA-GREET 1.8b included LNG boil-off rates of 0.05%/day for production plant and bulk terminal storage and 100% recovery rate while CA-GREET 2.0 includes boil-off rates of 0.1%/day and 80% recovery rate. It is unclear why these values were changed between the model versions.

Liquefaction: CA-GREET 2.0 appears to be internally inconsistent. The values used for liquefaction are different for LNG for NA NG and RNG. Furthermore, the formula for LNG energy efficiency is incorrect. The process says 1,414.29 btu of thermal energy in the form of natural gas is used per gallon of LNG. With the energy density in CA-GREET 2.0 (74,720 Btu/gallon), this results in 18,927.86 Btu natural gas for thermal / MMBtu LNG product. When you run the model and check cell AE42 on the NG tab, it calculates 111,771 Btu /MMBtu LNG or 8,351 Btu/gal LNG. The current formula overestimates the energy consumption by accounting for 1,414.29 Btu/gal for thermal energy plus the difference between natural gas entering the facility minus natural gas leaving as LNG. This is incorrect unless CARB is saying that an additional 1,414.29 Btu/gal LNG is required on top of the difference between natural gas entering the facility minus natural gas leaving as LNG which is not accurately represented in the fuel shares calculations.

There also appears to be an error in the natural gas to CNG energy efficiency calculation, cell E1278 on "TI Calculator" tab "=E1271*Fuel_Specs!B31/(E1270*Fuel_Specs!$B$53+E1274*E1271+***E1273*3412*E1271***)". The highlighted portion should either be correct to remove "*E1271" or replace "E1273*3412" with "E1275".

5.3 Pathway: CNG

Compression: As noted previously, ICF is confused by the introduction of methane loss during the compression of CNG. Cells E1229 and E1230 on the "TI Calculator" tab show a loss of 2% (1075 scf vs 1097 scf). This inaccuracy calculates incorrect energy efficiencies.

There also appears to be an error in the natural gas to CNG energy efficiency calculation, cell E1237 on "TI Calculator" tab "=E1230*Fuel_Specs!$B$53/(E1229*Fuel_Specs!$B$53+E1231*10^6***/E1230***+E1232*3412***/E1230***+E1240*E1229*Fuel_Specs!$B$53***/E1230***)". Given that ICF is unaware of why there would be any loss of methane at compression, and cells E1229 and E1230 were made equal on the "TI Calculator" tab, then compression energy efficiency equals 99.998% which is inaccurate. The "/E1230" should be removed from the calculation.

- If the kWh for electricity were adjusted to 100 kWh/1075 scf (an almost 20x increase), the efficiency would only drop from 98.00% to 97.97%.
- When cell E1229 is equal to the value in cell E1230 on the "TI Calculator" tab, this generates an energy efficiency of 97.99% and a carbon intensity of 2.14 (when using CAMX grid mix) that matches the 2.14 g/MJ in the original LCFS pathway documents.

If CARB is introducing a 2% loss of methane at the point of compression, then it is unclear how this is represented or why this change is made. The values in E1229 and E1230 are hard-coded into the model.

5.4 Pathway: Landfill Gas to CNG

Compression: It is unclear why the compression efficiency for RNG (6.4kWh/1075scf) is different than NA NG (5.98 kWh/1075 scf). Further, there is an incorrect formula for compression efficiency, E1370 on the "TI Calculator" tab, same as CNG compression above: =E1363*Fuel_Specs!$B$53/(E1362*Fuel_Specs!$B$53+E1364*10^6+E1365*3412)****0+98%.***. As in other formulas noted previously, the last element of the formula defaults the calculation to 98%, regardless of the values otherwise included.

5.5 Pathway: Landfill Gas to LNG

Liquefaction: The liquefaction data (65,000 scf / 100 gallons LNG) is not accurate and is compensated by an incorrect formula for process efficiency since E1397 (LNG gallons) *Fuel_Specs!$B$31 (btu/gallon) on the "TI Calculator" tab are the correct units and do not need a conversion factor =(E1397*Fuel_Specs!$B$31***/gal2ft3***)/(E1396*Fuel_Specs!$B$53+E1398*10^6+E1399*3412+E1408*E1396*Fuel_Specs!$B$53). If /gal2ft3 were removed, the efficiency would be 12%.

5.6 Pathway: Landfill Gas to LCNG

Liquefaction: The liquefaction data (8000000 scf / 11900 gallons LNG) are not accurate and are compensated by an incorrect formula for process efficiency since E1438 (LNG gallons) *Fuel_Specs!$B$31 (btu/gallon) on the "TI Calculator" tab are the correct units and do not need a conversion factor =(E1438*Fuel_Specs!$B$31***/gal2ft3***)/(E1437*Fuel_Specs!$B$53+E1439*10^6+E1440*3412+E1449*E1437*Fuel_Specs!$B$53). If "/gal2ft3" were removed, the efficiency would be 12%.

Energy efficiency: The energy efficiency calculations for regasification and compression are hard coded, cells E1471 and F 1471 on the "TI Calculator" tab. ICF's comments here are the same LCNG above for storage, regasification and compression

5.7 Pathway: Animal waste to CNG

Compression: There is an incorrect formula for compression efficiency, E1490 on the "TI Calculator" tab, similar to the CNG compression calculations mentioned previously: =E1483*Fuel_Specs!B53/(E1482*Fuel_Specs!B53+E1484*10^6+E1485*kWh2BTU)*0**+97%.** The last element of the formula defaults the entire calculation to 97% regardless of the other parameters.

6 The Impact of Natural Gas Changes to Electricity and Hydrogen

Note that electricity and hydrogen pathways cannot be run in the publicly available version of the CA-GREET 2.0 model, as they are not available in the drop-down list on the "T1 Calculator" tab. ICF reviewed the Electric and Hydrogen tabs. The tables below summarize the carbon intensity differences for electricity and hydrogen when utilizing the same electricity inputs.

Table 10. Carbon intensity differences for electricity

Pathways	California Average[22]	California Marginal[23]	CAMX	California Average [A]	California Marginal [A]
Model	CA-GREET1.8b	CA-GREET1.8b	CA-GREET2.0	CA-GREET2.0	CA-GREET2.0
Electricity Mix					
Residual Oil	0.05%	0%	1.4%	0.05%	0%
Natural Gas	43.1%	78.7%	50.8%	43.1%	78.7%
Coal	15.4%	0%	7.2%	15.4%	0%
Biomass	1.1%	0%	2.6%	1.1%	0%
Nuclear	14.8%	0%	15.2%	14.8%	0%
Other	25.6%	21.3%	22.9%	25.6%	21.3%
Carbon Intensity (gCO2e/MJ)	124.10	104.71	104.04	154.03	161.40
Percent Increase from 1.8b to 2.0	-	-	-	24%	54%

Notes:
A – Does not currently exist in GREET2.0, ICF utilized the "User Defined" electricity mix option

[22] Detailed California-Modified GREET Pathway for California Average and Marginal Electricity, February 2009. Available online at: http://www.arb.ca.gov/fuels/lcfs/022709lcfs_elec.pdf

[23] Ibid.

Table 11 Carbon intensity differences for hydrogen

Pathways[B]	HYNG001	HYNG002	HYNG003	HYNG004	HYNG005
CA-GREET 1.8b Carbon Intensity (gCO2e/MJ)[C]	142.20	133.00	98.80	98.30	76.10
CA-GREET 2.0 Carbon Intensity (gCO2e/MJ)– CAMX Grid Mix	148.75	138.32	104.19	100.36	84.30[D]
CA-GREET 2,0 Carbon Intensity (gCO2e/MJ)– User Defined CA Marginal Grid Mix	181.98	164.13	112.86	106.91	92.14[D]
Percent Increase from 1.8b to 2.0 with CA-Marginal Electricity Mix	28%	23%	14%	9%	21%[E]

Notes:

B – Pathways Descriptions: HYGN001 – gaseous hydrogen from central reforming of NA-NG with liquefaction and re-gas steps; HYGN002 - liquid hydrogen from central reforming of NA-NG; HYGN003 - gaseous hydrogen from central reforming of NA-NG; HYGN004 - gaseous hydrogen from on-site reforming of NA-NG; HYGN005 - gaseous hydrogen from on-site reforming of 2/3 NA-NG and 1/3 RNG

C – Modeling done in 1.8b using California Marginal Mix

D – There were multiple errors in the coding of cells U176 – U181 on the 'Hydrogen' tab, these values take into account the corrections

E – Increase is due to both fossil natural gas and renewable natural gas changes

6.1 Impacts on Electricity

Like GREET1 2013, CA-GREET 2.0 is updated to use the latest version of eGRID (v9) incorporating 2010 electricity generation mixes. CARB modified the grid regions in CA-GREET 2.0 to use the 26 eGRID subregions rather than the 10 NERC regions used in GREET1 2013. CARB also modified the CA-GREET 2.0 to use average rather than marginal subregional mixes "due to the uncertainty in determining the marginal resource mix accurately for each subregion."

When using the eGRID subregion mixes, not all electricity generation sources in eGRID match those in CA-GREET 2.0. Therefore, two sources are been reallocated:

- The "other fossil" source in eGRID has been assigned to "Residual oil" in CA-GREET 2.0
- The "other unknown fuel purchased" source in eGRID has been assigned to "Natural gas" in CA-GREET 2.0

This change leads to a small increase in natural gas share in the grid mixes in CA-GREET 2.0. For example, for the CAMX eGRID subregion, the "other unknown fuel purchased" source makes up 0.30% of the total grid mix. When reassigned to natural gas, this increases the share of natural gas in the grid mix from 50.45% to 50.75%.

The Draft Comparison Document also notes that CARB staff discovered additional data that may allow CA-GREET 2.0 to use subregion specific emission factors for electricity production. Staff plans to include this approach in CA-GREET 2.0 if there is a significant change and if the data are appropriate. The potential source is the U.S. EPA "Emission Factors for Greenhouse Gas Inventories," April 4, 2014.

In the CA-GREET 2.0 model, the fuel-cycle energy use and emissions of electric generation on the "Electricity" sheet incorporate updated values to fuel specifications on the "Fuel_Specs" sheets and natural gas recovery and processing assumptions on the "NG" sheet. Specifically, electricity calculations are impacted by:

- Changes to feed losses in the natural gas recovery process fuels mix,
- Changes to feed losses in the natural gas processing process fuels mix,
- Changes to natural gas loss factor,
- Addition of shale gas recovery and processing,
- Updates to natural gas pipeline transportation energy intensity, and
- Natural gas methane leakage assumptions.

CA-GREET 2.0 includes the CAMX electricity grid mix but does not include California Average and California Marginal electricity grid mixes that are included in the look-up table.[24] The table above shows that when these electricity grid mixes are included in CA-GREET 2.0, the carbon intensities increase significantly.

6.2 Impacts on Hydrogen

All hydrogen parameters in CA-GREET 2.0 match those in GREET1 2013. In adopting assumptions from GREET1 2013, many parameters are unchanged between CA-GREET 1.8b and CA-GREET 2.0 while several other parameters have changed between CA-GREET 1.8b and CA-GREET 2.0. All differences between CA-GREET 1.8b and CA-GREET 2.0 are summarized below:

- Central Hydrogen Plants Parameters (North American Natural Gas to Hydrogen)
  - Energy efficiency of production – increased from 71.5% to 72.0%
  - Fuel mix of production – changed from 99.8% natural gas and 0.2% electricity to 95.6% natural gas and 4.4% electricity
  - Share of feedstock input as feed (the remaining input as process fuel) – unchanged
  - Production of displaced steam energy efficiency – unchanged
  - Fuel mix of production of displaced steam (100% natural gas) – unchanged
  - H2 compression energy efficiency – decreased from 93.9% to 91.5%
  - Fuel mix for compression (100% electricity) – unchanged
- Hydrogen refueling stations parameters (North American Natural Gas to Hydrogen)
  - Energy efficiency of production – increased from 70.0% to 71.4%
  - Fuel mix of production – changed from 95.1% natural gas and 4.9% electricity to 91.7% natural gas and 8.3% electricity
  - Share of feedstock input as feed (the remaining input as process fuel) – unchanged
  - H2 compression energy efficiency – decreased from 93.9% to 91.5%
  - Fuel mix for compression (100% electricity) – unchanged

[24] LCFS Carbon Intensity Lookup Tables for Gasoline and Fuels that Substitute for Gasoline (Table 6) & Diesel and Fuels that Substitute for Diesel (Table 7). Available online: http://www.arb.ca.gov/fuels/lcfs/lu_tables_11282012.pdf; updated December 2012.

In the CA-GREET 2.0 model, the energy and emissions calculations on the "Hydrogen" sheet incorporate updated values to fuel specifications on the "Fuel_Specs" sheets and natural gas recovery and processing assumptions on the "NG" sheet. Specifically, hydrogen calculations are impacted by:

- Changes to feed losses in the natural gas recovery process fuels mix,
- Changes to feed losses in the natural gas processing process fuels mix,
- Changes to natural gas loss factor,
- Addition of shale gas recovery and processing,
- Updates to natural gas pipeline transportation energy intensity, and
- Natural gas methane leakage assumptions.

CA-GREET 2.0 includes the CAMX electricity grid mix but does not include California Average and California Marginal electricity grid mixes that are included in the look-up table. The table above shows that when these electricity grid mixes are included in CA-GREET 2.0 to model the hydrogen pathways, the increases in carbon intensity are substantial. It is also noted above that there were multiple formula errors in the HYNG005 pathway.

Appendix A: List of Abbreviations and Acronyms

AD	anaerobic digestion
ANGA	American Natural Gas Association
ANL	Argonne National Laboratory
API	American Petroleum Institute
CARB	California Air Resources Board
CH4	methane
CI	carbon intensity
CNG	compressed natural gas
DPF	diesel particulate filter
EPA	Environmental Protection Agency
GHG	greenhouse gas
GREET model	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model
GWP	global warming potential
H2	hydrogen
HDV	heavy-duty vehicle
HPDI	high pressure direct injection
LDV	light-duty vehicle
LFG	landfill gas
LNG	liquefied natural gas
MD	medium-duty vehicle
N2O	nitrous oxide
NG	natural gas
NGV	natural gas vehicle
NSPS	New Source Performance Standard
RNG	renewable natural gas
SCAQMD	South Coast Air Quality Management District
SCR	selective catalytic reduction
TWC	three-way catalyst
WVU	West Virginia University