CALIFORNIA
AIR RESOURCES BOARD

CA-GREET3.0
Lookup Table Pathways
Technical Support Documentation

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California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) ◆ California Ultra-low Sulfur Diesel (ULSD) ◆ Compressed Natural Gas ◆ Propane ◆ Electricity ◆ Hydrogen

CA-GREET3.0 Lookup Table Pathways - Technical Support Documentation

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Introduction

This document provides details of the CA-GREET3.0 Lookup Table Pathways for the following fuels:

- California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)
- California Ultra-low Sulfur Diesel (ULSD)
- Compressed Natural Gas
- Propane
- Electricity
  - California average grid electricity supplied to electric vehicles (ELCG)
  - Electricity that is generated from 100 percent zero-CI sources, which include eligible renewable energy resources as defined under California Public Utilities Code section 399.11-399.36, excluding biomass, biomethane, geothermal, and municipal solid waste (ELCR)
  - Electricity supplied under the smart charging or smart electrolysis provision with a CI based on curtailment probability (ELCT)
- Hydrogen
  - Compressed H_2 produced in California from central SMR of North American fossil-based NG (HYF)
  - Liquefied H_2 produced in California from central SMR of North American fossil-based NG (HYFL)
  - Compressed H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills (HYB)
  - Liquefied H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills (HYBL)
  - Compressed H_2 produced in California from electrolysis using California average grid electricity (HYEG)
  - Compressed H_2 produced in California from electrolysis using solar- or wind-generated electricity (HYER)

This document provides the input values and assumptions related to calculation of carbon intensities determined using CA-GREET3.0 for each of the pathways included in the Lookup Table.

Section A. California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)

I. Pathway Summary

California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) pathway carbon intensity includes greenhouse gas emissions from the following life cycle stages: crude oil recovery from all domestic and oversea sources, crude transport to California for refining, refining of the crude to gasoline blendstock in California refineries, transport to blending racks and distribution of the finished fuel, and tailpipe emissions[1] from final combustion in a vehicle. Based on the updated CA-GREET3.0, the carbon intensity (CI) of CARBOB is calculated to be **100.82** gCO_2e/MJ of CARBOB as shown in Table A.1.

Table A.1. Summary Table of CARBOB CI

Component	Total CI* gCO_2e/MJ
Crude Recovery and Crude Transport	11.78
Refining	14.80
CARBOB Transport	0.30
Tailpipe Emissions	73.94
Total CI	**100.82**

* Individual values may not sum to the total due to rounding

II. Pathway Assumptions, Details, and Calculation

1. Crude Oil Recovery and Transport to California:

Crude oil recovery for the year 2010 is based on the Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0c.[2] The CI is calculated to be **11.78** gCO_2e/MJ.

2. CARBOB Refining:

[1] Tailpipe emissions are determined for California reformulated gasoline (90 percent CARBOB and 10 percent ethanol by volume) and allocated to the blendstock on an energy basis.

[2] El-Houjeiri, H.M., Vafi, K., Masnadi, M.S., Duffy, J., McNally, S., Sleep, S., Pacheco, D., Dashnadi, Z., Orellana, O., MacLean, H., Englander, J., Bergerson, J and A.R. Brandt. Oil Production Greenhouse Gas Emissions Estimator (OPGEE) Model 2.0c, June 20, 2018

To calculate carbon intensity of refinery product streams for the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET®) model, Argonne National Laboratory (ANL) contracted with Jacobs Consultancy Inc. to develop a refinery linear programming (LP) model for evaluation of the petroleum refining process. The LP model represents process-based refinery operations, material flows, prices, and responses to changes in petroleum product specifications. The model maximizes refinery profit by determining the optimal volumetric throughput and utility balance among various processes under given market and technical conditions. The modeling results were validated against propriety data from 43 individual refineries in the U.S. in 2012. The validated models were also compared to the 2010 refinery statistical data available from the U.S. Energy Information Administration (EIA), and little difference was observed at the Petroleum Administration for Defense District (PADD) level.

From the LP modeling results, product-specific efficiency, the efficiency of producing an end product, should be calculated to estimate the emissions associated with each product. The product specific efficiency can be calculated as energy in an end product divided by energy associated with the production of the end product. Usually, the production of an end product takes one or more processes. The energy associated with the production of the end product is estimated from aggregating energy consumed in the processes of the pathways. Because many processes produce multiple output streams, the energy consumed in these processes is allocated to the output streams by the energy values of the output streams. Note that the LP model provides the volumetric and mass flow rates of individual process units in a given refinery. The energy flow rates of gaseous and solid streams are calculated using their heating values. The energy flow rates of liquid streams are calculated using a heating value regression formula by its API gravity. More detailed information relating to model development, refinery and unit efficiency calculation and allocation methodology used in this study is presented by Elgowainy et al.[3]

For the LCFS, ANL disaggregated PADD 5 data[4] and provided weighted average data for California refineries from the validated LP model. ANL included energy inputs, refining efficiency and refinery operational details for the production of CARBOB and these are shown in Table A.2.

Major inputs of CARBOB refining include crude oil, heavy unfinished oils, butane, blendstocks, natural gas, hydrogen and electricity. Heavy unfinished oils (e.g., vacuum gas oil) can be purchased from less complex refineries and processed in more complex refineries with deep conversion units (such as coker, hydrocrackers, etc.). Gasoline blendstocks (such as butane, reformates, alkylates, etc.) can also be purchased from other facilities to meet the gasoline specification depending on market conditions, refinery capacities, etc. NG is used to provide heat and electricity via combustion or to

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[3] Amgad Elgowainy, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman , Vincent B. Divita, and. "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries" May 2014. https://greet.es.anl.gov/publication-energy-efficiency-refineries

[4] PADD 5 includes California, Arizona, Nevada, Hawaii, Oregon, Alaska and Washington.

generate hydrogen via steam methane reforming. When combusted, NG is mixed with refinery off gases from process units. A portion of the hydrogen used in the refinery is purchased from external sources.

From the LP modeling, the total energy input for CARBOB is calculated to be **1,128,160 Btu** for every 1,000,000 MMBtu of finished product. This translates to a refining efficiency calculated as 1,000,000/1,128,160 and reported as 88.64% in Table A.2.

The energy inputs are derived from various inputs based on the LP modeling results and include:

- Crude: This is the quantity of crude-derived feedstock used in the production of CARBOB. From Argonne's modeling, a weighted-average California refinery uses 750,105 Btu of crude to produce 1,000,000 Btu of CARBOB.

- Additional external energy inputs are derived from purchased feedstock/blendstock, which include residual oil (as a surrogate for purchased unfinished oil and heavy products), natural gas, electricity, hydrogen, butane and other blendstock. The subtotal of these inputs makes up the remaining 1,128,160 - 750,105 = 378,055 Btu of input energy.

- During CARBOB refining, intermediate products such as pet coke and refinery still gas are combusted to provide additional energy to the refining process. Since these intermediates are generated from the input crude and other purchased energy, they do not contribute to the total energy input. However, their combustion contributes to the final CI for CARBOB. Table A.3 provides the emission factors (EFs) used in the calculation of GHG emissions from combustion of these intermediate products.

- A portion of purchased NG is used to produce H_2 in an on-site steam methane reforming (SMR) reactor. The CO_2 released in the SMR is considered as non-combustion emissions from NG and is included in the final CI for CARBOB.

- For the LCFS, since Crude Oil Recovery and Transport to California and the CARBOB Refining processes are calculated for the 2010 base year, the NG production and electricity mix data in the calculation have been adjusted to reflect 2010 values which were also applied in previous model version CA-GREET2.0.

Table A.2. Refining Parameters Used in CARBOB Refining CI Calculations

Parameter	Value	Unit	Note
CARBOB Refining Energy Efficiency	88.64	%	This is CA specific CARBOB refining energy efficiency (weighted average). Although the reference reports PADD-level results, same calculation methodology applies to CARBOB produced in California refineries.
CARBOB Refining: External Energy Inputs (Including Feedstocks and Process Fuels) for 1,000,000 Btu of finished product			
Crude oil	750,105	Btu	Crude input for the production of CARBOB
Residual oil	138,330	Btu	As a surrogate for purchased unfinished oil and heavy products.
Natural gas	85,478	Btu	A portion of purchased natural gas is converted into H_2 by on-site SMR (see Intermediate Products Non-combustion Emissions section below) while the rest is mixed with fuel gases and combusted to produce heat and electricity (see Intermediate Products Combustion section below).
Electricity	4,953	Btu	From grid.
Hydrogen	2,533	Btu	Purchased from external vendor.
Butane	77,161	Btu	Purchased butane is used mainly as a blendstock for gasoline. Assumes butane refining requires 1/3 of gasoline refining energy.
Blendstock	69,600	Btu	Other purchased blendstock (alkylates, reformates and natural gasoline) produced elsewhere. Assumes blendstock refining requires 2/3 gasoline refining energy.
Total	**1,128,160**	Btu	Total external energy input of 1,128,160 Btu for 1,000,000 Btu of CARBOB production
CARBOB Refining: Intermediate Products Combustion for 1,000,000 Btu of finished product			
Pet Coke	19,855	Btu	Since the FCC coke is an intermediate product derived from the external inputs (crude oil, unfinished oil, heavy products, etc.), on-site combustion of the FCC coke does not contribute to the total energy inputs. The emission factor of pet coke combustion in an industrial boiler (stationary application) is 101.66 gCO_2e/MJ (Table A.3).
Refinery Still Gas	94,100	Btu	Refinery still gas is a mix of purchased natural gas and internally produced fuel gas. Since refinery still gas is derived from the external inputs, on-site combustion of the refinery still gas does not contribute to the total energy inputs. The emission factor of refinery still gas combustion in an industrial boiler (stationary application) is 54.69 gCO_2e/MJ (Table A.3).

Parameter	Value	Unit	Note
CARBOB Refining: Intermediate Products Non-combustion Emissions for 1,000,000 Btu of finished product			
On-site Steam Methane Reformer (SMR)	1,113	gCO_2	CO_2 emission from the on-site SMR, which converts a portion of purchased NG into H_2.

The CI of refining in CA-GREET3.0 is **14.80** gCO_2e/MJ.

Table A.3. Emission Factors for Petroleum Coke and Refinery Still Gas as Refinery Intermediate Products

	Pet Coke	**Refinery Still Gas**
Combustion Technology	Industrial Boiler	Industrial Boiler
VOC, g/MMBtu	0.47	2.54
CO, g/MMBtu	23.95	22.21
CH_4, g/MMBtu	1.25	1.06
N_2O, g/MMBtu	0.86	0.75
CO_2, g/MMBtu	106,933	57,409
Emission Factor, gCO_2e/MJ intermediate product	**101.66**	**54.69**

3. CARBOB Transport and Distribution:

Transportation: CARBOB is transported to the blending terminal and is blended with ethanol. 80% is assumed to be transported by pipeline for 50 miles to a blending terminal and 20% is blended at the refinery and distributed 50 miles by Heavy Duty Diesel (HDD) truck (emissions for HDD distribution is accounted in the distribution step).

Distribution: Finished gasoline is distributed to gas stations and is assumed to be a total of 50 miles by HDD Truck.

4. Tailpipe Emissions:

Since CARBOB is a blendstock and not a final finished fuel, vehicle tailpipe emissions represent the portion of California Reformulated Gasoline (CaRFG) emissions allocated to CARBOB. The tailpipe emissions are based on CARB's EMFAC2011 model[5] and results are shown in Table A.4:

[5] California Air Resources Board. May 2014. California's 2000-2012 Greenhouse Gas Emissions Inventory Technical Support Document. State of California Air Resources Board. Air Quality Planning and Science Division. https://www.arb.ca.gov/cc/inventory/doc/methods_00-12/ghg_inventory_00-12_technical_support_document.pdf

Table A.4. Tailpipe Emissions from CARBOB

GHG	Tailpipe GHG from gasoline vehicles, g/MMBtu	gCO_2e/MJ
CH_4	5.87	0.14
N_2O	3.22	0.91
CO_2	76,904.65	72.89
Total	78,010.83	**73.94**

A comparison of refinery process details and pathway CI for CARBOB between CA-GREET2.0 and CA-GREET3.0 is provided in Table A.5.

Table A.5. Comparison of CIs and Refining Details for CARBOB Production between CA-GREET2.0 and CA-GREET3.0

CARBOB		CA-GREET2.0	CA-GREET3.0	Difference
Electricity source		3-CAMX Mix		
1) Crude Recovery				
Source (feedstock production)		OPGEE default		
Efficiency		92.58%	90.94%	
Share of process fuels	Natural gas	99.60%	98.99%	
	Diesel fuel	0.04%	0.20%	
	Electricity	0.26%	0.78%	
Feed loss		0.10%	0.03%	
CI, gCO_2e/MJ		**11.98**	**11.78**	**-0.20**
2) Crude Refining to CARBOB				
Source (fuel production)		CA Crude		
Efficiency		89%	88.64%	
Share of other energy inputs (excluding crude)	Residual oil	24.9%	36.6%	
	Diesel fuel	0.0%	0.0%	
	Gasoline	0.0%	0.0%	
	Natural gas	37.40%	22.6%	
	LPG	8.01%	0.0%	
	Electricity	3.5%	1.31%	
	Hydrogen	26.2%	0.7%	
	Butane	0.0%	20.4%	
	Blendstock	0.0%	18.4%	
Feed loss		0.0%	0.0%	
CI, gCO_2e/MJ		**13.45**	**14.80**	**1.35** [6]
3) CARBOB Transport				
80% pipeline to blending terminal, miles		50	50	
20% on-site blending and distributed by HDD truck, miles		0	0	
Distributed by HDD Truck, miles		50	50	
CI, gCO_2e/MJ		**0.41**	**0.30**	**-0.11**
4) Tailpipe Emissions		**73.94**	**73.94**	**0.00**
Methane (CH_4), g/MJ		0.14	0.14	
N_2O, g/MJ		0.91	0.91	
CO_2, g/MJ		72.89	72.89	
Total CI, gCO_2e/MJ		**99.78**	**100.82**	**1.04**

[6] Mainly due to improved data quality and refined resolution of the LP models.

Section B. California Ultra Low Sulfur Diesel (ULSD)

I. Pathway Summary

The California Ultra-low Sulfur Diesel (ULSD) pathway carbon intensity assessment includes greenhouse gas emissions from the following well-to-wheel life cycle stages: crude oil recovery from all domestic and overseas sources, crude transport to California for refining, refining of the crude to ultra-low sulfur diesel in California refineries, transport to blending racks and distribution of the finished fuel, and tailpipe emissions from final combustion of the fuel in a vehicle. Based on the updated CA-GREET3.0 model, the life cycle Carbon Intensity (CI) of California ULSD is calculated to be 100.45 gCO_2e/MJ as shown in Table B.1.

Table B.1. Summary Table of California ULSD CI

Aggregated Impact	CI Impact* gCO_2e/MJ
Crude Recovery and Crude Transport	11.78
Crude Oil Refining	13.57
ULSD Transport	0.24
Tailpipe Emissions	74.86
Total CI	**100.45**

* Individual values may not sum to the total due to rounding

II. Pathway Assumptions, Details, and Calculation

1. Crude Oil Recovery and Transport to California:

Crude oil recovery for the year 2010 is based on the updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model, version 2.0c.[2] The CI for this phase of the life cycle assessment is calculated to be **11.78** gCO_2e /MJ.

2. ULSD Refining:

To calculate carbon intensity of refinery product streams for the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model, Argonne National Laboratory (ANL) contracted with Jacobs Consultancy Inc. to develop a refinery linear programming (LP) model for evaluation of the petroleum refining process. The LP model represents process-based refinery operations, material flows, prices, and responses to changes in petroleum product specifications. The model maximizes refinery profit by determining the optimal volumetric throughput and utility balance among various processes under given market and technical conditions. The modeling results were validated against propriety data from 43 individual refineries in the U.S. in 2012. The validated models were also compared to the 2010 refinery statistical data available from the U.S. Energy Information Administration (EIA), and little difference was observed at the Petroleum Administration for Defense District (PADD) level.

From the LP modeling results, product-specific efficiency, the efficiency of producing an end product, should be calculated to estimate the emissions associated with each product. The product specific efficiency can be calculated as energy in an end product divided by energy associated with the production of the end product. Usually, the production of an end product takes one or more processes. The energy associated with the production of the end product is estimated from aggregating energy consumed in the processes of the pathways. Because many processes produce multiple output streams, the energy consumed in these processes is allocated to the output streams by the energy values of the output streams. Note that the LP model provides the volumetric and mass flow rates of individual process units in a given refinery. The energy flow rates of gaseous and solid streams are calculated using their heating values. The energy flow rates of liquid streams are calculated using a heating value regression formula by its API gravity. More detailed information relating to model development, refinery and unit efficiency calculation and allocation methodology used in this study is presented by Elgowainy et al.[3]

For the LCFS, ANL disaggregated PADD 5 data and provided weighted average data for California refineries from the validated LP model. ANL included energy inputs, refining efficiency and refinery operational details for the production of ULSD and these are shown in Table B.2.

Major inputs of ULSD refining include crude oil, heavy unfinished oils, butane, natural gas, hydrogen and electricity. Heavy unfinished oils (e.g., vacuum gas oil) can be purchased from less complex refineries and processed in more complex refineries with deep conversion units (such as coker, hydrocrackers, etc.). Butane as a blendstock can also be purchased from other facilities to meet the ULSD specification depending on market conditions, refinery capacities, etc. NG is used to provide heat and electricity via combustion or to generate hydrogen via steam methane reforming. When combusted, NG is mixed with refinery off gases from process units. A portion of the hydrogen used in the refinery is purchased from external sources.

From the LP modeling, the total energy input for California ULSD is calculated to be **1,164,551 Btu** for every 1,000,000 MMBtu of finished product. This translates to a refining efficiency calculated as 1,000,000/1,164,551 and reported as 85.87% in Table B.2. The energy inputs are derived from various inputs based on the LP modeling results and include:

- Crude: This is the quantity of crude-derived feedstock used in the production of ULSD. From Argonne's modeling, a weighted-average California refinery uses 978,161 Btu of crude to produce 1,000,000 Btu of ULSD.

- Additional energy inputs are derived from purchased feedstock and include residual oil (as a surrogate for purchased unfinished oil and heavy products), natural gas, electricity, hydrogen and butane. The subtotal of these inputs makes up the remaining 1,164,551 - 978,161 = 186,390 Btu of the input energy.

- During ULSD refining, intermediate products such as pet coke and refinery still gas are combusted to provide additional energy to the refining process. Since these intermediates are generated from the input crude and other purchased energy, they do not contribute to the total energy input. However, their combustion contributes to the final CI for ULSD. Table A.3 provides the emission factors (EFs) used in the calculation of GHG emissions from combustion of these intermediate products.

- A portion of purchased NG is used to produce H_2 in an on-site steam methane reforming (SMR) reactor. The CO_2 released in the SMR is considered as non-combustion emissions from NG and is included in the final CI for ULSD.

- For the LCFS, since Crude Oil Recovery and Transport to California and the ULSD Refining processes are calculated for the 2010 base year, the NG production and electricity mix data in the calculation have been adjusted to reflect 2010 values which were also applied in previous model version CA-GREET2.0.

Table B.2. Refining Parameters Used in ULSD Refining CI Calculations

Parameter	Value	Unit	Note
ULSD Refining Energy Efficiency	85.87	%	This is CA specific ULSD refining energy efficiency (weighted average). Although the reference reports PADD-level results, same calculation methodology applies to ULSD produced in California refineries.
ULSD Refining: External Energy Inputs (Including Feedstocks and Process Fuels) for 1,000,000 Btu of finished product			
Crude oil	978,161	Btu	Crude input for the production of ULSD.
Residual oil	38,877	Btu	As a surrogate for purchased unfinished oil and heavy products.
Natural gas	133,541	Btu	A portion of purchased natural gas is converted into H_2 by on-site SMR (see Intermediate Products Non-combustion Emissions section below) while the rest is mixed with fuel gases and combusted to produce heat and electricity (see Intermediate Products, Combustion section below).
Electricity	6,878	Btu	From grid.
Hydrogen	6,721	Btu	Purchased from external vendor.
Butane	373	Btu	Purchased.
Total	**1,164,551**	Btu	Total external energy input of 1,164,551 Btu for 1,000,000 Btu of ULSD production in California.
ULSD Refining: Intermediate Products Combustion for 1,000,000 Btu of finished product			
Pet Coke	7,076	Btu	Since the FCC coke is an intermediate product derived from the external inputs (crude oil, unfinished oil, heavy products, etc.), on-site combustion of the FCC coke does not contribute to the total energy inputs. The emission factor of pet coke combustion in an industrial boiler (stationary application) is 101.66 gCO_2e/MJ (Table A.3).
Refinery Still Gas	115,219	Btu	Refinery still gas is a mix of purchased natural gas and internally produced fuel gas. Since refinery still gas is derived from the external inputs, on-site combustion of the refinery still gas does not contribute to the total energy inputs. The emission factor of refinery still gas combustion in an industrial boiler (stationary application) is 54.69 gCO_2e/MJ (Table A.3).
ULSD Refining: Intermediate Products Non-combustion Emissions for 1,000,000 Btu of finished product			
On-site Steam Methane Reformer (SMR)	2,856	gCO_2	CO_2 emission from the on-site SMR, which converts a portion of purchased NG into H_2.

The CI for ULSD refining is calculated from CA-GREET3.0 to be **13.57** gCO_2e/MJ.

1. ULSD Transport and Distribution:

Transportation: After refining, ULSD is transported to the distribution terminal. The assumed transport route is 80% by pipeline for 50 miles, and 20% is directly transported by truck to a filling station (50 miles considered in distribution leg).

Distribution: Finished diesel is distributed from a diesel terminal to filling stations and this distance is assumed to be 50 miles by HDDT.

2. Tailpipe Emissions:

The tailpipe emissions are based on CARB's EMFAC2011 model[5] and results are shown in Table B.3:

Table B.3. ULSD Tailpipe Emissions

GHG	Tailpipe GHG Emissions from Diesel-fueled Vehicles ($gCO_2e/MMBtu$)	gCO_2e/MJ
CH_4	1.39	0.03
N_2O	2.56	0.72
CO_2	76,068.43	74.10
Total	79,866.31	**74.86**

A comparison of refinery process details and pathway CI for ULSD between CA-GREET2.0 and CA-GREET3.0 is provided in Table B.4.

Table B.4. Comparison of CIs and Refining Details for ULSD Production between CA-GREET2.0 and CA-GREET3.0

ULSD		CA-GREET2.0	CA-GREET3.0	Difference
Electricity source		3-CAMX Mix		
1) Crude Recovery				
Source (feedstock production)		OPGEE default		
Efficiency		92.58%	90.94%	
Share of process fuels	Natural gas	99.60%	98.99%	
	Diesel fuel	0.04%	0.20%	
	Electricity	0.26%	0.78%	
Feed loss		0.10%	0.03%	
CI, gCO_2e/MJ		**11.98**	**11.78**	**-0.20**
2) Crude Refining to ULSD				
Source (fuel production)		CA Crude		
Efficiency		88%	85.87%	
Share of other energy inputs (excluding crude)	Residual oil	24.9%	20.8%	
	Diesel fuel	0.0%	0.00%	
	Gasoline	0.0%	0.00%	
	Natural gas	37.40%	71.7%	
	LPG	8.01%	0.0%	
	Electricity	3.5%	3.7%	
	Hydrogen	26.2%	3.6%	
	Butane	0.0%	0.2%	
Feed loss		0.0%	0.0%	
CI, gCO_2e/MJ		**14.83**	**13.57**	**-1.26**[6]
3) ULSD Transport				
80% pipeline to blending terminal, miles		50	50	
20% on-site blending and distributed by HDD truck, miles		0	0	
Distributed by HDD Truck, miles		50	50	
CI, gCO_2e/MJ		**0.34**	**0.24**	**-0.10**
4) Tailpipe Emissions		74.85	74.86	**-0.01**
Methane (CH_4), g/MJ		0.03	0.03	
N_2O, g/MJ		0.724	0.724	
CO_2, g/MJ		74.1	74.1	
Total CI, gCO_2e/MJ		**102.01**	**100.45**	**-1.56**

Section C. Compressed Natural Gas

I. Pathway Summary

The North American fossil natural gas (NG) to compressed natural gas (CNG) pathway includes the life cycle stages depicted in Figure C.1. The fossil NG used as feedstock is modeled as an average unit of gas withdrawn from commercial pipelines, and reflects the shares of North American NG supply obtained from shale formations (50.2%) and from conventional fossil natural gas wells (49.8%).[7]

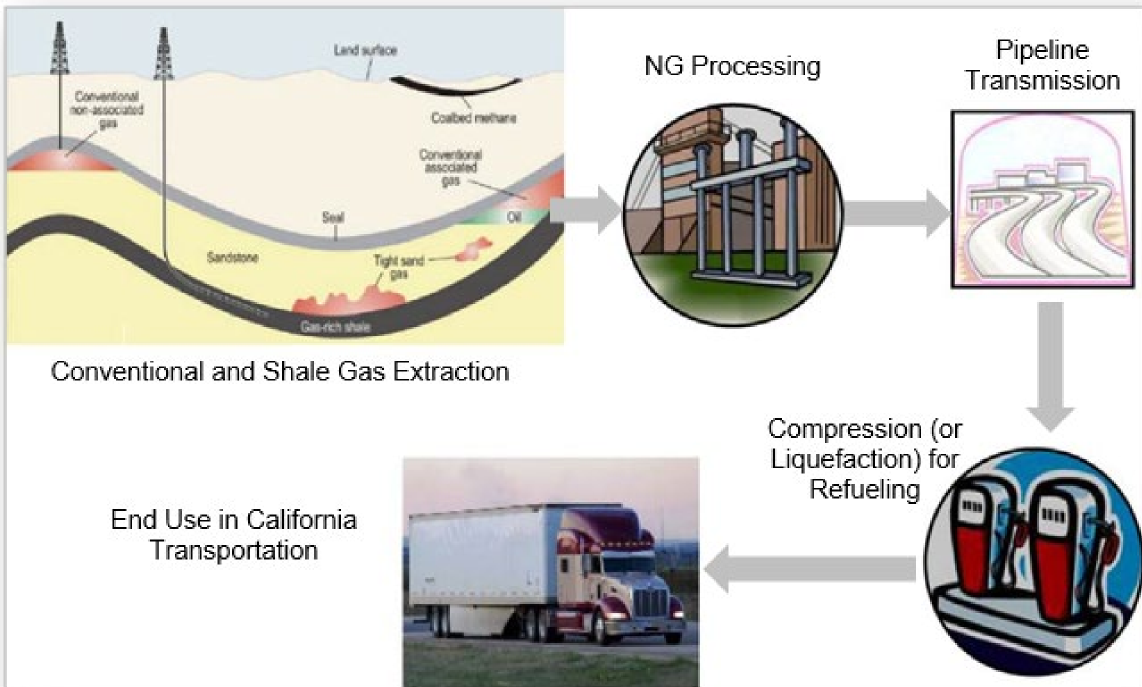

Figure C.1. Life Cycle Compressed Natural Gas Production and Use (Courtesy of Argonne National Lab)

Based on the CA-GREET3.0 model, the carbon intensity (CI) of Compressed Natural Gas is calculated to be **79.21** gCO_2e/MJ and is detailed in Table C.1.

[7] U.S. Energy Information Administration. Annual Energy Outlook 2015. Table: Oil and Gas Supply. Case: Reference case, Data year 2014. (accessed Oct, 2017) http://www.eia.gov/beta/aeo/#/?id=14-AEO2015&cases=ref2015

Table C.1. Summary Table of Compressed Natural Gas CI

Pathway Stage	Total CI* gCO_2e/MJ
Natural Gas (NG) Recovery	6.07
NG Processing	3.31
NG Transport	5.92
NG Compression	3.18
Tailpipe Emissions	60.73
Total CI	**79.21**

* Individual values may not sum to the total due to rounding

II. Pathway Details, Assumptions, and Calculations

Extracted NG is processed to meet pipeline specifications e.g., for methane content, heating value, and contaminant concentration. About 90% of fossil natural gas used in California is imported from natural gas basins stretching from western Canada to Texas, and 10% is produced in-state.[8] Figure C.2 shows sources of NG imported into California and their pipeline transmission linkages. For processed NG imported via pipeline to California, staff estimated a weighted average distance of approximately 1,200 miles however, due to lack of detailed data for intra-state supplied NG, an overall weighted transport distance of 1,000 miles was assumed for NG from all sources of NG used in California for the production of Compressed Natural Gas.

[8] California Energy Commission http://www.energy.ca.gov/almanac/naturalgas_data/overview.html (accessed 02/07/2018)

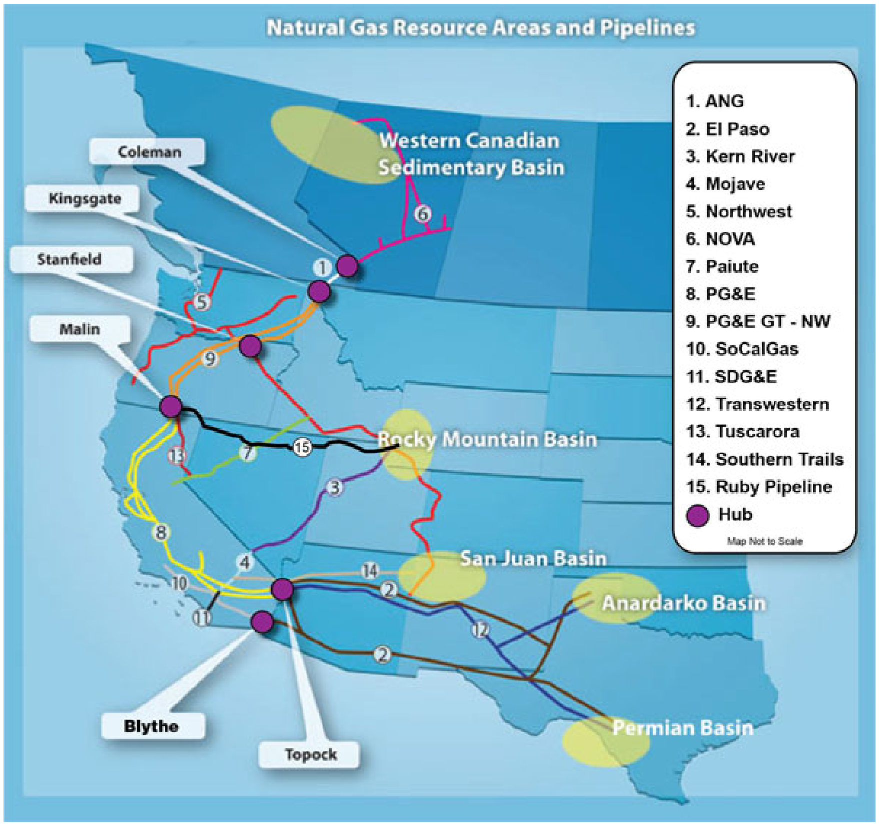

Figure C.2. Sources of Natural Gas Imported to California (from California Energy Commission[9])

Methane Leakage assumptions from extraction to final distribution in CA-GREET3.0 are the same as Argonne GREET1_2016 and detailed in Table C.2.

[9] Natural gas resource areas and interstate pipelines into California from California Energy Commission website (accessed 02/07/2018) http://www.energy.ca.gov/almanac/naturalgas_data/interstate_pipelines.html

Table C.2. Methane Leakage Assumptions

CH_4 leakage rate for each stage in conventional NG and shale gas pathways[10]			CH_4 leakage[11]	
Stage	Conventional NG	Shale gas	Conventional NG	Shale gas
	($g\ CH_4$/MMBtu NG)		Vol. %	
Recovery - Completion CH_4 Venting	0.5	11.8	0.00%	0.06%
Recovery - Workover CH_4 Venting	0.0	2.4	0.00%	0.01%
Recovery - Liquid Unloading CH_4 Venting	9.0	9.0	0.04%	0.04%
Well Equipment - CH_4 Venting and Leakage	134.9	134.9	0.65%	0.65%
Processing - CH_4 Venting and Leakage	26.2	26.2	0.13%	0.13%
Transmission and Storage - CH_4 Venting and Leakage (g CH_4/MMBtu NG/1000 miles)	46.7	46.7	0.23%	0.23%
Distribution - CH_4 Venting and Leakage	17.7	17.7	0.09%	0.09%
		Total	**1.14%**	**1.21%**

Table C.3 provides detailed CI calculations for the fossil NG pathway[12] using CA-GREET3.0. For NG recovery and processing, efficiency (expressed in percentage) represents the ratio of energy content in the output product over total energy input (including feedstock and process fuels). The table also lists fuels used in NG recovery and processing and provides a breakdown of the individual shares (expressed in percentage) used in these operations. Feed loss and flared gas during processing are also listed in the table. The table includes GHG emissions (expressed as CI in g/MJ) for each step from recovery to final use in transportation. Table C.3 also includes details of CI calculations for this pathway using factors and inputs in CA-GREET2.0 to provide a comparison of changes and related impacts relative to CA-GREET3.0.

[10] Burnham, A. Updated Fugitive Greenhouse Gas Emissions for Natural Gas Pathways in the GREET1_2016 Model. Table 3, Page 6. October 2016. Retrieved October 2017. https://greet.es.anl.gov/publication-updated-ghg-2016

[11] CA-GREET3.0 – Input Tab

[12] Clark, et al. Life-Cycle analysis of Shale Gas and Natural Gas. December 2011. Retrieved October 2017. https://greet.es.anl.gov/publication-shale_gas

Table C.3. Compressed Natural Gas Pathway CIs (comparison of CI CA-GREET2.0 and CA-GREET3.0)

Fossil NG		CA-GREET2.0		CA-GREET3.0		Difference
		Conventional NG	**Shale NG**	**Conventional NG**	**Shale NG**	
Electricity source		3-CAMX Mix				
Share of NG supply		77.20%	22.80%	49.78%	50.22%	
1) NG Recovery						
Efficiency		97.18%	97.07%	97.50%	97.62%	
Share of process fuels	**Residual oil**	0.88%	0.81%	1.00%	1.00%	
	Diesel	9.71%	8.87%	11.00%	11.00%	
	Gasoline	0.88%	0.81%	1.00%	1.00%	
	NG	77.23%	76.43%	86.00%	86.00%	
	Electricity	0.88%	0.81%	1.00%	1.00%	
	Feed loss	10.41%	12.28%	Included in NG as process fuel		
Natural Flared, Btu/MMBtu		8,370	8,292	10,486	10,327	
CI, gCO_2e/MJ		**3.98**		**6.07**		**2.11**[13]
2) NG Processing						
Efficiency		97.35%		97.35%		
Share of process fuels	**Residual oil**	0.0%		0.0%		
	Diesel	0.9%		1.0%		
	Gasoline	0.0%		0.0%		
	NG	90.07%		96.0%		
	Electricity	4.5%		3.0%		
	Feed loss	4.5%		0.0%		
CI, gCO_2e/MJ		**3.38**		**3.31**		**-0.07**
3) NG Transport						
Pipeline Miles		1,000		1,000		
CI, gCO_2e/MJ		**8.17**		**5.92**		**-2.25**[14]
4) Compression						
Efficiency		97%		97%		
CI, gCO_2e/MJ		**3.25**		**3.18**		**-0.07**
5) Tailpipe Emissions, g/MJ		**60.69**		**60.73**		**0.04**
Total CI, gCO_2e/MJ		**79.46**		**79.21**		**-0.25**

[13] Mainly due to the increased NG flaring during recovery.

[14] Due to lower updated NG transmission leakage rate.

Tailpipe emissions for CNG vehicles are calculated using emission factors from the Argonne GREET 1 2016 model for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in NG. Results of the tailpipe emissions are shown in Table C.4:

Table C.4. Summary of Tailpipe GHG Emissions from Compressed Natural Gas Vehicles[15]

GHG	Tailpipe GHG from Compressed Natural Gas, g/MMBtu	Tailpipe CI, gCO_2e/MJ
CH_4	203.28	4.82
N_2O	0.46	0.13
CO_2	58,853.65	55.78
Total	**64,073.17**	**60.73**

[15] CA-GREET3.0 – NG Tab

Section D. Propane

I. Pathway Summary

Propane (also termed Liquefied Petroleum Gas or LPG) is a co-product from the refining of crude oil and is also extracted during natural gas and crude oil recovery. It is a flammable mixture of hydrocarbon gases predominantly propane and butane. At atmospheric pressures and temperatures, propane will evaporate and is therefore stored in pressurized steel tanks. As a motor vehicle fuel, LPG is composed primarily of propane with varying butane percentages to adjust for vaporization pressure. Less than 3% of propane produced in the U.S. is currently used as a transportation fuel.[16]

Data from the Energy Information Administration[17] indicates that in PADD 5, approximately 25% of propane is produced from natural gas sources and 75% from refineries. Also, propane produced in the PADD 5 region exceeds propane used in California for all uses.[17] The propane pathway therefore assumes propane used in transportation is produced in-state and delivered 200 miles by heavy-duty truck to end-users or retail stations within California.

Based on the updated CA-GREET3.0 model, the carbon intensity (CI) of propane is calculated to be **83.19** gCO_2e/MJ and is detailed in Table D.1.

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[16] California Energy Commission, accessed Oct 2017: http://www.energy.ca.gov/drive/technology/propane.html

[17] U.S. Energy Information Administration. Petroleum & Other Liquids, Supply and Disposition, West Coast (PADD 5), Annual 2014, accessed Oct. 2017. https://www.eia.gov/dnav/pet/pet_sum_snd_d_r50_mbbl_a_cur-3.htm

Table D.1. Summary Table of Propane CI

Pathway Stage	CI, gCO_2e/MJ from 100% NG source	CI, gCO_2e/MJ from 100% crude source	Total CI* gCO_2e/MJ (weighted based 25/75 ratio of the sources)
Feeds Inputs from NG			
NG Recovery	6.05		1.51
NG Processing	3.30		0.82
NG Transmission	0.27		0.07
Feeds Inputs from Crude			
Crude Recovery		6.69	5.01
Crude Transport		1.60	1.20
Propane Refining from NG	3.07		0.77
Propane Refining from Crude		10.01	7.51
Non-Combustion Emissions	0.79	0.43	0.52
Propane Transport	0.74	0.74	0.74
Propane Storage	0.0	0.0	0.0
Tailpipe Emissions	65.03	65.03	65.03
Total CI	**79.26**	**84.50**	**83.19**

* Values may not sum to total due to rounding

II. Pathway Details, Assumptions, and Calculations

Since propane is recovered from both natural gas and crude sources, the production step includes contributions from both sources and is detailed below. Since 25% is produced from natural gas sources and 75% from crude sources, the CIs are proportionally weighted for the total propane produced.

1. Propane (from Natural Gas) Recovery, Processing, and Transport:

The propane recovery process from NG sources is assumed to be the same as the NG recovery process detailed in the fossil NG pathway in Section C. The clean, processed gas is pipelined 50 miles (assumed) to a LPG plant.[18]

Total CI of all three steps for propane production from NG sources: NG recovery (1.51 gCO_2e/MJ), NG processing (0.82 gCO_2e/MJ), and NG transport by pipeline (0.07 gCO_2e/MJ) is calculated to be **2.41** gCO_2e/MJ (all with 25% allocation).

[18] The loss factors during the NG transportation are different between a CNG plant (1000 mi pipeline) and a LPG plant (50 mi pipeline).

2. Propane (from Crude) Recovery, Processing and Transport:

U.S. crude source is used where CI from crude extraction is 5.01 gCO_2e/MJ and CI from crude transportation is 1.20 gCO_2e/MJ. These reflect 75% allocation for propane produced from crude sources. The total carbon intensity for propane production from crude sources is calculated to be **6.21** gCO_2e/MJ.

3. Propane Refining (from NG and Crude):

The energy efficiency and fuel used (with corresponding shares) of propane refining from NG and crude sources is detailed in Table D.2. After allocation, the carbon intensity of propane refining (from NG sources) is calculated to be 0.77 gCO_2e/MJ and propane refining (from crude sources) at 7.51 gCO_2e/MJ as shown in Table D.2.

Table D.2. Propane Refining Parameters *

	NG sources	Crude sources
Energy Efficiency	96.5%	89.5%
Energy Use	Btu/MMBtu	
Diesel	363	113,436
Natural Gas	34,819	47,674
Electricity	1,088	3,177
Hydrogen		7,610
Butane		65,169
CI results after 25/75 allocation	**0.77**	**7.51**

* Values may not sum to total due to rounding

4. Propane Non-combustion Emissions

CI from non-combustion emissions is calculated to be 0.20 g/MJ for propane derived from NG sources. The non-combustion emissions for propane produced from crude sources is calculated to be 0.32 g/MJ. Both these values reflect a 25/75 percent allocation for propane sourced from these two sources. Total emissions from non-combustion emissions is calculated to be **0.52 gCO_2e /MJ.**

5. Propane transport:

Propane transport distance is assumed to be 200 miles by HDD truck to LPG stations and shown in Table D.3. The GHG emissions from transport is calculated to be **0.74 gCO_2e /MJ**

Table D.3. Propane Transport and Distribution

Transport and distribution mode	Mileage	CI* gCO_2e /MJ
Distribution by Heavy Duty Diesel Truck	200 miles	**0.74**

* Values may not sum to total due to rounding

6. Tailpipe Emissions:

Tailpipe emissions from the use of propane in light duty propane vehicles are calculated using values from the Argonne GREET1_2016 model for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in propane and shown in Table D.4. Total tailpipe emissions calculations are shown in Table D.5.

Table D.4. Summary of Tailpipe CO_2 Emissions from Propane Vehicles

Parameter	Value
MPGGE (Miles per Gasoline Equivalent Gallon)	23.4
Total Propane Use, Btu/mile	4,795
CO_2 in Propane, grams CO_2/mile	326.3
CO_2 in Propane, convert to gCO_2/MMBtu	68,052.7

Table D.5. Summary of Tailpipe GHG Emissions from Propane Vehicles[19]

GHG	Tailpipe Emissions for Propane vehicles g/MMBtu	CI* gCO_2e/MJ
CH_4	3.18	0.075
N_2O	1.59	0.45
CO_2	68,052.7	64.50
Total	**68,607.25**	**65.03**

* Values may not sum to total due to rounding

[19] CA-GREET3.0 - Results Tab, LPGV section

Section E. Electricity

I. Pathway Summary

There are three pathways for electricity used as a transportation fuel in California in the Lookup Table and they are summarized in Table E.1 and E.1.a with calculated pathway CIs.

Table E.1. Electricity Lookup Table Pathways

Fuel Pathway Code	Fuel Pathway Description	Total CI gCO_2e/MJ
ELCG	California average grid electricity used as a transportation fuel in California (subject to annual updates)	93.75
ELCR	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	0.00
ELCT	Electricity supplied under the smart charging or smart electrolysis provision (subject to annual updates)	See Table E.1.a below

The smart charging (or smart electrolysis, when electricity is supplied to a hydrogen electrolyzer) carbon intensity values are calculated based on the marginal emission rates determined using the Avoided Cost Calculator (March 2018), which is incorporated herein by reference. A set of algorithmically neutral carbon intensity values are determined for each hour of the day, for the four quarters of the year, to represent the average marginal emission rates for EV charging or electrolytic hydrogen production that takes place during these times. Using electricity for EV charging or electrolysis could result in additional emission reductions relative to Average Grid Electricity during the periods when the marginal emissions are low.

Table E.1.a. Calculated Smart Charging or Smart Electrolysis Carbon Intensity Values for 2019*

Hourly Window	Q1	Q2	Q3	Q4
12:01 AM – 1:00 AM	87.06	86.91	86.87	90.25
1:01 AM – 2:00 AM	87.06	85.91	86.80	88.55
2:01 AM – 3:00 AM	87.06	87.20	86.77	87.80
3:01 AM – 4:00 AM	87.06	87.03	86.72	87.91
4:01 AM – 5:00 AM	87.63	91.45	87.17	90.98
5:01 AM – 6:00 AM	94.46	105.76	95.77	105.08
6:01 AM – 7:00 AM	110.98	94.28	92.09	122.40
7:01 AM – 8:00 AM	105.79	2.48	88.39	109.22
8:01 AM – 9:00 AM	86.35	1.96	89.39	94.27
9:01 AM – 10:00 AM	58.66	2.92	91.09	90.26

10:01 AM – 11:00 AM	57.80	50.25	93.23	89.84
11:01 AM – 12:00 PM	56.52	53.31	97.87	91.17
12:01 PM – 1:00 PM	55.97	55.12	104.23	92.03
1:01 PM – 2:00 PM	56.50	58.67	110.13	93.36
2:01 PM – 3:00 PM	56.53	63.57	115.76	95.25
3:01 PM – 4:00 PM	57.80	26.45	123.91	104.30
4:01 PM – 5:00 PM	92.45	48.57	131.52	136.96
5:01 PM – 6:00 PM	125.85	120.79	146.52	156.40
6:01 PM – 7:00 PM	144.90	151.38	155.70	153.00
7:01 PM – 8:00 PM	127.62	150.96	140.27	141.37
8:01 PM – 9:00 PM	114.50	122.63	118.35	130.78
9:01 PM – 10:00 PM	95.55	93.62	100.45	115.22
10:01 PM – 11:00 PM	88.25	88.12	91.21	102.03
11:01 PM – 12:00 AM	87.07	87.12	88.57	93.34

*Based on 2019 marginal emission rates determined using the Avoided Cost Calculator (March 2018) and subject to updates.

II. Pathway Details, Assumptions, and Calculations

A. California average grid electricity used as a transportation fuel in California (ELCG)

The California electricity generation mixes in CA-GREET3.0 are based on the Total System Electric Generation published by the California Energy Commission (CEC) for the 2016 data year.[20] This California electricity resource mix was used for the power generation and the U.S. average electricity resource mix was used for the feedstock production phase (NG, coal, etc.): the weighted carbon intensity (CI) of the feedstock production is calculated to be 16.11 gCO_2e/MJ, and the CI of the power generation is calculated to be 77.64 gCO_2e/MJ.[21] Based on the updated CA-GREET3.0 model, the CI of average California Electricity is calculated to be **93.75** gCO_2e/MJ and is detailed in Table E.2.

According to the U.S. Energy Information Administration (EIA),[22] of the 262 plants in the U.S. that generated electricity using fuel resources categorized as “unspecified,” 135 reported using natural gas, biogas, and/or land fill gas. Additionally, of the 21 plants in California that generated electricity using fuel sources categorized as “unspecified,” 13 reported using natural gas and/or biogas. Therefore, natural gas was used as a surrogate for “Unspecified” fuel category in the CA-GREET3.0. Additionally, “Other Petroleum” in the CEC 2016 was treated as “Residual Oil” in the calculation.

The calculation of emission factors was based on different combustion technologies and their energy conversion efficiencies of each fuel type (Table E.3). For example, residual oil-fired power plants use three combustion technologies: boiler, internal combustion engine, and gas turbine. In California, the shares of these three technologies are 72.4%, 15.5%, and 12.1%, respectively. Furthermore, the energy conversion efficiencies of these three technologies are 33.9%, 39.0%, and 27.6%, respectively. The combustion technology shares and their energy conversion efficiencies were calculated using aggregated data from EIA.[23] Complete details are available in Argonne’s 2013 report.[24]

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[20] 2016 California Total System Electric Generation data from California Energy Commission (CEC) website, accessed 11/2017: http://www.energy.ca.gov/almanac/electricity_data/total_system_power.html

[21] Assumes an average transmission loss from power lines is 6.5% for the U. S. from GREET 1 2016

[22] U.S. Energy Information Administration. List of plants for other, United States, all sectors, 2014. https://www.eia.gov/electricity/data/browser/#/topic/1?agg=2,0,1&fuel=00g&geo=g&sec=g&freq=A&datecode=2014&rtype=s&pin=&rse=0&maptype=0&ltype=pin&ctype=linechart&end=2016&start=2014

[23] U.S. Energy Information Administration. Form EIA-923 detailed data, accessed 2017. http://www.eia.gov/electricity/data/eia923

[24] Hao Cai, Michael Wang, Amgad Elgowainy, Jeongwoo Han. Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010. 2013. https://greet.es.anl.gov/publication-electricity-13

Table E.2. Summary of CI for California Average Grid Electricity Used as a Transportation Fuel in California*

	Electricity Resources Mix	Energy Inputs, Btu/MMBtu	Feedstock Production		Power Generation	
			Emission Factor, gCO2e/MMBtu	Contribution to CI, gCO2e/MMBtu	Emission Factor, gCO2e/MMBtu	Contribution to CI, gCO2e/MMBtu
Residual Oil	0.15%	4,714	14,820	69.86	253,578	402.28
Natural Gas	50.87%**	1,130,708	13,824	15,631	123,600	67,249
Coal	4.13%	127,364	5,515	702.39	289,776	12,807
Biomass	2.25%	106,711	2,242	239.22	8,713	210.13
Nuclear	9.18%	98,167	3,625	355.84	0	0
Hydro	11.87%	126,907	0	0	0	0
Geothermal	4.38%	46,805	0	0	26,669	1,248
Wind	9.06%	96,886	0	0	0	0
Solar PV	8.11%	86,771	0	0	0	0
Subtotal	100%			16,998		81,916
Tailpipe Emissions				0		0
Total CI, gCO2e/MMBtu			**98,914**			
Total CI, gCO2e/MJ			**93.75**			

* Values may not round to sum due to rounding.
** In the CA-GREET3.0 model, all undefined energy resources are assumed to be from natural gas. This value represents the sum of the reported natural gas used in the electricity mix (36.48%) and the undefined energy categories (14.39%), as the total share of natural gas (50.87%) in the CA Electricity Resources Mix.

Examples of calculation in Table E.2:

For Natural Gas (NG) Feedstock Production, the NG energy input is

$$\frac{50.87\%}{48.12\% \times (1 - 6.5\%)} \times 10^6 \text{Btu/MMBtu} = 1{,}130{,}708 \text{ Btu/MMBtu};$$

where:

Power generation share of NG = 50.87%;

Loss in electricity transmission = 6.5%; and

Power Plant Energy Conversion Efficiency (see Table E.3) =

$$\frac{1}{(6.4\% \div 32.0\%) + (3.3\% \div 32.8\%) + (89.2\% \div 51.1\%) + (1.1\% \div 34.4\%)} = 48.12\%$$

The contribution of NG to the feedstock production CI is:

$$\frac{1{,}130{,}708 \text{ Btu/MMBtu}}{10^6 \text{Btu/MMBtu}} \times 13{,}824 \text{ gCO}_2\text{e/MMBtu} = \mathbf{15{,}631} \text{ gCO}_2\text{e/MMBtu } (\mathbf{14.82} \text{ gCO}_2\text{e/MJ})$$

where:

EF of NG use in power plant = **13,824** gCO_2e/MMBtu
(CI value of the "Natural Gas for Electricity Generation" pathway in the NG tab).

For Natural Gas in Electricity Production, the contribution of NG to the power generation CI is:

$$\frac{\mathbf{123{,}600}\ gCO_2e/MMBtu \times 50.87\%}{(1\text{-}6.5\%)} = \mathbf{67{,}249}\ gCO_2e/MMBtu\ (\mathbf{63.74}\ gCO_2e/MJ)$$

where:

Power generation share of NG = 50.87%;

Loss in electricity transmission = 6.5%; and

EF of Electricity generation from NG (see Table E.3) =
[(634.08 gCO_2/kWh × 6.4%) + (618.58 gCO_2/kWh × 3.3%) + (397.17 gCO_2/kWh × 89.2%) + (588.66 gCO_2/kWh × 1.1%)] × 293.07 kWh/MMBtu = **123,600** gCO_2/MMBtu

Table E.3. Summary of Combustion Technology Shares and Energy Conversion Efficiencies for California Average Grid Electricity Used as a Transportation Fuel in California

	Emission Factors of Combustion Technologies in CA, gCO_2e/kWh	Combustion Technology Shares for a Given Plant Fuel Type in CA	Power Plant Energy Conversion Efficiency in CA
Residual Oil-Fired Power Plants			
Boiler	858.87	72.4%	33.9%
Internal Combustion Engine	746.79	15.5%	39.0%
Gas Turbine	1,055.11	12.1%	27.6%
Weighted Average			33.65%
Natural Gas-Fired Power Plants			
Boiler	634.08	6.4%	32.0%
Simple-cycle gas turbine	618.58	3.3%	32.8%
Combined-cycle gas turbine	397.17	89.2%	51.1%
Internal Combustion Engine	588.66	1.1%	34.4%
Weighted Average			48.12%
Coal-Fired Power Plants			
Boiler	988.76	100.0%	34.7%
IGCC	985.78	0.0%	34.8%
Weighted Average			34.70%
Biomass Power Plants			
Boiler	29.73	100.0%	22.6%
IGCC	28.69	0.0%	34.8%
Weighted Average			22.60%

B. Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (ELCR)

For electricity that is generated from 100 percent zero-CI sources, which include eligible renewable energy resources as defined under California Public Utilities Code section 399.11-399.36, excluding biomass, biomethane, geothermal, and municipal solid waste, and used as a transportation fuel in California, the pathway CI is **0.0** g/MJ.

C. California Average Grid Electricity supplied under the smart charging or smart electrolysis provision (ELCT)

1. Description of smart charging or smart electrolysis CI values:

The carbon intensity values for smart charging or smart electrolysis are calculated based on the marginal emission rates determined using the Avoided Cost Calculator (March 2018), which is incorporated herein by reference. A set of algorithmically neutral carbon intensity values are determined for each hour of the day, for the four quarters of the year, to represent the average marginal emission rates for EV charging or electrolytic hydrogen production that takes place during these times. Using electricity for EV charging or electrolysis could result in additional emission reductions relative to Average Grid Electricity during the periods when the marginal emissions are low.

2. Calculation of normalized average marginal emission rates for California Average Grid Electricity:

For calculation of marginal emission rates in the Avoided Cost Calculator, natural gas is assumed to be the marginal fuel for electricity generation in California in all hours and the hourly emissions rate of the marginal generator is calculated based on the day-ahead market price curve. The relationship between market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency generators to operate, resulting in increased rates of emissions at the margin. This relationship holds for a reasonable range of prices but breaks down when prices are extremely high or low. For this reason, the avoided cost methodology bounds the maximum and minimum emissions rates based on the range of heat rates of gas turbine technologies. Additionally, if the implied heat rate is calculated to be at or below zero, it is then assumed that the system is in a period of over-generation and therefore the marginal emission rate is correspondingly zero.

The Avoided Cost Calculator estimates marginal emission rates for Northern and Southern California which are based on the normalized hourly day-ahead heat rate profiles for CAISO NP-15 and SP-15 regions. Statewide average marginal emission rates for 2019, weighted by load, are calculated based on the load profile of large load serving entities (LSE) in the two geographical areas: Pacific Gas and Electric (PG&E) in Northern California, and Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) in Southern California. The CAISO demand profile for these three utilities for 2017 is shown in Table E.4.[25]

Table E.4. 2017 Demand Profile for California Investor-owned Utilities

LSE	Demand (MWh)	% of Total Demand
PG&E	11,945	45%
SCE	12,064	46%
SDG&E	2,307	9%
Total	**26,316**	**100%**

The resulting statewide average marginal emission rates for California Grid Average Electricity are normalized to the California Average Grid Electricity CI value over the year for each hourly window for the four quarters of the year, as shown in Table E.5.

[25] http://oasis.caiso.com/mrioasis/logon.do. The CAISO demand reported for PGE-TAC, SCE-TAC, and SDGE-TAC regions are used.

Table E.5. Normalized Marginal Emission Rates for California Grid Average Electricity for 2019

Hourly Window	Q1	Q2	Q3	Q4
12:01 AM – 1:00 AM	0.9286	0.9271	0.9266	0.9627
1:01 AM – 2:00 AM	0.9286	0.9164	0.9259	0.9445
2:01 AM – 3:00 AM	0.9286	0.9301	0.9255	0.9365
3:01 AM – 4:00 AM	0.9286	0.9284	0.9250	0.9377
4:01 AM – 5:00 AM	0.9347	0.9755	0.9298	0.9705
5:01 AM – 6:00 AM	1.0076	1.1281	1.0216	1.1208
6:01 AM – 7:00 AM	1.1838	1.0056	0.9823	1.3056
7:01 AM – 8:00 AM	1.1285	0.0264	0.9428	1.1650
8:01 AM – 9:00 AM	0.9211	0.0209	0.9535	1.0055
9:01 AM – 10:00 AM	0.6257	0.0311	0.9716	0.9628
10:01 AM – 11:00 AM	0.6165	0.5360	0.9944	0.9582
11:01 AM – 12:00 PM	0.6029	0.5686	1.0439	0.9725
12:01 PM – 1:00 PM	0.5970	0.5880	1.1118	0.9817
1:01 PM – 2:00 PM	0.6027	0.6258	1.1748	0.9958
2:01 PM – 3:00 PM	0.6030	0.6781	1.2348	1.0160
3:01 PM – 4:00 PM	0.6166	0.2822	1.3218	1.1125
4:01 PM – 5:00 PM	0.9861	0.5181	1.4029	1.4609
5:01 PM – 6:00 PM	1.3424	1.2884	1.5629	1.6683
6:01 PM – 7:00 PM	1.5456	1.6147	1.6608	1.6320
7:01 PM – 8:00 PM	1.3613	1.6103	1.4962	1.5080
8:01 PM – 9:00 PM	1.2213	1.3080	1.2624	1.3950
9:01 PM – 10:00 PM	1.0192	0.9987	1.0714	1.2290
10:01 PM – 11:00 PM	0.9413	0.9399	0.9730	1.0883
11:01 PM – 12:00 AM	0.9287	0.9293	0.9448	0.9956

3. Calculation of smart charging or smart electrolysis CI values:

The carbon intensity values for smart charging or smart electrolysis for a given time period is determined by multiplying the CI of California Average Grid Electricity by the normalized marginal emission rates for each hourly window. This calculation gives the estimated average carbon intensity for electricity as a result of using electricity for EV charging or electrolysis during a specific hourly window in a given quarter. The carbon intensity values calculated for smart charging or smart electrolysis pathways in 2019 are shown in Table E.1.a.

Section F. Hydrogen

I. Pathway Summary

There are six hydrogen pathways in the Lookup Table and they are summarized in Table F.1 with calculated CIs.

Table F.1. Hydrogen Lookup Table Pathways

Fuel Pathway Code	Pathway Description	Total CI gCO_2e/MJ
HYF	Compressed H_2 produced in California from central SMR of North American fossil-based NG	**117.67**
HYFL	Liquefied H_2 produced in California from central SMR of North American fossil-based NG	**150.94**
HYB	Compressed H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	**99.48**
HYBL	Liquefied H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	**129.09**
HYEG	Compressed H_2 produced in California from electrolysis using California average grid electricity	**164.46**
HYER	Compressed H_2 produced in California from electrolysis using solar- or wind-generated electricity	**10.51**

The six hydrogen pathways have the pathway characteristics as detailed in Table F.2.

Table F.2. Summary of Production Details and Transport Modes for the Six Lookup Table Hydrogen Pathways

Fuel Pathway Code:	HYF	HYFL	HYB	HYBL	HYEG	HYER
Process:	NG to Gaseous H_2 from SMR	NG to Liquid H_2 from SMR	Biomethane to Gaseous H_2 from SMR	Biomethane to Liquid H_2 from SMR	Gaseous H_2 from electrolysis (grid electricity)	Gaseous H_2 from electrolysis (wind/solar electricity)
Feedstock Types:	Fossil NG	Fossil NG	Biomethane from Landfills	Biomethane from Landfills	Water	Water
Feedstock Transport:	Pipeline	Pipeline	Pipeline	Pipeline	Water delivery infrastructure	Water delivery infrastructure
Process Fuel:	NG and Grid Electricity	NG and Grid Electricity	RNG and Grid Electricity	RNG and Grid Electricity	Grid Electricity	Wind or Solar Electricity *
Fuel Type:	Compressed gaseous H_2	Liquid H_2	Compressed gaseous H_2	Liquid H_2	Compressed gaseous H_2	Compressed gaseous H_2
Fuel Transport Mode	Tube Trailer (assumes 0.4 ton capacity)	Tanker Trailer (assumes 4 ton capacity)	Tube Trailer (assumes 0.4 ton capacity)	Tanker Trailer (assumes 4 ton capacity)	N/A	N/A
Regasification and Compression:[26]	N/A	Yes	N/A	Yes	N/A	N/A

* Pathway HYER assumes California average grid electricity is used at the refueling station for compression and dispensing. Electrolyzer load is met by zero-CI wind or solar energy.

The CIs for each of these pathways is dependent upon specific input parameters in worksheets of the CA-GREET3.0 model. The CI results by life cycle stage are detailed in Table F.3 for each hydrogen pathway.

[26] Regasification and compression is necessary for liquid hydrogen customers demanding 600+ kg of Hydrogen per day.

Table F.3. Summary of CI Results by Life Cycle Stage for Hydrogen Pathways

Fuel Pathway Code:	HYF	HYFL	HYB	HYBL	HYEG	HYER
Process Description:	NG to Gaseous H_2 from SMR	NG to Liquid H_2 from SMR	Biomethane to Gaseous H_2 from SMR	Biomethane to Liquid H_2 from SMR	Gaseous H_2 from electrolysis (grid electricity)	Gaseous H_2 from electrolysis (wind/solar electricity)
NG Recovery	6.07	6.07				
NG Processing	3.31	3.31				
NG or RNG Transport	5.50	5.50	9.47	9.47		
LFG Recovery			0.79	0.79		
LFG Processing			42.74	42.74		
H_2 Production	20.46	21.79	20.46	21.79	153.95	0
H_2 Production Non-Combustion	64.09	68.26	7.78	8.29		
Liquefaction		45.28		45.28		
H_2 Transport	7.21	0.74	7.21	0.74		
Gaseous H_2 Compression and Precooling	11.04		11.04		10.51	10.51[27]
Total CI	**117.67**	**150.94**	**99.48**	**129.09**	**164.46**	**10.51**

[27] Assumes CAMX grid electricity is used for compression and dispensing at refueling stations.

II. Pathway Details, Assumptions, and Calculations

A. Compressed H_2 produced in California from central SMR of North American fossil-based NG (HYF)

This pathway uses fossil natural gas as feedstock and California average grid electricity (CAMX). From a central reforming station, hydrogen is assumed to be transported by heavy-duty diesel-fueled tube trailers to refueling outlets throughout the State for a distance of 100 miles. The tube pressure is stepped up to 7,000 psi for transport to refueling stations. Once the tube trailer arrives at the refueling station, this pathway assumes a "trans-fill" method for the transfer of gaseous hydrogen loaded tube trailer to the hydrogen storage unit at the refueling station. Once the gaseous hydrogen has been delivered to the refueling station storage unit, it must undergo further compression and precooling to -40°C (also -40°F) before it can be dispensed into a vehicle. The final discharge pressure for hydrogen fuel is estimated to range between 10,000 and 12,000 psi. Only electrical energy is assumed to be consumed for compression and pre-cooling of the gaseous hydrogen. Table F.3 details inputs and assumptions for this Lookup Table pathway.

Table F.3. Summary of Input Parameters for Compressed H_2 produced in California from central SMR of North American fossil-based NG (HYF)

Parameter	Value
Plant	Central
Feedstock	Natural Gas
Process Fuel	Natural Gas and Grid Electricity
Finished Fuel	Gaseous Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Gaseous hydrogen Compression Efficiency	90.3%
Electric Generation Mix (Feedstock)	1-U.S. Ave. Mix
Electric Generation Mix (Fuel Prod)	3-CAMX Mix
Share of Feedstock as Feed	83%
NG Transport by Pipeline to Central Plant (miles)	1,000
Gaseous Hydrogen Bulk Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	0.4[28]

[28] Assumed capacity of a tube trailer carrying hydrogen fuel from Bulk Terminal to Refueling Station.

B. Liquefied H_2 produced in California from central SMR of North American fossil-based NG (HYFL)

This pathway uses fossil natural gas used as feedstock and grid-average electricity. It is identical to the gaseous hydrogen from fossil natural gas pathway with the addition of the liquefaction step, and the transport of liquid hydrogen to the dispensing station followed by re-gasification and compression. Staff assumes that the liquid hydrogen produced at a central plant will be transported to refueling stations by 4-ton heavy-duty diesel tanker trailers over a distance of 100 miles. Some natural gas is expended to boil-off hydrogen before recovery and some hydrogen is also lost due to boil-off. The liquid hydrogen is re-gasified and stored on site as compressed gaseous hydrogen. The compression and precooling requirements prior to dispensing are the same as described in the gaseous hydrogen pathway.

Table F.4 details inputs and assumptions for this Lookup Table pathway.

Table F.4. Summary of Input Parameters for Liquefied H_2 produced in California from central SMR of North American fossil-based NG (HYFL)

Parameter	Value
Plant	Central
Feedstock	Natural Gas
Process Fuel	Natural gas and Grid Electricity
Fuel	Liquid Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Hydrogen Liquefaction Efficiency	71%
Boil-Off Effects of liquid Hydrogen	0.30%
Duration of Storage (days)	5
Recovery Rate for Boil-Off Gas	80%
Electric Generation Mix (Feedstock)	1-U.S. Ave. Mix
Electric Generation Mix (Fuel Production)	3-CAMX Mix
Share of Feedstock as Feed	83%
NG Transport by Pipeline to Central Plant (miles)	1,000
Liquid Hydrogen Truck Transport from Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	4[29]

[29] Assumed capacity of a tanker carrying hydrogen fuel from Bulk Terminal to Refueling Station.

C. Compressed H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills (HYB)

This pathway is analogous to the fossil NG to gaseous hydrogen pathway discussed above with the exception that the feedstock includes renewable natural gas sourced from landfills. Staff assumes a transport distance of 1,600 miles[30] for renewable biomethane sourced from landfills in North America. The upgrading of biogas to biomethane assumes energy use to be similar to energy use in landfill to biomethane pathways certified in the LCFS program from January 2016 through August 2017.

All the hydrogen production, transport and dispensing parameters are the same as detailed in the pathway for gaseous hydrogen from fossil natural gas.

Biomethane Required to Produce Renewable Hydrogen
Since only part of the total gas input is used as feedstock (i.e., biomethane is converted to finished hydrogen), and the balance is fossil NG used as process energy (i.e., combusted to produce steam), it is critical to establish upstream quantity of biomethane required per unit of hydrogen produced. LHV-based calculations using CA-GREET3.0 with attendant efficiencies indicate a total of 1.371 MMBtu of NG is required to produce 1 MMBtu of hydrogen. Thus, in order to be considered renewable hydrogen, of the total amount of NG required, 1 MMBtu per MMBtu H_2 must be biomethane and the remaining 0.371 MMBtu is assumed to be from fossil NG. Applicants who use this pathway to report hydrogen use in transportation must provide evidence of equivalent quantities of biomethane for quantities of hydrogen (1 to 1 on an energy basis, or 0.126 MMBtu (HHV) RNG per kg H_2) reported to generate credits in the LCFS program.

Table F.5 details inputs and assumptions for this Lookup Table pathway.

Table F.5. Summary of Input Parameters for Compressed H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills (HYB)

Parameter	Value
Plant	Central
Feedstock	Biomethane from Landfills
Process Fuel	Biomethane and Grid Electricity
Finished Fuel	Gaseous Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Gaseous hydrogen Compression Efficiency	90.3%
Electric Generation Mix (Feedstock)	1-U.S. Ave. Mix
Electric Generation Mix (Fuel Prod)	3-CAMX Mix
Share of Feedstock as Feed	83%

[30] Represents average transport distance for biomethane from LCFS pathways.

Biomethane Transport by Pipeline to Central Plant (miles)	1,600
Gaseous Hydrogen Bulk Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	0.4

D. Liquefied H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills (HYBL)

This pathway is analogous to the liquid hydrogen pathway from fossil NG. Assumptions related to upstream biomethane are identical to the gaseous hydrogen from biomethane pathway (HYB) with the exception of additional steps to produce liquid hydrogen, transporting liquid hydrogen to the dispensing station followed by re-gasification and compression. Table F.6 details inputs and assumptions for this Lookup Table pathway.

Applicants who use this pathway to report hydrogen dispensed for transportation use to generate credits in the LCFS program must provide evidence of equivalent quantities of biomethane for quantities of hydrogen reported: 1 MMBtu/MMbtu, or 0.126 MMBtu (HHV) of biomethane per kg of hydrogen.

Table F.6. Summary of Input Parameters for Liquefied H_2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills (HYBL)

Parameter	Value
Plant	Central
Feedstock	Biomethane from Landfills
Process Fuel	Biomethane and Grid Electricity
Fuel	Liquid Hydrogen
Share of Hydrogen Production	100% Central
Production Efficiency	72%
Hydrogen Liquefaction Efficiency	71%
Boil-Off Effects of Liquid Hydrogen	0.30%
Duration of Storage (days)	5
Recovery Rate for Boil-Off Gas	80%
Electric Generation Mix (Feedstock)	1-U.S. Ave. Mix
Electric Generation Mix (Fuel Production)	3-CAMX Mix
Share of Feedstock as Feed	83%
Biomethane Transport by Pipeline to Central Plant (miles)	1,600
Liquid Hydrogen Truck Transport from Terminal to Refueling Station (miles)	100
Cargo Payload for Hydrogen Transport (tons)	4

E. Compressed H_2 produced in California from electrolysis using California average grid electricity (HYEG)

The feedstock for this production process is primarily water and electricity in the only energy used in the production of hydrogen. There are no transport emissions since the hydrogen is produced on-site. Dispensing parameters are the same as detailed in the pathway for gaseous hydrogen from fossil natural gas. Inputs to the CA-GREET3.0 model are detailed in Table F.7.

Table F.7. Summary of Input Parameters for Compressed H_2 produced in California from electrolysis using California average grid electricity (HYEG)

Parameter	Value
Feedstock	Water
Process Fuel	California Grid-Average Electricity
Fuel	Gaseous Hydrogen
Share of Hydrogen Production	On-site
Share of Feedstock	100% Electrolysis
Production Efficiency	66.8%
Gaseous Compression Efficiency	90.7%
Electric Generation Mix (Feedstock)	3-CAMX Mix
Electric Generation Mix (Fuel Prod)	3-CAMX Mix
Fraction Electricity Used for Gaseous Hydrogen Compression and Precooling	100%

F. Compressed H_2 produced in California from electrolysis using solar- or wind-generated electricity (HYER)

The feedstock for this production process is the same as the gaseous hydrogen produced by electrolysis using grid-average electricity. Dispensing parameters are the same as detailed in the pathway for gaseous hydrogen from fossil natural gas. Inputs to the CA-GREET3.0 model are detailed in Table F.8. The applicant must provide evidence of renewable electricity generation from solar or wind to correspond to hydrogen dispensed (as fuel in transportation) being reported in the LCFS program. For this pathway, 50 kWh of renewable electricity is consumed to produce one kilogram of hydrogen. Evidence to support appropriate quantities of renewable electricity to correspond to hydrogen dispensed being claimed must be provided on an on-going basis in order to be eligible to generate credits in the LCFS program.

Table F.8. Summary of Input Parameters for Compressed H_2 produced in California from electrolysis using solar- or wind-generated electricity

Input Details	Compressed H_2 produced in California from electrolysis using solar- or wind-generated electricity
Feedstock	Water
Process Fuel	Solar or Wind Generated Electricity
Fuel	Gaseous Hydrogen
Share of Hydrogen Production	On-site
Share of Feedstock	100% Electrolysis
Production Efficiency	66.8%
Gaseous Compression Efficiency	90.7%
Share of Renewable Electricity	100%
Electric Generation Mix (Feedstock)	100% renewable
Electric Generation Mix (Fuel Prod)	100% renewable
Electric Generation Mix (Compression)	3-CAMX Mix
Fraction Electricity Used for Gaseous Hydrogen Compression and Precooling	100%