Technical Support Documentation for Lookup Table Pathways

Proposed Amendments for the Low Carbon Fuel Standard Regulation

December 19, 2023

California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB) • California Ultra-low Sulfur Diesel (ULSD) • Conventional Jet Fuel • Compressed Natural Gas • Propane • Electricity

I. Table of Contents

I. Introduction

This document provides details of 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).

This document provides the input values and assumptions related to calculation of carbon intensities determined using a modified version of the Argonne GREET1 2022 model (CA-GREET4.0[1]) for each of the pathways included in the Lookup Table.

[1] California Air Resources Board, *CA-GREET4.0 (Proposed Rulemaking Version)*. (Released December 19, 2023). *https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation*

II. Lookup Table Pathways

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

1. 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[2] from final combustion in a vehicle. Based on emission factors in the CA-GREET4.0 model, the carbon intensity (CI) of CARBOB is calculated to be **100.60 gCO_2e/MJ** 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	12.61
Refining	13.45
CARBOB Transport	0.72
Tailpipe Emissions	73.82
Total CI	100.60

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

2. Pathway Assumptions, Details, and Calculation

a) 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 3.0b.[3] The CI is calculated to be **12.61 gCO_2e/MJ**.

[2] 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.
[3] Brandt, A.R., Masnadi, M.S, Rutherford, J.S., El-Houjeiri, Vafi, K., H.M., Langfitt Q., Duffy, J., Sleep, S., Pacheco, D., Dadashi, Z., Orellana, A., MacLean, H., McNally, S., Englander, J., & Bergerson, J., *Oil Production Greenhouse Gas Emissions Estimator OPGEE v.3.0b.* (Updated on May 14, 2022). *https://eao.stanford.edu/research-project/opgee-oil-production-greenhouse-gas-emissions-estimator*

b) CARBOB Refining:

To calculate carbon intensity of refinery product streams for the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET®) model[4], 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.[5]

For the LCFS, ANL disaggregated PADD 5 data[6] 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

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[4] Wang, M. et al., *GREET1 2022,* October release. Center for Transportation Research, Argonne National Laboratory (accessed November 2, 2022). *https://greet.anl.gov/greet_excel_model.model*

[5] Elgowainy, A., Han, J., Cai, H., Wang, M., Forman, G.S., & Divita, V.B., *Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries*. Environmental Science & Technology, 48(13), 7612-7624. May 28, 2014 (accessed October 15, 2023). *https://pubs.acs.org/doi/full/10.1021/es5010347* *https://greet.es.anl.gov/publication-energy-efficiency-refineries*

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

gasoline 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 CARBOB is calculated to be **1,128,165 Btu** for every 1,000,000 MMBtu of finished product. This translates to a refining efficiency calculated as 1,000,000/1,128,165 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 750,100 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 1,128,165 - 750,100 = 378,065 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-GREET3.0.

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	750,100	Btu	Crude input for the production of CARBOB
Residual oil	138,334	Btu	As a surrogate for purchased unfinished oil and heavy products.

Parameter	Value	Unit	Note
Natural gas	85,481	Btu	A portion of purchased natural gas is converted into H2 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	77,163	Btu	Purchased butane is used mainly as a blendstock for gasoline. Assumes butane refining requires 1/3 of gasoline refining energy.
Blendstock	69,602	Btu	Other purchased blendstock (alkylates, reformates and natural gasoline) produced elsewhere. Assumes blendstock refining requires 2/3 gasoline refining energy.
Total	1,128,165	Btu	Total external energy input of 1,128,165 Btu for 1,000,000 Btu of CARBOB production
CARBOB Refining: Intermediate Products Combustion for 1,000,000 Btu of finished product			
Pet Coke	20,975	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).
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 H2.

The CI of refining in CA-GREET4.0 is calculated to be **13.45 gCO_2e/MJ**.

Table A.3. Emission Factors for Petroleum Coke and Refinery Still Gas Combusted in an Industrial Boiler as Refinery Intermediate Products

Emissions Factor	Pet Coke	Refinery Still Gas
VOC, g/MMBtu	0.47	2.39
CO, g/MMBtu	23.95	17.23
CH_4, g/MMBtu	1.25	3.20
N_2O, g/MMBtu	0.86	0.62
CO_2, g/MMBtu	106,933	57,398
Emission Factor, gCO_2e/MJ intermediate product	101.66	54.69

c) 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.

d) 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 EMFAC2021 (v1.0.2) model[7] for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in CARBOB. The results are shown in Table A.4:

Table A.4. Tailpipe Emissions from CARBOB

GHG	Tailpipe GHG from gasoline vehicles, g/MMBtu	gCO_2e/MJ
CH_4	3.89	0.09
N_2O	2.89	0.82
CO_2	76,925	72.91
Total	77,882	73.82

A comparison of refinery process details and pathway CI for CARBOB between CA-GREET3.0 and CA-GREET4.0 is provided in Table A.5.

[7] California Air Resources Board, *Greenhouse Gas Emissions Inventory*. (Accessed October 25, 2023). https://arb.ca.gov/emfac/emissions-inventory

Table A.5. Comparison of CIs and Refining Details for CARBOB Production between CA-GREET3.0 and CA-GREET4.0

CARBOB		CA-GREET3.0	CA-GREET4.0	Difference
Electricity source		3-CAMX Mix		
1) Crude Recovery		N/A		
CI, gCO_2e/MJ		11.78	12.61	0.83
2) Crude Refining to CARBOB				
Source (fuel production)		CA Crude		
Efficiency		88.64%	88.64%	
Share of other energy inputs (excluding crude)	Residual oil	36.6%	36.6%	
	Diesel fuel	0.0%	0.0%	
	Gasoline	0.0%	0.0%	
	Natural gas	22.6%	22.6%	
	LPG	0.0%	0.0%	
	Electricity	1.3%	1.3%	
	Hydrogen	0.7%	0.7%	
	Butane	20.4%	20.4%	
	Blendstock	18.4%	18.4%	
Feed loss		0.0%	0.0%	
CI, gCO_2e/MJ		14.80	13.45	-1.35
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		0.30	0.72	0.42
4) Tailpipe Emissions		73.94	73.82	-0.12
Methane (CH_4), g/MJ		0.14	0.09	
N_2O, g/MJ		0.91	0.82	
CO_2, g/MJ		72.89	72.91	
Total CI, gCO_2e/MJ		100.82	100.60	-0.22

B. California Ultra Low Sulfur Diesel (ULSD)

1. 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 CA-GREET4.0 model, the life cycle Carbon Intensity (CI) of California ULSD is calculated to be **105.76 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	12.61
Crude Oil Refining	13.24
ULSD Transport	0.27
Tailpipe Emissions	79.64
Total CI	105.76

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

2. Pathway Assumptions, Details, and Calculation

a) 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 3.0b.[3] The CI for this phase of the life cycle assessment is calculated to be **12.61 gCO_2e /MJ**.

b) 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.[5]

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 **1,164,530 Btu** for every 1,000,000 MMBtu of finished product. This translates to a refining efficiency calculated as 1,000,000/1,164,530 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, gas-to-liuid (GTL) and butane. The subtotal of these inputs makes up the remaining 1,164,530 - 978,161 = 186,369 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-GREET3.0.

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	38,709	Btu	As a surrogate for purchased unfinished oil and heavy products.
Natural gas	133,563	Btu	A portion of purchased natural gas is converted into H2 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	6,916	Btu	From grid.
Hydrogen	6,786	Btu	Purchased from external vendor.
Butane	373	Btu	Purchased.
Gas-to-Liquid (GTL)	22	Btu	Purchased.
Total	1,164,530	Btu	Total external energy input of 1,164,530 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	7,476	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 H2.

The CI for ULSD refining is calculated from CA-GREET4.0 to be **13.24 gCO_2e/MJ**.

c) 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.

d) Tailpipe Emissions:

The tailpipe emissions are based on CARB's EMFAC2021 (v1.0.2) model[7] for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in Diesel. The results are shown in Table B.3:

Table B.3. ULSD Tailpipe Emissions

GHG	Tailpipe GHG Emissions from Diesel-fueled Vehicles (g/MMBtu)	gCO_2e/MJ
CH_4	0.27	0.006
N_2O	12.36	3.49
CO_2	80,333.94	76.14
Total	80,346.57	79.64

A comparison of refinery process details and pathway CI for ULSD between CA-GREET3.0 and CA-GREET4.0 is provided in Table B.4.

Table B.4. Comparison of CIs and Refining Details for ULSD Production between CA-GREET3.0 and CA-GREET4.0

ULSD		CA-GREET3.0	CA-GREET4.0	Difference
Electricity source		3-CAMX Mix		
1) Crude Recovery				
Source (feedstock production)		OPGEE default		
CI, gCO_2e/MJ		11.78	12.61	0.82
2) Crude Refining to ULSD				
Source (fuel production)		CA Crude		
Efficiency		85.87%	85.87%	
Share of other energy inputs (excluding crude)	Residual oil	20.8%	20.8%	
	Diesel fuel	0.0%	0.00%	
	Gasoline	0.0%	0.00%	
	Natural gas	71.7%	71.7%	
	LPG	0.0%	0.0%	
	Electricity	3.7%	3.7%	
	Hydrogen	3.6%	3.6%	
	Butane	0.2%	0.2%	
	Gas-to-Liquid (GTL)		0.01%	
Feed loss		0.0%	0.0%	
CI, gCO_2e/MJ		13.57	13.24	-0.33
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		0.24	0.27	0.03
4) Tailpipe Emissions		74.86	79.64	4.78
Methane (CH_4), g/MJ		0.03	0.006	
N_2O, g/MJ		0.724	3.49	
CO_2, g/MJ		74.1	76.14	
Total CI, gCO_2e/MJ		100.45	105.76	5.31

C. Conventional Jet Fuel

1. Pathway Summary

The Conventional Jet Fuel 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 conventional jet fuel in California refineries, transport and distribution of finished fuel, and tailpipe emissions from final combustion of the fuel. Based on the CA-GREET4.0 model, the life cycle Carbon Intensity (CI) of Conventional Jet Fuel is calculated to be **89.43 gCO_2e/MJ** as shown in Table C.1.

Table C.1. Summary Table of Conventional Jet Fuel CI

Aggregated Impact	CI Impact* gCO_2e/MJ
Crude Recovery and Crude Transport	12.61
Crude Oil Refining	3.32
Transport	0.28
Tailpipe Emissions	73.21
Total CI	89.43

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

2. Pathway Assumptions, Details, and Calculation

a) 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 3.0b[3]. The CI for this phase of the life cycle assessment is calculated to be **12.61 gCO_2e /MJ**.

1. The CI for refining is calculated from CA-GREET4.0 to be 3.32 gCO_2e/MJ.
2. Transport and Distribution:
    a. Transportation: After refining, the assumed transport route is 100% by pipeline for 110 miles to large airports/fuel terminals, and 20% is directly transported by truck to small airports (200 miles considered in distribution leg).[8]
    b. Distribution: Finished diesel is distributed from a fuel terminal to small airports and this distance is assumed to be 200 miles by HDDT.[8]

[8] California Air Resources Board, *CA-GREET3.0 Supplemental Document and Tables of Changes*. August 13, 2018 (accessed October 15, 2023). *https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/cagreet_supp_doc_clean.pdf?_ga=2.249502272.611476356.1694443979-877253845.1694124606*

b) Tailpipe Emissions:

The tailpipe emissions are taken from CA-GREET4.0 for Methane (CH_4) and Nitrous Oxide (N_2O). For CO_2, it is calculated based on Carbon in Conventional Jet Fuel. The results are shown in Table C.2:

Table F.2. Tailpipe Emissions

GHG	Tailpipe GHG Emissions (g/MMBtu)	gCO_2e/MJ
CH_4	0.09	0.002
N_2O	0.17	0.049
CO_2	77,191.42	73.16
Total	77,191.68	73.21

The refinery process details and pathway CI for conventional jet fuel using CA-GREET4.0 is provided in Table C.3.

Table C.3. CIs and Refining Details for Conventional Jet Fuel Production using CA-GREET4.0

Conventional Jet Fuel		CA-GREET4.0
Electricity source		CAMX Mix
1) Crude Recovery		
CI, gCO_2e/MJ		12.61
2) Crude Refining		
Source (fuel production)		CA Crude
Efficiency		94.9%
Share of other energy inputs (excluding crude)	Residual oil	25.1%
	Diesel fuel	0.0%
	Gasoline	0.0%
	Natural gas	60.1%
	LPG	0.0%
	Electricity	4.0%
	Hydrogen	10.7%
	Butane	0.1%
	Blendstock	0.0%
Feed loss		0.0%
CI, gCO_2e/MJ		3.32
3) CARBOB Transport		
100% pipeline to large airports/ terminal, miles		110
20% distributed by HDD truck to small airports, miles		200
CI, gCO_2e/MJ		0.28
4) Tailpipe Emissions		73.21
Methane (CH_4), g/MJ		0.002
N_2O, g/MJ		0.049
CO_2, g/MJ		73.16
Total CI, gCO_2e/MJ		89.43

D. Compressed Natural Gas

1. 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 (25%) and from conventional fossil natural gas wells (75%).[9]

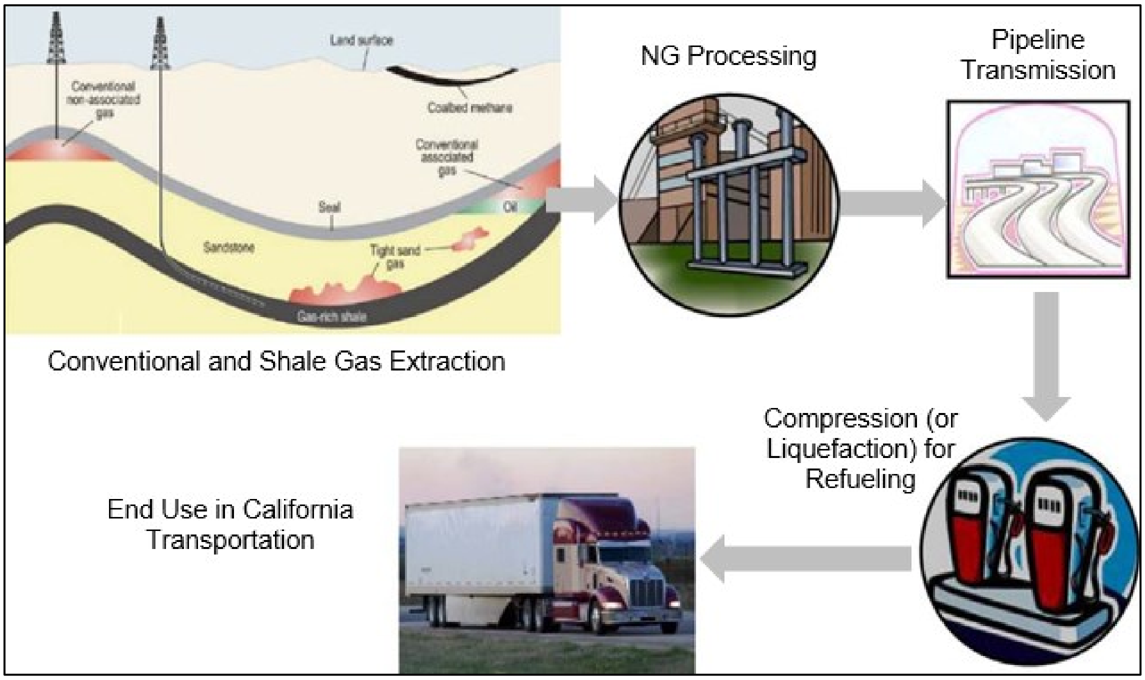

Figure C.1. Life Cycle Compressed Natural Gas Production and Use (Courtesy of Argonne National Lab)

Based on the CA-GREET4.0 model, the carbon intensity (CI) of Compressed Natural Gas is calculated to be **81.18 gCO_2e/MJ** and is detailed in Table D.1.

[9] California Air Resources Board, *CA-GREET4.0 - Inputs Tab (Proposed Rulemaking Version).* (Released December 19, 2023). *https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation*

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

Pathway Stage	Total CI* gCO_2e/MJ
Natural Gas (NG) Recovery	7.64
NG Processing	3.12
NG Transport	5.90
NG Compression	2.97
Tailpipe Emissions	61.56
Total CI	81.18

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

2. 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.[10] Figure D.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.

[10] California Energy Commission, *Supply and Demand of Natural Gas in California* (accessed February 7, 2018).

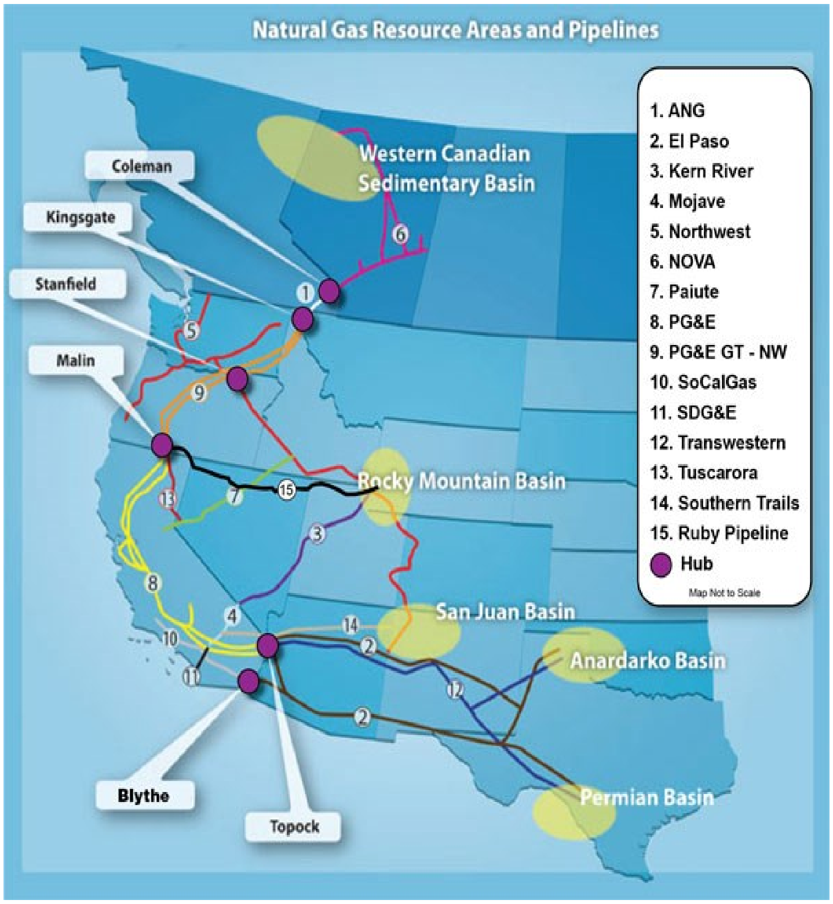

Figure D.2. Sources of Natural Gas Imported to California (from California Energy Commission[11])

Methane Leakage assumptions from extraction to final distribution are detailed in Table D.2.

Table D.2. Methane Leakage Assumptions

CH_4 leakage rate for each stage in conventional NG and shale gas pathways[12]			CH_4 leakage[13]	
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%

[11] California Energy Commission, *Natural Gas Resource Areas and Interstate Pipelines into California*. (Accessed February 7, 2018).
[12] *California Air Resources Board, CA-GREET4.0 - Inputs Tab (Proposed Rulemaking Version).* (Released December 19, 2023). *https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation*
[13] Ibid.

CH_4 **leakage rate for each stage in conventional NG and shale gas pathways**[12]			CH_4 **leakage**[13]	
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%
Well Equipment - CH_4 Venting and Leakage	134.9	134.9	0.65%	0.65%
Gathering and Boosting – CH_4 Venting and Leakage	31.2	31.2	0.15%	0.15%
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			1.29%	1.36%

Table C.3 provides detailed CI calculations for the fossil NG pathway[14] using CA-GREET4.0. 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 D.3 also includes details of CI calculations for this pathway using factors and inputs in CA-GREET3.0 to provide a comparison of changes and related impacts relative to CA-GREET4.0.

[14] Clark, C., Han, J., Burnham, A., Dunn, J.B., & Wang, M.Q., *Life-Cycle analysis of Shale Gas and Natural Gas.* Energy Systems Division, Argonne National Laboratory. December 2011 (accessed October 15, 2023). *https://greet.es.anl.gov/publication-shale_gas*

Table D.3. Compressed Natural Gas Pathway CIs (comparison of CI CA-GREET3.0 and CA-GREET4.0)

<table>
<tr><th colspan="2">Fossil NG</th><th colspan="2">CA-GREET3.0</th><th colspan="2">CA-GREET4.0</th><th>Difference</th></tr>
<tr><td colspan="2"></td><td>Conventional NG</td><td>Shale NG</td><td>Conventional NG</td><td>Shale NG</td><td></td></tr>
<tr><td colspan="2">Electricity source</td><td colspan="5">3-CAMX Mix</td></tr>
<tr><td colspan="2">Share of NG supply</td><td>49.78%</td><td>50.22%</td><td>49.78%</td><td>50.22%</td><td></td></tr>
<tr><td colspan="7">1) NG Recovery</td></tr>
<tr><td colspan="2">Efficiency</td><td>97.50%</td><td>97.62%</td><td>96.40%</td><td>96.80%</td><td></td></tr>
<tr><td rowspan="6">Share of process fuels</td><td>Residual oil</td><td>1.00%</td><td>1.00%</td><td>1.00%</td><td>1.00%</td><td></td></tr>
<tr><td>Diesel</td><td>11.00%</td><td>11.00%</td><td>11.00%</td><td>11.00%</td><td></td></tr>
<tr><td>Gasoline</td><td>1.00%</td><td>1.00%</td><td>1.00%</td><td>1.00%</td><td></td></tr>
<tr><td>NG</td><td>86.00%</td><td>86.00%</td><td>86.00%</td><td>86.00%</td><td></td></tr>
<tr><td>Electricity</td><td>1.00%</td><td>1.00%</td><td>1.00%</td><td>1.00%</td><td></td></tr>
<tr><td>Feed loss</td><td colspan="2">Included in NG as process fuel</td><td colspan="2">Included in NG as process fuel</td><td></td></tr>
<tr><td colspan="2">Natural Flared, Btu/MMBtu</td><td>10,486</td><td>10,327</td><td>10,486</td><td>10,327</td><td></td></tr>
<tr><td colspan="2">CI, gCO_2e/MJ</td><td colspan="2">6.07</td><td colspan="2">7.64</td><td>1.57[15]</td></tr>
<tr><td colspan="7">2) NG Processing</td></tr>
<tr><td colspan="2">Efficiency</td><td colspan="2">97.35%</td><td colspan="2">97.4%</td><td></td></tr>
<tr><td rowspan="6">Share of process fuels</td><td>Residual oil</td><td colspan="2">0.00%</td><td colspan="2">0.00%</td><td></td></tr>
<tr><td>Diesel</td><td colspan="2">1.00%</td><td colspan="2">1.00%</td><td></td></tr>
<tr><td>Gasoline</td><td colspan="2">0.00%</td><td colspan="2">0.00%</td><td></td></tr>
<tr><td>NG</td><td colspan="2">96.00%</td><td colspan="2">96.00%</td><td></td></tr>
<tr><td>Electricity</td><td colspan="2">3.00%</td><td colspan="2">3.00%</td><td></td></tr>
<tr><td>Feed loss</td><td colspan="2">0.00%</td><td colspan="2">0.00%</td><td></td></tr>
<tr><td colspan="2">CI, gCO_2e/MJ</td><td colspan="2">3.31</td><td colspan="2">3.12</td><td>-0.19</td></tr>
<tr><td colspan="7">3) NG Transport</td></tr>
<tr><td colspan="2">Pipeline Miles</td><td colspan="2">1,000</td><td colspan="2">1,000</td><td></td></tr>
<tr><td colspan="2">CI, gCO_2e/MJ</td><td colspan="2">5.92</td><td colspan="2">5.90</td><td>-0.02[16]</td></tr>
<tr><td colspan="2">4) Compression</td><td colspan="5"></td></tr>
<tr><td colspan="2">Efficiency</td><td colspan="2">97%</td><td colspan="2">97%</td><td></td></tr>
<tr><td colspan="2">CI, gCO_2e/MJ</td><td colspan="2">3.18</td><td colspan="2">2.97</td><td>-0.21</td></tr>
<tr><td colspan="2">5) Tailpipe Emissions, g/MJ</td><td colspan="2">60.73</td><td colspan="2">61.56</td><td>0.83</td></tr>
<tr><td colspan="2">Total CI, gCO_2e/MJ</td><td colspan="2">79.21</td><td colspan="2">81.18</td><td>1.97</td></tr>
</table>

The tailpipe emissions are based on CARB's EMFAC2021 (v1.0.2) 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 D.4:

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[15] Mainly due to the increased natural gas flaring during recovery.
[16] Due to lower updated natural gas transmission leakage rate.

Table C.4. Summary of Tailpipe GHG Emissions from Compressed Natural Gas Vehicles[17]

GHG	Tailpipe GHG from Compressed Natural Gas, g/MMBtu	Tailpipe CI, gCO_2e/MJ
CH_4	85.10	2.02
N_2O	12.36	3.49
CO_2	59,139.17	56.05
Total	59,236.62	61.56

E. Propane

1. 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.[18]

Data from the Energy Information Administration[19] 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.[19] 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[8].

Based on the CA-GREET4.0 model, the carbon intensity (CI) of propane is calculated to be **81.43 gCO_2e/MJ** and is detailed in Table E.1.

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[17] *California Air Resources Board, CA-GREET4.0 - Natural Gas Tab (Proposed Rulemaking Version). (*Released December 19, 2023). *https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation*

[18] California Energy Commission, *Propane Vehicles.* (Accessed on February 9, 2018).

[19] United States Energy Information Administration, *Petroleum & Other Liquids, Supply and Disposition, West Coast (PADD 5), Annual 2014.* (Accessed on February 7, 2018).

Table E.1. Summary Table of Propane CI CA-GREET4.0

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	7.61		1.90
NG Processing	3.11		0.78
NG Transmission	0.27		0.07
Feeds Inputs from Crude			
Crude Recovery		4.88	3.66
Crude Transport		0.85	0.63
Propane Refining from NG	3.10		0.77
Propane Refining from Crude		9.77	7.33
Non-Combustion Emissions	0.44	0.43	0.43
Propane Transport	1.02	1.02	1.02
Propane Storage	0.00	0.00	0.00
Tailpipe Emissions	64.83	64.83	64.83
Total CI	80.38	81.78	81.43**

* Values may not sum to total due to rounding
** CA-GREET3.0 CI for propane was 83.19 gCO_2e/MJ.

2. 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.

a) 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.[20]

Total CI of all three steps for propane production from NG sources: NG recovery (1.90 gCO_2e/MJ), NG processing (0.78 gCO_2e/MJ), and NG transport by pipeline (0.07 gCO_2e/MJ) is calculated to be **2.75 gCO_2e/MJ** (all with 25% allocation).

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

b) Propane (from Crude) Recovery, Processing and Transport:

U.S. crude source is used where CI from crude extraction is 3.66 gCO_2e/MJ and CI from crude transportation is 0.63 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 **4.30 gCO_2e/MJ**.

c) 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 7.33 gCO_2e/MJ as shown in Table E.2.

Table E.2. Propane Refining Parameters *

	NG sources	Crude sources
Energy Efficiency	96.50%	91.00%
Energy Use	Btu/MMBtu	
Residual Oil		104,592
Diesel	363	
Natural Gas	34,819	43,957
Electricity	1,088	2,929
Hydrogen		7,017
Butane		60,088
CI results after 25/75 allocation	0.77	7.33

* Values may not sum to total due to rounding

d) Propane Refining Non-combustion Emissions

CI from non-combustion emissions is calculated to be 0.11 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 **0.43 gCO_2e /MJ.**

e) Propane transport:

Propane transport distance is assumed to be 200 miles by HDD truck to LPG stations and shown in Table E.3. The GHG emissions from transport is calculated to be **1.02 gCO_2e /MJ.**

Table E.3. Propane Transport and Distribution

Transport and distribution mode	Mileage	CI (gCO_2e /MJ)*
Distribution by Heavy Duty Diesel Truck	200 miles	1.02

* Values may not sum to total due to rounding

f) Tailpipe Emissions:

Tailpipe emissions from the use of propane in light duty propane vehicles are calculated using values from the CA-GREET4.0 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 E.4. Total tailpipe emissions calculations are shown in Table E.5.

Table E.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	4,289
CO_2 in Propane, grams CO_2/mile	291.9
CO_2 in Propane, convert to gCO_2/MMBtu	68,040.4

Table E.5. Summary of Tailpipe GHG Emissions from Propane Vehicles[21]

GHG	Tailpipe Emissions for Propane vehicles g/MMBtu	CI (gCO_2e/MJ)*
CH_4	3.41	0.081
N_2O	0.911	0.26
CO_2	68,042.67	64.49
Total	68,056.38	64.83

* Values may not sum to total due to rounding

[21] California Air Resources Board, *CA-GREET4.0 - Results Tab, LPGV Section (Proposed Rulemaking Version).* (Released December 19, 2023). *https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation*

F. Electricity

1. 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 F.1 and F.1.a with calculated pathway CIs.

Table F.1. Electricity Lookup Table Pathways

Fuel Pathway Code	Fuel Pathway Description	Total CI gCO_2e/MJ (August 2018)	Total CI gCO_2e/MJ CA-GREET3.0
ELCG	California average grid electricity used as a transportation fuel in California (subject to annual updates)	93.75	81.00
ELCR	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	0.00	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, 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 F.1.a. Calculated Smart Charging or Smart Electrolysis Carbon Intensity Values

Hourly Window	Q1	Q2	Q3	Q4
12:01 AM – 1:00 AM	87.10	87.91	90.85	96.66
1:01 AM – 2:00 AM	87.07	86.06	87.80	92.47
2:01 AM – 3:00 AM	87.07	86.01	87.22	90.37
3:01 AM – 4:00 AM	87.07	85.97	87.00	89.92
4:01 AM – 5:00 AM	87.07	87.23	86.89	91.86
5:01 AM – 6:00 AM	92.55	95.80	88.86	103.53
6:01 AM – 7:00 AM	115.61	94.41	100.56	126.80
7:01 AM – 8:00 AM	114.77	30.13	96.61	125.28
8:01 AM – 9:00 AM	67.61	2.44	61.03	103.11
9:01 AM – 10:00 AM	2.20	1.79	7.52	40.37
10:01 AM – 11:00 AM	0.44	3.20	13.08	4.00
11:01 AM – 12:00 PM	0.00	50.34	21.99	8.07
12:01 PM – 1:00 PM	0.00	53.57	32.43	9.63
1:01 PM – 2:00 PM	0.00	55.54	45.52	12.02
2:01 PM – 3:00 PM	0.00	59.30	55.97	42.69
3:01 PM – 4:00 PM	30.37	64.33	105.71	80.03

Hourly Window	Q1	Q2	Q3	Q4
4:01 PM – 5:00 PM	67.27	27.72	111.19	131.76
5:01 PM – 6:00 PM	110.22	32.27	137.65	153.57
6:01 PM – 7:00 PM	145.35	80.02	151.04	156.76
7:01 PM – 8:00 PM	140.29	155.69	158.23	152.26
8:01 PM – 9:00 PM	129.66	156.76	149.31	144.86
9:01 PM – 10:00 PM	108.04	132.49	127.34	130.02
10:01 PM – 11:00 PM	93.39	100.05	108.58	115.45
11:01 PM – 12:00 AM	87.53	89.87	96.60	100.98

2. Pathway Details, Assumptions, and Calculations

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

The California electricity generation mixes in GREET are based on the Total System Electric Generation published by the California Energy Commission (CEC) for the 2020 data year.[22] 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 14.16 gCO_2e/MJ, and the CI of the power generation is calculated to be 66.83 gCO_2e/MJ.[23] Based on the CA-GREET4.0 model, the CI of average California Electricity is calculated to be **81.00** gCO_2e/MJ and is detailed in Table F.2.

According to the U.S. Energy Information Administration, of the 262 plants[24] 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-GREET4.0. Additionally, "Other Petroleum" in the CEC 2022 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 F.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.[25] Complete details are available in Argonne's 2013 report.[26]

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[22] California Energy Commission, *2020 Total System Electric Generation*. (Accessed on October 27, 2023). *https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation/2020*

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

[24] United States Energy Information Administration, *Number of plants for other, United States, all sectors*. (Accessed on October 27, 2023). *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*

[25] United States Energy Information Administration, *Form EIA-923 detailed data with previous form data*. (Accessed on October 15, 2023). *https://www.eia.gov/electricity/data/eia923/*

[26] Cai, H., Wang, M., Elgowainy, A., & Han, J., *Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors of the U.S. Electric Generating Units in 2010*. September 2013. *https://greet.es.anl.gov/publication-electricity-13*

Table F.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	
			Contribution to CI, $gCO_2e/MMBtu$	Emission Factor, $gCO_2e/MMBtu$	Contribution to CI, $gCO_2e/MMBtu$
Residual Oil	0.20%	6,356	94	253,578	542
Natural Gas	44.70%**	993,527	13,734	123,600	59,090
Coal	3.00%	92,466	510	289,776	9,298
Biomass	9.30%	99,465	360	0	0
Nuclear	2.30%	108,845	244	8,713	214
Hydro	10.20%	109,091	0	0	0
Geothermal	4.80%	51,337	0	26,669	1,369
Wind	11.40%	121,925	0	0	0
Solar PV	14.20%	151,872	0	0	0
Subtotal	100%		14,943		70,514
Tailpipe Emissions			0		0
Total CI, $gCO_2e/MMBtu$			85,457		
Total CI, gCO_2e/MJ			81.00		

* Values may not round to sum due to rounding.
** In the CA-GREET4.0 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 (37.9%) and the undefined energy categories (6.8%), as the total share of natural gas (44.7%) in the CA Electricity Resources Mix. Similarly, other petroleum sources in the CEC power mix are assumed as Residual Oil in CA-GREET4.0.

Examples of calculation in Table F.2:

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

$$\frac{44.70\%}{48.12\% \times (1 - 6.5\%)} \times 10^{6}\text{Btu/MMBtu} = 993{,}527 \text{ Btu/MMBtu;}$$

where:

Power generation share of NG = 44.70%;

Loss in electricity transmission = 6.5%; and

Power Plant Energy Conversion Efficiency (see Table F.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:

$$\frac{993{,}527 \text{ Btu/MMBtu}}{10^{6}\text{Btu/MMBtu}} \times 13{,}824 \text{ gCO}_2\text{e/MMBtu} = \mathbf{13{,}734} \text{ gCO}_2\text{e/MMBtu}$$

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:

$$\frac{\mathbf{123{,}600} \text{ gCO}_2\text{e/MMBtu} \times 44.7\%}{(1\text{-}6.5\%)} = \mathbf{59{,}090} \text{ gCO}_2\text{e/MMBtu}$$

where:

Power generation share of NG = 50.87%;

Loss in electricity transmission = 6.5%; and

EF of Electricity generation from NG (see Table F.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 F.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			
Boiler	858.87	72.40%	33.90%
Internal Combustion Engine	746.79	15.50%	39.00%
Gas Turbine	1,055.11	12.10%	27.60%
Weighted Average			33.65%
Natural Gas			
Boiler	634.08	6.40%	32.00%
Simple-cycle Gas Turbine	618.58	3.30%	32.80%
Combined-cycle Gas Turbine	397.17	89.20%	51.10%
Internal Combustion Engine	588.66	1.10%	34.40%
Weighted Average			48.12%
Coal			
Boiler	988.76	100.00%	34.70%
IGCC	985.78	0.00%	34.80%
Weighted Average			34.70%
Biomass			
Boiler	29.73	100.00%	22.60%
IGCC	28.69	0.00%	34.80%
Weighted Average			22.60%
Nuclear	1.21	100%	100%
Hydro	0	38%	100%
Geothermal	0	10.90%	100%
Wind	0	23.20%	100%
Solar PV	0	28%	100%

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 (May 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 2021 is shown in Table F.4.[27]

Table E.4. 2021 Demand Profile for California Investor-owned Utilities

LSE	Demand (MWh)	% of Total Demand
PG&E	11,411	46%
SCE	11,337	45%
SDG&E	2,145	9%
Total	24,893	100%

[27] The CAISO demand reported for PGE-TAC, SCE-TAC, and SDGE-TAC regions are used. Source: California ISO, *CAISO Peak Demand Forecast - OASIS Prod - PUBLIC - 1*. (Accessed on October 31, 2023). *http://oasis.caiso.com/mrioasis/default.do?tiny=SIddoA*

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.

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	1.0751	1.0851	1.1213	1.1931
1:01 AM – 2:00 AM	1.0747	1.0622	1.0837	1.1413
2:01 AM – 3:00 AM	1.0747	1.0616	1.0766	1.1154
3:01 AM – 4:00 AM	1.0747	1.0611	1.0738	1.1099
4:01 AM – 5:00 AM	1.0747	1.0766	1.0724	1.1338
5:01 AM – 6:00 AM	1.1423	1.1824	1.0968	1.2778
6:01 AM – 7:00 AM	1.4270	1.1652	1.2412	1.5650
7:01 AM – 8:00 AM	1.4166	0.3718	1.1924	1.5463
8:01 AM – 9:00 AM	0.8345	0.0301	0.7533	1.2726
9:01 AM – 10:00 AM	0.0272	0.0221	0.0928	0.4983
10:01 AM – 11:00 AM	0.0054	0.0396	0.1614	0.0494
11:01 AM – 12:00 PM	0.0000	0.6214	0.2714	0.0996
12:01 PM – 1:00 PM	0.0000	0.6612	0.4003	0.1188
1:01 PM – 2:00 PM	0.0000	0.6855	0.5618	0.1484
2:01 PM – 3:00 PM	0.0000	0.7319	0.6908	0.5270
3:01 PM – 4:00 PM	0.3749	0.7940	1.3048	0.9877
4:01 PM – 5:00 PM	0.8303	0.3421	1.3724	1.6263
5:01 PM – 6:00 PM	1.3605	0.3983	1.6990	1.8955
6:01 PM – 7:00 PM	1.7940	0.9877	1.8642	1.9348
7:01 PM – 8:00 PM	1.7315	1.9216	1.9530	1.8792
8:01 PM – 9:00 PM	1.6004	1.9348	1.8429	1.7879
9:01 PM – 10:00 PM	1.3335	1.6352	1.5717	1.6048
10:01 PM – 11:00 PM	1.1527	1.2348	1.3401	1.4250
11:01 PM – 12:00 AM	1.0804	1.1093	1.1923	1.2464

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 2023 are shown in Table E.1.a.