LOW CARBON FUEL STANDARD
ANNUAL UPDATES TO LOOKUP TABLE PATHWAYS

2023 Carbon Intensity Values for
California Average Grid Electricity Used as a
Transportation Fuel in California
and
Electricity Supplied Under the Smart Charging or
Smart Electrolysis Provision

Posted: November 2, 2022

I. Summary

This document provides the proposed carbon intensity (CI) values and a detailed description of the 2023 annual update to the two Lookup Table pathways for electricity under the Low Carbon Fuel Standard (LCFS). Section 95488.5(d) of the LCFS regulation[1] directs the Executive Officer to update the CI annually for these two Lookup Table pathways using the methodology described in Section E of the Lookup Table Pathways Technical Support Documentation.[2] Upon certification, the updated pathway CI values will be available for reporting fuel transactions that occur between January 1 and December 31, 2023. The proposed CI values and updated Fuel Pathway codes are shown in Tables 1 and 2.

Table 1. Proposed CI Values for 2023 Update to Electricity Lookup Table Pathways

Fuel Pathway Code	Fuel Pathway Description	CI (gCO_2e/MJ)
ELC000L00072023	California average grid electricity used as a transportation fuel in California (subject to annual updates)	81.00
ELCT	Electricity supplied under the smart charging or smart electrolysis provision (subject to annual updates)	See Table 2

[1] All citations to the LCFS Regulation are found in Title 17, California Code of Regulations (CCR), sections 95480-95503

[2] CA-GREET3.0 Lookup Table Pathways Technical Support Documentation. August 13, 2018. California Air Resources Board. Available at: https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut-doc.pdf?_ga=2.72734547.1572616437.1642472386-237633646.1594072165

Table 2. Proposed CI Values (gCO_2e/MJ) for Smart Charging or Electrolysis in 2023

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
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

These updates reflect changes in the carbon intensity of California grid electricity driven by rapidly increasing contributions from low-carbon sources in the California electricity mix (Figure 1) due to mandates driven by the Renewable Portfolio Standard (RPS), requirements related to integrated resource planning (IRP)[3], the inclusion of Cap-and-Trade carbon pricing in dispatch models, and other structural or systemic changes.

[3] Integrated Resource Plan and Long-Term Procurement Plan. California Public Utilities Commission. https://www.cpuc.ca.gov/irp/

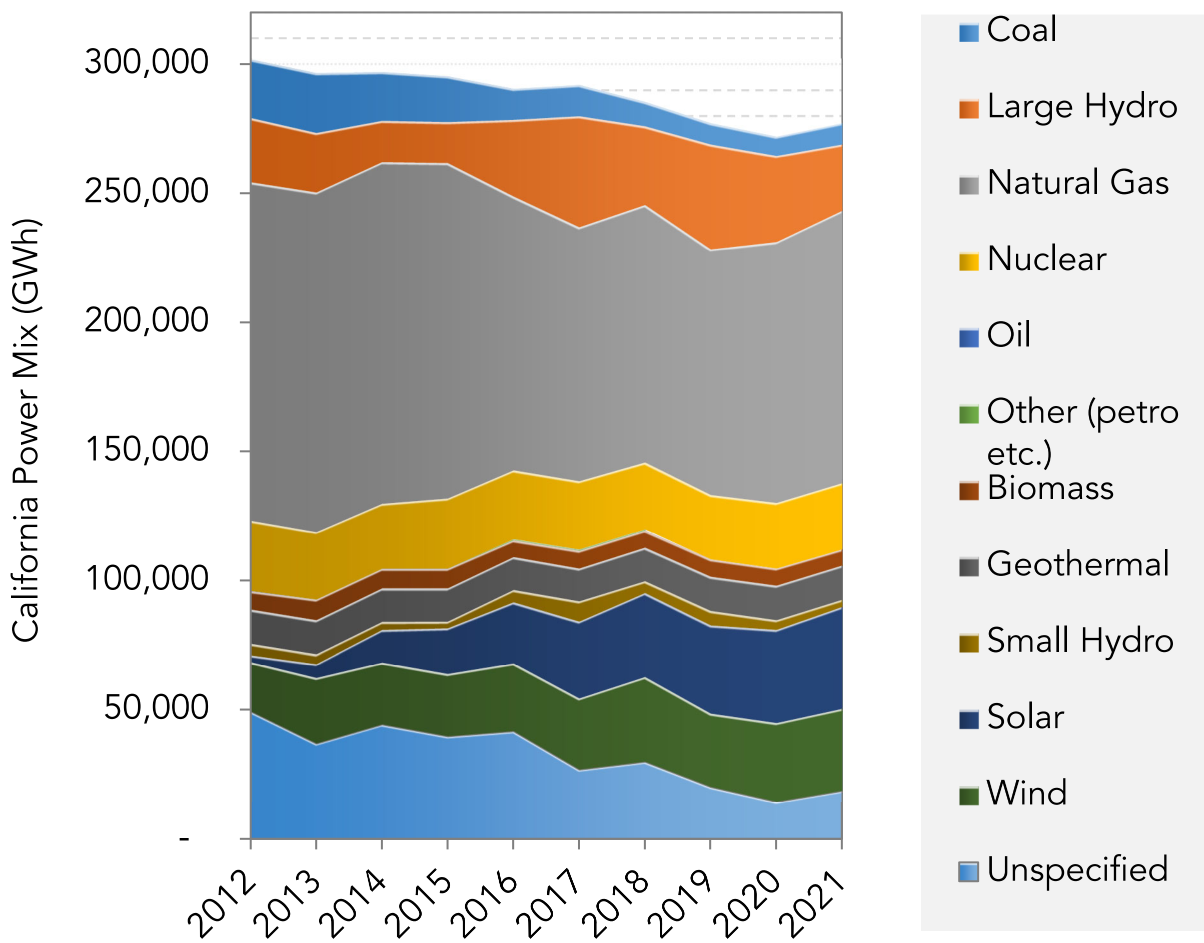

Figure 1. Total System Electric Mix in California in Gigawatt Hours (GWh)[4]

II. Pathway Details, Assumptions, and Calculations

1. California Average Grid Electricity Used as a Transportation Fuel in California

Pursuant to the methodology specified in the Lookup Table Pathways Technical Support Documentation (August 13, 2018), the "Power Generation" stage of the California average grid electricity pathway is modeled in CA-GREET3.0 using the California Power Mix from the Total System Electric Generation dataset provided by the California Energy Commission (CEC). The "Feedstock Production" stage is modeled using the U.S. average mix from the U.S. EPA Emissions & Generation Resource Integrated Database (eGRID2014v2).

[4] Data source: Total System Electric Generation, 2011-2021. California Energy Commission. Accessed 09/2022. Available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/california-electrical-energy-generation

Only the "Power Generation" stage of the life cycle is updated using Total System Electric Generation for the 2021 data year. The CEC's California Power Mix for 2020 and 2021 data years are compared in Table 1-1. The resulting CI for use in 2023 reporting is calculated, as described below, to be **81.00** gCO_2e/MJ, an increase from the CI of 76.73 gCO_2e/MJ certified for reporting year 2022.

Table 1-1. California Power Mix for Data Years 2020 and 2021[5]

	2021 CEC		2020 CEC	
	% Mix	GWh	% Mix	GWh
Residual oil	0.20%	502	0.20%	548
Natural Gas	44.70%	124,243	42.42%	115,637
Coal	3.00%	8,272	2.74%	7,474
Nuclear	9.30%	25,758	9.33%	25,434
Biomass	2.30%	6,271	2.45%	6,679
Hydro	10.20%	28,491	13.60%	37,073
Geothermal	4.80%	13,214	4.89%	13,336
Wind	11.40%	31,555	11.13%	30,343
Solar	14.20%	39,458	13.23%	36,052
Total	100%	**277,764**	100%	**272,576**

As described in the Technical Support Documentation, to harmonize resources reported by CEC with those in CA-GREET3.0, the "Other Petroleum Sources" category from CEC's mix was treated as "Residual Oil", while the "Unspecified Sources of Power" category was assumed to be from "Natural Gas" in CA-GREET3.0.

Table 1-2 details the updated contribution of each power resource in energy input, emission factor, and CI. This Table provides details of emission factors matched to appropriate resource mixes to calculate an average CI for electricity, which will be used for reporting in 2023 after completion of a public comment period.

[5] 2020 California Total System Electric Generation data from California Energy Commission (CEC) website, accessed 09/2022: [2021 Total System Electric Generation (ca.gov).]

Table 1-2. Summary of CI for California Average Grid Electricity Used as a Transportation Fuel in California for 2021[6]

	Electricity Resource Mix	Energy Inputs, Btu/MMBtu	Feedstock Production, $gCO_2e/MMBtu$	Power Generation Emission Factor, $gCO_2e/MMBtu$	Power Generation, $gCO_2e/MMBtu$
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
Nuclear	9.30%	99,465	360	0	0
Biomass	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
Total	100%		14,943		70,514
CI, gCO_2e/MJ			**14.16**		**66.83**
Total CI, gCO_2e/MJ					**81.00**

2. California Average Grid Electricity Supplied under the Smart Charging or Smart Electrolysis Provision

2.1. Description of Smart Charging or Smart Electrolysis CI Values

The CI values for smart charging or smart electrolysis provisions are calculated based on the marginal emission rates determined using the Avoided Cost Calculator developed by the California Public Utilities Commission.[7] A set of algorithmically neutral CI 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. Shifting EV charging or

[6] Values may not sum to the total 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 (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-GREET3.0.

[7] Energy and Environmental Economics, Inc. Avoided Cost Calculator, May 2018. Incorporated by reference into the LCFS Regulation, section 95481(a)(10). Accessed 8/2019. Available from the California Public Utilities Commission website at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/energy-efficiency/idsm

electrolysis could result in additional emission reductions as compared to Average Grid Electricity CI during the periods when the marginal emission reductions are low.

2.2. 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 relation between market prices and higher emissions rates is intuitive: higher market prices enable lower-efficiency (i.e., less economical) generators to operate, resulting in corresponding, 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 gas turbine technology heat rates. 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 as well.

The Avoided Cost Calculator estimates marginal emission rates for utilities in 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 2023, 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. Based on the CAISO OASIS data[8] for all three utilities from January 1, 2021 through December 31, 2021, approximately 46% of the annual average hourly load is served in Northern California and 54% is served in Southern California (includes SCE and SDG&E), as shown in Table 2-1.

Table 2-1. Large Load Serving Entity Average Hourly Load and Share of Total Load in California for 2021

Load-Serving Entity	Average Hourly Load (MW)[9]	% of Load
PG&E	11,411	46%
SCE	11,337	45%
SDG&E	2,145	9%
Total	**24,893**	**100%**

[8] CAISO Demand Forecast – Actual. Accessed: 10/2022 Available at: http://oasis.caiso.com/mrioasis/logon.do

[9] Average hourly load calculated as the average the load served for each hour in the year

The resulting statewide average marginal emission rates for California Grid Average Electricity are normalized to the annual average California Grid emissions rate over the year for each hourly window for the four quarters of the year, as shown in Table 2-2.

Table 2-2. Normalized Marginal Emission Rates for California Grid Electricity for 2023

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

2.3. 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 using the California Average Grid Electricity CI and the normalized marginal emission rates for that period. The carbon intensity values calculated for smart charging or smart electrolysis pathways in 2023 are shown in Table 2.

APPENDIX
Detailed Calculations of the Carbon Intensity for Electricity Used as a Transportation Fuel

This Appendix provides details of emission factors, combustion technologies, energy conversion efficiencies derived from CA-GREET3.0 and calculations to facilitate tracking of values used in Table 1-2.

Table A.1. Emission Factors, Combustion Technology Shares and Energy Conversion Efficiencies for Grid Electricity Used as Transportation Fuel in California in 2022

	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	72.4%	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			
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			
Boiler	988.76	100.0%	34.7%
IGCC	985.78	0.0%	34.8%
Weighted Average			34.70%
Biomass			
Boiler	29.73	100.0%	22.6%
IGCC	28.69	0.0%	34.8%
Weighted Average			22.60%
Nuclear	1.21	100%	100%
Hydro	0	38%	100%
Geothermal	0	10.9%	100%
Wind	0	23.2%	100%
Solar PV	0	28%	100%

1) Calculation of Contribution to Emissions from Residual Oil Use in Table 1-2

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 and details are available in Argonne's 2013 report.[10]

For residual oil (RO) feedstock production, the RO energy input is

$$\frac{0.20\%}{33.65\% \times (1 - 6.5\%)} \times 10^6 \text{Btu/MMBtu} = 6{,}356 \text{ Btu/MMBtu};$$

where:

Electricity resources mix share of residual oil = 0.20%.
Loss in electricity transmission = 6.5%; and
Power plant energy conversion efficiency (see Table A.1 above) =

$$\frac{1}{(72.4\% \div 33.9\%) + (15.5\% \div 39\%) + (12.1\% \div 27.6\%)} = 33.65\%$$

The contribution of RO to the feedstock production CI is:

$$\frac{6{,}356 \text{ Btu/MMBtu}}{10^6 \text{Btu/MMBtu}} \times 14{,}820 \text{ gCO}_2\text{e/MMBtu} = \mathbf{94} \text{ gCO}_2\text{e/MMBtu}$$

where:

Upstream EF of RO use in power plant = 14,820 gCO_2e/MMBtu (CI value of the "Petroleum" tab, RO and Crude sections).

The contribution of RO to the electricity generation CI is:

$$\frac{\mathbf{253{,}578} \text{ gCO}_2\text{e/MMBtu} \times 0.20\%}{(1\text{-}6.5\%)} = \mathbf{542} \text{ gCO}_2\text{e/MMBtu}$$

where:

EF of electricity generation from RO (see Table 1.2) = [(858.87 gCO_2/kWh × 72.4%) + (746.79 gCO_2/kWh × 15.5%) + (1,055.11 gCO_2/kWh × 12.10%)] × 293.07 kWh/MMBtu = **253,578** gCO_2/MMBtu

Note: 293.07 kWh/MMBtu is unit conversion from kWh to MMBtu

[10] 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

2) Calculation of Contribution to Emissions from Natural Gas Use in Table 1-2

Natural gas fired power plants (Table A.1) use four combustion technologies: boiler, simple-cycle gas turbine, combined-cycle gas turbine and internal combustion engine. In California, the shares of these four technologies are 6.4%, 3.3%, 89.2%, and 1.1%, respectively. Furthermore, the energy conversion efficiencies of these four technologies are 32.0%, 32.8%, 51.1% and 34.4%%, respectively. The combustion technology shares and their energy conversion efficiencies were calculated using aggregated data from EIA.[11] Additional details are available in Argonne's 2013 report.[10]

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:

Electricity resources mix share of NG = 44.7%
Loss in electricity transmission = 6.5%; and
Power plant energy conversion efficiency (see Table A.1) =

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

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:

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

The contribution of NG to electricity 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:

EF of electricity generation from NG (see Table 1.2) =
[(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

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

Note: 293.07 kWh/MMBtu is unit conversion from kWh to MMBtu

3) Calculation of Contribution to Emissions from Coal use in Table 1-2

For coal as feedstock production, the coal energy input is

$$\frac{3\%}{34.70\% \times (1 - 6.5\%)} \times 10^{6}\text{Btu/MMBtu} = 92{,}466 \text{ Btu/MMBtu};$$

where:

Electricity resources mix share of Coal = 3%
Loss in electricity transmission = 6.5%; and
Power plant energy conversion efficiency (see Table A.1) =

$$\frac{1}{(100\% \div 34.70\%) + (0\% \div 34.80\%)} = 34.70\%$$

The contribution of coal to the feedstock production CI is:

$$\frac{92{,}466 \text{ Btu/MMBtu}}{10^{6}\text{Btu/MMBtu}} \times 5{,}515 \text{ gCO}_2\text{e/MMBtu} = \mathbf{510} \text{ gCO}_2\text{e/MMBtu}$$

where:

Upstream EF of coal use in power plant = 5,515 gCO_2e/MMBtu
(CI value of the "Coal" tab).

The contribution of coal to the electricity generation CI is:

$$\frac{\mathbf{289{,}777} \text{ gCO}_2\text{e/MMBtu} \times 3\%}{(1\text{-}6.5\%)} = \mathbf{9{,}298} \text{ gCO}_2\text{e/MMBtu}$$

where:

EF of electricity generation from coal (see Table 1.2) =
[(988.76 gCO_2/kWh × 100%) + (985.78 gCO_2/kWh × 0%)] × 293.07 kWh/MMBtu = **289,777** gCO_2/MMBtu

4) Calculation of Contribution to Emissions from Nuclear Use in Table 1-2

CA-GREET 3.0 model assumes electricity from nuclear is generated in the light water reactor and uranium is U-235. Emissions are mostly from upstream of nuclear energy feedstock (uranium mining and transport):

Power generation share of nuclear = 9.30%

Loss in electricity transmission = 6.5%
Conversion factor for nuclear power plants = 6.926 MWh/g of U-235
EF of uranium mining and transport = **85,662** gCO_2e/gram of U-235

$$\frac{\mathbf{1{,}000{,}000\ Btu} \times 9.30\%}{(1\text{-}6.5\%)} = \mathbf{99{,}465\ Btu}/\text{MMBtu}$$

For nuclear use in electricity production, the contribution of nuclear to feedstock CI is:

$$\frac{\mathbf{85{,}662}\ \text{gCO}_2\text{e/grams of U-235} \times 99{,}465\ \text{Btu/MMBtu}}{(6.926\ \text{MWh/g U-235} \times 1{,}000 \times 3{,}412.14\ \text{Btu/kWh})} = \mathbf{360}\ \text{gCO}_2\text{e/MMBtu}$$

5) Calculation of Contribution to Emissions from Biomass Use in Table 1-2

The CA-GREET 3.0 considers forest residue as biomass used in power generation plant. For biomass as feedstock production, the biomass energy input is

$$\frac{2.30\%}{22.60\% \times (1 - 6.5\%)} \times 10^6\text{Btu/MMBtu} = \mathbf{108{,}845}\ \text{Btu/MMBtu};$$

where:

Electricity resources mix share of Biomass = 2.30%
Loss in electricity transmission = 6.5%; and
Power plant energy conversion efficiency (see Table A.1 above) =

$$\frac{1}{(100\% \div 22.6\%) + (0\% \div 34.80\%)} = 22.60\%$$

The contribution of biomass to feedstock production CI is:

$$\frac{108{,}845\ \text{Btu/MMBtu}}{10^6\text{Btu/MMBtu}} \times 2{,}242\ \text{gCO}_2\text{e/MMBtu} = \mathbf{244}\ \text{gCO}_2\text{e/MMBtu}$$

where:

Upstream EF of biomass use in power plant = 2,242 gCO_2e/MMBtu (CI value of the "EtOH" tab, "Forest Residue" section).

The contribution of biomass to the electricity generation CI is:

$$\frac{\mathbf{8{,}713}\ \text{gCO}_2\text{e/MMBtu} \times 2.45\%}{(1 - 6.5\%)} = \mathbf{214}\ \text{gCO}_2\text{e/MMBtu}$$

where:

EF of electricity generation from biomass (see Table 1.2) = [(29.73 gCO_2/kWh × 100%) + (28.69 gCO_2/kWh × 0%)] × 293.07 kWh/MMBtu = **8,713** gCO_2/MMBtu

6) Energy Contribution of Small and Large Hydro Power

CA-GREET 3.0 combines both small and large hydro for power generation. The EF of hydro power is considered zero. However, it has an energy input of:

$$\frac{1{,}000{,}000 \text{ Btu} \times 10.20\%}{(1 - 6.5\%)} = \mathbf{109{,}091} \text{Btu/MMBtu}$$

where:

Power generation share of hydro = 10.2% in Table 1-2
Loss in electricity transmission = 6.5%

7) Calculation of Contribution to Emissions from Geothermal in Table 1-2

Fugitive emissions from geo-fluid is 91 gCO_2e/kWh (or 26,669 gCO_2/MMBtu) for geothermal energy used in the electricity production. CO_2 emissions are calculated as:

$$\frac{\mathbf{26{,}669} \text{ gCO}_2\text{e/MMbtu x } 4.80\%}{(1 - 6.5\%)} = \mathbf{1{,}369} \text{ gCO}_2\text{e/MMBtu}$$

where:

Power generation share of geothermal = 4.80% in Table 1-2
Loss in electricity transmission = 6.5%
Energy inputs:

$$\frac{1{,}000{,}000 \text{ Btu} \times 4.80\%}{(1 - 6.5\%)} = \mathbf{51{,}337} \text{ Btu/MMBtu}$$

8) Energy Contribution of Wind Energy

The emission factor of wind is zero. However, it has an energy input of:

$$\frac{1{,}000{,}000 \text{ Btu} \times 11.40\%}{(1 - 6.5\%)} = \mathbf{121{,}925} \text{ Btu/MMBtu}$$

where:

Power generation share of wind = 11.40% in Table 1-2
Loss in electricity transmission = 6.5%

9) Energy Contribution of Solar PV Energy

The emission factor of solar PV is zero. However, it has an energy input of:

$$\frac{1{,}000{,}000 \text{ Btu} \times 14.2\%}{(1 - 6.5\%)} = \mathbf{151{,}872} \text{ Btu/MMBtu of electricity}$$

where:

Power generation share of Solar PV = 14.2% in Table 1-2
Loss in electricity transmission = 6.5%