Life Cycle Associates

WA-GREET 0.7a Supplemental Document and Tables of Changes

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1. Introduction

The Washington Clean Fuels Standards (CFS) uses a "well-to-wheel" life cycle analysis (LCA) to calculate the carbon intensity (CI) of all transportation fuels. To determine each fuel pathway's CI, the greenhouse gas (GHG) emissions from all steps in the fuel's life cycle are summed, adjusted to carbon dioxide equivalent (CO_2e), and divided by the fuel's energy content in megajoules. Carbon intensity is expressed in terms of grams of CO_2 equivalent per megajoule (gCO_2e/MJ).

The CIs are calculated based on a modified version of the CA-GREET3 model, developed by California Air Resources Board (CARB) to support the California Low Carbon Fuels Standards[1]. CA-GREET3 model was developed by CARB by progressive modification to the GREET1 model[2] developed by Argonne National Laboratory (ANL). ANL publishes yearly updated version of GREET1 model. CA-GREET3 model was based on GREET1_2016 model.

Oregon Department of Environmental Quality (DEQ), during the development of Oregon's Clean Fuels Program, adopted the latest available CA-GREET model and modified it to develop Oregon specific OR-GREET model[3]. Washington Department of Ecology followed similar approach to modify the latest available CA-GREET3 model to develop a Washington specific WA-GREET model. This model functions as the basis of CI calculation of the baseline fuels as well as low carbon fuel pathways to be developed under the Washington Clean Fuels Standards program.

This document provides the function of supporting documentation for WA-GREET. For more background information, please refer to the available documentation for GREET1_2016[4] and CA-GREET[5] models. This document provides details of the modifications made to the CA-GREET3 version to create the WA-GREET model.

In addition to development of WA-GREET, 8 simplified tier1 calculators were also developed for the Washington CFS. For this purpose, the simplified tier1 calculators from California's LCFS were re-adopted and modified to align with the developed WA-GREET model.

[1] See LCFS Life Cycle Analysis Models and Documentation (https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation)
[2] See ANL GREET1 (Fuel-Cycle) Models (https://greet.es.anl.gov/greet_1_series)
[3] See Oregon CFP Carbon Intensity Values (https://www.oregon.gov/deq/ghgp/cfp/Pages/Clean-Fuel-Pathways.aspx)
[4] See CA-GREET3.0 Supplemental Document and Tables of Changes at CARB Website, see footnote 1
[5] See Summary Updates for GREET1_2016 (PDF) available at https://greet.es.anl.gov/files/summary-updates-2016

2. Summary of Changes

WA-GREET model

This section describes the summary of major modifications made to the CA-GREET3.0 model to develop the Washington specific WA-GREET model. Majority of the structure, flow, and standard values from CA-GREET3 have been retained in WA-GREET. Most of the changes pertain to modifying the parameters specific to the Washington, for example addition of a new grid mix region for average Washington grid. The following list highlights the key details about the WA-GREET and crucial modifications made to CA-GREET3.0. Details are included in the following sections.

- Total two new electricity mix regions were added. One mix represents the Washington's average grid mix based on WA Disclosure data available at Washington Department of Commerce website[6]. The Oregon grid mix directly from OR-GREET3 was adopted as the second new grid mix region to allow better alignment across the two programs. This makes the total subregions in WA-GREET to 32. Additional details are included in the section 4 below.
- The baseline year for the Washington CFS program is 2017, as specified in the regulation. For the baseline crude, the crude oil CI values developed by CARB using the Oil Production Greenhouse Gas Emission Estimator (OPGEE2.0)[7] model were adjusted for transport to Washington. The Washington specific crude slate for 2017 was used Carbon intensity calculation for gasoline and diesel refining are based on US average gasoline and diesel refining inputs originally included in the model by ANL. The Washington electricity mix for 2017 is used for baseline CI values. WA-GREET uses 2017 as the target simulation year (on Inputs sheet) for the baseline CI calculations. This is described in more detail in section 3 of this document.
- Except for the calculation of the baseline gasoline, diesel, and jet CI values, WA-GREET uses 2018 as the baseline year to accommodate the latest available Washington electricity grid mix from 2018. The fuel shares for the 2018 Washington grid mix were also calculated based on the Washington fuel mix disclosure data.
- No changes have been made to the transportation distance for petroleum fuels from existing values in CA-GREET3.0 due to unavailability of state specific data
- The EF sheet in CA-GREET consists of reduced form emission factors (EF) as calculated in the model for easier export of EF to the tier 1 simplified calculators. Additions were made to this section to include more of the key emission factors, to make future updates of simplified calculators easier, and to add transparency to the standard values that go into the tier 1 calculators.

[6] WA Fuel Mix Disclosure Data, available here (https://www.commerce.wa.gov/growing-the-economy/energy/fuel-mix-disclosure/)

[7] See LCFS Crude Oil Life Cycle Assessment | California Air Resources Board (https://ww2.arb.ca.gov/resources/documents/lcfs-crude-oil-life-cycle-assessment)

- 2 additional copies of WA-GREET were further modified to model the CI of diesel and gasoline imported into Washington from Montana and Utah. These versions are not intended for biofuel pathway CI calculations. More details are included in the Petroleum section of this document.

Simplified Tier1 Calculators

The following is the list of all the 8 simplified tier1 calculators developed for the Washington CFS program.

- Starch and Fiber Ethanol (WA-tier1-sfe-calculator.xlsm)
- Sugarcane-derived Ethanol (WA-tier 1-sugarcane-etoh-calculator.xlsm)
- Biodiesel and Renewable Diesel (WA-tier1-bdrd-calculator.xlsm)
- LNG and L-CNG from North American Fossil Natural Gas (WA-tier1-nang-calculator.xlsm)
- Biomethane from North American Landfills (WA-tier1-lfg-calculator.xlsm)
- Biomethane from Anaerobic Digestion of Wastewater Sludge (WA-tier1-wws-calculator.xlsm)
- Biomethane from Anaerobic Digestion of Dairy and Swine Manure (WA-tier1-dsm-calculator.xlsm)
- Biomethane from Anaerobic Digestion of Organic Waste (WA-tier1-ow-calculator.xlsm)

The following list includes the major changes to the tier1 calculators

- Washington and Oregon grid mix regions were added to the list of available electricity region selection in calculators where applicable. Emission factor for these were based calculated in WA-GREET.
- All standard existing emission factors were updated to match the corresponding EF as calculated in WA-GREET. In most cases, the change was minor.
- All California state specific standard emission factors in the calculators were updated to reflect Washington state-specific EF (using 2018 Washington electricity mix in WA-GREET)
- A few of the standard EF which used in the calculator but were not represented on the EF Tables sheet were added to the sheet and were used as reference in the calculator. This allows for a more consistent flow of calculation and easier update to the standard values in the calculators.

Washington Utility CI Calculator

WA Clean Fuel Standard allows the use of utility specific carbon intensity for power use for certain purposes outside of biofuel pathways. For this purpose, a new calculator was developed by Life Cycle Associates external to the WA-GREET to allow calculation of the CI for a given specific utility within the Washington. The list of considered utilities and their corresponding electricity generation mix is derived from the annual Washington utility mix disclosure report[8]. This report is also available through the Washington Department of Commerce website and is separate from the statewide fuel mix disclosure report. The latest available data is from the

[8] WA Utility Mix Disclosure Data, available here (https://www.commerce.wa.gov/growing-the-economy/energy/fuel-mix-disclosure/)

year 2020 which can be used for the first year of the WA CFS notwithstanding the rulemaking and determination by Washington Department of Ecology.

The calculator adopts the self-reported utility mix disclosure data, transforms it into GREET compatible form and calculates the lifecycle well-to-plug emissions from the electricity generated by the user-selected utility. The calculator requires the user to select the desired utility by using the “Claimant ID” of the utility as reported under the raw utility mix disclosure report, also available in the calculator for reference. The calculator also supports the input of a user-defined electricity mix. More details on the calculator and the overall methodology of electricity life cycle carbon intensity calculation are available in the Appendix C: Electricity modelling in GREET of this document.

3. Petroleum Products

This section summarizes the approach for estimating Washington baseline crude CI, and subsequently the CI of Washington gasoline, diesel, and jet. Although the state is an overall net exporter of refined products, some gasoline and diesel are imported from Montana and Utah into eastern Washington. The most recent available pipeline transfer data[9] indicate that 6% of diesel consumed in Washington is refined in Montana and transported to Washington via the Yellowstone pipeline and 10% is refined in Utah and transported via the Tesoro pipeline.

Crude Refining

The petroleum fuels imported into the state from Montana and Utah were also incorporated in the baseline petroleum fuels CI values. First, a separate average crude CI values was calculated for Washington, Montana as well as Utah each. This was achieved by adjusting the 2017 Annual Crude CI analysis by CARB under California Crude. For more details on the calculation, crude CI lookup table, and intermediate steps, please refer to the "WA Baseline Crude Analysis Memo" included as an appendix to this document. A summary of the crude CI analysis is included in this section. For additional details on data sources and intermediate calculations, please refer to the "WA baseline crude CI analysis" included as Appendix A. This analysis was an update of a 2014 study conducted by Life Cycle Associates to assess average Washington Crude CI using the same approach as intended for Washington CFS.

The analysis relied on California crude oil CI values developed with the Oil Production Greenhouse Gas Emission Estimator (OPGEE2.0) model adjusted for transport to Washington by mode. The Washington crude oil mix was established using DOE's Energy Information Administration (EIA) data[10] combined with refinery survey data from the Washington Research Council. Given that EIA does not report crude imports by oil field, the average CI was calculated by volume-weighting California crude oil volumes consumed in 2017 under the LCFS program for foreign crude oil sources. This represents only about 8% of the crude oil input for Washington. The other major sources of crude including Alaska North Slope and North Dakota Bakken had only one CI in OPGEE, therefore no additional calculations were needed.

Canadian crude oil can be derived from oil sands and upgraded before introducing it to the pipeline or it can by conventional crude oil. For this analysis and in the absence of field-specific data, this analysis utilized methodology implemented by the Oregon Department of Environmental Quality (DEQ) during 2015 baseline crude oil CI determination in support of the Oregon Clean Fuels Program (CFP). The list of 60+ Canadian oil fields in OPGEE was first separated into oil sands vs conventional crude and their CI values were averaged separately for each category. Transportation distance adjustments were then applied using appropriate seas distance and rail calculators.

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[9] 2013 data provided by Hedia Adelman, Washington State Department of Ecology

[10] EIA Company Level Imports sorted for Washington state refineries, https://www.eia.gov/petroleum/imports/companylevel

The CI value for each crude oil source was adjusted for the difference in the transportation distance to Washington instead of California using OPGEE2.0 emission factors for crude oil transport by mode. Similar approach was followed to estimate the Crude CI for refineries in Montana and Washington.

The estimated average Washington crude CI is shown in the table below.

Table 1. Average Washington Crude CI

Location/Country	**Share[11]**	**Mode**	**CA CI**	**Distance Adjustment**	**WA CI**
North Dakota	23%	Rail	9.73	-1.03	8.70
US Alaska	35%	Vessel	15.91	-0.16	15.75
CANADA (Conventional)	24%	Mixed	8.40	-0.10	8.30
CANADA (Oil Sands)	10%	Mixed	23.88	-0.10	23.79
ANGOLA	0%	Vessel	8.12	0.16	8.28
ARGENTINA	0%	Vessel	10.15	0.16	10.31
BRAZIL	3%	Vessel	5.86	0.16	6.02
ECUADOR	0%	Vessel	9.36	0.16	9.52
GHANA	0%	Vessel	8.08	0.16	8.24
MEXICO	0%	Vessel	7.51	0.16	7.66
NIGERIA	0%	Vessel	17.27	0.16	17.43
RUSSIA	1%	Vessel	9.39	0.00	9.39
SAUDI ARABIA	2%	Vessel	9.18	0.16	9.34
TRINIDAD AND TOBAGO	1%	Vessel	7.41	0.16	7.57
BRUNEI	0%	Vessel	n/a		n/a
PAPUA NEW GUINEA	0%	Vessel	n/a		n/a
Average WA Crude CI					**12.56**

[11] Source: For domestic sources, WA Research Council, Economic Profile, Feb 2019. For foreign sources, EIA Company Level Imports, https://www.eia.gov/petroleum/imports/companylevel

Petroleum Fuels Refining

In addition to US average crude, gasoline, and diesel CI calculations, CA-GREET3 model also includes separate CI calculation for California average crude recovery, California gasoline (CA RFG), and California ultra-low sulfur diesel. The results from these do not affect the any other GREET model results or emission factor calculation.

In the WA-GREET model, the California specific crude, gasoline, and diesel modelling sections in CA-GREET3 were modified to represent Washington specific crude, gasoline, and diesel. For both WA gasoline and WA diesel, the refining parameter and inputs were modified to use the corresponding parameters and inputs from the existing US average gasoline and US low sulfur diesel refining respectively. No changes were made to jet refining parameters and inputs. This was coupled with the selection of 2017 as target simulation year in the model and 2-WAMX as the electricity mix for both feedstock and fuel region.

Next step was to align the Crude CI results as calculated by WA-GREET model with the calculated OPGEE based WA crude CI value. This was achieved by adjusting the WA crude recovery energy efficiency until the modelled crude CI value closely matched the externally calculated WA crude CI. This results in the WA-GREET calculating the average CI value for gasoline, diesel and jet produced in Washington.

The Crude CI values for MT and UT were similarly implemented in separate copies of WA_GREET model. 4-NWPP electricity mix was used in these versions of WA-GREET models as both Montana and Utah are part of the NWPP e-grid subregion. The CI values for gasoline and diesel from these models represent the CI of gasoline and diesel imported into Washington from Montana and Utah respectively for 2017 baseline year.

The three independent gasoline and diesel CIs can potentially be combined into a single value by a using weighted average calculation for the purposes of developing the CFS baseline or Lookup Table value for Washington average gasoline and diesel. The jet CI value from the WA-GREET model using WA-only crude directly represents the Washington average baseline jet CI. A new table is added to the Petroleum sheet of WA-GREET for this averaging calculation with draft values.

Table 2. OPGEE Based 2017 Baseline Crude CI

Crude Region	OPGEE Crude CI (g CO_2e/MJ)
Washington	12.56
Montana	20.86
Utah	9.16

After implementation in WA-GREET, the key parameters in and CI results from WA-GREET for each state are shown in the table below.

Table 3. Key Input Parameters for State-wise 2017 Baseline Petroleum Fuels CI

	Washington-only	Montana	Utah
GREET Simulation Year	2017	2017	2017
Electricity Mix Region	2-WAMX	4-NWPP	4-NWPP
GREET Crude Recovery Efficiency %	89.89%	81.59%	94.07%
GREET Crude CI (g CO2e/MJ)	12.569	20.860	9.158
GREET Refining Efficiency (%)			
US Gasoline	88.60%	88.60%	88.60%
State Gasoline	88.60%	88.60%	88.60%
US Low Sulfur Diesel	85.87%	85.87%	85.87%
State Low Sulfur Diesel	85.87%	85.87%	85.87%
GREET CI (g CO2e/MJ)			
Gasoline	99.47	109.61	95.82
Low Sulfur Diesel	100.83	110.02	97.86
Jet	89.98	n/a	n/a

The WA-GREET models using the MT and UT only crudes are only useful for developing the Washington Lookup table values for gasoline and diesel. For all biofuel pathway calculations, is intended to use the WA-GREET-WA model using the WA-only crude.

4. Electricity

The Argonne version of the model uses the 10-region North American Electric Reliability Corporation (NERC) to develop region-specific GHG emissions for electricity generation. In developing CA-GREET, however, CARB used EPA's Emissions & Generation Resource Integrated Database (eGRID) to determine the impact of stationary electricity use in fuel and feedstock production. The eGRID contains 26 subregions to capture subregional variabilities in GHG emissions for electricity generation and is used by CARB in fuel pathway CIs to ensure consistency across all subregions, in and outside of the state.

The conversion to the 26 eGRID subregional mixes in CA-GREET3.0 was accomplished by modifying the electricity resource mixes and subregions in the Fuel_Prod_TS tab of CA-GREET3.0 and the associated links to the Inputs tab. CARB also added U.S Average, User Defined, Brazilian Average and Canadian Average mixes, in addition to the 26 eGRID subregions, for a total of 30 subregional electricity mixes.

Oregon DEQ, while developing OR-GREET model, modified the CA-GREET model to include a new subregion to represent the specific grid mix of the state making the total subregions to 31. WA-GREET model further expands on the subregions, retaining the ORMX mix from OR-GREET and adding a new subregion, WAMX, to represent the average grid mix in the Washington. This increases the total subregions in WA-GREET to 32.

The following table shows the comparison of the Grid mix subregions list in CA_GREET3, OR_GREET3 and WA_GREET models. The changes from CA-GREET3 are highlighted in blue text.

Table 4. Comparison of Electricity Subregions in WA-GREET model

CA-GREET3.0				**OR-GREET3.0**				**WA-GREET**			
1	US Ave	17	SRSO	1	U.S Ave	17	SRSO	1	U.S Ave	17	SRSO
2	User Defined	18	NEWE	**2**	**ORMX**	18	NEWE	**2**	**WAMX**	18	NEWE
3	CAMX	19	NYUP	3	CAMX	19	NYUP	3	CAMX	19	NYUP
4	NWPP	20	RFCE	4	NWPP	20	RFCE	4	NWPP	20	RFCE
5	AZNM	21	NYLI	5	AZNM	21	NYLI	5	AZNM	21	NYLI
6	RMPA	22	NYCW	6	RMPA	22	NYCW	6	RMPA	22	NYCW
7	MROW	23	SRVC	7	MROW	23	SRVC	7	MROW	23	SRVC
8	SPNO	24	FRCC	8	SPNO	24	FRCC	8	SPNO	24	FRCC
9	SPSO	25	AKMS	9	SPSO	25	AKMS	9	SPSO	25	AKMS
10	ERCT	26	AKGD	10	ERCT	26	AKGD	10	ERCT	26	AKGD
11	MROE	27	HIOA	11	MROE	27	HIOA	11	MROE	27	HIOA
12	SRMW	28	HIMS	12	SRMW	28	HIMS	12	SRMW	28	HIMS
13	SRMV	29	Brazilian	13	SRMV	29	Brazilian	13	SRMV	29	Brazilian
14	RFCM	30	Canadian	14	RFCM	30	Canadian	14	RFCM	30	Canadian
15	RFCW			15	RFCW	**31**	**User Defined**	15	RFCW	**31**	**ORMX**
16	SRTV			16	SRTV			16	SRTV	**32**	**User Defined**
30 subregions				**31 subregions**				**32 subregions**			

Washington fuel mix disclosure data consists of yearly in-state electricity production data aggregated by the fuel type. However, the categorization of this dataset does not directly align with the fuel source categorization in GREET model. GREET does not have the resource categories used in Washington fuel mix disclosure data for “Waste”, “Co-generation”, “landfill gas”, “Other”, and “Unspecified.”

The fuel share corresponding to these categories were included by allocating “cogeneration”, “landfill gas”, and “unspecified” to natural gas, and “Waste” and “other” to Residual oil. The allocation is shown in the following table.

Table 5. Allocation of WA Fuel Mix Disclosure to GREET Resource Categories

WA Fuel Mix Disclosure Categories	GREET Fuel type Categories								
	Residual oil	Natural gas	Coal	Nuclear power	Biomass	Hydro electric	Geothermal	Wind	Solar PV
Hydropower						x			
Coal			x						
Cogeneration		x							
Natural Gas		x							
Nuclear				x					
Biomass					x				
Petroleum	x								
Waste	x								
Geothermal							x		
Landfill Gas		x							
Wind								x	
Other	x								
Solar									x
Unspecified		x							

The 2017 and 2018 WAMX grid mix following the above-described allocation is shown in the following table as incorporated in the WA-GREET model, along with the retained ORMX mix from OR-GREET3.

Table 6. Fuel Shares for Grid Mix Subregions Added to WA-GREET

Fuel Type	2017 WA Disclosure	2017 WAMX Mix	2018 WA Disclosure	2018 WAMX Mix	ORMX Mix
Residual oil	0.11%	0.33%	0.02%	0.10%	0.08%
Other	0.18%	-	0.05%	-	
Waste	0.04%	-	0.04%	-	-
Coal	13.39%	13.39%	10.22%	10.22%	32.78%
Natural gas	10.83%	10.96%	7.33%	20.46%	17.14%
Cogeneration	0.00%	-	0.00%	-	-
Unspecified	0.00%	-	12.93%	-	-
Landfill Gas	0.13%	-	0.20%	-	-
Nuclear power	4.19%	4.19%	4.75%	4.75%	3.08%
Biomass	0.60%	0.60%	0.45%	0.45%	0.36%
Hydroelectric	67.68%	67.68%	59.16%	59.16%	39.76%
Geothermal	0.00%	0.00%	0.00%	0.00%	0.12%
Wind	2.84%	2.84%	4.58%	4.58%	6.57%
Solar PV	0.00%	0.00%	0.28%	0.28%	0.11%

GREET further aggregates the fuel shares for hydroelectric, geothermal, wind, and solar PV into a single category referred to as “Others”. WAMX values for GREET’s “Other” category of resource mix can be calculated using the adjusted fuel shares calculated above. The following table shows the resulting fuel shares for the “Other” category in WA-GREET for 2018 WAMX mix.

Table 7. 2018 WAMX Fuel Shares for Electricity from "Other" Resources

WAMX "Other" Resource	%
Hydroelectric	92.39%
Geothermal	0.01%
Wind	7.16%
Solar PV	0.44%
Others	0.00%
Total	100.00%

While California has its own subregion under eGRID, Oregon and Washington fall under the NWPP eGRID subregion. Note that during the addition of the Oregon state grid mix to OR-GREET3, the NWPP mix was retained as-is in the OR-GREET3 model. With the development of WA-GREET model, 2 states have now been carved out of NWPP mix, potentially distorting the accuracy of the new NWPP subregion in WA-GREET. However, to maintain consistency with the California LCFS and Oregon CFP programs, the existing NWPP mix has been retained.

5. Appendix A: WA Baseline Crude Analysis

Introduction

There are five refineries in Washington[12] with a combined refining capacity of over 230 million barrels per year. Although the state is an overall net exporter of refined products, some gasoline and diesel are imported from Montana and Utah into eastern Washington. The most recent available pipeline transfer data[13] indicate that 6% of diesel consumed in Washington is refined in Montana and transported to Washington via the Yellowstone pipeline and 10% is refined in Utah and transported via the Tesoro pipeline. The remaining portion of diesel fuel is assumed to be refined in Washington. The following describes quantification of 2017 baseline crude oil average carbon intensity (CI) values for petroleum products refined in Washington, Utah and Montana. These CI values are then used in GREET modeling to calculate look-up table CI values for petroleum fuels consumed in Washington (including finished fuel imports from Montana and Utah).

Summary

The general approach to determine the average crude oil CI value for Washington refineries is summarized in Figure 1 below. Without performing crude oil CI modeling, this analysis relied on California crude oil CI values developed with the Oil Production Greenhouse Gas Emission Estimator (OPGEE2.0c)[14] model adjusted for transport to Washington by mode. The Washington crude oil mix was established using DOE's Energy Information Administration (EIA) data[15] combined with refinery survey data from the Washington Research Council[16]. Given that EIA does not report crude imports by oil field, the average CI was calculated by volume-weighting California crude oil volumes consumed in 2017 as reported under the LCFS program for foreign crude oil sources. This represents only about 8% of the crude oil input for Washington. The other major sources of crude including Alaska North Slope and North Dakota Bakken had only one CI in OPGEE, therefore volume-averaging was not necessary.

Canadian crude oil can be derived from oil sands and upgraded before introducing it to the pipeline or it can by conventional crude oil. For this analysis and in the absence of field-specific data, this analysis utilized methodology implemented by the Oregon Department of

[12] British Petroleum Cherry Point, Shell Oil Anacortes, Tesoro Anacortes, Phillips 66 Ferndale, and US Oil Tacoma.

[13] 2013 data provided by Hedia Adelman, Washington State Department of Ecology

[14] Stanford University, under contract with the California Air Resources Board (CARB), is in the process of updating the OPGEE model and oil field data for the 2024 California LCFS Amendments. The final version of the model has not been released at the time of this analysis and was not accessible to our team. Trinity recommends the use of the latest available OPGEE model version for future crude oil average CI updates for the Washington CFS.

[15] EIA Company Level Imports sorted for Washington state refineries, https://www.eia.gov/petroleum/imports/companylevel

[16] Washington Research Council, The Economic Contribution of Washington State's Petroleum Refining Industry in 2017, February 2019.

Environmental Quality (DEQ) during 2015 baseline crude oil CI determination in support of the Clean Fuels Program (CFP). The list of 60+ Canadian oil fields in OPGEE was first separated into oil sands vs conventional crude and their CI values were averaged separately for each category. Transportation distance adjustments were then applied using appropriate seas distance and rail calculators.

The crude oil CI calculation for Montana refineries utilized annual review data published by the Department of Natural Resources and Conservation of the State of Montana[17], which contains information on crude oil sources for the state refineries. Similarly, for Utah, state-level data was used from the Utah Department of Natural Resources[18] to determine crude oil inputs. OPGEE CI values were then used directly without any distance adjustments given the uncertainties in specific crude oil transport logistics and the minimal impact on the overall CI calculations for Washington petroleum fuels (jet, gas, and diesel).

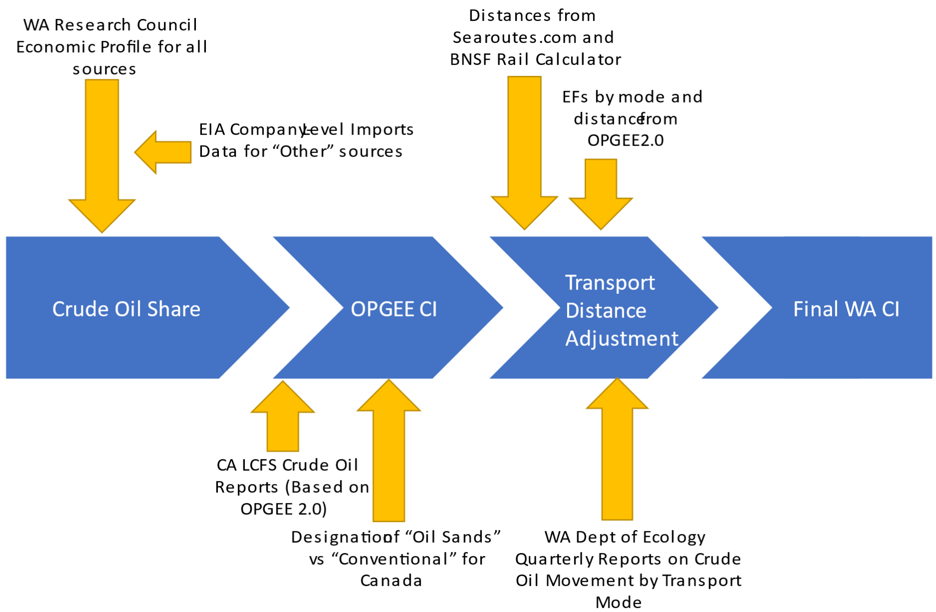

Figure 1. Baseline Crude Oil Average Calculation Methodology

[17] Department of Natural Resources and Conservation of the State of Montana, Oil and Gas Conservation Division, Annual Review, 2017.
[18] See https://www.bing.com/newtabredir?url=https%3A%2F%2Fopendata.utah.gov%2Fapi%2Fviews%2Fcq4t-mt5r%2Frows.pdf%3Fapp_token%3DU29jcmF0YS0td2VraWNrYXNz0.

Crude Oil Sources

Washington

Washington receives crude oil by vessel, pipeline, and rail. The Washington Research Council publishes a bi-annual Economic Profile Report summarizing crude oil inputs by origin based on refinery survey data. While the report groups all foreign sources into the "other" category, the EIA company-level crude oil imports data provide quantity of crude oil imported from foreign countries by destination state. Combining these two data sources, we were able to determine the shares of refinery crude inputs by country of origin, as shown in Table 1. Rail imports from Canada represent about a third of crude oil processed at Washington refineries, with another third coming via vessel from Alaska North Slope.

Table 8. Crude Oil Inputs to Washington Refineries, 2017

Country	Volume, 1000 bbl/day	Share	Mode
US North Dakota	133.3	23.3%	Rail
US Alaska	197.8	34.6%	Vessel
Canada Conventional	135.9	23.8%	Pipeline, Rail
Canada Oil Sands	59.5	10.4%	Pipeline, Rail
Other	45.1	7.9%	Vessel
Brazil		3.1%	Vessel
Ecuador		0.4%	Vessel
Mexico		0.2%	Vessel
Russia		1.3%	Vessel
Saudi Arabia		1.6%	Vessel
Trinidad and Tobago		0.7%	Vessel
Brunei		0.1%	Vessel
Papua New Guinea		0.4%	Vessel

Montana

According to the Montana Department of Natural Resources, the crude oil refined in Montana is largely from Canada (Table 9).

Table 9. Crude Oil Inputs to Montana State Refineries, 2017

Country	Volume, 1000 bbl	Share
Montana	1,192	2%
Wyoming	3,343	5%
Canada	61,046	93%

Since the vast portion of Canadian crude is coming from Alberta, the split between conventional and oil sands was assumed to be 16% to 84% according to Alberta's oil production data[19]. This assumption is generally in line with data reported by the Canadian Energy Board for PADD4 exports.

Utah

The most recently published data on Utah refinery crude oil sources (Utah Department of Natural Resources, 2021) is shown in Table 3 for 2017. Because Utah is in the same PADD as Montana, the mix of Canada heavy and light is assumed to be the same.

Table 10. Crude Oil Inputs to Utah State Refineries, 2017

Country	Volume, 1000 bbl	Share
Utah + other	30,395	45%
Colorado	5,763	9%
Wyoming	26,187	39%
Canada	4,967	7%

[19] Alberta's oil production data available at Oil Production (alberta.ca) (https://economicdashboard.alberta.ca/oilproduction#type)

Crude Oil CI Values

The California Air Resources Board (CARB) utilizes the OPGEE model, developed by researchers at Stanford University to quantify the carbon intensity of the crude oil recovery and transport portion of petroleum fuel pathways. Each year the CI is quantified for all of the oil fields that supply California refineries. For this analysis, we utilized the 2017 Annual Crude Oil Report from CARB[20]. However, granted that the 2017 CI values were developed with OPGEE1.0, we updated all crude CI values using OPGEE2.0[21] results for each oil field, consistent with crude oil CI for 2018 and subsequent years. Since the OPGEE model provides data for a number of oil fields in a given country, the CI values from multiple oil fields were weighted using 2017 crude import volumes to California, as appropriate. As mentioned earlier, this approach was only necessary for countries that contained multiple oil fields. Over half of crude imports into Washington were represented by single-field domestic sources (e.g., Bakken and North Slope).

Given that the Canadian crude imports into California were not representative of those to Washington (only 2% of crude oil processed in California refineries was from Canada in contrast to 33% in Washington), this analysis employed the Oregon DEQ approach and simple averaged all CI values for Canada available in in OPGEE depending on their designation (oil sand vs conventional) as determined by reviewing MCON summary information in OPGEE. Similar approach was applied to Montana and Utah crudes but using 2017 Alberta oil production data to differentiate between Canada oil sands and conventional crude. This split by crude oil type was also confirmed by reviewing Canada Energy Board data on PADD 4 exports for the same year. Since there was no OPGEE CI value for crude produced in Montana, this data point was omitted from the analysis impacting only 2% of the crude oil input to Montana refineries. The crude CI values for Wyoming and Utah crude oil fields were obtained from Table 9 of the California LCFS Regulation. The four oil fields in Utah were simple averaged for this analysis.

Distance Adjustment

The CI value for each crude oil source was adjusted for the difference in the transportation distance to Washington instead of California using OPGEE2.0 emission factors for crude oil transport by mode. For foreign crude oil sources that are imported via vessel through the Panama Canal, the difference in distance between ports of Los Angeles and Seattle of 1,346 miles was applied. This resulted in a CI increase of 0.16 g/MJ for all countries except for Russia, where the difference in distance travelled was assumed to be negligible. Similarly for Alaskan crude, the CI was decreased by the same amount. For North Dakota, BNSF rail distance calculator was used to compute the difference in transport distance between Seattle and Los Angeles, resulting in a CI reduction of 1.06 g/MJ. For Canadian crude, the vessel distance to California from Vancouver was replaced with distance by vessel, pipeline and rail from Vancouver to Seattle (maintaining pipeline distance from Edmonton to Vancouver same as in OPGEE2.0). Although a vast portion of Washington crude imports from Canada are by pipeline,

[20] See LCFS Crude Oil Life Cycle Assessment | California Air Resources Board (https://ww2.arb.ca.gov/resources/documents/lcfs-crude-oil-life-cycle-assessment).

[21] Note that OPGEE3.0 is currently under development by Stanford University. The latest model version is not yet publically available.

this analysis accounted for all three modes of transport based on Washington Crude Oil Movement Quarterly Reports for 2017[22]. As shown in Table 4, the OPGEE emission factors are four time higher for pipeline transport compared to vessel, therefore Canadian crude CI was estimated to be only 0.08 g/MJ lower than in California, with higher emission factors offsetting reduced transport distances. Further refining to transport adjustment is possible if OPGEE modeling is performed for each field taking its crude oil API other specific transport characters such as vessel size into account[23].

Table 11. OPGEE 2.0c Crude Transport Emission Factors

Transport Mode	$gCO2_e$/MMBtu-mile
Ocean Tanker	0.124
Pipeline	0.490
Rail	1.252

The same level of detail was not easily available for Montana and Utah crude oil movements; therefore, distance adjustments were not performed and California OPGEE CI results were used directly. This has a minor impact on the overall Washington petroleum fuels CI, since out of state finished fuel import contributed to only 16% of total fuel consumed in state.

CI Results

The sources of crude oil for Washington refineries and corresponding CI values are provided in Table 12, indicating that the average value for Washington refineries is 12.57 g/MJ[24]. Composite crude CI values for Montana (20.86 g/MJ) and Utah (9.16 g/MJ) are provided in Table 6 and Table 7, respectively. These values are combined with refining and finished fuel transport CI estimates from the GREET model based on crude type and electricity mix at the refinery.

[22] Washington Department of Ecology Publication and Forms - https://apps.ecology.wa.gov/publications/UIPages/PublicationList.aspx?IndexTypeName=Topic&NameValue=Crude+Oil+Movement+Quarterly+Reports&DocumentTypeName=Publication
[23] OPGEE2.0c emission factors are based on average API of 30.
[24] A small amount of crude also came from Brunei and Papua New Guinea. Because OPGEE did not provide CI values for oil fields in these countries they were omitted from the average. These field could utilize the “default” CI value which is recommended to be same as the baseline crude oil average.

Table 12. Washington Crude Sources and Carbon Intensity, 2017

Country	Share	CA OPGEE2.0 CI, gCO2/MJ	Transport Adjustment, gCO2e/MJ	WA CI, gCO2e/MJ
US North Dakota	23.3%	9.73	-1.03	8.70
US Alaska	34.6%	15.91	-0.16	15.75
Canada Conventional	23.8%	8.40	-0.08	8.32
Canada Oil Sands	10.4%	23.88	-0.08	23.80
Brazil	3.1%	5.86	0.16	6.02
Ecuador	0.4%	9.36	0.16	9.52
Mexico	0.2%	7.51	0.16	7.66
Russia	1.3%	9.39	0.00	9.39
Saudi Arabia	1.6%	9.18	0.16	9.34
Trinidad and Tobago	0.7%	7.41	0.16	7.57
Brunei	0.1%	NA	NA	NA
Papua New Guinea	0.4%	NA	NA	NA
Weighted Average	**100%**	**--**	**--**	**12.57**

Table 13. Montana Crude Sources and Carbon Intensity, 2017

Country	Share	CA OPGEE2.0 CI, gCO_2e/MJ
Montana	2%	NA
Wyoming	5%	10.98
Canada	93%	21.41
Weighted Average	**100%**	20.86

Table 14. Utah Crude Sources and Carbon Intensity, 2017

Country	Share	CA OPGEE2.0 CI, gCO_2e/MJ
Utah Average[25]	45%	6.03
Colorado	9%	6.81
Wyoming	39%	10.98
Canada	7%	21.41
Weighted Average	**100%**	9.16

[25] Simple average of all Utah crude sources available in Table 9 of the California LCFS Regulation.

6. Appendix B: Crude CI Lookup Table

Table 15. Crude CI Lookup table for 2017 Washington Crude

Country of Origin	Crude Identifier	CA Carbon Intensity (gCO_2e/MJ)	Crude Transport Adjustment	WA Carbon Intensity (gCO_2e/MJ)
Baseline Crude Average	Washington Crude Average applicable to crudes supplied during 2017			12.57
US North Dakota	Bakken	9.73	-1.03	8.70
US Alaska	Alaska North Slope	15.91	-0.16	15.75
Angola	Cabinda	8.99	0.16	9.15
	Clov	7.31	0.16	7.47
	Dalia	8.90	0.16	9.06
	Gimboa	8.86	0.16	9.02
	Girassol	9.95	0.16	10.11
	Greater Plutonio	8.72	0.16	8.88
	Hungo	8.23	0.16	8.39
	Kissanje	8.66	0.16	8.82
	Mondo	8.98	0.16	9.14
	Nemba	9.08	0.16	9.24
	Pazflor	8.02	0.16	8.18
	Sangos	7.06	0.16	7.22
Argentina	Canadon Seco	10.16	0.16	10.32
	Escalante	10.15	0.16	10.31
	Hydra	7.77	0.16	7.93
	Medanito	10.78	0.16	10.94
Brazil	Albacora Leste	5.99	0.16	6.15
	Bijupira-Salema	7.18	0.16	7.34

Country of Origin	Crude Identifier	CA Carbon Intensity (gCO_2e/MJ)	Crude Transport Adjustment	WA Carbon Intensity (gCO_2e/MJ)
	Frade	5.63	0.16	5.79
	Iracema	5.54	0.16	5.70
	Jubarte	6.28	0.16	6.44
	Lula	6.24	0.16	6.40
	Marlim	6.76	0.16	6.92
	Marlim Sul	7.78	0.16	7.94
	Ostra	5.65	0.16	5.81
	Papa Terra	4.29	0.16	4.45
	Peregrino	4.16	0.16	4.32
	Polvo	4.31	0.16	4.47
	Roncador	6.77	0.16	6.93
	Roncador Heavy	6.45	0.16	6.61
	Sapinhoa	6.00	0.16	6.16
	Tubarao Azul	5.45	0.16	5.61
	Tubarao Martelo	5.37	0.16	5.53
Canada	Access Western Blend	15.15	-0.08	15.07
	Albian Heavy Synthetic (all grades)	23.68	-0.08	23.60
	BC Light	8.11	-0.08	8.03
	Bonnie Glen	8.11	-0.08	8.03
	Borealis Heavy Blend	15.41	-0.08	15.33
	Boundary Lake	8.11	-0.08	8.03
	Bow River	9.42	-0.08	9.34
	Cardium	8.11	-0.08	8.03
	Christina Dilbit Blend	12.71	-0.08	12.63
	Christina Synbit	18.66	-0.08	18.58
	Cold Lake	17.87	-0.08	17.79
	Conventional Heavy	9.42	-0.08	9.34
	CNRL Light Sweet Synthetic	25.27	-0.08	25.19
	Federated	8.11	-0.08	8.03

Country of Origin	Crude Identifier	CA Carbon Intensity (gCO_2e/MJ)	Crude Transport Adjustment	WA Carbon Intensity (gCO_2e/MJ)
	Fosterton	9.42	-0.08	9.34
	Gibson Light Sweet	8.11	-0.08	8.03
	Halkirk	8.11	-0.08	8.03
	Hardisty Light	8.11	-0.08	8.03
	Hardisty Synthetic	36.39	-0.08	36.31
	Husky Synthetic	32.66	-0.08	32.58
	Joarcam	8.11	-0.08	8.03
	Kearl Lake	12.89	-0.08	12.81
	Kerrobert Sweet	8.11	-0.08	8.03
	Koch Alberta	8.11	-0.08	8.03
	Light Sour Blend	8.11	-0.08	8.03
	Light Sweet	8.11	-0.08	8.03
	Lloyd Blend	9.42	-0.08	9.34
	Lloyd Kerrobert	9.42	-0.08	9.34
	Lloydminster	9.42	-0.08	9.34
	Long Lake Heavy	30.54	-0.08	30.46
	Long Lake Light Synthetic	40.12	-0.08	40.04
	Mackay Heavy Blend	20.43	-0.08	20.35
	Medium Gibson Sour	8.11	-0.08	8.03
	Medium Sour Blend	8.11	-0.08	8.03
	Midale	8.11	-0.08	8.03
	Mixed Sour Blend	8.11	-0.08	8.03
	Mixed Sweet	8.11	-0.08	8.03
	Moose Jaw Tops	8.11	-0.08	8.03
	Peace	8.11	-0.08	8.03
	Peace Pipe Sour	8.11	-0.08	8.03
	Peace River Heavy	19.21	-0.08	19.13
	Peace River Sour	8.11	-0.08	8.03
	Pembina	8.11	-0.08	8.03

Country of Origin	Crude Identifier	CA Carbon Intensity (gCO_2e/MJ)	Crude Transport Adjustment	WA Carbon Intensity (gCO_2e/MJ)
	Pembina Light Sour	8.11	-0.08	8.03
	Premium Albian Synthetic	29.49	-0.08	29.41
	Premium Conventional Heavy	9.42	-0.08	9.34
	Premium Synthetic	27.38	-0.08	27.30
	Rainbow	8.11	-0.08	8.03
	Rangeland Sweet	8.11	-0.08	8.03
	Redwater	8.11	-0.08	8.03
	Seal Heavy	9.42	-0.08	9.34
	Shell Synthetic (all grades)	29.49	-0.08	29.41
	Smiley-Coleville	9.42	-0.08	9.34
	Sour High Edmonton	8.11	-0.08	8.03
	Sour Light Edmonton	8.11	-0.08	8.03
	Statoil Cheecham Dilbit	16.41	-0.08	16.33
	Statoil Cheecham Synbit	21.08	-0.08	21.00
	Suncor Synthetic (all grades)	27.09	-0.08	27.01
	Surmont Heavy Blend	22.48	-0.08	22.40
	Synbit Blend	22.64	-0.08	22.56
	Syncrude Synthetic (all grades)	31.62	-0.08	31.54
	Synthetic Sweet Blend	29.36	-0.08	29.28
	Tundra Sweet	8.11	-0.08	8.03
	Wabasca	6.88	-0.08	6.80
	Western Canadian Blend	9.42	-0.08	9.34
	Western Canadian Select	19.04	-0.08	18.96
Ecuador	Napo	8.31	0.16	8.47
	Oriente	10.07	0.16	10.23
Ghana	Ten Blend	8.08	0.16	8.24
Mexico	Isthmus	11.31	0.16	11.47
	Isthmus Topped	14.31	0.16	14.47
	Maya	7.85	0.16	8.01

Country of Origin	Crude Identifier	CA Carbon Intensity (gCO_2e/MJ)	Crude Transport Adjustment	WA Carbon Intensity (gCO_2e/MJ)
Nigeria	Agbami	12.04	0.16	12.20
	Amenam	10.65	0.16	10.81
	Antan	21.98	0.16	22.14
	Bonga	5.06	0.16	5.22
	Bonny	9.91	0.16	10.07
	Brass	14.27	0.16	14.43
	EA	6.66	0.16	6.82
	Erha	10.91	0.16	11.07
	Escravos	12.00	0.16	12.16
	Forcados	8.97	0.16	9.13
	Okono	8.67	0.16	8.83
	OKWB	22.76	0.16	22.92
	Pennington	11.18	0.16	11.34
	Qua Iboe	11.45	0.16	11.61
	Yoho	11.45	0.16	11.61
Russia	ESPO	11.55	0.00	11.55
	M100	17.35	0.00	17.35
	Sokol	6.94	0.00	6.94
	Vityaz	9.60	0.00	9.60
Saudi Arabia	Arab Extra Light	9.41	0.16	9.57
	Arab Light	9.23	0.16	9.39
	Arab Medium	8.72	0.16	8.88
	Arab Heavy	7.92	0.16	8.08
Trinidad	Calypso	7.41	0.16	7.57
	Galeota	11.41	0.16	11.57

7. Appendix C: Electricity Modelling in GREET

Electric Power Pathway in WA-GREET

Feedstock:	Natural Gas, Coal, Biomass, Nuclear, wind, water
Products:	Electricity
Documentation:	ARB 2009, ANL

Electricity is an intermediate source of energy used for fuel production and EV charging. Electricity is produced from a number of primary energy sources and via a number of different pathways. Power generation in GREET is modeled base on the mix of natural gas, coal fuel oil, nuclear, biomass, and renewable resources. For biofuel pathways, the WA CFP assigns electricity mix based on the average resource mix in each eGRID region shown in following Figure 2.

The life cycle GHG emissions are based on the generation resource mix for each region. Direct emissions from power plants are based on estimated power plant types in each region. Upstream life cycle GHG emissions correspond to the specific resource extraction and processing as modelled in the GREET model for all fuel cycle pathways.

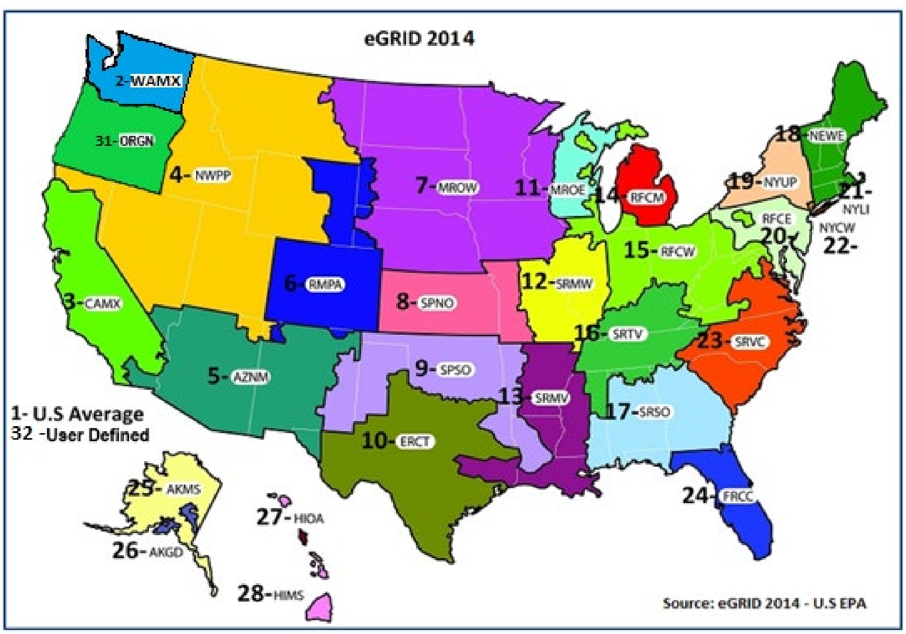

Figure 2. Electricity production regions in WA-GREET model

The U.S. Average Mix is produced by determining the % feedstock contribution for the entire U.S. Washington state average mix is developed based on the % contribution of various fuel types in total state electricity production over a given year, as reported under the annual Washington fuel mix disclosure reporting process.

In fuel cycle modeling, electricity is an intermediate fuel used in the recovery, processing, and production of other transportation fuels. Electricity is also a transportation fuel. Since electric vehicles do not emit any pollutants, fuel cycle emissions consist only of WTT emissions. The WTT emissions result from direct fuel combustion at the power plant and from upstream activities to recover, process, and transport fuels to the power plant. The system boundary for the electricity pathway, shown in Figure 3, includes the upstream activities of each fuel used to generate electricity, direct combustion of these fuels at the power plant, and losses through the transmission and distribution system. The following sections describe electricity generating resources and the WA-GREET electricity pathways.

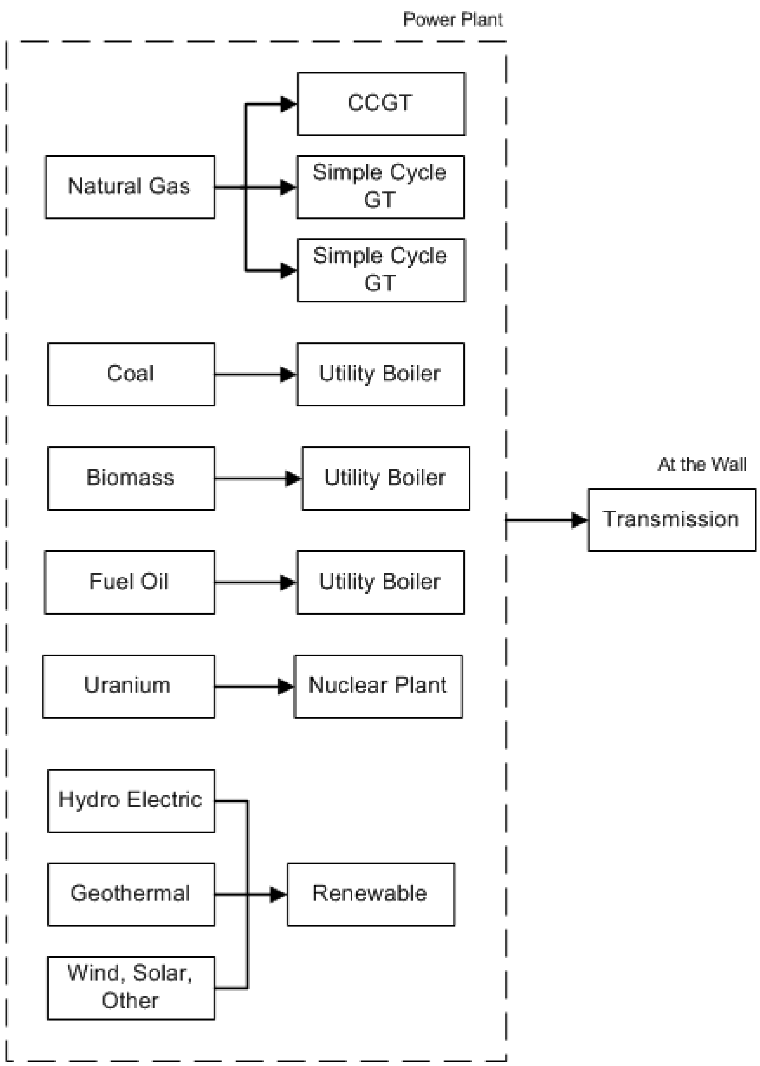

Figure 3. Electricity Production System Boundary Diagram

Sources of electric power

1. Coal to Electric Power

Despite strong head winds in the form of an aging fleet, increasingly stringent environmental regulations, and abundant new sources of domestic natural gas, coal is still utilized in much of the U.S. to generate electricity. Coal has traditionally been utilized in utility steam generators. A newer approach is to gasify the coal and then utilize the syngas in a combined cycle combustion turbine, or integrated gasification combined cycle (IGCC). IGCC is significantly more efficient than a steam generator and has lower emission rates. Moreover, it is more economical to capture carbon from an IGCC plant because the treated gas volumes are significantly lower.

2. Fuel Oil to Electric Power

Once commonly used in utility boilers, residual oil is now only used in times of natural gas curtailment in Washington. Diesel oil is also used emergency generators and some combustion turbines, but again, this is generally only allowed in times of natural gas curtailment.

3. Natural Gas to Electric Power

Natural gas can be utilized in steam generators, simple cycle combustion turbines (SCCTs), and combined cycle combustion turbines (CCCTs). In a steam generator, natural gas is burned in a furnace to raise steam which generates electricity as it passes through a steam turbine. In a simple cycle gas turbine, natural gas is burned in a combustor and then the hot combustion gases generate electricity as they flow through a gas turbine. A combined cycle plant is a combination of a simple cycle turbine and a steam generator. In a CCCT, the hot gases exiting the gas turbine are utilized to generate steam which then runs through a steam turbine to generate additional electricity. CCCTs are significantly more efficient than steam generators which are typically more efficient than simple cycle turbines.

Most new large capacity natural gas fired plants installed in the past few decades have been and will continue to be CCCTs because of their superior efficiency and lower cost. Historically, natural gas steam generators were base loaded facilities. However, with the advent of CCCTs over the past several decades, steam generators have been relegated to an intermediate cycling role, with SCCTs utilized as peaking units on hot summer afternoons.

4. Nuclear to Electric Power

Nuclear power does not generate any power plant emissions, but does have upstream emissions associated with uranium mining, processing and transport. There are two main types of nuclear reactors in the U.S.: light water reactors and high temperature gas cooled reactors. All of the nuclear plants in the western United States are of the light water reactor design.

5. Biomass to Electric Power

Biomass, such as farmed trees, perennial plants, or forest residue has long been utilized to generate electricity. Biomass is typically combusted boiler for steam production and power generation in a steam turbine. Boiler combustion methods range from stoker grates to fluidized beds. It is also possible to gasify the biomass and subsequently utilize the syngas in a combined cycle combustion turbine, similar to coal IGCC. Although the direct carbon emissions are biogenic, the upstream emissions associated with growing, harvesting and transporting the feedstock are quantified in a full fuel cycle analysis. Under the GREET model framework, the biomass used for power production have been considered carbon neutral.

6. Renewables to Electric Power

Resources that do not have any fuel cycle emissions (neither direct nor upstream) associated with them, including hydroelectricity, solar, wind, and geothermal. Under the WA-GREET framework, the renewable source derived electricity is considered to have zero CI.

Fuel Pathway Calculations

This section describes the GREET calculations for select fuel pathways. The emphasis is on the details for the WTT component of individual fuel pathways:

- Electric Power

The following describes the WTT portion with sufficient detail to understand the calculations and factors that affect the carbon intensity calculations. Upstream fuel cycle emissions are internally calculated in GREET. Some of the finished fuels, such as natural gas, diesel, and electric power are also inputs to other fuel production processes.

Electric Power

Fuel cycle emissions from electric power include emissions at the power plant and the upstream emissions to produce feedstocks. WA-GREET calculates the WTT LCI data for electricity use in fuel production processes. The electricity sub-module calculates the fuel cycle emissions for electric power generation from a variety of generation resources. The following sections describe the general calculation methodology.

Calculation Methodology

For electricity pathways, all of the emissions occur in the fuel cycle and no emissions occur during vehicle operations[xxvi]. The WTT emissions comprise the entire fuel life cycle. To estimate WTT emissions for electricity production, the typical GREET methodology is employed according to the following equation:

$$E_{Electricity,WTT} = \left(\sum_{i=1}^{n} \sum_{k=1}^{m} (S_{i,k} \times (E_{Plant} + E_{Fuel})_{i,k}) \right) \div (1 - LF_{T\&D})$$

where,

$E_{Electricity}$ = GREET WTT result for upstream fuel cycle for electricity, a data array of life cycle greenhouse gas and criteria pollutant emissions for the electricity pathway per unit transportation fuel

E_{Plant} = data array of upstream emissions for the power plant fuel (for example, the emissions associated with natural gas recovery, processing and transport to the power plant per unit natural gas)

[xxvi] Other emissions such as changes in break wear and ozone from motors may be attributed to EVs but are not discussed here. TTW emissions are treated as zero in this discussion.

E_{Fuel} = data array of direct emissions from the power plant (for example, the missions associated with burning natural gas in a combined cycle combustion turbine per unit natural gas)

$S_{i,k}$ = Specific energy of i fuel type consumed by k power plant type per unit of fuel produced (for example, the amount of natural gas burned in a utility boiler per unit of electricity produced)

i = different resources utilized to produce electricity (for example, natural gas, coal, oil, biomass, wind, etc.)

k = different types of combustion equipment utilized to generate power from a given fuel (for example boiler, combined cycle turbine, simple cycle turbine)

$LF_{T\&D}$ = Loss factor due to electrical losses along transmission and distribution lines

In general, the amount of each fuel type utilized in each different combustion device to produce a unit of electricity is an input ($S_{i,k}$). The WTT result is based on the weighted average for each fuel resource. The S is multiplied by the upstream and direct emissions per unit of fuel consumed. The resulting emissions from each fuel type and combustion device per unit of electricity produced are summed and then adjusted for transmission and distribution losses. The following sections describe in detail how the emissions are calculated, using the current WA CFP using Washington state average mix case as an example.

WTT Calculation

Fuel resource mix for the 2018 Washington average case is shown in Table 15. The Washington average fuel mix is an estimate of the share of each fuel consumed in Washington in 2018. The fuel mix was determined by allocating the fuel types as reported under the Washington fuel mix disclosure report to the fuel types compatible with the GREET model framework.

Table 16. Resource Mix for LCFS Washington Average Case

Resource Type	Share (S_i)
Residual Oil	0.10%
Natural Gas	20.46%
Coal	10.22%
Nuclear	4.75%
Biomass	0.45%
Non-combustion Renewables	64.03%

Following the default assumptions for the WECC region in CA-GREET3.0, the residual consumption is distributed among utility boiler, internal combustion engine, and gas turbine. All of the coal and biomass are burned in utility boilers. The natural gas is distributed among boilers, combined cycle combustion turbines (CCCT), simple cycle combustion turbines (SCCT), and internal combustion engine. All of the nuclear power is assumed to come from light water reactors. The combustion technology shares for each fuel type and the associated energy efficiency are provided in Table 16. The technology shares for all technologies are directly based on CA-GREET3.0 and is specific to a given region as classified under the North American Electric Reliability Corporation (NERC) classification. Washington state electricity mix CI calculation utilizes the WECC region technology shares as this region incorporates the Washington state.

Table 17. Combustion Technology Shares and Energy Efficiencies

Resource Type	Technology Share	Energy Efficiency	Specific Energy (Btu/MMBtu)	WAMX fuel Use (Btu/MMBtu)
Residual Oil-Fired Power Plants		33.65%		
Boiler	72.4%	33.90%	2,949,853	2,155
Internal Combustion Engine	15.5%	39.00%	2,564,103	401
Gas Turbine	12.1%	27.60%	3,623,188	442
Natural Gas-Fired Power Plants		48.12%		
Boiler	6.4%	32.00%	3,125,000	40,924
Simple-cycle gas turbine	3.3%	32.80%	3,048,780	20,587
Combined-cycle gas turbine	89.2%	51.10%	1,956,947	357,182
Internal Combustion Engine	1.1%	34.40%	2,906,977	6,543
Coal-Fired Power Plants		34.70%		
Boiler	100.0%	34.70%	2,881,844	294,388
IGCC	0.0%	40.00%	2,500,000	0
Biomass Power Plants		22.60%		
Boiler	100.0%	22.60%	4,424,779	19,770
IGCC	0.0%	40.00%	2,500,000	0
Nuclear Power Plants		100.0%	1,000,000	47,478
Other Power Plants (hydro, wind, geothermal, etc.)		100.0%	1,000,000	47,478
Hydroelectric	92.4%			
Geothermal	0.0%			
Wind	7.2%			
Solar PV	0.4%			
Others (Biogenic Waste, Pumped Storage, etc.)	0.0%			

Specific energy is the inverse of energy efficiency, multiplied by 1,000,000.
WA average fuel use is the specific energy multiplied by the fuel shares in the previous table for the 2018 Washington Average mix case

Before emissions can be estimated, the specific energy consumption for each fuel type must be determined. As mentioned above, specific energy is the amount of each type of fuel consumed per unit of electricity produced (Btu/mmBtu electricity) for each combustion device. The fuel resource mix, combined with efficiency of each generation device provides the basis to calculate the specific energy. The calculated average fuel use for each resource is then combined with the corresponding upstream factor associated with the resource extraction process modelled by other modules of the GREET model to calculate the total upstream emissions.

For each resource, the emissions from combustion for each given technology is combined with the corresponding technology share to calculate the emissions from electricity generation. Electricity generation emissions from all the resources are then combined with resource mix shares and added together to get the total electricity generation emissions from all the resources combined.

The upstream and the combustion emissions together represent the total emissions produced from the resource extraction as well as the combustion during the electricity generation at the outlet of the power plant.

Transmission Losses

GREET WTT results include transmission losses. The total emissions from power generation including the upstream resource extraction are adjusted to include the losses during electricity transmission.

The loss factor is defined such that:

$$\text{Power at wall} = \text{Power at plant} \times (1 - LF_{T\&D})$$

Based on CA-GREET3.0, WA-GREET uses a transmission loss factor of 6.5%. After such adjustment, the final value represents the lifecycle emissions from the electricity at the wall outlet or consumption location.

Washington Average Electricity Pathway

The WA-GREET model has one additional electricity pathway in comparison to CA-GREET3: Washington Average mix. It is utilized as an intermediate fuel in the production of other transportation fuels. The Washington Average pathway is used to estimate energy and emissions from electricity used for biofuel production. Table 17 provides a summary of the 2017 and 2018 Washington state average electricity mix. The mix is based on the annual Washington fuel mix disclosure report.[xxvii]

Table 18. Washington Average Resource Mixes

Fuel Type	2017 WA Disclosure	2017 WAMX Mix	2018 WA Disclosure	2018 WAMX Mix
Residual oil	0.11%	0.33%	0.02%	0.10%
Other	0.18%	-	0.05%	-
Waste	0.04%	-	0.04%	-
Coal	13.39%	13.39%	10.22%	10.22%
Natural gas	10.83%	10.96%	7.33%	20.46%
Cogeneration	0.00%	-	0.00%	-
Unspecified	0.00%	-	12.93%	-
Landfill Gas	0.13%	-	0.20%	-
Nuclear power	4.19%	4.19%	4.75%	4.75%
Biomass	0.60%	0.60%	0.45%	0.45%
Hydroelectric	67.68%	67.68%	59.16%	59.16%
Geothermal	0.00%	0.00%	0.00%	0.00%
Wind	2.84%	2.84%	4.58%	4.58%
Solar PV	0.00%	0.00%	0.28%	0.28%

Washington Utility Specific Power

The WA CFS regulation includes provision to allow the use of utility specific CI for certain purposes outside of biofuel pathways, like credit generation from Electric Vehicle charging within Washington. To this end, Life Cycle Associates developed a new calculator external to the WA-GREET that models the carbon intensity for the power generated by an individual utility within Washington. This calculator is based on the well-to-plug lifecycle emission calculation methodology from WA-GREET described above and utilizes the utility specific electricity generation mix as reported under the Washington utility mix disclosure data.

Under the annual Washington utility mix disclosure report, the fuel types used to generate electricity by each specific utility in Washington is also reported annually. Each utility in the

[xxvii] WA Fuel Mix Disclosure Data, available here (https://www.commerce.wa.gov/growing-the-economy/energy/fuel-mix-disclosure/)

disclosure report is classified by its unique "Claimant ID" which is also associated to the utility name as the "Claimant name."

This annual report includes the self-reported amount of electricity production, in MWh, from a defined list of fuel types. The fuel type categories in the report include the following types of fuel used by a given utility for its electricity production:

- Biogas
- Biomass
- Coal
- Geothermal
- Hydro
- Natural Gas
- Nuclear
- Other Biogenic
- Other Non-Biogenic
- Petroleum
- Solar
- Unknown
- Waste
- Wind
- Unspecified (Plant use)
- Unspecified (BPA purchase)

These categories are matched with the resource categories as defined and utilized in the GREET model framework to calculate a WA-GREET compatible electricity resource mix for any given utility. In consultation with the Washington Department of Ecology, a conservative approach was followed to perform this allocation as illustrated in the following Table 18.

Table 19 Allocation of Washington Fuel Mix Disclosure Resources Categories to WA-GREET Resources Categories

	Residual oil	Natural gas	Coal	Nuclear power	Biomass	Hydroelectric	Geothermal	Wind	Solar PV
Biogas		1							
Biomass					1				
Coal			1						
Geothermal							1		
Hydro						1			
Natural Gas		1							
Nuclear				1					
Other Biogenic		1							
Other Non-Biogenic	1								
Petroleum	1								
Solar									1
Unknown		1							
Waste	1								
Wind								1	
Unspecified (Plant)		1							
Unspecified (BPA)		1							

The WA utility CI calculator allows the selection of the utility for which the lifecycle carbon intensity result is desired using its Claimant ID as reported under the Washington utility mix disclosure report due to its unique nature. The calculator includes the data directly extracted from the utility disclosure report for reference and also for use in CI calculation.

The utility selection is available on the “Utility CI” sheet of the calculator using a combination of drop-down menus. The first drop-down menu allows the user to select between a pre-defined Washington utility or a User-Defined mix. The second drop-down menu allows the user to select a Claimant ID from the list of all the available claimant IDs under the utility mix disclosure data.

The utility selection is available on the "Utility_CI" sheet of the calculator using a combination of drop-down menus. The first drop-down menu allows the user to select between a pre-defined Washington utility or a User-Defined mix. The second drop-down menu allows the user to select a Claimant ID from the list of all the available claimant IDs under the utility mix disclosure data.

Upon selection of a claimant ID, the calculator shows the utility Claimant name of the corresponding ID from the utility mix disclosure report. Underneath the drop down menus, the calculator also includes a table showing the electricity generation mix for the selected utility as well as a section to input the custom user-defined mix.

Based on the selection of the first dropdown menu, the calculator activates the correct electricity generation mix as the active case. If User-defined mix is selected in the first drop-down menu, the second drop-down menu is functionally ignored, and the CI results correspond to the custom resource mix inputted by the user.

The drop-down menus and the generation mix table on the Utility_CI sheet on the Washington utility CI calculator is shown in the Table 19 below.

Table 20. Utility_CI sheet from the Washington Utility CI Calculator

1) Selection of Washington Utility or User Defined mix	1	1 - Washington Utility
		2 - User Defined Mix
1.1) Selection of the WA Utility ID for CI Results		
Utility Claimant ID	22	*List of all Utility IDs and names available on Fuel Share tab
Name of the Selected Utility Mix	Clallam County PUD #1	

2) Electric Generation Mix: Data Table

	Active Case for CI Calculation		
	Clallam County PUD #1	Clallam County PUD #1	User Defined Mix
Residual oil	0.00%	0.00%	0.10%
Natural gas	4.33%	4.33%	20.46%
Coal	0.00%	0.00%	10.22%
Nuclear power	10.77%	10.77%	4.75%
Biomass	0.00%	0.00%	0.45%
Others	84.90%	84.90%	64.03%

The calculator then follows the GREET methodology to calculate the lifecycle emissions from electricity produced at the selected Washington utility, or a user-defined mix, as selected by the user. The calculator shows the final well-to-plug electricity CI results for the selected source in gCO_2e/MJ as well as gCO_2e/KWh, as shown below in the Table 20.

Table 21. Categorization of GREET Resource Mix based on Utility Reporting

3) CI Results for: 22: Clallam County PUD #1

Details Breakdown of CI for Electricity Resources	Residual Oil	NG	Coal	Biomass	Nuclear	Other renewable energy sources	Total, g/MMBtu	Electricty Prod For Stationary Use	Final WTW CI
VOC	0.00	0.99	0.00	0.00	0.10	0.00	1.091	0.20	
CO	0.00	3.09	0.00	0.00	0.41	0.00	3.506	2.25	
CH4	0.00	25.04	0.00	0.00	0.52	0.00	25.557	0.10	
N2O	0.00	0.14	0.00	0.00	0.00	0.00	0.140	0.01	
CO2	0.00	636.91	0.00	0.00	143.75	0.00	780.651	5713.71	
Convert to gCO2e/MMBtu	0.00	1311.66	0.00	0.00	158.50	0.00	1470.159	5724.43	
g/MJ	0.00	1.24	0.00	0.00	0.15	0.00	1.39	5.43	6.82
g/kWh							5.02	19.53	24.55

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