THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION

Washington Clean Fuels Standard – Carbon Intensity Model Peer Review

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Overall Impressions and Summary of Recommendations

This peer review was conducted in support of Washington State Department of Ecology's rulemaking for a new rule, Chapter 173-424 WAC, Clean Fuels Program Rule. As part of this peer review, the International Council on Clean Transportation (ICCT) assessed the public documents shared at the March 15, 2022 stakeholder meeting developed by Life Cycle Associates. These documents included a draft carbon intensity model to inform the development of the Clean Fuels Program (CFP) and the accompanying calculations and supporting documentation. For this peer review, ICCT assessed the methodology and results of the draft carbon intensity model, Washington Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model (WA-GREET), itself an update of a similar model used in California (CA-GREET). In doing so, ICCT reviewed the calculations within the model for internal consistency as well as consistency with other life-cycle models, compared the data sources & assumptions to public data and the scientific literature, as well as assessed the recommendations of the modelers for the inclusion of indirect land-use change (ILUC) emissions outside of the model.

Overall, we find that the life-cycle fuel model updates developed by Life Cycle Associates (LC Associates) largely follow the existing precedent set by the California Air Resources Board (CARB) in its comprehensive life-cycle assessment (LCA) established in the California Low-Carbon Fuel Standard (LCFS). The changes made within WA-GREET to tailor it to Washington state-specific data on fossil fuel consumption and electricity production are largely aligned with existing life-cycle assessment practices and are consistent with the intended scope of the Washington Clean Fuels Program (WA CFP). We present a high-level summary of five key fuel pathways' emissions in Figure 1, illustrating the difference in their carbon intensity calculated for Washington in WA-GREET against values calculated for California's LCFS using CA-GREET. The most impactful changes in the Washington analysis are the inclusion of a Washington state-average carbon intensity for electricity (resulting in a 20% decrease in electricity grid carbon intensity relative to California), and the proposed use of a different ILUC emission factor for corn ethanol (a 17.5% decline in default corn ethanol carbon intensity relative to California). Changes to the crude oil carbon intensity were much smaller, with less than 1% difference compared to California petroleum products. Throughout this peer review, we document that there are several assumptions made in the analysis or omissions based on data gaps that affect the emissions estimates for petroleum products and electricity, and offer several recommendations on addressing those data gaps and developing more accurate estimates.

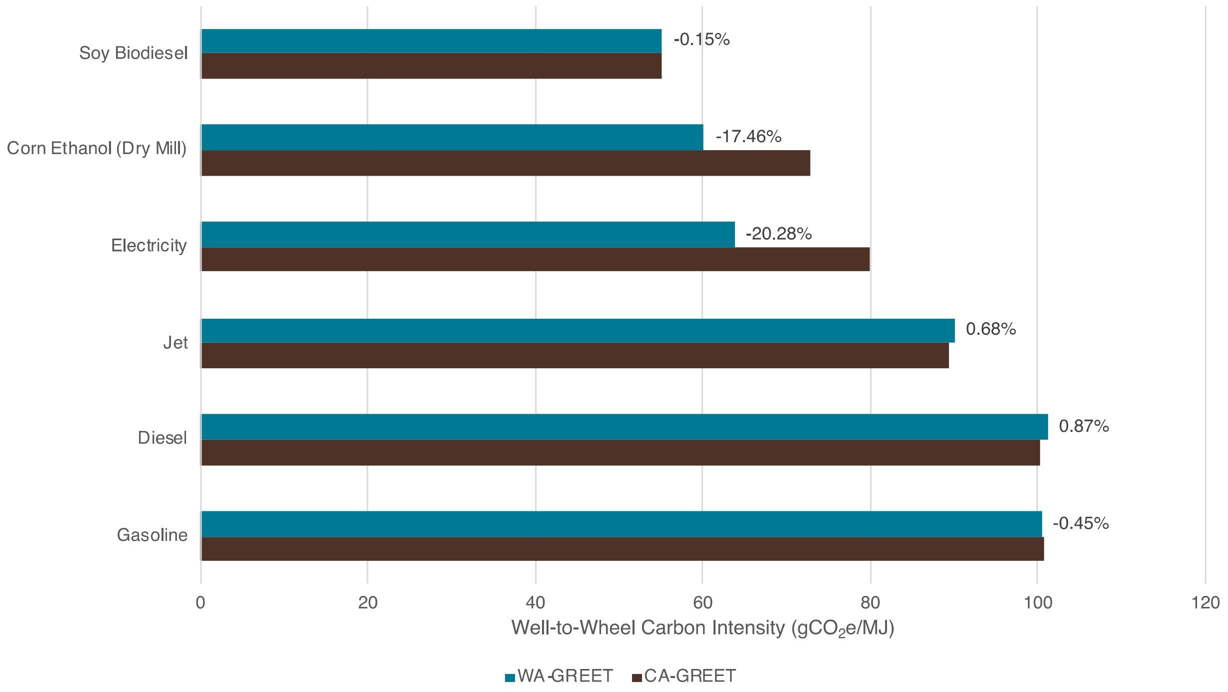

Figure 1: Comparison of well-to-wheel carbon intensities for a selection of fuel pathways for WA-GREET and CA-GREET

We also note several areas in which LC Associates did not develop model updates that may warrant updates prior to implementation of the WA CFP in order to reflect the latest scientific understanding of fuel production and climate change. This includes expanding the analysis of crude oil upstream emissions and refinery emissions to address data gaps and reflect state-specific fuels and practices. This will affect the emissions attributable to petroleum products used as a transportation fuel, as well as the emissions attributable to electricity and multiple fuel pathways using petroleum as a process fuel. We also recommend that WA-GREET incorporates updated global warming potential (GWP) values based on the IPCC's Fifth Assessment Report (AR5) to reflect an updated understanding of the climate impacts of different non-CO_2 greenhouse gases (GHGs).

Indirect land-use change (ILUC) emissions are an important consideration within policy making and must be calculated outside of a process-based attributional LCA model such as WA-GREET. These emissions estimates are based on economic modeling and come with a degree of epistemic uncertainty in addition to decision uncertainty. ILUC estimates may be limited by data gaps for key parameters as well as structural choices relating to model design, scenario design and risk tolerance. We note several methodological issues associated with the emission factor chosen for corn ethanol in the LC Associates report, based on model design and the emission factor model for land conversion. Therefore, we recommend using the full set of CARB's existing ILUC estimates for the WA CFP in the near-term, as well as further work to assess land-use change emissions for the WA CFP context. We also recommend against including a zero-ILUC value for cover cropped carinata, as there is not a definition of cover cropping in the proposed CFP nor a system for verifying that feedstocks are in fact being grown as a cover crop.

Over the next several sections of this peer review, we evaluate the major changes made to the WA-GREET and accompanying documentation. We first assess the methodology used for the changes and evaluate the data sources used and then document the impact of these changes on the calculated carbon intensity for relevant fuels. Where necessary, we provide recommendations to improve the rigor of the analysis and address data gaps.

Fossil Fuel Carbon Intensity

Crude oil mix

The calculation of average carbon intensity (CI) of WA's crude oil in 2017 is calculated primarily on two parameters: (1) the crude oil mix in WA, i.e., the volumetric distribution of the types of crude oil that comes from different location origins; and (2) crude oil CI of each source, which includes the GHG emissions during crude oil extraction and processing, as well as emissions from transporting the oil to WA. Based on the two parameters, a volumetric weighted average CI can be calculated to represent crude oil being used in WA. This crude oil CI is then used for the calculation of WA's petroleum product CIs in 2017, specifically gasoline, diesel, and jet fuel.

In addition to petroleum that is refined within the state, WA also imports refined petroleum products from Montana and Utah. A similar approach is adopted to estimate the volumetric-weighted average CI for crude oils in those two states, and consequently state specific petroleum CIs. The CIs, each of gasoline, diesel, and jet fuel, from the three states are then weight-averaged for a final gasoline, diesel, or jet fuel CI in WA, which serves as the baseline for the CFP.

This section identifies potential improvements that could be made regarding the methodology used to assess the mix of crude oils consumed in Washington as well as the calculation of the total well-to-wheel CI of petroleum products estimated.

In the peer review process, we evaluated the mix of crude oils provided by Washington State Department of Commerce and find that the estimation of total volumes and development of the weighted average mix matched the underlying data. The data was sufficient to determine country-level crude oil source data and identify suitable matches in California's previous crude oil life-cycle analysis. Data gaps on field level crude import data is not something that LC Associates can resolve, but nonetheless can cause difficulties when developing a comprehensive assessment of crude oil mix in WA. In the longer-term, a better understanding of the crude oil mix and its impact on Washington's fuel emissions can be achieved through regular reporting of the crude oil imports into Washington, similar to the annual reporting for California's LCFS.[1]

Crude oil from Canada can be categorized into conventional oil or oil sands and CI of each vary significantly. However, the state-level import data by oil type in Montana and Utah does not distinguish by source and thus is estimated. According to WA's crude oil carbon intensity analysis spreadsheet, the estimated distribution of conventional and oil sands from Canada in the two states are based on two sets of assumptions. First, it assumes the imported oil is from Alberta, based on Washington's own imports. Second, the distribution is based on the split

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[1] https://ww2.arb.ca.gov/resources/documents/lcfs-crude-oil-life-cycle-assessment

between conventional (16%) and oil sands (84%) per oil production in Alberta. There are two caveats using this split. First, there is no clarification if this split is based on the year 2017. Second, the oil produced is not necessarily proportional to the share of oil exported – it is possible that Alberta gives a preference to one type of oil for exports. The accuracy of distribution assumption would have a significant impact on final crude oil CI in the two states, especially for Montana where 93% of its oil is from Canada. Therefore, we recommend that LC Associates conducts additional research and collects more representative distribution data in Montana and Utah. Past studies and reports may provide some data information on the split of Canada's conventional oil and oil sands for PADD 4 in general, which might be more applicable than the current approach. A possible source is the Canadian Association of Petroleum Producers (CAPP), such as the annual Crude Oil Forecast, Markets and Transportation report.[2]

Crude oil carbon intensity

Crude oil extracted from different oil fields can have differing upstream GHG emissions due to variations in the energy and emissions associated with different extraction and processing techniques. To assess the upstream CI of different sources of crude oil, LC Associates retrieved CI of each of its oil origin from an existing life-cycle assessment developed by the California Air Resources Board (CARB) for California's Low Carbon Fuel Standard (LCFS), which is based on modeling performed using the Oil Production Greenhouse Gas Emission Estimator (OPGEE 2.0) model.[3] To develop the weighted CI for Washington's crude oil, the modelers made two adjustments. First, the CI values developed for the California LCFS have finer granularity in terms of the regional oil fields than WA and thus the modelers use weighted average were taken (e.g., averaging multiple fields' CI's in Saudi Arabia). Second, the modelers adjust the transportation emissions for crude oil to account for the change in distance between California and Washington. This section identifies potential improvements in these two adjustments.

Even within a single country or region, different crude oil fields can have very different carbon intensities for extraction and processing. While Washington does not provide detailed data on the specific oil fields that supply oil to WA, the California LCFS on the other hand provides CI and import values that are differentiated into oil fields for each country or U.S. state. Table 2 shows an example of how data fitting for oil from Brazil was carried out with the current approach. Specifically, WA only has the total amount of oil imported from Brazil, while LCFS provides import volume and CI by oil field in Brazil. In order to get a single Brazil CI for WA, the CI of each oil field in LCFS is weighted by its corresponding import volume in California. Such a data fitting approach is done for almost all oil origins that export to WA, except for Canada, Brunei, and Papua New Guinea. A potential problem with this approach is that the weighted average of the by oil field mix imported in California does not be able to represent the distribution in WA and thus the calculated average of imports in Washington is inaccurate.

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[2] CAPP's 2017 Crude Oil Forecast, Markets and Transportation report http://www.oscaalberta.ca/wp-content/uploads/2017/06/CAPP-2017-Crude-Oil-Forecast.pdf

[3] https://ww2.arb.ca.gov/resources/documents/lcfs-crude-oil-life-cycle-assessment

Table 1. An example of how CI from LCFS is fitted into Washington with current approach, using oil imports from Brazil as an example.

Data available in WA		Data available in LCFS	2017 import volume by oil field (thousand bbl per year)	Carbon intensity	Carbon intensity in WA	
2017 total volume imported from Brazil	5,855 thousand bbl per year	Brazil – Iracema (Cernambi)	3,457.3	5.54	Brazil	5.86
		Brazil – Lula	7,652	6.24	Weighted average based on oil field volume and CI in LCFS	
		Brazil – Ostra	1,608.7	5.65		
		Brazil – Peregrino	600.4	4.16		
		Brazil – Polvo	298.9	4.31		

An alternative approach when lacking the actual oil field volumetric data is to match fuels to CI's based on oil properties. For example, the Crude Imports dataset from EIA differentiates the import volume from each country into five crude oil grades: light sweet, light sour, medium, heavy sweet, and heavy sour.[4] The categorization of light vs heavy is based on the oil's API gravity number. The higher API, the lighter the oil. The categorization of sour vs sweet is based on the sulphur content in the oil. High sulphur means sour and low means sweet. Other datasets on crude oil might provide oil categorization for oil fields that are on the LCFS list and relevant for WA, or might provide the oil property information (i.e., API and sulphur content) on oil fields, such as the one from Eurostat.[5] By matching the oil fields with the import volume by oil grade from EIA, the oil field CI values can be weight-averaged based on WA specific volume information rather than California's information. Table 3 illustrates this alternative approach, again using oils from Brazil as an example. In this alternative approach, only oils from Iracema, Lula, and Peregrino oil fields are taken into account for CI fitting, as these are the ones that match with the imports information from EIA. The new CI of Brazil's oil into WA is thus estimated to be 5.76, compared to 5.86 per currently used approach—a minor difference. This alternative approach might be able to estimate country or state level crude oil CI values that are more representative of the cases in WA. Nonetheless, neither the currently adopted approach nor the proposed alternative approach can provide truly accurate field-level crude oil CIs for WA. In the longer term, particularly if a crude oil carbon intensity is revaluated later on in the lifetime of the CFP, WA could consider implementing a reporting system to track imports by oil field to develop more accurate crude oil CI's for the CFP.

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[4] https://www.eia.gov/petroleum/imports/browser/#/?d=000004000480&dt=RS&e=2021&f=a&gg=i&o=0000000000000000000000000000&od=d&ot=CTY&s=2017&vs=PET_IMPORTS.CTY_AO-RS_WA-LSW.A

[5] https://ec.europa.eu/eurostat/documents/38154/42198/ESTAT-ENERGY-COIR-July-2020.xlsx/ff082ff5-918b-0d3a-21d7-18550f1ed49d

Table 2. An alternative approach to fit crude oil CI from LCFS into Washington, using oil imports from Brazil as an example.

2017 import volume by oil grade from EIA (thousand bbl per year)			Oil grade produced by oil field	Carbon intensity from LCFS	Fitted carbon intensity of Brazil's oil for WA	
Brazil – heavy sour	818	Brazil – Iracema (Cernambi)	Medium	5.54	Current approach	Alternative approach
Brazil – medium	5037	Brazil – Lula	Medium sweet	6.24	5.86	5.76
		Brazil – Ostra	Heavy sweet	5.65		
		Brazil – Peregrino	Heavy sour	4.16	Weighted average based on oil field volume and CI in LCFS	Weighted average based on WA's imported oil grade volume and CI in LCFS
		Brazil – Polvo	API of 20 but no information on sulphur content (i.e., heavy but unknow sweet or sour)	4.31		

The LCFS crude oil CI list does not provide information for oils imported from Brunei and Papua New Guinea, while the two countries make up 0.5% of the oil imports in WA. Therefore, these two countries, thus their oil volumes, are completely omitted when calculating the WA state average crude oil CI from different origins. In other words, the weighted average CI is calculated based on the remaining 99.5% alone. Because the contribution of petroleum of these two countries is a small share of the total, the current approach likely only makes a minor impact on the final crude oil CI. However, for comprehensiveness, a literature review on crude oil CI in these two countries could be conducted. For example, one previous study that used OPGEE 2.0 to estimate country level crude oil CI estimates emissions from crude oil produced from these two countries.[6] Alternatively, an OPGEE assessment could be developed to estimate the CI for crude oil produced in these two regions.

Regarding crude oil CIs for Montana and Utah, the supplemental documentation does not provide the data source for the CI of crude oil produced in Wyoming, which is used when calculating the weighted average CI for both Montana and Utah. Although the spreadsheet indicated that CI value is from OPGEE, it is hard-coded and not shown in the LCFS's CI list in the spreadsheet. It is also not clear regarding how to get the simple averaged CI value of all Utah sources of crude oil, which is used when calculating the weighted average CI for Utah. The LCFS's CI list in the spreadsheet only provides one single CI value for Utah, which is 6.92 and differs from the hard-coded average Utah-sourced crude oil CI, which is 6.03. We recommend updating the supplemental documentation to provide additional information on crude oil CI sourced from Wyoming and Utah.

Crude oil produced in Montana contributes to less than 2% of the crude oil refined in Montana. However, there is not a corresponding CI estimate for Montana crude oil in California's LCFS data. Therefore, this source is omitted when calculating the weighted average CI in Montana. This omission has a minor impact, as the share of Montana-sourced oil is only approximately 0.1% of WA crude oil consumption, based on the assumption that Montana supplies 6% of

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[6] https://www.science.org/doi/10.1126/science.aar6859

Washington's petroleum. For comprehensiveness, the OPGEE model could be used to estimate a carbon intensity for crude oil extracted in Montana.

Crude oil transportation emissions

The crude oil CI's developed by CARB include emissions during crude oil transportation using a variety of modes. However, these emissions are applicable for oils imported to California, while the transportation distance of oils from the same origin to California and to WA are necessarily different distances thus it is necessary to adjust the CIs. To summarize the approach used to adjust transportation distances, the emissions for the distribution of crude oil are estimated by multiplying the transport distance for the crude oil by a mode-specific (cargo ship, rail, or pipeline) emission factor for transportation. Depending on the source of crude oil, these adjustments either increase or decrease the transportation emissions for that crude oil, based on the oil field's distance to Los Angeles vs. Seattle. If the distance from the crude oil source to Seattle is shorter, the emissions are reduced, whereas if it is further, the transportation emissions increase.

Though the methodology used to adjust transport distances for crude oils is sound, we recommend additional detail to document the approach in the supplementary documentation. Additional detail is necessary regarding the transportation of oils from Canada. The OPGEE2.0 assumed oils from Canada to be first transmitted through pipeline from Edmonton to Vancouver, which are then transported to the Los Angeles, California through vessel. In the case of Canadian oils to WA, the pipeline transmission from Edmonton to Vancouver would remain, while the needed distance adjustment is switching from vessel transport between Vancouver and LA to vessel or pipeline or rail transport between Vancouver and Seattle. However, such a description is not well documented in the spreadsheet, nor in the supplementary, which could lead to confusions and misinterpretations.

Currently, there is no distance adjustment for crude oils used in Montana and Utah. This means the California's OPGEE2.0 CI values are used directly. However, better estimates could be done for the oils in these two states. For Montana, it only needs to consider crude oil transported from Wyoming and Canada. First, a search on whether there was oil pipeline in 2017 between Wyoming and Montana. If no pipeline, then rail transport is highly likely and locations of oil refineries in Montana and locations of oil fields in Wyoming could be identified for an estimate of rail transport distance between the two states. The transport from Wyoming to California is likely found from the OPGEE dataset that is being used for the CI of oil sourced from Wyoming. Based on these sets of information, a distance adjustment for oils from Wyoming could be done. Regarding the adjustments for oils from Canada, it is likely to have rail transport from Canada to Montana, as in 2017, there appeared to be no existing pipeline between western Canada and Montana, according to the 2017 CAPP report.[7] A similar distance adjustment approach could be taken per rail transport from Canada to WA.

For Utah, the state report that provided volume information also specified pipeline imports of oils from Colorado, Wyoming, and Canada. Therefore, pipeline distance adjustment for the three origins could be conducted following similar approaches as for WA adjustments. We

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[7] http://www.oscaalberta.ca/wp-content/uploads/2017/06/CAPP-2017-Crude-Oil-Forecast.pdf

recommend that LC Associates incorporate transport distance adjustments for crude oils refined in Montana and Utah, consistent with the updates for crude oils refined in Washington.

The WA's crude oil carbon intensity analysis spreadsheet notes that emission factors for crude oil by transportation mode are retrieved from OPGEE 2.0 but does not explain how these emission factors differ from CA-GREET 3.0. Using emission factors from OPGEE 2.0 is internally consistent with the approach to calculate upstream crude oil emissions within OPGEE 2.0.[8] To better understand the impact of this choice, Table 4 compares the emission factors of different transportation modes in WA's crude oil calculation spreadsheet (sourced from OPGEE 2.0) and WA-GREET. Using the emission factors from WA-GREET in place of OPGEE would change the average crude oil CI in WA from 12.57 gCO2e/MJ to 12.63 gCO2e/MJ, a 0.6% difference.

Table 3. Transportation emissions factors in OPGEE 2.0 and WA-GREET

Transportation mode	**WA crude oil carbon intensity analysis spreadsheet (sourced from OPGEE 2.0)**		**WA-GREET**		**Percentage difference**
	g/MMBtu-mi	g/MJ-mi	gCO_2e/MMBtu-mi	gCO_2e/MJ-mi	
Ocean tank	0.124	0.00012	0.204395	0.000194	65%
Barge	1.696	0.00161	0.60723	0.000576	-64%
Pipeline	0.49	0.00046	1.85608	0.001759	279%
Rail	1.252	0.00119	0.738804	0.0007	-41%
Truck	4.257	0.00404	3.400397	0.003223	-20%

Refining carbon intensity

The weighted-average crude oil CI in each of WA, Montana, and Utah is then used to estimate the CI of petroleum products, particularly gasoline, diesel, and jet fuel, that are produced within the three states. Ultimately, the CI of each petroleum product is weighted by volume share of the three states for a WA average CI. These weight-average CIs serve as the baselines for policy targets of GHG emission reductions. The estimation of petroleum CI depends largely on refinery assumptions. Particularly, previous studies found that the properties of crude oil, the configuration of the refinery, as well as the finished product slate all affect the energy intensity and the consequent GHG emissions from petroleum production.[9]

The upstream emissions for the weighted crude average mix are combined with refinery and combustion emissions to develop a well-to-wake emission factor for gasoline, diesel, and jet fuel in the "Petroleum" tab in WA-GREET. In the current approach, for gasoline and low-sulfur diesel in WA, the refining assumptions, such as the energy efficiency and share of process fuels, are

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[8] We note that it would be helpful to clarify the unit of emission factors in the spreadsheet if it is grams of CO_2 equivalent (it is currently g/MMBtu/mi)

[9] https://pubs.acs.org/doi/full/10.1021/es5010347

using the U.S. average values. Comparing these assumed values to CA-GREET 3.0, the gasoline assumptions are different, while the assumptions for low-sulfur diesel are the same.

The refinery assumptions for each type of the petroleum product are estimated using the methodology by Elgowainy et al. (2014).[10] Specifically, an overall energy efficiency at the refinery level is first estimated. This efficiency is then adjusted for each petroleum product through energy allocation based on the energy intensity of the process units and their contributions to the product yields, for example, fluid catalytic cracking, catalytic reformer, hydrocracker, and alkylation units that contribute to gasoline. Similarly, the process fuel is also energy-allocated among products at the process unit level. Through this process, the product-specific energy efficiency and process energy can be derived with a production-weighted average.

To understand whether using U.S. average or California's assumptions are comparable for the refineries in WA, we collect the refinery capacity information in WA, California, and the U.S. from EIA, shown in Table 5.[11] Though we do not have detailed information on the refinery configurations for Washington's refineries, we draw upon EIA data to on the installed capacity by volume to infer its average configuration. The comparison of refinery capacity between Washington, California illustrated in Table 5 suggests that WA and California have similar profile for refinery operations; these values are also close to the U.S. average. Therefore, using California's or U.S. average assumptions for refining parameters likely yield a similar estimate. We note that the underlying assumptions and calculations of the petroleum CI values in Montana and Utah are also not included in WA-GREET and these values are instead hard-coded in the petroleum sheet. We therefore recommend that these calculations are included within the model for transparency.

Table 4. Refinery Capacity in Washington, California, and the United States in 2017

Refinery type breakdown (vol%)	Washington	California	U.S. average
Vacuum distillation	24%	22%	21%
Thermal cracking	7%	9%	7%
Catalytic cracking – Fresh	12%	13%	14%
Catalytic cracking – Recycled	0.2%	0.3%	0.2%
Catalytic hydro-cracking	5%	9%	6%
Catalytic reforming	12%	7%	9%
Hydrotreating/ Desulfurization	38%	39%	42%
Fuels solvent deasphalting	2%	1%	1%

Although we find that LC Associates' current approach largely aligns with existing practices in California, we note that transparency and accuracy of the crude oil CI could be improved through a dedicated refinery LCA. Concurrent with our recommendation for use of OPGEE to assess the LCA emissions for the specific crude oils used in Washington, a dedicated refinery LCA model could be used to assess the emissions attributable to petroleum products in

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[10] https://pubs.acs.org/doi/full/10.1021/es5010347#notes-1
[11] https://www.eia.gov/dnav/pet/pet_pnp_cap1_dcu_nus_a.htm

Washington specifically. For example, the open-source Petroleum Refinery Life Cycle Inventory Model (PRELIM) model could be used to combine fine resolution data on imported crudes with in-state refinery specifications.[12] In the long run, particularly if the fossil fuel baseline for petroleum fuels is subject to revision, this level of additional analysis could enhance the accuracy of the fossil fuel baseline emissions estimates.

Inclusion of fossil jet fuel

We first note that the draft CFP rule does not obligate conventional fossil aviation fuel as a deficit generating fuel and these fuels are except from the program. However, the draft rule does specify that alternative jet fuels are to be compared to benchmarks established within the program—though it does not specify a benchmark value for conventional jet fuel. The draft WA-GREET model developed by LC Associates includes a separate fossil jet fuel baseline estimated for the WA crude oil mix of 89.98 gCO_2e/MJ.

The estimated fossil jet fuel baseline is calculated by inputting the previously-derived WA upstream crude oil upstream CI and calculating downstream emissions on a consistent basis with the calculations in CA-GREET 3.0. The input assumes a WA-only crude mix, and does not take into account domestic imports from Utah and Montana, which had been done for diesel and gasoline. We note there is no documentation to describe the approach to estimating the refinery emissions attributable to jet fuel; this value appears to be based on the existing CA-GREET 3.0 analysis, changing the source of crude oil. Table 6 summarizes the differences in key assumptions for jet fuel between U.S. average and WA-GREET.

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[12] https://www.ucalgary.ca/energy-technology-assessment/open-source-models/prelim

Table 5. Differences in refinery assumptions for jet fuel between GREET 2021 and WA-GREET

	Jet fuel	
	WA-GREET (sourced from CA-GREET 3.0)	**GREET 2021**
Energy efficiency	94.9%	95.4%
Share of residual oil	22%	25.1%
Share of natural gas	71.8%	60.1%
Share of electricity	4.1%	4%
Share of hydrogen	1.7%	10.7%
Share of butane	NA	
Share of blendstock	NA	
Share of N-butane	0.27%	0.1%
Share of GTL	0.09%	0%

Though fossil jet fuel is not obligated in the CFP, we recommend the inclusion of a fossil jet baseline in the policy, as jet fuel has meaningfully different WtW emissions from road fuels. In practice, this means that displacing jet fuel has different climate outcomes than displacing diesel or gasoline, as it is estimated to have approximately 10gCO_2e/MJ lower WtW emissions than either road fuel. The WA-GREET emissions estimate for fossil jet is consistent with estimates of the jet WtW emissions conducted for California's LCFS (89.37 gCO_2e/MJ) and the international Civil Aviation Organization (89 gCO_2e/MJ).[13] Therefore, we recommend that the WA-GREET benchmark for fossil jet fuel is included within the WA CFP similar to the inclusion of a fossil jet fuel baseline for the opt-in aviation fuel pathway within the California LCFS, so as to ensure the accurate crediting of alternative aviation fuels. As in California, though the benchmarks for different fossil fuels would start at different levels, they would converge over the lifetime of the program as the overall CI target declines. Further, we recommend that the documentation is updated to reflect the methodology used to calculate the upstream refining emissions for WA jet fuel, as well as to ensure consistency with the methodology to calculate the crude oil mix and refinery emissions of road fuels in the program.

Electricity Grid Carbon Intensity

One of the major changes necessary to adapt the GREET life-cycle model used for California's LCFS to Washington is to model the electricity grid carbon intensity of Washington. This change is not only used directly to estimate emissions from electric vehicle charging, but also to

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[13] https://www.sciencedirect.com/science/article/pii/S1364032121006833

estimate the emissions for other fuels pathways that utilize electricity as an input. In general, LC Associates follows much of the same methodology as CARB does for California to estimate the average state-wide emissions intensity for Washington's electricity grid. The largest change in methodology is the introduction of a new grid electricity region integrated into the model, labeled WAMX, that represents the average electricity mix of electricity produced and consumed in Washington. This electricity mix is derived from a disclosure report published by the WA Department of Commerce (herein referred to as "Commerce") for the year 2018.[14] In 2018, hydropower made up the largest share of reported electricity production (59%) followed by coal (10%) and natural gas (7%). That year, a significant share of electricity was also attributed to "unspecified" sources defined as "electricity obtained in a transaction where the seller does not identify a specific generating source" (p. 3).[15] LC Associates does not document the rationale for selecting the 2018 electricity data rather than the most recently published (2020) or baseline year (2017) electricity mix assumptions.

In the WA-GREET model, electricity mix shares reported in percentages are combined with life-cycle emission factors reported in grams of carbon dioxide equivalent (CO_2e) per kilowatt-hour of electricity to estimate the GHG emissions associated with producing a unit of electricity. To integrate WA fuel mix assumptions into the GREET model, LC Associates allocated electricity production data among fuel sources that already have an existing emission factor in GREET. This includes allocating "landfill gas", and "unspecified" electricity toward the natural gas category and "waste" (i.e., waste-to-energy) and "other biogenic" electricity toward the residual oil category. Together, these sources comprise 13.2% of the WA electricity mix. The results of this reallocation in percentage fuel shares delivered to WA state end-users are presented in Table 7.

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[14] Greg Nothstein and Michael Furze, "Washington State Electric Utility Fuel Mix Disclosure Reports for Calendar Year 2018" (Washington State Department of Commerce, November 7, 2019).

[15] Ibid

Table 6. Average fuel mix delivered to WA state end-users

Source	2018 WA fuel mix (Commerce)	Reallocated WA fuel mix (LC Associates)
Hydro	59.16%	59.16%
Unspecified	12.93%	N/A
Coal	10.22%	10.22%
Natural Gas	7.33%	20.46%
Nuclear	4.75%	4.75%
Wind	4.58%	4.58%
Solar	0.28%	0.28%
Biomass	0.45%	0.45%
Biogas (landfill gas)	0.20%	N/A
Other Biogenic	0.05%	N/A
Waste	0.04%	N/A
Petroleum	0.02%	0.10%
Geothermal	0.004%	0.004%

We recommend that LC Associates update the model assumptions for two reasons:
1) estimated fuel mix shares in the reallocated scenario do not align with historical data and
2) LC Associates' reallocation methodology is not consistent with methodology previously adopted by Commerce to assign fuel mix shares to "unspecified" electricity generation. We further recommend that LC Associates could further refine their allocation shares by modifying the GREET model to include emission factors for landfill gas and incinerated waste electricity.

Because unspecified electricity is the second largest source of electricity in the original grid mix, the decision to allocate it all to natural gas is potentially significant; the result is a sharp increase in the assumed share of natural gas in the electricity grid. In energy terms, Commerce estimated that the quantity of natural gas electricity delivered to Washington end-users in 2018 was 6.86 TWh while LCA estimated that this value increases to 19.14 TWh following reallocation. To measure the annual state fuel mix, Commerce obtains documents from the Energy Information Authority (EIA) and Environmental Protection Agency (EPA) to aggregate electricity produced at specific generation facilities in addition to data on "unspecified power purchases" for which the electricity source is unknown. Until 2019, Commerce was statutorily required to assign fuel shares to unspecified power generation consistent with methodology outlined in 19.29A.060 RCW Section 4.[16] Section 4 directs electricity retail suppliers to allocate "unspecified" power purchases among generation sources based on the grid makeup of the bulk power market, the Northwest Power Pool. More specifically, retail suppliers are directed to

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[16] Washington State 56th Legislature, "Electricity Products - Fuel Mix Disclosure," Pub. L. No. RCW 19.29A.060, § 4, Chapter 213 (2000), https://lawfilesext.leg.wa.gov/biennium/1999-00/Pdf/Bills/Session%20Laws/House/2565.SL.pdf?cite=2000%20c%20213%20%C2%A7%204.

calculate their product fuel mix as the "weighted average of the megawatt-hours from declared resources and the megawatt-hours from the net system power mix for the previous calendar year according to the proportion of declared resources and net system power contained in the electricity product." In 2019, House Bill 1428 revoked this requirement and instead directed Commerce to report "unspecified" power as a separate category.[17] This bill change simplifies the reporting process and requires no product reallocation.

We compare disclosed natural gas production before House Bill 1428 was passed to natural gas production estimated between 2018-2020 using the reallocation methodology adopted by LCA (Figure 2). We find that between 2017-2018, generation estimates increased 86%, a sharp increase from previous trends. We review project data to confirm that no new natural gas capacity was built in the Northwest Power Pool market after 2017[18] to rule out the possibility that this upswing is attributed to new natural gas power capacity. However, because natural gas power plants can be easily dispatched, the quantity of natural gas electricity supplied to the grid can fluctuate year over year.

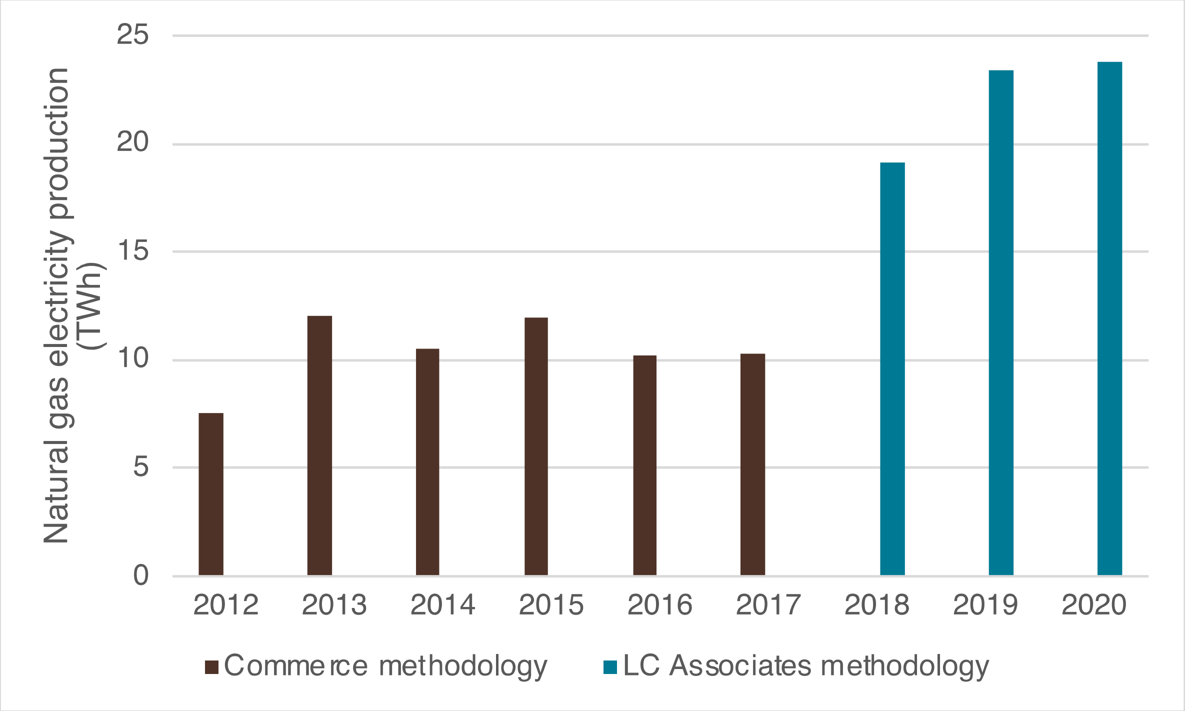

Figure 2: Estimated quantity of natural gas electricity delivered to WA state end-users (2012-2020)

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[17] Washington State 66th Legislature, "Electricity Product Attributes - Disclosure," Pub. L. No. RCW 19.29A.060, Chapter 222 15 (2019).

[18] Northwest Power and Conservation Council, "Map of Power Generation in the Northwest," accessed March 30, 2022, https://www.nwcouncil.org/energy/energy-topics/power-supply/map-of-power-generation-in-the-northwest/.

LC Associates' allocation methodology is a coarser approach than the methodology adopted by Commerce and assumes that all undeclared electricity is sourced from natural gas power plants. Presumably, this is because unspecified power purchases are typically made via short-term transactions in bulk power markets when localized electricity generators cannot meet real-time energy demand.[19] Although natural gas "peaker" plants are dispatchable and commonly used for periods of high electricity demand, they are not the only power generation source used for this purpose. An economic dispatch curve of electricity generated within the Western Interconnection region indicates that biomass units are the most likely to be sourced from during periods of maximum demand, followed by natural gas, and coal generating units.[20] Hydroelectric power can also be dispatched very quickly to meet excess electricity demand.[21] Renewable energy generation sources may also be a source of unspecified power; however, since they typically bundled with a renewable electricity credit (REC), electricity generated at these facilities is less likely to be unclaimed.[22] Finally, unspecified power is not limited to spot market purchases; thus, any resource on the bulk power market may be drawn from for this fuel category.

We follow Commerce's previous allocation methodology to provide a more precise estimate of fuel mix allocation within Washington in 2018. We compare these results to the fuel mix estimated by LCA and the fuel mix estimated by Commerce in 2017 (Table 8). Using this methodology, the share of natural gas electricity in the grid mix drops from 20.5% to 10.4% and is more closely aligned with previous disclosure reports.[23] This re-allocation has a minor impact on the average electricity emissions, reducing them by approximately 6 gCO_2e/kWh.

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[19] Nothstein and Furze, "Washington State Electric Utility Fuel Mix Disclosure Reports for Calendar Year 2018."

[20] Alan Jenn, "Electricity Dispatch Model," UC Davis Plug-In Hybrid & Electric Vehicle Research Center, accessed March 31, 2022, https://phev.ucdavis.edu/project/electricity-dispatch-model/.

[21] U.S. Department of the Interior Bureau of Reclamation Power Resources Office, "Hydroelectric Power," July 2005, https://www.usbr.gov/power/edu/pamphlet.pdf.

[22] Michael Nyberg, "2019 Total System Electric Generation," California Energy Commission (California Energy Commission, current-date), https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation/2019.

[23] Nothstein and Furze, "Washington State Electric Utility Fuel Mix Disclosure Reports for Calendar Year 2018"; Greg Nothstein and Michael Furze, "Washington State Electric Utility Fuel Mix Disclosure Reports for Calendar Year 2017" (Washington State Department of Commerce, November 2018).

Table 7. Comparison of LC Associates and ICCT fuel allocation methodology

Source	2017 Electricity Mix (Commerce)	2018 Electricity Mix (LC Associates)	2018 Electricity Mix (ICCT)
Hydro	67.7%	59.2%	64.8%
Unspecified	0.0%	N/A	-
Coal	13.4%	10.2%	13.6%
Natural Gas	10.8%	20.5%	10.4%
Nuclear	4.2%	4.8%	5.1%
Wind	2.8%	4.6%	4.6%
Solar	0.0%	0.3%	0.3%
Biomass	0.6%	0.5%	0.7%
Biogas (landfill gas)	0.1%	N/A	0.2%
Other Biogenic	0.0%	N/A	0.05%
Waste	0.2%	N/A	0.04%
Petroleum	0.1%	0.1%	0.19%
Geothermal	0.0%	0.0%	0.004%

Emission factor assumptions for secondary generation pathways

Because the fuel mix categorization listed in annual Commerce reports is not directly translatable to the GREET model, LC Associates assigned all unspecified power purchases toward resources with existing emission factors (EFs) in GREET. This includes attributing natural gas emissions to landfill gas electricity generation and residual oil emissions to the "other biogenic", "petroleum", and "waste" electricity categories. All other generation sources (together comprising 64% of the total grid mix) are lumped within an "other" fuel category and assigned an emission factor of 0.0034 gCO2e/MJ. This small quantity of emissions is attributed to fugitive carbon dioxide emissions from geothermal power plants.[24] Although LC Associates did not explicitly state their reasoning in supporting documentation, these allocations are presumably based on the assumption that landfill gas has similar emission factors to natural gas and other biogenic, petroleum and WTE have similar emission factors to the residual oil electricity pathway. We review the literature and find that there are significant differences among life-cycle EFs for the waste-to-energy and residual oil pathways and smaller differences among the EFs for landfill gas and natural gas.

Producing electricity from the incineration of waste (i.e., waste-to-energy [WTE]) is common practice in urban areas. Within Washington, the Spokane Waste-to-Energy Plant provides a

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[24] J. L. Sullivan et al., "Life-Cycle Analysis Results of Geothermal Systems in Comparison to Other Power Systems.," October 11, 2010, https://doi.org/10.2172/993694.

small share of electricity to the grid region managed by Avista utilities.[25] Avista does not publicly disclose facility-specific electricity data; however, its overall resource mix indicates that its percentage production share is less than 1%.[26] The other commercial WTE facility located within the NWPP is in Marion County, Oregon. The life-cycle emissions impact of incinerating waste is largely dependent upon its material composition, specifically its energy-weighted share of biogenic waste. The combustion emissions of the biogenic share of waste are typically treated as zero whereas the non-biogenic portion (e.g. plastics) have a carbon intensity that is comparable to petroleum-based products. ECY reports that 99.9% of incinerated waste at the Spokane facility is classified as municipal/commercial and the remainder as "medical waste" and "special waste".[27] Further, a recent survey of the state's municipal solid waste (MSW) stream found that approximately 53% of the post-recycle waste stream is composed of organic material. As recycling practices improve over time, we expect that the biogenic share of MSW will increase, followed by a decrease in its associated electricity EF.

Pfadt-Trilling et al. conducted a life-cycle analysis of electricity generated via MSW incineration using data from a WTE facility located in New York. [28] This study used a system expansion approach that quantified avoided emissions relative to a business-as-usual case scenario. Pfadt-Trilling found that the WTE electricity pathway has an emission factor (EF) of 0.082 kg CO_2e/kWh when system expansion is used and an EF of 0.775 kg CO_2e/kWh when avoided emissions are unaccounted for. We convert these factors to gCO2e/MJ assuming a calorific value of 10 MJ/kg for MSW[29] and conversion efficiency of 0.693 kWh per kg of MSW incinerated taken directly from the life-cycle study. The converted EFs range between 5.7 and 53.7 gCO2e/MJ. For comparison, the WA-GREET model reports an EF of 80.9 gCO_2e/MJ for electricity produced from residual oil. Thus, LC Associates' assumption that incinerated waste electricity has an EF equivalent to electricity derived from residual oil is likely to vastly overstate this pathway's emissions impact.

Like Pfadt-Trilling, ECY could conduct a case-specific analysis of the Spokane WTE facility to estimate an EF for "waste" electricity to be incorporated into the WA-GREET model. For WTE produced at other facilities on the bulk power market, a regional average emissions factor may be more appropriate. Washington has a higher recycling rate than New York state, so we would expect the case-specific EF to be higher than the Pfadt-Trilling et al. study. In that study, the authors assume a waste composition of 60% biomass and 40% non-biomass materials in the waste stream, relative to the 53% biogenic waste share measured by ECY.

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[25] "Waste to Energy Plant," Spokane City, March 31, 2022, https://my.spokanecity.org/solidwaste/waste-to-energy/.

[26] Avista utilities, "About Our Energy Mix," accessed March 31, 2022, https://www.myavista.com/about-us/about-our-energy-mix.

[27] Washington State Department of Ecology, "Solid Waste & Recycling Data," 2022, https://ecology.wa.gov/Research-Data/Data-resources/Solid-waste-recycling-data.

[28] Alyssa R. Pfadt-Trilling, Timothy A. Volk, and Marie-Odile P. Fortier, "Climate Change Impacts of Electricity Generated at a Waste-to-Energy Facility," Environmental Science & Technology 55, no. 3 (February 2, 2021): 1436–45, https://doi.org/10.1021/acs.est.0c03477.

[29] IEA Bioenergy, "Municipal Solid Waste and Its Role in Sustainability," 2003, https://www.ieabioenergy.com/wp-content/uploads/2013/10/40_IEAPositionPaperMSW.pdf.

We also review the EF of landfill gas-generated electricity relative to the EF of natural gas. WA-GREET already includes CI's for electricity combusted from biogas, which has a higher methane content and heating value than landfill gas. Landfill gas can be cleaned and upgraded into biogas that is burned in reciprocating engines. Thus, we determine that the EF for biogas electricity reported in GREET (65.96 gCO2e/MJ) is appropriate to adopt for landfill gas-generated electricity. This value is roughly 17% higher than the EF estimated for utility-scale natural gas. For natural gas burned in stationary reciprocating engines, the EFs are nearly equivalent.

If new fuel categories for landfill gas and WTE were introduced in WA-GREET and the electricity mix shares were updated to align with Commerce's previous allocation methodology, this would change the emission factor for WAMX electricity by approximately 5.9 gCO2e/kWh (or about 3.1%). Because electricity only makes up a portion of life-cycle emissions for most fuels (with electric vehicle charging as a notable exception) and the shares of these sub-categories within the electricity mix are so low, these changes are minor to the CI estimates for most finished fuels. For example, the CI for tallow biodiesel decreases from 39.78 gCO2e/MJ in the default model to 39.76 gCO2e/MJ in the updated model, or a reduction of 0.05%. This change is slightly more apparent for corn ethanol where life-cycle emissions decrease by 0.12% between the default and updated models. For fuels produced outside of Washington, changes to the WAMX emission factor on a fuel's final CI are inconsequential. The inclusion of these pathways and correct attribution of emission factors in the model increases in relevance for its impact on the estimate of utility-specific electricity grid emissions, which may incorporate larger shares of some waste-derived electricity.

In summary, to improve the accuracy of the WAMX emission factor, we recommend that LC Associates 1) use more recent data, and 2) break out the "unspecified" electricity into sub-categories based on the methodology pursuant with 19.29A.060 RCW, and 3) match remaining sources of electricity emissions to more accurate, technology-specific emission factors either in GREET or in the literature. To streamline modifications to the model, fuel types can be assigned to an existing electricity category in GREET. This includes grouping landfill gas and incinerated waste within the "Others" electricity category and grouping non-biogenic electricity within the "Residual oil" electricity category. Consistent with Recommendation 3, we recommend that ECY also explore the model's capability to set path dependencies for attributes (e.g., water consumption, emission factors) from fuel sources such as landfill gas and incinerated waste not currently built into GREET. The latter changes would require a more in-depth set of modifications but improve the accuracy of final fuel pathway CI estimates, particularly for individual utilities.

Choice of GWP factors

Atmospheric scientists estimate the global warming potential (GWP) of greenhouse gases to standardize the climate-forcing potential of GHGs relative to carbon dioxide. GWP measures the amount of energy a mass unit of emissions will absorb over a specified period of time relative to the energy absorbed by carbon dioxide.[30] The Intergovernmental Panel on Climate Change (IPCC) regularly updates GWP measurements in Assessment Reports; GWP values are then later adopted by regulatory agencies. IPCC's GWP estimates are considered "best practice" for emissions modeling. The most recent Assessment Report (AR6) was released in late 2021,[31] preceded by AR5 in 2014 and AR4 in 2007.

GWP values from AR4 were selected for the CA-GREET 3.0 model; these values were then subsequently adopted for WA-GREET. CA-GREET 3.0 was developed in 2018 and based on underlying modeling assumptions from the 2016 ANL GREET model.[32] The GWP values used the reference model were already outdated, leading to a continuation of outdated assumptions over time. Over the last 15 years, the science on radiative forcing and indirect emissions effects of gases has evolved, especially regarding the short-term climate-forcing impacts of methane release. In AR6, scientists updated their estimates for the indirect chemical effects of methane and nitrous oxide emissions as well as revised their atmospheric lifetimes. These changes led to a slight reduction in GWP estimates from the previous report (AR5).[33] An overview of GWP values published by IPCC for 100-year warming periods is provided in Table 9, summarizing the estimates from AR4 through AR6.

Table 8. Global warming potential (GWP) of primary greenhouse gases across IPCC assessment reports

	GWP100		
Greenhouse gas	**AR4**	**AR5**	**AR6**
CO2	1	1	1
CH4	25	30	27.9
N2O	298	265	273

We recommend that LC Associates update WA-GREET to utilize AR5 GWP factors. This would serve to align ECY and the CFP with the latest climate science, but also align the program with updated reporting guidelines under the Paris Agreement that require the United States to shift to use of AR5 100-year GWP values (without feedbacks) for national inventory reporting in 2024.[34]

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[30] OAR US EPA, "Understanding Global Warming Potentials," Overviews and Factsheets, January 12, 2016, https://www.epa.gov/ghgemissions/understanding-global-warming-potentials.
[31] IPCC, "Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change" (Intergovernmental Panel on Climate Change, 2021), https://www.ipcc.ch/report/ar6/wg1/.
[32] CARB, "LCFS Life Cycle Analysis Models and Documentation," accessed April 5, 2022, https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation.
[33] IPCC, "Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change."
[34] https://unfccc.int/process-and-meetings/transparency-and-reporting/reporting-and-review-under-the-paris-agreement

This would also align WA-GREET with the forthcoming OPGEE 3.0 release, which will be transitioning to using AR5 GWP values.

Tier 1 Calculators

As part of this peer review, ICCT also reviewed a set of 8 “Tier 1” calculators developed for the WA CFP and based on the draft WA-GREET model. The purpose of these calculators is to provide a simplified method for fuel producers to input their facility-specific data to estimate their emissions in lieu of a detailed life-cycle assessment. These calculators comprise a set of well-characterized commercialized fuel pathways, and are based on a set of extracted emission factors and data from WA-GREET. As part of this peer review, ICCT assessed the Tier 1 emissions calculators for consistency with the base model and separately provided recommendations to LC Associates on small modifications to the Tier 1 calculators to address minor data transcription errors. Overall, we found that these calculators matched the calculations in WA-GREET and provided users sufficient flexibility to provide their own estimates of site-specific emissions for their fuels. Major changes to the life-cycle assessment methodologies of these pathways, such as the use of different chemicals with different upstream emissions intensities as discussed by one commenter, may warrant additional analysis and may require a Tier 2 application.[35]

Proposed indirect land-use change emission factors

Life Cycle Associates recommends that Washington Department of Ecology (ECY) adopts many of the ILUC values calculated in a 2014 study commissioned by the California Air Resources Board (CARB) for their Low Carbon Fuel Standard (LCFS) program.[36] These include the ILUC values for soy, canola, and palm bio- and renewable diesel (i.e., biomass-based diesel [BBD]), and sugarcane ethanol, Life Cycle Associates also recommends that ECY selects the ILUC value for corn ethanol adopted under the Oregon Clean Fuels Program (CFP) based on modeling by Argonne National Laboratory (ANL);[37] the report also recommends that ECY adopt an equivalent ILUC value for sorghum ethanol. For these two pathways, land-use change estimates calculated in the GTAP-BIO-ADV economic model are supplemented with the Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) emission factor model to estimate ILUC emissions, measured in grams of carbon dioxide equivalent per Megajoule (gCO_2e/MJ) of fuel. The ILUC value for corn ethanol adopted by Oregon is approximately 60% lower than the equivalent ILUC value adopted by California. Finally, LC Associates recommends

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[35] https://scs-public.s3-us-gov-west-1.amazonaws.com/env_production/oid100/did1008/pid_202037/assets/merged/f70sirb_document.pdf?v=2MT63WQUR

[36] Katrina Sideco, “Detailed Analysis for Indirect Land Use Change” (CARB, 2014).

[37] State of Oregon Department of Environmental Quality, “Notice of Proposed Rulemaking: Clean Fuels Program Electricity 2021 Rulemaking,” December 22, 2020, https://www.oregon.gov/deq/Regulations/rulemaking/RuleDocuments/CFPE2021Notice.pdf.

that ECY adopt a zero ILUC value for all cover crops, based on CARB's feedstock-specific determination for camelina BBD.[38]

Background

ILUC models provide an informed estimate of the net change in global land cover due to policy-driven biofuels demand. Researchers use ILUC models to identify how much and what type of land area is cleared in response to a unit increase in biofuel demand; modeling results are then paired with emission factor models to quantify the greenhouse gas (GHG) emissions impacts of clearing and cultivating that equivalent area of land. One drawback to ILUC models is that they are inherently uncertain and based on various input assumptions such as demand and supply elasticities and linkages across economic sectors (e.g., trade restrictions). Computable general equilibrium models such as GTAP model market effects across the entire economy, while partial equilibrium models model these linkages across the global agricultural and forestry sectors at a more granular level. General equilibrium models are wider in scope and have drawbacks in their ability to accurately model land as well as agricultural processes.[39] California and Oregon have adopted results from a version of the GTAP model (i.e., GTAP-BIO-ADV) in their LCFS and CFP programs while the U.S. EPA uses results from FAPRI-FASOM, a combination of two partial equilibrium models, for biofuels certified under the federal Renewable Fuel Standard (RFS) program. Other models, such as GLOBIOM and MIRAGE have been utilized by the European Commission and the International Civil Aviation Organization.

Both GTAP and CCLUB have been subject to significant critique from subject matter experts.[40] Some of these criticisms are based on the argument that input assumptions to the models are not reflective of real-world conditions across the global agriculture and forestry sectors. In other cases, analysts find that the underlying datasets making up the foundation of these models are not comprehensive, or that modifications made over time are not well substantiated. We

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[38] Global Clean Eenrgy Holdings, Inc., "CARB Issues First-Of-Its-Kind LCFS Pathway for Sustainable Oils' Patented Camelina," GlobeNewswire News Room, February 5, 2015, https://www.globenewswire.com/news-release/2015/02/05/703358/12627/en/CARB-Issues-First-Of-Its-Kind-LCFS-Pathway-for-Sustainable-Oils-Patented-Camelina.html.

[39] Ehsanreza Sajedinia and Wallace E. Tyner, "Use of General Equilibrium Models in Evaluating Biofuels Policies," in World Scientific Studies in International Economics, by Peter Dixon, Joseph Francois, and Dominique van der Mensbrugghe, vol. 76 (WORLD SCIENTIFIC, 2021), 437–65, https://doi.org/10.1142/9789811233630_0014.

[40] Stephanie Searle, "Don't Throw out California's ILUC Factors Yet," ICCT Staff Blog (blog), March 9, 2018, https://theicct.org/dont-throw-out-californias-iluc-factors-yet/; Chris Malins, Richard Plevin, and Robert Edwards, "How Robust Are Reductions in Modeled Estimates from GTAP-BIO of the Indirect Land Use Change Induced by Conventional Biofuels?," Journal of Cleaner Production 258 (June 10, 2020): 120716, https://doi.org/10.1016/j.jclepro.2020.120716; Stephanie Searle and Chris Malins, "A Critique of Soil Carbon Assumptions Used in ILUC Modeling" (Washington, D.C.: International Council on Clean Transportation, June 13, 2016), https://theicct.org/publication/a-critique-of-soil-carbon-assumptions-used-in-iluc-modeling/. Comment on 'Carbon intensity of corn ethanol in the United States: state of the science', https://iopscience.iop.org/article/10.1088/1748-9326/ac2e35

summarize these critiques and provide recommendations for addressing these concerns within ECY's CFP program in the discussion below.

Limitations of CCLUB

CCLUB is an emissions factor model developed by ANL that can translate land use change (LUC) estimates reported in hectares for various types of land into GHG emissions reported in tonnes.[41] CCLUB uses emission factors from the CENTURY and COLE soil and forest biomass models as the default emission factors for the U.S., and emission factors calculated by Winrock et al. for the rest of the world.[42] The Winrock emission factor model was developed for U.S. EPA for its ILUC modeling for the Renewable Fuel Standard program. In contrast, California developed the AEZ-EF emissions factor model for use in its ILUC modeling.

Our assessment finds that CCLUB takes scientific liberties in its modeling of soil carbon changes and that its development process was far less transparent than the AEZ-EF model adopted by CARB. One of the major concerns with CCLUB is that the predicted change in soil carbon for certain land types modeled in CENTURY (part of CCLUB's modeling framework) contrast sharply with results from other emission factor models. Here, we delve into CCLUB's modeling of "cropland pasture", or land that has previously been cropped but is currently in a pasture state. Cropland pasture is not a standard land category in global land-use datasets; thus, measuring the impacts of cropping expansion onto this land type can be difficult to accurately quantify. The distinction between cropland and pasture is important, as soil can rebuild carbon stocks when it is left as pasture compared with soil carbon stock depletion during the conversion of pasture to cropland.

Malins et al. visualize how different emission factor models predict a change in soil carbon stocks following cropland pasture conversion, as shown below in Figure 3.[43] While Winrock et al. and the AEZ-EF model predict that the conversion of cropland-pasture to corn and soybean cropping results in soil carbon loss, the CENTURY model predicts the opposite effect – an increase in soil carbon.[44]

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[41] Jennifer B. Dunn et al., "Carbon Calculator for Land Use Change from Biofuels Production (CCLUB)," September 1, 2018, https://doi.org/10.2172/1480518.
[42] Dunn et al.
[43] Figure 6. Malins, Plevin, and Edwards, "How Robust Are Reductions in Modeled Estimates from GTAP-BIO of the Indirect Land Use Change Induced by Conventional Biofuels?"
[44] Figure 6. Malins, Plevin, and Edwards.

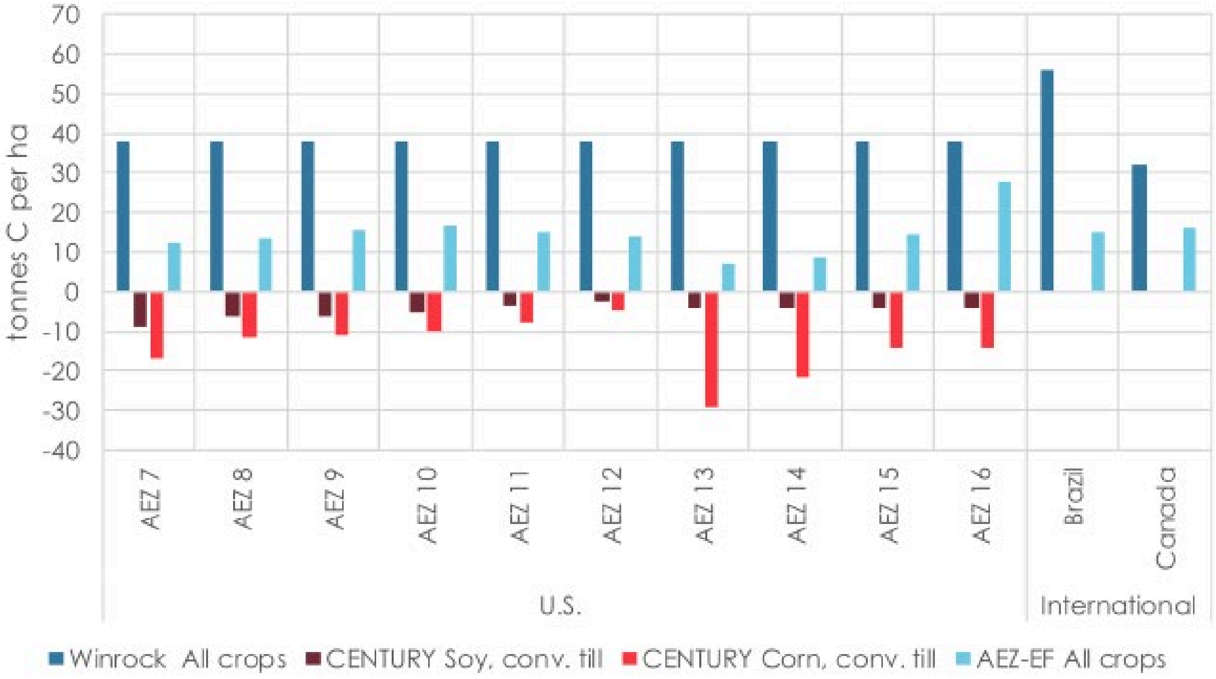

Figure 3: Carbon loss following cropland pasture conversion using Winrock, CENTURY and AEZ-EF emission factor models.

Reproduced from Malins et al. (2020).

One factor contributing to this counterintuitive finding is that CCLUB uses a very different interpretation of the "cropland-pasture" category than what is used in official statistics. The official definition of cropland-pasture in the United States Department of Agriculture's glossary is: "Cropland pasture—Generally is considered to be in long-term crop rotation. This category includes acres of crops hogged or grazed but not harvested and some land used for pasture that could have been cropped without additional improvement. Cropland pastured before or after crops were harvested was included as harvested cropland and not cropland pasture."[45] It is thus clear that cropland-pasture should currently be in a pastured state and not actively cropped. However, the CENTURY soil carbon stock values used in CCLUB are derived assuming cropland-pasture was in a cropped state for 35 years prior to conversion to corn production. This distinction is important; it is well-established in the scientific literature that the conversion of pasture results in large soil carbon losses while the conversion of cropland to corn is not a change in land use status at all. In a meta-analysis including 74 studies on the LUC effects on soil carbon stocks, Guo and Gifford estimate a 60% reduction in soil organic carbon (SOC) content from the conversion of pasture to cropland.[46] When CCLUB assumes cropland-

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[45] USDA ERS, "Major Land Uses - Glossary," accessed April 5, 2022, https://www.ers.usda.gov/data-products/major-land-uses/glossary/.
[46] L. B. Guo and R. M. Gifford, "Soil Carbon Stocks and Land Use Change: A Meta Analysis: SOIL CARBON STOCKS and LAND USE CHANGE," Global Change Biology 8, no. 4 (April 2002): 345–60, https://doi.org/10.1046/j.1354-1013.2002.00486.x.

pasture has been cropped for the past 35 years, it very likely is modeling the same level of soil carbon stocks that can be expected on permanent cropland, since soil carbon changes generally equilibrate within 10 or 20 years following land conversion.[47] Thus, while it is clear from USDA's definition that the conversion of cropland-pasture to cropland resembles the conversion of regular pasture – and thus can be expected to result in large soil carbon losses – by assuming cropland-pasture is actually cropland instead of pasture, CCLUB omits this carbon loss term entirely, and unjustifiably.

Another contributing factor to the strange result of soil carbon gains upon conversion of cropland-pasture to corn in CCLUB is a misinterpretation of the scientific literature. CCLUB uses inputs on soil carbon responses from a meta-analysis conducted by Qin et al.[48] This analysis has been previously critiqued.[49] In that critique, we found that Qin et al. misinterpreted the soil carbon literature in three ways. Firstly, Qin et al. took results from scientific studies measuring changes in soil carbon on cropland over time (i.e., land that has not been converted from cropland-pasture but has been cropland all along) and applied it to the conversion of cropland-pasture to corn. Secondly, the scientific studies cited in Qin et al., when aggregated, clearly show that soil carbon increases over time in corn/soy rotations but declines over time in continuous corn fields. Qin et al. combined the results from continuous corn and corn/soy rotations and applied the resulting soil carbon increase specifically to the conversion of cropland-pasture to continuous corn. Thirdly, we found that the linear regression used in Qin et al. was heavily influenced by a large number of data points from short-term studies finding soil carbon increases, while those from long-term studies indicated a soil carbon loss over time. Soil carbon is notoriously difficult to measure with high measurement error, and measurements of long-term soil carbon changes are much more reliable than those of short-term changes. In conclusion, CCLUB's prediction of a net soil carbon increase from converting a hectare of cropland pasture to hectare of corn production results from inappropriate and incorrect interpretations of statistics and the scientific literature.

One alternative to CCLUB is the AEZ-EF model developed for the California LCFS.[50] AEZ-EF is a user-friendly model available in Excel. AEZ-EF contains thorough documentation and a clear set of assumptions that can be traced back to the scientific literature. Although AEZ-EF is a simpler model than CCLUB, its underlying assumptions are more consistent with the scientific literature. For example, while CCLUB calculates an increase in SOC from the conversion of cropland pasture to corn, AEZ-EF calculates cropland pasture conversion as the average of the SOC change between cropland conversion and pasture conversion, resulting in a net SOC loss.

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[47] Danuse Murty et al., "Does Conversion of Forest to Agricultural Land Change Soil Carbon and Nitrogen? A Review of the Literature," Global Change Biology 8, no. 2 (2002): 105–23, https://doi.org/10.1046/j.1354-1013.2001.00459.x.

[48] Zhangcai Qin et al., "Influence of Spatially Dependent, Modeled Soil Carbon Emission Factors on Life-Cycle Greenhouse Gas Emissions of Corn and Cellulosic Ethanol," GCB Bioenergy 8, no. 6 (2016): 1136–49, https://doi.org/10.1111/gcbb.12333.

[49] Searle and Malins, "A Critique of Soil Carbon Assumptions Used in ILUC Modeling."

[50] -Richard J Plevin et al., "Agro-Ecological Zone Emission Factor (AEZ-EF) Model: A Model of Greenhouse Gas Emissions from Land-Use Change for Use with AEZ-Based Economic Models," February 21, 2014.

Limitations of GTAP-BIO-ADV

GTAP is a widely used general equilibrium model for biofuels policy analysis and in other research fields. The version most often used for biofuels policy analysis is GTAP-BIO-ADV, developed by researchers at Purdue University. The development of this model version and studies published by Purdue researchers using it have been criticized as favoring changes in model structure and input assumptions that tend to reduce ILUC estimates, while avoiding changes that would increase them. Here, we summarize these critiques.

Conversion of unmanaged forests

One drawback of GTAP-BIO-ADV is its inability to model the effects of biofuel expansion on forested and pastured land that is currently out of economic use. The GTAP-BIO-ADV model does not include unmanaged forests and other land and thus structurally cannot model the conversion of these types of land to cropland. All cropland expansion in GTAP-BIO-ADV must be on managed land that has direct economic use. This limitation prevents the model from reflecting the land use change, and thus GHG emissions, that very likely occur from cropland expansion in reality. This likely overstates the "intensification of existing agricultural lands and overestimat[ing] conversions from agriculture to forestry when carbon sequestration incentives are applied".[51] This modeling decision is in contrast with other ILUC models including GCAM, IFPRI MIRAGE, and EPPA that account for conversion of unmanaged land.[52]

It has been demonstrated that it is possible to include unmanaged land in GTAP: a modified version of GTAP developed by Golub and Hertel included the ability to model unmanaged forest.[53] In this version, authors noted that modelers "must account for the possibility that currently inaccessible forestland will be brought into commercial production" (p. 470) to accurately capture the effects of global markets on land development. Despite this development, a separate team of Purdue researchers opted not to adopt this modeling change from Golub and Hertel in the GTAP-BIO-ADV model they developed for the California LCFS.

Due to the prevalence of unmanaged land globally, we expect that excluding this parameter will have a significant effect on final ILUC results – as of 2004, an estimated 75% of forested land in

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[51] Alla A. Golub et al., "Global Climate Policy Impacts on Livestock, Land Use, Livelihoods, and Food Security," Proceedings of the National Academy of Sciences 110, no. 52 (December 24, 2013): 20894–99, https://doi.org/10.1073/pnas.1108772109.

[52] David Laborde and Hugo Valin, "Modeling Land-Use Changes in a Global CGE: Assessing the EU Biofuel Mandates with the MIRAGE-BioF Model," Climate Change Economics 03, no. 03 (August 2012): 1250017, https://doi.org/10.1142/S2010007812500170; P. Kyle et al., "GCAM 3.0 Agriculture and Land Use: Data Sources and Methods" (Pacific Northwest National Laboratory, December 2011), https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-21025.pdf; Angelo Gurgel, John M Reilly, and Sergey Paltsev, "Potential Land Use Implications of a Global Biofuels Industry," 2007, 36.

[53] Alla Golub and Thomas W. Hertel, "Global Economic Integration and Land Use Change," Journal of Economic Integration 23, no. 3 (2008): 463–88.

North America and more than 90% of forested land in Oceania is classified as inaccessible.[54] Plevin ran a version of the GTAP model for the period 2020-2060 to underscore the significance of this model limitation.[55] In this analysis, GTAP predicts that increased biofuel demand results in no loss of non-commercial forested land and that approximately half of managed forest that is converted to cropland in the U.S. is offset by an increase in the land area of timber plantations globally. An equivalent modeling simulation run using the base scenario of GCAM did not yield the same results and instead predicted a net loss in non-commercial forested land area and a net zero change in commercial forest area.

Put plainly, GTAP predicts that when commercial forested land area is converted to cropland, this change is offset by newly planted forested area elsewhere. This is based on the assumption that a constraint on timber supply raises its price, which timber suppliers compensate for by planting more forested land area. In reality, we would expect that much of forest land expansion would occur on unmanaged forests with a lower economic value, minimizing the likelihood of any afforestation at all. Thus, we expect that GTAP modeling is likely to understate ILUC impacts since it predicts that any loss of forest area is, to a significant extent, offset by afforestation elsewhere. This has an important impact on estimated ILUC emissions because forest loss results in large losses of terrestrial carbon stocks.

Price-induced yield

The price-induced yield elasticity is an important input used in GTAP-BIO-ADV. This factor attempts to quantify the relationship between increased biofuel demand, rising crop prices, and agricultural intensification. Because higher demand for biofuels raises the price of agricultural commodities, the theory is that farmers will then find it economical to use methods such as increased fertilizer consumption and higher rates of irrigation to improve yield. Price-induced yield is quantified using a “yield elasticity to price” (i.e., YDEL) factor, defined as the percent change in yield corresponding with a percent change in the price of the commodity. For example, a YDEL factor of 0.25 means that a 1% increase in the price of corn would result in a 0.25% increase in the yield of planted corn. A YDEL factor of 1 corresponds with perfect elasticity. GTAP modelers have used a range of YDEL factors throughout different iterations of the model – a YDEL factor of 0.25 was adopted under the California LCFS program while YDEL factors range between 0.175 and 0.325 in the most recently published ILUC studies by Purdue.[56]

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[54] Brent Sohngen and Colleen Tennity, “Country Specific Global Forest Data Set v.1” (Department of Agricultural, Environmnetal, and Development Economics Ohio State University, November 30, 2004).

[55] Richard J. Plevin et al., “Choices in Land Representation Materially Affect Modeled Biofuel Carbon Intensity Estimates,” Journal of Cleaner Production 349 (May 2022): 131477, https://doi.org/10.1016/j.jclepro.2022.131477.

[56] Taheripour, F., Cui, H., Tyner, W.E., 2017a. An Exploration of agricultural land use change at the intensive and extensive margins: implications for biofuels induced land use change. In: Qin, Z., Mishra, U., Hastings, A. (Eds.), Bioenergy and Land Use Change. American Geophysical Union, pp. 19e37. Retrieved from (continued on next page)

The YDEL factors used in recent GTAP studies by Purdue researchers indicate a fairly high elasticity between agricultural intensification and price. Other assessments in the literature find little or no statistically significant relationship between crop prices and yields. In an expert assessment for a CARB working group, Babcock et al. concluded that the average YDEL for U.S. crops ranges between 0.05 and 0.2, although it could be justifiable to use a higher value in ILUC modeling in order to implicitly account for an increase in the practice of double cropping that might also occur in response to increased commodity price.[57] Berry and Schlenker (2011) used an instrumental variable analysis to determine that there is no significant causal impact of the price and yield of corn, soy, wheat, and rice on the yields of these crops globally and within the U.S. and Brazil.[58] The YDEL factor of 0.25 used in the modeling for the LCFS regulation is greater than the high-end range estimated by expert reviewers, and is only justified on the basis that it implicitly includes the yield effects of double cropping.[59] Relative to other assessments, the YDEL factor adopted by CARB may overestimate the rate of cropland intensification and underestimate the area of land cleared to allow for increased biofuel demand.

Throughout different studies using different iterations of the GTAP model, Taheripour et al. adopted different YDEL factors for geographic regions. Although authors note the importance of preserving “the original central” YDEL value (i.e. 0.25) supported by the literature, in the 2017 study,[60] they chose to adopt a higher YDEL for 10 out of 19 agro-economic zone (AEZ) regions, and reduce the YDEL for 6 of them. Areas where YDEL was increased account for approximately 50% of land use change captured in a previous version of the GTAP-BIO model [61] while areas where YDEL was reduced only account for 10% of modeled land area.[62] Additionally, the decision to assign a YDEL factor of 0.3 to the entire U.S. exceeds the central

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https://books.google.co.uk/books?hl¼en&lr¼&id¼vWk9DwAAQBAJ &oi¼fnd&pg¼PA19&dq¼AnþExplorationþofþagriculturalþ landþuseþchangeþatþtheþintensiveþandþextensiveþmargins&ots¼ DCLdhoHgYh&sig¼heg7uMycBk6hpQ4W0q0jQFI9Ugc.

[57] Babcock, Bruce, Angelo Gurgel, Mark Stowers, and K. Adili. "Final recommendations from the elasticity values subgroup." ARB LCFD Expert workgroup, California Environmental Protection Agency (2011).

[58] Steven Berry and Wolfram Schlenker, “Empirical Evidence on Crop Yield Elasticities,” August 5, 2011.

[59] Malins, Plevin, and Edwards, “How Robust Are Reductions in Modeled Estimates from GTAP-BIO of the Indirect Land Use Change Induced by Conventional Biofuels?”

[60] Taheripour, F., Cui, H., Tyner, W.E., 2017a. An Exploration of agricultural land use change at the intensive and extensive margins: implications for biofuels induced land use change. In: Qin, Z., Mishra, U., Hastings, A. (Eds.), Bioenergy and Land Use Change. American Geophysical Union, pp. 19e37.

[61] Thomas W. Hertel et al., “Effects of US Maize Ethanol on Global Land Use and Greenhouse Gas Emissions: Estimating Market-Mediated Responses,” BioScience 60, no. 3 (March 2010): 223–31, https://doi.org/10.1525/bio.2010.60.3.8.

[62] Hertel et al.

value (0.25) used in the California modeling. Some researchers suggest that these changes to YDEL are not well-substantiated or justified based on evidence.[63]

Double cropping

Along with maintaining high YDEL factors, recent studies using the GTAP model have explicitly added an additional yield intensification factor, reflecting changes in the practice of multiple cropping (growing more than one crop in a year) in response to commodity prices. These studies have justified this modeling change by arguing that multiple cropping rates have increased in some world regions in recent years, and that this will continue in response to increased commodity demand. High and increasing rates of double cropping identified by Taheripour et al. (2017), is not well substantiated in the literature. Although Taheripour et al. cite multiple studies to support this assumption, only one, Babcock and Iqbal (2014) draw a direct link between increased cropping intensity and biofuel policies.[64] Babcock and Iqbal's analysis relied on comparing harvested area to total cropland area using the FAOSTAT database. In some cases, that study assumed harvested area increases cannot represent new cropland, for example arguing that Indonesia is so densely populated that cropland expansion is not possible – an argument undermined by continued evidence of significant cropland expansion in that country.[65] Moreover, Babcock and Iqbal simply try to demonstrate that cropping intensity has increased over the same time period that biofuel production has increased and do not attempt to demonstrate any sort of causal linkage. Even if an increase in multiple cropping has occurred over this time period, it could be driven by other factors unrelated to biofuel policy such as business-as-usual technology progress; neither Babcock and Iqbal nor any other study have attempted to directly tie the two trends together. Because of the likely influence of external factors, Cui and Tyner emphasize that LUC modelers must first prove the relationship between cropping intensity and policy-driven biofuel expansion and that if no relationship is determined, the "biofuels-driven part of the cropping intensity change needs to be effectively isolated."[66]

Several other studies indicate that the prevalence of double cropping may not be so common and that data limitations may contribute to a skewed result. Borchers et al. estimate that between 1999 and 2012, double cropped land made up only 2% of total U.S. cropland and did not increase according to any long-term trend.[67] Researchers from the FAO caution against

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[63] Malins, Plevin, and Edwards, "How Robust Are Reductions in Modeled Estimates from GTAP-BIO of the Indirect Land Use Change Induced by Conventional Biofuels?"
[64] Bruce A Babcock and Zabid Iqbal, "Using Recent Land Use Changes to Validate Land Use Change Models" (Ames, Iowa: Center for Agricultural and Rural Development, Iowa State University, November 2014).
[65] Kemen G Austin et al., "What Causes Deforestation in Indonesia?," Environmental Research Letters 14, no. 2 (February 1, 2019): 024007, https://doi.org/10.1088/1748-9326/aaf6db.
[66] Hao (David) Cui and Wally Tyner, "Modeling Land Intensification Response in GTAP: Implications for Biofuels Induced Land Use Change," Presented at the 20th Annual Conference on Global Economic Analysis, West Lafayette, IN, USA, http://www.gtap.agecon.purdue.edu/resources/res_display.asp?RecordID=5287.
[67] Allison Borchers et al., "Multi-Cropping Practices: Recent Trends in Double-Cropping," May 2014.

extrapolating the same cropland:arable land ratio to future years due to inconsistency in data collection and reporting across datasets.[68] Additionally, by comparing cropland pasture data reported by USDA and total arable area reported by FAO, we find that FAO has likely included cropland pasture in its reported total arable land area over time. This misclassification would increase the ratio of cropland:arable land area (i.e., cropping intensity) in FAOSTAT data.[69] Babcock and Iqbal (2014) did not rely on FAO data for the U.S. due to data issues, but Taheripour (2017) did.

Despite weak evidence, Taheripour et al. apply a cropping intensity ratio of 4 hectares of additional double cropping for every hectare of cropland expansion in subsequent versions of the GTAP-BIO model.[70] This assumption exacerbates the effects of a high YDEL factor on land conversion assumptions. This is demonstrated in Taheripour et al. (2017), where adding the new double cropping assumption reduces U.S. pasture and forest conversion by a factor of 5 and global pasture and forest conversion by half in the corn ethanol scenario. A high YDEL assumes that agricultural land is used more efficiently, minimizing total land area conversion, while a high cropping intensity ratio assumes that a larger area of land is converted to double cropping rather than sourced from newly cleared land. Thus, we conclude that a high YDEL factor (higher than 0.2) can only be justified if double cropping is not explicitly included in the modeling to minimize the risk of underestimating ILUC emissions. Such as high value is not justified if double cropping effects are modeled independent of YDEL.

Classification of cropland pasture

Another area of concern with the GTAP-BIO-ADV model is that the nesting structure results in cropland pasture being preferentially converted to conventional cropland in response to increased biofuel demand. This modeling structure change reflects an assumption that cropland expansion occurs more on cropland pasture than on other types of land, such as permanent pasture or forest, but this finding is not substantiated by evidence. Although cropland pasture rates reported in the USDA census have rapidly decreased over time (and thus could in theory reflect a strong trend of cropland pasture conversion to new cropland), USDA experts have stated that this is likely a matter of data misclassification rather than real-world trends. Bigelow and Borchers report that this decline is attributed to methodological changes in data collection including reclassifying a portion of “cropland pasture” to “permanent grassland pasture and range.”[71]

The GTAP-BIO-ADV developers have also directly reduced the rate of cropland expansion onto pasture and forest in the model. In a study released in 2013, Taheripour and Tyner reduced the

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[68] Nikos Alexandratos, “World Agriculture:Towards 2010” (Food and Agriculture Organization of the United Nations, 1995), https://www.fao.org/3/v4200e/v4200e00.htm; Nikos Alexandratos and Jelle Bruinsma, “World Agriculture towards 2030/2050: The 2012 Revision,” June 2012, 154.

[69] Malins, Plevin, and Edwards, “How Robust Are Reductions in Modeled Estimates from GTAP-BIO of the Indirect Land Use Change Induced by Conventional Biofuels?”

[70] Malins, Plevin, and Edwards.

[71] Daniel P Bigelow and Allison Borchers, “Major Uses of Land in the United States, 2012” (USDA Economic Research Service, August 2017).

land conversion elasticity of pasture and forested land area to cropland by a factor of 10 in 10 of 19 regions, while increasing it by 50% in 5 regions.[72] This asymmetric treatment results in a 55% reduction in global pasture and forest conversion and is not justified based on evidence. Because cropland expansion onto forested or pasture is less likely to occur in recent GTAP updates, this increases the likelihood of agricultural land intensification and cropland pasture conversion, along with an associated reduction in ILUC emissions. Together with the nesting change in cropland pasture, these changes results in a 34% reduction in ILUC emissions, according to the 2013 study.

Cover crops

LC Associates recommend that ECY adopt an ILUC value of zero for oilseed crops such as carinata because it can be grown as a secondary or cover crop (i.e., over the winter, in addition to the regular summer crop). The reasoning for this recommendation is that if carinata is grown as a cover crop, it does not necessarily increase the demand for cropland area. This could potentially apply to other oilseed crops such as camelina and pennycress. This recommendation is partly based on the certification of camelina for the California LCFS as zero ILUC; however, this fails to note that this certification has expired and was never formally certified as a fuel pathway.[73] That feedstock certification was also limited to pathway-certified seeds verified with a chain of custody, rather than to cover crops more generally.[74] EPA in its rulemaking on camelina for the RFS, anticipates that while it is likely that camelina will be cover-cropped for economic reasons, if grown on dedicated cropland it would exceed the land-use impacts of soy (thus qualifying for a D4 RIN), though does not estimate ILUC emissions for the pathway.[75] CORSIA assigns carinata grown in the U.S. with an ILUC score of -20.4gCO2e/MJ, based on modeling that explicitly assumes that it is planted as secondary or cover crop and avoids the displacement of other crops.[76] In theory, purpose-grown cover crops also do not displace crops from other competing uses such as food, livestock feed, or the oleochemicals market.

However, cover crops are not necessarily additional and can easily displace food or feed crops grown already grown as cover crops. For example, growing a second crop over the winter is already commonplace in much of Brazil; there, the safrinha corn crop (i.e. cover crop) grown during the winter season has surpassed the production of primary corn since 2012, and, in

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[72] Farzad Taheripour and Wallace E. Tyner, "Biofuels and Land Use Change: Applying Recent Evidence to Model Estimates," Applied Sciences 3, no. 1 (March 2013): 14–38, https://doi.org/10.3390/app3010014.

[73] CARB (n.d.) LCFS Pathway Certified Carbon Intensities. https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities

[74] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/2a2b/apps/so-camelina-oil-rpt-110714.pdf

[75] https://www.govinfo.gov/content/pkg/FR-2013-03-05/pdf/2013-04929.pdf

[76] ICAO, "CORSIA Default Life Cycle Emissions Values for CORSIA Eligible Fuels," March 2021, https://www.icao.int/environmental-protection/CORSIA/Documents/ICAO%20document%2006%20-%20Default%20Life%20Cycle%20Emissions%20-%20March%202021.pdf.

2021, accounted for three-quarters of Brazilian corn production.[77] Double cropping is also practiced in the U.S., although at much lower rates.[78] Thus, a low-carbon fuel policy that places high value on cover cropping incentivizes the farmer to sell the secondary (e.g. corn) crop to the biofuel market, increasing the demand for planted corn elsewhere. If farmers switch to planting an oilseed crop as the second crop instead of safrinha corn, this reduces the annual production of corn, with similar market effects. Replacing cover crops like safrinha corn that are already grown now with carinata or other biofuel feedstock will very likely cause ILUC impacts of a similar magnitude as using primary crops for biofuel production. Due to the widespread nature of multiple cropping even in the absence of biofuel use for those crops, we recommend that ECY develop a more precise definition for this feedstock category prior to incentivizing it within the CFP.

Further, planting a secondary crop on land that was previously fallow may even contribute to ILUC in regions where cover cropping practices are expanding. Under a business-as-usual, or counterfactual scenario, there is a high likelihood that farmers would have transitioned to double cropping in the absence of biofuel demand. This would result in a net deficit in crop production and associated ILUC impacts. It is hard to state with certainty that farmers that only grow in the offseason would have transitioned to double cropping without the introduction of a low-carbon fuels policy. However, oilseed cover crops grown on land that was previously used for crop production certainly have an ILUC impact that should be accounted for in emissions modeling.

Strong incentives for growing oilseed cover crops may also result in the direct clearing of land; if farmers can expect income from two crops instead of one, they would in principle be more likely to invest in clearing new cropland. Growing cover crops can also reduce primary crop yields.[79] Lastly, cover crops may increase fertilizer and water usage.

Recommendation

In its analysis, Life Cycle Associates recommends that ECY adopts ILUC values and methodology that are largely consistent with California’s LCFS program. A significant exception is corn and sorghum ethanol, for which Life Cycle Associates recommends the ILUC values adopted by the state of Oregon. We raise significant concerns regarding the accuracy and methodological integrity of the CCLUB emission factor model in the discussion above and recommend that ECY uses a land conversion emission factor model more representative of real-world conditions. To maintain consistency with California, the preferred emission factor model would be AEZ-EF.

We also raise concerns regarding the accuracy and framework of the GTAP-BIO-ADV equilibrium model, adopted for every biofuel pathway. Research is currently ongoing at the EPA and National Academy of Sciences to review the state-of-the-art research on ILUC; however, at

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[77] Joana Colussi and Gary Schnitkey, “Brazil: Corn Production in Three Crops per Year,” Farmdoc Daily (blog), April 12, 2021, https://farmdocdaily.illinois.edu/2021/04/brazil-corn-production-in-three-crops-per-year.html.

[78] Borchers et al., “Multi-Cropping Practices: Recent Trends in Double-Cropping.”

[79] Humberto Blanco-Canqui et al., “Harvesting Cover Crops for Biofuel and Livestock Production: Another Ecosystem Service?,” Agronomy Journal 112, no. 4 (2020): 2373–2400, https://doi.org/10.1002/agj2.20165.

this time, there is no clearly preferred alternative. In the interim, we recommend that ECY adopts California's ILUC values that were calculated using the GTAP-BIO-ADV model to maintain consistency with California and consult with EPA and expert reviewers to identify a more defensible LUC model for future adoption. We do not recommend WA ECY conduct new modeling using the GTAP-BIO-ADV model, but if the agency chooses to do so, we recommend that they either a) do not utilize a YDEL factor greater than 0.2, or b) utilize a YDEL factor no greater than 0.25 and exclude explicit double cropping increases in the model to avoid overestimating cropping intensity response. In the future, ECY can consult expert and state agency review and incorporate stakeholder feedback to identify more suitable ILUC models for Washington than GTAP-BIO-ADV.

For cover crops, we recommend against including an ILUC value of 0g CO_2e/MJ, particularly given the absence of any definition or verification of cover cropping. Rather than assuming that some feedstocks such as carinata are inherently cover cropped, we recommend that an ILUC estimate is developed for these crops as if they are purpose grown in the absence of verification of cover cropping. To qualify for a zero-ILUC score, we recommend the use of a separate verification scheme to ensure that they are in fact grown as cover crops and not competing with cropland.

Summary of Recommendations

Overall, this peer review finds that the bulk of the LCA estimates and methodology developed to inform the Washington draft Clean Fuel Program rule is methodologically rigorous, aligns with existing policies in other jurisdictions, and reflects best practices. We identify several small methodological discrepancies or data gaps that can be addressed to improve the accuracy of the LCA modeling for the WA CFP in the near-term. With these changes implemented, we anticipate that there is sufficient data and analysis to support the implementation of the program. However, we also provide several suggestions that can be implemented in the longer-term to improve the accuracy of the program, mitigate data gaps and provide greater certainty that the emissions reductions intended by the WA CFP are being achieved. We make the following recommendations.

In the longer-term, we recommend moving beyond the current analysis' reliance on California's previously calculated CI figures for crude oils, particularly if Washington's crude oil mix begins to diverge from what is consumed in California. We recommend additional transparency of Washington's crude oil imports and refinery activity in the future to facilitate closer analysis of field-level oil import data and life-cycle emissions accounting. With that information, a Washington-specific crude oil LCA developed using the forthcoming OPGEE 3.0 model, along with an LCA assessment of Washington's refinery emissions could enhance the accuracy of the fossil fuel baseline.

Allocate unspecified electricity based on more granular consumption data and incorporate additional electricity emission factors for waste-derived electricity. The existing work to develop a WAMX emission factor for Washington already reflects a more accurate estimate of state-specific electricity emissions than using either the California CAMX emission factor or the national-average emission factor. The impacts of data gaps on the estimated grid mix are relatively minor. However, we note that the attribution of the entire "unspecified" electricity category to natural gas may overstate emissions attributable to the electricity grid. Therefore, we recommend allocating the unspecified share of electricity to subsets of the electricity generation mix based on methodology previously used by WA Department of Commerce. Further, we recommend the inclusion of additional emission factors for landfill gas and waste-to-energy to more precisely attribute emissions from these pathways.

In the longer-term, we recommend that Washington updates its electricity CI to match ongoing changes in the electricity mix. As part of these updates, we recommend additional analysis and disclosure of electricity sources to reduce the uncertainty associated with unspecified electricity.

Include jet fuel fossil fuel baseline as a benchmark for alternative jet fuels. LC Associates estimated the life-cycle impact of fossil jet fuel to be approximately 10 gCO2e/MJ lower than that of gasoline and diesel fuel, consistent with previous estimates. Therefore, while fossil jet is not a deficit-generating fuel in the CFP, it may still be inappropriate to calculate GHG reductions from alternative aviation fuels relative to diesel or gasoline. Therefore, we recommend the inclusion of fossil jet fuel as a benchmark for assessing the GHG savings of alternative aviation fuels on an opt-in basis, similar to the inclusion of aviation fuels in the California LCFS.

Include AR 5 GWP values in WA-GREET. Since the publication of the IPCC Fourth Assessment Report (AR4) in 2007, the scientific understanding of the climate impacts of non-CO2 greenhouse gases has grown significantly, particularly their feedback effects. In order to reflect these changes and better align with forthcoming changes to greenhouse gas inventory reporting, we recommend that WA-GREET incorporate global warming potentials from the IPCC Fifth Assessment Report (AR5). This change would likely have a minimal effect on most pathways' estimates, except for those with high methane leakage or upstream avoided methane emissions.

Incorporate the full set of Indirect Land-Use Change emission factors used in the California Low-Carbon Fuel Standard. This peer review summarizes the literature on indirect land-use change and notes several weaknesses associated with the GTAP-BIO model and CCLUB land conversion emissions model, particularly with respect to underestimating the emissions impacts of cropland-pasture conversion, treatment of unmanaged forestland within the model, and assumptions of price-induced yield improvements. After more than a decade of research, ILUC emissions remain uncertain due to data limitations as well as disagreements on model choice, scenario design and risk tolerance. We find that the choice of the Oregon CFP value of 7.6 gCO_2e/MJ for corn and sorghum reflects recency and is not justified by the full body of literature on corn ILUC, particularly on soil carbon changes. Therefore, we recommend adopting the full set of existing ILUC estimates calculated previously by CARB for the California LCFS, which uses the AEZ-EF model for estimating land conversion emissions rather than CCLUB. We also recommend against including a 0 gCO_2e/MJ ILUC factor for cover crops; in order to justify this, we recommend the development of a formal definition for cover cropping and a system to ensure that these crops are being grown as cover crops without displacing existing cropland.

To develop a more robust assessment of ILUC in the WA CFP context, we recommend that in the long-term WA ECY develops an ILUC assessment of the impact of the CFP to better understand the interaction between the policy and indirect, market-mediated emissions in coordination with stakeholders, academic experts and regulators at EPA and CARB. We recommend that WA ECY consider other models beyond GTAP-BIO, and in particular, if the GTAP-BIO model is used, we recommend the use of the AEZ-EF model for estimate land conversion emissions.