Electronic Supplementary Material (ESI) for Sustainable Energy & Fuels.

Supplementary Information for Decarbonization Potentials of On-Road Fuels and Powertrains in the European Union and the United States: A Well-to-Wheels Assessment

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1. Key GREET and JEC parametric assumptions for calculating WTW GHG emissions of the examined vehicle/fuel systems

1.1 Petroleum gasoline and diesel production pathways

1.1.1 Upstream emissions (crude oil). U.S. refineries process conventional crude oil and Canadian oil sands. During crude oil recovery, the vented CH_4 and CO_2 emissions from associated gas flaring and venting contribute significantly to greenhouse gas (GHG) emissions. Canadian oil sands accounted for about 8.1% of the total crude inputs to U.S. refineries in 2015.[1] The recovery of crude from Canadian oil sands is more energy-intensive and GHG-emission-intensive than the recovery of conventional crude. Canadian oil sands are produced from surface mining or *in situ* production. Most of the surface-mined bitumen is upgraded to synthetic crude oil (SCO), but only a small share of the *in situ* produced bitumen is upgraded to SCO. The majority of *in situ* bitumen is diluted with natural gas (NG) condensate to form diluted bitumen (dilbit). Table S1 lists the key assumptions employed in assessing recovery of conventional crude and oil sands in GREET. Since upgrading bitumen to SCO requires a significant amount of hydrogen, the hydrogen consumption per unit of processed bitumen from surface mining is higher than that from the *in situ*-situ production, as shown in Table S1.

In Europe, the upstream contribution to the WTW carbon intensity of conventional (fossil-based) gasoline or diesel could vary from 5% to 10%. The difficulty of estimating numbers related to upstream emissions is high due to three major issues:

- Variety in the of crude oil slate per refinery (potentially based on a trading scheme including permanent contracts as well as on-the-spot operations, depending on the specific refinery).
- Production conditions for conventional crude oil that vary considerably between producing regions, fields and even between individual wells. It is only deemed meaningful to give typical or average energy consumption and GHG emission figures for the wide range of crudes relevant to Europe, hence the wide variability range indicated.

Table S1. Key assumptions for conventional crude recovery and Canadian oil sands recovery/upgrading[1,2]

Parameter	Conventional Crude	Canadian Oil Sands — Surface Mining	Canadian Oil Sands — *In-Situ* Production
Recovery efficiency: percent	98.0 [97.4; 98.5][a]	92.6[b] [90.6; 94.5]	83.1 [81.6; 84.7][b]
Vented CH_4 emissions: g CO_2e/MJ of crude	2.3[c]	3.2[c]	0
CO_2 from associated gas flaring: g CO_2e/MJ of crude	1.0[e]	0	0
Hydrogen use for upgrade: J H_2/MJ of SCO or dilbit		50,783	42,973

[a] The values in the square brackets indicate the P10 and P90 of the parameters.

[b] Including upgrading to SCO

[c] CH_4 emissions from vented associated gas and crude processing

[d] CH_4 emissions from tailings ponds

[e] CO_2 emissions from associated gas flaring and venting

- Data availability at the oil field. The lack of reliable public information per individual oil field is significant, and assuming one single number representative of a specific country has the risk of being misleading, since the efficiency of the operations and the behavior of the oil field could significantly impact the CO_2 intensity of the crude oil extraction and production processes.

Because of these factors, *JEC v5*[3-15] uses average numbers for the crude oils processed in Europe, based on a detailed study conducted by the International Council on Clean Transportation (ICCT) with Stanford University, Energy Redefined, and Defense Terre.[16] The aim of that European Commission-led project was to estimate the upstream emissions of fossil fuel feedstocks for transport fuels, and the final paper presents the results of several studies on the EU crude oil market, a model for lifecycle analysis of crude oil extraction (the Oil Production Greenhouse gas Emissions Estimator [OPGEE] model), and an estimate of the

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carbon intensity of oil supplied to the European Union in 2010 (latest consistent data set available).

In order to determine the average energy/CO_2e intensity value of crude oils used in Europe, the list of crudes consumed in Europe published by DG Energy in 2010[16] is used as the starting point. Based on location and information from the American Petroleum Institute (API) and the Crude Information Management System (CIMS) database, every crude stream is allocated to the oilfield from which it would most likely come (with important caveats around this assumption, as it is not possible to directly determine from the DG Energy data exactly which fields have supplied Europe). Then the average carbon intensity of the EU baseline is calculated from the field-specific carbon intensities using the OPGEE tool:

- Each oilfield in the baseline is associated with a particular crude from the DG Energy reporting.
- Having assigned CIs to each individual crude, these are used to estimate the average carbon intensity of crude supplied to Europe in 2010 overall. This is done by taking the average CI across all DG Energy identified crudes (calculated by OPGEE based on key parameters of every single oilfield, assuming default values when unknown) weighted by their contribution to the EU crude slate.

Despite the limitations of the available data and the OPGEE model as stated in [ICCT 2014], which most likely overestimates the energy consumption associated with the EU average crude slate, the JEC decided to use the results of the ICCT study in *JEC v5* as the best available estimate. Therefore, the updated oil upstream value (without including the oil transport stage) is 9.0 g CO_{2e}/MJ crude (0.0244 g CO_{2eq}/MJ crude as CH_4 emissions). This value is used in all related pathways of the present *JEC v5* study as the carbon intensity for the oil production stage. It is also aligned to what an EU Commission's Directorate-General for Climate Action (DG CLIMA)-led consortium presented as inputs for their *study on actual GHG emissions for diesel, gasoline, kerosene and natural gas*. In addition, the energy used to transport crude oil to crude oil refineries in Europe is indicated with about 0.008 MJ per MJ of transported crude oil, corresponding to about 0.7 g CO_{2eq}/MJ. [Exergia et al. 2015]

1.1.2 Refining emissions. In GREET, the average petroleum refining efficiencies for gasoline and diesel production were estimated at 89.2% as a function of crude oil quality and the refinery configuration.[17] In *JEC v5*, the diesel and gasoline carbon intensity values are derived from the Concawe linear programming model representing the behavior of the European refining system (as described in the main paper).

Table S2. Key assumptions of petroleum gasoline pathways in GREET and JEC analyses.

Assumption	GREET	JEC v5
Crude recovery efficiency	98% [97%; 99%][a]	-
Crude oil production, energy expended MJ/MJ_{crude}		0.1152
Flaring and fugitive emissions g CO_2e/MJ_{crude}		0.0344
Refining efficiency for gasoline	89% [97%; 90%]	-
Crude refining, gasoline production, energy expended MJ/MJ_{crude}	0.128	0.0820
Electricity consumed by pumping operations for fuel depoting MJ electricity/MJ of gasoline	NA	0.00084
Gasoline loss factor in local distribution MJ/MJ gasoline	0.0008 [0.0002; 0.0017]	0.0004
Electricity consumed for fuel dispensing at retail site MJ electricity/MJ of gasoline	NA	0.0034
Gasoline loss factor during gasoline dispensing MJ/MJ gasoline	NA	0.0008

[a] The values in the square brackets indicate the P10 and P90 of the parameters.

1.2 Natural gas production pathways

Table S3 summarizes the key parameters of conventional and shale natural gas (NG) production pathways in the U.S. (from GREET).[18-20]

Table S3. Recovery efficiency, processing efficiency, CH_4 leakage, and compression efficiency of conventional and shale natural gas production pathways

	GREET		JEC v5 (Example)
Parameter	**Conventional natural gas**	**Shale natural gas**	**Conventional natural gas imported from Russia***
Recovery efficiency	97.5% [95.4%; 99.5%][a]	97.6% [95.5%; 99.6%]	
Processing efficiency	97.4% [95.3%; 99.3%]		
Extraction and processing, MJ/MJ_{NG}	-	-	0.02
CH_4 leakage, g/mmBtu	82.632	87.891	
CO_2 venting, %	-	-	1%
CH_4 losses, g/MJ_{NG}			0.0796 (extraction) 0.0084 (long distance pipeline)
Compression efficiency, electric compressor	97.9% [97.3%; 98.4%]		-
Compressors powered by gas turbine fueled by natural gas	-	-	~30%

[a] The values in the square brackets indicate the P10 and P90 of the parameters.

Europe is a significant gas producer, mainly in the Netherlands and the UK (North Sea) and also in Denmark, Germany, Italy, and Romania (Note: The UK is included in *JEC v5* as part of Europe as figures were calculated before Brexit). Demand, however, far outstrips domestic production and current statistics show how the share of NG imports has increased in the most recent years. Therefore, in the second and third decades of this century, JEC has assumed that any extra supplies to Europe will most likely come from either the Middle East or Russia. Bringing this gas to Europe will involve either new pipelines or LNG schemes. We have therefore considered two main options:

- "Piped" gas transported to Europe via long-distance pipeline. In practice this represents additional availability from Russia or new sources in Central Asia.
- "Remote" gas from various producing regions (particularly the Arabian Gulf) either shipped into Europe as LNG or transformed at the source into liquid fuels.

The energy associated with extraction and processing varies considerably with the producing region. This reflects different gas qualities, practices and climatic conditions. For extraction, most of the energy is supplied directly in the form of natural gas (typically through an on-site power plant). Processing can take place near the wellhead or, as is common in Russia, at a central location where light hydrocarbons can be readily used as chemical feedstocks. In these cases, the energy supply may be mixed and include various hydrocarbon fuels as well as electricity from the local grid. Based on the various sources of information available, we have used a median figure of 2% of the processed gas energy with a range of 1% to 4%. We have not included any term for associated condensates, postulating that their production and use would globally be energy/GHG neutral (compared to alternative sources). In addition to the GHG emissions from energy use, we have included 1% volume venting as CO_2 and 0.4% volume of methane losses. Transportation accounts for the largest part of the energy requirement because of the large distances involved. Western Siberian fields are about 5,000 km from Europe (4,300 km to the EU border, which represents a mix of three corridors, and 700 km inside EU), whereas typical future southwest Asian locations may be 4,000 km away. For the supply of marginal piped natural gas, a transport distance of 4,000 km has been assumed, representing typical future Southwest Asian locations.

Beside the extraction process itself, processing is required to separate heavier hydrocarbons, eliminate contaminants such as H_2S, and separate inert gases, particularly CO_2, when they are present in large quantities. The associated energy and GHG figures are extremely variable depending on the location, climatic conditions, and quality of the gas. The figures used in *JEC v5* are reasonable averages; the large variability being reflected in the wide range. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2025+ horizon.

Combined leakages in the transportation system result in some methane losses directly emitted to the atmosphere. Although it has often been reported that such losses are very high in the Russian system, comprehensive studies such as conducted by Ruhrgas and Gazprom and by the Wuppertal Institute, give a more moderate picture. Based on the latter source, *JEC v5* assumes a loss of 0.13% of the transported gas per 1000 km.

1.3 Bioethanol production pathways

The key life-cycle stages for bioethanol production pathways are biomass feedstock production and conversion of the feedstock to bioethanol. Table S4 summarizes key farming parameters for ethanol production from corn, corn stover, sweet sorghum, sugarcane, and willow.[21-23]

Table S5 summarizes the efficiencies, energy use, co-product yields, and chemical use in corn and cellulosic ethanol plants.[22-25]

* Natural gas from Russia transported to EU by pipeline (4300 km to EU border and 700 km inside EU).

Table S4. Energy use, fertilizer application rates, and N_2O emission conversion rates for corn farming and corn stover harvest/collection

	GREET			*JEC v5*		
Parameter	**Corn Btu/bushel or g/bushel**	**Corn stover Btu/ton or g/ton**	**Sugarcane Btu/ton or g/ton**	**Corn imported from U.S. MJ/MJ EtOH, g/MJ grain**	**Wheat straw MJ/MJEtOH, g/MJ Straw**	**Sugar beet MJ/MJ EtOH, g/MJ SB**
Direct energy use for bio-feedstock farming	6,924 [5,687; 8,720]	223,592	979.6	0.18 farming MJ/MJ_{EtOH} *	- (0.07 MJ/ MJ_{EtOH} straw baling and collection, including fertilizer debit)	0.10 MJ/MJ_{EtOH}
Diesel use	3,409 [2,799; 4,292]	223,592	33,008	0.025	0.0096	0.0105
N fertilizer application	383 [290; 473]	3,183	889	1.18	-	0.35
P fertilizer application	139 [74; 222]	2,273	294	0.36	0.13	0.15
K fertilizer application	146 [35; 286]	13,641	1,368	0.42	0.71	0.26
Limestone application	1,290 [1162; 1418]	0	4,717	0.88	-	0.61
N_2O conversion rate of N inputs: %	1.225	1.225	1.225	-	-	-
N_2O field emissions				0.034	-	0.0126

Table S5. Ethanol yields, co-product yields, and enzyme and yeast usage in corn-based and corn stover-based ethanol production

	GREET			*JEC v5*
Parameter	**Corn**	**Corn stover**	**Sugarcane**	**Corn imported from U.S.**
Ethanol yield:	2.9 gal/bushel [2.8; 2.9]	85.0 gal/dry ton [74.1; 95.5]	21.4 gal/wet tonne [19.3; 23.6]	0.602 MJ_{EtOH}/MJ_{corn}
Ethanol plant fossil energy use:	26,856 Btu/gal [19,844; 33,941]	180 Btu/gal	300 Btu/gal [269.2; 330.6]	1.08 MJ/MJ_{EtOH}
Dried distillers grains with solubles yield	5.6 lb/gal [5.0; 6.1]	0 lb/gal	0 lb/gal	0.012 kg_{DDGS} (@7% moisture)/MJ_{EtOH}
Co-produced electricity	0 kWh/gal	2.4 kWh/gal [1.9; 3.7]	3.5 kWh/gal [0.5; 9.0]	-
Enzyme use	7.9 g/gal [7.3; 8.7]	106.7 g/gal [116.5; 878.9]	0 g/gal	-
Yeast use	2.7 g/gal [2.5; 3.0]]	26.6 g/gal [22.6; 31.2]	0 g/gal	-
Sulfuric acid	4.7 g/gal	346.2 g/gal	0 g/gal	-
Ammonia	17.8 g/gal	41.5 g/gal	0 g/gal	-

* Additional 0.06 MJ/MJ_{EtOH} from grain drying, storage and handling

1.4 Synthetic diesel: Fischer-Tropsch diesel (FTD) and pyrolysis based pathways

Table S6 summarizes the key parameters for forest residue-based FTD production pathways.[26]

1.5 Hydrogen production pathways

Table S7 summarizes the key parameters for NG SMR- and electrolysis-based hydrogen production pathways.[27]

1.6 Electricity generation

The emissions from electricity generation depend on the fuels and technologies used. Electricity generated from fossil fuels (coal, natural gas, and oil, etc.) incurs higher GHG emissions than electricity derived from renewable energy sources, such as wind and solar. The technologies used for electricity generation also play an important role due to differences in power generation efficiencies and combustion characteristics. GREET estimates the emissions from the power generation sector by investigating the shares and emissions of the major electricity generation fuels and technologies used in the U.S.[28]

First, the power generation efficiencies and emission factors of VOC, CO, NO_x, PM, CH_4, and N_2O are estimated for each combination of fuel and power generation technology. The emissions factors are estimated in two steps. First, plant-level emission factors are estimated by dividing the total emissions from a power plant that uses one dominant fuel and technology by the net electricity generation from the same plant. Second, national average emission factors are estimated as the average of the plant-level emission factors weighted by the net power generation. The CO_2 emissions factor is estimated for each fuel based on its carbon balance, using its power generation efficiency and the emission factors of the other pollutants. The GHG emissions of the power generation sector are then estimated based on the power generation share of each combination of fuel and technology as well as a loss factor to account for loss during electricity transmission and distribution. Results are also available for all the North American Electric Reliability Corporation (NERC) regions and all 50 states in the U.S. Table S8 lists the key parametric assumptions about electricity generation in the U.S.[28]

Table S6. Key parameters of forest residue-based FTD and pyrolysis production pathways

	GREET	*JEC v5*	
Parameter	**Forest residue to FTD**	**Forest residue to FTD**	**Forest residue to pyrolysis**
Fuel production efficiency	50%	45.1%	61.6%

Table S7. Key parameters of NG- and water electrolysis-hydrogen production pathways at central plants

	GREET		*JEC v5*	
Parameter	**NG to H_2**	**Water electrolysis to H_2**	**NG to H2**	Water electrolysis
H_2 production efficiency	72.0% [66.8%; 78.1%]	67.0%	69% (on-site SMR) 76% (central SMR)	65% 56% (min PEM) to 80% (max SOEC)*
Energy use for CCS (kWh/ton C captured)	357	NA	1.365 MJ/MJ H_2	NA
Gaseous H_2 compression efficiency	90.7% [89.4%; 92.0%]		0.0537 MJ electricity/MJ H_2 (3 to 50 MPa)	0.0864 MJ electricity/MJ H_2 (3 to 88 MPa dispensing)

1.6.1 Key parametric assumptions of electricity generation in JEC WTT v5

- Upstream emission factors
- Efficiencies: For renewable energy sources, the raw materials are considered unlimited and the energy efficiency is considered to be (conventionally) 100%. Due to the nature of JEC, it has been assumed that new large-scale capacity will be based on the combined cycle gas turbine (CCGT) concept with an efficiency of 58%. For coal, the conventional process represents a modern steam turbine plant with an efficiency of 43.5% whereas for integrated gasification combined cycle (IGCC) plants, an average value of 48% has been used. For wood, a conventional biomas power plant turbine/small scale) is represented with an efficiency of 32%. A wood-based IGCC plant of 200 MW_{th} is considered to have an efficiency of 48.2%, ranging down to 35.4% in the case of a 10 MW_{th} plant. If co-fired in coal power plant, biomass is considered to reach an overall efficiency of 43.5%. For nuclear power plants, 33% is assumed.
- Transmission losses in the high voltage system are about 2.6%, while losses for medium voltage distribution add 0.9% and low voltage distribution a further 3.4%.

* Related to LHV

Table S8. Key parametric assumptions of electricity generation in GREET

	Power plant type	Technology	Share	Efficiency	CO_2 emissions from combustion (g/kWh)
Fuel production	Coal-fired power plants				
		Boiler	24.4%	36.0% [33.8%; 37.9%]	
		IGCC	0.2%	39.0% [36.0%; 42.0%]	
		Overall	24.6%	36.0% [33.8%; 37.9%]	947.4
	Natural gas-fired power plants				
		Boiler	3.2%	34.0% [31.4%; 37.0]	
		Simple-cycle gas turbine	2.2%	34.0% [26.5%; 35.0%]	
		Combined-cycle gas turbine	30.9%	55.0% [40.1%; 61.5%]	
		Internal Combustion Engine	0.3%	34.0% [24.1%; 44.0%]	
		Overall	36.7%	50.0% [38.4%; 53.6%]	404.2
	Residual oil-fired power plants				
		Boiler	0.3%	35.0% [32.1%; 37.7%]	
		Internal Combustion Engine	0.0%	38.0% [32.7%; 43.6%]	
		Gas Turbine	0.1%	32.0% [22.1%; 42.0%]	
		Overall	0.4%	35.0% [30.1%; 38.2%]	840.3
	Biomass power plants				
		Boiler	0.3%	22.0% [16.5%; 27.5%]	
		IGCC	0.0%	40.0% [38.4%; 42.1%]	
		Overall	0.3%	22.0% [16.6%; 27.5%]	-9.1
Fuel distribution	Transmission loss (%)	4.86%			

Table S9. Upstream emission factors used in *JEC v5* (kg CO_{2eq}/GJ)

Hard coal	Brown coal	Peat	Coal gases	Petroleum products	Natural gas	Solid biofuels	Liquid biofuels	Industrial waste	Municipal waste	Biogases	Nuclear
16.0	1.7	0	0	10.7	12.8	0.7	46.8	0	0	14.9	1.4

In addition to individual electricity pathways, *JEC v5* also includes different electricity mix scenarios as defined below:

Table S10. EU electricity production mix in JEC WTT v5 (2016 data and projections for 2030)

% Share	**2016**	**2030**
Source	EEA 2018	IEA NPS (2030)- WEO 2017
Coal, lignite	21.2%	12.1%
Oil	1.8%	0.6%
Natural gas	19.7%	21.0%
Nuclear	25.8%	21.3%
Hydro	10.8%	11.8%
Wind	9.4%	19.7%
Solar	3.5%	5.3%
Other non-renewable fuels	2.2%	0
Other renewables	5.6%	8.2%

1.7 Renewable natural gas and compressed biomethane

Renewable natural gas (RNG) can be produced from waste feedstocks such as wastewater sludge, animal manure, and municipal solid waste (MSW). The waste feedstock is collected and converted to a CH_4-rich biogas via anaerobic digestion (AD). A fraction of the biogas is combusted on-site to generate heat and electricity for the facility. The remaining biogas goes through a two-step clean-up process to remove impurities including corrosive hydrogen compounds, water, low concentrations of non-methane organic compounds, and CO_2 to produce pipeline-quality renewable natural gas.

In GREET, the RNG is transmitted 80 km by pipeline to refueling stations.[29] The delivered RNG is then compressed to 28 MPa by electric compressors and eventually combusted in compressed natural gas vehicles (CNGV).[29] The residue of the AD process is applied to soil as fertilizer, and a small amount of carbon in the residue is emitted as methane. For the manure AD pathway, a significant amount (62%) of the carbon in the AD residue is oxidized to CO_2 and released to the atmosphere, while the rest is assumed to remain sequestered in the soil. For the sludge AD pathway, a fixed sequestration factor is used to estimate the sequestered carbon, while CO_2 emissions from soil application of sludge AD residue are not modeled.

GREET also models current management systems as the reference cases for two waste feedstocks.[29,30] Energy consumption and pollutant emissions from manure management systems are taken as a credit since they are avoided if waste feedstocks are used to produce biofuels. In the reference case, manure is sent to a current management system (e.g., anaerobic lagoon, deep pit, etc.) where CH_4 is emitted. For manure management systems like anaerobic lagoons and deep pits, CH_4 emissions can be collected and are thus "controllable," while CH_4 emissions from pastures and daily spread are "uncontrollable." Sixty percent of the controllable CH_4 emissions are flared to reduce GHG emissions. The residue from the manure management systems is used for soil application to displace synthetic fertilizers and generate emission credits.

The reference case for sludge management is similar to the process for CNG production in the sense that it also uses AD. However, most of the generated biogas is combusted without cleanup to provide heat for the facility, and the rest is flared. In a combined heat and power (CHP) CNG production facility, some biogas is combusted after initial cleanup to provide heat and electricity, and the rest is further cleaned to produce commercial-grade natural gas. Another difference between the reference case and the CNG production case is that AD residue is landfilled in the former due to environmental concerns, thus no fertilizer displacement credits are available.

The reference case for MSW management is landfilling.

Table S11. Key parametric assumptions of feedstock composition for CNG production in GREET

	Manure	**Sludge**	**MSW (food waste)**
Moisture	88%	NA	60%
Volatile solids	85%	61%	NA
Nitrogen	4%	NA	3%
Carbon	47%	NA	48%

Table S12. Key parametric assumptions of compressed biomethane production in GREET

			Manure		Sludge		MSW (food waste)	
Feedstock production	**Counterfactual scenario (avoided emissions[4])**		**Current manure management**		**AD with biogas flaring**		**MSW landfilling**	
Fuel production	Anaerobic digesters	Thermal energy requirement	1.16E+05	Btu/wet ton	5.15E+00	MJ/kg VS	3.51E+05	Btu/wet ton
		Electricity requirement	1.20E+01	kWh/wet ton	1.26E+00	MJ/kg VS	2.13E+05	Btu/wet ton
		Methane yield	3.14E+00	ft^3/lb VS	3.72E-01	m^3 CH_4/kg VS	8.84E+01	m^3/wet ton
	Soil application of digestate	Carbon Sequestration	5.21E-01	lb CO_2/lb TS	1.50E-01	kg CO_2/kg VS	3.28E+01	kg CO_2/wet ton
		CH_4 emissions	1.24E-04	lb CH_4/lb TS	3.89E-05	m^3 CH_4/kg VS	2.33E+00	g CH_4/wet ton
		N displaced	4.10E-02	lb /lb TS	4.10E-02	kg CO_2/kg VS	5.08E+00	kg/wet ton
		P displaced	0.00E+00	lb /lb TS	5.30E-02	kg CO_2/kg VS	8.31E-01	kg/wet ton
		K displaced	0.00E+00	lb /lb TS	4.00E-03	kg CO_2/kg VS	2.51E+00	kg/wet ton
	Biogas cleanup	NG processing Efficiency	94.4%					
		Leakage	2%					
	Co-product	Electricity	2.51E-02	MJ/MJ CNG	NA			
		Allocation	Energy-based allocation					
Fuel distribution	NG distribution	Distribution mode	Pipeline					
		Distance	8.05E+01 km					
		NG on-site compression	1.60E-02 MJ/MJ NG [1.50E-02; 1.60E-02]					
		NG off-site compression	2.20E-02 MJ/MJ NG [2.10E-02; 2.20E-02]					

[4] Avoided emissions include avoided methane emissions from soil application of digestate for anaerobic digestion of animal manure and sludge, and avoided methane emissions from landfills of MSW.

In *JEC v5*, the organic fraction to biogas follows the same approach as described above for GREET. The conversion level of the fermentation process is deemed to be ~70%, and the moisture content varies depending on the feedstock as it does in GREET (e.g., 85% for manure). Typically, the composition is 60%/40% methane and CO_2 depending on the type of feedstock, with small amounts of other substances such as H_2 (0%-1%), N_2 (0%-7%), H2S (0%-1%) and traces of NH_3, as well as water vapor, before it goes through the upgrading step (removing CO_2 and H_2S, among others). The treated biomethane is available at ~0.9 MPa and compressed up to 25 MPa to refuel a vehicle. The main parameters for JEC are detailed below:

Table S13. Key parametric assumptions for compressed biomethane production in *JEC v5*

			Manure	Sewage sludge	MSW
Feedstock production	**Counterfactual scenario (avoided emissions)**	**Current manure management**	**Closed digestate storage**		
Fuel production	Production & conditioning at source				
	GHG emissions credit from avoided manure storage				
	CH_4 emissions	g/MJ_{manure}	-1.4700		
	N_2O emissions	g/MJ_{manure}	-0.0279		
	Transportation to market				
	Manure transport (Road)				
	Distance	km	5		
	Transformation near market				
	Fermenter (closed digestate storage)				
	Raw gas yield	MJ/MJ_{waste}	0.4620	0.4620	0.7073
	Heat to process	MJ/MJ_{rawgas}	0.0909	0.4767	0.0976
	Electricity (EU-mix, LV) to process	MJ/MJ_{rawgas}	0.0182	0.0688	0.0293
	Internal heat generation using own raw gas				
	Efficiency	%	90.0%	90.0%	90.0%
	CH_4 emissions	g/MJ_{heat}	0.0056	0.0056	0.0056
	N_2O emissions	g/MJ_{heat}	0.0011	0.0011	0.0011
	Upgrading				
	Upgraded gas yield	MJ/MJ_{rawgas}	0.9700		
	Electricity (EU-mix, LV)	MJ/MJ_{gas}	0.0300		
Fuel distribution	**Conditioning and distribution**				
	Compression and dispensing				
	Electricity (EU-mix, MV)	MJ/MJ_{CBM}	0.0220	0.0220	0.0220
	CH_4 emissions	g/MJ_{CBM}	0.0113	0.0001	0.0001

1.7.1 Biodiesel and renewable diesel from oil feedstocks. Soy oil extracted from soybean can be converted to either biodiesel via transesterification or renewable diesel via hydrotreating. GREET models the entire life-cycle of soybean oil-based biodiesel and renewable diesel, including soybean farming, oil extraction, fuel production, fuel transportation and transmission, and fuel combustion. Key parametric assumptions of biodiesel and renewable diesel production are listed in Tables S14 and S15, respectively.

Another common feedstock for biodiesel production is tallow, which has high free fatty acids content. Tallow is treated as byproduct from meat production, hence the burdens from upstream processes include animal feed production, animal farming, and slaughtering. The system boundary of tallow-based renewable diesel includes rendering, tallow transport, renewable diesel production, and renewable diesel transportation and combustion.

Table S14. Key parametric assumptions of biodiesel production in GREET[31]

		Soybean based biodiesel		**Tallow based biodiesel**	
Feedstock production		Soybean farming		Tallow rendering	
	N fertilizer	2.0 [0.8; 3.7]	g/dry kg soybean		
	P_2O_5 fertilizer	7.9 [0.5; 12.3]	g/dry kg soybean		
	K_2O fertilizer	12.6	g/dry kg soybean		
	Herbicide	0.8	g/dry kg soybean		
	Insecticide	0.02	g/dry kg soybean		
	Diesel fuel	579	kJ/dry kg soybean		
	Gasoline	129	kJ/dry kg soybean		
	Liquefied petroleum gas	32.4	kJ/dry kg soybean		
	Natural gas	41.6	kJ/dry kg soybean	4.0	MJ/kg tallow
	Electricity	39.5	kJ/dry kg soybean	1.2	MJ/kg tallow
	Residual oil	-	-	2.3	MJ/kg tallow
Fuel production	**Oil extraction**			-	
	Inputs				
	Feedstock	4.65	dry kg soybean/kg soy oil		
	Residual oil	0.06	MJ/kg soy oil		
	Diesel fuel	0.03	MJ/kg soy oil		
	Natural gas	4.01	MJ/kg soy oil		
	Coal	1.97	MJ/kg soy oil		
	Electricity	0.86	MJ/kg soy oil		
	Hexane	0.11	MJ/kg soy oil		
	Biomass	0.06	MJ/kg soy oil		
	Landfill gas	0.03	MJ/kg soy oil		
	Co-product				
	Soy meal	3.63	dry kg per kg of soy oil		
	Co-Product allocation	Mass-based allocation			
	Biodiesel production (Transesterification)				
	Inputs				
	Feedstock	1.0 [0.98; 1.02]	kg soy oil/kg biodiesel	1.1 [1.0; 1.2]	kg rendered tallow/ kg biodiesel
	Diesel fuel	23.5	kJ/kg biodiesel	-	kJ/kg biodiesel
	Natural gas	1179.5	kJ/kg biodiesel	2162.7	kJ/kg biodiesel
	Electricity	146.7	kJ/kg biodiesel	310.6	kJ/kg biodiesel
	Methanol	2176.0 [1891; 2456]	kJ/kg biodiesel	2209.5 [1621; 2787]	kJ/kg biodiesel
	Nitrogen (grams)	2.1	kJ/kg biodiesel	6.8	kJ/kg biodiesel
	Sodium hydroxide (grams)	0.4	kJ/kg biodiesel	0.7	kJ/kg biodiesel
	Sodium methoxide (grams)	4.9	kJ/kg biodiesel	5.2	kJ/kg biodiesel
	Hydrochloric acid (grams)	2.5	kJ/kg biodiesel	3.6	kJ/kg biodiesel
	Phosphoric acid (grams)	0.4	kJ/kg biodiesel	0.3	kJ/kg biodiesel
	Citric acid (grams)	-	kJ/kg biodiesel	0.4	kJ/kg biodiesel
	Co-Product				
	Glycerin	90.5	g/kg biodiesel	81.5	g/kg biodiesel
	Fatty acids and distillation bottoms	7.3	g/kg biodiesel	101.3	g/kg biodiesel
	Co-product allocation	Market value-based allocation			

Vegetable oils can be converted to hydrocarbon fuels over catalytic beds in the presence of hydrogen. Renewable diesel produced from this technology is also known as hydrotreated vegetable oil (HVO), or hydroprocessed esters and fatty acid (HEFA).

1.7.2 Soybeans to biodiesel in *JEC v5*.

For comparison purposes, the table S15 presents the pathway in which soy beans are imported from USA into Europe and glycerine is used to generate biogas consumed internally during the biofuel production process. At present the main co-products of biofuel manufacture are rapeseed meal from biodiesel and Distiller's Dried Grain with Solubles (DDGS) from cereals-ethanol rich in protein (although not as rich as soybean meal, the main protein concentrate feed in EU). Therefore, JEC considers that DDGS substitute a mix of soybean meal and carbohydrate feeds as a credit in the total GHG intensity estimate (In JEC, the main marginal source of carbohydrate feed is cereals, which we represent by EU feed-wheat, whilst the main marginal source of protein is clearly soybean meal, as a weighted mix of soybeans from EU, Argentina, Brazil, and USA).

Table S15. Key parametric assumptions of renewable diesel production in GREET[32]

Inputs	GREET	
Feedstock	1.2	kg soy oil/kg fuel
Electricity	221.3	kJ/kg renewable diesel
Hydrogen	3892.1	kJ/kg renewable diesel
NG	192.0	kJ/kg renewable diesel
Co-products		
Propane fuel mix	2549.3	kJ/kg renewable diesel
Co-product allocation	Energy-based allocation	

Table S16. Key parametric assumptions of biodiesel production in *JEC v5*

Feedstock production	Biodiesel production		Soybean	Tallow	UCO
Fuel production	**Production & conditioning at source**				
	Soy cultivation				
	Fertilizers	g/MJ$_{Soy\ bean}$			
	N (as N)		0.08		
	P (as P_2O_5)		0.71		
	K (as K_2O)		0.69		
	$CaCO_3$ (as CaO)		4.16		
	Pesticides	g/MJ$_{Soy\ bean}$	0.06		
	Seeding material	g/MJ$_{Soy\ bean}$	1.33		
	Diesel	MJ/MJ$_{Soy\ bean}$	0.031		
	CH_4 emissions	g/MJ$_{Soy\ bean}$	0.000040		
	CO_2 from soil neutralisation	g/MJ$_{Soy\ bean}$	3.094		
	N_2O field emissions	g/MJ$_{Soy\ bean}$	0.0428		
	Beans to EU: Soy beans drying (13%), storage and handling				
	Diesel	MJ/MJ$_{Soy\ bean}$	0.0006		
	NG	MJ/MJ$_{Soy\ bean}$	0.0011		
	LPG (LRLP1)	MJ/MJ$_{Soy\ bean}$	0.0006		
	Electricity (EU-mix, MV)	MJ/MJ$_{Soy\ bean}$	0.00023		
	Transformation at source				
	Soy beans drying (13 to 11%)				
	NG	MJ/MJ$_{Soy\ bean}$	0.0029		
	Raw oil production (meal export)				
	Raw oil yield	MJ$_{oil}$/MJ$_{seed}$	0.348		
	Soya meal	kg/MJ$_{oil}$	0.110		
	Heat to process	MJ/MJ$_{oil}$	0.082		
	Electricity (EU-mix, MV)	MJ/MJ$_{oil}$	0.015		
	n-Hexane	MJ/MJ$_{oil}$	0.004		
	CO_2 emissions (from n-hexane)	g/MJ$_{oil}$	0.248		
	Credit for meal				
	Animal feed substitution				
	1 kg meal substitutes:				
	Dry corn	*kg/kg$_{Meal}$*	*-0.976*		
	Transportation to market				
	Soy oil long distance transport				
	Inland/coastal tanker (1.2 kt)				
	Distance	km	562		
	Sea-going tanker (23 kt)				
	Distance	km	11107		
	Soy beans long distance transport				
	Inland ship				
	Distance	km	615		
	Sea-going product carrier (Panamax)				
	Distance	km	9381		
	HFO	MJ/t.km	0.0078		
	Carcass transport		-	-	
	Road truck				
	Distance	km		30	
	Transformation near market				
	Tallow production (rendering plant)				
	Tallow yield	kg/kg$_{dry\ carcass}$		0.2865	
	Electricity (EU-mix, MV)	MJ/MJ$_{tallow}$		0.0029	
	HFO	MJ/MJ$_{tallow}$		0.0064	
	NG	MJ/MJ$_{tallow}$		0.0521	
	Tallow transport				
	Road truck	*km*		*150*	

	Biodiesel production				
	Biodiesel yield	$MJ_{Biodiesel}/MJ_{oil}$		0.965	0.965
	Methanol (feed)	$MJ/MJ_{Biodiesel}$		0.056	0.056
	CO_2 emissions (fossil carbon in methanol)	$g/MJ_{Biodiesel}$		3.889	3.889
	Electricity (EU-mix, MV)	$MJ/MJ_{Biodiesel}$		0.0068	0.0068
	NG	$MJ/MJ_{Biodiesel}$		0.0471	0.0471
	H_3PO_4	$g/MJ_{Biodiesel}$		0.047	0.047
	KOH	$g/MJ_{Biodiesel}$		0.427	0.427
	H_2SO_4	$g/MJ_{Biodiesel}$		0.295	0.295
	Heat surplus (used in process)	$MJ/MJ_{Biodiesel}$		-0.032	-0.032
	K fertiliser production	$g/MJ_{Biodiesel}$		-0.381	-0.381
	K fertiliser credit based on alternative mainstream production				
	Methanol production				
	NG	$MJ/MJ_{Methanol}$		1.463	1.463
	CH_4 emissions	$g/MJ_{Methanol}$		0.000083	0.000083

1.7.3 Per MJ WTT and Combustion Results

Table S17. WTT and combustion results of liquid fuel spark ignition (SI) ICEVs (g CO_2e/MJ)

		Feedstock production	Fuel production	Combustion	Biogenic carbon	Total	P10	P90
Petroleum gasoline	GREET	6.1	12.6	73.2	0.0	91.9	89.5	96.1
	JEC v5	10.5	6.5	73.4	0.0	90.4		
EtOH from corn	GREET	21.8	29.6	71.5	-71.0	51.8	45.6	59.8
	JEC v5	34.8	20.7	71.4	-71.4	55.6		
EtOH from sugarcane	GREET	15.2	10.4	71.5	-71.0	26.1	22.7	29.9
	JEC v5	Not available						
Cellulosic EtOH	GREET[a]	7.0	4.6	71.5	-71.0	12.1	9.4	28.5
	JEC v5[b]	14.1	3.7	71.4	-71.4	17.8		

a: From corn stover

b: From wheat straw

Table S18. WTT and combustion results of liquid fuel compression ignition (CI) ICEVs (g CO_2e/MJ)

		Feedstock production	Fuel production	Combustion	Biogenic carbon	Total	P10	P90
Diesel	GREET	7.1	7.6	75.7	0.0	90.3	85.2	94.1
	JEC v5	10.8	8.1	73.2	0.0	92.1		
FAME from soybean	GREET	9.2	21.0	76.5	-72.1	34.7	30.9	38.3
	JEC v5	48.7	7.3	76.2	-76.2	55.9		
FAME from canola/rapeseed	GREET	22.2	11.2	76.5	-75.8	34.1	29.6	36.8
	JEC v5	53.0	-4.6	76.2	-76.2	48.4		
FAME from tallow	GREET	0.0	19.5	76.5	-72.1	23.9	20.3	27.8
	JEC v5	5.3	8.5	76.2	-76.2	13.8		
RD/HVO from soybean	GREET	9.1	11.4	73.3	-72.6	21.2	20.3	24.7
	JEC v5	84.1	-23.9	70.8	-70.8	60.2		
RD/HVO from canola/rapeseed	GREET	18.4	10.8	73.3	-72.6	30.0	28.9	31.0
	JEC v5	53.0	-1.0	70.8	-70.8	51.9		
RD/HVO from UCO	GREET	10.8	10.1	73.3	-72.6	21.6	20.2	25.3
	JEC v5	0.0	11.1	70.8	-70.8	11.1		
FT diesel from forest residue	GREET	1.9	2.5	73.0	-72.3	5.2	5.0	5.3
	JEC v5	8.6	1.1	70.8	-70.8	9.7		
RD/HVO from fast pyrolysis of forest residue	GREET	4.2	20.3	73.3	-72.6	25.2	24.5	26.0
	JEC v5	7.2	15.7	73.2	-73.2	22.9		

Table S19. WTT and combustion results of gaseous fuel SI ICEVs (g CO_2e/MJ)

		Feedstock production	Fuel production	Combustion	Biogenic carbon	Avoided counterfactual emissions	Total	P10	P90
Fossil CNG	GREET	13.4	2.7	57.1	0.0	0.0	73.2	71.1	75.4
	JEC v5	8.8	3.1	56.2	-1.9		68.2		
Manure AD RNG	GREET	0.0	-92.3	57.1	-56.3	1.3	-90.2	-90.5	-88.7
	JEC v5	-111.0	8.1	56.7	-56.7		-103.0		
MSW AD RNG	GREET	0.0	20.8	57.1	-56.3	-122.1	-100.5	-101.4	-99.5
	JEC v5	0.0	9.5	56.7	-56.7		9.5		
Sewage sludge AD RNG	GREET	0.0	10.9	57.1	-56.3	-103.1	-91.4	-95.7	-86.4
	JEC v5	0.0	22.3	56.7	-56.7		22.3		

Table S20. WTT and combustion results of BEVs (g CO_2e/MJ)

		Feedstock production	Electricity generation	Combustion	Biogenic carbon	Total	P10	P90
BEV, Average Grid	GREET	10.3	96.6	0.0	0.0	106.9	100.2	117.0
	JEC v5	0.0	74.5	0.0	0.0	74.5		
BEV, Renewable Grid	GREET	0.0	0.5	0.0	0.0	0.5	0.5	0.5
	JEC v5	0.0	0.0	0	0	0		

Table S21. WTT and combustion results of FCEVs (g CO_2e/MJ)

		Feedstock production	H_2 production	Combustion	Biogenic carbon	Total	P10	P90
H_2 from NG (w/o CCS)	GREET	6.2	85.6	0.0	0.0	91.8	84.0	99.9
	JEC v5	17.0	83.8	0.0	0.0	100.8		
H_2 from NG (w/ CCS)	GREET	6.2	18.0	0.0	0.0	24.2	10.9	31.6
	JEC v5	17.7	22.0	0	0	39.7		
H_2 from average electricity mix	GREET	155.4	0.0	0.0	0.0	155.4	141.5	184.0
	JEC v5	113.0	5.7	0	0	118.6		
H_2 from renewable electricity mix	GREET	0.8	0.0	0	0	0.8	0.7	0.9
	JEC v5	0.0	9.5	0	0	9.5		

1.7.4 Per km WTW results

Table S22. WTW results for liquid fuel SI ICEVs (g CO_2e/km)

		WTP (WTT)	Vehicle operation	Total	P10	P90
Low-ethanol petroleum gasoline	GREET (E10)	35.0	159.4	194.4	191.2	199.8
	JEC v5 (E10)	19.7	103.8	123.5		
	JEC v5 (E5)	21.9	103.9	125.8		
EtOH from corn	GREET (E85)	-25.3	156.7	131.4	119.5	146.1
	JEC v5 (E100)	-22.1	100.8	78.7		
EtOH from sugarcane	GREET (E85)	-69.6	156.7	87.1	80.9	94.1
	JEC v5 (E100)	Not available				
Cellulosic EtOH	GREET (E85)	-93.8	156.7	62.9	58.2	93.0
	JEC v5 (E100)	-75.2	100.8	25.6		

Table S23. WTW results for liquid fuel CI ICEVs (g CO_2e/km)

		WTP (WTT)	Vehicle operation	Total	P10	P90
Diesel	GREET	29.1	150.2	179.3	166.0	190.5
	JEC v5	24.4	96.3	120.8		
B7	GREET (Soybean)	21.8	150.3	172.1	160.5	180.0
	JEC v5 (EU mix)	19.8	96.6	116.3		
RD/HVO from soybean	GREET	-103.5	145.5	42.1	39.7	50.2
	JEC v5	-17.5	92.7	75.3		
RD/HVO from rapeseed	GREET	-86.0	145.5	59.5	56.4	61.8
	JEC v5	-24.4	92.7	68.3		
RD/HVO from UCO	GREET	-102.6	145.5	43.0	39.7	50.2
	JEC v5	-77.0	92.7	15.7		
FT diesel from forest residue	GREET	-134.7	145.0	10.2	9.8	10.6
	JEC v5	-77.0	92.7	15.7		
RD/HVO from fast pyrolysis of forest residue	GREET	-95.6	145.5	49.9	47.8	51.9
	JEC v5	-65.2	96.3	31.1		

Table S24. WTW results for gaseous fuel SI ICEVs (g CO_2e/km)

		WTP (WTT)	Vehicle operation	Total	P10	P90
Fossil CNG	GREET	33.4	118.6	152.0	144.2	157.4
	JEC v5	20.9	78.4	99.4		
Manure AD RNG	GREET	-305.9	118.6	-187.3	-191.5	-178.7
	JEC v5	-221.1	80.5	-140.6		
MSW AD RNG	GREET	-327.3	118.6	-208.7	-215.8	-200.5
	JEC v5	-221.1	80.5	-140.6		
Sewage sludge AD RNG	GREET	-308.3	118.6	-189.7	-200.2	-176.8
	JEC v5	-47.6	80.5	32.9		

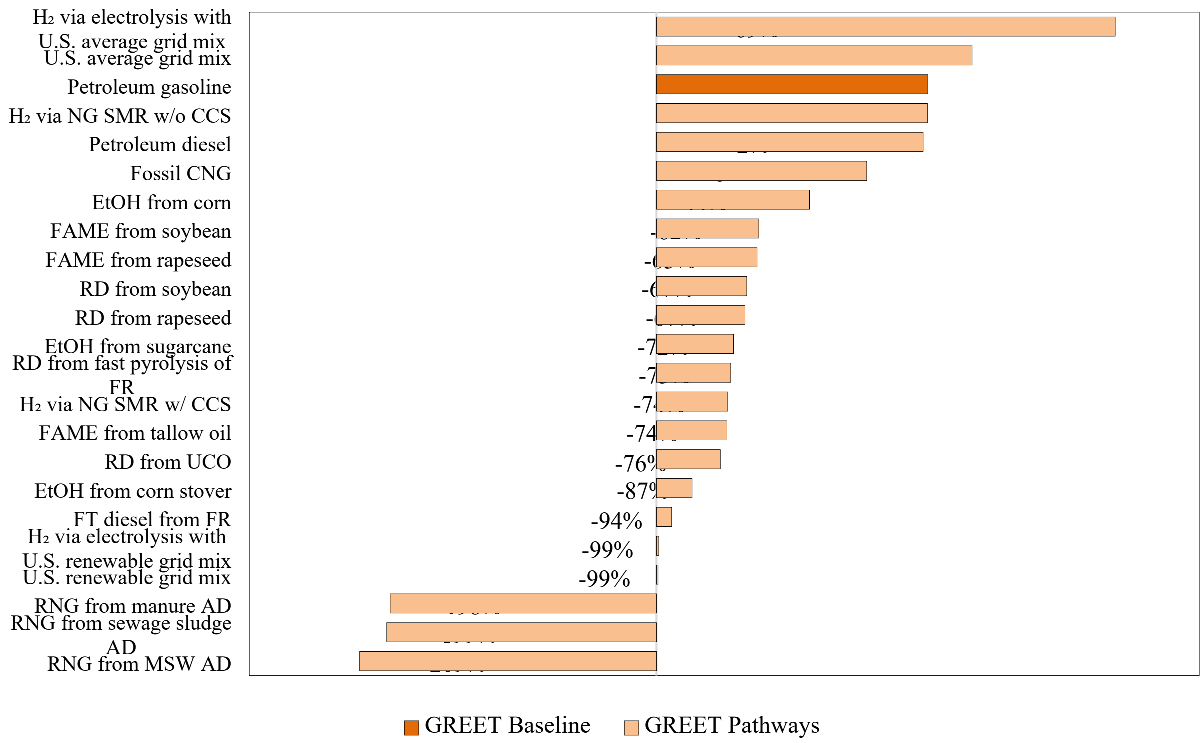
Table S25. WTW results for BEV (g CO_2e/km)

		WTP (WTT)	Vehicle operation	Total	P10	P90
Short-range BEV, average grid	GREET (161)	67.7	0	67.7	62.8	74.7
	JEC v5 (200)	31.9	0.0	31.9		
Short-range BEV, renewable grid	GREET (161)	0.3	0	0.3	0.3	0.4
	JEC v5 (200)	0	0	0		
Long-range BEV, average grid	GREET (483)	73.1	0.0	73.1	68.7	83.1
	JEC v5 (400)	33.3	0.0	33.3		
Long-range BEV, renewable grid	GREET (483)	0.4	0.0	0.4	0.4	0.4
	JEC v5 (400)	0.0	0.0	0.0		

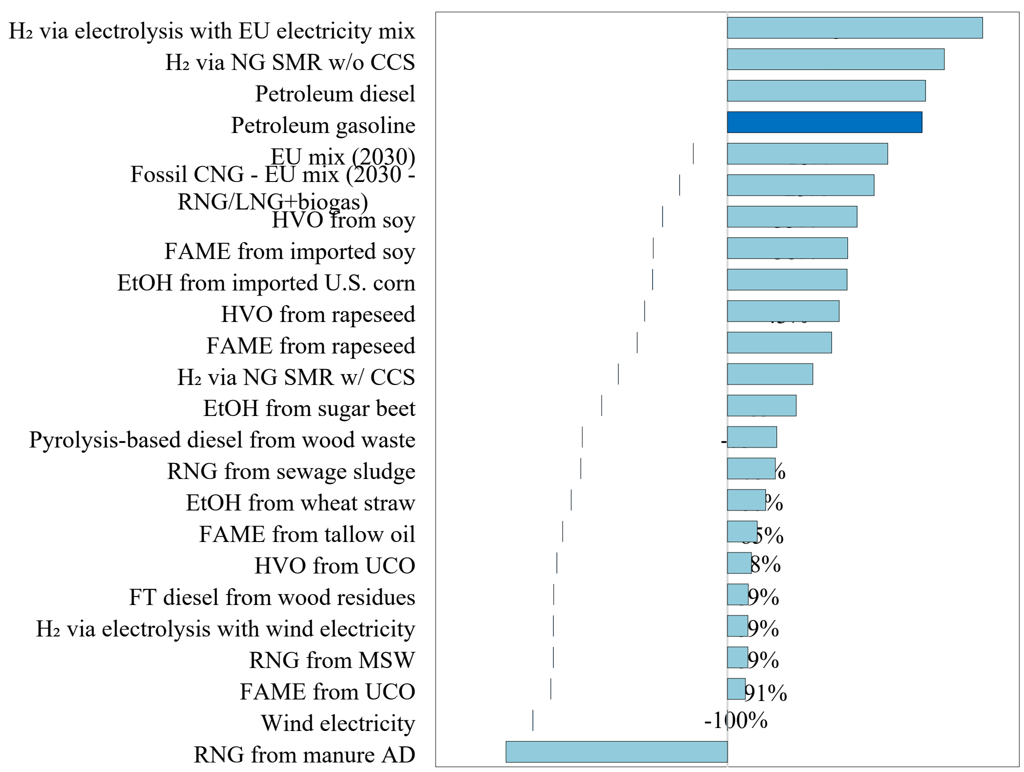
Table S26. WTW results for FCEVs (g CO_2e/km)

		WTP (WTT)	Vehicle operation	Total	P10	P90
H_2 from NG (without CCS)	GREET	88.2	0.0	88.2	79.9	96.1
	JEC v5	70.3	0.0	70.3		
H_2 from NG (with CCS)	GREET	23.2	0.0	23.2	10.7	30.1
	JEC v5	27.7	0.0	27.7		
H_2 from average electricity mix	GREET	149.3	0.0	149.3	136.3	176.1
	JEC v5	82.7	0.0	82.7		
H_2 from renewable electricity mix	GREET	0.8	0.0	0.8	0.7	0.8
	JEC v5	6.6	0.0	6.6		

3. Relative per MJ WTT and combustion GHG results



(a)



(b)

Figure S1. Per MJ WTT and combustion GHG emission reductions of fuel pathways relative to baseline petroleum gasoline (a) in the United States according to GREET and (b) in EU according to JEC v5. The results are normalized to the U.S. petroleum gasoline blendstock and EU petroleum gasoline blendstock as the baseline, respectively.

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