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Policy Analysis

Impacts of the Inflation Reduction Act on the Economics of Clean Hydrogen and Synthetic Liquid Fuels

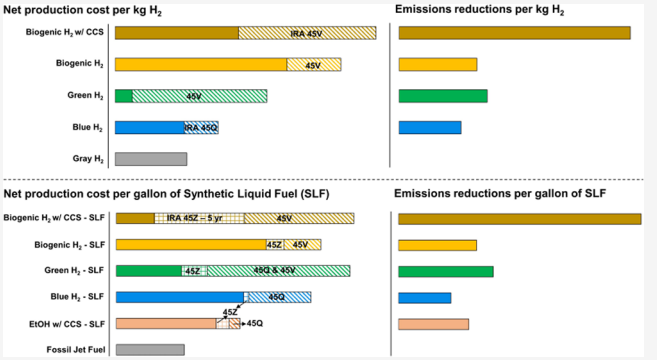
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ABSTRACT: The Inflation Reduction Act (IRA) in the United States provides unprecedented incentives for deploying low-carbon hydrogen and liquid fuels, among other low-greenhouse gas (GHG) emissions technologies. To better understand the prospective competitiveness of low-carbon or negative-carbon hydrogen and liquid fuels under the IRA in the early 2030s, we examined the impacts of the IRA provisions on the costs of producing hydrogen and synthetic liquid fuel made from natural gas, electricity, short-cycle biomass (agricultural residues), and corn-derived ethanol. We determined that, with IRA credits (45V or 45Q) but excluding the incentives provided by other national or state policies, hydrogen produced by electrolysis using carbon-free electricity (green H_2) and by natural gas reforming with carbon capture and storage (CCS) (blue H_2) is cost-competitive with the carbon-intensive benchmark gray H_2, which is produced by steam methane reforming. Biomass-derived H_2 with or without CCS is not cost-competitive under the current IRA provisions. However, if the IRA allowed biomass gasification with CCS to claim a 45V credit for carbon-neutral H_2 and a 45Q credit for negative biogenic CO_2 emissions, this pathway would be less costly than gray H_2. The IRA credit for clean fuels (45Z), currently stipulated to end in 2027, would need to be extended or similar policy support would need to be provided by other national or state policies in order for clean synthetic liquid fuel to be cost-competitive with petroleum-derived liquid fuels. The levelized IRA subsidies per unit of CO_2 mitigated for all of the hydrogen and synthetic liquid fuel production pathways, except for electricity-derived synthetic liquid fuel, range from $65−$384/t of CO_2. These values are within or below the range of the U.S. federal government's estimates of the social cost of carbon (SCC) in the 2030−2040 time frame.



KEYWORDS: *Inflation Reduction Act (IRA), Energy policy, Hydrogen, Synthetic liquid fuels, Bioenergy with carbon capture and storage (BECCS), Electrofuels, Economics*

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INTRODUCTION

In the United States, a commitment to cut greenhouse gas (GHG) emissions to half of the peak levels by 2030 and to net zero by midcentury has become a major driver for new laws that accelerate this clean energy transition.[1−3] The 2022 Inflation Reduction Act (IRA) provides unprecedented incentives for deploying low-GHG emissions technologies. These incentives include investment and production tax credits (ITCs and PTCs, respectively) that are designed to encourage businesses to invest in clean energy technologies.[a] The IRA's tax credits and other mechanisms are projected to result in an estimated $370 billion (potentially more) of federal government outlays toward this goal over 10 years (2023−2032),[4] including 45V credits for hydrogen that is produced with a lifecycle carbon intensity <4 kg of CO_2e/kg of H_2, 45Q credits for CO_2 capture, utilization, and storage (CCUS), 40B and 45Z credits for low-carbon emission liquid fuels, and 48D and 45Y credits for carbon-free electricity generation, e.g., from nuclear, wind, or solar. The IRA also stipulates penalties for emissions of methane from specific types of facilities, primarily in the oil and gas sector.[5,6]

Several macro-energy system modeling studies have estimated that investments stimulated by the IRA would help reduce U.S. GHG emissions to 33−40% below the levels of 2005 by 2030.[7−10] These studies estimate that GHG emissions reductions under the new law come largely from the decarbonization of the power sector via wind and solar power generation.[7,8] The act significantly boosts investment in wind, power, and solar photovoltaics (PVs), almost doubling the annual capital investment from $181 billion under existing policy (i.e., no IRA) to $334 billion in 2030.[7] In addition to

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Table 1. Summary of Evaluated Technologies for H_2 and SLF Production and Applicable Policies

	technology[a]	feedstock	relevant IRA credits[b]	other policy[c]
		Hydrogen (H_2)		
P1 SMR	steam methane reforming	natural gas[d]	N/A	N/A
P2 SMR-CCS	steam methane reforming w/ CCS	natural gas[d]	45Q or 45V	N/A
P3 ATR-CCS	autothermal reforming w/ CCS	natural gas[d]	45Q or 45V	N/A
P4 electrolysis	electrolysis	electricity (wind/solar)[e]	45V	N/A
P5 BG-H2	gasifier + water-gas-shift	biomass[f]	45V	N/A
P6 BGCCS-H2	gasifier + water-gas-shift w/ CCS	biomass[f]	45Q or 45V	N/A
		Synthetic Liquid Fuels (SLFs)[g]		
		Synthesis from Clean H_2 and Carbon-Neutral CO_2		
P7 SMR-SLF	SMR-CCS + reverse water-gas-shift-Fischer–Tropsch synthesis (RWGS-FTS)	H_2 (P2), CO_2 DAC (direct air capture)[h]	45Q or 45V for H_2, 45Q for CO_2 from DAC, 45Z	LCFS
P8 ATR-SLF	ATR-CCS + RWGS-FTS	H_2 (P3), CO_2 DAC[h]	45Q or 45V for H_2, 45Q for DAC, 45Z	LCFS
P9 elec-SLF	electrolysis + RWGS-FTS	H_2 (P4), CO_2 DAC[h]	45V for H_2, 45Q for DAC, 45Z	LCFS
P10 BG-SLF	BG-H2 + RWGS-FTS	H_2 (P5), bio-CO_2	45V for H_2, 45Z	LCFS
P11 BGCCS-SLF	BGCCS-H2 + RWGS-FTS	H_2 (P6), bio-CO_2	45Q or 45V for H_2, 45Z	LCFS
		Integrated Biomass-Gasification/FT Synthesis		
P12 int. bio-SLF	integrated biogasifier-FTS	biomass	45Z	RFS (D3),[j] LCFS
P13 int. bioCCS-SLF	integrated biogasifier-FTS w/ CCS	biomass	45Q or 45Z	RFS (D3),[j] LCFS
		Ethanol-to-SLF		
P14 EtOH-SLF	corn-derived ethanol[i] to SLF	corn-derived ethanol	N/A	RFS (D6),[j] LCFS
P15 EtOHCCS-SLF	corn-derived ethanol[i] w/ CCS to SLF	corn-derived ethanol w/ CCS	45Q and 45Z	RFS (D5),[j] LCFS

[a]Pathways P1–P6, P12, and P13 represent production occurring at single facilities, exploiting the single most remunerative IRA incentive among those for which they are eligible. The IRA disallows any one facility from claiming more than one of the 45V, 45Q, and 45Z credits. Pathways P7–P9 are assumed to consist of three facilities each, which enables these pathways to incorporate three separate IRA credits: 45V or 45Q for H_2 production, 45Q for direct air capture, and 45Z for SLF production. Pathways P10 and P11 each include two facilities, one that produces H_2 and CO_2 from biomass, garnering 45V or 45Q credits, and the other that combines H_2 and CO_2 from the first facility to synthesize liquid fuels, collecting 45Z credits. Similarly, pathway P15 includes capture of fermentation CO_2 at a stand-alone ethanol facility, claiming 45Q for CCS, and a separate ethanol-to-SLF facility, claiming 45Z. [b]In addition to these listed credits, our analysis embeds IRA 45Y credits for clean electricity production into the assumed electricity price for pathway P4 and the IRA's stipulated penalties for methane emissions into the assumed natural gas price for pathways P1–P3. (See Table S1 for descriptions of IRA credits.) All pathways are assumed to satisfy prevailing wage and apprenticeship requirements and, thus, qualify for the maximum level of credit within a given type of IRA credit. [c]Other policies that are considered in this study are the LCFS and RFS, but only for the SLF pathways. While hydrogen that is used in transport may be eligible for LCFS credits,[27] we do not consider this option (see Limitations). The P7–P15 pathways produce drop-in transportation fuels, and we assume that all are eligible for LCFS credits. The integrated biomass-gasifier-FTS pathways (P12 and P13) are eligible for RFS because they produce SLF directly from lignocellulosic biomass. [d]We assume upstream natural gas emissions of 1.7% (0.29 g of methane per MJ of delivered natural gas).[28] The IRA methane emissions penalty is $1500/t starting in 2025 (Table S1). We reflect this in the natural gas price assumed in our analysis ($4.3/GJ, see Table S3). The lifecycle upstream GHG emissions of natural gas is 13.8 kg of CO_2/GJ_{HHV} (Table S4), and its carbon content is 50 kg of CO_2/GJ_{HHV} (Table S5). [e]The electrolysis pathway is assumed to use wind- and/or solar-derived electricity as its input. The 45Y clean electricity PTC is incorporated into the electricity price that is assumed in our analysis. The input electricity price after applying the 45Y subsidy is $21.5/MWh (see Table S3), and the capacity factor for electrolysis is 0.55.[13,22] [f]The biomass used here is assumed to be agricultural residue, and we treat its biogenic CO_2 to be carbon-neutral, which is consistent with its treatment in the billion-ton study.[29] Upstream (nonbiogenic) emissions of 5.08 kg of CO_2/GJ (Table S4) are assumed from harvesting, transport, and preprocessing. The delivered cost of the biomass is $6.1/GJ (Table S3), and its carbon content is 87.9 kg of CO_2/GJ_{HHV} (Table S5). [g]A variety of SLF compositions are possible, depending on the process design. Here, we assume the composition to be 82% synthetic paraffinic kerosene (SPK) and 18% naphtha (lower heating value basis). This composition was determined in a prior detailed process modeling study that involved one of this paper's authors.[30] [h]For P7–P9, the requisite carbon-neutral CO_2 input is assumed to be from direct air capture (DAC) powered by renewable energy. The IRA's 45Q credit ($130/t of CO_2 for 12 years) is applied to reduce the cost of the CO_2 from DAC, giving CO_2 costs of $164/t of CO_2 (see footnote e of Table S3). [i]The corn-derived ethanol is assumed to be 90% from dry mills and 10% from wet mills (the U.S. industry average from GREET),[31] with a delivered cost of $1.83/gal (Table S3). For the corn-derived ethanol with CCS, the CO_2 from fermentation is compressed, transported, and stored at an added cost of $45/t of CO_2 (Table S3). [j]Pathways P12 and P13 can claim RFS cellulosic biofuel (D3) credits. Pathways P14 and P15 are eligible for RFS renewable fuel (D6) and advanced biofuel (D5) credits, respectively, based on the GHG emissions reductions that they provide.

investment in the power sector, modeling results also show the IRA driving annual capital investments of $60 billion by 2035 in hydrogen and $30 billion in synthetic liquid fuels (SLFs), including electrofuels and biomass-derived SLFs.[7]

Many modeling studies emphasize the crucial roles of hydrogen and SLFs in clean energy transitions.[11−13] H_2 is currently an important feedstock that is used in ammonia production and oil refining.[14] In addition to existing demands, H_2 has the potential to play a critical role in decarbonizing steel production,[12,15] power generation,[12,16] transportation,[17] and the petrochemical industry,[12,18] among others. For example, steel produced by clean H_2-based direct reduction of iron–electric arc furnace processes results in a 60% GHG emissions reduction when compared to conventional blast furnace–basic oxygen furnaces.[15] Biofuels and SLFs can be drop-in alternatives to petroleum-derived liquid fuels (e.g., jet fuel, diesel, and gasoline). Since SLFs can generally be utilized without requiring radical changes to fuel distribution and usage

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Table 2. Summary of the Evaluation of Hydrogen and SLF Technologies[a]

	technology	input feedstock intensity (IFI) (GJ_{in}/GJ_{out})	co-product (GJ/GJ)	CO_2 capture rate (%)	CAPEX ($/kW capacity)	fixed O&M ($/kW-year)	variable O&M ($/GJ)
H_2	SMR	1.23 (NG)	0	0	543	19	0.36
	SMR-CCS	1.26 (NG)	0.024	91.2	943	28	0.00
	ATR-CCS	1.2 (NG)	0.048	94.1	825	25	0.00
	electrolysis	1.28 (electricity)	0	0	1407	16	0.00
	BG-H2	1.78 (biomass)	−0.079	0	2482	44	3.89
	BGCCS-H2	1.78 (biomass)	−0.023	87	2587	46	3.89
SLF	RWGS+FTS	1.47 (H_2)	0	0	1004	27	0.73
	integrated bioFTS	2.02 (biomass)	0	0	3826	77	5.15
	integrated bioFTS-CCS	2.02 (biomass)	0	87	3944	79	5.15
	ethanol-to-jet	1.09 (ethanol)	0	0	258	26	2.15
	ethanol w/ CCS-to-jet	1.09 (ethanol)	0	0	258	26	2.15

[a]Here, parameter values are given per unit of output capacity or output energy. The energy values are on a higher heating value (HHV) basis. IFI is the input energy divided by the output energy (HHV). The co-product is the electricity for all of the cases; positive values are inputs, and negative values are outputs. See the SI, Section 3 (Table S2) for supporting details.

systems, they represent promising paths to displacing petroleum-derived liquid fuels for use in heavy-duty trucks, ships, and aircraft, thus reducing hard-to-abate emissions from the transportation sector.[12]

Currently, natural gas reforming is the primary process for hydrogen production in the U.S. with lifecycle GHG emissions of 10−12 kg of CO_2e/kg of H_2, depending on the conversion efficiency and level of upstream methane emissions.[19] Direct use of petroleum-derived liquid fuels accounts for about 88% of U.S. transportation fuel usage, while biofuel (primarily corn-derived ethanol) accounts for 5%.[20] Without policy support, nascent clean H_2 and SLF production technologies today are not competitive with their carbon-intensive fossil fuel counterparts. The IRA and other policy support is aimed at helping clean options gain early footholds in markets, scale up commercial deployment, and achieve cost reductions via economies of scale, experience, and incremental innovation, which support policies have previously achieved for other technologies, e.g., wind generation.[21]

In our previous study,[22] we analyzed technologies for H_2 and Fischer−Tropsch liquid (FTL) production and determined their environmental and economic performance in the context of an assumed universally applied carbon tax. Here, building on that work, we seek to provide a timely and nuanced analysis of specific provisions of the IRA that affect the cost-competitiveness of low-carbon and negative-carbon hydrogen and SLF production relative to carbon-intensive fossil fuel equivalents. The needed energy transition will be facilitated if clean H_2 and SLFs are less costly to produce than their fossil fuel counterparts. Other policies, including the federal Renewable Fuel Standard (RFS)[23] and California's Low Carbon Fuel Standard (LCFS),[24] have promoted clean fuels production for transportation prior to the passage of the IRA. Credit values under these programs have fluctuated significantly during the past 10 years, ranging from $0.05−$3/RIN in the RFS program[25] and from $20−$210/t of CO_2 in the LCFS program,[26] as discussed in Section S2 of the Supporting Information (SI).[b] Fuel producers can collect these incentives in combination with IRA credits, and we assess the potential outcomes of doing so.

In this paper, we present plant-level, techno-economic assessments in order to determine the levelized cost of fuel production (LCOF) for each of the 15 different clean hydrogen or SLF production technological pathways (Table 1), taking into consideration provisions of the IRA, RFS, and LCFS (Table S1). We compare the LCOFs of clean H_2 and SLFs with the production costs of equivalent fossil benchmarks (gray H_2 and petroleum-derived liquid fuel). The time frame of relevant IRA credits, their monetary values, and relevant statutory requirements are summarized in Table S1.

Overall, we seek to answer the following questions regarding clean hydrogen and clean liquid fuels:

(1) Can the IRA incentives make clean hydrogen and clean liquid fuels competitive on a production-cost basis in the 2030 time frame with their conventional, carbon-intensive, fossil fuel-based equivalents?

(2) Does the IRA appear to favor some production technology pathways over others?

(3) Are there shortcomings in the design of the IRA incentives for production of these materials, and if so, what modifications might help mitigate these?

METHOD

The time frame for relevant IRA credits, their values for different carbon intensity products, and other relevant statutory requirements are summarized in Table S1. Building on details provided in our previous study,[22] the performances and costs of technologies prospectively commercially deployed in the early 2030s are summarized in Table 2. Table S2 provides additional details. For pathways P1−P11, we used performance and cost data, as well as methods, from our previous study (Table 2), but with adjustments to the LCOF calculations in order to incorporate the impact of provisions of the IRA (Table S1) and of the LCFS and RFS (SI, Section 3). Pathways P12−P15 were not included in our previous study. We developed performance and cost metrics for these that are consistent with those in our prior study, as described in footnotes g and h of Table S2. All facilities are assumed to start operating by 2032 and have a book life of 15 years. We assumed that the plants start up in the early 2030s because (1) IRA credits accrue only to a producer who commences construction by the end of 2032 and (2) the time available between today and 2032 seems sufficient for commercial projects to be launched by then.

We use a derating factor (DF) to account for the impacts of different policy durations (e.g., 10 years for 45V and 12 years for 45Q) over the evaluated 15-year project lifetimes. A DF of

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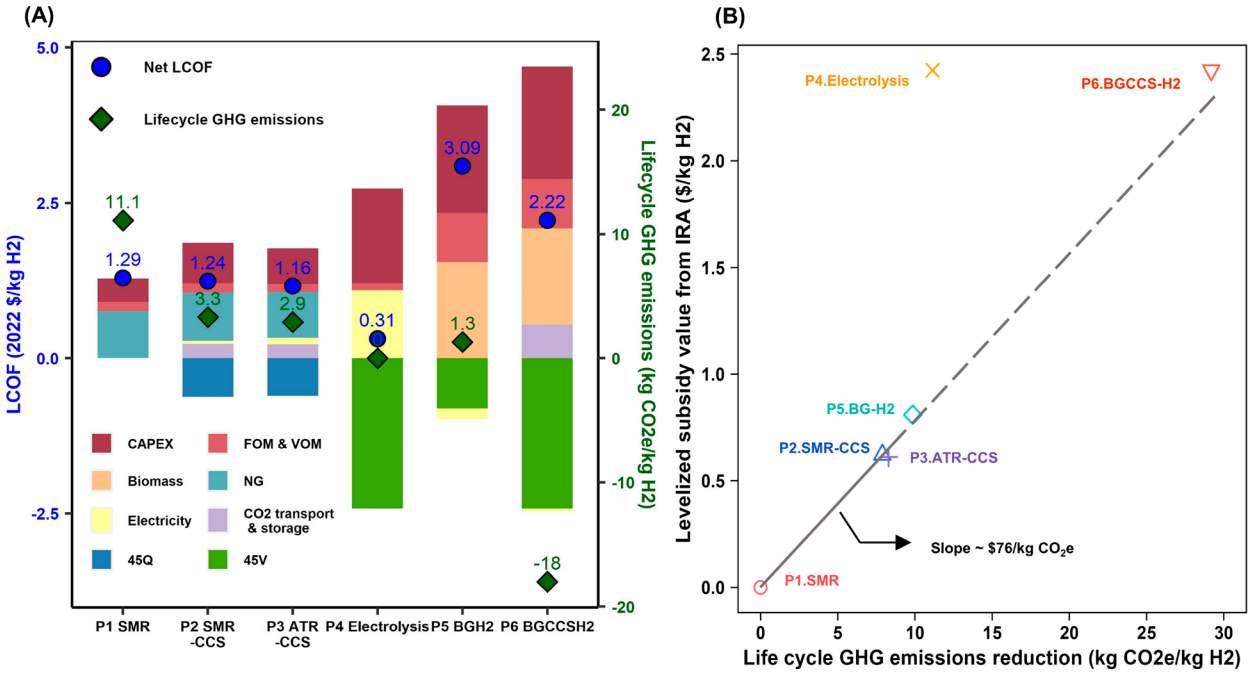


Figure 1. (A) Levelized cost of fuel production (LCOF), where positive values are costs and negative values are revenues from co-product sales or IRA credits, and lifecycle GHG emissions for the benchmark (P1 SMR) and five lower-emissions hydrogen production pathways. Methane emission fees are embedded in our assumed natural gas price for P1−P3, and 45Y clean electricity credits are embedded in our assumed electricity price for P4 (see Table S3). The lifecycle GHG emissions for P1−P6 (assuming GWP_{100} for non-CO_2 GHGs) are adopted from our previous analysis,[22] and 142 GJ_{HHV}/kg of H_2 is used to convert from kg of CO_2e/GJ_{HHV} in ref 22 to kg of CO_2e/kg of H_2. The IRA credits shown here are expressed as derated values to account for project economic lifetimes longer than the IRA-stipulated durations over which incentives are available, e.g., the $1/kg of H_2 and $3/kg of H_2 45V credits are derated to $0.8/kg of H_2 and $2.4/kg of H_2, respectively (see the discussion around eq 1 in Method). (B) Levelized IRA subsidy values as a function of the lifecycle GHG emissions reductions for clean hydrogen (P2−P6) versus the benchmark (P1).

1 means that the provision is available during the entire project lifetime. DF is determined by eq 1:

$$\mathrm{DF} = \frac{\sum_1^m (1/(1+r))^m}{\sum_1^n (1/(1+r))^n} \tag{1}$$

where r is the real weighted-average cost of capital (WACC), n is the book life of the facility (15 years), and m is the duration of the IRA provision (Table S1). A WACC value of 0.1 is used, as was used by Jones and Haley in modeling the H_2 and SLF production technologies in Annex A.2 of the Net-Zero America report.[13]

LCOFs for the hydrogen pathways are determined by eq 2:

$$\mathrm{LCOF}_{\mathrm{p,H_2}}(\$/\mathrm{kg}) = \frac{\mathrm{CAPEX_p} \times \mathrm{CRF} + \mathrm{FOM_p} + \mathrm{VOM_p} + F_\mathrm{p} + \mathrm{Seq_p}}{M_{\mathrm{p,H_2}}} - \frac{\mathrm{Max}(M_{\mathrm{ccs,p}} \times 45\mathrm{Q_p} \times \mathrm{DF_{45Q}}, M_{\mathrm{H_2,p}} \times 45\mathrm{V_p} \times \mathrm{DF_{45V}})}{M_{\mathrm{p,H_2}}} \tag{2}$$

where subscript p refers to a specific H_2 generation pathway (P1−P6), CAPEX is the overnight capital cost of the facility ($), CRF is the annual capital recovery factor (0.131), FOM is the annual fixed operating and maintenance cost ($), VOM is the annual nonfuel variable cost ($), F is the annual cost of feedstock (natural gas, electricity, or biomass; $), Seq is the annual CO_2 transport and storage cost ($), M_{H_2} is the annual hydrogen production (kg), M_{ccs} is the annual CO_2 sequestered (t), 45Q is the tax credit for CCUS ($/t of CO_2; based on Table S1), DF is the derating factor (eq 1), and 45V is the tax credit for clean hydrogen production ($/kg, as in Table S1). The hydrogen product that leaves the facility gate is at 30 bar. For all of the hydrogen production pathways other than electrolysis (P4), the final hydrogen product is delivered from pressure swing adsorption (PSA) units, which typically operate at a pressure around 30 bar.[32] For P4, the hydrogen product is delivered directly from PEM electrolyzers, which are currently capable of delivering H_2 at 30 bar.[33] The capacity factor for the H_2 routes is assumed to be 0.85, except for electrolysis, where it is assumed to be 0.55 (see footnote e of Table 1).

The SLF output of P7−P15 is assumed to be 82% synthetic paraffinic kerosene (SPK) and 18% naphtha on a lower heating value basis (see Table 1, footnote g). The 45Z credit is $1.75/gal and $1/gal for sustainable aviation fuel (SAF) and other types of clean fuels (e.g., synthetic diesel), respectively. Therefore, the 45Z tax credit for 1 gal of SLF in our analysis is $1.75 × 0.82 + $1 × 0.18 = $1.62/gal before applying any DF value. One gallon of SLF has a lower heating value (LHV) of 0.126 GJ. LCOFs of the liquid fuel pathways are determined by eq 3:

$$\mathrm{LCOF_p}(\$/\mathrm{gal}) = \frac{\mathrm{CAPEX_p} \times \mathrm{CRF} + \mathrm{FOM_p} + \mathrm{VOM_p} + F_\mathrm{p} + \mathrm{Seq_p}}{V_{\mathrm{p,SLF}}} + \frac{M_{\mathrm{dac,p}}(P_{\mathrm{dac}} - 45\mathrm{Q_{dac}} \times \mathrm{DF_{45Q}})}{V_{\mathrm{p,SLF}}} - \frac{M_{\mathrm{CO_2,ethanol,p}}(45\mathrm{Q_{ccs}} \times \mathrm{DF_{45Q}})}{V_{\mathrm{p,SLF}}} - (\mathrm{EF_p} \times \mathrm{DF_{45Z}} \times 45\mathrm{Z}) - \mathrm{RFS_p} - \mathrm{LCFS_p} \tag{3}$$

where subscript p refers to a specific SLF pathway (P7−P15), CAPEX, CRF, FOM, VOM, and Seq are analogously defined as for eq 2, F is the annual cost of feedstock ($; for biomass, ethanol, or H_2, where the H_2 cost is determined by eq 2), V_{SLF}

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is the annual SLF production (gal), M_{dac} is the annual external CO_2 from DAC that is used for SLF production (t), P_{dac} is the price of the CO_2 from DAC (i.e., \$280/t of CO_2, see footnote e of Table S3), $45Q_{dac}$ is the tax credit for CO_2 utilization from a DAC facility (i.e., \$130/t of CO_2, see Table S1), $M_{CO_2,ethanol}$ is the annual CO_2 captured from a corn-derived ethanol facility (t), $45Q_{ccs}$ is the tax credit for the CO_2 captured and sequestrated from corn-derived ethanol CCS facilities (i.e., \$85/t of CO_2, see Table S1), 45Z is the full tax credit for SLF production (i.e., \$1.62/gal), EF is the emissions factor for calculating the 45Z credit (Table S1), DF is the derating factor (eq 1), RFS is the renewable identification number (RIN) credit that SLF can receive under the RFS program (\$/gal; see eq S1), and LCFS is the carbon credit under California's LCFS program (\$/gal; see eq S2). Carbon footprints for assessing the 45Z credit values are statutorily determined using the GREET model, which uses LHV values by default.[31] Therefore, we convert the lifecycle GHG emissions given in Table S4 to a LHV basis (kg of CO_2/$MMBTU_{LHV}$) and use these values to determine the EF values. The capacity factor for all of the SLF pathways is assumed to be 0.85.

The CAPEX, FOM, and VOM values and the energy conversion efficiencies that are associated with all of the pathways are given in Table 2. See Table S2 for supporting details, including data sources, assumptions, and calculations, and Tables S3 and S4 for input energy and material prices and lifecycle GHG emissions, respectively.

Finally, the levelized subsidies for CO_2 mitigation (LSCMs) that are implied in the IRA credits for clean H_2 or SLF are determined by eq 4:

$$\mathrm{LSCM_p(\$/CO_2e)} = \frac{-\mathrm{NG\ Fee_p} + 45\mathrm{V_p} + 45\mathrm{Q_p} + 45\mathrm{Z_p} + 45\mathrm{Y_p}}{\mathrm{CI_{fossil}} - \mathrm{CI_p}} \quad (4)$$

For each pathway, the credits (45V, 45Q, 45Z, and 45Y) and the methane emissions penalty (NG Fee) are converted into \$/kg of H_2 or \$/gal of SLF of the final product. CI_p is the lifecycle carbon intensity of the pathway, expressed in kg of CO_2e/kg of H_2 or in kg of CO_2e/gal of liquid fuel. CI_{fossil} represents the carbon intensity of the fossil benchmark. For H_2, this is the CI of pathway P1 (11 kg of CO_2e/kg of H_2), and for SLF, CI_{fossil} is 10.7 kg of CO_2e/gal of liquid fuel (which is representative of conventional jet fuel).

RESULTS

Hydrogen Production Pathways. Figure 1A displays LCOFs and corresponding lifecycle GHG emissions for the hydrogen production pathways.

Upstream natural gas supply chain emissions and uncaptured CO_2 result in lifecycle GHG emissions for blue hydrogen pathways, SMR-CCS (P2) and ATR-CCS (P3), of 3.3 and 2.9 kg of CO_2e/kg of H_2, respectively. Hence, these two pathways qualify for only the lowest-level 45V credit, i.e., \$0.6/kg of H_2 (Table S1), and benefit more from taking the 45Q credit. The resulting LCOF of blue hydrogen via P2 SMR-CCS (\$1.24/kg of H_2) and P3 ATR-CCS (\$1.16/kg of H_2) is slightly lower than that for the benchmark gray hydrogen (P1, \$1.29/kg of H_2). Hydrogen from electrolysis using solar- or wind-derived electricity has zero carbon emissions and, thus, receives the maximum 45V credit (\$3/kg of H_2), which reduces its LCOF to \$0.31/kg of H_2, well below the cost of gray hydrogen. Hydrogen via the P5 BG-H2 pathway has lifecycle emissions of 1.3 kg of CO_2e/kg of H_2 due to upstream GHG emissions that are associated with biomass production, processing, and transportation. Thus, the 45V credit that is available in this case is \$1.00/kg of H_2, and the LCOF is uncompetitive at \$3.09/kg of H_2. Finally, hydrogen via the P6 BGCCS-H2 pathway has negative-carbon emissions because biogenic CO_2 is captured and stored. Unlike the case with SMR-CCS and ATR-CCS, the \$3/kg of H_2 credit from 45V has a larger effect on the LCOF than the \$85/t of CO_2 credit from 45Q. Thus, we apply 45V credits and obtain an LCOF of \$2.22/kg of H_2.

These results demonstrate that the IRA is likely to drive the commercial-scale deployment of green and blue H_2. Hydrogen produced via BGCCS-H2 (\$2.22/kg of H_2) is less economically attractive than green or blue hydrogen and costs significantly more than gray hydrogen. While the 45V hydrogen credit is a tiered credit system, it does not provide additional incentive for the negative emissions that characterize BGCCS-H2. Thus, under the IRA, the economics of BGCCS-H2 could be improved either by limiting the size of the CCS equipment required to capture and sequester just enough CO_2 to claim the full 45V credit or by capturing all CO_2 and selling the excess (about 95% of the total amount captured) to other facilities for revenue, if there is a market for biogenic CO_2. If the latter strategy is pursued, the revenue from selling biogenic CO_2 at a price of about \$45/t would bring the LCOF for BGCCS-H2 to the same level as gray H_2.

For each of the hydrogen pathways, Figure 1B plots the levelized IRA 45V or 45Q incentive, expressed per kilogram of H_2 produced, against the pathway's lifecycle GHG emissions reduction relative to the emissions from the benchmark pathway (P1). It can be seen that the levelized IRA subsidy for each pathway is not uniformly proportional to its emissions reduction. In particular, the electrolysis pathway (P4) departs markedly from proportionality. One likely explanation for this discrepancy is that IRA credits have two objectives: to achieve emissions reductions from hydrogen production in the near term and to create technological advancements that reduce clean hydrogen costs in the long term. As society seeks to reach net-zero emissions by midcentury, it seems unlikely that fossil fuel-based blue hydrogen pathways (P2 and P3) will play major roles in the long run. Thus, we conclude that the IRA incentives for the P2 and P3 pathways primarily incentivize near-term emissions reductions and not technological development. This conclusion is further supported by the fact that the reforming technologies at the core of the P2 and P3 pathways are commercially mature today: there are currently at least two commercial-scale reforming projects operating with CO_2 capture and storage, and several additional projects have been announced.[34,35] In contrast, electrolysis (P4) and biomass gasification (P5 and P6) technologies are not yet commercially mature and have the potential for significant cost reduction through further technological advances and learning. P4 and P6 also have zero or negative lifecycle GHG intensities and can, thus, play a key long-term role in net-zero emissions economies. Therefore, one might logically expect that the IRA incentives for these technologies would include an emissions reduction component comparable to that of P2 or P3 plus an additional "technology policy" incentive that promotes near-term technological advancement/cost reduction.

The slope of the best-fit line drawn in Figure 1B through the methane reforming pathways (P1−P3) is \$76/t of CO_2e reduced, which could be interpreted as the amount of IRA subsidy provided strictly for reducing emissions. Extrapolating

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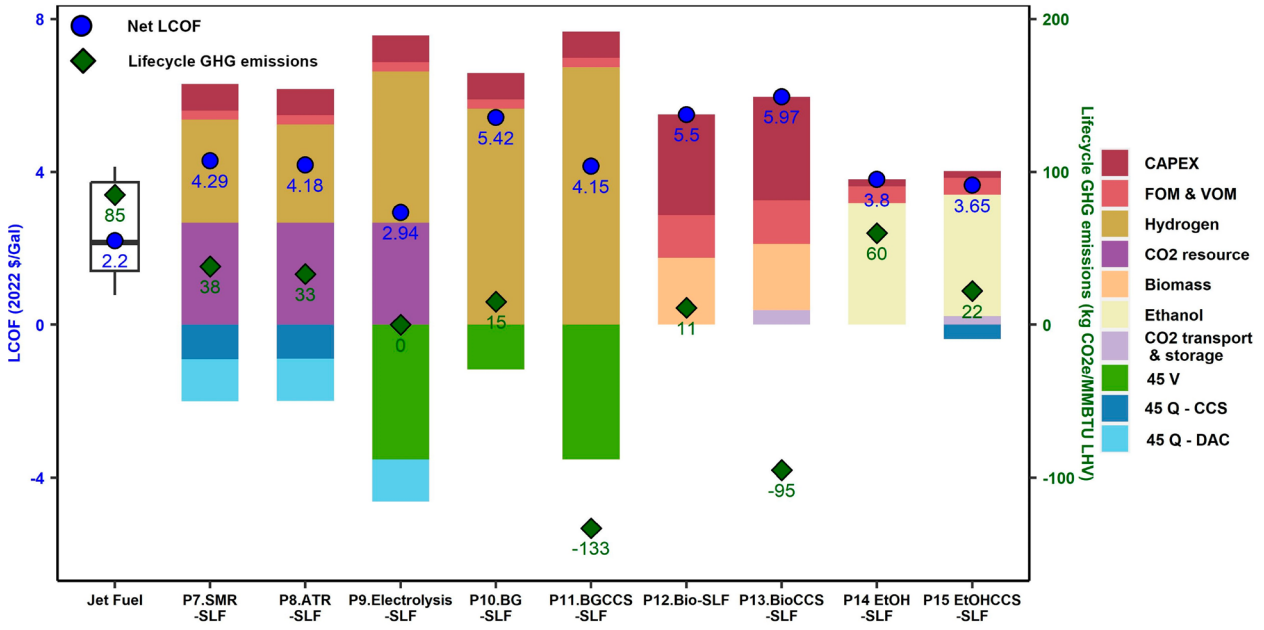


Figure 2. LCOFs and lifecycle GHG emissions (GWP_{100}) for the SLF production pathways. The SLF product is assumed to consist of 82% synthetic paraffinic kerosene (SPK) and 18% naphtha on an LHV energy basis (see Table 1, footnote g). The lifecycle GHG emissions for P7−P11 are adopted from our previous analysis[22] and converted to kg of $CO_2e/MMBtu_{LHV}$ here, assuming a HHV/LHV ratio of 1.05. The lifecycle GHG emissions of P12−P15 are determined using assumptions and methodologies consistent with ref 22. The left-most bar represents the range in the annual average wholesale petroleum jet fuel prices seen in the U.S. from 2012−2022.[41] The median value was $2.2/gal. For P7−P11, the 45V and 45Q-CCS credits shown here are those that are incorporated in the LCOF of H_2 (Figure 1A) but expressed on a per-gallon of SLF basis. The hydrogen cost plotted here is the gross H_2 cost (i.e., with the IRA credits excluded).

this line to the larger reductions in CO_2e emissions characterizing P4−P6 highlights that the IRA incentive for green hydrogen (P4), $217/t of CO_2e reduced, is nearly triple the level of incentive associated with emissions reductions alone. The additional IRA incentive aimed at spurring technological advancement and cost reduction in this case is $141/t of CO_2e reduced. Meanwhile, the total IRA incentives for H_2 for biomass gasification (P5) and BGCCS-H2 (P6) include negligible additional bonuses. It is difficult to know the reasons the IRA authors included a large bonus incentive for electrolytic hydrogen and nearly no bonus for biomass gasification-derived hydrogen. A partial explanation may be that they considered electrolysis to be an inherently modular technology, whereas biomass gasification and CCS are not. Modularity is regarded as being one of the most important factors for enabling rapid cost learning,[36] as evidenced by dramatic cost reductions and rapid market share gains of wind turbines and solar PV modules for electricity generation. Hence, a sizable IRA bonus incentive for electrolysis is well aligned with the ambitious goals of rapid societal electrification and deep decarbonization of the electricity sector. Conversely, by providing only a negligible bonus incentive for biomass gasification with CCS (P6), the pathway with the highest carbon mitigation potential, the IRA misses an opportunity to ensure early market deployment and scale-up of a technology that might also significantly contribute to rapid decarbonization and net-zero, economy-wide emission goals. If the IRA were to allow a biomass hydrogen producer to earn both 45V credits for carbon-neutral hydrogen and 45Q credits for negative biogenic CO_2 emissions, P6 hydrogen would be cost-competitive with gray (and blue) hydrogen, with an LCOF of $0.84/kg of H_2.

Synthetic Liquid Fuel Pathways. The SLF production pathways analyzed in this work (P7−P15) have three basic configurations. P7−P11 use an RWGS-FTS process, which takes clean hydrogen and carbon-neutral CO_2 derived from different processes (Table 1) as inputs, with hydrogen costs corresponding to the net LCOFs in Figure 1A. For P7−P9, the input CO_2 is assumed to be from DAC plants, and the IRA's credit for DAC under 45Q is applied to the input CO_2 price, giving $164/t of CO_2 (Table S3). Pathways P10 and P11 synthesize fuels using H_2 from P5 and P6, respectively, and carbon-neutral biogenic CO_2 recovered from the P5 and P6 facilities. The SLF costs for P10 and P11 incorporate 45V credits that are associated with the P5 and P6 facilities, which are assumed to be adjacent to, but separate from, the SLF production facility. CO_2 separation is intrinsic to making hydrogen from biomass; so, it is assumed that the SLF producer incurs no extra cost for the CO_2, beyond what is reflected in the cost of the delivered hydrogen.

Pathways P12 and P13 use biomass as input for integrated gasifier-FTS facilities, of which several configurations are under commercial development today.[37] Note that pathways P10 and P11 represent another approach to using biomass to make SLF. The design of P10 and P11 is motivated strictly by the fact that the IRA disallows any one facility from claiming more than one credit: input H_2 from a dedicated biomass-to-hydrogen facility and CO_2 from the same facility (from the separated CO_2 stream) are combined and converted to SLF via FTS at a second facility. Each facility involved may claim an IRA credit, which effectively stacks two credits, whereas the biomass-to-SLF integrated single-facility configuration of P12 or P13 is only eligible under the statute for one IRA credit at most.

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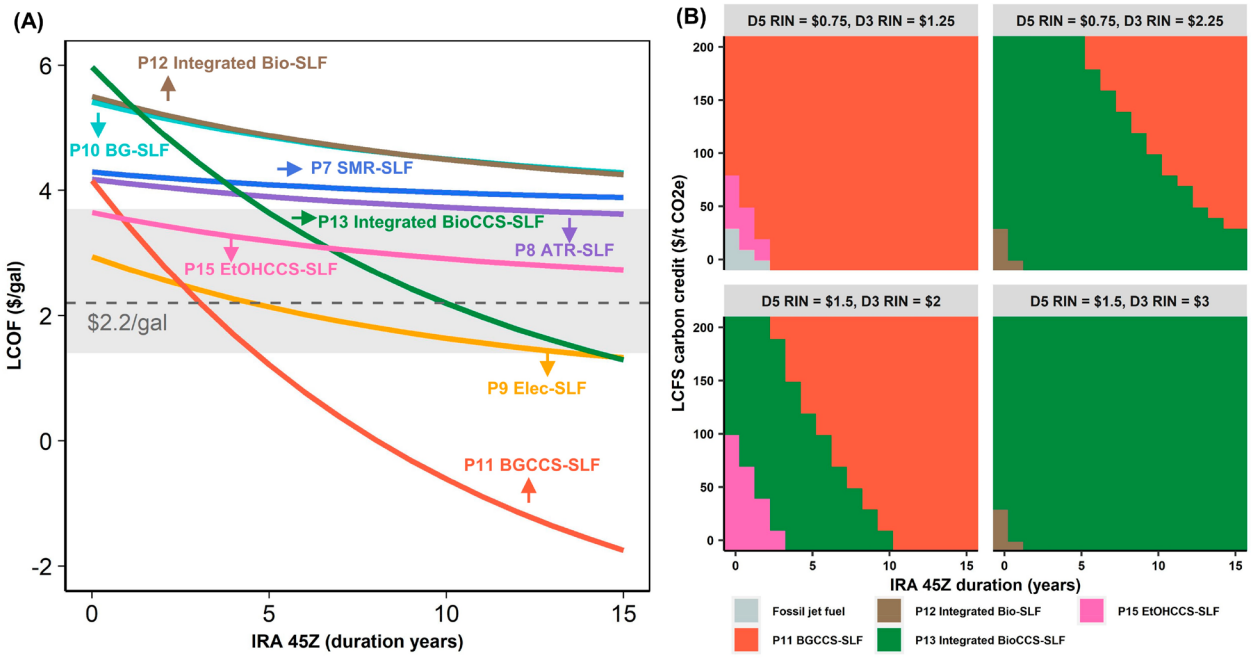


Figure 3. (A) LCOFs for the SLF production pathways as a function of 45Z duration. The shaded region represents the range in monthly average wholesale jet fuel prices in the U.S. from 2012−2022:[41] the lower bound is at the 10th percentile of the range ($1.4/gal), and the upper bound is at the 90th percentile ($3.72/gal). P14 is not shown on the graph because it is ineligible to receive 45Z and, thus, is insensitive to the duration of 45Z. (B) The SLF production pathways that would be competitive with fossil jet fuel priced at $2.2/gal under different 45Z durations, LCFS carbon credits, and RIN prices. All pathways (P7−P15) were considered in the analysis, but only P11−P13 and P15 are competitive in the variable space examined here. Pathways P12−P15 are eligible for RIN credits (at 1.64 RIN credits/gal). P14 and P15 are assumed to claim D6 and D5 RINs, respectively. Here, we assume that the D6 and D5 RIN prices are the same. P12 and P13 are assigned D3 RINs, and the D3 price is the D5 price plus $0.5 or $1.5, which are the 25th and 75th percentiles, respectively, of the price difference between D3 RINs and D5 RINs in the past 10 years. See the SI, Section 2 for a discussion of the RIN categories and prices.

Pathways P14 and P15 are based on upgrading ethanol into SLF via the dehydration of ethanol, the oligomerization of the resulting ethylene into long-chain hydrocarbons, the hydrogenation of the latter, and finally fractionation into the desired fuels (e.g., naphtha and SPK).[38] It is assumed that the ethanol used for P14 and P15 is produced at stand-alone facilities.

Unlike our analysis for hydrogen (Figure 1), we include no direct liquid fuel subsidies in our LCOF calculations for SLFs for two reasons. First, the IRA's 45Z credit that would apply to SLF is stipulated to expire in 2027 and, unlike 45V or 45Q, the 45Z credit does not offer a multiyear payment stream for projects that are eligible for the credit at the time they commence construction. Instead, payments from 45Z are made only for eligible fuels that are produced in the years in which the credit is in effect. Unless the credit is renewed and extended, it will therefore not be available to any facilities operating in the 2030s. Second, while the federal RFS and California's LCFS have been important driving factors for promoting the deployment of low-carbon fuels in the transportation sector, both credits are subject to high uncertainty and volatility (Figure S1). Hence, we chose to exclude all three of these policies from our baseline scenario analysis and instead decided to explore the impact of these as a sensitivity later in this paper.

Figure 2 presents the LCOFs and lifecycle GHG emissions for all of the SLF pathways. It was determined that using electrolytic H_2 and CO_2 from DAC to synthesize liquid fuels (P9 or "electrofuels") results in the lowest LCOF ($2.9/gal). While higher than the median value of recent fossil jet fuel prices ($2.2/gal), this estimated LCOF is within the recent historical range in jet fuel prices and, thus, may prove competitive without any explicit liquid fuel subsidy, especially for customers that have voluntary advanced market commitments to purchase sustainable aviation fuel.[39] Fossil hydrogen-based SLF pathways have much higher LCOFs at $4.3/gal (P7) and $4.2/gal (P8).

With biomass-derived H_2 and CO_2 as feedstocks (P10 and P11) or with direct biomass feedstock (P12 and P13), the LCOFs for the SLFs are generally higher, ranging from $4.2/gal to $6/gal. Comparing the two biomass-to-SLF approaches noted above, we find that the SLFs via P12 (integrated gasification-FTS) and P13 (integrated gasification-FTS with CCS) have higher LCOFs than their corresponding two-facility pathways P10 and P11, respectively. The single-facility configurations have a lower CAPEX value and a higher energy efficiency than the two-facility configurations (see footnote g of Table S2); this means that the LCOF would be lower for P12 versus P10 and for P13 versus P11 in the absence of any subsidies. However, given the IRA's prohibition against a single facility earning more than one tax credit, it is economically preferable to pursue the more capital-intensive and less efficient process of producing H_2 and CO_2 at one facility and producing SLF from H_2 and CO_2 at a different facility in order to claim multiple IRA credits. This is concerning, considering that sustainable biomass feedstock is a limited resource. This finding is explored further in the SI, Section 5.

As for the GHG emissions for P10 and P12, where CCS is not part of the pathways, total GHG emissions are due only to upstream biomass production, transportation, and processing. Since the biomass-to-SLF conversion efficiency for P12 is

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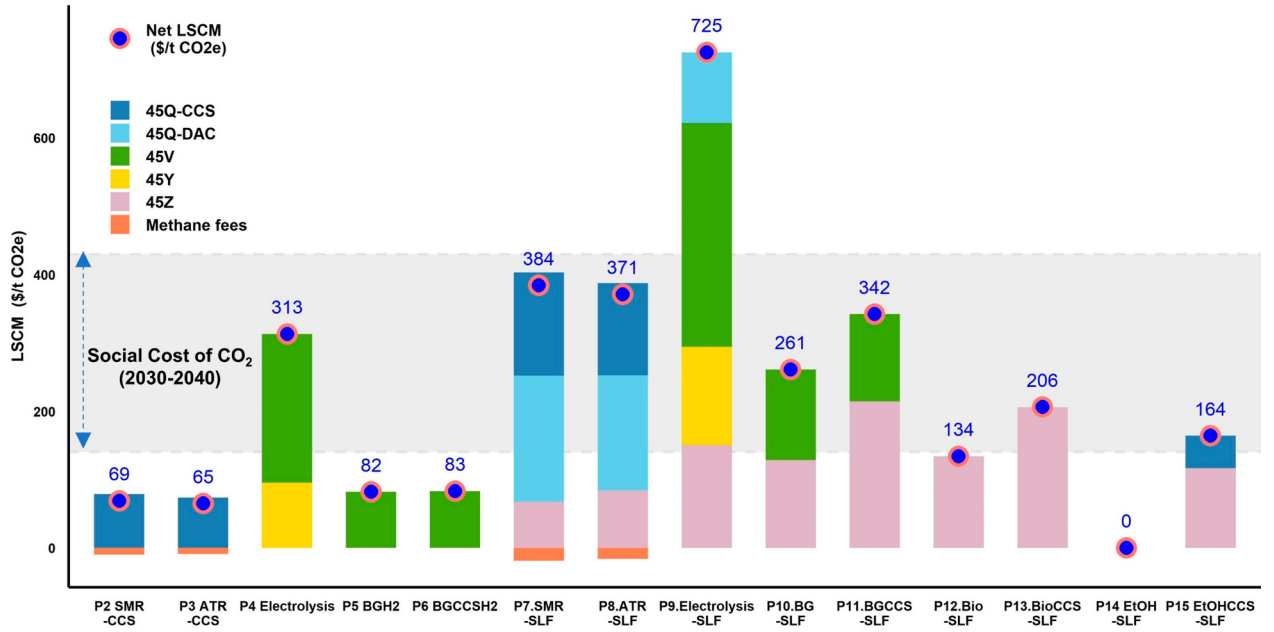


Figure 4. Levelized subsidy for carbon mitigation (LSCM) implied in IRA credits for all of the evaluated pathways. The assumed durations of 45Q, 45V/45Y, and 45Z/methane penalties are 12, 10, and 15 years, respectively. LSCM is the sum of IRA credits ($/kg of H_2 or $/gal of SLF) divided by the emissions that are avoided relative to fossil-derived hydrogen or liquid fuel. See eq 4. P14 did not receive any IRA credit. The indicated range in the social cost of CO_2 emissions (SCC) is for discount rates from 1.5% to 2.5%.[42] For 2030 and 2040, the SCC ranges are $140−$380/t of CO_2 and $170−$430/t of CO_2, respectively.

higher than that for P10, less biomass input is required for P12 and the GHG emissions are correspondingly lower. When CCS is part of the process, as in P11 and P13, biogenic CO_2 is captured and sequestered, resulting in net negative lifecycle GHG emissions. In this case, the process that converts biomass to SLF with lower efficiency (P11) results in more byproduct CO_2 that is available for capture (and less that is converted to SLF) and, thus, has more negative lifecycle GHG emissions than the more efficient pathway (P13).

Using ethanol to produce SLFs (P14 and P15) results in moderate LCOFs ($3.8/gal and $3.6/gal, respectively) that straddle the historically highest price of jet fuel seen in the past decade. These LCOFs are higher than the LCOF of electrofuels (P9) but are lower than that of the other SLF pathways evaluated in this study. The lifecycle GHG emissions of P14 are the highest among the SLF pathways, which is mostly due to emissions associated with corn-derived ethanol production, including emissions from corn farming and the heat and electricity used for refining.[40] Capturing the fermentation CO_2 (P15) reduces lifecycle emissions by nearly two-thirds, bringing them down nearly to the level of emissions for the biomass-SLF facilities without CCS (P10 and P12).

Sensitivity Analysis: Low-Carbon Fuel Subsidies. For the reasons noted previously, our baseline SLF analysis excluded any consideration of the 45Z, LCFS, or RFS credits. Here we explore how these subsidies might impact the LCOFs for SLF pathways.

To assess the impacts of extending 45Z into the 2030s, we determined the LCOF of each SLF pathway as a function of the 45Z duration, ranging from 0−15 years. Not surprisingly, longer durations yield lower LCOFs (Figure 3A). As noted earlier, the electrolysis-based pathway (P9) and the EtOHCCS-SLF pathway (P15) have LCOFs that fall within the recent historical price range for jet fuel even without any 45Z credit. If the 45Z duration is at least 2 years, then biomass-derived SLF (with H_2 and CO_2 from separate facilities, P11) also becomes competitive with historical jet fuel prices, while a 45Z term of 5 years or more would be needed to make bio-SLF at integrated facilities (P13) viable. The P11 pathway captures both 45V and 45Z credits, while P13 captures only a 45Z credit, which explains the lower LCOF for P11 than that for P13 at any given 45Z duration. Both the P11 and the P13 LCOFs fall rapidly with increasing durations of 45Z because their negative lifecycle emissions (Figure 2) lead to very high 45Z credit values (Figure S2 and eq S3). The LCOF for P11 falls more rapidly than that for P13, even though both pathways start with biomass and end with SLF being produced. Because P11 has a lower overall energy conversion efficiency, the pathway captures more CO_2 per unit of SLF produced and, thus, receives a larger 45Z credit than the more efficient P13 pathway. No other SLF pathways become economically viable with 45Z durations of less than 15 years.

In addition to 45Z, clean SLF may benefit from additional existing policies, such as the RFS and LCFS, if they do not expire in the 2030s. Here, we assume all SLF pathways claim LCFS credits based on their carbon intensity (see eq S2). The integrated biomass-SLF facilities (P12 and P13) and the ethanol-SLF facilities may additionally claim RIN credits under the categories of cellulosic biofuel D3 (for P12 and P13), advanced biofuel D5 (for P15), and renewable biofuel D6 (for P14), as discussed in the SI, Section 2. Due to the uncertainty and volatility of RIN and LCFS credits (Figure S1), we examine the LCOF values over a range of LCFS credit levels, RIN prices, and 45Z durations. Within this variable space, Figure 3B shows which pathways provide an LCOF that is competitive with a fossil jet fuel priced at $2.2/gal, the median historical value during 2012−2022.

With the D5 RIN at $0.75 and the D3 RIN at $1.25 (upper left panel in panel B), fossil jet fuel is the least costly option when the LCFS credit is below $25/t of CO_2e and the 45Z

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duration is less than 2 years. The P15 pathway is the most competitive option when the LCFS credit is between \$25/t of CO_2e and \$75/t of CO_2e and the 45Z duration is less than 2 years. The P11 pathway outcompetes all of the other SLF pathways in the rest of the variable space. When the D5 RIN value is \$0.75 and the D3 RIN value is \$2.25 (upper right panel in panel B), the P12 pathway is the most competitive pathway when the LCFS credit is below \$25/t of CO_2e and the 45Z duration is less than 1 year. The P13 and P11 pathways become the dominant options for the rest of the parameter space (a longer 45Z duration and a higher LCFS favors P11). When the D5 RIN value is \$1.5 and the D3 RIN value is \$2 (lower left panel in panel B), the P15 pathway is the most competitive option when the LCFS credit is below \$100/t of CO_2e and the 45Z duration is less than 3 years, and the rest of the parameter space is again dominated by P13 and P11. Finally, with the D5 RIN at \$1.5 and the D3 RIN at \$3 (lower right panel in 3B), P12 is the most cost-effective option when subsidies from 45Z and LCFS are small, but P13 outperforms all of the other pathways across the rest of the parameter space. Sensitivities to a wider range of D5 RIN and D3 RIN values are explored in Figure S4.

Measuring IRA Incentives against the Social Cost of Carbon. The IRA incentives can be viewed as subsidies for achieving GHG emissions reductions. In this context, it is of interest to express the incentives for each clean energy pathway in terms of the levelized subsidy for carbon mitigation (LSCM, eq 4) and compare these with recent U.S. federal government estimates of the social cost of carbon (SCC) for the 2030–2040 time frame.[42] The SCC is an estimate of the economic damages anticipated from climate change due to one additional tonne of CO_2 emissions. For this comparison, the amount of CO_2 that is mitigated by a pathway is taken to be the difference between the lifecycle emissions for the pathway and the lifecycle emissions for the pathway's fossil benchmark. Figure 4 shows LSCM values for all clean energy pathways, along with the range in estimated SSC for 2030–2040. For the SLF pathways, we assume the 45Z credit is extended and available for the full assumed asset life (15 years), representing a perhaps optimistic case for the liquid fuel pathways. Credits from RFS and LCFS have not been considered in determining these LSCM values.

LSCM values for four of the hydrogen pathways (P2, P3, P5, and P6) are below the SCC range, and for one pathway (P4), it is in the midrange of the SCC values. Our earlier analysis (Figure 1A) showed that, with IRA credits, blue H_2 (P2 and P3) and green H_2 (P4) are cost-competitive with incumbent (gray) H_2. Figure 4 shows that their deployment, especially blue H_2, would be societally cost-effective as well, considering avoided emissions-related damages. Our earlier analysis also showed that IRA credits for the P5 and P6 pathways are insufficient in making these pathways cost-competitive with gray H_2. Figure 4 indicates that higher credits are justified from a societal perspective. For example, if 45Q credits were allowed for biogenic CO_2 sequestration with P6, as mentioned in our discussion of Figure 1B, the P6 pathway would be cost-competitive with gray hydrogen and the implied LSCM (\$130/t of CO_2e) would still be below the lower bound of SCC.

Figure 4 shows that the LSCM values for the SLF pathways fall within or below the SSC range, except for the electrofuel pathway (P9). Our earlier analysis (Figure 3A) showed that, with IRA credits (assuming a 15-year 45Z duration), the P9, P11, P13, and P15 pathways would be cost-competitive with the fossil liquid fuel benchmark. Figure 4 shows that deployment in the cases of the P11, P13, and P15 pathways would also be cost-competitive from a societal perspective. However, this is not the case for P9, whose LSCM value is far above the SCC range. Furthermore, we previously suggested that it might be justified to incentivize negative emissions by allowing pathway P6 to claim 45V credits for low-carbon hydrogen production and, additionally, 45Q credits for negative (biogenic) CO_2 emissions. It would not be appropriate for a similar negative-emission incentive to be applied for liquid fuel production, however, because 45Z credits are already linked to a pathway's carbon intensity in such a way that the credit increases as the emissions grow more negative (Figure S2). Thus, allowing an SLF pathway like P11 or P13 to earn 45Q credits and 45Z credits simultaneously would, effectively, be providing two incentives for the same negative emissions.

DISCUSSION

Our results provide insights into each of the research questions posed in the Introduction.

First, our analysis demonstrates that the IRA subsidies will enable clean hydrogen to be cost-competitive with gray hydrogen. Blue hydrogen will have costs comparable to gray hydrogen thanks to the 45Q credit for CCS. Green hydrogen receives the highest subsidies among all of the evaluated hydrogen pathways due to the combination of a 10-year 45Y renewable electricity PTC and a 10-year 45V hydrogen PTC, which makes electrolysis the lowest cost option for hydrogen production. Biomass-derived hydrogen, however, is not cost-competitive despite the IRA subsidies. In our analysis, we used attributional LCA[43] and determined that green hydrogen has zero GHG emissions (Figure 1A) when carbon-free electricity sources are used. However, green hydrogen may result in consequential carbon emissions, such as when the procurement of carbon-free electricity for hydrogen production leads other electricity users to switch to fossil-generated power to meet their demands.[44] This raises concerns regarding the environmental benefits of green hydrogen, at least until the grid is fully decarbonized. Further efforts on LCA methodology (e.g., attributional/consequential LCA selection, co-product accounting, and system boundary definition) are necessary to ensure electrolytic hydrogen has near-zero lifecycle emissions.

Second, our results indicate that the IRA incentives favor the electrolytic production route of hydrogen over others because the subsidies for the other hydrogen production pathways are observed to be approximately proportional to their GHG emissions reductions (\$76/t of CO_2e reduced), while the electrolysis route receives a disproportionately higher subsidy (\$217/t of CO_2e). This suggests that the IRA is intended to incentivize technology innovation as well as emissions reductions in the case of green hydrogen. A similar technology policy rationale could also reasonably apply to the biomass gasification production routes of hydrogen, but this is not the case under the current IRA provisions.

Third, for the SLF pathways, we find that the renewal and extension of the 45Z credit would be necessary for most of the low- and negative-carbon emission SLF production pathways to be competitive with petroleum-derived jet fuels. The duration of a 45Z extension of 5 years would allow four clean SLF routes to achieve LCOFs that fall within the recent historical range of U.S. wholesale jet fuel prices without

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considering the impact of any additional incentives (e.g., RFS or LCFS).

We also find that stacking 45V and 45Z credits by artificially separating the production facilities (e.g., P10 and P11) provides for greater subsidies and results in lower LCOFs for SLF production from biomass when compared to stand-alone integrated facilities (P12 and P13). This is true despite the higher capital costs and lower conversion efficiencies that exist when converting biomass to fuel using separate production facilities. We further note that the IRA defines 45Z incentives to be a function of a pathway's lifecycle of GHG emissions. Accordingly, pathways with negative emissions receive the highest credits per gallon of produced fuel. This raises the possibility that 45Z credits by themselves may incentivize less energy-efficient production (P11) over more energy-efficient bio-SLF production with CCS (P13), as the lower efficiency enables greater CO_2 capture and storage, thus achieving stronger negative emissions. When federal RFS credits (RINs), which are available only to stand-alone biomass-SLF facilities (P12 and P13), are stacked with 45Z credits, the P13 pathway could be sufficiently incentivized such that it becomes more competitive than the P11 pathway. In addition, LCFS credits can be stacked with IRA credits for any of the SLF pathways. LCFS and RFS credits have historically fluctuated over time (Figure S1), and there is uncertainty around what they will be in the 2030s. For a wide array of combinations of 45Z duration, LCFS credit level, and RIN value, our analysis finds that the P11−P13 and P15 pathways are the most cost-competitive against the median monthly average wholesale price of jet fuel over the past decade. No SLF pathway is competitive with jet fuel priced at $2.2/gallon for short 45Z durations combined with low LCFS and RIN values.

Finally, we find that the IRA incentives for each pathway, when expressed in terms of LSCM, are below or within the range of the SCC estimated for 2030−2040, except for the electrofuel pathway (P9), which receives a significantly higher total incentive due to the stacking of multiple IRA credits. It is notable that, with IRA credits, BGCCS-H2 (P6) is not cost-competitive with gray H_2 (P1), though it has an LSCM well below the lower bound of the SCC range. If the IRA were to allow BGCCS-H2 to simultaneously claim 45V credits for low-carbon hydrogen and 45Q credits for negative emissions, it would become cost-competitive with gray H_2 and the LSCM would still be below the lower bound of the SCC range.

In addition to the hydrogen and SLF pathways that were investigated in our analysis, one can envision other pathways to exploit the stacking of credits in order to generate outsized financial benefits, but with marginal environmental gains. For example, if 45Y is applied to carbon-free electricity generators to power electrolysis, the 45V provides $3/kg of H_2 to the electrolysis facility for its hydrogen production. This hydrogen can end up in a hydrogen-fueled generator that could potentially claim a 45Y credit for its clean power generation. The system in this case consumes and produces carbon-free electricity, but the interior energy losses may be greater than other technologies that perform the same service (e.g., battery electricity storage). For these reasons, policies that prioritize the use of fuels (hydrogen in particular) in sectors where there are no other alternatives or where decarbonization may be more challenging would be useful.

In general, we find that the IRA achieves the objective of creating early commercial-scale deployment opportunities for emerging low-carbon hydrogen and liquid fuel technologies. Both green H_2 and blue H_2 pathways appear to be commercially viable under the IRA incentives, while only a modest extension of the 45Z clean fuels credit and/or incentives provided by the federal RFS or California's LCFS make one or more SLF pathways cost-competitive with historical fossil jet fuel prices. Accelerating the market deployment of these clean fuels may not only contribute to near-term GHG emissions reductions but also drive cost declines that enable deeper emissions reductions in the 2030s and 2040s, both in the U.S. and around the world. However, we find that the design of the IRA tax incentives is likely to favor pathways different than those with the highest carbon mitigation potentials (H_2 from biomass gasification with CCS and SLF from integrated biogasifier-FTS with CCS), which are pathways that could prove to be critical options for achieving a net-zero emissions future.

LIMITATIONS

Our work here is not without limitations, and we identify five key ones here that would benefit from additional examination in future work. (1) We have assumed that the tax credits accrued throughout the supply chain will all be passed on to the final product (e.g., H_2 or SLF). For instance, in a project that incorporates renewable generators for power generation and electrolyzers for H_2 manufacturing, we assume that the full 45Y PTC value will go toward reducing the cost of electricity to the H_2 producer. In reality, the price of electricity to the H_2 producer will depend on competitive market dynamics or a negotiated power purchase price. This could result in higher electricity costs to the H_2 producer. Liquid fuel pathways, especially the electrofuel pathway, may be more complicated due to the stacking of credits from multiple facilities. Although some entities, e.g., nonprofit organizations, and projects claiming the 45Q credits (within the first 5 years of operation) are eligible to receive the IRA credits as "direct pay", i.e., they receive payments that are equivalent to the tax credits, a more common scenario may be to transfer to third parties at some discount from full value. (2) We assume biogenic carbon to be carbon-neutral. This generally holds for agricultural residues because they absorb CO_2 as they grow on an annual cycle and do not introduce new CO_2 into the atmosphere when they are combusted. However, it may not apply for forest-derived biomass, which regrows on longer cycles. (3) For liquid fuel pathways, we have evaluated Fischer−Tropsch and ethanol-to-SLF routes, but there are others that could monetize IRA credits; these would need to be evaluated in order to provide a more complete understanding of all of the possibilities. (4) We did not differentiate our analysis of H_2 pathways by the intended use of the produced H_2. In particular, we did not explicitly assess the transportation use of H_2, which would likely require substantial new delivery and dispensing infrastructure to be established, but which might also qualify for LCFS and/or RFS credits. (5) The IRA subsidies may very well alter the international competitiveness of clean H_2 and SLF that are produced in the U.S. We have chosen to examine only domestic competitiveness implications, but the potential international implications would also be of interest.

ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.3c03063.

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Detailed summaries and interpretations of the Inflation Reduction Act (IRA), the Renewable Fuel Standard (RFS), and California's Low Carbon Fuel Standard (LCFS) incentives; a detailed summary of the evaluated technologies; prices of historical fuels and incentives; an additional discussion of extending 45Z and the complete design space of RIN credits; and a comparison of IRA credits and the social cost of carbon (SCC) (PDF)

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F.C.: conceptualization, investigation, methodology, formal analysis, visualization, and writing—original draft. H.L.: investigation, formal analysis, visualization, and writing—review and editing. J.D.J.: conceptualization, writing−review and editing, supervision, and funding acquisition. E.D.L.: conceptualization, investigation, writing—review and editing, supervision, funding acquisition, and project administration.

Notes

The authors declare the following competing financial interest(s): J.D.J. is part owner of DeSolve, LLC, which provides techno-economic analysis and decision support for clean energy technology ventures and investors. A list of clients can be found at https://www.linkedin.com/in/jessedjenkins. He serves on the advisory boards of Eavor Technologies Inc., a closed-loop geothermal technology company, and Rondo Energy, a provider of high-temperature thermal energy storage and industrial decarbonization solutions, and has an equity interest in both companies. He also provides policy advisory services to Clean Air Task Force, a nonprofit environmental advocacy group, and serves as a technical advisor to MUUS Climate Partners and Energy Impact Partners, both investors in early stage climate technology companies. E.D.L. is on the advisory board and has an equity interest in DG Fuels, an emerging renewable hydrogen and biogenic synfuels company.

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ADDITIONAL NOTES

[a]"Clean" in this paper is shorthand for low-carbon or negative-carbon emissions. Other factors such as criteria air pollutants (e.g., NO_x, SO_x, and particular matter) are not considered in the analysis.

[b]Unless otherwise indicated, all prices and costs in this paper are in 2022 U.S. dollars.

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