Electrofuel Synthesis from Variable Renewable Electricity: An Optimization-Based Techno-Economic Analysis

Evan D. Sherwin*

ABSTRACT: Sectors such as aviation may require low-carbon liquid fuels to dramatically reduce emissions. This analysis characterizes the economic viability of electrofuels, synthesized from CO₂ from direct air capture (DAC) and hydrogen from electrolysis of water, powered primarily by solar or wind electricity. This optimization-based techno-economic analysis suggests that using today’s technology, hydrocarbon electrofuels would cost upward of $4/liter of gasoline equivalent (lge), potentially falling to $1.7–1.8/lge in the next decade and <$1/lge by 2050. Only in the latter case are electrofuels potentially less costly than using petroleum fuels offset with DAC with sequestration. Achieving low-end electrofuel costs is contingent on substantial reductions in the capital cost of DAC, electrolysers, and renewable electricity generation. However, the system also requires sufficient operational flexibility to efficiently power this capital-intensive equipment on variable electricity. Such forms of flexibility include various types of storage, supplementary natural gas and grid electricity interconnections (penalized with a steep carbon price), curtailment, and the ability to modestly adjust fuel synthesis and DAC operating levels over time scales of several hours to days.

KEYWORDS: electrofuel, optimization, techno-economic analysis, DAC, systems dynamics, electrolysis, Fischer-Tropsch

1. INTRODUCTION

Avoiding 2 °C or more of global warming likely requires the complete elimination of net carbon dioxide (CO₂) emissions from the global economy within 4 to 7 decades.² This would necessitate decarbonization of difficult-to-mitigate sectors, including aviation, long-distance road transportation, and ocean shipping, representing roughly 6% of global energy-related greenhouse gas (GHG) emissions.² These applications currently use energy-dense liquid fuels to operate capital-intensive fleets of airplanes, trucks, and ships with asset lifetimes of 20 years or more. Thus, even with research and development breakthroughs in electric or hydrogen propulsion systems, a rapid transition to these fuels would likely require premature retirement or retrofitting on a massive scale. In particular, decade-scale regulatory approval processes for aviation suggest that it is unlikely that alternative airplane propulsion systems will be widely available to begin replacing the fleet before 2050. As a result, a carbon-neutral hydrocarbon fuel with the ability to “drop in” to existing infrastructure could greatly reduce the cost of deep decarbonization in these sectors and buy time for a smooth transition to lower-cost technologies if they emerge.

All hydrocarbons emit CO₂ when combusted, so achieving carbon neutrality requires that the carbon embedded in a hydrocarbon be sourced from the atmosphere. Biofuels achieve this using carbon captured by plants, algae, or other living organisms. However, biofuels generally have substantial net lifecycle emissions,³ ranging from roughly 5 to 75% of petroleum jet fuel emissions. Staples et al. estimate that such fuels could avert at most about 70% of global aviation emissions, requiring that biofuels constitute over 85% of total jet fuel.¹ Some analyses suggest a greater potential to scale low-emission biofuels,⁴ but even with large cost reductions, a biofuel-based mitigation strategy for aviation would still likely require substantial carbon dioxide removal (CDR) to achieve net-zero emissions. Hydrogen fuel cells and electric airplanes are still in the early stages of development.⁵,⁶

Electrofuels are fuels, generally hydrocarbons or oxygenates, derived from H₂ from electrolysis of water through processes that rely primarily on electrical energy, often via reactions with CO₂.⁷ Potential products include methanol, dimethyl ether, methane, ammonia, and Fischer–Tropsch liquid hydrocarbons such as gasoline, diesel, and jet fuel.⁸ Techno-economic estimates of the cost of electrofuels range from $2.1/lge using today’s technology and $2.9/lge using today’s technology and $2.9/lge, with harmonized ranges from Brynolf et al. of $2.0–2.9/lge using today’s technology and $2.1–2.9/lge in 2030, albeit with relatively high electricity prices,⁹ with most analyses assuming that CO₂ is sourced at low cost from industrial waste, such as biofuel production or cement manufacturing.⁹ Reusing

Received: November 24, 2020
Revised: April 14, 2021
Accepted: April 28, 2021
CO₂ captured from an industrial process generally cannot result in net-zero electrofuel emissions, as CO₂ is ultimately emitted upon fuel combustion. Electrofuels powered by solar or wind electricity and using CO₂ captured from the atmosphere via direct air capture (DAC) can approach net-zero emissions. Such a system must harness highly variable energy to operate capital-intensive equipment, requiring a sophisticated system design and operation approach, minimizing the cost per unit fuel produced. Fasihi et al.⁹‒¹¹ estimate the cost of electrofuel production from combined wind and solar installations using CO₂ from DAC with point estimates of techno-economic parameters, an aggregated representation of variability in renewable electricity, and relatively inexpensive storage of hydrogen and electricity, finding electrofuel costs on the order of $1.10/lge. Armijo et al. apply a simple optimization to the question of component oversizing in power-to-ammonia production in Chile and Argentina, finding benefits to building an ammonia synthesis system that operates at less than 100% capacity some of the time.¹²

These studies tend to use one or a few scenarios, providing insight into the operation and cost of a particular system after a decade or more of assumed rapid technological progress in what is fundamentally a deeply uncertain world. Much of the uncertainty in the future trajectory of technological progress is rooted in the fact that governments and institutions can strategically invest in research, development, and deployment (RD & D) illustrated by the rapid cost declines in solar photovoltaics.¹³

Given the limited budgets for RD & D and a desire to rapidly decarbonize the energy system, we need models that can help illuminate where we can most effectively invest to reduce the cost of technologies such as electrofuels. For a system as operationally complex as electrofuel production from variable renewable electricity, optimization-based techno-economics is an ideal tool for evaluating the relative importance of component-level cost and operational parameters (including efficiency, low-temperature or high-temperature DAC system design, minimum component operating level, and ramping).

This approach thus provides insights into the way in which technological advances affect not only system cost but also system dynamics. Indeed, this basic method has long been used to answer such questions in petroleum refinery design.¹⁴

I employ an optimization-based techno-economic framework to characterize the range of possible electrofuel production costs today, in the next-decade, and by 2050, using CO₂ from DAC, powered primarily by variable renewable electricity. The analysis focuses on synthesizing jet fuel from the Fischer–Tropsch process, a drop-in fuel approved by ASTM for blending up to 50% in commercial jet fuel (see the Supporting Information, Section S1 for further detail). Facilities are sized to produce 4.5 TW h (fuel)/yr, about equivalent to an average production of 7570 barrels of oil equivalent per day (bbl/d), to ensure full carbon price commensurate with the cost of DAC with sequestration (DACS) in that scenario. Evaluating the sensitivity of system cost and operational characteristics to changes in key parameters allows this approach to identify the most promising system components and characteristics for additional RD & D support. This is the first work of which the author is aware to use simultaneous optimization of system configuration and operation over a range of scenarios to determine priorities for RD & D for a capital-intensive system powered by variable renewable electricity.

2. MATERIALS AND METHODS

2.1. System Components and Optimization Structure. This analysis models the cost and optimal operation of an electrofuel production system comprising variable renewable electricity production, a DAC system heated primarily by variable renewable electricity, and hydrocarbon fuel synthesis infrastructure (a Fischer–Tropsch reactor with reverse water-gas shift and product upgrading).
transporting liquid fuel to market through a pipeline. To manage variability in electricity supply, the system can build storage of electricity, modeled as a lithium-ion battery system; heat, modeled as a molten salt, phase-change material, or supercritical CO₂ system; hydrogen, either in a pressurized above-ground tank or in an underground formation; CO₂ in a pressurized tank; and hydrocarbon fuel in a tank. The system can also build natural gas and grid electricity interconnections, paying a carbon price for the associated fossil CO₂ emissions. Figure 1 shows a diagram of the electrofuel production system modeled here. Each component is described in detail in the Supporting Information, Section S2.

Some system components, such as fuel synthesis and CO₂ and H₂ storage, require gas pressurization. Compressors are not modeled as independent components but are instead assumed to be included in the relevant component, including capital cost and compression energy requirements. Operating pressure is not specified explicitly for each component as this may vary as the technology advances through 2050. See the Supporting Information, Section S2.18 for further detail.

The key inputs to the model are the renewable electricity production profile for solar or wind and the unit cost, efficiency, and other techno-economic parameters for each system component. The model then uses linear programming optimization to determine the cost-optimal system configuration and operational profile required to produce a fixed amount of liquid fuel, given these inputs for a simulated representative year of production. The annual production scale for all scenarios is set at 4.5 TW h (fuel)/yr, equivalent to an average production of 7570 bbl/d. To ensure full economies of scale for all components, particularly high-temperature DAC, operating at 1 Mt (CO₂)/yr based on ref 15.

Inflexible operation of capital-intensive equipment based solely on the availability of variable wind or solar electricity can greatly increase costs and may not even be operationally feasible from an engineering perspective for components such as fuel synthesis or high-temperature DAC. Thus, the cost-optimal operation of such a system must allow various forms of operational flexibility to ensure a high level of utilization for capital-intensive components, potentially at the expense of utilization levels for less capital-intensive components.

This analysis models several forms of operational flexibility options.

- On-site storage of electricity, hydrogen, carbon dioxide, heat, and liquid fuel allows the system to shift resources over time. See the Supporting Information, Section S2 for a detailed discussion of each form of storage.

- External electric and natural gas grid interconnections allow the system to supplement on-site resources while paying a carbon price commensurate with the cost of DAC with sequestration to offset resulting emissions.

- Individual components have a minimum operating level and a maximum ramp rate, described in the Supporting Information, Sections S3.5 and S4 (Tables S11 and S12).

- The system can dispose of (curtail) excess products such as waste electricity and heat that would be uneconomic to use or store.

For a case without storage, external energy interconnections, or the ability to dispose of excess products (necessitating an unphysically flexible component-level operational profile, with all components operating at the same level of utilization as the renewable energy), see the Supporting Information, Section S5.5.

Thus, the linear program optimization can build capacity for each of the 13 system components: production and storage of each of the five products, that is electricity, heat, hydrogen, carbon dioxide, and liquid fuel, as well as an electric grid interconnection and pipelines for importing natural gas and exporting liquid fuel. System operation is then optimized based on the year’s renewable electricity production profile using a perfect foresight model. The perfect foresight assumption is likely justifiable for solar in the desert but may be less defensible for wind, particularly if the system makes seasonal storage decisions based on knowledge of wind production months in advance.

Thus, the system has five production components and three external energy interconnections, each with three time-varying operational parameters: production level, ramping, and upward ramping (parameterized separately to penalize potentially energy-intensive increases in production for DAC and fuel synthesis). There are also five storage components, each with three time-varying operational variables: input, storage level, and output. Finally, there can be waste for each of the five products in any time period. Water requirements for the electrolyzer and the DAC system are derived from these decision variables, meaning that small costs associated with water interconnection and purchase are not optimized directly in the model. See the Supporting Information, Section S3 for further detail.

Thus, the optimization has 13 component capacity decisions and 30 operational decisions in each time step (renewable electricity generation is exogenous and thus does not have production or ramping decisions). At 1 h resolution, this yields a total of 262,813 decision variables, with a run time of roughly 2.25 h for a single optimization scenario using the Gurobi linear programming solver in the Analytica programming environment. For computational tractability, 4 h resolution is used instead, with 65,713 decision variables, solving in 8.5 min. The effects of aggregating time from one-hour to four-hour resolution are on the order of 1% of levelized fuel cost, discussed in the Supporting Information, Section S3.10.

Operation of the true system would likely also have integer variables, such as minimum capacity or operation levels. The potential effects of this relaxation are discussed in the Supporting Information, Section S3.1.

The linear optimization is outlined below, with the full formulation described in Section S3:

Minimize Annualized system cost

Subject to:
- Fixed total annual electrofuel production
- Fixed renewable electricity production profile throughout the year
- Minimum capacity level ≤ production ≤ capacity for each component
- Storage level ≤ capacity
- Storage input ≤ production
- Storage output ≤ storage level
- Conservation of energy and matter
- Conservation of storage levels
- Ramping constraints

Note that because optimization sets capacity levels for each component, certain components are not used in some (or even in all) modeled scenarios.

https://doi.org/10.1021/acs.est.0c07995
Environ. Sci. Technol. XXXX, XXX, XXX--XXX
Because this optimization-based model can produce electrofuel, CO₂, H₂, or other products using electricity, it is named the “Power-to-X Optimization Tool”, P2XOpt.

The levelized cost of electrofuel, used to compare the competitiveness of electrofuels with fossil jet fuel, is the optimal annualized electrofuel production system cost, the optimal objective function value, divided by the total quantity of electrofuel produced. This is reported in $/liter of gasoline equivalent (lge).

For electrofuels, the cost of mitigating fossil GHG emissions, \( C_{\text{mitigation}} \), depends on the life-cycle GHG savings from switching from petroleum-based fuels to electrofuels (\( \text{GHG}_{\text{electrofuel}} \) savings) and the relative cost of the two fuels (\( C_{\text{electrofuel}} \) and \( C_{\text{petro-fuel}} \)).

\[
C_{\text{mitigation}} = \frac{C_{\text{electrofuel}} - C_{\text{petro-fuel}}}{\text{GHG}_{\text{electrofuel}}_{\text{savings}}}
\]

(1)

See the Supporting Information, Section S6 for further detail.

### 2.2. Electricity and Heat Sources.

Electricity can come from either on-site renewable electricity or a grid interconnection. Both solar PV and wind are simulated in locations within the United States with very high-quality resources, Tucson, Arizona and southern Wyoming, respectively, with capacity factors of 29.3% and 57.5%, illustrating the total annual output as a fraction of maximum potential annual output. This analysis does not consider solar-wind hybrid configurations, although this certainly could increase the electricity capacity factor in some cases.

Heat sources required for the DAC process include a high-temperature electric kiln, natural gas-based oxygen-fired heat (with the combustion assumed to take place within the DAC system at no additional capital cost), and, in some scenarios, waste heat from the electrolyzer and the fuel synthesis system. The electric kiln and oxygen-fired natural gas combustion are both capable of achieving the temperatures in excess of the 900 °C required for high-temperature DAC. In practice, low-temperature DAC systems could likely see modest cost reductions through lower temperature heat sources closer to the required 90 °C. See the Supporting Information, Sections S2.3, S2.4, S2.12, and S2.15 for further detail.

### 2.3. Carbon Price to Offset Incurred Emissions.

In some instances, it may be more cost-effective for the system to simply purchase electricity or natural gas from the grid, offsetting the resulting GHG emissions by paying an offset DACs facility to capture and sequester equivalent emissions, represented in this model by the carbon price. This option thus has a much lower capital cost than constructing additional renewable electricity capacity, or electricity or heat storage, but also incurs a substantial variable cost, particularly due to the carbon price.

Because the carbon price represents the cost of offsetting emissions through DACs, the carbon price is roughly commensurate with the cost of DAC within the system plus a sequestration cost, assumed to be negligible at optimally chosen locations. Ideally, one would set the carbon price exactly equal to the modeled levelized cost of DAC plus a sequestration cost in

each scenario, as described in eq 1. However, because the precise cost of CO₂ removed by DAC depends on the system’s operational characteristics, such an optimization formulation would cease to be linear and would thus become computationally intractable.

For low-temperature DAC systems, carbon prices in the today, next-decade, and by 2050 cases are $600/t(CO₂), $200/t(CO₂), and $100/t(CO₂), respectively, based on Climeworks’ estimated current costs and medium-term and long-term target costs. For the high-temperature next-decade and by 2050 cases, carbon prices are $230/t(CO₂) and $130/t(CO₂), respectively, based on medium-term and long-term cost estimates for pipeline-pressure CO₂ from Keith et al. I assume a negligible sequestration cost across the board, representing the low end of the estimates in the literature. See the Supporting Information, Sections S2.16 and S2.17 for further detail. See the Supporting Information, Section S5.3 for a case without penalties or constraints on fossil CO₂ use. See the Supporting Information, Section S5.4 for a case in which grid electricity and natural gas are not available.

### 2.4. CO₂ Sources and Storage.

The primary source of CO₂ is DAC, either using a low-temperature amine system, such as those used by Climeworks and Global Thermostat, or a high-temperature hydroxide-based system, such as that used by Carbon Engineering.

Both types of systems use an air contactor, similar to a horizontal cooling tower, to expose atmospheric CO₂ to a sorbent, either an amine or a hydroxide. Once CO₂ is adsorbed by the sorbent, the resulting solution undergoes an energy-intensive thermal regeneration process through which it releases pure CO₂, which can then be used or sequestered. Process heat can come from an electric kiln, described in the Supporting Information, Section S2.4, from natural gas, described in the Supporting Information, Section S2.12, or from waste heat, described in the Supporting Information, Section S2.15. See the Supporting Information, Section S2.3 for further detail on the DAC systems themselves.

The system can also use CO₂ from oxy-combusted natural gas used for process heat (paying a carbon price to offset an equivalent amount of CO₂ at another location using DACs). However, a constraint prevents the model from combusting more natural gas than the maximum instantaneous DAC heat requirement. This prevents the system from simply filling all system CO₂ demands via the combustion of natural gas. See the Supporting Information, Section S5.3 for more on this constraint and Section S3.8 for results with this constraint relaxed and no CO₂ price.

### 2.5. Fuel Synthesis.

The fuel synthesis system assumes a Fischer–Tropsch reactor preceded by a reverse water gas shift reactor to convert CO₂ and H₂ into synthesis gas of CO and H₂ and fuel upgrading to convert syn crude into jet fuel, as much as 50% of the total, as well as coproducts, predominantly diesel and naphtha, which can be refined into gasoline. For simplicity, coproducts are assumed to fetch the same selling price as electrojet fuel.

Patented in the 1920s, the Fischer–Tropsch process was originally used to convert coal and other fossil fuels into liquid transportation fuels and was used extensively in Germany during the Second World War and by South Africa since the 1980s. As a result, the technology is fairly mature. Fischer–Tropsch plants exist across the world.

### 2.6. Technology Scenarios and Baseline.

The analysis uses three main sets of techno-economic parameters. The first
Table 1. Capital Costs for All Components in All Cases
d
<table>
<thead>
<tr>
<th>component</th>
<th>units</th>
<th>today</th>
<th>next-decade</th>
<th>by 2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>solar PV</td>
<td>$/kW (e)</td>
<td>900</td>
<td>500</td>
<td>400</td>
</tr>
<tr>
<td>wind</td>
<td>$/kW (e)</td>
<td>1500</td>
<td>1250</td>
<td>1000</td>
</tr>
<tr>
<td>electrolyzer</td>
<td>$/kW (e)</td>
<td>1025</td>
<td>570</td>
<td>485</td>
</tr>
<tr>
<td>electric kiln</td>
<td>$/kW (e)</td>
<td>125</td>
<td>75</td>
<td>25</td>
</tr>
<tr>
<td>DAC [high-temperature]</td>
<td>$/(t(CO₂)/yr)</td>
<td>N/A</td>
<td>970</td>
<td>610</td>
</tr>
<tr>
<td>DAC [low-temperature]</td>
<td>$/(t(CO₂)/yr)</td>
<td>3030</td>
<td>1120</td>
<td>790</td>
</tr>
<tr>
<td>fuel synthesis</td>
<td>$/kW (fuel)</td>
<td>1770</td>
<td>1010</td>
<td>760</td>
</tr>
<tr>
<td>grid interconnection</td>
<td>$/kW (e)</td>
<td>340</td>
<td>180</td>
<td>45</td>
</tr>
<tr>
<td>fuel pipeline</td>
<td>$/kW (fuel)</td>
<td>20</td>
<td>10</td>
<td>2</td>
</tr>
<tr>
<td>natural gas pipeline</td>
<td>$/kW (th)</td>
<td>225</td>
<td>115</td>
<td>25</td>
</tr>
<tr>
<td>electricity storage</td>
<td>$/kW (e)</td>
<td>350</td>
<td>250</td>
<td>150</td>
</tr>
<tr>
<td>H₂ storage</td>
<td>$/kW (H₂)</td>
<td>25</td>
<td>15</td>
<td>6</td>
</tr>
<tr>
<td>heat storage [low-temperature]</td>
<td>$/kW (th)</td>
<td>25</td>
<td>20</td>
<td>15</td>
</tr>
<tr>
<td>heat storage [high-temperature]</td>
<td>$/kW (th)</td>
<td>N/A</td>
<td>55</td>
<td>25</td>
</tr>
<tr>
<td>CO₂ storage</td>
<td>$/(t(CO₂))</td>
<td>50,000</td>
<td>10,000</td>
<td>1000</td>
</tr>
<tr>
<td>fuel storage</td>
<td>$/kW (fuel)</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>WACC</td>
<td>%</td>
<td>10%</td>
<td>8%</td>
<td>5%</td>
</tr>
</tbody>
</table>

**Table 2. Efficiency and Energy Material Requirements for Each Component**

<table>
<thead>
<tr>
<th>component</th>
<th>units</th>
<th>today</th>
<th>next-decade</th>
<th>by 2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>electrolyzer electricity (ηₑₑ)</td>
<td>kW h (e)/kWh (H₂)</td>
<td>60%</td>
<td>65%</td>
<td>70%</td>
</tr>
<tr>
<td>electrolyzer water (ηₑₑ₃)</td>
<td>kg (H₂O)/kWh (H₂)</td>
<td>0.27%</td>
<td>0.27%</td>
<td>0.27%</td>
</tr>
<tr>
<td>electric kiln (ηₑ₃ₖ)</td>
<td>kwh (e)/kWh (th)</td>
<td>95%</td>
<td>95%</td>
<td>95%</td>
</tr>
<tr>
<td>DAC heat [high-temperature] (ηₑₑ₃₃₈)</td>
<td>GJ (th)/t(CO₂)</td>
<td>N/A</td>
<td>5.25%</td>
<td>5.25%</td>
</tr>
<tr>
<td>DAC electricity [high-temperature] (ηₑₐₑ₃₃₈)</td>
<td>kW h (e)/t(CO₂)</td>
<td>N/A</td>
<td>77%</td>
<td>77%</td>
</tr>
<tr>
<td>DAC water [high-temperature] (ηₑₑ₃₃₈₈)</td>
<td>t(H₂O)/t(CO₂)</td>
<td>4.7%</td>
<td>4.7%</td>
<td>4.7%</td>
</tr>
<tr>
<td>DAC heat [low-temperature] (ηₑ₃₃₈₈)</td>
<td>GJ (th)/t(CO₂)</td>
<td>7.9%</td>
<td>5.8%</td>
<td>4.4%</td>
</tr>
<tr>
<td>DAC electricity [low-temperature] (ηₑₐₑ₃₃₈₈)</td>
<td>kW h (e)/t(CO₂)</td>
<td>700%</td>
<td>400%</td>
<td>160%</td>
</tr>
<tr>
<td>DAC heat [low-temperature] (ηₑₐₑ₃₃₈₈₈)</td>
<td>t(H₂O)/t(CO₂)</td>
<td>-1%</td>
<td>-1%</td>
<td>-1%</td>
</tr>
<tr>
<td>fuel synthesis CO₂ (ηₑₑ₄₃₈₈)</td>
<td>t(CO₂)/MW h (fuel)</td>
<td>0.28%</td>
<td>0.28%</td>
<td>0.28%</td>
</tr>
<tr>
<td>fuel synthesis H₂ (ηₑₑ₃₈₈₈)</td>
<td>kW h (H₂)/kWh (fuel)</td>
<td>0.65%</td>
<td>0.70%</td>
<td>0.75%</td>
</tr>
<tr>
<td>electricity storage (ηₑₑ₃₈₈₈)</td>
<td>%</td>
<td>80%</td>
<td>85%</td>
<td>90%</td>
</tr>
<tr>
<td>H₂ storage (ηₑ₃₈₈₈)</td>
<td>%</td>
<td>99</td>
<td>99</td>
<td>99</td>
</tr>
<tr>
<td>heat storage [low-temperature] (ηₑₑ₃₈₈₈₈)</td>
<td>%</td>
<td>90%</td>
<td>90%</td>
<td>90%</td>
</tr>
<tr>
<td>heat storage [high-temperature] (ηₑₑ₃₈₈₈₈₈)</td>
<td>%</td>
<td>90%</td>
<td>90%</td>
<td>90%</td>
</tr>
<tr>
<td>CO₂ storage (ηₑₑ₃₈₈₈₈₈)</td>
<td>%</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>fuel storage (ηₑₑ₃₈₈₈₈₈)</td>
<td>%</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>natural gas combustion (ηₑₑ₈₈₈₈₈₈₈)</td>
<td>kW h (th)/kWh (th)</td>
<td>1%</td>
<td>1%</td>
<td>1%</td>
</tr>
</tbody>
</table>

**Notes:** DAC and fuel synthesis costs are given per unit output capacity, while all other production costs are modeled in terms of input power requirements. The variation in capital cost for interconnections is based on differing distance assumptions rather than technological advancement. Capital cost for the water interconnection is not modeled, as the water price is assumed to contain the interconnection cost. Some costs have been converted from different units or dollar-years, as described in the Supporting Information, Section S2. All costs are in 2017 dollars.

To motivate these timeframes, cost-competitive electrofuels by 2050 would likely enable direct decarbonization of aviation before a competing low-carbon fuel technology such as hydrogen can be brought to market to begin fleet turnover. With mitigation cost parity in the next decade, it may be possible to decarbonize light-duty transportation while retaining a substantial fraction of the gasoline and diesel fleet.

Note that given the large uncertainties in the future trajectory of the energy system, the next-decade and by 2050 cases should be considered not as forecasts but as scenarios informed by existing estimates from the literature. This scenario approach primarily allows (1) evaluation of whether modest or substantial technological improvements result in electrofuels outcompeting petroleum fuels with DACs and (2) sensitivity analysis, which
of a new technology. The next-decade case uses a WACC of to represent the assumed maturity of the relevant technology in convert capital cost into its present value, varies across scenarios heat reusability, ramping energy penalties, and maximum ramp variable costs, carbon prices, storage compression energy, waste system lifetime, combined annualized capital and O & M costs, Supporting Information, Section S4 for tables of O & M costs, and in the Supporting Information, Section S4, with several operating level. See the Supporting Information, Sections S2.3 production up or down by 5% of total capacity in an hour, with a the fuel synthesis and high-temperature DAC systems can ramp somewhat in process that, by virtue of its operating temperatures, is likely because it is not yet commercially available, also relies on a temperature DAC system, not modeled in the today case assumes that the fuel synthesis system must always operate at constructed to operate essentially continuously, the today case and performance improvements.

Figure 2. Levelized cost of electrofuel per liter of gasoline equivalent (lge) of liquid hydrocarbon fuel produced using solar (A) and wind (B) electricity, considering both high- and low-temperature DAC systems in the next-decade and by 2050 cases. In all cases, the three largest cost components are capital and non-energy operational costs for the DAC system, the electrolyzer, and the renewable electricity generation. Most cost components represent combined capital and non-energy operational costs, with the exceptions of natural gas, grid electricity, and water which represent the cost of commodities purchased from an external interconnection. The black dotted and dashed lines are the minimum, maximum, and average petroleum jet fuel prices from 2010 to 2019. All costs are in 2017$. The weighted average cost of capital (WACC), used to convert capital cost into its present value, varies across scenarios to represent the assumed maturity of the relevant technology in each case. The today case uses a WACC of 10%, representative of a new technology. The next-decade case uses a WACC of 8%, falling to 5% in the by 2050 cases, consistent with rates available to some mature energy utilities. The sensitivity analysis individually varies each parameter from its next-decade to today and by 2050 values, to identify the most important parameters for future cost and performance improvements.

Tables 1 and 2 show capital costs and material consumption requirements and efficiencies for each component. These parameter choices are explained further in Section 2.1. See the Supporting Information, Section S4 for tables of O & M costs, system lifetime, combined annualized capital and O & M costs, variable costs, carbon prices, storage compression energy, waste heat reusability, ramping energy penalties, and maximum ramp rates.

The sensitivity analysis explores the relative importance of each individual factor. Note that because conventional Fischer–Tropsch systems are constructed to operate essentially continuously, the today case assumes that the fuel synthesis system must always operate at 100% capacity with no ability to ramp production. The high-temperature DAC system, not modeled in the today case because it is not yet commercially available, also relies on a process that, by virtue of its operating temperatures, is likely somewhat inflexible. The next-decade case assumes that both the fuel synthesis and high-temperature DAC systems can ramp production up or down by 5% of total capacity in an hour, with a minimum operating level of 50%. The by 2050 cases allow both systems to ramp by up to 25% per hour with no minimum operating level. See the Supporting Information, Sections S2.3 and S2.5 for further detail.

The sensitivity analysis individually varies each parameter from its baseline value in the next-decade high-temperature solar electrofuel case to its today and by 2050 values in Tables 1 and 2, and in the Supporting Information, Section S4, with several exceptions described in the Supporting Information, Section S7.

3. RESULTS

Using today’s technology, electrofuel production using commercially available low-temperature DAC would be substantially more expensive than petroleum jet fuel, shown in Figure 2 at $4.41–$4.66 per liter of gasoline equivalent (lge), compared to the average US pre-tax jet fuel price of $0.59/lge from 2010 to 2019 (all in 2017$). However, costs in the next-decade and by 2050 cases, described in Materials and Methods, are dramatically lower, $1.68–1.76/lge and $0.95–0.99/lge, respectively, for high-temperature DAC, with almost identical costs for low-temperature DAC cases. Note that cost parameters for these five scenarios do not attempt to represent a full range of possible futures in the development of key component technologies but instead illustrate possibilities based on the available literature. The relatively conservative today case, which relies largely on the peer-reviewed literature and government reports, may not capture cutting-edge developments. See Materials and Methods for further discussion of the scenarios. The sensitivity analysis explores the relative importance of each individual factor.

In all cases, the combined capital and non-energy operating costs of renewable electricity generation, the electrolyzer, and the DAC system are dominant, representing 62.3–85.7% of fuel cost in all cases. Renewable electricity generation is 24.6–38.9% of fuel cost in all cases, with the electrolyzer at 17.7–23.4% in wind cases and 27.5–36.5% in solar cases. DAC represents 16.4–23.2% of fuel cost, with a roughly equal cost share in the comparable wind and solar cases.

In the today case for both wind and solar, the optimization supplements on-site renewable electricity with substantial amounts of natural gas and grid electricity despite incurring a cash cost of $600/ton(CO2) to offset the resulting emissions with offset DACs to ensure carbon neutrality (excluding facility construction life-cycle emissions). In the today wind case, these carbon price payments constitute the third largest cost component, at 21.3% of fuel cost, falling to 16.2% in the corresponding solar case. This is in large part because the Fischer–Tropsch system modeled for fuel synthesis in the today case cannot operate flexibly, forcing the system to ensure full operation for the entire year, largely through carbon-intensive grid electricity and natural gas to balance strongly seasonal wind and moderately seasonal solar. See the Supporting Information, Section S5.3 for cases with no carbon price.

Costs in the next-decade cases remain in the range of $1.68/lge–$1.77/lge, still close to three times the ten-year mean price of pre-tax jet fuel, $0.59/lge, but in a similar cost range to

https://doi.org/10.1021/acs.est.0c07955
Environ. Sci. Technol. XXXX, XXX, XXX–XXX
comparable biobased jet fuel alternatives.56 73.3−78.6% of fuel cost in these cases is capital and non-energy operational costs of the renewable electricity generation, the electrolyzer, and the DAC system. Fuel synthesis represents 9.6%−10.1% of fuel cost, while the cost of offsetting emissions from grid electricity and fossil natural gas is 5.4−7.7%, above the cost of the electricity and gas itself (including interconnection costs) at 3.5−4.2%.

In the by 2050 cases, costs fall to $0.95−0.99/lge, roughly 50% above 10-year mean jet fuel prices and only 15−22% above average jet fuel prices in 2012.55 In the high-temperature DAC cases, renewable electricity generation, electrolyzer, and DAC system costs represent 76−80% of fuel costs, rising to 83−86% in low-temperature DAC cases. This is due largely to the assumed ability to recycle heat from both the fuel synthesis and the electrolyzer to power the roughly 100 °C DAC amine regeneration process.48 The high-temperature systems continue to supplement their electric kiln with heat from fossil natural gas, amounting to 1.2−2.3% of the total cost plus an additional 3.3−6.3% to offset the emissions with a carbon price at the prevailing cost of offsite DAC ($130/t(CO2) in the high-temperature case). The low-temperature system can use recycled waste heat or heat from the electric kiln, which is less expensive to store at lower temperatures, to meet much of its heat demand, although it still uses some natural gas at 0.5−0.6% of the total cost plus 1.1−1.2% to offset the resulting emissions at $100/t(CO2), the assumed cost of standalone offsite low-temperature DACs. Thus, waste heat recycling allows low-temperature DAC to compete with lower capital cost high-temperature DAC.

All cases make extensive use of the system flexibility offered by various forms of energy and material storage as well as external fossil energy interconnections. In the absence of fossil energy interconnections, the today system produces 12% and 27% more expensive fuel for solar and wind systems, respectively, with greater reliance on costly hydrogen, electricity, and heat storage as well as overbuild and curtailment of renewable electricity generation capacity. Under next-decade assumptions, a no-fossil case yields smaller increases of 0.7−0.8% in solar cases and 7−11% for wind cases. By 2050 cases with no fossil carbon are at cost parity with cases that have fossil interconnections for solar and are 2−6% more expensive for wind cases. See the Supporting Information, Section S5.4 for further detail.

Another important and related form of flexibility is undersizing, also discussed in ref 57. Undersized components will operate at a higher capacity factor (total utilization as a fraction of maximum possible utilization) than the electricity generation source, as shown in Table 3. The most consistently undersized component (relative to renewable electricity generation capacity) is the capital-intensive DAC system, which operates above 90% utilization (total annual output as a fraction of potential annual output) in all solar cases and above 81% utilization in all wind cases. The fuel synthesis system is similar, with utilization above 84% in all solar cases and above 71% in all wind cases. Note that although the solar electric capacity factor is 29.3%, roughly half that of the wind capacity factor of 57.5%, the utilization of DAC and fuel synthesis is higher in the solar case due to less extreme seasonality in electricity availability (see the Supporting Information, Section S5.2 for further detail). In the solar cases, electrolyzers are also undersized to achieve a 38.8−42.1% utilization, whereas relatively inexpensive electric kilns are oversized in all cases, with utilization levels of 6.2−20.0% to transform excess electricity to heat for the DAC system as needed. This component undersizing provides substantial cost reductions, illustrated by a cost increase of 68% in the solar today case if all system components are required to (unphysically) operate at the same capacity factor as the renewable energy. Thus, although the components that provide system flexibility that enable undersizing (storage of hydrogen, heat, electricity, and CO2, and grid electricity and natural gas consumption including fossil emissions offset payments) constitute 25.6% of fuel cost, they bring savings on the order of twice their cost. See the Supporting Information, Section S5.5 for further detail.

Note that in the today and by 2050 low-temperature cases, the optimization dispenses entirely with the electric kiln, relying only on natural gas in the former, heavily supplemented by waste heat recycled from the fuel synthesis system and electrolyzer in the latter. See the Supporting Information, Section S5.1 for component capacity in each scenario. In addition, the model never builds liquid fuel storage as there are few if any benefits of undersizing the fuel export pipeline relative to the fuel synthesis plant. The solar next-decade cases and all wind cases dispense entirely with electricity storage, opting to simply use expensive

### Table 3. Capacity Factor for Each Production Component

<table>
<thead>
<tr>
<th>solar PV</th>
<th>today, low-temp (%)</th>
<th>next-decade, high-temp (%)</th>
<th>next-decade, low-temp (%)</th>
<th>by 2050, high-temp (%)</th>
<th>by 2050, low-temp (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>renewables</td>
<td>29</td>
<td>29</td>
<td>29</td>
<td>29</td>
<td>29</td>
</tr>
<tr>
<td>electrolyzer</td>
<td>39</td>
<td>40</td>
<td>39</td>
<td>42</td>
<td>40</td>
</tr>
<tr>
<td>kiln</td>
<td>N/A</td>
<td>15</td>
<td>6</td>
<td>20</td>
<td>N/A</td>
</tr>
<tr>
<td>DAC</td>
<td>100</td>
<td>90</td>
<td>95</td>
<td>95</td>
<td>95</td>
</tr>
<tr>
<td>fuel synthesis</td>
<td>100</td>
<td>86</td>
<td>84</td>
<td>85</td>
<td>84</td>
</tr>
<tr>
<td>grid connection</td>
<td>5%</td>
<td>1</td>
<td>3</td>
<td>3</td>
<td>2</td>
</tr>
<tr>
<td>fuel pipeline</td>
<td>100</td>
<td>86</td>
<td>84</td>
<td>85</td>
<td>84</td>
</tr>
<tr>
<td>natural gas</td>
<td>100</td>
<td>75</td>
<td>55</td>
<td>40</td>
<td>30</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>wind</th>
<th>today, low-temp (%)</th>
<th>next-decade, high-temp (%)</th>
<th>next-decade, low-temp (%)</th>
<th>by 2050, high-temp (%)</th>
<th>by 2050, low-temp (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>renewables</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
<td>58</td>
</tr>
<tr>
<td>electrolyzer</td>
<td>63</td>
<td>62</td>
<td>61</td>
<td>62</td>
<td>60</td>
</tr>
<tr>
<td>kiln</td>
<td>N/A</td>
<td>16</td>
<td>7</td>
<td>21</td>
<td>N/A</td>
</tr>
<tr>
<td>DAC</td>
<td>100</td>
<td>84</td>
<td>89</td>
<td>82</td>
<td>92</td>
</tr>
<tr>
<td>fuel synthesis</td>
<td>100</td>
<td>78</td>
<td>77</td>
<td>72</td>
<td>71</td>
</tr>
<tr>
<td>grid connection</td>
<td>18</td>
<td>8</td>
<td>10</td>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>fuel pipeline</td>
<td>100</td>
<td>78</td>
<td>77</td>
<td>72</td>
<td>71</td>
</tr>
<tr>
<td>natural gas</td>
<td>100</td>
<td>68</td>
<td>47</td>
<td>61</td>
<td>17</td>
</tr>
</tbody>
</table>

*Note that the DAC, fuel synthesis, and, to a lesser extent, the electrolyzer have a higher capacity factor than the renewable electricity in all cases.
grid electricity as a backup. Similarly, the today and next-decade cases, as well as the by 2050 high-temperature wind case, have no or almost no heat storage, opting for grid natural gas with a steep carbon price instead. All next-decade and by 2050 cases build CO₂ storage for seasonal shifting. See the Supporting Information, Section S5.7 for further detail.

A final important form of flexibility is curtailment. 4–26% of all renewable electricity generated in each scenario is curtailed as waste. The ability to curtail allows the system to undersize components, avoiding the construction of expensive production or storage capacity that would rarely be utilized. See the Supporting Information, Section S5.1 for further detail.

For low-temperature cases, water produced from the DAC system is sufficient to supply the electrolyzer. However, water costs in high-temperature cases represent at most $0.01/lge or 1.4% of the total cost.

3.1. GHG Mitigation Cost-Effectiveness. The implicit GHG mitigation cost in these scenarios, compared with fossil jet fuel at even its highest annual average value since 2010 of $0.81/lge, is $1.312–$1.400/t(CO₂) today, $315–$350/t(CO₂) in the next-decade, and $51–$65/t(CO₂) by 2050. This uses the method described in Section S5.8, which assumes that electrofuels have zero net carbon intensity by paying a carbon price for emissions offsets. If fossil jet fuel prices fall to their lowest annual average value since 2010 of $0.35/lge, these implicit mitigation costs each rise by $167/t(CO₂). Thus, simply offsetting fossil jet fuel emissions with the DACs technology used in each scenario (costs shown in Table S7) is a more cost-effective net-zero option in all scenarios except the by 2050 cases with a high fossil jet fuel price. Sequestration costs, assumed to be negligible in the main model, would have to rise above $85/t(CO₂), at the very high end of the existing literature, to make electrofuels cost-effective in any of the today or next-decade scenarios. See the Supporting Information, Section S5.8 for further detail.

3.2. Sensitivity: The Importance of Capital Cost and Flexibility. Figure 3 shows a sensitivity analysis that begins with the levelized cost of electrofuel in the next-decade solar high-temperature case, $1.68/lge, and varies each parameter to its today and by 2050 values, with a few exceptions described in the Supporting Information, Section S7. The x-axis shows the percent change in each input value. Lines with steeper slopes or larger vertical lengths for a given parameter imply greater sensitivity. WACC is the weighted average cost of capital used to convert capital cost into levelized cost. The high value of DAC electricity demand is 809% of the baseline value, beyond the x-axis limit shown. Parameters with sensitivity less than $0.05/lge are not shown. Note that no parameters associated with energy storage reach this level. See the Supporting Information, Section S5.6 for full sensitivity results.

4. DISCUSSION

Using today’s technology, electrofuel production is an expensive GHG mitigation option. Anticipated near-term reductions in the capital cost of DAC systems and electrolyzers could reduce the cost of electrofuels produced with the world’s best solar or wind resources to roughly $1.7/lge, comparable to many proposed low-carbon liquid fuels, in line with 2030 estimates from Brynolf et al. and about 70% higher than those from Fasihi et al. 8–11

Within several decades, foreseeable advances in the cost of DAC, electrolyzers, and other technologies could bring electrofuel costs below $1/lge, potentially outcompeting petroleum fuels with DACS as a net-zero liquid fuel option and even approaching cost parity with standalone petroleum fuels. This could allow rapid decarbonization of hundreds to trillions of dollars of existing petroleum-dependent infrastructure without the need for capital turnover. 12 However, if petroleum fuel prices remain on the low end of their historical levels and low-cost sequestration resources are plentiful, it may be more cost-effective to simply continue using fossil fuels and...
offset the resulting emissions with DACS, consistent with refs 60 and 61.

Even when electrofuels are not cost competitive with offsetting fossil emissions with DACS, they may still be a worthwhile pursuit as they may integrate more easily into existing policy mechanisms, such as California’s Low Carbon Fuel Standard, and they do not require permanent monitoring and verification of sequestered CO₂.

These lower electrofuel costs require two essential prerequisites. The first is large reductions in the capital cost of DAC, electrolyzers, and renewable electricity generation. Fuel synthesis costs are a smaller factor, consistent with ref 62. Because electrofuels would likely only be deployed on a large scale as part of an aggressive push to decarbonize the entire economy, these technologies may well receive substantial RD & D funding irrespective of explicit support for electrofuels.

The second key factor is enough system flexibility to right-size capital-intensive components such as the DAC system while making efficient use of available variable renewable electricity resources. Full co-optimization of capacity and operational decisions in this study allows valuation of the benefits of system flexibility, which comes in several forms:

- Storage of electricity, heat, hydrogen, and CO₂ allows the system to essentially store renewable energy over periods ranging from hours to seasons (see the Supporting Information, Section S5.7 for a discussion of seasonal CO₂ storage).
- Fossil natural gas and grid electricity interconnections provide important dispatchable flexibility, which the system tends to use even with high carbon prices.
- The ability to curtail excess renewable electricity.
- Modest ramping capabilities and lower minimum operating levels in the DAC and particularly fuel synthesis systems ensures that the system can avoid costly additional storage or fossil energy to maintain operation during extended periods of low renewable electricity availability.

System costs are fairly insensitive to the capital cost and efficiency of individual forms of storage or fossil interconnections. This suggests that different forms of flexibility can substitute for each other, meaning that the economic viability of electrofuels is not dependent on a breakthrough in a particular form of storage.

One key RD & D priority that may not yet be receiving sufficient attention is flexible hydrocarbon synthesis systems. 5% hourly ramping and a 50% minimum operating limit should be sufficient to bring the vast majority of the benefits of flexibility. Other modest but potentially important RD & D priorities suggested by this analysis are listed in the Supporting Information, Section S8.

The fact is that under comparable assumptions, electrofuel production costs are similar using both high-temperature and low-temperature DAC. Low-temperature DAC’s greater flexibility and ability to recycle waste heat compensates for what may be a higher capital cost. Given large uncertainties in the future cost of each technology, an RD & D strategy that pursues both technologies simultaneously is most likely to produce substantial reductions in the cost of electrofuel.

Note that predictable consistency in seasonal electricity supply can substantially reduce electrofuel cost, primarily by allowing DAC to operate at a higher capacity factor. This favors solar electricity in deserts over even very high-capacity-factor wind with strong seasonality.

Mass deployment of electrofuel production would likely require the use of solar or wind resources with slightly lower quality than those modeled here, resulting in modest increases in cost. Meeting all US jet fuel demand with electrofuels would require about 1% of the total US technical potential for solar or 23% of Arizona’s solar. For wind electrofuels, this would rise to 8% of US potential and more than 100% of Wyoming potential. See the Supporting Information, Section S9 for further detail. Still, given the low cost of transporting liquid fuels, one could scale electrofuel production in very high-quality locations, such as large deserts across the globe. At such remote locations where constructing electricity transmission may be prohibitively expensive, liquid fuel could be transported using the existing petroleum supply chain.

Electrofuels, particularly from solar electricity, require substantial land. Replacing all US jet fuel with solar electrofuel from systems modeled here would require roughly 3.0−4.5 Mha of desert, 0.3−0.5% of US land area, or 10.1−15.3% of Arizona. Wind electrofuels would require roughly 0.04−1.0 Mha of land, 0.005−0.114% of US land area, or 0.2−4.1% of Wyoming, assuming very high-quality wind resources are available in sufficient quantities. For comparison, switchgrass biofuels would require roughly 41 Mha, 4.4% of US land area, and 26% of arable land or 10% of agricultural land including pasture. See the Supporting Information, Section S9 for further detail.

Although water costs represent less than 2% of electrofuel cost in all cases, replacing all US jet fuel with high-temperature electrofuel would require roughly 1.4 Gt (H₂O), which is about 0.3% of US water consumption and 17% of Arizona’s current water consumption. For comparison, switchgrass biofuels would require roughly 0.4−1.8 Gt (H₂O), or 0.1−0.4% of US water consumption, depending on irrigation requirements. To avoid placing undue strain on local water resources, this would likely require the construction of pipeline infrastructure, perhaps to transport desalinated water from the ocean or another non-potable resource, potentially increasing electrofuel costs by at most a few percent. In low-temperature systems, the DAC and fuel synthesis produce all water needed for electrolysis. See the Supporting Information, Section S9 for further detail.

Alternative energy carriers such as hydrogen and electricity could play a significant long-term role in currently liquid-dependent sectors such as aviation and heavy shipping. However, given the long-lived nature of airplanes, ships, and heavy trucks, and the decades-scale regulatory approval processes for airplanes, it is unlikely that such alternative energy carriers will play a significant role in these sectors before 2050, highlighting the potential importance of electrofuels or fossil fuels or biofuels offset by atmospheric CDR.

In conclusion, electrofuels could play an important role in reducing the cost of transitioning difficult-to-decarbonize sectors to a net-zero emission future. However, this will only be possible with simultaneous advances in several technologies at varying stages of maturity. The modeling approach employed here can guide RD & D priorities to ensure the development and deployment of technologies with the characteristics we are most likely to need in the future.
**ASSOCIATED CONTENT**

**Supporting Information**

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.0c07955.

Blending electrofuels into commercial jet fuel and diesel; component descriptions; optimization formulation; optimization parameter values; supplementary results; electrofuel greenhouse gas mitigation cost-effectiveness definition; sensitivity analysis description; potential research, development, and deployment priorities; and land, water, and renewable energy use (PDF)

**AUTHOR INFORMATION**

**Corresponding Author**

Evan D. Sherwin — Department of Energy and Resources Engineering, Stanford University, Stanford, California 94305, United States; orcid.org/0000-0003-2180-4297; Phone: (650) 736-3491; Email: evands@stanford.edu

Complete contact information is available at: https://pubs.acs.org/10.1021/acs.est.0c07955

**Notes**

The author declares no competing financial interest.

Solar and wind electricity production data are derived from the National Renewable Energy Laboratory’s publicly available System Advisor Model using settings described in the Supporting Information, Section S2.1. The code supporting the current study is available at https://github.com/esherwin/ptxopt_electrofuel.

**ACKNOWLEDGMENTS**

I acknowledge Inês M.L. Azevedo, Max Henrion, Nathan S. Lewis, and David W. Keith and Geoffrey Holmes of Carbon Engineering; Adam R. Brandt, Jennifer L. Wilcox, Sean T. McCoy, Ken Caldeira, Klaus S. Lackner, Hadi Dowlatabadi, Selma Brynolf, Mahdi Fasihi, Noah Deich, and Matt Lucas of Carbon 180; and M. Granger Morgan, Kenneth Gillingham, J. Zico Kolter, Russell M. Meyer, Gabrielle Wong-Parodi, Jeremy F. Keen, Liza Reed, Rebecca E. Ciez, Michael Whiston, Verena Beckert, and Lonnie Cimrman for their thoughtful feedback and advice. Max Henrion helped design Figure 1. This material is based upon work supported by the National Science Foundation Graduate Research Fellowship Program under grant no. DGE-1252522. This work was funded in part by the Center for Climate and Energy Decision Making (SES-1463492) through a cooperative agreement between the National Science Foundation and Carnegie Mellon University. Any opinions, findings, and conclusions or recommendations expressed in this material are those of the author and do not necessarily reflect the views of the National Science Foundation.

**ABBREVIATIONS**

- bbl/d: barrels of oil equivalent per day
- CDR: carbon dioxide removal
- CO₂: carbon dioxide
- DAC: direct air capture (of CO₂)
- DACS: direct air capture (of CO₂) with sequestration
- GHG: greenhouse gas
- GJ: gigajoules
- Gt: billion metric tons
- H₂O: water
- kW h (e): kilowatt-hours of electrical energy
- kW h (H₂): kilowatt-hours of hydrogen energy
- kW h (th): kilowatt-hours of thermal energy
- kW h (fuel): kilowatt-hours of liquid fuel energy
- lge: liter of gasoline equivalent
- PEM: proton exchange membrane
- PtXOpt: Power-to-X Optimization Tool
- PV: photovoltaic
- RD & D: research, development, and deployment
- SI: supporting information
- TWh: terawatt-hours
- Mha: million hectares
- Mt: million metric tons
- WACC: weighted average cost of capital
- yr: year

**REFERENCES**


