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LEVELIZED COST OF CARBON ABATEMENT: AN IMPROVED COST-ASSESSMENT METHODOLOGY FOR A NET-ZERO EMISSIONS WORLD

BY S. JULIO FRIEDMANN, ZHIYUAN FAN, ZACHARY BYRUM, EMEKA OCHU, AMAR BHARDWAJ, AND HADIA SHEERAZI

OCTOBER 2020

$$L = \sum_{1}^{n} \left(\frac{1}{a} \left(\frac{C_{eff} + C_{disp}}{E_0 - E_1} \right)_1 + \frac{1}{a} \left(\frac{C_{eff} + C_{disp}}{E_0 - E_1} \right) \right)$$

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EXECUTIVE SUMMARY

New policies are needed to achieve the net-zero emissions required to address climate change. To succeed, these policies must lead directly to swift and profound abatement of greenhouse gas (GHG) emissions. Policies that appear effective on the surface too often have little real impact or are costly compared to alternatives. Governments, investors, and decision makers require better tools focused on understanding the real emissions impacts and costs of policies and other measures in order to design the most effective policies required to create a net-zero world.

This paper, from the Carbon Management Research Initiative at Columbia University's Center on Global Energy Policy, puts forward a **levelized cost of carbon abatement, LCCA**, an improved methodology for comparing technologies and policies based on the cost of carbon abatement. LCCA measures how much CO_2 can be reduced by a specific investment or policy, taking into account relevant factors related to geography and specific asset. It calculates how much an investment or policy costs on the basis of dollars per ton of emissions reduced. Previous marginal or levelized cost methodologies that assess carbon reduction options often failed to consider the specific contexts that determine the real, all-in costs of a policy and the real, all-in impacts on emissions. These costs and impacts can vary depending on the contexts and details of geography, existing infrastructure, timing, and other factors. LCCA attempts to improve understanding of the real climate costs and benefits by including specific and local CO_2 reductions in all estimations and consistently applying standard financial metrics that more accurately represent and compare costs.

Investors and policy makers interested in climate, energy, and decarbonization must balance many competing options. The scenarios and analyses presented in this report can provide a foundation for wider analytical applications, and can help focus investments in innovation for hard-to-abate sectors, determine essential infrastructure required to facilitate market uptake, and estimate the value of grants in deployment. If the LCCA is not estimated, decision makers will not know the value of their policies and investments in terms of achieving greenhouse gas reductions and their carbon goals or the opportunity costs of taking one path over another. Finally, although carbon abatement costs are only one consideration of many in crafting climate policy (e.g., jobs, trade, domestic security), LCCA analysis will deploy efficient and effective approaches of GHG reduction and help avoid waste.

This paper uses four scenarios to illustrate the discipline and value of LCCA analysis: first, the $/ton cost of using new solar power (utility or rooftop) to displace power-sector emissions in one market (California); second, the $/ton costs of new rooftop solar generation in several states with different solar resources, grid mixes, and policy environments; third, the $/ton cost of various technology options to decarbonize a range of primary iron and steel production methods; and fourth, the $/ton cost associated with sustainable aviation fuels and direct air capture and storage of CO_2.

The analysis provides insight into (a) the highest value for carbon reduction, (b) the relative discrete costs and benefits for decarbonization options, and (c) the potential shortfalls in policy or portfolio goals. In this context, the LCCA estimates for even simple cases can prove complicated depending on how emissions reductions are achieved. For example, our first scenario finds the costs of reducing emissions by replacing existing power generation in California with solar PV range from $60/ton (utility solar PV displacing natural gas power generation) to $300/ton (rooftop solar replacing a grid-average mix of generation) to more than $10,000/ton (any solar replacement of nuclear or hydropower). These large ranges are contingent on policy, investment, and/or technical decisions. Other key examples include:

- The value of learning by doing is substantial for solar deployment, suggesting that investment in innovation and supply chains can be worth $30–100/ton.
- When 100 percent of rooftop solar deployment is assumed to be associated with the solar investment tax credit (ITC), the abatement costs range from $31 (Texas) to $105 (New Jersey) for the same technology. If the ITC accounts for less than 100 percent deployment (i.e., less than 100 percent additionality), the costs are higher.
- When 100 percent of rooftop solar deployment is associated with renewable energy certificate programs, the costs can be much greater than $200/ton CO_2.
- The value to a ratepayer of an incentive is the opposite of the cost to the subsidizing party; LCCA can help clarify and measure who pays.
- Hard-to-abate sectors can be defined on the basis of their LCCA—specifically, when more than 75 percent of CO_2 reductions in a sector cost more than $200/ton under a set of reasonable assumptions.
- Most options to decarbonize primary iron and steel cost more than $150/ton, with carbon capture and storage and marginal zero-carbon electrification being substantial exceptions.
- Virtually all sustainable aviation fuels cost more than $300/ton for abatement and can only do 50 percent of the job due to blend-wall limits. Direct air capture today appears to be a cost-advantaged alternative to decarbonizing aviation.

The methodology put forward is suited to both static and dynamic aspects of CO_2 reduction (e.g., learning by doing, marginal supply curves), can assess technology options (e.g., replacing existing power generation) and policy options (e.g., tax credits), and is keyed to tons reduced relative to a base case. It should be considered one specific index or metric, and ultimately should be one of many considerations in designing policy or investments.

INTRODUCTION

The need for rapid, profound decarbonization has never been clearer, manifested in both the rapidly emerging environmental and capital damages attributed to climate change and in the global political consensus for higher ambition, reflected in the Paris Accords. The science and arithmetic required to hit these targets is straightforward: carbon emissions must drop swiftly worldwide, led by CO_2 reductions and ultimately coupled to large-scale CO_2 removal (IPCC, 2018). The gap between the current trajectory and the Paris stabilization goals is enormous (UNEP, 2018), and the world is likely to exceed the carbon budget required to reach stabilization at 1.5° or 2° C stabilization (IEA, 2019).

The new urgency associated with deep decarbonization in part is reflected in new policies aimed at net-zero emissions. These include national commitments (e.g., Government of the Netherlands, 2019), state commitments (e.g., New York State Senate, 2019 and State of California, 2019), and corporate commitments (e.g., BP, 2020; Blackrock, 2020; IIGCC, 2019). In each instance, the policy sets a greenhouse gas emissions target at a set date, which requires both reduction of emissions and ultimately CO_2 removal to balance any irreducible GHG emissions. In one case, Microsoft, the corporate policy is to remove all legacy emissions (Microsoft, 2020).

Net-zero policies like these share an aspect that's relatively new—actual reduction of CO_2 and other greenhouse gases. This is very different from many nationally determined contributions (NDCs) under the Paris accord, which set targets for clean power rollouts and in some cases explicitly allow near-term emissions growth at a slower than previous rate. This is also quite difference from the goal of the United Nations Framework Convention on Climate Change (UNFCCC) of avoiding "dangerous anthropogenic interference with the climate system," and the related topics of common but differentiated responsibilities (UNFCCC, 1992; Brunee and Streck, 2013). These are also different from Renewable Portfolio Standards (RPS), which require fractional displacement or carbon pricing schemes that add taxes or costs but do not directly reduce emissions (e.g., the European Trading Scheme). Net-zero policies are science-based targets required to achieve stabilization at *any* climate target, and the more ambitious net-zero plans attempt to achieve net-zero emissions in accordance with a 1.5° C stabilization carbon budget. In this, net-zero policies are arithmetically required foundations for any atmospheric stabilization and targets, including those agreed to under the Paris Accords.

Given this daunting and difficult task, it is reasonable for investors, business leaders, and policymakers to a seek the most cost-effective approach to reducing CO_2 emissions and achieving net-zero. Many studies, chiefly macroeconomic modeling approaches, have attempted to provide broad insights into cost-effective technologies and policies. Many governments and businesses have taken specific near-term measures (e.g., RPS; feed-in tariffs, mandates, emission targets) that deploy capital and technology locally.

Perhaps surprisingly, there is no common metric to assess technology and policy options. For example, some common metrics used to consider alternative approaches, e.g., levelized cost of electricity (LCOE), ***do not directly measure actual or likely CO_2 reductions***. Common policy approaches (e.g., EV subsidies) have clear associated costs but lack an understanding of the likely carbon abatement associated with implementation. This means that the climate cost-benefit is often masked, and some solutions that appear to be low-cost are not (Gillingham and Stock, 2018; Hasller et al., 2020).

To provide a simple tool to compare technologies and policies and provide better insight and means of measuring performance, we present an improved methodology that allows users to estimate the CO_2 reductions associated with specific actions and approaches—***a levelized cost of carbon abatement***, or ***LCCA***. Like any tool, LCCA is good for some purposes and not for others. However, it provides insight into one specific aspect of the modern task of decarbonization—how much CO_2 reduction can you get for your money. Specifically, the approach is only valid in association with GHG emission reductions or removal and is aimed to answer questions associated with that task.

This report aims to delineate the methodology and value of LCCA, provide a set of scenarios to help illustrate the methodology and its value, and discuss ways to improve upon the methodologies discussed here. It will also discuss limits of the methodology and approach and ideas to gather and share data around LCCA in service to current and future policymakers. Because policymakers must weigh many different priorities (e.g., jobs, national security, trade) along with climate, LCCA analysis can help ensure that the climate goals of policies are achieved at lowest cost and greatest efficiency and effectiveness.

BACKGROUND OF ESTIMATED ABATEMENT COSTS

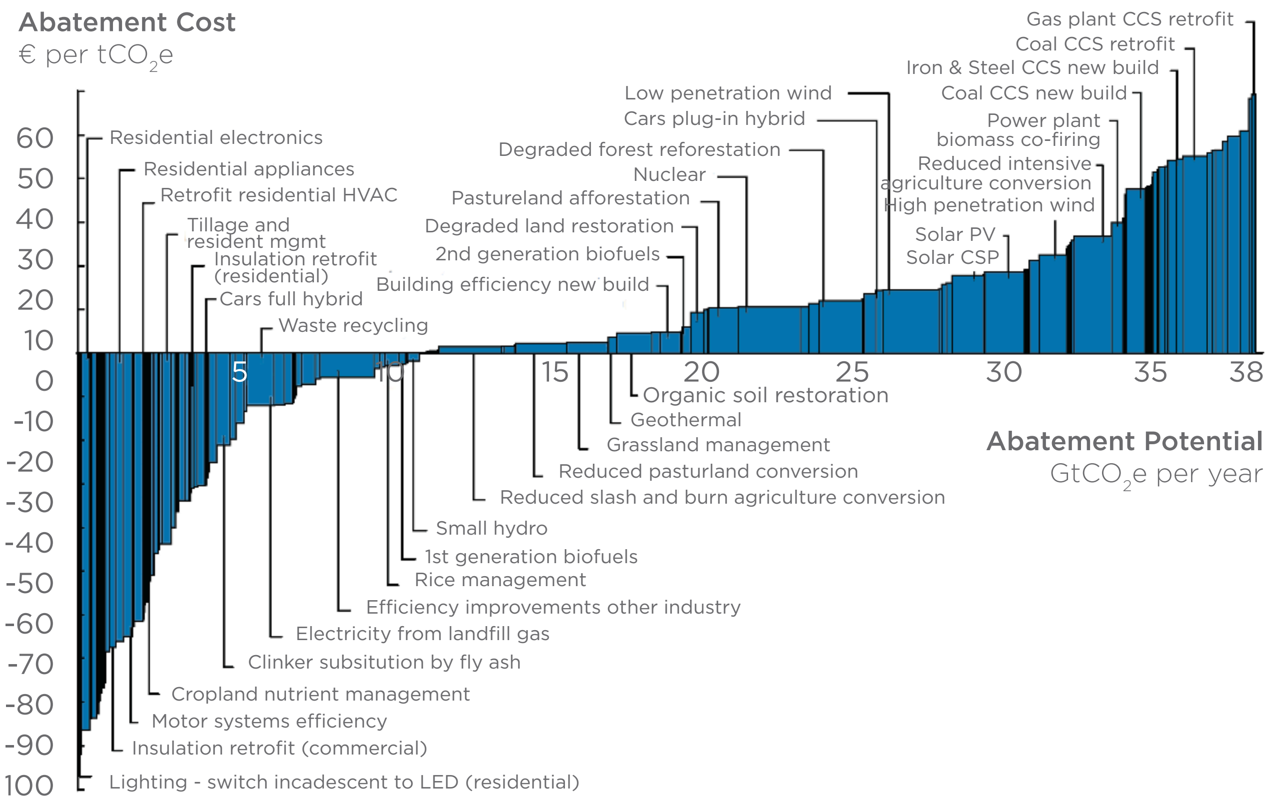
Many modelers and analysis over the years have attempted to understand the costs associated with the energy transition on a $/ton basis. Perhaps the most familiar forms are high-level macroeconomic analyses. These are commonly represented by general equilibrium models (GEMs) used in integrated assessment models (IAMs). These approaches assume or project global or market-specific conditions of key economic terms (demand, supply, growth rate, inflation, etc.), estimate projections of technology costs based on current performance and learning rates, and then assume emissions limits to exogenously drive replacement of emitting technologies with lower- or non-emitting approaches. These models also underlie estimates of social cost of carbon (SCC), which estimate future global economic activity and future economic costs associated with climate change (Nakicenovic et al., 1994; Stern, 2007; IPCC, 2014a, b).

One of the earliest and most well-known efforts was by Nordhaus (1991; 1992), who considered incremental costs of abatement (costs of slowing warming) associated with a general abatement minus the damages prevented by the incremental abatement. Similar, more sophisticated methodologies underlie other social costs of carbon estimates (e.g., Stern and Stiglitz, 2017 and references within) or are used to assess specific economic policies and policy assumptions (e.g., Hassler et al., 2020). The aim of these models is to provide broad, global estimates of mitigation costs based on their internal assumptions and module designs. Although attractive in their simplicity, they carry substantial limitations, including simplifications of climate dynamics, great uncertainty in the costs of climate damages, reliance on Ramsey–Cass–Koopmans model formulation, and discounted per capita allocation of benefits and costs across multiple generations (Stern, 2013; Dietz and Stern, 2015). The model results are also highly sensitive to discount rate (Kesicki, 2012) and other specific input assumptions (e.g., representation of "fat tail" costs and risks).

A different approach is to estimate marginal abatement costs (MAC) and use these estimates to generate a cost curve. While Ellerman and Decaux (1998) is considered the first MAC made using a GEM, the McKinsey MAC cost curves (2007; 2009) are perhaps the most well known (Figure 1). The 2007 study attempted to estimate the marginal abatement costs for the US and the 2009 study estimated costs across all sectors world-wide—noteworthy for its ambition alone. A key finding of many MAC analyses is that some measures were deemed to have "negative costs;" i.e., they generated revenues or savings as well as emissions reductions. Although the 2007 report did not include the up-front capital requirements for certain approaches (e.g., efficiency), the 2009 report presented initial up-front capital estimates as well.

The McKinsey MAC curves and updated estimates like Carbonomics (Goldman Sachs, 2019) can provide a lot of value in that they describe at the highest level what measures could deliver for abatement (Figure 2).[1] They are simple, intuitive, and can reveal important near-term opportunities. Importantly, such curves represent a snapshot in time and place and do not represent dynamic or system-wide effects (Kesicki, 2012; 2013). Unfortunately, they are also commonly misrepresented as an abatement supply curve (Vogt-Schilb et al., 2015).

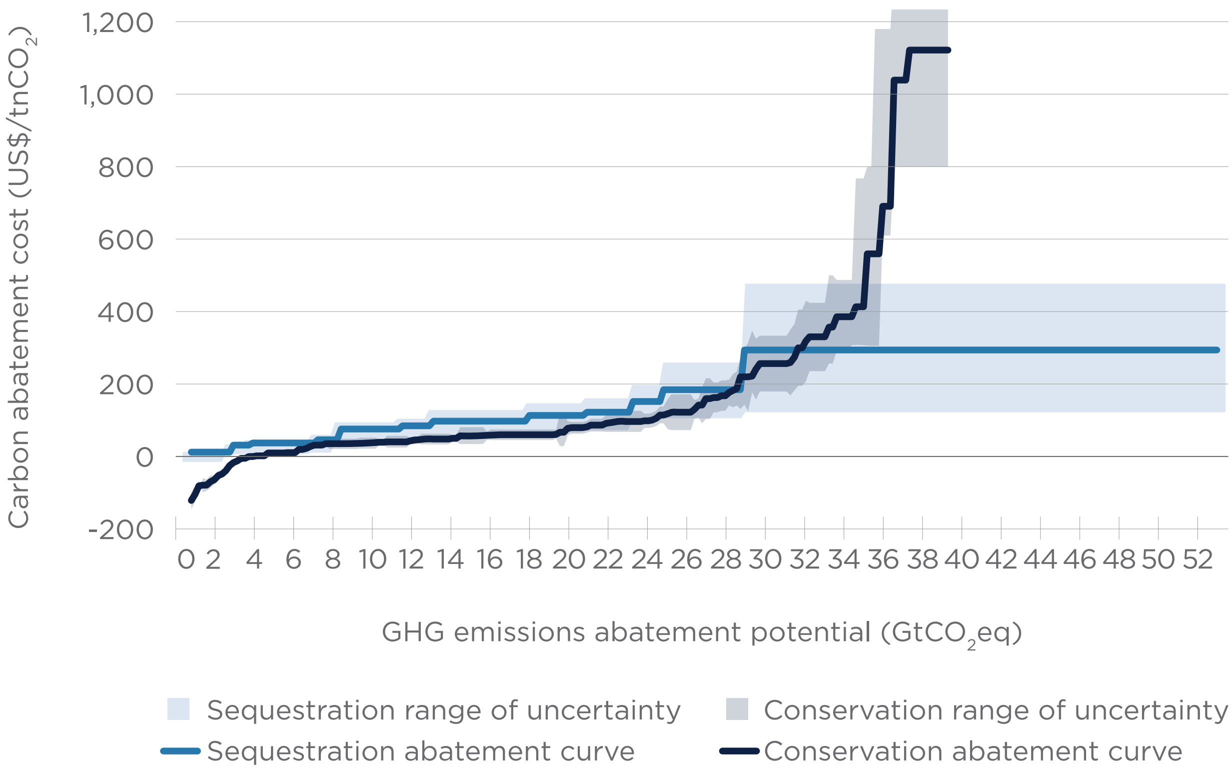
Figure 1: Global GHG abatement cost curve beyond business-as-usual (BAU)—2030/US energy system marginal abatement curve



Note: The curve presents an estimate of the maximum potential of all technical GHG abatement measures below €60 per tCO_2e if each lever was pursued agressively. It is not a forecast of what role different abatement measures and technologies will play.

Source: McKinsey, 2009.

Figure 2: Two costs curves for global CO_2 reduction and removal



Note: The navy blue curve estimates marginal abatement costs on conventional mitigation approaches, the lighter blue curve includes carbon sequestration and CO_2 removal approaches.

Source: Global CCS Institute, Goldman Sachs, 2020.

MAC curve methodology has other limitations. For example, it provides no information about the speed at which abatement is possible, and swift substitution or transition is often limited by many factors (e.g., availability of production lines, technology diffusion rates, availability of workers, presence of infrastructure) that require granular, local understanding to overcome technical inertia (Grubb et al., 1995; Vogt-Schilb et al., 2015). This contributes to other challenges, including inconsistencies in representation and estimation of costs, omission of non-finance costs, and inability to represent system interactions (Kesicki and Ekins, 2012).

A common limitation to MAC approaches is that they do not represent what substitution or transition occurs. For example, efficiency efforts or nuclear build-outs are deployed in the 2009 McKinsey MAC models, but it is unclear what energy sources they displace and how those displacement terms interact or limit each others' opportunity. Similarly, they commonly provide no information regarding the up-front costs associated with implementation, including near-term capital costs or new infrastructure costs.[2] Such concerns are of central importance at regional and local levels of policy and investment.

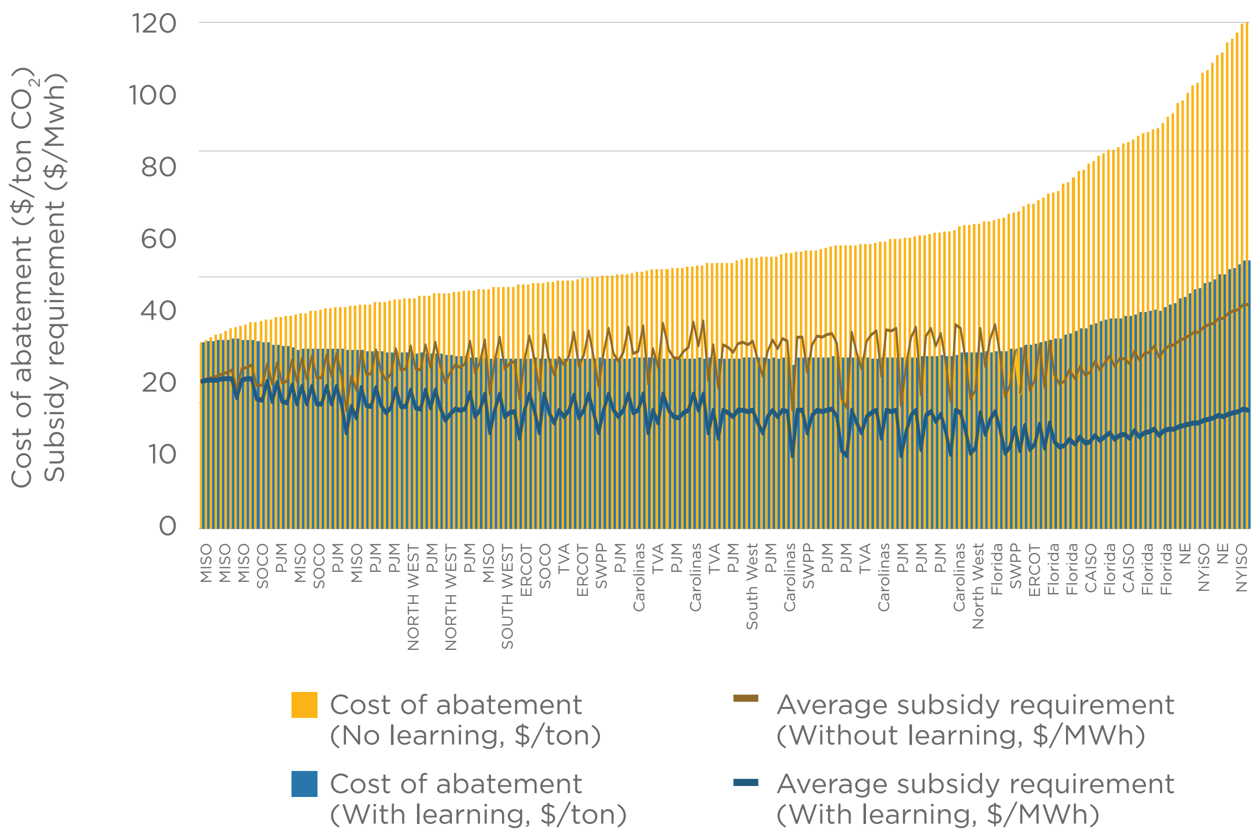
Both IAM and MAC approaches are very powerful and help communicate important aspects of climate policy and investment. By their nature and use, they also share specific and important limitations:

- Due to averaging and similar generalizations, many MAC and IAM estimates lack detailed local/regional specificity.
- Similarly, neither approach provides technical details based on consistent assumptions (Kesicki, 2013), which can limit understanding of where to invest marginal dollars, what policies will yield the most CO_2 reduction, and what sectors to prioritize.
- Many dynamic effects, e.g., rebound, are not incorporated in these approaches.
- Within both approaches, competition between options is often hard to see, buried in the code, or not overtly represented (Kesicki, 2012).

Consequently, MAC and IAM approaches ***underestimate costs and do not fully represent required investments*** within the energy transition. Often, users of these powerful tools misrepresent the difficulty, expense, and time needed to achieve long-term goals (Kesicki and Edwins, 2012; Vogt-Schilb et al., 2015).

More accurate approaches include attempts to show the instantaneous replacement of one generation for another on complex existing or hypothetical grid models. In addition to conventional cost elements, such estimates use data from grid operators to make substitutions based on time-of-day generation and load-balancing dynamics and use these models to simulate adoption of technologies and policies (e.g., E3, 2014, 2017; Das et al., 2020). These costs estimates are routinely higher than Lazard-style methodologies (and serve to provide different insights using different metrics and methodologies). The costs differences in part are due to representation of generation to maintain grid balance and in part due to the higher marginal cost associated with the challenges associated with displacement of the last emitting remnants (e.g., Jenkins et al., 2018). To provide greater complexity and accuracy, marginal abatement costs by Das et al. (2020) included local balancing needs, local markets, future abatement challenges, and dynamic factors such as learning (e.g., Figure 3).

Figure 3: Estimated initial through final abatement costs for the US power sector associated with 535 GW penetration of solar power



Note: Each bar represents a 2.5 GW tranche, with and without learning. Carbon reductions are associated with grid and regional capacity reductions and replacements of generating assets.

Source: Das et al., 2020.

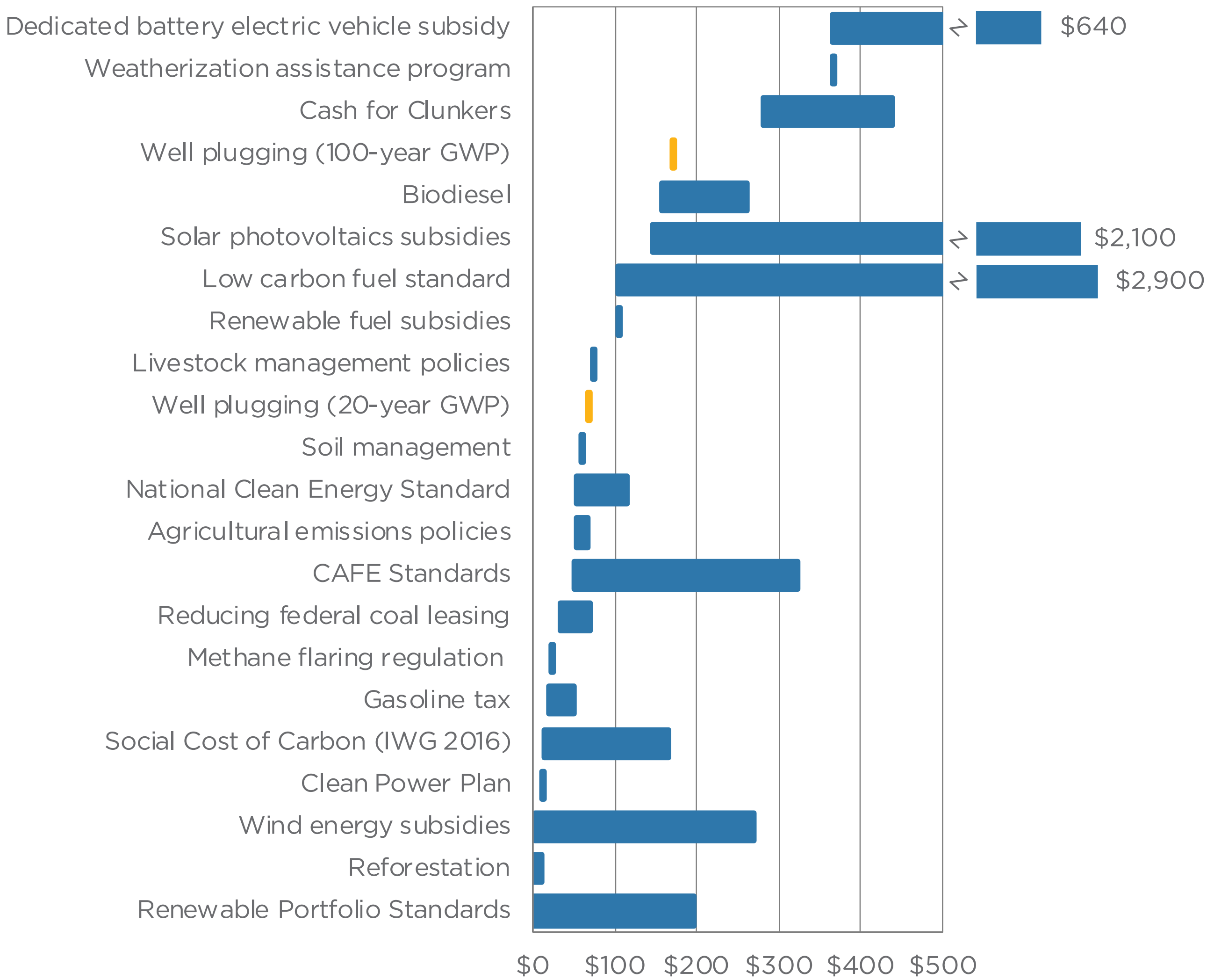
Beyond these approaches, many authors have attempted specific localized estimates for abatement cost as functions of technology, policy, geography, and specific use. One of the first, Rubin et al. (1992), looked at the cost of specific actions through fuel switching and facility modification, efficiency improvements, or replacements (e.g., replacing all US fossil plants in 1989 with nuclear plants). Their analysis, very similar to LCCA, estimated the $/ton costs associated with dozens of policies and actions, and found most efficiency measures to have negative costs (i.e., to generate revenue) despite substantial up-front costs.

Vogt-Schilb et al. (2018) were among the first to point out that, as an investment class, *abatement requires a new approach* to estimate and compare options. Similar to LCCA, they created a methodology called "levelized cost of conserved carbon," which includes the economic opportunity cost (*adjustment cost*) associated with resource allocation for discounted abatement. Importantly, they define their model (m_t) in terms of reduction relative to a baseline emissions scenario (E_{ref}) through quantitative abatement (a_t). They also point out that abatement potential is finite, that costs for economy-wide abatement will increase as abatement options are consumed, and that different sectors will follow different optimal trajectories. Using the methodology that includes the discounted cost of avoided carbon emissions, they estimate the static LCCA for a generic electric vehicle to be $734/ton CO_2.

Importantly, none of these methodologies allow a decision maker to readily understand who pays for abatement. Many approaches spread the costs broadly across the economy. However, specific policies (e.g., tax credits, border tariffs) accrue to treasuries, while other policies (e.g, RECs trading) accrue to a subset of ratepayers. *Displacement* of existing emissions sources often has highly localized costs which are borne by investors, debt- and bond-holders, and municipalities. Dislocations associated with displacement can have substantial and local costs (e.g., to local tax base or jobs) and require local infrastructure additions outside of the methodologies mentioned earlier. Some approaches (e.g., Goldman Sachs, 2019) attempt to better represent these costs through estimation of net-present value in their calculations,[3] but they rarely represent who will carry the cost of policy actions.

Gillingham and Stock (2018) summarized many published examples in Figure 4, expressing the range of estimated carbon abatement costs that reflect geographic and technology variation. They discuss both the complications of static estimations and the complexity of dynamic aspects of cost estimation, pointing out the limits of conventional estimates based on averaging, lack of indirect emissions (e.g., fugitive methane) or behavioral changes. Static estimates can be complicated by factors such as technology choice and maturity, up-front loading of costs, geographic variation, fuel and capital cost variations, and specific use. Dynamic complexity included learning effects, spill-over effects, and early purchase lock-in. Importantly, they pointed out how some policy interventions (e.g., a gasoline tax) have low abatement costs while others (e.g., Cash for Clunkers) have extremely high costs.

Figure 4: Static costs of past and present US policies based on a compilation of economic studies



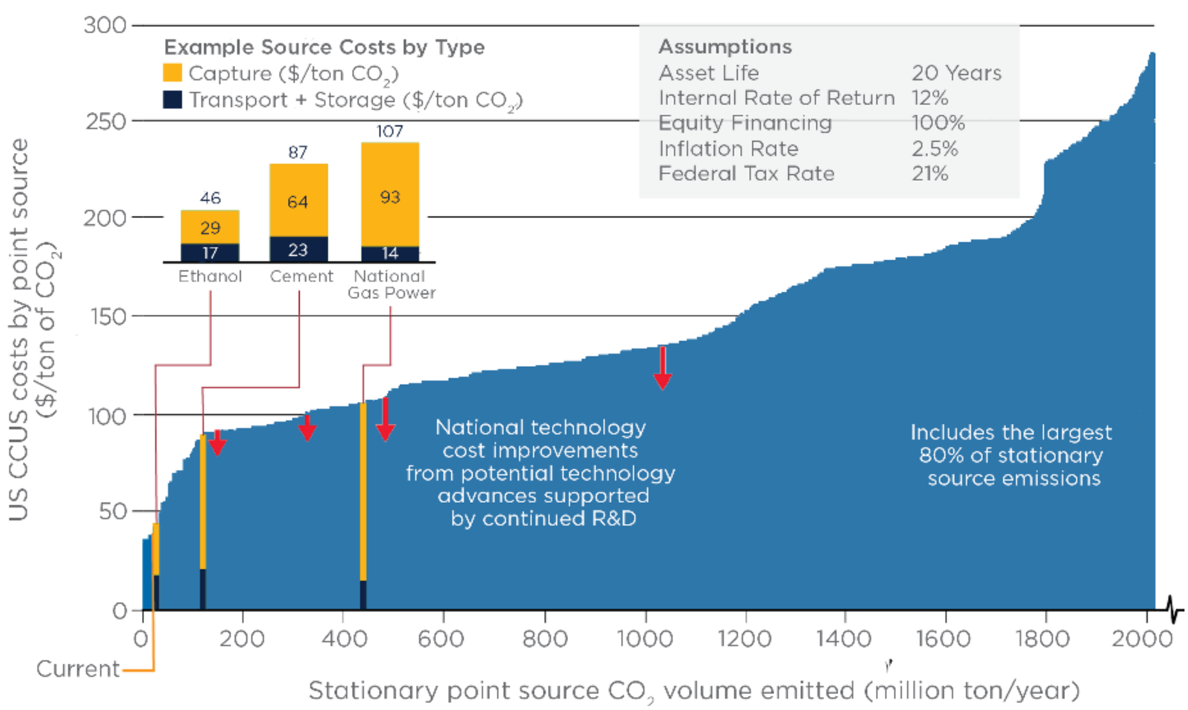
Source: Bordoff et al 2020. Data, Gillingham and Stock, 2018

Carbon Capture as a Special Case

Carbon capture and storage (CCS) as a technology set is framed entirely in terms of the cost of emissions reduction. For this reason, even early techno-economic estimates of CCS applications compared a controlled plant to an uncontrolled plant, estimating the emissions change and the transaction costs (e.g., Herzog et al., 2005). Workers recognized that if additional energy was used, then additional emissions must be included, yielding different estimates of cost for tons CO_2 captured vs. tons CO_2 avoided. Since geological storage was required for successful emissions reductions, many analyses included transportation and storage costs as well. Unsurprisingly, this led to characterizing CCS entirely as additional cost to existing systems, which arguably had a chilling effect on the evolution of policy support.

The recent NPC (2019) report created a MAC curve for carbon capture, use, and storage (CCUS) deployment. Unlike many other MAC curves, it represents specific US facilities and builds the curve with individual costs assuming a specific existing technology and then compares deployment opportunities and costs to existing and potential policy options. Like other MAC curves no timing and staging information was provided.

Figure 5: Marginal abatement cost (MAC) curve for application of carbon capture and storage technology to individual existing US point sources (both power and industrial sites)



Source: Figure ES-13, National Petroleum Council, 2019.

Many groups consider the case of new plants and compare alternate designs and technologies to estimate cost trade-off. To estimate emissions benefit, many workers assume avoided emissions against a counterfactual deployment of different options. For example, Lazard uses estimates for LCOE to compare alternative power projects and use avoided construction of coal or gas power to further estimate “implied abatement values” (Lazard, 2018, 2019). They include costs (capital, fixed operations and maintenance [O&M], and fuel) and manage differences in assumed capacity factor by “overbuilding” renewable facilities’ nameplate capacity. This assumes, then, 100 percent substitution of one kind of unbuilt plant for another, an assumption which does not represent typical use or dispatch of these different plant types. More importantly, ***these approaches do not estimate abatement costs*** since the comparison involves no displacement of existing generation, but rather estimates or ***compares avoided emissions growth***. Said differently, new zero-carbon sources that displace an extant emitter lead to emissions reduction, but these are different than LCOE and similar estimates.

In this report, we have built on these approaches to create a generic methodology, aligned with the Gillingham and Stock (2018) sensibilities. All of our estimates make simplifying assumptions (static or dynamic) and discuss more complicated, accurate, and precise pathways. As discussed below, the primary value is the ability to make “apples-to-apples” comparisons of CO_2 reduction or removal for any specific policy, technology, or investment decision.

METHODOLOGY

As discussed, many authors have published estimates of the cost of CO_2 abatement with varying degrees of confidence, accuracy, and precision. The methodology applied herein represents an attempt both to standardize approaches for estimating the cost of CO_2 abatement and to lay out the specific information and inputs needed to deliver a straightforward, robust estimate. By standardizing the approach, different technologies, actions, investments, and policies can be compared in a *levelized* manner, with each estimate representing a LCCA. Specifically, one must estimate a constant payment per ton of CO_2 abated required to recover the costs of the abatement measure over the life of the measure, reflecting a discount rate and all capital and operating costs. This includes standardizing finance and use assumptions across comparisons, such as costs of capital and operation, amortization and facility capital life expectancy, net-present value (based on an assumed discount rate), and applications in specific facilities (e.g., a cement production facility) or markets (e.g., transportation fuels).

This last step differentiates it from marginal costs estimates and makes it similar to a LCOE. In this context, and like an LCOE, an LCCA estimate is most useful when represented as a range, either due to a range of input assumptions or a range of realized values within one technology set or sector. Unlike LCOE, LCCA can only be calculated in the context of emissions reduction through displacement, efficiency, or CO_2 removal. This allows robust “apples-to-apples” comparisons across technology sets or sectors, provided the inputs and assumptions are valid and accurate, as well as quantification of uncertainties associated with assumptions and unknowns. Risks and potential problems are explored in the Discussion section.

NOTE: The levelization calculation here does not include opportunity cost associated with an alternative investment. It also excludes terms such as social costs or economic costs from decreased productivity and does not include discounted value of emissions over time (e.g., Wang, 1997; Baker and Khatami, 2019). Also, while economy-wide policies like carbon prices have great merit, the LCCA approach is ill-suited to assess macroeconomic policies and should be considered complementary to methodologies that assess impact and value of macroeconomic forcing.

Comprehensive Representation

LCCA methodology could include a wide complement of static and dynamic terms and sub-terms, summations, and partial differentials. It should be possible to couple emissions reductions across sectors (e.g., grid build-out and EV market share growth), although the authors did not attempt a coupled sectoral scenario in this report. Appendix A includes an initial attempt to provide a comprehensive formula that incorporates all important static and dynamic terms in a set of overarching equations. As practice, familiarity, and data precision grow, the LCCA comprehensive representation can grow or change to reflect that new understanding.

Simple

Any LCCA value must be represented as a monetary value (e.g., rubles, Euros, RMB) per unit of realized or estimated carbon abatement (tons CO_2).[4] For the LCCA to be valid, there must be actual reduction or removal of greenhouse gas emissions. The baseline for comparison is the actual emissions at the moment of estimation. As such, hypothetical emissions avoided by building a solar plant instead of a coal plant are not valid in an LCCA. However, real or hypothetical replacement of an existing coal plant with a solar plant would be valid for LCCA, since it leads to actual carbon abatement.[5]

To make a simple estimate LCCA (L), take the difference in annualized costs between approach X and Y and then divide by the difference in annual tons of CO_2 from X and Y:

$$\mathbf{L = C/(E_0 - E_1)}$$

Where C is the cost associated with the change of configuration, E_0 is the greenhouse gas emissions of the original configuration, and E_1 is the greenhouse gas emissions in the new configuration.[6] It should be noted that the cost terms used to estimate C include the levelization terms discussed earlier (e.g., depreciation and discount rate) and are represented differently for different scenarios in different appendices at the end of this report.

A few quick observations flow from this formulation:

- The output is always money per unit CO_2 equivalent reduction, or $/ton.
- If there are no emissions reductions, $E_1 = E_0$, the denominator is zero, and the LCCA is infinite, and the transaction fails to achieve climate benefits.
- If E_1 is less than E_0, there will be a fractional reduction in the cost of the transaction.
- A 100 percent reduction in emissions means $E_1 = 0$ emissions, so the cost is divided by emissions and the LCCA equals the cost of the transaction per ton.
- If the transaction results in CO_2 removal, E_1 is negative, so E_1 is *added* to E_0, which results in a large denominator and greater LCCA decreases.
- If money is saved in the transaction (e.g., in some efficiency actions), C is negative and LCCA is negative.
- **Special case:** If E_1 emits more than E_0, the denominator is negative. This means the new approach yields more emissions than the prior configuration, and the measure is a climate failure and not suitable for LCCA analysis.

The last point is important and is a formal limit on the value of the methodology. If substitution or action leads to emissions growth, the abatement costs should be "beyond infinite" using LCCA methodology and ***any negative denominator creates a specious result and represents an invalid LCCA estimate*** and should be a flag to all analysts and practitioners.[7]

Estimates for the transaction cost should include the basic costs of implementation, such as capital and operating costs, teardown cost, or cost of implementing a new policy. Often assumptions must be made about policy effectiveness (e.g., full additionality) to execute the calculation. More complex formulations can include more complex representations of these terms (see below). Depending on the scenario and specific application, the choice of discount rate can have a large effect on the LCCA estimate. Ideally, analysts would undertake sensitivity analyses to understand the impacts on estimated abatement cost.[8]

Negative LCCA Values

LCCA represents a reduction in emissions ($E_0 - E_1$). If mathematical formalism is strictly preserved, then one would also put $C_0 - C_1$ in the numerator, as is done in LCOE methodology. This would yield a negative number when costs are incurred—red ink in a ledger—which would naturally make most LCCA values negative. McKinsey (2009) realized this as well, and they reversed the formula numerator in their methodology to give a marginal cost expressed as ($C_1 - C_0/E_0 - E_1$). This is the general formulation and convention we follow as well, and it is detailed in the first simple scenario and in Appendices A and B.

In this convention, negative LCCA values, which represent savings, can be problematic. Consider the case of energy efficiency. Efficiency yield reductions in fuel costs, which often produce savings and a negative numerator. ***Such savings are real***. However, a small efficiency gain would make E_0 and E_1 very similar, creating a tiny denominator ($E_0 - E_1$). This would make the LCCA huge, even though the real tons of abatement would be modest. Similarly, a large efficiency gain would produce a large emissions reduction, making $E_0 - E_1$ larger and reducing LCCA. These issues are aided by thoughtful scenario construction and evaluation.

Static Formulations

The simple methodology discussed is just that: simple. There are many ways to make the terms in the equation more complicated (static) and complex (dynamic), hopefully in ways that improve accuracy and insight.

Static LCCA estimates can become more accurate by adding terms that more fully represent the costs or the greenhouse gas reductions. For example, the case of replacing a coal plant with a solar plant could be represented simply as the capital cost of the solar power array with an equivalent nameplate.

- At a minimum, the static estimate should include the real costs and functions of the transaction in question. For example, it should reflect the costs of the specific solar power technology (silicon-based PV vs. solar thermal power), the operating costs of both plants (fuel, labor, maintenance, replacement costs, possibly decommissioning costs), any capital value remaining in the existing coal plant, and real plant outputs (capacity factors and/or kilowatt-hours generated, ancillary service income).

- An accurate LCCA estimate would also consider terms like fraction of coal plant output displaced by mandated use of the solar power generated. Similarly, the solar facility output would vary as a function of solar radiation in the region, the heat rate and efficiency of the coal plant, and the transportation costs for fuel.
- If the solar plant were to displace an existing plant, it would have to estimate the capital status of the existing plant (i.e., is it fully depreciated?) and the operating expenses (e.g., cost of fuel). More complicated representations of cost would include cost of capital for the solar plant, which vary greatly from place to place (e.g., Japan vs. India).
- In yet more complicated estimates, the LCCA would not look at simple displacements of one plant with another, but rather represent the costs of new solar power displacing loads on a regional grid. This would be the product of the needs of the balancing authorities, the distribution and kind of generating assets on the grid, and the solar plant's capacity factor. To improve both accuracy and precision, annual averages should be replaced with daily, hourly, or spot market generation and market prices. If multiple power interconnects interact or exchange, this could further complicate static estimation.
- Some LCCA values, e.g., those associated with efficiency improvements, could have very low or negative values. Efficiency improvements can be simple (e.g., estimated instantaneously) or complex (e.g., estimated over the capital life of the associated changes, including up-front capital costs). Similarly, cases where the teardown costs are low and continued operating costs are high (e.g., replacing plants at end of life) could yield negative costs, provided the replacement system capital and operating costs were sufficiently low.

Ideally, a static LCCA estimate would include full life cycle assessments (LCA) of both configurations, including fabrication emissions, shipping emissions, fuel transportation emissions, retirement costs, etc. In cases where terms are not known precisely, ranges of inputs and coefficients would produce ranges of static estimates for any circumstance. As such, many LCCA representations would appear as tables given a range of input assumptions. The scenarios that follow take this approach.

Dynamic Formulations

As discussed in the background section, dynamic terms in economic forecasts can affect future costs of carbon abatement. A common finding is that seemingly expensive costs today are often cheaper in the future due to dynamic effects (Vogt-Schilb et al., 2015; Gillingham and Stock, 2018). LCCA methodology allows for some specific dynamic estimations of future approaches, costs, or methods, provided that material substitutions that reduce or remove CO_2 emissions can be reasonably represented.[9] For decision makers, this may be germane when considering the phasing of policy objectives or investment in multiple projects and approaches over time.

One example is around learning, whereby costs of a specific technology or technology set decrease through deployment and innovation. Learning effects are commonly represented as the cost reduction through a doubling of deployment, producing a learning curve and rate. The speed of doubling can vary greatly based on policy drivers or technological breakthroughs. Assumptions about learning curves can yield estimates on how the LCCA may change through time for a given technology or policy action.

Another dynamic case could examine how LCCA varies as a function of supply curves and natural resource limits. For example, biomass supply costs vary as a function of the availability of land. Similarly, battery costs vary as a function of their input material costs. Over time, those costs would grow if the availability of viable land or cobalt shrinks, and LCCA would increase as resources become scarce. If either biomass or battery production led to deforestation, the LCCA could increase sharply at the threshold where deforestation commenced.

Another dynamic example could examine how LCCA would change during the process of scaling. For example, continued addition of renewable supplies and energy storage to the electricity sector is found to have diminished marginal value, causing the LCCA to increase (e.g., Jenkins et al., 2017; Das et al., 2020). Scale-up of renewables can amplify curtailment percentages due to mismatch between demand and supply and consequently less fossil energy replaced. On the other hand, indirect cost will gradually lead to cost reduction during scaling and become cheaper per unit. For example, EV charging infrastructure and carbon storage infrastructure (pipeline and storage) will be expensive for initial projects/automobiles but well-established infrastructure can allow additional operation units with essentially no additional cost (which, among other things, could be used to estimate the carbon abatement value of building infrastructure).[10]

SIMPLE ILLUSTRATIVE SCENARIOS

To help explain and clarify appropriate use of LCCA methodology, we present a handful of scenarios meant to serve as examples. They share a few common characteristics consistent with LCCA methodology (e.g., replacement of one system with another). In the first two cases, one set of technologies displaces fossil emissions on a grid, in some cases with different geographies (and solar insolation values), grid mixes, and policy frameworks. In the second set of scenarios, unit production (e.g., steel or jet fuel) is replaced with other production methods (fully or partially).

The estimates presented here are meant to be representative, robust, and valid but not necessarily comprehensive regarding the inclusion of costs elements. The goal of these scenarios is to represent the thinking in accurate LCCA estimation and the degree to which additional components can be added for greater precision.

Scenario 1: Central California Solar Power

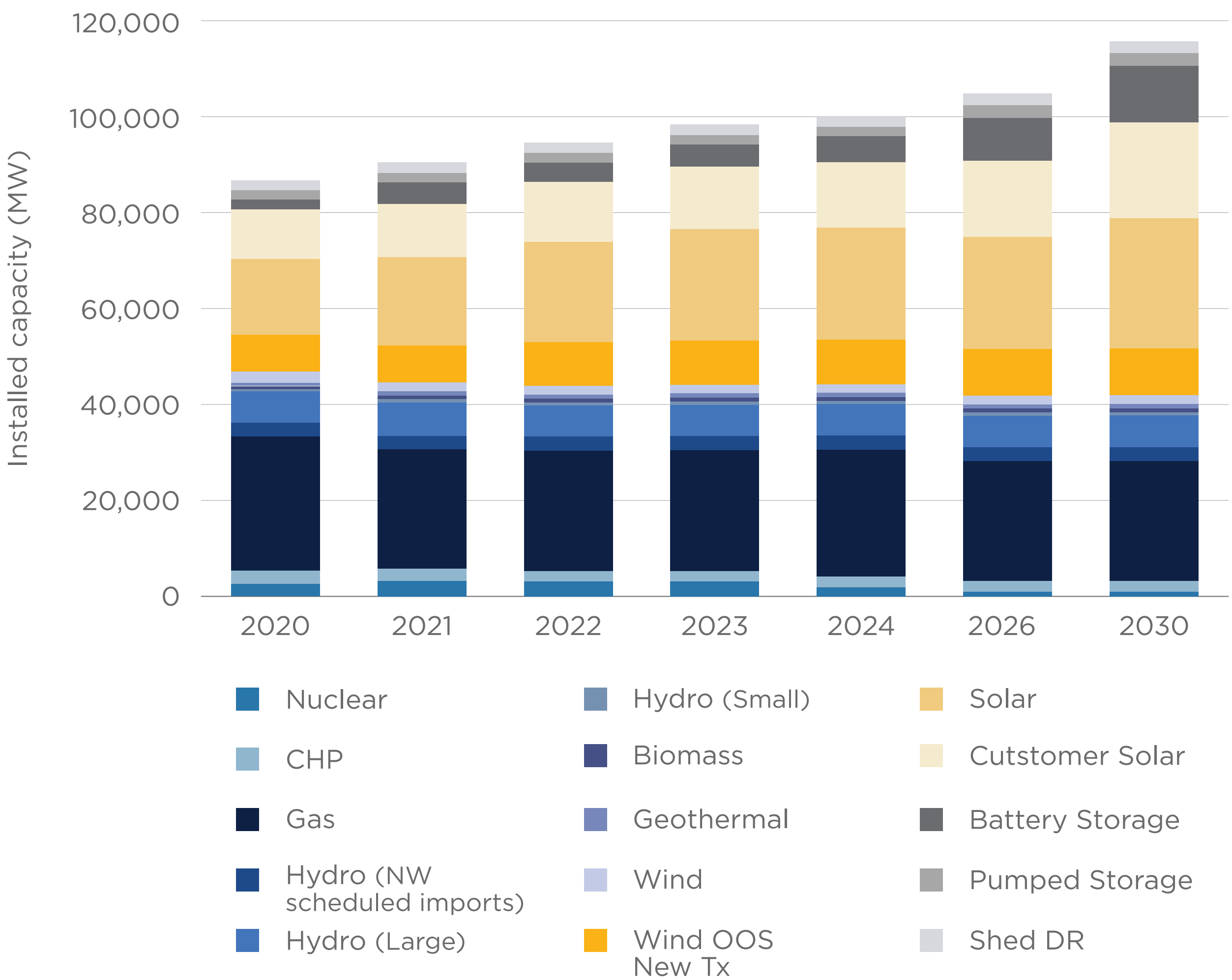
Through a set of legislative acts, the state of California provides a model for transition to clean, environmentally sustainable electricity generation. From its first statewide renewable electricity standards in 2002 (ILSR, 2020) to committing to reduce emissions drastically to 1990 levels by 40 percent in 2020 (California Senate, 2006), California has led a decarbonization drive toward a clean energy economy. This legislation helped form policy that led to 60 Mt emissions reduction in 15 years: from 485.9 million tCO_2 in 2002 to 424.1 million tCO_2 in 2017 (California ARB, 2019).

Emissions from electricity generation saw a gradual decline over time following gradual transition from conventional generation sources to more renewable electricity sources, such as solar, wind, small hydro, and biomass. In 2017, electric power contributed 14.7 percent (62.4 million tCO_2) to the total emissions in California, a decline from 22.4 percent (108 million tCO_2) in 2002 (California ARB, 2019). More aggressive reductions are in the works following the California Public Utilities Commission (CPUC) unanimous vote on March 26, 2020 to an electric sector GHG emissions reduction target of 46 MMt CO_2 by 2030, reflecting a 56 percent decrease in emissions compared to 1990 levels, and with prospects of exploring a further reduction to 38 million tCO_2 (CPUC, 2020).

Achieving this target means that 50 percent of electricity generation needs to be met from zero-emission sources, mostly variable renewables, requiring significant build-out of new capacity. The anticipated build-out includes 25,000 MW of additional renewables by 2030, doubling California's currently installed utility-scale solar capacity and adding 8,900 MW of battery storage—about eight times the nation's battery capacity levels in 2018 (Balerman, 2020). Additionally, there is very little anticipated load growth for the state, and conventional natural gas, nuclear, and large hydropower plants would be gradually displaced by new non-emitting generation. As direct displacement of emitting electricity sources by solar power is already underway in California, this situation provides a useful case study for evaluating the

LCCA of these displacements. The variations in LCCA between specific cross-sections of this case study can also give insights into the most economically efficient way for California to reduce its power-sector emissions in the coming decade.

Figure 6: Cumulative quantities of all resources in new 2018–2020 RSP



Source: CPUC, 2020.

Scenario-Specific Methodology

Our methodology is based on the scenario of 1,000 MW of residential rooftop or utility-scale solar capacity directly displacing 1,000 MW of capacity of an existing electricity source in central California. That is, the electricity generation from the new solar installation displaces the generation of the existing source. We assume this displacement occurs on a 1-to-1 basis, meaning every 1 kWh of electricity produced by a new solar installment displaces 1 kWh of existing plant generation, decreasing the capacity factor of the existing plant. We recognize that this is a gross *underestimate* of LCCA, since 1-to-1 displacement is rarely achieved. However, this assumption allows for simple comparison of cost estimates, knowing that real dispatch would lead to smaller displacement, smaller denominators, and larger LCCA values.

We also approximated California as a flat or decreasing electricity market (i.e., constant or decreasing demand for electricity), such that any increase in new solar electricity generation must be accompanied by an equal decrease in existing generation.[11] We analyzed the displacement of natural gas power, hydropower, and the grid average. Regarding average grid displacement, we ran two cases, one in 2018 using recent data and one for 2030 using the emissions targets set by the California Public Utilities Commission as actual emissions that year. For this particular scenario, the LCCA equation can be reformulated as

$$L = (C_1 - C_0)/(E_0 - E_1)$$

Where C_1 is the cost of a new solar installation plus the capital losses associated with decreasing the capacity factor of the existing plant. C_0 is the avoided costs in the displacement configuration due to the decreased capacity factor of the existing plant. E_0 is the CO_2 emissions of the original configuration, and E_1 is the CO_2 emissions in the displacement configuration.[12] The displacement configuration is the combination of the new solar capacity and the reduced capacity factor of existing generation, while the original configuration is the existing plant operating at its standard capacity factor. The difference $E_0 - E_1$ is represented as the emissions associated with the amount of existing generation displaced by solar power, as solar power is assumed to have zero emissions.

We first estimate the cost of displacing an existing power source with solar capacity—the numerator in our LCCA equation. As part of C_1, the lifetime cost of a new solar installment is calculated using NREL 2019 Annual Technology Baseline (ATB) cost metrics, assuming a 20-year lifetime of a solar installation. The capital losses of displacement are calculated by multiplying the depreciated capital cost of the existing plant by the ratio of the reduced capacity factor after displacement to the initial capacity factor (see Appendix B for details).

We calculate the carbon abatement of this displacement—the denominator of LCCA—by determining the emissions that would have been incurred from the displaced power generating units—in this case, grid average, natural gas power, or hydropower.[13] This gives the total carbon abatement over the 20-year lifetime of the solar installation. With a 1-to-1 displacement of energy generation, the carbon abatement associated with this displacement is the solar energy generation multiplied by the carbon intensity of the existing electricity source (see Appendix B for details).

We divide the overall cost of displacement by the carbon abatement of displacement to obtain a final LCCA estimate for each existing electricity source. Our results are summarized in Appendix B (Tables B.3 and B.4) along with detailed tables of input terms and the full calculation description.

We use this same methodology to calculate the LCCA for average California grid displacement in 2018 and 2030. We estimate C_0 for both years by assuming the displaced electricity is composed of 76.5 percent natural gas power and 23.5 percent hydropower, (the current ratio between the two sources in California) and take the weighted average of the C_0 costs of each source using that ratio. The carbon abatement of displacement is estimated using the current carbon intensity of the California grid for the 2018 case and using a projected carbon intensity for 2030 based on the California Public Utilities Commission's target of 50 percent renewables by 2030.

Finally, we use our framework to calculate LCCA when considering the effects of the solar investment tax credit (ITC), learning by doing (LBD), and cheaper natural gas fuel. Learning by doing (i.e., the aggregated cost reductions that occur through deployment) yields a percentage total cost decrease for every doubling of installed capacity—in this case, additional solar capacity installations are accompanied by a certain percentage decrease in the cost per watt of installed solar capacity. To understand how learning can affect LCCA, we assume a 16 percent full system LBD doubling rate and run LCCA cases after one and two doublings of global installed solar capacity. This anticipates future reductions in the solar installation cost by 16 percent for each doubling and leaves other LCCA terms unchanged. In separate calculations, we estimate the effects of a 30 percent ITC on LCCA by applying a 30 percent decrease in the rooftop and utility solar installment capital cost with all else equal. We illustrate the effect of a natural gas price decrease by recalculating avoided fuel costs for a natural gas plant—a component of C_0—with a $2/MMBtu gas price instead of the $3.5/MMBtu price we use in all other calculations.

Results

For 1,000 MW capacity and 20-year lifetime, we calculate a C_1 value of $1.7 billion for a utility-scale solar installation, using $1,111/kW capital expenses, $15/kW construction finance costs, and $20/kW-year fixed O&M costs (NREL, 2019). Similarly, for 1,000 MW and a 20-year lifetime, we determine a total C_1 cost of $3.4 billion for distributed residential solar, using $2,770/kW capital expenses and $24/kW-year fixed O&M costs (NREL, 2019). These numbers are similar to other estimates for rooftop and utility solar. For example, Lazard (2018), which also reflects IEA data, estimates installation capital cost and a fixed O&M of $950–1,250/kW and $9–12/kW-year, respectively for utility and $2950–3,250/kW and $15–20/kW-year, respectively for rooftop solar. Our total solar cost estimates align with real-world averages for utility and rooftop solar in California on a $/W basis, as reported by a number of sources (Bolinger et al., 2019; California Distributed Generation Statistics, 2019; SEIA, 2019; Perea et al., 2020).

As hydropower does not incur variable costs and is assumed to have fully depreciated capital cost, C_0 for hydropower is equal zero. For natural gas power, on the other hand, the starting capital cost of the 1,000 MW plant is set to $930 million and is depreciated annually. Assuming the new solar installation begins displacing the natural gas plant output in year 10 of the natural gas plant's 30-year capital life, a depreciated natural gas plant capital would be $419 million in year 10. We use this as the starting value for estimating capital losses due to displacement. This estimate is consistent with Lazard (2018) and NREL (2019), wherein new (year zero) natural gas plant cost estimates range between $700–1,300/kW and $927–1,250/kW, respectively.

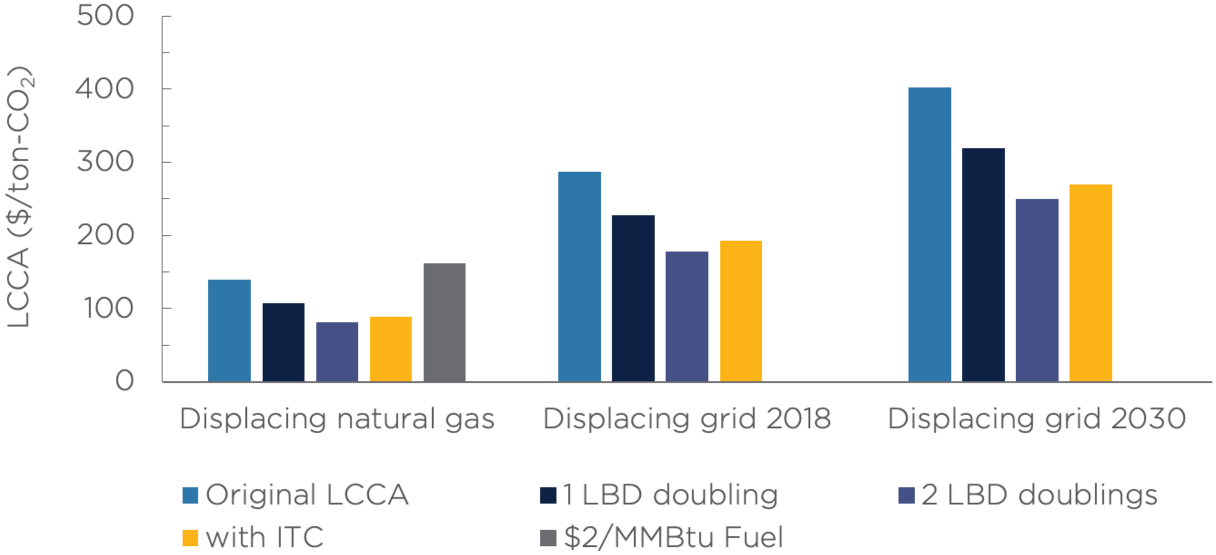
To estimate variable O&M and fuel costs after displacement, we calculate a lifetime electricity generation of 39.4 TWh for the 1,000 MW solar installation (20 years at 25 percent capacity factors) and reduce the existing plant output by that amount by reducing the capacity factor. Specifically, we reduce the natural gas plants output from 41.8 percent to 19.3 percent capacity factor.

Summing up the avoided O&M and fuel costs of the gas and hydro plants yields our C_0 value of $1.2 billion for the gas plant and $880 million for the grid average.

Meeting California's target of achieving 50 percent renewable electricity by 2030 would require roughly 30 percent of fossil generation to be replaced by renewables, which we represent as a 30 percent decrease in carbon intensity of electricity, assuming the average fossil fuel carbon intensity is displaced (California Energy Commission, 2019). This calculation yields a lifetime emissions abatement of 16.4 million tons of CO_2 when solar displaces natural gas. In the case of solar displacing hydropower, the carbon abatement is zero because we represent hydropower as a zero-emissions energy source. ***This yields infinite LCCA estimates for displacement of hydropower.*** Using this methodology, the grid emissions abatement would be 0.4 million and 0.3 million tons CO_2 for California's grid in 2018 and 2030, respectively.

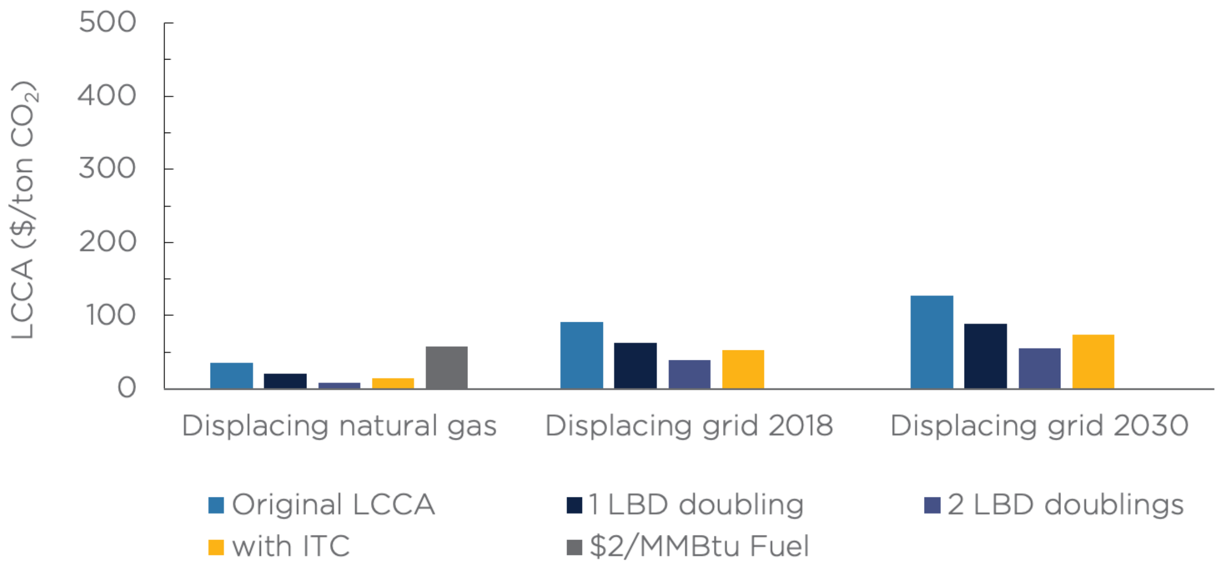
Our unsubsidized static scenario analysis calculated from these values yields an infinite LCCA estimate for solar displacing zero-C power, $140/ton for rooftop solar, and $34.9/ton of CO_2 for utility solar, respectively displacing natural gas generation. A reduced fuel cost to $2/MMBtu produces a lower C_0 value, which increases the estimated LCCA value to $162.4/ton and $57.5/ton of CO_2 for rooftop and utility solar, respectively displacing natural gas generation. For the grid estimates, our calculations yield LCCA values of $287/ton and $91/ton for 2018 grid; and $402/ton and $127/ton of CO_2 for 2030 grid, for rooftop and utility solar, respectively displacing grid generation.

Figure 7: LCCA results for residential rooftop solar displacing various existing sources



Note: Since displacing hydropower yields infinite LCCA value, it is excluded here.

Figure 8: LCCA results for utility-scale solar displacing various existing sources



Note: Since displacing hydropower effectively yields infinite LCCA value, it is excluded here.

Estimating the effects of LBD, assuming a 16 percent learning rate, reduces the LCCA values to $108/ton for rooftop and $20/ton of CO_2 for utility solar, displacing natural gas generation;

$227.9/ton for rooftop and $63/ton of CO_2 for utility solar, displacing 2018 grid generation and $319.3/ton for rooftop and $88.2/ton of CO_2 for utility solar, displacing 2030 generation.

Doubling the effects of LBD further reduces the LCCA values to $81/ton for rooftop and $8/ton of CO_2 for utility solar, displacing natural gas generation; $178/ton for rooftop and $40/ton of CO_2 for utility solar, displacing 2018 grid generation; and $249/ton for rooftop and $56/ton of CO_2 for utility solar, displacing 2030 generation.

We estimated the effect of tax incentives such as an ITC of 30 percent on LCCA values. The result of our estimation indicate that introducing an ITC improves LCCA values to $89/ton for rooftop and $15/ton of CO_2 for utility solar, displacing natural gas generation; $193/ton for rooftop and $53/ton of CO_2 for utility solar, displacing 2018 grid generation; and $270/ton for rooftop and $74/ton of CO_2 for utility solar, displacing 2030 generation. These costs accrue to the U.S. Treasury, as discussed in Scenario 2 below.

Discussion for Scenario 1

The analysis shown here yields insights into the value of using solar power growth as a means to reduce emissions:

- *Under most scenarios, utility solar has a lower cost of abatement than rooftop solar*: For many cases, LCCA is less than $100/ton and is locally lower. While incremental real costs may be higher, policies that support utility solar deployment in California appear cost-effective compared to many decarbonization options. Note: this result is matched by the finding of many authors (e.g., Lazard 2018; 2019; CPUC 2020).
- *Under all scenarios, rooftop solar has high costs of abatement*: Even in scenarios with 1-to-1 substitution for gas and high learning rates, rooftop solar does not appear to be cost-effective in reducing emissions, with most LCCA cases well above $200/ton.
- *The scenario assumptions underrepresent the real costs*. The assumption of 1-to-1 displacement is the optimal LCCA estimate.
    - If there is less than 100 percent substitution, the denominator is smaller and LCCA higher. In most grids, substitution of solar is less than 100 percent.
    - Adding electricity storage cannot improve on this estimate, since it already assumes 100 percent displacement. In this scenario's assumptions, adding storage only adds costs and does not increase displacement, since we already assume 100 percent. Real systems with storage cost more than those without, increasing the numerator.
- *Paying to displace any zero-emissions electrical supply yields LCCA values as infinite costs*. This is true for the hydropower case (see also Appendix B) but would be true for any zero-emission displacement (e.g., using solar to displace wind). To avoid this outcome, policy design should be careful not to displace zero-carbon sources.
- *LCCA value of the ITC varies greatly, between $20–130/ton*. Even with the assumption that 100 percent of the ITC support yields adoption and displacement (a generous

consideration), the real costs of the ITC appear high and vary depending on how it is applied. NOTE: the ITC results in savings for the ratepayer or project developer and also reflects real costs to the US treasury that are substantially higher than other tax credits (e.g., 45Q). These are discussed in scenario 2 (below).

- *The value of learning by doing is substantial*: Cases with one or two doublings over 10 years yield substantial cost reductions in the same outcomes. This suggests that investment in clean energy innovation reduces overall costs moderately and can reduce overall decarbonization costs substantially.
- *Lower fossil fuel costs produce higher LCCA values*: Since the LCCA calculation leads to avoided fuel costs, lower gas costs lead to a decrease in the savings from fuel costs and higher overall LCCA.
- *LCCA can be expected to increase appreciably as the California grid becomes cleaner*: a lower grid-average carbon intensity decreases carbon abatement and raises LCCA, making progress toward a zero-carbon grid progressively more expensive on a LCCA basis. We estimate grid decarbonization in California could increase LCCA for rooftop and utility solar by 40 percent in the next decade, all else being equal.

These are ***generous*** estimates, meaning real costs are likely to be higher. Already, these estimates are consistently higher than many published MAC curves and consistently higher than the Lazard estimates for implied carbon reduction (Lazard 2018, 2019). However, more comprehensive representation with additional terms (e.g., distribution system upgrades) or reducing displacement volumes (less additionality, grid dispatch models) would produce even higher costs.

One of the most consequential assumptions in our analysis is that solar electricity will displace the existing electricity source on a 1-to-1 energy basis. In reality, the temporal mismatch between the time-dependent output profiles of solar and existing sources makes it extremely difficult to achieve 1-to-1 displacement. Therefore, ***1-to-1 displacement represents an underestimate of LCCA*** since it provides the maximum energy and carbon displacement possible under the scenario.[14]

In all cases run, the difference in LCCA for rooftop and utility-scale solar arises entirely from their different direct system costs. The normalized cost (in $/W) is significantly lower for utility-scale solar facilities due to (a) project financing, (b) utility rate recovery, (c) economies of scale and lower cost of capital. The factor of two difference in solar costs translates into a much larger factor difference in LCCA due to the $C_1 - C_0$ calculation of the numerator. Since the utility solar C_1 is comparable in magnitude to C_0 in all cases, but the rooftop solar C_1 is billions of dollars larger than C_0, the numerator value of $C_1 - C_0$ is many times larger for rooftop solar than utility solar. The value of C_0 depends only on costs associated with the displaced electricity and therefore does not vary between types of solar. Carbon abatement in the LCCA denominator is also independent of the type of solar, as our rooftop and utility solar installations have the same capacity factor and nameplate capacity, and thus displace the same amount of electricity.

Between different sources of power being displaced, the C_0 avoided cost due to displacement is partly responsible for the variations in LCCA. Generally speaking, a lower avoided cost of displacement makes it more difficult to economically justify replacing existing generation with solar power, which is reflected in an increased LCCA. For natural gas power, the C_0 cost is composed of mostly avoided fuel costs, with a significant but smaller contribution from avoided variable O&M costs. Since fuel costs factor in, the price of natural gas fuel influences LCCA. When natural gas becomes cheaper, the avoided fuel costs decrease, lowering C_0 and increasing LCCA. We see this effect in the increase of LCCA from the original calculation for natural gas displacement, where the fuel price is $3.5/MMBtu, to the alternate calculation using a cheaper $2/MMBtu fuel price.[15]

The final value that dictates variations in LCCA is the abated CO_2 emissions due to the displacement, which comes from replacement of carbon intensive electricity by zero-emissions solar. Since the total electricity generation displaced remains constant in all cases, the carbon abatement varies solely as a function of the carbon intensity of electricity displaced. Within our calculations, the highest carbon intensity of electricity is seen for natural gas, followed by the California grid in 2018, and then the projected grid in 2030 after increased renewables penetration. Hydropower electricity is assumed to have zero emissions. ***When solar displaces less carbon intensive electricity, the carbon abatement is lower and the LCCA becomes larger.*** This also explains why the LCCA for displacing hydropower is infinite, as displacing a zero-emissions electricity source yields no carbon abatement regardless of money invested.

As has been widely documented (e.g., Rubin and et al, 2015; Elshufura et al., 2018; Sivaram et al., 2020), doubling of energy technology generally yields decreases in costs per MW and MWh. This percentage decrease, often referred to as a "doubling rate," is a dynamic effect that includes economies of scale, efficiencies and LBD. Through LBD, the industry learns to deliver solar capacity in an increasingly cost-effective way as installed capacity increases, through improvements in manufacturing and installation. Due to this dynamic effect, deployment of solar today will contribute to lowering the cost of solar in the future, which can increase demand for solar and further abate carbon emissions. Therefore, the carbon abatement of a solar installation is greater than the static estimate would suggest, which only incorporates the emissions reductions from directly displacing a carbon-emitting electricity source. For all displacement cases, each doubling of installed capacity results in a significant decrease in LCCA. A factor of four global buildout of installed solar PV capacity drops the LCCA of solar displacing natural gas nearly to zero.

Cost reductions due to ITC have similar effects in lowering LCCA. The ITC began as a 30 percent tax credit on investment in solar constructions. We obtain a significantly lower LCCA with a 30 percent ITC applied in all displacement cases. Assuming that 100 percent of deployment comes from the ITC (i.e., 100 percent additionality), the reduction in LCCA due to the ITC is larger than that due to one doubling of installed capacity in the LBD calculation. Considering the almost certainly larger cost associated with doubling global installed solar capacity compared to implementing an ITC policy, this result highlights the effectiveness of ITC purely from a cost standpoint in making new solar installments more attractive carbon abatement measures. More broadly, our findings for ITC and LBD together underscore that cost reductions of solar power, whether organic or subsidy-driven, can go far in making solar more favorable on a LCCA basis. Who pays and who benefits (i.e., accrual of value vs. cost) is discussed in scenario 2.

For the sake of developing a streamlined methodology, we have made a number of simplifying assumptions in our analysis that could be refined in the future for a more precise estimate. Chiefly, a 1-to-1 displacement assumption could be refined by considering grid roles and temporal output profiles for solar power and the existing sources being displaced. We have left out the life cycle emissions associated with solar power and hydropower, as these are small enough to be safely neglected. That may not be true for other technologies, e.g., grid-scale batteries or biomass, which may have much larger life cycle footprints.

Scenario 2: US Rooftop Solar Across Four States, Including Policy Assessments

As the previous scenario compared rooftop solar and utility solar in one market (central California), this section compares one technology across different markets. Specifically, we look at rooftop solar in four states; California, Texas, New Jersey, and Massachusetts. This comparison highlights the effects of various factors on solar power generation costs (e.g., solar radiation, installation cost), the carbon emissions reductions within a particular grid, and the LCCA for policies, including local renewable policies (e.g., traded as RECs based on regional policy regulation), and federal policy (e.g., ITC).

The four states discussed in this scenario are among the 29 US states with Renewable Portfolio Standards. Renewable Portfolio Standards (RPS) or Renewable Energy/Electricity Standards (RES) are state-specific policies that require all load-serving entities (LSEs) within a state's jurisdiction to supply a minimum percentage or amount of their retail load from designated sources of renewable energy by a certain date or year (EIA, 2020; NREL, 2020).[16] Renewable Portfolio Standards are a significant driver for renewable energy generation growth in the United States. RPS regimes vary considerably from state to state in their applications, exemptions, features, obligations, size, structure, targets, timeframes and enforcement mechanisms, and are typically revised by each state's regulatory authority on an annual basis (EIA, 2019).[17]

Assumptions

For each sub-case in this scenario, solar generation is modeled as a unit rooftop solar module (e.g., 5 kW module, or 10 kW module). Cost assumptions include total up-front capital cost defined as a range (both low and high values) and fixed O&M. The model assumes a 20 year unit lifetime with no other costs. To simplify, we assume no life cycle carbon emission from rooftop solar. Solar radiation differences due to various reasons (e.g., latitude, weather, climate patterns) are represented as capacity factors.

Within each state, the LCCA rooftop calculations assumes these substitutions: grid-average electricity (based on state average electricity, carbon intensity, and regional wholesale electricity cost) and full natural gas plant displacement for two different systems (a low efficiency single-cycle plant or a high efficiency combined cycle plant). For gas plant replacement, electricity gas price varies as a function of local gas price for each state. Given the small output of the rooftop array, we assume the gas plants will still exist at roughly the same capacity factor and therefore the cost is entirely savings on fuel.

California and Texas each operate as essentially independent grids managed by an independent system operator (CAISO and ERCOT, respectively). We represent average grid conditions for New Jersey (PJM) and Massachusetts (NEISO), knowing that this simplification produces a less accurate result.

Table 1: State-specific assumptions

Specification	California	Massachusetts	New Jersey	Texas
Solar capacity factor	0.284	0.165	0.168	0.246
State grid-average electricity carbon intensity (ton/MWh)	0.2189	0.3938	0.241	0.5337
State average whole-sale electricity cost ($/MWh)	48.67 (2018 average total energy cost, CAISO)	43.54 (2018 real-time wholesale, NEISO)	49.64 (2017 full-year cost, PJM)	35.63 (2018 average annual real-time, ERCOT)
Electricity gas cost ($/thousand cubic feet)	3.56	6	2.58	1.96

** Natural gas energy content (kWh/thousand cubic feet): 293.07. Gas carbon intensity (kg/ thousand cubic feet): 53.12.*
Source: EIA, 2020.

Finally, we did not assess the values of many rooftop solar subsidies (e.g., net-metering, grants or rebates for installation). We did assess the value for the federal ITC, currently at 26 percent, and did assess the value of RECs, including solar renewable energy credits (SRECs). Additional details and assumptions can be found in Appendix C.

Results

Sub-case 1

To standardize costs, we apply Lazard solar cost assumption to all four states (5 kW unit) and the electricity generated varies by capacity factor. This means the same capital and fixed cost assumption produce different LCOE results.

Table 2: Rooftop solar LCCA variations by solar radiance

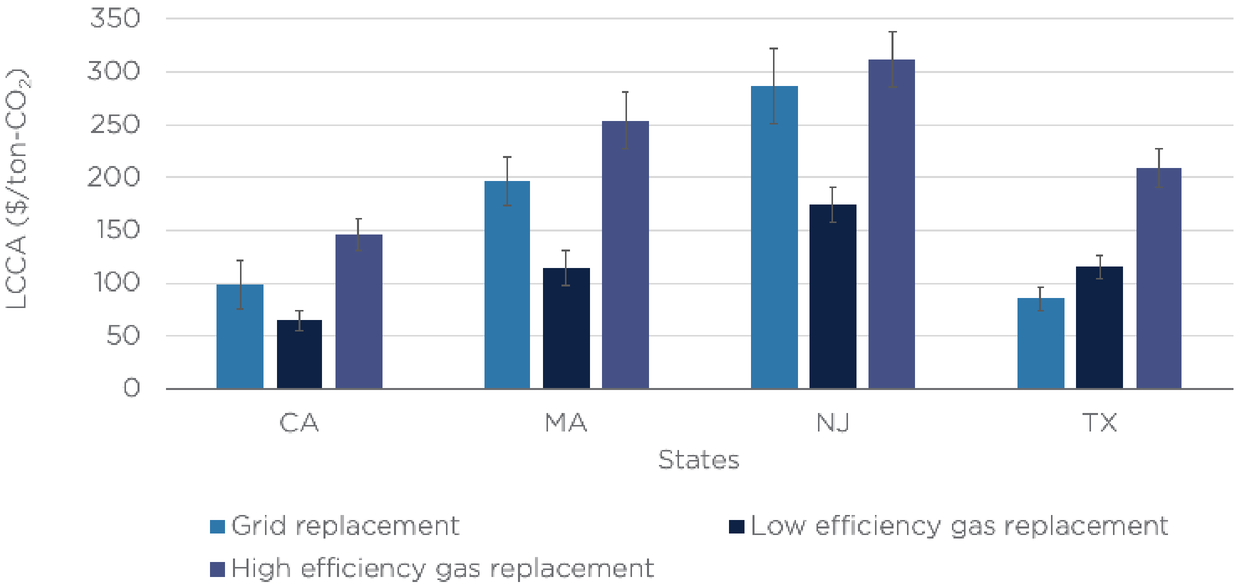
Specification	California	Massachusetts	New Jersey	Texas
Solar total capital cost ($/kW)	2950 ~ 3250			
Fixed O&M ($/kWh-yr)	14.5 ~ 25			
LCOE ($/MWh)	65.1~75.4	112.1~129.7	110.1~127.4	75.2~87
Grid-average replace-ment LCCA ($/ton)	75.1~122.0	174.0~218.8	250.8~322.7	74.1~96.3
Gas plant replacement with 34% efficiency LCCA ($/ton)	55.1~74.5	97.3~130.4	157.9~190.4	104.1~126.3
Gas plant replacement with 55% efficiency LCCA ($/ton)	130.6~161.7	227.1~280.7	285.5~338.0	191.2~227.1

Using unified solar cost assumptions, solar electricity characteristics are as follows:

- California has the best solar capacity factor—and therefore lowest LCOE—while Massachusetts has the highest.
- Although Texas solar LCOE is slightly higher, its grid-average replacement LCCA is the lowest since Texas has the highest grid electricity carbon intensity.
- Rooftop solar electricity replacing grid-average electricity has high LCCA in Massachusetts and New Jersey since solar capacity factor is low there and their grids are relatively clean, leading to minimal carbon displacement.

This last point underscores a well-known finding: replacing grid-average electricity with variable renewable supplies like solar is less effective in low-carbon intensity grids (e.g., Jenkins et al., 2016; Das et al. 2020). If the goal is carbon reduction, LCCA methodology reveals that it is more cost-effective to replace fossil power generation. While California has specific policies like loading order to achieve this goal, other states (e.g., Texas) do not.

Figure 9: Rooftop solar LCCA values and ranges for the four states: unified solar cost assumptions



The two gas plant replacement cases assume that the rooftop solar array will replace a fraction of gas electricity but won't retire the entire plant or affect its profitability. Therefore, the cost of the replaced electricity can be assumed very close to gas cost only (i.e., marginal cost only). Replacing gas plants with 34 percent efficiency, which is typical for old, single-cycle gas plants, the LCCA is much lower (i.e., more cost-effective) than that for grid-average replacement in California, New Jersey, and Massachusetts. However, in Texas, replacing a 34 percent efficiency gas plant has a higher LCCA than grid average because of the high average grid emissions there. Replacing a newer gas plant with higher efficiency (i.e., 55 percent efficiency case) will result in much higher LCCA, roughly double. Replacing a high efficiency plant is more expensive than grid average.

Sub-case 2

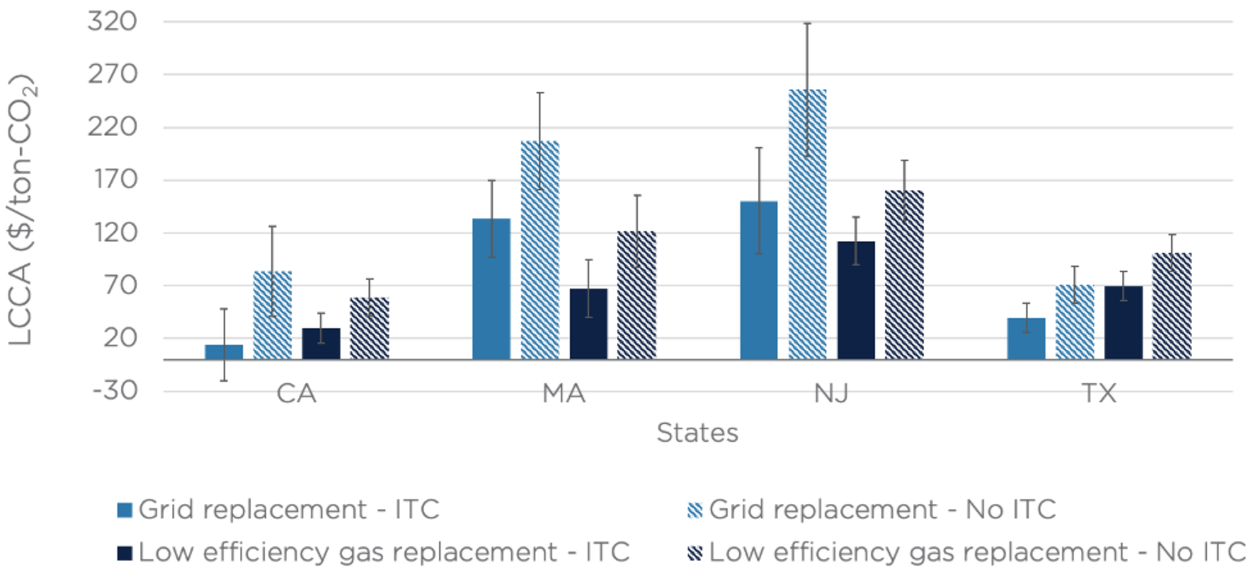
To understand the costs of the federal ITC on carbon reduction, we estimate LCCA for power generated by a 10 kW rooftop array in each state and the carbon abatement costs with and without the current ITC of 26 percent. In the case with the ITC, we assume that the deployment of the rooftop array only occurs due to the ITC. We also assume different installation costs as a function of local conditions (e.g., building codes, labor costs).

Table 3: Rooftop solar LCCA values with and without the ITC across the four states

Specification	California	Massachusetts	New Jersey	Texas
Solar total capital cost ($/kW), ITC	1909.2~2442	2072~2693.6	1879.6~2382.8	1835.2~2264.4
Solar total capital cost ($/kW), no ITC	2580~3300	2800~3640	2540~3220	2480~3060
Fixed O&M ($/kWh-yr)	14.5~25			
LCOE ($/MWh), with ITC	44.2~59.1	81.7~110.5	73.7~97.9	49.3~64.1
LCOE ($/MWh), no ITC	57.7~76.4	106.9~143.2	96.1~126.4	64.3~82.6
Grid average replacement LCCA ($/ton), with ITC	-20.4~47.8	96.9~169.9	99.9~200.4	25.6~53.4
Grid average replacement LCCA ($/ton), no ITC	41.2~126.5	160.9~253.1	193.0~318.4	53.7~88.0
LCCA value/cost of ITC ($/ton) for grid- average substitution	61.6-78.7	64.0-83.2	93.1-118.0	28.1-34.6
Gas plant replacement with 34% efficiency LCCA ($/ton), ITC	15.9~43.9	40.3~94.3	89.7~135.2	55.6~83.4
Gas plant replacement with 34% efficiency LCCA ($/ton), no ITC	41.2~76.2	87.6~155.7	131.8~188.5	83.7~118.0
LCCA value/cost of ITC ($/ton) for grid- average substitution	25.3-32.3	47.2-61.4	42.1-53.4	28.1-34.6

For sub-case 2, the core differences across different states remain qualitatively the same as in sub-case 1 (i.e., solar capacity factor and grid carbon footprint).

Figure 10: LCCA representation of electric power costs with and without the ITC



Note: The difference represents the value/cost of the ITC in each market for a 10 kW rooftop array.

Although ITC is federal policy, LCCA results vary greatly for different states. This is due to different capacity factors (solar resource) and grid carbon intensities, which both affect the denominator. If replacing grid-average electricity while ITC is applied, LCCA is roughly $60 cheaper in California and Massachusetts, $100 cheaper in New Jersey, and $30 cheaper in Texas. This result suggests the estimated LCCA value of the ITC is $30–100, which reduces the ratepayer costs and increases the taxpayer costs accordingly.

If the solar array displaces generation from an old gas plant with low efficiency, the ITC has much less value or cost, as it would make LCCA roughly $30 cheaper in California and Texas and roughly $50 cheaper in New Jersey and Massachusetts.

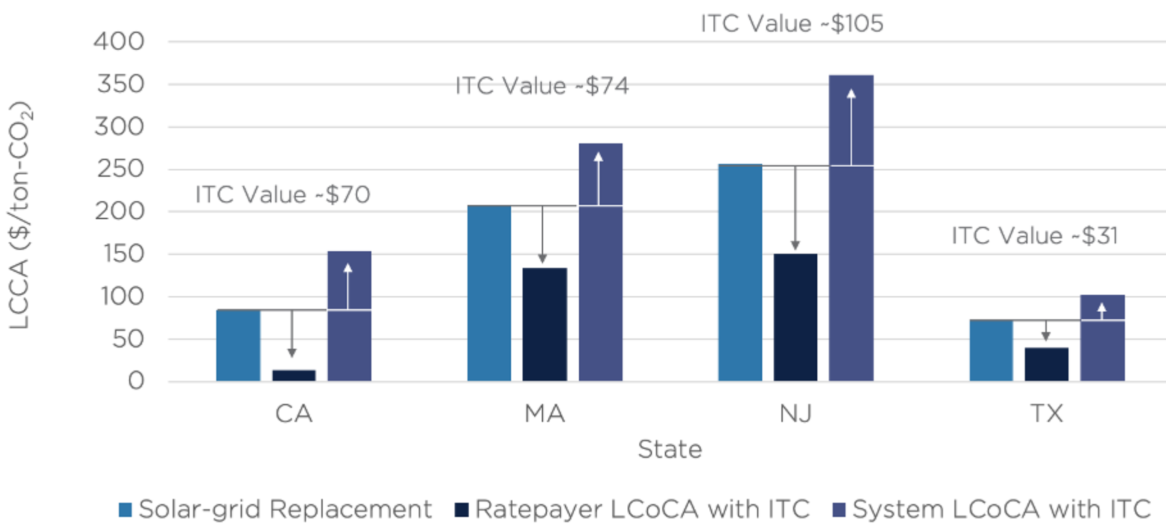
Comparing the states overall, Texas costs the least and New Jersey costs the most. But overall, the ITC could be seen as sound policy for jurisdictions where it delivers CO_2 reductions for modest costs (e.g., less than $80/ton CO_2 LCCA), provided that policy makers understand that the cost savings to generators from policies like the ITC accrue to their treasuries as real costs, and only if the ITC is fully additional.

Representing Policy in LCCA Analysis

In this scenario sub-case, carbon abatement costs estimated with LCCA are represented as savings to the ratepayer. Importantly, they could *also* be represented as costs to the Department of the Treasury. Both are acceptable using LCCA methodology. In this way, LCCA differs from project finance calculations and LCOE, where system costs are not represented.

It is reasonable to represent any external policy in terms of savings to ratepayers and costs to taxpayers. Using the data from solar-grid replacement above, the effect of ITC is represented as both in the chart below (Figure 11).

Figure 11: Value/cost estimates for solar ITC by state



Sub-case 3

In an attempt to get more displacement of carbon emissions through rooftop solar deployment, many states have enacted RECs or Alternative Compliance Payments (ACP) policies. These provide credits and market-trading mechanisms for rooftop solar generators and utilities. The value/costs of these policies are measured in terms of $/MWh, but not clear in terms of climate value ($/ton CO_2 abated) or effectiveness of deployment.

Renewable Electricity Certificates

Renewable Electricity Certificates or Credits (RECs) are tradeable, market-based instruments that represent ownership rights to the “renewable-ness” (i.e., environmental attributes) of one megawatt hour (MWh) of renewable electricity generated (WRI, 2020; EIA, 2019; EPA, 2019; Jones et al., 2015). A REC certifies the generation of one megawatt hour (MWh) of electricity from an eligible source of renewable power and its delivery to the grid.[18] Utilities that generate more renewable electricity than their RPS requirement may trade or sell RECs to other suppliers lacking sufficient RPS-eligible electricity to meet RPS requirements. Mandates on the volume of renewables, technology requirements, and penalties for non-compliance, such as the ACP, can significantly affect the cost of RECs.

RECs price volatility underscores the importance of recognizing that REC prices in any given year, "do not necessarily reflect the underlying incremental levelized cost of renewable generation," (Heeter et al., 2014, pp.24).

RECs and SRECs

States' Renewable Portfolio Standards may include "solar carve-outs," which require that a certain percentage of the state's electricity is generated only from solar panels. Solar renewable energy credits (SRECs) are created for each megawatt hour of electricity generated from solar energy systems, and the owners of SRECs possess the "solar" attribute of the power generated (EPA, 2020). SRECs are typically traded for physical delivery via a REC registry or tracking system that provides a reliable and transparent method to track and certify ownership of RECs. SRECs can be sold to electricity suppliers needing to meet their solar RPS requirement and the value of SREC markets can fluctuate drastically.

ACPs and Solar Alternative Compliance Payment

An ACP is a penalty levied on an LSE load-serving entity by the state's regulator if the utility fails to meet the state's RPS requirements by securing the necessary number of RECs. The ACP effectively sets a price ceiling on RECs as an LSE would not purchase a REC priced higher than the ACP. States with solar carve-outs, such as New Jersey, can also impose the Solar Alternative Compliance Payment (SACP) on LSEs that fail to meet solar requirements under the RPS.

In all states, RECs value is closely related to ACPs. ACPs are designed to be higher but very close to the RECs value to encourage RECs production and trading (e.g., Barbose 2017). They work in a similar principle from LCCA point of view: RECs give renewable producers additional benefit that lowers the cost, i.e., lowering down the LCCA for renewable producers. ACPs work as additional production cost for non-renewable producers that makes LCCA to be lower for any renewables to replace them. Both RECs and ACPs shows effect to narrow the gap between renewables and fossil energies, leading to lower LCCA and move the \$/ton-CO_2 burden away from renewable ratepayers.

Table 4: RECs and ACPs analysis based on sub-case 2 without ITC

Specification	California	Massachusetts	New Jersey	Texas
LCOE ($/MWh)	57.7~76.4	96.1~126.4	106.9~143.2	64.3~82.6
Cost of gas electricity ($/MWh)	35.7	25.9	60.2	19.7
Baseline LCCA - 34% efficiency gas	41.2~76.2	131.8~188.5	87.6~155.7	83.7~118.0
RECs/SRECs ($/MWh)	22.09 (REC)	226 (SREC)	317 (SREC)	1 (REC)
LCCA - RECs	-0.3~34.8	-292.1~-235.4	-507.1~438.9	81.8~116.2
ACPs ($/MWh)	24.3	258	316	50
LCCA - ACPs	-4.4~30.7	-352.2~-295.5	-505.2~-437.1	-10.1~24.3

Trading RECs allows renewables like rooftop or utility solar to be cheaper and ACP will make gas electricity much more expensive, both of which lead to a lower LCCA for the generator and a ***higher LCCA for the balance of ratepayers***. For example, the SREC in Massachusetts saves the rooftop owner $317/MWh for a LCCA reduction of -$507–438/ton; however, these costs are born by the other ratepayers in the system, so they are shouldering LCCA costs of $438–507/ton—an extraordinary and a regressive cost, since it falls on ratepayers least able to install rooftop solar.

In this analysis, we have assumed that all solar deployed in this scenario was a function of the RECs, SRECs, or APD credit and would not have happened otherwise—100 percent additionality. This is obviously a gross simplification, especially when additional policies (like solar ITCs) are active in the same market. However, the implication of 100 percent additionality is that these are the ***lowest*** LCCA estimated attribution, since lower fractional additionality would in fact produce a larger numerator (see Appendix A). This is one method to assign the policy costs to different stakeholders within the system.

The value of RECs and SRECs varies significantly among states that have to be analyzed separately. In California, no SRECs policy is available and the value of RECs is relatively low. In Texas, due to the market structure and composition, RECs have a minimum value that is below $1/MWh. This means that renewables receive no additional benefit under Texas's RECs policy (beyond the existing background of the RPS). In New Jersey and Massachusetts, SRECs policy is available and for that reason REC values are not considered (to avoid double counting). SRECs, coupled with solar carve-out creates a much higher value of solar electricity than RECs policy only, in the order $200–$300/MWh.

All results reveal that $1/MWh RECs or ACPs translate into ~$2/ton LCCA difference, since the specific electricity technology here the sub-case replacing is 34 percent efficiency gas. This gas technology has 0.53 ton/MWh carbon intensity and every dollar per MWh will be $2 per ton CO_2 roughly (assuming full additionality and perfect displacement). Depending on to whom the RECs are traded or ACPs are applied, LCCA will change accordingly, and the cost of the RECs-like policies will vary dramatically as a function of what is displaced.

Scenario 3: Decarbonizing Primary Iron and Steel Production

Primary iron and steel production is responsible for roughly 7 percent of global CO_2 emission today and is particularly hard to decarbonize, both due to high heat requirements and associated chemical process emissions (Friedmann et al., 2019; ICEF 2019). World crude steel production exceeded 1808 million tons in 2018, with three dominant production pathways accounting for 99.6 percent of total production: blast furnace/basic oxygen furnace (BF/BOF); electric arc furnaces (EAF) which make secondary steel or recycle scrap metal; and direct reduced iron (DRI) which feeds into an EAF (Table 5).

Table 5: Current global steel production profile according to production method

Baselines	Global production share	Hot metal (HM) carbon intensity (kg/ton-HM)	OpEx ($/ton-HM)	CapEx ($/ton-HM)	Total cost ($/ton-HM)
BF/BOF	71%	2225	365.79	47.15	412.94
DRI-EAF[19]	5%	1395 (gas)	432.11	48	480.11
EAF-scrap[19]	24%	842	356.25	28.67	384.92

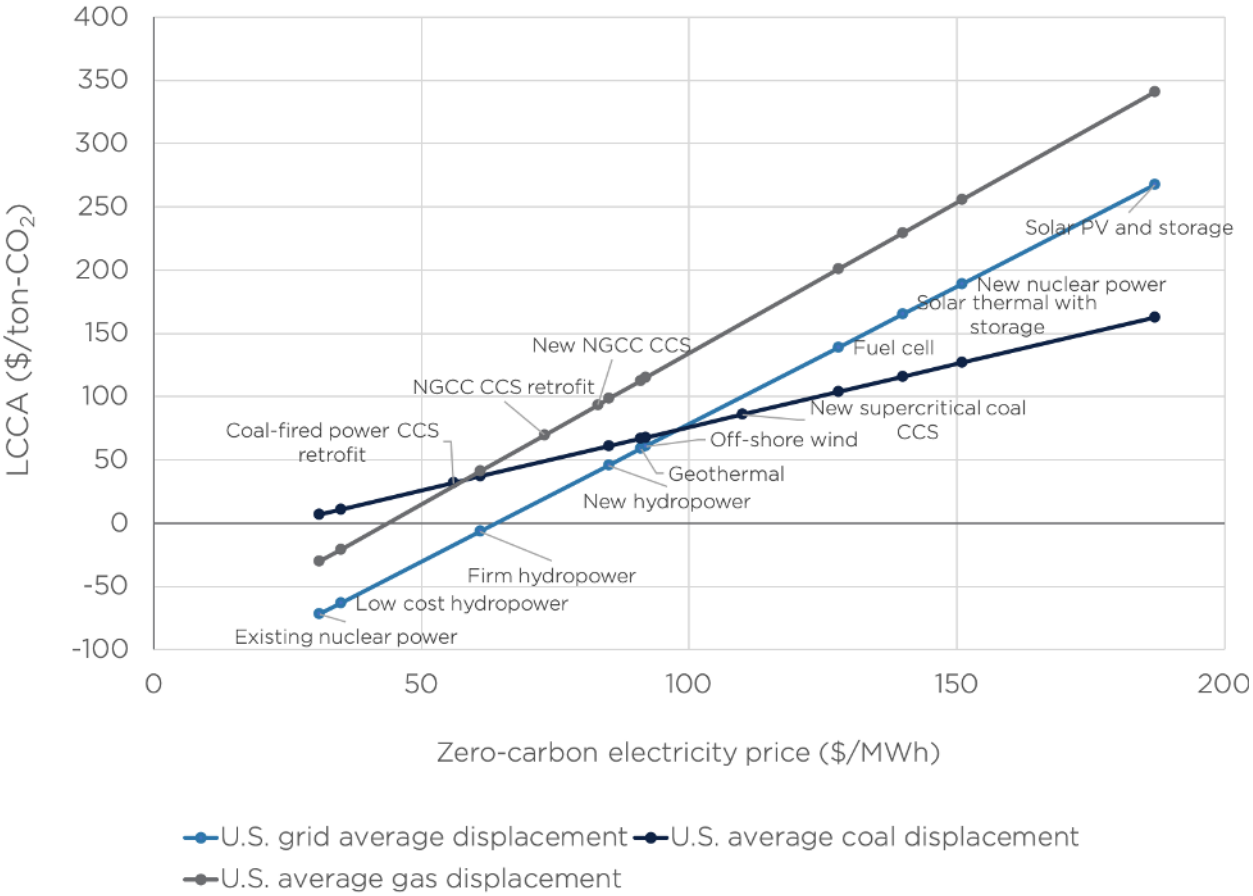
We assessed several cases for these three production methods to determine the LCCA of steel production in terms of CO_2 abatement costs ($/ton) for each ton of hot metal (ton-HM). These cases explored partial and full decarbonization using a range of technology options, including teardown and replacement of existing assets with non-emitting versions. To generate consistent carbon abatement values, the carbon intensity per ton-HM includes all necessary processes in an integrated steel mill (i.e., a simple LCA). For example: BF/BOF routes include processes such as coke production, sintering, and pelletizing. Similarly, the EAF cases include grid or zero-C power supply. To simplify, life cycle emissions and costs from iron ore mining and transportation are relatively minor compared to other costs and emissions sources and are excluded from this analysis. Additional details are provided in Appendix D.

Table 6: Zero-C electricity replacement baseline descriptions

Sub-case	Electricity price ($/MWh)	Electricity carbon Intensity (ton/MWh)	Remarks
US grid-average electricity replacement	64	0.46	Average industrial power price, 2018
US average coal-fire electricity replacement	24.11	1.00	2018 US average
US average gas electricity replacement	43.7	0.42	2018 US average

When analyzing the sub-case of replacing existing power supplies with zero-C electricity, we considered three replacement options: US grid-average replacement, US average coal-fired electricity (for coal CCS cases), and US average gas-fired electricity (for gas CCS cases). The coal and gas sub-case options reflect the fact that many industrial steel facilities have dedicated power plants that serve their needs and do not draw electricity from the grid. As previously discussed, different replacement will result in very different LCCA even with the same zero-C electricity (i.e., same price). Replacing coal-fire electricity cannot have negative LCCA since coal-fire electricity is very cheap, but it will have lower LCCA since coal electricity is more carbon intensive. US grid average and US average gas electricity (which have similar carbon intensities) are the opposite of coal.

Figure 12: LCCA of zero-carbon electricity as a function of electricity costs



Note: Comparisons of LCCA are between US grid (blue), a captive coal (navy) or natural gas plant (grey) with US average values. Local grids and local captive plants would haev different slopes and intercepts.

LCOE data source: Lazard 2018.

To help illustrate the effect of zero-carbon electricity on LCCA, we selected a wide range of zero-C supply options. Many of these may not prove applicable. For example, most steel operations have very high capacity factors (65–90 percent) which limits their viability—in the US, only nuclear power has such high capacity factors and is widely deployed. If other zero-C generation options (e.g., onshore wind) required grid-balancing to serve the load demands of the steel facility, the generation would not be zero-C, and the LCCA would increase. For the cases discussed here, zero-C electricity as decarbonization methods for steel making, the LCCA of steel decarbonization is entirely dependent on the LCCA of the zero-carbon electricity supply[20] and not supplemented by grid-based emitting sources.[21]

Based on Figure 12, $120/MWh may prove a reasonable threshold, separating different classes and approaches of technology additions across this large range of LCCA values. Importantly, most technologies below this threshold are geographically limited (e.g., hydropower, geothermal) or suffer from low capacity factors (e.g., offshore wind, existing hydropower), which could limit their industrial applicability. Table 7 applied $120/MWh values for zero-C electricity to displace current power supplies to steel plants and only apply to the electricity cases considered.

Table 7: LCCA comparison for low-carbon steel alternatives

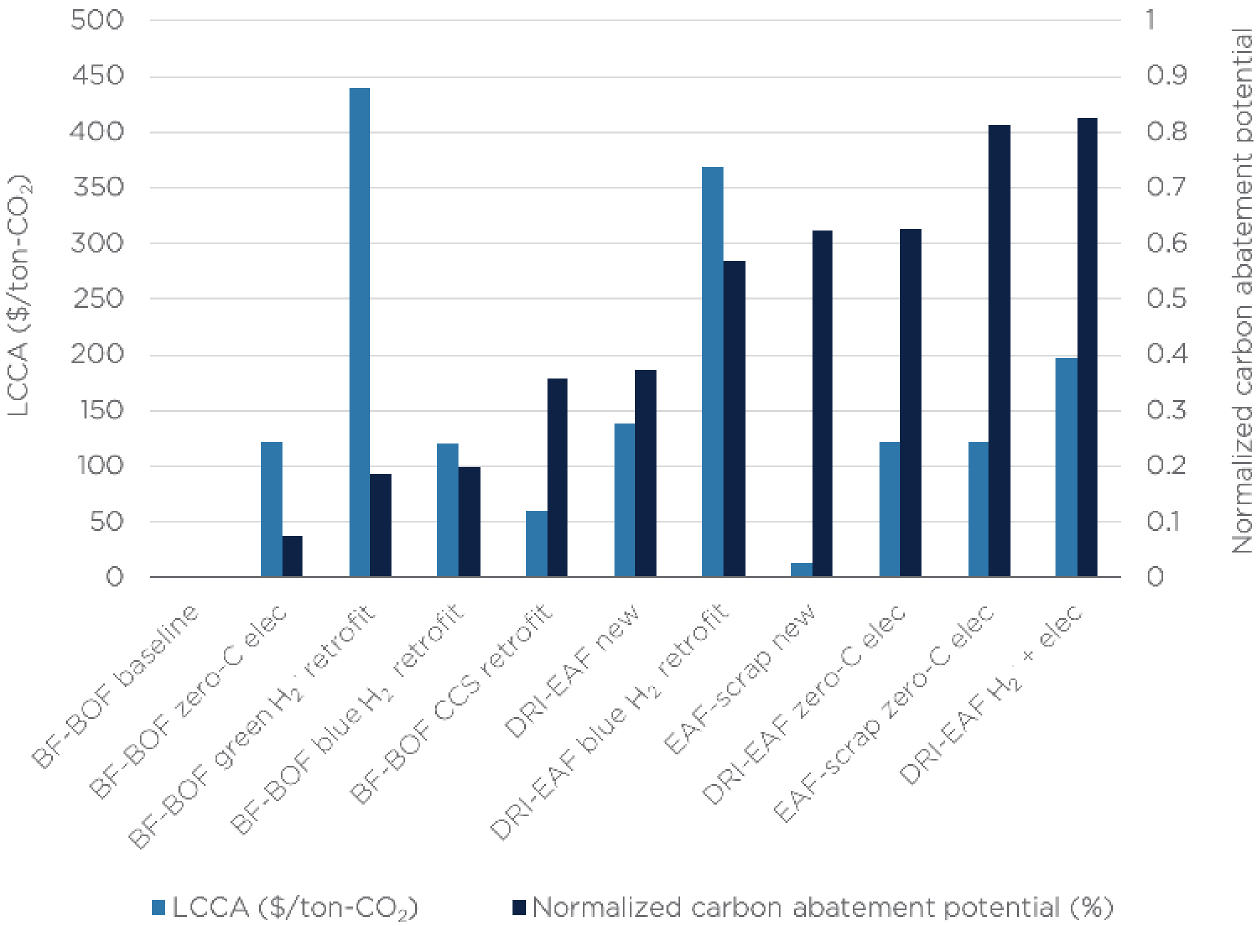
Comparison cases	Baseline	Carbon abatement (kg/ton-HM)	Carbon abatement fraction	Additional cost ($/ton-HM)	LCCA ($/ton-$CO_2$)
DRI-EAF new	BF/BOF (end-life*)	830	37.3%	114.32	137.73
EAF scrap new	BF/BOF (end-life*)	1383	62.2%	19.13	13.83
BF/BOF blue H_2 retrofit	BF/BOF	440	19.8%	53.08	120.64
BF/BOF green H_2 retrofit	BF/BOF	415	18.7%	182.46	439.66
DRI-EAF blue H_2 retrofit	DRI-EAF	438	31.4%	128.60	293.61
BF/BOF zero-C elec**	BF/BOF	164	7.4%	19.94	121.74**
DRI-EAF zero-C elec**	DRI-EAF	566	40.6%	68.94	121.74**
EAF scrap zero-C elec**	EAF scrap	422	50.1%	51.41	121.74**
BF/BOF CCS retrofit	BF/BOF	800	36.0%	38.4~56.8	48~71

**For replacing an existing steel production facility which is already capitally paid off, only OpEx is regarded as the original cost for LCCA calculation. This is a conservative assumption—early retirement and replacement of BF/BOF plants would add costs to the LCCA numerator.*

***Using zero-C electricity for iron and steel production, assuming electricity from the grid is zero-carbon and not subjected to additional retrofit cost with $120/ton-$CO_2$ LCCA.*

Blue hydrogen, in this analysis, refers to 89 percent CCUS hydrogen production from Steam Methane Reforming (SMR), and green hydrogen is hydrogen generation from renewable power, typically wind, solar, or hydropower.

Figure 13: Steel decarbonization technologies' LCCA and associated normalized decarbonization potential



Note; Steel plant decarbonization potential is normalized here against the uncontrolled emissions from a BF/BOF plant. A value of 0.5 represents 50 percent decarbonization of a facility against that baseline.

As shown in Figure 13, BF/BOF based decarbonization technologies typically have low decarbonization potential but can be subjected to very high cost per ton carbon abatement. Hydrogen-based technology typically has high LCCA due to the high value of hydrogen. Switching to DRI- and EAF-based technologies looks most promising for lower cost and more carbon abatement potential.

Discussion for Scenation 3

One of the important conclusions of this analysis is that "hard-to-abate" can be quantified in terms of LCCA and abatement potential. Most of the approaches considered have LCCA in excess of $100/ton. Most of the low-cost steel options also have low abatement potential, either by facility or with respect to the global market. The lowest cost option is building a new EAF, which itself does not produce primary iron and steel. One low-cost option, BF/BOF retrofit with CCS, has technical challenges and requires additional infrastructure. The discipline of assessing LCCA rigorously reveals the real costs, challenges, and liabilities associated with primary steel decarbonization.

For example, the highest fractional decarbonization comes from replacing a blast furnace/basic oxygen furnace with new facilities (i.e., a new DRI-EAF or EAF for scrap recycling). An EAF using steel scrap is the most cost-effective replacement and reduction, and it would greatly reduce the carbon intensity of steel by 62.2 percent. However, these two types of plants occupy different markets—most BF/BOF is for primary production and most EAF is for recycling—and rarely compete. It is true that steel recycling has the lowest LCCA value, suggesting policy options to pursue recycling wherever possible. However, in many advanced economies, over 90 percent of steel production is already recycling, making it hard to increase. EAF scrap recycling represents the only possible solution for negative LCCA (i.e., if fuel cost savings are sufficiently large). While DRI-EAF is not limited to recycled steel availability (it is a primary steel production method), building a new DRI-EAF integrated mill to replace an existing BF/BOF is expensive: estimates suggest it would add $114/ton-HM to the cost of primary production compared to the traditional BF/BOF method, making such plants uneconomic.[22]

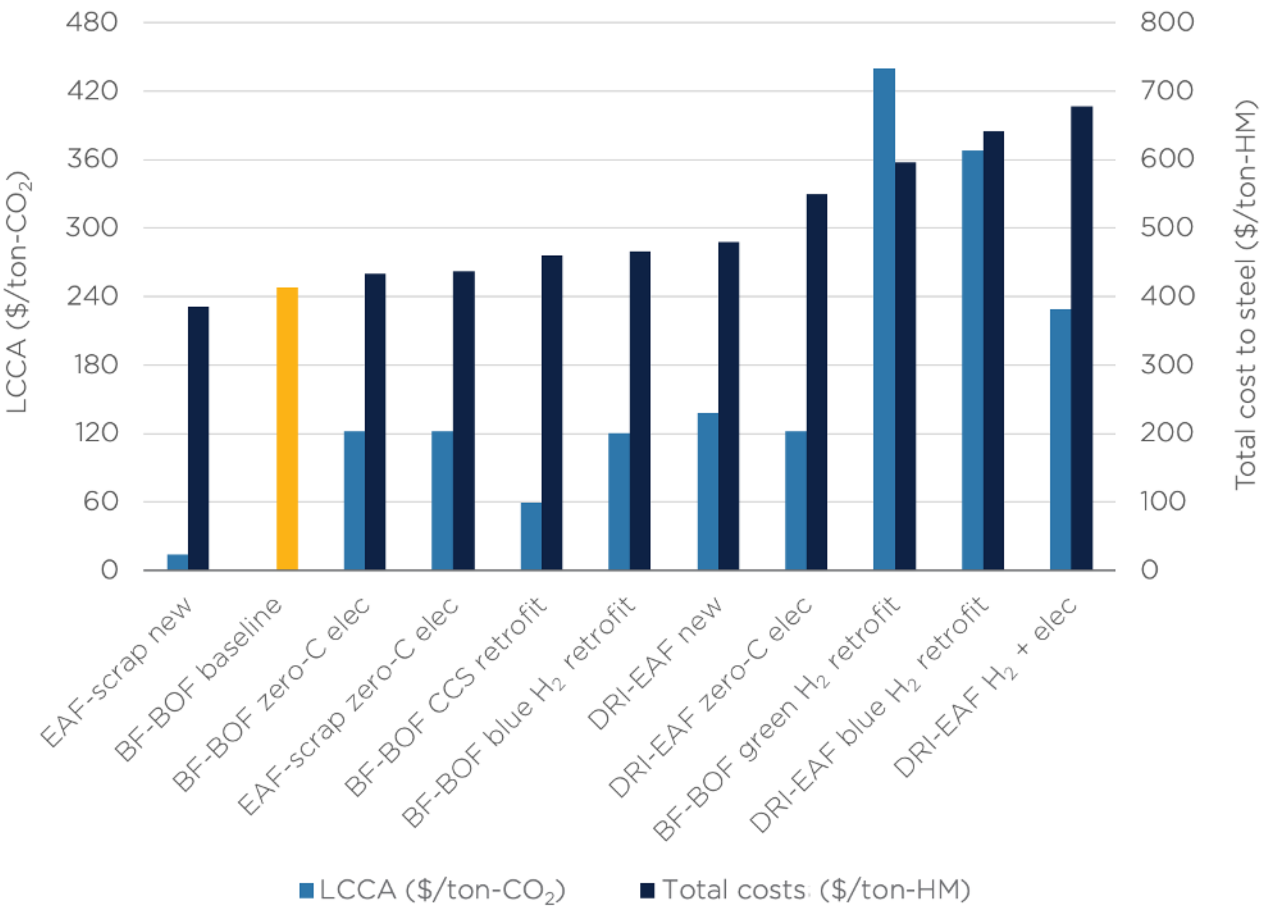
The BF/BOF production method accounts for more than 71 percent of steel globally, and a significant amount of that production capacity will operate for the next few decades. With this framing, zero-carbon hydrogen substitution should be considered as an important short-term solution to decarbonize primary steel production. Hydrogen could serve as a replacement fuel for both coal (BF/BOF) and gas (DRI). For BF/BOF retrofit, the LCCA for blue hydrogen substitution is slightly cheaper than building a new DRI-EAF plant for carbon saving, in part due to the high carbon intensity of coal. Blue hydrogen for DRI-EAF retrofit will result in much higher LCCA since hydrogen replaces natural gas in the DRI here, (less carbon abated = higher LCCA). Both hydrogen injection retrofits will require no or very little capital investment to the BF/BOF or DRI itself. Another significant difference of the analysis of hydrogen injection is that although hydrogen injection for gas-DRI is much more expensive, overall its deep decarbonization potential is much higher than BF/BOF hydrogen injection. In all hydrogen cases, the green hydrogen replacement remains expensive (Friedmann et al., 2019; IEA 2020). To assess the impacts of potential future cost reduction, separate LCCA analysis is needed.

Since electricity plays an important energy service in production for all three pathways, replacing existing electricity supplies with zero-carbon electricity can provide an opportunity that is swiftly actionable (provided that there is access to firm zero-C electrical supplies). Each of the primary pathways has different potential to reduce carbon intensity electrically: BF/BOF 7.4 percent, DRI-EAF 40.6 percent, and EAF scrap 50.1 percent. From a levelized cost perspective, the LCCA estimate fundamentally is determined by the LCCA of the zero-carbon electricity itself. LCCA analysis indicates that moving away from the BF/BOF pathway could provide double benefit for decarbonization: it can directly reduce carbon emission and provide more potential for low-carbon electricity penetration. Because it is commonly believed that the electricity sector is easier and quicker to be decarbonized, promoting both DRI-EAF and EAF scrap pathways can benefit more from power-sector decarbonization trends.

Ultimately, many groups conclude that CCS retrofits provide the fastest, most economical path to reduce emissions from existing facilities (Friedmann et al, 2019; IEA 2020; ETC, 2020; Fan and Friedmann, in press). LCCA analysis supports this. In considering retrofits to primary steel production, current designs only capture from off-gas (top-gas) from the main reactor (e.g., BF or DRI reaction chambers). We limit our analysis to partial capture of the system expressed as full capture of the top-gas, expressed as additional cost from CCS facility (both CapEx and OpEx) and the direct drop-in emitted CO_2. In this configuration, CCS on steelmaking is much cheaper on a LCCA basis than CCS on (blue) hydrogen production or doing hydrogen injection. For either case, it is likely that additional infrastructure is required, either to bring blue hydrogen to the site or to take CO_2 from the site.

Today, some opportunities exist for CO_2 use from steel facilities. In practice, BF/BOF facilities use CO-rich off-gas to provide heat (e.g., for steam making, coking coal) or electricity generation. The carbon emission can be significantly lower if the CO-rich off-gas can be used for ethanol production using anaerobic fermentation. One company, LanzaTech, operates a commercial facility at a steel mill in Hebei Province, China. Estimating LCCA for this system is complicated, however, since the carbon reduction associated with lowering the steel's production becomes tied to the sustainable fuel-use case.

Figure 14: Steel decarbonization technologies' LCCA and associated steel cost per ton hot metal



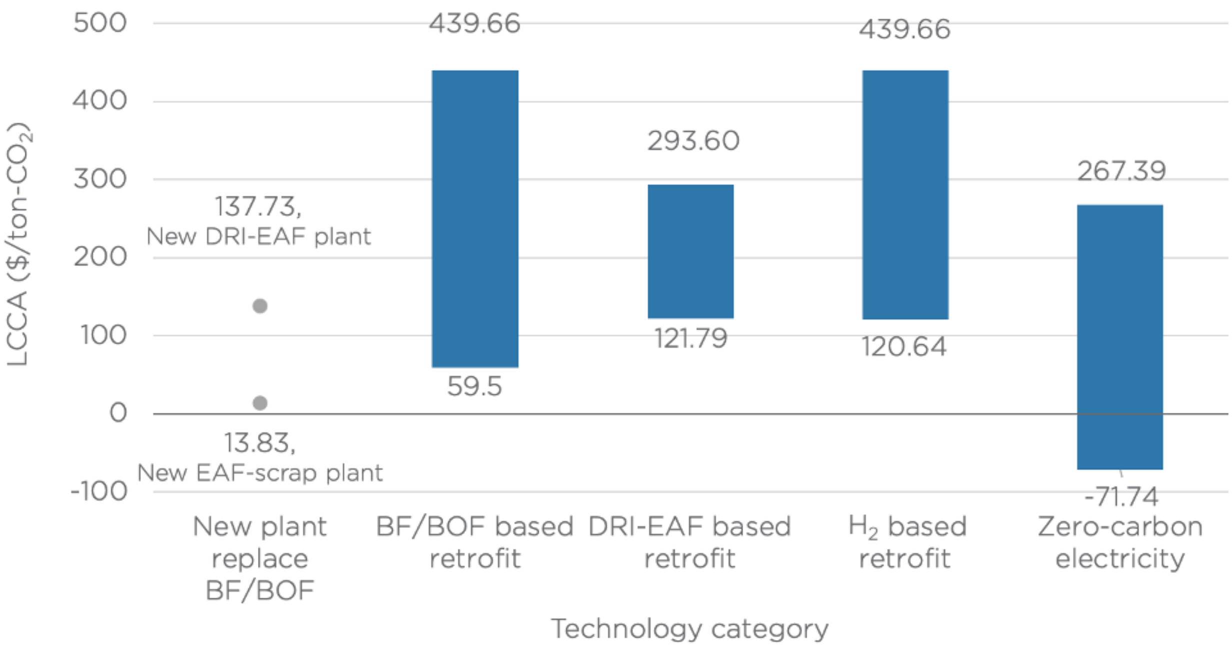
Carbon abatement cost is not the only criteria that stakeholders may consider. Especially for steel producers, the cost per ton hot metal is the most important assessment criteria for adopting certain decarbonization technology. Most BF/BOF-based decarbonization technology and zero-carbon electricity are among the lowest cost per ton hot metal. Hydrogen-based technology will greatly raise the cost per ton hot metal. Not surprisingly, DRI-EAF with both zero-C electricity and H_2 injection will add $300/ton-HM cost, although its LCCA is not the highest. High cost per ton hot metal may become a key barrier to the deployment of the decarbonization technology.

The LCCA estimates here are static estimates only. There are certainly dynamic terms that affect the LCCA and could be considered.

- *Innovation and learning effects*. DRI-EAF and EAF using steel scrap are both commercialized technologies. BF replacement with these technologies will have reasonable LCCA. Other approaches, such as hydrogen injection and CCS retrofit, have high costs today and large uncertainties, resulting in high initial LCCA estimates. Over time, learning and optimization and technology improvements will lower costs initially and then gradually converge to Nth of a kind.

- *Infrastructure limitations*. Many of the proposed decarbonization approaches require significant infrastructure support in addition to new plants or plant retrofits (e.g., blue hydrogen fuel and CCS retrofits may require pipelines; green hydrogen or full electrification approaches may require transmission upgrades). These infrastructure investments would increase LCCA for the system and are not currently part of project accounting. Conversely, creation of infrastructure can lead to accelerated rates of deployment and lower overall system costs.
- *Decarbonization potential limits*. Some of the proposed cases can be combined to present a much higher decarbonization potential, e.g., replacing existing BF with DRI-EAF and applying hydrogen injection and zero-carbon electricity. Every time a new technology is applied, more tons of carbon are reduced and LCCA value changes. The LCCA value is closely related to decarbonization potential, e.g., hydrogen injection for BF has a lower cost than DRI-EAF hydrogen injection, but a significant portion of carbon emissions will remain and very little additional methods can be applied other than CCS. DRI-EAF overall has a higher LCCA but allows much higher decarbonization potential in the future. This means that early actions could limit longer-term actions by raising LCCA for future substitutions (e.g., Vogt-Schilb et al., 2018).

Figure 15: Steel decarbonization LCCA summary by technology category



As shown in the summary Figure 14, building a new DRI-EAF plant or EAF scrap plant to displace a BF/BOF at the end of its life is among the cheapest pathways to decarbonize. Perhaps this helps explain Swedish steelmaker SSAB's decision to replace their four BF/BOF plants with DRI-EAF combinations by 2040 (Hoikkala and Starn, 2020), in large part made possible by a grid comprising very low-cost hydropower and nuclear power. Almost all retrofit technologies will result in higher LCCA, with the notable exception of CCS retrofit on BF/BOF top-gas. Hydrogen injection-based technologies can be widely applied to both BF/BOF plants and DRI-EAF plants and could provide deeper decarbonization potential but at a higher cost. Zero-C electrification is easier and can be cheapest (depending on the source) to decarbonize, which is the low-hanging fruit for cutting carbon emission. Unfortunately, zero-C electrification has low decarbonization potential in the sector (~7 percent) due to the prevalence of BF/BOF systems.

Scenario 4: Sustainable Aviation Fuels and CO_2 Removal

Air transport currently comprises approximately 2.5 percent of global carbon dioxide emissions.[23] Aviation is considered to be a hard-to-abate sector—today, electrification or storage technology cannot meet the power demands of air transportation, and carbon capture technology cannot be installed on jets to capture emissions in flight (ETC, 2018). Technological, infrastructural, and managerial efficiency improvements can reduce some of these emissions but cannot provide the dramatic reductions the global aviation sector requires and seeks.

Toward that end, the UN-sponsored International Civilian Aviation Organization (ICAO) has focused primarily on standards for sustainable aviation fuels as a decarbonization pathway. This effort, the Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA, 2020), seeks to create demand for low-carbon sustainable aviation fuels (i.e., renewable jet fuels) through a series of voluntary and mandatory emissions reduction targets. CORSIA is also considering conventional offsets as a compliance mechanism and has begun to explore other CO_2 removal approaches, such as direct air capture (DAC).

Today, sustainable aviation fuels (SAF) are typically biofuel or low-carbon fossil fuels that are blended with conventional jet fuel (Jet Fuel A). Currently, ASTM International[24] has approved six SAF pathways to develop synthetic kerosene blendstocks[25]:

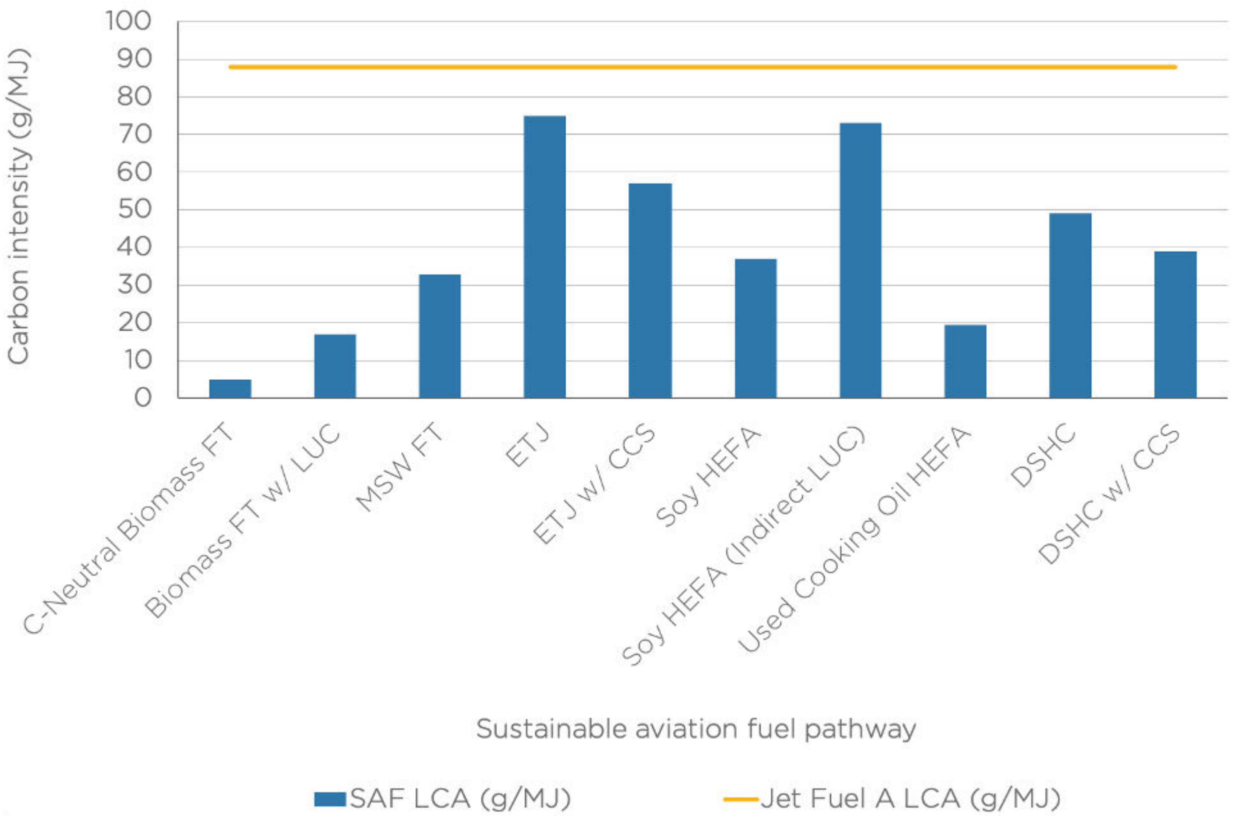
- Biomass Fischer-Tropsch synthesis (FT)
- Hydrotreated Esters and Fatty Acids (HEFA)
- Alcohol-to-Jet (AJT)
- Direct Sugar to Hydrocarbon (DSHC)
- Co-Processing
- Catalytic Hydrothermolysis Jet (CHJ)

The carbon abatement potential of each pathway varies considerably. Specific carbon reduction depends on factors such as feedstock type and availability, associated land-use changes, carbon intensity of processing, and blend fraction. Typical LCA yields a fuel carbon intensity by taking into account feedstock harvest and transport, biofuel processing, transport of the fuel to its end use, and combustion. Other factors may also be considered, such as how processing coproducts are allocated and whether they yield additional reductions.

This makes precise and accurate quantification of carbon intensity and life cycle footprint extremely difficult. For example, an LCA of HEFA-based aviation fuel may indicate that the CO_2 generated per ton is significantly less than Jet Fuel A. However, when including the CO_2 emissions from land-use changes, such as removing forested peatland for a biomass plantation, that SAF pathway may become drastically more carbon intensive, perhaps higher than Jet Fuel A. These considerations have created accounting difficulties for the CORSIA program and its members, suppliers, and stakeholders.

Of those six pathways, we focused our assessments on Fischer-Tropsch, Hydrotreated Esters and Fatty Acids, Alcohol-to-Jet, and Direct Sugar to Hydrocarbon. These pathways are in use today, benefit from a large body of analytical literature, and show both greater commercial maturity and greater likelihood of future cost reductions.[26] To illustrate aspects of the carbon-accounting challenge through LCCA analysis, we ran a set of scenarios for different fuels. For example, we assumed biomass-based FT to be carbon neutral, well knowing that this is commonly not the case, in order to understand how that assumption would affect levelized abatement costs. Additional details can be found in Appendix E.

Figure 16: Assumed, estimated, and calculated carbon intensity for sustainable aviation fuel pathways compared to the Jet Fuel A baseline



To complete the LCCA estimates, techno-economic assumptions to determine the cost per ton of CO_2 abated included (a) a simple, static analysis of the fuel's per-ton cost, taking into account land cultivation, transportation, and costs for feedstocks, financing, and operation of fuel production and (b) financing assumptions for production facilities, including industry standard assumptions regarding debt-to-equity ratios, plant size, capacity factors, and discount rates (these could be adjusted for specific assets under consideration and sensitized for different scenarios).

Consistent with LCCA methodology, each liter of SAF replaces one liter of fossil-based aviation fuels (similar to the kW-hr substitution in Scenario 1) on a MJ-for-MJ and ton-for-ton basis. While this approach is robust and valid, ***it would not be sufficient to consider full decarbonization of air-miles traveled***. Many SAFs can only partially substitute in commercial flights due to the limitations associated with allowable operating standards (i.e., blendwalls). As such, decarbonization of actual flights is limited by the blending limits (similar to capacity factor considerations in Scenario 1), and full decarbonization of miles traveled remains yet more difficult and expensive (see below).

Assumptions

In calculating the carbon footprint of a pathway, we exclude land-use changes (LUC) unless otherwise indicated. As such, combustion emissions from SAF derived from biomass are considered carbon neutral because carbon emitted is equal to carbon sequestered by the biomass. ***This underestimates the true levelized cost by overestimating the associated carbon reduction, sometimes severely***. More sophisticated analysis can (and should) incorporate land-use effects such as indirect land-use changes that may manifest as leakage and local ecosystem effects (e.g., destruction of peat forests, soil carbon release).

When possible, we selected medium plant sizes or average production levels to recognize that SAF production will not proceed at the pioneer plant level. This creates uncertainties due to the relative immaturity of SAF production as a whole, which we do not discuss or analyze here. The HEFA pathway is the most commercially established option and therefore has more accurate data for cost estimates; these were normalized to maintain methodological consistency (Appendix E).

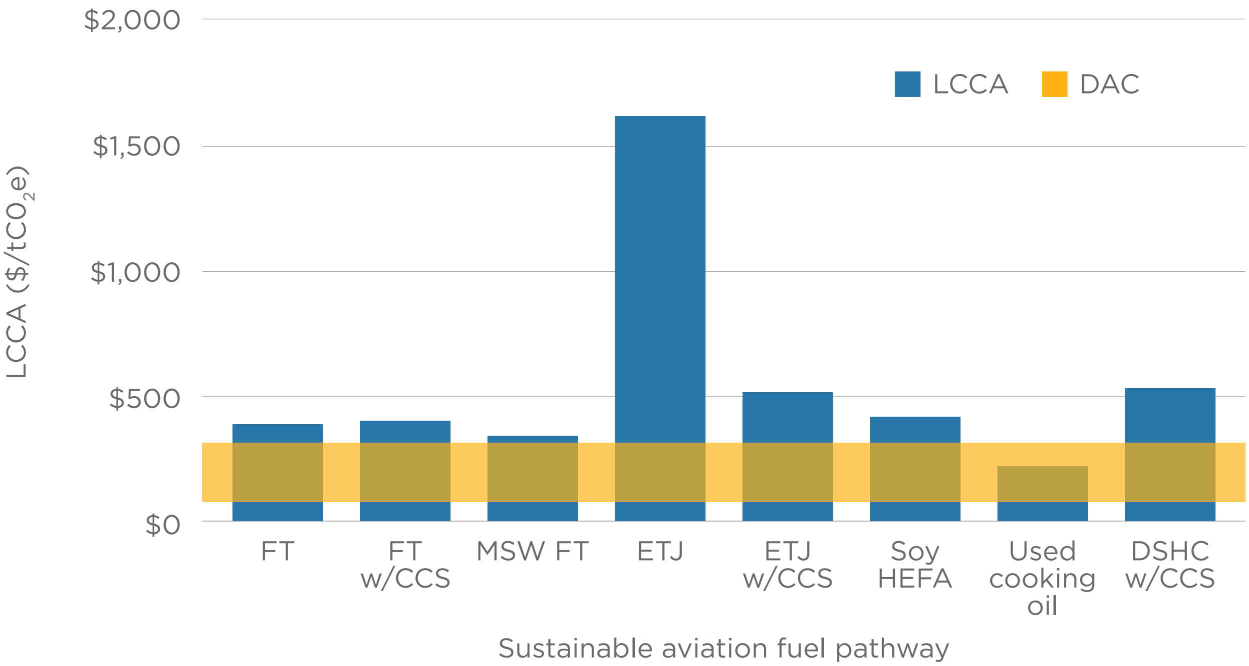
For the SAF options we assessed, the LCCA estimates could be amended or modified by inclusion of CCS. For the sake of brevity, we did not include a CCS alternative for every pathway, and instead applied it to DSHC and ethanol-to-jet (ETJ, a subset of ATJ). For those cases, we reduced the carbon intensity for their high purity byproduct streams, which amounts to a 20 percent reduction for DSHC's required hydrogen inputs and a 50 percent reduction on the feedstock ethanol used for ETJ. To be conservative, the costs of compressing, transporting, and storing CO_2 for a given pathway added approximately $20 to the LCCA after adjusting for the new carbon intensity.

Finally, we compared all SAF options to post-combustion CO_2 removal from the atmosphere using DAC without subsidies. DAC is considered a promising technology that can provide the necessary decarbonization for sectors or emission pathways with high abatement costs (ICEF, 2018; Rhodium Group, 2019). Although it is not a SAF, DAC is included in this comparison as it represents an alternate means of decarbonization for hard-to-abate sectors as a whole (Goldman Sachs, 2020), including aviation.

Table 8: LCCA comparison for SAF pathways. Full sources included in Appendix E

SAF pathway	Cost per ton ($/ton)	Heating value (MJ/kg)	Cost per energy ($/GJ)	Carbon intensity (g/MJ)	LCCA (USD 2020)
Jet Fuel A (baseline)	*$462*	*43.02*	*$10.74*	*88*	-
Lignocellulosic biomass FT	$1,750	44.2	$39.59	5	**$391**
Lignocellulosic biomass FT w/ Land-use	$1,750	44.2	$31.27	17.2	**$479**
Municipal solid waste FT	$1,238	44.2	$28.01	33	**$342**
Corn ethanol-to-jet	$1,260	43.4	$29.03	75	**$1,618**
Corn ethanol-to-jet w/ CCS	$1,260	43.4	$29.49	57	**$699**
Soy oil to HEFA	$1,313	44.15	$29.74	37	**$420**
Soy oil to HEFA (indirect LUC)	$1,313	44.15	$29.74	73	**$1,427**
Used cooking Oil to HEFA	$1,088	44.15	$24.64	19.4	**$209**
Catalytic conversion of lignocellulosic sugars	$1,278	43.99	$28.42	49	**$521**
Catalytic conversion of lignocellulosic sugars (w/ CCS hydrogen)	$1,278	43.99	28.42	39.4	**$438**
Direct air capture of CO_2					
First 1 Mt plant	n/a	n/a	n/a	n/a	**$124–325**

Figure 17: Levelized cost of carbon abatement analysis between sustainable aviation fuel pathways, compared to first-of-a-kind DAC facility (million tCO_2/y)



Source for DAC costs: Larsen et al. 2019

Key Findings from SAF Analysis

The Levelized Costs of Carbon Abatement for SAF appears high across the board, with all options exceeding $200/ton. This is primarily because SAF options do not substantially reduce fuel carbon intensity or are extremely expensive to produce (or both). The lowest cost option, converting used cooking oil to HEFA, struck the best balance of those two variables, however the vast majority of used cooking oil is already used to produce other biofuels and either cannot scale or will limit the options for other hard-to-abate sectors (e.g., heavy-duty vehicles). It is also worth noting that, like the range provided for direct air capture, all of the estimates can be expanded into ranges depending on assumptions and feedstocks.

Fischer-Tropsch for lignocellulosic biomass residues and municipal solid waste (MSW) yielded relatively low LCCA. MSW feedstocks, however, can have significantly variable LCAs, depending on the composition of the feedstock. Our MSW assumption used a median LCA as the baseline, which would include a 35 percent biogenic feedstock and the US average landfill gas recovery rate of 167 $kgCO_2e$/ton (Suresh et al., 2018). Many MSW feedstocks appear much more carbon intensive, limiting their carbon reduction value and increasing LCCA scores. Some MSW (i.e., composed of entirely organic materials) could decrease the carbon intensity by up to 320 percent (i.e., net negative emissions) when including avoided landfill methane emissions. This may prove difficult to scale. Similarly, biogas captured from landfills is largely already sold in major markets, and its sale may limit the availability of organic MSW for jet fuel.

Two findings emerge when considering the potential of carbon capture for LCCA. The first is that the benefit of using carbon capture during SAF production, specifically in the production of high purity fuel feedstocks like hydrogen and ethanol, is greater for pathways that have a higher LCA than for those with a low LCA. Reducing the carbon intensity of DSHC by incorporating CCS on its hydrogen feedstock reduces the LCCA much less than the reduction from CCS on ETJ. While the reduction in carbon intensity is greater for ETJ, the LCCA falls disproportionately more than it does for DSHC. This conforms mathematically, as a smaller denominator (a smaller carbon difference between jet fuel and SAF) will yield a larger LCCA.

The second carbon capture finding is that the range of estimated per-ton costs for direct air capture with geological carbon storage ($124–325/ton CO_2) in a one megaton plant is cheaper than the costs of all pathways except for used cooking oil. Considering that this range is for a one megaton pioneer plant and this technology is relatively immature, the cost reduction potential for DAC is profound and likely to drop rapidly through deployment. The high estimated costs of SAF also underscore why air travel is considered a hard-to-abate sector. And while a dynamic LCCA estimate may yield cost reductions due to economies of scale, it would also elucidate supply chain issues, such as competition for limited feedstock and LUC, that could offset those reductions.

While the default assumption for each pathway excluded LUC, we included two cases that assessed LUC. First, we found that direct emissions, or those associated with switching land production from food to switchgrass for lignocellulosic biomass FT increased the LCA by 12.2 g/MJ (Bundsberg et al., 2016). While this is cited as a high-end estimate, it is notable that it may prove to underestimate full LCA emissions and must be considered with uncertainty.

The emissions changes from considering LUC in soy oil production appear more significant. We consider four cases: a baseline with no LUC; LUC leakage (indirect emissions); low-impact direct LUC (replacement of the Cerrado Grasslands); and high-impact direct LUC (replacement of tropical rainforests). Although great uncertainty underlies estimation of biofuels' indirect emissions (for soybeans, the range can exceed hundreds of g/MJ), we assumed a HEFA-wide average range, which increased the LCA of soy oil by 36 g/MJ (Garrain et al., 2016). This relatively low figure was selected in order to illustrate the substantial LCCA increase as the carbon intensity of an SAF approaches that of conventional jet fuel.

Table 9: Sensitivity of soy-based jet fuel LCCA to land-use changes

SAF pathway	Cost per ton ($/ton)	Heating value (MJ/kg)	Cost per energy ($/GJ)	Carbon intensity (g/MJ)	LCCA (USD 2020)
Jet Fuel A (baseline)	*$462*	*43.02*	*$10.74*	*88*	-
Soy oil to HRJ (no LUC)	$1,313	44.15	$29.74	37	$420
Soy oil to HRJ (indirect LUC)	$1,313	44.15	$29.74	73	$1,427
Soy oil to HRJ (low LUC, Cerrado Grassland)	$1,313	44.15	$29.74	97.8	-$2,184 (invalid)
Soy oil to HRJ (high LUC, tropical rainforest)	$1,313	44.15	$29.74	564.2	-$45 (invalid)

This illustrates a key constraint of LCCA discussed in the methodology section: ***if the alternative jet fuel's carbon intensity is greater than that of Jet Fuel A, LCCA methodology is not applicable***, since LCCA is only valid for carbon reduction scenarios. Said differently, a negative denominator flags the approach as outside of LCCA methodology (as well as being counter to climate goals broadly). As shown in Scenarios 1 and 2 above, a negative LCCA can be achieved due to cost savings and carbon reductions—a good outcome because the option should produce savings or revenues. But a situation of paying more for higher emissions, as shown by these two SAF pathways, produces a negative LCCA number that is considered invalid. Thus, the methodology should not be used for a situation in which the option produces increased GHG emissions. Additionally, as the carbon intensity of an SAF pathway gets closer to that of Jet Fuel A's, the LCCA value increases disproportionately because the denominator is small; just as a denominator of zero yields an infinity LCCA, a dominator close to zero will yield a very high LCCA. Consequently, those who use the methodology should flag any scenarios with small denominators as sensitive toward carbon changes, and possibly reassess their carbon values.

The high LCCA values of SAF and operational constraints for SAF underscore the difficulty in fully decarbonizing aviation. In the best case (which is hard to scale), the cost of abatement is approximately $200/ton CO_2; most are around $500/ton CO_2 with an upper range of at least $1,600/ton. Realistically, when the methodology is adjusted to incorporate LUC (driving up the carbon intensity of many pathways), the actual LCCA could increase by magnitudes. This is more the case when considering decarbonization of air-miles traveled. While liter-to-liter replacement is an accurate assumption for SAF, it is incomplete when considering total miles traveled. Most SAF must be blended up to 50 percent with conventional jet fuel in commercial operations to maintain compatibility with aircraft fueling systems and operations. Said differently, fully half of all carbon from air-miles traveled cannot be managed through blending SAF. While future fueling designs may accommodate greater SAF use, thus easing the blending ratio constraint, full displacement of the 278 billion liters of jet fuel used annually will likely be a distant prospect. This suggests that DAC is likely to be a cost-effective option to decarbonizing aviation and should receive *at least* the same policy treatment as SAF and possibly greater support during early development and deployment.

SUMMARY DISCUSSION

In the new landscape of net-zero framing, greenhouse gas reduction is the core task. Decision makers in government, business, and civil society must consider which approaches should be discouraged and which encouraged, in addition to the relative merits of each approach. Although increasing clean energy supplies (e.g., green electricity, low-carbon fuel) remains important, it is insufficient—emissions reduction and displacement are essential. From a LCCA point of view, ensuring displacement of high emission technologies and practices by low emission technologies and practices has a new primacy to decision makers that they are only beginning to understand.

The value of LCCA methodology is determined by its utility in making decisions. In this context, it should be considered an index—one of many—to make decisions about energy, climate, and investment. Since reducing climate change damages and risks is a public benefit, LCCA should have particular value in considering and crafting policy options, including how to focus RD&D investments, what infrastructure investments are most valuable, and the specific value of accelerating market deployment through public grants. However, the explicit requirement to levelize the cost estimates using comparable capital and financial terms provides a clear, "apples-to-apples" metric needed to minimize poor investment and policy outcomes.

Traditionally, climate policy has provided either incentives and subsidies (e.g., tax credits, feed-in-tariffs), regulatory limits (e.g, emissions caps), or disincentives (e.g., border tariffs). Regulatory limits are measured at the tailpipe or smokestack, and they are commonly framed in terms of cost per ton (e.g., the European Trading System, the California LCFS). However, the other two policy families, incentives and disincentives, are almost never cast in terms of discrete climate measurements, but rather some other independent term (e.g., fractional tax on construction cost, Euros per MWh, 20 percent import tariff). While such policies may stimulate adoption of clean energy choices and lower barriers for widespread market entry, their climate benefits are less direct.

Importantly, it is not clear from many climate policies who pays or where costs accrue. Some policies (e.g., feed-in tariffs or tax credits) are borne by treasuries and taxpayers, and if the costs of such policies are not cast in terms of abatement value, then the public benefit of such costs are unclear. However, many policies (e.g., carbon markets, regulations) are borne by ratepayers or shareholders, with dramatic implications for equity and fairness. If loss of assets leads to bankruptcies or debt defaults, then costs are borne by taxpayers as well as shareholders. If local plants shut down, then tax base is lost and communities are placed at risk with specific local costs.

As discussed in the second scenario earlier, LCCA estimates costs but also provides insights to where those costs accrue. In this context, RECs trading is regressive. In estimating the value of policies, LCCA methodology allows one to represent the policy exchange as either a cost or a benefit to some party depending on where or how it is expressed within the equation. The same methodology and mathematical expression can show a price drop to some ratepayers and an increased cost to others. In this way, LCCA can express not only the localized magnitude of costs associated with a market, geography, policy, or technology action, but also clarifies where and to whom those costs and benefits formally accrue in the system. This allows instantaneous and evolving representation of the carbon reduction policy.

Similarly, policy options that have good LCCA scores today may have diminishing returns and greater expense in the future. Conversely, options that are expensive today may be much cheaper in the future or provide a dynamic benefit by creating and sustaining optionality (e.g., infrastructure investments). To clarify the near-term costs and benefits from a climate perspective, LCCA adds a straightforward, robust approach to understanding trade-offs.

It is also a way to assess the performance of existing policies. As in the first and second scenarios above, one can assess the value of the ITC and RECs policies even with incomplete knowledge, using LCCA to frame a discussion. One difficult component concerns additionality—what reduction can be attributed to the policy directly or even indirectly. Expert judgment can provide a basis to begin, as well as grounds for disagreement. Here, LCCA sensitivity analyses can provide some insight: full or fractional attribution of policy provides an overt quantitative estimate. For example, estimates of the costs of abatement for the German Energiewende indicate very high LCCA, even when the policy receives 100 percent attribution of emissions reductions (JP Morgan, 2015).

This is acutely important when considering policies concerning hard-to-abate options. As mentioned in the third and fourth scenarios above, LCCA provides one objective, quantitative measure of what "hard-to-abate" means. In this, we propose that sectors where ***greater than 20 percent of decarbonization requires pathways with LCCA estimates above $200/ton*** be considered hard-to-abate. Since so many options are expensive, policies that served the following metrics should be favored:

- Reduce costs of options profoundly: Here, innovation policies can prove essential (EFI, 2019a; Sivaram et al., 2020), and focus innovation on those areas that are most in need of cost reduction.
- Reduce the costs of alternative compliance and reduction approaches: For sectors and options with extremely high LCCA estimates, it may prove cost-effective to substitute emissions reduction with removal. For example, certain engineered CO_2 removal pathways (NASEM; EFI 2019b) are already cheaper than hard-to-abate pathways today. There may be broad climate and societal benefit to saving money through expansion and cost reduction of these options (Jackson and Lashof, 2020; Mackler et al., 2020).
- Help all sectors: Many of these kinds of policies are technology-agnostic. For example, building standards, "buy clean" procurement mandates, and portfolio standards based on carbon content (e.g., the California LCFS) provide umbrella policy platforms for nearly all options within a sector, allowing both high- and low-LCCA options to compete across many dimensions (e.g., performance, availability, industrial readiness).
- Serve multiple decarbonization pathway options: Here, infrastructure investments can have higher value, especially if they serve multiple pathways at once (e.g., new electric,

CO_2, or hydrogen transmission systems), providing decarbonization options across multiple sectors and geographies.

- Serve other policy objectives: Often, concerns about public health, manufacturing capability, market share, or labor dominate climate and energy discussions. These are not the same as reducing carbon but are important concerns. In crafting policies for hard-to-abate sectors, high cost options that serve multiple benefits are often more readily enacted and actionable.

On this final point, LCCA is only one dimension of decision making. Policy makers, business, and investors often make decisions based on a wide set of concerns. Many of these lie outside of immediate business or financial concerns (e.g., community service, branding, public perception, training) that merit consideration, investment, and support. This is particularly salient in considering climate and energy investments that address concerns like jobs or climate resilience. Some policies that could create a lot of jobs may have high, expensive LCCA estimates. The converse may also be true.

In using LCCA as a metric and methodology, ***it is essential to remember that it is orthogonal to and decoupled from other important concerns***. LCCA is focused chiefly on costs of CO_2 reduction. It should be considered one of many metrics, the way that EBITDA (earnings before interest, taxes, depreciation, and amortization), IRR (internal rate of return), and gross revenues are terms to frame a financial decision—helpful individually, better in aggregate.

FINDINGS AND RECOMMENDATIONS

Finding 1: Net-zero carbon arithmetic requires a focus on CO_2 reduction, removal, and displacement. Many environmental policies that are created with the goal of reaching CO_2 targets may be ill-designed. For example, efforts that focus solely on creating zero-carbon energy supplies may not deliver reductions. Policies that purport to reduce emission require metrics of success that measure actual tons of CO_2 reduced. Going forward, policy and actions must prioritize measuring the success of climate policies by tons of CO_2 as a metric. That includes focusing on metrics of reduction, such as tons displaced, carbon intensity changes, or life cycle assessment.

Finding 2: Policymakers, investors, and planners require localized and specific cost estimates associated with CO_2 reduction to make sound policy. Climate policy is not uniformly effective or economic. A given policy will have different costs and effectiveness based on where it is implemented due to geography, existing physical or energy infrastructure, labor conditions, and other inputs. For example, biofuels that use existing biomass sources will have a lower carbon intensity than existing fuel sources. However, biofuel may not necessarily have a lower carbon intensity if those biomass sources require carbon intense processing (e.g., additional logging to produce forest residue or clearing existing vegetation to grow fuel crops). The LCCA of biofuel, then, is dependent on how biomass is sourced. Localized estimates, like LCCA, enable planners to pick from a menu of options with an idea of what carbon abatement strategies will provide the greatest return or minimize costs.

Finding 3: LCCA is a formalized methodology to estimate the costs associated with specific localized reductions in GHG emissions. The core of the methodology involves capturing the real capital, operating, and production costs of options and estimating their carbon footprint as well as what is displaced or reduced. LCCA is only valid for cases with CO_2 reductions, not avoided growth options. It can reflect both static and dynamic aspects of CO_2 reduction but is poorly suited for global estimates and approaches.

> Recommendation 1: In addition to other approaches, LCCA should be regularly and routinely estimated to help guide investment and policy decision making. Policy makers, investors, and analysts should develop the capability to execute LCCA analyses as part of their regular work, like EBITDA, IRR, and WACC.

*Finding 4: If capital deployed or policy enacted does not reduce carbon emissions, the LCCA cost estimate is near infinite. If capital deployed or policy increases emissions, the denominator is negative and the specific LCCA estimate is **not** valid.* Climate arithmetic requires CO_2 reduction compared to a baseline. As a mathematical formulation, the tons abated are calculated in the denominator. This means that very small abatements make LCCA very large, and near-zero reductions are near infinite. It also means that a negative denominator indicates increased emissions and creates spurious results. In contrast, a negative numerator is not only valid but desirable, as it is an expression of cost avoided or revenues gained.

Finding 5: LCCA is well suited to estimates of partial or full carbon reductions for a process, *asset, facility, fuel, or system.* Because LCCA requires carbon accounting for an option to be considered, the methodology can account for baseline carbon intensity against which estimates of carbon reductions can be calculated. This should be true for substitutions at a component level, facility level, or system level, and it can serve to identify near-term opportunities that can be implemented swiftly.

Finding 6: For any technology or policy, LCCA values can vary dramatically by geography, market, and what is replaced. This means that the same dollar invested can have radically different carbon reduction values in different places (e.g., states, nations, regions) and contexts (e.g., sectors, markets, individual assets). For this reason, LCCA boundary conditions should be carefully assessed and explained to avoid misunderstanding. LCCA calculation is based on necessary understanding of associated carbon footprints and costs, both of which have embedded assumptions and uncertainties. Like LCA, the boundary issue of LCCA should be carefully understood to make a fair comparison, especially across different sectors.

Finding 7: LCCA values follow a different logic than conventional financial metrics. Because the focus is both carbon and dollars, the value does not necessarily reflect the actual "cost of carbon" in a traditional sense and may not fully represent the financial return since it also reflects the climate return. For example, solar incentives will make electricity prices lower for an electric power producer (utility or rooftop owner), but its cost is still paid by another entity (federal or state government). A sound financial decision may still provide limited carbon reductions and thus a high LCCA value, and system costs that are born by different actors may not appear on a project basis but may in a LCCA estimate.

> Recommendation 2: Great care is required in designing LCCA estimates and algorithms. Due to the complexity and degrees of freedom around system components and optionality, LCCA estimates are best represented as tables or scenarios, not as individual calculations.

Finding 8: A wide range of policies can be assessed in terms of LCCA. Specifically, policies that reduce the footprint of carbon emissions can be represented in many terms within an LCCA estimate. For example, LCCA values for ITC/PTF are straightforward to estimate, provided they are associated with a substitution term and lead to CO_2 reduction. Similarly, policies that lead to more substitution or more cost reductions can also improve (or, conversely, can worsen) LCCA estimates.

Finding 9: LCCA can provide a rigorous and robust comparison metric among distinct technologies. Often, sectors and technologies are considered easy or hard-to-abate without much specific definition. For example, the concept of "hard-to-abate sector" as applied to steel, cement, aviation, and shipping is widely accepted but vaguely defined. With LCCA, "hard-to-abate" can be quantified, and the LCCA value will reveal what price is required compared with "easy-to-abate" (e.g., previous analysis clearly shows that LCCA for RJF and steel is much higher than solar electricity, proving that they are financially harder to abate). Similarly, even wide and disparate technology options to achieve conservation and efficiencies (e.g., public transit additions, vehicle efficiency, replacing HVAC systems) can provide LCCA estimates that guide policy options (e.g., building or appliance standards, infrastructure investments, tax credits).

> Recommendation 3: Any sector in which greater than 20 percent of emissions reduction would cost more than $200/ton should be formally considered hard-to-abate. Policy makers should consider specific policies that reduce the cost of abatement (e.g., innovation, infrastructure) and reduce the cost of alternatives (e.g., CO_2 removal).

Finding 10: Carbon reduction is an independent value. Policy makers, businesses, and investors must balance many concerns and constituencies. Carbon reductions may or may not contribute to growth, may individually create, preserve, or destroy jobs, may save or cost money, and may affect productivity positively or negatively. Carbon reductions can support or hinder domestic industries, and the costs will vary by geography, market, sector, and application. In this, carbon reductions (and by extension LCCA) can be considered orthogonal to many other concerns—important, but not necessarily coupled or associated, and occasionally at odds, with other goals. LCCA serves as a discipline to understand these trade-offs in a policy or investment context. It is not an indication of economic productivity and growth, but an indication of carbon reduction potential and should thus only be used when the action is predicated on a carbon-based outcome.

> Recommendation 4: Policy makers should use LCCA in considering clean policies targeted at GHG reduction and climate change. In this context, LCCA should serve as one of many important metrics, like estimated job creation/loss, expense to treasuries, and overseas trade or sales. If LCCA is not estimated, however, policies run the risk of reducing emissions poorly or costing far more than alternatives.

FUTURE WORK

Continued development of LCCA methodology requires a great deal more formalization and codification. There are many ways in which the specific scenarios assessed here could be improved, especially in terms of more precise consideration of life cycle terms, including complex power generation/dispatch models, or more detailed representation of technology variations. LCCA methodology presents an endless terrain of potential future applications with varying degrees of complexity, precision, and accuracy.

The Carbon Management Research Initiative (CAMRI) at Columbia University's Center on Global Energy Policy plans to expand its work to codify and quantify LCCA across multiple energy systems. Many of the steps we plan have been outlined in the specific scenarios detailed in the report.

- General: This paper does not present sensitivity analyses in any of our scenarios or cases. Future work will include assessment of the impacts of discount rate, additionality, and other important factors.
- General: We will add dynamic elements to the sectoral modules, including factors like learning and supply limits, with improving precision and accuracy.
- General: We aim to create a simple, turn-key approach to estimating LCCA based on a set of robust and regular inputs.
- General: Our goal is to complete a set of LCCA estimates for "hard-to-abate" sectors and assess both near-term, low-cost options and long-term, deep reduction options.
- Power sector: We plan to use sophisticated grid models (e.g., AVERT, GridLAB-D) to understand the specific carbon displacement associated with technology options, including an accurate and up-to-date representation of battery and other power storage options.
- Power sector: To assess policy options, we plan to use other grid models (e.g., DGEN, SAM) to represent incremental and marginal changes in grid configurations stochastically. This can serve to illustrate how policy options might affect LCCA for different different grid configurations in terms of marginal cost and additionality.
- Industrial sector: Similar to the iron and steel case, we will explore cement, chemicals, hydrogen, glass, aluminum, and pulp and paper to generate LCCA estimates and new insights into pathways, opportunities, and trade-offs for industrial decarbonization.
- Transportation sector: Similar to the sustainable aviation fuels case, we plan to assess a range of fuels including biofuels, hydrogen, and synthetic CO-based drop-in fuels on a life cycle and LCCA basis.
- Web interface: To provide wider applicability to the tool and the solution set, we plan

to partner with software developers to build comprehensive databases for carbon displacement scenarios and construct a portal that allows a wide community of users to estimate LCCA for specific technologies, geographies, and policies.

Ultimately, LCCA could be used as a standard metric in policy and financial analysis. In this context, we will work with businesses, investors, and policymakers to understand their businesses and how LCCA can become one additional factor in planning.

APPENDIX A: COMPREHENSIVE REPRESENTATION OF LEVELIZED COST OF CARBON ABATEMENT

Due to the potential complexity of LCCA calculations (e.g., inclusion of financial, static, dynamic, and coupled systems), we recognize that this initial attempt at a comprehensive representation may be incomplete. We have separated the coupled equations into *core equations* and *input equations*. We look forward to future authors adding additional terms to the equations as is merited by the cases under consideration.

The existence of a comprehensive equation allows reasonable simplications and exclusion of terms to provide clarity or simplicity. In this regard, the following equations can be considered similar to the Navier-Stokes equation in fluid dynamics, which commonly is simplified or excludes terms for specific cases (e.g., flow in a pipe) to clarify aspects of the physics (as is the case in fluid dynamics as well, the specifics of the scenario under analysis drive the specific application of the methodology, and small terms can sometimes have large impacts).

Core Equation

The LCCA can be represented by L,

$$L = \sum_{1}^{n} \left(\frac{1}{a} \left(\frac{C_{eff} + C_{disp}}{E_0 - E_1} \right)_1 + \frac{1}{a} \left(\frac{C_{eff} + C_{disp}}{E_0 - E_1} \right)_2 + \dots \right)$$

which is the sum of displacements in the system represented from 1 to n; where *a* represents the fractional additionaility of a policy or action; C_{eff} is the marginal cost of a change in efficiency; C_{disp} is the marginal cost of displacing an emitting source term; E_0 is the emissions of the initial system configuration; and E_1 is the emissions of the new system configuration. ***Dynamic terms and levelizing terms are provided in the input equations.***

Note: additionality is represented as the fractional amount of abatement delivered by a policy or activity (e.g., a tax credit or procurement incentive). As an example, if adding RECS to a power market results in *all new purchases* of renewable power generation in a system, then a = 1. If adding RECS results in 75 percent of new purchases of renewable power generation in the system, then a = 0.75 and 1/a = 1.33, leading to higher LCCA values.

Input Equations: Costs

The efficiency cost, C_{eff}, can be calculated using the following equation:

$$C_{eff} = (C_{erem} + C_{enew} + F_{eff})$$

where C_{erem} is the cost of removing the original system, C_{enew} is the cost of installing the new system, and F_{eff} is the fuel costs (see below), here representing savings from efficiency gains and reduced fuel use. In this case, efficiency costs include things like the cost of removing existing insulation or lighting **and** the costs of installing new insulation or lighting; the costs of repurposing a factory floor of low-efficiency vehicles to produce high efficiency vehicles; and the fuel savings from either action. In the core equation, an efficiency mandate may be considered 100 percent additional, whereas an incentive for efficient alternatives may not be fully additional.

The displacement cost term, C_{disp}, can be calculated using the following equation:

$$\mathbf{C_{disp} = (C_{dnew} + C_{dorg} + F_{disp})}$$

where C_{dnew} is the cost of creating the new system, C_{dorg} is the cost of replacing the existing/original system, and Fdisp is the fuel costs (see below), here representing fuel avoided or displaced. In this case, displacement costs include things like heavy equipment purchases, decommissioning costs, installation costs, and loss of output.

Fuel costs, both F_{eff} and F_{disp}, are relatively simple to calculate:

$$\mathbf{F = (F_{new} - F_{org})}$$

where F_{new} is fuel costs of the new system and F_{org} is fuel costs of the original system. For many carbon abatement scenarios, F will be negative, either for displacement or efficiency terms, since the original system will commonly have higher fuel costs than the new system, leading to lower C_{eff} and C_{disp} values.

Estimating C_{erem}, C_{enew}, C_{dnew}, and C_{dord} is complicated. In each case, estimation should include capital expenses (CapEx), fixed operational and maintenance costs ($O\&M_{fixed}$), and variable operations and maintenance costs ($O\&M_{var}$). For example, C_{dorg} can be estimated as

$$\mathbf{C_{dorg} = (CapEx + O\&M_{fixed} + O\&M_{fvar})_t^*}$$

wherein * includes cost of capital, amortization, depreciation, and/or net-present value, annualized and summed over the lifetime of the project. ***This is the levelizing aspect of the calculation***. Without making these terms, one is making a marginal abatement calculation.

Each term of the input calculations (e.g., C_{dorg}, above) is estimated for a particular timestep, t. As costs change, e.g., due to supply scarcity, the input terms such as C_{dorg} will also change. Dynamic system changes can be expressed as arithmetic differences between these timesteps.

APPENDIX B: SOLAR SCENARIO

To calculate a LCCA for the scenario of solar power displacing an existing power generation source, we must consider the costs of both the new solar installation and the costs associated with the electricity displacement of the existing plant. For this particular scenario, the LCCA equation is formulated as

$$L = \frac{\text{(full cost of displacement configuration-full cost of original configuration)}}{(CO_2 \text{ emissions of original configuration-}CO_2 \text{ emissions of displacement configuration})}$$

Expressing the components of each term gives the following equation:

$$L = \frac{(CAPEX_s + \text{fixed } O\&M_s + \text{capital losses}_e) - (\text{avoided variable } O\&M_e + \text{avoided fuel cost}_e)}{\text{(carbon intensity of existing source x amount of electricity displaced)}}$$

Where the subscript s denotes the solar installation and the subscript e denotes the existing electricity source. Since the capital expenses and fixed O&M of the existing plant do not change due to displacement (a change in capacity factor does not affect fixed costs), these terms are not present in the difference between the cost of the displacement and original configurations. By representing the sum of first three terms of the numerator as C_1 and the sum of the final two terms as C_0 and representing the abated emissions as the difference between the original and displacement configurations $E_0 - E_1$, we arrive at the final equation[27] listed in the main text:

$$L = (C_1 - C_0)/E_0 - E_1)$$

Table B-1: Assumptions and calculation details

Key assumptions	Estimates	Source
Plant capacity (MW)	1,000	
Solar; gas; hydro capacity factor (%)	22.5; 41.8; 60.0	Gas and hydro (EIA); solar (derived)
Gas; hydro capacity factor after displacement (%)	19.3; 37.5	CF = total generation/ (capacity x hrs)
Total lifetime generation (MWh)	total generation = CF x capacity x hrs	
Natural gas/hydro electricity mix split (%)	76.5/23.5	Energy.ca.gov
Plant lifetime (yr)	20 (solar) and 30 (gas and hydro)	
STC power rating condition (W/m^2)	1,000	The Energy Grid
Global horizontal irradiance (Fresno) ($kWh/m^2/day$)	5.4	NREL and NSRDB
Years of Displacement (Yrs)	20	
Plant Costs		
Fuel cost ($/MMBtu)	3.5	EIA
Fixed O&M costs—rooftop solar (CapEx+construction finance+fixed O&M)	$2,770/kW; $15/kW; $20/kW/yr	EIA and NREL
Variable O&M costs—rooftop solar	0	
Fixed O&M costs—utility solar (CapEx+fixed O&M)	$1,111/kW; $24/kW/yr	EIA and NREL
Variable O&M costs—utility solar	0	
Fixed O&M costs (natural gas plant)	$11/kW-yr	EIA and NREL
Variable O&M costs (natural gas plant)	$7/MWh	EIA and NREL
Variable O&M costs (hydro power plant)	$112/kW-yr	EIA and NREL
Capital investment ($/kW)	927 (Gas); 5,620 (Hydro)	ATB
Depreciated plant CapEx ($) (gas)	418,645,161	Sum of Year's Digits Depreciation Method
Carbon intensity in California (tons)	2,205	EIA
Learning by doing doubling rate (%)	16	
ITC credit on solar CapEx (%)	30	

To calculate the LCCA of rooftop and utility solar in California, we accounted for the abatement costs through substitution of new solar for several generating cases: hydropower, natural gas power, and an average grid mix for 2018 and 2030.

- Displaced Energy Generation: We assume one-to-one displacement of electricity generation, meaning 100 percent of generation from the new solar installation displaces generation from the existing source. We also approximate California as a flat electricity market with constant or decreasing demand, such that new installed generating capacity must replace existing capacity.

- Generation Details: We assume nameplate capacity of 1,000 MW for all power sources. We assumed an average rooftop and utility solar installation lifetime of 20 years and a natural gas plant lifetime of 30 years. We use state average capacity factors (NREL, ATB, EIA) for natural gas and hydropower. We find the solar capacity factor based on the insolation in central California (5.4 kWh/m^2/day), which allows the installation to generate 22.5 percent of the energy it could generate under the constant 1,000 W/m^2 irradiance Standard Test Condition for capacity. To estimate the magnitude of generation displacement for use in cost and carbon abatement estimates, we find the lifetime energy generation of the solar installation by multiplying the installation's capacity factor by its nameplate capacity of 1,000 MW.

- Solar Cost: This is calculated by multiplying the solar capital cost and fixed O&M cost by plant capacity over the plant lifetime. Construction finance is also included in this calculation for the utility solar case. We assume no variable costs for solar.

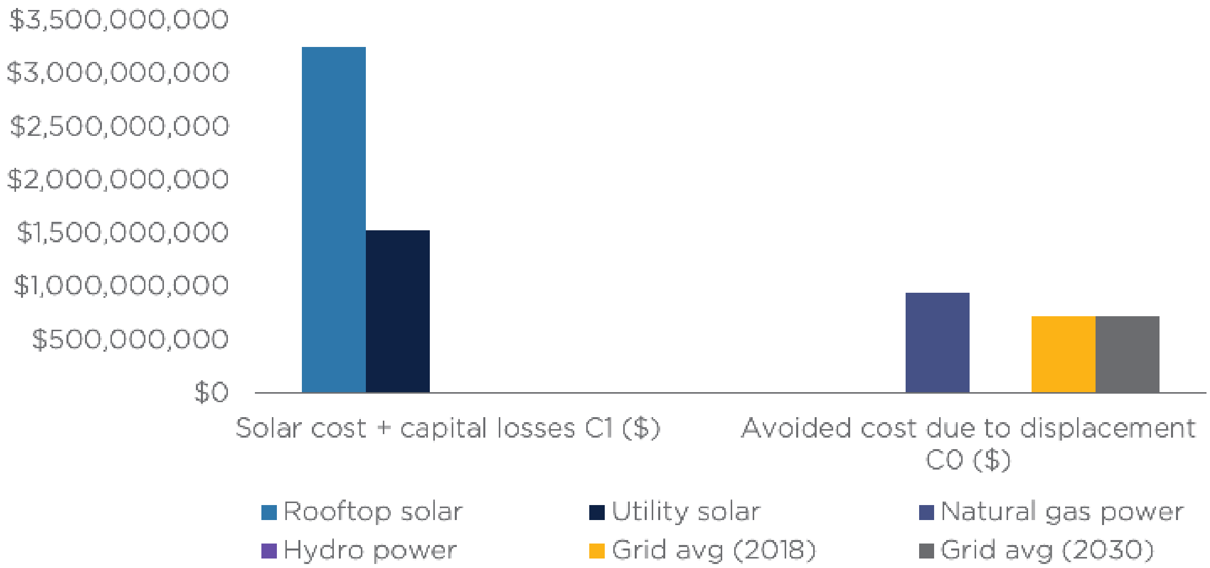
- Avoided Costs Due to Displacement: The avoided costs of the displaced plant (C0) include the avoided fuel costs and avoided O&M costs of the existing plant due to its reduced capacity factor in the displacement configuration. We assume a $3.5/MMBtu natural gas fuel cost unless otherwise noted. Fuel costs for natural gas are converted from $/MMBtu to $/MWh using a 6.45 MMBtu/MWh heat rate (NREL, 2019).

- Displaced Plant Cost: We assume that the displaced plant is not resold and there are no additional costs for remediation. Given the vintage of existing generating assets in California, we assume the hydropower plant capital cost is fully depreciated ($0) with no variable costs. We assume the displaced natural gas plant is partially depreciated to year 10 of its 30-year capital life using the sum of year's digits depreciation method. The capital losses of the existing plant due to displacement are found by multiplying the aforementioned depreciated capital cost by the ratio of the reduced capacity factor after displacement to the initial capacity factor of the existing plant.

- Abated CO_2 Emissions: We assume that utility-scale and rooftop solar generation emits zero CO_2 and that the hydropower source also emits zero. We neglect any life cycle costs for construction, which are generally small compared to lifetime power generation. In estimating the abated CO_2 emissions, we multiply the carbon intensity of the displaced energy generation by the total number of MWh displaced.

The avoided cost of the displaced existing power source, C_0, is the sum over the 20-year displacement period of the avoided variable O&M costs and the avoided fuel costs of the displaced plant due to its lowered capacity factor. To estimate these avoided variable costs, we first calculate full capital life electricity generation for the solar installation and decrease the existing plant output by that amount by reducing the existing plant's capacity factor

Figure B.1: Annualized lifetime and displaced plant costs



Note: The annualized costs for displacing hydropower are zero, as reflected in the chart.

We multiply the reduced gas plant energy generation by the normalized variable O&M and fuel costs (in $/MWh) to obtain these variable costs under displacement. Summing these avoided variable costs gives C_0. We subtract C_0 from C_1 to determine the cost of displacement—the numerator of LCCA.

Figure B.2: Carbon abatement due to displacement by 1,000 MW of solar power (Rooftop or Utility)

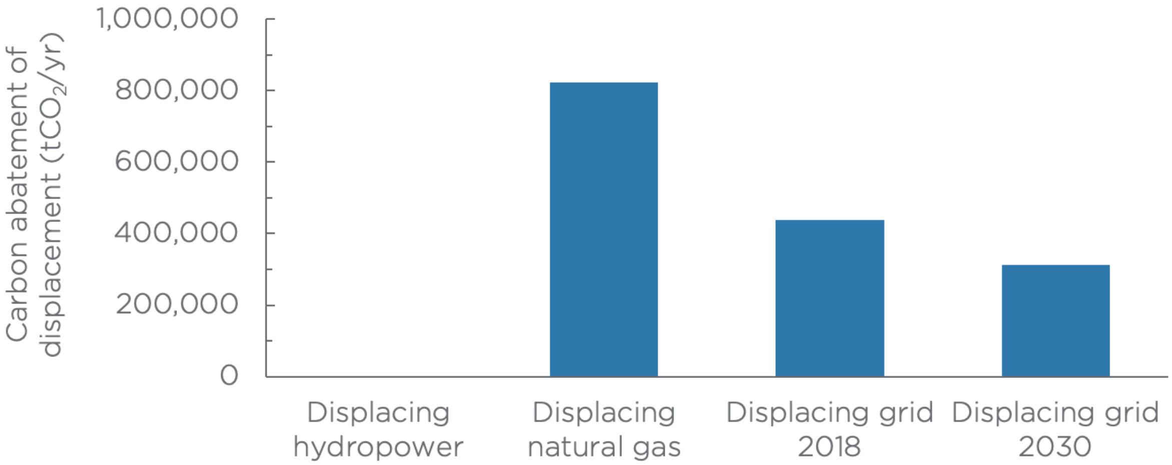


Table B.2: Calculation Details

Rooftop Solar in California (Residential)

Assumptions (Year 2018)	Rooftop Solar	Natural Gas	Hydro Power	Grid Avg. (2018)	Grid Avg. (2030)
Representative Plant Capacity (MW) A	1,000	1,000	1,000		
Capacity Factor (%) B	22.5*	41.8	60		
Plant Lifetime (yr) C	20	30	--	--	--
STC Power Rating Condition (W/m^2) D	1,000				
Global Horizontal Irradiance (Fresno) (kWh/m^2/day) E	5.4	0	0	--	
Total Lifetime Generation (TWh) F = A*B*C	**39.42**	**109.85**	**157.68**		
Capacity Factor after displacement (%) G	--	19.3 **	37.5 **		
Natural gas electricity mix split (%) H				0.765	
Solar Lifetime Cost ($) I	**3,250,000,000**				
Years of Displacement (yr) J		20	20	20	20
Energy generation after displacement (TWh) K		33.8	65.7		
Reduction in generation due to displacement (TWh) L;L*		39.42	39.42	39.42	39.42
Capital Investment ($/kW) M		927	5,620		
Plant Starting Capital Cost ($) N=A*M (MW)		927,000,000	5,620,000,000		
Electricity mix for grid avg. C_0 estimate (%) O		76.5	23.5		
Avoided Fuel Cost ($) Gas@$3.5/MMBtu P		869,999,400	0		
Reduced Avoided Fuel Cost ($) Gas@$2/MMBtu P*		497,086,200	--		
Avoided Variable O&M Costs ($) Q	--	275,940,000	0		
Depreciated Plant CapEx ($) (Gas and Hydro) R	--	418,645,161	0		
Capital Losses ($) S=G/B*R		193,297,885	0		
Derived C_1 Cost ($) T=I+S		**3,443,297,885**	**3,250,000,000**	**3,397,940,706**	**3,397,940,706**
Avoided cost due to displacement-Capital Losses ($) U=Q+P-E22; U*		952,641,515	0	36,455,251	36,455,251
Derived C_0 Cost ($) V=P+Q, V*		**1,145,939,400**	**0**	**877,045,725**	**877,045,725**
Carbon Intensity of Electricity (tons/MWh) W		0.417	0	0.223	0.159
Carbon Abatement of Displacement (tCO_2) X		16,447,347	0	8,777,880	6,267,400
Cost of Displacement $C_1 - C_0$ ($)		**2,297,358,485**	**3,250,000,000**	**2,520,894,980**	**2,520,894,980**

Utility Solar in California (Crystalline)

Assumptions (Year 2018)	Rooftop Solar	Natural Gas	Hydro Power	Grid Avg. (2018)	Grid Avg. (2030)
Representative Plant Capacity (MW) A	1,000	1,000	1,000		
Capacity Factor (%) B	22.5*	41.8	60		
Plant Lifetime (yr) C	20	30	--	--	--
STC Power Rating Condition (W/m^2) D	1,000	0	0	--	
Global Horizontal Irradiance (Fresno) (kWh/m^2/day) E	5.4	0	0	--	
Total Lifetime Generation (TWh) F = A*B*C	**39.42**	**109.85**	**157.68**		
Capacity Factor after displacement (%) G	--	0.193 **	0.375 **		
Natural gas electricity mix split (%) H				0.765	
Solar Lifetime Cost ($) I	**1,526,000,000**				
Years of Displacement (yr) J		20	20	20	20
Energy generation after displacement (TWh) K		33.8	65.7		
Reduction in generation due to displacement (TWh) L;L*		39.42	39.42	39.42	39.42
Capital Investment ($/kW) M		927	5,620		
Plant Starting Capital Cost ($) N=A*M (MW)		927,000,000	5,620,000,000		
Electricity mix for grid avg. C_0 estimate (%) O		76.5	23.5		
Avoided Fuel Cost ($) Gas@$3.5/MMBtu P		869,999,400	0		
Reduced Avoided Fuel Cost ($) Gas@$2/MMBtu P*		497,086,200	--		
Avoided Variable O&M Costs ($) Q	--	275,940,000	0		
Depreciated Plant CapEx ($) (Gas and Hydro) R	--	418,645,161	0		
Capital Losses ($) S=G/B*R		193,297,885	0		
Derived C_1 Cost ($) T=I+S		**1,719,297,885**	**1,526,000,000**	**1,673,940,706**	**1,673,940,706**
Avoided cost due to displacement-Capital Losses ($) U=Q+P-E22; U*		952,641,515	0	36,455,251	36,455,251
Derived C_0 Cost ($) V=P+Q, V*		**1,145,939,400**	**0**	**877,045,725**	**877,045,725**
Carbon Intensity of Electricity (tons/MWh) W		0.417	0	0.223	0.159
Carbon Abatement of Displacement (tCO_2) X		16,447,347	0	8,777,880	6,267,400
Cost of Displacement C_1 – C_0 ($)		**573,358,485**	**1,526,000,000**	**796,894,980**	**796,894,980**

Notes:

** Solar Capacity Factor = Global Horizontal Irradiance/(STC Power Rating Condition in a Day)/1,000)*

*** Capacity Factor After Displacement= (Annual Conventional Generation - Annual Utility Solar Generation)/Annual Capacity in Hours*

H = Used the current ratio of natural gas to hydro to calculate the percent breakdown of electricity mix.

I = CapEx + Fixed and Variable O&M x Plant Capacity over Plant Lifetime

*K = (Annual Plant Capacity in Hours *Capacity Factor after Displacement)/Years of Displacement*

L = Total Solar Lifetime Generation

L(Grid Average) = Total Solar Lifetime Generation/Years of Displacement*

P;P = Fuel Cost * Reduction in Generation Due to Displacement*

*Q = Hydro Fixed O&M Costs*Plant Capacity*Years of Displacement*

R = Calculated Using SYD Depreciation Method

U(Grid Average)= (Natural Gas Avoided Cost Due to Displacement in a Year* Natural Gas Electricity Mix Split)+(Hydro Natural Gas Avoided Cost Due to Displacement in a Year *1- Natural Gas Split Mix)*

V(Grid Average)= (Natural Gas C1 During Years of Displacement* Natural Gas Electricity Mix Split)+(Hydro C1 During Years of Displacement *1- Natural Gas Split Mix) * Years of Displacement*

W = Calculated the ratio of carbon intensity to the total carbon abatement intensity.

X = Reduction in Generation Due to Displacement x Carbon Intensit

Table B-3: Key LCCA Results for Residential Rooftop Solar, Scenario 1

Residential Rooftop Solar

Power Source Displaced	LCCA ($/t$CO_2$)	Cost of Displacement $C_1 - C_0$ ($)	Carbon Abatement of Displacement (tCO_2)
Unsubsidized: Natural Gas Power ($3.5/MMBtu Fuel)	**139.7**	2,297,358,485	16,447,347
Unsubsidized: Natural Gas Power ($2/MMBtu Fuel)	**162.4**	2,670,271,685	16,447,347
Unsubsidized: Hydropower	**infinite**	3,250,000,000	0
Unsubsidized: Grid Avg. 2018	**287.2**	2,520,894,980	8,777,880
Unsubsidized: Grid Avg. 2030	**402.2**	2,520,894,980	6,267,400
After 1 LBD Doubling: Natural Gas ($3.5/MMBtu Fuel)	**108.1**	1,777,358,485	16,447,347
After 1 LBD Doubling: Grid Avg. 2018	**227.9**	2,000,894,980	8,777,880
After 1 LBD Doubling: Grid Avg. 2030	**319.3**	2,000,894,980	6,267,400
After 2 LBD Doublings: Natural Gas ($3.5/MMBtu Fuel)	**81.5**	1,340,558,485	16,447,347
After 2 LBD Doublings: Grid Avg. 2018	**178.2**	1,564,094,980	8,777,880
After 2 LBD Doublings: Grid Avg. 2030	**249.6**	1,564,094,980	6,267,400
With ITC: Natural Gas ($3.5/MMBtu Fuel)	**89.2**	1,466,358,485	16,447,347
With ITC: Grid Avg. 2018	**192.5**	1,689,894,980	8,777,880
With ITC: Grid Avg. 2030	**269.6**	1,689,894,980	6,267,400

Notes:

** Solar Capacity Factor = Global Horizontal Irradiance/(STC Power Rating Condition in a Day)/1,000)*

*** Capacity Factor After Displacement= (Annual Conventional Generation - Annual Utility Solar Generation)/Annual Capacity in Hours*

H = Used the current ratio of natural gas to hydro to calculate the percent breakdown of electricity mix.

I = CapEx + Fixed and Variable O&M x Plant Capacity over Plant Lifetime

*K = (Annual Plant Capacity in Hours *Capacity Factor after Displacement)/Years of Displacement*

L = Total Solar Lifetime Generation

L(Grid Average) = Total Solar Lifetime Generation/Years of Displacement*

P;P = Fuel Cost * Reduction in Generation Due to Displacement*

*Q = Hydro Fixed O&M Costs*Plant Capacity*Years of Displacement*

R = Calculated Using SYD Depreciation Method

U(Grid Average)= (Natural Gas Avoided Cost Due to Displacement in a Year* Natural Gas Electricity Mix Split)+(Hydro Natural Gas Avoided Cost Due to Displacement in a Year *1- Natural Gas Split Mix)*

V(Grid Average)= (Natural Gas C1 During Years of Displacement* Natural Gas Electricity Mix Split)+(Hydro C1 During Years of Displacement *1- Natural Gas Split Mix) * Years of Displacement*

W = Calculated the ratio of carbon intensity to the total carbon abatement intensity.

X = Reduction in Generation Due to Displacement x Carbon Intensit

Table B-4: Key LCCA Results for Utility-Scale Solar, Scenario 1

Utility-Scale Solar

Power Source Displaced	LCCA ($\$/tCO_2$)	Cost of Displacement $C_1 - C_0$ ($\$$)	Carbon Abatement of Displacement (tCO_2)
Unsubsidized: Natural Gas Power ($3.5/MMBtu Fuel)	**34.9**	573,358,485	16,447,347
Unsubsidized: Natural Gas Power ($2/MMBtu Fuel)	**57.5**	946,271,685	16,447,347
Unsubsidized: Hydropower	**infinite**	1,526,000,000	0
Unsubsidized: Grid Avg. 2018	**90.8**	796,894,980	8,777,880
Unsubsidized: Grid Avg. 2030	**127.1**	796,894,980	6,267,400
After 1 LBD Doubling: Natural Gas ($3.5/MMBtu Fuel)	**20.0**	329,198,485	16,447,347
After 1 LBD Doubling: Grid Avg. 2018	**63.0**	**552,734,980**	8,777,880
After 1 LBD Doubling: Grid Avg. 2030	**88.2**	**552,734,980**	6,267,400
After 2 LBD Doublings: Natural Gas ($3.5/MMBtu Fuel)	**7.5**	124,104,085	16,447,347
After 2 LBD Doublings: Grid Avg. 2018	**39.6**	347,640,580	8,777,880
After 2 LBD Doublings: Grid Avg. 2030	**55.5**	347,640,580	6,267,400
With ITC: Natural Gas ($3.5/MMBtu Fuel)	**14.6**	240,058,485	16,447,347
With ITC: Grid Avg. 2018	**52.8**	463,594,980	8,777,880
With ITC: Grid Avg. 2030	**74.0**	463,594,980	6,267,400

Notes:

** Solar Capacity Factor = Global Horizontal Irradiance/(STC Power Rating Condition in a Day)/1,000)*

*** Capacity Factor After Displacement= (Annual Conventional Generation - Annual Utility Solar Generation)/Annual Capacity in Hours*

H = Used the current ratio of natural gas to hydro to calculate the percent breakdown of electricity mix.

I = CapEx + Fixed and Variable O&M x Plant Capacity over Plant Lifetime

*K = (Annual Plant Capacity in Hours *Capacity Factor after Displacement)/Years of Displacement*

L = Total Solar Lifetime Generation

L(Grid Average) = Total Solar Lifetime Generation/Years of Displacement*

P;P = Fuel Cost * Reduction in Generation Due to Displacement*

*Q = Hydro Fixed O&M Costs*Plant Capacity*Years of Displacement*

R = Calculated Using SYD Depreciation Method

U(Grid Average)= (Natural Gas Avoided Cost Due to Displacement in a Year* Natural Gas Electricity Mix Split)+(Hydro Natural Gas Avoided Cost Due to Displacement in a Year *1- Natural Gas Split Mix)*

V(Grid Average)= (Natural Gas C1 During Years of Displacement* Natural Gas Electricity Mix Split)+(Hydro C1 During Years of Displacement *1- Natural Gas Split Mix) * Years of Displacement*

W = Calculated the ratio of carbon intensity to the total carbon abatement intensity.

X = Reduction in Generation Due to Displacement x Carbon Intensit

APPENDIX C: SOLAR STATE COMPARISON

1. State solar-PV capacity factors: https://www.statista.com/statistics/1019796/solar-pv-capacity-factors-us-by-state/
2. LAZARD solar assumptions: https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf
3. state electricity natural gas cost: https://www.eia.gov/dnav/ng/ng_pri_sum_dcu_STX_m.htm
4. State electricity C-intensity -EIA: https://www.eia.gov/environment/emissions/state/
5. Sstate-specific solar cost assumptions (w and w/o ITC): https://news.energysage.com/how-much-does-the-average-solar-panel-installation-cost-in-the-u-s/
6. California ISO wholesale electricity cost: http://www.caiso.com/Documents/2018AnnualReportonMarketIssuesandPerformance-PresentationtoCPUC.pdf
7. Texas ERCOT wholesale electricity cost: https://www.potomaceconomics.com/wp-content/uploads/2019/06/2018-State-of-the-Market-Report.pdf
8. New Jersey PJM wholesale electricity cost: https://www.pjm.com/-/media/committees-groups/committees/mc/20180319-webinar/20180319-item-07a-markets-report.ashx
9. Massachusetts NEISO wholesale electricity cost: https://www.iso-ne.com/static-assets/documents/2019/03/20190312_pr_2018-price-release.pdf

APPENDIX D: STEEL SCENARIO

Methodology Specifics

The methodology of steelmaking LCCA analysis follows the general guideline of LCCA calculations. Cost difference and carbon emission difference are calculated to produce LCCA value: how much additional cost is paid to produce the same steel but with one ton less CO_2 emissions. In the baseline cost assumptions (i.e., baseline BF/BOF, DRI-EAF, EAF scrap), CapEx includes the primary capital charges represented as one unit. The OpEx includes the raw material costs (e.g., iron ore, coal, scrap, gases, electricity), associated transportation costs, and others (e.g., labor and maintenance). The carbon emission includes only the direct emission (onsite emission) and energy emission (e.g., electricity associated emission) associated with steel production, i.e., the emission does not include transportation emission and plant building emission. These assumptions mismatch (e.g., transportation emission is not included but transportation cost is included) is widely accepted since the cost burden is included for steel production, which must be counted. But the carbon emission burden is shared in other sectors typically (e.g., transportation sector emission) and is not counted. Please refer to the steel paper (in review) for other methodology details such as technology specific cost assumptions and carbon emissions.

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1. BF/BOF cost assumptions: https://www.steelonthenet.com/cost-bof.html

2. EAF cost assumptions: https://www.steelonthenet.com/cost-eaf.html

3. DRI-EAF cost assumption: https://www.oecd.org/sti/ind/Future%20of%20Steel%20-%20IIMA.pdf

4. For other specific technology cost assumptions and carbon emission data, please refer to Fan Z. & Friedmann S.J., (in review), Low-Carbon Production of Iron & Steel: Technology Options, Economic Assessment, and Policy, Progress in Energy, IOP Publishing

APPENDIX E: SUSTAINABLE AVIATION FUEL SCENARIO

Fischer-Tropsch (FT): a catalytic chemical process producing liquid fuels (hydrocarbons) from syngas ($CO + H_2$ mixture). The syngas mixture can be derived from coal, natural gas, or biomass, resulting in distinct carbon footprints. If biomass is used as feedstock, the method is categorized as Biomass-to-Liquid (BTL). Typical products are hydrocarbons with carbon chains of five or greater. Reaction happens with temperature below 300 °C. Blending ratio of FT SAF is 50 percent.

Hydrotreated Esters and Fatty Acids (HEFA): primary feedstock with vegetable oils, fats, or oil-riched organisms (e.g., algae). Process includes hydrogenation, isomerization, and separation, producing naphtha, kerosene, and diesel. HEFA is considered the most mature and commercialized pathway to produce SAF. Hydrogen production and gas recovery during HEFA will emit CO_2, and the carbon footprint can be improved with further capturing. Blending ratio of HEFA SAF is considered 50 percent.

Alcohol-to-Jet (ATJ): convert mainly ethanol and butanol (sometimes methanol) to SAF. The process includes dehydration, oligomerization, separation, and hydrogenation. The process also requires hydrogen support for making SAF, also subjected to potential carbon emission and improvement. Blending ratio of ATJ is 30 percent.

Direct Sugar to Hydrocarbon (DSTH): fermentation process that turns sugar beets, sugar canes, or lignocellulose into hydrocarbons. Primary process includes aerobic fermentation and hydrogenation. The product of DSTH is farnesane, whose blending ratio is limited to 10 percent.

Hydrotreated Depolymerize Cellulosic Jet (HDCJ): pyrolysis process by converting biomass to bio-crude for hydrogenation.

Scenario-Specific Methodology

Many studies have calculated Jet Fuel A's well-to-wake life cycle assessment, which examines the carbon intensity of the fuel's feedstock recovery and transportation, processing into fuel, transportation of fuel, and combustion (which vastly emits the most CO_2). These studies typically yield an LCA between 85 and 90 gCO_2e/MJ. This study uses 88 as the benchmark carbon intensity of Jet Fuel A, upon which the SAF pathways are compared.[28] SAF carbon intensities were sourced from techno-economic analysis of each respective pathway.

To make a simple estimate of the LCCA for sustainable aviation fuel (SAF), we use the equation

$$L = C/(E_0 - E_1)$$

Where C is the cost associated with the change of configuration, E_0 is the greenhouse gas emissions of Jet Fuel A, and E_1 is the greenhouse gas emissions of the sustainable aviation fuel.

Determine C by finding the cost per energy ($/GJ) of Jet Fuel A and the sustainable aviation fuel. This entails dividing the cost per ton of fuel ($/ton) by its heating value (MJ/kg).

$$\text{Calculate cost per energy} \left(\frac{\$}{GJ}\right) = \frac{\text{cost per ton fuel} \left(\frac{\$}{ton}\right)}{\text{heating value} \left(\frac{Mj}{kg}\right)}$$

The numerator C term, then, is additional cost per energy represented by the positive difference in cost per energy between Jet Fuel A and the SAF.

Next, determine the $E_0 - E_1$ by subtracting the carbon intensity of the SAF from Jet Fuel A. This yields the carbon savings per unit of energy. The LCA expressed in g/MJ can be converted to kg/GJ. The final equation, before adjusting for exchange rates where applicable and inflation (2020 USD), is

$$\text{LCoCA (unprocessed)} \left(\frac{\$}{ton}\right) = \frac{\text{additional cost per energy} \left(\frac{\$}{GJ}\right)}{\text{carbon savings per unit energy} \left(\frac{kg}{GJ}\right)} * 1{,}000$$

Table E.1: Energy content ranges for different sustainable aviation fuels

SAF pathway	Feedstock	Major reaction	Products	Blending ratio	Heating value
Jet Fuel A (baseline)	Fossil fuel	Refining	Jet Fuel A	N/A	43.02 MJ/kg 35.28 MJ/L[3]
FT	Syngas (biomass-derived, gas, coal)	Catalytic chemical reaction	Hydrocarbon (C5+, carbon chain >5)	50%[1]	44.2 MJ/kg[4] 36.3 MJ/L [2]
HEFA	Vegetable oil, fats, oil-rich organisms	Hydrogenation catalytic cracking	Naphtha, kerosene, diesel	50%[2]	44.15 MJ/kg[5] 33.4 MJ/L[5]
AJT	Methanol, ethanol, butanol (sugar, industrial off-gas)	Oligomeriza-tion	Naphtha, kerosene, diesel	30%[2]	43.40 MJ/kg[5] 34.10 MJ/L[5]
DSHC	Sugar	Aerobic fermentation	Farnesane (C15H32)	10%[2][5]	43.99 MJ/kg[6]

SAF Pathway	Cost per ton ($/ton)	Carbon Intensity (g/MJ)	LCCA (USD 2020)
Jet Fuel A (Baseline)	*$462* [1]	*88* [2]	[1] Alexander Zschocke, Sebastian Scheuermann, and Jens Ortner, *High Biofuel Blends in Aviation* (HBBA) (Cologne, Germany: Lufthansa AG, 2012), p. 29, https://ec.europa.eu/energy/sites/ener/files/documents/final_report_for_publication.pdf. [2] Stamatis Diakakis, "Sustainable Aviation Fuels" (internship project for DMT Environmental Technology, University of Groningen, Netherlands), https://fse.studenttheses.ub.rug.nl/21459/1/Sdiakakis-EES-Internship%20Project%20for%20DMT.pdf.
Lignocellulosic Biomass FT	$1,750[3]	5[4]	[3] Sierk de Jong et al., "Life cycle analysis of greenhouse gas emissions from renewable jet fuel production," *Biotechnol Biofuels* 10, no. 64 (2017), DOI 10.1186/s13068-017-0739-7, https://biotechnologyforbiofuels.biomedcentral.com/articles/10.1186/s13068-017-0739-7 [4] Sierk de Jong et al., "The feasibility of short-term production strategies for renewable jet fuels—a comprehensive techno-economic comparison," *Biofuel, Bioproducts, and Biorefining* 9 (2015): 778–800. DOI: 10.1002/bbb.1613, https://onlinelibrary.wiley.com/doi/pdf/10.1002/bbb.1613.
Municipal Solid Waste FT	$1,238[5]	33[5]	[5] Pooka Suresh et al., "Life Cycle Greenhouse Gas Emissions and Costs of Production of Diesel and Jet Fuel from Municipal Solid Waste," *Environmental Science and Technology* 52 (2018).
Corn Ethanol-to-Jet	$1,260[7]	75[8]	[7] Jeongwoo Han, Ling Tao, and Michael Wang, "Well-to-wake analysis of ethanol-to-jet and sugar-to-jet pathways," *Biotechnology for Biofuels* 10, no. 21 (2017), DOI 10.1186/s13068-017-0698-z. https://www.nrel.gov/docs/fy17osti/67911.pdf. [8] Ling Tao et al., "Techno-economic analysis for upgrading the biomass-derived ethanol-to-jet blendstocks," *Green Chemistry* 4, no. 19 (2017): 1082–1101, https://pubs.rsc.org/en/content/articlepdf/2017/gc/c6gc02800d/.
Soy Oil to HRJ	$1,313[9]	37[10]	[9] Stratton, Wong, and Hileman, *Life Cycle Green-house Gas Emissions from Alternative Jet Fuels*. [10] Matthew Pearlson et al., "A techno-economic review of hydroprocessed renewable esters and fatty acids for jet fuel production," *Biofuels, Bioproducts, and Biorefining* 7, no. 1 (2013), doi: 10.1002/bbb.1378, https://onlinelibrary.wiley.com/doi/full/10.1002/bbb.1378.
Used Cooking Oil to HRJ	$1,088[11]	19.4[11]	[11] Nikita Pavlenko, Stephanie Searle, and Adam Christensen, "The cost of supporting alternative jet fuels in the European Union," (working paper, The In-ternational Council on Clean Transportation, 2019).

SAF Pathway	Cost per ton ($/ton)	Carbon Intensity (g/MJ)	LCCA (USD 2020)
Catalytic Conversion of Lignocellulosic Sugars (w/ CCS hydrogen)	$1,250[13]	49.2[13]	[13] Wei-Chang Wang, *Review of Biofuel Jet Conversion Technologies* (Washington, DC: NREL, 2016), https://www.nrel.gov/docs/fy16osti/66291.pdf.
Direct Air Capture Megaton Plant	$124–325[15]	-	[15] John Larsen et al., Capturing Leadership, Policies for the US to Advance Direct Air Capture Technology (New York: Rhodium Group, 2019), Rhodium Group. https://rhg.com/wp-con-tent/uploads/2019/05/Rhodium_CapturingLeadership_May2019-1.pdf.

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APPENDIX F: ACRONYMS AND UNITS

ACP	Alternative Compliance Payment
AJF	alterantive jet fuel
ATB	Annual Technology Baseline
ATJ	Alcohol-to-Jet
AVERT	AVoided Emissions and geneRation Tool
BF/BOF	blast furnace/basic oxygen furnace
BTL	Biomass-to-Liquid
CAISO	California Independent System Operator
CapEx	capital expenditures
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CO_2	carbon dioxide
CPUC	California Public Utilities Commission
DAC	direct air capture
DRI-EAF	Direct Reduced Iron to Electric Arc Furnace
DSTH	Direct Sugar to Hydrocarbon
EBITDA	Earnings before interest, taxes, depreciation and amortization
ERCOT	Electric Reliability Council of Texas
EV	electric vehicle
FT	Fischer-Tropsch
GEMs	general equilibrium models
GHG	greenhouse gas
GW	gigawatt
HDCJ	Hydrotreated Depolymerize Cellulosic Jet
HEFA	hydroprocessed esters and fatty acids
HM	hot metal
IAMs	integrated assessment models
ISO-NE	ISO New England, Inc.
ITC	investment tax credit
kW	kilowatt
kWh	kilowatt-hour
LBD	learning by doing

LCOE	levelized cost of electricity
LCFS	Low Carbon Fuel Standard
LCCA	levelized cost of carbon abatement
LUC	land-use changes
MAC	marginal abatement costs
MJ	megajoule
MMBtu	one million British Thermal Units (BTU)
MMT	million metric ton
MSW	municipal solid waste
MT	megawatt
MWh	megawatt hour
NPC	National Petroleum Council
NREL	National Renewable Energy Laboratory
NYSERDA	New York State Energy Research and Development Authority
O&M	operations and maintenance
OpEx	operational expenditures
PJM	Pennsylvania, Jersey, Maryland Power Pool
PV	solar photovoltaic
REC	Renewable Energy Credit
RJF	renewable jet fuel
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SAF	sustainable aviation fuel
SCC	social cost of carbon
SMR	Steam Methane Reforming
SYD	sum of year's digits
TWh	terrawatt-hour
UNEP	United Nations Environment Programme
WACC	weighted average cost of capital

**For replacing an existing steel production facility which is already capitally paid off, only OpEx is regarded as the original cost for LCCA calculation. This is a conservative assumption—early retirement and replacement of BF/BOF plants would add costs to the LCCA numerator.*

***Using zero-C electricity for iron and steel production, assuming electricity from the grid is zero-carbon and not subjected to additional retrofit cost with \$120/ton-CO_2 LCCA.*

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NOTES

1. Some MAC estimates are levelized and estimate net-present value. Some are not. *Caveat emptor*.
2. McKensey attempted to ameliorate this circumstance in their 2009 MAC report.
3. These estimates can be very sensitive to the estimate of discount rate selection.
4. In this report, all values are represented as US dollars per ton CO_2 abated ($/ton).
5. In this context, estimating CCS costs as part of emissions reduction would be suitable for LCCA methodology, while estimating CCS costs for a new plant would not be valid. For comparison, both situations would be suitable for LCOE.
6. The denominator can also be expressed as E_0*(1 – (E_1/E_0) where E_1/E_0 is the fractional reduction in the greenhouse gas emissions associated with the new or proposed action.
7. Mathematically, if E1 is slightly larger than E0, the denominator would be close to negative and very small, yielding a “negative infinity” LCCA estimate. The more E1 emits relative E0, the denominator would be negative and growing, yielding smaller negative LCCA values—clearly not savings or revenues as shown by a negative numerator. See Appendix A.
8. LCCA methodology does not include opportunity costs in the cost estimate nor broad economic activity (such as growth in trade or improved local health from pollution reduction). Those may indeed be real costs or benefits, but are outside the scope of LCCA methodology.
9. Experts may be needed to assess the validity of these assumptions.
10. This problem is difficult but has precedent. OECD 2018 is an example.
11. If this condition were relaxed, the estimated LCCA value would go up due to lower displacement.
12. Since LCCA treats a *reduction* in emissions as a positive abatement value, the form requires that the numerator hold $C_1 – C_0$ and the denominator hold $E_0 – E_1$. See appendix for additional discussion.
13. In this scenario, hydropower is a convenient proxy for any fully amortized zero-C emission source. In other jurisdictions, nuclear or geothermal could be considered to similar effect.
14. If battery systems were added to improve temporal dispatch, they would also substantially increase costs and LCCA numerator accordingly.
15. Both avoided costs that comprise C_0 are variable costs that depend on the capacity factor of the existing plant. Thus, the magnitude of displacement of natural gas generation by

solar power completely prescribes C_0. The age of the displaced gas plant defines the depreciated capital cost of the existing plant based on its depreciation schedule, which is used to calculate capital losses due to displacement. The hydropower C_0 is 0 because we assume hydropower to have no variable costs.

16. These include biomass, geothermal, solar, wind, hydroelectricity, and may also include resources such as landfill gas, municipal solid waste, and ocean energy (EIA, 2020).

17. Additional details pertaining to the RPS of the states featured in this sub-case can be found in the Appendix C.

18. Each REC declares the underlying generation source, location of generation, and year of generation ("vintage") (WRI, 2020).

19. EAF can process pig iron (BF products), scrap steel (recycled), and DRI for its steel making. In practice, these different feedstocks are typically mixed for multiple reasons: costs, feedstock availability, and product quality control (DRI and pig iron are much purer than scrap steel and can be used to improve the steel quality and reduce energy consumption). The use of pig iron in EAF represents a negligible fraction of global primary production. For simplicity, we represent 100 percent scrap and 100 percent DRI cases only.

20. All trends are linear because only the numerator is affected (the denominator is constant because $E_1 = 0$).

21. We recognize that all these technologies have some non-zero life-cycle carbon emission which could marginally affect final LCCA estimates.

22. The typical market price is $400/ton and the marginal cost of the BF/BOF pathway is only $365/ton-HM.

23. As of this report's printing, it is not clear how the Covid-19 pandemic will affect global air travel in the years to come.

24. ASTM International is an international organization that develops technical standards for various products and commodities.

25. Detailed descriptions with references are provided in the Appendix E.

26. While other pathways may prove viable with time, a shortage of robust data and literature limits initial analysis.

27. The order of the C_1, C_0, E_0, and E_1 terms leads to cost represented as a positive number. If C_0 and C_1 were reversed, L would have a negative value, which commonly represents a cost in financial metrics

28. R.W. Stratton, H.M. Wong, and J.I. Hileman, *Life Cycle Greenhouse Gas Emissions from Alternative Jet Fuels* (Cambridge, MA: Partnership for Air Transportation Noise and Emissions Reduction, 2010), http://web.mit.edu/aeroastro/partner/reports/proj28/partner-proj28-2010-001.pdf.

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