Fossil-Fuel Options for Power Sector Net-Zero Emissions with Sequestration Tax Credits

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ABSTRACT: Three of the main challenges in achieving rapid decarbonization of the electric power sector in the near term are getting to net-zero while maintaining grid reliability and minimizing cost. In this policy analysis, we evaluate the performance of a variety of generation strategies using this "triple objective" including nuclear, renewables with different energy storage options, and carbon-emitting generation with carbon capture and storage (CCS) and direct air capture and storage (DACS) technologies. Given the current U.S. tax credits for carbon sequestration under Section 45Q of the Internal Revenue Code, we find that two options: (1) cofiring bioenergy in existing coal-fired assets equipped with CCS, and (2) coupling existing natural gas combined-cycle plants equipped with CCS and DACS, robustly dominate other generation strategies across many assumptions and uncertainties. As a result, capacity-expansion modelers, planners, and policymakers should consider such combinations of carbon-constrained fossil-fuel and negative emissions technologies, together with modifications of the current national incentives, when designing the pathways to a carbon-free economy.
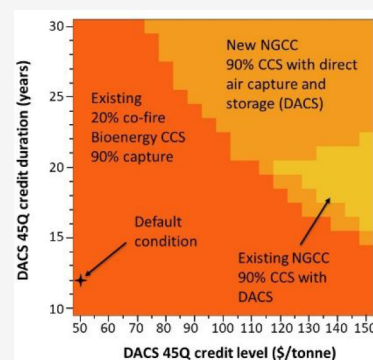
■ INTRODUCTION

According to the 2018 Intergovernmental Panel on Climate Change (IPCC) recommendations, limiting the future climate impact of anthropogenic carbon dioxide (CO_2) emissions to 1.5 °C warming will require reducing global greenhouse gas emissions to 55% of the 2010 level by 2030 and achieving a net-zero carbon economy by 2050.[1] Electrification of many sectors of the economy will be required to meet these economy-wide goals, thereby putting pressure on the power sector to increase generation while rapidly decarbonizing.[1−6] The apparent path forward for many nations to achieve these goals is to incorporate high levels of variable renewable energy (VRE) sources (primarily solar and wind generation) by increasing their global capacity growth rate from almost 250 gigawatts (GW) per year in 2020 to 1100 GW per year in 2030 and then to sustain that pace through 2050.[6]

Studies of the European and United States' (U.S.) electricity grids that have modeled feasible renewable-generation penetration levels of 50% and more (and are heavily dominated by VRE capacity) indicate that such an approach may be feasible.[7−26] However, achieving both net-zero carbon emissions and reliable coverage of 100% of the forecasted demand becomes both difficult and expensive for such portfolios as VRE penetration surpasses 80%.[17,22,25] The inherent variability of solar and wind patterns leads to periods of generation and demand imbalances.[17,27] Adding more VRE capacity to cover these periods can lead to dramatic asset overbuilding and many hours of excess generation curtailment.

This curtailed overcapacity can be as high as 3.4 times the annual demand[17] and has a direct effect on levelized cost of electricity (LCOE) calculations. Mixing and geographically distributing VRE assets can reduce the imbalance but may require continental distribution and additional generation sources.[7,8,10,16,17,20,22,24,26,30,31]

Balance can be restored in high-penetration VRE systems by shifting both generation and demand. The addition of technologies to store the excess energy in chemical, mechanical, or thermal states[28−30] allows the available electricity to shift from periods of resource abundance and low demand to periods of resource scarcity and high demand.[30,32] However, large-scale shifting of electricity availability will lead to much greater system costs, as more storage, 12 h of annual generation in the same U.S. study,[17] is required for balancing. On the demand side, flexibility strategies[30,32,33] can be employed to reduce some of the need for additional VRE capacity and the increase in VRE LCOE from underutilized assets (mechanisms not considered in this analysis). This shifting of demand is not without costs; the variability of the VRE assets must still be designed for, and

the consumer inconvenience considered and possibly compensated.

In addition to generation portfolios with large VRE components, carbon-free energy is often simulated in capacity-expansion and nonexpansion models with fossil fuel and cofired bioenergy (BE) electric generating units (EGU) for which carbon capture and storage (CCS) technology is employed to immediately capture carbon emissions.[34] In these cases, any remaining emissions can be captured (or offset) from the ambient air with a negative emissions technology (NET) such as direct air capture and storage (DACS) or dedicated bioenergy with CCS (BECCS), as can the initial emissions if an EGU is not equipped with CCS, to achieve net-zero or negative emissions.[24,35−38] Generation with such options employing carbon capture is made more attractive under the current U.S. tax policy (i.e., Section 45Q: credit for carbon oxide sequestration[39]) that provides significant incentives for capturing and storing carbon emissions (see Supporting Information (SI), Section S1).

Research on the impact of the current 45Q incentives on the promotion of CCS for existing fossil-fuel EGUs and new fossil-fuel capacity in the U.S. power sector has been inconclusive. Some indicates that there will be an increase in CCS capacity resulting primarily from utilization for enhanced oil recovery (EOR) in deference to that for immediate sequestration.[40−44] This increase is due to the additional revenue stream from selling the effluent for this purpose. Therefore, EGUs located near existing oil fields and CO_2 pipelines are more likely to be equipped with CCS. Other research finds that when the EOR option is not available, the 45Q incentive alone is inadequate to promote CCS because the incentive is insufficient to cover the CCS-associated costs.[44−46] Research suggest that this revenue gap is diminished with modifications to the current 45Q structure that include eliminating the CCS construction start-date deadline, lowering the qualifying annual capture rate threshold, and making the duration unlimited.[43,44]

In a previous paper,[47] we addressed two gaps in the aforementioned literature to achieve emission reductions with 45Q incentives in the 2030 U.S. fossil-fuel fleet. One gap addressed was the economic decision of the owner in determining the least-cost configuration of the individual EGU to achieve emissions reduction when faced with fungible competition. Rather than the binary decision of simply adding or not adding CCS,[40−43,45,46] this decision may entail doing nothing and paying a carbon tax, retrofitting the EGU with CCS, or retiring the EGU and replacing the generation with that from a zero-carbon source.

The second gap addressed was how the current 45Q incentives for immediate sequestration will influence this decision in the power sector. The sole examination of immediate sequestration is particularly relevant for future deep-reduction scenarios because a net emissions reduction of less than 0.2 million tonne (Mtonne) for each Mtonne of injected CO_2 may result if the related oil emissions are included when the effluent is used for EOR.[48,49] While Edmonds et al.[44] also examined the impact of the 45Q tax credit for immediate sequestration, the result is confounded with that for EOR and is further confounded across the power and industrial sectors. Anderson et al.,[47] also furthered the discussion of future 45Q policies to promote carbon capture[43,44] through modification of the credit level and duration to promote CCS for specific generation technologies.

These two gaps persist in the literature for achieving near-term, net-zero emissions in the U.S. power sector with NETs. DACS and dedicated BECCS were included in one study as a complementary mitigation technology to CCS for offsetting emissions from natural gas-fired EGUs.[35] However, net-zero emissions were not targeted until 2050, and coal-fired generation and 45Q incentives were excluded. Both dedicated BECCS and cofiring coal with up to 15% bioenergy while employing CCS were included in another study of the western U.S power sector that achieved net-zero emissions by 2040 in an aggressive reduction scenario.[36] While the grid in this study incorporated CCS for natural gas combined cycle (NGCC) capacity and included limited coal capacity with CCS, additional nuclear capacity and 45Q incentives were absent.

To further explore these gaps, in this policy analysis we expand upon previous work[47] and complete a LCOE comparison of 17 generation technologies at the national level in 2030 (shown in Table 1) that satisfy two constraints:

Table 1. Generation Technology, Energy Source, and Carbon Control Configuration for Studied Technologies

technology	energy source	carbon controls
existing cofire BECCS	coal & 20% bioenergy	90% CCS
new NGCC CCS	natural gas	90% CCS & DACS
existing NGCC CCS	natural gas	90% CCS & DACS
USC[a] cofire BECCS	coal & 20% bioenergy	90% CCS
small modular reactor	nuclear	N/A
advanced light-water reactor[b]	nuclear	N/A
dedicated BE	100% bioenergy	N/A
existing coal CCS	coal	90% CCS & DACS
wind	wind	N/A
solar	solar	N/A
USC CCS	coal	90% CCS & DACS
dedicated BECCS	100% bioenergy	90% CCS
long-duration storage	solar/wind/hydrogen	N/A
existing NGCC	natural gas	DACS
new NGCC	natural gas	DACS
existing cofire BE	coal & 20% bioenergy	DACS
existing coal	coal	DACS

[a]USC: ultra-supercritical. [b]While the advanced light-water reactor is modeled, the small modular reactor results are used as proxy because the LCOE results are within US$1 MWh^{-1} of each other.

(1) net-zero or zero-carbon emissions, (2) 100% resource adequacy. From this comparison, we contend that employing existing fossil-fuel assets with CCS and DACS technologies to achieve net-zero emissions may enable the U.S. power sector to decarbonize at a lower cost than relying on large VRE penetration with adequate energy storage to achieve resource adequacy (see SI Section S2). As a result, capacity-expansion modelers, planners, and policymakers should consider such combinations of carbon-constrained fossil-fuel technologies in the fuller context of the national grid, together with modifications of the current national incentives to capture the emissions, when designing the pathways to a carbon-free economy.

■ METHODS

Modeling Resource Adequacy. Because of globally declining capital costs[50] and the absence of variable operation and maintenance (VOM) costs for solar and wind capacity, VRE technologies have the lowest LCOE compared to the

other modeled technologies if the 100% resource adequacy constraint is relaxed. Adding the constraint forces the modeling of solar and wind generation variability and in turn the integration of balancing strategies and their associated costs[51] when one considers the addition of a (N-1) VRE source that might require the aforementioned addition of battery capacity or VRE capacity overbuild to meet this constraint in a high-penetration scenario. Previous studies have varied in how the distributions of VRE generation are created. Some high-penetration VRE capacity-expansion models have relied on relatively short periods of historical data (e.g., one year of insolation and wind data) over limited geographical regions (e.g., California or the western U.S.) that are averaged over time steps of a certain size (e.g., typically hours).[7,12,13,22,23] Increasing the length of the historical data set (e.g., 39 years)[8,16−21,23,24] and shortening the time step increases the variability of the generated electricity and complicates the balancing model requirements as periods of mismatched generation and demand must be accounted for. Long-duration variation[20,27] requires additional and/or negatively correlated VRE capacity, storage, or backup with dispatchable (firm) zero or net-zero carbon capacity to achieve resource adequacy.[52] Similar considerations are needed for demand-side modeling.

Adding only storage to the generation portfolio can achieve resource adequacy notwithstanding resource intermittency,[16−20,22] with the type and amount of storage required depending upon the power and energy requirements.[28,30] Several types of chemical batteries are cost-effective storage technologies for several-hour durations; lithium-ion (Li-ion) batteries are often modeled for this purpose as cost reductions by 2030 are projected to make this form the dominant technology for battery storage requirements of up to 4-h duration.[29] When 10s of hours of storage are required, pumped hydroelectric and compressed air storage are often modeled; however, these sources are geographically restricted and additional capacity is not available for all grids. Without these options, Li-ion storage is projected to dominate for durations up to 60 h.[29] Other storage solutions that have the potential to be less costly than Li-ion batteries, such as zinc−manganese dioxide flow batteries[53] or gravitational storage[54,55] may fill this segment; however, the development of these solutions is currently in the benchtop[53] or demonstration phase.[54,55] Furthermore, the uncertainty in the cost estimates for these technologies is sufficiently high that there is risk that the model results may be influenced by subjective assumptions about technological optimism and economies of scale. Therefore, this model uses Li-ion storage for this segment. For longer periods of low generation, using VRE capacity to produce hydrogen from electrolysis and then storing the gas until there is demand to use fuel cells or turbine generators to convert the gas into electricity (herein termed power-to-gas-to-power (PGP)), is possible as long-duration storage (LDS).[6,18,20,29]

Resource adequacy can also be achieved with backup capacity provided by firm nonrenewable, net-zero and zero-carbon emission EGUs, Table 1. Both existing and new coal-fired electric generating units (CFEGU) and NGCC plants can provide the requisite capacity with or without CCS, given that DACS or another NET are employed to remove any remaining emissions. While dedicated BECCS is often used for this purpose,[24,35−38] this study evaluates the performance of this technology as firm capacity to meet the target generation, rather than use this technology as a substitute for DACS (see

SI Section S5 for a comparative analysis). When CFEGUs equipped with CCS at 90% capture employ 20% bioenergy cofire on an energy basis (herein termed cofire BECCS), approximately net-zero emissions are achieved from a life-cycle analysis perspective.[56−58] Similarly, dedicated BE EGUs without CCS and cofire BE at 20% cofire with subbituminous coal and DACS are also considered net-zero emissions capacity. Finally, advanced nuclear capacity, such as small modular reactors (SMR), are often modeled in high VRE penetration systems to provide zero-carbon backup capacity.[18,23−25,59]

Modeling LCOE. Certain simplifying assumptions are made in this cost model to examine how fossil-fuel generation sources might be used as firm capacity for the VRE sources and to identify decarbonization options. These options that help bound the solution set can then be added to capacity-expansion dispatch models to further the policy discussion. One assumption is that this (N-1) source is a standalone unit and must maintain a target generation level to fulfill the exogenous adequacy requirement. The requirement for continuous load balancing is ignored for the VRE capacity (except for the costs that may be incurred from the weather-induced, long-duration shortfalls associated with longer weather data sets[20,27]), which is studied parametrically as the additional cost of storage capacity and overcapacity.[17] Therefore, the storage and overcapacity costs for the typical daily load balancing or shifting and system integration[51] are not considered. Furthermore, costs related to battery charging are assumed to be negligible. Finally, only technology-specific average capacity factors are considered as the target generation is expected to be maintained over at least 15 years with the greater resource variability given in the long-duration weather data set.

The technology LCOE comparison for achieving net-zero CO_2 emissions in 2030, agnostic of policy, is based on two fossil-fuel EGU configurations: One is configured as a 650 MW_{gross} subcritical CFEGU and the other as an NGCC plant of comparable capacity. Both of these sources operate at approximately a 60% capacity factor, based upon the U.S. Energy Information Administration's (EIA) projection of coal-fired capacity factor in 2030,[60] to achieve the target generation. The performance and cost projections for these EGUs are derived with the Integrated Environmental Control Model (IECM) version 11.2, a power-plant simulation tool developed by Carnegie Mellon University,[61] using region-specific inputs for the Midwest and national fuel prices projected for 2030 from the EIA's 2020 Annual Energy Outlook.[60] The emission intensity and fuel cost estimates derived from this IECM model are adjusted exogenously with fuel-specific regressions to account for the impact of the capacity factor deviation from maximum load on the plant net heat-rate (see SI Section S7.2.3 for details).

Options for reducing emissions from these baseline plants (while maintaining net generation) include cofiring with bioenergy, adding CCS, and building new fossil-fuel EGUs at the same capacity that are equipped with CCS. The performance and cost estimates for the EGUs fitted with these options are also simulated in the IECM or determined exogenously and added to the IECM output. When necessary, DACS is employed in conjunction with these options to achieve net-zero emissions from fossil-fuel plants, the removal rate and estimated cost of which is derived from a National Academies of Science, Engineering, and Medicine report[62] and

is studied parametrically with an initial estimate of $212 tonne^{-1}. Using substantially higher cost estimates do not alter these conclusions (see SI Section S7.3 for emissions reduction details).

Solar, wind, nuclear, and dedicated BE without and with CCS generation technologies serve as zero-carbon and negative emissions alternatives to net-zero emissions with these fossil-fuel technologies. Solar and wind capacities are added to equal the target net generation given their associated national capacity factors[63] with costs determined in the National Renewable Energy Laboratory 2019 Annual Technology Baseline report.[64] Two types of nuclear technologies are evaluated: SMR and advanced light water (see SI Section S7.4.2 for cost details). The capacity factors for both reactor types are held constant at 90% to simulate current operation of nuclear power plants in the U.S., even though SMR operations are capable of flexible operation and larger facilities in Europe are operated as such.[65] However, the SMR capacity is adjusted to maintain the target generation at this capacity factor. While both types of reactors are modeled, the advanced light-water reactor results are omitted since the results are within US$1 MWh^{-1} of those for the SMR.

The capacity for the dedicated BE EGU, modeled by the EIA,[66] is also adjusted to provide the target generation at a 60% capacity factor.[35,38] To determine the adjusted capital cost, the power rule (SI eq 20) is applied to the EIA's capital cost estimate. This EGU is modeled in the IECM for additional capital and O&M costs when equipped with CCS at 90% capture for negative emissions. [The dedicated BE and BECCS EGU capacities can also be adjusted for higher utilization so that the target generation is achieved at 90% capacity factor. In this case, both units advance in merit order but do not alter the conclusion. LCOE results for this case are shown in SI Figure S10 as a comparison to Figure 1.]

While fossil fuel, BE, and nuclear generation are dispatchable technologies and are capable of resource adequacy, variable renewable technologies on their own may not be capable of reliably supplying the grid for periods of high demand when the realized capacity factors are not adequate and a large
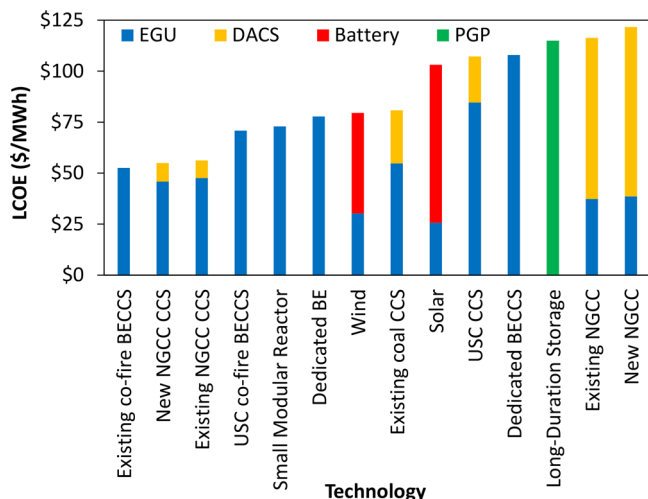
Figure 1. LCOE for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Four-hour duration battery storage is used for VRE technologies. Existing coal with DACS and existing cofire BE options are not shown because the LCOEs exceed US$160 MWh^{-1}.

portfolio of renewable resources that are temporally and geographically diverse is not available.[10,17,20,31,67] Additional renewable and/or energy storage capacities may be required to meet this requirement. The addition of these capacities in the model simulates the change to VRE LCOE as more VRE capacity is added to the system while this zero-carbon system is constrained to maintain adequacy.[51,68] To determine these costs, periods of renewable-energy resource intermittency requiring additional battery storage (from 0 to 40 h) are examined parametrically during which the target generation can be met by overbuilding capacity (by 0−50%) that will result in curtailment in resource excess conditions and/or adding storage from Li-ion batteries that are charged prior to curtailment or without cost from the grid, SI Table S17. In lieu of battery storage, LDS comprised of renewable generating capacity sufficient to meet demand *and* capable of producing hydrogen from dedicated or surplus generation in a PGP generation scenario is also evaluated as a standalone generation source. A US$108−123 MWh^{-1} cost range for the combination of these technologies,[18] at a median cost of $116 MWh^{-1}, is assumed for comparison to renewable curtailment and battery storage options, and the net-zero fossil-fuel equivalents for this analysis.

Fossil-fuel technologies configured for net-zero emissions and the zero-carbon and NET technologies configured to provide adequate grid reliability are evaluated on a cost basis that includes 45Q tax credits for carbon sequestration. The general form of the LCOE equation used to make the least-cost configuration decisions for the net-zero fossil fuel and bioenergy configurations is given in eq 1, and the equation for renewable generation inclusive of battery storage is shown in eq 2. The general LCOE equation for nuclear generation takes the form of eq 1 without the CO_2 emissions term. Details for LCOE components particular to a technology configuration are given in SI Section S7.

$$\text{LCOE}_i = \frac{CC_i \times \text{FCF}_i + \text{FOM}_i}{G_{\text{net},i}} + \text{VOM}_{\text{fuel},i} + \text{VOM}_{\text{nonfuel},i}$$
$$+ \frac{(\text{Seq} - \text{TC}_i)m_{\text{CCS},i} + (\text{DAC} + \text{Seq} - \text{TC}_i)m_{\text{DAC},i}}{G_{\text{net},i}} \quad (1)$$

where LCOE is the levelized cost of electricity (US$ MWh^{-1}), CC is the EGU capital cost (US$), FCF is the fixed charge factor (fraction), FOM is the annual fixed operation and maintenance cost for the EGU (US$), G_{net} is the EGU target annual net-generation (MWh), VOM_{fuel} is the variable operation and maintenance cost related to fuel (US$ MWh^{-1}), $\text{VOM}_{\text{nonfuel}}$ is the nonfuel variable operation and maintenance cost (US$ MWh^{-1}), C_{bat} is the total cost of the battery system (US$), TC is the 45Q emission tax credit level proportionally derated for the EGU economic lifetime (US$ tonne^{-1}), Seq is the CO_2 storage cost (US$ tonne^{-1}), m_{CCS} is the annual CO_2 emissions mass captured with CCS (tonnes), DACS is the direct air capture cost (US$ tonne^{-1}), m_{DAC} is the annual CO_2 emissions mass captured with DACS (tonnes), and i is the subscript specific for the generation technology and project life.

$$\text{LCOE}_i = \frac{1000(\text{Cap}_i)((CC_i)(\text{FCF}_i) + \text{FOM}_i) + C_{\text{bat},i}}{G_{\text{net},i}} \quad (2)$$

where LCOE is the levelized cost of electricity for the renewable source (US$ MWh^{-1}), CC is the capital cost of the

renewable source (US\$ kW^{-1}), Cap is the renewable source capacity (MW), FCF is the fixed charge factor (fraction), FOM is the fixed operation and maintenance cost for the renewable source (US\$ kW^{-1}), C_{bat} is the annual cost for the batteries (US\$), G_{net} is the target annual net-generation equivalent to that in eq 1 (MWh), 1000 is a conversion factor, and i is the subscript indicating solar or wind capacity.

RESULTS AND DISCUSSION

Cost Ranking of Technology Choices for Resource Adequacy. In a cost-based model without a resource adequacy constraint or with low VRE penetration, VRE technologies alone will have the lowest LCOE. However, satisfying the resource adequacy constraint during generation shortfall conditions increases the costs of VRE technologies to such a degree that they become noncompetitive, SI Figure S1. When low/no generation periods for VRE capacity require battery storage, solar and wind generation becomes noncompetitive to multiple fossil-fuel technologies. With a requirement of four hours of battery storage duration, Figure 1, the LCOE of VRE options are dominated by several net-zero fossil-fuel options while maintaining the target generation: 20% cofire BECCS with existing subcritical and new ultra-supercritical (USC) coal with CCS, and existing and new NGCC plants equipped with CCS and relying upon DACS to remove the remaining emissions. Such options are even preferred to the net-zero and zero-carbon technologies that are typically modeled: dedicated BE and BECCS, SMR, and LDS (even at the low-LCOE estimate). This dominance at a small battery requirement suggests that at the current 45Q levels (US\$50 tonne^{-1} tax credit for immediately sequestered CO_2, applicable for 12 years), decarbonized fossil-fuel EGUs have an important role in the carbon transition as VRE penetration reaches high penetration levels that require battery storage of almost any size.

While cofire BECCS is the LCOE-dominant option for the default conditions in this analysis, the LCOE for the fossil-fuel alternative of using NGCC with CCS and DACS—be it constructing a new plant or retrofitting an existing plant—is within US\$4 MWh^{-1} (7%) of the least-cost option. DACS removal cost and the EIA's projected fuel prices are significant uncertainties in these LCOE calculations.[36] A parametric analysis of DACS cost and the ratio of a variable natural gas (NG) price relative to the default cofire fuel prices (i.e., a combination of coal and bioenergy), Figure 2, shows that technology choice is more sensitive to the ratio of the projected fuel prices (further analysis is shown in SI Figure S2). This ratio must decrease by 6% from the default fuel-price ratio of 1.65 and the DACS cost estimate must decrease by 15% before cofire BECCS is not the preferred choice. This change in the fuel-price ratio is equivalent to the realized natural gas price decreasing by 6% or the realized coal price increasing by 9%, given the 20% cofire by energy-basis condition and a fixed bioenergy price. Since the cofire fuel is a composite, the projected bioenergy price needs to increase by over 20% for the 6% ratio reduction to occur, ceteris paribus. Given the uncertainties, such values in projected and realized natural gas and coal prices are possible.[69] Therefore, financial regret over the technology choice (defined as the difference in LCOE between the generation option chosen ex ante based upon the least-cost for the expected fuel prices and costs, and the corresponding ex post option with the projected fuel price and cost uncertainties) is more likely to come from variations
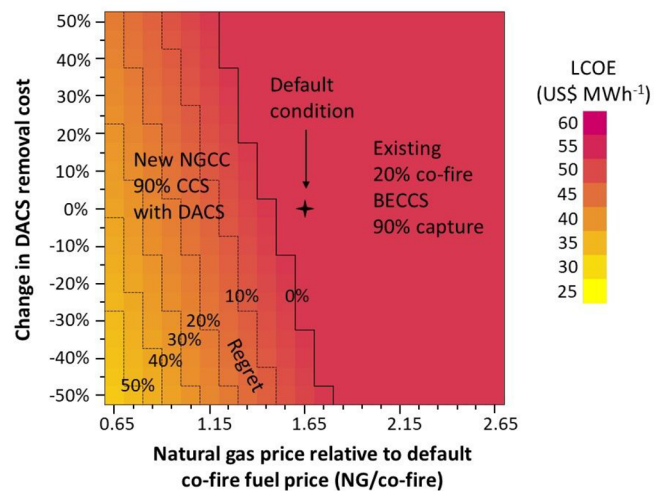

Figure 2. LCOE and regret based upon dominant generation technology choice for DACS removal cost and natural gas price relative to default cofire fuel price ranges with net-zero for fossil fleet, while fossil is meeting target generation. Regret is expressed as the percent difference between the realized LCOE and the LCOE for the ex-ante choice.

in fuel prices and greater emphasis should be placed on estimating these variables.

Under the current 45Q policy, cofire BECCS is the least-cost generation option. This is due in part to the incentives that favor EGUs that emit large amounts of CO_2 and have a remaining operational life that is aligned with the 12-year duration of the credits. A fully depreciated CFEGU with 15 years of remaining operation is well-aligned with such a policy, as the annual capital cost expenditure is the lowest of all options except for dedicated BE, SI Table S1. The policy can be tailored to further incentivize other fossil-fuel generation sources by modifying the credit level and duration. When the 45Q credit and duration are segregated by fuel and capture technology type (i.e., the CFEGUs and DACS technology credits are maintained at the current level), the credit level and/or duration must be increased before other fuel types dominate, Figure 3.

Here, natural gas dominates because the VOM and capital costs are lower than those for the other carbon-based alternatives. In general, the credit duration must be increased beyond 15 years before existing assets that are not fully depreciated dominate. Therefore, retrofitting existing NGCC assets with CCS and DACS at the base costs is the net-zero technology next-best to retrofitted existing cofire BECCS and can be as robust of a solution, SI Figure S3. Furthermore, dedicated BECCS can be the least-cost solution if greater credit levels for longer durations are applied to offset the greater VOM costs, SI Figure S4.

These characteristics suggest that any modifications to the 45Q incentives should consider alignment between project life and the credit duration and should incentivize NET differently from net-zero emission technologies, as the latter are less expensive alternatives. Conversely, increasing the incentives for DACS while leaving the incentives for CCS at the current 45Q levels does not promote CCS-reliant generation, due to the higher DACS removal cost, unless the credit level is greater than US\$145 tonne^{-1}, SI Figure S5. Therefore, a recent proposal in the U.S. Senate[70] to increase the DACS credit level to \$120 tonne^{-1} (2019 dollars) with 12-year duration may be
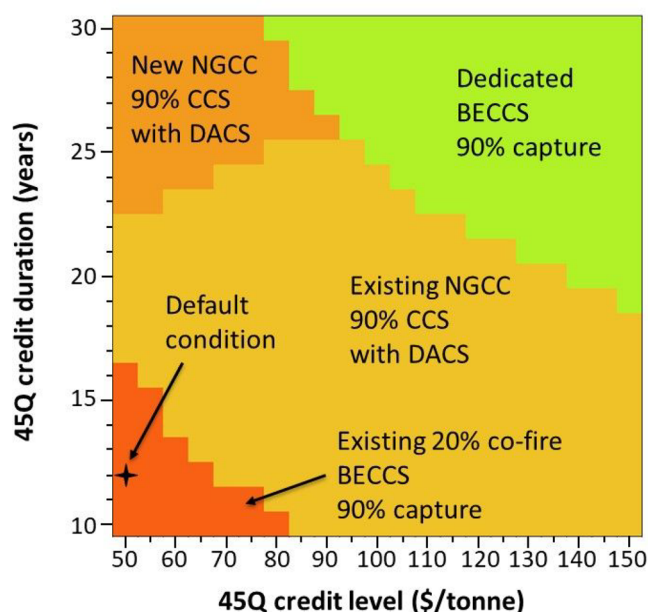
Figure 3. Dominant generation technology choice from modifying 45Q credit level and duration for immediate storage and constraining for net-zero emissions. Current 45Q policy employed for coal-fired CCS and DACS. Battery storage requirement is four hours for VRE technologies.

insufficient to promote such use for new plants. Similarly, a recent proposal in the U.S. House[71] to increase the credit level to $85 tonne^{-1} (2019 dollars) with 20-year duration, may only further existing cofired BECCS deployment rather than promote new construction with other fuel types.

Net-Zero Technology Dominance. Adding a resource adequacy constraint to the LCOE cost minimization model by requiring each EGU technology to produce the same net generation highlights the importance of firm capacity when there is high VRE penetration.[18−21,23−26,35] While SMR capacity is sized to produce the requisite generation at a 90% capacity factor, the other non-VRE generation technologies do so at capacity factors from 60 to 72% (SI Table S2). If the net-zero EGUs can operate at flexible loads, cofire BECCS and NGCC CCS with DACS are still the preferred options for firm capacity unless battery capital costs decline by 20%, SI Figure S6. Further capital cost reductions increase the minimum capacity factor at which the fossil-fuel EGUs are preferred and increase the allowable VRE-shortfall battery requirement beyond the 4-h duration used in this analysis, SI Figure S7a. However, even at a 10-fold decrease in battery capital costs, net-zero EGUs at the target-generation capacity factors are still preferred to VREs with a 10-h storage requirement, SI Figure S7b. Therefore, if batteries are to be a resource-intermittency solution for the 2035 decarbonization path,[72] the target for future battery costs must be reduced dramatically, SI Figure S7c.[17−19,26,59,73]

Technology choice for the resource-intermittency solution can also depend upon the sensitivity to other capital and O&M costs. At the 4-h battery duration, battery cost is so expensive that it is irrelevant to the choice between renewable technology with storage and the net-zero fossil-fuel alternatives. Instead, the choice is driven by the cofire fuel price and the DACS removal cost, SI Figure S8. The choice between SMR and the net-zero technologies is not as clear. Because the SMR capacity

is sized for a higher capacity factor (baseload operation) for this analysis, the SMR technology dominates the alternatives when the capacity factors for the net-zero options are analyzed below the load-following capacity factors for the target generation, SI Figure S6. However, the high capital cost for the SMR demotes this technology relative to the others when the target-generation capacity factors are used, unless the realized capital cost is more than 40% below the projected cost, SI Figure S9. Therefore, net-zero alternatives will continue to dominate SMR technology in load-following flexible operation, unless a large reduction in SMR capital cost is realized.

The dominance of net-zero technologies at load-following capacity factors suggests a further false equivalence. While VRE and SMR technologies operate at the target-generation capacity factors, other net-zero and zero-carbon emissions are governed by the target generation. In a competitive market—even one that restricts CO_2 emissions—the capacity factors would be governed by each technology's position in the merit order. This is an attribute that is better determined by dispatch models through matching the temporal-dependence of demand with that of the generation technologies through availability, VOM cost, and transmission, reliability and flexibility constraints. Increasing the capacity factor does decrease the LCOE for the net-zero technologies, despite the increasing DACS-related cost to achieve net-zero emissions; however, the VOM costs establishing merit order for these technologies are higher than those for VRE and SMR EGUs (SI Figure S4 and Table S3). It is only with the 45Q incentives that the high VOM expenses can be offset, absent mechanisms such as feed-in tariffs and renewable portfolio standards, to yield zero or negative marginal-production costs.

For cofire BECSS, the resulting tax credits from the current 45Q are great enough to produce a negative VOM, indicating that cofire BECSS should be first in the merit order and be operated in a dispatch model at a capacity factor greater than required to meet the target generation. The credits are insufficient for dedicated BECCS and the other technologies to change the merit order relative to VRE technologies: For dedicated BECCS to supplant VRE generation in economic dispatch, the credit level must be increased to more than US $160 tonne^{-1}, for a 12-year duration. The net-zero NGCC EGUs (with and without CCS) lag VRE and SMR technologies even with the modified 45Q levels shown in Figure S3 (US$65 tonne^{-1} for 15-year duration). Therefore, NGCC technologies may be load-following (and in a dispatch model have a capacity factor lower than that assigned to meet the target generation) unless a higher credit level and longer duration, or other mechanisms, are present to promote these technologies for greater utilization. For this to occur, the credit level must exceed US$95 tonne^{-1} for a 20-year duration for an existing plant. Yet even without this higher credit level, the merit order for NGCC CCS technologies with the current 45Q is higher than that for dedicated BE or BECCS technologies. This indicates that the combination of NGCC CCS and DACS not only dominates these dedicated options, but also that coupling NGCC CCS with DACS may be a preferred solution for the remaining CO_2 emissions to replacing the net generation from the plant with that from dedicated BECCS.

Fleet-Wide Insights for 45Q Application. As VRE capacity is not observed as the least-cost solution, fossil-fuel alternatives with CCS, DACS, and 45Q incentives should be considered as net-zero options in capacity-expansion dispatch models. Although the use of models with simplified dispatch

assumptions has been shown to underestimate the costs of VRE integration at high penetration levels[68] and models based on LCOE have been shown to promote the lower cost VRE technologies because system integration costs[51] and availability relative to demand are neglected, we note that VRE capacity is not included in the least-cost solution *even when its costs may be underestimated.* By making first-pass simplifying assumptions regarding the full extent of VRE load balancing and integration costs and the dynamic response of the alternative capacity, we are able to consider a broader range of available options for the 2030 fossil-fuel fleet than would otherwise be possible in more computationally intensive models. Subsequent analysis with full dispatch models may then be performed in more detail on the specific areas of interest identified by our modeling.

Achieving a power sector with high VRE penetration, be it through a CO_2 price policy or a net-zero mandate, will likely require political will as well as resource adequacy. Currently, there is no indication of such for these policies without protracted legal battles, but there is bipartisan political will to support incentives for capturing and storing carbon emissions.[39,70,71] While current and modified 45Q incentives alone have been shown unable to achieve a net-zero power sector[47] through promotion of retrofitted CCS for all existing fossil-fuel EGUs and additional capacity equipped with this capability, such an approach may decrease the resistance to such policies. This resource adequacy analysis to bound the capacity options for a net-zero power sector illustrates the various interdependencies of resource capital cost and availability, and fuel type and asset age that 45Q must balance to successfully promote carbon capture.

It further illustrates the role that such an incentive can play in decarbonizing the U.S. power sector without further decarbonization policies. When the modeling is expanded to a region-specific fleet of existing fossil-fuel EGUs and future capacity additions, the combination of credit level and duration within this broad set of technology options should be determined such that it achieves the required generation from net-zero technologies at a minimum total system cost. This analysis should be inclusive of resource intermittency when there is already high VRE penetration, as not all existing CFEGUs or NGCC plants are suitable for CCS retrofit and site-specific attributes are important.[47,74] Expanded to the national level, this may require as much as 20% of U.S. generation be produced by net-zero technologies to minimize the exponential rise in system costs from curtailment and storage solutions in a generation portfolio with high VRE penetrations.[17,22,25]

Promotion of existing and new assets to build a net-zero power sector in 2035 that can bridge to a net-zero economy in 2050[72] will require extending the 45Q eligibility construction-start date beyond 2030[70] and lengthening the credit duration. Such actions would make the economic proposition for higher capital cost and newer assets more attractive to investors, Table S1. In concert, the credit level should be set to adequately decrease the LCOE and VOM such that the CCS and DACS technologies are promoted relative to other options. These parameters will need to be set separately for coal and natural gas, as the carbon content, technology heat rates, and existing fleet ages differ. Notwithstanding this, such modifications in credit level and duration have little impact on DACS, because promoting this technology comes from coupling it with already low emission NGCC CCS to achieve net-zero generation, SI Table S4. This reliance may accelerate

adoption of DACS and decrease the cost for future applications.[62,73,75,76] Similarly, increasing credit levels for immediate sequestration, rather than for EOR, will drive CCS and DACS deployment to be applied for deeper decarbonization. This may allow new applications and markets to develop for CO_2 utilization as an input for bioenergy or conversion to synthetic fuels for other sectors[44,47,77,78] and enable these net-zero technologies to become viable without the 45Q incentives.

The dependence of commercially available CCS on DACS to achieve net-zero emissions will diminish as future CCS capture rates approach 99% and reduce the residual emissions load for DACS. If these higher rates are technically and economically feasible (see SI Section S6), additional existing and new fossil-fuel assets that require DACS may be promoted over zero-carbon technologies under an adequacy constraint, Figure 4. As our analysis makes clear, deeper CCS coupled
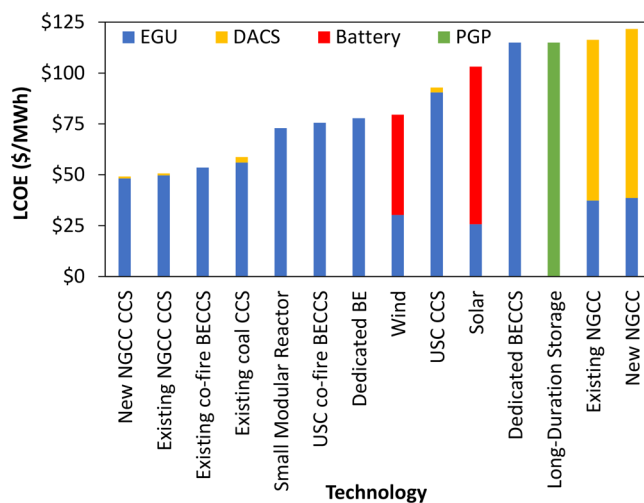
Figure 4. 99% capture rate rank order LCOE for generation technology options producing net-zero emissions and zero-carbon electricity while maintaining target generation. Four-hour duration battery storage is used for VRE technologies. Existing coal with DACS and existing cofire BE options are not shown because the LCOEs exceed $160/MWh.

with a net-zero technology option and sequestration incentives can play a significant role in the near-term transition to a net-zero power sector in 2035.

Policy Insights. Pursuing these technologies with policy incentives does not come without risks. In addition to poor public acceptance of carbon-removal technologies,[35,79,80] their large-scale deployment will require regional pipeline backbones to make storage options cost-effective.[6,43,81,82] Furthermore, these options have inherent technology issues.[35,56,66,67,81,83,84] Specific concerns for BECCS include availability and additional stress on land, water, and forest resources from competition with demands from food supply, biodiversity, other forms of bioenergy, and other sequestration methods.[20,56,62,81,85] CCS and DACS expansion may be restricted by land, water, and storage constraints, while DACS expansion may be further restricted by the high electrical and thermal requirements.[38,47,62,77,81,83,84] Additionally, methane leakage issues for NGCC CCS must be addressed to dissuade concerns. Finally, some may consider that policies incentivizing these net-zero technologies pose a moral hazard from the extension of fossil fuel use. Yet, there is a need for such firm capacity

technologies until LDS costs fall below the least-cost estimates and storage costs are dramatically reduced. As climate change progresses, weather extremes are expected to be more severe[17,62,86,87] and put additional stress on the generation-demand imbalance, possibly hindering or delaying high VRE penetration because of resource adequacy concerns, higher capital costs, and the development of other solutions.

The emergence in this analysis of existing and new cofire BECCS and NGCC CCS with DACS as lower-cost, firm-capacity solutions for these imbalances (at LCOEs lower than more conventional options such as SMR, LDS, and additional storage) indicates the importance of these fossil-fuel assets. Therefore, policymakers, and capacity-expansion modelers and planners should consider for providing the resource adequacy required to achieve a net-zero grid and economy at a lower total system cost through a diverse portfolio of technologies. CCS and DACS are both seen as highly necessary technologies to meet the 1.5 °C threshold;[1–3,62] therefore, it is important to promote these technologies with incentives[37,38,44,88] in the power sector now to avoid delays in using them in industrial and other sectors to achieve a net-zero economy by 2050. Furthermore, the finding that cofire BECCS can be on the least-cost path to net-zero emissions in the U.S. is a potentially faster decarbonization path forward for the U.S. Mountain West subregion that is coal-rich and natural-gas-poor. It is even faster for regions bereft of strong solar (New England) or wind (South Atlantic) resources. Such an option may also be a decarbonization path for similar-situated regions in developing nations that are heavily reliant on coal, such as in China[89] and India.[90]

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.1c06661.

Additional text, tables, and figures (PDF)

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