RESOURCES *for the* FUTURE

Benefits of Energy Technology Innovation

Part 1: Power Sector Modeling Results

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About the Authors

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Environmental Electricity Simulation Tool (E4ST). The current main E4ST development team consists of authors Shawhan, Funke, and Witkin. Ray D. Zimmerman, Paul Picciano, William D. Schulze, and Daniel Tylavsky are the other members of the current E4ST team. Past additional developers of E4ST include Biao Mao, Carlos Murillo-Sanchez, John T. Taber, Jubo Yan, Charles Marquet, Di Shi, Yujia Zhu, Doug Mitarotonda, Yingying Qi, Nan Li, Zamiyad Dar, Andrew Kindle, Robert J. Thomas, and Richard E. Schuler.

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Executive Summary

Policies and funding programs that support research, development, and demonstration (RD&D) for advanced energy technologies are critical elements of an overall strategy for advancing clean energy and decarbonization of the economy. In contrast to direct emissions reduction and technology deployment policies (e.g., standards, financial incentives), however, there have been limited efforts to quantitatively assess the impacts of proposed energy RD&D policies to help inform decisions. An important reason for this information gap is that it has been difficult to estimate (1) how much proposed policies will advance the technologies of interest and (2) how much such technology advances will be worth to society.

This study addresses the latter of these questions by estimating the net benefits to society that come from reducing the costs of five different advanced energy technologies. (We refer to these five technologies as the AETs). The AETs are each included in the American Energy Innovation Act (AEIA), which has been introduced in the US Senate, and are as follows:

- advanced nuclear fission power generation (hereafter, "nuclear")
- natural gas power generation with carbon capture and sequestration (NG-CCS)
- enhanced geothermal power generation ("geothermal")
- grid-connected diurnal electricity storage ("storage")
- direct air capture of carbon dioxide (DAC)

This study estimates the net benefits of reducing the costs of these AETs under scenarios with and without a national clean electricity standard. The components of total net benefits include reduced electricity consumer bills, changes in generator profits and government revenue, health benefits from reduced air pollution, and climate benefits from reduced greenhouse gas emissions. We will refer to the sum of the estimated dollar values of all these impacts as the "net benefits." Sometimes one or more of the components is negative. When that is the case, it reduces the net benefits. However, the term "net benefits," as we use it here, does not account for the costs of the technology innovation itself, such as RD&D spending. Instead, one can compare the net benefits estimated here with the associated RD&D spending necessary to achieve those cost reductions, in order to get an overall sense of net value to society.

Analytic Approach

This assessment employs the *Engineering, Economic, and Environmental Electricity Simulation Tool* (E4ST), a highly realistic simulation model of the US electric power sector. We use the model to determine how different magnitudes of cost reduction for each AET would influence its deployment in the electricity system, as well as the consequences of that deployment. E4ST predicts construction and retirement of grid-serving electricity generating units and hourly operation of the grid and the generating units in future years, under policies, prices, and other conditions specified by the user. The model begins with a highly detailed representation of the current grid, generating units, electricity demand, and hourly, location-by-location wind and solar data. Among the model's outputs are hourly locational electricity prices; emissions of carbon dioxide (CO_2), methane, sulfur dioxide (SO_2), and nitrogen oxides (NO_x); and all the components of total net benefits noted above.

The five AETs are incorporated in E4ST using high-quality data and an emphasis on representing how they will respond to different potential circumstances. For example, for any given NG-CCS or DAC plant, the cost of transporting and sequestering carbon dioxide is determined by a network model of the potential future carbon dioxide transportation system and of the estimated supply curve for sequestration in each state or offshore area with high sequestration potential. For enhanced geothermal, we use the model of enhanced geothermal supply curves in 134 US zones from the National Renewable Energy Laboratory (NREL). For diurnal storage, we explicitly model optimal charging and discharging for 52 representative hours and 16 representative days. New nuclear plants can be built at only about 300 locations that pass a suitability screen.

For each AET, we simulate five cost levels while holding the costs of the other four AETs constant. The five cost levels are the four shown in Table ES-1 plus a fifth which is higher than "high" and is sufficiently high that none of that technology can be built. We simulate the year 2050, and all cost levels shown are projections for 2050. For each technology, "high" is a projection, based on a highly credible source in the literature, of the cost of each technology in 2050 if it undergoes only minimal learning-by-doing.[1] "Low" cost is based on the lowest estimate of potential future cost we found from a highly credible source. The low cost tends to include substantial learning through deployment in addition to RD&D. Appendix B gives the sources of these estimates. "Medium" cost is halfway in between the high and low costs. As a further sensitivity, "very low" cost is uniformly 12.5 percent below low cost and can be motivated as a moderate degree of additional learning beyond low cost (see, e.g., Larsen et al. (2019), in which 12.5% is the central estimate of cost reduction from each doubling of cumulative capacity built).

[1]For storage, the "high" cost level assumes some commercial deployment. For the other four AETs, high costs do not assume any commercial deployment. For all AETs except geothermal, the high 2050 cost is still lower than current cost due to assumed cost reductions resulting from a baseline amount of RD&D.

Note that the high and low cost assumptions assessed for each technology are only rough indicators of how levelized costs might evolve with differing magnitudes of RD&D and deployment. This is partly because it is impossible to know with certainty how easily the cost of each technology can be reduced and partly because our low-cost projections for different technologies come from different sources, since no single source provides suitable projections for all the AETs.

Table ES-1. Technology levelized cost assumptions for 2050 (in 2020$)[a]

Technology	High	Medium	Low	Very low	Capacity factor[b]
Nuclear ($/MWh)	96	70	44	39	0.92
NG-CCS ($/MWh)[c]	68	58	49	43	0.80
Geothermal ($/MWh)[d]	560	313	58	50	0.85
Storage ($/MWh discharged)[e]	59	41	23	20	0.17
DAC ($/short ton captured)[c,f]	158	104	51	45	0.95

[a] All costs shown are for the year 2050. All dollar values in this study are in 2020$. For a breakdown of the cost assumptions, including assumed fixed costs, variable costs, and capital costs, see Appendix B.
[b] Capacity factors shown here are used for calculating levelized costs and are equal to average hourly output divided by maximum possible hourly output (nameplate capacity). Actual capacity factors are determined by the model.
[c] Levelized costs for NG-CCS and DAC do not include transport and sequestration costs of the captured CO_2. These costs vary and can be positive or negative depending on location and sequestration method. See Appendix B8. for details.
[d] Geothermal costs in E4ST vary by location based on resource quality. These geothermal costs are for a resource that is 250°C at 6 kilometers deep, which is a high quality resource class that is not rare.
[e] Levelized cost of storage does not include the cost of the electricity used to charge the storage system.
[f] Levelized cost of capture for DAC assumes a constant electricity price of $45/MWh. The actual electricity price is endogenous in E4ST.

In addition to varying the cost assumptions for each AET, we also consider two different background policy settings that vary the degree of assumed clean energy required in the power sector in 2050. We can thereby estimate how the expected net benefits of AET cost reductions vary depending on the stringency of policies that drive clean power deployment and emissions reductions. For instance, low-cost AETs are likely to be more valuable when policies call for rapid clean power deployment and decarbonization of the power sector than otherwise. In our power sector modeling, the two policy scenarios we simulate are (1) one without any new environmental policies by the US government and (2) one with a national clean electricity standard (CES) mandating that generation from "clean" sources must equal 100 percent of US retail electricity sales by 2050.[2] We

[2] In our power sector modeling, we use a CES rather than a carbon tax or a carbon cap because a CES approach currently has more attention as a power sector–specific policy option. In the CES, generators earn credit in proportion to how far their CO_2-equivalent emissions are below 0.82 metric tons (0.9 short tons) per megawatt-hour (MWh). The emissions counted are smokestack CO_2 emissions and estimated upstream methane emissions associated with natural gas and coal extraction and transportation. Appendix

henceforth refer to these two scenarios as the "Without CES" and "With CES" scenarios, respectively.

Net Benefits of Technology Cost Reductions

Figure ES-1 shows projected annual net benefits to the United States of each of the power-generating AETs (nuclear, NG-CCS, geothermal), as a function of its cost in 2050, holding other assumptions constant. For example, the nuclear curves in Figure ES-1 show how societal net benefits are affected by varying the cost of nuclear power from very high (such that no new nuclear can be built) to very low. In these scenarios, the costs of the other AETs are held at their medium levels. The top panel shows the results assuming no national CES is in place, while the bottom panel assumes there is a national CES.

For each of these three technologies, as with all technologies, there is a levelized cost of energy above which the technology provides little or no benefit to society because it is not cost-competitive to deploy, given other available options. We estimate that this cost level is roughly $60 per MWh without a national CES and $65-80 per MWh with a CES.[3] The costs at which AETs become competitive vary by technology, but consistently are higher with a national CES than without (see Section 5.2.2. for details). At costs sufficiently below these levels, each of the technologies becomes widely cost-competitive and produces billions of dollars of net benefits per year. The top panel of Figure ES-1 shows that this is the outcome even without a national CES, while the bottom panel shows even larger benefits of clean power innovation if there is a national CES.

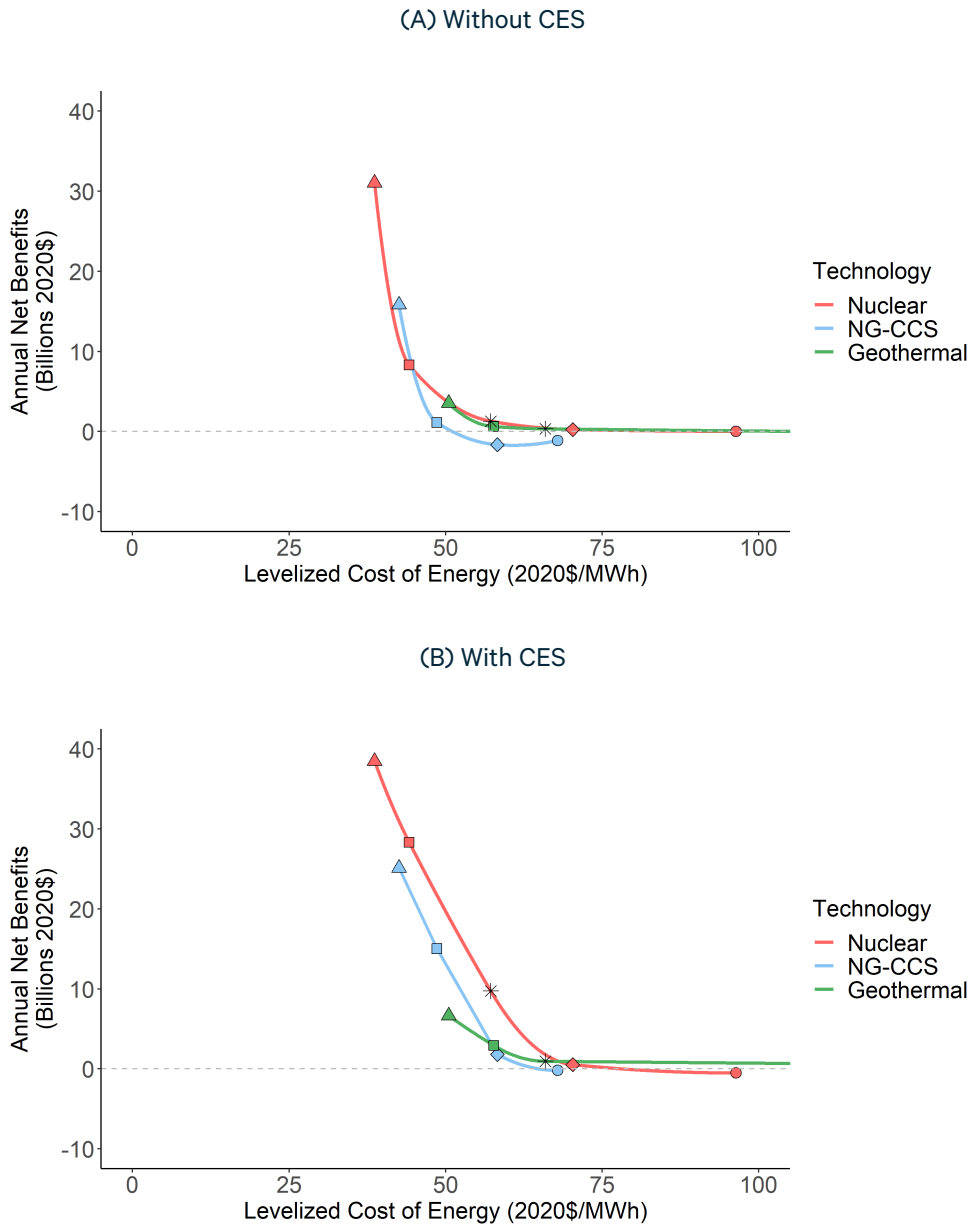
In the cost ranges for which the nuclear, NG-CCS, and geothermal benefit curves overlap, their net benefits are similar. The maximum net benefit shown for each technology is thus partly a function of the lowest cost simulated.

Focusing on nuclear, for example, at its high and medium costs, the net benefits of new nuclear are near zero because few nuclear plants are built, and the costs of those that are built are approximately equal to their benefits. At its low or very low costs, however, the net benefits of nuclear are approximately $8 billion and $31 billion per year, respectively, assuming no national CES (Panel A). With a national CES (Panel B), the net benefits of nuclear at its low and very low costs are substantially higher, at approximately $28 billion and $38 billion, respectively. The net benefits from NG-CCS and geothermal follow a

C2. describes the CES policy in greater detail.

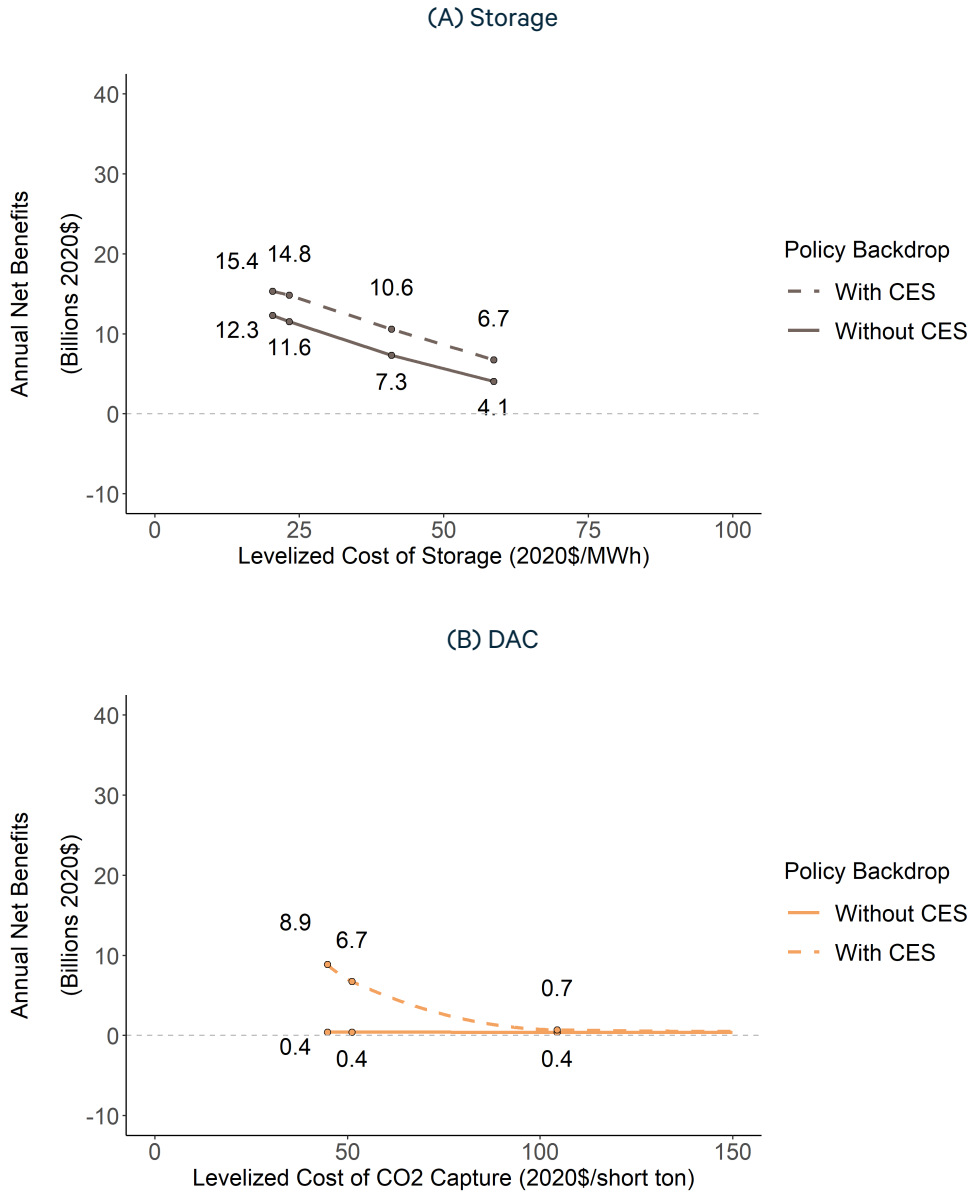
[3]Detailed numerical results, including these, depend on the specific assumptions of the model. We strive to use central tendencies for input values. Natural gas price assumptions are influential and our average natural gas price in each region is from the 2019 Annual Energy Outlook's "High Oil and Gas Resource and Technology" case, which matches natural gas futures prices better than the EIA "Reference" case prices do.

Figure ES-1. Annual net benefits of cost reductions for each technology, assuming medium costs for all other technologies.



Note: For each technology, the net benefits are relative to the situation in which that technology is not deployed and all other AETs are at their medium cost. Point shapes indicate the various cost levels for each AET: (circle) high cost, (diamond) medium cost, (square) low cost, and (triangle) very low cost. For geothermal and nuclear power, we included one extra cost between the medium and low costs to better estimate the turning point at which the technology becomes competitive. This additional cost level is marked with an asterisk. The high- and medium-cost cases for geothermal are not visible in the plot.

Figure ES-2. Annual net benefits of cost reductions for (A) diurnal storage and (B) DAC.



Note: For each technology, the net benefits are relative to the situation in which that technology is not deployed and all other AETs are at their medium cost. From right to left, the points correspond to the high, medium, low, and very low cost levels of storage and DAC, respectively. For DAC, the high cost level is not shown. Levelized cost of storage does not include the cost of the electricity used to charge the storage system.

similar pattern, but with a less steep slope in the cost range shown because in our model the costs of NG-CCS and geothermal vary more based on location than the costs of nuclear do.[4]

The slopes of the curves in Figure ES-1 (and ES-2) indicate the estimated net benefit per dollar of reduction of each technology's levelized cost per MWh. The steepest segment is for nuclear between low and very low costs, without a national CES. This is the steepest segment because, without a national CES, cost reductions within that range displace large amounts of conventional natural gas– and coal-fired generation and their associated harmful emissions. Within that nuclear cost range, the average benefit from a $1/MWh reduction in levelized cost is $4.1 billion annually.

Figure ES-2 shows similar benefit curves for storage and DAC. Storage is widely deployed under the various cost scenarios and provides billions of dollars of net benefits annually, even at its high cost and without a national CES. Consequently, storage cost reductions are projected to be beneficial even if they only attain the high cost levels, because solar and storage together become competitive with thermal generators, especially natural gas combined cycle. The net benefits of DAC in 2050 are $370 million to $420 million in the case with no national CES, increasing within that range as its cost decreases. In that case, DAC is used in the state with the most stringent emissions policy, which is a net-zero limit on in-state power sector CO_2e emissions. In that state, DAC enables NG-CCS and coal CCS generation, offsetting the resulting emissions. In the scenarios with a national CES, the benefits of DAC increase at lower levelized costs. As the cost of DAC decreases, it becomes competitive with other AETs for CES credits in multiple parts of the country.

Figure ES-3 shows a decomposition of the net benefits of reducing each AET's cost from medium to low individually, while holding other technologies at their medium costs. Furthermore, Table ES-2 and the rightmost column of Figure ES-3 show a similar decomposition of the net benefits resulting from reducing all AETs' costs from medium to low simultaneously. The figure shows the total net benefits with a short horizontal black line, and also divides them into five different benefit categories: electricity users (consumer savings), generator profits (electricity producers), government revenue, health benefits (SO_2 and NO_x emissions reductions), and climate benefits (CO_2 and methane emissions reductions). Panel A shows the scenario without a national CES, and Panel B shows the scenario with a CES.

[4] The negative benefits from NG-CCS at its high costs are a result of a simplifying assumption in our modeling for this project, that NG-CCS receives full credit in utility clean energy policies and in the California and New Mexico CES policies. Hence NG-CCS can fully substitute for zero-emitting generation such as solar or nuclear. When this occurs, NG-CCS increases environmental damages because it still has some emissions. This leads to the observed negative net benefits, which are likely to be avoided in reality if those policies, once fully defined, give NG-CCS less than full credit.

Figure ES-3. Composition of annual net benefits in 2050 from reducing AET costs from medium to low.

Note: The first five columns show the net benefits of reducing one AET's cost from medium to low when all other AETs' costs remain medium. The last column shows the net benefits of reducing all the AETs' costs from medium to low. Electricity user benefits come from electric bill savings as a result of lower electricity prices. Climate benefits come from a decrease in greenhouse gas emissions, and health benefits result from changes in SO_x and NO_x pollution.

Table ES-2. Annual net benefits in 2050 of reducing all the AETs from their medium to low costs (billions of 2020$)

Net Benefit Component	Without CES	With CES
Electricity Users	10.1	45.4
Generator Profits	-4.0	-17.2
Government Revenue	-0.1	0.1
Climate	4.7	3.7
Health	1.2	-0.1
Net Total	11.9	32.0

Note: These values correspond to the rightmost column in Figure ES-3. See section 3.2.1. for information on how climate and health benefits are calculated.

Without a national CES, benefits are split between bill savings for electricity users and reduced emissions damage. The AET cost reductions lower prices proportionally more than they reduce generation costs, boosting electricity user savings and correspondingly reducing generator profits, as shown by the red segments below the zero axis.

With a national CES, climate benefits and health benefits from AET cost reductions together are in no case more than a seventh of total net benefits, reflecting the fact that with the national CES policy as a backdrop, emissions are largely determined by the CES (as are the associated emissions reduction benefits). Instead, benefits in the form of bill savings to electricity users dominate the AET innovation benefits, reflecting benefits from lower electricity rates due to lower costs of generating clean power. In other words, lower-cost AETs allow electric utilities to meet the national CES and state and utility clean energy requirements at lower cost. Nuclear, NG-CCS, and geothermal cost reductions lower prices proportionally more than they reduce generation costs, increasing electricity user savings and correspondingly reducing generator profits. The decrease in generator profits could be offset or reversed by policies from federal, state, and local governments. The ability of energy policies to affect profits is, for instance, shown by the national CES. We estimate that at high and medium AET costs, the CES has a positive impact on annual generator profits of $24 billion and $11 billion, respectively, which is not shown in Figure ES-3. Overall, the highest net benefits to society are achieved in cases where there is a national CES and the AETs are at their low cost levels.

Figure ES-3 and Table ES-2 just discussed present the net benefits of reducing the costs of the AETs from their medium to their low levels. We also calculated the net benefits of reducing them from their high to their low costs. The estimated annual net benefits of reducing the five AETs, together, from their high to their low costs are $15.9 billion without the national CES and $47.4 billion with the national CES. The reduction in retail electricity price from reducing the costs of the AETs from high to low results in average per-household electricity bill savings of $3 per month without the CES, and $16 per month with the CES. With the CES, low-cost AETs reduce the electricity price enough to almost entirely offset the increase in price caused by the CES.

To further illustrate the results, the maps in Figure ES-4 show where the AETs are built and operated under the scenarios with a national CES and with all AETs at their medium costs (top panel) or at their low costs (bottom panel). In addition to illustrating the widespread geographic deployment of the AETs in specific locations appropriate to each AET, the different cost scenarios illustrate how particular AETs (e.g., nuclear and NG-CCS) compete with one another and face deployment prospects that depend considerably on the relative cost of other clean energy technologies. (Note that the maps show only the AETs and not other technologies that either already exist or are newly built in the simulations.)

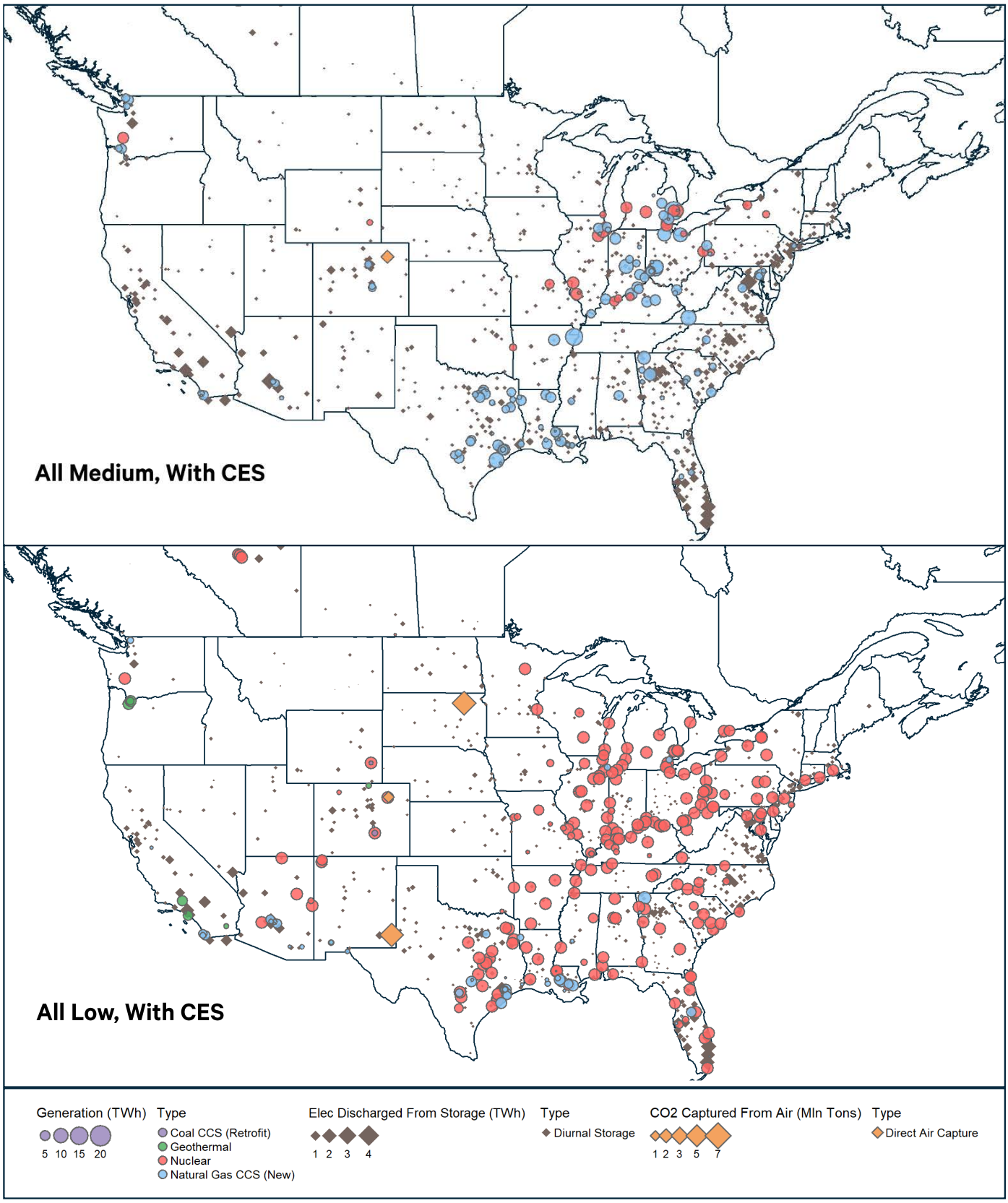
Our estimates of the net benefits of the AETs are conservative in several respects. First, cost reductions for the AETs can produce substantial benefits outside the power sector as well. For example, storage technologies can be deployed in transportation; direct air capture can offset emissions from difficult-to-decarbonize sectors such as industry and fuels; and geothermal, NG-CCS, and nuclear can provide heat for industry and buildings. These benefits outside the power sector are not captured in this study.

A parallel RFF report assesses the benefits of the broader application of one of the AETs, DAC, using an economy-wide computable general equilibrium model (see Hafstead (2020)). That analysis finds that the annual net benefits of DAC being at its low cost level (rather than its high level) would be $57 billion in 2050, assuming a cumulative carbon reduction target consistent with a pathway to 2050 emissions that are 80% below 2005 levels. These economy-wide benefits of DAC innovation are 9 times as large as the corresponding net benefits estimated solely in the power sector applications detailed in this report, which have a national CES as the policy backdrop.

Other factors also contribute to our estimates being conservative. The net benefits presented here are benefits only to the United States, and we omit the benefits from the use of the less costly AETs outside the country. The United States accounts for only about one-fifth of world power generation. In addition, we omit the benefits to the US economy of greater exports if the less costly advanced energy technologies are exported by US companies. Finally, geothermal and, to a lesser extent, nuclear allow for storing heat at times of low electricity demand and then generating more power at later times of high demand. This capability makes those technologies more valuable, but we have not yet represented this feature in the model.

The full report provides substantially more detail on the methodological approach and assumptions employed, as well as the results. In addition, a follow-on report will include experts' estimates of the effect of the AEIA on the costs of the five AETs considered here, so that one can better understand the degree to which the AEIA could help advance the innovation and cost reductions assessed in this report.

Figure ES-4. Locations of AETs built in the medium- and low–cost scenarios, with a national CES.



1. Introduction

The incentives for private companies to invest in RD&D that is worthwhile from a societal perspective fall far short of the net benefits to society because a large portion of those benefits accrues to others (Henderson and Newell, 2011). The failure of markets alone to provide socially optimal incentives in this situation can be addressed by public policy support for RD&D, through direct funding, tax incentives, and other approaches.

In contrast to direct emissions reduction and technology deployment policies (e.g., standards, financial incentives), however, there have been limited efforts to quantitatively assess the impacts of proposed energy RD&D policies to help inform decisions. An important reason for this information gap is that it has been difficult to estimate (1) how much proposed policies will advance the technologies of interest and (2) how much such technology advances will be worth to society.

In this study, we address the second of these questions by estimating the net benefits in 2050 of cost-reducing innovation for five emerging advanced energy technologies, which we refer to as the AETs:

- advanced nuclear fission power generation (hereafter, "nuclear")
- natural gas–fueled power generation with carbon capture and sequestration (NG-CCS)
- enhanced geothermal power generation ("geothermal")
- grid-connected diurnal electricity storage ("storage")
- direct air capture of carbon dioxide (DAC)

Each of these five AETs is included in proposed legislation that as of this writing has considerable bipartisan support in the US Congress: The American Energy Innovation Act (AEIA; S.B. 2657) and the Clean Economy Jobs and Innovation Act (H.R. 4447). The sponsors of the AEIA are the Republican chair and Democratic cochair of the US Senate Energy and Natural Resources Committee, Senator Lisa Murkowski and Senator Joe Manchin.

Each of the five AETs produce zero, low, or negative CO_2 emissions when they operate, and they are "firm" in the sense that they are more consistently able to operate up to their maximum potential than are wind- and solar-powered generators. In the context of a national or state deep decarbonization policy, these technologies can therefore complement wind and solar well. Without the AETs, the major firm, nonemitting generation resources available to complement wind and solar generation are just existing

nuclear and hydropower facilities and current technologies for new nuclear, carbon capture, biomass power, and electricity storage plants. These existing technologies are relatively costly, and new hydropower and conventional geothermal sites are very limited.

In light of the variability of wind and solar and the relatively high costs of existing nuclear and carbon capture technologies, less costly AETs could clearly reduce the costs of achieving decarbonization of the power sector. Using a highly realistic model of the power sector, this study specifically estimates how large the net benefits to the country would be of innovation that reduces the cost of AETs. We examine scenarios with different magnitudes of assumed cost reduction, and with different degrees of assumed decarbonization of the power sector: a clean electricity standard equal to 100 percent of retail sales (approximately 94 percent of generation) and a baseline scenario with no new national environmental policies.

One can compare the net benefits estimated here with the associated RD&D spending necessary to achieve those cost reductions, in order to get an overall sense of net value to society. In particular, the US Department of Energy's budget in fiscal year 2020 included approximately $1.6 billion for the AETs. We project that the AEIA, if fully funded, would increase that by approximately $1.75 billion per year. Table 1 shows the funding amounts by technology. In both FY2020 and year 2 of the AEIA authorizations, more than half is for nuclear, more than 30% is for CO_2 capture, utilization, and storage, and less than 2% is for DAC. A parallel effort is eliciting estimates from experts of the degree to which they expect the provisions of the AEIA to advance the AETs to the cost levels assessed in this report.

Our estimates of the net benefits of the AETs are conservative in several respects. First, cost reductions for the AETs can produce substantial benefits outside the power sector as well. For example, storage technologies can be deployed in transportation; direct air capture can offset emissions from difficult-to-decarbonize sectors such as industry and fuels; nuclear could produce hydrogen along with electricity; geothermal could produce valuable minerals such as lithium from its brine; and geothermal, NG-CCS, and nuclear can provide heat for industry and buildings. These benefits outside the power sector are not captured in this study.

Other factors also contribute to our estimates being conservative. The net benefits presented here are benefits only to the United States, and we omit the benefits from the use of the less costly AETs outside the country. The United States accounts for only about one-fifth of world power generation. In addition, we omit the benefits to the US economy of greater exports if the less costly advanced energy technologies are exported by US companies. Finally, geothermal and, to a lesser extent, nuclear allow for storing heat at times of low electricity demand and then generating more power at later times of high demand. This capability makes those technologies more valuable, but we have not yet represented this feature in the model.

Table 1. US DOE Spending on the AETs, Recent and Proposed in AEIA (millions of 2020$)

Technology[a]	Spending in FY2020	AEIA year-2 authorizations[b]
Nuclear[c]	935	1792
CCUS[d]	491	1116
Geothermal	110	165
Electricity storage[e]	56	221
Direct air capture	15	62
Total	1606	3356

[a] The technology names here have their general meanings rather than the more specific meanings used in this study. FY2020 funding amounts are for both advanced and conventional versions of these technologies, while the incremental amounts in the AEIA are primarily for the advanced versions.
[b] The AEIA funding authorization amount shown is the amount from year 2, which is the single year that best represents the average over the five years of funding authorizations.
[c] Nuclear amount is from H.R. 4447, which has a similar nuclear section. If the AEIA passes, it will go to a conference committee to be merged with H.R. 4447, and in that case the merged result is likely to be based primarily on the nuclear section of H.R. 4447.
[d] CCUS denotes "Carbon capture, utilization, and storage" and includes capture of CO_2 from both coal and natural gas
[e] The AEIA electricity storage amount shown here omits a $49 million per year program that is purely for long-duration storage.

2. Methods

2.1. Description of E4ST Power Sector Model

In this analysis, we use the *Engineering, Economic, and Environmental Electricity Simulation Tool* (E4ST), a model of the US and Canadian electricity grid with high spatial resolution in transmission, renewable resource profiles, generating resources, and electricity demand.[5] It predicts generator investment and retirement in future years or multiyear periods, along with hourly system operation, locational marginal electricity prices, emissions of greenhouse gases, emissions of sulfur and nitrogen oxides (SO_2 and NO_x), health effects of those SO_2 and NO_x emissions, and net benefits.

The components of total net benefits include consumer benefit (electricity bill savings), producer profit (from generation, storage, and CO_2 sequestration), transmission system revenue (rebated to consumers), government revenue, health benefit from reduced air pollution, and climate benefit from reduced greenhouse gas emissions. Sometimes one or more of the components is negative. When that is the case, it reduces the net benefits.

[5] E4ST has been developed in a collaborative effort among researchers at Resources for the Future, Cornell University, and Arizona State University, with funding, input, and review by the Department of Energy, the National Science Foundation, and industry (the New York Independent System Operator and the Power Systems Engineering Research Center).

The model works by solving an optimization problem that represents the decision criteria of both generation investor-owners and electricity users. It incorporates a physics-based representation of power flow in a transmission grid representation that has over 5,000 nodes and 20,000 transmission line segments. The transmission segments include all high-voltage (>200 kV) lines in the United States, as well as select lower-voltage segments in areas with high congestion. There can be existing or potentially buildable generators at any of the nodes, with capital costs, fixed operating costs, fuel costs, other variable costs, and hourly availability that are specific to the site and generator. This allows for precise representations of existing generators and site-by-site hourly wind, solar, and geothermal resources.[6]

Because of the high spatial resolution and detailed transmission representation, combined with endogenous construction and retirement of tens of thousands of existing and buildable generators, it is not possible to simulate every hour in a given year. We instead simulate 52 representative hours, spread over 16 representative days, that mimic the conditions expected in a year. The representative hours were carefully selected to represent all days of the year and weighted to match the frequency distribution of hourly electricity demand, wind, and sun in three recent years, in every region of the United States and Canada. We use days with lower weights to represent the hours of extreme electricity scarcity (e.g., high demand combined with low wind and solar output). For details on the selection process, see Appendix D3..

The five AETs are carefully represented. For example, for any given NG-CCS or DAC plant, the cost of transporting and sequestering carbon dioxide is determined by a network model of the potential future carbon dioxide transportation system and of the estimated supply curve for sequestration in each state or offshore area with high sequestration potential (EPA, 2018b). For enhanced geothermal, we use the model of enhanced geothermal supply curves in 134 US zones from the National Renewable Energy Laboratory (NREL). For diurnal storage, we explicitly model optimal charging and discharging during each of the 16 representative days. New nuclear plants can be built at only about 300 locations that pass a suitability screen.

[6]For more details on E4ST, its mathematical formulation, model validation tests, and key assumptions, see Shawhan et al. (2014), Mao et al. (2016), and Shawhan and Picciano (2019). For further details on wind and solar data used in this project, see Appendix D1.

3. Key Assumptions

3.1. Technology Costs and Performance

For each AET, we use four sets of cost and performance assumptions to represent the range of potential improvements in the technology and its costs by 2050, as well as a fifth case where the technology is not built because it has uneconomically high cost and/or low performance.

- **High cost** represents the case in which there is minimal technological development and learning-by-doing between now and 2050. In the case of diurnal storage, minimal is appreciably greater than zero, as the technology is already being commercially applied. In the case of the other technologies, minimal is essentially zero. Reductions from 2020 costs still occur because of R&D and general technological progress. Appendix B shows the sources of our high cost assumptions.
- **Medium cost** is the midpoint between high and low, and its cost and performance assumptions are averages of those in the high- and low-cost cases. For each AET, high and low cost assumptions are based on specific types of the technology and estimates from the literature, while the medium case, being an average, is not associated with a separate source.
- **Low cost** is the lowest cost projection we found in the literature from a highly credible source and represents the case in which there have been significant improvements in the technology and learning-by-doing has occurred. The low cost projections we use for nuclear, NG-CCS, and DAC are from sources that do not identify a specific year with the cost estimate. For geothermal, we use a projection for 2030 and reduce it by 12.5 percent, which can be motivated as a moderate degree of additional learning (see, e.g., Larsen et al. (2019)). Appendix B shows the sources of our low cost assumptions.
- **Very low cost** is low cost with all components (capital, fixed, and variable costs) reduced by 12.5 percent, which can be motivated as a moderate degree of additional learning beyond low cost (see, e.g., Larsen et al. (2019)).

For more details on the specific cost assumptions used in this study, see the tables in Appendix B. The tables show the year 2050 high and low assumed variable costs, fixed costs, and capital costs for each technology. They also include current technology costs, for comparison.

Along with the capital and operating costs of the AETs, we also vary financial assumptions — weighted average cost of capital (WACC), capital recovery factor (CRF), and eco-

nomic lifetime — over the cost levels. Capital recovery factor is how much of a project's total capital costs have to be recovered in a year for it to be profitable. To represent a higher degree of financial risk for AETs that have not yet been deployed at scale — DAC, enhanced geothermal, nuclear, and NG-CCS — we use an 8.3% CRF (based on 5.44 percent WACC and 20-year economic life) for the high cost level, and lower technology-specific CRF assumptions based on the NREL's 2020 Annual Technology Baseline (ATB) (NREL, 2020) for the low cost level. The lower CRFs are 6.9 percent for NG-CCS, 5.6 percent for geothermal, and 5.3 percent for advanced nuclear and direct air capture. These are based on economic lifetimes of 20 years for NG-CCS and 30 years for the other three. DAC is not included in the ATB, so its lower CRF is based on ATB natural gas financial assumptions but with a 30-year economic life.

The justification for using more favorable financial assumptions for the low-cost cases is that if the technologies become widely used, this implies they have a track record of success, and investors should consequently view them as less risky. However, this means that the effective reductions in levelized costs from the high- to medium- to low- to very low–cost cases employed in this analysis are larger than the improvements specifically in engineering and technology costs required to achieve those reductions, because the reductions in levelized costs are augmented by more favorable financial assumptions. To more directly compare the improvements in technology costs that underlie our cost scenarios, we present standardized levelized costs in Appendix B. These are calculated using uniform financial assumptions for all technologies and cost levels. The standardized levelized costs are not based on assumptions used in this analysis and are only another way to represent the differences in technology costs across the scenarios.

For technologies that are buildable in our simulations and are already being commercially deployed on a large scale, we use cost and financial assumptions from NREL's ATB, holding them constant over all simulations. These technologies and their CRFs are diurnal storage (6.9 percent), non-CCS NG (6.9 percent), solar (6.5 percent), onshore wind (6.7 percent), and offshore wind (6.9 percent).

We list the 2050 levelized costs of energy/storage/capture for our high, medium, and low cost levels of the AETs in Table 2. For more detail on sources, what technology subtypes these costs represent, the components of levelized costs, comparisons with current technology costs, and other important assumptions, please see Appendix B.

3.2. Emissions Rates

Of the five AETs, we assume that the operation of nuclear, enhanced geothermal, and energy storage plants results in no emissions of CO_2, SO_2, methane, or NO_x. Since the direct air capture plants modeled in this report do not use any fuel other than electricity, we assume they do not directly produce any emissions while capturing carbon. NG-CCS

Table 2. Technology levelized cost assumptions for 2050 (in 2020$)[a]

Technology	High	Medium	Low	Very low	Capacity factor[b]
Nuclear ($/MWh)	96	70	44	39	0.92
NG-CCS ($/MWh)[c]	68	58	49	43	0.80
Geothermal ($/MWh)[d]	560	313	58	50	0.85
Storage ($/MWh discharged)[e]	59	41	23	20	0.17
DAC ($/short ton captured)[c,f]	158	104	51	45	0.95

[a] All costs shown are for the year 2050. For a breakdown of the cost assumptions, including assumed fixed costs, variable costs, and capital costs, see Appendix B.
[b] Capacity factors shown here are used for calculating levelized costs and are equal to average hourly output divided by maximum possible hourly output (nameplate capacity). Actual capacity factors are determined by the model and may differ from the ones reported here.
[c] Levelized costs for NG-CCS and DAC do not include transport and sequestration costs of the captured CO_2. These costs vary and can be positive or negative depending on location and sequestration method. See Appendix B8. for details.
[d] These geothermal costs are for a resource that is 250°C at 6 kilometers deep. Geothermal costs in E4ST vary locationally by resource quality.
[e] Levelized cost of storage does not include the cost of the electricity used to charge the storage system.
[f] Levelized cost of capture for DAC assumes a constant electricity cost of $45/MWh. The actual cost is endogenous in E4ST.

plants modeled in this report are assumed to produce emissions at the rates specified in Table 3, with entries for a new conventional natural gas combined cycle plant without CCS (NGCC) for comparison. NG-CCS generators in the medium-cost case produce emissions at rates that are averages between the high- and low-cost cases. NG-CCS generators in the very low–cost case produce emissions at the same rates as in the low-cost case. Regardless of cost level or power plant type, we assume that the use of natural gas fuel results in methane emissions of 0.869 lbs/MMBtu NG (see Lenox et al. (2013) and Shawhan (2018)). The E4ST model, and thus the net benefits analysis in this report, only considers emissions related to operation of the electricity grid, and not emissions associated with plant construction or decommissioning.

When calculating CO_2 equivalent (CO_2e) in E4ST, which we use to calculate clean energy credits earned under a CES policy, we take into account the plant's emissions, upstream emissions from fuel production, and for plants that capture carbon, effects of the end use of captured carbon. DAC and CCS plants have the option of either selling their captured CO_2 for use in enhanced oil recovery (EOR) or paying for permanent sequestration of their CO_2 in saline aquifers (see Appendix B8. for more details). Since CO_2 sequestered in EOR can result in additional emissions from EOR operation and downstream emissions from petroleum products, we assume that a ton of CO_2 used in enhanced oil recovery results in CO_2e emissions of 0.27 tons (IEA, 2015).

Table 3. Emissions rates of NG-fueled generators in E4ST

	NG CCS (low cost)	NG CCS (high cost)	NGCC
Capture Percentage	98%	90%	0%
CO_2 Captured/MWh	0.337	0.440	0
CO_2 Emitted (tons/MWh)	0.006	0.044	0.377
CO_2e Emitted (tons/MWh)[a]	0.079	0.149	0.467
Methane Emitted (lbs/MWh)	4.528	6.537	5.603
NO_x Emitted (lbs/MWh)	0	0.151	0.129
SO_2 Emitted (lbs/MWh)	0	0.025	0.021

Note: Tons refers to short tons.

[a] CO_2e here includes direct emissions from electricity generation and upstream emissions from fuel production. CCS plants can incur additional CO_2e emissions depending on the end use of the captured carbon. See Appendix B8. for more details.

3.2.1. Calculation of Environmental and Health Damages

When calculating the net benefits of changes to the electricity system, it is important to give explicit economic value to the externalities of electricity generation. In E4ST, we split environmental damages into climate damages caused by CO_2 and methane and health damages caused by SO_2 and NO_x. We use a social cost of carbon for 2050 of $76.80 per short ton of CO_2 (Interagency Working Grp. On Soc. Cost of Carbon, 2016), and a social cost of methane of $2,783 per short ton (Marten and Newbold, 2012). For health damages, we use a linear approximation of the US Environmental Protection Agency's COBRA air pollution model to estimate the number of premature deaths due to emissions (EPA, 2018a), and then translate those into costs using values of $13.4 million per infant premature death and $12 million per adult premature death based on (EPA, 2013) updated to 2050 in accordance with (EPA, 2014).

3.3. Policies

Federal, state, and local policies can have a large impact on the future generation mix in the United States. The net benefits of AET cost reductions therefore depend on which policies are included in the E4ST modeling scenarios. In this analysis, we consider two different background policy scenarios: (1) a scenario without any new environmental policies by the US government and (2) a scenario with a national clean electricity standard (CES) of 100 percent of retail electricity sales (approximately 94 percent of generation). In the former, deployment of the AETs is driven almost entirely by state and utility initiatives, voluntary customer purchasing of green power, and market fundamentals. In the latter, the greater deployment of AETs is driven almost entirely by the national CES. These two policy scenarios are henceforth referred to as the "Without CES" and "With CES" policy scenarios, respectively.

In both scenarios, we model existing state and regional legislation with care. There is some ambiguity, however, in how best to do this. First, many existing policies terminate before 2050. States often focus on short-term goals and plan to amend policies for longer time frames in the future. To account for this, we assume that all state renewable portfolio standards (RPSs) and CESs will continue to exist and increase in stringency through 2050. Second, the extent to which the AETs should be assumed to be included as policy compliance options is unclear. Geothermal is already included in most existing state RPSs and CESs, and nuclear is currently included in most state CESs but not RPSs. However, NG-CCS is less commonly included and DAC is rarely included in either policy type. Also, there is a trend of states switching from RPSs to CESs, which might influence which AETs are included in future legislation, as CESs usually include a wider range of technologies than RPSs.

Table 4 shows the assumptions about the eligibility of AETs in the policies we use in this study. In the table, a check mark indicates that we assume a given AET is eligible to receive credit for the specified policy type. For instance, in the national CES (only exists in the With CES scenarios), all the AETs except storage are eligible to receive credit. In this policy, the amount of credit received varies linearly with the CO_2e emissions rate. Coal generation receives zero credits, while zero-emitting technologies receive one full credit per MWh generated.

Note that storage units are not included in any CES or RPS policy in our modeling, as we do not consider them net producers of electricity. This means that in policies that are specified as percentage of retail sale requirements (such as the national CES), energy lost during storage is not subject to the requirement and can be supplied by emitting generation sources. Storage devices therefore do not pay for CES and RPS credits for the energy they dissipate. Furthermore, we assume that although NG-CCS is not included in most state and regional CESs, it receives a full credit per MWh in the Arizona and New Mexico CES policies. NG-CCS thus counts as a zero-emitting technology in these policies, even though in reality NG-CCS still has CO_2 emissions. In the national CES we model, CCS plants earn partial credits per MWh, according to their actual emissions.

Notable policies in our model include (1) all announced state RPSs and CESs, (2) a zero-emissions cap on power generation in Colorado, (3) utility-driven clean energy requirements in nine US states, and (4) voluntary green power purchases amounting to 20 percent of retail sales in states with existing clean energy policies. For more details and assumptions about what emissions policies in the Without CES and With CES scenarios, please see Appendix C.

Table 4. Credit eligibility of the AETs in various energy policies, as assumed in our model.

AET	RPSs	State & Regional CESs	Utility Commitments	Carbon Caps	National CES
Nuclear	✗	✓	✓	✓	✓
NG-CCS	✗	✗[a]	✓[b]	✓	✓[c]
Geothermal	✓	✓	✓	✓	✓
Storage[d]	✗	✗	✗	✗	✗
DAC[e]	✗	✗	✗	✓	✓[f]

Note: A check mark indicates that in E4ST, the given technology is eligible to receive a credit in the policy. An *X* indicates that a technology is not eligible for credit. The National CES in the rightmost column refers to the federal CES in the With CES policy scenario.

[a] Exception: We include NG-CCS in CES policies of California and New Mexico. In these states, CCS is set to receive full CES credit.
[b] NG-CCS receives full credit to utility commitments.
[c] NG-CCS receives partial credit to the national CES. The credits received in the national CES range from 0.7 to 0.9 credits per MWh generated, depending on the CO_2 emissions rate of the power plant and end use of captured CO_2 .
[d] Storage units are not included in any CES or RPS policy, as we do not consider them a primary source of electricity. For policies that are specified as percentage of retail sale requirements (such as the national CES in the With CES case), energy lost during storage units does not count toward retail sales. Storage devices therefore do not pay CES and RPS credit for the energy they dissipate.
[e] In all RPSs and CESs, DAC units must buy credits to cover the electricity they use in operation.
[f] Receives 1 credit for each 0.82 metric tons of CO_2 stored.

4. Scenarios

We modeled scenarios with various combinations of cost assumptions across the AETs. We focus on the following subset of scenarios that address the key questions of interest, where each individual AET is denoted by X:

- X not built, others Medium: all AETs at their medium cost level except technology X, which is assumed to not be deployed in the simulation
- X High, others Medium: all AETs at their medium cost level except technology X, which is at its high cost
- X Low, others Medium: all AETs at their medium cost level except technology X, which is at its low cost
- X Very Low, others Medium: all AETs at their medium cost level except technology X, which is at a cost 12.5 percent lower than its low cost
- X Medium, others High: all AETs at their high cost level except technology X, which is at its medium cost
- All [Y]: all AETs at the cost level Y

Table 5. Examples of the scenarios simulated

Scenario	Adv. nuclear	NG-CCS	Geothermal	Storage	DAC
All High	High	High	High	High	High
All Medium	Med	Med	Med	Med	Med
All Low	Low	Low	Low	Low	Low
Nuclear not built, others Medium	NA	Med	Med	Med	Med
Nuclear High, others Medium	High	Med	Med	Med	Med
Nuclear Low, others Medium	Low	Med	Med	Med	Med
Nuclear Very Low, others Medium	0.875 · Low	Med	Med	Med	Med
High, Nuclear Medium	Med	High	High	High	High

Note: This table shows all the variations of advanced nuclear cost. Similar scenarios are run for all other AETs.

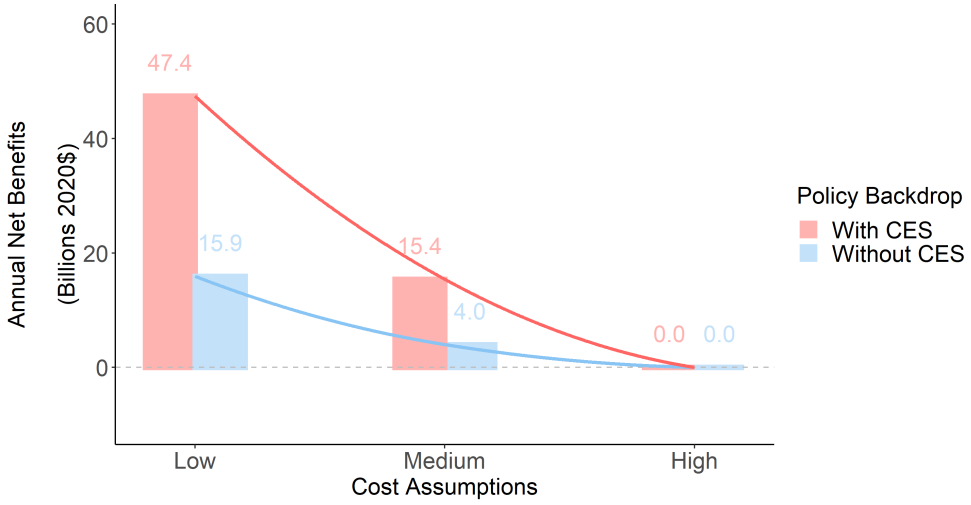
For clarity, Table 5 lists all three All $[Y]$ scenarios and the five scenarios in which the cost level of nuclear differs from the cost level of the other four AETs. We ran a corresponding set of five scenarios for each other technology. In all simulations, the cost assumptions of conventional (non-AET) generation technologies remain constant at projected 2050 levels from the NREL and the Energy Information Administration (EIA), as described in Appendix B.

5. Results

5.1. Benefits of Simultaneous Cost Reductions in All Technologies

Figure 1 shows the net benefits of reducing the cost of all the AETs from their high cost to their medium and low costs. As can be seen in the figure, the net benefits increase at an increasing rate as costs decrease and more of the AETs consequently become cost-competitive.

Figure 1. Annual net benefits in 2050 with the costs of all the AETs simultaneously reduced from their high to medium and low costs.



Note: The high, medium and low cost assumptions for each technology can be found in Table 2. The values shown in this figure are net benefits relative to the case where the technologies are all at their high costs. The curved line in the figure shows how net benefits increase with lower cost assumptions.

The benefits of reducing the costs of AETs are 3-4 times greater with a national CES than without. Reduced costs of the AETs make it easier and cheaper to meet stringent clean electricity standards. The net benefits of having all the AETs at their low rather than high cost levels amount to $15.9 billion per year without a national CES and $47.4 billion per year with a national CES. Without a national CES, the AETs are primarily implemented to meet state and regional clean energy policies, as well as utility clean power commitments and electricity users' voluntary green power purchasing. In contrast, with a national CES, the AETs are deployed more widely to satisfy that CES. The national CES has a more stringent requirement than some state and regional policies and renders them non-binding. The specific locations where AETs are built in each of these scenarios can be seen in Appendix A.

Figure 2 shows the generation mixes for the All High, All Medium, and All Low cases, with and without a CES. As can be seen, the generation mixes depend significantly on whether there is a national CES.

Without a CES, our model projects that 48-50 percent of US generation will come from coal or natural gas in 2050, across any of the assessed AET cost levels. These results are in close agreement with the reference case projections from the Annual Energy Outlook 2020, which projects that 49 percent of electricity will be generated from fossil fuels in 2050 (U.S. Energy Information Administration, 2020). The AET cost reductions have little effect on generation from fossil fuels or on the split between natural gas and coal, but they increase the use of NG-CCS and lower-emitting conventional natural gas–fueled generators over higher-emitting conventional natural gas–fueled generators.

With the national CES, reduced AET costs have a larger effect on the generation mix. Coal generation from both conventional and CCS-retrofitted plants nearly ceases, and natural gas including NG-CCS has a high of 24 percent of US generation in the All Medium case and a low of 17 percent in the All Low case. Less costly AETs have a larger effect on combined solar and wind generation, since they compete with wind and solar to satisfy the national CES. They reduce combined wind and solar generation from 59 percent of US generation in the All High case to 41 percent in the All Low case because they are able to produce similar emission reductions at lower cost.

In the scenarios we have simulated, reducing the AETs' costs from high to low has a smaller effect on coal- and natural gas–fueled generation than does adding a national CES (see Fig. 2). In the results of those scenarios, CO_2 emissions from the power sector are determined primarily by emissions policies rather than by AET costs, but the the AET cost reductions considered still have societal benefits of up to tens of billions of dollars per year. These estimated benefits come partly because of emission reductions but more because the AETs make meeting environmental policies easier and cheaper (see Fig. Figure 3). In addition, a potentially important effect we do not model is that lower-cost AETs may make it more likely that additional emissions policies or clean energy policies are adopted.

Figure 3 shows how the following components of net benefits change as the costs of all the technologies are reduced:

- **Electricity user savings**: electricity users' savings on their electric bills, a function of electricity prices
- **Generator profits**: the total revenues minus costs for electricity generators, electricity storage units, direct air capture units, and sequesterers of CO_2
- **Climate benefits**: net benefits to people from reductions in global climate change
- **Health benefits**: net health benefits to people in the United States from reduction

Figure 2. Absolute generation mix in 2050 for the scenarios All High, All Medium, and All Low, With and Without CES.

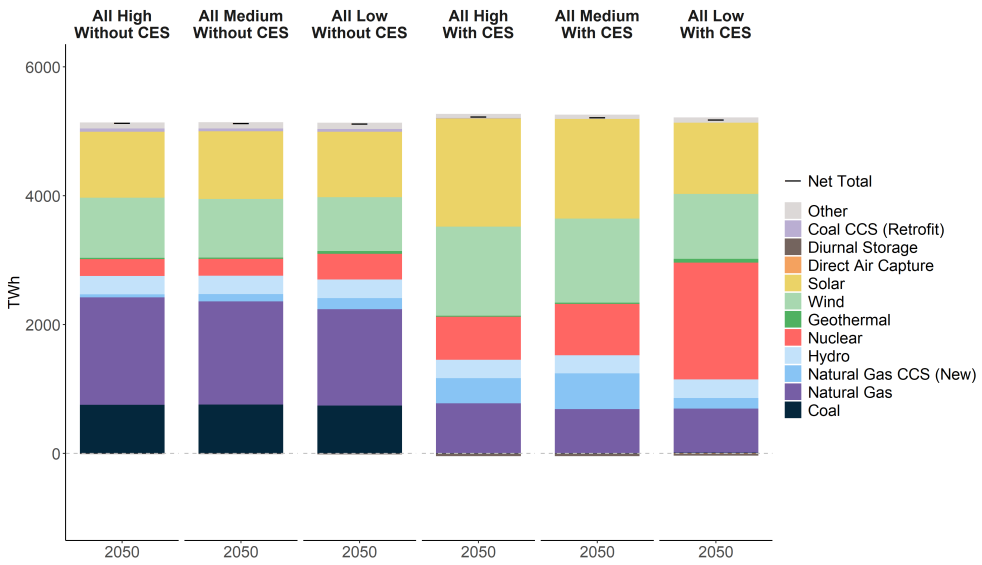
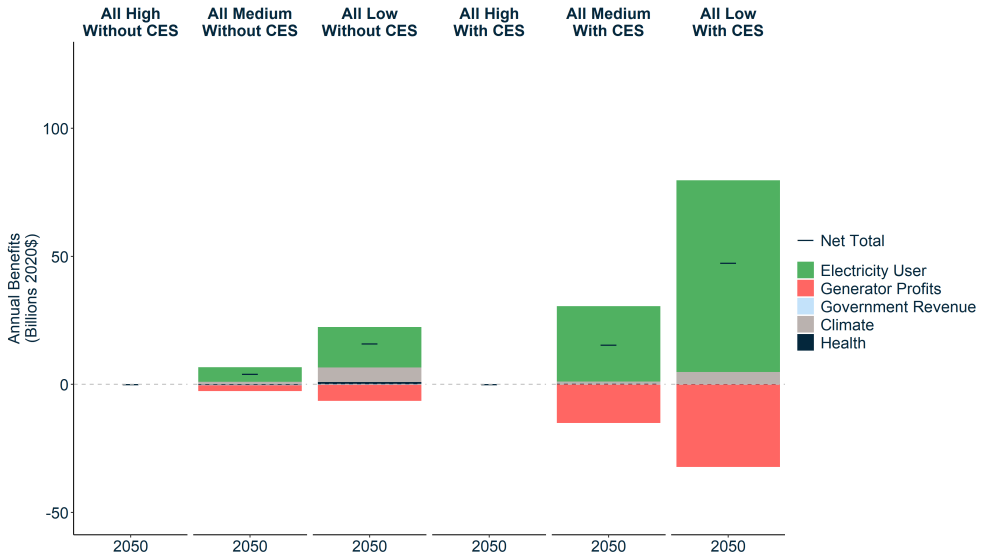


Figure 3. Change in net benefits associated with cost reductions in all technologies simultaneously.



Note: For scenarios without a national CES, net benefit values are shown relative to the All High, Without CES case. For scenarios with a national CES, net benefit values are shown relative the the All High, With CES case. Electricity user benefits come from electric bill savings as a result of lower electricity prices. Climate benefits come from the decrease in greenhouse gas emissions, and health benefits result from changes in SO_x and NO_x pollution.

in air pollution, specifically fine airborne particulate matter that forms from NO_x and SO_x

- **Government revenue**: revenue earned by governments from policies such as carbon cap-and-trade programs (e.g., Regional Greenhouse Gas Initiative and California's AB32)

As can be seen in Figure 3, annual bill savings for electricity users are the largest type of benefit of less costly AETs. These are $16 billion per year when AET costs change from All High to All Low without a national CES and $75 billion per year when AET costs change from All High to All Low with a national CES. [7] The less costly AETs reduce electricity rates *more than* they reduce generation costs, which expands the benefit for electricity users and reduces the profits of producers. The producers' rate of return on generator investment also decreases as AETs get cheaper, although to a lesser degree than the decrease in producer profit. This reduction in generator profits could be partially offset or reversed by policy from federal, state, and local governments. The ability of energy policies to affect profits is, for instance, shown by the national CES. We estimate that at high and medium AET costs, the CES has a positive impact on generator profit of $24 billion and $ 11 billion, respectively, which is not shown in the Figure 3. Other policies, tax rates, and fees can be changed, if desired, to partially or completely offset changes in producer profits and electricity users' bills. Overall, the highest net benefits to society are achieved in cases where there is a national CES and the AETs are at their low cost levels

The next-largest benefits of lower-cost AETs are the climate and health benefits. These are calculated as described in Section 3.2.1.. The combined climate and health benefits range from $680 million per year when AET costs change from All High to All Medium without a national CES to $6 billion per year when AET costs change from All Medium to All Low without a national CES.

5.2. Benefits of Cost Reductions in Individual Technologies

In this section, we examine how reducing the cost of each individual technology affects the US electricity generation mix, retail electricity prices, net benefits within the elec-

[7] Note that in Figure 3, as in Figure 1, benefits of each case are relative to the corresponding reference case, as they should be. To isolate the effect of less costly AETs, the Without-CES cases are compared with each other and the With-CES cases are compared with each other. Our model estimates that, in the presence of high-cost AETs, the CES itself will lead to total net benefits of $91 billion/year in 2050, which is not shown in this figure. The benefit of the CES comes primarily from climate benefits ($102 billion/year), health benefits ($35 billion/year), and producer profit ($24 billion/year), at the expense of consumer savings (-$68 billion/year). These numbers were obtained by comparing the "All High Without CES" case to the "All High With CES case."

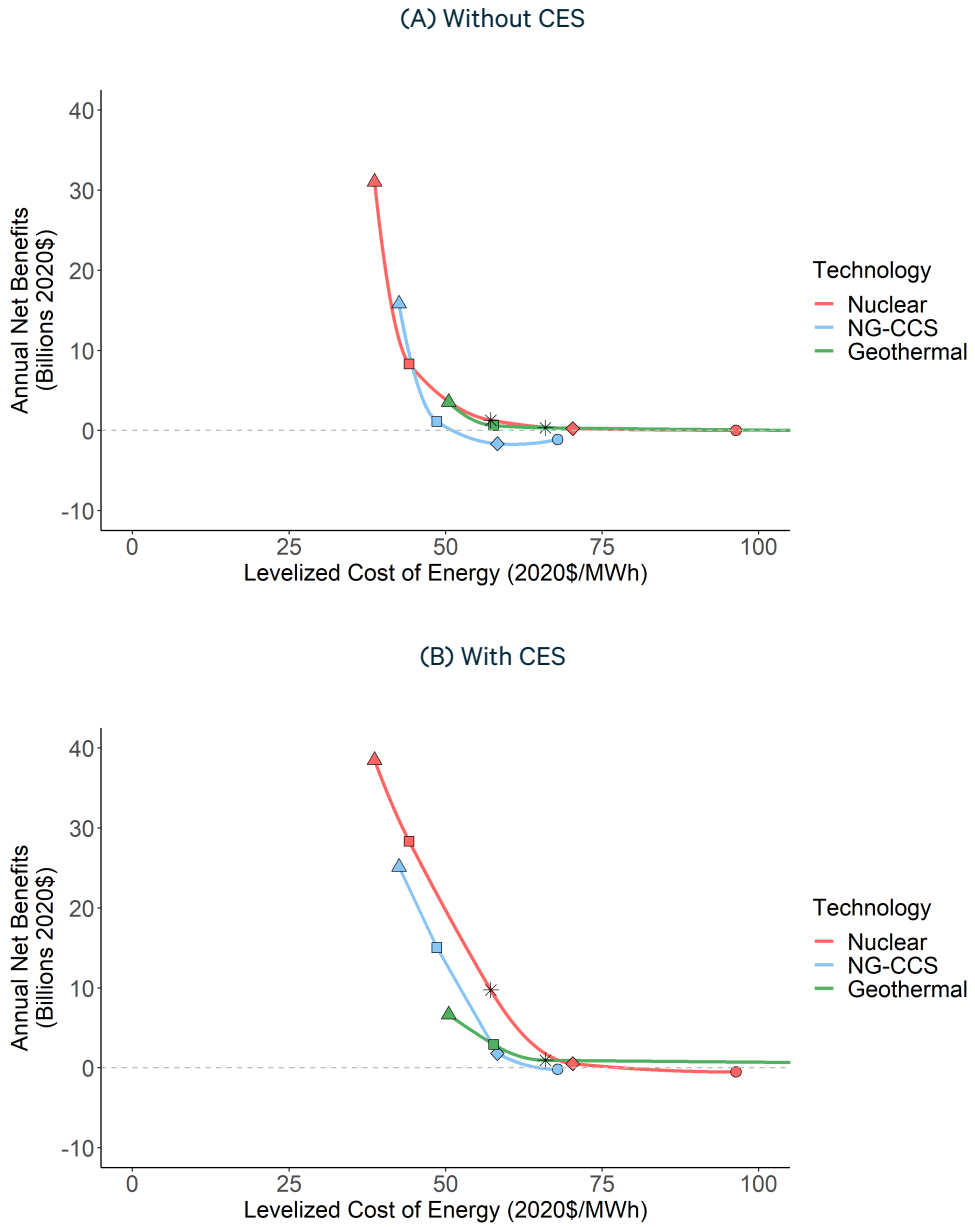
tricity sector, and health impacts of power generation. We do this through a series of perturbation analyses, in which we assume a default scenario and investigate how key system variables change when the cost of one of the AETs is increased or reduced. Naturally, the effects of these cost perturbations depend heavily on the default scenario. Unless otherwise stated, the default scenario in this section is the one in which all AETs are at their medium cost levels (All Medium). This scenario describes a future in which all technologies have become less costly to a moderate degree. At the end of this section, we briefly address how results may change if different default scenarios are used.

5.2.1. Net Benefits as a Function of Levelized Cost

Figures 4 and 5 show US net benefits as a function of cost for each AET. The curves for each AET are based on simulations with that technology at five different cost levels (not buildable, high, medium, low, very low), with all other technology costs held at their medium cost levels. For each curve, the total net benefit of zero is set to be the total net benefit in the case in which the technology of interest is not buildable. The three electricity generating AETs (nuclear, NG-CCS, and geothermal) are shown together in one graph (Fig. 4), as their costs can easily be compared using levelized cost of electricity (LCOE).

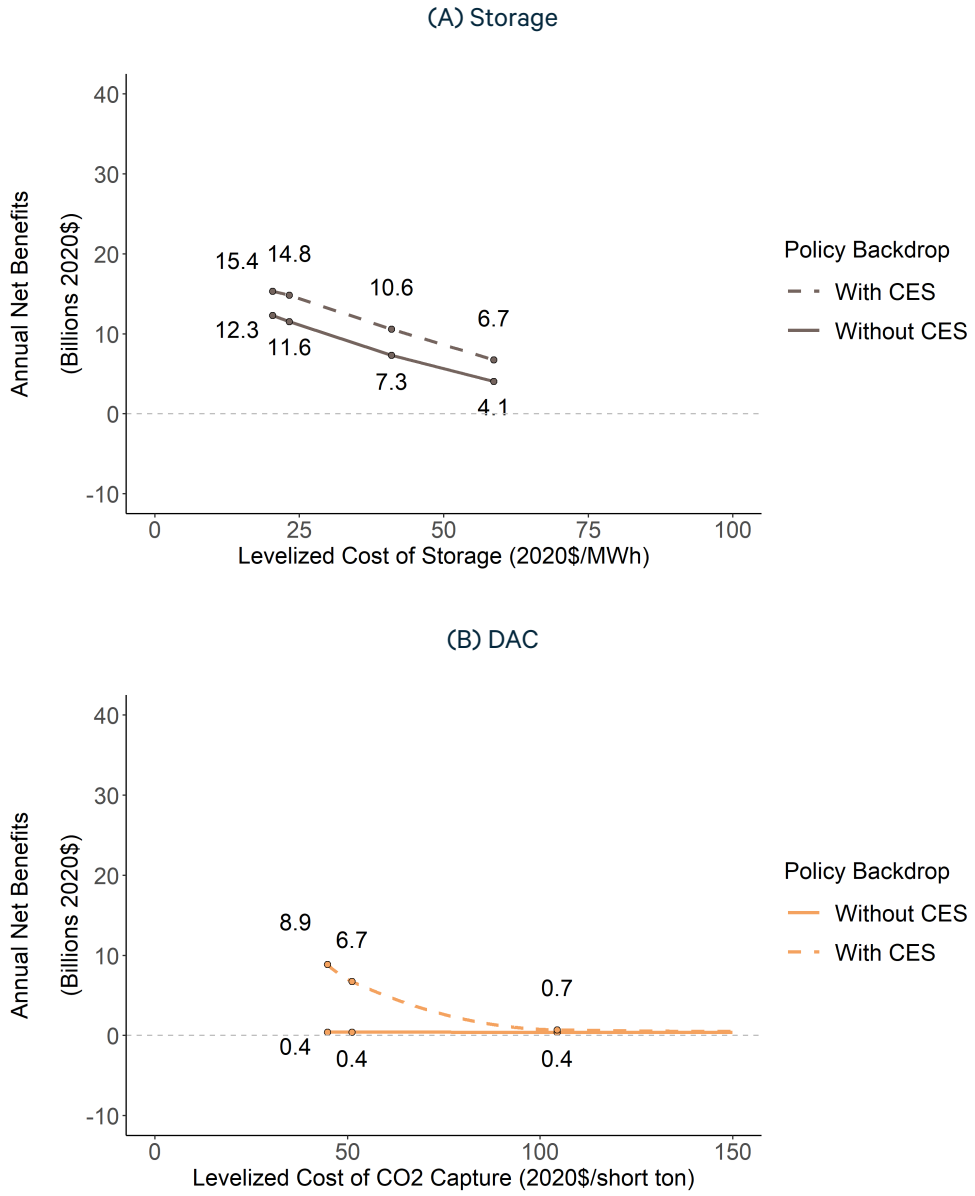
As seen in the figures, cost reductions in nuclear, NG-CCS, geothermal, and DAC have only a minor benefit to society over a range of cost values. For these costs, the technology is too expensive to be competitive and widely built. In several cases, cost reductions at high costs even produce small amounts of negative net benefits in our results, due to environmental externalities, the national CES design, and a simplifying assumption we make which may be unlikely in reality. First, with a CES, net benefits decrease slightly when nuclear is at its high cost level relative to when it is not buildable. This is due to the specific design of the CES. When nuclear becomes buildable at high cost, we find that (1) the United States exports slightly more electricity to Canada and Mexico, and (2) that there is more generation with emissions worse than the CES benchmark rate. Both of these factors can increase emissions under a CES, and thus increase environmental damages. Second, without a national CES, NG-CCS has negative net benefits at its high and medium cost levels. However, this NG-CCS effect is mostly or entirely an artifact of a simplifying assumption in our modeling, which is that NG-CCS receives full credit in utility clean energy policies and in the California and New Mexico CES policies. Hence NG-CCS can fully substitute for zero-emitting generation such as solar or nuclear. When this occurs, NG-CCS increases environmental damages because it still has some CO_2, methane, NO_x, and SO_x emissions, leading to the observed negative net benefits. If state CESs and utility and customer clean power purchase policies instead give NG-CCS less than full credit, which would be logical once the policies are fully defined, these negative net benefits of NG-CCS can be avoided.

Figure 4. Annual net benefits of cost reductions nuclear, NG-CCS, and geothermal, assuming medium costs for all other technologies.



Note: For each technology, the net benefits are relative to the situation in which that technology cannot be deployed at all and all other AETs are at their medium cost. Point shapes indicate the various cost levels for each AET: (circle) high cost, (diamond) medium cost, (square) low cost, and (triangle) very low cost. For geothermal and nuclear power, we included one extra cost between the medium and low costs to better estimate the turning point at which the technology becomes competitive. This additional cost level is marked with an asterisk. The high- and medium-cost cases for geothermal are not visible in the plot.

Figure 5. Annual net benefits of cost reductions for (A) diurnal storage and (B) DAC.



Note: For each technology, the net benefits are relative to the situation in which that technology cannot be deployed and all other AETs are at their medium cost. From right to left, the points correspond to the high, medium, low, and very low cost levels of storage and DAC, respectively. For DAC, the high cost level is not shown. Levelized cost of storage does not include the cost of the electricity used to charge the storage system.

Once technologies reach a critical threshold at which they become competitive, however, their benefits increase rapidly with reductions in the costs. Importantly, Figure 4 shows that the cost at which the technologies become competitive is similar across all three of the generating AETs. Below the threshold for each technology, benefits initially increase at an increasing rate with cost reductions. At costs significantly below the threshold, however, the benefit curves appear to become nearly linear. Further simulations would be required to confirm this.

The slope of each curve indicates the net benefit per dollar of reduction in levelized cost. The steepest segment is that for nuclear between low and very low cost, without a CES. In that range of costs, each $1/MWh reduction in levelized cost produces an estimated net benefit of $4.1 billion per year as of 2050. This is the steepest segment because nuclear cost reductions within that cost range displace large amounts of conventional natural gas– and coal-fired generation and their associated harmful emissions.

Storage has significant benefits even at its high cost, and the net benefits of diurnal storage increase roughly linearly as levelized cost of storage decreases (see Fig. 5a). Consequently, even if storage is at its high cost, cost reductions can produce significant benefits. This is true both with and without a national CES.

The net benefits of DAC in 2050 are $370 million to $420 million in the Without CES case, increasing within that range as its cost decreases (see Fig. 5b). At all cost levels, DAC is used in Colorado to help comply with the in-state net-zero power sector emissions cap that we assume exists in Colorado and no other state in 2050, based on the leadership of Colorado utilities in decarbonization. The role of DAC in Colorado indicates that it can be valuable in satisfying net-zero emissions policies. With a national CES, the benefits of DAC are billions of dollars per year higher at lower levelized costs. This reflects the fact that with a national CES, as the cost of DAC decreases, it becomes competitive with other AETs for CES credits in multiple parts of the country.

5.2.2. Estimated Costs Needed for Competitiveness in 2050

The high, medium, and low cost estimates for each AET represent the range of 2050 cost projections in the literature for each technology. Yet, we are interested specifically in what cost level would be necessary for an AET to be competitively deployed to a significant amount. We define “competitive” for each technology as described in Table 6. These criteria were chosen by the authors because they capture well the threshold after which a technology becomes widely deployed in the power system. While alternate definitions are possible, we do not expect them to have a large influence on the results in this section.

To determine cost-competitiveness for each AET, we looked at results of simulations in

which the costs of a single AET were set to high, medium, low, and very low while the other four AETs' costs were held constant at their medium cost levels. By examining the results of these simulations, we were able to approximate the most expensive levelized cost that would result in the AETs achieving the criteria in Table 6. These levelized costs are listed in Table 7.

Relationship Between Competitiveness and Credit Prices

Energy policies such as CESs and RPSs are usually implemented by granting clean or renewable energy credits to generators who earn them, then allowing them to be traded. Credits are given to the producers that are able to supply the desired clean energy at the lowest cost. As a result of this process, the final credit price is the marginal cost to the electric system of requiring one extra MWh of clean generation. In E4ST, the CES credit price for the national CES in the All Medium, With CES scenario is endogenously determined to be $76/MWh. This value is very close to the levelized cost of energy at which the three generating technologies (nuclear, NG-CCS, and DAC) become competitive in the With CES case. This is because generators receive revenue primarily from the locational marginal prices of the electricity and the clean electricity credits. For reasons discussed in the next section (5.2.3.), in our results, the average locational marginal price is near zero when there is a stringent national CES. Thus, in our results, the AETs become profitable approximately when their levelized cost of energy falls below the credit price for the national CES.

In the storage simulations with a CES, the costs within the range we simulated resulted in storage discharging 3.5 to 5 percent of US generation, more than the 1 percent criterion for competitiveness. The relatively high cost of storage is competitive when there is a CES policy, and it is possible that higher costs would also be competitive. Similarly, without a CES, the DAC costs within the range we simulated resulted in 1 million to 5

Table 6. Definitions of cost competitiveness for each technology, as used in this analysis.

AET	Criteria for competitiveness
Generating technologies (nuclear, NG-CCS, geothermal)	Generating 1% of total US generation in 2050. This is 51.25 TWh/year without a CES, and 52.1 TWh/yr with a CES.
Storage	Discharging 1% of total US generation in 2050 (same values as above) after storage efficiency losses.
DAC	Capturing 10 million short tons of CO_2 per year.

Table 7. Levelized costs at which each of the AETs becomes competitive, with and without CES (in 2020$).

AET	Without CES	With CES
Nuclear	58 $/MWh	80 $/MWh
NG-CCS	62 $/MWh	67 $/MWh
Geothermal	59 $/MWh	74 $/MWh
Storage[a]	56 $/MWh	>High
DAC[b]	<Very-Low	86 $/ton CO_2

[a] The values for storage do not include the purchase cost of electricity.
[b] The values for DAC include a fixed electricity cost of $45 per MWh. Cost is in short tons.

million short tons of CO_2 captured, less than our criterion for competitiveness. It would require considerably lower costs than we model for DAC to capture 10 million short tons of CO_2 per year in our Without CES policy case. The DAC that is built in the simulations without a CES is only in Colorado, in which we model a net-zero power sector emissions policy and allow DAC to contribute negative emissions to meeting that goal. Where and how much DAC gets built and operated are strongly influenced by policies.

5.2.3. A Closer Look at What Changes When an Individual Technology Gets Cheaper

In this section, we investigate how the electricity sector changes when one of the AET costs is decreased from medium to low (with all other AET costs remaining constant at their medium levels). We investigate changes in net benefits in more detail, as well as changes in generation mix, average retail electricity price, and premature mortality.

Figure 6 shows how individual components of total net benefits change when all technologies are at their medium costs and one technology is reduced from medium to low cost. For each AET, most of the benefits come from electricity user savings.

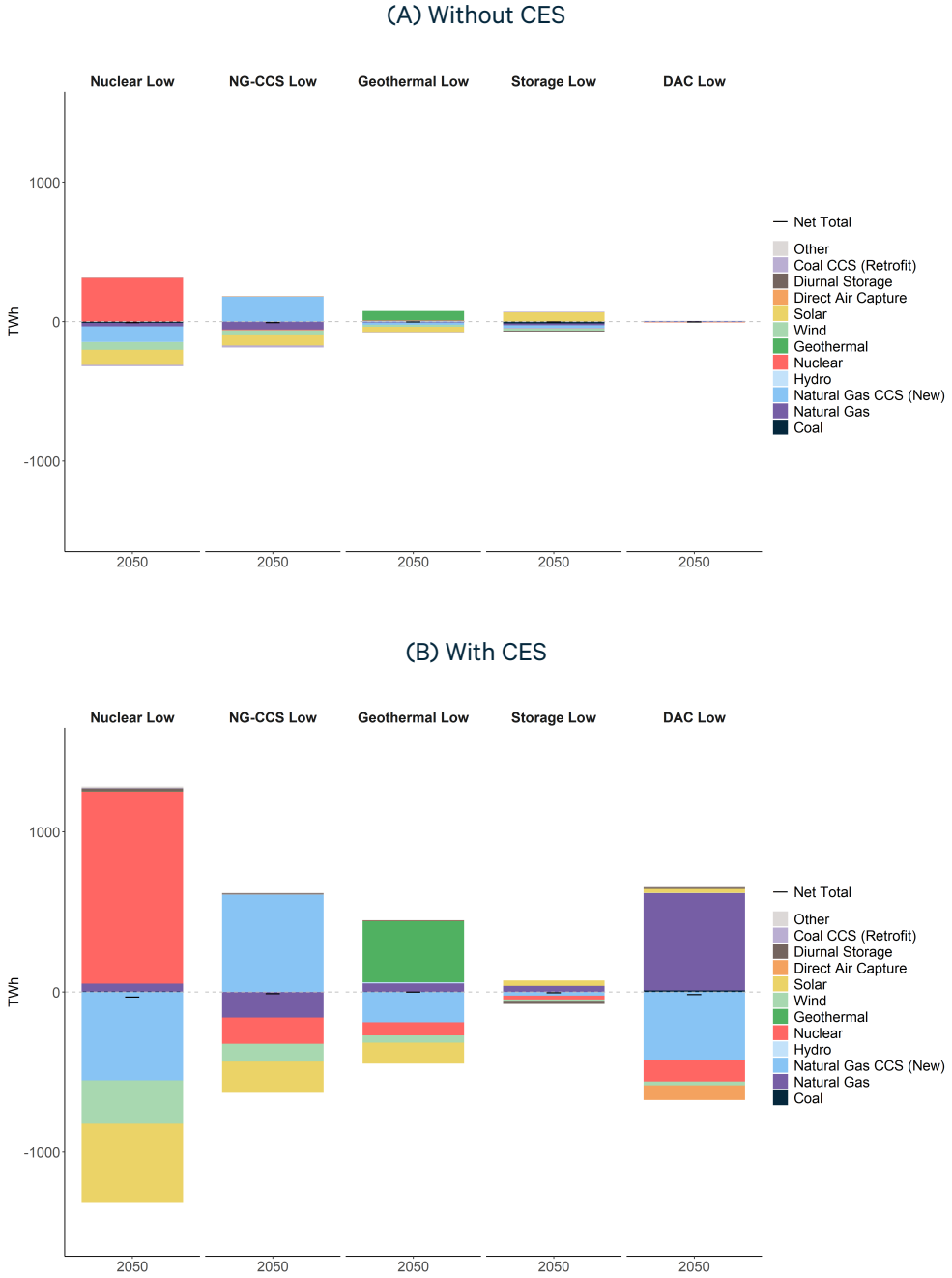
Increased deployment of a given power generating technology will decrease generation from other technologies. To some extent, the three generating AETs (nuclear, geothermal, NG-CCS) thus compete against each other. This is shown in Figure ES-4 and in Figure 7. For example, a cost reduction in nuclear power causes additional nuclear power to displace generation from NG-CCS power plants, wind, and solar. Similarly, a cost reduction in NG-CCS technologies causes an increase in NG-CCS generation, at the expense of nuclear, solar, and wind generation.

Diurnal storage and DAC each complement certain other generating technologies unusually strongly. As seen in Figure 7, a decrease in the cost of storage increases solar generation. Diurnal storage makes solar more profitable by allowing excess energy produced during the daytime to be used in the evening. The increase in solar generation is

Figure 6. Changes in the composition of annual net benefits when all technologies are at their medium cost and one technology is reduced to its low cost.

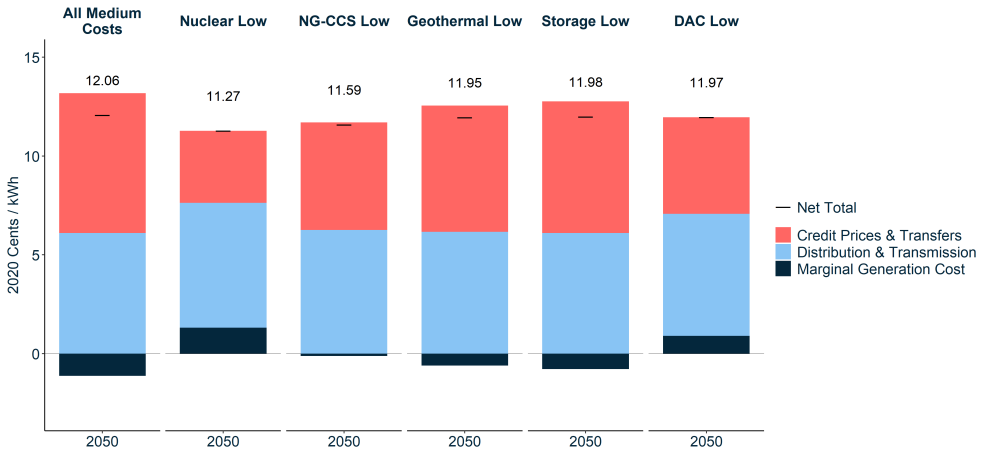
Note: Electricity user benefits come from changes in electricity user savings as a result of lower electricity prices. Climate benefits come from a decrease in greenhouse gas emissions, and health benefits result from changes in SO_x and NO_x pollution.

Figure 7. Changes in 2050 generation mix when all technologies are at their medium costs and one technology is reduced to its low cost.



Note: For generating technologies, negative values indicate a decrease in generation with the cost reduction, while positive values indicate an increase in generation with the cost reduction. For diurnal storage and direct air capture, which consume electricity in operation, negative values indicate an increase in usage with the cost reduction, while positive values indicate a decrease in usage.

Figure 8. Average US retail electricity prices in 2050 for five different scenarios with a national CES.



Note: From left to right, the scenarios shown are All Medium; Nuclear Low, others Medium; NG-CCS Low, others Medium; DAC Low, others Medium; Storage Low, others Medium; and Geothermal Low, others Medium.

offset by decreases in other generating technologies. Similarly, when there is a national CES, a cost decrease in DAC increases the amount of conventional natural gas generation. By removing CO_2 from the atmosphere, DAC enables more emitting generation to operate on the grid without violating the CES constraint. The increase in conventional natural gas comes at the expense of natural gas with CCS, which is more expensive and is built only when there are clean energy policies.

Next, we investigate how cost reductions in each of the AETs affects the average US electricity price. Naturally, we expect that cost reductions in generating technologies will lead to a decrease in the average retail electricity price. The magnitude and source of the cost reductions, however, depend on the technology. In our modeling efforts, we break the retail electricity price into three separate components: (1) the marginal generation costs (wholesale electricity price), (2) transmission and distribution costs, and (3) policy costs and transfer payments from consumers to other entities. The marginal generator cost is the incremental cost of generation in a given hour and at a given location. In our analysis, the marginal generation cost does not include payments that generators may receive from clean electricity credits. It may be negative when there is a strong environmental policy, such as a stringent CES. In this case, a generator may be willing to offer electricity at a negative price, knowing that it will also be compensated in the form of a clean electricity credit. Transmission and distribution costs include a distribution surcharge (assumed to be $67/MWh) and a transmission congestion cost. Finally, policy costs and transfer payments include all renewable or clean electricity credits, carbon taxes, and regulated generator profits that are passed to electricity users.

Without a national CES, the three components of the electricity price change little with reductions in AET costs. In all "X Low, others Medium" cases without the national CES, the US average marginal generation cost is 4.44 $\pm$ 0.05 ¢/kWh, the distribution cost is 6.37 $\pm$ 0.03 ¢/kWh, and the policy cost is around 0.28 $\pm$ 0.17 ¢/kWh. All in all, the average retail electricity price in these cases is 11.09 $\pm$ 0.09 ¢/kWh. These results are in agreement with previous findings that the benefits of AETs are lower without a stringent environment policy. Figure 8, on the other hand, shows the breakdown of the retail electricity price with a national CES, when each of the AET costs is reduced individually. As seen, the greatest reduction in electricity price comes from reductions in the cost of advanced nuclear power and NG-CCS. For these technologies, we estimate that each cost reduction in the LCOE of $1 decreases the US average retail electricity price by 0.03 ¢/kWh and 0.05 ¢/kWh, respectively.[8]

Using the EIA AEO's projections of U.S. household electricity consumption in 2050, we find that improving all AET costs from high to low results in average per-household electricity bill savings of $3 per month without the CES, and $16 per month with the CES. Lower AET costs also reduce the effect that adding a CES policy has on the electricity price. When AET costs are all high, adding the CES increases average per-household electricity bills by $14. When they are all low, adding the CES increases average per-household electricity bills by $2.

The final attribute of clean energy technologies we consider is the health impacts from air pollution in each scenario. In general, we find that cost reductions of AETs have a much smaller effect on air pollution than the CES. Without a national CES, we find that air pollution from the electricity sector leads to slightly over 5,000 premature deaths annually. Most of these health damages come from coal-fired power generation. The only AET whose cost reduction has a major impact on this number is nuclear. If nuclear power becomes cost-competitive, it displaces some of the coal-fired generation and thus has positive health effects. With a national CES, we estimate the total annual premature deaths to be around 600. Once again, this number changes little with cost reductions in the AETs. A cost reduction in DAC has the biggest effect, as DAC units allow more polluting generation to remain online through 2050. With DAC at its low cost, we therefore estimate the number of premature deaths to increase to 700.

5.2.4. Benefits of Each Technology When Other Technologies Advance Little

In the results we have discussed thus far, we assume a reference scenario in which all AETs are at their medium cost. In this section, we address the benefits of making a single technology cheaper when all the other technologies remain at their high cost.

[8] These values were calculated using the difference between electricity prices in the "X low, others medium" and the "All medium" scenarios.

Each cell of Table 8 shows the net benefits (billion $ per year) of changing one AET's cost from high to medium. However, in the two "Medium" columns, all the other AETs are at their medium cost levels, while in the two "High" columns, all other AETs are at their high cost levels. With a CES, the net benefits of improving each individual technology are greater when other technologies are more expensive. This makes sense since the AETs can predominantly substitute for each other. Each AET can by itself contribute toward fulfilling the CES requirement (storage does so indirectly by boosting variable renewable technologies). Naturally, a single technology thus plays a more essential role when the other technologies are less viable. A similar trend is seen without the national CES, although to a lesser degree, and nuclear is an exception.

Table 8. Change in annual US net benefits in 2050 resulting from a cost reduction in each AET from high to medium (billions of 2020$).

AET	Without CES		With CES	
	Other AETs at high cost	Other AETs at medium cost	Other AETs at high cost	Other AETs at medium cost
Nuclear	-0.1	0.2	9.4	1.0
NG-CCS	-0.3	-0.4	10.2	2.0
Geothermal	0.0	0.0	0.0	0.0
Storage	3.8	3.3	4.8	3.9
DAC	0.1	0.0	2.9	0.2

Note: Results are shown for four different background scenarios: (1) Without CES and all other technologies at their high cost; (2) Without CES and all other technologies at their medium cost; (3) With CES and all other technologies at their high cost; (4) With CES and all other technologies at their medium cost.

6. Sensitivity to Key Assumptions

In this section, we further discuss the role of key assumptions in the analysis, and how the results might change if they were to be adjusted.

6.1. Effects of Cost Assumptions

The results presented in this report depend heavily on the relative costs of each of the five AETs, as well as any new technologies that may appear in the future. Some AETs' costs may change little over the next 30 years, while others' costs may drop far below current expectations. For example, the cost of solar power fell by more than 80 percent over the course of the past decade, well beyond most predictions. Forecasting technology costs is particularly difficult because (1) it is not certain how large the effect of RD&D will be on a technology, and (2) even a small cost reduction from RD&D can turn into a much bigger reduction through deployment and subsequent learning-by-doing. Our analysis, however, provides several avenues to help address these uncertainties.

As discussed in Section 5.2.4., we find that the benefits of each individual AET increase when other technologies are less competitive. If all the AETs remain expensive in the future, even modest cost reductions in a single technology can result in a large benefit.

Our geothermal cost estimates are projections for 2030, which we decreased by 12.5 percent to extend them out to 2050. Between 2030 and 2050, geothermal could potentially become even less costly than the estimates we use. Unlike the other generating technologies, geothermal has a highly location-dependent cost and will likely be competitive at certain locations, where learning-by-doing can occur even before it becomes cost-competitive in most of the country.

6.2. Effects of Policy Assumptions

The results of this analysis are also highly dependent on which policies are assumed to be implemented over the next three decades. In this section, we discuss how key findings may change if different policies were simulated.

In the event of a weaker national clean electricity requirement or emissions cap-and-trade program than that in our simulated CES, we expect the benefits of the AETs to fall between our With CES and Without CES cases. Benefits of the AETs increase with more stringent emissions policies. With any national emissions standard, we thus expect benefits to exceed those of the Without CES case.

On the other hand, in the event of a more stringent national clean electricity requirement or emissions cap-and-trade program, such as a net-zero-emissions standard or a 100 percent-of-generation CES, we expect the value of the AETs to increase above the values currently stated in the With CES case.[9] More stringent policies would likely change the results in several ways. First, natural gas– or coal-fired power plants would no longer be allowed to operate on the electric grid without compensating capture of CO_2 (unless they were considered to be completely emissions-free). This would increase the value and prevalence of DAC units, particularly when advanced nuclear and NG-CCS remain expensive. Second, we would expect the value of geothermal, nuclear, and storage to increase.

In our model, the effects of a highly stringent emissions standard can be observed in Colorado, which has a net-zero power sector emissions cap in the year 2050. The AETs built in Colorado can be seen in maps in Appendix A. Even in the All High scenario, in which all the AETs are expensive, the model finds that building a large DAC unit would be a cost-effective means of compliance. In this scenario, DAC is used to offset emissions from natural gas and coal power plants with CCS. In the All Low scenario, in which both nuclear and geothermal are at their low costs, we see an increasing prevalence of advanced nuclear and geothermal in Colorado's generation mix. Even in this scenario, however, DAC remains an important component of meeting the zero-emissions cap.

While Colorado is useful for illustrating the impacts of a stringent CES, there are important differences between a Colorado emissions cap and a national emissions cap. Colorado can rely on its neighboring states for large imports of electricity from emitting sources. Such imports would play a much smaller role in a national zero-emissions policy, so we expect that AETs would play a larger role.

Policy support for DAC is a significant driver behind the use of this technology, and thus our model has DAC being built only in Colorado in the scenarios without a national CES. Although DAC has the potential to earn revenues from negative electricity prices and by selling the by-products of CO_2 capture, these revenues are rarely, if ever, enough for DAC to make a profit without also earning revenue from carbon and clean energy policies. One potentially significant carbon policy that we do not include in our simulations is California's Low Carbon Fuel Standard (LCFS). Although the LCFS directly allows DAC projects to earn credits, it is a transportation fuel policy rather than an electricity sector policy. Moreover, there is uncertainty about what LCFS credit prices will be in the future, making it difficult to include in our electricity sector model.

In the presence of an emissions fee or fixed-price clean electricity credit, the benefits of less costly AETs would consist mainly of reduced emissions and emissions damages, as the marginal cost of emissions reductions would be set by the fee or credit price. The

[9] In the national CES we model, energy lost during transmission and storage is not subject to the CES requirement, so polluting generators may still provide some generation, along with associated CO_2 emissions.

same logic would also apply if there were a clean electricity requirement or an emissions limit but the credit price were at the ceiling or floor, since then the policy would effectively be like an emissions fee or fixed-price clean electricity credit.

6.3. Other Modeling Assumptions

6.3.1. Electricity Demand and Electrification

To determine the levels of exogenous electricity demand, we use load projections from the EIA's Annual Energy Outlook 2019 for the United States and from the North American Electric Reliability Corporation (NERC) Electricity Supply & Demand (ES&D) database for Canada (U.S. Energy Information Administration, 2019; NERC, 2019). For the ES&D, which gives projections only up until 2030, we extend projections to 2050 by linearly extrapolating from the last projection year. To fully decarbonize the economy, many researchers think widespread electrification of industrial processes, transportation, and heating needs to occur. Such electrification would likely increase electricity demand and necessary generation past the exogenous levels of demand used in this study. The benefits of cheaper low-emitting generation, including AETs, would thus likely increase.

6.3.2. Multiday Scarcity and Storage

The E4ST model, as currently implemented, does not incorporate multi-day scarcity of renewable resources or multi-day storage. This likely has only a small effect, as our modeling for this study requires the simulated power grid to fully autonomously satisfy demand in some of the most extreme hours/days expected in a year. The simulated power grid should thus still be able to supply power, even in extended periods of scarcity.

Excluding multiday scarcity does, however, ignore potential benefits from long-duration storage, which here refers to energy storage over periods longer than one day (e.g., multiday storage, weekly storage, seasonal storage). Because of the likely high cost and limited capacity of long-duration storage, we expect this to have only a minor effect. Nonetheless, work is underway to add representations of multiday scarcity and long-duration storage to the E4ST model in order to better understand the effects.

6.3.3. Transmission Expansion

We make the assumption that new transmission spur lines can be built to connect new generation, storage, and DAC facilities to the grid, but that other transmission expansions cannot be made.

6.3.4. Non–Electricity Sector Benefits

Our analysis calculates only those net benefits that result directly from the electricity sector and DAC use in the United States. Cost reductions for the AETs can produce benefits both outside of the electricity sector and around the world. Outside of the power sector, electricity storage can support decarbonization of transportation, DAC can offset emissions from difficult-to-decarbonize sectors, and geothermal, NG-CCS, and nuclear can provide heat for various direct uses in industry and buildings. Also, the same innovation that improves AETs and makes them less costly could make other goods and services less costly. On a larger scale, we omit the benefits from the use of the less costly AETs outside the United States, although it accounts for only about one-fifth of world power generation, and cheaper AETs can provide benefits both inside and outside of electricity systems around the world. International deployment of AETs would have additional benefits to the US economy of greater exports if the less costly AETs are developed and exported by US companies.

6.4. Comparison with Economy-Wide Modeling of Direct Air Capture

In the results we have presented, DAC is used only in response to power sector clean electricity policies and thus only to offset a portion of power sector emissions. However, DAC has much more potential to be used as a compliance mechanism in policies that cover sectors with higher marginal abatement costs, such as the industrial and transportation sectors. In a parallel report, Hafstead (2020) uses an economy-wide model to simulate the four DAC cost scenarios with emissions target policies. Under a policy with cumulative emissions consistent with a path towards 2050 emissions that are 80% below 2005 levels, Hafstead (2020) finds that the level of DAC depends significantly on the level of future DAC costs. In his analysis, DAC storage (captured and sequestered CO_2) is projected to be 123, 520, 1152, and 1230 million short tons in 2050 under the High, Medium, Low, and Very Low cost scenarios. The amount of DAC storage also increases if the emission cap is made more stringent. For comparison, under the power-sector-only modeling in this report with a CES, DAC at low cost, and all other AETs at medium costs, DAC storage is projected to be 327 million short tons just to satisfy power sector emissions policies.

In Hafstead (2020), innovation in DAC lowers the economic cost of meeting economy-wide net emissions targets and the benefits of reducing the costs of DAC could be substantial. In his economy-wide modeling, the economic cost savings of reducing the cost of DAC from high to low are $57 billion in 2050 in the central policy scenario.[10]

[10] Under a cap-and-trade program, additional DAC utilization displaces gross emissions reductions and leads to increased local air pollutants. Hafstead's model is not able to quantify the costs of additional local

These welfare cost savings, or benefits, are approximately nine times as large as the $6.3 billion estimated net benefit of low-cost (vs. high-cost) DAC with a national CES in our power-sector-only modeling. The difference mainly reflects (1) the increased coverage in the Hafstead model, which includes all economy-wide emissions, and (2) the stringency of the policy, with compliance costs in his central policy scenario that are nearly three times as large as the compliance costs in our modeling. Finally, the economy-wide model includes general equilibrium effects that capture the benefits of reduced allowance prices and the corresponding reduction in energy prices when DAC technology costs decline. Economy-wide modeling would likely also increase the estimated net benefits of cost reductions for the other AETs, by widely varying amounts depending chiefly on how useful they are for purposes other than electricity generation or electricity storage.[11]

air pollutants at this time.

[11] A power sector model allows for a much more realistic and thorough representation of power sector effects, while an economy-wide model allows for representation of effects outside the power sector.

7. Conclusions

This study has assessed how much innovations in five different advanced energy technologies (AETs) are worth to society. These AETs are advanced nuclear generation (nuclear), generation with carbon capture and storage (NG-CCS), geothermally powered generation (geothermal), diurnal electricity storage (storage), and direct air capture of CO_2 (DAC).

We find that under a clean electricity standard that is equal to 100 percent of retail electricity sales, innovation in any one of the AETs has potential societal benefits of billions of dollars per year in 2050, in the form of reduced electricity supply costs and consequently lower electricity bills. For nuclear, NG-CCS, geothermal, and DAC, the benefits to society come only when a critical cost level is reached. After this threshold, even a $1 reduction in the levelized cost of nuclear and NG-CCS can produce benefits in excess of $1 billion annually. For storage, benefits of cost reductions are likely even if costs are at the high end of the range we consider. Cost reductions in all the AETs together could potentially lead to benefits of over $40 billion per year, depending on the cost reductions achieved.

Presuming there is no national target to decarbonize the electricity sector, the AETs can still have significant benefits to society. For modest cost reductions, the benefits of storage are larger than those of other AETs. For large cost reductions, our power sector model projects benefits from all technologies except DAC. DAC is more likely to be a cost-effective element of achieving net-zero targets in sectors with higher costs of emissions reduction, such as industry and transport. Cost reductions in the other four technologies together could potentially lead to benefits of over $15 billion per year, depending on the cost reductions achieved.

For comparison, our projection of the RD&D spending increase for the five AETs from enactment and full funding of the AEIA is approximately $1.75 billion per year.

We plan to provide cost experts' projections of how much enactment and full funding of the AEIA would reduce the costs of the five AETs by 2035 in a parallel report.

Appendix A Maps of AET Deployment

These maps show where, for a single scenario, the AETs are built and operated. The maps show only the AETs and not other conventional technologies that either already exist or are newly built in the simulations. Dot size corresponds to the electricity generated at the location over one year for generating technologies, the stored electricity released over one year at the location for storage, and the amount of CO_2 captured by DAC units over one year at the location.

Figure 9. Locations of AETs built in the high-cost scenarios

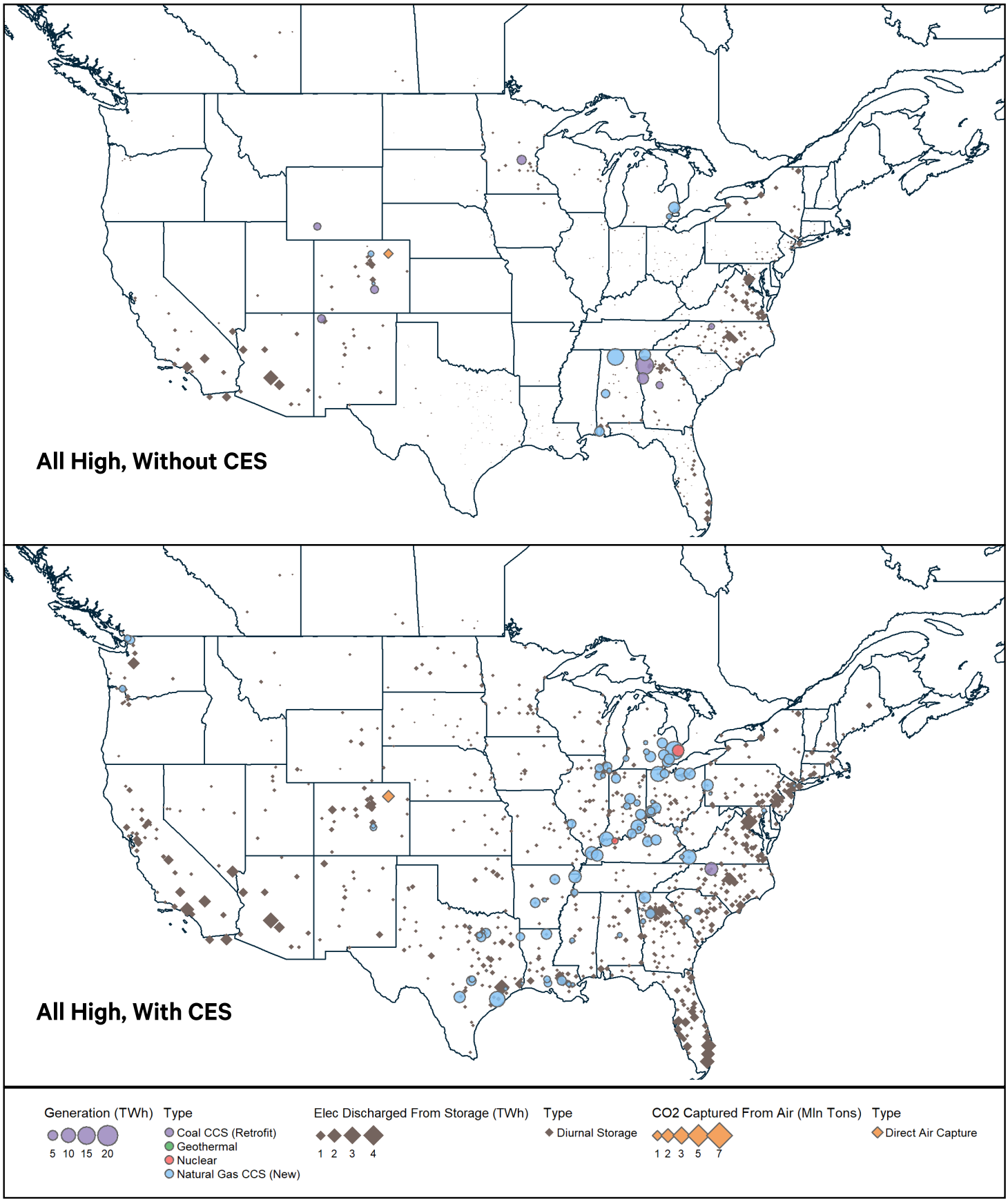


Figure 10. Locations of AETs built in the medium-cost scenarios

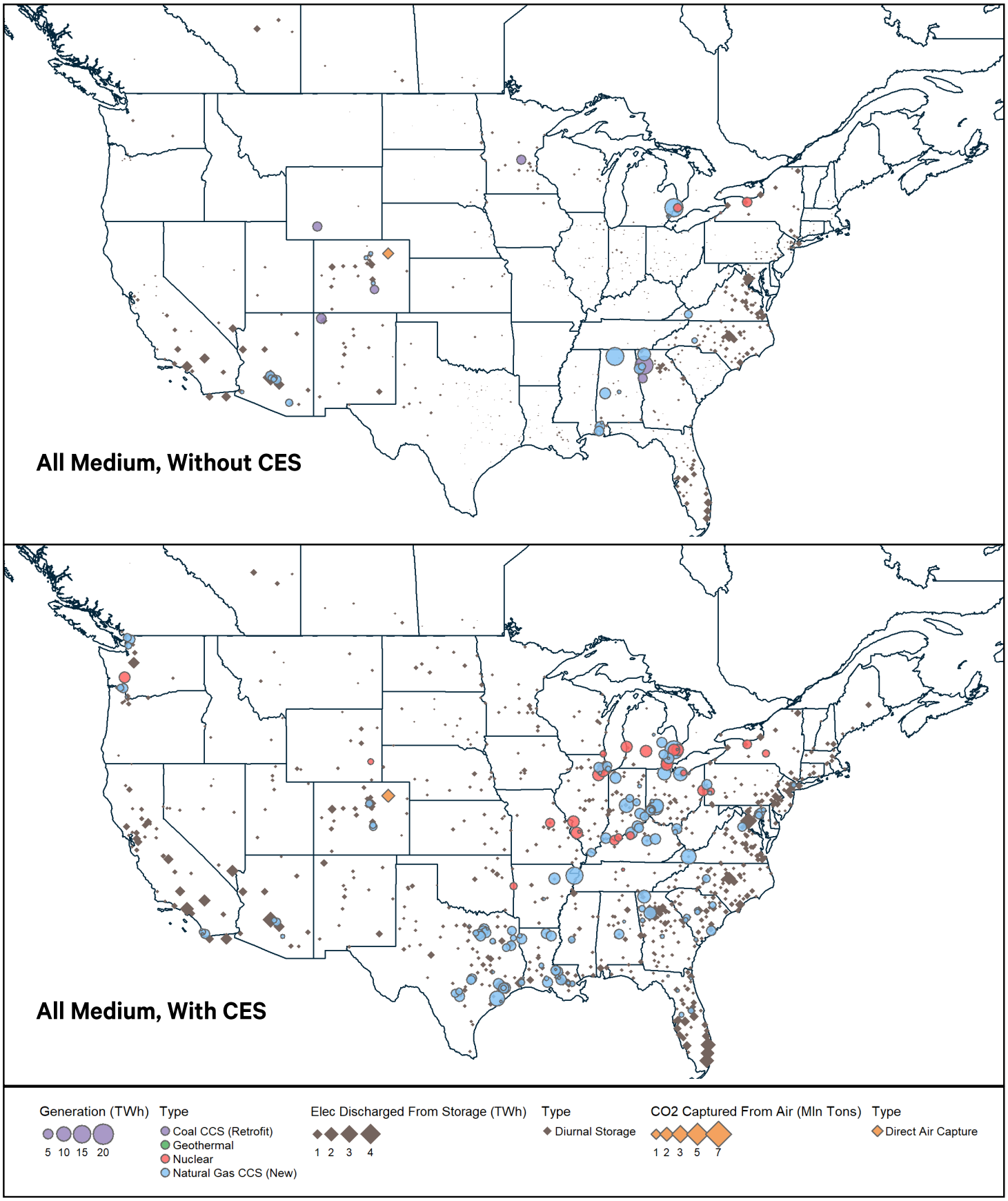
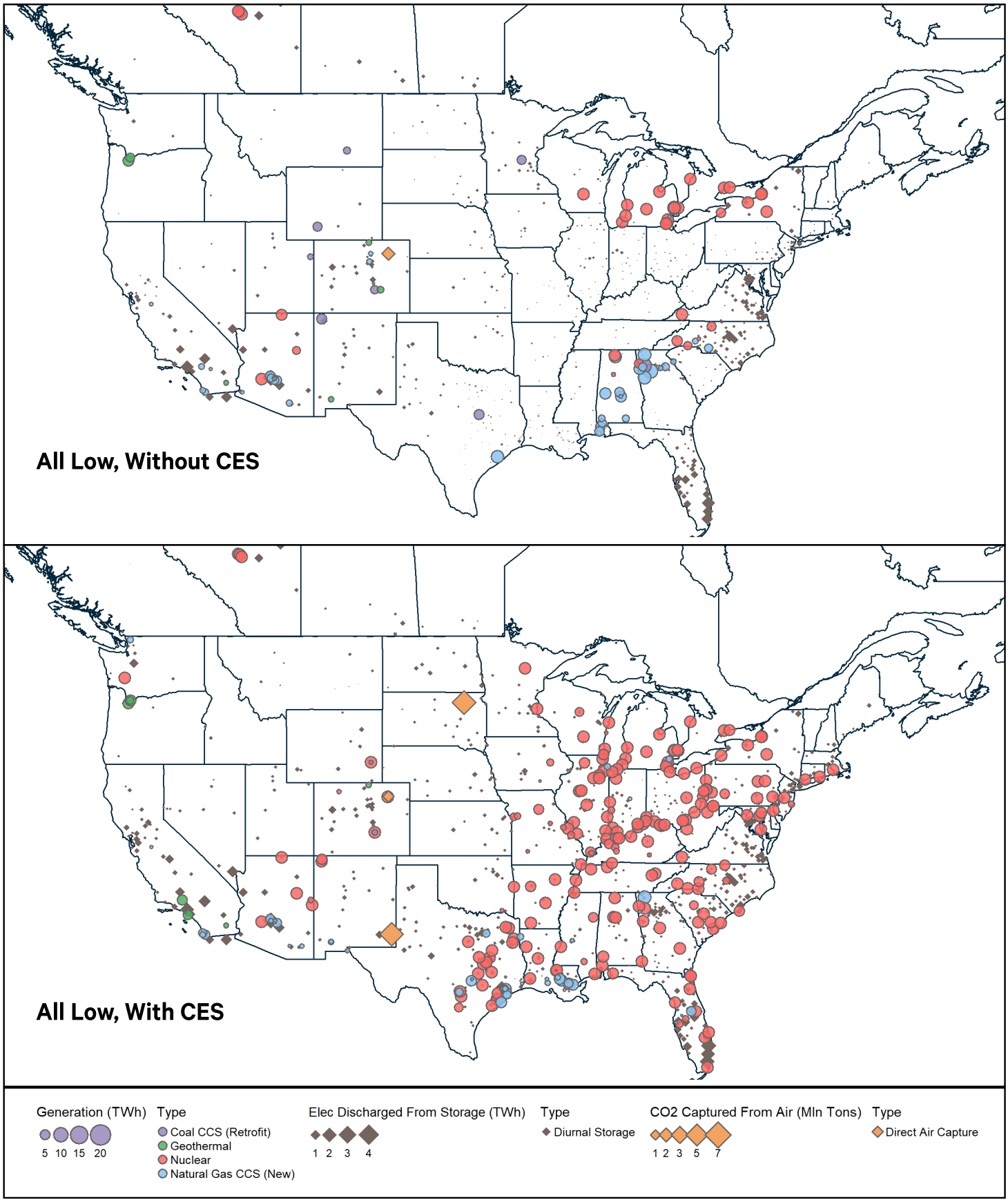


Figure 11. Locations of AETs built in the low-cost scenarios



Appendix B Detailed Cost Assumptions

This section contains more detailed descriptions of the cost and performance assumptions of each AET used in this analysis. For each AET, we present the high and low cost assumptions, as well as an estimate of current costs from the literature. For each AET cost level, we present an E4ST levelized cost and a standardized levelized cost. The former is the levelized cost using the case-specific financial assumptions that we use in the simulations, and the latter is a levelized cost that, for the purpose of comparison across cases, uses fixed financial assumptions of 4.0 percent weighted average cost of capital (WACC), 20-year economic lifetime, and a capital recovery factor of 7.36 percent.

For most technologies in E4ST, the costs to build a plant vary by location. Of the AETs, for NG-CCS and nuclear, we source variations in plant capital costs by sub-NERC region from the Annual Energy Outlook 2019 (U.S. Energy Information Administration, 2019). The costs in this section are national averages. Locational variations in geothermal costs are described in B3.. Storage and DAC costs do not vary by location.

B1. Advanced Nuclear

For our high cost of advanced nuclear in 2050, we use the 2020 ATB's projection for the cost and performance of a nuclear unit in 2050. For the low cost of advanced nuclear in 2050, we use the cost and performance of a future molten salt reactor (Richards et al., 2017). For comparison, we present the 2020 ATB's cost of nuclear in 2020 as the current state of the technology in Table 9. We assume an availability factor of 92 percent for nuclear plants. Additional sources we explored on low-cost projections came from the Energy Technologies Institute (ETI) and the Energy Innovation Reform Project (EIRP). The ETI report on advanced nuclear cost drivers (Ingersol et al., 2020) provides cost estimates for several types of advanced nuclear (light water, high temperature gas, liquid metal, and molten salt reactors), sourcing the costs from various national lab reports. They give a levelized cost of electricity of $51 for molten salt reactors. The EIRP report (EIRP, 2018) computed projected energy costs by compiling costs for advanced nuclear anonymously submitted by different companies, so while the study's low cost estimate is not transparent or attributed to a particular technology, it does provide a useful glimpse at a potential low cost estimate (LCOE of $36/MWh).

In E4ST, new nuclear plants are buildable at substations where at least 300 MW of either nuclear or coal capacity is currently connected. This is to restrict new nuclear plants to areas with the transmission infrastructure to support them.

Table 9. Cost and performance of advanced nuclear plants (in 2020$)

	Current	High	Low
Total cost to build (mln $/MW)	8.42	6.83	4.42
Required annual capital cost recovery (mln $/MW)	0.70	0.57	0.23
Annual fixed cost (mln $/MW)	0.12	0.12	0.10
Total variable cost w/ fuel ($/MWh)	10.53	10.53	2.79
Economic lifetime (years)	20	20	30
WACC	5.44%	5.44%	3.30%
Capital recovery factor	8.3%	8.3%	5.3%
E4ST levelized cost of energy ($/MWh)	112.85	96.39	44.18
Standardized levelized cost of energy ($/MWh)	102.70	88.16	55.49

B2. CCS

For our high cost of NG-CCS in 2050, we use the 2020 ATB's projection for the cost and performance of an NGCC-CCS unit in 2050. For the low cost, we use the cost and performance of a solid oxide fuel cell plant design from a yet-unpublished National Energy Technology Laboratory report. For comparison, Table 10 presents the 2020 ATB's cost of NGCC-CCS in 2020 as the current state of the technology.

These cost estimates include cost of capture and in-plant compression, but not the cost of CO_2 transport or sequestration, which we model (see Appendix B8.). We assume that NG-CCS plants have an availability factor of 85 percent and use a capacity factor of 80 percent in calculating the levelized cost of energy.

Table 10. Cost and performance of NG-fueled generating plants with carbon capture (in 2020$)

	Current	High	Low
Total cost to build (mln $/MW)	3.17	2.33	1.72
Required annual capital cost recovery (mln $/MW)	0.26	0.19	0.12
Annual fixed cost (mln $/MW)	0.028	0.028	0.038
Nonfuel variable cost ($/MWh)	5.90	5.90	5.26
Heat rate (MMBtu/MWh)	7.525	7.525	5.212
Total variable cost ($/MWh)	36.25	36.25	26.28
CO_2 capture percentage	90.0%	90.0%	98.1%
WACC	5.44 %	5.44 %	3.30%
Economic lifetime (years)	20	20	20
Capital recovery factor	8.3%	8.3%	6.9%
E4ST levelized cost of energy ($/MWh)	77.95	67.91	48.61
Standardized levelized cost of energy ($/MWh)	73.56	64.69	49.74

In E4ST, NG-CCS units are buildable at substations to which at least 100 MW of NG-fueled generation is already connected.

Coal CCS Retrofits. In E4ST, we allow existing coal plants the option to be retrofitted with systems that capture 90 percent of emitted carbon. The cost and performance of the retrofitted plants vary based on the characteristics of the existing plant and are based on the assumptions in the US Environmental Protection Agency's Platform v6 (EPA, 2018b). While we do not study coal CCS as a separate AET or vary its base costs among scenarios, we do tie its financial assumptions to that of NG-CCS, so its levelized cost improves as NG-CCS gets cheaper. New coal plants with CCS are not buildable in these simulations, since we found that they are not competitive with new NG-CCS plants.

B3. Enhanced Geothermal

We source both the high and low costs for enhanced geothermal systems (EGS) from the supply curves for deep enhanced geothermal presented in the 2020 ATB. We use the 2018 Base Scenario for the current costs and also the high costs, assuming that no technology improvement happens between now and 2050. The farthest-out projection for deep EGS in the ATB is the 2030 Advanced Scenario. To determine our low costs, we bring the 2030 Advanced Scenario up to 2050 by reducing the costs by 12.5 percent. This is equivalent to assuming a learning rate of 12.5 percent for geothermal and conservatively assuming one doubling of capacity between 2030 and 2050. Since the quality, quantity, and availability of geothermal resources depend on location, we use information on the available regional capacity of deep EGS for each temperature-depth pair in 134 US regions from NREL's Geovision study (Augustine, 2019). The cost of a deep EGS plant varies significantly based on temperature and depth, but for simplicity of comparison, Table 11 presents the costs for a plant that is built at a location with 250°C rock at 6 km deep. Some locations are able to build less expensive EGS plants at more favorable sites, but the 250°C/6 km class represents a relatively low-cost class of geothermal that is not extremely limited in buildable capacity. A single location in E4ST can build EGS plants at multiple depths. We assume an 85 percent availability factor for geothermal.

Table 11. Cost and performance of enhanced geothermal plants (in 2020$)

	High/Current	Low
Total cost to build (mln $/MW)	44.87	5.19
Required annual capital cost recovery (mln $/MW)	3.74	0.29
Annual fixed cost (mln $/MW)	0.42	0.13
Total variable cost ($/MWh)	0.07	0.02
Economic lifetime (years)	20	30
WACC	5.44%	3.70%
Capital recovery factor	8.3%	5.6%
E4ST levelized cost of energy ($/MWh)	559.7	57.7
Standardized levelized cost of energy ($/MWh)	501.6	70.0

B4. Diurnal Energy Storage

For our high and low costs of diurnal energy storage, we use the conservative and advanced estimates of the 2020 NREL ATB, respectively. The NREL ATB, however, assumes that batteries have no variable operating cost, which we believe is an unrealistic assumption. The operation of batteries leads to their degradation, implying that the operation does in fact have a variable cost. Furthermore, high battery variable costs disincentivize unrealistic cycling, which can be used to "waste energy" in the presence of negative electricity prices. Consequently, we transfer some of the NREL fixed costs and capital costs to variable cost. Assuming batteries fully charge and discharge once per day, our levelized cost of storage (LCOS) is the same as that that projected by NREL. Note that the variable cost and LCOS in Table 12 do not include the cost of purchased electricity for charging, since this is determined endogenously in the model. There are no limits on where storage units can be built in the simulations.

Table 12. Cost and performance of diurnal battery storage units (in 2020$)

	Current	High	Low
Total cost to build (mln $/MW)	1.73	0.66	0.27
Required annual capital cost recovery (mln $/MW)	0.123	0.046	0.018
Annual fixed cost (mln $/MW)	0.035	0	0
Total variable cost ($/MWh)	0	27.30	10.81
Storage efficiency	0.85	0.85	0.85
Economic lifetime (years)	20	20	20
WACC	3.3%	3.3%	3.3%
Capital recovery factor	6.9%	6.9%	6.9%
E4ST levelized cost of storage ($/MWh)	105.77	58.62	23.23
Standardized levelized cost of storage ($/MWh)	111.21	60.71	24.06

B5. Direct Air Capture

We use cost estimates for solid sorbent direct air capture plant designs from Sinha and Realff (2019) as our 2050 cost estimates, using the mid-low and mid-high cases from that report as our our low and high cost levels, respectively. We also include an additional electrical requirement of 0.48 gigajoules/metric ton CO_2 (0.121 MWh/short ton CO_2) for on-site CO_2 compression (NASEM, 2019). For comparison, Table 13 lists as current the costs for a liquid solvent plant design, scenario A in Keith et al. (2018). While this design has not yet been implemented at a commercial scale, the costs are informed by current pilot plant data. For the purpose of calculating levelized cost of carbon removed from the atmosphere in Table 13, we use an electricity cost of $45/MWh. The actual electricity cost is endogenous to the model and can differ based on scenario and location. DAC units are buildable throughout the United States in our simulations. These

cost estimates include the cost of CO_2 capture and in-plant compression, but not of CO_2 transport or sequestration, which we model (see Appendix B8.). We assume that thermal requirements for solid sorbent systems are satisfied by a mix of solar steam and waste heat, resulting in negligible additional net emissions. The liquid sorbent type used as the current cost burns NG and captures the CO_2, so some additional CO_2 transport and sequestration costs would apply. It also has CO_2e emissions due to the upstream effects of NG production. We assume an availability factor of 95 percent for DAC units.

Table 13. Cost and performance of direct air capture units (in short tons, 2020$)

	Current	High	Low
Total cost to build ($/ tCO_2/yr capacity)	1073	1425	528
Required annual capital cost recovery ($/ tCO_2/yr capacity)	89.43	118.67	27.96
Variable cost of thermal requirement ($/ton)	30.55	13.04	9.56
Electrical efficiency (MWh/ton)	0	0.4	0.26
Total variable cost ($/ton)	73.13	31.05	21.29
Economic lifetime (years)	20	20	30
WACC	5.44%	5.44%	3.30%
Capital recovery factor	8.3%	8.3%	5.3%
Levelized cost of gross removal ($/$tCO_2$)	167.2	155.9	50.71
Net thermal emissions (tCO_2e/tCO_2)	0.100	0.010	0.008
E4ST levelized cost of removal ($/$tCO_2e$)	185.9	157.7	51.1
Standardized levelized cost of removal ($/$tCO_2e$)	173.7	143.0	62.7

Direct air capture has a wide range of cost estimates in the literature because it is still undeveloped at commercial scales. Our low cost estimate of $51.1 per short ton is toward the lower end of that range, but the Rhodium Group projects that with widespread implementation and development, DAC costs could get as low as $46 per metric ton in 2018$ ($43 per short ton in 2020$) (Larsen et al., 2019). The lowest estimate of capture cost that we encountered in the literature is $16 per short ton, although the combination of factors required to reach this best-case cost may not be possible in practice (Sinha and Realff, 2019). DAC also has potential to earn profits from more than just policy credits. The CO_2 captured can be used to make fuels, chemicals, and building materials, allowing higher-cost DAC to have similar or greater net benefits to those in this analysis.

B6. Conventional Generation

In addition to the five AETs, the typical electricity generation options of non-CCS natural gas, solar, and wind are buildable in E4ST's simulations of 2050. With the exception of wind power, we source all the conventional technologies' 2050 cost and performance estimates from the 2019 NREL ATB. We source estimates for wind power from the 2020 ATB, using its Class 5 onshore and Class 10 offshore cost estimates. Details on the costs we assume for the most commonly built conventional technologies are in Table 14.

Table 14. Cost and performance of conventional generation in 2050 (in 2020$)

	Onshore wind[a]	Offshore wind	Solar	NGCC[b]	NGT[c]
Total cost to build (mln $/MW)	1.13	2.36	0.79	0.99	0.99
Required annual capital cost recovery (mln $/MW)	0.076	0.163	0.051	0.068	0.068
Annual fixed cost (mln $/MW)	0.03	0.04	0.02	0.01	0.01
Total variable cost ($/MWh)	0	0	0	28.92	47.12
Capital recovery factor	6.7%	6.9%	6.5%	6.9%	6.9%
Availability factor[d]	0.41	0.41	0.20	0.85	0.85
E4ST levelized cost of energy ($/MWh)	30.6	57.0	41.2	39.6	58.0
Heat rate (MMBtu/MWh)	NA	NA	NA	6.45	9.82

[a] In addition to the costs in this table, buildable onshore wind incurs a location-based transmission cost to connect the wind project to the grid.
[b] Natural gas–combined cycle
[c] Natural gas turbine
[d] Availability factors for wind and solar power are location-dependent, and some locations built in our simulations have higher availability factors than those in this table, resulting in lower levelized costs.

B7. Fuel Costs

We use projections of fuel costs in 2050 in each NERC subregion from the High Oil and Gas Resource and Technology scenario in the Annual Energy Outlook 2019. These have a national average of $4.03/MMBtu for NG, $2.14/MMBtu for coal, $19/MMBtu for fuel oil, and $0.74/MMBtu for uranium, all in 2020$. Our low advanced nuclear costs are based on a molten salt plant that uses thorium instead of uranium as fuel, so we use thorium costs from Richards et al. (2017).

B8. Carbon Transportation and Storage

In E4ST, DAC and CCS plants have the option of either selling their captured CO_2 for use in enhanced oil recovery (EOR) or paying for permanent sequestration of their CO_2 in saline aquifers. Both EOR and saline aquifer storage locations are limited in the amount of CO_2 they can accept in a year, so plants can send their CO_2 to multiple locations, and the price of sequestration in each state increases as the amount sequestered there increases. Plants must also pay for the transportation of CO_2 from the plant to the storage location. We get CO_2 storage costs, transportation costs, and state-by-state storage capacities from EPA's Platform v6 (EPA, 2018b).

Appendix C Policy Scenarios

C1. Without CES

In the Without CES scenario, there are no major new electricity-sector emissions policies in the United States other than those that have already been announced. Steps toward decarbonization of the electric grid are driven entirely by state and local regulations, as well as utility and corporate initiatives.

In this scenario, we simulate currently announced state renewable portfolio standards (RPSs) and regional emissions programs (such as the Regional Greenhouse Gas Initiative). All state RPSs are set to continue upward in the future at their current rates of increase instead of plateauing or disappearing as they do in some states under current law. This reflects the pattern that most states set RPS requirements for several years and plan to revisit them before they plateau or end.

Furthermore, this scenario includes voluntary purchasing of electricity from renewable sources. We estimate that these voluntary purchases continue upward at their recent historical rate, reaching 20 percent of electricity sales in 2050. Consistent with the rules of almost all current RPSs and CESs in the United States, we do not allow voluntary green power purchases to overlap with them. This voluntary green power purchasing that is equal to 20 percent of retail sales could alternatively be interpreted as a combination of voluntary green power purchasing and new utility and state and municipal clean energy policies that apply to the populations they serve, since we do not otherwise assume that any new utility, state, or municipal clean energy policies will be established between now and 2050.

Utility commitments are extremely difficult to model because of the large number of utilities and the high diversity of policies. We therefore simulate utility commitments in an approximate manner by imposing additional clean electricity requirements in selected states. Our approximate policies include (1) a 100 percent of retail sales in-state clean electricity standard in Alabama, Arizona, Georgia, Michigan, Minnesota, North Carolina, Virginia, and Wisconsin for which credits can be earned in any of the listed states; (2) a 100 percent of retail sales New Jersey clean electricity standard that can be satisfied anywhere in the PJM region; and (3) a net-zero power sector emissions requirement in Colorado. These are the states where the dominant utility or a dominant combination of utilities has a goal of net-zero CO_2 emissions or 100 percent carbon-free generation by 2050. In reality, not all utilities in these states have such a goal, and some utilities that have goals might not meet them. We expect, however, that resulting inaccuracies will be offset by the facts that multiple utilities outside these states also have goals, other utilities in these states have lesser goals (e.g., 80 percent emissions reduction), and other utilities inside and outside of these states are adopting such goals at a rapid pace.

Finally, we assume that Canada has a CO_2 emissions fee of US$36 per short ton and Mexico has one of US$42 per short ton. There are are no border carbon adjustments among the countries.

C2. With CES

In the With CES scenario, all policies in the Without CES scenario are simulated in addition to a US national clean electricity standard. The simulated CES is 100 percent of retail electricity sales (94 percent of generation) in 2050, and it has a benchmark emissions rate of 0.90 short tons per MWh (0.82 metric tons per MWh). In the CES, generators earn clean electricity credits proportional to their CO_2e emissions rate. For example, the benchmark emissions rate of 0.9 short tons per MWh means that a generator with a CO_2e emissions rate of 0.60 short tons per MWh earns one-third of a credit per MWh. Generators with emissions rates higher than the benchmark rate receive no CES credits, whereas generators with zero emissions receive one full credit per MWh. DAC units earn one credit for each 0.9 short tons of CO_2e that they capture and permanently sequester. DAC and storage units also have to buy clean electricity credits to cover the electricity that they consume in operation.

Appendix D Model Details

D1. Wind and Solar Data

D1.1. Wind Data

The US wind data are taken from the NREL Techno-Economic Wind Toolkit (Draxl et al., 2015). The raw data contain wind capacity and historical wind power outputs at over 120,000 potential offshore and onshore sites in the United States, at five-minute intervals. Of this data set, we use wind capacity and power outputs from the years 2008–10, aggregated to hourly averages. The wind sites in the data are then (1) filtered to remove sites in regions with population densities over eight persons per km^2, (2) filtered to remove sites farther than 200 km from a utility substation, and (3) clustered into potential wind farms by contiguity and proximity of wind sites. Each of the resulting wind farms (and the total capacity of the cluster) is represented as one buildable generator in E4ST. The availability factors of the wind farms are determined by the historical power output of the farm on a given representative day. The transmission distance is taken to be the shortest distance between a utility substation and any wind site of the wind farm, multiplied by 1.2 to account for any obstacles along the way.

For Canada, we repeat a similar procedure using data from Canadian Wind Energy Association (GE Energy Consulting, 2016)

D2. Solar Data

Solar data are taken from NREL's National Solar Radiation Database (Wilcox, 2012). Hourly solar radiation levels are extracted at each utility substation for the years 2008–10. These were then converted to solar availability factors using NREL's PVWatts calculator (Dobos, 2014).

D3. Representative Hours and Days

Because of the detailed spatial resolution of E4ST, modeling every hour would make the model too large to solve practically. We therefore, as other models of the electricity sector do, model only a handful of representative days. These days are carefully selected to represent accurately the frequency distributions of load, wind, and solar throughout a given time period. The representative days used in our modeling for this project are based on, and match, hourly data from the years 2008–10, except that electricity demand

is scaled up in each US region to match projected demand growth to 2050.

The value of different generating technologies is determined by the typical profiles of load, wind, and solar throughout the year, as well as by extreme values of load, wind, and solar. Our algorithm for selecting representative days thus consists of two parts: (*1*) selecting "average" days that represent the typical conditions expected throughout the year and (*2*) selecting days that represent the most extreme conditions.

For the typical conditions, we use the method described by Nahmmacher et al. (2016) to select 5 representative days consisting of 6 representative hours each (30 hours total).

To pick the extreme days, we determine for eight US regions the days with the most extreme hours of the following:

1. highest load
2. highest load and lowest wind
3. highest load and lowest solar
4. lowest wind and and lowest solar
5. highest load, lowest wind, and lowest solar

For the purposes of this study, an hour is considered extreme if it is within the 0.015 percent of most extreme hours in its category. Using a greedy algorithm, we select the lowest number of representative days that captures each of the above extremes for each NERC region. Within each of these selected days, we pick the most extreme hour and the least extreme hour to simulate. This procedure adds an additional 11 representative days with 2 hours each. The relative weight of extreme versus average hours is chosen in such a way that minimizes the deviation from historical frequency distributions of load, wind, and solar.

Appendix E Tables

Table 15. Annual net benefits of cost reductions of nuclear generation (Billions 2020$)

	High	Medium	Medium-Low[a]	Low	Very Low
LCOE ($/MWh)	96.390	70.288	57.193	44.186	38.663
Without CES	0.023	0.247	1.292	8.295	31.041
With CES	-0.525	0.523	9.741	28.318	38.452

Note: These values are visualized in Figures ES-1 and 4. The net benefits are relative to the scenario in which advanced nuclear is not deployed and all other AETs are at their medium cost.
[a] We included one extra cost between the medium and low costs to better estimate the point at which the technology becomes competitive.

Table 16. Annual net benefits of cost reductions of NG-CCS (Billions 2020$)

	High	Medium	Low	Very Low
LCOE ($/MWh)	67.906	58.261	48.615	42.538
Without CES	-1.108	-1.648	1.131	15.814
With CES	-0.208	1.806	15.026	25.114

Note: These values are visualized in Figures ES-1 and 4. The net benefits are relative to the scenario in which NG-CCS is not deployed and all other AETs are at their medium cost.

Table 17. Annual net benefits of cost reductions of enhanced geothermal (Billions 2020$)

	High	Medium	Medium-Low[a]	Low	Very Low
LCOE ($/MWh)	559.649	312.778	65.913	57.674	50.465
Without CES	-0.001	0.001	0.334	0.615	3.543
With CES	0.000	0.000	0.938	2.932	6.663

Note: These values are visualized in Figures ES-1 and 4. The net benefits are relative to the scenario in which enhanced geothermal is not deployed and all other AETs are at their medium cost.
[a] We included one extra cost between the medium and low costs to better estimate the point at which the technology becomes competitive.

Table 18. Annual net benefits of cost reductions of diurnal storage (Billions 2020$)

	High	Medium	Low	Very Low
LCOS ($/MWh)	58.624	40.929	23.235	20.331
Without CES	4.054	7.346	11.552	12.328
With CES	6.738	10.589	14.847	15.400

Note: These values are visualized in Figures ES-2A and 5A. The net benefits are relative to the scenario in which diurnal storage is not deployed and all other AETs are at their medium cost.

Table 19. Annual net benefits of cost reductions of DAC (Billions 2020$)

	High	Medium	Low	Very Low
LCOC ($/short ton)	157.707	104.418	51.128	44.736
Without CES	0.375	0.390	0.415	0.416
With CES	0.484	0.691	6.747	8.884

Note: These values are visualized in Figures ES-2B and 5B. The net benefits are relative to the scenario in which DAC is not deployed and all other AETs are at their medium cost.

Table 20. Composition of annual net benefits from reducing AET costs individually from medium to low without a national CES (Billions 2020$)

	Nuclear	NG-CCS	Geothermal	Storage	DAC
Electricity User	6.486	3.642	0.876	3.019	0.114
Generator Profits	-3.662	-1.318	-0.682	-0.527	0.036
Government Revenue	-0.078	-0.116	-0.133	-0.131	-0.001
Climate	3.963	0.664	0.546	1.744	-0.069
Health	1.338	-0.092	0.007	0.101	-0.055
Total	8.048	2.779	0.614	4.206	0.025

Note: These values are visualized in Figures ES-3A and 6A. Benefits are relative to the case where all AETs are at their medium cost and there is no national CES.

Table 21. Composition of annual net benefits from reducing AET costs individually from medium to low with a national CES (Billions 2020$)

	Nuclear	NG-CCS	Geothermal	Storage	DAC
Electricity User	37.896	22.936	5.505	3.912	4.676
Generator Profits	-14.545	-11.227	-2.837	1.705	1.848
Government Revenue	0.308	0.000	0.000	0.000	0.000
Climate	3.857	0.983	0.301	-1.219	0.838
Health	0.279	0.528	-0.038	-0.141	-1.307
Total	27.796	13.220	2.932	4.258	6.056

Note: These values are visualized in Figures ES-3B and 6B. Benefits are relative to the case where all AETs are at their medium cost and there is a national CES.

Table 22. Absolute generation mix in 2050 (TWh)

	Without CES			With CES		
	All High	All Medium	All Low	All High	All Medium	All Low
Coal	752.30	758.04	742.86	2.61	3.82	12.98
Natural Gas	1670.51	1600.16	1493.53	775.53	684.47	681.18
NG-CCS	47.58	113.69	172.55	390.93	553.85	164.12
Hydro	284.97	285.01	290.02	282.48	283.05	290.03
Nuclear	260.56	262.17	397.02	667.81	794.39	1811.42
Geothermal	20.50	20.58	43.05	19.08	19.79	57.55
Wind	931.65	910.26	835.89	1380.63	1303.78	1010.51
Solar	1024.57	1048.12	1017.79	1678.24	1545.91	1102.51
Direct Air Capture	-0.65	-0.74	-0.85	-1.01	-1.02	-5.99
Diurnal Storage	-10.61	-12.51	-14.98	-42.70	-41.76	-29.08
Coal CCS Retrofit	49.02	44.66	43.72	9.88	0.00	3.26
Other	96.03	96.38	96.85	60.89	67.15	81.54
Net Total	5126.43	5125.81	5117.45	5224.36	5213.43	5180.06

Note: These values are visualized in Figure 2

Table 23. Change in net benefits associated with cost reductions in all AETs simultaneously (Billions 2020$)

	Without CES			With CES		
	All High	**All Medium**	**All Low**	**All High**	**All Medium**	**All Low**
Electricity User	0.000	5.663	15.793	0.000	29.373	74.803
Generator Profits	0.000	-2.303	-6.304	0.000	-15.071	-32.253
Government Revenue	0.000	-0.051	-0.174	0.000	0.000	0.075
Climate	0.000	1.019	5.753	0.000	0.950	4.697
Health	0.000	-0.337	0.849	0.000	0.160	0.081
Net Total	0.000	3.991	15.917	0.000	15.412	47.403

Note: These values are visualized in Figure 3. For scenarios without a national CES, net benefit values are shown relative to the All High, Without CES case. For scenarios with a national CES, net benefit values are shown relative the the All High, With CES case. Electricity user benefits come from electric bill savings as a result of lower electricity prices. Climate benefits come from the decrease in greenhouse gas emissions, and health benefits result from changes in SO_x and NO_x pollution.

Table 24. Changes in 2050 generation mix (TWh) when all technologies are at their medium costs and one technology is reduced to its low costs, without a national CES

	Nuclear Low	**NG-CCS low**	**Geothermal Low**	**Storage Low**	**DAC Low**
Coal	-8.72	-0.29	1.00	-11.93	0.59
Natural Gas	-24.61	-56.29	-6.61	-13.71	4.96
NG-CCS	-112.65	178.61	-14.96	-20.91	-3.13
Hydro	-0.90	0.27	4.87	-1.04	0.03
Nuclear	311.87	-5.35	1.77	-2.13	-1.37
Geothermal	0.04	0.17	68.74	-0.11	0.00
Wind	-55.13	-36.00	-15.61	-15.37	-0.05
Solar	-108.26	-72.83	-37.48	67.46	-0.75
Direct Air Capture	0.12	0.28	0.02	-0.02	-0.49
Diurnal Storage	2.72	2.14	0.45	-6.23	0.12
Coal CCS Retrofit	-9.59	-15.54	-2.36	3.38	-0.35
Other	0.04	0.36	0.24	0.23	0.07
Net Total	-5.06	-4.45	0.06	-0.38	-0.36

Note: These values are visualized in Figure 7A. Values are changes from the scenario in which all AETs are at medium costs and there is no national CES. For generating technologies, negative values indicate a decrease in generation with the cost reduction, while positive values indicate an increase in generation with the cost reduction. For diurnal storage and direct air capture, which consume electricity in operation, negative values indicate an increase in usage with the cost reduction, while positive values indicate a decrease in usage.

Table 25. Changes in 2050 generation mix (TWh) when all technologies are at their medium costs and one technology is reduced to its low costs, with a national CES

	Nuclear Low	NG-CCS low	Geothermal Low	Storage Low	DAC Low
Coal	3.68	0.64	1.43	0.86	10.23
Natural Gas	48.51	-159.67	53.00	37.00	605.95
NG-CCS	-551.06	605.32	-188.62	-22.21	-427.68
Hydro	0.78	1.88	6.72	-0.33	1.57
Nuclear	1199.17	-163.35	-82.37	-24.18	-130.58
Geothermal	0.41	0.44	380.94	0.05	0.07
Wind	-271.59	-110.86	-45.20	-8.70	-24.71
Solar	-488.96	-194.57	-130.62	33.74	25.23
Direct Air Capture	0.61	0.67	0.57	0.07	-91.30
Diurnal Storage	18.36	6.27	4.30	-19.32	9.43
Coal CCS Retrofit	2.16	0.00	0.00	0.00	0.00
Other	9.16	4.69	1.27	0.72	8.19
Net Total	-28.78	-8.55	1.43	-2.30	-13.60

Note: These values are visualized in Figure 7B. Values are changes from the scenario in which all AETs are at medium costs and there is a national CES. For generating technologies, negative values indicate a decrease in generation with the cost reduction, while positive values indicate an increase in generation with the cost reduction. For diurnal storage and direct air capture, which consume electricity in operation, negative values indicate an increase in usage with the cost reduction, while positive values indicate a decrease in usage.

Table 26. Average US retail electricity prices (cents/kWh) in 2050 for five scenarios with a national CES

	All Medium	Nuclear Low	NG-CCS Low	Geothermal Low	Storage Low	DAC Low
Credit Prices & Transfers	7.08	3.65	5.44	6.39	6.66	4.90
Distribution & Transmission	6.10	6.32	6.26	6.16	6.11	6.17
Marginal Generation Cost	-1.12	1.31	-0.11	-0.61	-0.79	0.90
Total	12.06	11.27	11.59	11.95	11.98	11.97

Note: These values are visualized in Figure 8

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