REPORT

# PATHWAYS TOWARD GRID DECARBONIZATION:

## IMPACTS AND OPPORTUNITIES FOR ENERGY CUSTOMERS FROM SEVERAL U.S. DECARBONIZATION APPROACHES

Clean Energy Buyers Institute

Resources for the Future

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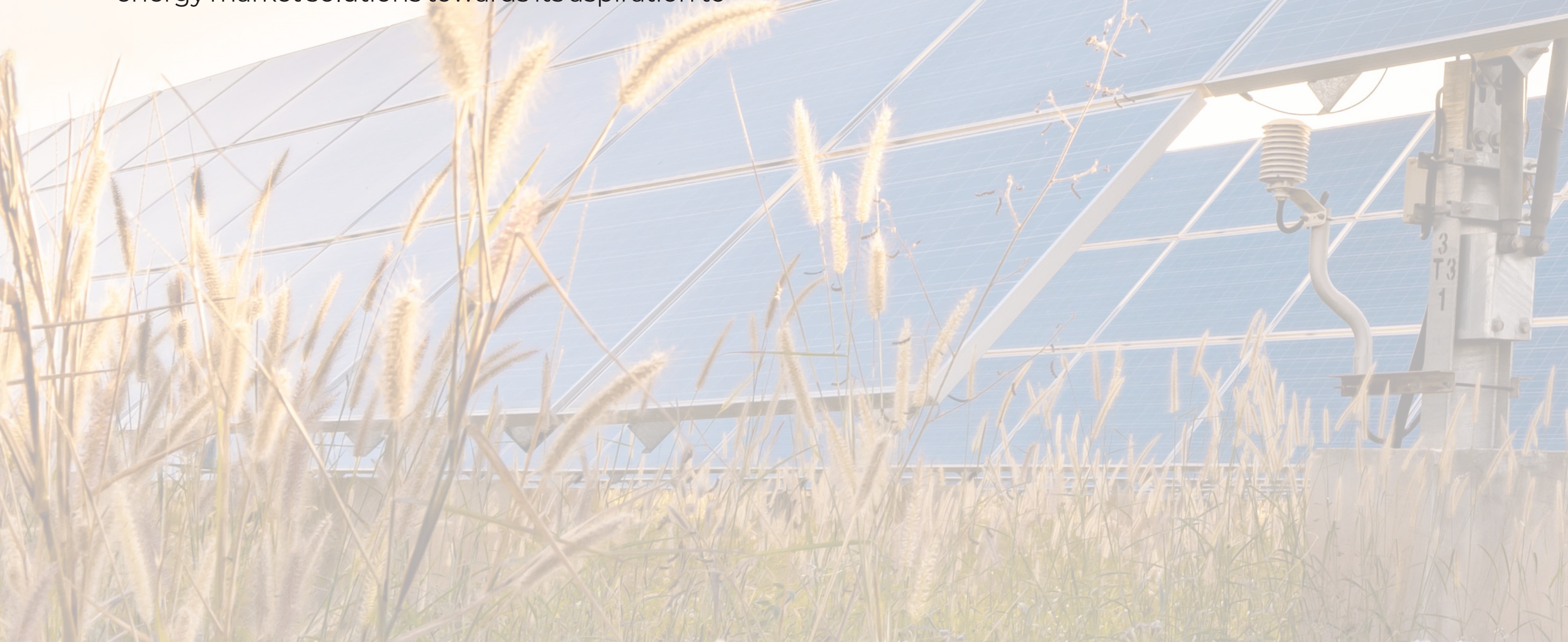
The Clean Energy Buyers Institute (CEBI) is a non-profit organization focused on solving the toughest market and policy barriers to achieving a carbon-free energy system in collaboration with policymakers, leading philanthropies, and energy market stakeholders. The Institute strives to be a center-of-excellence for advancing research and development of innovative clean energy market solutions towards its aspiration to achieve a 90% carbon-free U.S. electricity system and to cultivate a global community of energy customers driving clean energy. Three key market transformations will support achieving its bold aspiration, including: unlocking markets for energy customers, catalyzing communities of energy customers, and decarbonizing the grid for all.



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The power sector is the second largest source of greenhouse gas emissions in the U.S. and accounts for one-quarter of total emissions. Decarbonization of the power sector can play a leading role in cost-effective, economy-wide emissions reductions given that deep emissions reductions are projected to cost more in other sectors, and electrification is expected to be the lowest-cost means of decarbonizing many energy-using activities (NASEM, 2021). In this report, we examine the effects of several pathways to reduce GHG emissions in the U.S. power sector, and the impacts and opportunities for energy customers. For a brief summary of implications of the recently passed Inflation Reduction Act on this study, see the Summary for Policymakers.

## 1.1 DECARBONIZATION PATHWAYS EVALUATED IN THE ANALYSIS

We project the effects of the following key pathways:

1. A national clean electricity standard (CES)—both a Fast CES (100% clean generation target by 2035) and a Slow CES (100% clean generation target by 2050).
2. Utility-led Decarbonization—all vertically integrated investor-owned utilities (IOU) fully decarbonized by the end of 2050.
3. A national transmission macrogrid consisting of 7,830 miles of high-capacity direct-current transmission lines, constructed by 2035.
4. Expansion of competition among generators via expansion of organized wholesale electricity markets (OWMs) to the parts of the U.S. that do not currently have them.
5. Expansion of supply choice to almost all commercial and industrial (C&I) customers, combined with the OWM expansion just described.

These pathways can be combined for larger total net benefits. In addition to considering the effects of the individual pathways, this report evaluates the effects of certain pathway combinations, specifically:

- Combination of a national CES with a national transmission macrogrid
- Combination of a national CES with expansion of OWMs
- Combination of supply choice and OWM expansion

We project and evaluate the impacts of these pathways and combinations across several electricity sector outcomes in 2035 and 2050, including generation mix, emissions, retail prices, net benefits, and employment. Additionally, we project each pathway's effects on commercial and industrial (C&I) customers' access to clean electricity.

To help inform consideration of an 80% by 2030 (80x30) national CES, this report also projects the effects of such a policy in 2025 and 2030.

# 1.2 DECARBONIZATION PATHWAYS
## KEY TAKEAWAYS

Table 1 reports the effects of each pathway on two core metrics: GHG emissions from the power sector and net benefits to society. The following key takeaways from this analysis are informed by those outcomes as well as other results discussed in this report.

- The national CES pathways are the only pathways considered that approach full decarbonization of the U.S. power sector in the timeframe modeled. Both a Fast and Slow CES can reduce U.S. power sector emissions more than 90% by 2050. A Fast CES can reduce emissions faster by a 2030-2035 timeframe, but our analysis suggests that there is a balance to be struck between pace and cost.

- Every pathway produces emissions reductions and several billion dollars of annual net benefits, with a national CES producing the largest emissions reductions and approximately $100B per year in estimated net benefits by 2035. Other pathways varied greatly (see Figure 1).

- Full decarbonization by all vertically integrated IOUs by 2050 would, in that year, produce approximately half of the net benefits of the national CESs we model.

- The transmission macrogrid and OWM expansion would each reduce both costs and emissions. The estimated benefits of the macrogrid are three to four times the estimated costs, and include a net national average retail electricity rate reduction of approximately 1%. OWM expansion is estimated to save $11 billion per year.

- Large increases in clean generation can be achieved with relatively small projected price impacts.[1] For example, increasing 2035 clean generation from 42% in the reference scenario to 87% via the Fast CES increases projected national average retail electricity rates by 7%.[2] Increasing 2035 clean generation to 78% via the Slow CES increases rates by only 3%.

- The pathways would affect customers' ability to voluntarily choose green power. OWM expansion would increase access to green power, and adding supply choice would further increase it. A national CES or utility-led decarbonization could increase or decrease access, depending on utilities' and regulators' choices regarding voluntary green power access but would help accelerate greening the grid for all customers.

- Both CES pathways increase projected energy sector jobs through at least 2035. During the years 2023-2035, the Slow CES results in an average of just over 200,000 more jobs than the reference scenario. The Fast CES results in an average of nearly 300,000 more jobs than the reference scenario. During 2036 through 2050, the CES pathways have smaller effects on jobs, with the Slow CES still resulting in more jobs than the reference scenario and the Fast CES resulting in fewer jobs than the reference scenario. The Utility-led Decarbonization results in approximately 50,000 more jobs during 2023-2035 and fewer jobs during 2036-2050, compared with the reference scenario.

[1] For consistency, "clean" generation is defined for all purposes in this report as generation that would be considered clean under our CES policy assumptions. The cleanness of each MWh generated is determined by how far the $CO_2e$ emissions associated with its generation are below 0.4 metric tons per MWh. If a generator's emissions rate is zero then its generation is 100% clean. If the emissions rate is above 0.4, it is 0% clean, and if the emissions rate is between 0 and 0.4 the generator is considered partially clean, with the percentage depending on where the emission rate falls between 0 and 0.4.

[2] These rate impact projections assume no national clean electricity tax credits. Such credits would reduce the electricity rate impacts of a CES.

**Table 1: Net Benefits and Greenhouse Gas Emission Reductions from Pathways**

| Pathway | Description | Annual Net Benefits (Billion 2020$/year) | | Electricity Sector GHG Reductions (compared to reference in same year) | |
|---|---|---|---|---|---|
| | | **2035** | **2050** | **2035** | **2050** |
| Fast CES | A national CES with a target of 100% clean in 2035 | $88.1 | $107.5 | 78.8%* | 94.1%* |
| Slow CES | A national CES with a target of 78% clean in 2035, and 100% in 2050 | $77.2 | $110.6 | 59.9% | 93.4%* |
| Utility-led Decarbonization | All vertically integrated investor-owned utilities achieve 70% clean generation by 2035 and 100% by 2050 | $22.2 | $52.8 | 19.1% | 37.5% |
| Transmission Macrogrid | A national high-voltage DC transmission macrogrid is constructed by 2035 | $4.9 | $9.8 | 1.3% | 2.6% |
| OWM Expansion | OWMs are expanded throughout the U.S. | $18.8 | $24.0 | 7.5% | 8.1% |
| OWM & Supply Choice Expansion | OWMs are expanded, and electricity supply choice is expanded to almost all C&I customers | $19.9 | $24.5 | 9.6% | 9.8% |

*Note: The reason that the CESs do not achieve 100% clean generation is that we assume that there are caps on the prices that the CES credits can reach, based on the caps in recently proposed U.S. legislation. These price caps limit the costs of complying with the CESs.

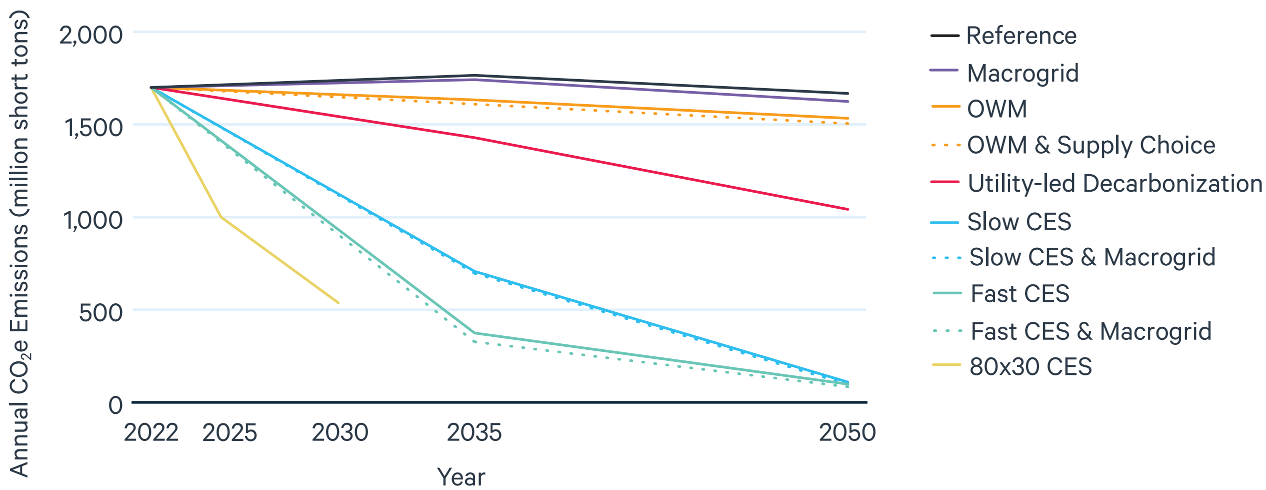
## 1.3 MODELING APPROACH

We use an advanced power sector model called the Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST) to project the effects of these pathways. There is one exception: the effects of OWM expansion are better estimated via other methods, so for that pathway we instead rely on prior studies.

All projected effects in this report are relative to outcomes in the same year in a reference scenario with no new national clean energy or environmental policies. The results are careful projections of what would happen in each pathway, but perfect predictions are not possible.

# 1.4 A NATIONAL CLEAN ELECTRICITY STANDARD (CES) PROVIDES THE GREATEST GHG EMISSION REDUCTIONS, REDUCING U.S. POWER SECTOR EMISSIONS BY MORE THAN 90%

**FIGURE 1** U.S. annual power sector $CO_2e$ emissions resulting from each decarbonization pathway and combination of pathways evaluated




We found that all decarbonization pathways reduce power-sector GHG emissions when compared to the reference scenario, but the magnitude of the reductions varies widely, as shown in Figure 1. A 100% national CES can reduce emissions more than twice as much as 100% decarbonization by vertically integrated IOUs, which in turn reduces emissions more than twice as much as organized wholesale market expansion or a national macrogrid. These CESs increase the share of clean generation far above the 42% share that is achieved in 2035 in the reference scenario.

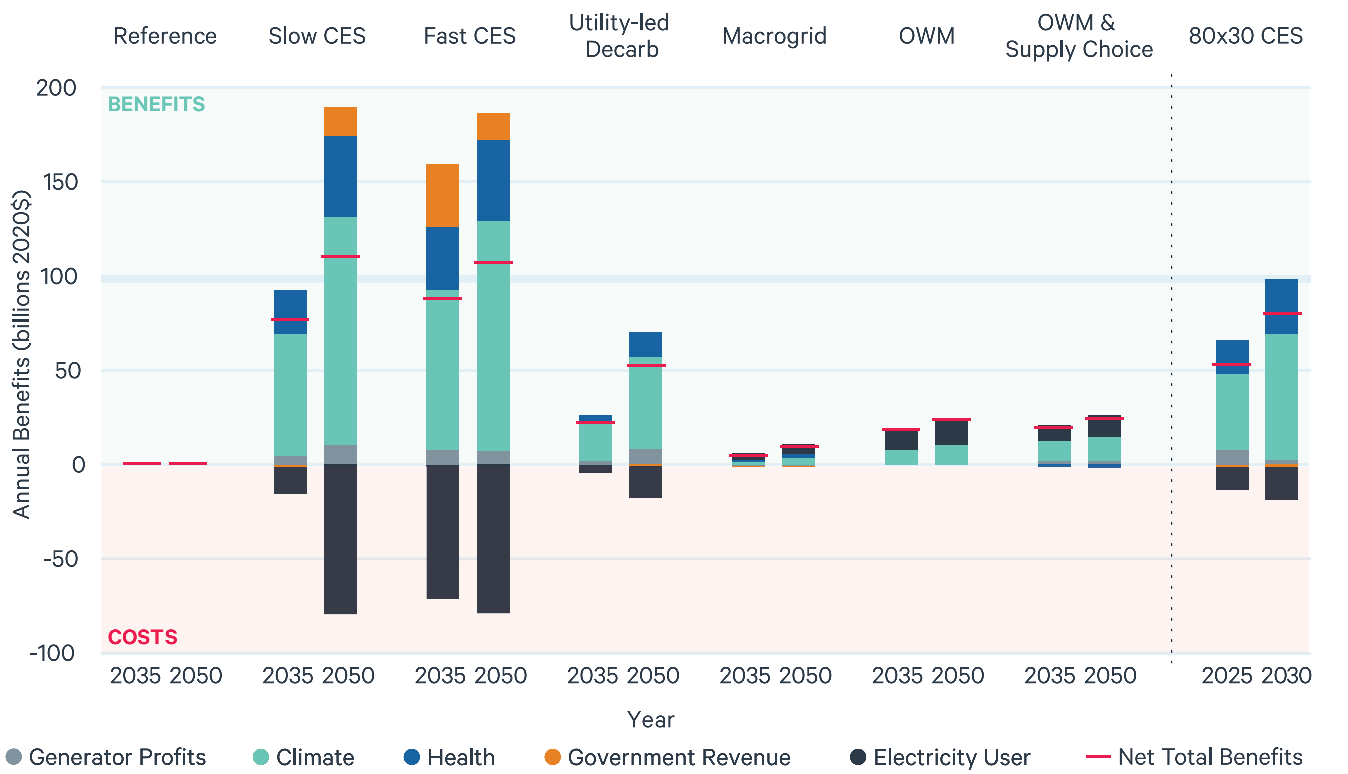
The reason that the CESs do not achieve zero emissions is that we assume that there are caps on the prices that the CES credits can reach, based on the caps in recently proposed U.S. legislation.[3] These price caps limit the costs of complying with the CESs.

Combinations of the pathways can reduce emissions more than any one of the pathways alone. Figure 1 illustrates this for a CES combined with the macrogrid. Also, OWM expansion can combine well with other pathways to further reduce emissions, since it tends to facilitate the transition to non-emitting generation.

[3] The Slow CES that we model has credit price caps of $46 in 2035 and $85 in 2050. The Fast CES has credit price caps of $54 in 2035 and $85 in 2050. All dollar values in this document are in 2020 U.S. dollars.

# 1.5 ALL PATHWAYS RESULT IN BILLIONS OF DOLLARS OF ANNUAL NET BENEFITS, WITH CESs PRODUCING THE LARGEST NET BENEFITS OF APPROXIMATELY $100B PER YEAR

**FIGURE 2** Projected benefits, costs, and net benefits of each pathway




For each pathway, we estimate overall net benefits to the U.S. These consist of the estimated benefits from less global climate change, fewer premature deaths in the U.S. from sulfur dioxide and nitrogen oxide emissions, higher or lower generator profits, the positive or negative effects on electricity user bills, and in some cases government revenue that can be used to reduce taxes.[4] Figure 2 shows the estimated value of each of these benefits and costs. Segments above the zero-line are benefits, while segments below are costs. Total net benefits are indicated by the short horizontal line and are equal to the benefits minus the costs.

The CESs produce the largest estimated net benefits of the pathways studied. Even after netting out the bill increases for electricity users, the estimated annual net benefits of both CESs approach $100 billion in 2035 and exceed $100 billion in 2050.

While not as large as the CES benefits, the net benefits from each other pathway studied are at least several billion dollars per year. Full decarbonization by vertically integrated IOUs produces approximately half as much net benefits by 2050 as the CESs do. This utility-

[4] We assume that climate damage is $61 per short ton of $CO_2e$ in 2035 and $77 per short ton of $CO_2e$ in 2050.

led decarbonization reduces U.S. power sector greenhouse gas emissions by 38% in 2050, with a 3% national average retail rate increase in 2050. A national CES policy could achieve the same amount of national emission reductions at an even lower cost.

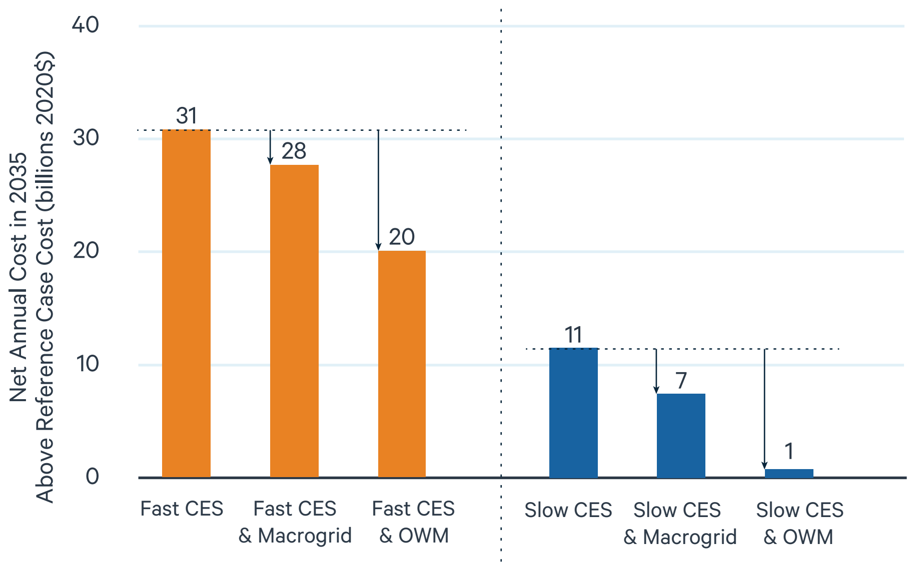
The other pathways save money. As Figure 2 shows, the macrogrid, OWM, and OWM & Supply Choice pathways reduce non-environmental costs, which produces pocketbook benefits for electricity users, generation owners, or both.

The estimated benefits of the macrogrid that were modeled are three to four times the estimated cost to build, finance, and maintain it. The estimated net benefits amount to $5 billion in 2035 and $10 billion in 2050. All net benefit and retail price estimates for pathways involving the macrogrid, such as those in Figure 2, are net of the costs of constructing and operating the macrogrid.

Expanding OWMs to all parts of the country provides an estimated $11 billion in annual cost savings as of 2035, due to more efficient investment, operation, and retirement decisions. It also reduces emissions and the resulting annual emissions damages by an estimated $8 billion. In the presence of a national CES or emission cap-and-trade program that did not reach its credit price cap, it would primarily make emission reductions less costly rather than further reducing emissions.

# 1.6 COMBINING A CES WITH COMPLEMENTARY PATHWAYS CAN OFFSET COSTS OF A CES

**FIGURE 3** Effects of CESs and policy combinations on total non-environmental annual cost of U.S. electricity supply in 2035




Combining a CES with cost-saving actions such as OWM expansion or suitable transmission expansions can result in a lower total electricity supply cost than a CES alone, offsetting some or even all the cost of the CES. Figure 3 compares the costs of the Fast CES and Slow CES, both on their own and combined with two complementary decarbonization pathways. As before, the Fast CES and its two combinations target 100% clean generation by 2035 while the Slow CES and its two combinations target 78% clean generation by 2035. The cost shown is the difference in total net annual system cost of electricity in 2035 relative to the reference scenario.[5] For example, the Fast CES results in a total annual electricity supply cost that is $31 billion higher than in the reference scenario. Adding the macrogrid reduces that annual cost by $4 billion, to $27 billion higher than in the reference scenario. Adding the macrogrid has a similar cost-reducing effect in the presence of the Slow CES. When OWM expansion is added instead, it reduces the projected annual electricity supply cost by $11 billion and can almost completely offset the projected cost of the Slow CES. While not shown in Figure 3, implementing the macrogrid and OWM expansion together would likely reduce the electricity supply cost further than either of them alone and could more than fully offset the cost of the Slow CES in 2035. The sum of the cost savings from both a macrogrid and OWM expansion is more than the estimated cost of the Slow CES in 2035.

In Section 4.7, we consider some additional effects of the pathway combinations that are shown in Figure 3.

[5] These cost projections include operational costs and amortized capital costs of generation and transmission. They do not include environmental or health damages.

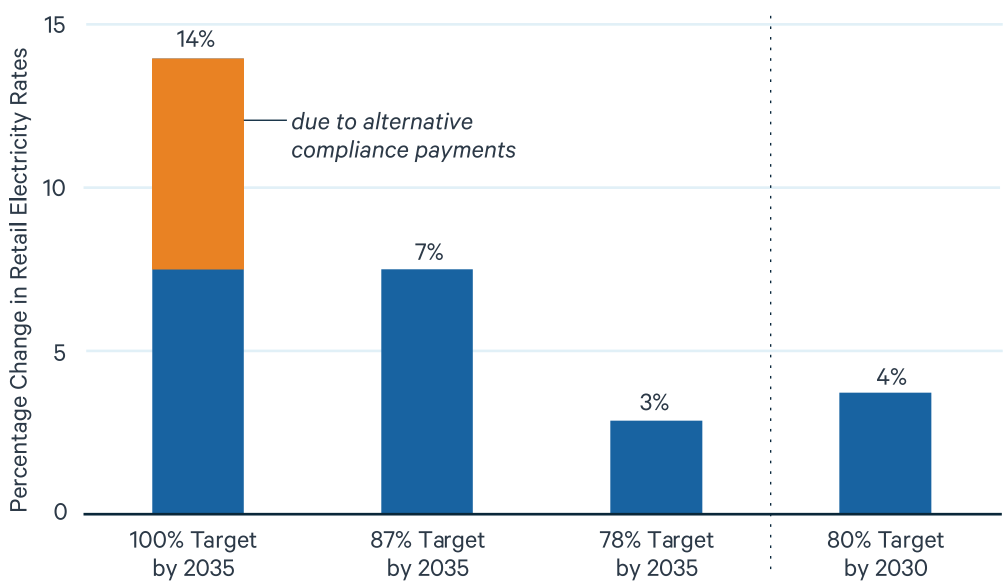
# 1.7 LARGE NEAR-TERM INCREASES IN CLEAN GENERATION CAN BE ACHIEVED WITH RELATIVELY SMALL PRICE IMPACTS

Our modeling indicates that ambitious near-term targets, such as an 80%-by-2030 CES, an 87%-by2035 CES, or a 100%-by-2035 CES with a $54 credit price cap, are worthwhile. These CESs increase the share of clean generation far above the 42% share that is achieved in 2035 in the reference scenario. The estimated benefits are larger than the estimated costs, as shown in Figure 2. However, if they are considered too costly to be politically viable, it might be necessary to reduce the cost.

Making the targets less ambitious can be doubly helpful for reducing the cost because it not only reduces the amount of clean energy required, but it also reduces the average cost per additional percentage point of clean energy as shown in Figure 4. For example, a 100%-by-2035 CES with a $54 credit price cap raises average national retail electric rates 14%, while an 87%-by-2035 CES raises them only 7%. This is an illuminating comparison. The 100% CES achieves 87% clean generation in 2035, not 100% in that year, because of the $54 CES credit price cap. For the remaining 13% of generation, it is less costly to pay the $54 per MWh alternative compliance fee than to pay for clean generation.The alternative compliance payments go to the U.S. government and allow it to reduce other taxes or increase investments or services. As a result, modeling results predict that an 87% CES would achieve the same amount of clean energy in 2035 as a 100% CES, but would increase retail rates by only about half as much, (7% vs 14%). The cost savings on electric bills would be offset by an approximately equal loss of government revenue.

The projected retail rate increase from a 78%by-2035 CES is even smaller, only 3% in 2035. Therefore, the modeling projects that clean generation can be increased from 42% to 78% by 2035 with a retail rate increase of just 3%.

**FIGURE 4** Effect of CES on average retail electricity rate, relative to reference scenario with no CES



Timing of targets matters too. Reaching similar levels of decarbonization, especially for decarbonization that is more ambitious, may have less impact on retail rates when it happens over a longer period. Quicker decarbonization can cost more because the need to rush can increase costs and because power plants that are constructed later may be less costly as technologies advance over time. On the other hand, more clean energy development in early years can cause more learning-by-doing, which can reduce costs later. That is an effect that is not incorporated or estimated in this study.

The electricity rate effects in Figure 4 assume that the cost of complying with the CES is passed along to energy customers in the form of higher rates. Section 4.2.8 discusses results of an alternative scenario under which the U.S. government covers that incremental cost. The modeling results estimate that a government outlay of $38 billion per year in 2035 covers the electricity bill increase from the Fast CES. An outlay of $16 billion per year in 2035 covers the electricity bill increase from the Slow CES. These outlays are just snapshots of the year 2035; the cost of such a policy would likely be lower in earlier years, higher in later years as the CES becomes more stringent, then lower again after the pace of needed clean energy investments slows. Policymakers could raise some of the funds to reduce the rate impact of a CES by charging electricity generators for emissions above an established benchmark emission rate. This added feature would also make the policy more efficient at reducing emissions.

## 1.8 EMPLOYMENT EFFECTS

Using an employment effects model, the report estimates the energy sector job effects of three clean energy pathways: the Fast CES, the Slow CES, and the Utility-led Decarbonization pathway. All three of these pathways produce a construction jobs boom that is largest in the earlier years of the 2022-2050 timespan. All three pathways also gradually reduce fuel supply jobs. The net effect is that all three pathways result in more energy sector jobs than the reference case in the near term, but they have mixed effects in later years which are even harder to predict. From 2023 to 2035, relative to the reference scenario, the Fast CES results in higher projected U.S. energy sector employment by an average of approximately 290,000 net jobs, the Slow CES by approximately 210,000 net jobs, and the Utility-led Decarbonization by approximately 50,000 net jobs. See Section 5 for full jobs analysis.

# 1.9 EFFECTS ON ELECTRICITY USERS' OPTIONS FOR BUYING CLEAN ELECTRICITY

This report examines each pathway's effects on C&I customers' access to options for voluntarily purchasing clean electricity. Both the national CES and Utility-led Decarbonization pathways would increase the mandatory clean generation delivered to customers. The pathways might reduce or increase C&I customer access to voluntary clean power procurement, depending on whether utilities and regulators react to the mandatory decarbonization policy by reducing, retaining, or improving voluntary access.

Expanding organized wholesale electricity markets increases C&I voluntary clean power access, particularly through financial, or virtual, power purchase agreements (PPAs). Expanding C&I supply choice combined with wholesale electricity markets further increases C&I voluntary clean power access, particularly through competitive suppliers and physical PPAs. See Table 1 for estimates of emissions reductions and net benefits of these two pathways.

Additional transmission capacity would not directly affect C&I customers' options for purchasing clean power but would tend to make clean power less costly for customers.

Readers interested in reading more but not necessarily the full report may be interested in the concluding summary in Section 8, which summarizes the findings in a complementary manner by pathway rather than by type of effect.

# 02 GENERAL METHODS AND ASSUMPTIONS

## 2.1 OVERVIEW

This report examines the effects of several decarbonization pathways for reducing $CO_2$ emissions in the electric power sector in the U.S. The pathways involve national clean electricity standards, electric utility-led decarbonization commitments, expansion of organized wholesale electricity markets, expansion of supply choice to more electricity customers, and construction of new long-distance transmission lines. An advanced power sector model is used to project the effects, benefits, and costs of each, as of 2035 and 2050. The exception is that for the CES that targets 80% clean electricity by 2030, we project the effects in 2025 and 2030.

## 2.2 ANALYTIC APPROACH

This analysis employs E4ST, a highly detailed simulation model of the U.S. electric power sector. The E4ST model was used to determine how each pathway's changes to policy, transmission, and market structure influence the future of the electricity system.

The pathways that we examine in this study can be divided into enabling, local mandatory, and national mandatory pathways. The enabling pathways enable voluntary actions that lower costs and emissions. These pathways include organized wholesale market expansion, supply choice expansion to all U.S. C&I customers served by investor-owned utilities, and a new set of long-distance, high-capacity transmission lines. The local mandatory pathway modeled is the adoption of clean generation commitments by all vertically integrated investor-owned utilities, which involves local (utility-specific) mandates that customers consume generation from clean sources. Modeling assumes that these utility commitments reach 70% by 2035 and 100% by 2050.

The national mandatory pathways we modeled are two nationwide CES designs, which are differentiated by the speed with which they aim to decarbonize the electricity sector. The Slow CES is based on previous U.S. Congressional proposals that have aimed for nearly 100% clean electricity by 2050: the Clean Energy Standard Act of 2019 (introduced by Senator Smith) and the Clean Energy Innovation and Deployment Act of 2020 (introduced by Representative DeGette). The Fast CES is based on the CLEAN Future Act of 2021, which was designed to implement President Biden's aspiration to fully decarbonize the power sector by 2035.

In general, in the reference scenario and for all model inputs that are standard across all pathways, we use medium assumptions, intended to best estimate future circumstances. Appendix 11.2 discusses these assumptions and model inputs.

# 2.3 THE E4ST POWER SECTOR MODEL

E4ST is a simulation model of the U.S. electric power sector with high spatial resolution in transmission, renewable resource profiles, generating resources, and electricity demand. E4ST predicts construction and retirement of grid-serving electricity generating units and simultaneously predicts hourly operation of generating units and the grid in future years. Among the model's outputs are hourly locational wholesale electricity prices and emissions of carbon dioxide ($CO_2$), methane, sulfur dioxide ($SO_2$), and nitrogen oxides ($NO_x$). For more details about the E4ST power sector model, see Appendix 11.

E4ST also calculates the following components of total net benefits of a change to the power sector: reduced electricity consumer bills, changes in generator profit and government revenue, estimated value of health benefits from reduced air pollution, and estimated value of climate benefits from reduced GHG emissions.[7] Sometimes one or more of the components are negative. When that is the case, it reduces the net benefits. For details on how we value health and climate effects from the power sector, see Appendix 11.2.5.

The buildable technologies in the model include solar photovoltaics (single-axis tracking), onshore wind, offshore wind, natural gas combined cycle (NGCC), natural gas turbines, natural gas with 99% carbon capture (NG-CCS), 90% carbon capture retrofits on existing coal plants, nuclear, diurnal battery storage, and multi-day storage (based on hydrogen produced from non-emitting electricity generation). Natural gas CCS retrofits and new coal-fired plants, with and without CCS, are not included because they are assumed to not be cost competitive. We use cost and performance projections for new units from the 2020 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) (NREL, 2020). For more details on technology cost and performance assumptions, see Appendix 11.2.1

[7] Note that "net benefits" in this report only includes benefits directly related to the results of the pathways in the electricity sector. It does not include societal benefits outside of the electricity sector. All dollar values in this document are in 2020 U.S. dollars.

# 2.4 EXISTING POLICIES

All state renewable portfolio standards (RPSs) currently on the books are included in the reference and all other scenarios (Barbose, 2021). The total RPS requirements for each state, as well as in-state carveouts for solar and wind, are represented in the modeling. For RPSs that plateau in or after 2021, the applicable state's percentage requirement is extended upward in the future at the state's pre-plateau rate of increase, replacing the plateau with the upward assumptions. This is only done for states in which no alternate energy legislation, such as an emissions cap or CES, has been announced to replace the RPS.

In addition to the RPSs, all announced state CESs that had been passed as legislated requirements or goals or set as targets by executive orders, by the time we set up our simulations, are included. This was done because we anticipate that states will continue to adopt clean electricity standards, and the states with goals or executive orders are, on average, more likely to adopt them than other states are.

The current U.S. cap-and-trade policies are included, specifically the Regional Greenhouse Gas Initiative and California's AB32. We do not assume the continuation of any tax credits or other national subsidies for clean generation. The 10% solar investment tax credit is on the books with no current end date, but that does not mean it will necessarily still be in effect in 2035 or 2050, especially because solar power will be more mature then than it is now.

# 2.5 EFFECTS OF MARKET STRUCTURE

Electricity market structures vary widely in the U.S. In some places, vertically integrated utilities leave consumers with no choice of their energy supplier, in some places, consumers have full choice of electricity suppliers that participate in an organized wholesale market (OWM) and some places are somewhere in between. In this study, we consider three factors which define the market structure blend of each state:

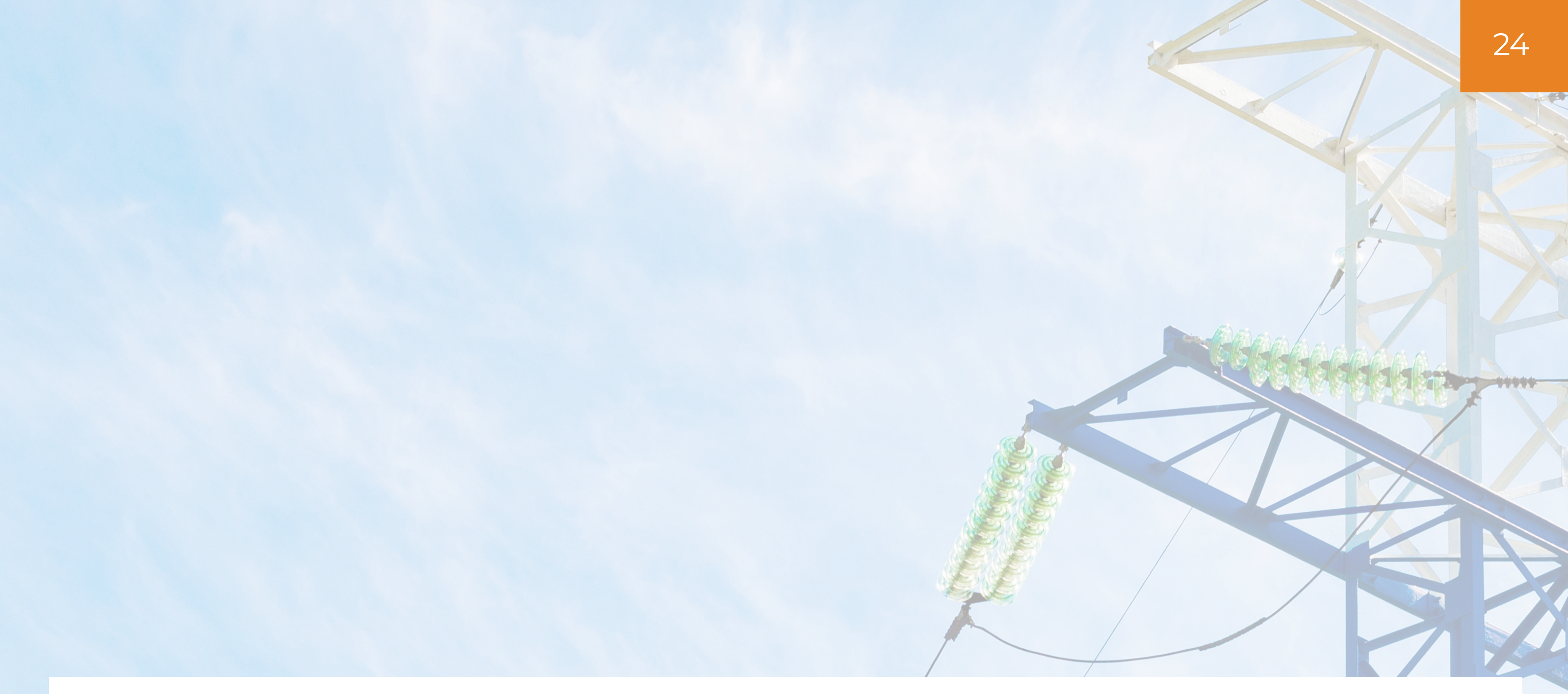
1. How much of the state is in an OWM.
2. The prevalence of cost-of-service (COS) regulation of power plants.
3. The prevalence of supply choice, the ability of electricity customers to choose their electricity supplier.

In most of the modeled pathways, we assume that the status quo with respect to market structure by location persists into the future. However, in two pathways we assume that OWMs expand to the parts of the U.S. that do not currently have them, and in one of those two pathways we assume also that supply choice expands and COS regulation correspondingly shrinks (see Appendix 11.2.9). These assumptions are included because it is common for expanded OWMs to coexist with COS regulation of generating units, but it is uncommon for supply choice to coexist with it. The effects of these market structure changes were projected on the efficiency of dispatch of fossil fueled generating units and on the voluntary purchasing of electricity from renewable sources. The effects were incorporated into the model. For OWM expansion, benefit estimates were extracted from existing studies of the effects of OWMs to predict how it would affect emissions, cost of the electricity supply, and total net benefits.

In practice, fossil-fueled generating units tend to be operated more than an optimal economic dispatch model would predict, and this overuse depends on the type of market in which that generating unit participates. We find that fossil-fueled generation is less overused when it dispatches into an OWM than when it doesn't, and similarly is less overused if it is not COS regulated than if it is COS regulated. The E4ST model was adjusted to represent this behavior, so that the share of fossil fueled generation in the simulations more closely reflects reality. For details on the projection of the effects that market structure types have on the efficiency of dispatch of fossil fuels, see Appendix 10.1.

There is a growing tendency of electricity customers, particularly C&I customers, to purchase power specifically from renewable sources, as shown in the Clean Energy Buyers Association (CEBA) Deal Tracker. Historical data on voluntary green power (VGP) purchasing indicates that VGP purchasing is increasing over time and is higher in states that participate in OWMs and/or have supply choice Heeter and O'Shaughnessy, (2020). To represent this, we estimated and implemented VGP purchasing as a percentage of load on a state-by-state basis. In partnership with the National Renewable Energy Laboratory (NREL), we developed a statistical model based on historical VGP data to estimate how VGP purchasing is influenced by the presence or absence of OWMs and of supply choice. For more details on the estimation and implementation of VGP purchasing, see appendices 10.2 and 11.1.4, and for details on the effects that increased VGP purchasing has on the power sector, see section 4.6.

Some methods of voluntarily purchasing green power incur additional costs, which is referred to as the VGP markup. This markup depends on both the size of the purchaser and local market features. See Appendix 10.2.2 for more details on these markups.



# 2.6 ELECTRICITY DEMAND AND TRANSMISSION

The electricity demand in our simulations is based on the medium electrification scenario in the NREL Electrification Futures Study (Mai et al., 2020). This modeling choice results in an increase in continental U.S. annual retail sales to 4,688 TWh in 2035 and 5,817 TWh in 2050.[8] These quantities demanded are respectively 24% and 53% higher than actual retail sales in 2019. Much of this growth in demand is driven by adoption of electric vehicles. In the medium electrification scenario, 66% of all light duty vehicles on the road in 2050 are plug-in electric vehicles. Of those, 57% are hybrids and 44% are pure electric (Mai et al., 2018).

In all pathways, a neutral transmission growth assumption was used, in which the capacity of each existing AC transmission line grows by the same factor that the national electricity demand grows. As a result, in our model, the capacity of each existing transmission line increases 53% by 2050. In reality, transmission capacity will instead tend to expand in places where such expansion is most valuable. Since this transmission expansion was included in all pathways, we do not measure its net benefits or employment impacts. In the macrogrid transmission pathways, in addition to the neutral transmission growth assumption and adding in a high-voltage direct current (HVDC) macrogrid, we allow AC transmission around the HVDC terminals to further increase their capacity so that the macrogrid's use is not unrealistically constrained by constraints in the AC lines near the HVDC line terminals.

In total, by 2050, the assumed U.S. transmission capacity as measured in GW-miles increase by approximately a factor of 2 in the macrogrid pathways and 1.5 (100% + 53% = 1.53 relative to 2019) in the other pathways. However, because our 1.5-fold expansion of the capacities of the existing transmission lines is spread across all lines, it is not the same as a 1.5-fold expansion in transmission capacity concentrated in the places where expansion is most valuable. As a result, simulations in this report are transmission-constrained relative to some visions of the future in which total GW-miles of transmission capacity are expanded by a similar amount or a larger amount.

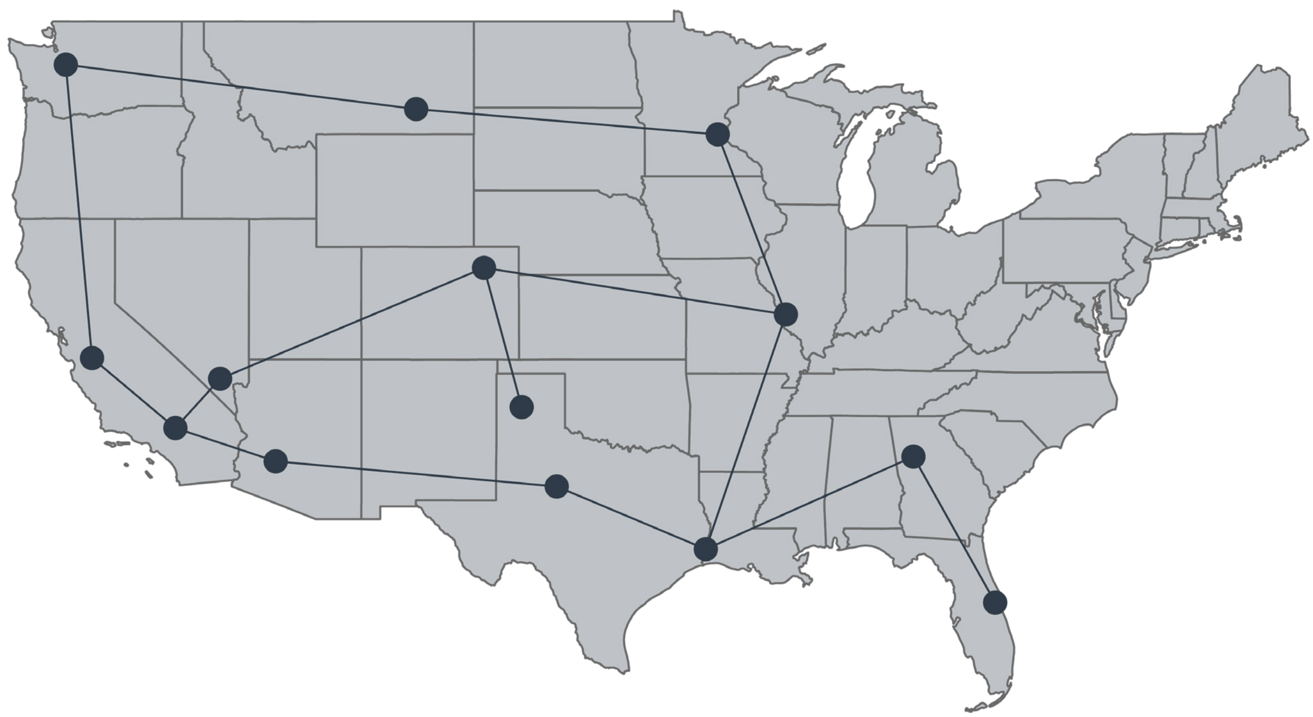
[8] We also assume an average electricity transmission and distribution loss rate of 6.3%, so these retail sales quantities are 93.7% of the total power-plant generation required to satisfy those retail sales.

# 2.7 MACROGRID DETAILS

In the Macrogrid pathway, as well as in some combination pathways with CESs, we model the addition of a high-voltage direct current (HVDC) "*macrogrid*." This macrogrid spans the three major interconnections in the U.S. and allows significant transmission across time zones. In particular, our macrogrid is designed to be similar to the HVDC grid from the Design 3, high-variable-generation case in NREL's Interconnections Seam Study (Bloom et al., 2020), and the macrogrid proposed in (Osborn, 2016). This analysis models the macrogrid in Figure 5, which connects 14 substations with 7830 miles (straight-line distance) of 8,066-MW capacity lines, for a total of around 63,150 GW-miles of HVDC lines. The 8,066-MW capacity of these lines can be compared with the total capacity of grid-serving generators in the U.S. in 2019, which was 1,197,917 MW. This capacity on single transmission path is unusual in the world today.

In reality, lower-capacity lines may be more likely, but there could be more of them such that the total GW-miles of new long-distance capacity built are the same. This analysis is still indicative of the effects of building new long-distance, inter-regional transmission capacity.

**FIGURE 5** High-voltage DC macrogrid represented in this study. The lines have a capacity of 8 GW



In the macrogrid scenarios, it is assumed that the macrogrid is online by 2035, and that generation investment in the years leading up to 2035 has been planned with the macrogrid in mind. To represent the expansions in the AC transmission system that would be made near the terminals of a new line with such a large capacity, line capacity constraints are eliminated in the model on the line segments that are directly connected to the DC line terminals (0.9% of the segments in our model of the U.S. and Canadian power grid) and double the line capacity constraints on the line segments that are adjacent to them (5% of the segments in our model). This results in an additional AC transmission line expansion around the HVDC terminals of about three to five thousand GW-miles in 2035 and four to six thousand GW-miles in 2050.

By combining cost estimates of the macrogrid from the Interconnections Seam Study with cost estimates of AC transmission from NREL ReEDS documentation (Brown et al., 2020), we estimate that the total investment cost of our HVDC macrogrid and adjacent AC line expansion is just above $50 billion dollars. A weighted average cost of capital (WACC) of 5.7% and an economic lifetime of 50 years is assumed to get a capital recovery factor of 6.1%, and so the annualized cost of the macrogrid is around $3.2 billion per year. The macrogrid scenarios factor the recovery of this macrogrid cost into retail electricity prices and subtract it from consumer savings.

## 2.8 EMPLOYMENT EFFECTS

The NREL Jobs and Economic Development Impact (JEDI) suite of models is used to estimate the employment effects of three of the pathways (NREL, N.D). The JEDI tools estimate both construction and operating and maintenance (O&M) jobs related to constructing and operating energy facilities and infrastructure such as power plant components, fuel production facilities, and engineering services. The JEDI tools take input expenditures from the E4ST power system model outputs for capital cost, fuel, fixed O&M, and variable O&M. Appendix 12 describes the employment effects estimation in greater detail. In section 5, this report provides estimates of the energy sector employment effects of three of the pathways.

# 03 CROSS-CUTTING RESULTS

# 03 CROSS-CUTTING RESULTS

The results charts showcased in this section are referred throughout the report as they relate to the effects of each individual pathway.

## 3.1 GENERATION BY TYPE

**FIGURE 6** Annual generation by type

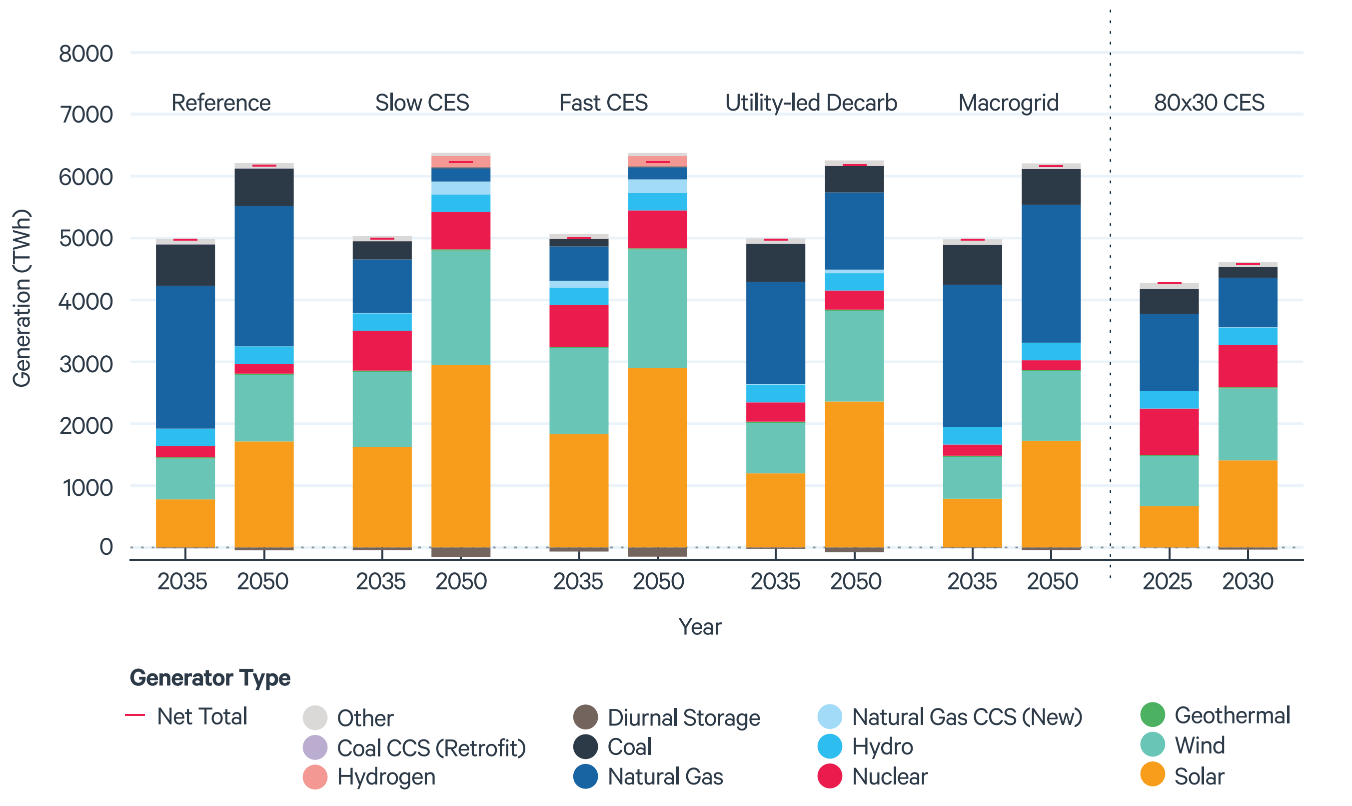


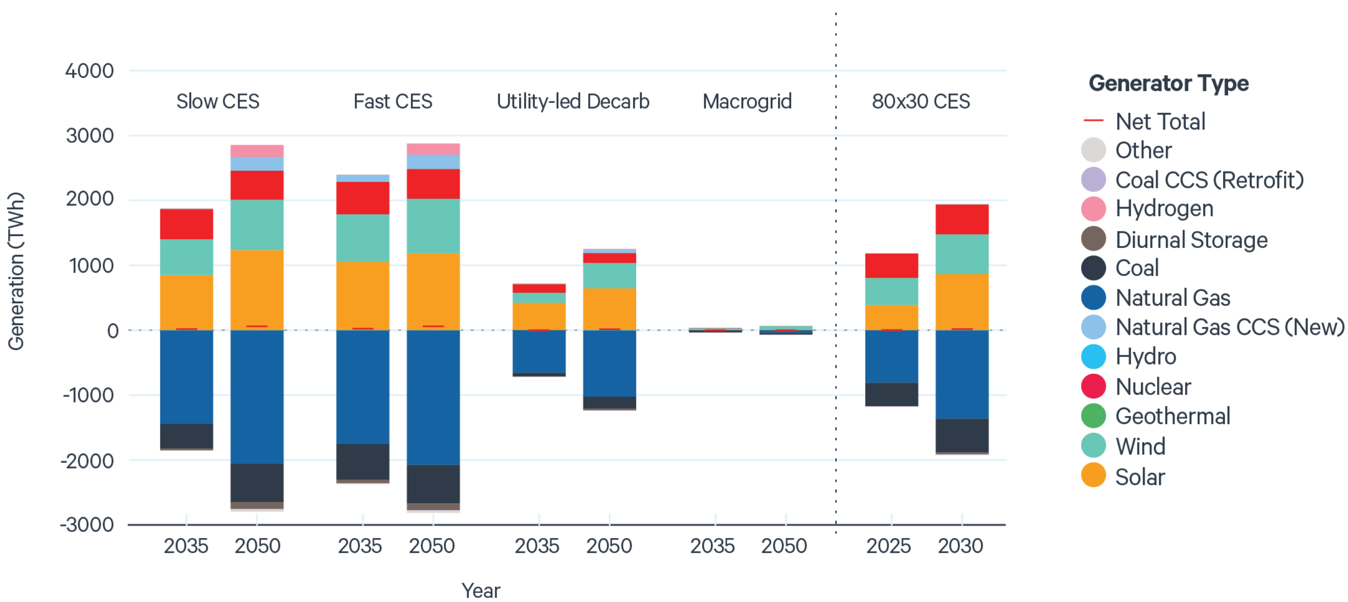

Figure 6 shows annual generation by primary energy source, also known as the *generation mix*, in each pathway. Table 2 likewise shows the percent of annual U.S. generation that is clean.[9] In the reference scenario, clean generation accounts for 42% of U.S. generation in 2035 and 55% in 2050. This clean generation comes chiefly from solar and wind, followed by existing hydropower facilities and less than half of the currently existing nuclear plants. A non-trivial amount of diurnal energy storage, such as battery storage, is built and used. Diurnal storage produces negative net generation because we assume it loses 15% of the electricity it stores.

Decarbonization by vertically integrated IOUs increases clean generation to 56% in 2035 and 73% in 2050. The Slow CES increases it to 78% in 2035 and 97% in 2050. The Fast CES increases it to 87% in 2035 and 97% in 2050. This clean generation again chiefly consists of solar and wind, but also includes considerably more nuclear generation than does the reference scenario because the CESs enable more of the existing nuclear generators to cover their going-forward costs and continue operating. The generation in the CES and Utility-led Decarbonization pathways also includes non-trivial amounts of generation from carbon-capturing generators and hydrogen. While these resources fill the need for firm low-carbon generation in a system with a high percentage of renewable generation, large near-term cost reductions for these technologies are not necessary for continuing to reduce power-sector emissions. In 2035, the Fast CES relies on CCS and hydrogen for 2.3% of national generation, while all other pathways, including the Slow CES, use these technologies for less than 0.4% of national generation. Even if these technologies remained too costly, high levels of decarbonization would still be achievable in 2035 and 2050 through more reliance on a combination of existing nuclear, short and long duration electricity storage, wind, and solar.

### Table 2: Percentage of clean generation

| | 2035 | 2050 |
|---|---|---|
| Reference | 42.1% | 55.0% |
| Macrogrid | 42.6% | 55.9% |
| Slow CES | 78.0% | 96.9% |
| Fast CES | 87.4% | 97.2% |
| Utility-led Decarbonization | 55.6% | 73.3% |

**FIGURE 7** Generation differences from reference case




[9] For consistency, percentage "clean" generation is defined for all purposes in this report as the percent of generation that is considered clean under our CES policy assumptions. The cleanness of each MWh generated is determined by how far the $CO_2e$ emissions associated with its generation are below 0.4 metric tons per MWh. If a generator's emissions rate is zero then it is 100% clean. If the emissions rate is above 0.4, it is 0% clean, and if the emissions rate is between 0 and 0.4 the generator is considered partially clean, with the percentage depending on where the emission rate falls between 0 and 0.4.

While Figure 6 shows generation amounts, Figure 7 shows the generation changes from the reference scenario. The charts show U.S. results. The generation changes do not sum to exactly zero because the pathways alter the net amount of electricity imported from Canada. While the macrogrid produces significant cost savings as shown in other figures, it has relatively little effect on the overall generation mix. We do not have generation mix projections for the OWM expansion pathway or the OWM & supply choice expansion pathway because projections of the effects of OWM expansion are based on a combination of other studies.

## 3.2 GREENHOUSE GAS EMISSION REDUCTIONS

**FIGURE 8** $CO_2$-equivalent emissions from the US power sector

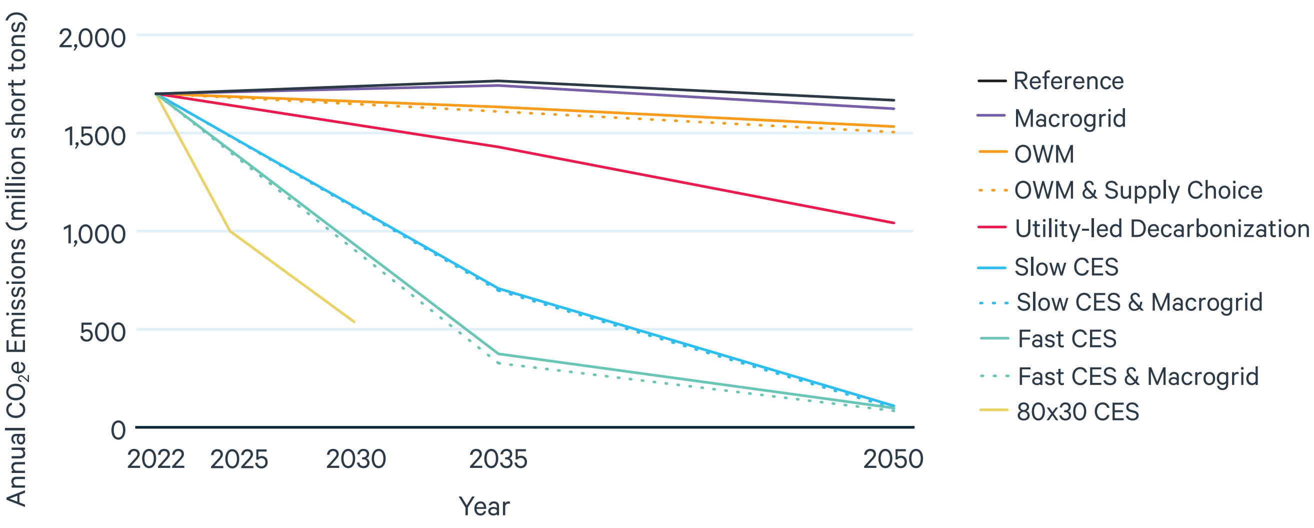



Figure 8 is similar to Figure 1, which is shown and discussed in the Executive Summary. Coal continues to be responsible for at least a third of $CO_2e$ emissions through 2050 in all scenarios, except after 2035 in the CES pathways. This is partly because the fuel price projections used are from the high oil and gas supply scenario from the U.S. Energy Information Administration's 2019 Annual Energy Outlook, which has natural gas prices increasing relative to coal prices. That slows the retirement of coal-fired generators and increases the use of those that remain, relative to the use of natural gas-fired generators.

# 3.3 AIR POLLUTION EVALUATED IN THE ANALYSIS

**FIGURE 9** Annual premature deaths avoided by each pathway

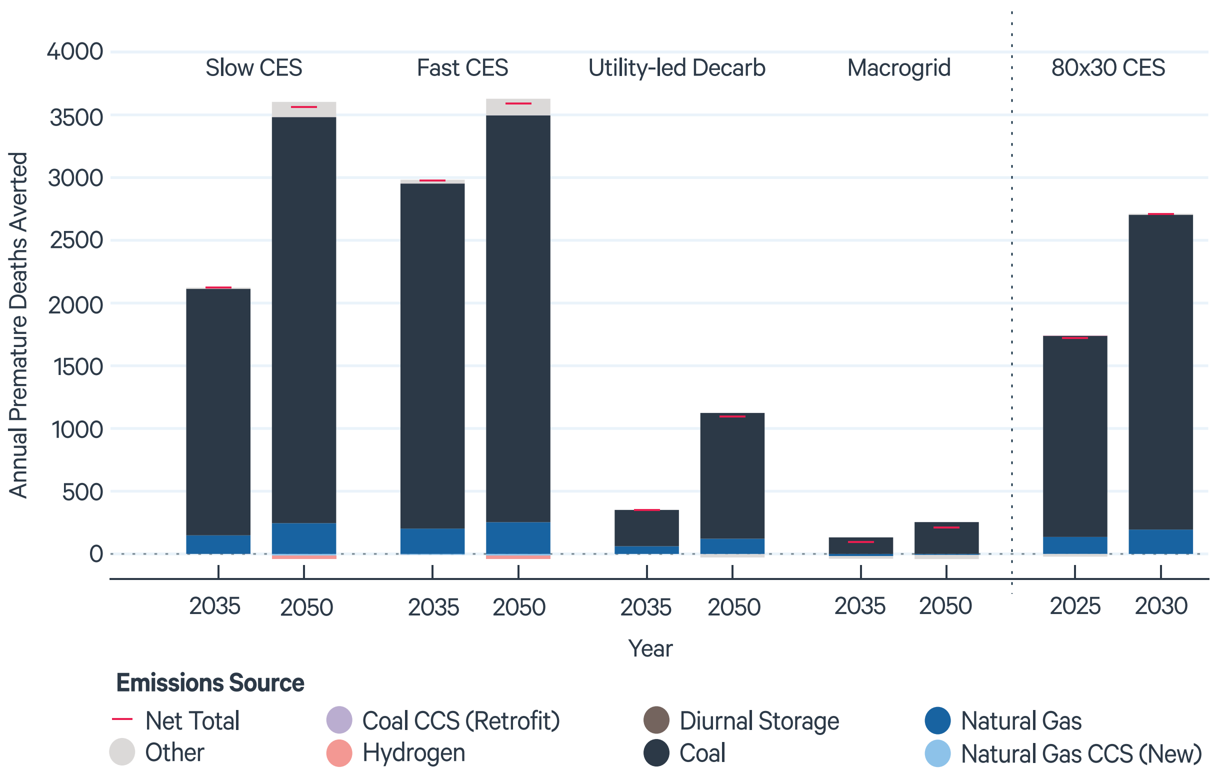



Figure 9 shows the estimated annual U.S. premature deaths that each pathway prevents by reducing sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$) emissions. As with greenhouse gas emissions, the CESs produce much larger reductions than the other pathways. In 2050, utility-led decarbonization can reduce premature deaths by approximately 30% as much as the CESs do.

Under the CESs, by 2050, the emission reductions of natural gas-fired plants are responsible for hundreds of projected lives saved per year, but the emission reductions of coal-fired plants are responsible for thousands of projected lives saved per year. This is mainly because $SO_2$ causes more estimated deaths than $NO_x$ does. Natural gas-fired power plants emit little $SO_2$. The secondary reason is that natural gas fueled plants tend to emit less $NO_x$ than coal fueled plants do.

# 3.4 RETAIL ELECTRICITY PRICE EFFECTS

**FIGURE 10** Percent increase in average retail electricity rate, compared to reference scenario

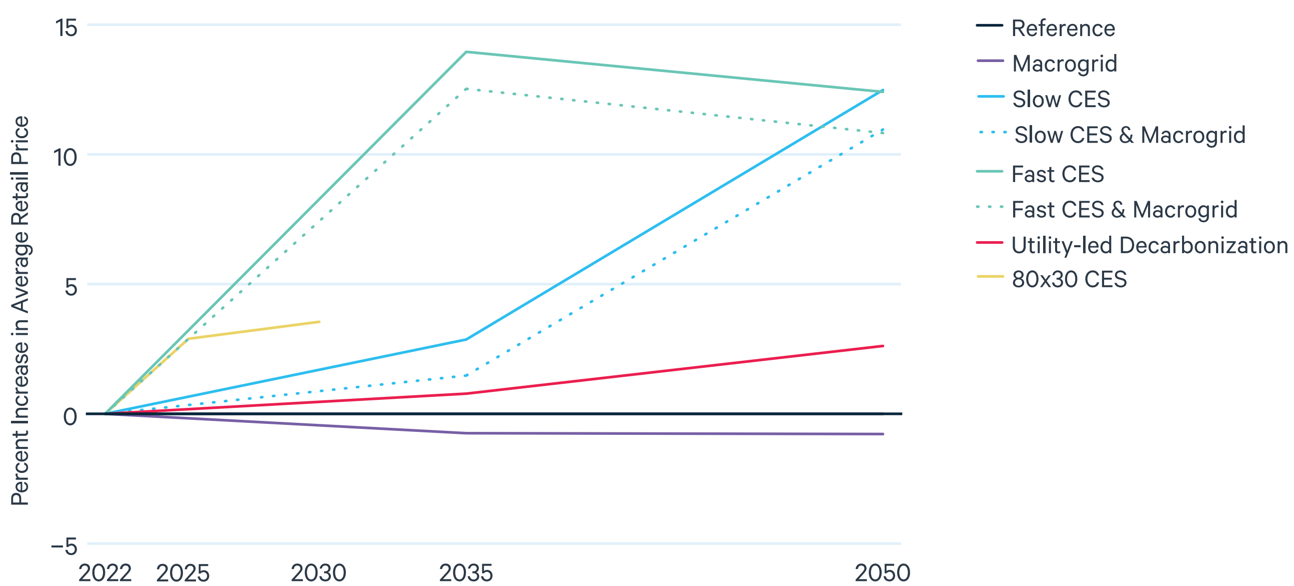
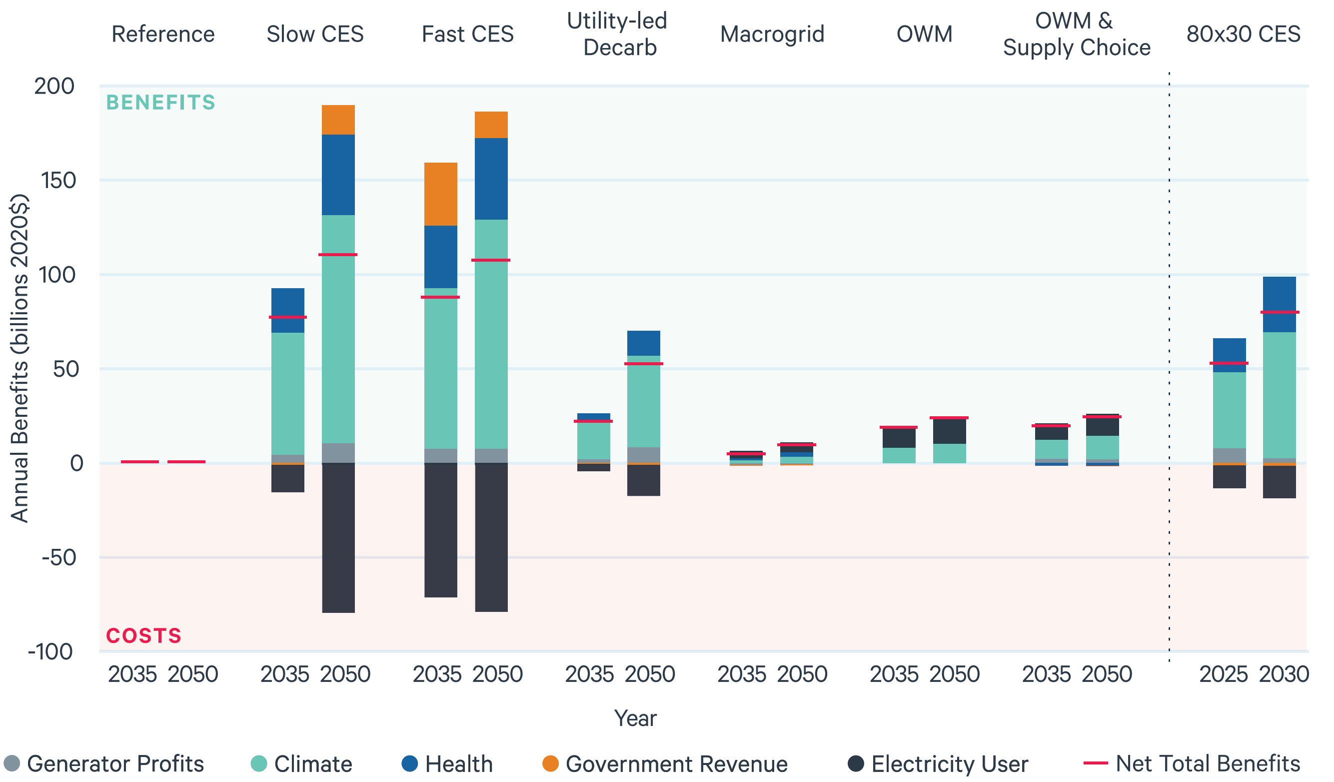



Figure 10 shows the projected percentage effects of the pathways on retail electricity rates, averaged across all U.S. electricity end-use sales by commercial, industrial, and residential customers together. The top three lines reflect the fact that greater decarbonization produces disproportionately greater projected electricity rate effects. The Fast and Slow CESs both increase rates by approximately 12.5% in 2050, but their difference in clean generation achieved by 2035 (87% vs. 78%) causes a large difference in their retail electricity rate effects in 2035. Complete decarbonization by just vertically integrated investor-owned utilities increases national average electricity rates 3% by 2050.

The macrogrid allows reliance on lower-cost generation resources, and consequently reduces the national average retail electricity price by approximately 0.8% (without a CES) to 1.5% (with a CES) after also counting the rate impact of paying for its construction over 50 years through electricity rates.

# 3.5 ESTIMATED VALUES OF BENEFITS AND COSTS

**FIGURE 11** Projected benefits and costs of each pathway




We estimate the dollar value of the emission effects of the pathways using the methods described in Appendix 11.2.5. Consequently, we can combine them with the costs and benefits that are inherently measured in dollars, to calculate net benefits.

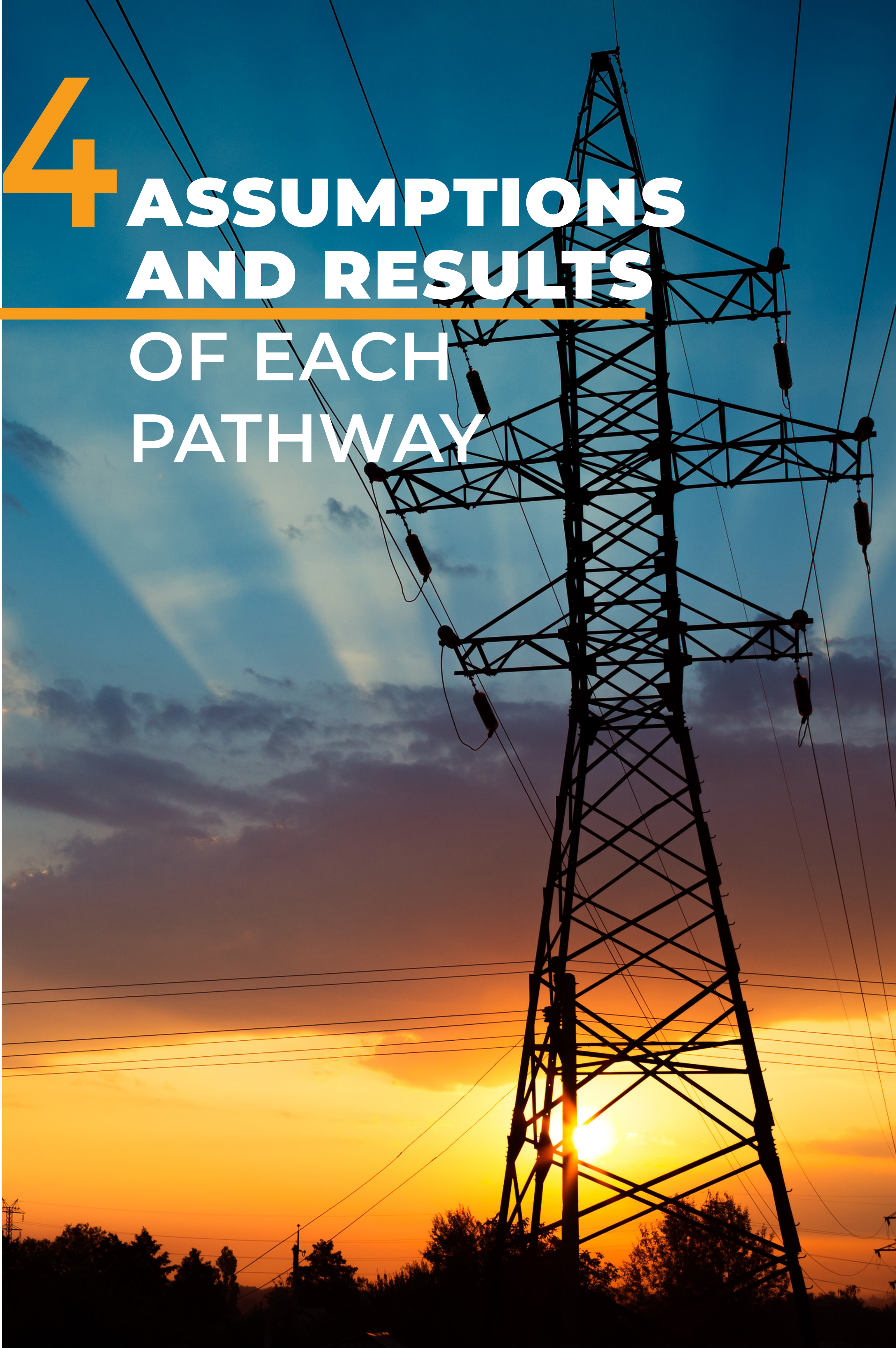
Figure 11 shows the estimated dollar values of the benefits and costs of each pathway. Segments above the zero-line are benefits, while segments below it are costs. Total net benefits are indicated by the short horizontal lines and are equal to the benefits minus the costs.

The CESs produce the largest net benefits because they produce the largest emission reductions, and the estimated benefits of the emission reductions are more than twice as large as the estimated costs. By 2050, decarbonization by vertically integrated investor-owned utilities produces net benefits just under half as large as the estimated net benefits of the CESs.

In contrast with the CESs and utility-led decarbonization, the macrogrid and OWM expansion reduce national average electric rates. The net benefits of the macrogrid are $5 billion and $10 billion per year, respectively, in 2035 and 2050. Again, these are after accounting for the cost of the macrogrid, amortized in electricity rates over 50 years.

The estimated net benefits of OWM expansion to the rest of the U.S. are $19 billion and $24 billion in 2035 and 2050. OWM expansion together with C&I supply choice expansion increases those net benefits by approximately $1 billion per year.

# 04 ASSUMPTIONS AND RESULTS OF EACH PATHWAY



## 4.1 REFERENCE SCENARIO

In the reference scenario, the electricity sector continues to evolve without any of the pathways. We assume the state policies that are currently on the books, as well as upward continuation of state RPSs that plateau or end in the future in current law. We assume no new national clean energy policies are implemented and make the baseline assumption that the existing utility clean energy goals have no effect.

We also assume no national clean energy tax credits. This is a difference from some other studies, which assume the future existence of U.S. national clean energy tax credits. Such credits would reduce the electric bill impact but increase the government fiscal cost (or reduce the fiscal benefit) of decarbonization.

In this report, we compare all pathways to the reference scenario in that same year in order to isolate the effect of the pathways from the effects of the business-as-usual progression of the power sector. In some of the figures, the values shown are relative to the reference scenario so the values shown for the reference scenario are zero.

In our simulations of the reference scenario, power sector $CO_2$ emissions stay roughly constant from current levels despite significant growth in electricity consumption. Coal accounts for 13% of generation in 2035 and 10% in 2050, as shown in Figure 6. Natural gas without CCS accounts for 46% of generation in 2035 and 37% in 2050.

## 4.2 CLEAN ELECTRICITY STANDARDS

A CES is a policy that requires that a certain portion of generation come from certain types of generators. It is similar to the renewable electricity portfolio standards (RPSs) that exist in approximately 20 U.S. states. Each MWh of qualifying generation earns one CES credit, so a CES credit represents one clean MWh. The number of credits earned must equal or exceed the percentage clean requirement. Some technologies, such as fossil fueled generation with carbon capture and sequestration, might earn only partial credit, depending on the design of the CES.

An alternative means of compliance is to make an alternative compliance payment, whose price is set as part of the policy. That makes sense to do only if the price of a CES credit equals (or exceeds) the alternative compliance price, which acts as a ceiling on the CES credit price, also referred to as a *price cap*. If the credit price reaches the price cap, then companies will choose to meet the remaining percentage points of the percentage target through alternative compliance payments to the government rather than through producing clean generation, and the price of credits will not rise further.

In 2021, Democrats in the U.S. Congress worked on developing a clean energy performance program that was somewhat similar to a CES but designed as a budgetary measure, rather than traditional policy. Such an approach would likely have effects somewhat different from those of the CESs we model because of design limitations, but would still aim to have the same type of decarbonization effect as the CESs modeled in this report.

This analysis simulated the effects of two national CESs in 2035 and 2050. The two CES pathways differ in the speed at which they attempt to decarbonize the electricity sector. Both have a benchmark emissions rate of 0.4 metric tons $CO_2e$/MWh, which means that electricity generators earn CES credits in proportion to how far their emission rates are below this value. Any generator with an emission rate above 0.4 metric tons $CO_2e$/MWh does not earn any CES credits, though it does not need to pay for exceeding that emission rate. In calculating $CO_2e$, we assume that each ton of estimated methane emissions from mines, wells, and pipelines is equivalent to 32 tons of $CO_2$.

A benchmark emission rate of 0.4 metric tons per MWh was assumed because it seems to be the most preferred benchmark emission rate among CES proponents in the U.S. Congress at the time of writing. It is low enough that it likely prevents natural gas-fueled generators without carbon capture from qualifying. If such a generator did qualify, by virtue of being very efficient and having very low upstream methane emissions, it would receive only a small fraction of a credit. For example, if a generator had a $CO_2e$ emission rate of 0.38 metric tons per MWh (including the $CO_2e$ of its upstream methane emissions), it would receive one twentieth of a credit per MWh.

Table 3 reports several outcomes of all the scenarios simulated that involve CESs. These outcomes will be discussed in more detail throughout this section. It also includes the results of the scenarios that add the macrogrid pathway along with a CES. We discuss the effects of the macrogrid in section 4.4 and its combination with CESs in section 4.7.

**Table 3: Effects of CESs and of CES-macrogrid combinations**

| Year | CES Type | Percent Clean | Credit Price | Retail Price Increase | Gov't Outlay to Prevent Price Increase ($ Billions/Yr) | Annual Premature Deaths Avoided | Annual Net Benefits ($ Billions) |
|---|---|---|---|---|---|---|---|
| 2050 | Fast | 97.2% | $85 (cap) | 12.4% | 65 | 3590 | 107.5 |
| | Fast + Macrogrid | 97.7% | $85 (cap) | 10.8% | 57 | 3639 | 117.1 |
| | Slow | 96.9% | $85 (cap) | 12.5% | 64 | 3564 | 110.6 |
| | Slow + Macrogrid | 97.3% | $85 (cap) | 11.0% | 56 | 3594 | 119.6 |
| 2035 | Fast | 87.4% | $54 (cap) | 14.0% | 38 | 2975 | 88.1 |
| | Fast + Macrogrid | 88.8% | $54 (cap) | 12.5% | 34 | 3181 | 96.9 |
| | Slow | 78% | $33.30 | 2.9% | 16 | 2122 | 77.2 |
| | Slow + Macrogrid | 78% | $28.52 | 1.5% | 9 | 2106 | 82.3 |
| 2030 | 80x30 | 80% | $40.38 | 3.7% | 19 | 2711 | 80.1 |
| 2025 | 80x30 | 63.4% | $21.31 | 2.8% | 13 | 1720 | 53.1 |

### 4.2.1 Slow CES (Targeting 100% of Generation in 2050)

The first CES presented is referred to as the "Slow CES," which aims for 78% clean generation in 2035, and aims to reach 100% clean generation in 2050. The Slow CES has credit price caps of $46 in 2035 and $85 in 2050. These price caps and this interim target are based on the CESs with targets that reach close to 100% in 2050 that have been proposed in the U.S. Congress in the last 3 years, as well as another that was under development by members of Congress in 2021. The price caps are based on the midpoints between those in the Smith-Lujan Clean Energy Standard Act of 2019 and the DeGette Clean Energy Innovation and Deployment Act of 2020.

In our simulations, the Slow CES reaches its 2035 goal of 78% clean generation without hitting its price cap. In 2035, the credit price is $33.30. That is the credit price that produces 78% clean generation. In 2050, it does hit its price cap of $85 and results in 96.9% clean generation. In both 2035 and 2050, the Slow CES increases generation from solar, wind, and electricity storage, and keeps more existing nuclear from retiring than in the reference case, as shown in Figure 6 and Figure 7. In both years, the Slow CES causes most of the generation in the U.S. to come from wind and solar power. The Slow CES reduces $CO_2e$ emissions by 60% in 2035 and 93% in 2050, compared with the reference scenario, as shown in Figure 8. The CES credit price cap is what prevents it from reducing emissions by 100% in 2050. The pathway reduces annual estimated premature deaths in the U.S. from $SO_2$ and $NO_x$ emissions by 2,122 in 2035 and 3,564 in 2050, as shown in Figure 9. These annual environmental benefits are worth an estimated $88 billion in 2035 and $164 billion in 2050. The estimated annual cost to electricity users via their electricity bills is $15 billion in 2035 and $79 billion in 2050, reflecting retail electricity price increases of 3% and 12% in 2035 and 2050. The CES increases generation owners' overall profits by $4 billion in 2035 and $10 billion in 2050.

In 2050, when the price cap is reached, the government implements it by selling credits at the price cap. This produces government revenue, while credits earned by clean generators do not. The sale of credits at the alternative compliance price does not change the overall net benefits but instead shifts the allocation of benefits from electricity customers to government revenue. The government revenue is a benefit because it can be used to reduce other taxes or increase government services. The overall ratio of environmental benefits to economic costs is 8:1 in 2035 and 3:1 in 2050. It is to be expected that the benefit-to-cost ratio decreases as the policy becomes more stringent, since greater emission reductions require more costly abatement actions and so increase the average cost per ton of reducing emissions. The net benefits are $77 billion per year as of 2035 and $111 billion per year as of 2050.

Because the CES does not reach zero emissions by 2050, emissions are likely to continue their decline after 2050, as declining costs for clean energy technologies enable successively greater emission reductions at a given credit price, and as the alternative compliance price potentially continues increasing.

### 4.2.2 Fast CES (Targeting 100% of Generation in 2035)

The second CES we discuss, which we call the "Fast CES," aims for 100% clean generation in 2035 and subsequent years. The Fast CES has a cap on the prices of its CES credits, which is $54 in 2035 (higher than the 2035 cap of the Slow CES) and $85 in 2050 (the same as the cap of the Slow CES). This policy is modeled after the CLEAN Future Act of 2021, which is the CES bill proposed in Congress that has a target of 100% in 2035 (it is different from the CLEAN Future Act of 2020).

Because of its 100% goals, the Fast CES hits its price cap in both years in our simulations. In 2035, at its credit price cap of $54, it achieves 87.4% clean generation nationally. In 2050, at its credit price cap of $85, it achieves 97.2% clean generation. Compared to the reference scenario in the same year, the Fast CES reduces $CO_2e$ emissions by 79% in 2035 and 94% in 2050. It also avoids 2,976 premature deaths per year from $SO_2$ and $NO_x$ emissions in 2035, and 3,590 per year as of 2050.

Relative to the reference scenario, costs to electricity users in 2035 are $71 billion per year, representing a 14% increase in retail electricity prices. However, this cost is more than offset by a $118 billion reduction of estimated environmental damages, a $33 billion increase of government revenue from selling credits, and an $8 billion increase of generator profits annually. This results in overall net benefits of $88 billion per year as of 2035, increasing to $108 billion per year as of 2050. The ratios of environmental benefits to economic costs are 4:1 in 2035 and 3:1 in 2050.

### 4.2.3 Comparison of Slow and Fast CESs

Even though the Fast CES drives quicker decarbonization than the Slow CES in earlier years, in 2050 both policies have the same credit price cap, and the Fast CES results in 97.2% clean generation, only 0.3% more than the Slow CES achieves in the same year. Both CESs in 2050 result in a U.S. generation mix, which is 45-46% from solar and 29-30% from wind with the vast majority of newly built capacity during the modeled period being wind, solar, or diurnal electricity storage. The generation share of solar is in line with the Biden Administration's goals of producing 45% of the nation's electricity from solar in 2050 (Romaine, 2021).

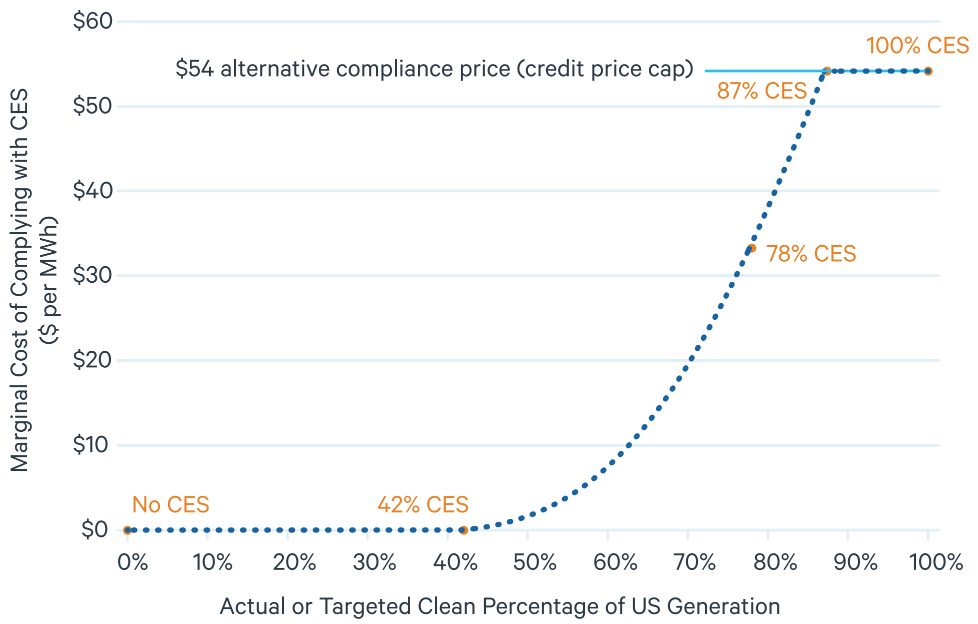
While Fast and Slow CESs have similar effects in 2050, there is a significant benefit from quicker decarbonization in terms of lower total emissions and premature deaths over the years in between the present and 2050. In 2035, the projected benefits of the Fast CES are $30 billion larger than those of the Slow CES, while the projected costs are $19 billion higher and the net benefit is consequently $11 billion higher. The benefit-to-cost ratio of choosing the Fast CES over the Slow CES is therefore 30/19 or approximately 1.6:1. The reason that the benefit-to-cost ratio of changing from Slow CES to Fast CES is smaller than the 8:1 benefit-to-cost ratio of changing from reference scenario to Slow CES is that once the power sector reaches higher levels of clean generation, additional decarbonization gets more expensive, and the incremental cost of that decarbonization approaches the value of the resulting incremental benefits.[10]

If the social cost of $CO_2$ emissions were higher than we assume, which is likely since the estimate we use is incomplete and does not adequately account for extreme potential outcomes (Rennert et. al, 2021, NASEM, 2021), then the benefits of all of the pathways in this study that reduce $CO_2$ emissions would be larger. This would increase the desirability of the Fast CES relative to the Slow CES.

[10] An even more ambitious CES, such as a 100% CES in 2035 without a price cap to limit costs, could produce lower net benefits than the Fast CES because the incremental cost compared to the Fast CES could be larger than the value of the incremental benefits.

### 4.2.4 Marginal Cost of Complying with CES in 2035

**FIGURE 12** Marginal cost of complying with clean generation requirement in 2035, as a function of the percentage requirement.




The stringencies of the Slow and Fast CESs differ in 2035, so a comparison among the reference, Slow CES, and Fast CES pathways allows us to plot in Figure 12 the marginal cost of complying with a CES requirement in 2035 as that requirement increases. The marginal cost is the added cost of complying if the clean energy requirement in 2035 is increased by 1 MWh. The percentage of generation that is clean in 2035 in the absence of a national CES is approximately 42% and is shown by one of the four dots. A CES with a percentage requirement below 42% therefore imposes no compliance cost (other than transaction costs, which we do not estimate and are relatively small). The marginal cost of compliance increases as the percentage requirement is increased, up through 87%. This is shown in Figure 12 by the upwardly sloping dashed line between clean percentages of 42% and 87%. 87% clean is what the industry achieves in 2035 under a CES with a credit price cap of $54 and a percentage target of at least 87% according to our modeling. If the credit price cap remained and the CES had a percentage requirement higher than 87%, the industry would achieve 87% clean generation and would get the rest of the way to the requirement by making alternative compliance payments of $54 per MWh. This is shown in Figure 12 by the horizontal dashed line to the right of 87% clean.

### 4.2.5 The Effects of Having a Clean Percentage Target That is Not Reached

In the case of the Fast CES, there is a 100% target in 2035, but clean generation reaches only 87% in that year because the alternative compliance price is reached. It is instructive to compare the results of this to the results of a CES with a target of 87%. A CES with a target of 87% in 2035 would have a credit price approximately equal to the alternative compliance price of $54, but the requirement would be met entirely through clean generation, with no alternative compliance payments needed. Consequently, having a target of 87% instead of 100% would mean lower electric bills and correspondingly lower government revenues. The 87% CES increases the average retail electricity rate by 7% instead of 14%. The benefits of a lower electricity rate increase are electric bill savings and more electrification to replace higher-emitting energy sources such as petroleum (which we do not model in this report). The detriment is less government revenue, necessitating some combination of higher taxes, higher borrowing, and lower government spending.

If policymakers wanted to reach the intended CES credit price without triggering any alternative compliance payments, it would not be possible to know exactly what clean percentage requirement to use so the credit price might end up lower than the intended price or, alternatively, some alternative compliance payments might be made. Policymakers might perceive this uncertainty as fine. If not, they could direct the implementing agency to adjust the percentage requirement periodically to keep the credit price at or close to the desired level with few or no alternative compliance payments. This also applies in the case of a CES-like policy that could be passed via the U.S. Senate budget reconciliation rules, though the details would differ.

### 4.2.6 The Socially Optimal CES Credit Price or Clean Generation Percentage in 2035

The socially optimal CES credit price is approximately equal to the environmental damage avoided per additional MWh of CES-qualified generation. According to the emissions quantities and air pollution health effects in our modeling results, the estimated average environmental and health benefit of each additional MWh of clean generation from 78% to 87% in 2035 is $64, suggesting that the optimal CES credit price is approximately $64.[11] This estimate is influenced by our assumptions, for example the assumed $61 per short ton social cost of $CO_2$ emitted in 2035, which comes from the U.S. government (Interagency Working Group on Social Cost of Greenhouse Gases, 2021). The true optimal credit price could be higher or lower than these estimates, but $64 is the estimate that results from our assumptions. A credit price of $64 could be achieved by having an alternative compliance price in 2035 of $64 and a clean percentage target at least as high as the clean percentage that would be achieved with a credit price of $64, which we estimate to be 92%.[12]

Setting the credit price instead of the percentage clean requirement can produce larger net benefits, for two reasons. First, it is easier to predict what credit price matches the estimated environmental damage per MWh than it is to predict what percentage target achieves the credit price that matches the estimated environmental damage per MWh. Second, the price is what matters most to emission abatement technology investors. The more certainty they have about what it will be, the lower their cost of capital will be, which can translate into significantly lower abatement costs.

[11] While the CES credit price brings with it an implicit price on $CO_2e$ emissions, that price per ton is not the same as the CES credit price, which is expressed in $/MWh. The average implied price on $CO_2e$ emissions is the credit price divided by the average emission rate of emitting generation displaced by making the CES marginally more stringent. With a benchmark emission rate of 0.4 metric tons per MWh, that emission rate is roughly 0.67 metric tons per MWh given the mix of natural gas- and coal-fueled generation displaced. Consequently, for example, the estimated optimal 2035 CES credit price of $64 is implicitly a $CO_2e$ emission price of approximately $64 / 0.67 = $96 per metric ton. This is higher than the assumed 2035 social cost of $CO_2$ of $61 per metric ton because reducing $CO_2$ emissions also reduces $SO_2$ and $NO_x$ emissions, which results in additional benefits.

[12] Again, all dollar values in this report are in 2020 U.S. dollars, so expressing them in the dollars of some other year such as 2035 requires a conversion. If the annual inflation rate from 2020 to 2035 were 2%, then one could convert from 2020 to 2035 dollars by multiplying by 1.35.

In some situations, it might be politically necessary to set a percentage requirement that is likely to be reached before the alternative compliance payment price is reached. However, otherwise net benefits are likely to be maximized by setting an alternative compliance payment that is likely to be reached before the percentage requirement.

Whatever the true optimal credit price is, credit prices within 10 or 20 dollars of it will produce net benefits that are nearly as large. The reason is that at credit prices approaching the optimum, the costs of increasing the clean percentage are similar to the benefits. Why? Because reaching the optimal clean generation percentage requires making increasingly costly changes from emitting to non-emitting generation, and the costliest changes cost nearly as much as the value of the environmental and health benefits they produce, so they have smaller effects on net benefits. One consequence of this for advocates of a national CES is that reducing stringency to gain political support and policy durability could have little effect on the net benefits of the policy. This applies also to clean percentage requirements. Whatever the true optimal clean percentage requirement is, clean percentages within five or 10 percentage points below it will produce similar net benefits.

#### 4.2.7 80% by 2030 CES

An 80% by 2030 (80x30) CES has been a prominent policy proposal in the U.S. recently, so we model it and present results of it in 2025 and 2030. This goal of 80x30 is based on the CLEAN Future Act of 2021, which is intended to be consistent with the goal of 100% decarbonization of the power sector by 2035. We do not assume any price caps for this CES. Unlike the other scenarios discussed in this report, we model the years 2025 and 2030 when we model the 80x30 CES, instead of 2035 and 2050. The 80x30 CES can be viewed as a steppingstone toward the Fast CES, although we do not combine the results in this report.

Our model projects that an 80x30 CES with a benchmark emission rate of 0.4 metric tons per MWh reduces U.S. power sector $CO_2e$ emissions in 2030 by 69% relative to the reference scenario and prevents 2,711 premature deaths per year in 2030. We project that the CES credit price would be $40 per MWh, and that the CES achieves 80% clean in 2030 with a retail price increase of 3.7% relative to the reference scenario as shown in Figure 4. The projected net benefits to society of 80% clean by 2030 are $80 billion annually as of 2030, with the value of the benefits in 2030 being six times the value of the costs. New technologies, specifically carbon capturing generation and long-duration storage, constitute less than 0.2% of projected generation, indicating that achieving 80x30 affordably is not dependent on cost reductions for new technologies.

### 4.2.8 Government Could Cover Some or All the Cost of a CES

The U.S. government could cover some or all the cost of a CES. The option of covering the full cost has been discussed recently in the context of discussions about a CES-like policy implemented via "budget reconciliation," mentioned near the beginning of section 4.2. In Table 3 we show the estimated U.S. government outlay necessary to make the average electricity bill impact of the CES zero. It depends on the speed of the CES and on what other policies it is combined with. If done efficiently, this would have little effect on the total cost of the CES; its largest effect would be to shift the electricity user cost to the U.S. government. Note that the consumer costs of a CES, and thus the government outlay needed to cover those costs, are higher than the electricity system costs displayed in Figure 3. This is because our model shows that the increase in renewable generation raises the profits of electricity producers, so the additional costs passed to consumers are somewhat higher than the actual additional costs of the electricity supply.

Covering part of the cost is also an option. One way to do so is with tax credits or other subsidies for energy sources that qualify for the CES. They would make qualifying generation sources less costly to the generation industry. The savings would largely be passed through to electricity users in the form of reduced electric bill impacts of the CES. Such subsidies have the potential to reduce or increase the total cost of the electricity supply. They could significantly reduce it (even after counting the subsidies among the costs) by spending appropriate amounts of money to promote promising new technologies and successfully make them competitive with more established technologies (Fischer and Newell, 2008). They could increase it by distorting investment decisions away from the lowest-cost emission reduction investments to more costly options (Fischer, Newell, & Preonas, 2013).

### 4.2.9 Factors that Increase or Decrease Our Estimates of the Costs of CESs

Our modeling of the power sector is unusually realistic, but still, like all modeling of the power sector, it involves some simplifications. We can categorize some of these simplifications into factors that increase or decrease our estimates of the costs of a CES.

In our modeling, Canadian generation cannot earn U.S. CES credits, electricity demand is not affected by electricity prices, natural gas prices are not affected by natural gas use, and the capacities of all transmission lines increase by the same percentage instead of transmission capacity increasing more where it is more valuable. Each of these simplifications omits features of reality that would in fact reduce the cost of a CES, so each of these simplifications increases our estimates of the costs of the CESs.

Our main simplification that reduces our estimate of the cost of CESs is that we assume that new generation facilities can be built at the rates our model predicts without an increase in costs over the projected costs. However, the rush required to comply with the CESs might increase costs, especially in the years leading up to and including 2035 or 2030. This applies most to the 80x30 CES policy and second-most to the Fast CES. On the other hand, higher manufacturing and deployment of the technologies could be expected to cause greater learning-by-doing and consequently lower costs relative to what we project, by 2050 and possibly by 2035.

Also, as previously mentioned, we assume no future clean generation tax credits. If they existed in the future, they could increase or decrease the total cost of complying with a CES, and they would shift some of the cost of decarbonization from electric bills to tax bills.

All these factors also apply to utility-led decarbonization. That is the next pathway we discuss.

# 4.3 UTILITY-LED DECARBONIZATION

To represent decentralized electricity supply decarbonization, we employ the assumption that all vertically integrated, investor-owned electric utilities in the U.S. achieve 70% clean generation by the end of 2035 and 100% by the end of 2050, without reducing the cleanness of the other electricity procurement in their states. This is based on a significant current trend. In the U.S., several leading vertically integrated electric utilities have announced aspirational goals of achieving net-zero emissions or the like, by 2050. This pathway represents the maximum potential of the decarbonization aspirations by such utilities. Investor-owned, vertically integrated utilities may have a stronger incentive to announce such a goal than other types of utilities because it may garner them permission from regulators to invest more money in new generation capacity and they typically are allowed by regulators to recover above-market rates of return from ratepayers. As a result, they profit from being allowed to make larger capital expenditures. Utilities that are not investor owned are non-profit entities, and do not have this incentive to announce 100% decarbonization goals. Utilities that are not vertically integrated cannot build generation and earn regulated, above-market rates of return on it, so they too do not have this incentive to announce such goals.

We model the collective decarbonization goals from utilities in each state as an in-state clean electricity standard, representing the utilities procuring enough in-state clean generation necessary to serve their customers while meeting the desired decarbonization goals. We also assume that the utilities that do not have decarbonization goals must procure at least the same percentage of clean generation as they do in the reference scenario. This ensures that, in our modeling, the utilities that have decarbonization goals actually drive more clean generation rather than mainly buying up more of the already existing clean resources to meet their goals. For the percentage of load in each state, which is served by a vertically integrated investor-owned utility, see Figure 24.

Utility-led decarbonization reduces gas and coal use and increases generation from solar, nuclear, wind, and storage relative to the reference scenario, but to a lesser extent than the CESs. Vertically integrated investor-owned utilities only serve 42% of national load, so the total decarbonization achieved is limited. This pathway reduces U.S. electric sector $CO_2e$ emissions 19% in 2035 and 38% in 2050 relative to the reference scenario, achieving 56% clean generation in 2035 and 73% in 2050. It also prevents 350 and 1,096 premature deaths per year as of 2035 and 2050, respectively. The estimated value of these environmental and health benefits is \$25 billion and \$62 billion per year in 2035 and 2050 respectively. The estimated annual cost to electricity users is \$4 billion as of 2035 and \$17 billion per year as of 2050, increasing the national average retail electricity price by 0.8% and 2.6%. However, these costs and benefits are not distributed evenly across the nation, as decarbonization only happens in certain areas. This pathway, like other pathways that mandate clean electricity generation, increases the overall profits of generation owners, by about \$2 billion per year in 2035 and \$8 billion per year in 2050. The overall ratio of environmental benefits to non-environmental net costs in 2050 is 7:1. The net benefits are \$22 billion per year as of 2035 and \$53 billion per year as of 2050.

The same emission reductions could be achieved at lower cost via a national policy such as a CES. A national policy could rely on the lowest-cost clean generation options regardless of location, rather than requiring certain amounts in certain states.

# 4.4 TRANSMISSION MACROGRID

In the Macrogrid pathway, the only change from the reference scenario is the addition of the HVDC macrogrid described in Section 2.7. We assume that the macrogrid is operational by 2035. In our modeling results, the macrogrid produces benefits of $8 billion per year in 2035 and $13 billion per year in 2050. After subtracting the assumed $3.2 billion of annual cost recovery for building the macrogrid, the resulting annual net benefits are $5 billion as of 2035 and $10 billion as of 2050. In both years, a large portion of the benefits comes in the form of electricity cost savings to users. Even if electricity users pay fully for the macrogrid investment, the projected electricity bill reductions are $4 billion per year in 2035 and $5 billion per year in 2050, corresponding with a 0.8% decrease in retail electricity prices compared to the reference scenario. The electricity cost savings are due to the macrogrid's ability to transfer large amounts of electricity across the country. This means that wind and solar generators can be sited where they are cheaper and more productive, farther away from the loads they need to serve. Also, at times of peak demand in one area of the country, that area can tap into unused capacity in another area of the country that isn't experiencing peak demand. Our model projects that with the macrogrid, 60 GW less generating and storage capacity is needed nationally to satisfy load than without the macrogrid. Using 2050 as an example, the other significant benefit of the macrogrid comes in the form of a 2.6% reduction in annual $CO_2e$ emissions, and 213 premature deaths avoided annually due to particulate emissions. The estimated value of these environmental benefits is just under $6 billion in annual benefits. This is due to the replacement of coal and gas fueled generation with increased wind and solar generation that is enabled by the macrogrid.

We also simulate the effects of the macrogrid in combination with the Slow CES and the Fast CES, and those results are presented in Section 4.7. The value of transmission expansion can be higher in the presence of an ambitious decarbonization policy because it enables greater use of low-cost and diversified non-emitting generation resources. In our 2035 simulation with the Fast CES, the estimated net benefit of the macrogrid is $9 billion, nearly twice as large as without a CES. In all the simulations involving the macrogrid, it produces annual net benefits of $5-9 billion in 2035 and $9-10 billion in 2050.

Our results from modeling the addition of an HVDC macrogrid are comparable to those in the NREL "interconnection seams" study, which studies a similar macrogrid (Bloom et al., 2020). The NREL seams study found that in the absence of any new national clean energy policy, adding a HVDC macrogrid increases wind and solar's share of U.S. generation by approximately one percentage point in 2038. In our results, it increases wind and solar's share by 1.6 percentage points in 2035 and 2 percentage points in 2050.

The NREL study also shares our findings that the presence of a macrogrid reduces the total installed capacity needed in the U.S., slightly reduces the solar capacity built, and slightly increases the wind capacity built. And to quote the NREL paper, "Most of the benefit occurs as a result of reduction in generation operational costs enabled by increased transfer capability provided by transmission builds."

That is comparable with our finding that, in the absence of a national clean electricity standard, 39-50% of the estimated benefit of the macrogrid is from cost reductions rather than emission reductions. Both our study and the NREL seams study find that the macrogrid produces cost savings that exceed the cost of the transmission investment.

In addition, a macrogrid could provide reliability and resilience benefits. Greater transmission capacity can prevent generation shortages like those that occurred in Texas in early 2021. Furthermore, direct-current transmission lines, which are used in the macrogrid we model, are much more controllable than typical transmission lines, which use alternating current. This makes them a tool for addressing reliability risks and for restoring power in the event of a wide-area blackout.

# 4.5 ORGANIZED WHOLESALE MARKET (OWM) EXPANSION

In this pathway, we examine the effects of expanding organized wholesale electricity markets (OWMs) into the parts of the U.S. that are not currently in them, which are the Southeast and much of the West. California and most of Texas have OWMs, while the rest of the West does not. OWMs are the markets administered by regional transmission organizations (RTOs) and independent system operators (ISOs). Because regional OWMs tend to be larger than areas controlled by vertically integrated utilities, planning of transmission expansion, renewable resource connection, generation investment, and capacity reserves happens over a larger region when OWMs are expanded. This is especially important as more intermittent renewable resources are incorporated into the grid. Planning over larger areas allows resources to be sited in cheaper and more desirable areas and having spatial diversity in generating resources and load profiles reduces the need for excessive capacity reserve margins. This, as well as being more welcoming of wind and solar generation, means that expanding OWMs is likely to result in some decarbonization.

Estimating the effects of expansion of OWMs is difficult and multi-faceted, and the effects are subject to considerable uncertainty. A thorough representation of such an expansion is outside of the scope and budget of this project, so we instead adapt and apply the results of prior studies that have attempted to estimate the effects of organized wholesale market expansion. We use both studies of existing organized wholesale markets (MISO, 2020; PJM, 2019; SPP, 2021; Cicala, 2017) and modeling results of OWM expansion into new regions (Clack et al., 2020). By and large, these studies estimate the effects of having a current U.S.-style RTO with a system operator, so that is what our benefits estimates represent.

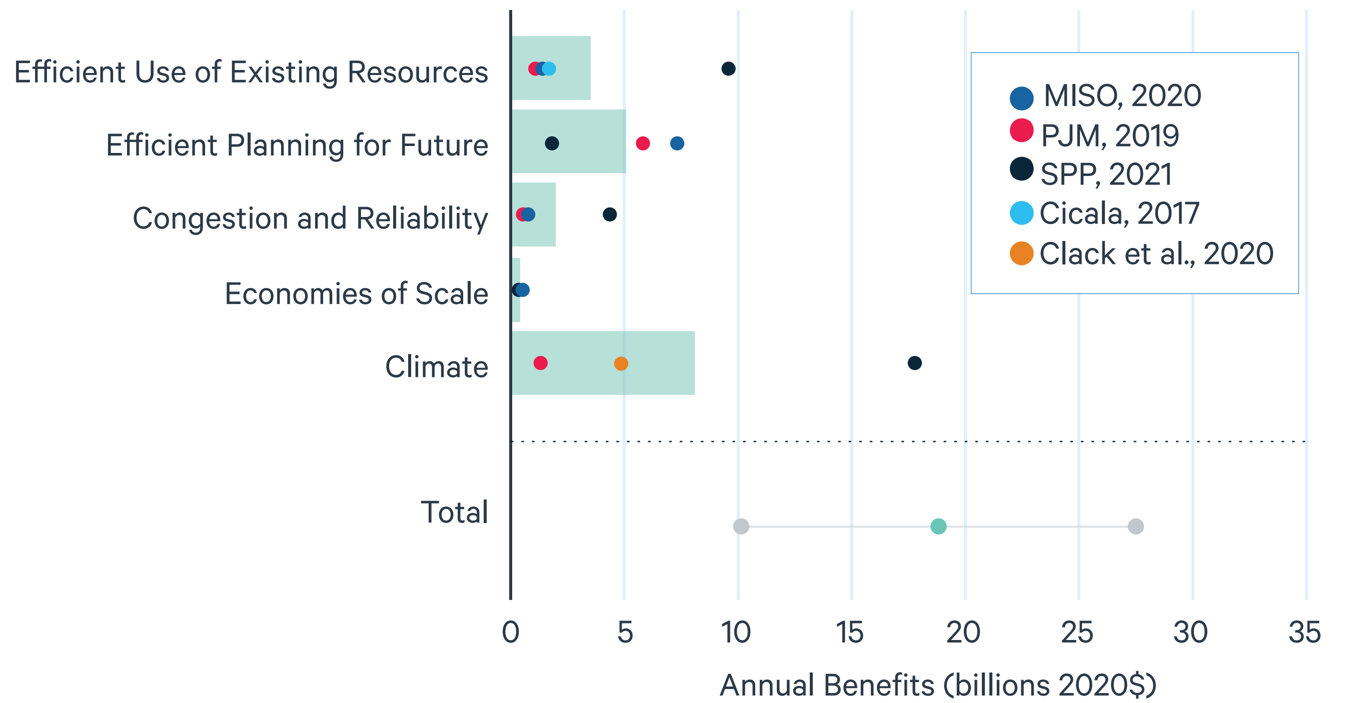
Based on our literature review, we find that many of the benefits of OWMs can be grouped into five categories. These are:

1. More efficient use of existing resources – This includes benefits from changes in both dispatch efficiency and the operating reserve requirement (Cicala, 2022; MISO, 2020; PJM, 2019; SPP, 2021). As previously mentioned, OWMs incentivize generation from the least-cost generating units, reducing overuse of plants with higher operating costs, especially some fueled by coal. RTOs coordinate dispatch across large regions, which increases the use of the lowest-cost resources and trade between parts of the region. Consequently, operating reserve requirements can also be shared over larger regions, reducing the amount of power plants that need to be kept available at any given time and allowing lower-cost plants to be used.
2. More efficient planning for future investment – This includes both more efficient integration of renewable energy resources and changes in the planning reserve requirement. OWMs make it easier for renewable resources to connect to the grid, and they enable capacity planning to occur at a larger geographic scale. This reduces the cost of interconnection for renewables and allows more renewables to be built at sites with higher capacity factors (Dahlke, 2018). OWMs also increase load diversity and generation diversity due to their larger geographic coverage. These changes allow for a lower planning reserve margin, reducing the required capacity that must be built. The greater geographic diversity also allows for greater reliance on wind and solar generation.
3. Increased grid reliability and decreased congestion – OWMs encourage transmission planning to occur at a larger regional scale. This can lead to transmission investments that are closer to optimal from a system-wide cost perspective, lower outage rates, and lower grid congestion.
4. Economies of scale – OWMs centralize many of the functions that previously needed to be done by smaller balancing authorities, reducing redundancy in training, professional services, and scheduling.
5. Climate benefits – OWMs may reduce GHG emissions from electricity generation. They do this by reducing fossil fuel generation and allowing renewables to be built more efficiently, for reasons mentioned above. In this section, we calculate emission benefits using a social cost of carbon of $61.21 (2020 dollars) per short ton $CO_2$ in 2035.

Few studies quantify the benefits of organized wholesale markets across all five of these categories. We thus treat each category separately and search for any studies that give a complete estimate of benefits in that category. We estimate the benefits of OWM expansion to the entire U.S. by assuming that benefits scale with load. From each study, we first compute the benefit per MWh of OWMs. We then multiply this benefit by the expected load in 2035 that is not already in an OWM in 2022.

Figure 13 shows the estimated benefits of OWM Expansion in 2035. The green bars show the average benefit across studies for each category. The points indicate estimates from individual studies. As can be seen, there is a large spread of benefit estimates between studies.

**FIGURE 13** Estimated benefits of OWM expansion in 2035




We aggregate the benefit estimates into a total benefit estimate using a bootstrap method. The total benefit is repeatedly estimated using a random sample of studies from each of the five categories. In Figure 13, the mean estimate of the total is shown by the light green dot. The error bars indicate one standard deviation above and below the central estimate.

Overall, we estimate that expansion of OWMs to the parts of the U.S. that do not currently have them yields annual benefits of $19 billion per year in 2035. These benefits come primarily from reduced greenhouse gas emissions, more efficient use of existing resources, and more efficient planning. Because we estimate the benefits of expanding OWMs on a per MWh basis, we can scale the 2035 benefits estimate to a 2050 estimate of $24 billion per year. Nearly half of these estimated benefits are climate benefits. The average of the three estimates of climate effects from the literature indicates that expanding OWMs into the rest of the contiguous U.S. reduces the total power sector $CO_2e$ emissions by 8%, equaling $8 billion in annual benefits in 2035 and $10 billion in 2050. The estimated non-environmental benefits of OWM expansion are $11 billion in 2035 and $14 billion in 2050. We use these central estimates of net benefits in figures throughout this report but note the wide range of estimates found in the literature.

The non-environmental benefit estimates we have for OWM expansion are total cost savings experienced by the power sector. In Figure 11, we assume that the pocketbook benefit for electricity users equals these total cost savings. It could be lower or higher in reality, with the difference accruing to the electricity supply industry and governments. Also, the environmental benefits assume that no new decarbonization policies are implemented.

Our estimate of the benefits of OWM expansion is broadly inclusive, but still not complete. The omission that we are aware of is environmental benefits other than GHG reductions. For example, GHG reductions are often accompanied by reductions in other emissions that cause premature deaths and illness, particularly in downwind areas.

While OWMs have been shown to be beneficial and cost-saving, it is important to note that the implementation of OWMs on their own is not sufficient to cause a full or near-full transition of the power sector to decarbonized generation in the timeframe we are considering. Current areas within OWMs are still fossil-fuel dependent, and modeling of a potential future OWM in the southeast shows about half of the generation in the southeast coming from natural gas without CCS through 2040 (Clack et al., 2020). By reducing overuse of fossil-fueled generators and reducing excessive reserve requirements, the expansion of OWMs can induce some retirement of polluting generators and replacement with decarbonized generation, but additional policies, commitments, or technology improvements would be needed to decarbonize more fully. In the context of such additional policies, commitments, or technology improvements, organized wholesale markets can, through their facilitation of more efficient investment and operation, contribute to reaching decarbonization goals more effectively and at lower costs.

Note that there have been some instances where the establishment of OWMs has harmed consumers and increased retail rates, in the initial years after the markets were established. The 2000-2001 California electricity crisis and the initial years after the 2002 deregulation of the Texas electricity market of the Texas RTO (TCAPTX, 2018) are estimated to have increased retail rates. In both cases, government legislation to ease the transition to OWMs allowed for firms to exert market power and raise electricity rates. While OWMs can yield large benefits, their implementation needs to heed the lessons learned from the now more than 20 years of U.S. RTO experience.

# 4.6 SUPPLY CHOICE EXPANSION TO COMMERCIAL AND INDUSTRIAL ELECTRICITY CUSTOMERS

In this pathway, we examine the effects of allowing all commercial and industrial (C&I) customers of investor-owned utilities to choose their electricity suppliers, therefore making it easier for buyers to specifically purchase clean generation and influence the deployment of more clean generation. We represent effects of supply choice expansion through the following two means together:

- Increased voluntary green power (VGP) purchasing. Section 4.6.1 describes this.
- Decreasing the prevalence of cost-of-service (COS) regulation in areas where supply choice is expanded, proportional to the amount of load which gains access to supply choice. The reason we assume the supply choice expansion would cause a reduction in COS regulation is that if the vertically integrated utilities are no longer responsible for the generation for their C&I electricity customers, they are likely to sell a corresponding portion of the generation assets they own. This decrease in COS regulation tends to improve the efficiency of generator scheduling and dispatch.

Allowing some electricity customers to switch to retail suppliers of electricity could affect the retail prices ultimately paid by the other electricity customers. This can be partly because of generator "stranded costs," which occur if the unrecovered capital expenditures on the generators owned by the local distribution utilities are larger than the revenue the utilities could obtain by selling them, or stranded benefits, if they are smaller. It can also be partly because the generation mix choices of the newly choosing electricity customers can affect electricity prices. To account for these changes, we assume that residential electricity customers will be "held harmless." We transfer the additional cost of generating electricity due to expanded supply choice from residential customers to C&I customers, so that residential customers do not see a price or benefits impact from the expansion of supply choice.

### 4.6.1 Estimated Effects of Organized Wholesale Market Expansion and Supply Choice Expansion on Voluntary Green Power Purchasing

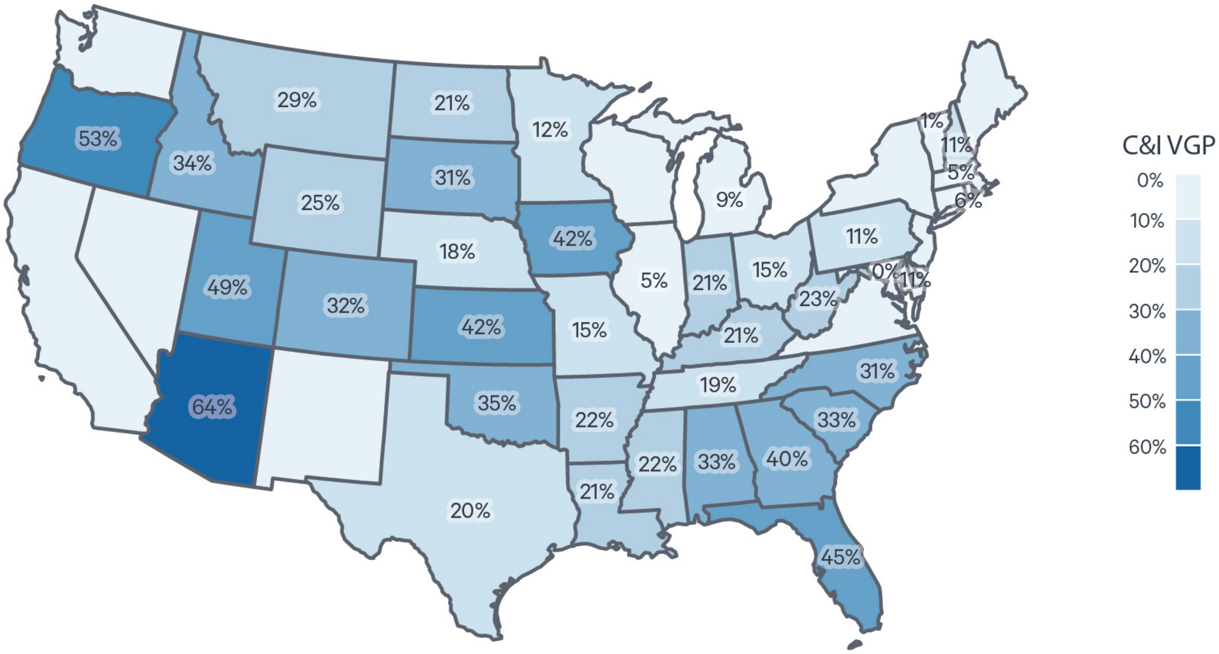
Based on the recent growth rate of VGP purchasing, we project that if there is no OWM or supply choice expansion in the U.S., VGP will account for 8.1% of total U.S. electricity consumption in 2035 and 10.0% in 2050. Table 4 shows this projection and Appendix 10.2.1 discusses how we developed it.

To model the expansion of supply choice to C&I customers in states, which currently have zero or constrained supply choice, we increase the rates of C&I customers voluntary purchasing green power to match those in areas that currently have supply choice. This is based on an econometric (statistical) analysis of state data. Nationally, this increases C&I VGP purchasing by 77% in 2035 and 89% in 2050 relative to the reference scenario. This increases total VGP purchasing (C&I plus residential) from 8.1% to 12% of U.S. electricity consumption in 2035 and from 10% to 15.5% in 2050. Table 4 contains our national-level estimates of the percentage of total electricity demand which is voluntarily purchased as green power in the reference, OWM, and OWM + Supply Choice pathways. For more information on VGP, see Appendix 10.

**Table 4: Actual Total VGP Purchasing in U.S. as Percentage of Load**

| Pathway | 2035 | 2050 |
|---|---|---|
| Reference | 8.1 % | 10.0% |
| OWM Expansion | 9.2% | 11.4% |
| OWM & Supply Choice Expansion | 12.0% | 15.5% |

**FIGURE 14** Projected C&I voluntary green power (VGP) purchasing in 2050 as percentage of C&I demand, in the OWM & Supply Choice Expansion pathway. Green power mandates proportionately reduce the VGP purchasing numbers in this map (as described in section 2.4). The states with 0% VGP purchasing have that because they have 100% green power mandates.




There are two additional noteworthy features of the way we model VGP purchasing. First, we assume that half of the VGP demand from a state must be purchased within the buyer's RPS credit region, but the other half can be purchased from anywhere in the U.S. The RPS credit regions defined in our model and shown in Figure 23, are where renewable generation can generally be sourced to satisfy RPSs of states within the region, based on the actual current eligibility rules of those state RPSs. We make this assumption to reflect that while there are methods of purchasing green power from anywhere in the country, or even abroad, some companies and other electricity users favor purchasing from or owning local sources.

Second, we define "VGP" as the voluntary green power purchasing that does not overlap with clean generation mandates, which for our purposes consist of state RPSs, state CESs, national CESs, and utility commitments. Overlapping means that a green power kWh purchased voluntarily is also used to meet a clean generation mandate of one of the types just mentioned. Such voluntary purchases could have a considerably lower price than voluntary purchases that do not overlap with clean generation mandates, and might not increase clean generation at all. There might be some voluntary green power purchasing that does overlap with clean generation mandates, as discussed in Section 6, but our VGP projections do not include it.

We do allow VGP to fully overlap with carbon emissions pricing policies such as cap-and-trade programs, since this is already common in places with carbon emissions pricing programs. In other words, in our modeling and analysis, a green power kWh purchased voluntarily can also be considered non-emitting generation for the purposes of an emissions pricing policy. These assumptions are designed to approximate reality.

### 4.6.2 Effects of Supply Choice Expansion Accompanied by Organized Wholesale Market Expansion

Supply choice expansion is usually accompanied by OWM expansion because competition in providing generation for electricity end-users is difficult without an OWM to provide an open, fair marketplace for generation. Therefore, we first present the effects of supply choice expansion accompanied by OWM expansion.[13] Figure 1, Figure 2, and most of the figures in Section 3 show estimated effects of supply choice expansion accompanied by OWM expansion, from combining the incremental effect of supply choice with the effect of expanding OWMs. We estimate that expanding OWMs to the rest of the country and supply choice to C&I customers of IOUs results in $20 billion in net benefits per year in 2035 and $25 billion in net benefits per year in 2050 from cost savings and greenhouse gas emission damage reductions. Just under half of these benefits are due to a 10% reduction in power sector $CO_2e$ emissions relative to the reference scenario in both years. These benefit estimates omit two important classes of benefits. The first is the damage reduction from reducing non-greenhouse-gas emissions such as $SO_2$, $NO_x$, and particulate matter. The second is the benefits to C&I electricity customers. Their employees, owners, and customers can enjoy greater happiness from knowing that they are using less environmentally damaging sources of power generation.

### 4.6.3 Effects of Supply Choice Expansion if Organized Wholesale Market Expansion Has Already Occurred

If OWM expansion has already occurred, our model estimates that the incremental net benefits of expanding supply choice total $0.5 to $1 billion per year. The benefit comes entirely from a 2% increase in national non-emitting generation, which in turn causes a 2% decrease in $CO_2e$ emissions in both 2035 and 2050. The total cost of producing electricity changes little, as the additional wind and solar generation is only slightly more costly to produce than the other generation it displaces. There is a benefit we are not able to estimate: the greater satisfaction of employees, owners, and customers from supporting clean generation.

The 2% increase in national clean generation is only about half as large as the increase in national VGP purchasing induced by the expansion of supply choice. In some areas, increased VGP purchasing does not translate to additional clean generation or reduced emissions. The reason is that the projected costs of renewable generation facilities are low enough that in many regions, the amount of renewable generation resulting from market forces alone exceeds the amount required by mandates and VGP purchasing together. This is more likely to be true in states that have smaller renewable energy mandates, smaller projected amounts of VGP purchasing, more abundant wind and solar resources, and lower electricity demand per square mile. This reduces the effect of supply choice expansion on total clean generation. In our simulations without a national CES, we see VGP purchasing being a larger driver of green generation in 2035 than in 2050. In 2035, it drives additional clean power particularly in the southwest, PJM, New York, and North Carolina regions. In later years such as 2050, market forces and the California and northeast cap-and-trade programs cause there to be enough wind and solar power that VGP purchasing only drives additional clean power in the PJM region and nowhere else.

[13] Because we use estimates from literature instead of modeling to characterize the net benefits of OWMs, we combine those estimates with modeling to understand the total benefits of expanding both OWMs and supply choice. We use two simulations, with and without supply choice, to estimate the incremental effects of expanding supply choice, and then add those to the estimated net benefits of OWMs. One simulation captures much, but not all, of the environmental benefits of expanding OWMs by reducing the overuse of natural gas and coal resources. The second simulation adds onto that the VGP and deregulation effects of expanding supply choice. The reason we do this, instead of adding the effects of supply choice relative to our reference scenario, is that while both OWMs and Supply Choice independently offer environmental benefits and increase the share of clean generation, the effects are not completely additive. For example, additional clean generation brought online because of OWMs can help satisfy additional VGP purchasing brought on by expanded supply choice.

VGP purchasing is more effective in areas with stricter clean mandates because then it is likely to drive additional clean generation rather than just participating in purchasing the green power that would already be generated due to market fundamentals.

Also, the assumption that some VGP will be purchased regionally instead of nationally is important. We find that market forces cause enough clean generation to be built in the U.S. to exceed the sum of requirements from state RPSs, state CESs, and the projected national total VGP demand. If VGP could be purchased from anywhere in the country, the projected amount of VGP demand would not actually increase the clean generation in the US. Requiring that some of the VGP be built more locally is realistic and causes VGP purchasing to increase the amount of clean generation in some parts of the U.S. and hence also increases the national total.

## 4.7 COMBINING CES WITH COST-SAVING PATHWAYS CAN REDUCE COST INCREASES

Decarbonization mandates result in a cleaner power system, but building it costs money, as seen in the CES and Utility-led Decarbonization pathways. In 2035, our model projects that the Fast CES would increase the total non-environmental cost of the electricity supply in that year by $31 billion and the Slow CES would increase it by $11 billion, as shown in Figure 15. The non-environmental electricity supply costs referenced in this section and in the rest of this document include the operating and maintenance costs of all generators. They also include the capital costs of all generators, levelized over the 30 years after each capital expenditure, including cost of financing. In pathways involving the transmission macrogrid, the full up-front and financing costs of the macrogrid are included, levelized over 50 years. In our results, we charge the macrogrid costs to electricity users, we charge net generation costs of vertically integrated utilities to their customers, and most other cost changes flow through to electricity users. Our results indicate that the non-environmental costs of a CES are more than offset by health and environmental benefits estimated to be much more valuable, but the costs could still present a political impediment.

In addition to considering each pathway separately, we also modeled the potential for some pathways to work together to decarbonize more quickly and/or at lower cost. We modeled the combinations of the Fast and Slow CESs with the transmission macrogrid and expanded OWMs. The macrogrid and expanded OWMs are likely to reduce, rather than increase, costs and retail electricity prices, and can be a way to offset some or potentially all of the costs of a CES.

**FIGURE 15** Effects of CESs and policy combinations on total non-environmental annual cost of U.S. electricity supply in 2035

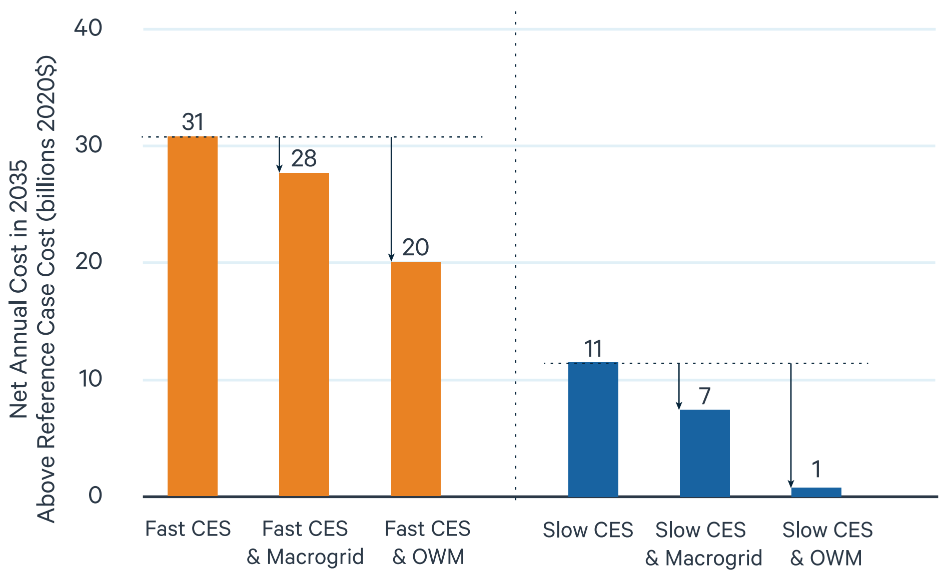


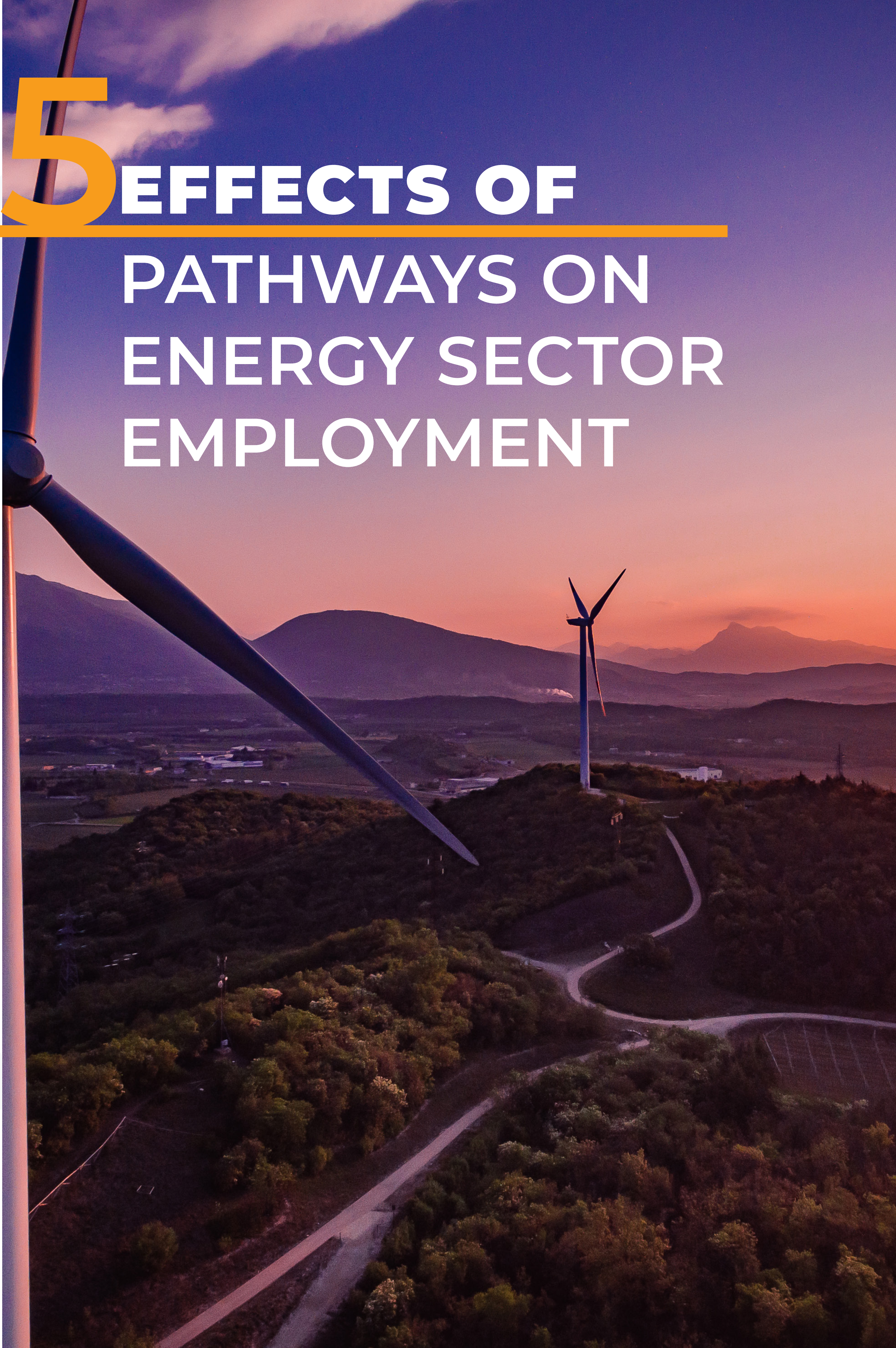

Figure 15 shows the resulting cost estimates. In the presence of a CES, the HVDC macrogrid would annually save $4 billion to $5 billion more than it would cost (including levelized recovery of capital costs), so the combination of a CES and the macrogrid would cost $4 billion to $5 billion less than the CES by itself. Approximately 100% of these cost savings get passed through to the consumer.

Table 3 shows some additional information about the results of these scenarios. In the case of the Fast CES, because the credit price has hit its price cap, the addition of the macrogrid allows more low-cost clean generation to be accessed, resulting in a slight increase in clean generation achieved at the same credit price. This adds an additional $5 billion in annual climate and health benefits.

For expansion of OWMs to the parts of the contiguous U.S. that do not already have them, we assume that the cost savings would be the same in the presence of a CES as they are estimated to be without a CES, $11 billion per year in 2035. We therefore estimate that OWM expansion may nearly offset the national average cost of the slow CES in 2035.

Based on the estimated cost of the Slow CES and the estimated savings from OWM expansion and the macrogrid, it is likely that combining all three together would reduce the total cost of the electricity supply while also achieving the clean generation goals of the Slow CES in 2035. Further reductions in net costs could be achieved through more transmission investment; more carefully designed transmission investment; improvements in the economic efficiency of OWMs and utility decisions; and research, development, and demonstration funding for generation technologies (Shawhan, Cleary, and Witkin, 2021).

# 05 EFFECTS OF PATHWAYS ON ENERGY SECTOR EMPLOYMENT



# 5 ENERGY SECTOR EMPLOYMENT IMPACTS

We estimate energy sector employment effects for three decarbonization pathways and the reference scenario using the Jobs and Economic Development Impact (JEDI) models, as described in sections in sections 2.8 and 12. All mention of job increments, reductions, effects, or differences, are compared to the reference scenario. The reference scenario represents the future without any of the emission reduction pathways that are considered in this report.

The jobs considered in this report are U.S. jobs in the following activities:

- Construction of new power plants and new spur transmission lines to connect them to the grid
- Construction needed every 20 to 40 years at existing power plants to replace major components such as boilers
- Operation and maintenance of existing and future power plants
- The supply chains for construction, operation, and maintenance, including fuel supply jobs
- The induced jobs that result from the construction, operation, and maintenance jobs. Induced jobs result from spending by people who are directly or indirectly paid by energy projects, for example providing goods and services bought by people employed in constructing, maintaining, operating, and supplying fuel for power plants.

There are some even more indirect job effects that could be estimated using a broader model, but they are beyond the scope of this study. In this report, we refer to the estimated job effects as "energy sector" job effects to remind the reader that they do not include these even more indirect job effects. However, calling them "energy sector" job effects is not completely accurate because they include supply chain and induced jobs, which result from the spending of companies and people in the energy sector, but are not necessarily in the energy sector.

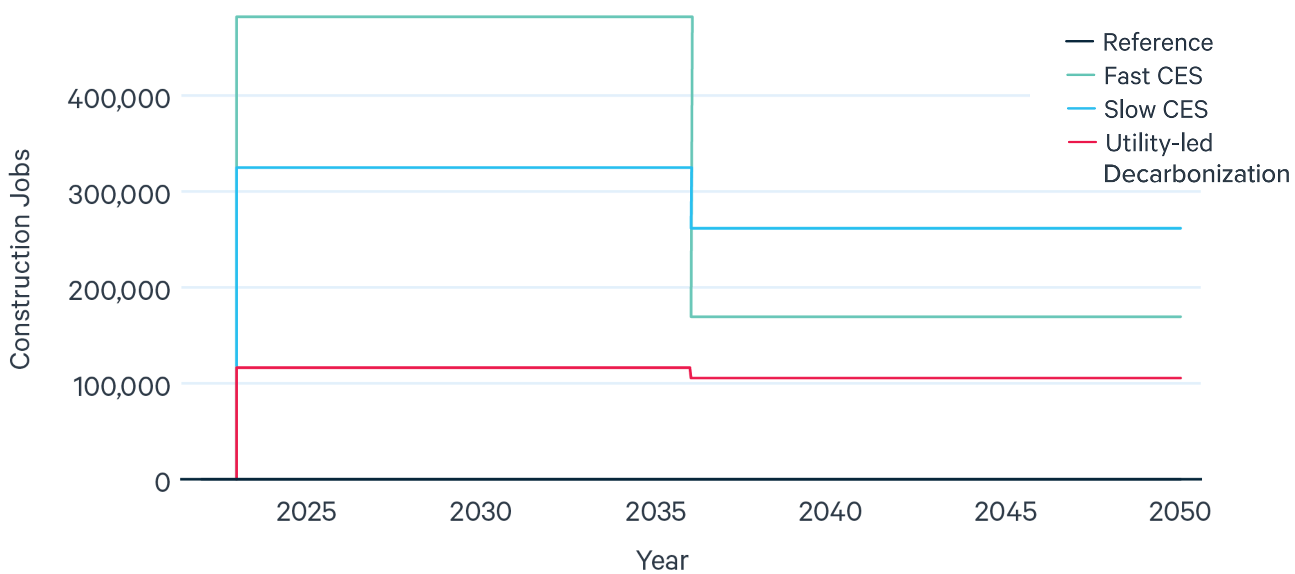
# 5.1 ENERGY SECTOR EMPLOYMENT EFFECTS 2023-2050

We have estimated the effect of three pathways on employment in the U.S. energy sector from 2023 through 2050. These three pathways are the Fast CES, the Slow CES, and the Utility-led Decarbonization pathway. In these pathways, our modeling projects a net increase in jobs supported by the energy sector through 2035 when compared to the reference scenario. A Slow CES produces more energy sector jobs than the reference scenario, with an average of 210,000 more energy sector jobs than the reference scenario through 2035, then an average of 60,000 more energy sector jobs than the reference scenario from 2036 through 2050. A Fast CES creates an average of approximately 290,000 more than the reference scenario through 2035, then an average of approximately 170,000 less than the reference scenario from 2036 through 2050. Utility-led decarbonization produces an average of approximately 50,000 more than the reference scenario through 2035, then an average of approximately 70,000 less than the reference scenario from 2036 through 2050.

### 5.1.1 Energy Sector Construction Job Effects

In all three of these pathways, there is a clean generation construction boom that lasts at least through 2050 (see Figure 16). Note that figures in this section do not show total energy sector jobs. Rather, they show the difference in energy sector jobs relative to the reference scenario. Consequently, the line for the reference scenario is always at a height of zero. The figures that follow show additional annual employment effect values.[14] The job effects in all employment figures in this report include the resulting supply chain and induced jobs, not just the onsite jobs.

**FIGURE 16** **Projected U.S. energy sector construction jobs, relative to reference scenario, 2022-2050.**




*The abrupt changes are a result of our assumption of uniform paces of construction in 2023-35 and 2036-50. In reality, the job effects would likely change gradually, as a result of a gradually changing credit price cap and other factors.*

[14] For the employment results only, we reconceptualize the E4ST simulation results to represent time periods 6 months later than they represent in other portions of this report. We do this partly for clarity, so that we can report job results for calendar years rather than for periods from mid-year to mid-year.

As Figure 16 shows, the construction boom is larger before 2035 than after that year. This reflects a slowed pace of clean generation investment in the power sector simulation results.

In the CES pathways, the increased construction activity would likely remain even after 2050, as the caps on CES credit prices (described on section 1.4) mean that clean generation would continue to be added to the grid after 2050. The Utility-led Decarbonization pathway, however, could see construction activity drop off after 2050, as we assume in that scenario that all the goals set by vertically integrated investor-owned utilities have been achieved by the end of 2050.

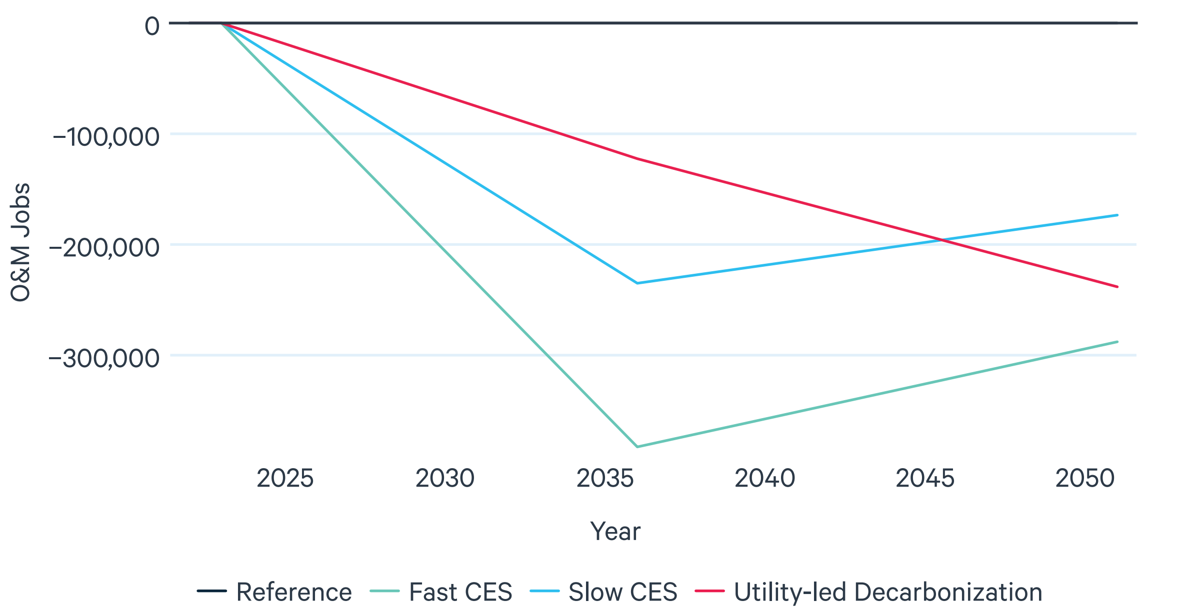
We modeled the years 2035 and 2050 and the construction and retirement of generators leading up to each of those years. We assume that the effect of each pathway on construction employment is constant from 2023 to 2035 and constant from 2036 through 2050. However, they would not be constant in each of those time periods and the changes would not be as abrupt as shown in the figure. The 2023-2035 and 2036-2050 cumulative totals in the figures are consistent with the modeled estimates, but the annual numbers could change more gradually and still be consistent with our simulation results. It might take a few years to accelerate clean generation construction as much as shown in 2023. Also, the downward transition from 2035 to 2036 would likely not be abrupt but instead be spread over more than a decade because of a gradually changing credit price that would be set by a gradually changing credit price cap. The recent U.S. congressional CES bills mentioned in sections 2.2 and 4.2 have gradually changing credit price caps, and our modeling indicates that with a Fast CES the gradually changing credit price cap would likely be reached and would consequently set the credit prices, starting several years before 2035 and continuing through 2050. The pace of change in construction activity and employment would also be influenced by the multi-year timeframes of most power plant construction.

### 5.1.2 Energy Sector Operation and Maintenance Job Effects

Accelerated clean power plant construction in all three of these pathways gradually replaces natural gas- and coal-fueled generation with non-emitting or very-low-emitting generation. Operating and maintaining most non-fossil generation methods is estimated to be less costly and labor-intensive than operating and maintaining coal- and natural gas-fueled generation, per unit of electric energy produced. This is largely because most of the non-fossil-fueled generation methods do not require fuel or require less fuel (in the case of nuclear). Consequently, as the pathways gradually increase clean generation relative to the reference scenario, total energy sector O&M jobs decrease over time (see Figure 17). For example, in 2030, there are approximately 130,000 fewer energy sector O&M jobs with the Slow CES than in the reference scenario.

Toward later years such as 2050, the CES pathways receive a boost in O&M jobs from hydrogen-fueled generation, which like gas- and coal-fired generation requires fuel, and involves more O&M jobs per unit of electric energy produced because it is assumed to be a more costly and labor-intensive fuel. This explains the upward slopes of the CES O&M jobs after 2035. However, in 2050, energy sector O&M jobs are still lower in these pathways than in the reference case.

**FIGURE 17** **Projected U.S. energy sector O&M jobs, relative to reference scenario, 2022-2050.**

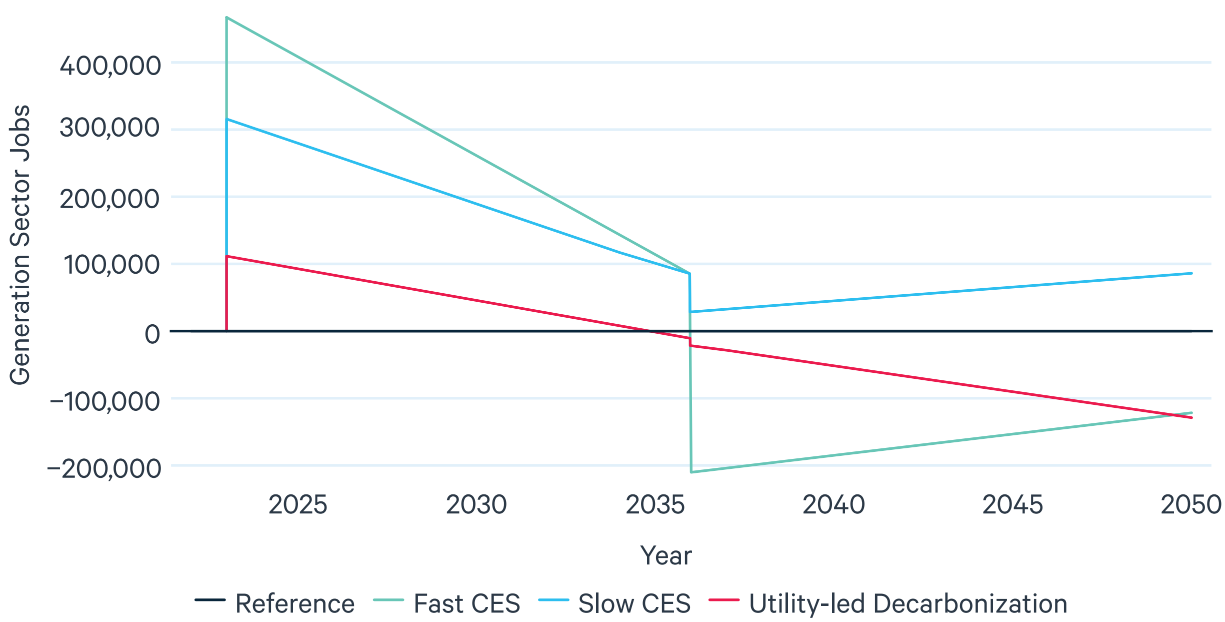



The shapes of the lines in our annual jobs plots (Figure 16 - Figure 18) are drawn under the assumption that construction jobs and changes in O&M jobs are spread evenly over each of the two time periods: 2023-2035 and 2036-2050. This explains why they are straight lines until and after 2035. As mentioned above, power plant construction and the reduction in fossil fuel O&M jobs, which can only occur after that construction, would likely occur less uniformly within each period.

### 5.1.3 Total Energy Sector Job Effects

Figure 18 combines the estimated effects on construction jobs with the estimated effects on O&M jobs, to show the estimated path of total energy-sector employment effects of these three pathways, relative to the reference scenario. The net effect is that all three pathways result in more energy sector jobs than the reference case prior to 2035, while the post-2035 effects are a mix of fewer and more jobs based on the factors described in the two immediately preceding sub-sections.[15]

**FIGURE 18** **Projected U.S. energy sector jobs, relative to reference scenario, 2022-2050.**




*The abrupt changes are a result of our assumption of uniform paces of construction in 2023-2035 and 2036-2050. In reality, the job effects would likely change gradually, as a result of gradually changing credit price cap and other factors.*

In earlier years, the Fast CES increases energy sector jobs somewhat more than the Slow CES does. However, over the span from 2022 to 2050, there are more jobs supported by the energy sector, on average, with the Slow CES than with the Fast CES. This is because the Slow CES has approximately the same total amount of clean generator construction by 2050 as the Fast CES, so a similar number of construction jobs, but construction is less concentrated in the pre-2036 years. The reduction of O&M jobs that follows construction occurs later and the average O&M job reduction from the reference case is consequently smaller with the Slow CES.

There are reasons to value nearer-term job effects more highly than later-term job effects. First, people tend to value nearer-term outcomes more than later-term outcomes. Second, if average wealth per person grows in the U.S., as it has historically, people in the future will suffer less loss of well-being from periods of unemployment and from paying higher taxes to pay unemployment benefits to others relative to what they will suffer from the same in the earlier future.

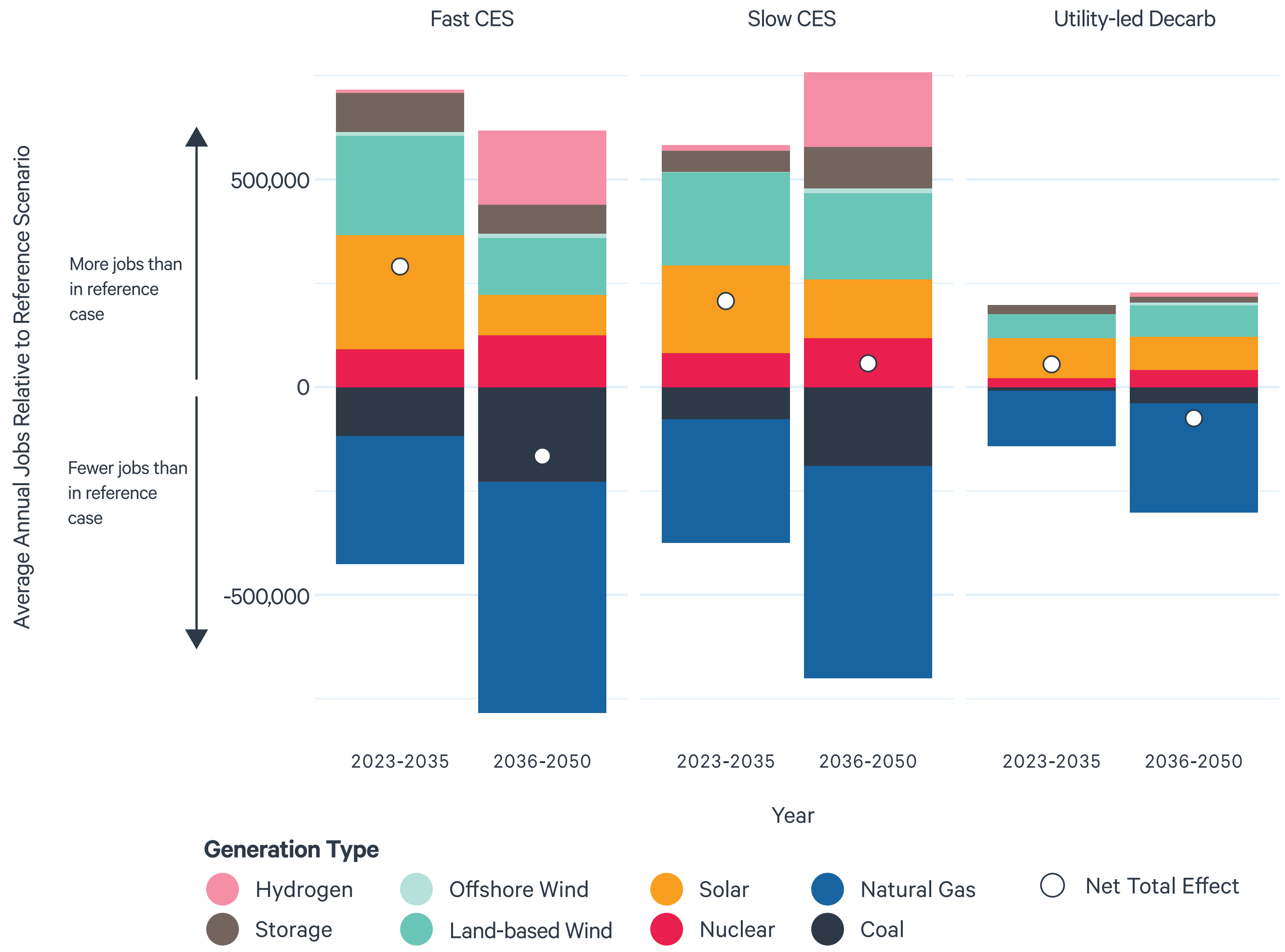
[15] In the results, the projected job effects of the Fast CES and Slow CES grow larger from 2036 through 2050 because of increased use of hydrogen, which is employment-intensive. If we were to model beyond 2050, this trend could continue as hydrogen-powered generation could increase further to move electricity generation beyond the 97% clean achieved in 2050, closer to 100% clean.

# 5.2 EMPLOYMENT EFFECTS BY GENERATION TYPE, 2023-2050

For the three pathways whose job effects we projected, Figure 19 shows the average annual employment effect of each pathway for each generation type, relative to the reference scenario. It shows this separately for 2023-2035 and for 2036-2050. Bars above the zero-line show job increments while bars below the zero-line show job reductions, relative to the reference scenario. Across all three pathways and both time periods, land-based wind, solar nuclear, short-duration storage (four hour batteries), hydrogen, and offshore wind see job increments, because these technologies are used to comply with these three pathways. Natural gas and coal are the only technologies with job reductions relative to the reference scenario, with larger job reductions for natural gas than for coal because natural gas has a larger share of reference-case fossil fuel-powered generation.

Each white dot in Figure 19 shows the net average annual job effect relative to the reference scenario. The vertical position of each white dot is the sum of all the positive changes, minus the negative changes. If the positive segments are larger in total than the negative segments, then the white dot is above the zero-line and vice versa. Each white dot matches the average from Figure 18 for its time period and pathway.

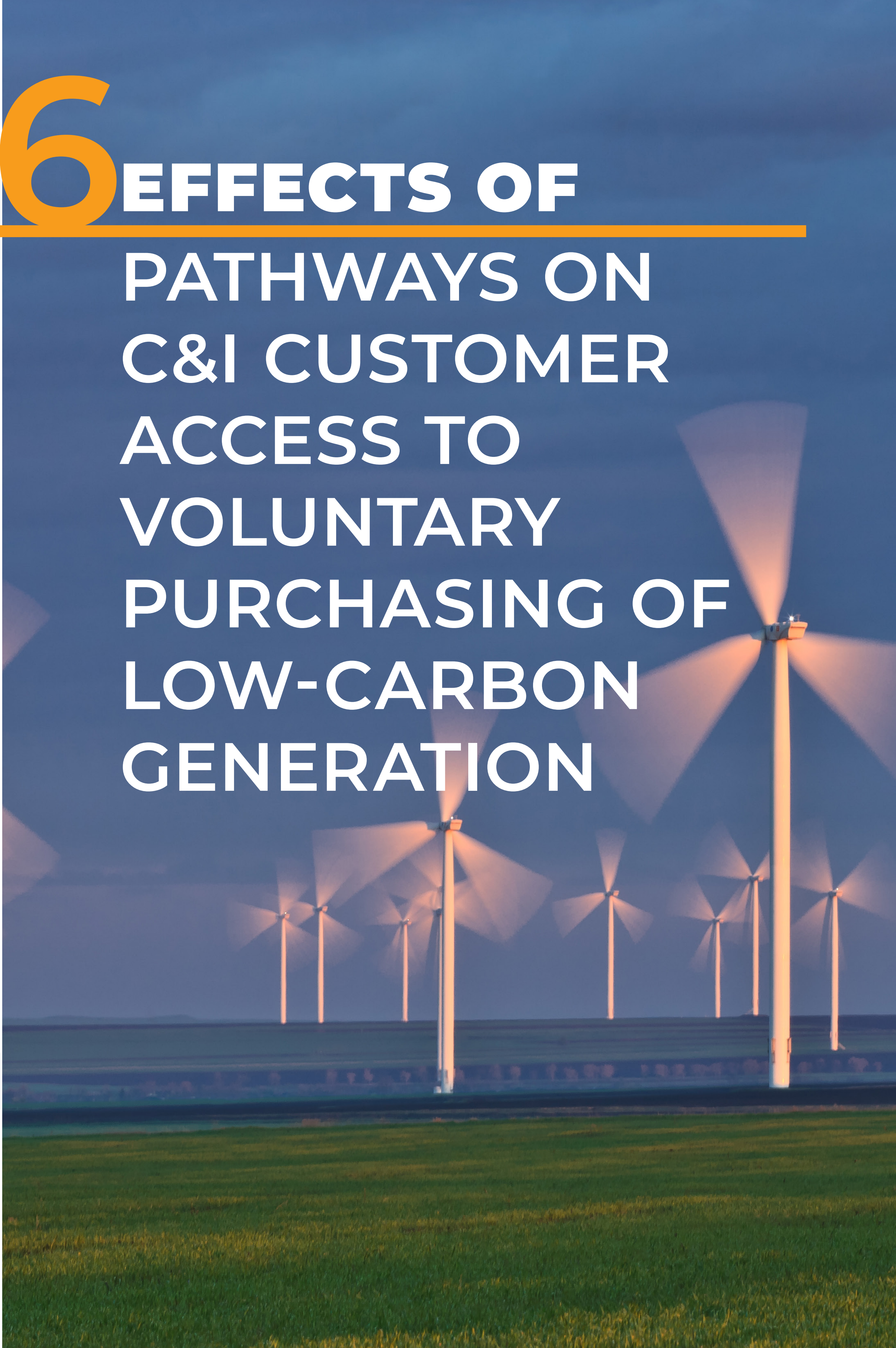
**FIGURE 19** **Average employment effect by generation type, relative to reference scenario, 2023-2035 and 2036-2050.**



# 5.3 EMPLOYMENT EFFECTS OF 80% BY 2030 CES

Since we only modeled the 80x30 CES out to 2030, we can only project its job effects through 2030. From 2023 through 2030, the 80x30 CES results in an average of approximately 430,000 more jobs than in the reference scenario. Like the CES pathways described above, the jobs gains in the 80x30 pathway consist mainly of increases in employment in construction and operation of solar, land-based wind, and electricity storage facilities. The negative differences in job estimates, which are considerably smaller in the 2023-2030 time period, consist mainly of a reduction in jobs in fueling, operating, and maintaining natural gas and coal power plants, and in building natural gas power plants.

# 06 EFFECTS OF PATHWAYS ON C&I CUSTOMER ACCESS TO VOLUNTARY PURCHASING OF LOW-CARBON GENERATION



# 06 ACCESS TO LOW-CARBON GENERATION

NREL modeled commercial & industrial (C&I) access to voluntary purchasing of low-carbon generation[16] under the reference scenario and four of the decarbonization pathways:[16]

1. A national CES
2. 100% decarbonization by vertically integrated IOUs
3. Expanded organized wholesale electricity markets
4. Expanded C&I supply choice and organized wholesale electricity markets

This section outlines how each of the four pathways could affect C&I access to low-carbon generation relative to the reference scenario. For the purposes of this section, we define access as a C&I customer's ability to voluntarily buy low-carbon generation through specific products, unfettered by significant legal or economic barriers. Voluntary purchasing means purchasing a product other than the utility's standard offer generation product. Table 5 defines the relevant products and details the barriers to access for each of these products. We largely exclude unbundled renewable energy certificates (RECs) from our discussion, given that all C&I customers have access to unbundled RECs under all pathways. In addition, C&I customers are increasingly minimizing unbundled RECs in their low-carbon generation portfolios for various reasons outside the scope of this report. Unbundled RECs can therefore be viewed as a backstop for C&I procurement: C&I customers will attempt to buy low-carbon generation through other products but can always buy unbundled RECs if all other options fail. Further, our analysis is limited to the potential impacts of the pathways on existing products. It is possible or even likely that clean energy markets will respond to the different pathways with unforeseen product innovations that could affect C&I customer access to clean energy.

**Table 5. C&I Low-Carbon Generation Products and Legal Impediments**

| Product | Definition | Barriers to Access |
|---|---|---|
| Unbundled renewable energy certificates (RECs) | Customer buys RECs unbundled from underlying power | None, all C&I customers have access to unbundled RECs |
| Competitive supplier product | Customer buys low-carbon generation from non-utility retail electricity supplier | Only available in states with restructured electricity markets allowing for retail electricity choice |
| Physical power purchase agreement (PPA) | Customer contractually buys power directly from generator | Only possible in states that allow customers to buy power directly from generators |
| Financial PPA | Customer financially backs a project, buys RECs, and sells power into wholesale market | Only possible for generation projects in states with organized wholesale electricity markets |
| Utility green tariff | Customer buys low-carbon generation contractually via the utility | Currently only possible in states that are traditionally regulated; requires regulatory approval from state public utility commission |

[16] NREL data on purchasing trends are specific to "renewable energy" rather than "low-carbon" generation, but we use the term "low-carbon" for consistency with the rest of the report.

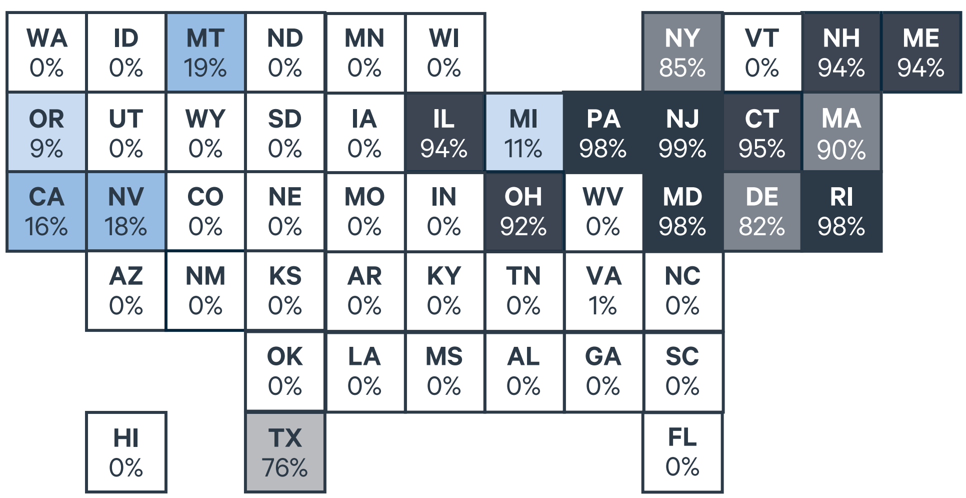
# 6.1 REFERENCE SCENARIO

For the reference scenario, we make projections of future C&I access under the assumption that there are no changes in relevant national policy. In the cases of competitive suppliers and both PPA types, there is little reason to suspect any changes in access in the reference scenario relative to current access. We therefore base the reference scenario projections for these products on current C&I access to these products. In contrast, C&I access to utility green tariffs has expanded considerably over the past several years, and this expansion is likely to continue if there are no changes in national policy. We account for projected future expansion.

Access to competitive suppliers is determined by the percentage of C&I customers with access to supply choice. We generate a supply choice variable according to the following logic:

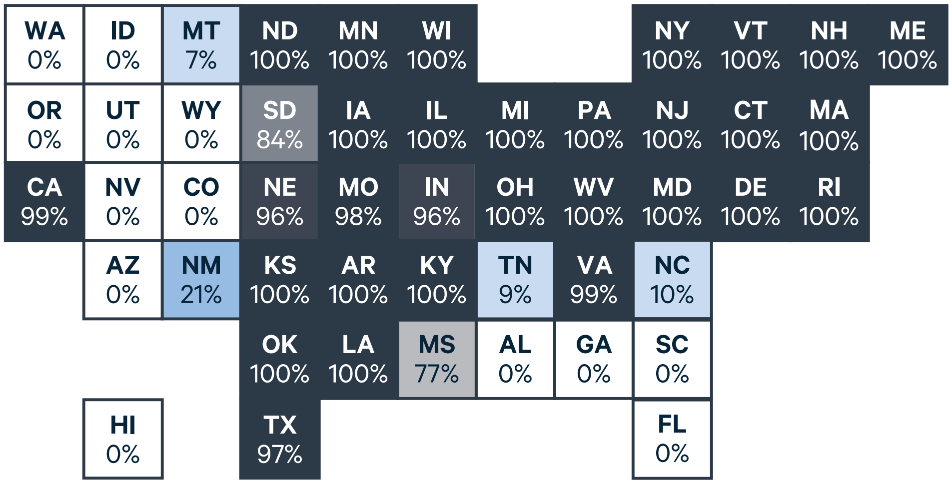
- In states with full supply choice, the variable is equal to the percentage of C&I demand in IOU service territories, based on EIA-861 data.
- In states with partial supply choice, the variable is equal to the percentage of C&I demand in IOU service territories served by competitive suppliers, based on the assumption that the caps are binding.

**FIGURE 20** **C&I access to supply choice by state in the reference scenario**




C&I access to physical PPAs is largely determined by whether the state has retail competition for customers of investor-owned utilities (reflected in Figure 20). In states with such competition, even customers of government-owned and cooperative utilities tend to have access to physical PPAs, and we assume they do. C&I access to financial PPAs is determined solely by the presence of organized wholesale electricity markets that encompass the locations of the generation facilities. The wholesale market variable is equal to the percentage of the state's electricity load that is served by an organized wholesale market (independent system operator or regional transmission organization), as estimated by RFF.

**FIGURE 21** Wholesale market access by state in the reference scenario




Finally, a relatively small number of states have authorized utilities to offer utility green tariffs, and several states have authorized one-off bilateral contracts between C&I buyers and utilities. Utility green tariffs have expanded considerably over the past several years, and it is reasonable to assume that more utilities will offer green tariffs in the future. To provide a rough projection of C&I access to green tariffs in a reference scenario, we assume that all investor-owned utilities in traditionally regulated states that have authorized utility green tariffs or bilateral contracts will offer utility green tariffs to both large and small C&I customers, based on states identified by the World Resources Institute and CEBA (Bonugli, Hutchinson, and Barua 2020).

# 6.2 NATIONAL CLEAN ELECTRICITY STANDARD

In this pathway, the federal government implements a clean electricity standard (CES) mandating load-serving entities (LSEs) to procure 100% of generation from zero-carbon sources by 2050. In this section, we do not differentiate between the Fast and Slow CESs.

Utilities facing stringent clean-energy targets would be likely to expand the availability of green tariffs as a way to achieve the utility-wide targets at a lower cost to the customers who do not choose to voluntarily purchase green power. Duke Energy, for example, cited utility green tariffs as one tool to meet a 2050 100% carbon neutral target (Morehouse, 2019). Green tariffs could be an alternative to the standard generation procured by the utility. For example, a green tariff could offer a 100% renewable alternative to the 100% clean (but not necessarily 100% renewable) standard offering. We assume that under a national CES, utilities would expand utility green tariffs to facilitate C&I contributions toward utility clean energy targets. Figure 22 and Tables 6 through 9 assume that all vertically integrated investor-owned utilities would phase in utility green tariffs under the Fast or Slow national CES, for both large and small C&I customers. This is an approximation as not all such utilities would necessarily do this, while some distribution utilities of other types might.

Aside from increasing utility green tariff availability, we assume in Figure 22 and Tables 6 through 9 that a national CES does not otherwise change C&I access. However, in reality, distribution utilities and regulators could make the other voluntary green power products either more or less widely accessible. They could make them more widely accessible to facilitate decarbonization. They could make them less widely accessible because they are completely decarbonizing standard offer service and may not consider it necessary to continue to make some other voluntary green power purchasing option available.

## 6.3 UTILITY-LED DECARBONIZATION

In this pathway, vertically integrated IOUs commit to 100% clean energy by 2050 and follow through with those commitments. As stated in the preceding subsection, utilities with 100% clean energy targets, especially vertically integrated ones, would be likely to expand the availability of green tariffs. For this pathway, we assume in the chart and tables below that all vertically integrated investor-owned utilities would phase in utility green tariffs before reaching 100% clean energy. This is an approximation, as some might not.

Other than for green tariffs, it is difficult to project the effects of utility-led decarbonization on C&I access. In Figure 22 and Tables 6 through 9, we assume that utility-led decarbonization does not change C&I access to the other voluntary green power products. However, the utilities could make the other voluntary green power products more widely available or less widely available, for the same reasons stated in the preceding subsection.

## 6.4 EXPANDED ORGANIZED WHOLESALE ELECTRICITY MARKETS

This pathway assumes that wholesale market access expands to all states that currently lack organized wholesale markets. This pathway would expand access to financial PPAs to all customers but would not affect access to the other three voluntary green power products.[17]

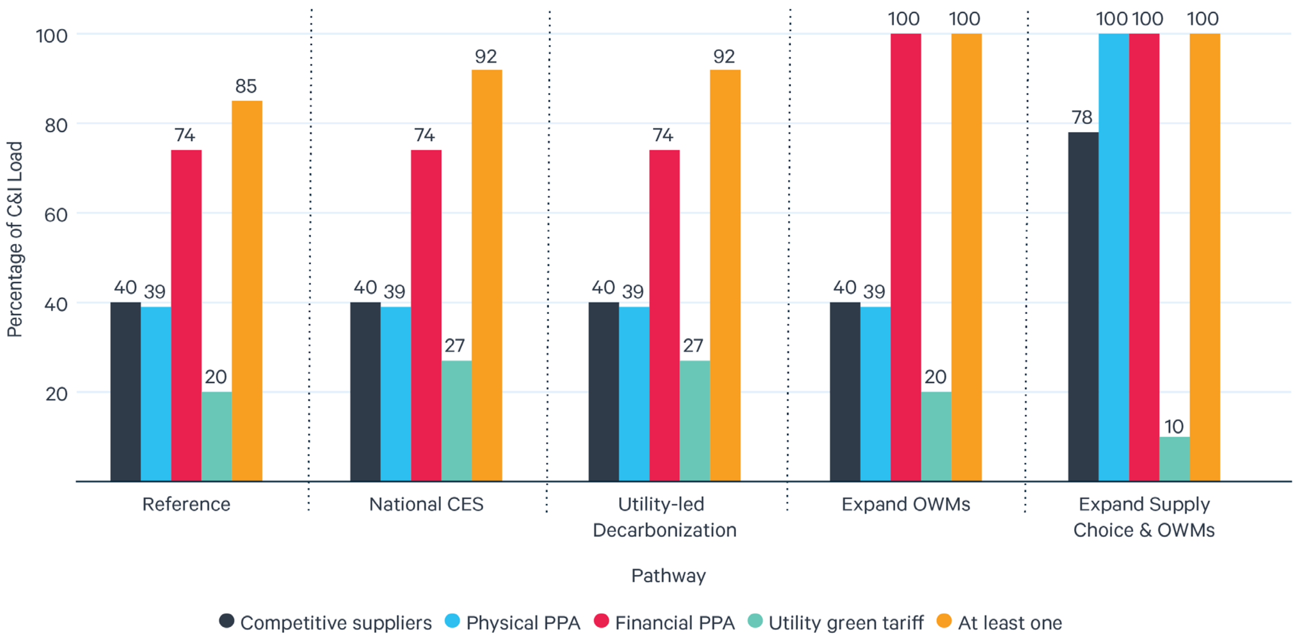
## 6.5 EXPANDED C&I SUPPLY CHOICE AND WHOLESALE ELECTRICITY MARKETS

This pathway assumes C&I supply choice and organized wholesale markets expand to all states that currently lack choice or wholesale markets. This would expand access to competitive suppliers, physical PPAs, and financial PPAs.[17] We assume that C&I supply choice would expand only to C&I customers of investor-owned utilities, not government-owned or cooperative utilities, so the C&I access to competitive suppliers does not reach 100%. We assume that it would give 100% of C&I customers access to physical PPAs, since that access is largely determined by whether the state has retail competition for customers of investor-owned utilities, as mentioned in Section 6.1. Expanded supply choice would be likely to reduce utility green tariffs, since they currently are rarely offered by utilities that offer supply choice.

[17] Although customers can sign financial PPAs currently regardless of where their load is located, as long as the renewable energy project is located in a wholesale market, signing financial PPAs far from the customer's load does not mitigate electricity supply cost risk as well as signing PPAs near the load, and is not common today.

# 6.6 NUMERICAL ESTIMATES

**FIGURE 22** C&I customers' access to options for purchasing clean generation




We now present numerical projections of the effects of the pathways on the amounts of C&I customers and C&I customer load that would have access to voluntary green power products. There is considerable uncertainty about how each pathway would actually affect such access. Despite that large uncertainty, Figure 22 presents projected percentages of C&I load that would have access to voluntary green power products in each pathway. The similarities of the numbers from one pathway to the next result from the fact that the pathways do not necessarily affect access to voluntary green power products.

The four tables following Figure 22 provide the full numerical estimates of C&I customer access in terms of customers (Table 6), percentage of customers (Table 7), load (Table 8), and percentage of load (Table 9). In these tables, "At least one" means the population of C&I customers or C&I load that has access to at least one of these four voluntary clean energy products.

These access numbers are based on technical feasibility of access to each type of green power product. However, for small customers, in this case small C&I customers, physical and financial PPAs are unlikely to be practical options unless sellers start offering them to small customers at affordable prices.

### Table 6: C&I Customer Access (Millions of Customers)

| | Pathways | | | | |
|---|---|---|---|---|---|
| Product | Reference | National CES | Utility-led Decarbonization | OWM Expansion | OWM & Supply Choice Expansion |
| Competitive suppliers | 7 | 7 | 7 | 7 | 16 |
| Physical PPA | 7 | 7 | 7 | 7 | 21 |
| Financial PPA | 15 | 15 | 15 | 21 | 21 |
| Utility green tariff | 4 | 5 | 5 | 4 | 2 |
| At least one | 17 | 19 | 19 | 21 | 21 |

### Table 7: C&I Customer Access (% of Customers) to Voluntary Non-Emitting Power Products Other than Unbundled Renewable Energy Credits

| | Pathways | | | | |
|---|---|---|---|---|---|
| Product | Reference | National CES | Utility-led Decarbonization | OWM Expansion | OWM & Supply Choice Expansion |
| Competitive suppliers | 33% | 33% | 33% | 33% | 75% |
| Physical PPA | 33% | 33% | 33% | 33% | 100% |
| Financial PPA | 72% | 72% | 72% | 100% | 100% |
| Utility green tariff | 19% | 26% | 26% | 19% | 9% |
| At least one | 82% | 90% | 90% | 100% | 100% |

### Table 8: C&I Load Access (TWh)

| | Pathways | | | | |
|---|---|---|---|---|---|
| Product | Reference | National CES | Utility-led Decarbonization | OWM Expansion | OWM & Supply Choice Expansion |
| Competitive suppliers | 1,100 | 1,100 | 1,100 | 1,100 | 2,170 |
| Physical PPA | 1,090 | 1,090 | 1,090 | 1,090 | 2,780 |
| Financial PPA | 2,060 | 2,060 | 2,060 | 2,780 | 2,780 |
| Utility green tariff | 560 | 750 | 750 | 560 | 280 |
| At least one | 2,360 | 2,560 | 2,560 | 2,780 | 2,780 |

### Table 9: C&I Load Access (%)

| | Pathways | | | | |
|---|---|---|---|---|---|
| Product | Reference | National CES | Utility-led Decarbonization | OWM Expansion | OWM & Supply Choice Expansion |
| Competitive suppliers | 40% | 40% | 40% | 40% | 78% |
| Physical PPA | 39% | 39% | 39% | 39% | 100% |
| Financial PPA | 74% | 74% | 74% | 100% | 100% |
| Utility green tariff | 20% | 27% | 27% | 20% | 10% |
| At least one | 85% | 92% | 92% | 100% | 100% |

Again, all customers have access to another type of voluntary renewable energy product, unbundled RECs, but tend to prefer one or more of the above voluntary renewable energy products over that one. For those two reasons, we have not included it in the tables, charts, and pathway discussions above. In addition, CESs and utility-led decarbonization involve mandatory access to clean energy, which we have not included in the chart and tables in this section.

Based on the definitions of the pathways, only the two pathways that involve expansion of OWMs imply a change in the availability of voluntary green power products for the customers of cooperative or government-owned distribution utilities. However, a wave of decarbonization commitments by utilities could include some of these utilities and could consequently cause an expansion or reduction of voluntary green power options for their customers, while a national CES could cause some of these utilities to expand or end the availability of some voluntary green power products.

## 6.7 SUMMARY

A national CES and decarbonization by vertically integrated IOUs would increase mandatory clean generation access by C&I customers. The effects of these two pathways on voluntary clean generation access are less clear – they would be likely to increase the utility green tariff option and might increase or decrease C&I customer access to the other voluntary green power products.

Expanded organized wholesale electricity markets would increase C&I voluntary clean power access. Expanded wholesale electricity markets combined with expanded C&I supply choice would increase it even more. Neither of these pathways would directly affect mandatory clean generation access.

# 07 UNCOUNTED BENEFITS AND COSTS

This report presents a relatively comprehensive accounting of the benefits and costs of the policies it simulates. However, like all studies, it omits some benefits and costs. Some of the omitted effects are environmental – the only environmental impacts we include are premature deaths from $SO_2$ and $NO_x$ emissions and damage from the GHG emissions, $CO_2$, and methane. However, prior studies (National Research Council 2010, Friedrich 2005) indicate that these effects are likely to account for most of the environmental damage from electricity production. In addition, some of the omitted effects are non-environmental – if a given generation technology is built more in one scenario than another, that tends to reduce its cost, but we do not include that effect.

For greater voluntary purchasing of green power by C&I electricity customers, we estimate the emission reduction benefits just mentioned and the higher wholesale electricity costs and prices that result from that greater purchasing of it. However, voluntary purchasing of green power has some benefits and costs for which we do not have estimates. There are the omitted benefits and costs mentioned in the preceding paragraph. Also, voluntarily buying green power probably takes some time. These uncounted costs are presumably more than counter-balanced by the greater profits and satisfaction of the businesses that buy more green power; otherwise, they would not voluntarily buy more of it. The larger profits would result from gaining customers or better employees because of being more sustainable.

In addition, the policies would have effects on reliability and resilience, which we do not calculate. However, in every pathway, the generation capacity is adequate to meet load in all our 52 representative hours. These hours include oversampling of the hours with greatest scarcity in each of the 10 major reliability regions of the U.S. and Canada. Effectively, we are holding generation adequacy constant across all pathways. This greatly reduces the reliability and resilience differences among the pathways. Furthermore, it is difficult to predict the signs of the reliability and resilience effects of each pathway. For example, the CES pathways have more solar, wind, and energy storage capacity than the other pathways. Solar, wind, and energy storage are variable or energy limited and do not have inertia. However, they are versatile and fast in changing their real and reactive power outputs in response to system needs and are not subject to sustained, unanticipated wide-area outages because of natural gas supply disruptions.

# 08 CONCLUDING SUMMARY

This report has considered several decarbonization pathways for reducing electric power sector emissions. Each of the pathways produces billions of dollars of estimated net benefits per year and the pathways can be combined.

Of the four emission reduction pathways we consider, the national CESs are the ones that can realistically reduce U.S. power sector emissions by more than 90%. As a result, they also have the largest estimated net benefits, on the order of $100 billion per year by 2050, mainly from reduced climate change damages and reduced U.S. deaths from $SO_2$ and $NO_x$ emissions. The Fast CES results in an average of 290,000 more net energy sector jobs than the reference case from 2023 through 2035 and an average of 170,000 fewer than the reference case from 2036 through 2050. The Slow CES results in an average of 210,000 more jobs than the reference case from 2023 through 2035, and 60,000 more than the reference case from 2036 through 2050.

Full decarbonization by all the nation's vertically integrated investor-owned utilities produces emission reductions and net benefits approximately half as large as those of the national CESs we model, likewise because of emission reduction benefits. These policies increase the overall profits of generation owners, though this is a small benefit relative to the projected climate and health benefits. This pathway results in an average of 50,000 net projected energy sector jobs more than the reference case from 2023 through 2035, and an average of 70,000 fewer than the reference case from 2036 through 2050.

The remaining pathways, which are the enabling pathways, do not have the ability to increase zero- and low-carbon generation as much. However, each of them can still play very important roles. The enabling pathways provide benefits, and induce emission reductions, whether combined with national mandatory pathways or not. Notably, they reduce system costs (even before counting environmental cost reductions) while also reducing emissions.

The direct-current macrogrid that we model produces benefits that are projected to be three to four times as large as the costs of building and maintaining it. The net pocketbook savings for electricity customers are roughly as large as the estimated environmental and health benefits, assuming that clean energy and emission policies are not made more stringent in response to the construction of the macrogrid. The results of our simulation of the macrogrid are remarkably similar to the results of a simulation of a similar macrogrid by researchers at NREL (Bloom et al., 2020), even though our analysis was independent of theirs and used a different model. The macrogrid is just one type of transmission expansion that may be beneficial. Other actions, such as expanding and building new AC transmission lines, are essential to building a resilient and decarbonized power grid, but we do not examine their benefits in this report.

The two parts of the U.S. that do not have organized wholesale electricity markets are the Southeast and much of the West. The benefits of OWMs, resulting largely from more economically efficient decisions, are diverse. Estimating their value effectively is very time consuming and calls for considerable empirical input and different approaches than the ones we use in our own modeling for this study. As a result, we rely on past studies that focus on estimating the benefits of OWMs. Based on those studies, we estimate the benefits of expanding organized wholesale markets to the rest of the U.S. before 2035. The projected annual pocketbook benefits are $11 billion per year as of 2035 and $14 billion per year as of 2050. In addition, the projected reduced annual greenhouse gas emissions in 2035 are worth an estimated $8 billion and the projected emissions reduction in 2050 are worth an estimated $10 billion.

Supply choice, also known as retail choice, has been granted to approximately 31% of the commercial and industrial load in the U.S. We model the expansion of supply choice to the C&I electricity customers of investor-owned electric utilities that do not currently offer supply choice. Normally, the expansion of supply choice has been accompanied by the expansion of an OWM to the same geographic area. This C&I supply choice expansion combined with the OWM expansion described in the preceding paragraph produces estimated annual net benefits of $20 billion as of 2035 and $25 billion as of 2050.

The projected incremental benefits of this C&I supply choice expansion, if OWM expansion were already in place or already planned, are $1 billion per year in 2035 and $0.5 billion per year in 2050. These incremental benefits of C&I supply choice expansion by itself result almost entirely from reduced emissions. The C&I supply choice expansion reduces emissions by increasing voluntary green power purchasing and reducing ownership and overuse of emitting power plants by vertically integrated electric utilities. We carefully estimate the strengths of both of these phenomena and apply them in our modeling.

Our estimates of the benefits and costs of the pathways are designed to include the most significant benefits and costs, but it is not possible to be exhaustive. The estimated benefits of supply choice expansion might include a smaller portion of total benefits than for the other pathways. It does not include the benefit to business owners, employees, and customers from knowing that they are supporting clean energy production, and it does not include the other benefits of C&I customers having more diverse electricity supply offerings that might for example hedge financial risks better.

The pathways can all co-exist harmoniously. In fact, in some cases the benefits of combining them are larger than the sum of the benefits of the individual pathways. For example, transmission expansion, including the building of a high-voltage macrogrid and OWM expansion support the cost-effectiveness of national CESs.

For commercial and industrial electricity customers, the pathways can affect the availability and appeal of the options for procuring non-emitting electricity generation. In response to a clean generation requirement, regulators and utilities can remove the option of voluntary clean power purchases or can preserve or expand it to allow customers to choose alternative non-emitting generation that might be better for the customer. When there is a clean generation requirement of less than 100%, allowing voluntary green purchases in addition to the percentage requirement can speed decarbonization or reduce costs for other customers. Wholesale electricity market expansion tends to increase voluntary non-emitting generation procurement options and adding supply choice increases them even more.

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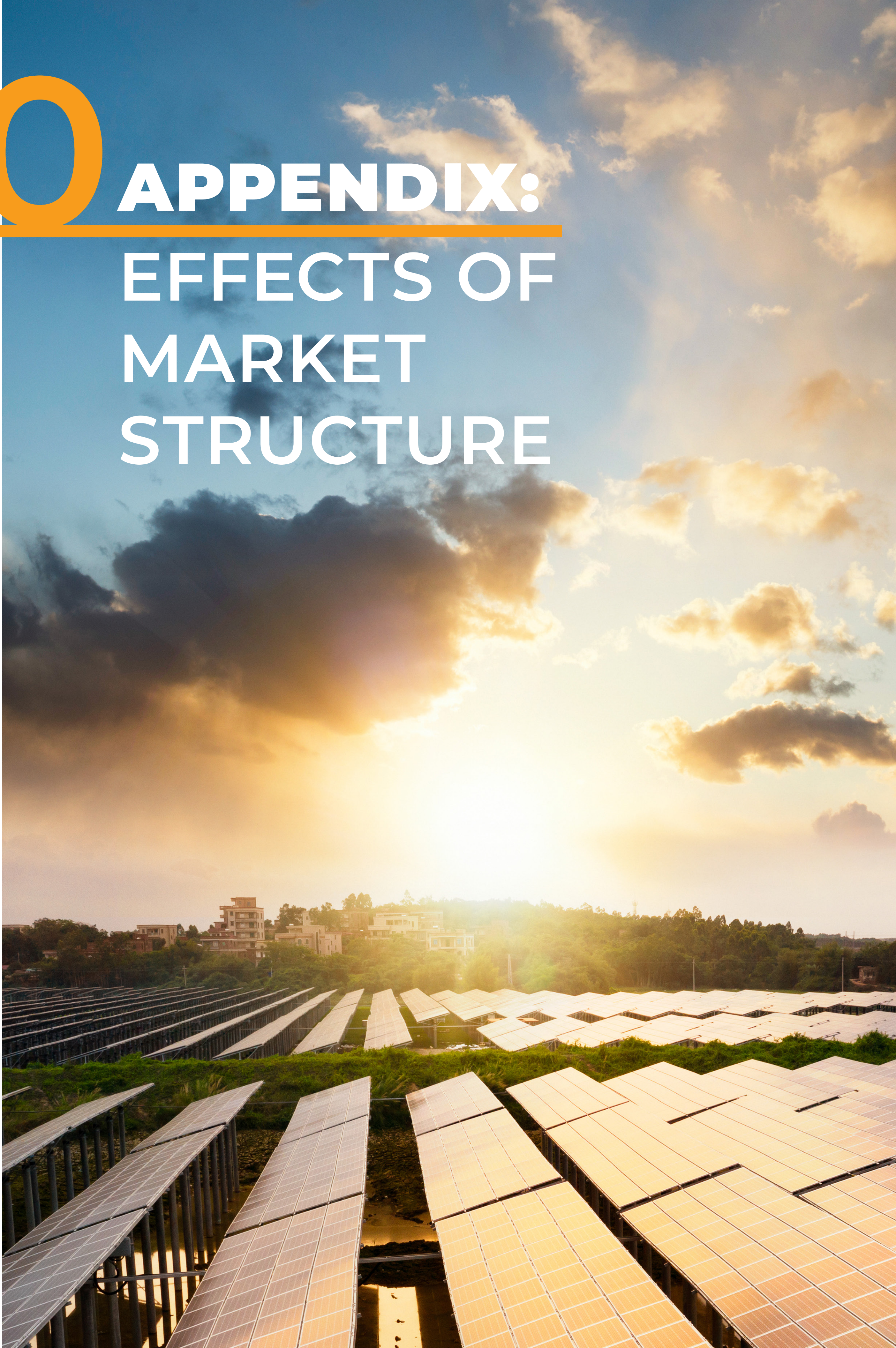
# 10 APPENDIX: EFFECTS OF MARKET STRUCTURE



# 10 APPENDIX: EFFECTS OF MARKET STRUCTURE

Electricity market structures vary widely in the U.S.. In some places, vertically integrated utilities leave consumers with no choice of their energy supplier, in others, consumers have full choice of electricity suppliers that participate in an organized wholesale market, and other places are somewhere in between. In this study, we consider three factors that define the market structure of an area:

1. **The presence of an organized wholesale electricity market (OWM)**
2. **The prevalence of cost-of-service (COS) regulation of electricity generating facilities**
3. **The level of access that consumers are given to supply choice, which is the ability to choose their electricity supplier.**

We assume that the prevalence of COS regulation stays the same in all scenarios except for the OWM & Supply Choice Expansion pathway, where expansion of supply choice decreases the prevalence of COS regulation (see Appendix 11.2.9).

## 10.1 EFFICIENCY OF FOSSIL-FUEL DISPATCH

An important feature of our representation of the presence of OWMs and supply choice is its effect on the propensity to operate coal- and gas-fired generators. In practice, fossil-fueled generating units tend to be operated more than an economic dispatch model would optimally predict. At times, fossil-fueled generating units remain operating when there are cheaper generation sources available, and sometimes more expensive fossil-fueled generating units are dispatched instead of less expensive fossil-fueled generating units. There are multiple reasons why this may happen. Fossil-fueled generating units provide ancillary services, have inflexible operation, and especially in areas with COS regulation and outside of organized markets, owners have incentives to operate them uneconomically (Fisher et al., 2019). To measure the effect that market structure has on the strength of this phenomenon, we calculated adjustments to the variable operating costs of generating units which capture the difference in overuse of fossil-fueled generating units between the following four market structure types.

1. **With COS regulation and in OWMs**
2. **With COS regulation and outside of OWMs**
3. **Without COS regulation and in OWMs**
4. **Without COS regulation and outside of OWMs**

We did this separately for coal-fueled and natural gas-fueled generating units, for a total of eight categories of generating units. We imposed constraints in E4ST (a linear program) on the total generation from each of the eight categories to match natural gas and coal-fueled generation in an E4ST simulation of 2016 with historical 2016 generation amounts in each market type. The shadow prices on these eight constraints are the cost adjustments and can be interpreted as the degree to which a typical generating unit in each category was overused in 2016. Since the purpose of these adjustments is to capture the difference between market structure types, we use adjustments relative to the most efficient category, natural gas-fueled generating units inside OWMs without COS regulation, giving it an adjustment of zero. The resulting adjustments are in Table 10.

**Table 10: Variable Operating Cost Distortions on Fossil-Fueled Generators, by Market Type**

| 2020$ / MWh | Coal | | Natural Gas | |
|---|---|---|---|---|
| | In OWM | Out OWM | In OWM | Out OWM |
| COS Regulated | -8.66 | -13.91 | -3.68 | -8.35 |
| Not COS Regulated | -7.57 | -10.58 | 0 | -1.54 |

For example, the adjustment values indicate that a typical COS-regulated coal plant inside an organized wholesale market in 2016 was dispatched as much as it would have been if it cost $8.66/MWh less than the actual cost of operating the plant. And the larger in magnitude the adjustment is, the more that class of generating units is overused, or the less it is underused, relative to how much it would be used in a world with perfect economic dispatch. These adjustments reveal patterns in the overuse of fossil fuel plants. First, coal fueled units are overused more than natural gas fueled units are. Second, it shows that all else equal, the level of overuse for both coal and natural gas is lower inside OWMs than outside. Third, coal and natural gas units that are COS regulated are overused more than those that are not COS regulated.

While we adjust the variable cost of each natural gas- and coal-fueled generating unit by the corresponding constant from the table above in our simulations, we use the unadjusted variable cost of each generating unit after each simulation, when we calculate final costs, benefits, and other effects of each pathway. We used generating unit data from S&P Global to determine whether a generator dispatches into an OWM.

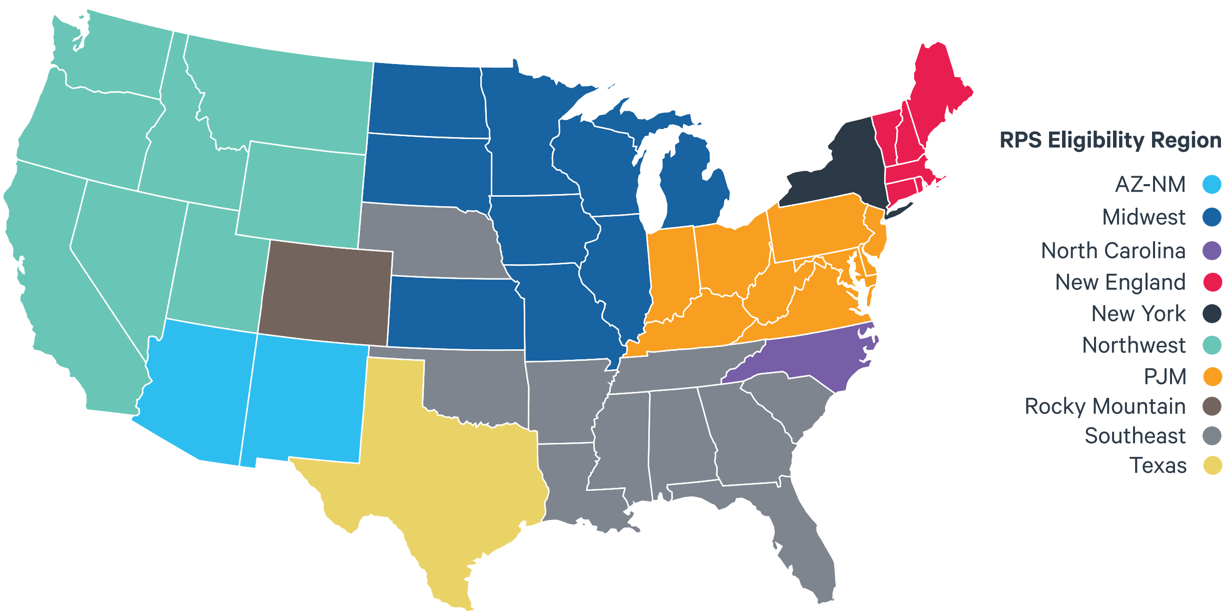
# 10.2 VOLUNTARY GREEN POWER PURCHASING

To represent the growing tendency of both C&I and residential electricity customers to voluntarily purchase power from renewable resources, we project and model future voluntary green power (VGP) purchasing under different market structure scenarios.

Again, our definition of VGP is just voluntary green power purchasing that does not overlap with clean generation mandates, as discussed in section 4.6.1.

We assume that all VGP purchased in the U.S. must be sourced from the U.S., and furthermore half must come from the customer's local RPS eligibility region, as defined in our model. In E4ST, utilities can obtain the renewable generation from within their RPS eligibility region shown in Figure 23, and these regions are designed to capture existing renewable credit tracking systems and information on credit eligibility in current state policies, while still keeping the model tractable and manageable (Martin, 2015; Brown et al., 2020).

**FIGURE 23** RPS eligibility regions, assumed in E4ST




### 10.2.1 Voluntary Green Power Uptake Projections

Using data from 2010 to 2019 (Heeter, 2020), we project national average VGP as a percentage of load that is not mandated to be met with green power. According to the data, residential customers purchased VGP at about the same rate that C&I customers did in 2019, and the average annual growth rate of purchasing over the 10 years prior to 2020 was approximately the same. We assume that all voluntary green power purchasing through 2019 is non-overlapping with clean generation mandates, as described in section 4.6.1. To the extent that that is not true, our projections of VGP could be seen as over-projections, since we define VGP as voluntary green power purchasing that does not overlap with clean generation mandate. Projected national average VGP, as a percentage of load not mandated to be met with green power, begins at 4.5% in 2019 and grows annually by approximately 0.4 percentage points per year. This applies to both C&I and residential VGP. For example, VGP sales in our projections make up 4.5% + 0.4% = 4.9% in 2020, 5.3% in 2021, and so on. These are percentages of load not mandated to be met with green power, so VGP as a percentage of total load is lower. Also, VGP as a percentage of total load grows at less than 0.4% per year, because the percentage of load that is mandated to be green increases over time. In the Reference, OWM Expansion, and OWM & Supply Choice Expansion scenarios, this increase in the percentage of load that is mandated to be met with green power results solely from increasing state RPS and CES requirements. In the Utility-led Decarbonization pathway, it results from increasing state RPS and CES requirements as well as utility-led decarbonization policies. In the CES scenarios, it results from increasing state RPS and CES requirements as well as the national CES.[18]

**Table 11: Projected C&I VGP Purchasing in U.S. as a Percentage of C&I Load**

| Pathway | 2035 | 2050 |
|---|---|---|
| Reference | 8.1 % | 10.0% |
| OWM Expansion | 9.8% | 12.2% |
| OWM & Supply Choice Expansion | 14.3% | 18.8% |
| Utility-led Decarbonization | 6.3% | 5.9% |
| Slow CES | 2.8% | 0% |
| Fast CES | 0% | 0% |

**Table 12: Projected Total VGP Purchasing in U.S. as Percentage of Load**

| Pathway | 2035 | 2050 |
|---|---|---|
| Reference | 8.1 % | 10.0% |
| OWM Expansion | 9.2% | 11.4% |
| OWM & Supply Choice Expansion | 12.0% | 15.5% |
| Utility-led Decarbonization | 6.3% | 5.9% |
| Slow CES | 2.8% | 0% |
| Fast CES | 0% | 0% |

In the OWM and OWM & Supply Choice expansion pathways, VGP purchasing by C&I customers further increases because of the OWM and supply choice expansion. As part of this project, NREL and RFF developed a statistical model based on empirical state-level data to estimate how VGP purchasing is influenced by the presence of OWMs and supply choice. The model estimates that expanding OWMs into a state that previously participated in neither supply choice nor OWMs would multiply C&I VGP purchasing, as a percentage of load not mandated to be met by green power, by a factor of 1.55. Adding supply choice to a state which already participated in OWMs multiplies the same measure by a factor of up to 1.96, depending on the prevalence of investor-owned utilities. Specifically, the multiplier is 1 + (0.96 * proportion of C&I load in the state that is served by vertically integrated investor-owned utilities). We applied those effects state by state to predict VGP purchasing in each state in each of the pathways. Table 11 shows percentages of total national C&I load projected to consist of VGP, assuming the CES percentage targets are met.

In Table 12, we show total VGP (C&I plus residential) as a percentage of total load (C&I plus residential). We include projected residential VGP in our modeling, but we assume that VGP purchasing from residential customers is not affected by OWM expansion or by expansion of supply choice, since that expansion is just to C&I customers. As a result, the changes in VGP percentage from OWM and supply choice expansion are smaller as a percentage of total U.S. electricity consumption than they are as a percentage of U.S. C&I electricity consumption. C&I customers constitute approximately 62% of U.S. electricity consumption.

[18] A very minor related detail is that, for the purpose of projecting voluntary green power purchasing, our definition of "mandates" includes the national CES targets even if they are not fully met. For example, in 2050, the national clean generation target under both the Fast and Slow CESs is 100% but the actual clean generation percentage is only about 97% because the national CES credit price reaches its cap before 100% is reached. In these cases, we use 100% as the amount of generation "mandated" to be clean, just for the purpose of projecting voluntary green power purchases.

### 10.2.2 Markups on Voluntary Green Power

We assume that different methods for purchasing VGP are available under different market structures, and that each method for purchasing VGP incurs a markup over the prices usually paid by C&I customers for undifferentiated utility power, which is power that might or might not include some green power but has no premium for being green. Both the markup and the purchase methods available depend on whether the customer is large or small, with the majority of C&I customers being small, and large customers being those with enough load to contractually purchase wholesale green power, and enough expertise to access certain more difficult procurement methods. Clean Kilowatts LLC, working as an NREL subcontractor as part of this project, has estimated markups for several VGP purchase methods, displayed in Table 13.

**Table 13: Estimated Markups Over the Price of Utility Power for VGP Purchase Methods**

| Method | Necessary Market Structure | Available To (customer size) | Markup (2020$/MWh) |
|---|---|---|---|
| Power purchase agreement (PPA) | Inside Wholesale Market | Large | -$1.15 |
| Buying unbundled RECs | Always available | Large | $1.15 |
| Utility green tariffs | Outside Wholesale Market | Large | $1.9 |
| Utility green pricing programs | Always available | Small | $10 |
| Competitive supplier | Supply Choice | All | $10 for small customers, $1.15 for large customers |

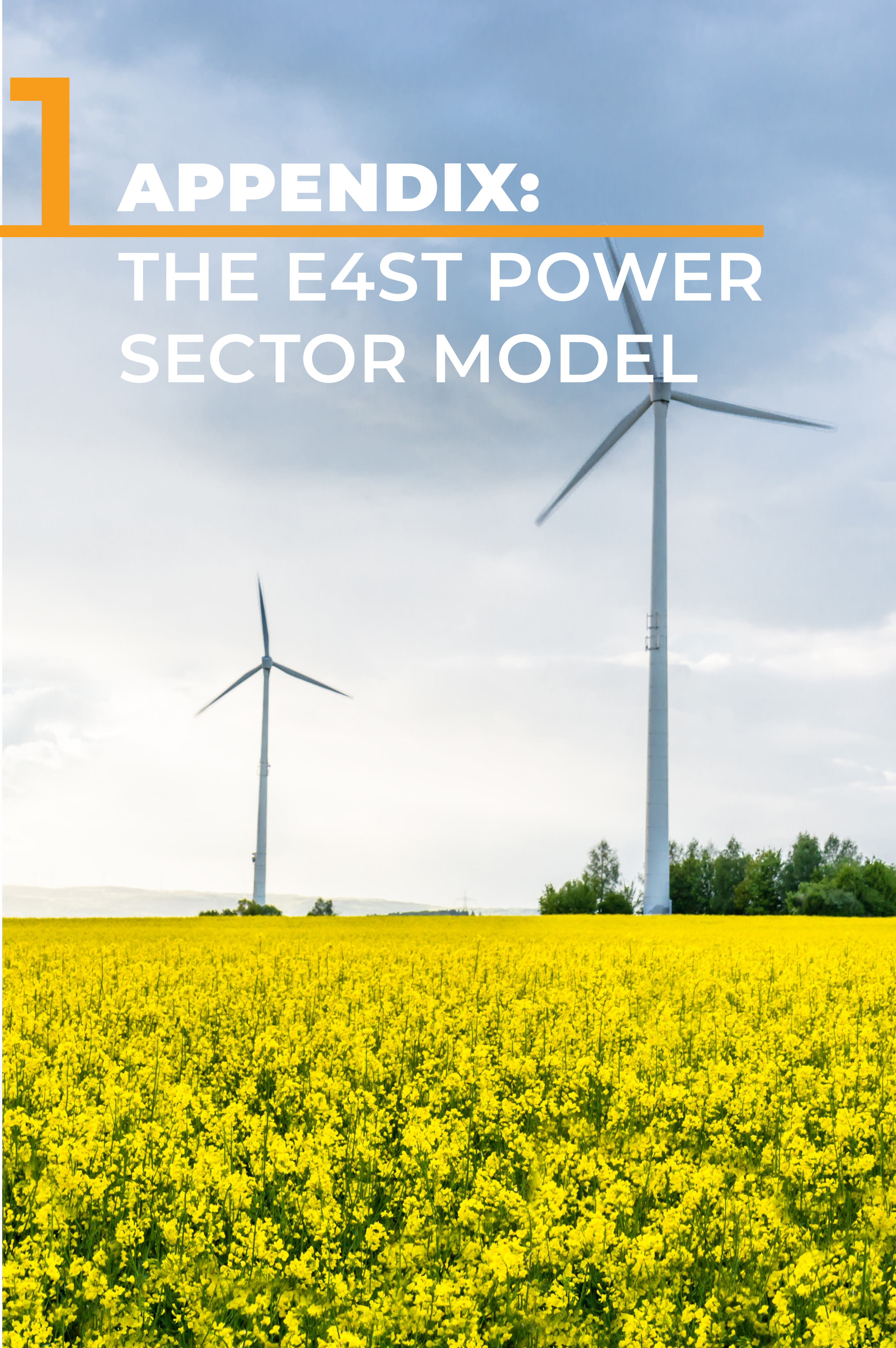
Given this information, and assuming that large customers choose evenly between the VGP buying options that are available to them, we obtain estimated average markups on VGP based on market structure for large customers in Table 14. According to these assumptions, introducing organized wholesale electricity markets reduces the markups that large C&I electricity customers pay for VGP, by $1.525 per MWh for those customers that do not have supply choice, and by $1.15 per MWh for those that do have supply choice.

**Table 14: Estimated Average VGP Markups for Large Customers Based on Market Structure**

| 2020$ / MWh | No Supply Choice | Supply Choice |
|---|---|---|
| Outside Wholesale Market | 1.525 | 1.15 |
| Inside Wholesale Market | 0 | 0 |

For small customers, according to these assumptions, changes in market structure do not reduce their markup on purchasing VGP, which is always $10/MWh. We use these markups to estimate the cost savings that result from customers who buy VGP having access to less expensive VGP purchasing methods in the pathways.

# 11 APPENDIX: THE E4ST POWER SECTOR MODEL



# 11 APPENDIX: THE E4ST POWER SECTOR MODEL

The Engineering, Economic, and Environmental Electricity Simulation Tool (E4ST) is a simulation model of the U.S. electric power sector with high spatial resolution in transmission, renewable resource profiles, generating resources, and electricity demand. E4ST predicts construction and retirement of grid-serving electricity generating units and hourly operation of the grid and generating units in future years. Among the model's outputs are hourly locational electricity prices, and emissions of carbon dioxide ($CO_2$), methane, sulfur dioxide ($SO_2$), and nitrogen oxides ($NO_x$).

E4ST also calculates the following components of total net benefits: reduced electricity consumer bills, changes in generator profit and government revenue, health benefits from reduced air pollution, and climate benefits from reduced greenhouse gas emissions. Sometimes one or more of the components is negative. When that is the case, it reduces the net benefits.

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 more than 5,000 nodes and 17,000 transmission line segments. The transmission segments include all high-voltage (>200 kV) lines in the U.S., as well as select lower-voltage segments in areas with high congestion, and what are called "Ward-equivalenced" segments that represent in reduced form the tens of thousands of lower-voltage segments that are not individually retained.

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 resources for wind, solar, and more.

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 computationally prohibitive 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 U.S. and Canada. We use days with lower weights to represent the hours of extreme electricity scarcity (high demand and/or low wind and/or low solar output), so that we represent well the hours of extreme scarcity in each region. For details on the selection process, see Wind Data and Solar Data appendices.

# 11.1 MODELING CLEAN POWER DRIVERS

Each generation-based policy or commitment aimed at increasing the prevalence of clean power in the electricity sector consists of three main components: how much electricity must be generated from clean sources, what sources of power qualify to satisfy that requirement, and where the electricity to satisfy that requirement must be generated.

In E4ST, there are two different sets of technologies that are used to define clean power. The first, the “RPS Set,” is the stricter of the two, and only consists of solar, wind, and geothermal-powered generation. This is the set of technologies that qualify towards state RPS policies. The second set, the “CES Set,” takes a broader approach and allows generation from solar, wind, geothermal, hydro, nuclear, biomass, hydrogen, and natural gas with CCS[19] technologies to qualify as clean. The CES Set qualifies toward state CES policies and utility commitments.

As for where clean energy must be generated to satisfy these requirements, there are three common areas: national, regional, and in-state. National and in-state are self-explanatory, but we define regional as being from within a state's “RPS region,” which is the area where credits can be obtained for the state's RPS or CES policies. For the few states that do not have any type of crediting policy, we combine them into an existing credit region in which the regional renewable and clean energy requirements are not high enough in any scenario to have an effect.

The last component of these policies and commitments, the actual amount of clean power required, depends on the type of policy.

### 11.1.1 State Policies

Many states have RPS and/or CES policies on the books. In E4ST, we assume that RPSs must be satisfied by the RPS Set of technologies, CESs must be satisfied by the CES Set of technologies, and both policies must be satisfied by regional generation. We can denote these policies' requirements for each state “s” and year “y,” by the following:

$R_{sy}^{rps}$: The percentage of load in state “s” that is mandated to be clean under a state RPS policy in year “y.”

$R_{sy}^{ces}$: The percentage of load in state “s” that is mandated to be clean under a state CES policy in year “y.”

We obtained these input values through a review of the current state policies. 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. We also model any technology-specific carve-outs that are on state books, which require a specific amount of generation to come from a single technology in state.

### 11.1.2 National CES

While state RPS and CES policies only allow certain types of generation to count toward their requirements, the national CES that we model is technology neutral, meaning that all generation types can qualify provided their emission rate is low enough. The rate at which electricity generation contributes credits toward satisfying the CES's requirements, if at all, depends on the specific emissions rate of that generation. Both the Fast and Slow CES have a benchmark emissions rate

[19] In E4ST, NG-CCS generation does not earn a full credit toward state CES policies and utility commitments, but instead earns credits according to how far its emissions are below a benchmark emission rate of 0.6 metric tons $CO_2$e/MWh

of 0.4 metric tons $CO_2e$/MWh, so if a MWh of electricity was generated with a carbon intensity of r metric tons $CO_2e$/MWh, it generates max(0, 1 - r/4) credits. National CES credits can then be bought and sold nationally, so that while consumers must buy credits to cover a certain percentage of their electricity consumption, those credits can be generated anywhere in the U.S. and all have the same price. We can denote the percentage of load in state “s” that must be covered by national CES credits in year “y” by $R_{sy}^{nat}$. In scenarios where no national CES is active, these values are zero.

Both the Fast and Slow CESs have price caps, meaning that if the CES credit price reaches a certain limit, consumers can satisfy their requirement through an alternative compliance payment to the national government instead of obtaining CES credits. Essentially, consumers must still purchase enough credits to cover their requirements, but the credits can be either from clean energy generation or purchased from the government at the price cap level.

### 11.1.3 Utility Commitments

In the Utility-led Decarbonization pathway, we model utility commitments on a state-by-state basis. The input data for these utility commitments are, for each state “s:”

$L_s^{uc}$: **The percentage of load in state “s” that is served by utilities that have made decarbonization commitments. In the Utility-led Decarbonization pathway, this is the load share of vertically integrated investor-owned utilities.**

$G_{sy}^{uc}$: **The percentage-clean target in state s and year “y” for utilities that have made commitments. We assume that all utilities in the state have the same schedule of targets. In the Utility-led Decarbonization pathway, for all states s, $G_{(s,2035)}^{uc}$=0.5 and $G_{(s,2050)}^{uc}$=1, so all vertically integrated investor-owned utilities aim to be 50% clean in 2035 and 100% clean in 2050, with 100% adherence.**

$R_{sy}^{util}$: **The percentage of load in state “s” that is mandated to be clean by a utility commitment in year “y.” $R_{sy}^{util}=L_s^{uc}*G_{sy}^{uc}$**

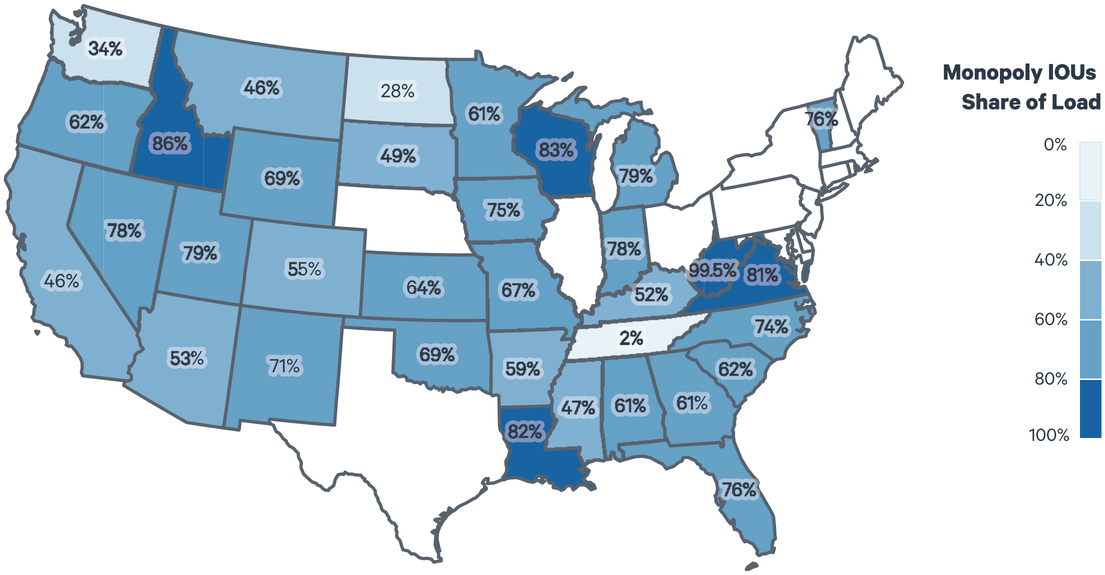
Generally, it is expected that if some, but not all, of the utilities in a state have a clean energy commitment, especially one that reaches 100%, the utilities that do not have a commitment will still generate or procure some amount of clean energy, instead of ceding all clean generation to the committed utility(ies). Since we model utility commitment constraints at the state level, we need to reflect that the effective clean energy generated in the state will exceed the amount committed to by utilities. To do this, we assume that the non-committed utilities in the state will retain a baseline level of cleanness seen in the reference scenario where there are no utility commitments. We prevent the amount of clean in-state generation for the non-committed utilities from decreasing because of the commitments of the committed utilities. We can denote the baseline percent of in-state generation that is clean by $K_{sy}^{base}$, so the effective percentage of load in state “s” in year “y” that should be covered by clean in-state generation due to utility commitments is

$$RE_{sy}^{util}=R_{sy}^{util}+(1-L_s^{uc})*K_{sy}^{base}.$$

Similarly, when a state has a CES policy, the requirement falls equally on each utility in the state, and if a utility's clean commitment is stronger than the CES requirement in year “s,” the utility would choose to retire its excess CES credits rather than sell them to less-clean utilities. So, the non-committed utilities will have to meet the CES requirement independent of the committed utilities, and the effective clean energy required as a percentage of state load in state s and year y due to the combination of a CES and utility commitments is

$$RE_{sy}^{ces}=R_{sy}^{ces}+(L_s^{uc}*max(0,G_{sy}^{uc} - R_{sy}^{ces})) .$$

**FIGURE 24** Percentage of load served by vertically integrated investor-owned utilities in each state.




*In the Utility-led Decarbonization pathway, we assume that all this load is satisfied with clean generation by 2050*

### 11.1.4 Voluntary Green Power Purchasing

To represent the growing tendency of commercial and industrial (C&I) and residential customers to purchase power specifically from renewable sources, we calculate and implement voluntary green power purchasing (VGP) on a state-by-state basis.

For each state “s,” we calculate the following values in each year “y.” Details about projecting “green power demand” can be found in appendix 10.2.1.

Again, we define "VGP" as only voluntary green power purchasing that does not overlap with clean generation requirements (CESs, RPSs, and utility-led decarbonization), as described in section 4.6.1. This applies to all of our mathematical notation with "VGP" in it and to our discussions of voluntary green power purchasing within the definitions of that notation.

$VGP_{sy}^{ci}$: “C&I green power demand” The percentage of load in state “s” in year “y” that is from C&I customers who would, if not otherwise mandated to be clean, voluntarily choose to purchase their electricity from clean sources.

$VGP_{sy}^{res}$: “Residential green power demand” The percentage of load in state “s” in year “y” that is from residential customers who would, if not otherwise mandated to be clean, voluntarily choose to purchase their electricity from clean sources.

$L_{sy}^{free}$: “Free Load” The percentage of load in state “s” in year “y” that is not mandated to be clean by any policy or commitment. $L_{sy}^{free}=(1-\max(R_{sy}^{rps},RE_{sy}^{ces},R_{sy}^{nat},R_{sy}^{util}))$.

$VGPR_{sy}^{ci}$: “Real C&I VGP” The actual percentage of load in state “s” in year “y” that is purchased from clean sources as part of C&I voluntary green power purchasing. $VGPR_{sy}^{ci}=VGP_{sy}^{ci}*L_{sy}^{free}$

$VGPR_{sy}^{res}$: “Real residential VGP” The actual percentage of load in state “s” in year “y” that is purchased from clean sources as part of residential voluntary green power purchasing. $VGPR_{sy}^{res}=VGP_{sy}^{res}*L_{sy}^{free}$

$VGPR_{sy}$: “Real VGP” the total percentage of load in state “s” in year “y” that is purchased from clean sources as part of voluntary green power purchasing. $VGPR_{sy}=VGPR_{sy}^{ci}+VGPR_{sy}^{res}$

In these simulations, only the RPS Set of technologies can qualify toward satisfying VGP. The RPS Set is a subset of the CES Set of qualifying technologies, so VGP effectively increases the state's generation requirement from both sets. VGP also effectively increases the number of credits obtained toward a national CES requirement. To represent the preference of customers to purchase power locally or regionally, we assume in these simulations that while all VGP must be procured from within the U.S., at least half of VGP must be procured regionally, defined as from within a state's credit region.

To keep track of the final amount of clean power required from each state, and where it must be generated, we define and calculate the following values:

$RR_{sy}^{rps}$: The percentage of load in state “s” in year “y” that must be satisfied by generation from the RPS Set of technologies in state “s's” credit region. $RR_{sy}^{rps}=R_{sy}^{rps}+(VGPR_{sy})/2$

$RR_{sy}^{ces}$: The percentage of load in state “s” in year “y” that must be satisfied by generation from the CES Set of technologies in state “s's” credit region. $RR_{sy}^{ces}=RE_{sy}^{ces}+(VGPR_{sy})/2$

$RN_{sy}^{rps}$: The percentage of load in state “s” in year “y” that must be satisfied by generation from the RPS Set of technologies from anywhere in the U.S. $RN_{sy}^{rps}=R_{sy}^{rps}+VGPR_{sy}$

$RN_{sy}^{ces}$: The percentage of load in state “s” in year “y” that must be satisfied by generation from the CES Set of technologies from anywhere in the U.S. $RN_{sy}^{ces}=RE_{sy}^{ces}+VGPR_{sy}$

$RE_{sy}^{nat}$: The percentage of load in state “s” in year “y” that must be covered by national clean energy credits. $RE_{sy}^{nat}=R_{sy}^{nat}+VGPR_{sy}$

Note that VGP can fully overlap with carbon-pricing policies such as cap & trade programs because, unlike VGP, these policies do not mandate that a certain amount of generation must come from specified generation types.

# 11.2 DISCUSSION OF SELECTED INPUT PARAMETERS

### 11.2.1 Technology Costs and Performance

The buildable technologies in the model include solar photovoltaics (single-axis tracking), onshore wind, offshore wind, natural gas combined cycle (NGCC), natural gas turbines, natural gas with 99% carbon capture (NG-CCS), 90% carbon capture retrofits on existing coal plants, nuclear, diurnal battery storage, and multi-day storage (based on hydrogen). Natural gas CCS retrofits and new coal-fired plants, with and without CCS, are not included because they are assumed, based on projected costs and test simulations, to not be cost competitive.

We adapt cost and performance projections for new units from the 2020 NREL ATB (NREL, 2020). We use a weighted average cost of capital (WACC) of 5.44% and an economic life of 30 years, resulting in a capital recovery factor of 6.84%. This is the percentage of capital costs that a newly built unit must earn each year, after covering operating expenses, to be profitable and to be built in our model. We use regional variations in capital cost from (EIA, 2018). The cost and performance effects of retrofitting existing coal plants with CCS vary depending on the characteristics of the coal plant, based on the assumptions in the U.S. Environmental Protection Agency's Platform v6 (EPA, 2018b). We adapt the ATB's costs for NG with 90% carbon capture to costs for a unit with 99% carbon capture; see Appendix 11.2.2 for details. For hydrogen-fueled generators, we assume that capital and fixed costs match that of a new NGCC unit, but fuel costs for green hydrogen decline linearly between current costs and $1.5/kg in 2050, which is a relatively conservative estimate (Bloomberg NEF, 2020). In general, these are medium assumptions, intended to represent our central estimates or “best guesses” about the future.

**FIGURE 25:** Levelized cost of new generation in E4ST

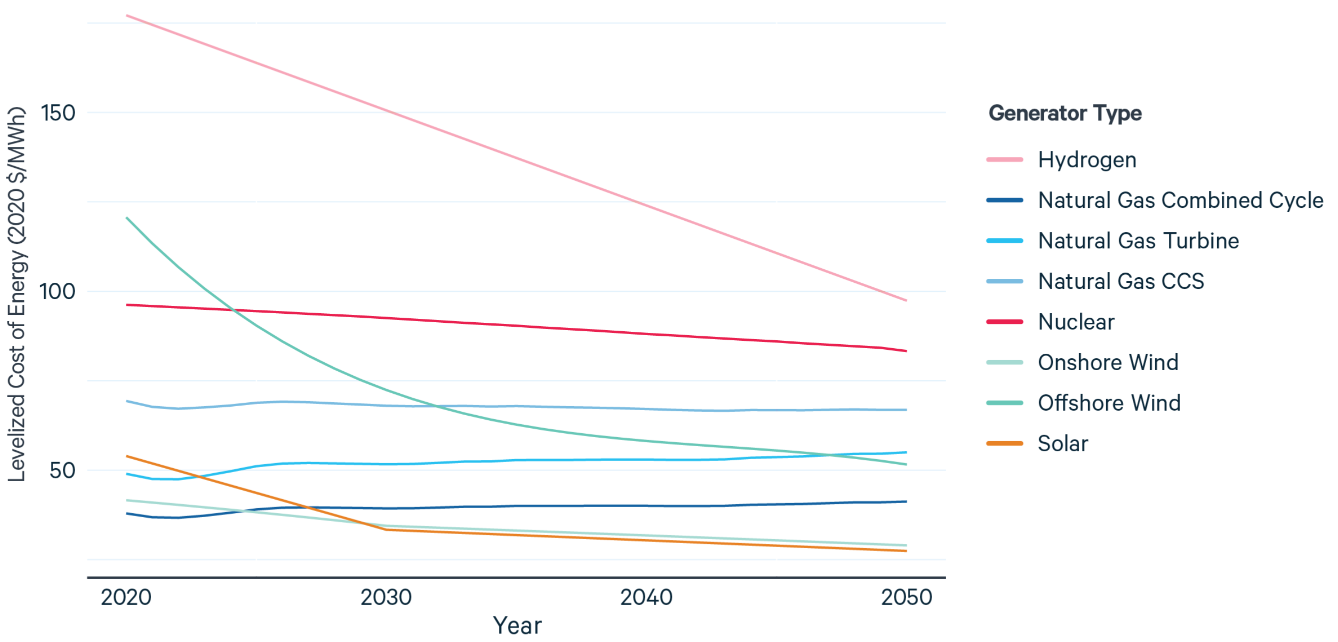



Figure 25 displays the resulting assumed levelized cost of energy (LCOE) of new generators over time. The LCOEs in Figure 25 assume capacity factors of 75% for hydrogen and all natural gas generation, 92% for nuclear generation, 25% for solar, and 45% for onshore and offshore wind. In our modeling, capacity factor, and thus levelized cost of energy, is endogenous, so they can and do vary. Capital, variable and fuel costs also vary by location. For more details on fuel prices, see Appendix 11.2.3.

Pre-existing units in the model have unit-specific cost, performance, and emissions rates, as compiled by S&P Global. As units age, they must pay periodic life-extension costs if they do not retire.

### 11.2.2 Natural Gas with Carbon Capture Costs

For these simulations, we chose to model buildable natural gas with carbon capture (NG-CCS) as having a 99% capture rate, rather than a lower capture rate such as 90%. The reason why is that capture percentages higher than 90% are possible, and even at 90%, NG-CCS may be too carbon intensive to be used in national policy and utility zero-carbon goals. At 99% we assume that NG-CCS qualifies for state CESs and utility-led decarbonization commitments. Also, utility and government policies are likely to include direct air capture of $CO_2$ (DAC), which we don't model, so in a way, increasing the price to reduce the carbon emissions from NG-CCS is an approximation of paying for DAC.

Feron et al. (2019) offers a techno-economic analysis of NG-CCS as capture percentages increase from 90% to 99%. However, its analysis is not focused on North America, so to transfer their findings to cost estimates for a North American NG-CCS plant, we calculated the percentage change in heat rate and costs between their 90% capture and 99% capture designs and applied them to NREL ATB's 90% capture NG-CCS. The resulting values are the cost and performance that we use for 99% NG-CCS in these simulations. This results in 99% NG-CCS being about 6.5% more expensive than 90% NG-CCS.

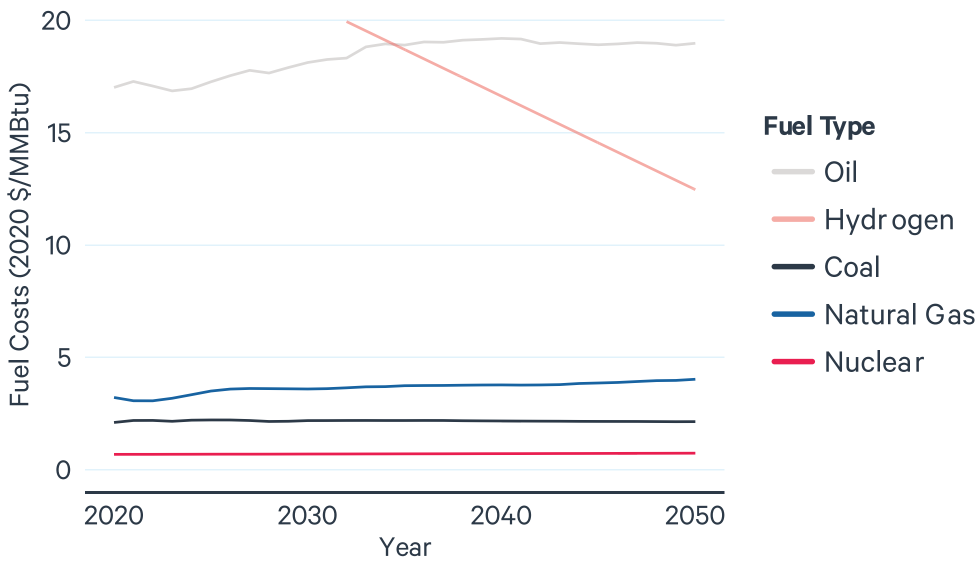
### 11.2.3 Carbon Transportation and Storage

In E4ST, 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. 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, which can be in any of several states with good locations for sequestering $CO_2$. The transportation costs depend on each combination of source state and sequestration state. We get $CO_2$ storage costs, transportation costs, and state-by-state storage capacities from EPA's Platform v6 (EPA, 2018b).

### 11.2.4 Fuel Costs

For all fuels but hydrogen, we use projections of fuel costs in each NERC subregion from the High Oil and Gas Resource and Technology scenario in the Annual Energy Outlook 2019. For hydrogen, we assume a linear decline in costs between $3.2/kg, the current cost for green hydrogen, and $1.5/kg in 2050 (Bloomberg NEF, 2020).

**FIGURE 26** Assumed national average fuel costs in E4ST




### 11.2.5 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 2035 and 2050 of $61.21 and $76.80 per short ton of $CO_2$, respectively (Interagency Working Grp. On Soc. Cost of Carbon, 2016), and a social cost of methane of $2,003 and $2,783 per short ton (Marten and Newbold, 2012). For health damages, we use a linear approximation of the U.S. Environmental Protection Agency's Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) to estimate the number of premature deaths due to emissions (EPA, 2018a), and then translate those into costs using values of $12 million per adult premature death and $13.4 million per infant premature death based on (EPA, 2013) updated in accordance with (EPA, 2014).

### 11.2.6 $CO_2e$ Emissions Rates

When calculating $CO_2$ equivalent ($CO_2e$) in E4ST, which we use to calculate credits earned under a CES policy, we consider the plant's emissions, upstream emissions from fuel production, and for plants that capture carbon, effects of the end use of captured carbon. 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 EOR results in $CO_2e$ emissions of 0.27 tons (IEA, 2015).

We assume that the upstream methane emission rates from natural gas and coal fuels in the future are half of what they are now, due to increased awareness and control of methane leakage. In our simulations, use of natural gas fuel results in methane emissions of 0.434 lbs/MMBtu NG, and use of coal results in methane emissions of 0.175 lbs/MMBtu coal. For current estimates of upstream methane emissions rates, see Lenox et al. (2013) and Shawhan (2018). We convert methane to $CO_2$e by multiplying by 32 based on the 100-year global warming potential of methane. This almost exactly matches the ratio of methane to $CO_2$ damage per ton estimated by Marten and Newbold (2012). 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.

### 11.2.7 Wind and Solar Data

The U.S. 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 U.S., 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 8 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, proximity, and availability factor, which is a measure of wind resource quality. We do this separately for onshore and offshore 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 energy output that a wind turbine in that location would have produced in the 2008-2010 period. 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).

Solar data are taken from NREL's National Solar Radiation Database (Wilcox, 2012). Hourly solar radiation levels were 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).

### 11.2.8 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 some other models of the electricity sector do, model only several 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 U.S. region to match projected demand growth to 2050.

In reality and in our model, the value of different generating technologies is determined partly by days with non-extreme amounts of load, wind, and sun, and partly by days with extreme values of load, wind, and solar. Our algorithm for selecting representative days therefore 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 non-extreme days, we use the method described by Nahmmacher et al. (2016) to select five representative days consisting of six representative four-hour periods each (30 representative hours total).

To pick the extreme days, we determine for eight U.S. 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 lowest solar
5. highest load, lowest wind, and lowest solar

Each variable for each region is normalized by dividing it by its standard deviation. For the purposes of this study, an hour is considered extreme if it is within the 0.015 percent of the most extreme hour 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 two representative hours each. The relative weight of extreme versus average hours is chosen in a way that minimizes the deviation from historical frequency distributions of load, wind, and solar.

## Expanding Supply Choice

In the OWM & Supply Choice Expansion pathway, in addition to expanding organized wholesale markets to the entire U.S., we also expand supply choice to all C&I customers served by investor-owned utilities in the U.S. While we assume that the expansion of organized wholesale markets does not affect the prevalence of cost-of-service (COS) regulation, we assume that deregulation of generation ownership will happen along with the expansion of supply choice. Our general assumption is that a state will deregulate by the same percentage by which supply choice increases. We make this calculation using the following information for each state "s:"

$L_s^{ci}$: The percentage of load in state "s" sold to commercial and industrial customers.

$SC_s^{ci}$: "C&I supply choice access" The percentage of C&I demand in state "s" that historically has access to supply choice.

$L_s^{(ci,iou)}$: The percentage of C&I demand in state "s" that is served by IOUs. In our model, this is the percentage of C&I demand that has access to supply choice in the Supply Choice pathway.

$SC_s^{add}$: The percentage of load in state "s" that gains access to supply choice in the Supply Choice scenario. $SC_s^{add} = L_s^{ci} * (L_s^{(ci,iou)} - SC_s^{ci})$

$SR_s$: The historical percentage of generating capacity in state "s" that is under COS regulation.

$SR_s^{new}$: The new percentage of generating capacity in state "s" that is under COS regulation after the expansion of C&I supply choice. $SR_s^{new} = SR_s * (1 - SC_s^{add})$

The COS regulation status of a natural gas- or coal-fueled generator impacts what variable cost adjustment factor is applied to it in our model, as explained in section 10.1.

# 12 APPENDIX: EMPLOYMENT ANALYSIS METHODOLOGY

*This appendix complements results section 5, "Effects of Pathways on Energy Sector Employment" and methodology subsection 2.8, "Employment Effects."*

# 12.1 METHODS

The JEDI models, which incorporate economic outputs and multipliers from IMPLAN, estimate U.S. jobs resulting from power plant construction and U.S. jobs resulting from power plant operation and maintenance (O&M), including from fuel production. JEDI inputs from the E4ST model included expenditures for capital cost, fuel, fixed O&M, and variable O&M. Within each industry, the number of jobs estimated by JEDI is calculated using these expenditures.

The JEDI job effects models used in this analysis use outputs and multipliers from the IMPLAN Input-Output (I-O) model (IMPLAN, N.D.) to estimate gross jobs and economic impacts from various energy generation technologies. I-O models represent economy-wide transactions between industries, households, investors, government, and the rest of the world via imports and exports. Every purchase by one of these entities or sectors is represented as a sale from another. Businesses buy inputs for production from other businesses, pay taxes and possibly receive government subsidies, pay workers, and earn income such as profits.

The JEDI job estimates encompass the following three categories:

- Onsite jobs are the most closely related to an energy project. These are jobs held by workers either located at a job site or employed by the energy developer, installer, or operator.
- Supply chain jobs are "spillover" effects that accrue as a result of producers making purchases within an economy. A wind developer, for example, that buys blades manufactured in the U.S. would support supply chain jobs in blade manufacturing. A pre-existing power plant that uses fuel would support supply chain jobs in fuel production and transportation.
- Induced jobs are those supported by onsite and supply chain workers spending their earnings. These are commonly in industries such as retail sales, education, and health services.

JEDI also uses domestic content percentages to limit impact estimates to the U.S. Purchases made from overseas are not included in the calculation of U.S. jobs.

State results are not reported individually in this report because it is difficult to accurately calculate the exact locations of the estimated jobs.

The freely available JEDI models include coal, natural gas, land-based wind, and offshore wind models. This analysis also used in-house models for solar and storage. These models are "working models" used at NREL and with clients upon request. Hydrogen construction and non-fuel O&M jobs were calculated using the natural gas JEDI model.

JEDI does not cover jobs from nuclear or hydrogen fuel production, so multipliers from the IMPLAN model were used to estimate these impacts. As with JEDI, expenditures were adjusted to reflect those made within the U.S. and individual states. These adjustments were based on regional purchase coefficients (RPCs). RPCs are the percentage of supply for a commodity within a region relative to demand. If demand is greater than what is supplied or produced, this coefficient is less than 100%. The RPCs used in this study do not exceed 100%. RPCs directly correlate to jobs, so an RPC of 50% would lead to half as many estimated jobs as an RPC of 100% would.

In our modeling results, jobs resulting from construction are expressed in person-years of employment during the time periods of the construction, in our case 2023-2035 and 2036-2050. To convert these to average jobs per year, we make the simplifying assumption that the added construction jobs begin suddenly at the beginning of 2023, are constant from 2023 through 2035, are constant at a different level from 2036 through 2050, and end at the end of 2050.

The effects of the pathways on O&M (including fuel production) jobs are expressed in our modeling results as jobs in the snapshot years only, which are 2035 and 2050. To estimate O&M jobs in the other years, we linearly interpolate between 2022 and 2035 and between 2035 and 2050. We assume that the pathways have no effect on jobs until the beginning of 2023.

Detailed manuals, descriptions of the JEDI tool, and standard JEDI assumptions are available at the following links:

- JEDI Homepage: https://www.nrel.gov/analysis/jedi/
- JEDI Methodology: https://www.nrel.gov/analysis/jedi/methodology.html
- JEDI Factsheet: https://www.nrel.gov/docs/fy15osti/64129.pdf

## 12.2 LOCAL CONTENT ASSUMPTIONS

JEDI takes assumptions on local content – the percentage of the expenditures that are made within the area of analysis. Within the JEDI model for each technology, we modeled onsite jobs estimates at the state level and supply chain and induced jobs at the national level. Consequently, "local" means within the state for onsite jobs and nationally for supply chain and induced jobs. State level onsite jobs are summed up to give the national estimates presented in this report. Onsite, supply chain, and induced effects are defined and modeled in such a way that together they provide an estimate of total U.S. jobs resulting from the modeled expenditures in generation and storage technologies and their supply chains.

# 12.3 LIMITATIONS OF EMPLOYMENT MODELING

As with all economic models, I-O models have limitations and ways to interpret results. The job estimates in this report are estimates of jobs supported by the modeled expenditures. I-O models use fixed, proportional relationships between economy sectors, meaning sectors always purchase the same set of inputs over time, per unit of output, regardless of changes in technology, prices, and preferences. The modeling for this report uses relationships based on those in the year 2019. Changes in the future economy and factors such as changing consumption patterns are not represented in these models. Also, future changes in supply chains are not reflected in the modeled results.

The job estimates are those supported by project level capital and operational expenditures, including supply chains and induced effects, as described above. There are even more indirect job effects that are not included in the modeling. The estimated impacts do not account for far-reaching and potentially negative impacts such as those that may occur from changes in energy prices. This might change the amount of energy and other goods that businesses and households consume and drive substitution of energy intensive goods to less energy intensive goods. Similar substitutions could also occur as a result of changes in taxes, subsidies, tariffs, and housing costs.

Another category of job effects that is not included is changes in other employment sectors that may be affected by decarbonization pathways, such as transmission and distribution (except the new spur lines associated with new generation facilities), building electrification, or ecological restoration.

JEDI models also do not make assumptions about economies of scale. An expenditure in a given technology type and region will yield the same number of jobs per million dollars spent, regardless of the projected size of expenditure. The models also assume no economies of scale in terms of workers; for example, a new power plant of a given technology type in a given region will require twice as many workers, not less, if its size is doubled.

# 13 GLOSSARY OF ABBREVIATIONS

| | |
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| 80x30 | 80% by 2030 national clean electricity standard |
| ATB | Annual Technology Baseline |
| C&I | commercial and industrial |
| CCS | carbon capture and storage |
| CEBA | Clean Energy Buyers Association |
| CEBI | Clean Energy Buyers Institute |
| CES | clean electricity standard |
| $CO_2e$ | carbon dioxide equivalent |
| COBRA | Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool |
| COS | cost of service |
| DAC | direct air capture of $CO_2$ |
| E4ST | Engineering, Economic, and Environmental Electricity Simulation Tool |
| EIA | Energy Information Administration |
| EOR | enhanced oil recovery |
| GHG | greenhouse gas |
| HVDC | high-voltage direct current |
| I-O | input-output |
| IOU | investor-owned utility |
| ISO | independent system operator |
| JEDI | Jobs and Economic Development Impact Models |
| LSE | load-serving entity |
| NERC | North American Electric Reliability Corporation |
| NG | natural gas |
| NG-CCS | natural gas with carbon capture |
| $NO_x$ | nitrogen oxides |
| NREL | National Renewable Energy Laboratory |
| O&M | operating and maintenance |
| OWM | organized wholesale electricity market |
| PPA | power purchase agreement |
| REC | renewable energy certificate |
| RFF | Resources for the Future |
| RPC | regional purchase coefficient |
| RPS | renewable portfolio standard |
| RTO | regional transmission organization |
| $SO_2$ | sulfur dioxide |
| VGP | voluntary green power |
| WACC | weighted average cost of capital |

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