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Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035

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List of Acronyms

AC	alternating current
ACS	American Cancer Society
ADE	accelerated demand electrification
AEO	Annual Energy Outlook
B2B	back-to-back
BECCS	bioenergy for carbon capture and storage
CCGT	combined cycle natural gas turbine
CCS	carbon capture and storage
CO_2	carbon dioxide
CREZ	competitive renewable energy zones
CSP	concentrating solar power
CT	combustion turbine
DAC	direct air capture
DC	direct current
dGen™	Distributed Generation Market Demand model
DOE	U.S. Department of Energy
EASIUR	Estimating Air pollution Social Impact Using Regression
EIA	U.S. Energy Information Administration
FERC	Federal Energy Regulatory Commission
GHG	greenhouse gas
GW	gigawatt
GWh	gigawatt-hour
HVDC	high-voltage direct current
IWG	Interagency Working Group on the Social Cost of Greenhouse Gases
kg	kilogram
kV	kilovolt
LCC	line-commutated converter
Li-ion	lithium-ion
LTS	*Long-Term Strategy of the United States*
MMBtu	million British thermal unit
MT	million tonnes (tonne is a metric ton)
MWh	megawatt-hour
NPV	net present value
NREL	National Renewable Energy Laboratory
$PM_{2.5}$	fine particulate matter
PV	photovoltaics
quad	unit of energy equal to 1 quadrillion (10^{15}) British thermal units
ReEDS	Regional Energy Deployment System model
SCC	social cost of carbon
SMR	steam methane reforming (note that SMR also commonly refers to small modular reactors; we do not use that acronym in this report)
TW	terawatt
TWh	terawatt-hour
TW-mi	terawatt-mile
VSC	voltage source converter

Executive Summary

This study evaluates a variety of scenarios that achieve a 100% clean electricity system (defined as zero net greenhouse gas emissions) in 2035 that could put the United States on a path to economywide net-zero emissions by 2050. These scenarios focus primarily on the supply of clean electricity, including technical requirements, challenges, and benefit and cost implications. The study results highlight multiple pathways to 100% clean electricity in which benefits exceed costs. The study does not comprehensively evaluate all options to achieve 100% clean electricity, and it focuses largely on supply-side options.

This Report and the Inflation Reduction Act and the Bipartisan Infrastructure Law

The analysis presented in this report was conducted prior to the passage of the Bipartisan Infrastructure Law (BIL) of 2021 and the Inflation Reduction Act (IRA) of 2022, which include incentives for and investments in clean energy technologies along with other energy system modernization provisions. Initial analyses estimate that the energy provisions of these new laws can help lower U.S. economy-wide greenhouse gas emissions by approximately 40% below 2005 levels by 2030.[1]. The impacts of these provisions are expected to be most pronounced for the power sector, with grid emissions initially estimated to decline to 68-78% below 2005 levels by 2030 and the share of generation from clean electricity sources estimated to rise to 60-81%. Investments in end-use sector decarbonization measures, including efficiency and electrification, are also supported by the IRA provisions. While the longer-term implications of these new laws are more uncertain, they are unlikely to drive 100% grid decarbonization and the levels of electrification envisioned by 2035 in the primary scenarios analyzed in this report.

More specifically, existing state and federal policies relevant to the power sector as of October 2021 are represented in the modeled scenarios; none of the scenarios presented in this report includes the energy provisions from the IRA or BIL, or other newer enacted federal or state policies or actions. As the addition of IRA and BIL provisions are not expected to enable the U.S. power system to reach 100% carbon-free electricity by 2035, their inclusion is not expected to significantly alter the 100% systems explored in this study. As such, the study's qualitative findings for the implications of achieving 100% are expected to still apply. However, given the potential significant impact of these new laws, the incremental differences between the Reference and 100% scenarios are expected to be lower than estimated here. Including IRA and BIL provisions would likely lower emissions in the Reference scenarios, resulting in a smaller gap between them and the 100% scenarios. As a result, the incremental electricity system costs of the 100% scenarios are expected to be lower with the inclusion of the IRA and BIL provisions. Similarly, the climate and air quality benefits of the 100% scenarios (relative to the Reference scenarios) would also be reduced. These changes have not been quantified and it is important to note that the analysis in this report does not provide any estimates of the impacts of these new laws.

100% Clean Electricity by 2035 Scenarios

We evaluated four main 100% clean electricity scenarios, which were each compared to two reference scenarios: one with "current policy" electricity demand (Reference-AEO)[2] and a second with much higher load growth through accelerated demand electrification (Reference-ADE). The Reference-ADE case includes rapid replacement of fossil fuel use with low-carbon alternatives across all sectors, including electrified end uses and low-carbon fuels and feedstocks,

[1] Example analyses: https://www.energy.gov/articles/doe-projects-monumental-emissions-reduction-inflation-reduction-act; https://rhg.com/research/climate-clean-energy-inflation-reduction-act/; https://energyinnovation.org/wp-content/uploads/2022/08/Modeling-the-Inflation-Reduction-Act-with-the-US-Energy-Policy-Simulator_August.pdf; https://repeatproject.org/docs/REPEAT_IRA_Prelminary_Report_2022-08-04.pdf

[2] This refers to the projections in the Annual Energy Outlook (AEO) from the U.S. Energy Information Administration (EIA 2021a).

resulting in annual electricity demand that is 66% higher than in the Reference-AEO case in 2035. The four core scenarios apply a carbon constraint to achieve 100% clean electricity by 2035 under accelerated demand electrification and reduce economywide energy-related emissions by 53% in 2030 and 62% in 2035 relative to 2005 levels.

Table ES-1 summarizes the four primary scenarios evaluated, which represent a range of uncertainties and themes (e.g., technology availability) and which are described below. In each scenario, assumptions common to all scenarios are called "reference," and details are provided in the main body and Appendix C.

- **All Options** is a scenario in which all technologies continue to see improved cost and performance consistent with the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (NREL 2021). This scenario includes the development and deployment of direct air capture (DAC) technology, while the other three main scenarios assume DAC does not achieve the cost and performance targets needed to be deployed at scale.[3]
- **Infrastructure Renaissance** assumes improved transmission technologies as well as new permitting and siting approaches that allow greater levels of transmission deployment with higher capacity.
- **Constrained** is a scenario where additional constraints to deployment of new generation capacity and transmission both limits the amount that can be deployed and increases costs to deploy certain technologies.
- **No CCS** assumes carbon capture and storage (CCS) technologies do not achieve the cost and performance needed for cost-competitive deployment. This scenario also acts as a point of comparison to demonstrate the potential benefits of achieving cost-competitive deployment of CCS at scale. This is the only scenario that includes no fossil fuel capacity or generation in 2035, and therefore it is the only scenario that includes zero direct GHG emissions in the electric sector.

[3] Executive Order 14057 defines "carbon pollution-free electricity" as "electrical energy produced from resources that generate no carbon emissions, including marine energy, solar, wind, hydrokinetic (including tidal, wave, current, and thermal), geothermal, hydroelectric, nuclear, renewably sourced hydrogen, and electrical energy generation from fossil resources to the extent there is active capture and storage of carbon dioxide emissions that meets EPA requirements". The inclusion of non-generation, negative emission technologies such as direct air capture is not consistent with the Administration's 2035 clean electricity goal but are considered in the study's All Options Scenarios because of their potential deployment, emissions, and cost impacts. https://www.federalregister.gov/documents/2021/12/13/2021-27114/catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability

Table ES-1. 100% Clean Electricity Scenarios and Sensitivities Evaluated in This Study

<table>
<tr><th rowspan="2">Scenario</th><th rowspan="2">Demand Assumptions</th><th colspan="5">Generation Resource Assumptions</th></tr>
<tr><th>Renewable Resources</th><th>CCS Technologies</th><th>Transmission</th><th>Nuclear</th><th>Other Infrastructure</th></tr>
<tr><td>All Options</td><td rowspan="4">ADE</td><td rowspan="2">Reference</td><td>All including DAC</td><td>Reference interregional AC expansion</td><td rowspan="2">Reference</td><td>Reference</td></tr>
<tr><td>Infrastructure Renaissance</td><td rowspan="2">No DAC</td><td>HVDC macrogrid</td><td>Lower-cost transport and storage for H2, CO2, biomass</td></tr>
<tr><td>Constrained</td><td>Reduced land available for wind, solar, and biomass</td><td>Intraregional transmission only, higher (5x) costs</td><td>Not allowed in regions with current legislative restrictions</td><td>Higher-cost transport and storage for H2, CO2, biomass</td></tr>
<tr><td>No CCS</td><td>Reference</td><td>No CCS, bioenergy with CCS, or DAC</td><td>Reference</td><td>Reference</td><td>Reference</td></tr>
<tr><td>Sensitivities (applied to each of the four core scenarios)</td><td colspan="6">Annual Energy Outlook (AEO) and the U.S. Long-Term Strategy (LTS) demand cases
Supply-side sensitivities include renewable energy costs, storage costs, nuclear costs, electrolyzer costs, CCS cost and performance, transmission constraints, new natural gas restriction, natural gas fuel costs, expanded biomass supply, low-cost geothermal, and allowing DAC in the Infrastructure Renaissance and Constrained cases.</td></tr>
</table>

Beyond the four core 100% scenarios, 142 additional sensitivities were also analyzed to capture future uncertainties related to technology cost, performance, and availability. Of these 142 sensitivities, 122 cases model 100% carbon-free electricity by 2035. We also evaluated all scenarios with a sensitivity case using electricity demand from the *Long-Term Strategy of the United States* (LTS) (White House 2021a) to reflect an alternative demand-side pathway to reaching a net-zero emissions economy by 2050. The LTS reflects higher levels of energy efficiency and demand-side flexibility, resulting in slower annual load growth of 1.8%/year (compared to 3.4%/year under ADE) and, importantly, lower demand peaks that occur predominantly in summer as compared to the sharp winter peaks assumed for our primary ADE scenarios. In addition to direct electricity demand, both ADE and LTS assumptions include demand for clean hydrogen production for transportation and industrial applications, which may be produced from electrolysis or from natural gas with CCS depending on scenario. Non-power sector demand for hydrogen is an input to the analysis; however, hydrogen demand for electricity generation (for seasonal storage) is also considered and is an outcome of the scenarios. Electricity generation and capacity needed to produce hydrogen—for both power and non-power applications—are also considered in the modeling.

Across these scenarios, this work uses NREL's Regional Energy Deployment System (ReEDS) model to identify the resulting least-cost investment portfolios from a range of different generation, storage, and transmission technologies while considering the significant geographical variation in demand and resource availability, including the regional and temporal variations in the output of renewable resources. The geographical and temporal variability of various resources is evaluated by ReEDS, including additional transmission costs needed for remote resources and the need to maintain an adequate supply of energy during all hours of the year. A detailed list of limitations of the modeling approach and key caveats regarding scope, and cost elements included is provided in the Key Caveats section (Section 2.4, page 17).

Scenario Deployment Results

Achieving a 100% clean electricity system requires significant clean energy deployment, and a summary of the results from the 100% scenarios is provided in Figure ES-1, including generation capacity, annual generation, average annual installation rate, and transmission capacity.

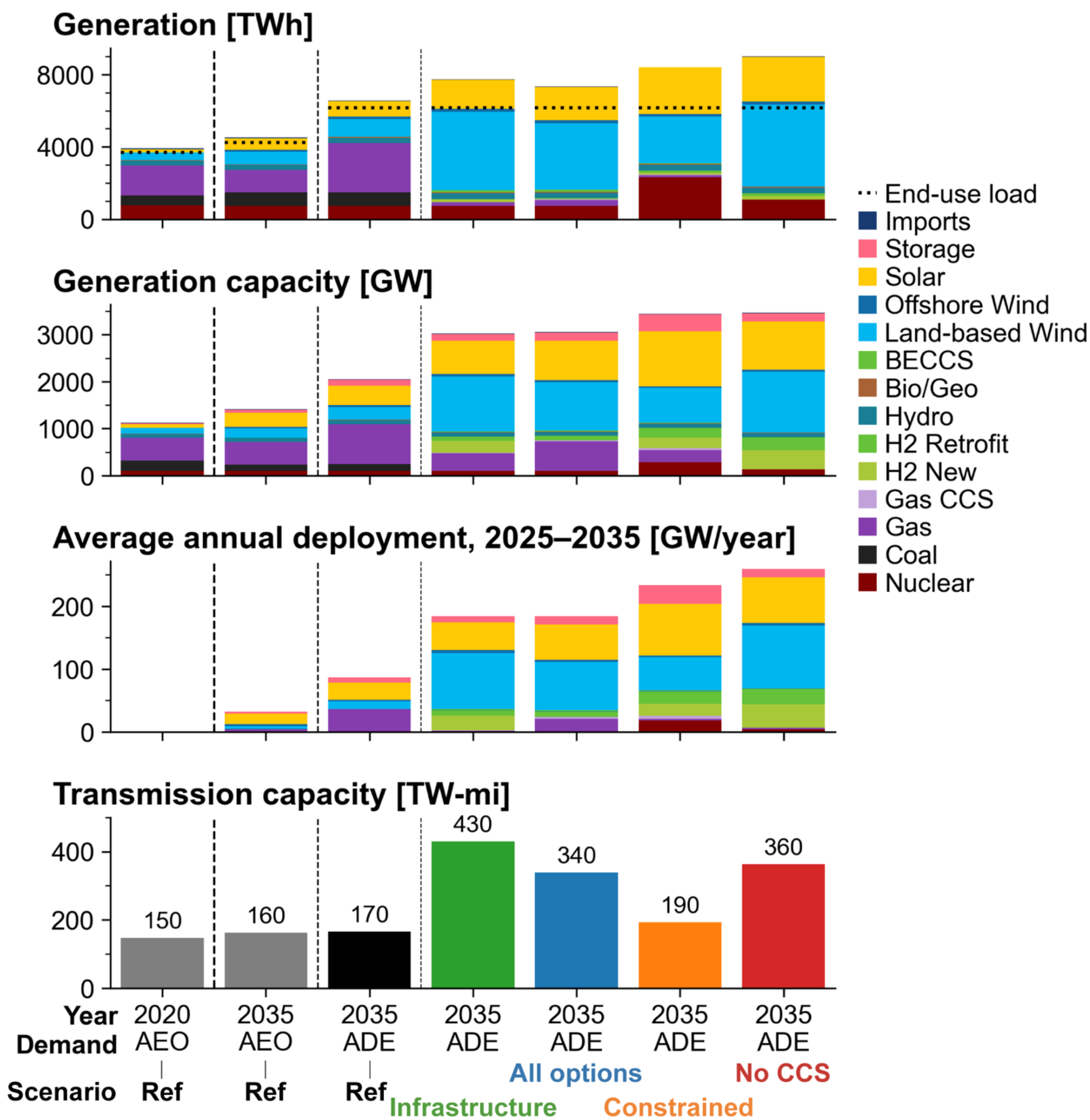

Figure ES-1. Summary results of the main scenarios show a large increase in renewable capacity, with wind and solar providing about 60%–80% of electricity.

Challenges to transmission and wind siting result in nuclear providing about 27% in the Constrained scenario. Differences in the capacity mix for the remaining resources are driven largely by assumptions about technology availability, particularly those related to CCS and negative emissions technologies.[4] Interregional transmission capacity grows by two to three times current capacity in three of the scenarios, allowing greater access to low-cost wind resources and providing the benefits of spatial diversity.

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[4] Imports are from Canada, largely hydropower imports into the Northeast. Bio/Geo = conventional biopower such as wood waste, landfill gas, and geothermal. BECCS = bioenergy with CCS. Natural gas includes combustion turbines (CT), combined cycle (CC), and older oil and gas-fired steam plants, which are tracked individually but

Based on assumed growth in demand due to end-use electrification, and electric demand associated with hydrogen production (for direct use or for production of other clean fuels), total electricity generation grows by about 95%–130% from 2020 to 2035. Total generation is shown for all end-use loads (dotted line in Figure ES-1Figure) plus the additional generation needed for transmission losses and generation used by the electric sector to produce hydrogen for seasonal electricity storage. There are differences between scenarios in absolute amounts of generation based on differences in storage (and associated losses) and hydrogen production. The need for new generation capacity would be even higher without the energy efficiency and demand-side flexibility measures assumed in the ADE trajectory. Results from the LTS sensitivity cases result in a 16%–20% reduction in the need for new installed capacity compared to the ADE cases due, in part, to the higher levels of energy efficiency assumed in LTS.

Wind and solar provide most (60%–80%) of the generation in the least-cost electricity mix in all the main scenarios. Nuclear capacity more than doubles in the Constrained scenario, reaching 27% of generation, while limited growth in the other three core scenarios results in a contribution of 9%–12%, largely from the existing fleet. The overall generation capacity grows to roughly three times the 2020 level by 2035, including a combined 2 TW of wind and solar. This would require growth rates in the range of 43–90 GW/year for solar and 70–145 GW/year for wind by the end of the decade, which would more than quadruple the current annual deployment levels for each technology in many scenarios. Across the four core scenarios, 5–8 GW of new hydropower is deployed by 2035 by adding capacity at unpowered dams and uprates at existing facilities, while geothermal capacity increases by about 3–5 GW by 2035.

Differences in energy contribution among the four core scenarios are largely driven by constraints in transmission and renewable siting. In all scenarios, significant transmission is constructed in many locations, and significant amounts are deployed to deliver energy from wind-rich regions to major load centers in the eastern United States. Total transmission capacity (which is a mix of AC and HVDC depending on scenario) in 2035 is 1.3–2.9 times current capacity. Beyond already planned additions, these total transmission builds would require 1,400–10,100 miles of new high-capacity lines per year, assuming new construction began in 2026.[5] The Infrastructure Renaissance scenario constructs the most transmission and wind, and it results in the lowest average system cost.[6]

The Constrained scenario limits both renewable energy and transmission deployment, resulting in higher costs. The higher costs of renewables makes new nuclear capacity more cost-competitive, and in this scenario, the model builds about 200 GW of new nuclear capacity between 2030 and 2035. This scenario would require about 40 GW/year of new installation, or about four times the maximum historical rate in the United States.

The core scenarios deploy 120–350 GW of diurnal storage to help support power system resource adequacy (ensuring demand for electricity is met during all hours of the year) and better align output of wind and solar with demand patterns. Storage in Figure ES-1 includes diurnal

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combined for reporting purposes. Solar includes all utility-scale and rooftop solar photovoltaics (PV) and concentrating solar power (CSP). TWh = terawatt-hours. GW = gigawatts. TW-mi = terawatt-miles.

[5] From 2010 to 2020, the maximum annual installation in the United States was about 4,100 miles/yr.

[6] This includes capital and operating costs for the generation, storage, and transmission infrastructure.

storage with discharge capacity of 2–12 hours, which includes batteries and pumped storage hydropower but could also include a variety of technologies under various stages of development.

Based on assumed cost declines of renewable energy technologies, the pathway to achieving roughly 90% clean electricity is fairly consistent across the scenarios, and wind and solar provide the most generation in three of the scenarios, supplemented by significant nuclear deployment in the Constrained scenario. The variation between the scenarios is largely focused on the specific technologies that can most cost-effectively meet peak demand and can contribute to the last 10% of clean generation. This is reflected largely in the differences in *capacity* contribution among the four scenarios, which are driven by multiple factors, including uncertainty about technology availability at scale in the coming decades.

The main uncertainty in reaching 100% clean electricity is the mix of technologies that achieves this target at least cost—particularly considering the need to meet peak demand periods or during periods of low wind and solar output. The analysis demonstrates the potentially important role of several technologies that have not yet been deployed at scale, including seasonal storage and several CCS-related technologies. The mix of these technologies varies significantly across the scenarios evaluated depending on technology cost and performance assumptions.

Seasonal storage is represented in the modeling by clean hydrogen-fueled combustion turbines but could also include a variety of technologies under various stages of development assuming they achieve similar costs and performance. There is significant uncertainty about seasonal storage fuel pathways, which could include synthetic natural gas and ammonia, and the use of alternative conversion technologies such as fuel cells. Other technology pathways are also discussed in the report. Regardless of technology, achieving seasonal storage on the scale envisioned in these results requires substantial development of infrastructure, including fuel storage, transportation and pipeline networks, and additional generation capacity needed to produce clean fuels.

In all scenarios, the 100% requirement is met on a net basis—meaning gross emissions can be offset through negative emissions technologies that rely on carbon capture. In the No CCS scenario, the 100% requirement precludes any fossil generation and has the greatest use of seasonal storage. In the other cases, fossil generators—from existing and new plants—continue to contribute through 2035, but their emissions must be offset by negative emissions technologies including DAC and bioenergy with carbon capture and storage (BECCS) to achieve net-zero emissions. Fossil plants with CCS must also have negative emissions offsets because capture rates are assumed to be 90% and upstream methane leakage from natural gas production must also be offset.[7] Across all scenarios, 0%–5% of 2035 generation is from fossil technologies (both with and without CCS), and the All Options scenario includes about 660 GW of fossil capacity of all types in 2035). Under All Options, which is the only primary scenario that allows DAC, 190 million tons/year of CO_2 are removed using DAC and BECCS.

[7] Higher capture rates are evaluated in sensitivity cases.

The Constrained scenario emphasizes the potential challenges with siting and land use associated with the required infrastructure to achieve a fully decarbonized grid, although these challenges are apparent across all scenarios. Figure ES-2 (page xiv) shows the regional capacity of wind, solar, and transmission, demonstrating significant deployment in many regions. The figure also illustrates the land use associated with wind, solar, and long-distance transmission in the main scenarios, along with several other historical land use activities, but the figure does not include land use associated with ongoing processes such as future fossil fuel extraction. Solid boxes represent areas dedicated to a single primary use. For wind, this includes area physically occupied by wind turbine pads, roads, and other infrastructure. Boxes with dashed lines represent area that could have multiple uses. For wind, this area represents the spatial extent of entire wind farms, including the space between turbines that is available for agriculture, grazing, and other uses. The total area physically occupied by wind and solar infrastructure (solid boxes) is about equal to that currently occupied by railroads.

Although they are not modeled in detail here, several other demand-side mechanisms can reduce the supply-side infrastructure needs in the scenarios. These include geothermal heat pumps, which could reduce annual and peak load relative to other electric space heating options especially in cold climates; even greater demand-side flexibility than what we considered; and broader sector-coupling opportunities, especially between heating and electricity and for clean fuels. The LTS sensitivity results highlight that increased energy efficiency and demand-side flexibility measures can potentially reduce the overall capacity required to meet the 100% target. On average, by 2035, the LTS sensitivities deploy about 20% less capacity and require about 25% less generation than the ADE scenarios (Figure ES-3). The reduced deployment driven by energy efficiency and demand-side flexibility could result in lower power system costs. However, the LTS data do not comprehensively capture demand-side capital and implementation costs; therefore, a direct cost comparison is not presented in this study.

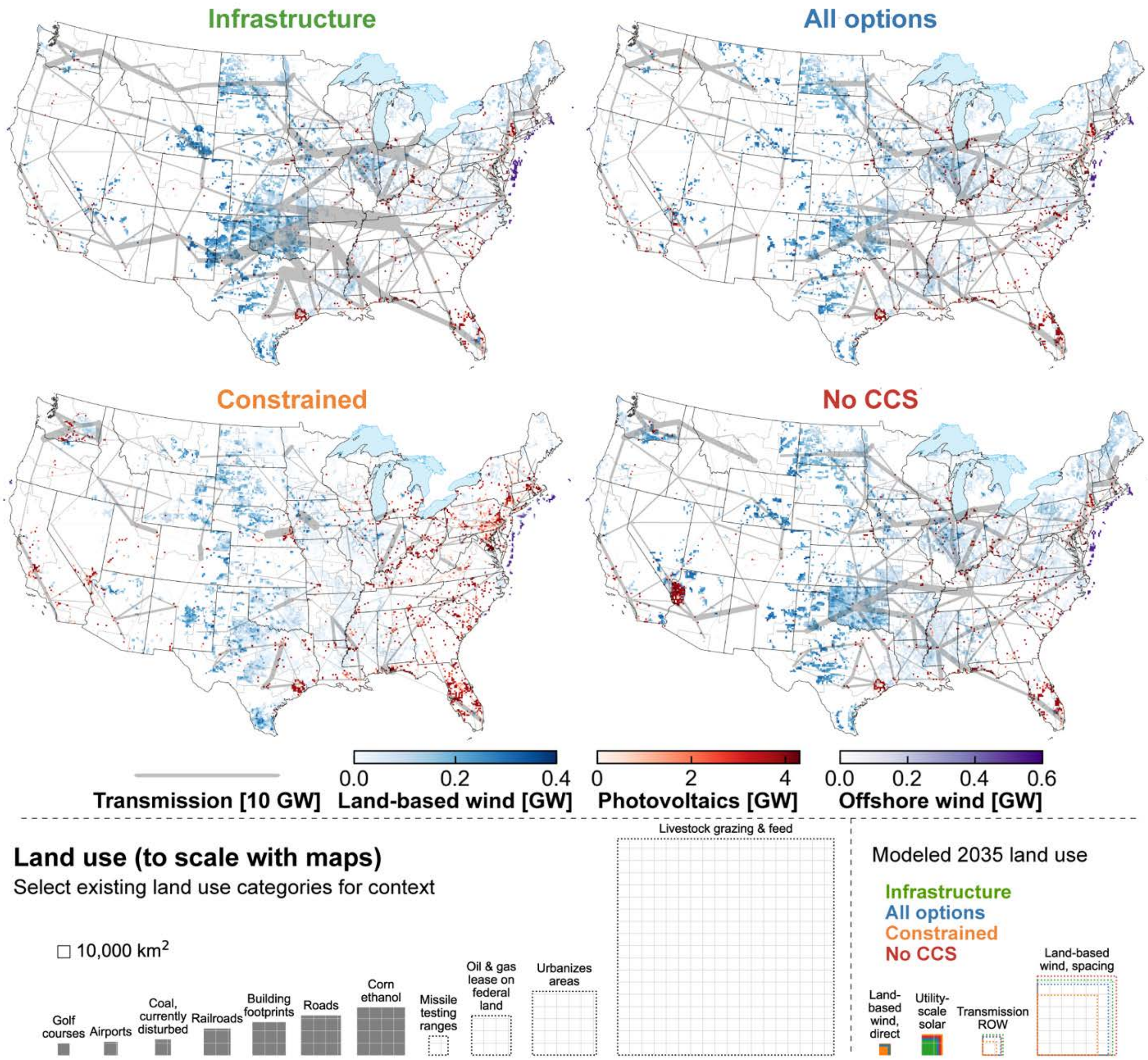


Figure ES-2. Regional capacity of wind, solar, and transmission (top) shows substantial transmission additions into wind-rich regions of the United States in the 2035 ADE scenarios.

Wind deployment is significant in all regions but is particularly concentrated in the Midwest. Total land use (bottom) includes area dedicated largely for a single use, including land physically occupied by wind and solar infrastructure (filled boxes) and land used for multiple applications (open boxes). This is particularly important for wind development, where most occupied by the plant is available for other uses.[8]

[8] Historically, disturbed land area for coal mining (~34,000 km^2) is larger than the currently disturbed land area shown here (~17,000 km^2) (Global Energy Monitor 2021). Oil and gas production on federal lands represents less than 25%. (https://www.blm.gov/programs-energy-and-minerals-oil-and-gas-oil-and-gas-statistics).

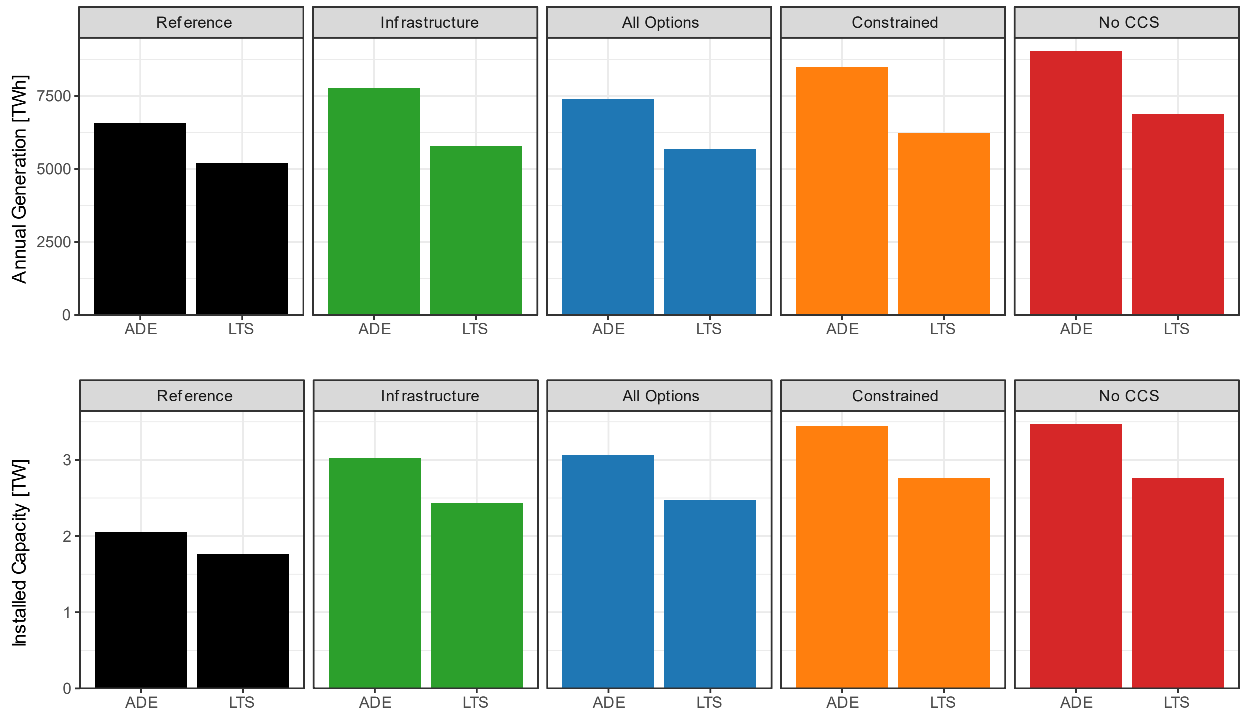
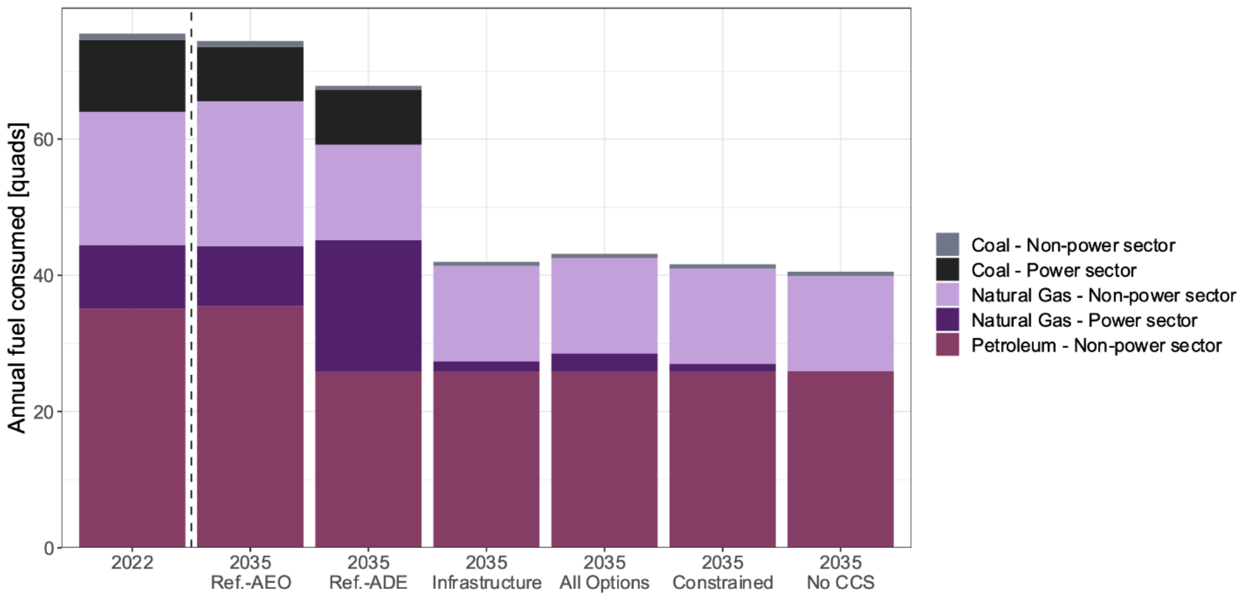


Figure ES-3. Impact of LTS demand assumptions show a 23%–26% reduction in annual generation (top) and 19%–20% reduction in total capacity requirements (bottom).

Benefits and Costs of 100% Clean Electricity

Achieving 100% clean electricity produces benefits that, in most scenarios, outweigh the additional direct costs relative to a reference scenario. Figure ES-4 (top) shows the reduction in fossil fuel use. Compared to Reference-AEO, the electrification that occurs in the Reference-ADE scenario leads to substantial reductions in (1) petroleum use in transportation and (2) natural gas in buildings and industry by 2035. Moving to the 100% clean electricity scenarios further reduces fossil fuel use in the power sector.[9] This fossil fuel reduction leads to a 54% reduction in GHG emissions compared to 2020 (bottom). Reduction of particulates, SO_2, and other emissions in the electric sector leads to an estimated 40,000–130,000 avoided premature deaths between 2020 and 2035 due to improved air quality.

[9] The reduction in petroleum use in the 100% clean electricity scenarios relative to Reference-ADE is zero because both have the same level of transportation electrification. The additional benefits of electrification accrue to the electric sector, primarily in reduced natural gas use.



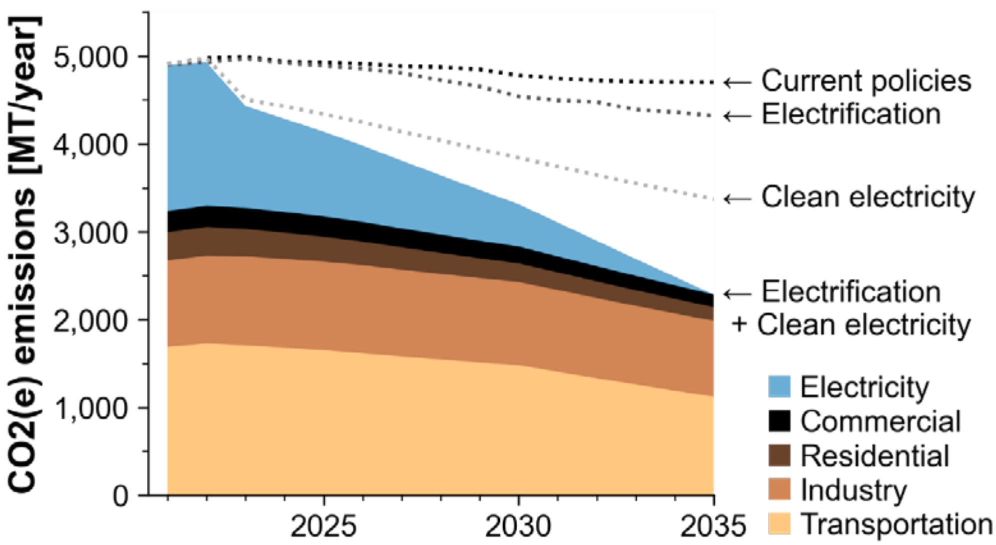


Figure ES-4. The 100% scenarios produce a substantial reduction in fossil fuel consumption (top) and a corresponding reduction in GHG emissions compared to 2020 (bottom), with electrification playing an important role in decarbonizing energy use.

Figure ES-5 compares the system costs against a limited set of emissions-related benefits. System costs include capital, fixed, and variable costs associated with generation and transmission, but they do not include administrative costs or costs of maintaining or upgrading the distribution system. The figure shows an estimate of the net present value of the evaluated costs and benefits from 2023 to 2035, presented as differences between the 100% scenarios and Reference-ADE. The left bar in each scenario represents the system costs with a negative value (meaning additional cost) of $330 billion to $740 billion, which represents the additional costs of achieving 100% clean electricity compared to the Reference-ADE scenario.

The Constrained and No CCS scenarios have the greatest increase in direct costs. In the Constrained scenario, limits to new transmission result in significant increases in overall system costs (an additional $370 billion relative to All Options). This is because the amount of wind that can be delivered to population centers is constrained, which results in additional deployment of storage and nuclear generation. The increased costs in the No CCS scenario demonstrate the potential benefit of negative emissions technologies to offset continued use of fossil resources for meeting peak demand, as well as the potential value 100%-capture CCS could provide.

The next bar to the right of the system cost bar in Figure ES-5 shows the benefit of reduced human health impacts resulting from certain criteria air pollution at fossil-fueled power plants (this does not include emissions reductions from transportation). The benefit is shown as a positive value on top of the negative value associated with the higher system costs. Premature mortality from these power plant emissions results in about $390 billion in estimated monetary impacts in 2020 and declines toward zero in the 100% scenarios. The 100% scenarios provide health benefits from reduced power plant emissions of $390 billion to $400 billion, which suggests these benefits alone outweigh the cost of achieving 100% in three of the four scenarios. The third bar adds the value of avoided climate damages measured by the social cost of carbon (SCC) value used by the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) (IWG 2021), which is about $80/tonne in 2020 and increases to about $100/tonne in 2035. This SCC value adds a benefit of about $1,200 billion to $1,300 billion, resulting in a net benefit of $900 billion to $1,300 billion (solid horizonal arrows). Finally, the fourth bar also adds avoided climate damages, but with a higher (constant) value of $275/tonne from Pindyck (2019), producing net benefits exceeding $3,500 billion.

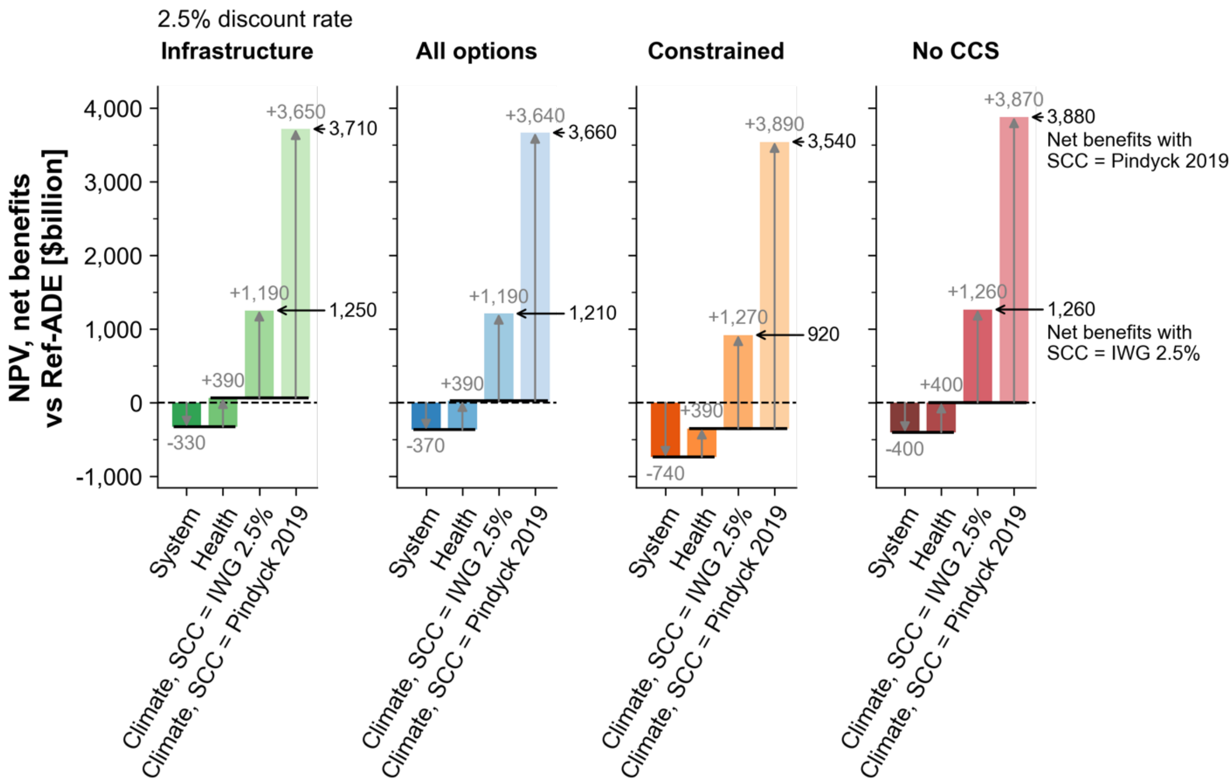


Figure ES-5. Achieving 100% clean electricity results in significant net benefits over the study period.

Additional power system costs (represented by negative values in the far-left bar of each chart) are $330 billion to $740 billion compared to the Reference-ADE cost, with the largest difference resulting from restrictions to new transmission and other infrastructure development in the Constrained scenario. This cost is offset by health benefits from improved air quality (positive value of $390 billion). The final two bars add the benefit of avoided SCC. Using the lower SCC value (third bar) produces a net benefit of $900 billion to $1,300 billion, while the final bar shows the value of the higher SCC value, producing a net benefit of $3,400 billion to $3,900 billion.

All the core scenarios (and sensitivities) produce benefits that exceed costs, even when using the lower SCC values. The avoided health and climate damages are shown as positive values (additional benefits). The LTS sensitivity cases (with lower electricity demand) have lower system costs ($307 billion to $506 billion) because of the lower amount of new generation and transmission required, but these costs do not include the investment in efficiency upgrades needed to achieve the reduction in generation.

Furthermore, most generation across the core scenarios is derived from generators that have zero fuel costs (or costs have historically been relatively stable, in the case of nuclear) and therefore provide a predictable cost trajectory and reduce potential price shocks, including price stability in electrified industrial and transportation applications. There are expected to be significant air quality and environmental justice benefits associated with the electrification of transportation, buildings, and other end uses; however, these benefits are not assessed in this work.

Implications and Future Research

The rapid reduction in the costs of renewable and several other clean energy technologies over the past two decades allows for continued large-scale deployments that are expected to generate benefits that substantially outweigh the associated power system cost, assuming these technology cost declines continue in the coming decades. However, achieving the transformation of the U.S. energy system to 100% clean electricity as envisioned in these scenarios requires four challenging actions to occur in the next decade:

1. **Dramatically accelerating electrification and increasing the efficiency of the demand sectors to get the country on the path to net-zero emissions by midcentury.** Electrification will dramatically increase demand, which in turn may make it more difficult to decarbonize the electricity system due to the higher rate of generation and transmission capacity additions needed. However, electrification of end uses in buildings (with a critical parallel focus on efficiency of those end uses) and much of transportation and industry is likely a key part of the most cost-effective pathway to achieving large-scale decarbonization across the economy. Furthermore, a parallel focus on efficiency and flexibility of end uses has the potential to greatly impact generation supply needed. More flexible operation could provide higher utilization of generation, transmission, and distribution assets, lowering the delivered cost of electricity. To achieve decarbonization of all energy sectors by 2050, further electrification, low- to zero-carbon fuel production, energy efficiency, and demand flexibility measures will be needed.
2. **Installing new energy infrastructure rapidly throughout the country.** This includes siting and interconnecting new renewable and storage plants at rates of three to six times recent levels, potentially doubling or tripling the capacity of the transmission system, upgrading the distribution system, building new pipelines and storage for hydrogen and CO_2, and/or deploying nuclear and carbon management technologies with low environmental disturbance and in an equitable fashion to all communities.
3. **Expanding clean technology manufacturing and the supply chain.** The unprecedented deployment rates for clean electricity technologies envisioned in the 100% scenarios requires a corresponding growth in raw materials supply, manufacturing facilities, and trained workforce throughout the supply chain. Further analysis is needed to understand how to achieve the scale-up of manufacturing as part of a just transition to a clean electricity system. This includes evaluating the economic and energy security benefits of increasing domestic manufacturing.
4. **Accelerating research, development, demonstration, and deployment to bring emerging technologies to the market.** Technologies that are being deployed widely today can provide most U.S. electricity by 2035 in a deeply decarbonized power sector. A 90% clean grid can be achieved at low incremental cost by relying primarily on new wind, solar, storage, advanced transmission, and other technologies already being deployed at scale today. However, the path from 90% to full decarbonization is less clear, as many of the technologies that could best aid full decarbonization, such as clean hydrogen and other low-carbon fuels, advanced nuclear, price-responsive demand response, CCS, and DAC, have not yet been deployed at large scale. A concerted research, development, demonstration, and deployment effort is needed to reduce costs

and improve performance to enable these technologies to be commercialized at scale and support a fully decarbonized grid.

This ambitious list of tasks will require explicit support to be achieved in the coming decade. Failing to achieve any of these actions could increase the difficulty of realizing a 100% clean grid by 2035. However, damages from climate change are not binary, so even if emissions reductions fall short of those envisioned in the scenarios here, significant harm to human health, economies, and the ecological system can be avoided by making progress toward decarbonization.

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1 Introduction

This study evaluates a variety of scenarios that achieve a 100% clean electricity system (defined as zero net greenhouse gas emissions) in 2035. The trajectories analyzed put the United States on a path to economywide net-zero emissions by 2050, but pathways beyond 2035 are not evaluated in this work.[10]

This work builds on previous National Renewable Energy Laboratory (NREL) analyses, including the Renewable Electricity Futures Study (NREL 2022a), North American Renewable Integration Study (Brinkman et al. 2021), Electrification Futures Study (NREL 2022b), Storage Futures Study (NREL 2022c), and Solar Futures Study (Ardani et al. 2021). This work also joins the growing body of work that examines 100% renewable and 100% clean electricity systems in the United States and internationally. Recent examples include Brown and Botterud (2021), Larson et al. (2021), EPRI (2021) and DeAngelo (2021). There are also reviews and summaries of several studies provided by Azevado et al. (2021), Bistline (2021), and Breyer et al. (2022). Among the goals of this present study is to contribute to this larger body of work, much of which examines various pathways and timelines. These previous studies illustrate several consistent themes, including:

- Maintaining resource adequacy while increasing contribution of renewable energy and other clean energy resources is technically feasible.
- Wind and solar, enabled by energy storage, are typically the least-cost technologies used to meet most energy needs in the power sector.
- Transmission expansion—especially interregional expansion—increases access to low-cost generation resources and improves system flexibility, helping to achieve reliability at lowest cost.
- Demand growth, particularly due to electrification, can dramatically increase overall generation requirements, potentially offset to various degrees by energy efficiency measures.

Previous NREL studies mentioned looked at various levels of clean electricity deployment through 2050. In contrast, this study considers an accelerated time frame and complete decarbonization of the electric sector to achieve net-zero greenhouse gas (GHG) emissions by 2035. Though many of the trends seen in the previous studies are consistent with those seen in this study, this study also identifies the particular challenges of the scale and rate of deployment needed to reach 100% clean electricity by 2035. This study also illustrates the rapid accumulation of benefits associated with near-term reductions in both criteria pollutants and GHGs that result from achieving this target.

The results highlight multiple pathways to 100% clean electricity in which benefits exceed costs, with the main uncertainty being the mix of technologies that achieves the 100% target at least cost. The uncertainty is particularly related to the challenges of moving from 90% to 100% clean electricity and providing reliable electricity during periods of peak demand. The study examines wide-ranging scenarios with different mixes of electricity supply-side options—including

[10] Throughout this report, we refer to the U.S. power system as a shorthand for the power system of the contiguous United States, which excludes Alaska and Hawaii.

renewable power, nuclear, carbon capture (and negative emissions technologies), energy storage, and transmission—that could reach 100% clean electricity and meet demands from current and newly electrified loads. The main scenarios assume widespread electrification to maximize the use of carbon-free electricity to support economy-wide decarbonization, but further study focused on the demand sectors, including the potential role of energy efficiency, demand-side flexibility, and low-carbon fuels, is needed to understand the trade-offs between supply-side and demand-side solutions to decarbonization.

All the scenarios evaluated achieve benefits that exceed the power system costs of achieving 100% clean electricity. The benefits analysis in this work includes reductions in CO_2 and methane emissions in the electricity sector[11] and a high-level examination of the public health impacts of improved air quality resulting from electricity sector emissions reductions. It does not consider the additional health benefits from reduced emissions in buildings, industry, and transportation, or distributional aspects of these benefits, including environmental justice, nor does it assess energy security and geopolitical implications. A detailed discussion of what is and is not considered in this work (including costs and benefits) is discussed in the Key Caveats section (Section 2.4, page 17).

[11] Note that when we report CO_2 emissions, we are actually reporting the combination of direct CO_2 emissions and the CO_2 equivalent emissions from methane leakage in the power sector, as discussed in the Methods section (Section 2, page 3). We estimate reductions in CO_2 emissions in several other energy sectors, including transportation, buildings, and industry, due to electrification and use of clean fuels. We quantify these emission reductions benefits but do not account for them in the final cost/benefit analysis, as we do not estimate the cost of implementing these measures.

2 Study Methods and Assumptions

This study is designed to examine changes in the U.S. electric sector required to achieve 100% clean electricity by 2035, focusing on the mix of clean energy generation resources that must be deployed, along with enabling technologies such as energy storage and transmission. It consists of three major steps, illustrated in Figure 1. The following section details how each step was performed.

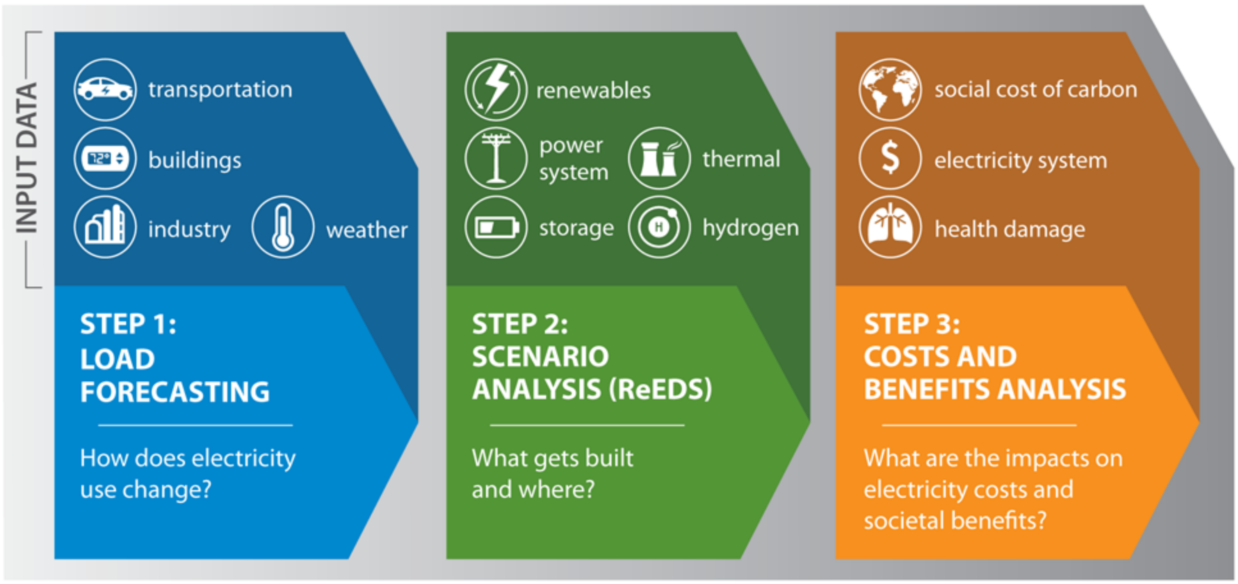

Figure 1. The three-step process conducted for this study.

ReEDS refers to the Regional Energy Deployment System model.

2.1 Demand Assumptions

Step 1 in Figure 1 requires estimating the changes in electricity demand that could occur by 2035. The demand scenarios are constructed to be on a path to economywide decarbonization in 2050.

In 2020, the electric sector generated 2,408 TWh of electricity from fossil fuels,[12] representing about 32% of total CO_2 emissions across all sectors (EIA 2021a), which means decarbonization of electricity alone is insufficient to meet climate goals. Four approaches are often considered to decarbonizing end-use energy sectors. One is electrification—the conversion of devices currently burning fossil fuels to run on electricity—while simultaneously decarbonizing the electric sector. The second approach involves taking energy efficiency measures to reduce demand. The third is using low- to zero-carbon liquid or gas fuels. Finally, the fourth is to capture and sequester CO_2 to reduce emissions from fossil fuel use to offset emissions through CO_2 removal. We assume all approaches will be deployed to achieve energy system decarbonization by 2050, with rapid

[12] This includes 774 TWh from coal, 1,617 TWh from natural gas, and 17 TWh from oil (EIA 2022a).

electrification occurring in the near term and having the most direct impact on electricity supply-side changes.

We evaluated three demand trajectories, all serving as inputs to the power sector modeling. The first is a business-as-usual electricity demand based on the Annual Energy Outlook (AEO) 2021 (EIA 2021a). The second is the accelerated demand electrification (ADE) case, which is used as our primary demand trajectory in the core scenarios; it assumes all measures to decarbonize end-use sectors but features substantial electrification. The third trajectory is used as a sensitivity and is based on a scenario from the *Long-Term Strategy of the United States* (LTS), which assumes greater energy efficiency adoption and less electrification than ADE (White House 2021a).

The LTS report presents multiple pathways for the U.S. economy to achieve net-zero emissions by 2050 and was based on diverse analytical tools and consultation from a wide range of stakeholders. The core scenarios use the ADE demand assumptions, as they reflect a high bound on future electricity supply needs demonstrating the potential need for large increases in electricity supply. However, LTS sensitivities are highlighted throughout, given the broad uncertainties for end-use decarbonization pathways, and they illustrate the potential impact of further efficiency measures to reduce the need for supply-side resources.[13]

Figure 2 summarizes this study's projected growth in annual end-use electricity demand from 2020 to 2035 by sector. The AEO 2021 reference trajectory shows a small annual increase in demand (0.9%/year from 2020 to 2035) associated with population and economic growth and minimal electrification in a "no new policy" scenario. The ADE trajectory assumes significant electricity demand growth (3.4%/year), and the LTS sensitivity trajectory is between AEO and ADE (1.8%/year). In the ADE case, growth in demand is driven by aggressive electrification of end uses, including space and water heating, and deployment of electric vehicles. This electrification-driven demand growth assumption results in 6,200 TWh of annual direct electricity consumption in 2035, compared with 3,700 TWh in 2020. In contrast, 2035 electricity demand is 21% (1,300 TWh) lower than ADE in the LTS case, largely through greater assumed energy efficiency. Appendix C provides a detailed summary of the assumptions across various sectors for the ADE and LTS cases.

[13] Final energy consumption for 2035 is estimated to be 78 quads, 71 quads, and 60 quads for the AEO, ADE, and LTS scenarios respectively. A quad is a unit of energy equal to 1 quadrillion (10^{15}) British thermal units. Electricity's share of final energy in 2035 is estimated to be 19%, 30%, and 28% for the same respective scenarios. See Appendix C for details.

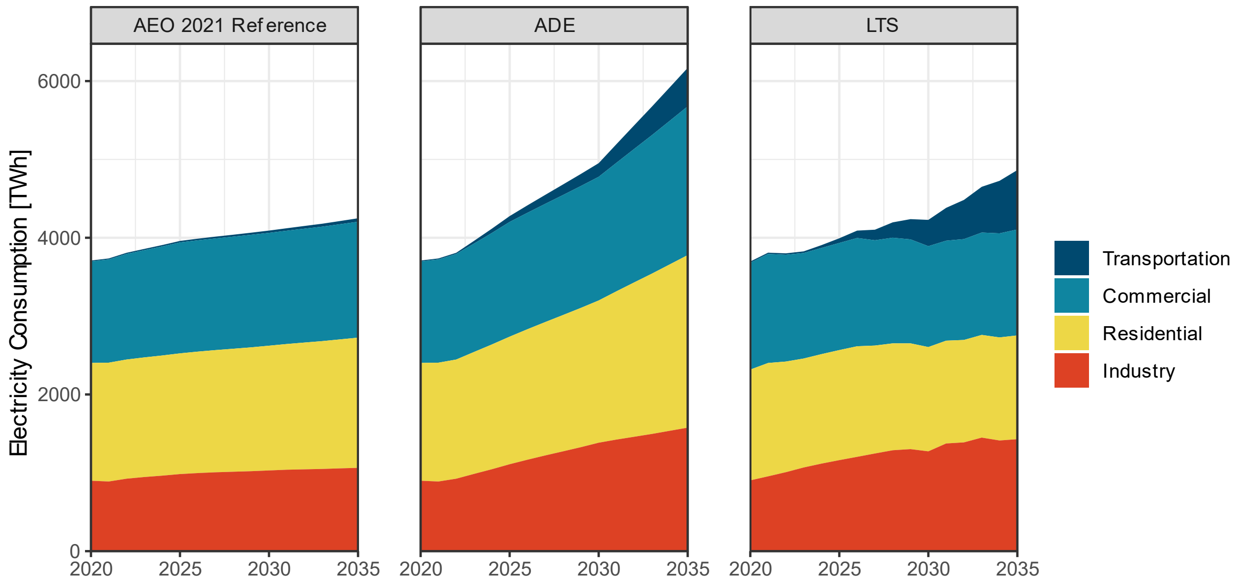

Figure 2. Electricity demand projections show a substantial increase in the ADE assumptions due to electrification, offsetting energy demand in other sectors.

Figure 2 shows the assumed electricity demand *inputs*, but the total generation required will be larger due to electricity for clean fuel production losses, transmission and distribution losses, and energy storage losses. Direct use of multiple clean fuels—including hydrogen, biofuels, synthetic hydrocarbons, and ammonia—is considered for decarbonization of the transportation and industrial sectors. Assumed electricity and hydrogen fuel input required for this clean fuel production is prescribed in Appendix C. The amount of electricity needed for hydrogen production varies across the different scenarios based on two factors: the amount of hydrogen needed for direct and indirect use and the source of hydrogen production.

Figure 3 shows the assumed demand for clean hydrogen required for processes where direct electrification can be more challenging due to technical or economic reasons—for example, long-haul freight, ships, aviation, and certain industrial processes. We assume 14.3 million tonnes (MT) of clean hydrogen demand in 2035—for both direct use and as fuel input to other low-carbon fuels—for these non-grid applications for scenarios that use the ADE demand assumptions (see Appendix C); the LTS scenario assumes 7.5 MT of clean hydrogen demand by 2035. This demand for new clean hydrogen is distinct from the current demand for hydrogen (~10 MT annually, largely derived from natural gas) to produce refined petroleum products and other existing uses.[14] In addition to providing direct end uses, we assume hydrogen can help meet electricity demand during periods of very low wind and solar output, providing a form of seasonal storage. This demand for additional clean hydrogen used by the grid is determined by the model used in this study and varies substantially depending on scenario; therefore, the total amount of hydrogen needed is an output of the model. We represent hydrogen production from natural gas steam methane reforming (SMR) with carbon capture and sequestration (CCS) and

[14] Given the reduction in motor gasoline and diesel fuels in the transportation sector under the ADE and LTS scenarios, this demand would likely decline over time. Hydrogen production to serve these needs is also expected to transition to lower-emissions pathways given the overall economywide decarbonization trajectory modeled under the scenarios. These dynamics are not modeled explicitly in our analysis.

from water electrolysis using clean electricity. The selection of one of these two hydrogen production pathways is determined by the model based on the input technology cost and performance assumptions and scenario specifications (e.g., SMR with CCS is not allowed in the No CCS scenarios). Hydrogen production, biofuels, and other clean fuels are discussed further in Section 2.2 (page 8) and Section 3.6 (page 33).

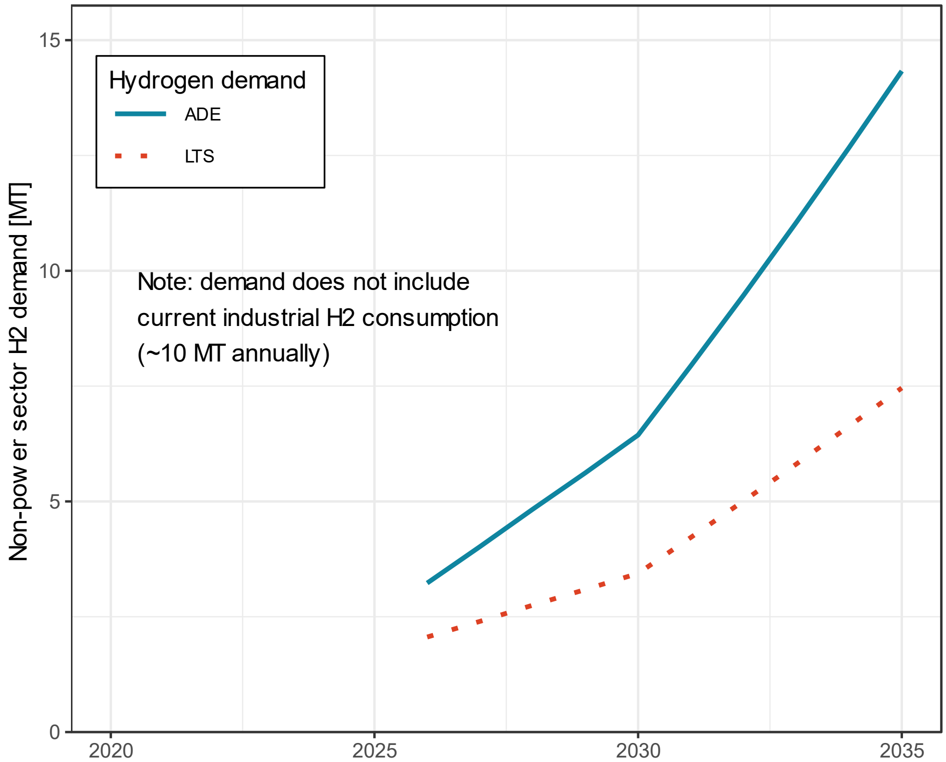

Figure 3. Assumed clean hydrogen demand for industry and transportation.

Additional hydrogen, not shown here, is used for seasonal storage, so total hydrogen production is substantially higher than shown due to use in the electric sector and is summarized in Section 3.6.

Electrification of end uses changes both how much electricity is used and when it is used. Peak demand in most of the United States currently occurs during summer afternoons, driven by air conditioning, but electrification of heating may shift peak demand to the winter. Our scenarios assume significant deployment of air-source heat pumps, which enable electrification of space and water heating in buildings and are more energy efficient than fossil-fuel-based heating options. However, widespread electrification of space heating could substantially raise evening winter peaks and reduce the ability of solar energy to meet demand peaks.[15]

Figure 4 shows the demand profiles for the entire United States by season as modeled in 2035. The ADE case (top) has much greater electrification; hourly peaks are 35% higher in winter than in summer, and more than double the overall U.S. peak demand in 2020. The LTS sensitivity

[15] The modeled electric demand profiles of heat pumps are based on air-source heat pumps (see Appendix C). Alternatively, significant adoption of geothermal heat pumps would reduce winter peaks—and the corresponding amount of capacity needed to meet these peaks. Further research is needed to compare the relative benefits and costs of different end-use technologies, including different heating options.

with lower buildings electrification is assumed to have similar load shapes to current patterns, with the most significant increase in demand being electric vehicles, which do not show a strong seasonal pattern (Muratori and Mai 2020). Note that the demand profiles analyzed are based on a historical (2012) weather year only.[16] Further research is needed on changing demand patterns resulting from electrification and climate change, and the associated increase in frequency and severity of extreme weather events.

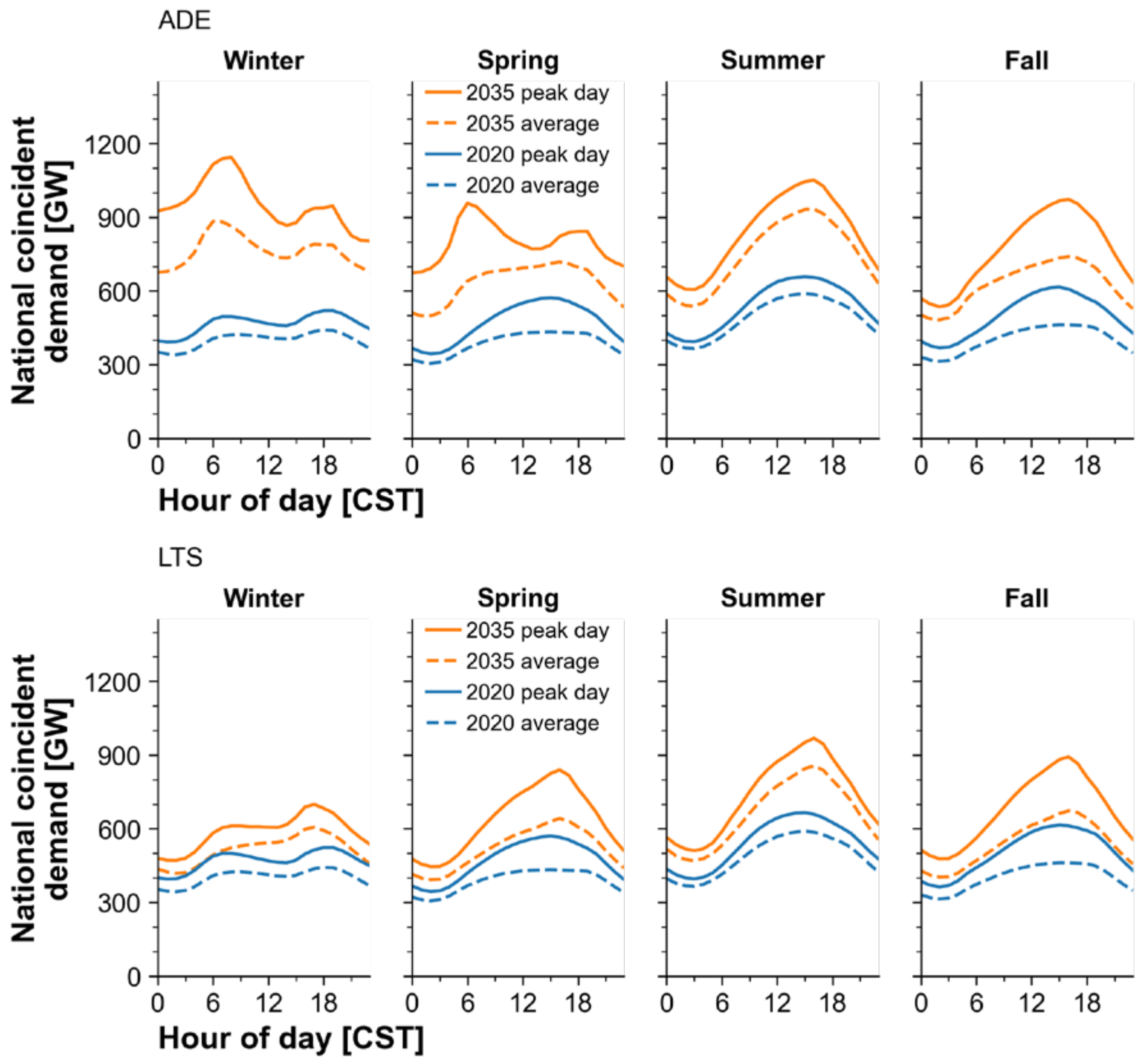

Figure 4. U.S. load profiles for seasonal peak days in the ADE scenario (top row) show how electrification increases peak demand and shifts the peak from summer to winter in 2035 due to electric space heating.

Panels show the projected hourly load for the day of each season in which the full U.S. hourly load reaches its seasonal peak (solid lines) and the average seasonal profile (dashed lines). The LTS scenario (bottom row) has lower electrification and increased efficiency, resulting in lower demand and a continuation of summer peaks.

[16] The AEO 2021 scenario uses historical demand profiles for all years (based on 2012 weather, equipment stock, and behavior).

The tremendous growth in electrification in the ADE demand trajectory provides opportunities for flexible demand to help integrate variable generation by shifting timing of electric vehicle charging, hydrogen production, and certain other loads. Power systems have long relied on demand-side resources—including demand response, interruptible load, and demand flexibility—to meet some of these needs, as the cost of dropping noncritical loads can be less than that of building new generation capacity with low capacity factor. Policy mechanisms to incentivize demand flexibility include rate structures (e.g., real-time or time-of-use pricing, demand charges) and direct incentives to consumers.

The default demand flexibility is derived from the Base Flexibility Case in NREL's Electrification Futures Study (NREL 2022b), which results in about 5% of annual demand being flexible in 2035. This is supplemented with a "super peak" demand response assumption that clips the peak of the top 1% of hours, which reduces 2035 peak coincident demand for the contiguous United States by 246 GW in cases using ADE load profiles (this is captured in Figure 4 above, with unclipped profiles and additional details provided in Appendix C). Additional demand flexibility could potentially reduce the cost of achieving the high levels of reliability assumed here, and significant research is needed to assess the potential role of flexible loads for grid and energy-system decarbonization (Zhou and Mai 2021; Sun et al. 2020).

2.2 Scenario Framework

The second step in the analysis process is to understand the supply-side (generation) resources needed to meet the demand profiles created in Step 1 in Figure 1. Given the significant uncertainty about the future cost and performance of low- and zero-carbon technologies, four primary technology evolution scenarios with varying assumptions regarding resource costs and technology availability were evaluated. Table 1 summarizes the four core scenarios, which are described below. In each scenario, assumptions common to all scenarios are called "reference," and details are provided in Appendix C.

- **All Options** is a scenario in which all technologies continue to see improved cost and performance consistent with the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (NREL 2021). This scenario includes the development and deployment of direct air capture (DAC) technology. The other three main scenarios assume DAC does not achieve the cost and performance targets needed to be deployed at scale, but they do consider availability of DAC in sensitivity cases.[17]
- **Infrastructure Renaissance** assumes improved transmission technologies and new permitting and siting approaches that allow greater levels of transmission deployment with higher capacity.

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[17] Executive Order 14057 defines "carbon pollution-free electricity" as "electrical energy produced from resources that generate no carbon emissions, including marine energy, solar, wind, hydrokinetic (including tidal, wave, current, and thermal), geothermal, hydroelectric, nuclear, renewably sourced hydrogen, and electrical energy generation from fossil resources to the extent there is active capture and storage of carbon dioxide emissions that meets EPA requirements". The inclusion of non-generation, negative emission technologies such as direct air capture may not be consistent with the Administration's 2035 clean electricity goal but are considered in the study's All Options Scenarios because of their potential deployment, emissions, and cost impacts. https://www.federalregister.gov/documents/2021/12/13/2021-27114/catalyzing-clean-energy-industries-and-jobs-through-federal-sustainability

- **Constrained** is a scenario where additional constraints to deployment of new generation capacity and transmission both limits the amount that can be deployed and increases costs to deploy certain technologies.
- **No CCS** scenario assumes CCS technologies do not achieve the cost and performance needed for cost-competitive deployment. This scenario also acts as a point of comparison to demonstrate the potential benefits of achieving cost-competitive deployment of CCS at scale. This is the only scenario that includes no fossil fuel capacity or generation in 2035, and therefore it is the only scenario that includes zero direct GHG emissions in the electric sector.

The four primary technology evolution scenarios all reach 100% clean electricity by 2035 and use the ADE demand trajectory, with the LTS trajectory as a primary sensitivity. An additional 122 sensitivities with the same 100% by 2035 constraint were also evaluated across all four core scenarios. Major sensitivity categories are shown at the bottom of Table 1 and described in detail in Appendix A.[18]

[18] This amounts to roughly 44 sensitivities per core scenario. Note that not all core scenarios have all sensitivities applied to them; for instance, we do not test a "low-cost CCS" sensitivity on the No CCS scenario.

Table 1. 100% Clean Electricity Scenarios and Sensitivities Evaluated in This Study

<table>
<tr><th rowspan="2">Scenario</th><th rowspan="2">Demand Assumptions</th><th colspan="5">Generation Resource Assumptions</th></tr>
<tr><th>Renewable Resources</th><th>CCS Technologies</th><th>Transmission</th><th>Nuclear</th><th>Other Infrastructure</th></tr>
<tr><td>All Options</td><td rowspan="4">ADE</td><td rowspan="2">Reference</td><td>All including DAC</td><td>Reference interregional AC expansion</td><td rowspan="2">Reference</td><td>Reference</td></tr>
<tr><td>Infrastructure Renaissance</td><td rowspan="2">No DAC</td><td>HVDC macrogrid</td><td>Lower-cost transport and storage for H2, CO2, biomass</td></tr>
<tr><td>Constrained</td><td>Reduced land available for wind, solar, and biomass</td><td>Intraregional transmission only, higher (5x) costs</td><td>Not allowed in regions with current legislative restrictions</td><td>Higher-cost transport and storage for H2, CO2, biomass</td></tr>
<tr><td>No CCS</td><td>Reference</td><td>No CCS, bioenergy with CCS, or DAC</td><td>Reference</td><td>Reference</td><td>Reference</td></tr>
<tr><td>Sensitivities (applied to each of the four core scenarios)</td><td colspan="6">AEO and LTS demand cases. Supply-side sensitivities include renewable energy costs, storage costs, nuclear costs, electrolyzer costs, CCS cost and performance, transmission constraints, new natural gas restriction, natural gas fuel costs, expanded biomass supply, low-cost geothermal, and allowing DAC in the Infrastructure Renaissance and Constrained cases.</td></tr>
</table>

In addition, "current policy" reference cases with both the AEO[19] and ADE demand trajectories (referred to as Reference-AEO and Reference-ADE respectively) are also modeled under each of the four core scenarios from Table 1.[20]

[19] The AEO demand is derived from the 2021 Annual Energy Outlook (EIA 2021a).
[20] This produces two reference cases for each of the four core scenarios.

The study uses NREL's Regional Energy Deployment System (ReEDS) model to simulate planning and operation of the U.S.[21] electric power system (Ho et al. 2020), while considering the significant geographical variation in demand and generation resource availability.[22] ReEDS examines the demand for electricity at various points on the grid, as well as the cost and performance of multiple generation technologies that can meet this demand, and selects the mix of technologies that produces the lowest power system cost under the various assumptions applied in each scenario.

The model performs resource adequacy calculations to ensure the total capacity (and availability) of all resources is sufficient to meet the peak demand for electricity during hot summer afternoons, when air conditioning demand is at its highest, or cold winter nights and mornings, when heating demand—increasingly served by electric heat pumps—is at its highest. These calculations require evaluating the availability (i.e., capacity credit) of all resources using hourly resource and load data in the model, and how this capacity credit is impacted as the generation mix evolves (see Text Box 1 and Text Box 2 at the end of this section for discussion of capacity credit and related terms).[23] The model also enforces the need for operating reserves used to address random and unpredictable variations in supply or demand, including power plant outages.

In this study, the model simulates the evolution of the power grid for each year from 2020 through 2035, using projections for electricity demand patterns in multiple regions.[24] The model uses historical weather data, which essentially assumes future years will have similar weather to the recent past and therefore does not account for the potential impacts of climate change on demand or renewable energy availability profiles, including potential increased frequency and severity of extreme weather events. Changing land use patterns from climate change and other factors (which impact renewable energy supply) are also not included.

The model can select from among 14 technology categories, summarized in Table 2, to produce a least-cost resource mix. All technologies except distributed grid-connected rooftop photovoltaics (PV) are considered as part of the ReEDS optimization. Rooftop PV deployments and corresponding generation profiles are an input to the ReEDS model using values from the Distributed Generation Market Demand (dGen™) model (Sigrin et al. 2016) (additional

[21] Throughout this report, we refer to the U.S. power system as a shorthand for the contiguous United States, which excludes Alaska and Hawaii.

[22] ReEDS uses hourly data to represent contributions to resource adequacy, but it relies on simplified dispatch modeling given the long-term investment decision-making scope of the model. More detailed grid simulations were not executed for this study, but paired use of ReEDS and production cost and probabilistic resource adequacy modeling has been employed in multiple prior studies that examined very high renewable energy systems with ReEDS (e.g., the North American Renewable Integration Study [Brinkman et al. 2021], Solar Futures Study [Ardani et al. 2021]). Results from these previous studies act as a partial validation of the ReEDS resource adequacy calculations. However more detailed analysis will be needed to complete evaluate the adequacy and operational reliability of the modeled scenarios.

[23] A more thorough discussion of how ReEDS treats capacity credit is provided in the full model documentation (Ho et al. 2020).

[24] The model is run through 2050, but we report results to 2035 for most cases. After 2035, the model is run using 5-year timesteps.

discussion of distributed resources is provided in the Text Box 4 in Section 3.8).[25] Unless otherwise noted, technology cost and performance data are derived from the 2021 Annual Technology Baseline's Moderate case (NREL 2021). Appendix B provides details about the assumptions for the various technologies, including capital and variable costs, performance, and data sources, which describe how the model considers the regional and temporal variations in the output of wind and solar. The model outputs the total capacity of each resource in each region over time, demonstrating the growth rates required for the various technologies and their annual energy contribution in each year.

Table 2. Supply-Side Technologies Considered

Type	Technology	Notes
Renewable Generation	Utility-scale PV	Ground-mount performance reflects one-axis tracking
	Rooftop PV	Rooftop systems; quantity and locations externally generated from the dGen model using the deployment levels across all scenarios
	Hydropower	Adding generators unpowered dams and uprates at existing facilities
	Land-based wind	Range of turbines (hub heights) and rotor diameters depending on region and scenario
	Offshore wind	Includes both fixed-bottom and floating technologies
	Nuclear	Conventional light-water reactors; can be deployed in all states except in the Constrained scenario; lower-cost advanced nuclear considered in sensitivity cases[26]
	Geothermal	Multiple geothermal technologies
	Concentrating solar power (CSP)	Includes thermal storage, including options with 10 and 14 hours of capacity
Fossil Generation (without CCS)	Natural gas combustion turbine	Standard natural gas fueled technology
	Natural gas combined cycle (CCGT)	Standard natural gas fueled technology; higher cost but more efficient than CT
	Conventional coal	Standard pulverized coal technology
Storage	Hydrogen-fueled CT/ seasonal storage	New or retrofit of existing (CT and CCGT) plants; provides seasonal storage

[25] Rooftop PV trajectories were identical for all ADES scenarios and derived from the Solar Futures Study (Ardani et al. 2021). Trajectories for the AEO and LTS scenarios were derived from the Standard Scenarios 2021 Mid-case (Cole et al. 2021).

[26] Advanced nuclear represents an unspecified mix of next-generation technologies with reduced cost, as discussed in the main body and Appendix. Nuclear is used for production of electricity only. While its heat and electricity can be used for hydrogen generation in the overall grid, dedicated hydrogen production via thermal cycles is not considered.

Type	Technology	Notes
	Storage (2- to 10-hour duration)	Cost and performance based on Li-ion batteries
	Storage (12-hour duration)	Cost and performance based on pumped storage hydro
Carbon Capture or Negative Emissions	Natural gas CC with carbon capture and storage (CCS)	New plants with a 90% capture rate; retrofit of existing plants evaluated in a sensitivity case; higher capture rates (95% and 99%) evaluated in sensitivity cases
	Coal with CCS	New or retrofit of existing plants with a 90% capture rate; higher capture rates (95% and 99%) evaluated in sensitivity cases
	Bioenergy with CCS (BECCS)	Uses woody biomass and produces net negative emissions of about -1.2 tonnes/MWh
	Direct air capture (DAC)	Not a generation or storage technology, but it uses electricity to capture and store carbon from the atmosphere, producing negative emissions. Use of fossil technologies without CCS and incomplete capture in CCS plants requires offsets with either DAC or BECCS. The CO_2 constraint must be met in each year; there is no banking or borrowing of emissions between years.
Other	Hydrogen production	Hydrogen can be produced from either electrolysis (assuming 51–55 kWh per kg) or via steam methane reforming with CCS (requiring 0.2 MMBtu natural gas and 2 kWh electricity per kg)
	Transmission	Model can deploy conventional alternating-current (AC) lines in all scenarios. In the Infrastructure Renaissance scenario, the model can also choose from two direct-current (DC) technologies.

The model includes representation of existing and new transmission, including the associated costs and benefits. New high-capacity alternating-current (AC) and high-voltage direct current (HVDC) (where allowed) transmission may be added starting in 2026, reflecting lead time for siting, permitting, and construction. The cost of the types of new transmission allowed varies by scenario, as discussed in Section 3.7 (page 43) and Appendix B.

In addition to different transmission siting restrictions, the scenarios consider varying restrictions on the siting of new wind and solar to reflect development challenges or other factors that may impact deployment. The All Options, No CCS, and Infrastructure Renaissance scenarios use "reference" siting availability while the Constrained scenario uses "limited" availability (Lopez et al. 2021).

The pathway to the 2035 clean electricity target is modeled via a national constraint on annual *net* CO_2 emissions from the electric sector, starting in 2023. Figure 5 illustrates historical emissions (EIA 2022b) and the clean electricity trajectory met by the model. The core 100% scenarios all follow the same trajectory, shown in green, which reaches an 80% reduction in 2030 relative to 2005. This trajectory is not intended to represent a specific policy under consideration but instead considers a general decarbonization pathway, and it follows the general trend seen from 2010 to 2020. Existing policies, including state clean energy targets (including trajectories) and federal tax credits (including currently legislated ramp-downs and expirations), are included, but no additional policies are evaluated.

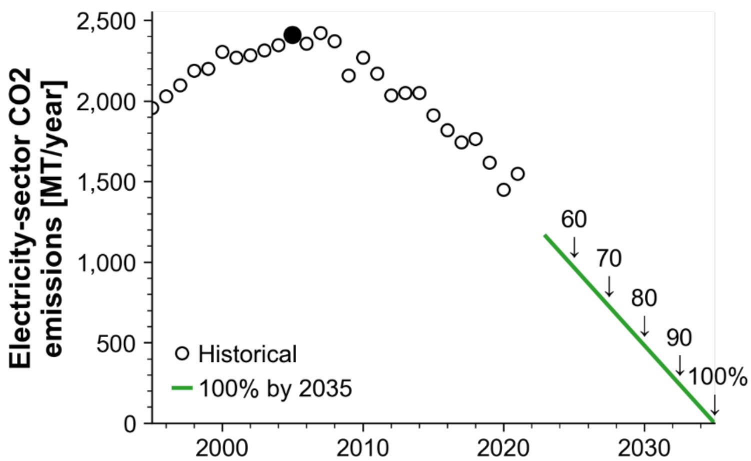

Figure 5. Electricity-sector emissions pathways for 100% clean electricity scenarios.

Emissions reductions are defined relative to 2005 (solid dot). Historical emissions measure only direct CO2 emissions from combustion, while modeled trajectories also include the CO2 equivalent emissions from estimated methane leakage.

We account for CO_2 emissions in the electricity sector associated with direct combustion, as well as the global warming potential of upstream methane leakage in the natural gas production and delivery system for gas usage in electricity generation and hydrogen production.[27] We assume a leakage rate of 2.3% (Alvarez et al. 2018), which drops to 1.6% by 2030 to reflect a reduction in methane emissions of 30% by the end of the decade relative to their 2020 level (Mason and Alper 2021).

We also account for incomplete capture in fossil CCS plants. CCS is allowed in new or retrofit applications starting in 2026 in all scenarios except the No CCS scenario. Scenarios with CCS assume a 90% capture rate from CCS plants (with additional sensitivities with higher capture rates), that captured CO_2 is permanently stored in geologic formations, and that no leakage of CO_2 occurs. However, the model does not account for all life cycle GHG emissions, including those from plant construction, operation and maintenance, and fuel processing and transport. Enhanced oil recovery or other applications that would impact the net carbon reduction benefits are not considered.

Any net emissions from fossil plants without CCS or from less than 100% capture rates (and upstream methane leakage) must be offset by negative emissions technologies such as BECCS

[27] CO_2 equivalent emissions from upstream methane are sensitive to assumptions regarding leakage rate and the time horizon for methane global warming potential. Other life cycle emissions (often with considerable uncertainty) are not included here, including methane from hydropower, biomass net emissions, CO_2 leakage from CCS, and other emissions. Methane leakage is not included in emissions estimates for transportation or residential/commercial/industrial end-use applications, or in historical (pre-2021) estimates of electricity sector emissions.

and DAC. Multiple other negative emissions pathways—such as afforestation, biomass carbon removal and storage, biorefining with CCS, enhanced mineralization, and ocean-based carbon dioxide removal—can also be used to offset emissions from fossil plants, but they are not modeled. BECCs results in a net negative emissions rate because carbon from the atmosphere is captured during photosynthesis and then sequestered after combustion.[28] The use of negative emissions technologies allows for continued operation of fossil plants without CCS even at 100% clean electricity because of the ability to achieve net-zero emissions.

2.3 Costs and Benefits

The final step in the analysis process is to evaluate the costs and benefits of the various 100% clean electricity scenarios. Three cost and benefit components were evaluated, and all monetary values are reported in 2021 U.S. dollars.

In general, most comparisons are made between the 100% scenarios and the Reference-ADE scenario. Comparisons between the 100% scenarios and the Reference-AEO scenario would likely include significant additional benefits associated with electrification, but since the costs of these electrification measures are not estimated, here would be limited context provided for these additional benefits.

The first cost and benefit component is associated with bulk power system expenditures, including capital and operating costs for generation, storage, and transmission.[29] We calculate the average system cost for each year, which is the annualized cost of these components divided by annual electricity demand. This is somewhat analogous to a wholesale cost of electricity and does not include several other costs (e.g., distribution and administration)—and therefore does not reflect the total cost seen by consumers and cannot be directly compared with retail electricity prices.[30] Nonetheless, the reported average system cost provides an internally consistent measure to compare how estimated costs change over time and between scenarios, and these cost *differences* can be compared with historical changes in retail prices. The average system cost is calculated for each year—in real terms and on an undiscounted basis.

Separately, cumulative net present values of costs and benefits between 2023 and 2035 are also calculated by summing and discounting the total annual costs, using a 2.5% real discount rate based on the Interagency Working Group on the Social Cost of Greenhouse Gases (IWG) (IWG 2021). Results using other discount rates are provided in Appendix A; changing the discount rate does not qualitatively change the findings.

The second component calculated is associated with mortality from long-term exposure to fine particulate matter ($PM_{2.5}$) from fossil fuel combustion in the electric sector. For each case, we

[28] Because we do not consider regional variations in BECCS fuel type, we assume a uniform fuel cost and emissions rate for all BECCS plants.
[29] It also includes the capital and operating costs for DAC and hydrogen production (e.g., electrolyzers). The value of hydrogen used in non-grid applications is based on the annual marginal cost of hydrogen production and is accounted for as a revenue for the electricity system cost metrics.
[30] The cost metric used reflects the *average* costs of electricity, in contrast to *marginal* costs reflected in wholesale prices from power markets, which also do not include all grid services. Therefore, costs reported here cannot be directly compared with historical energy prices from restructured power markets.

used estimates of the mortality risk per tonne of emissions from three reduced complexity air quality models (AP2, EASIUR, and InMAP).[31] Each of these models estimates $PM_{2.5}$ formation associated with emissions of precursor pollutants (NO_x and SO_2). To generate annualized premature mortality, the models apply concentration response function models from two studies which link exposure to $PM_{2.5}$ to increased mortality risk. These are abbreviated ACS (from an American Cancer Society Study) and H6C from the Harvard Six-Cities study (Gilmore et al. 2019). Total emissions are multiplied by the mortality risk per tonne of pollutant to get total mortality, with a range of results across the different combinations of air quality model and concentration response function. We show the mortality results for the entire set of models, but for the final benefit-cost analysis we use the most conservative model which combined ACS and EASIUR, which produces the lowest mortality rates and therefore the lowest benefit associated with cleaner air.

Annual premature deaths from air pollution are translated into a monetary value by applying a value of a statistical life, using the U.S. Environmental Protection Agency's estimate of $7.4 million in 2006 dollars (EPA 2022) inflated to a present-day dollar value ($9.9 million in 2021 dollars). These costs can then be translated into costs per unit of generation and cumulative (discounted) cost over the study period. Air quality benefits associated with electrification or in other sectors (such as transportation, buildings, and industry) are also not considered.

The third component is associated with damages from GHG emissions and is evaluated using the social cost of carbon (SCC). The SCC represents an estimate of the future damages of climate change caused by a marginal increase in GHG emissions. It is commonly measured in terms of cost per unit of emissions (e.g., $/tonne CO_2). This estimate requires several major steps, each with significant uncertainty. First, it requires estimating the future emissions trajectory and the response of global climate to additional emissions. Then it requires estimating the impacts of various degrees of climate change on reduced agricultural output, human health (mortality/morbidity), economic growth, and other factors. Finally, these impacts must be translated into a total economic value, considering many components, such as the value of a statistical life and the degree to which future impacts should be discounted. The choice of discount rate is contentious, but it is generally agreed that intergenerational discount rates should be lower than discount rates used for shorter-term decision-making (IWG 2021).

The IWG produced SCC estimates in 2013 (IWG 2021); later values from 2016 and 2021 update the original 2013 values based on inflation. Recent studies report higher SCC estimates than the IWG; updated estimates of human mortality (Bressler 2021) and uncertain but potentially catastrophic climate "tipping points" (Cai et al. 2016) could increase the SCC further. Figure 6 shows examples of several SCC values, demonstrating a large difference between the highest and lowest value for emissions occurring in 2020. Given the large uncertainty in SCC, we present costs using two values. The lower estimate value uses the IWG (2.5% discount rate) value, which is about $80/tonne in 2020 and increases to about $100/tonne in 2035 (teal line). The higher estimate uses a constant value of $275/tonne (green line) from Pindyck (2019). Total emissions in each scenario are multiplied by the marginal SCC for a total cost impact in each year. As with

[31] Additional description of the models and the data sources used for this study is provided at https://www.caces.us/data.

the other two cost components (direct electricity costs and health costs), SCC can then be translated into costs per unit of generation and cumulative (discounted) cost over the study period.

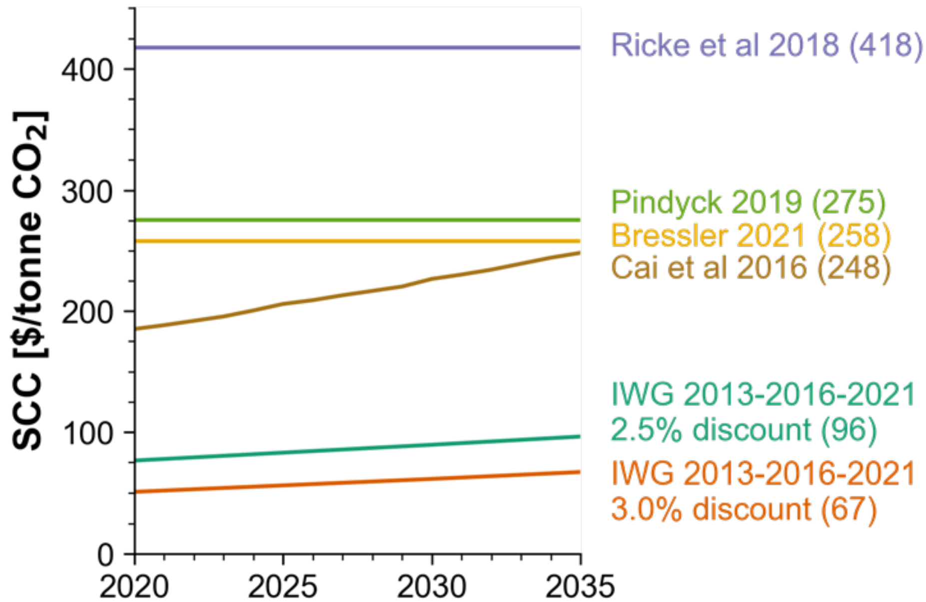

Figure 6. Examples of the large range in estimates of SCC.

Values in parentheses indicate the SCC from the relevant source in 2035.

Finally, we estimate the benefit-cost ratio over the study period. The benefits are calculated as the sum of (1) the difference in cumulative health impacts between the 100% clean electricity scenarios and the Reference-ADE scenarios and 2) the difference in cumulative SCC impacts between the 100% clean electricity scenarios and the Reference-ADE scenarios. The cost is the difference in cumulative power system costs between the 100% clean electricity scenarios and the Reference-ADE scenarios. Overall, a limited set of costs and benefits are evaluated in this work, as highlighted in the following section.

2.4 Key Caveats

Although ReEDS is designed to model many aspects of the power grid, the large scope of the model necessitates simplifications. One limitation of ReEDS is that its scope is limited to the bulk power system and the model does not directly consider an economywide optimization.

The ADE trajectory assumes electrification plays a very large role, consistent with other recent literature. But there is uncertainty about the degree of electrification, which this study does not seek to resolve. The LTS scenario represents a demand pathway that does not use as much electrification and can be a proxy for any other non-electrification heavy scenario of decarbonization. But additional economy-wide analysis would be required to assess optimal portfolios across the entire economy. For example, the non-electricity costs and benefits associated with electrification and demand-side changes (e.g., costs of electric vehicles and avoided gasoline expenditures) are outside the study scope. Similarly, we do not include analysis of the evolving workforce needs for the transition described in this work, or how some clean energy pathways may be more compatible with the existing workforce. We also do not consider repurposing existing fossil infrastructure that could reduce system costs, beyond retrofits of existing generators to run on clean hydrogen. Other economy-wide impacts such as manufacturing requirements and trends, and international trade balance are not considered. Broader national and regional benefits, such as national security and many aspects of environmental justice, including distributional aspects of costs and benefits, are also not considered.

Within the power sector, this study does not consider the costs or impacts related to changes that may occur on the distribution system; for this study, a single, predetermined projection is used to specify rooftop PV capacity by region and year in all ADE scenarios explored. Additional research is needed to understand the opportunities and operational impacts of widespread deployment of distributed generation in 100% scenarios. Electricity demand profiles and demand flexibility are also determined outside the model framework. There are many factors that could result in substantial changes in electricity demand patterns not considered here. These include the impacts of climate change and extreme weather, changing work patterns resulting from the COVID-19 pandemic, and other social and macroeconomic factors.

Though ReEDS considers a large range of supply-side technologies, it does not represent all possible technologies that may be important in decarbonized energy systems. In particular, it represents a small subset of possible energy storage technologies and fuel production pathways, and it does not include all generation technologies that might be deployed by 2035. Therefore, results should be interpreted as representative but not determinate, as a variety of solutions may be cost-competitive. Though the model includes a variety of factors that can restrict development of individual technologies, including cost, siting restrictions, access to transmission, and contribution to resource adequacy, it does not consider limits to growth that could result from supply chain issues, financing, and local or regional factors. It also does not consider the interaction of resource limits that could result from competition from other sectors, such as the supply of critical materials. Likewise, fossil fuel prices are based on AEO projections and do not consider the additional impact of significant reduction in the demand for these fuels in the 100% clean electricity scenarios.

Like all national-level models, ReEDS does not model specific transmission rights-of-way with detailed AC power flow simulation; transmission is modeled as aggregated regional transfer capacities with controllable flow.[32] Additional intraregional network reinforcement would also be needed given the high degree of electrification that is assumed here, but this is not modeled in ReEDS. Though ReEDS performs detailed calculations to estimate the ability of the various scenarios to provide resource adequacy and operating reserves, it does not perform a comprehensive assessment of all aspects of reliability and resilience. Future analysis using detailed unit-commitment, economic dispatch, probabilistic outages, and contingency analysis will be needed to validate findings from this work. Lastly, ReEDS applies a systemwide least-cost planning approach across all technologies that may not fully reflect investment decisions

[32] This results in increased utilization of transmission assets compared to today's grid, which could be accomplished using flexible AC transmission components (see Text Box 3 in Section 3.7.)

made in response to competitive wholesale markets or regional, state, and local planning decisions.

The ReEDS model is used to calculate a variety of costs and benefits represented in Step 3 (Figure 1, page 3). The primary cost metric considers impacts on the bulk system, but because it does not evaluate the distribution network, total costs seen by end consumers are not calculated. Analysis of overall energy burden and electricity rate impacts, including analysis of new rate structures that could potentially unlock demand flexibility, will be an important component of future work when assessing policy options. Benefits analysis includes direct energy-sector GHG emissions that result from fossil-fuel combustion and methane leakage but does not include other life cycle GHG emissions associated with electricity production or emissions from agriculture and other land use (except BECCs). The benefits analysis associated with improved air quality is also limited to premature mortality from only the electric sector and therefore does not assess the benefits from emissions reductions in other sectors—such as industry and transportation—or include other benefits such as reduced morbidity, changes to hospitalizations, or ecosystem damage. Previous work has found that accounting for mortality results in the largest component of monetized benefits (EPA 1999; NRC 2010) and that $PM_{2.5}$ exposure is the driver of 90%–95% of all mortalities related to air pollution (Tessum, Hill, and Marshall 2017; Tschofen, Azevedo, and Muller 2019). So, we likely capture most of the monetized benefits related to air quality improvements related to power sector decarbonization with this method, though other additional benefits not estimated here may have more salience in particular communities. In addition, while some aspects of land use changes are modeled, several other environmental impacts, such as potentially reduced water use or localized ecosystem changes, are not.

Text Box 1. Capacity-Related Terms Used in This Report

Capacity (also “nameplate capacity” or “peak capacity”) generally refers to the rated output of a power plant when operating at maximum output. The capacity of individual power plants is typically measured in kilowatts (kW) or megawatts (MW). The cumulative capacity of systems is often measured in gigawatts (GW) or terawatts (TW). Capacity of power plants is typically measured by their net AC rating, and we use this standard in this report.

Capacity factor (%) is a measure of how much energy is produced by a plant compared to its maximum output. It is calculated by dividing the total energy produced during some period by the amount of energy it would have produced if it ran at full output over that same period.

Capacity credit is a measure of the contribution of a power plant to resource adequacy, meaning the ability of a system to reliably meet demand during all hours of the year. It is measured either in terms of capacity (kW, MW) or as the fraction of its nameplate capacity (%), and it indicates the amount or portion of the nameplate capacity that is reliably available to meet load during times of highest system stress—typically the highest net-load hours of the year. Capacity credit may also be referred to as capacity value, but the latter term sometimes refers to the monetary value of physical capacity (Mills and Wiser 2012).

Firm capacity refers to generation capacity with high capacity credit. Note that capacity credit, and therefore the ability of a resource to provide firm capacity, may vary substantially as a function of location and amount of deployment. For example, the capacity credit of a PV plant may be high at low levels of deployment (meaning it can provide significant firm capacity) but drop as increased solar deployment results in demand peaks that shift to periods later in the day or across seasons. Likewise, the ability of storage to provide firm capacity can change substantially depending on the mix of resources deployed.

Text Box 2. The Three Rs: Resource Adequacy, Operational Reliability, and Resilience

There are multiple aspects to maintaining a reliable power grid.

Resource adequacy represents planning for the system's ability to supply enough electricity—at the right locations—to keep the lights on, even during extreme weather days and when "reasonable" outages occur. An adequate system has sufficient spare capacity to replace capacity that fails or is out of service for maintenance. Resource adequacy is measured by the probability of an outage over an extended period. Increasingly, it must account for the variability of renewable energy supply, the role of storage, and changes in demand patterns.

Operational reliability represents the ability of the power system to balance supply and demand in real time by managing variability, ramping constraints, and flexible loads. This includes immediately following an "event" like a large power plant or transmission line failure. A reliable power system can keep the lights on during these unexpected events with power plants that can rapidly vary output or end-users that can reduce their electricity consumption. Maintaining operational reliability with growth in inverter-based resources is an important element of the power sector transition. This study assumes continued growth in smart inverters along with the use of new generators to provide services such as voltage support and frequency response.

Resilience represents the power system's ability to withstand and reduce the impact of disruptive events. This has overlap with the other aspects of reliability; however, a unique aspect is related to system recovery, or how quickly power can be restored after an outage. This study considers resource adequacy and operational reliability by maintaining adequate capacity (including weather variability) and operating reserves; however, it does not directly assess the resilience of the projected systems.

3 Scenario Deployment Results

Regardless of generation mix, achieving 100% clean electricity by 2035 will require installing generation resources at an unprecedented rate.

Figure 7 shows the generation *outputs* (results) from the model, showing the total electricity generation among the scenarios. This is equal to the demand shown in Figure 2 (page 5), plus additional electricity required to account for losses in transmission, distribution, and storage, along with the electricity used to produce hydrogen fuel and for DAC—all of which vary by scenario.

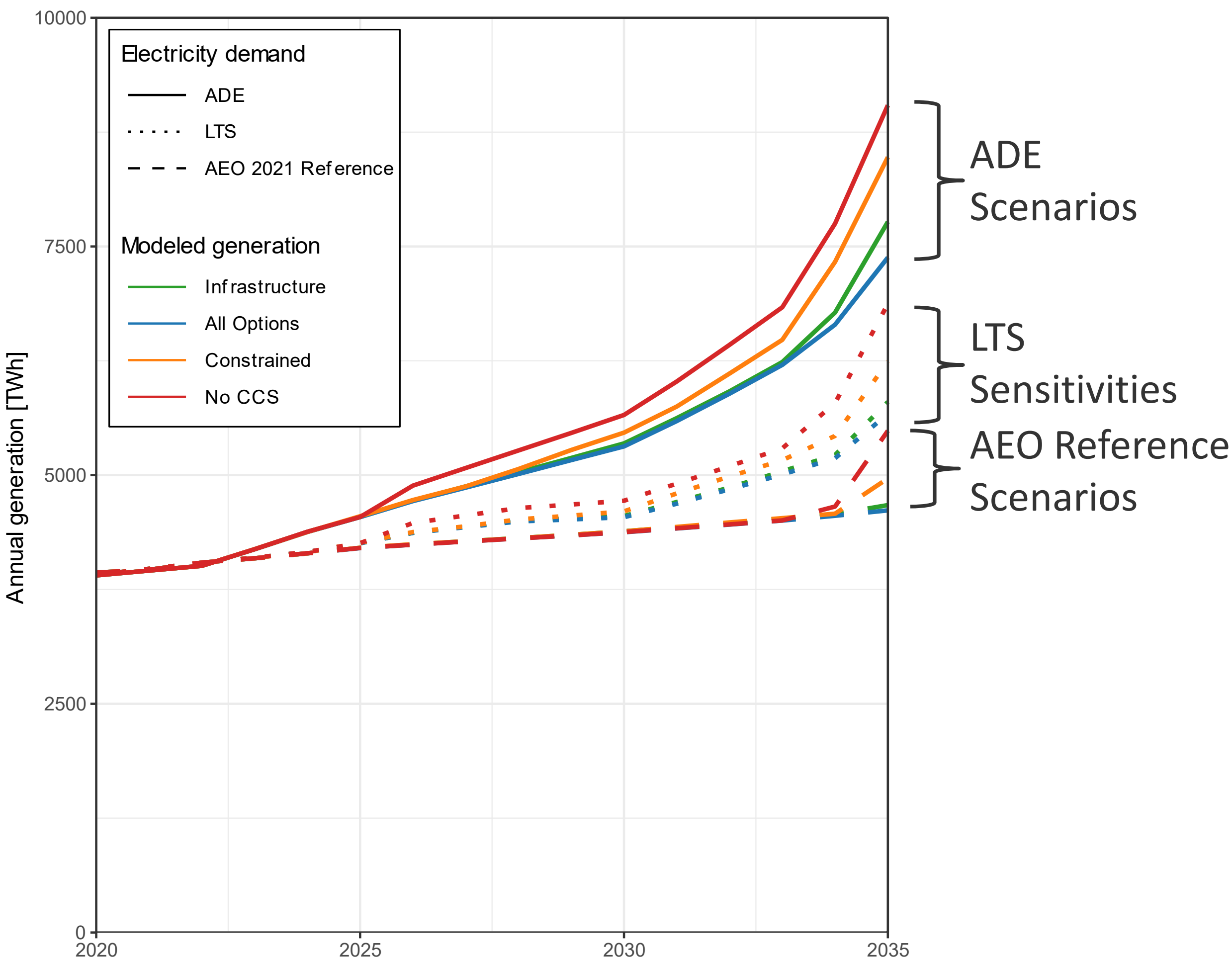

Figure 7. Total annual generation for each of the four pathways exceeds end-use electricity demand because of transmission/distribution/storage losses and electricity use for hydrogen production and DAC.

Differences in generation are associated with the availability of various technologies, including greater electrolytic hydrogen production when CCS is not available.

Figure 8 shows the contribution by resource in 2035 in the core scenarios using the ADE demand trajectory; the 2020 mix is shown for reference. The top chart shows total electricity provided by each major resource category. Wind and solar produce most (60%–80%) of the generation in the least-cost energy mix for each of the main scenarios in 2035. Nuclear provides 27% of generation in the Constrained scenario and 9%–12% in the other three core scenarios. The wind and solar shares of generation varies among the four main scenarios, and they are sensitive to cost and transmission constraints. The bottom chart shows the total installed capacity by resource, including energy storage. Differences in the capacity mix for the remaining resources is driven largely by assumptions about technology availability, particularly related to CCS and negative emissions technologies.

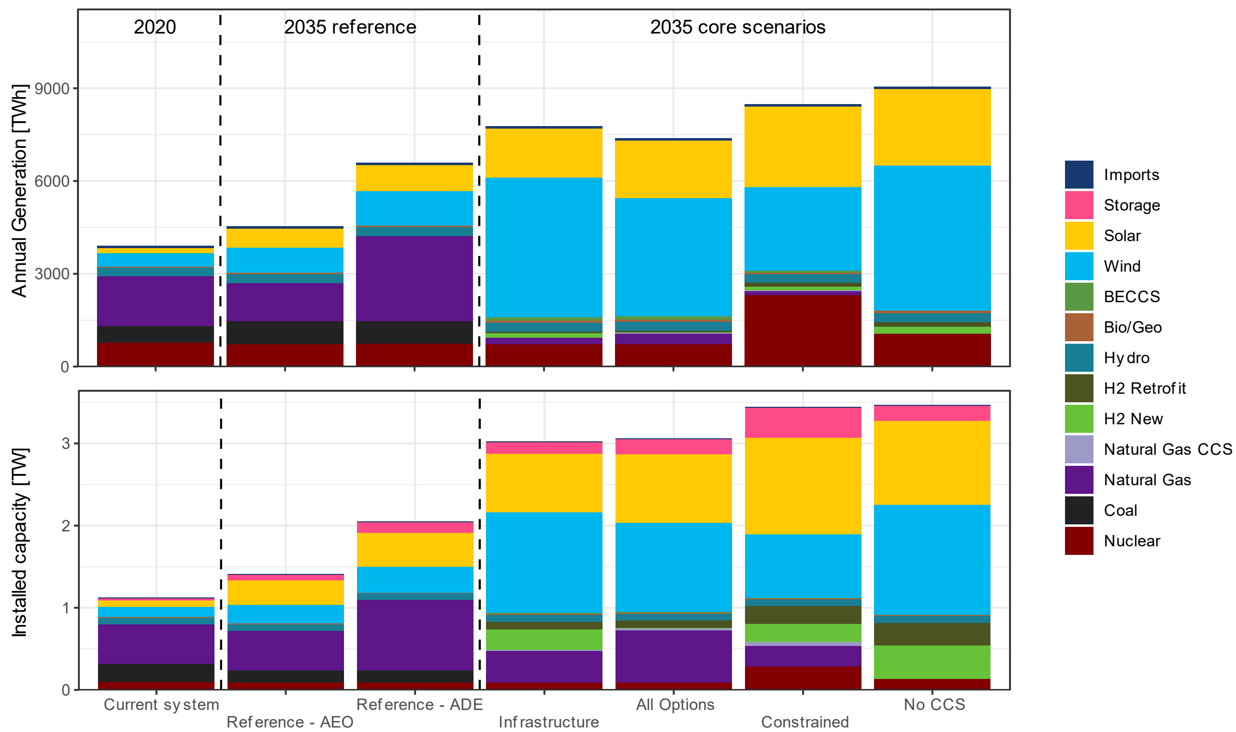

Figure 8. Energy and capacity contribution by resource in the main scenarios in 2020 and 2035 (ADE demand case) demonstrates large growth in several clean energy technologies.

Imports are from Canada, largely hydropower imports into the Northeast. Bio/Geo = conventional biopower such as wood waste, landfill gas, and geothermal. Natural gas includes CT, CC, and older oil and gas-fired steam plants, which are tracked individually but combined for reporting purposes. Solar includes all PV (utility-scale and rooftop) and CSP.

Figure 9 illustrates generation over time for the reference and 100% clean electricity cases. The assumed emissions trajectory (Figure 5, page 14) results in a rapid decrease in coal use, which produces significant near-term improvement in air quality, as discussed in Section 4.

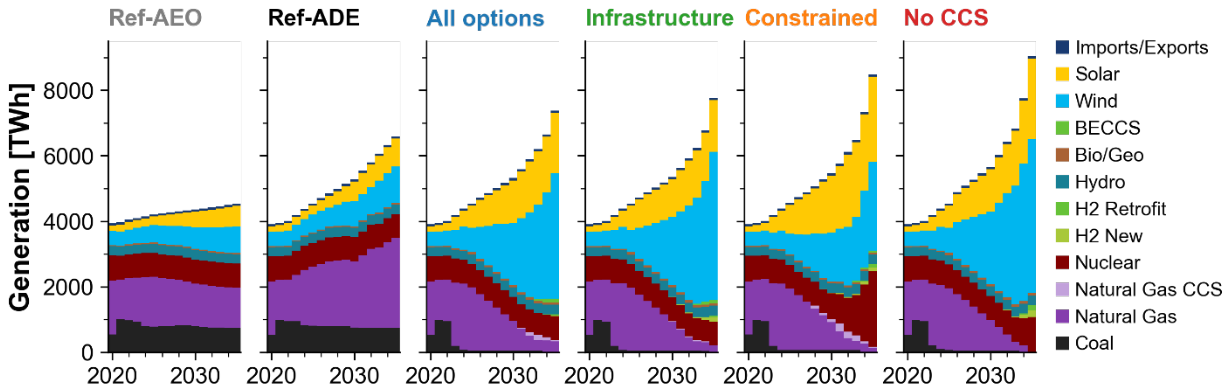

Figure 9. Generation by resource type over time demonstrates the rapid transition to clean energy resources.

We also modeled a wide range of sensitivities, and those results are provided in Appendix A. Figure 10 briefly summarizes the results across the 122 100% clean electricity sensitivity cases.

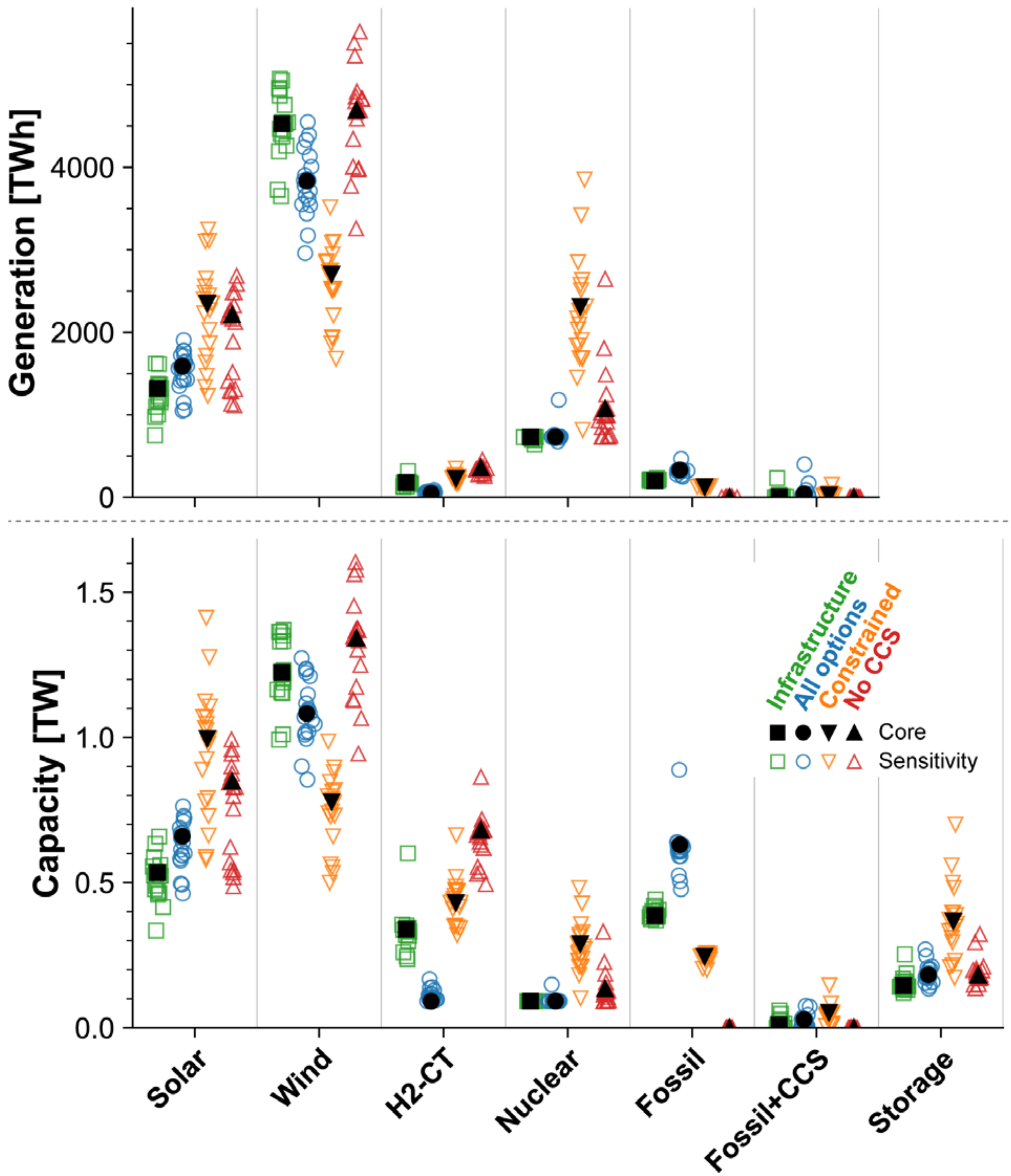

Figure 10. Capacity and energy contribution by resource in 2035 show significant wind, solar, and storage deployments in all 122 100% clean electricity sensitivity cases.

A wide range of potential resource mixes and a considerable range of deployments of technologies are used to meet the remaining balance of supply and demand. Black symbols are the four main scenarios (ADE demand case), and colored symbols show sensitivity cases.

All scenarios demonstrate large growth in wind, PV, and storage. However, there is a wide range of results for several other resources that are used to balance supply and demand and assist with maintaining resource adequacy—including fossil (offset with CCS), nuclear, and hydrogen-fueled combustion turbines. Figure 11 provides the total installed capacity between 2020 and 2035 for all 122 100% clean electricity sensitivity cases for seven technology classes.

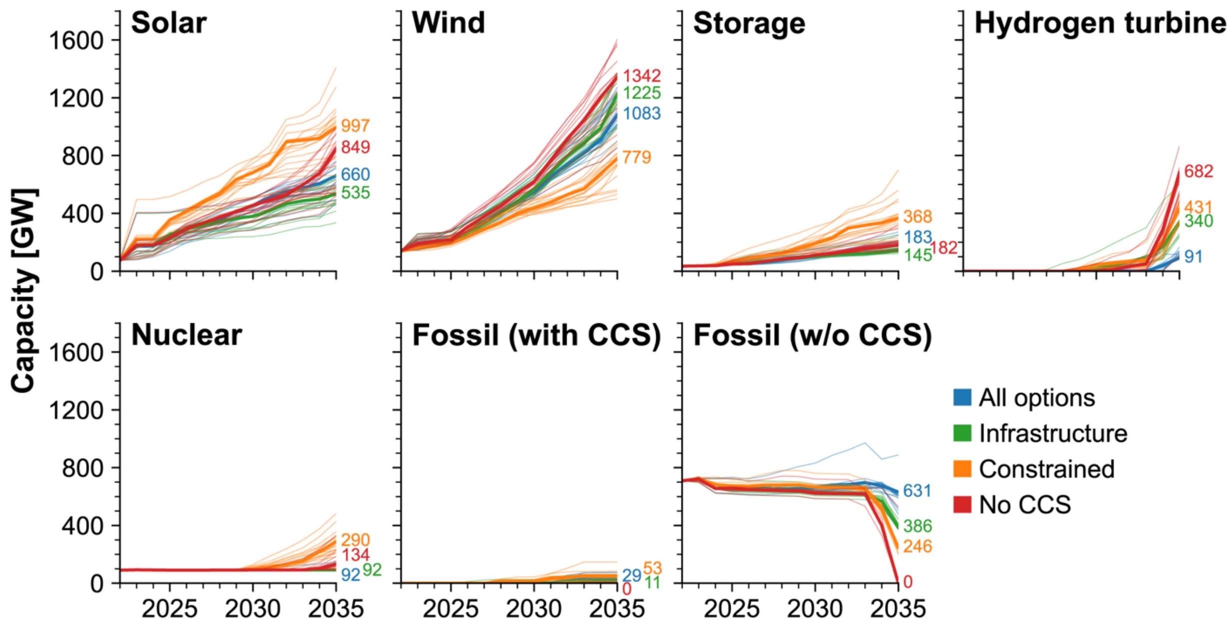

Figure 11. Annual growth in capacity of seven technology classes across all 122 clean electricity sensitivity cases.

Core scenarios (ADE demand case) are indicated by thick lines, with 2035 values labeled; sensitivity cases are indicated by thin unlabeled lines.

Growth from 2021 to 2030 is largely in solar, wind, and storage to provide large amounts of energy and reduce emissions from existing fossil plants. Beyond 2030, new wind, solar, and diurnal storage contribute little to meeting the growing peak demand or during periods of low wind and period output. As a result, increased growth in other technologies that contribute more to system resource adequacy occur during this period. Figure 12 (page 26) shows the annual installation rate across the main scenarios, where the annual results are shown as 5-year averages. [33]

This growth will require significant growth in existing supply chains and development of supply chains for new technologies and fuels, including adequate development of raw materials and financing. Challenges to installing this capacity include lead times for construction and workforce development for both manufacturing and installation. Market, policy, and regulatory design will also need to keep pace with this rapid growth in clean energy generation. Additional

[33] The ReEDS model solves for each year. However, we show 5-year averages, as the actual yearly installations will likely vary substantially. The key takeaway is that large and sustained growth is required.

discussion of the major technologies, including comparisons to historical and international growth rates, is provided below.

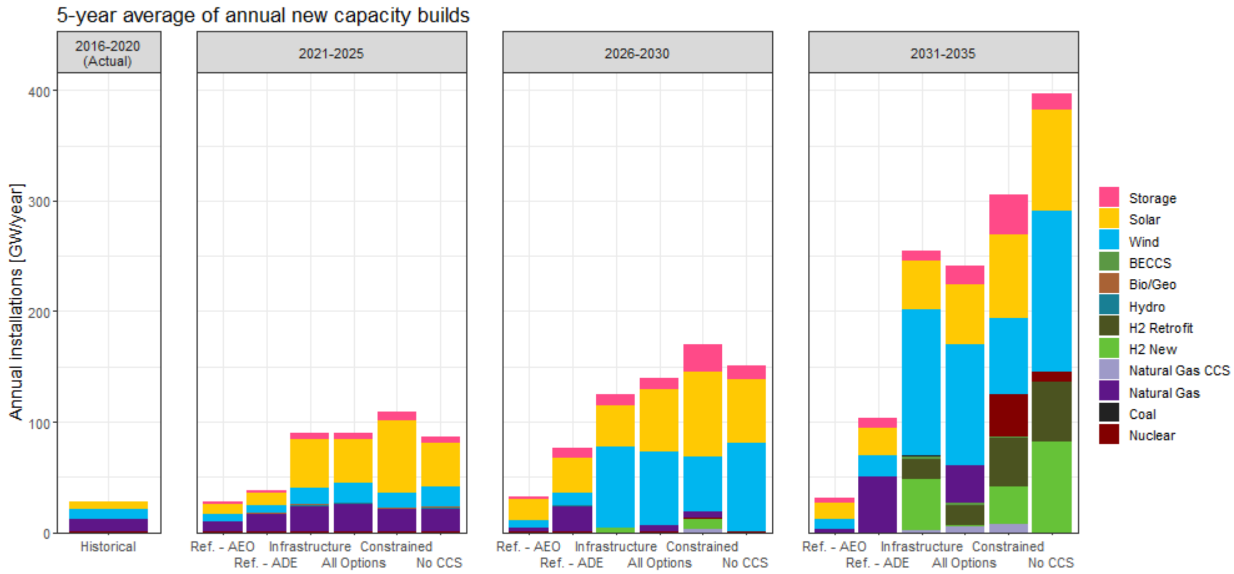

Figure 12. Annual growth in capacity in the main scenarios (ADE demand case).

Initial growth is primarily wind, solar, and storage. In later years, large clean peaking capacity is needed to reach 100% by 2035 while maintaining reliability, including hydrogen-fueled combustion turbines and natural gas (offset by negative emissions technologies).

3.1 Wind

There is significant growth in wind across the four main scenarios, which is enabled by assumed continuing cost declines and improved performance due to factors such as increased hub heights—capacity factors as high as about 55% are achieved in high-quality resource regions (NREL 2021) (see Appendix B for details). Access to high-quality wind is also significantly enabled by new transmission.

Figure 13 shows the installation rates for wind in the core scenarios. Over the 10-year period from 2026 to 2035, the average annual installation rate exceeds 60 GW/year in all core scenarios and is about 88 GW/year in the All Options scenario. This is about 6 times the U.S. installations in 2020 (14.2 GW—the highest to date) (EIA 2021b) and 1.4 times the installations in China in 2020 (52 GW) (Wiser et al. 2021). Worldwide wind installation in 2020 was about 93 GW (Wiser et al. 2021).

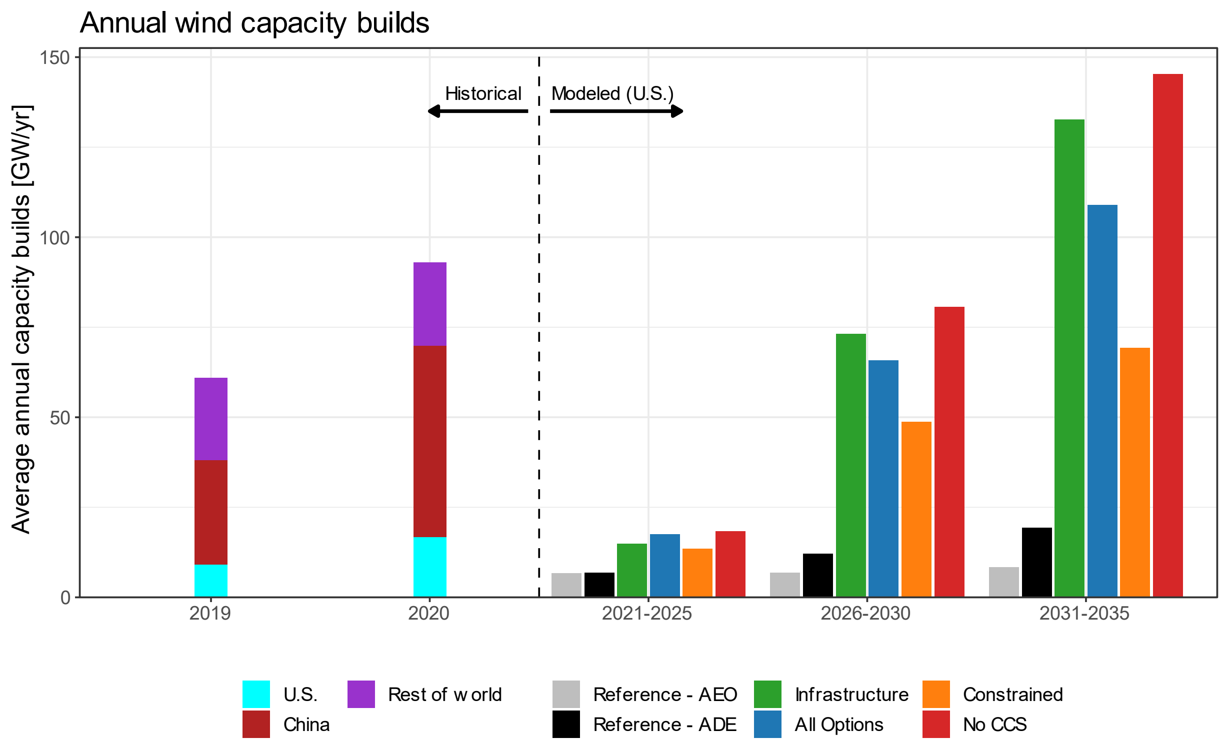

Figure 13. Growth in wind across the four main scenarios (ADE demand case) ranges from 60 to 160 GW/year by the end of the decade.

This growth will require increasing installation rates by a factor of about 5–11 times that of 2020 installations, or about 80% to 160% of worldwide installations in 2020.[34]

Most deployments are land-based wind. Though the United States has significant resource potential (4 TW) (NREL 2022d), the U.S. offshore wind industry is at a nascent stage, with 42 MW operating in 2020. However, nearly 33 GW of offshore wind has been installed globally, including in European markets with over a decade of experience and in rapidly growing markets in Asia (Musial et al. 2021). Additionally, the U.S. offshore wind project pipeline—including projects at various stages of permitting and approval—recently surpassed 35 GW, reflecting significant interest and ambitions primarily driven by state energy policies (Musial et al. 2021) and increasing cost-competitiveness (Wiser et al. 2021). Moreover, the Biden administration announced a national target of 30 GW of offshore wind capacity by 2030 (White House 2021b).

Other drivers of interest in offshore wind include its potentially higher capacity factor and capacity credit and proximity to load centers, which might reduce transmission requirements and mitigate land-use conflicts. Although current deployment largely focuses on fixed-bottom applications, future technology and supply chain advancements, including floating offshore wind, could enable deployment in more U.S. regions such as the Pacific Coast and the Great Lakes (Lantz et al. 2021).

[34] Historical wind installations from GWEC (2021).

3.2 Solar

The scenarios consider deployment of both utility-scale and rooftop PV (with 190 GW of rooftop PV deployed by 2035; see Section 3.8 for discussion of the role of distributed resources). Costs are assumed to decline by 14%–44% by 2030 (NREL 2021), and by 2035 PV contributes 20%–36% of total electricity supply and is the largest generation resource in the Constrained scenario.[35] Scenarios also add 25–50 GW of CSP capacity (with integrated thermal storage) by 2035, and achieving Solar Energy Technologies Office cost targets (Ardani et al. 2021) could increase its contribution, with the low-cost CSP sensitivity resulting in 36–210 GW of installed CSP capacity in 2035.

Figure 14 shows the installation rates for PV in the main scenarios. Over the 10-year period from 2026 to 2035, the average annual installation rate is at least 40 GW/year. The annual installation rate over this period in the All Options scenario (56 GW) is nearly four times the U.S. installations in 2020 (15 GW—the highest to date) (Wiser et al. 2021; Feldman Wu, and Margolis 2021), and about 1.5 times the installations in China in 2020 (37 GW) (Feldman Wu, and Margolis 2021). Worldwide PV installation in 2020 was about 107 GW (Feldman Wu, and Margolis 2021).[36] As with all other generation technologies, this represents nameplate AC output and assumes a DC/AC ratio of 1.3.[37]

[35] The overall solar capacity in the four main scenarios range from 540 GW to 1,000 GW, which is similar to the 760 GW and 1,000 GW projected in the two main Solar Futures Study scenarios (Ardani et al. 2021).
[36] Estimates of AC PV capacity in China and worldwide are based on DC capacity with a 1.3 DC/AC ratio.
[37] The trend in DC/AC ratios may increase, particularly with deployment of DC-coupled hybrid PV plus storage plants (Seel et al. 2022).

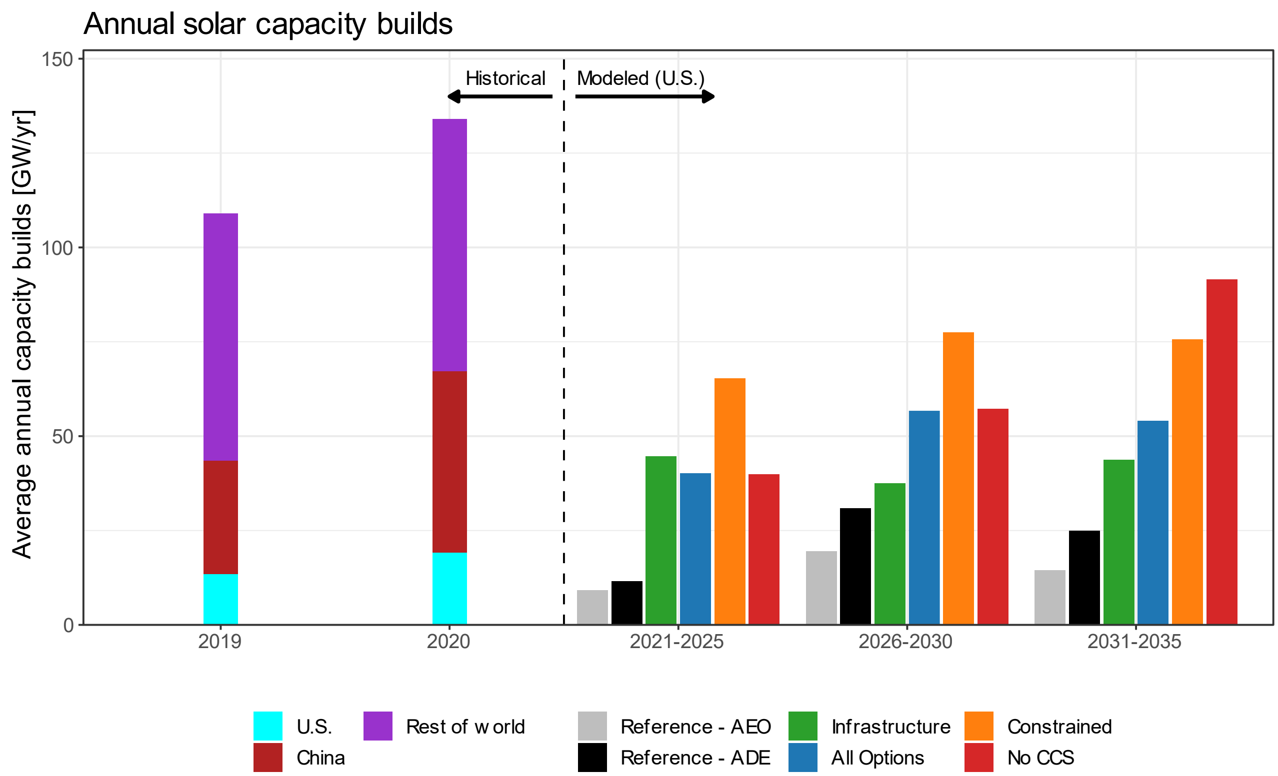

Figure 14. Growth in solar across the four main scenarios (ADE demand case) ranges from 25 to 120 GW/year by the end of the decade.

This will require increasing installation rates by a factor of about 2–8 times that of 2020 U.S. installations, or equal to about 25% to 110% of worldwide installations in 2020.

3.3 Geothermal, Hydropower, and Biopower

Several other renewable resources play an important role in providing energy and firm capacity in the scenarios studied.

Figure 15 (page 30) shows the growth in geothermal and hydropower resources. Core scenarios add about 8 GW of new geothermal capacity based on assumed declining costs and its high capacity credit, while sensitivity cases with aggressive cost reductions (see Appendix B) demonstrate the potential for much greater growth (DOE 2019). Existing hydropower continues to be a key source of energy capacity, and across all scenarios 5–8 GW of new hydropower is deployed by 2035 based on opportunities for adding capacity at unpowered dams and uprates at existing facilities (DOE 2016a).

Several biomass- and biofuel-based pathways are also available. Liquid biofuels such as ethanol and biodiesel could also be used as a renewably derived fuel in new or retrofit combustion turbines; however, we assume these fuels will be more valuable in transportation applications. We consider use of solid fuel biomass resources in Section 3.6.2, primarily as a potential source of negative emissions to help offset remaining fossil resources used to meet peak demand.

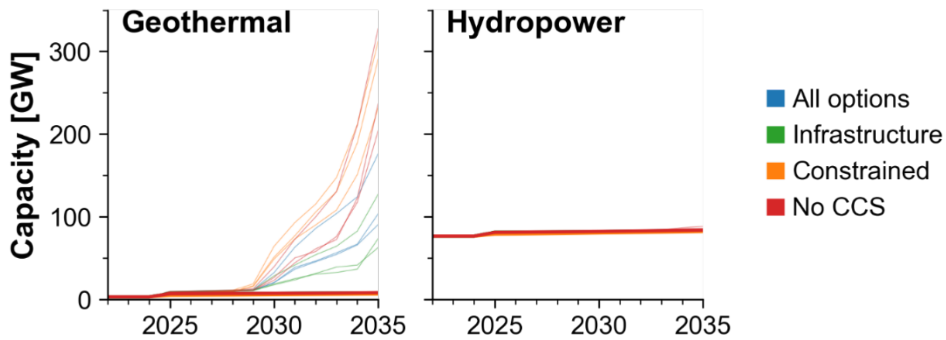

Figure 15. Growth in geothermal includes about 8 GW of new capacity in all scenarios, with much greater growth in sensitivity cases with low-cost geothermal.

Sensitivity cases include aggressive cost reductions for deep enhanced geothermal systems, as summarized in Appendix B. Hydropower adds about 5–8 GW across all scenarios. Core scenarios (ADE demand case) are indicated by thick lines; sensitivity cases are indicated by thin lines.

3.4 Nuclear

New nuclear is allowed to be constructed in the model starting in 2030, with no siting restrictions in any scenarios except the Constrained scenario, where new nuclear is not permitted in the 11 modeled states where new deployment is currently restricted (NCSL 2021).[38] An existing nuclear power plant that has not yet announced a retirement date is given an 80-year maximum lifetime.[39] The scenarios include about 3 GW of new nuclear demonstration plants, which are potentially more cost-competitive than current technologies (Nuscale 2022; Office of Nuclear Energy 2020a).[40] However, the cost assumptions used in the core scenarios do not expect that research and development efforts will yield significant cost improvements for plants completed before 2035 (costs start at $6,200/kW in 2020 and decline to $5,600/kW by 2035). As a result, there is no significant growth in All Options and Infrastructure Renaissance. However, the No CCS scenario adds about 40 GW of new nuclear (Figure 16); in the Constrained scenario, the restrictions on renewable energy and transmission deployment make nuclear more cost-competitive, and the model builds about 200 GW of new capacity by 2035, even with modeled restrictions against deployments in 11 states. This would require about 40 GW/year of new installation if deployment starts by 2030. The maximum annual installation rate of nuclear in the United States (based on online date) was 10 GW in 1986 (EIA 2021c).

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[38] Though the study assumes no new policies, it is important to understand the potential impact of additional nuclear deployment that could result from elimination of siting restrictions. These changes could be driven by long-term waste solutions and new reactor designs that are safer and potentially offer increased performance, both of which may increase public acceptance.

[39] The only nuclear plants that retire between 2022 and 2035 under our 80 year license extension are the Palisades plant in Michigan and the Diablo Canyon plant in California.

[40] Advanced reactor demonstrations include sodium-cooled fast reactors, high-temperature gas-cooled reactors, and advanced light-water reactors at both small modular and micro-reactor scales at multiple locations.

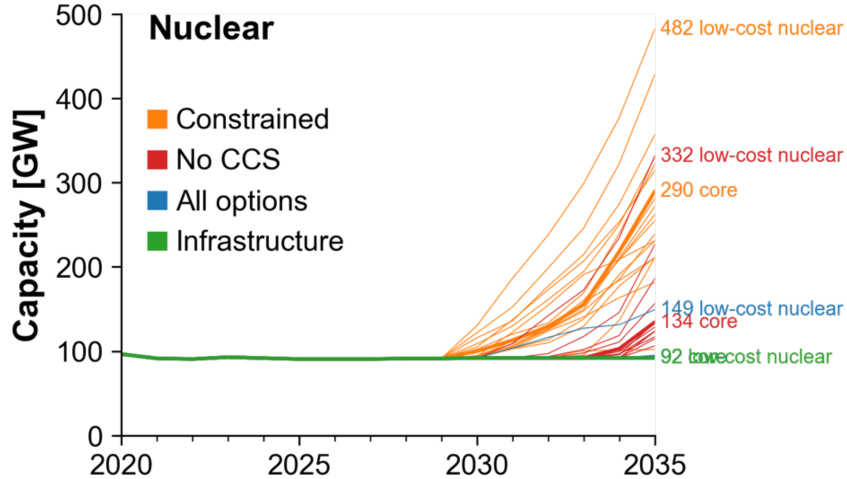

Figure 16. Growth in nuclear is largest in the Constrained scenario, adding about 200 GW.

Core scenarios (ADE demand case) are indicated by thick lines; sensitivity cases are indicated by thin lines.

A major focus of the U.S. Department of Energy (DOE) and industry is developing and demonstrating advanced reactor designs that can lower the costs, reduce construction times, and enhance the safety of nuclear power plants.[41] The low-cost nuclear sensitivity cases which feature advanced technologies such as small modular reactors, achieve costs of $4,500/kW by 2035) and demonstrate significant growth potential, as seen in Figure 16.

3.5 Diurnal Energy Storage

Energy storage is used to shift the supply of generation to better align with demand and provide a source of firm capacity. Nearly all capacity deployed in the grid to date (largely in the form of pumped storage hydropower, but increasingly batteries) has been in the form of diurnal storage, with durations of 2–12 hours (meaning a fully charged system discharge at rated output for this length of time).

Though we base cost and performance assumptions for diurnal storage on lithium-ion batteries and pumped storage hydropower [42] (detailed in Appendix B), this category could represent a variety of potential storage technologies currently in various stages of development and deployment, including alternative battery chemistries, thermal storage technologies, next-generation compressed-air energy storage, and novel gravity-based technologies. This also could include deploying new pumped storage designs that reduce land impact and do not interact with natural bodies of water (DOE 2016a; Koritarov et al. 2022). The U.S. Department of Energy has established the Long-Duration Storage Energy Earthshot with the goal of substantially reducing the cost of grid-scale energy storage, which could accelerate cost reductions of promising storage technologies (Office of Energy Efficiency and Renewable Energy 2021).

[41] For example, the Advanced Reactor Demonstration Program is supporting “two advanced nuclear reactors that can be operational within seven years” and “innovative and diverse designs with potential to commercialize in the mid-2030s” (Office of Nuclear Energy 2020b).

[42] Existing pumped storage is modeled as having 12 hours of capacity. Pumped storage is modeled with a supply curve to account for variations in available land, as detailed by Rosenlieb, Heimiller, and Cohen (2022).

Assumed cost declines, along with the increasing value of storage in enabling variable renewable generation, result in very large-scale deployment, as illustrated in Figure 17.

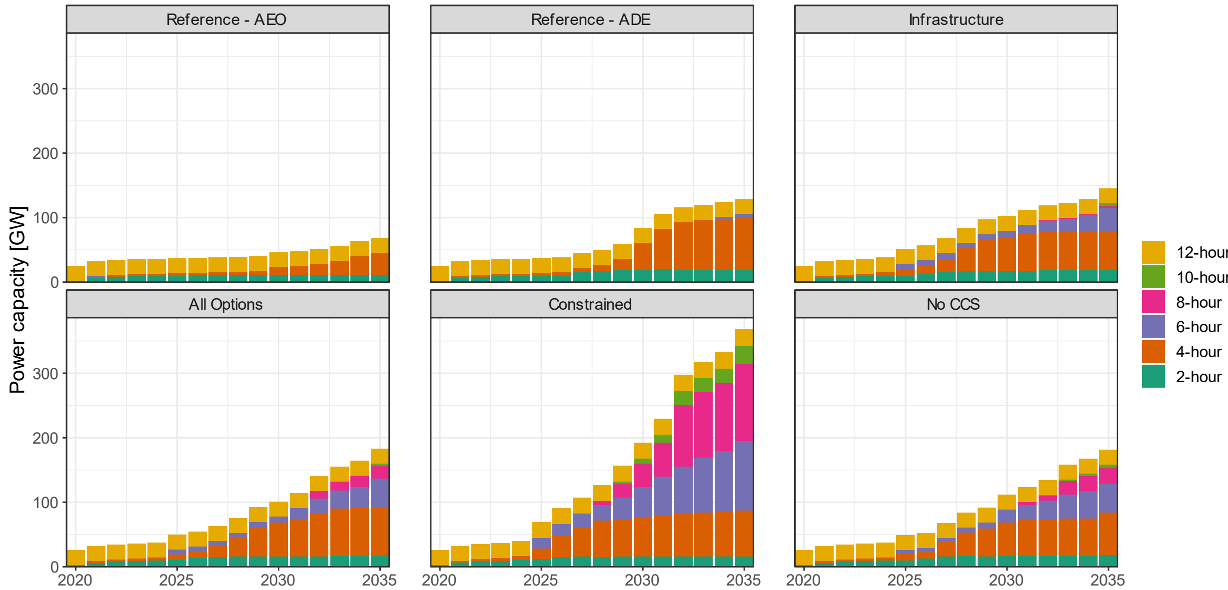

Figure 17. Cumulative diurnal storage deployment (ADE demand case; measured by power capacity) shows large-scale growth, with significant contribution from capacity with 4-hour durations used to meet the summer peaks and absorb surplus solar generation in the late morning and early afternoon.

Before 2030, the model tends to deploy capacity with durations of 2–6 hours. This follows previous analysis demonstrating that storage with this level of duration can help meet peak demand during hot summer days by addressing the mismatch in timing between peak solar output in the middle of the day and the demand peak in the early evening. Furthermore, storage with this duration is increasingly cost-competitive with gas turbines for providing peaking capacity (Frazier et al. 2021). As a result, even without specific targets for achieving emissions reductions, significant growth in storage is expected which explains in part the large growth in storage seen in the Reference-ADE case. The most significant growth of storage is in the Constrained scenario, where limited transmission and wind deployments lead to greater use of solar and dependence on storage to shift generation to address the diurnal mismatch challenge.

The average annual installation rate of stationary storage (measured by power capacity) from 2025 to 2035 is 10–30 GW/year, with peak installation rates in the range of 20–70 GW/year. In terms of actual battery production rates, the demand for electric vehicle batteries is much greater than for stationary (grid) storage, illustrated in Figure 18.[43] This shows the total storage capacity (measured in gigawatt-hours of stored energy) needed for stationary applications and for electric vehicles, based on the assumptions detailed in Appendix C. Estimated Li-ion battery

[43] These estimated amounts do not consider the potential opportunities for second-use applications where used electric vehicles batteries could be repurposed for stationary applications (Neubauer and Pesaran 2011; Reinhardt et al. 2019).

manufacturing capacity in 2020 was about 59 GWh in the United States and 747 GWh worldwide (FCAB 2021).

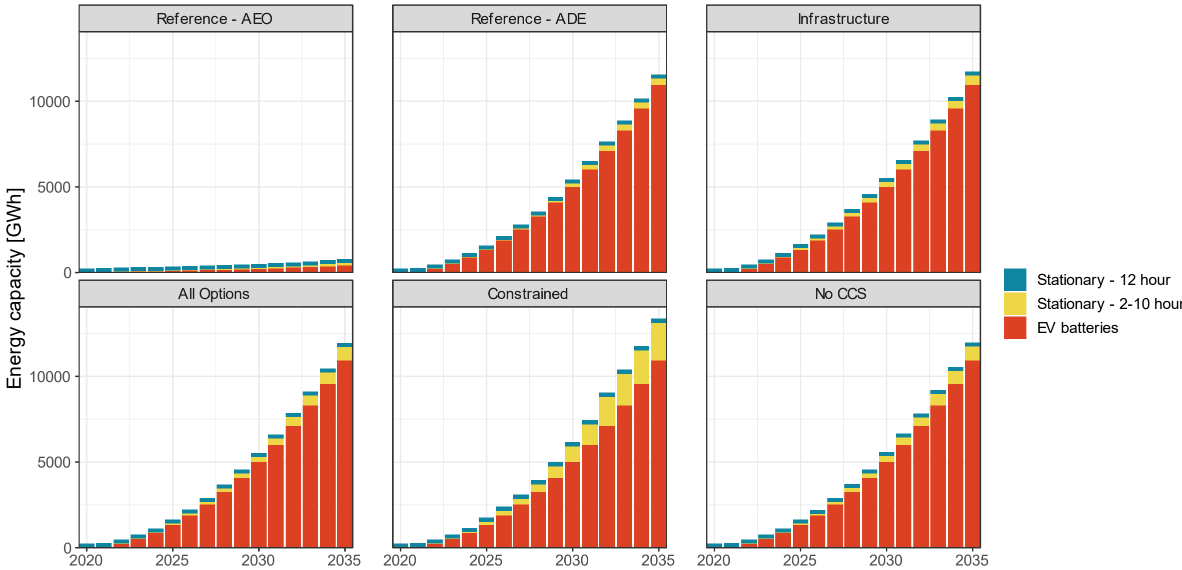

Figure 18. Cumulative storage deployment (ADE demand case; measured by energy capacity) shows electric vehicles as the main driver for growth in manufacturing capacity and overall battery demand on the path to economywide decarbonization.

These results do not include stationary battery storage or electric vehicle battery capacity that existed before 2021.

Beyond 2030, there is a gradual transition to deployment of longer-duration storage; however, solving the diurnal mismatch addresses most of the challenges of getting to high (but less than 100%) levels of clean electricity. Beyond a certain level of clean electricity in the range of 80%–95% depending on assumptions, we begin to see the challenges associated with the multiday to seasonal mismatch of variable renewable supply and demand. At this point, seasonal storage and other technologies begin to play a role, and the next sections discuss the significant deployment of seasonal storage that occurs in several scenarios.

3.6 Technologies That Help Address the Challenge of Seasonal Mismatch

Achieving 100% clean electricity will require addressing challenges associated with meeting demand during net load peaks. The term net load is defined here as the electricity load at a given point in time minus the contribution of variable generation resources to meeting load at that time. Net load peaks occur during periods of some combination of high demand and low renewable output, which increases the challenges of cost-effectively serving this demand with clean energy resources.

Figure 19, which shows the capacity and generation mix in 2035 in the All Options scenario, demonstrates the important role of the remaining fossil assets, which provide much of the capacity needed to meet peak demand on hot summer afternoons and during cold winter days but only a small amount of annual generation, which is offset through BECCS and DAC.

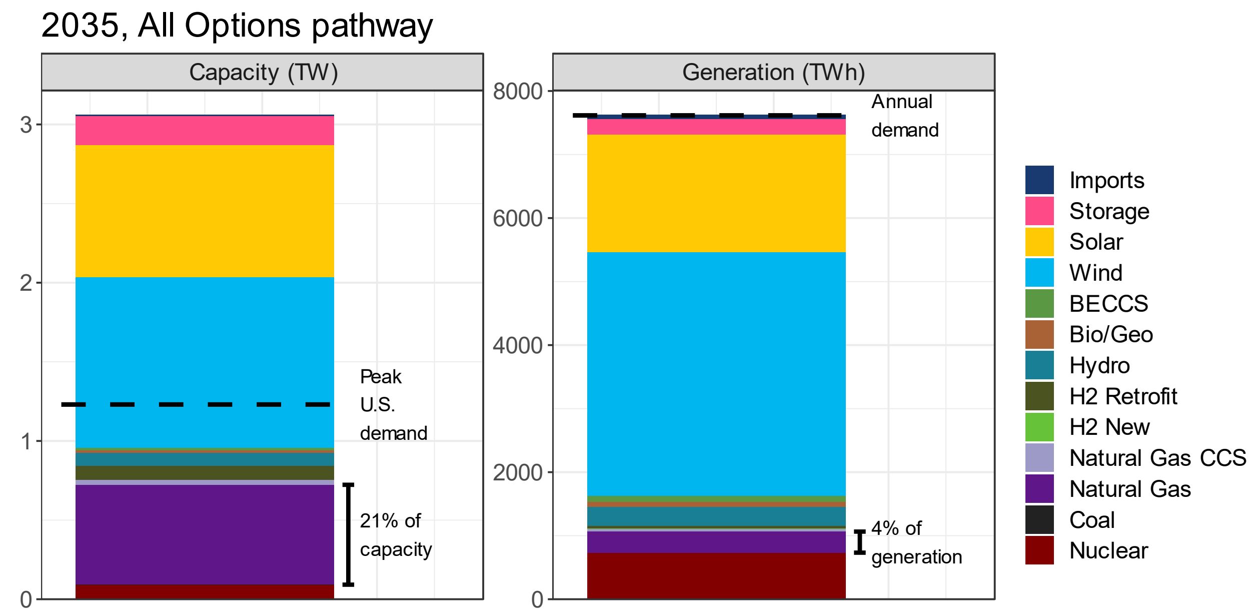

Figure 19. Energy and capacity in the 2035 All Options scenario (ADE demand case) show the significant dependence on remaining fossil-fueled capacity to provide peaking capacity and ensure resource adequacy during the clean energy transition.

About 21% of total capacity in the form of fossil generators without CCS operates as peaking capacity, providing about 4% of annual electricity demand, primarily during the hottest and coldest days of the year.

In this example, about 21% of the total system capacity provides about 4% of energy demand. This is similar to today's power system, where peaking plants represent a large fraction of the system's capacity but provide a small fraction of total energy, operating with low capacity factors (often well under 20%) (EIA 2022d). This low utilization is the main reason meeting peak demand inherently has higher than average costs: the capital and other fixed costs of this capacity must be recovered with less generation compared to plants that run more frequently. This low utilization favors plants such as natural gas combustion turbines, which have lower capital cost, and for which variable cost is of less importance.

Achieving complete decarbonization requires offsetting the carbon emissions of these remaining fossil assets, or replacing the primary service provided by these plants—which is a relatively small amount of energy on an annual basis, but it must be delivered exactly when needed. Generators serving this role must be able to provide reliable generation for multiple days during periods of lower wind and solar, and also during periods of extreme heat or cold. Because of lower utilization, plants with high capital costs (regardless of their variable costs) are at a particular disadvantage compared to plants with lower capital but higher variable costs in serving peak demand.

Another key challenge of achieving 100% clean electricity is the declining ability of many clean energy resources to economically serve this net peak demand because of the seasonal mismatch. As more variable renewable generation is added, net load peaks continue to shift to periods of low variable generation output, and more capacity is needed for each unit of usable output during the remaining net demand. This means the value of incremental deployments of variable generation declines rapidly as systems approach 100% clean electricity. This challenge is exacerbated by electrification—particularly electrification of space heating, which substantially increases peak demand in the winter, during periods of lower solar output.

Figure 20 shows the seasonal mismatch challenge using hourly results from the All Options scenario from 2035, when the system has reached 100% clean electricity. The hourly load (grey) shows the increased demand during the summer, as well as large (but shorter-duration) demand spikes in the winter, which create the new annual peak. The net demand in red shows the 6% of electricity demand met by fossil assets (with and without CCS) and other combustion resources (primarily hydrogen-fueled turbines) needed mostly in the summer and winter. It also shows the oversupply of renewable generation during much of the spring and fall (blue). This is due in part to transmission constraints, which explains the occurrence of both residual load and curtailment during many of the hours of the year when there is too much renewable generation in one location, too much load in another location, and not enough transmission capacity between them.

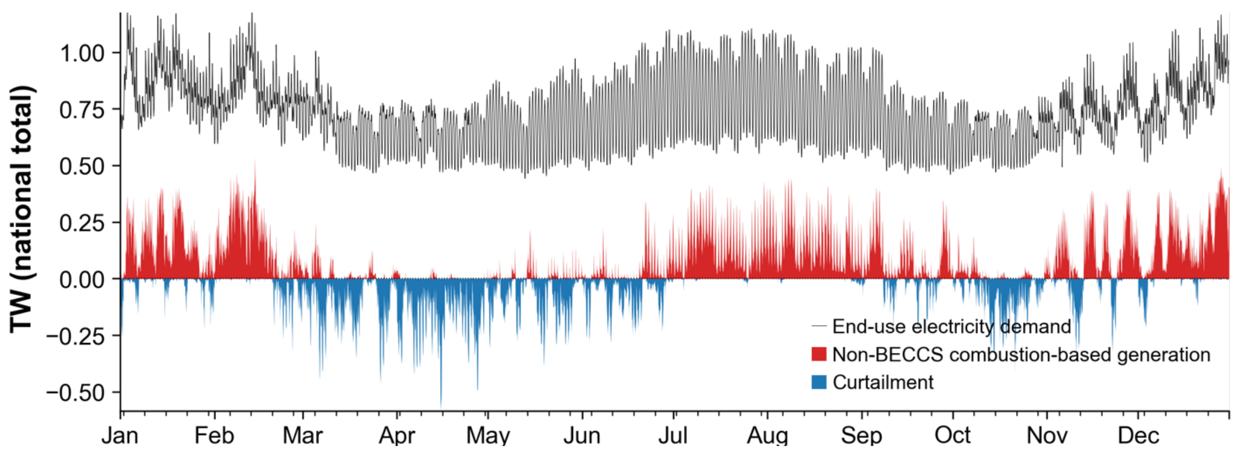

Figure 20. The seasonal supply/demand balance for the contiguous United States in the All Options scenario (ADE demand case) in 2035 shows the seasonal mismatch challenge.

Demand met by fossil- and hydrogen-fueled resources (red) occurs largely during periods of lower wind and solar output, or periods of very high electricity demand. The supply of wind and solar generally exceeds demand resulting in curtailment (blue) in the spring and fall, often for continuous periods. Additional wind and solar to provide energy in the summer and winter would have overall lower utilization, particularly as an increasing amount of wind and solar generation does not occur during periods of the remaining net demand.

The remaining 6% of demand met by fossil- and hydrogen-fueled generators occurs during periods of peak demand in the summer and winter—which also can be periods of lower variable renewable output, which creates an increased challenge for meeting 100% of demand with these resources if they primarily produce during periods when the demand is fully saturated. This study analyzes the contribution of all resources during hours of net peak demand for each season. Previous analysis has demonstrated the feasibility of continued economic deployment of variable generation and diurnal storage, particularly with transmission that can be deployed in such a way to optimize renewable deployments and the flow of energy across the entire continent (Brown and Botterud 2021). However, the results of any analysis of 100% clean electricity systems are highly sensitive to assumed capital costs for technologies that can provide firm capacity, many of which are still maturing. This means there is considerable uncertainty about which pathway will provide the least-cost 100% clean electricity system, and the generation mixes that provide firm capacity during periods of net peaks shown here are representative of a broader range of technologies that could serve this need.

Figure 21 shows the firm capacity mix in 2035, which is the same capacity shown in Figure 8 (page 22) but derated based on actual availability during the summer and winter peak. Diurnal storage of various durations provides significant firm capacity. Solar has limited ability to provide capacity during peak demand in the winter, while wind has lower availability during hot summer afternoons. The combination of seasonal storage (modeled as hydrogen-fueled combustion turbines) and fossil generation (either with integrated CCS or with CCS-based offsets) provides 40%–50% of capacity needed during peak periods. The range of scenarios and sensitivities in this study demonstrates the potentially important role of these two technology classes in providing firm capacity and meeting peak demand and is discussed in detail in the following subsections.

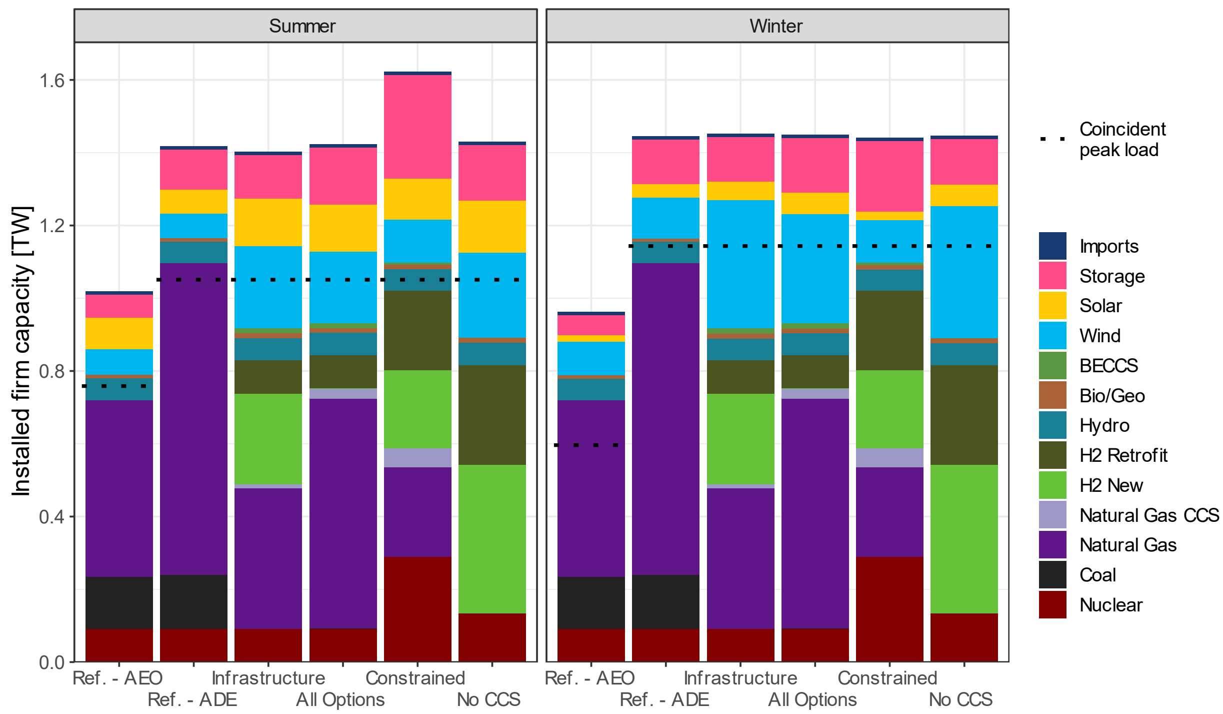

Figure 21. Sources of firm capacity in the winter and summer in the 100% clean electricity scenarios in 2035 (ADE demand case) show a much greater mix of resources compared to those providing energy.

Wind, solar, and storage provide about 50% or less of total firm capacity. The other capacity is provided by nuclear, two types of peaking capacity-fossil plants offset by negative emissions technologies (BECCS and DAC), and hydrogen-fueled generators.

3.6.1 Seasonal Storage

Seasonal storage is used to mitigate supply/demand imbalances over longer timescales. Hydrogen-fueled combustion turbines are used by the ReEDS model as a form of seasonal storage and to provide firm capacity. Though we use hydrogen as a storable, electricity-derived fuel, other pathways could provide fuel for electricity generation to help provide firm capacity in highly decarbonized systems. For example, methane produced from CO_2 or biomass (synthetic natural gas) could be used in existing gas-fired generators without any modification, and it can use existing natural gas pipelines and other infrastructure. Ammonia can also serve as a hydrogen carrier and potentially be used in combustion applications with proper fuel handling and emissions controls. There are also non-combustion conversion processes, such as fuel cells, that avoid local emissions. While acknowledging there are multiple potential fuel pathways and seasonal storage options that do not depend on fuels, such as geologic thermal energy storage, we model only a single fuel pathway in this analysis to represent a generic seasonal storage technology (Wendt et al. 2019), given the large uncertainty about the cost-optimal mix of such options.

Figure 22 (top) (page 38) shows for each core scenario the total hydrogen production over time, which is the sum of the assumed input requirements (Figure 3) and the amount needed to meet peak electricity demand as determined by the model. The demand varies significantly depending on the availability of CCS and DAC to offset generation from fossil plants without CCS. Without DAC, much more hydrogen is needed for peaking applications, and a corresponding increase in new clean electricity generation capacity must be constructed to support electrolysis. The No CCS case increases this requirement even further. Though this capacity can be constructed in locations with excellent wind and solar resources, it adds to the challenges of deploying these supply technologies at scale (e.g., transmission and land use). In addition to hydrogen production costs (considering both capital costs and variable costs detailed in Appendix B.2), the model considers transport and storage. Pipelines and storage facilities are not directly modeled but instead assume a variable cost of \$100–\$900/tonne depending on scenario. The challenges of permitting and siting this new fuel infrastructure are not considered in this analysis.

Figure 22 (bottom) shows sources of clean hydrogen across the various scenarios in 2035 (which does not include current hydrogen production from SMR with uncontrolled emissions). Two options for hydrogen production are considered in this study. One is electrolytic hydrogen. Hydrogen can be produced from clean energy generation, particularly during the spring and fall when there are abundant renewable generation resources, with the resulting fuel stored in underground formations until needed weeks, months, or even years later. During periods of high net demand, this supply is drawn down. This seasonal variation in supply and demand is similar to the production, storage, and delivery of natural gas in the current system. The other option is SMR/CCS, which is part of the larger overall role of CCS-based technologies (see Section 3.6.2). SMR/CCS allows production of hydrogen from domestic natural gas resources and can partially use existing natural gas infrastructure that will be less utilized in the future, given the reduced demand in other sectors. As modeled, the use of SMR/CCS requires negative emissions technologies to offset methane leakage (Alvarez et al. 2018). Regardless of technology, achieving seasonal storage on the scale envisioned in these results requires substantial infrastructure development.

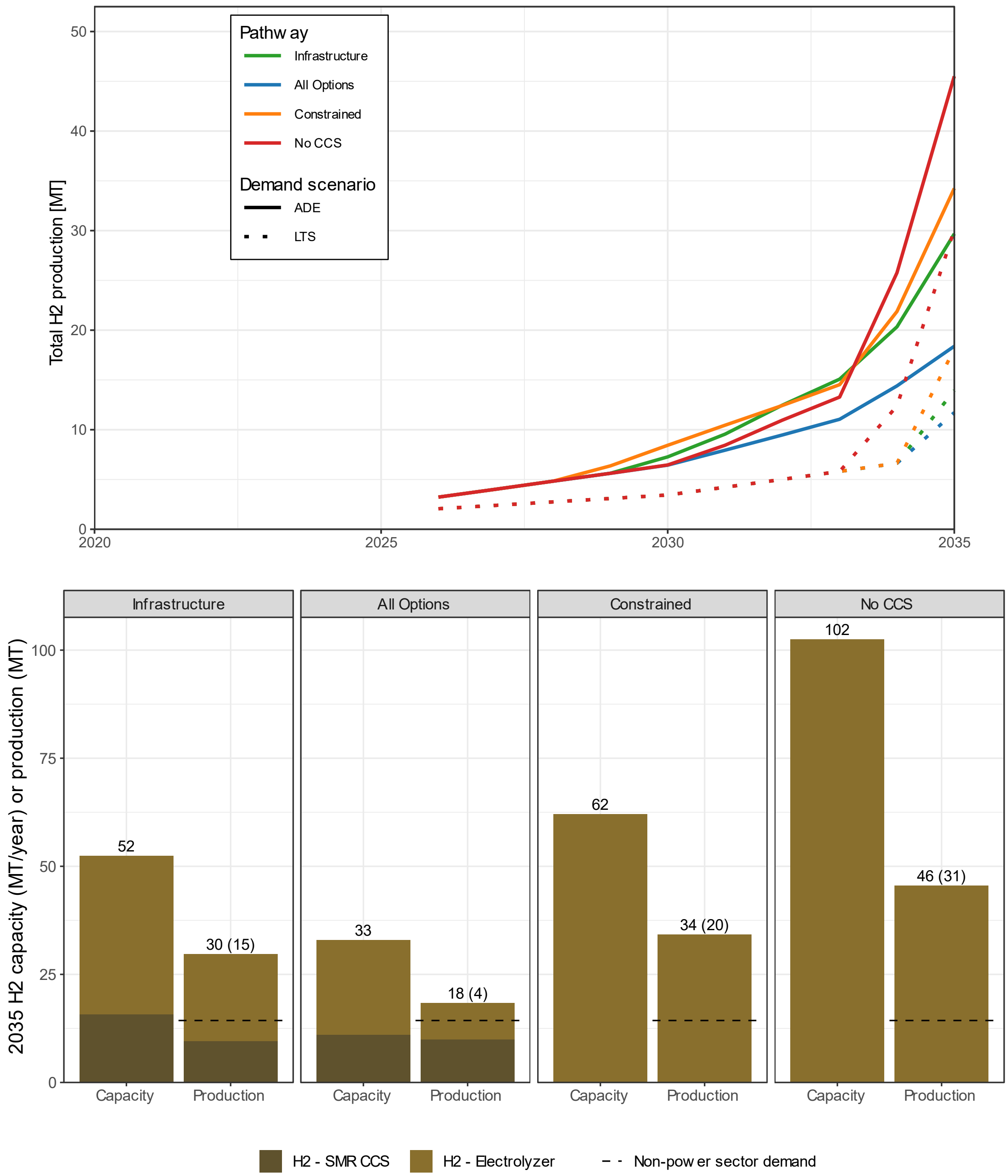

Figure 22. Sources of hydrogen fuel production (ADE demand case) shows the potentially important role of electrolysis.

The top chart shows the annual production from various sources, where additional hydrogen production is required in the No CCS scenario due to its role in providing peaking capacity. The All Options scenario shows the lowest production due to the availability of DAC, which allows for continued use of natural gas to provide peaking capacity. The lower figure shows the mix of hydrogen from SMR/CCS or electrolysis in 2035. The left bar in each scenario represents production capacity (MT/year if running at full output), and the right bar provides actual production (MT). Numbers at the top of each bar indicate the total hydrogen capacity or production, with the values in parentheses specifying the total production used for the power sector.

Hydrogen-fueled combustion turbines can be either new installations or retrofits of existing natural-gas-fueled plants, and installations are allowed beginning in 2026. Figure 23 shows the total capacity of hydrogen-fueled combustion turbines installed by 2035. In the All Options scenario, there is limited deployment, as emissions from natural-gas-fueled plants without CCS can be offset by DAC. In the three scenarios without cost-competitive DAC, there is significant growth in hydrogen-fueled combustion turbine capacity. The No CCS scenario has the largest capacity, about 680 GW, with the associated challenges of hydrogen production and associated infrastructure, including fuel storage and transportation. Production of hydrogen in the No CCS scenario requires about 2,400 TWh of clean electricity generation, or about 27% of all electricity generated. Differences in hydrogen demand between the scenarios reflect changes in power sector demand for clean fuels and are affected by the key scenario drivers—primarily the availability of CCS.

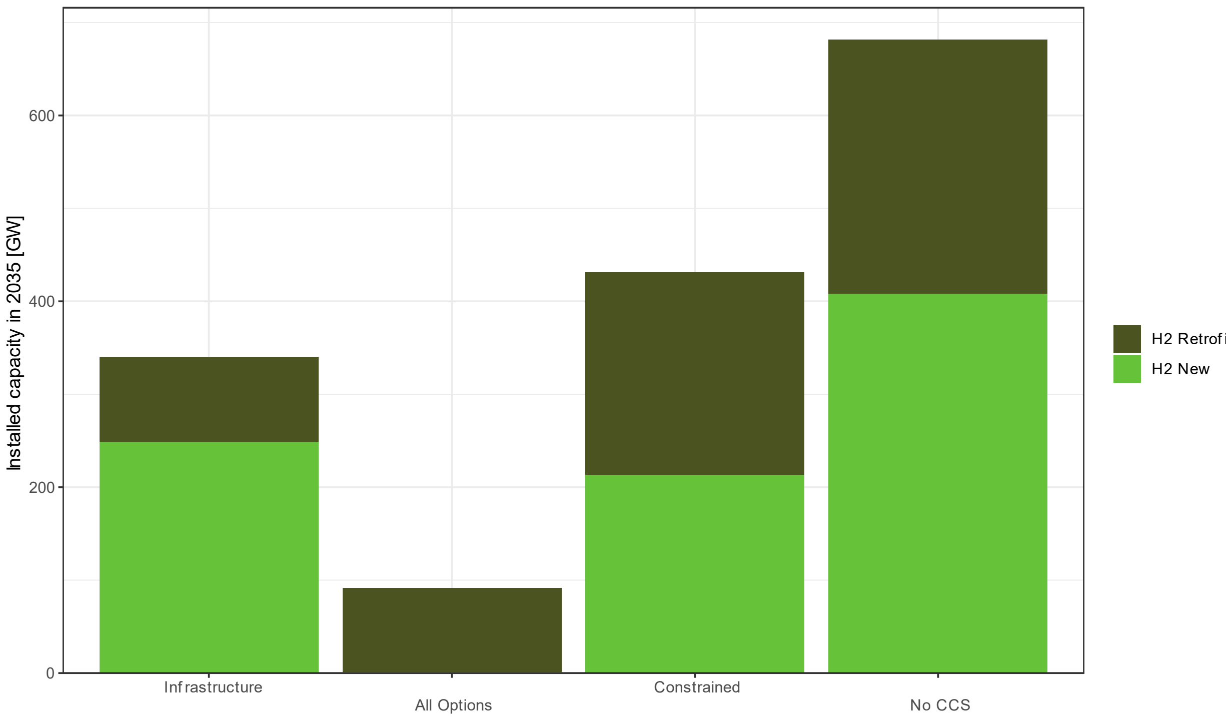

Figure 23. Capacity of hydrogen-fueled combustion turbine generators in 2035 (ADE demand case) shows the importance of these technologies, particularly if CCS is not available.

Seasonal storage in the form of hydrogen-fueled combustion turbines has lower round-trip efficiency (modeled as 35%), which increases the variable cost of generation compared to shorter-duration storage.[44] However, if used as a peaking resource, the resulting low utilization makes seasonal storage less sensitive to fuel costs than plants that operate at a higher capacity factor.

[44] This efficiency is the product of the electricity-to-hydrogen conversion efficiency, the compression-and-storage efficiency, and the thermal efficiency of converting hydrogen to electricity, with the last step having the greatest impact. Gas turbines and fuel cells have fuel-to-electricity efficiencies typically below 50% (excluding combined heat and power applications).

3.6.2 CCS and DAC

Three of the four main scenarios allow deployment of fossil CCS or BECCS starting in 2026. For fossil plants, this includes either retrofits or new plants. For CCS, we assume a 90% capture rate and residual emissions must be offset by negative emissions technologies (BECCS or DAC where allowed). We assume captured CO_2 is permanently stored in geologic formations and no leakage of CO_2 occurs. CO_2 pipelines and storage facilities are not directly modeled, but we instead assume a variable cost of $5–$60/tonne depending on the scenario and sensitivity. Fossil fuel prices are based on AEO projections and do not consider the additional impact of significant reduction in the demand for these fuels in the 100% clean electricity scenarios, both within and beyond the power sector, on future prices.

Achieving CCS cost and performance targets helps meet 100% clean electricity in several ways. One is the production of low-carbon fuels, as noted in the previous subsection. A second benefit is the ability of CCS-based technologies to help address the challenge of meeting peak demand. Fossil CCS plants provide firm capacity, and potentially could be retrofit to existing plants, reducing power system costs.

Figure 24 (top) shows deployments of CCS technologies, along with fossil plants without CCS. Because of the less than 100% capture and methane leakage, to achieve a net-zero emissions rate, plants with CCS must offset their residual emissions by using negative emissions technologies (BECCS or DAC where allowed).[45] Sensitivities were performed without methane leakage and show higher deployments of fossil CCS, which shows the impact of requiring negative emissions technologies to achieve net-zero emissions, and points to greater opportunities for CCS if further reductions in leakage can be achieved. Emissions accounting is performed in the model on a yearly basis. The use of negative emissions technologies also allows for another potential important pathway for cost-effective emissions reductions while keeping sufficient capacity to meet peak demand. BECCS and DAC enables the continued operation of existing fossil plants in a 100% clean electricity scenario, as well as the construction of new fossil plants, which are used to maintain reliability by providing firm capacity during periods of net peak demand. As discussed previously, much of the peaking capacity needed to provide reliable service operates at very low capacity factor. One way to address this need is to use existing fossil plants operating with very low annual energy production and very low annual emissions, which could then be offset by DAC or BECCS.

The future cost and performance of BECCS, CCS, and DAC are highly uncertain given their low levels of current deployment. The All Options scenario includes DAC, which is assumed to be available beginning in 2026 and requires 3.7 MWh of electricity generation per tonne of CO_2 removed. Assumed fixed and variable costs of DAC (described in Appendix B) make this resource cost-competitive, resulting in deployments by 2035 with the capacity to remove 78 MT/year, which represents a peak electricity demand of 33 GW.

We assume BECCS fuel is woody biomass that requires minimal processing, with a total availability of 105 million dry tonnes/year in the All Options and Infrastructure Renaissance

[45] Other possible sources of carbon sequestration include afforestation and regenerative agriculture, for example. These are not considered in this study.

scenarios and which is halved in the Constrained scenario (DOE 2016b). The available supply is fully utilized in those scenarios. Other biomass-based fuel sources (e.g., crops) are assumed to be reserved for other applications such as transportation fuels and chemical feedstocks.[46] Because biomass extracts carbon from the atmosphere during plant growth, and this carbon is then captured and stored (with the same capture rate assumed as fossil CCS), BECCS produces a net negative emissions rate (comparative emissions rates across all technologies are provided in Appendix B).

Figure 24 (bottom left) illustrates the energy provided by fossil plants and BECCS, as well as the energy consumed by DAC plants. The net emissions that result from fossil plants without CCS and methane leakage must be offset by negative emissions technologies (bottom right).

[46] The use of wood biomass in other sectors could reduce the availability of this resource for BECCS and potentially require alternate pathways to achieve net-zero emissions. Alternatively, the importance of negative emissions in the electric sector could incentivize use of nonwoody biomass resources for BECCS. The total potential biomass supply and multiple possible uses are also discussed in the *Billion-Ton Report* (DOE 2016b).

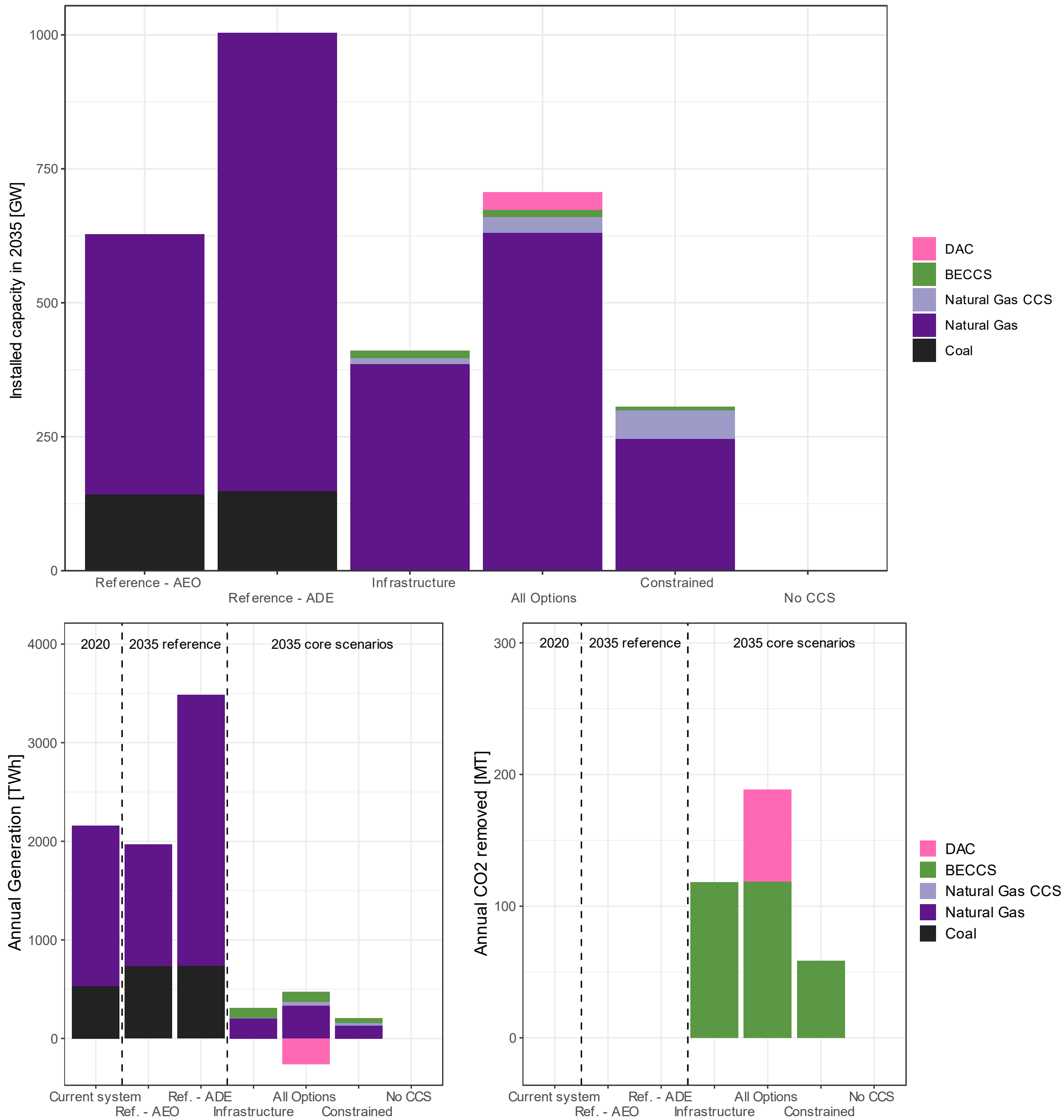

Figure 24. Capacity and energy contribution of fossil and CCS-related technologies (ADE demand case) shows the ability of negative emissions technologies to offset remaining fossil generation used for peaking capacity.

The bottom left panel shows annual generation from fossil and CCS technologies, along with annual energy requirements for DAC. The bottom right panel shows annual CO_2 removed by BECCS and DAC, which is required to offset remaining natural gas generation, methane leakage, and residual emissions from CCS plants. BECCS (which is limited by fuel availability) also allows for continued use of fossil units and is needed to offset residual emissions from units with CCS.

Figure 24 shows how a small amount of negative emissions DAC or BECCS capacity can support a much larger amount of non-CCS fossil capacity used infrequently for peaking capacity. For example, in the Constrained and Infrastructure Renaissance scenarios, BECCS is the only negative emissions technology considered. The small amount of BECCS capacity (about 7 GW in the Constrained case and 14 GW in the Infrastructure Renaissance case) offsets the emissions by 250–375 GW of fossil (without CCS) capacity. The means BECCS acts as capacity "multiplier," allowing a greater capacity of combustion turbines without CCS operating at low capacity factors. The role of DAC is similar; however, DAC requires additional clean energy generation for carbon removal (shown as the negative generation in the lower left panel of Figure 24), and operation must consider the emissions and cost impacts of the generation needed. Because we do not perform an economy-wide analysis, it is possible that further deployments of BECCS and DAC (or increased utilization of assets deployed to offset remaining emission from the electric sector) could be used to offset remaining positive emissions in other sectors in a fully decarbonized economy.

Overall, systemwide carbon emissions, which vary on an hourly basis, are largely net positive in the winter and summer, and are net negative in the spring and fall, with the net total being zero on an annual basis in 2035. Fossil resources without CCS operate largely in the winter and summer, and they generate little in the spring and fall. DAC operates more continuously but avoids full output during periods of net peak net demand, and BECCS operates more continuously throughout the year.

Across the three scenarios where CCS is allowed, in 2035, 68–290 MT/year of CO_2 is captured and stored (Table 3).[47] In cases where CCS is not allowed, a very large amount of new generation capacity is required to both replace existing fossil capacity and generate clean fuels.

Table 3. Total CO_2 Captured and Stored (MT/year) in 2035 (ADE Demand Case) in the Scenarios That Allow CCS

	All Options	Constrained	Infrastructure Renaissance
Power generation (Fossil CCS + BECCS)	133	68	120
Hydrogen production (SMR CCS)	87	—	84
Carbon-dioxide removal (DAC)	70	—	—
Total	290	68	204

Collectively, the modeling demonstrates that the availability of seasonal storage and CCS has a strong impact on the power system costs, particularly as the contribution of clean electricity approaches 100%, as discussed in Section 4.

3.7 Transmission

Transmission is a key enabling technology for a clean electricity system because it allows access to higher-quality renewable energy resources and better utilization of those resources, including

[47] For comparison, in 2020, about 40 MT of CO_2 was captured and stored worldwide, roughly 2 MT of which was from power generation (IEA 2021).

reduced curtailment of wind and solar. It also helps smooth the variability of both electricity demand and variable supply across large regions across various timescales. In addition, transmission can increase reliability by expanding electricity imports and exports and enhancing coordination across larger regions.

Figure 25 shows the location of the highest-quality U.S. wind and solar resources. Most electricity demand occurs in the eastern United States, and limited transmission is currently available to major population centers from wind- and solar-rich regions.

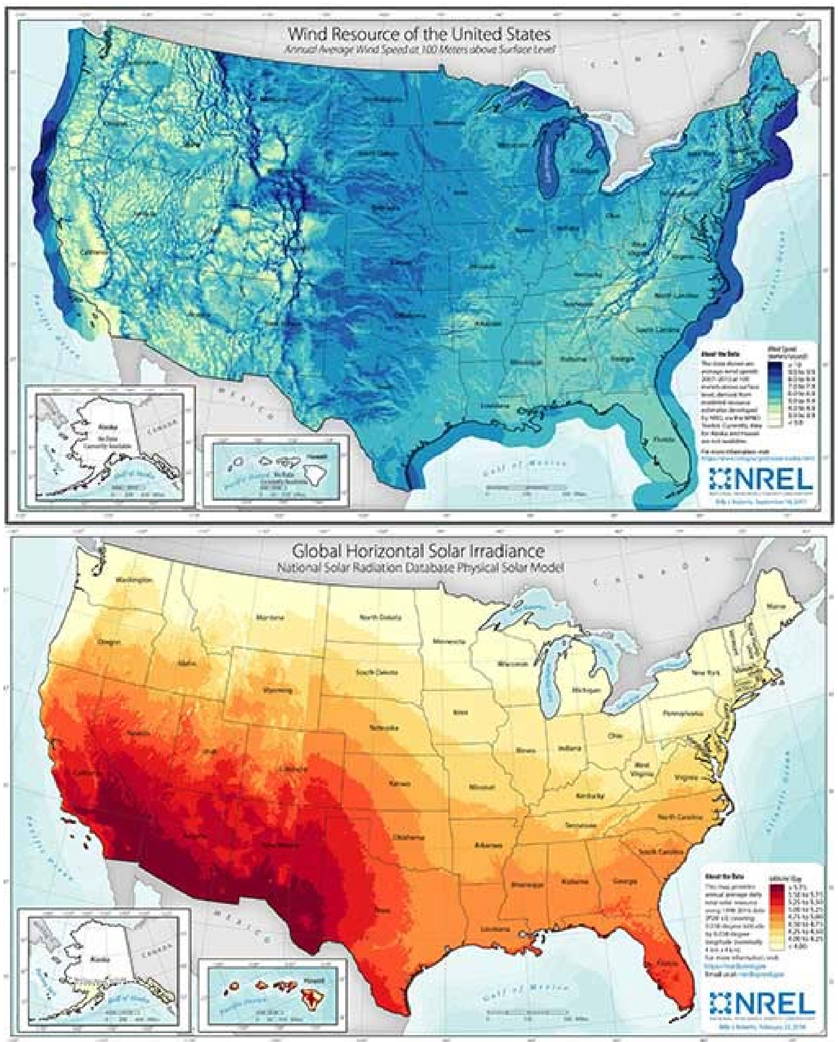

Figure 25. Wind and solar resource maps of the United States show that many of the best resources are in locations remote from demand centers in the eastern part of the country, which require new transmission.

This study makes several important assumptions regarding the ability to site and build new transmission. Currently planned lines can be built starting in their estimated online year; new, currently unplanned transmission is not allowed to be built until 2026, reflecting the time required to site, permit, and construct new transmission. After this date, transmission can be added with geographical restrictions and costs that vary by scenario. In the Constrained scenario, new transmission is restricted to within transmission planning regions based on Federal Energy

Regulatory Commission (FERC) Order 1000 (see map in Appendix B), reflecting some of the current challenges with building long-distance transmission that crosses multiple jurisdictions and siting authorities. This case also assumes transmission costs that are five times higher than the cost estimates used in the All Options and No CCS scenarios, loosely representing the cost of underground transmission for 50% of new lines. The All Options and No CCS scenarios allow transmission expansion between all regions and use central cost estimates (described in Appendix B), generally reflecting new overhead 500 kV AC transmission. Finally, the Infrastructure Renaissance scenario includes the option to build a multiterminal high-voltage DC macrogrid (see Text Box 3 at the end of this section, page 49) with lower $/MW-mile costs than the default AC interregional lines (details are provided in Appendix B). As with generation, ReEDS does not simulate transmission developed in a competitive market. It develops transmission as part of the least-cost mix of resources, and transmission costs vary depending on resource, with remote wind resources requiring greater costs than local resources. Overall, all core 100% scenarios add a large amount of new transmission capacity (Figure 26); regional details are provided in Appendix A.

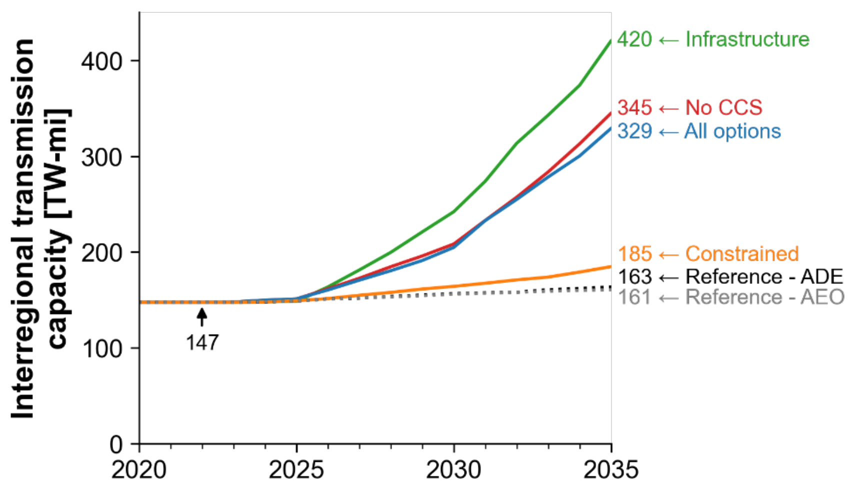

Figure 26. Interregional transmission capacity grows substantially in three of the four scenarios (ADE demand case).

This result allows greater access to high-quality (low-cost) wind resources and provides the benefits of spatial diversity.

Figure 26 quantifies transmission capacity and provides units of terawatt-miles (TW-mi) for convenience. The actual capacity of high-power transmission lines is typically in the range of 1,500–3,000 MW, so 1 TW-mi roughly corresponds to 330–670 miles of new transmission capacity.[48] Another point of comparison is the Texas Competitive Renewable Energy Zones (CREZ) project, which developed about 3,500 miles of lines (Powering Texas 2018). Though most CREZ lines are smaller than the double-circuit 500 kV lines used above, the national deployment requirement corresponds to 0.4–2.9 CREZ-scale developments per year. Assuming installation of higher-capacity lines, this means the scenarios deploy from about 13,000 miles of new interregional transmission lines in the Constrained case to about 91,000 miles in the

[48] The lower value for capacity corresponds to single-circuit 500 kV or double-circuit 345 kV lines. The upper value for capacity is based on 500 kV double-circuit or HVDC lines. However, much higher-capacity lines have been installed internationally (Alassi et al. 2019).

Infrastructure Renaissance case. Assuming construction begins in 2026, the levels of deployment would require about 1,400 to 10,100 miles per year. Historical U.S. installation rates vary; in 2013, about 4,100 miles of transmission above 230 kV were completed (the highest value from 2010 to 2020) (Wiser et al. 2021).[49] Note that Figure 26 only includes interregional transmission capacity; spur lines connecting wind and solar installations to nearby grid features are included in the system cost but not the TW-mi values discussed here.[50] Additional intraregional network reinforcement would also be needed given the high degree of electrification assumed here, but this is not modeled in ReEDS.

Figure 27 shows the approximate locations and capacities of transmission in the core scenarios. Transmission is constructed in many locations and is particularly important for accessing the nation's highest-quality wind resources.[51]

[49] This 4,100 mile value includes lower capacity lines than those anticipated, so while the distance is the same, the challenge would be greater because larger lines typically require wider rights of way. This may be partially mitigated by HVDC with smaller rights of way than an equivalent capacity AC line.

[50] We do not model (or estimate the cost of) network reinforcements likely needed for new large nuclear or fossil CCS plants.

[51] As ReEDS is a zonal model, the thickness of the lines shown in Figure 27 (and similar figures) represents aggregated interface transfer capacities between zones. Representative cost-minimizing corridors between the largest demand centers in connected zones are used to determine representative lengths, costs, and losses for interzonal transmission capacity.

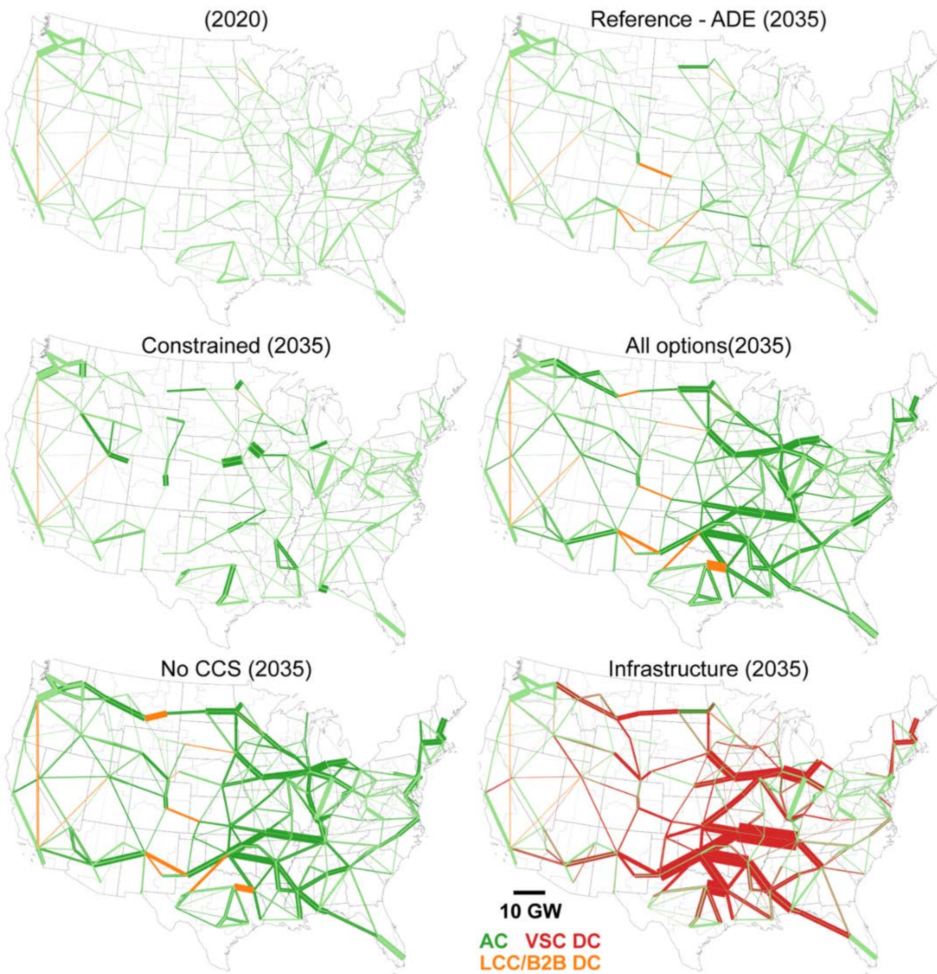

Figure 27. Maps of transmission capacity in 2020 and 2035 (ADE demand case) show substantial additions into wind-rich regions of the United States.

Transmission capacity is differentiated into alternating-current (AC) and two direct-current (DC) technologies: lines using voltage source converters (VSC) and lines using line-commutated converters (LCC) or back-to-back interties (B2B).[52]

Transmission expansion offers systemwide benefits but is particularly complementary to wind (DOE Office of Policy 2022). The Infrastructure Renaissance scenario constructs the most transmission and wind, and it results in the lowest average cost, as discussed in Section 4.2. In the Constrained scenario, wind and transmission expansion are limited, and PV becomes the dominant energy resource.

Figure 28 shows the change in the contribution of wind, solar, storage, and nuclear relative to transmission across the entire set of sensitivity cases. Even in the Constrained scenario, where transmission is more expensive and difficult to construct, the model chooses to increase today's

[52] All DC lines currently installed in the United States use LCC technology, which is most suitable for individual long-distance lines given its high voltage compatibility, low losses, and relatively low cost. VSC architectures have higher losses and converter costs but are compatible with meshed multi-terminal architectures. We assume zones currently linked by LCC and B2B AC/DC/AC converters utilize LCC for future expansion, while the multi-terminal macrogrid in the Infrastructure Renaissance scenario uses a VSC architecture.

transmission system capacity by about 26% as part of the least-cost solution. In all scenarios, building transmission that enables low-cost wind and other energy resources is often cheaper than the alternatives, such as use of higher-cost but local resources (and potentially additional storage).

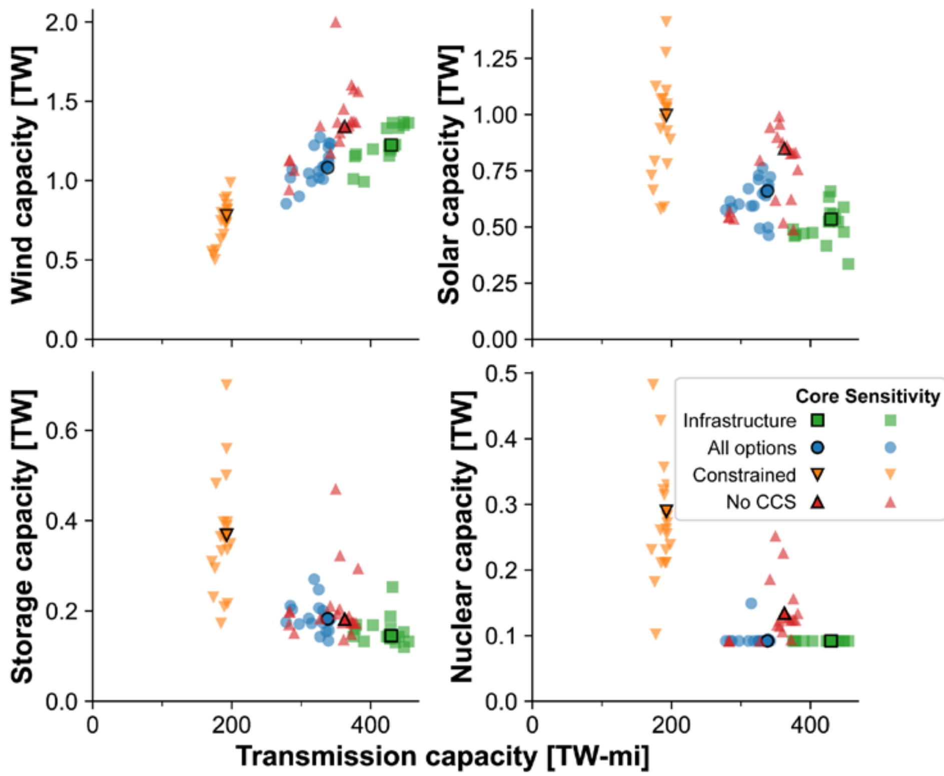

Figure 28. Wind capacity relative to transmission capacity in 2035 (top left) shows the synergy between the technologies.

In cases with much lower transmission development (primarily the Constrained scenario), additional solar (top right) and storage (bottom left) are deployed to offset the decrease in wind supply and resource diversity. Nuclear capacity (bottom right) shows that restrictions to wind and transmission development increase nuclear deployment, which does not require as much transmission capacity if it can be sited closer to load. Sensitivity cases are indicated by filled colored markers; core cases (ADE demand case) are indicated by black-outlined markers.

The top left in Figure 28 panel shows the clear relationship between transmission and wind, as wind is the generation technology most dependent on new transmission capacity. In most scenarios, the Constrained scenario shows the largest difference between the technologies. The top right panel shows the most significant increase in solar occurs as wind becomes less cost-competitive, and solar deployments increase due in part to reduced reliance on long-distance transmission. This also is seen in storage deployment (lower left), where the increased solar deployment in the Constrained scenario incentivizes additional storage because of the synergy between solar output and diurnal storage. Finally, the most dramatic impact of the Constrained scenario is to increase the cost-competitiveness of nuclear capacity, which does not require as much transmission as wind if nuclear can be sited closer to load.

Achieving 100% clean electricity by 2035 requires addressing siting challenges for rapid and widespread deployment of multiple generation resources and transmission. Even with significant new transmission deployment, large deployments of wind and utility-scale solar (in addition to rooftop solar, which does not incur land use conflicts) would likely be sited across the United States—including relatively close to major population centers.

Figure 29 provides an overview of regional transmission, wind, and solar deployments in 2035 across the four scenarios, showing significant deployment of transmission to access high-quality wind resources.

Text Box 3. Delivering More with Less: Benefits of Enhanced Transmission Technologies

HVDC can deliver more energy, with less losses, along a given right-of-way corridor than conventional AC transmission. Greater use of HVDC is one of several approaches and technologies that could reduce the challenge of siting the many new transmission corridors needed to enable large amounts of new renewable energy deployments.

Another is flexible AC transmission systems (FACTS). The flow of AC power typically cannot be controlled in a transmission network. This means the system is inherently limited by its weakest component and some transmission capacity is always underutilized—transmission elements that could actually carry more power—but attempting to deliver more power on those elements would overload other elements. FACTS (along with HVDC) can allow the system to increase the flow on the elements that are operating below their thermal limits, essentially allowing greater overall system capacity.

Dynamic line (and equipment) ratings can also allow transmission capacity to increase during periods of lower temperature. Deployments of these proven technologies that minimize right-of-way requirements, reduce costs associated with long distance, and increase carrying capacity can help enable the significant benefits of transmission demonstrated in this study.

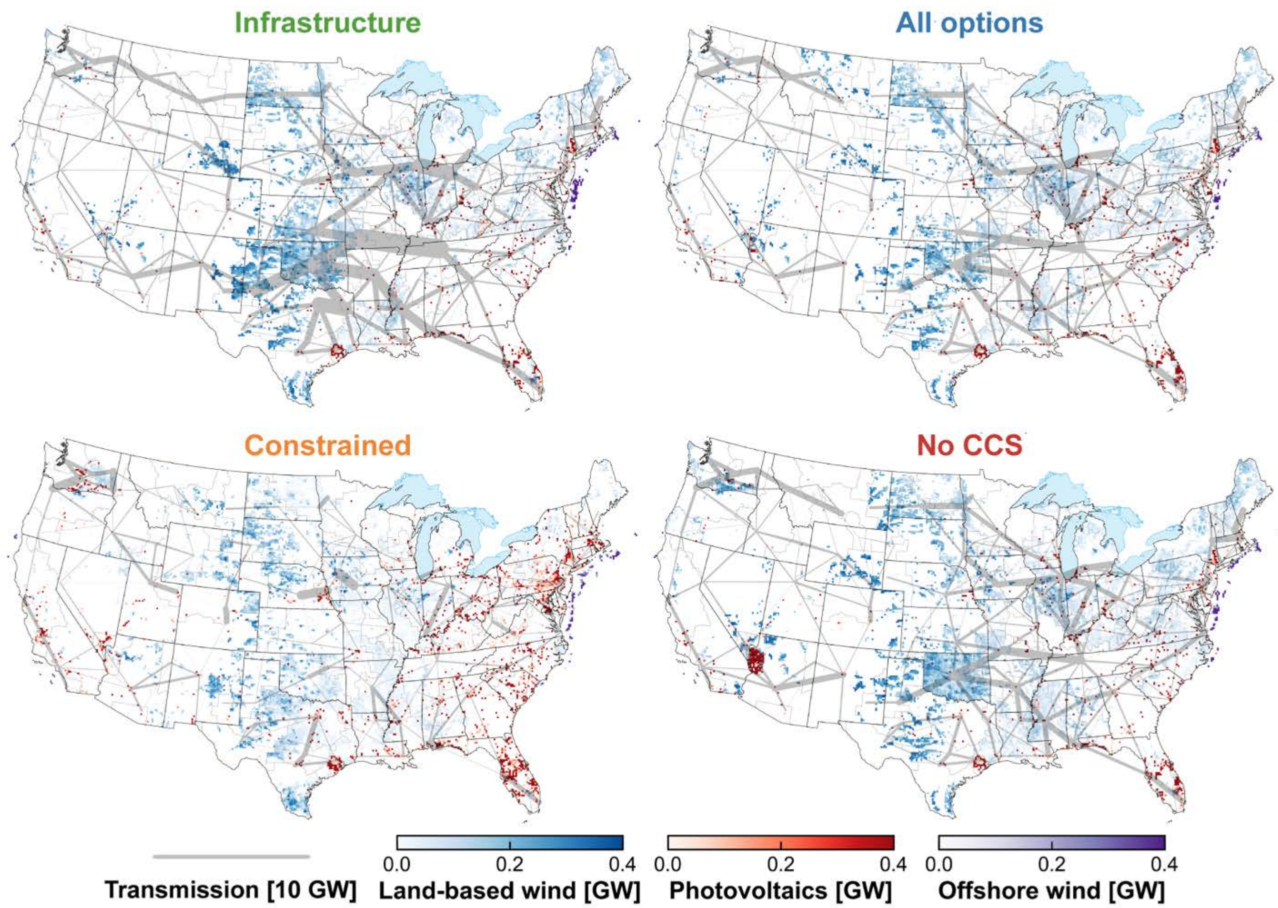

Figure 29. Regional capacity of wind, solar, and transmission shows the importance of codevelopment of resources in several regions (ADE demand case).

Each marker indicates the installed capacity in a single 11.5-km×11.5-km grid cell of modeled utility-scale PV, land-based wind, or offshore wind plant capacity. Given the small fraction of directly utilized area for wind, PV and land-based wind are allowed to occupy the same grid cell without competition. Site PV capacities reach up to 4.3 GW; in this figure, to facilitate comparison with wind, all PV sites > 400 MW are shown in the same color.

3.8 Land Use

The modeling approach relies on high-resolution geospatial analysis that considers resource quality, grid interconnections, and land availability (Lopez et al. 2021).[53] The developable potential for wind (referred to here as resource potential as measured in units of capacity) accounts for land exclusions in protected and urbanized areas, documented state and county setback and height ordinances, mountainous or difficult terrain, and conflicts with other existing infrastructure, such as buildings, roads, railroads, and radar.[54] Similar siting constraints to the

[53] The geospatial modeling used to generate the developable potential operates at several spatial resolutions, including down to 90 m for land use and land cover data.

[54] Setbacks to existing infrastructure have a large impact on the developable land-based wind potential. A setback of 1.1 times the maximum tip height is assumed in all cases except the Constrained case, where a larger 3.0 times setback assumption is used.

developable area for utility (non-rooftop) PV are assumed.[55] Changes to land use patterns, including impacts of climate change on land availability, are not considered. As a result of these assumptions, about 2,213,000 km^2 (~29%) of the contiguous U.S. land area is available for wind development and 3,000,000 km^2 (~39%) for solar development in the All Options, No CCS, and Infrastructure Renaissance scenarios. The Constrained scenario has additional restrictions (see Appendix B), resulting in 675,000 km^2 (~9%) of the U.S. land area available for wind development and 1,106,000 km^2 (~14%) for utility-scale solar development. The availability and deployment of rooftop PV is determined externally by the dGen model and does not vary across scenarios.

Of the resource potential available for wind development, about 20%–25% is used by 2035 across the core scenarios; however, this fraction varies regionally. Appendix A provides additional details about regional resource potential and use, showing the significant use of the resource potential in many eastern states. Though utility-scale solar is far less constrained, the modeled scenarios still use a sizable fraction of the resource in some densely populated regions.

Figure 30 illustrates the land use associated with wind, solar, and long-distance transmission[56] in the core scenarios, along with several other land use activities.[57] Solid boxes represent areas dedicated to a single primary use. For wind, this represents area physically occupied by the wind turbine pad, roads, and other infrastructure. Boxes with dashed lines represent area that could have multiple uses. For wind, this represents the area within the perimeter of the wind plants that is available for agriculture, grazing, or other uses. Overall, about 2% of the total area within a wind power plant is occupied by wind infrastructure, and the remaining 98% is available for other uses (Denholm et al. 2009). Table 4 provides additional details.

[55] For utility-scale PV, we also exclude "prime" or "important" croplands and farmlands as designated by the U.S. Department of Agriculture. The developable PV resource is also limited to sites that are within 20 km of existing transmission in all cases except the Constrained case, where a 5-km cutoff is used.

[56] This includes all transmission linking the 134 ReEDS balancing regions, but no intrabalancing-area transmission or wind/solar spur lines.

[57] The total occupied land in 2035 for wind, solar, and long-distance transmission rights-of-way (~51,000 km^2) is less than half the area of active (2020) oil and gas leases (~105,000 km^2). The All Options scenario builds about 250,000 wind turbines, assuming 4 MW per turbine, which is considerably less than the 1.5 million oil and gas wells currently in the United States; see the Homeland Infrastructure Foundation-Level Database (U.S. Department of Homeland Security 2019).

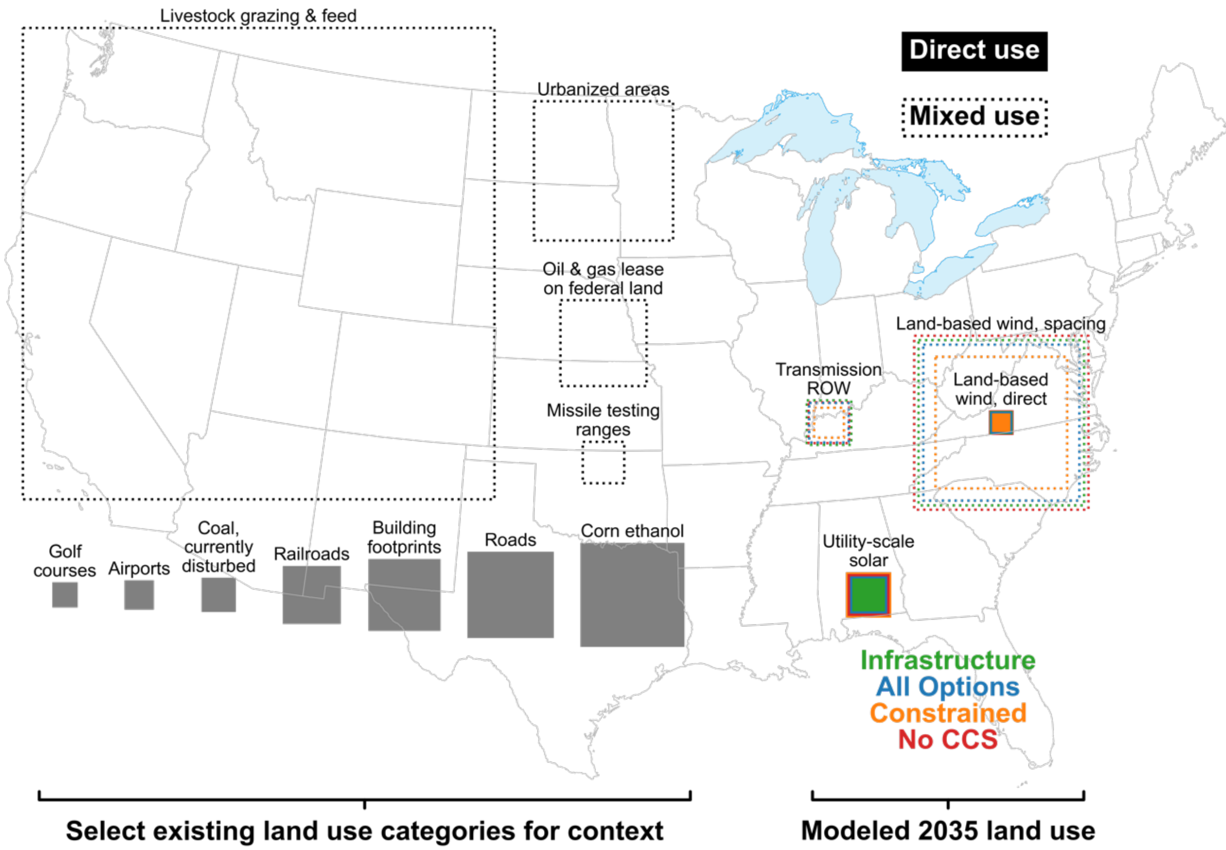

Figure 30. Total area occupied by wind turbine and solar infrastructure (solid boxes) is about equal to the land occupied by railroads (ADE demand case).

Rooftop PV is not included because it does not require any additional land use. The areas within unfilled boxes represent multiple use areas, and for wind, represent the area not occupied by turbine infrastructure and thus available for other purposes including those illustrated above, such as livestock and agriculture. Note that some land is counted in multiple categories (e.g., part of the area indicated as “roads” and “building footprints” represents land also included in “urbanized areas”). Boxes have the same scale as the map.[58]

[58] The category "coal, currently disturbed" is land that is currently occupied/modified in some way by coal mining. Historically disturbed land area for coal mining (~34,000 km^2) is larger than the currently-disturbed land area shown here (~17,000 km^2) (Global Energy Monitor 2021). Oil and gas production on federal lands represents <25% of total U.S. oil and gas production (https://www.blm.gov/programs-energy-and-minerals-oil-and-gas-oil-and-gas-statistics).

Table 4. Footprint Comparison (ADE Demand Case) (km^2)

	Infrastructure Renaissance	All Options	Constrained	No CCS
Land-based wind	389,000 (spacing) 8,000 (direct)	346,000 (spacing) 7,000 (direct)	247,000 (spacing) 5,000 (direct)	431,000 (spacing) 9,000 (direct)
Utility-scale solar[59]	15,000	20,000	29,000	25,000
Offshore wind	11,000 (spacing)	8,000 (spacing)	11,000 (spacing)	9,000 (spacing)
Interregional transmission rights-of-way (≥500 kV)	28,000	22,000	13,000	24,000

There may also be siting challenges with other clean energy technologies that are not considered in this analysis. With the exception of the Constrained scenario, where state-level restrictions (as of early 2022) to new nuclear are applied, we do not consider any restrictions for new nuclear due to local opposition or the need to develop new spent-fuel storage (NCSL 2021). Extensive deployment of CCS technologies may require siting and permitting of pipeline infrastructure and long-term CO_2 storage. We do not account for any land use or siting constraints associated with CO_2 transport or storage.

[59] Utility-scale solar includes plant buffer and spacing between PV rows. Direct land occupation is ≥90% of the values listed here. Values for solar assume 32 MW_{AC}/km^2. Recent estimates indicate solar land use is decreasing over time due to increases in panel efficiency and use of bifacial modules (Bolinger and Bolinger 2022).

Text Box 4. The Role of Distributed Resources

The potential for distributed energy resources to support a low-carbon grid and reduce siting challenges associated with utility-scale generators is not examined comprehensively in this work. However, the ADE scenarios include 190 GW of distributed PV deployment by 2035, as determined by the dGen model (Sigrin et al. 2016). This trajectory is a fixed input into ReEDS, which then determines the balance of the system, including utility-scale PV. Rooftop PV tends to offset utility-scale PV deployment in the ReEDS model (Cole et al. 2016).

This study does not include modeling of other distributed energy resources—such as behind-the-meter batteries (including vehicle-to-grid) or distributed wind—nor does it consider all value streams for rooftop PV. Nevertheless, these resources have an important role in high renewable energy systems, especially under futures with significant land use or siting constraints.

The technical potential for rooftop PV is 1,118 GW (Gagnon et al. 2016), so there may be additional opportunities beyond the 190 GW deployed in this study (Prasanna et al. 2021). Distributed wind has a similarly large technical and economic potential (McCabe et al. 2022), as well as the potential to scale to 40 GW (Lantz et al. 2016) from the 1.1 GW installed in 2020 (Orrell, Kazimierczuk, and Sheridan 2021). Distributed batteries can also provide many of the grid services offered by storage located in the bulk system, as well as additional distribution system and resilience benefits (Prasanna et al. 2021).

Depending on technology trends and regional energy system evolution, other distributed resources, including flexible electric vehicle charging and flexible industrial and building loads, including thermal storage and geothermal heat pumps, may also play a significant role in a decarbonized energy system (Liu et al. 2019; Langevin, Harris, and Reyna 2019).

3.9 Deployment Results of the LTS Sensitivity

The results presented thus far have focused on scenarios that use the ADE demand assumptions, which includes a combination of electrification, energy efficiency, and other emissions-reduction measures that put the U.S. energy system on a pathway to net-zero emissions (Appendix C). Given the uncertainty associated with carbon abatement pathways in the end-use sectors—and their potential implications to electricity demand—we also evaluate scenarios achieving 100% clean electricity supply under an alternative pathway to achieving a net-zero energy system. The LTS demand case, which assumes a lower rate of load growth (2.1%/year compared with 3.4%/year under ADE) through greater energy efficiency and lower electrification (particularly for buildings), provides this alternative.

Lower demand growth reduces the need for new clean generation by 2035. Figure 31 shows how the lower demand assumed under the LTS assumptions results in 23%–29% less clean electricity generation in 2035 than the ADE assumptions and more pronounced impacts in the 100% clean electricity scenarios than the reference cases. In addition to lower requirements for clean energy, the LTS case also has significantly lower peak demand and demand shapes that are more similar to historical summer peaking trends (Section 2.1). The combination of these differences results in a different resource mix for achieving 100% clean electricity and a 16%–20% reduction in total 2035 installed capacity (Figure 34). While the reductions occur for all technologies, they are most pronounced (in absolute terms) for variable generation technologies

Lower electricity consumption and demand peaks in the LTS cases result in less deployment of other technologies as well. In the Constrained scenario, growth in new nuclear is also more limited, with total 2035 nuclear capacity reaching 124 GW under LTS compared to 290 GW under ADE. Hydrogen used for non-grid applications, as well as for seasonal grid storage, is also lower under LTS than ADE; in the scenario with the most hydrogen (No CCS), 30 MT of total clean hydrogen are produced in 2035 when using the LTS assumptions, whereas 45 MT are produced under ADE. Lower demand growth also reduces reliance on carbon dioxide removal in the scenarios that allow it. With ADE assumptions, up to 290 MT of CO_2 are removed annually by 2035 in the All Options scenario, but this declines to 170 MT under LTS.[60] Unlike other technologies, installed diurnal energy storage capacity increases under the LTS sensitivity, reaching 260–375 GW by 2035 compared to 180–370 GW in the primary scenarios using ADE. This reflects interactions between technologies in the model; as the LTS demand is summer peaking, it becomes more economic to utilize more diurnal storage.

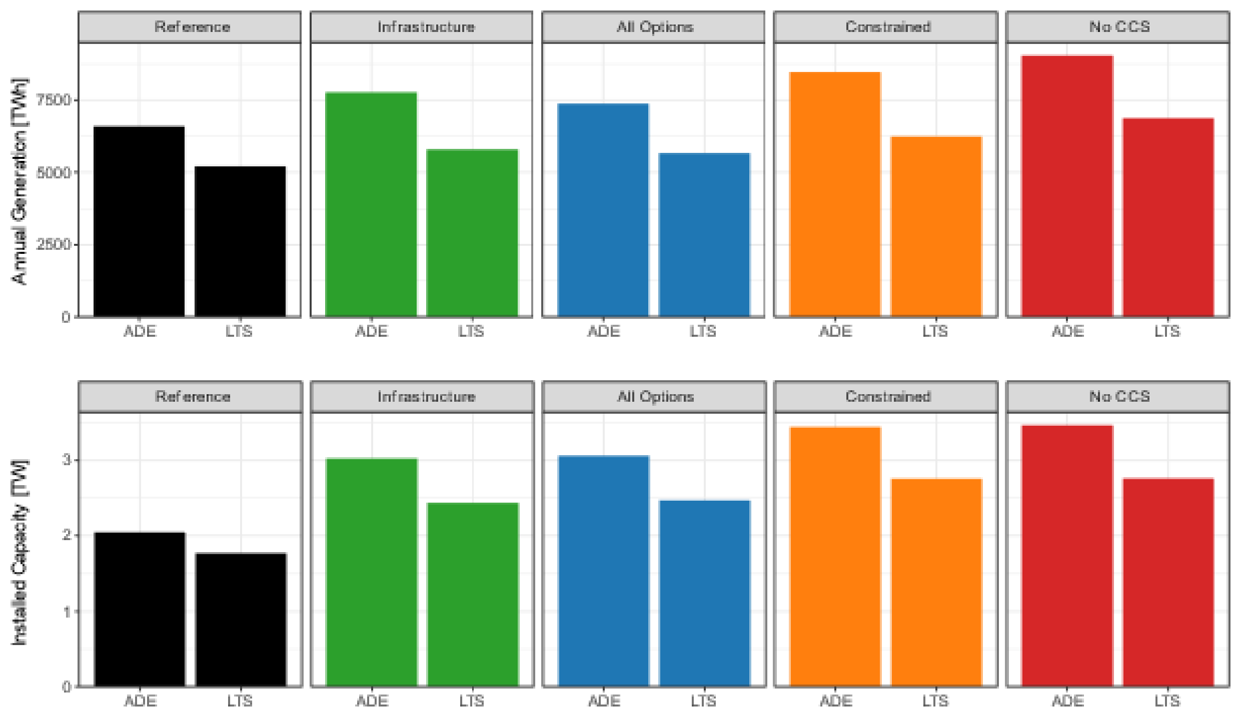

Figure 31. Total generation (top) and capacity (bottom) in 2035 in the ADE scenarios compared to the LTS sensitivity cases

Demand-side flexibility differs from energy efficiency in that it does not significantly impact the amount of electricity consumed, but it can alter when electrical power is required. In doing so, demand-side flexibility can reduce the need for new capacity development and can have operational benefits. In all scenarios that achieve 100% clean electricity by 2035, we assume about 5% of 2035 load is flexibility through managed electric vehicle charging and flexibility from buildings and industry (Section 2.1). However, the isolated effects of flexibility are not analyzed here. Nonetheless, prior studies (Murphy et al. 2021; Zhou and Mai 2021) have identified the potential value of demand-side flexibility in reducing demand peaks and enabling more efficient use of infrastructure through higher utilization.

[60] The LTS scenario also relies on carbon dioxide removal through carbon capture in biorefineries and using DAC (White House 2021a).

The comparisons of the LTS and ADE scenarios highlight how different demand growth assumptions, driven primarily by relative differences in energy efficiency and electrification, can have a significant impact on the supply-side resource mix. Notably, lower electricity demand reduces the need for new generation capacity and other infrastructure, and the impact of the associated barriers to their development. (Section 4 addresses the cost implications.)

4 Costs and Benefits

4.1 Summary Results

The emissions reduction and associated human health impacts of achieving 100% clean electricity result in societal benefits that exceed incremental costs over the reference scenarios. Figure 32 shows the cumulative net present value of the evaluated costs and benefits from 2023 to 2035 for the core scenarios, shown as differences between the 100% scenarios and Reference-ADE.[61]

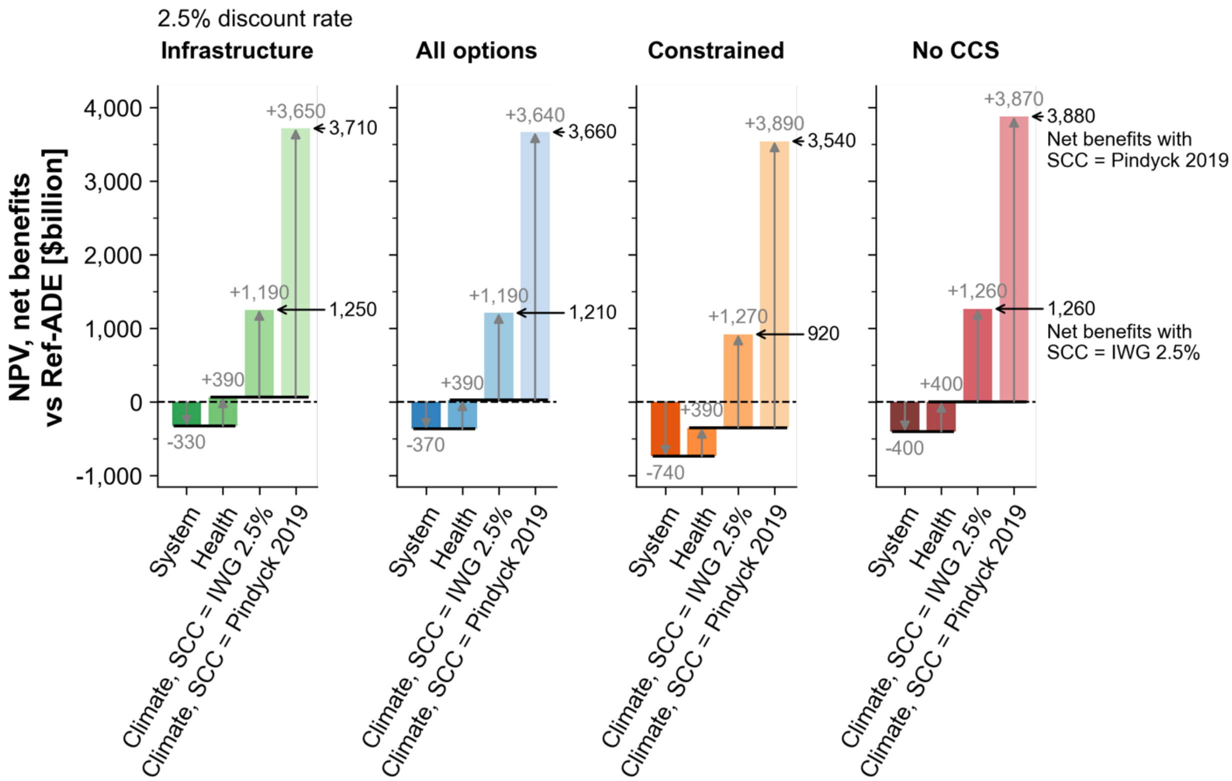

Figure 32. Achieving 100% clean electricity results in significant net benefits over the study period.

Additional power system costs (represented by negative values in the far-left bar of each chart) are of $330 billion to $740 billion compared to the Reference-ADE cost, with the largest difference resulting from restrictions to new transmission and other infrastructure development in the Constrained scenario. This cost is offset by health benefits from improved air quality benefits (positive value of $390 billion). The final two bars add the benefit of and avoided social cost of carbon (SCC). Using the lower SCC value (third bar) produces a net benefit of $900 billion to $1,300 billion, while the final bar shows the value of the higher SCC value, producing a net benefit of $3,400 billion to $3,900 billion.

[61] All comparisons of total costs and benefits are made to Reference-ADE. A full comparison to Reference-AEO is not possible because we do not have estimates of the electrification costs and benefits associated with transitioning from Reference-AEO to Reference-ADE, which would drive much of the difference between Reference-ADE and Reference-AEO. Using the Reference-ADE as a point of comparison allows for an estimate of the difference associated with achieving 100% clean electricity.

The left bar in each scenario represents the system costs (capital and operating costs in the bulk power system) with a negative value (meaning additional cost over Reference-ADE) of $330 billion to $740 billion, which represents the additional costs of achieving 100% clean electricity

The next bar to the right of the system cost bar shows the avoided health damages are shown as positive values (additional benefits). The 100% scenarios provide health benefits of $390 billion to $400 billion, meaning *these benefits alone outweigh the cost in three of the four scenarios*. Avoided climate damages are added in the final two bars with either the lower value (IWG) producing cumulative benefits of about $1,600 billion or the upper value (Pindyck 2019) producing a benefit of $4,000 billion to $4,300 billion. The horizontal lines show the sum of all three components, with the solid (lower) line using the lower SCC and producing a net benefit of $900 billion to $1,300 billion, and the dashed (upper) line using the higher SCC with values exceeding $3,500 billion in net benefits.

Figure 33 provides another measurement of the costs of the 100% scenarios (lower panels) compared to the reference cases (upper grayscale panels). Each curve provides the total cost of electricity per unit of generation borne either directly by consumers or indirectly via impacts to human health and the environment, using the same components as in Figure 32 but with health and climate damages shown as costs. The arrows below each graph indicate the reduction in annual emissions relative to 2005 along the path to 100%.

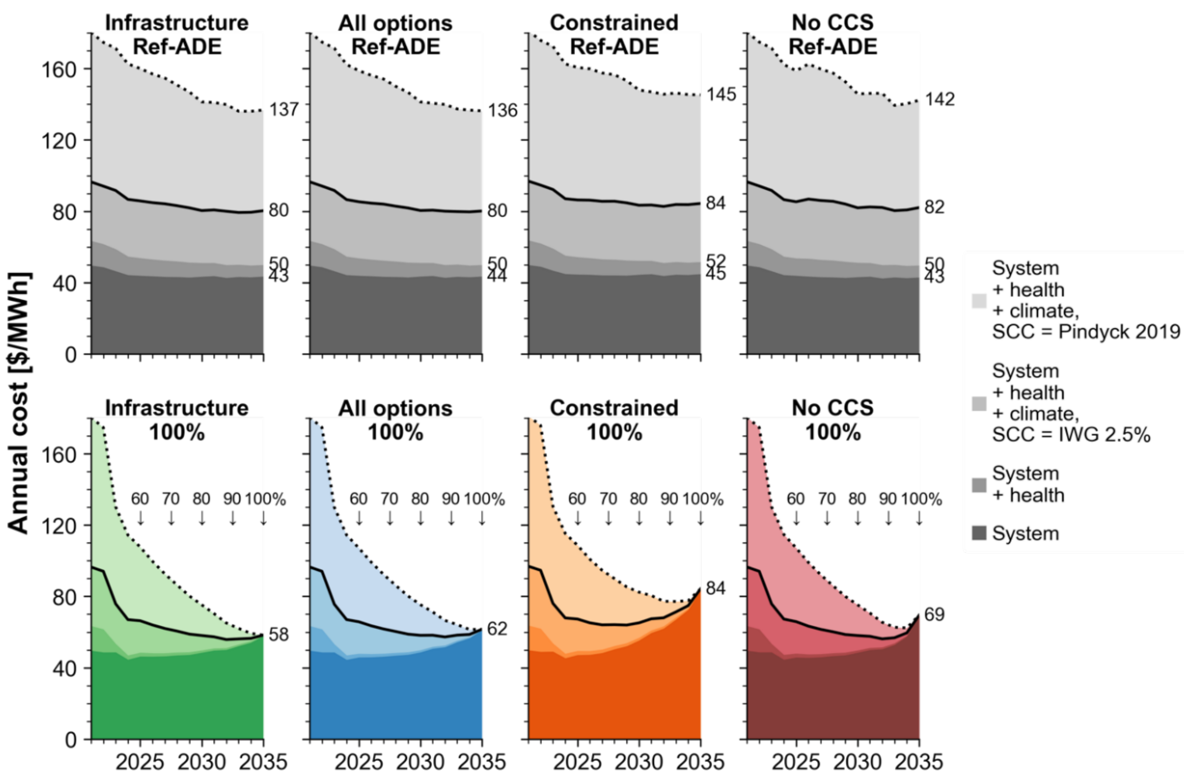

Figure 33. Net system costs adding electricity system, health damages, and climate damages over time.

Costs combine electricity system costs (darkest band at the bottom), health costs (middle band), and climate costs (upper band). Climate costs are shown with two values, and the sum of all three using the lower value for SCC is represented by the dark solid line.

The bottom area in each curve (darkest color) is the electric system cost, which is the annualized capital and operating costs in the bulk power system divided by annual electricity demand.[62] This begins at about \$50/MWh in 2022.[63] The area above the system cost is the cost associated with human health, which is about \$10/MWh in 2022 using the ACS EASIUR model results. The third cost (shown at the top) is the SCC. The lower SCC value (solid black line) adds about \$34/MWh in 2022, which produces a total cost of about \$94/MWh in 2022. The higher value (dotted line) uses the Pindyck (2019) SCC values, adding about \$115/MWh in 2022. This produces a total cost of about \$175/MWh in 2022.

The 100% scenarios show a rapid decline in total costs that is largely associated with a decline in health and climate costs. Health-related costs decrease as emissions from the most harmful pollutants, including fine particulates and SO_2, are largely eliminated by 2030, while most of the decline is associated with the SCC. Using the higher SCC value, all 100% scenarios have a significantly lower total cost in 2035 (\$61–\$79/MWh in lower costs than Reference-ADE). Using the lower SCC value, three of the four 100% scenarios have a lower cost in 2035 than Reference-ADE, while the Constrained scenario has lower costs in most years before 2035. However, achieving 100% clean electricity results in an increase in direct power system costs, particularly associated with the challenges of meeting the last 10% or so of demand in the Constrained and No CCS scenarios.[64]

4.2 Drivers of Costs and Benefits

Figure 34 (page 60) further examines the average system cost of electricity across the main scenarios and sensitivity cases. There are two important points of comparison when considering the relative cost increases observed. The first is the difference between the two reference cases represented by the two dashed lines (Reference-AEO in gray and Reference-ADE in black). These cases show a \$2–\$4/MWh (about 0.2–0.4 cents/kWh) difference in 2035 resulting from the additional demand due to electrification. Neither case has a carbon constraint beyond existing policies; the increase in cost in the ADE case compared to the AEO is due to the increased costs associated with supplying the increased electric demand, including the increase in winter peak demand. However, the ADE case accrues a considerable carbon reduction benefit due to electrification and the lower carbon content of electricity in 2035 compared to fossil fuels used for heating, transportation, and other end uses. This power-sector-focused study does not comprehensively evaluate the net benefits of electrification, such as the potentially lower cost of electricity than gasoline or diesel for use in transportation. Both the Reference-AEO and Reference-ADE cases also demonstrate a \$5–\$9/MWh reduction in system cost relative to 2020, largely as a result of continued cost reductions for wind and solar and their resulting economic deployment. The second point of comparison considers the increase in power system cost

[62] The average system cost also accounts for revenue from non-power hydrogen consumers, and for self-consistency, the electricity demand in the denominator excludes electricity used to produce hydrogen to meet non-electric-sector demand.
[63] The small difference between the Constrained and other scenarios in 2022 is due to constraints on wind and solar deployment that result in added costs.
[64] While the cost of the Constrained scenario in 2035 is slightly higher than Reference-ADE (\$2/MWh), it is significantly lower in previous years, which results in cumulative benefits that are greater than costs as observed in Figure 32 (page 54).

associated with achieving increased levels of clean electricity. This is the difference between the Reference-ADE line and the various 100% clean electricity lines.

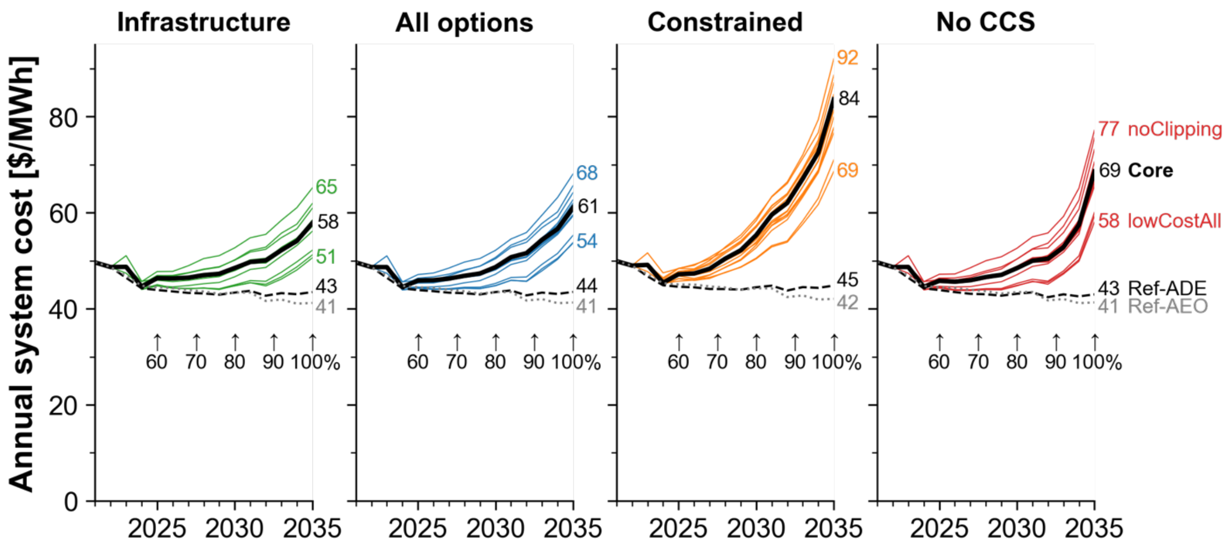

Figure 34. Average system cost increases by $15–$39/MWh (about 1.5–3.9 cents/kWh) in the main scenarios compared to the Reference-ADE case, and $8–34/MWh relative to 2020.

Annual system cost trajectories across core and sensitivity cases show that constraints in transmission and other infrastructure result in the highest costs in 100% clean electricity scenarios. Core cases are indicated by thick black lines; current-policy reference cases with accelerated demand electrification (Reference-ADE) are indicated by dotted black lines; sensitivity cases are indicated by thin colored lines. The 2035 annualized system costs are indicated for the highest- and lowest-cost sensitivity cases and for the core cases.

Due to the assumed decreasing cost of renewable technologies, we see very small differences in average system cost up to about 60%–70% clean electricity (less than $5/MWh for many scenarios). Beyond about 70% clean electricity the cost differences between the reference and 100% clean electricity scenarios increase. The most significant increase in costs on the path to 100% clean electricity observed in Figure 34 is associated with the last 10% of demand. This last 10% range also shows the greatest divergence among scenarios and represents the greatest uncertainty both in terms of technologies deployed and their associated costs. The Infrastructure Renaissance and All Options scenarios have a similar cost impact, which implies that the ability to greatly enhance transmission capacity (along with lower-cost transport and storage of hydrogen) is roughly equivalent to the value of achieving the assumed DAC cost targets. The No CCS scenario adds about $8/MWh compared to All Options, demonstrating the potential importance of CCS in meeting the last 10% of demand, particularly by enabling continued use of fossil plants without CCS via negative emissions technologies. Finally, the Constrained scenario is the most expensive. Although the scenario can deploy CCS, the lack of DAC combined with more limited deployment of transmission and renewables increases costs by another $15/MWh compared to the No CCS scenario (or $23/MWh compared to All Options).

Overall, these scenarios show the value of improvements to the cost and performance of several technologies including seasonal storage, CCS, and enhanced transmission. Figure 35 demonstrates more explicitly the impact of technology improvements by comparing the cumulative net present value of costs for 2023 and 2035 in the base scenarios and the low-cost technology sensitivities (which use lower cost assumptions for renewables, CCS, nuclear, and storage). Across all scenarios, technology improvements that could occur from further research and development could decrease the cumulative NPV of power system costs by over $160 billion.

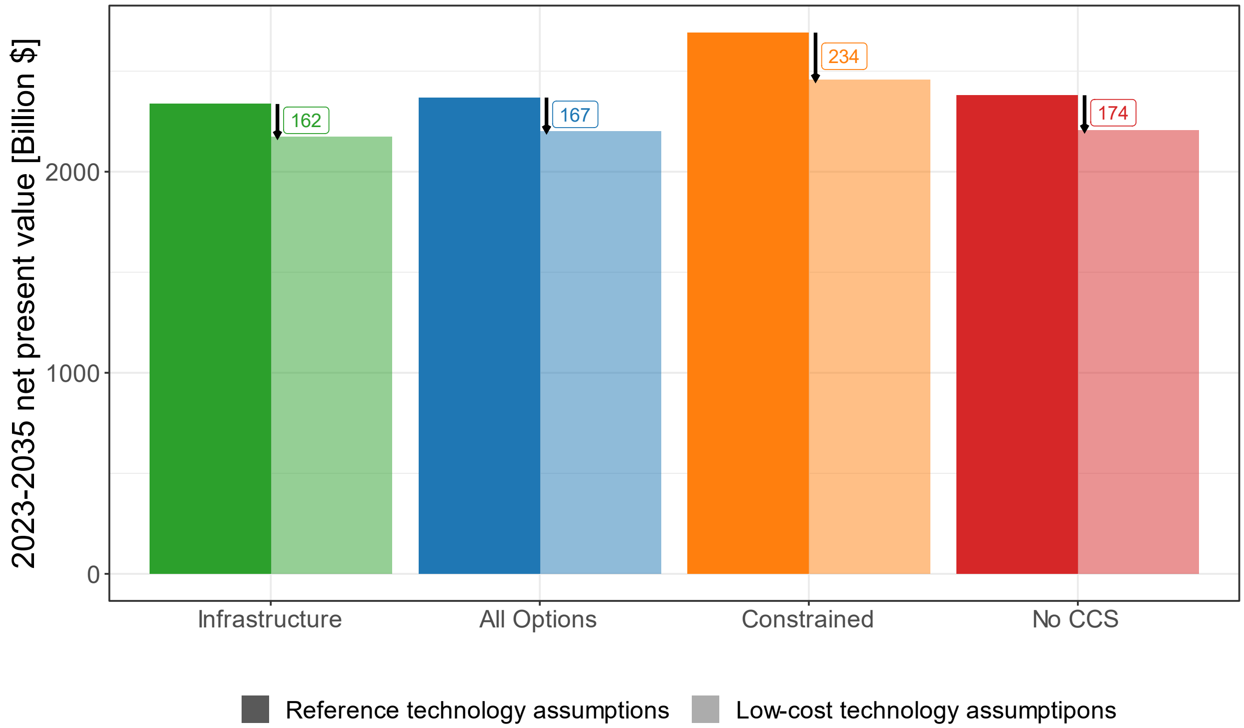

Figure 35. Low technology cost assumptions reduce the cumulative costs of achieving 100% clean electricity by 2035 (cumulative net present value of system costs calculated using a 2.5% discount rate).

Achieving the low-cost technologies results in about a 7%–9% decrease in costs.

To provide additional context to the estimated incremental costs of the 100% clean electricity scenarios, Figure 36 shows the change in average system cost for the four core and two reference scenarios (relative to the modeled 2020 value), compared to historical fluctuations in *retail* costs. All scenarios shown use the default technology assumptions.[65] The Reference-ADE scenario shows a decline in system costs, due in part to the declining costs of renewable energy plants that provide about 30% of total demand by 2035. The 100% clean electricity scenarios show an increase of 0.8–3.7 cents/kWh by 2035, representing about a 7%–34% increase in the national average retail rate for electricity (about 11 cents/kWh in 2020).[66] This increase reflects the rapid transition from today's fossil-dominated grid to a zero-carbon one, while simultaneously meeting sharply increasing electricity demand.

[65] The reference cases shown in the figure use the All Options assumptions because there are only very small differences ($2/MWh, or about 0.2 cents/kWh) between the various reference scenarios that use other assumptions (i.e., Constrained, No CCS, Infrastructure).
[66] About 13 cents/kWh for residential, 11 cents/kWh for commercial, and 7 cents/kWh for industrial customers (EIA 2022c).

Despite the increasing system costs associated with these transformational changes, Figure 36 shows how incremental costs for all four 100% clean electricity scenarios are well within the range of historical fluctuations in retail electricity costs, which are driven in part by changes to fossil fuel prices. Furthermore, while prices increase through 2035, system costs stabilize and have the potential to decline once demand growth slows and capital investments are paid off. This is shown in part by extending the analysis to 2050 in the figure.

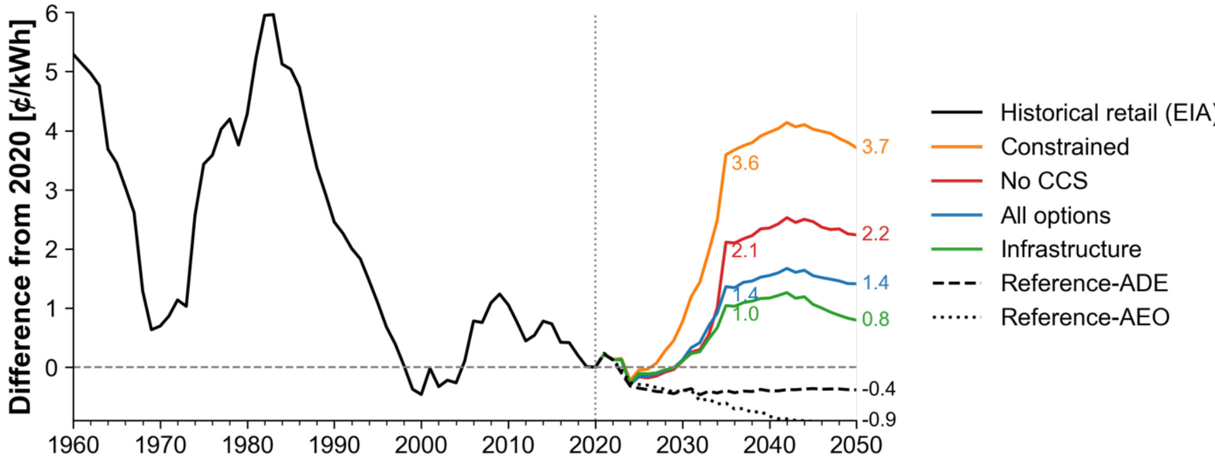

Figure 36. The increase in electricity cost associated with 100% clean electricity is within the historical range of variations in retail costs.

Costs rise through 2035 as the system transitions to 100% clean electricity but stabilize afterward. Monetary values are adjusted to 2021 U.S. dollars based on BLS (2021).

The analysis evaluates the costs of transitioning to low-emissions energy systems and considers numerous technology pathways and sensitivities. However, the modeling does not consider the impacts of market shocks, fuel supply disruptions, or other abrupt changes to energy prices. These factors have impacted historical energy prices—including electricity prices, as shown by the solid black line in Figure 36. Reducing exposure to fossil fuel price changes is another potential benefit of the 100% clean electricity scenarios, but it is not quantified in this analysis. Most generation across the core scenarios is derived from generators that have zero fuel costs (or costs that are more stable in the case of nuclear) and therefore provide a predictable cost trajectory and reduce potential price shocks.

Electrification combined with a grid with little reliance on fuel-based technologies leads to expanded benefits from price stability to historically non-electric uses. For example, less volatile (and potentially lower) gasoline and natural gas prices can benefit vehicle owners and heating customers respectively. Additionally, by reducing demand for fossil fuels, whose prices are to a degree set in global markets, the 100% scenarios may enhance energy security in the United States. Figure 37 shows the change in modeled fossil fuel use across the 100% clean electricity scenarios compared to Reference-ADE and Reference-AEO. Compared to Reference-AEO, petroleum use is reduced by about 25% across the scenarios, largely due to electrification of transportation.[67] Reduction in natural gas use varies depending on the role of CCS, but the average across the scenarios is about 50%.

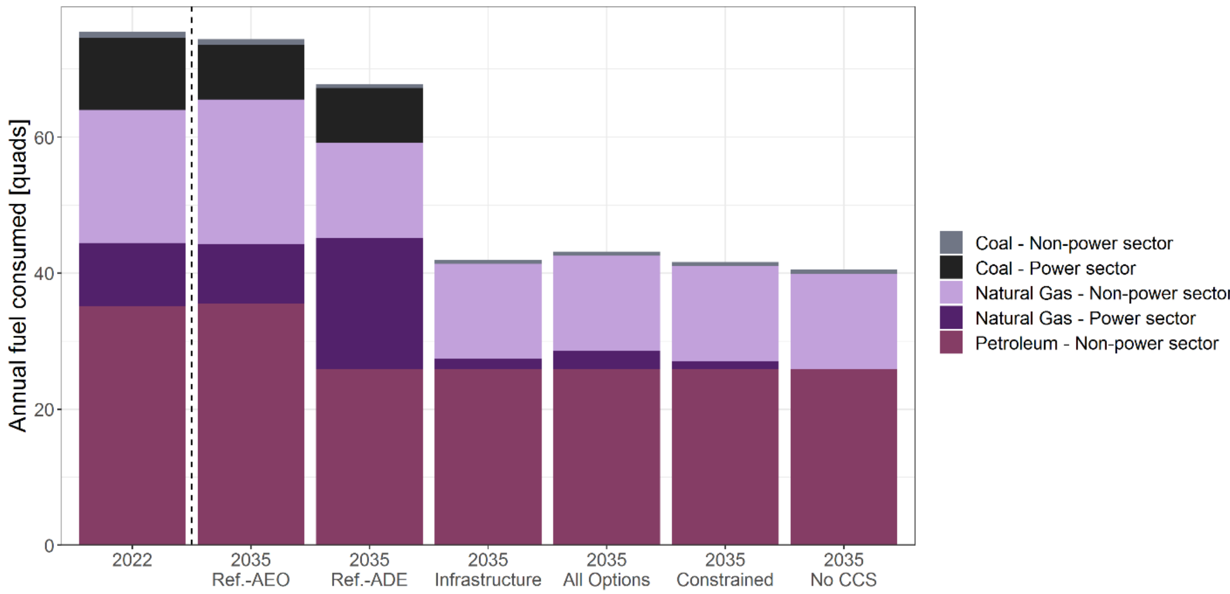

Figure 37. Avoided fossil fuel use in 2035 100% clean electricity scenarios relative to reference cases by fuel type and scenario.

Avoided coal and petroleum consumption is comparable for each of the four ADE core scenarios.

This reduction in fossil fuel use translates into avoided GHG emissions, shown across the various clean electricity trajectories by sector in Figure 38 (page 64). The top panels show the total emissions trajectories of the Reference-AEO, Reference-ADE, and 100% scenarios. The emissions in the Reference-ADE scenario are lower than in the Reference-AEO case even without additional carbon policy. This is because electricity is cleaner than fossil fuels in many applications such as the transportation sector, particularly due to the increasing use of clean electricity resources, even without explicit carbon targets. The emissions in all 100% scenarios are the same, as they all follow the same emissions pathway (Figure 5, page 14). The 100% scenarios reduce energy-related emissions by 53% in 2030 and 62% in 2035 relative to 2005 levels (White House 2021c).[68]

The bottom panels show avoided GHG emissions by sector. The bottom left panel shows the emissions avoided moving from the Reference-AEO to the Reference-ADE scenario. In this case, the emissions from the electric sector increase (due to lack of carbon policy), but the net emissions (white circles) decrease due to avoided emissions from other sectors that are electrified. The bottom right panel shows the cumulative changes between the Reference-AEO

[67] The reduction in petroleum use in the 100% clean electricity scenarios relative to Reference-ADE is 0 because both have the same level of transportation electrification. The additional benefits of this electrification accrue to the power sector, primarily through reduced natural gas use.
[68] The 2030 emissions reductions are largely aligned with the U.S. nationally determined contribution of a 50%–52% reduction from 2005 levels (White House 2021a). However, the nationally determined contribution is based on net GHG emissions for the whole U.S. economy, whereas we are estimating energy-system carbon CO_2 only.

and 100% scenarios. This reinforces the importance of electrification as a critical component of economywide decarbonization.

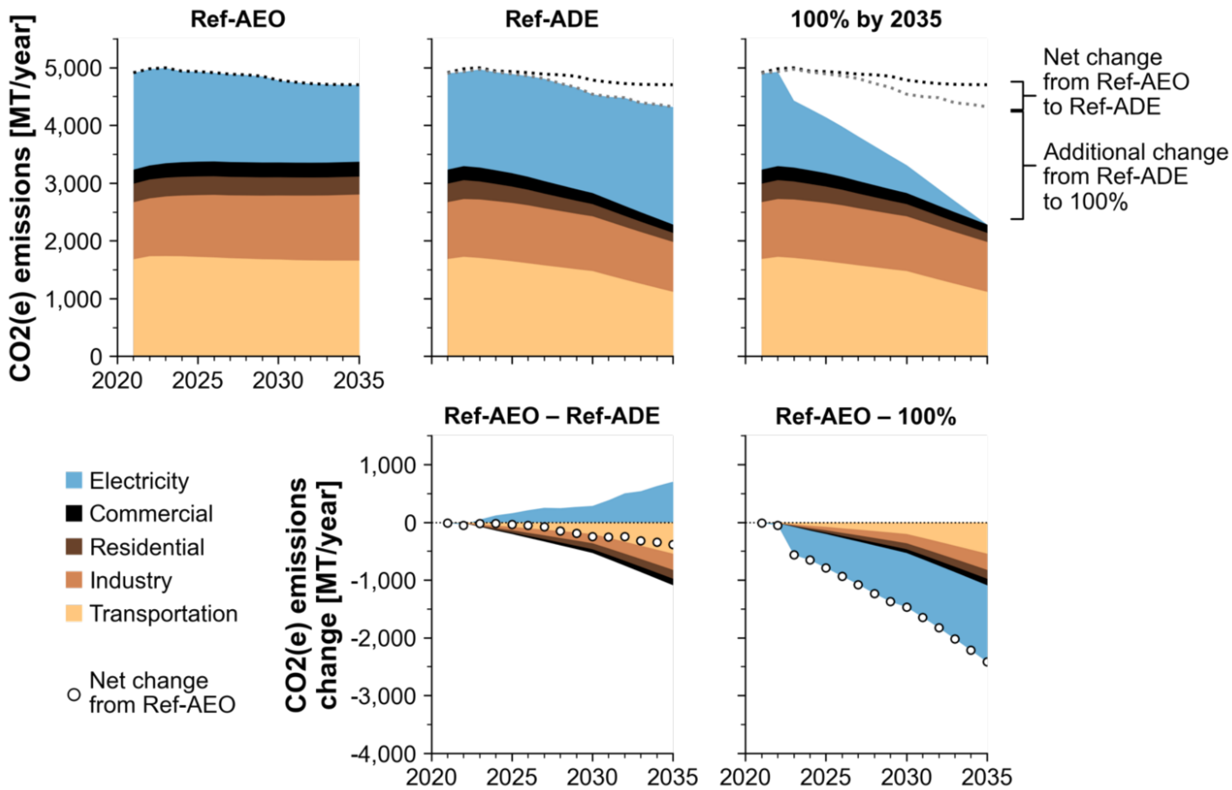

Figure 38. Total sector CO_2(e) emissions (top row) trajectories for the Reference-AEO, Reference-ADE, and 100% scenarios.

The Reference-ADE case shows significant reduction compared to Reference-AEO, as electricity is significantly cleaner than fossil fuels for industry and transportation; thus, even though the emissions from electricity increase (because this is a reference case), overall emissions are lower. The 100% clean electricity case shows the significant further decline in electricity-related emissions. The bottom row shows the net reduction in emissions of the Reference-ADE and 100% scenarios compared to the Reference-AEO scenario by sector. This highlights how electrification can reduce emissions even in the absence of explicit carbon policy, particularly in the transportation sector. In the 100% clean electricity scenarios, roughly half of the overall emissions benefits are due to electrification, demonstrating the importance of electrification in reducing economywide emissions.

Figure 39 translates the avoided emissions into a corresponding annualized benefit (compared to Reference-ADE) using a variety of SCC values. Using the median IWG estimate with a 2.5% discount rate (solid teal line) results in an annual benefit of about $200 billion in 2035. Figure 39 uses a wide range of estimates for avoided climate damages, and the lower ranges do not consider many potential impacts such as heat-related mortality. The figure does not include the additional climate benefits associated with electrification (provided in Appendix A).

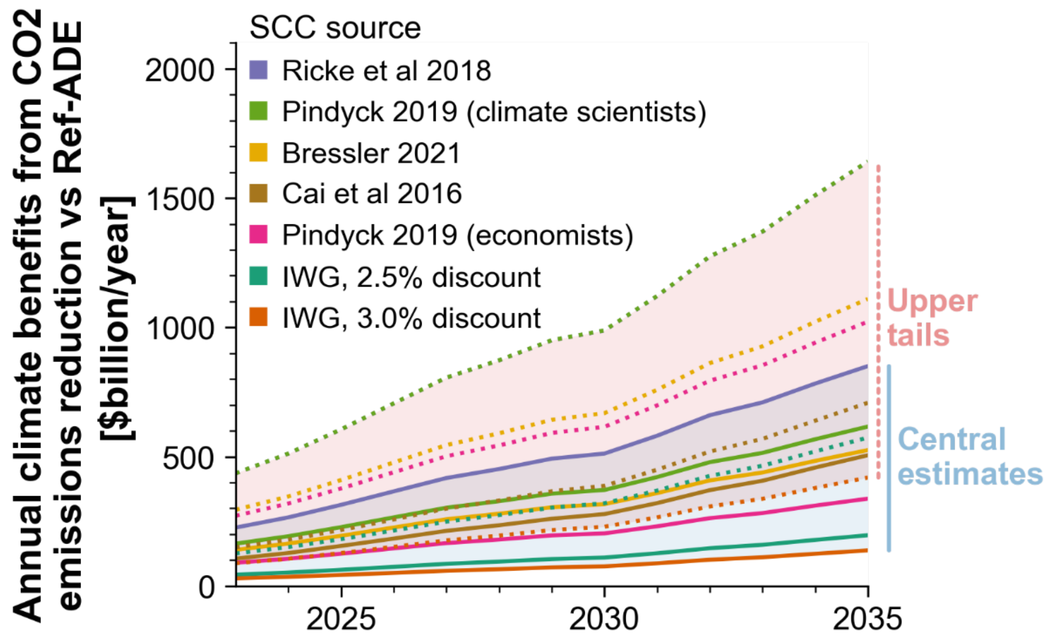

Figure 39. Annual climate benefits of 100% clean electricity using different estimates of the SCC.

Solid lines indicate median values; dotted lines indicate 95% confidence levels for IWG and Pindyck 2019, 83.3% confidence levels for Ricke et al. 2018, 90% confidence levels for Bressler 2021, and upper bounds for Cai et al. 2016. The blue shaded area shows the range of central estimates; the red shaded area shows the range of upper estimates.

Figure 40 shows estimates of annual avoided deaths associated with cleaner air (left axis) and monetary value (right axis) by applying a value of a statistical life, ($7.4 million in 2006 dollars [EPA 2022] inflated to a present-day dollar value). Central reported estimates of health benefits use the ACS EASIUR (second to bottom) value. There will also be significant air quality benefits associated with electrification of transportation, many of which will be of particular benefit to addressing environmental justice, which is not evaluated in this work.

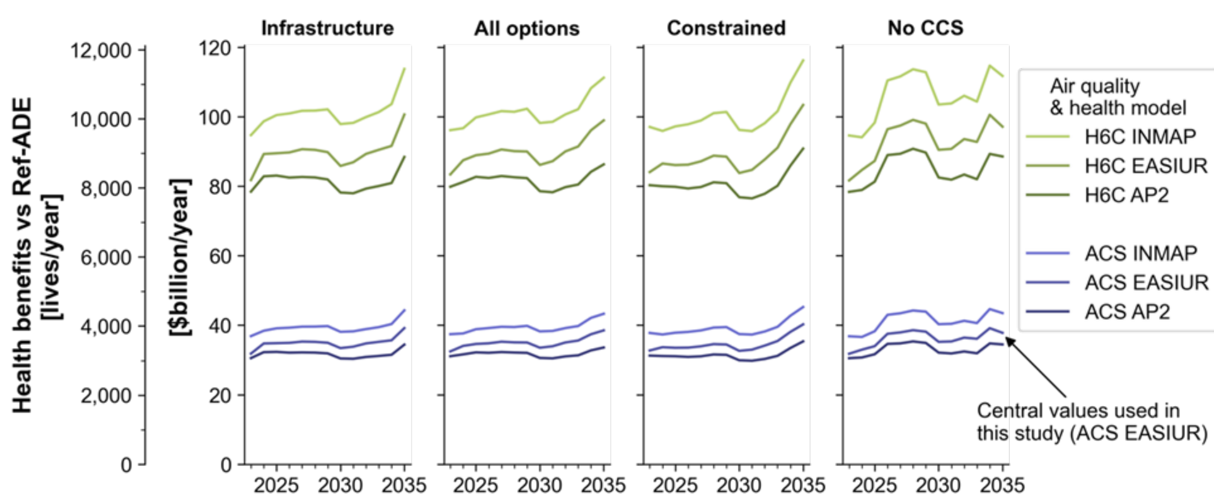

Figure 40. Estimates of annual avoided deaths and costs from 100% clean electricity scenarios compared to Reference-ADE.

Combined, this limited set of benefits outweighs the costs in all sensitivity cases in addition to the core scenarios as seen previously. Figure 41 (left) shows the overall range of benefits and costs across all sensitivities and the overall range of benefit-cost ratios (right). Overall, the large value associated with the benefits produces a benefit-cost ratio greater than 1 for all scenarios and sensitivities evaluated, with the core cases ranging from about 2.2 for the Constrained scenario to 4.8 for the Infrastructure Renaissance scenario (using the lower SCC value).

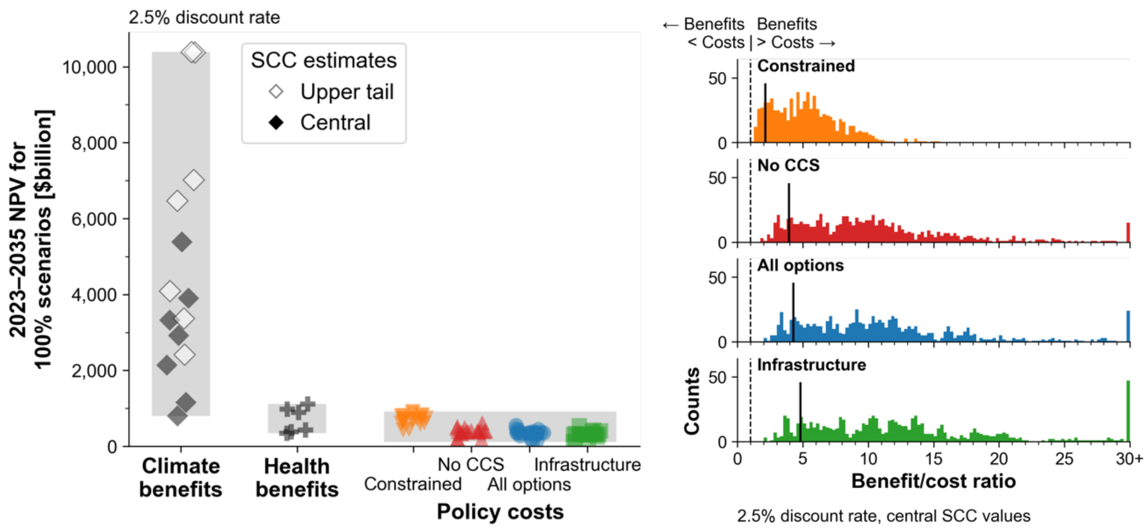

Figure 41. Cumulative net present value of costs and benefits produces a positive benefit-cost ratio for all sensitivities evaluated.

The left plot includes the range of values produced by all SCC sources in Figure 39, all air quality and health models in Figure 40, and all sensitivity cases in Figure 34. The histogram on the right includes all combinations of these three collections of values for each of the four core cases.[69] The black line indicates the benefit-cost ratio for the core case combined with the IWG (2.5% discount) SCC and ACS EASIUR health and air quality models.

4.3 Cost Results of the LTS Sensitivity

Lower demand growth and reduced capacity requirements in the LTS sensitivity result in lower power system costs in achieving 100% clean electricity scenarios. Figure 42 (page 67) shows the net present value of electricity system costs for the ADE scenarios and LTS sensitivity cases. The 100% clean electricity cases using the LTS demand trajectories result in between $307 billion and $506 billion less in investments over the study period, which is equal to about a 16%–19% reduction in costs. Reductions in the annual system cost of electricity, which normalizes all bulk power system expenditures by total delivered electricity, are more modest but remain significant. The annual system cost in 2035 is 2%–15% lower when using the LTS demand compared to the ADE across the four core scenarios: the range of average system costs are $56–$70/MWh for the LTS sensitivities compared to $58–$84/MWh for the main scenarios based on ADE.

[69] The sample set includes all combinations of the 7 central climate benefit values, 6 health benefit values, and 19 sensitivity cases (shown in the left plot), giving 798 samples for each of the four core cases. The final bin includes all observations with a benefit-cost ratio of ≥30.

These cost savings indicate the potential opportunities for additional efficiency improvements that could result in reduced infrastructure investments, as well as the deployment challenges associated with a 100% clean electricity system. However, these lower costs do not consider the investment costs associated with efficiency upgrades. Evaluating relative costs for different carbon reduction pathways requires a more comprehensive assessment of the relative costs and impacts for energy efficiency, electrification, and other demand-side mitigation options. Furthermore, energy efficiency offers a potential diversification benefit in terms of resources, workforce, and manufacturing, which also needs consideration and is beyond the scope of this study.

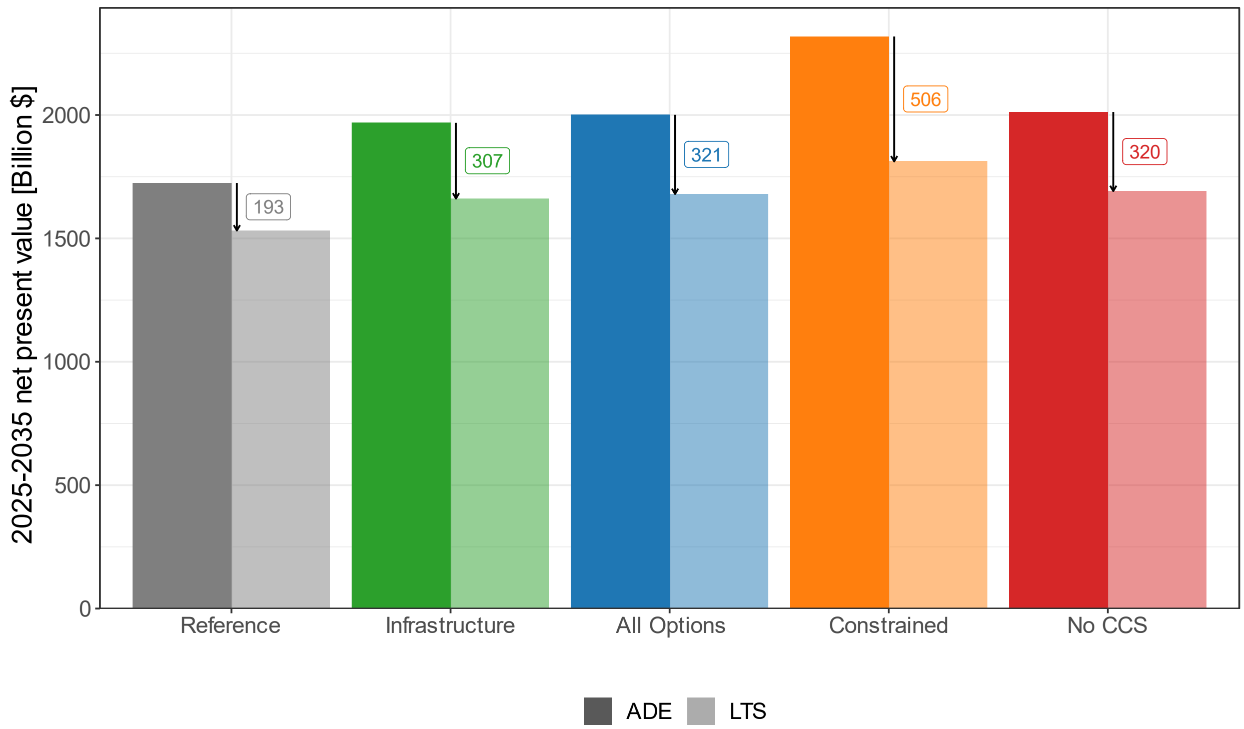

Figure 42. Net present values of system costs in the ADE scenarios and LTS sensitivity cases show a reduction in investment costs associated with the lower LTS demand.

5 Conclusions and Future Research

The costs of renewable and other clean energy technologies have declined so dramatically in the last two decades that aggressive acceleration of their deployment represents a pathway with benefits that substantially outweigh the expense. There are multiple pathways to achieve a 100% clean electricity system, and while they differ in the final mix of technologies, there are several consistent themes and challenging sets of actions needed in the next decade to achieve the transformation of the U.S. energy system to 100% clean electricity as envisioned in these scenarios:

- **Dramatically accelerating the electrification of demand sectors to get the country on the path to net-zero emissions by midcentury.** Electrification will dramatically increase demand, which in turn makes it more difficult to decarbonize the electricity system due to the rate of deployment needed. However, the most cost-effective pathway to achieving large-scale decarbonization across the economy likely involves electrification of end uses in buildings and much of transportation and industry. Aggressive energy efficiency and demand management measures can help reduce deployment needs.
- **Installing new electricity infrastructure rapidly throughout the country.** This includes siting and interconnecting new renewable and storage plants, doubling or tripling the transmission system, upgrading the distribution system, building new pipelines and storage for hydrogen and CO_2, and deploying nuclear and carbon management technologies with low environmental disturbance and in an equitable fashion to all communities.
- **Expanding clean technology manufacturing and the supply chain.** The unprecedented deployment rates for wind, solar, batteries, and other clean electricity technologies envisioned in the 100% scenarios require corresponding growth in the raw materials, manufacturing facilities, and trained workforce throughout the supply chain. Some of these technologies are more modular and amenable to rapid manufacturing scale-up than others, while size and scale of deployments will also impact the ability to site these technologies where they are needed (Wilson et al. 2020).
- **Accelerating research, development, demonstration, and deployment to bring emerging technologies to the market.** Technologies that are being deployed widely today represent the vast majority of the solution to achieving a deeply decarbonized power sector. A 90% clean grid can be achieved at low incremental cost by relying primarily on new wind, solar, storage, transmission, and other technologies already installed today. However, the path from 90% to full decarbonization is less clear, as multiple technologies, such as hydrogen and other low carbon fuels, advanced nuclear, CCS, and DAC, can aid full decarbonization but are not yet ready for cost-effective deployment at large scale. A concerted research, development, demonstration, and deployment effort is needed to reduce costs and improve performance to enable these technologies to be commercialized at scale and support a fully decarbonized grid.

This is an ambitious list of tasks that will require explicit support to achieve in the coming decade. However, damages from climate change scale with emissions, so even if emissions reductions fall short of those envisioned here, significant harm to human health, economies, and the ecological system can be avoided. Failing to achieve any of these tasks could increase the difficulty of achieving a 100% clean grid by 2035.

As noted throughout this report, even the combination of aggressive electrification and a 100% clean electricity supply will be insufficient to reduce emissions to levels needed to address climate change. Additional analysis is needed to evaluate the least-cost path to economywide decarbonization in 2050.

Working with the national laboratories and other experts, future economywide decarbonization analysis will assess the benefits, costs, and trade-offs for potential pathways. Specific activities could include:

- **Power Sector Evolution:** Additional analysis is required to better capture potential price, performance, and infrastructure uncertainties associated with nascent technologies (e.g., DAC, BECCS, CCS, advanced nuclear, clean hydrogen, long-duration storage) and the integration of distributed energy resources. High-resolution simulations could be conducted to assess the reliability and resource adequacy of potential generation and transmission portfolios, given the increased frequency of extreme weather. Lastly, the full range of benefits attributed to power sector decarbonization could be quantified, and their intersection with equity and environmental justice could be explored.
- **End-Use Electrification and Efficiency:** This study demonstrated the oversized impact that increased electricity demand can have on power sector evolution. Additional analysis is required to assess the cost-competitiveness of different electrification pathways across end-use sectors, simulate the operational and reliability impacts of electrification at scale, and better understand the role of consumer behavior. Moreover, further study is needed to evaluate trade-offs between electrification, energy efficiency, distributed energy resources, and other demand-side measures in reducing emissions at lowest cost for households and other stakeholders.
- **Clean Fuel and Feedstocks:** Economywide decarbonization will have supply and demand interactions across sectors. Clean fuels and feedstocks will play an increased role in the power, buildings, industry, and transportation sectors. Additional analysis is needed to better understand cost trajectories, feedstock dependencies, and infrastructure requirements of clean fuel pathways, and the potential impact trade-offs for end-use applications.

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Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035: Appendices

List of Acronyms and Abbreviations

ADE	accelerated demand electrification
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
B2B	back-to-back
BA	balancing area
BECCS	bioenergy with CCS
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CSP	concentrating solar power
CT	combustion turbine
DAC	direct air capture
DC	direct current
DOE	U.S. Department of Energy
EFS	Electrification Futures Study
EIA	U.S. Energy Information Administration
GW	gigawatts
H2	hydrogen
HVDC	high-voltage direct current
LTS	Long-Term Strategy
MMBtu	million British thermal units
MT	million tonnes
MW	megawatts
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laboratory
NG	natural gas
PV	photovoltaics
ReEDS	Regional Energy Deployment System
ROW	right(s) of way
SMR	steam methane reforming
TWh	terawatt-hours
VRE	variable renewable energy
VSC	voltage-source converter

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Appendix A. Additional Results from Main Scenarios and Sensitivities

A.1 Full Sensitivity List

Table A1 details the full suite of sensitivities evaluated for this study. Each sensitivity is evaluated for each of the four core scenarios except when a scenario is listed in the Excluded Scenarios column. When considering the combinations of scenarios and sensitivities, a total of 142 sensitivities were run for this study.

Throughout this appendix, runs are referred to using the nomenclature of [scenario]_[sensitivity modeling name]; for example, the sensitivity evaluating AEO demand trajectory for the All Options scenario is referred to as AllOptions_demandAEO.

Table A1. All Sensitivities Evaluated for This Study

Each sensitivity was evaluated for each of the four core scenarios except when a scenario is listed as excluded. A total of 142 sensitivity cases were run for this study, 122 of which get to 100% carbon-free electricity by 2035.

Grouping	Modeling Name	Sensitivity Name	Description	Excluded Scenarios
CO_2 targets and demand growth	noPolicy	Reference	There are no carbon constraints (i.e., reference case).	none
	demandAEO	AEO demand	Electricity demand is based on the AEO projection.	none
	noPolicyDemandAEO	Reference with AEO demand	There are no carbon constraints, and electricity demand is based on the AEO projection.	none
	highEFS	High EFS[a] demand	Electricity demand is based on the Electricity Futures Study projection.	none
	noPolicyHighEFS	Reference with High EFS demand	There are no carbon constraints, and electricity demand is based on the Electricity Futures Study projection	none
	demandLTS	LTS (Long-Term Strategy) demand	Electricity demand is derived from LTS (White House 2021)	none
	noPolicyHighLFS	Reference with LTS demand	There are no carbon constraints, and electricity demand is derived from LTS.	none
	noClipping	No clipping of top 1% of demand	It is assumed that no demand response	none

Grouping	Modeling Name	Sensitivity Name	Description	Excluded Scenarios
			can reduce demand in top 1% of hours (applied to the Advanced Demand Electrification demand projection).	
	noPolicyNoClipping	Reference and no clipping of top 1% of demand	There are no carbon constraints and it is assumed that no demand response can reduce demand in top 1% of hours (applied to the Advanced Demand Electrification demand projection).	none
High-cost pathways	highCostHydro	High hydropower costs	There are no reductions in hydropower costs over time.	none
	highCostPV	High PV costs	PV costs follow ATB 2021 conservative cost projections.	None
	highCostWind	High wind costs	Onshore and offshore wind costs follow ATB 2021 conservative cost projections.	None
	highCostBatt	High storage costs	Battery storage costs follow ATB 2021 conservative cost projections.	None
	highCostREBatt	High renewable energy and storage costs	Costs for renewable energy technologies (solar, wind, geothermal, CSP, and hydropower) and battery storage follow high-cost assumptions.	None
	highCostGas	High natural gas cost	Natural gas fuel costs follow a high trajectory based on the AEO low oil and gas projection.	None

Grouping	Modeling Name	Sensitivity Name	Description	Excluded Scenarios
Low-cost pathways	lowCostCCS	Low CCS costs	Costs of CCS on fossil generation follow ATB 2021 advanced cost projections.	No CCS
	lowCostCSP	Low CSP costs	CSP costs follow ATB 2021 advanced cost projections.	None
	lowCostGeo	Low geothermal costs	Geothermal costs follow ATB 2021 advanced cost projections.	None
	lowCostHydro	Low hydropower costs	Hydropower costs follow aggressive cost reduction over time.	None
	lowCostPV	Low PV costs	PV costs follow ATB 2021 advanced cost projections.	none
	lowCostNuclear	Low nuclear costs	The overnight capital cost of small modular nuclear reactors reaches \$4,500/kW by 2035 and \$3,600/kW by 2050.	none
	lowCostWind	Low wind costs	Onshore and offshore wind costs follow ATB 2021 advanced cost projections.	none
	lowCostElectrolyzer	Low electrolyzer costs	Aggressive cost declines are assumed for electrolyzers.	none
	lowCostBatt	Low storage costs	Battery storage costs follow ATB 2021 advanced cost projections.	none
	lowCostREBatt	Low renewable energy and storage costs	Costs for renewable energy technologies (solar, wind, geothermal, CSP, and hydropower) and battery storage follow low-cost assumptions.	none

Grouping	Modeling Name	Sensitivity Name	Description	Excluded Scenarios
	lowCostAll	Low costs all	Costs for renewable energy technologies (solar, wind, geothermal, CSP, and hydropower), nuclear, fossil CCS, battery storage, and electrolyzers all follow low-cost assumptions.	none
	lowCostDAC	Low DAC (direct air capture) cost	Costs of DAC decline over time based on projected learning rates in Fasihi, Efimova, and Breyer (2019).	Infrastructure, No CCS, Constrained
	lowCostGas	Low natural gas cost	Natural gas fuel costs follow a low trajectory based on AEO high oil and gas projection.	none
Allowed capacity builds	transRestrict	Restrict transmission to intra-regional transmission organization	New transmission can only be within existing footprints of regional transmission organizations.	none
	gasCCSupgrades	Allow Gas-CC-CCS upgrades	Upgrades of existing natural gas combined cycle plants to include CCS are allowed.	No CCS
	noNewGas	No new builds of gas capacity	New gas builds are disalowed after 2022.	none
	bioExpand	Expanded biomass	Woody biomass supply available for electric power generation is doubled.	Constrained
	allowDAC	Allow for DAC	Direct air capture is enabled (by default DAC is only allowed in All Options).	All Options, No CCS
	noH2CT	No H2-CTs	Hydrogen combustion turbines are disallowed.	none
Fossil fleet treatment	CCS95	95% Capture CCS	CCS technology is modeled with a 95% capture rate.	No CCS

Grouping	Modeling Name	Sensitivity Name	Description	Excluded Scenarios
	CCS99	99% Capture CCS	CCS technology is modeled with a 99% capture rate.	No CCS
	noMethaneLeak	No methane leakage	The CO_2 equivalent of leaked methane is not included in the carbon constraint.	none
	methaneLeak20	Account for methane leakage using 20-yr global warming potential	The CO_2 equivalent of leaked methane is evaluated using a 20-year global warming potential.	none

[a] *EFS: Electrification Futures Study*

A.2 Capacity and Generation for All Sensitivity Cases

The following figures show the installed capacity, generation, and generation share for all sensitivity cases.

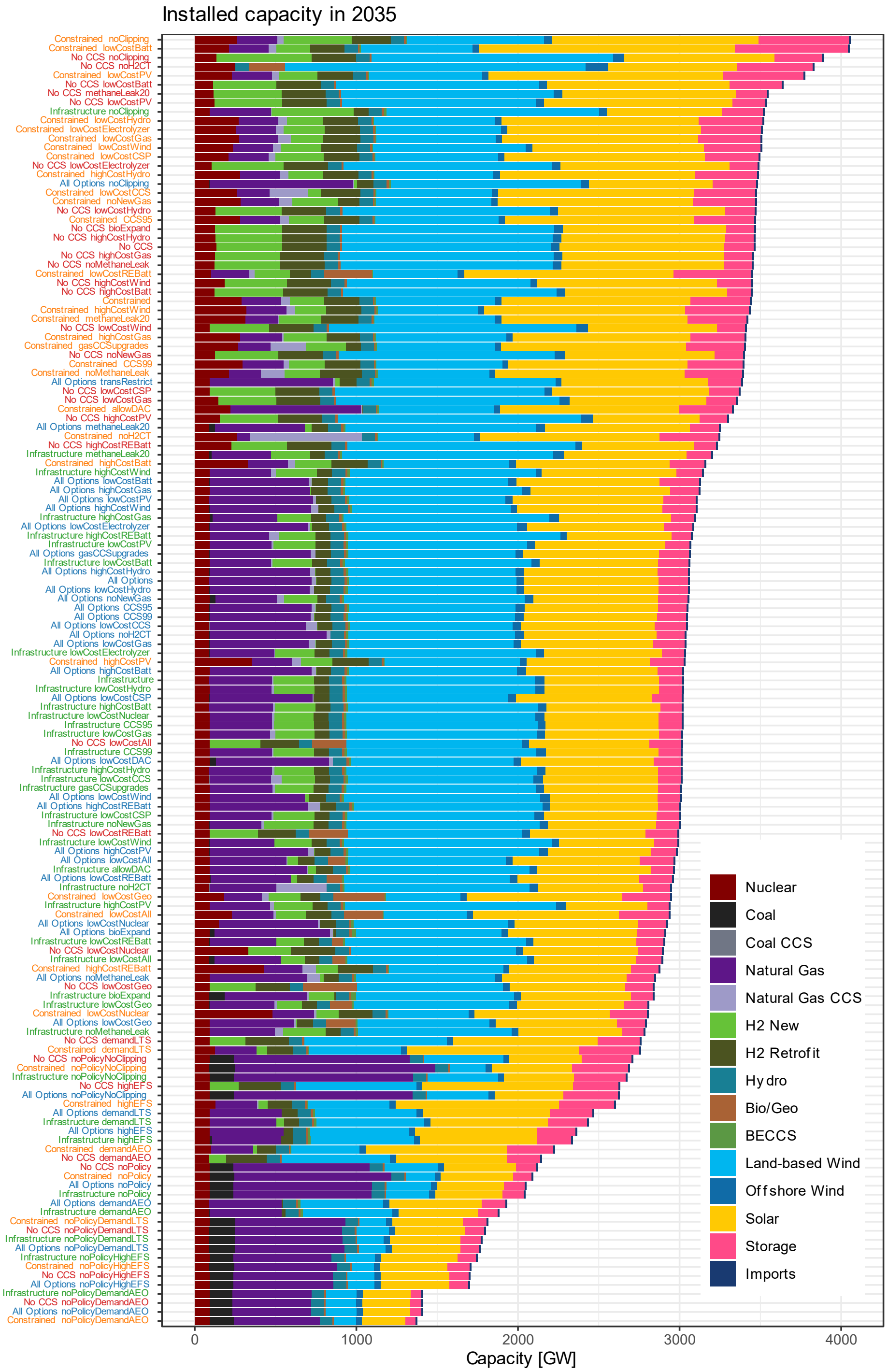

Figure A1. Installed generating capacity (GW) in 2035 by technology for all sensitivity cases

Sensitivity names are colored based on their core scenario.

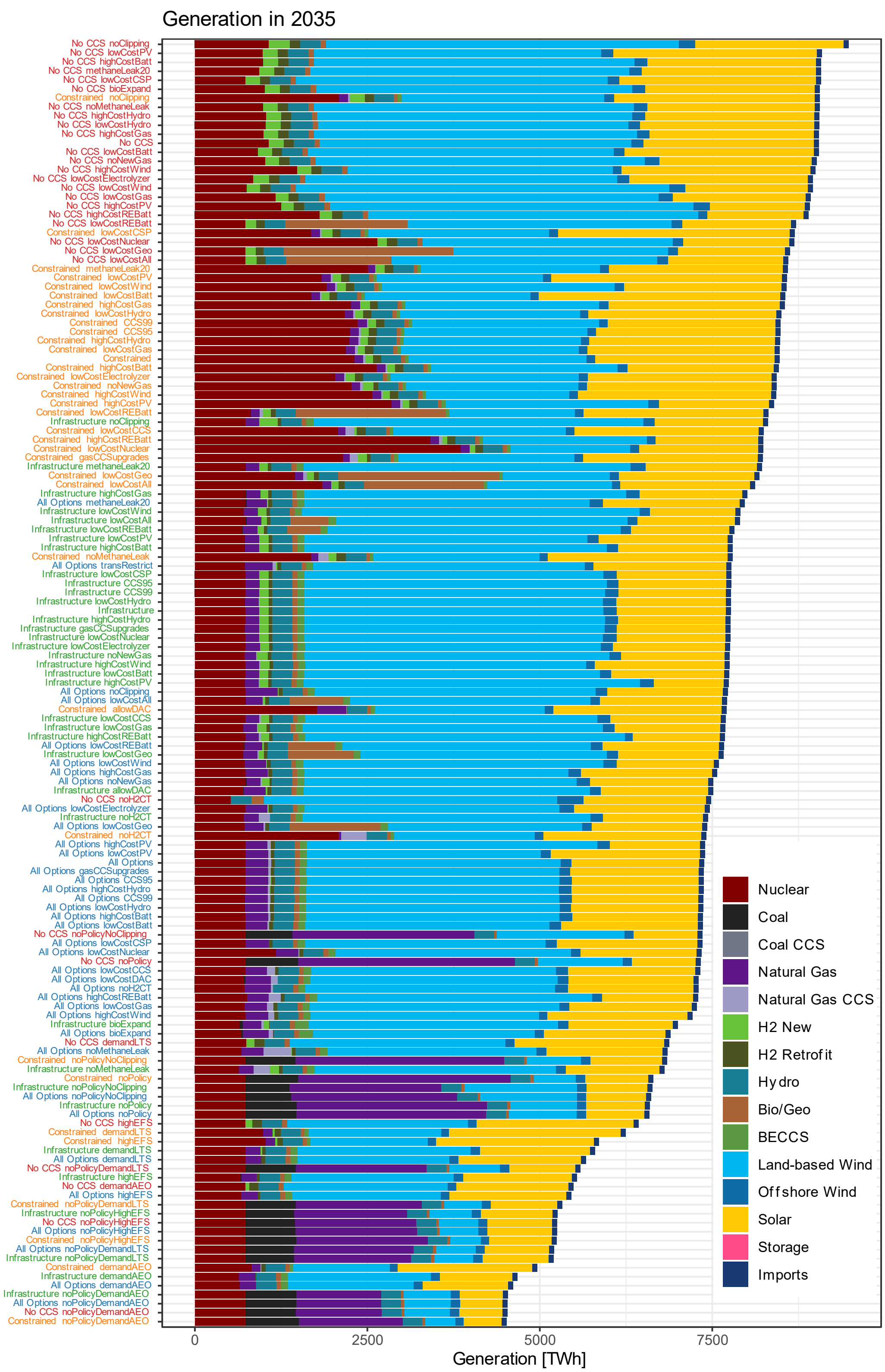

Figure A2. Annual generation (TWh) in 2035 by technology for all sensitivity cases

Sensitivity names are colored based on their core scenario. Storage and DAC not included as they do not generate electricity

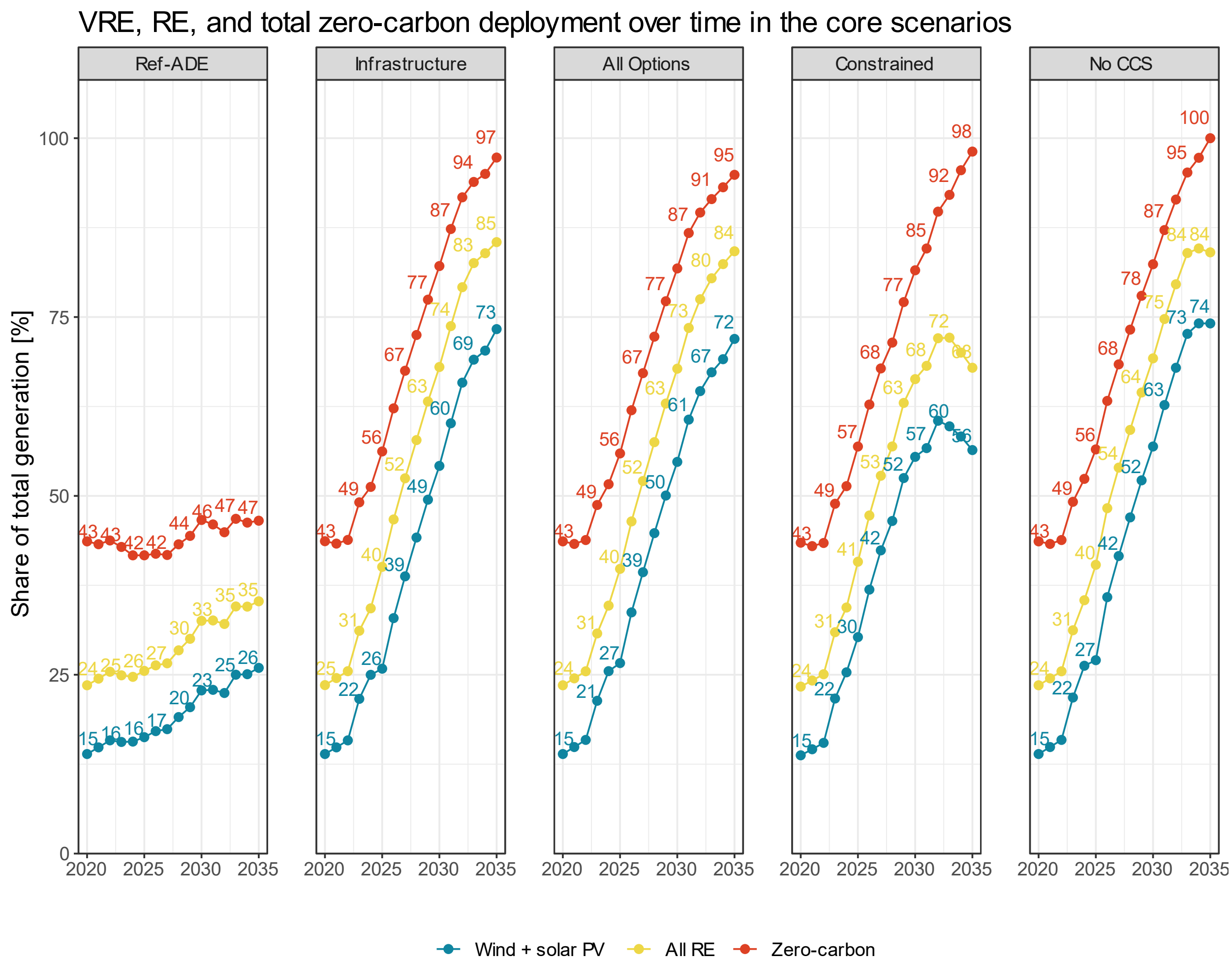

Figure A3. Share of total generation coming from variable renewable sources (VRE, comprising wind and solar PV), all renewable energy (VRE + biomass, geothermal, CSP, and hydropower), and all clean (i.e., zero-carbon) sources (VRE, other renewable sources, and nuclear) by year for the four core scenarios and the accelerated demand electrification (ADE) reference

RE: renewable energy

A.3 Cost Results for All Sensitivity Cases

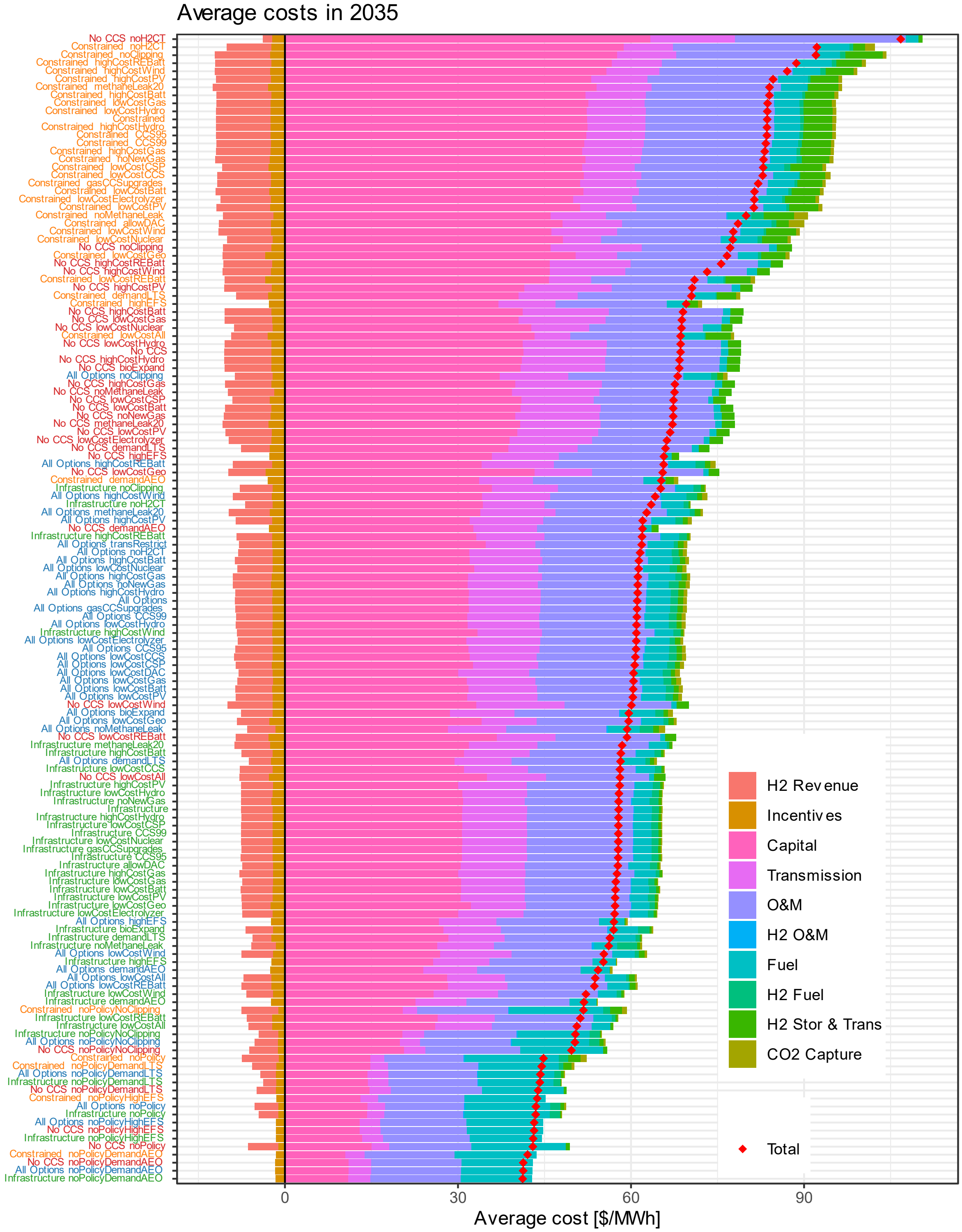

Figure A4. Average cost ($/MWh) in 2035 for all sensitivities, broken down by cost category

Diamonds indicate total average cost for each sensitivity. Value from incentives (e.g., federal production tax credit and investment tax credit) and hydrogen sold for use outside the power sector are treated as revenues that offset power sector costs.

A.4 CO_2 trajectories

Figure A5 illustrates the annual electric sector CO_2 emissions by source for the reference and 100% clean electricity cases.

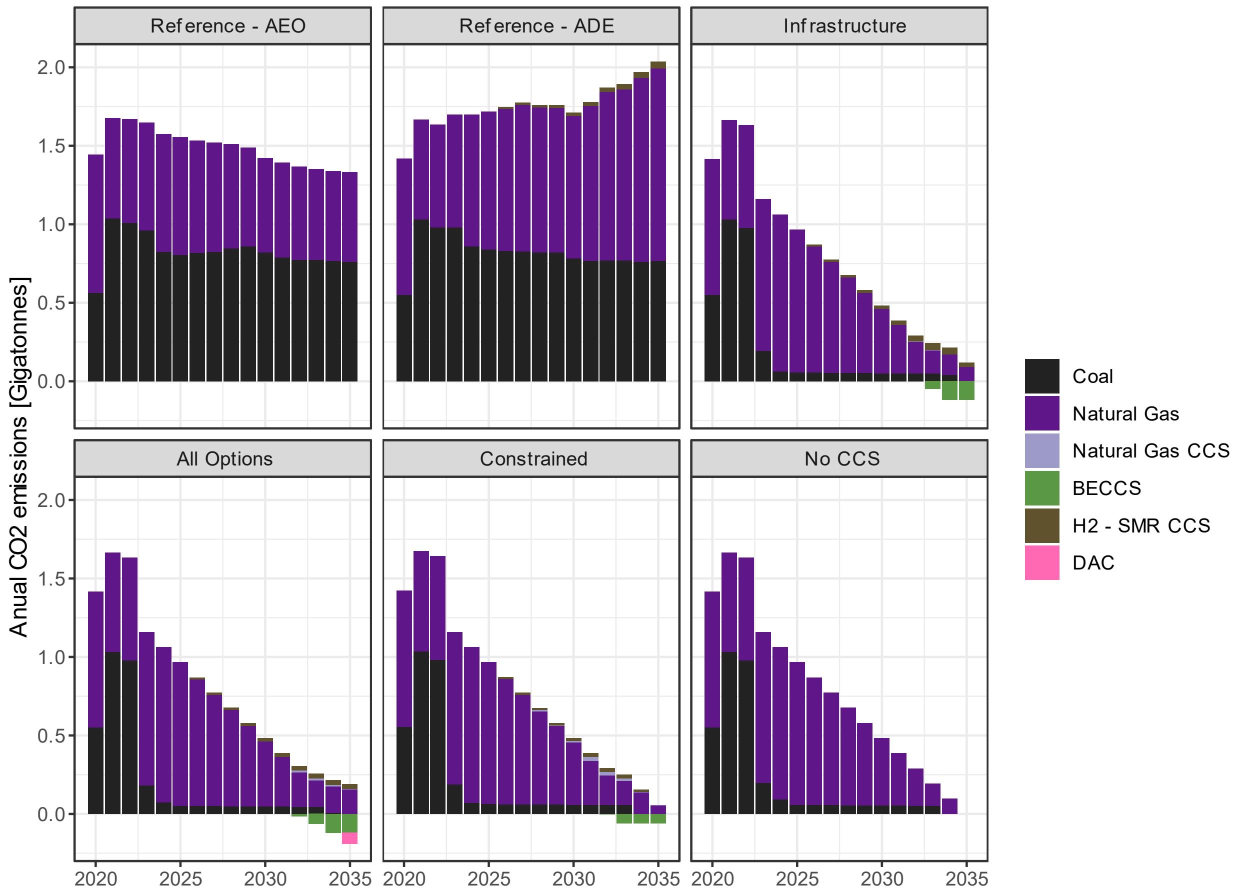

Figure A5. Power sector CO_2 emissions by year and technology type for the reference and core scenarios

All core scenarios achieve net zero emissions in 2035, with some scenarios using negative emissions (DAC and BECCS) to meet the target.

Figure A6 illustrates the climate benefits of achieving this trajectory relative to Reference-AEO. This includes the benefits of both electrification and clean electricity. The total benefits calculations in the results section include only those relative to Reference-ADE (which do not include the benefits of electrification), as the costs of electrification were not calculated.

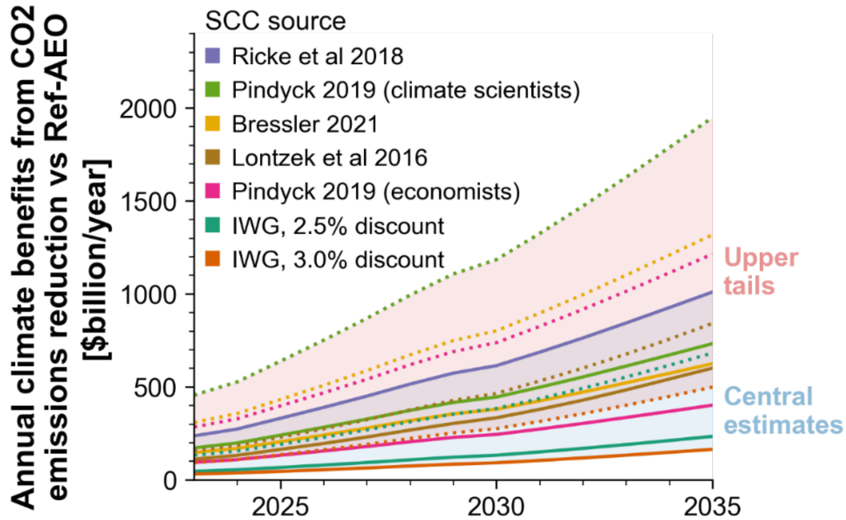

Figure A6. Climate benefits for the 100% clean electricity scenarios relative to Reference-AEOCO$_2$

All core scenarios achieve net zero emissions in 2035, with the benefits accruing in both the power sector and other sectors that are electrified.

A.5 Land Use and Siting

Figure A7 shows the total capacity deployed in 2035, compared to the total amount of developable capacity based on restrictions in each of the four core 100% clean electricity scenarios. Figure A8 and Figure A9 show the land used by utility-scale PV and land-based wind power plants in each state. For wind, this value represents the area occupied by the perimeter of the wind plants where about 98% of the area is available for agriculture or other uses. Of the total area, about 2% is occupied by the wind turbine pad, roads, and other infrastructure. Figure A9 and Figure A10 show the ratio of land area occupied by PV and wind capacity in 2035 to total state land area (i.e., the dark bars in Figure A7 and Figure A8 divided by the black lines) and developable land area (i.e., the light bars in Figure A7 and Figure A8 divided by the black lines), including the entire perimeter of wind plants. Land area directly occupied by wind and solar infrastructure is ≤7% of total land area in all states and scenarios and <1% in ~94% of states and scenarios.

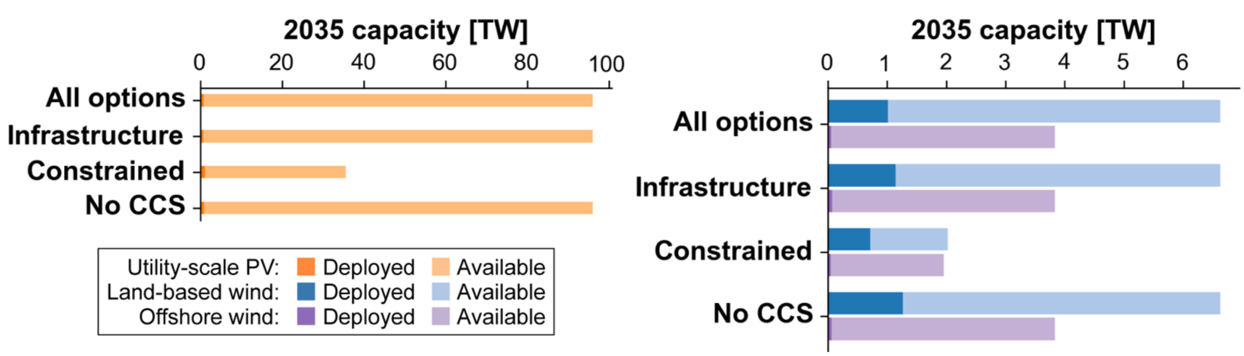

Figure A7. Available capacity (light bars) and deployed capacity in 2035 (dark bars) for utility-scale PV (orange), land-based wind (blue), and offshore wind (purple) for the contiguous United States

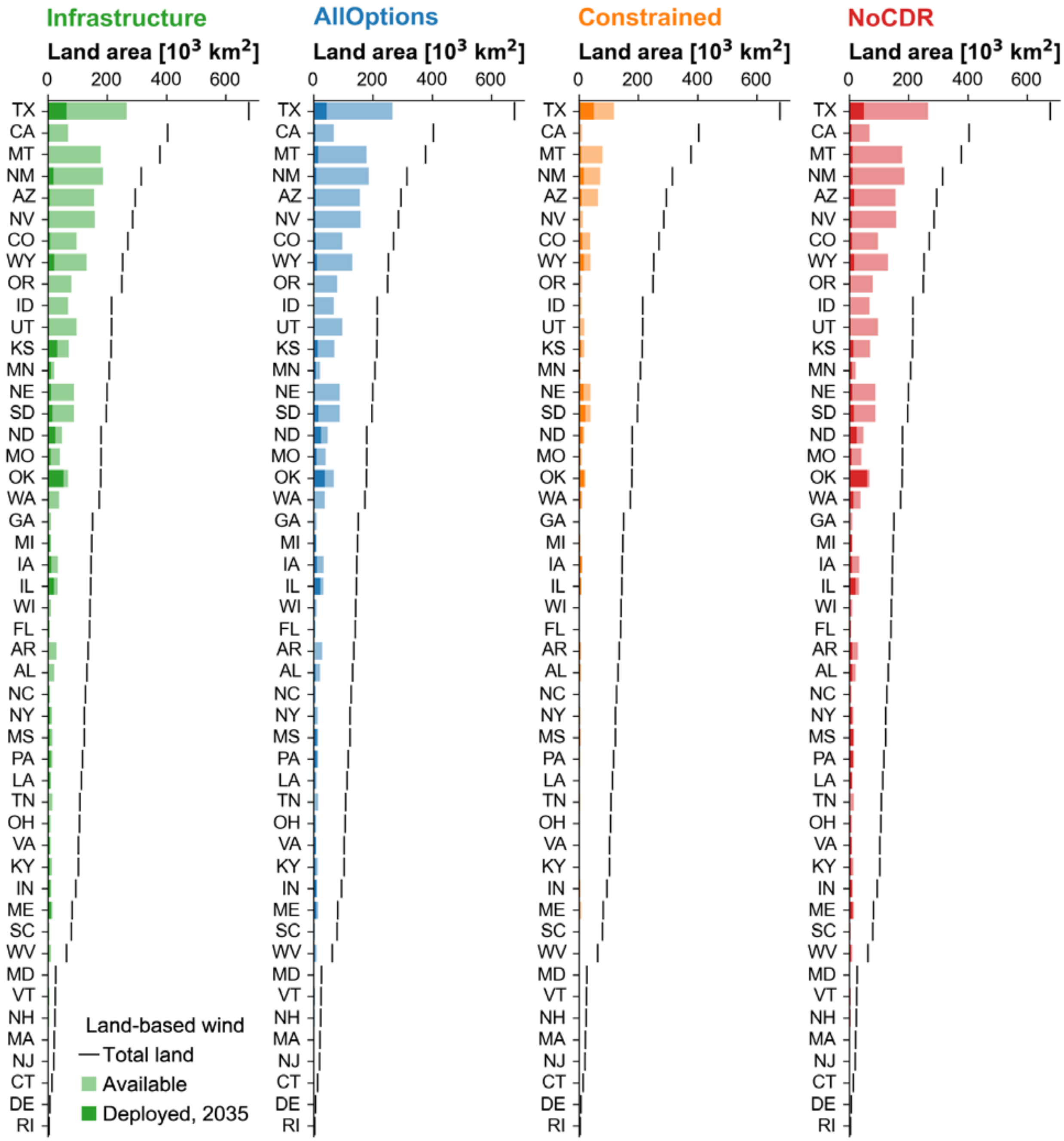

Figure A8. Total land area (black lines), available land area for wind deployment (light bars), and land area occupied by wind capacity in 2035 (dark bars) by state

The available and deployed land area for wind include the complete perimeter of the modeled wind plants, only ~2% of which is occupied by wind turbine infrastructure.

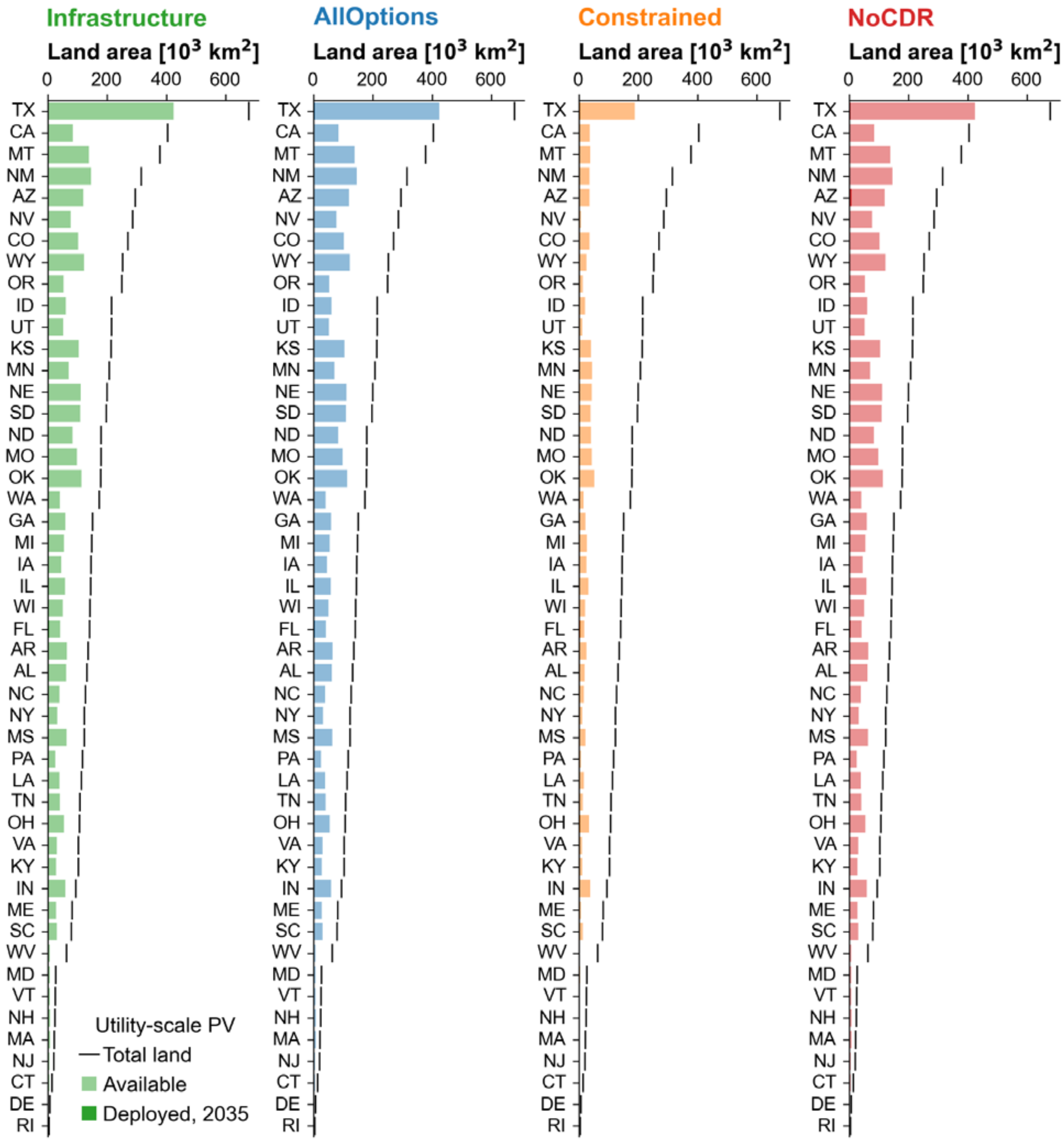

Figure A9. Total land area (black lines), available land area for utility-scale PV deployment (light bars), and land area occupied by utility-scale PV capacity in 2035 (dark bars) by state

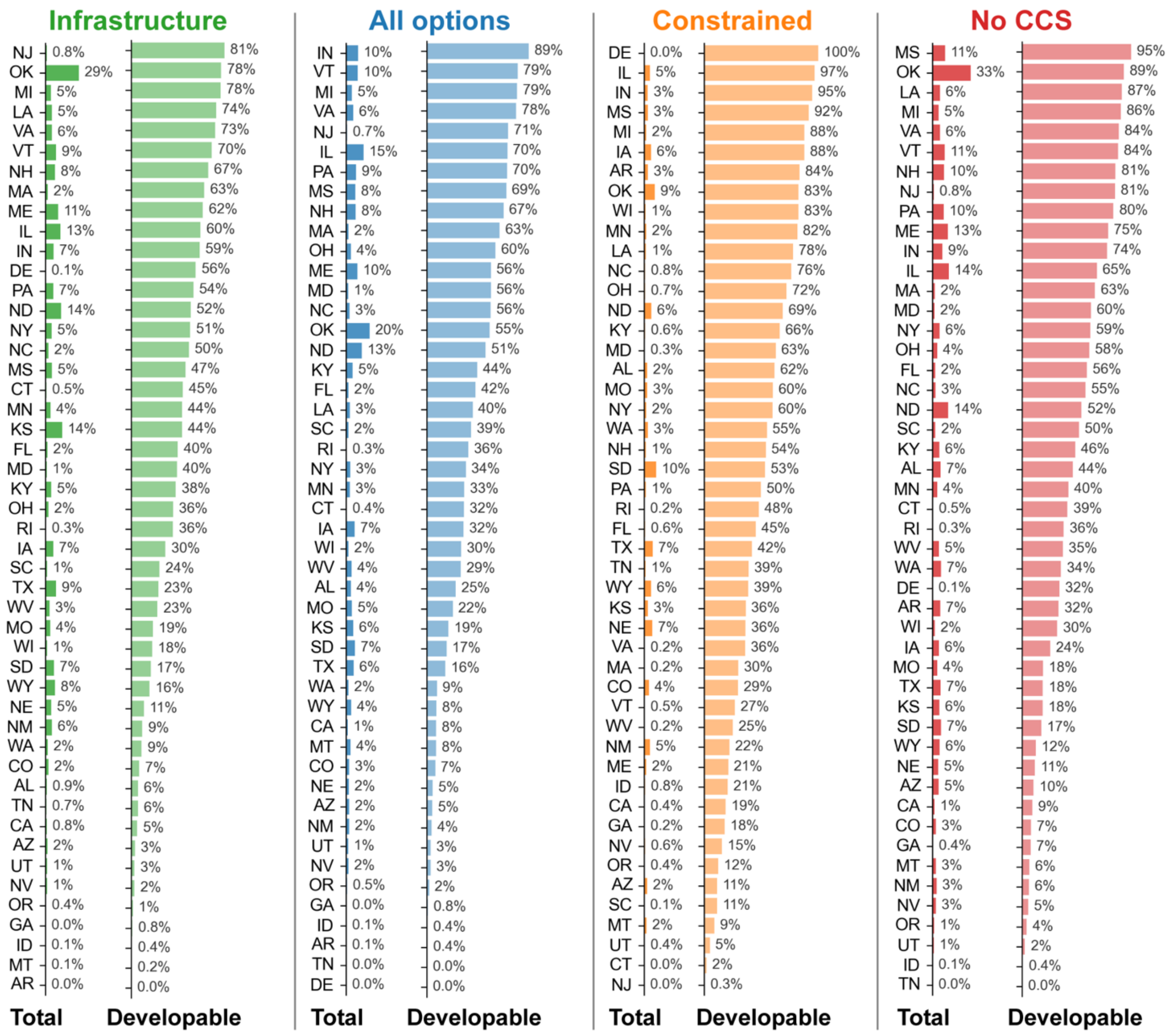

Figure A10. Percentage of total state land area (dark bars on left of each scenario pair) and percentage of developable area (light bars on right of each scenario pair) occupied by land-based wind capacity in 2035

The land area for wind includes the complete perimeter of the modeled wind plants, only ~2% of which is occupied by wind turbine infrastructure.

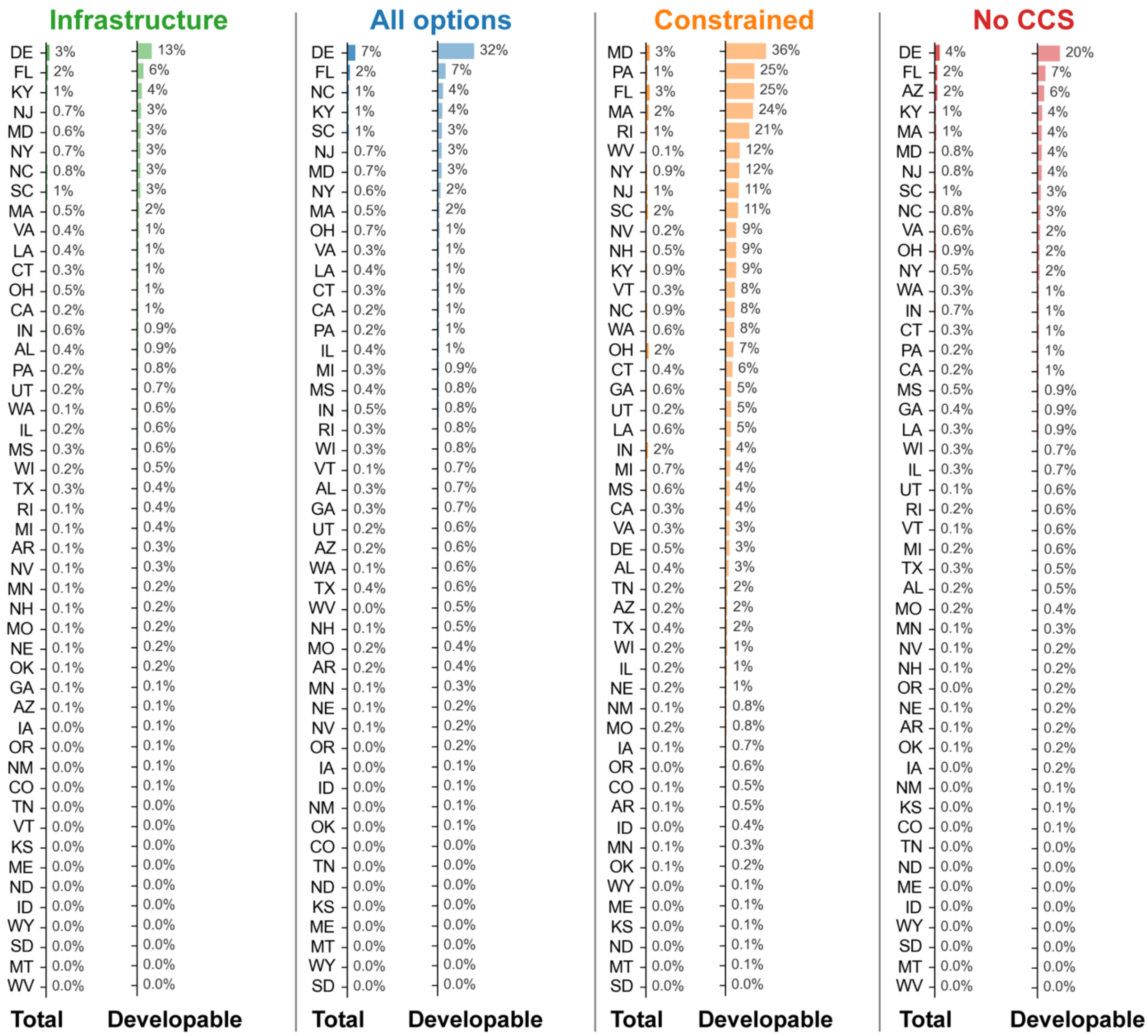

Figure A11. Percentage of total state land area (dark bars on left of each scenario pair) and percentage of developable area (light bars on right of each scenario pair) occupied by utility-scale PV capacity in 2035

Table A2 summarizes the land use values for comparison shown in the body of the report.

Table A2. Land Use Comparison

Land Use Category	Area (km^2)	References and Notes
Airports	12,140	Merrill and Leatherby (2018)
Building footprints	73,578	Lopez et al. (2021); Microsoft Buildings Database[1]
Bureau of Land Management land	989,000	CRS (2020)
Coal (historically disturbed)	16,700	MIT (2015)
Contiguous United States	7,653,004	U.S. Census Bureau (2012)
Ethanol for biodiesel	153,780	Merrill and Leatherby (2018)
Existing transmission ROWs (≥69 kV)	67,531	Lopez et al. (2021) Direct footprint only; ROW values are not included.
Golf courses	9,083	Merrill and Leatherby (2018)
National parks	376,357	Merrill and Leatherby (2018)
Oil and gas lease on federal land	105,218	BLM (n.d.)
Oil and gas lease on federal land (active)	51,799	BLM (n.d.)
Railroads	47,774	Lopez et al. (2021) Direct footprint only; ROW values are not included.
Roads	106,215	Lopez et al. (2021) Direct footprint only; Right of way (ROW) values are not included.
Urbanized areas	275,538	Center for Sustainable Systems (2021)

[1] https://github.com/microsoft/USBuildingFootprints

A.6 Hydrogen Production and Prices

Figure A11 shows hydrogen production in 2035 across all sensitivity cases.

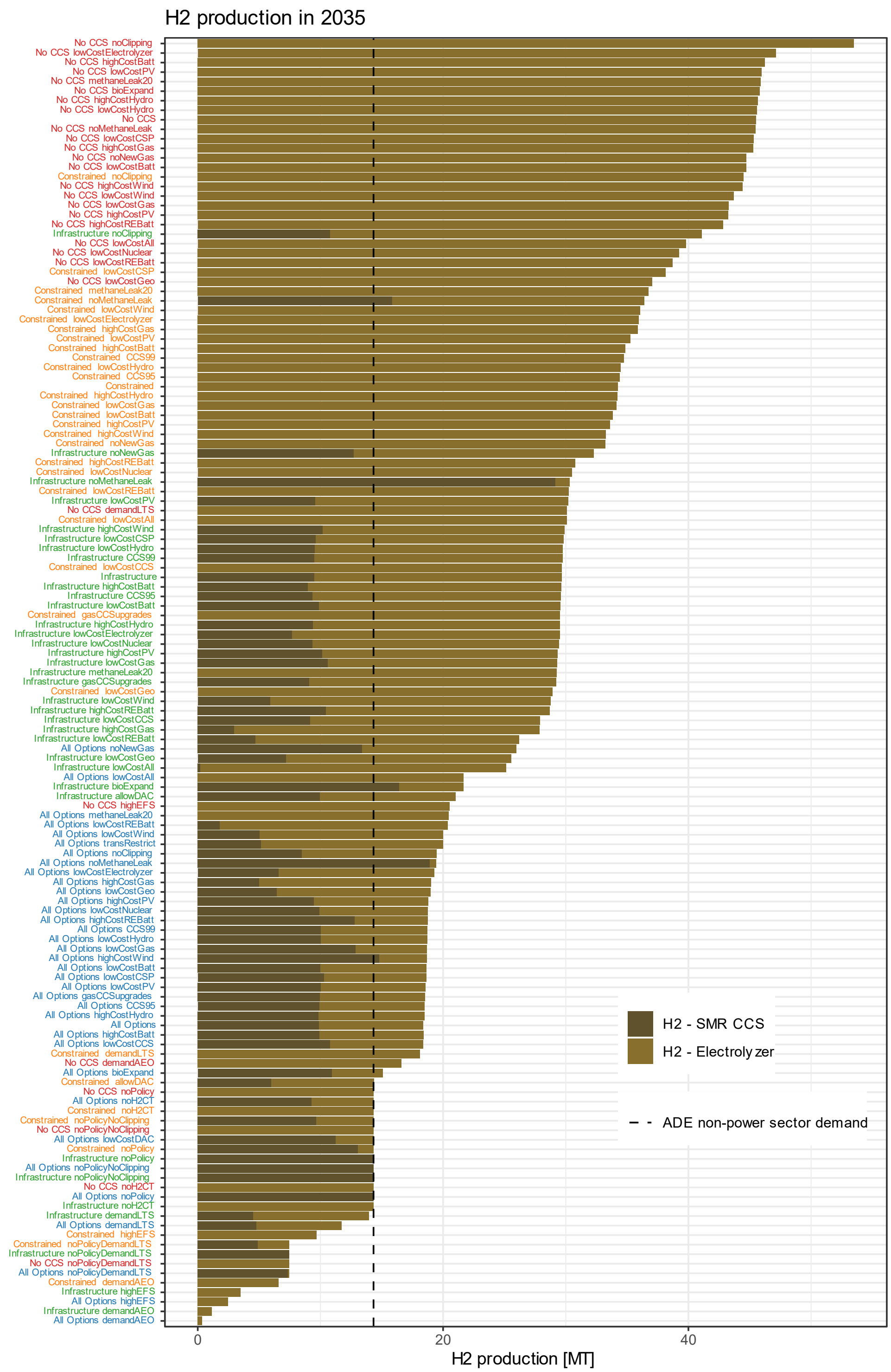

Figure A12. Hydrogen production (MT) in 2035 by technology for all sensitivity cases

Sensitivity names are colored based on their core scenario. The dashed line indicates the non-power sector hydrogen demand for the ADE scenario, which is assumed to be about 14 MT.

Figure A13 illustrates the hydrogen price across all sensitivities in the 100% clean electricity scenarios. These prices reflect the marginal cost to produce hydrogen in each year as estimated in the model. For most scenarios and years, hydrogen prices range from about $1.50/kg to $3/kg. Variations in prices are driven by differences in hydrogen production mechanism, electricity costs, and electrolyzer cost and utilization. The representation of the hydrogen system in ReEDS is limited and additional analysis would be needed to more robustly assess future prices, including pathways to and impacts of achieving the DOE's EarthShot.[2] ReEDS uses simple cost adders for hydrogen storage and delivery (Appendix B) and does not explicitly model hydrogen infrastructure. Other potential delivery costs, such as for refueling stations, are also not represented directly.

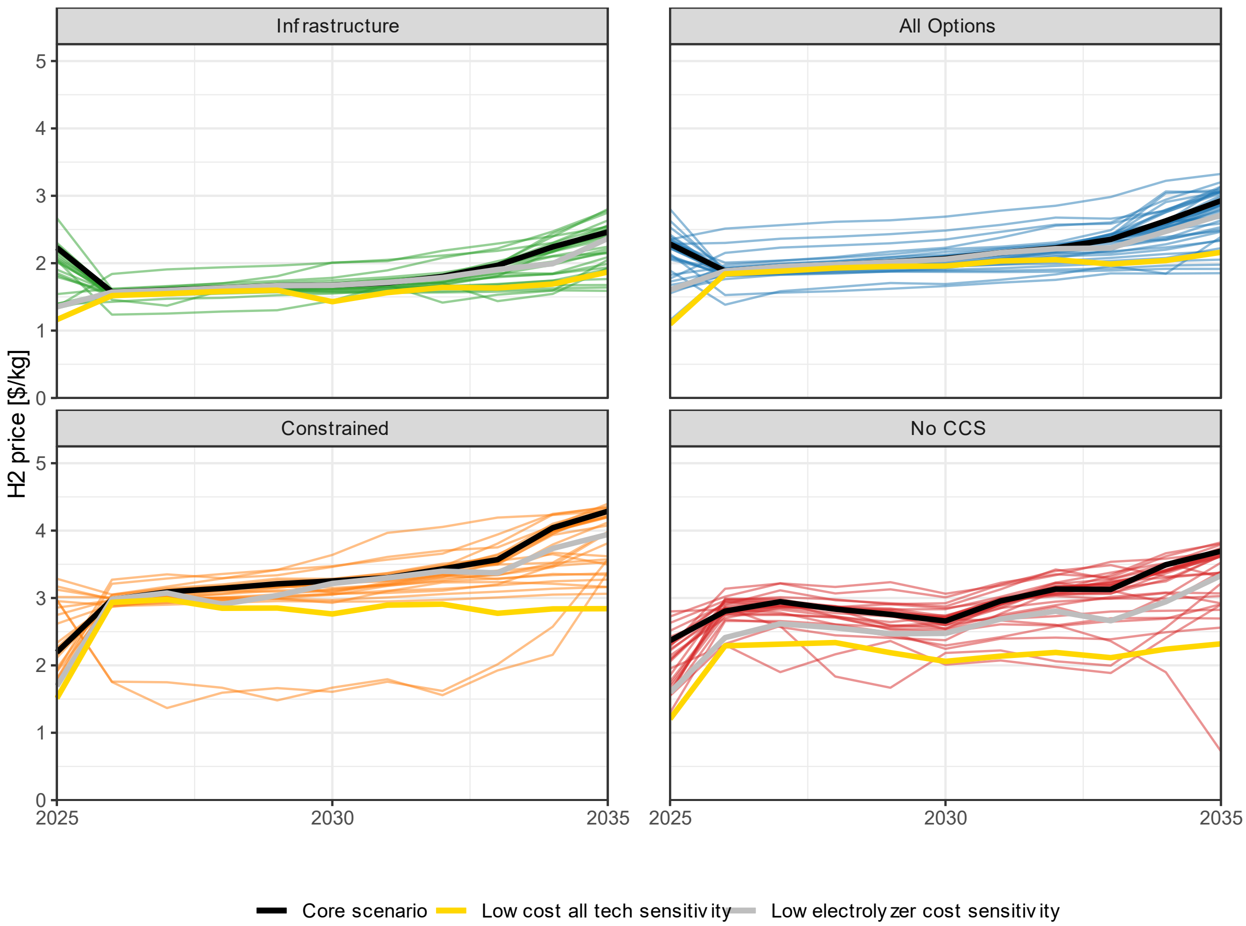

Figure A13. Hydrogen price ($/kg) across all sensitivities

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[2] https://www.energy.gov/eere/fuelcells/hydrogen-shot

A.7 Benefit-Cost Assessment with Alternate Discount Rates

Figure A14 summarizes the NPVs of costs and benefits using three discount rates. The the solid horizontal lines represent net benefits after subtracting costs from the health and climate benefits.

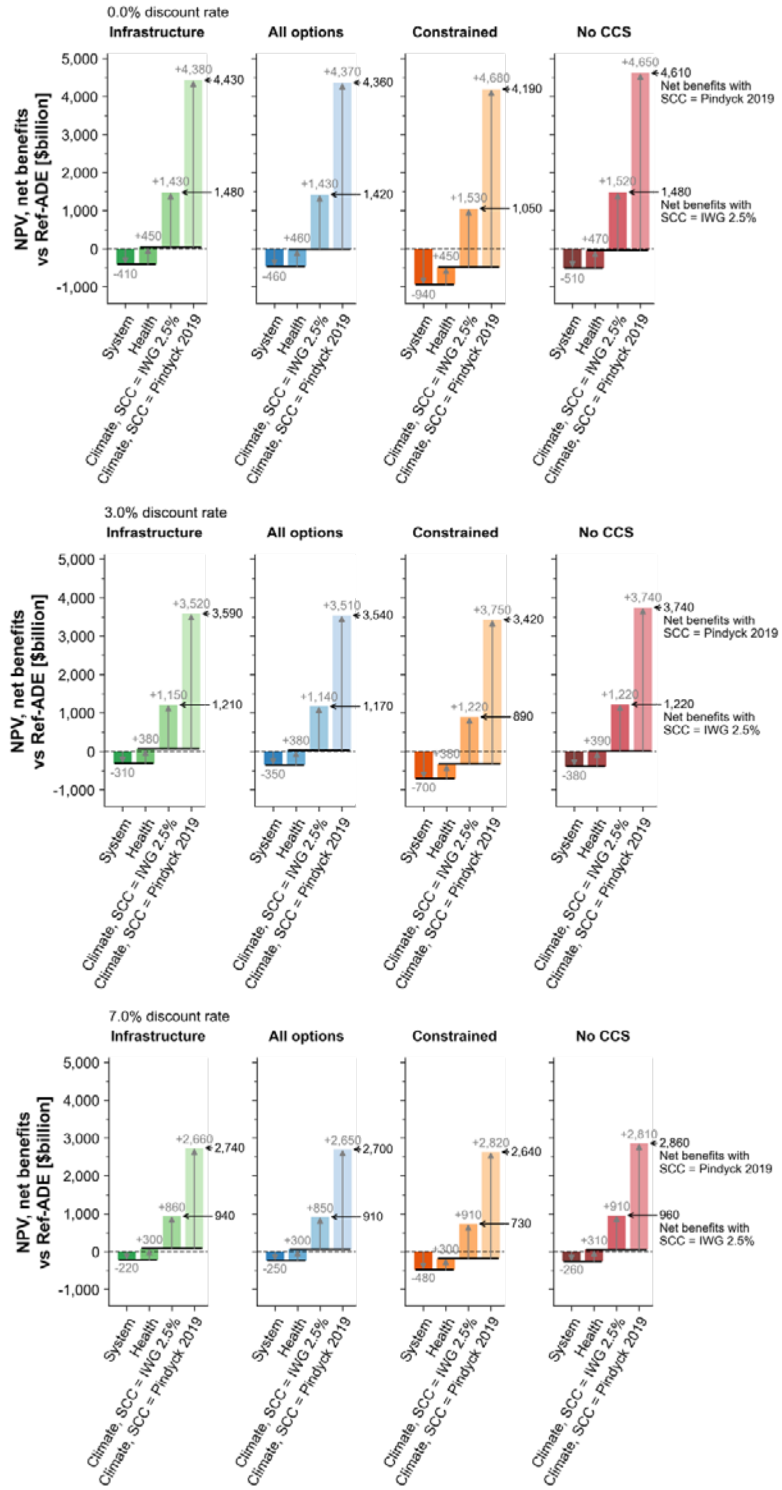

Figure A14. Cumulative net present value of costs and benefits with 0% (top), 3% (middle), and 7% (bottom) discount rate

A.8 References

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Appendix B. ReEDS Model Details

B.1 Model Overview

The ReEDS model has been employed in a wide range of studies examining the evolution of the electricity system. Most of these are for the United States, and they typically examine futures with greater deployment of renewable energy than today. As of this writing, more than 120 published studies have relied on the ReEDS model.[3] The ReEDS model is extensively documented by Ho et al. (2021), and the model code and inputs are available at no cost.[4]

The ReEDS model has higher spatial resolution than other national-scale power sector models (Cole et al. 2017). It has 134 balancing areas (BAs) and 356 wind and CSP resource regions (see Figure B1). Transmission is represented between each of the 134 BAs, including the AC-DC-AC interties that cross the interconnections.

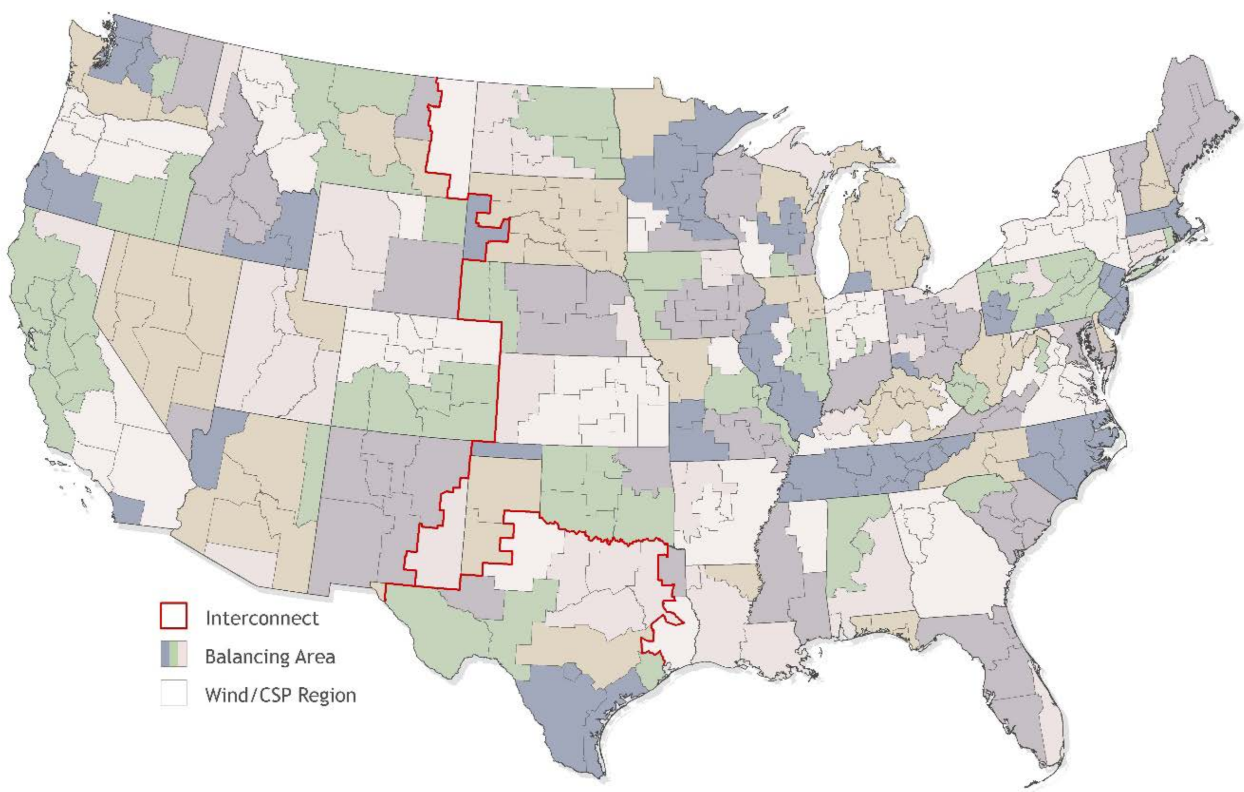

Figure B1. Regions used by the ReEDS model

The colored areas are the 134 BAs. The wind and concentrating solar power (CSP) regions within a BA provide higher-resolution resource information for wind and CSP technologies.

The ReEDS model makes new investments in transmission, generation, and storage based on minimizing total system cost. The model can also retire generators if doing so would lower

[3] Those publications are listed at "Regional Energy Deployment System Model Publications," NREL: Regional Energy Deployment System Model, https://www.nrel.gov/analysis/reeds/publications.html.
[4] See "Request Access to Download Model," NREL: Regional Energy Deployment System Model, https://www.nrel.gov/analysis/reeds/request-access.html.

system costs (this would occur if the fixed cost of maintaining the plant is greater than the value provided to the system by the plant). In addition, generators and storage plants are also retired once they reach their maximum plant age. Maximum plant ages vary by type, ranging from 15 years for battery storage to 100 years for hydropower. Existing nuclear power plants that have not yet announced a retirement date are given an 80-year maximum lifetime.[5]

Imports and exports of electricity between Canada and the United States are modeled exogenously with projected flows taken from the National Energy Board's Canadian Electricity Futures Reference Scenario (NEB 2018). Each Canadian province is required to send electricity to or receive electricity from the ReEDS regions that have transmission lines connecting that province to the ReEDS region. These flows change over time but are the same across all scenarios. Electricity exchanges with Mexico are ignored in this work due to the relatively limited transmission exchange that currently exists between the two countries.

The ReEDS model includes current state and federal policies as of June 2021. Policies represented include state renewable portfolio standards and clean energy standards, the California CO_2 cap-and-trade program, the Regional Greenhouse Gas Initiative, the Cross-State Air Pollution Rule, the investment and production tax credits, and accelerated depreciation schedules.

Firm Capacity Assessment

The ReEDS model ensures sufficient capacity is in the system by enforcing planning reserve margins. The planning reserve margins are based on the North American Electric Reliability Corporation (NERC) reference reserve margin levels (NERC 2018; Reimers, Cole, and Frew 2019). We define firm capacity as the capacity that is counted toward the planning reserve margin provision and the capacity credit as the fraction of nameplate capacity that is firm capacity. For example, if a 100-MW PV plant has a capacity credit of 0.3, 30 MW of the PV plant is counted toward the planning reserve margin provision as firm capacity.

Non-variable, non-storage resources such as natural gas, coal, and nuclear power have a capacity credit of one because the planning reserve margin already captures the impact of forced outages. For variable sources such as wind and PV, the capacity credit is calculated endogenously within the model by determining the contribution of wind and PV to the top 10 peak load and peak net load hours in each season. Net load profiles are assessed within 18 capacity credit regions (Figure B2) for the All Options, Constrained, and No CCS scenarios and within three interconnections (Figure B1, page 103) for the Infrastructure scenarios, reflecting an increased level of interregional coordination of planning and operations in the Infrastructure scenarios. The capacity credit calculation is performed using hourly data for the 7 years of time-synchronous wind, solar, and load data within the model. Because these calculations are nonlinear, they are done outside the ReEDS linear program. After ReEDS solves a given year, it performs these capacity credit calculations before moving into the next solve year. In this way, the marginal

[5] The only nuclear plants that retire between 2022 and 2035 under our 80 year license extension are Palisades and Diablo Canyon.

capacity credit contributions of new resources can be represented linearly but are updated after each solve year.

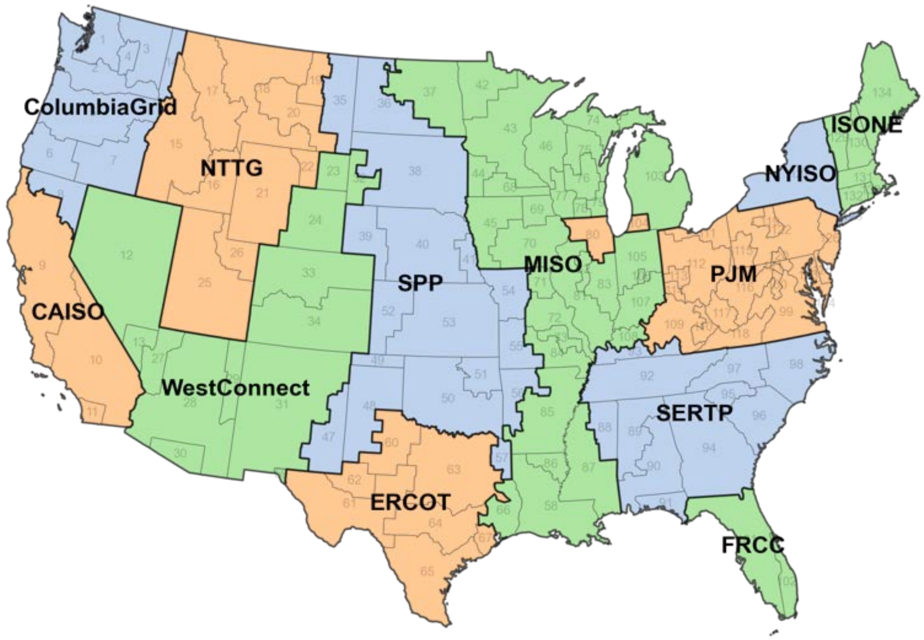

Figure B2. Capacity credit regions used in ReEDS

Storage capacity credit is calculated using the same 7 years of hourly data. Storage is dispatched chronologically to determine how much energy is needed to achieve a certain level of reduction in the net load. Details for this method are provided by Frazier et al. (2020). To represent uncertainty in the forecast of the net load, the storage duration is derated by one hour when doing this capacity credit calculation. For example, a 6-hour storage device would receive full capacity credit for service peaks of 5 hours or less but would get 5/6 = 0.83 capacity credit for a 6-hour peak, 5/7 = 0.71 capacity credit for a 7-hour peak, and so on.

Firm capacity is allowed to be traded between regions as long as transmission capacity is available between those two regions. Transmission losses are applied to firm capacity trading at the rate as for power flows (discussed below).

Curtailment

Curtailment of renewable energy generators is also calculated endogenously within ReEDS. Curtailment is calculated using only a single year of wind, solar, and PV data in order to reduce run times. The most typical year (2012) of the 2007–2013 data set is used for these curtailment calculations, where the typical year is defined as the one that had annual average wind speed and solar insolation closest to the 7-year mean.

Curtailment is calculated using a simplified hourly dispatch model in ReEDS. This dispatch model includes only transmission constraints, variable and fuel costs, maximum generation and stored energy constraints, and hydropower operation constraints. After the dispatch model is run, a post-process step determines whether any generators are operating below their rated minimum generation level. Any generators operating below this minimum generation level have their generation increased until they are at the minimum generation level.

Curtailment is then calculated as the amount of remaining variable renewable energy that cannot be used to meet load. Marginal curtailment rates are calculated by each type of wind and PV resource in each region to determine how much of that new generation will be unable to meet load. The ability of new transmission to reduce marginal curtailment is also calculated between each pair of source and sink BAs based on the hourly coincidence between curtailment in the source BA and net load in the sink BA. New multi-link lines can reduce 1 MW of curtailment in the source BA in a given hour if there is at least 1 MW of unmet net load in the sink BA, and if at least 1 MW of transmission capacity is added to each BA-BA link along the capital-cost-minimizing path between the source and sink BA.

Storage is included in the simplified hourly dispatch model and therefore is available to reduce curtailment. Existing and new storage can be used to reduce marginal curtailment rates of new generators.

Like the capacity credit calculations, the curtailment calculations are performed between solve years. For example, after the 2030 year is solved, ReEDS calculates the curtailment using the method described above and sends the updated curtailment parameters into ReEDS for the next solve year.

Operating Reserves

ReEDS represents three types of operating reserves: regulation, spinning, and flexibility. These reserve types represent the broader range of reserves in current U.S. markets (Denholm, Sun, and Mai 2019). The reserve types are a function of load, wind generation, and PV capacity as shown in Table B1. These reserve requirements are also enforced in PLEXOS to ensure the model holds sufficient operating reserves. All non-VRE generators (including storage) can contribute toward the operating reserve requirements provided they have sufficient headroom to do so (i.e., a plant operating at full capacity cannot provide reserves). Generators are limited in the amount of reserve they can provide by their ramp rates. If they cannot fully ramp within the timescale needed for the reserve product, only a portion of their headroom can be used to meet the requirement. For example, if a 100-MW plant can ramp at 1% per minute, it could provide up to 5 MW of regulating reserves, 10 MW of spinning reserves, and/or 60 MW of flexibility reserves provided it would not violate any minimum generation levels (e.g., if the minimum generation level is 45 MW, the plant could never provide more than 55 MW of total operating reserves). Operating reserves are allowed to be traded with other regions inside a regional transmission organization or independent system operator provided sufficient transmission capacity is available. Details about the operating reserve implementation are provided by Cole et al. (2018).

The flexibility reserve product has been introduced in a few market regions in the United States (Denholm, Sun, and Mai 2019). It is included in the model to account for forecast errors in the short-term VRE generation. For example, if wind energy drops unexpectedly within the next 30 minutes, the flexibility reserve would be called on to fill the reduction in wind output.

Table B1. Summary of Operating Reserve Requirements

Reserve Type	Load Requirement	Wind Requirement	PV Requirement	Timescale
Spinning	3% of load	—	—	10 min
Regulation	1% of load	0.5% of wind generation	0.3% of PV capacity[a] during daytime hours	5 min
Flexibility	—	10% of wind generation	4% of PV capacity[a] during daytime hours	60 min

[a] PV is based on capacity because PV-induced reserves are most needed during dawn and dusk when generation is low.

B.2 Scenario Inputs

Scenario inputs and model assumptions are consistent with the *2021 Standard Scenarios Report* (Cole et al. 2021). Technology cost and performance inputs are from the 2021 Annual Technology Baseline (ATB) (NREL 2021). Key overnight capital cost projections from the 2021 ATB are summarized in Figure B3. For battery storage, only 4-hour storage is shown, the durations of 2, 4, 6, 8, and 10 hours are included in the model.[6] The CCS technologies are assumed to have a 90% CO_2 capture rate, except in the sensitivity scenarios that specified a higher capture rate in which we tested capture rates of 95% and 99%. ReEDS also includes regional capital cost multipliers to represent differences in labor rates and siting costs (Ho et al. 2021). These multipliers differ between technologies. Assumed grid connection costs also vary by region and resource class for wind and solar technologies (Maclaurin et al. 2019).

[6] To test whether longer-duration battery storage resources would change the model solution, we ran an additional group of 100% renewable energy scenarios that included a 24-hour battery storage option. This 24-hour battery system was not selected by the model in any of the scenarios because it was more expensive than other resource options.

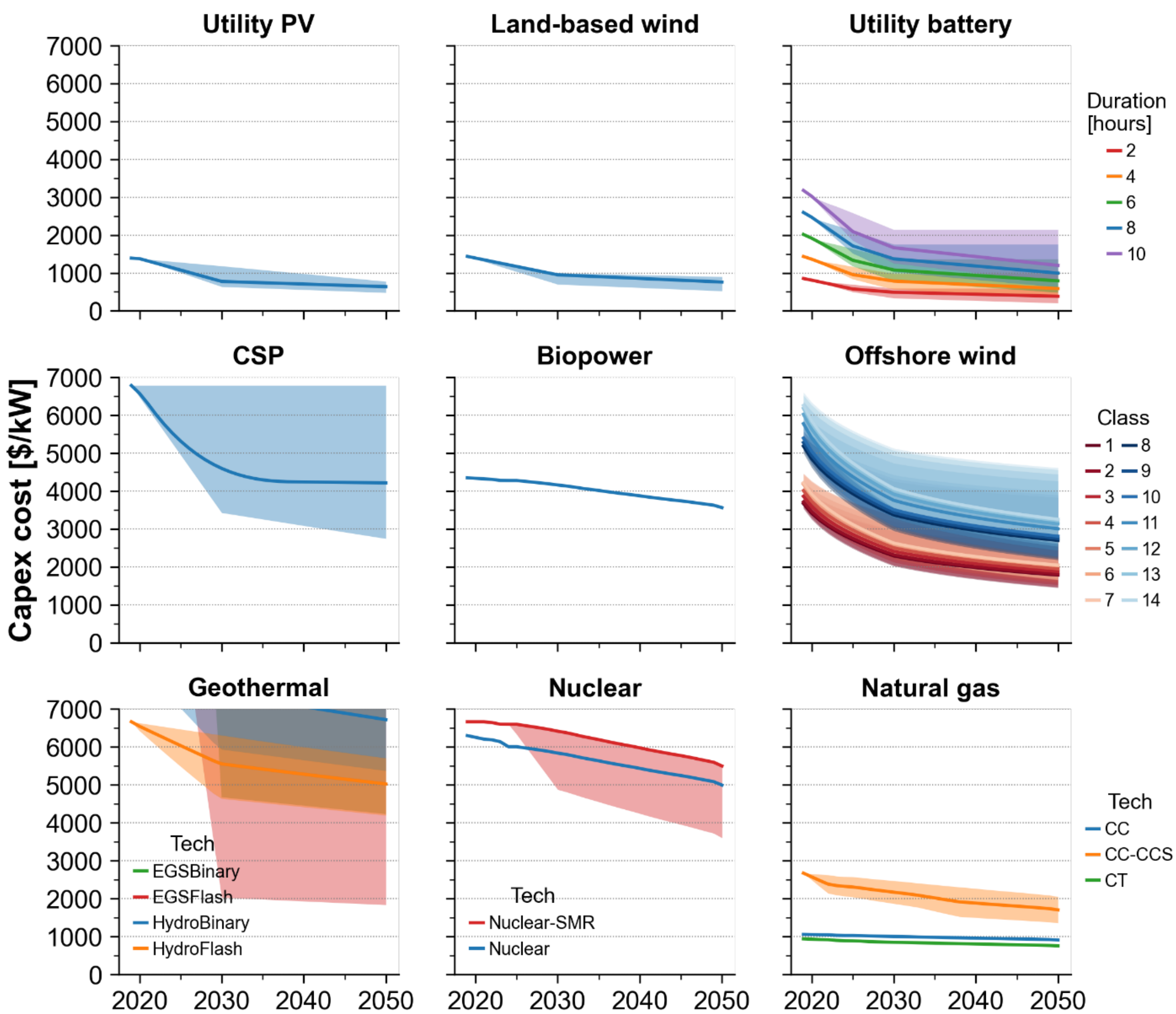

Figure B3. Overnight capital cost inputs for utility-scale solar PV, land-based wind, utility-scale battery energy storage, concentrated solar power (CSP), biopower, offshore wind, geothermal, nuclear, and natural gas under moderate (center line), advanced (bottom of shaded area), and conservative (top of shaded area) cost assumptions

All costs except nuclear and geothermal "advanced" costs are from the 2021 ATB. The advanced cost case for nuclear is based on a trajectory that achieves capital cost targets of $4,500/kW in 2035 and $3,600/kW by 2050. The advanced geothermal cases were generated for this report and will be documented in the 2022 ATB. Additional cost details and other input costs are documented in the 2021 ATB (NREL 2021).

Financial assumptions, which are also from the 2021 ATB, vary over time and by technology. Interest rates are initially 4%–5% (nominal), escalate by 1% (nominal) by 2030, and then remain constant until 2050. The rate of return on equity ranges from 7.8% to 10.0% (nominal) and is constant from 2021 to 2050. The debt fraction depends on the technology type and year. The book life for all technologies is assumed to be 20 years.

Renewable technology capacity development is constrained by regional resource potential estimates. Technical potential estimates for wind and solar are assessed based on geospatial analyses that consider land area requirements of power plants (e.g., assumed power densities), renewable resource quality, and land area exclusions based on land use and land cover classifications (e.g., protected lands, wetlands, and urban areas) (Lopez et al. 2012; Maclaurin et al. 2019). Specific exclusions, other assumptions, and methods used to generate the PV and CSP resource potential estimates are documented by Lopez at al. (2012) and Murphy et al. (2019) respectively. Supply curves for wind that were developed recently (Lopez et al. 2021) using higher-fidelity modeling account for setbacks to individual buildings, roads, railroads, and transmission infrastructure along with other exclusions associated with radar, mountainous terrain, siting regulations, and other land use and land cover data. Geothermal, hydropower, and pumped storage hydropower resource constraints are evaluated on a more site-specific basis. Geothermal, resource availability under moderate cost assumptions is limited to hydrothermal resources and is consistent with the BAU resource in the GeoVision Study (Augustine, Ho, and Blair 2019). Geothermal under advanced costs reduces costs through aggressive drilling improvements and increasing geothermal plant sizes. Coupled with advanced geothermal costs, enhanced geothermal systems (EGS) become available for investment, adding 3.9 TW of resource potential and expanding the geothermal resource beyond the Western United States. Conventional hydropower resource assessments are from (DOE 2016b) and pumped storage hydropower resource assessments are based on a bottom-up geospatial site identification and cost modeling (Rosenlieb, Heimiller, and Cohen 2022). Hydropower resources modeled include capacity upgrades in existing hydropower plants, non-powered dams, and new stream reaches.

Though no siting constraints are modeled for biopower facilities, supply curves based on data from the Oak Ridge National Laboratory's *2016 Billion-Ton Report* (DOE 2016a) are used to represent biomass feedstock costs and resources. Only woody biomass resources are allowed to be used for biopower plants. No resource constraints are applied for nonrenewable energy technologies. Figure B4 illustrates the resource map and total supply curve by region as derived from the *2016 Billion-Ton Report* and used in this study. Nationally, approximately 116 million dry tons of woody biomass are assumed to be available to the power sector. In addition to the supply curve price (which represents the cost of the resource in the field), ReEDS also assumes costs of $15 per dry ton for collection and harvesting, as well as an additional $15 per dry ton for transport, as based on estimates from a 2014 INL study (Jacobson et al. 2014). Pathways with more limited biomass model the impact of a halving of the available resource and a doubling of collection, harvesting, and transport costs (58 million dry tons and $60 per ton), whereas the enhanced resource scenario models the opposite (doubling the available resource to 232 million dry tons and halving collection, harvesting, and transport costs to $15 per ton).

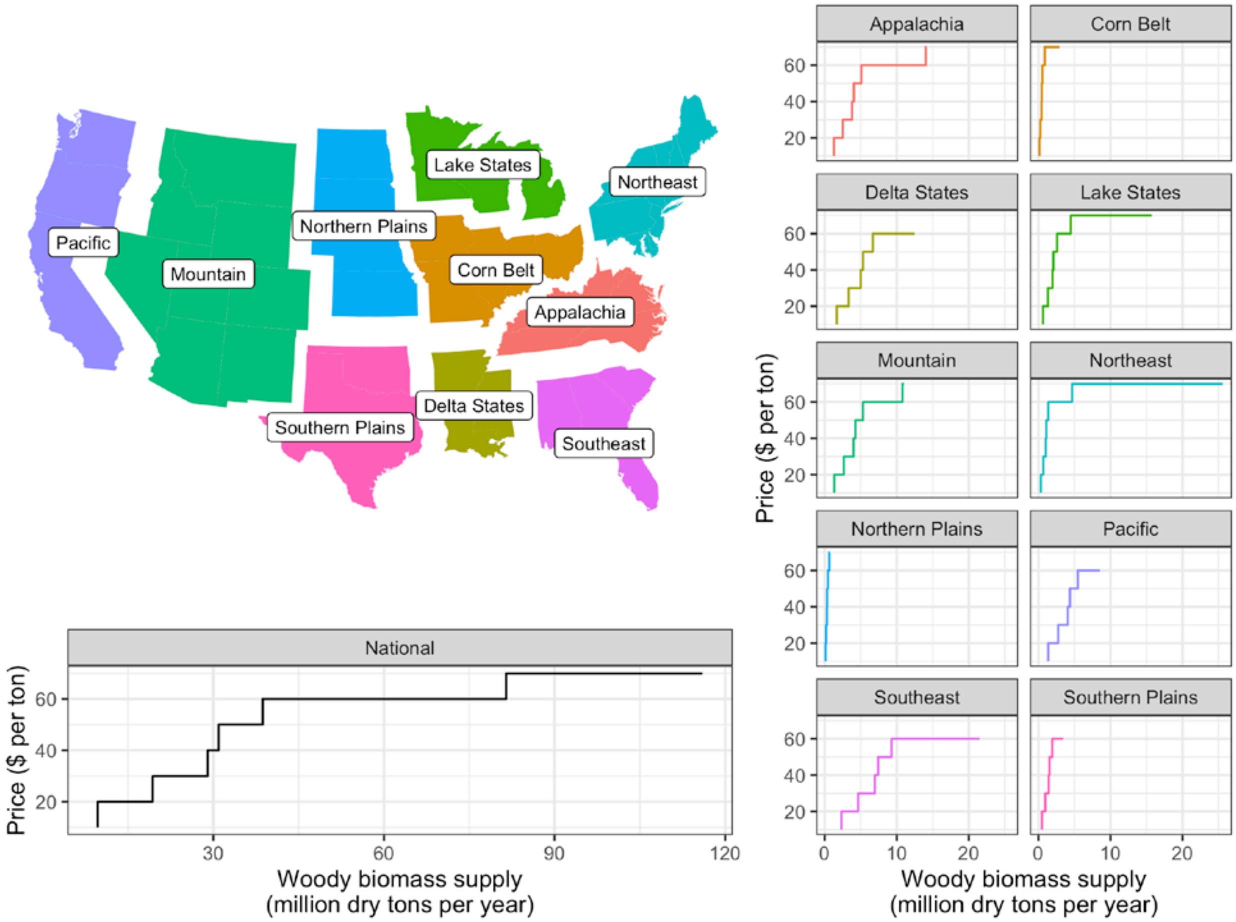

Figure B4. Depiction of the regions used for the biomass supply curves (map, top left), based on U.S. Department of Agriculture regional divisions

The line plots to the right indicate the woody biomass supply curves for each region as used in ReEDS, as derived from data in 2016 Billion-Ton Report. The bottom-left plot summarizes the total national supply curve.

For this analysis and to represent the resource potential land-based wind, offshore wind, and PV, we use the 2021 versions of the supply curves available.[7] Specifically, for land-based wind and PV, the 2021 Reference Access supply curves are used in most scenarios. An exception is the Constrained Scenario where the Limited Access supply curves are used for these technologies. Offshore wind supply curves are represented using the Open Access supply curve in the All Options, Infrastructure, and No CCS scenarios and the Limited Access supply curve in the Constrained scenarios. Note that significant regional variations exist for a given supply curve due to differences in resource potential and land use conflicts as well as between supply curves. For example, siting constraints in the Limited Access onshore wind supply curve has a much greater

[7] "Renewable Energy Supply Curves," NREL: Geospatial Data Science, https://www.nrel.gov/gis/renewable-energy-supply-curves.html. For land-based wind, we exclude all sites with less than 5.5 MW of available capacity. For offshore wind, we exclude sites with less than 15 MW of developable capacity and any sites with water depth greater than 1,300 meters.

impact on the developable capacity in populated areas in the Midwest and East than in the West and Plains regions (Lopez et al. 2021).

For wind and solar technologies, resource constraints and technology cost and performance assumptions are varied using multiple resource classes: 10 wind speed classes for onshore wind, 14 wind speed classes for offshore wind, 7 classes for PV based on global horizontal irradiance, and 12 classes for CSP based on direct normal irradiance (Ho et al. 2021).

The ReEDS model uses these supply curves to choose the sites for developing new renewable energy resources. Each resource supply curve site includes a unique profile and transmission spur line connection cost. When renewable energy resources are retired at the end of their lifetimes, the sites become available for new development, and new renewable energy resources built at those sites are not required to pay the transmission spur line cost.

Natural gas input prices are based on the electricity sector natural gas prices from AEO2021 (EIA 2021). The prices are shown in Figure B5 (left) and are from the AEO2021 Reference scenario, the AEO2021 Low Oil and Gas Resource and Technology scenario, and the AEO2021 High Oil and Gas Resource and Technology scenario (EIA 2021). The reference coal and uranium price trajectories (Figure B5, right) are from the AEO2021 Reference scenario. All fuel prices are assumed to be fully inelastic.

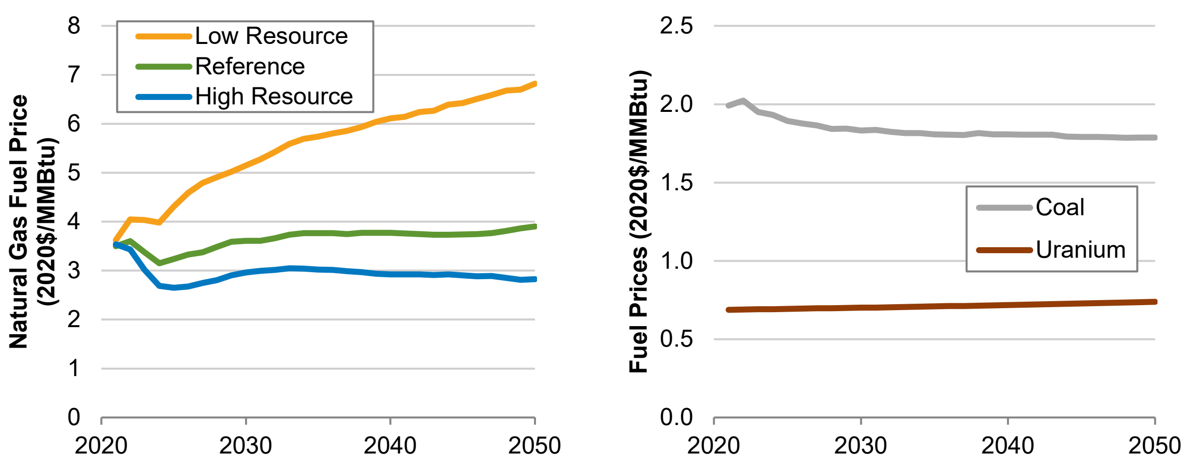

Figure B5. Price trajectories for the low, mid, and high natural gas prices (left) and price trajectories for coal and uranium (right)

New fossil and nuclear units are allowed to be sited in any region, though regional cost multipliers are applied to account for differences in labor costs and construction requirements. The Constrained scenario does not allow new nuclear in the 11 states in the contiguous U.S. that currently have a policy limiting new nuclear power: California, Connecticut, Illinois, Maine, Massachusetts, Minnesota, New Jersey, New York, Oregon, Rhode Island, and Vermont. No fuel supply constraints or waste disposal issues are considered. New nuclear is allowed to be built starting in 2030, and new fossil with CCS units are allowed to be built starting in 2026.

Hydrogen production in ReEDS is represented using electrolyzers, steam methane reforming (SMR), and SMR with CCS (SMR-CCS). Cost and performance parameters for these technologies are summarized in Table B2. Electrolyzer costs are based on Hunter et al. (2021),[8] and SMR and SMR-CCS costs are based on NETL (2011). SMR and SMR-CCS technologies buy natural gas at a cost that is 17% higher than the electricity sector natural gas price. This 17% value is derived by comparing the industrial natural gas price to the electricity sector natural gas price in the AEO2021.

Table B2. Cost and Performance Assumptions for Hydrogen Production Technologies

Electrolyzer	Capital Cost ($/kW)	Variable O&M[a] ($/kWh)	Fixed O&M ($/kW-yr)	Electricity Use (kWh/kg)	Natural Gas Use (MMBtu/kg)
2020	1,028	0	39.5	56.1	N/A
2025	759	0	37.2	55.3	N/A
2030	490	0	34.9	54.6	N/A
2035	460	0	32.6	53.8	N/A
2040	430	0	30.3	53.0	N/A
2045	400	0	28.0	52.2	N/A
2050	371	0	25.6	51.5	N/A

[a] *operation and maintenance*

SMR	Capital Cost ($/kg/day)	Variable O&M ($/kg)	Fixed O&M ($/kg/day-yr)	Electricity Use (kWh/kg)	Natural Gas Use (MMBtu/kg)
2020	600	0.081	19.3	0.88	0.192
2025	596	0.081	19.1	0.88	0.192
2030	591	0.081	19.0	0.88	0.192
2035	586	0.081	18.8	0.88	0.192
2040	583	0.081	18.7	0.88	0.192
2045	579	0.081	18.6	0.88	0.192
2050	575	0.081	18.5	0.88	0.192

SMR-CCS	Capital Cost ($/kg/day)	Variable O&M ($/kg)	Fixed O&M ($/kg/day-yr)	Electricity Use (kWh/kg)	Natural Gas Use (MMBtu/kg)
2020	1,303	0.082	41.8	1.9	0.192
2025	1,251	0.082	40.2	1.9	0.192
2030	1,199	0.082	38.5	1.9	0.192
2035	1,147	0.082	36.8	1.9	0.192
2040	1,147	0.082	36.8	1.9	0.192
2045	1,147	0.082	36.8	1.9	0.192
2050	1,147	0.082	36.8	1.9	0.192

[8] 2050 costs are taken from Table S28 under "PEM Electrolyzer: Power" using the average learning rate.

Hydrogen demand for non-power sector applications is specified exogenously in ReEDS as a national, annual demand for hydrogen. For the decarbonization scenarios, the exogenous hydrogen demand is required to be served using electrolyzer and SMR-CCS technologies.

Within the power sector, ReEDS endogenously represents both the production and consumption of hydrogen. Hydrogen is used to produce electricity using hydrogen combustion turbines (H2-CT). The H2-CTs have a capital cost 3% higher than a new natural gas combustion turbine (NG-CT) to represent the added cost of adding a clutch, which allows the H2-CT to act as a synchronous condenser when not generating. The heat rate and the operation and maintenance (O&M) costs for H2-CT is assumed to be equivalent to a NG-CT. Existing NG-CT and natural gas combined cycle (NG-CC) plants are allowed to be upgraded to H2-CT plants at a cost of 20% the cost of building a new plant. These assumptions for H2-CTs are consistent with the Solar Futures Study (DOE 2021).

Because hydrogen transportation and storage are not explicitly considered within the model, we apply a static cost for all produced hydrogen to account for costs associated with transportation and storage. The All Options and No CCS scenarios use a hydrogen transportation and storage cost of $300/tonne of produced hydrogen, and the Infrastructure scenarios use $100/tonne and the Constrained scenarios use $900/tonne.

Upfront costs for new inter-BA transmission are determined for representative routes between the largest population centers in connected BAs, including cost multipliers for the terrain (flat, hilly, or mountainous) and use class (barren, pasture/farmland, wetland, suburban, urban, or forest) of the traversed land. Inter-BA routes and costs for AC transmission are shown in Figure B6.

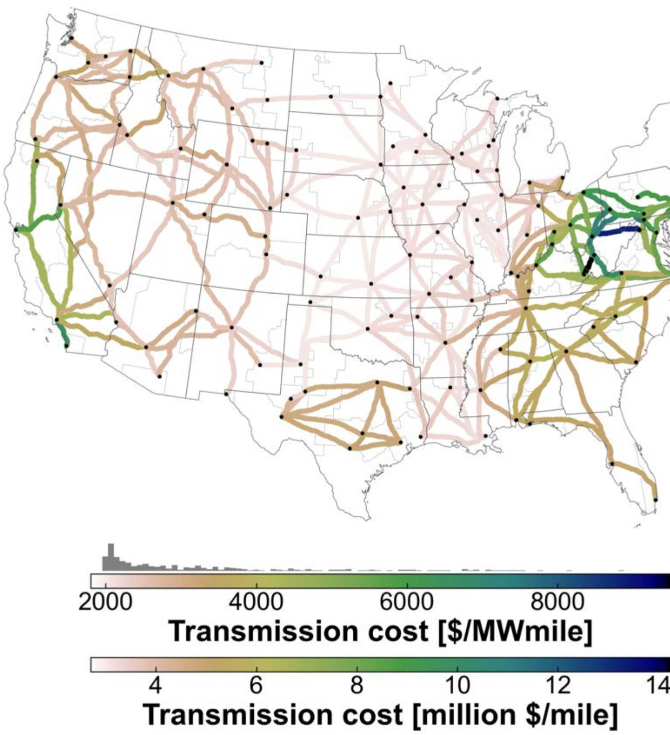

Figure B6. Inter-BA transmission costs and representative routes. Costs are for a 500 kV AC transmission line with 1500 MW capacity and are shown in units of both $/MW-mile and $/mile.

The cost, performance, and model representation of inter-BA transmission are described by Ho et al. (2021) and are supplemented by three additions:

1. Transmission fixed O&M costs for existing and new capacity are assumed to be 1.5% of the upfront transmission capital expenditures (CapEx) per year, without regional modifiers (Weidner et al. 2014).
2. AC losses are assumed to be 1%/100 miles for 500kV and above and 3%/100 miles for 345 kV (345 kV is only used in the Northeast). DC losses are assumed to be 0.5%/100miles, and there are additional fixed converter losses of 0.7% for line-commutated converters and 1.0% for voltage-source converters (VSCs). Expansion of the capacity of back-to-back AC/DC/AC converters between interconnects, as well as expansion of existing point-to-point DC lines, is assumed to use 500-kV DC lines with two line-commutated converters per line.
3. The Infrastructure scenarios include a multi-terminal 500-kV DC macrogrid as an investment option. In these scenarios, DC lines can be added between any pair of BAs that are currently connected by existing (or under-construction) AC or B2B (back-to-back) AC/DC/AC links (Figure B6). VSC capacity can be deployed independently of DC line capacity (in contrast to point-to-point DC lines using line-commutated converters, where the converter capacity at each end of the line is always equal to the capacity of the line itself). Power injection and withdrawal to and from the DC macrogrid is limited by the VSC capacity in the injecting/withdrawing BA, but DC power flow through a BA "node" of the macrogrid is not limited by VSC capacity. As shown in Figure B6, the

resulting macrogrid design employs single links of varying capacity, and VSC capacity is sized appropriately to the injection/withdrawal needs in each BA.

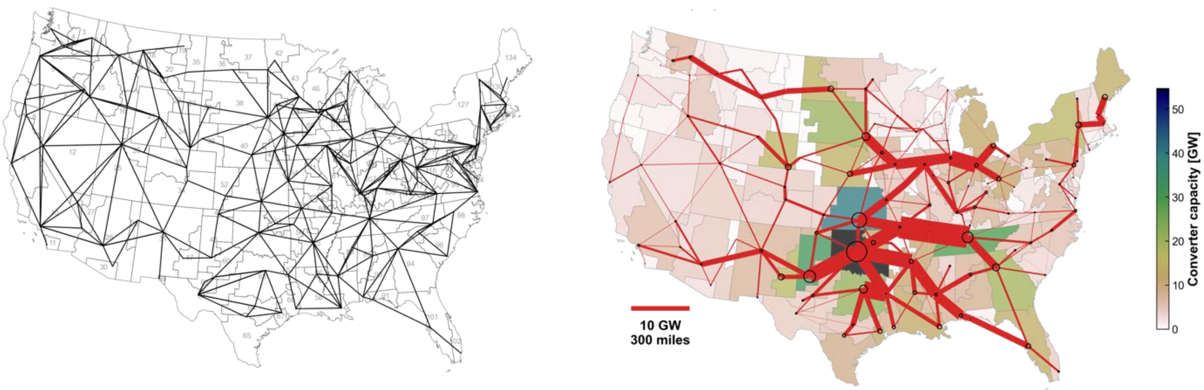

Figure B6. Transmission links (left) and DC macrogrid capacity for the Infrastructure case in 2035 (right)

DC line capacity in B is indicated by line thickness; VSC capacity by BA is indicated by the size of the black-bordered circle and by the color of the BA.

The model can invest in two options for carbon capture and storage (CCS): capturing emissions directly from generation sources—either fossil or biomass—and direct air capture. The first year for investment in any of these technologies is assumed to be 2026. Although ReEDS does not explicitly model the pipeline network for transporting and sequestering CO_2, it accounts for the cost of transport and storage using an adder ($/tonne) on all captured CO_2. The baseline assumption for this transport and storage cost is $15/tonne, based on previous estimates from National Energy Technology Laboratory (NETL) (Grant et al. 2019), with a range of $5/tonne to $60/tonne tested across the core scenarios.

By default, new coal with CCS and Gas-CC with CCS plants are considered along with retrofits of existing coal plants with CO_2 capture. Retrofit costs are based on the difference in cost of a new CCS plant and the original uncontrolled facility. Because many natural gas plants are in areas with insufficient space for CCS, the model does not allow existing Gas-CC plants to add CCS by default, although this feature is tested in a sensitivity. Note that the plant remains a CC after the retrofit.

Table B3 and Table B4 summarize cost and performance input assumption for Coal-CCS and Gas-CC-CCS technologies, and provide a comparison to the values for uncontrolled fossil technology.[9] These estimates are preliminary and there is considerable uncertainty to the future costs of CCS deployed at scale (Irish et al., forthcoming). We assume a default capture rate of 90% for both new and retrofitted capacity, with sensitivities testing capture rates of 95% and 99%. CCS options for NG-CT are not modeled.

[9] The cost and heat rate values in Table B3 are for the full CCS power plant and not the incremental costs relative to a no-capture system.

Table B3. Cost and Performance Assumptions for Coal-CCS Technologies

Capture rate	Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/kWh)	Heat rate (MMBtu/MWh)
90% (default)	2020	4,678 80%	122.3 70%	14.26 81%	10.834 28%
	2035	3,719 63%	109.1 60%	13.49 84%	9.677 24%
	2050	3,118 54%	105 54%	13.06 78%	9.467 22%
95% (sensitivity)	2020	4,788 84%	125 74%	14.8 88%	10.998 30%
	2035	3,806 67%	111.6 64%	14.0 90%	9.824 26%
	2050	3,191 57%	107.4 57%	13.5 84%	9.611 24%
99% (sensitivity)	2020	4,995 92%	130.3 82%	15.4 96%	11.366 34%
	2035	3,971 74%	116.3 70%	14.6 98%	10.152 30%
	2050	3,329 64%	111.9 64%	14.1 92%	9.932 28%

Percentages indicate the cost or performance premium of these values relative to the values for uncontrolled fossil generation.

Table B4. Cost and Performance Assumptions for Gas-CC-CCS Technologies

Capture rate	Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/kWh)	Heat rate (MMBtu/MWh)
90% (default)	2020	2,345 145%	65.1 138%	5.73 229%	7.159 13%
	2035	1,838 106%	61.7 126%	5.44 213%	6.416 1%
	2050	1,550 87%	60.4 121%	5.32 206%	6.17 -3%
95% (sensitivity)	2020	2,385 149%	66.2 142%	5.9 240%	7.210 13%
	2035	1,870 110%	62.7 130%	5.6 223%	6.462 2%
	2050	1,577 91%	61.4 125%	5.5 216%	6.214 -2%

Capture rate	Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M ($/kWh)	Heat rate (MMBtu/MWh)
99% (sensitivity)	2020	2,475 159%	68.6 151%	6.2 225%	7.402 16%
	2035	1,940 118%	65.0 138%	5.9 237%	6.634 4%
	2050	1,636 98%	63.7 133%	5.7 230%	6.379 0.3%

Percentages indicate the cost or performance premium of these values relative to the values for uncontrolled fossil generation.

Because the model assumes zero lifecycle emissions for biomass, generation sources that use biomass with carbon capture and storage (BECCS) are assumed to be negative emissions. Table B4 summarizes cost and performance assumptions for BECCS plants. The uncontrolled emissions rate of woody biomass fuel is assumed to be 88.5 kg/MMBtu (Bain et al. 2003); after accounting for the heat rate of a BECCS plant and a 90% CCS capture rate, the negative emissions are approximately -1.22 to -1.11 tonnes/MWh of generation. Fuel consumed in BECCS plants is counted against the total biomass supply curve described above. Given the limited deployment of BECCS, there is considerable uncertainty about cost and performance, and additional analysis is needed of the net emissions rate, including the full life-cycle of biomass production and use.

Table B5. Cost and Performance Assumptions for BECCS

BECCS	Capital Cost ($/kW)	Variable O&M ($/kWh)	Fixed O&M ($/kW-yr)	Heat Rate (MMBtu/MWh)	Emissions Rate (tonnes CO_2/MWh)
2020	5,580	16.6	162	15.295	-1.22
2035	5,333	16.6	162	14.554	-1.16
2050	5,100	16.6	162	13.861	-1.11

The model can also procure negative emissions by removing and storing CO_2 from the atmosphere using direct air capture (DAC). For this study, DAC in the ReEDS model is a sorbent design that uses only electricity as an input, with an energy consumption of 3.72 MWh per tonne of CO_2 removed. Overnight capital costs are assumed to be $1,932 per tonne-year capture capacity, with annual fixed O&M costs of 4.6% of the capital costs and nonfuel variable O&M cost of $21 per tonne.

Table B5 summarizes the settings used in the four main pathways considered in the body of the report. Settings not listed in the table are the same across the four scenarios.

Table B6. Settings Used for the Four Pathways Examined in this Work

Setting	Infrastructure	No CCS	All Options	Constrained
Biomass supply	116 million dry ton	116 million dry ton	116 million dry ton	58 million dry ton
Biomass transport and storage cost	$15/ton	$30/ton	$30/ton	$60/ton
CCS allowed	Yes	No	Yes	Yes
DAC allowed	No	No	Yes	No
CO_2 transport and storage cost	$5/tonne	N/A	$15/tonne	$60/tonne
Hydrogen transport and storage cost	$100/tonne	$300/tonne	$300/tonne	$900/tonne
Minimum generation level for nuclear plants	40%	70%	70%	70%
Resource supply curves	Default	Default	Default	Limited
Transmission cost multiplier	1	1	1	5
Long-distance HVDC transmission allowed	Yes	No	No	No
Transmission coordination regionality	Interconnection	Interconnection	Interconnection	Transmission Regions

B.3 References

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Appendix C. Electricity and Hydrogen Demand

Trieu Mai, Paige Jadun, Colin McMillan, Jack Mayernik, and Jonathan Ho

C.1 Process Overview

This study focuses on power system scenarios for the United States through 2035, and these scenarios are intended to reflect futures where the U.S. *energy* system is headed toward achieving net zero emissions by 2050. Following such a path would require a substantial reduction in fossil fuel consumption and a replacement of fossil fuels with other low or zero-emission resources in all sectors. Such a replacement would impact future demand for electricity and hydrogen through direct and indirect electrification along with energy efficiency and carbon capture and sequestration. This appendix summarizes the methods and assumptions used to generate electricity and hydrogen demand trajectories used as inputs for the power sector modeling in the study. It also details how we estimated direct (non-power) carbon dioxide (CO_2) emissions in the scenarios.

The study uses three sets of demand assumptions from the Annual Energy Outlook 2021 (AEO2021) Reference case (EIA 2021), the Accelerated Demand Electrification (ADE) trajectory generated for this study, and the Long-Term Strategy (LTS) (White House 2021). Given that the AEO and LTS scenarios are described in the referenced reports, we focus on the ADE scenario, which is developed specifically for this study. Electricity and hydrogen demand from the other scenarios are included for comparison.

We do not employ a detailed energy system model to generate the ADE scenario. The power sector modeling used for the study described in this report requires as input the following electricity and hydrogen demand data: (1) annual and hourly electricity consumption for all modeled regions and years and (2) annual U.S. non-power hydrogen demand assumption over time. To develop these data, we start with final energy consumption projections from the AEO2021 Reference case and manually adjust—through expert judgment informed by existing studies and data sources—projected fuel use by replacing fossil fuels with low-emission alternatives for each subsector. Section C.2 describes this process and the assumptions used for each sector. Electricity and hydrogen demand with such replacements are then calculated after accounting for differences in technology performance and fuel conversions. Temporal and spatial disaggregation are also processed based on existing data and studies. Section C.3 describes these steps. Figure C1 summarizes the process used to develop the ADE demand trajectory.

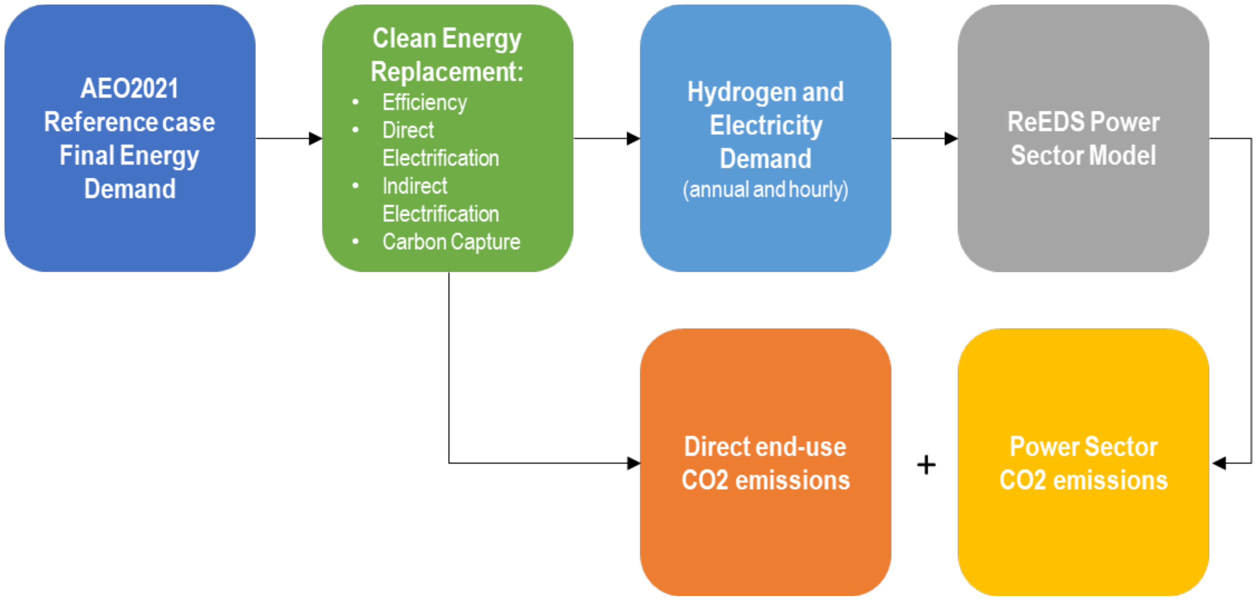

Figure C1. Process flow for developing the Accelerated Demand Electrification trajectory

Electricity and hydrogen demand from the end-use sectors serve as inputs to ReEDS. Any additional demand for hydrogen for grid applications, or additional electricity demand for hydrogen production, are estimated endogenously in ReEDS. Power sector CO_2 emissions are also outputs from ReEDS. Annual (nonelectric) direct CO_2 emissions are estimated and calibrated based on the final energy estimates as described in Section C.4. The combination of power sector and direct end-use emissions represents total energy system emissions reported in this study. Note that CO_2 emissions from non-energy sectors (e.g., agriculture) and non-CO_2 greenhouse gas emissions (except methane leakage in the power sector) are not estimated.

The simple approach used to develop the ADE demand trajectory has many uncertainties and limitations. Market shares are based on expert judgment and not on more-detailed modeling of economic and consumer choice considerations. The assessment is based on annual final energy consumption and does not explicitly consider stocks and vintages. Demand sector energy use is modeled separately from the power sector modeling; integrated aspects such as electricity-price and fuel-price feedbacks to consumer adoption are not considered. Other feedbacks between the energy system and social and environmental systems are also not considered. The demand profiles are based on a single weather year (2012).

Although these limitations are significant, the ADE trajectory appropriately serves its role of providing a trajectory that points the United States to a path to a net zero emissions economy by 2050 especially given the focus of the study on the power system evolution through 2035. In addition, the LTS demand trajectory provides an alternative path—one with greater reliance on energy efficiency and offsets from CO_2 removal—to achieving net zero emissions. The LTS was developed using economy-wide modeling (White House 2021), but with exogenous prescriptions for certain decarbonization measures (e.g., CO_2 removal). The combination of the ADE and LTS demand trajectories provide a broad range of possible requirements for power sector evolution and associated implications for reaching 100% emissions reductions by 2035, which is the focus of this study, within the context of broader economy-wide decarbonization. Significant research is needed to assess demand sector decarbonization more robustly.

C.2 Sector Assumptions

In this section, we present the annual final energy[10] consumption estimates for each of the demand sectors separately and in aggregate. As noted in Section C.1, these estimates for the ADE trajectory start from the AEO2021 Reference case projections but with (uncontrolled) fossil fuel use declining over time. Specifically, analyst judgment is used to develop annual energy consumption for 2030 and 2050 for each subsector in the AEO. Estimates for intervening years are linearly interpolated. Estimates between 2022 and 2030 are also interpolated linearly with the 2022 data directly from the AEO. Figure C2 shows U.S. final energy consumption from 2020 to 2035 for all three demand scenarios. Electricity's share of final energy grows from 18% in 2020 to 30% in 2035 under the ADE scenario and 28% in 2035 under LTS, compared to 19% in 2035 for the AEO2021 Reference case. Total final energy use in 2035 is also 8 and 18 quads lower in the ADE and LTS scenarios, respectively, compared to AEO due to typically lower conversion losses with electric- and hydrogen-based technologies and through greater adoption of energy efficiency measures. The following subsections describes estimates for each sector in detail.

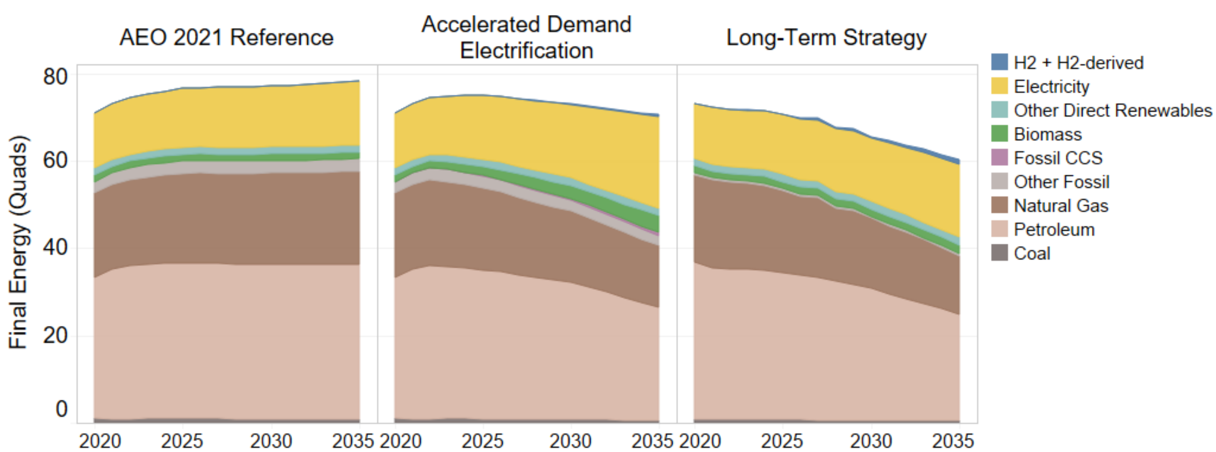

Figure C2. U.S. final energy consumption for the AEO, ADE, and LTS scenarios

Electricity, hydrogen, and hydrogen-derived fuels displace direct fossil fuel use in the ADE scenario relative to AEO. Additional hydrogen is produced for electric sector as determined in each scenario.

Buildings

The buildings sector—including the commercial and residential sectors—are currently the most electrified of the demand sectors; however, buildings used 10.0 quads of direct fossil fuel in 2020 and are projected to continue to use fossil fuel based on the AEO case. Most of the fossil fuel energy use in buildings is concentrated in a few subsectors, especially space heating, water heating, and cooking. For the ADE scenario, fossil fuel use is assumed to be nearly completely eliminated by 2050. These reductions in fossil fuel use over time are primarily achieved through a combination of energy efficiency and direct electrification measures based on extrapolations

[10] "Final" energy is used at the point of consumption (e.g., purchased by the consumer). "Primary" energy, which we do not estimate in this study, is a form of energy before any conversions to secondary forms of energy and any losses in the conversion or transport of energy. Note that there can be losses in the conversion of final energy to the services ultimately used (e.g., losses when burning gasoline to propel a vehicle).

from Langevin, Harris, and Reyna (2019).[11] Energy efficiency improvements for the major subsectors are summarized in Table C1. Note that the efficiency improvements in Table C1 are incremental to improvements estimated from the AEO. Also, the improvements indicated in Table C1 are above and beyond energy use reductions from fuel-switching (i.e., electrification). Electrification of space and water heating are assumed to be much more widespread through adoption of electric heat pumps. In the ADE scenario, fossil fuel use in 2035 is estimated to decline to 5.4 quads, compared with 10.2 quads in the AEO scenario. The LTS scenario assumes even greater levels of energy efficiency, but less electrification, than ADE. Overall, fossil fuel use in 2035 is estimated to decline to 4.9 quads.

Table C1. Incremental Building Energy Efficiency Improvement Assumptions Beyond the AEO2021 Reference Case Projections for the ADE Scenario

	Direct Fuel Efficiency Annual Improvement Rate		Electricity Efficiency Annual Improvement Rate	
	2022–2030	**2030–2050**	**2022–2030**	**2030–2050**
Clothes Dryers	0.3%	0.2%	—	—
Clothes Washers	—	—	6.7%	2.0%
Lighting[a]	—	—	6.9%	1.1%
Refrigeration	—	—	0.7%	—
Space Cooling[b]	1.8%	1.0%	0.9%	0.8%
Space Heating[b]	2.0%	1.2%	2.1%	1.3%
Ventilation	-	-	0.4%	0.9%
Water Heating	0.4%	—	2.7%	1.2%

[a] Includes the impact of select window technologies that reduce lighting demand

[b] Includes the impact of building envelope (e.g., insulation, air-sealing) and window technologies that reduce demand for space conditioning

No efficiency improvements beyond what was assumed in the AEO2021 Reference case are assumed for the subsectors not listed.

Figure C3 shows the differences in annual fossil fuel consumption in the (combined residential and commercial) buildings sector for the ADE scenario. The leftmost bar shows buildings fossil energy use in 2020, and the rightmost one shows estimates for 2035 for the labeled scenario. The intervening waterfalls show the changes (1) between 2035 and 2020 from the business-as-usual AEO case, (2) from the impacts of demand reduction (e.g., energy efficiency) and (3) electrification. Figure C4 shows annual final energy consumption by fuel type in 2035 for the three demand trajectories and for 2020.

[11] Electrification can also be considered a form of energy efficiency as electric end-use technologies (e.g., electric heat pumps) for buildings are typically much more efficient than their fossil counterparts. However, for this analysis we refer to energy efficiency as those measures separate from fuel-switching ones. Examples of energy efficiency include improved insulation and other measures to improve the building envelope.

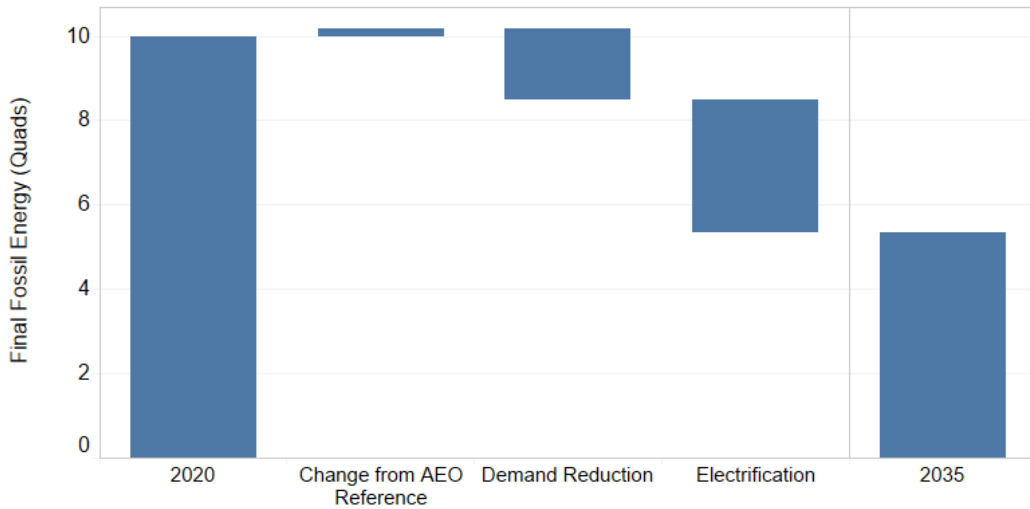

Figure C3. Change in buildings fossil fuel use for the ADE scenario

Demand reduction includes energy efficiency measures.

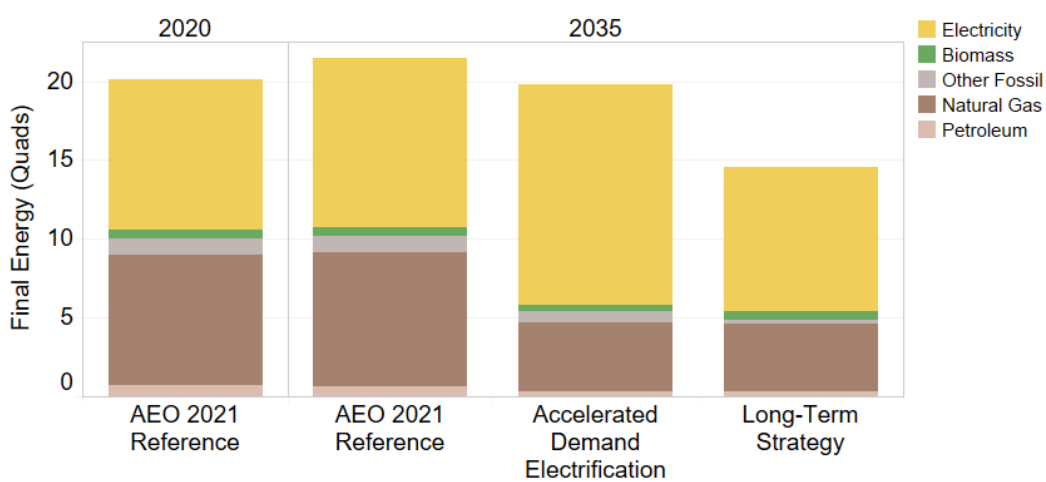

Figure C4. Buildings final energy use by demand scenario

Other Fossil includes propane for residential heating and cooking, and kerosene, coal, residual fuel oil, and motor gasoline for commercial uses.

Industry

Industry decarbonization estimates are largely based on studies from the Bandwidth Studies (DOE 2007, 2015a–c, 2017a–d), the preliminary Decarbonization Roadmap from the DOE's Advanced Manufacturing Office, and McMillan et al. (2021). These sources do not comprehensively identify decarbonization pathways across all processes and subsectors, which results in significant but incomplete decarbonization for industry through 2050 in the ADE scenario. The associated emissions from the remaining industrial fossil fuel use could be offset by negative emissions through natural land sinks or carbon dioxide removal technologies (to achieve net-zero emissions), but we do not focus on 2050 or specific industrial decarbonization pathways in this study. In the ADE scenario, continued fossil energy use is particularly prevalent in the cement, iron and steel, and chemicals industries and future fossil use is also assumed across a wide range of other industrial end uses. Despite the incomplete decarbonization of the sector and assumed growth in total energy consumption, fossil fuel consumption declines from 20.7 quads in 2020 to 20.1 quads by 2035 in the ADE scenario (an additional 0.7 quads are assumed to use carbon capture with sequestration for cement, chemicals, iron and steel, and food industries). Annual fossil fuel consumption for industry in 2035 is 18% less than estimates from the AEO (Figure C5). Fossil fuel use is largely replaced by electrification options, such as heat pumps and electric boilers, but low-carbon fuels and carbon capture with sequestration is also relied on in this scenario. Reductions in fossil fuel use are also observed in the LTS scenarios, including an 11% reduction from 2020 to 2035, which corresponds to 25% lower 2035 fossil fuel use than AEO projections. (Use of hydrogen and hydrogen-derived fuels in industry and transportation are presented in Section C.3.) Both scenarios also assume energy efficiency—including 25%–50% of the full energy efficiency technical potential in the ADE scenario—is realized over the next three decades.

Figure C5 shows changes in fossil fuel use in industry for the ADE scenario from the AEO projections and for 2020. Figure C6 shows annual final energy consumption in industry by fuel type in 2035 for the three demand trajectories and for 2020.

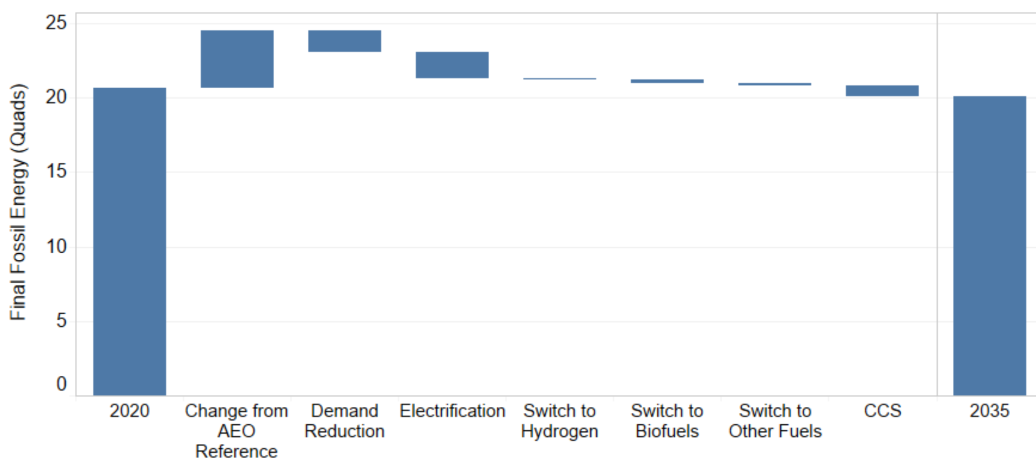

Figure C5. Change in industrial fossil fuel use for the ADE scenario

Demand reduction includes energy efficiency measures.

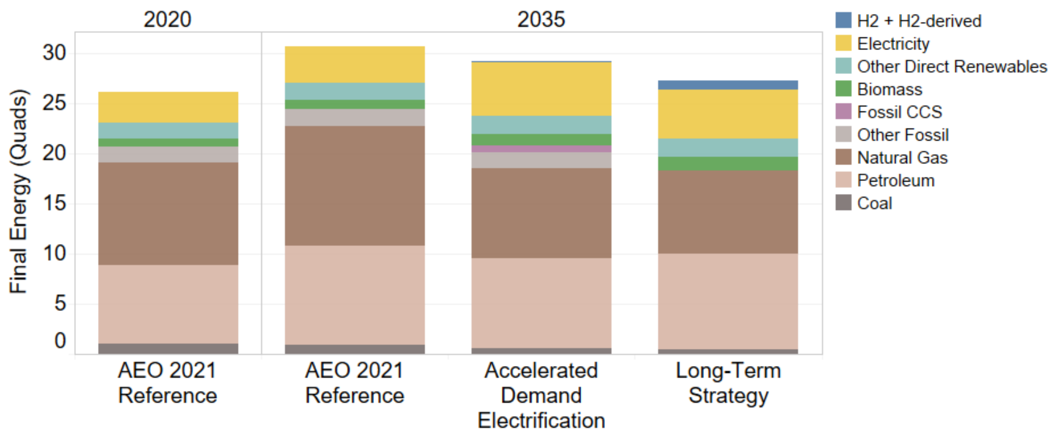

Figure C6. Industry final energy use by demand scenario

H2+H2 derived fuels includes ammonia and synthetic hydrocarbons.
We include biofuels produced with hydrogen in the Biomass category.

Transportation

Transportation decarbonization in the ADE scenario is primarily met through a combination of direct and indirect electrification measures based approximately on Ledna et al. (2022) and in consultation with the DOE sustainable transportation offices. We assume light-duty cars and trucks transition almost entirely to battery electric vehicles by 2050. Similarly, local delivery trucks and other vocational vehicles, buses, and commuter rails are also assumed to be predominantly electric. Freight trucks are assumed to rely on a combination of electricity, hydrogen, and biofuels—although with a majority being electric by 2050. Electricity use for all transportation end uses is about 7% of total 2035 electricity demand under the ADE scenario. Biofuels comprise nearly all sustainable aviation fuels by 2050. For marine shipping, we assume a near-equal mix of biofuels, ammonia, and synthetic hydrocarbons. These changes are estimated to result in 30% lower 2035 fossil fuel consumption from the transportation sector under the ADE scenario, relative to 2020. In comparison, the LTS scenario results in 37% lower fossil fuel consumption for transportation compared to 2020.

Figure C7 shows changes in fossil fuel use in transportation for the ADE scenario from the AEO projections and for 2020. Figure C8 shows annual final energy consumption in industry by fuel type in 2035 for the three demand trajectories and for 2020. Note that the share of electricity use for transportation understates the level of electric vehicle adoption; the share of service demand (i.e., vehicle miles traveled) for light-duty vehicles is higher due to the increased efficiency of electric vehicles.[12]

[12] In the ADE scenario, electric vehicles are assumed to be 3–4 times more efficient than internal combustion engines.

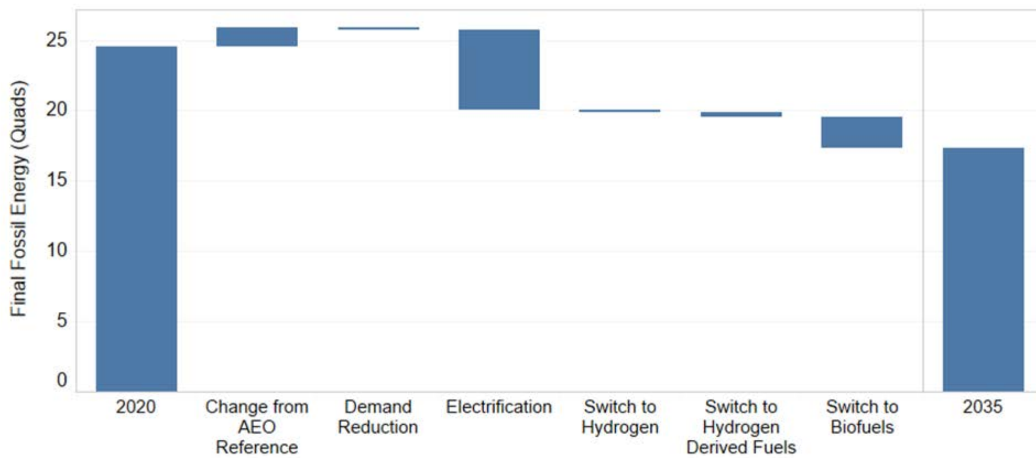

Figure C7. Change in transportation fossil fuel use for the ADE scenario

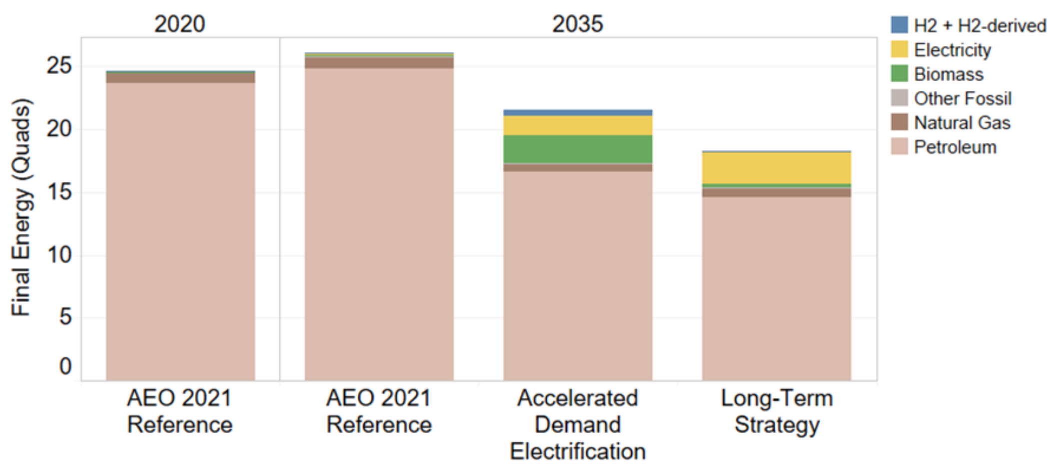

Figure C8. Transportation final energy use by demand scenario

H2+H2 derived fuels includes ammonia and synthetic hydrocarbons.
We include biofuels produced with hydrogen in the Biomass category.

C.3 Electricity and Hydrogen Demand

The final energy demand estimates described in Section C.2 are converted to electricity and clean hydrogen demand in ReEDS, which endogenously models the *supply* of these two energy carriers. For electricity demand, the national annual estimates are disaggregated to the 134 BAs in ReEDS with hourly demand profiles for each region.

Indirect Use

The final energy use estimates from Section C.2 do not account for intermediate or indirect use of electricity or hydrogen to produce some of these other low-carbon fuels; accounting for all electricity and hydrogen demand in ReEDS would require including these indirect uses. Table C2 shows the electricity and hydrogen fuel input required for biofuels, synthetic hydrocarbons, ammonia, and methanol based on data from the Solar Futures Study, Appendix 2-D (DOE 2021). Note that hydrogen production could also require electricity, but this is accounted for endogenously in ReEDS and is not discussed here.

Table C2. Electricity and Hydrogen Fuel Input Required (Quads) Per Quad of Low-Carbon Fuel Consumed

	Biofuels[a]	Synthetic Hydrocarbons	Ammonia	Methanol
Electricity	0.00	0.38	0.12	0.31
Hydrogen	0.53	1.49	1.16	1.25

[a] 1.74 quads of biomass are also required per quad of biofuel.

Electricity

A simple unit conversion factor (3,412 Btu/kWh) is used to convert the annual electricity consumption, including both direct end-use and indirect use, from quads to megawatt-hours. National demand for electricity is disaggregated to each of the 134 BAs in ReEDS using the spatial distribution of demand from 2010. Figure C9 shows the U.S. annual electricity demand by sector in the three demand scenarios. The compound annual growth rates (from 2020 to 2050) in electricity demand are 1.0%, 3.4%, and 2.1% in the AEO, ADE, and LTS scenarios respectively.

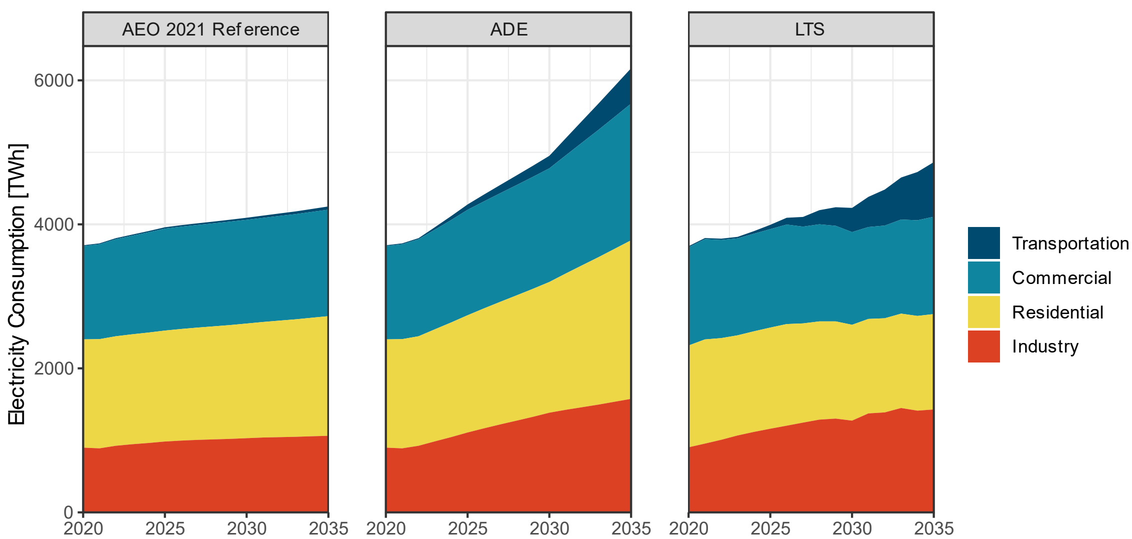

Figure C9. Annual electricity demand by scenario

For the ADE and LTS scenarios, hourly profiles are generated based on the subsector-specific profiles from the Electrification Futures Study (EFS) (Mai et al. 2018).[13] For subsectors without profiles from the EFS, we apply the aggregate profile, across all sectors, from the corresponding year. All profiles are based on weather data from 2012. For the ADE scenario, the top 88 hours (1% in each year) are lowered to match demand during the 99th percentile as a proxy for

[13] EFS profiles for space heating do not fully account for electric resistance backup, and thus could underestimate winter peak demand. More generally, increases in winter peak demand are very sensitive to assumptions about heat pump equipment performance and sizing, as well as building insulation and other envelope considerations. The analysis also does not consider future weather considerations, which could also alter load peaks estimated here.

interruptible load or other demand-side flexibility measures that may be implemented in the future. This is applied for each model BA.

Figure C10 shows the modeled demand profile for 8,760 hours in the year for 2020 and 2035 from the ADE and LTS scenarios as a result of this process. Figure C11 shows the corresponding load duration curves. The figures highlight the growth in average hourly demand and peak demand in the ADE scenario due in large part due to the increased electrification assumed. This electrification, specifically in buildings for space heating, shifts the demand peak from the summer in 2020 to the winter in 2035. The greater amount of energy efficiency—and lower levels of electrification—under LTS results in broader peaks that largely remain in the summer for most regions.

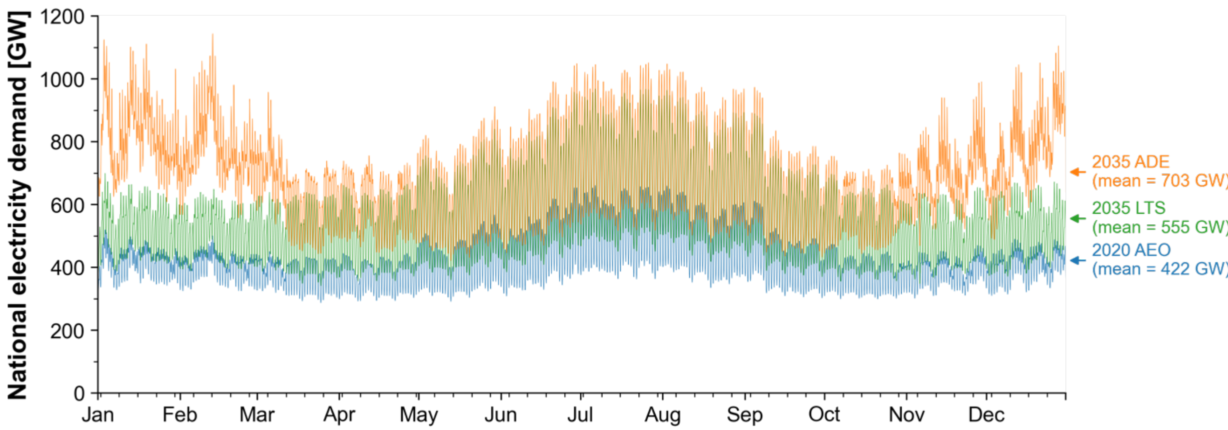

Figure C10. Modeled hourly electricity demand for 2020 (blue), 2035 under the LTS scenario (green), and 2035 under the ADE scenario (orange)

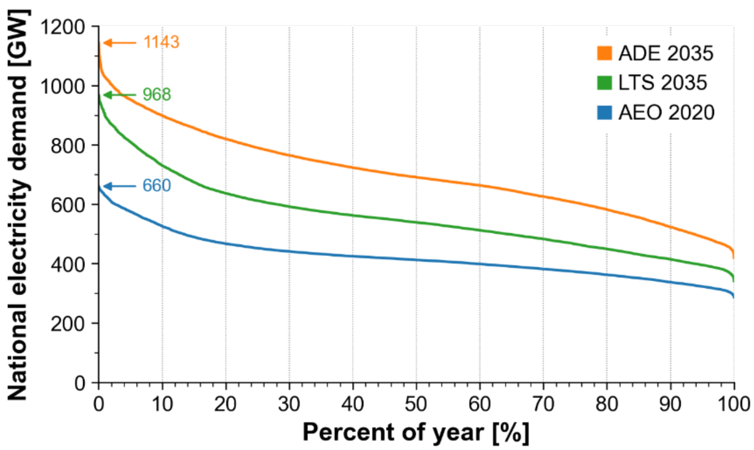

Figure C11. Load duration curves for 2020 (blue) and 2035 under the ADE (orange) and LTS (green) scenarios

The profiles presented in Figures C9 and C10 include the reduction in the top 1% peak hours but otherwise exclude the impacts of demand-side flexibility, which could reduce the variations between peak and average demand. Model representation of demand flexibility, including assumptions for flexibility constraints and consumer participation, are taken directly from the EFS "base" flexibility case

(Sun et al. 2020). In this scenario, 5% of annual demand is flexible in 2035. However, given the coarse representation of demand flexibility in this analysis, we do not quantitatively estimate the value of flexibility in this study. Future work is needed to analyze the role of demand-side resources under carbon-free electricity systems.

Hydrogen

Demand for hydrogen results from direct use of hydrogen at the final point of consumption based on the assumptions described in Section C.2 as well as indirect use of hydrogen to produce other low-carbon fuels (e.g., biofuels, synthetic hydrocarbons, and ammonia). Under the ADE scenario, non-power hydrogen demand grows to 14.3 MT-H2 in 2035. Table C3 shows the distribution of hydrogen demand in transportation and industry subsectors in this case. The LTS scenario also includes non-power demand for hydrogen, including 7.5 MT-H2 in 2035.[14] Power sector demand for hydrogen as a low-carbon fuel for combustion turbines are modeled endogenously and are additive to these estimates. Hydrogen demand and consumption are modeled at the national scale and on an annual basis only. Simple adders for transport and storage costs are included in the scenarios (Appendix B). Additional research is needed to assess the pipeline and storage needs under a low-carbon energy system.

The analysis assesses only the demand and production of hydrogen from low-carbon sources, including using SMR with CCS or electrolyzers using clean electricity. As a result, the current U.S. production and consumption of hydrogen (~10 MT) are excluded (Connelly, Elgowainy, and Ruth 2019). Currently, hydrogen is used in part for refined petroleum products. Given the reduction in motor gasoline and diesel fuels in the transportation sector under the ADE scenario, this demand would likely decline over time. Hydrogen production to serve these needs are also expected to transition to lower-emissions pathways given the overall economy-wide decarbonization trajectory modeled under the ADE scenario. These dynamics are not modeled explicitly in our analysis. Although domestic demand for refined petroleum products declines under the ADE scenario, some existing demand for hydrogen (such as for exported refined products or agriculture uses) might persist or grow. In this case, additional electricity generation beyond what is estimated in the scenarios would be needed if this hydrogen is to be produced using low-carbon electricity.

More generally, there is considerable uncertainty in the future demand for hydrogen—driven by uncertainties in decarbonization pathway, fuel conversion pathways, and how existing hydrogen production facilities and demand might evolve. The analysis is not designed to capture all these uncertainties nor does it forecast future hydrogen demand. Instead, the ranges used across scenarios are intended to reflect how increased demand for clean hydrogen and other low-carbon fuels might impact the electricity supply options.

[14] 2050 non-power demand for hydrogen is estimated to be 46 MT and 26 MT under the ADE and LTS cases, respectively. See table C3 for ADE.

Table C3. Annual Hydrogen Demand by Subsector in the ADE Scenario

Sector	Subsector	End-Use Fuel	Hydrogen Demand (MT)	
			2035	**2050**
Industry	Agriculture	Biofuel	0.6	2
	Bulk chemical	Hydrogen	0.4	1.6
		Biofuel	<0.1	-
	Construction	Biofuel	0.4	-
	Iron and steel	Hydrogen	0.1	0.4
		Biofuel	<0.1	-
	Other	Biofuel	<0.1	-
Transportation	Air	Biofuel	4	14.4
		Synfuel	0.9	4.5
	Light-duty vehicles	Hydrogen	<0.1	<0.1
		Biofuel	0.4	-
	Marine	Ammonia	0.9	2.7
		Biofuel	0.4	1.3
		Synfuel	1.2	3.5
	On-road freight	Hydrogen	0.4	6.3
		Biofuel	2.4	2.3
	Other	Biofuel	1	3.6
		Synfuel	0.1	0.6
	Rail	Hydrogen	0.2	0.9
		Biofuel	0.3	0.6
		Synfuel	0.4	1.7
Total			**14.3**	**46.3**

Values may not sum to total due to rounding. Synfuel = synthetic hydrocarbons.

C.4 CO_2 Emissions

Direct CO_2 emissions from the demand sectors are estimated based on the final energy assumptions from Section C.2. Specifically, emissions for each sector are projected using subsector-level fuel consumption in the ADE scenario and CO_2 coefficients by fuel (EIA 2021a). We calibrate annual direct CO_2 emissions at the sectoral level for 2020 with nonelectric emissions detailed in AEO2021 (EIA 2021b). Emissions from the LTS scenario are based directly on the economy-wide modeling used to develop the scenario and include CO2 removal (White House 2021). Figure C12 shows annual CO_2 by sector from 2020 to 2035 for all three demand scenarios, and the differences from the AEO case for the ADE and LTS scenarios. Power sector emissions are modeled endogenously in ReEDS and are added to the demand sector emissions to estimate total energy system CO_2. Note we do not assess CO_2 emissions outside the U.S. energy system nor do we assess non-CO_2 greenhouse gas emissions (with the exception of methane leakage associated with natural gas production for gas-fired electricity generation and hydrogen production, which is included in the national CO_2 cap as noted in the main body of the report).

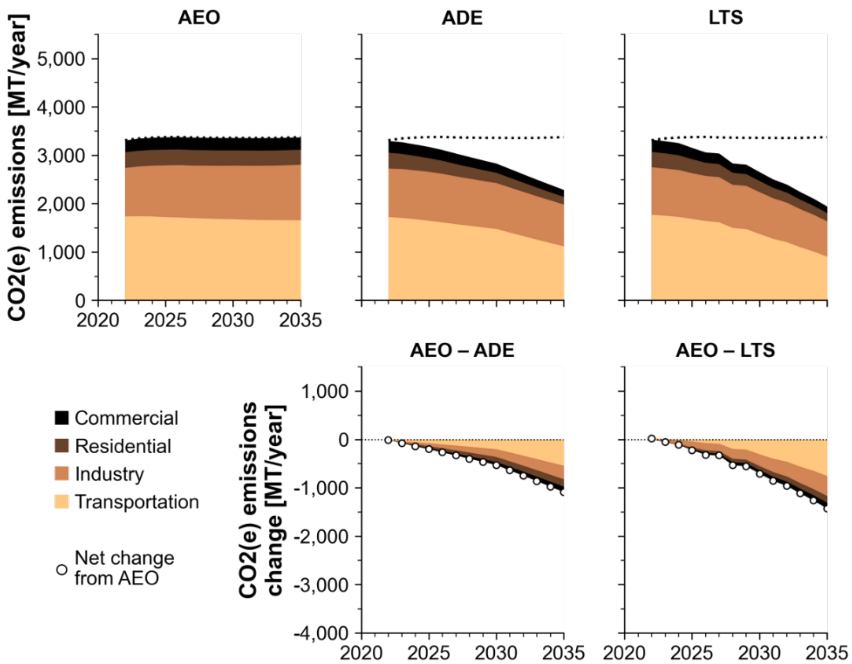

Figure C12. Annual CO_2 direct emissions by end-use sector by scenario (top) and difference in emissions from the AEO scenario (bottom)

C.5 References

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