2024 Standard Scenarios Report: A U.S. Electricity Sector Outlook

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Preface

This report is one of a suite of National Renewable Energy Laboratory (NREL) products intended to support forward-looking electricity sector analyses and decision making. The objective of the effort is to identify a range of possible futures for the U.S. electricity sector while illuminating specific energy system issues and discussing future trends in outcomes such as energy technology deployment and production, energy costs, and emissions.

The effort is supported by the U.S. Department of Energy's (DOE's) Office of Energy Efficiency and Renewable Energy. It leverages significant activity already funded by that office to better understand individual technologies, their roles in the larger energy system, and market and policy issues that can impact the evolution of the electricity sector.

Specific products from this effort include the following:[1]

- An Annual Technology Baseline (ATB) workbook documenting detailed cost and performance data (both current and projected) for various generation technologies
- An ATB summary website describing each of the technologies and providing additional context for their treatment in the workbook
- This Standard Scenarios report and dataset describing U.S. electricity sector futures
- The Cambium datasets, which contain a broader suite of metrics for a subset of scenarios from this report.

This report documents the tenth edition of the annual Standard Scenarios. Though many potential futures are included in this analysis, the set of scenarios is not exhaustive. To supplement this report, see "Future System Scenario Analysis" (https://www.nrel.gov/analysis/future-system-scenarios.html), which lists NREL publications that are designed to more thoroughly investigate specific phenomena (such as electrification or transmission infrastructure).

[1] To access these products, see "Annual Technology Baseline" (https://atb.nrel.gov/), "Standard Scenarios" (https://www.nrel.gov/analysis/standard-scenarios.html), and "Cambium" (https://www.nrel.gov/analysis/cambium.html).

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We gratefully acknowledge the many people whose efforts contributed to this report. We thank Ashna Aggarwal, Paul Basore, Adria Brooks, Patrick Bryant, Jaquelin Cochran, Colin Cunliff, Jason Frost, Patrick Gilman, Natalie Lefton, Brandon McMurtry, Glenda Oskar, Gian Porro, Jun Shepard, Paul Spitsen, and Dean Williams for their comments on a draft of this report. The effort reported here was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy Strategic Analysis Team, under contract number DE-AC36-08GO28308. All errors and omissions are the sole responsibility of the authors.

List of Abbreviations and Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BECCS	bioenergy with carbon capture and storage
CAGR	compound annual growth rate
CapEx	capital expenditures
CARB	California Air Resources Board
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
dGen	Distributed Generation Market Demand Model
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EPA	United States Environmental Protection Agency
H2-CT	hydrogen-fueled combustion turbine
HVDC	high-voltage direct current
IRA	Inflation Reduction Act of 2022
ITC	investment tax credit
LCC	line commuted converters
MMBtu	million British thermal units
MMT	million metric tons
MW	megawatt
MWh	megawatt-hour
NETL	National Energy Technology Laboratory
NG-CC	natural gas combined cycle
NG-CT	natural gas combustion turbine
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
OGS	oil-gas-steam
O&M	operation and maintenance
PTC	production tax credit
PV	photovoltaic(s)
RE	renewable energy
RE-CT	renewable energy combustion turbine
ReEDS	Regional Energy Deployment System
TW	terawatt
TWh	terawatt-hour
TW-mi	terawatt-mile
USLCI	U.S. Lifecycle Inventory Database
VSC	voltage source converter

Executive Summary

This report documents the tenth edition of the annual Standard Scenarios. It summarizes 61 forward-looking scenarios of the U.S. electricity sector that have been designed to capture a wide range of possible futures.

The Standard Scenarios are simulated using the Regional Energy Deployment System (ReEDS) model. ReEDS projects possible electricity sector evolution by identifying the least-cost build-out and operation of utility-scale assets that meet policy, reliability, and operational constraints. Such a least-cost approach is intended to reflect the results of a well-functioning market or well-regulated system.

The scenarios can be viewed and downloaded from the National Renewable Energy Laboratory's (NREL's) Scenario Viewer.[2] Annual results are available for the full suite of scenarios in the Standard Scenarios projects in the viewer, whereas the Cambium projects contain a broader suite of metrics at hourly resolution for a subset of scenarios.[3]

Relative to the 2023 edition, key model and assumption changes include a new stress-periods-based method for assessing resource adequacy, inclusion of interconnection queue data for improving near-term generator investment representation, institutional frictions represented through inter-regional hurdle rates and limits on firm capacity imports (both of which are modeled as improving over time), representations of the updated Clean Air Act (CAA) Section 111 rules, and updated representations of the Inflation Reduction Act of 2022 (IRA) tax credits.

The Standard Scenarios includes a scenario called the Mid-case, which has central or median values for core inputs such as technology costs and fuel prices, moderate end-use electricity demand growth (which averages 1.8% per year), and both state and federal (but not local) electricity sector policies as they existed in August 2024. Sensitivities are then created by varying key inputs such as technology and fuel prices, resource availability, demand growth, the availability of nascent technologies, and the future policy environment (such as the extension of IRA's tax credits or the presence of an electricity sector decarbonization constraint). New to this year's suite is the inclusion of scenarios with 100% net lifecycle CO_2-equivalent (CO_2e) decarbonization by 2035.[4]

[2] Scenario Viewer-Data Downloader," NREL, https://scenarioviewer.nrel.gov/.
[3] "Cambium," NREL, https://www.nrel.gov/analysis/cambium.html.
[4] All decarbonization constraints in this report are on a net basis and for the U.S. electricity sector only. Additionally, in this report, "lifecycle CO_2e" refers to the CO_2-equivalent for CO_2, CH_4, and N_2O for both combustion as well as precombustion activities (fuel extraction, processing, and transport) calculated with AR6 global warming potentials. Note that, while this is a broader consideration of greenhouse gas emissions than in prior editions of the Standard Scenarios, it is not exhaustive – for example, it does not consider other sources such as the emissions associated with infrastructure construction or decommissioning.

There are several noteworthy differences in results relative to the 2023 Standard Scenarios:

1. *Coal without carbon capture and storage (CCS) mostly retires or retrofits with CCS by 2032:* The inclusion of updated CAA 111 rules results in a significant decline in non-CCS coal capacity through 2032, with the majority of scenarios having less than 1 gigawatt (GW) of non-CCS coal at that point.[5] In all scenarios with CCS enabled as an investment option, at least a portion of the coal fleet is retrofitted with CCS.
2. *The introduction of 100% net lifecycle CO_2e decarbonization scenarios results in capacity mixtures not seen previously:* In prior years, decarbonization was defined only in terms of CO_2 emissions from combustion. In this year's suite, a subset of the decarbonization scenarios define their emissions reduction targets to include CH_4 and N_2O from combustion as well as from precombustion activities (fuel extraction, processing, and transport). The broader consideration of greenhouse gases (GHG) tends to decrease the role of natural gas CCS technologies while increasing the role of nuclear, geothermal, and hydrogen.
3. *Most, but not all, scenarios see an increase in natural gas capacity:* In the 2023 Standard Scenarios, all scenarios saw an increase in natural gas capacity. This trend holds again this year for all analyses that do not have a 100% net lifecycle CO_2e decarbonization constraint, with natural gas capacity increasing by 16% to 100% over 2023 capacity by 2050 in scenarios without such a constraint. In all of the scenarios with a 100% net lifecycle CO_2e decarbonization constraint, however, natural gas capacity decreases—ranging from a 13% to 27% reduction by 2050 relative to 2023 capacity.

In addition to the above observations, below are highlights that are broadly in line with the 2023 Standard Scenarios:

1. *Wind, solar, and storage grow significantly, making up the majority of new capacity*. By 2050, wind, solar, and storage capacity reach 820 GW, 1,020 GW, and 330 GW respectively (5, 7, and 8x increases over 2023 levels, respectively) in the Mid-case. Across all scenarios, combined wind and solar generation contributes between 48% and 79% of total nonstorage generation in 2050.

2. *In later years, fossil generators without carbon capture provide a greater share of firm capacity than generation.* In 2050, in the Mid-case under Current Policies, fossil generators (natural gas, oil, and coal) provide 46% of firm capacity but only 15% of nonstorage generation (ranging from 23% to 61% of firm capacity and 3% to 35% of nonstorage generation across all scenarios). Generation from natural gas without carbon capture tends to decline slightly (either by retiring or retrofitting with CCS) in scenarios without decarbonization constraints and more materially in scenarios with decarbonization constraints.

[5] The remaining non-CCS capacity complies with 111 through a state-level rate-based emissions compliance pathway. This pathway assesses compliance for a technology based on a state's fleetwide emissions rate, which must achieve a specified emissions intensity. In this modeling, a small amount of non-CCS coal capacity can remain compliant by operating at low capacity factors in combination with generation from with-CCS coal generators (whose performance exceeds the specified level) within the same state.

3. *Currently nascent technologies play a limited role under current policies and a larger role in futures that achieve 95%–100% net decarbonization.*[6] Some currently nascent technologies (natural gas with CCS coal with CCS, bioenergy with CCS, hydrogen combustion turbines, and small modular nuclear reactors) are all deployed in the Mid-case, although the combined contribution of all those technologies reaches a maximum of only 1% of total annual generation and 3% of firm capacity. The contribution of these nascent technologies can be much greater in scenarios with breakthrough cost and performance improvements or with national electricity sector GHG emissions constraints, where they reach a maximum contribution of 23% of total generation and 33% of firm capacity.
4. *U.S. electricity sector emissions decrease significantly through the 2030s*. Relative to estimated lifecycle CO_2e emissions in 2023, annual U.S. national electricity sector lifecycle CO_2e emissions in 2035 are reduced by 64% in the Mid-case and 54%–75% across all scenarios with current policies.
5. *Clean electricity tax credits are available through 2050 for most scenarios without additional decarbonization policies*. The clean electricity tax credits in IRA are scheduled to phase out either at the end of 2032 or when national GHG emissions from the production of electricity drop below 25% of the level in 2022, whichever occurs later. In 11 of 17 scenarios with current policies, including the Mid-case, that emissions threshold is never passed—and the clean electricity tax credits therefore do not phase out.
6. *In the Mid-case, 95% net CO_2 decarbonization by 2050 is achieved with less than a 1% increase in the present-value bulk electricity sector costs (relative to the Current Policies Mid-case).* In comparison, 95% net lifecycle CO_2e decarbonization by 2035 increases costs by 8%, and 100% net lifecycle CO_2e decarbonization by 2035 increases costs by 14%.

To illustrate some of these trends, Figure ES-1 shows the generation and capacity projections for two scenarios. One scenario is the Mid-case mentioned previously, and the other shares the same core assumptions as the Mid-case but with a national electricity sector lifecycle CO_2e constraint that reaches 100% net decarbonization by 2035.

[6] The classification of technologies as either nascent or established was an analytical judgment based on the technology's readiness level, the current installed capacity globally, the current presence or absence of the technology in resource plans in the United States, the level of understanding of permitting and sitting challenges, and the breadth and quality of future performance and cost estimates from multiple institutions. The designation of a technology as nascent is not intended to pass judgment on the difficulty or likelihood of the technology ultimately achieving commercial adoption. Indeed, many of the technologies have high technology readiness levels, and some have operational demonstration plants. Nonetheless, even if a technology is technically viable, there still can be great uncertainty about its future cost and performance as well as a lack of understanding of other considerations relevant to projecting deployment, such as siting preferences and restrictions.

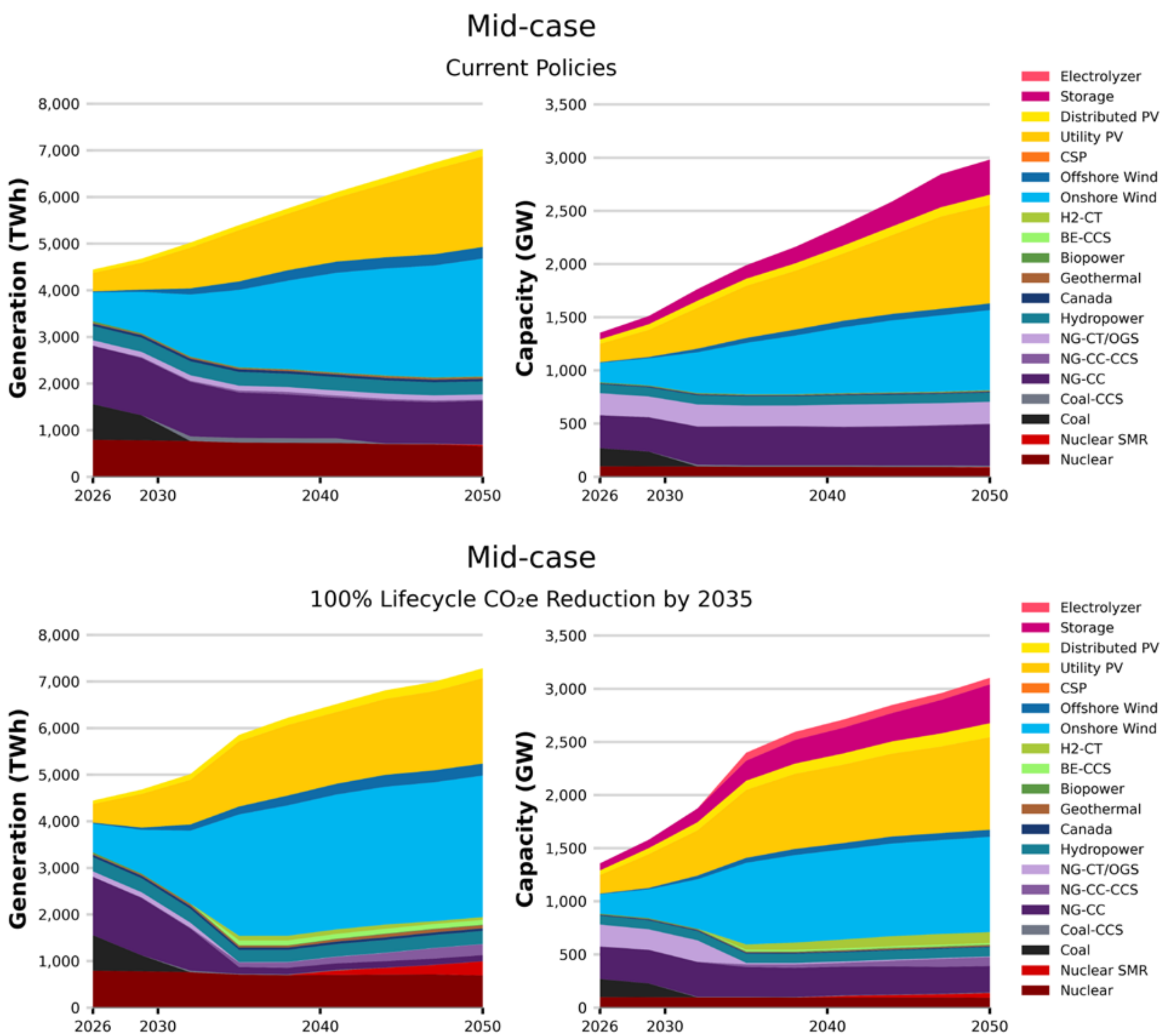

Figure ES-1. U.S. electricity sector generation (left) and capacity (right) over time for the *Mid-case Current Policies* and *Mid-case 100% Net Lifecycle CO_2e Reduction by 2035* scenarios

PV is photovoltaic, NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam, H2-CT is hydrogen combustion turbine, BE is bioenergy, CSP is concentrating solar power, CCS is carbon capture and storage, and SMR is small modular reactor. Electrolyzers are not generators; they consume electricity to produce H_2. Storage includes 4-hour batteries, 8-hour batteries, and pumped hydropower.

As mentioned above, the Standard Scenarios include numerous additional scenarios that vary factors such as fuel prices, demand growth, technology costs, resource availability, transmission conditions, and the policy environment. Figure ES-2 shows the annual generation by technology class for the full suite of scenarios.

In general, wind and solar see significant growth over the coming decades, reaching a maximum of 5,500 terawatt-hours (TWh)/year and 3,400 TWh/year, respectively. Throughout the suite of results, demand growth is a strong driver of wind and solar generation: the seven scenarios with the greatest wind and solar generation are all sensitivities with electricity demand that more than doubles by 2050 relative to current levels. Drivers of demand growth on that scale could include electrification, new manufacturing, data centers, and/or hydrogen production through electrolysis. The scenarios with the lowest wind and solar generation have low demand growth or omit IRA's electric sector tax credits.

Compared to last year's Standard Scenarios, there are more scenarios that see increases in nuclear generation, including two scenarios where nuclear generation increases more than twice over current levels due to combinations of significant cost declines, high load growth, and the presence of aggressive decarbonization constraints. These scenarios are the exception, however, as the majority of scenarios see nuclear generation that stays within ±20% from current levels.

Most scenarios do not exceed 10 GW of geothermal capacity, although scenarios with combinations of lower geothermal costs, decarbonization constraints, and high demand growth can exceed that amount—with two scenarios slightly exceeding 50 GW. Hydropower sees little additional deployment across the scenario suite, with capacity remaining between 83 and 89 GW across all years and scenarios in the results.

In the majority of scenarios without decarbonization constraints, generation from natural gas without CCS tends to decline slightly from current levels. The scenario with the greatest amount of non-CCS natural gas is the scenario without IRA's tax credits (but which retains a CAA 111 representation). In most scenarios with current policies, natural gas capacity increases even as generation decreases, indicating a trend of more natural gas generators with lower capacity factors relative to the current grid. Scenarios with 100% net lifecycle decarbonization see declines in the total amount of natural gas capacity, in part because of the upstream fugitive CH_4 emissions associated with the use of natural gas in both with- and without-CCS generators—although even in such scenarios, both with- and without-CCS natural gas generators are always present in some degree.

In part because of CAA 111, and in part because of general economic competition, the quantity of coal without CCS significantly decreases in all scenarios by 2032 where the updated rules are included. The scenario with the greatest coal generation post-2032 is the sensitivity without IRA's tax credits or 111 represented, and the second-most is the scenario without 111 represented. Some coal is retrofitted with CCS in all scenarios where it is an investment option other than those without either or both of IRA's tax credits or 111. In scenarios with coal CCS retrofits, the retrofitted plants operate at high capacity factor for 12 years while receiving the 45Q credit and then generally significantly decrease their capacity factor when they stop receiving the credit.

Despite many scenarios containing 100% net lifecycle decarbonization trajectories, all scenarios have at least some generation from fossil generators. Fossil generation in 100% net decarbonization scenarios is enabled by the model also deploying either bioenergy with CCS (which is represented as a negative emissions technology in this modeling) or direct air capture (in sensitives where it is allowed as an investment option). Using bioenergy with CCS or direct air capture to offset emissions from already-built natural gas generators—and operating those generators primarily for firm capacity (i.e., to provide power during the times of highest system stress)—is seen by the model as lower-cost than replacing them entirely with non-emitting resources. Hydrogen combustion turbines also have their greatest contribution in scenarios with 100% net lifecycle decarbonization, where they are built primarily to provide firm capacity.

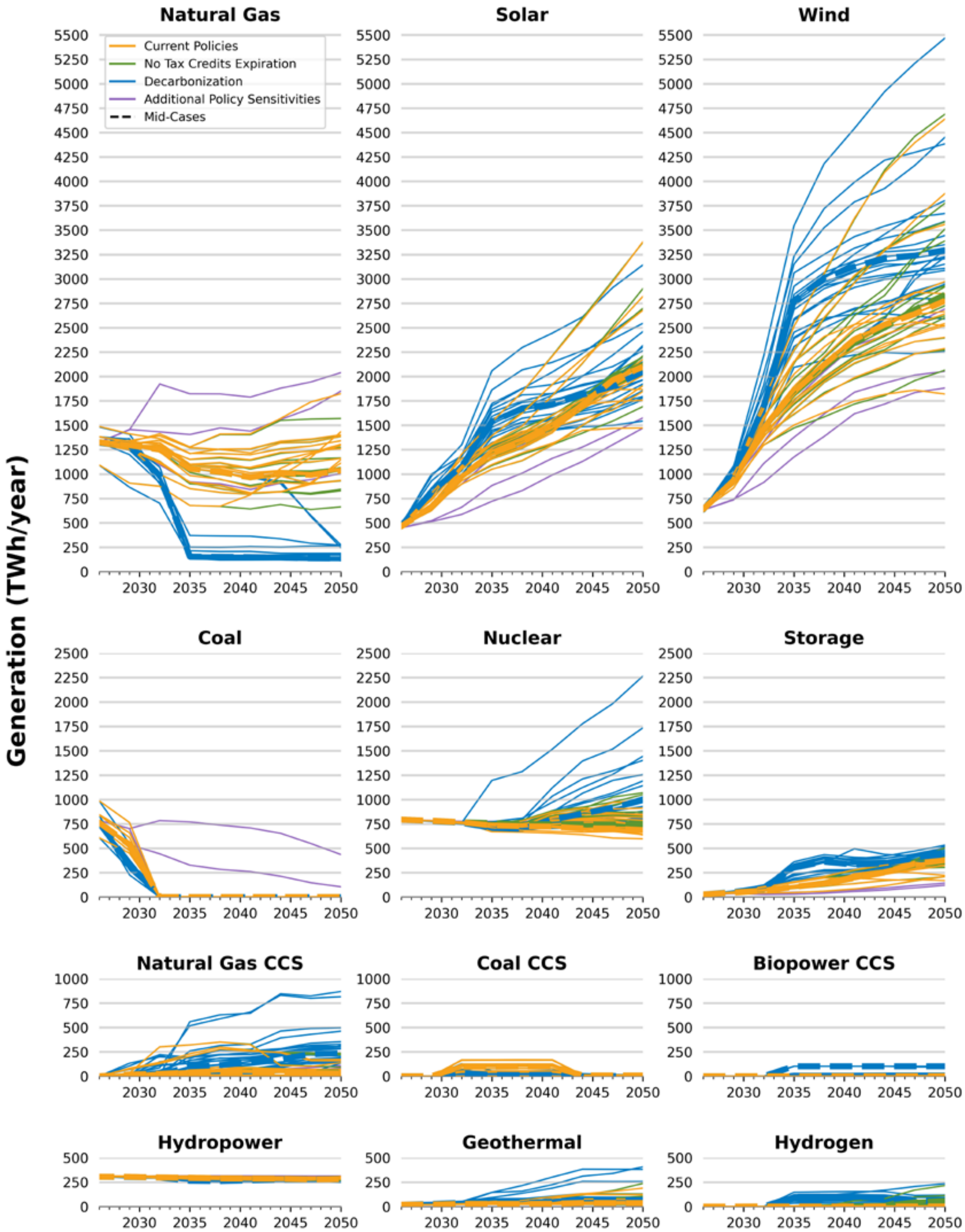

Figure ES-2. Generation across the suite of Standard Scenarios by fuel type

The Mid-case scenarios are shown with the heavier dashed lines. The *Additional Policy Sensitivities* group consists of three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules. Solar includes PV and CSP with and without thermal energy storage. Storage includes electric batteries and pumped hydropower.

Note that the quantity and timing of the deployment of nascent technologies (e.g., CCS, hydrogen combustion turbines, and small modular nuclear reactors) should be treated as particularly uncertain, given higher uncertainty about the future cost and performance of these technologies. Additionally, ReEDS assumes varying degrees of cost declines for all nascent technologies, based on exogenously estimated future cost trajectories (as opposed to endogenously estimated costs influenced by deployment, i.e. learning-by-doing). If such cost reductions do not materialize in practice, the quantity of deployment seen in some scenarios may be less likely to occur. Several sensitivities with varying assumptions for these technologies are included in the scenario suite to partially characterize these uncertainties; also included is a scenario where nascent technologies are excluded from the model.

Figure ES-3 shows the annual CO_2e electricity sector emissions for the full suite of scenarios. The left panel is lifecycle emissions (here defined as inclusive of both combustion and precombustion emissions), whereas the right panel is only combustion emissions (both panels reflect any CO_2 captured and stored with carbon removal technologies). The scenario with the greatest emissions in 2050 is a sensitivity without representations of either the IRA tax credits or updated CAA 111 rules, while the scenario with the second-greatest emissions omits only the IRA tax credits. The scenarios with the lowest emissions are scenarios with decarbonization constraints.

Note that Figure ES-3 shows only GHG emissions for the electricity sector—because some of the sensitivities implicitly vary GHG emissions beyond the electricity sector, the trends in economywide GHG emissions may differ. For example, the scenario with the third-highest 2050 emissions has significant load growth from electrification and non-power-sector hydrogen use, which would imply a reduction in non-power-sector emissions—possibly resulting in lower economywide emissions overall. Because the model used for this study does not represent economywide emissions, such results are not characterized in this report.

As mentioned above, most scenarios with current policies do not pass the emissions threshold specified in IRA, which determines if and when the clean generation tax credits expire. The threshold is set at 25% of 2022 GHG emissions from the production of electricity, shown in Figure ES-3 as the red dotted line; therefore, the clean generation tax credits are available through 2050. In the scenarios where the threshold is passed, the tax credits phase out, and if there is no national GHG emissions constraint or extension of IRA tax credits, there can be a rebound in electricity sector GHG emissions.[7]

[7] The rebound does not occur immediately when the threshold is passed because the credits do not phase out immediately and there are safe-harbor periods, both of which push back the date at which generators could come online while still receiving a tax credit.

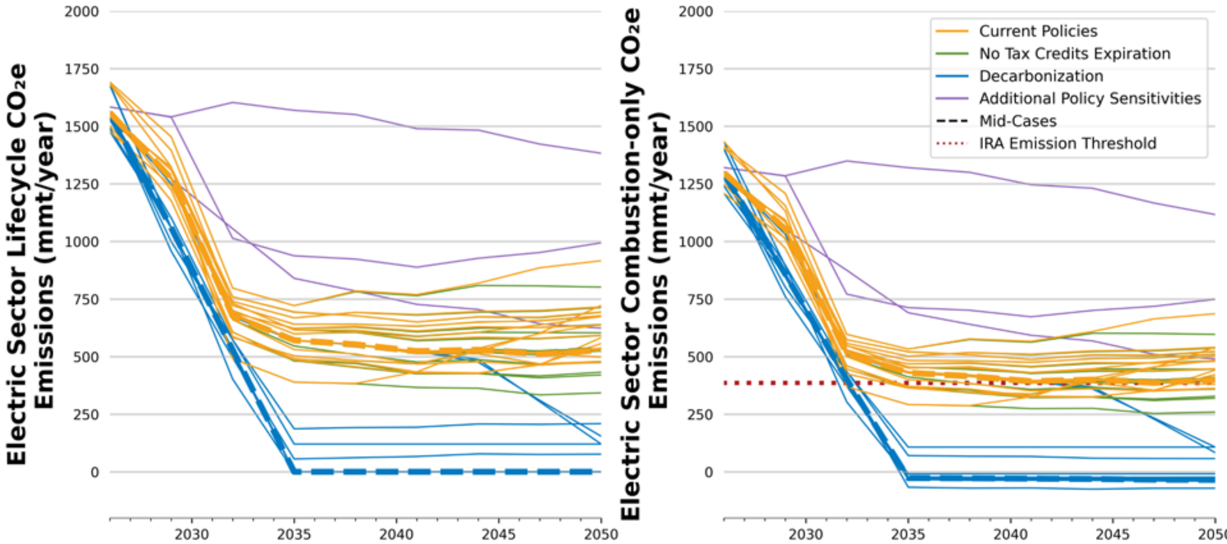

Figure ES-3. Electricity sector CO_2e emissions for the full suite of Standard Scenarios

Left panel: CO_2e emissions from both combustion and precombustion activities (fuel extraction, processing, and transport). Right panel: CO_2e from combustion only. The Mid-case scenarios are shown with the heavier dashed lines. Carbon captured by carbon removal technologies reflected in both figures. The GHG emissions included here are CO_2, CH_4, and N_2O, combined using 100-year AR6 global warming potentials. The exact value of the threshold that would trigger the IRA clean electricity tax credits phasing out has not been announced but is estimated to be 386 million metric tons (mmt) of combustion-only CO_2e in this modeling, shown in the right panel. The *Additional Policy Sensitivities* group consists of three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

The body of this report summarizes key results from the full suite of scenarios and documents the input assumptions for each scenario. Data for these scenarios are available for viewing and downloading in the Standard Scenarios 2024 project via the NREL Scenario Viewer.

Though many potential futures are included in this analysis, the set of scenarios is not exhaustive. Other NREL projects have explored certain aspects of these scenarios in more detail, such as the 100% Clean Electricity by 2035 Study[8] and the Electrification Futures Study.[9] And forthcoming studies include more detailed analysis of the impacts of transmission on the U.S. electricity sector.[10]

[8] "100% Clean Electricity by 2035 Study," NREL, https://www.nrel.gov/analysis/100-percent-clean-electricity-by-2035-study.html.
[9] "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.
[10] For a list of NREL's analysis of future power systems analyses, see "Future System Scenarios Analysis," NREL, https://www.nrel.gov/analysis/future-system-scenarios.html.

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1 Introduction

The U.S. electricity sector continues to undergo rapid change driven by evolutions in technologies, markets, and policies. This tenth installment of the Standard Scenarios is intended to help advance the understanding of the implications, drivers, and key uncertainties associated with this change.[11] This year's Standard Scenarios comprise 61 electricity sector scenarios for the contiguous United States that consider the present day through 2050.

The Standard Scenarios are simulated using the Regional Energy Deployment System (ReEDS) model, which projects utility-scale electricity sector evolution for the contiguous United States using a systemwide, least-cost approach subject to policy and operational constraints (Ho et al. 2021). ReEDS draws from the Distributed Generation Market Demand Model (dGen) for projections of behind-the-meter solar adoption.[12]

Relative to the 2023 edition, key model and assumption changes include a new stress-periods-based method for assessing resource adequacy, inclusion of interconnection queue data for improving near-term generator investment representation, institutional frictions represented through inter-regional hurdle rates and limits on firm capacity imports (both of which are modeled as improving over time), and representations of updated Clean Air Act (CAA) 111 regulations and Inflation Reduction Act (IRA) tax credit guidance. See the appendix for more details on model structure, inputs, and changes from prior editions.

The Standard Scenarios suite explores a range of possible future conditions and how the U.S. electricity sector may evolve under those conditions. Although these projections are intended to be broad and reasonable, they should not be the sole basis for making decisions. Analysts are encouraged to draw from multiple scenarios within the full set, as well as from projections from other sources, to benefit from diverse analytical frameworks and perspectives when forming their conclusions about the future of the electricity sector.

The National Renewable Energy Laboratory's (NREL's) models, in particular, have been designed to capture the unique traits of renewable energy generation technologies and the resulting implications for the evolution of the electricity sector. This work aims to accurately capture issues related to renewable energy integration, including resource adequacy and interactions of curtailment and storage on investment decisions. Other modeling and analysis frameworks will have different emphases, strengths, and weaknesses. The material in this report provides a perspective that complements those provided by others.

Although the models used to develop the Standard Scenarios are sophisticated, they do not capture every relevant factor. For example, the models do not explicitly model supply chains, learning-by-doing, or permitting. Additionally, ReEDS does not have foresight, uses only historical weather data, has a simplified representation of transmission networks, and identifies a systemwide cost-minimizing solution (subject to policy and operational constraints) rather than representing specific market actors or rules. Therefore, results should be interpreted within the

[11] See "Archives: NREL ATB and Standard Scenarios," NREL, atb.nrel.gov/archive for the previous Standard Scenarios reports and data.

[12] For more information about ReEDS and dGen, see www.nrel.gov/analysis/reeds and www.nrel.gov/analysis/dgen, respectively. For lists of published work using ReEDS and dGen, see www.nrel.gov/analysis/reeds/publications.html and www.nrel.gov/analysis/dgen/publications.html, respectively.

context of model limitations. A more complete list of model-specific caveats is available in the models' documentation (Ho et al. 2021, Section 1.4; Sigrin et al. 2016, Section 2.2).

In addition to this report, which focuses on high-level trends, state-level outputs are available for viewing and downloading through NREL's Scenario Viewer.[13]

[13] The Scenario Viewer-Data Downloader (scenarioviewer.nrel.gov) provides additional state-specific data from the scenarios; however, note as a national-scale model, ReEDS is not specifically designed to assess in detail the full circumstances of any individual state.

2 Scenario Definitions

The 2024 Standard Scenarios comprise 61 scenarios that project the possible evolution of the contiguous United States' electricity sector through 2050. Scenario assumptions have been updated since 2023 to reflect the technology, market, and policy changes that have occurred in the electricity sector, and many modeling enhancements have been made (see Section A.2 for details on key model changes since the prior edition).

Relative to the 2023 suite of scenarios, this year's suite has replaced one of the core future policy assumptions (demoting the 95% net decarbonization set to a policy sensitivity and raising up the *No Expiration of IRA Tax Credits* sensitivity to be one of the core future policy assumptions), altered another (extending the 100% net decarbonization scenarios to include CH_4 and N_2O in addition to CO_2 as well as emissions from precombustion activities), added additional policy sensitivities, and added a *Conservative Nuclear Cost* sensitivity.

The 61 scenarios were selected to capture a wide range of key drivers of electricity sector evolution, such as the cost and performance of technologies and fuel. The diversity of scenarios is intended to cover a range of potential futures. For example, in addition to considering traditional sensitivities such as demand growth and fuel prices, other factors that can impact the development of the electricity sector are also assessed, such as transmission build-out and technology progress. Analysts drawing from these results are encouraged to use data from multiple scenarios where feasible to reflect the inherent uncertainty in the evolution of the U.S. electricity sector.

The scenarios are summarized in Figure 1.

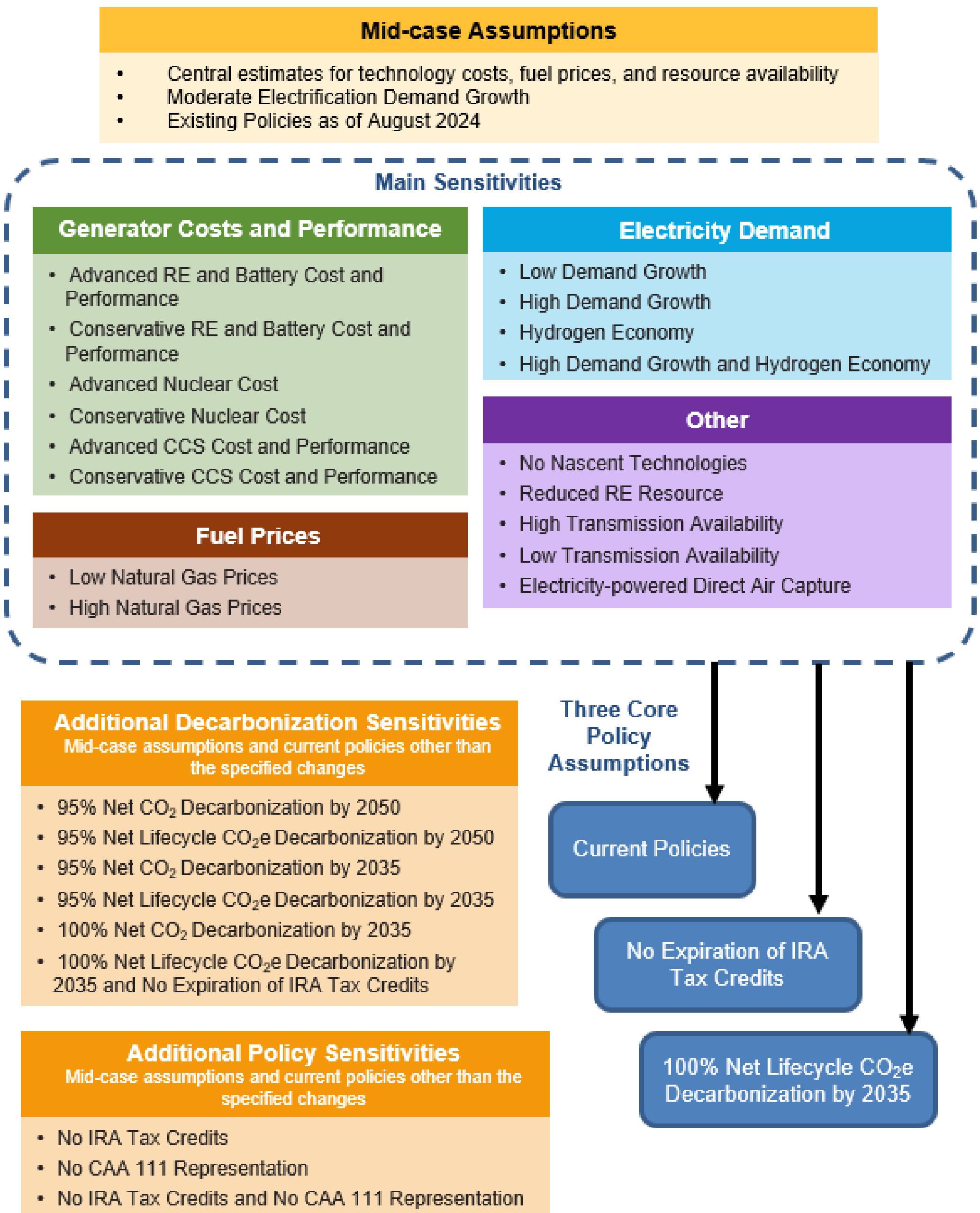

Figure 1. Summary of the 2024 Standard Scenarios

There are 61 scenarios: 18 base assumptions (1 Mid-case set of assumptions and 17 main sensitivities) multiplied by 3 different core policy assumptions, less 2 because the No Nascent Technologies sensitivity was run only under Current Policies, plus 10 additional sensitivities that are analyzed with Mid-case assumptions and current policies except as otherwise specified in the scenario's definition. Lifecycle CO_2e is CO_2, CH_4, N_2O for both combustion and precombustion activities (fuel extraction, processing, and transport). RE is renewable energy. CCS is carbon capture and storage. Scenario details are in Table A-1 in the appendix. All scenarios reflect federal and state electricity policies enacted as of August 2024 unless their scenario definition indicates otherwise. Nascent technologies are floating offshore wind, enhanced geothermal systems, generators with carbon capture and storage, nuclear small modular reactors, and hydrogen combustion turbines. A full list of technologies can be found in Table A-4 in the appendix.

The scenarios shown in Figure 1 are briefly described below. For more details about specific scenario definitions and inputs, see Section A.1 and A.3 of the appendix. The models and inputs used to generate these scenarios are publicly available.[14]

2.1 Generator Costs and Performance Sensitivities

The Mid-case uses central estimates of future technology costs and performance. Six of the sensitivities vary those assumptions for renewable energy technologies and batteries, nuclear generators, and CCS generators. The *Advanced* sensitivities assume lower future costs and better performance for their named technology groups, whereas the *Conservative* sensitivities assume higher future costs and lower performance. See Section A.1 *Technology Cost and Performance* for more details.

2.2 Electricity Demand Sensitivities

The Mid-case assumes moderate electricity demand growth averaging 1.8% per year and no demand for electrolysis-produced hydrogen beyond the model's endogenous use of it for the power sector. The *Low Demand Growth* and *High Demand Growth* sensitivities have lower and higher end-use electricity demand growth assumptions (0.9% and 2.8% per year, respectively). The *Hydrogen Economy* sensitivity assumes the same end-use demand growth as the Mid-case but adds on significant demand for electrolysis-produced hydrogen, which adds significantly to the total electricity demanded by the power sector. The *High Demand Growth and Hydrogen Economy* combines the high electricity demand growth assumption and exogenous hydrogen demand assumption, for a scenario that reaches in 2050 approximately 2.5 times the current levels of electricity demand. See Section A.1 *Electricity Demand* and *Endogenous Hydrogen Production and Hydrogen Demand* for more details.

2.3 Fuel Price Sensitivities

The Mid-case uses central estimates for future natural gas prices from the U.S. Energy Information Administration's (EIA's) Annual Energy Outlook. The *Low Natural Gas Prices* and *High Natural Gas Prices* sensitivities draw from lower and higher AEO projections, respectively. See Section A.1 *Fuel Prices* for more details.

2.4 Other Sensitivities

This year's scenario suite includes technologies that are still nascent. The *No Nascent Technologies* sensitivity does not include such technologies for investment.[15] The designation of a technology as nascent is not intended to pass judgment on the difficulty or likelihood of the technology ultimately achieving wide commercial adoption. Several of the technologies have high technology readiness levels, and some have operational demonstration plants. See Section A.1 *Nascent and Establish Technologies* for more details.

The *No IRA Tax Credits* sensitivity does not include a representation of the IRA electric sector tax credits. The *No 111 Representation* does not include a representation of the updated CAA

[14] See www.nrel.gov/analysis/reeds and www.nrel.gov/analysis/dgen/.

[15] The technologies designated as nascent are enhanced geothermal systems, floating offshore wind, CCS generators, nuclear small modular reactors, and hydrogen combustion turbines.

111 rules. The *No IRA Tax Credits and No 111 Representation* sensitivity combines the prior two sensitivities. See Section A.1 *Policy/Regulatory Environment* for more details.

The *Reduced Renewable Energy Resources* sensitivity draws from renewable energy supply curves that were developed with more stringent siting restrictions, which results in both a general reduction in the total technical potential of the resources as well as removing some high-quality sites from investment. See Section A.1 *Renewable Energy Resource and Siting* for more details.

The *High Transmission Availability* and *Low Transmission Availability* respectively lower and raise barriers to transmission development by varying where new transmission corridors can be built, the presence or absence of restrictions on annual transmission investment, and the availability of high-voltage direct current lines for investment. See Section A.1 *Transmission Expansion* for more details.

In the *Electricity-powered Direct Air Capture (DAC)* sensitivity, DAC is available as an investment option in the model. DAC is not available in any other scenarios.

2.5 No Expiration of IRA Tax Credits

New to the 2024 scenario suite is the *No Expiration of IRA Tax Credits* as one of the three core future policy sets (prior editions had this as a sensitivity—in this edition it has been elevated). In this set, IRA's tax credits for capturing and storing carbon (45Q), incentives for existing nuclear generators (45U), clean hydrogen production tax credit (45V), and the production tax credit (PTC) and investment tax credit (ITC) for utility-scale clean generation are all extended indefinitely.

This set was introduced this year for two reasons: First, historical federal tax credits have frequently been extended beyond their nominal expiration date (CRS 2020), and thus this set is a plausible set of futures that an analyst may wish to use. Second, the existence of a threshold for the expiration of the clean generation PTC and ITC creates results that can complicate some analyses, such as having the electricity sector CO_2 emissions being greater in the *Advanced RE and Battery Cost and Performance* scenario than its *Conservative* equivalent—creating a suite of scenarios where the federal policy is held constant may be beneficial for some analyses.

Note that other IRA provisions (such as various demand-side incentives) may influence the electricity sector, but because they are not directly modeled in ReEDS, they are not altered in this set of scenarios.

2.6 Decarbonization Constraint Representation

This year's Standard Scenarios suite contains six different national electricity sector greenhouse gas emissions constraints. As indicated above in Figure 1, five are sensitivities that are modeled under Mid-case assumptions, whereas the sixth is implemented as one of the three core sets of policy assumptions (and therefore modeled across all of the sensitivities, other than the "additional" sensitivities).

The decarbonization scenarios vary along three dimensions:

- **Emissions Categories:** "CO_2" trajectories consider CO_2 emissions only from the direct combustion of fuel for electricity generation. The "Lifecycle CO_2e" scenarios consider the CO_2-equivalent value, inclusive of CO_2, CH_4, and N_2O, all across emissions from the direct combustion of fuels as well as precombustion activities (fuel extraction, processing, and transport).
- **Percent Reduction:** 95% or 100% reduction, defined as the specified emissions category (above) reaching a percentage reduction on net relative to U.S. electricity sector CO_2 emissions in 2005 emissions.
- **Timeline:** The specified percentage reduction is met in either 2035 or 2050, with a linear reduction from 2027's values.[16]

These trajectories are implemented as a national electricity sector greenhouse gas emissions constraint. The constraint applies only to the U.S. electricity sector. None of the scenarios in this analysis model U.S. economywide or international decarbonization, which would impact factors such as fuel prices, generator costs, and the magnitude and shape of electricity demand. All scenarios with national emissions constraints retain their representations of existing state and federal policies—i.e., the national emissions constraints are additional to existing policies, not replacements of them.

The trajectories constrain the national net electricity sector emissions, meaning that the constraint is applied to specified emissions category (CO_2 or CO_2e), less any CO_2 captured and stored through carbon capture technologies (generators with CCS or DAC, if present). The emission limit does not incorporate emissions from activities not already mentioned (e.g., they do not include the emissions induced by construction or decommissioning activities).

Note that, in the scenario that excludes nascent technologies, there are no carbon removal options—and that DAC is enabled as an investment option only in the *Electricity-powered DAC* sensitivities.

2.7 Other Resources

The scenario suite in the Standard Scenarios is designed to cover a wide range of futures. It is, however, not exhaustive. Other NREL analyses have studied aspects of power sector evolution beyond what is covered in this suite of scenarios. For example:

- An analysis of the role of transmission in the U.S. power system (DOE GDO 2024)
- An evaluation of the impacts of the Inflation Reduction Act and Bipartisan Infrastructure Law on the U.S. Power System (Steinberg et al. 2023)
- A study of nuclear power's potential role in a future decarbonized U.S. electricity system (Murphy et al. 2023)
- The 100% Clean Electricity By 2035 Study has a broader suite of electricity sector decarbonization scenarios that explores different policy designs and the technologies that may come into play in such a future

[16] The decarbonization trajectories are applied starting in 2027 in this analysis to avoid potential interactions stemming from near-term generator investment constraints that are present through the 2026 model solve.

- The Electrification Futures Study[17] explores a broader range of end-use electrification, provides more data describing those electrification trajectories, and conducts a more thorough exploration of the possible role of demand-side flexibility
- The annually released Cambium[18] datasets provide a broader suite of metrics at hourly resolution for a subset of the Standard Scenarios.

See https://www.nrel.gov/analysis/future-system-scenarios.html for a more complete list of NREL's other future power systems analyses.

[17] "Electrification Futures Study," NREL, https://www.nrel.gov/analysis/electrification-futures.html.
[18] "Cambium," NREL, https://www.nrel.gov/analysis/cambium.html.

3 The Mid-Case Scenario Results

3.1 Overview of the Standard Scenarios Mid-Case Results

There are three Mid-case scenarios in the 2024 Standard Scenarios, which vary in their assumptions about the future policy environment: A *Current Policies Mid-case*, a *No Expiration of IRA Tax Credits Mid-case*, and a *100% Net Lifecycle CO_2e Decarbonization by 2035 Mid-case*. These scenarios use central assumptions for demand growth, resource availability, fuel price, and technology inputs (see the appendix, Section A.1 for more details about the assumptions). In this way, the Mid-case scenarios provide reference points for comparing scenarios and assessing trends. Section 3.2 provides some additional context for how the Current Policies Mid-case scenario compares with projections from other organizations.

Figure 2 shows the generation and capacity mix through 2050 for the three Mid-case scenarios.

All three scenarios see significant increases in wind, solar, and storage deployment. Notably, however, the 75% emissions reduction threshold specified in IRA is not passed in the *Mid-case with Current Policies* scenario (which would trigger the phaseout of the clean generation tax credits). Because of this, wind and solar make up most new generation throughout the modeled horizon in that scenario. Because the clean generation tax credits do not phase out under current policies, that scenario is largely similar to the *Mid-case with No Expiration of IRA Tax Credits*. Both scenarios are shown here for completeness.

In the Mid-case scenario with 100% net lifecycle CO_2e decarbonization constraint, the IRA threshold is passed. This results in a phaseout of the tax credits for clean generation, although the presence of a decarbonization constraint that includes precombustion emissions (thereby including fugitive CH_4 emissions prior to combustion in natural gas generators) results in clean generators still predominately meeting incremental demand growth after the phaseout.

With the significant value of the 45Q incentive for captured and stored carbon in IRA, all three scenarios see generators with CCS (bioenergy, natural gas, and coal) deployed, although the deployment is relatively small in both the *Current Policies* scenario and the *No Expiration of IRA Tax Credits* scenario. In both of these scenarios, there is an initial deployment of CCS generators which operate at their maximum capacity factor for the 12-year duration of the 45Q credit—but which typically revert to lower capacity factors to primarily provide firm capacity once the credit expires.[19] Natural gas with CCS plays a larger role post-2035 in the *100% Net Lifecycle CO_2e Decarbonization by 2035* scenario, relative to the other two scenarios, although the inclusion of precombustion emissions in the emissions constraint results in a lower contribution than what is seen in decarbonization sensitivities defined only in terms of combustion emissions. See Section 4.3 later in this report for figures showing the firm capacity contribution of different technologies in these scenarios and Section 4.7 for discussions specifically around carbon capture technologies.

[19] Note that ReEDS does not have the ability to operate CCS generators with their capture equipment turned off or to remove the equipment entirely. In practice, these generators may disable their capture equipment when they are no longer receiving the 45Q credit.

Two other nascent technologies are also deployed in these three Mid-case scenarios: hydrogen combustion turbines and small modular nuclear reactors. In both the *Current Policies* and *No Expiration of IRA Tax Credits* scenarios, the deployment of small modular nuclear reactors is small (less than 5 gigawatts [GW]). Hydrogen combustion turbine deployment is even smaller under *Current Policies* (reaching 2 GW) but slightly greater in the *No Expiration of IRA Tax Credits* (15 GW). The deployment of both technologies is materially greater in the decarbonization scenario (with nuclear small modular reactors reaching 44 GW and H2-CTs reaching 103 GW).

As emphasized previously, the future deployment of these nascent technologies is exceptionally uncertain, as it will ultimately depend on their future costs and performance—the projection of which is more uncertain than with more established technologies.

Natural gas capacity without CCS remains in all three scenarios. Its capacity increases in the two scenarios without a decarbonization constraint. Its capacity declines by about one-third in the *100% Net Lifecycle CO_2e Decarbonization by 2035* scenario, although nearly 300 GW remain in 2035 despite the stringent GHG limits. The capacity persists in the decarbonization scenario by running at low capacity factors and by having its emissions offset using bioenergy with CCS. These natural gas generators—along with other resources such as nuclear, hydropower, storage, and geothermal plants—provide a source of firm capacity for periods with low wind and solar output. Firm capacity is especially important in the winter when solar resources are low and load tends to be high (Cole, Greer, et al. 2020), especially given the increasing winter peaks projected in the Reference and High demand growth trajectories used in this analysis (see the appendix, Section A.1). For more discussion of the firm capacity contribution of different technologies, see Section 4.7.

Due to the updated CAA 111 rules and general economic competition, coal without CCS significantly declines by 2032 in all three scenarios. Some of the coal plants are retrofitted with CCS in all three scenarios although in relatively small quantities (14, 12, and 4 GW in the *Current Policies*, *No Expiration of IRA Tax Credits*, and decarbonization scenarios, respectively). The coal with CCS capacity operates at a high capacity factor when receiving the 45Q credit, but once the credit has expired (after 12 years for a given plant), the utilization decreases.

Existing nuclear plants are not subject to economic retirement through 2032, due to ReEDS's representation of the IRA incentives for existing nuclear. Beyond 2032, the generators generally remain sufficiently competitive to avoid early retirement, resulting in the majority of existing nuclear capacity persisting through 2050 in all three scenarios.[20] As mentioned above, nuclear small modular reactors are deployed in all three scenarios.

[20] Nuclear power plants have an assumed lifetime of 80 years within the model unless an earlier retirement date has been announced, although the model can retire them for economic reasons earlier than that. Note that the anticipated repowering of the Palisades nuclear generator is represented in this modeling, whereas the potential repowering of the Three Mile Island nuclear generator is not represented.

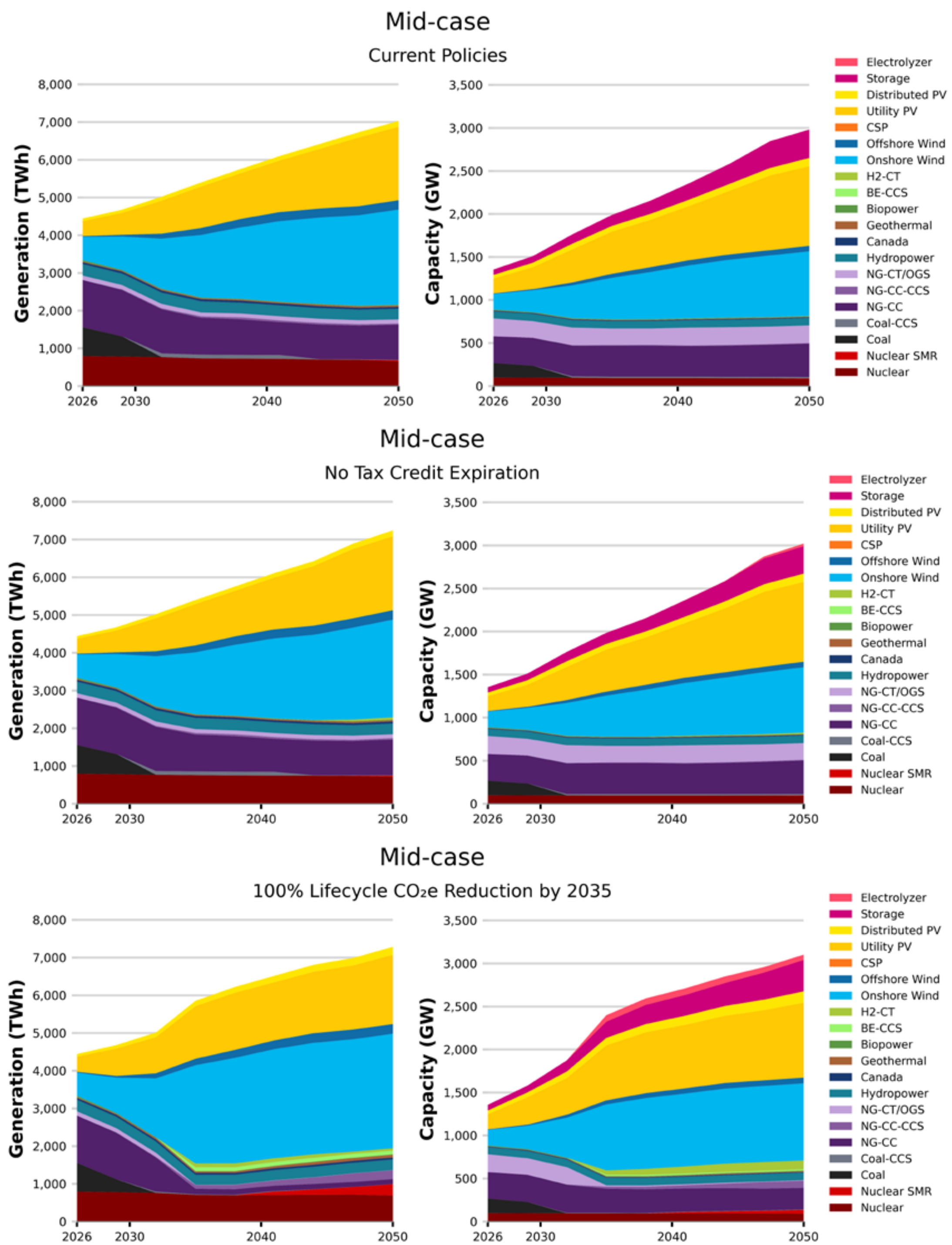

Figure 2. U.S. electricity sector generation (left) and capacity (right) over time for the three Mid-case scenarios

PV is photovoltaic, CSP is concentrating solar power, H2-CT is hydrogen combustion turbine, BE is bioenergy, NG-CC is natural gas combined cycle, NG-CT is natural gas combustion turbine, OGS is oil-gas-steam, CCS is carbon capture and storage, and SMR is small modular reactor. Electrolyzers consume electricity to produce hydrogen. Storage includes 4-hour batteries, 8-hour batteries, and pumped hydropower.

3.2 Comparison With Other Organizations' Projections

In this section, the *Current Policies Mid-case* projection is compared with recent projections from three other organizations: EIA, the International Energy Agency, and BloombergNEF.[21] These comparisons are presented in Figure 3 to enable readers to compare NREL's historical projections with other organizations' projections and to see how projections have changed over time. Although NREL and most of these organizations publish multiple scenarios that span a wide range of assumptions, this comparison uses only the "reference" scenarios.[22]

Note that the reversal of trends projected by NREL in the 2022 Mid-case was due to IRA tax credits expiring, which has not been projected to occur within the analysis horizon for either the 2023 or 2024 editions.

The projected near-term decline in greenhouse gas emissions shown in Figure 3 aligns with other modeled projections. A multimodel study exploring the impacts of IRA and drawing from nine independent models showed economywide greenhouse gas emissions reductions between 43% and 48% below 2005 levels by 2035 (Bistline et al. 2023). Note that the projections shown in Figure 3 are for the U.S. electricity sector only, not the whole economy.

At the time of publication of this report, sufficient calendar time has elapsed that post-IRA Standard Scenarios editions can be compared with what has actually occurred. For example, the Mid-case of the 2022 edition of the Standard Scenarios, which was published several months after the passage of IRA, projected 165 GW of onshore wind, 162 GW of utility-scale PV, and 11 GW of batteries by the end of 2024. This would have necessitated a rapid increase in the rate of deployment. Capacities realized in practice are estimated at 154 GW of onshore wind, 128 GW of utility-scale PV, and 30 GW of batteries, meaning that the 2022 Standard Scenarios overestimated the scale-up of wind and solar deployment and underestimated batteries.[23] Since that 2022 edition, NREL has worked to better represent the landscape after the passage of IRA. That includes development meant to represent or help capture durable phenomena (e.g., higher interconnection and network reinforcement costs, increasing the temporal resolution of the model, energy and firm capacity trading friction between market and planning regions, continual updating of siting restrictions), as well as development meant to improve the near-term performance of the model (such as growth constraints, the inclusion of interconnection queue data, and the inclusion of EIA 860 data). The performance of the model is evaluated regularly, and improvements to both the model and its input data will continue. Nonetheless, the performance of near-term deployment in the 2022 edition is a helpful reminder of the significant uncertainties involved in modeling the future.

[21] The NREL scenario is the Current Policies Mid-case. The BloombergNEF case is either the New Energy Outlook scenario (prior to 2024) or the Economic Transition scenario (2024) depending on the year plotted. The EIA case is the Annual Energy Outlook Reference Case. The International Energy Agency scenario is the World Energy Outlook Stated Policies scenario. Note that the EIA did not release an Annual Energy Outlook 2024, and therefore there is no 2024 line on the corresponding subplots.

[22] The input assumptions, including the policies represented, differ among these reference scenarios.

[23] Estimated realized capacity drawn from the October 2024 EIA-860M, combining operating facilities and planned facilities reporting a 2024 online date. Capacities are reported as net summer capacity to align with ReEDS.

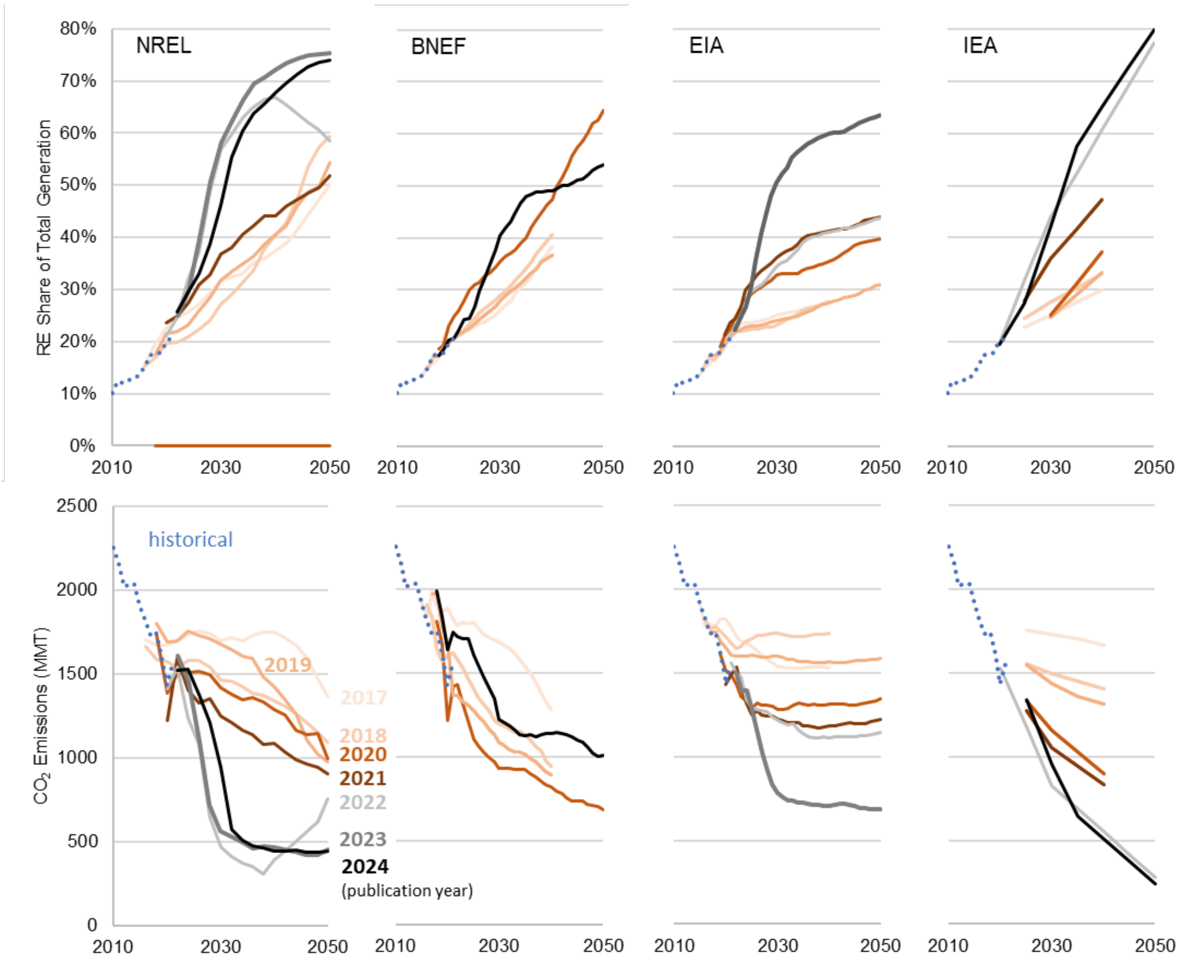

Figure 3. Renewable energy generation fraction (top) and electricity sector CO_2 combustion emissions (bottom) from the organizations and publication years indicated

Only reference case scenarios are shown.

4 Range of Outcomes Across All Scenarios

This section presents the range of several key metrics across the full suite of scenarios to help gain an understanding of how the evolution of the electric grid may differ from what is projected in the Mid-cases.

Note that, because sensitivities are perturbations of the Mid-case set of assumptions, there is a natural clustering of projections around the Mid-case scenarios. This clustering should not be interpreted as indicating a higher likelihood. This sensitivity set was designed to help illustrate the impact of key assumptions varied across plausible ranges, not to describe a probabilistically representative spread of possible futures.

4.1 Generation

Figure 4 shows the generation by fuel type across the full suite of scenarios. In general, wind and solar see significant growth over the coming decades, reaching a maximum of 5500 terawatt-hours (TWh)/year and 3400 TWh/year, respectively. Throughout the suite of results, demand growth is a strong driver of wind and solar generation: The seven scenarios with the greatest wind and solar generation are all sensitivities with electricity demand that more than doubles by 2050 relative to current levels. The scenarios with the lowest wind and solar generation have low demand growth or omit IRA's electric sector tax credits.

Generation from natural gas without CCS tends to decline slightly (either by retiring or retrofitting with CCS) in scenarios without decarbonization constraints, and more materially in scenarios with decarbonization constraints. Due in part to fugitive CH_4 emissions associated with natural gas generators, scenarios with 100% net lifecycle decarbonization see significant declines in the total amount of natural gas generation—although even in such scenarios, both with- and without-CCS natural gas generation is always present in some degree. The scenario with the greatest amount of non-CCS natural gas is the scenario without IRA's tax credits (but which retains a CAA 111 representation).

In all scenarios with a representation of CAA 111 rules, the generation from coal without CCS significantly declines by 2032, although in many scenarios the presence of the 45Q tax credit for captured carbon induces retrofitting of some coal plants with CCS. The generation contribution of coal CCS units is highest when the plants are receiving the 12-year 45Q credit but declines in the 2040s when plants have stopped receiving the credit. Even scenarios with indefinite extension of the 45Q credit or advanced CCS assumptions do not see significant contribution of coal CCS past the 2040s.

Two scenarios see nuclear generation increasing to more than twice current levels due to combinations of sensitivities with significant cost declines, high load growth, and the presence of aggressive decarbonization constraints. The scenario with the greatest nuclear generation has advanced nuclear assumptions (i.e., low costs) and a 100% net lifecycle CO_2e decarbonization constraint. Scenarios such as this are the exception, however, as the majority of scenarios see nuclear generation that stays within ±20% from current levels.

Bioenergy with CCS is deployed in most scenarios, although its deployment is always a small fraction of total generation (not exceeding 2% across the scenario suite) due in large part to the model's representation of biomass supply curves (i.e., bioenergy becomes more expensive more rapidly as its utilization increases, relative to other technologies). Bioenergy with CCS plays the largest role in the 100% scenario, where it is used as a negative emissions generator to offset emissions from natural gas generators.

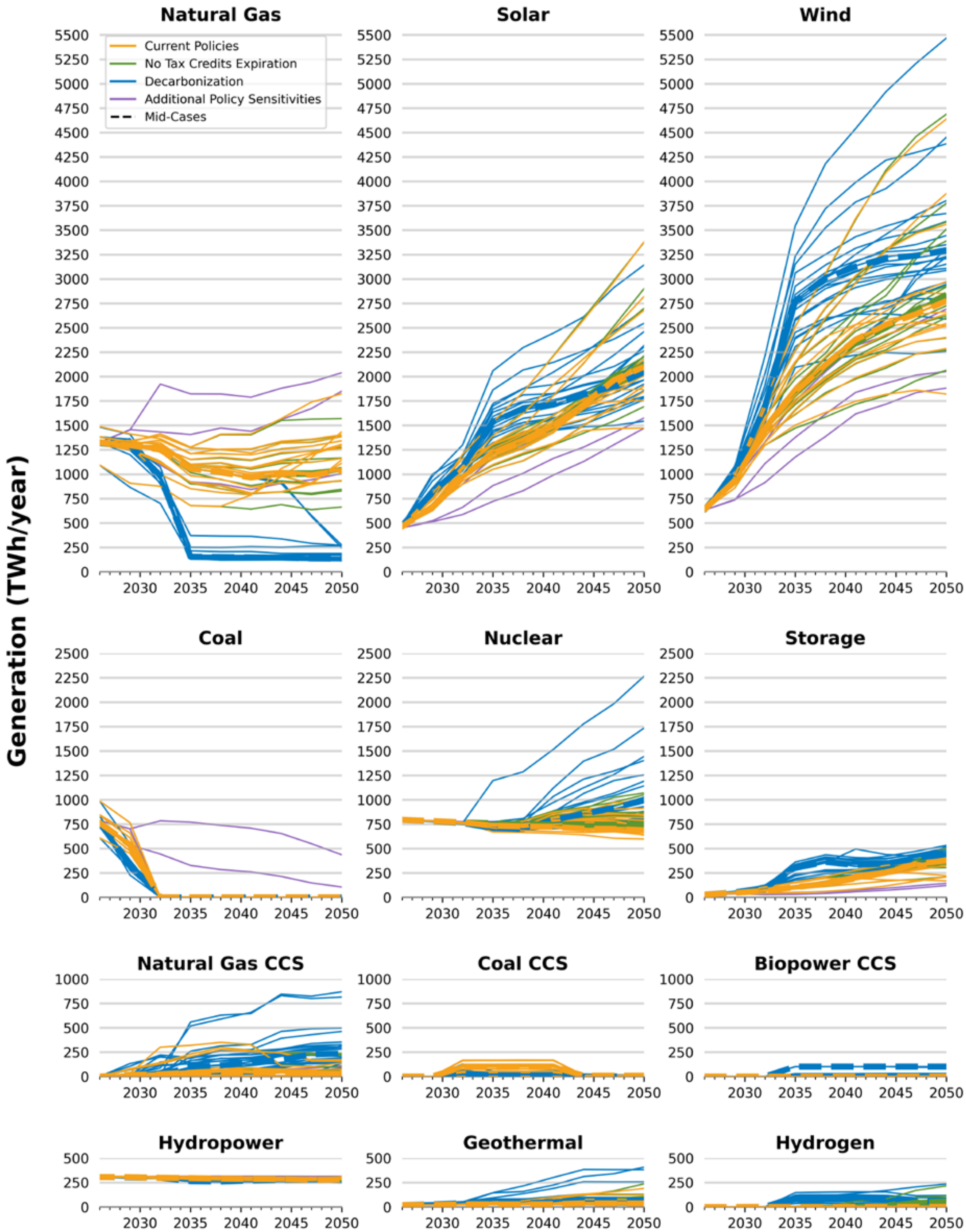

Figure 4. Generation by fuel type across the Standard Scenarios

The Mid-case scenarios are shown with the heavier dashed lines. Solar includes PV and CSP with and without thermal energy storage. Storage includes both electric batteries and pumped hydropower. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

4.2 Capacity

Figure 4, above, shows the generation trends by technology. Figure 5 , below, shows the net summer capacity trends by technology. Firm capacity trends by technology are shown in Section 4.3.

Natural gas capacity (CCS and non-CCS combined) grows in all scenarios without a 100% Net Lifecycle CO_2e constraint and declines in all scenarios with such a constraint. The scenario with the greatest non-CCS natural gas capacity is the scenario omitting both IRA's tax credits and CAA 111 representations. The presence of natural gas without CCS across all scenarios, even in ones with national CO_2 emissions constraints, is largely because it is a low-cost source of firm capacity. In the scenarios with national emissions constraints, the natural gas generators provide firm capacity while operating with low utilization rates, retrofitting with CCS, or offsetting their emissions through the deployment of other carbon removal technologies such as bioenergy with CCS (BECCS) and DAC.

Solar and wind have the widest range of 2050 deployment, which can vary considerably depending on costs, resource availability, electric demand, and policy assumptions. The scenarios with the greatest wind and solar generation tend to have significant load growth (through electrification and hydrogen production). The scenario with the lowest wind and solar deployment is the scenario that omits both IRA's tax credits and CAA 111 representation.

Nuclear, storage, natural gas with and without CCS, and H2-CTs all also have significant ranges of capacity deployment across the suite, driven by costs, demand, and policy assumptions.

Coal without CCS capacity declines significantly in most scenarios. The scenario with the greatest non-CCS coal capacity in 2050 is the scenario omitting both IRA's tax credits and CAA 111 representation, followed by the scenario that omits only IRA's tax credits.

Of the three CCS technologies, natural gas sees the potential for the greatest deployment, which occurs in the decarbonization scenarios where it provides firm capacity. Bioenergy with CCS likewise sees its greatest deployment in decarbonization scenarios, where it acts as a negative emissions technology to offset the emissions from natural gas generators.

Note that across many scenarios, fossil generators (both with and without CCS) are often present but with low capacity factors—i.e., they generate electricity only for relatively small fractions of the year, primarily to provide power when other generators are not able to generate. This merits a caveat, as the ReEDS model does not evaluate specific plants' revenue sufficiency, nor does it model potentially material increases in per-unit fuel costs at low utilization. In practice, the ability for such plants to stay online will depend on market design and supply chain considerations not modeled here. This caveat is most relevant for the small amount of coal CCS retained by the model after 45Q expires, which the model retains for firm capacity but operates at low capacity factors.

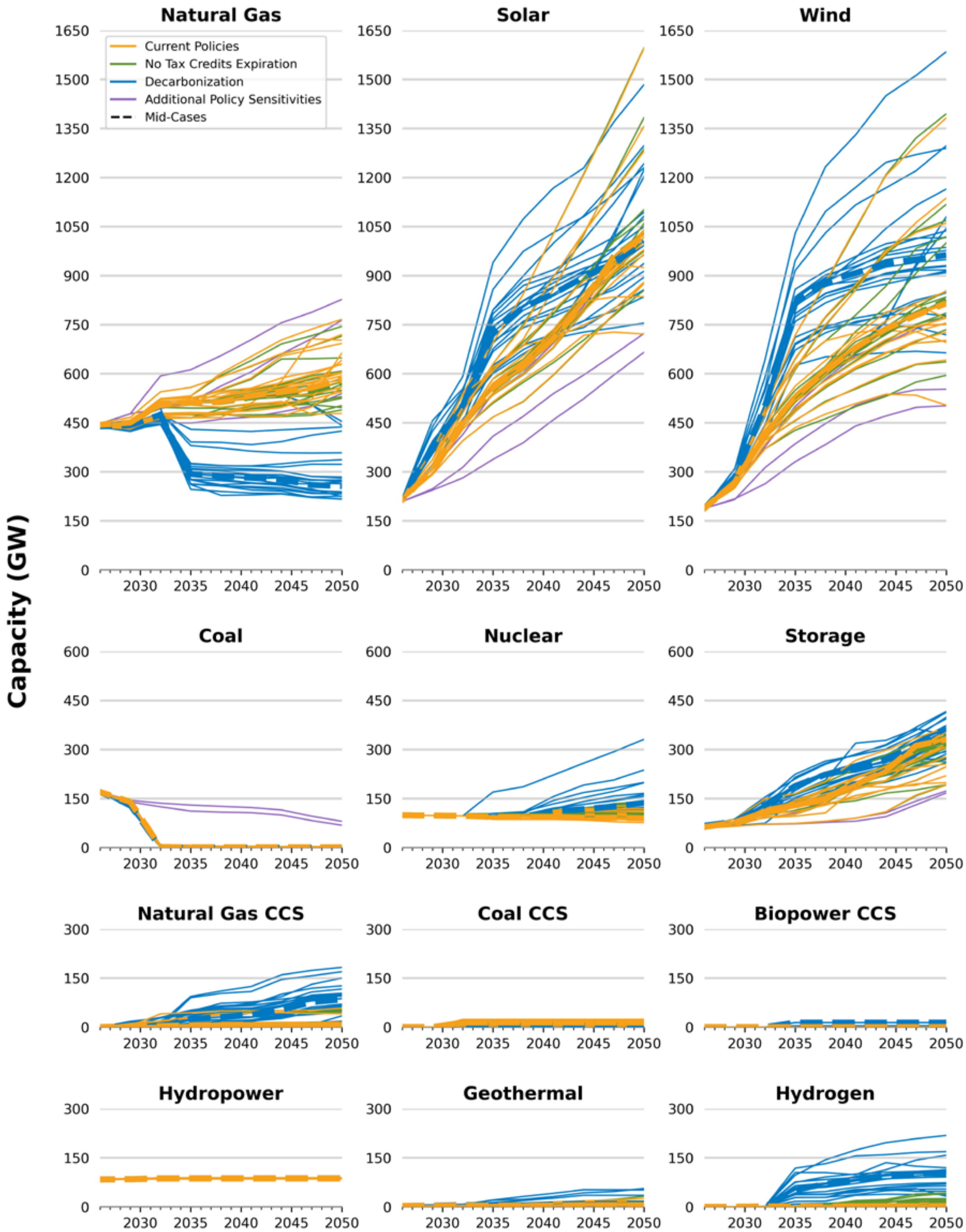

Figure 5. Capacity by fuel type across the Standard Scenarios.

The Mid-case scenarios are shown with the heavier dashed lines. Solar includes PV and CSP with and without thermal energy storage. Storage includes both electric batteries and pumped hydropower. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

4.3 Firm Capacity

Firm capacity is the capacity that is reliably available during the most demanding hours on the grid. There are various methods for estimating firm capacity, such as those derived from purpose-built probabilistic models or expected contributions of generators during predefined periods of time (Jorgenson et al. 2021). Here, firm capacity by technology is estimated by calculating the average generation by technology during the model's stress periods, weighted by the shadow price on the reserve margin constraint during each hour.[24] The result is shown in Figure 6.

Weighing on the shadow price of the reserve margin constraint endogenizes the determination of which time periods are the most costly for the model to meet on the margin. In practice, this method tends to produce relatively low credit for variable renewable technologies, as the model identifies time periods as being costly to meet in large part due to low variable renewable generation during those times.

This phenomenon can be seen most clearly in Figure 6 for solar, where solar generally has low firm capacity relative to its significant installed capacity. This occurs because extensive solar deployment pushes the periods of system stress to hours when solar has low or zero output. In such a situation, solar generation tends to be low or zero during many of the most difficult time periods, and therefore its firm capacity is estimated as being relatively low. Wind suffers from the same phenomenon, although to a lesser degree, such that the firm capacity from wind is still often second only to non-CCS natural gas in terms of total firm capacity contribution.

Natural gas without CCS contributes significant firm capacity across all scenarios, generally being the technology with the greatest firm capacity contribution. Contribution from natural gas without CCS is significant even in the scenarios with 100% net lifecycle CO_2e decarbonization, although there is a decline in the 2030s in those scenarios, due to generators retrofitting with CCS or retiring due to the constraint. The presence of natural gas without CCS in 100% net decarbonization scenarios is enabled by operating them at extremely low capacity factors and offsetting their emissions with negative emission bioenergy with CCS generators (or direct air capture, in the sensitivities where that is enabled as an investment option). Natural gas with CCS plays the largest role in decarbonization scenarios, although its contribution is always lower than that of its non-CCS counterpart.

The firm capacity of coal without CCS declines to zero or near zero in all scenarios by 2032 except the two scenarios without a representation of CAA 111 rules, partially due to retrofitting with CCS but primarily due to retirements. Nuclear firm capacity remains relatively constant in most scenarios, although in scenarios where more nuclear is deployed, its firm capacity contribution correspondingly increases.

The firm capacity of storage grows significantly across all scenarios, aligned with its capacity deployment. In most scenarios, storage is the third-greatest contributor of firm capacity.

[24] A shadow price is an optimization model's reporting of how much the objective function would have decreased if a particular constraint had been relaxed by one unit. In this case, the shadow price conveys the marginal cost of meeting the reserve margin constraint for each region and each time slice.

Hydropower, geothermal, and hydrogen all have firm capacity trends that generally track their capacity deployment.

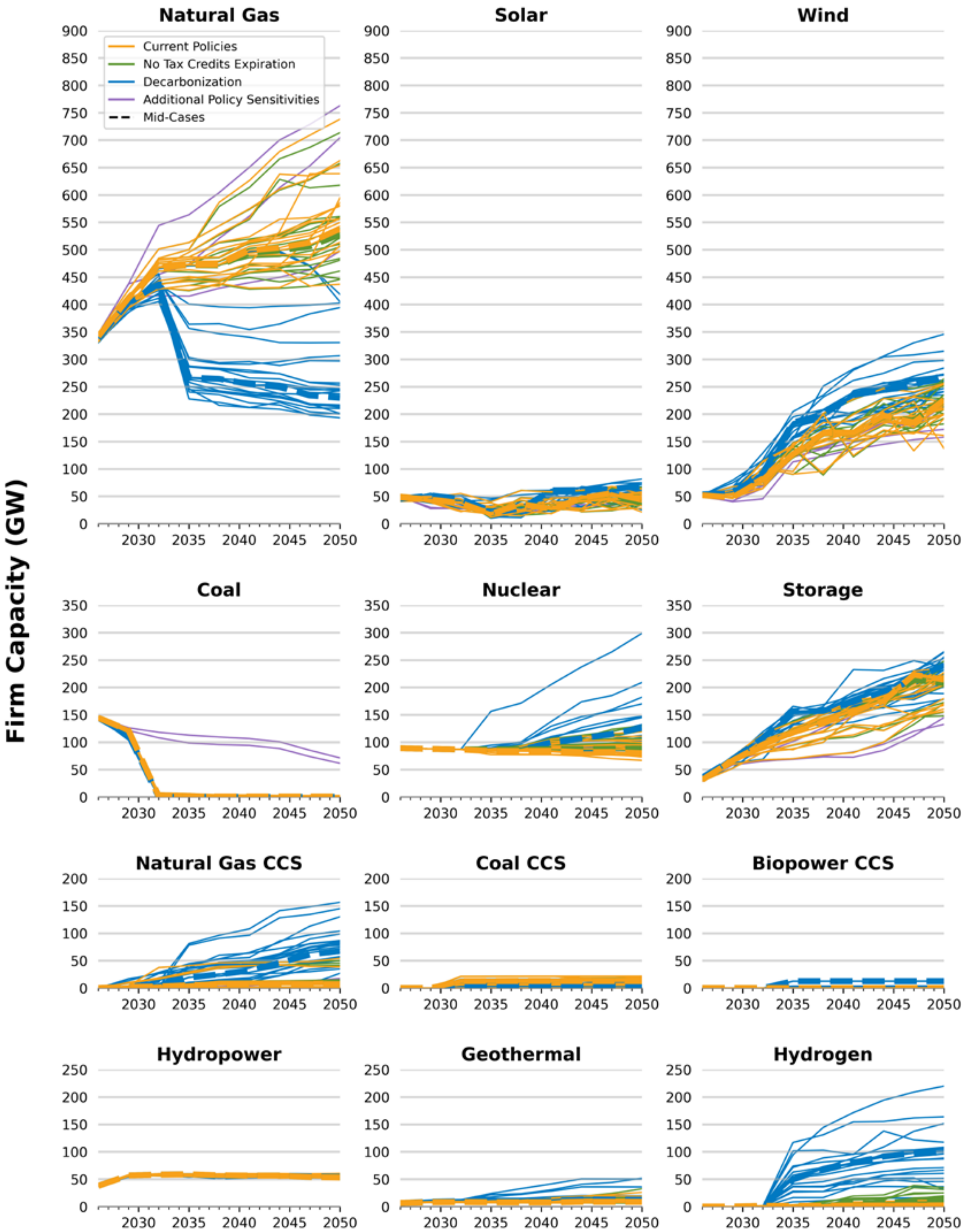

Figure 6. Firm capacity by technology across the suite of scenarios

The Mid-case scenarios are shown with the heavier dashed lines. Solar includes PV and CSP with and without thermal energy storage. Storage includes both electric batteries and pumped hydropower. The Additional Policy Sensitivities group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

4.4 Renewable Energy and Clean Generation Share

Total renewable energy share, which is defined as the fraction of total generation that is from renewable energy generators, ranges from approximately 54% to 87% in 2050 (Figure 7). Total clean generation share, which is the renewable set plus nuclear, ranges from 65% to 96% in 2050. The scenarios with the greatest renewable and clean shares are the scenarios with 100% net lifecycle CO_2e decarbonization constraints. The scenarios with the lowest renewable and clean shares are the scenarios without a representation of IRA's electric sector tax credits.

From the generation figures above (Figure 4), the increase in renewable energy deployment can be seen as primarily from wind and solar. In scenarios with 2035-based decarbonization constraints, the renewable energy share growth generally outpaces the renewable energy share growth in the other scenarios within the remainder of the 2020s, indicating that the constraint becomes binding early on.

Some scenarios see declines in renewable shares in later years. This is caused in some scenarios by the expiration of IRA clean generation tax credits and in other scenarios by the later-year deployment of nuclear small modular reactors.

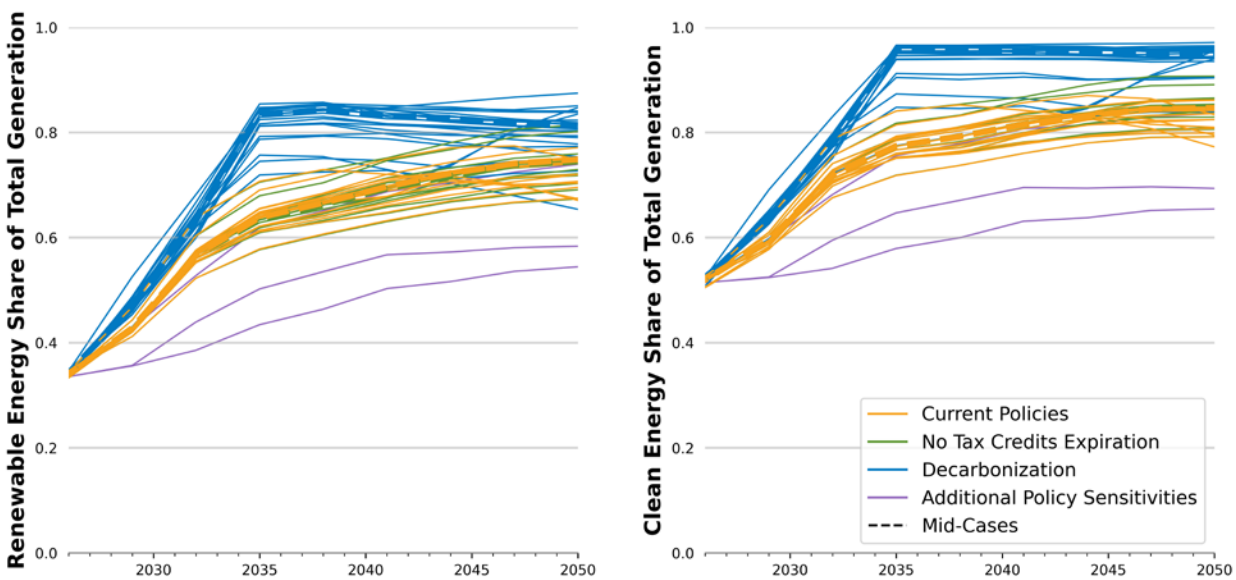

Figure 7. Renewable and clean energy share over time across the Standard Scenarios. The Mid-case scenarios are shown with the heavier dashed lines. Renewable energy share is defined as annual renewable energy generation divided by total generation (excluding storage generators). Renewable generators, for this figure, are hydropower, geothermal, hydrogen, imports from Canada, bioenergy, solar, and wind powered. Clean generators are the same list, plus nuclear. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

4.5 Transmission Capacity

Figure 8 shows transmission expansion across the scenarios. The left panel shows interzonal transmission capacity between the 133 ReEDS zones and is most analogous to higher-capacity and higher-voltage (230+ kilovolt [kV]) transmission lines, which are meant to move energy long distances. The right panel also includes network reinforcement and spur lines, which are analogous to shorter and lower-voltage lines used to interconnect generation capacity to the local network. Neither metric comprehensively describes transmission capacity, as not all intrazonal transmission capacity is represented within the ReEDS model.

Interzonal transmission capacity increases 12%–142% across all scenarios, with 2050 interzonal transmission capacity of 186 TW-mi, 184 TW-mi, and 227 TW-mi for the *Mid-case with Current Policies*, *No Expiration of IRA Tax Credits*, and *100% Net Lifecycle CO_2e Decarbonization by 2035*, respectively. Network reinforcement and spur line capacity results in a total of 292 TW-mi, 290 TW-mi, and 343 TW-mi for the Mid-case scenarios.

The scenarios with the greatest transmission expansion tend to be the scenarios with a 100% Net Lifecycle CO_2e constraint, where the model identifies significant interzonal transmission build-out to be part of the least-cost reliable grid build-out.

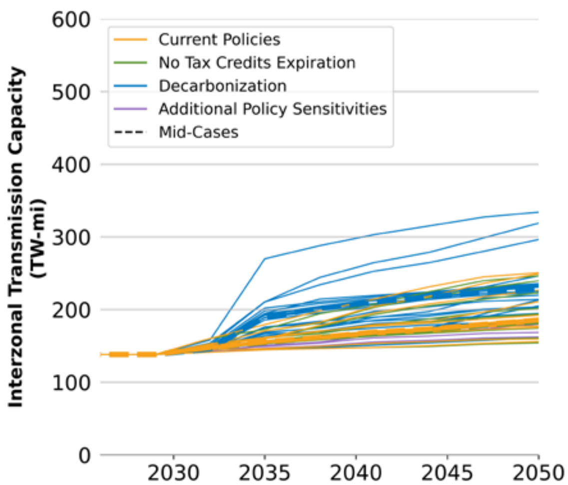

Figure 8. Interzonal transmission capacity (left) and interzonal + network reinforcement + spur line transmission capacity (right) across the Standard Scenarios.

The Mid-case scenarios are shown with the heavier dashed lines. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

4.6 Electricity Sector CO_2e Emissions

Electricity sector CO_2e emissions are shown in Figure 9. The left panel is lifecycle emissions (here defined as inclusive of both combustion and precombustion emissions), whereas the right panel is combustion emissions only (both panels reflect any CO_2 captured and stored with carbon removal technologies).

Emissions decline rapidly through the mid-2030s in all scenarios, other than the *No IRA Tax Credits and No 111 Representation* sensitivity), although they generally level off after that for scenarios without decarbonization constraints. The scenario with the second-highest 2050 emissions is the scenario that omits IRA's tax credits (but retains a CAA 111 representation). Note that holding total emissions constant equates to a continual slow reduction of the emissions per unit of electricity of the electricity sector, since demand continues to grow in all scenarios.

Figure 9 shows greenhouse gas emissions only for the electricity sector. Because some of the sensitivities implicitly vary greenhouse gas emissions beyond the electricity sector, the trends in economywide greenhouse gas emissions may differ from what is shown in Figure 9. For example, the scenario with the third-highest 2050 emissions has significant load growth from electrification and non-power-sector hydrogen use, which would imply a reduction in non-power-sector emissions—possibly resulting in lower economywide emissions overall. Because the model used for this study does not represent economywide emissions, such results are not characterized in this report.

The majority of decarbonization scenarios reach net-zero lifecycle CO_2e emissions, due to the constraint that imposes that outcome. Several decarbonization scenarios do not reach that point, however, because their targets are not specified as 95% reductions, do not include precombustion emissions, or do not include CH_4 or N_2O. Note further that many of the scenarios with net-zero lifecycle CO_2e emissions have negative combustion-only CO_2e emissions, due to the need to offset any emissions from precombustion activities.

The red dotted line in Figure 9 shows the threshold that, once crossed, triggers the phaseout of IRA's clean generation tax credits—after which there is a rebound in electricity sector CO_2e emissions. Under Current Policies, this occurs in 6 of the 17 scenarios (*Low Demand Growth, Advanced Renewable Energy and Storage Costs and Performance, Advanced Nuclear Costs, High Transmission Availability, High Natural Gas Prices*, and the *Advanced CCS Cost and Performance* sensitivities). In these scenarios, there is a several-year lag from when the threshold is passed before the emissions trend starts to reverse; this is caused by safe-harbor provisions that allow generators that are placed in service several years after the nominal expiration of the tax credits to still capture them (safe harbor periods vary by technology and are assumed here to range from 4 to 10 years; see Section A.3 in the appendix). The threshold is crossed, and the tax credits phase out in all the decarbonization scenarios, which alters the relative competitiveness of various technologies but does not result in an emissions rebound due to the presence of the emissions constraints.

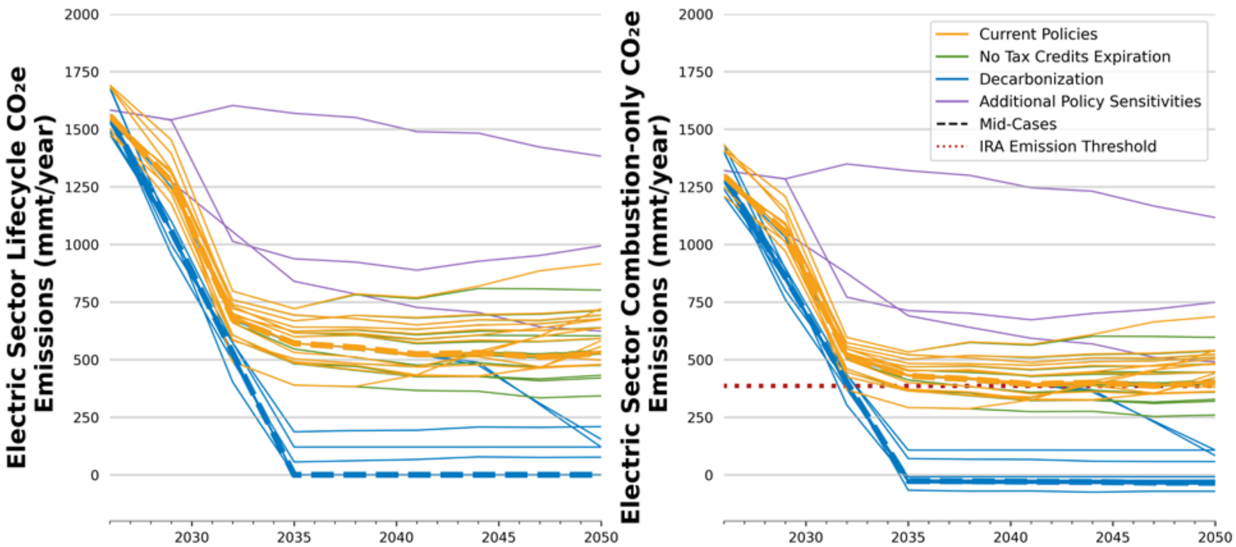

Figure 9. Electricity sector emissions over time across the Standard Scenarios.

Left panel: CO_2e emissions from both combustion and precombustion activities (fuel extraction, processing, and transport). Right panel: CO_2e from combustion only. The Mid-case scenarios are shown with the heavier dashed lines. Carbon captured by carbon removal technologies reflected in both figures. The greenhouse gas emissions included here are CO_2, CH_4, and N_2O, combined using 100-year AR6 global warming potentials. The exact value of the threshold that would trigger the IRA clean electricity tax credits phasing out has not been announced but is estimated to be 386 million metric tons of combustion-only CO_2e in this modeling. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

4.7 Carbon Capture and Storage

State policies, CAA 111, and the 45Q incentive for capturing and storing carbon induce the deployment of generators with CCS in all scenarios where they are enabled as an investment option. The amount of deployment varies significantly, with most scenarios without decarbonization constraints having less than 50 GW deployed at any time and several scenarios with decarbonization constraints seeing more than 150 GW deployed (Figure 10). The two scenarios with the greatest CCS deployment are the sensitivities with 100% Net CO_2-only Decarbonization by 2035 and 95% Net CO_2-only Decarbonization by 2035 (202 GW and 176 GW, respectively)—these scenarios have greater CCS deployment than their Lifecycle CO_2e counterparts because they do not incorporate fugitive CH_4 emissions into their decarbonization constraint. The scenario with the third-highest CCS deployment is the Advanced CCS with 100% Net Lifecycle CO_2e Decarbonization by 2035 scenario, where the low cost of CCS counterbalances the inclusion of precombustion emissions in the decarbonization constraint.

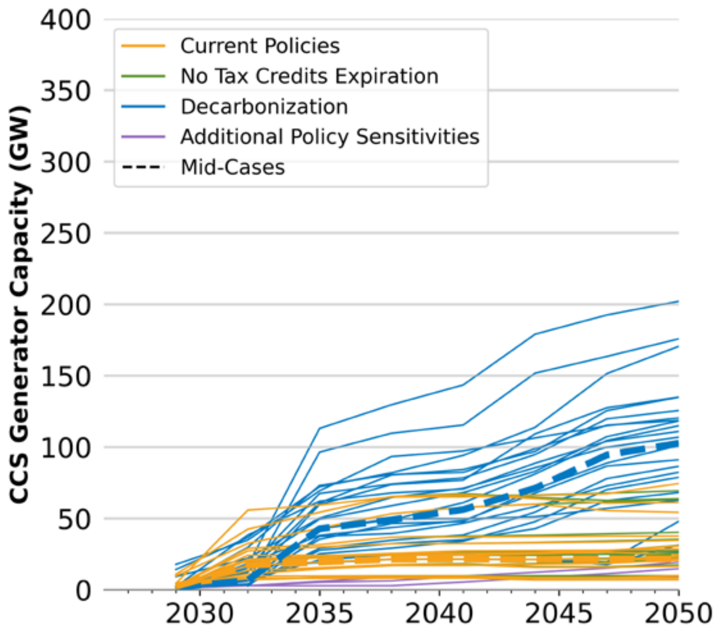

Figure 10. Deployment of CCS generator technologies across the Standard Scenarios

The Mid-case scenarios are shown with the heavier dashed lines. This figure shows only CCS generator capacity, not the capacity from DAC facilities. CCS capacity is not shown prior to 2029 because it is not enabled as an investment option in the model prior to that point. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

As a nascent technology, the future cost and performance of generators with CCS is exceptionally uncertain. Because of this uncertainty, this year's scenario suite included an *Advanced CCS Cost and Performance* as well as a *Conservative CCS Cost and Performance* sensitivity. See the *Carbon Capture Costs and Performance* in Section A.1 of the appendix for further discussion of these inputs.

Under current policies, the amount of CCS deployed ranges from less than 9 GW under conservative assumptions to 84 GW under advanced assumptions. Under 100% net lifecycle CO_2e decarbonization, the amount of CCS deployed ranges from 68 GW under conservative assumptions to 171 GW under advanced assumptions. See Section A.6 of the appendix for generation and capacity figures corresponding to these sensitivities.

Figure 11 shows the annual quantity of CO_2 that is captured and stored in four of the scenarios. Note that DAC is available as an investment option only in the sensitivities that bear its name, and within those three sensitivities, it is deployed in meaningful quantities only in the 100% net decarbonization scenario (reaching 171 GW in that scenario, versus less than 1 GW in the other two).

In some scenarios (e.g., the two in the top row of Figure 11), there is an initial ramp up of captured carbon, which then declines at a later point. This is caused by the 12-year duration of the 45Q tax credit for capturing and storing carbon. The model operates CCS generators at maximum capacity factor when receiving the credit and then significantly decreases their capacity factor when the credit expires while often still retaining the generator as a source of firm capacity. Note that in practice, operators may turn off the capture equipment once they are no longer receiving 45Q (an option that is not represented in the model used here). Furthermore, as mentioned previously in Section 4.2, the continued operation of CCS generators after they are no longer receiving the 45Q credit will ultimately depend on market design and supply chain considerations not modeled here. Scenarios with 100% net decarbonization constraints do not see the later-year reduction in captured carbon, which is described above.

By comparing the bottom two panels of Figure 11, whose scenarios are identical other than the availability of DAC as an investment option, it can be observed that the model identified DAC as lower cost than BECCS, as a means of offsetting emissions from both non-CCS and CCS fossil generators. The lower abatement costs result in slightly greater deployment and use of CCS generators in the DAC sensitivity. This result is highly sensitive to the relative costs of DAC and BECCS, both of whose costs for at-scale deployment are highly uncertain.

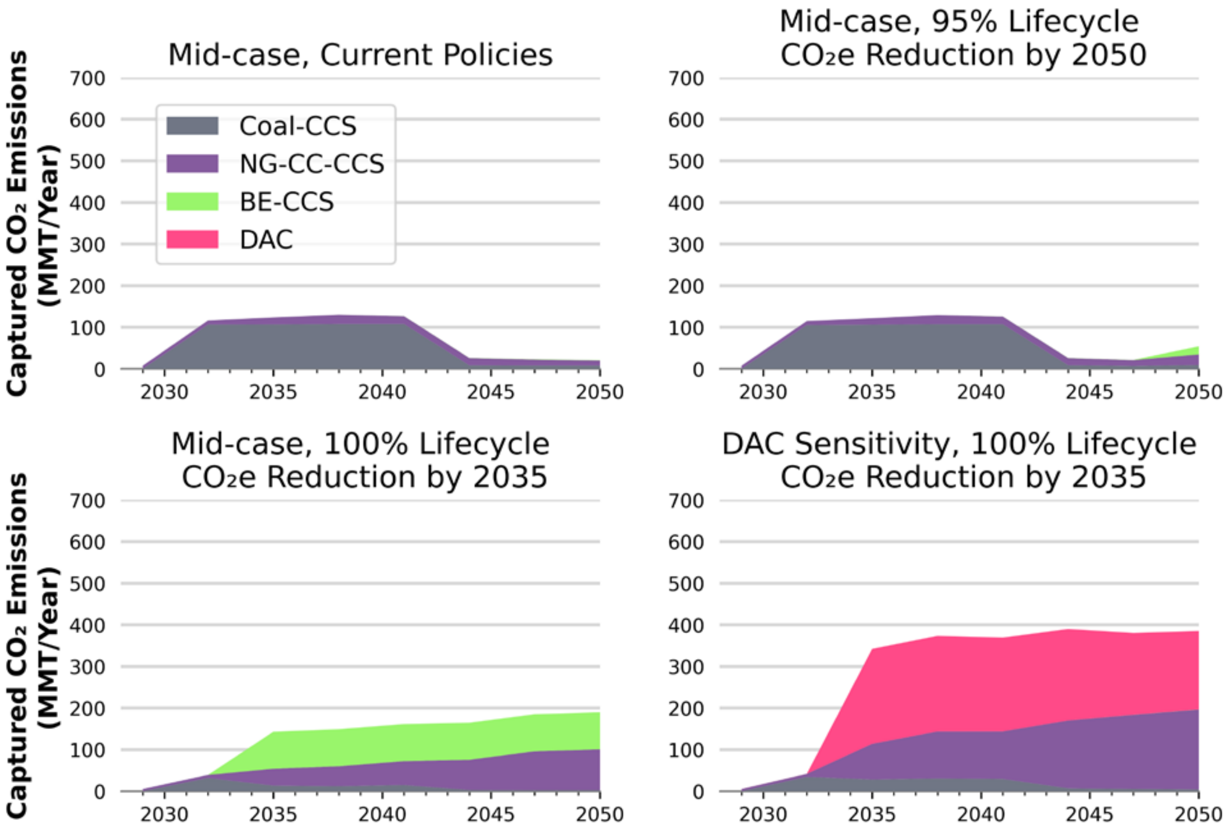

Figure 11. Annual CO_2 captured and stored, by technology

4.8 Present-Value System Costs

This section discusses the present-value of the bulk electricity sector costs (less the value of tax credits) that are modeled within ReEDS, from 2024 through 2050, assessed with a social discount rate of 1.7% (OMB 2023).[25] The costs are not comprehensive—there are many costs associated with building and operating the electricity sector not modeled within ReEDS (e.g., administrative costs, distribution infrastructure costs, and so forth). Therefore, these values should primarily be used for relative comparison within this suite of scenarios and not as a comprehensive estimate of total costs.

The Mid-case with Current Policies has a present value of $6,002 billion, and the full suite of Current Policies sensitivities ranges from $5,297 billion (in the *Low Demand Growth* sensitivity) to $7,853 billion (the *High Demand Growth and Hydrogen Economy* sensitivity). As suggested by the bounding scenarios, demand growth is the strongest driver of costs among the sensitivities, although natural gas prices and renewable energy costs can also have material impacts (with the corresponding sensitivities lowering and raising costs by -4% and +10%, respectively, for natural gas and -5% and +5%, respectively, for renewable energy costs).

The present-value bulk electricity sector costs for select decarbonization scenarios are given in Table 1.

Table 1. Present Value of Bulk Electricity Sector Costs for Various Decarbonization Sensitivities Applied on the Mid-case Assumptions

Scenario	Present-Value Costs (billion 2023$)	Increase Relative to Current Policies Mid-case
Reference (no decarbonization)	$6,002	-
95% Net CO_2 by 2050	$6,016	0.2%
95% Net Lifecycle CO_2e by 2050	$6,016	0.2%
95% Net CO_2 by 2035	$6,388	6.4%
95% Net Lifecycle CO_2e by 2035	$6,494	8.2%
100% Net CO_2 by 2035	$6,676	11.2%
100% Net Lifecycle CO_2e by 2035, No IRA Tax Credit Expiration	$6,768	12.8%
100% Net Lifecycle CO_2e by 2035	$6,814	13.5%

The cost of the scenarios with 2050 targets is relatively small primarily because the decarbonization of the grid under current policies outpaces those trajectories for much of the time frame, and when the trajectories do start to influence the grid composition in the mid-2040s, the technology suite available to the model gives a solution that can be achieved without significant increases in costs. Furthermore, although the presence of the decarbonization

[25] Modeled costs are generator and storage capital and operations and maintenance (O&M) costs, transmission capital and O&M costs, interconnection costs, CO_2 transport and storage, and alternative compliance payments for relevant state policies. Modeled benefits are the tax credits described in Section A.3 of this report.

trajectory triggers a phaseout of the clean generation tax credits, it happens sufficiently late that it has small impact on those sensitivities' total present value costs.

The costs of the scenarios with 2035 targets are greater, ranging from 6.4% to 13.5% increases over the reference no-decarbonization scenario. This is because the costs occur sooner (therefore both being discounted less as well as persisting within the time frame for more years), the clean generation tax credit phaseout is triggered earlier, and two of the scenarios are more stringently defined as 100% instead of 95%. The impact of the tax credit phaseout can be seen by comparing the *100% Net Lifecycle CO2e* scenario and the *100% Net Lifecycle CO2e, No IRA Tax Credit Expiration* scenario. The impact of the tax credit phaseout is relatively modest because a significant proportion of deployment has already occurred prior to the phaseout, in that scenario.

Note that the values in this section report electricity sector costs only. Because some sensitivities implicitly vary nonelectricity sector costs, these estimates do not fully reflect economywide costs in each sensitivity. For example, scenarios with higher electric demand tend to have higher electricity sector costs but potentially lower costs outside of the electricity sector (e.g., reduced gasoline and diesel costs for transportation due to vehicle electrification). Because the ReEDS model represents only the electricity sector, these economywide impacts are not characterized here.

4.9 Wind and Solar Curtailment

Figure 12 shows the annual curtailed energy from wind and solar generators, in terms of both absolute amounts of curtailment as well as the percentage of total wind and solar generation. In all scenarios, curtailment increases significantly from present-day levels. The strongest driver of curtailment is the presence of IRA's clean electricity tax credits, which makes wind and solar competitive enough to build in quantities that result in curtailment rates beyond 5% in many scenarios. Some scenarios see later-year decreases in curtailment rates—this is caused by the expiration of the tax credits in those scenarios.

The scenarios with the greatest variable renewable energy (VRE) curtailment (more than 15%) are the three sensitivities with 95% net decarbonization constraints that are not reached until 2050. These see high curtailment rates in part because of the 2050 timeline: By the time the decarbonization constraints become stringent, 45Q and 45V have expired—reducing the attractiveness of CCS or H2-CTs relative to scenarios with 2035 targets.

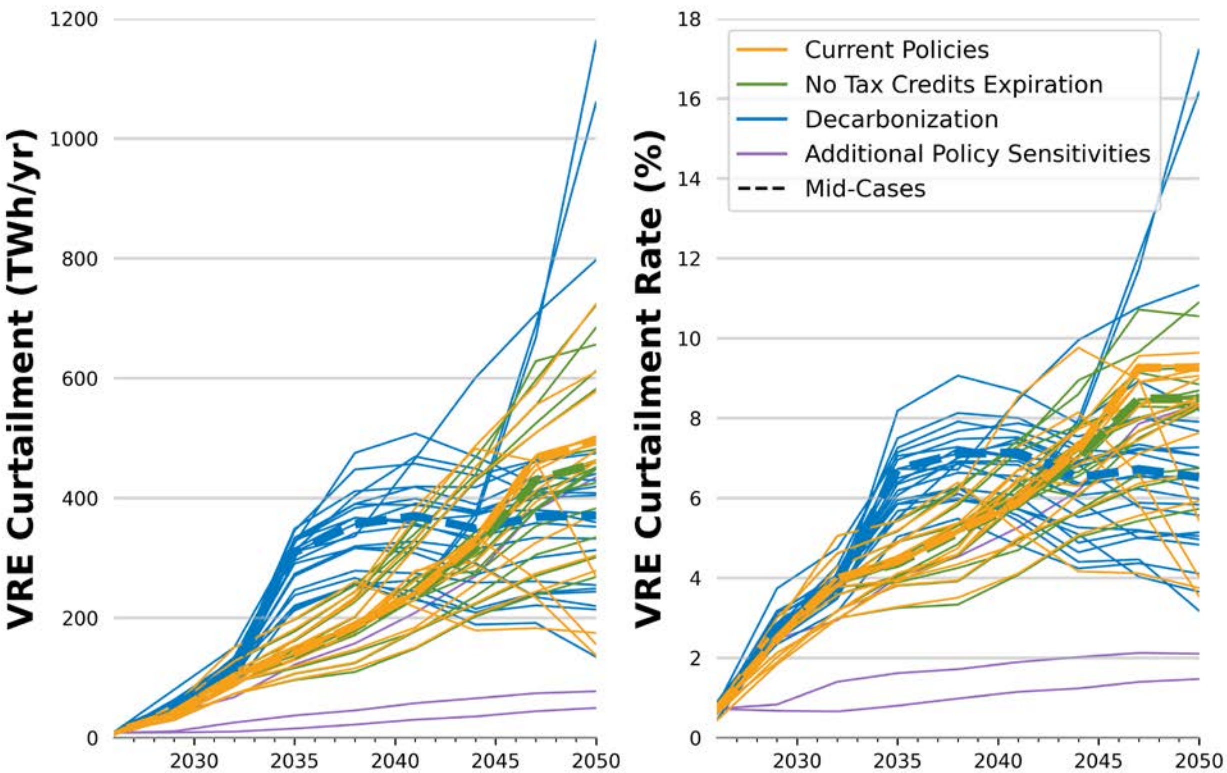

Figure 12. Wind and solar curtailment

The Mid-case scenarios are shown with the heavier dashed lines. The *Additional Policy Sensitivities* group comprises three scenarios that omit IRA's electricity sector tax credits and/or updated CAA 111 rules.

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Appendix

A.1 Standard Scenarios Input Assumptions

Table A-1 gives a high-level summary of the input assumptions used in the Standard Scenarios, followed by more detailed discussion in the subsections after the table.

For details about model structure and assumptions not mentioned here, see the documentation for ReEDS (Ho et al. 2021) and dGen (Sigrin et al. 2016). Both models are publicly available, and inputs are viewable within the model repositories.[26] For ReEDS, the settings file used to create all the scenarios used in this report is included in the repository, so that any of the scenarios can be recreated.

Table A-1. Summary of Inputs to the 2024 Standard Scenarios

The scenario settings listed in blue italics correspond to those used in the Mid-case scenarios.

Group	Scenario Setting	Notes
Electricity Demand Growth	*Reference Demand Growth*	*End-use electricity trajectory reaching 6,509 TWh/year of demand (1.8% compound annual growth rate [CAGR]) with conservative assumptions about the impact of demand-side provisions in IRA*
	Low Demand Growth	End-use electricity trajectory reaching 5,054 TWh/year (0.9% CAGR) based on service demand projections from AEO 2022 (i.e., does not include the impacts of IRA)
	High Demand Growth	End-use electricity trajectory reaching 8,354 TWh/year (2.8% CAGR) consistent with 100% economy-wide decarbonization by 2050
	Hydrogen Economy	The Reference Demand Growth trajectory (above), combined with exogenous (i.e., non-power-sector) demand for electrolysis-produced hydrogen reaching 46.3 MMT/year. Reaches 8,893 TWh/year end-use demand (3.1% CAGR)
	High Demand Growth and Hydrogen Economy	The High Demand Growth trajectory (above) combined with exogenous (i.e., non-power-sector) demand for electrolysis-produced hydrogen reaching 46.3 MMT/year imposed. Reaches 10,737 TWh/year end-use demand (3.8% CAGR)

[26] See https://github.com/NREL/ReEDS-2.0 and www.nrel.gov/analysis/dgen/model-access.html.

Group	Scenario Setting	Notes
Fuel Prices	*Reference Natural Gas Prices*	*AEO2023 reference*[a]
	Low Natural Gas Prices	AEO2023 high oil and gas resource and technology[a]
	High Natural Gas Prices	AEO2023 low oil and gas resource and technology[a]
Electricity Generation Technology Cost and Performance	*Mid Technology Cost and Performance*	*2024 ATB moderate projections*
	Advanced RE and Battery Cost and Performance	2024 ATB advanced projections for renewable energy and electric battery storage technologies[b]
	Conservative RE and Battery Cost and Performance	2024 ATB conservative projections for renewable energy and electric battery storage technologies[b]
	Advanced CCS Cost and Performance	2024 ATB advanced projection for coal and natural gas CCS greenfield technologies; EIA-NEMS plant-level costs for CCS retrofits with declines based on ATB advanced projections
	Conservative CCS Cost and Performance	2024 ATB conservative projection for coal and natural gas CCS greenfield technologies; EIA-NEMS plant-level costs for CCS retrofits with declines based on ATB conservative projections
	Advanced Nuclear Costs	2024 ATB advanced projections for nuclear technologies
	Conservative Nuclear Costs	2024 ATB conservative projections for nuclear technologies
Resource Availability	*Default RE Resource Availability*	*Reference resource availability. See Renewable Energy Resource and Siting subsection for details.*
	Reduced RE Resource Availability	Limited siting supply curves for wind and PV; 50% reduction to all other renewable energy resource supply curves
Generation Technology Set	*All Generation Technologies Available*	*All generation technologies available, see Nascent and Established Technologies subsection below*
	No Nascent Generation Technologies	Nascent generation technologies excluded, see Nascent and Established Technologies subsection below

Group	Scenario Setting	Notes
Transmission Availability	*Reference Transmission Availability*	*No unannounced intra-regional transmission investment until 2032, then unrestricted investment between ReEDS regions currently connected. Existing Line-commuted converters (LCC) can be expanded but no new interfaces. voltage source converter (VSC) HVDC transmission lines disabled as investment option*
	High Transmission Availability	No unannounced intra-regional transmission investment until 2032, then unrestricted transmission expansion between regions currently connected. Existing LCC can be expanded but no new interfaces. VSC HVDC transmission lines enabled as investment option
	Low Transmission Availability	No unannounced intra-regional transmission investment until 2032, then 1.07 TW-mile/year limit on new transmission investment, only allowed within 11 transmission planning regions and between regions already connected. VSC HVDC transmission lines disabled as investment option. Existing LCC can be expanded but no new interfaces.
Direct Air Capture	*Electricity-powered DAC of CO_2 Not Allowed*	*Electricity-powered DAC not available as an investment option*
	Electricity-powered DAC of CO_2 Allowed	Electricity-powered DAC available as an investment option
Policy/Regulatory Environment	*Current Policies*	*Includes state, regional, and federal policies as of August 2024. Electric sector IRA tax credits expire or persist based on current legislation, see section A.3.*
	No Expiration of IRA Tax Credits	*Electric-sector IRA tax credits extended through 2050*
	100% Net Lifecycle CO_2e Decarbonization by 2035	*Net-zero electricity sector CO_2-equivalent emissions by 2035, inclusive of six categories: CO_2, CH_4, and N_2O, all three for emissions from both the direct combustion of fuels, as well as precombustion activities (fuel extraction, processing, and transport).*
	No IRA Tax Credits	Electric-sector IRA tax credits not represented.

Group	Scenario Setting	Notes
	No IRA Tax Credits	No representation of updated CAA 111 rules.
	No IRA Tax Credits and No 111 Representation	Electric-sector IRA tax credits not represented and no representation of updated CAA 111 rules
	95% Net CO_2 Decarbonization by 2050	95% net reduction (relative to 2005) in electricity sector combustion-only CO_2 emissions by 2050 (relative to 2005)
	95% Net Lifecycle CO_2e Decarbonization by 2050	95% net reduction (relative to 2005) in electricity sector CO_2-equivalent emissions by 2035, inclusive of six categories: CO_2, CH_4, and N_2O, all three for emissions from both the direct combustion of fuels, as well as precombustion activities (fuel extraction, processing, and transport).
	95% Net CO_2 Decarbonization by 2035	95% net reduction (relative to 2005) in electricity sector combustion-only CO_2 emissions by 2035.
	95% Net Lifecycle CO_2e Decarbonization by 2035	95% net reduction (relative to 2005) in electricity sector CO_2-equivalent emissions by 2035, inclusive of six categories: CO_2, CH_4, and N_2O, all three for emissions from both the direct combustion of fuels, as well as precombustion activities (fuel extraction, processing, and transport).
	100% Net CO_2 Decarbonization by 2035	Net-zero electricity sector combustion-only CO_2 emissions by 2035.
	95% Net Lifecycle CO_2e Decarbonization by 2035	Net-zero electricity sector CO_2-equivalent emissions by 2035, inclusive of six categories: CO_2, CH_4, and N_2O, all three for emissions from both the direct combustion of fuels, as well as precombustion activities (fuel extraction, processing, and transport). Electric-sector IRA tax credits extended through 2050.

[a] Natural gas prices are based on AEO electricity sector natural gas prices but are not identical because of the application of natural gas price elasticities in the modeling. See the Fuel Prices section below for details.

[b] For the purposes of these sensitivities, renewable energy technologies are behind-the-meter PV, utility-scale PV, concentrating solar power, geothermal, hydropower, onshore wind, and offshore wind.

Electricity Demand

End-use electricity demand profiles in the Standard Scenarios are based on state-level hourly projections created with the EnergyPATHWAYS model from Evolved Energy Research (EER).[27] EnergyPATHWAYS is a bottom-up stock accounting model, which begins with historical equipment stock data (based on surveys) and simulates the turnover of end-use equipment stock. Stock turnover is defined in EnergyPATHWAYS by assumptions around the useful life of end-use equipment and customer adoption rates for different equipment options, such as internal combustion engine vehicles versus battery electric vehicles, gas furnaces versus air-source heat pumps, and so on.

EnergyPATHWAYS simulates the evolution of the end-use equipment stock and, in turn, projects changes to the load profile shapes in each state. Load profile shapes define the timing and magnitude of electricity demand; they are rooted in assumed customer adoption rates and final energy demand patterns and requirements for a given level of end-use service demand (e.g., space heating). Annual electricity demand and the load profile shapes vary by year, state, and demand trajectory.

This year's Standard Scenarios suite includes three different trajectories for future end-use electricity demand: Reference Demand Growth is the default assumption, and sensitivities include Low Demand Growth and High Demand Growth.

The Reference Demand Growth trajectory aligns with EER's IRA Conservative scenario, and it assumes lesser impacts from the IIJA and IRA on end-use equipment stock.[28] By 2050, electricity demand grows to 6,509 TWh, which corresponds to a compound annual growth rate (CAGR) of 1.8% (relative to electricity demand in 2024). It assumes an increase in customer adoption of light-duty electric vehicles (cars and trucks; Table 1), which contributes the bulk of growing electricity demand (Table 2). By 2050, 60% of final energy consumption by light-duty vehicles takes the form of electricity, compared to 1% in 2024 (Table 3). The electrification of residential and commercial space heating, residential water heating, and (to a lesser extent) commercial water heating contribute more modestly to growing electricity demand over time.

The Low Demand Growth trajectory aligns with the Baseline scenario from EER's Annual Decarbonization Perspective 2023 report. This scenario reflects the end-use equipment stock evolution that would occur if recent trends in customer adoption continue, consistent with the Energy Information Administration's Annual Energy Outlook (2023).[29] As a result, the Low Demand Growth scenario reflects more limited electrification of end-use subsectors (Table 1) reaching 5,054 TWh of electricity demand in 2050 (a CAGR of 0.9% relative to 2024).

The High Demand Growth trajectory aligns with the Central scenario from EER's Annual Decarbonization Perspective 2023 report. This scenario represents customer adoption of end-use equipment that is consistent with one pathway for achieving net-zero carbon emissions

[27] ReEDS endogenously calculates inter-regional transmission system losses, but it does not endogenously represent distribution losses. Therefore, the end-use load must be scaled up to busbar load to account for distribution losses, which are assumed to be 5%. The ReEDS constraint related to electricity demand is based on busbar load, while this section summarizes end-use load assumptions.

[28] The IRA Conservative scenario was originally prepared for the Princeton REPEAT project.

[29] While the Annual Energy Outlook (2023) was designed to represent the impacts of the IIJA and IRA, results from the National Energy Modeling System indicate more modest rates of electrification.

throughout the U.S. economy by 2050. The widespread adoption of electric vehicles, air-source heat pumps, and other electric end-use technologies (Table 1) drives a rapid and sustained increase in electricity demand (Table 2). By 2050, U.S. electricity demand grows to 8,354 TWh, (a CAGR of 2.8% relative to 2024).[30] This is despite the Central scenario also assuming higher adoption of energy efficiency end-use technologies over the same time period, which somewhat blunts the impacts of electrification.

Figure A-1 below shows the three end-use demand assumptions used in the Standard Scenarios.

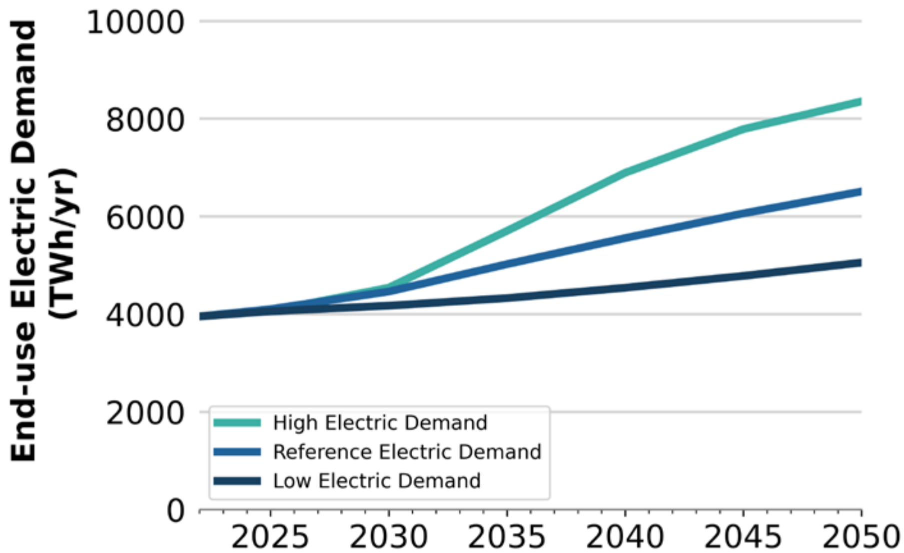


Figure A-1. End-use demand trajectories used in the Standard Scenarios

In addition to the three end-use demand trajectories described above, two sensitivities (Hydrogen Economy, High Demand Growth and Hydrogen Economy) also have an imposed demand for hydrogen for non-power-sector use, which increases electricity sector demand. See the following section on endogenous hydrogen production for more details.

Inelastic, inflexible end-use electricity demand is assumed in all scenarios in this year's suite (note however that, when present, electrolysis and direct air capture are elastic and flexible). This is a poor assumption—grid-responsive flexible loads currently exist in practice, and the increasing value of energy arbitrage in many of the futures modeled may induce more loads to become grid-responsive, especially with the electrification of certain end-uses (such as vehicles). The inclusion of elastic and flexible loads would tend to create systems that are less expensive, relative to situations where load is elastic and flexible.

The following tables summarize key statistics from the three end-use demand scenarios. Table A-2 summarizes the percentage of stock in several key subsectors that have transitioned to electric end-use technologies. Table A-3 summarizes the electricity demand associated with the electrified stock. Table A-4 reports the share of final energy demand (for each key end-use

[30] EER's Central scenario assumes electrification plays a major role (combined with rapid decarbonization of the U.S. power sector), but other strategies also contribute to achieving a net-zero U.S. economy by 2050.

subsector) that is met by electricity. All three tables summarize the subsectors that have the greatest impact on the ReEDS solution (i.e., the greatest impact on annual and peak electricity demand) – note, however, that widespread electrification is projected in other sectors (e.g., cooking and clothes dryers) as well, especially under the High Demand Growth scenario.

Equipment stock trends (Table A-2) are more pronounced than changes in electricity demand (Table A-3) or electricity's share of final energy demand (Table A-4) when electric end-use equipment is significantly more efficient than incumbent direct fuel equipment.

Table A-2. The Share of Equipment Stock Captured by Electric End-Use Technologies in Key Energy-Intensive Subsectors

		2024	2030			2050		
Demand Trajectory		Low	Low	Reference	High	Low	Reference	High
Electric Vehicles[31]	Light Duty Cars/Trucks	2%	3%	14%	11%	9%	75%	87%
	Medium Duty Trucks	<0.5%	<0.5%	4%	2%	<0.5%	34%	69%
	Heavy Duty Trucks	<0.5%	<0.5%	2%	2%	<0.5%	42%	62%
	Transit Buses	2%	2%	19%	13%	2%	45%	90%
Air-Source Heat Pumps[32]	Residential Space Heating	11%	11%	18%	17%	13%	28%	74%
	Residential Water Heating	--	--	8%	5%	--	15%	45%
	Commercial Space Heating	5%	5%	17%	4%	4%	33%	61%
	Commercial Water Heating	<0.5%	<0.5%	<0.5%	6%	<0.5%	<0.5%	55%

[31] The percent of vehicle stock captured by electric technologies is based on customer adoption of battery, plug-in hybrid, and fuel cell electric vehicles divided by the total number of assumed vehicles in each sub-sector and year presented.
[32] The percent of residential and commercial space and water heating stock captured by air-source heat pump technologies includes pure and hybrid (or multi-fuel) heat pump equipment.

Table A-3. Approximate Annual Electricity Demand (TWh) for Select Energy-Intensive End-Use Subsectors[33]

	2024	2030			2050		
Demand Trajectory		Low	Reference	High	Low	Reference	High
Light-Duty Vehicles (Cars and Trucks)	20	50	250	170	140	1,200	1,400
Medium Duty Trucks	~0	~0	10	~0	~0	130	270
Heavy Duty Trucks	~0	~0	10	10	~0	220	250
Transit Buses	~0	~0	~0	~0	~0	10	20
Residential Space Heating	180	180	210	210	160	230	390
Residential Water Heating	190	190	190	200	200	200	290
Commercial Space Heating	30	30	50	50	30	90	170
Commercial Water Heating	~0	~0	~0	18	~0	~0	130

[33] Rounding is performed to avoid over-precision. Values less than 10 TWh are presented as ~0.

Table A-4. Share of End-Use Service Demand Met by Electricity[34]

	2024	2030			2050		
Demand Trajectory		Low	Reference	High	Low	Reference	High
Light-Duty Vehicles (Cars and Trucks)	1%	1%	7%	5%	4%	60%	85%
Medium Duty Trucks	<0.5%	<0.5%	3%	2%	<0.5%	27%	70%
Heavy Duty Trucks	<0.5%	<0.5%	1%	1%	<0.5%	31%	46%
Transit Buses	--	--	4%	3%	--	16%	75%
Residential Space Heating	13%	13%	16%	15%	13%	21%	61%
Residential Water Heating	36%	35%	39%	41%	35%	40%	97%
Commercial Space Heating	5%	5%	9%	8%	5%	21%	58%
Commercial Water Heating	4%	4%	4%	9%	4%	4%	97%

[34] For this table, electricity consumption includes the full suite of electricity demand, including highly efficient, conventional, and hybrid equipment.

Figure A-2 shows the month-hour demand patterns for the Reference electric demand trajectory in 2024, which is similar to the 2024 values in the other two demand trajectories. To give a sense of how the patterns evolve over time, A-3 through A-5 show the month-hour demand patterns for the Low, Reference, and High electric demand trajectories respectively.

Note that scenarios with greater load growth tend to have greater winter peaks, relative to scenarios with lower load growth. By 2050 in the High load growth trajectory, the winter peak becomes approximately the same magnitude as the summer peak, driven in large part by the electrification of heating. The patterns shown below are for the nation—individual regions can have winter peaks that exceed summer peaks.

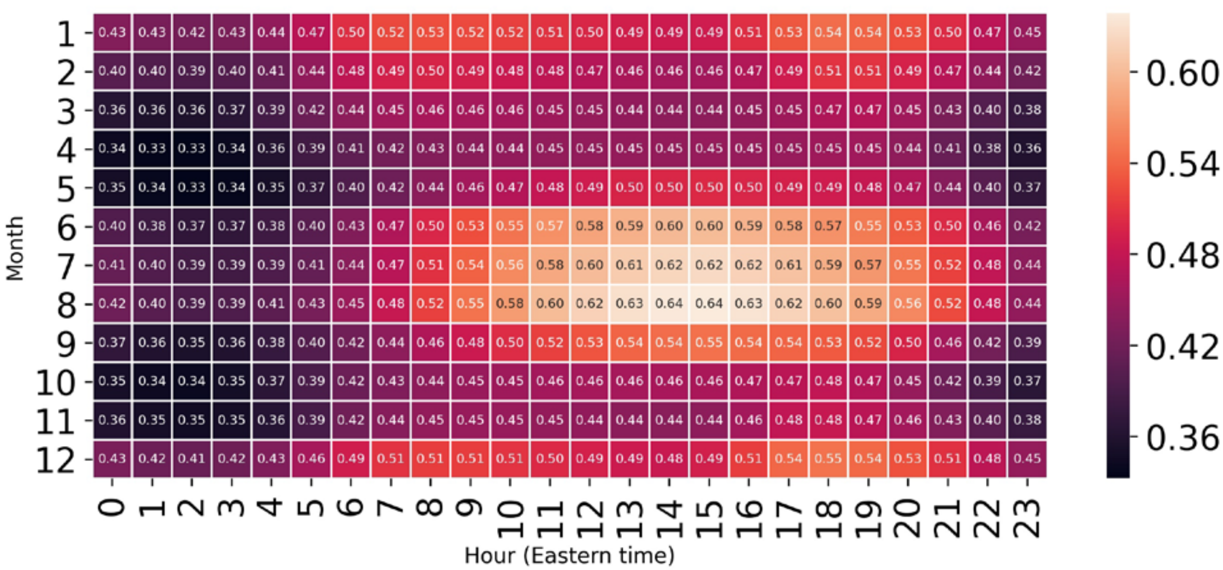


Figure A-2. Month-hour end-use national demand, in TWh, in 2024 for the Reference demand trajectory

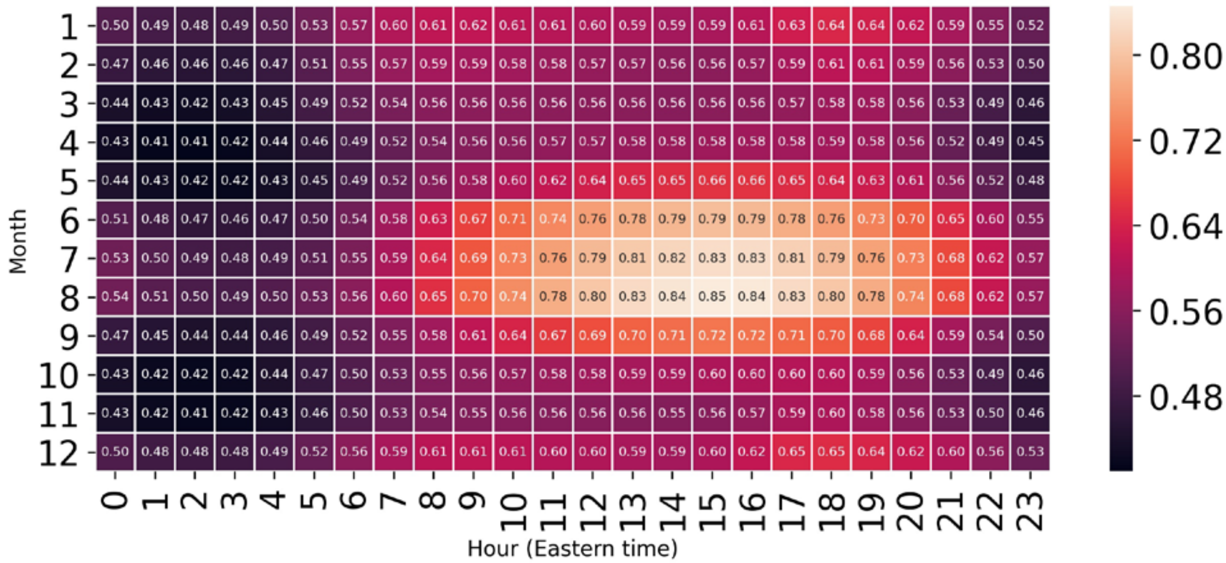


Figure A-3. Month-hour average end-use national demand, in TWh, in 2050 for the Low demand trajectory

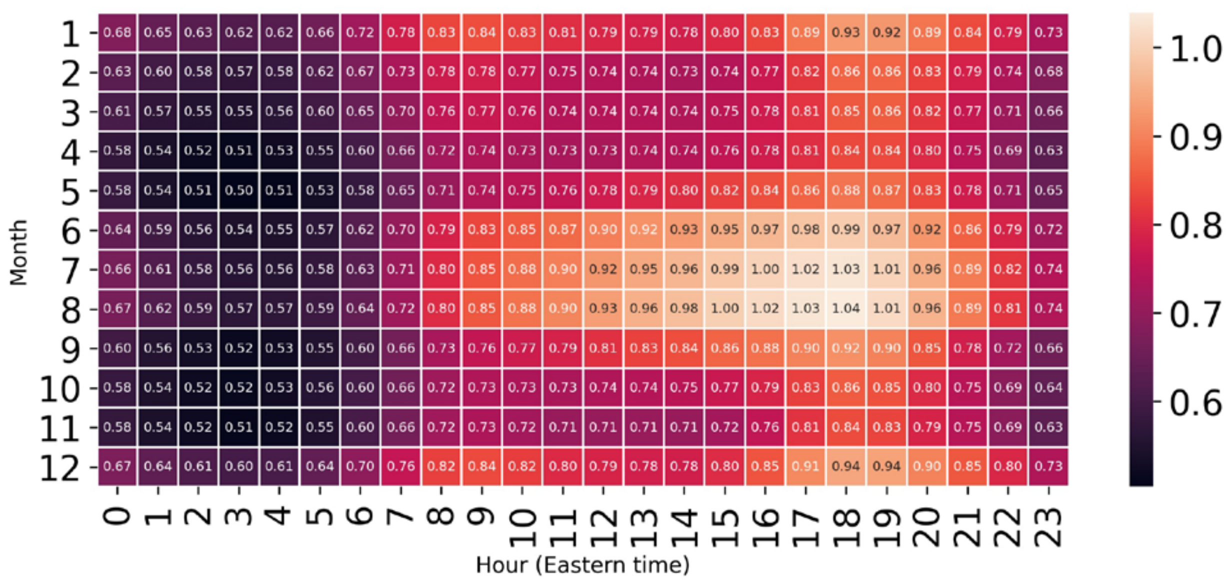


Figure A-4. Month-hour average end-use national demand, in TWh, in 2050 for the Reference demand trajectory

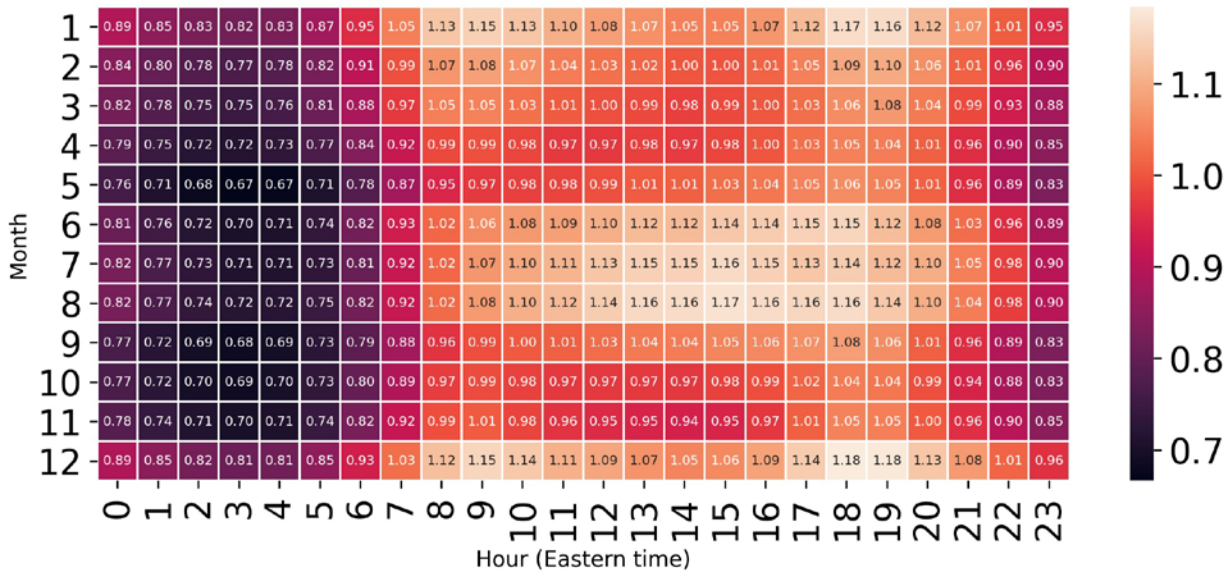


Figure A-5. Month-hour average end-use national demand, in TWh, in 2050 for the High demand trajectory

Endogenous Hydrogen Production and Hydrogen Economy Sensitivities

This year's Standard Scenarios includes endogenous representation of hydrogen production using low temperature electrolyzers. Electrolyzers consume electricity and create hydrogen, therefore the fuel cost of H2-CTs is endogenously calculated within the model. Hydrogen storage (salt cavern, lined rock cavern, or underground pipe storage, depending on the location) is represented within the model, and incurs an investment cost, to temporally connect the production of hydrogen to its usage. All H2-CTs must be paired with a minimum of 24 hours of hydrogen storage (that is, ReEDS must invest in hydrogen storage that, if full, would be sufficient to operate the H2-CTs in the region at full output for a minimum of 24 hours) The minimum allowable hydrogen storage, for H2-CTs, is set at 24 hours of storage. No hydrogen transport is represented in this modeling—when used by the power sector in combustion turbines, hydrogen must be both produced and consumed in the same ReEDS balancing area. Hydrogen storage cost estimates are obtained from (Papadias and Ahluwalia 2021) and geological availability estimates are obtained from (Lord, Kobos, and Borns 2014).

The endogenous production of hydrogen for power sector use (in H2-CTs) is available in all scenarios (except the sensitivity that excludes nascent technologies).

Two sensitivities within the suite (indicated by *Hydrogen Economy* in their names) include an externally imposed non-power-sector demand for hydrogen, that must be met with electrolyzers, thereby adding load to the electric grid. The H_2 demand trajectory is shown in Figure A-6. The non-power-sector demand trajectories correspond to estimates of hydrogen demand for fully decarbonizing U.S. energy sectors (Denholm et al. 2022). This exogenous hydrogen demand is imposed as an annual, national constraint—meaning that any costs for the transportation and storage of this non-power-sector hydrogen is not reflected in the model's optimization or cost reporting. In all other scenarios, the demand for non-power-sector hydrogen is zero.

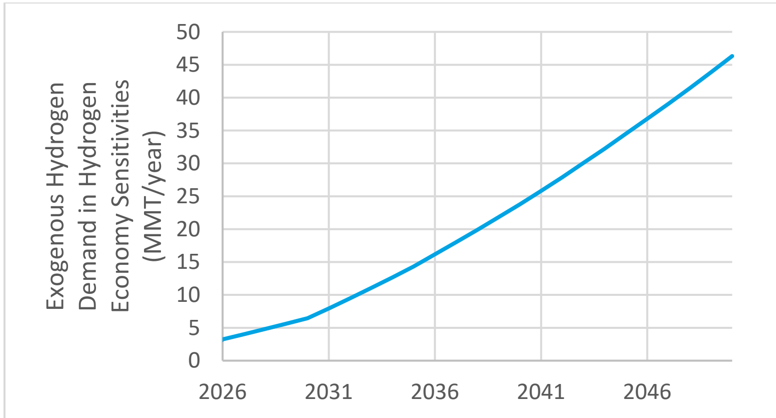


Figure A-6. Non-power-sector hydrogen demand in Hydrogen Economy sensitivities

In practice the amount of electricity used for H_2 production depends on how much of the H_2 is produced by electrolysis rather than routes such as steam methane reforming. In this modeling, ReEDS only represents hydrogen produced by electrolysis, and does not include representations of other production routes. These scenarios therefore represent approximately an upper bound to the electric load added to the grid for a given level of H_2 production. Additional drivers of electricity demand not explicitly modeled include data centers and increased manufacturing, which could lead to similar or greater levels of electricity demand than observed in the Hydrogen Economy sensitivities.

All electrolyzer capacity in results is endogenously determined by the ReEDS model, although in the Hydrogen Economy sensitivities it can be driven by the above described exogenous demand trajectory.

Fuel Prices

Natural gas input price points are based on the trajectories from AEO2023 (EIA 2023). The input price points are drawn from the AEO2023 Reference scenario, the AEO2023 Low Oil and Gas Supply scenario, and the AEO2023 High Oil and Gas Supply scenario. Actual natural gas prices in ReEDS are based on the AEO scenarios, but they are not exactly the same; instead, they are price-responsive to ReEDS natural gas demand in the electricity sector. Each census region includes a natural gas supply curve that adjusts the natural gas input price based on both regional and national demand (Cole, Medlock III, and Jani 2016). Figure A-7 shows the output natural gas prices from the suite of scenarios.

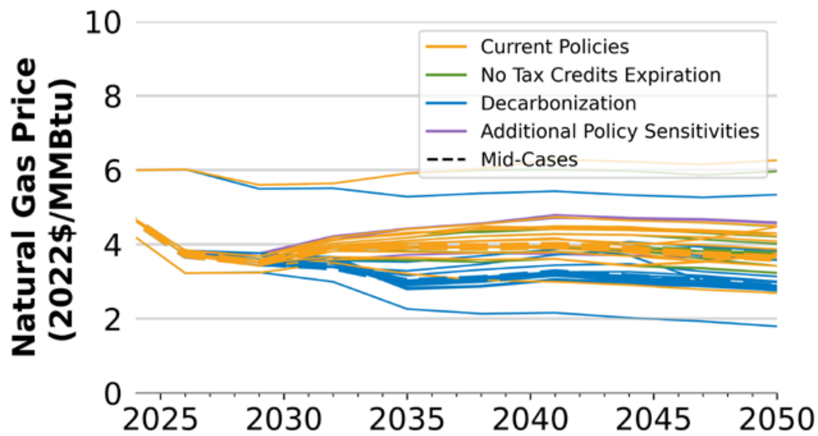


Figure A-7. National average natural gas price outputs from the suite of scenarios

The coal and uranium price trajectories are from the AEO2023 Reference scenario and are shown in Figure A-8. Both coal and uranium prices are assumed to be fully inelastic. Coal prices vary by census region (using the AEO census region projections). Figure A-8 shows the coal prices by census region. Uranium prices are the same across the United States.

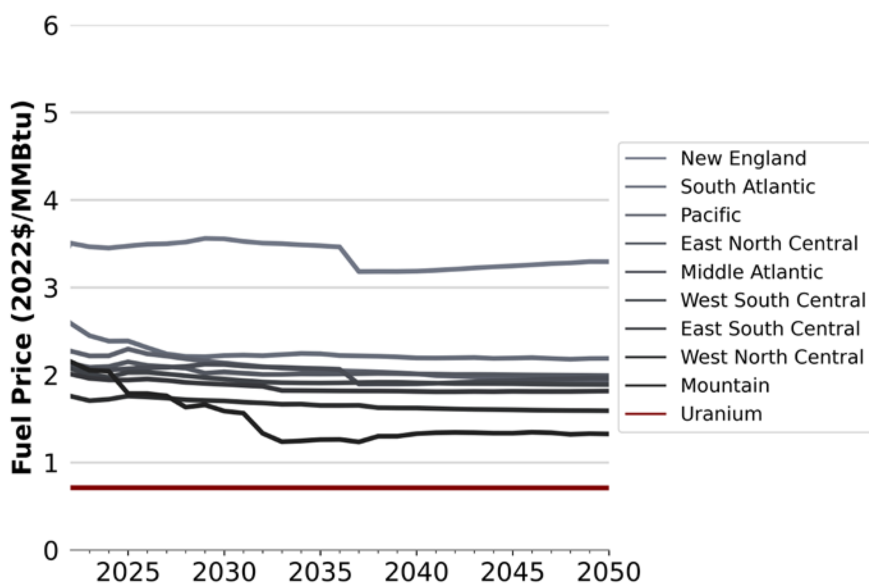


Figure A-8. Input coal and uranium fuel prices used in the Standard Scenarios

Uranium prices (red) are the same across the United States. Coal prices (grey) vary by census region, and as listed in descending order of average price in the legend in this figure.

Technology Cost and Performance

Technology cost and performance assumptions are taken from the 2024 ATB (NREL 2024). The ATB includes advanced, moderate, and conservative cost and performance projections through 2050 for the generating and storage technologies used in the ReEDS and dGen models.

The *Advanced Renewable Energy and Battery Cost and Performance* scenarios use the advanced projections for all renewable energy and battery technologies, and the *Conservative Renewable*

Energy and Battery Cost and Performance scenarios use the conservative projections. For these scenarios, RE technologies include all solar, geothermal, hydropower, and wind generators. Likewise, the *Advanced* and *Conservative* nuclear cost scenarios draw from the respective advanced and conservative trajectories in the ATB (the ATB only varies the cost of the two nuclear technologies across its scenarios, not their performance, hence the difference in the sensitivity name from the other technology sensitivities).

See the following section, Carbon Capture Cost and Performance, for discussion of those technologies.

Hydrogen combustion turbines (H2-CT) are represented consistent with the RE-CT technology in the Solar Futures Study (DOE 2021). H2-CTs can be built either as greenfields (at a cost 3% higher than their natural gas turbine equivalent) or upgraded from natural gas turbines (for 33% of the capital cost of a new gas turbine). Heat rates and operation and maintenance costs are the same as natural gas turbines. All H2-CT units are assumed to be clutched to allow them to also act as synchronous condensers.

Generator lifetimes are shown in Tables A-5 and A-6. These lifetimes represent that maximum lifetimes generators are allowed to remain online in the model. The model will retire generators before these lifetimes if their value to the system is less than 50% of their ongoing fixed maintenance and operational costs (50% is assumed, instead of 100%, to roughly approximate the friction of plant retirements, as retirement decisions in practice are often not strictly economic decisions). If a retirement date has been reported for a generator, ReEDS will retire capacity equivalent to that generator's capacity at that date or earlier.

Table A-5. Lifetimes of Renewable Energy Generators and Batteries

Technology	Lifetime (Years)	Source
Land-based wind	30	Wind Vision (DOE 2015)
Offshore wind	30	Wind Vision (DOE 2015)
Solar PV	30	SunShot Vision (DOE 2012)
CSP	30	SunShot Vision (DOE 2012)
Geothermal	30	GeoVision (DOE 2019)
Hydropower	100	Hydropower Vision (DOE 2016)
Biopower	50	2021 National Energy Modeling System plant database (EIA 2021)
Battery	15	Cole, Frazier, and Augustine (2021)
H2-CT	50	Matching natural gas combustion turbines

Table A-6. Lifetimes of Nonrenewable Energy Generators

Technology	Lifetime for Units Less than 100 MW (Years)	Lifetime for Units Greater than or Equal to 100 MW (Years)
Natural gas combustion turbine	50	50
Natural gas combined cycle and CCS	60	60
Coal, all technologies, including cofired	65	75
Oil-gas-steam (OGS)	50	75
Nuclear	80	80

Carbon Capture Cost and Performance

The scenario suite includes sensitivities for both *Advanced CCS Cost and Performance* as well as *Conservative CCS Cost and Performance*. Four costs were varied across the sensitivities (greenfield capital costs, retrofit capital costs, variable operation and maintenance (O&M), and fixed O&M) as well as heat rates.

Greenfield capital costs, variable O&M costs, and fixed O&M costs for gas and coal CCS technologies are taken from the conservative, reference, and advanced trajectories of the 2024 ATB.

Plant-level retrofit capital cost estimates are provided in the EIA-NEMS dataset used to initialize the generator fleet in ReEDS (this file can be viewed in the ReEDS GitHub repository). This value was implemented as the cost for retrofitting a generator in 2028. Beyond 2028, that cost declines at the rate of the CCS retrofit capital cost declines for the corresponding technology in the ATB.

Heat rates for CCS generators are based on the values in the three trajectories in the 2024 ATB. These heat rates are adjusted with the same multipliers as was previously described in the Technology Cost and Performance section—the multipliers for their non-CCS equivalents are used, due to the lack of empirical data on CCS generator performance.

Aligned with the 2024 ATB, this modeling assumes greenfield CCS generators have capture facilities that can achieve 95% capture, while retrofit CCS generators have capture facilities that can achieve 90% capture.

Note that the first year the ReEDS model is enabled to have fossil-CCS become operational is 2028, reflecting construction lead times.

DAC cost and performance values are the *Conservative* assumptions from Fasihi, Efimova, and Breyer (2019). Biomass with CCS cost and performance values are from EPRI (2020).

Renewable Energy Resource and Siting

The Standard Scenarios has two renewable energy resource availability and siting assumptions, a reference assumption and a limited assumption. For land-based wind, additional setbacks and land exclusions are applied in the limited case that reduce the resource available to 4.2 TW, compared with 9.5 terawatts (TW) in the reference case. For offshore wind, the deployable resource is reduced from 3.0 TW in the reference case to 2.2 TW in the limited case due to more stringent siting constraints that stem primarily from lower capacity density to accommodate fishing and shipping industries through required 1-nuatical mile spacing of turbines and from greater setbacks from shore as a proxy for coastal viewshed concerns.

Similar but coarser resource representation for PV results in a reduced resource potential scenario of 45 TW in the limited case, compared with 99 TW in the reference case. For other renewable energy technologies (CSP, geothermal, hydropower, and biopower) technical potential is reduced by 50% in the limited case, relative to the reference case. The reduction is applied uniformly across geography and resource classes (i.e., all regions and classes experience the same 50% reduction).

The methods for developing the land-based wind and PV supply curves are largely similar to the methods described in (Lopez et al. 2024), and the methods for developing offshore wind are largely similar to the methods described in (Zuckerman et al. 2023). Updated documentation corresponding to the supply curves in this report will be published in an upcoming NREL report, *Renewable Energy Technical Potential and Supply Curves for the Contiguous United States: 2024 Edition*, Lopez et al.

Nascent and Established Technologies

Most of the scenarios in this year's Standard Scenarios have a broad set of technologies available for investment, including various still-nascent technologies. The only scenario that does not have the full set of technologies is the *No Nascent Technologies* sensitivity, which has a relatively conservative set that only includes technologies that have achieved commercial procurement in the United States. The technology classifications are given in Table A-7.

Table A-7. Generation Technology Classification in the 2024 Standard Scenarios

Technology Group	Technologies
Established	• Electric batteries (4-hour and 8-hour duration) • Biopower • Coal • Concentrating solar power (CSP) with and without thermal energy storage • Distributed rooftop solar photovoltaics (PV) • Natural gas combined cycles (NG-CC) • Natural gas combustion turbines (NG-CT) • Conventional geothermal • Hydropower • Landfill gas • Conventional nuclear • Oil-gas-steam (OGS) • Pumped storage hydropower • Utility-scale PV • Onshore wind • Fixed-bottom offshore wind
Nascent	• Bioenergy CCS • Coal CCS • Enhanced geothermal systems • Floating offshore wind • Natural gas CCS (NG-CC-CCS) • Nuclear small modular reactors (SMR) • Hydrogen combustion turbine (H2-CT)

Note that electricity-powered DAC is not included as an investment option, other than the sensitivity that bears its name.

The classification of technologies as either nascent or established was an analytical judgement call based on the technology's readiness level, the current installed capacity globally, the current presence or absence of the technology in resource plans in the U.S., the level of understanding of permitting and sitting challenges, and the breadth and quality of future performance and cost estimates from multiple institutions.

The designation of a technology as nascent is not intended to pass judgement on the difficulty or likelihood of the technology ultimately achieving commercial adoption. Indeed, many of the technologies have high technology readiness levels, and some have operational demonstration plants. Nonetheless, even if a technology is technically viable, there is still great uncertainty about its future cost and performance, as well as a lack of understanding of other considerations relevant to projecting their deployment, such as siting preferences and restrictions. Given these uncertainties, a sensitivity is included that does not include these technologies.

Transmission Expansion

All scenarios allow for endogenously determined expansion of the current transmission network starting in 2032 (no transmission investment is allowed prior to 2032, other than two planned projects scheduled for operation in 2025 and 2026). Under all three transmission availability assumptions, expansion can occur only between any two of the 134 ReEDS regions that are currently connected by transmission. In the low transmission availability sensitivity, expansion is further restricted to being only within 11 transmission planning regions (based on Federal Energy Regulatory Commission Order 1000 transmission planning regions and the Electric Reliability Council of Texas, or ERCOT).

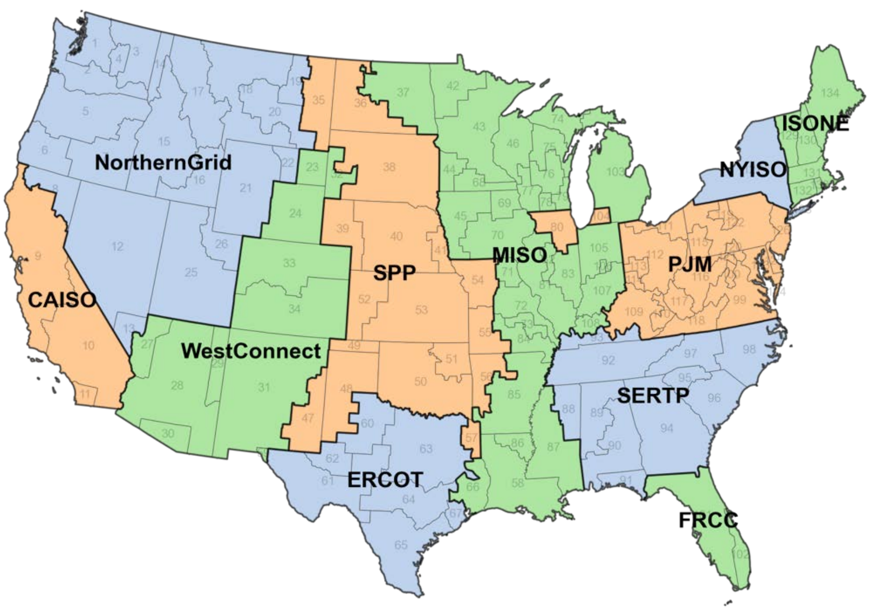


Figure A-9. Transmission planning regions used in Low Transmission Availability sensitivity

In the reference and high transmission availability assumptions, there are no restrictions on annual transmission investment. Under the low transmission availability assumption, new interregional (i.e., between ReEDS balancing areas) transmission capacity investment is restricted to 1.07 TW-mile/year.

The high transmission availability sensitivity allows new high-voltage direct current (HVDC) transmission capacity to be built between any pair of ReEDS regions that are connected by existing transmission. HVDC transmission is assumed to have a loss rate of 0.5%/100 miles (as compared to 1%/100 miles for AC) and to use voltage source converters (VSC) with a 1% loss rate for AC/DC conversion. For additional descriptions of how the transmission networks are modeled, see Section B.2 in the appendix of (Denholm et al. 2022). VSC HVDC capacity is not enabled as an investment option in the reference and low transmission availability assumptions.

Rooftop PV Adoption

The Standard Scenarios uses projections from the dGen model to provide estimates of rooftop PV deployment over time. dGen produces projections for rooftop PV deployment over time using marginal electricity costs from ReEDS. This year's Standard Scenarios incorporate rooftop PV adoption projections that were generated based on the outputs of the 2023 Standard Scenarios analysis. Five adoption projections were used, corresponding to low, central, and high rooftop PV adoption under current policies and two different decarbonization scenarios. Each scenario in this report used, as an exogenous input, the rooftop PV adoption scenario that aligned most closely with the scenario's assumptions. ReEDS then projects the grid evolution through 2050, resulting in most of the outputs reported here. See Section A.3 for a discussion of the interpretation of IRA's provisions for distributed generation.

Policy/Regulatory Environment

All scenarios include representations of state, regional, and federal policies as of August 2024 unless otherwise specified. These include representations of IRA's provisions, updated CAA section 111 regulations based on the rules finalized in May 2024, state renewable and clean portfolio standards, and regional programs such as the Regional Greenhouse Gas Initiative. Local policies (e.g., city-level) are not represented. Because policies often have complexities that are difficult to represent in a model like ReEDS, the representation within the model is generally an attempt to reflect the most important elements of a policy, while not being able to capture all details—see section A.3 for a summary of the representation of the various components of the Inflation Reduction Act, and the ReEDS repository and documentation for more information about the exact representation of policies.

In the default, Mid-case policy representation, policies and programs are represented as currently enacted, including the potential for a phaseout of the IRA tax credits for clean generation. In the *No Expiration of IRA Tax Credits* policy assumption set, the IRA clean electricity PTC and ITC, the IRA incentive for existing nuclear production (45U), the production tax credit for clean hydrogen (45V), and the IRA incentive for capturing and storing carbon (45Q) are all extended indefinitely.

This year's scenario suite includes a representation of the Clean Air Act's Section 111 implementing regulations for both existing coal plants and new gas plants as finalized in May 2024. For existing coal plants, ReEDS models an emissions rate-based compliance mechanism, enforced at the state level.[35] In 2032 and for every year thereafter, the emissions rate (tonnes CO_2 per MWh) of a states' coal fleet must be less than or equal to the emissions rate of a coal-CCS plant with a 90% capture rate. This makes it possible for non-CCS coal plants to remain online after 2032 if the state they are located in also has coal-CCS plants (with capture rates that exceed 90%), as long as the generation-weighted emissions rate of the with-CCS and without-CCS generators have a combined effective 90% capture rate. Also starting in 2032, new gas plants (built after May 23rd, 2023) must either retrofit with CCS or operate below a 40% capacity factor. Existing gas plants are not regulated per the regulations. The representation of this policy is held constant across the scenario suite.

[35] ReEDS assumes that every state opts into this emissions rate-based compliance mechanism for its coal fleet, instead of the best system of emissions reduction (BSER) compliance mechanism in which every coal plant must meet its BSER.

The representation of the decarbonization scenarios is described in Section 2 .. In all scenarios with a decarbonization target of 2035, growth penalties are removed, reflecting the assumption that historically unprecedented growth in the rate of deployment may be observed under those conditions.

Near-term Generator Investment

ReEDS was built primarily to explore potential futures of the U.S. electricity system. It does not contain endogenous representations of many phenomena that can influence the near-term rate of generator investment, such as supply chain limitations and rates of expansion, the administrative processing capabilities associated with interconnection queues, lead times for constructing transmission infrastructure, and so forth.

For this analysis, ReEDS was implemented with three features, intended to better anticipate the likely rate of near-term generator investment: State-level growth penalties, inclusion of interconnection queue data to guide model siting decisions, and a limit on the maximum national deployment of certain technologies through the 2026 model solve.

Generator growth penalties are applied through 2034, based on the annual installation rate at the state level by technology. When the annual installation rate is equal to or less than 130% of the prior maximum, no penalty is applied. When the annual installation rate is between 130% and 175% of the prior maximum, a 10% penalty is applied to the generator's capital costs. When the annual installation rate is between 175% and 200% of the prior maximum, a 50% penalty is applied. Growth rates are not allowed to exceed 200% of the prior maximum. The interaction between the rate of deployment growth and costs is not well understood and is likely to vary significantly by situation (e.g. technology and location). Here, growth penalties were derived from an analysis of historical state-level deployment trends combined with analyst judgement. Note that growth penalties are removed from any scenario with a national emissions constraint with a target date of 2035.

Generator interconnection queue data is used to guide near-term model siting decisions (Rand et al. 2024). In the 2026 solve, ReEDS is restricted to generator investment that has an executed interconnection agreement. In the 2029 solve, ReEDS is restricted to generator investment that is present within the queue currently, regardless of the status of the agreement. This feature only applies to the 2026 and 2029 solve years.

National maximum investment in wind, solar, and batteries is constrained in the 2024-2026 solve period. The upper limit is derived by the sum of capacity within the EIA 860M data that was deployed within 2024 or has a planned online year of 2024 or 2025, plus the greater of either that value or the historical maximum annual installation for the technology. That equates to 85.7 GW for PV, 36.1 GW for batteries, and 26.6 GW for wind (12.0 GW/year, 28.6 GW/year, and 8.9 GW/year respectively).

In some limited situations, the above limits can come into conflict with other constraints. To avoid infeasibilities, the limits above have been implemented with "relief valves" (i.e., being represented not as firm caps, but as high-cost limits that would not be selected by the model in absence of a conflict with another constraint). If a scenario's results violate one of the above limits, therefore, it is likely due to conflict with another constraint.

All scenarios represent the anticipated restart of the Palisades nuclear reactor in 2025. Other potential nuclear reactor restarts, such as Three Mile Island, are not represented in this modeling. Any announced or anticipated behind-the-meter generator investment is not reflected in this modeling.

A.2 Changes from the 2023 Edition

Table A-8 summarizes key model and input changes since last year's Standard Scenarios report (Gagnon et al. 2024). Rows labelled with "No change" saw a change between the 2022 and 2023 report, but not between the 2023 and 2024 report – they are presented as such here to help a reader identify that the input did not change again.

Table A-8. Key Differences in Model Inputs and Treatments for ReEDS Model Versions

Inputs and Treatments	2023 Version	2024 Version
Fuel prices	AEO2023	No change
Demand growth	Trajectories modeled by EER in 2023	No change
Generator technology cost, performance, and financing	2023 ATB[a] for most technologies, other than where specified in the 2023 Standard Scenarios report	2024 ATB[a] for most technologies, other than where specified in section A.1 above
Existing and planned generator plant database	AEO2023, and additional units from EIA860M that are reported as under construction or completed.	AEO2023, and additional units from the March 2024 EIA860M that are reported as under construction or completed.
Advanced Small Modular Reactor costs	Drawn from (Abou Jaoude et al. 2023)	Drawn from 2024 ATB
First year for endogenous builds	2026	No change
Near-term generator investment constraints	Growth penalties.	In addition to growth penalties: through 2029, endogenous generator deployment now constrained by interconnection queue data, EIA860M planned builds, and historical maximum rates of deployment. Described in *Near-term Generator Investment* section of A.1.
Endogenous hydrogen production	RE-CTs replaced with H2-CTs, hydrogen fuel price endogenously determined within the model through electrolysis production within the same modeled region as the generator.	No change

Inputs and Treatments	2023 Version	2024 Version
ReEDS temporal resolution	32 representative days and 9 outlying high load/low renewable energy days (for a total of 41 representative days). Each day represented with 6 4-hour periods, for a total of 246 representative time periods	32 representative days and 9 outlying high load/low renewable energy days (for a total of 41 representative days). Each day represented with 8 3-hour periods, for a total of 328 representative time periods
Supply chain capital cost adjustment	Adder removed	No change
Wind, solar, pumped hydro, and geothermal supply curves	Wind and solar supply curves produced by NREL's reV model, version 2023	Geothermal incorporated into reV. Wind, solar, and geothermal supply curves produced by NREL's reV model, version 2024. Pumped hydro updated with new bottom-up cost model
Network reinforcement costs	Network reinforcement costs for generator interconnection incorporated, derived in reV model	No change
Rooftop PV curtailment	Disallowed	No change
Generator minimum capacity factors	Generator minimum capacity factor constraint applied at the Balancing Area level by type	No change
Transmission flows	Combined flows across RTO/ISO boundaries constrained to n-1	No change
Transmission investment	No transmission investment prior to 2028 in any scenario.	No transmission investment prior to 2032 in any scenario.
Voluntary procurement of clean energy credits	Voluntary (e.g., corporate) demand for clean energy credits starts at 5.5% of retail sales and grows at 0.16%/year. The rates are based on observed trends (Heeter, O'Shaughnessy, and Burd 2021).	No change
PV-battery hybrid technology	PV-battery hybrids not explicitly represented in the modeling	No change
State policies	Policies as of September 2023	Policies as of August 2024
Minimum Hydrogen Storage Duration	No minimum	H2CTs must be paired with a minimum of 24 hours of hydrogen storage.
Retail rate adder for electricity consumption (DAC, electrolysis)	$20.5/MWh ($2004 dollars)	No retail rate adder

Inputs and Treatments	2023 Version	2024 Version
Offshore wind incentive representation	Transmission costs not assumed to be included in the basis for the investment tax credit	Transmission costs (e.g., inter-array, export cable, substation) now assumed to be included in the basis for investment tax credit
Geographic resolution	134 balancing areas	133 balancing areas (p119 and p122 combined)
Rooftop PV adoption projections	Drawn from dGen modeling in 2022	Drawn from dGen modeling in 2023. Total adoption substantially lower (approximately half in 2050, in central case) due to higher cost assumptions and changes in compensation for exported electricity in some locations.
Firm capacity import constraints	No constraint on the amount of firm capacity a region could obtain from other regions	Net firm capacity import limit, as percentage of peak load, initialized based on historical data, persists at that level through 2031, and then and linearly declines to no constraint by 2050
Clean Air Act Section 111	No explicit representation of CAA 111 in the model	Representation of new CAA 111 rules in ReEDS, as described in *Policy/Regulatory Environment* section above.
Resource adequacy assessment methodology	Capacity credit methodology	Stress periods methodology. See preprint *Incorporating Stressful Grid Conditions for Reliable and Cost-effective Electricity System Planning*, Mai et al. 2024, for more details.
Clean hydrogen production tax credit (45V)	No representation of clean hydrogen production tax credit	Clean hydrogen production tax credit implemented in ReEDS
Interregional hurdle rates	No hurdle rates between regions	Hurdle rates, representing various types of friction between regions, added to the model. Start at $8/MWh and phases down to $4/MWh or $0/MWh depending on region. See ReEDS repository for implementation details

[a] The default cost recovery periods are 20 years in ReEDS, while it is 30 years in the ATB.

A.3 Representation of the Inflation Reduction Act of 2022

The scenario suite includes representations of the main electricity sector provisions from the Inflation Reduction Act of 2022 (IRA). Note that not all IRA's provisions are represented. Additionally, as with any modeling of complex policy, the representation of the provisions are generally simplifications. These omissions and simplifications are highlighted below.

Five electricity sector tax credits are represented in ReEDS:

- **Clean Electricity PTC:** \$26/MWh for 10 years (2022 dollars) plus a bonus credit that starts at \$1.3/MWh and increases to \$2.6/MWh by 2028
- **Clean Electricity ITC:** 30%, plus a bonus credit that starts at an additional 5% and increases to 10% by 2028 (for totals of 35% and 40% respectively)
- **Captured CO_2 Incentive (45Q):** \$85 per metric ton of CO_2 for 12 years for fossil-CCS and bioenergy-CCS, and \$180 per metric ton of CO_2 for 12 years for DAC; nominal through 2026 and inflation adjusted after that
- **Existing Nuclear PTC (45U):** This tax credit is \$15/MWh (2022 dollars), but it is reduced if the market value of the electricity produced by the generator exceeds \$25/MWh. As a simplification, this dynamic calculation was not directly represented in ReEDS. Instead, to represent the effect of this provision, existing nuclear generators are not subject to economic retirement in ReEDS through 2032.
- **Clean Hydrogen Production Tax Credit (45V):** A tax credit up to \$3/kg-H_2 for 10 years (2022 dollars) for the production of clean hydrogen.

Note that IRA allows for bonus credits for both the clean electricity PTC and ITC (but not applicable to 45Q, 45U, or 45V) if a project either meet certain domestic manufacturing requirements or is in an "energy community." Projects can obtain both bonus credits if they meet both requirements, which would equate to \$5.2/MWh for the PTC and 20% for the ITC. ReEDS assumes that wind and solar projects will, on average, capture one of the bonus credits by 2028, the value of which is expressed in the summary above. Other clean generation projects are assumed to capture, on average, half of the domestic content bonus credit and an energy communities credit based on the presence or absence of an energy community in the balancing area the projected is deployed in. In practice, there will likely be greater diversity of captured credits among projects. Relatedly, the values above are based on the assumption that all projects will meet the prevailing wage requirements.

Under IRA, eligible clean electricity projects can select whether to take the PTC or the ITC. As implemented in ReEDS, however, an a priori analysis was performed to estimate which credit was most likely to be more valuable, and the technology was assigned that credit. The assignments are:

- **PTC:** Onshore wind, utility-scale PV, and biopower
- **ITC:** Offshore wind, CSP, geothermal, hydropower, new nuclear, pumped storage hydropower, distributed PV, and batteries.

In implementations of tax credits in ReEDS prior to IRA, the value of tax credits was reduced by 33% as a simple approximation of the costs of monetizing the tax credits (such as tax equity financing). Due to provisions in IRA that make it easier to monetize the tax credits, that cost penalty is reduced to 10% for non-CCS technologies and 7.5% for CCS technologies.[36] These cost penalties are not reflected in the values given for each incentive above.

[36] CCS projects are eligible for a direct pay option for the first 5 years of the 45Q credit or until 2032 (whichever comes first), with the credits returning to non-refundable status after that point. The lower monetization penalty is meant to approximate the benefit of the direct pay option.

The clean electricity PTC and ITC are scheduled to start phasing out when greenhouse gas emissions from the production of electricity fall below 25% of 2022 levels, or 2032, whichever is later. Once the tax credits phaseout, they remain at zero—there is no reactivation of the credits if the emissions threshold is exceeded at a later point. The exact value of the threshold that would trigger the IRA clean electricity tax credits phasing out has not been announced but is estimated at 386 million metric tons of CO_2e in this modeling. The 45Q, 45U, and 45V credits do not have a dynamic phaseout and are instead just scheduled to end at the end of 2032.

All IRA tax credits are assumed to have safe-harbor periods, meaning a technology can capture a credit as long as it started construction before the expiration of the tax credit. The maximum safe-harbor periods are assumed to be 10 years for offshore wind, 6 years for CCS and nuclear, and 4 years for all other technologies. Generators will obtain the largest credit available within their safe-harbor window, meaning that once a credit starts to phase down or terminate, ReEDS assumes efforts were made to start construction at the maximum length of the safe-harbor window before the unit came online. In practice this means ReEDS will show generators coming online and capturing the tax credits for several years beyond the nominal year in which they expired.

In the dGen model, distributed PV was assumed to take an ITC: the 25D credit for residential, and the Section 48 credit for commercial and industrial. For residential projects placed in service through 2032 the ITC was assumed to be 30%, declining to zero for projects placed in service in 2036. For commercial and industrial projects coming online through 2035 the ITC was assumed to be 40%, dropping to zero after that. These representations are simplifications, as there can be greater diversity in captured value depending on factors such as ownership type and tax status. Furthermore, due to limitations of the models used in this study, the dynamic phaseout of the Section 48 ITC was not reflected. In practice, most scenarios did not cross the emissions threshold specified in IRA at this point, and therefore the adoption of commercial and industrial distributed PV in the later years of those scenarios was potentially underestimated.

IRA includes additional bonus credits (up to 20%) for up to 1.8 GW per year for solar facilities that are placed in service in low-income communities. The dGen model runs used in this analysis did not have an explicit representation of that additional bonus credit. Instead, 0.9 GW per year of distributed PV was added to the original dGen estimates through 2032. The estimate of 0.9 GW reflects the assumption that some of the projects capturing the bonus credit may not be additional (i.e., they would have occurred anyway even if the bonus credit was not available).

The impact of manufacturing incentives in IRA are not explicitly represented. Instead, it is simply assumed that the incentives will have no net impact on technology costs and will be sufficient to enable the assumptions about domestic content bonus credits described above.

This year's scenario suite includes a representation of the clean hydrogen production tax credit, also known as 45V.[37] This tax credit provides up to $3 per kilogram of hydrogen produced, based on the lifecycle emissions of hydrogen production. For electrolyzers, use of grid-average electricity leads to emissions rates associated with hydrogen production that far exceed the emissions threshold of 45V. Therefore, to qualify for the highest value of 45V, electrolyzers must purchase and retire Energy Attribute Certificates (EACs) from qualifying clean

[37] 26 U.S. Code § 45V

technologies to demonstrate use of clean electricity.[38] Under 45V, the EACs that are purchased and retired must meet certain guidelines regarding the location and time of electricity generation and vintage of the electricity generator. To address this, in ReEDS, EACs are tracked by the region and hour in which they are produced and the commercial online year of the generator they are produced from. Electrolyzers must purchase and retire these EACs for a majority of electricity they consume to receive the 45V credit, which is assumed to be the full $3 per kilogram of hydrogen.

45V applies for electrolyzers that commence construction before January 1, 2033. The credit is available for ten years from the date the electrolyzer is placed in service. ReEDS assumes a 4-year safe-harbor period for hydrogen producers from a facility starting construction to being placed in service. Therefore, electrolyzers built as late as 2036 can qualify for the credit, and disbursements could still be occurring through 2046.

Lastly, IRA includes demand-side provisions. While not directly represented within ReEDS, the Reference demand trajectory used in most of this year's Standard Scenarios (produced by EER) was produced with a modeling workflow that incorporated representations of IRA's impact on demand.

A.4 Metric Definitions

This section defines the metrics that are available for download through NREL's Scenario Viewer (https://scenarioviewer.nrel.gov/).

Metric Family: capacity by technology
Metric Name: *technology_MW*
Units: MW

These metrics report the total net summer capacity within a region for each of the specified technologies. Capacity is reported in MW_{ac}, -- to calculate MW_{dc} for photovoltaic generators, an inverter loading ratio of 1.34 is assumed for UPV and 1.1 for rooftop PV. The capacities of wind and solar generation are reported at their original capacities when they were installed (i.e., their reported capacity is not reduced over time by degradation, even though the model internally represents degradation in its generation outputs). Electric battery capacities are reported by their duration (e.g., *battery_4_MW* is the MW capacity of 4-hour electric battery storage).

The capacity of DAC and electrolyzer devices are reported as *dac_MW* and *electrolyzer_MW*. It should be noted that DAC and electrolyzers consume electricity, they do not generate it.

Metric Family: generation by technology
Metric Name: *technology_MWh*
Units: MWh_{busbar}/year

These metrics report the total generation within either a state or the nation for the specified technology. These generation values do not include curtailed energy. Generation from behind-the-meter PV, which is assumed to occur at the point of end use, is reported as an equivalent

[38] Qualifying clean technologies include land-based wind, offshore wind, solar PV, geothermal, hydropower, nuclear and gas plants with CCS.

amount of busbar generation. Storage generation is reported as the total discharge from a given technology over the course of the year (as opposed to the net effect, which would be negative due to losses). Electric battery generation is reported by its duration (e.g., *battery_4_MWh* is the total MWh of electric discharge from 4-hour electric batteries storage).

Metric Family: electric load
Metric Name: *load_enduse_MWh, load_dist_loss_MWh, load_trans_loss_MWh, load_storage_charging_MWh, load_electrolyzer_MWh, load_dac_MWh, load_MWh*
Units: MWh_{busbar}/year

These metrics report various types of electrical load within each region.

Load_enduse_MWh is the load consumed by end uses in a region (excluding load from storage charging, DAC, and electrolyzers). *Load_dist_loss_MWh* is the energy lost in distribution losses in the region. *Load_trans_loss_MWh* is the energy lost in transmission losses in the region. *Load_storage_charging_MWh* is the load from charging storage devices (electric batteries and pumped hydro storage). *Load_electrolyzers_MWh* is the load from electrolyzers in the region. *Load_dac_MWh* is the load from DAC in the region. *Load_MWh* is the sum of all the categories, and is therefore the total busbar load in each region.

Metric Family: Hydrogen production
Metric Name: *generation* and *generation_for_aer*
Units: metric tons

The *generation* metric is the sum of all generation in the region, plus electricity imported from Canada. It includes generation from storage as well as generation from the original source generators the storage charged from. The *generation_for_aer* metric reflects utility-scale original source generation, for use the in average emissions rates metrics described below.

Metric Family: total emissions by region
Metric Name: *co2_c_mt, co2_c_net_mt, co2e_c_mt, co2e_c_net_mt, ch4_c_mt, n2o_c_mt, so2_c_mt, nox_c_mt, co2_p_mt, co2e_p_mt, ch4_p_mt, n2o_p_mt, co2e_mt, co2e_net_mt*
Units: metric tons

This family of metrics reports the total emissions from all generation within a region, in metric tons. No adjustment is made for imported or exported electricity.

The effects of CCS on natural gas and coal generators is reflected in these metrics. BECCS is represented as a zero-emission generation source for this metric, and any CO_2 capture by DAC is not reflected in these metrics (i.e., this metric is only for emissions from generation, and the net capture effect of BECCS and DAC is reflected through the *net* and *co2_capture* metric families below).

The emissions are reported by emission type (CO_2, CO_2e, CH_4, N_2O, SO_2, and NO_x) and whether the emissions are from direct combustion or precombustion activities (which include fuel extraction, processing, and transport). "*_c*" indicates emissions from direct combustion, whereas "*_p*" indicates emissions from precombustion activities. Metrics without a *"_c"* or *"_p"* are the combined values of the two.

The CO_2e metrics report the combined CO_2 equivalence of CO_2, CH_4, and N_2O, using global warming potentials from IPCC AR6.

Metric Family: total emissions by region, net of captured and stored carbon
Metric Name: *co2_c_net_mt, co2e_c_net_mt, co2e_net_mt*
Units: metric tons

This family of *net* emissions metrics reflects the corresponding metric from the preceding metric family, but also includes the effects of any capture by DAC, as well as the lifecycle capture implications of BECCS. For example, the *co2_c_net_mt* is equivalent to the *co2_c_mt* metric, but with each region's CO_2 capture by DAC and BECCS incorporated.

Metric Family: carbon capture and storage by region
Metric Name: *co2_capture_dac_mt, co2_capture_fossil_mt, co2_capture_beccs_mt*
Units: metric tons

These metrics report the quantity of captured and stored CO_2 by DAC, fossil generators (natural gas and coal), and BECCS.

Metric Family: average emission rates of in-region generation
Metric Name: *co2_c_kg_per_mwh, co2e_c_kg_per_mwh, ch4_c_g_per_mwh, n2o_c_g_per_mwh, so2_c_g_per_mwh, nox_c_g_per_mwh, co2_p_kg_per_mwh, ch4_p_g_per_mwh, n2o_p_g_per_mwh*, *co2_kg_per_mwh, co2e_kg_per_mwh*
Units: $kg/MWh_{generation}$ for CO_2 and CO_2e, $g/MWh_{generation}$ for all others

This family of metrics reports the average emission rate from all original source utility-scale generation within a region. Generation from storage, generation from behind-the-meter PV, and electricity imported from Canada is not included in this metric. The effect of CCS on fossil generators is incorporated. BECCS is represented as a zero-emissions generation source. The effect of DAC is excluded. The total generation used in calculating these metrics is given in *generation_for_aer*.

CO_2 and CO_2e metrics are reported in kg per MWh, whereas the others are reported in grams per MWh. No adjustment is made for imported or exported electricity.

The emissions are reported by emission type (CO_2, CO_2e, CH_4, N_2O, SO_2, and NO_x) and whether the emissions are from direct combustion or precombustion activities (which include fuel extract, processing, and transport). "*_c*" indicates emissions from direct combustion, whereas "*_p*" indicates emissions from precombustion activities. Metrics without a *"_c"* or *"_p"* are the combination of the two (e.g., *co2_kg_per_mwh* is the sum of *co2_c_kg_per_mwh* and *co2_p_kg_per_mwh)* . The CO_2e metrics report the combined CO_2 equivalence of CO_2, CH_4, and N_2O, using global warming potentials from IPCC AR6.

Metric Family: Hydrogen production
Metric Name: *h2_produced_mt*
Units: metric tons

This metric reports the total quantity of hydrogen produced within the region (for both power sector and non-power-sector uses).

A.5 Emission Factors by Fuel

Previous editions of the Standard Scenarios only reported CO_2 emissions from direct combustion of fuels for electricity generation. Starting with the 2022 edition, the emissions reported and available through the online data downloader have been expanded. The emissions metrics are calculated using the fuel-specific emissions factors given in this section. The resulting emissions per megawatt-hour of electric generation is a function of the generator's heat rate (i.e., the rate at which fuel is converted into electricity), which can vary by generator. Heat rates for newly built generators generally follow the projections in NREL's ATB. Heat rates for existing generators draw from EIA data. The input data and logic driving the overall mixture of heat rates in ReEDS can be viewed via the publicly available ReEDS repository.

Emissions factors for CO_2, CH_4, and N_2O are national averages. SO_2 and NO_x emissions factors for non-CCS gas, non-CCS coal, and oil are the average of state-level averages for those fuels from 2019 and 2020 eGRID data. The remaining SO_2 and NO_x emissions factors are national averages drawn from the ATB or prior ReEDS assumptions. There are no precombustion values for SO_2 or NO_x. All reported emissions (other than precombustion CH_4 for natural gas generators) are derived from historical emissions intensities, which neglect how emissions may change in the future (e.g., increases in emissions intensities from more variable generator operations or decreases in emissions intensities from improvements in control technologies).

The precombustion emission factors include fuel extraction, processing, and transport, including fugitive emissions. The precombustion emissions for natural gas are drawn from (Alvarez et al. 2018). Power plants are assumed to avoid distribution losses, which results in a fugitive methane emissions rate that starts at 2.2% in 2022 and decreases linearly by 30% by 2030.[39] If an analyst wishes to make a consistent assumption for a technology that incurs local distribution losses (e.g., residential appliances), the value would start at 2.3% in 2022 and likewise linearly decrease by 30% by 2030.

Emissions from ongoing, non-combustion activities (e.g., the emissions induced by O&M activities) are not included in the emissions metrics. Emissions from commissioning or decommissioning generators or other physical infrastructure are also not included.

Bioenergy with CCS is assumed to have a net combustion rate of negative 60.0 kg of CO_2 per MMBtu of fuel (where the CO_2 removal from feedstock growth and subsequent capture post-combustion is combined into a single factor). The bioenergy with CCS values for precombustion activities take the same values as the biomass category. Natural gas and coal generators with carbon capture are assumed to have a 90% reduction in their CO_2 from direct combustion.

[39] Assuming power plants avoid distribution losses was explicitly stated by Skone et al. in a predecessor publication (Skone et al. 2014).

Sources indicated in Table A-9 are:

- US LCI: U.S. Lifecycle Inventory Database (NREL 2021)
- ReEDS 2021: *Regional Energy Deployment System (ReEDS) Model Documentation: Version 2020* (Ho et al. 2021)
- EPA 2016: *Greenhouse Gas Inventory Guidance: Direct Emissions from Stationary Combustion Sources* (United States Environmental Protection Agency 2016)
- 2021 ATB (NREL 2021)
- California Air Resources Board (CARB) 11-307: *Assessment of the Emissions and Energy Impacts of Biomass and Biogas Use in California* (Carreras-Sospedra et al. 2015).
- Alvarez et al. 2018: *Assessment of methane emissions from U.S. oil and gas supply chain*, Science.
- eGRID: eGRID2019 Data File, eGRID2020 Data File (EIA 2022).

Table A-9. Emission Factors by Fuel

Fuel	Type	Emission	Emission Factor	Units	Source
Coal	Precombustion	CO_2	2.94	kg/MMBtu	USLCI: Bituminous Coal at power plant
		CH_4	208.26	g/MMBtu	USLCI: Bituminous Coal at power plant
		N_2O	0.05	g/MMBtu	USLCI: Bituminous Coal at power plant
	Combustion	CO_2	95.52	kg/MMBtu	ReEDS 2021
		CH_4	11.00	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		N_2O	1.60	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		SO_2	state	g/MMBtu	eGRID 2019 & 2020
		NOx	state	g/MMBtu	eGRID 2019 & 2020
Coal CCS	Precombustion	CO_2	2.94	kg/MMBtu	USLCI: Bituminous Coal at power plant
		CH_4	208.26	g/MMBtu	USLCI: Bituminous Coal at power plant
		N_2O	0.05	g/MMBtu	USLCI: Bituminous Coal at power plant
	Combustion	CO_2	9.55	kg/MMBtu	ReEDS 2021
		CH_4	11.00	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)

Fuel	Type	Emission	Emission Factor	Units	Source
		N_2O	1.60	g/MMBtu	EPA 2016: Table A-3, Coal and Coke, Mixed (Electric Power Sector)
		SO_2	0.0	g/MMBtu	ATB 2021
		NOx	35.0	g/MMBtu	ATB 2021
Natural Gas	Precombustion	CO_2	6.27	kg/MMBtu	USLCI: Natural Gas at power plant
		CH_4	571.6 – 400.2	g/MMBtu	571.6 g/MMBTu in 2022 (Alvarez et al. 2018). Decreases linearly to 400.2 g/MMBTu in 2030, constant thereafter.
		N_2O	0.02	g/MMBtu	USLCI: Natural Gas at power plant
	Combustion	CO_2	53.06	kg/MMBtu	ReEDS 2021
		CH_4	1.00	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		N_2O	0.10	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		SO_2	state	g/MMBtu	eGRID 2019 & 2020
		NOx	state	g/MMBtu	eGRID 2019 & 2020
Natural Gas CCS	Precombustion	CO_2	6.27	kg/MMBtu	USLCI: Natural Gas at power plant
		CH_4	571.6 – 400.2	g/MMBtu	571.6 g/MMBTu in 2022 (Alvarez et al. 2018). Decreases linearly to 400.2 g/MMBTu in 2030, constant thereafter.
		N_2O	0.02	g/MMBtu	USLCI: Natural Gas at power plant
	Combustion	CO_2	5.31	kg/MMBtu	ReEDS 2021
		CH_4	1.00	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		N_2O	0.10	g/MMBtu	EPA 2016: Table A-3, Natural Gas
		SO_2	0.0	g/MMBtu	ATB 2021
		NOx	1.5	g/MMBtu	ATB 2021
Residual Fuel Oil	Precombustion	CO_2	9.91	kg/MMBtu	USLCI at power plant
		CH_4	153.45	g/MMBtu	USLCI at power plant
		N_2O	0.17	g/MMBtu	USLCI at power plant
	Combustion	CO_2	75.10	kg/MMBtu	ReEDS 2021
		CH_4	3.00	g/MMBtu	EPA 2016: Table A-3, Petroleum Products, Residual Fuel Oil No. 6
		N_2O	0.60	g/MMBtu	EPA 2016: Table A-3, Petroleum Products, Residual Fuel Oil No. 6
		SO_2	state	g/MMBtu	eGRID 2020
		NOx	state	g/MMBtu	eGRID 2020

Fuel	Type	Emission	Emission Factor	Units	Source
Uranium	Precombustion	CO_2	0.84	kg/MMBtu	USLCI: Uranium at power plant
		CH_4	2.10	g/MMBtu	USLCI: Uranium at power plant
		N_2O	0.02	g/MMBtu	USLCI: Uranium at power plant
	Combustion	CO_2	0.00	kg/MMBtu	ReEDS 2021
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
		SO_2	0.00	g/MMBtu	-
		NOx	0.00	g/MMBtu	-
Biomass	Precombustion	CO_2	2.46	kg/MMBtu	CARB 11-307: Table 15
		CH_4	2.94	g/MMBtu	CARB 11-307: Table 15
		N_2O	0.01	g/MMBtu	CARB 11-307: Table 15
	Combustion	CO_2	0.00	kg/MMBtu	ReEDS 2021
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
		SO_2	36.00	g/MMBtu	ATB 2021
		NOx	0.00	g/MMBtu	ATB 2021
Hydrogen	Precombustion	CO_2	0.00	kg/MMBtu	-
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
	Combustion	CO_2	0.00	kg/MMBtu	ReEDS 2021
		CH_4	0.00	g/MMBtu	-
		N_2O	0.00	g/MMBtu	-
		SO_2	0.00	g/MMBtu	ReEDS 2021
		NOx	70.00	g/MMBtu	ReEDS 2021

A.6 Generation and Capacity Figures for All Scenarios

The figures in this section show the generation and capacity for all scenarios:

- Mid-case (Figure A-10)
- Advanced Renewable Energy and Battery Costs and Performance (Figure A-11)
- Conservative Renewable Energy and Battery Costs and Performance (Figure A-12)
- Advanced Nuclear Cost (Figure A-13)
- Conservative Nuclear Cost (Figure A-14)
- Advanced CCS Cost and Performance (Figure A-15)
- Conservative CCS Cost and Performance (Figure A-16)
- Low Demand Growth (Figure A-17)

- High Demand Growth (Figure A-18)
- Hydrogen Economy (Figure A-19)
- High Demand Growth and Hydrogen Economy (Figure A-20)
- Low Natural Gas Prices (Figure A-21)
- High Natural Gas Prices (Figure A-22)
- No Nascent Technologies (Figure A-23)
- Reduced Renewable Resources (Figure A-24)
- High Transmission Availability (Figure A-25)
- Low Transmission Availability (Figure A-26)
- Electricity-powered DAC (Figure A-27)
- Additional Decarbonization Sensitivities (Figure A-28)
- Additional Policy Sensitivities (Figure A-29).

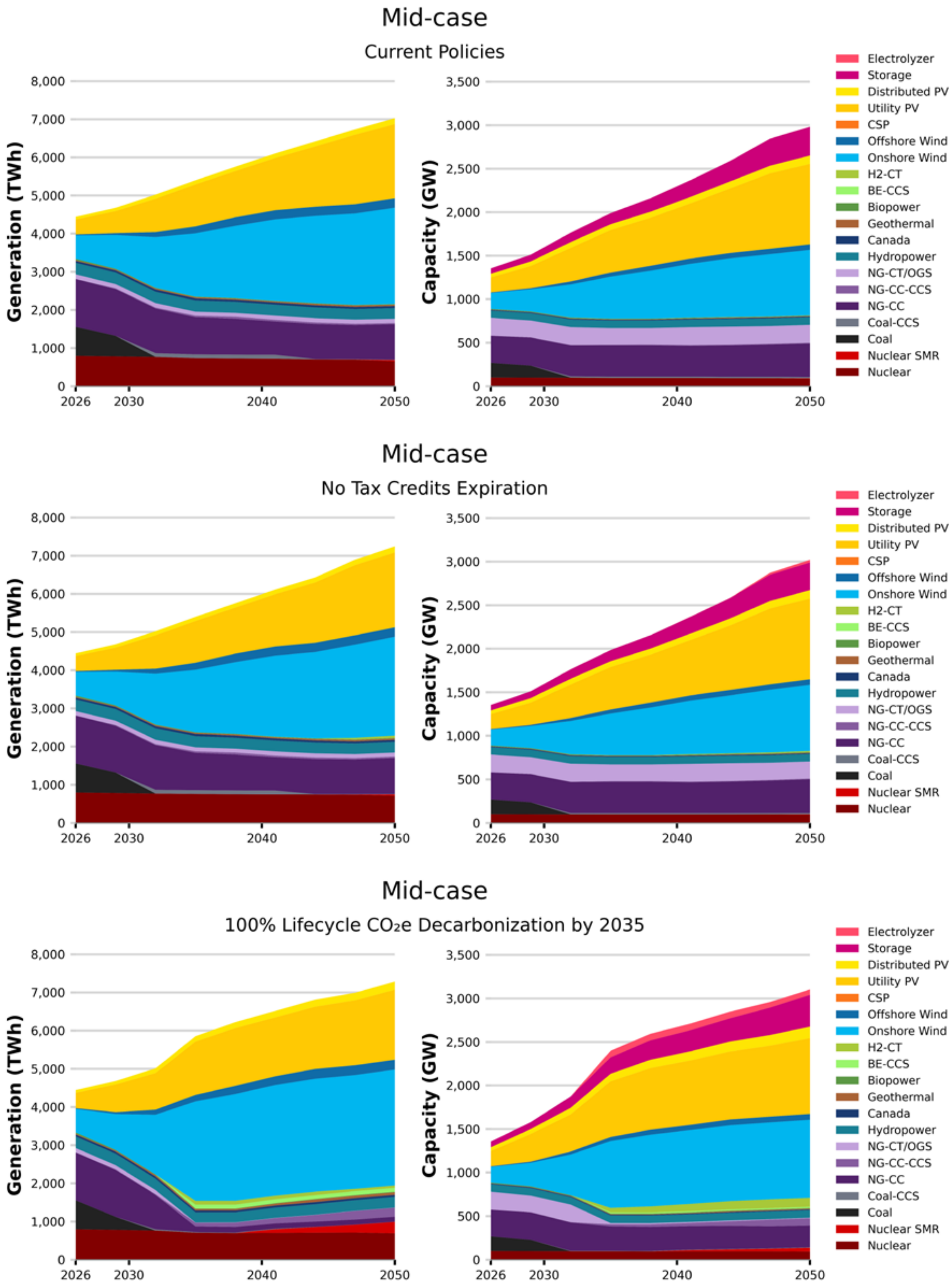


Figure A-10. Mid-case: Generation and capacity

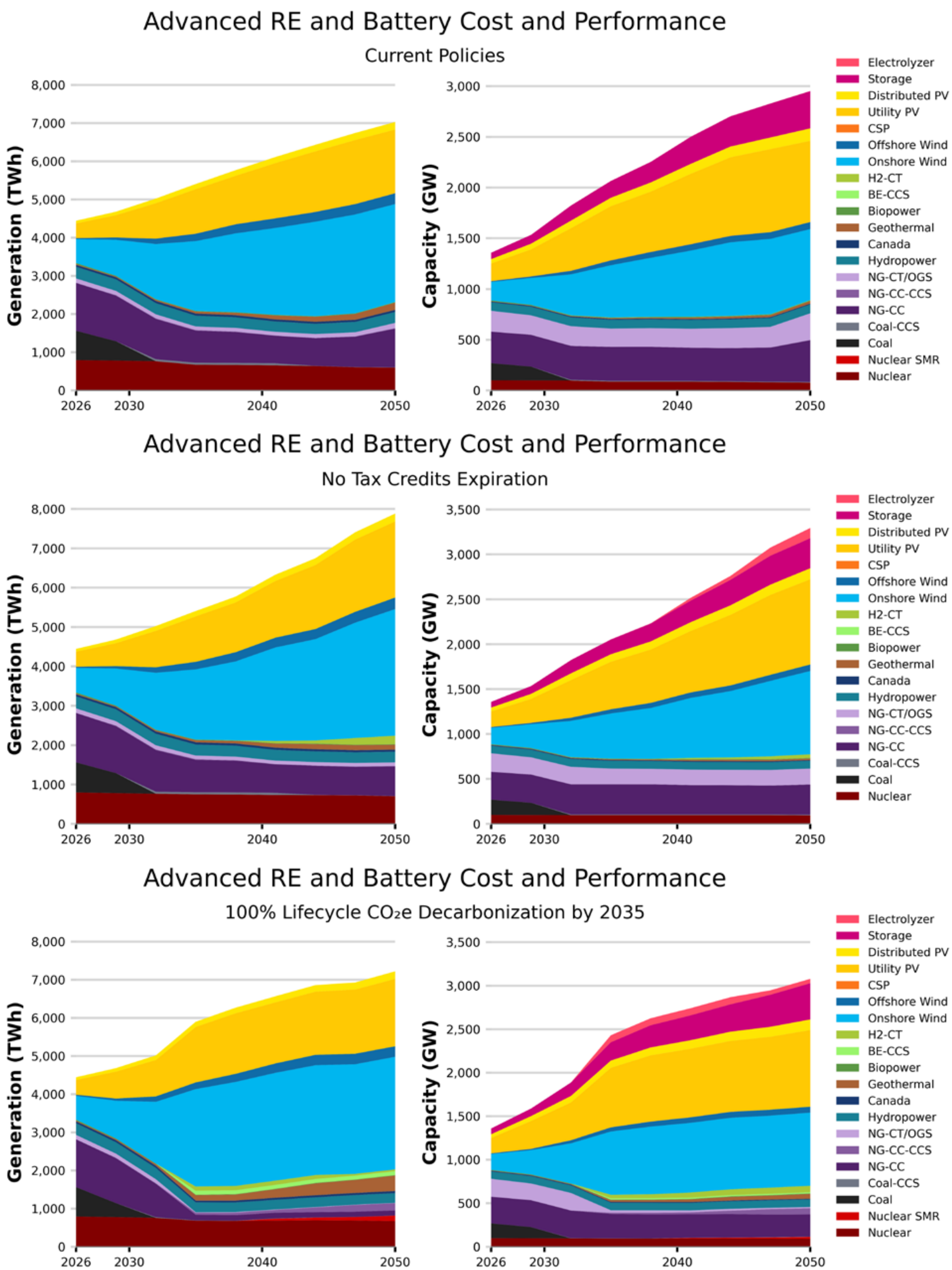


Figure A-11. Advanced Renewable Energy and Battery Costs and Performance: Generation and capacity

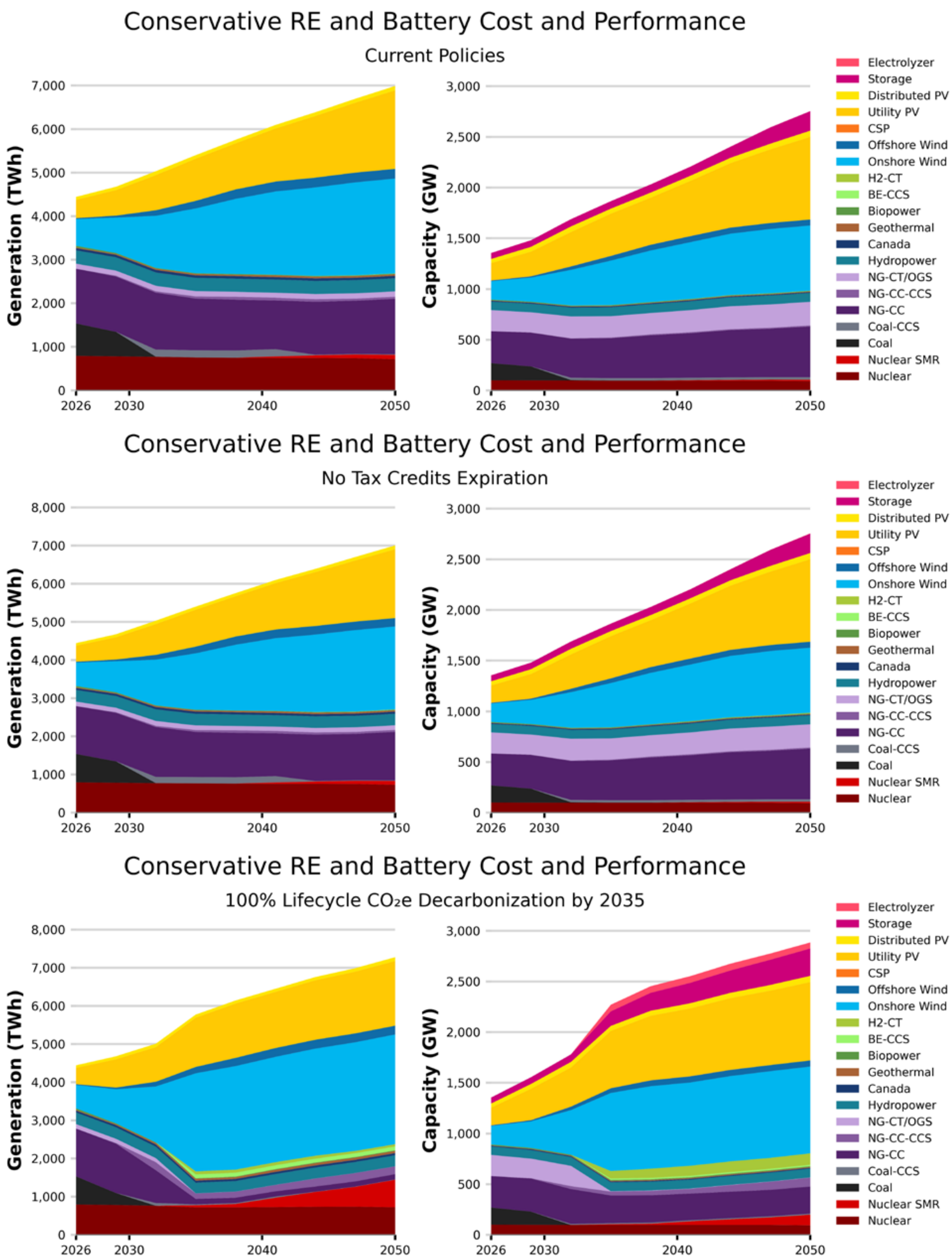


Figure A-12. Conservative Renewable Energy and Battery Costs and Performance: Generation and capacity

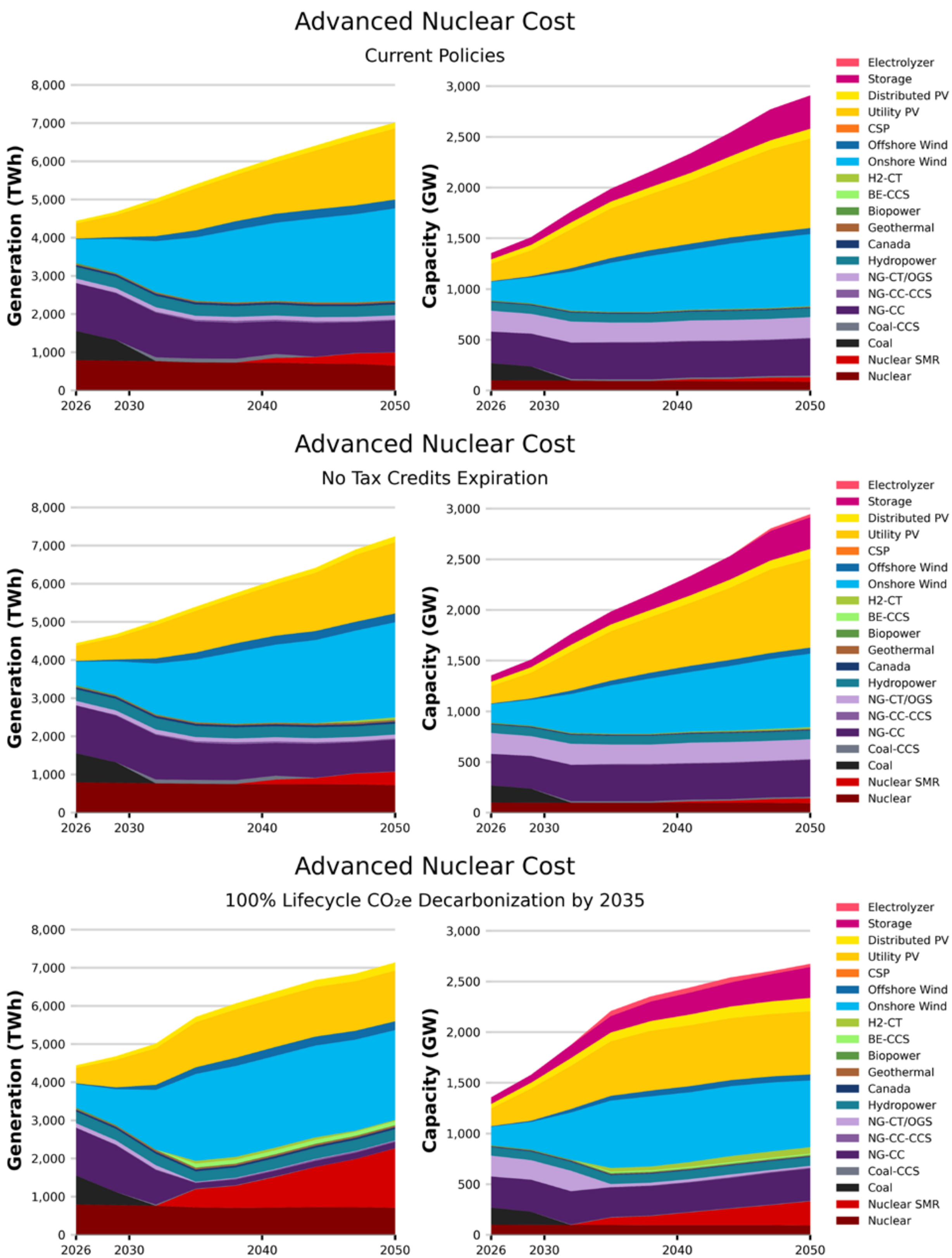


Figure A-13. Advanced Nuclear Cost: Generation and capacity

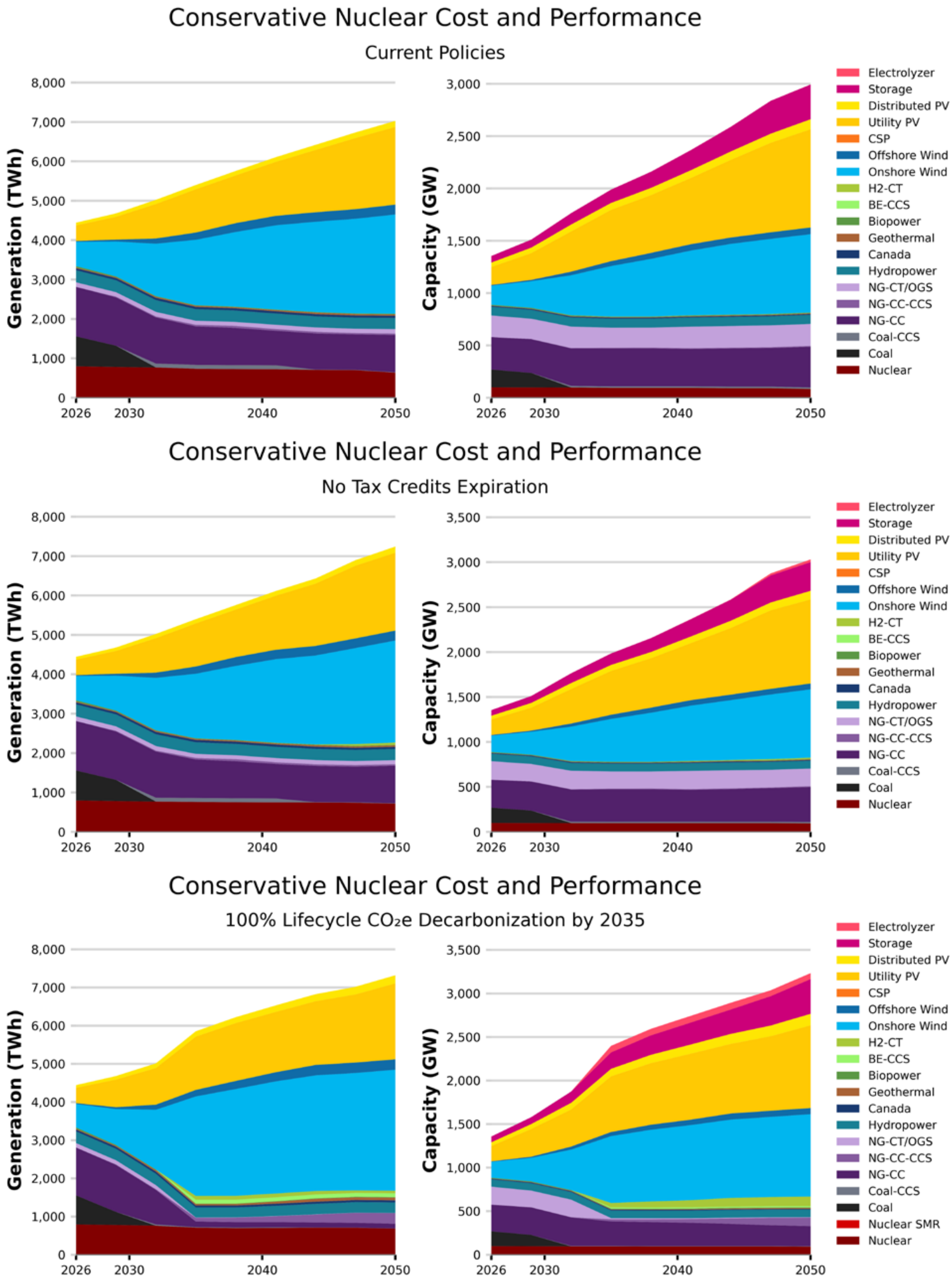


Figure A-14. Conservative Nuclear Cost: Generation and capacity

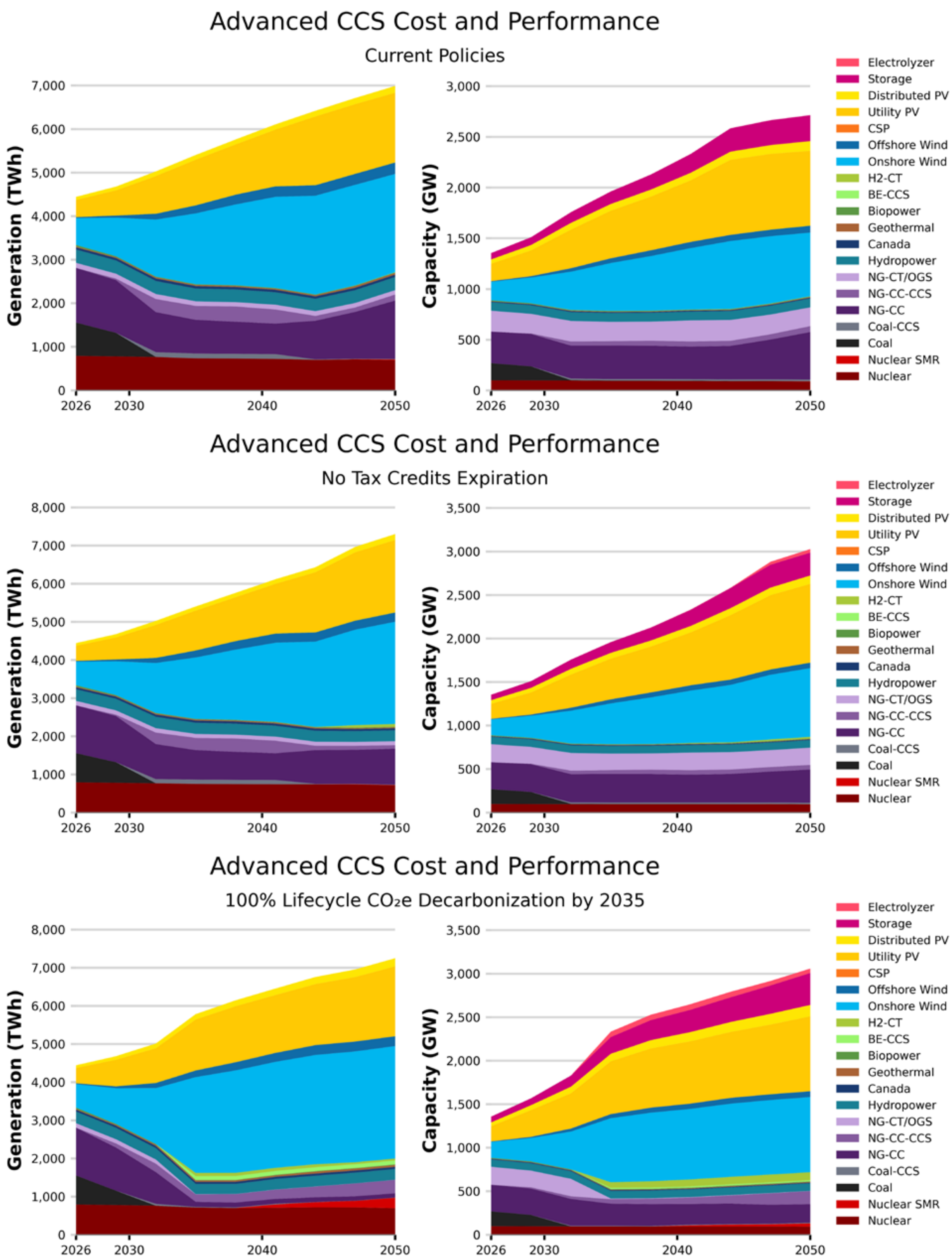


Figure A-15. Advanced CCS Cost and Performance: Generation and capacity

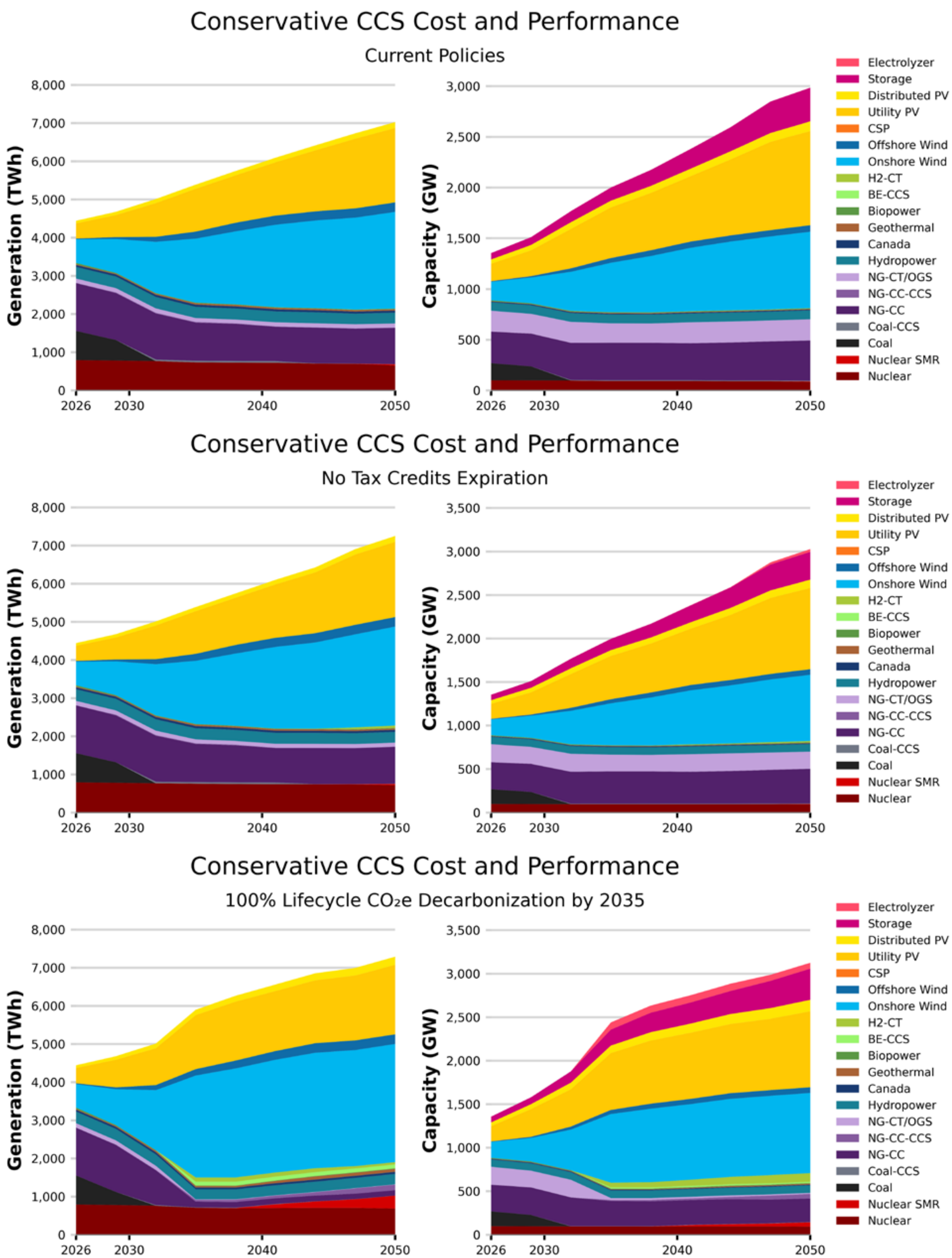


Figure A-16. Conservative CCS Cost and Performance: Generation and capacity

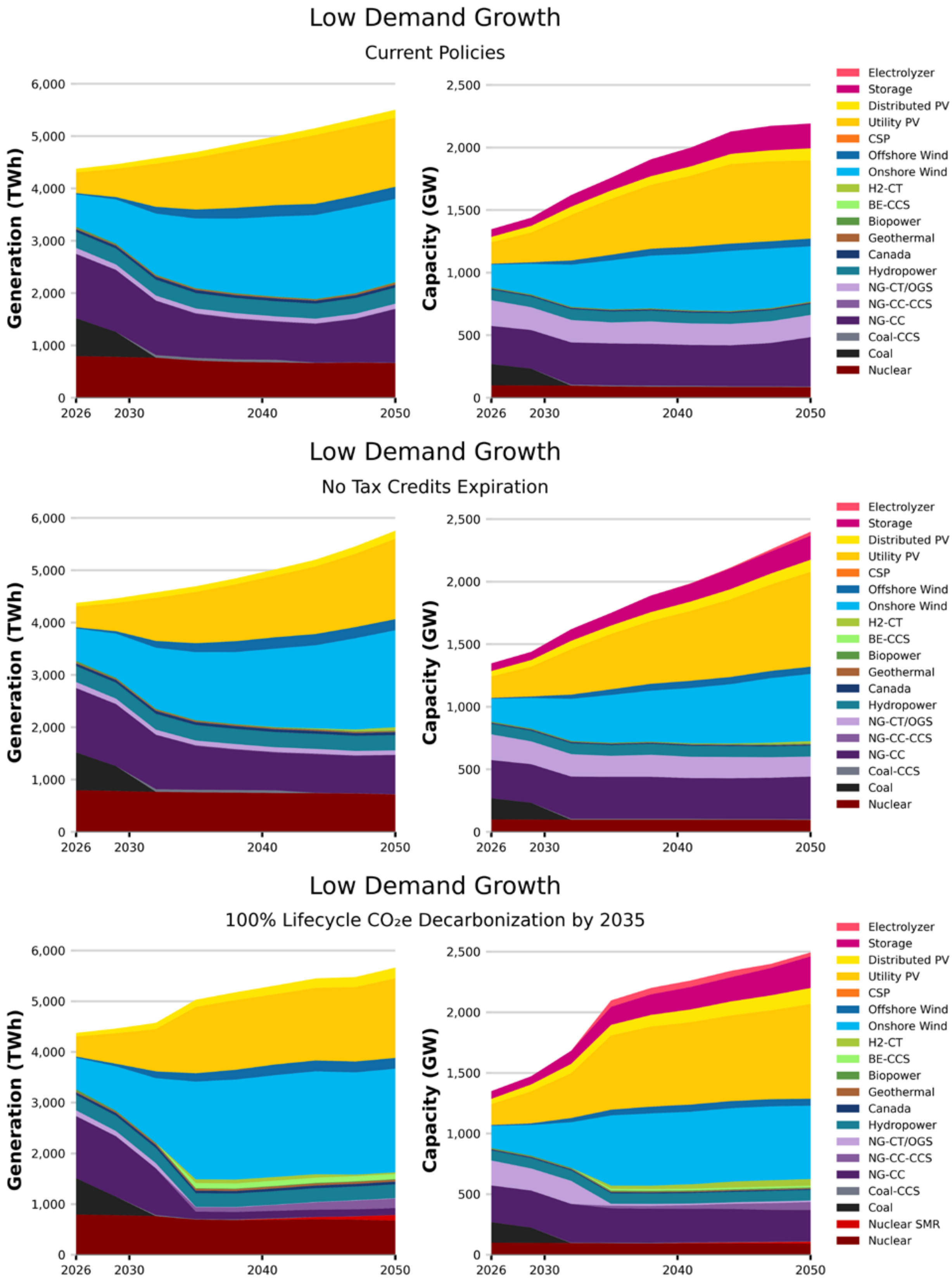


Figure A-17. Low Demand Growth: Generation and capacity

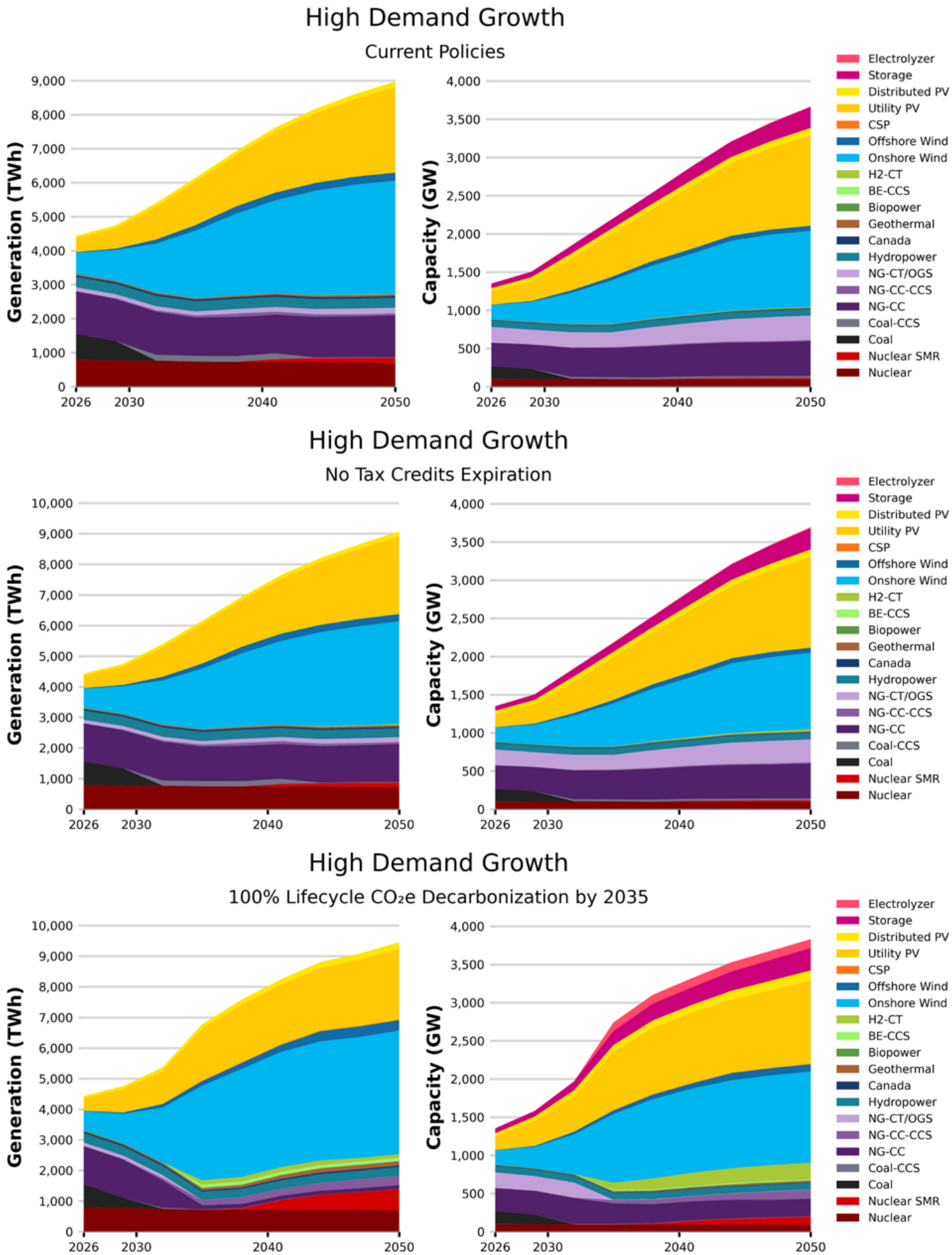


Figure A-18. High Demand Growth: Generation and capacity

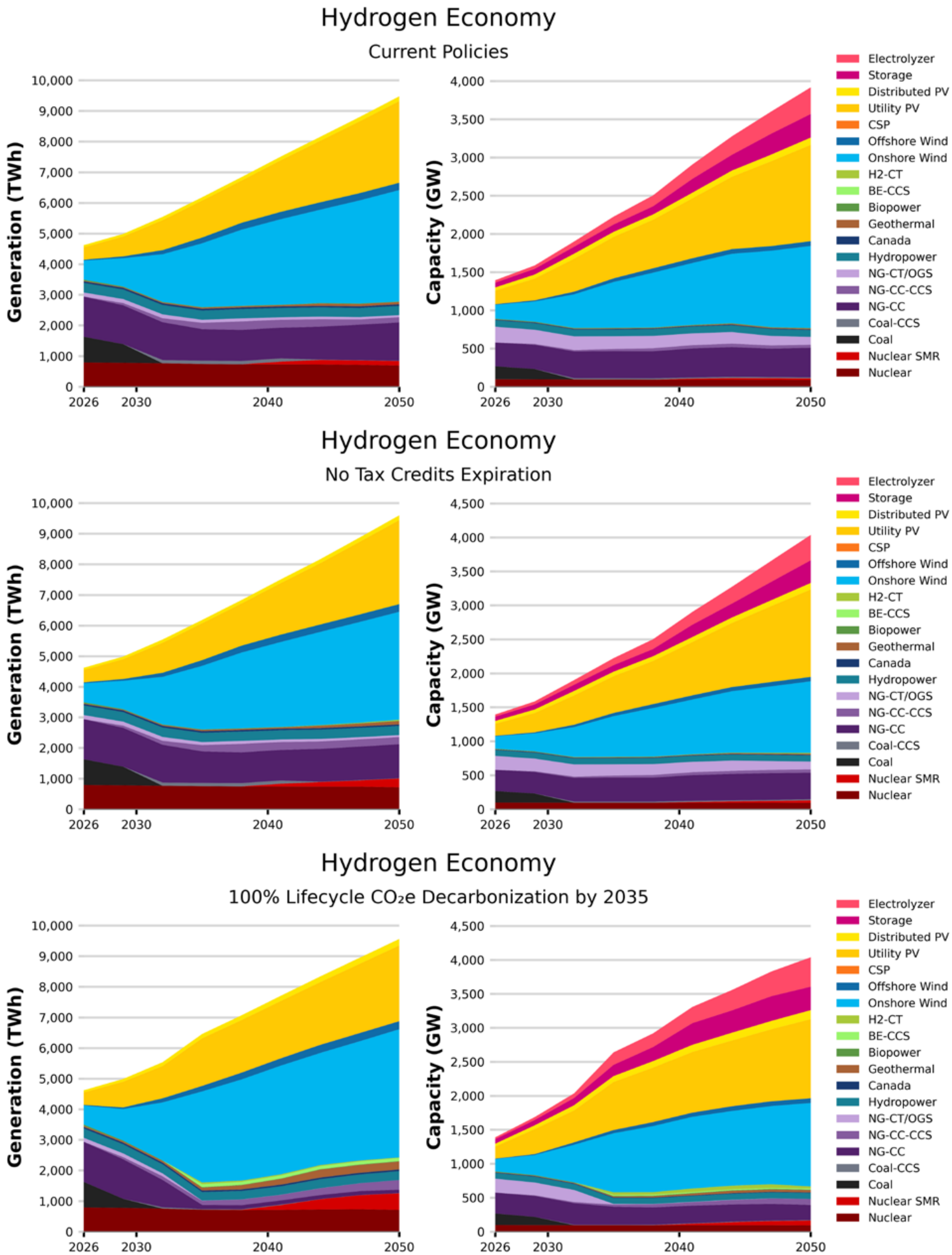


Figure A-19. Hydrogen Economy: Generation and capacity

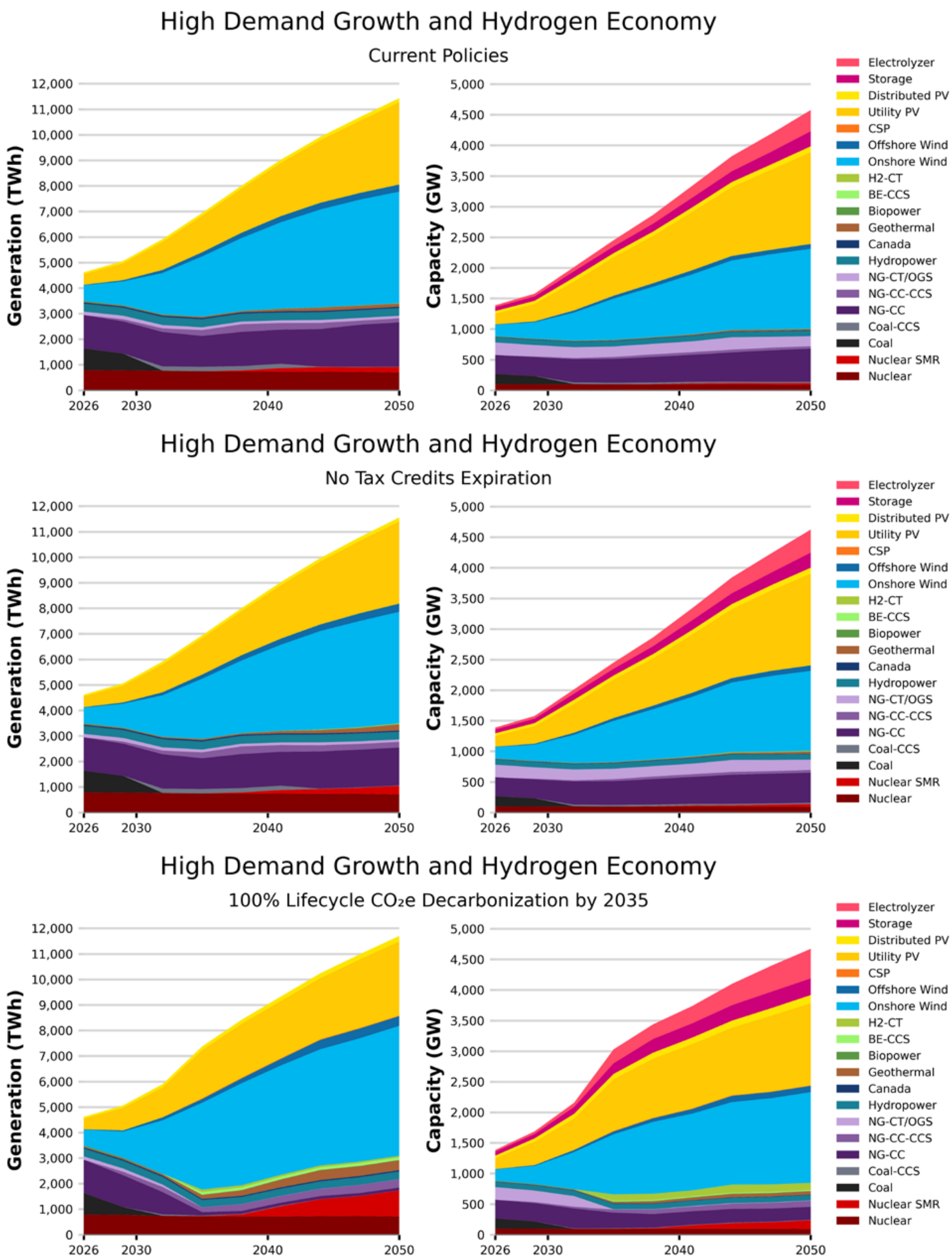


Figure A-20. High Demand Growth and Hydrogen Economy: Generation and capacity

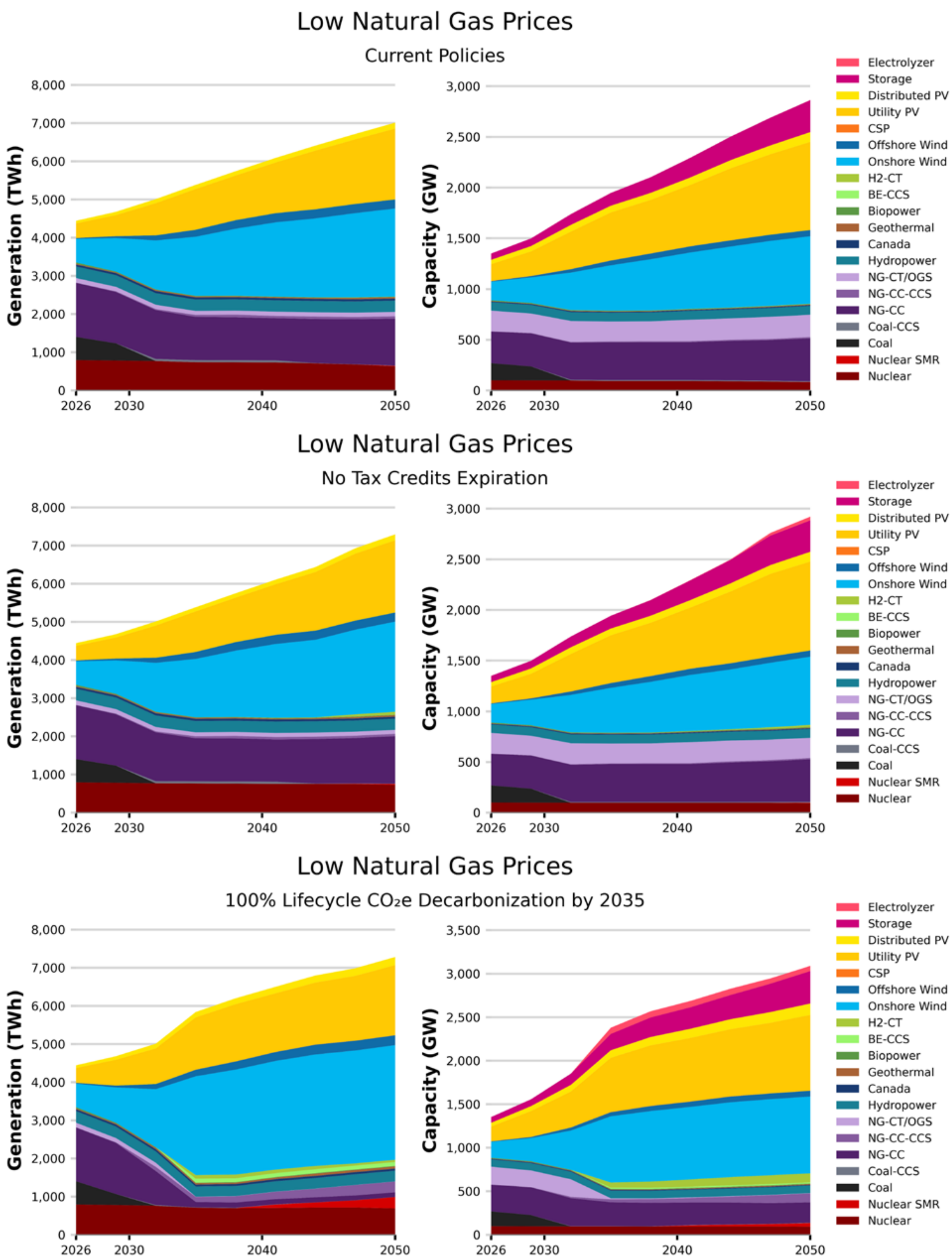


Figure A-21. Low Natural Gas Prices: Generation and capacity

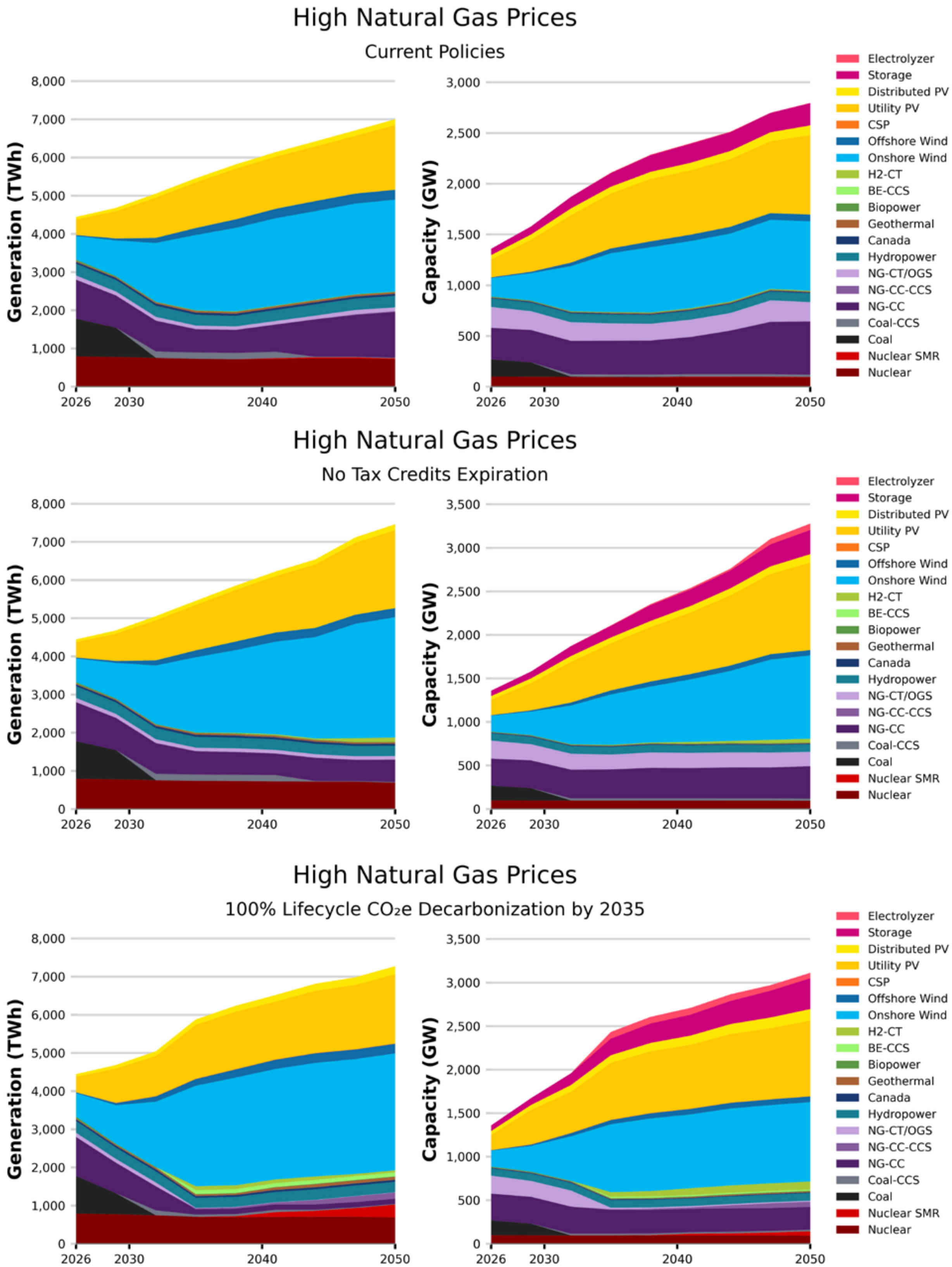


Figure A-22. High Natural Gas Prices: Generation and capacity

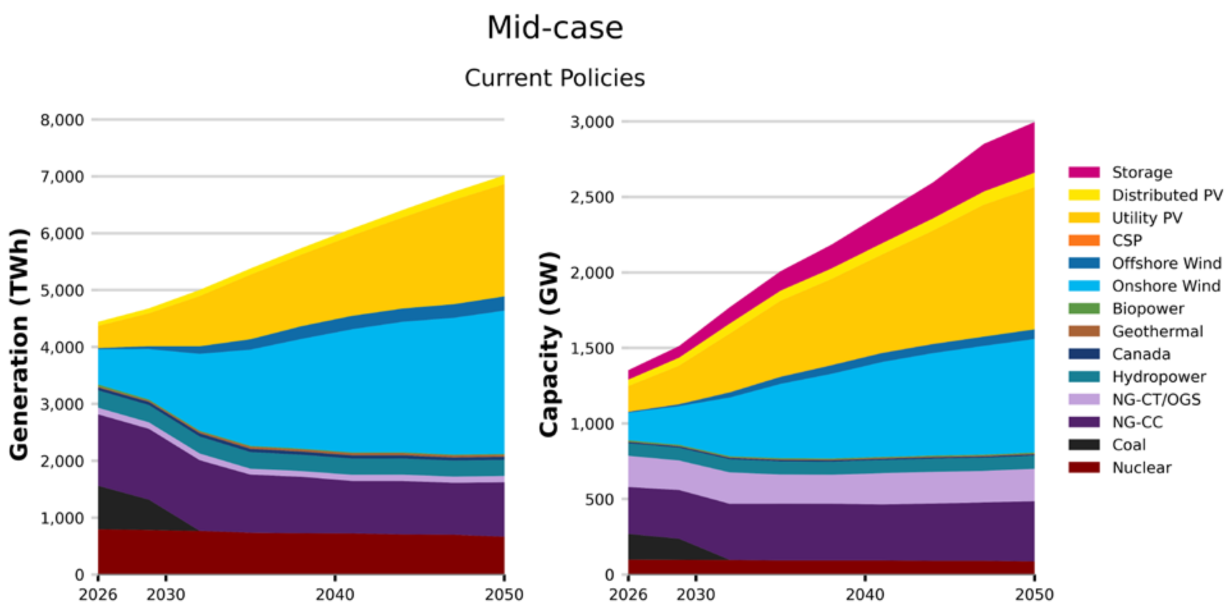


Figure A-23. No Nascent Technologies: Generation and capacity

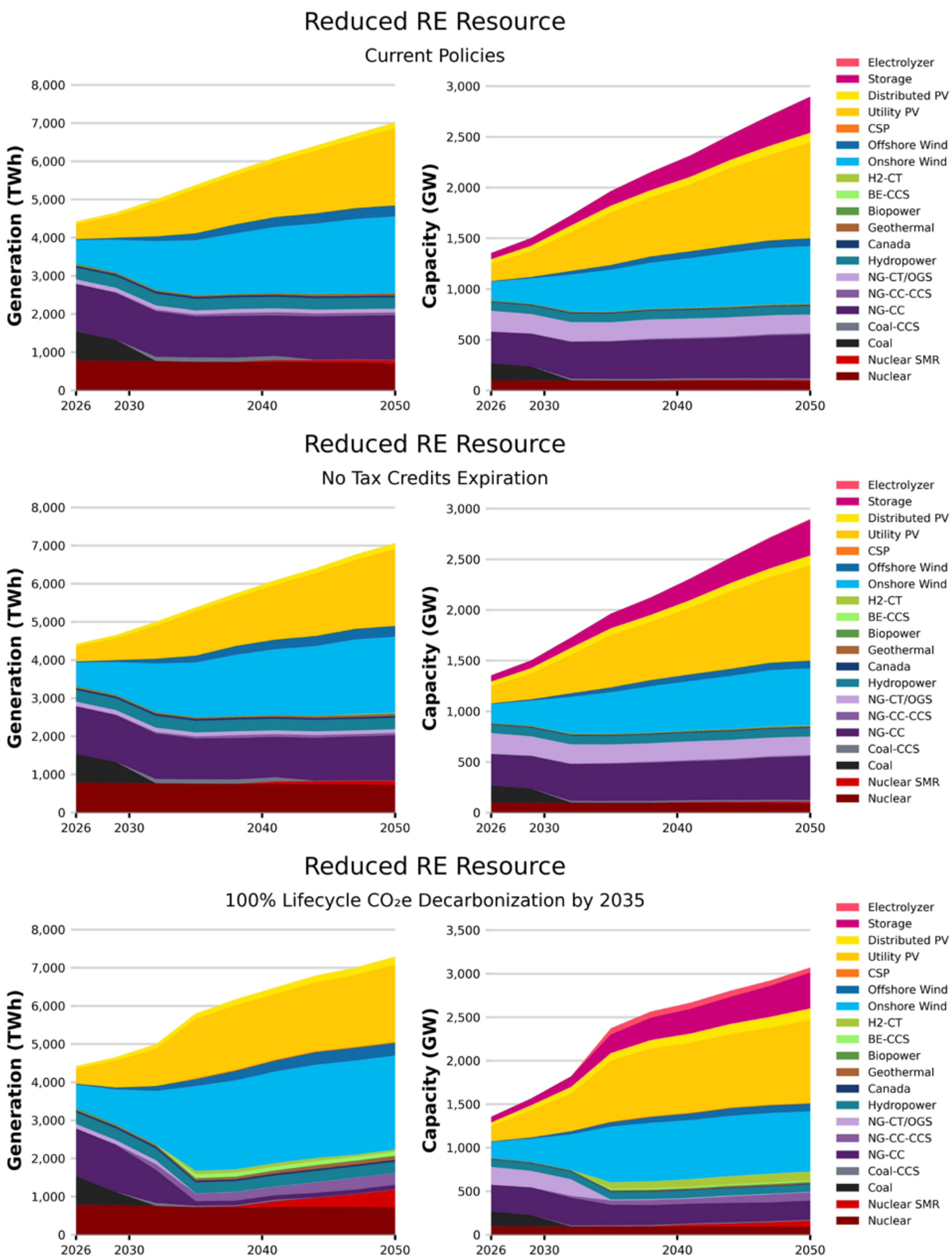


Figure A-24. Reduced Renewable Resources: Generation and capacity

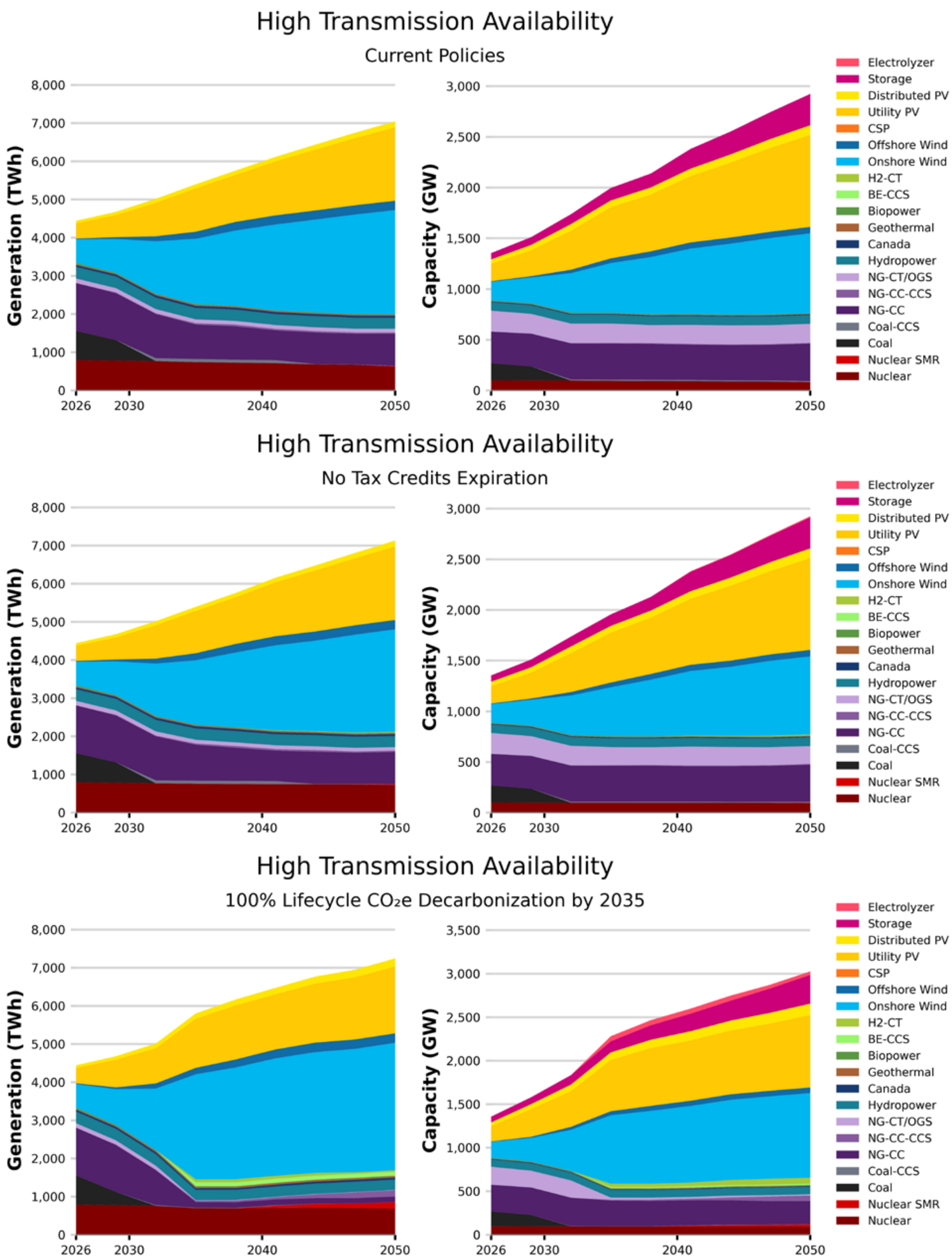


Figure A-25. High Transmission Availability: Generation and capacity

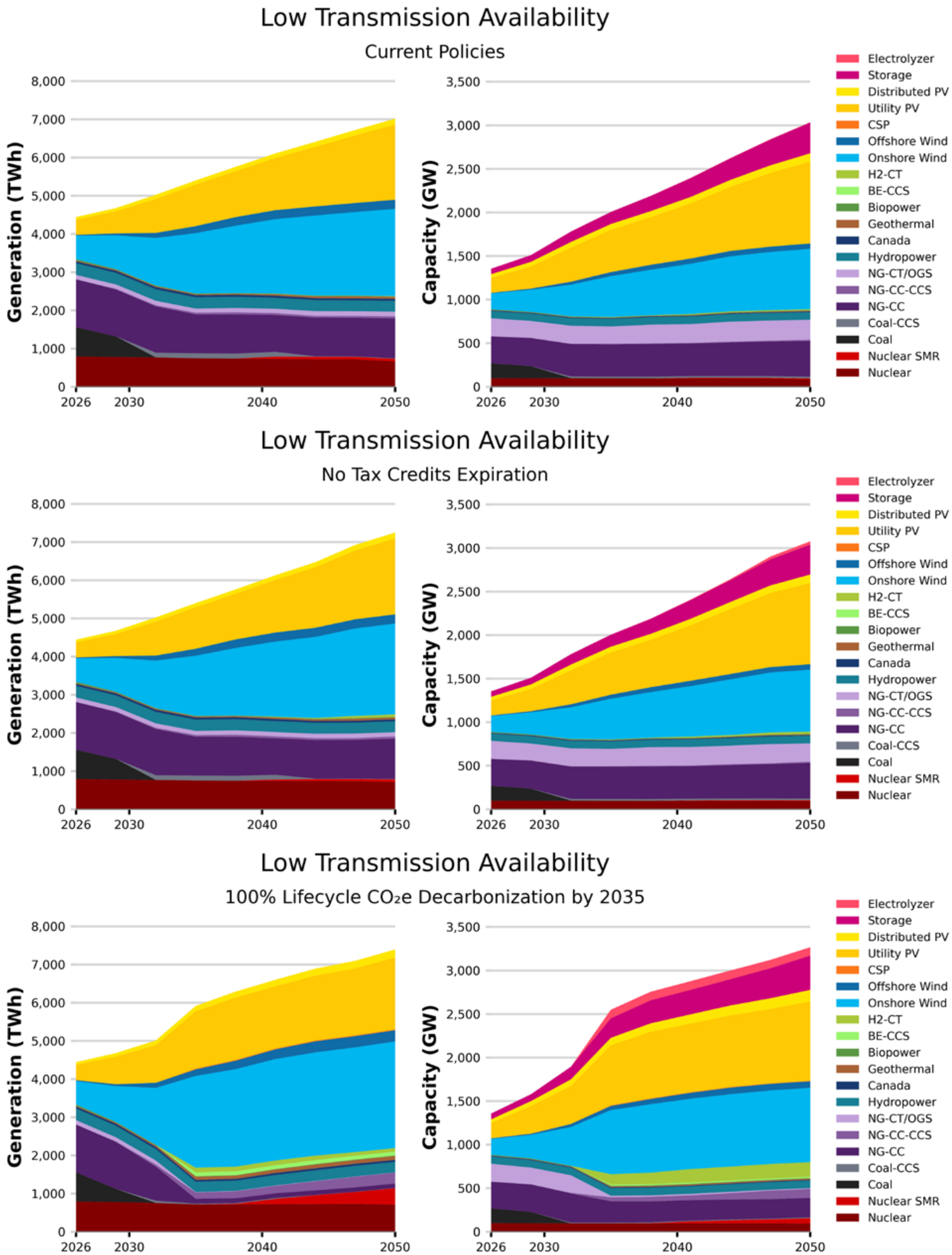


Figure A-26. Low Transmission Availability: Generation and capacity

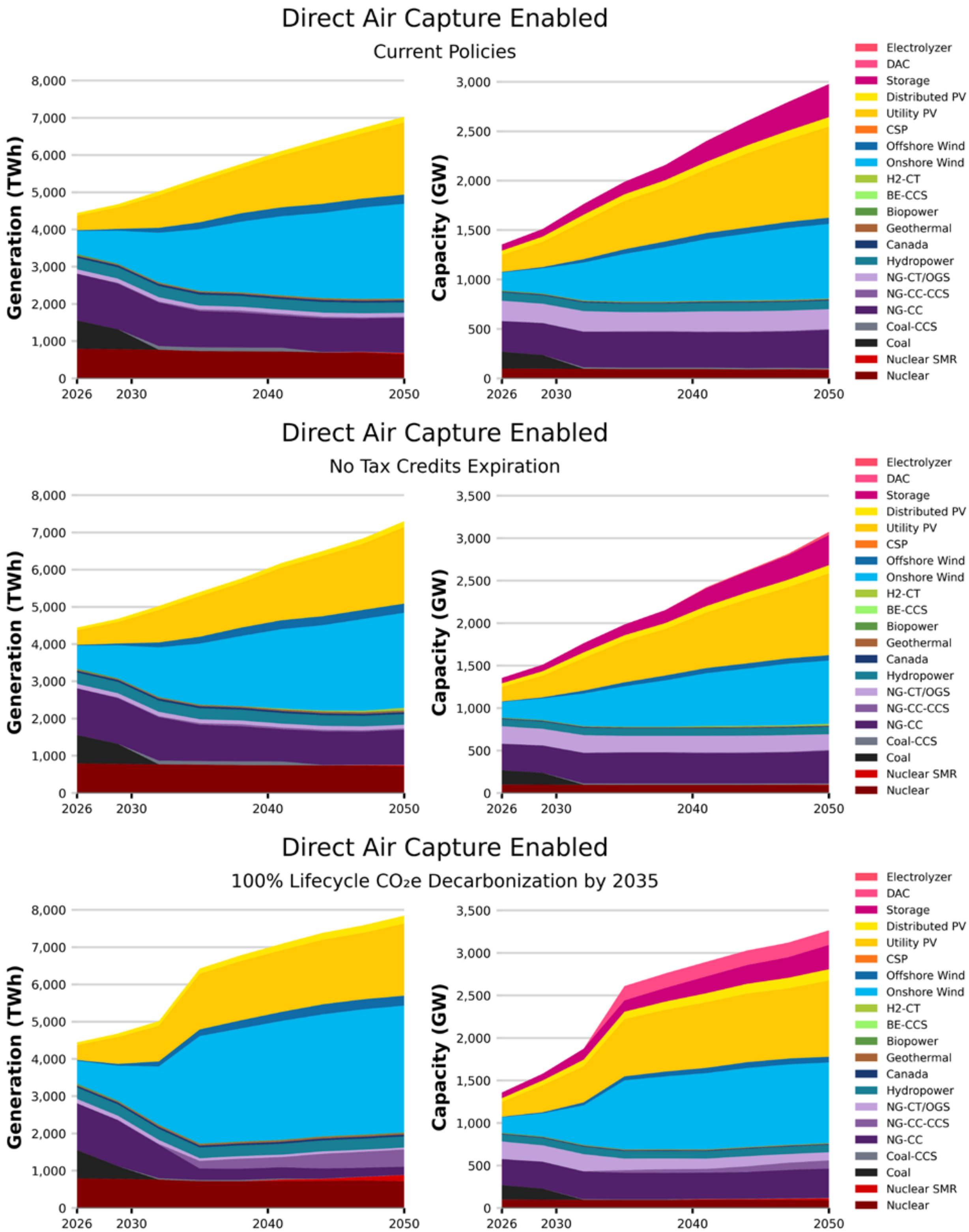
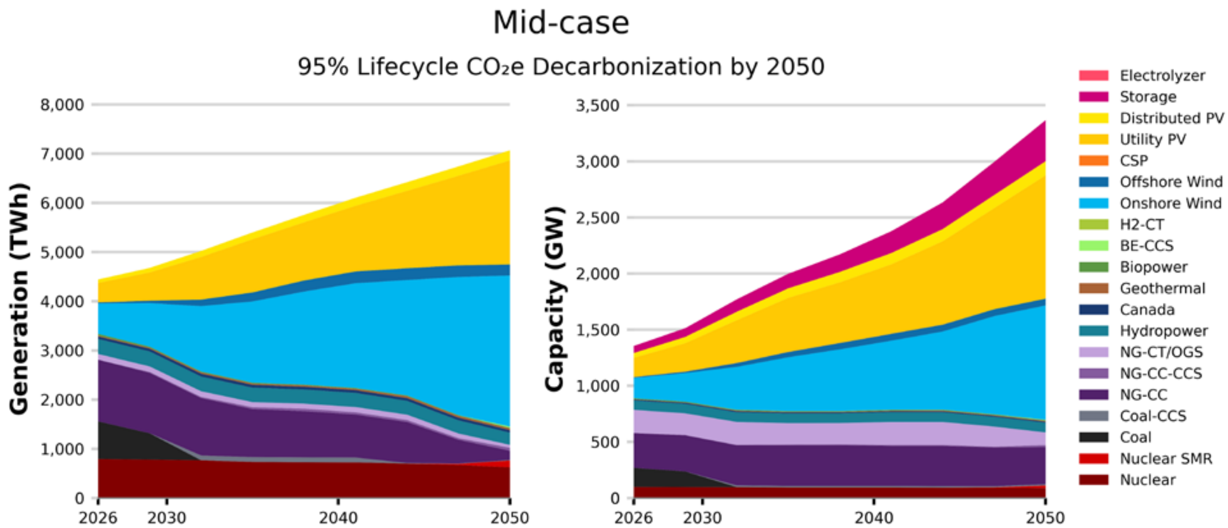
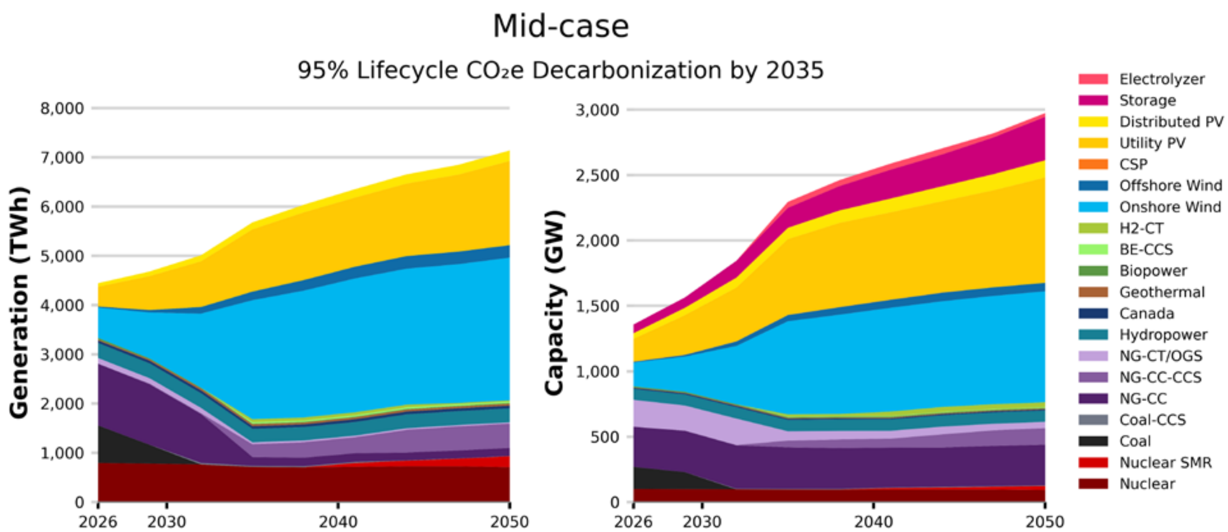
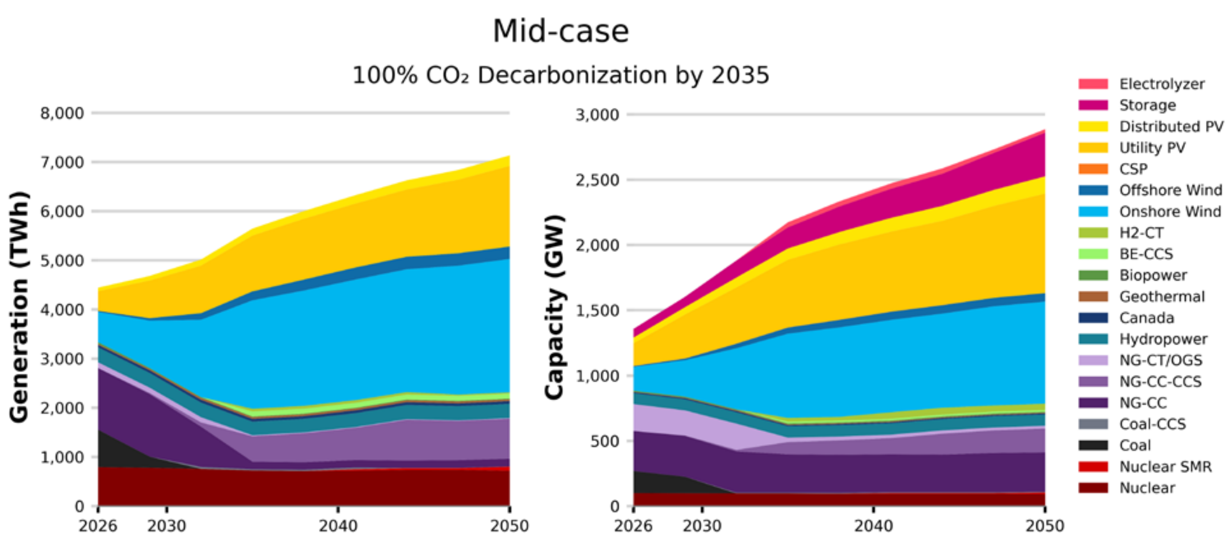


Figure A-27. Electricity-powered DAC: Generation and capacity


Mid-case
95% Lifecycle CO₂e Decarbonization by 2050
Generation (TWh)
Capacity (GW)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
500
1,500
2,500
3,500
2026
2030
2040
2050
Electrolyzer
Storage
Distributed PV
Utility PV
CSP
Offshore Wind
Onshore Wind
H2-CT
BE-CCS
Biopower
Geothermal
Canada
Hydropower
NG-CT/OGS
NG-CC-CCS
NG-CC
Coal-CCS
Coal
Nuclear SMR
Nuclear


Mid-case
95% Lifecycle CO₂e Decarbonization by 2035
Generation (TWh)
Capacity (GW)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
500
1,500
2,500
2026
2030
2040
2050
Electrolyzer
Storage
Distributed PV
Utility PV
CSP
Offshore Wind
Onshore Wind
H2-CT
BE-CCS
Biopower
Geothermal
Canada
Hydropower
NG-CT/OGS
NG-CC-CCS
NG-CC
Coal-CCS
Coal
Nuclear SMR
Nuclear


Mid-case
100% CO₂ Decarbonization by 2035
Generation (TWh)
Capacity (GW)
0
1,000
2,000
3,000
4,000
5,000
6,000
7,000
8,000
500
1,500
2,500
2026
2030
2040
2050
Electrolyzer
Storage
Distributed PV
Utility PV
CSP
Offshore Wind
Onshore Wind
H2-CT
BE-CCS
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NG-CT/OGS
NG-CC-CCS
NG-CC
Coal-CCS
Coal
Nuclear SMR
Nuclear

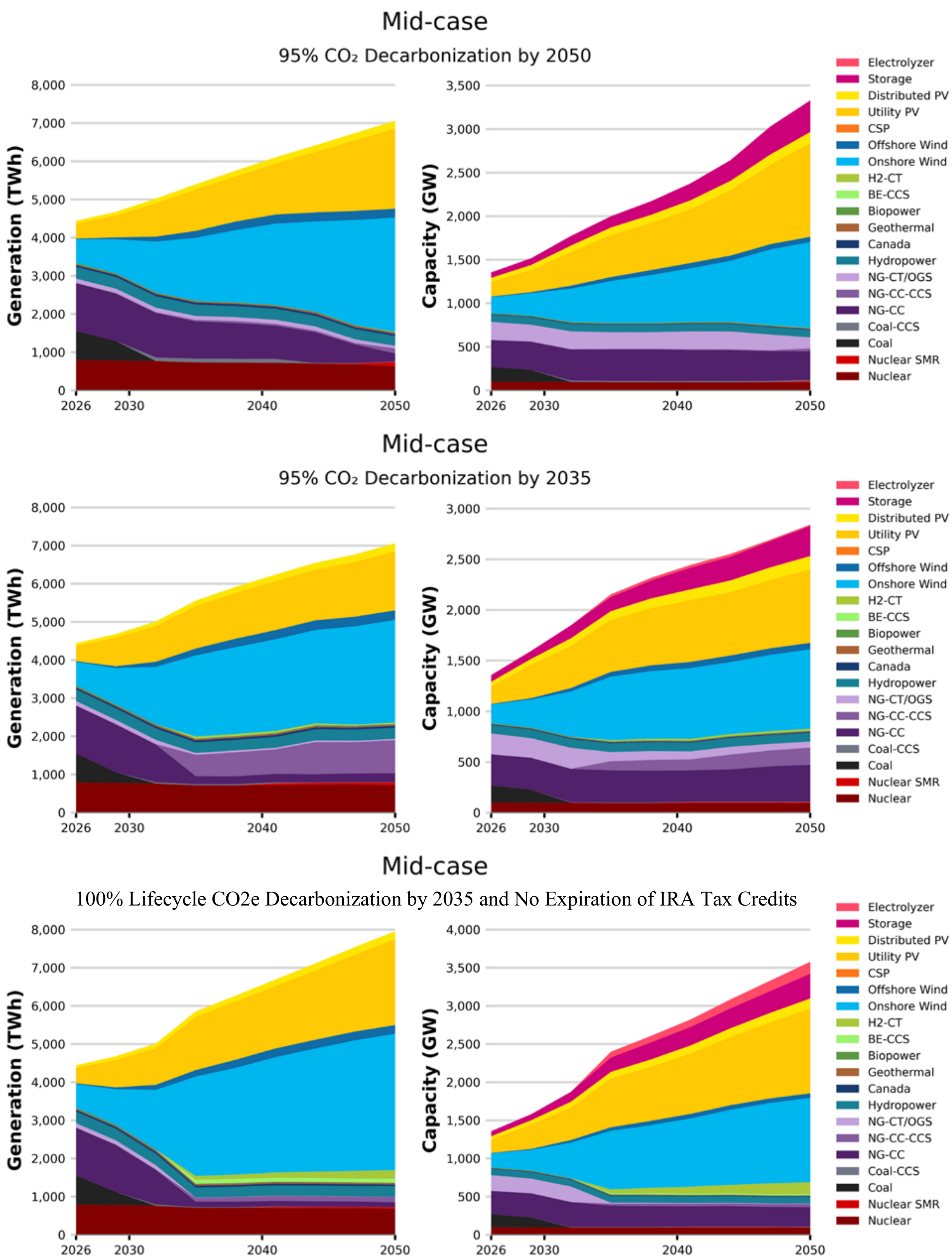

Figure A-28. Additional Decarbonization Sensitivities: Generation and capacity

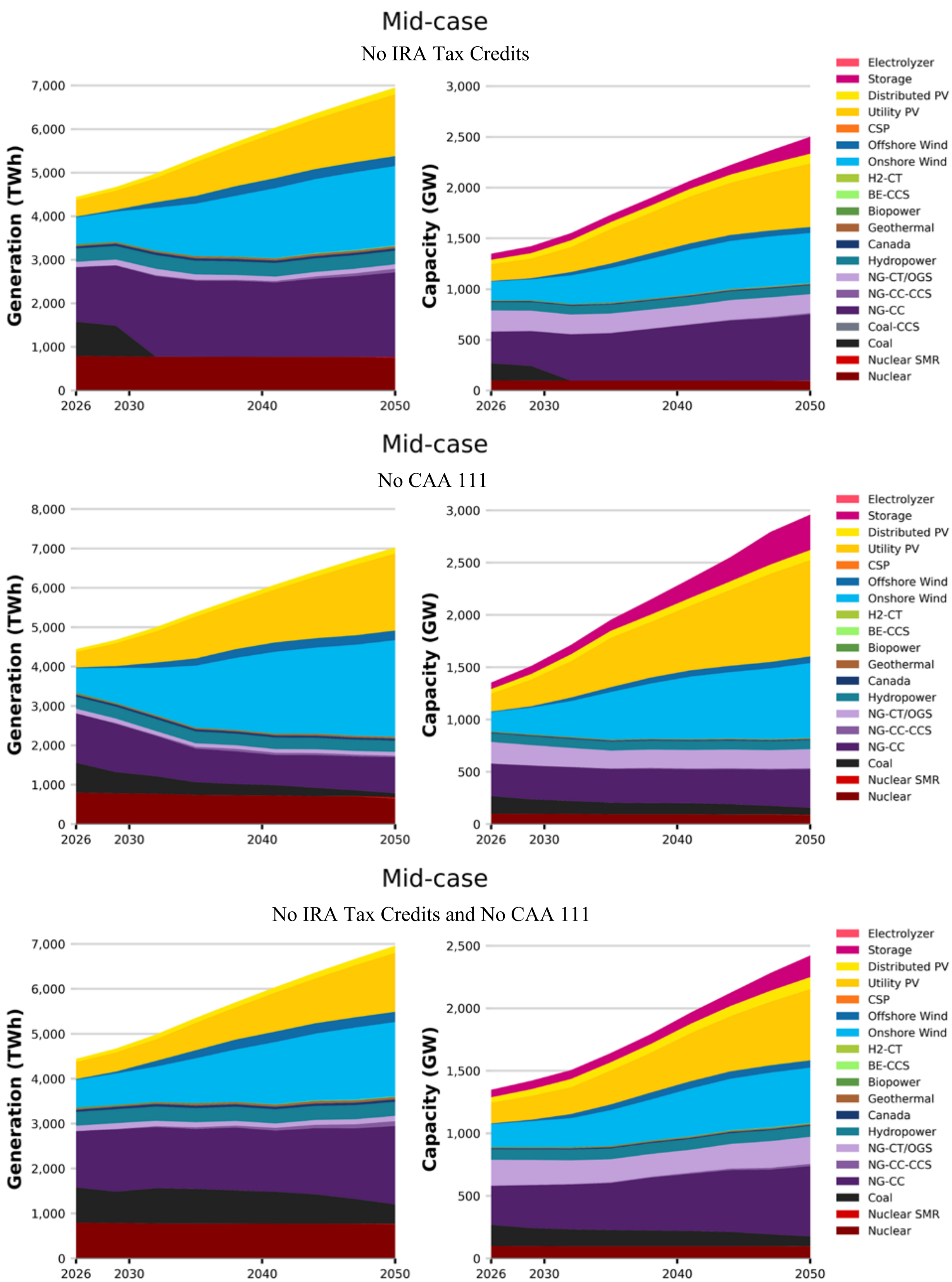

Figure A-29. Additional Policy Sensitivities: Generation and capacity