2023 Standard Scenarios Report: A U.S. Electricity Sector Outlook

Primary Authors: Pieter Gagnon, An Pham, Wesley Cole

Contributing Authors: Sarah Awara, Anne Barlas, Maxwell Brown, Patrick Brown, Vincent Carag, Stuart Cohen, Anne Hamilton, Jonathan Ho, Sarah Inskeep, Akash Karmakar, Luke Lavin, Anthony Lopez, Trieu Mai, Joseph Mowers, Matthew Mowers, Caitlin Murphy, Paul Pinchuk, Anna Schleifer, Brian Sergi, Daniel Steinberg, and Travis Williams

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Technical Report
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Revised January 2024

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Errata

This report, originally published in December 2023, has been revised in January 2024. There were three changes in the revision. First, Anthony Lopez was added as a contributing author, as he had been erroneously omitted in the original publication. Second, in appendix section A.1 the cost of upgrading a hydrogen combustion turbine from a natural gas turbine was erroneously reported as 20% when it should have been 33%. Lastly, appendix Figure A-8 was erroneously a duplication of the same figure from the Standard Scenarios 2022, it has now been updated to reflect this year’s data.

Preface

This report is one of a suite of National Renewable Energy Laboratory (NREL) products aiming 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 seeking to illuminate 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) 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:[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 scenario framework, report, and data set describing U.S. electricity sector futures
- The Cambium data sets, which contain a broader suite of metrics for a subset of scenarios from this report.

These products are built and applied to analyses to ensure (1) the analyses incorporate a transparent, realistic, and timely set of input assumptions and (2) they consider a diverse set of potential futures. The application of the Standard Scenarios, clear documentation of underlying assumptions, and model versioning is expected to result in:

- Improved transparency of modeling input assumptions and methodologies
- Improved comparability of results across studies
- Improved consideration of the potential economic and environmental impacts of various electricity sector futures
- An enhanced framework for formulating and addressing new analysis questions.

This report documents the ninth edition of the annual Standard Scenarios. Though many potential futures are included in this analysis, the set of scenarios is not exhaustive, nor is the analysis targeted at comprehensively understanding specific phenomena.[2]

[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).

[2] For a list of other NREL analyses that complement this effort, see "Future System Scenarios Analysis," https://www.nrel.gov/analysis/future-system-scenarios.html.

Acknowledgments

We gratefully acknowledge the many people whose efforts contributed to this report. We thank Adria Brooks, Juan Carvallo, Jaquelin Cochran, William Dean, Zachary Goff-Eldredge, Anna Hagstrom, Cara Marcy, Gian Porro, Mark Ruth, Paul Spitsen, and Ryan Wiser for their comments on a draft of this report, and Mike Meshek for editing this work. 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. Life Cycle Inventory Database
VSC	voltage source converter

Executive Summary

This report documents the ninth edition of the annual Standard Scenarios. It summarizes 53 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, which projects utility-scale electricity sector evolution for the contiguous United States using a system-wide, least-cost approach subject to policy and operational constraints. A subset of the scenarios are simulated in the PLEXOS production cost model to obtain a broader suite of metrics at the hourly resolution, which are made available through the National Renewable Energy Laboratory's (NREL's) annual Cambium[3] data sets.

The scenarios can be viewed and downloaded from NREL's Scenario Viewer.[4] Annual results are available for the full suite of scenarios in the *Standard Scenarios* projects in the viewer, whereas the *Cambium* projects contain hourly data for a subset of scenarios.

Relative to the 2022 edition, the most impactful changes are materially higher electricity demand projections (with many regions becoming winter-peaking), higher costs for interconnecting renewable generators to the grid, the introduction of growth penalties, the inclusion of electricity-produced hydrogen, as well as the general updating of fuel and technology cost projections.

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, end-use electricity demand growth averaging 1.8% per year, and both state and federal (but not local) electricity sector policies as they existed in September 2023. 17 sensitivities are then created by varying key inputs such as technology and fuel prices, resource availability, demand growth, and the availability of nascent technologies. Lastly, all scenarios are modeled under current policies, as well as under two national electricity sector CO_2 emissions constraints: one that reach 95% net decarbonization by 2050 and another that reaches 100% net decarbonization by 2035.

We highlight seven observations from this year's scenarios:

1. *Wind and solar grow significantly, making up the majority of new capacity*. By 2050 wind deployment reaches 770 GW and solar deployment reaches 1,090 GW (5× and 10× increases over current levels respectively) in the Mid-case. Across all scenarios combined wind and solar generation contributes between 55% and 85% of total generation in 2050.
2. *Natural gas capacity continues to expand*. In the Mid-case with current policies, natural gas capacity increases by 200 GW through 2050, whereas it increases by 130 GW in the Mid-case with 95% net decarbonization imposed.
3. *In later years, fossil generators without carbon capture play a reduced role in providing generation, but a larger role in providing firm capacity.* By 2050, uncontrolled fossil generators (natural gas, coal, and oil without carbon capture and storage) provide only

[3] "Cambium," NREL, https://www.nrel.gov/analysis/cambium.html.
[4] Scenario Viewer-Data Downloader," NREL, https://scenarioviewer.nrel.gov/.

14% of total generation in the Mid-case (1% through 24% across all scenarios), but 47% of total firm capacity (16% through 56% across all scenarios).

4. *Currently-nascent technologies play a limited role under current policies, and a larger role in decarbonized futures.*[5] Currently-nascent technologies (natural gas with carbon capture and storage (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 only reaches a maximum of 1% of total annual generation and 3% of firm capacity under current policies. The contribution of nascent technologies can be much greater in scenarios with breakthrough cost and performance improvements or with national electricity sector CO_2 emissions constraints, where they reach a contribution of 22% of total generation and 35% of firm capacity.
5. *U.S. electricity sector emissions decrease significantly through the 2030s*. Relative to 2005, annual U.S. national electricity sector CO_2 emissions in 2035 are reduced by 81% in the Mid-case and 71%–86% across all scenarios with current policies (a range of 52% to 77% reduction relative to emissions in 2022).
6. *Clean electricity tax credits persist through 2050 for most scenarios without decarbonization policies*. The clean electricity tax credits in the Inflation Reduction Act of 2022 (IRA) are scheduled to phase out either at the end of 2032 or when national electricity sector greenhouse gas emissions drop below 25% of the level in 2022, whichever occurs later. In 13 of 17 scenarios with current policies, including the Mid-case, that emissions threshold is never passed, and the clean electricity tax credits correspondingly persist.
7. *In the Mid-case, 95% net decarbonization by 2050 is achieved with a 0.5% increase in the present-value bulk electric sector costs. 100% net decarbonization by 2035 increases costs by 14%.*

To illustrate some of these trends, we show in Figure ES-1 the generation and capacity projections for three scenarios. One scenario is the Mid-case mentioned previously, and the other two share the same core assumptions as the Mid-case but with national electricity sector CO_2 emissions constraints that reach 95% net decarbonization by 2050 and 100% net decarbonization by 2035 (both relative to 2005 CO_2 emissions):

[5] 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.

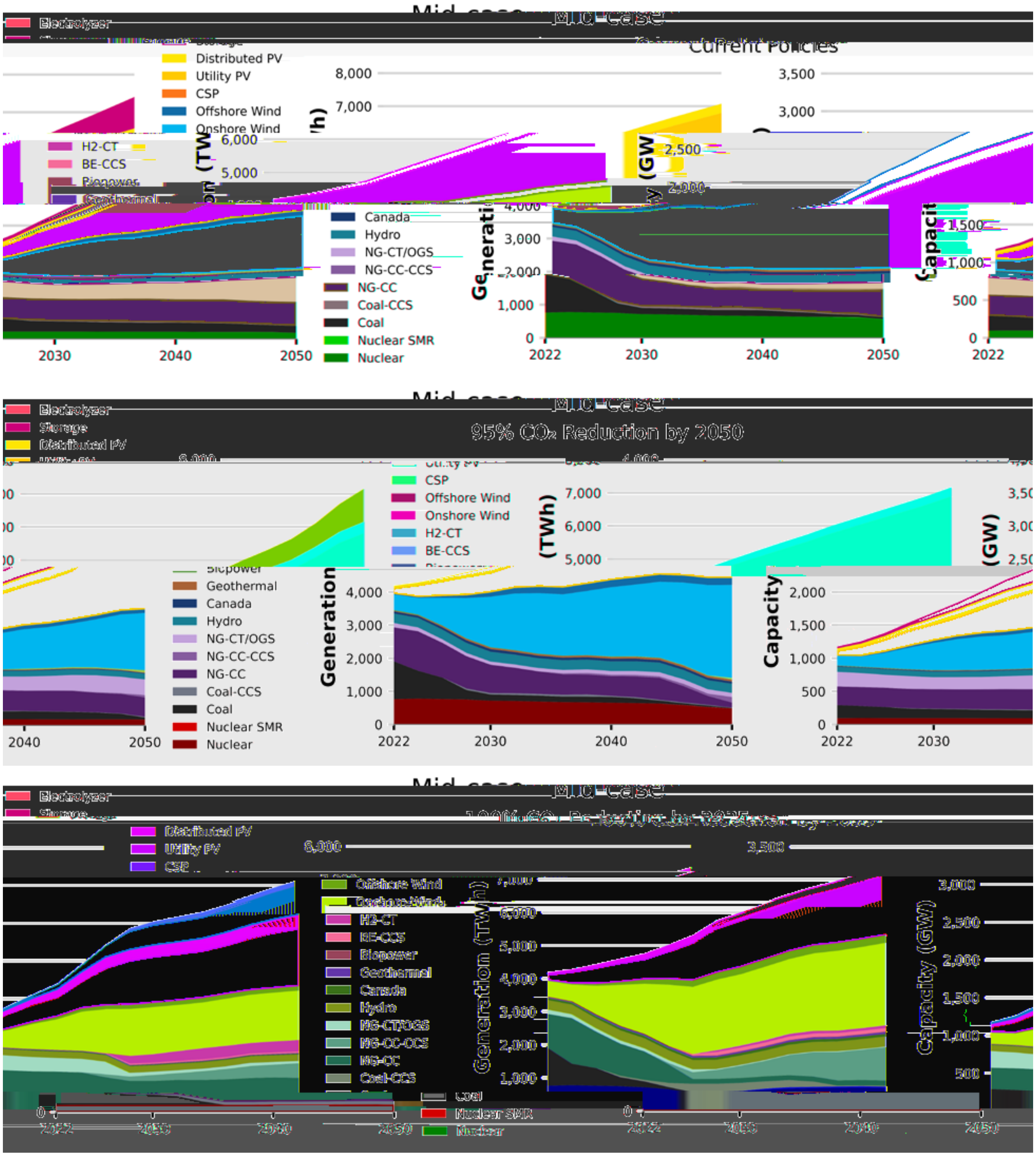

Figure ES-1. U.S. electricity sector generation (left) and capacity (right) over time for the three Mid-case scenarios

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, Canada is imported energy from Canada, 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.

As mentioned above, the Standard Scenarios include 17 sensitivity scenarios that vary factors such as fuel prices, demand growth, technology costs, resource availability, and transmission conditions. Each sensitivity is performed for the three combinations of CO_2 emission limits that are shown in Figure ES-1.

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. The maximum wind and solar generation is materially higher than in the 2022 edition—reaching 4000 TWh/year for solar and 5600 TWh/year for wind, compared to last year's maximums of 3000 TWh/year for both. This is driven by scenarios with materially higher electricity demand, due to both electrification and the introduction of hydrogen production. Throughout the suite of results, demand 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.

Nuclear generation can vary slightly due to the ordering of curtailment in the presence of zero-marginal-cost renewable generators, and it sees some retirements in later years in many scenarios as well as some investment in small modular reactors in the later years of some net 100% decarbonization scenarios, but overall, nuclear generation remains fairly constant across scenarios compared to other technologies. Hydropower and geothermal also have relatively constant contributions, although geothermal does see greater deployment in scenarios with lower-cost, higher-performing geothermal assumptions.

Generation from natural gas without CCS declines slightly through the mid-2030s, but in scenarios without national CO_2 emissions constraints, it often rebounds to near present-day levels or greater (while being lower in fractional terms, due to demand growth). Coal without CCS declines significantly through the remainder of the 2020s, although it still persists at low levels through 2050 in the scenarios without national CO_2 emissions constraints. CCS technologies see their greatest deployment in scenarios with national CO_2 emissions constraints, although the IRA tax credits for capturing and storing CO_2 still induce a small amount of CCS in the scenarios without emissions constraints.

Despite many scenarios containing 100% net decarbonization trajectories, all scenarios have at least some generation from fossil generators. This is enabled by deploying bioenergy with CCS, which is represented as a negative emissions technology in this modeling. Using bioenergy with CCS 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 in net 100% decarbonization scenarios as lower-cost than replacing them entirely with non-emitting resources. Hydrogen combustion turbines also have their greatest contribution, as a firm capacity resource, in scenarios with net 100% decarbonization.

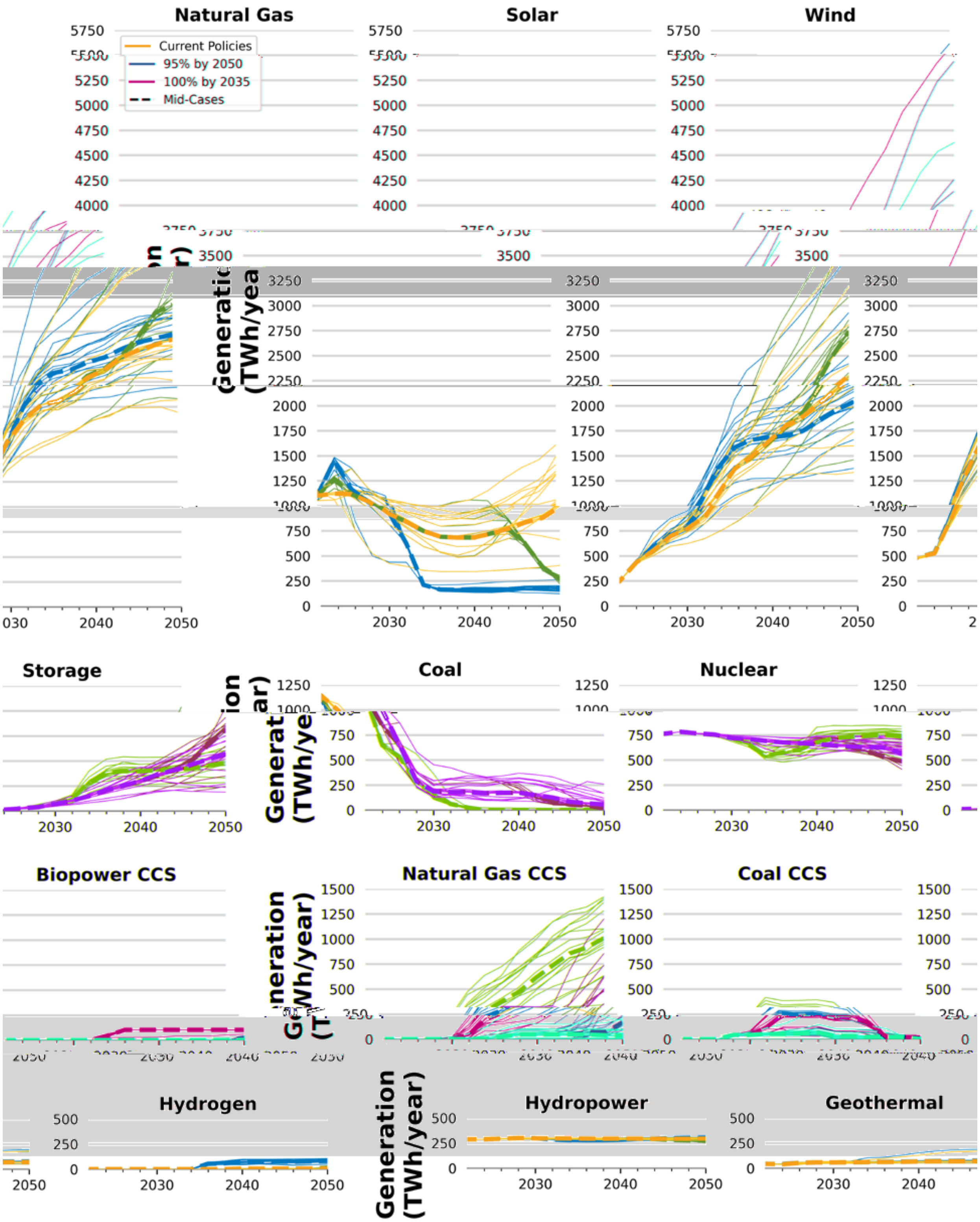

Figure ES-2. Generation across the suite of Standard Scenarios by fuel type.

The Mid-case scenarios are shown with the heavier dashed lines. 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. 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_2-equivalent (CO_2e) emissions from electricity sector fuel combustion (less any CO_2 captured and stored with carbon removal technologies) for the full suite of scenarios. Note that Figure ES-3 shows only greenhouse gas emissions for the electricity sector—as some of the sensitivities implicitly vary greenhouse gas emissions beyond the electricity sector, the trends in economy-wide greenhouse gas emissions may differ. For example, scenarios with greater electrification may have higher electricity sector emissions but lower economy-wide emissions. As the model used for this study does not represent economy-wide emissions, such results are not characterized in this report.

As mentioned above, most scenarios with current policies do not pass IRA's emission threshold, which is set at 25% of 2022 greenhouse gas emissions, as shown in Figure ES-3 as the red dotted line; therefore, the renewable energy tax credits persist through 2050. In the scenarios where the threshold is passed, the tax credits phase out, and if there is no national CO_2 emissions constraint, there can be a rebound in electricity sector CO_2e emissions.[6] This result differs from the 2022 Standard Scenarios, where the IRA threshold was typically passed in the scenarios with current policies (resulting in an emissions rebound). The difference is driven primarily by greater demand growth as well as higher costs of connecting renewable generators to the electric grid.

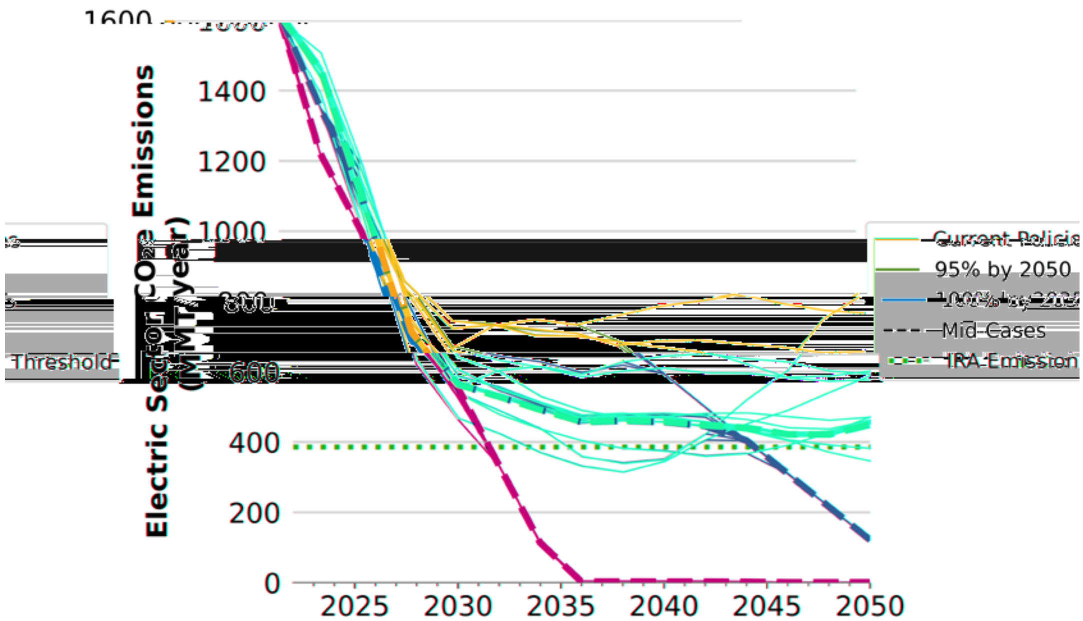

Figure ES-3. Electricity sector CO_2e emissions for the full suite of Standard Scenarios

[6] 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, which both push back the date at which generators could come online while still receiving a tax credit.

The Mid-case scenarios are shown with the heavier dashed lines. Emissions are only CO_2e emissions from direct combustion of fuel (i.e., stack emissions) less carbon captured by carbon removal technologies. The greenhouse gas emissions included here are CO_2, CH_4, and N_2O, combined using 100-year global warming potentials. The emissions do not include other pre- or post-combustion emissions. 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 CO_2e in this modeling.

Figure ES-4 shows the present-value costs of the bulk electricity sector across the suite of scenarios, using a social discount rate of 1.7% (OMB 2023).[7] Note that the values reported here are materially higher than in prior Standard Scenarios—the differences are caused by a number of factors, such as the inclusion of new cost categories into the ReEDS model, a lower discount rate, and significantly greater load growth.

The cost of the Mid-case with the 95% by 2050 decarbonization trajectory is only 0.5% greater than the cost of the Mid-case under current policies. This is primarily because the decarbonization of the grid outpaces the 95% by 2050 trajectory for much of the time frame, and once the trajectory does start to influence the grid composition, the technology suite available to the model gives a solution that can achieve 95% decarbonization without significant increases in costs.

The cost of the Mid-case with the 100% by 2035 decarbonization trajectory is 14% greater than the cost of the Mid-case under current policies. Unlike the 95% by 2050 scenario, the costs to achieve 100% net decarbonization occur sooner (therefore both being discounted less as well as persisting within the time frame for more years).

The most significant drivers of cost are decarbonization policy and load growth. The five-highest cost scenarios are all sensitivities with higher demand growth, and the two lowest cost scenarios are sensitivities with lower demand growth.

Note that Figure ES-4 only shows electricity sector costs. Because some sensitivities implicitly vary non- electricity sector costs, these estimates do not fully reflect economy-wide 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 fuel costs for transportation, due to vehicle electrification). As the ReEDS model only represents the electricity sector, these economy-wide impacts are not characterized here.

[7] The values reported here are the present-value of the costs, less the value of tax credits, that are modeled within ReEDS. The costs are not comprehensive—there are many costs associated with building and operating the electric grid not modeled within ReEDS, such as administrative, health, and distribution infrastructure costs. Therefore, these values should primarily be used for relative comparison, not as a comprehensive estimate of total costs.

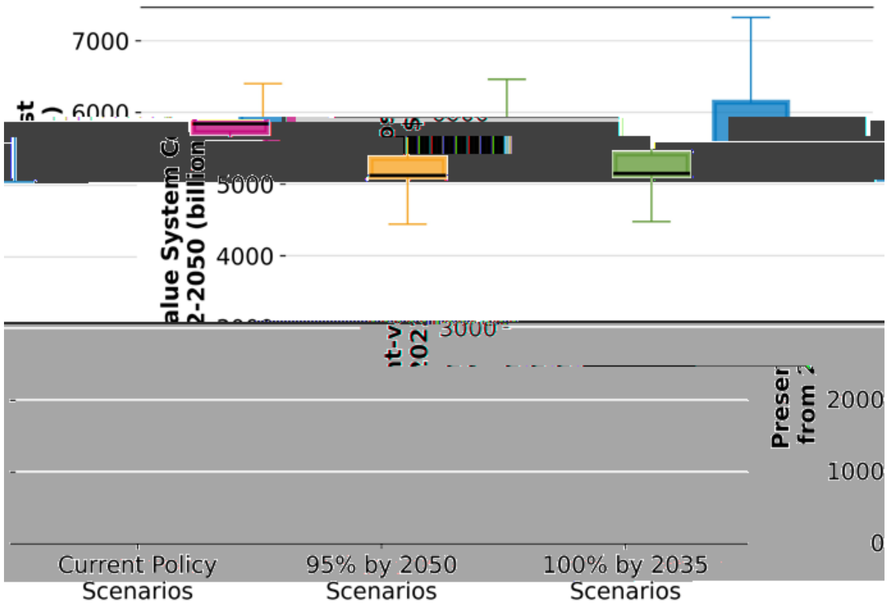

Figure ES-4. Present-value costs of the bulk electricity sector, 2022-2050

The boxes show the 25th–75th percentile of results, the black bar is the median value, and the whiskers show the full range of results. System costs are the present-value (2022$) of the U.S. bulk power system from 2022 through 2050 using a 1.7% social discount rate. The three mid-cases have values of $5,104 billion, $5,131 billion, and $5,842 billion for the Current Policies, 95% by 2050, and 100% by 2035 scenarios respectively.

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 2023 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. To help advance the understanding of the implications, drivers, and key uncertainties associated with this change, we are providing this ninth[11] installment of the Standard Scenarios. This year's Standard Scenarios consist of 53 electricity sector scenarios for the contiguous United States that consider the present day through 2050 and include a representation of the Inflation Reduction Act of 2022.

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 system-wide, 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]

The objective of the Standard Scenarios is to explore a range of possible future conditions and how the U.S. electricity sector may evolve under those conditions. Although we strive to produce reasonable projections of the future, these projections should not be the sole basis for making decisions. We encourage analysts to draw from multiple scenarios within the full set, as well as draw from projections from other sources, to benefit from diverse analytical frameworks and perspectives when forming their conclusions about the future of the electricity sector.

Our 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. We aim to accurately capture issues related to renewable energy integration, including capacity adequacy and interactions of curtailment and storage on investment decisions. Other modeling and analysis frameworks will have different emphases, strengths, and weaknesses. The work we report here 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, as just several examples. Additionally, ReEDS does not have foresight, uses only historical weather data, has a simplified representation of transmission networks, and identifies a system-wide cost-minimizing solution (subject to policy and operational constraints) rather than representing specific market actors or rules. Therefore, results should be interpreted within the 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).

[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.

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

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

2 The Suite of Scenarios

The 2023 Standard Scenarios comprise 53 scenarios that project the possible evolution of the contiguous United States' electricity sector through 2050. Scenario assumptions have been updated since 2022 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 in the appendix for a complete list of changes).

As with the 2022 Standard Scenarios, this year's Standard Scenarios includes provisions from the Inflation Reduction Act of 2022 (IRA). The representation of IRA's provisions is discussed in the appendix (Section A.3). A notable omission from the IRA provisions is the 45V clean hydrogen production tax credit, which is not represented in this modeling. The omission is due to fact that the Treasury Department has not released guidance on how the determination of clean hydrogen will be conducted, and alternative potential implementations have significant impact on the provision's impact on the power sector.

This year's modeling contains new modeled projections of end-use electricity demand growth that incorporate estimates of the potential impacts of IRA's demand-side provisions. A notable omission is that all end-use electric demand (other than demand from electrolyzers) is represented as inelastic and inflexible. This tends to result in modeled systems that are more expensive than the otherwise could be if load was grid-responsive—especially for the decarbonization scenarios. See Section A.1 for more discussion about load assumptions.

The scenarios included in this report are summarized in Figure 1 (page 4). Details about specific scenario definitions and inputs are provided in Section A.1 of the appendix.

The 53 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, we also assess other factors that can impact the development of the electricity sector, such as transmission build-out and technology progress. We encourage those doing analyses that use data from these scenarios to draw from multiple scenarios, to reflect the inherent uncertainty in the evolution of the U.S. electricity sector.

We note that, to enhance transparency, the ReEDS and dGen models and inputs we used to generate these scenarios are publicly available.[14]

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

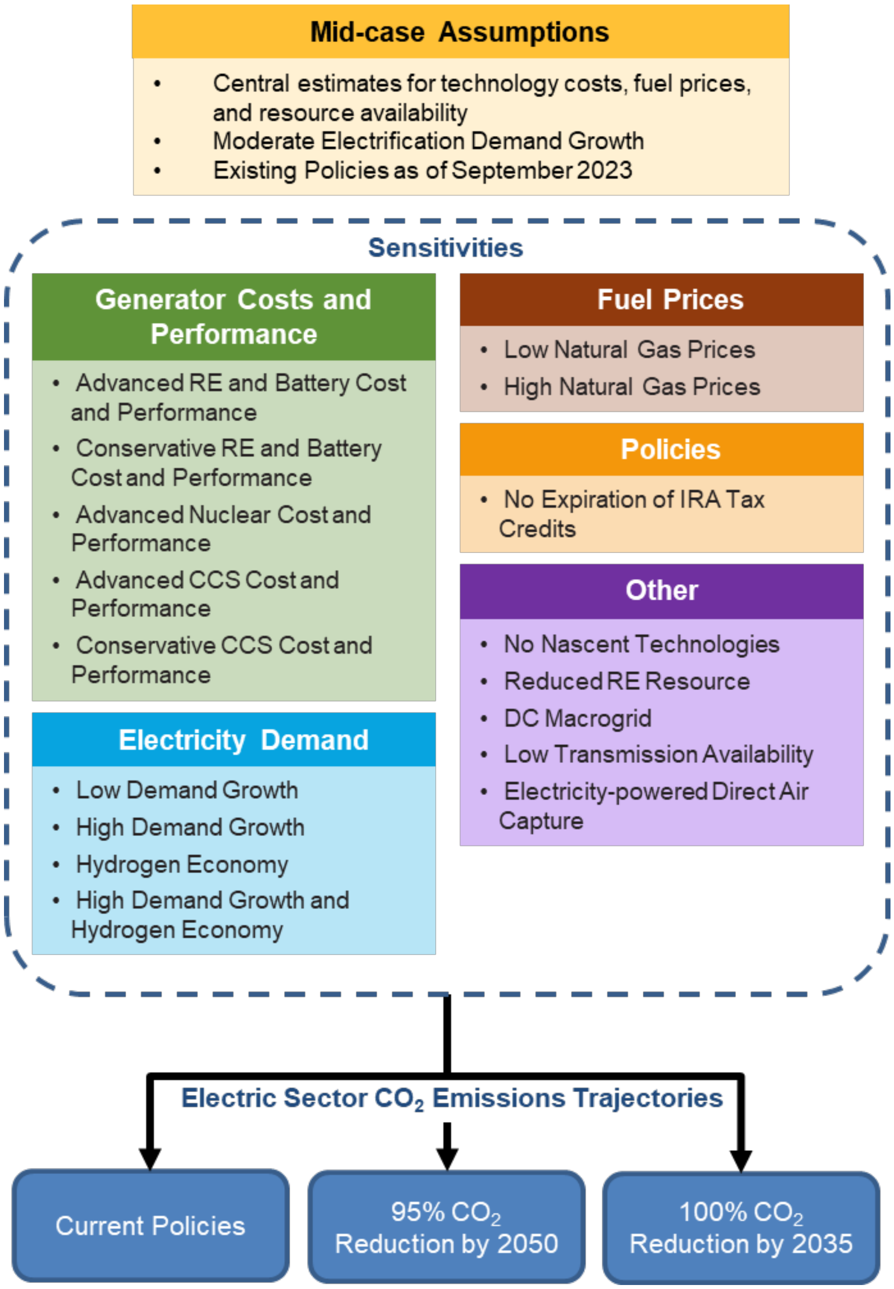

Figure 1. Summary of the 2023 Standard Scenarios

There are 53 scenarios, which are a product of 18 base assumptions (1 Mid-case set of assumptions and 17 sensitivities), multiplied by 3 different electricity sector emissions trajectories, less 1 because the No Nascent Technologies with 100% CO_2 Reduction by 2035 was omitted. RE is renewable energy, and 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 September 2023. 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.

Note that the 100% by 2035 emission trajectory is not combined with the No Nascent Technologies sensitivity. This is primarily because the ReEDS model lacks foresight, and consequently the patterns of deployment leading up to and including the year the emissions constraint reaches zero are unrealistic. For readers interested in a more detailed exploration of zero-carbon systems under a 2035 time frame, we direct them to NREL's 100% Clean Electricity by 2035 Study (Denholm et al. 2022).[15]

This year's Standard Scenarios include two sensitivities (the two Hydrogen Economy demand sensitivities) that impose a demand for electrolysis-produced hydrogen for non-power-sector end-uses. The demand trajectory imposed is significant (reaching 46.3 million metric tons of H_2 per year in 2050, which imposes approximately 2000 additional TWh/year of electrolyzer demand, aligned with an estimate of the possible demand for full decarbonization of the U.S. economy (Denholm et al. 2022)). This demand is represented as an annual, national constraint—meaning that any transportation and storage costs for the non-power-sector portion of hydrogen production are not reflected in the optimization and cost reporting for the sensitivities with such demand. We re-emphasize here that these sensitivities omit a representation of IRA's production tax credit for clean hydrogen, due to a current lack of the Treasury Department's guidance on the exact implementation of the determination of clean hydrogen. Given this omission, an analyst should interpret these scenarios either as the impact of hydrogen production if 45V did not exist, or if an implementation is adopted where hydrogen producers are able to claim sufficient clean generation to cover their consumption from generation that would have occurred regardless of the presence of the production tax credit.

The No Expiration of IRA Tax Credits sensitivity extends indefinitely IRA's tax credits for capturing and storing carbon (45Q), incentives for existing nuclear generators (45U), and the PTC and ITC for utility-scale renewable generation. Other IRA provisions (such as the incentives for clean hydrogen production and various demand-side incentives) may influence the electricity sector, but as they are not directly modeled in ReEDS, they are not extended in this sensitivity.

For further details about specific scenario definitions and inputs, see Section A.1 of the appendix.

Lastly, although the scenario suite covers a wide range of futures, it is not exhaustive. We note that other NREL analyses have studied particular aspects of power sector evolution in more depth than is covered in this suite of scenarios. For example:

- 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.

[15] "100% Clean Electricity by 2035 Study," NREL, https://www.nrel.gov/analysis/100-percent-clean-electricity-by-2035-study.html.

- The Electrification Futures Study[16] 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[17] data sets 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.

Definition of Decarbonization Scenarios in the Standard Scenarios

In this year's Standard Scenarios, two national electricity sector CO_2 emissions constraints are applied to a subset of the scenarios: the 95% Reduction by 2050 and the 100% Reduction by 2035. These trajectories correspond to a percentage reduction in net U.S. electricity sector CO_2 emissions relative to 2005 emissions.

These trajectories are implemented as a national electricity sector CO_2 constraint. The CO_2 constraint only applies to the U.S. electricity sector. None of the scenarios in this analysis model U.S. economy-wide 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 CO_2 emissions retain their representations of existing state and federal policies—i.e., the national CO_2 emissions constraints are additional to existing policies, not replacements of them.

The trajectories limit the net electricity sector CO_2 emissions, meaning that the constraint is applied to CO_2 emissions from the direct combustion of fuel for electricity generation, less any CO_2 captured and stored through carbon capture technologies (generators with CCS or direct air capture [DAC], if present). The emission limit does not incorporate other greenhouse gases, emissions from precombustion or post-combustion activities such as fuel extraction and transport (other than the CO_2 removed from the atmosphere during feedstock growth for bioenergy with CCS), or the emissions induced by construction or decommissioning activities.

Note that, in the scenarios that exclude nascent technologies, there are no carbon removal options—and that DAC is only enabled as an investment option in the electricity-powered DAC sensitivities.

The definition of a CO_2 constraint given above is only one possible definition—others may include the CO_2 equivalence of other greenhouse gases or include non-combustion emissions (e.g., emissions from fuel extraction, processing, and transport). Furthermore, other definitions may involve different approaches to the accounting around carbon removal, including completely prohibiting offsets (such as CO_2 capture). Other possible definitions of power sector decarbonization were explored in NREL's 100% Clean Electricity by 2035 Study.

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

3 The Mid-Case Scenarios

The Mid-case scenarios use central assumptions for demand growth, resource availability, fuel price, and technology inputs (see Figure 1, for a summary of those assumptions and the appendix, Section A.1 for details about the assumptions). In this way, the Mid-case scenarios provide reference points for comparing scenarios and assessing trends. Section 3.1 provides some additional context for how the Mid-case scenario relates to projections from other organizations.

Figure 2 (page 9) shows the generation and capacity mix through 2050 for the Mid-case scenarios under the three levels of electricity sector decarbonization. The Current Policies trajectory does not impose any CO_2 emission limit other than those already in place at the sub-national level (i.e., regional and state), the 95% by 2050 trajectory imposes a net 95% reduction in national electricity sector CO_2 emissions by 2050 relative to 2005, and the 100% by 2035 trajectory requires that national CO_2 emissions are net zero by 2035. DAC is not enabled in these scenarios, but bioenergy with carbon capture is available to offset stack emissions from CO_2-emitting generators.

All three scenarios see significant increases in wind, solar, and storage deployment. Notably, however, the 75% emissions reduction threshold specified in IRA is not achieved in the Mid-case with current policies (which would trigger the phaseout of the renewable energy tax credits). Because of this, wind and solar make up most new generation throughout the modeled horizon in that scenario. In the two Mid-case scenarios with national CO_2 emissions constraints, the IRA threshold is achieved (resulting in a phaseout of the tax credits). In the scenario with 95% decarbonization by 2050, the phaseout occurs sufficiently late in the modeling horizon that wind and solar still make up the significant majority of new generation throughout the modeling horizon. In the 100% decarbonization by 2035 scenario, however, the clean electricity tax credits phase out in the 2030s, and consequently new demand is met in similar magnitudes by natural gas with CCS, wind, and solar.

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 95% decarbonization by 2050 scenario (reaching 0.7% of total capacity in the nation under Current Policies and 1.4% in the 95% by 2050 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.[18] As mentioned above, natural gas with CCS plays a larger role post-2035 in the 100% by 2035 scenario (see section 4.7 later in this report, for figures showing the firm capacity contribution of different technologies in these scenarios, and section 4.6 for discussions specifically around carbon capture technologies).

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 95%

[18] 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 once they are no longer receiving the 45Q credit.

by 2050 scenario the deployment of small modular nuclear reactors is exceptionally small (it does not exceed 1.1 GW). Hydrogen combustion turbine deployment in those scenarios is larger, reaching 11 GW under Current Policies and 29 GW in the 95% by 2050 scenario. The deployment of hydrogen combustion turbines is much greater in the 100% scenario (reaching 154 GW), although their capacity factors are low as they are primarily used for firm capacity. As a reminder, this modeling did not include a representation of IRA's production tax credit for producers of clean hydrogen, which could increase the future competitiveness of hydrogen combustion turbines for the power sector.

We emphasize that 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 generation without CCS remains in all scenarios. Its energy contribution is greatest in the Current Policies scenario, but also provides significant firm capacity in both decarbonization scenarios despite the stringent CO_2 limits. The capacity persists by running at lower capacity factors and, in the 100% by 2035 scenario, 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.

Coal generation declines significantly by 2030 in all scenarios, even when taking into consideration coal with CCS. Coal without CCS capacity persists at lower utilization rates in the Current Policies and 95% by 2050 scenario as a provider of firm capacity. All coal without CCS is retired by 2035, in the 100% by 2035 scenario.

Existing nuclear plants are not subject to economic retirement through 2032, due to ReEDS' representation of the IRA incentives for existing nuclear, and beyond 2032, they generally remain sufficiently competitive to avoid early retirement,[19] resulting in a near-constant level of nuclear capacity and generation through 2050 in the Current Policies scenario. In both of the decarbonization scenarios nuclear capacity remains mostly constant, but the utilization rates of the plants are seen to decrease in some years. This is because the model preferentially curtails nuclear before wind and solar because of assumed small but non-zero variable costs of nuclear production. In practice, the relative curtailment of wind, solar, and nuclear would potentially be influenced by generator and market characteristics that are not well represented by the ReEDS model.

[19] 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.

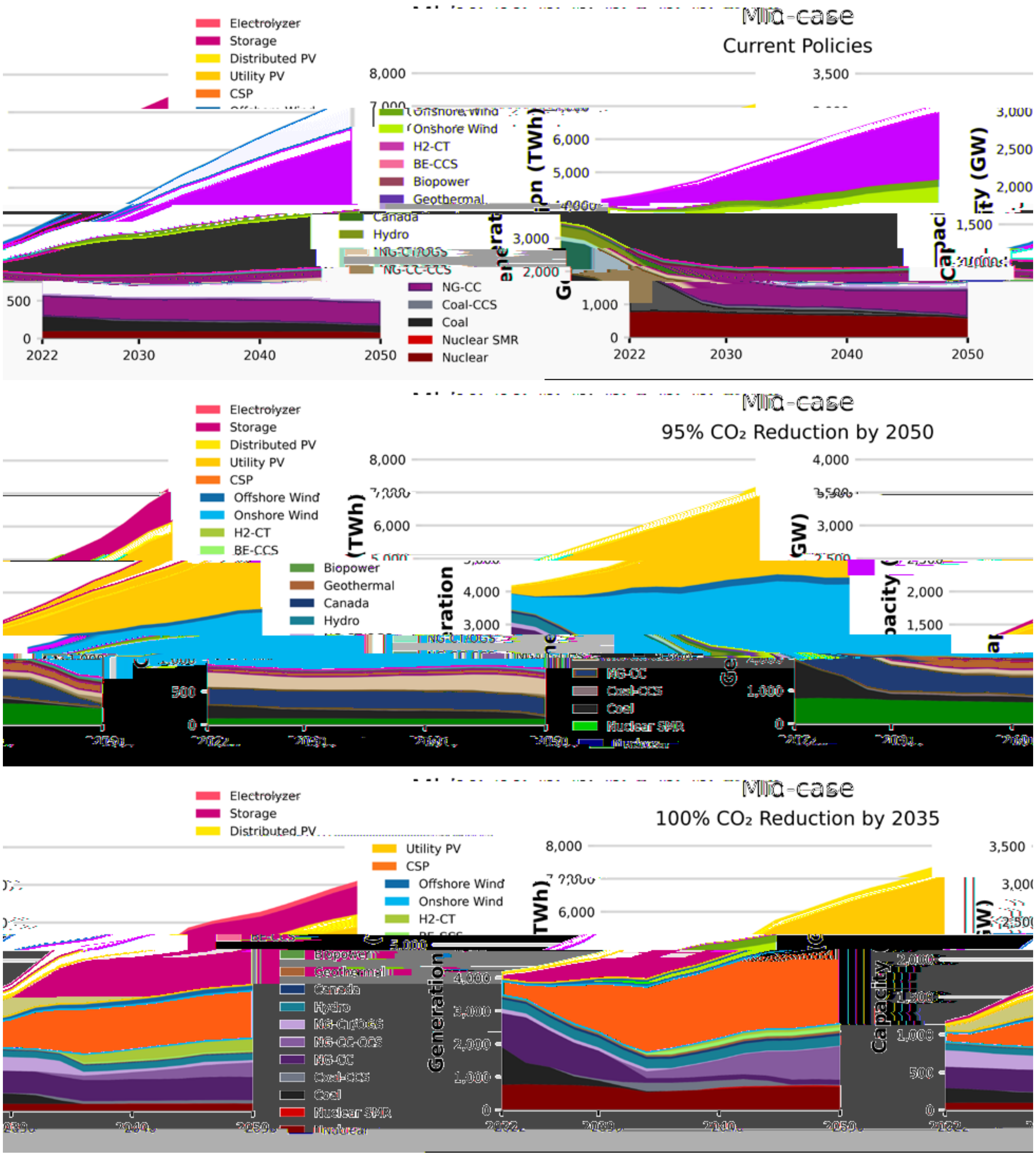

Figure 2. U.S. electricity sector generation (left) and capacity (right) over time for the three Mid-case scenarios with both established and nascent generation technologies

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.

Table 1 and Table 2 show the generation fraction for the major fuel types in 2036 (the first modeled year after the 100% by 2035 scenario reaches 100%) and 2050, respectively for the Mid-case scenarios with different levels of CO_2 emission limits. The 2036 mixtures of the Current Policies and the 95% by 2050 scenarios are identical, because the IRA-induced emissions reduction outpaces the 95% by 2050 decarbonization trajectory at that point in time. However, there is greater variation between these scenarios (Current Policies and 95% by 2050) and the 100% by 2035 scenario in 2036, and between all scenarios in the 2050 mixtures. Note that the 2050 renewable energy fraction in the 100% by 2035 scenario is lower than the other two scenarios in large part because of the earlier expiration of IRA's clean electricity tax credits in that scenario.

Note that the generation fractions in Table 1 and Table 2 do not sum to 100 because not all technologies are listed. For the complete data sets, for all scenarios and all years, see the 2023 Standard Scenario project in NREL's Scenario Viewer.

Table 1. Generation Fraction in 2036 for Each Fuel Type in the Mid-Cases under Three Levels of CO_2 Requirements

Fuel Type	Current Policies	95% by 2050	100% by 2035
Total Renewables	69%	69%	80%
Wind	37%	37%	41%
Solar	25%	25%	27%
Nuclear	12%	12%	10%
Total Natural Gas	13%	13%	8%
Non-CCS Natural Gas	13%	13%	3%
CCS Natural Gas	1%	1%	5%
Total Coal	4%	4%	4%
Non-CCS Coal	3%	3%	0%
CCS Coal	1%	1%	4%

Table 2. Generation Fraction in 2050 for Each Fuel Type in the Mid-Cases under Three Levels of CO_2 Requirements

Fuel Type	Current Policies	95% by 2050	100% by 2035
Total Renewables	76%	85%	71%
Wind	38%	42%	37%
Solar	32%	38%	28%
Nuclear	8%	7%	10%
Total Natural Gas	15%	6%	16%
Non-CCS Natural Gas	14%	4%	2%
CCS Natural Gas	0%	2%	14%
Total Coal	1%	0%	0%
Non-CCS Coal	1%	0%	0%
CCS Coal	0%	0%	0%

Comparison with Other Reference Case Scenarios

Here, we compare the Current Policies Mid-case projection with recent projections from three other organizations: the U.S. Energy Information Administration (EIA), the International Energy Agency, and BloombergNEF.[20] We compare these projections in Figure 3 to enable readers to compare NREL's historical projections against 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.[21] Note also that, due to the timing of its release, the 2022 AEO from the EIA did not include a representation of IRA, while the 2022 releases from NREL and the International Energy Agency both did include IRA representations.

Note that the reversal of trends projected by NREL in the 2022 Mid-cases were due to IRA tax credits expiring, which is no longer projected to occur in the Mid-case within this analysis horizon, and therefore the reversal does not occur.

The near-term decline in greenhouse gas emissions is reflected in other modeling as well. A multi-model study exploring the impacts of IRA and drawing from nine independent models showed economy-wide greenhouse gas emissions reductions between 43 and 48% below 2005 levels by 2035 (Bistline et al. 2023). Note that the projections shown in Figure 4 are only for the U.S. electricity sector, not the whole economy.

[20] The NREL scenario is the Current Policies (previously No New Policy) Mid-case including nascent technologies. The BloombergNEF case is the New Energy Outlook scenario. 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 International Energy Agency's *World Energy Outlook 2023* was not yet available at the time of this writing and that in 2021 BloombergNEF changed their forecasts to be centered on the pathways for power sector decarbonization, and therefore are no longer updated here.

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

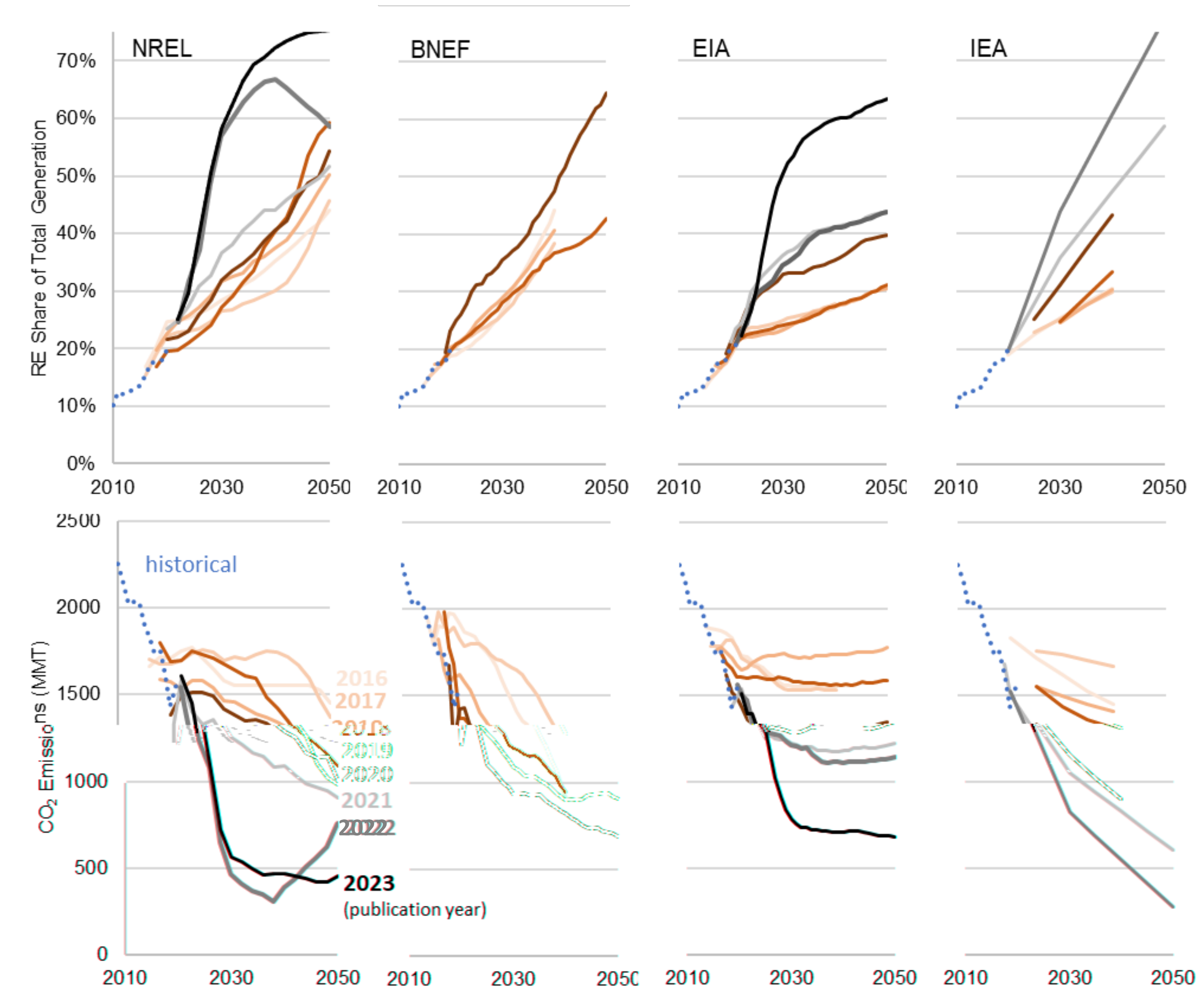

Figure 3. Renewable energy generation fraction (top) and electricity sector CO_2 emissions (bottom) from the organizations and publication years indicated

Only reference case scenarios are shown.

4 Range of Outcomes Across All Scenarios

In this section, we highlight 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.

We note that, because sensitivities are perturbations off 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 5 (page 14) shows the generation by fuel type across the full suite of scenarios. Natural gas (both with and without CCS), solar, and wind show the largest range in 2050 generation across the scenarios. The scenarios with higher electrical demand (including the ones with high electricity demand from electrolyzers producing hydrogen for non-power-sector use) tend also to have high levels of generation. Natural gas varies the most in the Current Policies scenarios; its contribution in the scenarios with national emissions limits is generally less and mostly driven by the specific policy (95% or 100% decarbonization).

Non-CCS coal generation tends to decline over time, although some of the decline is from the retrofitting of existing generators with CCS. Coal CCS generation appears in many scenarios while the 45Q credit for capturing and storing carbon is active, although it decreases once the credit expires.

Nuclear generation remains largely constant across most of the scenarios, with small increases above today's level appearing only in several of the 100% decarbonization scenarios. Some scenarios see a slight decline in nuclear generation (without a corresponding decline in nuclear capacity) due to decreases in use induced by higher deployment of variable RE).

Bioenergy with CCS is deployed in most scenarios, although its deployment is always a small fraction of total generation 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.

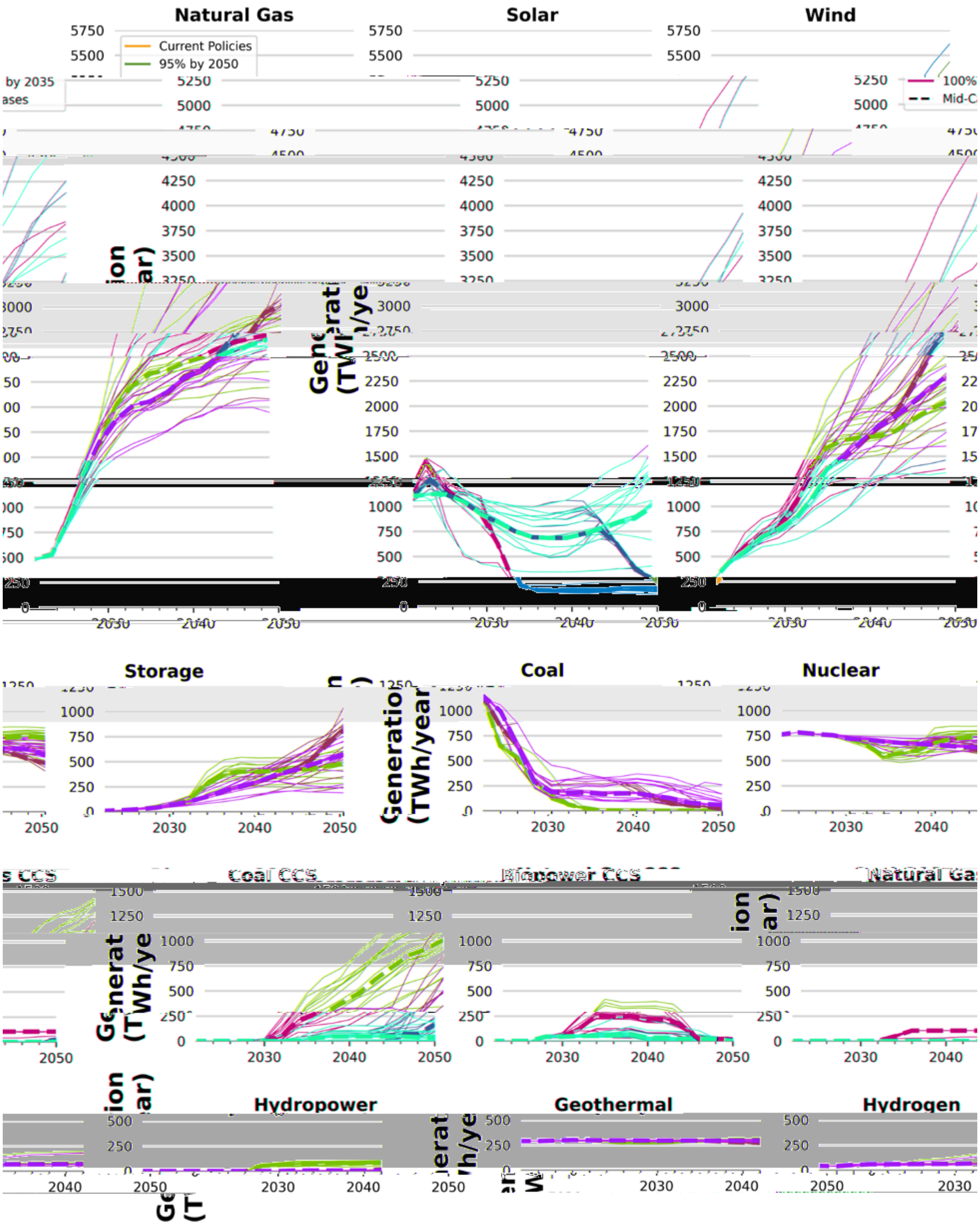

Figure 4. Generation by fuel type across the Standard Scenarios. The Mid-case scenarios are shown with the heavier dashed lines. Solar includes PV and CSP with and without thermal energy storage. Storage includes both electric batteries and pumped hydropower.

4.2 Capacity

Figure 5, above, showed the generation trends by technology. Figure 6, below, shows the capacity trends by technology.

Natural gas without CCS capacity grows in all Current Policy scenarios and the 95% by 2050 scenarios. There is a slight to moderate reduction in all but one of the 100% by 2035 scenarios, but this is in part due to retrofitting units with CCS (the single 100% scenario without a decline is the DAC sensitivity—in that situation the model sees it as cost effective to invest in DAC and operate it at high capacity factors rather than investing in capture equipment for natural gas generators that are operated at low capacity factors primarily for firm capacity). 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 lowering their 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). Nuclear has the smallest variation, with only limited new builds or retirements across the full suite of scenarios.

Of the three CCS technologies, natural gas sees the most deployment. This occurs in the decarbonization scenarios where it provides firm capacity. Bioenergy with CCS sees its greatest deployment in the 100% by 2035 scenario, where it acts as a negative emissions technology to offset the emissions from natural gas generators.

Note that across many scenarios, fossil generators (both unabated and those with CCS) are often present but with low capacity factors—i.e., they only generate electricity 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 plant's 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.

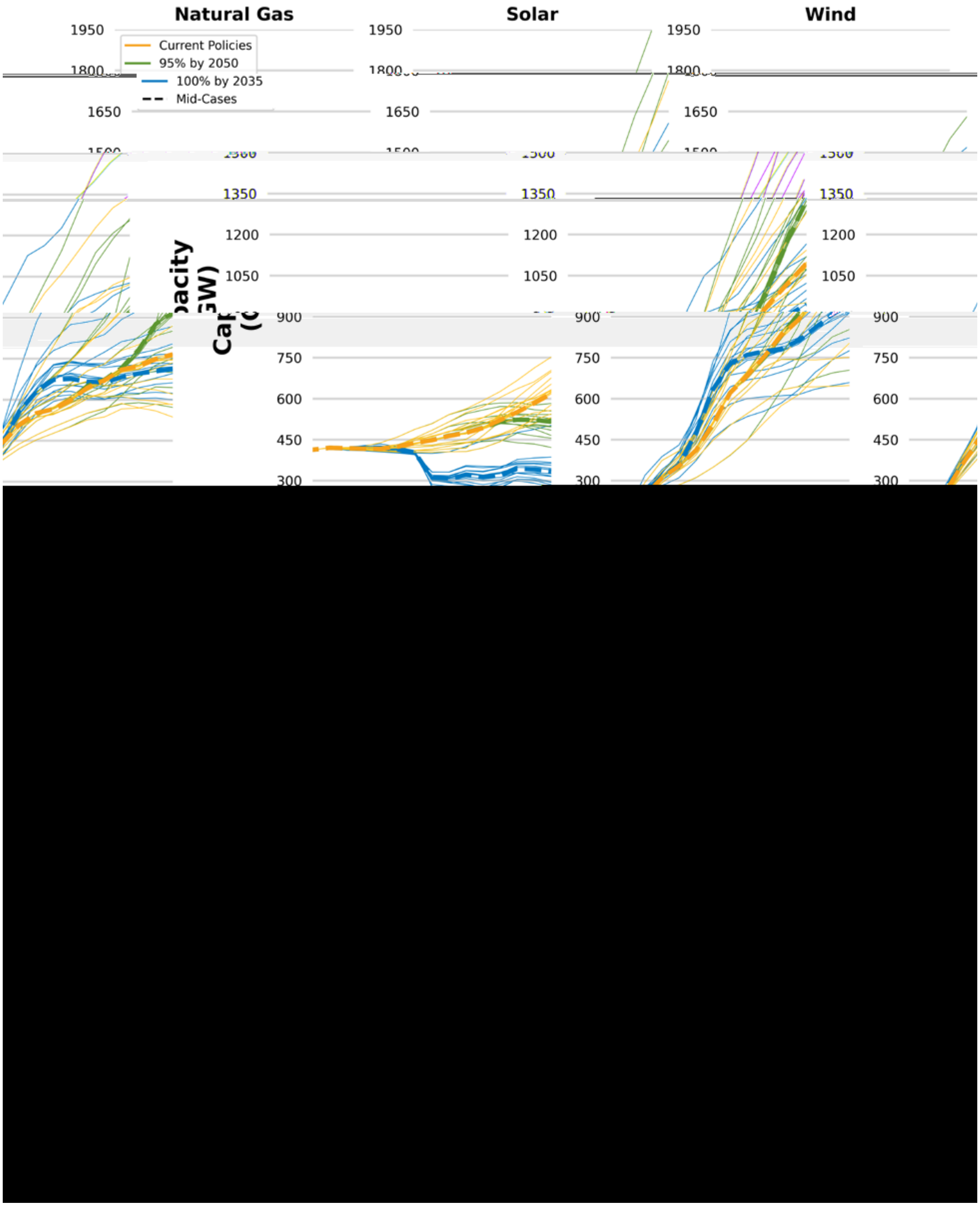

Figure 5. Capacity by fuel type across the Standard Scenarios. The Mid-case scenarios are shown with the heavier dashed lines. Solar includes PV and CSP with and without thermal energy storage. Storage includes both electric batteries and pumped hydropower.

4.3 Renewable Energy Share

Total renewable energy share, which is defined as the fraction of total generation that is from renewable energy generators, ranges from approximately 65% to over 85% in 2050 (Figure 7). From the generation figures above (Figure 5), the increase in renewable energy deployment is primarily from wind and solar. The renewable energy share is not generally influenced by the national emissions constraints until the early 2030s for the 100% by 2035 scenario and the mid 2040s for the 95% by 2050 scenario. This is because the emissions reductions under current policies generally outpace the decarbonization trajectories until those time frames—meaning that those constraints generally do not have an effect until later years. Renewable energy shares do not climb much beyond 80% because the existing nuclear capacity is able to fill most of the remaining gap to meet the emission limits.

Counterintuitively, the renewable energy shares in 2050 of the 100% by 2035 scenarios are generally lower than their counterparts under the 95% by 2050 trajectory—this occurs because the IRA clean electricity tax credits expire in the 2030s under the 100% trajectory, and consequently natural gas with CCS becomes competitive with wind and solar, playing a larger role in meeting growing demand in later decades.

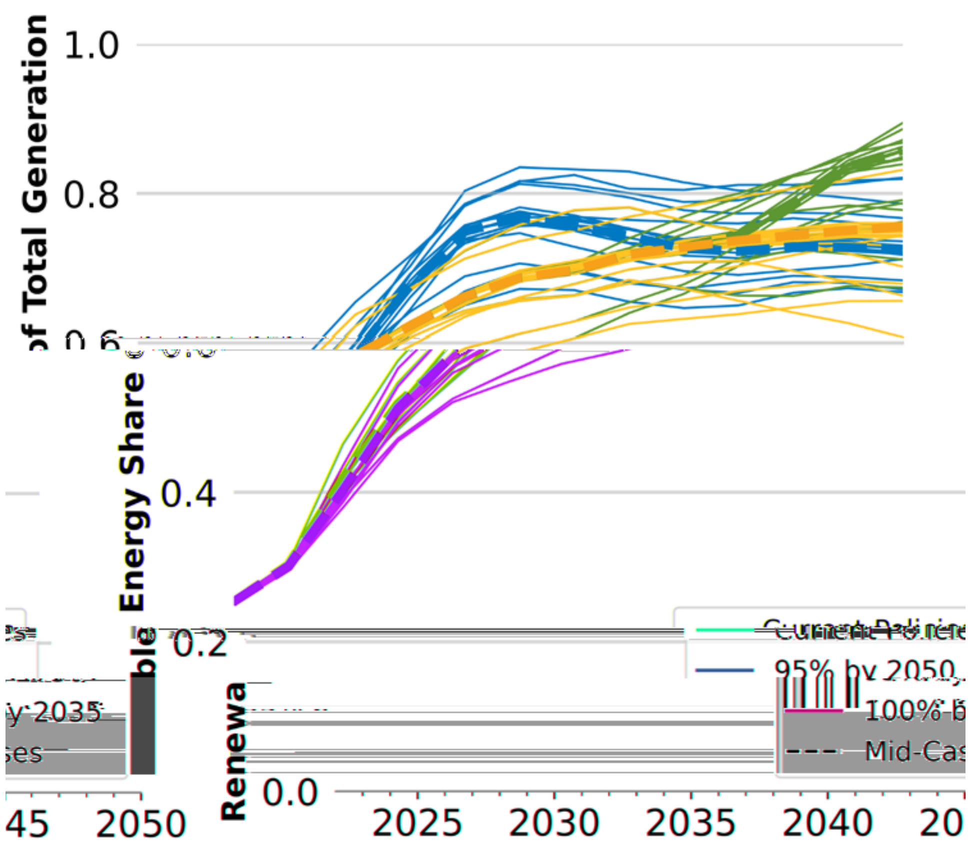

Figure 6. Renewable energy share over time across the Standard Scenarios. The Mid-case scenarios are shown with the heavier dashed lines. Renewable energy share is defined as annual renewable energy generation divided by total generation (excluding storage generators). Renewable generators are hydropower, geothermal, bioenergy, solar, and wind powered.

4.4 Transmission Capacity

Figure 8 shows the transmission expansion across the scenarios. The left panel shows interzonal transmission capacity between the 134 ReEDS zones, and is most analogous to higher capacity and higher voltage (230+ 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.

Higher levels of transmission development are correlated with both renewable energy deployment and higher natural gas prices. Higher renewable energy buildouts can benefit from more transmission that can move energy from regions with high concentrations of variable renewable energy to load centers where that otherwise-excess energy can be consumed. Higher natural gas prices create high energy prices, which can lead to greater price arbitrage opportunities between regions, thereby increasing the value of transmission.

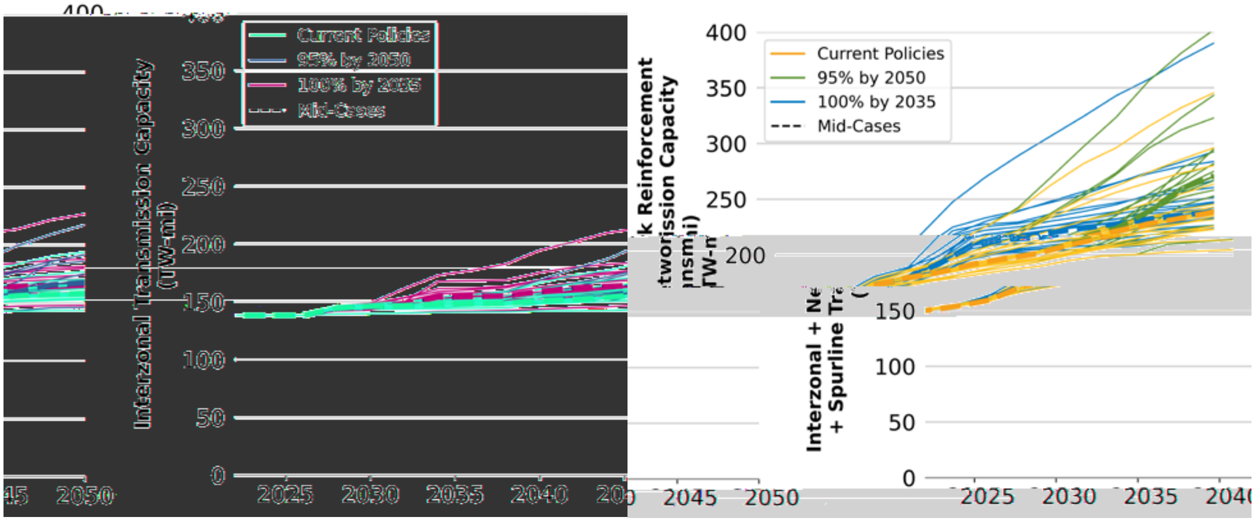

Figure 7. Interzonal transmission capacity (left) and interzonal + network reinforcement + spur line transmission capacity (right) across the Standard Scenarios.

The Mid-case scenarios are shown with the heavier dashed lines.

4.5 Electricity Sector CO_2e Emissions

Electricity sector CO_2e emissions are shown in Figure 9 (page 19).[22] Emissions decline rapidly in the 2020s in all scenarios, although they generally level off after that for scenarios under Current Policies (which equates to a continual slow reduction of the emissions per unit of electricity of the electricity sector, since demand continues to grow in those scenarios). Note that Figure 8 only shows greenhouse gas emissions for the electricity sector—as some of the sensitivities implicitly vary greenhouse gas emissions beyond the electricity sector, the trends in economy-wide greenhouse gas emissions may differ. For example, scenarios with greater electrification may have relatively higher electricity sector emissions, but relatively lower

[22] Note that this section presents values for CO_2e from direct combustion, while elsewhere in the report just CO_2 from direct combustion is used (e.g., the decarbonization scenarios are defined in terms of CO_2 not CO_2e).

economy-wide emissions. As the model used for this study does not represent economy-wide emissions, such results are not characterized in this report.

The red dotted line in Figure 8 shows the threshold that, once crossed, triggers the phaseout of IRA's renewable energy tax credits. Under Current Policies, this only occurs in the Low Demand Growth, Advanced Renewable Energy Costs and Performance, High Natural Gas Prices, No Tax Credit Expiration, and Advanced CCS Cost and Performance sensitivities.[23] 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.

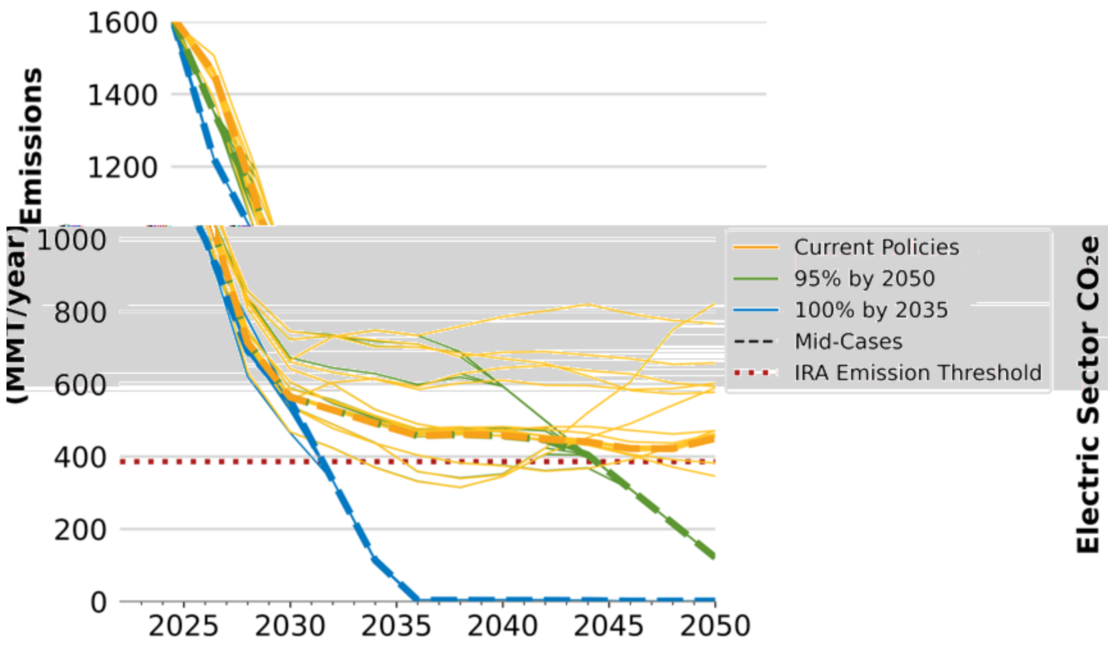

Figure 8. Electricity sector emissions over time across the Standard Scenarios. The Mid-case scenarios are shown with the heavier dashed lines. Emissions are only CO_2e emissions from direct combustion of fuel (i.e., stack emissions) less carbon captured by carbon removal technologies. The greenhouse gas emissions included here are CO_2, CH_4, and N_2O, combined using 100-year global warming potentials. The emissions do not include other pre- or post-combustion emissions. 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.

4.6 Carbon Capture and Storage

The incentive for capturing and storing carbon in IRA induces the deployment (both retrofitting as well as greenfield builds) of generators with CCS in all scenarios[24]—although the range is significant, with most scenarios under Current Policies having less than 25 GW deployed at any time, while several scenarios with 100% decarbonization see over 350 GW deployed (the Advanced CCS Cost and Performance, High Demand Growth, and Conservative RE Cost and Performance sensitivities have the greatest CCS generator deployment). Figure 10, below, shows

[23] The threshold is crossed in the No Tax Credit Expiration sensitivity because of the extension of 45Q, the tax credit for capturing and storing carbon.
[24] Other than the sensitivities without nascent technologies, where CCS is excluded as an investment option.

the installed capacity of CCS generators through 2050 across the suite of scenarios that include nascent technologies and Table 4 (page 20) shows the maximum deployment for different CCS technologies.

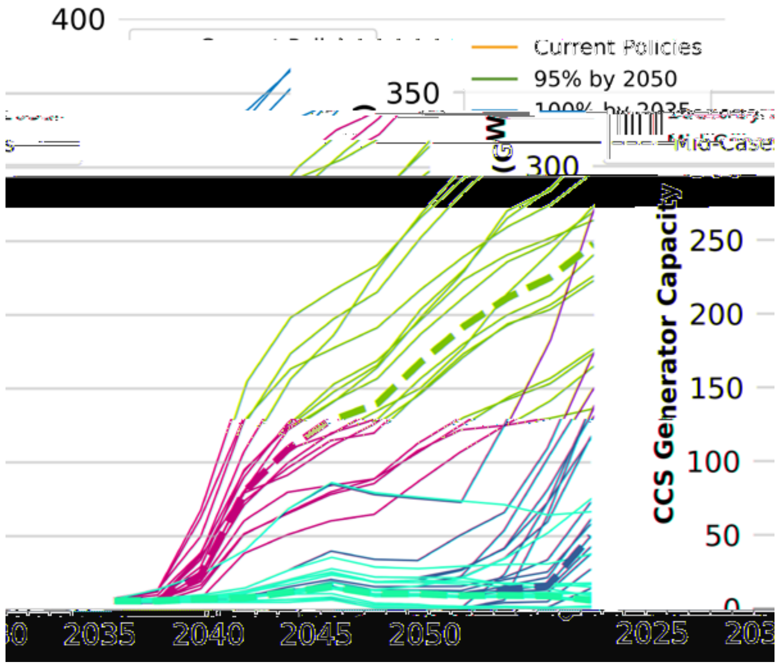

Figure 9. Deployment of CCS generator technologies across the Standard Scenarios

The Mid-case scenarios are shown with the heavier dashed lines. This figure only shows CCS generator capacity, not the capacity from DAC facilities.

Table 3. Maximum CCS Capacity (in gigawatts) of Each Type Deployed in 2050 across All Scenarios

Technology	Current Policies	95% by 2050	100% by 2035
NG-CC with CCS	75	233	308
Coal with CCS	36	35	70
Bioenergy with CCS	1	6	14
DAC	0	0	79

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 7 GW under Conservative assumptions to 102 GW under Advanced assumptions. Under 100% decarbonization, the amount of CCS deployed ranges from 174 GW under Conservative assumptions to 367 GW under Advanced assumptions. See Section A.6 of the appendix for generation and capacity figures corresponding to these sensitivities.

Figure 12 shows the annual quantity of CO_2 that is captured and stored in four of the scenarios. Note that DAC is only available as an investment option in the sensitivities that bear its name, and within those three sensitivities, it is only deployed in the 100% decarbonization scenario.

The quantity of carbon captured from coal CCS is seen to often peak in the 2030s and then decline 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 once 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.

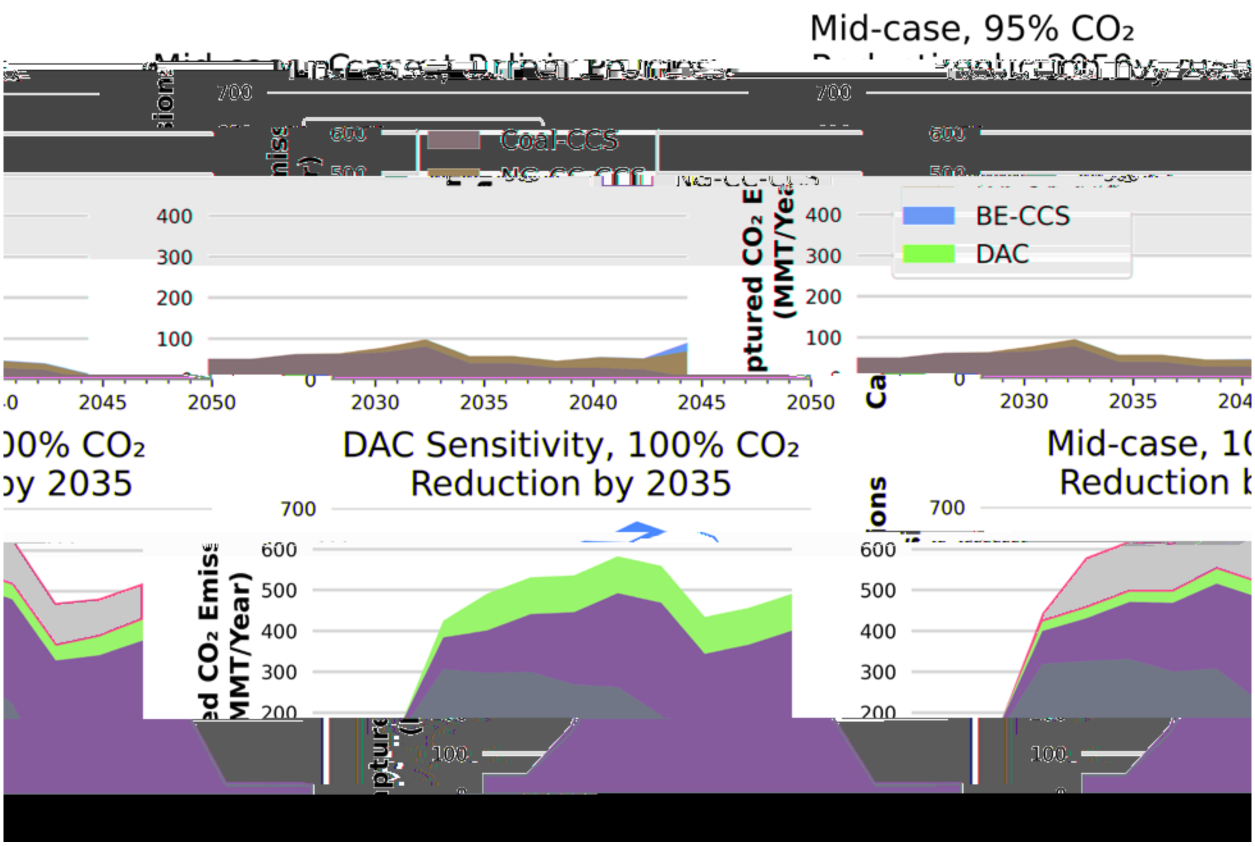

Figure 10. Annual CO_2 captured and stored, by technology

4.7 Firm Capacity by Technology

Firm capacity is the capacity that is reliably available during the most demanding hours on the grid. As the ReEDS model is not stochastic, it uses outage de-rates to reflect the expected reliable contribution of dispatchable generators, and capacity credit calculations to reflect the expected contribution of variable generators. Firm capacity is reported here, in Figure 13, as the contribution of each technology during the time periods with the greatest shadow price on the reserve margin constraint (averaged across the 134 ReEDS regions).

Natural gas without CCS contributes significant firm capacity across all scenarios, even scenarios that reach 100% decarbonization. The presence of natural gas without CCS in 100% decarbonization scenarios is enabled by operating them at extremely low capacity factors, and offsetting their emissions with negative emission bioenergy with CCS generators. Natural gas with CCS plays the largest role in decarbonization scenarios, where its contribution is similar to its unabated counterpart.

Storage, nuclear, and hydropower also contribute significant firm capacity across all scenarios. Coal's contribution starts high but declines across all scenarios. Wind and solar generally have low capacity credits as their output is often low during the most demanding hours on the grid (which are often demanding because of low wind and solar output), therefore despite having significant capacity, they only have moderate firm capacity contributions.

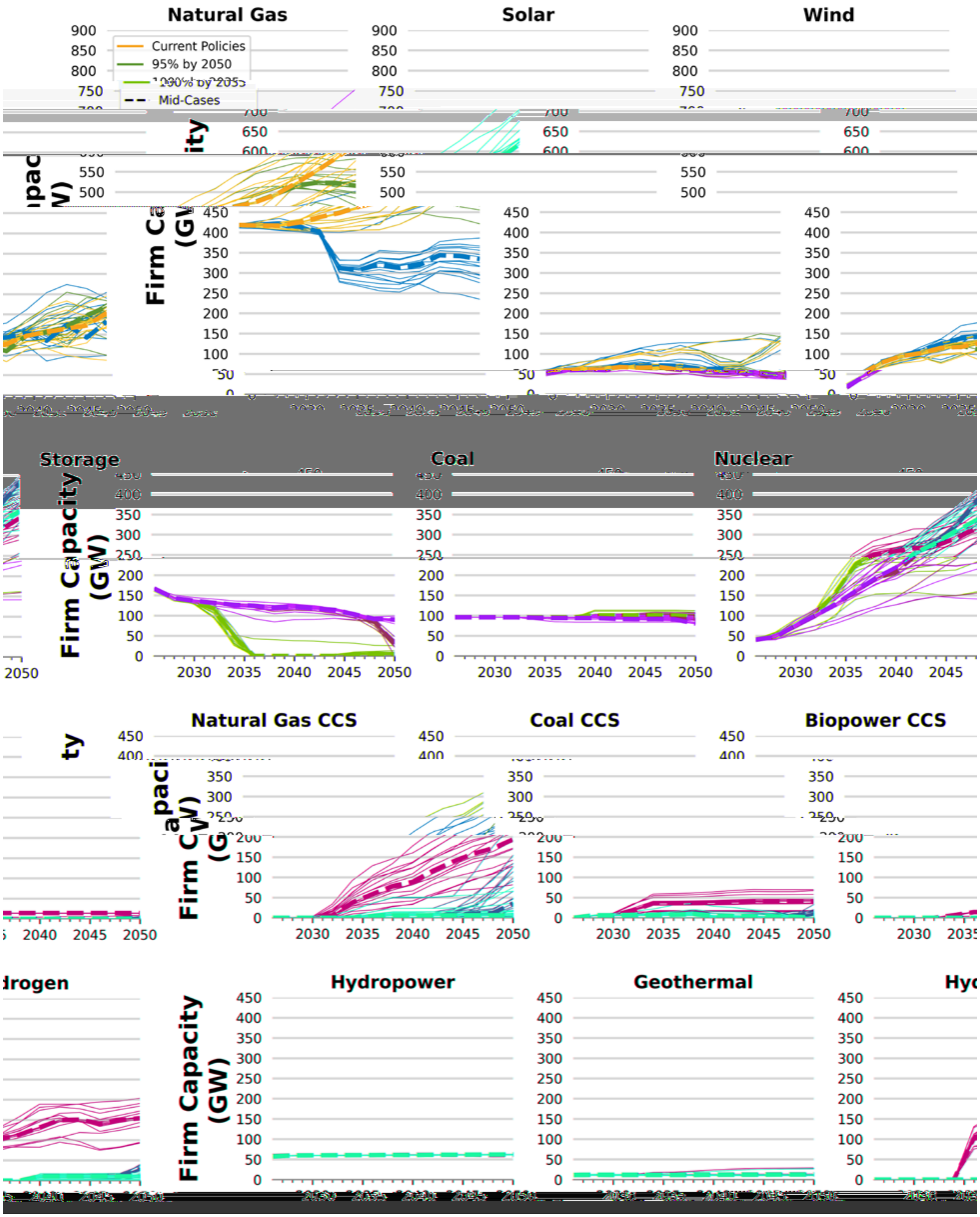

Figure 11. Firm capacity, by technology across the suite of scenarios

4.8 Present-Value System Costs

Figure 12 shows the distribution of electricity sector costs across scenarios. The value shown is the present-value of the electricity sector costs (less the value of tax credits) that are modeled within ReEDS from 2022 through 2050, using 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 values reported here are materially higher than in prior Standard Scenarios (Cole et al. 2021). The difference is caused by a number of factors, such as the inclusion of new cost categories into the ReEDS model (e.g., network reinforcement costs), a lower discount rate, and significantly greater load growth.

The cost of the Mid-case with the 95% by 2050 decarbonization trajectory is only 0.5% greater than the cost of the Mid-case under current policies. This is primarily because the decarbonization of the grid outpaces the 95% by 2050 trajectory for much of the time frame, and once the trajectory does start to influence the grid composition, the technology suite available to the model gives a solution that can achieve 95% decarbonization without significant increases in costs.

The cost of the Mid-case with the 100% by 2035 decarbonization trajectory is 14% greater than the cost of the Mid-case under current policies. Unlike the 95% by 2050 scenario, the costs to achieve 100% net decarbonization occur sooner (therefore both being discounted less as well as persisting within the time frame for more years).

The most significant drivers of cost are decarbonization policy and load growth. The five-highest cost scenarios are all sensitivities with higher demand growth, and the two lowest cost scenarios are sensitivities with lower demand growth.

Note that Figure 12 only shows electricity sector costs. Because some sensitivities implicitly vary non- electricity sector costs, these estimates do not fully reflect economy-wide 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 fuel costs for transportation, due to vehicle electrification). As the ReEDS model only represents the electricity sector, these economy-wide impacts are not characterized here.

[25] Modeled costs are generator and storage capital and 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.

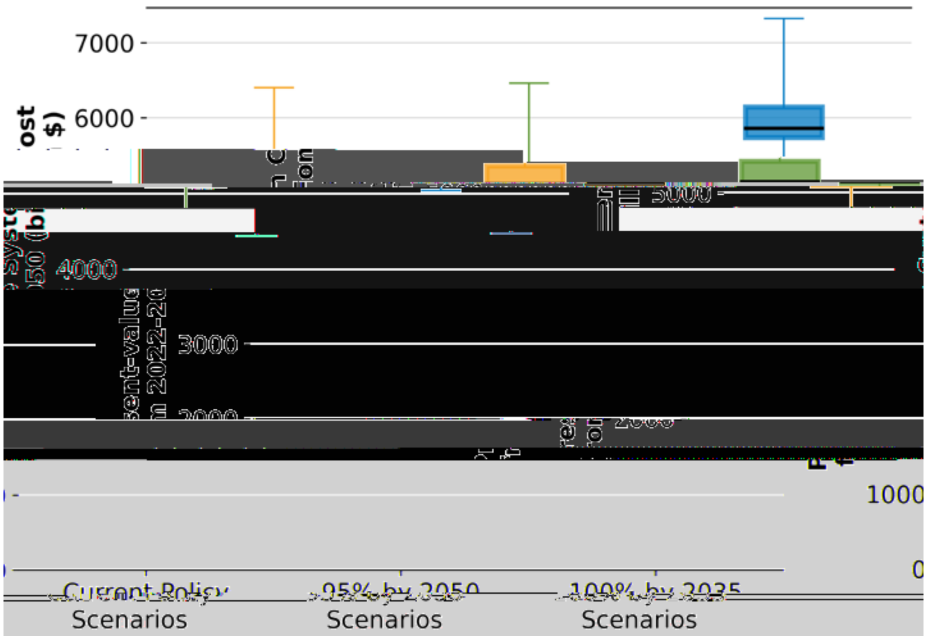

Figure 12. Present-value system costs, 2022–2050

The boxes show the 25th–75th percentile of results, the black bar is the median value, and the whiskers show the full range of results. System costs are the present-value (2022$) of the U.S. bulk power system from 2022 through 2050 using a 1.7% social discount rate. The three mid-cases have values of $5,104 billion, $5,131 billion, and $5,842 billion for the Current Policies, 95% by 2050, and 100% by 2035 scenarios respectively.

4.9 Marginal Energy and Capacity Costs

Figure 11 shows the trends in the marginal costs[26] of two major grid services modeled in ReEDS. The services are energy (providing enough generation to meet demand at each point in time) and capacity (maintaining enough capacity to meet the planning reserve requirement, which is the annual maximum demand and an additional margin that varies by region).[27]

[26] These marginal costs are the shadow prices on the constraints that represent these grid services. These marginal costs are not equivalent to average expenditures per unit of electricity. Non-modeled costs, such as the costs of maintaining and expanding the distribution system, administrative costs, or program management costs, are not included.

[27] Figure 11 starts in 2026 because the ReEDS model does not have endogenous capacity expansion prior to that point, and therefore the system is not in long-run equilibrium.

Marginal energy costs are influenced by the presence or absence of the IRA's tax credits, the CO_2 reduction requirement, natural gas prices, and technology costs. Energy costs tend to decline slightly over time under Current Policies due primarily to steadily declining technology costs and improving technology performance. The 95% by 2050 scenarios follow a similar trend until the late 2040s, when the national CO_2 emissions constraint typically starts to have an effect (i.e., prior to that point the national emissions reductions outpaced the constraint), raising marginal energy costs. The 100% by 2035 scenarios have materially higher marginal energy costs, both because of the stringency of the national CO_2 emissions constraint as well as the relatively early expiration of IRA's renewable energy tax credits.

In both the Current Policies as well as 95% by 2050 scenarios the marginal planning reserve costs tend to grow rapidly through the remainder of the 2020s and afterward largely level out. The 100% by 2035 scenarios have generally similar magnitudes until the national CO_2 emissions constraint reaches 100%, after which the marginal planning reserve costs are materially higher than in their counterpart sensitivities.

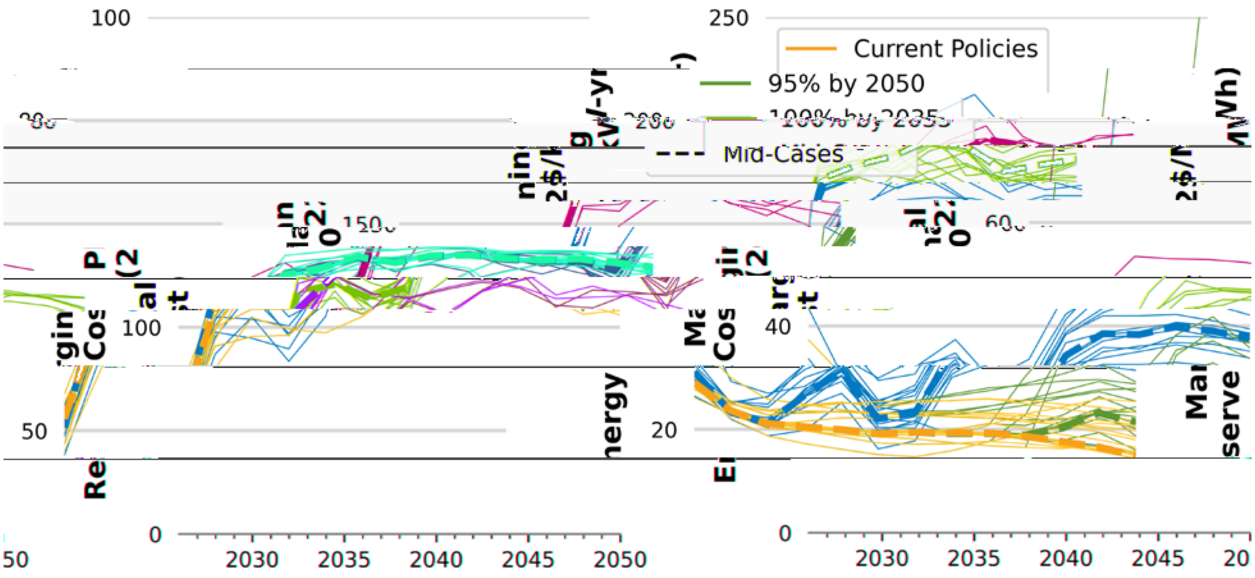

Figure 13. National annual average marginal costs for energy and capacity services. The Mid-case scenarios are shown with the heavier dashed lines. Costs are in 2022 dollars.

4.10 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 often result in curtailment rates beyond 10% in 2050.

The impact of the clean electricity tax credits can be seen most clearly in the 100% by 2035 scenarios: the tax credits phase out by the late 2030s, after which the curtailment rate drops significantly. The single 100% scenario that does not have a drop is the No Expiration of IRA Tax Credits sensitivity, which has the clean electricity tax credits persist indefinitely.

Figure 14. Wind and solar curtailment

The Mid-case scenarios are shown with the heavier dashed lines.

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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 section after the table.

For details about the structure and assumptions in the models not mentioned here, see the documentation for ReEDS (Ho et al. 2021) and dGen (Sigrin et al. 2016). Both models are publicly available,[28] and inputs are viewable within the model repositories. 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 2023 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)

[28] 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*	*2023 ATB moderate projections*
	Advanced RE and Battery Cost and Performance	2023 ATB advanced projections for renewable energy and electric battery storage technologies[b]
	Conservative RE and Battery Cost and Performance	2023 ATB conservative projections for renewable energy and electric battery storage technologies[b]
	Advanced CCS Cost and Performance	2023 ATB advanced projection for coal and natural gas CCS greenfield technologies; EIA-NEMS plant-level costs for CCS retrofits with declines based on 2023 ATB advanced projections
	Conservative CCS Cost and Performance	2023 ATB conservative projection for coal and natural gas CCS greenfield technologies; EIA-NEMS plant-level costs for CCS retrofits with declines based on 2023 ATB conservative projections
	Advanced Nuclear Costs	Small modular reactor costs decline to $4000/kW (2019$) by 2030, decline based on ATB mid projection rate after that
Resource Availability	*Default Resource Constraints*	*Reference resource constraints. See* ReEDS documentation (Ho et al. 2021) *for details.*
	Reduced RE Resource	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 Technology Sets section below*

Group	Scenario Setting	Notes
	No Nascent Generation Technologies	Nascent generation technologies excluded, see Technology Sets section below
Transmission Availability	*Reference Transmission Availability*	*Unrestricted transmission expansion 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	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	VSC HVDC transmission lines disabled as investment option; new transmission builds only allowed within 11 transmission planning regions and between regions already connected, existing LCC can be expanded but no new interfaces, 1.07 TW-mile/year limit on new transmission investment
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 Law*	*Includes state, regional, and federal policies as of September 2023*
	95% by 2050	*95% net reduction in electricity sector CO_2 emissions by 2050 (relative to 2005)*
	100% by 2035	*Net-zero electricity sector CO_2 emissions by 2035*
	No Expiration of IRA Tax Credits	IRA tax credits for energy technologies (clean electricity PTC, clean electricity ITC, 45Q, 45U) 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.
[c] VSC is voltage source converter, LCC is Line-commutated converters.

Demand Growth and Flexibility

This year's Standard Scenario suite includes three different non-hydrogen end-use electricity demand trajectories, all produced through modeling by Evolved Energy Research (EER). The Reference Demand Growth trajectory reaches 6,509 TWh/year of electric load by 2050 (a CAGR of 1.8% from 2024 through 2050, see Figure A-1). It reflects relatively conservative assumptions about the impact of demand-side provisions in the Inflation Reduction Act (relative, compared to other scenarios developed by EER). More information about EER's outlook can be found in (Haley et al. 2022), although their published material does not yet describe their modeling of the impacts of IRA.

The Low Demand Growth trajectory reaches 5,054 TWh/year of electric load by 2050 (a CAGR of 0.9% from 2024 to 2050, see Figure A-1). It is largely similar, but not identical, to EER's Baseline scenario from (Haley et al. 2022). EER describes the scenario as a business-as-usual scenario based on the EIA's AEO 2022. It does not include the effects of IRA's demand-side provisions.

The high demand growth trajectory reaches 8,354 TWh/year of electric load by 2050 (a CAGR of 2.8% from 2024 to 2050). It is largely similar, but not identical, to EER's Central scenario from (Haley et al. 2022). EER describes the scenario as achieving least-cost economy-wide net-zero greenhouse gas emissions for the U.S. by 2050, inclusive of energy and industrial CO_2, non-CO_2 greenhouse gases, and the land CO_2 sink. It does not directly include representations of IRA's demand-side provisions, although many of IRA's provisions would prompt directionally similar changes in demand.

In addition to the three non-hydrogen end-use demand trajectories, two sensitivities (Hydrogen Economy, High Demand Growth and Hydrogen Economy) also have an imposed demand for electrolysis-produced hydrogen. The hydrogen demand is described further in the following section; in Figure A-1 below we show the total end-use electric demand for those scenarios, inclusive of the electricity consumption necessary to produce the required hydrogen, given the assumed electrolyzer efficiencies. The electrolyzer efficiencies start at 55 kWh/kg-H_2 in 2026 and reach 51.5 kWh/kg-H_2 by 2050.

We assume inelastic, inflexible electricity demand in all scenarios. 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 would likely induce more loads to become grid-responsive, especially with the electrification of certain end-uses (such as vehicles). The omission of elastic and flexible loads from this modeling would tend to create systems that are more expensive and more difficult to integrate variable generators into, relative to situations where load is elastic and flexible.

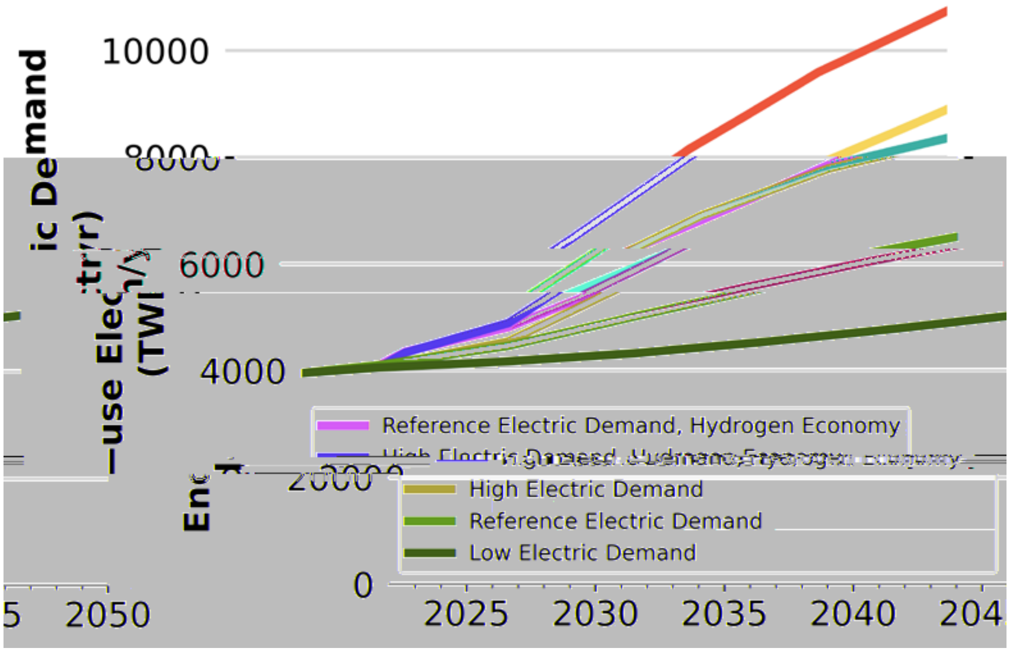

Figure A-1. End-use demand trajectories used in the Standard Scenarios

The two Hydrogen Economy trajectories include the annual electric load necessary to produce the imposed hydrogen demand, given the assumed electrolyzer efficiency

Figures A-2 through A-5 show average national end-use electricity demand patterns by hour and month (excluding any demand for hydrogen production). Note that the figures show the national demand patterns in Eastern Time, which has the effect of smoothing the diurnal patterns—the diurnal pattern for any specific region would tend to be peakier.

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 the trend that, the greater the assumed load growth, the greater the winter peaks in the load profiles. 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.

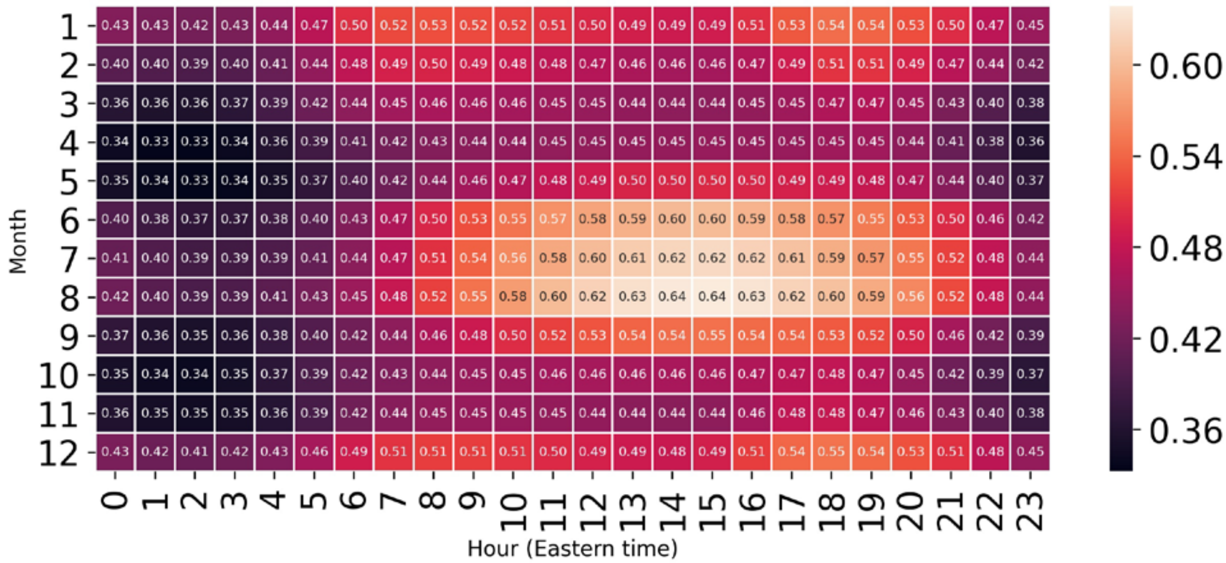

Figure A-2. Month-hour end-use national demand, in TWh, in 2024 for the Reference demand trajectory

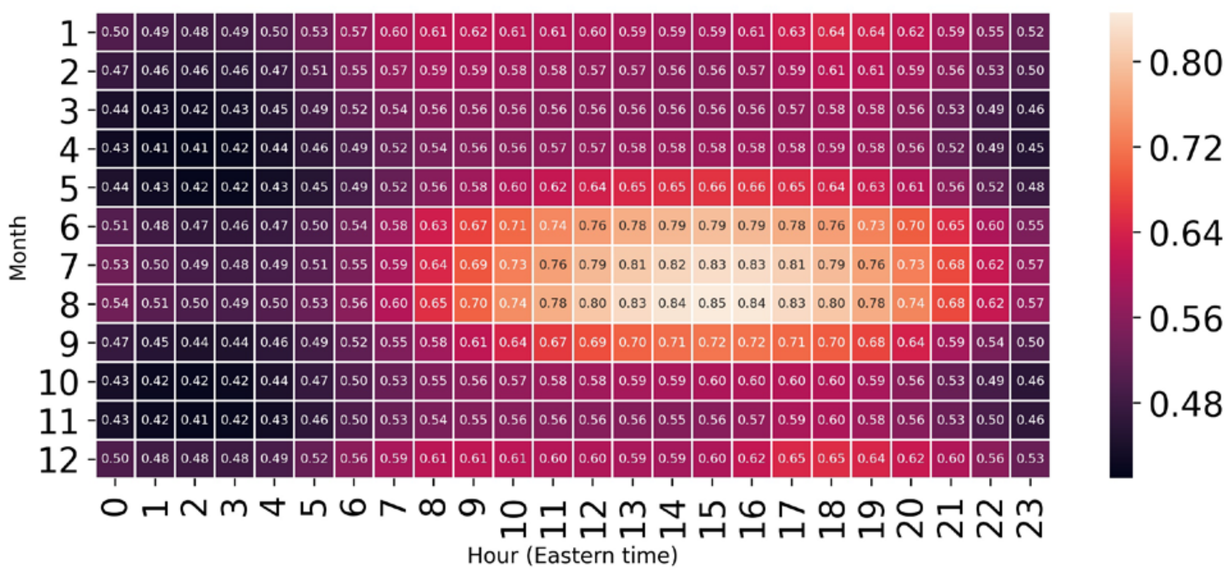

Figure A-3. Month-hour average end-use national demand, in TWh, in 2050 for the Low demand trajectory

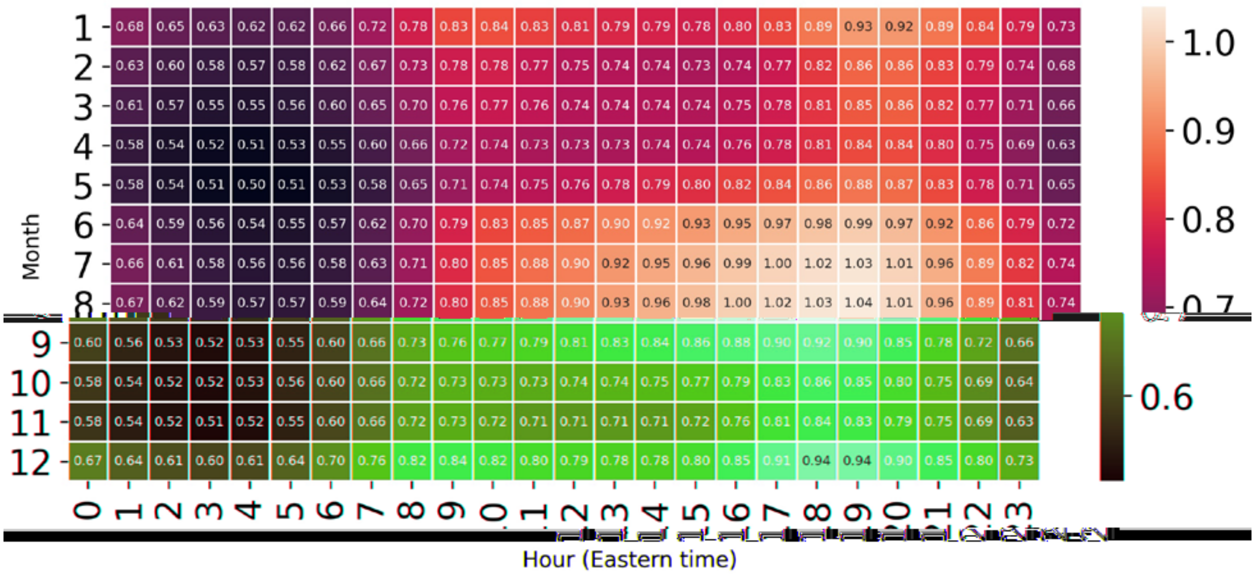

Figure A-4. Month-hour average end-use national demand, in TWh, in 2050 for the Reference demand trajectory

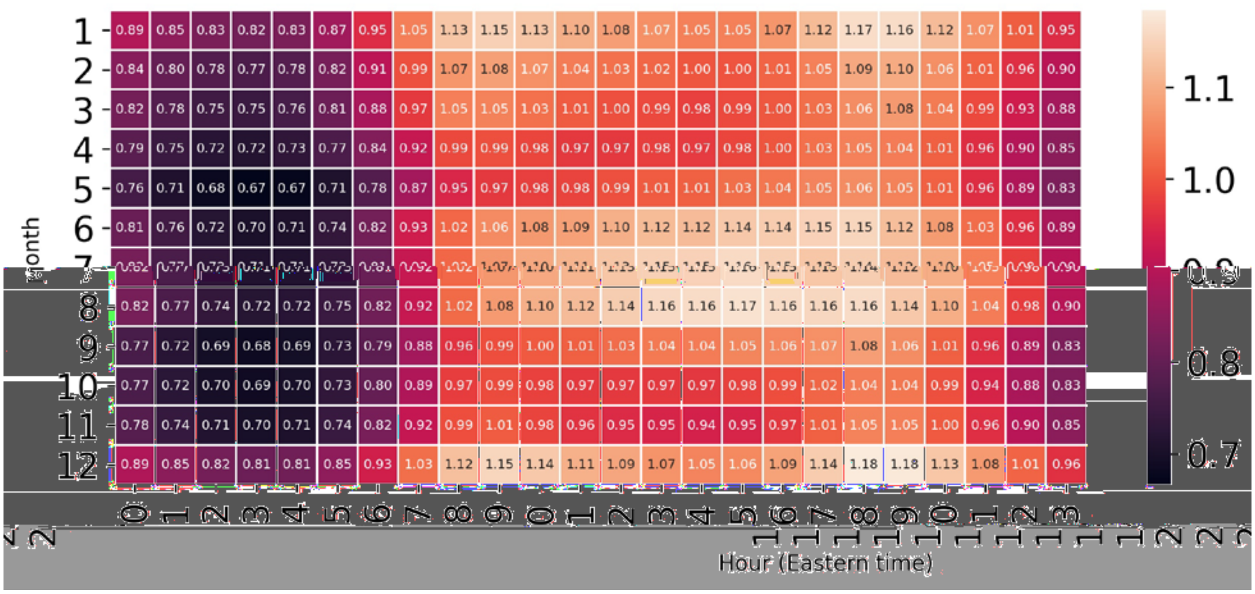

Figure A-5. Month-hour average end-use national demand, in TWh, in 2050 for the High demand trajectory

Endogenous Hydrogen Production and Hydrogen Economy Sensitivities

Unlike previous Standard Scenarios, this year's modeling includes an endogenous representation of hydrogen production using low temperature electrolyzers. Electrolyzers consume electricity and create hydrogen, therefore the fuel cost of H2-CTs is now 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. 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 sensitivities that exclude nascent technologies).

None of the scenarios include a representation of 45V, the tax credit for the production of clean hydrogen in IRA, as the Treasury Department has yet to release guidance on how the determination of the emissions intensity of hydrogen will be conducted.

Additionally, there are two sensitivities that 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, and the electric load from the production of that hydrogen was shown previously in Figure A-1. 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 exogenous demand for non-power-sector hydrogen is zero.

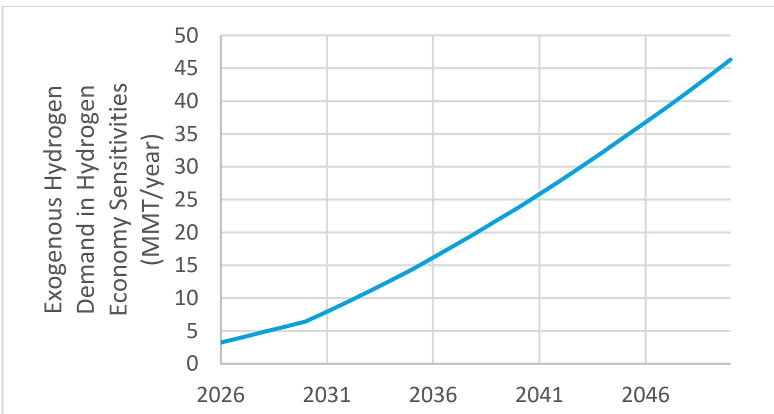

Figure A-6. Non-power-sector hydrogen demand in Hydrogen Economy sensitivities

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.

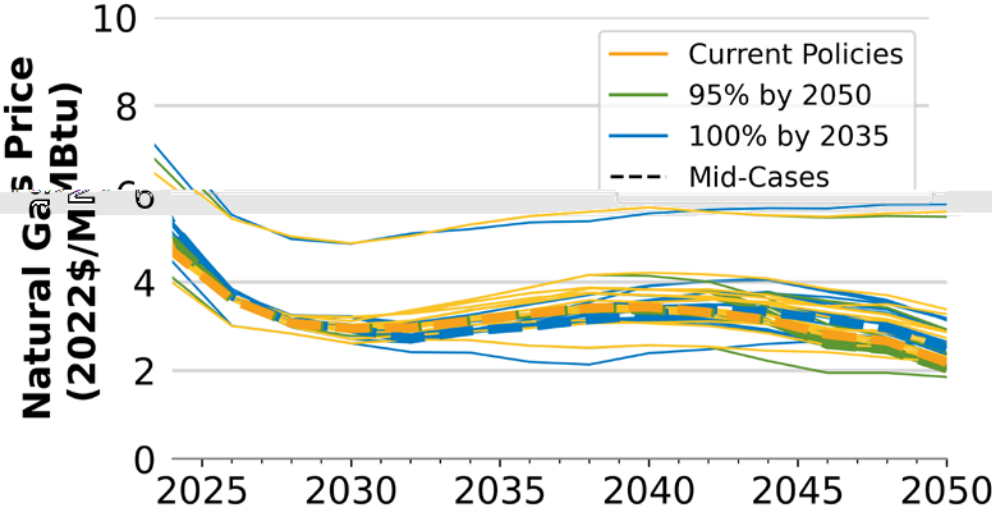

Figure A-7. National average natural gas price outputs from the suite of scenarios

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.

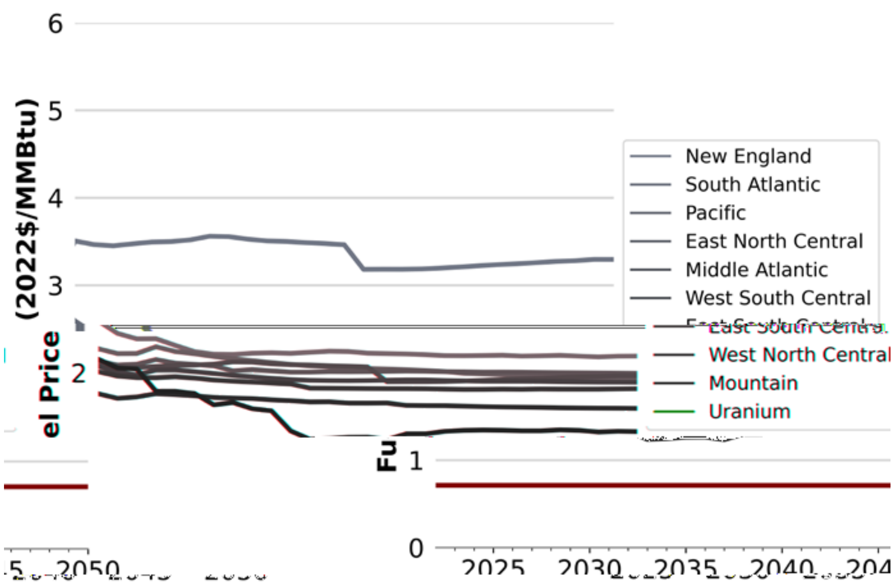

Figure A-8. Input coal and uranium fuel prices used in the Standard Scenarios

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 2023 ATB (NREL 2023). 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 low renewable energy (RE) and battery cost scenarios use the advanced projections for all renewable energy and battery technologies, and the high RE and battery cost scenarios use the conservative projections (for these scenarios, RE technologies include all solar, geothermal, hydropower, and wind generators).

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

Low nuclear costs are not available in the ATB, so to create a low nuclear cost projection, we assume nuclear overnight capital costs for small modular reactor technologies decline to $4000/kW (2019$) (the Low estimate from (Abou Jaoude et al. 2023)) by 2030, and then continue to decline at the same rate as the ATB Reference trajectory declines from 2030 through 2050 (see Figure A-9).

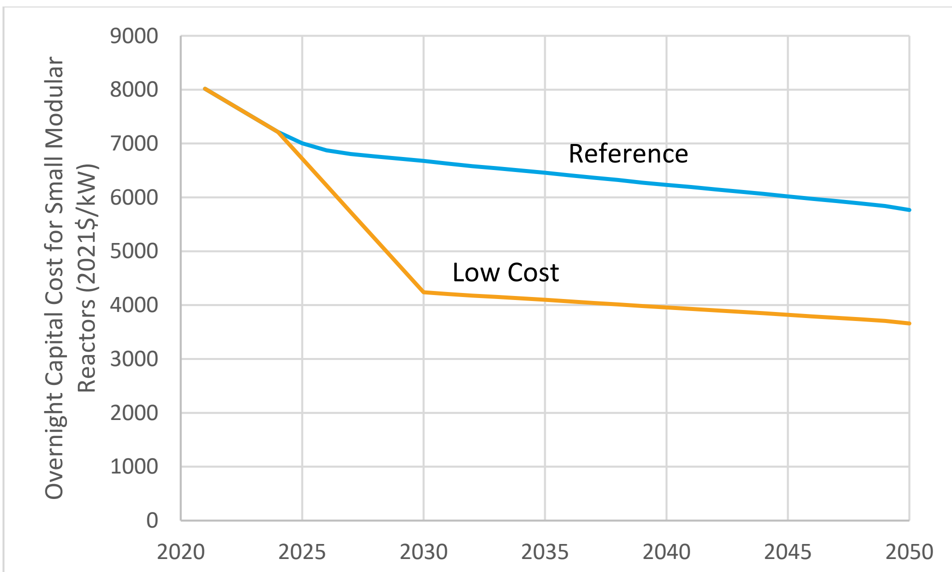

Figure A-9. Capital cost projections for small modular reactor technologies

Hydrogen combustion turbines (H2-CT) are represented consistent with the RE-CT technology in the Solar Futures Study (DOE 2021). H2-CTs can 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-2 and A-3. 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-2. 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-3. 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

As a nascent technology, the future cost and performance of generators with CCS is particularly uncertain. Because of this, this year's Standard Scenarios 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 for gas and coal CCS technologies are taken from the conservative, reference, and advanced trajectories of the 2023 ATB. Variable and fixed O&M cost estimates are both taken from the 2023 ATB's three trajectories.

Plant-level retrofit capital cost estimates are provided in the EIA-NEMS data set 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 2023 ATB.

Heat rates for CCS generators are based on the values in the three trajectories in the 2023 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 2023 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).

Reduced Renewable Energy Resource and Restricted Siting

This scenario reduces the amount of renewable energy resource that could be developed in ReEDS. For land-based wind, additional setbacks and land exclusions are applied that reduce the resource available to 5.9 TW, compared with 11.1 terawatts (TW) in the default case. The reductions vary by region and are largely based on the methods and assumptions from Lopez et al. (2021), but updated to consider the impacts of shadow flicker. A similar method is applied for offshore wind, where the deployable resource is reduced from 4.3 TW in the default cases to 2.0 TW with more stringent siting constraints. These reductions 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 57.7 TW, compared with 112.4 TW in the default case. For other renewable energy technologies (CSP, geothermal, hydropower, and biopower) technical potential is reduced by 50%. The reduction is applied uniformly across geography and resource classes (i.e., all regions and classes experience the same 50% reduction).

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-4 below.

Table A-4. Generation Technology Classification in the 2023 Standard Scenarios

Technology Group	Technologies
Established	• Electric batteries (4-hour and 8-hour duration) • Biopower • Coal • 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, we have included a sensitivity that does not include these technologies.

Transmission Expansion

All scenarios allow the current transmission network to be expanded starting in 2028 (no transmission investment is allowed prior to 2028). 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 1,000 transmission planning regions and the Electric Reliability Council of Texas, or ERCOT).

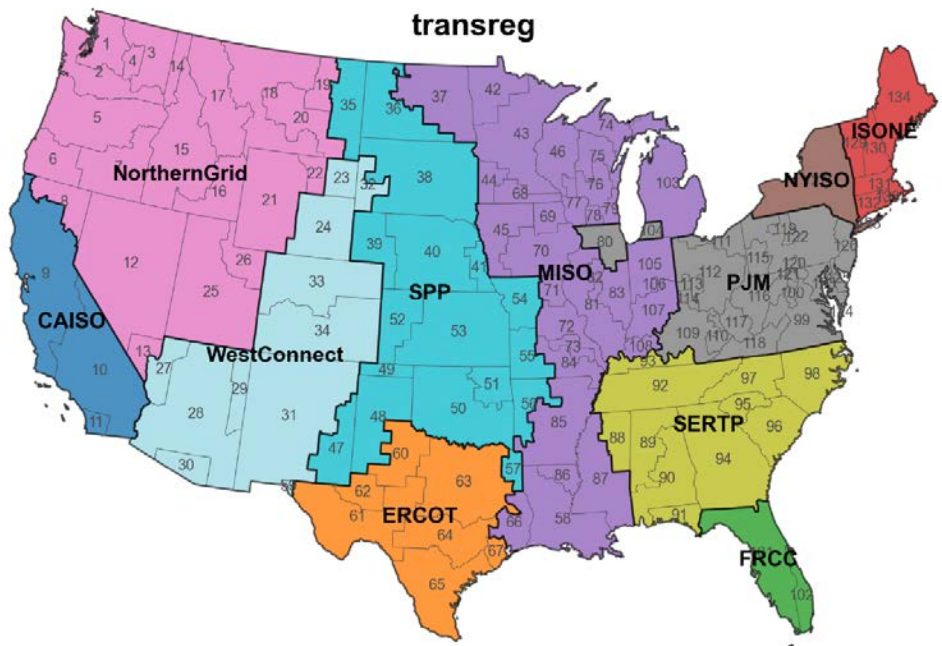

Figure A-11. Transmission planning regions used in Low Transmission Availability sensitivity

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 rely on 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. Due to staffing limitations, this year's Standard Scenarios did not generate new rooftop PV adoption projections: the projections from last year's Standard Scenarios were used again here. Three adoption projections were used, corresponding to the Mid-case, Low RE Cost, and High RE Cost assumptions. The dGen projections for rooftop PV are used as exogenous inputs in the ReEDS model. ReEDS then projects the grid evolution through 2050, resulting in most of the outputs reported here. See Section 2.3 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 September 2023. These include representation of IRA's provisions, 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. Only enacted legislation or programs are included: proposed rules, proposed modifications to existing rules, and unenforced goals 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 the ReEDS repository and ReEDS 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 phaseout of IRA tax credits. In the No Expiration of IRA Tax Credits sensitivity, the IRA clean electricity PTC and ITC, the IRA incentive for existing nuclear production (45U), and the IRA incentive for capturing and storing carbon (45Q) are all extended indefinitely.

A.2 Changes from the 2022 Edition

Since last year's Standard Scenarios report (Gagnon et al. 2022), we have made the key modeling changes in the ReEDS model that are summarized in Table A-5.

Table A-5. Key Differences in Model Inputs and Treatments for ReEDS Model Versions

Inputs and Treatments	2022 Version	2023 Version
Fuel prices	AEO2022	AEO2023
Demand growth	Electrification Futures Study, AEO2022	Trajectories modeled by EER in 2023
Generator technology cost, performance, and financing	2022 ATB[a] for most technologies, other than where specified in the 2022 Standard Scenarios report	2023 ATB[a] for most technologies, other than where specified in section A.1 above
Existing and planned generator plant database	AEO2022	AEO2023, and additional units from EIA860M that are reported as under construction or completed.
First year for endogenous builds	2022	2026 (2024 solve year assumed to be reflected in EIA860M data)

Inputs and Treatments	**2022 Version**	**2023 Version**
Endogenous hydrogen production	Fixed, exogenously defined fuel price for RE-CTs	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.
ReEDS temporal resolution	17 time-slices	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
Supply chain capital cost adjustment	Based on empirical observations in proprietary market reports, a technology-neutral multiplier of 1.1 was applied to the capital expenditures (CapEx) of all generators in 2022, linearly decreasing to 1.0 over 5 years.	2023 ATB cost estimates now incorporate the phenomena we sought to address; the adder was therefore removed.
Wind and Solar Supply Curves	Supply curves produced by NREL's reV model, version 2022	Supply curves produced by NREL's reV model, version 2023, includes updated setback and exclusions layers.
Network reinforcement costs	No network reinforcement costs	Network reinforcement costs for generator interconnection added, derived in reV model
Rooftop PV curtailment	Allowed	Disallowed
Generator minimum capacity factors	Generator minimum capacity factor constraint applied nationally by generator type	Generator minimum capacity factor constraint applied at the Balancing Area level by type
Transmission flows	No treatment of combined flows at interface	Combined flows across RTO/ISO boundaries constrained to n-1
Transmission investment	ReEDS can endogenously invest in up to 1.4 TW-mi per year from 2023 through 2027, and investment is unrestricted after that.	No transmission investment prior to 2028 in any scenario. In 2028 and onward, limit of 1.07 TW-mi per year of investment in the Low Transmission Availability sensitivity, otherwise no restriction on investment.
Voluntary procurement of clean energy credits	Not included	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).

Inputs and Treatments	2022 Version	2023 Version
CCS retrofit costs	Single retrofit cost derived from the difference between greenfield technologies with and without CCS plus 20% adder	Plant-level CCS retrofit costs now utilized from the EIA-NEMS plant database that is also used to initialize the model
Growth Penalties	No penalties or constraints on the rate of generator deployment	Cost penalties for rapid increases in the rate of generator deployment now imposed. When annual installation rate (state level by technology) exceeds 30% of prior maximum, 10% cost penalty added. When it exceeds 75%, 50% cost penalty added. Not allowed to exceed 100% year-over-year increases. Location of bins derived from historical deployment data.
PV-battery hybrid technology	Not available by default; only included in a sensitivity case due to lack of inputs for the Reduced RE Resource sensitivity. When enabled, multiple configurations are available for investment.	PV-battery hybrids were excluded from this year's modeling.
State policies	Policies as of September 2022	Policies as of September 2023

[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

As with the 2022 Standard Scenarios, this year's Standard Scenarios includes a representation of the main electricity sector provisions from the Inflation Reduction Act of 2022 (IRA). We 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. We highlight these omissions and simplifications below, and where analysts are using the data provided to perform derivative analyses, we encourage them to reflect critically on whether any omission is impactful for their specific purpose.

Four 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.

Note that IRA allows for bonus credits for both the clean electricity PTC and ITC (but not applicable to 45Q or 45U) 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. In ReEDS, we assume projects will, on average, capture one of the bonus credits by 2028, the value of which is expressed in the summary above. 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.[29] These cost penalties are not reflected in the values given for each incentive above.

The clean electricity PTC and ITC are scheduled to start phasing out when electricity sector greenhouse gas emissions 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 and 45U credits do not have a dynamic phaseout and are instead just scheduled to end at the end of 2032.

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

[29] 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.

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).

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.

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.

The 45V clean hydrogen PTC from IRA is not represented in this modeling. The omission is because the Treasury Department has yet to make a determination as to the methodology that will be used to evaluate the emissions intensity of hydrogen (and therefore the eligibility of production for the tax credit), and alternative proposals could materially affect how the grid evolves to support that production.

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

These metrics report the total nameplate capacity within a region for each of the specified technologies. Behind-the-meter PV is reported as the AC inverter capacity—it is not adjusted to a busbar equivalent capacity. The capacities of wind and solar generation are reported at their original nameplate capacities when they were installed (i.e., their reported capacity is not reduced over time by degradation). Electric battery capacities are reported by their duration (e.g., *battery_4_MW* is the MW capacity of 4-hour electric battery storage).

The nameplate 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 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. In 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 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 (Littlefield et al.

2019). Power plants are assumed to avoid distribution losses, which results in a fugitive methane emissions rate of 1.08%.[30]

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.

Sources indicated in Table A-6 are:

- US LCI: U.S. Life Cycle 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).
- National Energy Technology Laboratory (NETL) 2019: *Life Cycle Analysis of Natural Gas Extraction and Power Generation* (Littlefield et al. 2019)
- eGRID: eGRID2019 Data File, eGRID2020 Data File (EIA 2022).

Table A-6. 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)

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

Fuel	Type	Emission	Emission Factor	Units	Source
		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)
		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	277.45	g/MMBtu	NETL 2019
		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	277.45	g/MMBtu	NETL 2019
		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

Fuel	Type	Emission	Emission Factor	Units	Source
	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
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-12)
- Advanced Renewable Energy and Battery Costs and Performance (Figure A-13)
- Conservative Renewable Energy and Battery Costs and Performance (Figure A-14)
- Advanced Nuclear Cost and Performance (Figure A-15)
- Advanced CCS Cost and Performance (Figure A-16)
- Conservative CCS Cost and Performance (Figure A-17)
- Low Demand Growth (Figure A-18)
- High Demand Growth (Figure A-19)
- Hydrogen Economy (Figure A-20)
- High Demand Growth and Hydrogen Economy (Figure A-21)
- Low Natural Gas Prices (Figure A-22)
- High Natural Gas Prices (Figure A-23)
- No Expiration of IRA Tax Credits (Figure A-24)
- No Nascent Technologies (Figure A-25).
- Reduced Renewable Resources (Figure A-26).
- DC Macrogrid (Figure A-27).
- Low Transmission Availability (Figure A-28).
- Electricity-powered DAC (Figure A-29).

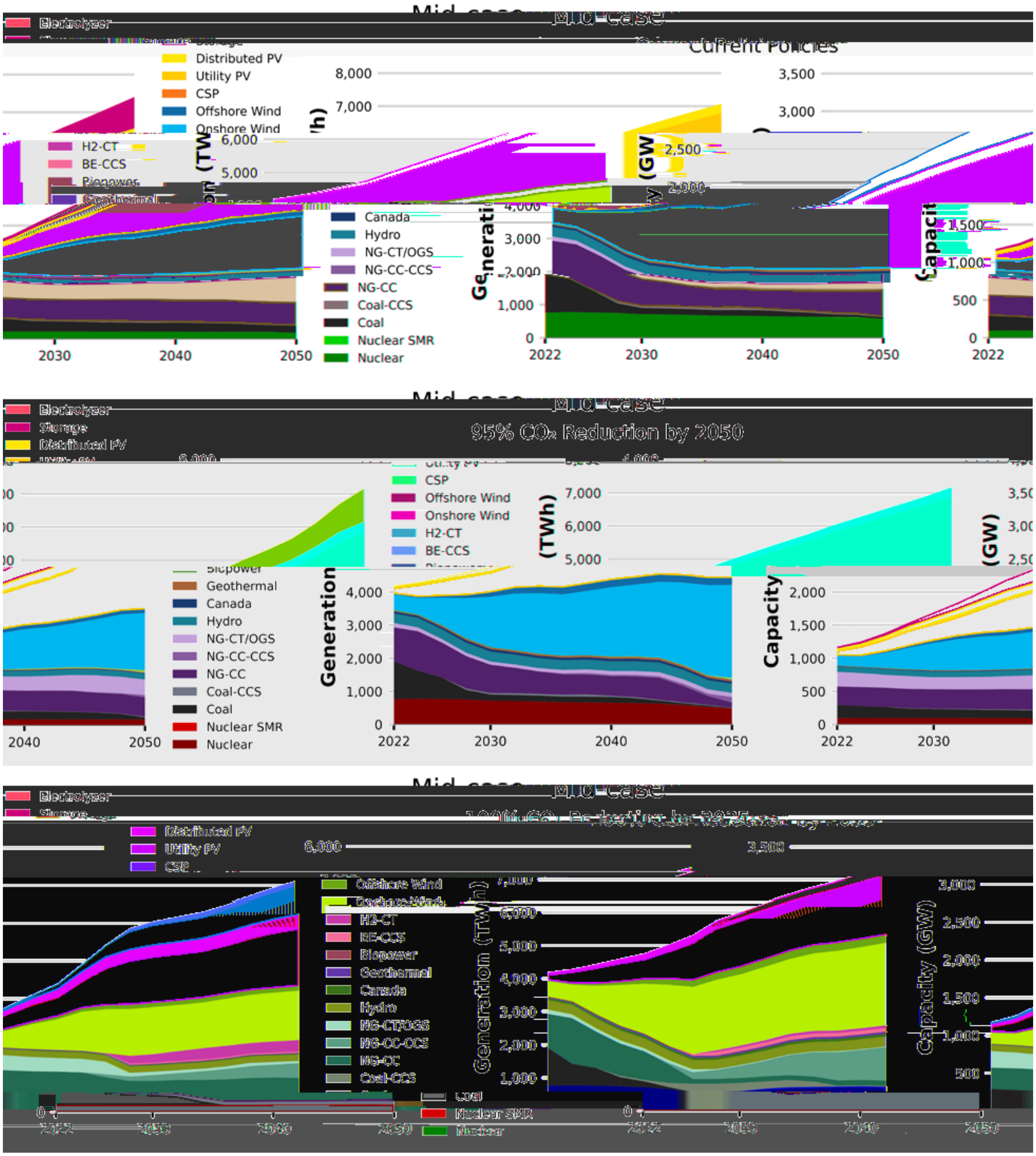

Figure A-12. Mid-case: Generation and capacity

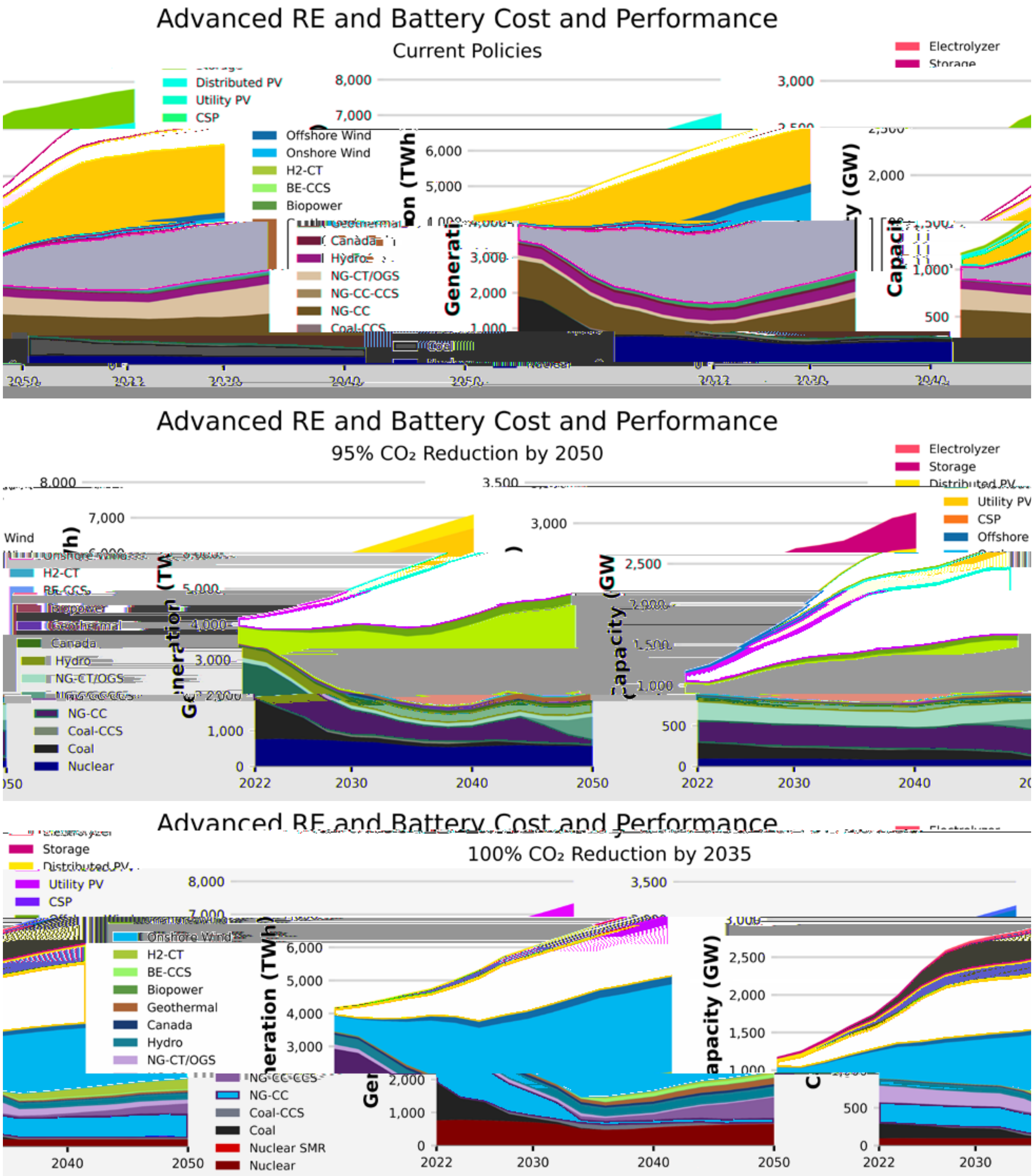

Figure A-13. Advanced RE and Battery Cost and Performance sensitivity: Generation and capacity

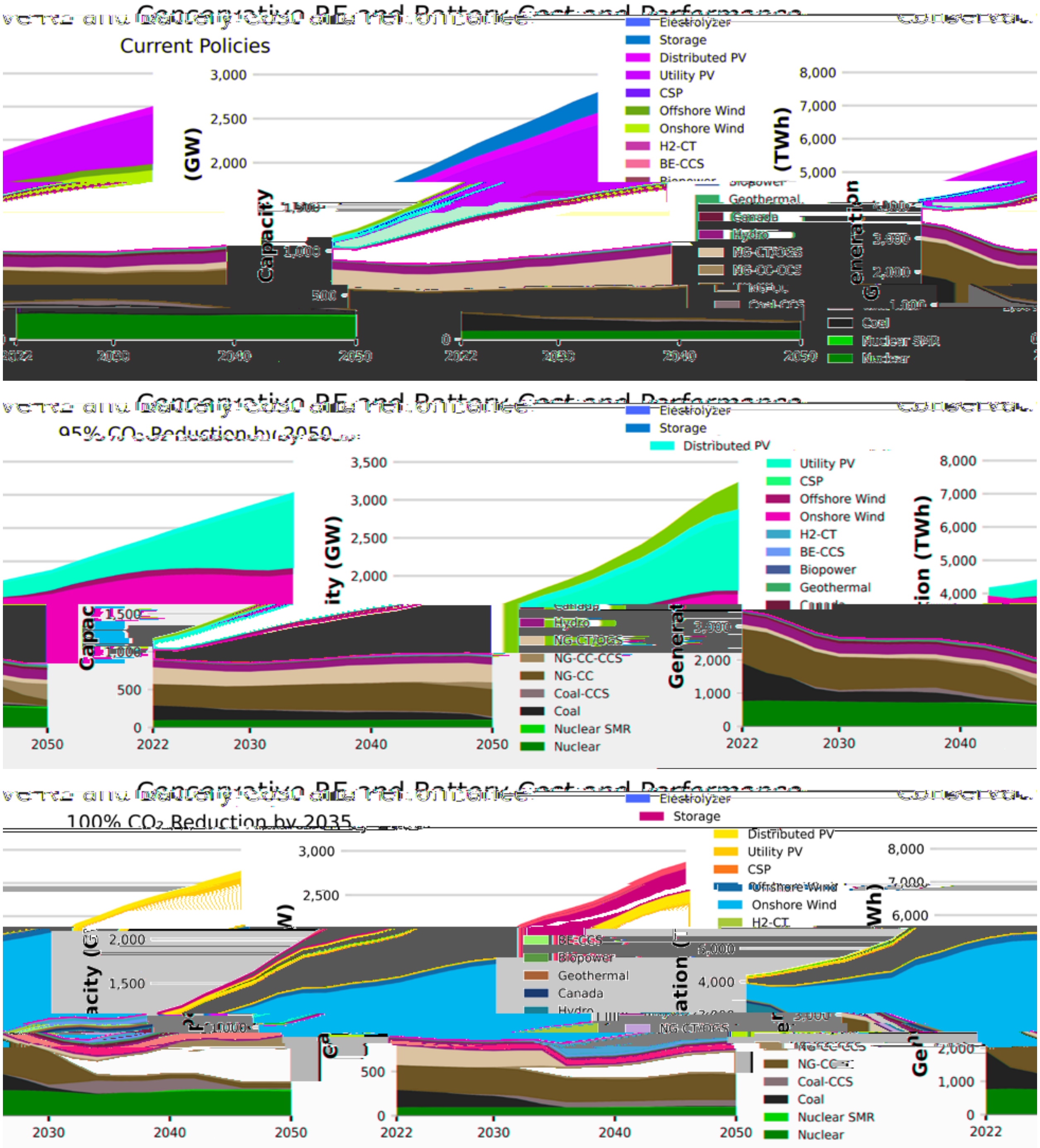

Figure A-14. Conservative RE and Battery Cost and Performance sensitivity: Generation and capacity

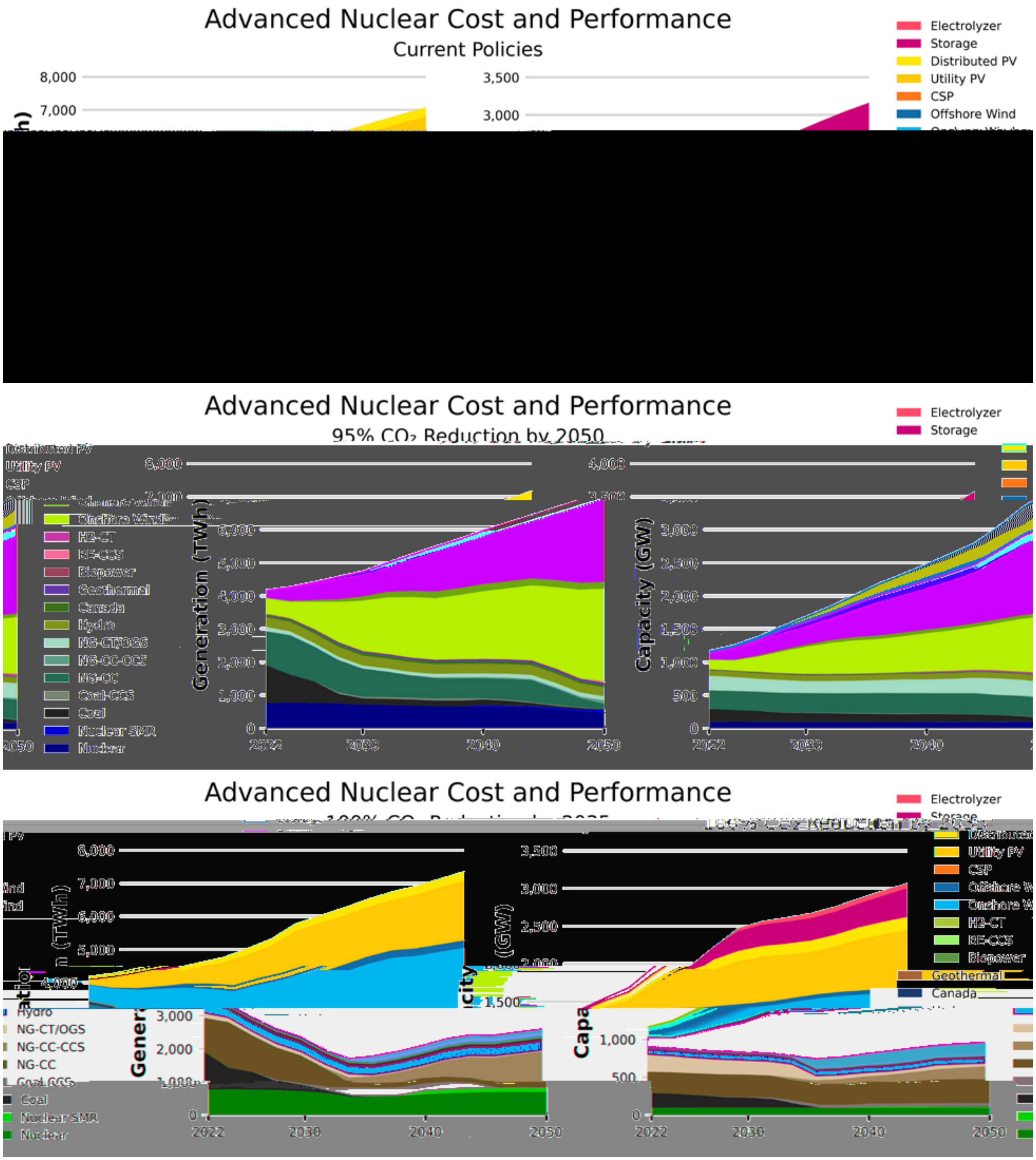

Figure A-15. Advanced Nuclear Cost and Performance sensitivity: Generation and capacity

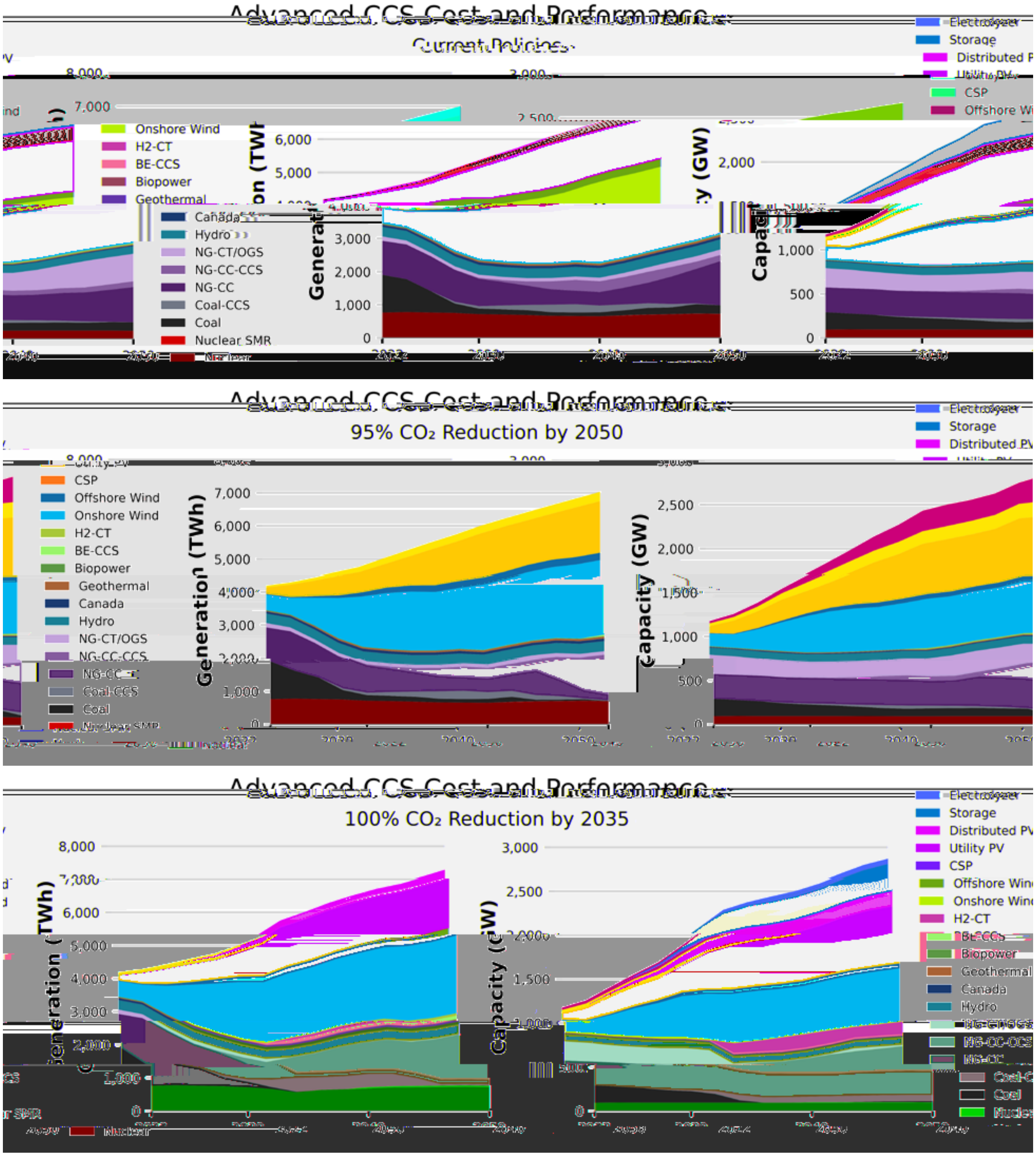

Figure A-16. Advanced CCS Cost and Performance sensitivity: Generation and capacity

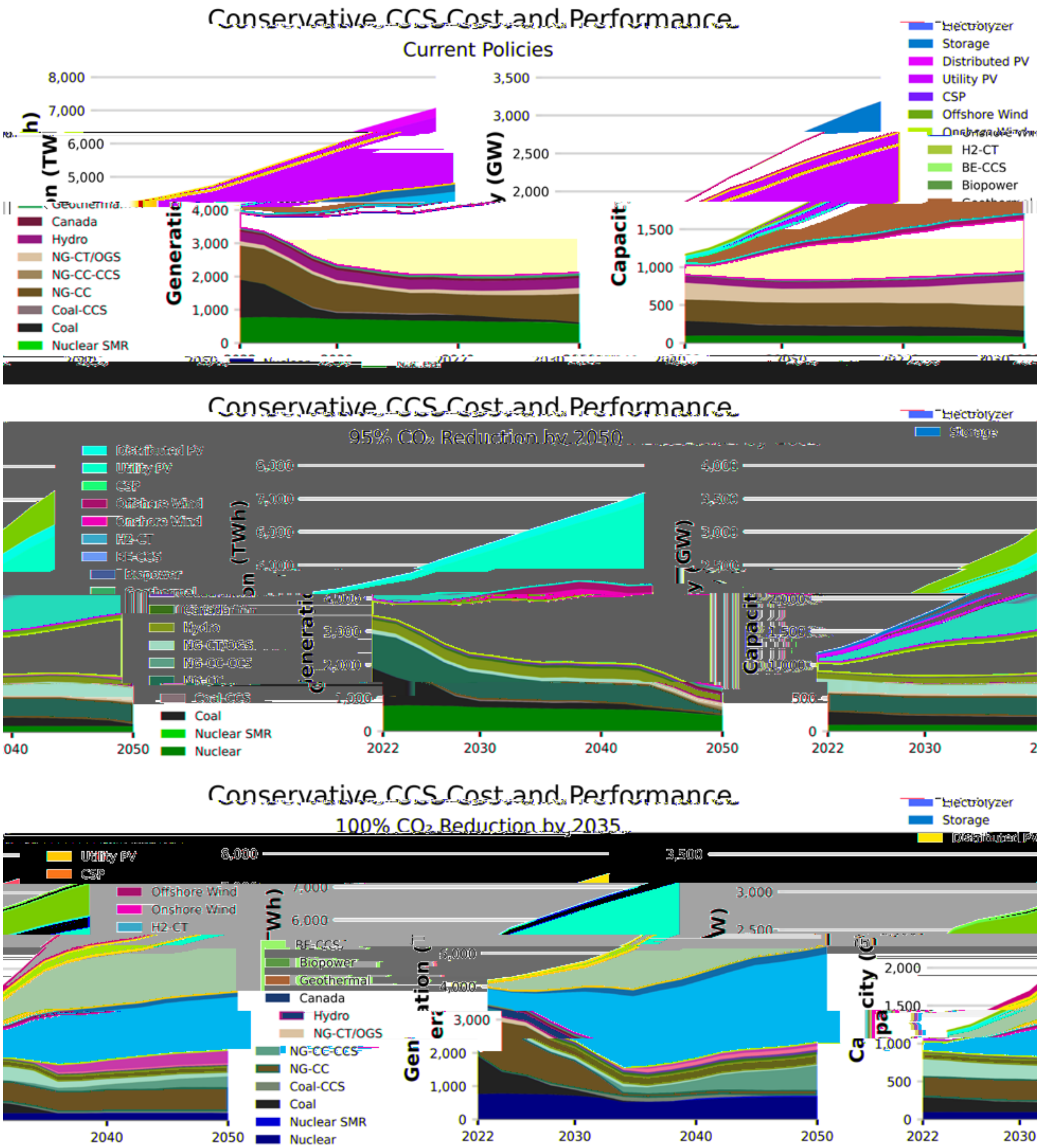

Figure A-17. Conservative CCS Cost and Performance sensitivity: Generation and capacity

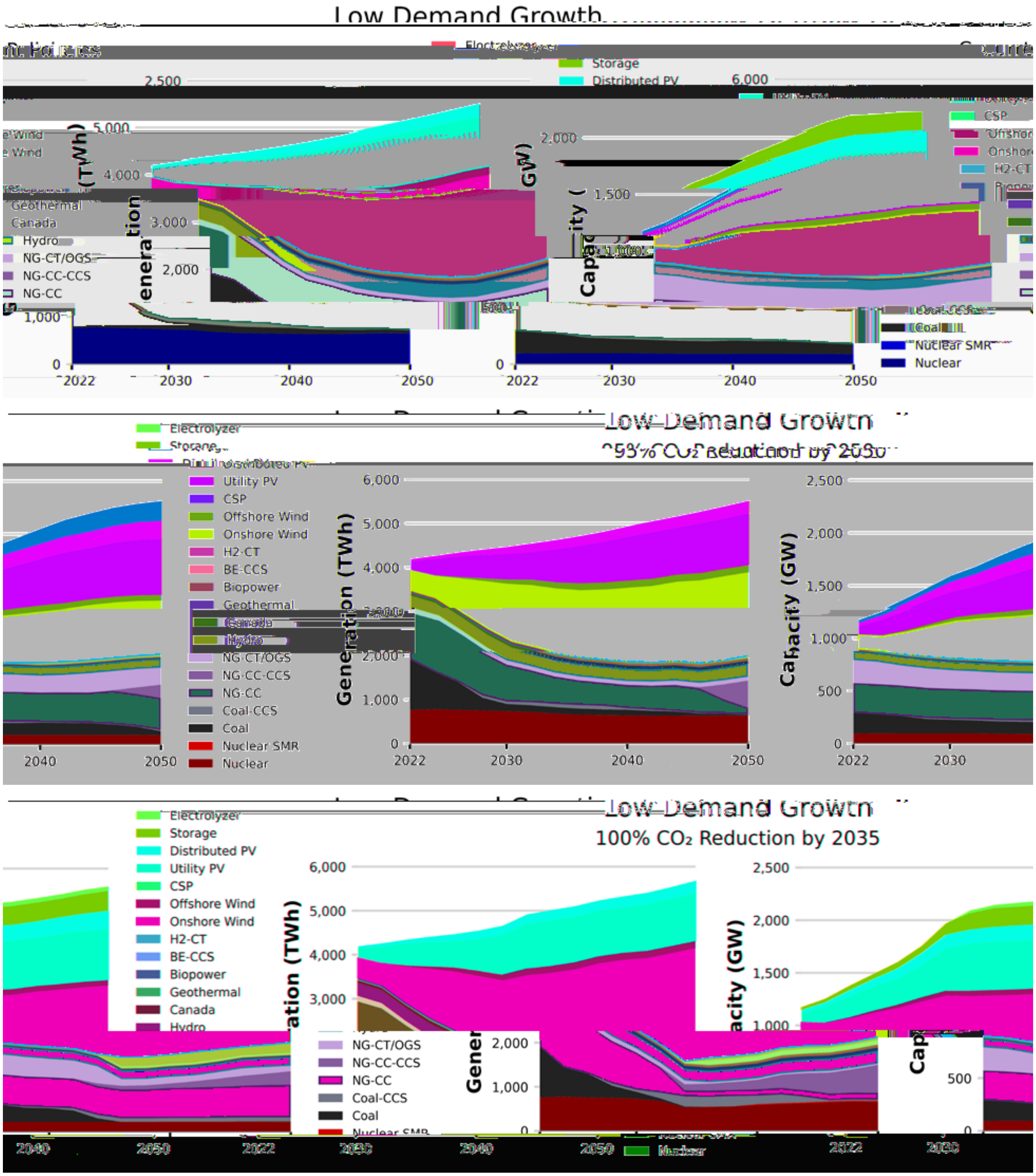

Figure A-18. Low Demand Growth sensitivity: Generation and capacity

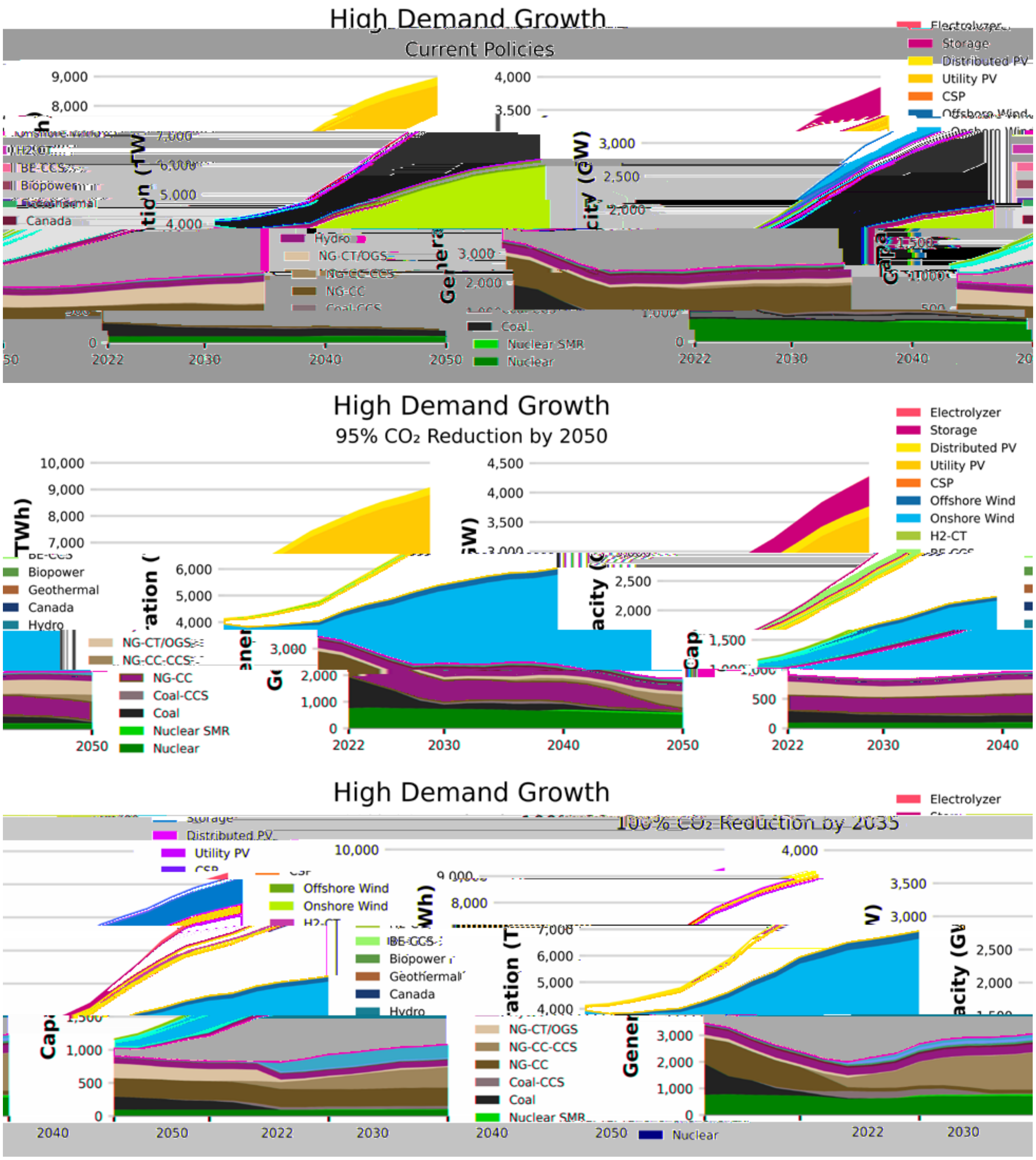

Figure A-19. High Demand Growth sensitivity: Generation and capacity

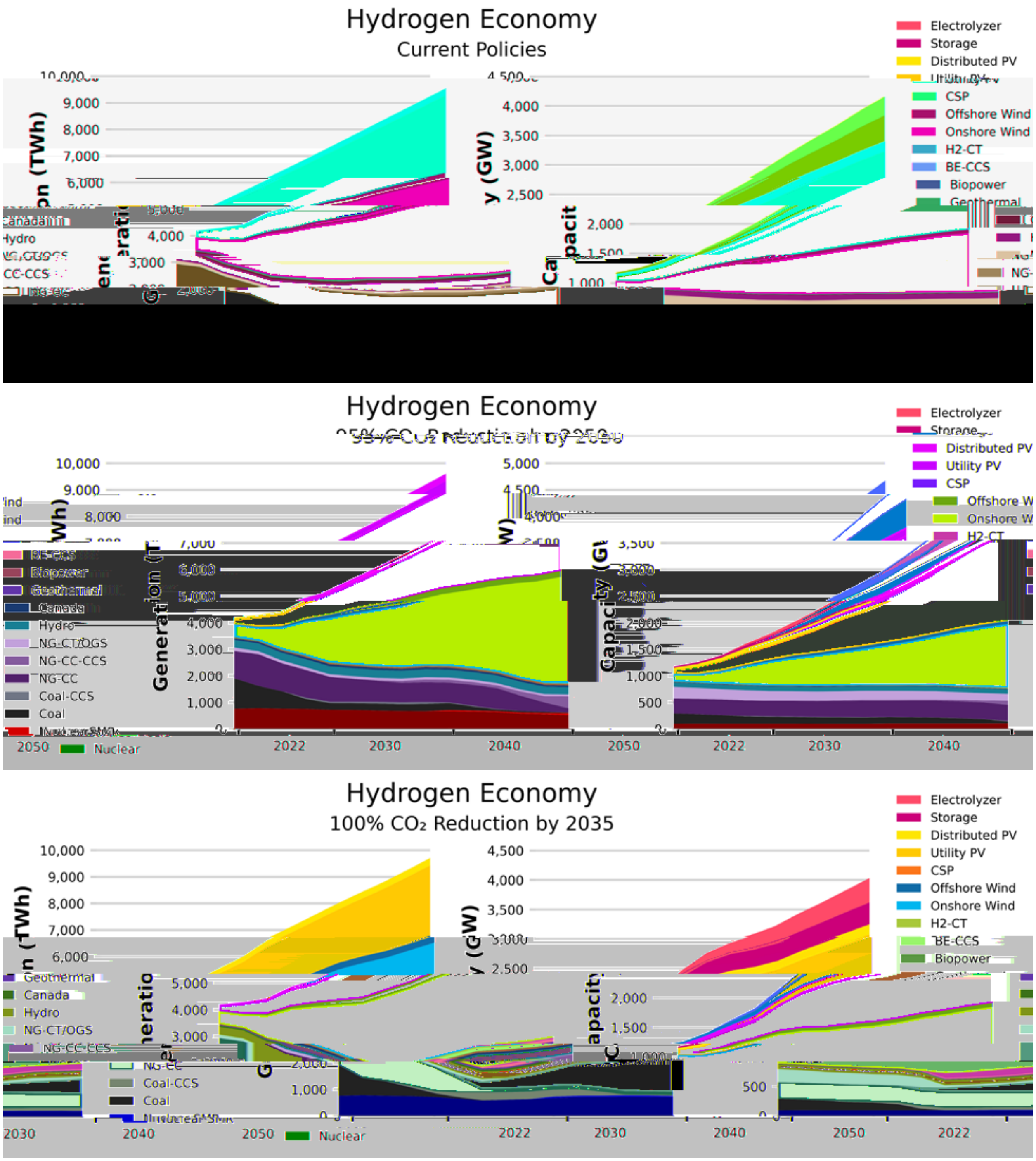

Figure A-20. Hydrogen Economy sensitivity: Generation and capacity

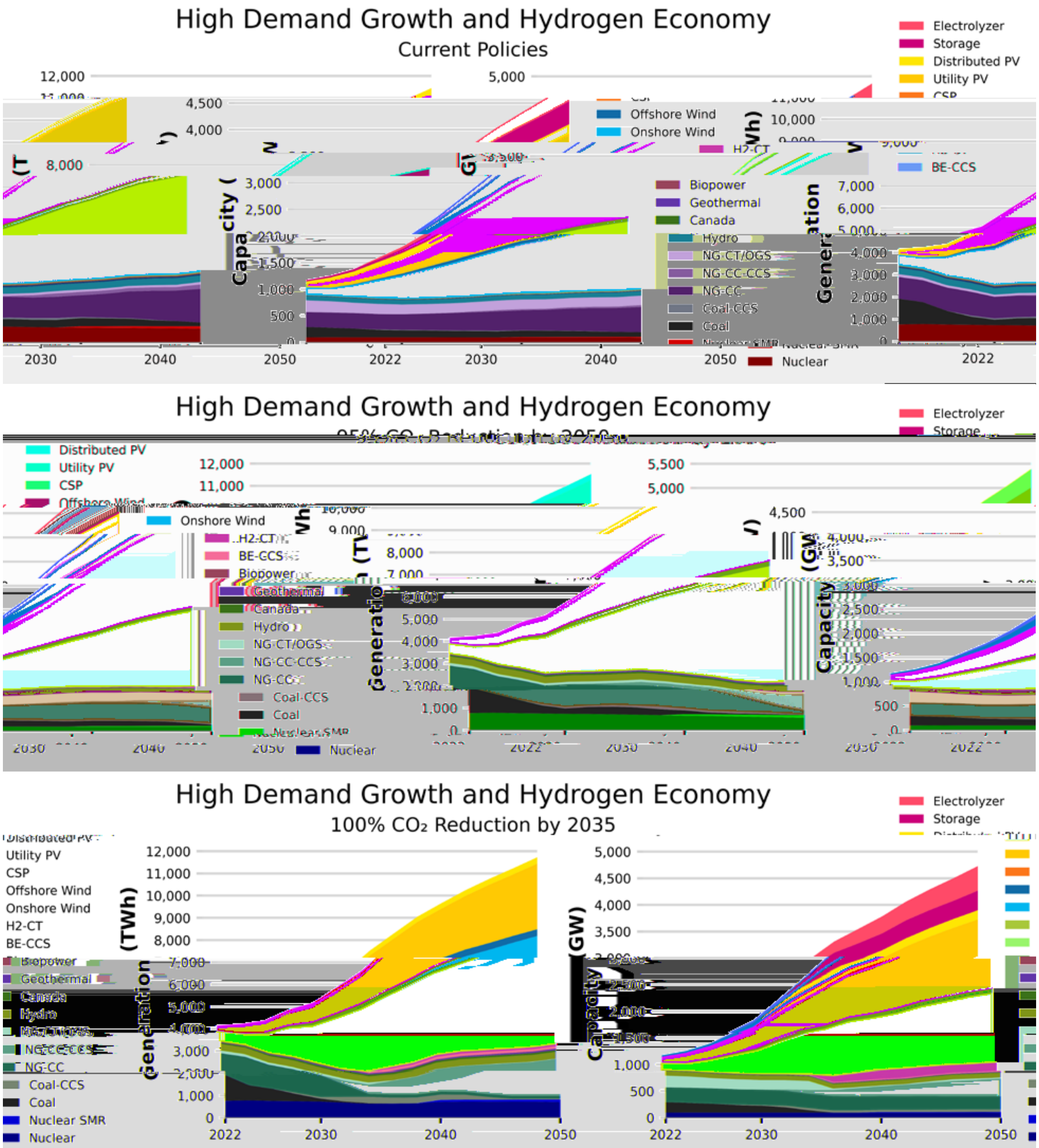

Figure A-21. High Demand Growth and Hydrogen Economy sensitivity: Generation and capacity

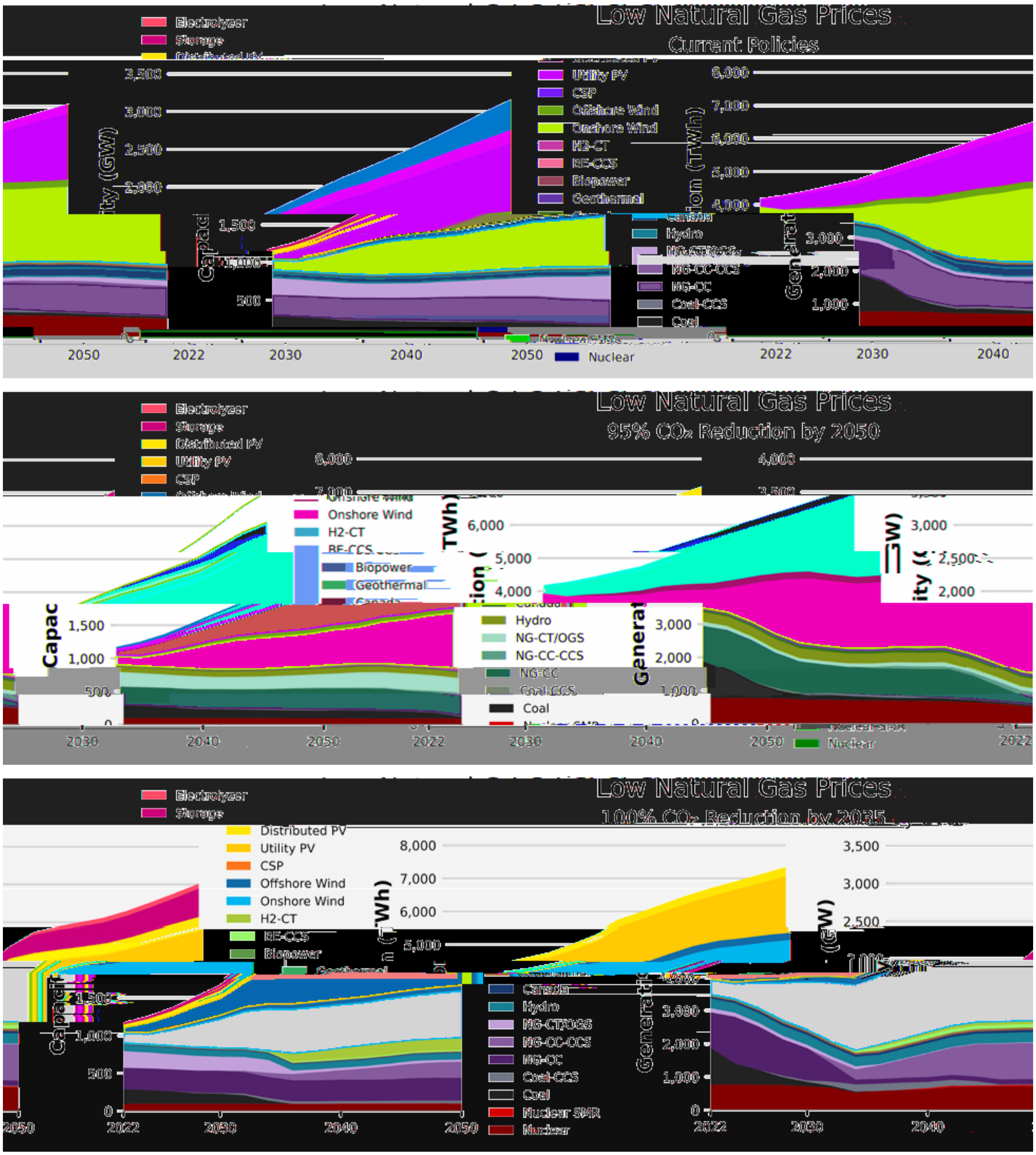

Figure A-22. Low Natural Gas Prices sensitivity: Generation and capacity

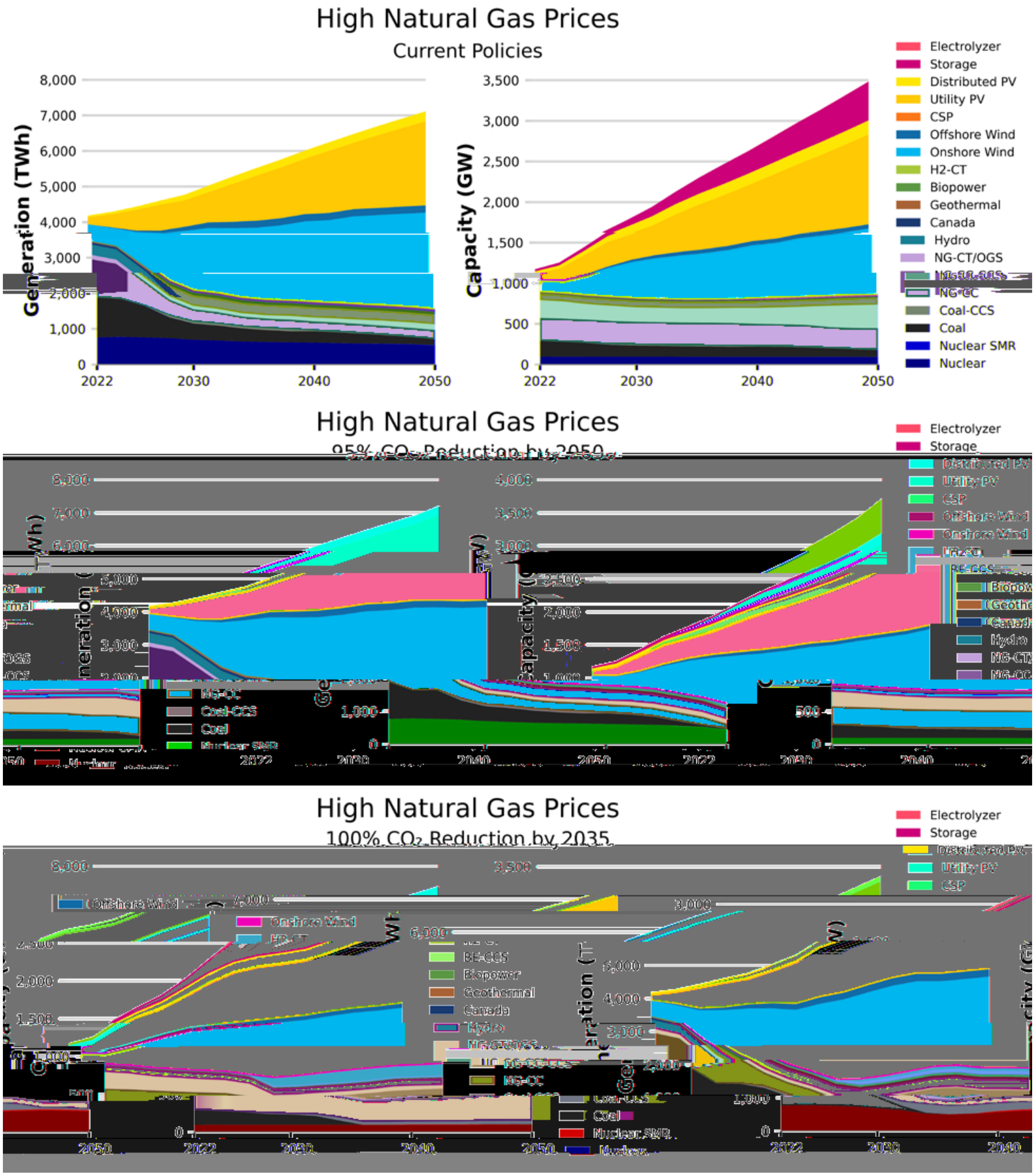

Figure A-23. High Natural Gas Prices sensitivity: Generation and capacity

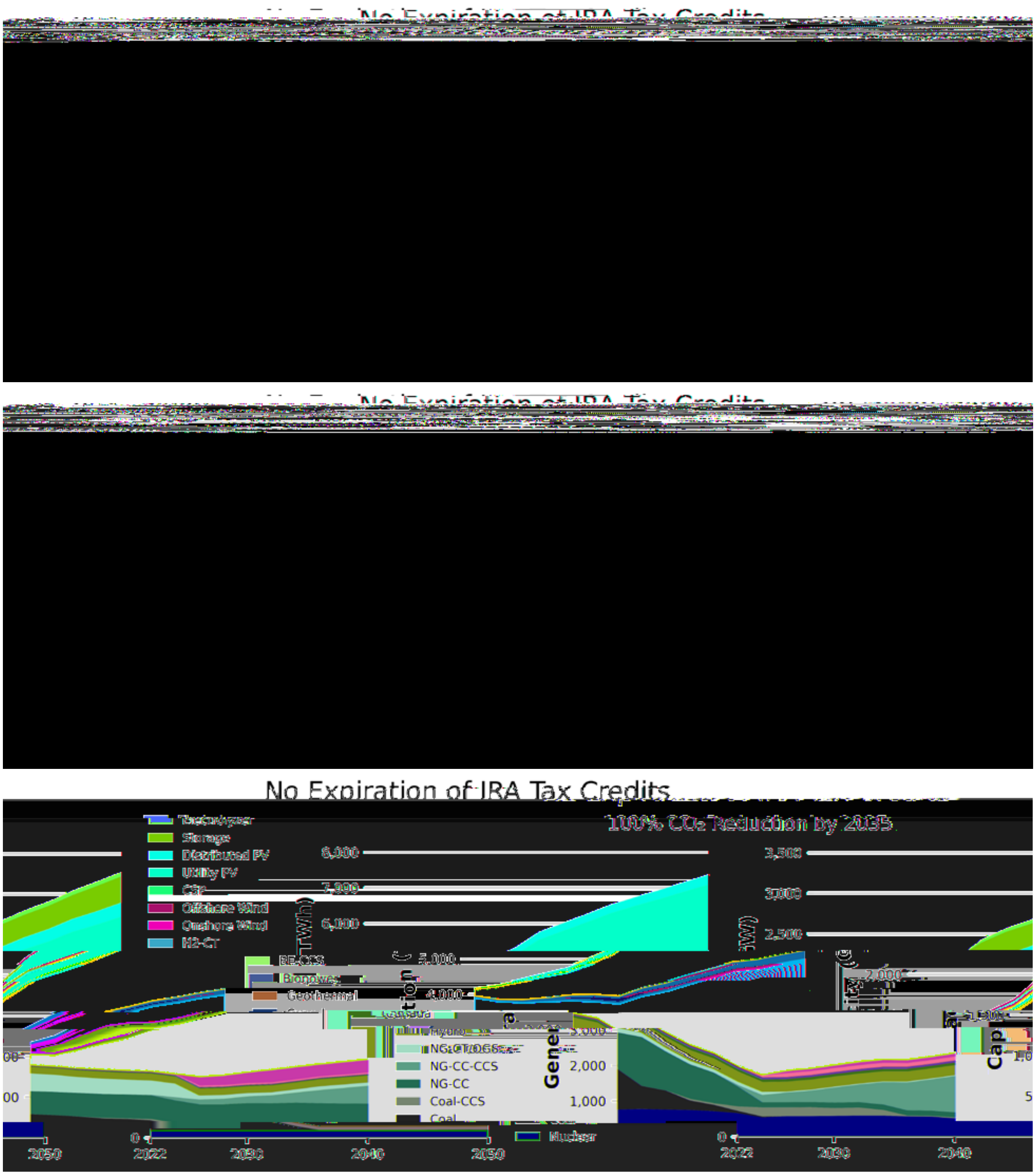

Figure A-24. No Expiration of IRA Tax Credits sensitivity: Generation and capacity

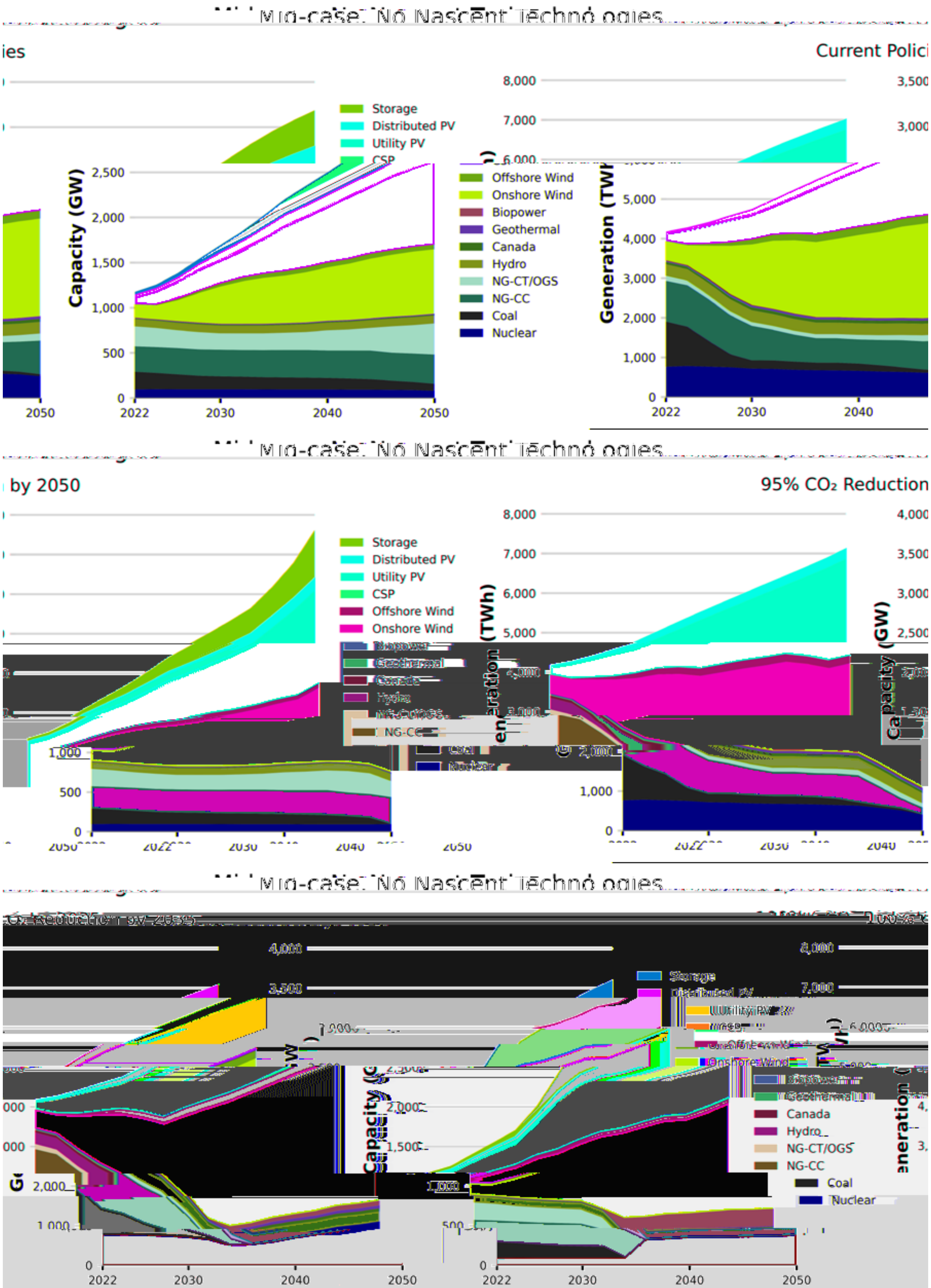

Figure A-25. No Nascent Technologies sensitivity: Generation and capacity

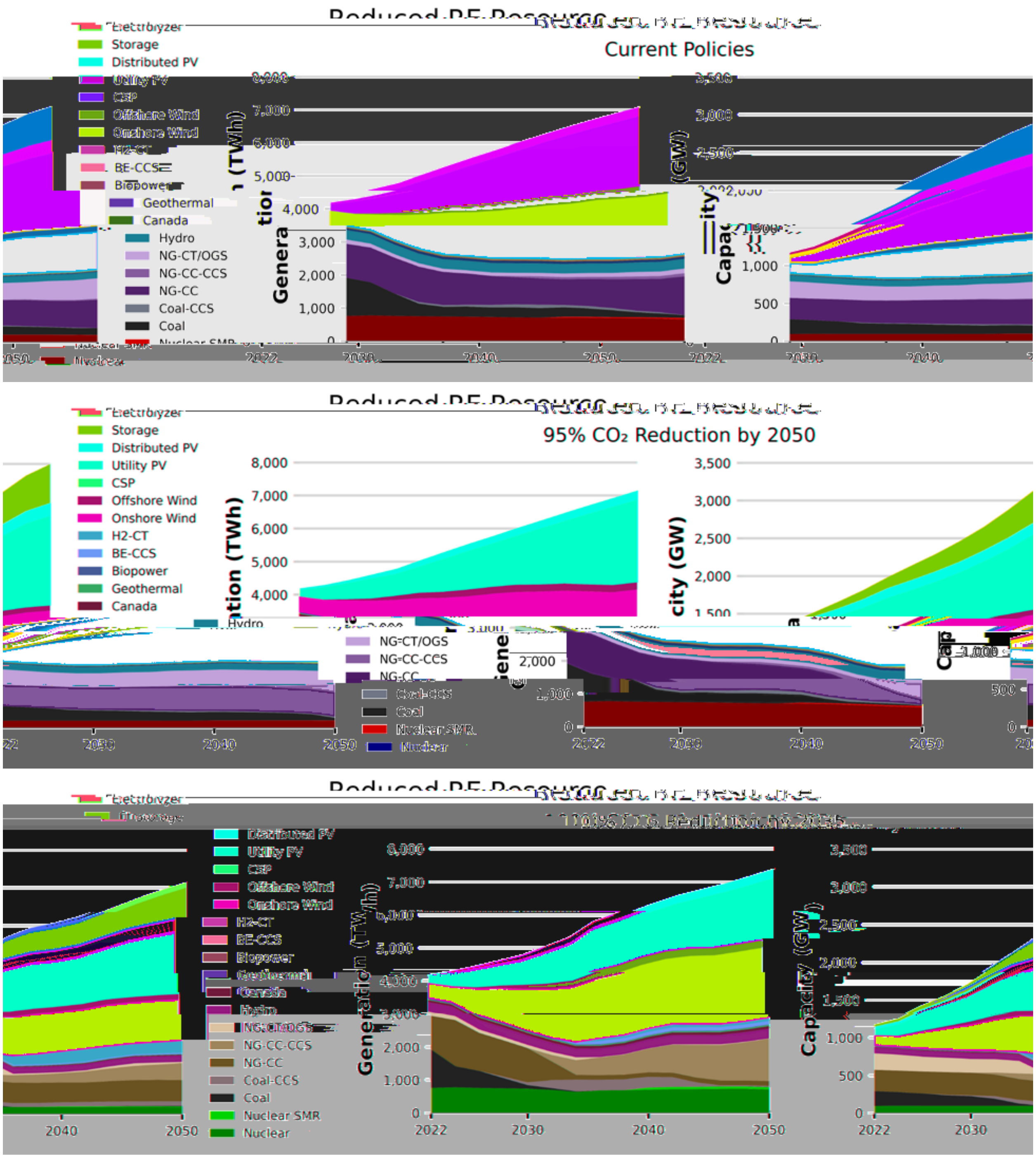

Figure A-26. Reduced Renewable Energy Resources sensitivity: Generation and capacity

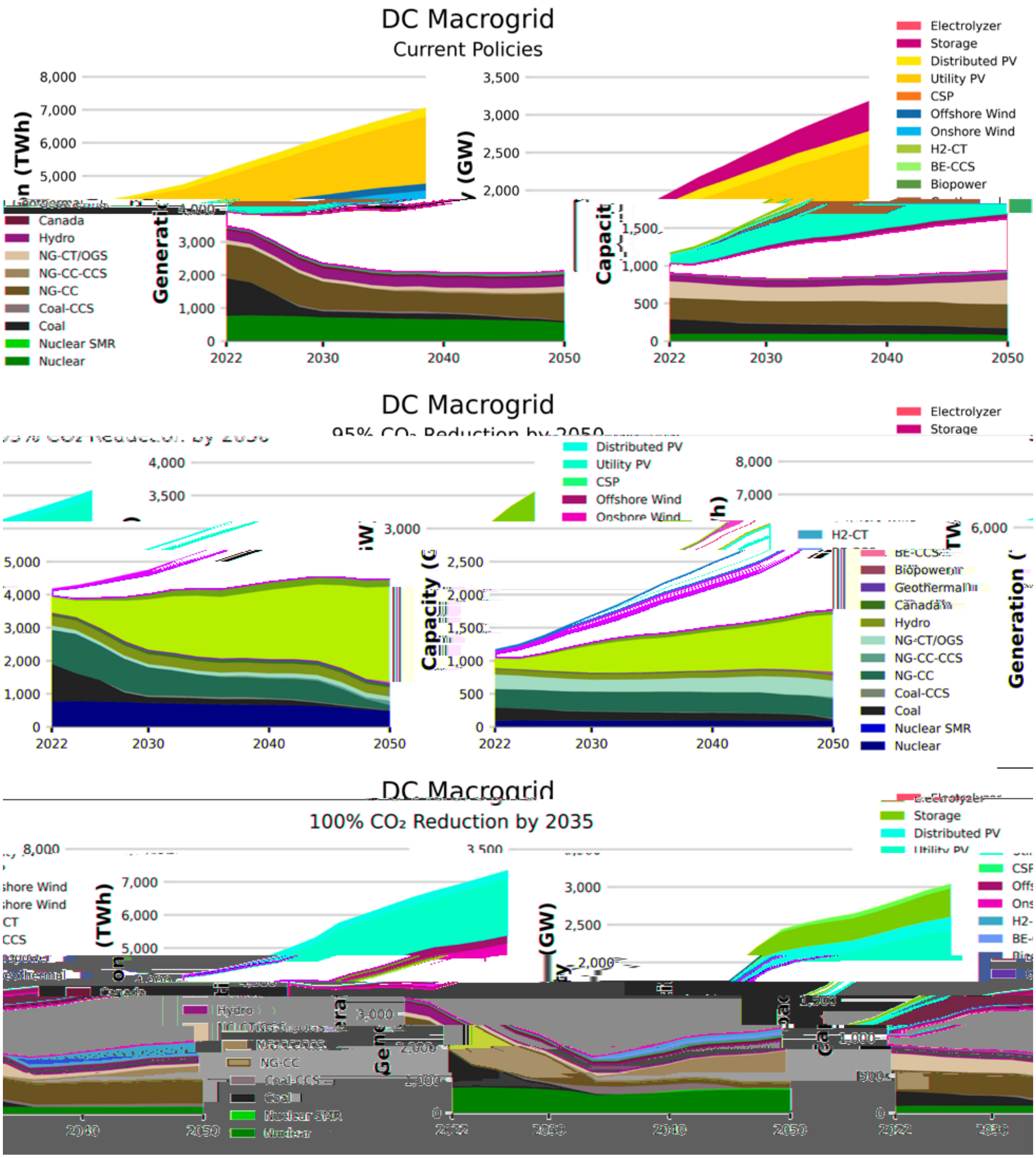

Figure A-27. DC Macrogrid sensitivity: Generation and capacity

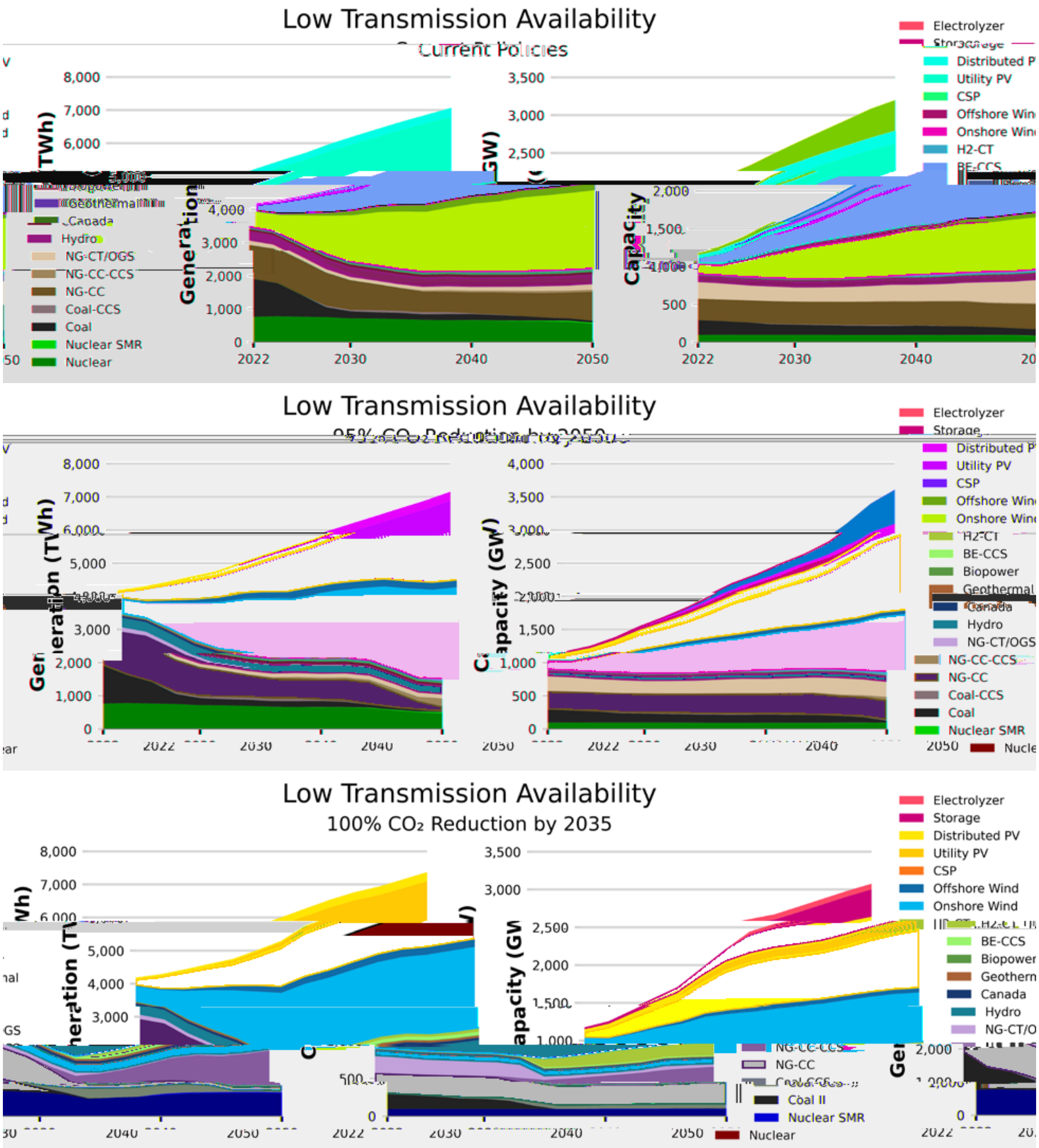

Figure A-28. Low Transmission Availability sensitivity: Generation and capacity

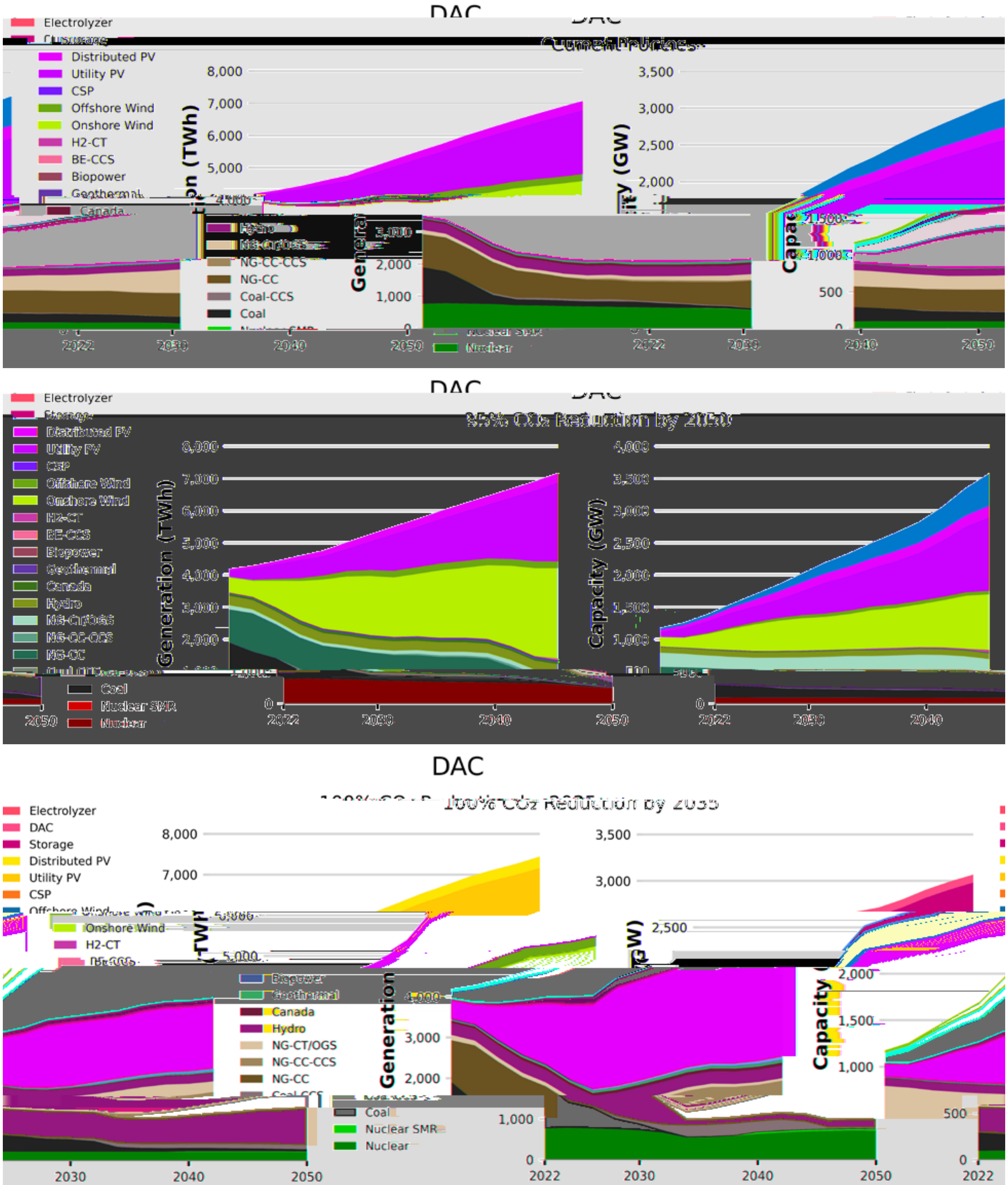

Figure A-29. Electricity-powered DAC sensitivity: Generation and capacity