Scenarios of Nuclear Energy Use in the United States for the 21st Century

Nuclear Technology Research and Development

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Executive Summary

This analysis investigates the potential range and timing of future nuclear energy contributions to the US energy system. The interactions of improved nuclear competitiveness through nuclear reactor capital cost reductions and alternative climate mitigation policies are explored to assess the potential expansion of nuclear power throughout the 21st century. Multiple long-term scenarios of the US energy system are generated using the PNNL GCAM model for clarifying the role of nuclear capital cost reductions, the role of carbon penalties and emission constraints, and their combined impact on the deployment of nuclear power and on carbon emissions in the US.

Nuclear overnight capital costs of 2600, 3600, 4600, 5600, and 6600 $/kW were investigated with scenarios of alternative carbon mitigation policies including 50, 100, and 150 $/t$CO_2$ carbon tax scenarios and economy-wide net-zero emission goals by 2050, 2060, and 2070 for the US.

Key Findings:

- Reductions in nuclear capital costs and increased nuclear competitiveness resulted in significant nuclear power expansion. In the range of nuclear capital costs assumed, 6600 down to 2600 $/kW, the nuclear power capacity in the Reference scenario was 130 to 240 GW in 2050 and 90 to 450 GW in 2100, respectively. The Reference scenario is a business-as-usual scenario and did not include carbon mitigation policies. Nuclear cost assumptions play a major role in the future contribution of nuclear energy.

- The above range of nuclear capacities resulted in a 30% decrease in electric power sector CO_2 emissions and a 15% decrease in total economy CO_2 emissions by 2100 between the high and low nuclear cost cases of the Reference scenario. Thus, efforts to reduce the nuclear cost contribute to and support emissions reduction goals without explicit carbon mitigation policies.

- The 50 and 100 $/t$CO_2$ carbon taxes further improved the nuclear competitiveness and significantly expanded nuclear power deployments relative to the Reference scenario. In the 100 $/t$CO_2$ carbon tax scenario, the nuclear capacity was 150 to 400 GW in 2050 and 180 to 720 GW in 2100 for the high and low nuclear cost cases, respectively. Emission reductions achieved with the 100 $/t$CO_2$ carbon tax were 50 to 55% for the total economy and 80 to 90% for the electricity sector.

- Carbon penalty beyond 100 $/t$CO_2$ had a diminishing impact on the additional deployment of nuclear power since the carbon tax level is sufficiently high enough to decarbonize the electric power sector near fully.

- Isolating the impact of carbon taxes and nuclear cost reductions indicates that a 50 $/t$CO_2$ carbon tax has a nuclear capital cost equivalency of 1000 $/kW reduction, and a 100 $/t$CO_2$ carbon tax has an equivalency of 2000 $/kW reduction.

- A fixed carbon tax, such as 100 $/t$CO_2$, applied throughout the century is capable of progressively reducing electricity carbon emissions over time, as the longevity of nuclear power plants contributes to the accumulation of total carbon-free power capacities and the diminished role of fossil power over time.

- Net-zero emission goals are more stringent carbon mitigation policies than the 50, 100, and 150 $/t$CO_2$ fixed carbon tax scenarios investigated.

- Modeling results of carbon tax values for achieving net-zero goals peaked at approximately 300 \$/tCO_2 for all target years, and the electricity sector is fully decarbonized by midcentury for all net-zero scenarios.

- The primary determinant of the carbon tax rates in the net-zero goals was driven not by the electric sector but by the emissions mitigation potential from buildings, industry, and transport sectors. Due to the availability of multiple low-cost carbon-free power options, alternative nuclear capital cost sensitivities had little impact on the carbon tax levels needed to achieve net-zero goals.

- Carbon penalties increased the relative price of fossil fuels by a greater amount than electricity at the end-use. Energy price changes due to carbon penalties favored electricity use rather than fossil fuels and total electricity demand increased by about 30% in the net-zero scenarios relative to the Reference scenario by the end of the century. This was a doubling of the 15% increase in total electricity demand in the 150 \$/tCO_2 carbon tax scenario.

- In the net-zero scenarios, the nuclear power capacities in 2050 were 190 to 460 GW in Nz50 (net-zero by 2050), 180 to 450 GW in Nz60 (net-zero by 2060), and 170 to 420 in Nz70 (net-zero by 2070) for the high and low nuclear cost cases. By 2100, the range increased to 210 to 790 GW in Nz50, 220 to 830 GW in Nz60, and 220 to 850 in Nz70.

- In the net-zero scenarios, negative emissions from electric power sector BECCS (biomass energy carbon capture and storage) were necessary to compensate for the persistent and difficult-to-remove emissions from buildings, industry, and transport sectors. Improvements to nuclear power costs, which directly reduced electricity prices, had some impact on reducing the amount of power sector negative emissions necessary for achieving net-zero goals.

- This analysis focused on the deployment of nuclear power for the electricity sector. The application of nuclear energy for buildings, industry, and transport energy services, other than through electrification, was not investigated. Nuclear heat, nuclear hydrogen, nuclear heat and hydrogen for synfuels production, and nuclear power with direct-air-capture are areas of future research that can further contribute to carbon emission reduction efforts.

- Nuclear cost reductions have a significant and disproportionate impact on the composition of power generation over the long-term. By 2100, the nuclear share of electricity was 50% or more with very low nuclear cost under carbon mitigation efforts.

- The longevity of nuclear power technologies and sustained investments of competitive nuclear power contribute to the accumulation of total nuclear power capacity and high nuclear shares over time.

- Reductions in the capital costs of nuclear power technologies were beneficial for the expanded deployment of nuclear under all circumstances, no matter the carbon tax level. An aggressive reduction of the nuclear costs had a clear and pronounced impact on the expanded deployment of nuclear power under all scenarios investigated.

Abstract

The uncertainty in the cost of nuclear energy coinciding with efforts to address climate change are contributing to the uncertainty in the future role of nuclear energy in the US energy system and the response to addressing global climate change. Sensitivity cases of alternative nuclear capital costs, ranging from 2600 to 6600 $/kW, were investigated with scenarios of alternative carbon mitigation policies, including 50, 100, and 150 $/t$CO_2$ carbon tax cases and economy-wide net-zero goals by 2050, 2060, and 2070 for the US. The resulting US nuclear power capacity ranged from 130 to 240 GW in 2050 and 90 to 450 GW in 2100 from nuclear cost sensitivity cases without carbon mitigation policies. Imposing policies to achieve the decarbonization of electricity and net-zero emission goals increased the range of nuclear power capacity from 190 to 460 GW in 2050 and 210 to 850 GW by 2100, where the range is from the high and low nuclear cost cases, respectively. Carbon penalties beyond 100 $/t$CO_2$ had a diminishing role on the expansion of nuclear power as the electricity sector becomes fully decarbonized. The 50 $/t$CO_2$ tax had the nuclear capital cost equivalency of 1000 $/kW reduction, while the 100 $/t$CO_2$ tax had the equivalency of 2000 $/kW reduction. Net-zero goals increased the contribution of nuclear power due to the increase in total electricity demand, but the delay in the timing of net-zero did not significantly affect the role of nuclear in the long-term. All net-zero goals were similar in their energy system impact with resulting carbon tax levels reaching 300 $/t$CO_2$. Electricity is fully decarbonized in the net-zero scenarios and carbon pricing beyond 100 to 150 $/t$CO_2$ had little influence on the additional deployment of nuclear power. Regardless of the carbon policy, however, nuclear capital cost reductions had a clear and pronounced impact on the expanded deployment of nuclear power under all scenarios.

Acknowledgements

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SCENARIOS OF NUCLEAR ENERGY USE IN THE UNITED STATES FOR THE 21ST CENTURY

1. Introduction

Nuclear power generation in the United States has made significant contributions to the energy system for nearly fifty years and is currently the largest single source of carbon-free electricity generation in the US. The bulk of the currently operating nuclear reactors were constructed from the 1970's and 1980's and few new reactors have been added to the existing fleet (EIA, 2022). Due to the lack of nuclear reactor builds in the last thirty years, there has been a loss in the continuity of new nuclear construction and deployment experience (DOE, 2020). Recent efforts to build new reactors have experienced significant construction delays and cost overruns coinciding at a time when climate change concerns have motivated a greater desire for the expanded deployment of nuclear energy. Thus far, uncertainty remains for the potential of nuclear energy for addressing climate change.

Climate change is one of the most pressing and difficult environmental challenges of our time. In response, the United Nations Framework Convention on Climate Change (UNFCC) has as its objective to "stabilize greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system" (UNFCCC, 1992). In the recent Paris Agreement, more than 100 countries endorsed limiting global warming to below 2° C above pre-industrial levels and recognized the importance of pursuing 1.5° C above pre-industrial levels (UN, 2015).

This analysis investigates the potential range and timing of future nuclear energy contributions and the interplay of increased nuclear competitiveness and carbon mitigation policies. The capital cost is the largest component of new nuclear reactor cost, which dictates the competitiveness of nuclear energy generation. Significant uncertainty in the nuclear capital cost range exists due to the many diverse designs of evolutionary and advanced reactors, reactor power capacity, country of origination, construction management experience, and supply chain issues. There is a lack of consistency in the reported and projected cost of nuclear reactors among many diverse sources of energy information, such as the US Energy Information Agency (EIA) and the OECD International Energy Agency (IEA). Thus, alternative capital cost projections were investigated to understand the impact of improved nuclear power competitiveness on the expanded deployment of nuclear energy.

Addressing global climate change and ongoing efforts to mitigate carbon emissions in the US are compounding the uncertainty in the relationship of nuclear costs and nuclear competitiveness. It is difficult to assess the disparate energy and emissions policies that are currently in place and future climate change policies that may arise. To clarify the interactions of nuclear costs to alternative climate mitigation efforts several alternative carbon mitigation policies with varying degrees of stringency were investigated.

Carbon mitigation scenarios are constructed in this analysis to assess the role of climate policies on the prospect for improving the competitiveness of nuclear power and to quantify the potential range of nuclear power deployments under alternative nuclear capital cost assumptions. Additionally, scenarios of carbon penalties applied in fixed increments and scenarios of economy-wide net-zero emission goals are differentiated to assess the mitigation potential from electricity, buildings, industry, and transport sectors.

The carbon mitigation scenarios included fixed carbon tax rates of 50, 100, and 150 $/t$CO_2$ and net-zero emission goals by 2050, 2060, and 2070. Carbon pricing levels for the decarbonization of electricity as well as for achieving net-zero goals were investigated, and the differential impact of economy-wide net-zero emissions goals and sector specific carbon penalties were assessed.

Multiple factors are involved in the potential expanded role of nuclear energy. Another important consideration, in addition to nuclear cost and carbon mitigation efforts, is the potential for the electrification of end-use energy services and the overall increase in the demand for electricity. The comprehensive representation of end-use energy demands in this analysis clarifies the role of electricity and the nuclear power response under the changing scale of the US energy system.

The report begins with introductory remarks and an overview of the Pacific Northwest National Laboratory's (PNNL) Global Change Analysis Model (GCAM) (Calvin et al., 2019). The representation of the electric power sector in GCAM is described, as well as the assumptions of electric power technology cost and characteristics. This is followed by a further description and summary of nuclear cost sensitivity cases and carbon mitigation scenarios. GCAM modeling results follow with a detailed analysis of electricity demand, composition of electricity generation, nuclear energy deployments, and potential for CO_2 emission reductions in the US. The report is closed with concluding remarks and discussions for future work.

2. Global Change Assessment Model (GCAM)

2.1 GCAM Overview

GCAM is a tool for simulating long-term projections of energy use, agriculture production and land-use change, and greenhouse gas emissions (JGCRI, 2022). It has been utilized extensively for understanding a broad range of global change related issues and in particular, for investigating the role of technologies and policies in alternative scenarios of the future and in the context of global climate change. GCAM is used in this analysis to investigate the role of nuclear energy in the US for addressing climate change and for reducing carbon emissions.

GCAM simulates a hundred years of future global energy use and runs from 1990 to 2100 in 5-year time steps. The current publicly available version of GCAM has 32 global regions with the USA as a separate region. Although the full global version is utilized, the focus of the modeling results is on the US in this analysis.

The 1990 to 2015 modeling time periods are calibrated to historical datasets and provide consistent context from history to future projections. GCAM's strength is in its ability to track energy resources, transformation of resources to final fuels and energy carriers, and simulation of the demand for energy and energy services from all end-use sectors of the economy, while accounting for GHGs from all emissions activities. GCAM is an economic model with long-term equilibrium behavior in the supply and demand of goods and services. Economic sectors are linked through a market concept and changes in the market prices affect the supply and demand of goods and services. For each period, model solution is reached when supplies and demands for all goods and services in the regional and global economy simultaneously reach equilibrium.

All technologies in GCAM including electric power technologies compete based on their economic costs. Technology costs are separated into resource, fuel or energy costs, and non-fuel costs that include capital and operations & management (O&M) costs. Energy resources, including conventional crude oil, unconventional oil, natural gas, coal, and uranium, are represented by a supply curve based on graded resources and their cost of extraction. Renewable technologies including hydro, geothermal, wind, and solar are also modeled based on their resource potential and cost of power generation, delivery to grid, backup energy or storage requirements, and systems integration. Numerous technologies for energy transformation from crude or raw fuels to refined fuels are represented, as well as the conversion of solid fuels such as coal and biomass to liquids and gases, and gaseous fuel to liquids.

CO_2 and other emissions from all emissions activities are calculated with emissions coefficients included for each fossil fuel, crude oil, natural gas, and coal. Biomass use for energy is treated similarly as fossil fuels and contributes to carbon emissions during combustion. However, carbon emissions credits are provided to the agriculture sector in equal amount to the carbon removed from the atmosphere during biomass cultivation. Other than the additional energy inputs for processing and refining of biomass fuels, biomass is treated as a carbon-neutral source of energy. Land-use change emissions from biomass production are accounted for. Nuclear and renewable energy are treated as carbon-free sources of energy.

2.2 GCAM Electricity System and Technology Assumptions

Integrated-assessment models, such as GCAM, operate at highly aggregated spatial and temporal resolutions to capture the global and regional long-term behavior of energy use. The electricity supply sector for each region is represented as a single balancing authority and electricity trade within a region is not modeled. All power supply technologies including carbon emitting and non-emitting technology options are included. Demands for electricity from all end-use sectors, buildings, industry, and transport, and all energy services are represented to provide a comprehensive assessment of the total electricity demand over time. Changing prices of fuels and energy carriers, and carbon penalties applied to supply and demand activities affect the choice of electric technology and the demand for electricity.

Since the temporal resolution of GCAM is at the annual scale, diurnal and season behaviors of electricity generation and use are not explicitly represented. Electric generating units are not dispatched on an hourly or time-slice basis. Instead, annual shares of electric power technology choices are determined by a statistical approach. Electric power technology competition utilizes the discrete choice method for the technology choice and power market share by technology (McFadden, 1974). A logistic model using levelized cost of electricity (LCOE) and historically calibrated model parameters is implemented. The LCOE provides a distilled and aggregated measure of technology costs that is readily calculated. Historical calibration of model parameters captures unobserved factors, such as diurnal, seasonal, and other impacts, that are not measured by the LCOE alone. Strategies for determining the LCOE of renewable energy technologies and addressing intermittency issues are discussed below.

GCAM version 5.3 utilized for this analysis includes recent updates to the electricity cost data based on the National Renewable Energy Laboratory's Annual Technology Baseline for 2019 (NREL ATB) (NREL, 2020). Historical and projected overnight capital costs for electric power technologies are provided up to 2050 in the NREL ATB. Since GCAM needs cost assumptions to 2100, technology cost assumptions beyond 2050 were determined by technology maturity and technical improvement potential as described by Muratori et al. (Muratori et al., 2017). Table 1 documents the power technology cost, capacity factor, and lifetime assumptions used in this analysis.

Table 1. Electric power plant capital cost, capacity factor and lifetime assumptions in GCAM (NREL ATB costs adjusted to 2019 USD).

Technology	Capital Cost 2015 [$/kW]	Capital Cost 2050 [$/kW]	Capital Cost 2100 [$/kW]	Capacity factor	Lifetime [years]
Coal (steam plant)	3827	3514	3321	0.85	60
Coal CCS (steam plant)	5180	5335	4848	0.8	60
Coal (IGCC)	4106	3457	3193	0.8	60
Coal CCS (IGCC)	6775	5176	4516	0.8	60
Natural Gas (simple cycle)	927	822	799	0.8	45
Natural Gas (CC)	1086	818	803	0.85	45
Natural Gas CCS (CC)	2266	1836	1659	0.8	45
Oil (simple cycle)	927	822	799	0.8	45
Oil (CC)	1086	818	803	0.85	45
Oil CCS (CC)	2699	2130	1900	0.8	45
Biomass (steam plant)	4015	3548	3257	0.85	45
Biomass CCS (steam plant)	7732	5968	4878	0.8	45
Biomass (IGCC)	6024	4743	3947	0.8	45
Biomass CCS (IGCC)	8886	6454	4950	0.8	45
Nuclear	6428	5282	4211	0.9	60
Wind (on-shore)	1700	1078	961	0.37	30
Wind (on-shore + battery)	6337	2797	2145		30
PV (large-scale)	2515	822	780	0.2	30
PV (large-scale + battery)	7148	2590	2028		30
PV (rooftop)	4083	1218	1142	0.17	30
CSP (+ thermal storage)	8558	3593	3178	0.5	30
Geothermal	5033	3732	3374	0.9	30

Due to the intermittent nature of renewable energy technologies, the use of LCOE, based strictly on nameplate costs and characteristics, cannot be directly utilized as a consistent or comparable metric for power technology choice (Joskow, 2011). Thus, the LCOE of intermittent energy technologies is treated specially in GCAM to account for the added cost of systems integration. In addition to representing wind and solar resource supply curves that account for the spatial distribution of graded wind and solar resources and distance to load centers, intermittent energy technologies in GCAM incur additional cost for integration as a function of renewable share of total electricity generation. This feature of GCAM ensures that the treatment of intermittent technologies properly reflects the complexity and increased cost of renewable energy penetration for capturing realistic levels of renewable energy use under climate mitigation scenarios.

Multiple factors contribute to the added cost of renewable energy integration. Ueckerdt et al. summarizes these costs into three main drivers, balancing cost, grid cost and profile cost, which contribute to the total systems integration cost of renewable energy (Ueckerdt et al., 2015). Balancing cost arises from need for highly responsive backup energy systems that stabilizes the electricity grid from rapid changes in the output of renewable energy. Grid cost arises from additional transmission lines required for transferring remote sources of renewable energy to load centers, and efforts required for the optimal distribution of power within the grid. Profile cost arises from the mismatch of renewable energy supply with the load demand profiles.

At low levels of renewable energy penetration, the profile cost may be negligible since most or all the renewable energy can be readily absorbed (Hirth, Ueckerdt, & Edenhofer, 2015). Balancing and grid costs remain however and may constitute the bulk of the systems integration costs at low levels. At high levels of renewable energy penetration, the profile cost dominates due to the overall mismatch of renewable supply with demand. Profile cost includes idling, more frequent cycling, and less than optimal operation of dispatchable generation, and the reduced utilization of renewable energy from overproduction or curtailment. At high renewable penetration rates, estimates of 50% additional integration cost are projected based on more detailed dispatch models with greater spatial and temporal resolutions (Hirth et al., 2015). The systems integration cost of renewable energy is modeled in GCAM as a function of renewable energy penetration with the profile cost as the main obstacle to high levels of renewable energy use (JGCRI, 2022).

Wind and solar energy technologies with dedicated energy storage are also included as options for power generation. Renewable technologies with dedicated energy storage are not treated as variable generation and do not incur any additional integration costs. The total combined costs of renewables with dedicated storage are shown in Table 1.

For a more accurate representation of the US nuclear energy system, further disaggregation of nuclear power representation has been included in this analysis. Each existing nuclear reactor in the US is discretely represented as shown in Figure 1, including Georgia's Vogtle Units 3 and 4 that will come online in 2023 (NRC, 2020). The discrete representation of each reactor more accurately represents the longevity of nuclear plants, as well as the more accurate profile of the nuclear retirement schedule. All operating reactors are assumed to have a total lifetime of 80 years (DOE, 2008; NRC, 2021) in this analysis, except for California's Diablo Canyon Units 1 and 2 that are assumed to retire by 2025. This implies that the bulk of energy generation from existing reactors will occur until 2050 and decline thereafter to 2070 when most existing reactors will have retired. Three reactors, Watts Bar-2, Vogtle-3, and Vogtle-4 are assumed to provide energy throughout the remainder of the 21st century.

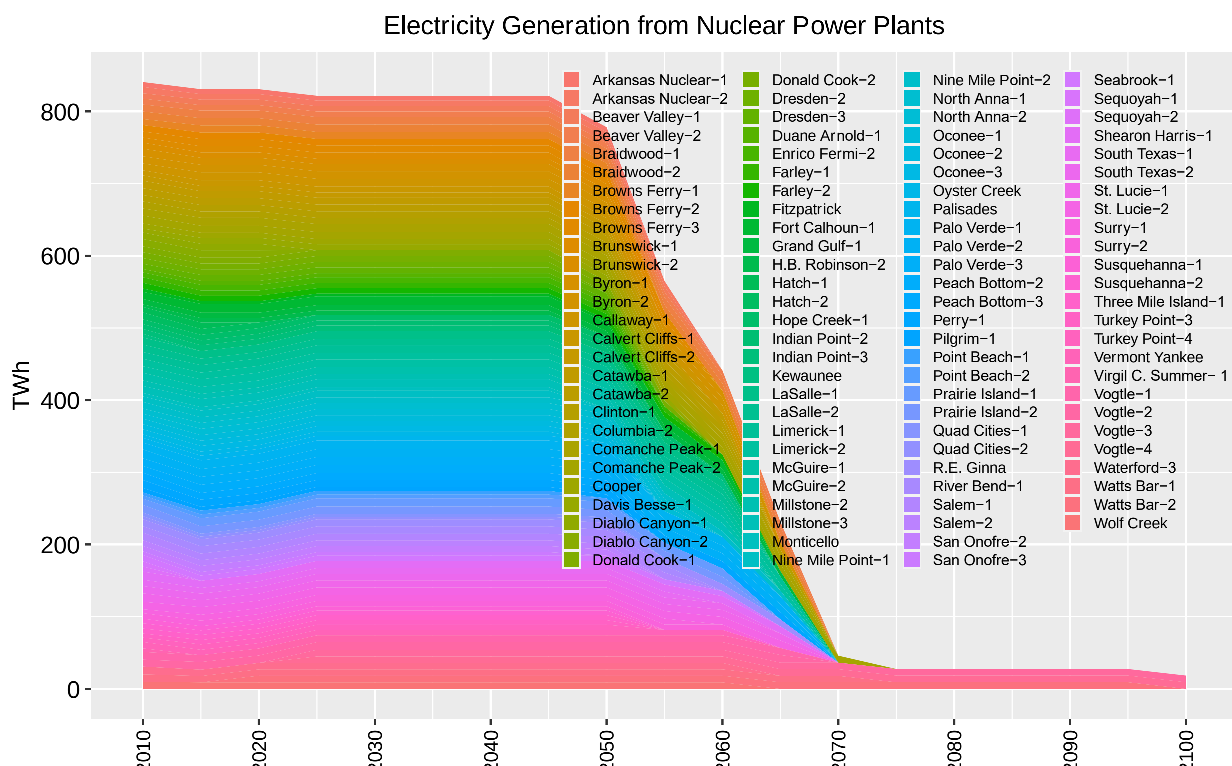

Figure 1. Electricity generation from existing nuclear power reactors in the US assuming 80-year lifetimes and including Watts Bar-2, Vogtle-3, and Vogtle-4 reactors.

3. Nuclear Capital Cost and Carbon Mitigation Scenarios

Multiple GCAM scenarios are generated to explore the interactions of nuclear power capital costs and alternative carbon mitigation policies for assessing the potential role of nuclear energy in the US energy system. Five nuclear capital cost sensitivity cases spanning the potential range of future nuclear capital costs, under seven future climate policy backgrounds, for a total of thirty-five scenarios were generated. All cost sensitivity cases, and climate mitigation scenarios are summarized in Table 2. A Reference scenario without climate policy is generated to serve as a basis for comparison. Currently existing renewables portfolio standards (RPS), federal production tax credits (PTC), and investment tax credits (ITC) are not included in the Reference scenario to prevent overlap with carbon policy scenarios. Three fixed carbon tax scenarios with progressively increasing carbon tax levels, and three net-zero emission scenarios exploring alternative net-zero target years of 2050, 2060 and 2070 provide alternative levels of carbon mitigation response.

Nuclear overnight capital costs of 2600, 3600, 4600, 5600, and 6600 $/kW by 2050 are explored for the US. The capital costs are based on the Idaho National Laboratory (INL) Nuclear Cost Basis Report and span the range of cost distribution for an LWR (INL, 2022). The cost range also captures the recent cost estimates of nuclear reactors deployed around the world (IEA, 2020). Capital cost increments of 1000 $/kW were selected to assess the graduated response to cost improvements and to allow for the relative comparison to alternative carbon mitigation efforts. Nuclear capital cost sensitivities were applied to the US only. The nuclear capital cost for all other regions utilized the nuclear cost assumption shown in Table 1. Although changes in the US nuclear capital costs are likely to affect nuclear capital costs in other regions, cost assumptions for other regions were not changed across the nuclear sensitivity cases to isolate the impact for the US.

Table 2. GCAM nuclear capital cost sensitivity and carbon mitigation scenario description.

Nuclear Capital Cost ($/kW)	**Ref (No Climate Policy)**	**Carbon Tax 50 $/tCO2**	**Carbon Tax 100 $/tCO2**	**Carbon Tax 150 $/tCO2**	**Net-Zero Emissions by 2050**	**Net-Zero Emissions by 2060**	**Net-Zero Emissions by 2070**
2600	Nuc26_Ref	Nuc26_Ct50	Nuc26_Ct100	Nuc26_Ct150	Nuc26_Nz50	Nuc26_Nz60	Nuc26_Nz70
3600	Nuc36_Ref	Nuc36_Ct50	Nuc36_Ct100	Nuc36_Ct150	Nuc36_Nz50	Nuc36_Nz60	Nuc36_Nz70
4600	Nuc46_Ref	Nuc46_Ct50	Nuc46_Ct100	Nuc46_Ct150	Nuc46_Nz50	Nuc46_Nz60	Nuc46_Nz70
5600	Nuc56_Ref	Nuc56_Ct50	Nuc56_Ct100	Nuc56_Ct150	Nuc56_Nz50	Nuc56_Nz60	Nuc56_Nz70
6600	Nuc66_Ref	Nuc66_Ct50	Nuc66_Ct100	Nuc66_Ct150	Nuc66_Nz50	Nuc66_Nz60	Nuc66_Nz70

The capital cost assumptions are phased-in gradually and assumed to be achieved by 2050 as shown in Figure 2. The nuclear capital cost of 6200 $/kW was assumed for 2025. From there, the cost was linearly decreased to the targeted cost goal by 2050 for each of the cost cases except for the 6600 $/kW case. The 6600 $/kW case was assumed fixed from 2025 to 2050. Beyond 2050, nuclear capital costs were assumed to improve modestly at 0.1% per year for the 2600 to 5600 $/kW cases, while the 6600 $/kW remained fixed.

Nuclear reactor fixed O&M costs of 66, 73, 81, 88, and 95 $/kW and variable O&M costs of 1, 1.5, 2, 2.5, and 3 $/MWh were associated with the capital costs of 2600, 3600, 4600, 5600, and 6600 $/kW, respectively (INL, 2022). A fixed charge rate of 13% was utilized to calculate the LCOE of nuclear power.

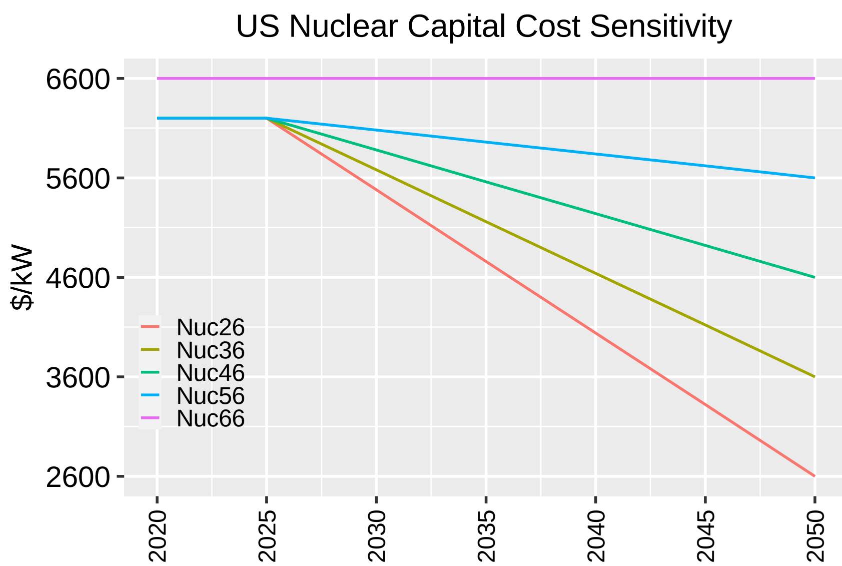

Figure 2. Nuclear power reactor overnight capital cost cases for the US at 2600, 3600, 4600, 5600, and 6600 $/kW by 2050 (2019 USD).

Nuclear cost sensitivity cases are run in a reference scenario without any climate mitigation policy, and under three alternative carbon tax scenarios. In the carbon tax scenarios, fixed carbon penalties of 50, 100 and 150 $/tCO$_2$ are applied economy-wide to all carbon emitting activities. As shown in Figure 3, carbon taxes are imposed beginning in 2025 and are assumed to remain in place throughout the 21st century. Carbon taxes more heavily penalize fossil fuels and emissions activity with greater carbon content and emissions. Utilizing fixed carbon taxes directly provides the ability to control a specified level of price penalty imposed on carbon emissions activities and technologies. The incremental cost additions on carbon emitting technologies can be directly calculated. Progressively increasing levels of carbon taxes provide the ability to measure the emissions mitigation response and technology competitiveness in a controlled and graduated approach.

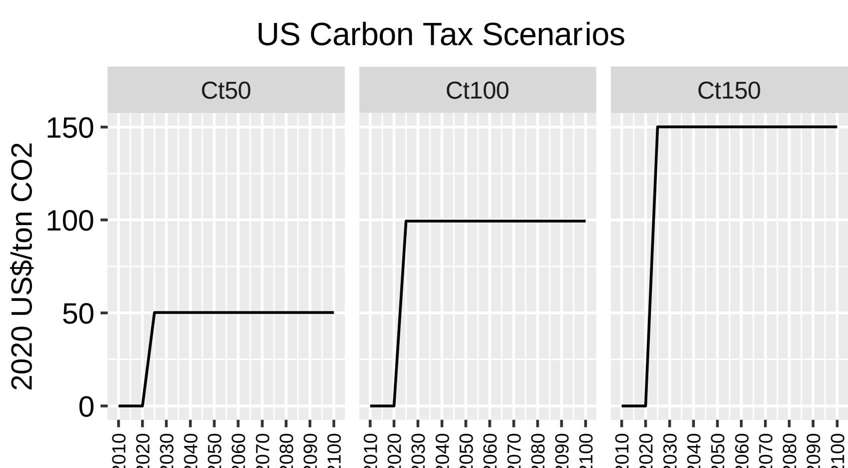

Figure 3. Economy-wide US carbon tax scenarios.

As an alternative to the fixed carbon tax scenarios, net-zero emissions scenarios are explored (US Excutive Office, 2021). Net-zero emission goals are a more stringent response to addressing climate change than the fixed carbon taxes since all emissions are eliminated. While the carbon tax reduces the amount of emissions, it does not explicitly control the desired level of emissions. Net-zero scenarios are, however, achieved by imposing emission constraints which allow for the direct control of the desired levels of emissions over time.

In this analysis, net-zero scenarios constrained the total economy-wide carbon emissions from 2020 to a linearly decreasing pathway to net-zero emissions by a desired target year. Three alternative target years, 2050, 2060 and 2070, were explored as shown in Figure 4. In the net-zero scenarios, an annual emissions constraint drives the emissions mitigation behavior, and the model determines the level of carbon taxes that is necessary for meeting the annual emissions constraint. The resulting carbon tax levels are modeling results in the net-zero scenarios and are not input assumptions as in the carbon tax scenarios. It is also important to highlight that the net-zero emissions constraint is imposed on the economy as a whole and not specifically for the electric power sector only. The consequence of this more broadly applied constraint is that transport, industrial and buildings sectors also play a role in determining the level of the carbon tax or carbon pricing necessary for achieving net-zero emissions, in addition to the electric power sector. This implies that electric power technologies alone do not determining the ultimate carbon tax levels for achieving economy-wide net-zero emissions.

The net-zero emission scenarios in this analysis are consistent with efforts to limit the Earth's mean surface temperature change to 1.5 and 2° C. The net-zero emissions goal by 2050 is consistent with the 1.5 ° C limit, while the net-zero goals by 2060 or 2070 are more consistent with the 2° C limit (IPCC, 2018). The cumulative allowable CO_2 emissions for the US in this analysis are 79, 105, and 131 gigatons of CO_2 ($GtCO_2$) from 2020 to 2100, respectively, for the 2050, 2060, and 2070 net-zero target goals.

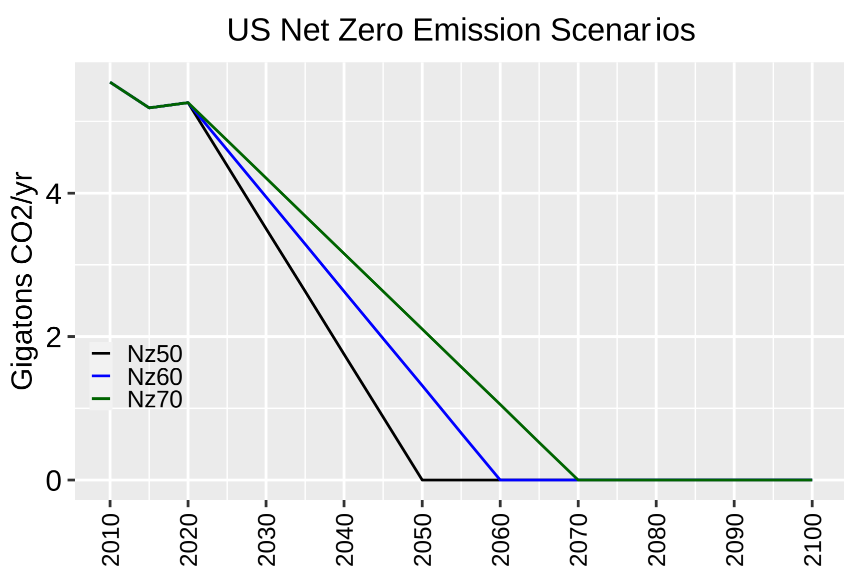

Figure 4. Economy-wide US net-zero CO_2 emission scenarios by 2050, 2060 and 2070.

4. Results: Nuclear Energy Scenarios

4.1 Impact of Nuclear Capital Cost Reductions in the Reference Scenario

Tremendous growth in the US electricity system is projected by the end of the 21st century. US electricity demand in the Reference scenario grows from 4770 TWh in 2020 to approximately 8300 TWh by 2050, a 70% increase from 2020. By 2100, it reaches 9500 TWh, a doubling of the 2020 level. Growth in the demand for electricity is driven by population and economic growth and the increased electrification of end-use energy services over time. Figure 5 shows the composition of electricity and total electricity demand for all nuclear sensitivity cases in the Reference scenario.

Wind and solar energy technologies have significant and growing contributions to electricity generation due to their technological and cost improvements. By 2050, the solar electricity share is greater than 10% and wind electricity share is greater than 11%, representing a combined share of 21%. Hydropower and biomass generated power play a limited role in the US electricity system in the Reference scenario.

Without measures to mitigate climate change in the Reference scenario, fossil power generation continues to be a major source of electricity for the US. Natural gas maintains the largest fraction of power generation by 2050, representing nearly 35% share, followed by coal at 22% share. Power generation from oil remains small. Thus, the combined fossil power generation in the Reference scenario comprise nearly 60% of total power generation by 2050.

The continued dominance of fossil power generation in the Reference scenario is, however, contingent on the competitiveness of nuclear power and nuclear cost improvements achieved by 2050. Beyond midcentury, reductions in the nuclear costs have a significant impact on the expanded role of nuclear energy leading to the diminished role of fossil power generation.

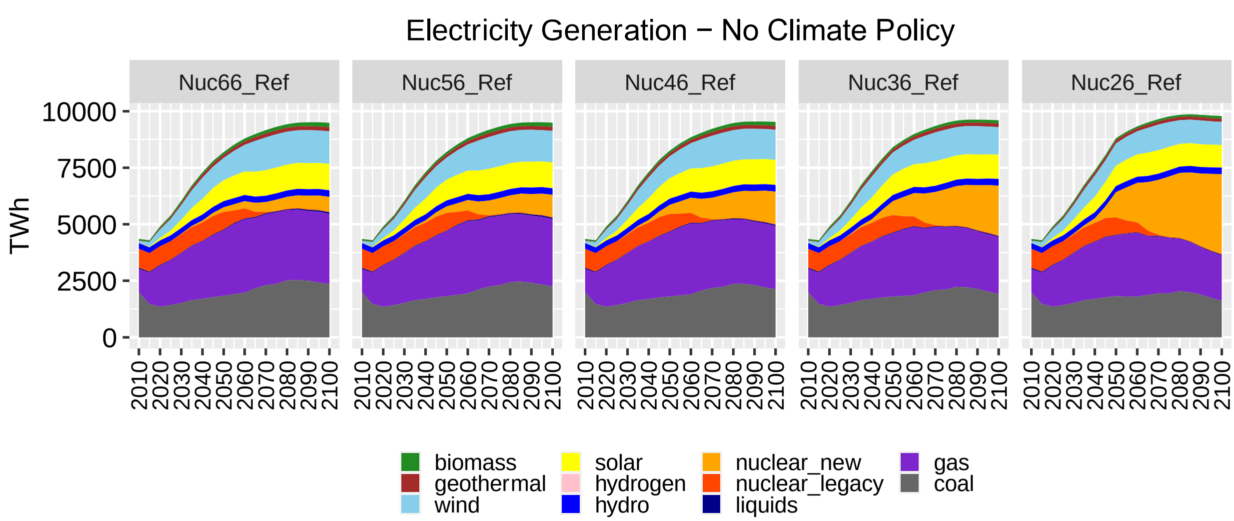

Figure 5. Electricity generation by fuel type in the Reference scenario for alternative nuclear capital cost cases.

In the near-term, nuclear power contribution declines as few additional reactors are deployed due to their high capital costs. The impact of the nuclear capital cost improvements of this analysis is not observed until after 2035. The nuclear power capacity remains flat until 2035 and the nuclear share of electricity generation declines to 13% in 2035 as the few limited nuclear deployment is not able to keep up with the increasing demand for electricity in the near-term, as shown in Figure 6.

Reductions in the nuclear capital cost have a significant impact on nuclear deployment by midcentury and beyond. By 2050, the total nuclear capacities are 130, 140, 150, 180, and 240 GW for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. The significant expansion of nuclear capacity is due to nuclear cost reductions alone and without the benefit of any carbon penalties in this Reference scenario. At 2600 $/kW, the levelized cost of electricity (LCOE) for nuclear is one of the lowest of all competing technologies and is competitive with natural gas, solar, and wind power in this analysis. The nuclear share in 2050 spans from 12% to 22% in the Nuc66 and Nuc26 reference cases, respectively. Only the lowest cost assumption of the Nuc26 case can ramp up nuclear expansion to maintain current levels of nuclear share for the next several decades.

By 2100, the nuclear capacities are 90, 130, 190, 280, and 450 GW for the Nuc_66, Nuc_56, Nuc_46, Nuc_36, and Nuc_26 cases, respectively, as shown in Figure 6. The future cost assumptions of nuclear power dictate nuclear energy's competitiveness and long-term contribution to the US energy system. The nuclear energy contribution is stagnant and diminishing when nuclear capital costs are greater than 4600 $/kW, such as in the Nuc56 and Nuc66 reference cases. These cases have nuclear electricity shares of 7 to 11% by 2100. On the other hand, nuclear capital costs less than 4600 $/kW contribute to the improved competitiveness of nuclear power and additions of new nuclear capacity accumulate in the latter half of the 21st century (SEAB, 2016). The nuclear electricity shares are 16, 23, and 37% for the Nuc46, Nuc36, and Nuc26 reference cases, respectively, by 2100. Nuclear capital costs in the range of 2600 to 4600 $/kW enable nuclear energy contributions to maintain or exceed current levels within a US electricity system that experiences tremendous growth throughout the 21st century.

As nuclear capital costs decline, nuclear energy shares increase predominantly at the expense of decreasing fossil power shares. Nuclear electricity becomes more competitive relative to fossil generated electricity than to renewable energy. By 2100, the combined fossil share consisting of natural gas, coal, and oil falls from 58% to 37% in the Nuc66 to Nuc26 cases, respectively, while the combine wind and solar share falls from 28% to 21%. Variable renewable energy remains competitive at lower levels of penetration since higher grid integration costs are not incurred.

The longevity of nuclear power plants ensures that incremental investments in nuclear capacity continue to add and build on the total nuclear capacity resulting in a steadily increasing share of nuclear electricity generation for the US energy system. The impact of lifetime differences across technologies are not typically highlighted in many long-term analyses. Since GCAM tracks all electric power technology vintages by period, all new nuclear reactors deployed after 2020 with an assumed lifetime of 80 years contribute to power generation throughout the 21st century. This response is particularly noticeable in the high shares of nuclear over time in the low-cost case. Other technologies with significantly shorter lifetimes incur more rapid capital stock turnover that hinder capacity building and the long-term stability of the electric power system.

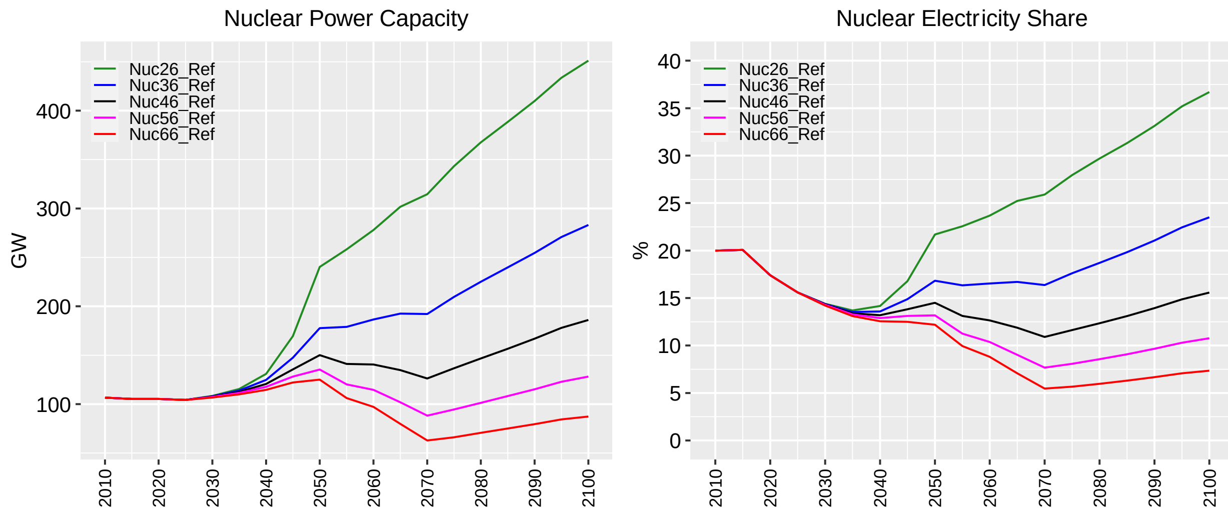

Figure 6. Nuclear power capacity and share of electricity generation in the Reference scenario for alternative nuclear capital cost cases.

Increased nuclear electricity contributions across the nuclear cost sensitivity cases play a significant role for US CO_2 emissions. The substitution of fossil power for nuclear results in large carbon emissions differences from the electricity sector starting from midcentury to the end of the century as shown in Figure 7. By 2100, the difference in annual electricity emissions between the two nuclear extremes, Nuc66 and Nuc26, is 0.9 $GtCO_2$/year or as much as 33% of the electricity emissions of the Nuc66 case. The percentage reductions in CO_2 emissions with increasing nuclear energy penetration is displayed in Figure 7, right panel.

Efforts to reduce the capital cost of nuclear power not only increases nuclear power competitiveness but is an effective strategy for carbon emissions reduction in lieu of an explicit carbon mitigation policy. More competitive nuclear power primarily substitutes for other dispatchable fossil generation and thus the increased nuclear market share results in lower electricity carbon emissions.

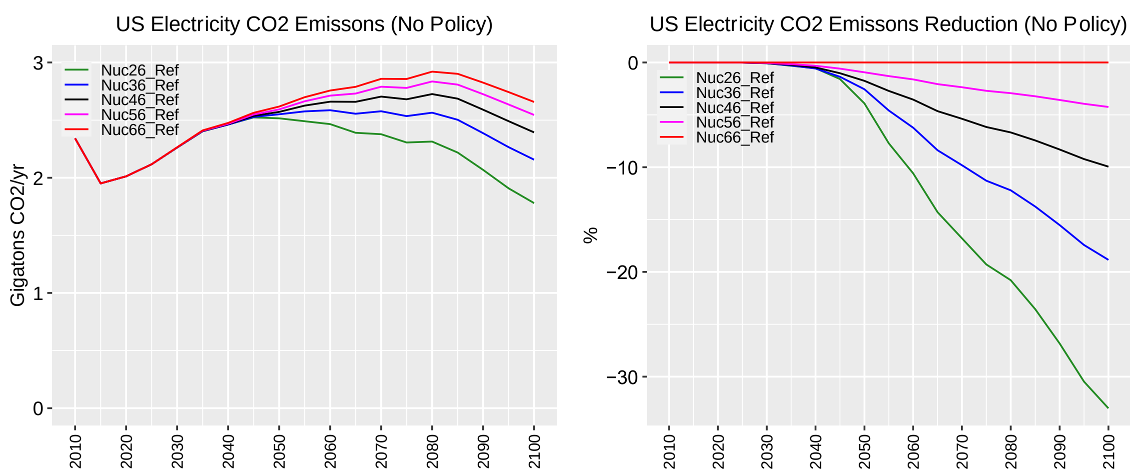

Figure 7. US electricity sector CO_2 emissions and impact of nuclear power capital cost reductions in the Reference scenario.

Electricity carbon emissions are a major source of total US carbon emission throughout the 21st century. With increased electrification of the end-use sectors, such as the ongoing electrification of the transport sector, electricity carbon emissions are the dominant source of emissions for the US in the long-term. Total US emissions across the nuclear cases are shown in Figure 8. Electricity CO_2 emissions represent nearly half of the total emissions in 2050 and 34% to 44% of total emissions by 2100 depending on the nuclear case. The impact of the nuclear cost sensitivity cases is the reduction of total US CO_2 emissions of 4% in 2050 and 16% in 2100 between the two nuclear energy extremes, Nuc66 and Nuc26, as shown in Figure 8, right panel.

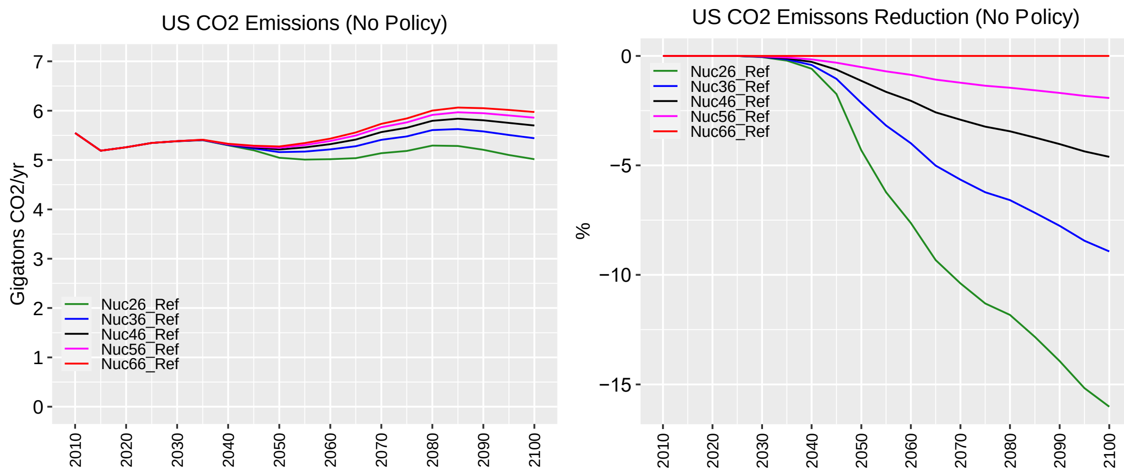

Figure 8. Total US CO_2 emissions and the emissions impact of nuclear sensitivity cases in the Reference scenario.

Absolute differences in total economy-wide CO_2 emissions are somewhat greater than the emission differences from the electricity sector indicating the indirect feedback of lower electricity prices throughout the economy. Lower electricity prices due to cheaper nuclear technologies encourage greater utilization of electricity relative to fossil fuels at the end-use. At the same time, increasing nuclear market share results in decreasing carbon emissions per unit electricity. The combined impact is the total economy-wide emissions difference of 1.0 $GtCO_2$/year between the Nuc66 and Nuc26 cases by 2100, as compared to the electricity sector emissions difference of 0.9 $GtCO_2$/year as discussed above.

Thus, strategies for improving the nuclear market share supports climate mitigation goals without the added burden of an explicit climate mitigation policy and losses in economic efficiency incurred from carbon penalties.

4.2 Carbon Tax and Nuclear Capital Cost Interactions

Carbon taxes are imposed on all emissions activities throughout the economy for each of the nuclear capital cost cases to assess their combined impact on the electricity demand, composition of electricity generation, nuclear energy deployment, and potential for CO_2 emissions reductions in the US. Carbon penalties imposed throughout the economy are expected to change the relative prices of refined fuels and energy carriers and induce long-term changes to the overall energy demand. The resulting impact of 50, 100, and 150 $/$tCO_2$ carbon taxes on the demand for electricity in the US are shown in Figure 9.

Electricity demand increases in response to the carbon taxes as well as from nuclear cost reductions. In the highest nuclear cost case, Nuc66, electricity demand is 9400, 9700, and 10300 TWh by 2100 for the Ct50, Ct100, and Ct150 tax scenarios, respectively. Electricity demand is 1, 4, and 10% greater than the

Reference scenario in the Nuc66 case for the 50, 100, and 150 $/tCO$_2$ carbon tax scenarios, respectively, by 2100. In the lowest nuclear cost case, Nuc26, electricity demand is 10100, 10600, and 11100 TWh by 2100 for the Ct50, Ct100, and Ct150 tax scenarios, respectively. Electricity demand is 4, 9, and 15% greater than the Reference scenario in the Nuc26 case for the 50, 100, and 150 $/tCO$_2$ carbon tax scenarios, respectively, by 2100.

The first observation from Figure 9 is that imposing any carbon penalty increases the total demand for electricity relative to a no policy scenario over the long-term for all nuclear cases. All carbon tax scenarios have higher electricity demand than the Reference scenario. The second observation is that raising the carbon penalty further increases the demand for electricity as shown by the progressively greater changes in electricity demand in Ct150 relative to Ct100 and Ct50. And the third observation is that improvements in the cost of nuclear power induces even greater electricity demand for electricity under the carbon penalty. Electricity demand changes in the Nuc26 case are greater than in the Nuc66 case as described above.

The carbon penalty, the stringency of the penalty, and the nuclear cost all contribute to determining the total demand for electricity as all three factors affect the relative cost difference of electricity to refined fossil fuels. Substitution to electricity and greater electricity demand occur when electricity prices fall relative to refined fossil fuels at the end-use. Multiple low-cost carbon-free power options and the progressive decarbonization of the electric sector over time diminish the impact of the carbon penalty on electricity prices. Ultimately, electricity prices are unaffected by the carbon penalty when electricity generation becomes fully decarbonized (Kim, 2022). Fossil fuel use, on the other hand, continues to be impacted by the carbon penalty at the same rate.

Additionally, lowering nuclear capital cost increases the nuclear electricity share, which contributes to both lower electricity prices and greater electricity decarbonization. Relatively lower electricity prices with low-cost nuclear energy, such as in the Nuc26 case, leads to greater divergence in the electricity price relative to refined fossil fuels, and thus, greater overall demand for electricity under the carbon tax cases.

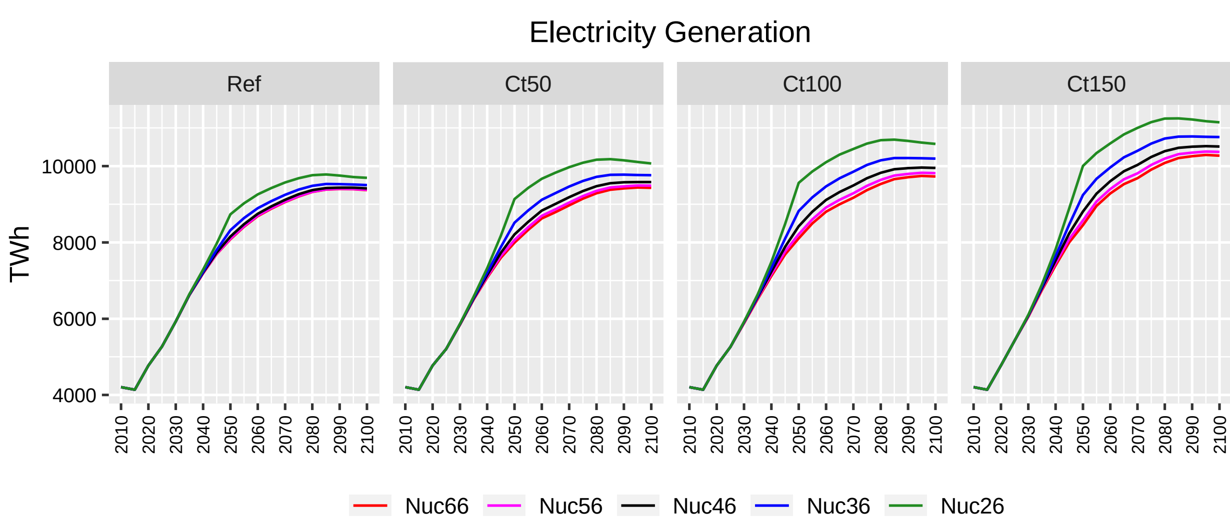

Figure 9. Total US electricity demand in the 50, 100, and 150 $/tCO$_2$ carbon tax scenarios.

The composition of electricity generation in the 50, 100, and 150 $/tCO$_2$ carbon tax scenarios across the nuclear sensitivity cases is shown in Figure 10. The lowest carbon tax case at 50 $/tCO$_2$ has an impact on increasing the deployment of carbon-free technologies beyond the Reference scenario, but the carbon penalty is not sufficiently high enough to induce major changes in the composition of electricity for each nuclear case.

By 2050 in the Ct50 scenario, the share of wind and solar combined is 28%, fossil is 38%, biomass is 1%, nuclear is 28%, and other is 5% (geothermal and hydro) for the lowest nuclear cost case (Nuc26_Ct50)., For the highest nuclear cost case (Nuc66_Ct50), the share of wind and solar combined is 30%, fossil is 48%, biomass is 2%, nuclear is 14 %, and other is 6% by 2050.

By 2100 in the Ct50 scenario, the share of wind and solar combined is 23%, fossil is 23%, biomass is 1%, nuclear is 49%, and other is 4% for the lowest nuclear cost case (Nuc26_Ct50). For the highest nuclear cost case (Nuc66_Ct50), the share of wind and solar combined is 35%, fossil is 46%, biomass is 3%, nuclear is 12%, and other is 4% by 2100. The shares of fossil and biomass power generation include some contributions from carbon capture and storage (CCS) technologies.

Carbon penalties primarily reduce the contribution of fossil power for greater use of wind, solar, and nuclear energy. But large shares of natural gas and coal power generation continue to operate without CCS and CO_2 emissions continue at the 50 $/t$CO_2$ carbon tax level. For high nuclear cost cases, the composition of electricity generation is not significantly different than in the Reference scenario. However, for low nuclear cost cases, the combined contribution of low cost nuclear with the carbon penalty induces significantly greater substitution of fossil power for nuclear. The specific nuclear contributions are discussed further below.

Doubling the carbon tax to 100 $/t$CO_2$ has a clear and more aggressive impact on the deployment of all carbon-free power technologies as shown in Figure 10. Fossil and biomass CCS technologies penetrate to a greater degree, and all carbon-free technologies including wind, solar, nuclear, and CCS, constitute the bulk of power generation. Although significant penetration of carbon-free power generation occurs, a carbon tax of 100 $/t$CO_2$ is still not high enough to completely remove all sources of power sector carbon emissions. Some levels of power generation from natural gas and coal with free venting of carbon emissions continue throughout the 21st century in the 100 $/t$CO_2$ scenario.

By 2050 in the Ct100 scenario, the share of wind and solar combined is 32%, fossil with and without CCS is 27%, biomass with and without CCS is 2%, nuclear is 33%, and other is 6% for the lowest nuclear cost case (Nuc26_Ct100). For the highest nuclear cost case (Nuc66_Ct100), the share of wind and solar combined is 35%, fossil with and without CCS is 41%, biomass with and without CCS is 3%, nuclear is 15%, and other is 6% by 2050.

By 2100 in the Ct100 scenario, the share of wind and solar combined is 23%, combined fossil with and witout CCS is 15%, biomass with and without CCS is 2%, nuclear is 54%, and other is 6% for the lowest nuclear cost case (Nuc26_Ct100). For the highest nuclear cost case (Nuc66_Ct100), the share of wind and solar combined is 36%, combined fossil with and witout CCS is 39%, biomass with and without CCS is 5%, nuclear is 15% and other is 5% by 2100.

The highest carbon tax scenario of 150 $/t$CO_2$ is fully capable of decarbonizing the US electricity sector and all carbon-free technology options are deployed. The electricity sector is fully decarbonized around the middle of the century with some variations on the timing of when full decarbonization occurs dependent on the cost of nuclear energy. At 150 $/t$CO_2$, negative emissions from BECCS compensate for emissions from natural gas power generation as well as emissions from CCS losses for achieving electricity sector net-zero emission.

By 2050 in the Ct150 scenario, the share of wind and solar combined is 33%, fossil with and witout CCS is 25%, biomass with CCS is 5%, nuclear is 32%, and other is 5% for the lowest nuclear cost case (Nuc26_Ct150). For the highest nuclear cost case (Nuc66_Ct150), the share of wind and solar combined is 37%, fossil with and witout CCS is 36%, biomass with CCS is 6%, nuclear is 15%, and other is 5% by 2050.

By 2100 in the Ct150 scenario, the share of wind and solar combined is 25%, combined fossil with and witout CCS is 14%, biomass with CCS is 3%, nuclear is 53%, and other is 5% in the lowest nuclear cost case. For the highest nuclear cost case (Nuc66_Ct150), the share of wind and solar combined is 38%, combined fossil with and witout CCS is 35%, biomass with CCS is 7%, nuclear is 15%, and other is 5% by 2100.

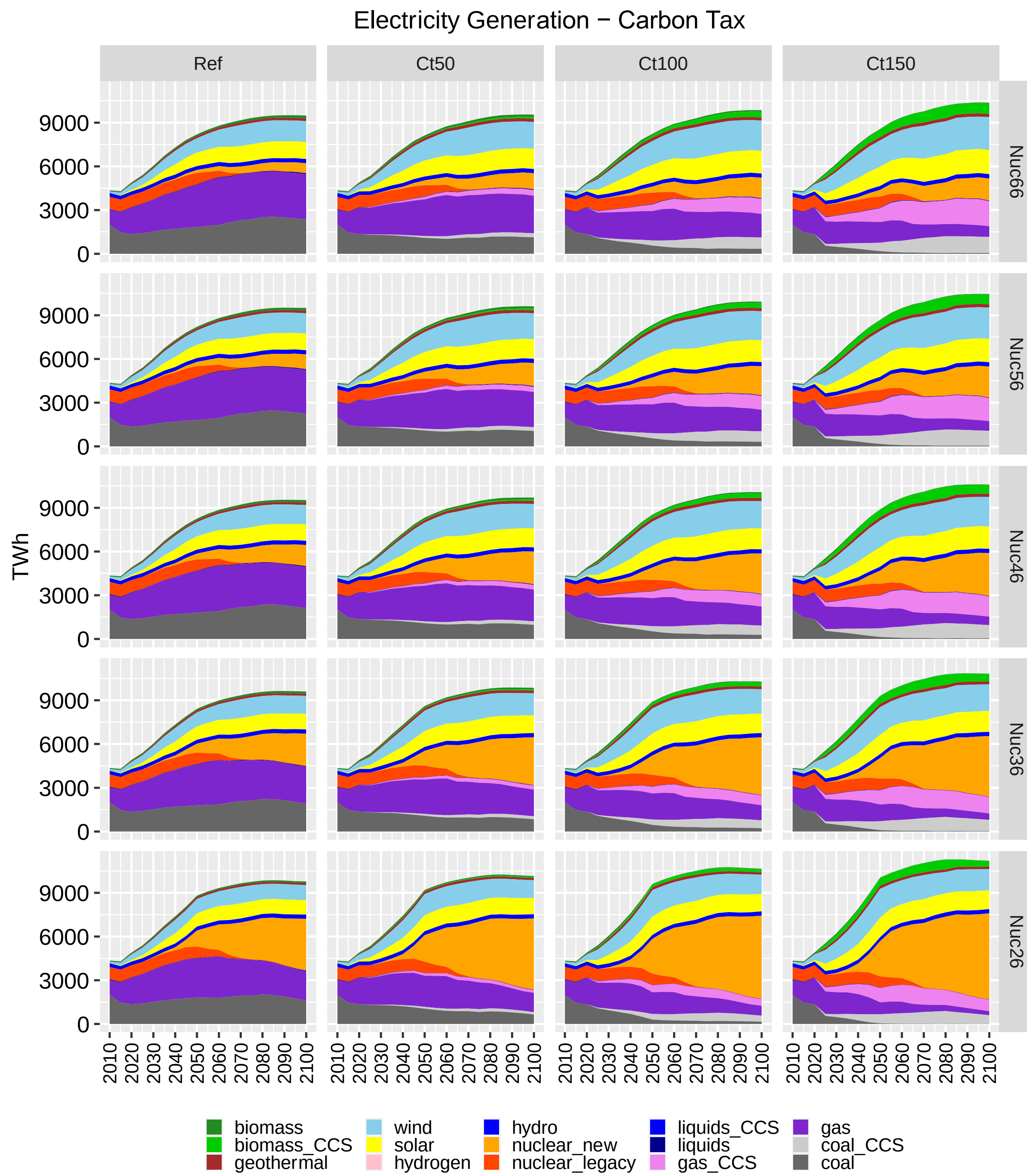

Figure 10. Electricity generation by fuel type for alternative nuclear capital costs and carbon tax scenarios.

Both the reduction in the nuclear capital cost and imposition of carbon taxes contribute to the expanded deployment of nuclear energy. Expected observations of nuclear capital cost reductions is the increase in total nuclear power capacity deployed and nuclear market shares under all carbon tax scenarios. Figure 11 and 12 displays the nuclear capacity and nuclear electricity shares for all carbon tax scenarios and nuclear cost cases. In general, the carbon penalty on fossil power benefits nuclear power further relative to the Reference scenario for each nuclear cost case.

The carbon tax of 50 $/tCO_2$ increases nuclear capacities to 140, 160, 180, 230, and 330 GW by 2050 in the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively, as shown in Figure 11. The corresponding nuclear electricity shares are 14, 15, 17, 21, and 28% for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively, as shown in Figure 12. By 2100, nuclear capacities are 140, 200, 290, 420, and 620 GW and shares are 12, 17, 23, 34, and 49% for the Nuc66, Nuc56, Nuc46, Nuc36 and Nuc26 cases, respectively.

Higher carbon penalties encourage even greater utilization of nuclear energy. The 100 $/tCO_2$ carbon tax increases nuclear capacities to 150, 170, 210, 269, and 400 GW by 2050 in the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. The corresponding nuclear electricity shares are 15, 17, 19, 24, and 33% for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. By 2100, nuclear capacities are 180, 250, 350, 500, and 720 GW and shares are 15, 20, 28, 39, and 54% for the Nuc66, Nuc56, Nuc46, Nuc36 and Nuc26 cases, respectively.

While a 150 $/tCO_2$ carbon tax was necessary to fully decarbonize the power sector, a carbon tax beyond 100 $/tCO_2$ has a diminishing impact on the deployment of nuclear energy. In the 150 $/tCO_2$ tax case, the nuclear capacities are 160, 180, 210, 280, and 410 GW by 2050, with corresponding shares of 15, 16, 19, 24, and 32% for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. By 2100, nuclear capacities are 190, 270, 380, 530, and 750 GW and shares are 15, 21, 28, 39, and 53% for the Nuc66, Nuc56, Nuc46, Nuc36 and Nuc26 cases, respectively.

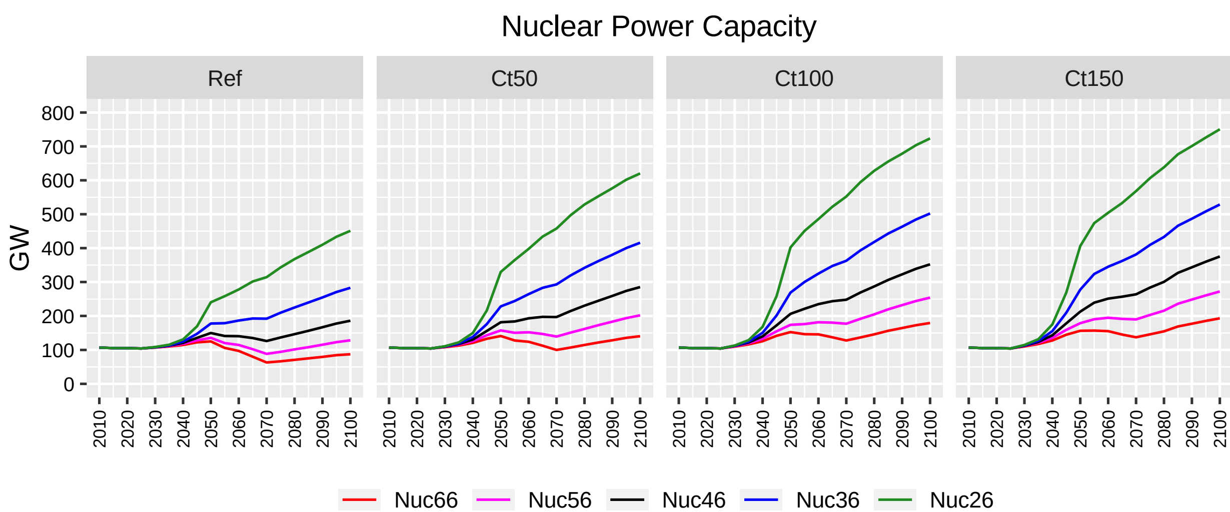

Figure 11. Nuclear power capacity by carbon tax scenarios for alternative nuclear capital cost cases.

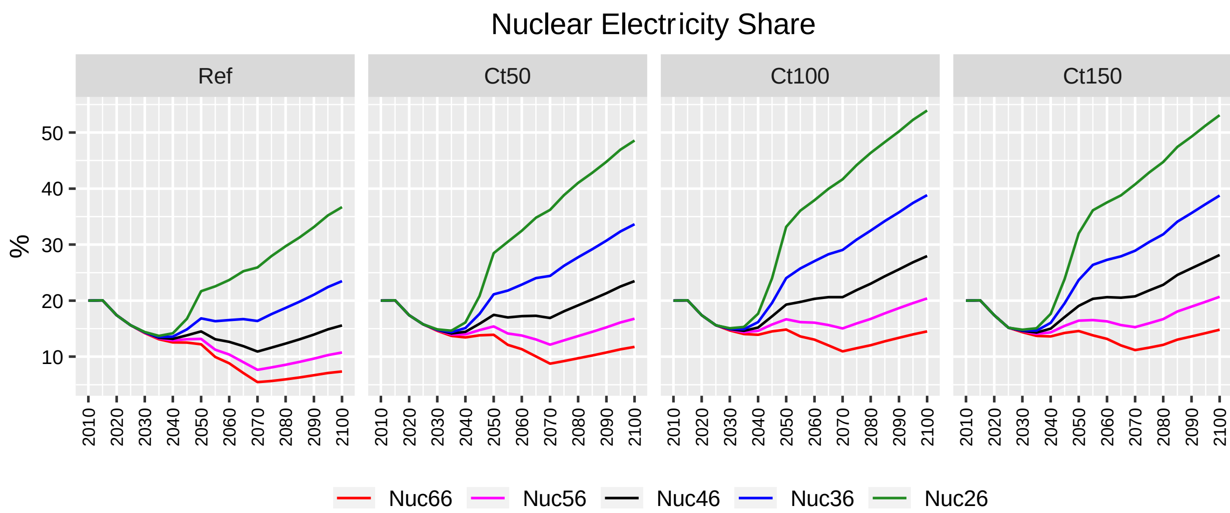

Figure 12. Nuclear electricity share by carbon tax scenarios for alternative nuclear capital cost cases.

Differences between the 100 and 150 $/t$CO_2$ carbon tax on nuclear deployments are much smaller than the nuclear capacity differences between the 50 and 100 $/t$CO_2$ carbon tax. See Figure 13 where nuclear capacities are plotted by carbon tax scenarios and grouped by each nuclear cost case. As the electricity sector becomes progressively decarbonized with rising carbon penalties fewer opportunities remain for the substitution of fossil power for nuclear power. A carbon tax much beyond 100 $/t$CO_2$ has diminishing benefits for the additional deployment of nuclear power as shown in Figure 13. Beyond 100 $/t$CO_2$, there are greater benefits for nuclear expansion from the reduction of nuclear capital costs than to increase carbon penalties further. Figure 13 also highlights that no matter the carbon tax scenario, lowering the capital cost of nuclear is always beneficial for the expansion of nuclear energy. In the long-term, reducing the nuclear cost had a relatively greater impact on nuclear expansion than from the carbon penalty as is detailed below.

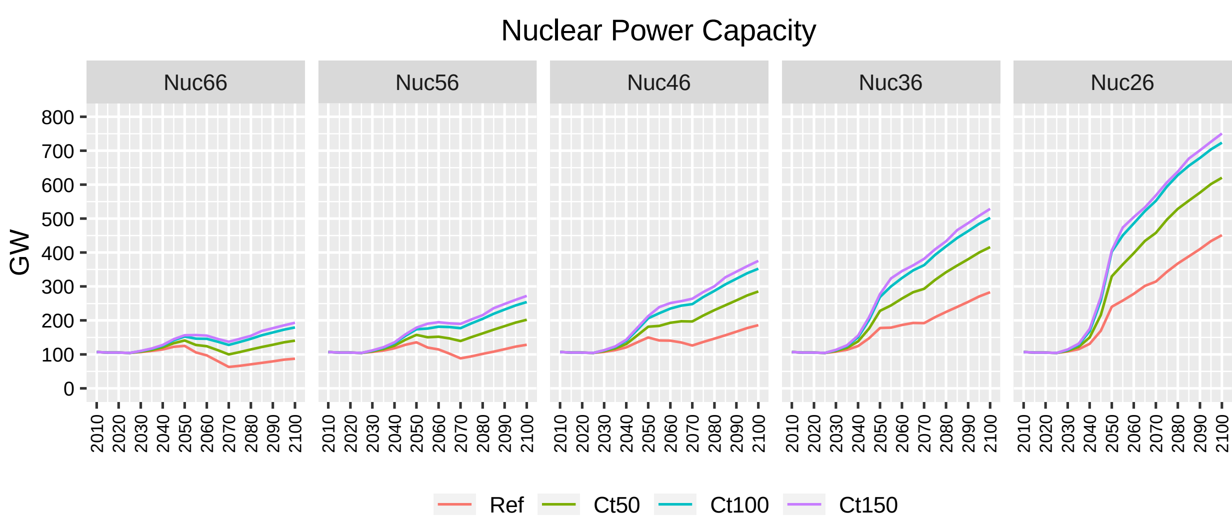

Figure 13. Nuclear power capacity for carbon tax scenarios grouped by each nuclear capital cost cases.

Carbon penalties increase the competitiveness of nuclear power as demonstrated by the increase in nuclear capacities in the carbon tax scenarios relative to the Reference. A 50 $/tCO_2$ is equivalent to reducing the nuclear capital cost by 1000 $/kW as observed in Figures 14. For instance, a 50 $/tCO_2$ enables the 6600 $/kW case (Nuc66_Ct50) to match or slightly exceed the nuclear capacity of the 5600 $/kW case (Nuc56_Ref) without any carbon penalties. This 1000 $/kW equivalence of 50 $/tCO_2$ carbon tax holds for all nuclear costs cases but cost reductions play a great role at very low nuclear costs.

The 100 $/tCO_2$ impact on nuclear deployment is even more dramatic as it is equivalent to reducing the nuclear capital cost by 2000 $/kW as observed in Figure 15. The nuclear capacities of the 100 $/tCO_2$ cases are nearly equal to the Reference scenario nuclear cases at a cost that is 2000 $/kW less. For instance, the 6600 $/kW case with 100 $/tCO_2$ (Nuc66_Ct100) has similar nuclear capacity as the 4600 $/kW case without tax (Nuc46_Ref). Again, this equivalency holds for other nuclear cost cases as well but with greater benefit from nuclear capital cost reductions at very low nuclear costs.

Variations exist in the equivalency of the carbon tax to nuclear capital cost savings and the resulting inferred equivalency of capital cost savings is not a strictly fixed and static relationship between carbon tax levels and nuclear capital costs. At very low nuclear capital costs, such as in the 2600 $/kW case (Nuc26_Ref), there is greater nuclear capacity expansion than at higher capital cost with the carbon tax, such as 4600 $/kW case with 100 $/tCO_2$ tax (Nuc46_Ct100). By 2100, the nuclear capacity is 450 GW in Nuc26_Ref, whereas the nuclear capacity is 350 GW in Nuc46_Ct100.

The results of the 150 $/tCO_2$ equivalency on the nuclear capital cost is similar to the 100 $/tCO_2$ case and thus, is not discussed. In general, there is a greater nonlinear benefit from an aggressive reduction in nuclear capital cost than a progressive increase in the carbon penalty.

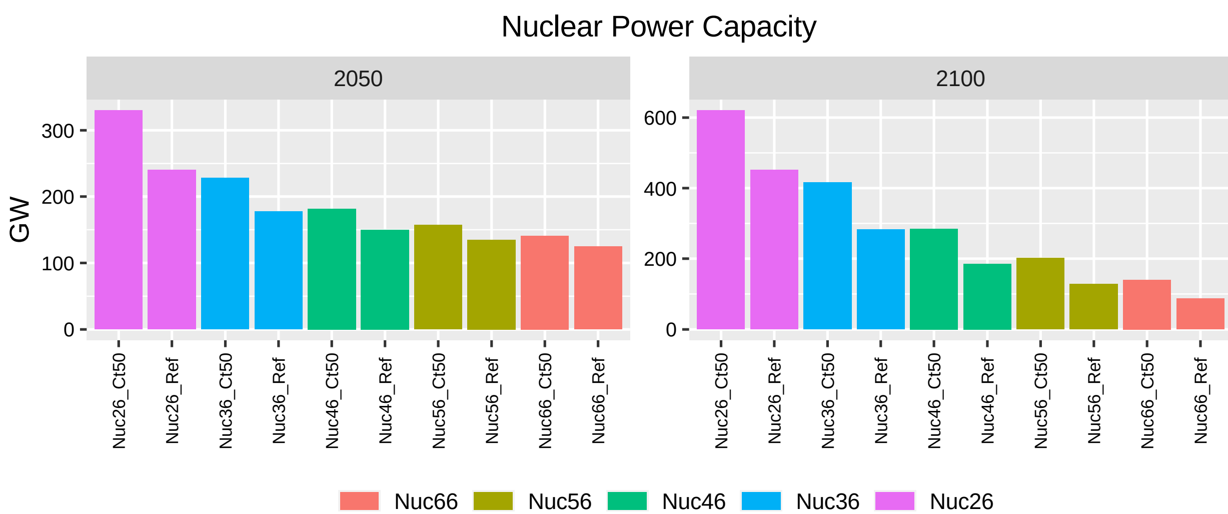

Figure 14. Comparison of nuclear power capacity in 2050 and 2100 for the Reference and 50 $/tCO_2$ carbon tax scenarios at alternative nuclear capital costs.

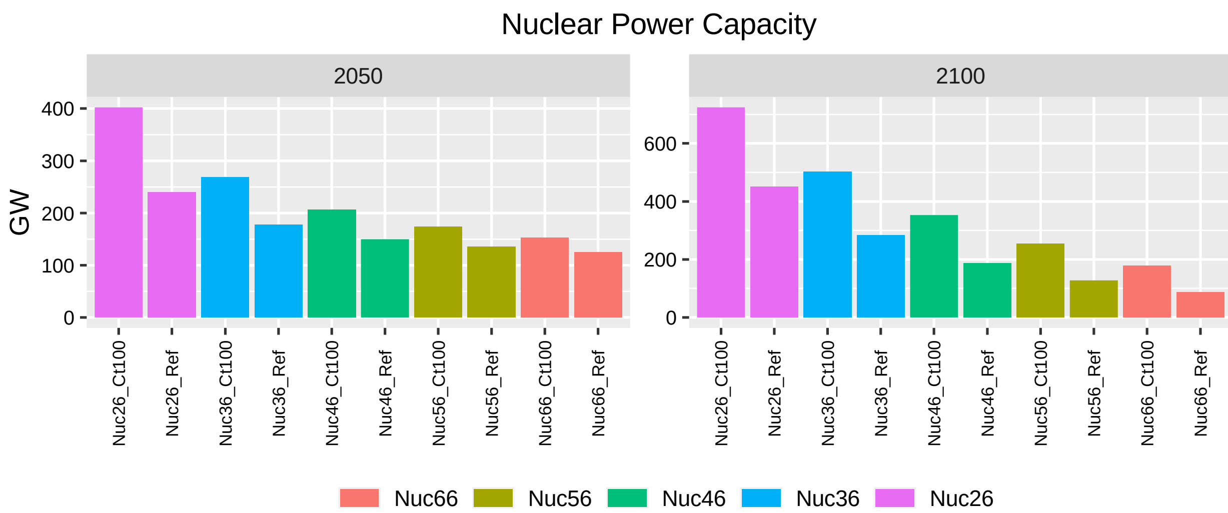

Figure 15. Comparison of nuclear power capacity in 2050 and 2100 for the Reference and 100 $/t$CO_2$ carbon tax scenarios at alternative nuclear capital costs.

US CO_2 emissions by sector (building, cement, industry, transport, and electricity) for all carbon tax scenarios and nuclear cost cases are shown in Figure 16. Carbon taxes applied to all emissions activities contribute to the reduction of total economy-wide emissions with greater reductions occurring with progressively higher carbon taxes. However, carbon taxes have varying levels of impact across the economic sectors, and the electricity sector is the most responsive to the carbon tax since there are multiple low-cost carbon-free technology options that can substitute for fossil power.

The 50 $/t$CO_2$ tax reduces total economy-wide emissions by 29 to 32% by 2100 for the nuclear cost cases relative to the Reference scenario, and the carbon tax level is insufficient to achieve net-zero emissions in total or for any sector. The 100 $/t$CO_2$ tax reduces total economy-wide emissions by 54 to 55% by 2100 for all nuclear cases relative to the Reference scenario. While net-zero emission is not achieved, significant reductions in electric sector CO_2 emissions are achieved by 2100 with the 100 $/t$CO_2$ tax. Electricity sector emissions are nearly eliminated by 2100, with a reduction of 80 to 90% from the 2010 level. See Figures 17 for electricity sector CO_2 emission by carbon tax scenario.

The 150 $/t$CO_2$ tax reduces total economy-wide emissions by 73 to 75% by 2100 for the nuclear cost cases relative to the Reference scenario. The tax level is still insufficient to achieve net-zero emissions in total but is sufficiently high enough to achieve net-zero electricity emissions in the middle of the century as shown in Figure 16. The specific year in which net-zero electricity emissions is achieved (2050 to 2065) is dependent on the nuclear case which is more clearly shown in Figure 17. A fixed tax level between 100 and 150 $/t$CO_2$ is also likely to result in net-zero electricity emissions within the 21st century but that specific value was not investigated in this analysis.

At a carbon tax level of 150 $/t$CO_2$, differences in nuclear capital cost no longer play a significant role in power sector CO_2 emissions reduction in the long-term. There is some impact of nuclear capital cost differences around midcentury, but little impact after that as observed in Figure 17. The tax level is sufficiently high enough to fully decarbonize the electricity sector and enable other carbon-free technology options to penetrate instead of nuclear power if nuclear costs remain high. While lowering nuclear capital cost does not affect electricity sector emissions at this tax rate, it does play a role in increasing the nuclear market share.

It is also noteworthy that a carbon tax applied at a fixed rate (such as 100 $/tCO_2$) throughout the century is capable of progressively reducing electricity emissions over time. In addition to the availability and improved competitiveness of multiple carbon-free technology options, the longevity of electric power technologies contributes to the accumulation of total carbon-free power capacities over time. New power investments favor carbon-free technologies and the total capacity of fossil power diminishes with time.

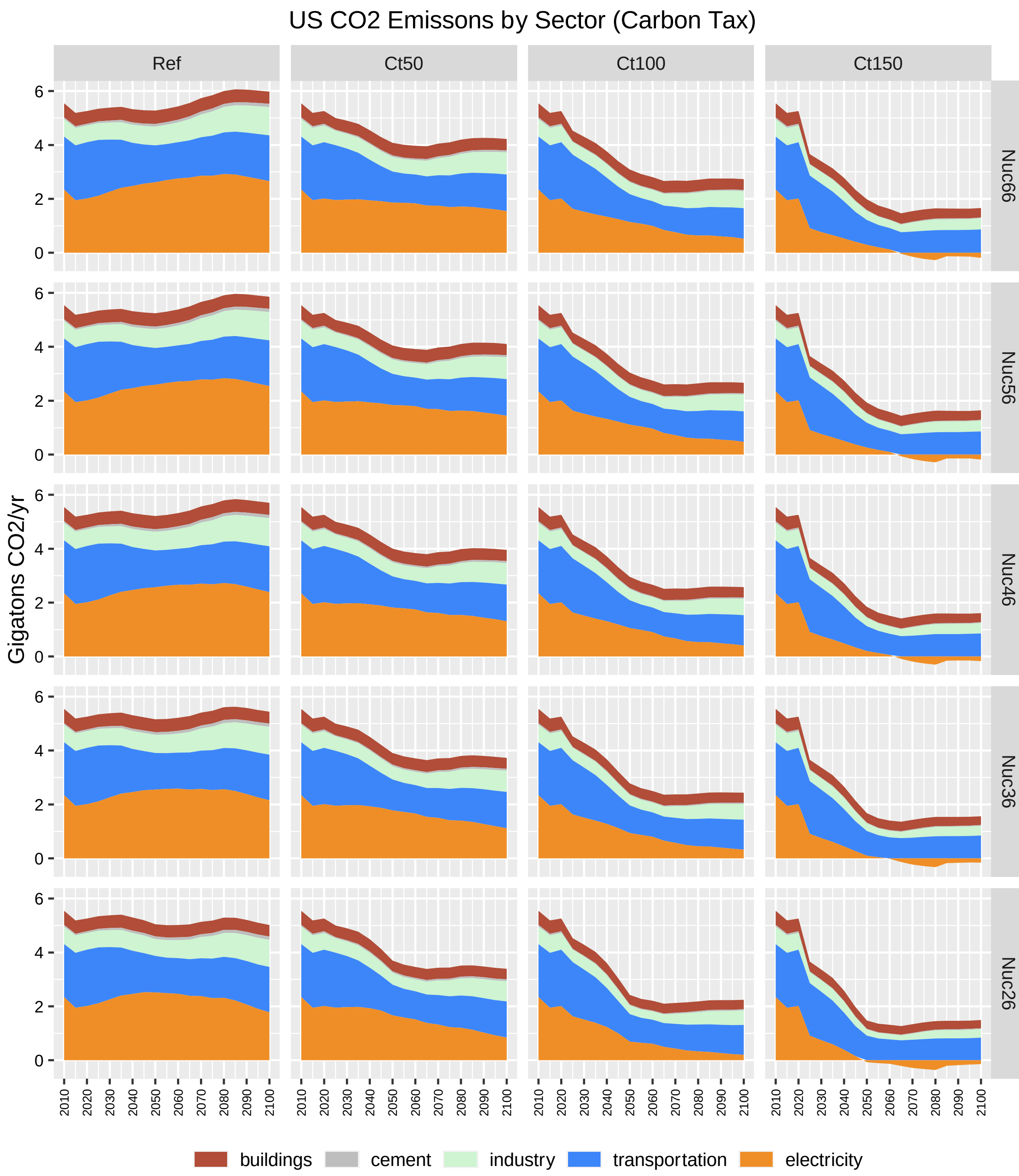

Figure 16. US CO_2 emissions by sector for all carbon tax scenarios and alternative nuclear capital costs cases.

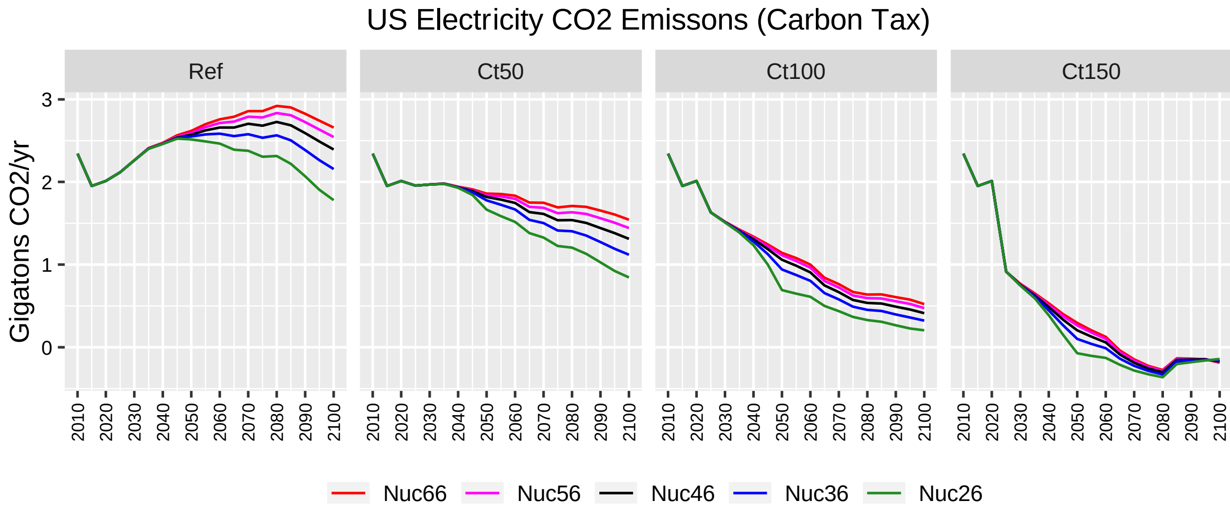

Figure 17. US CO_2 emissions from electricity generation for the carbon tax scenarios with alternative nuclear cost cases.

4.3 Net-Zero Emission Goals and Nuclear Capital Cost Interactions

Net-zero emission goals are more aggressive emissions mitigation policies for addressing climate change than the fixed carbon tax levels explored thus far. Achieving economy-wide net-zero emission implies stabilization of GHG concentrations in the atmosphere and the long-term stability of the climate system.

Model results of the net-zero policies show that carbon tax levels of approximately 300 \$/tCO_2, or double the highest carbon tax level explored above, is required to achieve net-zero emissions. The resulting carbon taxes for the 2050, 2060 and 2070 net-zero goals are as displayed in Figure 18. The initial and peak carbon tax levels are dependent on the net-zero target years and the nuclear capital cost cases.

In the net-zero by 2050 scenario (Nz50), carbon taxes begin at 107 \$/tCO_2 in 2025 and reach 291 to 304 \$/tCO_2 by 2050 dependent on the nuclear cost case. The lowest nuclear cost results in the lowest peak carbon tax. Carbon taxes fall for a couple of decades after reaching the peak in 2050 as the economy has fully decarbonized and fewer carbon-free or negative emissions technologies are needed to maintain net-zero emissions. As the economy and energy demand continue to grow, carbon taxes rise again from 2070 until the end of the century. However, the carbon tax never approaches the peak levels of 2050 due to technical change and steady improvements in the cost of all carbon-free technologies over time.

In the net-zero by 2060 scenario (Nz60), carbon taxes begin at 92 \$/tCO_2 in 2025, which is less than the initial tax of the 2050 net-zero goal since the delay in the target year relaxes the initial emissions constraint to some degree. Nevertheless, carbon taxes peak at a slightly higher rate due to the higher baseline or reference scenario emissions after 2050. Carbon taxes reach 304 to 317 \$/tCO_2 by 2060 dependent on the nuclear case, with the lowest cost nuclear determining the lower tax rate.

In the net-zero by 2070 scenario (Nz70), carbon taxes begin at 81 \$/tCO_2 in 2025, which is even less than the initial tax of the 2060 net-zero goal. Taxes reach a peak of 297 to 304 \$/tCO_2 by 2070 dependent on the nuclear cost case.

In general, alternative target years of 2050, 2060, or 2070 for achieving economy-wide net-zero emissions have similar magnitude of carbon penalties with some differences in the initial and peak carbon tax rates and the timing of when the peak occurs. Additional factors affect the specific value of the carbon tax such as the cost and lifetime of all technologies and the growth in the demand for energy in the long-term. The primary determinant of the carbon tax rates, however, is driven by the emissions mitigation potential from outside of the electricity sector and in the buildings, industry, and transport sectors.

The alternative nuclear capital cost sensitivity cases had some influence on the carbon tax at around midcentury but little impact on the peak levels needed to achieve net-zero emission. Differences in the peak carbon tax rates from the lowest and highest nuclear cost cases were no more than 5%.

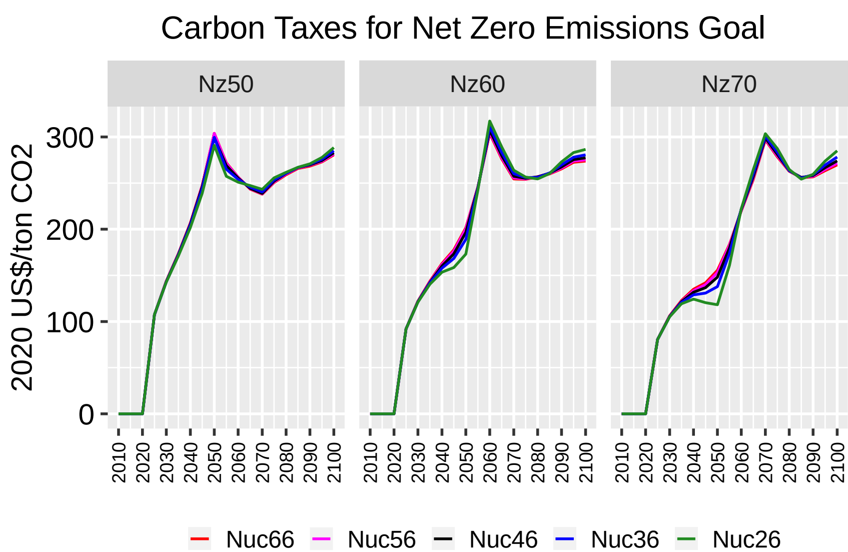

Figure 18. Model results of carbon taxes required to meet net-zero emissions goal by 2050, 2060, and 2070.

Greater reductions of carbon emissions necessary for achieving net-zero emissions require much higher carbon penalties which significantly affects the relative prices of all energy carriers and fuels. When electricity becomes fully decarbonized, it is no longer impacted by the carbon penalty. This is in constrast to the direct utilization of fossil fuels which continue to be charged at a higher penalty as the carbon tax increases. Relative energy price differences favor the increased utilization of electricity at the end-use and the demand for electricity is significantly greater in the net-zero scenarios than in the Referece scenario or fixed carbon tax scenarios investigated above. See Figure 19 for the projection of electricity demands in the net-zero scenarios.

By 2050, electricity demand increases to a range of 9660 to 11200 TWh in Nz50, 8840 to 10200 TWh in Nz60, and 8440 to 9730 TWh in Nz70 for the nuclear senstivity cases. The range in demand is from the alternative nuclear cases with the highest and lowest nuclear cost corresponding to the lowest and highest electricity demand, respectively.

The relative changes in electricity demand by 2050 are 20 to 26% in Nz50, 9 to 17% in Nz60, and 4 to 11% in Nz70, relative to the Reference scenario. Delaying the net-zero target years relaxes the total increase in electricity demand around the middle of the century.

By 2100, the electricity demand increases to a range of 11700 to 12500 TWh for all three net-zero scenarios, Nz50, Nz60, and Nz70. Electricity demand increases by 25 to 29% in Nz50, 25 to 30% in Nz60, and 26 to 30% in Nz70 by 2100, relative to the Reference scenario. The range in electricity demand and their changes are due to the alternative nuclear costs. There is little difference in long-term electricity demand due to the initial timing of net-zero goals since all three scenarios utimately enforce net-zero emissions for most of the second-half of the century.

Overall, electricity demand has changed by similar levels for all three net-zero scenarios and about 30% additional increase in electricity demand is projected from the net-zero goals by the end of the century. This is a doubling of the eletricity demand changes as compared to the 15% increase in electricity demand from the 150 $/tCO$_2$ carbon tax case above.

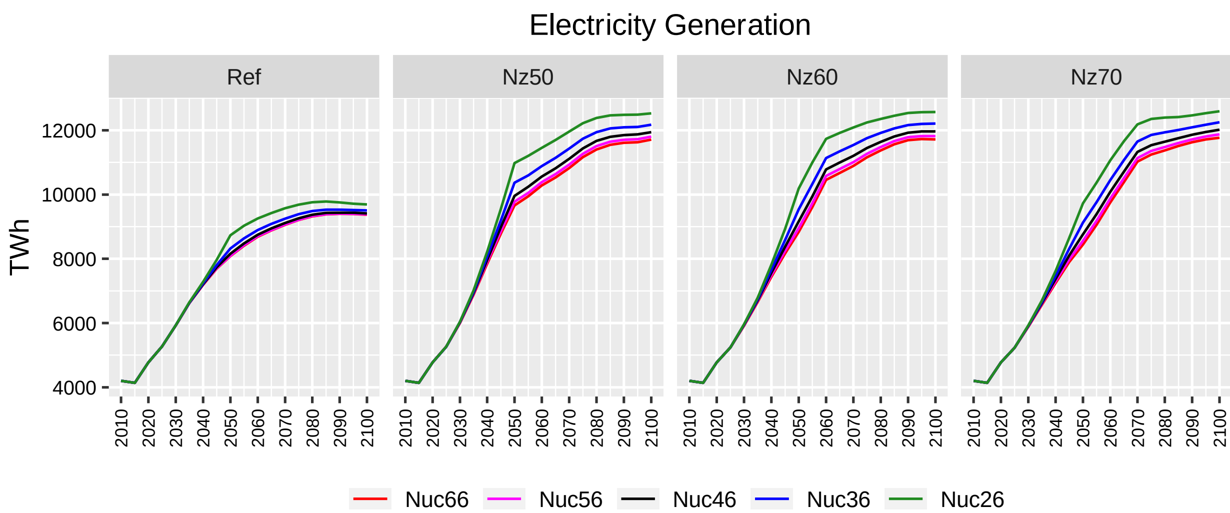

Figure 19. Total US electricity demand in the net-zero 2050, 2060, and 2070 scenarios.

Net-zero emisson goals induce the complete decabonization of the electricity sector and all available carbon-free or low-carbon technology options contribute to power generation. The composition of power generation by fuel type for net-zero goals is shown in Figure 20.

In Nz50 by 2050, the share of wind and solar combined is 33 to 39%, fossil CCS is 21 to 30%, BECCS is 9 to 12%, and nuclear is 15 to 33%, with variations due to nuclear cost cases. The composition of electricity generation is highly dependent on the nuclear cost, with low cost nuclear increasing the nuclear contribution at the expense of all other carbon-free technology options. Nuclear cost differences have the greatest single impact on natural gas power generation.

In Nz60 by 2050, the share of wind and solar combined is 33 to 39%, combined fossil with and without CCS is 22 to 34%, BECCS is 5 to 7%, and nuclear is 16 to 35%. And similarly in Nz70 by 2050, the share of wind and solar combined is 32 to 37%, fossil with and witout CCS is 25 to 35%, BECCS is 3 to 5%, and nuclear is 16 to 34%.

Relaxing the net-zero goal by delaying the target year by a couple of decades reduces the demand for carbon-free power generation and more fossil power with emissions is utilized in the interim.

By 2100, the electricity sector is not only fully decarbonized but also provides net-negative emissions from BECCS. Negative emissions from power sector BECCS compensate for emissions occuring outside of the electricity sector. In the Nz50 scenario, the share of wind and solar combined is 25 to 38%, fossil CCS is 21 to 30%, BECCS is 6 to 11%, and nuclear is 14 to 50% by 2100. In the Nz60 scenario, the share of wind and solar combined is 23 to 36%, fossil CCS is 14 to 32%, BECCS is 6 to 12%, and nuclear is 15 to 52%. While in the Nz70 scenario, the share of wind and solar combined is 22 to 35%, fossil CCS is 15 to 35%, BECCS is 6 to 12%, and nuclear is 15 to 53%.

Nuclear cost reductions have a significant and disproportioate impact on the composition of power generation over the long-term. By 2100, the nuclear share of electricity is 50% or more in the net-zero scenarios for the lowest nuclear cost case as compared to about 35% at most in 2050. This is attributed to the longevity of nuclear power technologies and the sustained investments in nuclear power which contributes to the accumulation of total nuclear power capacity throughout the 21st century. Other carbon-free technologies with shorter lifetimes may have higher levels of incremental investments but a portion of this new investment goes towards replacement capacity and does not contribute to expanding their market shares.

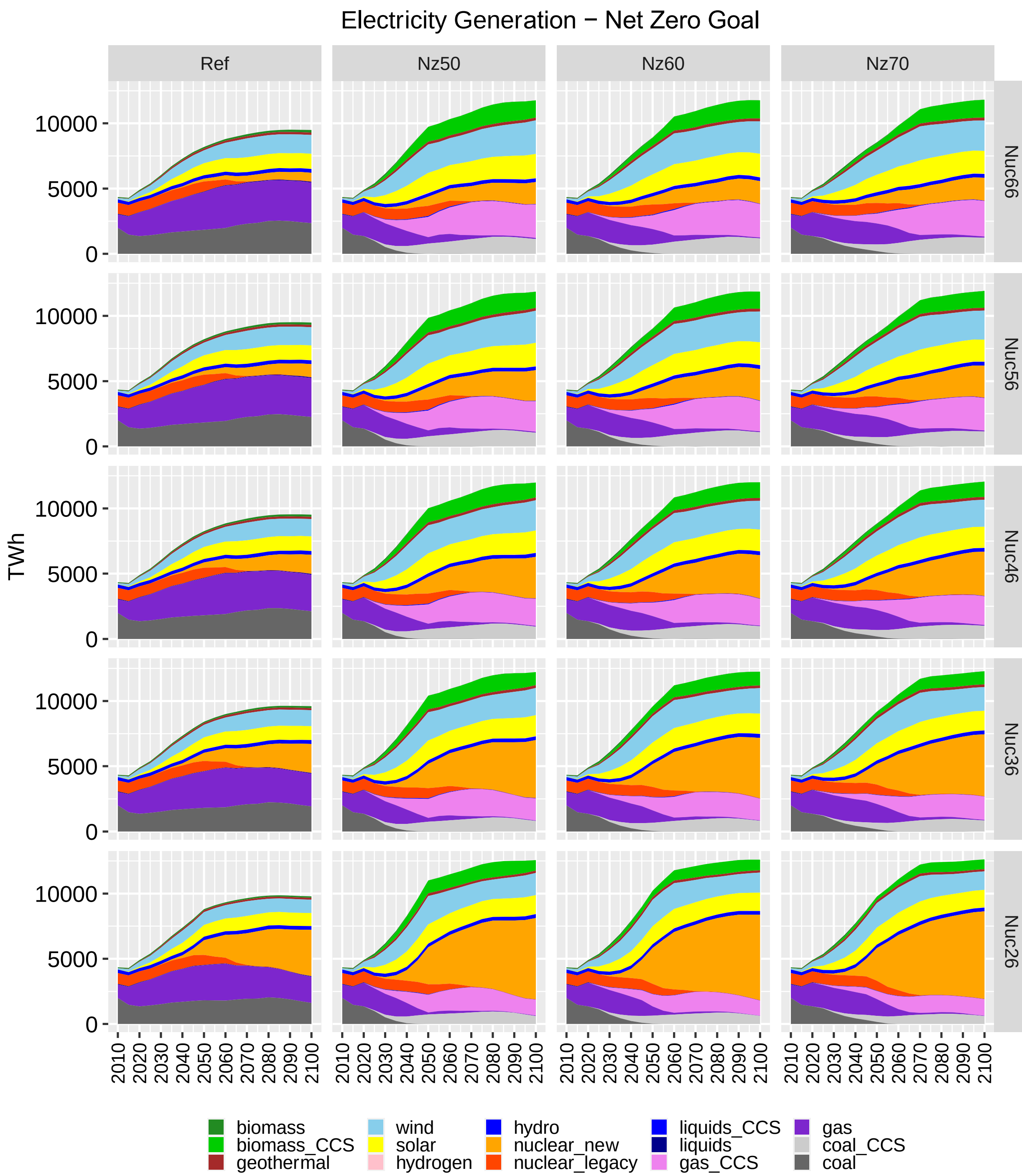

Figure 20. Electricity generation by fuel type for alternative nuclear capital costs and net-zero emission scenarios.

Although there are some differences in the total nuclear capacity and share across alternative net-zero scenarios, the profile and magnitude of the nuclear expansions over time are very similar. Figures 21 and 22 display the nuclear power capacity and market shares for the net-zero scenarios. In the Nz50 scenario, nuclear capacities are 190, 220, 260, 340, and 460 GW by 2050 for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively, and the corresponding nuclear electricity shares are 15, 18, 21, 26, and 33%. By 2100, nuclear capacities have increased to 210, 300, 410, 560, and 790 GW in Nz50, with shares of 14, 20, 27, 37, and 50% for the Nuc66, Nuc56, Nuc46, Nuc36 and Nuc26 cases, respectively.

Delayed net-zero goals to 2060 and 2070 (Nz60 and Nz70) have similar levels of nuclear power deployment over the long-term. In Nz60 by 2050, nuclear capacities are 180, 210, 250, 320, and 450 GW for the Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. While in Nz70 by 2050, the nuclear capacities are 170, 200, 230, 300, and 420 GW for the nuclear cases. As compared to the Nz50 scenario, nuclear capacities are about 5% and 10% less on average in the Nz60 and Nz70 scenarios, respectively, in 2050.

By 2100, nuclear capacities are 220, 310, 420, 590, and 830 GW in Nz60 and 220, 310, 430, 610, and 850 GW in Nz70 for Nuc66, Nuc56, Nuc46, Nuc36, and Nuc26 cases, respectively. Relative to Nz50, the nuclear capacities are 4 and 6% more on average in the Nz60 and Nz70 scenarios, respectively, by 2100.

There are differences in the nuclear capacities and shares from 2050 to 2070 in the Nz50, Nz60 and Nz70 scenarios for the nuclear cases. The timing of net-zero goals and high carbon penalties aligned with the timing of existing reactor retirements induces greater incremental investments in nuclear from 2050 to 2070 when the bulk of existing reactor retirements occur. Thus, the Nz70 scenario, as well as Nz60, resulted in greater total nuclear capacity than Nz50 by 2100.

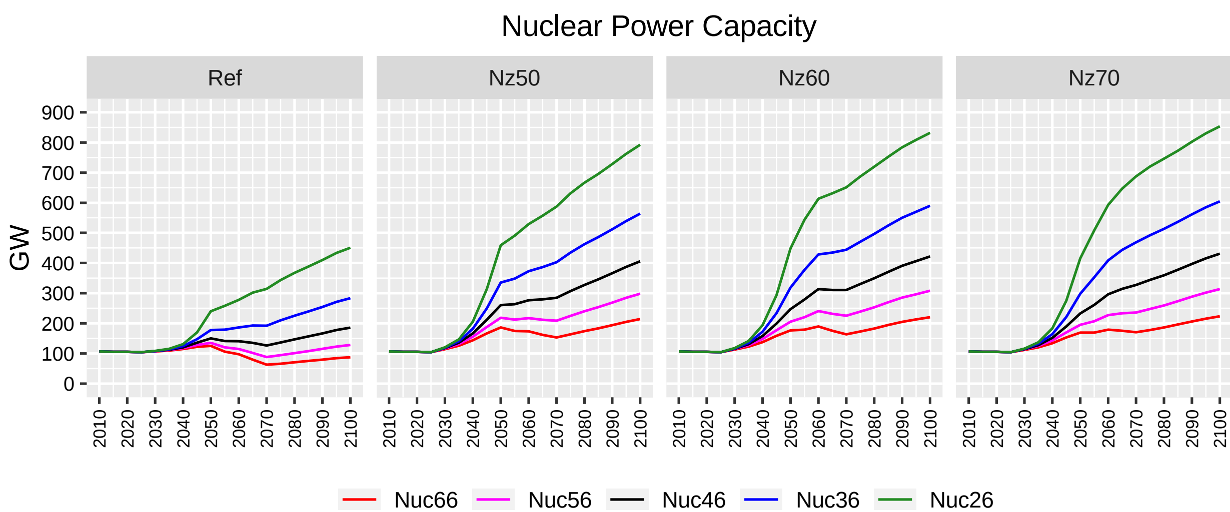

Figure 21. Nuclear power capacity in the net-zero emission scenarios for alternative nuclear cost cases.

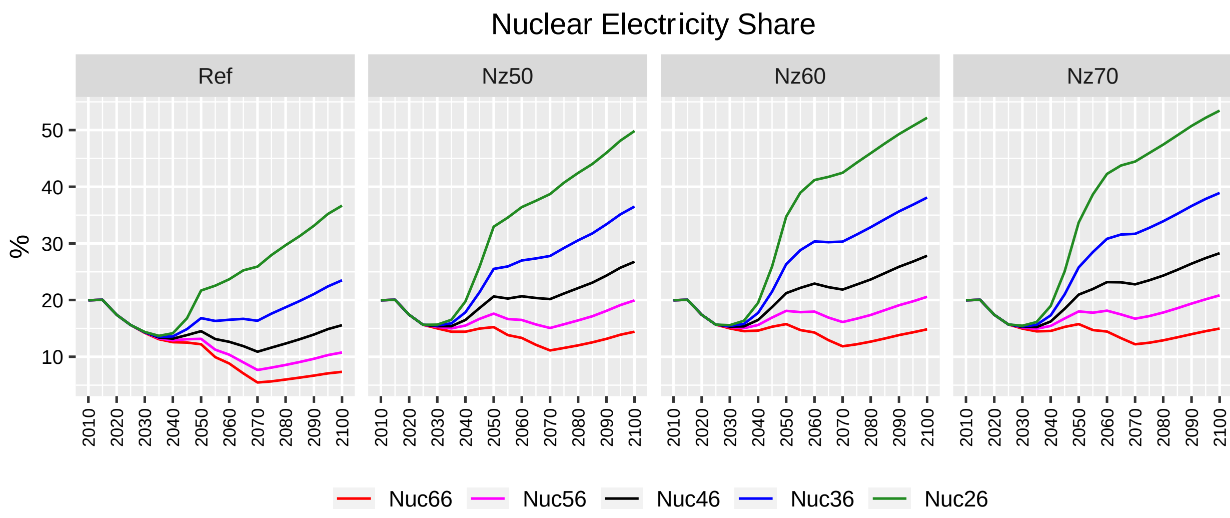

Figure 22. Electricity generation by fuel type for alternative nuclear capital costs and carbon tax scenarios.

An alternative view of the nuclear capacity results across the net-zero scenarios highlights the importance of improving the nuclear capital costs. Figure 23 displays the nuclear capacity for the net-zero scenarios grouped by nuclear cost cases. While there is a clear departure in the nuclear capacity with and without the net-zero policy, differences among the alternative net-zero goals are marginal. The stringency of the net-zero emissions goals drives the demand for all available carbon-free technology options. If nuclear is not a competitive option, other carbon-free technologies are utilized instead. However, reducing nuclear capital costs has a direct impact on the competitiveness of nuclear energy relative to other carbon-free or low-carbon power options. Within the alternative net-zero goals, reductions in the nuclear cost had a clear and pronounced impact on the deployment of nuclear power.

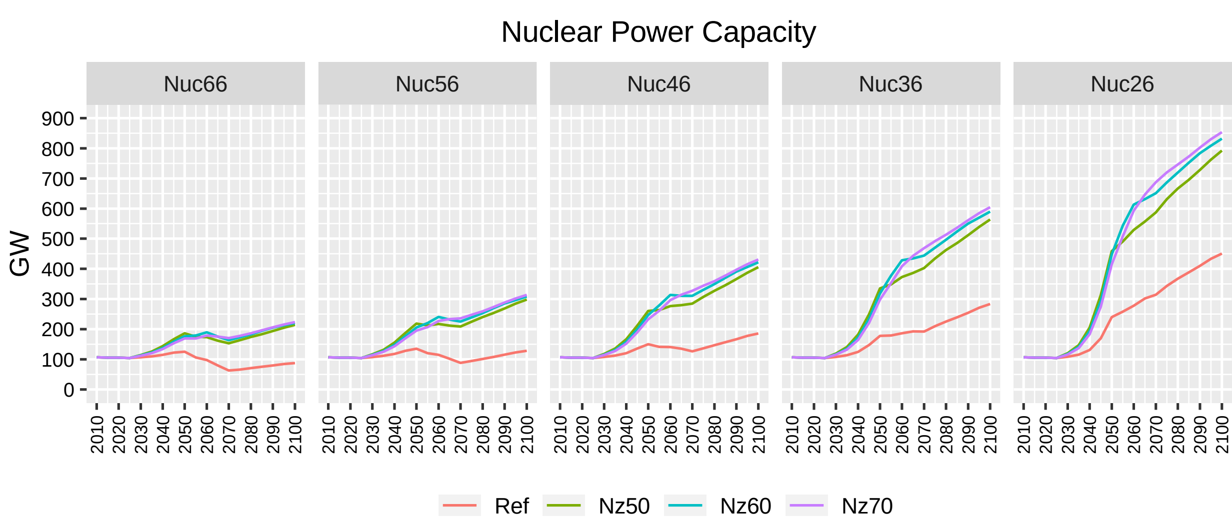

Figure 23. Nuclear power capacity for alternative net-zero scenarios grouped by nuclear cost cases.

US CO_2 emissions by sector (building, cement, industry, transport, and electricity) for the net-zero scenarios and nuclear cost cases are shown in Figure 24. Economy-wide net-zero emissions are achieved by 2050, 2060, or 2070 according to the policy implementation. The electricity sector is the first to decarbonize as there are multiple low-cost carbon-free technology options. Other sectors also reduce their emissions but not all carbon emissions from industrial processes and end-use energy services can be readily eliminated, for instance emissions from cement manufacturing and long-distance transport. Thus, net-negative emissions from power sector BECCS compensate for difficult-to-remove emissions from buildings, industries, and transport. In this analysis, negative emissions from BECCS are a more cost-effective approach for achieving net-zero emissions where non-emitting substitutes are too costly or not available for some services (IPCC, 2014). The ability to remove or negate these persistent end-use sector emissions ultimately determines the carbon tax levels for the net-zero goals. Emerging concepts for nuclear power based direct air capture technologies were not included in this analysis and remain as future work for the Systems Analysis & Integration Campaign.

Several observations emerge from Figure 24 and the changes in sectoral CO_2 emissions over time in the net-zero scenarios. All sectors make steep reductions in emissions in compliance with the rapidly declining emission constraints of the net-zero goals. Total emissions decline linearly until the target years as prescribed by net-zero emission constraints. Upon reaching the target years, however, emissions from transport, buildings, and cement are not completely removed. The remaining emissions are approximately 10 to 15% of 2010 emissions and varies due to the nuclear cost cases. Net-zero emissions are, however, achieved by utilizing negative emissions from power sector BECCS deployment.

Except for the timing of when net-zero goals are achieved, the general pattern of sectoral and total carbon emissions reductions are similar in the net-zero scenarios across all nuclear cost sensitivity cases. Moreover, the alternative nuclear cost cases had little impact on the overall response to the emissions mitigation behavior.

Differences in the cost of nuclear and their impact on electricity prices do have a small but noticeable feedback on the amount of power sector negative emissions needed to achieve net-zero, as highlighted in Figure 25. Lower electricity prices with low cost nuclear induce greater end-use electrification, lower end-use emissions, and less need for compensating negative emissions. By 2100, approximately 17% reduction in electricity prices between the highest (Nuc66) and lowest (Nuc26) nuclear cost cases results in approximately 0.5 $GtCO_2$ less compensating negative emissions.

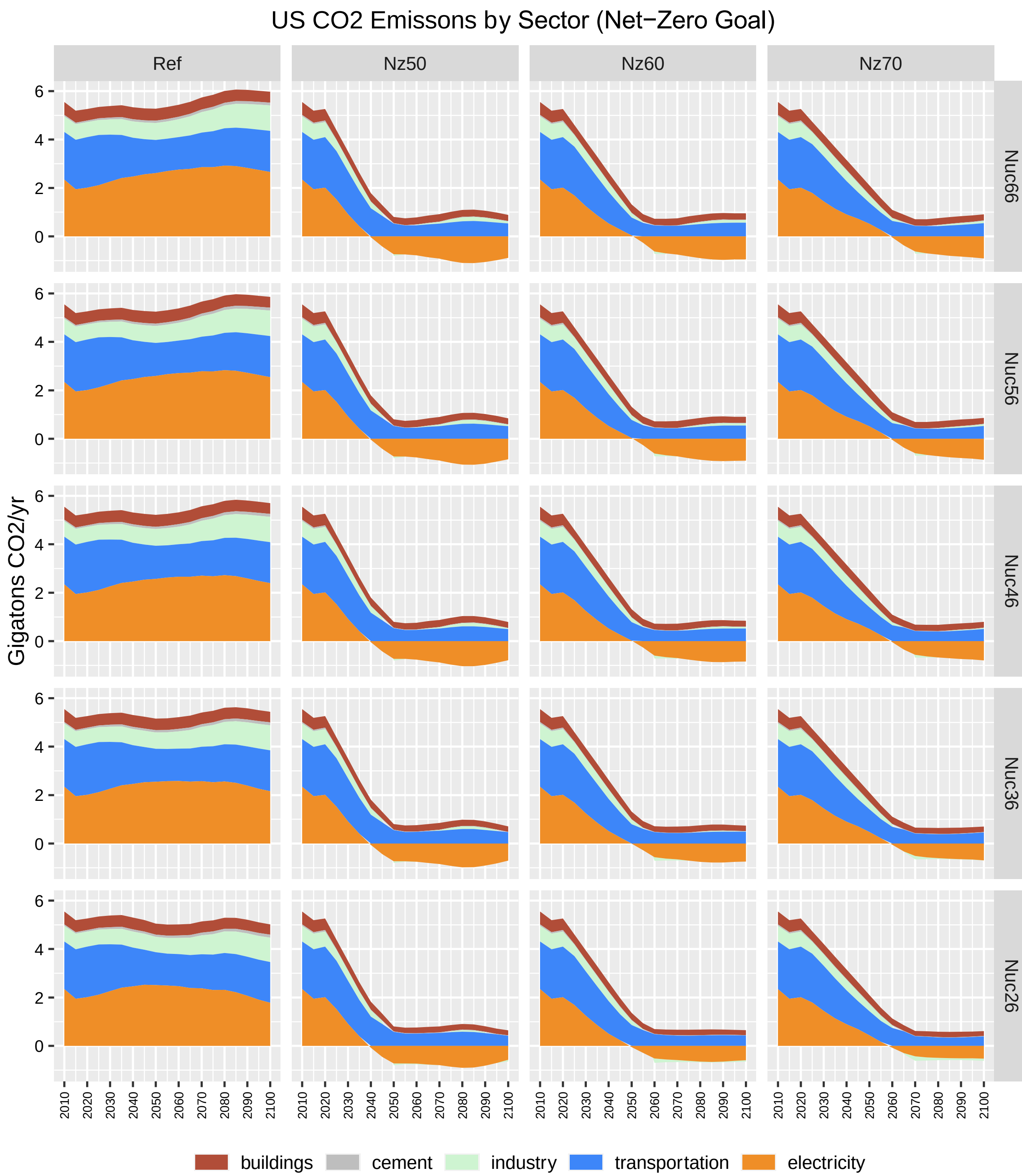

Figure 24. US CO_2 emissions by sector with economy-wide net-zero emission goals.

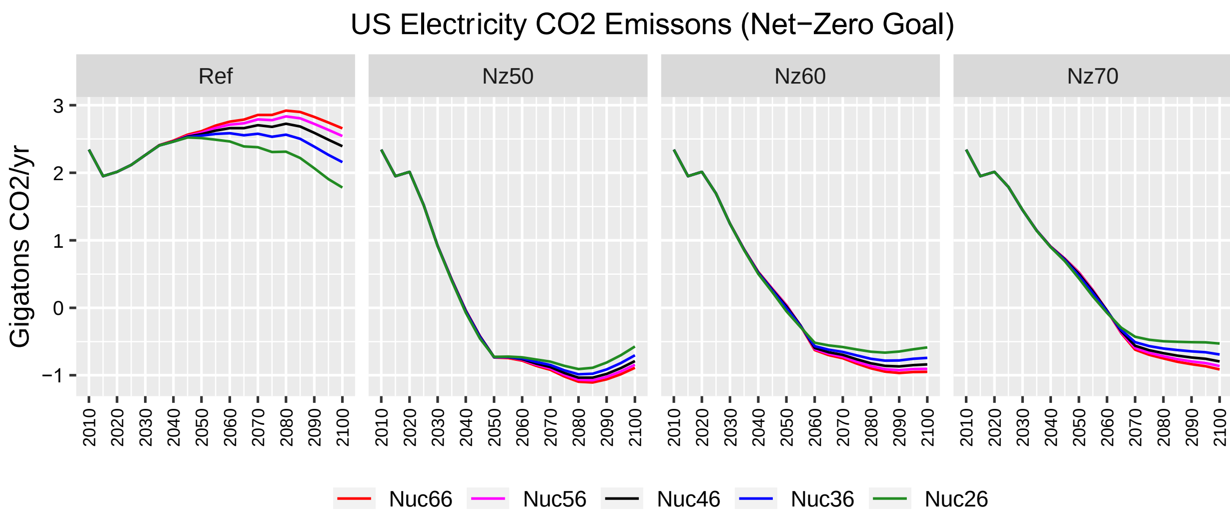

Figure 25. US electricity sector CO_2 emissions with economy-wide net-zero emission goals.

5. Conclusions

This analysis investigates the potential range and timing of future nuclear energy contributions to the US energy system. The interactions of improved nuclear competitiveness through nuclear reactor capital cost reductions and alternative climate mitigation policies are explored to assess the potential expansion of nuclear power throughout the 21st century. Multiple long-term scenarios of the US energy system are generated using the PNNL GCAM model for clarifying the role of nuclear capital cost reductions, the role of carbon penalties and emission constraints, and their combined impact on the deployment of nuclear power and on carbon emissions in the US.

Reduction of nuclear capital costs and increased nuclear competitiveness resulted in significant nuclear power expansion and carbon emissions mitigation even without an explicit carbon mitigation policy. In the range of nuclear capital costs assumed, 6600 down to 2600 $/kW, the nuclear power capacity was 130 to 240 GW in 2050 and 90 to 450 GW in 2100 in the Reference scenario without carbon policy. Thus, nuclear cost assumptions play a major role in the future contribution of nuclear energy. The range of nuclear capacities resulted in a 30% decrease in power sector CO_2 emissions and a 15% decrease in total economy-wide CO_2 emissions by 2100 between the high and low nuclear cost cases. Thus, efforts to reduce the nuclear cost contribute to and support emissions reduction goals without an explicit emissions mitigation policy.

On top of the nuclear capital cost improvements, fixed carbon taxes at 50, 100, and 150 $/tCO_2$ were overlayed to assess the impact of a progressively rising carbon penalty on the expansion of nuclear power. The 50 and 100 $/tCO_2$ carbon taxes further improved nuclear competitiveness and significantly expanded nuclear power deployments. In the 100 $/tCO_2$ carbon tax scenario, the nuclear capacity was 150 to 400 GW in 2050 and 180 to 720 GW in 2100 for the high and low nuclear cost cases. Emission reductions achieved with the 100 $/tCO_2$ carbon tax were 50 to 55% for the economy as a whole and 80 to 90% for the electricity sector.

A carbon penalty beyond 100 $/tCO_2$ had a diminishing impact on the additional deployment of nuclear power since the carbon tax level is sufficiently high enough to decarbonize the electric power sector near fully. Progressive decarbonization of the electricity sector with rising carbon penalties presents fewer opportunities for the substitution of fossil power generation for nuclear power. Differences between the 100 and 150 $/tCO_2$ carbon tax on nuclear deployments were much smaller than the differences between the 50 and 100 $/tCO_2$ tax scenarios. On the other hand, lowering the nuclear capital cost was always beneficial for the expanded deployment of nuclear energy no matter the carbon tax level, and in the long-term, an aggressive reduction of the nuclear cost had a relatively greater impact on nuclear expansion than the carbon penalty.

Separating the impact of carbon taxes and nuclear cost reductions indicates that a 50 $/tCO_2$ carbon tax is equivalent to reducing the nuclear capital cost by 1000 $/kW, and a 100 $/tCO_2$ carbon tax is equivalent to reducing the nuclear capital cost by 2000 $/kW. Variations exist in the equivalency of the carbon tax to nuclear capital cost savings and the resulting inferred equivalency is not strictly a static relationship. Very low nuclear capital costs, such as 2600 $/kW, had a relatively greater impact on nuclear expansion than with carbon taxes at much higher nuclear costs.

It is also noteworthy that a fixed carbon tax, such as 100 $/tCO_2$, applied throughout the century is capable of progressively reducing electricity emissions over time. The longevity of nuclear power plants contributes to the accumulation of total carbon-free power capacities and the diminished role of fossil power over time.

Net-zero emission scenarios were also explored as an alternative to the carbon tax scenarios to investigate the impact of more stringent climate mitigation goals on nuclear power expansion. Alternative target years of 2050, 2060, and 2070 were investigated for achieving economy-wide net-zero emission goals to provide a broader range of potential nuclear impacts.

Modeling results of carbon tax values for achieving net-zero goals peaked at approximately 300 $/t CO_2 for all target years. The electricity sector is fully decarbonized by midcentury for all net-zero scenarios, and the primary determinant of the carbon tax rates was driven not by the electric sector but by the emissions mitigation potential from buildings, industry, and transport sectors. Additionally, alternative nuclear capital cost sensitivities of 2600 to 6600 $/kW had little impact on the carbon tax levels needed to achieve net-zero emission goals due to the availability of multiple low-cost carbon-free power options.

With higher carbon taxes in the net-zero goals, relative energy price differences favoring the substitution of fossil fuels for electricity at the end-use increased the electricity demand by about 30% relative to the Reference scenario by the end of the century. This was a doubling of the electricity demand change as compared to the 15% increase in the 150 $/t CO_2 carbon tax case.

The nuclear power capacities in 2050 with the net-zero goals were 190 to 460 GW in Nz50 (net-zero by 2050), 180 to 450 GW in Nz60 (net-zero by 2060), and 170 to 420 in Nz70 (net-zero by 2070), where the capacity range is from the high and low nuclear costs, respectively. By 2100, the range increases to 210 to 790 GW in Nz50, 220 to 830 GW in Nz60, and 220 to 850 in Nz70. Additional nuclear capacity expansion in the net-zero scenarios reflected the increase in total electricity demand as well as the improvement in nuclear cost. Some differences in nuclear capacities were observed due to the overlap in the timing of the net-zero goals and retirement schedules of existing nuclear reactors, which assumed an 80-year lifetime.

In the net-zero scenarios, negative emissions from electric power sector BECCS were necessary to compensate for the persistent and difficult-to-remove emissions from buildings, industry, and transport sectors. Improvements to nuclear costs, which reduced electricity prices, had some impact on reducing the amount of power sector negative emissions necessary for achieving net-zero goals.

Nuclear cost reductions have a significant and disproportionate impact on the composition of power generation over the long-term. By 2100, the nuclear share of electricity was 50% or more with low cost nuclear under carbon mitigation efforts. The longevity of nuclear power technologies and the sustained investments of competitive nuclear power contributed to the accumulation of total nuclear power capacity and high nuclear shares over time. Reductions in the capital cost of nuclear power technologies had a clear and pronounced impact on the expanded deployment of nuclear power under all scenarios.

6. Discussion

This analysis focused on the deployment of nuclear power for the electricity sector. The application of nuclear energy for buildings, industry, and transport energy services, other than through electrification, was not investigated. Nuclear heat, nuclear hydrogen, nuclear heat and hydrogen for synfuels production, and nuclear power with direct-air-capture are areas of future research that can further contribute to carbon emission reduction efforts (Clark, 2022; Shannon Bragg-Sitton, 2020).

Achieving the net-zero emissions goal requires that all emissions are removed from the economy, and for some industrial processes and end-use energy services in buildings and transport, it may be difficult to do so with present technology. Thus, the level of carbon penalties for achieving net-zero goals was driven by emissions activities outside of the electric power sector. Nuclear energy applications beyond the power sector could help to reduce the carbon penalty and the economic impact of net-zero emission goals. In this analysis, the carbon price of electricity sector decarbonization versus full economy-wide decarbonization was approximately a factor of two (150 $/tCO_2$ and 300 $/tCO_2$). Thus, higher cost nuclear energy applications for non-power sector applications could be a competitive option.

Several challenges remain for clarifying the potential diverse role of nuclear energy beyond the power sector in determining whether the utilizations of nuclear electricity or nuclear heat are complements or substitutes, and in quantifying the future market potential of electricity and heat demands. Ongoing electrification of transport, buildings, and industrial energy services is adding significant new demands for electricity, but not all energy services can be readily electrified.

Additionally, novel approaches for the utilization of nuclear power plants, such as the direct air capture of CO_2 from cooling towers and waste heat from existing and future nuclear reactors, could affect the choice of energy pathways for addressing climate change. Modeling capabilities need to include greater detail of all end-use energy services, along with representations of novel and advanced nuclear technology applications. Further research is needed to clarify the potential wide-ranging role of nuclear energy in the 21st century.

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