Joint Institute for Strategic Energy Analysis

Considering the Role of Natural Gas in the Deep Decarbonization of the U.S. Electricity Sector

Natural Gas and the Evolving U.S. Power Sector Monograph Series: Number 2

Wesley Cole, Ross Beppler, Owen Zinaman, and Jeffrey Logan

National Renewable Energy Laboratory

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Technical Report
NREL/TP-6A50-64654
February 2016

Contract No. DE-AC36-08GO28308

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Foreword

Natural Gas and our Changing Energy Economy

Unconventional natural gas produced from shale is reshaping the U.S. energy sector. In 2011, the Joint Institute for Strategic Energy Analysis (JISEA) published its first major report in a series of studies on natural gas and the U.S. energy sector. *Natural Gas and the Transformation of the U.S. Energy Sector: Electricity* provides a new methodological approach to estimate natural gas-related greenhouse gas emissions, tracks trends in regulatory and voluntary industry practices, and explores various electricity futures.

Since then, our work has examined additional critical topics related to the role of natural gas in our energy economy, including potential synergies between natural gas and renewable energy in the power and transportation sectors; the state of knowledge about emissions of natural gas systems compared to other fuel sources; and the research required to better characterize the potential role that natural gas can play in a more environmentally sustainable energy economy. We've also convened panels of energy thought leaders on behalf of the White House. Our ongoing work in this space will explore economic, environmental, and systems impacts of natural gas development and use.

As the natural gas landscape continues to shift in the United States and globally, JISEA believes that bringing objective views and analytical expertise to bear on these issues can help move the discussion forward on a productive path. It is part of our mission to provide leading-edge, objective, high-impact research and analysis to guide global energy investment and policy decisions. JISEA has a growing portfolio of natural gas research that reflects our commitment to "getting gas right."

This report is the second in a three-part monograph series focusing on natural gas and the electricity sector. This piece explores the question of natural gas as a bridge to a more sustainable electricity sector. The first monograph provides a high-level view of recent trends in the U.S. electricity sector, and how natural gas is affecting policy, operational, and investment decisions therein, and a third will consider the flexibility attributes that natural gas can offer to electric power sectors around the world.

We look forward to your feedback and thank you for your interest in the work of JISEA.

Doug Arent
Executive Director, Joint Institute for Strategic Energy Analysis

Acknowledgments

We thank America's Natural Gas Alliance (ANGA), E.ON Climate & Renewables, Alstom, and Southern Company for making this work possible, and providing valuable feedback along the way. While the sponsoring organizations provided invaluable perspective and advice along the way, individual members may have different views on one or more matters addressed in the report. They were not asked individually or collectively to endorse the report findings nor should any implied endorsement by the sponsoring organizations be assumed. We thank Trieu Mai for his input on this work. Findings, content, and conclusions of this study are the sole responsibility of the authors.

Executive Summary

Natural gas generation in the U.S. electricity sector has grown substantially in recent years, while the sector's carbon dioxide (CO_2) emissions have generally declined. Many attribute the decrease in CO_2 emissions to increased natural gas use, which raises questions related to the concept of natural gas as a potential enabler of a transition to a lower-carbon future. This report examines the role of natural gas as increasingly strict carbon emission targets are imposed on the electricity sector. Utilizing the National Renewable Energy Laboratory (NREL) Regional Energy Deployment System (ReEDS) long-term capacity expansion model of the U.S. electricity sector, various natural gas price futures and multiple scenarios that emphasize various portfolios of low-carbon technologies are evaluated. Specifically, scenarios with high amounts of energy efficiency (EE), low nuclear power costs, low renewable energy (RE) costs, and low carbon capture and storage (CCS) costs are evaluated within a framework of total sector CO_2 emission constraints (e.g., no carbon tax or cap and trade systems are included). Scenario details are explained within the body of the report.

Within these scenarios, requiring the electricity sector to lower CO_2 emissions over time increases near- to mid-term (through 2030) natural gas generation (see Figure ES-1—left). The long-term (2050) role of natural gas generation in the electricity sector depends on the level of CO_2 emission reduction required. Moderate reductions in long-term CO_2 emissions have little impact on long-term natural gas generation, while more stringent CO_2 emission limits lower long-term natural gas generation (see Figure ES-1—right). More stringent carbon targets also impact other generating technologies, with the scenarios considered here showing significant decreases in coal generation, while both nuclear and renewable energy technologies increase over time, depending on relative costs.

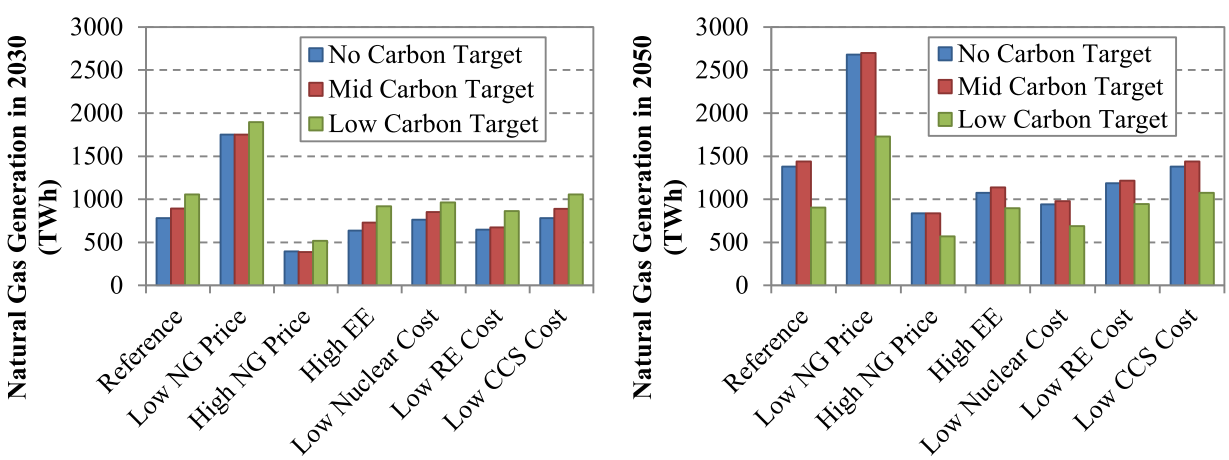

Figure ES-1. Natural gas generation in 2030 (left) and 2050 (right) for a variety of scenarios with varying carbon targets applied.[1]

The strictest carbon target (in green) increases 2030 natural gas generation, but decreases 2050 natural gas generation relative to the other carbon targets.

[1] The mid carbon target reaches a 21% reduction in 2030 and a 41.5% reduction in 2050 power sector CO_2 emissions relative to 2005, while the low carbon target reaches a 42% reduction in 2030 and an 83% reduction in 2050.

Figure ES-1 also demonstrates the role of natural gas in the context of scenarios where a specific low-carbon technology becomes more cost competitive. In 2030, natural gas generation in the technology scenarios is quite similar to that in the reference scenarios, indicating little change in the role of natural gas in the near- to mid-term due to advancements in those technology areas. The 2050 natural gas generation shows more significant differences, suggesting that technology cost and performance improvements will likely have substantial impacts on the role of natural gas in the longer-term timeframe. Natural gas generation differences are most strongly driven by alternative natural gas price trajectories—changes in natural gas generation in the Low NG Price and High NG Price scenarios are much larger than in any other scenario in both the 2030 and 2050 timeframes.

The only low-carbon technology scenarios that show any increase in long-term natural gas generation relative to the reference case are the Low CCS Cost scenarios. Carbon capture and storage technology costs are currently high, but have the potential to allow fossil fuels to play a larger role in low-carbon grid. This work considers three CCS cost trajectories for natural gas and coal generators: a baseline trajectory and two lower cost trajectories where CO_2 capture costs reach \$40/metric ton and \$10/metric ton, respectively. We find that with these assumed cost trajectories, CCS can increase the long-term natural gas generation under a low carbon target (see Figure ES-2). Under less stringent carbon targets, CCS does not evolve as part of the electricity generating portfolio for the scenarios considered in this work.

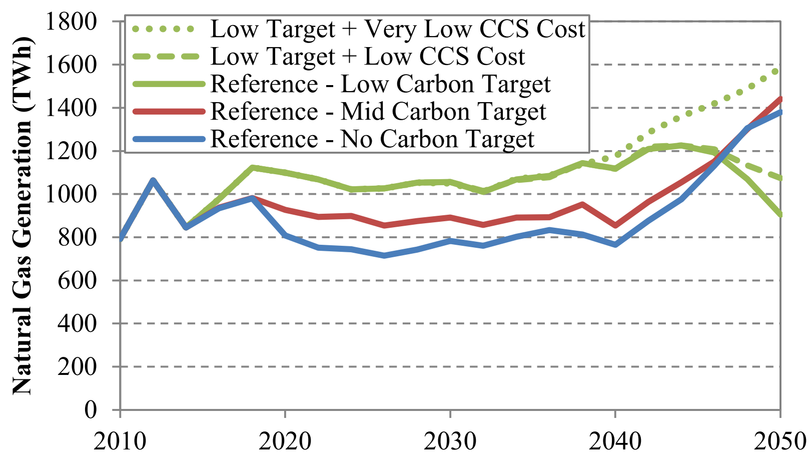

Figure ES-2. Natural gas generation over time.

Natural gas generation trends upward post-2040 with the no and mid carbon targets, but decreases with the low carbon target unless very low cost CCS technology is available. Only the low carbon target scenarios show CCS deployment.

Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
CC	combined cycle
CCS	carbon capture and storage
CO_2	carbon dioxide
CSP	concentrating solar power
CT	combustion turbine
DC	direct current
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GW	gigawatt
MW	megawatt
MWh	megawatt-hour
NG	natural gas
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PV	photovoltaic
RE	renewable energy
ReEDS	Regional Energy Deployment System model
RPS	renewable portfolio standards

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1 Introduction

The advent of unconventional natural gas resources in the United States has triggered a significant transformation of the energy landscape. In April 2015, the generation of electricity from natural gas exceeded that of coal for the first time in U.S. history. Figure 1 shows that this is indicative of a larger trend in which natural gas, and renewables to a lesser extent, have been replacing coal generation.

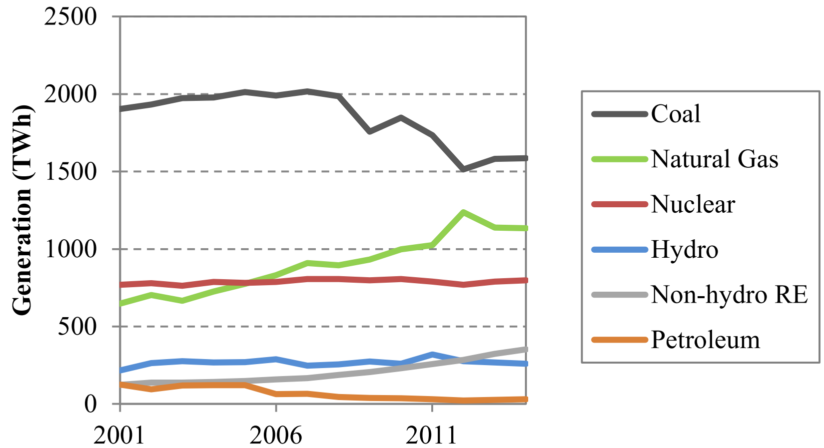

Figure 1. Annual net U.S. electricity generation by source for 2001–2014

Source: EIA (2015)

Abundant, low-cost natural gas and a relatively large existing fleet of natural gas power generators with available run time (low capacity factor utilization), combined with declining renewable electricity costs and new environmental regulations, have led to an electric sector undergoing the largest shift in portfolio and operation since World War II (Logan et al. 2012). Furthermore, projections indicate that this may be only the beginning of the shale gas boom: Figure 2 indicates that in all 2015 Annual Energy Outlook (AEO) (EIA 2015) oil and gas resource scenarios, the production of natural gas continues to grow, driven primarily by shale resources.

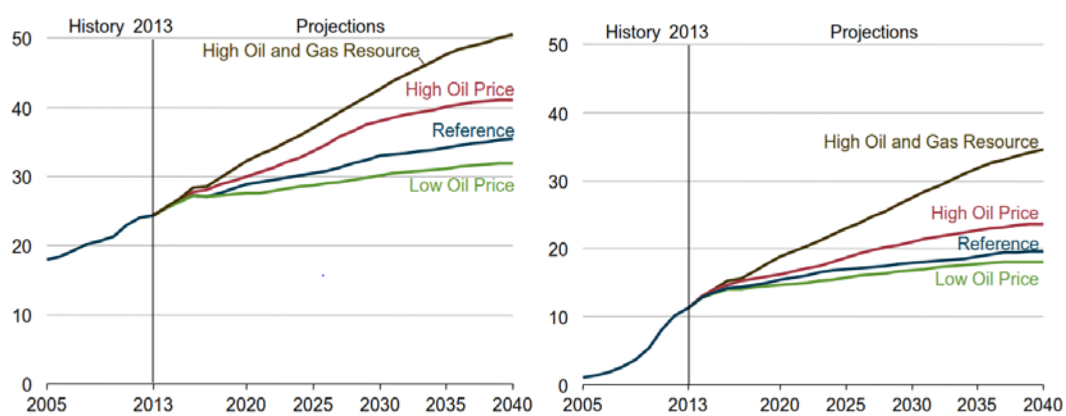

Figure 2. Projected U.S. dry natural gas (left) and shale gas (right) production under four scenarios from 2005-2040

Source: EIA (2015)

These trends have led to academic discussions and public discourse around natural gas as a "bridge fuel" for the electric sector. In serving as a bridge fuel, natural gas would replace the relatively more carbon intense coal generation in the near term and eventually phase down itself in favor of zero-carbon emission resources. Several researchers have proposed that this natural gas bridge could aid in the transition toward a deep decarbonization scenario for the U.S. electric sector (see, e.g., Brown, Krupnick, and Walls 2009; Kerr 2010; Cathles III et al. 2012). In tandem to such dialogues, there has been significant investigation into the climate impacts of shale gas, focusing on the extent to which methane leaks into the environment throughout the life cycle, from initial production to ultimate use (Howarth, Santoro, and Ingraffea 2012; Cathles 2012; Brandt et al. 2014; Heath et al. 2014; Arent et al. 2015; Hausfather 2015). The many perspectives offered into this continued debate lead to an increasingly robust body of literature on the topic.

Because of the recent, rapid increase in U.S. natural gas production coupled with the concept of natural gas a bridge fuel, many researchers have investigated the impacts of abundant natural gas on long-term climate forcing. Across a variety of energy models, these works have largely found that abundant natural gas, by itself, leads to substantial changes in the overall energy mix but to relatively little change in long-term greenhouse gas emission impacts (Huntington 2013; Shearer et al. 2014; McJeon et al. 2014; Newell and Raimi 2014; Arent et al. 2015). Without other intervening mechanisms, the energy models find that abundant, low-cost natural gas does accelerate the displacement of coal-fired generation, which reduces power sector CO_2 emissions. However, the low-cost natural gas also slows deployment of low-carbon generators (such as renewable energy), and in some cases, increases energy demand because of the low cost of energy (due to the cheap natural gas). Other mechanisms, such as new policies, are likely needed in order for natural gas to operate as a bridge to a low-carbon future (Lazarus et al. 2015).

Natural gas is generally not the focus of deep decarbonization discussions. Within the literature that considers deep decarbonization, whether of the electricity sector or of the entire economy, there are four primary technologies that tend to play a prominent role: energy efficiency, nuclear power, renewable energy, and CCS.[2] For example, Luderer et al. (2011) present an inter-model comparison of deep decarbonization scenarios using three integrated assessment models. The study found that new nuclear, CCS, renewable energy generators, and energy efficiency improvements were all major components of deep decarbonization, though the contribution of each of those technologies varied substantially from scenario to scenario and from model to model.

Other literature on decarbonization considers interactions among energy efficiency, nuclear power, renewable energy, and CCS technologies. For example, McJeon et al. (2011) examined hundreds of low-carbon scenarios and found that CCS plays an important role in reducing the risk of a very high-cost, low-carbon future, especially in the absence of new nuclear generation. Jägemann et al. (2013) found that a mixed approach (nuclear + CCS + renewable energy) is more cost effective than excluding technology options, and that, like McJeon et al., the cost of decarbonization can vary widely depending on scenario assumptions. Wright and Kanudia

[2] This is not an exclusive list. Other technologies, such as combined heat and power, also appear in literature, but they tend to receive less mention or can often be categorized with these four technologies. For example, combined heat and power can be categorized as an energy efficiency technology.

(2014) found nuclear and CCS technologies to play a large role in a low-carbon future of the U.S. power sector, but that abundant natural gas can displace these technologies to some extent. Denholm et al. (2012) examined the potential synergies between nuclear power, thermal storage, and variable renewable energy for decarbonization. Nelson et al. (2014), in considering the deep decarbonization of the western United States, found that renewable energy plays a critical role, especially if nuclear power is not available. They also found energy efficiency measures to play a strong role in the decarbonization effort. In a California-only study, Hart and Jacobson (2012) found that using multiple renewable energy technologies is more effective in carbon abatement than singling out a single technology. Similarly, in a solar-focused study, Pietzcker et al. (2014) found that in their decarbonization scenarios, solar photovoltaics (PV) are most cost-effective in earlier years. In later years, their decarbonization scenarios rely more heavily on concentrating solar power (CSP) with thermal storage.

Within the natural gas framework, research work has also characterized the potentially synergistic relationship between natural gas and renewable energy resources across a variety of sectors (see e.g., Lee et al. 2012). Recent stakeholder meetings supported the conclusion that natural gas and renewables "can help contribute to a low carbon, resilient, and reliable electrical grid by diversifying the electricity mix and hedging risk associated with market and policy uncertainties" (Pless et al. 2015). Natural gas generators are also relatively flexible, and that flexibility often allows them to complement variable renewable energy resources (Lund et al. 2015). Logan et al. (2013) performed a natural gas scenario analysis of the U.S. power sector using the renewable energy-focused ReEDS model; that analysis considered natural gas supply and demand variations and examined a clean energy standard as a potential decarbonization policy mechanism. Though somewhat similar to the work presented here, the work by Logan et al. relied on now-outdated projections, especially regarding renewable energy, and focused on a "clean energy standard" mechanism for carbon reduction.

Apart from some studies focusing on CCS (e.g., Nichols and Victor 2015), most deep decarbonization work focuses on the technologies needed for deep decarbonization rather than on the role that natural gas plays in the deep decarbonization process. This work aims to fill that space, especially given that future natural gas prices and climate policies are two major uncertainties in the power sector (Bistline 2015). This report presents results of the investigation of the role of natural gas in the U.S. electricity sector as it is decarbonized. We use the ReEDS capacity expansion model, building on previous natural gas scenario analyses (Logan et al. 2013; Sullivan et al. 2015). We investigate how different resource and technology assumptions impact the role of a natural gas and its role over time out to 2050 under different carbon constraints and with various technology price and performance sensitivities. This work is not intended to be predictive, but rather to provide a suite of internally consistent scenarios that can used to understand the impact and role of technology and resource evolution.

Section 2 of this study provides a brief overview of the ReEDS model and discusses the key scenario inputs that will shape the results. Section 3 presents the results; Section 3.1 describes the suite of scenarios that do not include any carbon targets, Section 3.2 presents the results of the scenarios with a mid or low carbon target, and Section 3.3 discusses the roll of CCS in context of a low carbon future. Section 3.4 adds some additional discussion around the full suite of scenarios considered, and Section 4 summarizes and concludes the work.

2 Methodology

This section describes the ReEDS capacity expansion model and describes the key inputs that drive the scenario results presented in this work. We do not comprehensively provide all input assumptions in the present report, but instead provide key references throughout.

2.1 Regional Energy Deployment System (ReEDS) Model Overview

The ReEDS model is a capacity expansion optimization model of the electricity system for the continental United States (Short et al. 2011; Sullivan et al. 2015). For a given year, ReEDS solves a combined planning and dispatch problem, meaning that it simultaneously solves for the optimal new investments and the optimal system dispatch that leads to the lowest overall system cost. Because the actual U.S. electricity system does not operate in a cooperative, least-cost minimization framework, ReEDS functions not as a prediction tool, but as an analysis tool for comparing internally consistent scenarios. ReEDS is a sequential model, beginning in 2010 and marching through time until 2050.

ReEDS is a full electric sector analysis tool, with in-depth representation of all technologies, and specific capabilities that allow detailed investigation of the integration of renewable energy technologies into the grid. ReEDS accounts for resource and demand diversity through the use of 356 individual resource regions (for CSP and wind resources) and 134 balancing areas (for all other technology types, demand, and transmission) across the continental United States (see Figure 3). ReEDS includes explicit representation of key issues related to renewable energy, such as variability and uncertainty in wind and solar output, transmission costs and constraints, and ancillary services requirements. ReEDS uses a reduced network with 134 nodes (center-to-center of balancing areas) connected by roughly 300 aggregate lines, shown in Figure 3.

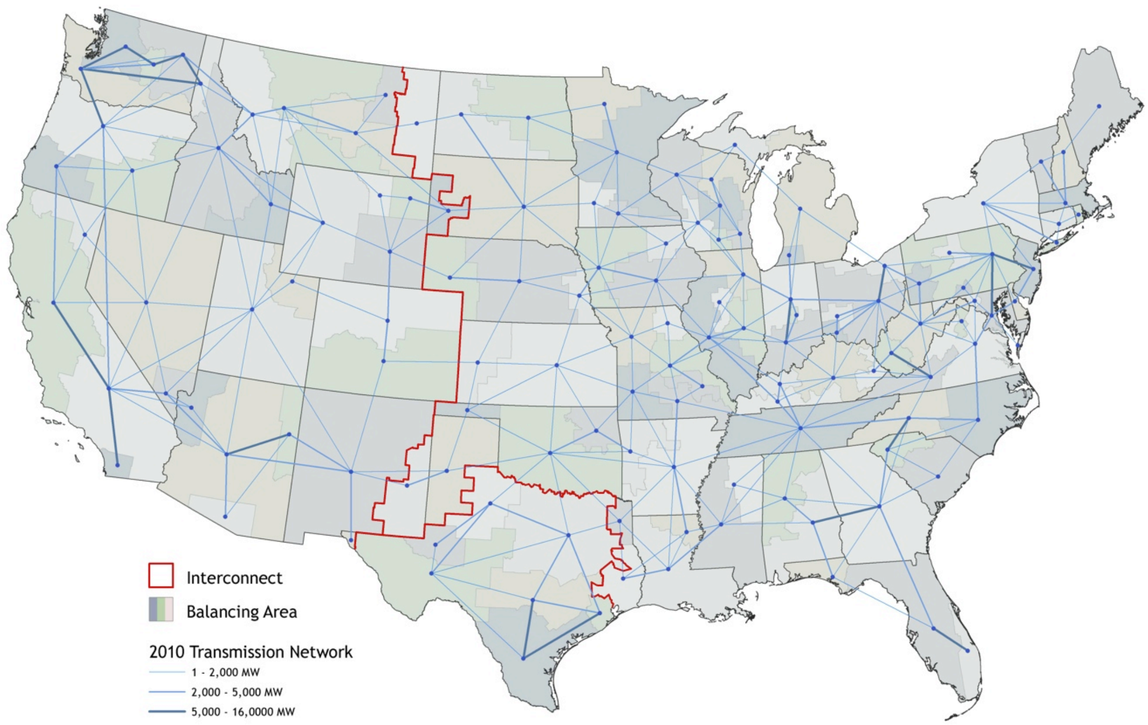

Figure 3. Map showing the ReEDS regional structure, 134 model balancing areas, and aggregated transmission network

ReEDS includes a full suite of conventional generating technologies, a system dispatch that reflects seasonal and diurnal load shapes, a reduced transmission network, and dynamic capabilities for fuel supplies. The major conventional thermal generating technologies in ReEDS include simple and combined cycle natural gas, several varieties of coal, oil/gas steam, and nuclear. In addition to conventional generators, ReEDS models geothermal, hydropower, biopower, wind, CSP, and PV as renewable energy generators. ReEDS models utility-scale PV within its standard optimization framework, while rooftop PV is modeled exogenously via the SolarDS model (Denholm, Margolis, and Drury 2009).[3] Electricity storage technologies in ReEDS include pumped hydropower storage, compressed-air energy storage, and sodium sulfur batteries.

Retirements are either lifetime based or economically driven. For lifetime based decisions, plant age and assumed lifetimes determine retirement dates. The initial online year of the existing generating units are taken from a commercial generator database (Ventyx 2014—Ventyx has since been renamed by ABB). Coal plants with a capacity of less than 100 megawatts (MW) are retired after 65 years; coal plants with a nameplate capacity greater than 100 MW—and all ultra-supercritical facilities—are retired after 75 years. Natural gas- and oil-fired units are assumed to have a 55-year lifetime. Nuclear plants are assumed to be granted a single license renewal period, giving existing nuclear plants a 60-year life. No refurbishment costs or increased operations and maintenance (O&M) costs are applied to extend the nuclear or fossil plant life.

[3] All scenarios in this work use the same exogenous rooftop PV capacity trajectory, which reaches 67 gigawatts (GW) in 2030 and 130 GW in 2050 (Sullivan et al. 2015).

In addition to age-based retirements, certain near-term coal retirements are prescribed according to announced retirements (Saha 2013), and additional long-term retirements can occur based on plant utilization. Modeled utilization-based coal retirements are a proxy for economic-based considerations and accelerate coal retirements. This utilization-based retirement is implemented by comparing each region's coal fleet capacity annual factor to a minimum utilization threshold. If the capacity factor is beneath the threshold in a given year, capacity is retired such that the remaining capacity in the region, assuming the same annual production, would operate at the capacity factor threshold. The utilization-based retirement is not active until 2020 and becomes increasingly stringent over time.[4] The oldest and least efficient extant units are retired preferentially in this scheme.

This work relies on the ReEDS model version 2015.2. Cost and performance inputs for these scenarios are most closely aligned with the 2015 Standard Scenarios Annual Report (Sullivan et al. 2015) and the *Wind Vision* report (DOE 2015). Fuel prices, demand growth, and conventional generators costs are from the AEO 2015 (EIA 2015).

ReEDS represents several policies that influence model outcomes, including state renewable portfolio standards (RPS), the Mercury and Air Toxics Standards (MATS), the Clear Air Interstate Rule (CAIR), and the Cross-State Air Pollution Rule (CSAPR). California's Assembly Bill 32 (AB-32) is also modeled and impacts CO_2 emitting generators that reside in California or that serve load in California. The production tax credit (PTC) and investment tax credit (ITC) are also modeled for the years and technologies for which they are eligible.[5] Per the New Source Performance Standard, no new coal generation is allowed without CCS (EPA 2015b). For more details on how these policies are implemented, see Sullivan et al. (2015). None of the work presented here includes the Regional Greenhouse Gas Initiative carbon cap and trade system or the recently finalized Clean Power Plan (EPA 2015a).

2.2 Scenarios

Because ReEDS is not a predictive tool, analyzing a single scenario in ReEDS is not often a useful exercise. Rather, we consider a suite of scenarios and compare them to one another to understand trends and drivers that impact results. Table 1 summarizes the scenarios used in this work. The Reference scenario uses the mid renewable energy cost and performance inputs from the NREL Annual Technology Baseline (ATB) (NREL 2015) and the conventional energy and fuel costs from the AEO 2015 (EIA 2015). The remaining scenarios provide variations in natural gas prices and four low-carbon technologies. Each of the scenarios uses the same cost, performance, and other inputs as the Reference scenario except for the specific item noted in Table 1. For example, the inputs and assumptions for the Low NG Price scenario are identical to the Reference scenario except for the assumed natural gas price trajectory. Although other factors apart from costs impact the deployment of the technologies in a low-carbon future (Iyer et al. 2015; Spiecker, Eickholt, and Weber 2014), we only consider cost impacts in this work.

[4] The capacity factor threshold starts at 0.01 in 2020, increases linearly to 0.50 in 2040, and stays at that value until 2050.

[5] This work was completed prior to the passing of the PTC and ITC tax credit extensions in December 2015, so the PTC and ITC represented in these model runs represents the tax credit policy as of the December 1, 2015.

Table 1. Summary of scenarios used in this work. Except for the low and very low cost CCS scenarios, all the scenarios were run with no carbon target, the mid carbon target, or the low carbon target. The low and very low cost CCS scenarios were only used for the mid and low carbon targets.

Scenario Name	Scenario Summary
Reference	Mid Renewable Energy Costs from ATB, Conventional Capital and Fuel Costs and Demand Growth from AEO 2015 Reference Scenario
Low NG Price	NG Prices from High Oil & Gas Resource Scenario in AEO 2015
High NG Price	NG Prices from Low Oil & Gas Resource Scenario in AEO 2014*
High EE	No changes in end-use demand after 2014
Low Nuclear Cost	30% reduction in nuclear capital costs relative to AEO 2015
Low RE Cost	Low Wind & CSP Cost Trajectories from the ATB; PV reaches $0.75/W in 2040
Low CCS Cost	CCS Costs reach $40/metric ton of CO_2 Captured
Very Low CCS Cost	CCS Costs reach $10/metric ton of CO_2 Captured

* The AEO 2015 does not include a low oil & gas resource scenario, so we instead use the scenario from AEO 2014.

The suite of scenarios shown in Table 1 is run under three different carbon futures: no carbon target, mid carbon target, and low carbon target (see Figure 4), resulting in a total of 24 scenarios. The low carbon target linearly reduces 2050 power sector CO_2 emissions by 83% compared to 2005 (Sullivan et al. 2015). The mid carbon target scenario achieves one half the overall reduction by 2050 (41.5% by 2050 compared to 2005). On an economy-wide basis, deep decarbonization outside of the electricity sector may electrify loads, thus increasing electricity demand. Conversely, however, energy efficiency may offset any potential new electricity demands; the High EE scenario explores this option through holding electricity demand at the 2014 level through 2050. For this work we do not attempt to optimally allocate emission reductions among sectors. Others (e.g., Williams et al. 2012; Audoly, Vogt-Schilb, and Guivarch 2014) have found that greater decarbonization in the power sector would likely be needed to efficiently reach economy-wide carbon targets.

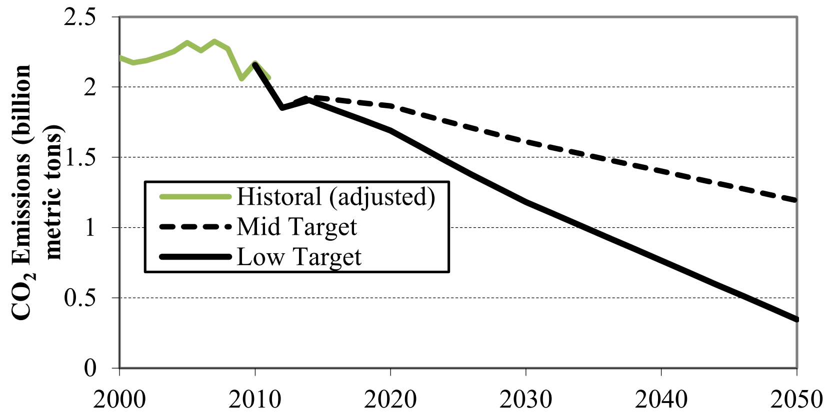

Figure 4. CO_2 emission targets used in this work.

The low target represents an 83% decrease in CO_2 emissions from 2005 to 2050 and the mid target represents half of that decline (41.5% decrease from 2005 to 2050).[6]

As shown in Figure 4, under both the low and mid carbon targets, an intermediate target of 17% and 8.5% reduction from 2005 levels, respectively, is applied in 2020. Banking and borrowing carbon credits between years is not allowed, and only burner-tip emissions from the power sector are considered (e.g., upstream methane leakage and other greenhouse gas emissions are not considered in this work).

The Reference and Low NG Price scenarios used in this work utilize projections from the AEO 2015 (EIA 2015), using the reference and high oil and gas resource scenarios, respectively. Because the AEO 2015 does not include a high natural gas price scenario, the High NG Price scenario used here was adapted from the AEO 2014 low oil and gas resource scenario (EIA 2014). Figure 5 shows these natural gas price trajectories. These prices are used as a basis to parameterize the natural gas supply curves within the model.[7] Natural gas prices in ReEDS are determined endogenously using supply curves to reflect the elasticity of natural gas demand and supply (see Logan et al. 2013). AEO natural gas price and consumption trajectories for the electric sector are used as a "set point" for the ReEDS model. If ReEDS utilizes that exact amount of natural gas that the AEO projects will be used in a given year, ReEDS will see the exact pricing as reflected in the AEO. If ReEDS natural gas demand surpasses demand observed in the AEO scenario in a given year, the price of natural gas is increased according to the supply curve parameters within ReEDS, in order to reflect the elasticity of supply and demand.

[6] Historical emissions were adjusted because ReEDS does not model combined heat and power plants, so emissions from combined heat and power plants were removed from the historical numbers reported here. Combined heat and power plants contributed about 0.1 billion metric tons of CO_2 emissions to the power sector in 2012.
[7] ReEDS includes nine regional supply curves—one for each EIA census region.

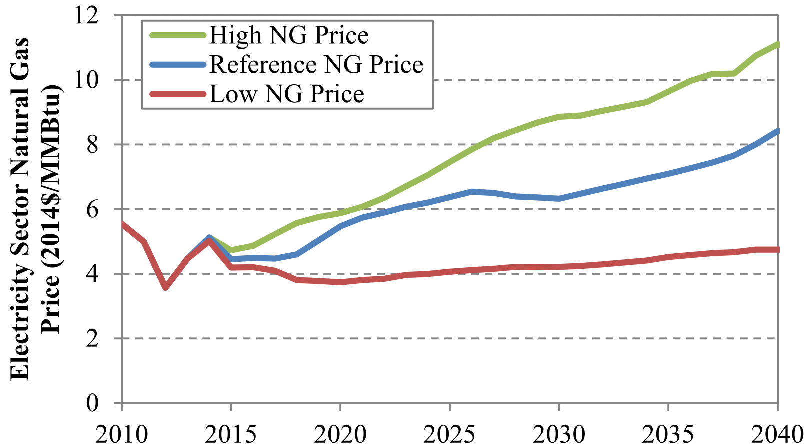

Figure 5. Electricity sector natural gas price trajectories used in this work based on the 2014 and 2015 Annual Energy Outlooks (EIA 2014; EIA 2015).[8]

The Annual Energy Outlook only includes price forecast through 2040, so post 2040 fuel prices set points are held set to the 2040 levels.

The remainder of this section describes the scenario settings for the four low-carbon technologies. These scenario settings are not meant to represent a specific future, but rather to generate inputs such that the impacts of that technology can be more readily evaluated.

2.2.1 High Energy Efficiency Deployment

Figure 6 shows the electricity demand growth trajectories used in this work. The Reference demand growth trajectory is from the AEO 2015 Reference scenario (EIA 2015). The high EE trajectory assumes no changes in demand after 2014. Although artificial, this scenario is meant to provide a future in which energy efficiency plays a large role such that even with economic and population growth electricity demand does not increase.

[8] Current (summer 2015) natural gas prices are lower than those reported by the Annual Energy Outlook. For example, Henry Hub prices are under $3/MMBtu for the summer of 2015. These higher near-term prices we use in this work result in lower near-term natural gas generation, but have essentially no impact on long-term results, which is the focus of this work.

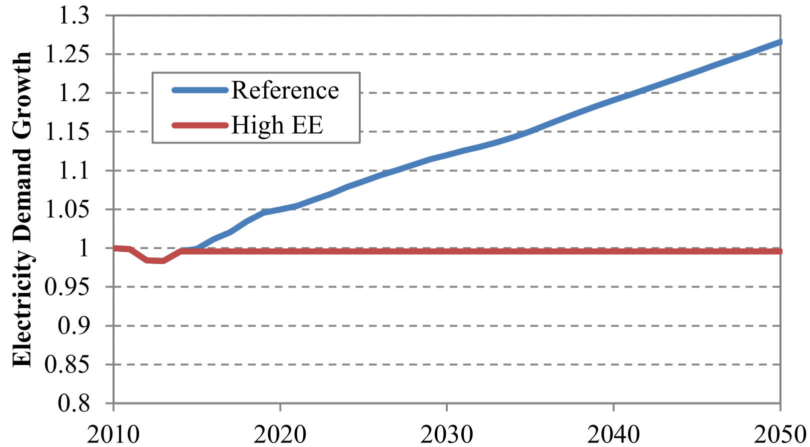

Figure 6. Electricity demand growth trajectories used in this work.

The high EE trajectory assumes no demand growth after 2014.

2.2.2 Low Nuclear Cost

Nuclear overnight capital costs for the Reference and Low Nuclear Cost scenarios are shown in Figure 7. The Low Nuclear Cost trajectory is a 30% reduction from the AEO 2015 Reference scenario nuclear capital costs, reaching just over $2,900/kW by 2040.[9] Although the cost reduction is implemented immediately in ReEDS, no new nuclear power plants (except for those already under construction) are allowed before 2022 due to anticipated lead times to construct a new plant. Uranium prices are exogenously based on prices reported in AEO 2015, although access to sufficient fuel might be an important factor in the role of nuclear power in a low-carbon future (Liu et al. 2012). Nuclear power plants in this work are not allowed to operate at part-load.

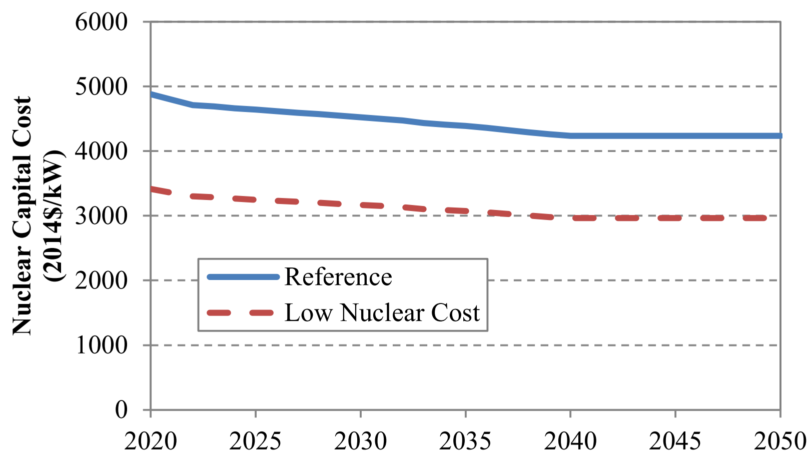

Figure 7. Nuclear overnight capital costs for the Reference and Low Nuclear Cost scenarios

[9] North American nuclear power overnight capital costs range from $2,400–$7,000/kW according to http://www.world-nuclear-news.org/NN-New-trends-in-financing-1509201401.html, while world overnight capital costs range from $1,600–$7,200/kW.

2.2.3 Low Renewable Energy Cost

Figure 8 shows the renewable energy cost trajectories used in the Reference and Low RE Cost scenarios. Only PV, CSP, and wind technologies experience a cost reduction; other renewable energy technologies are held at the Reference scenario levels. More information on these technology low cost trajectories is documented by Blair et al. (2015) and Sullivan et al. (2015).

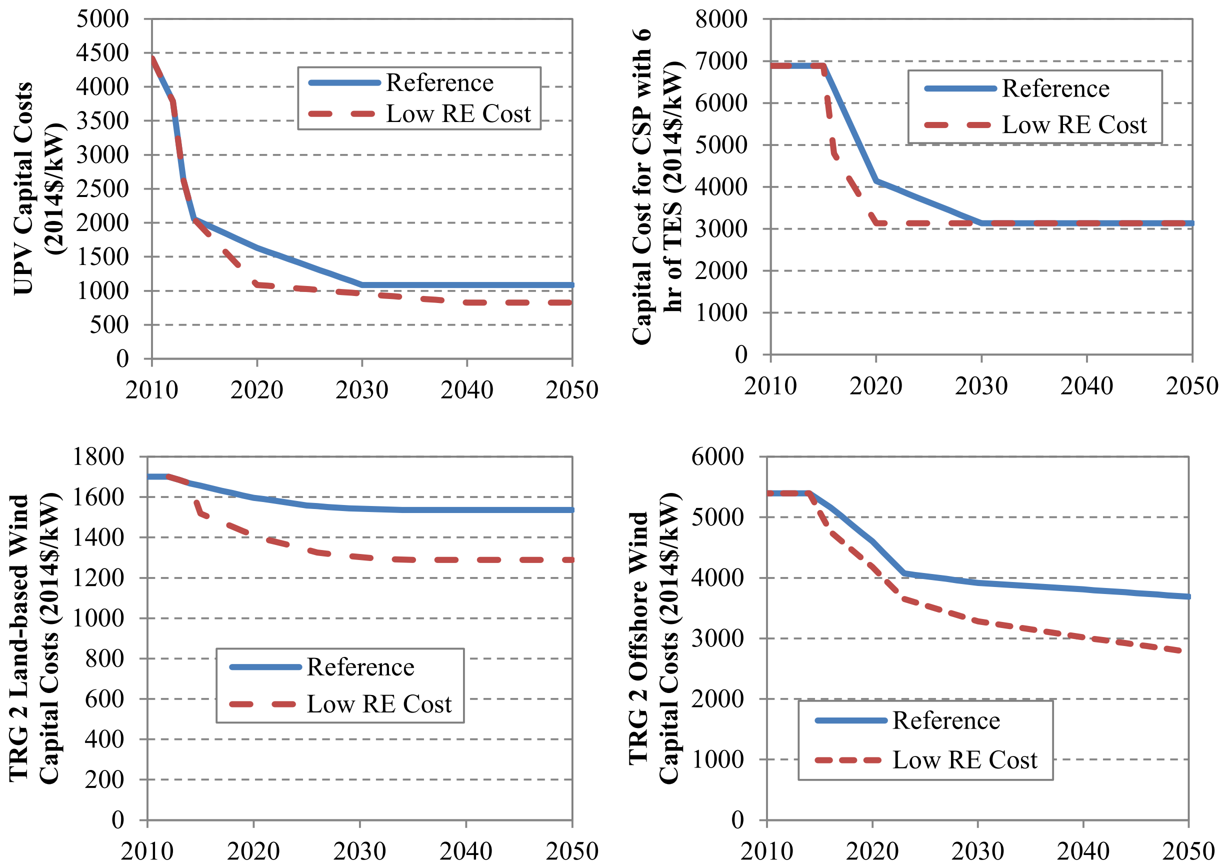

Figure 8. Renewable energy cost trajectories used in the Reference and Low RE Cost scenarios. TRG stands for technical resource group (see the Wind Vision Report [DOE 2015] for more details).

2.2.4 Low Carbon Capture and Storage Cost

The reference case CCS technology cost and performance inputs are from the AEO 2015 reference scenario (EIA 2015), which assumes a 16% reduction from 2020–2040 in overnight capital costs for natural gas combined cycle units with CCS (NG-CCS) and a 13% reduction for coal-fired integrated gasification combined cycle (coal-CCS) units. Both coal-CCS and NG-CCS are assumed to capture 85% of the combustion CO_2 emissions (Black & Veatch 2012).[10] Existing coal units are allowed to be retrofitted with CCS, although none of the scenarios here found coal CCS retrofits to be economical.[11]

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[10] New source pollution standards from EPA do not require 85% capture, but we only model 85% capture in these scenarios. Modeling CCS systems with lower capture rates might lead to additional CCS capacity getting deployed.

[11] The value of coal CCS retrofits is plant specific, and may be economical for a subset of U.S. plants using a more plant-specific methodology (Zhai, Ou, and Rubin 2015).

In order to incorporate lower cost alternatives for CCS technologies, we developed two additional trajectories that are generally based on the goals published in the Carbon Capture Technology Program Plan (DOE 2013). The cost reduction goals are stated in terms of $/metric ton carbon capture costs for coal-fired CCS systems, but we apply the carbon capture cost goal to NG-CCS systems as well, to allow evaluation of alternative trajectories that enable us to examine the role of CCS if costs decline below the AEO 2015 projections.

The two additional cost trajectories are labeled "low" and "very low" cost CCS, and the trajectories are shown in Figure 9 and Figure 10 for natural gas and coal, respectively. The low trajectory is based on a capture cost of $40/metric ton of CO_2 captured in 2025, and the very low trajectory is based on a capture cost of $10/metric ton in 2035 (DOE 2013).[12] We assume that non-CCS coal and gas units do not experience any additional costs declines due to the reduced costs of the CCS units. For the purposes of examining the scenarios, we will present the Low CCS Cost scenario alongside the other low-carbon technology scenario, but we will only discuss the Very Low CCS Cost scenario in the section that explicitly considers the impact of CCS on natural gas generation (Section 3.3).

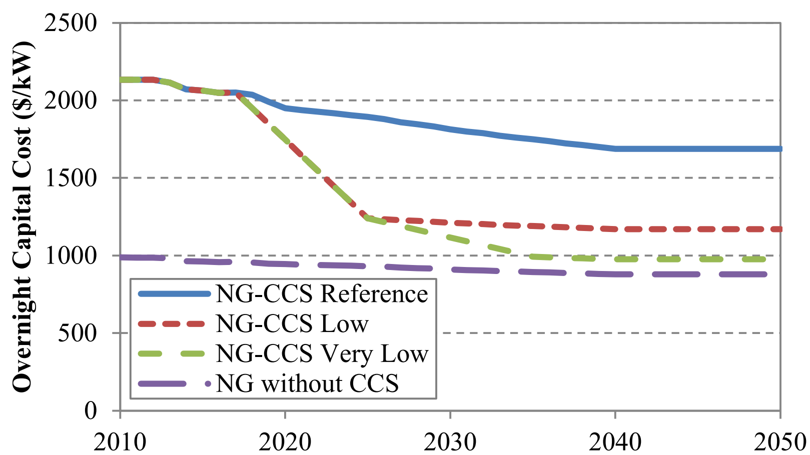

Figure 9. Overnight capital costs used in this work for natural gas combined cycle plants with and without CCS.

Costs are in 2013$.

[12] Because ReEDS is an electricity only model, we do not model any revenue that might be produced from selling the CO_2 for enhanced oil recovery, for example. This additional revenue can be critical for first-generation CCS installations.

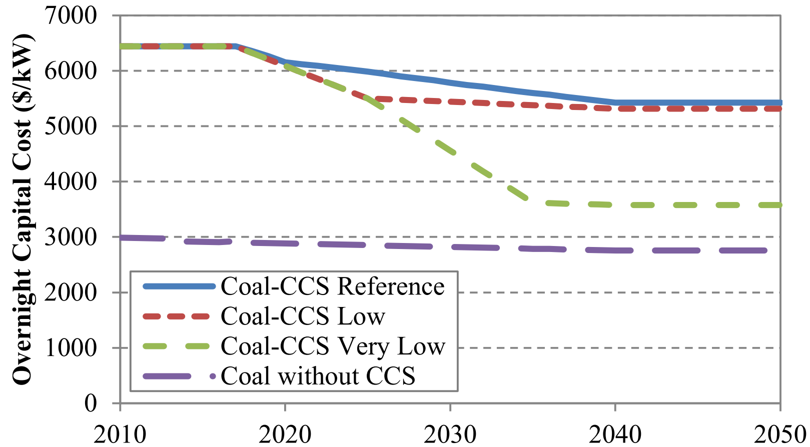

Figure 10. Overnight capital costs used in this work for coal-fired plants with and without CCS.

Costs are in 2013$.

The low CCS targets also includes a 13% reduction in fixed and variable O&M costs relative to the reference NG-CCS costs by 2025 (DOE 2013). The very low NG-CCS target includes a 53% and 47% cost reduction in fixed and variable O&M costs, respectively, representing O&M costs that are 5% higher than the NG without CCS costs. The very low NG-CCS configuration also includes a heat rate that is 5% higher than the NG without CCS. These changes are summarized in Table 2.

Table 2. Cost and heat rate inputs for the natural gas systems with and without CCS for the year 2040. Costs are expressed in 2013$ and are generally based on the goals published in the Carbon Capture Technology Program Plan (DOE 2013).

	Capital Cost ($/kW)	Fixed O&M ($/MW-yr)	Variable O&M ($/MWh)	Heat Rate (MMBtu/MWh)
NG-CCS Reference	1,687	31,770	6.78	7.49
NG-CCS Low	1,170	27,640	5.90	7.49
NG-CCS Very Low	978	14,970	3.61	6.89
NG without CCS	879	14,260	3.44	6.57

3 The Role of Natural Gas in a Low Carbon Future

Because natural gas combined cycle burner tip emission rates are approximately half that of a coal-fired unit on a pound-CO_2/MWh basis, natural gas has the potential to play a large role in emissions reduction by displacing coal-fired generation. Conversely, natural gas can also hold market share that could be utilized by generators that have no carbon emissions. The scenarios examined here consider the role that natural gas plays in a future where lower carbon emissions are exogenously imposed. These scenarios, therefore, consider a range of outcomes, given various market drivers and conditions, for natural gas in a low carbon future. We first consider the range of baseline scenarios where no carbon targets are applied (Section 3.1). We then consider the impact of imposing the mid and low carbon targets (Section 3.2). We include a section on how lower CCS costs impact the role of natural gas (Section 3.3). The final section summarizes findings from the full range of scenarios (Section 3.4).

3.1 No Carbon Targets

When no CO_2 emission targets are imposed, the electricity system is allowed to evolve in a least cost manner with no consideration to system CO_2 emissions. As such, natural gas generation is built and operated whenever it leads to this least cost solution. Total natural gas generation, therefore, is a function of end-use demand, fuel prices, and costs for competing technologies (e.g., wind, solar, and nuclear).

Figure 11 shows how natural gas generation evolves over the time horizon of 2010–2050.[13,14,15] Except for the high and low natural gas price scenarios, natural gas generation remains near recent historical levels through 2040 before beginning to increase substantially. Even though natural gas prices are rising (see Figure 5), natural gas generation remains quite steady. The Low NG Price scenario shows rapid immediate and sustained growth in natural gas generation. The High NG Price scenario leads to near- and mid-term reductions in natural gas generation, but retirements and continued demand growth lead to the recapture of natural gas generation post-2040 (to levels equivalent to 2010–2015) despite high natural gas prices (over $10/MMBtu; see Figure 5).

[13] ReEDS has been designed as a long-term model of the U.S. electric power sector. As such, scenario results are most useful when comparing scenarios to one another rather than considering the absolute outputs from the scenarios, especially in the early model years.
[14] The Low CCS Cost and Very Low CCS Cost scenarios are not shown because they are identical to the Reference scenario when there is no carbon target.
[15] The Appendix contains stacked capacity and generation plots for the reference scenario with no carbon target.

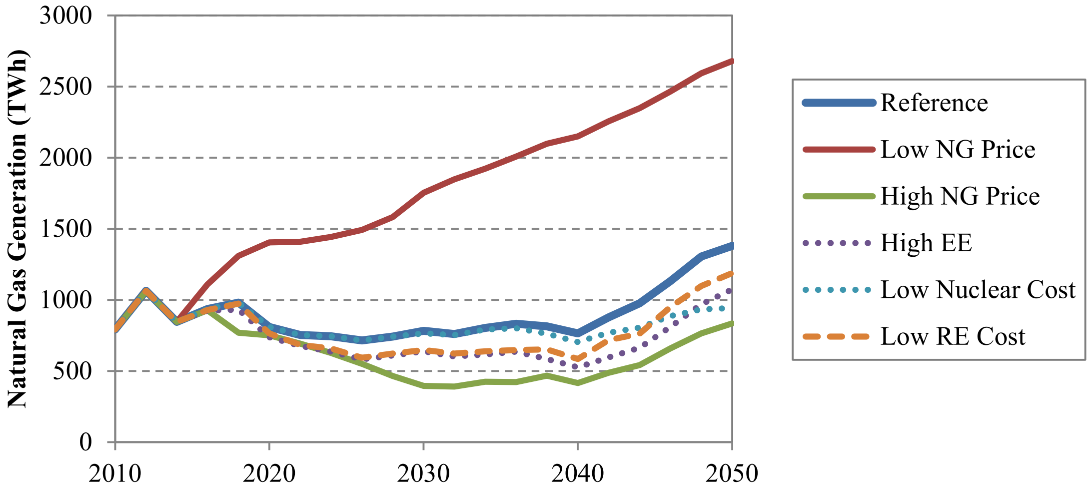

Figure 11. Natural gas generation over a range of market-related sensitivities. In all cases, natural gas generation increases from 2030–2050, though some scenarios do show a slight decline in natural gas generation in the 2020–2030 timeframe. The Low NG Price scenario is an obvious outlier, with sustained low-cost natural gas driving additional generation.

Figure 12 shows the natural gas combined cycle and combustion turbine capacities for the same set of scenarios. In the near-to-mid-term, relatively little natural gas combined cycle capacity is added, except in the Low NG Price scenario. Many regions in the current electricity system have excess capacity and, when coupled with new renewable energy, (driven in some cases by RPS requirements and in other cases by economics), keeps natural gas capacity level in the near-term.[16] Post-2030, new capacity needs are frequently met using new combustion turbine capacity, with combined cycle units providing significant new capacity only after 2040. These natural gas capacity additions are driven by a combination of load growth (except the High EE case), nuclear and coal retirements, and increased need for system flexibility due to higher renewable energy penetration.

[16] Because ReEDS is solving a least-cost optimization problem, it very rarely builds capacity above reserve margin requirements. In the real world, plant owners often make decisions on a single plant's profitability, and not on the overall least cost system requirements resulting in different outcomes than what is seen in the early years in the ReEDS outputs.

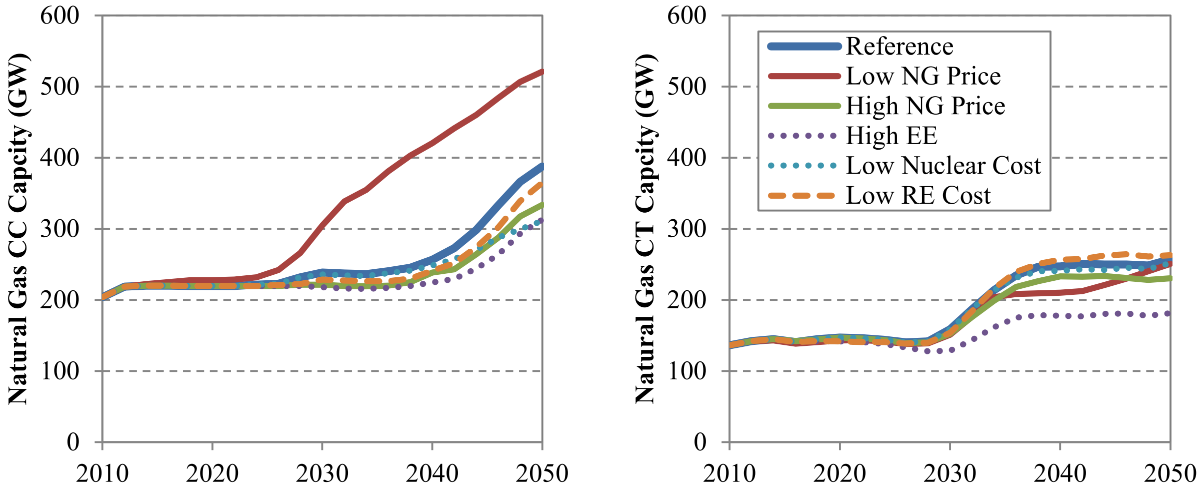

Figure 12. Natural gas combined cycle (CC—left plot) and combustion turbine (CT—right plot) capacity over a range of market-related sensitivities (legend applies to both graphs). Combustion turbines meet capacity needs in the 2030s over the range of scenarios, while combined cycle units fill in new capacity needs in the 2040s.

The evolution of the grid involves not just natural gas—renewable energy generation, coal generation, and nuclear generation also play a major role in the overall energy mix. Renewable energy generation for the no carbon target scenarios is shown in Figure 13 and coal-fired generation is shown in Figure 14. Nuclear generation is not shown because it remains the same for all scenarios without a carbon target. Renewable energy generation increases steadily over time, though the rate of increase is strongly dependent of the scenarios considered. Because of RPS requirements, renewable energy is a primary means of meeting near-term load growth and capacity needs in these scenarios and is a major contributing factor to long-term CO_2 emission levels. Except for in the Low NG Price scenario, coal-fired generation in these scenarios eventually returns to near-2010 levels of generation, but then steadily decreases over time as the fleet ages and retirements occur. The near-term increase in coal-fired generation is primarily driven by the increasing cost of natural gas (see Figure 5), which allows coal to slowly regain market share lost to the recently low natural gas prices. Per the EPA New Source Performance Standards, no new coal units are allowed without CCS (EPA 2015b), and new coal-CCS units are not economical in these scenarios.

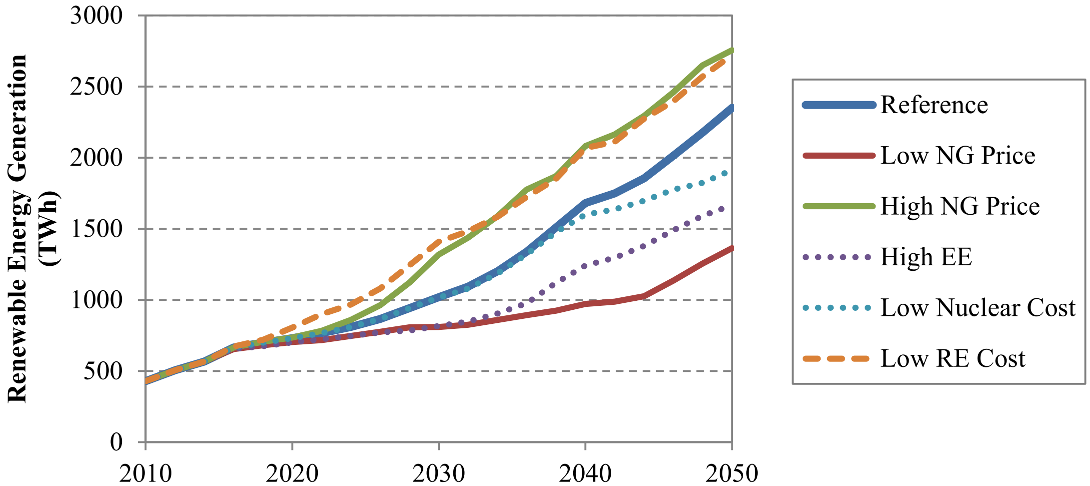

Figure 13. Renewable electricity generation increases across this suite of scenarios, though renewable energy growth is slowed by low natural gas prices. After 2030, the High NG Price scenario leads to more renewable energy generation than the Low RE Cost scenario. These correspond to renewable energy penetrations of 28%–56% in 2050.

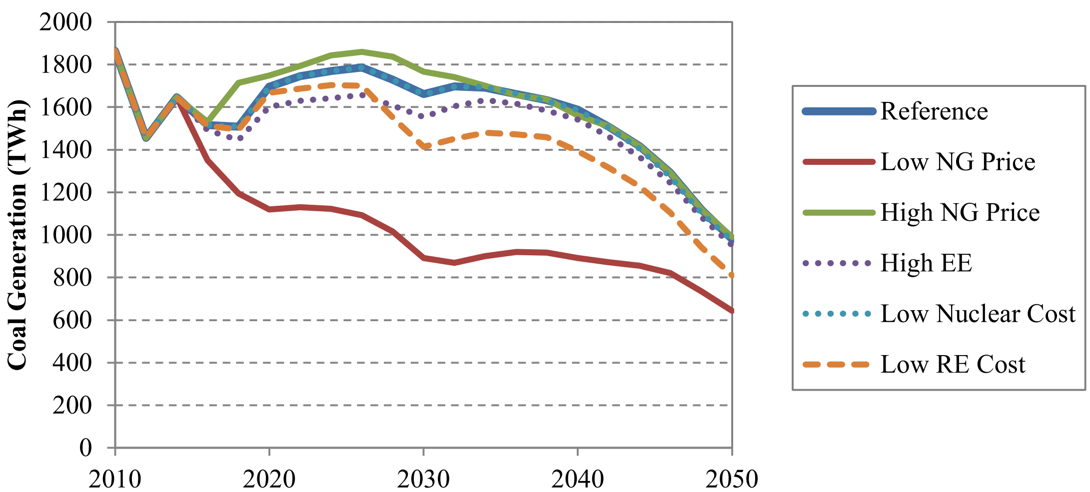

Figure 14. Coal-based generation across the scenarios with no carbon target. Except in the Low NG Price scenario, coal generation returns to its 2010 level before beginning to decline.

Figure 15 shows the range of combustion-only CO_2 emissions over time for scenarios without a carbon target. This range overlaps with the mid carbon target through 2032 and with the high carbon target through 2020 indicating that the evolving market may put the system on a path for lower carbon emissions based on economics and existing policies only. By 2050, the range of annual CO_2 emissions is 4%–37% higher than the mid carbon target.

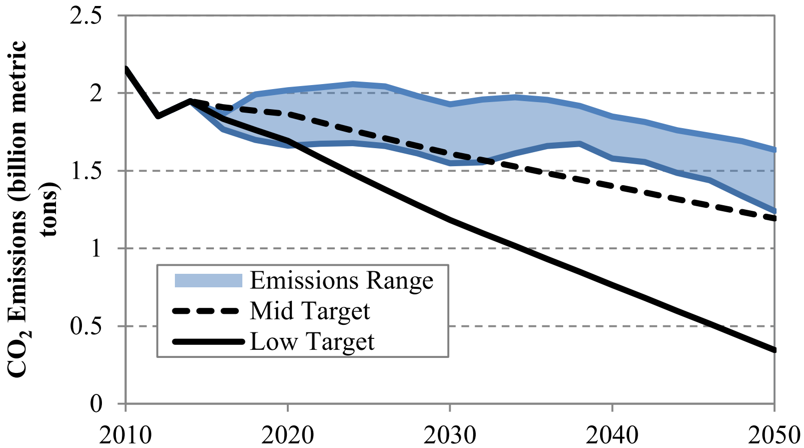

Figure 15. Burner-tip CO_2 emissions across the scenarios with no carbon target enforced. The mid carbon target and low carbon target trajectories are also shown for reference.

The suite of scenarios without any carbon targets do not yield strong evidence of natural gas acting as a bridge to a low-carbon future.[17] The suite of scenarios does generally lead to somewhat lower CO_2 emissions over time (see Figure 15), but natural gas generation increases over the long term rather than acting as a bridge that is replaced with lower emitting options. Rather, coal generation is the primary technology that is phased out over time in these scenarios (see Figure 14).

Because the Low NG Price scenario is generally an outlier in the results discussed above, it deserves some additional consideration. As shown in Figure 5, natural gas prices in the Low NG Price scenario remain quite low through the time interval considered here, which allows natural gas to be a dominant generation resource in both the near and long term. The higher levels of natural gas have two primary impacts on carbon emissions. First, the abundant natural gas generation displaces coal generation (see Figure 14), which lowers CO_2 emissions across all non-historical years. Second, low-cost natural gas reduces investment in renewable energy technology (see Figure 13), which increases CO_2 emissions over time. The net result is that the CO_2 emissions in Low NG Price scenario are lower relative to the Reference scenario until the mid-2040s (see Figure 16).

[17] If natural gas were acting as a bridge fuel to a cleaner energy future, one would expect the longer-term (e.g., post-2040) CO_2 emission would drop more significantly that what was observed in these scenarios.

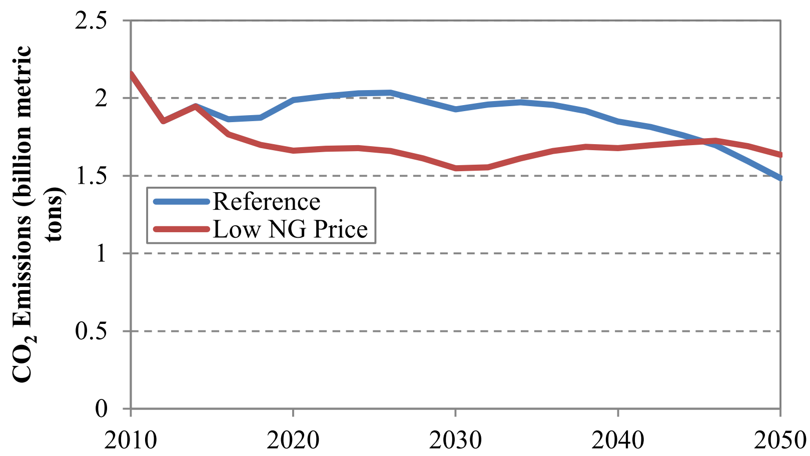

Figure 16. CO_2 emissions over time in the Reference and Low NG Price scenarios. The Low NG Price scenario maintains lower emissions than the Reference scenario until the mid-2040s.

3.2 Mid and Low Carbon Targets

In nearly all scenarios, implementing the mid and low carbon targets increases 2030 natural gas generation relative to the no carbon target scenarios (see Figure 17[18]), indicating a coal-to-gas switching in order to reduce 2030 CO_2 emission levels.[19] The only exceptions to increased natural gas generation are the Low and High NG Price scenarios under the mid carbon target. In the Low NG Price scenarios, the CO_2 emissions are sufficiently low that the carbon target is not binding in 2030 and therefore, no changes are observed. In the High NG Price scenarios, the system relies more heavily on renewable energy technologies, but still uses nearly the same amount of natural gas as when no carbon target is present.

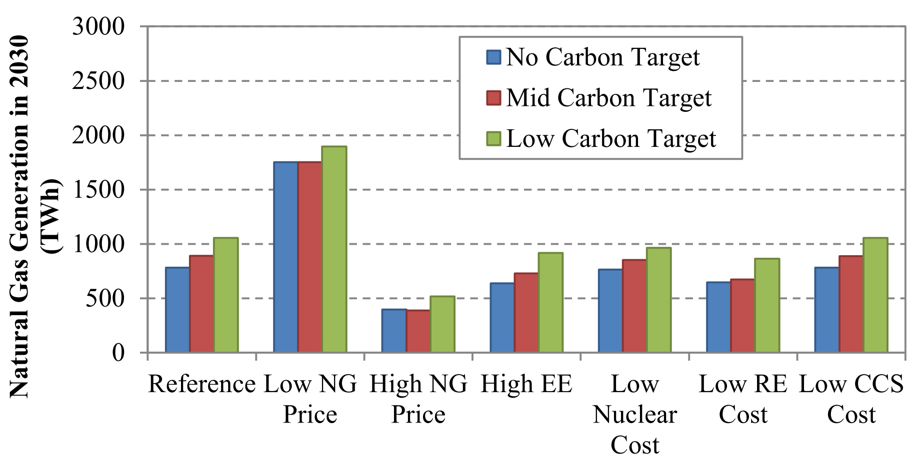

Figure 17. Natural gas generation in 2030 for the suite of scenarios with the three carbon target trajectories. In all scenarios the natural gas generation is the same or higher as the carbon stringency increases.

[18] The Very Low CCS Cost scenarios are not shown in this section, but are discussed in Section 3.3.
[19] The Appendix includes stacked capacity and generation plots for the reference scenarios with no, mid, and low carbon targets.

Figure 18 shows the natural gas generation in 2050. The mid carbon target scenarios are very similar to the no carbon target scenarios, irrespective of the other market conditions considered. The mid carbon target scenarios have more natural gas generation than the no carbon target scenarios, but the differences across all scenarios are quite minor (the largest difference is the High EE scenarios, with a 6% difference). The low carbon target scenarios, however, have notably lower natural gas generation than the no and mid carbon target scenarios. This points towards natural gas acting as a bridge-like fuel, with natural gas generation reduced compared to the no and mid carbon target cases. Because the mid carbon target scenarios do not show any decline in long-term natural gas generation, but the low carbon target scenarios do, it appears that within the contexts of the scenarios considered here, the long-term role of natural gas is dependent on the level of CO_2 emissions reductions. Smaller reductions in CO_2 emissions can increase the market share of natural gas while larger reductions can decrease market share.

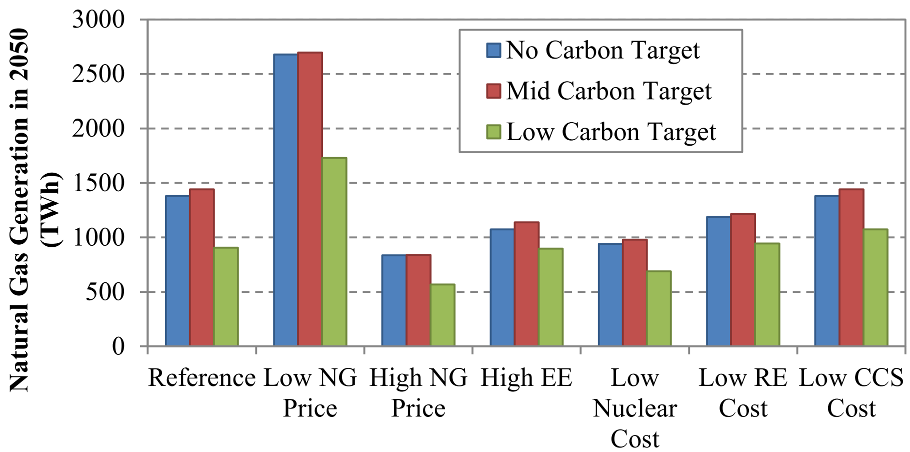

Figure 18. Natural gas generation in 2050. The mid carbon target scenarios are similar to the no carbon target scenarios, while the low carbon target scenarios are significantly lower.

Figure 17 and Figure 18 also demonstrate the role of natural gas in the context of scenarios in which a specific low-carbon technology is advantaged. In 2030, natural gas generation in the technology scenarios is quite similar to that in the reference scenarios, indicating relatively little change in the role of natural gas in the near- to mid-term due to advancements in those technology areas. The 2050 natural gas generation shows more significant differences, suggesting that technology advancements will likely have substantial impacts on the role of natural gas in the longer term timeframe.

Natural gas generation differences are most strongly driven by alternative natural gas price trajectories—changes in natural gas generation in the Low NG Price and High NG Price scenarios are much larger than in any other scenario in both the 2030 and 2050 timeframes. Figure 19 shows the range of natural gas generation for the reference and four technology scenarios (High EE, Low Nuclear Cost, Low RE Cost, and Low CCS Cost) in the left plot. The right plot shows the range of natural gas generation for the natural gas price scenarios (Low NG Price and High NG Price). The ranges for the natural gas price scenarios dwarf the range for the technology scenarios irrespective of the presence of a carbon target. This sensitivity to gas prices indicates that innovation and capabilities to abundantly produce cheap natural gas might have a greater impact on the power sector generation mix than advancements in other low-carbon technologies. The sensitivity also might indicate that the level of uncertainty in future natural gas prices is much greater than the level of uncertainty in future technology cost and performance.

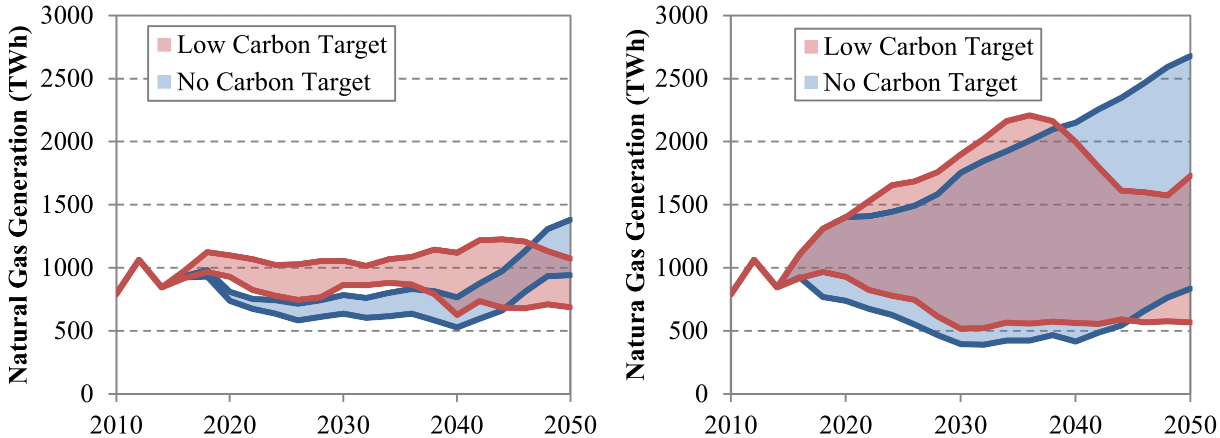

Figure 19. The left plot shows the range of natural gas generation under the reference and four technology scenarios (High EE, Low Nuclear Cost, Low RE Cost, and Low CCS Cost) with and without the low carbon target. The right plot shows the range of natural gas generation under the reference and alternative natural gas price scenarios (Low NG Price and High NG Price) with and without the low carbon target.

Figure 20 shows the amount of renewable energy generation in 2030 and 2050 across a range of scenarios and carbon targets. Renewable energy generation increases over time irrespective of the scenario or carbon target. Renewable energy generation also increases as the carbon target is lowered. Natural gas prices have a clear impact on renewable energy generation (as seen by comparing the Low NG Price scenarios with the High NG Price scenarios), but that impact is markedly smaller in 2050 under the low carbon target. In 2030, the High NG Price scenarios actually have more renewable energy than the Low RE Cost scenarios when there is a carbon target present.

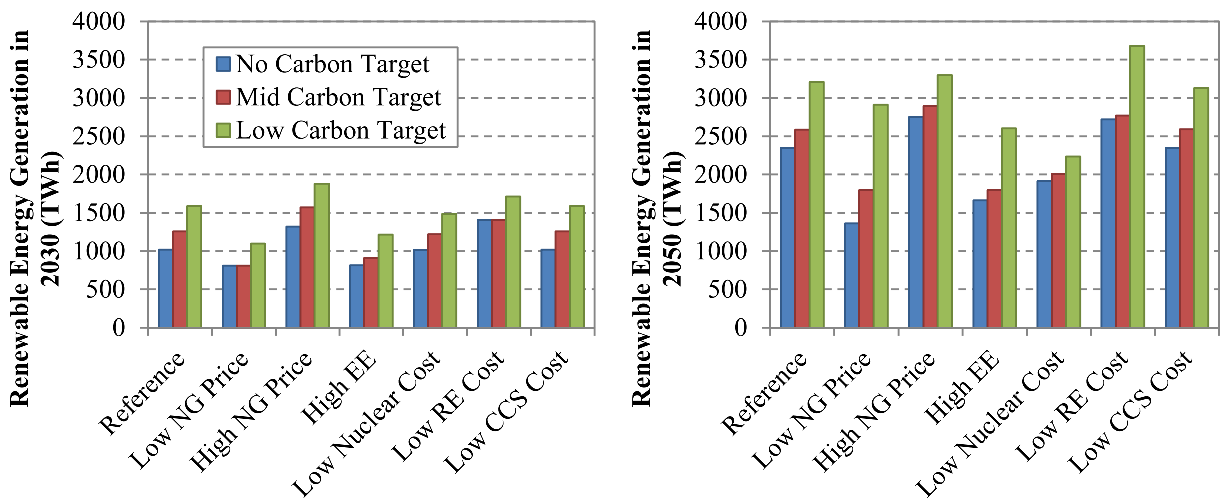

Figure 20. Renewable energy generation in 2030 (left) and 2050 (right). In all scenarios, renewable energy generation remains steady or increases as the carbon target is lowered.

Without a carbon target imposed, coal capacity is retired over time as the coal fleet ages. As stricter carbon targets are imposed, coal generation decreases even further in order to meet those targets (see Figure 21). The low carbon target leaves almost no coal generation by 2050. Generation levels in 2030 are strongly dependent on future natural gas prices, regardless of the level of carbon target, while 2050 generation levels are highly dependent on the carbon target.

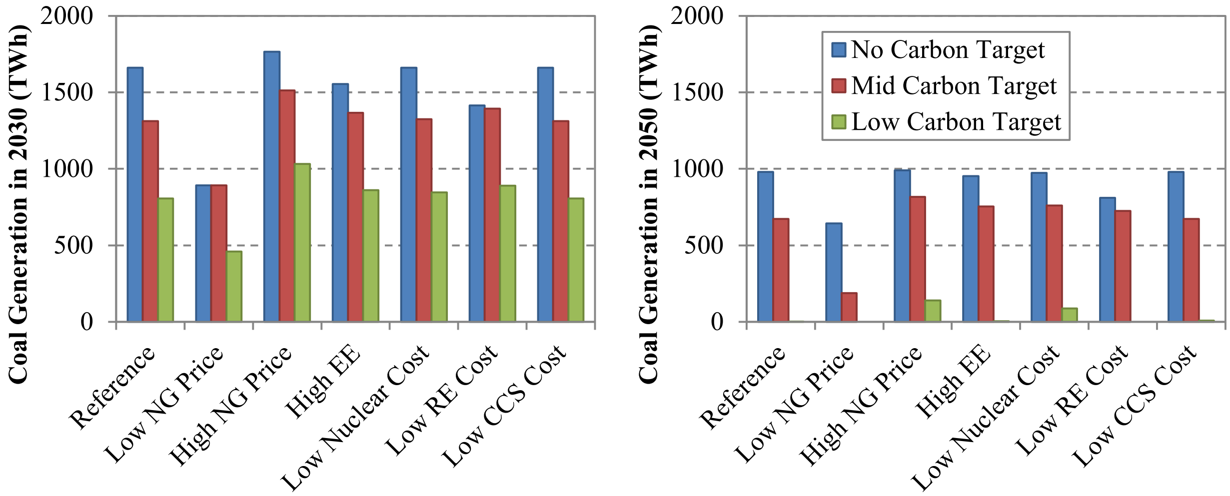

Figure 21. Coal-fired generation in 2030 (left) and 2050 (right). The low carbon target essentially squeezes coal out of the generation mix by 2050.

Nuclear power can also play a substantial role in these scenarios. Figure 22 shows the nuclear capacity in 2050 across the scenarios and carbon targets.[20] Because nuclear plants are assumed to have a 60-year life (i.e., they do not receive a second license renewal), nuclear capacity from the existing fleet is substantially reduced by 2050 relative to the current ~100 GW operating today. However, high natural gas prices and low carbon targets allow nuclear to be cost-competitive, and substantial amounts of new nuclear capacity are observed.

[20] Nuclear capacity in 2030 is not shown because there is very little difference across scenarios and relatively few nuclear retirements have occurred.

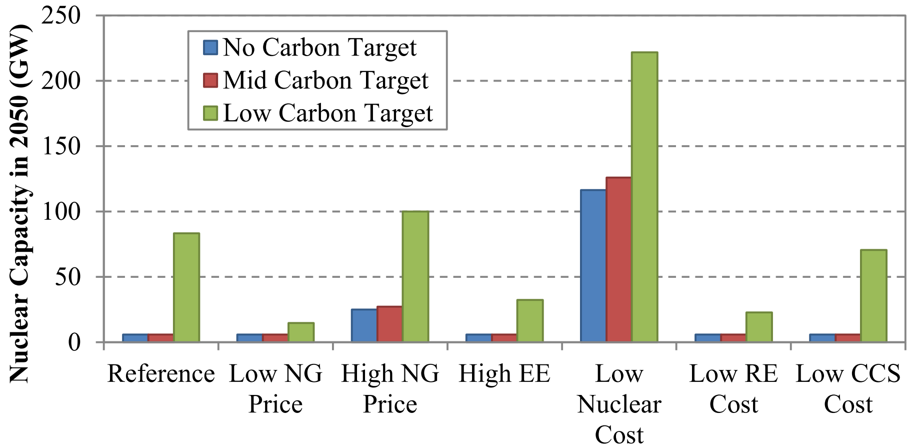

Figure 22. Nuclear capacity in 2050. Nuclear plants are assumed to not receive a second license renewal, limiting nuclear lifetimes to 60 years. Thus the nuclear capacity shown here represents newer nuclear units. The role of nuclear power is significantly increased with the low carbon target.

Figure 23 shows the inter-regional alternating current (AC) transmission capacity in 2050 across the scenarios. The low carbon target scenarios always have more transmission capacity, primarily due to increased renewable energy capacity (see Figure 20).[21] However, the mid carbon target scenarios often have lower transmission capacity relative to the no carbon target scenarios. The mid carbon target scenarios tend to rely more on local solar resources, increase the amount of system storage (both compressed-air energy storage and utility-scale batteries), and increase the direct current (DC) intertie capacity between interconnections. Also of note is that the Low NG Price scenarios always have the lowest transmission capacity across the scenarios even though they do not always have the lowest amount of renewable energy generation. Under the low carbon target, the Low Nuclear Cost scenario has the lowest amount of renewable energy generation, but has higher transmission builds than the Low NG Price scenario. This difference is driven by the relative inflexibility between the two systems in those scenarios. Because nuclear plants are less flexible than natural gas plants, the system with higher nuclear penetrations relies more on the transmission to help the system deal with the variable renewable resources.

[21] Transmission capacity expansion is important in enabling more low-cost renewables for the decarbonization of the electricity sector (Haller, Ludig, and Bauer 2012).

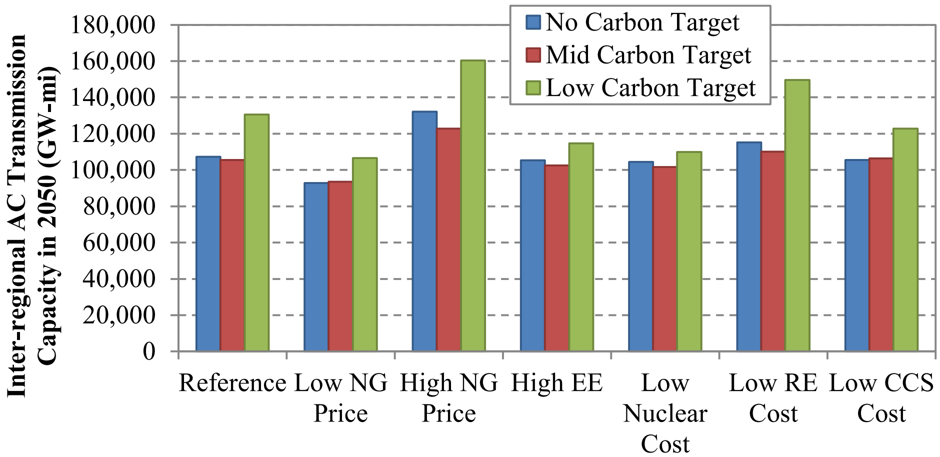

Figure 23. Inter-regional AC transmission capacity in ReEDS in 2050. The Low NG Price scenarios always have the lowest transmission capacity even though they do not always have the lowest deployment of renewable energy (see Figure 20).

3.3 Carbon Capture and Storage

In all of the scenarios considered here, none of the scenarios saw coal-CCS deployed. This does not imply that coal-CCS cannot play a role in a low carbon future, only that coal-CCS was found to be less economic than NG- CCS, given the CCS cost inputs for these scenarios (see Figure 9 and Figure 10).

Figure 24 shows the amount of NG-CCS capacity that was built for any scenario that had non-zero NG-CCS capacity. Under the mid carbon target, only the Very Low CCS Cost scenario saw any NG-CCS capacity. In the other mid carbon target scenarios, coal-to-gas switching, new renewable energy generation, and new nuclear generation are sufficient and more cost-effective than the CCS options. For the low carbon target scenarios, NG-CCS appears in all scenarios except the High NG Price and Low Nuclear Cost scenarios, though the capacity of NG-CCS ranges from 1 GW in the Reference scenario to 174 GW in the Very Low CCS Cost scenario. The scenarios that directly lower the NG-CCS costs, either through lower capital costs or lower fuel costs, result in the highest levels of NG-CCS deployment.

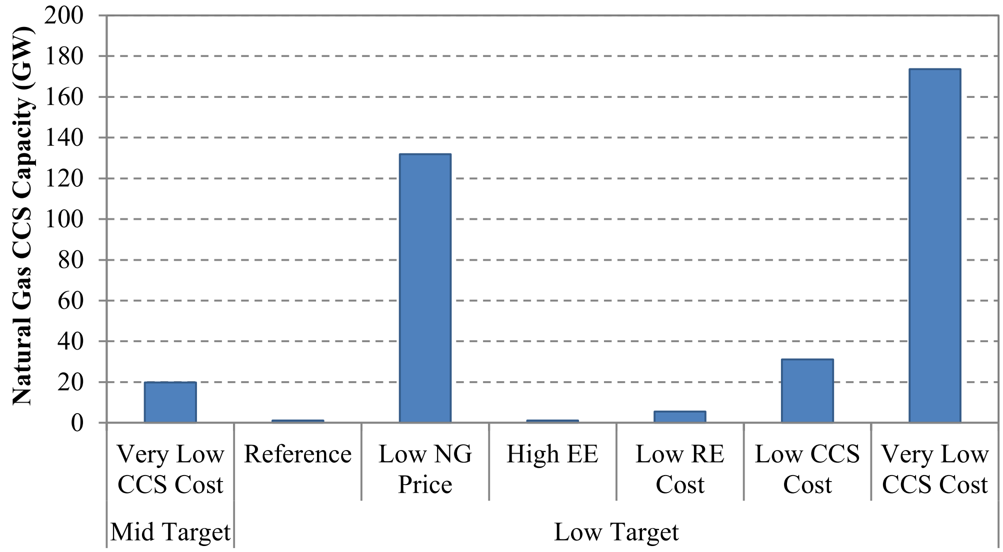

Figure 24. Total natural gas CCS capacity in 2050 for each of the scenarios with CCS capacity. If a scenario is not shown here, it is because there was no CCS capacity in that scenario.

Figure 25 shows the natural gas generation for the Reference scenario with the three carbon targets. Natural gas generation from 2020–2040 increases as the carbon target becomes more stringent. Beyond 2040, natural gas generation increases without a carbon target and with the mid carbon target. Natural gas generation decreases over this time period. Low CCS costs slow the decline to some extent, but very low CCS costs allow natural gas generation to continue to grow.

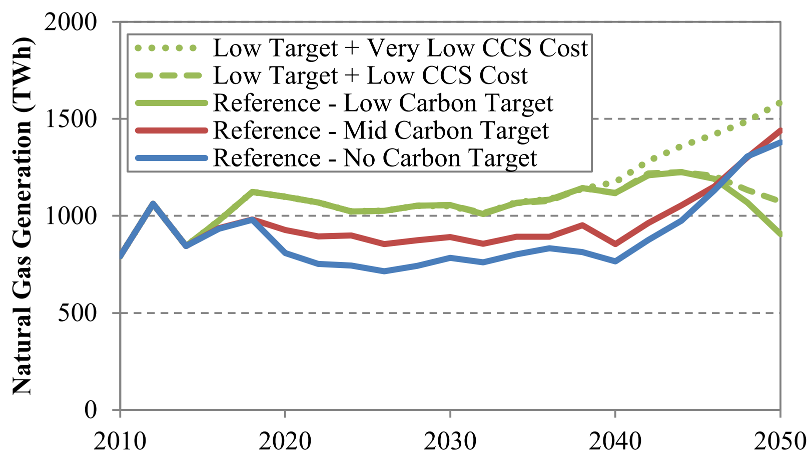

Figure 25. Natural gas-fired generation in the Reference scenario with the different carbon targets. Natural gas generators with CCS can increase the generation in later years under the Low and Very Low CCS Cost assumptions.

3.4 Additional Discussion

The scenarios presented in this paper demonstrate futures in which both natural gas generation and renewable energy generation increase, sometimes substantially. Although natural gas and renewable energy are often competing technologies, they both are able to grow over time under a wide range of scenarios, including scenarios with significant CO_2 reductions.

Increased variable renewable energy generation can lead to increased renewable energy curtailment.[22] This relationship is shown in Figure 26. As the renewable energy penetration increases, curtailment rises in a nonlinear fashion. In general, at higher levels of renewable energy penetration, more energy is lost via curtailment. Figure 26 also highlights several points associated with the Low Nuclear Cost scenario. These points have significantly higher curtailment rates for the same variable renewable energy fraction. Because nuclear power is relatively inflexible and abundant in this scenario, the system cannot as readily use all of the renewable energy and more is curtailed (see also Brouwer et al. 2015). It is possible that nuclear power and other technologies may become more flexible in a low-carbon future and therefore reduce the challenge of incorporating high levels of variable renewable energy (Voll et al. 2012).

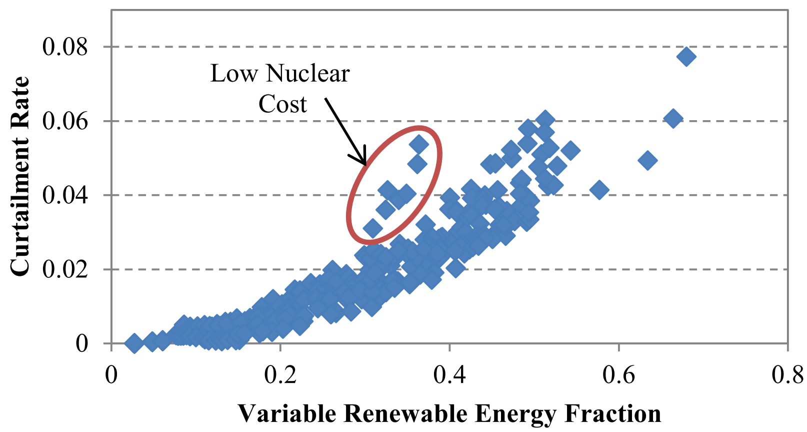

Figure 26. System-wide curtailment rate as a function of variable renewable energy fraction (defined as variable renewable energy bus bar generation divided by bus bar load). Each point represents one year from one scenario. The points in this plot are from all scenarios used in this paper such that there are 462 points (22 scenarios x 21 solve years).

Natural gas appears to be able to provide at least some level of mitigation in this area. Figure 27 shows the same curtailment data as Figure 26, but for only three scenarios: High NG Price, Reference, and Low NG Price, all without a carbon target. The High NG Price scenario has less natural gas capacity and generation than the Reference scenario, while the Low NG Price scenario has more natural gas capacity and generation than the Reference scenario (see Figure 11 and Figure 12). For a given level of variable renewable energy penetration, the Low NG Price scenario has lower curtailment than the Reference scenario, which in turn has lower curtailment than the High NG Price scenario. This relationship suggests that additional natural gas capacity can serve to lower curtailment. At a variable renewable fraction of 0.22 (the end-point of the Low NG Price scenario), the High NG Price scenario has 37% more curtailment than the Reference scenario, while the Low NG Price scenario has 25% lower curtailment than the Reference scenario. Other factors are also at play among these scenarios, such as storage, additional transmission, and the relative mix of wind and PV, but nonetheless natural gas abundance appears to be a factor in reducing system-level curtailment.

[22] Curtailment is excess renewable energy generation that cannot be used by the system.

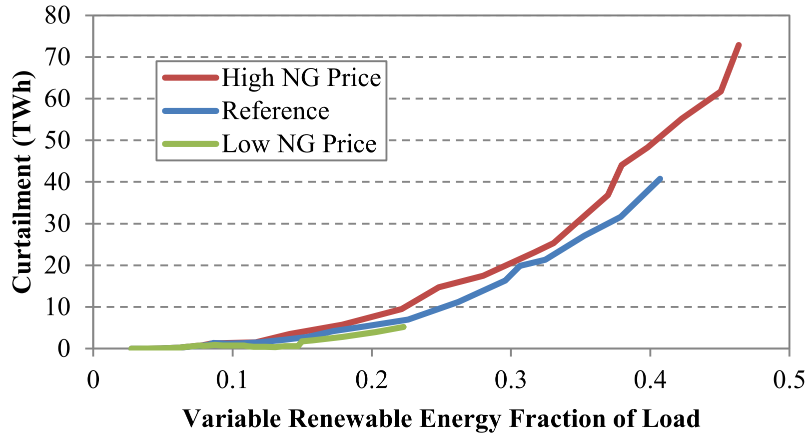

Figure 27. Fraction of bus bar load met by variable renewable generation (wind and PV) versus system-wide curtailment for three scenarios with no carbon target enforced. For a given penetration level, the Low NG Price scenario has lower curtailment than the Reference scenario, which in turn has lower curtailment than the High NG Price scenario.

As the level of curtailment increases, storage becomes an increasingly attractive option within the system-wide, least-cost optimization framework. The relationship between storage capacity and variable renewable energy fraction is shown in Figure 28. Higher penetrations of variable renewable energy lead to more storage capacity. Three outlier scenarios are also highlighted. Storage is also a function of natural gas prices and penetration levels. The Low NG Price scenario has a more flexible system (because of the abundant natural gas) and cheaper peaking units and therefore less need for new storage capacity. The High NG Price scenario has just the opposite. The inflexibility of the Low Nuclear Cost scenario is also highlighted as storage is a least cost solution to help integrate the variable renewable energy.

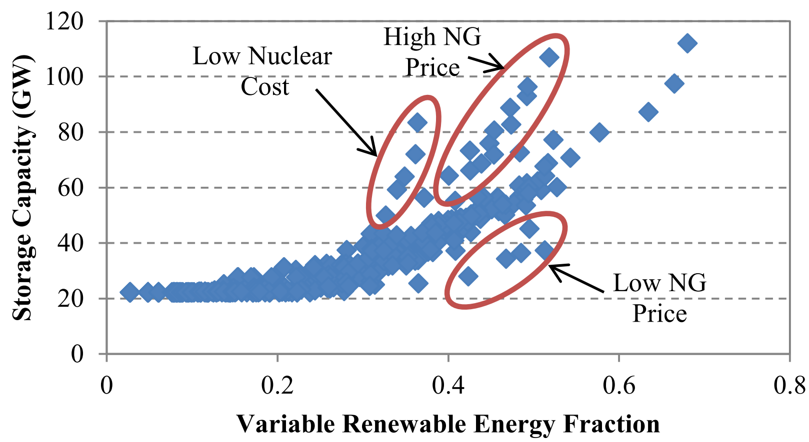

Figure 28. Storage capacity versus variable renewable energy fraction

4 Conclusions

For the scenarios considered here, natural gas is an important player in the U.S. electricity sector out to 2050 regardless of the level of carbon reduction considered, though the role of natural gas varies based on the stringency of the carbon target imposed. Across all scenarios, natural gas generation was far more sensitive to changes in natural gas price than to assumptions of carbon mitigation or technology costs for other low-carbon technologies.

Without a carbon target enforced, natural gas generation in the scenarios considered grows over the long-term, showing no indication of a natural gas bridge that eventually phases out over time. Applying a carbon target that forces the electricity system to reduce 2050 CO_2 emissions by 41.5% below 2005 levels results in little change in natural gas generation relative to the same scenarios with no carbon target imposed.

This situation is not the same, however, when 2050 electricity system emissions are reduced by 83% below 2005 levels. In these low carbon target scenarios, 2050 natural gas generation is reduced relative to the scenarios with no carbon target, indicating that under a stringent CO_2 emission requirement, natural gas shows signs of acting as a bridge to a low-carbon future.

Under the least cost optimization modeling framework, and the CCS costs considered here, CCS only begins to play a prominent role under the most stringent carbon target (83% CO_2 emissions reduction by 2050), and only when costs are favorable (i.e., with lower natural gas prices or lower CCS costs). If costs are favorable, CCS allows natural gas generation to increase through 2050 while still achieving the levels of emission reduction required by the scenario.

Natural gas on the system may help to reduce curtailment of variable renewable energy resources. Under more stringent carbon mitigation, additional renewable energies are deployed, and the flexibility offered by natural gas offers least cost system wide solutions.

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Appendix

Figures A-1 through A-3 show stacked capacity and generation plots for the Reference scenarios with no carbon target, mid carbon target, and low carbon target, respectively.

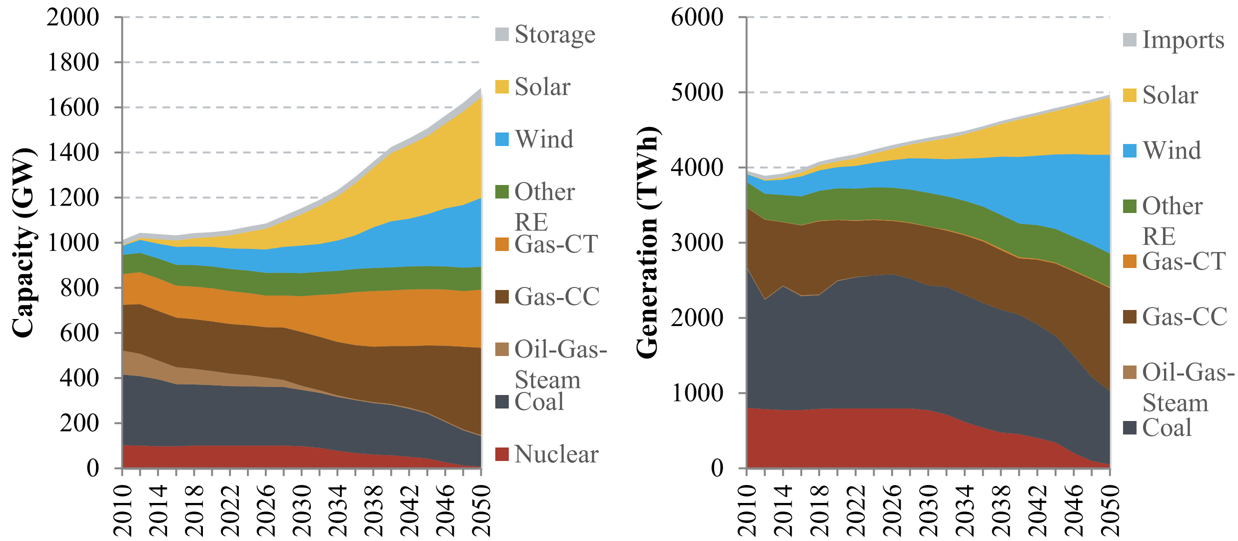

Figure A-1. Capacity and generation plots from the Reference scenario with no carbon target

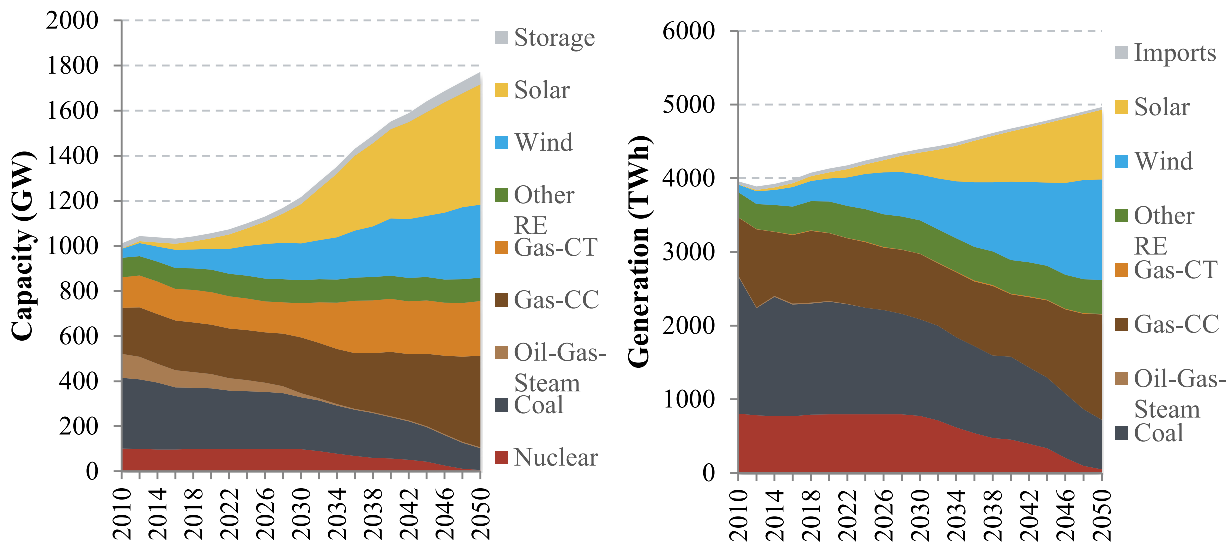

Figure A-2. Capacity and generation plots from the Reference scenario with the mid carbon target

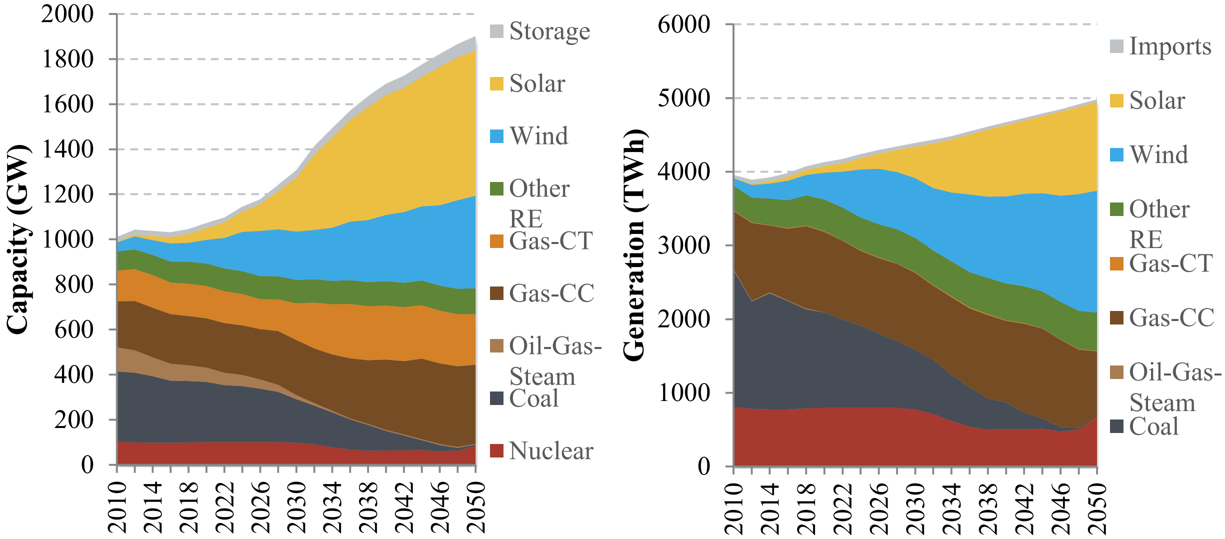

Figure A-3. Capacity and generation plots from the Reference scenario with the low carbon target