U.S. electricity infrastructure of the future: Generation and transmission pathways through 2050

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Abstract

The future development of the U.S. electricity sector will be shaped by technological, economic, and policy drivers whose trajectories are highly uncertain. In this article, we develop an optimization model for the integrated generation and transmission system in the continental U.S. and use it to explore electricity infrastructure pathways from the present through 2050. By comparing and contrasting results from numerous scenarios and sensitivity settings, we ultimately affirm five key policy-relevant insights. (1) U.S. electricity can be substantially decarbonized at modest cost, but complete decarbonization is very costly. (2) Significant expansion of renewables is fairly certain, although solar PV and battery storage are more affected by cost assumptions than wind. (3) Investments in long-distance transmission are very limited, while investments in battery storage are much greater, under a wide range of assumptions. (4) Optimal solutions include large investments in natural gas capacity, but gas capacity utilization rates decline steadily and significantly. (5) Cost structures shift away from operating expenditures and toward capital expenditures, especially under climate policy. We conclude our article by discussing the policy implications of these findings.

Keywords: Energy modeling, electricity, generation, transmission, optimization, United States

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1. Introduction

The electricity sector in the United States (U.S.) is in the midst of a dynamic period in its long-run evolution, driven by profound technological, economic, and policy changes. The shale gas revolution has resulted in lower natural gas prices that caused natural gas to surpass coal as the leading fuel used to generate electricity, and continue to drive substitution of gas for coal (Feijoo et al., 2018). Costs of renewable technologies such as wind turbines and solar photovoltaic (PV) panels, as well as battery electricity storage, have decreased sharply in recent years and continue to decline (Sivaram et al., 2018). Electricity market restructuring has instituted competitive markets in many regions of the U.S., a shift which is causing utilities to be cautious about investing in large, capital-intensive generation facilities, and instead favor smaller, more flexible projects (Rhodes, 2018). Growing awareness of the dangers associated with climate change has led to a complex and constantly evolving patchwork of regulations governing greenhouse gas (GHG) emissions at local, state, and federal levels. These include renewable portfolio standards in a majority of the 50 states (Barbose et al., 2016), the Clean Power Plan setting carbon dioxide (CO₂) emissions reduction targets for individual states, subsidies and tax incentives for clean technologies like solar PV (Hagerman et al., 2016), and cap-and-trade programs in California and the Regional Greenhouse Gas Initiative states on the East Coast (Chan and Morrow, 2019).

Considerable uncertainty about the trajectories of technological, economic, and policy drivers has led to a wide range of projections for how the U.S. electricity sector will – or ought to – evolve over the coming decades. For instance, there is a general consensus that the power sector will have to play a crucial role in climate change mitigation, as most analyses suggest that a highly decarbonized electricity system is required for climate stabilization (de Sisternes et al., 2016). Nevertheless, researchers disagree about the costs of reducing CO₂ emissions from electricity, the ideal extent of decarbonization, and the optimal mix of technologies to deploy. Some argue that the U.S. electricity system can achieve complete decarbonization at no additional cost, based on a combination of wind, water, and solar energy together with various storage technologies (Jacobson et al., 2015). Other scholars propose relying on a broader portfolio of technology options to transition to a low-carbon electricity future (Clack et al., 2017). For example, MacDonald et al. (2016) contend that U.S. electricity CO₂ emissions can be reduced substantially at no additional cost by deploying renewables in concert with nuclear and natural gas generation, and investing in long-distance transmission lines to balance variability in intermittent renewable power supplies.

On the other hand, based on the very long and gradual energy transitions typically observed in the
historical record, some researchers claim that any large-scale transition from fossil fuel electricity to intermittent renewables will necessarily take many decades (Smil, 2016).

In this paper, we investigate the future development of U.S. electricity infrastructure through 2050 by developing a least-cost optimization model of the integrated generation and transmission system in the continental U.S. Our model is a customized and expanded version of the Open Source Energy Modeling System (OSeMOSYS) framework (Howells et al., 2011). We represent 13 regions distinguished by their electricity demand profiles, wind and solar PV capacity factors, hydro and geothermal resources, and existing generation capacities. Compared to existing tools, our model incorporates greater temporal resolution using a multi-level representation of time. Generation and transmission capacity investment decisions are made every five years, inter-seasonal variability in loads and resources is captured, and 24-hour dispatch solutions in each season allow us to faithfully project the operation of future electricity systems featuring significant intermittent renewables and battery storage. We apply this model to compare and contrast results from four main scenarios and additional sensitivity analyses in order to obtain policy-relevant insights into future pathways for the U.S. electricity sector. Based on our results, we affirm five key takeaways regarding the optimal development of the electricity system, and discuss their policy implications in Section 5.

1. The U.S. electricity sector can be substantially decarbonized at modest cost, but complete decarbonization is very costly.
2. Significant expansion of renewable generation is fairly certain, although solar PV and battery storage are more affected by economic and policy assumptions than wind.
3. Investments in long-distance transmission are very limited, while investments in battery storage are much greater, under a wide range of assumptions.
4. Natural gas capacity growth is strong and robust, but utilization of gas capacity declines steadily and significantly.
5. Electricity system costs shift away from operating expenditures and toward capital expenditures over time, especially in the presence of climate policy.

The remainder of this article is organized as follows. In Section 2, we review the literature on energy system modeling and its application to the U.S. electricity sector. We describe our model and document our data sources in Section 3. Scenario results are presented, compared, and discussed in Section 4. We conclude the article in Section 5 by acknowledging limitations, summarizing the five key takeaways, and discussing their policy implications.
2. Literature review

Researchers have developed a multitude of energy system models to explore how energy pathways are shaped by technological, economic, and policy drivers. In this section, we review the literature on two modeling paradigms that are commonly applied to electricity generation and transmission expansion: optimization and market equilibrium. We focus primarily on the former class of models because the framework we develop for this study adopts an optimization structure. Afterward, we briefly summarize what equilibrium models tend to reveal about the future of electricity.

2.1. Energy system optimization models

Energy system optimization models aim to identify the ideal transformations of energy systems over time, including decisions on capacity investments and operations (Pfenninger et al., 2014). The objective is typically to minimize the total present discounted cost while satisfying all demands and respecting a host of constraints. Energy system optimization is often considered a bottom-up modeling approach since it represents energy technologies in great detail but handles macroeconomic drivers of energy demand via broad, exogenous assumptions. This modeling paradigm inherently assumes that a single, rational decision maker controls all investment and operational decisions throughout the system. The energy system pathways that optimization models produce should therefore be viewed as normative results describing how a system should evolve (conditional on the structural and parametric assumptions encoded in the model) rather than predictions for how the system will evolve.

Popular energy system optimization frameworks include OSeMOSYS (Howells et al., 2011), Regional Energy Deployment System (ReEDS) (Short et al., 2011), Market Allocation (MARKAL)/The Integrated MARKAL-EFOM System (TIMES) (Loulou et al., 2004; Loulou and Labriet, 2007), Solar and Wind Energy Integrated with Transmission and Conventional Sources (SWITCH) (Nelson et al., 2012), and National Electricity with Weather System (NEWS) (MacDonald et al., 2016). Some of these tools are designed to examine a specific system (e.g., NEWS for the U.S. power sector) while others are essentially model generators that can be used to define a wide range of models tailored to particular applications (e.g., OSeMOSYS). The models differ in many respects such as geographical scope, regional disaggregation, temporal resolution, sets of technologies, and whether they represent spatial infrastructure networks (e.g., transmission). Which features are represented
in detail, and which are treated in a simple manner or omitted entirely, depend on the modeler’s perspective and the goals of the analysis (Wilkerson et al., 2015).

2.1.1. Open Source Energy Modeling System (OSeMOSYS)

The model we develop in this study to explore the future development of the U.S. electricity system is a customized and expanded version of OSeMOSYS. We describe the standard version of OSeMOSYS here, then delineate our modified implementation in Section 3. OSeMOSYS is a highly flexible and modular energy system optimization framework structured as a linear program that minimizes cost by determining optimal technology capacity investments and dispatch schedules (Howells et al., 2011). Unlike many other energy modeling platforms, the standard version of OSeMOSYS is available open source to encourage dissemination and improve research transparency (DeCarolis et al., 2012).\footnote{The standard OSeMOSYS model and more information about it can be found at the website www.osemosys.org.} For a comprehensive description of the standard OSeMOSYS framework, see the original documentation published by Howells et al. (2011).

The literature based on OSeMOSYS showcases a diverse range of applications. Welsch et al. (2014) use OSeMOSYS to analyze high renewable electricity penetration in Ireland. Cervigni et al. (2015) employ OSeMOSYS to study strategies for enhancing the climate resilience of African infrastructure. Groissböck and Pickl (2016) apply the model to the Saudi Arabian power sector to study the tradeoff between cost and environmental objectives. Brozynski and Leibowicz (2018) build a version of OSeMOSYS with integrated electricity and transportation to evaluate urban-scale decarbonization strategies in Austin, Texas. de Moura et al. (2018) incorporate endogenous transmission investments into OSeMOSYS to study cross-border electricity trade in South America. By reformulating OSeMOSYS as a stochastic program, Leibowicz (2018) investigates optimal hedging strategies for expanding electricity generation under climate policy uncertainty. Gardumi et al. (2018) review the evolution of the OSeMOSYS developer and user communities since their inception, as well as a number of customized extensions that researchers have created.

2.1.2. Other energy system optimization models

ReEDS (Short et al., 2011) is perhaps the energy system optimization model most similar to the one we develop in this paper. ReEDS also depicts the regionally disaggregated U.S. electricity sector, integrates generation and transmission, and simultaneously solves for capacity investments and dispatch. It uses geographic information system (GIS) databases to achieve impressive spatial
resolution, but this focus on spatial detail comes at the expense of temporal resolution. Specifically, ReEDS includes 134 load balancing areas and 356 regions for establishing renewable capacity factor profiles, but only 17 representative annual timeslices to capture the electricity demand and dispatch solution (Eurek et al., 2016). These timeslices correspond to four six-hour blocks on four representative seasonal days, plus one additional timeslice to reflect peak load conditions. Relative to ReEDS, our model developed in Section 3 features less spatial disaggregation, but more time granularity to capture temporal variations in demands and renewable capacity factors, and to more faithfully analyze generation dispatch and electricity storage operations.

Cole and Frazier (2018) employ ReEDS to study 38 scenarios for the evolution of the U.S. electricity system. They find that wind and solar PV capacities grow significantly in almost all scenarios, and that their expansions raise the demand for flexibility within the rest of the generation fleet. Zhou et al. (2018) use ReEDS to evaluate the impacts of misestimating renewable capacity credits on the U.S. power sector. They find that the system is robust to small underestimates of renewable capacity credits, but large underestimates (> 50%) can adversely affect the relative costs and values of variable renewable energy technologies enough to reduce their deployment. Using ReEDS, Reimers et al. (2019) demonstrate that the optimal capacity expansion pathway is sensitive to the way that regional reserve margins are formulated. Energy modelers often assume the reserve margins recommended by the North American Electric Reliability Council (NERC), but regional reserve margins have historically exceeded these in many cases. Therefore, using NERC reserve margins typically leads to lower near-term capacity investments.

Nelson et al. (2012) use the SWITCH mixed-integer linear programming model to analyze least-cost generation and transmission expansion in the western U.S. and Canada. The authors find that stronger carbon policy can achieve a 54% reduction in power sector emissions below the 1990 level by 2030, using a mix of existing generation technologies. Intermittent renewables contribute 17–29% of total generation in 2030, depending on cost assumptions. The increase in overall electricity system cost does not exceed 20%. MacDonald et al. (2016) obtain even more optimistic results using the NEWS model, which co-optimizes generation investments, transmission expansion, and dispatch across the U.S. The model incorporates very detailed weather data and captures cost savings from geographic diversity, load smoothing, reserve pooling, and reduced energy density requirements. Their results claim that emissions can be reduced 80% below the 1990 level using existing technologies and their current cost projections, and without electricity storage, at no increase in levelized electricity cost.
2.2. Energy system equilibrium models

While the model we develop in this paper follows the optimization paradigm, it is helpful to briefly introduce a few equilibrium-based energy-economy models to gain more insights into future electricity sector pathways, and to clarify the relative strengths and limitations of the two modeling approaches. Equilibrium models endogenously determine prices that balance supply and demand in a set of represented markets. Models that endogenously solve for equilibria only in selected energy markets (e.g., electricity, natural gas) are known as *partial* equilibrium models, whereas *general* equilibrium models balance supply and demand across all markets that comprise an economy. This top-down approach is valuable for studying the macroeconomic forces that drive energy demand, as well as demand-side mitigation levers such as energy efficiency investments and price-induced demand reductions. It is also useful for analyzing interactions among multiple decision makers (e.g., firms, consumers, different countries), unlike optimization models which adopt the point of view of a single agent. Computable general equilibrium (CGE) models capture the ripple effects of energy and climate policies throughout the economy, beyond just energy sectors. Relative to optimization-based platforms, equilibrium models typically feature much less technological, temporal, and spatial detail. However, researchers have experimented with hybrid modeling approaches that couple a bottom-up optimization model with a top-down equilibrium model, and solve them iteratively (Messner and Schrattenholzer, 2000; Young et al., 2017).

The U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model is one such hybrid framework that couples a capacity expansion and dispatch model of the power sector with a CGE model of the U.S. economy (Young et al., 2017). Blanford et al. (2014) employ US-REGEN to analyze the effects of a clean energy standard under scenarios with varying technology assumptions. Results show that the future capacity and generation mixes are very sensitive to constraints on technology deployment; for example, constraints on inter-regional transmission expansion limit the growth of wind and allow nuclear to take on a larger role. They also find that the clean energy standard can induce extreme electricity system transformations at the regional level even when the national transformation is relatively subdued. Bistline (2017) uses US-REGEN to quantify the decline in the marginal value of wind and solar PV capacity as deployment levels increase. His analysis reveals that the correlations in capacity factors across space are critical determinants of this relationship, and that electricity storage helps mitigate the drop in value. Inter-regional transmission also bolsters the value of intermittent renewables by connecting locations with complementary resource profiles.
The Energy Modeling Forum (EMF) 32 study assesses GHG emissions reduction strategies in the U.S. power sector using 15 different models (Creason et al., 2018; Murray et al., 2018), 11 of which adopt an equilibrium structure. These include US-REGEN and ReEDS-USREP, which links the ReEDS model described above to a CGE formulation. For the most part, all models agree that the largest emissions reductions are achieved under scenarios with low natural gas prices, low renewable technology costs, and low energy efficiency costs. Gas prices and renewable costs exert the most significant effects on projected capacity investments, generation mixes, and emissions. Within EMF 32, Mai et al. (2018) evaluate the effects of model structure and input assumptions on renewable energy penetration. They find that inter-model differences in the structural representations of storage, transmission, and intermittency can cause significant variations in model outcomes even if input parameter values are harmonized as much as possible.

3. Methods

3.1. Model scope

The model we develop is a customized and expanded version of OSeMOSYS implemented in Python as a linear program, and solved using CPLEX. We described the standard OSeMOSYS framework (Howells et al., 2011) in Section 2.1.1, and in this section we document our structural extensions and original input database.

Our model determines the least-cost transformation of the integrated electricity generation and transmission system in the continental U.S., including capacity investments and operational dispatch. The timeframe of the analysis is 2016–2050, with each model period corresponding to a five-year decision making time step for capacity investments. Within each model period, 96 timeslices representing 24-hour profiles for four average seasonal days allow for a simplified computation of dispatch. Our inclusion of a full day of hourly dispatch in each season is crucial for capturing temporally varying solar and wind capacity factors, loads, and the endogenous dynamics of battery storage operations.

We divide the continental U.S. into the 13 regions outlined in Table 1, which are defined according to state boundaries. The regional definitions are based on the regions that the EIA uses to report electricity system operating data, which are themselves based on the territories of load balancing authorities and independent system operators (ISOs). However, we make several modifications to the regions to ensure that states grouped together have roughly similar energy
resources and demand profiles. Regions are linked in the model by the inter-regional transmission network, which we add to the standard OSeMOSYS structure. We do not represent the transmission and distribution grids within each region, so the network in our model constitutes long-distance transmission used to balance electricity supply and demand on a broad spatial scale.

Table 1. Model region definitions.

<table>
<thead>
<tr>
<th>Model region</th>
<th>Abbreviation</th>
<th>States included</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northwest</td>
<td>NW</td>
<td>WA, OR</td>
</tr>
<tr>
<td>California</td>
<td>CA</td>
<td>CA</td>
</tr>
<tr>
<td>Mountain North</td>
<td>MN</td>
<td>MT, ID, WY, NV, UT, CO</td>
</tr>
<tr>
<td>Southwest</td>
<td>SW</td>
<td>AZ, NM</td>
</tr>
<tr>
<td>Central</td>
<td>CE</td>
<td>ND, SD, NE, KS, OK</td>
</tr>
<tr>
<td>Texas</td>
<td>TX</td>
<td>TX</td>
</tr>
<tr>
<td>Midwest</td>
<td>MW</td>
<td>MN, WI, IA, IL, IN, MI, MO</td>
</tr>
<tr>
<td>Arkansas-Louisiana</td>
<td>AL</td>
<td>AR, LA</td>
</tr>
<tr>
<td>Mid-Atlantic</td>
<td>MA</td>
<td>OH, PA, WV, KY, VA, NJ, DE, MD</td>
</tr>
<tr>
<td>Southeast</td>
<td>SE</td>
<td>TN, NC, SC, MS, AL, GA</td>
</tr>
<tr>
<td>Florida</td>
<td>FL</td>
<td>FL</td>
</tr>
<tr>
<td>New York</td>
<td>NY</td>
<td>NY</td>
</tr>
<tr>
<td>New England</td>
<td>NE</td>
<td>VT, NH, ME, MA, CT, RI</td>
</tr>
</tbody>
</table>

Each region is given its own electricity demand growth projection, load profile, hydroelectric and geothermal resources, and solar and wind capacity factor profiles. A model run begins in the 2016 base year with the existing regional generator fleets and transmission network, and can endogenously invest in additional generation and transmission capacity over the model timeframe. Existing generation facilities are exogenously retired according to the schedule in EIA (2017c). The set of included generation technologies is delineated in Table 2. In addition to these generation technologies, the model can invest in transmission and battery electricity storage.

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2 For example, we divide the Northwest region used by the EIA into a Northwest region consisting of Washington and Oregon, and a separate Mountain North region including states in the interior West. We consider this important because Washington and Oregon feature significant hydroelectric resources and less extreme seasonal load variations than the Mountain North states.
Table 2. Electricity generation technologies.

<table>
<thead>
<tr>
<th>Electricity generation technology</th>
<th>Abbreviation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal integrated gasification combined cycle</td>
<td>COALPP</td>
</tr>
<tr>
<td>Natural gas fired combined cycle</td>
<td>NGCC</td>
</tr>
<tr>
<td>Natural gas fired combustion turbine</td>
<td>NGCT</td>
</tr>
<tr>
<td>Nuclear</td>
<td>NUC</td>
</tr>
<tr>
<td>Hydroelectric</td>
<td>HYDROPP</td>
</tr>
<tr>
<td>Wind turbine</td>
<td>WINDPP</td>
</tr>
<tr>
<td>Solar photovoltaic</td>
<td>PV</td>
</tr>
<tr>
<td>Biomass</td>
<td>BIOPP</td>
</tr>
<tr>
<td>Geothermal</td>
<td>GEOPP</td>
</tr>
<tr>
<td>NGCC with carbon capture and storage</td>
<td>NGCCCS</td>
</tr>
<tr>
<td>IGCC with carbon capture and storage</td>
<td>COALCCS</td>
</tr>
</tbody>
</table>

3.2. Structural extensions

In this subsection, we describe structural extensions that we add to the equations of the standard OSeMOSYS framework to incorporate new capabilities into our model.

3.2.1. Flow balance constraints

Incorporating an inter-regional transmission network requires us to impose the flow balance constraints

\[
\text{Production}(r, l, y) + \sum_{s \in R} \text{Import}(s, r, l, y) \geq \text{Demand}(r, l, y) + \text{Use}(r, l, y) + \sum_{s \in R} \text{Import}(s, r, l, y) \\
\forall r \in R, l \in L, y \in Y.
\] (1)

These constraints mandate that for every region \( r \), dispatch timeslice \( l \), and year \( y \), the sum of local electricity production plus electricity imports from all adjacent regions must satisfy the sum of local electricity demand, endogenous local use (e.g., for battery storage charging), and exports to all adjacent regions. The \text{Import} decision variables are added to standard OSeMOSYS to depict the operation of the transmission segments.
3.2.2. Capacity growth constraints

Ample historical evidence suggests that energy transitions are long affairs that unfold gradually over time, due to system inertia and lags in deploying large-scale, capital-intensive, infrastructure-dependent technologies (Fouquet, 2010; Grubler, 2012). Therefore, we introduce capacity growth constraints that limit the annual scale-up rates of technologies to avoid unrealistic “bang-bang” solutions where the optimization scheme could respond to a small change in the relative costs of technologies by rapidly altering the capacity mix. The formulation we use, adapted from Leibowicz et al. (2016) and Brozynski and Leibowicz (2018), is

\[
NewCapacity(r, t, y) \leq \text{TotalCapacityAnnual}(r, t, y - \tau) \cdot \text{MaxCapacityGrowthRate}(r, t) + \text{StartUpValue}(t) \quad \forall r \in R, t \in T, y \in Y.
\]

(2)

MaxCapacityGrowthRate is the maximum annual percentage growth in the total installed capacity of technology \( t \) and \( \tau \) represents the time step used in the model (i.e., \( \tau = 5 \)). The value of MaxCapacityGrowthRate varies by technology to reflect the fact that granular technologies like solar PV, wind turbines, and battery storage typically diffuse faster than large-scale options like thermal power plants (Grubler et al., 1999). The StartUpValue parameter is added to allow for some small deployment of technologies with essentially no existing capacity.

3.2.3. Reserve margin constraints and capacity adequacy

Since our 96 dispatch timeslices represent average 24-hour profiles for the four seasons, they do not include the true peak load in each region. We account for this difference between the true peak load and the highest load featured in the 96 timeslices by adding to the reserve margin that drives total generation capacity. We assume that the reserve margin requires adequate capacity to satisfy demand 15% higher than the true peak load to accommodate unforeseen circumstances. Then, this reserve margin is raised to reflect the difference between the true peak load in the full 8760-hour profile and the maximum load included in the representative seasonal days. The reserve margin constraints are

\[
\text{TotalCapacityAnnual}(r, t, y) \cdot \text{CapacityFactor}(r, t, l, y) + \xi \sum_{s \in R} \text{TotalTransmissionCapacityAnnual}(s, r, y) \geq \text{TotalCapacityInReserveMargin}(r, t, y) \quad \forall r \in R, t \in T, l \in L, y \in Y.
\]

(3)
The coefficient $\xi \in [0, 1]$ determines the fractional contribution of import transmission capacity toward the regional reserve margin. Following de Moura et al. (2018), we credit import transmission links at 50% of their capacities (i.e., $\xi = 0.5$) for satisfying the regional reserve margin.

3.3. Input database

The input database includes values of numerous parameters such as existing generation and transmission capacities, capital costs, fixed and variable operation and maintenance (O&M) costs, fuel costs, conversion efficiencies, load profiles, demand growth projections, hydroelectric and geothermal resources, and solar and wind capacity factors. Table 3 comprehensively documents our data sources, all of which are publicly available. For wind and solar capacity factors, since empirical data in some parts of the country are lacking, we estimate regional capacity factor profiles by simulating generation time series at myriad locations (NREL, 2017b).

Table 3. Documentation of data sources.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Annual demand forecast</td>
<td>ERCOT (2017b), NERC (2017), MISO (2017b)</td>
</tr>
<tr>
<td>Hourly demand profile</td>
<td>ERCOT (2017a), MISO (2017a), NYISO (2017b),</td>
</tr>
<tr>
<td></td>
<td>PJM (2017a), ISO-NE (2017)</td>
</tr>
<tr>
<td>Average hourly wind capacity factor</td>
<td>NREL (2017b)</td>
</tr>
<tr>
<td>Average hourly solar PV capacity factor</td>
<td>NREL (2017b)</td>
</tr>
<tr>
<td>Existing power plant capacity</td>
<td>EIA (2017c)</td>
</tr>
<tr>
<td>Existing transmission capacity</td>
<td>FERC (2017), EIA (2017d)</td>
</tr>
<tr>
<td>Power plant conversion efficiency</td>
<td>EIA (2017a)</td>
</tr>
<tr>
<td>Input activity ratio</td>
<td>EIA (2017b)</td>
</tr>
<tr>
<td>Capital cost</td>
<td>NREL (2017a)</td>
</tr>
<tr>
<td>Variable cost</td>
<td>NREL (2017a)</td>
</tr>
<tr>
<td>Fixed cost</td>
<td>NREL (2017a)</td>
</tr>
<tr>
<td>CO$_2$ emission factors</td>
<td>IPCC (2017)</td>
</tr>
</tbody>
</table>
Fig. 1 illustrates selected, key input parameters. Fig. 1a shows how the annual electricity demand in each region is projected to evolve. Trends vary considerably across regions, from strong growth in TX to declining electricity demand in NY. Projected capital costs for a sample of technologies are depicted in Fig. 1b. According to the NREL Annual Technology Baseline (ATB) data source, capital costs of most technologies will decline slightly over time, while solar PV and batteries will experience larger cost reductions. Fig. 1c visualizes the representative seasonal load profiles for two regions, TX and NW. The TX load peaks sharply in summer due to strong space cooling demand, while the NW load varies less from season to season and actually peaks in winter. The diurnal profiles within each season are also apparent, as loads tend to be highest in the late afternoon or early evening, and lowest in the early morning. Fig. 1d plots the 24-hour load profile for the entire U.S. in each season, demonstrating the same trends. The winter profile has two distinct peaks, one in the morning and one in the evening, reflecting when people are at home and the outdoor temperature is lower than in the afternoon. Altogether, the input data plotted in Fig. 1 confirm the importance of spatial and temporal disaggregation for capturing system operating conditions that vary across space and time (daily, seasonally, and annually).

3.4. Scenario analysis

In our scenario analysis, we compare and contrast results from four scenarios to obtain insights into how the ideal evolution of generation and transmission varies with important parameters and uncertainties. The four scenarios we investigate are (1) No Policy, (2) No New Transmission, (3) Pessimistic Costs, and (4) Carbon Tax. They are summarized in Table 4.

The No Policy scenario is interpreted as a baseline development of the electricity system used to assess the effects of the particular factors that distinguish the other scenarios from it. It assumes that no policy constraints, incentives, or penalties (e.g., carbon tax) are imposed to guide the electricity sector toward or away from particular technologies or environmental outcomes.

The No New Transmission scenario constrains the transmission capacity investment decision variables to be zero, thus prohibiting expansion of the transmission network. By comparing the minimum cost objective value achieved under this scenario to that realized in the No Policy case, we can quantify the value of new transmission in the continental U.S. over the next several decades. This result helps put into perspective the potential economic losses stemming from regulatory constraints on new transmission lines, such as inadequate permitting processes and inability to obtain right of way.
The declining costs of renewables and battery storage are assumed to have a strong influence on the future of electricity. However, there is considerable uncertainty about future costs, and the NREL ATB assumptions could be viewed as optimistic. To test the sensitivity of optimal capacity investments and generation mixes to these costs, we consider the Pessimistic Costs scenario in which the capital costs of solar PV, batteries, and wind turbines decline over time at only 20% of the rate assumed in the other scenarios. Therefore, the increase in objective value from the No Policy scenario to the Pessimistic Costs scenario quantifies the value of realizing the full capital cost reductions assumed in the NREL ATB as opposed to just 20% of them.

The Carbon Tax scenario is used to explore how a tax on CO₂ would affect future electricity investments and dispatch. This scenario reflects the persistent uncertainty about the future of climate policy in the U.S. The sample tax trajectory we consider is introduced at the moderate
Table 4. Summary of the four main scenarios we investigate.

<table>
<thead>
<tr>
<th>Scenario name</th>
<th>Description</th>
</tr>
</thead>
</table>
| No Policy              | • A scenario with no policy constraints, incentives, or penalties in effect.  
                          | • Interpreted as a baseline development of the U.S. electricity system, against which the other scenarios are compared.                      |
| No New Transmission    | • Prohibits new investments in the inter-regional transmission network.  
                          | • Used to quantify the value of new, long-distance transmission investments in the U.S. electricity sector.                                  |
| Pessimistic Costs      | • Assumes that only 20% of the reductions in solar PV, battery, and wind turbine capital costs projected by the NREL Annual Technology Baseline will actually materialize.  
                          | • Used to test the sensitivity of capacity investments, generation mixes, and total cost to uncertain future cost assumptions.               |
| Carbon Tax             | • Imposes a carbon tax initialized at $20/tCO$_2$ in the base year that rises linearly over time to $200/tCO$_2$ in 2050.  
                          | • Used to assess how climate policy would affect capacity investments, generation mixes, CO$_2$ emissions, and total cost.                     |

In addition to thoroughly exploring these four scenarios, we also conduct wider sensitivity analyses to establish how the capital cost of new transmission influences total transmission investments, and how the percentage reduction in total CO$_2$ emissions affects electricity system costs.
4. Results

Section 4.1 demonstrates that the model dispatch solution is well calibrated to actual base year generation data. Sections 4.2–4.5 present and discuss the results of each scenario individually, beginning with the No Policy case. Then, in Section 4.6, we present and analyze summary figures that compare the developments of key electricity sector outcomes and metrics across the four scenarios, and emphasize policy-relevant insights.

4.1. Base year comparison

Fig. 2 shows the actual, regional generation mixes from the base year (2016), and then the regional generation mixes produced by our model using the existing generation capacities. The model results should not be expected to exactly match reality due to temporal, spatial, and technological aggregation in the model, and because the U.S. electricity sector is not actually operated by a single optimizing agent to achieve cost minimization. However, it is comforting to confirm that the model-based dispatch and the true generation mixes are quite similar, as seen in Fig. 2.

4.2. No Policy scenario

Fig. 3a illustrates the evolution of the national cumulative new capacity (top) and generation (bottom) mixes through 2050 in the No Policy scenario. Even without a policy stimulus, the generation mix shifts significantly toward renewable technologies like wind and solar PV. Combined, these two technologies contribute 54% of total generation in 2050. Coal and natural gas generation both decline, by 18% and 25%, respectively, from 2016 to 2050. Most of the reductions in coal and gas generation occur during the later years of the No Policy case, as the rates of wind and solar PV expansion increase due to falling costs, including the cost of battery of storage, and retirements of conventional generation facilities. Natural gas generation is more affected than coal because gas complements intermittent renewables by serving as the marginal production technology, ramping up production when renewable output drops or load is high. The story for capacity additions shown in the top plot of Fig. 3a is quite different, as far more gas capacity is added through 2050 than coal capacity. Therefore, considerable investments in natural gas capacity are warranted in the No Policy case, but the utilization rate of gas capacity falls over time. This is a theme that consistently emerges across our scenarios, with important policy implications discussed in Section 5.

Figs. 4a and 5a are map-based snapshots of the regional generation and cumulative installed (new) capacity mixes, respectively, in 2050 in the No Policy scenario. Wind still plays a larger role
Fig. 2. Model calibration for the base year 2016. (a) illustrates the actual, regional generation mixes from that year, and (b) plots the optimal dispatch solution computed by the model.

In generation than solar PV, despite solar PV having a lower capital cost than wind, an advantage that widens over the next few decades. Wind offers higher average capacity factors and less extreme diurnal variability, which means that less dispatchable generation or storage capacity is required to
Fig. 3. Annual cumulative new installed capacity (top row) and generation mix (bottom row) for the whole continental U.S., by scenario.

As shown by the arrows in Fig. 4a representing electricity imports, the model makes extensive use of the existing inter-regional transmission network. The optimal solution includes 6162 GW-miles of new transmission capacity added to the system by 2050. To put the scale of this investment in perspective, though, the existing network in the 2016 base year comprises a total of 190,395 GW-miles. Therefore, expanding the transmission network does not constitute a major component of the electricity system transformation in the No Policy scenario. The transmission that is added serves more to address existing imbalances between regional generation resources and demands than to take advantage of superior renewable resources in other regions.

Expansion of intermittent, renewable electricity induces complementary growth of battery storage capacity, illustrated by the black, vertical bars in Fig. 5a. Storage improves the utilization of wind and solar resources. As a result of significant growth in renewable generation and storage,
CO₂ emissions decline substantially in the No Policy scenario. By 2050, annual CO₂ emissions fall to 53% below their 2016 level. This reinforces the suggestion made by MacDonald et al. (2016) and others that U.S. electricity sector emissions can be significantly reduced using existing technologies, assuming that costs decline as projected. This is true even without a clear policy stimulus, which reflects the impacts of recent and continuing reductions in the costs of renewable generation options and electricity storage. However, it should be noted that a 53% decline in power sector CO₂ emissions by 2050, while substantial, is almost surely insufficient to be in alignment with climate policy goals such as constraining global warming to 2°C (Audoly et al., 2018).

4.3. No New Transmission scenario

Given the fairly limited role that transmission capacity additions play in the No Policy scenario, prohibiting investments in the transmission network in the No New Transmission scenario has only minor effects. Generation capacity investments and generation mixes are not noticeably affected by the inability to build new long-distance transmission, so we omit this scenario from a number of the figures in this section. Certain regions are forced to be slightly more self-sufficient in the No New Transmission case, so they add dispatchable capacity mainly in the form of coal to provide electricity when intermittent renewable output is low or demand peaks. The decline of CO₂ emissions by 2050 is 0.5% lower in this case than in the No Policy scenario, due to minor transmission constraints on the utilization of renewable electricity and greater investment in fossil-based capacity.

4.4. Pessimistic Costs scenario

Fig. 3b shows how the generation mix and cumulative capacity additions evolve in the Pessimistic Costs scenario. As expected, the conservative cost assumptions dampen the growth of wind and solar PV compared to the No Policy scenario, and have a larger effect on the latter. Solar PV is more strongly affected because the baseline assumptions project its capital cost to fall more than that of wind, and also because solar PV is more reliant on cost-effective battery storage due to its more extreme diurnal variability. Interestingly, nuclear power benefits from the less favorable economics of wind, solar PV, and battery storage in the Pessimistic Costs setting. In this case, installed nuclear capacity doubles by 2050, when it provides 33% of total generation. As seen in Fig. 4b, nuclear generation takes on a sizable share of the mix in more regions than in the No Policy scenario, including regions like MA and CA where it was a negligible contributor under the baseline technology cost assumptions. The substitution of nuclear electricity for intermittent renewables in
Fig. 4. Regional generation mixes and electricity imports in 2050, by scenario.
Fig. 5. Regional cumulative new installed capacity mixes in 2050, by scenario.
the Pessimistic Costs scenario helps limit the increase in CO$_2$ emissions relative to the No Policy scenario.

On the other hand, while the Pessimistic Costs setting does not induce greater investment in fossil-based capacity, it increases the utilization rates of coal and natural gas power plants. With lower deployment of wind and solar PV, the net load profiles are higher and more stable, allowing dispatchable fossil capacity to satisfy more demand during more hours. As a result, coal generation in Fig. 4b expands in regions like TX and CE. Since the capacity additions in the Pessimistic Costs scenario (e.g., nuclear) tend to have higher capacity factors than those in the No Policy scenario (e.g., wind, solar PV), cumulative capacity additions of all technologies combined are lower under Pessimistic Costs.

The smaller capacities of wind and solar PV added in the Pessimistic Costs case mean that battery storage and transmission investments are lower than in the No Policy setting. The existing transmission network is still used extensively, but the new transmission added drops to 3266 GW-miles, relative to 6162 GW-miles under No Policy. The black, vertical bars representing battery storage capacity are lower in Fig. 4b than in Fig. 4a, and disappear completely from some regions where No Policy storage investment was substantial (e.g., MA). Battery storage capital cost has a long way still to decline in the ATB assumptions, and its deployment is also predicated on significant expansion of wind or solar PV. In consequence, its growth is very sensitive to cost assumptions for these technologies.

Total CO$_2$ emissions in the Pessimistic Costs case decline to 51% below their 2016 level by 2050. This is a slightly smaller reduction than in the No Policy scenario (53%), but overall, the results suggest that U.S. electricity sector emissions will fall substantially even if wind, solar PV, and battery costs do not decline nearly as much as the ATB projects. Of course, this is also based on its assumptions about future nuclear costs, which are also highly uncertain. If nuclear were assumed to be more expensive, or were constrained by non-economic factors, then higher costs for intermittent renewables and storage would lead to more fossil-based generation and higher CO$_2$ emissions.

4.5. Carbon Tax scenario

Fig. 3c charts the growth of new capacity and the evolving generation mix in the Carbon Tax scenario. Early on, the penalty on CO$_2$ emissions causes the system to phase out coal generation faster than in the other scenarios, with natural gas use increasing to compensate. Wind, solar PV,
and other low- or zero-carbon technology options are still relatively expensive during these early years, and their up-scaling is limited by capacity growth rate constraints. Furthermore, existing gas capacity can be dispatched at higher utilization rates to offset the drop in coal generation while reducing emissions. Near-term substitution of gas for coal is a familiar, ongoing trend in the U.S. electricity sector, partially due to relative fuel prices, and partially driven by policy goals. As seen in Fig. 4c, regional generation mixes increasingly consist of wind, solar PV, and nuclear electricity by 2050, with natural gas shares still sizeable but nevertheless decreasing. With a high carbon price at the end of the timeframe, gas-fired plants with CCS account for small generation shares in many regions, while geothermal capacity is added in NW, CA, and SW.

The Carbon Tax scenario is a boon for nuclear investment, which is 2.3 times higher in this setting than in the No Policy case. Wind capacity additions are 7% higher in the Carbon Tax scenario, but solar PV capacity additions are interestingly 9% lower. The latter outcome reflects the ability of increased nuclear capacity to provide substantial carbon-free baseload generation, as continuing to expand solar PV would require significantly higher storage investments. On the whole, the optimal solution in the Carbon Tax case includes more investment in battery storage and the transmission network compared to that in the No Policy case. Total storage additions are 4% higher under the Carbon Tax, and these investments are logically concentrated in regions where wind and solar PV contribute more than 50% of electricity in 2050 (see Figs. 4c and 5c). Cumulative transmission investments sum to 8231 GW-miles, which represents a one-third increase over the No Policy result. Additional transmission capacity helps maximize the utilization of carbon-free, intermittent, renewable electricity output by allowing it to satisfy demands in multiple regions. Fig. 5c reveals that the transmission links which are augmented in the Carbon Tax scenario are largely in the western U.S., used to import more renewable electricity into the high-demand CA and TX regions.

The carbon price successfully reduces CO$_2$ emissions far below the level reached in the No Policy case. Under the Carbon Tax, annual CO$_2$ emissions are 91% lower in 2050 than in 2016, a much larger decline than we observed in the No Policy scenario (53% reduction). Looking at the full timeframe from the base year through 2050, the Carbon Tax scenario leads to 48% lower cumulative CO$_2$ emissions than the No Policy case. The deeper GHG reductions achieved under the Carbon Tax come at a cost, but the cost appears to be fairly moderate given the extent of additional decarbonization. The total cost objective value is 13.5% higher than in the No Policy scenario.
Fig. 6. Comparison of cumulative capacity investments (a) and cost breakdowns (b) across the scenarios.

4.6. Scenario comparisons

4.6.1. Capacity investments

Fig. 6a compares the cumulative capacity additions over the full analysis timeframe across the four scenarios. Wind and solar PV capacities are expanded in all cases, though solar PV investment is more sensitive to the scenario than wind investment. Continued solar PV deployment will rely more heavily on further cost reductions, so its growth is noticeably dampened in the Pessimistic Costs scenario. Some nuclear capacity is added in every scenario, but nuclear growth is much stronger if either wind, solar PV, and battery costs decline less over time (Pessimistic Costs), or a carbon price penalizes fossil generation (Carbon Tax). New coal investments are relatively small in all cases, and nearly extinguished under the Carbon Tax. Natural gas capacity growth is significant and evidently robust to the particular scenario parameterization. Gas capacity has a relatively low capital cost, and can serve versatile roles ranging from providing affordable bulk generation with lower CO\textsubscript{2} emissions than coal, to backing up intermittent renewables when required to satisfy net load. Plants incorporating CCS are only deployed in the Carbon Tax case, as expected. The scale of total CCS investment, however, is not large. Total cumulative capacity additions are lower in the Pessimistic Costs scenario than in the other settings, because it features less solar PV (lower capacity factors) and more nuclear (higher capacity factor).
4.6.2. Costs

The total discounted present costs in each scenario are broken down into capital costs, O&M costs, and fuel costs in Fig. 6b. Capital costs are further decomposed into generation, storage, and transmission. As previously described, long-distance transmission expansion plays a minor role in all scenarios, and the associated capital costs are barely noticeable in the bar chart. The existing transmission network continues to be heavily utilized, but only limited transmission additions are economically justified, a finding similar to what Phillips and Middleton (2012) observed. Battery storage investments are larger, signaling an interesting trend in the electricity sector as less investment is allocated to transmission and more resources are invested in storage. However, capital costs for storage are still small compared to the total investment in the generation system. Capital costs for new generation capacity are greater in the Pessimistic Costs scenario, where intermittent renewable and battery costs decline less, and in the Carbon Tax scenario, which induces a swifter and more extensive transformation toward low- and zero-carbon technologies. In general, the results in Fig. 6b reveal that electricity sector expenditures over the next three decades will slant heavily toward capital costs, with fuels accounting for a smaller fraction of overall costs than in the past. This is particularly pronounced under the Carbon Tax, which leads to more deployment of capital-intensive technologies like nuclear, wind, gas plants equipped with CCS, geothermal, and battery storage.

4.6.3. Gas capacity utilization

Fig. 7b shows that natural gas capacity growth is significant and robust across the four scenarios, with 700-800 GW added from 2016–2050 in all cases. For much of the model timeframe, the Carbon Tax scenario actually induces the strongest expansion of gas capacity, due to its ability to substitute for coal in the short-run and to complement intermittent renewables in the long-run. Additional gas capacity helps a system with significant intermittent renewables cope with fluctuations in their output. However, as the 2050 time horizon is approached, the Carbon Tax case ceases to feature the most cumulative gas investment because the carbon price reaches very high levels and the costs of renewables and storage become increasingly competitive.

While gas capacity continues to be added, the average utilization rate of this capacity declines steadily through 2050, another outcome which holds across all scenarios. This is clearly visible in Fig. 7a. The average utilization rate falls from roughly 40–45% in 2016 down into the 5–10% range by 2050. Early on, gas capacity utilization is highest in the Carbon Tax scenario, reflecting coal-to-
gas switching due to the effect of the carbon price on economic dispatch. Soon, however, the Carbon Tax case exhibits the lowest gas utilization rate as gas plants assume more of a backup generation role due to the growth of nuclear, wind, and solar PV generation, as well as battery storage that offers an alternative strategy for balancing intermittency. The availability of gas capacity is still imperative for satisfying peak net loads plus reserve margins, but increasing variable renewable output with essentially zero marginal cost will continue to erode gas capacity utilization.

4.6.4. Growth of transmission and battery storage

Fig. 8a illustrates the timing of transmission and storage investments in the four scenarios. In all parameter settings, the model expands the transmission network early on, and finishes investing in transmission by 2035. Battery storage capacity, on the other hand, grows steeply later in the analysis timeframe once the costs of intermittent renewables and batteries have fallen considerably. The Carbon Tax case induces the largest capacity additions in transmission and storage, both of which help maximize the utilization of intermittent renewables. Interestingly, storage investments are nearly as high in the No New Transmission scenario. The inability to add transmission capacity makes storage more valuable as a way of coping with intermittency locally within a region, and also because storage allows for more complete utilization of transmission capacity by spreading electricity imports over time.
(a) Cumulative additions of battery and transmission capacities, by year

(b) Cumulative additions of battery and transmission capacities, with respect to renewables

Fig. 8. Cumulative additions of battery storage and transmission capacities in the whole continental U.S. with respect to time (a) and cumulative growth in intermittent renewable generation capacity (b).

Fig. 8b also plots cumulative transmission and storage capacity additions, but does so relative to the endogenous growth of wind and solar PV capacity on the x-axis. It shows that all scenarios produce similar transmission and storage expansion trajectories with respect to their growth in intermittent renewables. As renewable capacity increases, the transmission network initially grows quickly, but this relationship does not continue indefinitely and the growth of transmission capacity saturates. Battery storage, by contrast, continues to grow roughly linearly with the increase in intermittent renewables even as the latter reach progressively higher penetration levels. In general, our scenario analysis suggests that the contributions of long-distance transmission expansion to balancing intermittent renewable electricity are limited and confined to the short-run, whereas battery storage is the preferred strategy in the long-run.

Fig. 9 confirms that the electricity sector will devote more resources to expanding long-distance transmission in the short-run, but eventually shift to allocating investment to storage in the long-run. The scale of the total storage investment through 2050 is much larger than the scale of the total transmission investment. Of course, significant costs might be incurred in reality to expand transmission and distribution within each region, a level of spatial granularity that our model cannot be used to investigate.
4.6.5. Sensitivity analysis: Transmission capital cost and capacity additions

A notable outcome under all our scenarios is that new investments in the long-distance transmission network are insignificant relative to the broader electricity system transformation. Since the capital cost of building transmission in the future is uncertain, we test how sensitive our finding is to this assumption by reducing the capital cost of transmission below its $1000/GW-mile reference value and re-running the No Policy scenario. Fig. 10a shows how much total transmission capacity the model adds over the full analysis timeframe as a function of its assumed capital cost. These sensitivity results suggest that transmission would have to be many times cheaper, available at a cost unlikely to be plausible, in order for significantly more transmission capacity to be constructed. We thus conclude that the minor role of long-distance transmission expansion in the scenario results is robust to its capital cost.

4.6.6. Sensitivity analysis: CO₂ emissions reduction and total cost

Even in the No Policy scenario, annual U.S. electricity sector CO₂ emissions are 53% lower in 2050 than in 2016. In this sensitivity analysis, we specify increasingly stringent CO₂ reduction targets that must be reached by 2050, and explore how the corresponding total cost objective values rise as emissions are reduced toward zero. The allowed total CO₂ emissions are assumed to linearly decline over time from the initial 2016 level down to the specified 2050 target. Fig. 10b illustrates the percentage increase in total cost relative to the No Policy scenario as CO₂ emissions are reduced more and more. The relationship between emissions reduction and cost is approximately linear until about a 90% reduction (similar to the reduction achieved under our Carbon Tax scenario),
Fig. 10. Sensitivity analysis results showing how total transmission capacity additions respond to the capital cost of transmission (a), and how the increase in total cost (objective value) responds to the targeted percentage reduction in CO₂ emissions by 2050 (b). Note that the x-axis in (a) is logarithmic.

but begins to rise much more steeply after that. Eliminating the last remaining emissions is very expensive because it rules out the use of relatively low-carbon technologies like fossil generation equipped with CCS, biomass, and natural gas peaking plants, and essentially demands either enough battery storage to balance all intermittent renewables or a generation mix dominated by nuclear power. As Clack et al. (2017) suggest, it is extremely difficult to achieve complete decarbonization of the electricity system using currently available technologies, even if substantial decarbonization can be achieved at fairly moderate cost.

5. Conclusions and policy implications

In this study, we developed a least-cost optimization model of the integrated U.S. electricity generation and transmission system, and used it to study the evolution of U.S. electricity infrastructure through 2050. The model is a customized and expanded version of the OSeMOSYS framework (Howells et al., 2011) with 13 regions. We applied this model to run and compare results from four main scenarios as well as additional sensitivity analyses.

As with any model, our framework has limitations. The sheer scope of the analysis requires considerable temporal and spatial aggregation that limits its applicability to issues that are highly
resolved in space or time. For example, our model cannot shed light on the value of transmission and
distribution investments at scales smaller than each of our 13 regions, or complications associated
with ramp rates on time scales less than one hour. The optimization paradigm assumes perfect
foresight of future parameter values and seamless coordination across regions governed in reality by
many different decision makers. Therefore, the pathways produced by the model should be viewed
as idealized transformations of the U.S. electricity system rather than predictions of how it will
evolve. Parameter assumptions become more uncertain as the analysis progresses toward its 2050
time horizon. While we have performed scenario and sensitivity analyses to explore how model
outcomes vary with specific important assumptions, there are many other parameters in the model
whose assumed values are highly uncertain. Despite these limitations, we have compared results
across a number of different parameterizations to obtain policy-relevant insights about the future
of U.S. electricity infrastructure. The following subsections clearly assert what we view as the five
key takeaways from our analysis, and discuss their policy implications.

5.1. The U.S. electricity sector can be substantially decarbonized at modest cost, but complete de-
carbonization is very costly

In our scenario results, U.S. electricity sector CO₂ emissions in 2050 are 53% below their 2016
level even without a policy stimulus. This reflects the rapidly declining costs of renewable and
storage technologies. Additional emissions reductions can be achieved at fairly moderate cost. For
instance, annual CO₂ emissions can be reduced by 80% from 2016 to 2050 with only a 9% increase
in total present discounted costs (see Fig. 10b). However, beyond a 90% reduction, marginal
abatement costs rise very steeply. We find that complete decarbonization of U.S. electricity by
2050 would raise total costs by 69% relative to the No Policy case. It is not surprising that costs
escalate significantly as the last remaining CO₂ emissions are eliminated. Complete decarbonization
rules out low-carbon technologies like fossil generation with CCS, and requires massive investments
in electricity storage to ensure reliability.

To put the high cost of reducing the last few percent of CO₂ emissions in perspective, it is
instructive to compare this cost to mainstream estimates of the social cost of carbon (SCC), which
quantifies the benefits of reducing emissions in monetary terms. In terms of cumulative CO₂
emissions from 2016–2050, raising the 2050 emissions reduction target from 97.5% to 100% entails
an average abatement cost of $2108/tCO₂ for eliminating the last 2.5% of emissions. This figure
is an order of magnitude greater than even the high end of currently accepted SCC estimates
(Nordhaus, 2017).

Overall, our findings indicate that U.S. electricity will undergo significant decarbonization, and that policies to reduce annual emissions by 80–90% by 2050 are achievable at moderate cost. Targeting complete decarbonization, however, would sharply increase costs and does not appear to be justified on economic grounds when comparing marginal abatement costs to the SCC. Therefore, while policymakers should strive to encourage substantial decarbonization of electricity, pursuing a zero-emissions electricity sector under current technology cost projections would risk major increases in electricity costs that could engender more resistance to mitigation efforts.

5.2. Significant expansion of renewable generation is fairly certain, although solar PV and battery storage are more affected by economic and policy assumptions than wind

Renewable technologies expand considerably through 2050 regardless of the scenario, but solar PV and battery storage growth are more sensitive to assumptions than wind deployment. Furthermore, future technology costs appear to be stronger drivers of renewables expansion than climate policy. Compared to the No Policy setting, the Carbon Tax scenario does not increase renewable capacity and generation as much as the Pessimistic Costs scenario decreases them. While wind and solar PV still grow in the latter case, their cumulative capacity investments are 40% lower in the Pessimistic Costs scenario than in the No Policy setting. Most of this difference is attributed to lower solar PV deployment, with wind less affected. Wind is a more mature technology than solar PV and its future growth is less dependent on further cost reductions. In addition, with its more extreme diurnal capacity factor variations, solar PV expansion relies more heavily on falling battery storage costs, which also decrease less in the Pessimistic Costs scenario.

The increase in CO₂ emissions in the Pessimistic Costs case is limited because nuclear power offsets most of the decline in wind and solar generation. This suggests that nuclear can be a reasonably cost-effective, carbon-free substitute for intermittent renewables and storage if costs develop as projected by NREL (2017a). This is far from guaranteed, but the results do demonstrate that extensive decarbonization of U.S. electricity is robust to the costs of any one technology, as long as other economically competitive mitigation options exist. Policymakers should thus maintain a broad portfolio of low- and zero-carbon electricity supply technologies to ensure that higher-than-expected future costs of any one technology do not induce a major increase in emissions.
5.3. Investments in long-distance transmission are very limited, while investments in battery storage are significant, under a wide range of assumptions

In contrast to some other studies (MacDonald et al., 2016), we find that expansion of the long-distance transmission network does not play a major role in future electricity infrastructure pathways. The scenario results show that, due to rapidly falling wind, solar PV, and battery storage costs, investing in renewable generation closer to the loads it serves is generally more economical than installing renewables further away to take advantage of higher capacity factors, but needing to install new transmission capacity. Our model results thus support Lovins (2017), who essentially advanced this same argument. The diminishing importance of long-distance transmission should come as a relief to policymakers, since siting and approval of inter-state transmission projects has been politically challenging due to public opposition and having to navigate multiple complex regulatory environments (Vajjhala and Fischbeck, 2007; Zichella and Hladik, 2013).

On the other hand, battery storage investments are much greater and accelerate over the next several decades. Given the considerable value that storage offers to the electricity system, policymakers should ensure that market mechanisms fully compensate storage providers for the many valuable services it can provide. As Sioshansi (2017) describes, storage owners must often decide whether to earn revenue through competitively priced services (e.g., energy arbitrage) or services subject to rate-based cost recovery (e.g., transmission deferral) since they are not allowed to be compensated for both sets of activities. As a result, the range of valuable services that storage can provide is constrained, which discourages storage investments. Market design solutions to this artificial separation of competitive and regulated services have been proposed, such as auctioning storage capacity rights to third parties (Sioshansi, 2017), and their effective implementation will become more important as the need for storage intensifies.

5.4. Natural gas capacity growth is strong and robust, but utilization of gas capacity declines steadily and significantly

Our results consistently show that large investments in natural gas capacity continue to be part of the optimal system transformation, but that average utilization rates of this gas capacity decline steadily and significantly through 2050. Utilization drops as intermittent renewables expand and continue to be dispatched whenever available. Cost-effective storage improves utilization of wind and solar generation, which further erodes the utilization of gas-fired power plants. However, gas capacity is still required to maintain reliability during hours of high demand and low variable
renewable output. This constitutes another market design challenge for policymakers, who must have mechanisms in place to properly remunerate natural gas generation facilities for the reliability services they provide. There is some doubt as to whether the high wholesale electricity prices available during a few peak net load hours when power is scarce will allow gas plants to recover their costs in energy-only markets such as the Electric Reliability of Council of Texas and the Southwest Power Pool (Ela et al., 2015). Capacity markets and creative approaches for rewarding flexible, dispatchable capacity (such as the flexible ramping product introduced by the California ISO) can help overcome the missing money problem and ensure resource adequacy (Brown, 2018; Hobbs and Oren, 2019; Newbery, 2016). Policymakers should actively learn from successes and failures in other jurisdictions and adopt market design approaches that incentivize sufficient capacity investments.

5.5. Electricity system costs shift away from operating expenditures and toward capital expenditures over time, especially in the presence of climate policy

As fossil fuel generation gives way to renewables, storage, and nuclear power in a decarbonizing electricity system, costs will shift away from operating expenditures and toward capital expenditures. This trend makes access to financing critical and threatens to extend payback periods, which could be at odds with one another in an increasingly competitive electricity landscape where market-based prices present considerable risk. Investment is increasingly directed toward renewable and natural gas projects that are smaller than traditional coal and nuclear units (Rhodes, 2018), a shift that helps manage project risk. This investment trend is currently well aligned with emissions reduction goals. In the future, however, if less granular technologies like fossil plants with CCS or nuclear power are expected to form part of the decarbonization portfolio, then policymakers might need to help insulate these capital-intensive projects from risk in competitive market areas. This would become more important if wind, solar PV, and battery storage costs do not decline as much as anticipated.

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