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# Emissions Benefits of Electric Vehicles: Influencing Electricity Generation Choices

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CONTENTS



## Executive Summary

Electric vehicles (EVs) represent a new source of electricity demand and their market share is expanding at a fast pace. Over the next several decades, these vehicles may well become a driving force in the economy with the potential to significantly increase total electricity requirements in the United States—at a time when more traditional sources of demand in aggregate are expected to grow less than one percent a year. How electricity is generated for these vehicles will, to a large degree, determine their net emissions benefits and their value in meeting any long-term climate and environmental goals.

These vehicles are entering the marketplace at a time when the electricity industry is already transforming rapidly because of changes in fuel prices, environmental regulations, and declines in the costs of renewables. The last decade has seen substantial coal-plant retirements, nuclear plants on the edge of profitability, cheap natural gas from shale fields, and the construction of many new gas combined-cycle (NGCC) and wind and solar photovoltaic (PV) plants. In this shifting environment, focusing on today's generation mix is not particularly useful when estimating the emissions benefits of electric vehicles.

What matters at this juncture is how the electricity industry will have to evolve in order to generate the additional electricity needed to supply vehicles in the future (potentially at times of the day that are different from current demands). While it would be hard to do a "real-world" experiment to determine what types of generation are being constructed specifically to supply EVs, the detailed dispatch models often used by the utility industry to evaluate future trends can perform precisely this type of thought experiment. Future scenarios with and without electric vehicles can be analyzed to estimate the incremental generation needed to provide for this new source of demand. Model results can be used to determine how sensitive future pathways are to fuel prices, policies, construction costs, and the numbers of vehicles on the roads.

This paper does not evaluate the potential of electric vehicles to displace conventional vehicles, the rate at which this transformation may take place, or how/when/where EVs are likely to charge.[1] These assumptions are taken from other studies that have looked at these questions in great detail. Instead, the focus of this paper is strictly on estimating the types of incremental generation that are likely to supply electricity demand from vehicles, how policies and market conditions might influence these choices, and the resulting net emissions benefits of EVs across a range of possibilities. The analysis also does not examine how electrification in sectors of the economy other than light-duty vehicles might affect demand.

External forecasts of vehicle choices at the state/regional level, including sales, vehicle miles traveled (VMT), and fuel use, are taken from EIA's Annual Energy Outlook (EIA 2019a) and the National Renewable Energy Laboratory's (NREL) Electrification Futures Study (NREL 2018b). Several possible scenarios from these studies are examined:

- AEO 2019 Scenario: projections from the Annual Energy Outlook 2019 (AEO), where EVs reach a 14 percent share of total VMT by 2050
- NREL Scenarios: the light-duty vehicle component of the NREL Electrification Futures Study
- NREL Medium Scenario – EVs are 64 percent of total VMT by 2050
- NREL High Scenario – EVs are 83 percent of total VMT by 2050
- Intermediate Scenario: halfway between AEO and NREL Medium (EVs are 36 percent of VMT in 2050)

To evaluate the potential generation impacts of these scenarios, the analysis uses the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), which includes a detailed electricity dispatch model of U.S. wholesale electricity markets, and builds on work done with the DIEM model regarding technology adoption and interactions with climate-related policies (Ross 2018; Ross and Murray 2016; Murray et al. 2015). The model represents intermediate- to long-run decisions of the industry regarding generation, transmission, capacity planning, and dispatch of units. To estimate impacts, it minimizes electricity generation costs while meeting electricity demand and environmental policy goals. For this analysis, seasonal electricity demands are represented using 24 hourly blocks within each season in order to examine implications of the timing of EV charging.

Market forces with the largest impacts on generation tend to be those related to natural gas prices and costs of building renewables. To investigate how these conditions may affect technology choices for the different EV pathways, the modeling starts with the AEO 2019 Reference Case ("Ref") assumptions for natural gas prices and contrasts these results to AEO low gas-price and high gas-price futures. The analysis also compares the model's standard reference assumptions on wind and solar PV costs from the NREL Annual Technology Base (ATB) medium-cost case with a low-cost renewables scenario based on the ATB low-cost case (NREL 2018a). Note that the external forecasts for EV penetration are relatively aggressive, which may more analogous to a future with optimistic forecasts for renewables costs.

Possible extensions of federal tax credits for wind and solar generation (production tax credits, PTC, and investment tax credits, ITC) are modeled to see how policy choices might affect new generation built to supply EVs, compared to current rules under which the credits expire within the next several years. Four possible hourly charging patterns for EVs are

[1] The analysis of generation also does not consider potential electrification in other sectors of the economy. Additional electrification would enhance some trends found in this analysis and could potentially alter other trends if the nature and timing of vehicle electricity demands are different from other new sources of demand.

compared. And finally, the DIEM model estimates how the electricity sector might evolve if carbon prices are combined with the different EV pathways.

## HIGHLIGHTS

Excluding electricity demand from light-duty vehicles, demand growth is forecasted to grow by less than 0.7 percent per year through 2050 (EIA 2019a). Depending on which pathway for EVs is realized, they may increase electricity demand between 3 percent and 22 percent by 2050, which can cause significant shifts in the generation mix of the industry. The modeling suggests the following broad conclusions about how vehicle demands may affect electricity-generation choices and the resulting emissions:

- Emissions benefits of electric vehicles: Across all the scenarios investigated for different levels of EV adoption and various market conditions, meaningful net reductions in $CO_2$ and $NO_x$ emissions occur. Emissions reductions from replacing on-road internal-combustion engine (ICE) vehicles with electric vehicles dwarf any potential increases in generation emissions. Benefits increase over time as EV numbers rise and as renewables form a larger share of generation.
- Role for policy interventions in generation: Net emissions benefits of EVs can be increased significantly by continuing current tax credits for renewables or by putting even a small price on the carbon content of fossil fuels used for generation. Extension of current federal tax credits for renewables could lead to wind and solar providing all the incremental electricity needs of vehicles.
- Construction of new generating units: In the absence of new policies, over the short to medium term (less so in the long term), electricity demand from EVs may be supplied through new NGCC units. This finding tends to be driven by the low natural gas prices in the AEO 2019 forecasts.
- Generation by renewables: Over time, renewables play an increasing role in providing the electricity needed by vehicles. In the modeling, solar PV tends to contribute more than new wind. A significant shift into renewables and out of NGCC generation can be assisted by the policy interventions or additional declines in renewables costs beyond those in some forecasts.
- Operation of existing units: Depending on the policy setting, electricity demand from vehicles has the potential to keep existing nuclear plants in operation. The same can be true for coal plants in a setting without any environmental policy responses.
- Natural gas prices: Alternative price forecasts can shift the generation mix overall, regardless of EVs. However, the changes in generation that occur in response to new, incremental vehicle demands are relatively insensitive to gas prices. Gas prices do affect the ability of renewables to compete with NGCC.
- EV charging patterns: Different assumptions about the timing of charging can have important impacts on generation choices. Cheap wind and solar will accentuate these impacts.

This analysis focuses on generation impacts and emissions outcomes, rather than the costs of supplying electricity, because the driver of the estimated impacts—electricity demand from vehicles—comes from external forecasts, and data are not available on the full economy-wide costs—or cost savings—associated with replacing conventional vehicles with electric vehicles. Thus, we were unable to develop a complete picture of net costs—or savings—that includes all the changes to generation, electricity demand, vehicle costs/savings, and impacts of changes in the vehicle fleet on the rest of the economy.

## SUMMARY OF NATIONAL FINDINGS FOR GENERATION AND EMISSIONS

While it is important to consider the total generation mix when evaluating how the industry will be positioned to respond to future market conditions and environmental policies, what is relevant for a discussion of electric vehicles is the incremental generation sources that may supply EV demands and where any related, new construction may occur.[2] It is

[2] The NREL EFS forecasts of electric vehicle adoption are available at a state level (NREL 2018b), which allows the modeling to consider how the

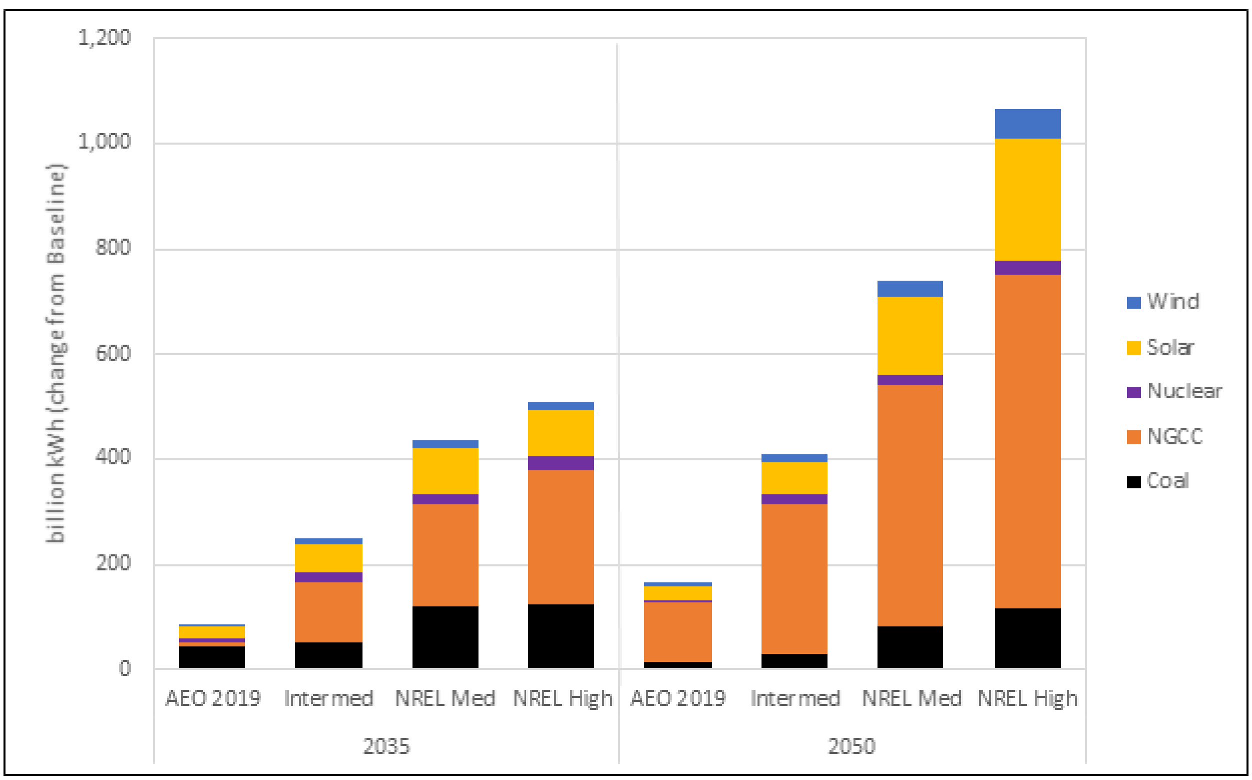
also important to note that which options are available—and cost effective—in the future to supply EV demand depend on what options have already been built to supply demand from other sectors of the economy.

If, for example, all of the cheap locations for siting wind turbines have been used to supply needs in other sectors of the economy, regardless of the level of electric-vehicle utilization, the number of EVs on the road won't have much effect on new wind generation. On the other hand, some generation options such as nuclear plants are facing difficulties in today's low demand-growth environment. In their case, if it appears that new sources of demand from vehicles are going to materialize, nuclear plants may be more likely stay in operation (the same may also hold true for coal plants currently considering retirement).

Using the initial model assumptions, Figure ES-1 looks at how the different levels of electricity demand across four possible EV pathways will increase incremental generation above the levels in a standard baseline case at the national level.[3] Adding AEO 2019 levels of EV utilization from the scenario list above into a DIEM model baseline without EVs increases electricity demand, and thus generation, by a few percentage points. Over the next three decades, this modest increase in electricity demand is met in the medium term by operating existing coal plants and building new solar PV, and in the longer term by additional gas generation.

For this specific set of reference model assumptions about future market conditions, in the scenarios with higher adoption rates for EVs (from Intermediate EV levels through NREL High), NGCC units continue to supply a significant share of the incremental generation needs. However, the larger electricity-demand growth encourages existing coal plants—and to a less extent, existing nuclear—to remain in operation, rather than retire as they did in the model baseline without any assumed demand from EVs. Along with these fossil and nuclear units, new solar PV plays an increasing role and some wind is encouraged, particularly by nighttime EV charging. The relative shares of new generation change across the demand levels, but—for this set of assumptions about the future—new natural gas is always the largest source supplying EV demands.

**Figure ES-1. DIEM Estimates of Incremental U.S. Generation to Meet Demand from EVs**




location of new demands matches existing generation technologies and potential new options.

[3] The model baseline uses AEO 2019 reference assumptions about natural gas prices and NREL medium-cost renewables.

Given that the model results shown in Figure ES-1 raise the possibility that demand from electric vehicles could encourage fossil fuel generation, including existing coal plants and new NGCC plants, the question becomes how broadly do these incremental generation results hold across alternative assumptions about future market conditions and what policy options might alter this outcome, assuming lower-emitting generation mixes are considered desirable. To address these issues, it is first helpful to examine how overall generation emissions respond to different assumptions about the future and, subsequently, to look at the range of estimated net emissions benefits from EVs.[4]

Unless the incremental new demand from electric vehicles is supplied completely by renewables—which is not the case in Figure ES-1, emissions from the electricity sector of the economy will increase. Before looking at how on-road emissions are reduced as EVs enter the transport sector of the economy, and how net emissions benefits across the two sectors are affected, Figure ES-2 presents model estimates of total CO2 emissions from electricity generation in 2050, along with how four sets of assumptions about market trends and policies may affect those emissions estimates (emissions reductions from displaced ICE vehicles are not included in the figure, just any emissions changes within the electricity sector).

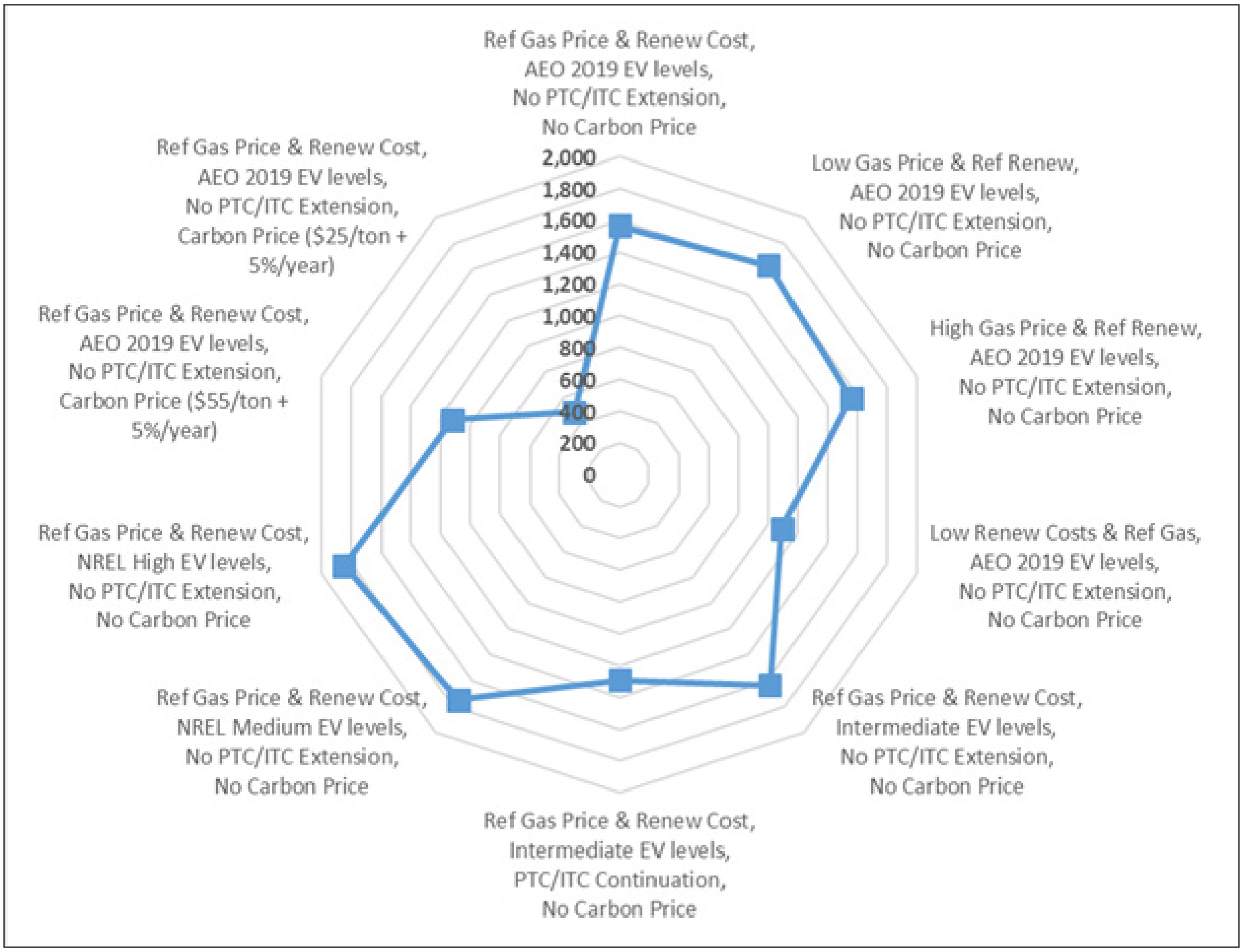
The first line of each scenario label in the figure states whether reference levels for natural gas prices and renewables costs are used in determining emissions results or if low/high prices and costs are used. The next line indicates the EV scenario under consideration: AEO 2019, Intermediate, or one of the two NREL options. The third line in the label says whether or not current tax credits for renewables (PTC and/or ITC) are extended. Lastly, the fourth line shows if there is no carbon price in the electricity sector (outside of existing state policies that result in a price today) or if a carbon price is used ($5 per ton or $25 per ton starting in 2025 and growing at 5 percent per year in real terms—$17 per ton or $85 per ton by 2050, respectively).

At the top of Figure ES-2, reference assumptions for prices, costs, and modest penetration of EVs in the AEO 2019 scenario—and no new environmental policies—result in emissions from generation of around 1,500 MMTCO2 in 2050, or 10 percent lower than they are today. Moving clockwise around the figure, different assumptions about natural gas prices have little effect on emissions by 2050 (emissions in intervening years can vary substantially as shown in the main section of modeling results). This happens because low gas prices encourage new NGCC units and lead to retirement of existing coal plants, but also tend to force out existing nuclear plants and discourage construction of new renewables. Conversely, high gas prices lead to less NGCC generation and more nuclear and renewable generation, but also help keep existing coal plants in operation.

As was implied by the generation results in Figure ES-1, the higher levels of electricity demand from vehicles in the Intermediate and NREL Medium/High scenarios can lead to somewhat higher emissions from generation. However, low renewables costs, whether from technological advancements leading to lower construction costs or a continuation of current PTC/ITC tax credits, can significantly reduce emissions from generation. Finally, carbon prices have the most dramatic impact on $CO_2$ emissions in 2050; the $5/ton+5 percent/year scenario ($17/ton by 2050) reduces emissions by around 30 percent compared to the forecast, and the $25/ton+5 percent/year scenario ($85/ton by 2050) reduces emissions by 70 percent (reductions of these general magnitudes occur regardless of the amount of EVs on the road).

[4] The main section of the paper shows the specific generation changes that correspond to these emissions changes from EVs.

**Figure ES-2. DIEM Model Estimates of CO2 Emissions from Electricity Generation in 2050 (MMTCO2)**




A full evaluation of the environmental impacts of electric vehicles requires more than looking at any emissions increases from generation; it also involves looking at the reductions in on-road emissions as EVs displace conventional internal-combustion-engine (ICE) vehicles. Although $CO_2$ emissions from generation may rise as the sector supplies electric vehicles, the modeling estimates that any such emissions increases are more than offset by the declines in on-road emissions as conventional ICE vehicles are displaced by the EVs and consumption of gasoline and diesel fuels declines. Thus, the next figure expresses emissions as "net benefits" that combine changes in generation emissions with reductions in emissions estimated from the NREL (2018b) scenarios to get net impacts of EVs.[5]

Figure ES-3 shows these annual net $CO_2$ benefits in 2050 across three different EV scenarios related to vehicle miles traveled (the three lines in the graph) and across different assumptions about the future of the electricity industry (the points around the circle on each line). As before, the top of each scenario label around the circle states whether reference levels for natural gas prices and renewables costs are used in determining emissions results or if low/high prices and costs are used. The second line refers to a specific EV charging pattern: "Charging at Home" is from a NREL (2018c) study of residential charging behavior; "Charging at Home/Public" is from a California Energy Commission (2018) study of charging behavior in support of their infrastructure planning; a hypothetical "(mostly) Night" charging pattern is adapted from a EPRI (2007) paper in which the charging pattern split the charging hours between overnight hours when wind is peaking and, to a lesser extent, mid-day hours when solar PV is peaking; and a "(mostly) Day" pattern that is the reverse of the "(mostly) Night" option and concentrates EV charging during daylight hours.

Starting with the scenario label at the top of Figure ES-3, these net emissions benefits are based on the model assumptions regarding fuel prices, renewables costs, and policies that led to the NGCC and coal generation increases shown in Figure

[5] NREL (2018b) provides estimates of state-level reductions in gasoline and diesel use by vehicles to go along with the estimates in state-level increases in electricity demand from vehicles. These changes in fossil-fuel use are converted into their corresponding changes in $CO_2$ emissions.

ES-1. The analysis suggests that, even for this set of assumptions that led to increases in fossil generation, electric vehicles still provide net $CO_2$ emissions benefits of around 600 $MMTCO_2$ per year by 2050 for the NREL High EV scenario, around 400 $MMTCO_2$ per year for the NREL Medium scenario, and around 200 $MMTCO_2$ for the Intermediate scenario. Next, moving clockwise around the figure from the top, the following three scenario labels show variations across assumptions about charging behavior. The "Charging at Home" pattern, which has a relatively high percentage of mid-day charging (see Figure 6), has higher net benefits than the "Charging at Home & Public" or "Charging (mostly) at Night" options since wind generation has some difficulties competing with the relatively cheap natural gas prices in the AEO 2019 forecasts. The "Charging (mostly) during Day" pattern has the highest net benefits due to its encouragement of solar PV.

Moving clockwise farther around the circle, the next modeling scenario assumes low natural-gas prices (these emissions benefits can be compared to those farther up the circle to evaluate the impact that gas prices have on the emissions outcome). Low natural-gas prices in generation can lead to smaller net benefits from EVs as the cheap natural gas tends to crowd out renewable generation. Conversely, a high natural-gas price leads to higher net benefits from EVs as the high price encourages renewables. The Low Renewable Cost scenario has net benefits similar to those seen in the high natural-gas price scenario (recall that, as was shown in Figure ES-2, the low-cost renewables case also has some of the lowest total $CO_2$ emissions).

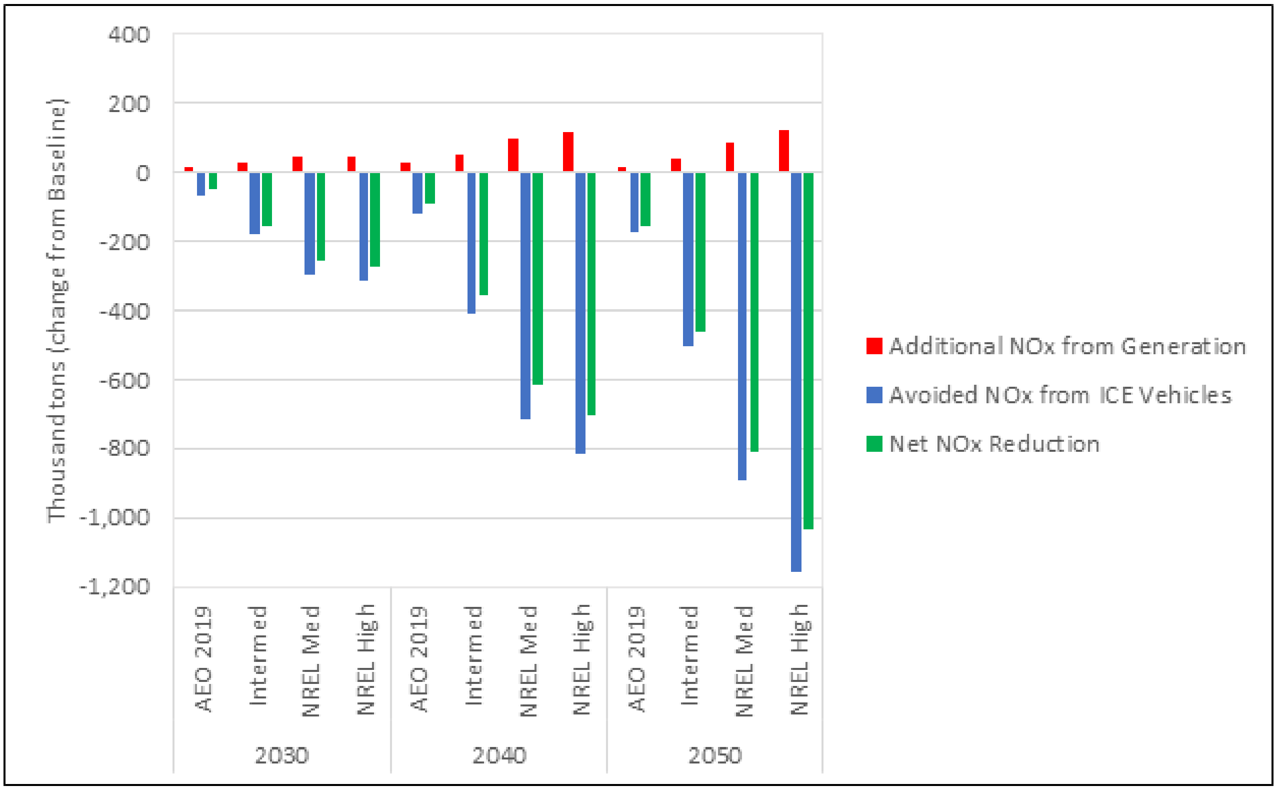
The final three scenario labels around the circle show net emissions benefits if EV adoption is combined with policies that encourage low- or zero-emitting generation; either a continuation of subsidies for wind and solar generation, or a small carbon tax ($34/ton by 2050 in this "$10/ton+5 percent case). The PTC/ITC continuation nearly doubles the net emissions benefits in the EV scenarios. The timing of EV charging continues to play a role in determining the net benefits as the total amount of renewables increases with these policies. The small carbon tax provides emissions benefits roughly comparable to those from the renewables policies. Although not shown for scaling reasons, higher carbon prices provide continually increasing net benefits: the "$25/ton+5 percent" scenario achieves net annual reductions of 1,270 $MMTCO_2$ by 2050 for the Intermediate scenario, and up to 1,670 $MMTCO_2$ for the NREL High scenario.

Overall, every EV scenario has net emissions benefits across all the model assumptions investigated. The levels of those benefits depend mostly on a combination of the number of EVs on the road and whether policies are enacted to continue encouraging renewable electricity generation. Similar figures could be drawn for the other years in the analysis and these patterns would hold, though net benefits are lower in the earlier years when fewer electric vehicles are on the road and renewables form a somewhat smaller share of total generation.

**Figure ES-3. DIEM Estimates of Net Annual $CO_2$ Emissions Benefits of EVs in 2050 ($MMTCO_2$)**

Along with changes in $CO_2$ emissions, EV adoption will affect generation emissions of both nitrogen oxides (NOx) and sulfur dioxide ($SO_2$) and the on-road emissions of NOx from vehicles. Figure ES-4 shows the increase in NOx from electricity generation in red for the scenarios from Figure ES-1, and contrasts that with avoided NOx emissions from the ICE vehicles that have been replaced by electric vehicles.[6] The findings suggest that avoided emissions from ICE vehicles are between 4 and 14 times larger than the NOx increases from additional generation, leading to significant net reductions. This pattern holds across all of the alternative modeling assumptions investigated in the paper. (Changes in $SO_2$ emissions are discussed in the main results section of the paper.)

**Figure ES-4. DIEM Approximations of Changes in NOx Emissions from Vehicles and Electricity Generation**



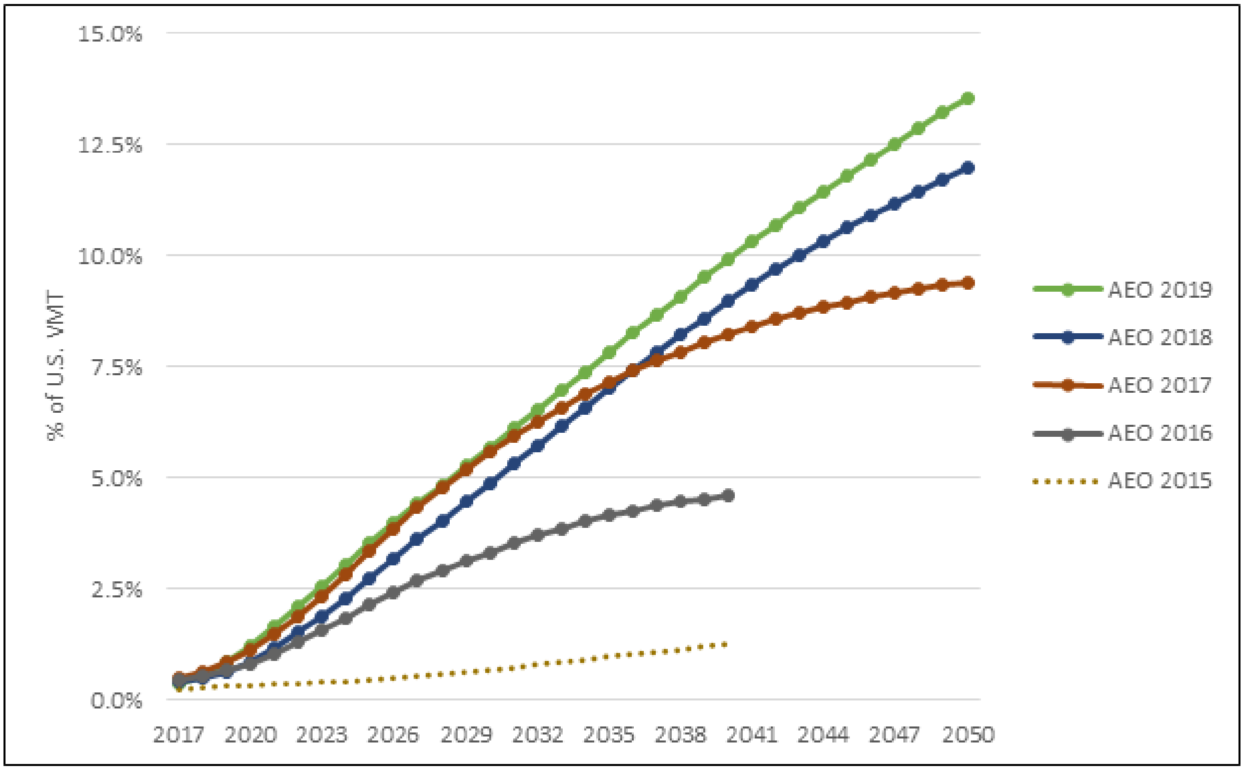

The next sections in this paper provide background on the electric-vehicle scenarios and charging patterns used in this analysis, discuss the DIEM model structure and assumptions in more detail, define the policy scenarios investigated, and examine the model findings for baseline generation without EVs and contrast that to the changes in the industry needed to provide electricity demanded by vehicles.

## *Background on Electric Vehicle Scenarios*

Sales of light-duty electric vehicles have grown rapidly over the last decade; annual growth rates have ranged between 24 percent and 200 percent per year (excluding a small decline in 2015) and the growth rate in 2018 was 81 percent as the Tesla Model-3 and other new models entered the marketplace (EV-Volumes.com 2019). The rapid, and variable, evolution of the market has made forecasting any future trends difficult. Over the last five years, the U.S. EIA (2019) has revised their forecasts significantly between releases of the Annual Energy Outlook (AEO). Figure 1 shows how expectations of miles traveled by electric vehicles as a share of total U.S. light-duty vehicle miles traveled (VMT) have changed. In 2015, forecasts were that the EVs would represent less than 1 percent of total VMT in 2040. By the AEO 2016 forecast, this had increased to close to 5 percent, and in the AEO 2017 the EV share reached 8 percent of total light-duty VMT. The most recent AEO 2019 expects EVs to comprise 14 percent of total VMT by 2050.

[6] Vehicle VMT from NREL (2018) have been combined with estimates of NOx emissions rates of conventional vehicles from California ARB (2005) to approximate the reductions in ICE NOx emissions.

**Figure 1. Electric Vehicles as Percentage of Total U.S. Light-Duty Vehicle Miles Traveled (AEO Forecasts)**




*Source:* Author's calculations based on U.S. Energy Information Administration forecasts (U.S. EIA 2019).

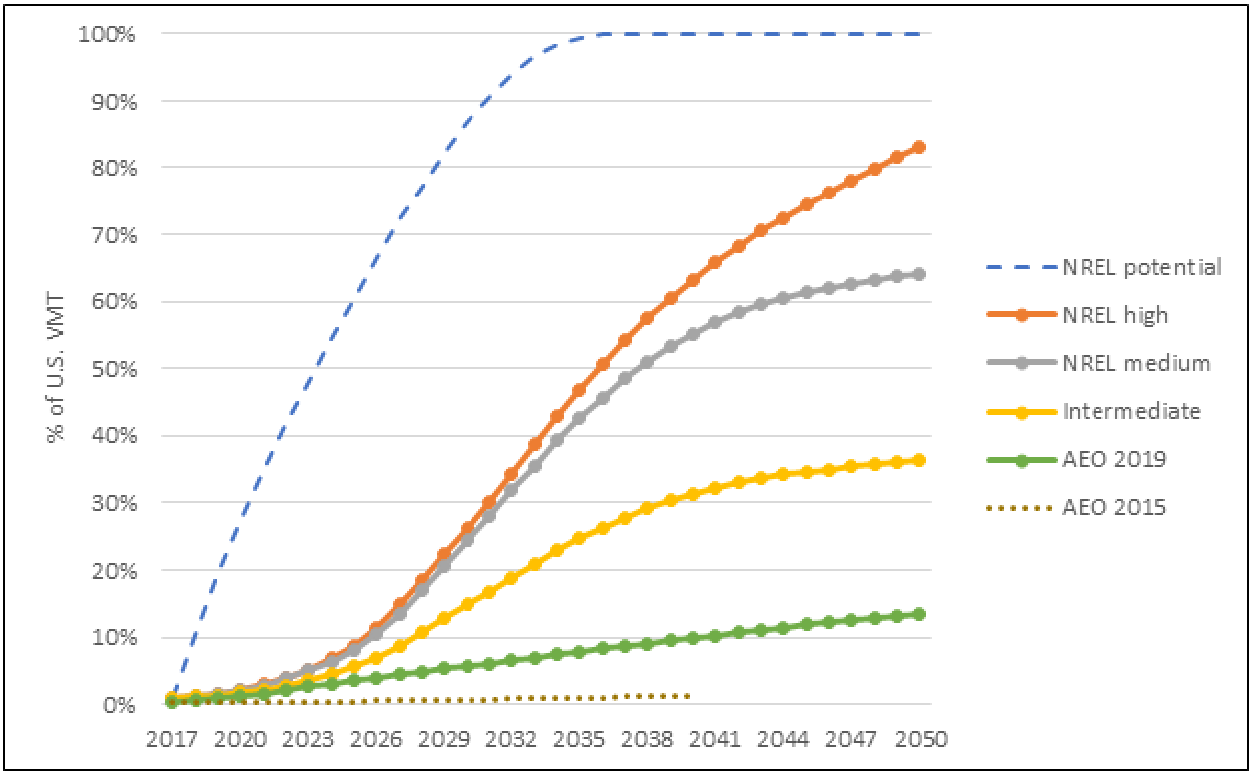
The National Renewable Energy Laboratory (NREL 2018b) is conducting an Electrification Futures Study (EFS) that looks at scenarios of electric technology advancement and adoption across the whole economy. The analysis in this paper focuses specifically on their forecasts for light-duty electric vehicles:[7]

- "NREL Reference"—As a starting point, NREL developed a reference scenario that is generally based on the AEO 2017 (this scenario is not used on the modeling analysis in this paper).
- "NREL Medium"—This scenario assumes widespread electrification among "low-hanging fruit" opportunities in EVs (and other technologies), but without "transformational change."
- "NREL High"—This scenario is based on combining technology advancements, policy support, and consumer enthusiasm to facilitate transformational change in electrification.
- "NREL Potential"—This scenario illustrates an extreme bounding case in which all vehicles sold are electric (this scenario is included in these comparison graphs, but is not used on the modeling analysis in this paper).

The NREL study and modeling provide data at the state level on electric vehicle sales, stocks, vehicle miles traveled, and energy consumption. Figure 2 converts these data into forecasted EV shares of total light-duty VMT and contrasts these scenarios with the AEO forecasts. An Intermediate scenario is also added in this analysis, which represents the mid-point between the NREL Reference and NREL Medium forecasts. In contrast to the AEO 2019 that has a 14 percent EV share of VMT by 2050, the NREL Medium forecast for EVs reaches 64 percent of U.S. VMT and the NREL High forecast reaches 83 percent of VMT.

[7] NREL EFS (2018b) includes all sectors of the economy in their examination of electrification including medium-duty and heavy-duty vehicles, buildings, and industry technologies.

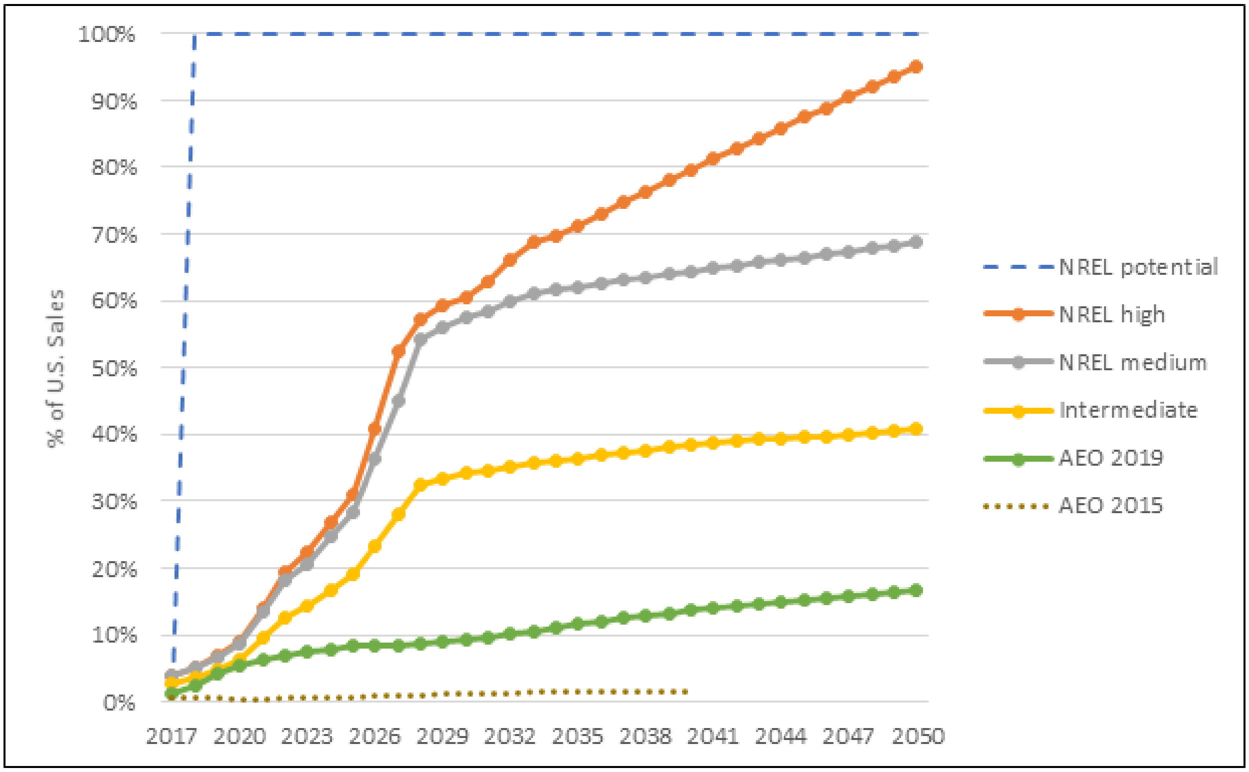
**Figure 2. Electric Vehicles as Percentage of Total U.S. Light-Duty Vehicle Miles Traveled (NREL Scenarios)**




*Source:* Author's calculations based on NREL (2018b) and U.S. EIA (2019).

Given the assumption in NREL's modeling that the light-duty vehicle stock takes around 20 years to fully turn over, EV sales increase fairly rapidly over the next decade in NREL's estimates of VMT by EVs on the roads (Figure 3), although these increases are not out of line with what has been seen in the last several years. At the other end of the recent forecasts, the AEO 2019 projects that electric vehicles reach 10 percent of all vehicles sales by 2030, starting from a 2.1 percent share in 2018 (a growth rate of only 14 percent per year compared to the growth rate of 81 percent that occurred between 2017 and 2018—EV-volumes.com 2018). The NREL Medium and High scenarios have EVs as close to 60 percent of all sales in 2030, an increase in their share of around 32 percent per year. After 2030, the NREL scenarios move to more linear growth through 2050.

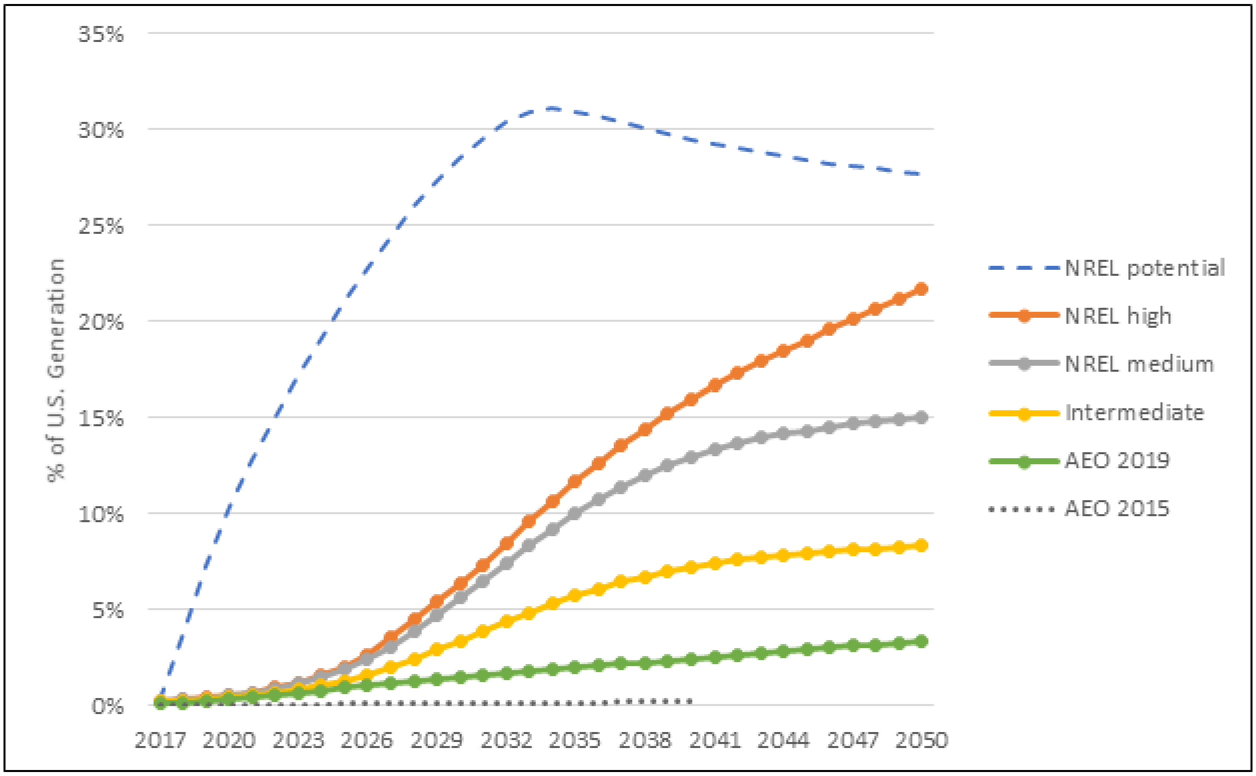
**Figure 3. Electric Vehicle Sales as Percentage of Total U.S. Light-Duty Vehicle Sales**




*Source:* Authors' calculations based on NREL (2018b).

The NREL and AEO forecasts also provide the energy-consumption forecasts for the electric vehicles (and fossil-fuel consumption by conventional ICE vehicles) that are needed for this analysis of generation. Figure 4 shows that the AEO 2019 forecast of electricity use by EVs represents 3.3 percent of total economy-wide electricity consumption in 2050. By contrast, the NREL Medium scenario implies that EVs would increase electricity demand by 15.1 percent in 2050, and the NREL High scenario would raise demand by 21.7 percent. Changes in electricity demand of these magnitudes has the potential to cause significant shifts in how (and when) electricity is produced.

**Figure 4. Electricity Demand from Light-Duty Vehicles as Share of U.S. Baseline Generation**




*Source*: Author's calculations based on NREL (2018b) and U.S. EIA (2019)

How vehicle charging patterns correlate with renewable availability will determine what types of generation can be used to supply electric vehicles. Figure 5 illustrates average hourly U.S. availability of wind power and solar PV in the summer (USEPA 2019). These hourly patterns can be compared to Figure 6, which shows four possible hourly charging patterns from the literature:

- "Home" charging: this hourly pattern is aggregated from detailed 10-minute data on residential EV charging behavior from NREL (2018c). The pattern aggregates Level 1 and Level 2 charging and shows the average pattern across a summer season (May through September). Note that charging at home is generally assumed to represent 80–88 percent of total personal EV electricity use.
- "Home & Public" charging: this hourly pattern is from a California Energy Commission (CEC 2018) study of charging infrastructure needs in the state through 2025. The study combines charging needs from Level 1 and Level 2 at home, Level 2 at work, and Level 2 and DC fast charging at public facilities.
- "(mostly) Night" charging: this hypothetical pattern is based on an EPRI (2007) study of the greenhouse gas emissions consequences of adding significant numbers of EVs to the roads.
- "(mostly) Day" charging: this hypothetical pattern is the reverse of the "(mostly) Night" pattern and emphasizes daylight charging.

Each of the four charging patterns (Figure 6) show the percentage of total annual EV demand in each hour of a five-month summer season (May through September). Overall, the EV charging patterns suggest that, in the absence of measures to control the timing of charging, EV electricity demands are negatively correlated with both peak wind and peak solar PV generation (the dotted lines).

The "Home" charging pattern (NREL 2018c) has some charging demand during the middle of the day when solar PV is available, however, peak home demand occurs in the evening hours when people return from work. In those hours, solar

PV generation is declining and wind generation has not yet risen. The “Home & Public” pattern used by CEC (2018) in their EV infrastructure planning has even less correlation with renewable availability; there is a small morning peak as people arrive at work and hook up to Level 2 chargers (and some public facility charging), but most EV demand is concentrated in the evening hours shortly after the end of the work day. The “(mostly) Night” hourly pattern from the EPRI (2007) study proposes one possible alternative to these evening-peaking patterns. It assumes roughly 76 percent of charging occurs overnight when wind is available, and most of the remaining 24 percent is spread out through the middle of the day when solar PV is more productive. The “(mostly) Day” hourly pattern reverses the nighttime charging and assumes that incentives of some (unspecified) sort are used to encourage daytime charging with the result that 76 percent of all charging occurs when solar electricity is available. How these options might influence the types of generation needed—and the resulting emissions from generation—is examined in the modeling analysis in subsequent sections.

**Figure 5. U.S. Average Summer Renewable Availability from U.S. EPA (2019)**

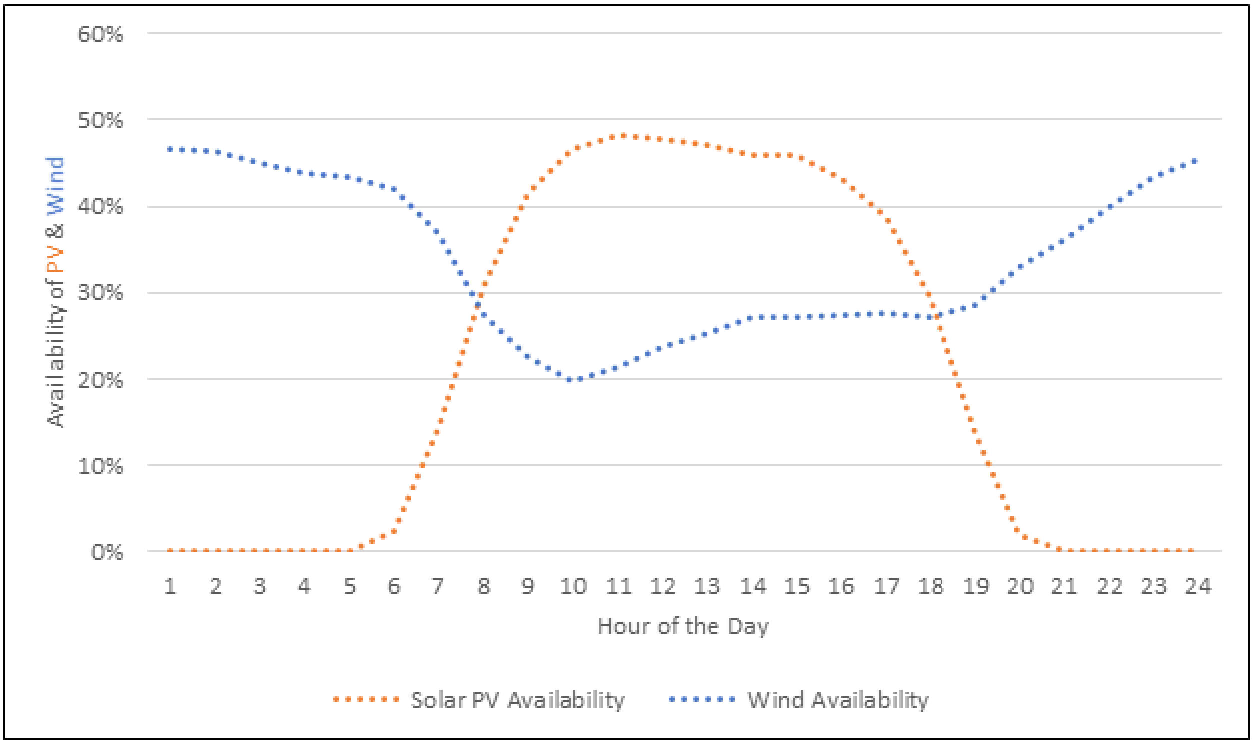
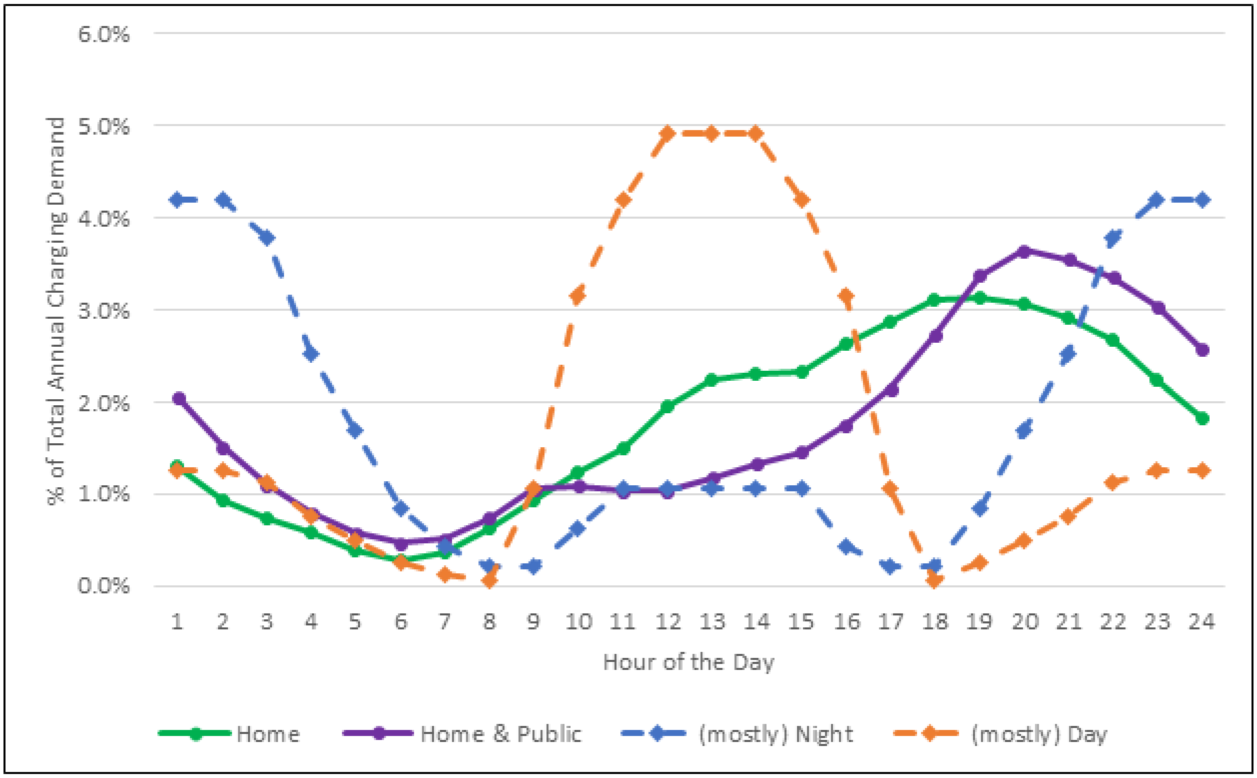


**Figure 6. Hourly Charging Patterns for Electric Vehicles**




*Source*: Author's calculations based on NREL (2018c), CEC (2018), and EPRI (2007)

## MODELING METHODS AND ASSUMPTIONS

The electric-vehicle scenarios are analyzed using an updated version of the Dynamic Integrated Economy/Energy/Emissions Model (DIEM), developed at Duke University's Nicholas Institute for Environmental Policy Solutions (see Ross 2014, 2018, and Ross et al. 2016 for documentation of previous versions and policy analyses). DIEM includes a macroeconomic, or computable general equilibrium component (DIEM-CGE), and an electricity dispatch component that provides a detailed representation of U.S. regional electricity markets (DIEM-Electricity). For this analysis, DIEM-Electricity is run as a stand-alone model, assuming that electricity demands are fixed at future forecasted levels. Given the focus on how electric vehicles will change demand and generation, this approach facilitates interpretation of model insights.

Broadly, DIEM-Electricity is a dynamic linear-programming model of U.S. wholesale electricity markets with intertemporal foresight regarding future market conditions and electricity policies. It represents intermediate- to long-run decisions about generation, transmission, capacity planning, and dispatch of units. To estimate policy impacts, the model minimizes the present value of generation costs (capital, fixed operating and maintenance or O&M, variable O&M, and fuel costs) subject to meeting electricity demands, reserve and spinning margins, and any policy constraints. Existing generating units, which are based on data from the latest National Electric Energy Data System (NEEDS) database v.6 (U.S. EPA 2019), are aggregated into model plants on the basis of their location, characteristics, and equipment configurations to reduce the dimensionality of the mathematical programming problem.[8] Attributes of some types of new plants, largely for fossil and nuclear generation, are based on costs and operating characteristics from Annual Energy Outlook 2019 (U.S. EIA 2019a, 2019b). In addition, the AEO forecasts provide annual demand and fuel price forecasts. Data on capital costs, availability, and effectiveness of wind and solar units are taken from several other sources, as discussed below.

Plants in the model are dispatched on a cost basis to meet demand within each region through at least the year 2060. The version of DIEM-Electricity used in this analysis includes 48 electricity markets, defined along continental U.S. state lines.

[8] Data from U.S. EIA (2019d) are added to account for the most recent construction and retirement decisions.

These regional boundaries and the associated state electricity demands are developed from a combination of the U.S. EPA's Integrated Planning Model (IPM) unit and transmission data (EPA Platform v6 in U.S. EPA 2019), AEO regional forecasts, and state-level demand data from the State Energy Data System, or SEDS (U.S. EIA 2019c).

Within each region, hourly load duration curves from the EPA (U.S. EPA 2019) are aggregated to show the amount of electricity demand in a number of load "blocks." These blocks convert annual electricity demands from the AEO into subcomponents to capture the nonstorable nature of electricity within a year. For this analysis, three seasons are defined using EPA Platform v6 categories: winter (December through February), spring/fall (October, November, and March, April), and summer (May through September). Each season has 24 hourly blocks across a typical day within the season in order to capture how intermittent renewable generation may interact with EV charging decisions. Note that, while this hourly definition helps capture correlations between wind/solar availability and EV charging patterns, the aggregation into seasons (which is necessary for dimensionality reasons) will miss short-term variations in renewable generation that occur across days within a season. Due to the seasonal representation of hours across a year, the modeling does not examine how increased utilization of battery storage in electricity generation might alter choices between the timing of charging and the timing of generation, which could shift the generation balance towards more renewables than are seen in the current results.[9] However, the four charging patterns investigated in the paper cover a range of possible outcomes across hours and could have similar impacts to those from using additional battery storage to shift generation and EV consumption across hours of the day.

Among the more important assumptions in the model are those regarding natural gas prices and construction costs for renewable generation. As a consequence, results from DIEM are presented for a set of reference assumptions and a range of alternatives to better reflect future market uncertainties. For natural gas, the starting point is price projections for the electricity-generation sector from the AEO 2019 Reference Case (U.S. EIA 2019a). This Reference Case has natural gas prices that start at $3.24/MMBtu in 2020 and increase to $5.10/MMBtu by 2050, with an average price of $4.20/MMBtu.[10] The AEO also provides side cases that have significantly lower or higher gas prices (the AEO High/Low Resource Cases). The low prices start at $2.97/MMBtu in 2020 and reach $3.71/MMBtu in 2050 with an average of $3.39/MMBtu. The high prices start at $3.75/MMBtu in 2020, reach $8.20/MMBtu in 2050, and average $6.04/MMBtu.

Capital costs for renewable generation, along with renewable efficiency, are also significant determinants of the generation choices made to supply electricity to vehicles. These costs can vary substantially from one data source to another. Costs for wind and especially solar photovoltaics (PV) have been declining rapidly, but future trends are not well established. The reference case assumptions in DIEM are based on EPA Platform v6 (U.S. EPA 2019), and are adjusted to match the NREL Annual Technology Database (ATB) medium forecast (NREL 2018a) in aggregate.[11] However, the EPA hourly wind and solar PV generation patterns imply capacity factors that are below historical levels in the U.S. EIA data, thus, the availability of these sources of electricity is scaled to match EIA data. To test the sensitivity of model results to these assumptions, forecasts from the NREL ATB low case (NREL 2018a) are used in some model runs—referred to as a Low Renewables Cost case.

Another important assumption for the modeling is the expected level of non-EV electricity demand growth. For these demands, the reference case assumption in DIEM uses growth rates from the AEO 2019 Reference Case (U.S. EIA 2019a), which implies demand growth of 0.68 percent per year on average for the United States between 2020 and 2050 (regions within the U.S. can grow at faster or slower rates). To provide a clean starting point for comparisons across EV forecasts, electricity consumption by EVs in the AEO 2019 forecast is removed from DIEM's baseline case. As shown in Figure 4, vehicles account for 0.5 percent to 3.3 percent of total electricity demand in the forecasts—removing this source of demand lowers the average electricity growth rate to 0.60 percent. Electricity demand from personal vehicles is then added to non-EV demand to get new, higher demand growth. These EV forecasts are based on either AEO 2019 or NREL (2018b) forecasts, as discussed below.

Additional model assumptions that will affect the policy results include: RGGI emissions targets in the ten member states, state policies on RPS, other state actions such as the climate and renewable policies in California, recent extensions

[9] Future battery storage costs are rather speculative. Accurately representing their benefits and costs would also require coordination between this long-term dispatch and capacity-planning modeling and shorter-term unit-commitment modeling.
[10] All dollar values cited in this paper are converted to 2015 dollars.
[11] Wind resources by state, cost class, and wind class are taken from the EPA IPM model (U.S. EPA 2019).

of the federal tax credits for specific types of renewable generation have been added to DIEM in the initial model year of 2020 (by 2025, new units are no longer eligible for tax credits), and the assumption that, in the longer term, nuclear plants can receive a second 20-year life extension and are able to run for 80 years if they are economically viable. Recent announcements by some states on the East Coast regarding expansion of offshore wind are not yet included in the model baseline—their inclusion would lower total $CO_2$ emissions in the region and have some effect on hourly generation mix, but would have relatively minor effects on the incremental generation choices made to supply electricity vehicles that are the focus of this analysis (since the offshore wind would already be in the model's baseline, and would not have been chosen in the EV scenarios as the method to supply vehicle demands, the incremental generation choices in the model's scenarios are relatively unaffected).

To summarize, the reference assumptions for this analysis include the following:

- AEO 2019 Reference Case natural-gas prices (averaging $4.2/MMBtu over the next thirty years)
- EPA and NREL data on renewables capital costs for wind and solar, along with EIA data on current effectiveness and NREL trends for future effectiveness
- Electricity demand growth of 0.6 percent per year, excluding any EVs (AEO 2019 Reference Case)
- 24 hourly demand blocks in each of three seasons of the year
- Renewable units currently under construction or entering service in the initial model year of 2020 can qualify for federal tax credits for wind (a production tax credit, PTC, for the first ten years of service) or solar (an investment tax credit, ITC, of up to 30 percent of initial construction costs). These credits are not extended to units entering service in—or after—the second model period of 2025.

These reference assumptions are used in the model to develop several baseline generation forecasts, where the term "reference" is used to refer to the specific set of AEO/NREL Reference Case assumptions and the term "baseline" is used to refer to the DIEM model forecast resulting from those assumptions.

In addition to national results for the continental United States, some results are presented for the East Coast, separated into two aggregated regions (shown in Figure 7) with different existing generation mixes, opportunities for renewables, and environmental policies. The Northeast region includes the current nine RGGI states, plus New Jersey which has indicated it intends to rejoin RGGI in 2020, and Virginia and Pennsylvania. It is not assumed in the baseline case that Virginia or Pennsylvania will join RGGI (these states may join in the future, but the form of this potential participation is not yet fully defined). For states currently participating in RGGI, the model's baseline forecast assumes that the emissions cap will be adjusted, if necessary, so that the Emissions Containment Reserve trigger price of $6 per ton in 2021 and growing at 7 percent per year is at least met through 2030, along with the corresponding upper bound price established by the Cost Containment Reserve. After 2030, the RGGI emissions caps are maintained, but no further assumptions are made about how or if they might continue to tighten. No other policies such as caps on emissions from transportation are assumed. The Southeast region includes the southern states along the I-95 corridor and two surrounding states (Alabama and Tennessee) with interconnected electricity markets.

**Figure 7. Southeast and Northeast Grouping of States for Reporting East Coast Results**


### *EV Scenarios*

Starting from the reference assumptions that affect the model's baseline forecast for the industry, the electric vehicle scenarios examine how generation will change in response to alternative futures regarding EV adoption and charging decisions, energy prices, and potential policy options. These scenarios begin with the NREL estimates of electricity demand by EVs, which are added on top of reference assumptions of electricity demand growth using one of four possible vehicle charging patterns, under a range of market conditions and potential policy options. These NREL forecasts for EVs are contrasted with the AEO 2019 forecast and a mid-range forecast between the NREL Medium forecast and the AEO forecast.

The various EV scenario assumptions, sensitivities, and policy options include:

#### Scenario assumptions and sensitivities

- Electricity demand scenarios for vehicles (as discussed in the Background section):
    - AEO 2019—EVs reach a 14 percent share of total VMT by 2050
    - Intermediate—halfway between the AEO and NREL Medium (EVs are 36 percent in 2050)
    - NREL Medium Scenario—EVs are 64 percent of total VMT by 2050
    - NREL High Scenario—EVs are 83 percent of total VMT by 2050
- EV charging behavior:
    - "Home"—based on the NREL (2018c) study of residential charging patterns
    - "Home & Public"—based on CEC (2018) modeling using EVI-Pro model
    - "(mostly) Night"—based on a hypothetical pattern in EPRI (2007) that emphasizes overnight charging from wind
    - "(mostly) Day"—the reverse of "(mostly) Night" with an emphasis on daylight charging

- Natural gas prices:
    - Reference—prices start at $3.24/MMBtu in 2020 and reach $5.10/MMBtu by 2050
    - Low—prices start at $2.97/MMBtu in 2020 and reach $3.71/MMBtu by 2050
    - High—prices start at $3.75/MMBtu in 2020 and reach $8.20/MMBtu by 2050

### Policy options

- Production and investment tax credits (PTC/ITC):
    - No PTC/ITC Extension—current policy where renewable tax credits expire soon
    - PTC/ITC Continuation—a continuation of current policies where wind units receive $0.023/kWh in tax credits over the first ten years of operation and solar units receive a 30 percent tax credit based on their construction costs
- Carbon prices within the electricity sector:
    - No carbon price (outside of RGGI and California) unless otherwise specified
    - Carbon price runs—Prices starting in 2025 of $5–$25 per ton, which grow at 5 percent per year

## MODEL RESULTS FOR BASELINE GENERATION AND EMISSIONS TRENDS

As might be expected from the changes seen in the electricity industry over the last decade, forecasts of the generation mix are quite sensitive to expected future market conditions. These conditions will influence what types of new generation are constructed to provide electricity for an expanding EV fleet. The next two graphs illustrate DIEM model results regarding how generation might evolve in the absence of electricity demand coming from EVs (subsequent sections show the incremental changes in generation and emissions associated with adding electric vehicles to the modeling).[12]

Figure 8 shows DIEM baseline forecasts of the U.S. generation mix in 2030, 2040, and 2050.[13] Over first decade, the largest differences between a baseline forecast using the Reference Case assumptions and the alternative gas-price and renewable cost forecasts are those related to fossil generation. Declines in coal generation continue from today's levels under reference conditions, though the rate of decline is modest compared what has been seen over the last few years. By 2030, natural gas generation from combined-cycle units (NGCC) has increased from around 1,200 billion kWh in 2018 to over 1,600 billion kWh in the reference baseline.

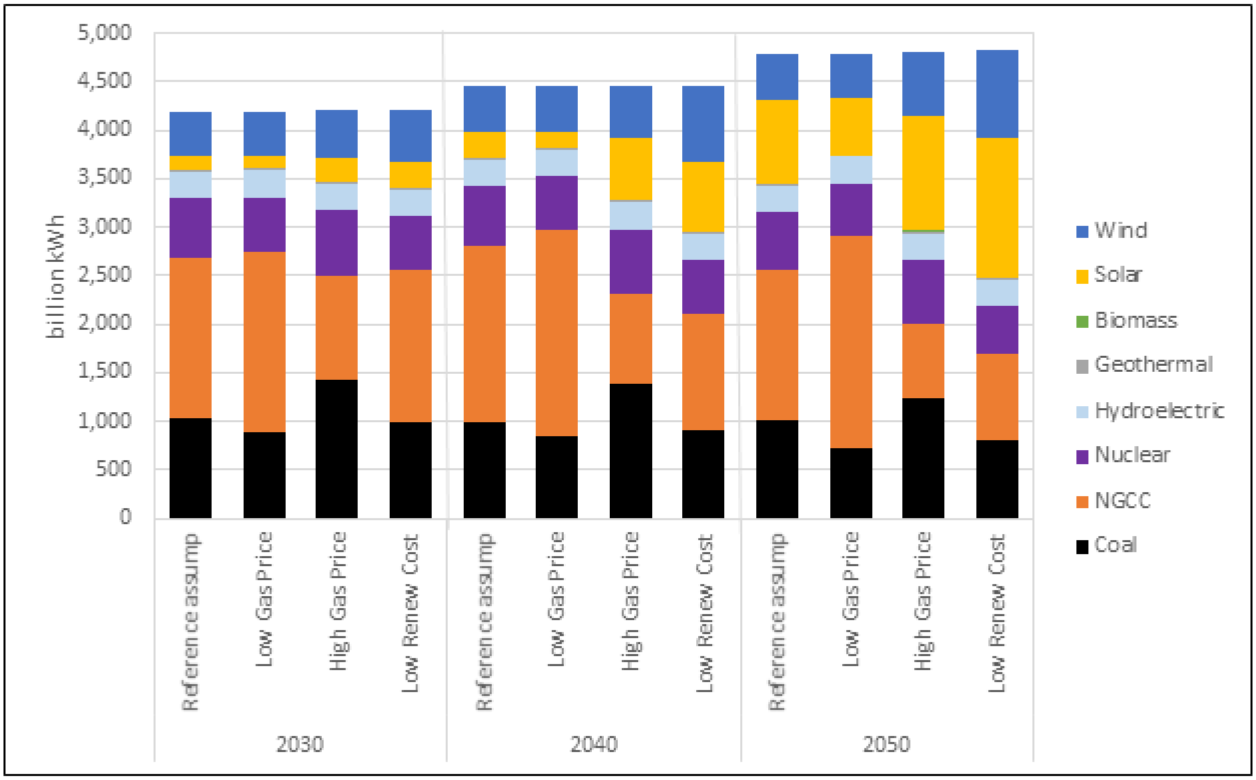
The mix of coal and natural gas, however, can vary significantly depending on expected gas prices. High gas prices increase the utilization rates of existing coal plants and prevent further retirements. Low-cost renewables (or high gas prices) can expand wind generation and double solar generation over the next ten years, but substantial shifts in the generation mix are more likely in the decades after 2030. Although hard to distinguish in Figure 8, based on operating cost assumptions from the U.S. EPA (2019), nuclear capacity declines significantly by 2030—from around 100 GW in 2018 to around 75 GW by 2030 in a baseline using AEO Reference assumptions. High gas prices (and thus less competition from NGCC units) keep the nuclear fleet at 85 GW, while low gas prices or low renewables costs cause additional retirements and the nuclear fleet decreases to around 70 GW.

As time goes on, gas prices are forecast to increase (except for the low-gas price case where they remain flat) and renewables costs are expected to continue declining. The modeling suggests this leads to wind and solar supplying most demand growth in the baseline (still excluding to this point in the analysis the demand from electric vehicles). Coal generation remains relatively constant after 2030 in the absence of new environmental policies, unless gas prices are low. Renewables tend to compete with potential new NGCC units and can outcompete them significantly by 2040/2050,

[12] Demand from EVs in the AEO 2019 forecast that provides these baseline market conditions are backed out of total electricity demand (this has only minor effects since electricity demand by EVs represents on 1.4 percent of total generation in 2030).
[13] Small categories such as petroleum generation and landfill gas are included in the data, but not labeled separately for readability.

though low gas prices would moderate this trend. The share of solar PV generation expands more than that for wind as photovoltaic costs are projected to fall more dramatically than those for wind units.

**Figure 8. U.S. Baseline Generation under Alternative Assumptions about Future Cost Trends**




Along with a broad national perspective, this paper represents model findings for two groups of East Coast states (Southeast and Northeast) to assess possible regional impacts of substituting electric vehicles for light-duty ICE vehicles (the version of the DIEM dispatch model used in this analysis runs at the state level). The East Coast region is of interest for several reasons: first, they collectively represent slightly more than 40 percent of the total U.S. VMT by electric vehicles in the NREL (2018b) forecasts and are linked by the I-95 highway corridor; second, they have different existing generation mixes and opportunities to adjust that mix; and, third, coal is retiring more quickly in some parts of the East Coast area than in other areas (due to the relative age of plants in this region as well as regional regulatory structures and regional natural gas prices). It is therefore informative to study changes in the generation mix in such regions that are expected to span a range of reliance on coal in the coming years.

As noted, generation for these East Coast regions have characteristics somewhat different than the national totals shown in Figure 8. Although it is possible for electricity trade among regions to shift the balance slightly (international trade is assumed to be fixed at AEO 2019 levels), regional generation provides a fairly good sense of the characteristics of electricity supplies within a region (a region's net imports from states outside the region make up the difference between generation and consumptions, ignoring losses). Many of the U.S. coal plants expected to retire for economic reasons in the baseline forecasts are located in East Coast states, leading to more reliance on gas generation (unless gas prices are high) as can be seen in Figures 9 and 10. Onshore wind resources are relatively limited compared to other parts of the country such as the Plains states, and offshore wind remains more expensive in the forecasts, but solar PV becomes increasingly important over time in the forecasts. If gas prices are high or construction costs for PV are low, solar will outcompete many of the potential new NGCC units, along with some of the existing nuclear plants that would have remained in operation under reference assumptions.

**Figure 9. Southeast Baseline Generation under Alternative Assumptions about Future Cost Trends**

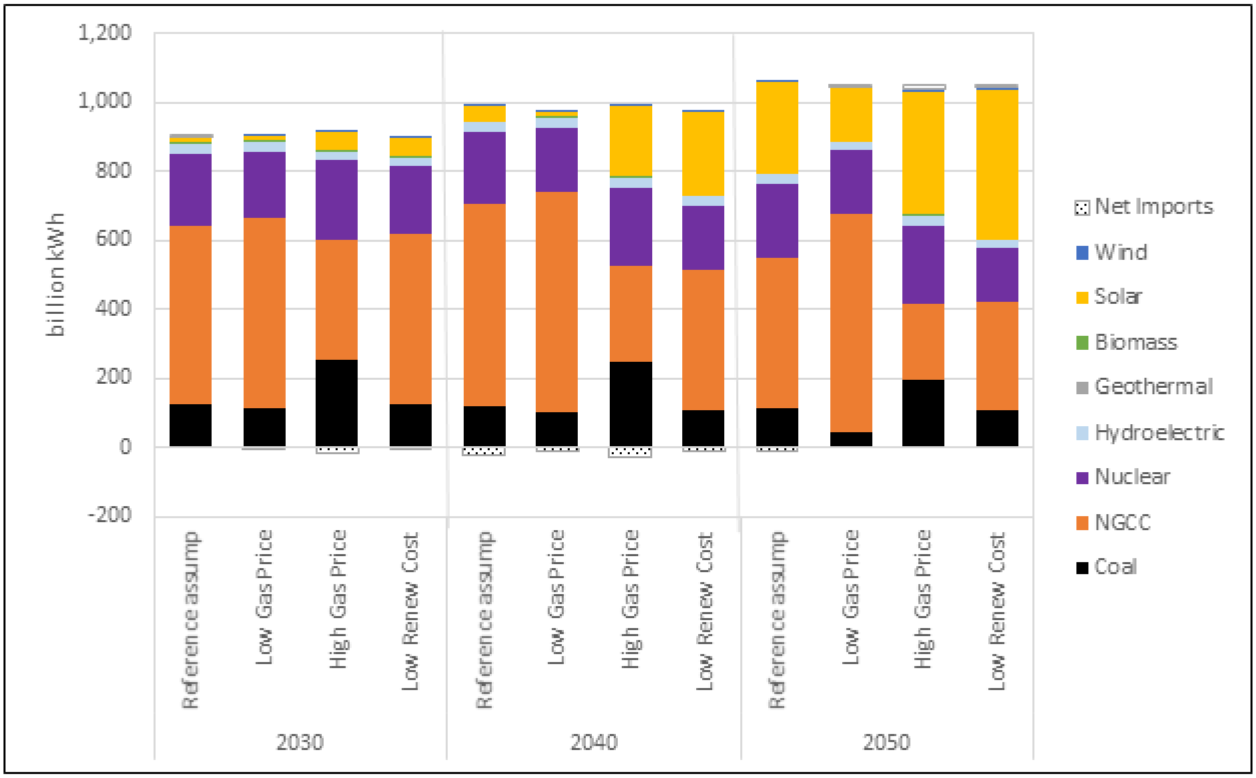
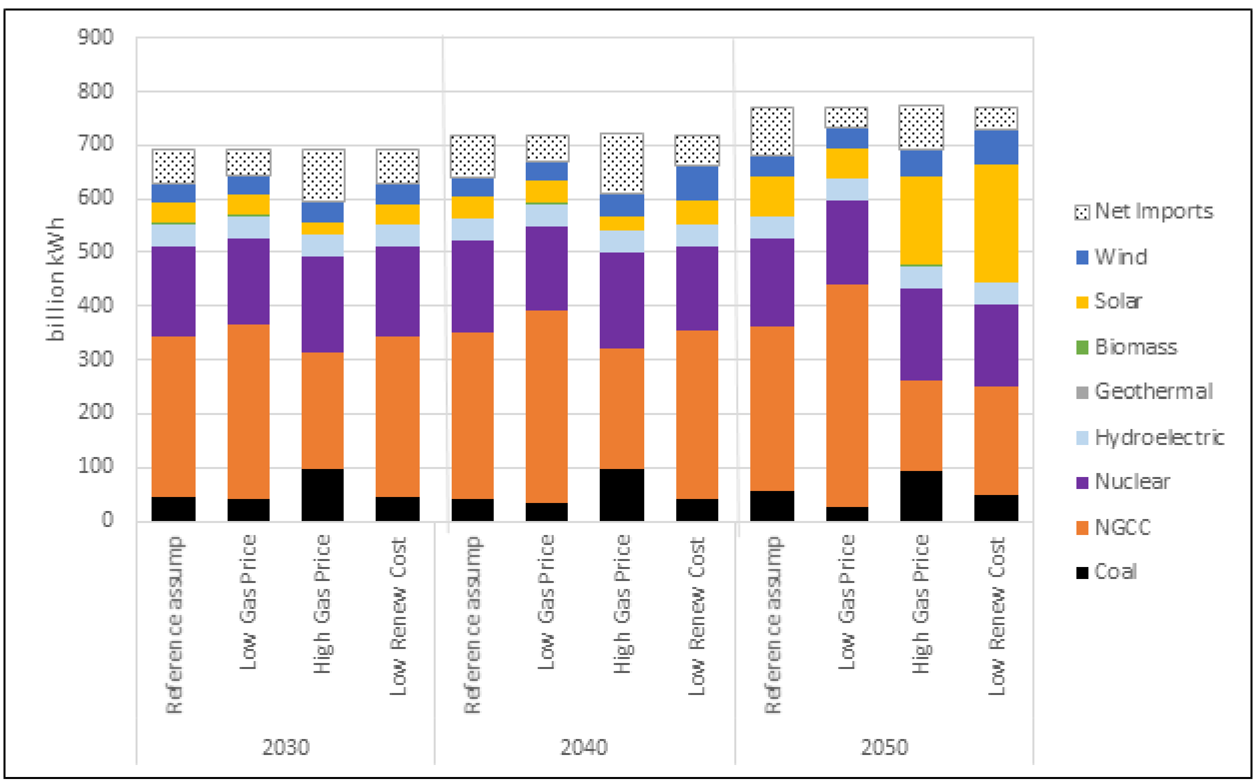


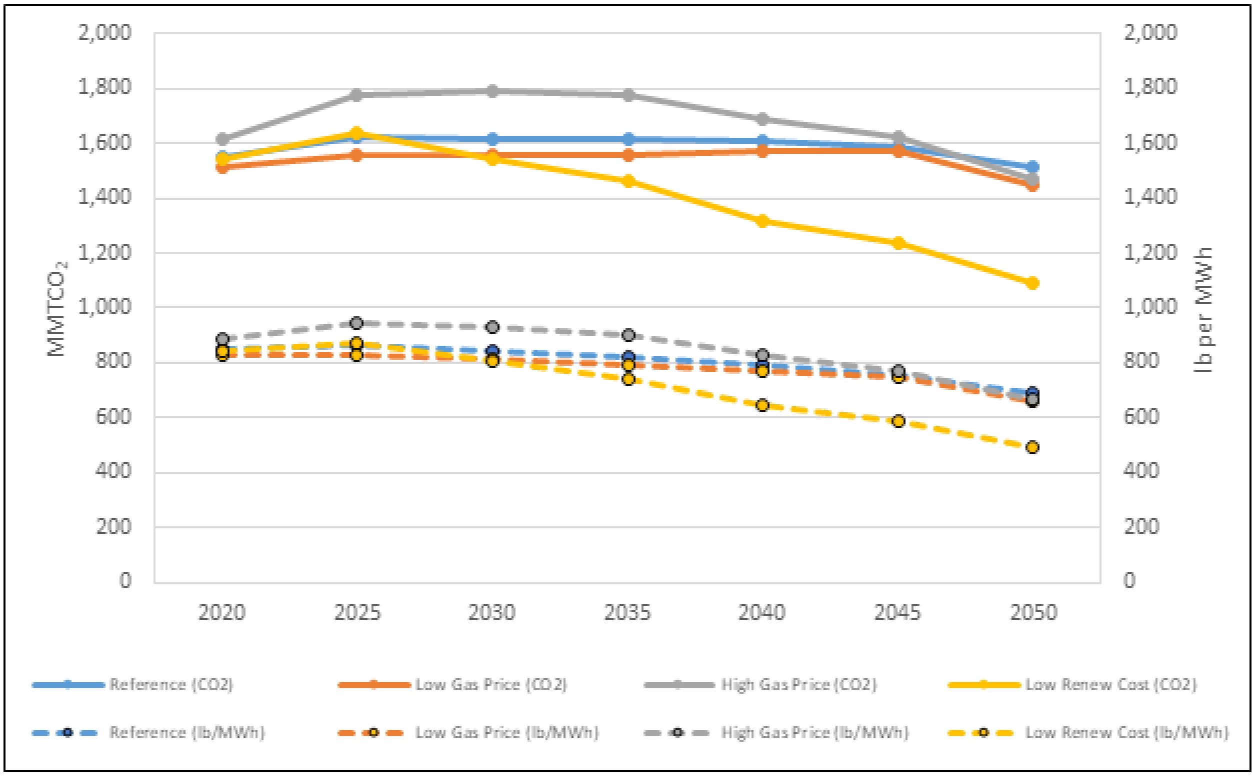

**Figure 10. Northeast Baseline Generation under Alternative Assumptions about Future Cost Trends**




The emissions trends associated with these national and regional baselines are largely driven by the mix of coal and natural gas generation (petroleum contributes an insignificant amount). Figures 11–13 illustrate the breadth of possible emission paths that could occur, nationally and among East Coast states, in the absence of any new environmental policies in the industry. The left axis in each graph shows total $CO_2$ emissions, and the right axis expresses emissions as a rate in pounds per megawatt hour, MWh (using total MWh of generation, not just those from fossil-fuel generation).

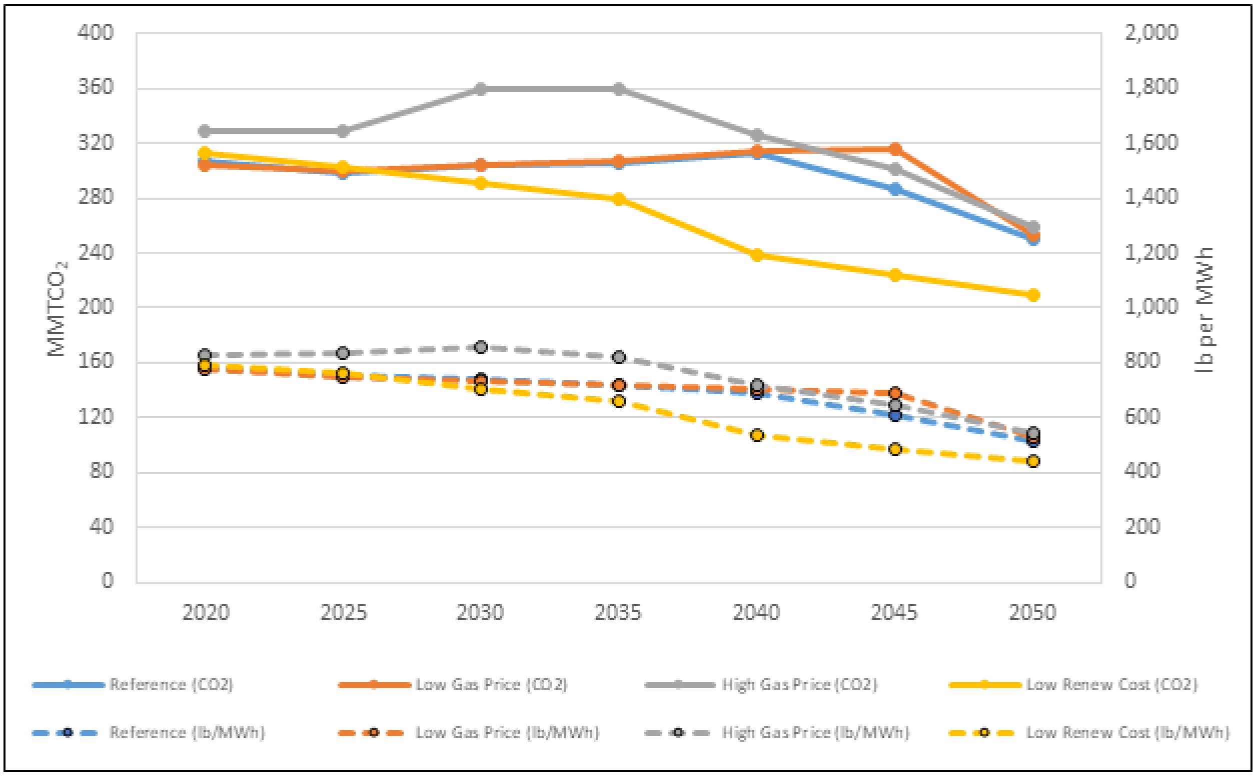
For the United States, shown in Figure 11, the reference assumptions have relatively flat emissions as coal and gas generation are stable over time. The Low Gas Price case also shows little change in the absence of other policies as declines in emissions from coal generation are offset by new gas units (which also displace nuclear, wind, and solar generation). The High Gas Price case leads to additional coal generation in the near term, but lower NGCC generation and eventually the higher nuclear and new renewable generation in this scenario bring emissions back in line with the other two forecasts. Only the Low Renewables Cost case leads to significant declines in emissions in the absence of new policies in the baseline. Emissions rates follow trends quite similar to total $CO_2$ emissions.

**Figure 11. U.S. Total Baseline CO2 Emissions under Alternative Cost Assumptions**



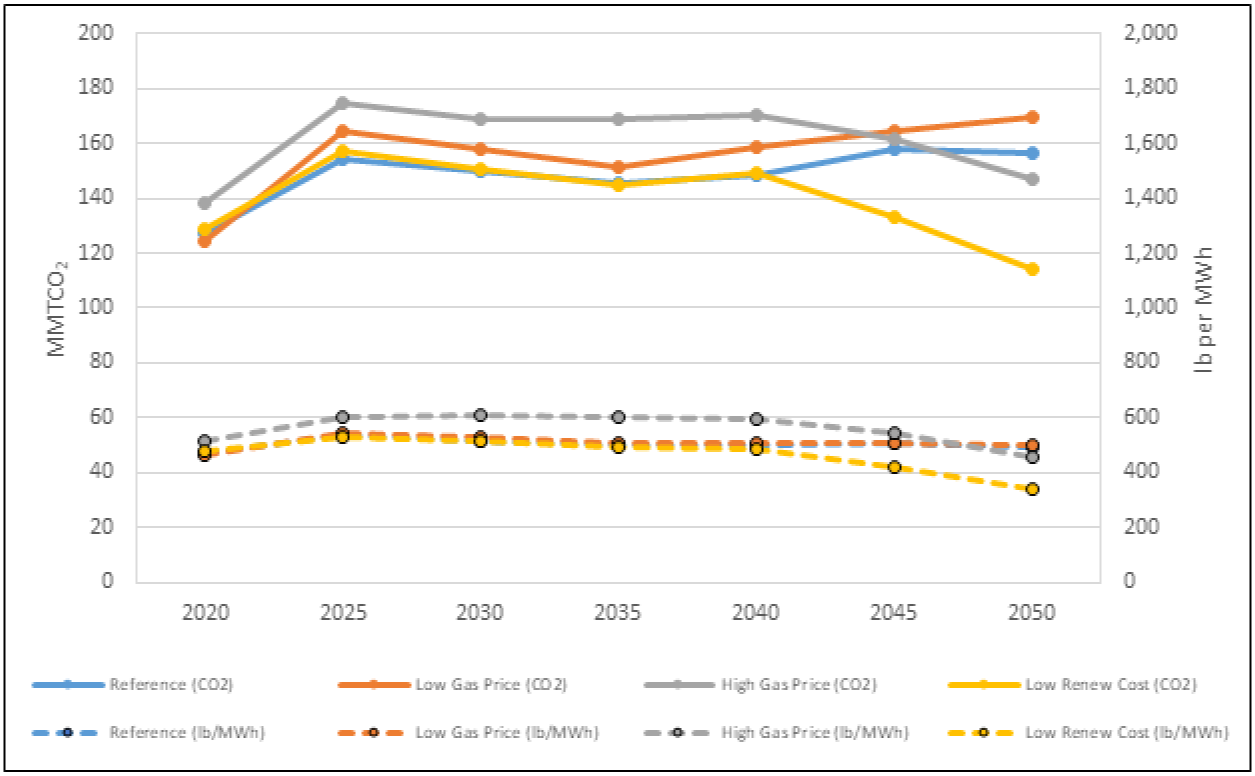

The Southeast region in Figure 12 has baseline trends somewhat similar to national totals, although emissions per kWh are slightly below the national averages due in large part to nuclear generation in Southeast states. A high gas price again leads to additional generation from existing coal units and higher emissions; however, a low gas price has very little effect on emissions through 2040. Similar to the national results, low renewables costs lead to the lowest emissions.

**Figure 12. Southeast Baseline CO2 Emissions under Alternative Cost Assumptions**




The Northeast region in Figure 13 has baseline trends lower than the national totals. Reference assumptions give relatively flat emissions through 2040, after which there are slight increases because RGGI targets are not assumed to tighten after 2030, and also emissions growth occurs in surrounding Northeast states outside of RGGI. Unlike low gas prices at a national level that lead to retirement of existing coal, coal generation in this region is comparatively limited, causing cheap gas to result in enough additional gas generation to more than offset any additional coal retirements. However, high gas prices can still maintain coal generation, largely in states not assumed to participate in RGGI. Emissions rates in this region are significantly below baseline trends in the country overall as the result of policies such as RGGI and past retirements of the coal generators. On average, emissions rates for this group of Northeast states are around 40 percent below the national rate, even under scenarios where emissions increase slightly after 2020.

**Figure 13. Northeast Baseline CO2 Emissions under Alternative Cost Assumptions**




## NATIONAL-LEVEL MODEL RESULTS FOR ELECTRIC VEHICLE SCENARIOS

Analysis of the electric-vehicle scenarios begins with an examination of how the generation mix changes from its baseline levels when using different assumptions about EV demand. After examining how market conditions outside of the industry's control influence generation choices to supply EVs, the analysis looks at how charging decisions affect the mix of technologies chosen, followed by emissions under the various outcomes. After examining these changes in incremental generation and emissions, several policy options are examined that could offset any emissions increases associated with additional generation for vehicles.

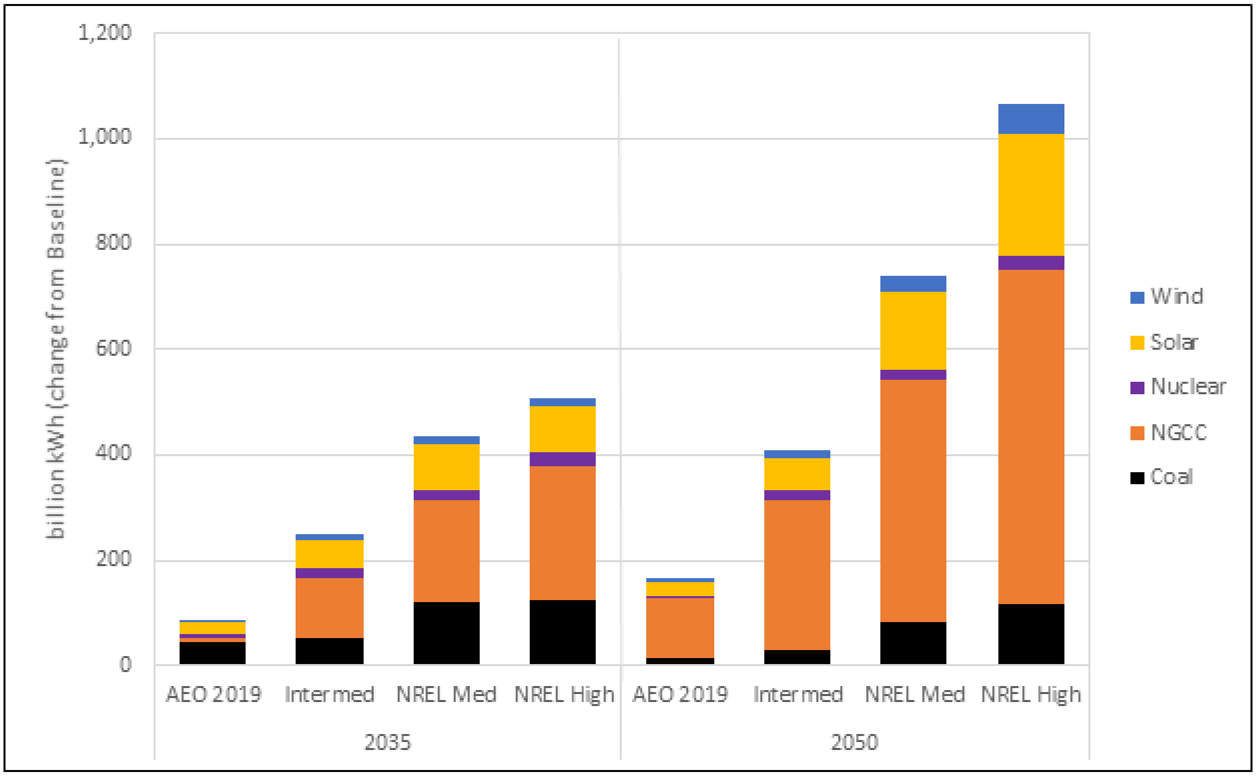
### *Generation*

The following discussion uses AEO Reference cost assumptions and looks at how generation may increase above a baseline forecast in order to accommodate additional electricity demand from vehicles. Some of these technology responses might hold regardless of what factors—or sectors of the economy—drive an increase in electricity demand. Other generation decisions will be affected by the specific timing of EV demands throughout a day. Regardless of the causes of higher demand, what is of interest is the incremental generation that enters the market.

The analysis starts by looking at how the different levels of aggregate electricity demand across the EV scenarios will increase generation above the baseline when using the standard reference assumptions about fuel prices and renewables costs. Figure 14 shows how increases in electricity consumption for the four EV scenarios will expand the industry (the "Home & Public" hourly charging pattern is used as the default in any figures unless otherwise specified). Adding the AEO 2019 assumptions about EV adoption to the baseline from Figure 8 raises demand, and thus generation, by a few percent over a baseline without electric vehicles. In this case, over the coming three decades, this modest increase is met largely by additional gas generation with a small amount of solar PV (with initial some additional coal generation).

For the EV scenarios with higher penetration levels (from Intermediate EV levels through NREL High), NGCC units also supply a significant share of the incremental generation. However, higher levels of demand encourage existing coal plants—and to a lesser extent, existing nuclear—to remain in operation. Along with these units, new solar PV plays an increasing role and some wind is encouraged by nighttime charging. Relative shares of new generation change across the different EV demand levels, but new gas is almost always the largest supplier of additional demand from EVs when using Reference assumptions about gas prices and renewables costs Several graphs below look at alternative market conditions where this dominance by gas may not occur.

**Figure 14. Change in U.S. Generation across EV Scenarios (Reference Assumption, "Home/Public" Charging)**




The findings above in Figure 14 are a function of market conditions from the reference assumptions. In evaluating how markets are likely to evolve, it is helpful to get a sense for how sensitive modeling results are across a range of alternative cost assumptions. Figure 15 looks specifically at the EV demand levels from the Intermediate EV case and then varies fuel prices and construction costs within that scenario to examine the sensitivity of the possible outcomes, compared to those based on the reference assumptions from Figure 14. When interpreting these incremental generation results, they must be compared back to their corresponding baselines in Figure 8 in order to understand what is happening in aggregate—otherwise the incremental increases may move in counterintuitive directions.

For example, in a baseline without any demand from EVs, a low-gas price encourages NGCC units at the expense of existing coal units and new renewables. However, adding new demand from EVs on top of other sources of electricity demand can result in existing coal plants staying online that would have otherwise retired. In part, this occurs because gas prices rise above the initial Low Gas Price levels as more gas is used.[14] In part, gas prices have a seasonal component in the model (see USEPA 2019) that coal prices do not, so responses of the different fuels are not the same. And, in part, it is cheaper to run the existing coal plants to supply the additional EV demand than to continue to build even more NGCC units than were already built in a baseline with low gas prices. However, in aggregate, coal generation in a scenario that includes the higher EV demand is still lower in the Low Gas Price case than it is when reference-level gas prices are assumed.

High natural gas prices work in the opposite direction. In the baseline (Figure 8), high prices have discouraged NGCC units and kept existing coal and nuclear plants in operation, along with encouraging new renewables. But then, if demand is greater than expected because of electric vehicles, there is little additional response from existing coal plants since they were already operating anyway in a high-gas-price environment. Thus, the results in Figure 15 suggest that high

[14] Gas supply curves from the USEPA (2019) model are used to determine how gas prices increase when gas demand rises.

gas prices—and correspondingly higher electricity prices—make it more likely that new NGCC units and additional renewables will be cost-effective options (even though the high-gas-price baseline already had high levels of renewables). Finally in the graph, low renewables costs lead to an increase in renewables to supply EVs, but the changes are not very dramatic since renewable levels were already high in a baseline forecast with low renewable costs. As a consequence, when looking at the incremental changes in generation for the low-cost renewables scenario in Figure 15, model results show that new NGCC units are built along with more renewables as the opportunities for wind, in particular, become less extensive as more wind is built.

**Figure 15. Changes in U.S. Generation in the Intermediate EV Case (Alternative Cost Assumptions)**

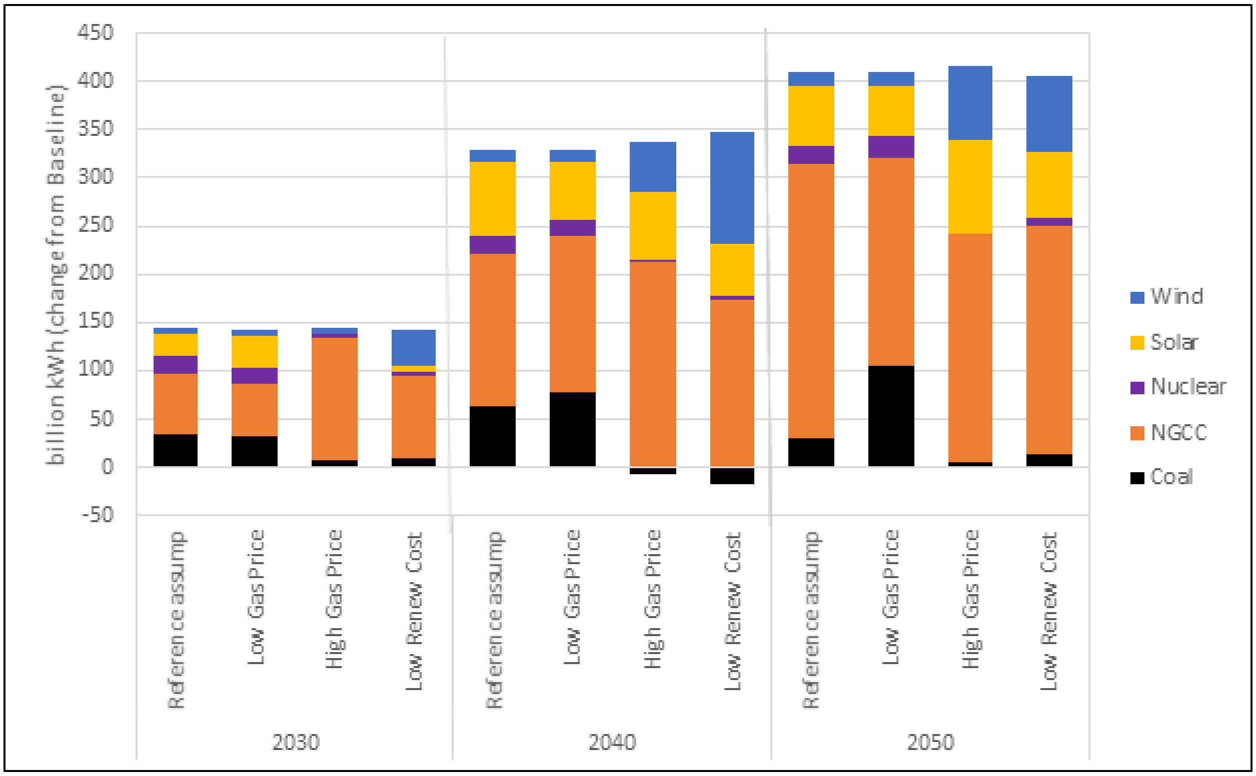
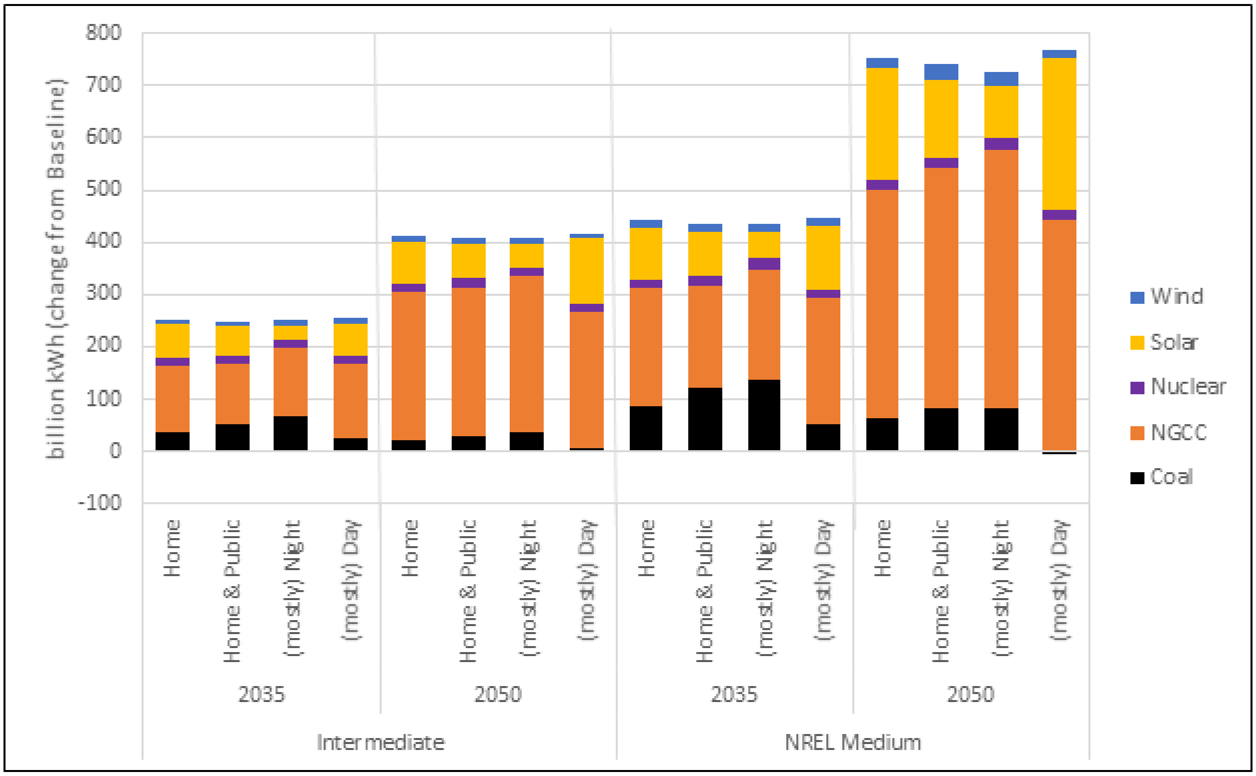



Figure 16 examines how sensitive the generation mix may be to the charging behavior of EV owners; where the "Home" charging pattern tends to emphasize afternoon and early evening charging, the "Home & Public" hourly pattern has a mid-morning peak and then a more extreme evening peak, the "(mostly) Night" pattern is intended to split mid-day and overnight charging in a way that incentivizes overnight wind availability as much as possible with some solar PV during the day, and the "(mostly) Day" pattern reverses the mostly-night charging pattern and emphases mid-day charging.

In the model results, whether looking at the Intermediate or NREL Medium levels of EV penetration, incremental generation for vehicles can vary fairly significantly across the different charging patterns, particularly by 2050 when renewables costs have declined significantly (lower cost renewables in the near term would give a similar pattern).[15] The "Home" pattern encourages some additional mid-day solar PV generation at the expense of coal units that might have remained in operation under different charging options. The "Home & Public" pattern places less emphasis on mid-day solar and makes up the difference with gas. The "(mostly) Night" pattern is more likely to encourage gas generation, which can operate throughout the day, than to increase wind generation. Essentially, the model is suggesting that wind costs may need to decline more than is currently assumed in the U.S. EPA (2019) and NREL medium (2018a) forecasts for new wind units to be competitive with NGCC units. This was implied by Figure 8, which showed significant increases in wind when using the NREL low-renewable cost assumptions, and can also be seen in policy discussions below that look at other ways to encourage renewables. Finally, the "(mostly) Day" pattern results in a significant shift into solar PV generation, and it also eliminates the increase in coal generation seen across the other options.

[15] The total generation reported may vary across options, especially by 2050, as different levels of renewables give rise to different levels of curtailment of wind or solar and different amounts of transmission losses as trade patterns change.

**Figure 16. Changes in U.S. Generation across Charging Options (Intermediate & NREL Medium)**



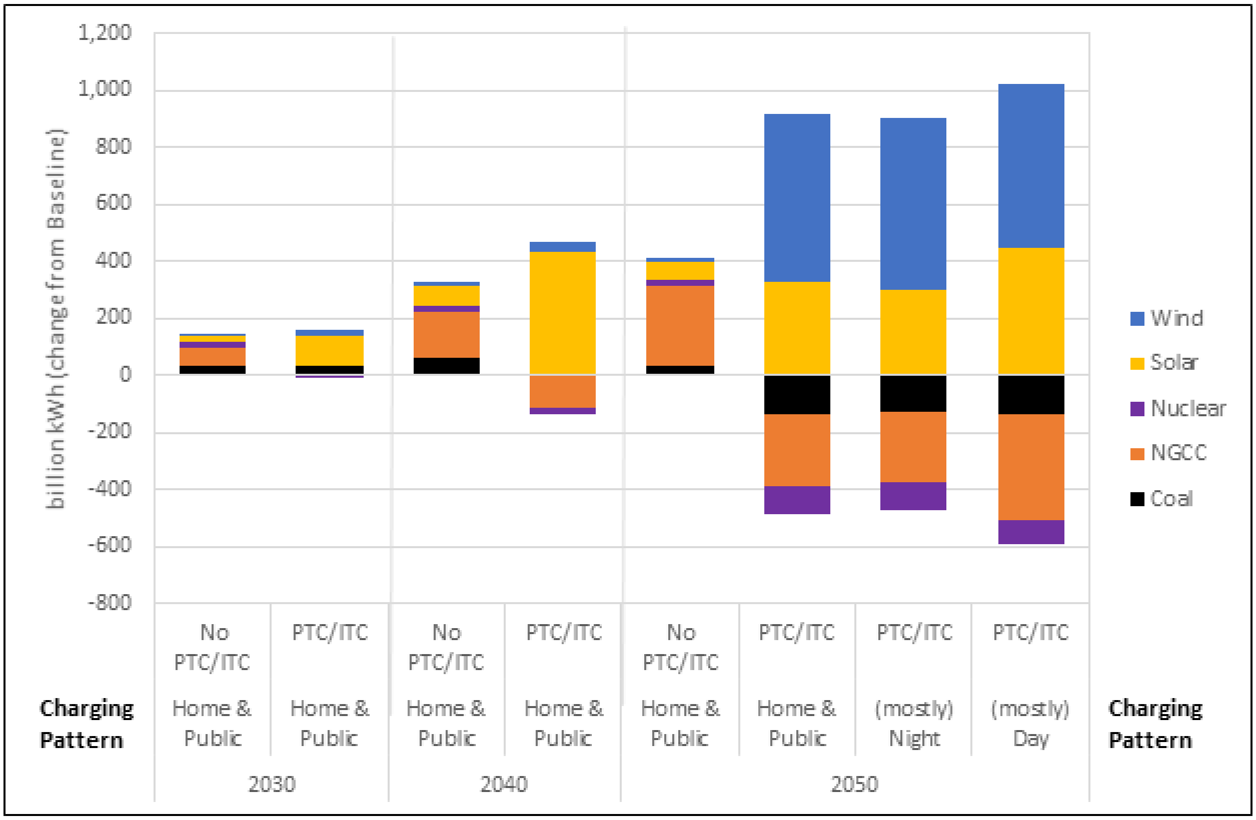

## *Policy Options*

If the types of generation changes shown above are not going to achieve particular environmental goals, the question arises: what policies could help ensure that more of the incremental demands from EVs are met by renewable generation? While there are a large number of policies that could drive a cleaner generation mix, or encourage EV charging to take place during hours when renewables are meeting a higher share of the load, this paper analyzes possible impacts of just two policy options (in addition to the question of the timing of charging): an extension of current federal tax credits for wind and solar, and a range of carbon prices.

In the first set of these possible policy runs, it is assumed in the modeling that the current PTC/ITC are extended past the years 2020/2021 in response to anticipated increases in electricity demand caused by vehicles and/or as an integrated part of whatever policy regimes lead to significant EV penetration. Thus, focusing on the Intermediate EV scenario, Figure 17 compares what happens in a model run with the renewables tax credits and higher electricity demand from EVs to what happened in a baseline case without any extension of current credits (and without higher demand from EVs). The "Home & Public" default charging pattern is used for most of these model runs; the final two columns focusing on 2050 contrast this charging pattern to the "(mostly) Night/Day" patterns that shift when EV demand occurs.

The model results suggest that, even by 2030, continuing the tax credits would lead to vehicle electricity demand being largely supplied by renewables, rather than natural gas. By 2050, the tax credits are not only causing renewables to supply the roughly 400 billion kWh needed by EVs in the Intermediate scenario, but the PTC/ITC credits are causing the displacement of around 500 billion kWh of fossil and nuclear generation. Charging EVs at mostly at night increases wind generation by a few percentage points—larger impacts on wind might be seen if turbine technologies or available wind resources increase more than forecast, or if offshore wind costs decline. Charging EVs during the day increases solar PV generation by more than one-third over the "(mostly) Night" option and decreases new NGCC generation correspondingly.

**Figure 17. Changes in U.S. Generation across Alternative Subsidies (Intermediate EVs)**




A second policy option that could increase the supply of low-emissions generation is placing a carbon price to $CO_2$ emissions from electricity, whether through a carbon tax or cap on carbon emissions (no carbon price or adjustments are assumed in the rest of the economy).[16] Figure 18 focuses on the Intermediate EV scenario and looks at a range of possible carbon prices, starting between $5/ton and $25/ton in the year 2025 and then increasing at 5 percent per year.[17] Even the $5/ton scenario (with a carbon price of $16.9/ton in 2050) is sufficient to simultaneously retire roughly half of the existing coal generation and supply EVs with a combination of new natural gas and solar PV plants by 2050.[18] Higher carbon prices lead to retirement of most coal by 2040 and essentially all coal by 2050, even when demand is higher because of vehicles. In many scenarios, the results suggest that most new generation would be supplied by renewables by 2050. The existing nuclear fleet largely maintains its generation levels with the carbon prices from the $10/ton case or higher (and the higher electricity demands associated with the Intermediate EV case).

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[16] In some types of policy analyses, modeling might assume that higher production costs associated with a carbon price, whether through higher costs for fossil fuels or the need to supply additional non–fossil fuel generation, would lead to lower electricity demand. However, since this analysis is focused on specific demand levels needed to support electric vehicles, it is assumed that demands are fixed at the levels needed to supply vehicles and other sectors of the economy. In part this is necessary since the EV forecasts come from an external modeling analysis, which did not consider how a carbon price might affect EV choices.

[17] For RGGI states, it is assumed that the carbon price is at least the suggested Emissions Containment Reserve trigger price.

[18] Increases in specific types of generation compared to the baseline case are shown as positive numbers, while declines in generation are shown as negative numbers.

**Figure 18. Changes in U.S. Generation across Carbon Prices (Intermediate EV Scenario w/Home & Public)**

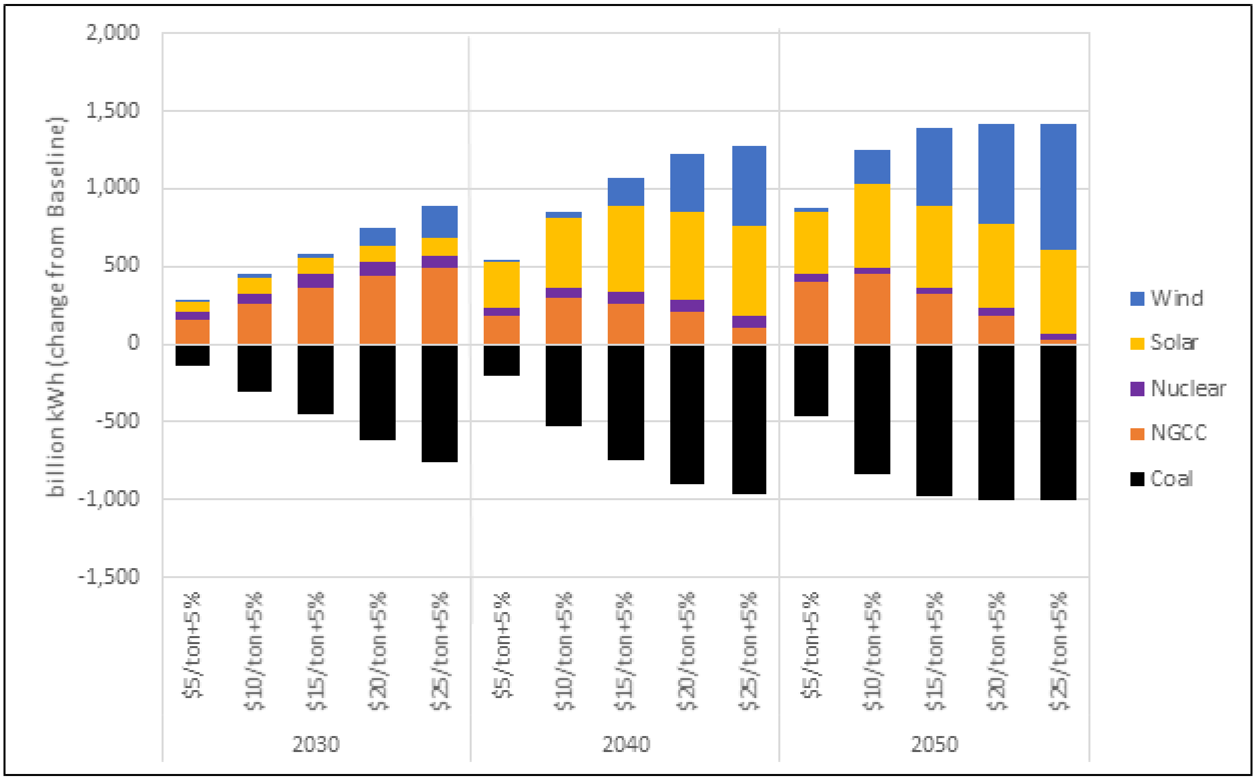
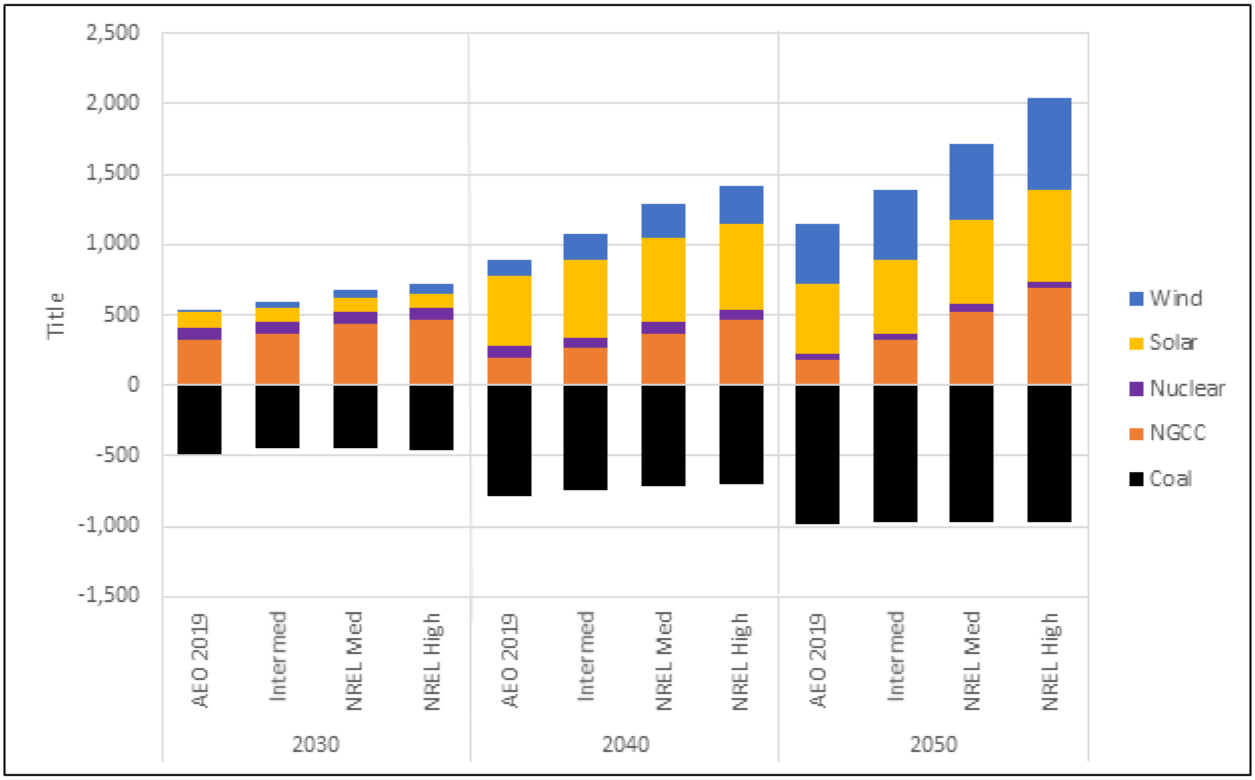



Figure 19 compares all four EV scenarios from Figure 14 (with the "Home & Public" charging pattern) for the medium carbon price case of $15/ton starting in 2025 and growing at 5 percent per year. This carbon price is sufficient to shut down around one-half of coal generation by 2030, three-quarters by 2040, and essentially all coal generation by 2050. In the near term, the majority of declines in coal are offset by NGCC generation, along with a mix of nuclear (existing units that stay in business because of improved economics and higher electricity demand from vehicles), new solar, and new wind. By 2040, the carbon price in this scenario has risen to a point where most electricity demand from new EVs is met by wind and solar. Gas generation remains slightly above baseline levels in the NREL Medium and High scenarios with the highest electricity demand. By 2050, solar PV has become the largest supplier of electricity needed by EVs, followed by wind.

**Figure 19. Changes in U.S. Generation across EV Scenarios with a Carbon Price of $15/Ton + 5 Percent/Year**




### *CO2 and NOx/SO2 Emissions*

Setting aside for the moment consideration of all the avoided $CO_2$ emissions from having fewer ICE vehicles on the roads, it is possible that an increase in electricity demand from EVs could lead to additional $CO_2$ emissions from fossil generation, as was shown in the generation graphs above. How emissions will be affected will depend on market conditions and policy responses to the increased demand. To look at some of these factors, Figure 20 shows how $CO_2$ emissions associated with electricity generation evolve over time for the Intermediate EV scenario across a range of cost and policy assumptions (recall that the original baseline emissions without EVs from Figure 9 remains relatively constant over time at around 1,600 $MMTCO_2$—for the model run with Reference assumptions about gas prices, etc.). High natural gas prices, combined with higher demand from vehicles, lead to the most emissions through 2040 as existing coal plants operate at higher utilization rates and delay retirement. By 2040, gas prices become less important in determining emissions as renewables play an increasing role.

This role for renewables is accelerated in the low-cost renewables case. In the policy scenarios, continuation of the current PTC/ITC for wind and solar leads to emissions from the Intermediate EV scenario that are below the emissions levels of around 1,600 $MMTCO_2$ in the baseline with reference assumptions (which didn't have any electricity demand from vehicles). The $5/ton carbon price case stabilizes emissions in the near term and results in emissions declines of 20 percent below reference levels by 2050. Higher carbon prices cause significant declines in emissions, even in the face of higher electricity demand from vehicles.

**Figure 20. CO2 Emissions from Generation across Alternative Assumptions (Intermediate EV Scenario)**

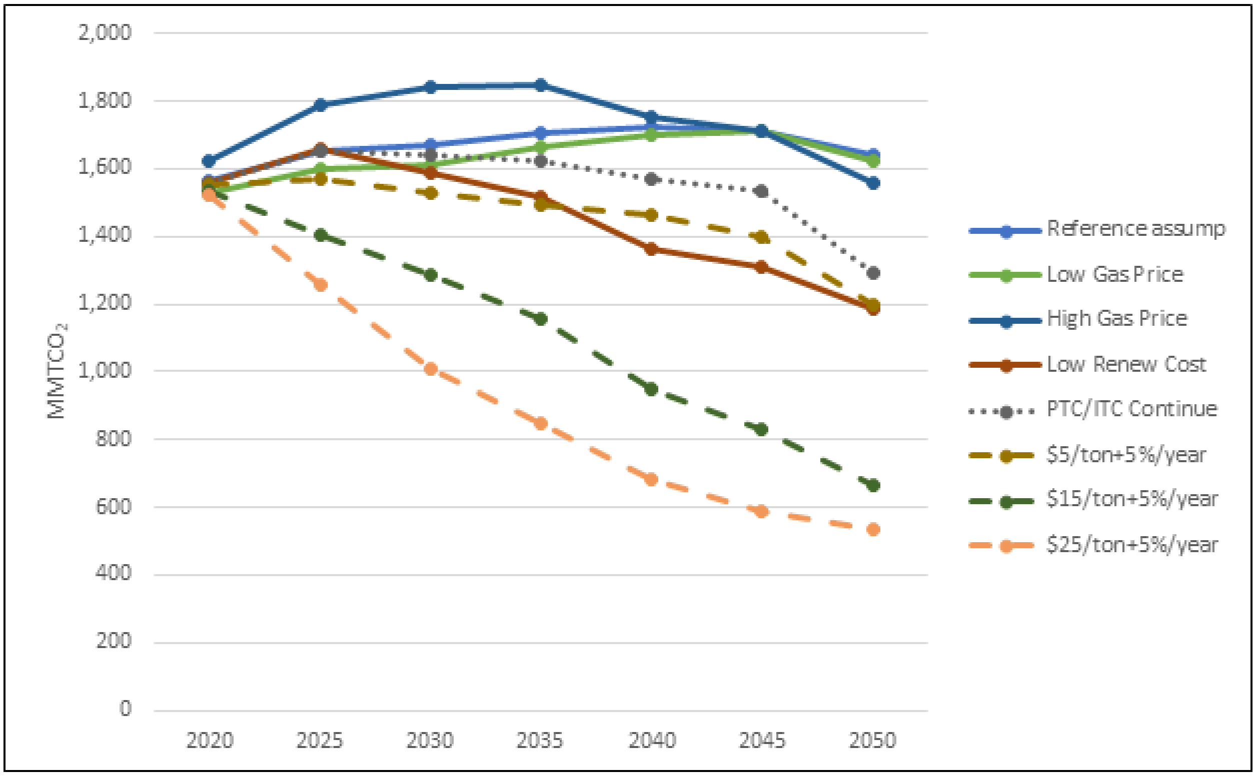
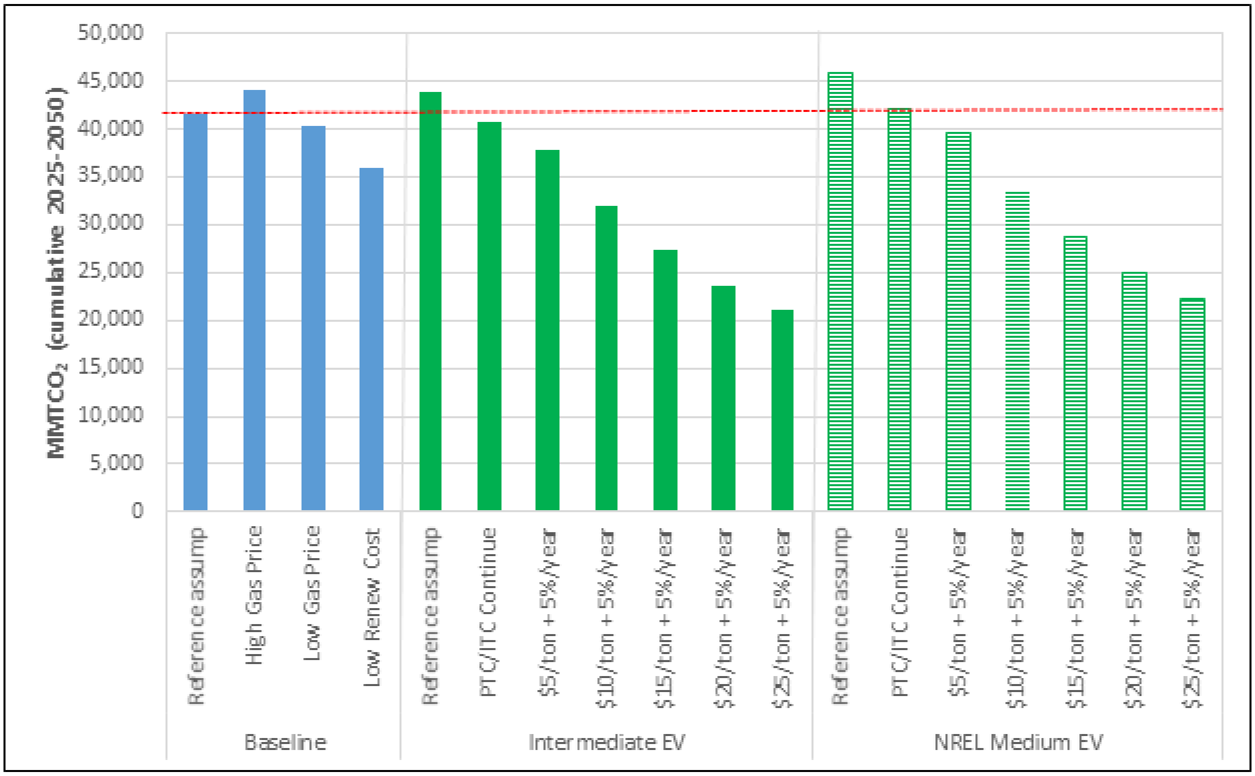



Figure 21 looks at cumulative emissions from generation over the 2025–2050 time frame related to the carbon-price policies. The baseline bars in blue show emissions estimates without the impact of electric vehicles across different market conditions. A baseline with high gas prices has more cumulative emissions than a baseline with reference or low gas prices since high gas prices encourage existing coal units to keep generating. As shown in the previous graph, a future with low renewables costs has the lowest baseline emissions. The red line in the figure merely provides a point of reference to compare with emissions under the Intermediate and NREL Medium EV scenarios.

The heights of the green bars for the EV scenarios compare cumulative emissions under reference assumptions about gas prices and renewables costs to the baseline with reference assumptions. The area of green bars above the red line show how additional electricity demand from vehicles might increase emissions from generation, in the absence of any countervailing policies. The green bars for the PTC/ITC continuation policy suggest that renewables policies extending current federal tax credits for wind and solar are all that is needed to offset any additional emissions from the generation for EVs (even prior to considering the emissions benefits of removing fossil-powered vehicles from the roads). Finally, carbon prices starting at levels in the $5/ton scenario are sufficient to reduction emissions below baseline levels, even as demand from EVs increases.

**Figure 21. Cumulative CO2 Emissions from Generation across Alternative Assumptions (2025–2050)**

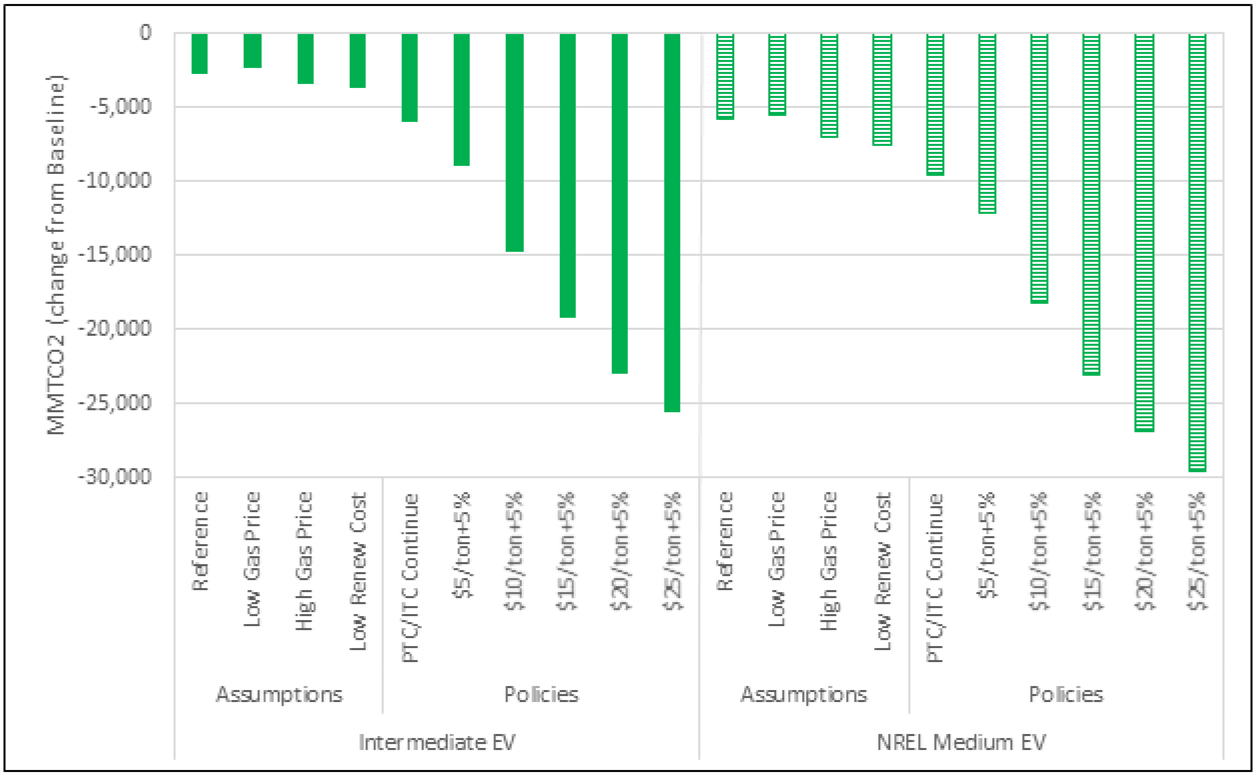



Shifting from ICE vehicles to electric vehicles will significantly lower on-road emissions of CO2 and NOx. The net effect of these two influences will control the environmental benefits realized from EVs. Thus, Figure 22 looks at the full net CO2 emissions benefits of electric vehicles, considering both emissions reductions from displaced ICE vehicles and any changes in generation emissions associated with supplying electricity for vehicles.[19] For either the Intermediate EV case or the NREL Medium EV case, the Assumptions bars illustrate how net benefits may vary across assumptions about future market conditions related to gas prices and renewables costs without any additional policy interventions to increase net benefits. (Net benefits are calculated compared to a baseline with the same market conditions). Note that in these calculations, cumulative emissions reductions associated with reduced ICE vehicle travel are estimated at 5,100 MMTCO2 for the Intermediate EV case and at 10,200 MMTCO2 for the NREL Medium EV case.

Across all market assumptions, electric vehicles provide net emissions reductions, even after considering any increases in generation to provide more electricity. These cumulative emissions benefits are enhanced when renewables costs are low, whether as the result of market conditions or PTC/ITC credits that affect installation and operation costs. Finally, instituting a carbon tax can significantly increase these benefits.

[19] In these calculations, the avoided emissions from ICE vehicles are estimated using the reductions in gasoline and diesel consumed by light-duty vehicles in the NREL EV forecasts.

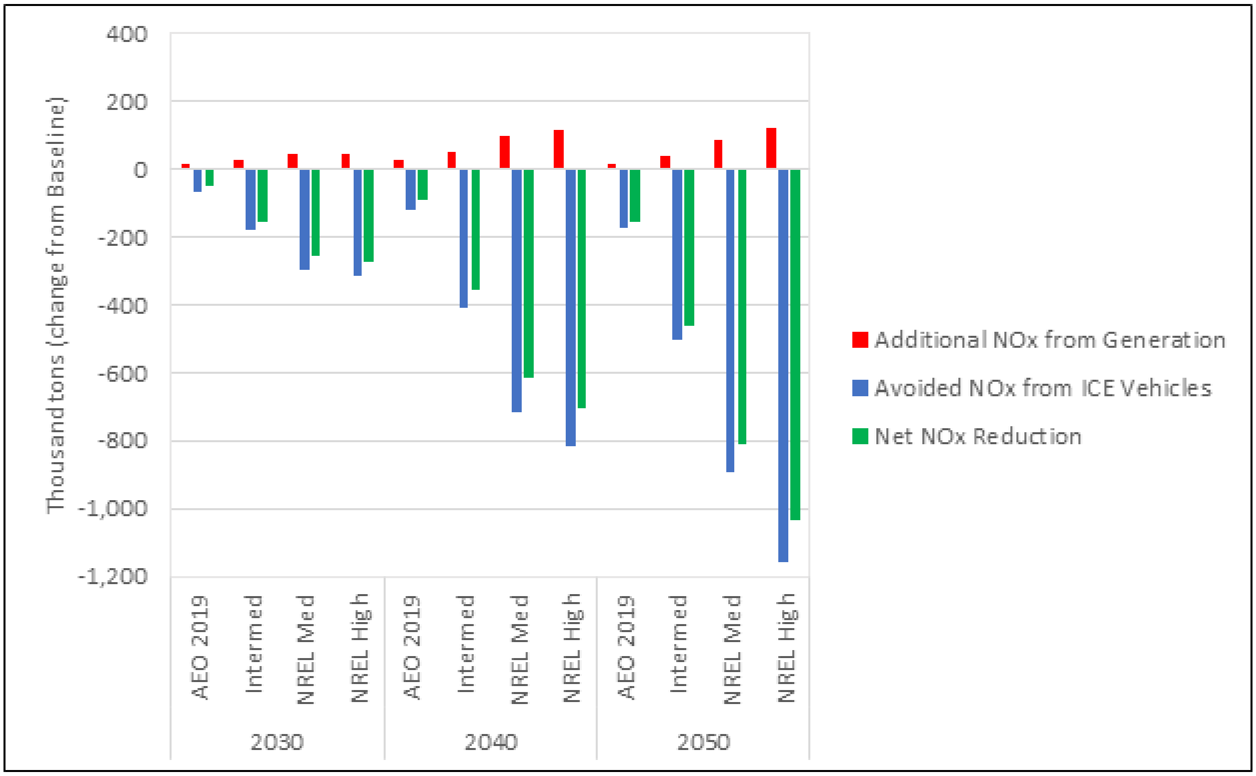
**Figure 22. Net Cumulative CO2 Emissions across Alternative Assumptions and Policies (2025–2050)**




The DIEM model estimates any changes in NOx emissions from generation based on fuel choices, control equipment, and relevant emissions policies. In Figure 23, these emissions from generation are combined with declines in NOx from ICE vehicles to shown the net benefits of electric vehicles. NOx emissions from nonelectric light-duty vehicles are estimated based on changes in VMT from NREL (2018b), combined with a California ARB (2005) study that estimated average NOx emissions from vehicles at 0.34 grams per mile (for comparison, the EPA Tier I Standard is 0.40 g/mile). While this may somewhat overestimate the emissions benefits of switching away from ICE vehicles as they might be configured several decades in the future, it provides a starting point for estimating net changes in emissions.

The results in Figure 23 suggest that the additional NOx emissions from any increases in coal and NGCC generation are significantly outweighed by the reductions in NOx from on-road vehicles. Across all the years and EV forecasts shown, reductions from ICE vehicles are 4–14 times any increase in emissions from additional generation to supply electric vehicles.

**Figure 23. Changes in NOx Emissions across EV Scenarios (“Home/Public” Charging, Reference Fuel Prices)**




While the results in Figure 23 are from the first scenario investigated (Figure 14)—where most generation for electric vehicles comes from new NGCC units, Figures 24 and 25 look in more detail at NOx and SO2 emissions from generation, respectively, across several reference cost and policy-option assumptions. Among the variations in baseline market conditions (the first four groups of columns in the graphs), high gas prices lead to the highest emissions as they encourage existing coal units to increase generation. Low gas prices or renewables costs in the baseline will move emissions in the opposite direction. In the Intermediate EV and NREL Medium EV scenarios, emissions rise slightly under reference assumptions about prices and costs compared to those in the baseline. For either type of emissions, a continuation of current PTC/ITC for wind and solar is sufficient to offset this emissions increase compared to the baseline. A carbon price starting at $5 per ton and growing at 5 percent per year leads to significant declines in total emissions from generation, and higher carbon prices expand upon these trends. Bear in mind that these figures only consider how different factors will affect emissions from generation—net NOx emissions from replacing ICE vehicles with electric vehicles are always negative when factoring in the declines in on-road emissions (these declines remain at the levels shown by the blue bars in Figure 23; Figure 24 shows how the red bars in Figure 23 could be reduced).

**Figure 24. NOx Emissions from Generation across Alternative Assumptions ("Home/Public" Charging)**

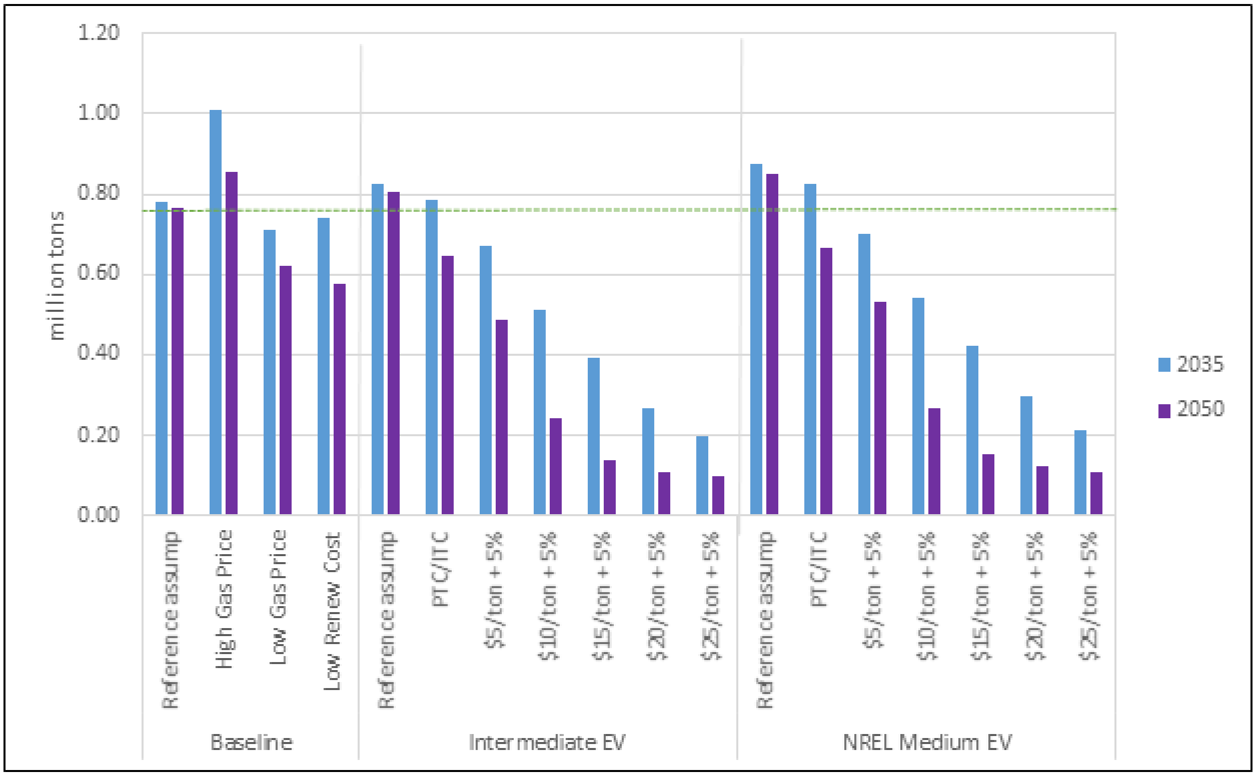
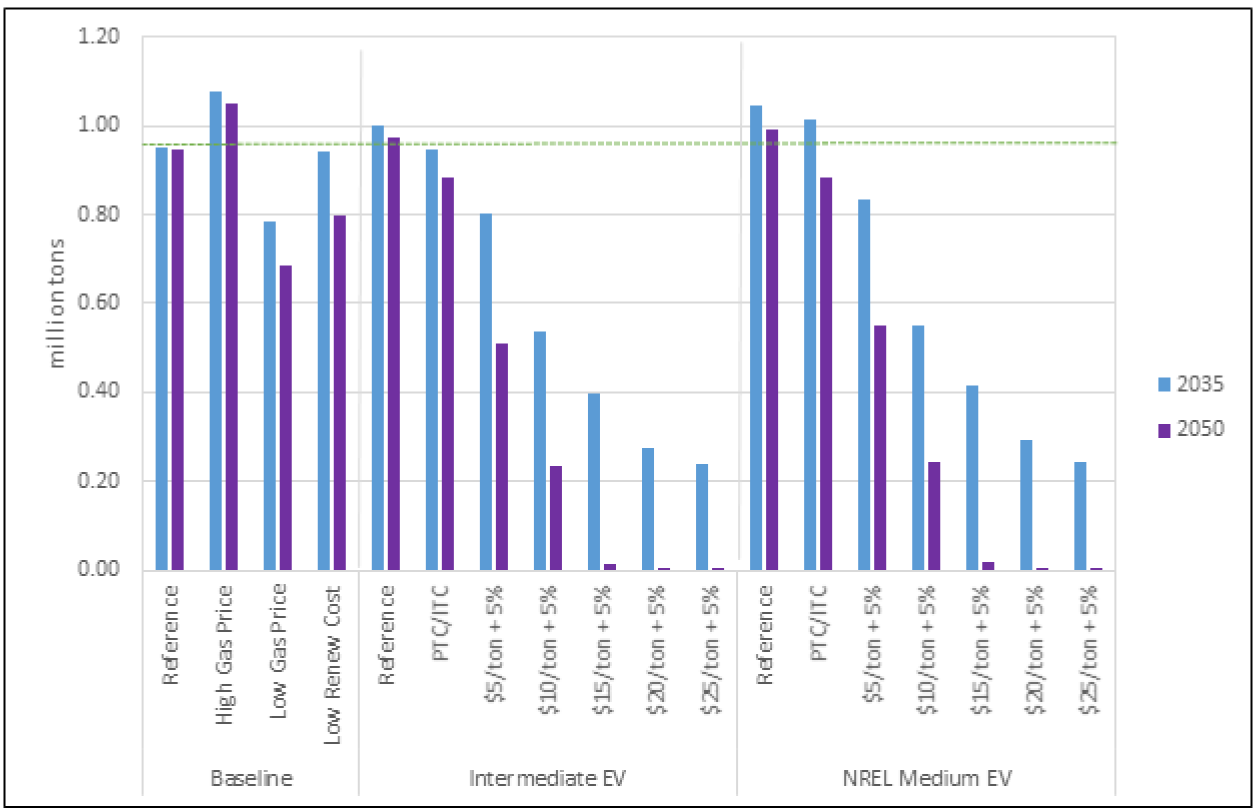



**Figure 25. SO2 Emissions from Generation across Alternative Assumptions ("Home/Public" Charging)**



## EAST COAST MODEL RESULTS FOR ELECTRIC VEHICLE SCENARIOS

Collectively, the 18 states in the East Coast region (plus the District of Columbia) represent around 40 percent of national vehicle miles traveled by electric vehicles in the NREL (2018b) forecasts. Their transportation network is also broadly linked through the I-95 highway corridor. However, there are significant differences across the East Coast with regards to the existing generation mix, environmental policies in place, fuel prices, and opportunities for renewables. These differences will affect how generation is likely to respond to increased electricity demand from vehicles.

The Southeast region today has a generation mix that is relatively more dependent on coal generation than the rest of the East Coast (Figures 9 and 10)—both regions have comparatively high levels of nuclear generation. The Southeast also has promising opportunities for solar PV, but little onshore wind resources. Figure 26 uses the standard set of assumptions about fuel prices and renewables costs from the Reference case to look at how different levels of EV growth will affect generation in the region.

As was seen in the national results in Figure 14, new natural gas in the Southeast supplies a significant share of the incremental generation for EVs, particularly over the next decade. Existing nuclear plants also have higher generation over all the years (through remaining in operation) than in the baseline without demand from vehicles. A few more renewables are built by 2030, but more significant growth in wind and especially solar occurs in 2040 and 2050. In the higher EV demand scenarios, some of the emissions benefits of the renewables are offset by existing coal plants generating more—or not retiring—in order to supply the expanding vehicle fleet (net emissions benefits are discussed below). Wind generation, even onshore wind, is not considered to be a cost-effective option in the modeling.

Unlike the Southeast, the Northeast has access to onshore wind, which forms an important part of the response to electric vehicles.[20] Solar PV also plays a significant role by 2050, and existing nuclear plants may remain in operation longer at higher levels of electricity demand. Parts of this Northeast region, both within the RGGI group of states and in states such as Pennsylvania that are not in RGGI, have access to low-priced gas in the AEO 2019 forecasts, leading to some increase in new NGCC generation, in the absence of new policy interventions (see Figure 31 for policy options give different responses). Coal generation within RGGI is limited, however, coal use may be affected in states outside of RGGI (in the modeling, Pennsylvania and Virginia are part of this Northeast region, but are assumed to remain outside RGGI).

[20] Offshore wind resources are also considered in the modeling for states along the East Coast. However, it does not enter the model solution without specific policies to encourage its construction. If recent state announcements about offshore wind development were forced into the modeling, that offshore wind would appear in the baseline results shown in Figures 9 and 10, not in these incremental adjustments that are occurring in the future solely as a response to electric vehicles.

**Figure 26. Changes in Southeast Generation across EV Scenarios ("Home & Public" Charging)**

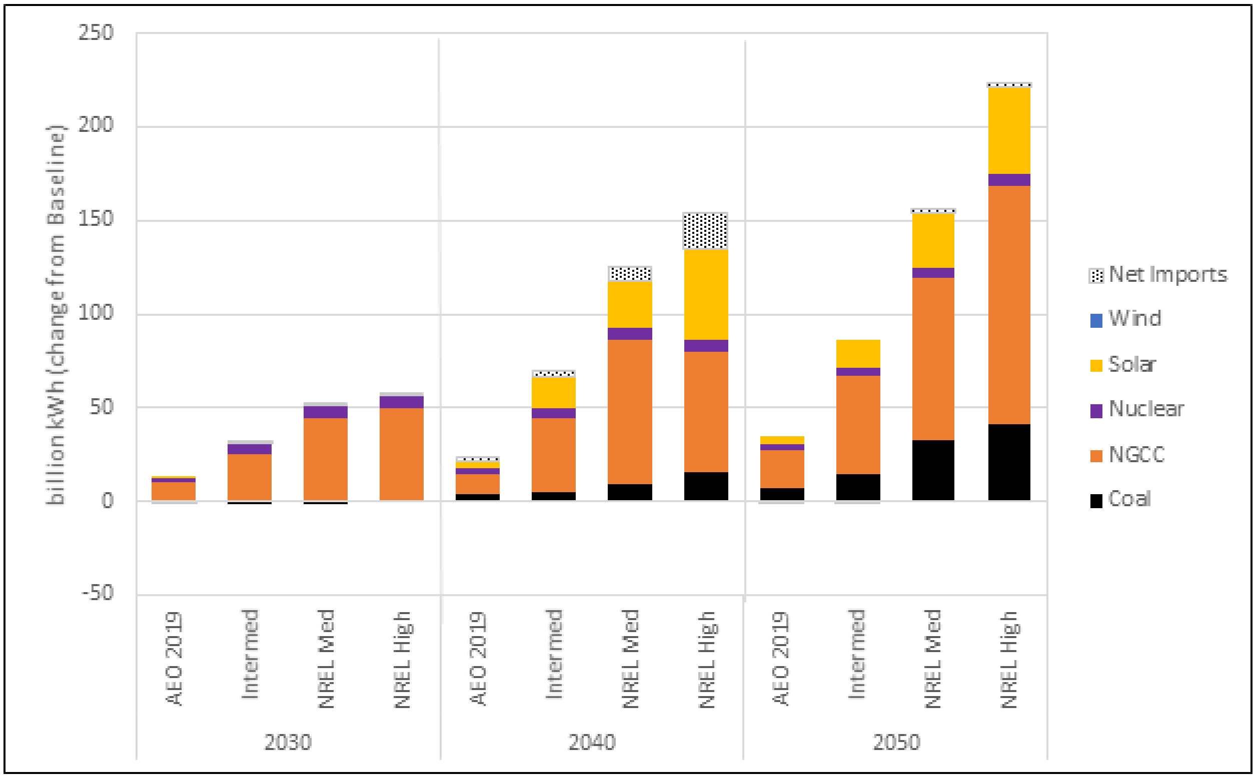
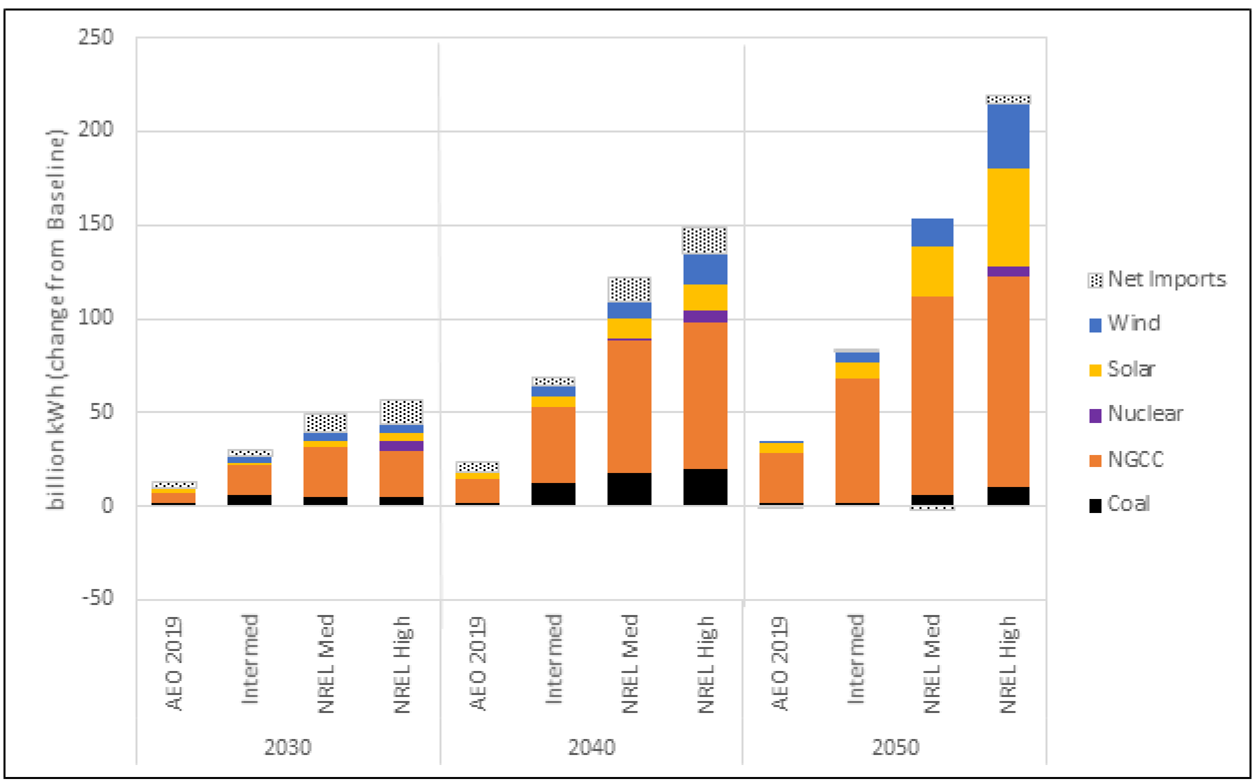



**Figure 27. Changes in Northeast Generation across EV Scenarios ("Home & Public" Charging)**



The next two figures illustrate the sensitivity of model results for the Intermediate EV scenario in 2050 (Figures 26 and 27) to different charging patterns, renewables costs, and natural gas prices.[21] The first four bars in each graph compare how different EV charging behavior throughout the day affects the types of generation needed. For the Southeast, impacts on coal and nuclear generation are limited, with a fairly consistent increase across the charging options. There are much more significant shifts in the choice between NGCC and solar generation. If charging is concentrated during daylight hours (whether through policy interventions or some sort of time-of-use pricing to influence people's behavior or other technologies such as utility-scale or residential battery storage), solar PV has the potential to provide a large fraction of the generation needed for EVs. Electricity imports also can shift as states within the Southeast region trade with nearby states such as Mississippi or, to a lesser extent, with states farther to the west that may have extra wind supplies.

In the Northeast (Figure 29), changes in EV charging behavior have more limited effects on the generation choices. Coal plays much less of a role since there are fewer existing units around, and current policies such as RGGI discourage this option. Wind has a larger role, even though it already plays a larger part in the baseline generation in the region. Solar PV is slightly less effective in the Northeast than in the Southeast, and also forms a larger share of baseline generation, resulting in smaller adjustments based solely on charging behavior (other policy interventions can alter this finding—see Figure 31). States within the defined Northeast region (which includes Pennsylvania and Virginia outside of RGGI) may also be inclined to export electricity to surrounding states outside of the 12-state Northeast region to take advantage of low-prices gas supplies (this includes states that are not part of the defined Northeast region, but are part of the interconnected PJM electricity market).

The last three columns in Figures 28 and 29 look at how sensitive the results are to different natural gas prices and renewables costs. In the Southeast, a low gas price encourages so much new gas generation in the baseline—even without higher demand from vehicles—that fewer opportunities are available for additional expansion of the NGCC fleet to supply EV demand (coal that would have retired without EV demand is more likely to remain in operation in this higher demand environment than it was with low gas prices and low electricity demand growth). A similar story can be seen in the Southeast for low-cost renewables, which already penetrate the market in the baseline—without demand from EVs—and thus are less affected if demand were higher in a future with significant EV penetration. Other differences across market assumptions include nuclear in a high-gas price environment, where the nuclear plants are already likely to remain in operation and don't have additional room to generation more to supply electricity in the EV scenarios.

In the Northeast, a low gas price leads to nuclear retirements in the baseline (without EVs), however, higher demand growth in the Intermediate EV scenarios encourages them to remain in operation. Conversely, a high gas-price environment has already led to nuclear operation in the baseline, leaving no additional room to expand nuclear generation to supply additional EV demand. Similarly, low-cost renewables significantly increase the solar and wind shares of total generation in the Northeast in the baseline, thus expansion of renewables in response to EV demand is more limited (additional policies can alter this outcome—see Figure 31).

[21] Negative net imports are net exports from states within one of the two defined regions to surrounding states outside of that region.

**Figure 28. Changes in Southeast Generation in 2050 across Alternative Assumptions (Intermediate EVs)**

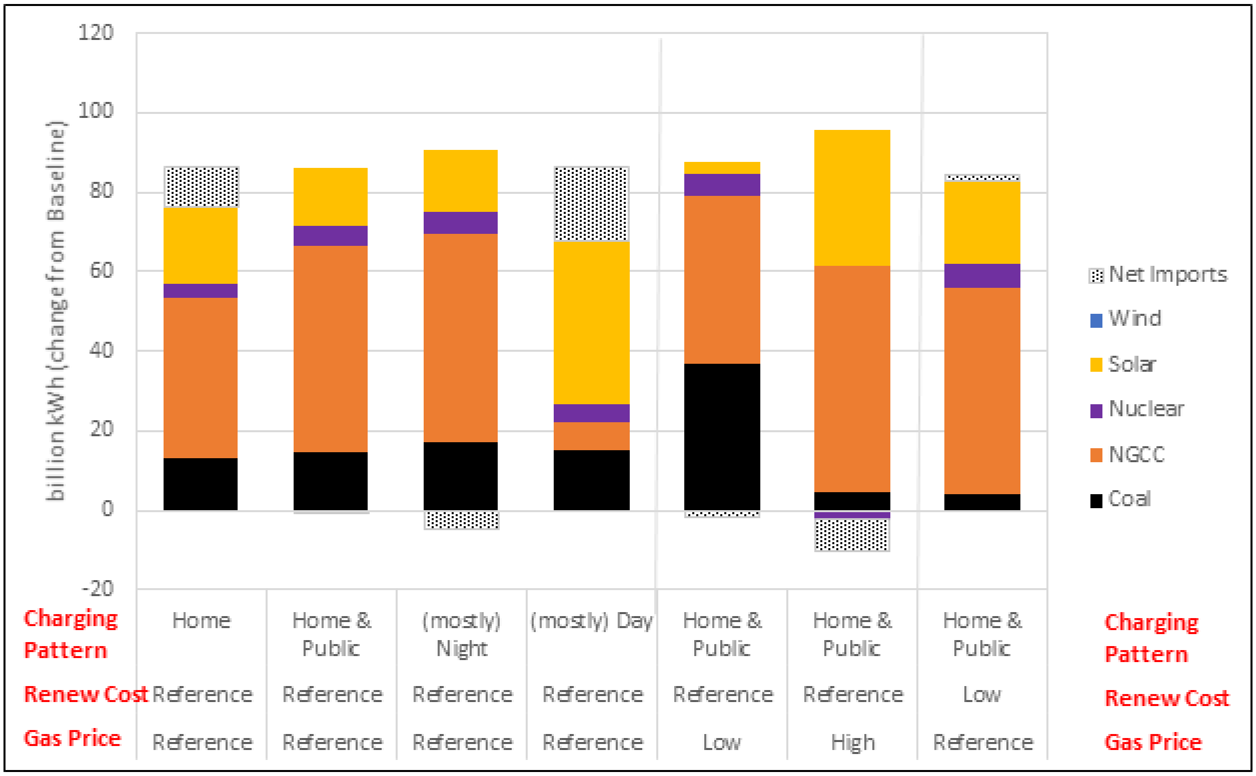
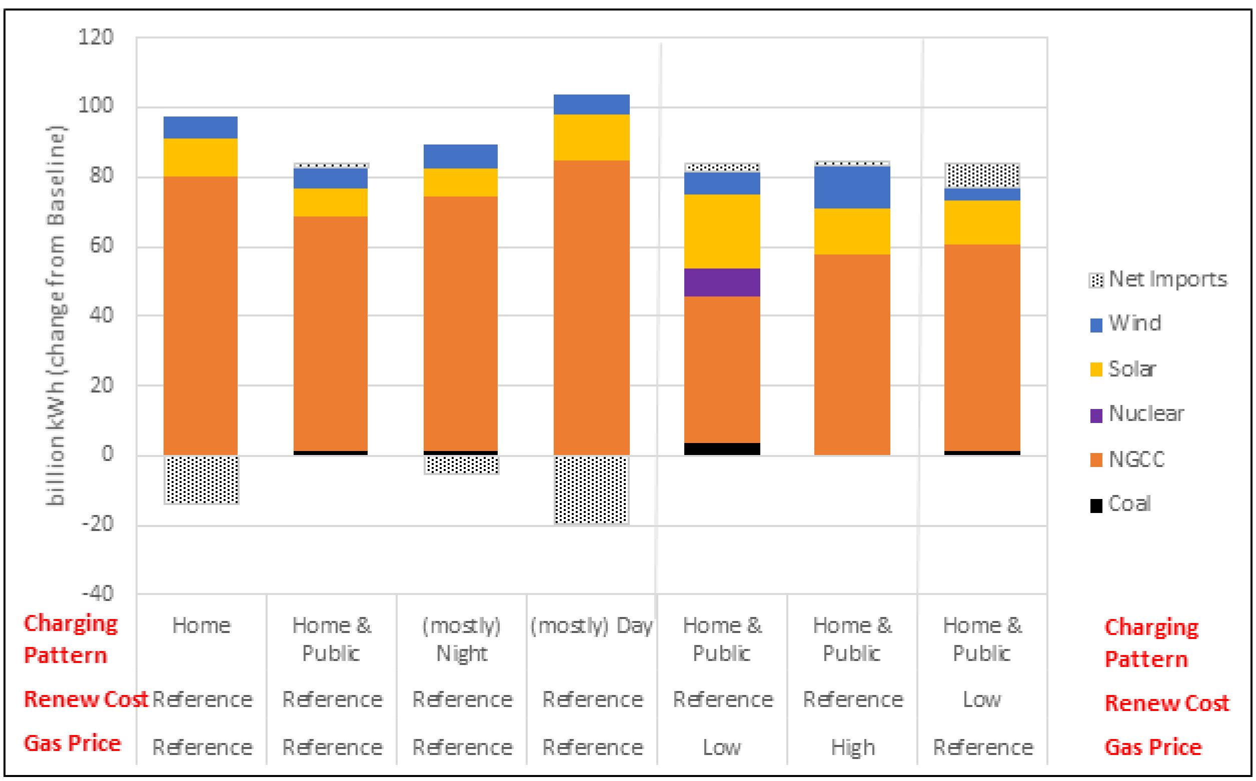



**Figure 29. Changes in Northeast Generation in 2050 across Alternative Assumptions (Intermediate EVs)**

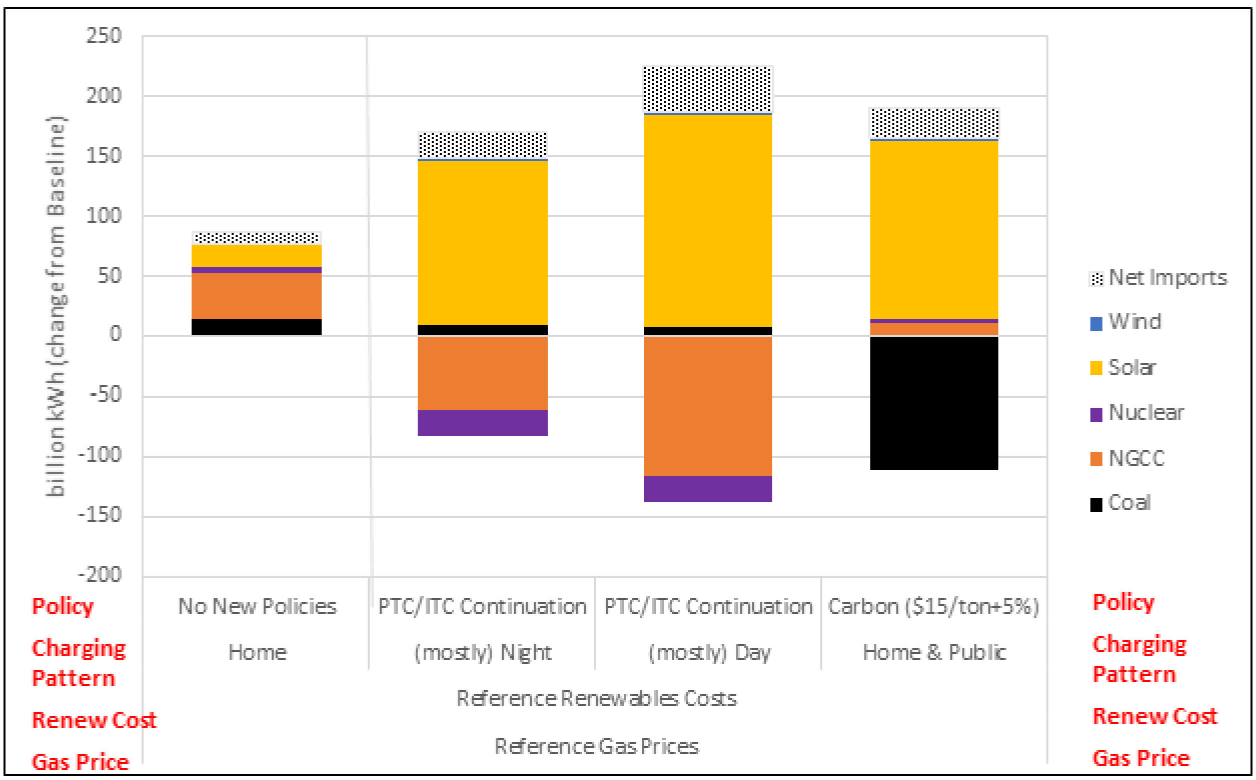



Figures 30 and 31 compare the effects of the PTC/ITC and carbon-price policy interventions by 2050 across several types of EV charging behaviors, focusing on the Reference assumptions for natural gas prices and renewables costs. The first column in each of these graphs repeats the first column in Figures 28 and 29, respectively, to highlight how the policies alter the generation mix. In the Southeast, continuation of current PTC/ITC for renewables as part of an integrated response to EV growth results in all of the new electricity demand by EVs coming from solar PV. There are also fewer new NGCCs built to supply baseline demands in other sectors of the economy (some nuclear plants may also be displaced). In the Northeast, all EV electricity demand is supplied by a mix of new wind and solar. There are fewer impacts of the PTC/ITC extension on units supplying baseline demand in this region since the emissions intensity in many states in the Northeast is already low by 2050 (see Figure 13).

In the Southeast, applying a $15 per ton carbon price in 2025 that grows at 5 percent per year (around $50 by 2050) results in significant declines in coal generation by 2050 (and earlier). These declines—and the new demand from vehicles in the Intermediate EV scenario—are offset by increases in solar. The increase in solar PV in the Southeast is similar to that under the PTC/ITC continuation policy, but the effects on fossil generation are quite different since a carbon price has more effect on existing coal units than new NGCC units. A carbon price, unlike the PTC/ITC extension, does more to encourage operation of existing nuclear units.

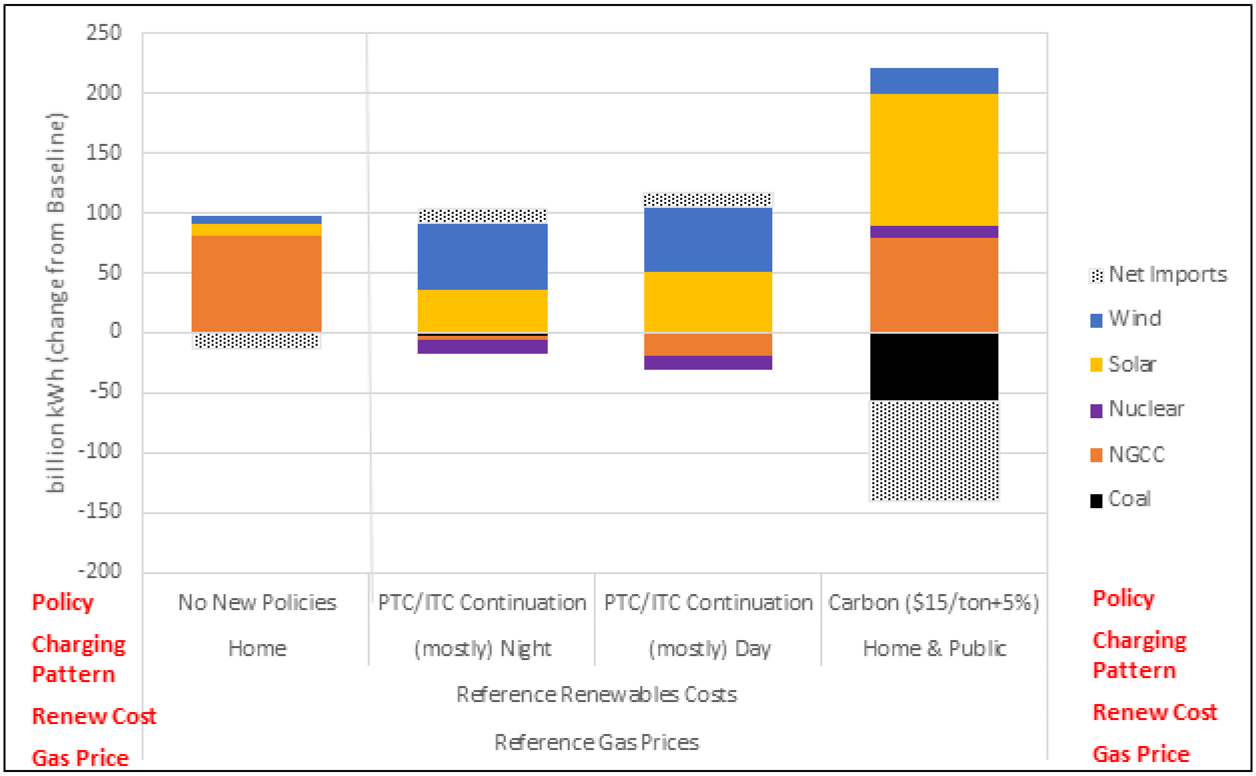
While many of the states in the defined Northeast region have a carbon price through the RGGI program, the "$15/ton+5 percent/year" carbon price used in Figure 31 is higher than the RGGI Cost Containment Reserve trigger price for the next several decades (excluding the model year of 2020 since the carbon price of $15/ton starts in 2025 in the model).[22] This carbon price, which reaches $50 per ton by the year 2050 shown in the graph, leads to additional coal-plant retirements (in states outside of the ten RGGI members). In the short- and medium-term, the carbon price shifts generation overall—and for EVs in particular—into new, efficient NGCC units, some additional wind generation, and significant amounts of new solar. The decline in coal generation is largely offset by these new NGCC units.

**Figure 30. Changes in Southeast Generation in 2050 across Alternative Policy Options (Intermediate EVs)**




[22] The ten RGGI member states maintain their emissions caps throughout the modeling.

**Figure 31. Changes in Northeast Generation in 2050 across Alternative Policy Options (Intermediate EVs)**




A shift into electric vehicles has particularly pronounced net benefits for NOx emissions on the East Coast. There are relatively limited increases in NOx from new NGCC units, there are retirements of coal and existing NGCC plants, and the avoided NOx emissions from ICE vehicles are high in these states as large numbers of nonemitting vehicles enter the market (state-level forecasts from NREL 2018b). For most years and levels of EV penetration, avoided NOx emissions are 10–25 times higher than the additional NOx from generation (other years have even higher ratios, if they are smaller in total benefits).

Figures 34 and 35 focus on total NOx emissions from generation (the small, positive red bars in Figures 32 and 33) to see which market forecasts and policy choices will affect these levels, and to what degree. Overall, total NOx emissions do not increase materially from the power sector in response to additional demand from vehicles.[23] As was true in Figures 32 and 33, net emissions are always negative when factoring in declines in on-road NOx emissions. The model estimates that high gas prices do the most to raise baseline emissions, while low gas prices or renewables costs have little effect particularly in 2035. For any additional generation for vehicles in the Intermediate and NREL Medium scenarios, which may cause a trivial increase in generation NOx emissions, those emissions changes can be offset by PTC/ITC subsidies or small carbon prices.

[23] The majority of the CO2 or NOx emissions increases shown—if any—happen in Northeast states not included in the RGGI program as that region is defined for this analysis.

Figure 32. Changes in Southeast NOx Emissions across EV Scenarios (“Home/Public” Charging)

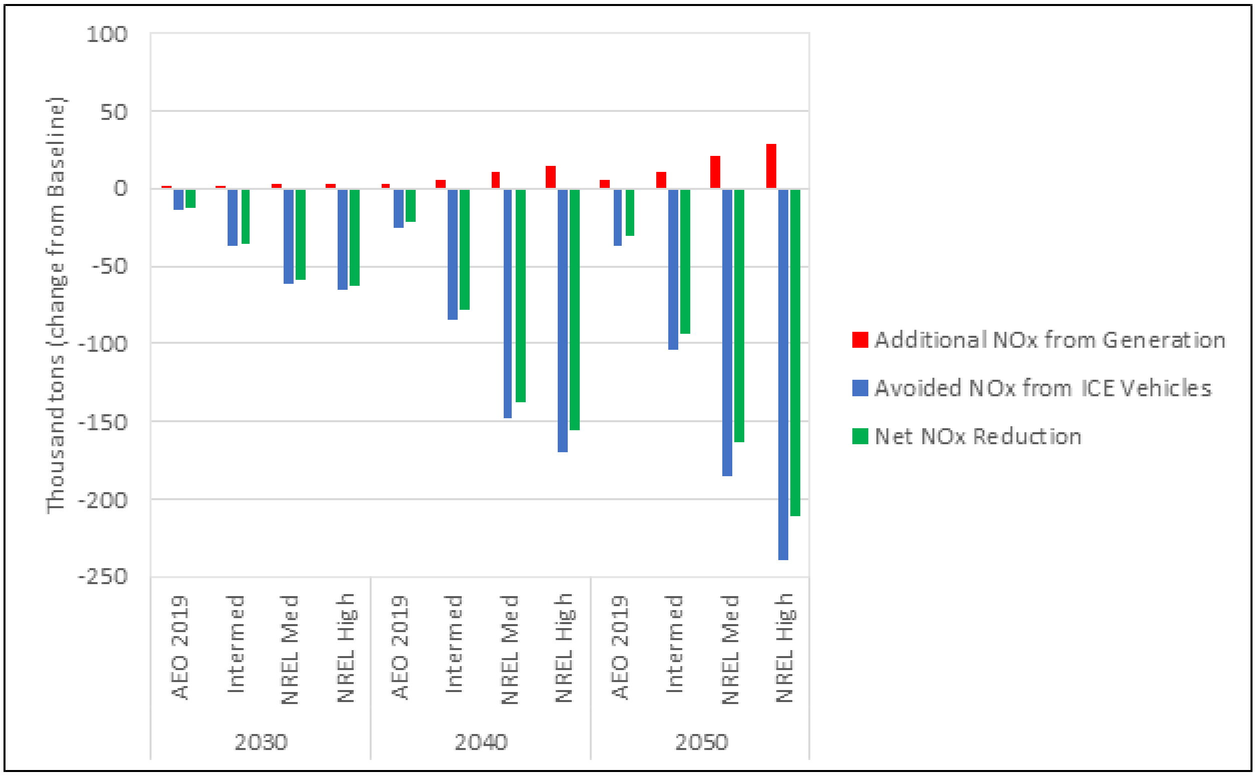



Figure 33. Changes in Northeast NOx Emissions across EV Scenarios (“Home/Public” Charging)

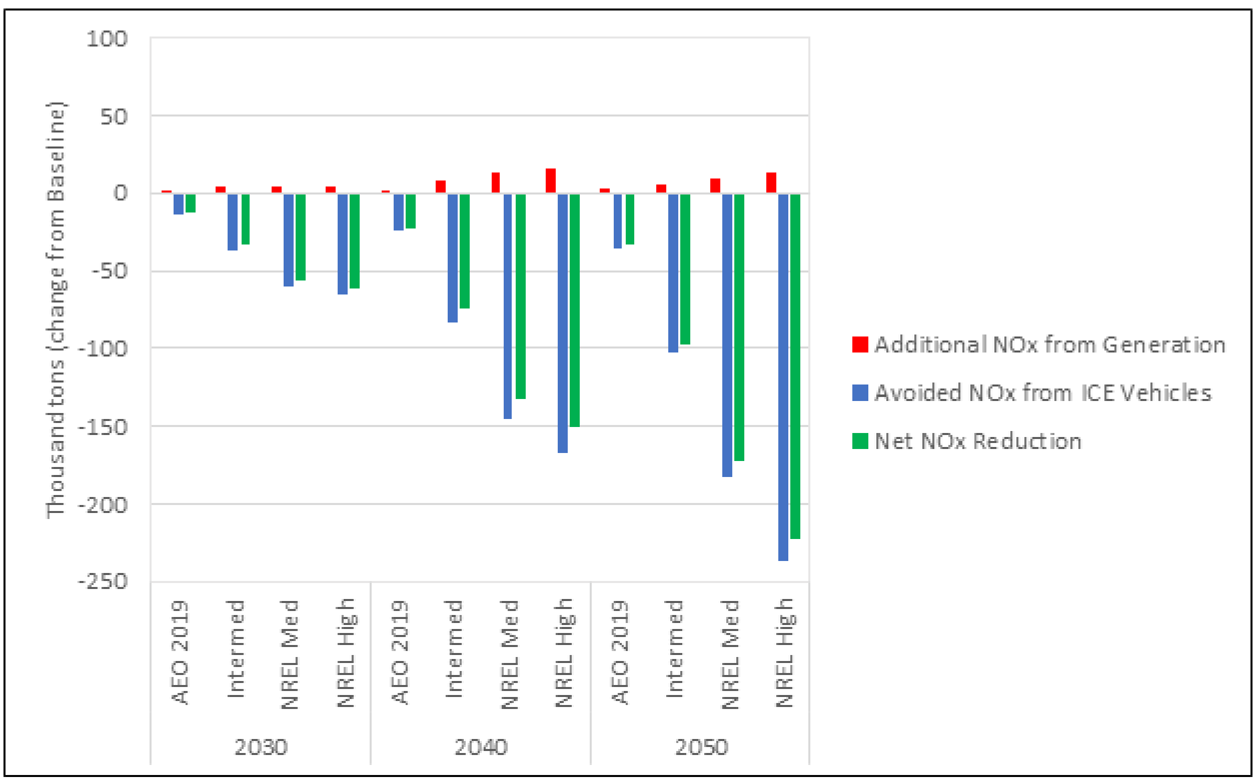


**Figure 34. Southeast NOx Emissions from Generation across EV Scenarios ("Home/Public" Charging)**

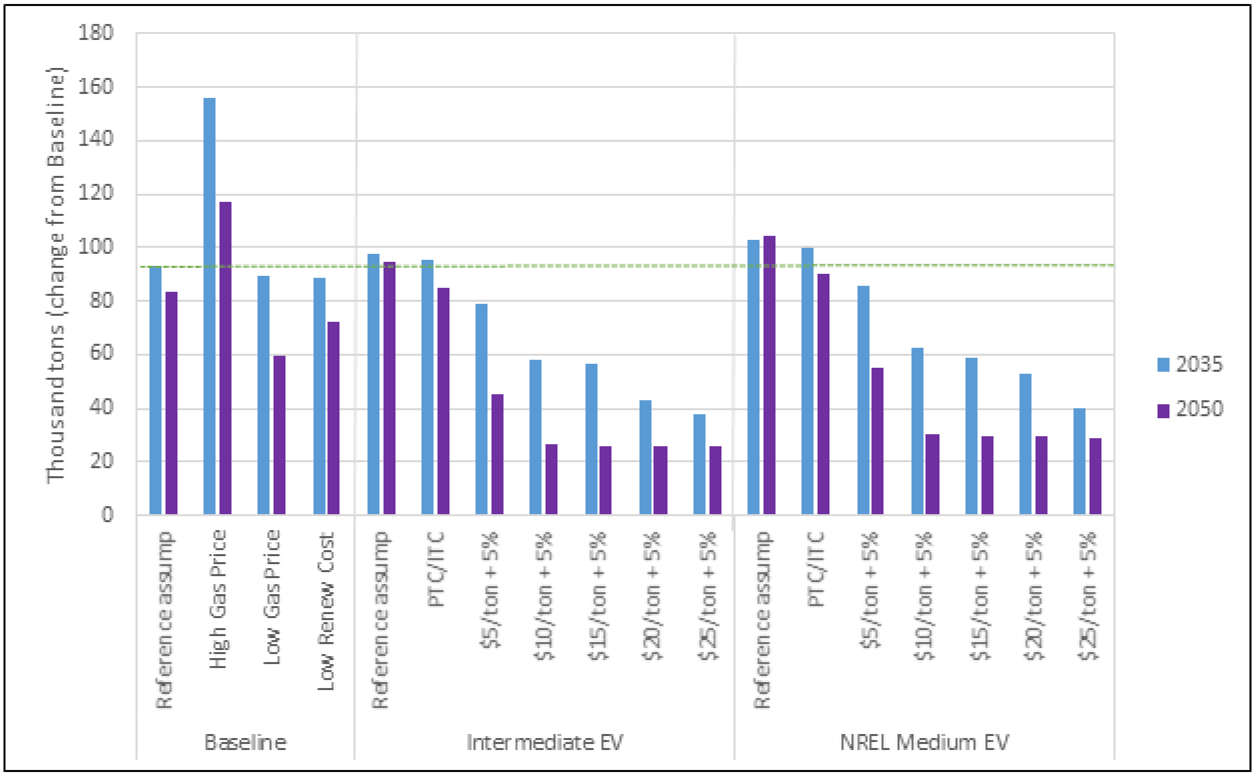
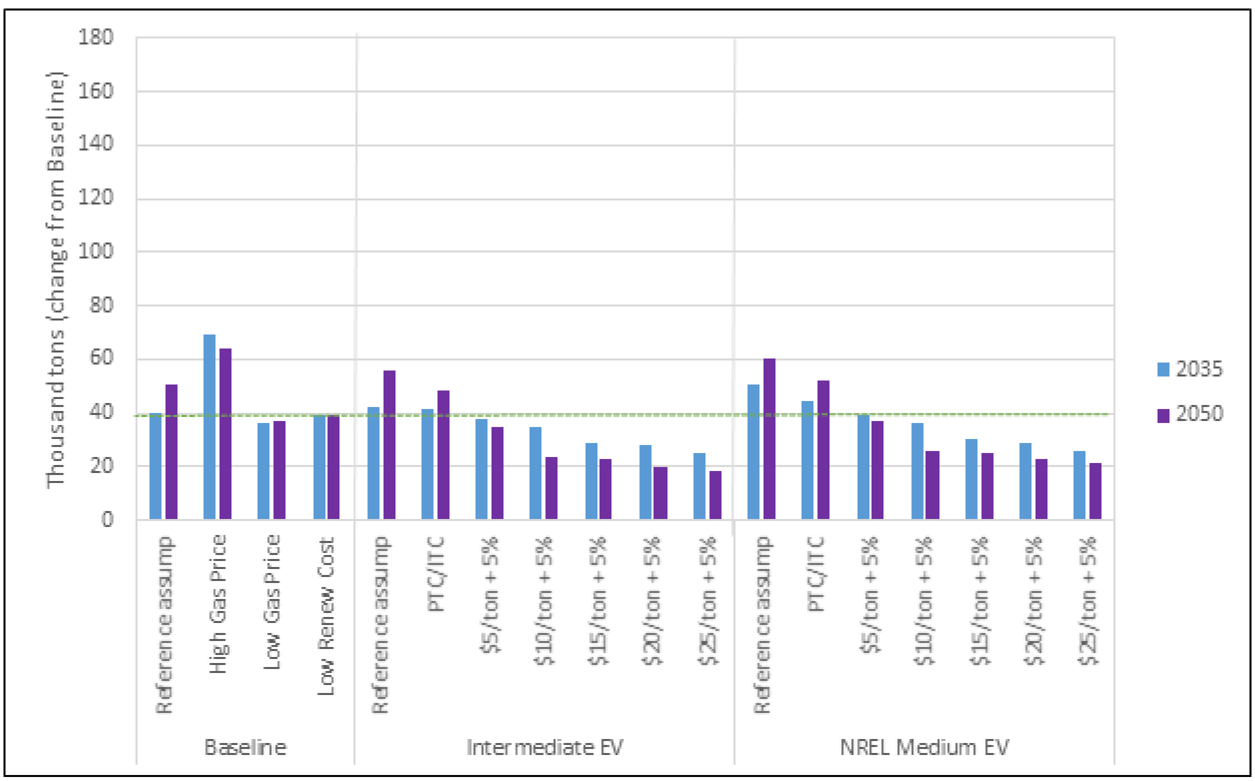



**Figure 35. Northeast NOx Emissions from Generation across EV Scenarios ("Home/Public" Charging)**

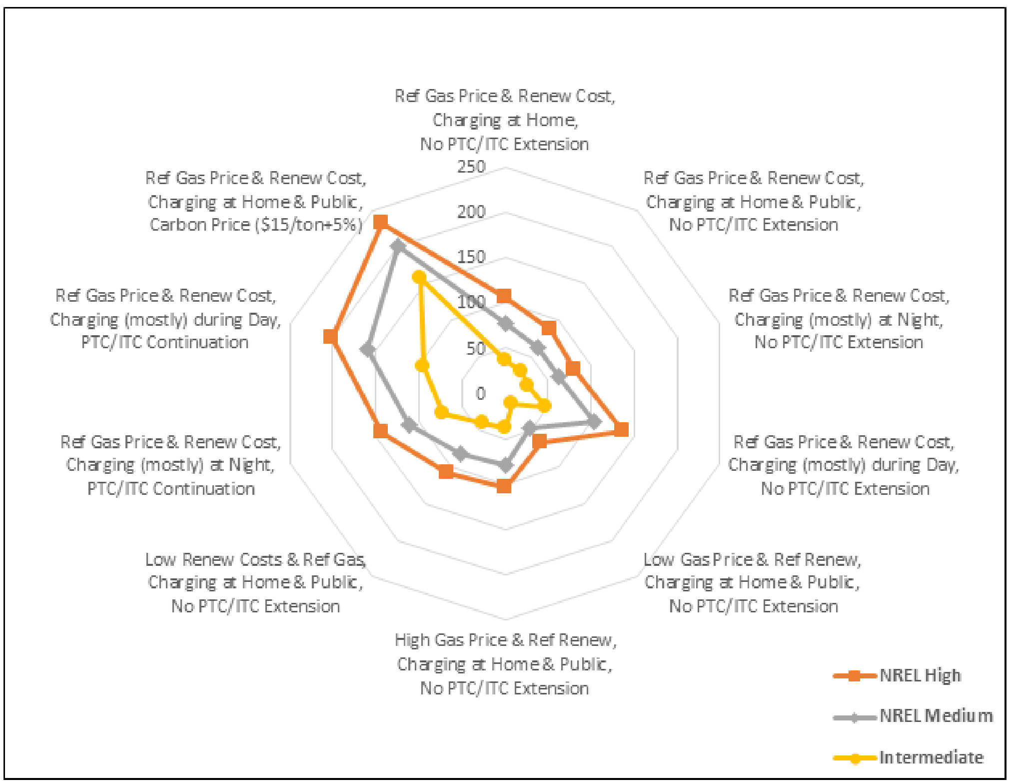



The next two figures combine generation $CO_2$ emissions impacts for East Coast states with reductions in on-road $CO_2$ emissions to get net impacts of the different EV scenarios across assumptions about the future of the electricity industry. Figure 36 looks at annual emissions benefits in 2050 for the Southeast region across three sets of variables for each data point and for three EV scenarios (corresponding to the generation impacts shown in Figures 28 and 30). The top line in each scenario label states whether reference levels for natural gas prices and renewables costs are used in determining emissions results or if low/high prices and costs are used. The second line refers to a specific EV charging pattern, and the third line states whether or not current tax subsidies for renewables are extended or whether there is a carbon price.

Starting with the scenario label at the top of Figure 36 and including the next three clockwise entries, these net benefits represent variations in charging behavior around the reference assumptions for fuel prices and renewables costs. The results suggest that, even for a set of assumptions about the future that lead to the additional fossil generation shown in Figure 27, electric vehicles provide net $CO_2$ emissions benefits of 82 to 137 MMT$CO_2$ per year by 2050 for the NREL High EV scenario, 63 to 103 MMT$CO_2$ per year for the NREL Medium scenario, and 28 to 47 MMT$CO_2$ for the Intermediate scenario. Differences across the first three charging patterns—"Home," "Home & Public," and "(mostly) Night"—are relatively minor since there are fewer opportunities than at the national level to choose between wind generation (concentrated at night) and solar generation (during the day). Of these three options, the largest net emissions benefits in the Southeast region happen in the "Home" charging scenario, but this is because of increased imports of electricity into the region rather than large differences in the generation response. Charging during the day, however, has net benefits that are significantly larger than the other charging options since daylight charging encourages a lot of new solar generation in the Southeast.

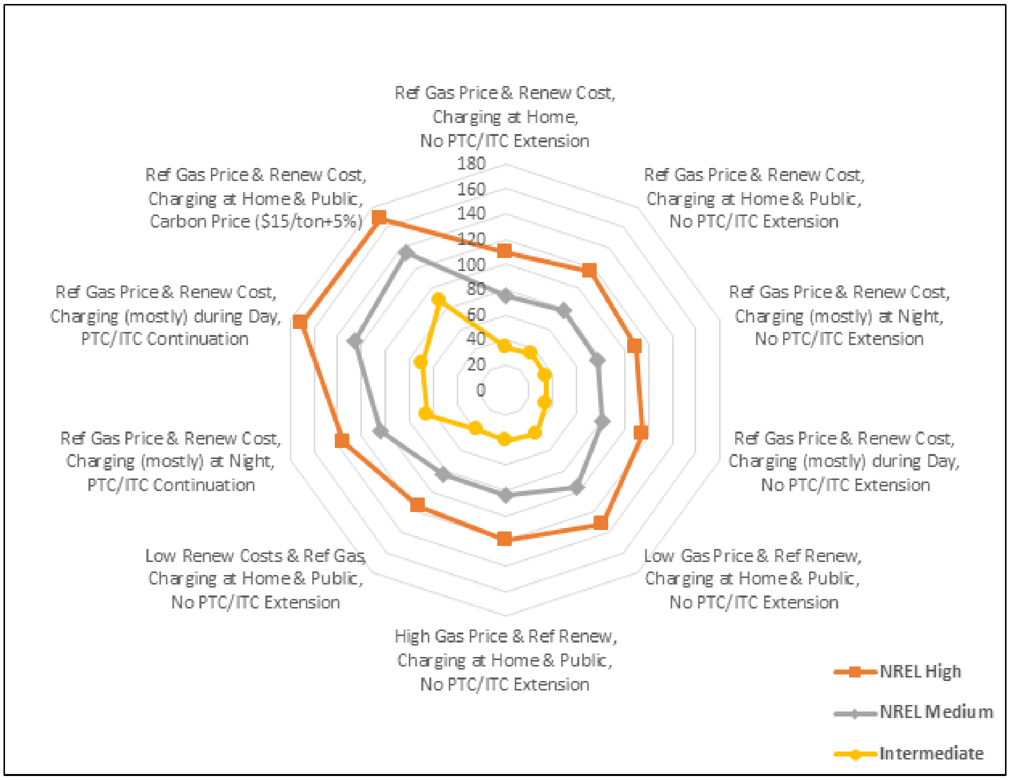
Moving farther clockwise around the circle, the next three scenario labels for the Southeast show some variation for low natural gas prices, but less for high gas prices or low renewables costs. Finally, the last three scenario labels in Figure 36 show the net emissions benefits for the Southeast if EV adoption is combined with a continuation of PTC/ITC credits or carbon prices. The benefits in these cases are relatively large for all of the EV scenarios, with similar impacts of an PTC/ITC extension with daylight charging and the $15 per ton carbon price shown. A PTC/ITC extension combined with (mostly) nighttime charging has fewer additional benefits for the Southeast due to the relative lack of onshore wind resources.

**Figure 36. Southeast Net Annual $CO_2$ Emissions Benefits of EVs in 2050 (MMT$CO_2$)**




The Northeast also shows net $CO_2$ emissions benefits from electric vehicles across all the levels of EV adoption and model sensitivities (Figure 37). There is less variation in benefits across the sensitivities and assumptions than in the Southeast region since the emissions intensity per kWh in the Northeast is below national averages and existing policies such as RGGI affect the generation choices to supply EVs. Without policy interventions, alterations in charging behavior have only minor effects on net emissions benefits since new NGCC units provided most of the electricity for EVs in these model runs (Figure 29). However, additional policies such as the PTC/ITC continuation or carbon prices that are applied to all Northeast states (and higher by 2050 than the RGGI levels in 2030) lead to additional reductions in emissions from generation and higher net benefits. As was shown in Figure 31, some of these options can not only supply higher electricity demand from vehicles, but also displace fossil generation that would have supplied other sectors of the economy in the baseline.

**Figure 37. Northeast Net Annual CO2 Emissions Benefits of EVs in 2050 (MMTCO2)**




## CONCLUSIONS AND NEXT STEPS

The expanding utilization of electric vehicles is going to transform both the transportation and the electricity-generation sectors over the coming decades. How these transformations occur will, to a large degree, determine the net emissions benefits of these vehicles and their value in meeting any long-term climate and environmental goals. This paper examines how electricity may be generated to power EVs and the ways in which their contributions to environmental policies can be maximized. The analysis uses external forecasts of light-duty vehicle demand, combined with a detailed electricity dispatch model of U.S. wholesale electricity markets, to explore generation decisions and potential policy options to amplify the emissions reductions associated with replacing conventional vehicles with electric vehicles.

Broadly, the analysis finds that EVs can provide significant net emissions benefits, which increase over time as the vehicles form larger shares of the total on-road fleet. There are potential roles for policy interventions on the generation side of the equation that can expand these benefits through encouraging renewable generation. Either tax credits for renewables or options that put a price on carbon can be effective. A number of variables in future markets will influence how these trends play out—natural gas prices, EV charging patterns, and technology advancements that affect the costs of electricity generation.

While this paper has attempted to explore some of the most important sensitivities regarding generation for electric vehicles, a number of extensions in the future could shed additional light on the topic. Additional forecasts of EV adoption and other potential adjustments in the transportation field (e.g., changings in ride sharing, urban planning, or new options such as electric scooters and bikes) may alter how many non–fossil fuel vehicles are on the roadways. Trends in light-duty vehicle electrification are likely to extend to other parts of the economy such as heavy-duty vehicles, industry, and residential applications. Such increases in electricity demand will affect the generation sector as a whole and how electricity is provided to EVs. Improvements in battery storage—and the modeling of storage impacts or even using vehicles as storage for the grid—has the potential to affect the conclusions drawn from electricity-dispatch modeling (although the range of charging patterns investigated here may bookend the ability of storage to shift charging demand from day to night). Finally, new policy proposals such as deep carbonization targets over the next several decades will accelerate the need to capitalize on the emissions benefits of EVs and ensure that they are powered using renewable energy.

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