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**Technical Report**
NREL/TP-5500-55588
September 2013

Contract No. DE-AC36-08GO28308

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# List of Acronyms

| | |
|---|---|
| 4HA | 4-hour-ahead |
| BA | balancing authority |
| C&M | capital and maintenance |
| CAISO | California Independent System Operator |
| CC | combined-cycle |
| CEM | continuous emissions monitoring |
| CF | capacity factor |
| CFE | Comisión Federal de Electricidad |
| CG | Columbia Grid |
| $CO_2$ | carbon dioxide |
| CSP | concentrating solar power |
| CT | combustion turbine |
| CY | calendar year |
| DA | day-ahead |
| DC | direct current |
| DCOE | delivered cost of energy |
| DG | distributed generation |
| DOE | U.S. Department of Energy |
| EFOR | equivalent forced outage rate |
| EIA | Energy Information Administration |
| EPA | Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| ERCOT | Electric Reliability Council of Texas |
| FFT | fast Fourier transform |
| GHI | global horizontal irradiance |
| GT | gas turbine |
| GW | gigawatt |
| GWh | gigawatt hour |
| HRSG | heat recovery steam generator |
| IID | Imperial Irrigation District |
| ISO | independent system operator |
| LAWP | Los Angeles Department of Water and Power |
| LRS | Loads and Resources Subcommittee |
| MAE | mean average error |
| MISO | Midwest Independent System Operator |
| MMBtu | million British thermal units |
| MW | megawatt |
| MWh | megawatt hour, energy |
| MW-h | megawatt hour, reserves |
| NTTG | Northern Tier Transmission Group |
| $NO_X$ | nitrogen oxides |
| NREL | National Renewable Energy Laboratory |
| NWP | numerical weather prediction |
| O&M | operations and maintenance |
| PC1 | Portfolio Case 1 |

| | |
|---|---|
| PPA | power purchase agreement |
| PV | photovoltaic |
| RBC | reliability-based control |
| ReEDS | Regional Energy Deployment System |
| RMSE | root-mean-square error |
| RPS | renewable portfolio standard |
| SMUD | Sacramento Municipal Utility District |
| $SO_2$ | sulfur dioxide |
| SPP | Southwest Power Pool |
| SPI | solar power index |
| ST | steam turbine |
| TEPPC | Transmission Expansion Planning Policy Committee |
| TRC | Technical Review Committee |
| TW | terawatt |
| TWh | terawatt hour, energy |
| TW-h | terawatt hour, reserves |
| VG | variable generation |
| VOM | variable operations and maintenance |
| WC | WestConnect |
| WECC | Western Electricity Coordinating Council |
| WI | Western Interconnection |
| WITF | Wind Integration Task Force |
| WWSIS-1 | Western Wind and Solar Integration Study Phase 1 |
| WWSIS-2 | Western Wind and Solar Integration Study Phase 2 |

# Executive Summary

The electric grid is a highly complex, interconnected machine, and changing one part of the grid can have consequences elsewhere. Adding wind and solar affects the operation of the other power plants and adding high penetrations can induce cycling of fossil-fueled generators. Cycling leads to wear-and-tear costs and changes in emissions. Phase 2 of the Western Wind and Solar Integration Study (WWSIS-2) evaluated these costs and emissions and simulated grid operations for a year to investigate the detailed impact of wind and solar on the fossil-fueled fleet. This built on Phase 1, one of the largest wind and solar integration studies ever conducted, which examined operational impacts of high wind and solar penetrations in the West (GE Energy 2010).

Frequent cycling of fossil-fueled generators can cause thermal and pressure stresses. Over time, these can result in premature component failure and increased maintenance and repair. Starting a generator or increasing its output can increase emissions compared to noncyclic operation. And operating a generator at part-load can affect emissions rates. Utilities are concerned that cycling impacts can significantly negate the benefits that wind and solar bring to the system. And to plan accordingly, power plant owners need to understand the magnitude of cycling impacts.

In WWSIS-2, we calculated these wear-and-tear costs and emissions impacts. These data were incorporated into commercial software that simulates operations of the western grid (which includes the United States, Canada, and Mexico) on a subhourly basis, because wind and solar output can change within the hour. We designed five hypothetical scenarios to examine up to 33% wind and solar energy penetration in the Western U.S. and to compare the impacts of wind and solar. We then examined how wind and solar affected operation, costs, and emissions from fossil-fueled generators. This work was overseen by a Technical Review Committee (TRC) to ensure that assumptions, methodologies, and analyses were realistic and credible. Our results are based on the specific characteristics of the western grid and key assumptions, including an average gas price of \$4.60/MMBtu, significant balancing authority cooperation, and least-cost economic dispatch and transmission usage that does not model bilateral transactions. The goal of WWSIS-2 is to quantify the cycling impacts that are induced by wind and solar. It does not address whether wind and solar should be built, but rather what happens if they are built.

In this study, we found that up to 33% of wind and solar energy penetration increases annual cycling costs by \$35–\$157 million in the West. From the perspective of the average fossil-fueled plant, 33% wind and solar penetration causes cycling costs to increase by \$0.47–\$1.28/MWh, compared to total fuel and variable operations and maintenance (VOM) costs of \$27–\$28/MWh. The impact of 33% wind and solar penetration on system operations is to increase cycling costs but also to displace annual fuel costs by approximately \$7 billion. WWSIS-2 simulates production or operational costs, which do not include plant or transmission construction costs. From the perspective of wind and solar, these additional cycling costs are \$0.14–0.67 per MWh of wind and solar generated compared to fuel cost reductions of \$28–\$29/MWh, based on the generator characteristics and modeling assumptions described in this report.

This study finds that up to 33% wind and solar energy penetration in the United States' portion of the Western grid (which is equivalent to 24%–26% throughout the western grid) avoids 29%–34% carbon dioxide ($CO_2$) emissions, 16%–22% nitrogen oxides ($NO_x$) emissions, and 14%–24% sulfur dioxide ($SO_2$) emissions throughout the western grid. Cycling had very little (<5%) impact on the $CO_2$, $NO_X$, and $SO_2$ emissions reductions from wind and solar. For the average fossil-fueled plant, we found that wind- and solar-induced cycling can have a positive or negative impact on $CO_2$, $NO_x$, and $SO_2$ emissions rates, depending on the mix and penetrations of wind and solar.

# Motivation

Phase 1 of the Western Wind and Solar Integration Study (WWSIS-1) was a landmark analysis of the operational impacts of high penetrations of wind and solar power on the Western Interconnection (GE Energy 2010). The study found no technical barriers to accommodating the integration of 35% wind and solar energy on a subregional basis if adequate transmission was available and certain operational changes could be made. The two most important of the operational changes were increased balancing authority (BA) cooperation and increased use of subhourly scheduling between BAs for generation and interchanges.

The variability and uncertainty of wind and solar can have profound impacts on grid operations. Figure ES-1 shows the most challenging week of the 3 years of data studied in WWSIS-1, when high penetrations of wind and solar caused fossil-fueled plants to cycle more frequently. In this report, cycling is a broad term that means shutting down and restarting, ramping up and down, and operating at part-load.

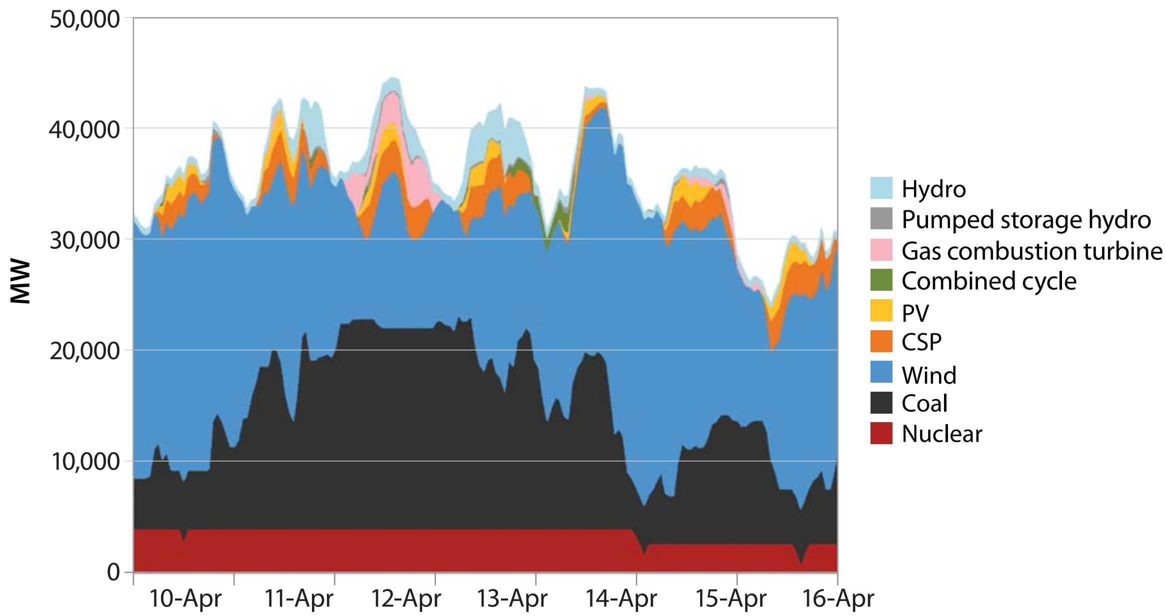


**Figure ES-1. WWSIS-1 dispatch for the most challenging week of 3 years of data analyzed**

Notes: PV, photovoltaic; CSP, concentrating solar power

Utilities were concerned about this type of operation and its impacts on repair and maintenance costs and component lifetimes. In addition, some analysts asserted that the emissions imposed by cycling could be a significant fraction of—or even larger than—the emissions reduced by wind and solar (Bentek Energy 2010; Katzenstein and Apt 2009).

WWSIS-2 was initiated in 2011 to determine the wear-and-tear costs and emissions impacts of cycling and to simulate grid operations to investigate the detailed impact of wind and solar on the fossil-fueled fleet. WWSIS-1 focused on whether high penetrations were technically feasible. In WWSIS-2, we analyzed the cycling impacts in detail and with a higher degree of fidelity. WWSIS-2 simulates operation of the entire Western Interconnection but wind and solar is only added to the U.S. portion of the Western Interconnection because data from outside the United States are lacking.

In WWSIS-2, we dove deep into the impacts of cycling on the operation of fossil-fueled plants. We created new data sets and simulated subhourly grid operations to answer questions such as the following:

- What are the increased costs because of wear and tear on fossil-fueled plants?
- Do these wear-and-tear costs significantly reduce the benefits of wind and solar?
- Will incorporating these costs into optimization of grid operation reduce cycling?
- What are the emissions impacts of cycling?
- How do wind impacts compare to solar impacts on cycling and grid operations?

This study focused on simulating grid operations on a subhourly basis. The results discussed here are specific to the Western Interconnection and the characteristics of the generation and transmission in the West. Adapting these results to other regions would require simulating the characteristics of those regions.

WWSIS-2 was one piece in a larger puzzle of understanding the impacts of wind and solar on the electric power grid. Although WWSIS-2 needed hypothetical scenarios of renewable energy siting and transmission expansion, these were not the main focus. System reliability and stability issues were not the focus of this study either, but are being examined in Phase 3 of WWSIS.

# Background

Impacts of cycling induced by wind and solar additions can be investigated in different ways. The first is from the perspective of a fossil-fueled plant. If that plant is required to cycle more frequently, this can affect wear-and-tear costs and emission rates, which in turn affect that plant's marginal costs and emissions requirements. The second way to frame these impacts is from a system perspective. Wind and solar can impact grid operations by displacing fossil-fueled generation (and the costs and emissions associated with fossil fuels) but also increasing cycling (and the costs and emissions impacts associated with it). This study examines whether these cycling impacts significantly reduce the benefits of displacing fossil-fueled generation.

From the perspective of a power plant owner or a resource planner, the delivered cost of energy (DCOE) from a specific plant is important. From the perspective of the overall system or in terms of societal impacts, costs across the entire system are important. This report attempts to examine cycling impacts from all these perspectives.

The DCOE for a specific plant looks very different for a fossil-fueled plant than for a wind/solar plant, as shown in Figure ES-2. The DCOE for a fossil-fueled plant is a mix of fixed costs and production costs. The DCOE for a wind/solar plant is nearly all fixed capital costs. Fixed costs are those costs that do not change based on how much the plant is run, such as power plant and transmission construction costs and fixed operations and maintenance (O&M) costs. Production costs are the variable costs that increase as the plant produces more electricity and consist of fuel and VOM. VOM, in turn, comprises cycling O&M (which consists of start fuel plus wear and tear from starts and ramps) and noncyclic O&M (which are the routine overhauls and maintenance costs from the plant running at some steady-state output). The *only* capital costs included in production costs are capitalized maintenance (e.g., more frequent boiler tube replacements) because cycling and steady-state operation reduces the lifetimes of those components. Production simulation tools, such as the one used in this study, model operations of the power system. Production costs are key outputs of these tools.

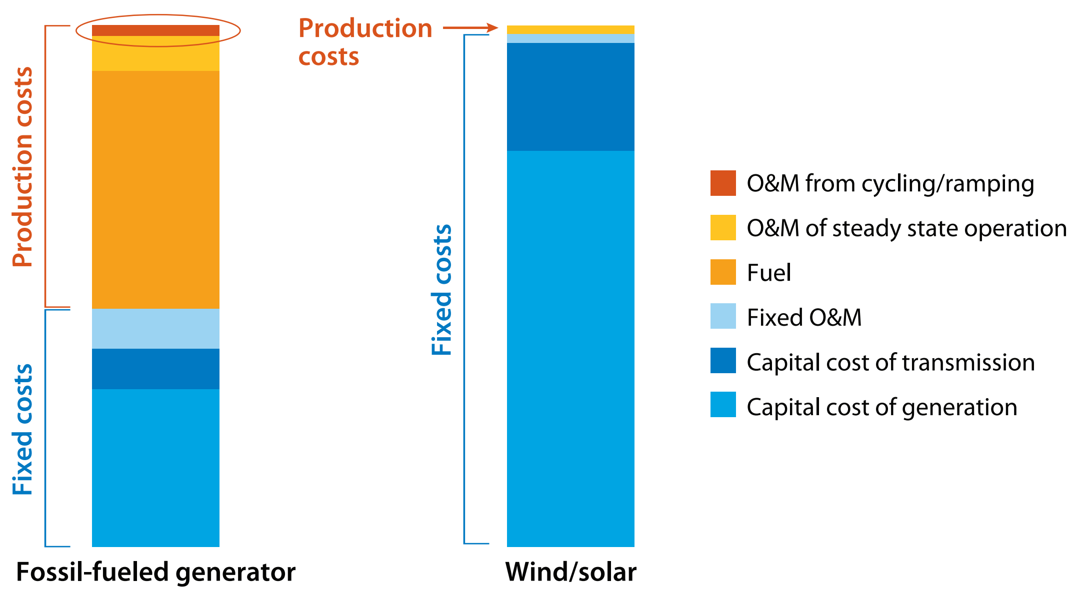


**Figure ES-2. Illustrative DCOE for a fossil-fueled plant and a wind/solar plant**

Adding any new generation to the power system will change the way existing plants operate. Studies show that adding wind and solar can cause existing fossil-fueled plants to cycle more and have lower capacity factors (EnerNex 2011; GE Energy 2010). Adding new, low-priced baseload generation can also cause the incumbent fossil-fueled plants to cycle more and have lower capacity factors (Milligan et al. 2011). An incumbent fossil-fueled plant that now has a lower capacity factor (and likely reduced revenue) and a higher O&M cost (because of cycling) might have a hard time remaining viable. This raises questions about who should pay for the cycling costs of incumbent plants or what happens in the marketplace to address the viability of a plant that might be needed for reliability but might no longer be profitable. These questions are not addressed in this technical report.

When O&M from cycling increases, the cost of energy component circled in red in Figure ES-2 also increases. Before this study, little wear-and-tear data for different types of cycling operation were publicly available. WWSIS-2 investigates this cost in depth. It explores the magnitude of that cost, how that cost changes when wind and solar are added to the system, how that cost changes the fuel savings that wind and solar bring to the system, and how increased wind and solar penetration affects that cost.

From a system perspective, utility planning decisions have resulted in a given portfolio of plants. Those fixed capital costs (or power purchase agreements [PPAs] if the utility is buying from an independent power producer) are now sunk costs. The system operator's job is to manage operations of that portfolio to supply reliable power at low cost to consumers. The operators do not see the fixed costs, only the production costs. If we consider the what-if scenario of this same system with a new wind/solar plant (for simplicity, ignore the bilateral transactions and incentives such as production tax credits), we can see that the near-zero production cost of wind/solar will lead the operator to dispatch the wind/solar instead of fossil-fueled generation, as long as it is within all the constraints of transmission and operating limits. This displaces the fossil-fueled generators' production costs (fuel and O&M). The change in production cost with and without wind/solar is shown in Figure ES-3. From the perspective of the system operators, this reduction in fuel cost is the benefit that wind and solar bring to the system. WWSIS-2 addresses how that benefit is affected when cycling costs are modeled in detail. The cost of wind/solar is the difference in fixed costs (capital costs of the wind/solar plants and transmission). WWSIS-2 did not conduct a cost-benefit analysis of wind and solar to determine profitability. Instead, it posited that if wind/solar is present, what benefit does it bring to the system and how much is that value reduced by cycling?

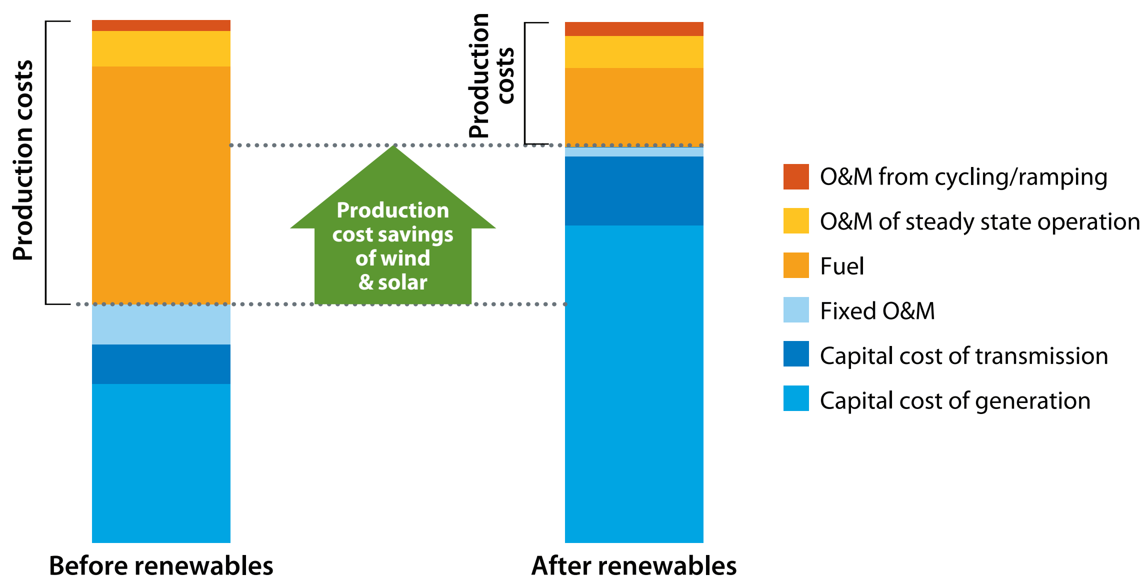


**Figure ES-3. Illustrative system-wide costs before and after wind/solar**

Notes: The wind/solar requires additional fixed costs but offsets production costs.
The change in production cost from wind/solar is shown by the green arrow.

# Study Approach

WWSIS-2 examined the impact of up to 33% wind and solar energy penetration on the U.S. portion of the Western Interconnection. We explicitly calculated values for various types of wear-and-tear costs resulting from cycling. We used the wear-and-tear start costs to optimize detailed operations of the grid and included ramping costs in the total cost impact. We considered the impacts of both the variability and the uncertainty of wind and solar on starts, ramps, and operation of the power system. We modeled five scenarios that were designed to illuminate the impacts of increased wind and solar and compare the impacts of wind and solar on the power system.

To assess the cycling impacts on the fossil-fueled fleet induced by wind and solar, we needed the following information:

- Wear-and-tear costs and impacts for cycling
- Emissions impacts resulting from cycling
- Subhourly wind and solar plant output for future hypothetical plants
- A tool to model grid operations on a subhourly time frame.

This study was conducted by a team of researchers from the National Renewable Energy Laboratory (NREL), GE Energy, Intertek-APTECH (APTECH), and RePPAE. The TRC met every 2 months to discuss and review assumptions, data inputs, methodology, and results. TRC members included representatives from utilities, transmission planning groups, the Western Electricity Coordinating Council (WECC), and DOE and its laboratories, along with power system and fossil-fueled plant experts. As data sets or preliminary results were completed, they were vetted in public forums and peer-reviewed publications. This study has been thoroughly reviewed for technical rigor.

## Wear-and-Tear Costs and Impacts Data

Cycling of thermal plants can create thermal and pressure stresses in power plant components. This leads to increased O&M costs, more frequent repairs, reduced component life, and more frequent forced outages. Power plants that were designed for baseloaded operation suffer much more wear-and-tear damage from cycling. In this report, a *start* is defined as "starting a unit that is offline." *Ramping* is defined as "load-following operation in which a generating unit increases its production." *Cycling* includes both starts and ramping.

To address the lack of public data on the wear-and-tear costs and impacts from cycling of coal and gas generators, NREL and WECC jointly retained APTECH to create a data set. APTECH had previously investigated these costs for hundreds of plants around the world. For each plant, APTECH had determined a best fit and a lower-bound and an upper-bound fit for cycling costs, where the bounds reflected the uncertainty range for that plant. APTECH statistically analyzed those proprietary data to develop generic costs and impacts for seven categories of coal and gas generators (Kumar et al. 2012). Figure ES-4 shows the statistics for the lower-bound costs for cold starts for the seven plant types. The medians of these lower-bound costs were used in the operational optimization so that the wear and tear on fossil-fueled generators was considered in the decision to commit and dispatch units. Upper-bound start costs were then applied to this dispatch to estimate the range of start costs. This may yield a conservative estimate because using those upper-bound costs in the unit commitment process could reduce cycling. On the other hand, many plant operators do not consider wear-and-tear costs in their dispatch decisions, so this may reflect a realistic view of current operations. Unless otherwise specified, ranges of wear-and-tear costs in this report reflect the uncertainty range from the lower to the upper bound. High-impact, low-probability events such as a generator failure were not included in these wear-and-tear costs because there was not enough data to assess the impact of cycling on those events.

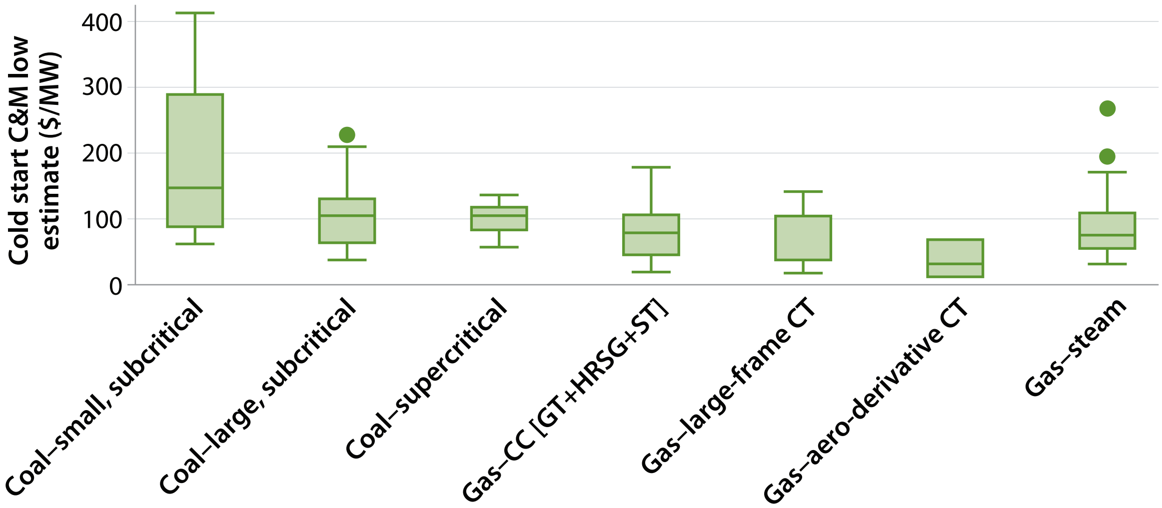


**Figure ES-4. Lower-bound costs for one cold start**

Notes: C&M, capital and maintenance; CC, combined cycle; GT, gas turbine; HRSG, heat recovery steam generator; ST, steam turbine; CT, combustion turbine. The range shows the 25th to 75th percentile, with the median shown within that range. Nonoutlier extrema are depicted by the whiskers in the plots. Outliers are represented as dots.

## $CO_2$, $NO_X$, and $SO_2$ Emissions Data

Starts, ramping, and part-loading also have impacts on emissions. To address the lack of emissions data from cycling, NREL analyzed unit-specific measured emissions from the U.S. Environmental Protection Agency (EPA) Continuous Emissions Monitoring (CEM) data set (EPA 2009) to develop refined emissions rates for most units in the U.S. portion of the Western Interconnection for $CO_2$, $NO_x$, and $SO_2$. Figure ES-5 shows an example of how heat rates and emissions rates were calculated for part-load. In addition, unit-specific incremental emissions from starts and ramps were calculated using these measured emissions data. Part-loading generally results in a higher emission rate overall, except for $NO_x$ emission rates, which decrease for coal and gas steam units. Compliance with existing or proposed emissions regulations was not analyzed.

## Wind and Solar Power Output Data

In WWSIS-2, we updated the wind and solar plant output and forecast data sets from WWSIS-1 to best represent current technologies and methodologies. For example, we capitalized on recent advances in modeling of utility-scale PV plants on a subhourly timescale. The following types of plants were modeled in WWSIS-2: utility-scale wind, rooftop distributed generation PV, utility-scale PV, and CSP with 6 hours of thermal storage.

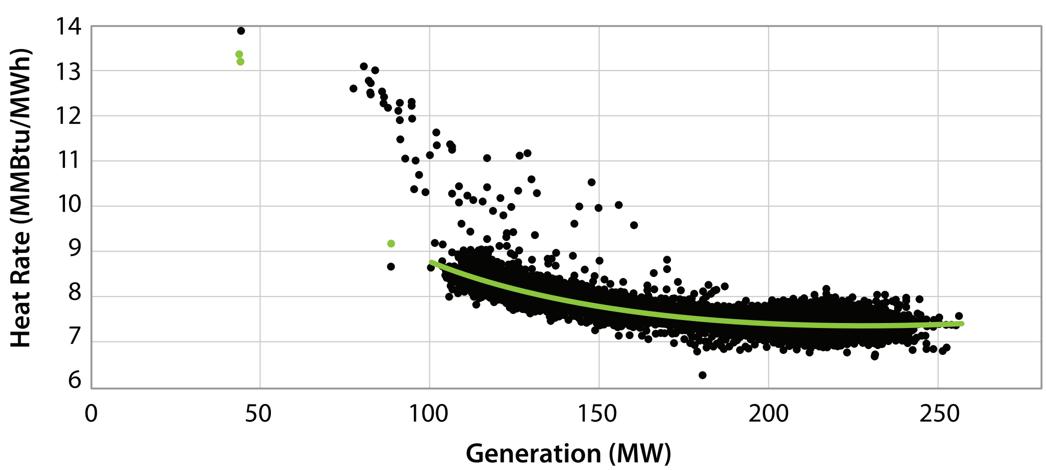


**Figure ES-5. Heat-rate curve for a typical gas CC unit**

Notes: The black dots show measured emission rates for every hour of the year. The green line shows a local linear fit.

## Production Simulations and Scenarios

Production simulations were used as the primary tool to examine operations of the power system. These simulations produce extensive data outputs including generator commitment and dispatch, emissions, costs, and transmission path flows for each time step. Production costs are a key output. Fixed capital costs and PPAs are not included in these simulations.

We simulated scenarios in 2020 using the WECC Transmission Expansion Planning Policy Committee's (TEPPC's) 2020 Portfolio Case 1 as the basis for the production simulation modeling (WECC 2011). Because that case had a relatively high ($7.28/MMBtu) average gas price, we used the gas price projections from WECC TEPPC 2022, which averages $4.60/MMBtu, for the base runs. Load and weather data from 2006 were used. The following five scenarios were created, with penetrations by energy:

- No Renewables—0% wind, 0% solar
- TEPPC—9.4% wind, 3.6% solar
- High Wind—25% wind, 8% solar
- High Solar—25% solar, 8% wind
- High Mix—16.5% wind, 16.5% solar.

Table ES-1 shows installed capacities. NREL's Regional Energy Deployment System (ReEDS) model was used to select which regions were optimal locations for siting the wind and solar based on resources, load, and transmission (Short et al. 2011). We used the commercial production simulation tool PLEXOS to model unit commitment, dispatch, and power flow for the system for a year. The power flow was an optimal direct current (DC) power flow, respecting transmission constraints and using power transfer distribution factors, not a simplified pipeline model. We added capacity to interfaces with high shadow prices and iterated until all shadow prices were within a consistent cutoff. The shadow price is the marginal value of relaxing the interface limit constraint. It defines the potential value of new transmission along each interface (but not the cost). The nearly 40 BAs in the Western Interconnection were modeled using the 20 WECC Load and Resource Subcommittee zones, which were the most granular we could obtain from WECC. The production simulation was run zonally so that collector systems would not need to be designed for each plant. This means that we assumed that sufficient intrazonal transmission was built for each plant and ignored local congestion that could result in curtailment.

**Table ES-1. Installed Solar and Wind Capacity and Average Capacity Factor for Each State for Each Scenario**

**TEPPC**

| | Rooftop PV | | Utility Scale PV | | CSP | | Wind | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| State | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF |
| **Arizona** | | | 1,171 | 22% | 472 | 43% | 3,681 | 30% | 5,324 | 30% |
| **California** | | | 3,545 | 25% | 3,221 | 44% | 7,299 | 30% | 14,065 | 32% |
| **Colorado** | | | 1,342 | 20% | 169 | 37% | 3,256 | 29% | 4,767 | 27% |
| **Idaho** | | | | | | | 523 | 27% | 523 | 27% |
| **Montana** | | | | | | | 838 | 34% | 838 | 34% |
| **Nevada** | | | 304 | 22% | 334 | 42% | 150 | 25% | 788 | 31% |
| **New Mexico** | | | 140 | 27% | 156 | 39% | 494 | 28% | 790 | 30% |
| **Oregon** | | | | | | | 4,903 | 26% | 4,903 | 26% |
| **South Dakota** | | | | | | | | | | |
| **Texas** | | | | | | | | | | |
| **Utah** | | | 571 | 20% | | | 323 | 31% | 894 | 24% |
| **Washington** | | | | | | | 4,652 | 27% | 4,652 | 27% |
| **Wyoming** | | | | | | | 1,784 | 42% | 1,784 | 42% |
| **Total** | | | 7,074 | 23% | 4,352 | 43% | 27,900 | 29% | 39,326 | 30% |

### High Solar

| | Rooftop PV | | Utility Scale PV | | CSP | | Wind | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| State | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF |
| **Arizona** | 4,498 | 19% | 9,570 | 23% | 9,644 | 42% | 270 | 33% | 23,982 | 30% |
| **California** | 9,006 | 18% | 14,258 | 23% | 9,197 | 43% | 5,203 | 33% | 37,663 | 28% |
| **Colorado** | 1,127 | 18% | 4,437 | 22% | 1,440 | 35% | 3,617 | 31% | 10,620 | 27% |
| **Idaho** | 3 | 15% | 2 | 16% | | | 583 | 28% | 588 | 28% |
| **Montana** | 25 | 15% | 34 | 17% | | | 988 | 35% | 1,047 | 34% |
| **Nevada** | 772 | 19% | 6,503 | 24% | 672 | 40% | 150 | 25% | 8,098 | 25% |
| **New Mexico** | 943 | 20% | 2,874 | 24% | 574 | 38% | 644 | 32% | 5,034 | 26% |
| **Oregon** | 101 | 14% | 126 | 21% | | | 4,665 | 26% | 4,892 | 26% |
| **South Dakota** | 4 | 17% | 6 | 19% | | | 330 | 37% | 340 | 37% |
| **Texas** | 233 | 20% | 335 | 23% | | | | | 568 | 22% |
| **Utah** | 2,132 | 17% | 3,759 | 21% | | | 323 | 31% | 6,214 | 20% |
| **Washington** | 405 | 13% | 759 | 19% | | | 4,952 | 27% | 6,116 | 25% |
| **Wyoming** | 10 | 18% | 18 | 21% | | | 1,634 | 43% | 1,662 | 42% |
| **Total** | 19,261 | 18% | 42,680 | 23% | 21,526 | 42% | 23,357 | 31% | 106,824 | 27% |

### High Wind

| | Rooftop PV | | Utility Scale PV | | CSP | | Wind | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| State | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF |
| **Arizona** | 1,975 | 19% | 2,330 | 25% | 3,303 | 43% | 4,941 | 30% | 12,548 | 31% |
| **California** | 4,875 | 18% | 5,372 | 25% | 2,469 | 45% | 11,109 | 30% | 23,824 | 28% |
| **Colorado** | 1,059 | 18% | 1,128 | 22% | 169 | 37% | 6,226 | 35% | 8,581 | 31% |
| **Idaho** | 3 | 15% | 2 | 16% | | | 1,333 | 29% | 1,338 | 29% |
| **Montana** | 22 | 15% | 34 | 17% | | | 6,658 | 36% | 6,714 | 36% |
| **Nevada** | 398 | 19% | 344 | 22% | 439 | 42% | 3,270 | 31% | 4,452 | 30% |
| **New Mexico** | 172 | 20% | 209 | 27% | 156 | 39% | 4,784 | 38% | 5,321 | 37% |
| **Oregon** | 91 | 14% | 101 | 22% | | | 5,473 | 26% | 5,665 | 26% |
| **South Dakota** | 4 | 17% | 6 | 19% | | | 2,640 | 36% | 2,650 | 36% |
| **Texas** | 76 | 20% | 122 | 27% | | | | | 198 | 24% |
| **Utah** | 361 | 17% | 489 | 21% | | | 1,343 | 32% | 2,193 | 27% |
| **Washington** | 371 | 13% | 492 | 20% | | | 5,882 | 27% | 6,745 | 26% |
| **Wyoming** | 9 | 18% | 18 | 21% | | | 10,184 | 43% | 10,211 | 43% |
| **Total** | 9,417 | 18% | 10,647 | 24% | 6,536 | 43% | 63,840 | 34% | 90,439 | 32% |

**High Mix**

| | Rooftop PV | | Utility Scale PV | | CSP | | Wind | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| State | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF | Capacity (MW) | CF |
| **Arizona** | 3,655 | 19% | 5,394 | 25% | 9,374 | 42% | 1,440 | 32% | 19,863 | 33% |
| **California** | 8,412 | 18% | 9,592 | 23% | 3,594 | 44% | 6,157 | 31% | 27,754 | 26% |
| **Colorado** | 1,127 | 18% | 1,653 | 22% | 169 | 37% | 4,396 | 33% | 7,344 | 29% |
| **Idaho** | 3 | 15% | 2 | 16% | | | 1,093 | 29% | 1,098 | 29% |
| **Montana** | 25 | 15% | 34 | 17% | | | 4,288 | 36% | 4,347 | 36% |
| **Nevada** | 772 | 19% | 3,282 | 26% | 562 | 40% | 1,560 | 32% | 6,177 | 28% |
| **New Mexico** | 943 | 20% | 1,280 | 27% | 298 | 40% | 3,134 | 38% | 5,654 | 33% |
| **Oregon** | 101 | 14% | 126 | 21% | | | 5,413 | 26% | 5,640 | 26% |
| **South Dakota** | 4 | 17% | 6 | 19% | | | 1,950 | 36% | 1,960 | 36% |
| **Texas** | 208 | 20% | 193 | 25% | | | | | 401 | 22% |
| **Utah** | 1,204 | 17% | 1,216 | 22% | | | 683 | 33% | 3,102 | 22% |
| **Washington** | 405 | 13% | 709 | 19% | | | 5,762 | 27% | 6,876 | 26% |
| **Wyoming** | 10 | 18% | 18 | 21% | | | 7,244 | 44% | 7,272 | 44% |
| **Total** | 16,870 | 18% | 23,504 | 24% | 13,997 | 42% | 43,118 | 34% | 97,489 | 30% |

Note: CF, capacity factor

Operations of the entire Western Interconnection were modeled in detail in PLEXOS. We ran a day-ahead (DA) unit commitment for all generation using DA wind and solar forecasts. Coal and nuclear units were committed during the DA market. We next ran a 4-hour-ahead (4HA) unit commitment to commit CC and gas steam units, using 4HA wind and solar forecasts. Finally, we ran a real-time economic dispatch on a 5-minute interval to dispatch all units (i.e., gas CT and internal combustion units were allowed to start during the real-time dispatch).

Load forecasts were assumed to be perfect because we lacked a consistent set of load forecasts; as a result, all the uncertainty in operations came from wind and solar. This assumption may result in putting more of a burden on wind/solar than is realistic. Variability, on the other hand, came from both load and wind/solar.

Three types of operating reserves were held: contingency, regulating, and flexibility (or load-following). Contingency reserves were unchanged with wind and solar because no wind or solar plant was the single largest contingency. Regulating reserves covered 1% of load and 95% of the 10-minute forecast errors of wind and PV. Increases in regulation requirements were modest in the high-penetration scenarios: up to 10% greater than in the No Renewables Scenario. Finally, flexibility reserves, specifically to address load-following needs for wind and PV, were held to cover 70% of the 60-minute forecast errors of wind and PV.

We conducted statistical analysis to examine the geographic diversity of wind, solar, and load. We investigated monthly, diurnal, hourly, and subhourly variability to determine increased ramping needs and correlations between load, wind, and PV. Extreme event analysis determined maximum ramping needs and tail events.

Production simulation models are not a perfectly accurate representation of operations. As much as possible, we used WECC TEPPC assumptions, data, and scenarios because they have been widely vetted. It is important to note the following:

- Most of the Western Interconnection (except California and Alberta) today operates on the basis of a combination of short-term and long-term bilateral contracts. This information is confidential and could not be used in this study. As a result, the grid was assumed to be operated on the basis of least-cost economic dispatch.

- Most of the Western Interconnection today primarily uses contractual obligations to schedule transmission. Transmission that is not accessible to other generation might be available. In this study, we did not model these contracts; instead, we assumed that existing available transmission capacity was used in a way that minimized production costs across the Western Interconnection.

What are the impacts of these assumptions? If a bilateral contract results in operating a less economic plant, that increases production cost. It might also result in more wind/PV curtailment or less flexibility available to balance the system, which could increase cycling. If sufficient transmission capacity is not available, that might also result in more wind/PV curtailment.

# Key Findings

Our analysis in WWSIS-2 yielded a tremendous amount of noteworthy results, which are detailed in the main report. All study results are in 2011 nominal dollars. Under the scenarios studied, we found the following for the Western Interconnection:

- High penetrations of wind and solar increase annual wear-and-tear costs from cycling by \$35–\$157 million[1]. This represents an additional \$0.47–\$1.28/MWh of cycling costs for the average fossil-fueled generator. Cycling diminishes the production cost reduction of wind and solar by \$0.14–\$0.67/MWh, based on the specific system and generator characteristics modeled. These costs are a small percentage of annual fuel displaced across the Western Interconnection (approximately \$7 billion) and the reduction in fuel costs (\$28–\$29/MWh of wind and solar generated). The costs are, however, significant compared to the average steady-state VOM and cycling costs of fossil-fueled plants (\$2.43–\$4.68/MWh, depending on scenario). Production costs do not include the capital or PPA costs to construct power plants or transmission.

- $CO_2$, $NO_X$, and $SO_2$ emissions impacts resulting from wind- and solar-induced cycling of fossil-fueled generators are a small percentage of emissions avoided by the wind and solar generation. Wind- and solar-induced cycling has a negligible impact on avoided $CO_2$ emissions. Wind- and solar-induced cycling will cause $SO_2$ emissions reductions from wind and solar to be 2%–5% less than expected and $NO_x$ emissions reductions to be 1%–2% larger than expected. From a fossil-fueled generator perspective, this cycling can have a positive or negative impact on $CO_2$, $NO_X$, and $SO_2$ emissions rates.

- Solar tends to dominate variability challenges for the grid; wind tends to dominate uncertainty challenges. Both of these challenges can be mitigated. Because we know the largest component of solar variability, the path of the sun through the sky, we can plan for this in the unit commitment. The DA wind forecast error can be mitigated with a 4HA commitment of gas units to take advantage of the improved forecasts.

- Although wind and solar affect the grid in very different ways, their impacts on system-wide production costs are remarkably similar.

## Wind and Solar Displace Primarily Gas Generation and Increase Coal Ramping

As the quantity of resources with zero or very low marginal cost (such as wind and solar, but also possibly hydropower [hydro] or nuclear) increases, the new resources displace higher-cost resources (such as gas). The new resources can, however, also start to displace more traditional low-cost resources (such as coal). Figure ES-6 shows the dispatch stacks in the summer, depicting the high loads that lead the increased wind/solar to displace mostly gas CC units. The significant solar output in the High Solar Scenario, though, resulted in some displacement of coal generation even in the summer.

The impacts on other resources were amplified in the spring, when loads are low and both wind and solar generation are high. Figure ES-7 shows the most challenging week, defined by the minimum net load condition (net load is load minus wind minus solar). In the High Wind Scenario, the significant wind on March 29 displaced nearly all the gas output and severely cut into the coal output. Some wind and PV was curtailed, as shown by the dashed line in the dispatch stack on March 29 and 30. The curtailment occurred when the other types of generation hit their minimum generation levels. Coal was cycled, but without any periodicity and relatively slowly over days. The High Solar Scenario had a very different impact. Solar generation was high enough at midday to lead to significant curtailment of wind/PV and ramping of coal up and down on a daily basis. Impacts from wind- and solar-induced cycling are likely to be greater during the spring than during the summer.

[1] The low and high ends of this range give an uncertainty range for cycling costs and represent application of the lower-bound and upper-bound cycling costs, respectively. The high end of the uncertainty range is an overestimate because of the method used.

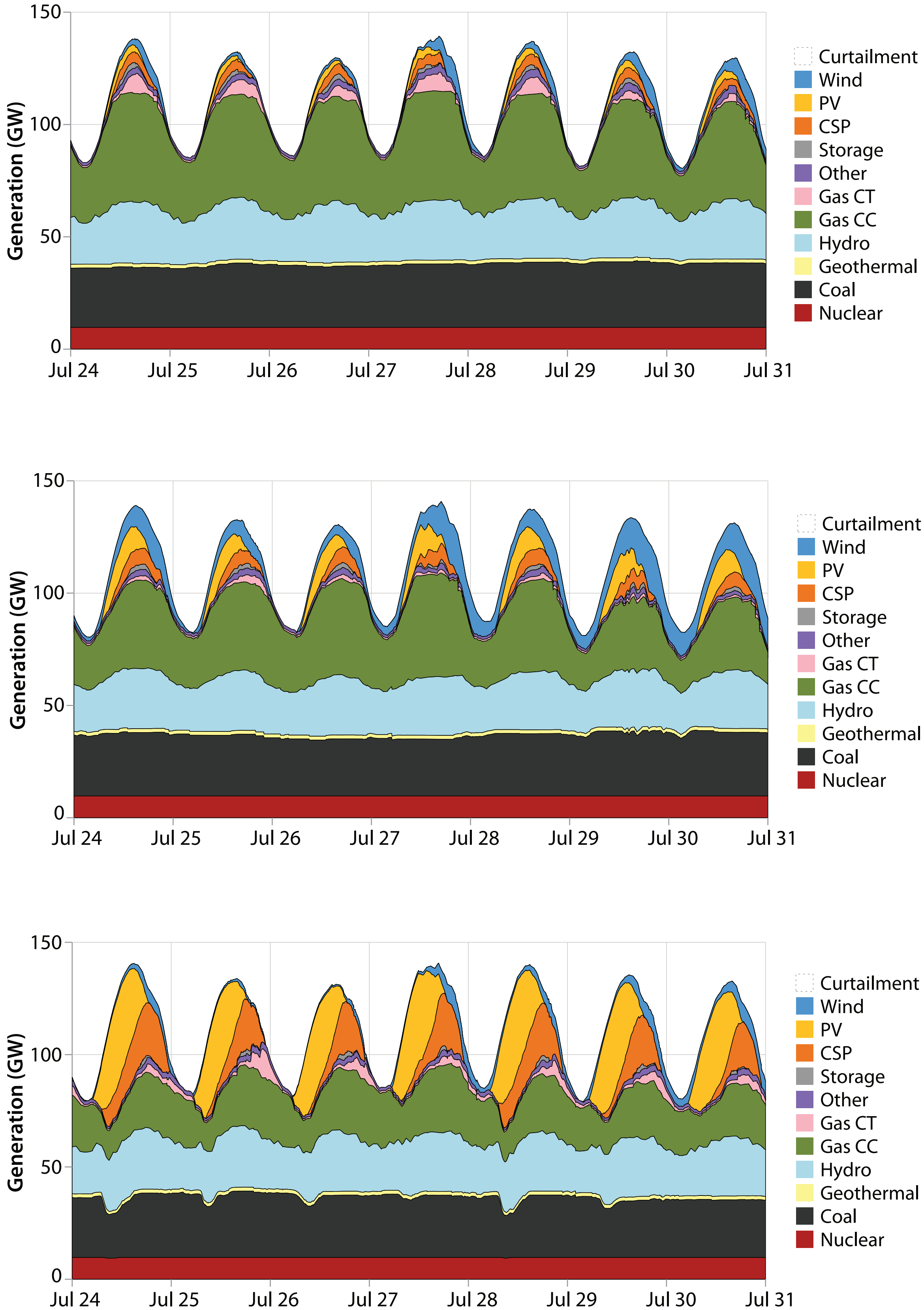


**Figure ES-6. Five-minute dispatch stacks for the (top) TEPPC, (middle) High Wind, and (bottom) High Solar Scenarios for a week in July**

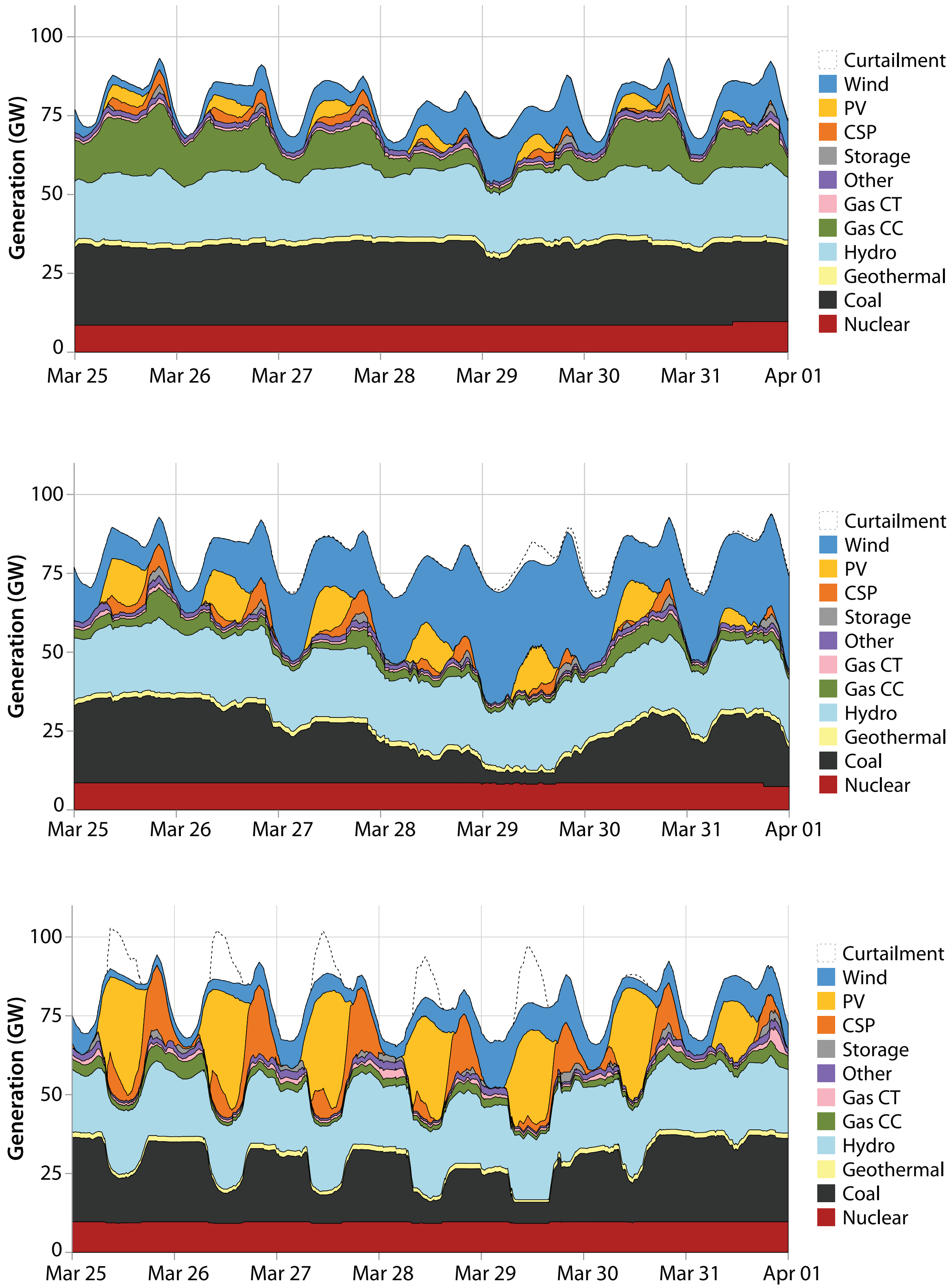


**Figure ES-7. Five-minute dispatch stacks for the (top) TEPPC, (middle) High Wind, and (bottom) High Solar Scenarios for a week in March**

Note: This week represented the minimum net load condition.

Despite these challenges, the 5-minute production simulation results showed that the system can operate and balance load and generation. Operational results for contingency, regulating, and flexibility reserves were examined, and issues were minimal. There were no regulating reserve violations and very few contingency reserve violations. Figure ES-8 shows that wind and solar mostly displace gas CC generation. Displacement of coal increased with increasing penetrations of wind, because gas already tends to be decommitted or backed down at night when there are high levels of wind.

The dispatch stacks showed that the system used the least expensive methods for flexibility from various types of generators to serve load and reserves. In the summer, capacity was required more than flexibility. In the spring, balancing the load with high instantaneous wind/solar penetrations required a lot of flexibility. Ramping hydro within its constraints was one source for flexibility; wind/PV curtailment was another. Cycling of fossil-fueled plants was a third, and we delve into that here. The High Solar Scenario ramped coal up and down on a daily basis. In the High Wind Scenario, coal was shut down and restarted on a weekly or longer frequency, especially during the low net load event on March 29. In all scenarios, CTs are shut down and restarted frequently, running for only several hours per start.

Over the course of 1 year, Figure ES-9 shows the cycling impact by plant type by scenario. Coal starts do not change appreciably but the High Wind Scenario decreased the average coal runtime per start by a third and the High Solar Scenario increased the number of ramps by an order of magnitude compared to the No Renewables Scenario. The High Wind Scenario required somewhat less ramping of coal units compared to the High Solar Scenario.

**Wind and solar generation displaced primarily gas generation, based on an average gas price of $4.60/MMBtu.**

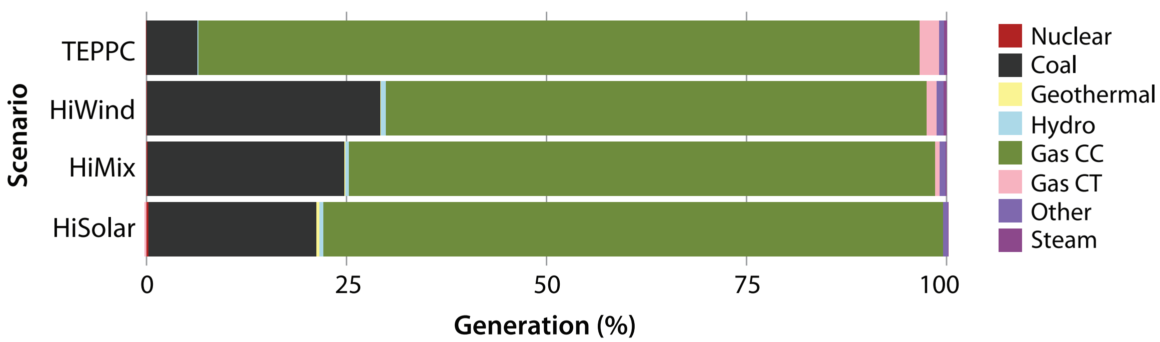


**Figure ES-8. Generation displaced by wind/solar, compared to the No Renewables Scenario**

Increasing wind/solar first increased and then decreased the number of CC starts. Even moderate penetrations halved the CC runtime per start, where it basically remained even at high penetrations. CC ramps actually decreased in the high-penetration scenarios.

Wind causes a significant reduction in CT cycling (and generation). The High Solar Scenario, however, shows more CT capacity started compared to the No Renewables Scenario, partly because of the correlation of evening peak load with decreased PV output at sunset.

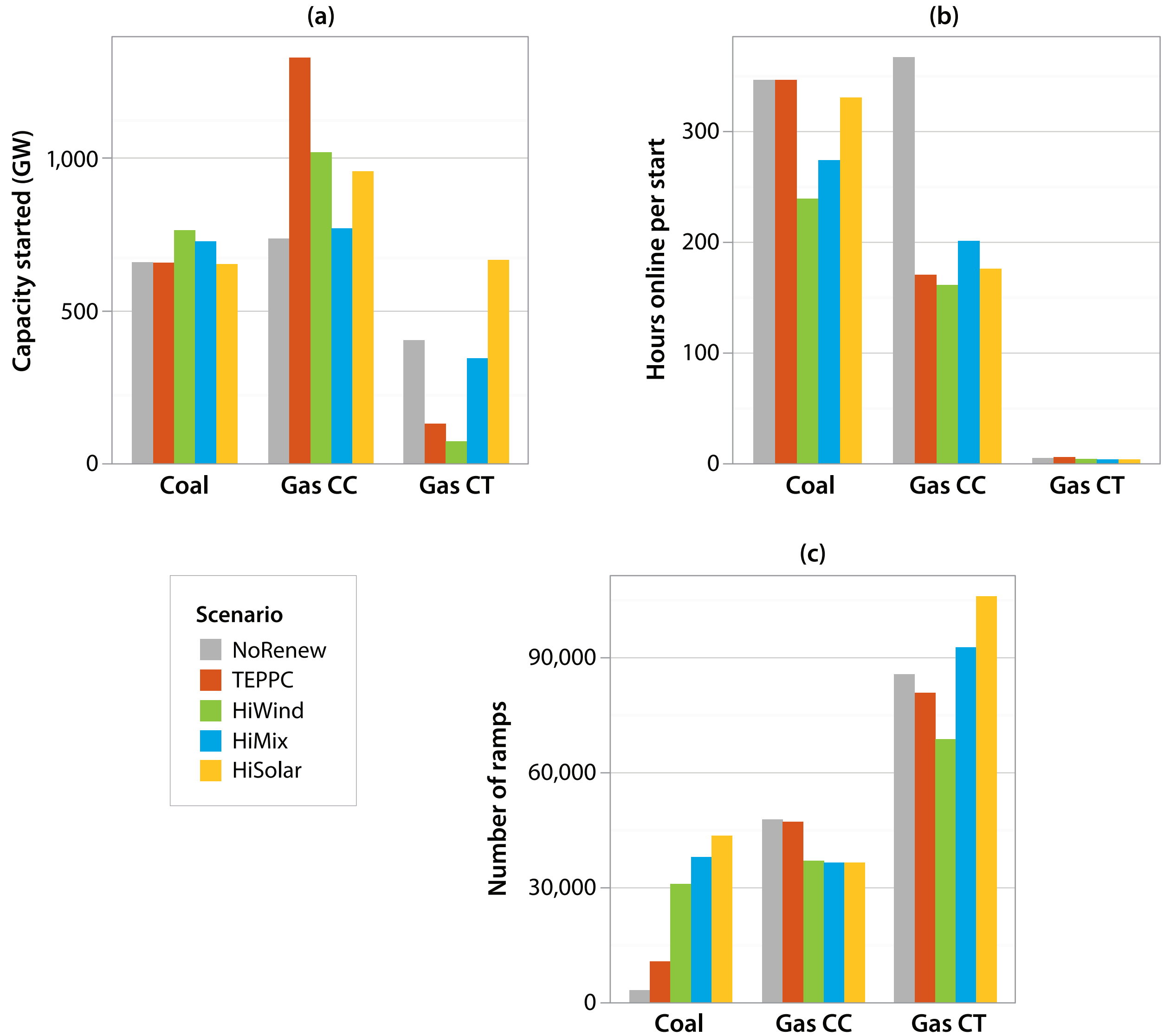


**Figure ES-9. (a) Capacity started, (b) average number of hours online per start (must-run CTs have been excluded), and (c) total number of ramps for each plant type by scenario for 1 year**

To determine the importance of considering wear-and-tear start costs during optimization, we ran the High Wind Scenario without including wear-and-tear start costs (but including start fuel costs) to compare to the original High Wind Scenario. Although this had almost no impact on annual generation from different unit types, it had a very significant impact on the number of starts at CC and CTs, which have very low start fuel costs. This demonstrates that it is important to consider wear-and-tear start costs during optimization.

Figure ES-10 gives a more detailed look into the starts and ramps. The solid line shows the committed coal capacity and the shaded area shows the dispatched capacity. The white area between the solid line and the shaded area illustrates how far the coal capacity has been backed down. In the No Renewables and TEPPC Scenarios, there is little change in coal commitments and the coal plants are typically running at or near full output, with an exception during the minimum net load day of March 29. In the high-penetration scenarios in the spring, coal capacity is shut down approximately each week, and the coal is ramped up and down each day, especially with high penetrations of solar. In the summer, coal is ramped very little except for some ramping in the High Solar Scenario during the day.

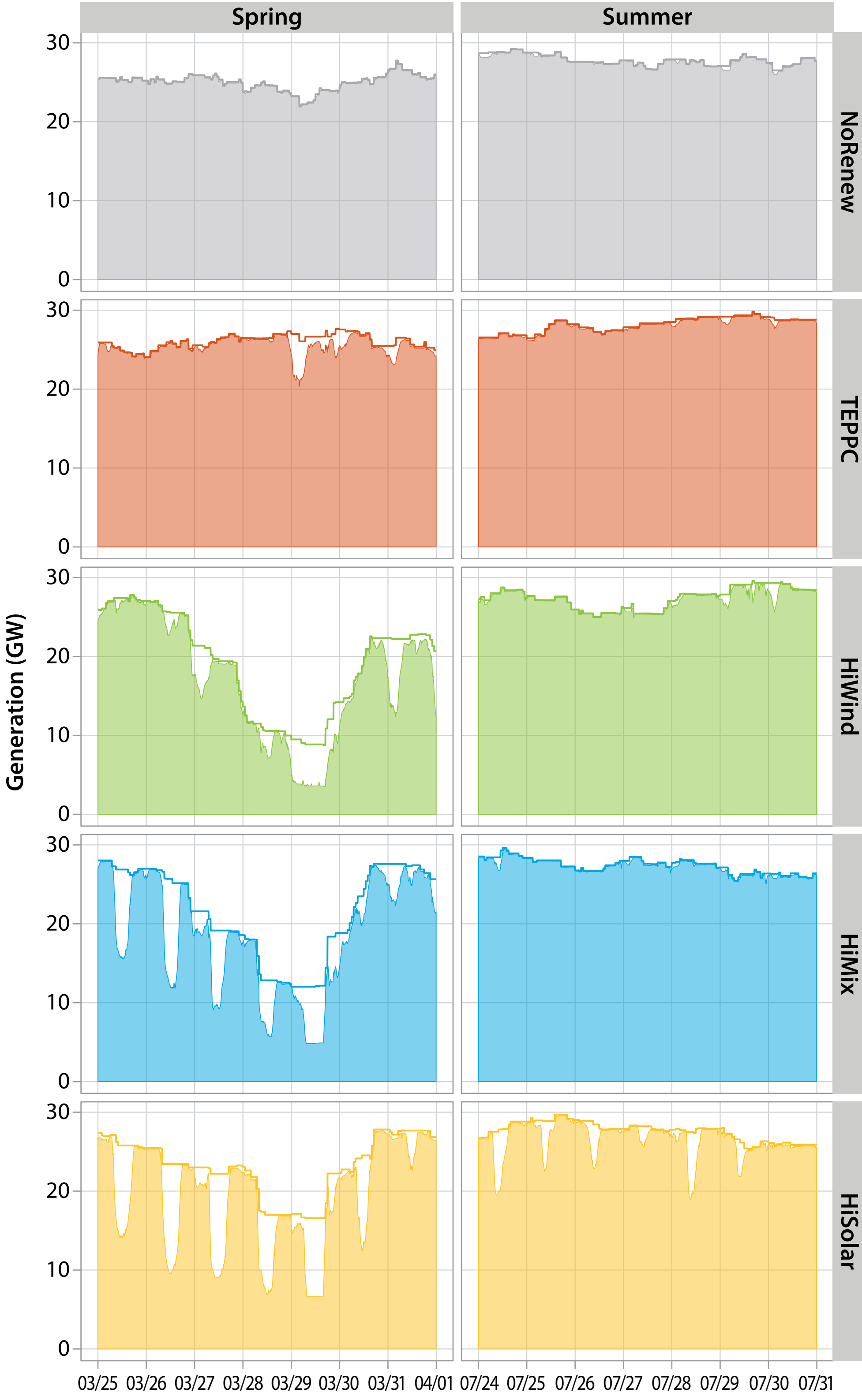


**Figure ES-10. (Solid line) capacity committed and (shaded area) dispatched for coal units during March and July sample weeks**

## Wind- and Solar-Induced Cycling Affects Fossil-Fueled Plant Operations and Maintenance Costs

Figure ES-11 shows the production cost (operational cost of meeting load in the Western Interconnection in 2020) of each scenario. Production costs do not include any capital costs, except capitalized maintenance caused by cycling or noncyclic operation. The production cost was dominated by fuel costs, assuming an average natural gas price of $4.60/MMBtu and a zero carbon price. Noncyclic VOM costs comprise about a tenth of the total production cost. Cycling VOM costs (starts, start fuel, and ramping costs) were all a small percentage of the total production cost. They range from 1.5% of the total production cost in the No Renewables Scenario using lower-bound cycling costs to 7% in the High Solar Scenario using upper-bound cycling costs.

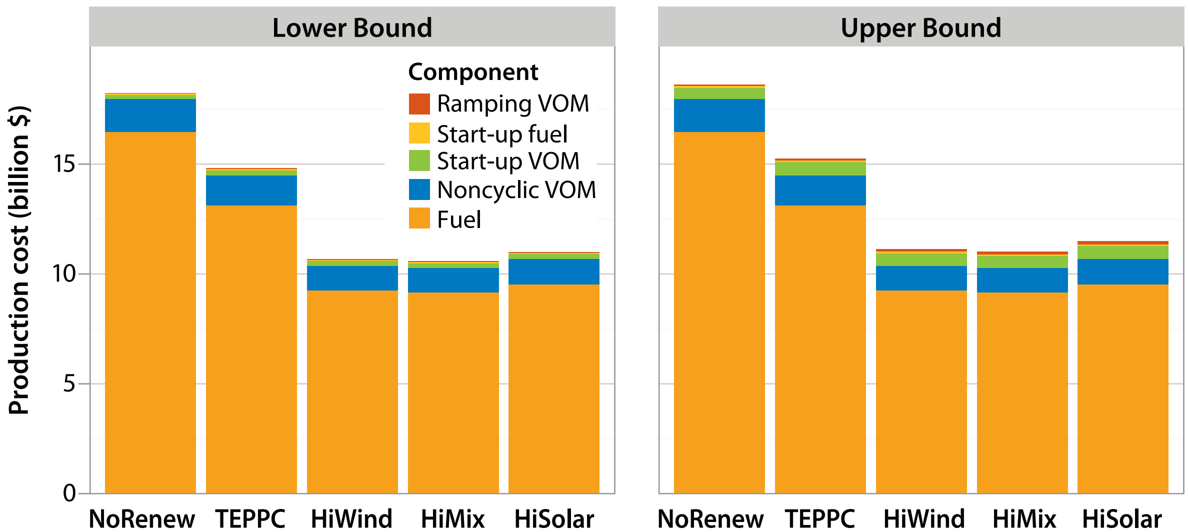


**Figure ES-11. Production cost for each scenario showing the (left) lower and (right) upper bound for the cycling costs**

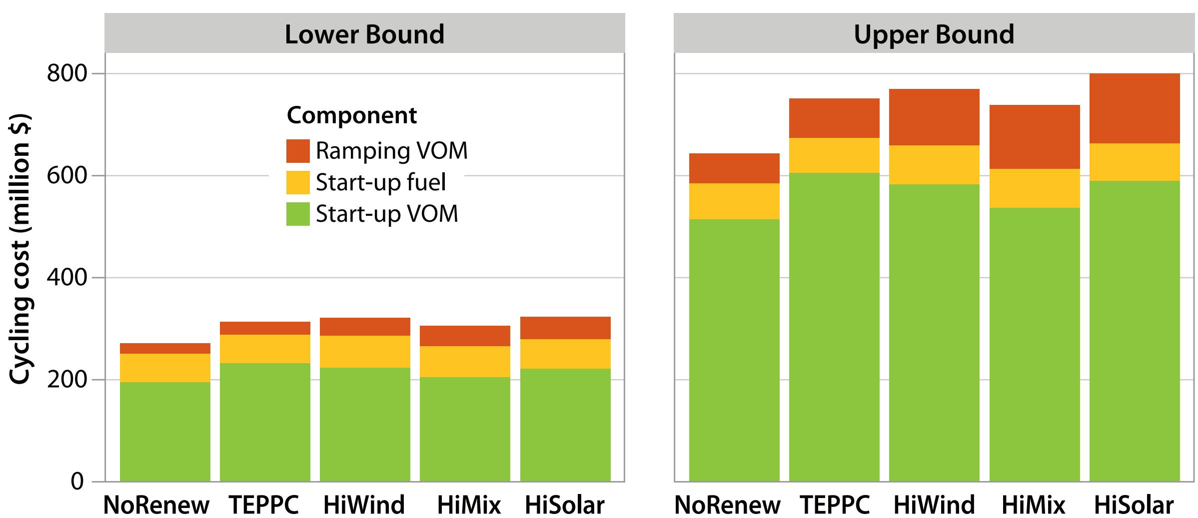


**Figure ES-12. Production cost components resulting from cycling, showing the (left) lower and (right) upper-bound wear-and-tear costs for each scenario**

Note: Cost components have been broken down into starts, start fuel, and ramping costs.

Figure ES-12 shows only the cycling portion of these same costs. The cycling costs range from about $270 million in the No Renewables Scenario using the lower-bound cycling costs to about $800 million in the High Solar Scenario using the upper-bound cycling costs. When wind and solar are added to the system, cycling costs increase by $35–$157 million, or 13%–24%. Interestingly, the High Mix Scenario has a higher wind/solar penetration but lower cycling costs than the TEPPC Scenario. There is not necessarily a monotonic increase in cycling costs with wind/solar penetration. In terms of cycling costs, there may be a big step in going from 0% to 13% wind/solar, but a much smaller step in going from 13% to 33%.

**Wind- and solar-induced cycling increases average fossil-fueled plant O&M costs by $0.47–$1.28/MWh in the high-penetration scenarios. Gas CTs bear the highest wear-and-tear cycling costs.**

We first examine these costs from the perspective of the fossil-fueled plants. Figure ES-13 divides the cycling costs shown in Figure ES-12 by each MWh of fossil-fueled generation. These cycling O&M costs increase from $0.45–$1.07/MWh in the No Renewables Scenario to $0.63–$1.51/MWh in the TEPPC Scenario, where the ranges reflect the uncertainty in the wear-and-tear costs. This cycling wear and tear increases to $0.92–$2.36/MWh in the high-penetration scenarios. Table ES-2 shows the cycling cost impacts of wind and solar for each scenario.

**Table ES-2. Increase in Cycling Cost (Compared to No Renewables Scenario)**

| Scenario | Total (Million $) | Per MWh Wind/Solar Generation | Per MWh of Fossil-Fueled Generation |
|---|---|---|---|
| **TEPPC** | 42–108 | $0.41–$1.05/MWh | $0.18–0.44/MWh |
| **High Wind** | 50–127 | $0.20–$0.50/MWh | $0.52–1.24/MWh |
| **High Mix** | 35–95 | $0.14–$0.38/MWh | $0.47–1.14/MWh |
| **High Solar** | 52–157 | $0.22–$0.67/MWh | $0.50–1.28/MWh |

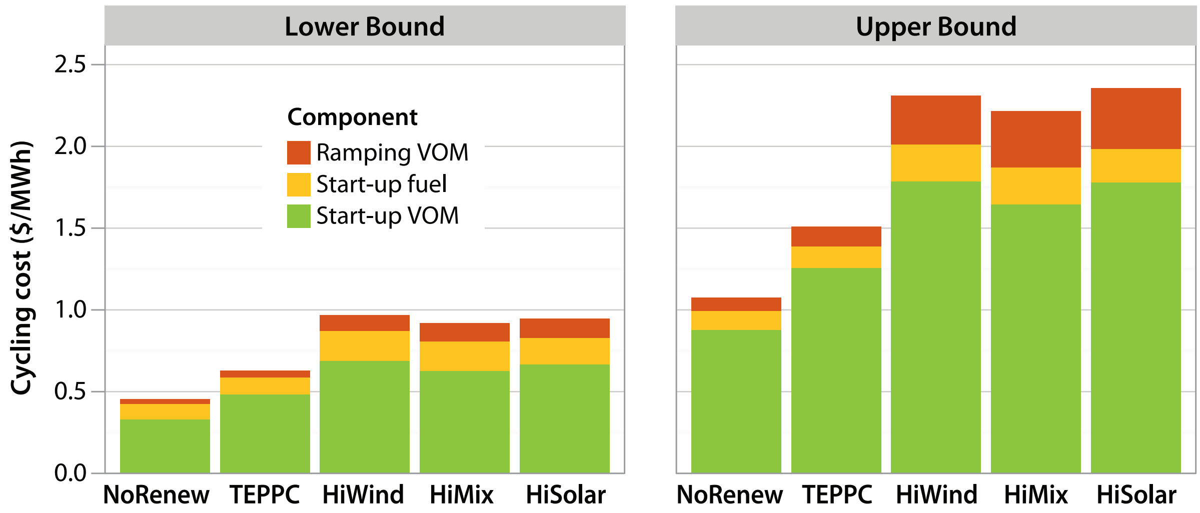


**Figure ES-13. Cycling cost, showing the (left) lower- and (right) upper-bound wear-and-tear costs for each scenario**

Note: These cycling costs are defined as the total system-wide cycling costs per MWh of fossil-fueled generation.

Figure ES-14 further disaggregates the cycling cost by plant type. For confidentiality reasons, only the lower bounds can be shown. Note, however, that although the absolute magnitudes of costs are higher with the upper bounds, the relative comparisons discussed here also hold true for the upper bounds. CTs (must-run CTs were excluded to delve into these impacts) bear the brunt of the wear-and-tear costs (Figure ES-14, right). Notably, these cycling costs actually decrease at low wind/solar penetrations (TEPPC Scenario) and do not change in the High Wind Scenario from the No Renewables Scenario. For the coal plants (Figure ES-14, left), cycling costs are only slightly affected. For the CC plants (Figure ES-14, center), cycling costs increase with increasing wind/solar penetrations.

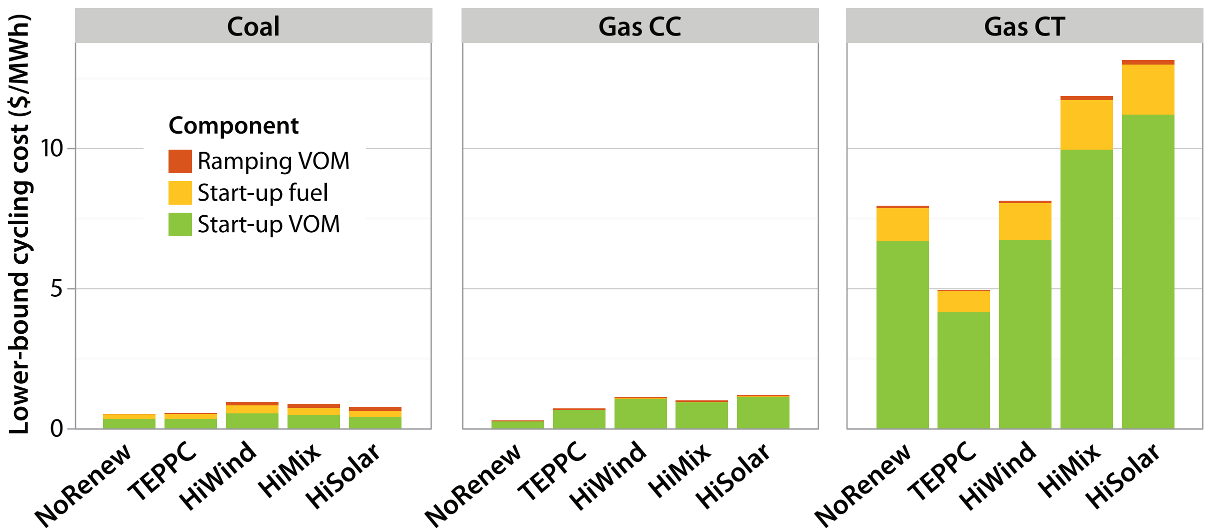


**Figure ES-14. Lower-bound cycling cost for (left) coal, (center) gas CC units, and (right) gas CTs (excluding the must-run CTs)**

Note: Total, system-wide, lower-bound cycling costs were disaggregated by plant type and divided by MWh of generation of that plant type.

## Cycling Increases Production Costs Slightly

We next examine these costs from a system perspective. When we compared the production cost of each scenario to the No Renewables Scenario, we saw a decrease of $3.34–$3.43 billion at low penetrations (TEPPC Scenario) and $7.12–$7.65 billion in the high-penetration scenarios (see Section 6). This change in production cost is dominated by displaced fuel costs.

Dividing this production cost reduction by the amount of wind and solar energy delivered yielded a production cost reduction of $32.6–$33.2/MWh in the TEPPC Scenario and $29.4–$30.6/MWh in the high-penetration scenarios (see Table ES-3 for details). Figure ES-15 breaks down the production cost reduction into cost components. Cycling costs (shown by the positive values) offset $0.14–$0.67 of the fuel and VOM reduction per MWh of wind and solar generated in the high-penetration scenarios. This production cost reduction does not reflect fixed capital costs or PPA costs. Utility planners conducting a cost-benefit analysis of wind and solar might want to weigh such fixed capital costs against production costs, but that analysis is not conducted here.

**Cycling costs increase by $0.14–$0.67 per MWh of wind and solar generated in the high-penetration scenarios, based on the specific system characteristics of the Western Interconnection.**

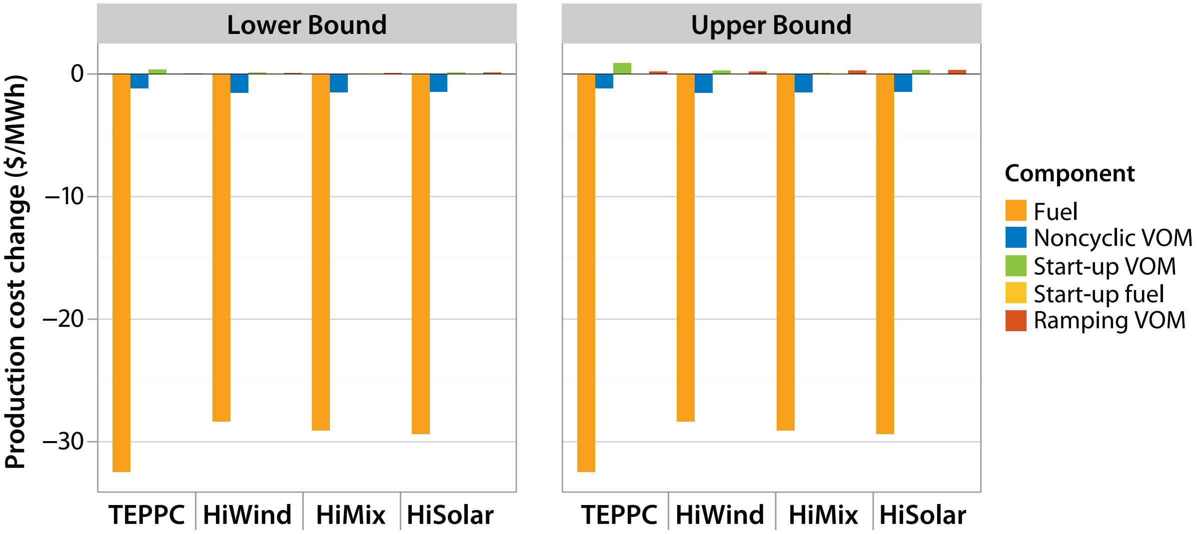


**Figure ES-15. The change in production cost for each scenario relative to the No Renewables Scenario, per MWh of wind and solar generation, for the (left) lower-bound and (right) upper-bound wear-and-tear costs**

Note: Production costs do not include any fixed capital or PPA costs.

**Table ES-3. Change in Production Cost, Compared to No Renewables Scenario**

| Scenario | Production Cost Reduction (Billion $) | Production Cost Reduction ($ per MWh of Wind and Solar Generated) |
|---|---|---|
| **TEPPC** | 3.34–3.43 | 32.6–33.2 |
| **High Wind** | 7.48–7.56 | 29.4–29.7 |
| **High Mix** | 7.59–7.65 | 30.2–30.4 |
| **High Solar** | 7.12–7.23 | 30.2–30.6 |

Note: Production costs do not include any fixed capital or PPA costs.

## $CO_2$, $NO_X$, and $SO_2$ Emissions Reductions Are Significantly Greater Than Cycling Emissions

Figure ES-16 (left) shows the total $CO_2$ emissions for each scenario. Ramping had no significant impact on $CO_2$ emissions, so those estimates are not shown. The start-up $CO_2$ emissions (shown by the thin, dark green line at the top of each bar) were negligible in all cases. Figure ES-16 (right) shows the $CO_2$ emissions saved by each MWh of wind/solar. Avoided $CO_2$—considering part-load, ramping, and starts—was 1,100 lb/MWh to 1,190 lb/MWh of wind and solar produced in the high-penetration scenarios (see Table ES-4). $CO_2$ emissions from starts were negligible. We also calculated the part-load penalty—which was the incremental $CO_2$ emissions from part-loading—as negligible. This emissions analysis reflects aggregate emissions across the Western Interconnection. Any specific plant might have lower or higher emissions than shown here. Because wind tended to displace more coal compared to solar, and because coal emission rates of $CO_2$, $NO_x$, and $SO_2$ are higher than those of gas, higher penetrations of wind resulted in higher levels of avoided emissions.

**Starts, ramps, and part-loading had a negligible impact on $CO_2$ emissions reductions of wind and solar.**

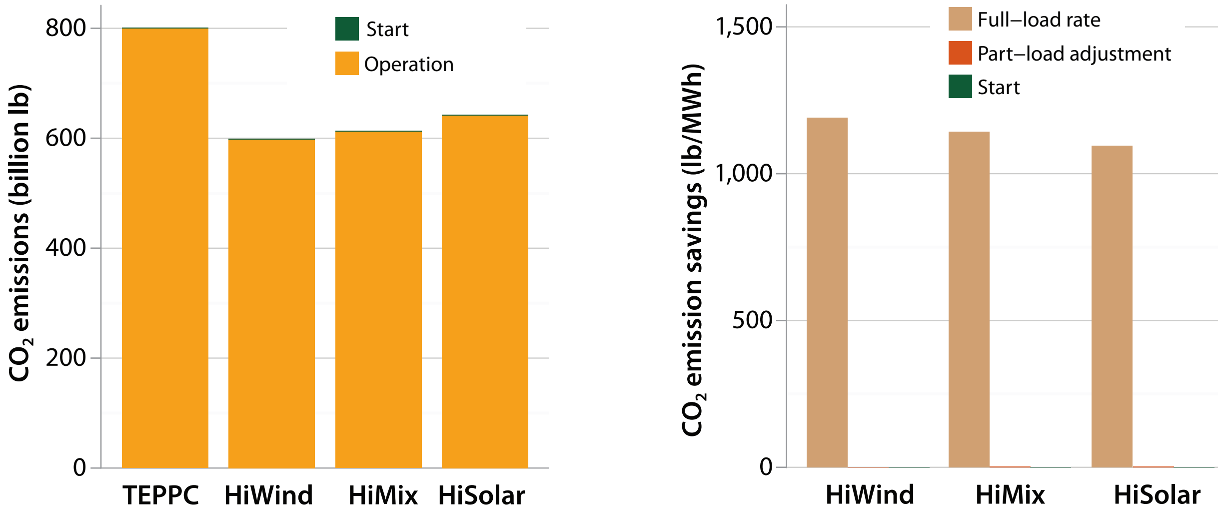


**Figure ES-16. $CO_2$ emissions by scenario: (left) absolute $CO_2$ emissions for operation and starts and (right) $CO_2$ emission reductions compared to the No Renewables Scenario, separated into the constant emissions rate assumption and adjustments for part-load and starts**

Note: Ramping emissions are excluded because they have no significant impact on $CO_2$ emissions.

**Table ES-4. Emissions Avoided per MWh of Wind and Solar—Considering Part-Load, Ramping, and Start Impacts**

| Scenario | Avoided $CO_2$ (lb/MWh) | Avoided $NO_x$ (lb/MWh) | Avoided $SO_2$ (lb/MWh) |
|---|---|---|---|
| **High Wind** | 1,190 | 0.92 | 0.56 |
| **High Mix** | 1,150 | 0.80 | 0.44 |
| **High Solar** | 1,100 | 0.72 | 0.35 |

Note: Part-load impacts were not studied for $SO_2$ because of inadequate data.

From the fossil-fueled plant perspective, average $CO_2$ emission rates of coal, CCs, or CTs change only slightly with wind and solar as shown in Figure ES-17 (top). Figure ES-17 (bottom) shows that adding wind and solar can positively or negatively affect emissions rates, depending on plant type and scenario. Generally for coal and CCs, wind/solar improves emissions rates by up to 1%. The largest negative impact of wind- and solar-induced cycling is in the High Wind Scenario on the CTs where the emissions rate increases by 2%. This is on average; individual units might be more or less affected.

**Wind- and solar-induced cycling can have a small positive or negative impact on $NO_x$ and $SO_2$ emissions rates, and it depends on the pollutant and mix of wind and solar.**

Figure ES-18 shows the analysis for $NO_x$ emissions. There was a negligible impact of starts on $NO_x$. Ramping reduced the avoided $NO_x$ by 2% to 4%. This is shown in Figure ES-18 (right) as a small negative contribution. Part-loading impacts, on the other hand, increased avoided $NO_x$ by 4% to 6%. On average, coal units in the West emit less $NO_x$ per MWh of generation at part-load. The net impact of considering cycling improved avoided $NO_x$ emissions from wind/solar by 1% to 2%.

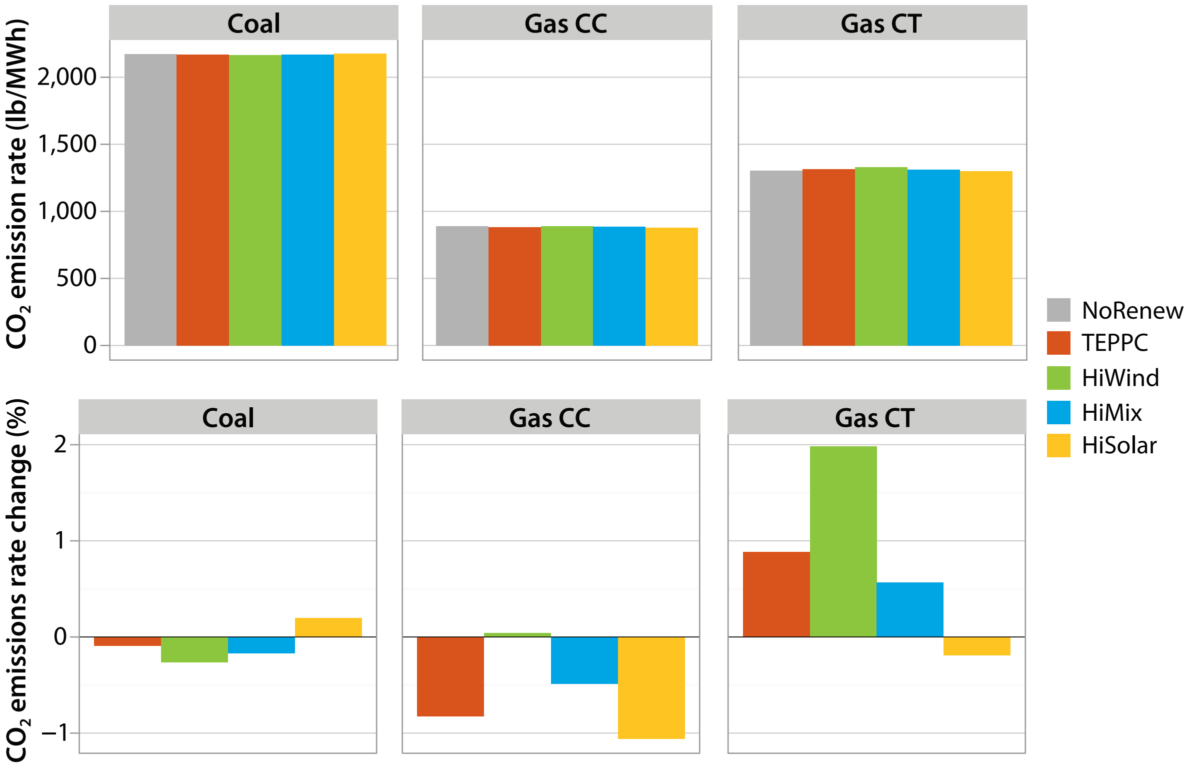


**Figure ES-17. (Top) average $CO_2$ emission rates by plant type (defined as $CO_2$ emissions divided by MWh of coal, CC, or CT generation) for each scenario and (bottom) change in emissions rate compared to the No Renewables Scenario**

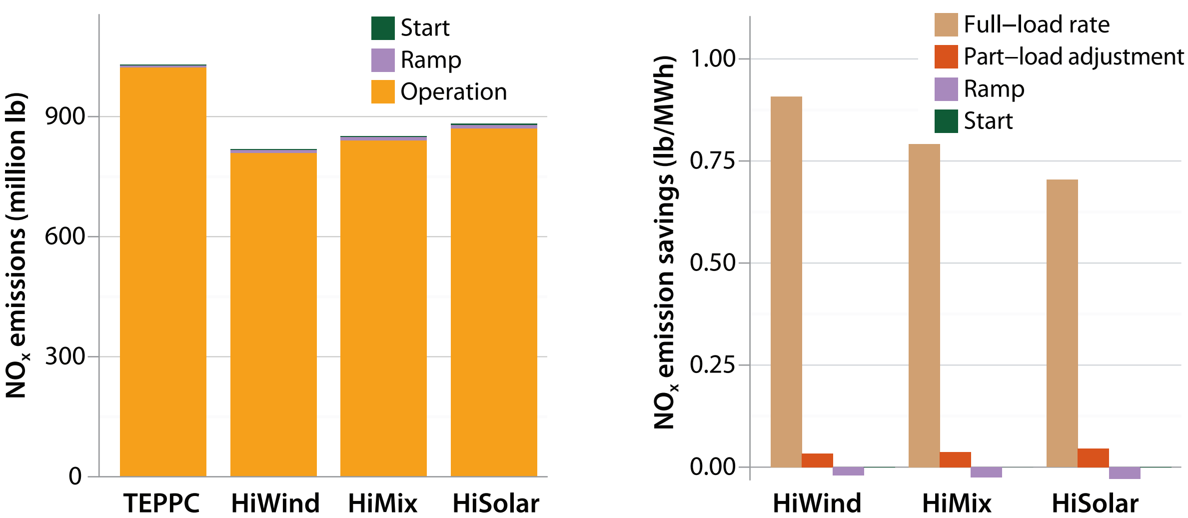


**Figure ES-18. $NO_x$ emissions by scenario: (left) absolute $NO_x$ emissions for operation, ramps, and starts, and (right) $NO_x$ emission reductions compared to the No Renewables Scenario, separated into the constant emissions rate assumption and adjustments for part-load, ramps, and starts**

Figure ES-19 shows that average $NO_x$ emission rates for different plants can also be positively or negatively affected by wind/solar. Wind- and solar-induced cycling impacts on $NO_x$ emissions rates are relatively small. Impacts on coal units are negligible, but high-penetration scenarios increase overall CC $NO_x$ emission rates by approximately 5%. CTs show the largest impacts. The scenarios with a high wind-to-solar ratio show reductions in CT emissions rates by approximately 10% and the scenario with a high solar-to-wind ratio shows increases in CT emissions rates by approximately 10%. This is on average; individual units might be more or less affected.

Figure ES-20 shows the emissions analysis for $SO_2$. Because there were inadequate data to create $SO_2$ emission part-load curves, part-load impacts were not studied for $SO_2$. Ramping impacts on avoided $SO_2$ were modest for the high-penetration scenarios, reducing avoided $SO_2$ by 2% to 5%. Start-up emissions affected the avoided emissions rates by significantly less than 1%. The net impact of considering starts and ramps lessened avoided $SO_2$ from wind/solar by 2% to 5%.

Figure ES-21 shows the $SO_2$ emissions rates for coal plants. The High Wind Scenario improves the $SO_2$ emission rate by 1%; the High Solar Scenario increases the $SO_2$ emission rate by 2%.

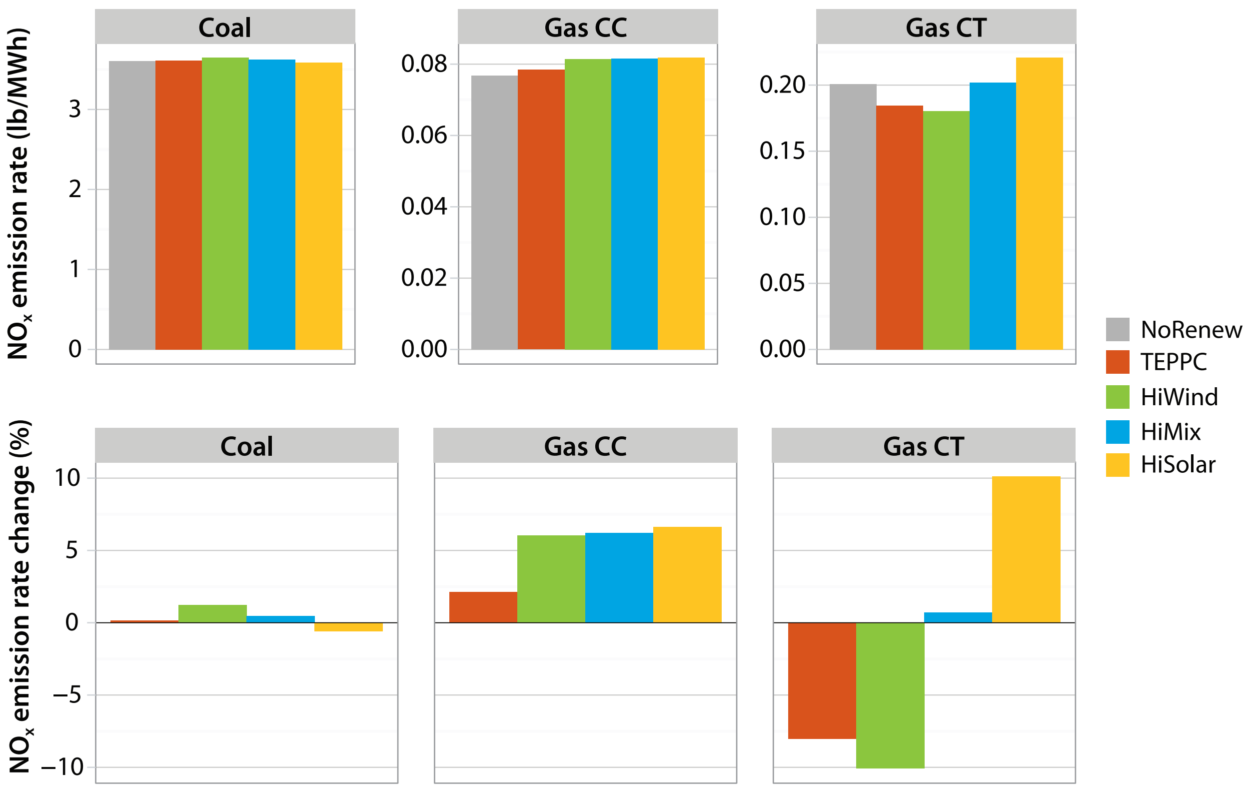


**Figure ES-19. (Top) average $NO_x$ emissions rates by plant type for each scenario and (bottom) change in $NO_x$ emissions rate from the No Renewables Scenario**

Note: Observe the difference in y-axes.

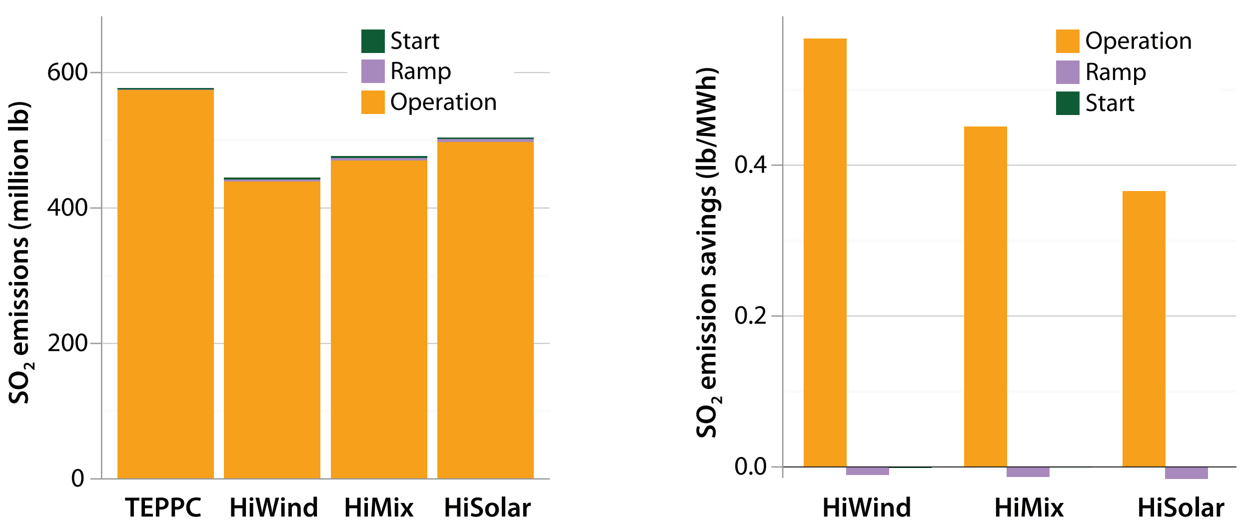


**Figure ES-20. $SO_2$ emissions by scenario: (left) absolute $SO_2$ emissions for operation, ramping, and starts, and (right) $SO_2$ emission reductions compared to the No Renewables Scenario, separated into the constant emissions rate assumption and adjustments for ramps and starts.**

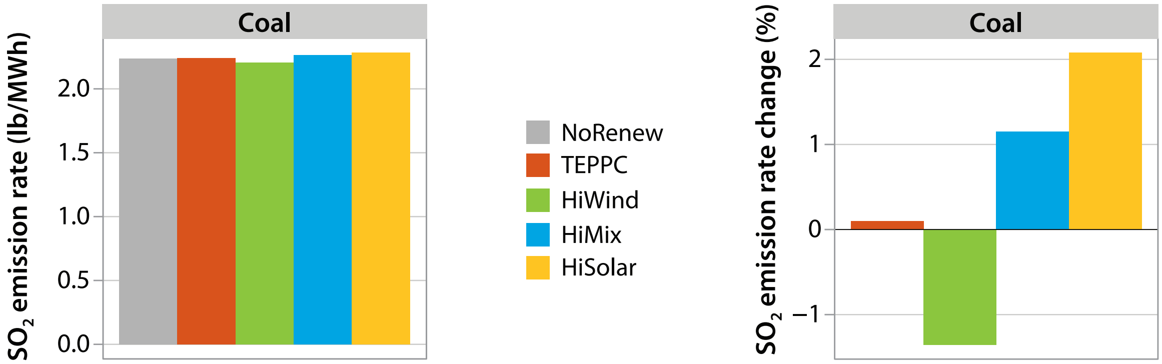


**Figure ES-21. (Left) average $SO_2$ emission rate for each scenario and (right) change in $SO_2$ emission rate from No Renewables Scenario**

Sometimes, transmission congestion or minimum generation levels of the thermal plants result in a need for curtailment. We curtailed wind and solar in these situations. Wind/solar curtailment was highest in the High Wind and High Solar Scenarios, and much reduced (to below 2%) in the High Mix Scenario (see Figure ES-22). High solar penetrations resulted in the highest curtailment, but curtailment was still modest (below 5%). High solar penetrations resulted in curtailment midday; high wind penetrations more frequently resulted in curtailment at night. We did not model take-or-pay contracts or production tax credits, which would result in a cost for wind/solar curtailment, and possibly reduced wind/solar curtailment at the expense of increased fossil-fueled plant cycling. Because wind/solar curtailment was low, however, we do not think a cost for wind/solar curtailment would change our results significantly.

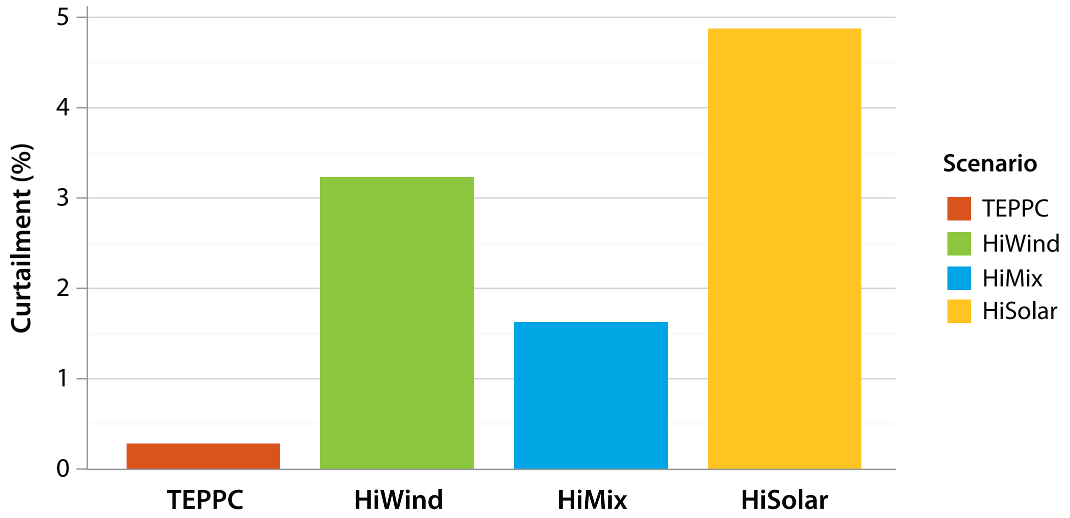


**Figure ES-22. Curtailment as a percentage of potential wind and solar generation**

**The high-penetration scenarios saw the least curtailment with a balanced mix of wind and solar.**

## Gas Price Has a Greater Impact on Cycling Costs than Wind and Solar Penetration

To understand the impacts of gas prices on the results, we modeled the High Mix and No Renewables Scenarios with gas prices averaging \$2.30/MMBtu, \$4.60/MMBtu (the core assumption), and \$9.20/MMBtu. In the \$2.30 case, system operations changed significantly because gas CC units often became cheaper than coal units. As a result, the gas CC units were often operated as baseload and cycled less. Adding wind and solar in all cases, however, displaced approximately one-quarter coal and three-quarters gas CC generation. Figure ES-23 shows the annual generation for all unit types.

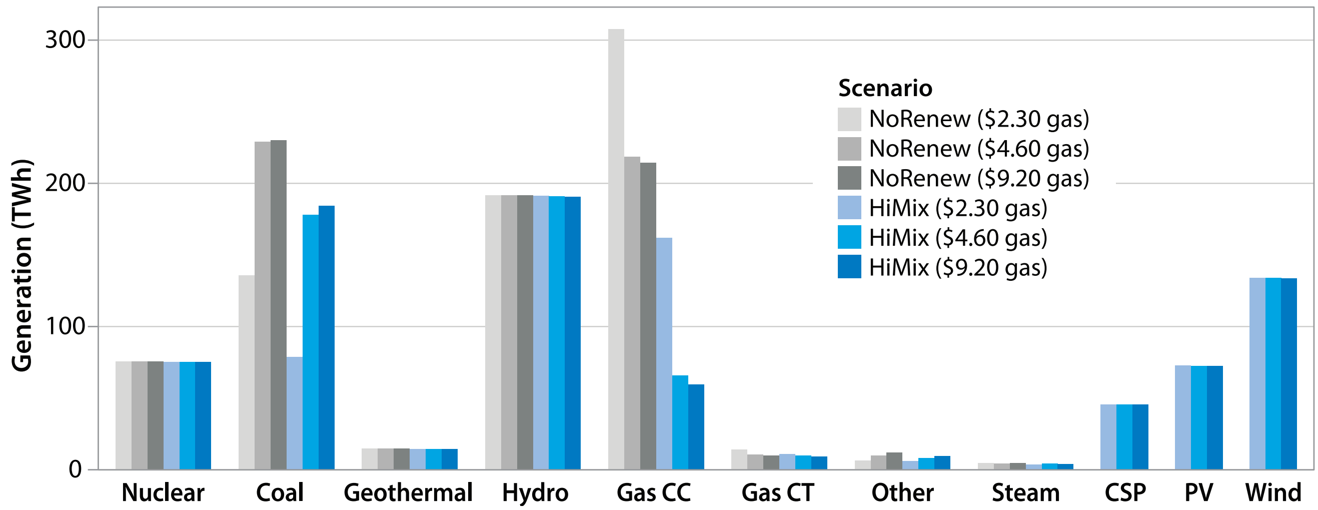


**Figure ES-23. Annual generation by type in the gas price sensitivities**

Figure ES-24 shows the capacity started in the gas price sensitivities. This plot also illustrates that gas CC units are operated as baseload units in the \$2.30 No Renewables Scenario, and as "peakers" (meaning that they are run for a relatively short period each time they are turned on) in the \$9.20 cases. Coal units are started less often (and generate less power) in the \$2.30 cases because gas CC units are cheaper.

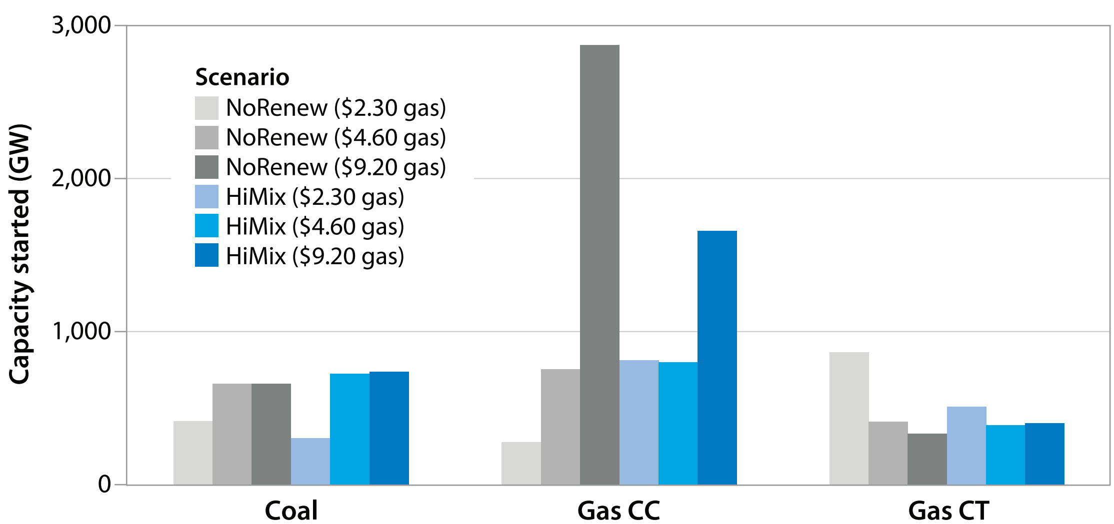


**Figure ES-24. Capacity started in the gas price sensitivities**

Figure ES-25 shows that cycling costs are affected much more by gas price assumptions than by wind and solar penetration. In the $2.30 and $9.20 gas price sensitivities, adding wind and solar actually reduces the overall cycling cost slightly because some of the starts are displaced at various unit types. Because fossil-fueled generation is displaced, though, adding wind and solar increases the cycling cost per MWh of fossil-fueled generation by $0.30–$1.16, a range that is relatively consistent regardless of gas price. Cycling costs increase at fossil-fuel units despite the reduction in overall cycling costs because fossil-fuel unit operation is significantly reduced in the High Mix Scenario.

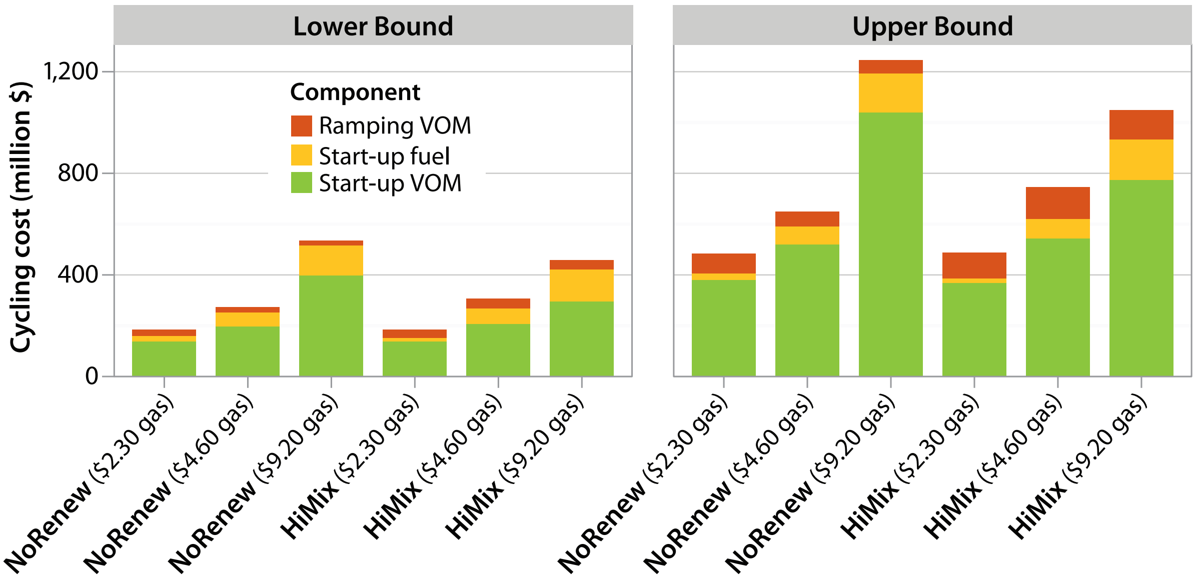


**Figure ES-25. Cycling cost in the gas price sensitivities showing (left) lower and (right) upper bounds**

**The price of gas has a much greater impact on system-wide cycling costs than the addition of wind and solar. Adding wind and solar affects the cycling cost per MWh at thermal units similarly under various gas price assumptions.**

## Solar Dominates Variability and Wind Dominates Uncertainty

Many integration studies have investigated high wind penetrations (EnerNex 2011; Charles River Associates 2010; New York Independent System Operator 2010; Intelligent Energy 2009; GE Energy 2008; United Kingdom Department of Enterprise, Trade, and Investment 2008; EnerNex 2006). Fewer studies have examined high penetrations of solar—in part because high solar penetrations have only recently become a concern and in part because of lack of data to model solar well (Orwig et al. 2012; Navigant Consulting et al. 2011).

Utilities have concerns about whether fast-moving clouds over PV plants might result in high variability. PV has two characteristics that affect this variability: (1) the size of the plant and (2) the number of plants. A small plant, such as a rooftop PV system, might see high variability from clouds, but the impact of a small system's variability on the bulk power system is minimal. Impacts could be seen on a distribution level, but WWSIS-2 focuses only on impacts at the transmission level. A large plant can have a higher impact on the bulk power system, but its larger area helps to smooth out the variability. With additional PV plants, the geographic diversity of the plants and the improbability of cloud fronts obscuring all PV plants at the same time result in further smoothing of this variability, as shown in Figure ES-26.

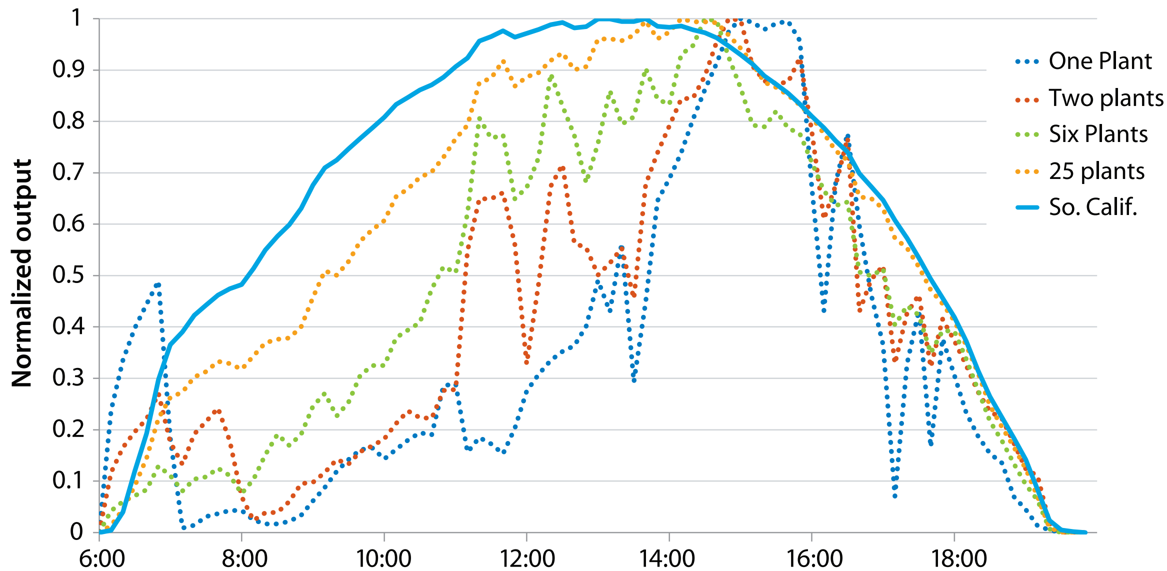


**Figure ES-26. Normalized power output for increasing aggregation of PV in Southern California for a partly cloudy day**

**Solar dominates variability extreme events. At a system level, however, most of this variability comes from the known path of the sun through the sky, instead of from fast-moving clouds.**

The sunrise and sunset *do,* however, affect variability significantly with high penetrations of solar. High penetrations of solar dominate variability on a 5-minute and an hourly basis, and extreme events are because of sunrise and sunset (see Figure ES-27). Although extreme variability events increase, they can also be relatively easily mitigated because we know when the sun sets and rises every day. In fact, because we know the path of the sun through the sky for every hour of the year, system operators can accommodate much of this diurnal variability. We removed this known diurnal variability when we calculated reserves for solar (see Section 5).

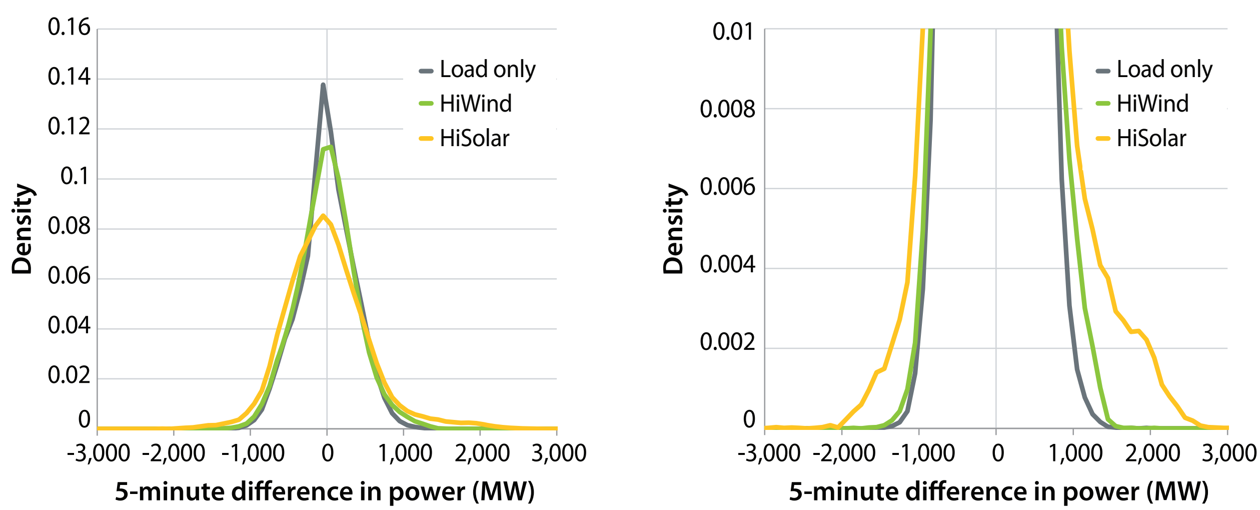


**Figure ES-27. (Left) distributions of 5-minute changes in power output for load only and the net load for the High Wind and High Solar Scenarios and (right) an enlargement of the tails of the distribution**

Wind, on the other hand, led to greater uncertainty. The high penetrations of wind led to greater extremes in the DA forecast error, as shown in Figure ES-28. Because the 4HA wind forecasts are much more accurate, shown by the tighter distribution in Figure ES-29, this uncertainty in the DA time frame can be mitigated with a 4HA unit commitment of CCs and CTs. Similarly, higher penetrations of wind led to higher reserve requirements (Ibanez et al. 2013) than those with high penetrations of solar because reserve requirements for wind/solar are driven by short-term uncertainty.

**Wind dominated the uncertainty extreme events in the DA forecast. We can mitigate this by committing gas CCs and CTs in the 4HA time frame, in which forecasts are more accurate.**

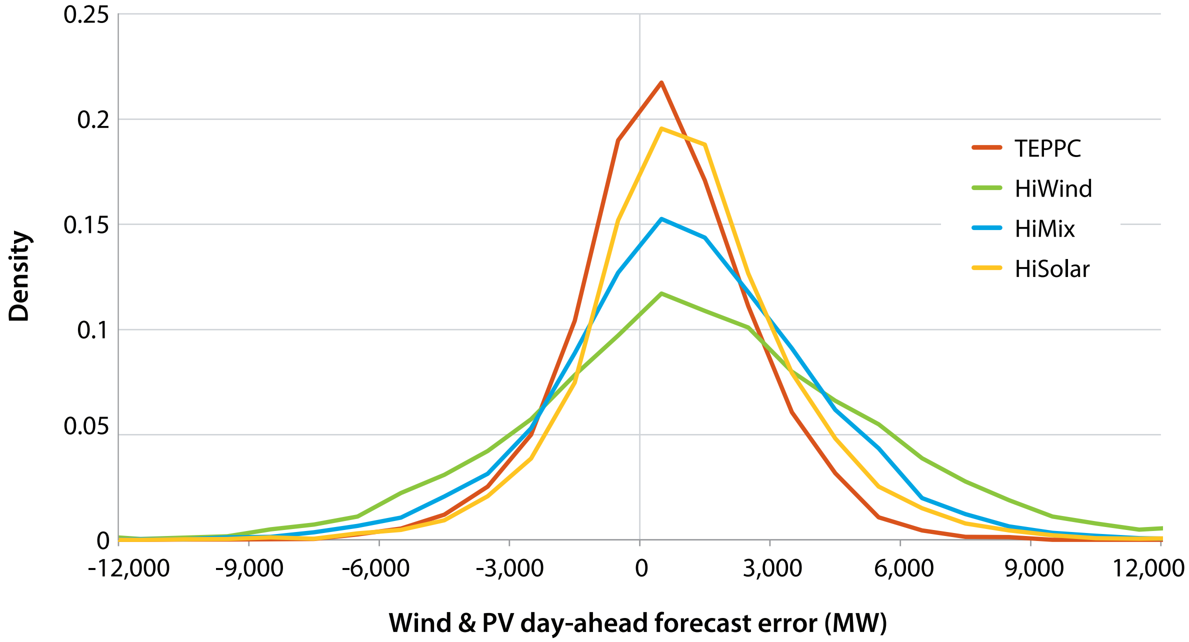


**Figure ES-28. DA wind and PV forecast error for the TEPPC, High Wind, High Mix, and High Solar Scenarios**

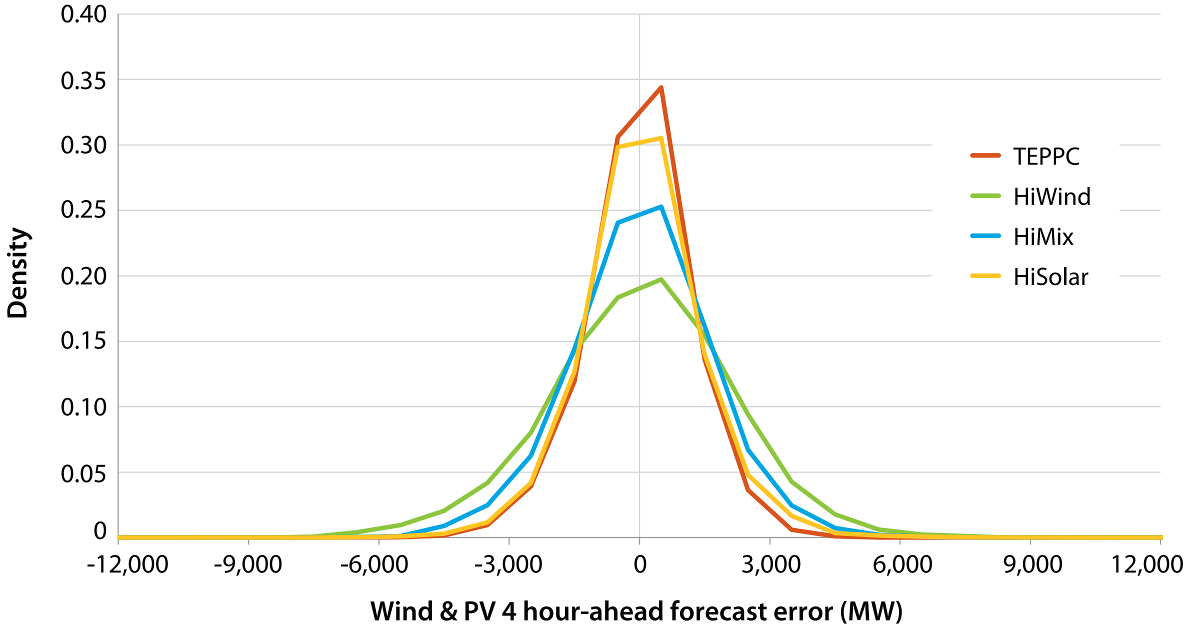


**Figure ES-29. 4HA wind and PV forecast error for the TEPPC, High Wind, High Mix, and High Solar Scenarios**

# Conclusions

We conducted a detailed operational analysis of the Western Interconnection, focusing on the wear-and-tear costs and emissions impacts from cycling of fossil-fueled plants. Detailed wear-and-tear costs and forced outage rate impacts were determined for seven categories of plants for starts, ramps, and noncyclic operation. Emissions impacts were obtained for every power plant for starts, ramps, and part-load operation. Subhourly impacts were examined using a unit commitment and an economic dispatch model with 5-minute dispatch resolution.

In this study, we found that wind and solar increase annual cycling costs by $35–$157 million, or 13%–24%, across the Western Interconnection. Cycling costs for the average fossil-fueled plant increase from $0.45–$1.07/MWh to $0.63–$2.36/MWh, compared to total fuel and VOM costs of $27–$28/MWh. Any specific unit could see more or less cycling and associated costs. Starts, not ramps, drive total cycling costs. CTs bear the brunt of the cycling costs, although CT cycling costs do not increase in the High Wind Scenario and are actually decreased in the TEPPC Scenario. Wind and solar lead to markedly increased ramping for coal generators, and coal runs fewer hours per start with high wind penetrations. Coal units ramp daily instead of weekly as wind/solar, especially solar, penetrations increase. Wind and solar have a relatively small impact on the number of starts for coal units. Wind and solar mostly displace gas CC generation and cut CC unit runtime per start in half. Gas CTs start and ramp less often in scenarios with high ratios of wind to solar penetration. High solar penetrations, on the other hand, lead to more starts, shorter run times, more ramping, and more generation for CTs.

From a system perspective, the $35–$157 million cycling cost increase is a small percentage of the annual fuel displaced by wind and solar of approximately $7 billion. Each MWh of wind and solar generation displaces $29.90–$33.60 of fuel and VOM costs. Wind- and solar-induced cycling offsets $0.14–$0.67/MWh of this reduction in the high-penetration scenarios and $0.41–$1.05/MWh in the low-penetration scenario, based on the specific generator and system characteristics modeled for the Western Interconnection.

We found that cycling impacts on $CO_2$ emissions are negligible. Emissions reductions of NOx are 1%–2% more than expected when considering cycling and part-load in detail because, on average, coal plants in the West have lower $NO_x$ emissions rates at part-load. Emissions reductions of $SO_2$ are 2%–5% less than expected because of cycling.

We also compared the impacts of wind and solar, using new data sets that illuminated the subhourly variability of utility-scale PV. Wind and solar generation affect the system in different ways. They both mostly displace gas CC generation, but wind also tends to displace more coal. Solar tends to dominate variability extremes, but it can be mitigated because most of this variability is known and can be anticipated in the unit commitment. Wind tends to dominate uncertainty extremes because of tail events in the DA wind forecast error. This can be mitigated by committing gas CC units in the 4HA time frame and gas CTs in shorter time frames. High wind/solar penetrations result in modest curtailment—up to 5%. WWSIS-2 finds that a balanced mix of wind and solar reduces curtailment to less than 2%.

# Future Work

Even though system-wide impacts of cycling are modest, an individual unit could suffer higher than average cycling. Plant owners in this situation will want to know whether they should retrofit their unit or change their operations to better manage cycling at a lower overall cost. Ongoing work includes research on potential retrofits or operational strategies to increase the flexibility of fossil-fueled generators. This includes analysis of the costs and benefits of retrofitting existing plants for options such as lower minimum generation levels or faster ramp rates.

Additional analysis work that would illuminate the impacts of cycling and further compare wind and solar includes the following:

- Market impacts on fossil-fueled plants: How do increased O&M costs and reduced capacity factors affect cost recovery for fossil-fueled plants? What market structures might need revision in a high wind and solar paradigm? How do the economics look for those plants that were most affected?
- Fuel-price sensitivities: How are operations and results affected by different fuel prices for coal and gas?
- Different retirement scenarios: How are operations and results affected if significant coal capacity is retired or if the balance of plants is flexible versus inflexible?
- Storage: Does storage mitigate cycling and is it cost effective?
- Impacts of dispersed versus centralized PV: How does rooftop versus utility-scale PV affect the grid?
- Reserves requirement testing to fine tune flexibility reserves: What confidence levels of flexibility reserves are most cost effective and still retain reliable grid operation?
- Scenarios with constrained transmission build-outs: If transmission is constrained, what is grid performance and how is cycling affected?
- Reserve-sharing options: How do different reserve-sharing options affect grid operations?
- Increased hydro flexibility and modeling assumptions: How does flexibility in the hydro fleet affect grid operations and what is the impact on cycling?
- Hurdle rates to represent market friction: With higher hurdle rates to mimic less BA cooperation, how are grid operations and cycling affected?
- Comparison of the detailed 5-minute production simulation modeling with cycling costs to hourly production simulation modeling without cycling costs: How much more accurate is the detailed modeling?
- Gas supply: Is additional gas storage needed? How does increased wind/solar affect gas scheduling and supply issues?
- Market sequence: How much does the system benefit from the 4HA market?