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GREENING THE GRID:

Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I—National Study

GREENING THE GRID PROGRAM
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Prepared by

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LIST OF ACRONYMS

ATC	available transfer capacity
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CTU	central transmission utility
DA	day-ahead
ER	Eastern region
GHI	global horizontal irradiance
GW	gigawatt
IPP	independent power producer
INR	India Rupee
LSE	load serving entity
MIP	mixed-integer programming
MMT	metric tonne
MNRE	Ministry of New and Renewable Energy
MW	megawatt
MWh	megawatt-hour
NER	Northeastern region
NR	Northern region
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
PLF	plant load factor
POSOCO	Power System Operation Corporation
POWERGRID	Power Grid Corporation of India Limited
PPA	power purchase agreement
PV	photovoltaic
RE	renewable energy
RLDC	Regional Load Dispatch Center
RPO	renewable purchase obligation
RT	real-time
SCADA	supervisory control and data acquisition
SLDC	State Load Dispatch Center
SR	Southern region
USAID	U.S. Agency for International Development
USE	unserved energy
WR	Western region
WRF	Weather and Research Forecasting

ABSTRACT

The use of renewable energy (RE) sources, primarily wind and solar generation, is poised to grow significantly within the Indian power system. The Government of India has established a target of 175 gigawatts (GW) of installed RE capacity by 2022, including 60 GW of wind and 100 GW of solar, up from 29 GW wind and 9 GW solar at the beginning of 2017. Using advanced weather and power system modeling made for this project, the study team is able to explore operational impacts of meeting India's RE targets and identify actions that may be favorable for integration.

Our primary tool is a detailed production cost model, which simulates optimal scheduling and dispatch of available generation in a future year (2022) by minimizing total production costs subject to physical, operational, and market constraints. Our team comprises a core group from the Power System Operation Corporation, Ltd. (POSOCO), which is the national grid operator (with representation from the National, Southern, and Western Regional Load Dispatch Centers) under Ministry of Power, National Renewable Energy Laboratory (NREL), and Lawrence Berkeley National Laboratory (Berkeley Lab), and a broader modeling team that includes Central Electricity Authority (CEA), POWERGRID (the central transmission utility, CTU), and State Load Dispatch Centers in Maharashtra, Gujarat, Tamil Nadu, Karnataka, Rajasthan, and Andhra Pradesh. Our model includes high-resolution wind and solar data (forecasts and actuals), unique properties for each generator, CEA/CTU's anticipated buildout of the power system, and enforced state-to-state transmission flows.

Assuming the fulfillment of current efforts to provide better access to the physical flexibility of the power system, we find that power system balancing with 100 GW of solar and 60 GW of wind is achievable at 15-minute operational timescales with minimal RE curtailment. This RE capacity meets 22% of total projected 2022 electricity consumption in India with annual RE curtailment of 1.4%, in line with experiences in other countries with significant RE penetrations (Bird et al. 2016). Changes to operational practice can further reduce the cost of operating the power system and reduce RE curtailment. Coordinating scheduling and dispatch over a broader area is the largest driver to reduce costs, saving INR 6300 crore (USD 980 million) annually when optimized regionally. Lowering minimum operating levels of coal plants (from 70% to 40%) is the biggest driver to reduce RE curtailment—from 3.5% down to 0.76%. In fact, this operating property is more influential than faster thermal generation ramp rates in lowering the projected levels of curtailment.

While this study does not answer every question relevant to planning for India's 2022 RE targets, it is an important step toward analyzing operational challenges and cost saving opportunities using state-of-the-art power system planning tools. Further analysis can build upon this basis to explore optimal renewable resource and intrastate transmission siting, system stability during contingencies, and the influence of total power system investment costs on customer tariffs.

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1 INTRODUCTION

The use of renewable energy (RE) sources, primarily wind and solar generation, is poised to grow significantly within the Indian power system. India's power grid is one of the world's largest synchronized networks, with about 300 gigawatts (GW) of installed capacity serving one billion people. The grid is also one of the most rapidly growing grids. During the last decade, India's economy and electricity demand grew at an annual average of 7% (OECD/IEA 2016). The demand for power is expected to continue to increase to support India's growing manufacturing sector and meet the rising aspirations of its people.

The Government of India has therefore seized energy development and security as critical policy objectives, and RE, in a country with immense solar and wind resources and falling technology costs, serves a central role in meeting these objectives. The government has established an installed capacity target of 175 GW RE by 2022, including 60 GW of wind and 100 GW of solar, up from 29 GW wind and 9 GW solar today.[1] India's Nationally Determined Contribution extends this ambition to 40% non-fossil fuels-based electricity generation capacity by 2030 (250–300 GW of solar and wind capacity depending on load). To meet these targets, the Ministry of Power has undertaken a number of initiatives to facilitate such large scale RE integration.

Global experience demonstrates that power systems can integrate wind and solar at this scale, but that evidence-based planning helps facilitate this integration at least cost. This report describes a large-scale study of the Indian power system so that the potential impacts of high levels of RE can be rigorously calculated and serve as the basis for decision-making. At the heart of this study is a detailed electricity production cost model that establishes how the Indian power system can operate at least cost. To understand the impacts of increased variability and uncertainty of large-scale RE expansion, we employed high-resolution weather data to capture the time- and place-specific nature of wind and solar generation. Applying this generation data to the production cost model creates a realistic assessment of the impacts of high levels of RE based on the way the Indian grid is currently configured and operated. With high levels of RE, the model captures the key impacts of wind and solar energy—variability and uncertainty—in detailed simulations performed at 15-minute intervals for an entire year. In this report, we describe how the project team closely collaborated with power industry experts, Ministry of Power and other government representatives, and other stakeholders so that the study could incorporate key technical and policy insights, helping to ensure a high-quality model grounded in the Indian context. We describe the modeling effort, key results, and alternative scenarios that reflect a range of RE targets and modes of operating the system. The richness of the data and modeling allows us to quantitatively explore options to integrate RE into the power system so that the benefits—energy security and reduction in emissions—can be maximized for the entire country.

This work is conducted under a broader program, Greening the Grid*,* which is an initiative co-led by India's Ministry of Power and the U.S. Agency for International Development (USAID), and includes collaboration with World Bank, the U.S. Departments of Energy and State, and the 21st Century Power Partnership.

[1] This RE target also includes 10 GW from biomass and 5 GW from small hydro.

1.1 Overcoming Challenges of Variable RE

At relatively low levels, integrating wind and solar energy to the grid in an effective manner can be achieved relatively easily. But at higher levels, wind and solar generation can present some challenges to grid operations because of the additional variability and uncertainty they bring to the power system.

Power systems routinely experience variability in load that arises partly as a function of weather and as a result of other factors that broadly consist of differing electricity usage patterns by residential, commercial, and industrial customers. Power systems also are subject to uncertainty—load can be forecasted but with a margin of error, and mechanical or electrical failures at power plants, substations, or transmission lines can occur without warning. Power system operators have developed methods for managing this variability and uncertainty and are very capable of responding by operating the power system in an effective manner. Renewable energy—wind and solar energy—bring some additional variability and uncertainty to the power system. By using a detailed operational model, such as used in this study, it is possible to assess how the power system can be operated with high levels of RE. With the detailed grid representation plus renewable energy inputs, the model thus captures the key impacts of the additional variability and uncertainty that wind and solar energy bring to the power system. The model performs detailed simulations for each 15-minute chronological interval for an entire year.

Many countries have successfully integrated significant levels of variable RE in spite of the attendant additional variability and uncertainty.[2] These countries' experiences demonstrate a range of solutions that can help integrate RE. For example, diversifying the locations of RE generation can smooth RE variability and reduce uncertainty. Changing market designs or operational practice may improve the ability of system and market operators to access lower-cost resources needed for balancing.

There is no one-size-fits-all approach to RE integration; therefore, careful analysis of India's operations under high-RE scenarios is needed to identify system-specific solutions. This grid integration study addresses a critical planning element toward meeting the government's targets: understanding the impacts to power system operations of adding variable RE and the value of changes to operations and infrastructure to improve RE integration. The results will help inform a coordinated, systemwide approach to grid integration—the regulatory, policy, and market frameworks that can enable grid operations with high penetration levels of variable RE.

1.2 Objective and Scope of Analysis

The purpose of this analysis is to evaluate the operation of India's power grid with 175 GW of RE to identify potential grid reliability concerns and actions needed to cost-effectively integrate this level of wind and solar generation. For example, can the future power system provide 24 x 7 power throughout the year with 175 GW of RE without significant new infrastructure investments (beyond those anticipated already)? How can the cost of operating a system with high RE be reduced through alternative operating procedures or technologies? What characteristics of thermal plant flexibility would help reduce RE curtailment? Are batteries essential for balancing 175 GW of RE?

Our primary tool is a production cost model, which simulates optimal scheduling and dispatch of available generation by minimizing total production costs subject to physical, operational, and market constraints. Production costs are the variable costs incurred to generate electricity, which are largely

[2] Examples of countries or states that have used wind to meet a significant percentage of demand include Denmark (42%), Ireland (23%), and Uruguay (16%) (REN21 2016).

fuel costs but also include start-up and some maintenance costs. We treat fixed costs as sunk investment costs when comparing scenarios and sensitivities; savings come from minimizing the production costs of installed capacity. This may seem paradoxical, but the objective is to mimic the scheduling and dispatch decisions that are based on variable or production costs.

Using detailed data for India's power system and for wind and solar generation, we identify if and how the Indian power system is balanced every 15 minutes in a future year (2022). The model calculates the impact of operations on RE curtailment (wind and solar energy that is available but not used), changes in the way conventional power plants are dispatched, whether the existing flexibility of thermal generation is sufficient to balance the system at all times, and potential periods of stress on the system. All simulations observe the physical constraints and limits of the grid, including flow constraints on major corridors. We use these results to inform regulatory and policy decisions, including potential actions to improve system flexibility.

This grid integration study is intended to be complementary to other analyses that are also critical to meeting the 175-GW targets. A complete set of analyses would include capacity expansion, to evaluate optimal growth in generation and transmission investments (types, locations, timing), as well as power flow analysis and stability studies to address other operational concerns (e.g., real and reactive power flow; contingency response). Our study provides an empirical basis that can inform the value of policy, regulatory, and investment decisions; however, we do not discuss the tradeoffs in *how* to implement RE integration strategies. These issues will be addressed, in part, in other components of Greening the Grid. In addition, this analysis informs but does not directly address ancillary market designs, the overall cost-effectiveness of RE, policies to improve investor confidence in RE, or retail tariff implications. Our analysis seeks solutions that minimize electricity production costs in an already built system. Optimizing the build-out of a system with high levels of RE, and thus minimizing fixed costs, is beyond the scope of our study.

1.3 Modeling Participants and Stakeholder Review Committee

A hallmark of this grid study is extensive engagement and validation with experts from across the Indian power system—through a multi-institutional modeling team and a broad stakeholder review committee. The objective of this rigorous review is to harness the experience, judgment, and expertise of the committee, and therefore maximize the accuracy and benefit of this study.

The modeling team comprised a core group from the Power System Operation Corporation, Ltd. (POSOCO), which is the national grid operator (with representation from the National, Southern, and Western Regional Load Dispatch Centers [RLDCs]), National Renewable Energy Laboratory (NREL), and Lawrence Berkeley National Laboratory (Berkeley Lab), and a broader modeling team of more than 20 engineers representing central and state agencies: Central Electricity Authority (CEA), POWERGRID (the central transmission utility), and State Load Dispatch Centers (SLDCs) in Maharashtra, Gujarat, Rajasthan, Tamil Nadu, Karnataka, and Andhra Pradesh. The team had constant support and guidance from the Ministry of Power. All modelers received formal training on the use of the production cost software, and each of these states has worked toward customized production cost models for their own planning and analysis.

Technical stakeholder review was provided by three teams of Grid Integration Review Committees. A technical review committee is an instrumental component of a rigorous, industry-grounded RE grid integration study. The purpose of the committee is to ensure that the direction of the study is relevant to industry and that the results are technically accurate. We met four times in each of three locations

(Delhi, Bangalore, Mumbai) with more than 150 technical experts from central agencies (the Central Electricity Regulatory Commission, Solar Energy Corporation of India, National Institute of Wind Energy), state institutions (grid operators, power system planners, RE nodal agencies, distribution utilities), and the private sector (RE developers, thermal plant operators, utilities, research institutions, market operators, other industry representatives). The Review Committees provided peer review and guidance at all stages of the study, from scenario design and modeling assumptions through implications of results.

1.4 Structure of the Report

The report is structured as follows. Section 2 describes the study scenarios, assumptions, and methodology. Section 3 reviews the treatment of India-specific characteristics in the model. Section 4 analyzes the operational impacts of the official Ministry of New and Renewable Energy (MNRE) target—175 GW RE integrated into the 2022 power system. Section 5 analyzes strategies to improve RE integration. Section 6 analyzes the operational impacts of all five study scenarios, each with differing RE capacity installations. Section 7 concludes with a summary of high-level findings, particularly with regard to priority actions that can be taken to integrate 175 GW RE. Following the main report, the appendices provide additional details on the data inputs and modeling methodology. Following the appendices is a glossary of technical terms used in the report.

This national study is the first of a two-volume report. The second volume is a more in-depth study of the Western and Southern regions (Palchak et al. 2017). The national model (focus of volume 1) runs relatively quickly, so that the team can explore more questions and spot major trends in operations from a national perspective, such as major energy flows across the country and role for non-RE rich states to facilitate balancing. To investigate more deeply system operations in each of the states with the potential for significant growth in RE capacity, we also ran a higher resolution of the model that includes intrastate transmission flows and congestion limits (focus of volume 2). This regional model builds upon the same inputs in the national model but includes all transmission lines and substations within each of the states in the Southern and Western regions plus Rajasthan. Therefore, the regional model provides more robust views of localized operations and can offer more relevant planning needs to specific states.

2 STUDY SCENARIOS, ASSUMPTIONS, AND METHODOLOGY

The key study objectives are: (1) assess the impacts of adding significant wind and solar generation (variable RE) to the power system; and (2) evaluate strategies to improve variable RE integration. To meet the first objective, the study first characterized the future power systems to be evaluated and compared. How much and where will the wind and solar be located? What transmission will be available? What will be the demand for electricity? This section answers these questions with a review of the scenario definitions, the methodology used to assess the impacts of adding wind and solar generation, and assumptions about the 2022 power system. The overall methodology for our analysis is presented in Figure 1.

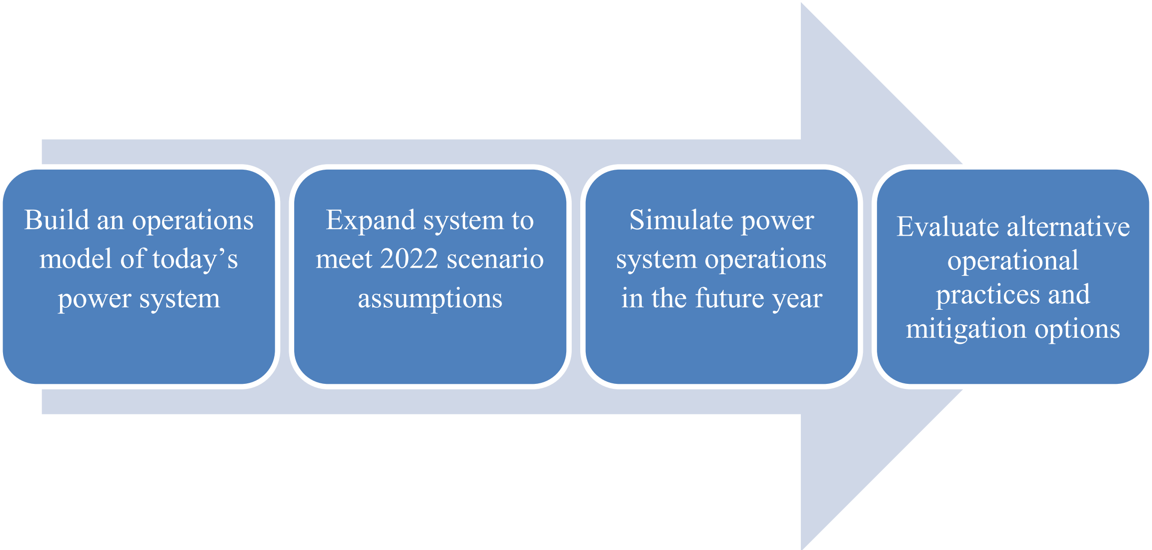


Figure 1. Process for building and simulating the 2022 system

Because it is impossible to know the future with certainty, this study developed a range of scenarios that represent plausible buildouts and locations of wind and solar energy. These scenarios, described below, were then added to the electricity production cost model, along with key assumptions regarding the future state of the system and how the system would be operated.

2.1 Study Scenarios

A study scenario defines one possible future electric power system with projections of electricity demand (load), generation, and transmission. Under the guidance of the Review Committee, this study adopted five RE growth scenarios to evaluate, as described in Table 1. The study year for each scenario is 2022. We adopted official projections for load, and plans for conventional generation and transmission for 2022 rather than suggesting an optimal build-out from now to 2022, which would be both outside the scope of our study and independent of investments already under way. We further augmented the generation capacity with the following combinations of wind and solar.

Table 1. Description and Purpose of Scenarios Used in the Study

SCENARIO NAME	SOLAR (GW)	WIND (GW)	DESCRIPTION	PURPOSE
No New RE	5	23	Wind and solar capacities installed as of 2016	Establish a baseline to measure impact of adding new RE to the system
20S-50W	20	50	Total installed capacity as targeted in Green Energy Corridors & National Solar Mission	Evaluate changes to power system planning and operations to meet near-term targets
100S-60W	100	60	Current Government of India target for 2022	Evaluate changes to planning and operations to meet the official target of 175 GW RE
60S-100W	60	100	Solar and wind targets reversed in comparison to official target	Understand differential impacts of wind versus solar on need for system flexibility
150S-100W	150	100	Ambitious RE growth	Evaluate how needs for system flexibility would change under a higher wind and solar build-out

Note: All scenarios take place in the year 2022.

The aim of the study is not to predict what will happen in 2022 or assess the timing of infrastructure investments, but to anticipate some of the operational challenges of high-RE systems and evaluate strategies that improve RE integration. We analyze multiple levels of RE to examine how robust our insights are against different levels of RE penetration. The combinations of generation, transmission, and load evaluated are intended to represent scenarios that could occur at any point in the 5- to10-year horizon.

Because the 100S-60W scenario represents the official Government of India target for 2022, we focus the bulk of our analysis on this scenario.

2.2 Assumptions About the 2022 Power System

This section reviews the study's assumptions regarding the major components of the 2022 electric system across all five of the study scenarios: operations, conventional generation, transmission, wind and solar generation, and load. To create the power system model, we began by developing a model of the existing system. This model was built in collaboration with contributing partners and verified through a large number of simulation benchmarks and technical meetings. The development of the 2022 power system was incremental to the existing system and is described below and in more detail in Appendix C.

2.2.1 Operations

The operation of the power system is simulated using a production cost model, which simulates both unit commitment and dispatch and incorporates constraints such as transmission, scheduling sequences, and physical parameters of generating plants. The model commits and dispatches generating units on an hourly basis, 24 hours ahead using forecasts for load[3] and RE, and then runs an economic dispatch using load and real-time RE data for each 15-minute block of the year. Within each 15-minute time block, the model finds a least-cost solution for meeting the electricity demand of the whole system. The model assumes that all plants, within their physical constraints, are available for scheduling if they are not on an outage. Constraints we have not modeled include bilateral contracts, allocations of centrally owned plants,[4] and must-run status of conventional plants needed for reliability. See Appendix B for more details on the model setup and execution.

2.2.2 Conventional Generation

The set of assumptions about 2022 conventional generation comprises both capacity expansion plans and generator properties.

For capacity expansion, we used CEA's/CTU's transmission system planning model for 2022, which is a PSS/E[5] AC power system model. This model includes network topology and technical details for existing and planned generators, including capacity and network location. We obtained installed capacity for our study year by matching generator data in this model against knowledge of the existing system and of generators expected to be installed by the end of India's 13th plan (2017–2022).[6] The main scenarios in this study assume no plant retirements from the 13th plan, based on guidance from CEA, although we do analyze a sensitivity (Section 5) in which retirements are considered based on plant load factors. Table 2 summarizes total installed conventional capacity by fuel type and region assumed in the model. For reference, Figure 2 maps the states to the five formal regions.[7]

[3] Unlike RE forecast data, load forecasts are assumed to be perfect.
[4] The Ministry of Power administers a portion of the electricity generation in India through centrally owned companies. Allocations refer to the contracts by state governments to utilize these plants.
[5] PSS/E is a power transmission system and simulation software planning tool developed by Siemens PTI.
[6] See Appendix C for a description of the methodology for modeling the existing system, which draws largely from POSOCO's PSS/E AC network model.
[7] The two interconnections with Bhutan are also considered in the model with monthly hydro availability based on 2014 SCADA data provided by POSOCO.

Table 2. Total Installed Conventional Capacity by Fuel Type in 2022

FUEL TYPE	INDIA (GW)	WR (GW)	SR (GW)	NR (GW)	ER (GW)	NER (GW)
Super-Coal	69	33	11	14	11	0
Sub-Coal	165	64	35	33	34	0.6
Gas Combined Cycle (CC)	22	10	4.9	5.7	0	1.2
Gas Combustion Turbine (CT)	1.5	0	1.0	0	0	0.4
Hydro	59	7.9	13	26	5.7	6.1
Nuclear	7.9	1.8	4.3	1.7	0	0
Other[8]	3.7	0.6	1.8	1.3	0	0.04
Total Conventional	328	117	70	82	50	8.4
Total Including 160 GW RE	487	166	140	114	57	9.1

ER=Eastern region, NER=Northeastern region; NR=Northern region; SR=Southern region; WR=Western region.

Figure 2. The five operating regions of the Indian electricity grid

[8] "Other" consists of all generation that has small total capacity, such as oil, naptha, lignite, diesel, bagasse, biofuel, and waste-heat recovery.

This conventional generation build-out was used in each of our 2022 scenarios; only wind and solar capacities varied between scenarios. Figure 3 summarizes installed capacity for each scenario; Figure 4 presents this information by region.

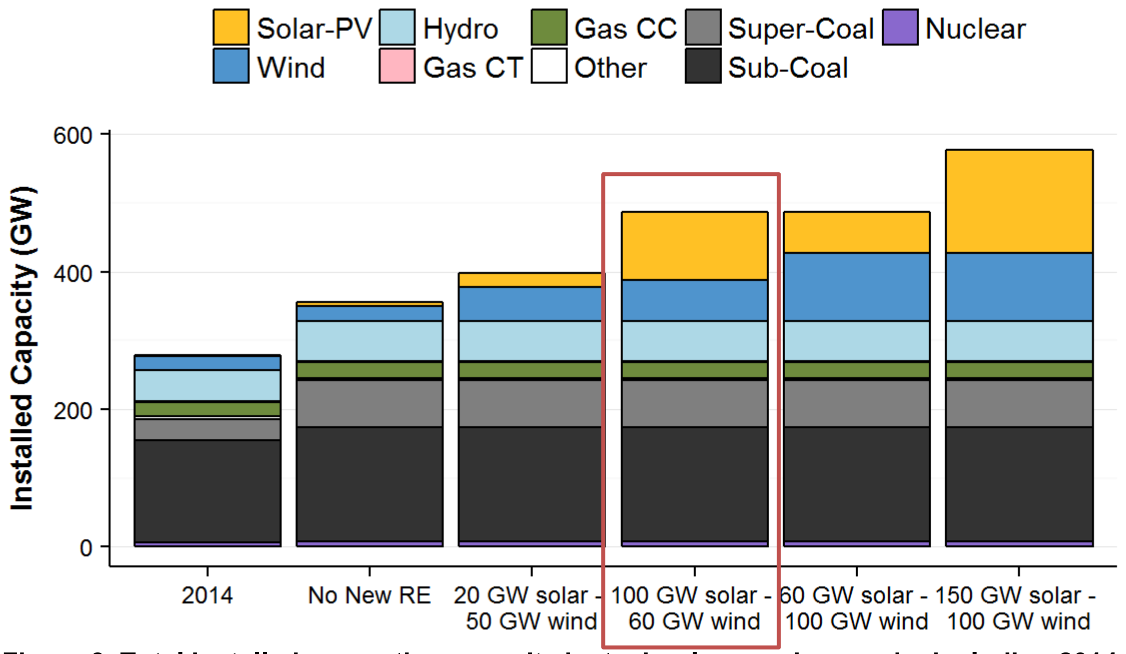


Figure 3. Total installed generation capacity by technology and scenario, including 2014 reference case

Note: Scenario marked by red border represents the official Government of India target for wind and solar.

Compared to the 2014 RE capacity, the No New RE scenario includes some additional solar and wind capacity that was added between the years 2014 and 2016.

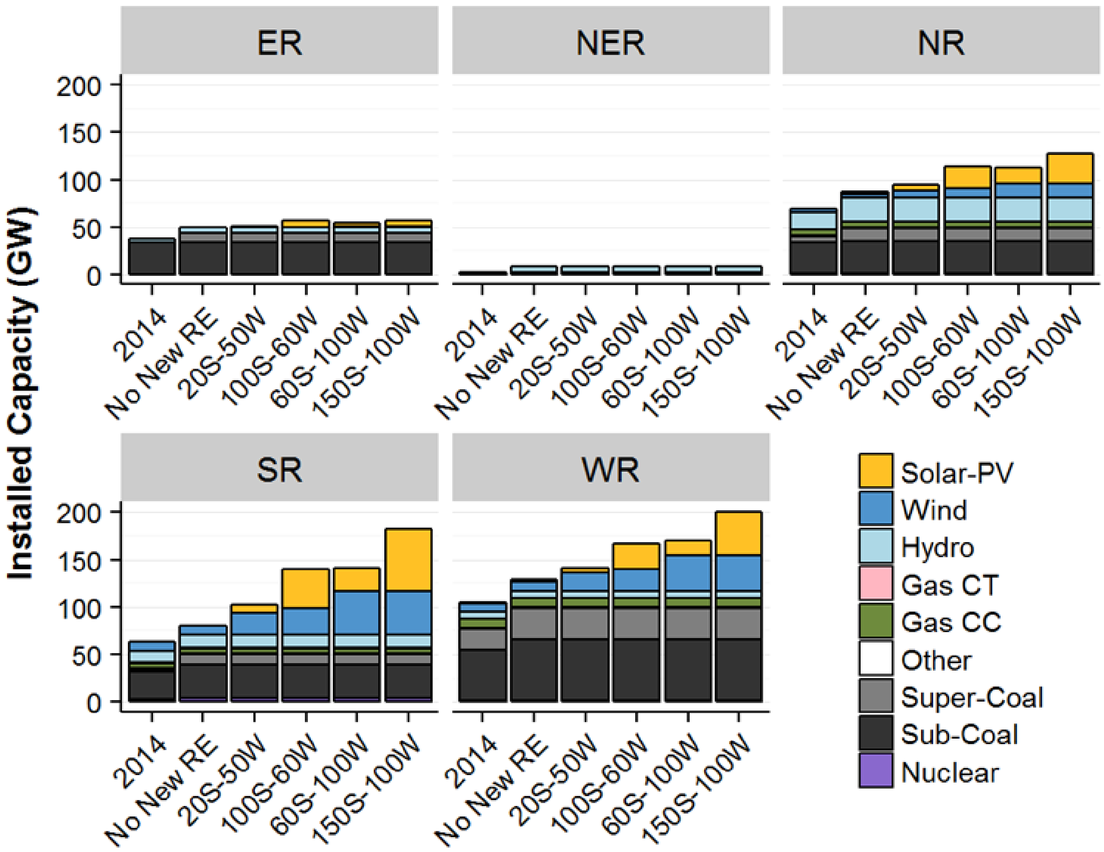


Figure 4. Total 2022 installed generation capacity by technology, scenario, and region

Accurate generator properties are critical to ensuring that the production cost model realistically captures the flexibility of and constraints on the power system. We collected generator properties from multiple sources, and wherever possible used plant-specific information in our data sets. Table 3 summarizes the average characteristics for each thermal plant type.[9]

[9] Nuclear plants are given a must-run status. Outage rates are assumed to be 27% based on feedback from the Grid Integration Review Committee in combination with international norms.

Table 3. Assumptions on Select Properties of Thermal Generators

PROPERTY AND SOURCE	SUB-COAL	SUPER-COAL	GAS CC	GAS CT
Minimum Generation Level (% of Maximum Capacity) Source: CERC regulations	55	55	50	60
Ramp Rate (% of Maximum Capacity per Minute) Source: National Thermal Power Corporation	1	1	3	3
Average[10] Variable Operations and Maintenance Cost (INR/kilowatt-hour)[11] Source: Collected by POSOCO for all states where available. Where not available, average by region and fuel type.	2.46	2.16	4.25	3.34
Average Start-Up Cost (INR/megawatt [MW]) Source: National Thermal Power Corporation and CEA Recommendations on Operation Norms for Thermal Power Stations Tariff Period 2014–2019	15632	14147	7030	6352
Heat Rate - Average or Range from Full Load to Minimum Generation Level of 55% (gigajoule/megawatt hour [MWh]) Source: CERC norms, modified to have increasing marginal heat rates and includes auxiliary consumption	11.39-12.95	10.82-11.93	7.29	11.07
Minimum Up Time (Hours) Source: POSOCO, SLDCs	24	24	8	2
Minimum Down Time (Hours) Source: POSOCO, SLDCs	24	24	8	2
Average Annual Outage Rates (Sum of Forced and Maintenance Outages) (% of Year) Source: CEA Thermal Performance Review data for 2012–2013 (unit specific); if not available assumptions were taken from similar databases (Western Electricity Coordinating Council 2024 Common Case[12]) *Note: In the case of gas generators, outage rates were used as a modeling mechanism to assume the non-availability of fuel as well as mechanical issues.*	25.0	24.9	47.7	31.1
Mean Time to Repair After Planned or Unplanned Outages (Hours) Source: Western Electricity Coordinating Council 2024 Common Case	404	404	389	256

[10] All averages in this table are simple averages (not capacity weighted).
[11] All references to costs in this report are in 2016 INR. No inflation to fuel or start-up prices is assumed for 2022.
[12] https://www.wecc.biz/Reliability/2024-Common-Case.zip.

We collected 2014 variable cost data from RLDCs and SLDCs for existing conventional generators and assumed that these costs would not change in 2022. The majority component of variable costs is the cost of fuel, which we assumed would remain the same in our study year. This assumption is not a projection of what the actual fuel costs would be in 2022. Because the relative costs of fuel (e.g., coal relative to gas) and the dominance of coal as a fuel source are expected to remain the same, assumptions regarding fuel costs do not significantly impact our conclusions, which are based on relative cost comparisons of RE integration strategies (as discussed in Section 5).

New conventional generation capacity (plants built after 2015) is given similar physical parameters to existing capacity. For these new plants, we assumed their variable costs to be at the 10th percentile of existing plants of the same technology within a region, a reflection of the higher efficiency expected of newly built plants.

As the plant load factor of a thermal generator decreases, its average heat rate increases, thus increasing fuel usage, cost, and emissions per unit of generation. To account for this inefficiency during partial load conditions, we assumed increasing partial load heat rates with decreasing generation levels for coal generators. The partial load heat rates are based on CERC norms but are slightly modified to ensure convex marginal heat rates (increasing with generation level), which is required for solving our optimization model. These partial load heat rates will affect the cost and emissions of those coal plants that may need to cycle to balance higher RE penetration. The partial-load heat rates would likely be even higher in plants that cycle frequently. On average, a subcritical coal generator with the modeled partial load heat rates uses 12% less fuel per MWh when it operates at maximum capacity versus minimum stable level.[13]

Hydro plant characteristics are challenging to model due to the multiple uses of water outside the electricity sector as well as the diurnal and seasonal variations in resource availability. To recreate hydro availability, we used plant-specific generation data from 2014 (from POSOCO's supervisory control and data acquisition [SCADA] data). Hydro plants with storage (reservoir or pondage) are constrained by maximum energy production (monthly or daily) to capture the finite energy available and daily minimum power output to capture the need to release water for agriculture or high discharge requirements during the monsoon season. The combination of the minimum power output and maximum energy generation constraints mimics the ability of these plants—because of their storage capabilities—to be dispatched flexibly. Figure 5 shows the monthly energy limits and the operable range (constrained by the capacity of the plant and the minimum load requirement) for a single storage plant for the study year. Run-of-river plants are treated as must-take, with fixed flows by day based on a weekly average of generation, due to the inability of these plants to control the water flow. Pumped storage plants are treated as a flexible resource and are required to pump the equivalent to energy production plus efficiency losses (25%) within their operable range.

[13] Partial load heat rates used in this model deviate from CERC norms for partial load heat rates due to the confounding effects of the requirement to make marginal heat rates convex for optimization efficiency while keeping estimates conservative.

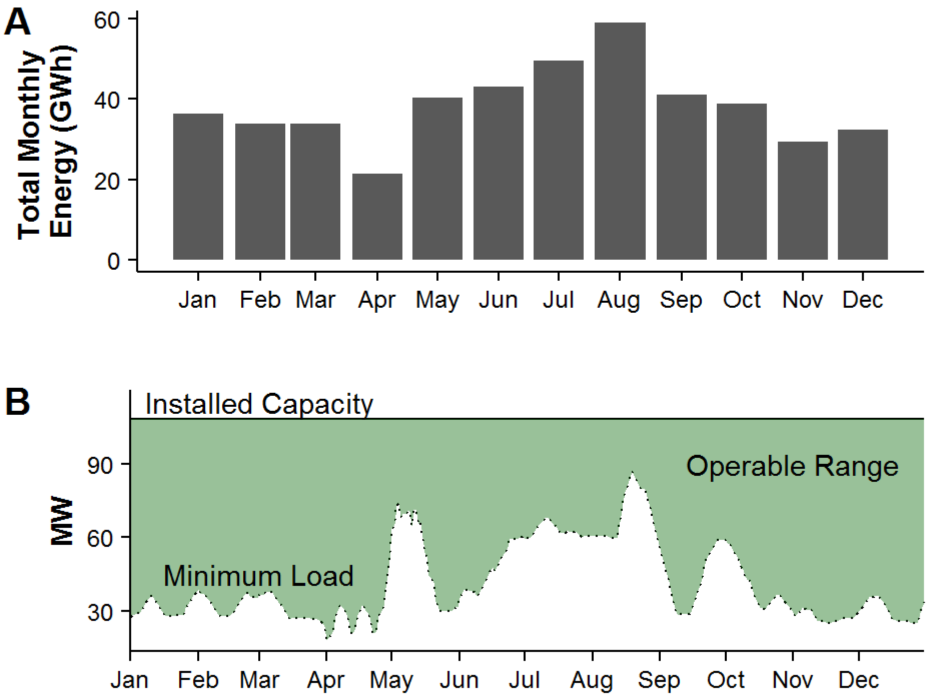


Figure 5. Constraints on a single storage hydro plant's operation: total monthly energy limits (A), and limits on the production in every period by the unit capacity and the minimum allowable operating point (B)

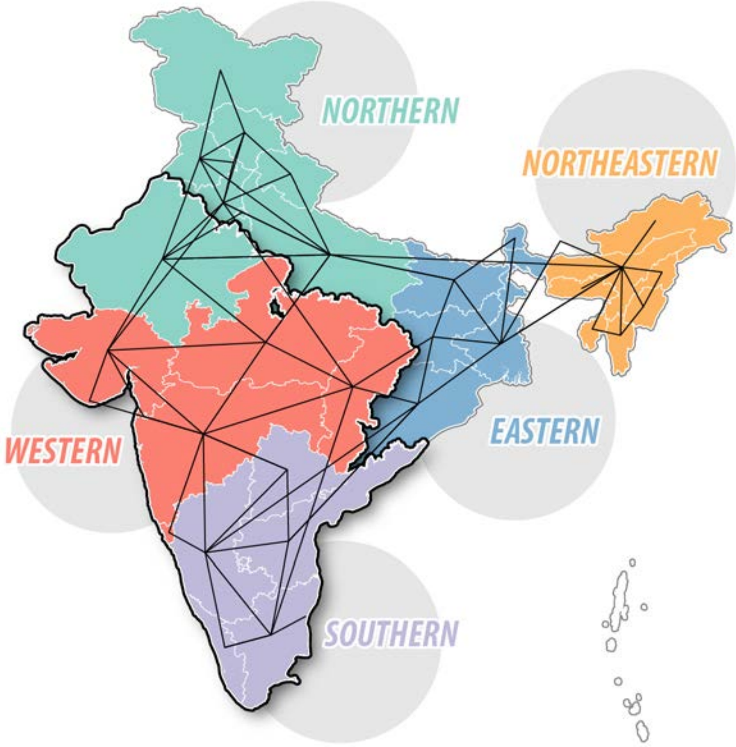
Note: Combined, the two charts illustrate the higher allowable monthly energy production and minimum loading requirements during monsoon season.

2.2.3 Transmission

We adopted CEA/CTU's 2022 PSS/E power system model as the planned transmission build-out for 2022. This model reflects all finalized transmission plans for 2022, including all phases of the Green Energy Corridor plans.[14] Refinements were made to this database in consultation with CTU to ensure that major transmission corridors are correctly represented in the production cost model based on the viability of ongoing projects.

For this national study, we consider only interstate interconnections and ignore all intrastate transmission networks.[15] The flow limits on interregional interconnections were based on the total capacity of known transmission projects through India's 13th plan in addition to known 2014 available transfer capacity limits.[16] The flow limits on the rest of the interstate interconnections were based on the total surge impedance loading limits of all participating lines between two given states. Power flows between states are calculated using linearized DC optimal power flow, which is a typical simplification made in large system production cost models. Figure 6 illustrates the transmission representation in the national study.

[14] Based on working sessions with CEA and POWERGRID to confirm all known transmission projects on major transmission corridors. State plans are taken as is from the PSS/E file.
[15] The simplification of the transmission system is meant to approximate the behavior of the full transmission system while keeping the model computationally tractable. In some cases, this equivalent network needed to be modified so that flows reflect reality. Details of the modifications to the 2022 network are in Appendix C.
[16] Available transfer capacity (ATC) limits are enforced on major corridors to ensure reliability. Details of regional transmission limits are provided in Appendix C.



Interregional Interfaces	6
Interstate Interfaces	70
AC lines	627
DC lines	24
Nodes	36

Figure 6. Transmission representation in the national study

2.2.4 Wind and Solar Generation

In all power systems, the weather has some influence on load. With high-RE futures, weather becomes a more significant factor for electricity supply. Weather drives the wind and solar generation patterns and timing; thus, it is critical to ensure that demand, wind, and solar data are consistent with the underlying weather driver. Because it is not possible to forecast the weather (and impacts on load and wind and solar generation) for an entire future year at 15-minute time intervals, the standard practice is to base the analysis of a future year on actual weather data from the past. This means that we are assuming 2014 weather in 2022 so that the demand, wind, and solar data are consistent. This approach is a well-accepted way to develop consistent data sets (Milligan et al. 2012).[17]

Credible production cost modeling results require quality, high temporal- and spatial-resolution solar and wind resource data. A simplified alternative—scaling up current generation profiles of existing RE sites to meet future capacity targets—would create unrealistically high-ramping generation profiles because it would represent building more generation exactly at existing sites. The scaling process does not recognize the geographic smoothing effect that occurs because each wind turbine or solar panel will not receive the same weather impact at the same moment. Therefore, it is important to ensure that the wind and solar data be representative of this geographic dispersion. We assume that RE capacity will be located in a broader number of sites with different weather patterns, and thus in aggregate will produce smoother generation outputs. To produce site-specific data profiles for existing and new wind locations, we used a weather prediction model that generates unique, 5-minute weather profiles for each 3 x 3 kilometer (km)^2 area across most of India.[18] Solar resource data was drawn

[17] Using a different "weather year" for these data sets can result in anomalies—periods of time when the wind power, solar power, and demand are not based on a consistent weather pattern.
[18] Wind data sets will be made public.

from NREL's National Solar Radiation Database, which incorporates impacts of clouds and aerosols, at hourly timescales for each 10 x 10 km^2 area across all of India.[19]

Because we simulate both day-ahead unit commitment and real-time dispatch in our electricity system model, we created two sets of RE data: RE day-ahead forecasts on which unit commitment decisions will be made, and RE actuals for the real-time dispatch. RE forecasts are intended to have accuracy comparable to real-life day-ahead forecasting. See Appendix A for details on the resource data creation and modeled forecast errors.

RE Site Selection

The RE site-selection process determined the locations of wind and solar plants for each of our scenarios. This process is intended to produce a realistic set of locations for wind and solar energy, and therefore a realistic representation of variable generation, even if actual site development will occur in different areas. To do this, we conducted a geospatial site suitability analysis for utility-scale RE by excluding protected areas, water bodies, high slope and elevation areas, certain land use land cover types,[20] and thresholds for average wind speed and solar global horizontal irradiance. We then estimated the potential for installed capacity for each of these potential project sites. See Appendix A for more information on the site suitability analysis.

In order to identify sites for each of our scenarios, we chose potential project sites that cumulatively totaled each RE capacity target.

- **Existing locations** (No New RE scenario: 5 GW solar; 23 GW wind): Because exact locations of all existing wind and solar plants are not publicly documented, we approximated these locations by selecting project sites with the highest resource quality that are within 25 km of a known RE pooling substation or an existing solar park. RLDCs and SLDCs provided existing wind and utility-scale solar PV capacity by substation, and POWERGRID provided the locations and capacity of planned utility-scale solar parks.
- **Wind capacity additions** (100S-60W scenario: 37 GW new capacity to total 60 GW wind): To meet the additional 37 GW target of the 100S-60W scenario, we chose the best potential project sites defined by resource quality from among the states with MNRE capacity targets for 2022 (MNRE 2017).
- **Utility-scale solar capacity additions** (100S-60W scenario: 55 GW new capacity to total 60 GW[21]): Several utility-scale solar parks are being planned across the country. POWERGRID provided the locations of planned solar parks with a cumulative capacity of 20 GW. To meet the solar capacity targets of the 100S-60W scenario, we first selected potential project sites with the best resources within 25 km of these solar parks. We then selected the best potential project sites from across the country to meet the remainder of the utility-scale solar target. To ensure adequate geographic diversity, we restricted the installed utility-scale solar capacity within a state to no more than 15% of the total national target.[22]

[19] Solar data sets can be found at https://nsrdb.nrel.gov/.
[20] Land use land cover types are classifications of land parcels that include different types of forests and agricultural lands; barren, snow-covered, and urban lands; and water bodies.
[21] The 100-GW target specifies 60 GW of utility-scale solar and 40 GW from rooftop solar.
[22] Note: State-wise RPO targets (MNRE 2017), which are consumption-based, were not used for setting state generation targets. Originally, we conducted our solar site selection using these targets, but the state-wise targets are proportional to the state's electricity demand and are not related to likely areas of RE production, which

- **Rooftop solar capacity additions** (100S-60W scenario: 40 GW new rooftop capacity): We assigned all rooftop solar capacity targets to cities that were chosen to be part of the Smart Cities program, plus six additional large cities (e.g., Bangalore). For states with multiple Smart Cities, we assigned the state target in proportion to the built-up area of the chosen cities.[23]

We used a similar approach for site selection for the other study scenarios. For 20S-50W, we added new capacity in order of best resources (starting with known solar parks) until targets were met. For wind in 60S-100W and 150S-100W scenarios (both 100 GW wind), we began with all wind sites selected for 100S-60W and then added wind to states in proportion to the 60-GW state-wise wind targets. For solar in the 150S-100W scenario (150 GW solar), we began with the sites in the 100-GW scenario, and added the new 50 GW as utility-scale solar PV from among the best resource sites, holding to the state-wise limit of 15% of total national utility-scale solar capacity. Locations for installed utility-scale solar and wind capacity for all scenarios are shown in Figure 7 and Figure 8. See Appendix A for tables of installed wind and solar capacities by state for each scenario.

would be the states with best resource sites. It is presumed that states can meet their MNRE targets by partially purchasing RE from the high wind and solar states.

[23] Built-up or urban land is comprised of areas of intensive use with much of the land covered with structures (USGS 2016).

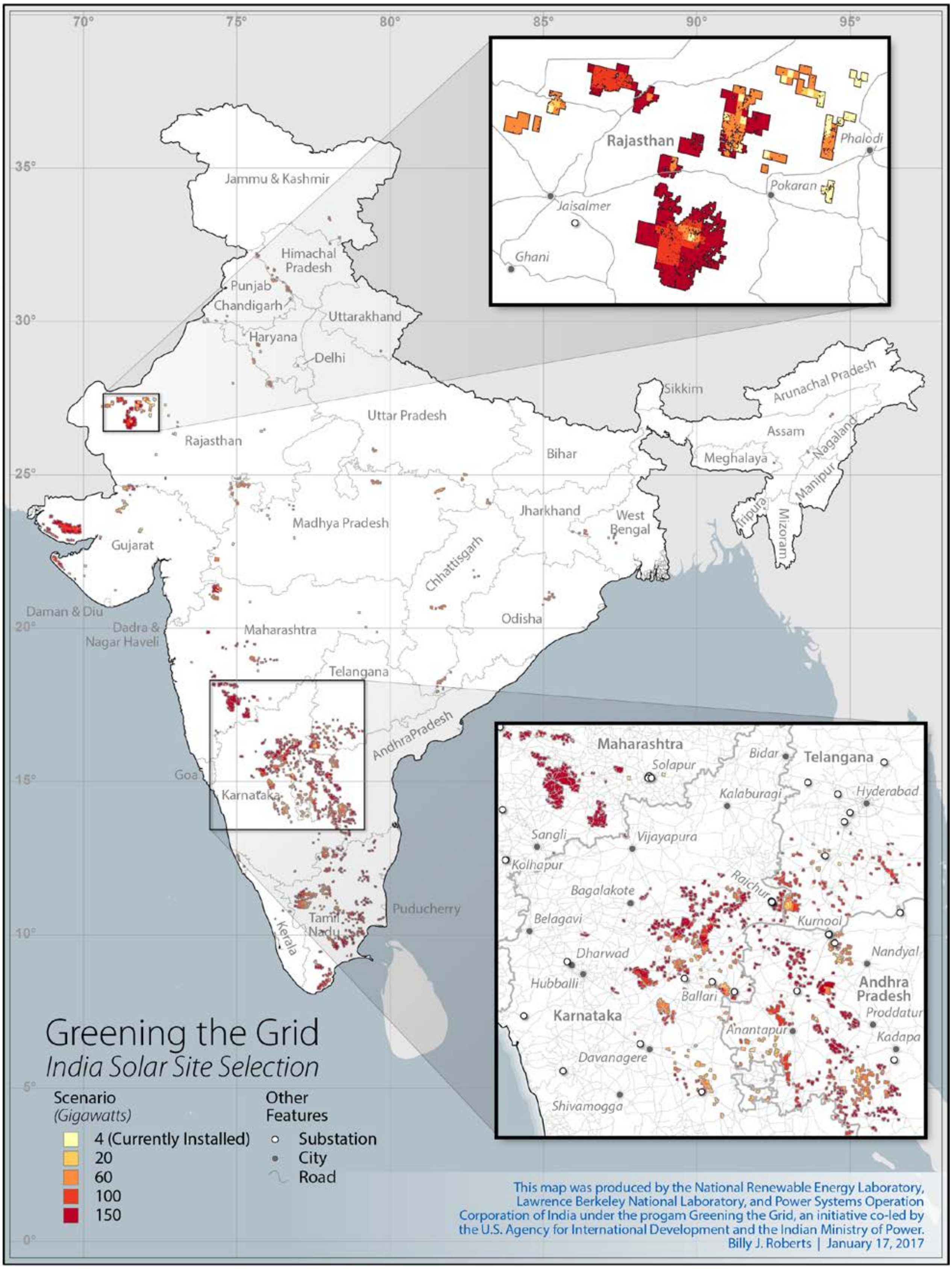


Figure 7. Locations of installed utility-scale solar capacity for each scenario

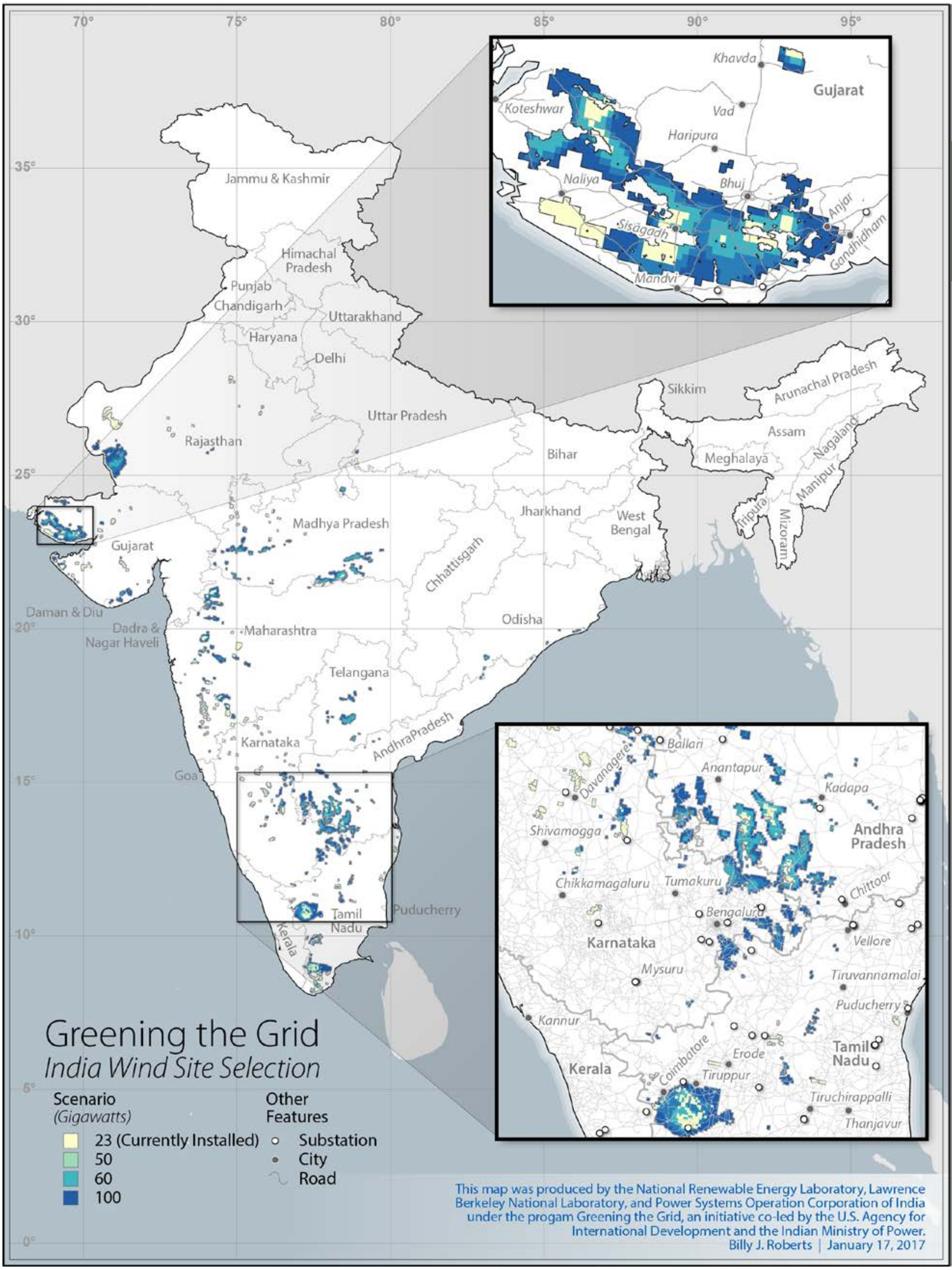


Figure 8. Locations of installed wind capacity for each scenario

RE Generation Data

The final step in preparing RE input data was to produce site-specific, time-series generation data, which we repeated for both actuals and forecast data. We first associated each selected RE project site with the nearest point of an RE resource time series, the methodology of which is detailed in Appendix A. To create the 15-minute interval solar generation data, we used the solar data associated with each selected solar PV project site as inputs to the System Advisory Model (SAM).[24] We assumed each solar PV project to be a fixed-tilt system, with the tilt set at the latitude of the site location. We simulated the 15-minute interval wind generation data for the selected sites using the wind speed resource data and wind power curves. Apart from wind speeds, wind power generation depends on the class of wind turbine, its hub height, and the air density of the location. We assumed an 80-m hub height for all existing wind turbines, and a 100-m hub height for all new installations. Appendix A provides further details.

2.2.5 Load

The production cost model requires a time series of load in 15-minute increments for the full year to be simulated. The CEA published its last annual state-wise energy and peak load forecasts to 2031–2032 in the 18th Electric Power Survey. However, these forecast figures are expected to be significantly scaled down in the not-yet-released 19th Electric Power Survey. In the meantime, CEA provided interim load forecasts, which we have used in this study.

To create the time series profiles of load for the 2022 study year, we used a combination of algorithms to extrapolate the historical 15-minute interval data for 2014 for each state, which were provided by POSOCO. The historical 2014 load data had several extreme subhourly variations, primarily for two reasons: (1) missing data because of loss of link in the SCADA system or a temporary lapse in the communication system, and (2) sudden load curtailment events, either planned or unplanned. Because we did not want to extrapolate and exaggerate these data anomalies to the study year, we created load trends by smoothing the subhourly variations of the entire data set using a moving average filter with a window spanning 75 minutes (two intervals before and after the actual ramping event). The relatively small moving average window affected primarily the extreme subhourly variations in the state load profiles. We then linearly extrapolated the load duration curves of the 2014 load trend to 2022. Using a combination of linear and exponential functions, we adjusted the load duration curves to match both the annual energy and peak load forecasts of CEA.

Figure 9 shows the national average daily load profiles for each month in 2014 and 2022.

Load shapes in 2022 may also change with changing appliance ownership (e.g., air conditioners) and usage patterns. However, we did not modify the load shapes, assuming that the changes may not be significant by 2022. A significant change in load shape by 2022 as compared to the present-day load shape could alter the net load ramp rates significantly and needs to be studied separately.

[24] https://sam.nrel.gov/.

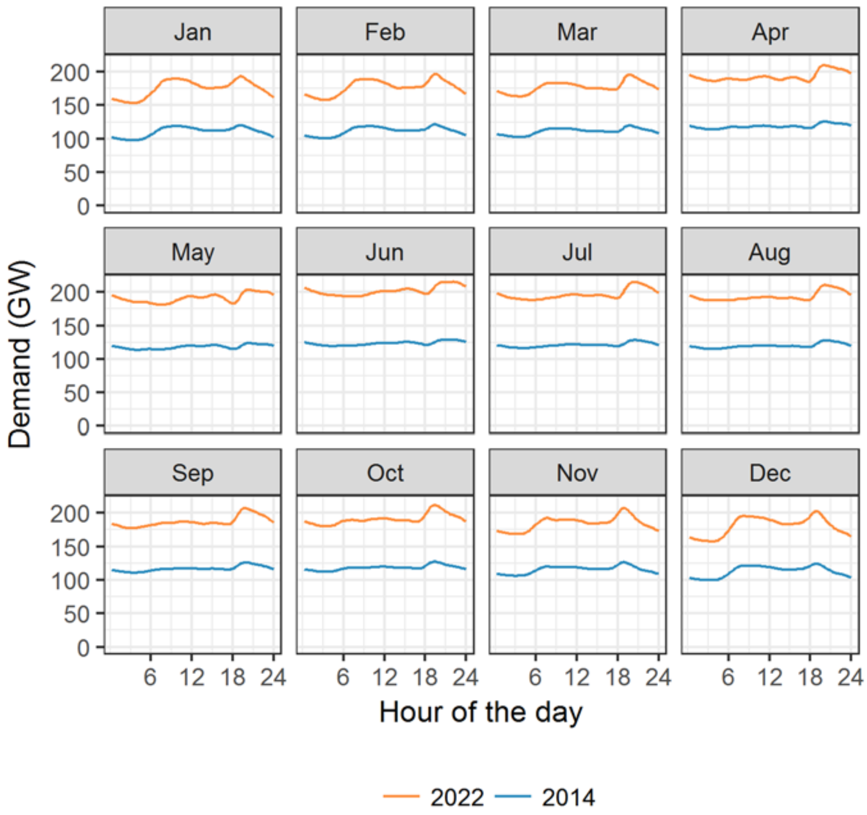


Figure 9. National average daily load profiles for each month in 2014 and 2022

2.3 Summary

To summarize, building and simulating today's power system allowed us to calibrate and test the model against actual data, in this case generation and power flows of 2014.[25] Using the calibrated 2014 model as a starting point for data collection and validation, we mapped this information to our 2022 system model, based on plans from CEA. For each high-RE scenario, we also added solar and wind capacity. We then used the production cost model to simulate power system operations for a full calendar year and analyzed results. Finally, by testing sensitivities, we evaluated options to improve RE integration, as measured, for example, by lower production costs and reduced RE curtailment. Sensitivities included alternative operating practices (e.g., improved opportunities for interstate trades) and technological solutions (e.g., storage, increased transmission).

[25] Appendix C has a detailed explanation of the validation efforts made on the 2014 model. In addition to the collection of current power system data, the results of simulations for 2014 were used to ensure the accuracy of key assumptions.

3 CUSTOMIZING THE MODEL FOR THE INDIAN CONTEXT

For the grid integration study to accurately provide insights into how to integrate 175 GW of RE, the production cost model must capture India-specific characteristics of how the power system is operated. The Grid Integration Review Committee took considerable interest in the following aspects of the Indian power system:

- Responsibility for Scheduling and Dispatch
- Allocations of Central Generators
- RE Connected to Inter- Versus Intrastate Lines
- Must-Run Status for RE
- Reserve Requirements

In this section, we summarize how we addressed each of these characteristics in the model.

3.1 Responsibility for Scheduling and Dispatch

At present, state planning agencies are responsible for ensuring sufficient long-term capacity—through state-owned generation, bilateral contracts with independent power producers (IPPs), and/or allocations from central generators. Day-ahead scheduling and dispatch of central generating stations, although done in coordination through POSOCO, is also the responsibility of each state, typically performed by the distribution companies (also referred to as DISCOMs), an aggregating DISCOM procurement entity, or the SLDCs, acting on behalf of the DISCOMs. Each DISCOM, DISCOM procurement aggregator, or SLDC schedules generation among its owned, contracted, and allocated generation, drawing on additional energy as needed through the day-ahead power exchanges or through short-term, direct bilateral trades.

The Indian power grid is a single interconnected system; however, it is operated in a decentralized manner. Because the DISCOMs/SLDCs are scheduling plants within their own balancing area with limited knowledge of schedules of neighboring balancing areas, there is little coordination among DISCOMs/SLDCs across states, which represents an economic inefficiency. This uncoordinated commitment and dispatch among neighboring areas could, for example, result in two neighboring states running plants at part-load. A more efficient outcome would be if the more economic plant were to run at a higher (or full) output level, allowing the more expensive plant to be either turned down or shut off, depending on specific conditions. If this coordination were to occur only in the economic dispatch time frame, then the most likely outcome would be that the costlier unit would be dispatched down and the least costly unit would be dispatched up. If the coordination were to also include unit commitment, then it is possible that the costlier unit could be turned off or not started in the first place, allowing greater economic savings.

Our model optimizes generation across India's entire interconnected system of generators by choosing the least-cost commitment and dispatch. However, to reflect the decentralized scheduling model in practice today in India, we use a modeling parameter that represents a disincentive to use energy from a neighboring state, referred to as a hurdle rate.[26] Hurdle rates are not costs and do not directly add to

[26] This approach has been widely used in other studies that utilize production cost models to evaluate the economic benefit of coordination. NREL's analyses of energy imbalance markets (Milligan et al. 2013; Jordan and Piwko 2013), which examined increasing levels of coordination in the western United States under

the production cost, but by creating a price differential before which a state will import, hurdle rates affect scheduling and dispatch decisions and therefore total costs. We apply hurdle rates to simulate existing scheduling and dispatch mechanism, and these are included in both day-ahead unit commitment and real-time dispatch decisions.

The state-to-state hurdle rates serve as an economic incentive for each state to use its own resources to balance generation and load before importing generation that would otherwise have similar production costs. This feature enables the model to more accurately capture present practices. We validated this method and calibrated the hurdle rate (1050 INR/MWh[27]) by matching the 2014 model to actual data, namely interregional power flows, as well as fleetwide generation and plant load factors for different fuel types.

The state-level hurdle rates therefore provide a way to capture the interstate flows in the model, but they do not address the interregional flows. To capture inefficiencies in the interregional flows, we also add hurdle rates to flows on lines between regions (ranging from INR 175 to 1200/MWh, depending on the corridor). These hurdle rates were used to tune the model to simulate actual 2014 flows between regions. As a result, the model also has a preference for states within a region to use other generation within that region, and thus reduce region-to-region flows. This allowed us to ensure that the model accurately represents interstate and interregional flows on the transmission system.[28] The same hurdle rates are applied to both day-ahead unit commitment and dispatch decisions.

In the future, it is possible that India may consider modifying the commitment and dispatch process so that additional coordination between states and/or regions could be done at lower cost. The hurdle rate mechanism allows us to investigate the savings that could arise from several alternative levels of coordination. For example, we can simulate the potential benefit of increased coordination among states by removing the state-to-state export hurdle rates, leaving the interregional hurdle rates unchanged. To simulate nationally coordinated dispatch, and hence an elimination of all barriers to efficient scheduling, all hurdle rates would be eliminated. We show results of all three types of operations in Section 5 in our sensitivity analyses, which employ "State Dispatch," Regionally Coordinated Dispatch" and "Nationally Coordinated Dispatch" to identify the extent of coordination in operations.

3.2 Allocations of Central Generators

Generators can be distinguished by which entity owns and operates them. The schedule and operations of central generating units is overseen by RLDCs, although the power from these units can be allocated to multiple states and is integrated within those states' scheduling processes. State-owned generating units are scheduled and operated by the SLDCs. IPPs can fall in either category depending on the off-taker and connectivity.

Based on feedback from the Grid Integration Review Committee, we had attempted to model central generating units as virtual balancing areas in each region, instead of assigning those plants to the states where the plants are physically located. Central units (conventional and RE) would be treated as imports to states, and subject to the hurdle rates described in the previous section. The purpose of the virtual balancing authority within each region is to exclude central plants from resources available to

dispatch-only coordination and combined commitment-dispatch coordination, applied separate hurdle rates to economic dispatch and commitment.

[27] The hurdle rates were lower in the Northeast region, which, to match 2014 actual flows, requires a lower rate to maintain sharing across the NER states without importing from the Eastern region.

[28] For more information on the model validation, see Appendix C.

the states in which they are located for dispatch and hence not overestimate the level of flexibility available to each state.

However, making these changes to the model had unintended consequences. Separating central plants into new regions introduced significant complexity to the modeling, which we could not validate due to limitations on available data and time. This is especially the case for the national study given the complications introduced when collapsing each state to one node. Also, including the hurdle rates on all central units meant that the central plant generation is more expensive for all the states, which does not reflect reality. Removing the hurdle rates allows all states to have access to all the central plants, not just the ones they have contracts for, which also does not reflect the constraints of today's contracts. Only with specific contract information would we be able to assign central plant capacity and cost to their matching states, and while this contract information exists for existing capacity, it does not yet exist for the significant amount of new capacity for the 2022 study year.

Because of the inability of this approach to capture important operational characteristics of the grid, we turned to another approach. Because each state's total allocated capacity and average costs are similar to the capacity and costs of the central units located in that state, this allows us to use physical locations as a proxy for allocations, without significantly affecting merit order dispatch.[29] In our model, states have access to the entire central plant capacity geographically located in their states, without incurring hurdle rates. The central plants within their states have similar capacities and costs as their actual allocated capacities.

In the scenarios in which we coordinate scheduling and dispatch at regional and national levels, the central versus state distinction becomes immaterial. As described in the previous section, those scenarios do not include state-level hurdle rates, and therefore all generating units within the region (or nation) are treated equally.

3.3 RE Connected to Inter- Versus Intrastate Lines

New RE capacity will be interconnected on both inter- and intrastate lines. If connected to intrastate lines, the state hosting the capacity is responsible for maintaining balance. If connected to the interstate network, RLDCs (or the off-taker) are responsible for balancing.

Members of the Grid Integration Review Committee proposed that we incorporate this distinction in the model, so that we do not impose the full balancing burden of the 160 GW wind and solar on the high-RE states. For example, one solution proposed was to add capacity to the intrastate lines until renewable purchase obligation (RPO) targets are met, and above that to interstate lines. We originally attempted to model this by adding the RE connected to the interstate lines to the virtual balancing areas described above. However, we are limited in capturing balancing responsibility without knowing plant-specific allocations, which do not yet exist.

In practice, the interstate RE plants are expected to provide their schedules to the RLDCs, and any changes in the schedule due to variability and forecast errors are expected to be balanced either by the central plants or the out-of-state buyer. However, without contract-specific information, we cannot attribute each MW of RE generated to a specific state or out-of-state buyer and still keep physical

[29] Among our six high-RE states, Maharashtra, Karnataka, Tamil Nadu, and Rajasthan have greater allocations relative to the central plant capacity located within those states. Thus for these states our model makes imports from some of the central plant capacity more expensive compared to their actual allocations in reality.

transmission limits. This would introduce many assumptions and complications that are not central to our study objective—how a system with high RE can be operated at least cost. Moreover, the cost of balancing interstate RE, whether it is borne by out-of-state buyers or RLDCs, can be addressed through financial contracts and does not need to affect the physical dispatch of the system. Thus, in the end we have kept RE within the balancing control areas of the states in which they are located. Plants at the margin, irrespective of their ownership, will be dispatched or backed down to balance net load variability. As RE development proceeds in India, the modeling framework we have developed for this study could be used in the future to investigate the impact of alternative electrical locations for RE, including both actual geographical locations and/or virtual scheduling, which would alter the electrical balancing needs from the affected areas.

3.4 Must-Run Status for RE

In India's present system, central generators of coal and gas recover capital costs through fixed tariffs (capacity charges), which are paid based on availability, independent of actual production. Separately, operating costs are recovered through production-based tariffs (energy charges). In contrast, fixed costs for utility-scale RE, which have no fuel costs, are recovered through a production-based feed-in tariff. The feed-in tariff is either set by state tariff regulations or discovered via an auction mechanism. Our model does not use this feed-in tariff for making dispatch decisions for RE because of the study's focus on production costs and exclusion of fixed costs of other generation types. An assumption of zero variable cost for wind and solar is a reflection of RE's actual production (fuel) cost of generation. Additionally, because wind and solar are considered must-run in practice, modeling RE with zero variable costs achieves a similar dispatch outcome to India's treatment of RE as having variable costs but with must-run status.

Modern wind and solar power plants can be controlled to provide frequency support and downward economic dispatch. Our model recognizes the capability of wind and solar plants to be dispatched down, and thus treats utility-scale wind and solar plants the same as conventional plants in that they are dispatched according to least-cost principles. This means that wind and solar can be curtailed if it is economical from a total system optimization perspective, for example, to avoid an uneconomical (from a system perspective) shutdown and restart of a conventional generator. This approach matches current practice at SLDCs and eliminates the need to hold additional down-reserves for high-RE futures (discussed in more detail below). Rooftop PV, on the other hand, is must-take because DISCOMs/SLDCs are unlikely to have control of those resources without significant changes to interconnection standards.

3.5 Reserve Requirements

Reserves for secondary and tertiary control are held according to the CERC order for operationalizing reserves in the country. In the model, reserves are held on a regional level, and the regional reserve requirement is the sum of secondary reserve requirements, which equal 100% of the largest unit in the region, and tertiary reserve requirements, which equal the sum of 50% of the largest unit of each state in the region. The total quantum of the combined regional reserves can be provided by gas and coal central, state, and IPP plants from anywhere in the region based on least-cost principles.[30]

The model uses these same reserve requirements, with magnitudes adjusted based on expected capacity in 2022; see Table 4 for magnitude of reserves held in each region. The model will choose

[30] Gas power plants in the Southern region were excluded from providing reserves in that region because of the uncertainty about consistent gas supplies to these plants in the future.

eligible generating plants to meet these reserve requirements based on least-cost principles co-optimized with energy dispatch. The model holds but does not dispatch these reserves because the short time frame in which reserves are actually dispatched is smaller than the timescales analyzed in this study. Because we are not modeling the dispatch of reserves, and because RE can provide downward reserves, the model only holds up-reserves to ensure sufficient headroom is maintained and that the appropriate reserves and other constraints are satisfied.

Table 4. Reserves Held in Each Region in 2022 Database

REGION	RESERVES HELD (MW)
Eastern	2,160
Northeast	363
Northern	2,224
Southern	2,722
Western	2,332

Based on feedback from the Grid Integration Review Committee, we also evaluated whether to adjust these state-specific reserve holdings based on RE development. For example, high-RE states do not want the burden of holding additional reserves and would prefer that forecast errors be balanced by other states. However, this was not straightforward to model—we cannot assign reserves based on the amount of RE that it would be purchasing as we are not capturing contracts. Nor do we want to assign reserves exclusively based on the location of RE generation because, in practice, much of this generation would be exported and balanced by other states. Therefore, we are keeping the existing CERC regulations, which do not differentiate responsibility based on RE.

We were also asked to evaluate whether the quantum of reserves should be adjusted in high-RE scenarios. Contingency reserves, which are typically calculated based on the size of the largest generator, would not be affected by RE growth. RE power plants are built from multiple small generators. Absent a transmission line trip and assuming all plants have low-voltage ride through capabilities, RE plants do not pose a credible contingency event because a reduction in power that results from a change in solar insolation or wind speed cannot happen in the contingency time frame (under a second). Of course, a line outage, delayed fault clearance, or absence of low- voltage ride through can result in disconnection of a wind farm and lead to a situation where contingency reserves could be inadequate. A contingency caused by the plant itself would be a rare event. Sudden wind speed increases that can cause overspeed conditions for wind turbines happen over many minutes or even hours, depending on the size of the wind plant. Cloud cover can have an impact on solar plants, but even a sudden cloud cover would trigger power reductions over seconds to minutes, or longer time frames if the plant size is geographically large enough. A total solar eclipse event would be known in advance and preparations made well in advance similar to the 20 March 2015 eclipse experienced in continental Europe. In contrast, secondary reserves can be affected by RE penetration levels. An optimal level of secondary reserves can be calculated using a combination of load, wind, and PV forecast errors. A comprehensive analysis of optimal reserve products and quantities is outside the scope of this study, and we therefore kept reserves consistent with the current CERC regulations.[31]

[31] Insufficient reserves with high levels of RE will generally cause either insufficient generation—lost load or reserve violations—or excess curtailment. During most operating hours there is latent up-reserve because some units will be running below rated capacity; this headroom functions as an implicit reserve.

4 OPERATIONAL IMPACTS OF 175 GW RE

Using a variety of metrics, we analyzed the results of the 100S-60W scenario to better understand how 100 GW of solar and 60 GW of wind could impact India's power system. In particular, we address the following questions:

- How do wind and solar contribute to total generation?
- How does net load change?
- How do operations of the conventional fleet change?
- How do operations of hydro change?
- How does RE affect exports and interregional power flows?
- What causes RE curtailment?
- How does the power system manage forecasting errors?

Where relevant, we compared these results to the No New RE scenario. For both the 100S-60W and No New RE scenarios, we assume state-level scheduling and dispatch, with hurdle rates applied to both state net exports and interregional flows, as described in Section 3.

4.1 Contribution of Solar and Wind Generation to the Electricity System in 2022

Solar and wind generation can be measured in a variety of ways to inform planning and operations: total generation, annual and instantaneous penetration levels, capacity factors, and RE curtailment, among others.

The 160 GW of solar and wind generate 370 terawatt hours (TWh) of energy annually, resulting in a 22% penetration level of RE.

The total annual generation from solar and wind in the 100S-60W scenario is 4.7 times greater than that from the 28 GW of variable RE capacity in the No New RE scenario.[32] These 160 GW of variable RE contribute toward meeting 22% of India's demand in 2022: 11% from solar and 12% from wind.[33]

Figure 10 shows solar and wind generation and their penetration levels (percentage of total generation by load) by month. Solar generation output remains fairly constant month-to-month, with the greatest output being in the dry, summer months of March, April, and May. Wind generation is seasonal and is greatest during the monsoon months, peaking in June and July. The highest average monthly RE generation levels occur during June and July (each 31%), with an instantaneous peak of 54% on 21 July. The lowest monthly average RE penetration level is 15% in November, when wind generation is at its lowest level.

[32] Although the No New RE scenario has the same installed variable RE capacity as 2014, the simulated RE generation is significantly greater than actual RE generation in 2014 because of our assumption that the entire fleet of existing wind turbines have an 80-m hub height, which is likely higher than the average hub height of the existing fleet. Actual 2014 RE generation is also lower because of curtailment, which is not captured in 2014 data.

[33] Actual contribution of wind and solar generation will depend on realized demand in 2022 and multiple factors, including but not limited to hub heights of wind turbine fleets, weather in 2022, fleetwide efficiency, locations of new RE capacity, and curtailment due to congestion.

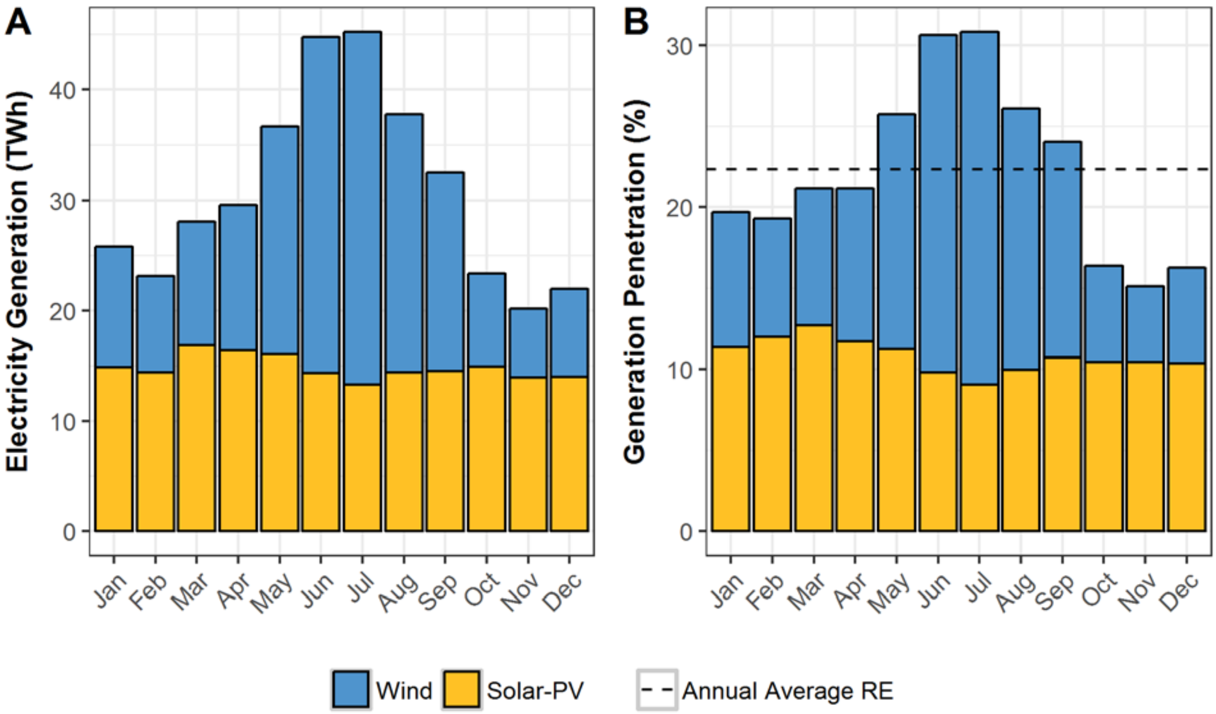


Figure 10. Monthly available wind and solar generation (A) and penetration as percent of load (B), 100S-60W scenario

Significant spatial variation in RE generation exists across India. Southern and western states are expected to install and generate RE significantly more than the rest of the country due to the availability of excellent solar and wind resources in these areas. The eight states shown in Figure 11 are responsible for 89% of total RE generation in the 2022 model. Six of these states exceed 30% annual average penetration levels relative to their load.

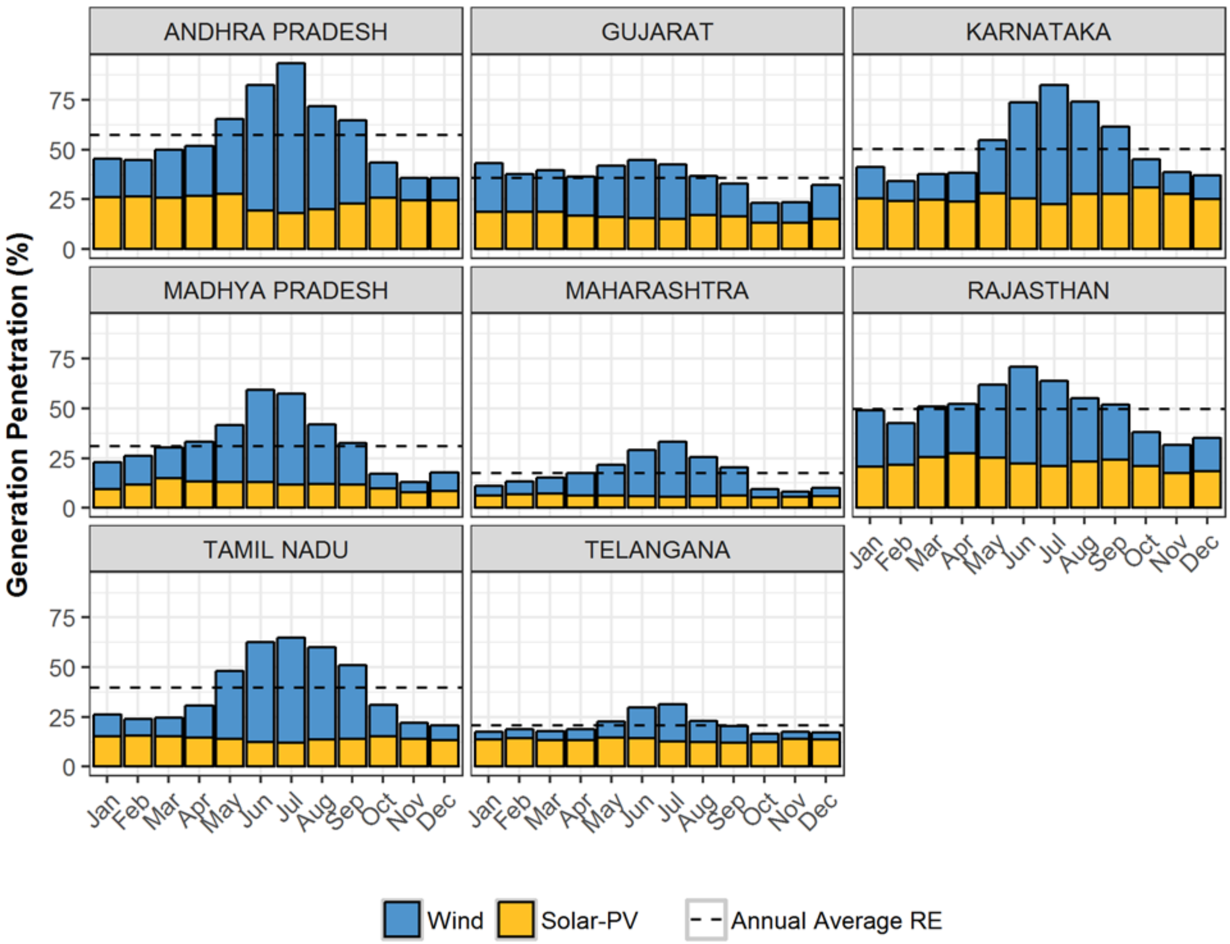


Figure 11. Monthly wind and solar penetration as percent of load in high-RE states, 100S-60W scenario

Figure 12 illustrates the spatial distribution of solar, wind, and load in the 2022 modeled system. Some of the other states have less annual RE generation compared to the highest RE states, suggesting that these states may import RE to meet state RPO targets.

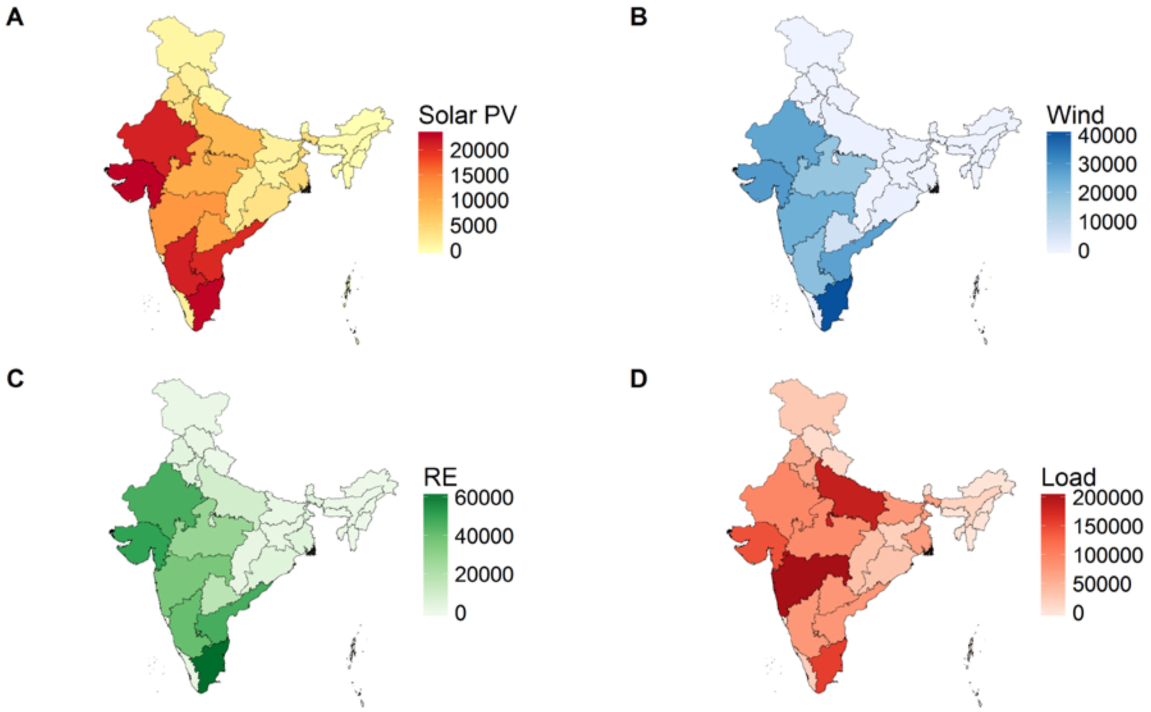


Figure 12. Spatial distribution of annual load and solar, wind, and total variable renewable energy generation (gigawatt-hours [GWh]) by state, assuming zero curtailment, 100S-60W scenario

Figure 13 is the dispatch of the Southern region during a particularly high RE period (late July) for the No New RE and 100S-60W scenarios. Notable changes in the 100S-60W scenario include the very high RE penetrations, reaching 88% of load in the Southern region, as well as the shift from mostly importing in the No New RE scenario to shifting daily between importer and exporter in the 100S-60W scenario.

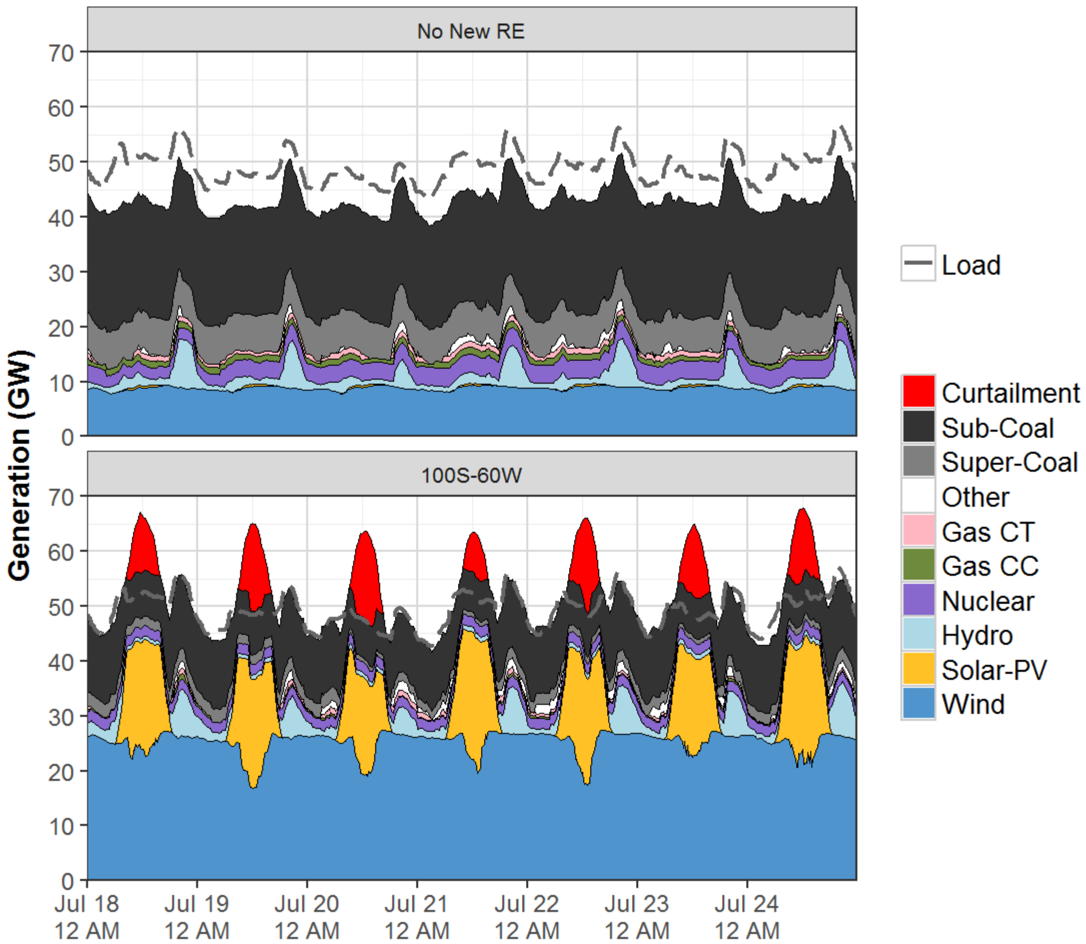


Figure 13. Dispatch for the Southern region for 18–24 July, No New RE and 100S-60W

Note: This period encompasses the highest nationwide RE penetration period (54%, 21 July, 12:15.)

Table 5 shows the highest instantaneous RE penetration as a percentage of load, by region and India-wide. The peak RE penetration for India, 54%, occurs on 21 July at 12:15. Nationally, RE penetrations exceed 50% for just 0.9% of the year, primarily in June and July, but exceed 30% more consistently (29% of the year). This change in instantaneous penetration could signify a substantial shift in the way the grid is balanced.

Table 5. Maximum Instantaneous Penetration of RE by Region

REGION	NO NEW RE	100S-60W
Eastern	0%	28%
Northeast	3%	39%
Northern	9%	53%
Southern	23%	88%
Western	21%	75%
India	13%	54%

Average annual capacity factor is 21% for solar PV plants and 36% for wind plants.

Capacity factor is a measure of how much energy is produced by a generator compared with its maximum rated output. The average annual capacity factors, post-curtailment, for solar and wind calculated by our model are indicated in Table 6. These capacity factors are a modeling result based on weather profiles, not a modeling input based on CERC standards.

As explained in footnote 32, the capacity factors of wind in our modeling outputs are greater than the existing fleet due to higher assumed hub heights (80 and 100 m in 2022, versus a mix of 50 and 80 m today), better site selection (best wind resource areas, without consideration of all factors determining availability of those sites), and no curtailment due to local transmission constraints and line outages. Simulated capacity factors of the solar PV fleet could differ from those realized in the future depending on how the mix of solar PV technologies (fixed tilt or tracking) evolves, effects of PV panel degradation, and how the aerosol layer changes across India.[34]

Table 6. Average Annual Capacity Factors for Utility-Scale PV, Rooftop PV, and Wind in 100S-60W Scenario

	SOLAR UTILITY-SCALE	SOLAR ROOFTOP PV	WIND
Capacity Factor	21%	20%	36%

At 160 GW RE, 1.4% of potential wind and solar may be curtailed annually, based on transmission assumptions in the national study.

Although it is seemingly uneconomic to discard generation that is free to produce, there are times when curtailing RE results in the least-cost electricity production from a system perspective. Curtailment can occur for a number of reasons, including insufficient transmission capacity or an event where ramping requirements exceed the capabilities of available conventional plants.[35]

Figure 14 compares the average curtailment profile between monsoon and non-monsoon months. Curtailment is much higher during the monsoon months—more energy from wind and hydro is available, and flexibility from hydro is lower. Curtailment in the 100S-60W scenario primarily occurs during the day due to a combination of operating constraints and economics. For example, during the day when solar output is high, coal generation, which should otherwise be reduced due to higher fuel costs, is dispatched because the plant's output is needed in the evening. The model chooses to curtail RE generation due to operating constraints such as minimum up/down time or due to economic calculations such as that the value of curtailed RE is less than the cost of shutting down and restarting the coal plant to meet evening peak. In most cases, it is difficult to isolate a single cause of curtailment, as changing different factors (transmission capacity and locations, minimum thermal generation set points, operating costs) all affect the timing and locations of curtailment. As a hypothetical example, curtailment that occurs because local generating plants are not able to ramp quickly to match net load could be eliminated by any number of different strategies: improving ramp rates, increasing transmission capacity to neighboring regions, increasing the balancing area to include other RE generation that smooths net load, changing power purchase agreement (PPA) terms

[34] Aerosols in the atmosphere are significantly rising due to increased human and industrial activity as well as forest burning. Aerosols reduce the amount of sunlight that reaches the Earth's surface, thereby reducing the solar radiation available to solar power plants.

[35] From the model's perspective, available solar and wind energy at the same location are interchangeable because of their identical zero variable costs. We therefore do not differentiate between solar and wind curtailment.

that free up available physical capacity, and so forth. Section 4.6 describes causes of curtailment based on 2022 operations in more detail; Section 5 explores the interrelationships between RE curtailment and the physical and operational aspects of the power system.

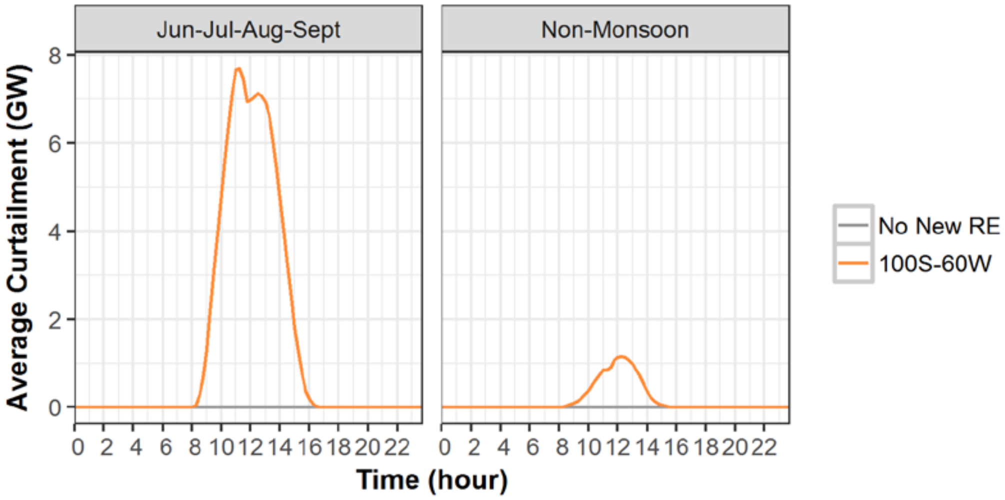


Figure 14. Average curtailment by hour, India-wide, monsoon (left) and non-monsoon (right), No New RE and 100S-60W

The rest of this section describes the timing, locations, and magnitude of curtailment. Figure 15 shows monthly RE curtailment by energy (total GWh energy curtailed) and as a percentage reduction compared to output that would have been generated given available wind and solar resources.

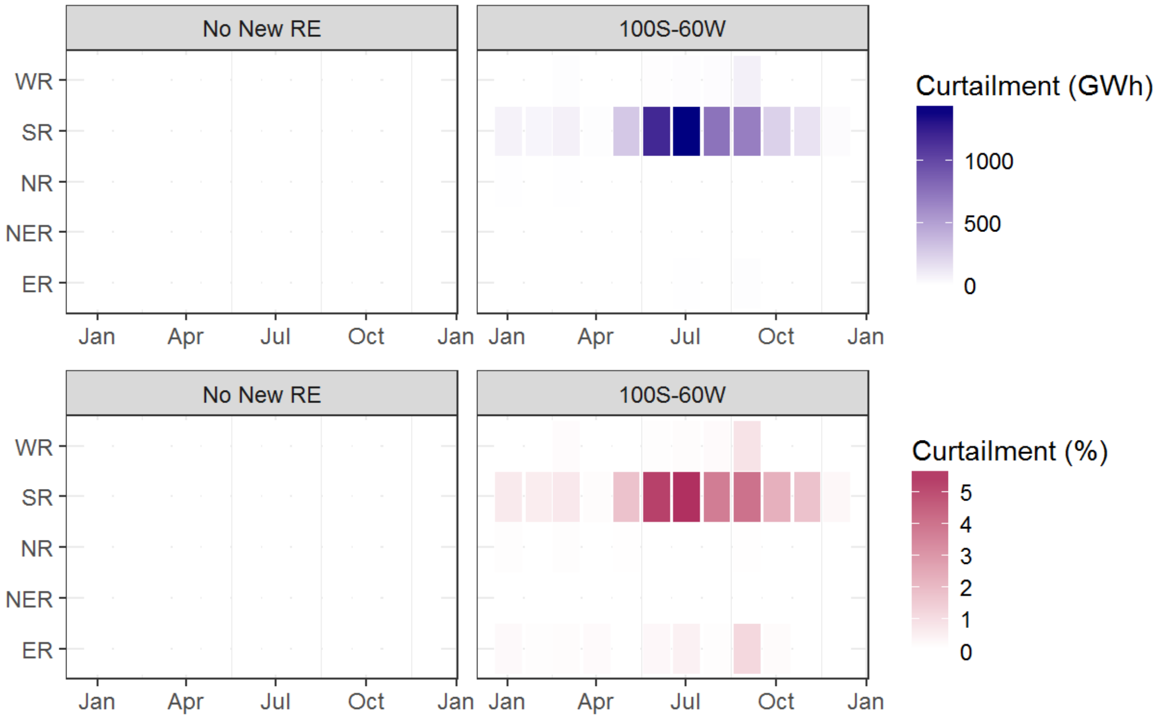


Figure 15. RE curtailment in energy (GWh) and as a percentage reduction against available, by region and month, No New RE and 100S-60W

The Southern region contains the highest quantity of RE in the country; its resources account for 42% of the installed solar and 38% of the installed wind capacity in the 100S-60W scenario. Additionally, because the Southern grid was recently synchronized with the rest of the country,[36] there is less available transmission over which to trade this RE with other regions. As a result of these two factors, the Southern region experiences the greatest amount of curtailment of any region. Southern region curtailment accounts for 97% of the country's total, with 82% of that occurring in the monsoon months of June through September. Almost one-third of the total happens in July alone; 5.8% of the Southern region's RE generation potential is curtailed in that month. This finding indicates opportunities for curtailment reduction by focusing on integration strategies in the Southern region.

Table 7 summarizes by region the number of hours in which there is RE curtailment.

Table 7. Hours in Which There Is RE Curtailment, by Region, 100S-60W

REGION	NUMBER OF HOURS IN WHICH THERE IS RE CURTAILMENT
SR	1000
ER	61
WR	39
NR	82

For load duration curves for wind, solar, RE curtailment, net load, coal, gas, hydro, and other fuels, see Figure 16.

[36] Dates of synchronization: http://www.powergridindia.com/_layouts/PowerGrid/User/ContentPage.aspx?PId=78&LangID=english.

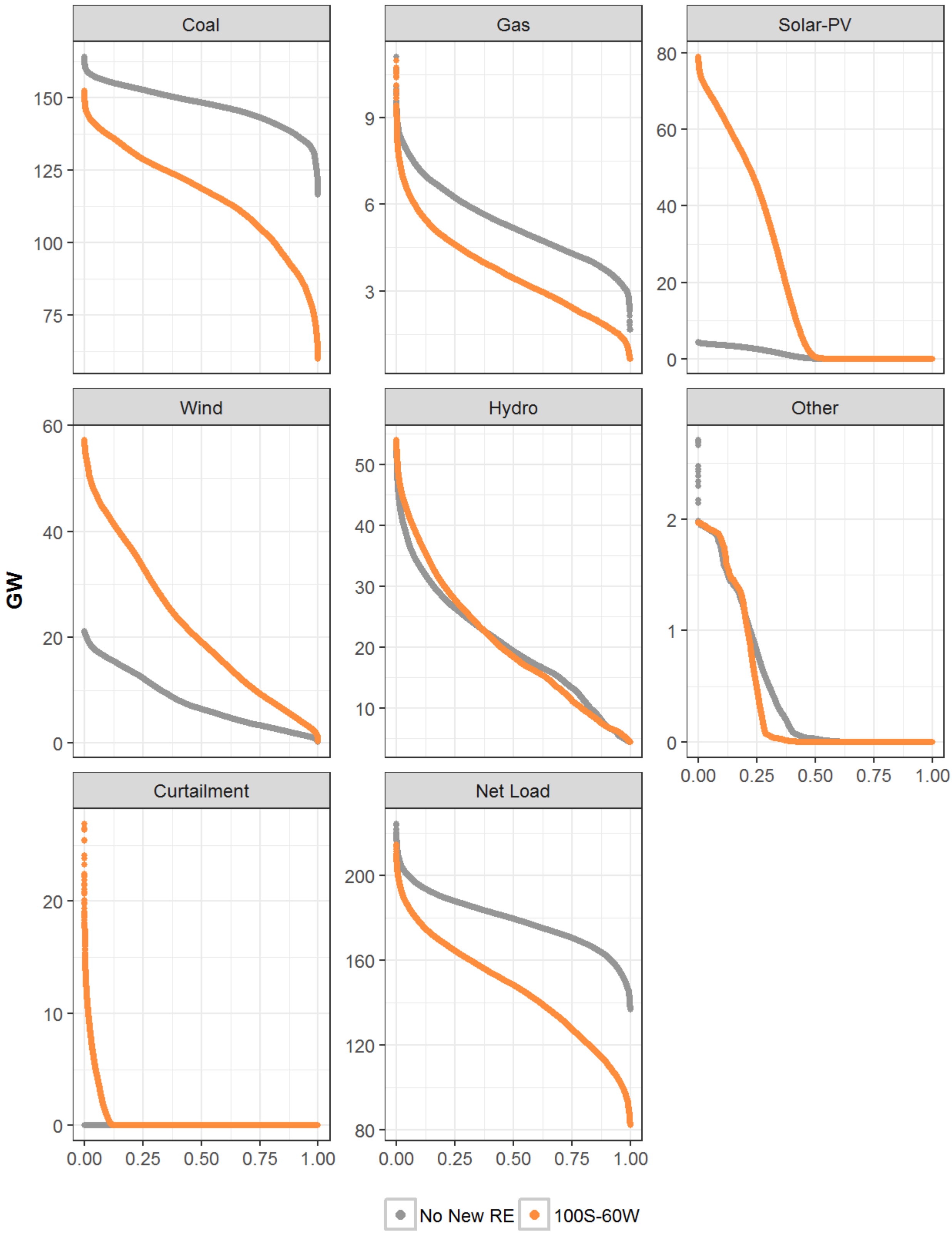


Figure 16. Annual duration curves comparing coal, gas, solar, wind, hydro, other generation, RE curtailment, and net load, No New RE and 100S-60W

Note: The x-axis is the fraction of the year during which the GW capacity exceeds the corresponding y-axis value.

4.2 How Net Load Changes

The production simulation results provide a wealth of information about how the power system operates, both with and without high levels of RE. Additional analyses can be performed on various system time series, such as load, net load, wind, and solar generation. These time series are key inputs to the production simulation model and are the key driver of results. Therefore, one can obtain insights to system operation by analyses of these time series data. In this section, we provide such an analysis of the Indian power system.

Nationally in the 100S-60W scenario, for 0.6% of the year, net load up-ramps exceed 25 GW/hour, greater than any hour in the No New RE case, and peak at almost 32 GW/hour.

Figure 17 shows the load and the net load for the Southern and Western regions during a period of high RE penetration. In comparison with load, net load in both regions can be characterized by steeper ramps and lower minimum generation levels. Hence the generation that serves net load, in aggregate, must be more flexible. In this example, each region is meeting net load with its own thermal and hydro fleets, as well as imports and exports to smooth the net load variability.

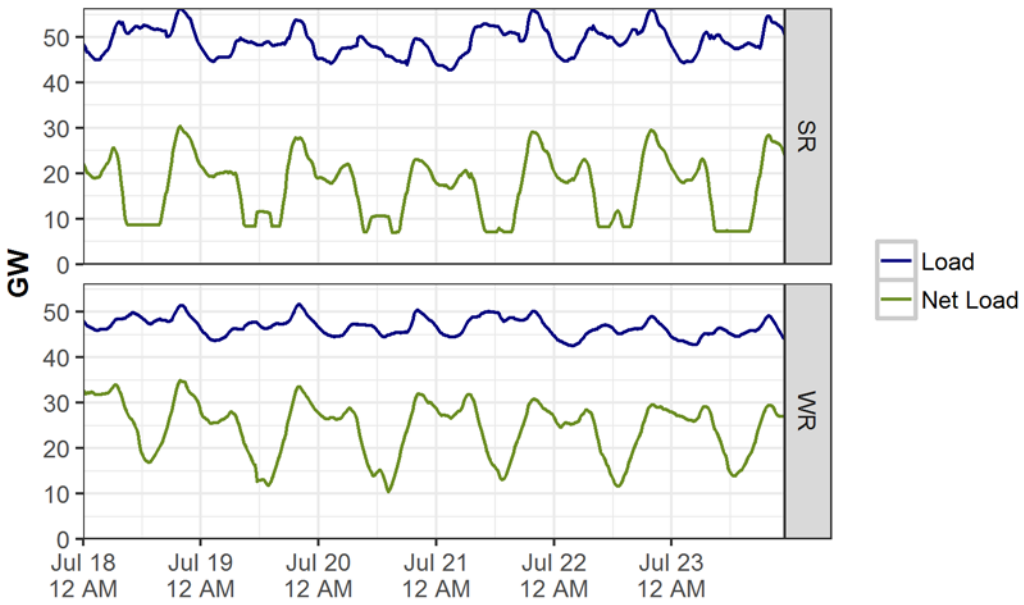


Figure 17. Load and net load for 18–23 July in the Southern (top) and Western (bottom) regions, 100S-60W

Note: This period contains the highest penetration of wind and solar nationally.

Analyzing net load helps to identify periods that may be operationally challenging given a more variable and uncertain profile. Figure 18 shows the annual net load time series for both No New RE and 100S-60W for all of India and the Western and Southern regions. The thicker net load bands in the 100S-60W scenario, Southern region in particular, reflect higher peak-to-valley ramping over each day.

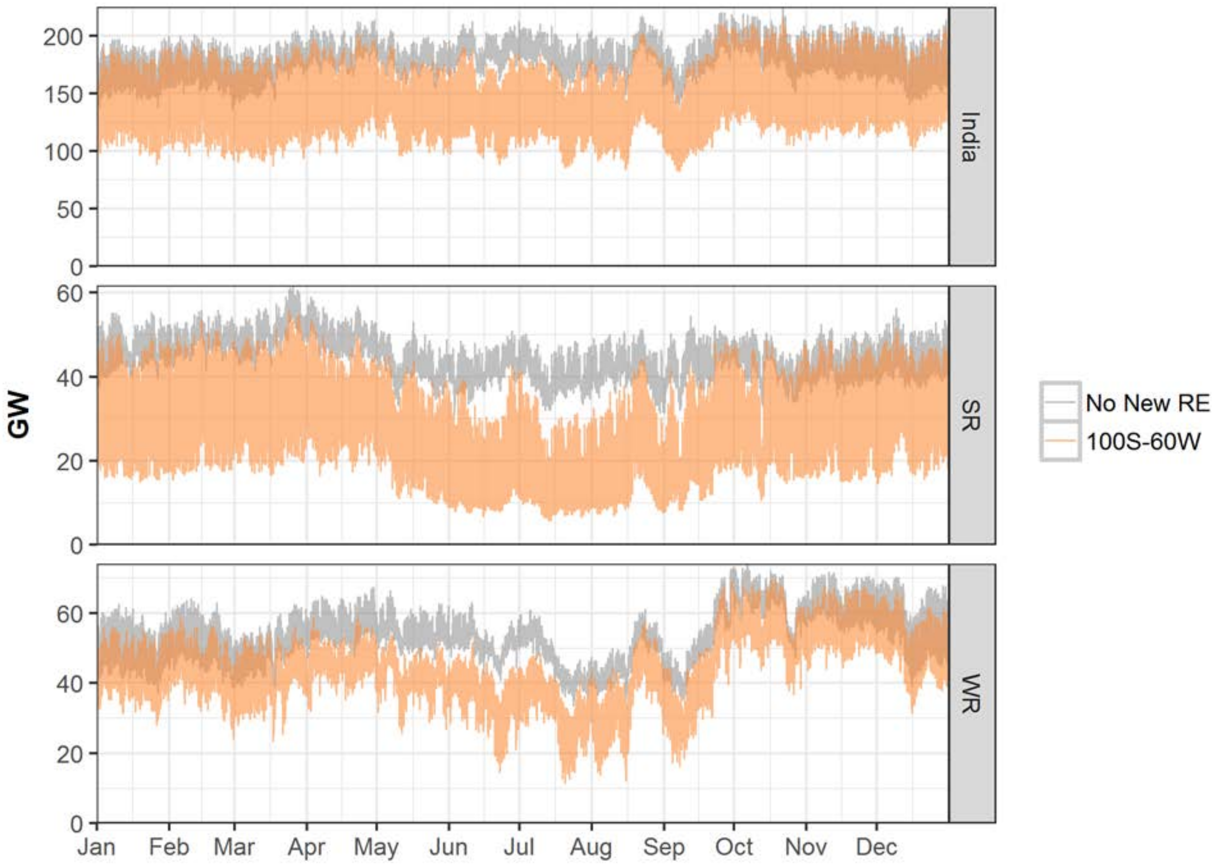


Figure 18. Net load for all India, Western region, and Southern region, No New RE and 100S-60W

Note: The thicker net load bands in the 100S-60W scenario reflect higher peak-to-valley ramping over each day.

Figure 19 organizes the ramps into a duration curve (A), and also shows a distribution of ramps (B), aggregated to the national level. The peak 1-hour upward ramp increases 27% to 32 GW in the 100S-60W scenario. In the 100S-60W scenario, 0.64% of 1-hour upward ramps exceed the No New RE scenario's 25-GW peak. The peak 1-hour downward ramp is 26 GW, greater than the 19-GW peak in No New RE. In addition to increases in peak ramps, the distribution of the middle 50% of ramps is far wider in the 100S-60W scenario (Figure 19, B).

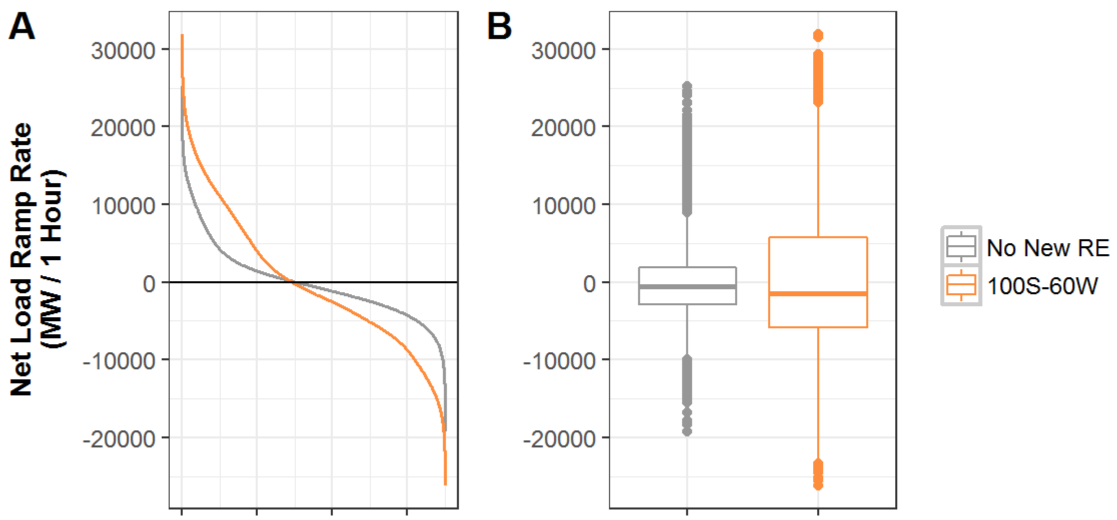


Figure 19. Net load ramp rate per hour, arranged from highest to lowest for all periods of the year (8,760 hours) (A), and as a distribution (B), No New RE and 100S-60W

Note: Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the ramps, those inside the box are the middle 50%, and those below are 25% of the ramps. The middle line is the median.

Local ramp rate changes can be more severe. Figure 20 shows hourly ramp for all of India as well as the high-RE regions. The Northern, Western, and Southern regions all have wider distributions of ramps as well as greater extremes in the 100S-60W scenario compared to No New RE. Additionally, the Southern region experiences the greatest daily net load ramping changes, with the maximum daily peak-to-valley ramp increasing by 120% from the No New RE scenario to 34 GW (28 March). The Northern region also experiences increased net load ramping during extreme periods, with the daily peak-to-valley ramp increasing by 47% to 37 GW (23 October).

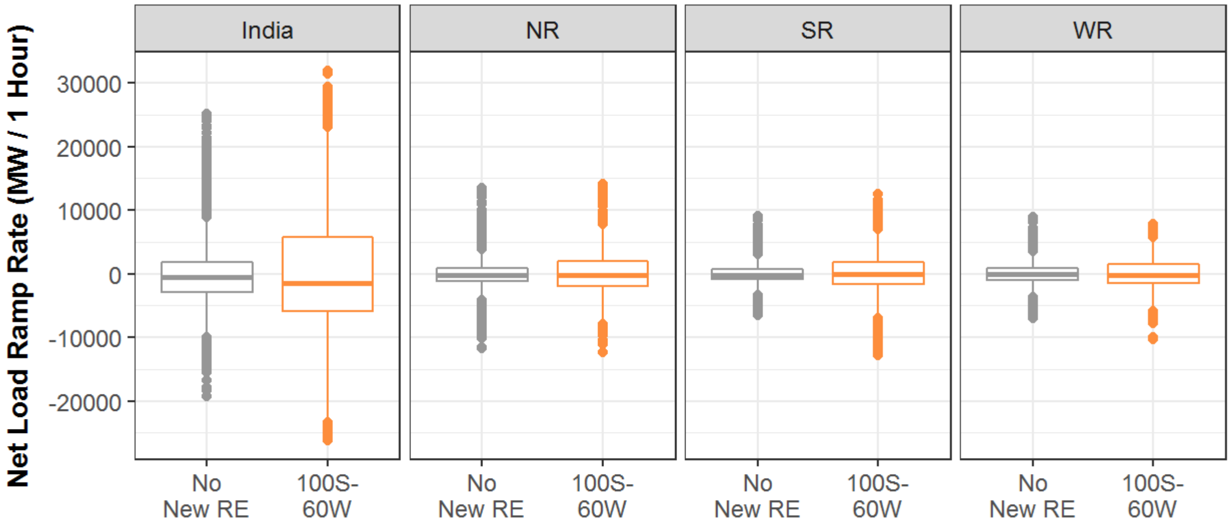


Figure 20. Hourly net load ramp rates nationally and by region, No New RE and 100S-60W

Figure 21 shows hourly ramps normalized by the non-RE online capacity (total nameplate capacity of all units that have been committed in the period that the ramping starts). The distribution of ramps is similar to Figure 20 indicating that even though thermal energy is displaced, the majority of units are still online during periods when ramping is needed.

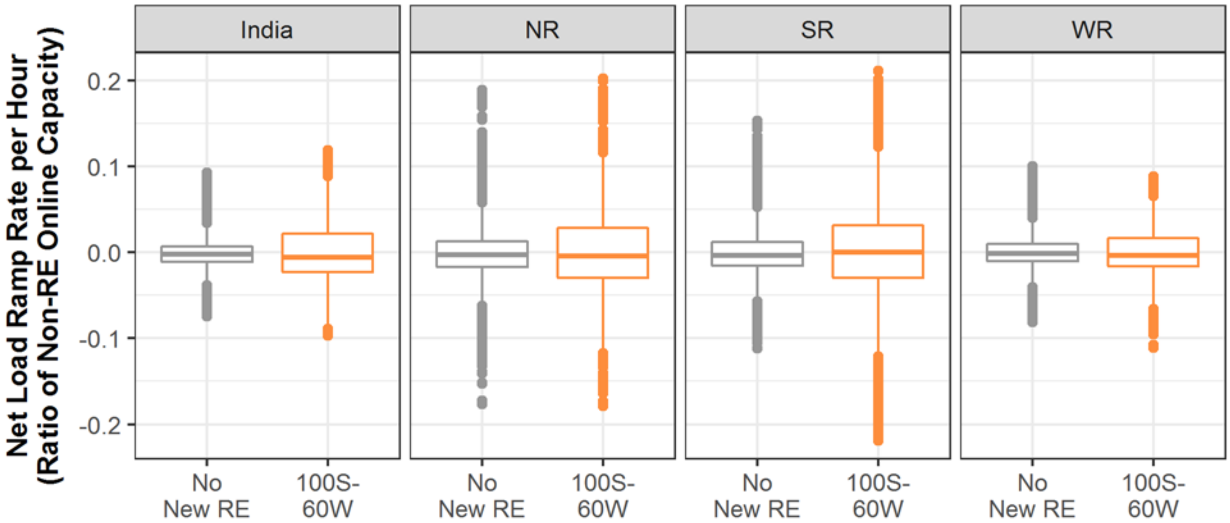


Figure 21. Hourly net load ramp rates as a ratio of non-RE online capacity, nationally and by region, No New RE and 100S-60W

4.3 Impact of High RE Penetration Levels on the Operations of Thermal Plants

Low operating-cost generation, such as hydro, wind, and solar, added to any system affects the dispatch of higher operating-cost generation, such as that from coal and natural gas. The higher operating-cost generation is dispatched less frequently, and as a result, those plants have lower plant load factors (PLFs). This occurs because the cost optimization process minimizes total cost of electricity production; thus, low variable-cost generation will always displace the highest variable-cost generation unless specific constraints or economic conditions prevent it. The variable output of wind and solar generation causes an additional impact. Not only are conventional plants run less often, but they are operated more flexibly. This flexibility impacts system operations in the following ways:

- Thermal plants individually experience greater cycling. Cycling refers to the range of operations in which a plant's output changes (starting up, shutting down, ramping, and operating at part-load).
- The system as a whole requires greater and faster ramping of conventional generation. Ramping refers to the changing output of generation needed to keep the system in balance.

This section quantifies the impacts of RE on thermal operations in the 100S-60W scenario.

Generation from the 160 GW of solar and wind displaces 270 TWh of coal and 15 TWh of gas compared with the No New RE scenario, a 21% and 32% reduction, respectively.

Figure 22 illustrates installed capacity and annual generation by type, comparing the 100S-60W scenario with No New RE. Coal-based generation is the most dramatically affected, which generates 270 TWh, or 21%, less in the 100S-60W scenario than in No New RE. Subcritical coal plants are on average less efficient and therefore have higher operating costs and, as a result, are impacted more. While subcritical coal's generation falls 24% between scenarios, supercritical coal's output decreases by only 14%.

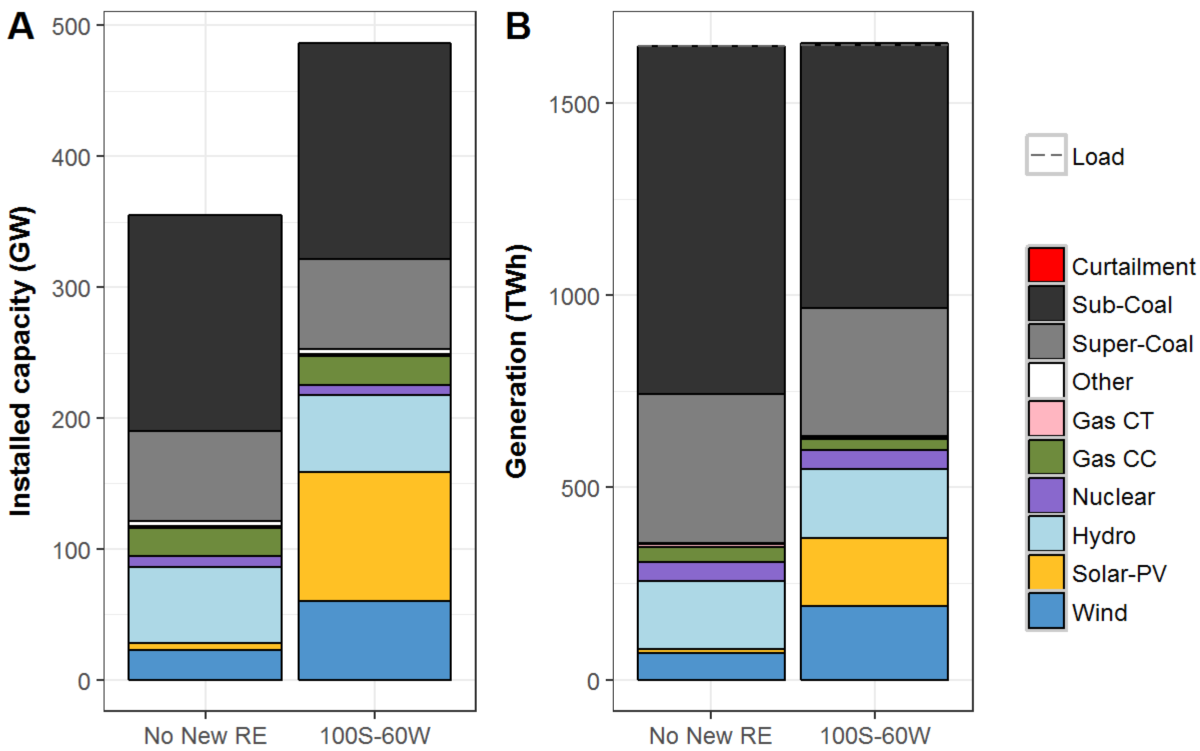


Figure 22. Installed capacity (A) and annual generation (B) by fuel type, No New RE and 100S-60W

Figure 23 compares monthly coal and gas generation for the 100S-60W and No New RE scenarios. The monthly pattern of coal generation, while showing the displacement from RE generation, is very similar between the scenarios—a seasonal dip in the monsoon followed by peak generation in October. The impacts of 100S-60W on gas generation are uneven throughout the year, although gas generation does decline most significantly during the high wind and hydro months of May through September.

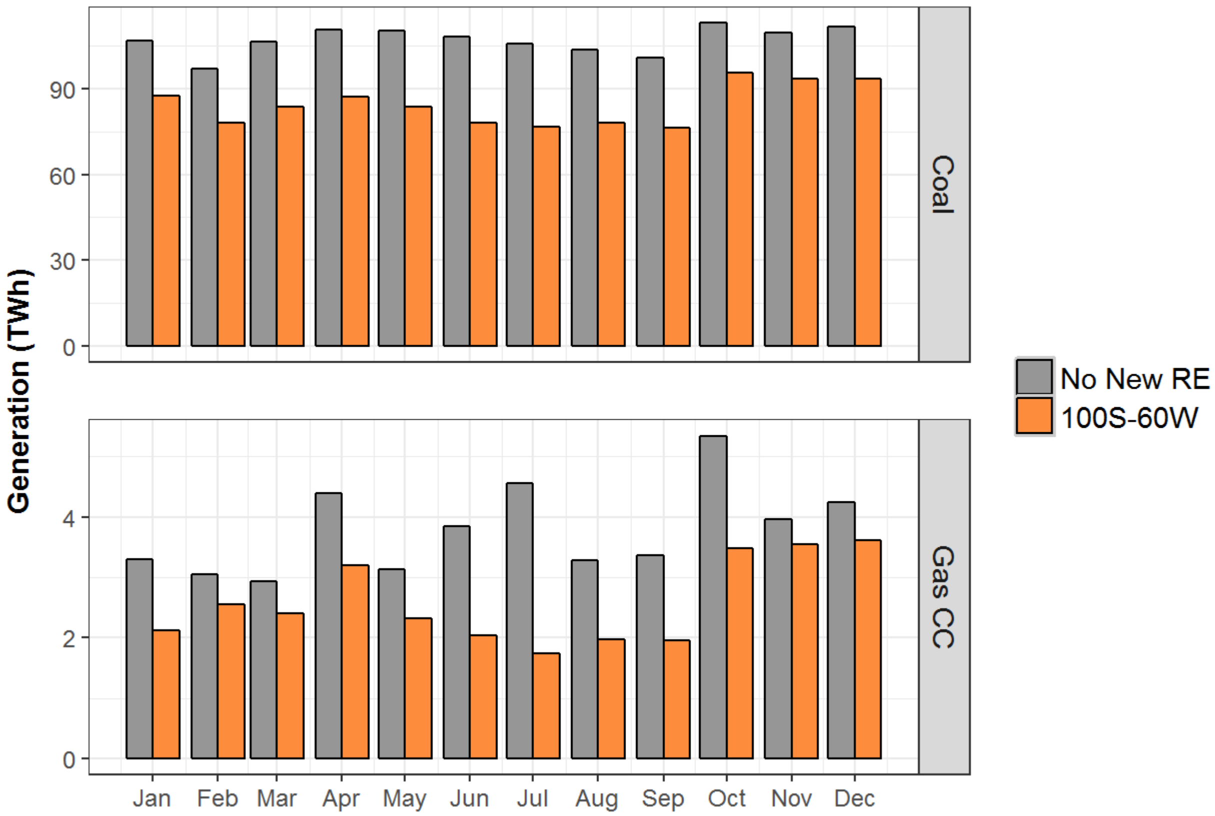


Figure 23. Coal generation by month, No New RE and 100S-60W

Based on the RE capacity expansion discussed in Section 2.2, the majority of new RE generation occurs in the Southern and Western regions, although the Northern region also has substantial new RE capacity, concentrated primarily in Rajasthan. Figure 24 shows the difference in annual generation of the 100S-60W and No New RE scenarios, by region. Wind and solar are displacing coal and gas within and beyond their respective regions. For example, the Southern region generates about 134 TWh more RE in the 100S-60W scenario, but its thermal generation only decreases by about 94 TWh.

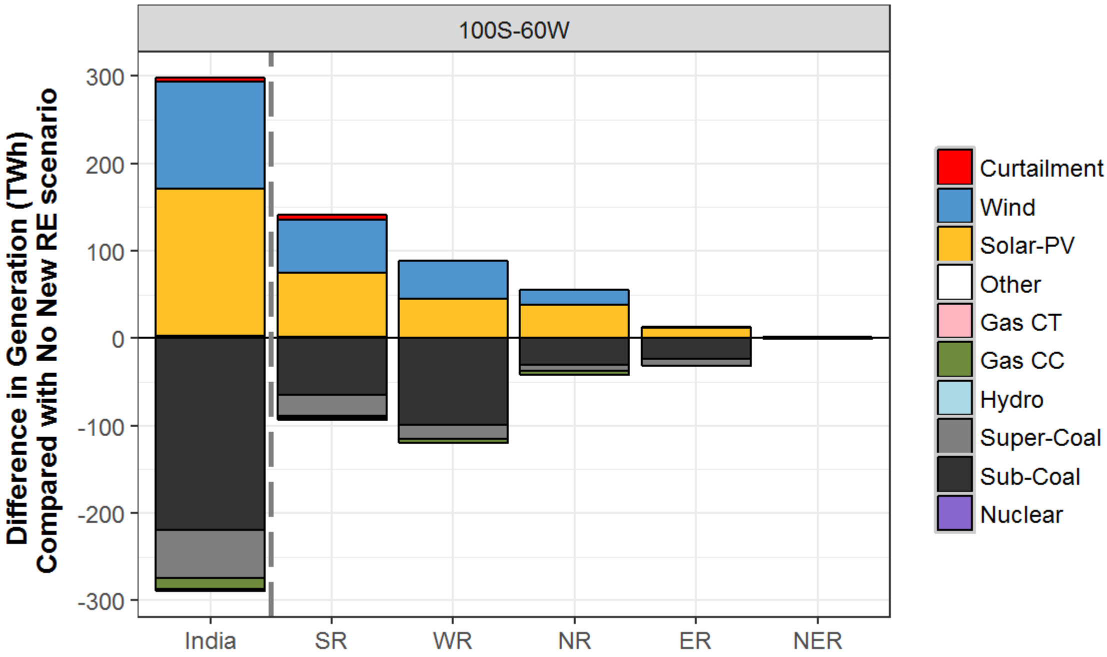


Figure 24. Difference in generation in the 100S-60W scenario compared to No New RE

Note: Negative generation means there is less in 100S-60W than in No New RE; positive means more.

The reduction in thermal generation reduces fuel consumption by 140 million metric tonnes (MMT) of coal and 2.1 MMT of gas, a decrease of 20% and 32%, respectively. As a result, CO_2 emissions fall by 280 MMT in the 100S-60W scenario, a 21% reduction from No New RE.

Table 8 compares annual generation, fuel consumption, and carbon emissions between the 100S-60W and No New RE scenarios. The reduction in coal and gas generation reduces total annual CO_2 emissions. Almost all the reduction in CO_2 emissions come from reduced coal consumption.

Table 8. Generation, Fuel Use, and Emission Reduction in 100S-60W Scenario Compared to No New RE Scenario

FUEL TYPE		NO NEW RE (TOTAL)	100S-60W (DIFFERENCE)
Coal	Generation	1,290 TWh	- 21%
	Fuel Use	690 MMT	- 20%
Gas	Generation	47 TWh	- 32%
	Fuel Use	6.4 MMT	- 32%
Both	CO_2 Emissions	1,370 MMT	- 21%

PLFs of coal plants fall to an average of 50%, with nearly 20 GW of capacity that never starts.

PLFs for coal plants fall from 63% to 50% between the 100S-60W and No New RE scenarios; gas plant PLFs also fall, from 23% to 15%.[37]

[37] PLF in this section is calculated using capacity-weighted averages.

Table 9 summarizes the PLFs of gas, supercritical coal, and subcritical coal plants. In each case, the PLFs drop, with subcritical coal plants affected the most. The amount of coal capacity that never starts rises from 9.6 GW in the No New RE scenario to nearly 20 GW in the 100S-60W scenario. These plants are uneconomical to run at any point in the year, reflecting the presence of excess generation capacity even in the absence of new wind and solar installations.

Table 9. PLFs by Type, and Capacity That Never Starts, No New RE and 100S-60W[38]

FUEL TYPE	NO NEW RE **INCLUSIVE** OF CAPACITY NOT STARTED	100S-60W **INCLUSIVE** OF CAPACITY NOT STARTED	100S-60W **EXCLUSIVE** OF CAPACITY NOT STARTED
Gas	23%	15%	17%
Super-Coal	64%	55%	58%[39]
Sub-Coal	62%	47%	52%
CAPACITY THAT NEVER STARTS (GW)			
Gas	2.7	2.2	
Coal	9.6	20	

As shown in Table 10, the capacity of coal plants operating under 30% PLF increases in the 100S-60W scenario, reaching greater than 25% of the installed coal fleet. This is up from 13% in the No New RE scenario. The capacity of coal plants operating above 80% PLF is also impacted by more RE, as 25% of the coal fleet is able to operate with very high PLF in No New RE, versus only 9% in the 100S-60W scenario. Gas capacity operating below 30% is also impacted in the same direction as coal, with RE causing more capacity in the sub-30% PLF tranche.

Table 10. PLFs of Coal and Gas Below 30% and Above 80%, No New RE and 100S-60W

PLF	NO NEW RE	100S-60W
<30% PLF	31 GW coal 16 GW gas	65 GW coal 19 GW gas
>80% PLF	61 GW coal 0 GW gas	22 GW coal 0 GW gas

[38] The calculation of PLF does not count the provision of spinning reserves contributing toward a higher PLF, even though plants are backed down to hold up reserves. Appendix C provides details of procuring reserves in our model.

[39] There is 3.6 GW of supercritical coal capacity in Odisha that does not start due to the high variable cost that was associated with these plants compared to other plants in the state. These plants are new since 2014, and therefore variable costs were assumed based on methodologies outlined in Section 2.2.2. There is likelihood that these plants would displace subcritical coal in Odisha if the future variable costs are different than assumed.

Figure 25 and Figure 26 illustrate the distribution of PLFs across coal and gas plants, with a shift toward lower PLFs in both fuel types between the No New RE and 100S-60W scenarios. The greater dispersion of PLFs in coal, indicated by the greater dispersion of individual plant PLFs and the wider box, is driven primarily by medium-to-large coal plants, which are mostly grouped above the median of 63% in the No New RE scenario and are distributed over the whole range in the 100S-60W scenario. The shift to lower PLFs in gas plants is driven by all plant sizes, although the large plants (200 MW and above) that operate at the highest PLFs in No New RE drop to below 40% PLF in 100S-60W. This is largely driven by the displacement of gas by solar during the day. Instead, gas generates primarily during the net load peaks during the evenings. An example of this is in Figure 27, which shows dispatch for all of India for a week in June. In the 100S-60W scenario, gas generation is reduced significantly during the day and peaks at dusk, as opposed to the No New RE scenario, in which gas has a relatively flatter generation profile.

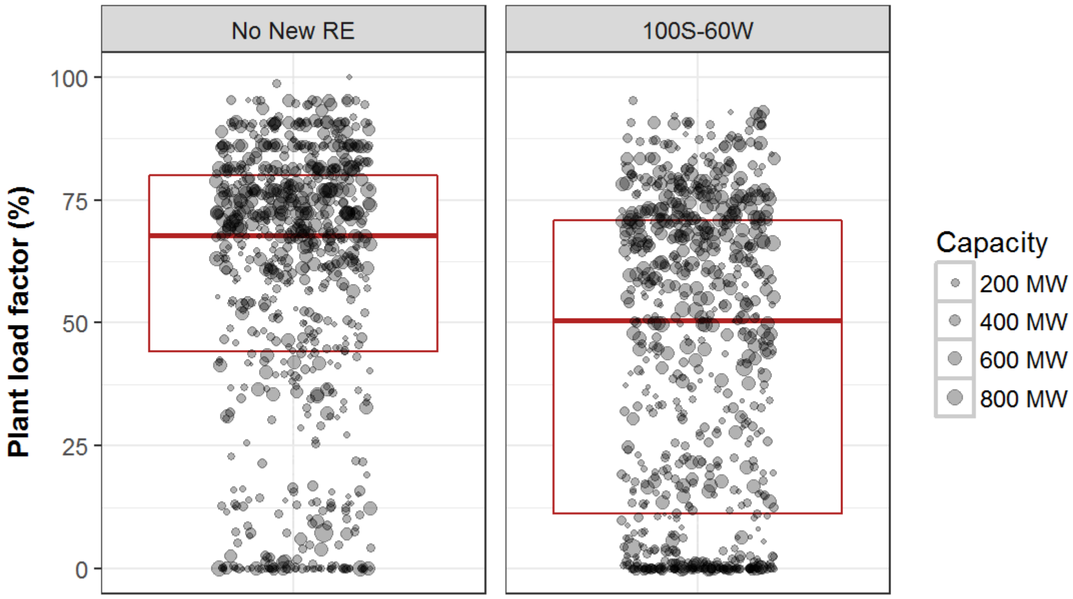


Figure 25. Coal PLFs, No New RE and 100S-60W

Note: Dots represent individual plants sized to nameplate capacity. Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the capacity, those inside the box are the middle 50%, and those below are 25% of the capacity. The middle line is the median.

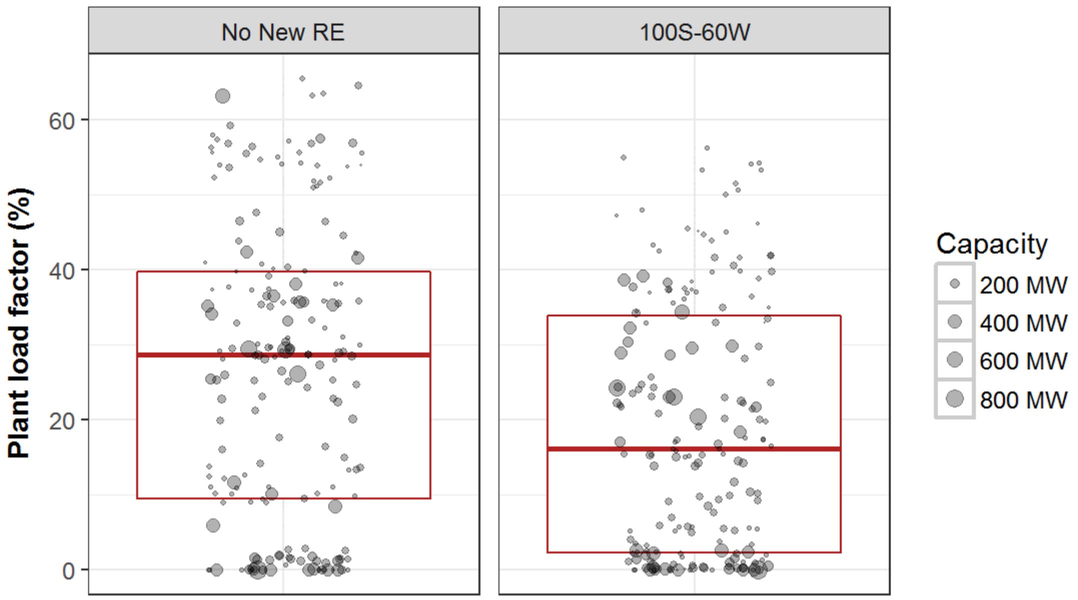


Figure 26. Gas PLFs, No New RE and 100S-60W

Note: Dots represent individual plants sized to nameplate capacity. Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the capacity, those inside the box are the middle 50%, and those below are 25% of the capacity. The middle line is the median.

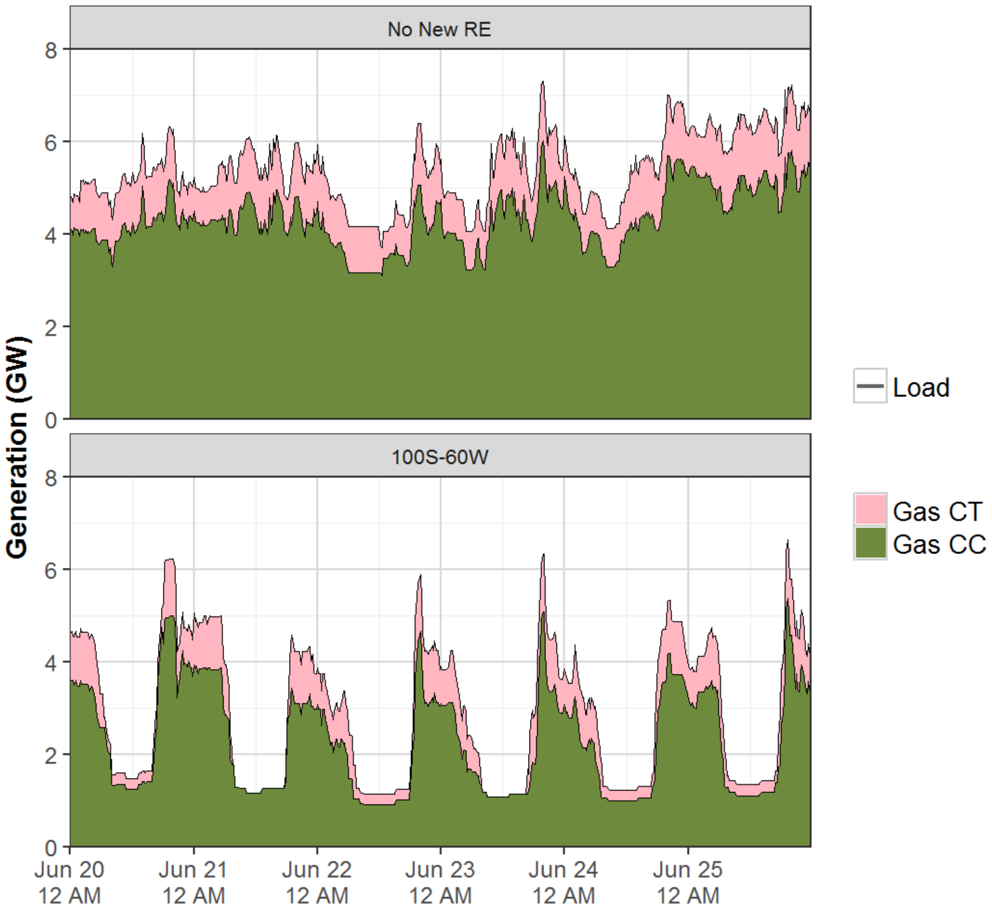


Figure 27. Gas operation for all of India, 20–25 June, No New RE and 100S-60W

Central- and state-controlled thermal plants are affected differently by the presence of RE.[40] Table 11 compares the PLFs for thermal plants in the 100S-60W and No New RE scenarios. Central plants have a decrease of 8%, whereas state-controlled generators have a decrease of 14%. While there may be some impacts based on the distribution of central and state plants in high-RE regions, the primary driver behind this trend is likely due to the slightly higher efficiencies and lower variable costs of central plants.

Table 11. PLFs for Central- and State-Controlled Thermal Plants, No New RE and 100S-60W

	NO NEW RE	100S-60W
CENTRAL	64%	56%
STATE	57%	43%

In the 100S-60W scenario, coal plants experience 2.8% more starts (starting an off-line unit) and spend 195% more of their operating time at minimum generation. Gas plants also cycle more frequently, with 105% more starts than in the No New RE scenario.

Figure 28 compares No New RE with 100S-60W in terms of impacts on annual number of starts for coal and gas plants. For both plant types, the 100S-60W scenario has a higher number of starts, reflecting an increased number of occurrences when the thermal plants are shut down during periods of high RE generation. Gas more than doubles its number of unit starts over the year in the 100S-60W scenario, indicating that its flexibility relative to coal is being utilized. Coal, on the other hand, experiences a relatively modest increase in generator starts of 2.8%.

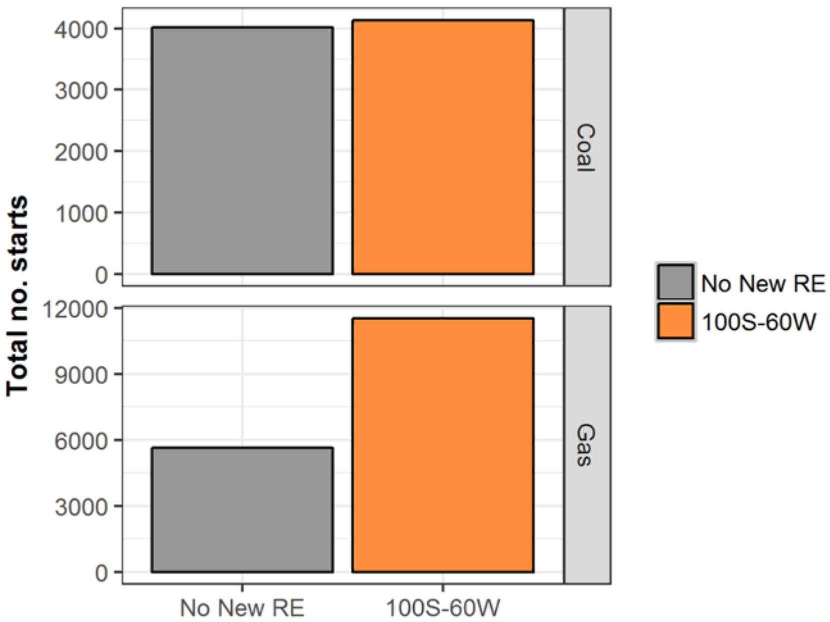


Figure 28. Total number of starts for coal (top) and gas (bottom), No New RE and 100S-60W

While the fleetwide impact on coal seems relatively low, the impact of increased starts is apparent at the plant level, especially when considering how costs affect operations. Table 12 and Table 13 show the change to starts for coal and gas based on their relative variable costs. The most expensive coal plants are starting less in the 100S-60W case, but the midrange plants experience a substantial shift toward increased starts. This change is driven by the displacement of the most expensive units from

[40] We define thermal plants as those fueled with coal, gas, oil, diesel, bagasse, or uranium.

the merit order when more RE is on the system. Midrange coal plants cycle on and off in their absence, while the lowest cost units continue to get committed as regularly as in the No New RE scenario. The increase of gas starts occurs across all variable costs tranches because its flexibility is used to follow a more variable net load in 100S-60W. The least-cost units are, however, dispatched more often and therefore have the largest increase in starts.

Table 12. Number of Starts for Coal Based on Relative Variable Cost, No New RE and 100S-60W

RELATIVE VARIABLE COST	NO NEW RE	100S-60W	% CHANGE
TOP 1/3	1,535	1,387	-10%
MID 1/3	1,161	1,369	18%
LOW 1/3	1,323	1,375	4%
TOTAL	**4,019**	**4,131**	**3%**

Table 13. Number of Starts for Gas Based on Relative Variable Cost, No New RE and 100S-60W

RELATIVE VARIABLE COST	NO NEW RE	100S-60W	% CHANGE
TOP 1/3	1,545	3,116	102%
MID 1/3	2,436	4,466	83%
LOW 1/3	1,648	3,937	139%
TOTAL	**5,629**	**11,519**	**105%**

Figure 29 and Figure 30 illustrate an additional impact on coal plants in the 100S-60W scenario—percentage of total time online when plants are operating at minimum generation (55% of rated capacity for coal). Power plants spend more time operating at minimum generation in the 100S-60W scenario, with 25% of capacity operating at minimum generation over a third of the year (indicated by dots above the boxes). This change reflects the increased amount of time that plants are turned down when RE generation is high, but when it is still economical to keep these plants online in order to keep them available for when, for example, the sun sets and daily load peaks in the evening.

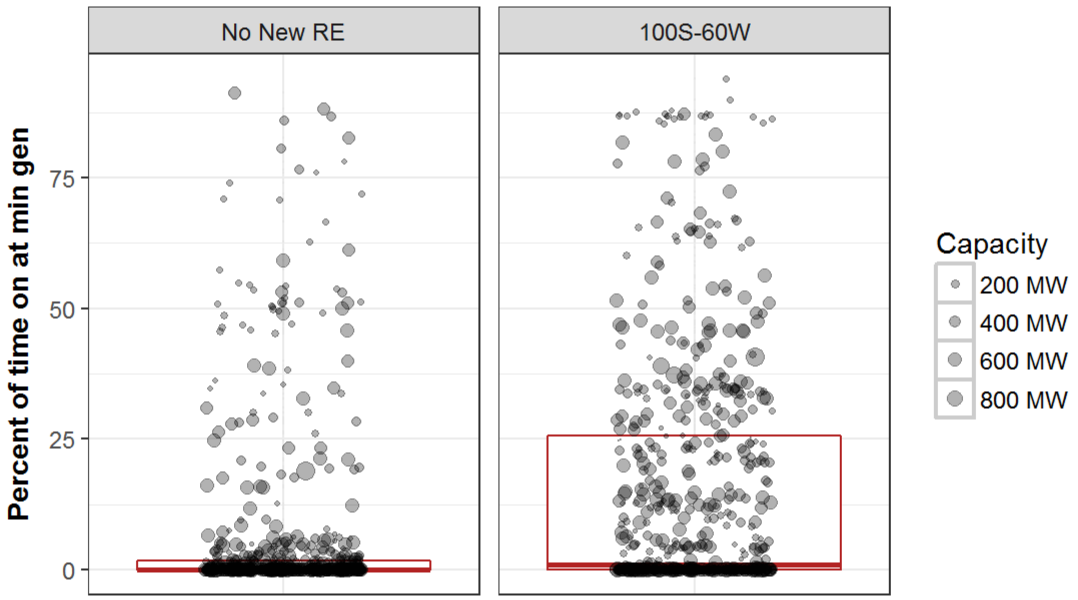


Figure 29. Time coal plants spend at minimum stable level when online, No New RE and 100S-60W

Note: Dots represent individual plants sized to nameplate capacity. Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the capacity, those inside the box are the middle 50%, and those below are 25% of the capacity. The middle line is the median.

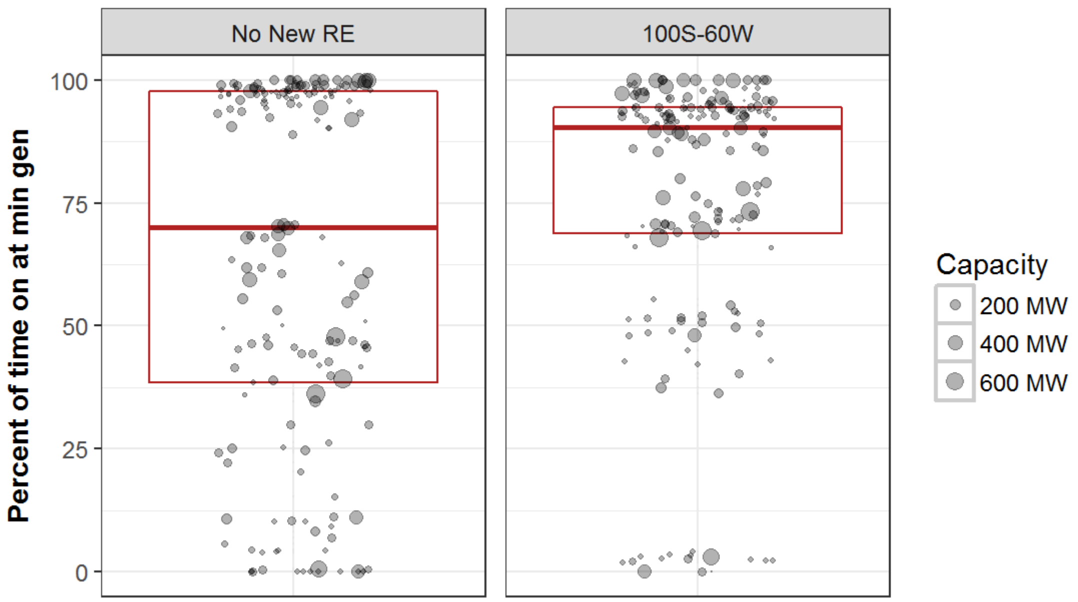


Figure 30. Time gas plants spend at minimum stable level when online, No New RE and 100S-60W

Note: Dots represent individual plants sized to nameplate capacity. Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the capacity, those inside the box are the middle 50%, and those below are 25% of the capacity. The middle line is the median.

When plants are started in the 100S–60W scenario, they are not online for as long. Table 14 shows average days online per start.

Table 14. Average Days on per Generator Start, No New RE and 100S-60W

SCENARIO	LARGE COAL	SMALL COAL	LARGE GAS	SMALL GAS
NO NEW RE	43	31	5.3	3.7
100S - 60W	32	24	1.3	2.0
DIFFERENCE	-25%	-22%	-75%	-45%

Note: Large coal plants are defined as those with 500 MW capacity and above; large gas plants are defined as those with 60 MW capacity and above. Figures are not further weighted by capacity.

The overall gas fleet averages only 1.6 days on per start in the 100S–60W scenario, down from 4.5 days in the No New RE scenario. Only 19% of individual gas generators average more than a week online per start in 100S–60W compared to 43% in No New RE.

Figure 31 shows the combined unit commitment and dispatch of thermal plants during a high-RE week. The comparison of committed capacity to generation reveals the extent to which coal units are backed down to low PLFs and even minimum generation levels in a daily pattern.

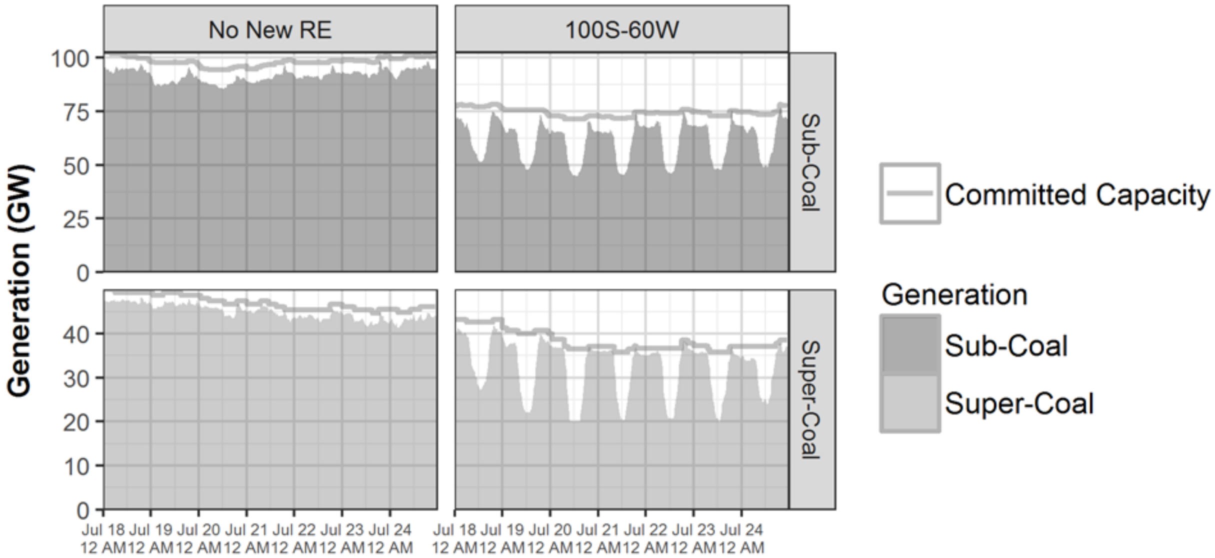


Figure 31. Coal commitment and dispatch for a period in July, No New RE and 100S-60W

The increased number of starts and time spent at minimum generation can impose maintenance costs on coal plants that are not reflected in production cost models. See "The Costs of Cycling Thermal Plants" sidebar for additional details on the impacts of cycling on coal plant maintenance.

THE COSTS OF CYCLING THERMAL PLANTS

The cycling of coal and gas plants, while an instrumental source of flexibility for the power system, does cause damage and affect plant life expectancies. The primary type of damage is thermal fatigue, created by large temperature swings, for example as a plant starts up and materials heat up at different rates, which causes cracking and part failures (Cochran, Lew, and Kumar 2013). Other types of damage include wear and tear on cycling-specific auxiliary equipment and corrosion from oxygen entering the system and condensation from cooling steam.

Several studies have evaluated the costs of cycling, including Kumar et al. (2012), which calculated operating, maintenance, and repair costs associated with start-ups, operations at minimum generation, and other cycling operations. Figure 32 illustrates an example set of lower-bound costs for one cold start.

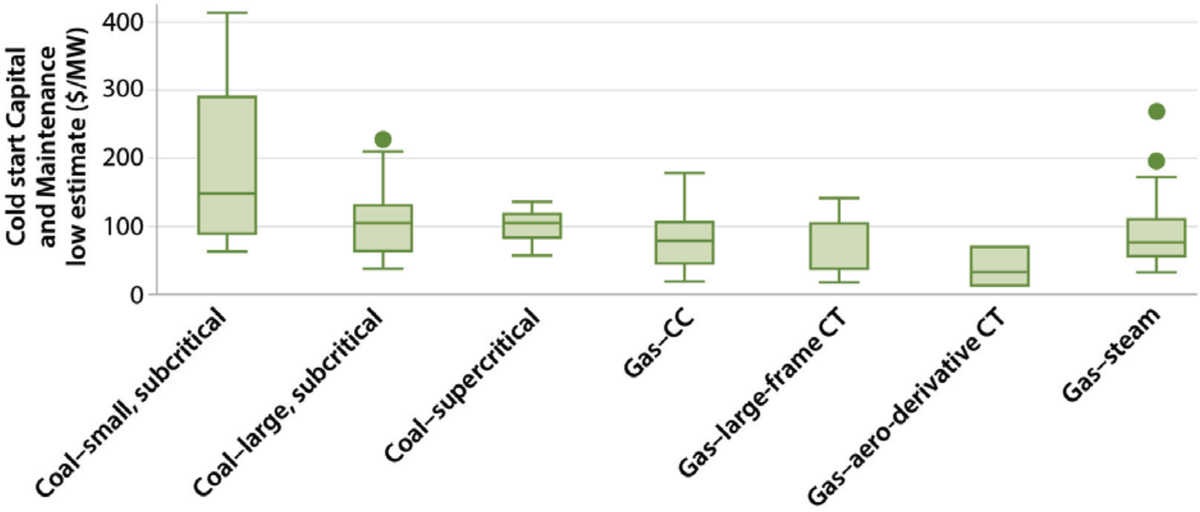


Figure 32. Lower-bound costs for one cold start

Source: Lew et al. (2013)

Lew et al. (2013) incorporated these cycling costs into a unit commitment and dispatch optimization of a high-RE future in the western United States. The cycling costs affect dispatch—there was a reduction in cycling compared to a previous study (NREL 2010) that did not include these costs. Nevertheless, from a system perspective the costs of cycling were small. Figure 33 shows cycling costs associated with the scenarios evaluated.[41] Cycling costs in the high-RE scenarios ranged from $0.92-$2.36/MWh, a small fraction of fuel costs that range $20-$40/MWh, which is the major driver of dispatch decisions and production costs. Overall cycling costs as a percentage of production costs ranged from 1.5% in the no renewables scenario to 7% in the high solar scenario using upper-bound costs (Lew et al. 2013).

[41] Each high-RE scenario (HiWind, HiMix, HiSolar) had wind and solar penetration levels of 33%. The scenarios were: NoRenew—0% wind and solar; TEPCC: 9.4% wind, 3.6% solar; HiWind: 25% wind, 8% solar; HiMix: 16.5% each wind and solar; HiSolar: 25% solar, 8% wind.

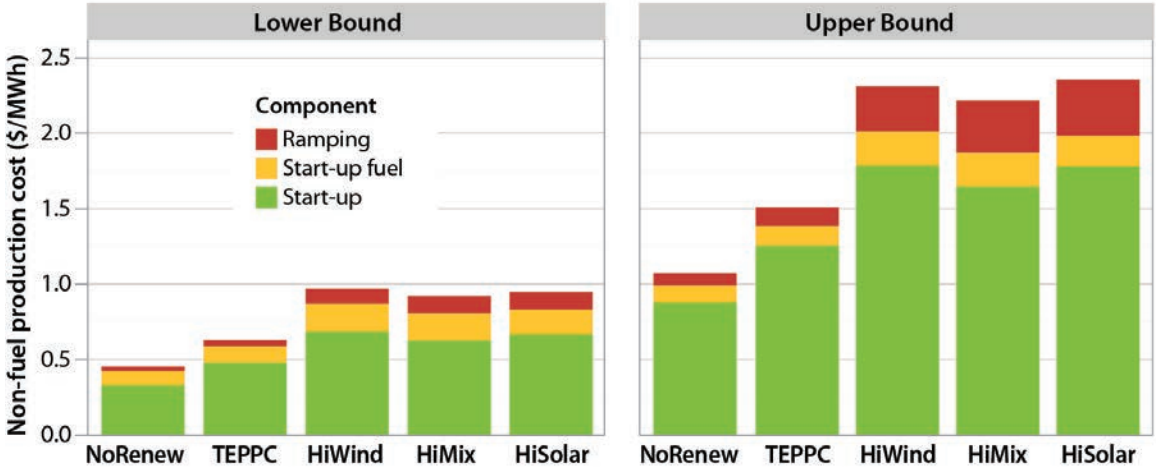


Figure 33. Cycling costs using lower bound (left) and upper bound (right) for each scenario evaluated

Source: Lew et al. (2013)

Figure 34 provides an illustrative example of the share of cycling costs (circled) relative to the overall cost of delivered energy (fixed plus operating costs).

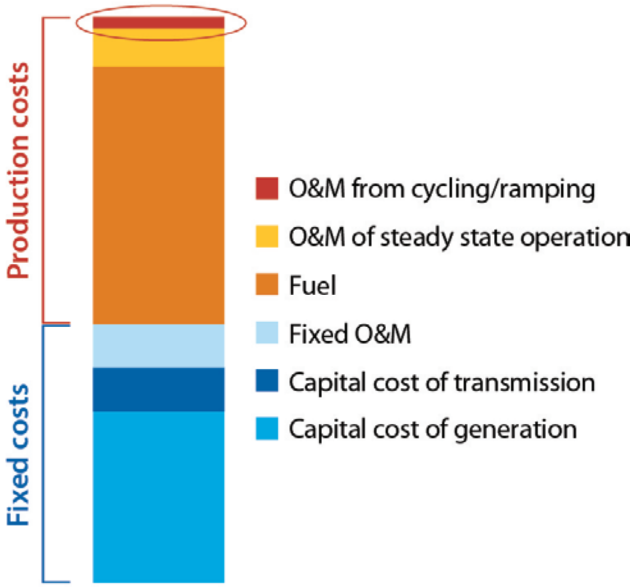


Figure 34. Illustrative delivered cost of energy for a fossil fuel plant

Source: Lew et al. (2013)

Experience with coal cycling has demonstrated that a number of changes to operating procedures and plant equipment can minimize the impact of cycling and recovery time from plant outages. For example, controlling the rate of temperature change during plant start-up and shutdown, combined with rigorous training and inspection programs, can minimize physical damage and economic impacts of forced outages. A coal plant in North America observed that once some modest physical modifications were made, 90% of the plant's subsequent savings in cycling costs derived from changes to operating procedures (Cochran, Lew, and Kumar 2013).

4.4 How Hydro Plants Operate to Help Balance a System with High RE Generation

Hydro plants experience a shift in operations over the course of a day in the 100S-60W scenario. With the additional RE, the net demand takes on a dual-peak pattern that is different than today (for example, see Figure 17). Hydro generation, subject to various flow constraints, is dispatched during the periods of highest value, which occur during the net demand morning and evening peaks.

As shown in Figure 35, in the No New RE scenario, hydro typically has a relatively flat profile, rising in the evenings to meet peak load. In the 100S-60W scenario, hydro generation more often experiences two peaks—morning, falling off during the day when solar generation is high, and rising again in the evening but at a higher evening peak compared to No New RE. This profile shows a trend to match the lower turn downs and shorter peaks associated with the net load rather than the total load shown in Figure 17.

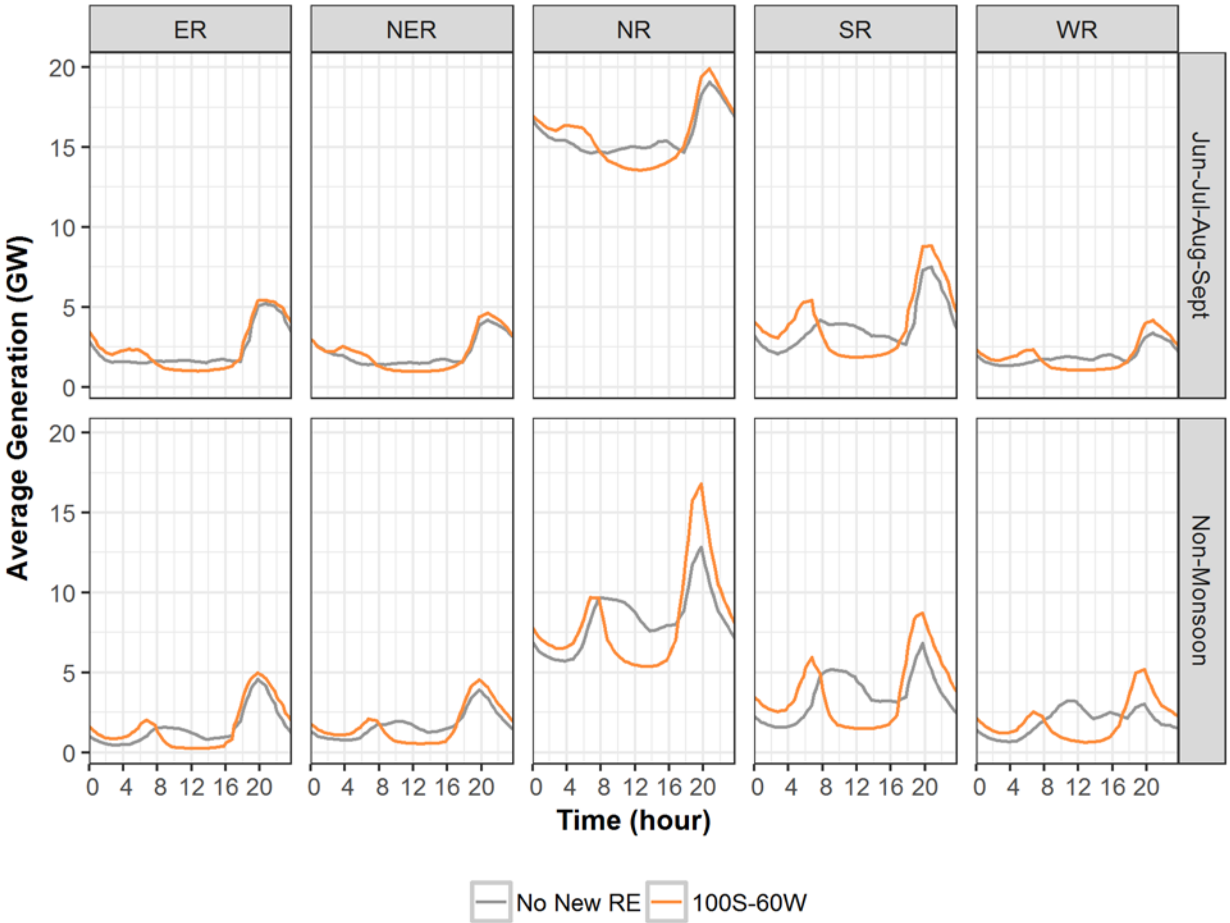


Figure 35. Average day of hydro operation, by season and region, No New RE and 100S-60W

Figure 36 illustrates an average daily profile of pumped storage generation, by season and region, for both the No New RE and 100S-60W scenarios.[42] While pumped storage's peak generation occurs during the evening load peaks in both scenarios, in the 100S-60W scenario, the pumping mode of pumped storage shifts from nighttime to midday to coincide with greater solar generation.

[42] Pumped storage plants are free to optimize pumping and generating within each day, subject to storage level constraints imposed in the optimization's planning phases. All plants are modeled with 75% efficiency.

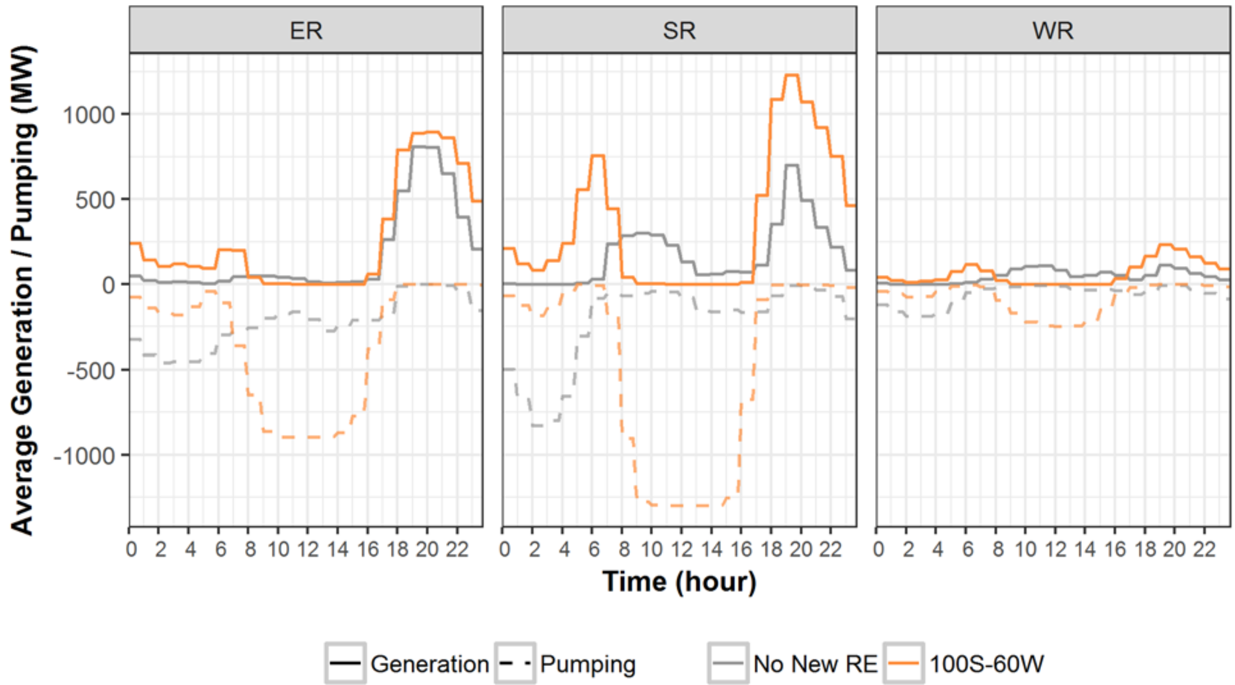


Figure 36. Pumped storage average daily generation and pumping, No New RE and 100S-60W

Note: Negative values indicate the plant is in pumping mode, positive that it is in generation mode.

Figure 37 shows the duration curve of the combined hourly ramp rates for hydro generators in No New RE and 100S-60W. The steeper curve in the 100S-60W scenario indicates that hydro contributes to the increased systemwide ramping of a more variable net load, although not dramatically. The up-ramp rates experienced by hydro are generally larger in the 100S-60W scenario. While hydro's maximum upward ramp in both scenarios is roughly 23 GW, its 99th percentile falls at 16 GW in 100S-60W and at 11 GW in No New RE.

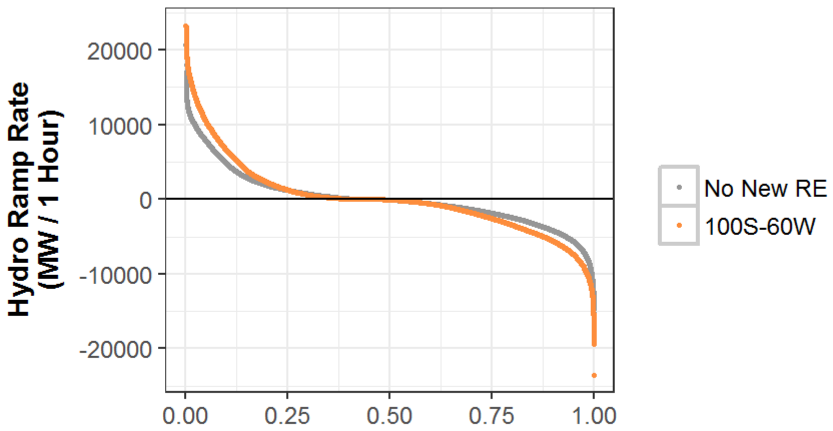


Figure 37. Duration curve for hydro generation, No New RE and 100S-60W

Note: The x-axis is the fraction of the year during which the hourly ramp rate exceeds the corresponding y-axis value.

4.5 How RE Affects Exports and Interstate Transmission Flows

Adding 100 GW solar and 60 GW wind affects imports and exports and transmission flows within and between regions. RE-rich states have a disproportionate amount of low variable-cost generation compared to other states. Also, daily and hourly variability of net load increases, which increases the relative value of interchange as a resource for balancing load and generation. The optimal choice in many instances is to use the transmission system to move energy to areas with higher-cost energy instead of cycling nearby thermal generators to address added variability.

In the 100S-60W scenario, interstate energy exchanges fall 9.6% within the Western region and 5.9% within the Southern region compared to the No New RE scenario.

Energy exchanges on interstate transmission corridors in the highest installed RE regions, Western and Southern, decrease in the 100S-60W scenario, while the Northern and Eastern regions increase slightly (2.4% and 4.8%, respectively). The Southern and Western region reductions are driven by their geographically dispersed and zero marginal cost wind and solar generation. Figure 38 shows total imports and exports for Western region states. Thermal generation comprises 100% of Chhattisgarh's fleet, which decreases exports substantially and drives the above-mentioned reduction in the Western region's interstate exchange. The increased importing to Maharashtra is complicated by the connection to the Southern region, although it is trading less with its Western region neighbors.

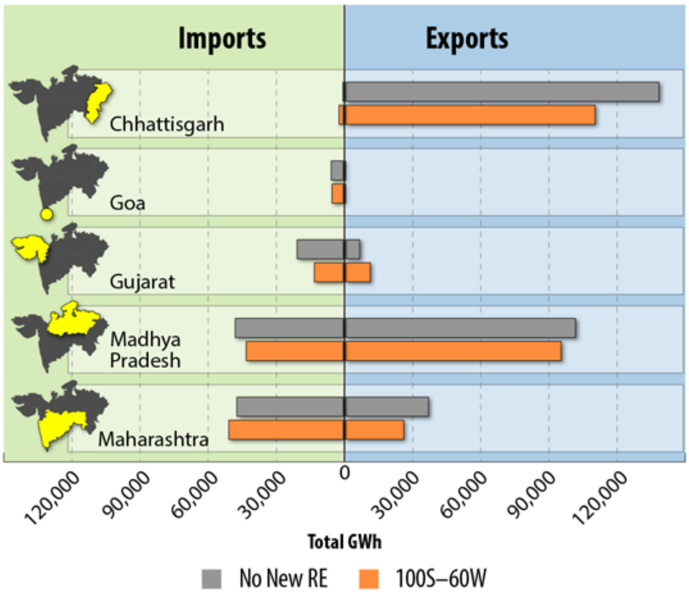


Figure 38. Annual total imports and exports in the Western region states, No New RE and 100S-60W

The Northern region, whose small increase in interstate energy exchanges is counter to trends seen in high RE regions, is explainable by the concentrated RE in Rajasthan. This would incentivize flow to the higher-load areas in the region, which do not have expansive RE growth in our 100S-60W scenario.

Interregional energy exchanges decrease 16% between the 100S-60W and No New RE scenarios.

Following the trend of decreased *intra*regional trade, aggregate interregional imports and exports also decrease with increased wind and solar in the 100S-60W scenario.

Figure 39 shows total imports and exports by region between the two scenarios. The Western region's exports (usually to the Northern region) and the Southern region's imports show the largest declines. Net imports to the Southern region meet 13% of the Southern region's energy demand in the No New RE scenario. Southern region net imports fall to 3.7% of its demand in the 100S-60W scenario due to its much higher wind and solar generation.

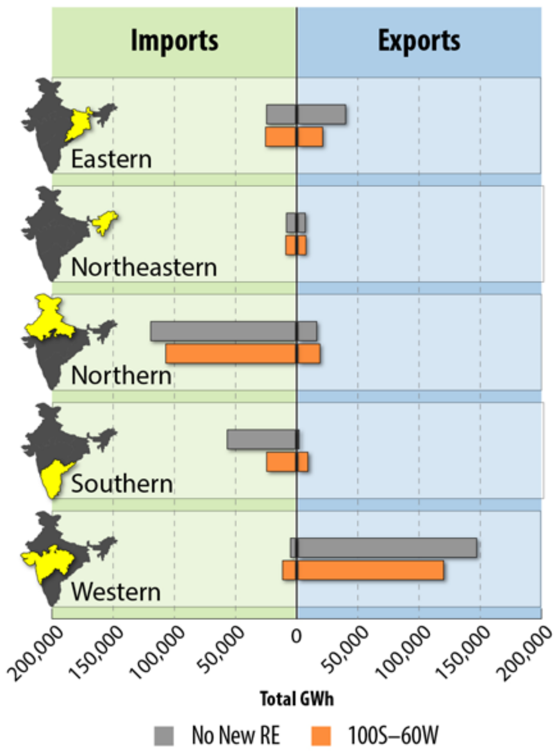


Figure 39. Regional annual imports and exports

Figure 40 compares monthly regional imports and exports between the No New RE and 100S-60W scenarios. The No New RE scenario illustrates seasonal trends due to changing patterns in load and hydro plant generation. All regions show some departures from No New RE in the 100S-60W scenario. In particular, Southern region becomes an exporter of power during peak monsoon season, which is reflected in the increased imports to Western region during these months. Other interfaces in the 100S-60W scenario follow the general trends, though diminished, of the No New RE scenario.

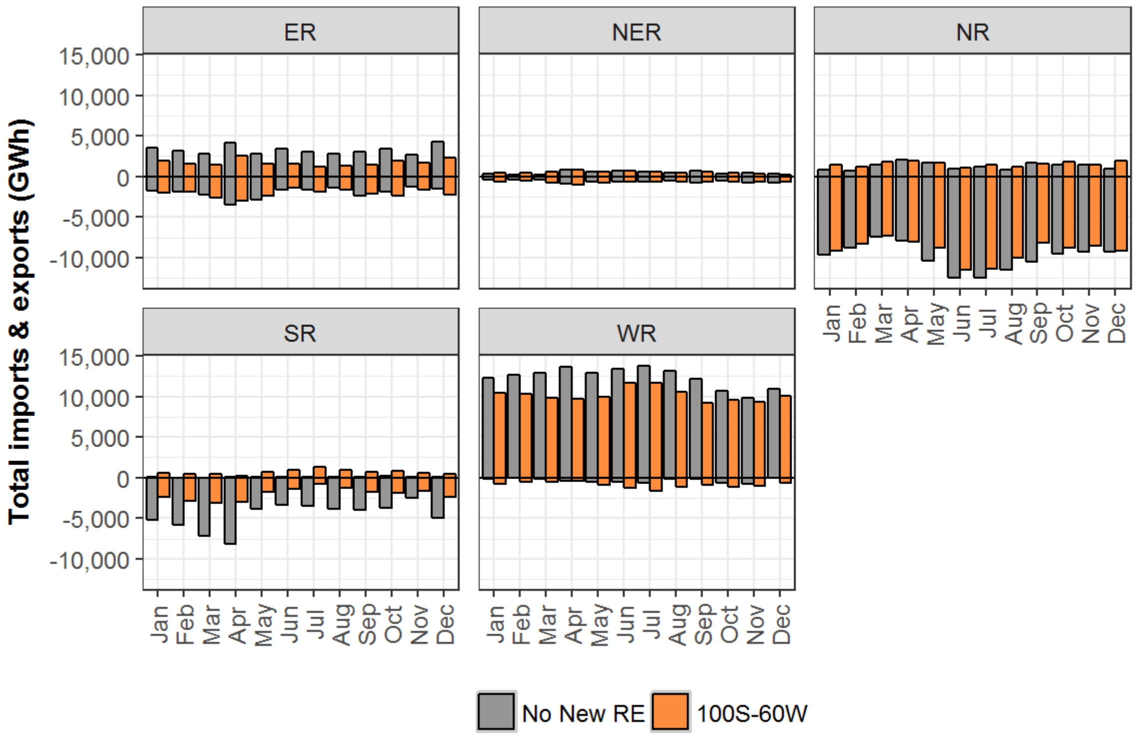


Figure 40. Regional monthly imports and exports

Note: Positive values represent total export; negative values represent total import.

The magnitude of flows and number of changes in direction of flows between Southern and Western regions increase significantly in the 100S-60W scenario during the monsoon period.

In addition to annual and monthly changes to total energy flows across interstate networks, daily load flow patterns also change in the 100S-60W scenario. Figure 41 compares the No New RE and 100S-60W scenarios with regard to daily exports of energy between regions during an example monsoon week. The biggest change between the scenarios is apparent in the flows connecting the Eastern and Western regions to the Southern region. In the No New RE scenario, the Southern region is almost always importing. However, in the 100S-60W scenario, because of its plentiful wind and solar resources, the Southern region regularly exports to the Western region during the day and imports from the same after sunset. It also curtails daytime imports from the Eastern region but less frequently exports there because of the INR 1050 interregional hurdle rates imposed on SR–ER flows (see Appendix C, Table 53). Flows on the Western and Northern region interface also change in magnitude substantially, especially during the middle of the day, although the Western region continues to be an exporter to the Northern region during this sample week.

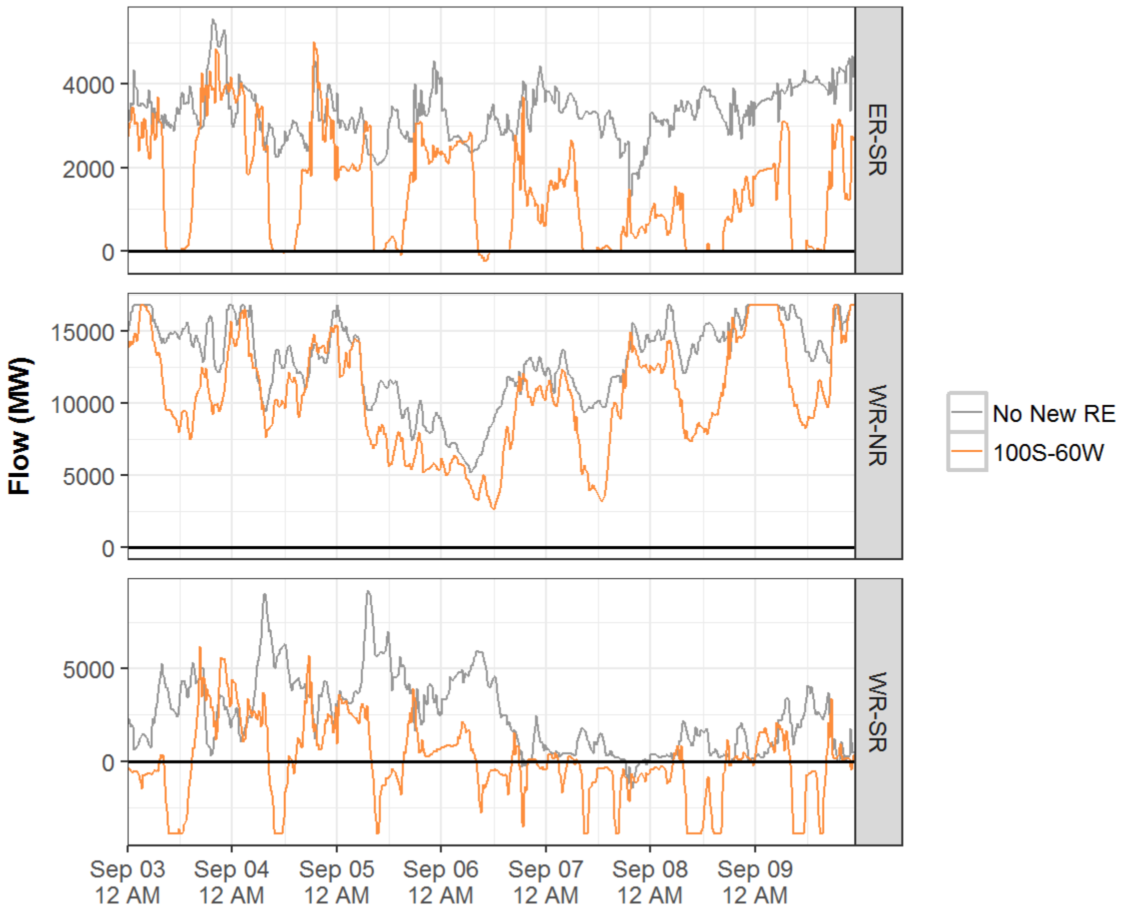


Figure 41. Flows on the ER-SR, WR-NR, and WR-SR interfaces, No New RE and 100S-60W

Note: Positive flows indicate direction of the name (i.e., WR-SR is positive if flowing from WR to SR), and negative flows the opposite direction.

For an annual time series of imports and exports for each region, see Figure 42.

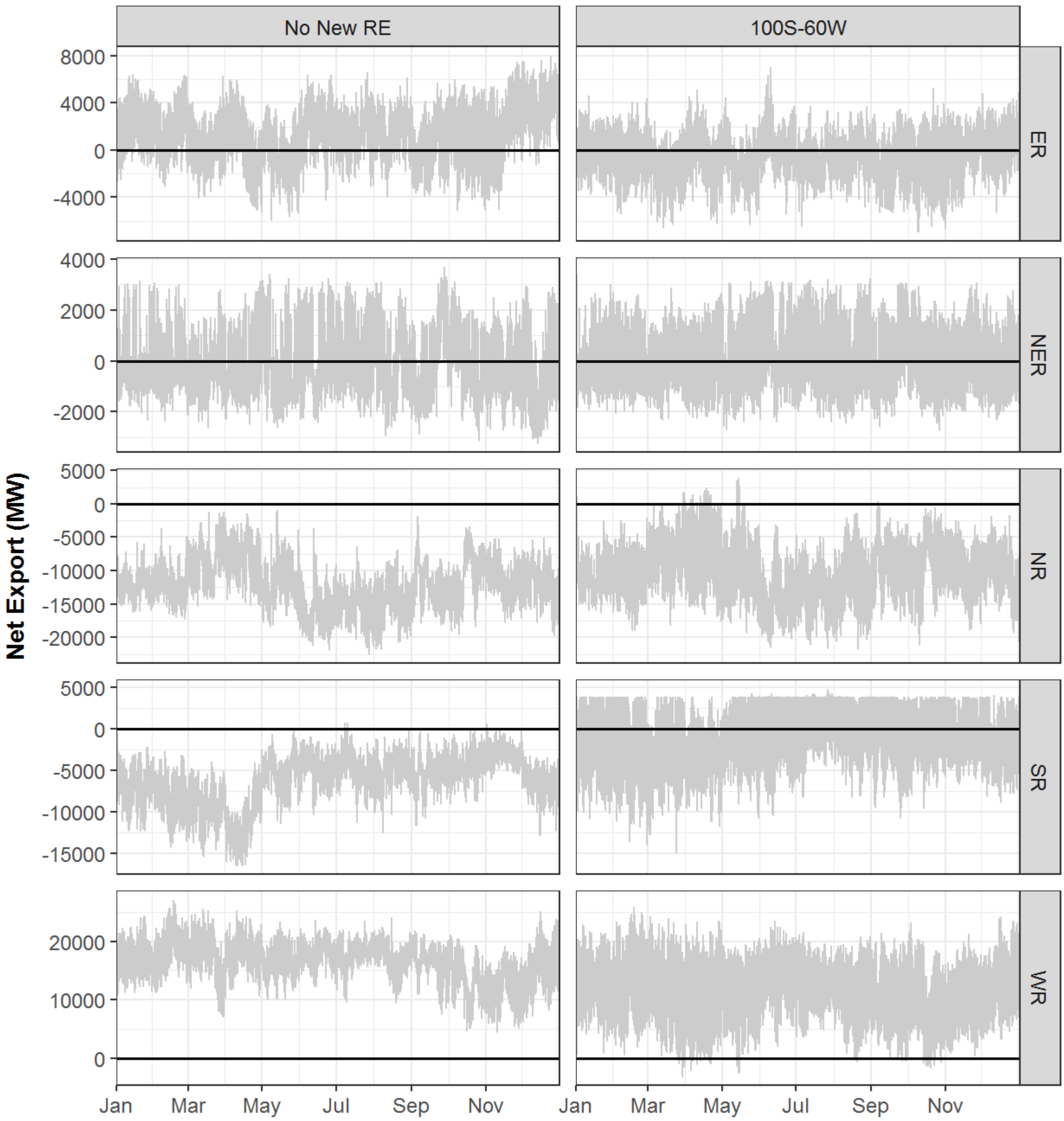


Figure 42. Net exports for each region, No New RE and 100S-60W

Note: Negative values indicate importing. Y-axis is different for each plot.

4.6 Causes of RE Curtailment

RE curtailment can occur for a number of reasons based on the model objective of serving load at least cost while adhering to the physical constraints of the system. Curtailment is almost always a result of more than one, and sometimes many, physical or economic limitations that are being met simultaneously. Described below are four constraints that contribute to curtailment in our modeling results. The first two are physical constraints; the second two are economic and/or institutional.

Transmission Congestion

Line limits constrain how much energy may move between two locations in the power system. A line is constrained or congested when its flow is at its maximum allowable limit. Ideally, power flows through the transmission network from areas with low to high marginal cost generation. However, transmission congestion limits trade, forces comparatively expensive generators to meet local load, and prevents price convergence between interconnected areas. When RE generation increases in an area with lower marginal cost, and other more expensive local generators are unable to reduce their output, a least-cost solution would export this electricity elsewhere. A congested transmission line may prevent this export and cause RE to be curtailed.

Thermal and Hydro Inflexibility

Ideally, thermal generators would be able to adjust their output instantaneously to meet net load. Instead, technical limitations constrain the speed and scope of their response to changing system conditions. Coal and gas generators have their commitment status set with a day-ahead schedule, meaning they cannot turn on or off based on conditions in real time. Additionally, when they are turned on they must always generate at or above their minimum stable level. They can change their output in real time, but this is limited by the ramp rate of the individual units. Finally, a thermal generator turning on or off cannot immediately reverse its decision. Instead, it must adhere to minimum up and down times. For details on the thermal fleet parameters used in our model, see Section 2.2. These physical constraints can create conditions in which RE is curtailed to maintain system balance.

Like the thermal fleet, hydro generators must adhere to a variety of physical constraints that prevent their instantaneous adjustment to changing net load. Many hydro generators are required to produce a minimum amount of output, either for environmental or irrigation reasons or required discharge during high water levels in the monsoons. In the event of excess electricity supply when hydro generators are at their minimum output levels and other economic or physical constraints prevent thermal generators from turning down, RE generators are required to curtail in order to maintain energy balance.

Start and Stop Costs

In addition to minimum up and down times that constrain generators from starting and stopping quickly, starting a generator also results in a significant one-time cost. Because of start costs, it may be more cost effective to avoid shutting down a thermal generator in high RE generation periods—even if the plant is physically capable of shutting down and restarting—if system-level costs are lower with curtailed RE and avoided start costs. During such high RE generation periods, the thermal generator output may displace RE generation and cause curtailment.

Trade Barriers

If interregional energy exchanges could be scheduled instantaneously based on marginal costs, energy would be traded between regions until prices (cost of the marginal generator) converge. If RE generation in one region increases, the price in that region will fall, thus incentivizing the region to export to its neighbors until prices converge to an overall reduced price. In reality technical limitations to data exchange, the physics of power flow, bilateral contracts, and imperfect communication between neighboring balancing regions make perfectly optimized energy exchange impossible. Because it is impractical to forecast such bilateral contracts and institutional relationships in 2022, we use a modeling technique called hurdle rates, as described in Section 3. Hurdle rates disincentivize interregional and interstate energy exchange unless price differences exceed an interface-specific threshold. As a result, a region with a lower price will only export energy to a neighboring region with a higher price if the differential is greater than the hurdle rate. If the price differential does not exceed the hurdle rate and other constraints prevent local thermal units from backing down, additional RE generation in the lower price region will be curtailed rather than exported.

A Closer Look at the Maximum Curtailment Period in 100S-60W

Figure 43 (top) shows the dispatch of four regions for 7 September, the day of maximum instantaneous RE curtailment in the 100S-60W scenario. The pink band marks intervals with RE curtailment anywhere in the country. In the bottom panel, the black line represents total installed capacity, grey shading represents off-line thermal capacity, red represents thermal capacity at its maximum down-ramp rate, and orange represents thermal capacity at its minimum stable level. Any remaining committed capacity (the area in white below the black line) is unconstrained physically and has flexibility to turn down. If there is no white area at any given time, the region's thermal fleet is fully inflexible—all available thermal capacity in a region is turned off, at minimum stable level, or ramping down at its maximum rate. Any additional wind or solar generation must be either exported or curtailed. Note that due to challenges of modeling hydro, the model fixes hydro generation in the day-ahead simulation and prevents changes to generation in real time; thus, the model limits hydro's flexibility to day-ahead scheduling.

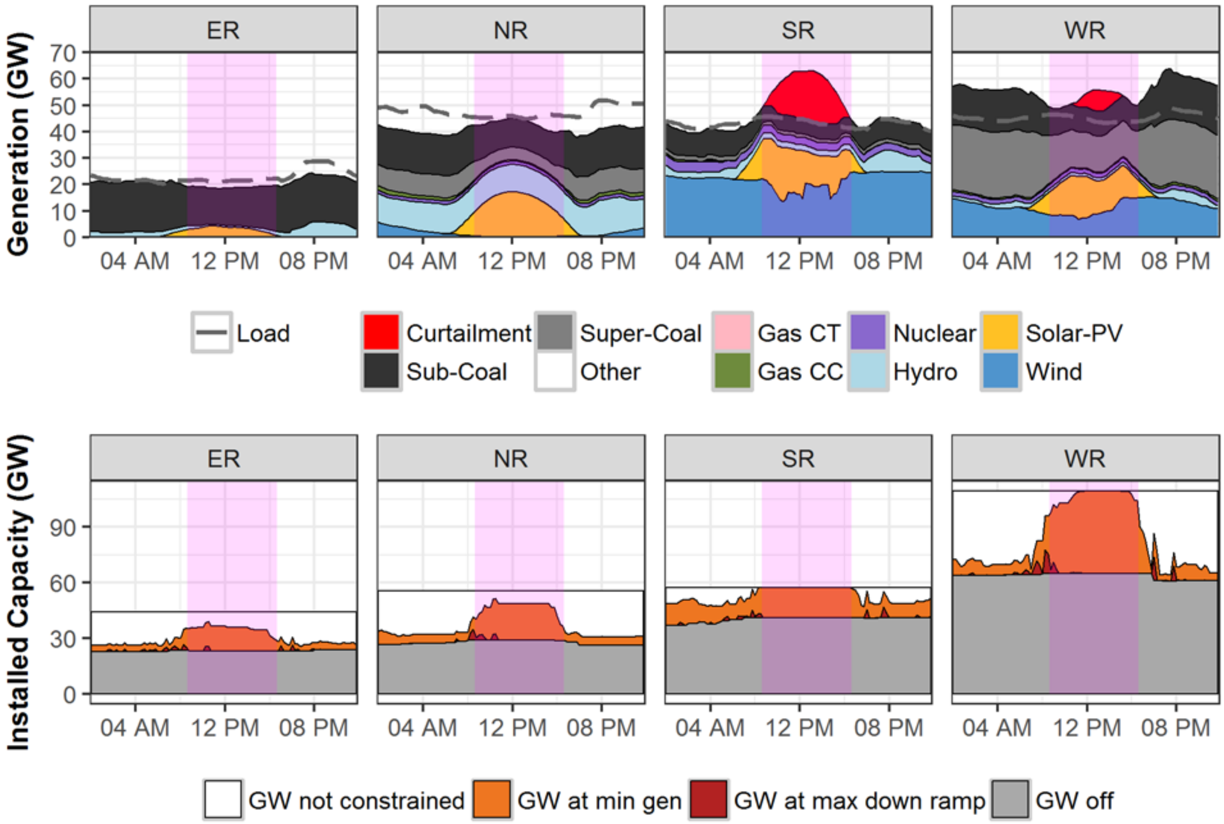


Figure 43. Generator dispatch (top) and coal and nuclear fleet constraints (bottom) on 7 September, the day of maximum instantaneous curtailment in 100S-60W

Note: The pink band marks intervals with RE curtailment anywhere in the country. In the bottom panel, the black line represents total installed capacity.

The majority of the curtailment on 7 September is in the Southern region. Within this time period, most of the coal in the region is turned off. The online coal generation is operating at minimum stable level throughout the 8:45–16:30 curtailment window. Why use thermal generation at all if available RE already exceeds load? Nuclear generation, which makes up a large portion of the Southern region's daytime conventional dispatch, is fully committed in our model if not on outage. The remaining online coal capacity is committed to avoid start costs and adhere to minimum up times while meeting the need for increased thermal generation at night. Because its thermal fleet is fully backed down and its hydro generation is at its minimum allowable output, the Southern region must either export excess RE generation or curtail. However, the Western region also has its coal generation off or at minimum generation levels for the majority of this period and cannot further back down to accept imports.

Yet the Eastern and Northern regions do have some capacity with the flexibility to further reduce output and prevent some RE curtailment. Thus, other factors, such as trade barriers and transmission limits, not directly illustrated in the figure, are preventing price convergence. This same high curtailment period is examined in Section 5 to illustrate how trade barriers and transmission constraints contribute to the Southern region's curtailment.

4.7 How the Power System Manages Forecasting Errors

Power system operators rely on forecasts to anticipate how much RE will be available in the near future, usually in the 24-hour or smaller time frame. RE forecasts help to determine how much and when non-RE generation resources should be scheduled to meet net load. A forecasting error is when actual wind or solar generation deviates from forecasted generation. Forecasting errors require the power system to respond with limited resources in real time to balance electricity supply and demand. This section is divided into three parts. First, we examine how forecast errors from the day-ahead schedule affect the real-time dispatch of coal generators in the Southern region.[43] Second, we look at why certain periods may cause reliability concerns given forecast errors in a highly constrained system. Third, we investigate how changing reserve products can address these periods of concern.

Finding System Balance Despite RE Forecast Errors

There are two categories of forecasting errors that affect dispatch operations: underforecasting and overforecasting. Underforecasting events occur when actual RE generation is greater than forecasted generation, while overforecasting events occur when actual RE generation is lower than forecasted generation. Both of these error types are illustrated in Figure 44.

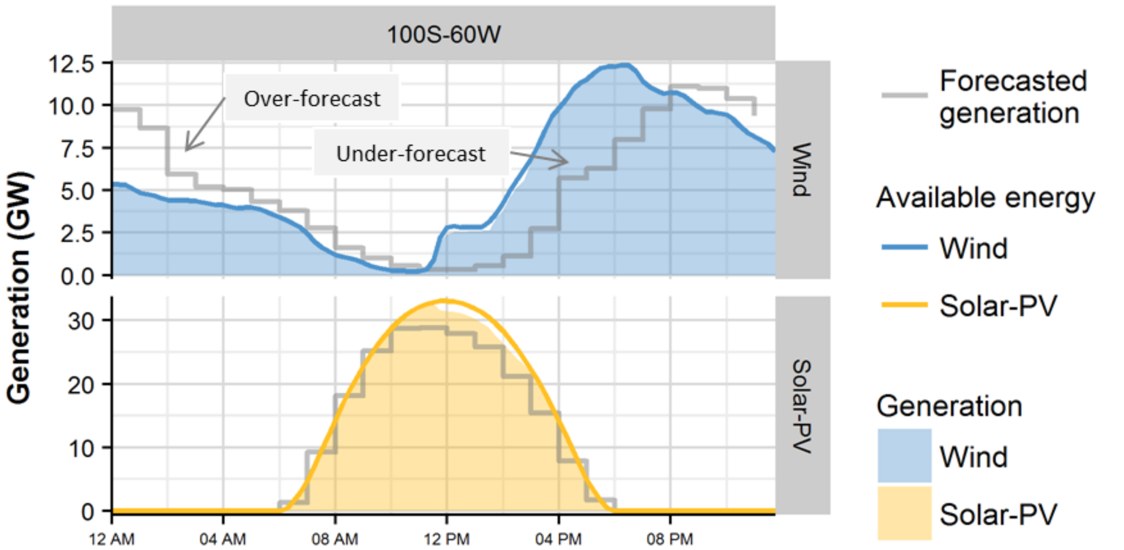


Figure 44. Solar and wind energy forecasts, available capacity, and real-time generation on 25 September in the Southern region

Note: The difference between available capacity and generation is curtailment.

[43] Details of forecasting results are provided in Appendix A.

Figure 45 illustrates coal operations during a relatively large underforecasting event in the Southern region, the same day as illustrated in Figure 44.

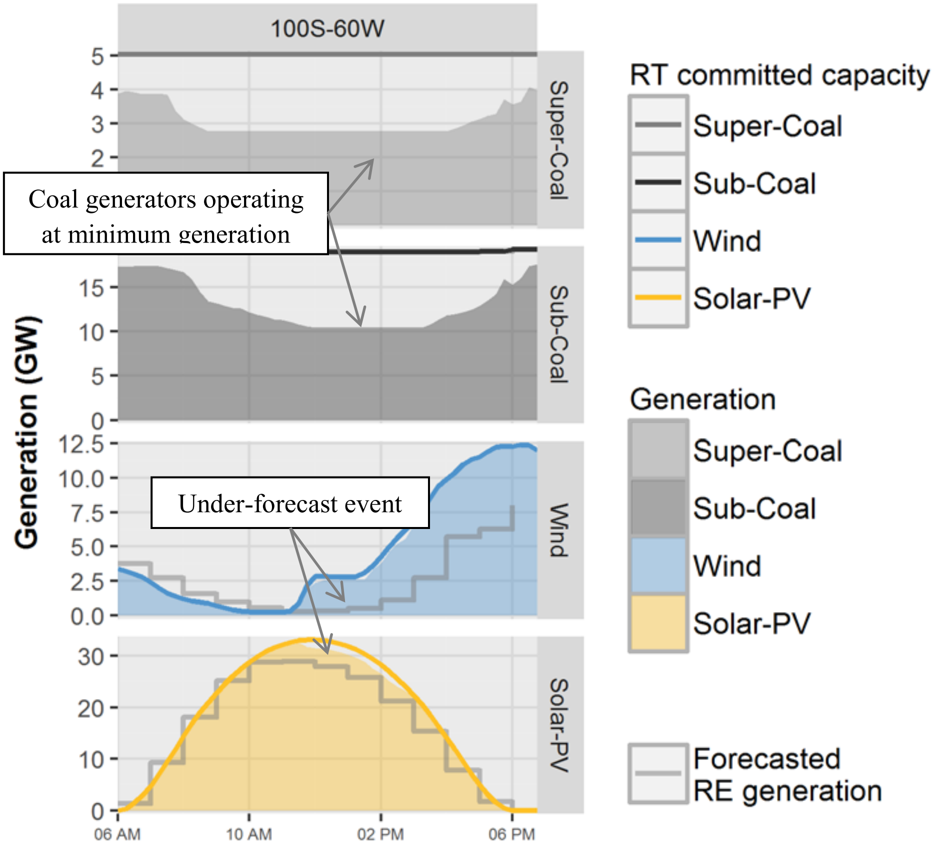


Figure 45. Underforecasting event: committed capacity, real-time dispatch, and renewable energy forecasts on 25 September in the Southern region

Note: Y-axis is different for each fuel type.

The underforecasting event happens from 10:00 to 20:00 on 25 September, with much more wind and modestly more solar energy available than forecasted. In response to more than expected RE on the system, coal generators turn down or delay ramping up. Between approximately 12:00 and 14:30, all coal units reduce output to minimum generation levels. This is the lowest possible dispatch for coal generation in the Southern region during this time because units that are committed in the day-ahead schedule cannot reduce output below the minimum generation level in real-time dispatch, and the model does not allow these units to be decommitted in real time, even if the underforecasting event lasts 10 hours (in reality, the system operators would likely be able to revise the schedules of some coal generators).

In this example, the underforecasting event overlaps with part of the evening peak load. In a perfectly forecasted system, the coal generation would be operating at or close to committed capacity during the evening peak, but in this case the coal generation remains backed down to accommodate the higher-than-anticipated levels of wind. During the daytime when total RE is greatest and all coal units are operating at minimum generation levels as planned, some solar and wind energy is curtailed.

Figure 46 illustrates coal operations during a relatively large overforecasting event in the Southern region on 9 June.

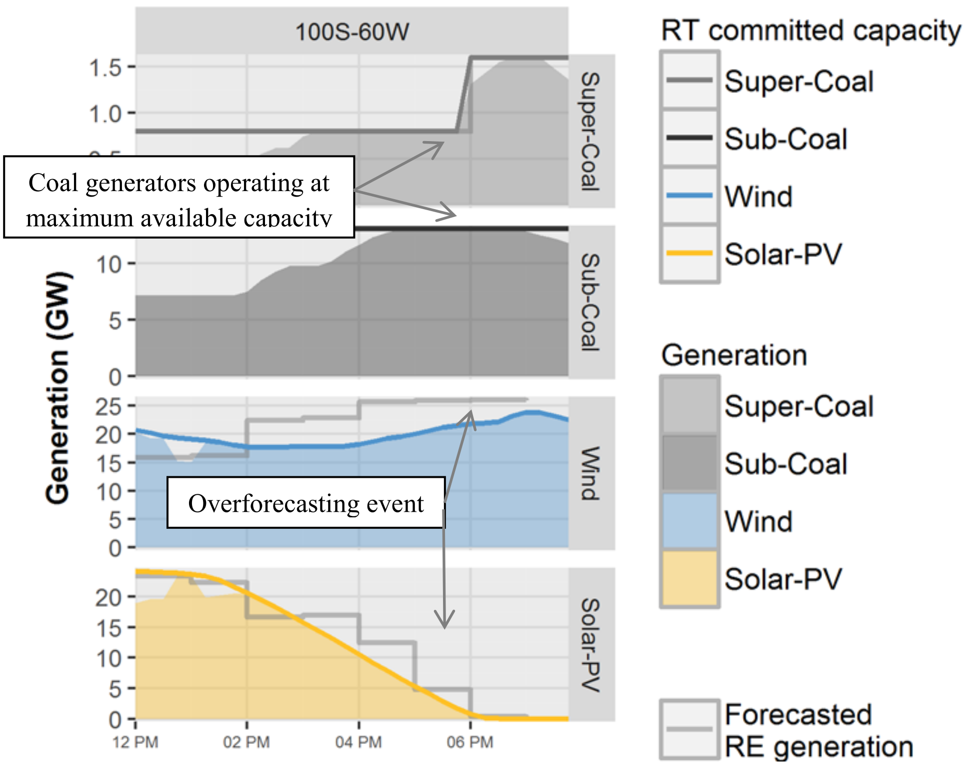


Figure 46. Overforecasting event: committed capacity, real-time dispatch, and renewable energy forecasts on 9 June in the Southern region

From 14:00 to 20:00 on 9 June, less solar and wind energy are available than forecasted. Coal generators ramp up starting at 14:00. All coal units in the Southern region are dispatched to full capacity to recover from the forecast error. The maximum coal generation at this time is constrained by the day-ahead commitment because only committed coal units are running and ready to be called on in real-time dispatch.

With more wind and solar on the system in the 100S-60W scenario, forecast errors are larger in magnitude and require more adjustment of dispatch schedules in real time. Larger forecast errors with higher RE may also contribute to more energy exports and imports or, in extreme cases, may lead to reliability concerns in certain periods. The next section identifies periods in which the power system is highly constrained in the model, and actions that may help mitigate those challenges.

Forecasting Errors in Highly Constrained Real-Time Operations

There are some periods of the year when load is not able to be met reliably in our model, which we refer to as unserved energy. This accounts for only 0.02% of total demand in the year, although some periods have a higher instantaneous percentage of unserved energy. Many of these periods can be attributed to modeling constraints and therefore do not reflect credible concerns to reliability.[44] However, the model does highlight periods that portend realistic circumstances in a high-RE future. Primarily, periods of unserved energy can be at least partially attributed to the impact of RE overforecasting errors.

Overforecasting errors can lead to a system with low committed capacity from thermal units in real-time operations. In these conditions, the model responds in the following order, based on least-cost

[44] See Appendix D for a broader explanation of unserved energy and how modeling constraints lead to this outcome.

principles and bound by physical constraints of the system: (1) all latent headroom in thermal and gas units will be utilized, within ramp and transmission constraints; (2) any units that were not committed in the day-ahead schedule but can be in real time will start (diesel, oil, combustion turbines); and 3) reserves that were provisioned day-ahead will be dropped where needed, and the headroom in the thermal plants that were holding reserves will be dispatched as energy.[45] Unserved energy occurs when these three strategies are insufficient to recover from the forecasting error.

Figure 47 and Figure 48 illustrate how the thermal fleet is used to respond to one such over-forecasting event. The highlighted period shown has a forecasting error that is 19.8 GW, or 10 GW over the 9.8 GW of reserve provision.[46] In response, all thermal units are turned up to the maximum physical capability, reserves have been dropped (real-time generation is equal to day-ahead commitment for all coal and gas), and 4.8% of load (10.2 GW) remains unserved.

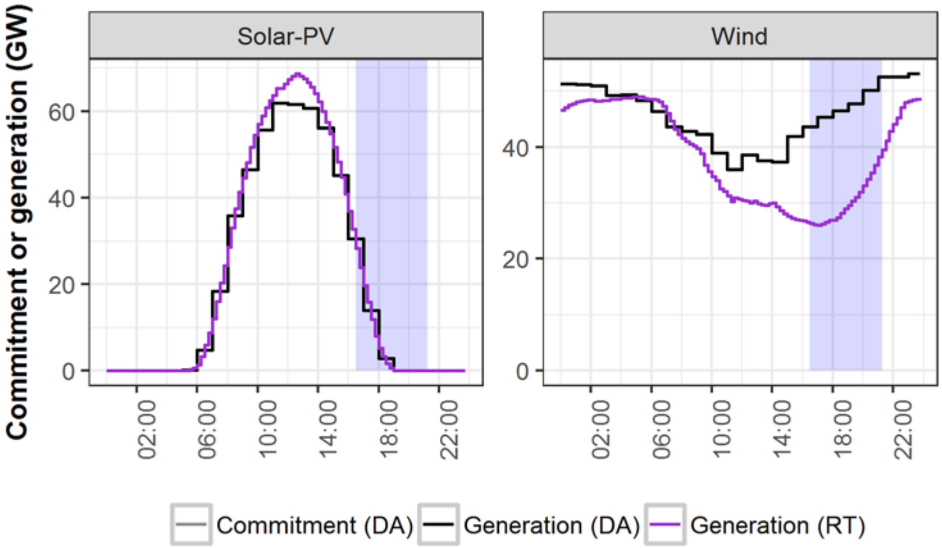


Figure 47. Wind and solar generation in both day-ahead (DA) and real-time (RT) schedules.

Note: Highlighted band is period of unserved energy.

[45] Employing this strategy leads to some periods when reserves are not fully provisioned at the required levels. In the 100S-60W scenario 93% of the annual reserves are met.

[46] Forecasting errors from a day-ahead schedule have the potential to be as large as they are in this period based on international review; however, events such as this are very rare given state-of-the-art forecasting (Hodge et al. 2012). A small number of periods with smaller forecast errors also impact the ability of the system to serve load for similar reasons, although not as drastically as the example period. It is likely that a forecast error this large could be mitigated by any number of solutions, including demand response or operator intervention.

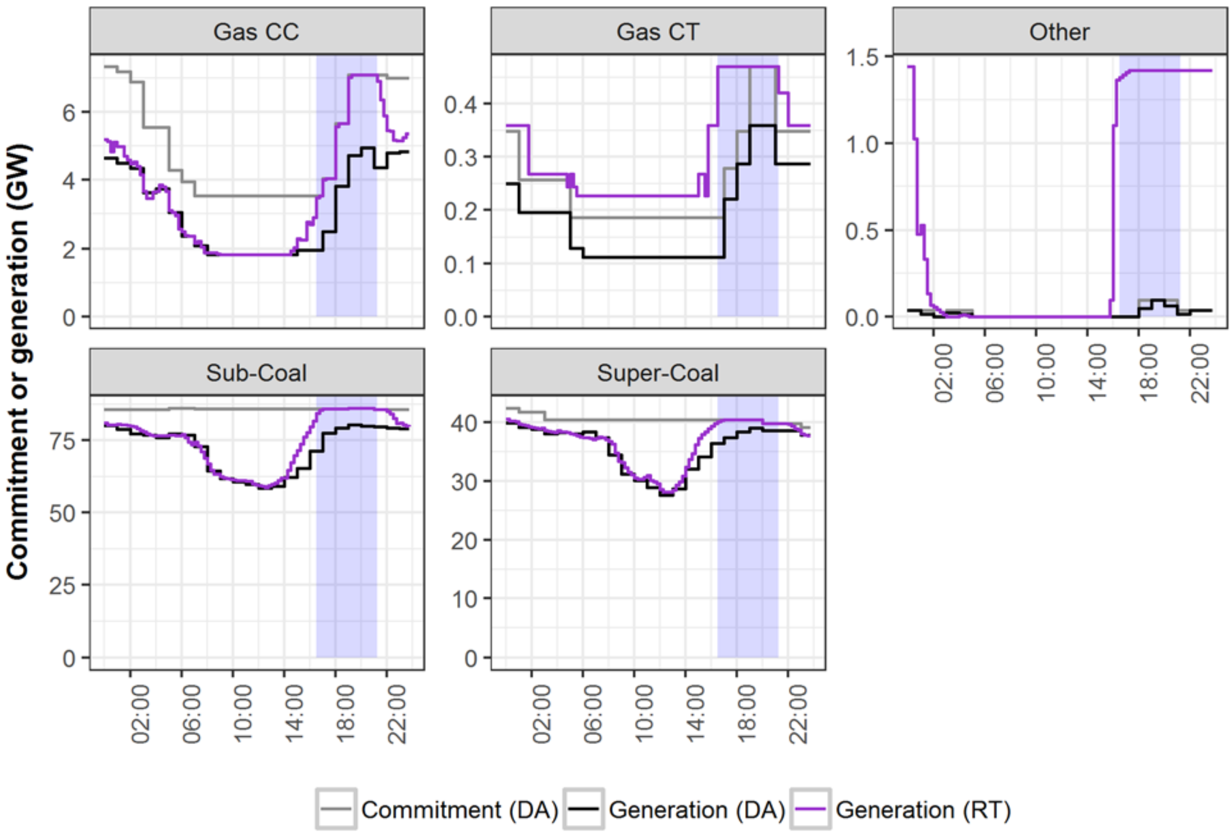


Figure 48. Thermal fleet day-ahead commitment and dispatch, and real-time adjustments to generation, in response to an overforecasting event.

Note: Highlighted band is period of unserved energy.

Figure 49 shows the annual duration curve of forecast error, with negative values indicating overforecasts and positive indicating underforecasts. The dashed line shows the India-wide up-reserve requirement. There are a substantial number of overforecasting errors that are greater than the up-reserve requirement (indicated by points below the dotted line), which indicates that those periods may risk unserved energy if the rest of the system is also constrained.[47]

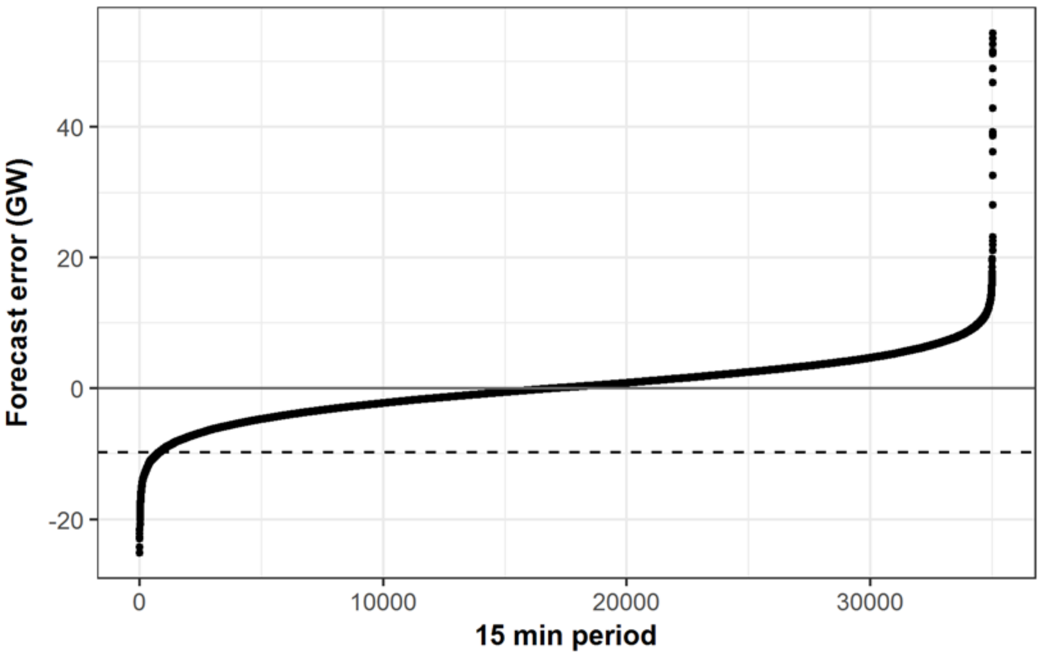


Figure 49. Forecasting error duration curve, where negative values indicate overforecasting events. The dashed line shows the 9.8-GW India-wide up-reserve requirement.

Note: Negative values represent overforecasting events (less RE than forecast), and positive values represent underforecasting events (higher RE than forecast). Overforecasting errors that exceed up-reserve requirements have the greatest potential to create conditions for unserved energy.

Modifying Reserve Requirements to Address Large Forecasting Errors

Operating reserves are currently modeled to act as a last resort in serving energy and ideally should be preserved for sub-15-minute frequency and imbalance services. However, reserve scarcity should usually preempt unserved energy, and in that sense the current reserve requirements do provide a large amount of reliability, despite the instances of unserved energy. A full study on the optimal reserve product and quantity that would most benefit India's high-RE future is beyond the scope of this study. Additionally, optimal reserve products will likely need to be re-evaluated as RE capacity is installed and location-specific reliability questions are raised. The quality of the RE forecasts also affects the optimal reserve requirements.

However, within this study we can test whether certain reserve products, however overreaching in necessity, might further contribute to reliability. In one test on the 100S-60W scenario, we doubled the reserve requirement to 19.6 GW and released 9.8 GW of this in real time for energy use. This doubling ensures that sufficient headroom on thermal units is available for energy and ramping. This

[47] The ability to utilize operating reserves relies on an unconstrained transmission path. Therefore, addressing forecast errors that are above the reserve line may also be difficult in periods of congestion and cause periods of unserved energy in certain parts of the country in our model. Power system regulations often require that adequate transmission capacity is readily available to transfer reserve power, although that consideration is beyond the scope of this study. Underforecasts are usually not a reliability concern within our model because RE is able to be curtailed if generation is greater than demand.

method does expunge most of the unserved energy and maintains nearly all (99.8%) of the original reserve requirement for the sub-15-minute time frame. This is very likely a larger reserve requirement than necessary, but it does indicate that the assumed thermal capacity in 2022 is sufficient to reliably integrate high amounts of RE. A more judicious method for optimizing reserves could be based on time of day and season.[48]

Modifying reserve requirements are sometimes considered an "integration cost," a concept explored more thoroughly in the following sidebar.

INTEGRATION COSTS: THE CHALLENGE IN DEFINING AND ASSESSING INTEGRATION COSTS

Integration cost—the cost imposed on the power system to integrate a resource—is a deceptively challenging concept to define and calculate. At its most basic, the concept highlights that the levelized cost of energy (the average cost per MWh) does not reflect the full cost (and value) of a resource. As wind and solar energy began to be added to power systems around the world, integration cost methods were developed so that the cost of wind/solar's variability and uncertainty—not typically captured in production cost simulation models—could be evaluated. Some of the costs that have been attributed to wind and solar resources include:

- Reserves to accommodate the variability and uncertainty of wind and solar, sometimes called "flexibility reserves"
- Thermal generator cycling costs that result from more frequent changes in dispatch to complement wind and solar's variable output (cycling can lead to greater operations and maintenance costs and reduced plant efficiencies)
- Transmission expansion to serve locations with strong solar and wind resources
- Stranded investments in conventional generators that are displaced by wind and solar.

Nevertheless, these costs are not unique to renewable energy. Reserves are an extension of existing practices to balance the system. Cycling costs and stranded investments, and in some cases, new transmission, occur anytime a new resource is added to the system. This was first identified in Milligan et. al (2011), which showed how new baseload generation could increase the cycling of other thermal plants, and how the introduction of a new, large power plant can increase the contingency reserve—and thus costs—of other generation (or generation owners). A more systematic study by Stark (2015) examined the integration cost of several types of resources and market structures. The findings showed that there are many sources of integration costs—costs imposed by one resource on another.

However, integration costs are not directly calculable or observable—the costs of maintaining a reliable power system reflect the complex interactions among resources and loads, making it difficult, if not impossible, to untangle costs and allocate them to individual cost-causers—generation or load. Since the first integration cost studies were performed more than a decade ago, there has been no widespread agreement on any common method. Therefore, comparisons between studies are rarely valid, and the lack of commonly accepted methods leads to the conclusion that a rigorous, defendable method may not exist. Recent meta-studies have examined the vast literature on integration costs, such as Heptonstall, Gross, and Steiner (2017) and Agora (2015). Heptonstall et al. point out the risk of double-counting and the overall complexity of integration cost methods, and say that a full-cost

[48] Another approach to lower the required operating reserves is to shorten the dispatch intervals (e.g. from 15-minutes to 5-minutes) which decreases the amount of regulating reserve required and can lead to lower overall costs (Porter et al. 2012).

comparison between systems with and without RE is a more comprehensive perspective and less prone to error. Agora discusses various assumptions and how they differ among studies, and states that “comparing total system costs of different scenarios would be a more appropriate approach.”

COMPARING COSTS BEFORE AND AFTER RE IS ADDED

If we want to highlight some of the changes to operating costs specific to the addition of RE, we can evaluate cost changes associated with RE’s variability and uncertainty. The uncertainty component can be reasonably addressed by assessing the increase in the appropriate reserve cost caused by RE. This can be carried out with a production simulation model. Because RE varies as a function of the resource (wind speed or solar irradiation) the optimal reserve holdings would be dynamic—based on what the RE is doing now and what it may be doing in the future time step(s) of interest. But because of the latent reserve that exists in the generation dispatch stack, often there is no need for additional reserves, and this can be tested in a suitable production simulation model. Stark (2015) provides a good example of how the cost of reserves can be calculated for many alternative resources.

The other major way in which RE can affect operating costs is the cost of variability. Although simple to calculate in principle, cycling costs of thermal and hydro generators is a function of cumulative cycling and a function of the cycling depth. This makes a precise estimate very difficult because cycling costs will therefore change through time, even on the same unit.

Moreover, some of the cost of variability can be mitigated or eliminated by deploying the controllability that is now part of wind turbine and solar inverter technologies. Very fast frequency response, sometimes in timescales so short that they simulate inertial response, can be provided by RE. RE can also supply a regulation service (AGC) and can respond to dispatch instructions. This means that RE may not increase AGC/frequency response requirements on the system, and may, in many cases, be able to provide these services. Thus it would not be appropriate to isolate the cost of variability without accounting for RE’s contributions to system frequency control.

COSTS OF RE IN THIS STUDY

For this study we are not able to estimate the cycling cost impacts of RE; however, we do cite cost estimates from the most rigorous cycling-cost study to date (see “The Costs of Cycling Thermal Plants” sidebar in Section 4.3). This gives an indication of what cycling costs might be for India.

In the India model, we used the same level of operating reserve as currently proposed for the Indian power system. After adding the RE for the various scenarios into the study, we find that this level of reserve is adequate to maintain reliability for over 99.98% of demand for the year. The modeling does not indicate any significant cost of uncertainty of RE on the Indian power system.

COST ALLOCATION

The costs of added variability and uncertainty—from any source—are typically allocated to load, the end users. For example, reserves (regulation and contingency) are allocated to load because it is (1) very difficult to isolate or allocate costs of variability and uncertainty across each source and (2) power plants (especially large power plants) were typically developed as systemwide assets shared among customers.

A detailed approach to cost allocation requires three interlocking types of analysis:

1. Substantive—What are the costs? Can they be minimized?
2. Procedural—How are costs allocated?
3. Public policy—How could costs be allocated in a way that aligns with larger policy goals?

To the extent that there are meaningful costs associated with variable RE integration, the public policy priorities in the United States and elsewhere have generally favored approaches that socialize the costs of integration except in circumstances where there is direct and attributable need for new investment, in which case costs are typically split according to the “beneficiary pays” principle.

4.8 Summary

We find that based on the fulfillment of current regulatory and planning efforts to provide better access to the physical flexibility of the power system, power system balancing with 100 GW of solar and 60 GW of wind is achievable at 15-minute operational timescales with minimal RE curtailment. The system is able to do this based on existing plans for interstate transmission and capacity expansion, and does not require new fast-ramping infrastructure for RE, such as combustion turbines or storage. The planned fleet of generation and transmission provides sufficient capacity to handle RE forecast errors, changes in net load (ramps), and times of the day and year when RE generation is low. This is all possible while meeting the majority of requirements to hold secondary and tertiary reserves, although optimal reserve requirements were not studied in detail. Analysis of highly constrained periods suggests that reserve requirements may benefit from varying by season or time of day. The companion regional study addresses the importance of in-state transmission in maintaining low RE curtailment.

Table 15 summarizes key findings relative to how a system with 100 GW of solar and 60 GW of wind is balanced.

Table 15. Key Findings on Balancing the Indian Power System with 100 GW Solar and 60 GW Wind

RE GENERATION

- RE generates 370 TWh energy annually
- Annual RE penetration is 22%, with an instantaneous peak of 54% of total demand
- Annual capacity factors of the RE plants are 21% for solar PV and 36% for wind
- RE curtailment averages 1.4% of total available RE energy, for a total of 5.1 TWh. The Southern region experiences the highest curtailment levels of 2.9% annually
- RE curtailment occurs somewhere in the country during 1,057 hours, or roughly 12% of the year, and peaks at 27 GW on 7 September

IMPACTS ON THERMAL UNITS AND PLANT OPERATIONS COMPARED TO THE NO NEW RE SCENARIO

- Coal and natural gas generation decreases 270 TWh and 15 TWh, respectively, a drop of 21% and 32%
- CO_2 emissions drop 21% (280 MMT)
- Plant load factors of coal drop from 63% to 50%, with more than 19 GW of capacity that never starts, and 65 GW of capacity that experiences plant load factors below 30%
- Coal plants on average experience 2.8% more starts and, when operating, spend 195% more time at minimum generation
- Aggregated nationally, for 0.64% of the year, systemwide up-ramps exceed 25 GW/hour, greater than any ramp requirement in the No New RE scenario, and peak at almost 32 GW/hour
- Hydro generation follows a two-peak net load profile

IMPACTS ON IMPORTS AND EXPORTS AND TRANSMISSION FLOWS COMPARED TO THE NO NEW RE SCENARIO

- Annual interstate energy exchanges within the Western and Southern regions decrease 9.6% and 5.9% to 120 TWh and 45 TWh, respectively
- Total annual net energy exchanges between regions decrease 16% to 180 TWh
- The magnitude of flows and number of changes in direction of flows between the Southern and Western regions increase significantly during the monsoon period, when wind generation is highest

Table 16 provides a snapshot of generation during interesting periods affected by RE integration. Figure 50 illustrates each fuel's relative generation compared to its maximum and minimum output during periods of maximum and minimum load and net load. See Appendix E for additional details, including visuals of the generation dispatch on each of these days.

Table 16. Snapshot of Generation During Max/Min Periods of Load, RE, Net Load, and RE Penetration Levels in 100S-60W Scenario

SNAPSHOT	TIME (24 HR)	LOAD (GW)	COAL (GW)	RE (GW)	HYDRO (GW)	GAS (GW)	NUCLEAR (GW)	OTHER (GW)	RE CURTAILMENT (GW)	RE PENETRATION (% OF LOAD)
MAX LOAD (230 GW)	30 June 21:15	230	127	48	48	5	3	0	0	21%
MIN LOAD (143 GW)	28 Feb. 3:30	143	109	19	7	3	5	0	0	14%
MAX NET LOAD (215 GW)	21 Oct. 19:00	228	150	13	47	10	7	0	0	6.0%
MIN NET LOAD (82 GW)	7 Sept. 11:30	160	60	78	15	1	6	0	21	49%
MAX RE (111 GW)	23 June 12:15	205	73	111	16	1	4	0	10	54%
MIN RE (3 GW)	29 Nov. 6:15	190	147	3	25	8	6	2	0	1.8%
MAX RE PENETRATION (54%)	21 July 12:15	190	66	104	16	1	5	0	7	54%
MIN RE PENETRATION (1.8%)	29 Nov. 6:15	190	147	3	25	8	6	2	0	1.8%
MAX COAL GENERATION (152 GW)	11 Nov. 16:45	192	152	12	16	6	5	1	0	6%
MIN COAL GENERATION (60 GW)	7 Sept. 11:30	160	60	78	15	1	6	0	21	49%
MAX HYDRO GENERATION (54 GW)	22 Aug. 20:45	225	136	23	54	5	6	0	0	10%
MIN HYDRO GENERATION (4 GW)	21 Dec. 11:45	184	100	69	4	3	7	0	0	38%
MAX RE CURTAILMENT (27 GW)	7 Sept. 13:15	157	61	74	15	1	6	0	27	47%
MAX NET LOAD RAMP (92 GW) **START OF RAMP** **[END OF RAMP]**	21 Oct. 12:45- [19:00]	195 [228]	102 [150]	73 [13]	8 [48]	4 [10]	7 [7]	0 [0]	10 [0]	37% [6%]

Operational Impacts

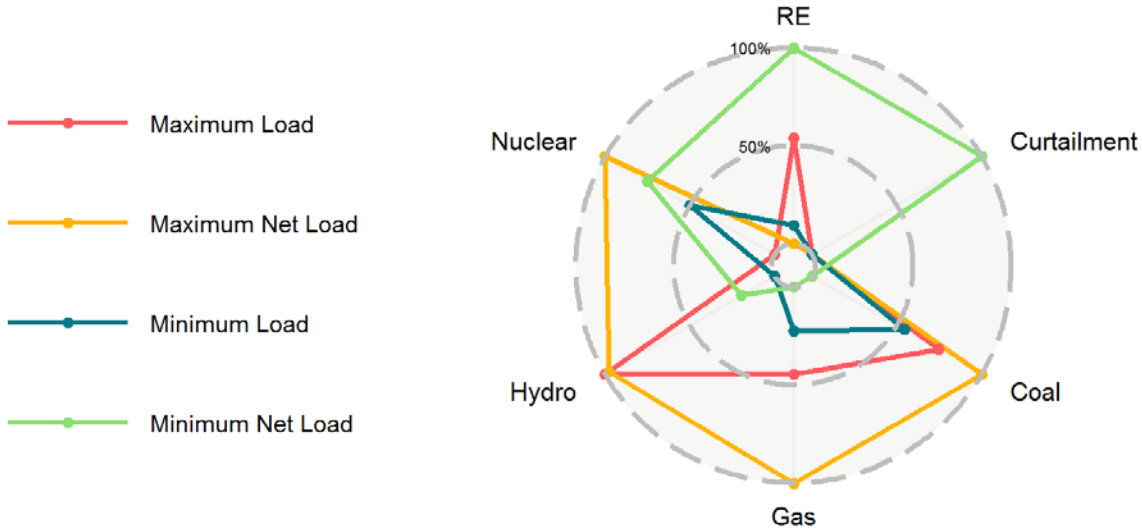


Figure 50. Each fuel's relative generation compared to its maximum and minimum output during periods of maximum and minimum load and net load

Note: MW values are normalized to a 0-1 scale, specific to each fuel, with 0% being the least generation and 100% being the highest within these four periods. For example, coal is generating most during Maximum Net Load (orange) and least during Minimum Net Load (green) relative to the other time periods.

5 STRATEGIES TO IMPROVE RE INTEGRATION

While the previous section analyzed the impacts of adding 160 GW wind and solar to the power system with the operating characteristics of today, the objective of this section is to evaluate changes to power system operations that have the potential to more efficiently integrate variable RE. To evaluate these changes, we compare the impacts of the strategies on electricity production costs and RE curtailment. Introducing one change at a time to the model makes it possible to evaluate the benefit of specific strategies, either individually or in combination, to provide insights for decision-makers. All sensitivities are conducted on the 100S-60W scenario, unless otherwise noted.

The sensitivities we evaluated are listed in the following tables (Table 17 through Table 21) address five aspects of flexible operations:

- National and regional coordination of scheduling and dispatch
- Operation of coal plants
- Availability of transmission
- Availability of storage
- Availability of hydro energy.

Table 17. Description of Sensitivity: Coordinated Scheduling and Dispatch

SENSITIVITY	REFERENCE CASE	LESS FLEXIBLE	MORE FLEXIBLE
Size of balancing area for scheduling and dispatch	State (current practices)		Regional National

Table 18. Description of Sensitivity: Operation of Coal Plants

SENSITIVITY	REFERENCE CASE	LESS FLEXIBLE	MORE FLEXIBLE
Minimum plant generation levels (% rated capacity)	55%	70%	40%
Ramp rates (% rated capacity per minute)	1%	0.5%	
Minimum up/down times (hours)	24/24		12/12
Start-up costs (per MW)	15,038 INR	Double	
Coal capacity	CEA projections	Retirement of plants ≤ 15% PLF in reference case (46 GW)	

Note: We also evaluated some variations on these sensitivities, such as retiring 20% of coal plants and restricting flexible coal parameters to just centrally operated plants.

Table 19. Description of Sensitivity: Transmission Capacity

SENSITIVITY	REFERENCE CASE	LESS FLEXIBLE	MORE FLEXIBLE
Interregional transmission	CEA projections	-25% transmission corridor capacity	+25% transmission corridor capacity
Copper plate	CEA projections		No physical transmission or market/transactional constraints

Table 20. Description of Sensitivity: Storage

SENSITIVITY	REFERENCE CASE	LESS FLEXIBLE	MORE FLEXIBLE
Storage	No new storage (existing pumped storage is 2.45 GW)		Double storage capacity (5 GW total)

Table 21. Description of Sensitivity: Hydro

SENSITIVITY	REFERENCE CASE	LESS FLEXIBLE	MORE FLEXIBLE
Storage	Hydro energy available in 2014	January–June +/- 7% energy July–December +/- 15% energy Each direction can have positive and negative implications for flexibility	

5.1 Value of Better Coordination Across State Balancing Areas

Power system coordination conducted over a larger geographic and electrical footprint improves the cost-effectiveness of operations. A larger balancing region leverages the smoothing effect of diversity in both load and RE generation (Denholm and Cochran 2015). A larger pool of conventional generators is also more cost effective to operate because a broader customer base can access energy from the most efficient plants in the balancing region without the incentive to use generation in their state.

To represent alternative levels of operational coordination, we used hurdle rates to capture existing preferences among states and regions to conduct their own scheduling and dispatch, without perfect coordination with other areas, as described in Section 3. Because coordination between balancing areas has been demonstrated in other countries to be an effective strategy to integrate RE, we analyzed three levels of scheduling and dispatch coordination: state (our reference case), regional coordination, and national coordination.

- State scheduling/dispatch approximates current responsibilities for balancing.
- Regionally coordinated scheduling/dispatch implies that system operators in each of the five electricity regions have efficient access to all generation within their region in order to schedule and dispatch generation at least cost.
- Nationally coordinated scheduling/dispatch assumes system operators in each state have efficient access to all generation within the country in order to schedule and dispatch generation at least cost.

Table 22 summarizes the hurdle rates used to represent this behavior in our sensitivities, which are applied to both unit commitment and dispatch. Hurdle rates on state balancing area exports capture constraints on the ability of states to import freely from other states, whereas hurdle rates on interregional transmission interfaces are calibrated by comparing modeled flows against observed data.

Table 22. Hurdle Rates Used to Capture Existing Barriers to Trade and to Evaluate Value of Alternative Operating Practice

HURDLE RATES[49]	STATE SCHEDULING/ DISPATCH	REGIONALLY COORDINATED SCHEDULING/ DISPATCH	NATIONALLY COORDINATED SCHEDULING/ DISPATCH
Interregional corridors	225–1050 INR/MWh	225–1050 INR/MWh	None
State net exports	1050 INR/MWh (except 450 INR/MWh in NER)	None	None

Efficiencies of greater coordination are demonstrated in our simulations through reduced production costs and RE curtailment. The results of these sensitivities are illustrated below. Figure 51 compares the production costs and percentage of RE curtailment across these three modes of scheduling and dispatch. Annual production costs drop INR 6300 crore (approximately USD 980 million[50]), equivalent to 2.8%, when schedules are optimized at the regional level rather than by state.[51] Nationally coordinated scheduling and dispatch further reduces production costs by INR 1500 crore, totaling INR 7800 crore (USD 1.2 billion) or 3.5% less as compared to state-based schedules.[52]

Greater scheduling coordination has a relatively small impact on RE curtailment compared to its impact on production costs. In shifting from state to regionally to nationally coordinated scheduling and dispatch, RE curtailment decreases from 5,100 to 4,800 to 3,300 GWh, respectively, which represents 1.4%, 1.3%, and 0.89% of total RE potential generation. The greatest drop in curtailment is seen in the Southern region, which, as described in Section 4, is where curtailment is most pronounced.

Integration Strategies

[49] Details of the specific hurdle rates are provided in Appendix C.
[50] Exchange rate in late June 2017 was INR 64.5 to USD 1.
[51] The change in production costs represents savings in operations, with no change to fixed costs.
[52] These savings, and all savings reported in this study, are in today's rupees and do not consider inflation or fuel cost escalation. The savings could be higher or lower in 2022 when these two factors are considered.

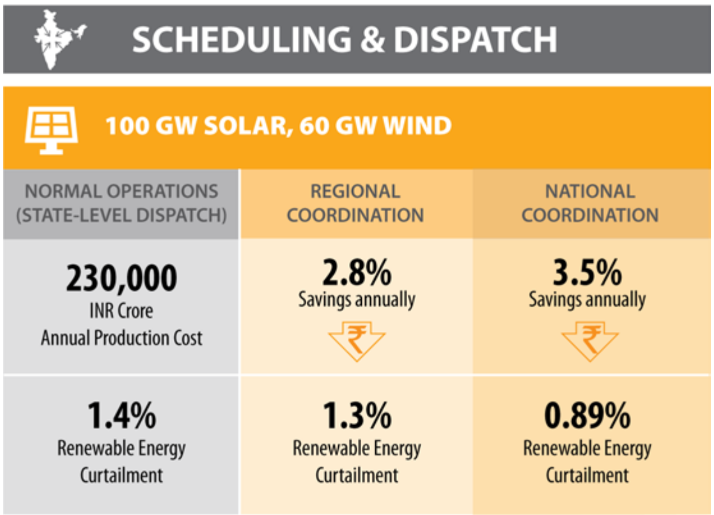


Figure 51. Impact of coordinated dispatch on annual production costs and curtailment

Removing the hurdle rates on state exports in the regionally coordinated dispatch scenario affects merit order dispatch, with cheaper conventional generation from some states being more available for exports and thus displacing more expensive generation from other states. Further, removing hurdle rates on the interregional interfaces in the nationally coordinated dispatch scenario allows greater trade between regions and in turn lower overall costs. **This sensitivity applied to No New RE also results in cost savings. Regional coordination, even in absence of new RE, can yield an annual production cost savings of 1.2% (INR 3600 crore).**

As illustrated in Figure 52, the impact by region depends on which level of coordination. Overall, with increased coordination, generation increases in the Western and Eastern regions, and decreases in the Southern and Northern regions. In other words Western and Eastern regions export more to the Southern and Northern regions due to the relative cost of generation, which is more easily accessed once coordination within a region goes up.

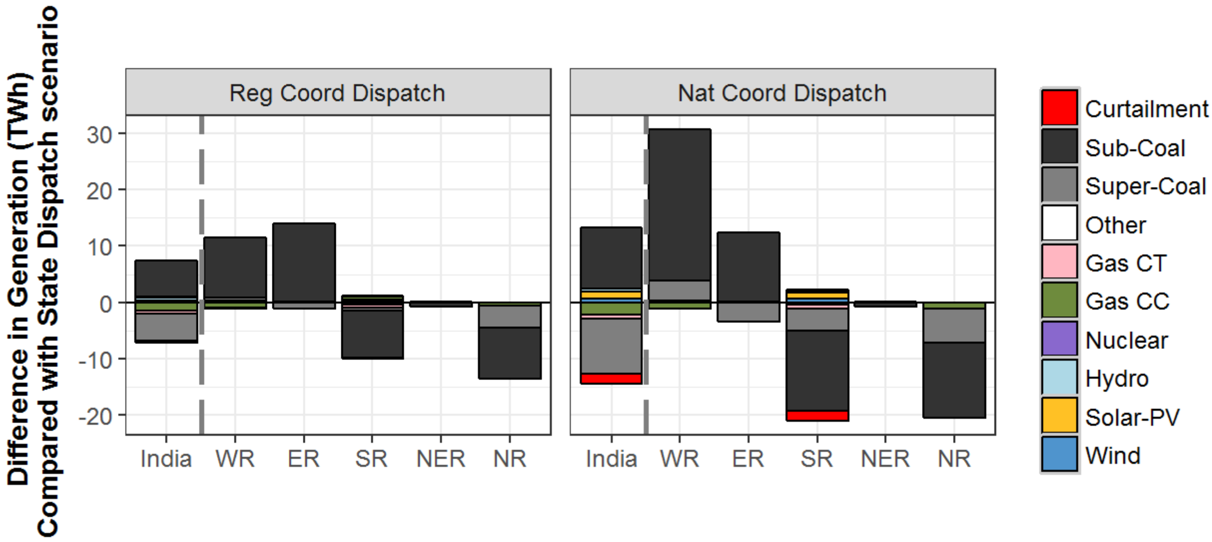


Figure 52. Impact of coordinated dispatch on annual generation, by fuel type and region

Note: Differences are in comparison with state dispatch.

To help explain why some supercritical coal capacity is displaced with coordination, Figure 53 illustrates the impact to each region by showing changes in annual generation for each generator based on its variable cost when shifting from state dispatch to regionally coordinated dispatch. Each dot represents the difference in annual generation of a generator plotted against its variable cost. The figure highlights the change in merit order dispatch when shifting from state to regionally coordinated dispatch, particularly in the Western region. The WR plot, on the far right, shows lower cost subcritical coal offsetting more expensive sub- and supercritical coal, which (not illustrated) are located in different states of the Western region. The most significant increase in coal generation occurs in Chhattisgarh, Madhya Pradesh, Odisha, and Andhra Pradesh, whereas the largest decrease in generation occurs in Maharashtra.

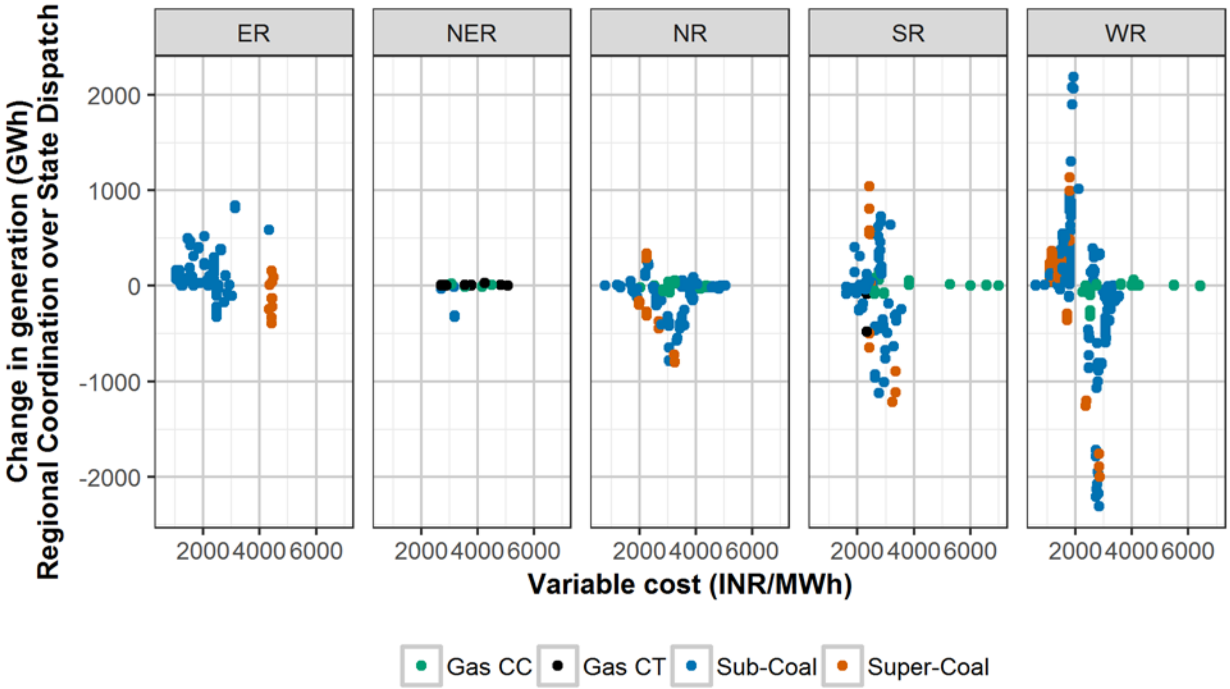


Figure 53. Change in generation between regionally coordinated and state dispatch, by region, fuel type, and variable cost

Impacts of coordinated scheduling and dispatch can also be seen in changes to day-ahead unit commitments. Greater coordination allows more efficient sharing of generation resources, requiring fewer conventional generation units to be committed in the day-ahead schedule. Because there are fewer conventional generation units operating, they are operating at higher part-load levels. And as such, they have greater turn-down capacity during dispatch when managing periods with high RE generation, resulting in less RE curtailment during low net load periods. Conversely, increased coordination that results in fewer committed units creates less flexibility to turn up generation when managing underforecast errors.

The effect on coal commitments is quite pronounced in the Southern region, where the states share their thermal resources and rely more heavily on imports, resulting in an average decrease in committed coal capacity of 2.5% with regionally coordinated dispatch, and 7.1% with nationally coordinated dispatch. With fewer committed thermal units running at higher capacity factors, the Southern region's ability to turn down its thermal fleet and absorb RE is increased.

In aggregate, regionally and nationally coordinated dispatch reduce average committed coal capacity by 0.68 GW and 0.66 GW, respectively. In both cases ~0.5% less coal is committed. Trade patterns also change. Most notably, committed coal capacity rises by 5.9% in the Eastern region under regionally coordinated dispatch. Northern, Southern, and Western regions compensate with reductions of 2.6%, 2.5% and 1.2%, respectively. With trade barriers removed, more economical sources of coal in the Eastern region are used to meet load elsewhere.

Figure 54 shows the impact of coordination on transmission flows (A) and congestion (B) on interregional interfaces. With more coordinated dispatch, total flows across all interregional interfaces increase. Annual absolute flows on interregional interfaces increase from 180 TWh for state dispatch to 210 TWh (17% increase) in the regionally coordinated dispatch scenario and to 270 TWh (50% increase) in the nationally coordinated dispatch scenario. At the same time, the percentage of time these interfaces are congested also increases. Some interfaces, such as ER-NR, are congested for more than 35% of the year in all scenarios. When congestion occurs, it prevents access to least-cost generation and thus increases overall system costs.

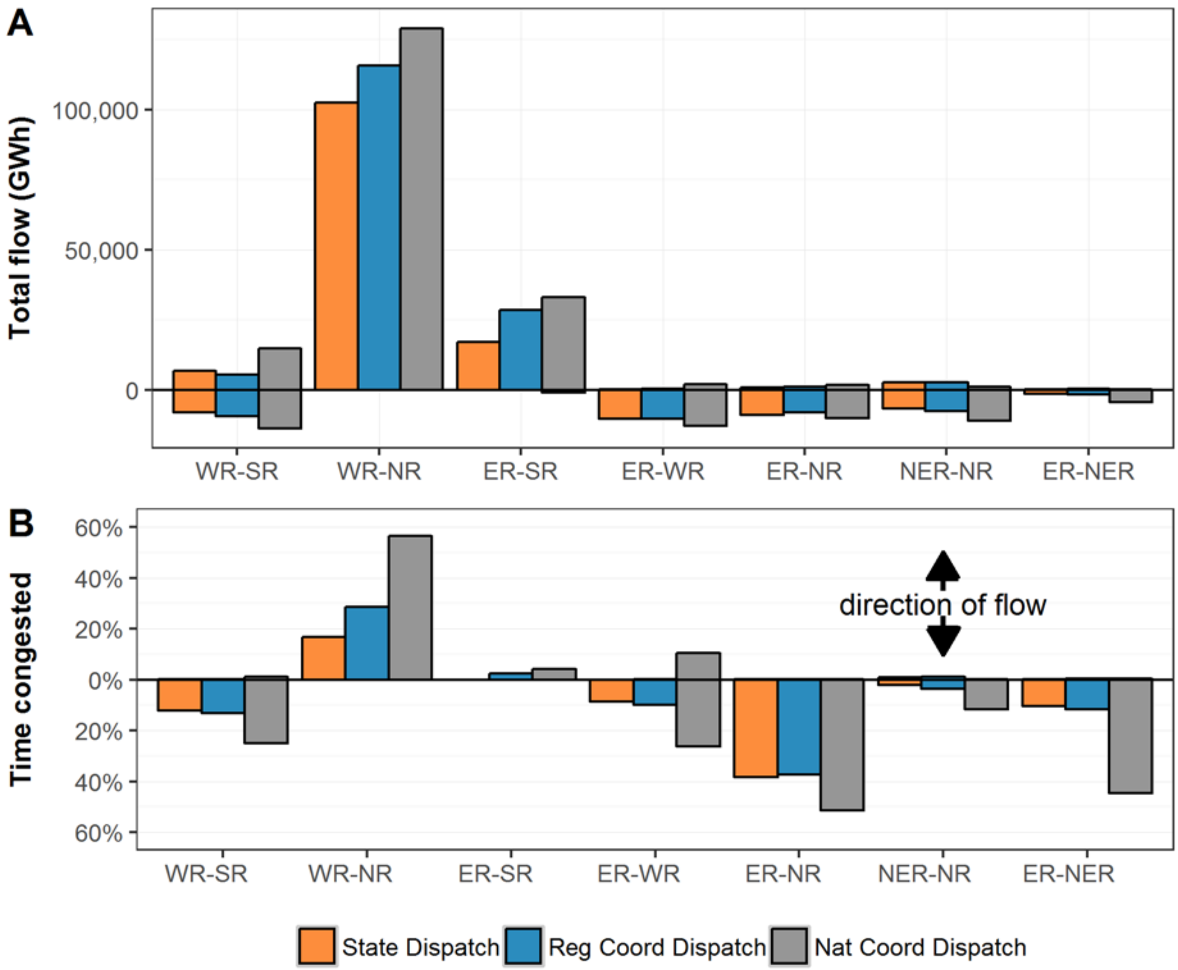


Figure 54. Impact of coordinated dispatch on interregional transmission flows (A) and interface congestion (B)

Note: Horizontal axis names refer to the direction of flow and congestion (e.g., WR-SR means that above zero on the y-axis is the total flow or time congested in the Western to Southern region direction. Below zero on the y-axis means Southern to Western direction is congested.)

How Does Better Coordination Impact RE Curtailment?

We now examine the same RE curtailment period (7 September) discussed in Section 4.6. During this period, there is curtailment in all coordination scenarios—state dispatch, regionally coordinated dispatch, and nationally coordinated dispatch. As coordination increases and trade barriers are removed, the primary cause of curtailment changes from economic to physical, i.e., from trade barriers to transmission congestion.[53]

During the day, Southern region must either export RE generation or curtail. Its ability to find a trading partner depends on the level of interregional coordination

As discussed in Section 4.6, transmission congestion, thermal and hydro fleet inflexibility, start and stop costs, and trade barriers are the main causes of curtailment in our model. Increased scheduling and dispatch coordination eliminates trade barriers and incentivizes states to displace expensive local generation with imported RE. In the national coordination sensitivity, which has no trade barriers, a state will always export excess RE rather than curtail unless prevented by transmission congestion.

We consider 7 September in detail, the day of maximum instantaneous RE curtailment in all three coordination sensitivities. Figure 53 compares dispatch and thermal fleet constraints for the Southern region across the three sensitivities. The Southern region is by far the biggest RE curtailer on 7 September in all three coordination sensitivities. However as dispatch coordination improves from state to regional to national, the duration and quantity of its curtailment falls by 13% and 20%, respectively. In every interval with curtailment, the Southern region's thermal fleet is fully backed down, meaning regardless of the sensitivity, it needs a trading partner to absorb its RE generation.

[53] The transmission system is likely planned assuming that some trade barriers will always be in place between regions and states. Nevertheless, the nationally coordinated dispatch scenario gives insight into physical limitations that may exist in an ideal future without trade barriers.

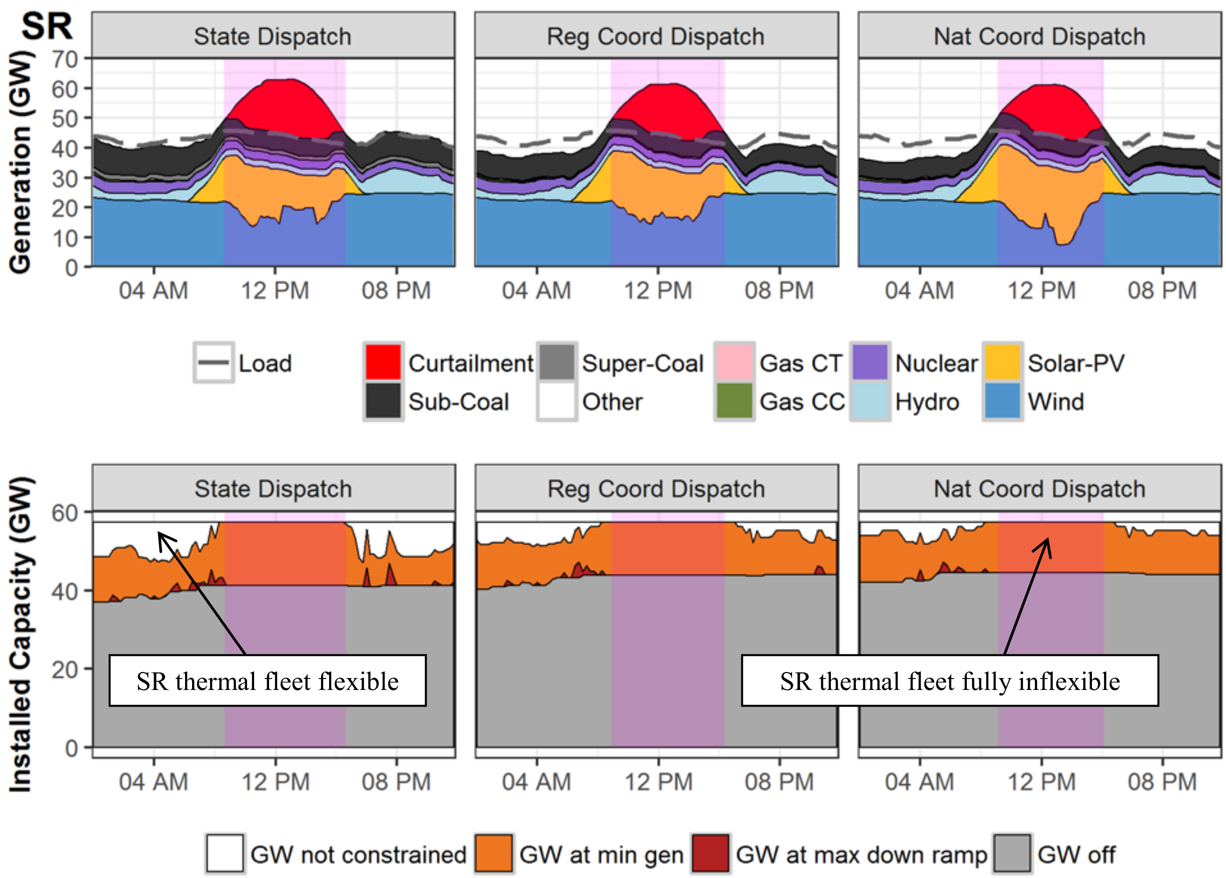


Figure 55. Southern region generator dispatch and thermal fleet constraints on 7 September, the day of maximum instantaneous curtailment in 100S-60W

Note: The pink band marks intervals with RE curtailment anywhere in the country on 7 September in the state dispatch reference case. In the bottom panel, the black line represents total installed capacity, grey shading represents off-line thermal capacity, red represents thermal capacity at its maximum down-ramp rate, and orange represents thermal capacity at its minimum stable level. Any remaining committed capacity (the area in white below the black line) is unconstrained physically, and has flexibility to turn down. If in a particular interval all available thermal capacity in a region is turned off, at minimum stable level, or ramping down at its maximum rate, the region's thermal fleet is fully inflexible. The plants cannot further decrease output to accommodate zero-cost RE generation. Because hydro generation is fixed in the day-ahead simulation and therefore inflexible in real time, such a region's conventional fleet is fully constrained. Any additional wind or solar generation must be either exported or curtailed.

Figure 56 shows the same dispatch and thermal constraints on 7 September for the Western region. On this day, the Western region's thermal fleet is almost always fully backed down whenever it curtails RE (except for a 1.25-hour period in the state dispatch scenario). However, in the hours when the Southern region—but not the Western region—curtails RE, the Western region often has flexible thermal capacity. For example, at 9:45 in the state dispatch scenario, the Western region has 6.5 GW of flexible thermal capacity that can be turned down while the Southern region curtails 7.8 GW of RE. Trade barriers prevent the Western region from backing down and accepting the import. At 9:45 in the nationally coordinated dispatch scenario, the Western region also has 7.5 GW of flexible thermal capacity while the Southern region curtails 2.9 GW. If trade barriers are removed, why does the Western region not coordinate with the Southern region to eliminate the final 2.9 GW of RE curtailment? It cannot, because unlike with state dispatch, the SR-WR interface is congested at 9:45. Without trade barriers, the two regions can coordinate up to the point of congestion.

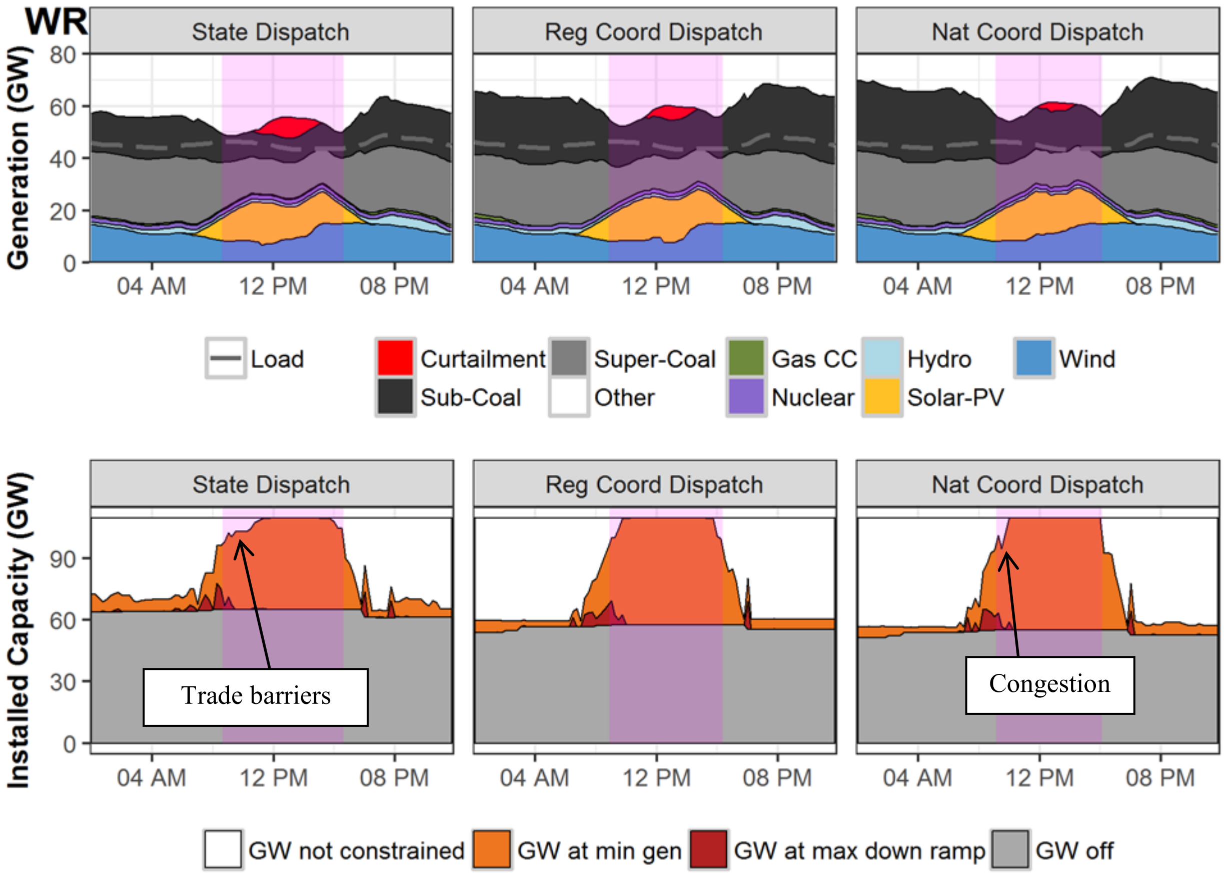


Figure 56. Western region generator dispatch and thermal fleet constraints on 7 September, the day of maximum instantaneous curtailment in 100S-60W

Note: The pink band comprises all time periods with RE curtailment in any region on 7 September in the state dispatch scenario.

Improved dispatch coordination means curtailment is less severe, but more widespread

Figure 57 shows the same dispatch and thermal constraints on 7 September for the Northern region. Surprisingly, better dispatch coordination means the Northern region curtails more RE even though nationwide curtailment is much lower. Without trade barriers, a curtailing region shares thermal fleet constraints with its neighbors. Two perfectly coordinating balancing authorities will, absent congestion, both curtail when their combined thermal fleet is backed down; however, this is a less frequent event.

Seventeen subcritical coal generators in Uttar Pradesh that do not fully back down cause the afternoon plateau of inflexible generation in the bottom left panel of Figure 57, despite RE curtailment in Southern and Western regions during this period. These 17 generators have average variable costs of INR 1515 per MWh, significantly below the INR 2470 per MWh average for subcritical coal. Because of the state dispatch scenario's trade barriers, they are locally competitive with and presumably less costly than RE imports to the Northern region. However, in regionally and nationally coordinated dispatch, their generation is displaced by imports from the south, and the Uttar Pradesh generators become fully backed down, causing the Northern region to be fully inflexible. The result is reduced overall RE curtailment nationwide, despite the emergence of a small amount of RE curtailment in the now fully inflexible Northern region.

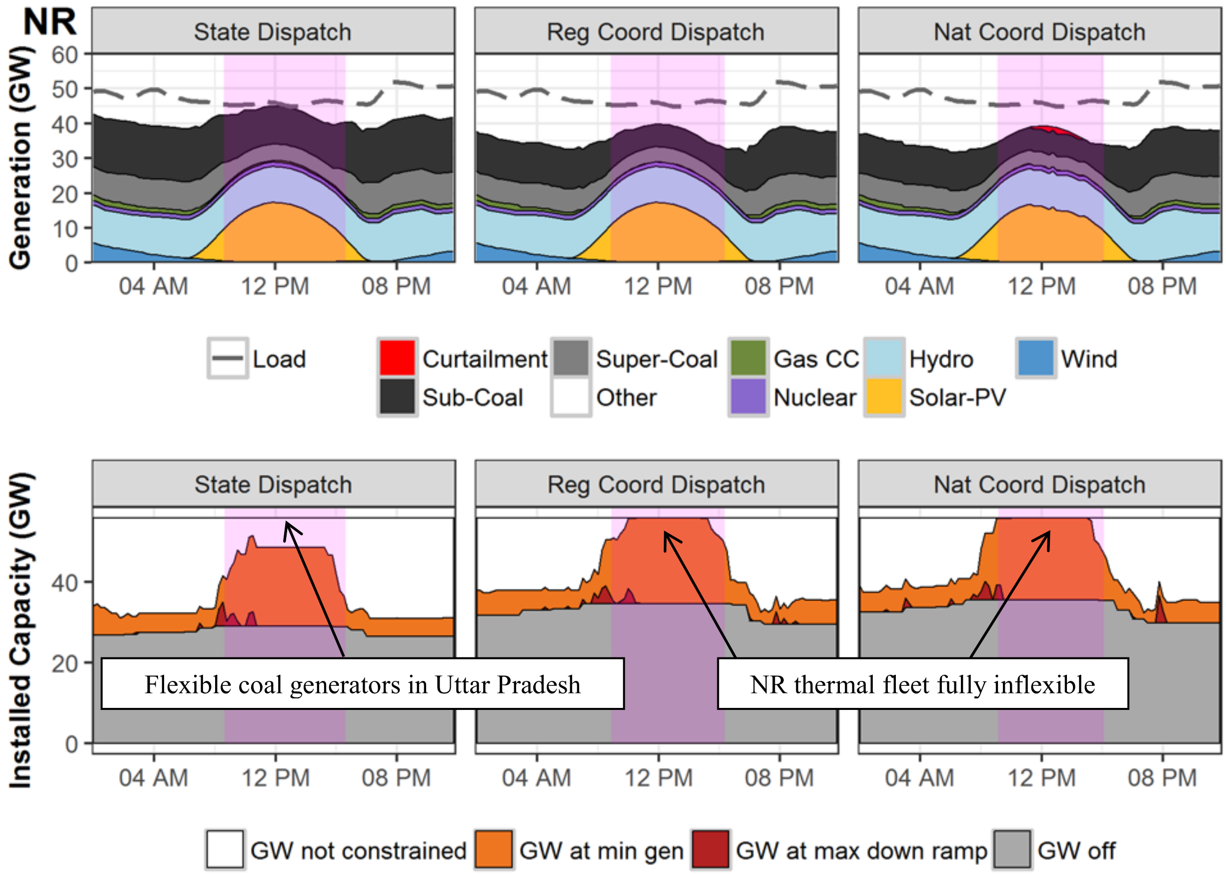


Figure 57. Northern region generator dispatch and thermal fleet constraints on 7 September, the day of maximum instantaneous curtailment in 100S-60W

Table 23 summarizes curtailment by region and scenario on 7 September and illustrates the geographic distribution but overall reduction of RE curtailment with improved dispatch coordination.

Table 23. RE Curtailment on 7 September Across Dispatch Coordination Sensitivities

	STATE DISPATCH (GWh)	REGIONAL DISPATCH (GWh)	NATIONAL DISPATCH (GWh)
SR	99	87	79
WR	22	12	6.0
NR	0.0	0.0	3.7
ER	0.0	2.3	2.4
TOTAL	120	102	91

Transmission congestion prevents perfectly coordinating regions from minimizing overall RE curtailment

Figure 58 shows conditions in the Eastern region during the same period. With nationally coordinated dispatch, we would expect that, absent congestion, any interval with curtailment would be accompanied by a fully backed-down thermal fleet nationwide. However, in the bottom left panel of Figure 58, despite curtailment from 09:15 to 16:00 in the Southern region, the Eastern region's thermal fleet is only backed down from 10:30 to 11:30. This indicates that transmission congestion is not allowing the flexibility in the Eastern region to be accessed across the whole country in the nationally coordinated dispatch scenario.

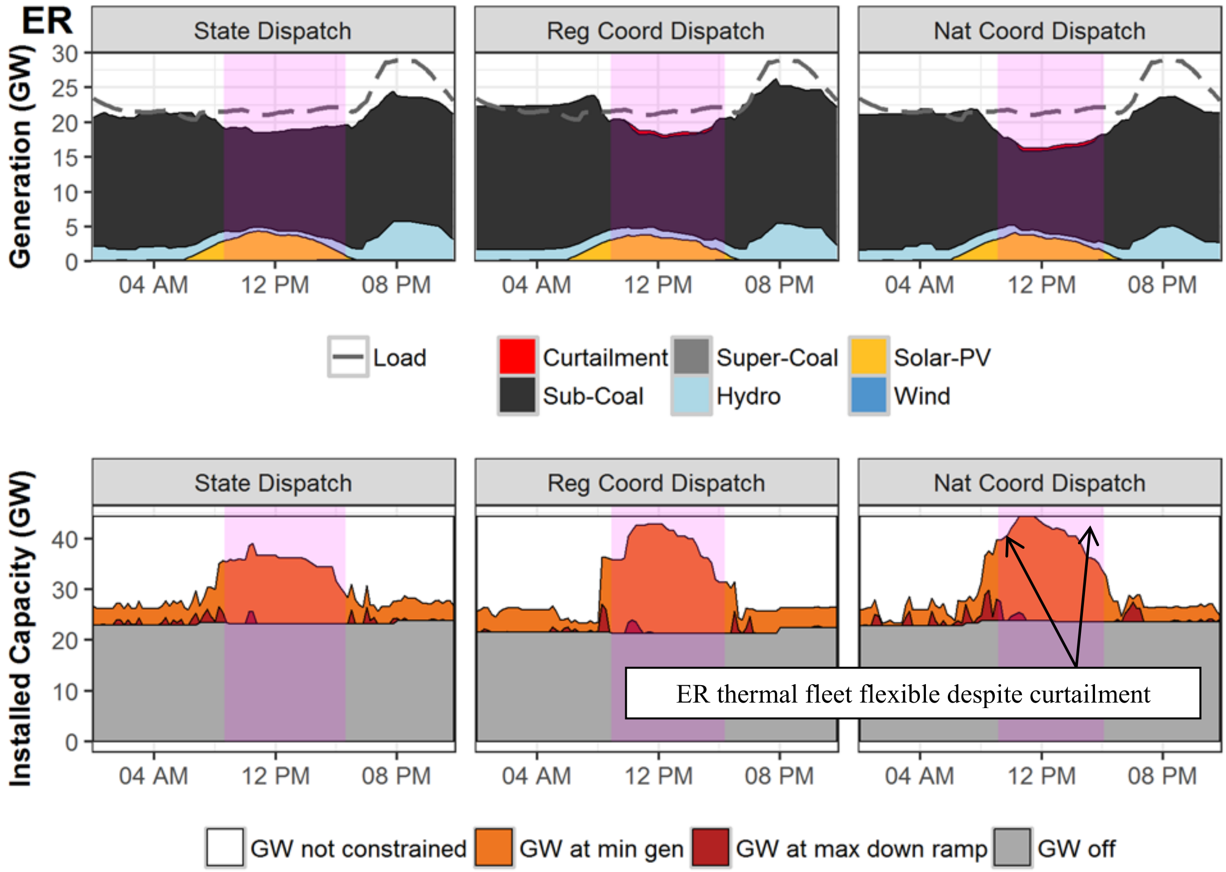


Figure 58. Eastern region generator dispatch and thermal fleet constraints on 7 September, the day of maximum instantaneous curtailment in 100S-60W

With nationally coordinated dispatch, the WR-SR interface is congested in all intervals on 7 September when the Northern or Western region could back down thermal generators and accept imports from the curtailing Southern region. With state dispatch, congestion plays a smaller role in curtailment, as only 22% of the periods when the Northern region could have backed down are impeded by SR-WR interface congestion, and 39% for the Western region. Similarly, on 7 September, with regionally and nationally coordinated dispatch the Odisha-West Bengal interface is always congested. In both cases, the vast majority of flexible thermal capacity in the Eastern region during curtailment hours is in West Bengal or Jharkhand. Because of the congestion, West Bengal is effectively isolated from the rest of the country and must run its thermal fleet rather than accept further imports. The Odisha-West Bengal congestion largely explains the Eastern region's flexible capacity in Figure 58.[54,55]

[54] With nationally coordinated dispatch on 7 September, the WR-ER corridor is congested 61% of the time when the Southern region is curtailing and the Eastern region has thermal plant flexibility. This corridor is never congested during this period with regionally coordinated and state dispatch.

[55] The Odisha-West Bengal interface faces more congestion in the model than is seen in today's operation. This is partially explained by the additional RE in the Southern region but may also be a result of the transmission simplification that causes more energy to be exported from south to east than may be expected in the future given in-state transmission constraints.

Table 24 examines intervals throughout the whole year when energy exchange between a "curtailing" and "flexible" region would reduce curtailment but does not occur. For each pair of trading partners, we calculate the fraction of potential trades that coincide with congestion across a relevant corridor. For example, with nationally coordinated dispatch, 100% of the time that the Western region is curtailing and the Northern region has flexible thermal capacity, the WR-NR interface is congested. With regionally and nationally coordinated dispatch, underused flexibility among the Northern, Western, and Southern regions is almost entirely explained by congestion across their shared interfaces. The lower percentages of congested periods under state dispatch imply that even without congestion, RE curtailment occurs due to trade barriers, among other factors.

Table 24. Relationship Between Extent of Coordination and Congestion During Periods of Potential Trades

Note: Percentage represents the fraction of periods of potential trade (curtailing region that could export to a region with flexible thermal generation) that coincide with congestion across a relevant corridor.

WR TO NR INTERFACE CONGESTION				
CURTAILING REGION	**FLEXIBLE REGION**	**STATE DISPATCH**	**REGIONAL DISPATCH**	**NATIONAL DISPATCH**
WR	NR	0%	100%	100%
SR	NR	4%	22%	69%
SR TO WR INTERFACE CONGESTION				
CURTAILING REGION	**FLEXIBLE REGION**	**STATE DISPATCH**	**REGIONAL DISPATCH**	**NATIONAL DISPATCH**
SR	NR	89%	99%	99%
SR	WR	92%	100%	100%
SR	ER	90%	96%	97%

Summary

This section has explored the value of alternative levels of operational coordination to efficiently integrate RE. Moving from state to regional coordination would result in a 2.8% cost savings for India as a whole, with production cost savings by region shown in Table 25. Moving to a higher level of coordination (national) results in additional savings. Although curtailment even in the state reference case is not significant, curtailment continues to reduce in moving from state to regionally and to nationally coordinated dispatch.

Higher levels of coordination result in an increased use of transmission over larger distances, which can increase congestion. The highest congestion by energy is the WR-NR flow under all three coordination levels. However, the incremental congestion on these interfaces was not significantly different than that of others.

Table 25. Summary of Production Cost Savings and RE Curtailment by Region for Coordinated Scheduling and Dispatch Sensitivities

Note: Production cost savings are compared to state-based dispatch.

	STATE DISPATCH		REGIONALLY COORDINATED DISPATCH			NATIONALLY COORDINATED DISPATCH		
REGION	RE curtailment (GWh)		Production Cost Savings	RE curtailment (GWh)		Production Cost Savings	RE curtailment (GWh)	
NR	12	0.02%	6.6%	16	0.02%	9.9%	19	0.03%
WR	130	0.11%	3.1%	50	0.04%	-2.3%	29	0.02%
SR	5,000	2.9%	4.6%	4,700	2.8%	9.5%	3,200	1.9%
ER	23	0.19%	-7.1%	19	0.16%	-2.5%	43	0.35%
NER	0	0.0%	5.4%	0.2	0.01%	5.1%	0	0.0%
INDIA	**5,100**	**1.4%**	**2.8%**	**4,800**	**1.3%**	**3.5%**	**3,300**	**0.89%**

5.2 Value of Increased Flexibility of Conventional Generators

Conventional generation, especially coal, which dominates the Indian power system, has an instrumental role in contributing to a flexible power system. The ability to cycle and run at low minimum loads allows flexible plants to generate when of most value to the system, such as when RE generation is low. This section analyzes several aspects of coal flexibility—and the value of this flexibility in reducing RE curtailment and production costs:

- **Minimum plant generation levels**. Lower minimum generation levels allow the plants to turn down when the value of their generation to the system is low, such as during the day when solar generation is high, and yet still be available to ramp up for the evening net load peaks.
- **Ramp rates**. Faster ramp rates increase the coal plants' ability to follow changes in net load that result from either high levels of variability or forecast errors.

- **Start-up costs**. Lower start-up costs reflect the ability of coal plants to shut down and start up more frequently because of better economics, whereas higher start-up costs represent reduced flexibility of coal plants.
- **Minimum up/down times**. Shorter up and down times allow coal plants to cycle off/on more frequently, e.g., to be turned off during periods of high RE generation.

We also evaluated whether reducing available coal capacity affects overall fleet and system flexibility by retiring plants operating under 15% PLF in our reference case.

The results of these sensitivities are illustrated in the following figures.

Figure 59 shows impacts of coal flexibility on annual production costs and curtailment. Changing minimum plant generation levels has the largest impact on annual cost savings—INR 2000 crore savings result from reducing 70% to 55%, and INR 640 crore savings result from reducing from 55% to 40% minimum generation level, in operations with state-based dispatch. Likewise, minimum generation level has the largest impact on RE curtailment. Curtailment reduces from 3.5% to 1.4% when minimum generation levels are dropped from 70% to 55%. Further reducing minimum generation levels to 40% reduces curtailment to 0.76%. In contrast, coal ramp rates, start-up costs, and minimum up/down time do not significantly affect RE curtailment or production costs. Doubling start-up costs does increase overall costs by approximately 1.5%, but the higher start-up cost itself, not resulting changes to merit order or RE curtailment, is the primary driver behind the change in production costs. RE curtailment is most affected in the Southern region, where most of the overall curtailment occurs.

COAL FLEXIBILITY

100 GW SOLAR, 60 GW WIND

NORMAL OPERATIONS	LOWER MINIMUM PLANT GENERATION	HIGHER MINIMUM PLANT GENERATION	SLOWER COAL RAMPING	DOUBLE START COSTS	FASTER CYCLING
55% minimum generation, 1% coal ramping, 24 hour up/down time	40% of capacity	70% of capacity	0.5% of capacity per minute	2x₹	12hr Minimum up/down time
230,000 INR Crore Annual Production Cost	Negligible Savings annually	0.9% Increased cost annually	Negligible Increased cost annually	1.5% Increased cost annually	Negligible Increased cost annually
1.4% Renewable Energy Curtailment	0.76% Renewable Energy Curtailment	3.5% Renewable Energy Curtailment	1.4% Renewable Energy Curtailment	1.5% Renewable Energy Curtailment	1.4% Renewable Energy Curtailment

Figure 59. Impact of coal flexibility on annual production costs and curtailment

Figure 60 compares the impacts of coal flexibility scenarios combined with regionally coordinated scheduling and dispatch. Moving from state-level coordination to a regional dispatch simultaneously with a reduction in coal minimum generation constraints (70% to 55%) offers a production cost savings of INR 8300 crore (approximately USD 1.3 billion). This equals the sum of each sensitivity individually—the INR 6300 crore benefit from wider regional coordination and the INR 2000 crore benefit from reducing coal minimum generation.

COAL FLEXIBILITY WITH REGIONALLY COORDINATED DISPATCH

100 GW SOLAR, 60 GW WIND

NORMAL OPERATIONS	LOWER MINIMUM PLANT GENERATION	HIGHER MINIMUM PLANT GENERATION	SLOWER COAL RAMPING	DOUBLE START COSTS	FASTER CYCLING
State-level dispatch, 55% minimum generation, 1% coal ramping, 24 hour up/down time	40% of capacity	70% of capacity	0.5% of capacity per minute	2x₹	12hr Minimum up/down time
230,000 INR Crore Annual Production Cost	3.3% Savings annually	1.7% Savings annually	2.8% Savings annually	1.4% Savings annually	2.8% Savings annually
1.4% Renewable Energy Curtailment	0.73% Renewable Energy Curtailment	3.1% Renewable Energy Curtailment	1.3% Renewable Energy Curtailment	1.4% Renewable Energy Curtailment	1.3% Renewable Energy Curtailment

Figure 60. Impact of combined coal flexibility and regionally coordinated dispatch on annual production costs and curtailment

If Ability to Meet Flexibility Standards Is Limited to Central Plants

The 100S-60W scenario is based on expectations of coal plant flexibility in place in 2022 for state- as well as centrally controlled plants, per newly established CERC regulatory guidelines. This, at least in most cases, presumes more flexibility in the coal fleet than exists today. To test a case in which only central plants are able to meet these guidelines, we ran a sensitivity in which state-controlled plants (including state IPPs), which comprise 74% of India's coal capacity, remain less flexible in 2022.

To establish the effects of little to no improvements to flexibility, we assumed that the minimum up time (i.e., the minimum time a plant is required to stay on once committed) of state coal plants is 96 hours instead of 24, and that the minimum down time (the length of time a unit must remain off after decommitting) is 48 hours instead of 24. We also assumed that only central plants are able to achieve a minimum operating point of 55%, while the minimum generation level of state-controlled plants is 70%. The result of these changes to state coal flexibility is that RE curtailment increases significantly, from 1.4% to 2.4%, and production costs increase 0.7%.

Figure 61 shows when and where the additional curtailment takes place. The Eastern region experiences a relatively large increase in curtailment, indicating that flexible thermal generation may be especially important to this region even though there is comparatively little RE there. The Southern region also shows a significant increase in curtailment during the nonmonsoon periods, which indicates increased flexibility of even a portion of thermal plants will always be useful to the system, not just during periods when low-production-cost generation (hydro, RE) is high.

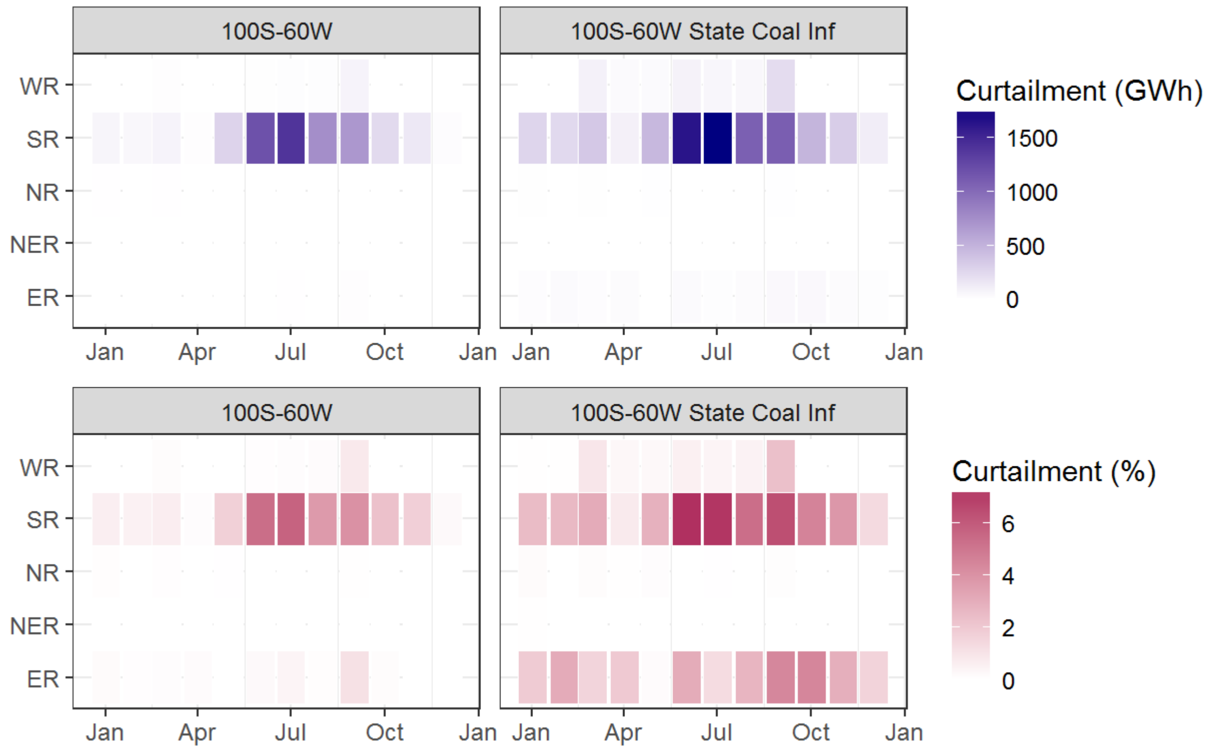


Figure 61. RE curtailment in energy (GWh, upper charts) and as a percentage reduction against available (lower), by region and month, 100S-60W and 100S-60W State Coal Inflexible

Retiring 46 GW of Coal Does Not Adversely Affect System Flexibility or Reliability

Retiring coal plants that operate at a PLF of less than 15% annually in the 100S-60W case has almost no effect on system operations. These plants, totaling 46 GW (20% of installed coal capacity), account for only 1.0% of coal generation, and in their absence, the generation from the remaining 547 generators in the coal fleet increases from 1,007 TWh to 1,015 TWh, just shy of the 1,017 TWh of total coal generation when the low PLF plants are operated. While the Western region's absolute retirements are the largest at 14 GW, the Eastern region retires the largest fraction of its installed capacity, 27%, followed closely by the Northern region at 25%. Paradoxically, coal plants in the higher-RE states in the south and west still remain more competitive than their northern and eastern counterparts.

With these plants retired, the coal fleet's average PLF increases to 62%, up from 50% in the reference case, as shown in Table 26.

Table 26. Percentage of Coal Fleet Capacity at Different Ranges of Plant Load Factors

	PERCENTAGE OF TOTAL COAL FLEET CAPACITY WITH PLFS UNDER/OVER:		
Scenario	under 0.2	over 0.8	over 0.5
100S-60W Reference Case	24%	9.4%	59%
Coal Retirements	1.0%	12%	74%

Figure 62 shows the change in distribution of PLFs after the retirements. Note that while the fleetwide average PLF increases with the retirement of low-PLF plants, individual PLFs of the remaining plants remain similar to their preretirement numbers.

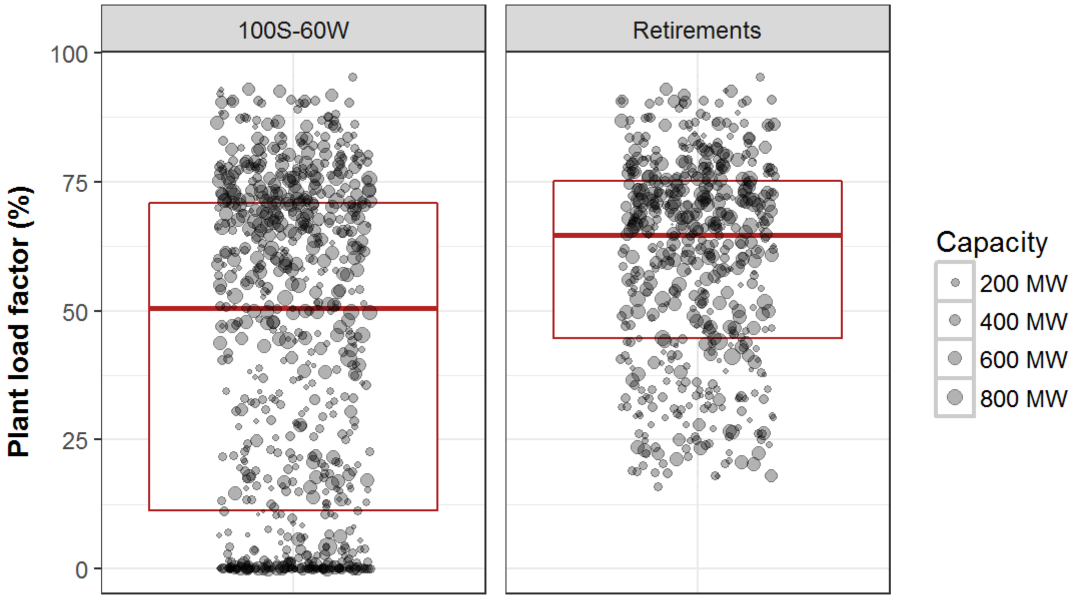


Figure 62. Change in coal plant load factors after 46 GW of coal plants are retired

Other impacts of coal retirement include: CO_2 emissions fall by 0.20%, RE curtailment remains at 1.4%, and interregional energy exchanges rise by 1.8%, driven in large part by an 11% boost to Eastern region exports and a 6% boost to Southern and Western region imports. Production costs change little between the two scenarios.

Based on new emission norms from the Ministry of Environment and Forests related to SO_x and other pollutants, potentially up to 72 GW of coal plants may lack space for required flue gas desulphurization equipment. Thus, further analysis could investigate the impact of retiring these plants in particular on system flexibility.

Summary

Increasing the flexibility of coal plants can help improve the ability of the system to efficiently integrate RE. Relaxing the constraint on coal plant minimum generation levels has a greater impact on reducing curtailment compared to increasing coal ramp capability and other aspects of coal flexibility. These improvements to minimum generation levels reduce operating cost whether operational coordination is at the state or the regional level. Retiring the least efficient 20% of coal capacity does not affect operational flexibility.

5.3 Value of Increased Interregional Transmission Capacity

India's wind and solar resources are concentrated in the west and south, and maximizing the use of these lower-cost resources to achieve national RE targets requires sufficient transmission capacity to meet load across a broader area. In addition to transmitting RE generation, improved connections between regions are fundamental to enabling regionally and nationally coordinated scheduling and dispatch. Coordinated system operations has the effect of smoothing RE and load variability, accessing more efficient merit order, and increasing system flexibility.

To explore the significance of interregional transmission capacity to RE integration, we evaluated two sensitivities: +/- 25% interregional transmission corridor capacity compared to known transmission projects planned for 2022. These sensitivities were applied to the state dispatch and regionally coordinated dispatch scenarios. We also applied the + 25% sensitivity to the nationally coordinated dispatch scenario.

Reducing the 2022 interface capacity by up to 25% (we do not decrease capacity below what is currently available) can indicate the sensitivity of RE curtailment and production costs to delays in interregional transmission expansion. Increasing the transmission corridors allows us to compare the effect of transmission expansion to alternative sources of flexibility, such as from coal plants.

The results of these sensitivities are illustrated in Figure 63. The figure illustrates the impacts of changes to interregional transmission capacity on production costs and curtailment for state, regionally coordinated, and nationally coordinated dispatch. The changes in both directions are small compared to the earlier sensitivities—extent of coordination and coal flexibility. In a system with state dispatch, lower transmission capacity raises annual production costs by 0.9%, while higher capacity reduces costs by 0.5%.

INTERREGIONAL TRANSMISSION

100 GW SOLAR, 60 GW WIND

NORMAL OPERATIONS (Current CEA Plans)	WITH STATE-LEVEL DISPATCH		WITH REGIONALLY COORDINATED DISPATCH		WITH NATIONALLY COORDINATED DISPATCH
	LOWER TRANSMISSION (25% less capacity)	HIGHER TRANSMISSION (25% more capacity)	LOWER TRANSMISSION (25% less capacity)	HIGHER TRANSMISSION (25% more capacity)	HIGHER TRANSMISSION (25% more capacity)
230,000 INR Crore Annual Production Cost	**0.9%** Increased cost	**0.5%** Savings annually	**2.0%** Savings annually	**3.2%** Savings annually	**3.9%** Savings annually
1.4% Renewable Energy Curtailment	**1.6%** Renewable Energy Curtailment	**1.2%** Renewable Energy Curtailment	**1.5%** Renewable Energy Curtailment	**1.1%** Renewable Energy Curtailment	**0.74%** Renewable Energy Curtailment

Figure 63. Impact of interregional transmission capacity on annual production costs and curtailment

With increasing available interregional transmission capacity (-25%, reference case, +25%), curtailment decreases from 1.6% to 1.4% to 1.2% for state dispatch and 1.5%, to 1.3%, to 1.1% for regionally coordinated dispatch, respectively. RE curtailment falls to 0.74% in the scenario with nationally coordinated dispatch and 25% additional transmission capacity, which is slightly lower than the impact of reducing coal minimum generation to 40%. Interestingly, the incremental benefit of reduced curtailment in different transmission build-out scenarios does not appear to depend on whether dispatch is coordinated at a state or regional level, as discussed in Section 5.1. However, as also anticipated in Section 5.1, the scenario with no trade barriers—nationally coordinated dispatch—does show benefits to curtailment from the 25% extra transmission.

Figure 64 compares the annual flows on interregional corridors for the -25%, reference case, and +25% transmission scenarios with state dispatch. Increased transmission capacity enables increased energy flows across many but not all interregional corridors. The ER-WR corridor experiences a small drop in flows with higher interface limits. Increased transmission capacity also lowers congestion, except on the ER-NR interface, where transmission flows increase significantly and congestion increases.

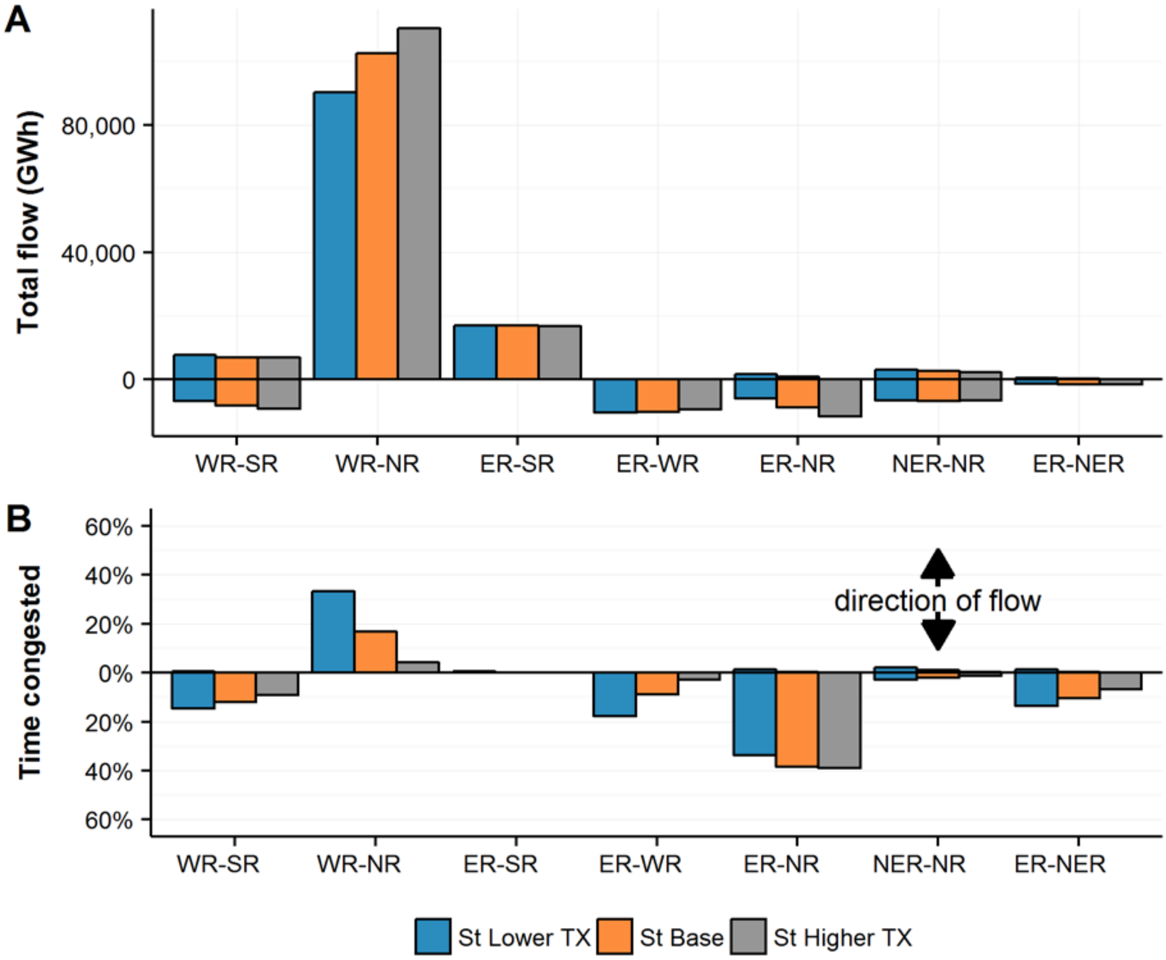


Figure 64. Impact of interregional transmission capacity on interregional transmission flows (A) and interface congestion (B) for state dispatch.

Note: Horizontal axis names refer to the direction of flow and congestion (e.g., WR-SR means that above zero on the y-axis is the total flow or time congested in the Western to Southern region direction. Below zero on the y-axis means Southern to Western direction is congested.)

Copper Plate Sensitivity

To understand how the power system would balance with no transmission constraints, as well as no barriers to scheduling, we also ran an idealized "copper plate" sensitivity. The copper plate is similar to the national coordination sensitivity, but with infinite interregional corridor capacities. Such a scenario reduces production costs by 4.7%. In comparison, scheduling and dispatch optimized at the regional level delivers over half this savings. Scheduling and dispatch optimized at the national level plus higher interregional transmission capacity (+25%) allows the system to realize 84% of the production cost savings possible with the copper plate sensitivity. Curtailment drops to 0.13% in copper plate, although any emissions reductions from more RE generation are negated by the increase in emissions from subcritical coal relative to gas and supercritical coal. Table 27 summarizes changes in annual generation compared to the state dispatch reference case.

Table 27. Changes in Annual Generation, by Fuel, Between State Dispatch and Copper Plate

FUEL	STATE DISPATCH (TWh)	COPPER PLATE (TWh)	% DIFFERENCE
Gas	32	26	-17%
Subcritical coal	690	700	1.9%
Supercritical coal	330	320	-3.8%
Other	3	4	13%
Solar	180	180	1.5%
Wind	190	190	1.0%

Figure 65 shows the net exports, in time series and duration curve, across the regional interfaces in the copper plate sensitivity. The flows in the copper plate sensitivity are still subject to DC power flow constraint and therefore capture the flow directions and magnitudes that would be likely if transmission caused no constraints. The maximum flows between regions are summarized in Table 28. Note positive flows indicate direction of the name (i.e., WR to SR is positive if flowing from WR to SR), and negative flows the opposite direction. Y-axis is different for each plot.

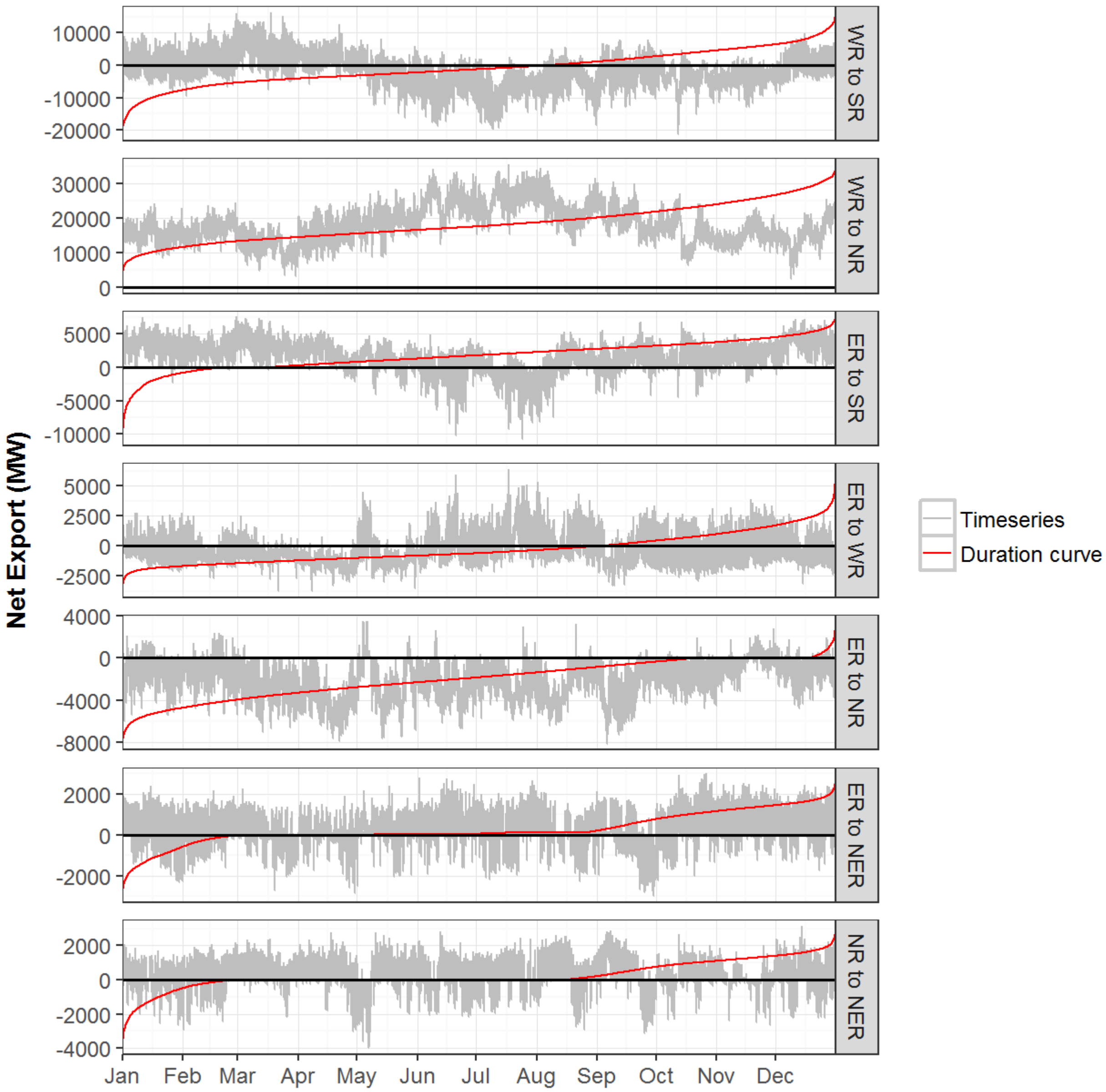


Figure 65. Net export time series and duration curves across regional interconnections in the copper plate sensitivity

Note: Positive flows indicate direction of the name (i.e., WR to SR is positive if flowing from WR to SR), and negative flows the opposite direction. Y-axis is different for each plot.

Table 28. Peak Instantaneous Power Exchange Across Regional Interconnections in the Copper Plate Sensitivity

INTERCONNECTION	PEAK INSTANTANEOUS POWER EXCHANGE (MW)
ER to NER	3,000
ER to NR	3,500
ER to SR	7,500
ER to WR	6,400
NER to ER	3,000
NER to NR	4,000
NR to ER	8,100
NR to NER	3,200
NR to WR	-2,300
SR to ER	11,000
SR to WR	22,000
WR to ER	3,800
WR to NR	36,000
WR to SR	16,000

Summary

In the reference case with state dispatch, increasing interregional transmission capacity has a modest effect on production costs and RE curtailment. Production costs decrease 0.5% annually, and curtailment reduces to 1.2%, compared to the reference case. When combined with nationally coordinated dispatch, in which trade barriers are removed and flows on interregional lines increase, the value of additional transmission does reduce curtailment, to 0.74%. A copper plate sensitivity yields annual production cost savings of 4.7%, with curtailment decreasing to 0.13%.

5.4 Value of Storage to Reduce Curtailment and Offset Peak Conventional Capacity

Analysis thus far has been primarily focused on operations, although results from production cost models can also be used to gain insight into capacity needs, both generation and transmission, of a power system. This section looks specifically at whether storage helps in mitigating challenges associated with RE integration, and also whether storage is an effective alternative to coal capacity at the 15-minute and higher time frames.[56]

With the addition of 100 GW of solar and 60 GW of wind, peak coal generation falls by only 12 GW compared to No New RE. Figure 66 illustrates an annual duration curve for coal generation in which

[56] This analysis is not a replacement for a comprehensive capacity planning study, although results could be used as a precursor to such an exercise in identifying promising pathways.

the x-axis represents the percent of time the coal plants are at or above the associated generating capacity. This figure indicates that some coal capacity is needed only a few hours of the year, after which the change in coal generation between No New RE and 100S-60W widens. The times of greatest coal use occur shortly after sundown during months in which wind generation is seasonally low. Figure 67 highlights the hours of the year that experience the top 1% of coal generation in both the No New RE and 100S-60W scenarios. Coal generation is generally highest in No New RE in April and December and peaks on 8 December. In 100S-60W, peak coal generation shifts to November when RE penetration is lowest.

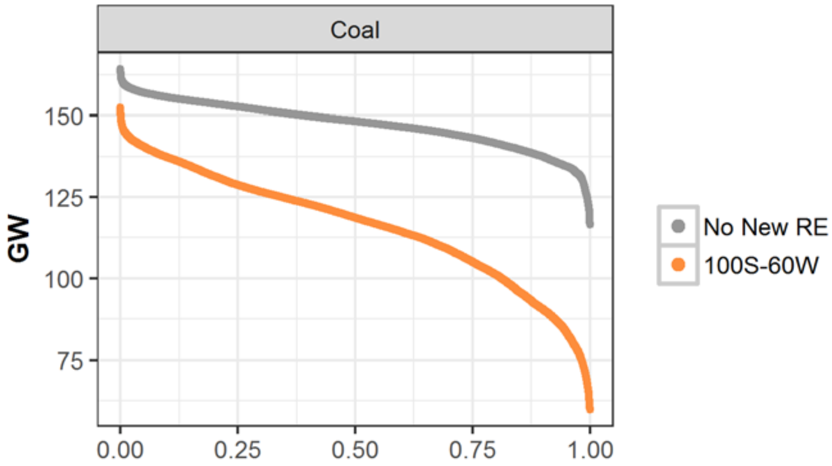


Figure 66. Duration curve for coal generation, No New RE and 100S-60W

Note: The x-axis is the fraction of the year at or below a corresponding y-axis generation level.

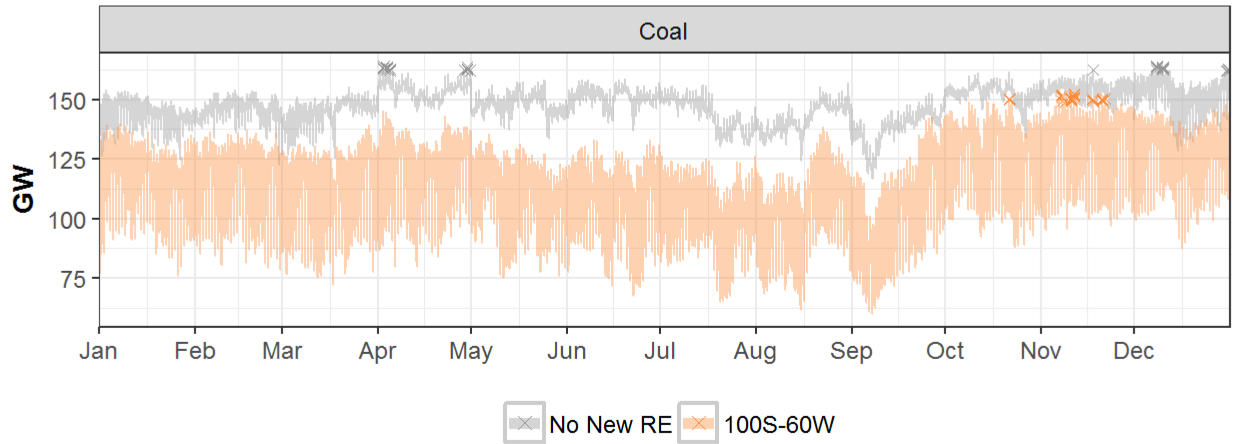


Figure 67. Annual coal generation with top 1% of generation in each scenario highlighted, 100S-60W and 60S-100W

Note: Y-axis does not start at 0.

There are several potential means to offset peak coal generation and thereby reduce the amount of coal capacity needed to meet reliability needs. Options include storage (shift timing of energy supply), demand response (shift timing of energy demand), and electricity imports from neighboring countries.

Because many types of storage have high capital costs, measuring the operational value that storage provides helps assess the investment's value relative to alternatives. The operational value can be measured from a system perspective (avoided fuel and start-up costs for both energy and ancillary

Integration Strategies

services, avoided transmission and distribution upgrades, capacity value, value of other grid services such as voltage support) and from an investor perspective (market revenue from provision of capacity, energy, and ancillary services). Studies have found strong correlations between the value of storage and RE penetration. A recent study of the western United States showed that storage's value (including both energy and ancillary services) rose from $59/kilowatt-year at 33% RE penetration levels to $109/kilowatt-year at 40% RE penetrations, chiefly because of the value of storage in providing operating reserves (Eichman et al. 2015). Avoided start-up costs comprised a significant portion of storage's value (29% to 67%, depending on the scenario).

To test the impacts of storage on peak conventional generation and assess the associated energy value of storage (avoided fuel and start-up costs), we added batteries in each of the RE-rich states (Gujarat, Rajasthan, Maharashtra, Tamil Nadu, Karnataka, and Andhra Pradesh). Each battery has a maximum power output equal to 2% of its state's peak load rounded to the nearest 100 MW, for a total of 2.5 GW across the six states, approximately doubling the operational storage capacity in the country.

Batteries in our model are 75% efficient, which means that a battery must charge for four hours in order to discharge at the same energy level for three. The resulting 25% difference between a battery's load and generation is lost. Batteries are assumed to ramp instantaneously and be able to generate at maximum capacity for eight hours from full charge (which equates to 20 GWh of total storage capacity). The model optimizes battery operations in the day-ahead simulation and fixes battery dispatch patterns in real time. Battery operators able to react to changing system conditions inside a 24-hour time frame would be more flexible and provide potentially greater benefits than our model suggests.

Impacts of Battery Storage on Peak Coal Are Negligible

Battery capacity does not displace the need for a corresponding amount of coal capacity. Battery sensitivities were run on both the 100S-60W and 60S-100W scenarios (the higher wind scenario is described more fully in Section 6). Results show a small reduction in peak coal generation in both scenarios. The impacts of this storage on peak coal are summarized in Table 29.

Table 29. Impact of 2.5 GW New Battery Storage on Peak Coal Generation

	PEAK COAL GENERATION (GW)	DIFFERENCE WITH BATTERIES (GW)	PEAK GAS GENERATION (GW)	DIFFERENCE WITH BATTERIES (GW)
100S-60W	152.4		11.0	
100S-60W WITH BATTERIES	151.4	-1.0 (0.66%)	10.5	-0.47 (4.5%)
60S-100W	146.5		10.4	
60S-100W WITH BATTERIES	145.9	-0.63 (0.43%)	9.7	-0.70 (6.7%)

Peak coal periods between the scenarios with and without batteries are shifted to different times of the year. Regardless, batteries are operating at their full capacity of 2.5 GW during the peak coal period in the 100S-60W scenario. This is not the case for the peak coal period in 60S-100W, when the batteries are just starting to ramp up for the evening peak and are only generating at 12% of capacity. Part of the reason for a lessened impact to peak coal is that displacement of generation does not directly apply to coal but also displaces even more expensive generation such as gas and other small fossil-based plants.[57]

For the remainder of the section, we will examine batteries' effect on curtailment, cost savings, and emissions reduction. In each area, we conclude that improvements due to batteries at the national level are small for the 160 GW RE scenarios because of relatively low levels of curtailment seen in the system without storage, as well as relatively small daily variability in marginal cost generation, which is usually coal.

Batteries Reduce Curtailment of RE, Although the Proportional Reductions to Emissions and Cost Are Negligible

Batteries do reduce curtailment (from 1.4% to 1.3%). However, the benefits of reduced curtailment—e.g., reduced emissions, use of lower-cost generation—are offset by the batteries' energy losses. For example, batteries in 100S-60W scenario reduce curtailment by 1.2 TWh. However because of their 75% efficiency, they lose 2.0 TWh during operation. The result is similar in the 60S-100W scenario, where 1.7 TWh in losses offsets a 0.66 TWh reduction in curtailment.

The losses in excess of reduced curtailment occur because batteries charge on sources besides RE generation. For example, during periods of high RE output, coal units are also generating. Figure 68 corresponds to the 100S-60W scenario and compares average battery generation and loading in each hour of the day to the change in generation caused by batteries. In the early afternoon of the non-monsoon season, coal generation is, relative to the reference case, up on average roughly 2 GW at the same time that charging batteries increase load by 2.5 GW. The effects to gas are negligible. The implication is that batteries charge not only on solar generation but also coal during the day. After sunset, batteries discharge to displace peak coal generation, in effect using inexpensive coal during low net load periods to offset expensive coal during high net load periods.

[57] This result is reflective of the least-cost optimization and therefore does not reflect a battery that could potentially be optimized to reduce power plant capacity needs.

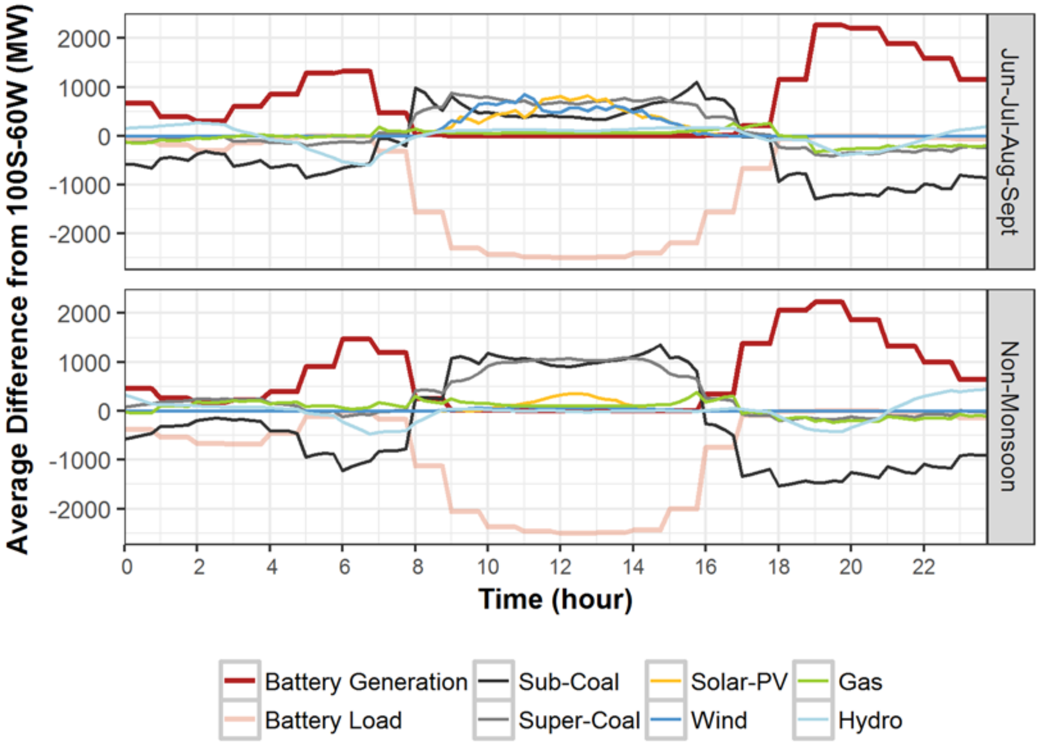


Figure 68. Average hourly battery operations and resulting difference in coal generation, 100S-60W

In both scenarios, because batteries charge partly on coal during the day to offset it at night, they do not reduce annual coal generation or carbon emissions. Charging on coal just to offset it later can produce increased emissions because of the 75% efficiency of the battery, which cancel out the emissions savings from greater RE generation (i.e., from reduced curtailment).[58] Total cost of generation does not reduce significantly with the addition of batteries. Figure 69, the 60S-100W equivalent of Figure 68, shows that gas generation remains roughly unchanged throughout the day despite batteries. Hydro generation shifts to later in the evening to displace coal and charge batteries. The time of day during which coal generates shifts, but not the overall amount as described above. The system reduces production costs in peak periods, when battery generation replaces more expensive sources. However, these savings are negated by the extra generation due to the batteries' losses.

[58] This assumes the same heat rate for charging a battery as the displaced generation (i.e., 4 GWh to charge a battery results in 3 GWh of energy available for discharge later because of 75% efficiency, increasing emissions by 33%).

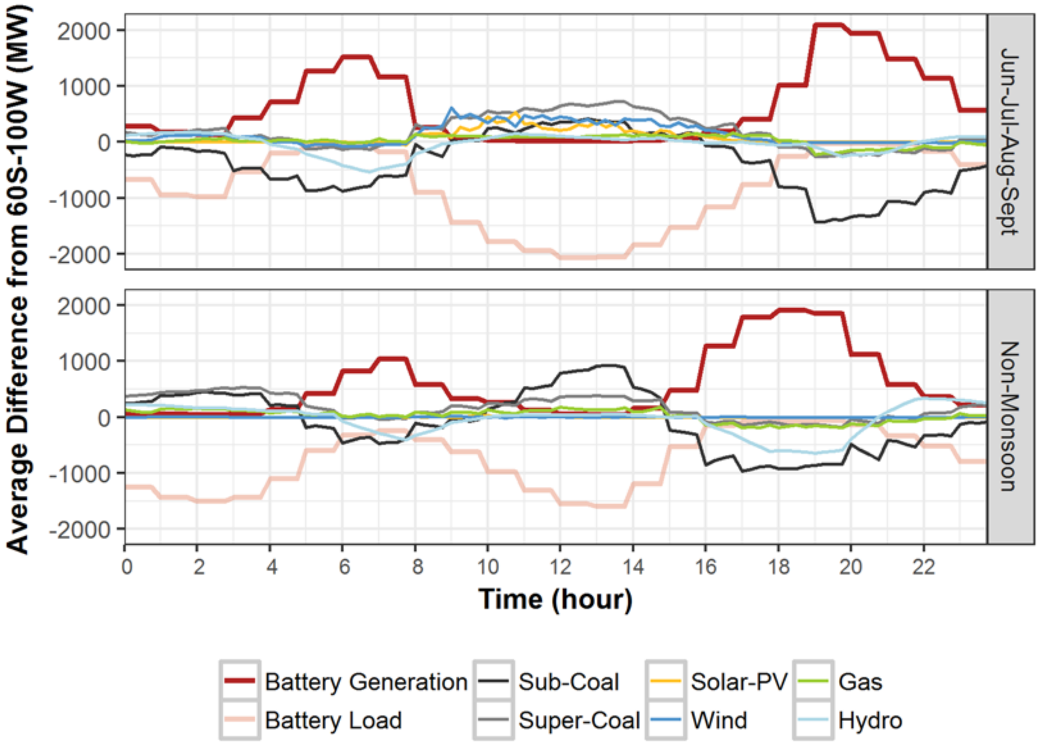


Figure 69. Average hourly battery operations and resulting difference in coal, hydro, and gas generation, 60S-100W

Batteries generate 5.9 TWh in the 100S-60W scenario compared to 5.2 TWh in the 60S-100W scenario. The discrepancy is explained in part because the additional solar generation in 100S-60W allows batteries to charge 72% more during the day than their 60S-100W counterparts and, as a result, generate longer into the night. This increased charging in the high solar scenario is influenced by the daily pattern of solar and the accompanying pattern in price, which increases opportunities for arbitrage within a day.[59]

At 2.5 GW and 75% efficiency, and with the 160-GW RE systems as modeled, batteries provide negligible operational benefits from a 15-minute scheduling and dispatch perspective. Figure 74 shows the difference in annual production costs and curtailment with the addition of 2.5 GW of battery storage. Perhaps with higher efficiencies, or in a system less dominated by coal generators with similar variable costs, batteries may perform more effectively.[60] It is also possible that batteries could show greater localized benefits. However, we did not look at any of these alternate scenarios.

[59] Batteries will only operate if it decreases the total system cost, not on price signals. However, prices in PLEXOS reflect marginal cost of generation and therefore provide a proxy for evaluating when and why a battery would charge or generate. For a battery to operate, the system must be able to offset the 25% losses that accompany battery operation within the 48-hour window that is visible when commitment and dispatch of the battery is decided. Therefore, higher daily price differentials would lead to more opportunities for batteries' cost savings to offset operational losses.

[60] This analysis is not comprehensive of the value that batteries might contribute to the Indian power system. As noted above, studies of other power systems have shown that batteries can be effective at providing reserves or other ancillary services, or may have localized grid benefits, although this evaluation is outside the scope of this study.

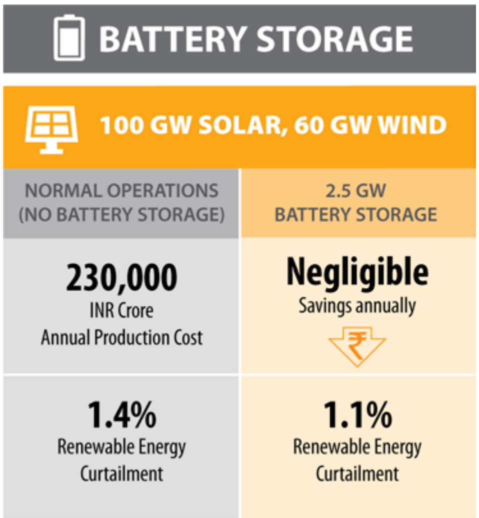


Figure 70. Impact of battery storage on annual production costs and curtailment in the 100S-60W scenario

5.5 Impact of Hydro Availability on RE Integration

The availability of hydro energy in all the scenarios and sensitivities presented thus far is based on 2014 historical operations, as described in Section 2.2.2, consistent with our choice of weather year. However, hydro generation can vary from year to year depending on weather. This variation is seen not just because of weather during the monsoon months, but also because of weather in the prior seasons that may affect flows, especially from reservoir-based hydro plants.

Because hydro can be a source of both flexibility (e.g., dispatchable during net peak load) and inflexibility (e.g., high minimum generation requirements during monsoon months), we evaluated the impact of low and high availability of hydro generation on RE integration.

Table 30 outlines the two scenarios that enable us to evaluate how RE integration can be helped or hindered by a change in the availability of hydro generation within our study year. The low- and high-hydro profiles were developed based on SCADA outputs of hydro in years surrounding 2014, which is considered an average year. As described in the table, low- and high-hydro years—dominated by the midyear monsoon—more dramatically alter the second half of the year. The scaling factors outlined in Table 30 apply to all types of hydro generation profiles and also all constraints, where applicable, which includes both monthly and daily energy and daily minimum generation requirements.

Table 30. Hydro Scenarios, Parameters, and Purpose

SCENARIOS	HYDRO ENERGY AVAILABILITY CHANGE FROM 2014 WEATHER YEAR		KEY QUESTION
HIGH HYDRO	January – June	+7%	How does the availability of more zero-variable-cost hydro energy and higher hydro minimum generation levels affect system flexibility?
	July – December	+15%	
LOW HYDRO	January – June	–7%	How does a low-hydro year affect system flexibility and operations of conventional plants?
	July – December	–15%	

Section 4.4 demonstrated the value of hydro's flexibility to RE integration. With high RE generation, especially solar, hydro generation shifts to two-peak daily profiles to follow the times of highest value. This section presents a sensitivity on the 100S-60W scenario using the low- and high-hydro weather years. Additionally, we analyzed a low-hydro year in combination with the 20S-50W scenario to capture the impact on reliability in a year with both low hydro and low RE.

Availability of Hydro Neither Helps Nor Hinders RE Integration

Table 31 summarizes the results of the 100S-60W scenarios with low and high hydro. High hydro generation displaces fossil based plants (mostly coal), leading to lower costs and emissions. Low hydro generation has the opposite effect, with a higher impact to costs, indicating the use of more expensive generation relative to what was displaced in the high-hydro year. However, RE curtailment has a negligible change across all sensitivites, indicating that these weather years do not significantly help or hinder RE integration. The reason for this null result is that hydro generation, even when changed significantly, stills only accounts for a small change to the total generation mix. The increase in coal shows that there is likely some flexibility within the thermal fleet during the majority of periods of the year, albeit more expensive.

Table 31. Results from Low- and High-Hydro Scenarios as Compared with Reference Case

NORMAL OPERATIONS (100S-60W)	HIGH HYDRO	LOW HYDRO
HYDRO GENERATION AS % OF TOTAL GENERATION (10.9%)	+0.9%	-0.9%
PRODUCTION COST (230,000 CRORE)	- 1.9%	+ 2.3%
COAL GENERATION (1,000 TWh)	- 1.7%	+ 1.7%
CO_2 EMISSIONS (1,100 MMT)	- 1.6%	+ 1.7%
RE CURTAILMENT (1.4%)	1.4%	1.4%

Similar conclusions can be made about the more capacity-constrained case of 20S-60W in a low-hydro year. RE curtailment remains at 0% in the case with low hydro, and the system is able to operate reliably. The largest annual impacts of low hydro availability in this scenario are to coal and gas generation, which increase by 1.5% and 1.9%, respectively, compared to generation in the 20S-50W scenario. In the 100S-60W scenario, coal generation increases 1.7% when hydro availability drops from normal to low.

5.6 Implications for Policy

Coordinating scheduling and dispatch over broader areas (regionally or nationally) facilitates more efficient operation of thermal plants, even in the absence of new RE capacity. In the 100S-60W scenario, production costs reduce by INR 6300 crore (2.8%) in shifting from state to regionally coordinated dispatch, and by a total of INR 7800 crore (3.5%) with nationally coordinated dispatch. This coordination also reduces curtailment, but by a somewhat smaller percentage compared to the impacts on production costs. RE curtailment across the sensitivities—state, regionally coordinated dispatch, and nationally coordinated dispatch—are 1.4%, 1.3%, and 0.9%, respectively.

Improving coal flexibility also reduces production costs and RE curtailment, although only one aspect of coal flexibility has a significant impact—minimizing plant generation levels. In contrast, other metrics of coal flexibility like start costs, minimum up and down times, and ramp rates are much less significant to effective system operations. In operations with state dispatch, lowering plant output minimum levels from 70% to 55% saves INR 2000 crore and reduces curtailment from 3.5% to 1.4%. Further reducing these levels to 40% saves an additional INR 640 crore and cuts curtailment in half, to 0.76%. Keeping 70% minimum generation levels but coordinating regionally still provides savings—INR 3800. This underscores that the value of each strategy to integrate RE—e.g., coordinated scheduling and dispatch, coal flexibility—is dependent upon the underlying assumptions. When sensitivities in the same direction of flexibility are combined—e.g., coordination with coal flexibility—the impacts become more pronounced. The production costs in a system with state dispatch and 70% minimum coal generation levels exceed costs of a more flexibly operated system (regional coordination and 55% minimum generation levels) by more than INR 8000 crore. Retiring 46 GW of the least efficient coal plants does not affect operational flexibility or production costs.

Changes to interregional transmission capacity has a more limited effect on production costs—less than 1% whether that capacity is decreased or increased 25%. However, when combined with nationally coordinated dispatch, the added interregional transmission capacity reduces RE curtailment to 0.74%, commensurate with the effects of reducing coal minimum generation levels to 40%.

The addition of battery storage does not affect the overall generation mix or production costs. The savings from reduced RE curtailment (1.2 TWh) are offset by the losses due to battery inefficiencies (2.0 TWh).

Low and high weather years do not affect RE curtailment, including in a capacity-constrained system (low hydro combined with a low-RE scenario).

Table 32 summarizes the changes in production costs based on the RE integration strategies.

Table 32. Summary of Savings in Production Costs from RE Integration Strategies

SENSITIVITIES TO TEST RE INTEGRATION STRATEGIES	PERCENTAGE DIFFERENCE IN PRODUCTION COSTS COMPARED TO REFERENCE CASE ASSUMPTIONS (1% RAMPING, 55% MIN GEN, STATE DISPATCH)	PERCENTAGE OF RE CURTAILMENT (1.4% IN REFERENCE CASE)
Improved scheduling coordination (regional/national)	Regional coordination: 2.8% **savings** National coordination: 3.5% **savings**	1.3% 0.9%
Coal min gen (40%/70%)	40% min gen: negligible 70% min gen: 0.9% **increased cost**	0.76% 3.5%
Slower coal ramping (0.5%)	Negligible	1.4%
Shorter down/up times	Negligible	1.4%
Central plants flexible (55%) but state plants inflexible (70% and longer min up/down times)	0.7% **increased cost**	2.4%
46 GW of coal retirements	Negligible	1.4%
Coal min gen 40% with regionally coordinated dispatch	3.3% **savings**	0.73%
Interregional transmission interface capacity with state dispatch	25% more capacity: negligible 25% less capacity: 0.9% **increased cost**	1.2% 1.6%
Interregional transmission corridor capacity with regionally coordinated dispatch	25% more capacity: 3.2% **savings** 25% less capacity: 2.0% **savings**	1.1% 1.5%
Interregional transmission interface capacity with nationally coordinated dispatch	25% more capacity: 3.9% **savings**	0.74%
Copper plate	4.7% **savings**	0.13%
Addition of 2.5 GW of batteries	Negligible	1.1%
Hydro availability	Low hydro: 2.3% **increased cost** High hydro: 1.7% **savings**	1.4% 1.4%

This analysis demonstrates several options to reduce electricity production costs and RE curtailment. These mitigation measures can be undertaken individually or in combination. Because each approach has different benefits and costs and different pathways to implementation, this report may be useful in stimulating further discussions regarding implementation strategies that can be developed in concert to achieve the desired policy objectives efficiently.

6 IMPACTS OF OTHER RE TARGETS ON THE INDIAN POWER SYSTEM

In addition to modeling the No New RE and 100S-60W scenarios, we analyzed three other solar and wind targets, as described in Section 2.1. The five scenarios, also referred to as RE build-out scenarios, are summarized in Table 33.

Table 33. Additional Study Scenarios

SCENARIO	SOLAR (GW)	WIND (GW)	DESCRIPTION	PURPOSE
No New RE	5	23	Wind and solar capacities installed as of 2016	Establish a baseline to measure impact of adding new RE to the system
20S-50W	20	50	Total installed capacity as targeted in Green Energy Corridors & National Solar Mission	Evaluate changes to power system planning and operations to meet near-term targets
100S-60W	100	60	Current government of India target for 2022	Evaluate changes to planning and operations to meet the official target of 175 GW RE
60S-100W	60	100	Solar and wind targets reversed in comparison to official target	Understand differential impacts of wind versus solar on need for system flexibility
150S-100W	150	100	Ambitious RE growth	Evaluate how needs for system flexibility would change under a higher wind and solar build-out

With increasing installed RE capacity the Indian power system experiences reduced thermal generation and CO_2 emissions, larger net load ramps, more gas cycling, and lower overall transmission usage. This section analyzes the impacts of the alternative RE targets by addressing three key questions:

1. How do system operations differ between the higher solar (100S-60W & 150S-100W) and higher wind (20S-50W & 60S-100W) scenarios?
2. How does RE curtailment increase with RE build-out?
3. How does additional RE capacity stress the transmission system?

6.1 How System Operations Differ Between the Higher Solar (100S-60W & 150S-100W) and Higher Wind (20S-50W & 60S-100W) Scenarios

We compared the results of system operations in the five build-out scenarios with a particular focus on differences between the higher solar (100S-60W & 150S-100W) and higher wind (20S-50W & 60S-100W) scenarios.

Across all scenarios, increased RE generation displaces coal and gas generation. Figure 71 shows total generation by fuel type for each scenario. In the lowest RE expansion scenario, 20S-50W, coal produces 9% less energy and gas 15% less energy compared to the No New RE scenario. In the 150S-100W scenario, coal generates 35% less energy compared to the No New RE scenario. In all RE expansion scenarios, subcritical coal plants reduce their generation far more than supercritical coal plants because of their comparatively high variable costs.

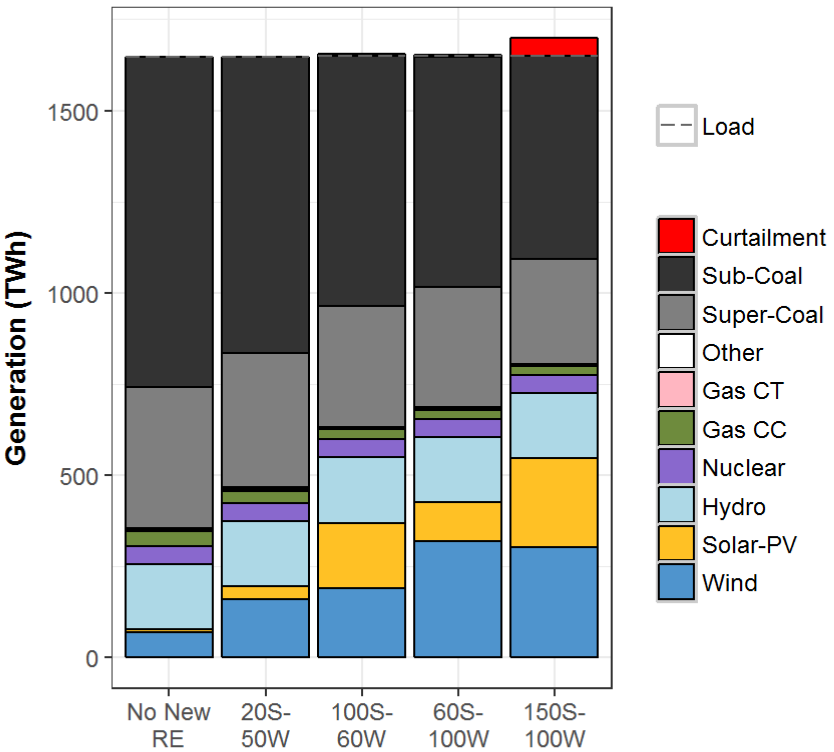


Figure 71. Annual generation by fuel across RE build-out scenarios

Table 35 summarizes RE penetration in the five build-out scenarios. Installed wind capacity generates more RE than installed solar capacity because of its higher capacity factor. As a result, the 22% RE penetration in the 100S-60W increases to 26% in 60S-100W. Across all scenarios, due to the differing capacity factors, a megawatt of wind capacity generates 1.75 times as much energy as a megawatt of solar capacity.

Table 34. RE Penetration Rates and Capacity Factors Across RE Build-Out Scenarios, After Curtailment

SCENARIO	RE PENETRATION RATE OF ANNUAL GENERATION	AVERAGE UTILITY-SCALE PV CAPACITY FACTOR	AVERAGE ROOFTOP PV CAPACITY FACTOR	AVERAGE WIND CAPACITY FACTOR
No New RE	4.8%	21%	–	35%
20S-50W	12%	21%	20%	37%
100S-60W	22%	21%	20%	36%
60S-100W	26%	21%	20%	36%
150S-100W	33%	18%	20%	35%

Production Cost Savings per TWh of RE Generation Fall 16% Between the 20S-50W and 150S-100W Scenarios

Because we assume zero variable cost for RE generation, the addition of RE capacity yields decreased production costs. RE generation and CO_2 emissions for all scenarios, as well as cost savings compared to the No New RE scenario, are summarized in Table 35. As more RE capacity is added to the system, the additional RE generation displaces more conventional generation starting with the most expensive units without violating physical constraints. As a result, the marginal savings from each additional unit of RE generation decline between the lowest (20S-50W) and highest build-out scenario (150S-100W).

While cost savings per TWh of RE generation have a declining trend as more RE is added to the system, the 160 GW RE scenarios provide insight into how wind and solar generation individually affect production costs. The higher wind scenario (60S-100W), while generating 15% more energy than the higher solar scenario (100S-60W), has a 2.3% greater savings per TWh of RE generation. This is counter to the trend that more RE equals less per unit savings. The effects of wind and solar generation on thermal fleet dispatch that enable 60S-100W to more efficiently use RE are discussed later in this section.

Despite Equal RE Capacities, the 60S-100W Scenario Emits 6.1% Less CO_2 Than 100S-60W

The largest component of CO_2 emissions is fuel use in thermal plants. CO_2 emissions from coal account for about 98% of total CO_2 emissions in all scenarios. The significant reductions in coal generation drive emissions reductions with marginal contributions from the displacement of other fuel types such as gas and diesel. Because of its higher capacity factor, the 160-GW higher-wind scenario reduces CO_2 emissions more than the 100S-60W scenario on a per-GW-of-installed-capacity basis. Despite equal RE capacities, the 60S-100W scenario emits 6.1% less CO_2 than its 100S-60W counterpart. The same is true when comparing emissions reductions on a per-TWh basis, which indicates that the system is able to optimize around wind production more efficiently than solar.

Table 35. RE Penetration Rates and Capacity Factors Across RE Build-Out Scenarios

SCENARIO	INSTALLED RE CAPACITY	RE GENERATION	CO_2 EMISSIONS	EMISSIONS REDUCTION W/ ADDITIONAL RE CAPACITY	EMISSIONS REDUCTION W/ ADDITIONAL RE GENERATION
	(GW)	(TWh)	(MMT)	(MMT/GW)	(MMT/TWh)
				Differences from No New RE	
No New RE	30	80	1,370	-	-
20S-50W	70	200	1,250	2.8	1.00
100S-60W	160	370	1,090	2.1	0.97
60S-100W	160	420	1,020	2.6	1.00
150S-100W	250	550	910	2.1	0.98

Conventional Generators Spend More Time at Minimum Stable Level, Where They Are Most Inefficient, When More Solar Is Installed

Where do the additional savings and emissions reduction in higher wind scenarios originate? The same quantity of wind or solar generation will reduce generation of thermal resources equally. However, net load profiles shaped predominantly by solar generation are reduced during the daytime but unchanged at night, whereas net load profiles shaped predominantly by wind generation are more evenly reduced throughout the day. The flatter net load profile of the higher-wind scenarios, which reduces the need for coal plants to cycle, enables conventional units to generate at lower cost, using less fuel and producing less CO_2 than a net load profile encompassing the same total demand but shaped by higher solar generation.

A flatter net load profile is more cost effective to follow for a thermal fleet because of the two ways in which a generator incurs cost: start-ups and variable operating costs. All else being equal, more starts means higher production costs. Additionally, a unit's variable cost increases as its generation level decreases (i.e., heat rate is increased)—a generator at its minimum stable level uses more fuel and therefore incurs more costs per unit of energy produced than when it operates near maximum capacity.

The thermal fleet is therefore most efficient when all generators are either at maximum capacity or off, with nothing in between. However, in practice, the more variable net load profile characteristic of higher-solar scenarios means more thermal starts, more time at minimum stable level, and higher costs. If a thermal generator is needed in two nonconsecutive high net load periods but not in the intermediate low net load period, it has two options: shut off in the interim and incur a start cost, or spend the interim operating at its minimum stable level. We see both inefficiencies in our results. Figure 72 shows the percent of time coal generators spend at minimum generation across the build-out scenarios. As RE capacity goes up, more coal capacity spends more time at minimum generation, indicated by the shifted distributions toward a higher percent of time in the higher-RE scenarios. However, despite the extra RE generation in 60S-100W, coal generators spend 31% less operating time at minimum stable level than in the 100S-60W scenario. At 150S-100W, some coal generators are almost constantly at minimum.

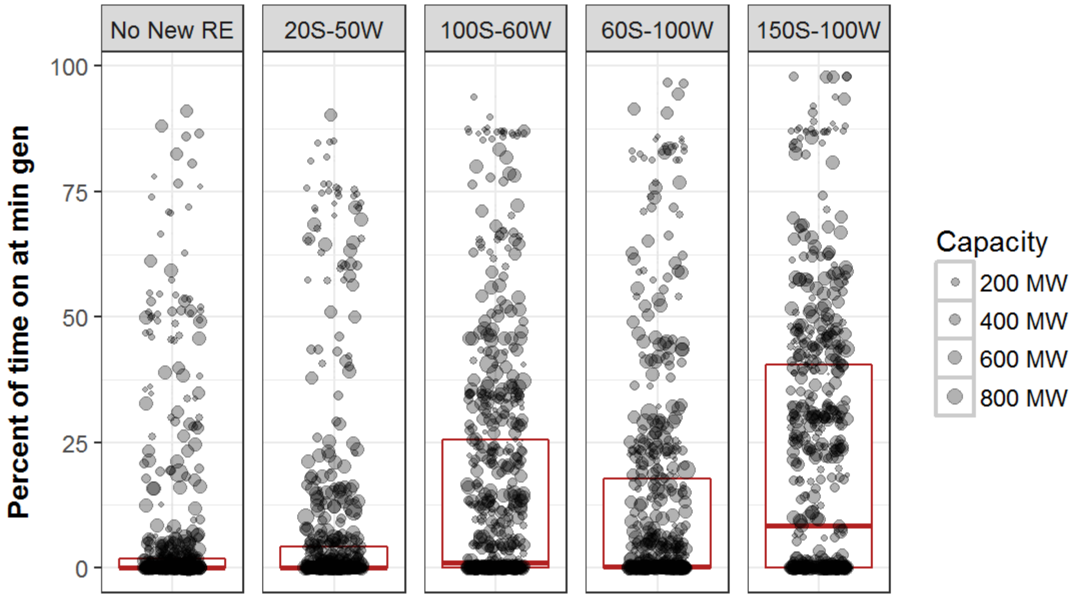


Figure 72. Percent of time spent at minimum stable level for the coal fleet across RE build-out scenarios

Note: Dots represent individual plants sized to nameplate capacity. Boxes represent divisions into 25th percent quantiles, meaning those above the box represent 25% of the capacity, those inside the box are the middle 50%, and those below are 25% of the capacity. The middle line is the median.

More RE Does Not Significantly Impact the Number of Coal Generator Starts, Although Gas Starts Rise

Coal plants do not significantly change their start patterns in higher-RE scenarios for two reasons: 1) starts are expensive compared to variable cost, and it is usually less expensive to leave a plant at minimum generation for more than 30 hours than turn it off then on again,[61] and 2) coal generators are forced to turn off for 24 hours if shut down, and stay on for 24 hours if started. These constraints affect a plant's ability to adjust to a net load cycle that is less than the 24-hour constraint. Instead, coal generation often drops during the middle of the day, but rises again in the evening as solar turns down. As a result, coal generator starts fall a small amount in higher wind scenarios and rise only slightly in higher solar scenarios, as shown in Figure 73.

Other RE Targets

[61] This tradeoff varies by generator.

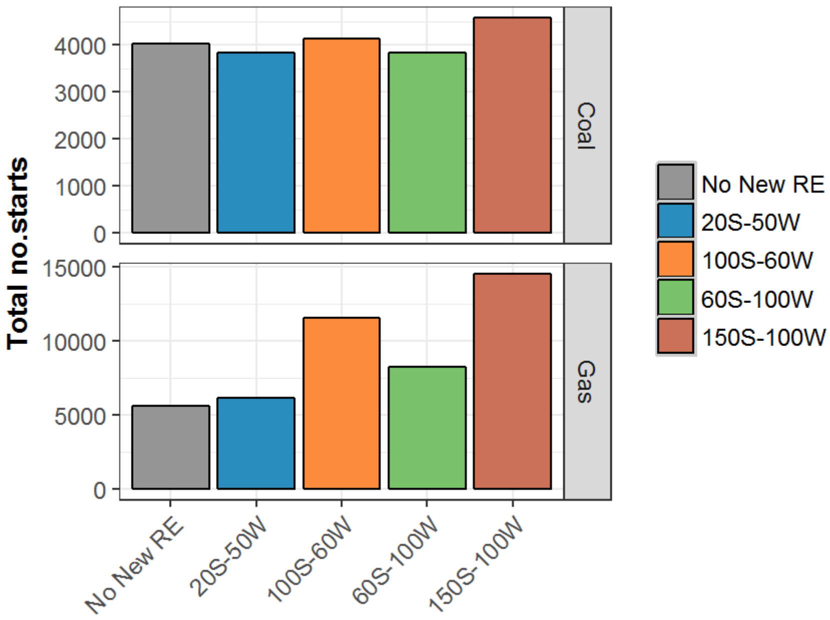


Figure 73. Total number of starts for coal plants (top) and gas plants (bottom), all scenarios

Gas starts rise in higher RE build-out scenarios, most notably in 100S-60W and 150S-100W, suggesting that gas generators contribute to the flexibility needed to meet the larger net load ramps characteristic of high installed solar capacity.[62] The 100S-60W scenario requires 39% more gas generator starts than 60S-100W, while the 150S-100W scenario requires 160% more gas generator starts than No New RE.

Net Load Ramps in 100S-60W Utilize More of the Conventional Fleet's Inherent Flexibility Than in 60S-100W

Table 36 provides basic net load ramp statistics for the five scenarios. While net load ramps in the 20S-50W and 60S-100W scenarios barely depart from the No New RE ramp requirements, the additional ramp requirements in the higher solar scenarios are significant. In every scenario, the maximum net load ramp is far greater than the top 1 percentile, which is also far more demanding than the scenario's typical ramp.

Table 36. One-Hour Ramp Statistics in RE Build-Out Scenarios[63]

SCENARIO	MAX RAMP-UP (GW)	99TH PERCENTILE RAMP-UP (GW)	99TH PERCENTILE RAMP DOWN (GW)	MAX RAMP DOWN (GW)
No New RE	25	15	10	19
20S-50W	25	14	10	19
100S-60W	32	22	18	26
60S-100W	27	15	13	20
150S-100W	41	32	26	37

[62] We model gas generators with a single heat rate regardless of generation level and half the per-MW start costs of coal, as described in Section 2.2.

[63] 12:00–1:00, 12:15–1:15 etc., are counted a separate 1-hour net load ramps

When considering the demands that net load ramps place on the system, it is important to consider both a ramp's steepness and duration. One-hour ramps above the 99th percentile often occur sequentially, resulting in particularly demanding, multihour net load ramps, which can be more stressful to the system than an isolated ramp. The highest 3-hour net load up-ramps in the 100S-60W and 60S-100W scenarios are 71 GW and 52 GW, respectively. A 71-GW net load ramp is equivalent to increasing the generation of more than 60% of India's projected 2022 installed thermal capacity from its minimum generation level of 55% to full output. In the 100S-60W and 250S-100W scenarios, 7% and 15% of 3-hour up-ramps exceed 50 GW, compared to only 0.2% in 60S-100W.

Figure 74 shows the net load curve shape for a sample monsoon and non-monsoon day. Increased wind generation during the monsoon season, especially at night, causes the net load profiles of all scenarios to be flatter than their non-monsoon counterparts.

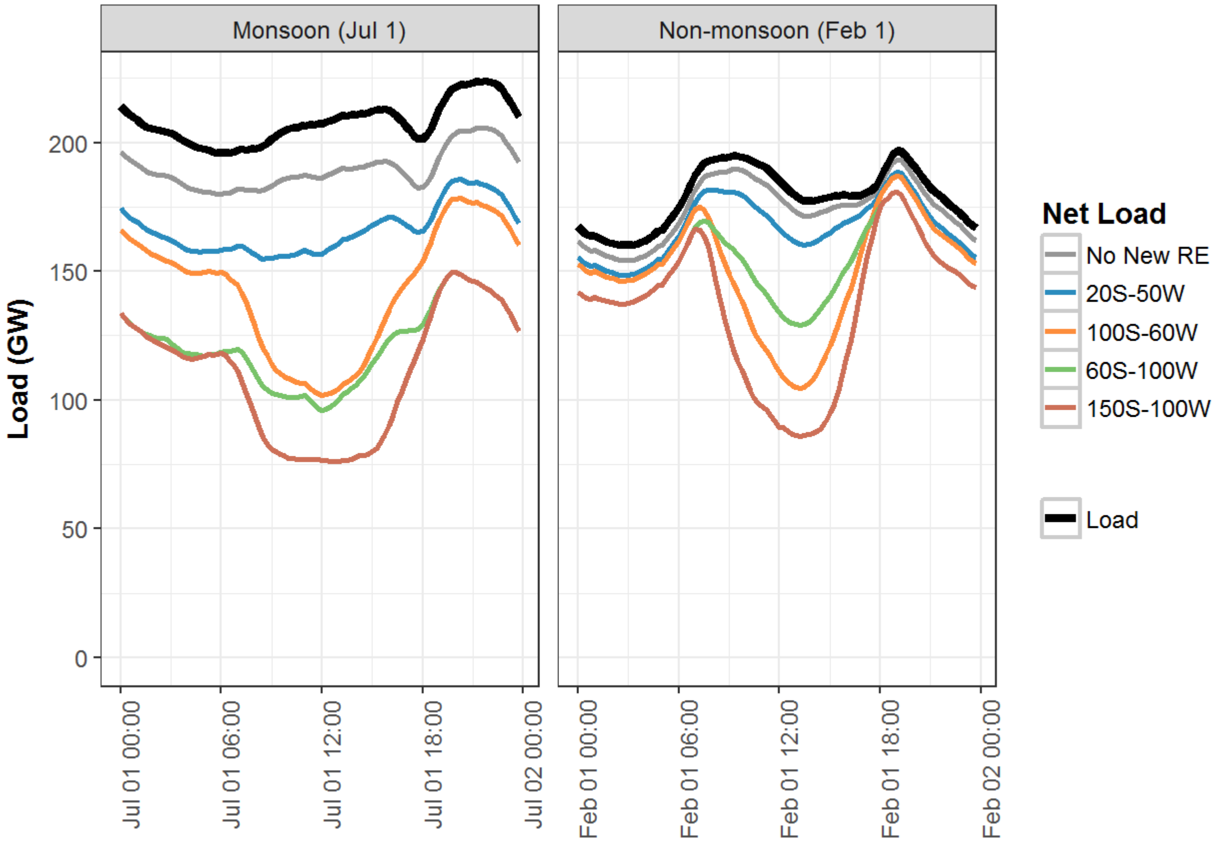


Figure 74. Net load ramping on a monsoon and non-monsoon day, all scenarios

In the No New RE Scenario Much More Coal Operates Above 75% PLF Than Below 25%; in 150S-100W, the Opposite Is True

Plant load factors in the coal fleet drop substantially as RE build-out increases and wind and solar generation displace the most expensive generators. Gas fleet PLFs also fall. However, even as gas is used less, more gas capacity overall is turned on because short-term gas commitments are used to address variable net load. This decrease in PLFs across the thermal fleet happens despite increases in ramping and starts, as shown in Figure 72 and Figure 73. However, even with its extra RE generation, the 60S-100W scenario operates the same amount coal capacity at over 75% PLF as 100S-60W. Table 37 summarizes coal and gas fleet PLFs across scenarios.

Table 37. Comparison of PLFs, by Type, Inclusive of Capacity That Never Starts

FUEL TYPE	NO NEW RE	20S-50W	100S-60W	60S-100W	150S-100W
AVERAGE PLF					
Super-Coal	64%	61%	55%	55%	48%
Sub-Coal	62%	56%	47%	44%	38%
Gas CC	21%	18%	14%	14%	12%
Gas CT	50%	41%	31%	29%	28%
CAPACITY (GW) ≥ 75% PLF					
Super-Coal	23	23	10	13	2.0
Sub-Coal	69	58	36	33	19
Gas CC	0	0	0	0	0
Gas CT	0	0	0	0	0
CAPACITY (GW) ≤ 25% PLF					
Super-Coal	6.8	8.8	12	13	13
Sub-Coal	23	35	49	59	64
Gas CC	11	13	17	17	17
Gas CT	0	0.35	0.35	0.35	0.54
CAPACITY THAT NEVER STARTS (GW)					
Super-Coal	3.6	4.2	3.6	3.6	3.6
Sub-Coal	6.0	14	16	20	21
Gas-CC	2.7	3.3	2.2	3.8	1.2
Gas-CT	0	0	0	0	0

6.2 How RE Build-Out Affects RE Curtailment

RE curtailment does not increase linearly with additional RE capacity. Instead, the two lowest RE scenarios (No New RE and 20S-50W) experience no curtailment, with relatively low curtailment in both 160-GW RE scenarios and a sharp rise in 150S-100W. Table 38 summarizes generation and curtailment across the five scenarios.

Table 38. National Annual RE Electricity Generation and Curtailment, All Scenarios

SCENARIO	SOLAR GENERATION (TWh)	WIND GENERATION (TWh)	RE CURTAILMENT (TWh)	RE CURTAILMENT (%)
No New RE	10	69	0	0%
20S-50W	36	160	0	0%
100S-60W	178	191	5.1	1.4%
60S-100W	106	318	4.4	1.0%
150S-100W	242	304	49.8	8.3%

As discussed in Section 4.1, curtailment in the 100S-60W scenario is concentrated in the Southern region. The same holds true for the 60S-100W and 150S-100W scenarios, as shown in Figure 75, which breaks down RE generation and curtailment by region. In the 60S-100W scenario, 99% of curtailment occurs in Southern region, even higher than the 97% in 100S-60W. In 150S-100W, the share of curtailment in the Western region rises significantly, to 11% of total curtailment compared to Southern region's 88%.

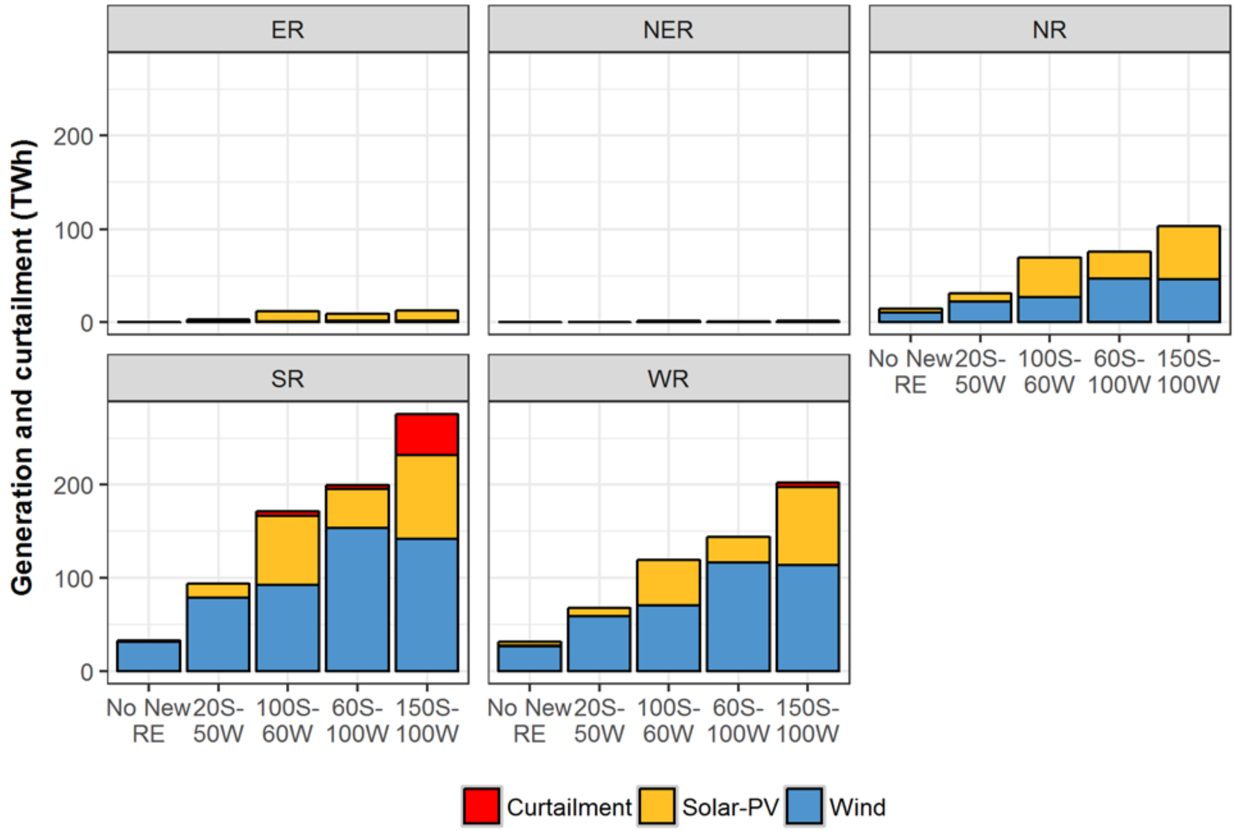


Figure 75. Regional annual RE electricity generation and curtailment, all scenarios

Figure 76 compares RE curtailment across the three highest RE build-out scenarios. At 8.3%, curtailment is only a significant year-long concern in the 150S-100W scenario; however, even when nationwide curtailment is low, the Southern region experiences significant curtailment during the monsoon season, at 4.9% and 3.8% in the higher-solar (100S-60W) and higher-wind (60S-100W) scenarios, respectively. Because the Eastern region has little installed RE capacity, total curtailment is low, but it reaches 1.7% of available energy in the 150S-100W scenario.

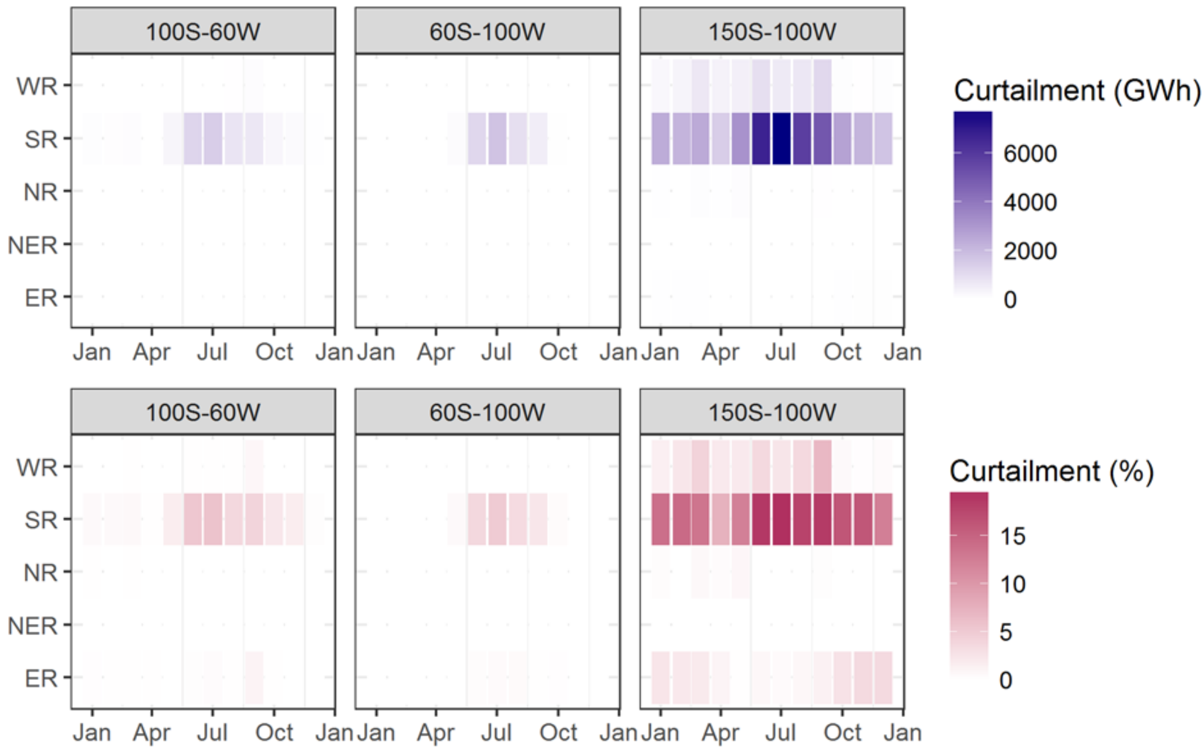


Figure 76. Total curtailment and curtailment as percent of available RE energy in the build-out scenarios

RE curtailment is driven by generator constraints, such as ramping and minimum stable level; barriers to interregional trade, such as those we impose in the state dispatch scenario; and transmission constraints. As RE penetration increases, RE is curtailed where and when the system is most constrained, which is most frequent in the Southern region during the monsoon season. As constraints become more widespread, so does curtailment. For low levels of RE penetration, such as in the 20S-50W and No New RE scenarios, the system is not constrained even in the Southern region during the monsoons, thus avoiding curtailment.

Table 39 shows the percent of the year that the thermal fleet in each region is fully backed down. In a backed-down state, every thermal generator within a region is either off, at its maximum ramp rate, or at minimum stable level and unable to decommit. If we do not consider imports, exports, and hydro flexibility, any fully backed-down region is unable to accommodate more RE energy and the system must curtail to respect the thermal fleet's constraints. This situation arises more frequently as more RE is added to the system. The Southern region, in particular, experiences this frequently. Its thermal fleet is fully backed down 15% and 16% of the year in the 160-GW RE scenarios, and this rises to 40% in the highest RE scenario. Even in the Northern region, which does not experience significant curtailment, the thermal fleet is fully backed down most in the highest RE build-out scenarios to accommodate imports from higher-RE regions. In other words, the Northern region thermal fleet responds when the Western and Southern regions' thermal fleets are fully inflexible to accept more imports from the curtailing regions. The far right column in Table 39 is the percent of time when no thermal generator in the country can provide additional flexibility.

Table 39. Percent of Year That Every Generator in the Thermal Fleet Is Either Off, Committed but Operating at Minimum Generation, or Constrained by Ramping—by Region, All Scenarios

SCENARIO	SR THERMAL FLEET CONSTRAINED	WR THERMAL FLEET CONSTRAINED	NR THERMAL FLEET CONSTRAINED	ER THERMAL FLEET CONSTRAINED	ENTIRE THERMAL FLEET CONSTRAINED
No New RE	0%	0%	2%	2%	0.0%
20S-50W	1%	2%	4%	3%	0.4%
100S-60W	16%	5%	7%	5%	0.8%
60S-100W	15%	6%	10%	7%	2.0%
150S-100W	40%	21%	14%	8%	2.5%

The Higher-Wind Scenario (60S-100W) Results in Lower RE Curtailment, in Both Magnitude and as a Percent of Available Generation, Than the Higher-Solar Scenario (100S-60W)

Although the 60S-100W scenario generates 15% more RE than 100S-60W, it curtails 14% less. Figure 77 compares average hourly net load, committed coal capacity, and curtailment between the two scenarios. Daily net load variability is higher in 100S-60W, which results in higher average coal commitment and—as a result of minimum generation constraints—higher curtailment, especially midday in monsoon. Peak net load at dawn and dusk in 100S-60W, coupled with lower nighttime production, requires more online thermal capacity at either end of the day than 60S-100W (Figure 77, top panel). However, because of start costs and minimum up times, 100S-60W must maintain its higher average committed coal capacity throughout the day (Figure 77, middle panel). As a result, at midday 100S-60W has both more committed thermal capacity and more available RE generation than 60S-100W.

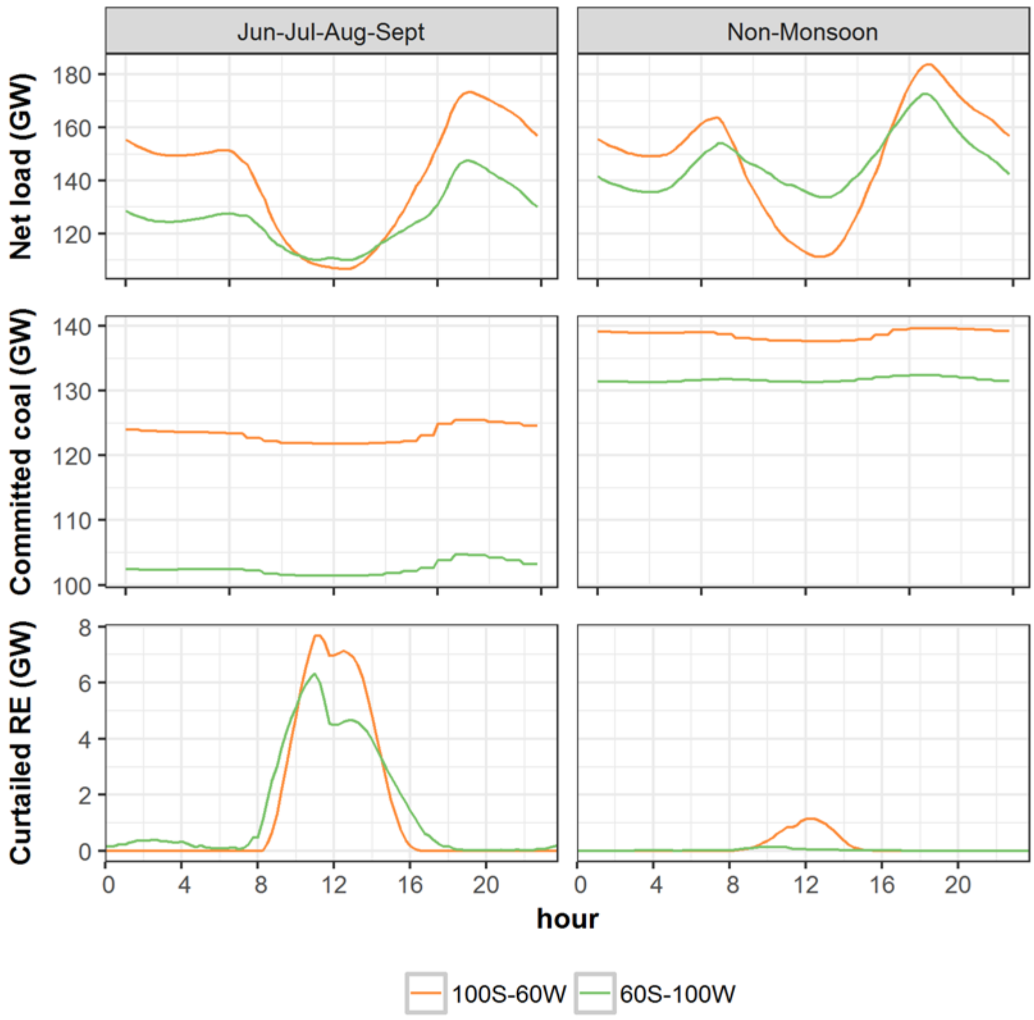


Figure 77. Average hourly net load, committed coal capacity, and curtailment in 100S-60W and 60S-100W

6.3 How Additional RE Capacity Affects the Transmission System

In Section 5.4, we discuss how increased RE generation in the 100S-60W scenario causes overall transmission usage to fall. Utility-scale solar and wind generation distributed throughout the Southern and Western regions reduces the reliance on flows to meet local load from traditional exporters such as Chhattisgarh, Madhya Pradesh, and Odisha. As shown in Figure 78, the trend persists in all five RE build-out scenarios, particularly along the heavily used WR-NR and ER-SR corridors. The Southern region's net imports fall dramatically with its additional RE generation. However, while total interregional energy exchanges fall by 18% between the No New RE and 150S-100W scenarios, the amount of congestion on interregional interfaces increases by 54%. This is driven by the SR-WR and NR-ER corridors. Despite reduced total energy flowing, additional RE generation places stress on the transmission system by increasing time under congestion and changing trading patterns.

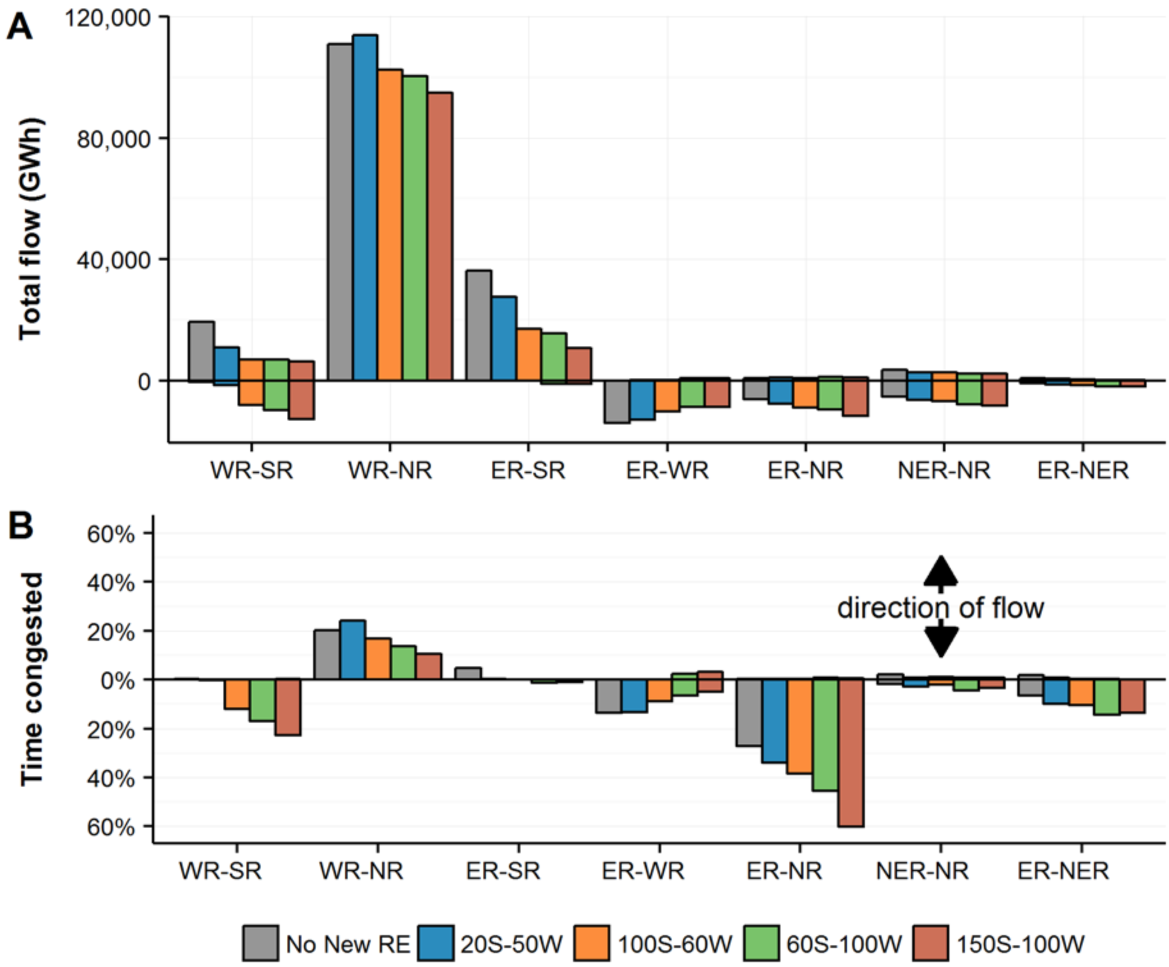


Figure 78. Impact of additional RE capacity on interregional transmission flows (A) and interface congestion (B) for state dispatch, all scenarios

Interregional congestion is greatest in the monsoon season when RE generation and curtailment are highest. Despite having 22% less RE generation than the 150S-100W scenario, 60S-100W experiences similar or worse congestion on every interregional interface during the monsoon season except on the ER–WR and NR–ER corridors. Table 40 shows congestion on interregional interfaces during the monsoon season across three RE build-out scenarios.

Table 40. Comparison of Percent of Time Congested on Interregional Corridors in Monsoon Season

Note: This table only represents the limits on interregional corridors and not the state-to-state interfaces that may also be experiencing congestion.

INTERREGIONAL CORRIDOR	100S-60W	60S-100W	150S-100W
SR–ER	0.0%	3.6%	3.0%
WR–NR	22%	14%	10%
NER–ER	8.5%	16%	15%
NR–NER	2.1%	6.0%	4.8%
NER–NR	2.9%	1.8%	1.6%
NR–ER	30%	38%	55%
SR–WR	21%	44%	44%
ER–WR	0.9%	7.2%	9.4%
WR–ER	6.6%	3.4%	2.0%

6.4 Summary

With increasing installed RE capacity, the Indian power system experiences reduced thermal generation and CO_2 emissions, larger net load ramps, more gas cycling, and lower overall energy flowing around the country.

Greater wind capacity, which has higher capacity factors than solar, helps achieve a higher annual RE penetration rate (26% as compared with 22% in the 100S-60W scenario), reduces CO_2 emissions (6.1% lower than the 100S-60W scenario), and results in lower RE curtailment (1.0% compared to 1.4% in the 100S-60W scenario). Because of its relatively less-variable net load profile, the higher-wind scenario creates fewer conditions requiring thermal plant flexibility. Consequently, the coal fleet in the 60S-100W scenario starts less (7.3%) and, while operating, spends 31% less time at minimum stable level than in 100S-60W. The reduced flexibility required of the thermal fleet in the 60S-100W scenario results in greater cost and emissions savings per unit of RE generation than in the 100S-60W scenario.

RE curtailment is low in the two 160-GW scenarios but becomes a more serious concern in the highest-penetration 150S-100W scenario, where it reaches 8.3% nationally and 16% in the Southern region. In the lower-RE penetration scenarios, the majority of curtailment happens in the Southern region during monsoon season but becomes more pronounced in other regions and seasons as RE penetration goes up.

Regardless of challenges introduced by increased curtailment and thermal fleet cycling, the 150S-100W scenario would enable a 33% annual RE penetration level, which, in combination with hydro and nuclear generation, would achieve the Nationally Determined Contribution target of over 40% generation by non-fossil sources, albeit in the context of load projections for 2022, which are lower than 2030 forecasts. Eliminating the 8.3% RE curtailment through a combination of integration strategies would enable an annual penetration rate of over 36% with just wind and solar. Additional studies can evaluate integration strategies such as those below to help develop a more cost-effective pathway toward 250 GW.

- Changes to RE plant locations (e.g., to other regions given that RE curtailment is primarily a concern in the Southern region) compared to this study's site selection
- Optimized transmission planning
- Improved coordination of scheduling and dispatch to regional or national levels
- Lower minimum generation capacity for coal
- Dynamic scheduling of RE, which would allow another region to virtually balance some of the Southern region RE generation.

Table 41 summarizes annual information on generation, emissions, and fuel use across the five RE build-out scenarios.

Table 41. Summary of Annual Generation, Emissions, and Fuel Use Across the Five Scenarios

	NO NEW RE	20S-50W	100S-60W	60S-100W	150S-100W
Generation (TWh)					
Solar-PV	10	36	180	110	240
Wind	69	160	190	320	300
Sub-coal	910	810	690	630	560
Super-coal	390	370	330	330	290
Hydro	180	180	180	180	180
Gas CC	40	34	28	26	24
Gas CT	6.4	5.3	4.0	3.8	3.6
Nuclear	50	50	50	50	50
Other	3.9	4.1	3.4	3.8	3.4
Total	1,650	1,650	1,650	1,650	1,650
RE Curtailment	0	0	5.1	4.4	50
Emissions (MMT)	1,400	1,200	1,100	1,000	900
Fuel Use (million GJ)					
Coal	15,000	13,000	12,000	11,000	9,700
Other[64]	400	350	280	270	250

[64] Other combines gas, diesel, and oil fuel use.

7 CONCLUSION

7.1 Key Findings of This Study: Core Scenario—100 GW Solar, 60 GW Wind

Based on the fulfillment of current regulatory and planning efforts to provide better access to the physical flexibility of the power system, power system balancing with 100 GW of solar and 60 GW of wind is achievable at 15-minute operational timescales with minimal RE curtailment.

The Indian power system with 100 GW of solar and 60 GW of wind generates 370 TWh annually, a 22% share of total electricity consumption in India, reaching a nationwide instantaneous peak of 54%. Based on existing plans for transmission and generation capacity expansion and optimal siting of RE and in-state transmission, the system is able to do this with only 1.4% RE curtailment[65] and does not require new fast-ramping infrastructure for the RE, such as combustion turbines or storage. The planned fleet of generation and transmission provides sufficient capacity to handle errors from state-of-the-art RE forecasts, changes in net load (ramps), and times of the day and year when RE generation is low. However, continued investment in transmission would be essential at both state and interstate levels to ensure minimal RE curtailment. While physically the system has the flexibility to manage added variability and uncertainty, the challenge going forward is accessing this flexibility through appropriate regulations, operational rules, operating reserve requirements, market mechanisms, and software and control systems.

Changes to operational practice can reduce the cost of operating the power system and reduce RE curtailment but are not essential for RE integration of 100 GW of solar energy and 60 GW of wind energy.

Existing merit-order operations, in which generators with lower variable costs are dispatched before higher variable cost generators, capture many of the efficiencies necessary to integrate 160 GW of wind and solar. The 2022 analysis suggests that existing operations, which follow a decentralized state-by-state level unit commitment and dispatch, can integrate future levels of RE with only 1.4% RE curtailment nationally.

Nevertheless, we find that scheduling and dispatch optimized at the regional or national level can support more efficient operations of thermal plants and help achieve more economical operations with annual operating cost savings of roughly 2.8%, or INR 6300 crore in today's rupees (approximately USD 980 million) for regional coordination and 3.5% or INR 7800 crore for national coordination. In addition to improving access to least-cost generation, coordination between states helps reduce the number of coal plants at part load, providing greater operational range to the remaining committed coal plants to lower generation output when RE generation is high.

Reducing minimum generation levels of large thermal plants is the biggest driver to reducing RE curtailment.

Changing minimum generation levels of all coal plants, from 70% today to 55% of rated capacity (consistent with the CERC regulations) reduces RE curtailment from 3.5% to 1.4% and annual operating cost by 0.9%, or INR 2000 crore. Reducing minimum generation levels further, to 40%, reduces RE curtailment to 0.76%, with negligible decreases to annual operating costs. If only centrally owned plants achieve 55% minimum generation levels but state-controlled plants maintain minimum generation levels of 70%, RE curtailment is 2.4%.

[65] This level is within the range of experiences in other countries with significant RE. For example, Spain and Ireland have wind penetration levels of around 20% with 2-3% RE curtailment (Bird et al. 2016).

The peak systemwide 1-hour up-ramp increases 27% compared to a system with no new renewables, to almost 32 GW, up from 25 GW. This ramp rate can be met if all generating stations exploit their inherent ramping capability.

Aggregated nationally, for 56 hours of the year, systemwide one hour up-ramps exceed 25 GW, greater than any ramp requirement in the No New RE scenario, and peak at almost 32 GW. The current generation fleet is shown to successfully respond to these ramp events within our operating assumptions. We found no significant change in either production cost or RE curtailment when coal generation ramp rates were made less flexible in the simulations, although this study assumes a similar load shape for 2022 as prevailing today. A significant change in load shape could affect the net load ramp rate. Five-minute scheduling and dispatch has been demonstrated elsewhere to better handle ramping, if required at a later stage.

The latent flexibility in hydroelectric generation helps maintain system balance.

With RE, net load takes on a dual-peak pattern that is different than today. Hydroelectric (hydro) generation, subject to various flow constraints, is dispatched during the periods of highest value, which occur during the net demand peaks. The adaptability of hydro helps the power system to absorb the variability that RE adds to the system, complementing the flexibility from the thermal fleet. Additionally, sensitivities representing high- and low-hydro years did not hinder RE integration, as the flexibility of the system is still sufficient to maintain balance.

Annual energy flow on major corridors does not change significantly, although corridors connected to the Southern region frequently carry power in both directions, a change from today's system and a low RE future scenario.

We find that total energy flows change somewhat under the 100S-60W case and interregional corridors are congested some periods during the year; however, these changes do not appear to hinder the effective integration of 160 GW of RE. Without the growth of RE, the Southern region is a steady importer. But under the 100S-60W scenario, the major change to flows occurs between the Western and Southern regions, causing more bidirectional flows than in the No New RE case. Overall, the total energy moving around the country decreases because certain states and regions are more self-sufficient in their generation supply with the addition of RE.

A copper plate sensitivity delivers 4.7% savings and 0.13% RE curtailment.

Our copper plate represents a transmission system with no constraints and operations with no barriers to scheduling. Though not a physically plausible scenario, this scenario provides insights into the maximum achievable savings if all transmission and market constraints could be relaxed. Such a scenario reduces RE curtailment to 0.13% and production costs by 4.7%. In comparison, scheduling and dispatch optimized at the regional level and with transmission constraints delivers over half of these savings. Nationally coordinated dispatch combined with an additional 25% interregional transmission capacity delivers 84% of the savings compared to the idealized copper plate.

The copper plate sensitivity results in a peak of 36 GW power transfer from west to north and leads to loop flows from west to north to east.

The copper plate sensitivity indicates the likely transmission requirements for 2022 for least-cost generation dispatch. Under this scenario, power flow on the Western-to-Northern region corridor is expected to touch a maximum 36 GW. Additionally, flows typically go from Northern to Eastern, which leads to loop flows of Western to Northern to Eastern. Flow on the Western-to-Southern region corridor may also become bidirectional depending upon the wind generation. Further, full AC power flow and related analyses would be necessary to complement the existing studies by the transmission planning teams in India (who use power flow software extensively). Through this integration study, stakeholders within India have identified the need for a mandatory production cost modeling study for the purpose of transmission planning for a large country like India with diverse resources. CERC will be updating regulations on transmission planning and could consider this aspect to ensure the right plan and build-out of transmission.

Batteries insignificantly impact emissions and total cost of generation.

Batteries do reduce curtailment (from 1.4% to 1.1%); however, the value of this curtailment is offset by the batteries' efficiency losses during operation. In the 100S-60W scenario, 2.5 GW of batteries (75% efficient) reduce RE curtailment by 1.2 TWh annually but lose 2.0 TWh annually due to inefficiencies. Also, there is insignificant impact on the total cost of generation because the overall generation mix changes little. Batteries charge during the early afternoon when multiple resources, including coal, are online and displace coal at night, resulting in an insignificant drop in total coal generation. Peak coal generation is decreased by less than the capacity of the batteries in both the 100S-60W and 60S-100W scenarios. Batteries could be economically desirable for RE integration for grid services that are outside the scope of the study (e.g., frequency regulation, local transmission congestion).

Retiring 46 GW of coal (20% of installed coal capacity) does not adversely affect system flexibility.

In the 2022 projections for generation capacity, the least efficient coal plants are rarely dispatched. Even in the absence of new RE capacity (No New RE scenario), nearly 10 GW of coal plants never run at any point of the year. Retiring coal plants that operate less than 15% of their capacity annually (205 generation units totaling 46 GW in capacity) has almost no effect on system operations. With retirements, the average plant load factor of the coal fleet is 62%, up from 50%. RE curtailment remains constant at 1.4%, with negligible impact to annual production costs. This suggests that in the long term there may be an opportunity to save money on fixed-cost contracts by strategic retirements of excess generation.

Summary: Power system balancing with 100 GW of solar and 60 GW of wind is achievable with minimal integration challenges, bringing benefits of reduced fuel consumption and emissions. Meeting existing regulatory targets for coal flexibility, enlarging geographic and electrical balancing areas, expanding transmission in strategic locations, and planning for future flexibility can enable efficient and reliable operation of the power system now and in the future.

Coordinated planning for transmission, operations, and generator flexibility will support cost-effective integration of even higher levels of RE, while minimizing RE curtailment. These changes to operations and planning will reduce operating cost regardless of the level of renewable energy that is ultimately integrated into the Indian power grid. The specific approaches to achieving coordinated planning are beyond the scope of this study but can be developed to address Government of India and stakeholder policy preferences.

Table 42 consolidates and summarizes key findings from the India grid integration study. The table focuses on the key scenario of 160 GW RE in how a system with 100 GW of solar and 60 GW wind is balanced.

Table 42. Key Findings for India's Power System with 100 GW Solar, 60 GW Wind

RE GENERATION

- RE generates 370 TWh energy annually
- Annual RE penetration is 22%, with an instantaneous peak of 54% of total demand
- Annual capacity factors of the RE plants are 21% for solar PV and 36% for wind
- RE curtailment averages 1.4% of total available RE energy, for a total of 5.1 TWh. Southern region experiences the highest curtailment levels of 2.9% annually
- RE curtailment occurs somewhere in the country during 1,057 hours, or roughly 12% of the year, and peaks at 27 GW in September

IMPACTS ON THERMAL UNITS AND PLANT OPERATIONS COMPARED TO THE NO NEW RE SCENARIO

- Coal and natural gas generation decrease 270 TWh and 15 TWh, respectively, a drop of 21% and 32%
- CO_2 emissions drop 21% (280 MMT)
- Plant load factors of coal drop from 63% to 50% with nearly 20 GW of capacity that never starts, and 65 GW of capacity that experiences plant load factors below 30%
- Coal plants on average experience 2.8% more starts and operate three times longer at minimum generation level
- Aggregated nationally, for 0.64% of the year, systemwide up-ramps exceed 25 GW/hour, greater than any ramp requirement in the No New RE scenario, and peak at almost 32 GW/hour.
- Hydro generation follows a two-peak net load profile

IMPACTS ON IMPORTS AND EXPORTS AND TRANSMISSION FLOWS COMPARED TO THE NO NEW RE SCENARIO

- Annual interstate energy exchanges within the Western and Southern regions decrease 9.6% and 5.9% to 120 and 45 TWh, respectively
- Total annual net energy exchanges between regions decrease 16% to 180 TWh
- The magnitude of flows and number of changes in direction of flows between Southern and Western regions increase significantly during the monsoon period, when wind generation is highest

IMPACTS ON PRODUCTION COSTS AND RE CURTAILMENT FROM RE INTEGRATION STRATEGIES COMPARED TO REFERENCE SCENARIO OF STATE-LEVEL DISPATCH AND 55% MINIMUM GENERATION LEVELS ON COAL PLANTS

- Improved scheduling and dispatch coordination
  - Regional coordination: 2.8% cost savings, 1.3% RE curtailment (down from 1.4%)
  - National coordination: 3.5% cost savings, 0.9% RE curtailment
- Different coal minimum generation levels
  - 40% min gen: negligible cost savings, 0.76% RE curtailment
  - 70% min gen: 0.9% cost increase, 3.5% RE curtailment
- Combined regional coordination with 40% min generation: 3.3% cost savings, 0.73% RE curtailment
- Combined national coordination with 25% increase in interregional interface capacity: 3.9% cost savings, 0.74% RE curtailment
- Copper plate (no transmission constraints or barriers to optimal scheduling): 4.7% cost savings, 0.13% curtailment

7.2 Key Findings for Scenarios with Different RE Penetration Levels

A wind-dominated system achieves higher RE penetration rates and requires less thermal fleet flexibility.

We developed two 160 GW RE scenarios: the official target of 100 GW solar and 60 GW wind (100S-60W scenario), and the opposite—60 GW solar and 100 GW wind (60S-100W scenario). In the latter scenario, greater wind capacity, which has higher capacity factors than solar, helps achieve a higher annual RE penetration rate (26% as compared with 22% in the 100S-60W scenario), reduces CO_2 emissions (6.1% lower than the 100S-60W scenario), and has lower RE curtailment (1.0% compared to 1.4% in the 100S-60W scenario). Because of its relatively less variable net load profile, the higher wind scenario creates fewer conditions requiring thermal plant flexibility. Consequently, the coal fleet in the 60S-100W scenario experiences 7.3% fewer starts and, while operating, spends 31% less time at minimum stable level than in 100S-60W. The reduced flexibility required of the thermal fleet in the 60S-100W scenario results in greater cost and emissions savings per unit of RE generation (2.3% and 3.6%, respectively) than in the 100S-60W scenario.

A 250-GW RE system could achieve India's Nationally Determined Contribution targets early by 2022 but would likely result in levels of RE curtailment that may not be cost effective unless additional mitigation actions are taken. In this high-RE scenario, high curtailment in the Southern region suggests the need for new RE integration strategies.

At 250 GW solar and wind, the Nationally Determined Contribution target of over 40% of non-fossil generation could be achieved, but curtailment in the Southern region would rise to 16% while curtailment in other regions remains under 3%. RE contributes 33% of the energy demand in this scenario, which in combination with hydro and nuclear generation would achieve the 40% target. Eliminating the national average of 8.3% annual RE curtailment through a combination of integration strategies, such as load shifting to support electric vehicle charging, would enable an annual penetration rate of 36% with just wind and solar energy. Given that RE curtailment is only a significant issue in the Southern region, additional studies can evaluate whether locating more of the 250-GW RE capacity in other regions would alleviate this curtailment and thus provide a more viable pathway toward 250 GW.

Table 43 summarizes RE generation, curtailment, and reductions in CO_2 emissions across the scenarios.

Table 43. RE Penetration Level, Curtailment, and Reductions in CO_2 Emissions, All Scenarios

SCENARIO	WIND AND SOLAR PENETRATION RATE OF ANNUAL GENERATION	RE CURTAILMENT	PERCENTAGE CO_2 REDUCTIONS COMPARED TO NO NEW RE
NO NEW RE	4.8%	0.0%	-
20S-50W	12%	0.0%	8.6%
100S-60W	22%	1.4%	21%
60S-100W	26%	1.0%	25%
150S-100W	33%	8.3%	34%

Table 44. Implications for Policy

- RE targets of 175 GW are achievable with continued investment in interstate and intrastate transmission
- Interstate transmission identified through Green Corridors is sufficient to reliably operate the system, but intrastate transmission will require new planning based on projected locations of RE.
- New fast-ramping plants and storage are not necessary at these penetration levels.
- Improving the operations of existing infrastructure, however, does provide high value to RE integration. Operating the power system from a regional or national perspective, rather than state-by-state, achieves efficiencies in operations by reducing the need for costly start-ups and shutdowns. Operating coal plants more flexibly—reducing their minimum output to 55% as currently mandated for central generators, or even to 40%—provides additional flexibility in managing midday peak RE output.
- At high RE penetration levels, coal plant load factors will decline to near 50%, which calls into question economic viability. This will create economic implications for distributions utilities that pay for availability.
- Strategic uses of RE curtailment will become an important source of flexibility to minimize system-level costs. Regulations and PPAs that mandate must-run status could restrict access to this flexibility. To maintain confidence for RE investors, removing must-run status will need to accompany an adherence to merit order dispatch (based on production costs, not tariffs) at the system operator level.
- A 175-GW RE target that places greater emphasis on wind over solar (100 GW wind, 60 GW solar), achieves higher RE capacity factors, and therefore higher RE penetration levels (26% compared to 22% in the 100 GW solar, 60 GW wind scenario) and lower CO_2 emissions. The characteristics of wind generation make it easier to operate, but this report does not assess the full suite of questions that would be required for a policy cost-benefit analysis, including fixed costs and financing availability, among other factors.
- At 250 GW RE, the best wind and solar resources remain in the southern region, but continued siting of RE in that region will create excessively high levels of RE curtailment without additional mitigation strategies, such as new transmission or improved coordination of scheduling and dispatch.
- Achieving more ambitious RE targets will require detailed, model-based planning, and will benefit from an institutionalized process for maintaining the model and sharing data.

7.3 Policy Implications

A number of insights from this study help inform policy. Although specific policy recommendations are outside the scope of this study, there are several broad directions that may increase India's capability to efficiently plan and operate the power system in a way that is consistent with national goals related to climate and renewable energy deployment. At the same time, the study provides insights to areas that may *not* be particularly helpful in reliably and cost-effectively integrating renewable energy. Policymakers who are mindful of these distinctions can adopt the efficient methods while avoiding potentially costly new policies that have little or no positive impact on the desired outcome. Table 44 above summarizes the policy implications.

Prerequisite for analyzing potential policy directions:

1. ***Institutionalizing the Model***

   In the sections below we discuss various policy directions that India may wish to take, following up on the current study. Because of the complex interactions between power system control methods and machine and network characteristics, along with institutional and operational settings and practice, many changes in the system that lead to improved integration outcomes will come at a cost. Ensuring that no RE is ever curtailed may, for example, be very costly because it would require expensive transmission expansion; yet the amount of curtailment that could be eliminated may be too small to economically justify the line expansion.

   Potential action: Provide institutional support for the continued use of production cost modeling, including ongoing training for responsible staff. This will allow for continued use of the model in the future, updated periodically with state-level transmission and RE locations. Use this model to evaluate RE integration strategies and provide information on curtailment risks to state planners and RE developers. As conditions change over the next few years, this modeling framework can be adapted so that changing network characteristics, generation mix and constraint, renewable build-out, and others can be continuously evaluated so that policymakers can make decisions based on best-available information. Putting a technical team in place and supporting it with computing capability, data, and continuous training can help inform rational decisions. Because of the need for flexibility with high levels of RE, computer planning models that perform generation planning expansion optimization will also be useful.

Policies that have a positive effect on RE integration:

1. ***State-Level Planning***

   The RE targets of 175 GW are achievable, and continued investment in both interstate and intrastate transmission will help facilitate these targets. The *inter*state transmission as planned under Green Energy Corridors is shown to be sufficient for meeting demand requirements as analyzed in this study, but additional *intra*state transmission planning should consider project locations of new RE development, which may differ somewhat from the scenarios evaluated in this study. If nationally coordinated scheduling and dispatch is pursued in which trade barriers between regions are removed, this study highlights the value of reducing RE curtailment via increasing transmission capacity in at least some interregional corridors.

   Potential action: At a minimum, coordinate RE generation and transmission at the state level to ensure sufficient in-state transmission. Create a nationwide model that helps optimize generation and transmission build-outs. Create regulatory or policy guidelines to support institutionalization of cost-optimized capacity expansion planning.

2. ***Larger Balancing Footprint***

Enhancing operations by moving toward larger electrical balancing footprints (e.g., regional or national instead of state-level dispatch) has the potential to reduce system operating costs and curtailment of RE. In coordination with strategic transmission planning and development, larger operational footprints are investments that can help with efficient system operation regardless of the pathway to, and ultimate build-out of, renewable energy. Enhanced operational methods also do not suffer from depreciation, making this an attractive policy direction. India already implements some elements that enable a larger electrical balancing footprint: state utilities utilize their long-term allocations from the central sector plants and IPPs, power exchanges facilitate day-ahead and intraday trades, and recent central ancillary services provide spinning reserves via central generators. India may also be moving toward a change in dispatch, an "all India merit order" for central plants that fall under RLDC jurisdiction. This will likely move India further toward a more coordinated operational future. Evaluating a move toward more centralized dispatch or markets or something similar may prove effective in helping to efficiently integrate the planned levels of RE.

Although we do not analyze the complex policy and regulatory changes required to implement more coordinated scheduling and dispatch over larger areas, we briefly list some strategies that could be further explored:

- Facilitating an increased number of bilateral exchanges, such as through existing power exchanges, for both day-ahead and imbalance management, to help optimize resources nationally.
- Reducing information asymmetry (e.g., costs, generator availability) to enable more coordinated dispatch.
- Using coordinated electricity markets to facilitate least-cost dispatch.
- Customizing contracts and allocations to allow greater scheduling and dispatch flexibility.
- Establishing a mechanism to improve coordination requires detailed analysis of market designs and regulatory changes, which are outside the scope of this study.[66]

Potential action: Evaluate options for enhanced coordination. Design questions include: markets vs. non-market options; regional vs. national participation; voluntary vs. mandatory participation; and energy imbalances only or full day-ahead scheduling and dispatch.

3. ***Flexibility from Coal***

This study finds that the minimum stable operating level of coal plants can limit the flexibility of the power system and can therefore increase curtailment of RE. Modifying the minimum generation levels of all coal plants so that the plants can operate at a lower fraction of their rated capacity is one option among many RE integration strategies that policymakers may want to consider, at minimum on a plant-by-plant basis. Reducing the minimum generation levels will

[66] Note, a companion study under USAID and the India Ministry of Power's Greening the Grid program is analyzing policy and regulatory issues associated with scheduling, balancing and forecasting for improved RE integration. This study is based on field investigations at the Indian state and central levels with regulators, utilities, and private sector actors; analysis of central and state Indian regulations; analysis of strategies used in the western United States; and cross-analysis based on stakeholder input.

come at a cost of greater wear and tear on the plants (Lew et al. 2013), and this cost can be evaluated against the costs and benefits of this and other mitigation measures. Because there are many complex system interactions, some combination of mitigation approaches may be most useful.

Potential action: Establish at central and state levels comprehensive regulations regarding flexibility of conventional generators, including minimum generation levels, ramp rates, and minimum up and down times (current CERC regulation applies to central generators but not state generators). Encourage states to match or exceed CERC guidelines for central generators that require 55% minimum operating levels for coal plants; evaluate on plant-by-plant basis further reductions. Provide training curricula that help coal plant operators minimize damage from cycling.

4. ***Flexibility from Hydro***

The flexibility derived from operating hydro and pumped hydro is important for absorbing renewable energy. This study shows that the pump operation is required to be shifted to midday to coincide with greater solar generation output and the generation operation is required during evening peak. The study further shows that hydro generation operates at 16% of installed capacity during high-RE periods.

Potential action: Revise policy/regulatory-level guidelines to use the full capability of hydro and pumped hydro stations. Suitable incentive mechanisms can encourage operation of hydro and pumped hydro depending upon system requirements.

5. ***Weighing Options***

Multiple approaches to alleviate RE curtailment exist, which can be compared to the economics of continuing relatively low-level RE curtailment. Some curtailment may be the most cost-effective option. Approaches to consider here include points raised above: transmission expansion, balancing area expansion, and minimum generating operations of existing plants.

Potential action: Apply production cost simulation tools to evaluate the production cost impacts between curtailment and other options to reduce or eliminate this curtailment. This analysis can be updated periodically as changes to the power system are anticipated.

6. ***Compensating Flexibility***

Central thermal generators receive an availability-based tariff, which is paid based on availability to be scheduled and dispatched, with separate tariff components for the fixed and variable costs. The fixed cost portion is used to pay off fixed (capital) costs of the plant. Distribution utilities must still pay this tariff even as overall plant load factors decline. At the same time, flexibility that will be needed to help manage RE is not explicitly contracted for, reducing the incentive for plants to provide such services. A new framework surrounding PPAs could consider (a) a mechanism to compensate for the plant fixed cost, especially for coal units during the transition to a higher-RE future, in which they would be scheduled less and (b) how to compensate for flexibility that will be needed to manage the increase in variability and uncertainty from higher levels of RE. The challenge is to develop a new framework that can simultaneously address legacy generating plants during the transition to a higher-RE future, plants that come online during the transition and plants that will be developed after the transition has largely occurred. The solution to this issue is also related to whether India moves to more coordinated system operation and, if so, whether this is facilitated by some type of wholesale power market or a coordinating entity.[67] Under a market-based construct, PPAs need to be developed with market design as a backdrop. In either case, however, PPA structures (and market designs) can be revised to recognize, compensate, and incentivize the characteristics that would be needed to operate the power system under a high level of RE. These characteristics include minimum operating levels, ramping, and short start-up, shutdown, and minimum up-/down-times so that investments in power system assets can facilitate efficient system operations.

Potential action: Create a model tariff contract that can be used for contracts that are new and up for renewal based on economics of coal plants with lower plant load factors. For existing contracts, explore options used in other countries to renegotiate contracts. Develop a new tariff structure that moves away from focusing on energy delivery. Agreements can specify various performance criteria, such as ramping, specified start-up or shutdown times, minimum generation levels, along with notification times and performance objectives that achieve flexibility goals. The tariff structure should allow for full cost recovery, be applicable to both renegotiated contracts and new contracts, and be effective both during the transition to a high-RE future and after the high-RE future has been reached.

7. ***Flexibility from RE***

Once RE is brought into the grid, its value should be maximized by dispatching it when it is economical for the system. Traditionally, this value has been achieved through must-run status, as is present in the Indian grid code. However, in some cases RE curtailment is cheaper than costs of, for example, avoided shutdowns and start-ups of coal generation units. The power system could have the physical flexibility to integrate RE, but access to this flexibility could be limited by contract terms. Policymakers could explore alternative means to facilitate merit order dispatch (based on production costs rather than tariffs) and to build confidence in RE investors that their financial risks related to RE curtailment are limited. Policymakers can also require economic optimization (cost minimization) explicitly in power system operations and planning.

Potential action: Use the regulatory platform to require merit order dispatch based on production costs; supplementary software may be required to identify economic scheduling and dispatch that considers the combined effects of conventional and renewable variable costs, transmission congestion and losses, and various other factors.[68] Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks, such as annual caps on curtailed hours. PPAs or regulations can also be used to require commercially available controls and communications systems that help extract the full value of RE from a system perspective.

8. ***Additional Transmission***

A market that is based on a nationally optimized least-cost dispatch principle with no transmission constraints and no barriers to trade between the states and regions is represented by our copper plate sensitivity. This kind of market in India would require additional transmission on certain corridors. The result for this scenario shows that the power flow on the Western-to-Northern region corridor would go up to a maximum 36 GW, and flow on the Eastern-to-Northern region

[67] This coordinating entity could be at the respective state levels (vs. the existing paradigm in which distribution utilities self-schedule, as is the case in many states) or the regional or central level.
[68] Various forms of software could support economic dispatch. In the United States, these programs are known as Security Constrained Unit Commitment and Security Constrained Economic Dispatch tools, which are integrated into the Energy Management Control Systems.

corridor would get reversed for most of the time leading to loop flow from west to north to east. Further, the flow on the Western-to-Southern region corridor would become bidirectional depending upon wind generation in the South.

Potential action: Additional investment in transmission is required for a nationally optimized market based on least-cost dispatch principle with no constraint. More transmission needs to be planned for bulk transfer of power, especially on the Western-to-Northern region corridor. This kind of market would also require a shift in the transmission planning process for which necessary regulatory and policy level guidelines need to be issued.

9. ***Analysis-Based Targets***

Alternative mixes of wind and solar energy in the overall national RE portfolio impact system operations differently. Based on this study, a 175-GW RE target that places greater emphasis on wind over solar (100 GW wind, 60 GW solar), achieves higher RE capacity factors and therefore higher RE penetration levels (26% compared to 22% in the 100 GW solar, 60 GW wind scenario) and lower CO_2 emissions. The characteristics of wind generation (the timing of its availability, its smoothing over large geographies, its impacts on net load ramp rates) make it easier to operate, but this report does not assess the full suite of questions that would be required for a policy cost-benefit analysis, including fixed costs and financing availability, among other factors.

Potential action: Create and maintain a nationwide model that helps optimize generation and transmission build-outs, which can then be used to inform investment decisions and RE policies. Develop an institutional home for this model and for staff that can support it. Make such studies mandatory for generation planning, transmission planning, and operational planning.

10. ***Planning for Beyond 175 GW***

At higher RE levels, such as the 250-GW level evaluated here, continued evaluation of actual and likely RE sites will be important so that system planning can maximize the cost-effectiveness of network design, power system operation, and reliability. At 250 GW RE, the best wind and solar resources remain in the Southern region, but continued siting of RE in that region may create excessively high levels of RE curtailment in the absence of additional mitigation strategies. This issue can be more fully explored in a detailed evaluation of the various trade-offs between high levels of RE in the South with more transmission development vs. diversifying RE development to other, potentially less energetic, locations that require fewer changes. The implication of the type and location of non-RE plants may also be significant.

Potential action: To achieve more ambitious RE levels, use detailed, model-based planning, including both capacity expansion and production cost modeling. This will inform long-term trade-offs and sensitivities to changing technological and economic conditions.

11. ***Forecasting***

The real-time model used in this study assumes certain RE forecast errors based on existing state-of-the-art RE forecasting facilities and perfect load forecast. It is important that each state have state-of-the-art load and RE forecasting facilities to address the challenges posed by large-scale RE integration into the grid.

Potential action: Equip all states with the latest, state-of-the-art load forecasting facilities. In addition, equip RE-rich states with state-of-the-art RE forecasting tools. Further, build capacity of all system operators in this regard so that in-house capability is developed to create and customize such tools in the future.

12. Data Sharing

As is typical for integration studies, acquiring required data for the production cost model was a challenge and assumptions had to be made wherever required data were not available. It is important that data sets for performing basic studies like power flow and production cost studies are made available in the public domain.

Potential action: Regulatory guidelines may be issued to make it mandatory for stakeholders to provide data required to perform production cost studies.

Other strategies may be beneficial to RE integration in the Indian context but were not analyzed in this study. For example, demand response—increasing the responsiveness of electricity demand to operator controls and/or price signals—can improve system flexibility and better align demand with RE supply. This type of flexibility can be accessed through a combination of software, controls, regulatory interventions, retail tariffs, and incentives. For example, air-conditioning and agricultural pumping may be possible sources of flexible load.[69]

Policies that have a neutral impact on RE integration at this time:

1. Ramping

This study found that fast-ramping (non-RE) plants are not necessary at the penetration levels associated with 160 GW of wind and solar because ramping as low as 0.5% of maximum capacity per minute results in no significant change in either production cost or RE curtailment. Although it is possible that ramping could become a constraint in high-RE futures, there are several technologies that could provide fast ramping. Rather than dictating a specific flexible technology, policies can instead focus on the attribute. If faster ramping is identified as a future need, a policy approach that focuses on the needed capability in a technology-agnostic way can incentivize the most cost-effective technology (which may be some new unforeseen technology). We did not evaluate ramping capabilities in time periods less than 15 minutes.

2. Storage

As modeled in this study, batteries reduce RE curtailment, but the value of that gain in electricity is offset by efficiency losses generated by the battery in operations. Batteries have almost no effect on production costs or CO_2 emissions. A number of changes could affect the value of batteries, including improvement to battery efficiencies and broadening the value of batteries to include mitigation of local transmission constraints and/or provision of ancillary services. Valuing these services is outside the scope of this study.

[69] Efforts under way in this regard include an automated demand side management pilot under Greening the Grid, which is a partnership between USAID, BESCOM, SRLDC, Karnataka Power Transmission Company Limited, and Innovari. This pilot aims to provide the utility and grid operators with a software platform to access flexibility in large commercial and industrial consumer end uses. A companion study under way by U.S. Department of Energy laboratories will investigate how to scale automated demand side management in India for the purpose of supporting RE integration.

APPENDIX A. WIND AND SOLAR RESOURCE DATA AND GENERATION PROFILES

This appendix provides details on how the wind and solar resource data were produced—both actuals and forecasts—and how these data were used to identify sites for new capacity and create site-specific RE generation profiles.

Wind Actuals and Forecasts

We simulated the wind actuals data using the Weather and Research Forecasting (WRF) model, a mesoscale numerical weather prediction model designed for atmospheric research and weather forecasting. We created an annual data set of physical parameters for the year 2014 that includes wind speed, relative humidity, and temperature at a spatial resolution of 3 km, and a temporal resolution of 5 minutes. We used the Climate Forecast System Reanalysis data to define the boundary conditions (conditions that are specified at the edge of the India model domain). The wind actuals data set encompasses all states that are known to have a significant quality of wind resource.[70] We then extracted the data at heights of 80 m and 100 m to correspond to the hub heights of wind turbines that are most likely to dominate the installed capacity in 2022.

For the wind forecasts, we used the WRF model with the Global Forecast Ensemble System data as boundary conditions at a spatial resolution of 9 km and a temporal resolution of 30 minutes. This method was adopted from the Wind Integration National Dataset Toolkit, which was developed by NREL for the continental United States (Draxl et al. 2015). We chose Global Forecast Ensemble System data and a lower resolution of 9 km to produce day-ahead wind forecasts because higher-resolution model runs, such as for the wind actuals, have shown to produce unrealistic forecast errors that were too low. The lower resolution of the forecast data enables us to simulate day-ahead forecast errors that are comparable to current state-of-the-art forecasts.

Solar Actuals and Forecasts

The solar actuals data, in the form of global horizontal irradiance (GHI), is from NREL's National Solar Radiation Database (NSRDB), simulated using the SUNY Semi-Empirical model.[71] This model accounts for aerosols as well as cloud cover using observational data from 2014. These data have a temporal resolution of one hour, which we linearly interpolated to 15 minutes to match the resolution of our electricity model (see Section 2.2.5, "Operations"). The spatial resolution of the data is 10 km.

The solar forecasts were created from the same WRF model used to generate the wind forecast data. The WRF model produced the GHI, and meteorological data sets at half-hourly and 9-km temporal and spatial resolutions. The data sets were interpolated to 15-minute interval and translated to direct normal irradiance and the diffuse horizontal irradiance, which were the required input parameters in the power generation software, System Advisor Model (SAM). Compared to the NSRDB used for solar actuals, the WRF model has a lower accuracy in predicting effects on radiation due to cloud cover. The WRF model also does not account for the effects of aerosols, thus over-predicting solar radiation. Therefore, the solar radiation forecasts provided, on average, a 5% bias toward higher solar resource availability compared to actuals. Because a 5% bias on 100 GW is potentially significant, we

[70] The extent consists of two square areas and includes the states of Andhra Pradesh, Chhattisgarh, Gujarat, Karnataka, Kerala, Madhya Pradesh, Maharashtra, Orissa, Rajasthan, Tamil Nadu, Telangana, and Uttar Pradesh.
[71] https://nsrdb.nrel.gov.

adjusted the power generation profiles to remove the bias (at each substation for each month and hour of day) but maintain the forecast errors as described in the section on RE Generation Data below.

RE Site Suitability Analysis

Not all locations are appropriate for new RE installations, even if the solar or wind resource availability is high. To choose locations for new installations, we first conducted a preliminary screening for suitable sites, excluding areas unsuitable for RE such as water bodies and land dedicated to alternative uses (e.g., agricultural land in the case of solar). Table 45 summarizes the categories from the National Remote Sensing Centre's land use and land cover geospatial data considered unsuitable for each technology. We also excluded areas with resource quality below thresholds of 5.5 m/s wind speed (approximately 200 Watts per m^2 power density) for wind and 4.3 kilowatt-hours per m^2 per day for solar PV. We also excluded areas with slopes greater than 5% for solar and 20% for wind, as well as those areas with elevation above 5,000 m. Finally, we also excluded land designated as protected areas.[72] Site suitability analyses were performed at 500-m resolution using South Asia Albers Equal Area Conic projection.

[72] World Database for Protected Areas and Protected Planet.

Table 45. National Remote Sensing Centre's Land Use/Land Cover Categories Included for Each Technology

CODE	CATEGORY	UTILITY-SCALE SOLAR	ROOFTOP PV	WIND
1	Built-up (urban)	excluded	-	excluded
2	Kharif (cropland)	excluded	excluded	-
3	Rabi (cropland)	excluded	excluded	-
4	Zaid (irrigated cropland)	excluded	excluded	-
5	Double/triple (irrigated cropland)	excluded	excluded	-
6	Current fallow (cropland)	excluded	excluded	-
7	Plantation/orchard	excluded	excluded	excluded
8	Evergreen forest	excluded	excluded	excluded
9	Deciduous forest	excluded	excluded	excluded
10	Scrub/degenerated forest	excluded	excluded	excluded
11	Littoral swamp	excluded	excluded	excluded
12	Grassland	-	excluded	-
13	Other wasteland	-	excluded	-
14	Gullied	excluded	excluded	excluded
15	Scrubland	-	excluded	-
16	Water bodies	excluded	excluded	excluded
17	Snow covered	excluded	excluded	excluded
18	Shifting cultivation	excluded	excluded	-
19	Rann	-	excluded	-

We then split these suitable areas into spatial units of approximately 5 x 5 km^2, which we define as potential project sites. Typical land use factors for wind and utility-scale solar are 9-MW per km^2 and 30 MW per km^2, respectively (Denholm et al. 2009; Ong et al. 2013). However, the entire area of a potential project site may not be available for RE development. By restricting the land availability to 25%, we assumed effective land use factors of 2.25 MW per km^2 for wind and 7.5 MW per km^2 for utility-scale solar plants.

RE Site Selection

Based on the methodology described in Section 2.2.3, we selected sites for each scenario, starting with suitable sites within 25 km of existing RE power plants or RE pooling substation as shown in Figure 79, and then the best available sites to meet overall capacity targets for each technology.

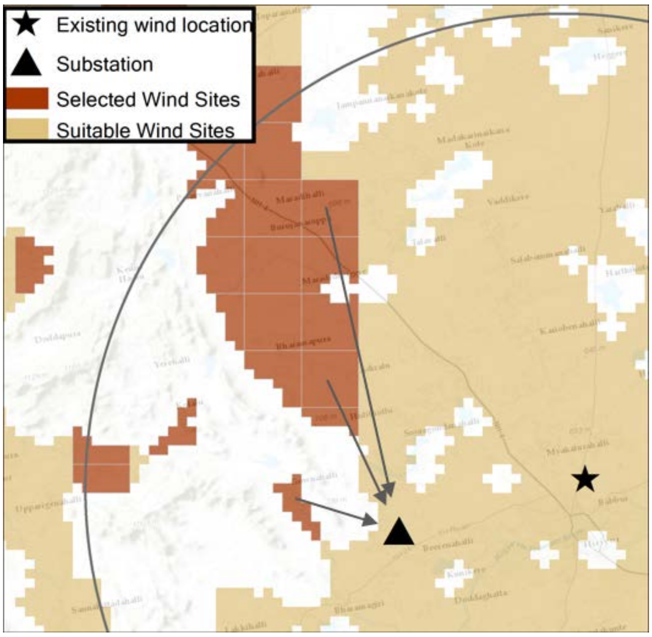


Figure 79. Suitable and selected wind sites and their association with nearest substation.

Circle represents 25-km distance from existing wind power plant or RE pooling substation.

Table 46, Table 47, and Table 48 summarize installed capacity of wind, utility-scale PV, and rooftop PV by state for each scenario. Because of the discrete sizes of the potential project sites, the actual capacities selected in each state and total capacities for each scenario may differ slightly from the nominal targets chosen for the study scenarios. This small mismatch has an insignificant effect on the results of the study. Further, the islands of Lakshadweep, Andaman, and Nicobar are excluded from the study because they are not part of the Indian national grid.

Table 46. Total Installed Wind Capacity (MW), by State and Scenario

STATE	NO NEW RE[73]	20S-50W	100S-60W	60S-100W	150S-100W
Andhra Pradesh	1,037	6,755	8,111	13,495	13,495
Gujarat	3,639	7,329	8,808	14,663	14,663
Karnataka	2,856	5,166	6,199	10,332	10,332
Madhya Pradesh	881	5,179	6,207	10,329	10,329
Maharashtra	4,442	6,328	7,589	12,662	12,662
Orissa	0	256	313	510	510
Rajasthan	3,728	7,174	8,600	14,327	14,327
Tamil Nadu	5,790	9,912	11,891	19,817	19,817
Telangana	0	1,679	2001	3,333	3,333
Uttar Pradesh	0	264	304	501	501
Total	22,373	50,042	60,023	99,969	99,969

[73] No New RE installed capacities represent current installed capacities as of March 2015 for wind (Source: InWEA) and May 2015 for utility-scale solar (Source: MNRE, http://mnre.gov.in/file-manager/UserFiles/State-wise-Installed-Capacity-of-Solar-PV-Projects-under-various-Scheme.pdf.).

Appendices

Table 47. Total Installed Utility-Scale Solar Capacity (MW), by State and Scenario

STATE	NO NEW RE	20S-50W	100S-60W	60S-100W	150S-100W
Andhra Pradesh	271	1,787	8,950	5,364	16,439
Assam	0	0	90	90	90
Chandigarh	24	24	24	24	24
Chhattisgarh	16	16	538	538	538
Delhi	28	28	28	28	28
Gujarat	1,048	1,266	8,951	2,031	16,449
Haryana	92	92	559	559	559
Himachal Pradesh	0	0	1,004	1,004	1,004
Jammu & Kashmir	0	0	138	138	138
Jharkhand	28	28	28	28	28
Karnataka	80	1,784	8,950	5,109	16,476
Kerala	0	70	230	230	230
Madhya Pradesh	596	846	3,406	3,406	3,406
Maharashtra	594	594	2,157	2,120	14,404
Meghalaya	0	0	33	33	33
Nagaland	0	0	87	87	87
Orissa	41	41	1,012	1,012	1,012
Punjab	210	210	210	210	210
Rajasthan	1,953	2,184	8,982	6,163	16,467
Tamil Nadu	160	1,811	8,931	5,222	16,444
Telangana	73	661	3,957	1,065	4,216
Tripura	41	41	41	41	41
Uttar Pradesh	0	244	638	638	638
Uttarakhand	0	0	63	63	63
West Bengal	28	28	502	502	502
All India	5,283	11,755	59,509	35,705	109,526

Table 48. Total Installed Rooftop PV Capacity (MW), by State and Scenario

STATE	NO NEW RE	20S-50W	100S-60W	60S-100W	150S-100W
Andhra Pradesh	0	398	1,998	1,198	1,998
Assam	0	49	249	149	249
Bihar	0	198	998	598	998
Chandigarh	0	19	99	59	99
Chhattisgarh	0	138	698	418	698
D. & N. Haveli	0	40	200	120	200
Delhi	0	218	1,098	657	1,098
Goa	0	30	150	90	150
Gujarat	0	635	3196	1,914	3,196
Haryana	0	318	1598	958	1,598
Jammu & Kashmir	0	88	448	268	448
Jharkhand	0	160	800	480	800
Karnataka	0	457	2,296	1,376	2,296
Kerala	0	160	800	480	800
Madhya Pradesh	0	434	2,197	1,313	2,197
Maharashtra	0	931	4,690	2,811	4,690
Manipur	0	9	49	29	49
Meghalaya	0	9	49	29	49
Mizoram	0	10	50	30	50
Nagaland	0	10	50	30	50
Orissa	0	199	999	599	999
Puducherry	0	20	100	60	100
Punjab	0	399	1,999	1,199	1,999
Rajasthan	0	456	2,295	1,377	2,295
Tamil Nadu	0	694	3,496	2,095	3,496
Telangana	0	399	1,998	1,198	1,998
Tripura	0	9	49	29	49
Uttar Pradesh	0	850	4,291	2,570	4,291
Uttarakhand	0	70	350	210	350
West Bengal	0	417	2,098	1,257	2,098
All India	0	7,824	39,388	23,601	39,388

For the primary scenario analyzed (the official 100 GW solar, 60 GW wind), Table 49 summarizes total RE capacity by state, and in comparison to the MNRE state-wise targets for wind and solar. We assume any states with capacities under their targets will purchase RE capacity or RE credits from the higher-RE states. This study does not evaluate political implications of meeting the MNRE targets, for example if there is resistance from states to add RE capacity above RPO targets, or policy and regulatory changes that might be needed to enforce RPO targets.

Table 49. Total Installed RE Capacity (GW) by State for the 100S-60W Scenario and in Comparison to the MNRE State-Wise Targets[74]

STATE	100S-60W (GW)	MNRE STATE-WISE TARGETS FOR WIND AND SOLAR (GW)
Andhra Pradesh	19.1	17.9
Assam	0.3	0.7
Bihar	1.0	2.5
Chandigarh	0.1	0.2
Chhattisgarh	1.2	1.8
D. & N. Haveli	0.2	0.4
Delhi	1.1	2.8
Goa	0.2	0.4
Gujarat	21.0	16.8
Haryana	2.2	4.1
Himachal Pradesh	1.0	0.8
Jammu & Kashmir	0.6	1.2
Jharkhand	0.8	2.0
Karnataka	17.4	11.9
Kerala	1.0	1.9
Madhya Pradesh	11.8	11.9
Maharashtra	14.4	19.5
Manipur	0.0	0.1
Meghalaya	0.1	0.2
Mizoram	0.1	0.1
Nagaland	0.1	0.1

[74] The total RE capacity is slightly lower than the official MNRE target of 160 GW as per the individual state targets provided by MNRE (Source: http://mnre.gov.in/file-manager/UserFiles/Tentative-State-wise-break-up-of-Renewable-Power-by-2022.pdf.)

STATE	100S-60W (GW)	MNRE STATE-WISE TARGETS FOR WIND AND SOLAR (GW)
Orissa	2.3	2.4
Puducherry	0.1	0.2
Punjab	2.2	4.8
Rajasthan	19.9	14.4
Tamil Nadu	24.3	20.8
Telangana	8.0	2.0
Tripura	0.1	0.1
Uttar Pradesh	5.2	10.7
Uttarakhand	0.4	0.9
West Bengal	2.6	5.3
All India	158.9	159.5

RE Generation Data Profiles

This section describes the process to create site-specific, time-series generation data, repeated for both actuals and forecast data.

To create the 15-minute-interval solar generation data, we used the solar data associated with each selected solar PV project site as inputs to SAM. We assumed each solar PV project to be a fixed-tilt system, with the tilt set at the latitude of the site location. We estimated the power generation for 1-MW_{AC} systems and extrapolated those data to the potential installed capacity at each selected solar site. We assumed no degradation in PV panel quality. See Table 50 for assumptions used in the SAM simulation.

Table 50. Assumptions for Solar PV Generation Simulation in the System Advisor Model

PARAMETER	VALUE
System DC capacity	1.1 MW_{DC}
DC-to-AC ratio	1.1
Tilt of fixed-tilt system	Latitude of location
Azimuth	180°
Inverter efficiency	96%
Losses	14%
Ground cover ratio	0.4

To create wind generation data, we classified each selected wind project site into the three prevalent wind turbine classes based on the average wind speed for that site. We used normalized wind power curves for each of the classes and adjusted them for 10 different air densities.[75] We estimated air densities for all sites using temperature and relative humidity data from the WRF model, and elevation from the digital elevation model. Associating each wind project site to the appropriate wind power curve based on the wind turbine class, hub height, and average air density of the location, we then converted the wind speeds into wind power generation for all selected sites.

For creating the wind and solar generation inputs for the production cost model, we associated each selected RE site to the nearest geospatially located substation, as shown in Figure 79. We then aggregated the generation profiles of all RE sites associated with a particular substation to create a normalized RE generation profile and an aggregated installed RE capacity for that substation.

RE Forecast Analysis

Errors between the day-ahead RE forecast and real-time RE generation influence production costs, RE curtailment, and unserved energy in a power system. On the one hand, an overforecast (when forecast is higher than actual generation) can lead to fewer conventional generation units being committed day-ahead to serve net load and in real time may lead to more expensive units (such as faster responding combustion turbines) being dispatched to meet the energy shortfall, or the error could result in unserved energy in the absence of such units. On the other hand, an underforecast (when forecast is lower than actual generation) can lead to more inflexible conventional generation units (such as coal) being committed day-ahead that in real time cannot back down below their minimum generation levels to accommodate the unexpected higher RE generation levels, thus potentially leading to RE curtailment. In both cases, production costs increase, either because of dispatch of more expensive generators, cost of unserved energy, or curtailment of zero-variable-cost RE generation.

Figure 80 shows the distribution and means of day-ahead, mean absolute forecast errors for utility-scale solar PV, rooftop solar PV, and wind generation profiles aggregated at the substation level for each state in the 100S-60W scenario. The average mean absolute errors across the states were relatively small for solar generation (2%–5%) but much higher for wind generation (12%–15%).

Appendices

[75] Normalized wind power curves were developed by NREL by aggregating power curves from different wind turbine models, and normalizing by their turbine ratings (King, Clifton, and Hodge 2014).

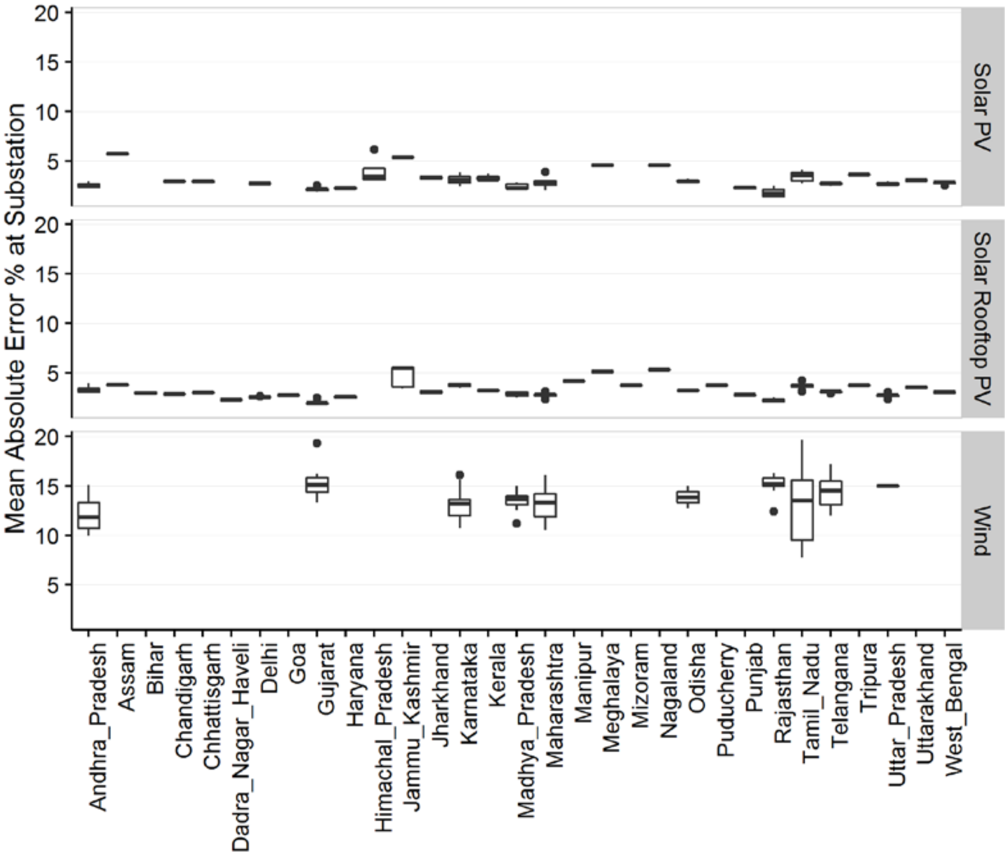


Figure 80. Distribution of day-ahead, mean absolute error for solar and wind generation at the substation level for each state in the 100S-60W scenario

Although the methodology for creating forecast and actual RE generation profiles was developed to simulate realistic day-ahead forecast errors, actual realized errors on the ground may differ depending upon the forecast methodology, availability of data, time between forecast and real time, amount of RE capacity connected at the substation, and other factors.

As RE capacity connected to a substation increases, the geographical diversity of RE sites increases, and the correlation between forecast errors of the connected fleet decreases. Therefore, mean absolute forecast errors of the aggregated RE generation profiles at the substation level decrease as connected RE capacity increases. This relationship between the mean absolute forecast error and the RE capacity connected at the substation is shown in Figure 81.

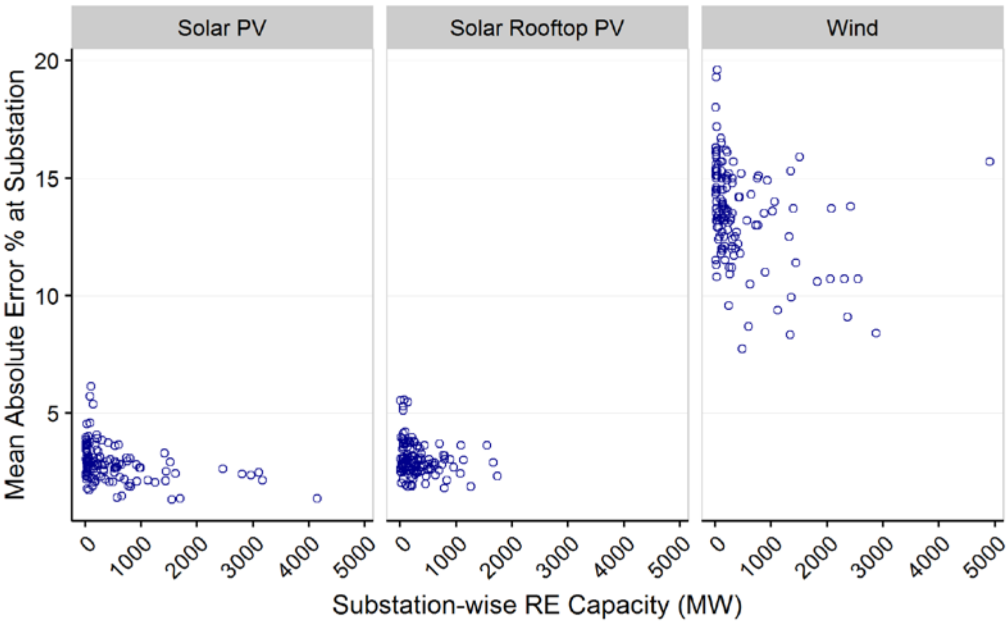


Figure 81. Relationship between mean absolute forecast error at substation level and the connected RE capacity in the 100S-60W scenario

Figure 82 shows the distribution of mean absolute forecast errors for solar and wind generation aggregated at the state level for all RE build-out scenarios. Forecast errors of RE generation aggregated at the state level are lower than those aggregated at the substation level because of aggregation of generation profiles across larger capacities. In our model, the mean absolute errors averaged across all states are between 2% and 3% for solar generation across all scenarios, but those for wind generation are between 8% and 12%.

We used existing wind locations to select sites in the No New RE scenario. These existing wind locations were relatively geographically diverse. For wind site selection in higher-RE scenarios, our algorithm, after selecting sites around existing locations, selected the best sites within a state, which were more concentrated than the No New RE scenario. Therefore, the state-level forecast errors for the higher-RE scenarios appear to be greater than the No New RE scenario. With higher wind targets, as more sites were selected across a state, the geographical diversity increased, and, consequently, mean state-level forecast errors decreased. Similarly, for utility-scale solar PV site selection, the 20S-50W scenario has significant geographical diversity because of site selection in known solar park locations. For the 60-GW solar PV target, after selecting sites around known plant locations and solar parks, utility-scale solar PV sites were selected based on best available solar resource. These selected sites were more concentrated than the 20-GW solar target scenario and resulted in slightly higher mean forecast errors. With even higher solar PV targets (100 GW and 150 GW), the geographical diversity of sites across a state increased, resulting in a drop in state-level mean forecast errors. While the relative comparison of errors between scenarios are somewhat dependent on our site selection algorithm, overall, mean absolute forecast errors at the state level should decrease with higher RE capacities due to increased geographical diversity.

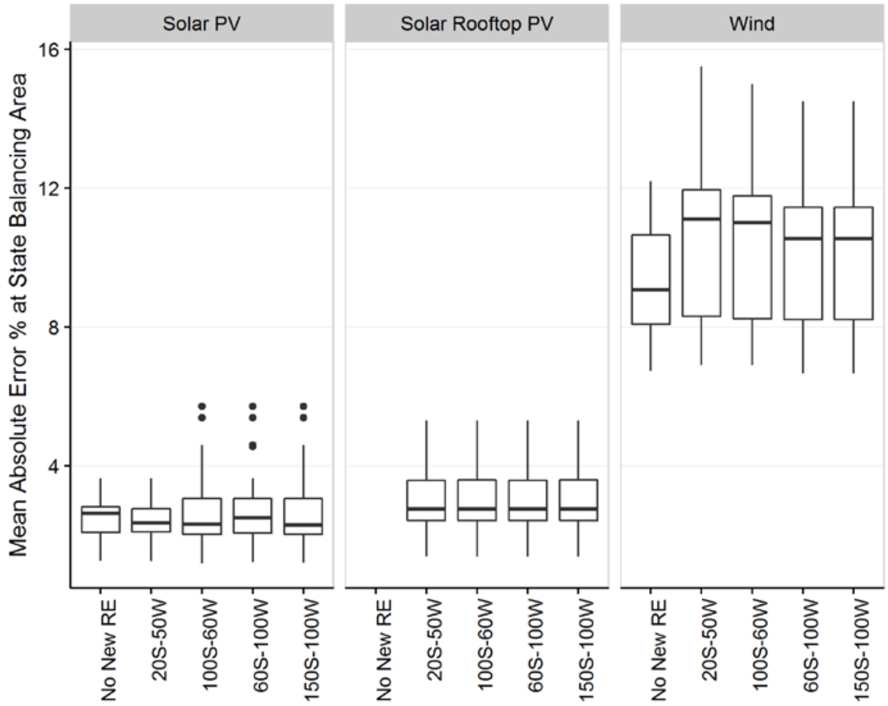


Figure 82. Distribution of mean absolute errors for solar and wind generation at state balancing area level for each RE build-out scenario

APPENDIX B. UC AND ED MODEL SETUP AND EXECUTION

We simulate unit commitment and economic dispatch decisions using mixed-integer programming (MIP) with the software package PLEXOS Integrated Energy Model, developed by Energy Exemplar.[76] The software commits and dispatches generators to meet load with cost minimization as the objective function, while adhering to thousands of physical constraints, including transmission limits, generator parameters, and hydro energy limits. As noted in Section 2.2.5, we do not model bilateral contracts, allocations of centrally owned plants, or must-run status of conventional plants needed for reliability. Unserved energy is permitted at a price of INR 1 crore per MWh.[77] We use a DC-Optimal Power Flow formulation and do not model transmission losses.[78]

Day-Ahead and Real-Time Execution

System operations in India are scheduled by three tiers of state, regional, and national LDCs. An LDC typically evaluates costs and makes decisions about unit commitment and dispatch the day before the start of operations. Because of unexpected outages and forecasting errors, it adjusts its original schedule to maintain energy and frequency balance in real time (RT). In India, schedules are iteratively revised and republished, sometimes dozens of times as system conditions change.

Similar to how the Indian power system operates, our model runs in two temporal resolutions and in a sequence similar to a day of operations. A day-ahead (DA) simulation uses forecasted RE to optimize for the commitment of larger, inflexible generators for each hour of the upcoming day. The commitment status of these inflexible generators is then used in the RT, or actual, operation phase to redispatch based on updated information about actual RE generation. Some fast-start units, such as diesel or combustion turbines, are also allowed to start in this phase. The following sections give details of generator constraints and modeling assumptions regarding the sequence of operations.

DA–RT Setup

The DA simulation receives all information about generator availability, with the exception of RE generation, which is based on forecasted rather than actual availability. Note the model ignores changes to availability between DA and RT for generation (due to forced outages) and load (due to forecast errors). The model applies yearly, monthly, and daily constraints in a three-stage process and solves 365 one-day optimization steps, each consisting of 24-hour intervals. This optimization step mimics actual planning decisions in an operations room with DA schedules, but there are sometimes less quantifiable decisions being made that include knowledge of conditions beyond 24 hours into the future (e.g., Tomorrow's peak load will be large because it is a holiday; most big generators should be kept spinning). To more closely align the decision making of the model with reality, each DA schedule optimizes based on 24 hours of 1-hour resolution, plus an additional 24 hours of look-ahead which uses less granular data (4-hour temporal resolution). The second 24-hour period is not directly used for dispatch, but affects commitment and dispatch decisions for the day in focus.

Table 51 summarizes the constraints of generators in each phase of the simulation by fuel type. The DA outputs for hydro generation; hydro pump load; and the commitment status of coal, nuclear, and

[76] We used version 7.3 with a minor software bug fix performed by Energy Exemplar in December 2016. Consequently, all study simulations were performed with a nonpublicly released version of PLEXOS, although modifications to software were passed through to version 7.4 releases of PLEXOS.
[77] For a more complete analysis of unserved energy see Section 4.7 and Appendix D.
[78] Load data collected by POSOCO already includes any losses on the state transmission networks based on the point of collection.

gas CC generators become fixed inputs to the RT. The RT simulation then reoptimizes generation using actual RE generation instead of the DA forecast RE profiles, allowing the generators with fixed commitments to ramp in RT within their operating parameters. The RT simulation solves in 35,040 steps of 15 minutes each.

Table 51. Commitment and Dispatch Constraints and Optimization Between DA and RT Simulations

Note: All fixed RT unit commitments are based on DA outputs.

	DA COMMITMENT STATUS AND DISPATCH SET POINT		RT COMMITMENT (ON/OFF)	RT DISPATCH SET POINT
Nuclear	Fixed[79]	→	Fixed	Fixed
Coal	Optimized	→	Fixed	Optimized
Gas CC	Optimized	→	Fixed	Optimized
Diesel	Optimized		Optimized	Optimized
Run-of-river hydro	Fixed	→	Fixed	Fixed
Other hydro	Optimized		Fixed	Fixed
Other dispatch	Optimized		Optimized	Optimized

Unless otherwise noted, all results presented in this report are from the RT results.

Operational Assumptions for Wind and PV

Wind and solar generators have no marginal costs in our model. Their available generation is based on forecasted and actual generation profiles that represent free available energy inputs to the power system. Because of insufficient load, transmission constraints, generator inflexibility, and export charges, it is not always optimal or possible to make use of available RE generation. Our model allows all RE except rooftop PV to curtail generation.

[79] Nuclear units are always committed in DA at 100% if not on outage.

APPENDIX C. 2014 MODEL DEVELOPMENT AND TRANSLATION TO 2022

To validate the data and methodology used for this study, we ran several cases with a database representing system conditions in 2014. By comparing these results to actual data from 2014, we confirmed that our model could show credible trends in grid outcomes on national and regional levels. We then built our 2022 model using validated properties from the 2014 database, such as generator characteristics, interface transfer capability limits, and the amount of market friction between states and regions. This appendix describes the process of building the 2014 database, final results of the validation simulations, and the combination of 2014 data with assumptions about future generation build-out used to construct the 2022 database.

2014 Model Development

The 2014 model was based on POSOCO's PSS/E database representing peak load in October 2015. Our model represents a steady state of operations, meaning any outages or contingencies that may have existed during that time are ignored, and the full network model is used. This PSS/E case details the Indian system network and comprises network topology, line and transformer impedances, and generator location and capacity. To run this case in a production cost model, we added economic properties (such as variable cost and fuel type) and intertemporal constraints (such as ramp rates and hydro energy production limits). These additional data came from experts at agencies under Ministry of Power such as POSOCO and POWERGRID and common assumptions made in other production cost modeling work. Table 52 summarizes the origin of most of the data in our final 2014 database.

Table 52. Summary of Sources for Data in the 2014 Database

DATA	SOURCE
Network data (node connections, line ratings and impedances, transformer ratings and impedances, generator node, generator max capacity)	POSOCO Full Network Model (October 2015, peak load, no outage lines)
Generator fuel type, variable cost	Collected by POSOCO for all states where available. Where not available, noncapacity weighted average by region and fuel type
Generator technical minimums	CERC regulations
Generator outage rates	CEA's "Recommendations on Operation Norms for Thermal Power Stations Tariff Period 2014-19" where available; if not available, assumptions were taken from similar databases (WECC 2024 Common Case, www.wecc.biz/Reliability/2024-Common-Case.zip). Gas outage rates were calibrated based on CEA reported fleetwide outage rates for March 2015 (www.cea.nic.in/reports/monthly/generation/2015/March/actual/opm_17.pdf).
Generator repair times	WECC 2024 Common Case
Generator min up/down times	WECC 2024 Common Case, with modifications suggested by POSOCO

DATA	SOURCE
Generator ramp rates, min up/down time, start costs	Fuel-based assumptions from NTPC
Generator start costs	NTPC and CEA's "Recommendations on Operation Norms for Thermal Power Stations Tariff Period 2014-19"
Available transfer capacity (ATC) between regions	POSOCO, using 2014 data
2014 wind and solar generation data	From states, collected by POSOCO
Hydro operations limits	SCADA data, submitted by RLDCs
2014 load profiles and distribution between nodes	POSOCO load profiles by state for 2011–2014, load node distribution factors calculated from the 2014 POSOCO PSS/E model

We also included hurdle rates, which, as described in Section 3, are the charges added to states' net exports and on transmission lines between regions. These hurdle rates do not reflect actual system charges but instead are proxies that represent the suite of contracts, policies, and limited information exchange that may prevent optimal dispatch from occurring in a large, decentralized electricity system. The magnitude of these hurdle rates determines the ease with which different states and regions can trade with each other: the higher the hurdle rate, the more difficult trading is. During the validation process, we tested a range of hurdle rates to identify the appropriate magnitude, as discussed in the next section.

2014 Model Validation

Validating the 2014 model was a two-phase process. First, we ran a case to ensure that our generator, line, and transformer properties were producing results resembling historical data. This included checking more general trends in our operations model; such as defining interfaces from existing transmission line information, fine-tuning hydro assumptions to ensure operations are reflective of reality, and assuring generator parameters produce operations reflective of typical plants in India. Then we iteratively adjusted hurdle rates between states and between regions by setting these rates to certain values, running a year-long simulation, comparing generation by fuel type and interregional transmission flows between the simulation results and actual data from 2014, and using these comparisons to adjust hurdle rate values in the next iteration. During this process, we also allowed for tuning of generator properties like outage rates for gas and nuclear plants. Table 53 shows the hurdle rates that are used on regional interfaces for the 2022 model.

Table 53. Interregional Hurdle Rates (INR per MW) That Were Calibrated with Our 2014 Model Validation and Transferred to our 2022 Model

INTERFACE	CHARGE ON FLOW IN REFERENCE DIRECTION	CHARGE ON FLOW IN OPPOSITE DIRECTION
ER to NER	1000	225
ER to NR	500	250
ER to SR	225	1,050
ER to WR	225	550
WR to NR	450	850
WR to SR	550	350

Figure 83 (annual generation), Figure 84 (monthly generation), Figure 85 (interregional transmission flows), and Figure 86 (daily hydro generation) compare actual data versus simulated results and were the primary comparison metrics for calibration. Hurdle rates from this case were used in the 2022 database.

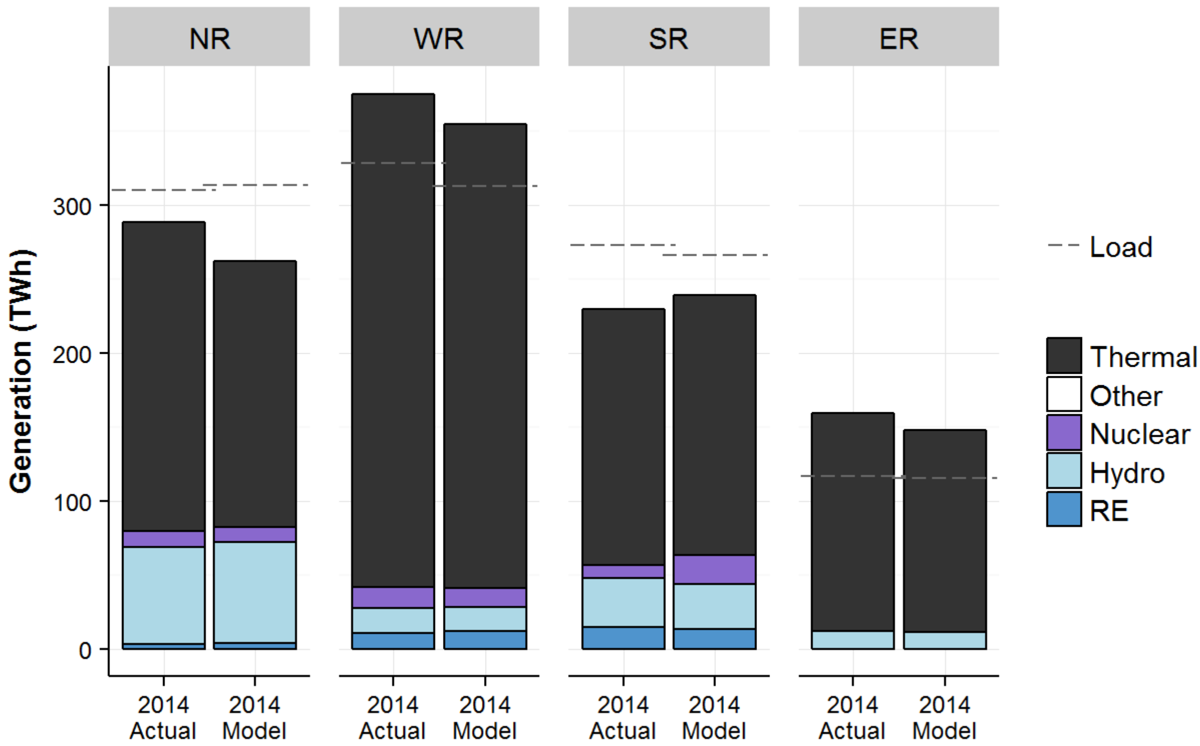


Figure 83. Total annual generation, by fuel type and region, comparing 2014 actual data and model results

Note: The figure illustrates that the distribution of thermal, nuclear, hydro, and renewable generation, and the magnitude of interregional imports and exports, are similar between the actual and modeled results.

Appendices

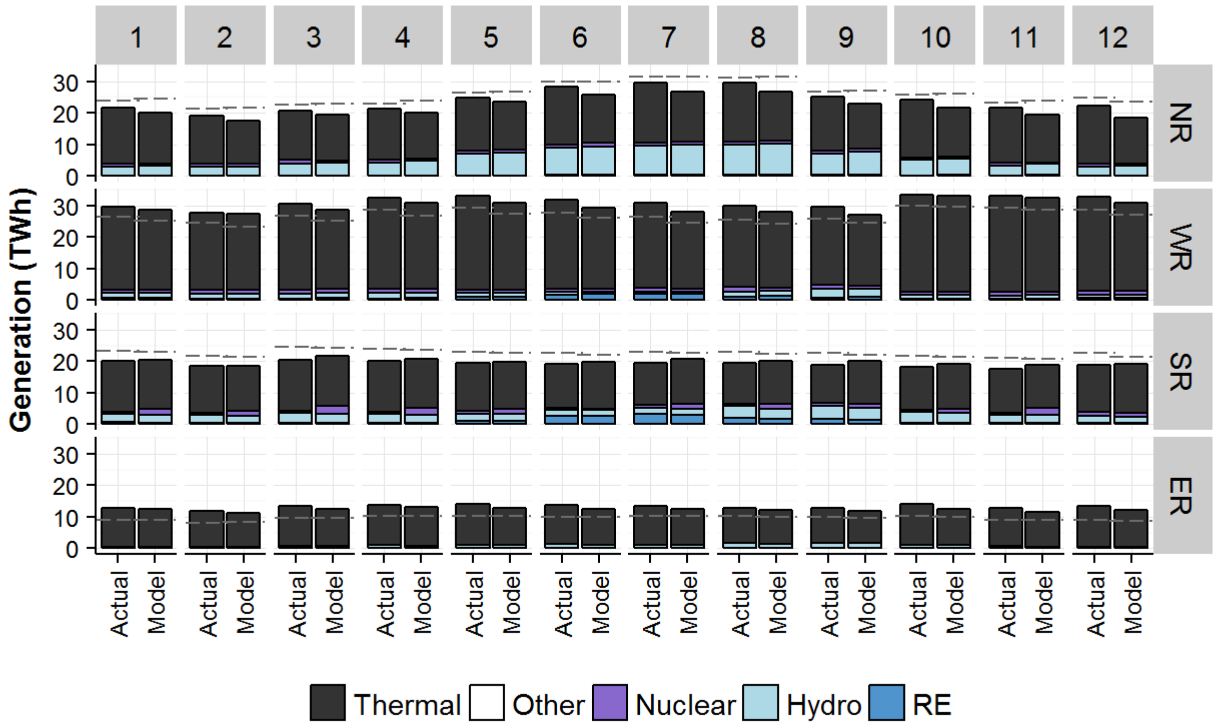


Figure 84. Monthly generation, by fuel type and region, comparing 2014 actual data and model results

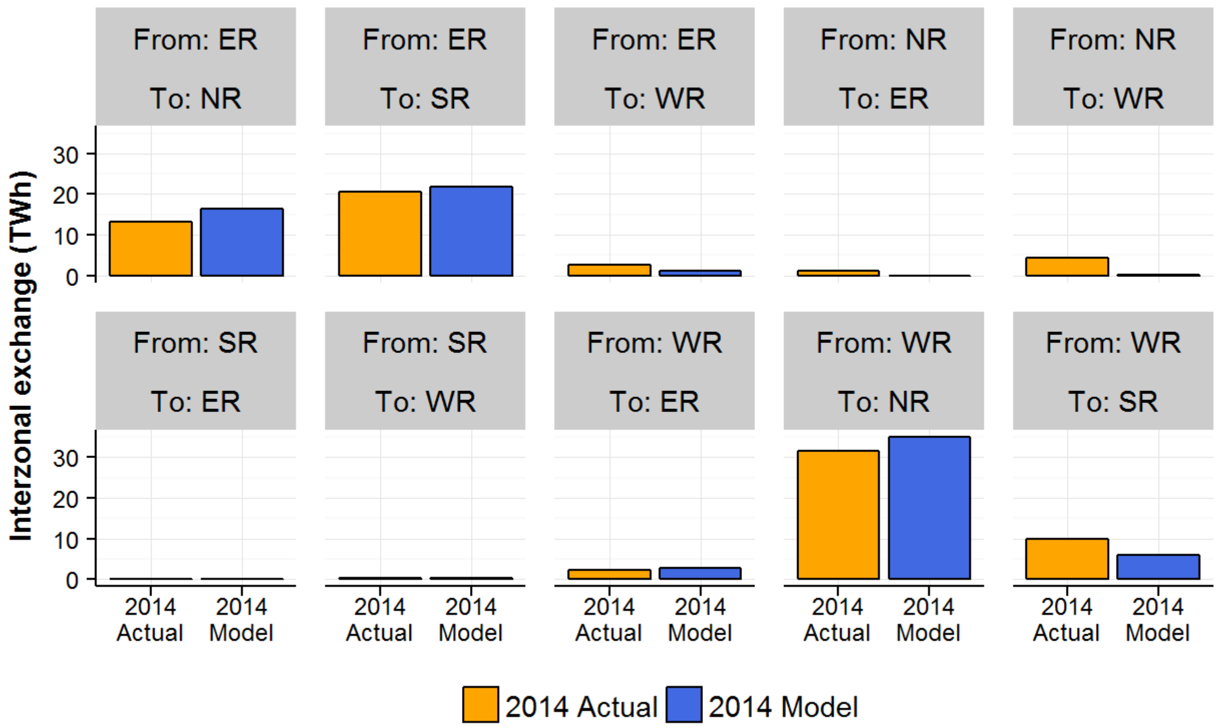


Figure 85. Total annual flows between regions, comparing 2014 actual data and model results

Appendices

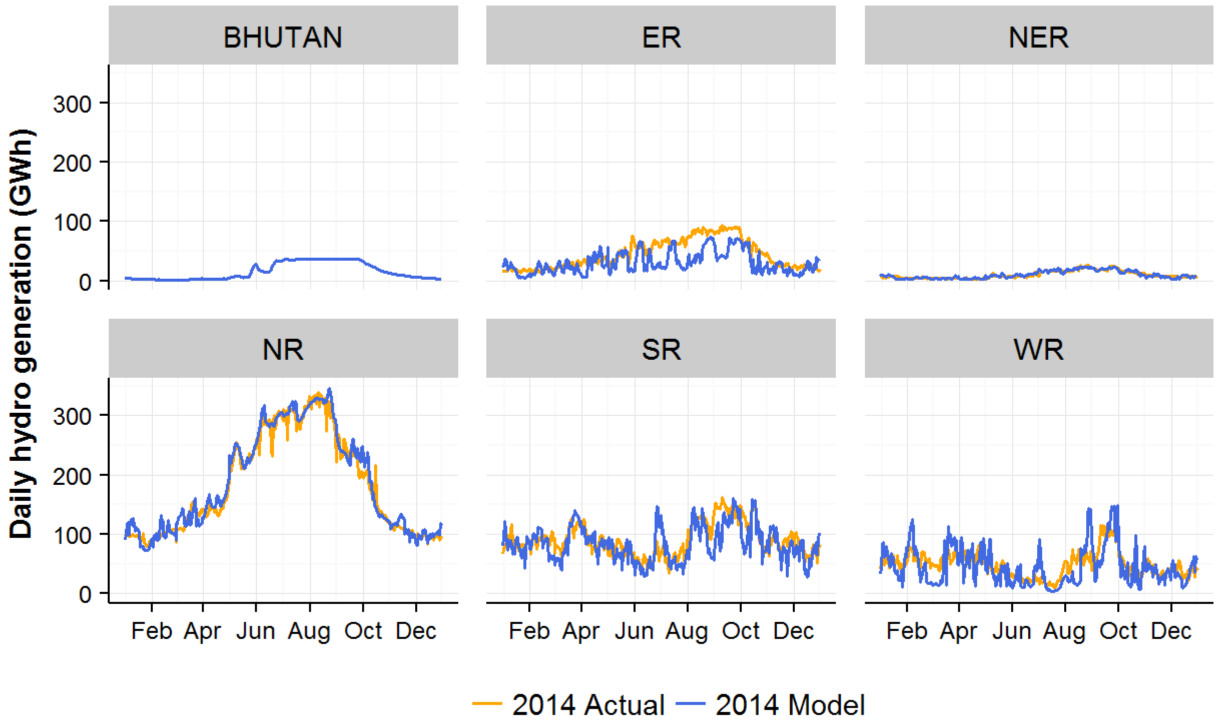


Figure 86. Daily hydro daily generation, comparing 2014 actual data and model results

As indicated by these figures, our models are able to reflect trends in actual system behavior, including generation by fuel type and flow patterns. This gave us confidence that a database representing a future system using similar data and methodology would be able to produce useful and relevant results.

Building the 2022 Database

Similar to the 2014 case, the 2022 database was built from CEA's 2021–2022 PSS/E file with additional economic and intertemporal constraint data. The primary steps for building this database are described in Section 2.2. We used the calibrated hurdles rates from the 2014 validation process in the 2022 database to represent scenarios in which barriers to centralized optimization remain in the future.

Translating Properties from 2014 to 2022

The CEA 2022 PSS/E file that serves as the basis for our assumptions on generation and transmission build-out uses different node names and a slightly different network representation compared to the 2015 PSS/E database. Because the production cost model was validated using the 2015 file, we wanted to use the properties of the 2014 PLEXOS model—generator fuel type, variable cost, outage rate, and hydro operations limits—but the build-out and network representation of the CEA 2022 database. To do this, we implemented a set of network-matching algorithms to find mappings between nodes in the two databases. Using a combination of these algorithms and some manual matching, we were able to account for 95% of the 2014 generation (excluding wind and solar) in the 2022 case (see Figure 87). The 5% that we were not able to match was added to the capacity expansion build-out summarized in the next section.

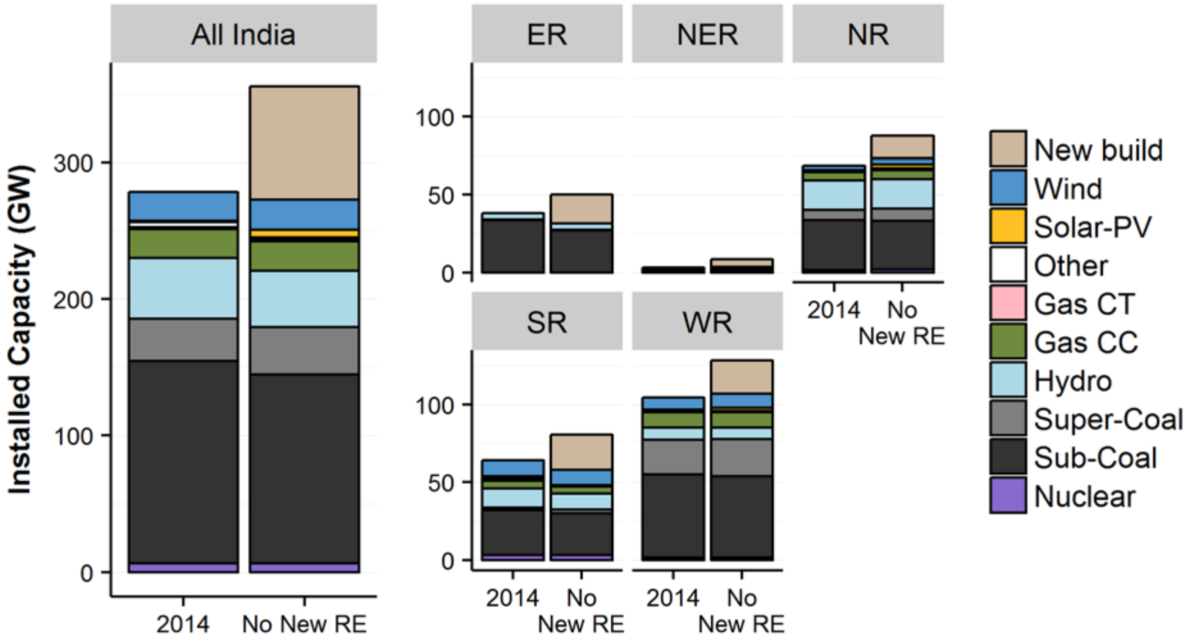


Figure 87. Comparison between generation capacity by fuel type and region in the 2014 database and the set of "existing-in-2014" generators in the 2022 database

Implementing the 2022 Generation Build-Out

The 2022 generation capacity used in this study reflects the total capacity that will be expected in that year according to the 12th and 13th plans (as of May 2016) if no plant retirements were to happen. The generation capacity in the CEA 2021–2022 PSS/E file needed to be adjusted down to achieve this for two reasons: (1) projected builds were not likely to be finished by 2022, or (2) plans for expansion were adjusted down based on updated load projections. In addition to the 12th and 13th plans, the 5% of generation capacity that was unaccounted for in our shift from the 2014 to the 2022 database was added to the final total. Extensive efforts were made to match the 2022 PSS/E file generation plants with the plants from the 12th and 13th plans, although some of the capacity was not able to be matched exactly due to naming mismatches or missing data in the PSS/E file. In these cases, capacity was chosen by fuel and state until the necessary capacity was reached. This ensures that each state has the same generation capacity that CEA expects in 2022.

Implementing the 2022 Transmission Build-Out

As mentioned in Section 2.2.3, the transmission system modeled in this study only represents interstate interconnections. This information was taken from the CEA/CTU PSS/E file and updated during working sessions with CTU to ensure alignment with ongoing projects. However, because of the simplified network representation in this study, it is more reflective of actual conditions to enforce reliability-based limits on interregional or interstate corridors rather than individual line capacities.

Flow limits on interstate corridors were set to the sum of their component lines' surge impedance loading. Flow limits on interregional corridors were calculated in a more complex manner using monthly ATCs from 2014, which were calculated using an AC power flow model. Because we had no ability to determine ATC values for the 2022 system, we found the ratio of each corridor's 2014 ATC to the sum of that corridor's 2014 line capacities. Then we applied that ratio to the sum of this corridor's projected 2022 line capacity to find a proxy for reliability-based corridor transfer limits in 2022. Table 54 gives the 2014 ATC levels and the resulting 2022 regional corridors limits based on this calculation.

Table 54. Interface Flow Limits Based on Proportional Scaling from 2014 Available Transfer Capability

Note: Table lists interface limits and the total line capacity available in each interconnection. A hyphen indicates that an interconnection limit is not enforced. All values are in MW.

		2014 LINE CAPACITIES	2014 ATC LIMITS		2022 LINE CAPACITIES	2022 ASSUMED TRANSFER LIMITS	
			Forward	Backward		Forward	Backward
INTERREGIONAL INTERFACES							
WR–SR	Jan	5,650	2,500	-1,000	22,012	9,740	-3,896
	Feb		2,500	-1,000		9,740	-3,896
	Mar		2,500	-1,000		9,740	-3,896
	Apr		2,500	-1,000		9,740	-3,896
	May		2,500	-1,000		9,740	-3,896
	Jun		2,500	-1,000		9,740	-3,896
	Jul		2,500	-1,000		9,740	-3,896
	Aug		2,500	-1,000		9,740	-3,896
	Sep		2,500	-1,000		9,740	-3,896
	Oct		2,500	-1,000		9,740	-3,896
	Nov		2,500	-1,000		9,740	-3,896
	Dec		2,500	-1,000		9,740	-3,896
WR–NR	Jan	9,463	3,900	-2,500	32,534	13,408	-8,595
	Feb		4,200	-2,500		14,440	-8,595
	Mar		4,200	-2,500		14,440	-8,595
	Apr		4,200	-2,500		14,440	-8,595
	May		4,200	-2,500		14,440	-8,595
	Jun		4,700	-2,500		16,159	-8,595
	Jul		4,700	-2,500		16,159	-8,595
	Aug		4,900	-2,500		16,846	-8,595
	Sep		4,900	-2,500		16,846	-8,595
	Oct		4,900	-2,500		16,846	-8,595
	Nov		4,900	-2,500		16,846	-8,595
	Dec		4,900	-2,500		16,846	-8,595

		2014 LINE CAPACITIES	2014 ATC LIMITS		2022 LINE CAPACITIES	2022 ASSUMED TRANSFER LIMITS	
			Forward	Backward		Forward	Backward
INTERREGIONAL INTERFACES							
ER–SR	Jan	3,000	2,650	-1,100	7,600	6,713	-2,787
	Feb		2,650	-1,100		6,713	-2,787
	Mar		2,650	-1,100		6,713	-2,787
	Apr		2,650	-1,100		6,713	-2,787
	May		2,650	-1,100		6,713	-2,787
	Jun		2,650	-1,100		6,713	-2,787
	Jul		2,650	-1,200		6,713	-3,040
	Aug		2,650	-1,200		6,713	-3,040
	Sep		2,700	-1,200		6,840	-3,040
	Oct		2,650	-1,200		6,713	-3,040
	Nov		2,000	-1,200		5,067	-3,040
	Dec		2,650	-1,200		6,713	-3,040
ER–WR	Jan	10,284	1,000	-1,800	17,681	1,719	-3,095
	Feb		1,000	-1,800		1,719	-3,095
	Mar		1,000	-1,800		1,719	-3,095
	Apr		1,000	-1,800		1,719	-3,095
	May		1,000	-1,800		1,719	-3,095
	Jun		1,000	-1,800		1,719	-3,095
	Jul		1,000	-1,800		1,719	-3,095
	Aug		1,000	-1,700		1,719	-2,923
	Sep		1,000	-1,600		1,719	-2,751
	Oct		1,000	-1,600		1,719	-2,751
	Nov		1,000	-1,600		1,719	-2,751
	Dec		1,000	-1,900		1,719	-3,267

		2014 LINE CAPACITIES	2014 ATC LIMITS		2022 LINE CAPACITIES	2022 ASSUMED TRANSFER LIMITS	
			Forward	Backward		Forward	Backward
INTERREGIONAL INTERFACES							
ER–NR	Jan	15,032	3,600	-1,100	21,022	5,035	-1,538
	Feb		3,600	-1,100		5,035	-1,538
	Mar		3,800	-1,100		5,314	-1,538
	Apr		3,800	-1,100		5,314	-1,538
	May		3,800	-1,100		5,314	-1,538
	Jun		4,000	-1,100		5,594	-1,538
	Jul		3,700	-1,100		5,174	-1,538
	Aug		3,400	-1,100		4,755	-1,538
	Sep		3,400	-1,100		4,755	-1,538
	Oct		2,800	-1,800		3,916	-2,517
	Nov		3,400	-1,100		4,755	-1,538
	Dec		3,600	-2,000		5,035	-2,797
NR–NER	Jan	-	-	-	3,000	3,000	-3,000
	Feb		-	-		3,000	-3,000
	Mar		-	-		3,000	-3,000
	Apr		-	-		3,000	-3,000
	May		-	-		3,000	-3,000
	Jun		-	-		3,000	-3,000
	Jul		-	-		3,000	-3,000
	Aug		-	-		3,000	-3,000
	Sep		-	-		3,000	-3,000
	Oct		-	-		3,000	-3,000
	Nov		-	-		3,000	-3,000
	Dec		-	-		3,000	-3,000

		2014 LINE CAPACITIES	2014 ATC LIMITS		2022 LINE CAPACITIES	2022 ASSUMED TRANSFER LIMITS	
			Forward	Backward		Forward	Backward
INTERREGIONAL INTERFACES							
ER–NER	Jan	2,322	720	-500	3,656	1,134	-787
	Feb		720	-570		1,134	-897
	Mar		720	-550		1,134	-866
	Apr		720	-580		1,134	-913
	May		720	-550		1,134	-866
	Jun		645	-500		1,016	-787
	Jul		645	-550		1,016	-866
	Aug		645	-500		1,016	-787
	Sep		700	-690		1,102	-1,086
	Oct		700	-690		1,102	-1,086
	Nov		700	-600		1,102	-945
	Dec		710	-690		1,118	-1,086
Total line capacity		**45,751**			**107,505**		
Total interconnection limits (sum of means)			**14,920**	**-8,214**		**42,783**	**-21,052**
S1– S2	Jan	11,302	5,600	-	14,803	-	-
	Feb		5,650	-		-	-
	Mar		5,650	-		-	-
	Apr		5,650	-		-	-
	May		5,650	-		-	-
	Jun		5,650	-		-	-
	Jul		5,650	-		-	-
	Aug		5,650	-		-	-
	Sep		5,650	-		-	-
	Oct		5,650	-		-	-
	Nov		5,650	-		-	-
	Dec		5,650	-		-	-

APPENDIX D. MODELING CONSTRAINTS THAT AFFECT UNSERVED ENERGY

A number of modeling constraints can lead to periods of unserved energy that do not reflect credible concerns to reliability. For instance, due to computation constraints, day-ahead schedules are set hourly in the model and do not allow for commitment of coal or gas to be changed intrahour. This modeling simplification causes some inflexibility at hourly seams, which India's system operators, who schedule in 15-minute time blocks, may not experience. Additionally, hydro generation is fixed in the day-ahead schedule, with no changes allowed during dispatch, further exacerbating inflexibility around hourly seams in the model. Test runs have shown that having a day-ahead commitment of 30 minutes in the model greatly reduces the amount of unserved energy, showing that hourly commitment is unrealistically constraining thermal operations.

Figure 88 shows the seasonal and daily patterns of unserved energy for 100S-60W. Total unserved energy accounts for 0.02% of the load in the year, which is confined to 2% of periods in the year. The majority of periods occur during the evening peak when solar would be recently off or turning down, and load, and possibly wind, is ramping up. This time period reflects the constraints of the model described above. The model commits RE on hourly schedules, which, when overlapping with sunset and changes to load, can create periods within the hour in which insufficient thermal capacity is committed.

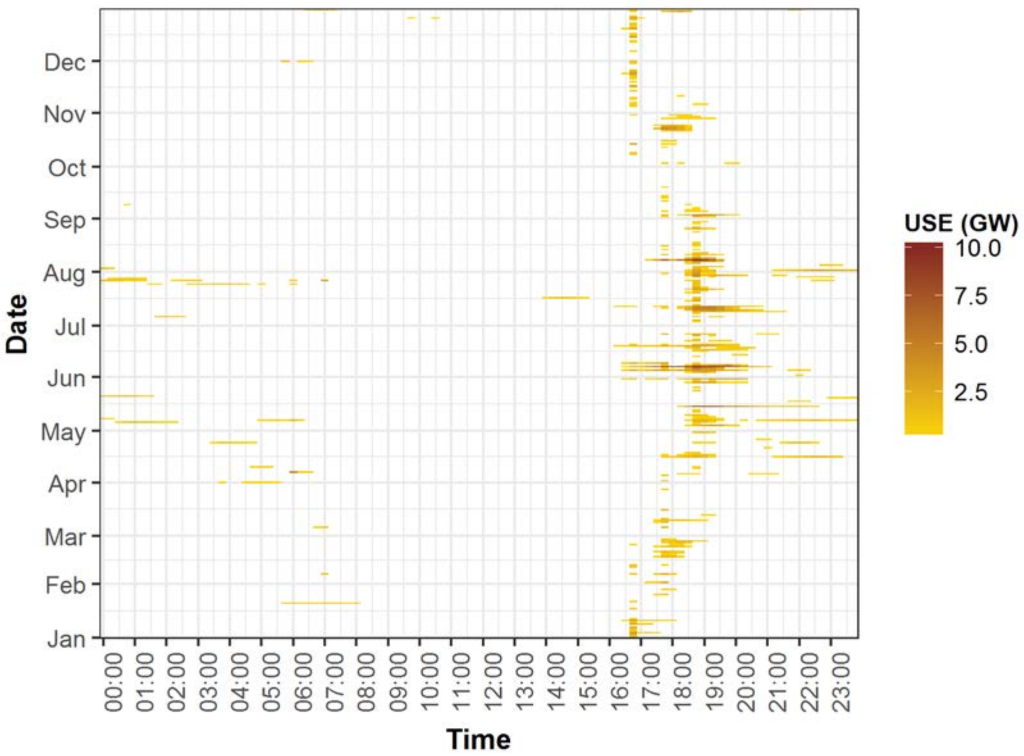


Figure 88. Daily and seasonal pattern of unserved energy (USE) in the model, 100S-60W

A number of other modeling simplifications might also cause unserved energy. A particularly challenging aspect of power system operations to capture in production cost models is operator intervention. An example of when operator intervention might result in a different outcome than our model suggests is the period analyzed in Section 4.7. The period of unserved energy results from a large forecast error event that lasts more than 12 hours. The model does not allow updates to the commitment schedule from the day-ahead, and unserved energy occurs many hours after the start of the forecast error. In reality, system operators could respond to a forecast error of this magnitude and duration by updating thermal commitments in the early hours of the forecast error event and avoid the unserved energy. Although this method of intraday commitment of thermal generating units is uncommon in India's operations today, test model runs showed that unserved energy was greatly reduced if updated RE forecasts were used by central generators in an intraday commitment.[80]

[80] This test was done with perfect foresight of RE generation at hourly resolution in 4-hour optimization steps. Commitment of only central generators was allowed intraday; all IPP and state plants remained constrained to the day-ahead schedule.

APPENDIX E. GENERATION DISPATCH DURING PERIODS OF INTEREST

The following figures and tables (Figure 91–Figure 102) present the generation dispatch for the 100S-60W scenario on days of max net load ramp and maximum and minimum conditions of load, net load, RE generation, RE penetration as percent of load, coal generation, hydro generation, and RE curtailment.

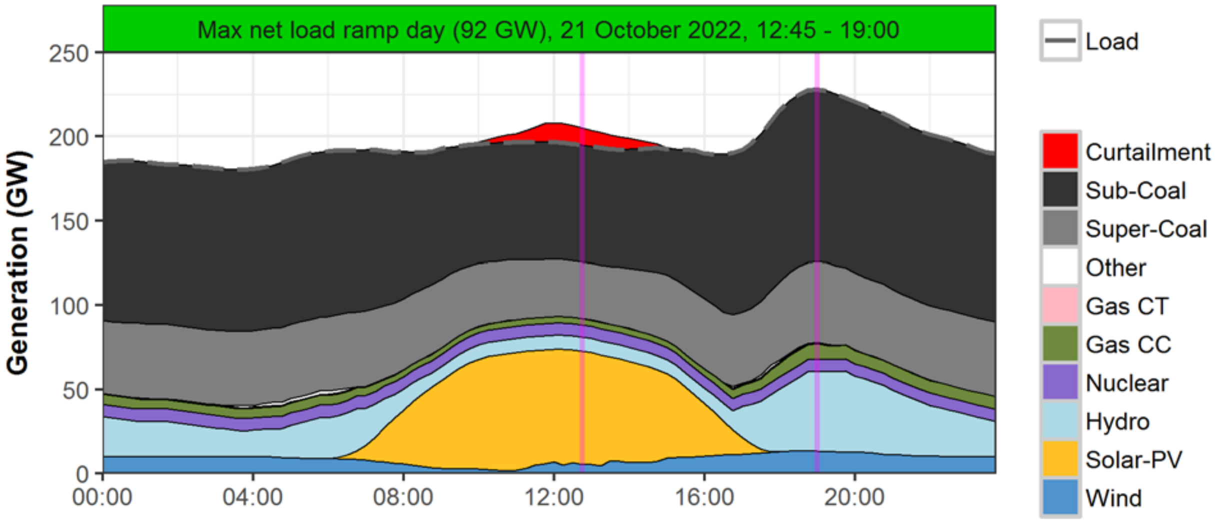


Figure 89. Maximum net load ramp day (92 GW), 21 October 2022, 12:45–19:00

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Max net load ramp (Start/End)	195/228	102/ 150	73/13	8/48	4/10	7/7	0/0	10/0	37%/6%

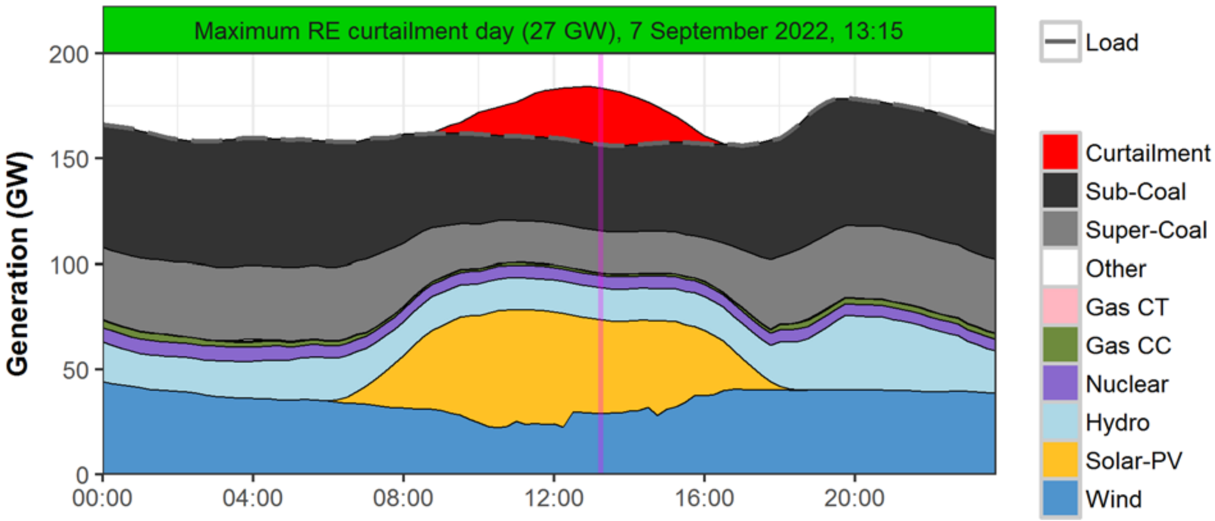


Figure 90. Maximum RE curtailment day (27 GW), 7 September 2022, 13:15

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtail-ment (GW)	RE penetration (% of load)
Max RE curtailment	157	61	74	15	1	6	0	27	47%

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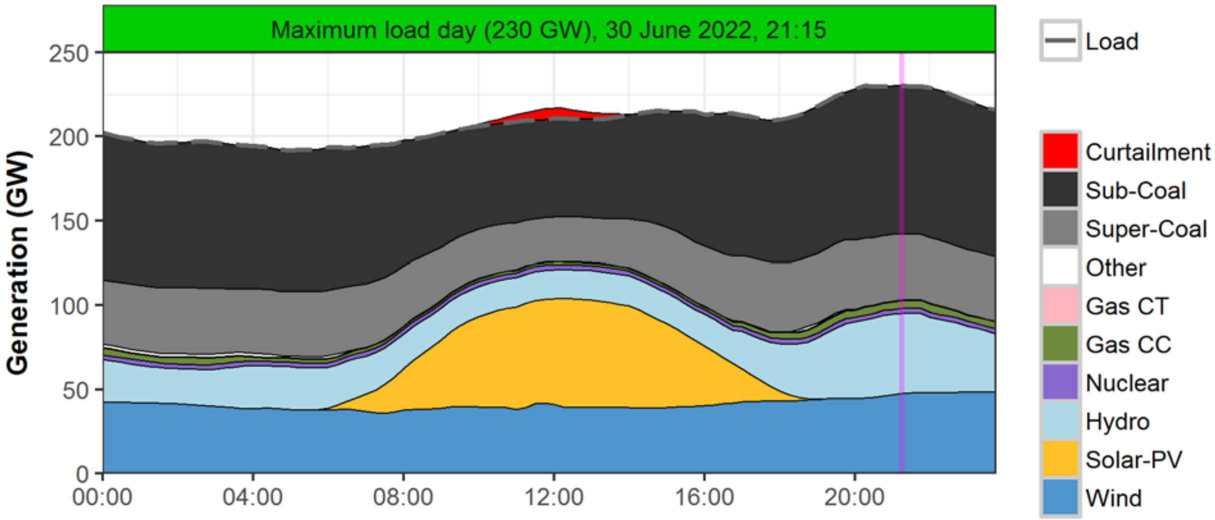

Figure 91. Maximum load day (230 GW), 30 June 2022, 21:15

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Max load	230	127	48	48	5	3	0	0	21%

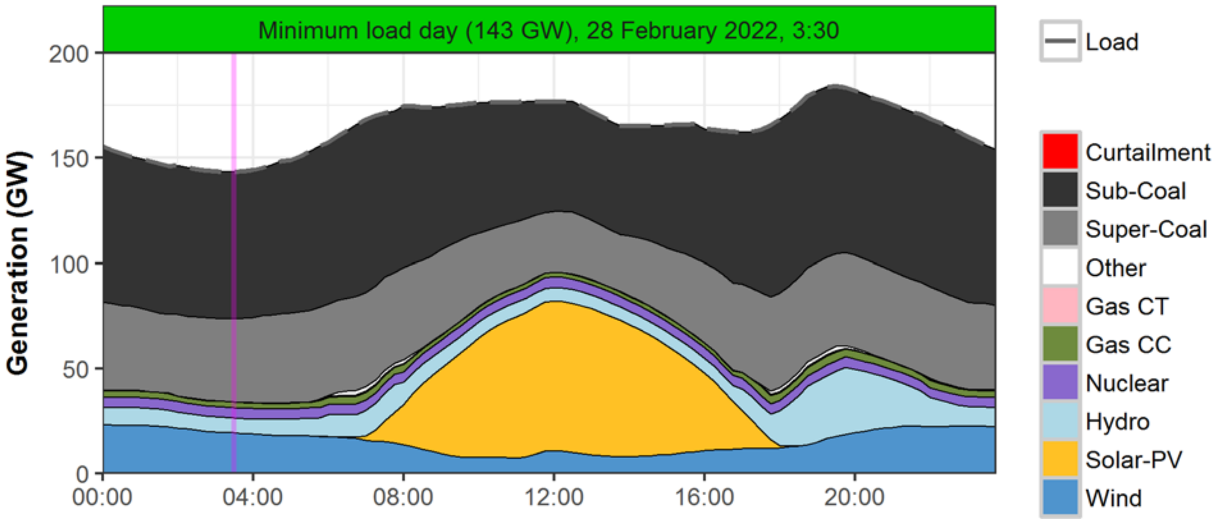

Figure 92. Minimum load day (143 GW), 28 February 2022, 3:30

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Min load	143	109	19	7	3	5	0	0	14%

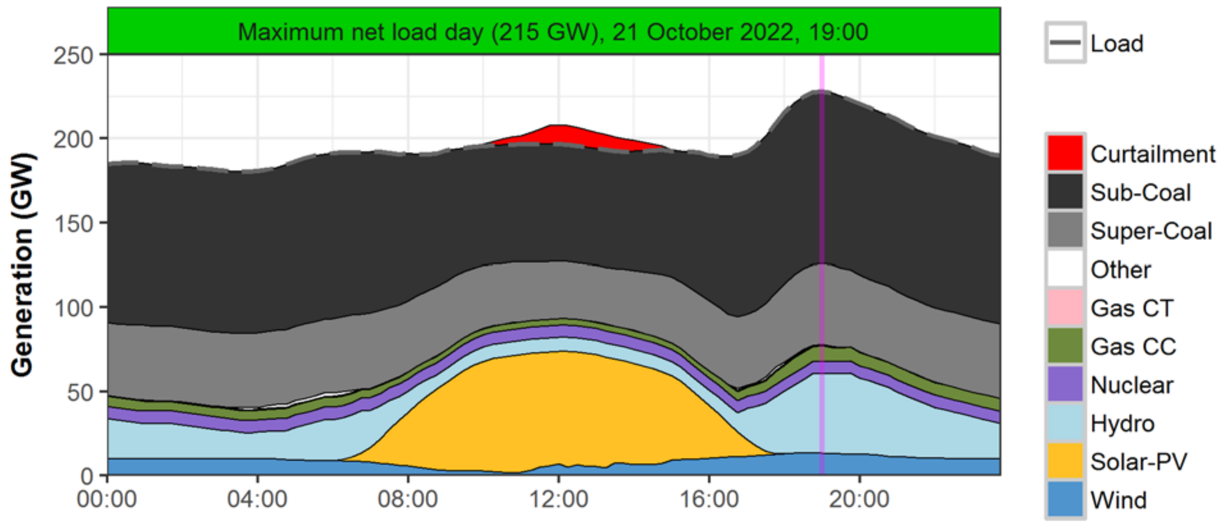

Figure 93. Maximum net load day (215 GW), 21 October 2022, 19:00

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Max net load	228	150	13	47	10	7	0	0	6.0%

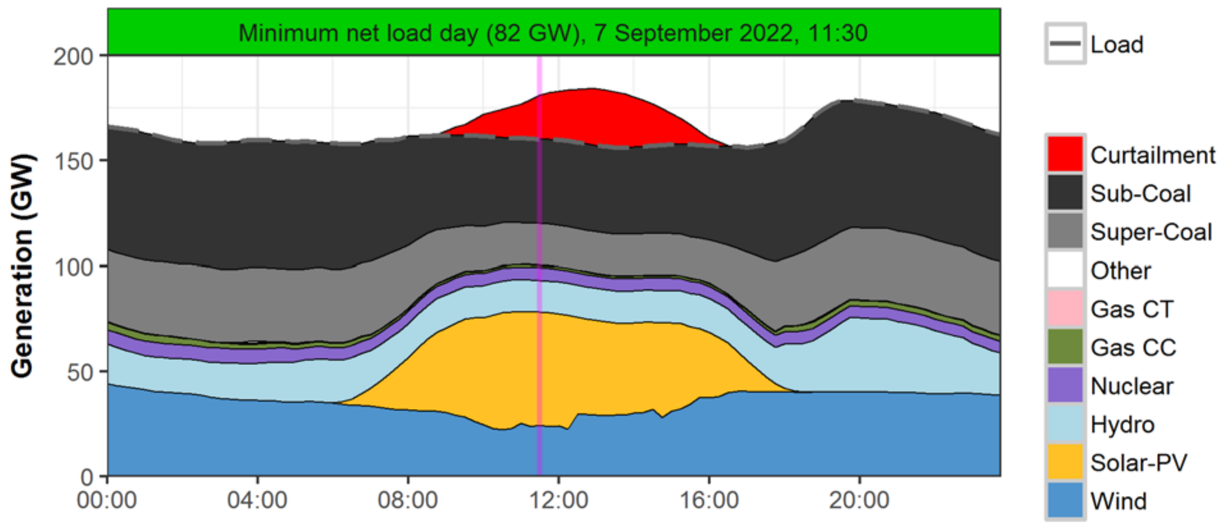

Figure 94. Minimum net load day (82 GW), 7 September 2022, 11:30

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Min net load	160	60	78	15	1	6	0	21	49%

Appendices

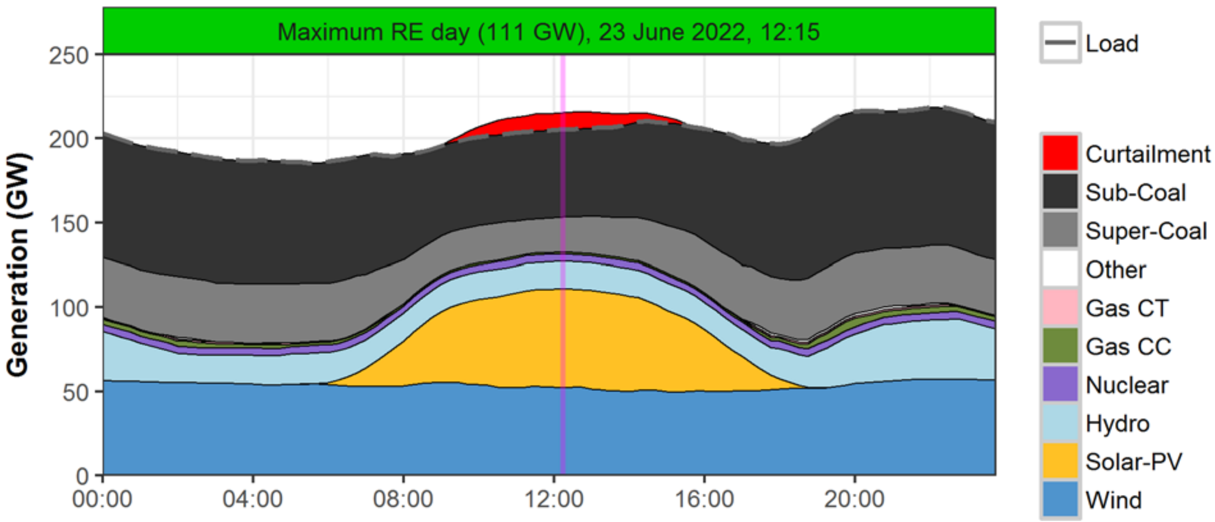

Figure 95. Maximum RE day (111 GW), 23 June 2022, 12:15

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Max RE	205	73	111	16	1	4	0	10	54%

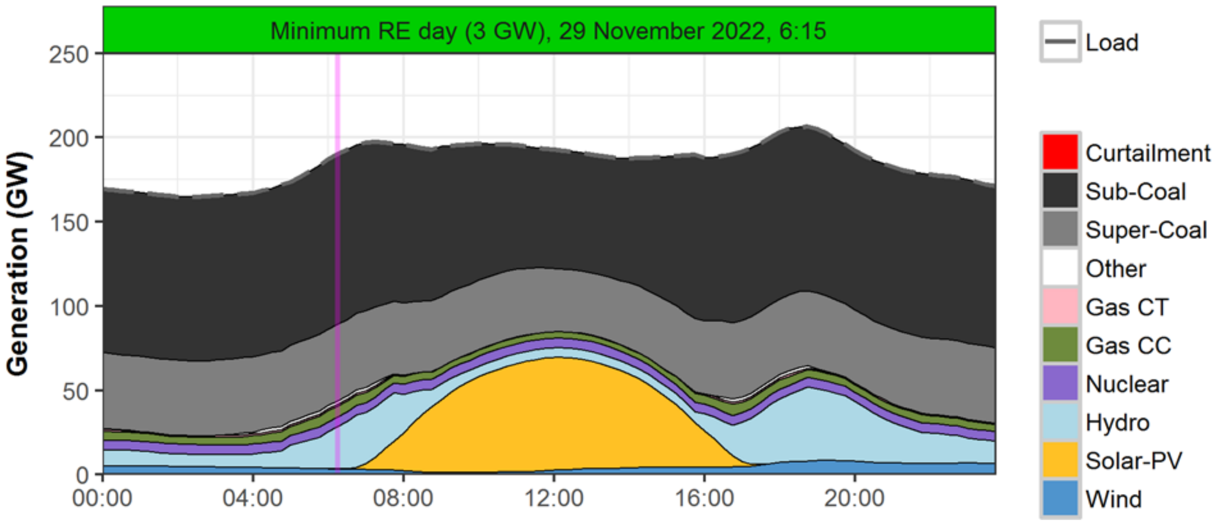

Figure 96. Minimum RE day (3 GW), 29 November 2022, 6:15

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Min RE	190	147	3	25	8	6	2	0	1.8%

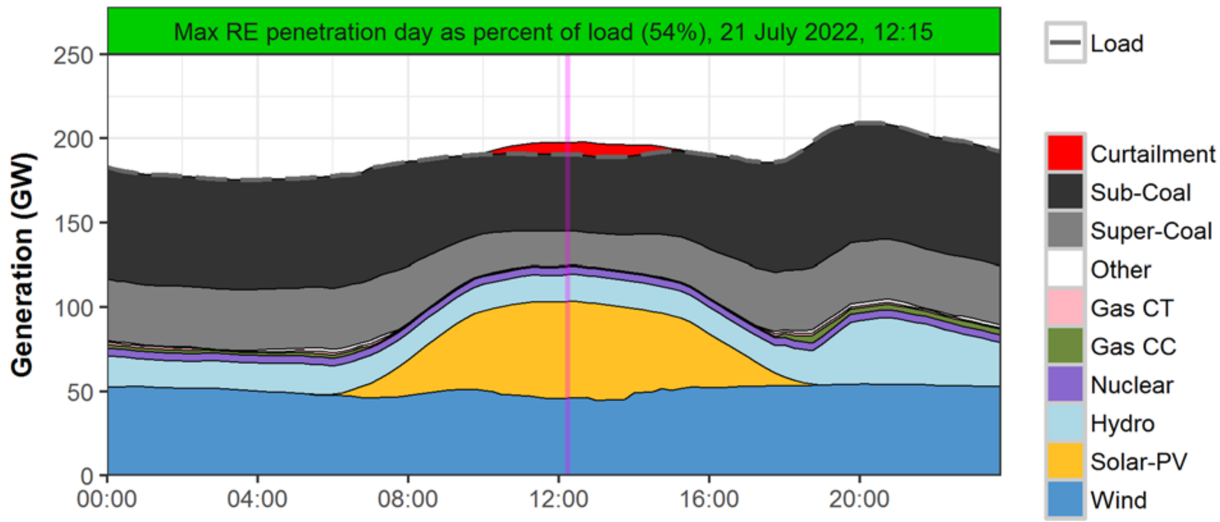

Figure 97. Maximum RE penetration day as percent of load (54%), 21 July 2022, 12:15

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetra-tion (% of load)
Max RE penetration	190	66	104	16	1	5	0	7	54%

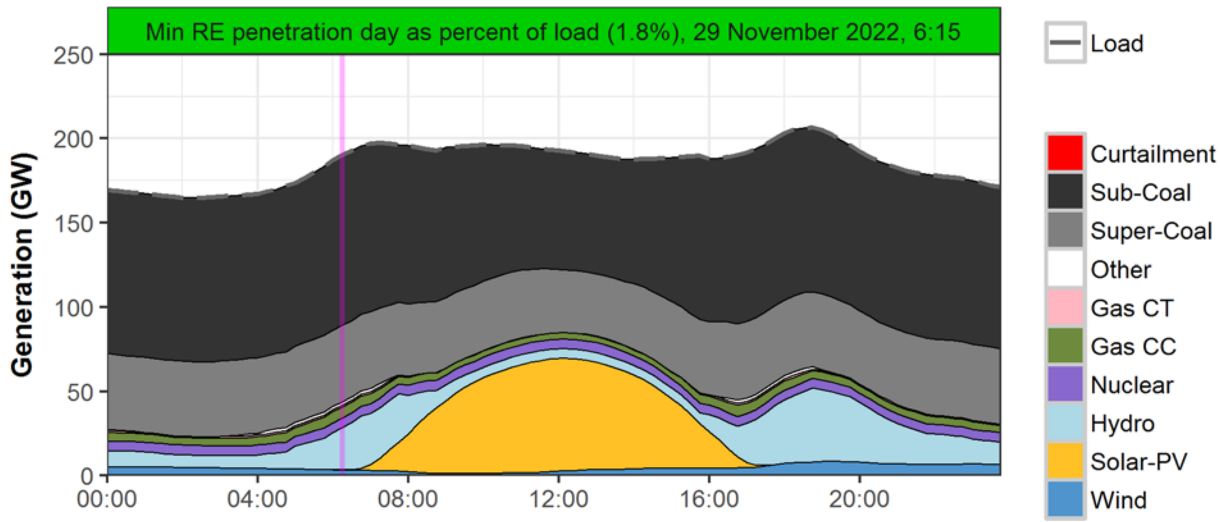

Figure 98. Minimum RE penetration day as percent of load (1.8%), 29 November 2022, 6:15

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtail-ment (GW)	RE penetr-ation (% of load)
Min RE penetration	190	147	3	25	8	6	2	0	1.8%

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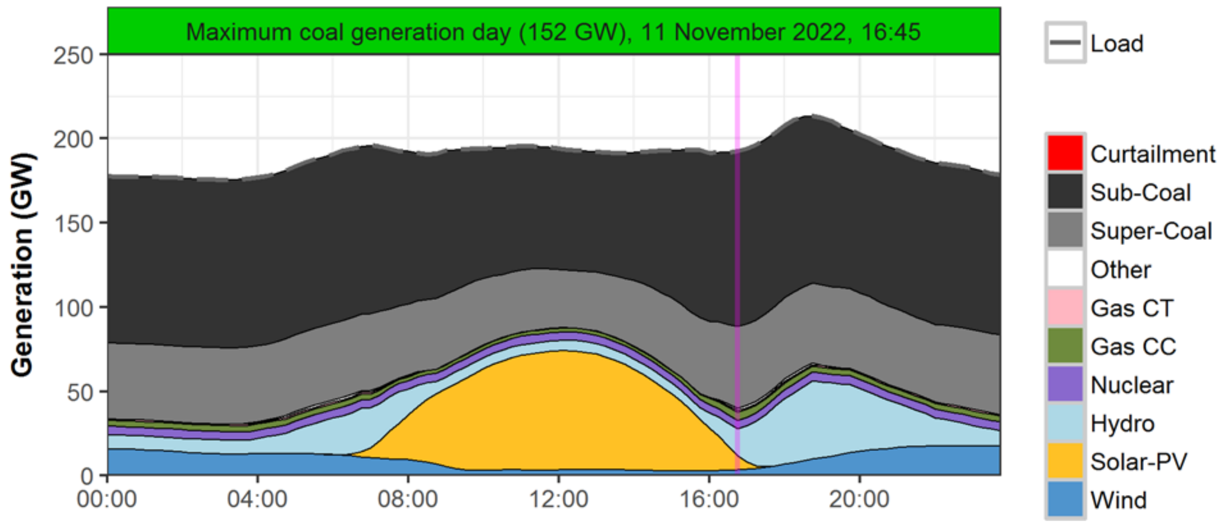

Figure 99. Maximum coal generation day (152 GW), 11 November 2022, 16:45

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Max coal	192	152	12	16	6	5	1	0	6%

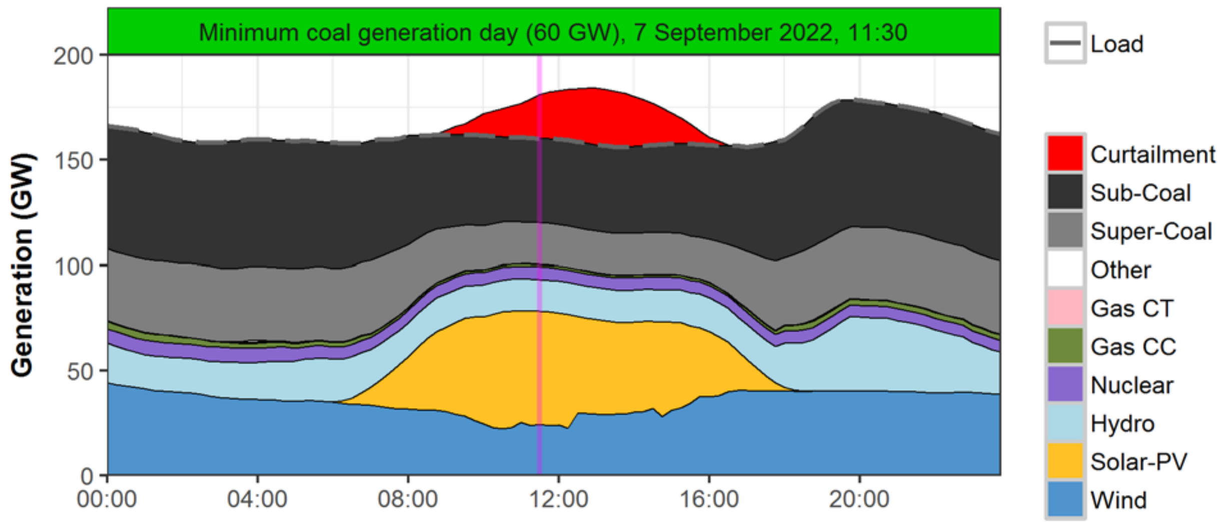

Figure 100. Minimum coal generation day (60 GW), 7 September 2022, 11:30

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Min coal	160	60	78	15	1	6	0	21	49%

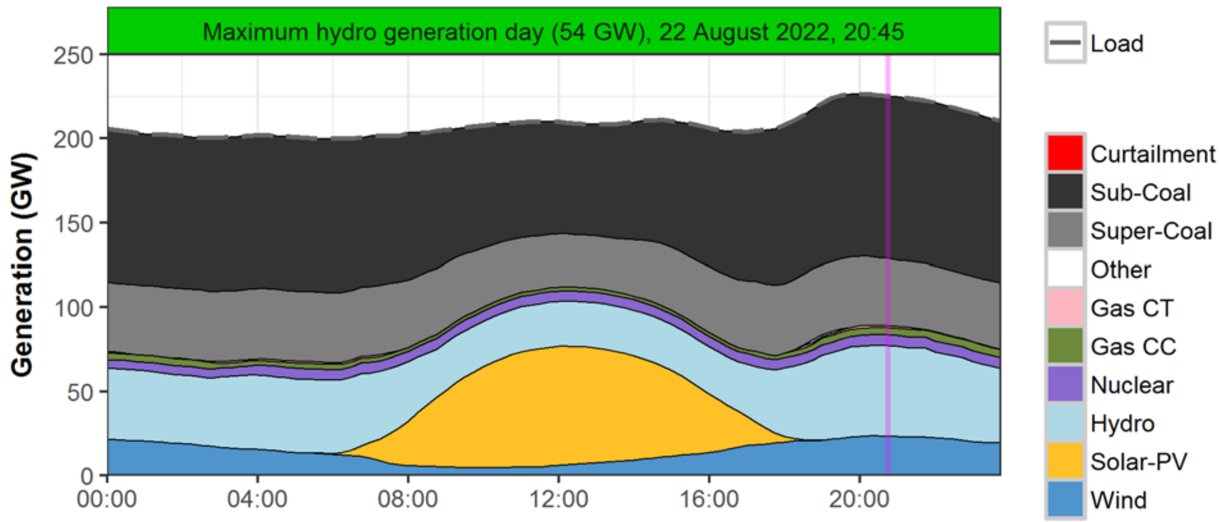

Figure 101. Maximum hydro generation day (54 GW), 22 August 2022, 20:45

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Max hydro	225	136	23	54	5	6	0	0	10%

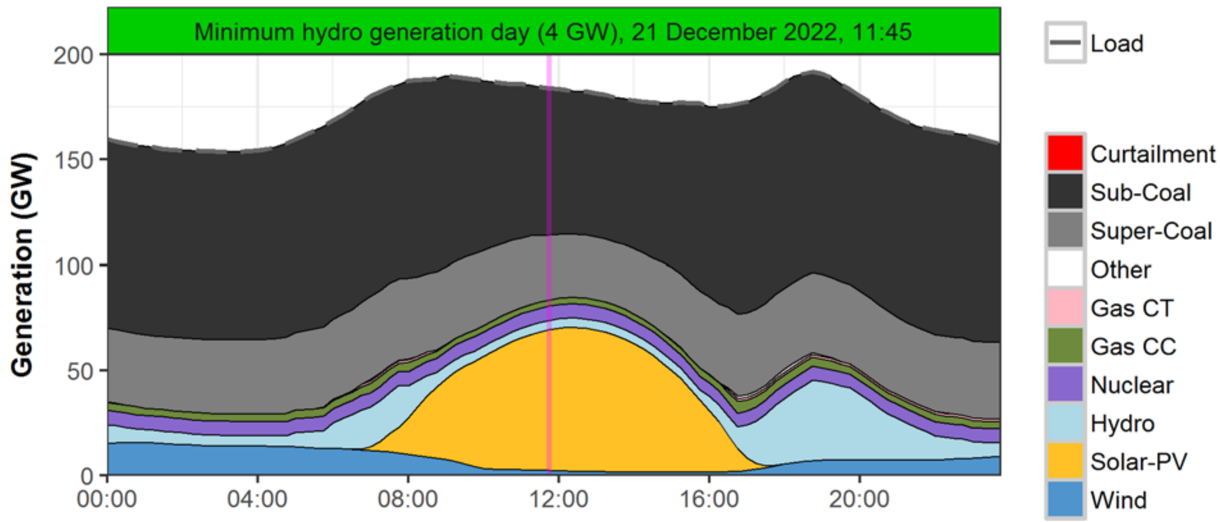

Figure 102. Minimum hydro generation day (4 GW), 21 December 2022, 11:45

	Load (GW)	Coal (GW)	Wind & Solar (GW)	Hydro (GW)	Gas (GW)	Nuclear (GW)	Other (GW)	RE Curtailment (GW)	RE penetration (% of load)
Min hydro	184	100	69	4	3	7	0	0	38%

Appendices

GLOSSARY

Source: http://greeningthegrid.org/resources/glossary, which is based on definitions from the Federal Energy Regulatory Commission, the North American Electric Reliability Commission, and NREL's Transmission Grid Integration Glossary.

Ancillary service. Those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the transmission service provider's transmission system in accordance with good utility practice.

Automatic generation control. A regulatory mechanism and set of equipment that provides for automatically adjusting generation within a balancing area from a centralized location to maintain a specified frequency and/or scheduled interchange.

Balancing authority. The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.

Balancing (authority) area. The collection of generation, transmission, and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.

Capacity. The maximum output (generation) of a power plant. Capacity is typically measured in a kilowatt (kW), megawatt (MW), or gigawatt (GW) rating. Rated capacity may also be referred to as "nameplate capacity" or "peak capacity." This may be further distinguished as the "net capacity" of the plant after plant parasitic loads have been considered, which are subtracted from "gross capacity."

Capacity factor. A measure of how much energy is produced by a plant compared with its maximum output. Capacity factor is measured as a percentage, generally by dividing the total energy produced during some period of time by the amount of energy the plant would have produced if it ran at full output during that time. Typical capacity factors for wind and solar PV in regions with good resources are about 30%–50% and 15%–20%, respectively.

Contingency reserves. Reserves used to respond to an unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element.

Curtailment. A reduction in the output of a generator from what it could otherwise produce given available resources.

Economic dispatch. The allocation of demand to individual generating units online to effect the most economical production of electricity.

Electric energy storage. Technologies capable of storing electricity generated at one time and for use at a later time. Storage technologies include batteries, pumped hydroelectric power, compressed air storage, thermal storage, and others.

Energy imbalance service. A market service that provides for the management of unscheduled deviations in individual generator output or load consumption.

Flexibility (operational). The ability of a power system to respond to changes in electricity demand and supply.

Flexible generation. The ability of the generation fleet to change its output (ramp) rapidly, start and stop with short notice, and achieve a low minimum turn-down level.

Flexible transmission networks. Extending transmission lines and interconnecting with neighboring networks provides the power system greater access to a range of balancing resources. The aggregation of generation assets through interconnection improves flexibility and reduces net variability across the power system. Other sources of flexibility include smart network technologies and advanced network management practices that minimize bottlenecks and optimize transmission usage.

Forecast error. The difference between actual and predicted time-series values of wind and solar resource data.

Frequency response. The ability of generation (and responsive demand) to increase output (or reduce consumption) in response to a decline in system frequency and decrease output (or increase consumption) in response to an increase in system frequency. Primary frequency response takes place within the first few seconds following a change in frequency. Secondary frequency response (also known as regulating reserve) takes place on a timescale of minutes (or faster) following a disturbance.

Grid congestion. The event that occurs when actual or scheduled flows of electricity over a line or piece of equipment are constrained below desired levels.

Grid integration of renewable energy. The practice of power system planning, interconnection, and operation that enables efficient and cost-effective use of renewable energy while maintaining the stability and reliability of electricity delivery.

Grid integration study. An analysis of a set of scenarios and sensitivities that seeks to inform the stakeholders on the ability and needs of a power system to accommodate significant variable renewable energy.

Interconnection. An independent electricity system network that operates at a particular frequency. An interconnection consists of one or more balancing area authorities that balance demand and generation within certain geographic areas of the interconnection.

Line capacities. The maximum and minimum voltage, current, frequency, and real and reactive power flows on individual equipment under steady state, short-circuit, and transient conditions, as permitted or assigned by the equipment owner.

Load. An end-use device or customer that receives power from the electric system.

Load serving entity (LSE). An organization that supplies energy and transmission to meet the electricity demand of its end-use customers. A utility is an example of an LSE. An LSE procures electricity from power producers, which operate electricity generating facilities, and which may be independent or owned by the LSE.

Minimum generation (turn-down) level. The minimum output that can be provided by a generator. Different generators have different minimum run levels based in part on fuel source, plant design, and common use.

Net load (net demand). Demand that must be met by other generation sources if all wind and solar power is consumed.

Operating reserves. Electricity generating capacity that is available to a system operator to provide for regulation (i.e., response to random movements during normal conditions), load forecasting error, forced and scheduled equipment outages, and local area protection. Other types of reserves include contingency (deployed in response to generator failures), regulating (secondary frequency response via AGC), or flexibility (reserves to address variability and uncertainty on timescales longer than regulating reserves).

Peak load. 1. The highest hourly demand within a balancing area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the balancing area.

Production cost simulations. Production cost simulations optimize the scheduling of load and generation resources to meet expected demand over various time frames with consideration of cost and constraints (system, physical, operational). This is the leading tool to evaluate the impacts of variable renewable power on the operational costs of a system.

Ramp. The increase or decrease in output of electricity supply to follow changes in net demand.

Ramp rate. The change in output of a generating unit per unit time, often measured in megawatts per minute.

Rated capacity. The maximum capacity of a generating unit.

Regulating reserves (also called secondary frequency reserves). Respond to random movements and maintain area control error during normal (nonevent) conditions in a time frame that is faster than economic dispatch. Requires automatic control by the system operator.

Scheduling. The practice of ensuring a generator is committed and available when needed. It also can refer to the scheduling of imports into and exports out of a balancing area.

Spinning reserve. Generation and responsive load that is online; can begin responding immediately.

Supervisory control and data acquisition (SCADA). A system of remote control and telemetry used to monitor and control the transmission system.

System. A combination of generation, transmission, and distribution components.

System operator. An individual at a control center of a balancing authority, transmission operator, or reliability coordinator who operates or directs the operation of the bulk electric system in real time.

Transmission constraint. A limitation on one or more transmission elements that may be reached during normal or contingency system operations.

Transmission network. A system of structures, wires, insulators, and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV and are capable of transmitting large quantities of electricity over long distances**.**

Uncertainty. The inability to perfectly predict the electricity demand and/or generator output, either due to unexpected outages or the unpredictability of the resource.

Unit. A single generator that may be part of a multiple-generator power plant.

Unit commitment. The process of starting up a generator so that the plant is synchronized to the grid.

Variability. The changes in power demand and/or the output of a generator due to underlying fluctuations in resource or load.

Variable renewable energy. Electricity generation technologies whose primary energy source varies over time and cannot easily be stored. Variable generation sources include solar, wind, ocean, and some hydro generation technologies.

Variable renewable energy generation forecasts. Forecasts of time- and location-specific wind and solar resource data. Used as the basis for estimating power generation potential and characterizing variability and uncertainty.

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The Ministry of Power is primarily responsible for the development of electrical energy in the country. The Ministry is concerned with perspective planning, policy formulation, processing of projects for investment decision, monitoring of the implementation of power projects, training and manpower development, and the administration and enactment of legislation in regard to thermal, hydro power generation, transmission, and distribution.

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The National Renewable Energy Laboratory (NREL) is the U.S. Department of Energy's (DOE's) primary national laboratory for renewable energy and energy efficiency research. NREL deploys its deep technical expertise and unmatched breadth of capabilities to drive the transformation of energy resources and systems.

About Power System Operation Corporation Limited

Power System Operation Corporation Limited (POSOCO) is an independent government company in India that operates the National Load Despatch Centre and Regional Load Despatch Centres. POSOCO ensures integrated operation of regional and national power systems to facilitate transfer of electric power within and across regions.

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The Energy Sector Management Assistance Program is a global knowledge and technical assistance program administered by the World Bank. It provides analytical and advisory services to low- and middle-income countries to increase their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth.

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The 21st Century Power Partnership, an initiative of the Clean Energy Ministerial, aims to accelerate the transition to clean, efficient, reliable, and cost-effective power systems. The initiative engages in a broad range of research and technical assistance activities to support bilateral and multilateral collaboration that accelerates the diffusion of high-impact policy and regulatory strategies.

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