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GREENING THE GRID:
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. II—Regional Study

GREENING THE GRID PROGRAM
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Prepared by

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LIST OF ACRONYMS

CAISO	California Independent Systems Operator
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CREZ	Competitive Renewable Energy Zone
EIM	energy imbalance market
ERCOT	Electric Reliability Council of Texas
GSECL	Gujarat State Electricity Corporation Limited
GW	gigawatt
INR	India Rupee
IPP	independent power producer
kV	kilovolt
kWh	kilowatt-hour
MISO	Midcontinent Independent System Operator
MOP	Ministry of Power
MW	megawatt
MWh	megawatt-hour
PLF	plant load factor
RE	renewable energy
SRMC	short-run marginal cost
TCN	transmission curtailing node
TEAM	Transmission Economic Assessment Methodology
USAID	U.S. Agency for International Development

ABSTRACT

The higher-spatial-resolution model of "Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. II—Regional Study" (the Regional Study), which better represents the impact of congestion on least-cost scheduling and dispatch, provides a deeper understanding of the relationship among renewable energy (RE) location, transmission, and system flexibility with regard to RE integration, compared to "Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I—National Study." The Regional Study validates the relative value of mitigation strategies demonstrated in the National Study—namely, coordinated operations among states reduce production costs, and reducing coal minimum generation levels reduces RE curtailment. Significantly, the Regional Study also highlights a potential barrier to realizing the value of these mitigation strategies: when locations of RE development are planned independently of state-level transmission, intrastate congestion can result in undesirable levels of RE curtailment.

Therefore a key objective of this study is to illustrate to state-level power system planners and operators, in particular, how a higher-resolution model, inclusive of intrastate granularity, can be used as a planning tool for two primary purposes:

- To better anticipate, understand, and mitigate system constraints that could affect RE integration; and
- To provide a modeling framework that can be used as part of future transmission studies and planning efforts.

The Regional Study is not intended to predict precisely how RE will affect state-level operations. There is considerable uncertainty regarding the locations of the RE development, as well as how contract terms can affect access to the inherent physical flexibility of the system. But the scenarios analyzed identify the types of issues that can arise under various RE and transmission expansion pathways. The model developed for this study provides a rigorous framework for future work and can be updated with the characteristics of new capacity as more information on the future power system is known.

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1 INTRODUCTION

"Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. II—Regional Study" (hereafter referred to as the Regional Study) is a companion document to "Greening the Grid: Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid, Vol. I—National Study" (hereafter referred to as the National Study [Palchak et al. 2017]). Both studies are conducted under a broader program, Greening the Grid, which is an initiative co-led by India's Ministry of Power (MOP) and the U.S. Agency for International Development (USAID). The studies are designed to address operational impacts of meeting India's renewable energy (RE) targets and identify actions that may be favorable for grid integration.

Both studies use the same underlying model, but intrastate transmission is simplified in the National Study to capture trends, policy implications, and value of RE integration strategies based on RE site selection with no intrastate transmission constraints. This Regional Study captures the effects of intrastate transmission to analyze RE integration specific to the Southern and Western regions and six high-RE states—Andhra Pradesh, Gujarat, Karnataka, Maharashtra, Rajasthan, and Tamil Nadu. The Regional Study provides a more appropriate platform for detailed state-level planning and more accurately captures the complex relationships among scheduling and operations, transmission, RE site selection, and generator flexibility with regard to RE integration. Nevertheless, the Regional Study is not intended to predict precisely how RE will affect state-level operations; uncertainty regarding the locations of RE development and associated intrastate transmission, among other factors, suggests that this study be interpreted as a caution about the importance of state-level planning, and as a first draft to this type of analysis.

Details of the study's modeling team, grid integration review committee, methodology, scenario designs, assumptions, RE site selection, and generator and transmission characteristics are provided in Volume I and, because they are the same for Volume II, are not repeated here except to note the different assumptions on transmission used in this regionally focused study. Volume I also includes policy implications, which are also not repeated here except to note key findings specific to each region.

1.1 Comparison of the National and Regional Studies

In the National Study, we examine strategies that aid in the integration of 175 gigawatts (GW) of RE, including 100 GW of solar and 60 GW of wind (100S-60W), with a focus on accurately capturing generator properties and state-to-state and region-to-region transmission corridor constraints. This approach allows us to focus on considerations of national perspective, such as the requirement and ability of thermal generators to cycle in response to RE variability and uncertainty, and the role for non-RE-rich states, for example in the Eastern region, to facilitate balancing. The National Study also allows us to evaluate the technical and commercial value of a wide variety of strategies to improve RE integration. Nevertheless, intrastate transmission constraints, which were excluded from the National Study due to their added modeling complexity, can be important drivers of curtailment and production cost. Capturing the relationship among intrastate transmission, system flexibility, and RE locations is one of the objectives of the Regional Study.

To investigate system operations in more detail in each of the regions with significant RE, we used a higher-resolution network for the model that includes intrastate transmission flows and congestion limits for Southern and Western regions plus Rajasthan. This version of the model uses the same number of generating units and interstate transmission lines, but rather than aggregating all intrastate connections to one state-level node, as in the National Study (for a total of 36 aggregated nodes, as shown in Figure 1 [left]), the Regional Study maintains the transmission resolution to individual nodes (substations) in the two regions plus Rajasthan (for a total of 3,280 nodes, as shown in Figure 1 [right]). The intrastate transmission in the model is limited to the plans that are known and modeled in the Central Electricity Authority (CEA) planning model for 2022. In addition, transmission line limits are captured for intrastate lines equal to and greater than 400 kilovolts (kV). Outside the states of focus, the rest of the country is modeled identically to the National Study—one node per state without capturing intrastate transmission flows or limits in the model. The text box explains the modeling distinctions between the two approaches in more detail.

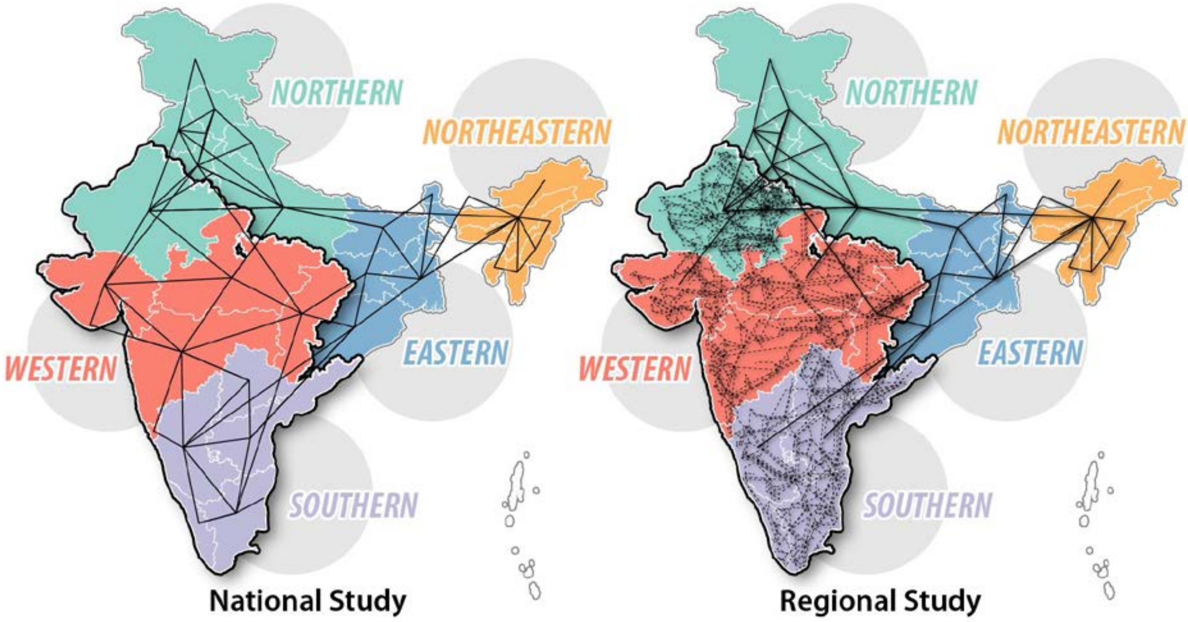

Figure 1. Comparison of transmission representation in the National Study (left) and the Regional Study (right)

Methodological Differences Between National and Regional Studies

The Regional Study uses a higher-spatial-resolution version of the model used in the National Study. The underlying modeling inputs are nearly identical, including the same number and characteristics of generators and same weather and load data.[1] The primary difference between the models is in how they capture transmission flows and constraints. The National Study model simplifies all generation and transmission to a single node per state (i.e., all intrastate transmission flows and constraints are ignored), whereas the Regional Study model includes the nodal details and enforces transmission constraints on all lines 400 kV and greater in the Southern and Western regions plus Rajasthan.[2] The Regional Study model also includes some additional transmission capacity to reduce transmission congestion, as elaborated in Section 1.2 and Appendix B.

Figure 1 compares the two approaches. Figure 1 (left) shows network representation in the National Study. From the model perspective, all generation is located at one point in each state. The model recognizes state-to-state transmission lines and constrains flows based on the total surge impedance loading limits of all participating lines between two given states. The flow limits on interregional lines

[1] A small number of generators present in the National Study are not present in the Regional Study due to lack of transmission connectivity within our input file (a PSS/E file, which is used by CEA and POWERGRID for long-term transmission planning). Simplifications to transmission in the National Study allow these generators to be dispatched without additions to transmission; in contrast, the Regional Study does not dispatch these generators due to lack of connectivity. The discrepancy is 2.4 GW of thermal generation capacity, although these units are rarely operated and accounted for only 0.3% of total generation in the National Study 100S-60W scenario.

[2] Statewide load profiles are dispersed to substations according to load participation factors from the PSS/E file.

are based on the 2014 available transfer capacity limits plus expected additions to the system by 2022. Within a state, transmission capacity has no limits and does not affect scheduling and dispatch.

Figure 1 (right) shows network representation in the Regional Study. For all states outside the two regions and Rajasthan, the regional model treats electricity flows identically to the National Study. For the two regions and Rajasthan, however, the model recognizes all intrastate transmission lines and enforces limits on significant intrastate corridors. Enforcing limits on significant intrastate lines allows for representation of detailed transmission while maintaining run-time tractability. By carefully selecting which lines to enforce, we are able to ensure that most nearby lines will also be enforced effectively. Figure 2 provides an illustrative example. Because of the relative reactances of lines A, B, and C in this simple system, assuming voltages of all lines are the same and there are no losses, 80% of power transferred between the blue “Generation” and red “Load” will always flow over line A, assuming no load or generation at the intermediate substation. Therefore, once the power flow limit on line A is reached, no additional energy will be able to flow on lines B or C. In that way, power flow over lines B and C can never exceed 20% of line A’s flow limit. As long as the limits of lines B and C are greater than line A’s, enforcing only the flow limit on line A is equivalent to enforcing all three.

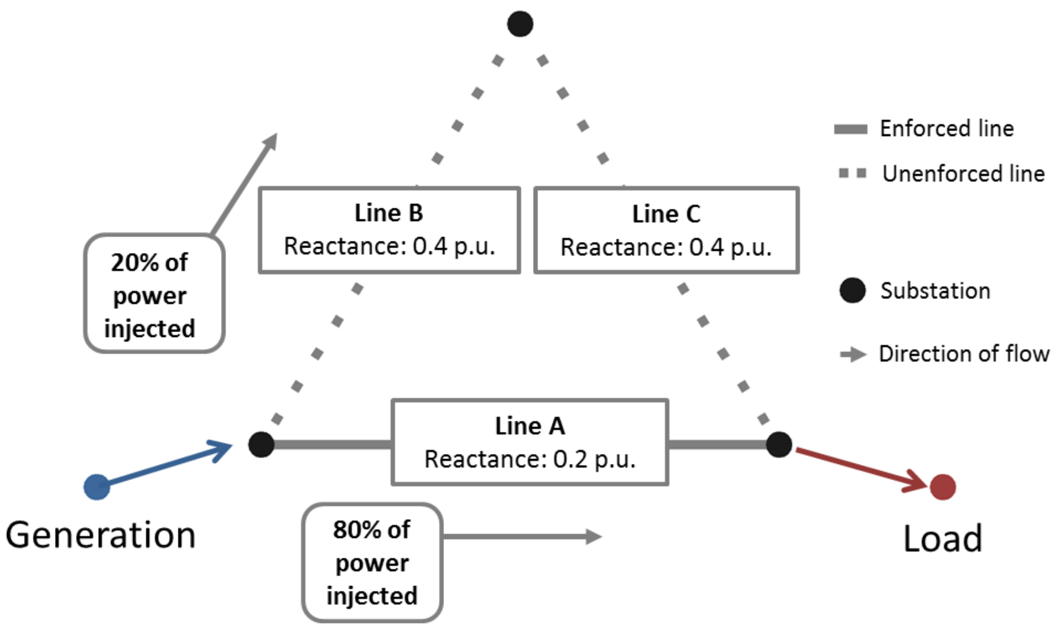

Figure 2. Example of line enforcement representation in the Regional Study

The implication for the integration study is that intrastate transmission flow limits in the Regional Study can affect the ability to access least-cost generation, resulting in redispatching around the constraint. Not only would production costs rise as a result of congestion, but RE curtailment can also increase. For example, congestion can directly cause curtailment if the congestion occurs on lines needed to evacuate the RE. Congestion can also indirectly cause curtailment if the congestion causes the dispatch of a coal plant that cannot be backed down to accommodate rising RE output.

The benefit of using a lower-spatial-resolution national model that is coupled with a higher-resolution regional model is that we can analyze a larger number of sensitivities using the national model because of its lower computational times. With the insights obtained from the national model, we can then better select scenarios for more rigorous analysis with the regional model. This approach ensures that the uncertainties in state-level transmission plans do not affect National Study results, and that the economic impacts of different mitigation strategies are not dwarfed by local impacts of congestion that may (or may not) actually occur in the future, depending on final locations of new RE and transmission. The advantage of the Regional Study is that we can better understand the complex relationship among system operations, transmission, generator flexibility, and RE locations with regard to RE integration when the intrastate transmission is factored.

1.2 Assumptions on Transmission Capacity to Evacuate New RE

The modeling approach in the Regional Study allows us to better capture the complexity of the transmission system in the high RE-regions and its effects on least-cost scheduling and dispatch. In a comprehensive capacity expansion and transmission study, the selection of RE sites would occur in tandem with detailed modeling of the transmission system. The result would be an integrated transmission and generation expansion plan. However, this detailed transmission modeling and planning is not part of our study. Because many of the future RE sites were not known, the modeling team selected RE sites based on near-term project plans and RE resource quality and not on future transmission evacuation capacity.[3] Therefore, our model results can indicate local transmission congestion that may or may not occur in reality.

To help mitigate the lack of coordination between RE site selection and transmission planning, the modeling team added additional 400 kV and greater transmission capacity in key locations. The locations for additional transmission capacity were chosen to alleviate substantial transmission congestion and resulting RE curtailment that were primarily due to the location of RE capacity within the network. The process for adding transmission is described in Appendix B. Table 1 summarizes the capacity of additional intra- and interstate transmission lines in the model. Our goal was to strike a reasonable set of assumptions on how transmission could codevelop with RE site selection.

[3] Our team, as described in Volume I, comprises a core group from POSOCO, the National Renewable Energy Laboratory (NREL), and Berkeley Lab, and a broader modeling team from CEA, POWERGRID, and the states of Gujarat, Karnataka, Madhya Pradesh, Maharashtra, Rajasthan, and Tamil Nadu. A multi-city, multi-institutional grid integration review committee guided the process. While most of the power system characteristics were developed by the full modeling team, NREL and Berkeley Lab provided estimates for aspects of the 2022 power system that are not yet addressed within formal government plans, including some new RE locations and associated intrastate transmission.

Table 1. Transmission Capacity Added to the Model to Evacuate New RE

Appendix B describes the characteristics of and methodology for adding these new lines.

Location	Transmission Added
GUJARAT	FOUR 400-KV AC LINES, 517–560 MW
KARNATAKA	ONE 400-KV AC LINE, 517 MW
MADHYA PRADESH	TWO 400-KV AC LINES, 517–560 MW
MAHARASHTRA	ONE 400-KV AC LINE, 517 MW ONE 400-KV DC LINE, 700 MW
RAJASTHAN	NINE 400-KV AC LINES, 517 MW
TAMIL NADU	ONE 400-KV AC LINE, 550 MW ONE 765-KV AC LINE, 48 MW[4]
CHHATTISGARH - MADHYA PRADESH	ONE 400-KV AC LINE, 517 MW
KERALA - TAMIL NADU	ONE 400-KV AC LINE, 517 MW ONE 400-KV DC LINE, 1,000 MW
MAHARASHTRA - KARNATAKA	ONE 400-KV AC LINE, 675 MW
RAJASTHAN - GUJARAT	TWO 400-KV AC LINES, 517 MW
TELANGANA - ANDHRA PRADESH	ONE 400-KV AC LINE, 517 MW

1.3 Impact of Greater Transmission Fidelity

The inclusion of intrastate transmission in the Regional Study more accurately captures the combined effect that various factors have on RE integration. Intrastate transmission affects merit-order dispatch and access to system flexibility, and therefore affects the value of RE integration strategies.

Fundamentally, the results of the Regional Study are consistent with the National Study. The strategies to improve cost and reduce curtailment that are identified in the National Study are still found to be effective in the Regional Study. Coal technical minimum levels still drive curtailment, and regional coordination of scheduling and dispatch is still a driver of production cost savings.

While impacts are directionally similar between the studies, there are differences in the way the RE integration strategies impact results because of the additional transmission detail represented in the Regional Study cases. In addition to affecting physical access to RE generation and sources of system flexibility, transmission constraints can also increase the cost of marginal generation, and thus the economics of RE integration.

As a result of both the physical and economic impacts of including transmission constraints, the impact of and value of the RE integration strategies also change, and these changes manifest differently depending on the type of flexibility measure. For example, in the National Study, most of the production cost benefit of regional coordination derives from changes to which generators are committed. Because of the decreased trade barriers between states, cheaper generators could be used more effectively over a wider geographic area. This switching from more expensive to cheaper generators affects almost 6% of generation. In the Regional Study, however, only about 5% of generation is switched when regional coordination is introduced. Because localized transmission

[4] One Tamil Nadu 765-kV line in 2022 plans, which this line supplements, also had 48-MW flow limits. Presumably, either its voltage or flow limits have been incorrectly represented in the model.

constraints limit the system's ability to effectively use cheaper generation over a larger area, regional coordination provides fewer benefits in the Regional Study than in the National Study.

In contrast, higher levels of transmission constraints make coal flexibility more valuable in the Regional Study compared to the National Study. The adjustment of physical parameters of a coal plant interacts strongly with localized transmission. Particularly in terms of curtailment, raising minimum generation levels of coal plants increases curtailment more in the Regional Study than in the National Study, and lowering minimum generation constraints decreases curtailment more in the Regional Study than in the National Study. Lowering minimum generation levels can both enable access to additional flexibility at the generator level and help alleviate constraints arising from local transmission limits. Conversely, raising minimum generation levels can magnify the effects of local transmission constraints on curtailment.

These differences demonstrate that while the National Study can be used to understand directional impacts of a variety of flexibility measures, the detail of the Regional Study allows for a more accurate representation of transmission constraints and economic dispatch.

The rest of this study is divided first by region—Southern and Western. For each Regional Study, we present results in two ways. First, we briefly summarize high-level annual results for the region, with and without additional integration strategies. Then we investigate more deeply the interaction between different technical and economic factors that affect system operation in the high-RE scenarios. In the appendices, we demonstrate how to use this model as a component of power system planning, and we provide customized modeling assumptions and results for each of the six states of focus: Andhra Pradesh, Gujarat, Karnataka, Maharashtra, Rajasthan, and Tamil Nadu.

2 SOUTHERN REGION

The Southern region has a wealth of both wind and solar potential. Most of the states in the Southern region have encouraged the development of wind over the last couple of decades through feed-in tariff policies. More recently, auction-based procurement has resulted in record low prices for both solar PV and wind. As a result, several of the southern states have begun developing significant new RE capacity.

The Southern region could face several challenges in integrating these high shares of RE. These challenges stem from multiple factors, including three specific to the region. First, the Southern region has potential constraints related to interconnectedness with other regions. Second, in spite of having some gas generation capacity, the region has limited gas storage, which reduces the ability to use this flexible capacity when needed. Third, high RE penetrations relative to load in 2022—38% compared to 14% and 23% in the Northern and Western regions, respectively—require significant flexibility internally (e.g., in the region's conventional generation fleet) to absorb the variability of RE and/or increase the need to export RE to neighboring regions.

In addition, aggressive development of RE could create transmission constraints in the future because of the significantly longer time frame required for transmission planning and buildout compared to RE project development. If India is to meet its targets of 100 gigawatts (GW) of solar and 60 GW of wind, and more ambitious RE targets beyond 2022, a significant share of this capacity will likely be installed in the Southern region, making transmission planning and its timely buildout critical to evacuate RE generation and minimize curtailment. At the same time, adequate transmission capacity would enable states in the Southern region to share flexibility and low-cost generation as well as access the same from neighboring regions.

In this Southern-region section of the report, first we review annual trends of meeting higher RE penetrations in the region. Then we explore the effects on these trends of two RE integration strategies—regional coordination of operations and improved coal flexibility. We then use one example day to investigate more deeply the operational impacts of higher RE penetrations to better understand the meaning of the annual summaries. Finally, we conclude with implications for decision makers.

2.1 Annual Summaries for the Southern Region

Using the high-resolution regional model, we analyzed the 100S-60W scenario to anticipate impacts to power system operations in the Southern region. This section summarizes for the Southern region a select number of impacts: generation, operational impacts to thermal generators, and interstate energy and transmission flows. Additional details about the 100S-60W scenario are provided in the state-specific sections.

2.1.1 Generation

With 70 GW of installed RE capacity in the Southern region in the 100S-60W scenario, total annual generation across all fuel types increases 11% to 405 terawatt-hours (TWh) compared to the No New RE scenario, including 91 TWh of wind and 72 TWh of solar, as illustrated in Figure 3. This increased generation enables the region to reduce its net imports by 64% and meet more of its annual load, 427 TWh, using generation from within the region. Coal and gas generation within the region fall by 33% and 48%, respectively. RE comprises 40% of all generation in the Southern region.

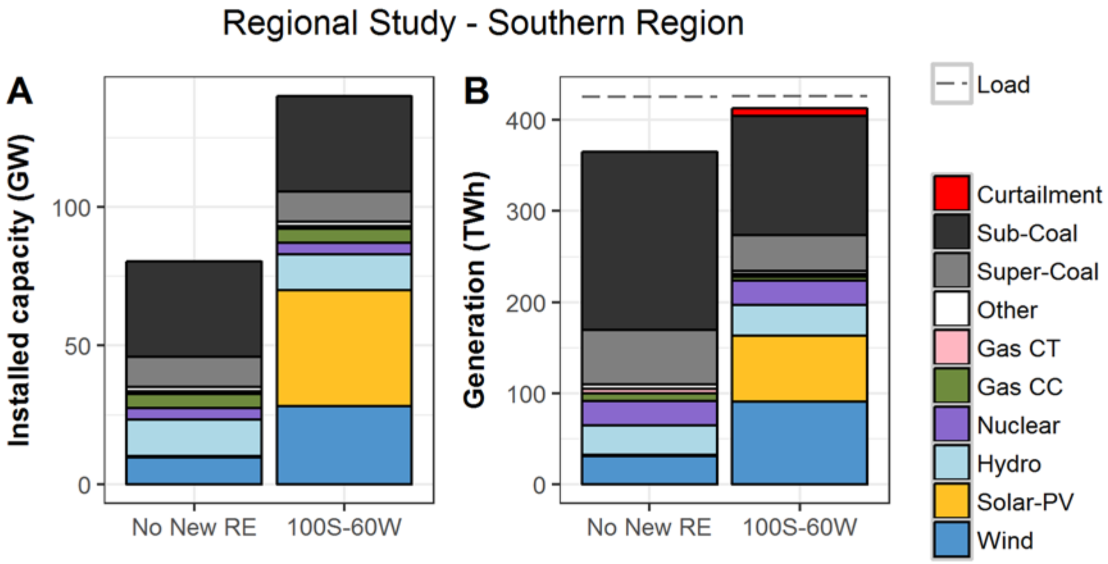

Figure 3. Installed capacity (A) and annual generation (B), No New RE and 100S-60W, Southern region

Figure 4 summarizes the penetration of RE generation as a percent of load, by state, as both annual average and instantaneous 15-minute peak. Generation from Southern region RE meets the equivalent of 38% of load annually. Two states, Andhra Pradesh and Karnataka, meet the equivalent of more than 40% of their annual load with RE. The region as a whole experiences an instantaneous peak RE penetration of 89% of load, which occurs in July.

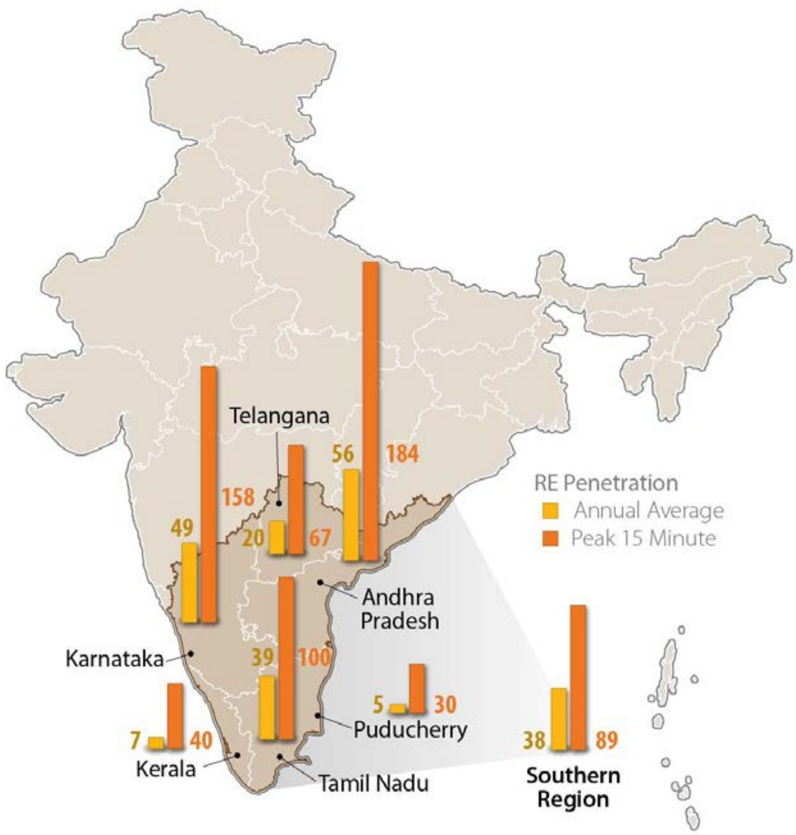

Figure 4. Annual and 15-minute peak instantaneous penetration of RE generation as a percent of load, 100S-60W, Southern region

Figure 5 summarizes RE penetration as a percent of load by month. RE generation is highest in the monsoon season because of increased wind generation. RE meets the equivalent of 63% of the Southern region's load in July.

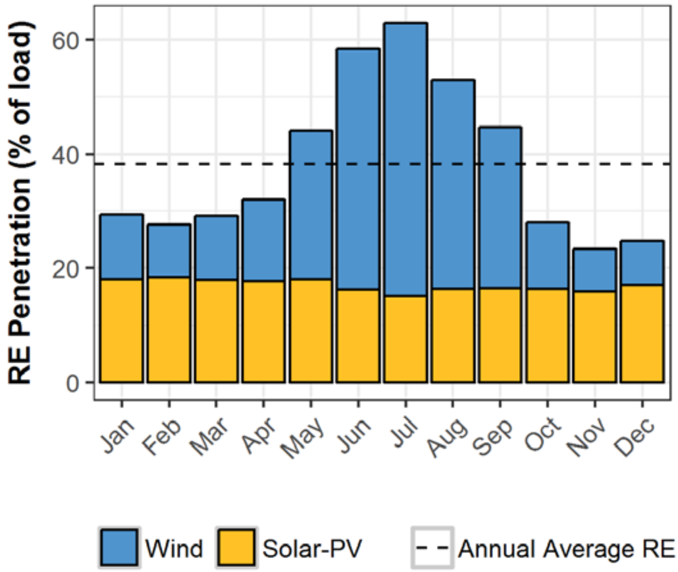

Figure 5. Monthly wind and solar penetration as percent of load, 100S-60W, Southern region

2.1.2 Operational Impacts to Thermal Generators

With more RE on the system, thermal generators operate less and differently. An important aspect of RE integration that impacts the non-RE portion of the fleet is the concept of net load. Net load is the load that is not met by RE and therefore must be served by conventional generation.[5] Noncoincident timing of RE generation and load can lead to large ramps in net load that must be met by conventional generation in the absence of other tools to shift load, such as storage or demand response.

Figure 6 compares the Southern region load and net load between No New RE and 100S-60W for three different days in the year. Solar generation during the daylight hours causes increased net load ramping down in the morning and ramping up in the evening in all days. During the example monsoon day, 4 July, an increase in wind generation further lowers net load compared to February and November. The flat net load profile in the middle of that day represents a period when RE curtailment prevents further reductions in net load.

Annually, the peak 1-hour net load up-ramp is 22 GW, up from 9.9 GW. The maximum net load valley-to-peak ramp is 34 GW on 24 March, up from 15 GW on 30 August in the No New RE scenario.

[5] Net load is sometimes calculated pre-curtailment; however, in this study, we define net load as total load less actual RE generation.

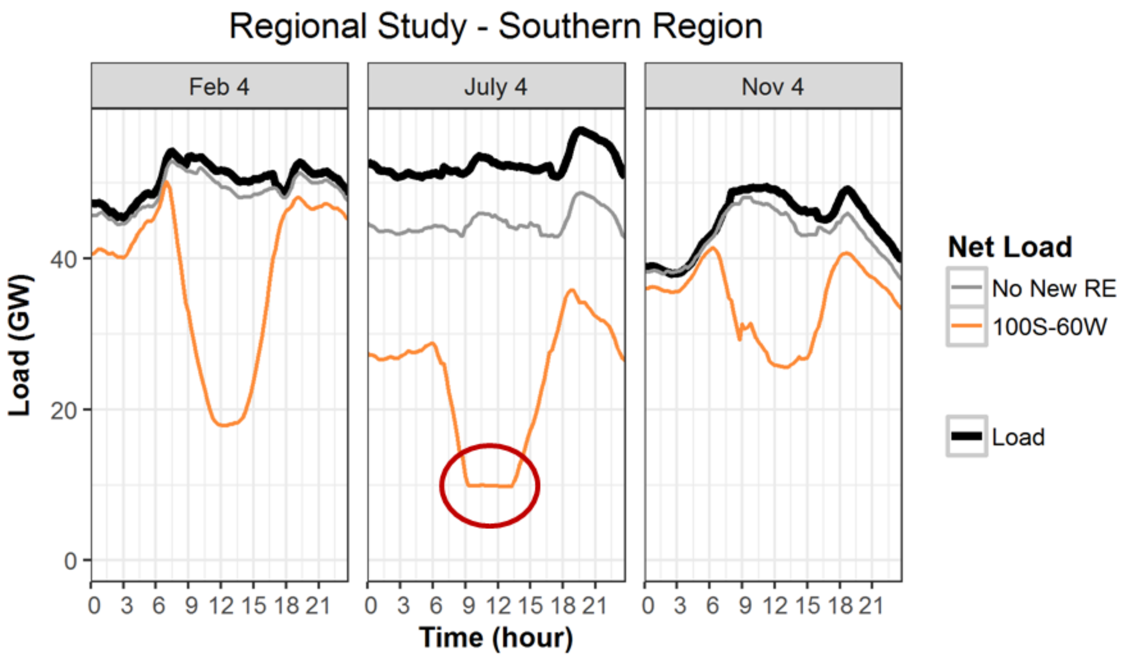

Figure 6. Comparison of net load by season, No New RE and 100S-60W, Southern region

Net load is load minus wind and solar generation post-curtailment.

The change in net load shape requires changes to operations of hydro and thermal plants to keep the system balanced. Figure 7 shows the average day of hydro operations for both the No New RE and 100S-60W scenarios for the Southern region. In the 100S-60W scenario, hydro generation turns down lower during the day—when solar generation is high—and instead contributes more to ramping and energy needs during the morning and evening net load peaks.

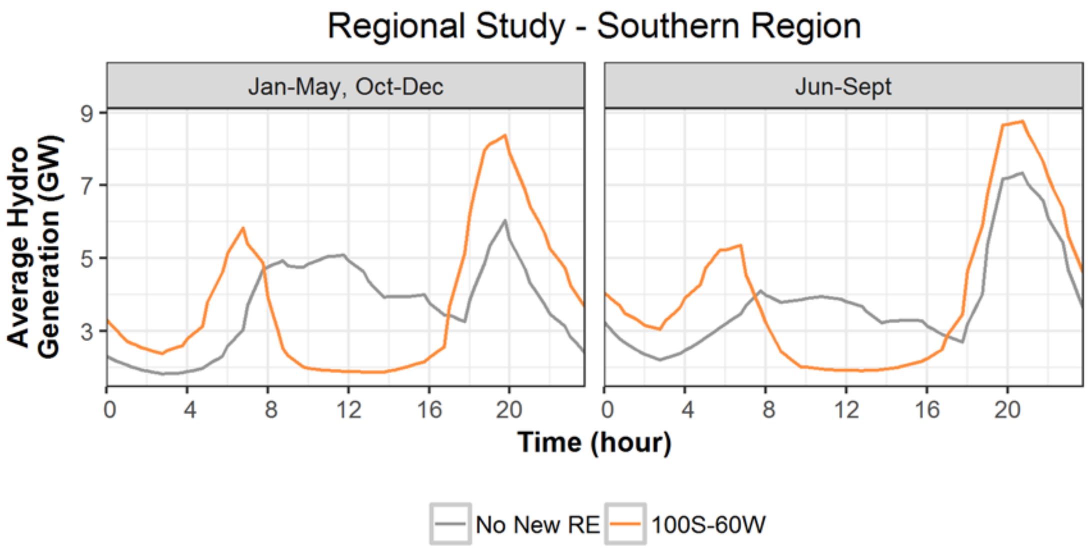

Figure 7. Average day of hydro operations by season and region, No New RE and 100S-60W, Southern region

The rest of this section will explore how coal fleet operations change with the more variable net load profile characteristics of the 100S-60W scenario.

Coal generation meets the equivalent of 40% of the load and accounts for 42% of the energy generated in the Southern region annually. Figure 8 shows the monthly variability of coal generation for both the No New RE and 100S-60W scenarios. Coal generation is lower in the 100S-60W scenario throughout the year but is even further displaced during the windier monsoon season.

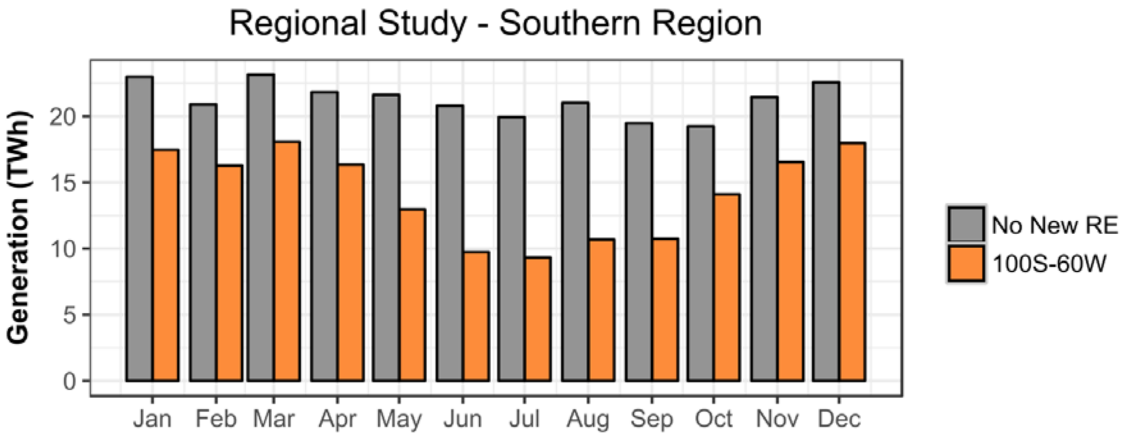

Figure 8. Coal generation by month, No New RE and 100S-60W, Southern region

The daily variability of coal also changes as more RE is added to the system. Figure 9 illustrates coal commitment and generation during an example week in May for both scenarios. The coal fleet in the No New RE scenario maintains a relatively flat generation profile compared to the daily turn down of coal in response to the lower daytime net load in the 100S-60W scenario.

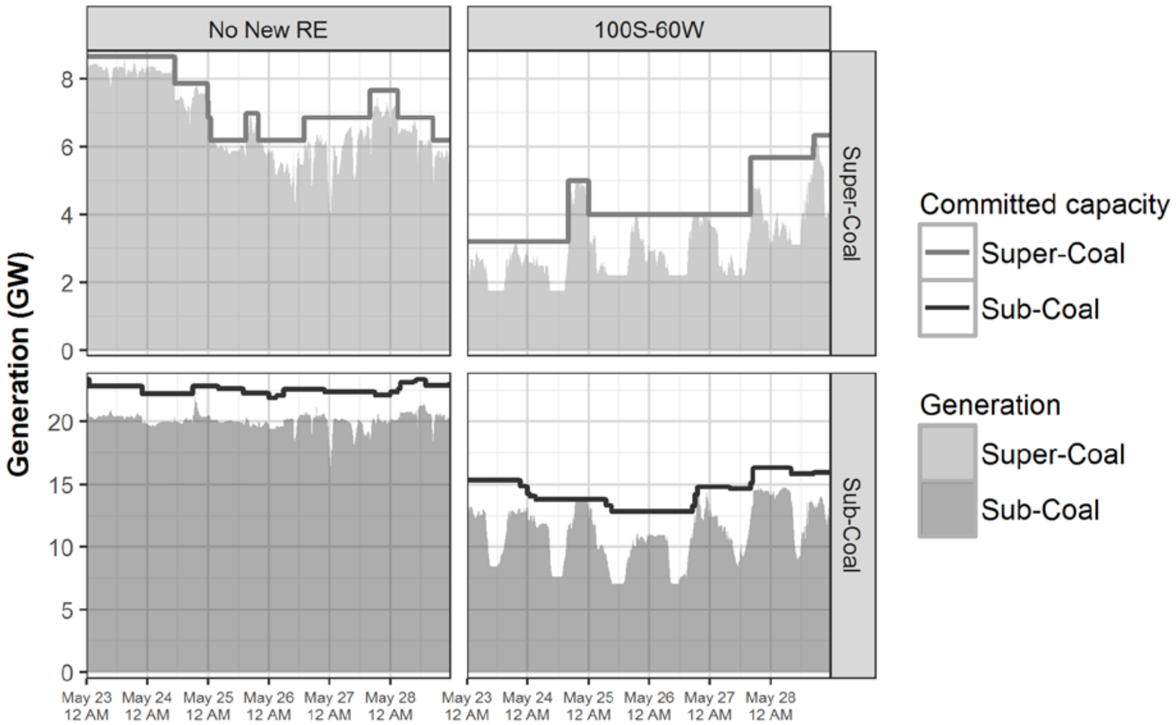

Figure 9. Committed capacity and generation during a high-RE week, 23–29 May, for sub- and supercritical coal, No New RE and 100S-60W, Southern region

As a result of the diurnal and seasonal variations in coal generation in the 100S-60W scenario, coal plants operate less frequently, cycle more, and spend more time at minimum generation. Table 2 summarizes changes in plant load factors (PLFs) and coal starts between the No New RE and 100S-

60W scenarios. This information is disaggregated by the relative variable cost of the plants to reflect merit order impacts, as well as ownership/control (central vs. state plants). Average PLFs of coal plants decrease by 33% from the No New RE to the 100S-60W scenario. The top third most expensive coal units are impacted most by increased RE availability, dropping from an average PLF of 42% to 15%. The modest 4% rise in total starts masks significant operational changes in subsections of the coal fleet. Relatively inexpensive and centrally owned coal generators must cycle significantly more to address variable net load, whereas the top third most expensive coal units, including many state-owned or independent power producer (IPP) generators, cycle significantly less, reflecting that they are not run as often or at all. Of the Southern region's coal, 830 MW of capacity never starts in the 100S-60W scenario, compared to 0 megawatts (MW) in the No New RE scenario.

Table 2. Comparison of Coal Plant Load Factors and Number of Starts, Disaggregated by Variable Cost and Plant Ownership, No New RE and 100S-60W, Southern Region

	PLF%			Capacity Not Started (MW)		Number of Coal Starts		
Relative Variable Cost	No New RE	100S-60W	% Change	No New RE	100S-60W	No New RE	100S-60W	% Change
Top 1/3	42	15	-64	0	830	566	338	-40
Mid 1/3	69	45	-35	0	0	311	454	46
Low 1/3	80	68	-15	0	0	202	331	64
Ownership								
State/IPP	61	38	-37	0	830	830	695	-16
Central	72	55	-25	0	0	249	428	72
All	64	43	-33	0	830	1,079	1,123	4

2.1.3 Transmission and Energy Flows within the Southern Region

The transmission flows between states in the Southern region change in response to more RE on the system, both in terms of peak and total usage. This change leads to some periods when there is a greater reliance on transmission for balancing. Figure 10 shows the distribution of flows on state-to-state corridors in the Southern region for both the No New RE and 100S-60W scenarios. Although many corridors have very similar distributions of flow magnitude between the scenarios, a few corridors experience much greater changes. For example, the flows from Andhra Pradesh to Telangana experience a peak that is 72% higher in the 100S-60W scenario.

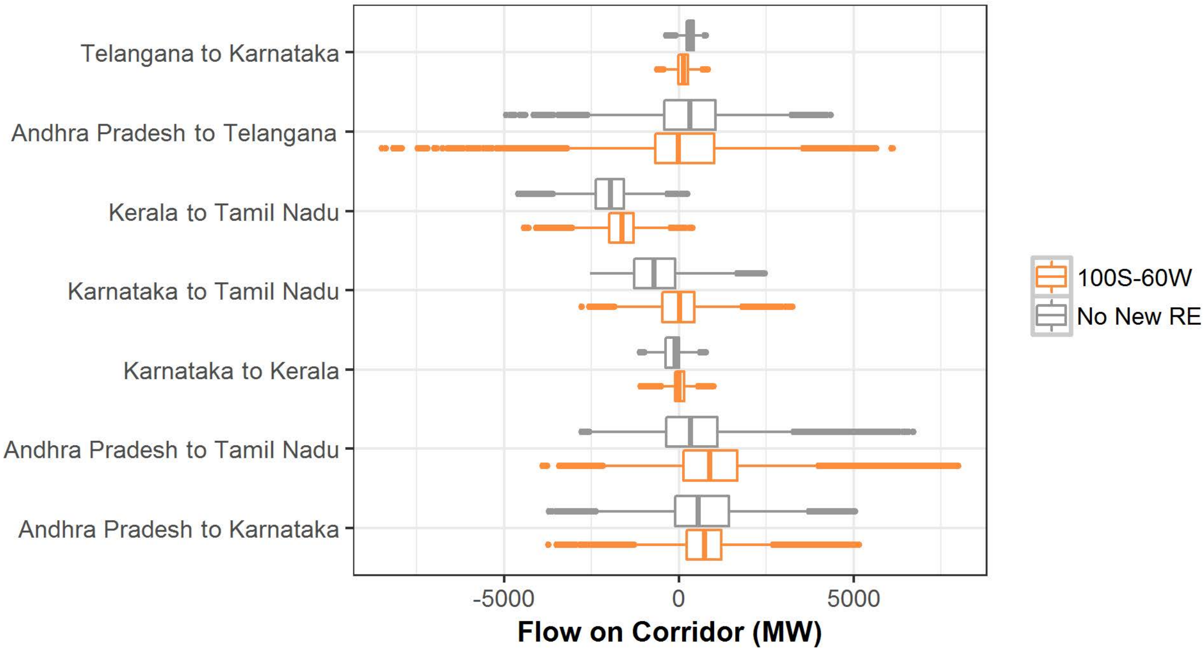

Figure 10. Distribution of flows across state-to-state corridors within the Southern region, No New RE and 100S-60W

Boxes represent divisions into 25th percent quantiles. The middle line is the median. Positive flow indicates direction as indicated in legend, and negative flows the opposite direction.

A change in flow patterns can cause changes to congestion on certain transmission corridors. Table 3 compares time in which there is congestion within or between Southern region states in 100S-60W compared to No New RE. Tamil Nadu experiences a 56% increase in periods when intrastate congestion affects dispatch. Karnataka, on the other hand, experiences a 16% decrease in intrastate congestion.

Table 3. Percent Change in Time During Which There Is Congestion within a Southern Region State or between Southern Region States

STATE	% CHANGE FROM NO NEW RE
Andhra Pradesh	-7 (7% decrease of periods with intrastate congestion)
Karnataka	-16
Kerala	62
Tamil Nadu	56
Telangana	-1
Interstate	-17 (17% decrease of periods with interstate congestion in Southern region)

While flows on key corridors in the Southern region indicate that transmission continues to play an important part in least-cost system balancing, energy exchange between states in the Southern region decreases by 8% as more states are able to serve their own demand with local generation. Additionally, energy exchanges between the Southern region and its neighbors decrease. In particular, total energy exchanges on the Southern region (SR)-Western region (WR) interface fall by 37% between the No New RE and 100S-60W scenarios. Figure 11 shows flows across the SR-WR interface for a three-day period in May. The top panel shows the combined interregional interface flow, and the subsequent panels show flows across the six main transmission corridors that compose the interregional interface. Pink shading indicates periods when there is RE curtailment somewhere in the Southern region, and the black horizontal lines represent total interface maximum and minimum flow limits. While the Southern region consistently imports in the No New RE scenario during this period, it becomes an exporter during the daytime hours in the 100S-60W scenario. Exports typically flow from Karnataka to Maharashtra, while imports come through Tamil Nadu via DC ties with Chhattisgarh. In many periods when the Southern region experiences RE curtailment, the SR-WR interface is constrained. The interaction of the many constraints that cause RE curtailment is examined further in Section 2.3.

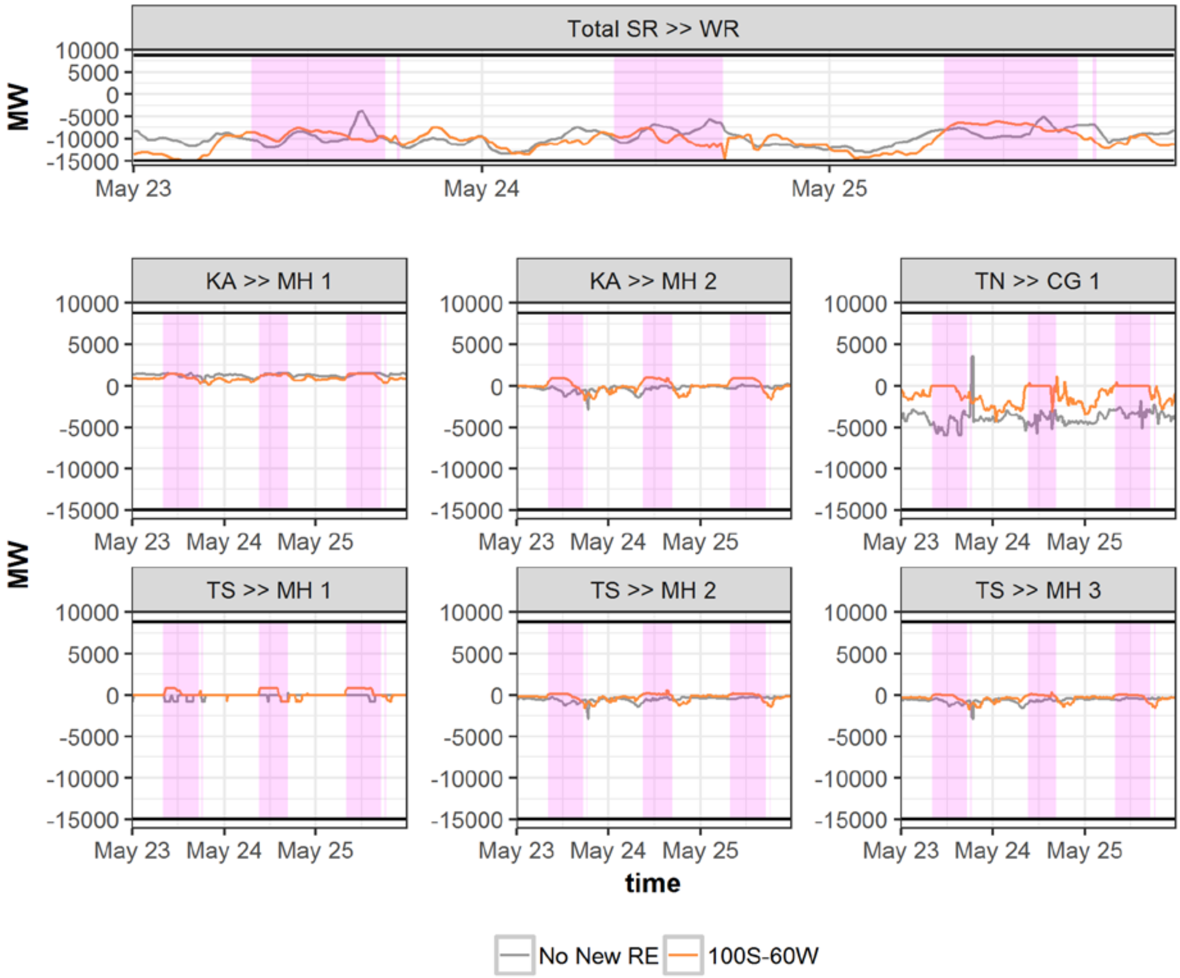

Figure 11. Flows across SR-WR interface for a three-day period in May, No New RE and 100S-60W

Horizontal black lines indicate total interface flow limits. Pink shading marks periods of RE curtailment in the Southern region. Positive flows indicate power leaving the Southern region.

CG=Chhattisgarh, KA=Karnataka, MH=Maharashtra, TN=Tamil Nadu, TS=Telangana

2.1.4 Summary of Annual Impacts of High-RE Scenario

RE generation in the Southern region:

- 70 GW of wind and solar power (as part of the 160-GW national goal) generates 160 TWh annually (91 TWh wind, 72 TWh solar), which is 40% of all generation in the Southern region.
- Wind and solar generation result in an annual RE penetration of 38% of load.
- In July, the month with the highest RE generation, average RE penetration is 63%, with an instantaneous peak of 89% of total load.

Impacts on thermal units and plant operations in the Southern region compared to the No New RE scenario:

- Peak 1-hour net load up-ramp is 22 GW, up from 9.9 GW.
- Maximum net load valley-to-peak ramp is 34 GW on 24 March, up from a peak of 15 GW on 30 August in the No New RE scenario.
- Coal and natural gas generation decrease 85 TWh and 6.3 TWh, respectively, a drop of 33% and 48%.
- Plant load factors of coal drop from 64% to 43%; PLFs of state and private plants fall from 61% to 38%.
- 830 MW of coal capacity never starts compared to 0 MW in No New RE.
- Coal units with the highest variable costs are impacted most by increased RE availability, with PLFs of the top third most expensive units dropping to an average PLF of 15% from 42%.

Impacts on imports and exports and transmission flows compared to the No New RE scenario:

- Peak flow increases on almost all state-to-state corridors in the Southern region, including a 72% increase in the peak transmission flow from Andhra Pradesh to Telangana.
- Interstate energy exchanges inside the Southern region fall 8% between No New RE and 100S-60W as all states decrease their reliance on imports to serve load.
- With new RE, total annual generation in the region across all generation types increases 11% to 405 TWh, enabling the region to reduce its net imports by 64%.
- Karnataka shifts from net importer to net exporter, while Tamil Nadu decreases exchanges with other states by 22%.
- Tamil Nadu experiences a 56% increase in periods when intrastate congestion affects dispatch as a net result of increased use of intrastate transmission to transfer RE and decreased exchanges with neighbors. Karnataka, on the other hand, experiences a 16% decrease in intrastate congestion.

2.2 Strategies to Improve Integration

The National Study demonstrates potential value of two integration strategies: improved operational coordination resulted in production cost savings, and coal flexibility alleviated curtailment. We therefore chose to investigate these two strategies in the Regional Study, to understand their impacts in the context of a more detailed transmission network. To look at thermal flexibility, we ran the most effective coal flexibility sensitivities from the National Study (coal minimum generation levels at 55%, 70%, and 40%). While the National Study evaluates coordinated operations both nationally and regionally, the Regional Study evaluates just regional coordination but at two timescales—(1) both day-ahead scheduling and real-time dispatch, as investigated in the National Study, and (2) dispatch only, also referred to as an energy imbalance service or energy imbalance market (EIM). These two integration strategies are defined in Table 4.

Table 4. Description of Integration Strategies Tested

SENSITIVITY	BASE	LESS FLEXIBLE	MORE FLEXIBLE
Size of balancing area for scheduling and dispatch	State (current practice)		Coordinated dispatch: state-based day-ahead scheduling (status quo) but regionally coordinated real-time dispatch Coordinated scheduling and dispatch, by region
Minimum plant generation levels (% rated capacity)	55%	70%	40%

The rest of this section reviews the impacts of each of these strategies.

2.2.1 Regional Coordination

The purpose of coordination between balancing areas is to reduce costs through improved merit order scheduling and dispatch and, in particular as it relates to RE integration, share over a broader area the power system's variability, uncertainty, and flexibility. We ran three coordination cases: state scheduling and dispatch (the reference 100S-60W case), regionally coordinated scheduling and dispatch (as in the National Study), and an energy imbalance market.

Energy imbalance services or markets achieve this coordination for economic dispatch. Each balancing area conducts its own day-ahead scheduling but shares projected load and available capacity with a centralized market or system operator in real time. The operator redispatches generators within their available generating ranges to produce electricity at least cost.

By effectively enlarging the footprint of real-time operations, EIM smooths the power system's variability and shares resources to respond to RE uncertainty that can lead to under- or overforecasting availability (Brinkman et al. 2016). Overforecasting can result in insufficient capacity committed to meet load, potentially requiring more expensive quick-start generation. Underforecasting can result in too much committed capacity, potentially leading to more thermal plants operating at less efficient part-loads and/or RE curtailment. EIM helps minimize the impacts of under- and overforecasting by providing access to the full set of balancing resources within the larger balancing footprint.

Full coordination includes the improved efficiencies of coordinated dispatch but also addresses barriers to suboptimal day-ahead unit commitment, when one balancing area may not have sufficient visibility of generation availability and needs in a neighboring area, thereby limiting optimal merit order scheduling. Coordinated unit commitment broadens the pool of conventional generators, resulting in improved merit order generation.

Figure 12 maps typical operations to the timescale at which they occur and the extent to which coordination supports RE integration. Coordinating over longer timescales aids in RE integration but does increase the complexity of implementation, for example in automating communications on transmission and generator availability and costs, and instituting financial compensation mechanisms. Thus, while coordinated unit commitment offers more opportunities for cost savings and efficient plant operations, EIM may be easier to implement and could serve as an intermediate step toward full day-ahead coordination if desired in the long run.

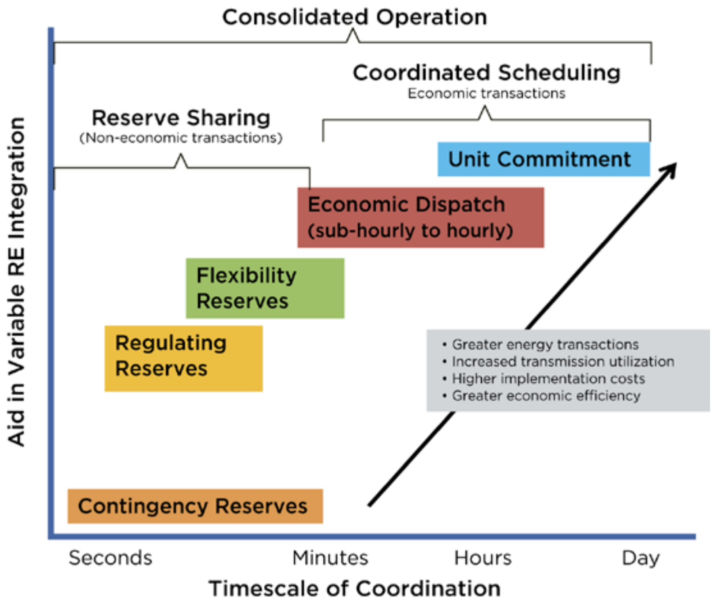

Figure 12. When balancing areas coordinate activities over longer timescales, they are able to increase the economic benefits of coordination to support RE integration; however, coordination over longer timescales introduces greater complexity and higher implementation costs

Source: Denholm and Cochran (2015)

As described in Section 3 of the National Study, we use a modeling parameter, referred to as a hurdle rate, which represents informational or market barriers to optimal scheduling and dispatch. Hurdle rates create a price differential before which a state will import, thus creating an economic incentive for each state to use its own resources to balance generation and load before importing generation with similar production costs. Table 5 summarizes how hurdle rates are applied to the coordination sensitivities in this study. To simulate state-level scheduling and/or dispatch, hurdle rates of INR 1050/megawatt-hour (MWh) are applied. To simulate perfect coordination between states within a region, the state-to-state hurdle rates are removed.[6] Thus, to simulate EIM, which has state-level unit commitment but coordinated economic dispatch, we apply the hurdle rate only for unit commitment.

[6] A small hurdle rate of INR 50/MWh remains in place on interstate lines after removing the hurdle rates reflecting barriers to trade. Because we do not model losses, the small hurdle rate penalizes feasible solutions that nevertheless have unrealistically large loop flows.

Table 5. Comparison of Hurdle Rates Applied to State-to-State Trades across the Coordination Sensitivities

HURDLE RATES	STATE SCHEDULING/DISPATCH	EIM	REGIONALLY COORDINATED SCHEDULING/DISPATCH
Day-ahead unit commitment	INR 1050/MWh	INR 1050/MWh	None
Real-time economic dispatch	INR 1050/MWh	None	None

Across all scenarios, hurdle rates of INR 225-1050/MWh are applied to interregional trades with the Southern region, both day-ahead and real time, as described in more detail in the National Study.

Impacts to Generation

Nationally, regional coordination reduces production cost by 2.4% annually, and part of these savings arises from the ability to more efficiently use generation within the Southern region and around the rest of the country. Within the Southern region low cost generation in Andhra Pradesh, including RE, is able to displace high cost generation elsewhere in the region. Additionally, coordination in the Western region allows for greater access to low cost generation and therefore more energy is imported from the Western region.

The following example illustrates how regional coordination—both EIM and full day-ahead scheduling and dispatch coordination—affects coal plant operations and reduces costs. Tamil Nadu has relatively high-cost generation compared to other states in the Southern region. With increased coordination, generation is optimized over a broader area, which results in less generation in Tamil Nadu and more imports from neighboring states. Figure 13 shows the dispatch stack (top) and the day-ahead unit commitment and generation set point for coal as well as actual coal generation in real time (bottom), for 26 March. As typical for the year, Tamil Nadu is a net importer. Without coordination (state dispatch), the real-time dispatch of coal largely adheres to the day-ahead schedule in the early part of the period and then drops below schedule during the day to accommodate an RE forecast error.

With regional coordination of dispatch (EIM), day-ahead commitment remains the same, but dispatch set points are readjusted due to two factors: forecast errors, which when netted regionally are typically reduced, and newly accessible lower-cost generation through the EIM. For this reason, relatively expensive, committed generation in Tamil Nadu is turned down to a minimum so the state can meet more of its load with less expensive imports.

With regional coordination of both scheduling and dispatch, day-ahead scheduling is also optimized, and relatively expensive coal generators in Tamil Nadu are not committed, resulting in a 16% drop in committed coal capacity on 26 March. Because the geographic area of optimization is the same both day-ahead and real-time, the real-time generation more closely matches the scheduled generation and is adjusted only to accommodate regionwide forecast errors. Tamil Nadu imports more generation throughout the day to take advantage of the lower-cost generation in neighboring states.

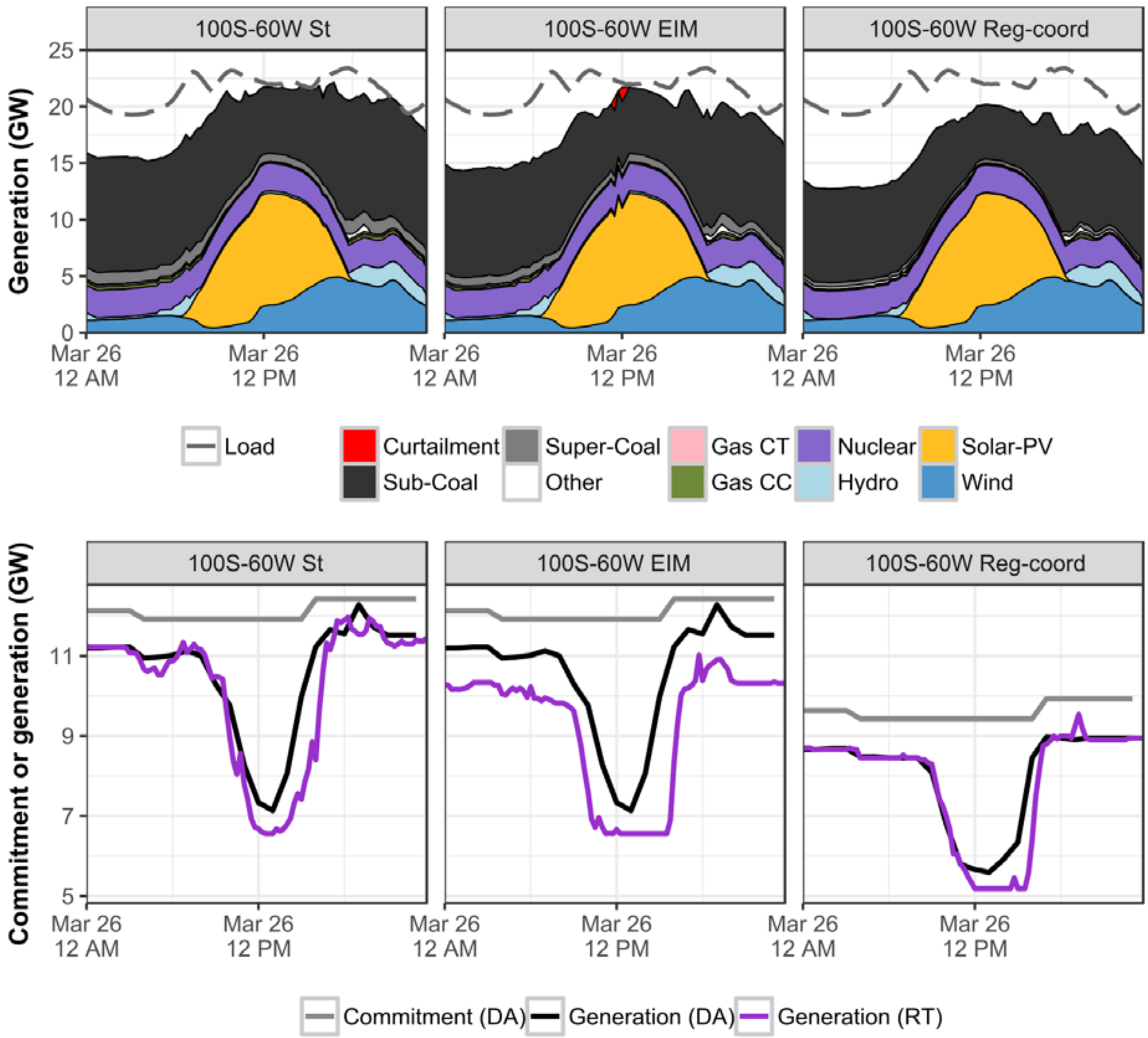

Figure 13. Generation dispatch (top) and commitment and dispatch of coal generation (bottom) in Tamil Nadu for 26 March for state dispatch, EIM, and regional coordination

Looking annually and across the whole region, Table 6 shows the average variable cost of generation by state within the Southern region.

Table 6. Average Variable Cost (INR/MW) of Generation by State within the Southern Region, across Coordination Sensitivities

SCENARIO	ANDHRA PRADESH	KARNATAKA	KERALA	TAMIL NADU	TELANGANA
State Dispatch	1,150	1,150	393	1,560	1,660
EIM	1,160	1,140	374	1,550	1,650
Regional Coordination	1,250	1,050	305	1,470	1,520

Most states experience a decrease in average cost of generation as coordination increases, with the exception of Andhra Pradesh, where average costs of generation increase. The relatively low-cost coal generation as well as surplus capacity in Andhra Pradesh allows it to provide energy to states within the Southern region at a cost lower than the other states can produce. Andhra Pradesh, in serving an expanded market, must therefore draw on more expensive generators within its state, thus increasing the average variable cost. Karnataka and Kerala also have relatively low-cost energy, although the average shown in Table 6 is driven by the zero-variable-cost hydro and RE that make up a large portion of the generation in these states; the relatively more expensive coal generation in these states is operated less frequently. The marginal unit of energy in Karnataka typically comes from nuclear at INR 3.0/kilowatt-hour (kWh), while the marginal unit in Andhra Pradesh typically comes from natural gas at INR 2.8/kWh.

Our model assesses the cost of generation in each state based on increased regional coordination. The model does not determine how the overall savings to the region that occur from regional coordination would be allocated across states. If Andhra Pradesh, for example, participates in a regional market and provides more efficient generation to neighboring states, the terms of such contracts and impacts on customer tariffs within each state are outside the scope of this study. Complementary pieces of Greening the Grid and ongoing efforts by Indian stakeholders, including the Central Electricity Regulatory Commission (CERC), aim to address the regulatory aspects of regional coordination.

Figure 14 summarizes the annual difference in generation that results from the changes in optimization with the coordinated scenarios.

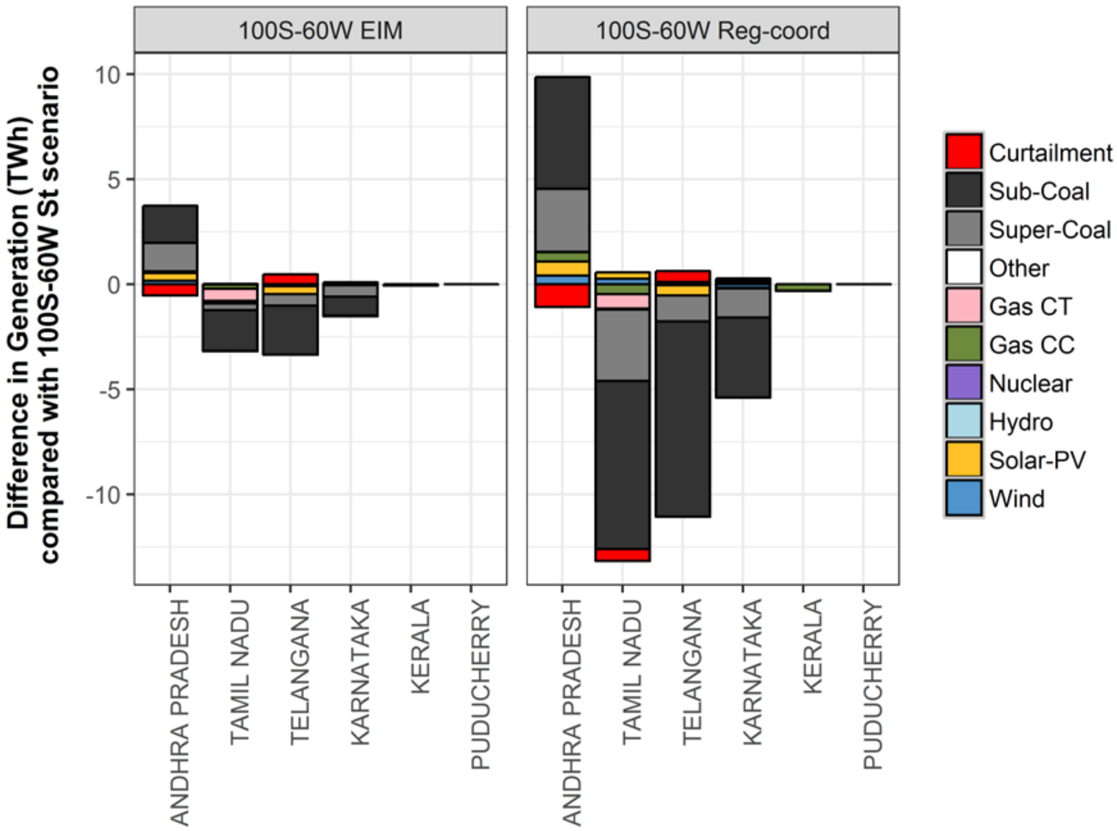

Figure 14. Difference in generation compared to state dispatch with regional coordination, in the Southern region by state

The average annual production costs in the Southern region fall with increased coordination, from INR 1330/MWh with status quo coordination, to INR 1320/MWh (0.8% decrease) with EIM, and to INR 1260/MWh (5.4% decrease) with regional coordination of both unit commitment and dispatch. The coordination has much less impact on RE curtailment, remaining largely unaffected with EIM and falling from 4.9% to 4.3% with coordinated scheduling.[7]

The Southern region is a net importer in the 100S-60W scenario, and it remains so in all coordination scenarios. Imports to the region increase by 19% in EIM and 85% in regional coordination from the state dispatch scenario.[8] Flows within states are also impacted by coordination as lower cost resources are more easily accessible to all states within the region. However, greater accessibility can lead to greater demands on the transmission system. Table 7 shows the percent of time that at least one line is congested within the states of the Southern region for all coordination scenarios.

Table 7. Percent of Time That at Least One Line Is Congested in States in the Southern Region, All Coordination Sensitivities

	STATE DISPATCH	EIM	REGIONAL COORDINATION
Andhra Pradesh	54	63	74
Karnataka	52	64	74
Kerala	2	2	1
Tamil Nadu	56	56	62
Telangana	29	30	32

2.2.2 Coal Flexibility

One of the key findings from the National Study is that coal flexibility—specifically reducing minimum plant generation levels—is a big driver to reducing RE curtailment. In the 100S-60W scenario, coal plants, particularly in the Southern and Western regions, frequently operate at minimum generation levels during the day when RE generation is at its highest. Lowering minimum generation levels enables the coal plants to turn down when solar generation is high, thereby reducing the instances of RE curtailment while maintaining the ability to ramp up to meet evening peak.

Impacts to Generation

In this section we apply the same set of sensitivities in the Regional Study, using minimum generation levels of 40%, 55%, and 70% of rated capacity as three parameters to measure the impact to RE integration of flexible coal. Coal flexibility affects RE curtailment significantly—minimum generation levels of 40%, 55%, and 70% have RE curtailment of 3.0%, 4.9%, and 8.4%, respectively. The impact of decreasing coal minimum generation levels produces significant savings for the

[7] RE curtailment is sensitive to assumptions that the National Renewable Energy Laboratory and Berkeley Lab made about locations of new RE and intrastate transmission, and, as noted in Section 1, these modeling assumptions were made independent of a formal transmission study. Therefore, these numbers should not be used as a predictor of RE curtailment if intrastate transmission and RE locations are effectively planned.

[8] Part of the impact to interregional flows is from the impacts coordination has on the other regions where coordination is also increased. For example, a more efficient dispatch in the Western region could lead to a larger difference in marginal energy between regions, which would incentivize trade.

Southern region. The largest impact occurs by assuming achievement of the CERC regulation of 55% minimum generation levels from current operating practices of 70%. Not meeting this regulation would result in a potential cost increase of 2.3% in the region. A reduction to 40% minimum operating point in coal units saves an additional 1.3% of Southern region production costs. Most of these savings come from reduced curtailment of RE.

Figure 15 shows the difference in generation between the 55% base scenario and the 40% and 70% scenarios by state. Curtailment decreases in all states when shifting minimum generation levels from 55% to 40%, and increases in all states when increasing minimum generation levels to 70%. The primary tradeoff in curtailment is with coal, which displaces RE as coal flexibility is decreased to 70%, and is displaced as flexibility is increased to 40%.

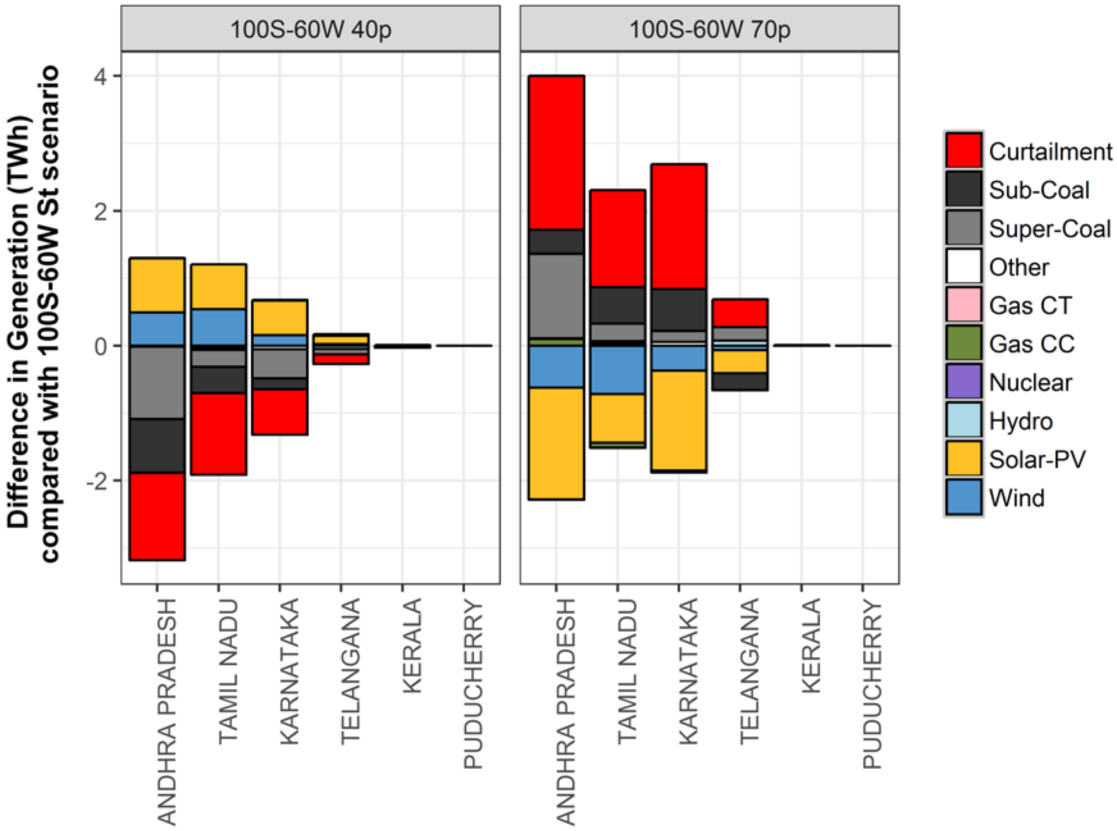

Figure 15. Difference in generation in lower and higher minimum generation levels compared to the base case of 55%, in the Southern region by state

Table 8 summarizes RE curtailment as a percent of available energy for each state, across the three coal flexibility sensitivities. All states are able to decrease curtailment by decreasing the minimum generation of coal plants, although Andhra Pradesh and Karnataka experience the biggest gains in terms of using available RE.

Table 8. Curtailment as a Percent of Available Energy Based on Coal Minimum Generation Levels of 40%, 55%, and 70% in Southern Region States

REGION	40% MINIMUM GENERATION	55% MINIMUM GENERATION	70% MINIMUM GENERATION
Andhra Pradesh	2.8	5.6	10.4
Karnataka	5.0	6.6	11.1
Kerala	0.0	0.4	0.5
Tamil Nadu	2.4	4.3	6.5
Telangana	1.5	2.3	4.7

2.2.3 Summary of Impact of RE Integration Strategies

Changing the minimum generation levels of coal plants significantly affects curtailment. The results show that changing only one parameter—reducing the minimum generation levels of the fleet from 70% to 55% and 40% of rated capacity—changes curtailment in the Southern region from 8.4% to 4.9% and 3.0%, respectively, which also results in production cost savings due to zero-marginal-cost RE displacing coal. Regionally coordinated scheduling and dispatch offers even greater production cost savings per unit of generation due to more efficient use of least-cost generation. Regionally coordinated dispatch but with state-level scheduling (EIM) offers much less savings and negligible changes to RE curtailment, although EIM could serve as an intermediate step toward full coordination.

2.3 Example Day of Operations

We consider system operations on an example day in May to illustrate the multiple constraints experienced in the Southern region on a high RE generation day, as well as how strategies to support integration relieve some of these constraints. On this day, the addition of intrastate transmission from the National Study raises the Southern region's average costs by 51 INR/MWh in the 100S-60W scenario. Because total generation is roughly the same, the majority of this increase can be attributed to intrastate transmission constraints rather than a shift in net exports.

On this day, 11 intrastate transmission corridors experience congestion, and the short-run marginal cost of the Southern region's most expensive committed generator is higher in 40 of 96 15-minute periods compared to results in the National Study where intrastate transmission is unconstrained.

New transmission constraints are not the sole reason for increased costs and curtailment. Instead, imposing more transmission constraints can indirectly impact the system by increasing the severity of constraints related to the local thermal fleet and dispatch coordination. Thus, observations on this day showcase several characteristics of RE integration in the Southern region, which we will explore in this section:

- Individually, thermal, hydro, and transmission constraints may not create barriers to RE integration. Together, however, they can force the system operator to dispatch suboptimally, resulting in economic losses. On this day, the impact of congestion on nodal variable cost creates the economic conditions that restrict access to available thermal flexibility at a time when RE is curtailed.

- On this day, RE curtailment occurs in Karnataka even without transmission and thermal constraints due to intrastate generation affecting flows and intrastate transmission congestion in other states.
- Improved dispatch coordination and 40% minimum generation levels relax the Southern region's multiple constraints to ease RE integration.

2.3.1 How Thermal, Hydro, and Transmission Constraints Interact to Cause RE Curtailment

As discussed in Section 4.6 of the National Study, transmission congestion, thermal and hydro fleet inflexibility, start and stop costs, and trade barriers are the causes of curtailment in our model. Figure 16 illustrates the interplay of generator dispatch (top panel) and thermal fleet[9] inflexibility (bottom panel) in four Southern region states with significant available RE capacity.

The top panel shows generation dispatch in each state, with highlighted areas representing periods when the RE is getting curtailed. Green vertical bands mark intervals during which RE is getting curtailed and has a fully inflexible thermal fleet. Pink vertical bands mark intervals during which RE is getting curtailed despite having thermal generation that is physically available to ramp or turn down. In the bottom panel, the black horizontal line represents total installed thermal capacity for each state, 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 is flexible 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 cannot further decrease its output to accommodate zero-cost RE generation. Because hydro generation is fixed in the day-ahead simulation and therefore inflexible in real time, the state's conventional fleet is fully constrained. Any additional wind or solar generation must be either exported or curtailed.

[9] Thermal fleet refers to all coal, gas, nuclear, diesel, oil, bagasse cogeneration, and waste-heat recovery power generation.

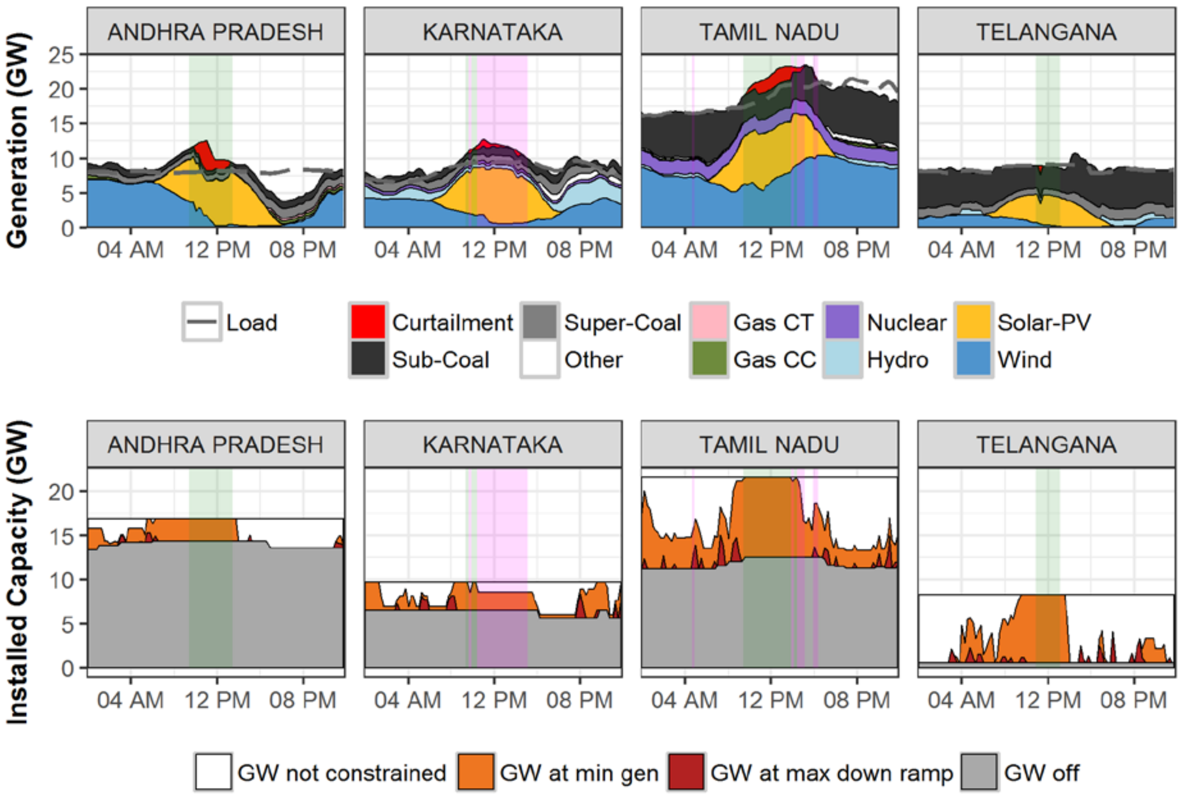

Figure 16. Generator dispatch and thermal fleet constraints in four Southern region states on an example day in May, 100S-60W

Green bands mark intervals during which a state curtails RE and has a fully inflexible thermal fleet. Pink bands mark intervals during which a state curtails RE despite having some unconstrained thermal generation.

The periods when RE is getting curtailed despite having thermal flexibility—represented by the pink bands—provide a strong indicator of intrastate transmission congestion as a contributor to curtailment. In Karnataka's bottom panel of Figure 16, two units equaling 1.2 GW of thermal capacity are flexible from 10:30 to 15:00, concurrent with RE curtailment. Both units operate at max capacity from 11:00 to 15:00. While the two flexible coal generators are electrically distant from the RE curtailment, they are in the same state and therefore a more expensive option than RE in an unconstrained system. However, from 10:30 to 13:30, Karnataka experiences congestion on a single corridor.

Figure 17 shows the transmission network around Karnataka's congested line (colored red). Red nodes are those that curtail RE despite the state having available flexible thermal capacity. Even though both coal plants (which are too far away to capture in Figure 17) could turn down to alleviate RE curtailment, their continued operation actually results in lower-cost overall dispatch.

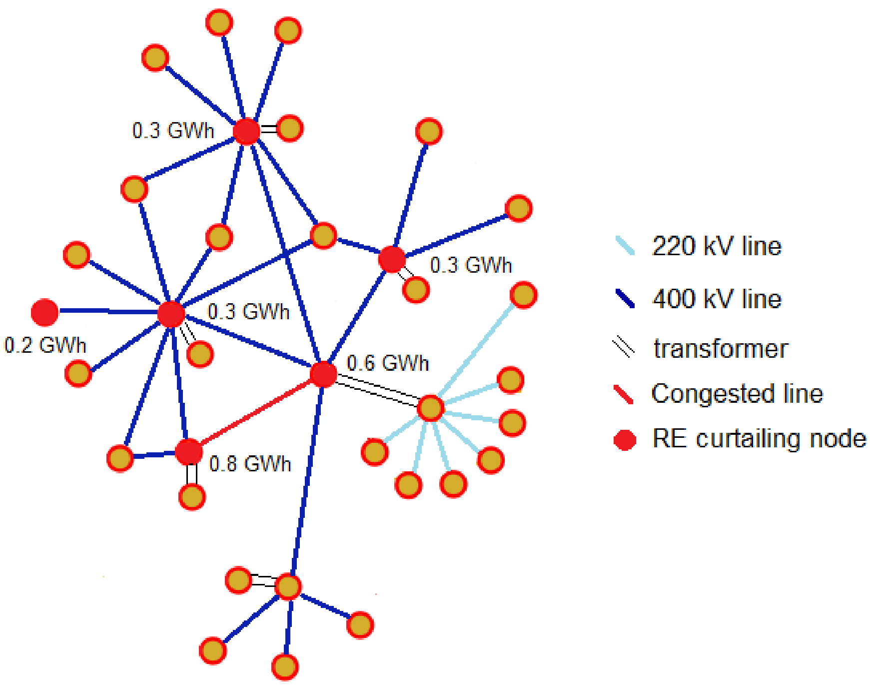

Figure 17. Transmission map of the six Karnataka nodes that curtail RE despite flexible, intrastate thermal capacity on an example day in May

The number beside each red node indicates its total RE curtailment on this day.

Although Karnataka's system is unconstrained and there is available thermal fleet flexibility during the 13:45–15:00 time period, two transmission corridors elsewhere in the Southern region are congested during this time and contribute to 1 GWh of RE curtailment. This is a consequence of least-cost dispatch, which considers all relevant constraints on the system (not just those within the balancing authority area). Because Karnataka's generation affects flows on external congested lines, dispatch within Karnataka is adjusted so that its power injection alleviates, instead of contributes to, the overloading, which can lead to curtailment of RE or the thermal fleet being backed down.[10]

2.3.2 How More Coordination Affects Operations on an Example Day in May

Figure 18 shows Southern region generation dispatch for the state dispatch, EIM, and regionally coordinated scheduling dispatch sensitivities on an example day. Differences in generator dispatch between state dispatch and EIM are small, but the average variable cost of generation falls by 1.3% in this period. With full regional coordination, RE curtailment falls by 2.5 GWh, or 14% compared to state dispatch. Committed coal capacity is also 17% lower, in part because increased imports from the Western and Eastern regions displace 6% of generation in the Southern region. The resulting reduction in average variable cost is 12%.

[10] If curtailment of RE at different substations achieves the exact same least-cost objective, the optimization solver will randomly assign curtailment. This is most likely to occur in periods when there is no transmission congestion.

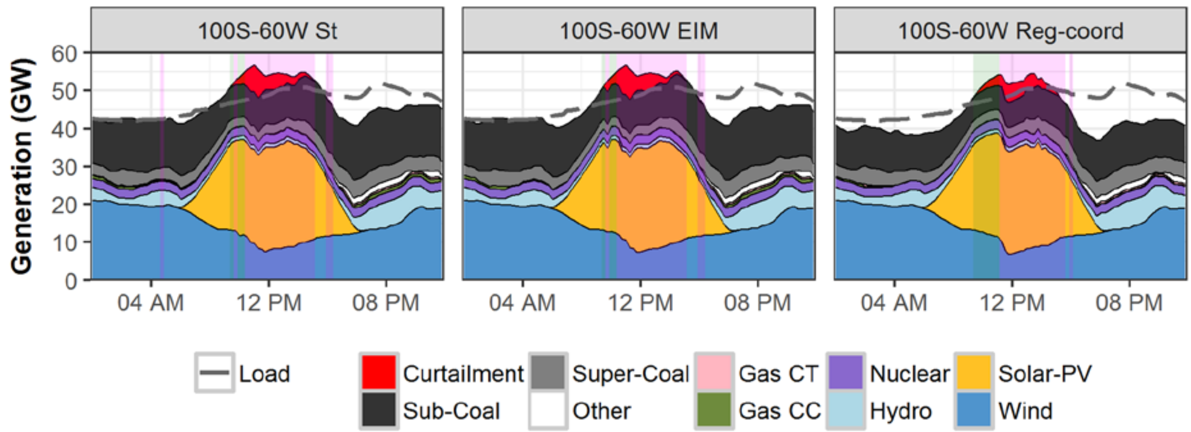

Figure 18. Generation dispatch in the Southern region on an example day in May, regional coordination sensitivities

Green bands mark intervals during which the Southern region curtails RE and has a fully inflexible thermal fleet. Pink bands mark intervals during which the Southern region curtails RE despite having some unconstrained thermal generation.

Thermal commitment and dispatch is optimized over a larger area with regional coordination, and therefore states with relatively expensive thermal fleets commit less and import more. For example, under state dispatch, Telangana commits an average of 7.7 GW of coal capacity and has 3.3 GWh of net exports on this day. With regional coordination, Telangana's average coal commitment falls to 5.4 GW and it has net imports of 37 GWh. As shown in Section 2.2, this increased coordination leads to lower curtailment and production cost savings for the Southern region as a whole.

Figure 19 takes a closer look at the displacement of expensive generation in the Southern region on this day. Each bar represents the quantity of power produced in in the corresponding cost bin. Between state dispatch and EIM, use of expensive oil and diesel generation (red-shaded on the far right) decreases by 19%. The distribution of coal generation by cost remains roughly the same.

Moving from EIM to full day-ahead commitment and real-time dispatch results in additional cost savings from the more efficient use of coal. With state dispatch, the top 25% of subcritical coal generation (70 GWh) is produced at a variable cost above INR 2535/MWh. Only 12% (27 GWh) of subcritical coal generation is produced above the same cost threshold with regional coordination. Regional coordination also significantly reduces expensive natural gas generation. The percentage of combined cycle gas generation above the mean variable cost of all fuels falls from 87% with state dispatch to 30% with full regional coordination.

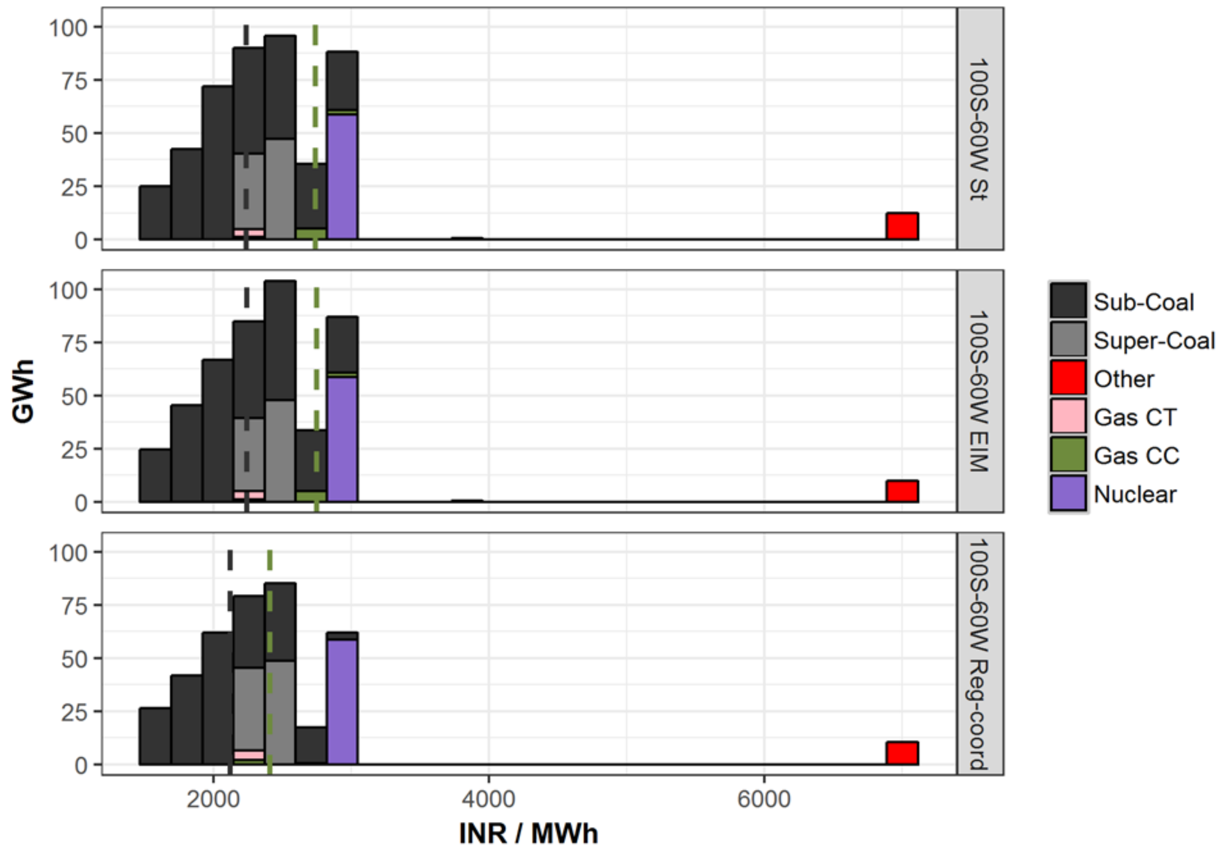

Figure 19. Generation by variable cost band for the Southern region on an example day in May across regional coordination sensitivities

The dotted lines indicate mean variable costs per MWh for subcritical coal and combined cycle gas. Zero-cost generation is excluded.

2.3.3 How Coal Flexibility Affects Operations on an Example Day in May

Section 2.2 demonstrates that increased coal flexibility reduces RE curtailment and lowers generating costs for the Southern region. Figure 20 shows the generation dispatch for the Southern region for three different levels of coal plant minimum generation. Most notable is the severe reduction in curtailment during the whole 24-hour period when coal is more flexible. Between the 70% and 40% scenarios, RE curtailment falls on this day from 6.2% to 1.3% of available energy, net imports rise by 14 GWh (or roughly 1% of total generation), and the average cost per MWh of generation falls by 2.8% (from INR 1072/MWh to INR 1042/MWh). As discussed in Section 2.2, the decrease in average costs is mainly attributable to reduced curtailment rather than more efficient thermal fleet operation.

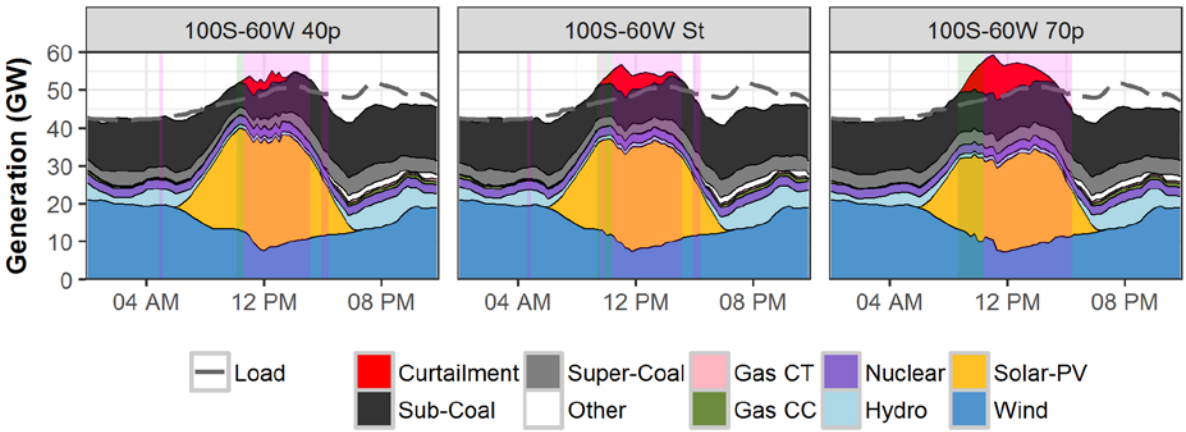

Figure 20. Generator dispatch in the Southern region on an example day in May, coal flexibility sensitivities

Green bands mark intervals during which the Southern region curtails RE and has a fully inflexible thermal fleet. Pink bands mark intervals during which the Southern region curtails RE despite having some unconstrained thermal generation.

2.3.4 Summary of Example Day Results

Operations on a high RE day in May illustrate how transmission and thermal plant constraints interact to cause RE curtailment. Curtailment can occur even when thermal plants are available to turn down because transmission constraints affect the least-cost solution, making it advantageous to run thermal plants above minimum generation levels despite concurrent RE curtailment. RE curtailment can also occur when transmission or thermal plants are not constrained. Despite Karnataka's lack of internal transmission constraints, its generation affects flows in other states with congestion. Maintaining its thermal output above minimum generation in order to alleviate the external congestion contributes to the oversupply of generation, which in turn causes the RE curtailment in Karnataka.

Applying regional scheduling and dispatch coordination results in new commitment and dispatch decisions that reduce expensive variable-cost units in favor of greater output from lower-cost units. For the Southern region, imports from other regions become more economically attractive, which results in less committed coal within the region (17% decrease) and therefore less internal congestion (10% decrease) and more interregional congestion (27% increase) on this day.

Coal flexibility on this day reduces RE curtailment, as expected. Improved coal flexibility reduces the time in which thermal plants are constrained while RE is curtailed. This flexibility results in reductions to average cost of generation primarily due to improved RE integration.

2.4 Conclusion: Implications for Decision Makers

This study shows that in the context of meeting India's RE goals of 160 GW wind and solar, the Southern region can integrate 70 GW of RE at 15-minute timescales, enabling the region to reduce its net imports by 64%. As a result of a comparatively constrained system and high levels of RE relative to load, RE integration strategies have a larger impact and value in the Southern region compared to other parts of India. Nevertheless, regionally coordinated scheduling and dispatch and improved coal flexibility offer larger improvements to optimizing power system operations and costs compared to the rest of the country.

For example, improving coal flexibility reduces curtailment from 8.4% with 70% minimum generation levels, and to 4.9% and even 3.0% with 55% and 40% levels, respectively. Unlike in the Western region, improving coal flexibility also reduces per-unit production costs by 2.3% per MWh of generation in moving from 70% to 55% minimum generation levels. This savings occurs primarily from the ability to integrate RE rather than curtail it, which can then be used to displace fuels with more expensive variable costs. This impact is particularly the case for Andhra Pradesh and Karnataka, which experience annual RE curtailment over 10% if plants remain at 70% minimum generation levels. RE curtailment in Andhra Pradesh drops dramatically from 10.4% to 2.8% in moving from 70% to 40% minimum generation levels. Because coal generation in Andhra Pradesh serves as a flexible and lower-cost resource throughout the region, using the integration strategies of improved regional coordination and coal flexibility to enhance the value of Andhra Pradesh's resource will have benefits throughout the region.

Due to the greater integration challenges relative to other parts of the country, policymakers may want to consider multiple strategies to integrate RE, including strategies outside the scope of this study, such as alternative locations of RE generation or new transmission connections. In the Southern region, in particular, strategies such as coordinated operations and coal flexibility impact flows and congestion, and implementing such integration strategies would benefit from transmission and generation planning conducted in tandem. Although transmission planning is outside the scope of this study, this model can be used to help identify the value and operational impacts of new transmission, as discussed in Appendix A. Because of the sensitivity of RE curtailment to intrastate transmission capacity, this study does reinforce the value of planning that optimizes both transmission and generation capacity using high-resolution RE resource data.

3 WESTERN REGION

The Western region is rich with wind and solar potential. Most of the states in the Western region have encouraged the development of wind through feed-in tariff policies. More recently, auction-based procurement has resulted in rapid development of solar PV, driving down its price to record lows.

A number of advantages exist for the Western region for integrating large amounts of wind and solar. Most prominent of these is its central location, which has already helped to establish the region as an energy supplier for the rest of the country. Interties to three other regions can help balance variability and uncertainty introduced by wind and solar if utilized effectively. However, challenges of being an exporter include committing generation based on other regions' needs. This can lead to difficulty in accessing the full flexibility of the system as minimum generation levels and minimum run-times of plants coincide with the need to use transmission to evacuate energy out of the states and region.

A substantial portion of the 2022 target of 100 GW of solar and 60 GW of wind will likely be installed in the Western region. Accessing this energy will rely on significant intrastate transmission investments as well as completion of interstate transmission to move power around the region and country. However, trading with neighboring regions will also be significantly impacted by the ability of those regions to meet more demand with local RE generation, especially in the Southern region. In a high RE future, it is likely that operational strategies of the exporting Western region will need to adjust in real time to changing conditions in the Southern region to effectively integrate RE.

In this Western region section of the report, first we review annual trends of meeting higher RE penetrations in the region. Then we explore the effects on these trends of two RE integration strategies—regional coordination of operations and improved coal flexibility. We then use one example day to investigate more deeply the operational impacts of higher RE penetrations to better understand the meaning of the annual summaries. Finally we conclude with implications for decision makers.

3.1 Annual Summaries for the Western Region

Using the high-resolution regional model, we analyzed the 100S-60W scenario to anticipate impacts to power system operations in the Western region. This section summarizes for the Western region a select number of impacts: generation, operational impacts to thermal generators, and interstate energy imports and exports and transmission flows. Additional details about the 100S-60W scenario are provided in the state-specific sections.

3.1.1 Generation

The addition of 38 GW of wind and solar power in the Western region between the No New RE and 100S-60W scenarios alters the *type* of energy generated within the Western region, but does not substantially affect the *total* amount of energy generated within the region. The installed RE capacity in the 100S-60W scenario generates 70 TWh of wind and 48 TWh of solar annually, which accounts for 19% of overall generation in that scenario. Increased RE generation displaces coal and gas generation, which fall by 16% (85 TWh) and 31% (6.3 TWh), respectively. Despite this fuel switching, total annual generation across all fuel types falls by only 1%. Net exports decline by 5%.

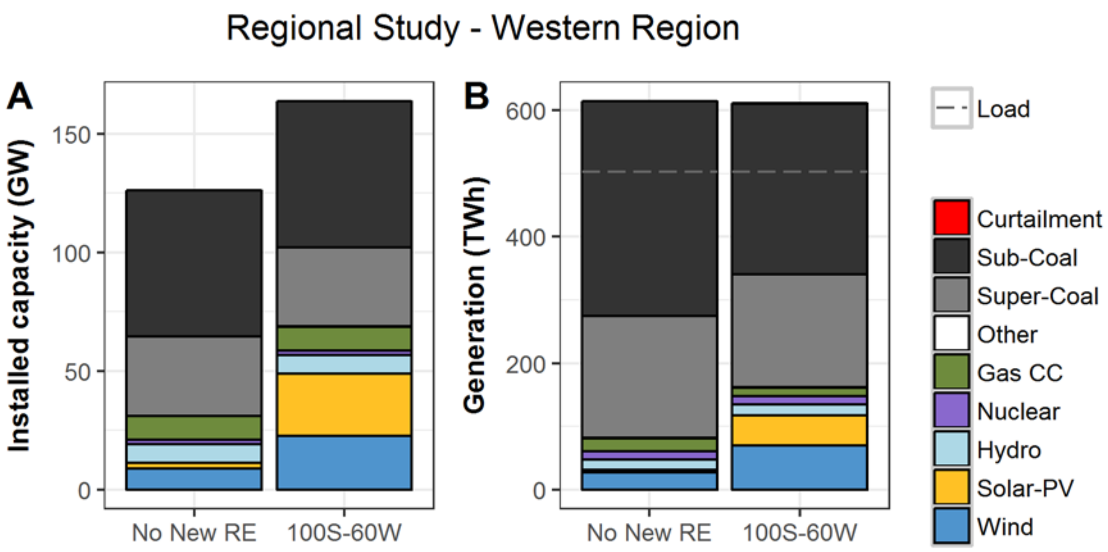

Figure 21. Installed capacity (A) and annual generation (B), No New RE and 100S-60W, Western region

Figure 22 summarizes the penetration of RE generation in the Western region as a percent of load, by state, as both annual average and instantaneous 15-minute peak. Generation from RE meets the equivalent of 23% of load (502 TWh) annually. Two states—Gujarat and Madhya Pradesh—meet the equivalent of at least 30% of their annual load with RE. The region as a whole experiences an instantaneous peak RE penetration of 75% of load, which occurs in July.

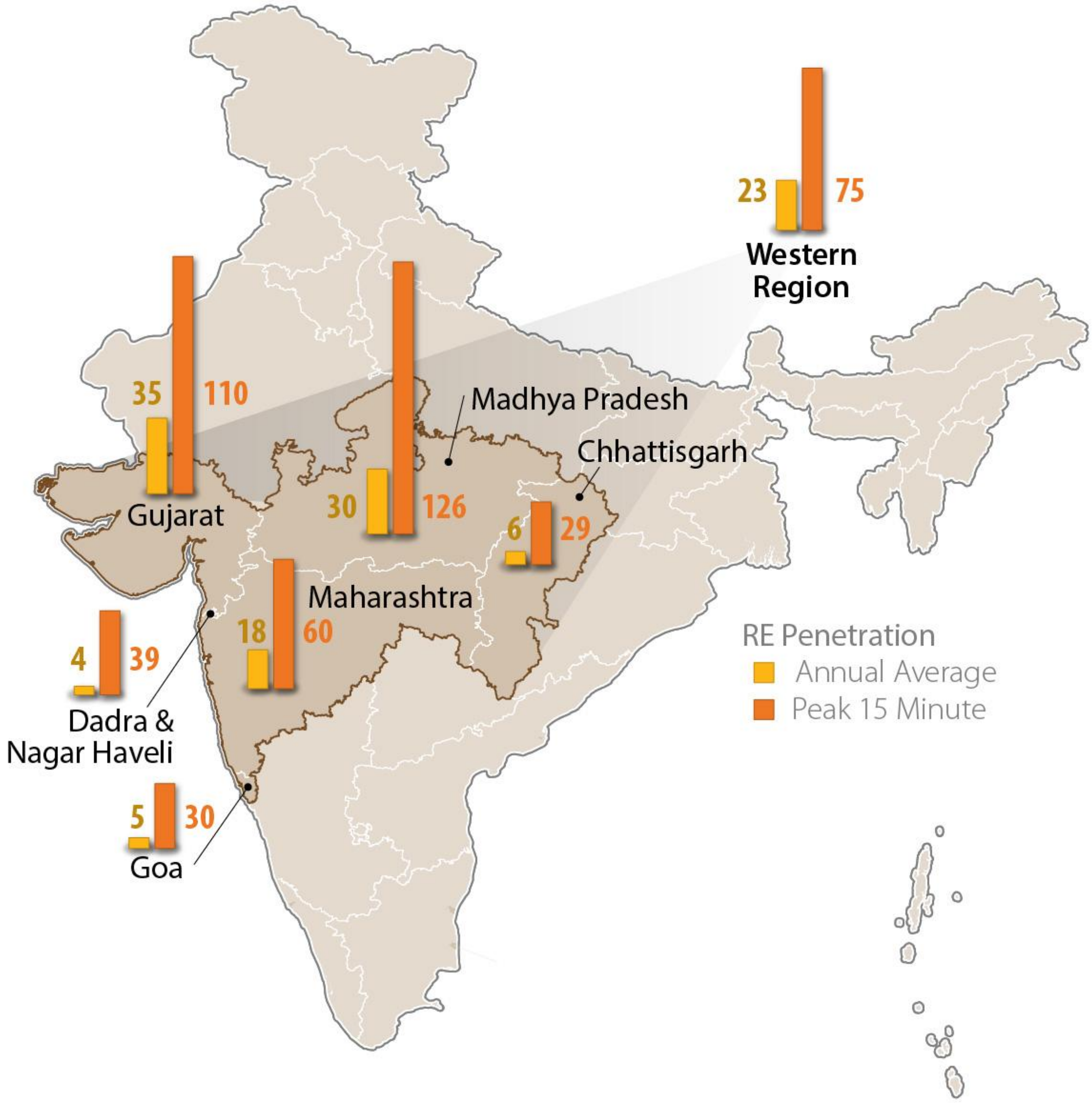

Figure 22. Annual and 15-minute peak instantaneous penetration of RE generation as a percent of load, 100S-60W, Western region

Figure 23 summarizes RE penetration as a percent of load by month. RE generation is highest in the monsoon season because of increased wind availability. RE meets the equivalent of more than 35% of the Western region's load in June and July.

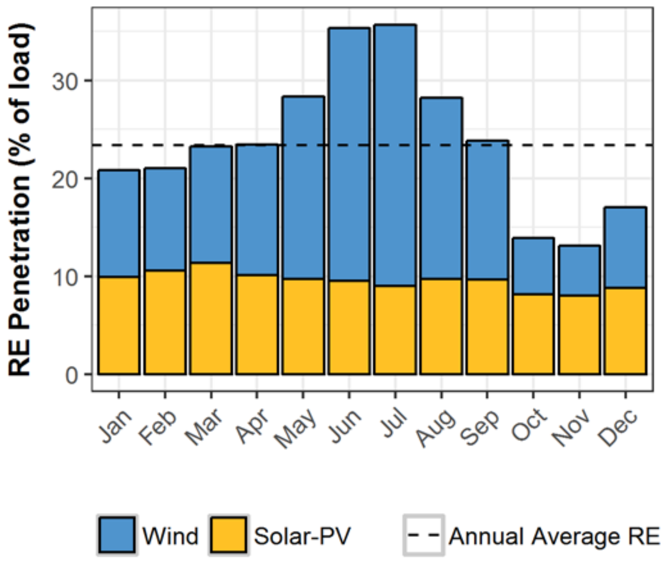

Figure 23. Monthly wind and solar penetration as a percent of load, 100S-60W, Western region

3.1.2 Operational Impacts to Thermal Generators

With more RE on the system, thermal generators operate less and differently. An important aspect of RE integration that impacts the non-RE portion of the fleet is the concept of net load. Net load is the load that is not met by RE and therefore must be served by conventional generation.[11] Noncoincident timing of RE generation and load can lead to large ramps in net load that must be met by conventional generation in the absence of other tools to shift load, such as storage or demand response.

Figure 24 compares the Western region load and net load between the No New RE and 100S-60W scenarios for three different days in the year. Solar generation decreases the duration of net load up-ramping in the morning and increases net load up-ramping during the evening peak. During the example monsoon day, 4 July, wind generation further lowers net load compared to the nonmonsoon days in February and November.

Annually, the peak 1-hour net load up-ramp is 7.9 GW, down from 9.3 GW in the No New RE scenario. This result is counter to the ramping trend seen in other regions and the country as a whole because load in the Western region often peaks midday instead of in the evening, meaning that solar generation can help offset load during peak periods. During the nonmonsoon seasons, the load ramps steeply in the morning, coinciding with increased solar production. Therefore, solar generation typically decreases the duration of the net load up-ramp in the morning although it creates an extended down-ramp. In the evening, solar generation exacerbates up-ramp requirements, contributing to, at times, ramps that are steeper and longer in duration than the morning ramps.

[11] Net load is sometimes calculated pre-curtailment; however, in this study, we define net load as total load less actual RE generation.

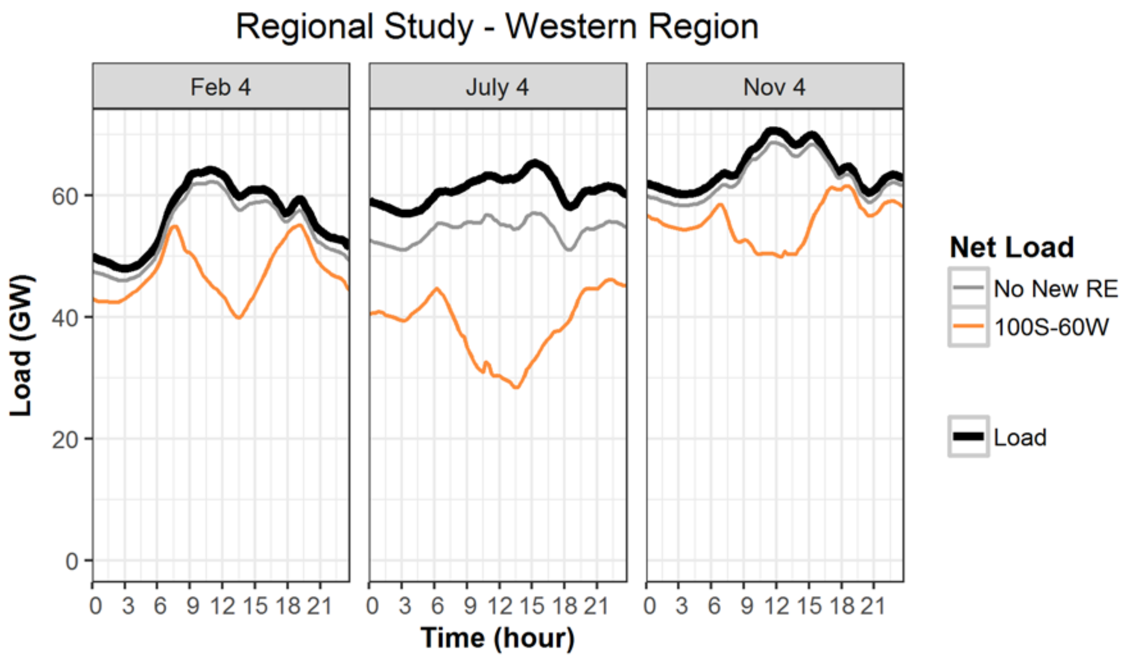

Figure 24. Comparison of net load by season, No New RE and 100S-60W, Western region

Net load is load minus wind and solar generation post-curtailment.

The change in net load shape requires changes to operations of hydro and thermal plants to keep the system balanced. Figure 25 shows the average day of hydro operations for both the No New RE and 100S-60W scenarios for the Southern region. In the 100S-60W scenario, hydro generation turns down during the day—when solar generation is high—and instead contributes more to ramping and energy needs during the morning and evening net load peaks.

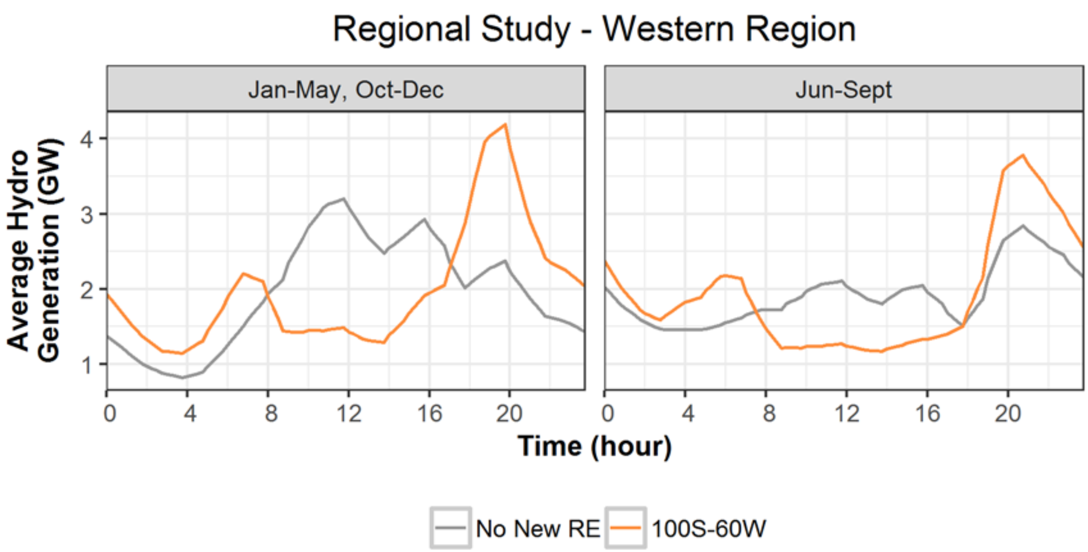

Figure 25. Average day of hydro operations by season and region, No New RE and 100S-60W, Western region

The rest of this section will explore how coal fleet operations change with the more variable net load profile characteristics of the 100S-60W scenario.

Annually, coal generates the equivalent of 89% of the Western region's load, or 73% of its generated energy. Figure 26 shows the monthly variability of coal generation for the No New RE and 100S-60W scenarios. Coal generation in the Western region is consistently lower in the 100S-60W scenario than in the No New RE scenario, but that difference does not show the same seasonal variation as it does in the Southern region.

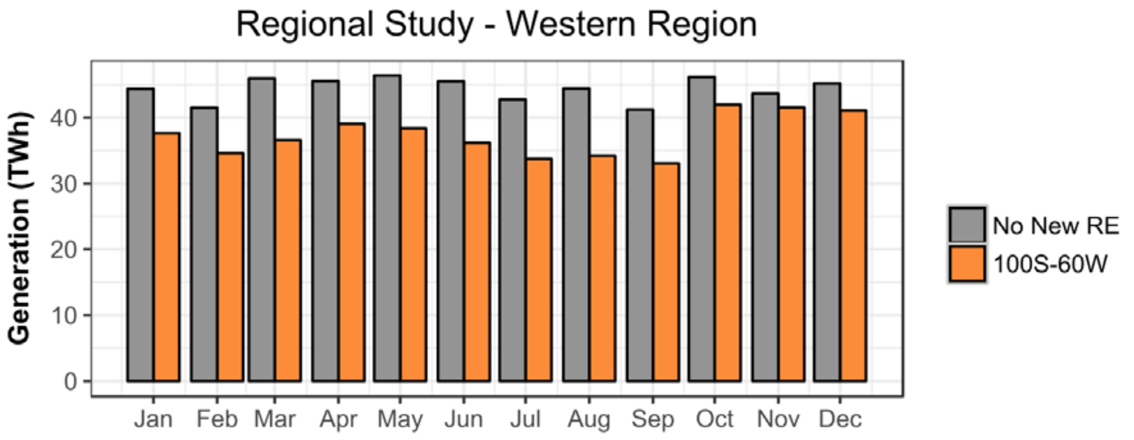

Figure 26. Coal generation by month, No New RE and 100S-60W, Western region

The daily variability of coal generation also changes as more RE is added to the system. Figure 27 illustrates coal commitment and generation during an example week in May for both scenarios. The coal fleet in the No New RE scenario maintains a relatively flat generation profile compared to the daily turn down of coal in response to the lower daytime net load in the 100S-60W scenario.

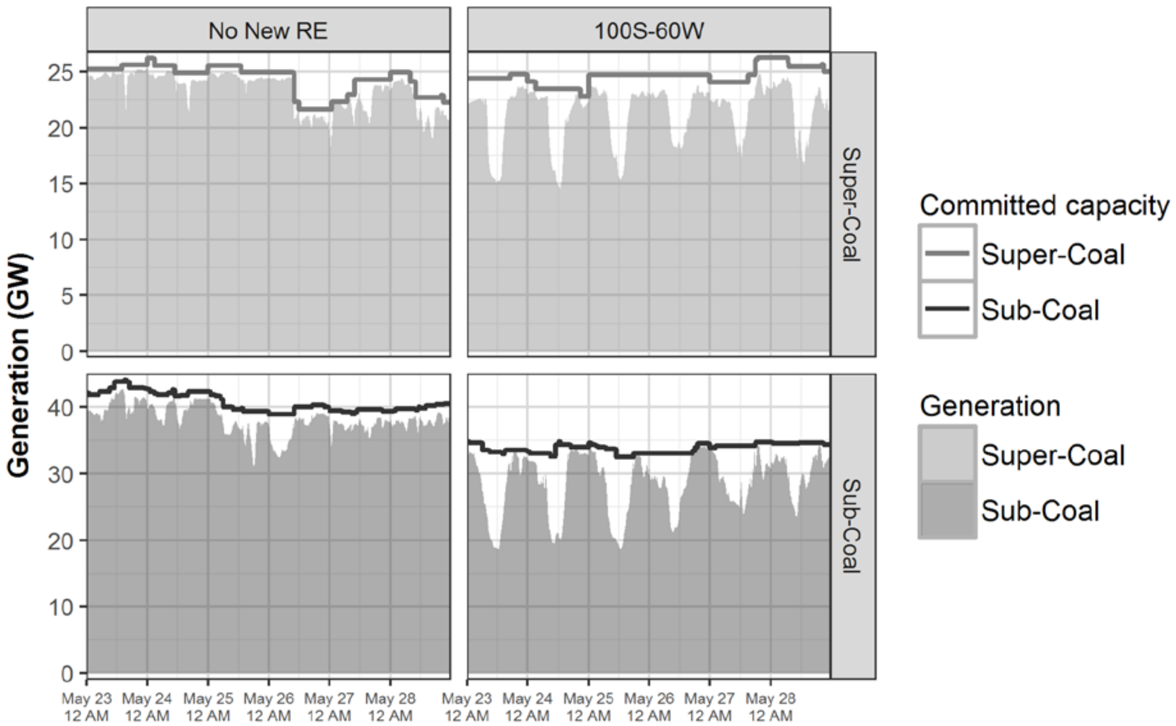

Figure 27. Committed capacity and generation during a high-RE week, 23–29 May, for sub- and supercritical coal, No New RE and 100S-60W, Western region

As a result of the diurnal and seasonal variations in coal generation in the 100S-60W scenario, coal plants operate less frequently, cycle more, and spend more time at minimum generation. Table 9 summarizes changes in plant load factors and coal starts between the No New RE and 100S-60W scenarios. This information is disaggregated by the relative variable cost of the plants to reflect merit order impacts, as well as ownership/control (central vs. state plants). Average PLFs of coal plants decrease by 16% from the No New RE to the 100S-60W scenario. The third most expensive coal units are impacted most by increased RE availability; their PLF decreases 28%. Total coal starts rise a modest 4%, although the increase is concentrated in the less expensive and central units, which are operated more often. Of the Western region's coal, 720 MW of capacity never starts in the 100S-60W scenario, compared to 600 MW in the No New RE scenario.

Table 9. Comparison of Coal Plant Load Factors and Number of Starts, Disaggregated by Variable Cost and Plant Ownership, No New RE and 100S-60W, Western Region

	PLF%			Capacity Not Started (MW)		Number of Coal Starts		
Relative Variable Cost	No New RE	100S-60W	% Change	No New RE	100S-60W	No New RE	100S-60W	% Change
Top 1/3	51	37	-28	600	600	1,383	1,358	-2
Mid 1/3	61	46	-25	0	0	788	835	6
Low 1/3	72	67	-7	0	120	661	769	14
Ownership								
State/IPP	59	48	-19	600	720	2,529	2,629	4
Central	77	70	-9	0	0	303	333	9
All	64	54	-16	600	720	2,832	2,962	4

3.1.3 Transmission and Energy Flows within the Western Region

The transmission flows on state-to-state corridors in the Western region change in response to more RE on the system in the 100S-60W scenario compared to No New RE. The most significant changes take place on corridors connecting coal-dominant states of Madhya Pradesh, Maharashtra, and Chhattisgarh. Figure 28 shows the distribution of flows on state-to-state corridors in the Western region for both the No New RE and 100S-60W scenarios. The Chhattisgargh-Madhya Pradesh corridor has a peak flow that is 45% higher in the 100S-60W scenario, while the Madhya Pradesh-Maharashtra corridor has a peak flow that is 65% higher in the 100S-60W scenario. Increases along these borders indicate that the transmission system connecting coal-dominant regions of the country are playing a critical role in system balancing by enabling access to coal flexibility.

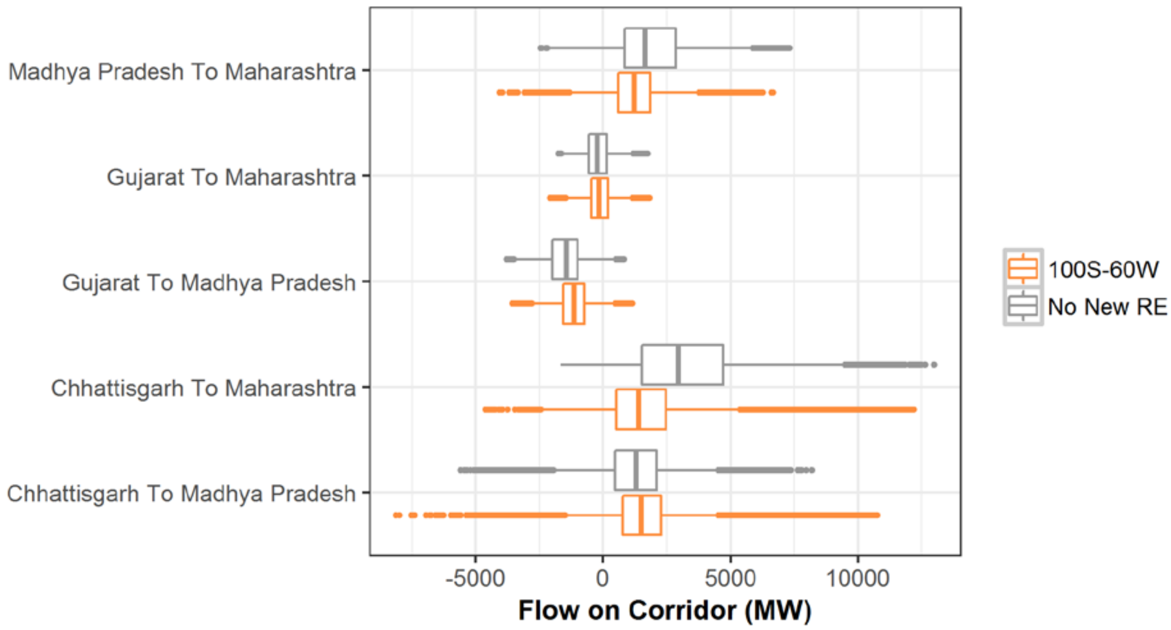

Figure 28. Distribution of flows across state-to-state corridors within the Western region, No New RE and 100S-60W

Boxes represent divisions into 25th percent quantiles. The middle line is the median. Positive flow indicates direction as indicated in legend, and negative flows the opposite direction.

Energy exchanges between the Western region and its neighbors decrease in the 100S-60W scenario. In particular, total energy exchanges on the WR-SR interface decrease by 37% between the No New RE and 100S-60W scenarios. Figure 29 shows flows across the WR-SR interface for a three-day period in July. The top panel shows the combined interregional interface flow, and the subsequent panels show flows across the six transmission corridors that comprise the interregional interface. Pink shading indicates periods when there is RE curtailment somewhere in the Western region, and the black horizontal lines represent total interface maximum and minimum flow limits. While the Western region consistently exports in the No New RE scenario during this period, it becomes an importer during most of this period in the 100S-60W scenario. Exports typically flow from Chhattisgarh to Tamil Nadu, while imports come through Maharashtra from Telangana and Karnataka. In many periods when the Western region experiences RE curtailment, the WR-SR interface is constrained. The interaction of the many constraints that cause RE curtailment is examined further in Section 3.3.

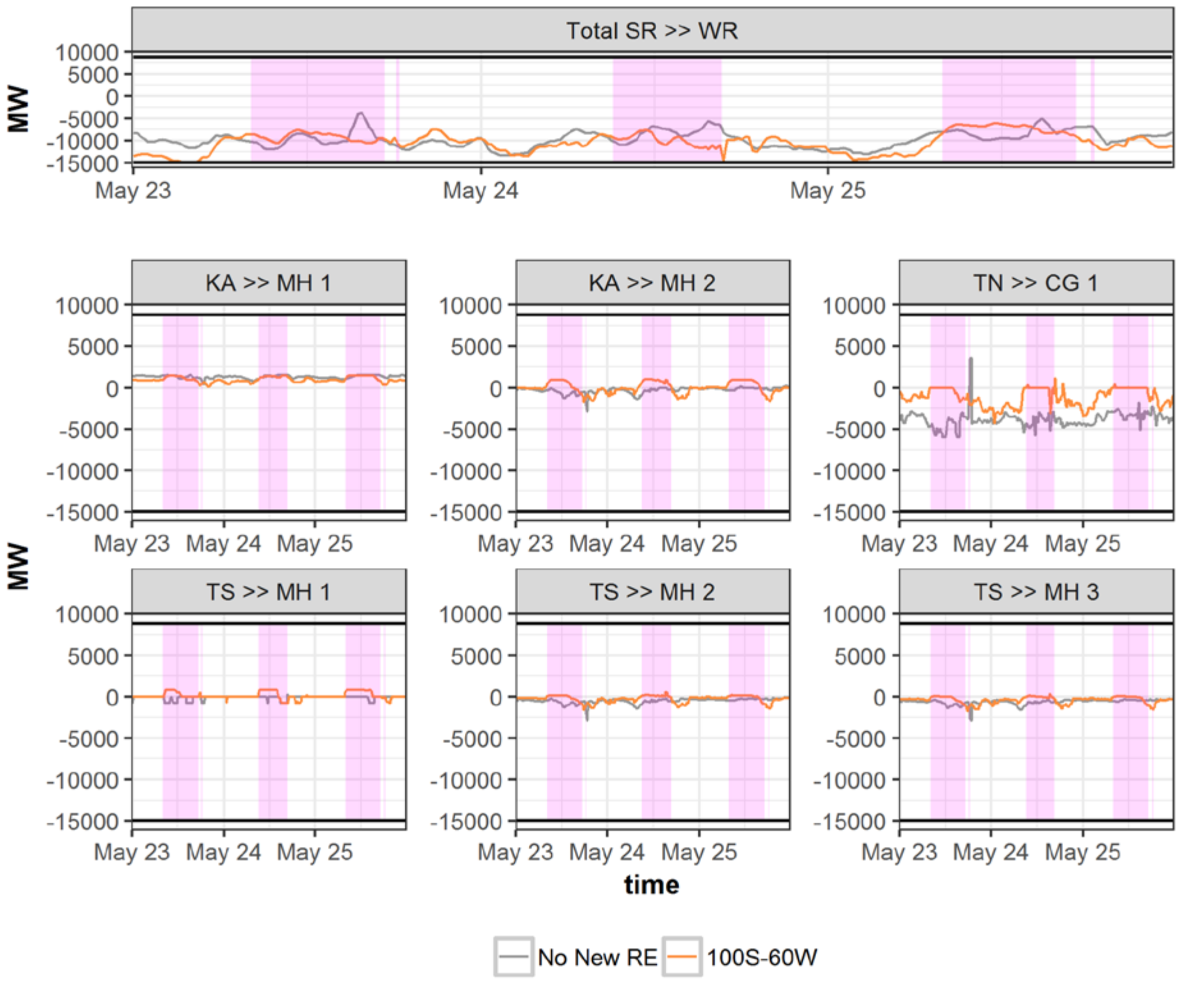

Figure 29. Flows across the WR-SR interface for a three-day period in July, No New RE and 100S-60W

Horizontal black lines indicate total interface flow limits. Pink shading marks periods of RE curtailment in the Western region. Positive flows indicate power leaving the Western region.

CG=Chhattisgarh, KA=Karnataka, MH=Maharashtra, TN=Tamil Nadu, TS=Telangana

3.1.4 Summary of Annual Impacts of High-RE Scenario

RE generation in the Western region:

- 49 GW of wind and solar power in the Western region, as part of the 160-GW national goal, generates 120 TWh annually (70 TWh wind, 48 TWh solar), which is 19% of all generation in the Western region.
- Wind and solar generation result in an average annual RE penetration of 23% of load.
- In June and July, the months with the highest RE generation, RE meets more than 35% of the Western region's load, with an instantaneous peak of 75% in July.

Impacts on thermal units and plant operations in the Western region compared to the No New RE scenario:

- Peak 1-hour net load up-ramp is 7.9 GW, down from 9.3 GW.
- Maximum net load valley-to-peak ramp is 24 GW on 29 December, up from a peak of 23 GW on the same day in the No New RE scenario.
- Coal and natural gas generation decrease 85 TWh and 6.3 TWh, respectively, a drop of 16% and 31%.
- Plant load factors of coal drop from 64% to 54%; PLFs of state and private plants fall from 59% to 48%.
- 720 MW of coal capacity never starts, compared to 600 MW in the No New RE scenario.
- Coal units with the highest variable costs are impacted most by increased RE availability, with the PLFs of the top third most expensive units dropping to an average of 37% from 51%.

Impacts on imports and exports and transmission flows compared to the No New RE scenario:

- Annual generation across all generation types in the Western region decreases by 1% to 610 TWh due to the net effect of increased RE generation, decreased thermal generation, and decreased net exports of 5%.
- Peak transmission flows on the Chhattisgarh-Madhya Pradesh corridor increase by 45% and on the Madhya Pradesh-Maharashtra corridor by 65% in the 100S-60W scenario compared to No New RE. Transmission allows for the coal-dominant region of the country to play a significant role in system balancing.

3.2 Strategies to Improve Integration

The National Study demonstrates potential value of two integration strategies: improved operational coordination resulted in production cost savings, and coal flexibility alleviated curtailment. We therefore chose to investigate these two strategies in the Regional Study, to understand their impacts in the context of a more robust transmission network. To look at thermal flexibility, we ran the most effective coal flexibility sensitivities from the National Study (coal minimum generation levels at 55%, 70%, and 40%). While the National Study evaluates coordinated operations both nationally and regionally, the Regional Study evaluates just regional coordination but at two timescales—(1) both day-ahead scheduling and real-time dispatch, as investigated in the National Study, and (2) dispatch only, also referred to as an energy imbalance service or energy imbalance market. These two integration strategies are defined in Table 10.

Table 10. Description of Integration Strategies Tested

SENSITIVITY	BASE	LESS FLEXIBLE	MORE FLEXIBLE
Size of balancing area for scheduling and dispatch	State (current practice)		Coordinated dispatch: state-based day-ahead scheduling (status quo) but regionally coordinated real-time dispatch Coordinated scheduling and dispatch, by region
Minimum plant generation levels (% rated capacity)	55%	70%	40%

The rest of this section reviews the impacts of each of these strategies.

3.2.1 Regional Coordination

The purpose of coordination between balancing areas is to reduce costs through improved merit order scheduling and dispatch and, in particular as it relates to RE integration, share over a broader area the power system's variability, uncertainty, and flexibility. We ran three coordination cases: state scheduling and dispatch (the reference 100S-60W case), regionally coordinated scheduling and dispatch (as in the National Study), and an energy imbalance market.

Energy imbalance services or markets achieve this coordination for economic dispatch. Each balancing area conducts its own day-ahead scheduling but shares projected load and available capacity with a centralized market or system operator in real time. The operator redispatches generators within their available generating ranges to produce electricity at least cost.

By effectively enlarging the footprint of real-time operations, EIM smooths the power system's variability and shares resources to respond to RE uncertainty that can lead to under- or overforecasting availability (Brinkman et al. 2016). Overforecasting can result in insufficient capacity committed to meet load, potentially requiring more expensive quick-start generation. Underforecasting can result in too much committed capacity, potentially leading to more thermal plants operating at less efficient part-loads and/or RE curtailment. EIM helps minimize the impacts of under- and overforecasting by providing access to the full set of balancing resources within the larger balancing footprint.

Full coordination includes the improved efficiencies of coordinated dispatch but also addresses barriers to suboptimal day-ahead unit commitment, when one balancing area may not have sufficient visibility of generation availability and needs in a neighboring area, thereby limiting optimal merit order scheduling. Coordinated unit commitment broadens the pool of conventional generators, resulting in improved merit order generation.

Figure 30 maps typical operations to the timescale at which they occur and the extent to which coordination supports RE integration. Coordinating over longer timescales aids in RE integration but does increase the complexity of implementation, for example in automating communications on transmission and generator availability and costs, and instituting financial compensation mechanisms. Thus, while coordinated unit commitment offers more opportunities for cost savings and efficient plant operations, EIM may be easier to implement and could serve as an intermediate step toward full day-ahead coordination if desired in the long run.

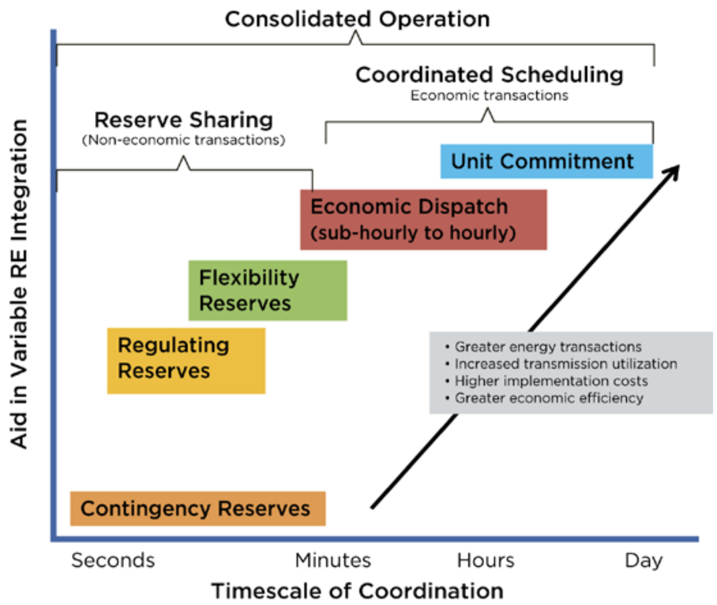

Figure 30. When balancing areas coordinate activities over longer time scales, they are able to increase the economic benefits of coordination to support RE integration. However, coordination over longer timescales introduces greater complexity and higher implementation costs.

Source: Denholm and Cochran (2015)

We ran the three coordination cases using a modeling parameter referred to as a hurdle rate. As described in Section 3 of the National Study, a hurdle rate represents informational or market barriers to optimal scheduling and dispatch. Hurdle rates add a price differential between local and out-of-state generation, thus creating an economic incentive for each state to use its own resources before importing. Table 11 summarizes how hurdle rates are applied to the coordination sensitivities in this study. To simulate state-level scheduling and/or dispatch, hurdle rates of INR 1050/MWh are applied. To simulate perfect coordination between states within a region, the state-to-state hurdle rates are removed.[12] Thus, to simulate EIM, which has state-level unit commitment but coordinated economic dispatch, we applied the hurdle rate only for unit commitment.

[12] A small hurdle rate of INR 50/MWh remains in place on interstate lines after removing the hurdle rates reflecting barriers to trade. Because we do not model losses, the small hurdle rate penalizes feasible solutions that nevertheless have unrealistically large loop flows.

Table 11. Comparison of Hurdle Rates Applied to State-to-State Trades across the Coordination Sensitivities

HURDLE RATES	STATE SCHEDULING/DISPATCH	EIM	REGIONALLY COORDINATED SCHEDULING/DISPATCH
Day-ahead unit commitment	INR 1050/MWh	INR 1050/MWh	None
Real-time economic dispatch	INR 1050/MWh	None	None

Across all scenarios, hurdle rates of INR 225–850/MWh are applied to interregional trades with the Western region, both day-ahead and real time, as described in more detail in the National Study.

Impacts to Generation

Nationally, regional coordination reduces production cost by 2.4% annually, and part of these savings arise from the ability to use cheaper Western region coal to serve load in other parts of the country. Therefore, regional coordination sensitivities impact the Western region in two ways. First, Western region exports increase as coal from the Western region displaces more expensive coal elsewhere. Second, within Western region, Maharashtra’s relatively expensive coal power is displaced by power from coal in Madhya Pradesh, Gujarat, and Chhattisgarh. Coordination has an insignificant impact on RE curtailment in the Western region, which remains at 1.6%.

The following example illustrates how regional coordination affects operations and reduces costs within the Western region, in which generation from Maharashtra is displaced by other Western region coal. Figure 31 shows the dispatch stack (top) and the day-ahead unit commitment and anticipated generation set point for coal as well as actual coal generation in real time (bottom), for 13 December. As is typical for the year, Maharashtra is a net importer. Without coordination (state dispatch), the real-time dispatch of coal largely adheres to the day-ahead schedule except in the middle of the day to accommodate an RE forecast error.

With regional coordination of dispatch (EIM), day-ahead commitment remains the same as in the state dispatch reference case, but dispatch set points are readjusted due to two factors: forecast errors and newly accessible lower-cost, out-of-state generation through the EIM. For this reason, relatively expensive, committed generation in Maharashtra is turned down lower so the state can meet more of its load with less expensive imports.

With regional coordination of both scheduling and dispatch, day-ahead scheduling is also optimized, and relatively expensive coal generators in Maharashtra are not committed, resulting in an approximate 20% drop in committed coal capacity on 13 December. Because the geographic area of optimization is the same both day-ahead and real-time, the real-time generation more closely matches the scheduled generation and is adjusted only to accommodate forecast errors.

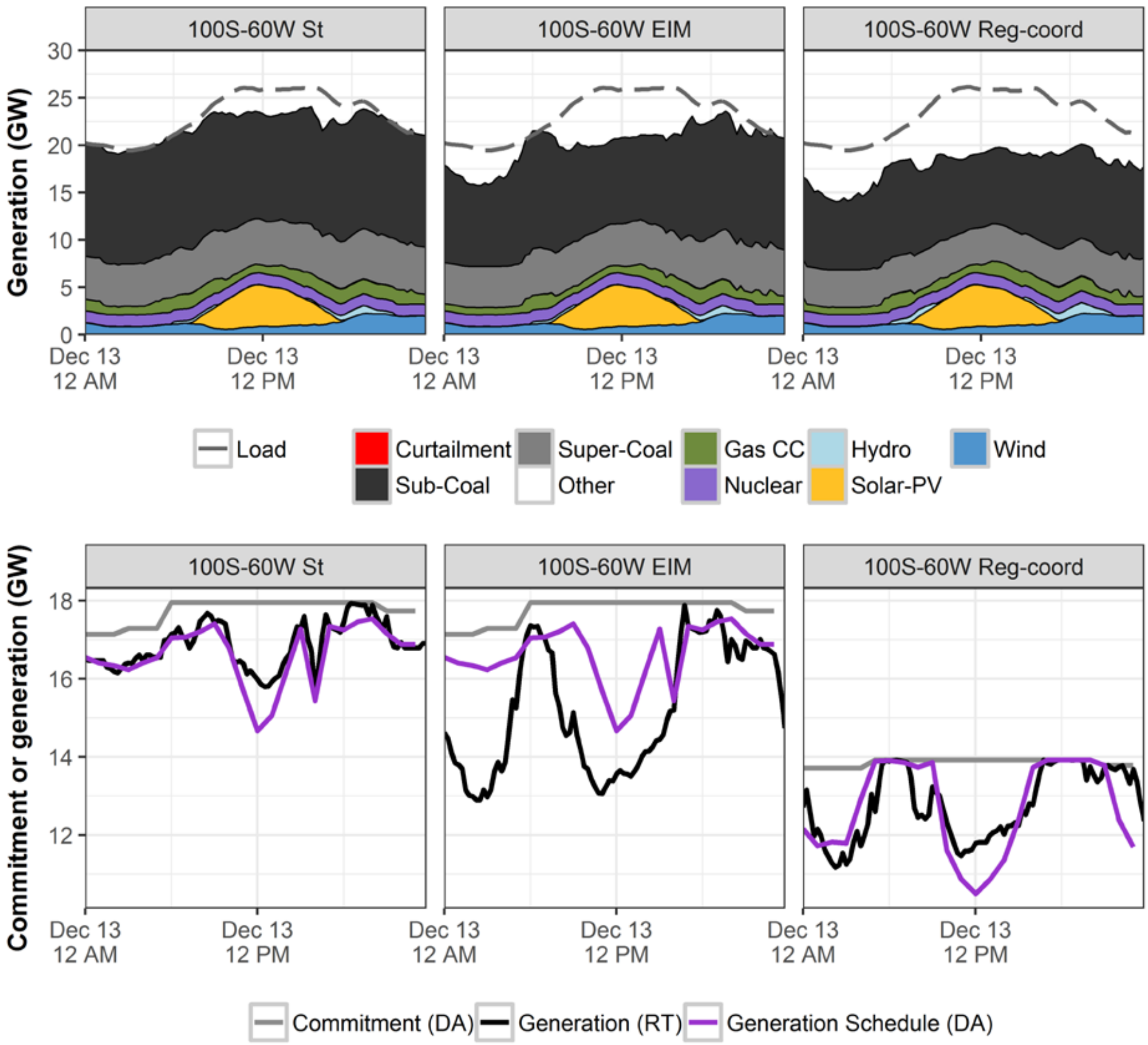

Figure 31. Generation dispatch (top) and commitment and dispatch of coal generation (bottom) in Maharashtra for 13 December for state dispatch, EIM, and regional coordination

Our model assesses the cost of generation in each state based on increased regional coordination. The model does not determine how the overall savings to the region that occur from regional coordination would be allocated across states. If Madhya Pradesh, for example, participates in a regional market and provides more efficient generation to neighboring states, the terms of such contracts and impacts on customer tariffs within each state are outside the scope of this study. Complementary pieces of Greening the Grid and ongoing efforts by Indian stakeholders, including CERC, aim to address the regulatory aspects of regional coordination.

The trend of other Western-region coal displacing Maharashtra's holds throughout the year and is illustrated in Figure 32, which shows that in both coordination scenarios (EIM and full regional coordination), Maharashtra coal generation is lower than in the state dispatch scenario, and other Western region states' coal generation is higher.

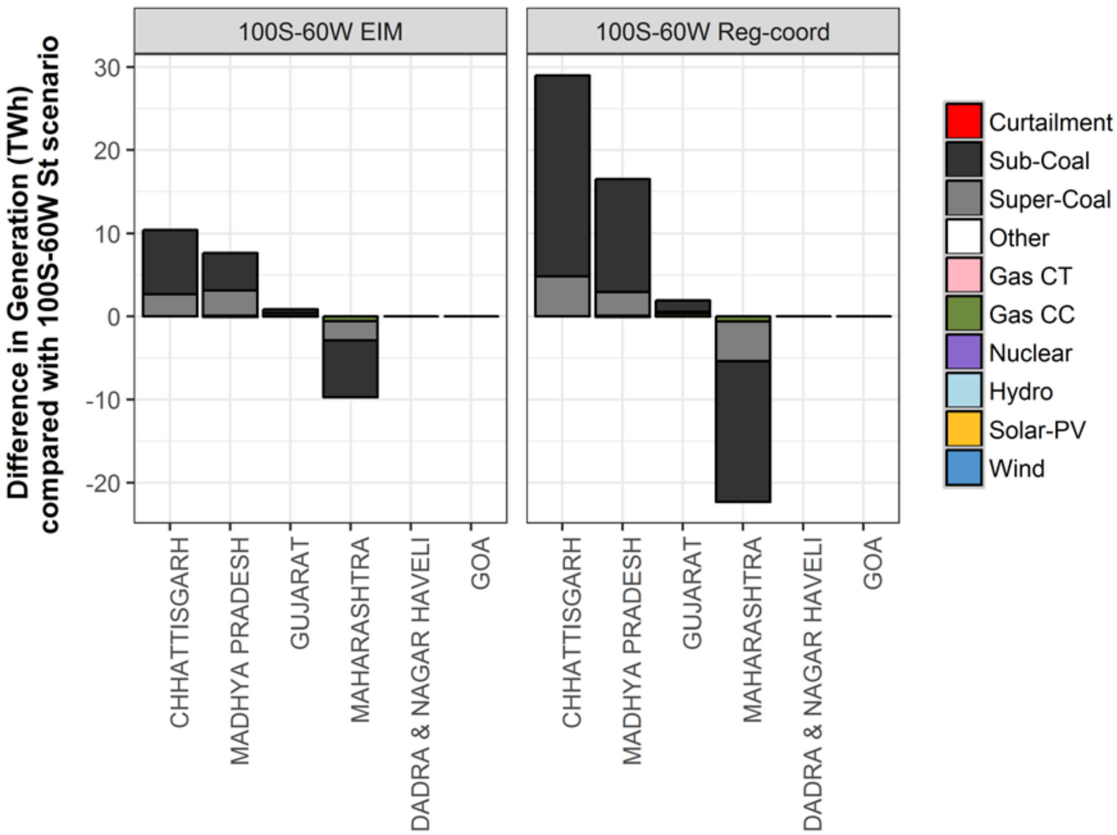

Figure 32. Difference in generation for regional coordination compared to state dispatch, in the Western region by state

Looking across the whole region, the use of coal in Madhya Pradesh, Chhattisgarh, and Gujarat to displace more costly generation elsewhere is evident in trends in both variable cost and net exports between the coordination scenarios. Table 12 shows the average variable cost of generation by state within the Western region.

Table 12. Average Variable Cost (INR/MW) of Generation by State, across Coordination Sensitivities

SCENARIO	CHHATTISGARH	GUJARAT	MADHYA PRADESH	MAHARASHTRA
State Dispatch	1,450	1,260	1,110	1,830
EIM	1,440	1,270	1,120	1,810
Regional Coordination	1,500	1,280	1,180	1,720

All states in the Western region experience an increase in the average cost of generation as coordination increases, with the exception of Maharashtra, where average costs decrease. The relatively low-cost coal generation as well as the surplus capacity in Chhattisgarh and Madhya Pradesh allows those states to provide energy to Maharashtra at a cost lower than Maharashtra can produce, as seen in Figure 33.

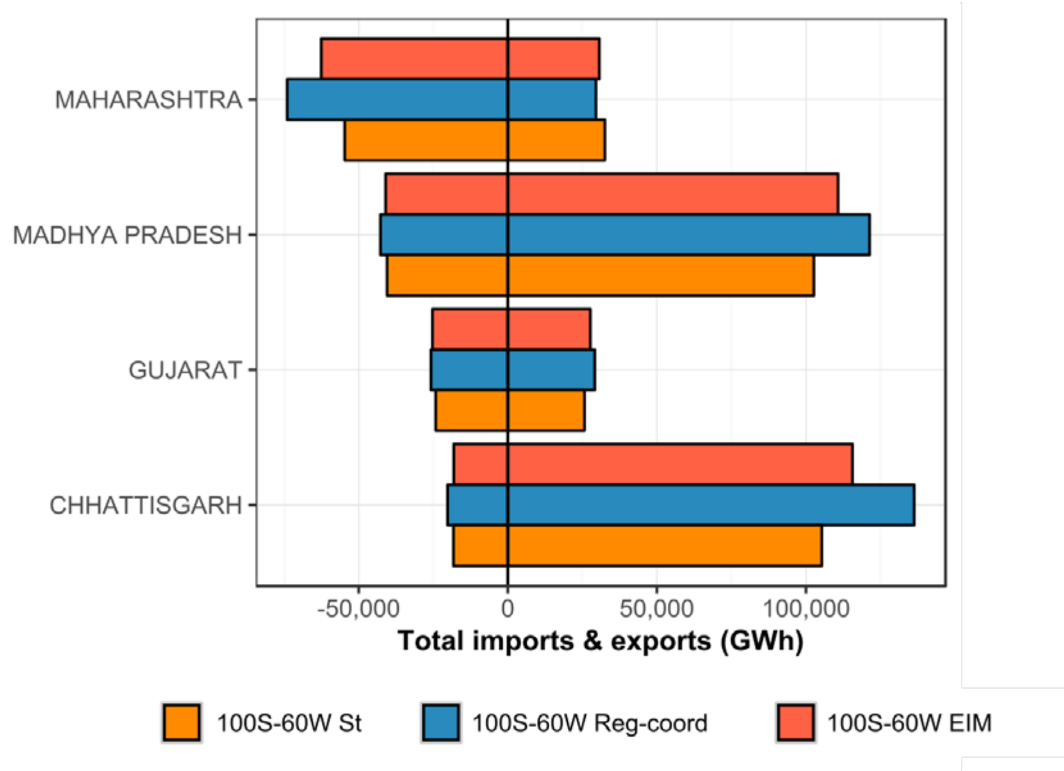

Figure 33. Comparison of total imports (left of 0 GWh) and exports (right of 0 GWh) by state in the Western region across coordination sensitivities

With regional coordination, Western region coal displaces more expensive coal in other regions due to a larger interregional price differential, on average. Exports to the Southern region rise with increased coordination by 27% with EIM and 160% with regional coordination of both unit commitment and dispatch. The exports to the Northern region also increase by 9% and 16% in the EIM and full regional coordination sensitivities, respectively. Combined with slight a decrease in exports to the Eastern region, total exports from the region increase by 8% in EIM and 23% in full regional coordination. However, nationally, system costs decrease because of the contributions of the Western region, and, while this is not represented in the model, it is likely that revenues to the region would reflect this systemwide benefit.

Average annual production costs in the Western region fall slightly with increased coordination, from INR 1410/MWh with status quo coordination to INR 1400/MWh for both EIM and full regional coordination. This relatively small decrease in costs with more coordination is primarily the result of two changes to operation: (1) expensive coal is being displaced in Maharashtra, driving the regionwide marginal energy costs down and (2) lower marginal costs relative to other regions results in increased exports, which requires more expensive units to meet the increase in total generation. Therefore, much of the efficiency gained through coordination is masked by the increased average costs due to greater exports.

3.2.2 Coal Flexibility

One of the key findings from the National Study is that coal flexibility—specifically reducing minimum plant generation levels—is a big driver to reducing RE curtailment. In the 100S-60W scenario, coal plants, particularly in the Southern and Western regions, frequently operate at their minimum generation levels during the day when RE generation is at its highest. Lowering minimum generation levels enables the coal plants to turn down when solar generation is high, thereby reducing instances of RE curtailment while maintaining the ability to ramp up to meet evening peak. To test the impact of coal minimum generation levels in the Regional Study, we ran the set of sensitivities from the National Study: coal minimum generation levels of 55% (100S-60W reference case), 40%, and 70% of rated capacity.

Impacts to Operations

Nationally and in the Western region, the inflexibility of a coal fleet with high minimum generation levels results in coal generation displacing RE generation, leading to higher levels of curtailment. Scenarios with coal minimum generation levels set at 40%, 55%, and 70% result in RE curtailment of 0.9%, 1.6%, and 3.4%, respectively.[13] Table 13 summarizes RE curtailment as a percent of available energy for each state, across the three coal flexibility sensitivities. In all states, decreasing the minimum generation of coal plants results in less RE curtailment, although Chhattisgarh, where installed RE is relatively small, experiences the largest relative gains from coal flexibility. Madhya Pradesh and Gujarat also see substantial benefits from decreasing minimum generation levels from 70% to 55%; RE curtailment in these states is reduced by half.

Table 13. Curtailment as a Percent of Available Energy Based on Coal Minimum Generation Levels of 40%, 55%, and 70% in Western Region States

STATE	40% MINIMUM GENERATION	55% MINIMUM GENERATION	70% MINIMUM GENERATION
Chhattisgarh	1.4%	2.6%	6.1%
Gujarat	1.1%	2.4%	5.3%
Madhya Pradesh	1.3%	1.8%	3.5%
Maharashtra	0.3%	0.4%	0.5%

Because of the increase in coal generation, much of which occurs in the Western region, exports from the Western region are higher in scenarios with less flexible coal. For example, between the 70% scenario and the 55% scenario, Western region exports to the Southern region decline by 20%, and between the 55% scenario and the 40% scenario, they decline by 3.2%. Similarly, the location of coal generation within the Western region changes between scenarios. Figure 34 shows the difference in generation between the three coal flexibility scenarios. As minimum generation levels fall from 70% to 55% to 40%, coal generation increases in Chhattisgarh, Gujarat, and Madhya Pradesh but declines in Maharashtra.

[13] RE curtailment is sensitive to assumptions that NREL and Berkeley Lab made about locations of new RE and intrastate transmission, and, as noted in Section 1, these modeling assumptions were made independent of a formal transmission study. Therefore, these numbers should not be used a predictor of RE curtailment if transmission and RE locations are effectively planned.

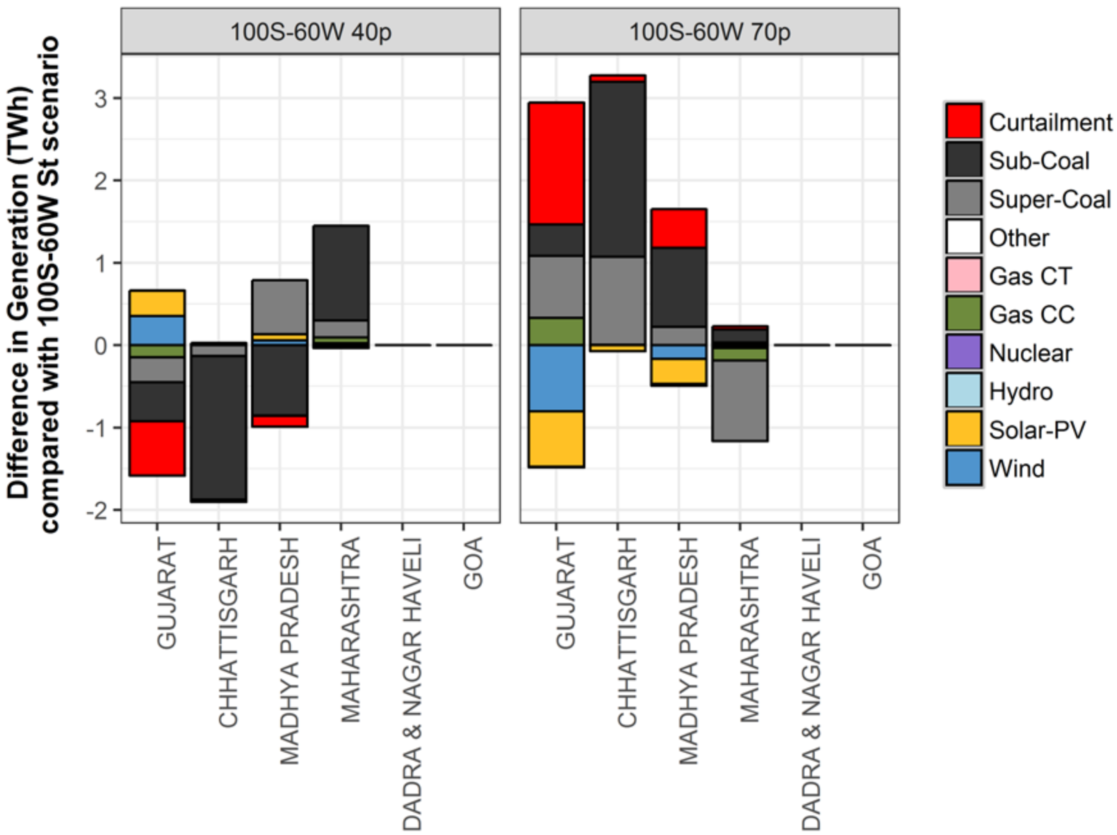

Figure 34. Difference in generation with lower and higher minimum generation levels compared to the base case of 55%, in the Western region by state

Rather than changes to average coal commitment, the differences in Figure 34 are caused primarily by how much a state's coal fleet turns down midday to accommodate RE generation. Table 14 shows the average decrease in coal generation between 6:00 and 12:00 by state across the coal flexibility sensitivities. Maharashtra is the only state that turns down its coal fleet less with 40% than with 70% minimum generation levels, explaining why it is also the only state to increase coal generation in the 40% sensitivity.

Table 14. Average Decrease in Coal Generation (GW) between 6:00 and 12:00 at Coal Minimum Generation Levels of 40%, 55%, and 70% in Western Region States

STATE	40% MINIMUM GENERATION	55% MINIMUM GENERATION	70% MINIMUM GENERATION
Chhattisgarh	6.2	5.1	3.6
Gujarat	3.0	2.7	2.1
Madhya Pradesh	5.5	5.2	3.8
Maharashtra	1.7	2.4	2.6

The reason Maharashtra turns down its coal fleet *less* with 40% minimum generation levels than with 70% relates to the plant heat rates at part load. When RE generation increases midday, the decision of which coal plants to turn down is driven by the relative inefficiencies of operating plants at minimum stable level versus max capacity. Table 15 compares the average increase in variable cost (INR/MWh) when each state turns coal generation from maximum capacity down to a 55% minimum stable level.

Table 15. Average Increase in Variable Cost (INR/MWh) When Operating Coal Generation at 55% Minimum Stable Level Versus Max Capacity in Western Region States

STATE	AVG. VARIABLE COST AT MAX CAPACITY (INR/MWh)	AVG. VARIABLE COST AT 55% MINIMUM STABLE LEVEL (INR/MWh)	AVERAGE INCREASE (INR/MWh)
Chhattisgarh	1,593	1,787	194
Gujarat	1,950	2,194	243
Madhya Pradesh	1,477	1,649	172
Maharashtra	2,578	2,916	338

Average variable costs are weighted by installed capacity.

It is relatively inexpensive for coal plants in Chhattisgarh and Madhya Pradesh to provide flexibility, providing an incentive to decrease their midday (and overall) generation in sensitivities with lower minimum generation levels. Maharashtra's coal flexibility is more expensive, creating incentives to maintain its level of output and import flexibility from other states when available, which is much more likely in the 55% and 40% minimum generation sensitivities.

Gujarat's coal flexibility is also relatively expensive, but it still turns down its coal fleet more in the sensitivities with lower minimum generation levels. Presumably transmission constraints and trade barriers limit how much external flexibility it can access, while its relatively high RE curtailment makes turning down its local coal fleet especially valuable.

3.2.3 Summary of Impact of RE Integration Strategies

The Western region's position as an exporter of coal power to the rest of the country affects how changes to coordination and coal flexibility impact its operations.

Regional coordination improves power system operations and costs but offers no reduction in RE curtailment. In contrast to results in other regions, regionally coordinated dispatch with state-level scheduling (EIM) offers a slightly higher savings to average generation costs within the Western region compared to regionally coordinated scheduling and dispatch. This Western-specific result reflects the increase in exports to other regions as coordination increases (8% increase in EIM, 23% in full coordination). More expensive generators are used to serve the larger export market, thereby limiting the production cost savings per unit of energy generated.

Conversely, changing the minimum generation levels of coal plants reduces curtailment, although with total curtailment low in the Western region, the change is less dramatic than in individual states with higher annual curtailment. The results show that changing one parameter—reducing the minimum generation levels of the coal fleet from 70% to 55% and to 40% of rated capacity—reduces curtailment in the Western region from 3.4% to 1.6% to 0.9%, respectively. This is due to the Western region's position as an exporter of coal power; the more flexible the country's coal fleet, the less coal generation is needed overall and the less coal power will be generated in and exported from the Western region. Changes to average production costs are negligible.

3.3 Example Day of Operations

We consider system operations on an example day in May to illustrate the multiple constraints experienced in the Western region on a high RE generation day, as well as how strategies to support integration relieve some of these constraints. This day showcases a few characteristics of RE integration in the Western region:

- Transmission constraints can limit the role of coal flexibility in relieving RE curtailment.
- Low-RE, coal-dominant states play a significant role as a flexible resource for RE-rich states.
- With 55% minimum coal generation, RE curtailment occurs primarily in Gujarat; when coal is less flexible (70%), RE curtailment is widespread throughout the region, and the coal-dominant states are limited in serving as flexible resources for RE-rich states.
- Improved coordination reduces the need for hydro to meet evening load, increases intra- and interregional congestion, and contributes to the ability for the coal-dominant states to support RE integration in the high-RE states.

3.3.1 How Thermal, Hydro and Transmission Constraints Interact to Cause RE Curtailment

As discussed in Section 4.6 of the National Study, transmission congestion, thermal and hydro fleet inflexibility, start and stop costs, and trade barriers are the causes of curtailment in our model. Figure 35 illustrates the interplay of generator dispatch (top panel), thermal fleet[14] inflexibility (middle panel), and congestion (bottom panel) in four Western region states with significant available RE capacity.

The top panel shows generation dispatch in each state, with highlighted areas representing periods when the state is curtailing RE. Green vertical bands mark intervals during which a state curtails RE and has a fully inflexible thermal fleet. Pink vertical bands mark intervals during which a state curtails RE despite having some unconstrained thermal generation. In the bottom panel, the black horizontal line represents total installed thermal capacity for each state, 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 is flexible to turn down. If, in a particular interval, all available thermal capacity in a state is turned off, at minimum stable level, or ramping down at its maximum rate, the state's thermal fleet cannot further decrease its output to accommodate zero-cost RE generation. Because hydro generation is fixed in the day-ahead simulation and therefore inflexible in real time, the state's conventional fleet is fully constrained. Any additional wind or solar generation must be either exported or curtailed.

[14] Thermal fleet refers to all coal, gas, nuclear, diesel, oil, bagasse cogeneration, and waste-heat recovery power generation.

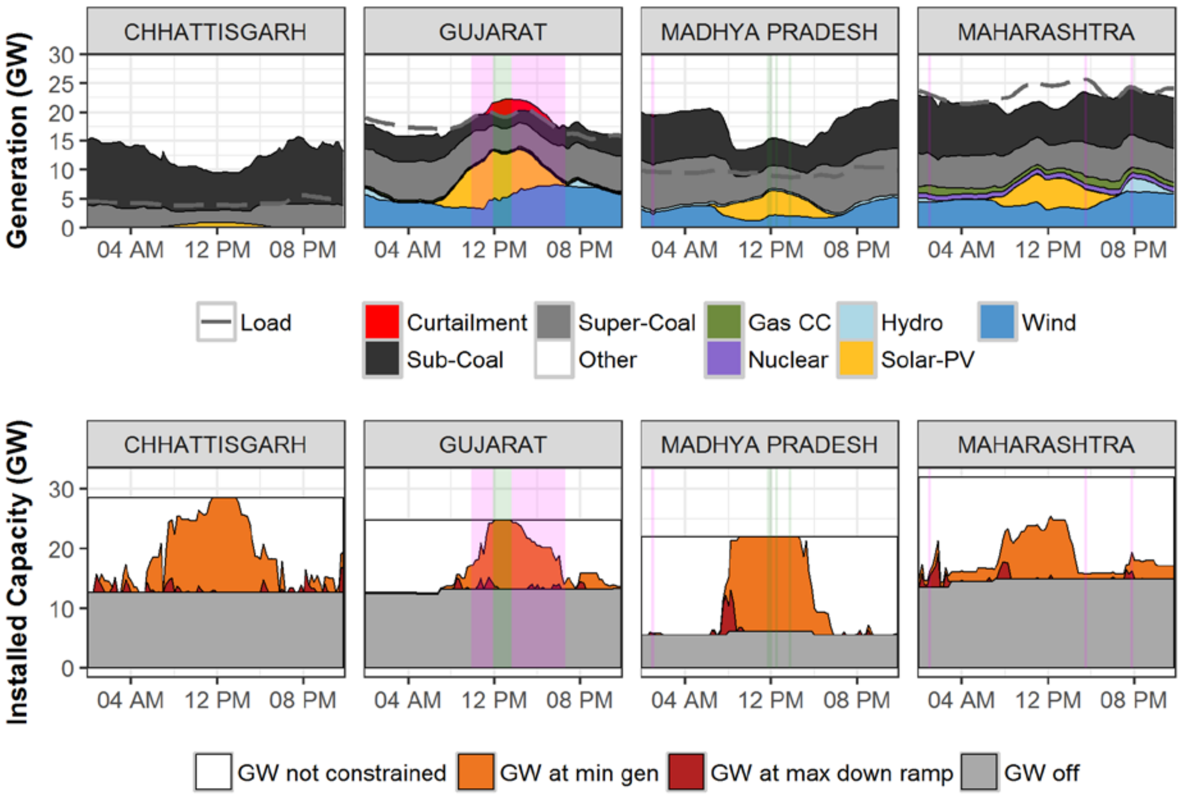

Figure 35. Generator dispatch and thermal fleet constraints in four Western region states on an example day in May, 100S-60W

Green bands mark intervals during which a state curtails RE and has a fully inflexible thermal fleet. Pink bands mark intervals during which a state curtails RE despite having some unconstrained thermal generation.

Gujarat, which experiences the most RE curtailment on this day, also has significant, frequent transmission congestion and thermal fleet constraints. From 12:00 to 13:30, 41% of its total RE curtailment occurs while its thermal fleet is completely inflexible (green shading). Its remaining 6.6 GWh of RE curtailment occurs while it has on average 4.1 GW of flexible thermal capacity that could back down (pink shading). The available flexibility of the thermal fleet combined with no intrastate trade barriers is a strong indicator that intrastate transmission is causing curtailment during these periods.

Maharashtra also has significant flexible thermal capacity on this day, even from 12:00 to 13:30 when all other thermal generation in the Western region is fully backed down and there is no transmission congestion between Maharashtra and other Western region states. Only one interregional corridor, between Maharashtra and Telangana, is congested from 7:45 to 14:45, although Maharashtra still has flexibility in its thermal fleet to accept more imports from Gujarat. However, Maharashtra experiences substantial transmission congestion on this day, which handicaps its ability to export thermal flexibility to its border for export.

Coal-Dominant States Serve as Flexible Resources for RE-Rich States

Madhya Pradesh's thermal fleet is also inflexible from 9:00 to 14:30. It ramps down coal generation by 7.6 GW between 6:00 and 12:00, far more than the corresponding increase in its RE generation of 2.5 GW. The resulting decline in net exports of 4.5 GW (42%) means that other states benefit from Madhya Pradesh's midday thermal fleet flexibility. Likewise, although Chhattisgarh's RE penetration as a percent of load on this day is only 5.9%, it provides critical thermal fleet flexibility to ease RE integration in the rest of the Western region. Like Madhya Pradesh, it backs down its thermal fleet significantly midday, reducing net exports by 2.9 GW (34%) between 6:00 and 12:00. Its turned-down dispatch profile on this day demonstrates how trade between high- and low-RE-penetration states can be important for RE integration.

3.3.2 How Coal Flexibility Affects Operations on an Example Day in May

Section 3.2 demonstrates that increased coal flexibility reduces the Western region's RE curtailment and generation costs. With 55% minimum coal generation, RE curtailment occurs primarily in Gujarat. When coal is less flexible (70%), RE curtailment is widespread throughout the region and the coal-dominant states are limited in serving as flexible resource for RE-rich states. Madhya Pradesh's ability to export thermal fleet flexibility, as described Section 3.3.1, is sensitive to minimum generation levels. When coal minimum generation levels increase to 70%, coal generation in Madhya Pradesh backs down by 5.3 GW between 6:00 and 12:00 (compared to 7.6 GW and 9.9 GW with 55% and 40% minimum generation levels, respectively). At 70% minimum coal generation RE curtailment in Madhya Pradesh rises from 0.1% to 6.9% for the day.

Figure 36 shows the generation dispatch for the Western region for three different levels of coal plant minimum generation on the same day analyzed in Section 3.3.1. Between the 70% and 40% scenarios, RE curtailment across the region falls from 4.7% to 1.2% of available energy, and average cost per MWh of generation falls by 0.7% (INR 1250/MWh to INR 1240/MWh).

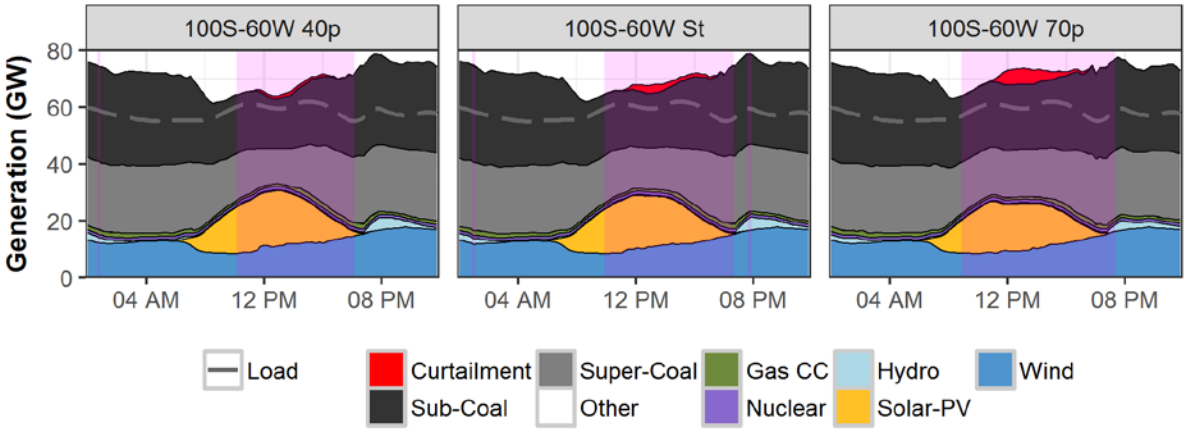

Figure 36. Generator dispatch in the Western region on an example day in May, coal flexibility sensitivities

Pink bands mark intervals during which the Western region curtails RE despite having some unconstrained thermal generation.

Figure 37 shows the amount of thermal fleet flexibility in the Western region across the three coal minimum generation sensitivities. In no sensitivity is the thermal fleet ever fully constrained; however, plants must ramp down longer to reach their 40% minimum stable levels in the left panel, illustrated by the increased capacity constrained by max down ramp rate in that sensitivity (red area). Additionally, with 70% minimum generation levels, only 1.5 GW of thermal capacity is flexible from 11:30 to 13:30, primarily consisting of five 300-MW subcritical coal generators at two substations in Maharashtra.

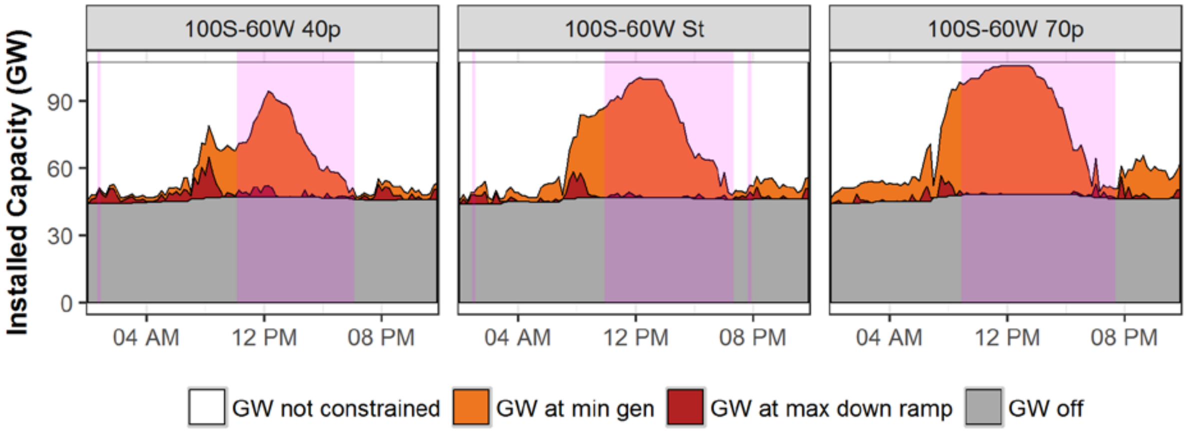

Figure 37. Thermal fleet constraints and congestion in the Western region on an example day in May, coal flexibility sensitivities

Pink bands mark intervals during which the Western region curtails RE despite having some unconstrained thermal generation.

3.3.3 How More Coordination Affects Operations on an Example Day in May

Figure 38 shows the generation dispatch for the Western region for the state dispatch, EIM, and regional coordination sensitivities on an example day in May. Although the Western region's overall generation increases by 4.1% with regional coordination, variable costs per MWh fall 1%. Removal of interstate trade barriers enables the cost reduction and significantly changes the Western region's commitment patterns. Average coal commitment on this day rises in Chhattisgarh (from 16 to 20 GW) and Madhya Pradesh (from 16 to 18 GW) and falls in Maharashtra (from 15 to 11 GW), which causes Maharashtra's net imports to rise by 91 GWh (16% of total load). The reason for the increased Maharashtra import is that the average variable cost of a coal plant operating at maximum capacity is INR 2570/MWh in Maharashtra compared to INR 1590/MWh in Chhattisgarh, which makes the Chhattisgarh coal generation more attractive when trade barriers are removed.

With regional coordination, Maharashtra relies on imports instead of local hydro generation to meet evening load on this day, reducing the Western region's overall hydro generation by 24% (5.6 GWh). Hydro generation does not change significantly between coordination scenarios, although the 5.6 GWh drop in hydro generation indicates that regional coordination more efficiently dispatched hydro to other times during the month.

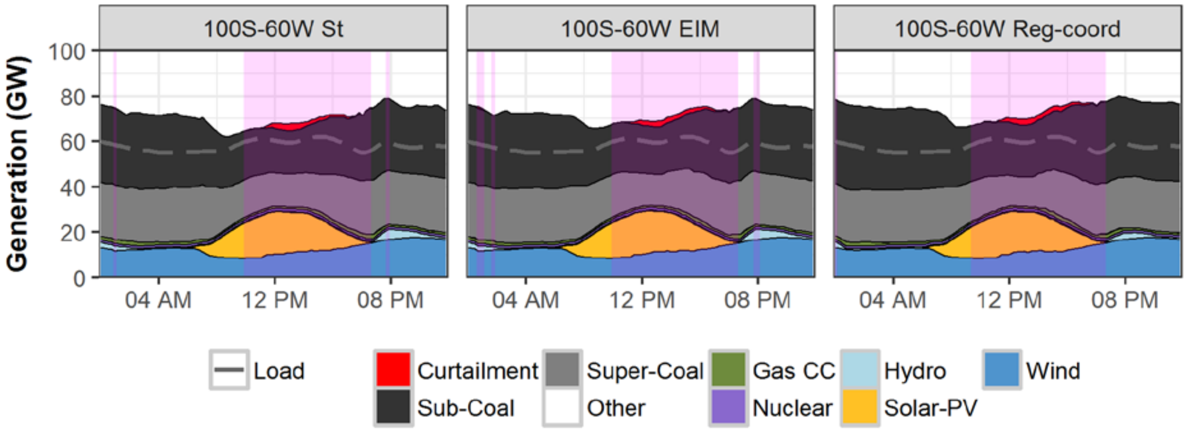

Figure 38. Generator dispatch in the Western region on an example day in May, dispatch coordination sensitivities

Pink bands mark intervals during which the Western region curtails RE despite having some unconstrained thermal generation.

More limited regional coordination—real-time dispatch through EIM but separate state-level day-ahead scheduling—also affects generation. Although generation by fuel type appears to change little in Figure 38 between state dispatch and EIM (left two panels), the 3% rise in total coal generation with EIM masks unit-level changes that result in an average savings of INR 18/MWh across all fuel types. Figure 39 illustrates how EIM uses coordinated real-time operations to access more of the Western region's inexpensive capacity. The figure compares generation by unit between state dispatch and regionally coordinated dispatch, organized by variable cost. Generators with costs above INR 2000/MWh decrease their output by 9.4% (26 GWh) with EIM, whereas generators with costs below INR 2000/MWh increase their output by 6.4% (59 GWh).

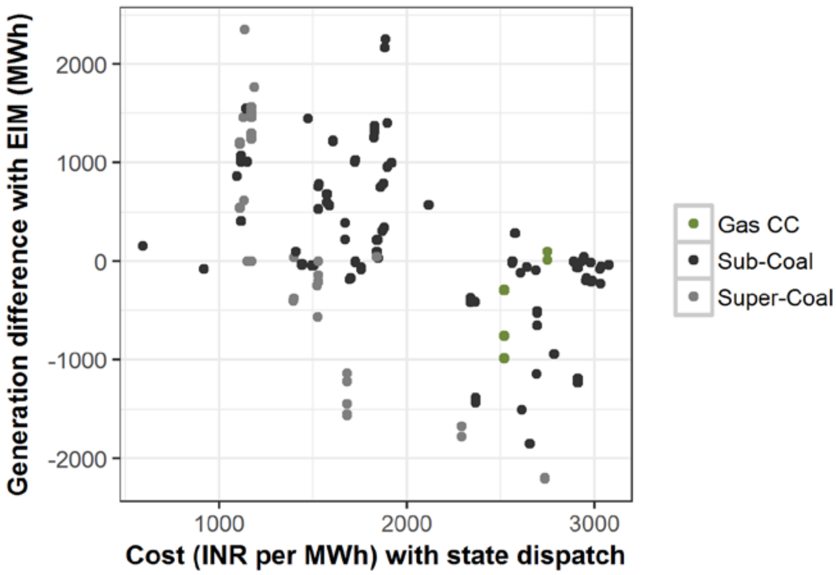

Figure 39. Change in generation between EIM and state dispatch, by fuel type and variable cost, in the Western region, example day in May

Note: Unit commitment is the same between state dispatch and EIM

Figure 40 illustrates the displacement of expensive generation in the Western region on this May that results from regional coordination. Each bar represents the quantity of power produced within the corresponding x-axis cost bracket. Average costs fall despite increased overall generation in the EIM and regional coordination sensitivities. A MWh of coal generation costs on average INR 1700 with state dispatch, falling 2.2% with EIM to INR 1660 and 3.1% with regional coordination to INR 1650. With state dispatch, the top 25% of subcritical coal generation (165 GWh) is produced at a variable cost above INR 2340/MWh. Only 19% (147 GWh) of subcritical coal generation is produced above the same cost threshold with regional coordination.

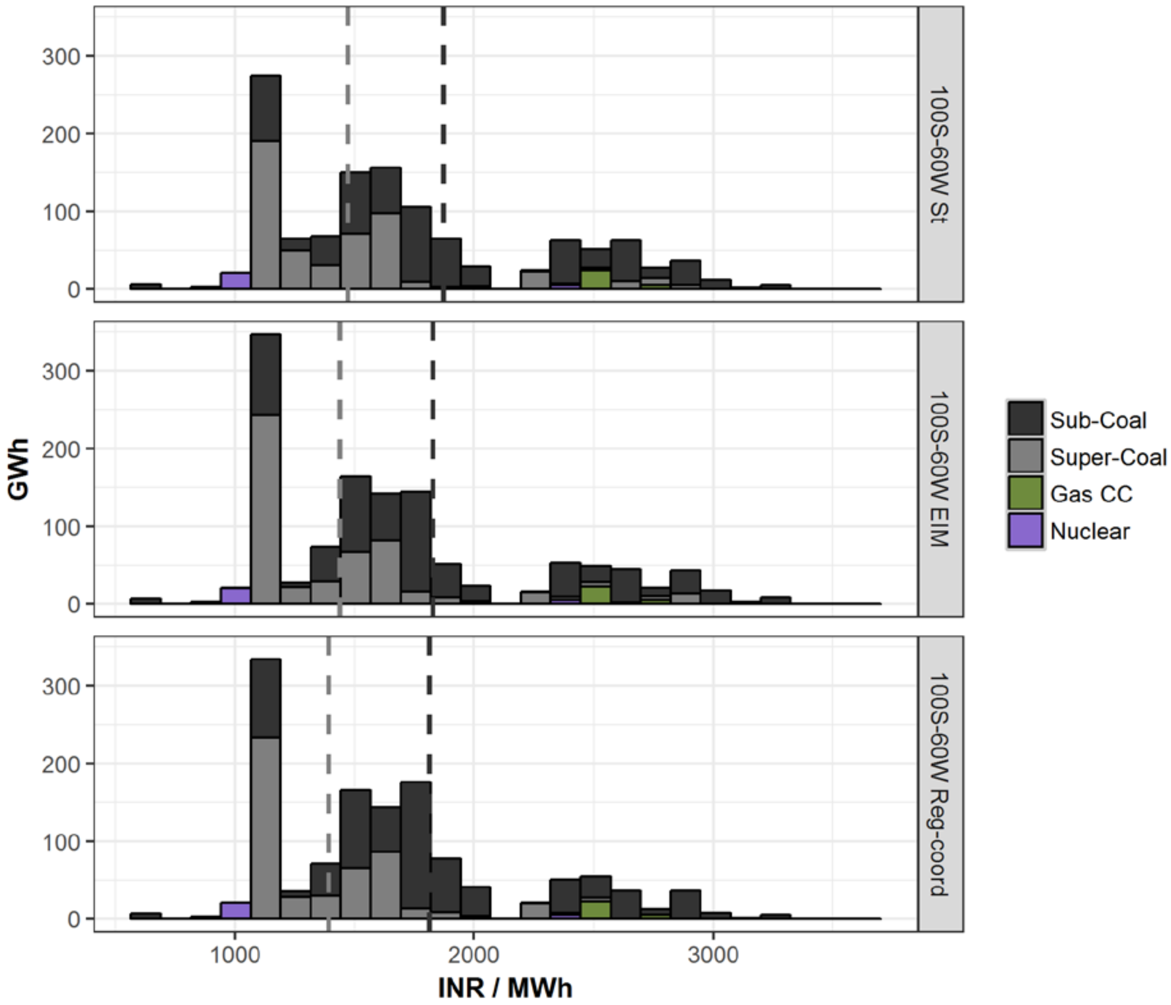

Figure 40. Generation by variable cost band for the Western region on an example day in May across dispatch coordination scenarios

Note: The dotted lines indicate mean variable costs per MWh for the two coal fuel types. Zero-cost generation is excluded.

3.3.4 Summary of Example Day Results

The Western region's operations during an example day in May illustrate how constraints placed on transmission, thermal flexibility, and dispatch coordination can interact to increase RE curtailment and production costs. Transmission constraints can limit the thermal fleet's ability to back down in low net load periods, as evidenced in periods when RE is curtailed despite flexible coal and absence of trade barriers. Likewise coal flexibility—within both low- and high-RE states—affects RE curtailment. As coal flexibility improves, RE curtailment declines despite increased transmission constraints. Coal flexibility also enables coal-dominant (low RE) states to serve a critical source of flexibility for the high-RE states. The ability of those states to turn down generation and reduce exports during periods of high RE generation in neighboring states helps avoid RE curtailment. This ability for coal-dominant states to contribute to RE integration is also sensitive to the extent of regional coordination. Coordinated scheduling and dispatch on this day also lowers generation costs (1% decrease)—despite overall increased generation in the region (4% increase)—and increases congestion interregionally). The analysis of operations on this day is consistent with annual results—multiple pathways can support RE integration, with the value and effectiveness of each strategy mediated by the interplay of the other factors that affect RE integration. The Western region's operations on this example day particularly highlight the role low-cost, coal-dominant states like Chhattisgarh and Madhya Pradesh can play to support RE integration, both regionally and nationally. The flexible coal capacity in these states is an important reason the Western region's annual RE curtailment remains low.

3.4 Conclusion: Implications for Decision Makers

This study shows that in the context of meeting India's RE goals of 160 GW of solar and wind, the Western region can integrate 49 GW of RE at 15-minute timescales. Because of its unique advantages—strong interconnectedness with other regions and intra-regional coal flexibility—the Western region is able to effectively smooth swings in net load and limit RE curtailment. Coal-dominant states such as Chhattisgarh, Maharashtra, and Madhya Pradesh serve as a critical source of flexibility for high RE states like Gujarat, even with state-to-state trade barriers. The value of these coal resources in supporting RE integration is further enhanced with regional coordination and minimum generation levels lowered to 40% of rated capacity, while a less flexible system, with 70% minimum generation levels, experiences significantly increased RE curtailment.

While transmission does not present significant constraints to RE integration overall, specific corridors do adversely affect system flexibility. Also, these results are contingent on the 12 intra- and interstate lines that were added in the Western region in the model to serve new RE installations in the region and that supplement CEA's 2021–2022 plans. Without these added lines, annual RE curtailment is very high in certain locations. Although transmission planning is outside the scope of this study, this model can be used to help identify the value and operational impacts of new transmission, as discussed in Appendix A. Because of the sensitivity of RE curtailment to intrastate transmission capacity, this study does reinforce the value of planning that optimizes both transmission and generation capacity using high-resolution RE resource data.

In addition to the policy implications detailed in the National Study, several policy implications can be customized to the Western region:

- State regulatory standards for coal flexibility in low-RE, coal-dominant states can play an important role in facilitating RE integration elsewhere in the region. With 55% minimum generation standards, coal plants in Chhattisgarh and Madhya Pradesh, which are relatively low-variable-cost producers and have sufficient capacity to export, are able to back down and reduce exports midday, which contributes to overall low RE curtailment in the region. Thus, there is value to considering state standards for coal flexibility, even in non-RE-rich states.

  The challenge will be in designing policies that sufficiently incentivize the provision and performance of this flexibility, and providing technical assistance to operators of older coal plants to implement required modifications. Experience with older coal plants elsewhere has demonstrated that cycling-related costs can be minimized with changes to operating practices (e.g., controlling temperature ramp rates, implementing rigorous training and inspection programs), even if physical modifications are cost-prohibitive (Cochran, Lew, and Kumar 2013). One pilot being considered under the USAID-MOP Greening the Grid program includes a partnership with Gujarat State Electricity Corporation Limited (GSECL) to demonstrate technical and economic feasibility of coal flexibility, including a cost-benefit analysis. Under the pilot, the Greening the Grid program will also help develop a road map to guide GSECL on improving coal flexibility, including investment requirements and regulatory support.

- Regional coordination—particularly at both unit commitment and dispatch timescales—improves efficient operations of plants and export opportunities. The relatively small change in operating costs within the region—INR 1400/MWh from 1410/MWh—that results from improved coordination mask several significant changes to energy flows and dispatch patterns. For example, exports to the Southern region increase 130% when commitment and dispatch are coordinated. Within the region, commitment patterns change—coal generation in Maharashtra falls 17%, while it increases 19% across Chhattisgarh and Madhya Pradesh.

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APPENDIX A: APPLICATION OF A PRODUCTION COST MODEL FOR POWER SYSTEM PLANNING

Production cost models are an important component of planning in many power systems around the world. This tool can help in assessing the value and operational impacts of adding or retiring generators or transmission as well as quantifying the impacts of policies on the power system. This section provides a background of production cost models in planning processes within U.S. markets as well as two examples of using the India PLEXOS database for evaluating additions to transmission and generation. The first application uses the model to evaluate the impact of adding a transmission line in a corridor that is frequently congested within the state of Gujarat. The results show that adding a line does not substantially change the production costs for the state, but it does allow for more energy to be sold as exports. The second application of the model is reviving non-operational pumped storage in two specific locations in Gujarat and Telangana. The results show small decreases to production costs nationwide, although the states in which the pumps are installed reap the greatest benefits. Results such as these are useful and necessary inputs in understanding the full impact of an investment or retirement.

Methodology of Using the Model to Evaluate Transmission Lines

Production cost models are an important tool in planning transmission investments in many regions around the world. These models help evaluate the economic impacts of adding new transmission, typically as part of a cost-benefit analysis, complementing power flow analyses that address reliability.

New transmission can affect production costs in multiple ways, including: (1) relieving congestion, (2) improving access to least-cost generation and increasing competition among generators, (3) creating access to new locations for RE development, (4) reducing the impact of extreme events and contingencies, (5) smoothing net variability in load and generation, (6) reducing thermal cycling costs, and (7) reducing the amount of ancillary services needed (Pfeifenberger, Chang, and Sheilendranath 2015).[15]

The perspective of multiple stakeholders, including generators and other market participants, ratepayers, and transmission owners, is an important aspect of the economic impact analysis. The primary role of the stakeholders is to decide which scenarios should be modeled to address different policy and/or market futures and which sensitivities, such as fuel prices and extreme events, are most relevant and have potential for economic impact.

Below are descriptions of how some jurisdictions in the United States use production cost modeling:

California and CAISO: California has had among the most aggressive renewable energy policies in the United States, namely through an increasingly more stringent renewable portfolio standard (equivalent to the renewable purchase obligation in India). In October of 2015, California approved a 50% RPS to be achieved by 2030. To facilitate transmission planning for RE, the Renewable Energy Transmission Initiative (RETI) was formed in 2007, which is a joint effort among the California Public Utilities Commission (CPUC), California Energy Commission (CEC), CAISO, and utilities. Through the RETI stakeholder process, competitive renewable energy zones were identified using economic and environmental criteria; a conceptual transmission plan was developed based on least-regrets transmission planning principles; and an objective methodology for assessing the usefulness of transmission components towards supporting renewable energy was developed. The conceptual plan has since fed into detailed transmission planning (Olsen et al. 2012; CEC 2017a). In 2015, RETI 2.0 was initiated address California’s 50% RE goal (CEC 2017b).

[15] Typical cost-benefit analyses for transmission also include monetary benefits not captured in a production cost model, such as market liquidity, environmental impacts, and deferred capacity investments.

An important element of the planning process in California is multi-agency coordination. Three cyclical processes, by three agencies, form the core of electric infrastructure planning: (1) long-term energy demand forecast by the CEC; (2) long term procurement plan by the CPUC; and (3) the transmission planning process (TPP) by CAISO. The TPP incorporates production cost modeling in its process (CPUC, CEC and CAISO Staff 2014). Coordination helps to ensure that the state's policy goals are met in more economical ways and also ensures consistency in the data sets used in the analysis led by different agencies.

As part of its TPP, CAISO developed the "Transmission Economic Assessment Methodology (TEAM)," a methodology to address the impacts of transmission on (1) access to customers and generation resources, (2) incentives to invest in new generation, and (3) market competition. CAISO, and subsequently, the CPUC, must approve new transmission projects. Prior to TEAM, CAISO's methodology for assessing new projects focused on reliability. TEAM's role is to provide a transparent and predictable methodology for CAISO to evaluate proposed upgrades from an economic perspective (Awad et al. 2006). TEAM uses production cost modeling to create a benefits analysis from multiple perspectives (CAISO, Western region, CAISO ratepayers, market participants), using sensitivities to weigh these benefits by probability. The application of TEAM found that a significant share of the economic benefit of an upgrade is realized during extreme events, such as high load growth or high gas prices (Awad et al. 2006).

Electric Reliability Council of Texas (ERCOT): ERCOT was a pioneer in the use of production cost models, not only for their use in its annual planning process, but also to develop new locations for RE as part of the Competitive Renewable Energy Zone (CREZ) process. Wind developers in West Texas had built 760 MW of capacity in 2002 but had only 400 MW of transmission to move the energy to load, resulting in curtailments (Hurlbut 2015). As part of the process to develop new transmission to this wind-rich area, ERCOT evaluated multiple scenarios with varying RE capacity targets and optimal transmission needed to serve those targets. For each scenario, the production cost model enabled ERCOT to evaluate RE generation and curtailment, impact on wholesale market prices, and power system operations. These savings were then evaluated against cost projections for building new transmission. Ultimately, the CREZ led to the development of transmission to serve 18.5 GW of RE. Figure 41 provides an overview of technical, economic, and regulatory analyses and actions under the CREZ process.

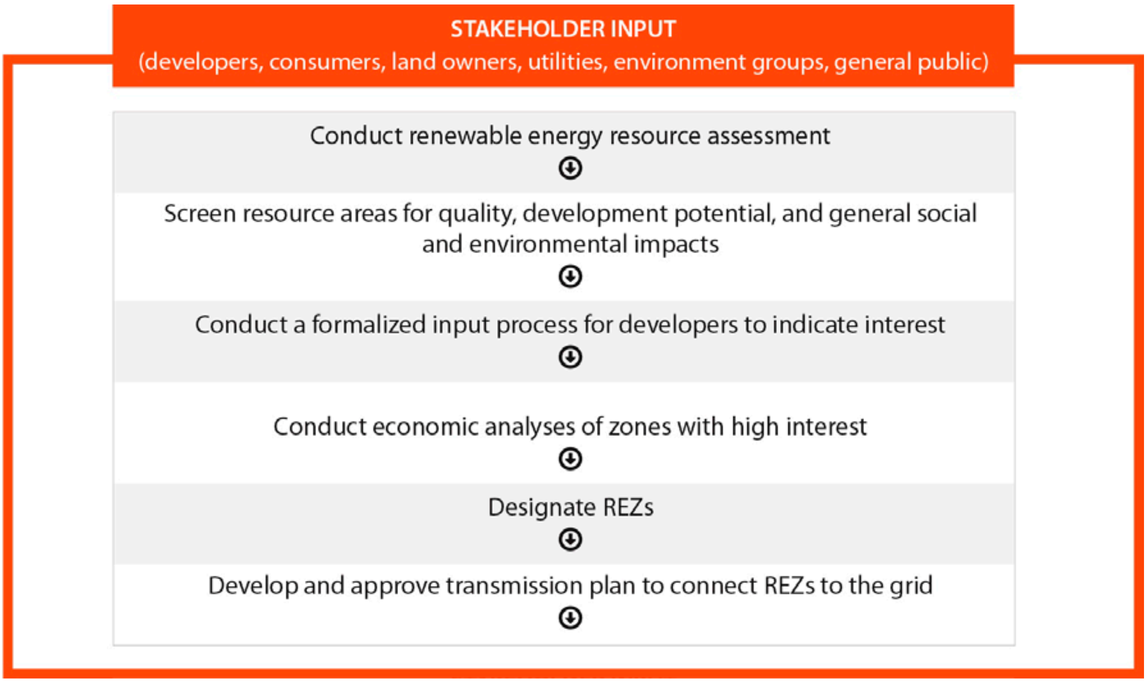


Figure 41. Technical, economic, and regulatory steps that comprise ERCOT's CREZ

Note: Production cost modeling is used to conduct the economic analyses required to finalize the list of RE zones to be developed.

Source: Hurlbut, Chernyakhovskiy, and Cochran (2016)

Midcontinent Independent System Operator (MISO): MISO's transmission planning process links multiple time-horizon planning studies: long-term, top down studies (e.g., 20 years into the future) to address optimal transmission needed to meet different energy futures; short-term, bottom-up studies to address incremental transmission needed for a particular location; and midrange studies (e.g., 10 years into the future) that help sequence transmission expansion between the short- and long-term plans (Osborn and Lawhorn 2009). Production cost modeling is a critical element of all three. Bottom-up analyses use power flow models as the primary tool to evaluate the impact of a new line on reliability, but all projects are also evaluated for their economic benefits. Long-range studies use capacity expansion models as the primary tool but also use production cost models to evaluate system operations with each future scenario and calculate production costs for energy and reserves. The midrange studies use both power flow and production cost models to refine transmission plans and ensure the bottom-up studies are in line with longer-term objectives.

Summary

Effective transmission planning for renewables has required novel approaches in the United States. There are two key themes in the context of transmission planning for RE. First, proactive transmission planning can be an effective way to integrate RE in a least-cost manner (Pfeifenberger and Chang 2016; Liu et al 2013; Alagappan, Orans, and Woo 2011). The CREZ processes in both California and Texas are examples of anticipatory transmission planning efforts. Second, transmission planning in many regions requires cross-agency coordination because no single agency overseas electric infrastructure planning. Production cost models can be an important tool in the many phases of transmission planning across these agencies.

Applying the India Production Cost Model to Evaluate the Impact of New Transmission to Relieve Congestion: A Case Study of Gujarat

In this section we take a simplified approach to this planning process to show the value and potential methodology of using the India-specific production cost model to evaluate the benefits of new transmission within Gujarat.

In this example we analyze the economic impact of adding a single transmission line to the existing network of our 2022 model. This analysis is not meant to suggest that any specific line should or should not be built in the future but rather to give an example of how this model could be integrated into state transmission planning methods. Our 2022 model assumes new RE capacity based on best quality resources and state-level targets only, whereas in an actual transmission planning study, assumptions about new RE locations will also incorporate project developers' and other stakeholders' inputs.

Changing the transmission topology of a state with the addition of a line can have effects that are not easily calculable through a simple projection of generation and load within that state. In some cases, a new line within a state opens up the possibility of more trade with neighbors, either through access to more generation or by changing the difference between states of the marginal costs of generation and therefore altering the economics of cross-border trading.

The first step in this analysis is to choose an existing corridor that has significant congestion in our 2022 simulations and add transmission capacity.[16] The second step is to run the model for some period of time deemed representative and compare the operational costs. This comparison gives a critical piece of information in a cost-benefit analysis of a line.

We added a new line to an existing corridor that had significant amounts of congestion in the annual No New RE and 100S-60W scenarios to give a range of benefit that might be possible with its addition. We added a 400-kV, 560-MW capacity line in the corridor from substation 354018_HADALA_400 to 354026_VADINAR_400.[17] This corridor was congested 47% of the year in the 100S-60W scenario and 58% of the year in the No New RE scenario.

This demonstration uses four weeks of the year and extrapolates the results to provide insights into the impact new transmission lines would have on a year of operation.[18] Figure 42 shows the changes to generation in the Western region states between the control scenarios and those with the new line added. In both the No New RE and 100S-60W scenario, the biggest impact of the new line is on Gujarat supercritical coal, which displaces subcritical coal and gas generation and also decreases RE curtailment slightly. Gujarat generation overall increases—the state meets more of its load and also increases exports.

[16] Because this example is meant to illustrate methodology, we used the single metric of line congestion as a proxy for a more rigorous analysis with stakeholder input to identify corridor additions that may improve. operational efficiency. Congestion is the inability of a specific transmission line to carry more power from low-cost generation to a specific load center.

[17] Substation names refer to identification tags from the CEA PSS/E file.

[18] Two weeks in both February and August were chosen to give equal weight to monsoon and nonmonsoon in this example. Most planning procedures include at least a year of simulation using a production cost model.

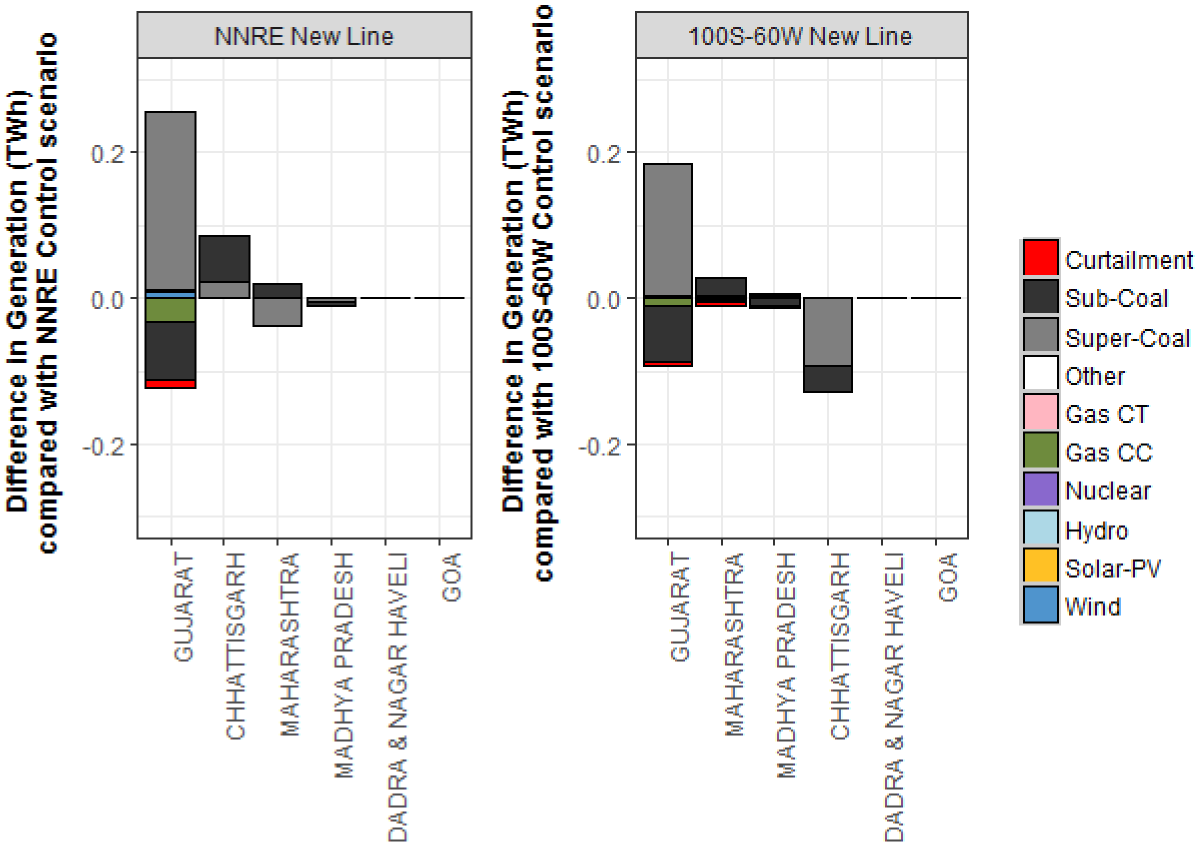


Figure 42. Difference in generation with the new line compared to the control scenario in the Western region by state, No New RE and 100S-60W

Curtailment of RE in Gujarat is 2.4% in the 100S-60W scenario and does not change significantly when a new line is added. However, Gujarat is able to generate more energy and in turn increase exports by 31% with the existence of the new line in the 100S-60W scenario. In No New RE, Gujarat is an importer in both scenarios, although the addition of the new line allows the state to decrease imports by 47%. Additionally, even though Gujarat produces more energy, the cost of generating each unit has a very slight decrease of INR 0.003/MWh in 100S-60W and INR 0.022/MWh in No New RE, showing the new line leads to more efficient dispatch of the resources used in Gujarat.

The complete benefit to Gujarat of selling more energy in 100S-60W is not easily captured given the lack of information on contracts and other market interactions, although changes to price do provide a way to see the value that may get passed down to retail consumers. Short-run marginal cost acts as a proxy for price in that it reflects the cost of the next unit of energy. Figure 43 shows the SRMC duration curves for plants in Gujarat for the No New RE and 100S-60W scenarios with and without the line. Both scenarios show a general shift to the left when the new line is added, illustrating that the new line produces benefits in terms of wholesale price. In the 100S-60W scenarios, the majority of periods have as the marginal unit of energy a relatively inexpensive combined cycle gas plant at a cost of INR 2750/MWh. However, more than 25% of the time the marginal unit of energy comes from a plant that is more expensive because it is partially loaded (and less efficient) or has a higher base variable cost, or it is necessary to import the next unit of energy from an expensive neighbor. The new line reduces the amount of time that Gujarat relies on these more expensive units in both scenarios. The average SRMC across the four sample weeks is reduced from INR 3089.4/MWh to INR 3042.2/MWh in the 100S-60W scenario and from INR 4561.8/MWh to INR 4540.3/MWh in the No New RE scenario.

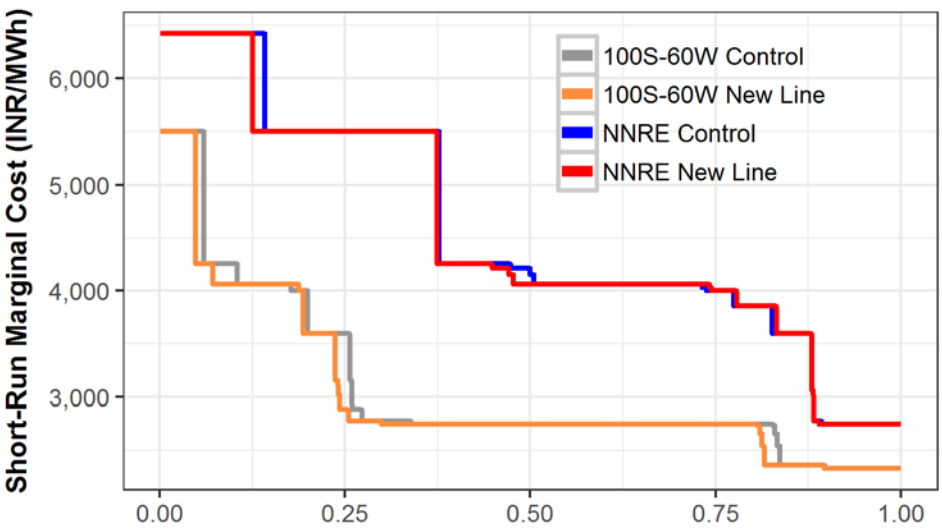


Figure 43. Short-run marginal cost duration curve for Gujarat for control and new line scenarios

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

Summary

Table 16 shows a summary of variables that were affected by the addition of 560 MW of capacity on the 354018_HADALA_400 to 354026_VADINAR_400 corridor. The ranges represent the benefits seen by both the No New RE and the 100S-60W scenarios. While there is not a large benefit in terms of production cost savings, Gujarat does increase its ability to export in a high-RE future and decreases its reliability on neighbors in a future with no RE growth. The cost per unit of energy generated decreases in both scenarios because of greater dispatch efficiency regardless of the future scenario, which may have benefits to individual generators not captured in this analysis.

Table 16. Summary of Impact on Gujarat from the Addition of the New Transmission Line

	BENEFIT TO GUJARAT
IMPORTS	31%–47% decrease
EFFICIENCY OF ENERGY PRODUCTION	INR 0.003.2–0.022.2/MWh savings
AVERAGE SHORT-RUN MARGINAL COST	INR 22–47/MWh decrease

Reviving Nonoperational Pumped Storage in Gujarat and Telangana

Pumped storage generators provide flexibility by storing excess energy when the value of energy is low and releasing it when the value of energy increases. In the National Study's 100S-60W scenario pumps typically pump (consume energy) midday and generators produce energy shortly before and after sundown to help meet net load peaks. The magnitude of pumping and generation increases when moving from the No New RE to 100S-60W scenario, suggesting that the value of storage is greater at higher RE penetrations.

Pumped storage operational constraints are similar to batteries—energy demand can be shifted, although this comes at a cost of energy losses due to the inefficiencies of pumps. While the National Study does not indicate a strong value for battery storage at 15-minute operational timescales, the addition of intrastate transmission constraints may improve the value proposition of storage at particular locations.[19] The value of energy varies based on its location relative to transmission congestion. Pumped storage generators optimize their energy value by loading in low-cost periods, such as when transmission congestion prevents a substation from exporting its generation (e.g., absorbing RE generation that would otherwise be curtailed) and generating in uncongested, high net load periods when costs are higher.

We revived the pumping mode of four hydro plants to test the value of specific storage opportunities with the more detailed transmission representation (2,190 MW total in India, 706 MW of which is in Telangana and 1,440 MW of which is in Gujarat).[20] Nationally, the flexibility provided by the additional 2190 MW of pumped storage reduces the average production costs and RE curtailment, although only negligibly. Because we model pumped storage plants with 75% efficiency, the new pumps incur losses of 1.5 TWh, which must be counterbalanced with additional generation. While the revived pumps cause average nationwide coal commitment to fall by 780 MW (0.6%), total coal generation remains virtually unchanged. The decrease in coal commitment indicates that there is some efficiency gained in scheduling coal generation, although this does not lead to much of a cost benefit. The rest of this section looks closer at the value of the pumps to the region and state in which they reside.

Southern Region

Figure 44 shows Southern region's average day of pumped storage operation, with and without the revived plants in Telangana. The 706 MW of additional pumped storage capacity is utilized similarly to the existing pumped storage and contributes to generation during the daily net load peaks in the evening and morning. It pumps primarily during the middle of the day. This is a reflection of the cost changes throughout the day as pumps run when costs are relatively low, and generate when cost are relatively high.

[19] Pumped storage schedules are fixed from the day-ahead schedule and as a result may be neglecting value that could be gained from flexibility closer to real-time operations.

[20] The four hydro plants were originally modeled with minimum generation constraints, which we left in place for consistency between simulations but which force the plants to sometimes generate and pump at the same time.

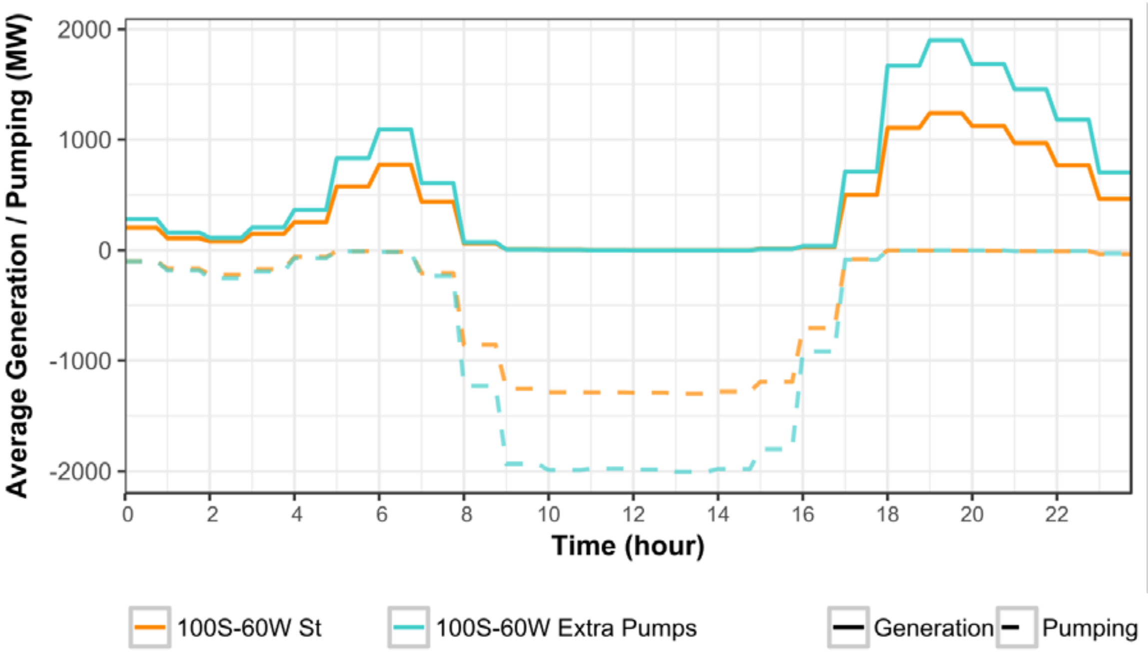


Figure 44. Comparison of average pumping day in the Southern region with and without extra pumps

The benefit of the additional pumps to the Southern region is negligible in terms of total production costs, however the pumps are utilized indicating some increased efficiency. RE curtailment also decreases from 4.9% to 4.6%. This benefit can be better captured by looking specifically at what operational changes occur within Telangana. Figure 45 compares dispatch stacks in Telangana on 20 June with and without extra pumped storage. Daytime load increases to accommodate the pumping, absorbing some of Telangana's RE curtailment, while exports increase in the evening when the pumps are discharged.

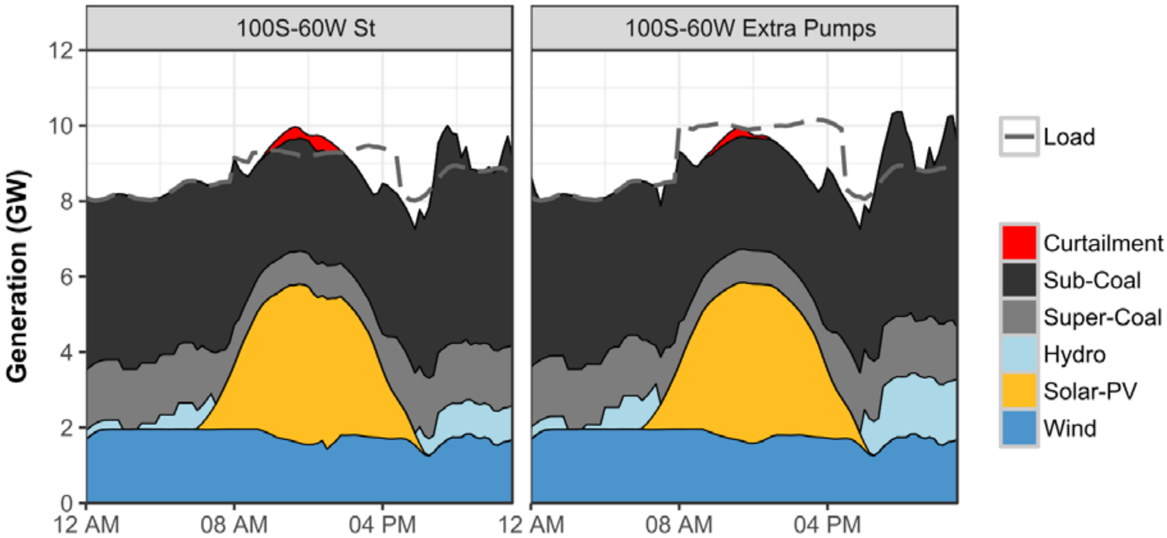


Figure 45. Comparison of dispatch in Telangana on 20 June, with and without extra pumps

The operational changes like those observed in Figure 45 lead to a shift in production costs around the region, with advantages to Telangana and Andhra Pradesh whose average production costs decrease by 2% and 1%, respectively. The localized benefits of reviving Telangana's pumped storage may have a wider impact given better interstate coordination or co-optimized planning of transmission specifically to access this flexibility.

Western Region

Figure 46 shows the Western region's average day of pumped storage operation, with and without the revived plants in Gujarat. The 1,440 MW of additional pumped storage capacity is utilized and contributes to generation during the daily net load peaks in the evening and morning. It pumps primarily during the middle of the day. This is a reflection of the cost changes throughout the day as pumps run when costs are relatively low, and generate when cost are relatively high.

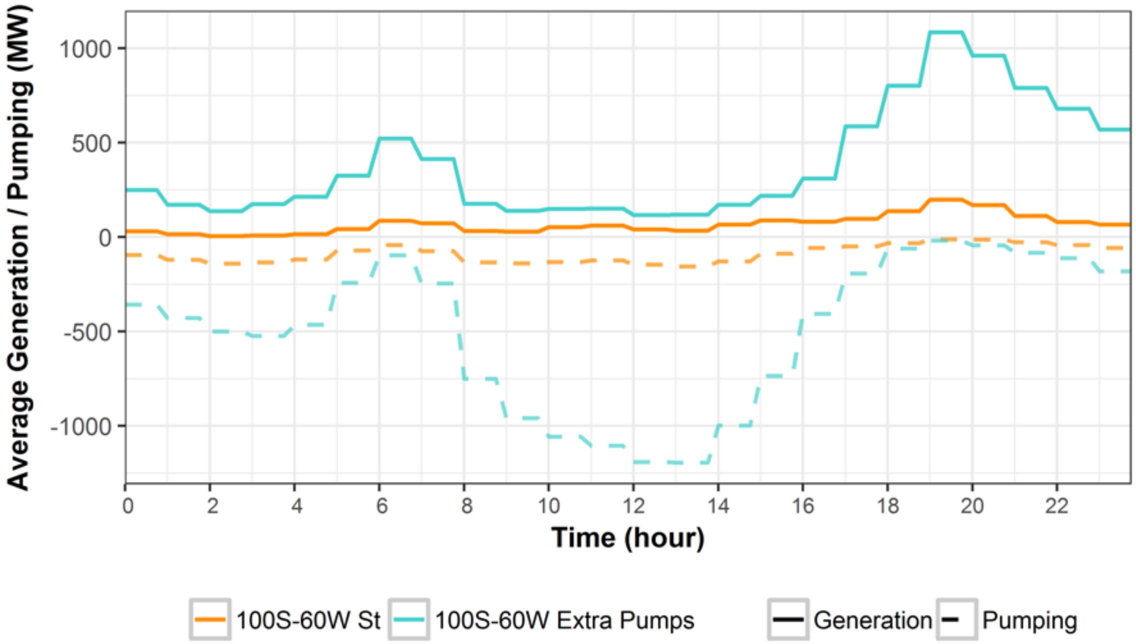


Figure 46. Comparison of average pumping day in the Western region, with and without extra pumps

The biggest benefit from the revived pumps is locally to Gujarat, where the average production cost decreases by 3%, although the benefit to the Western region as a whole is negligible. RE curtailment regionwide also sees a slight increase from 1.6% to 1.7%. A primary reason for the increased curtailment as well as relatively small benefits from the revived pumps is that transmission congestion is not allowing the flexibility to be accessed. Figure 47—dispatch in Gujarat on 22 June—demonstrates how intrastate transmission congestion can prevent pumped hydro from supplying the full breadth of its flexibility. The revived pumped storage plants increase Gujarat's daytime load. However, multiple intrastate transmission constraints prevent RE curtailment from meeting the increased demand. Instead Gujarat's midday RE curtailment actually rises, while decreased exports and increased coal generation supply the pumps. Hydro generation (from pumped storage plants) increases in the late evening hours despite simultaneous RE curtailment, which occurs in a different part of the state, isolated by transmission congestion. The localized benefits to Gujarat of reviving pumped storage may have a wider impact given better interstate coordination or co-optimized planning of transmission specifically to access this flexibility.

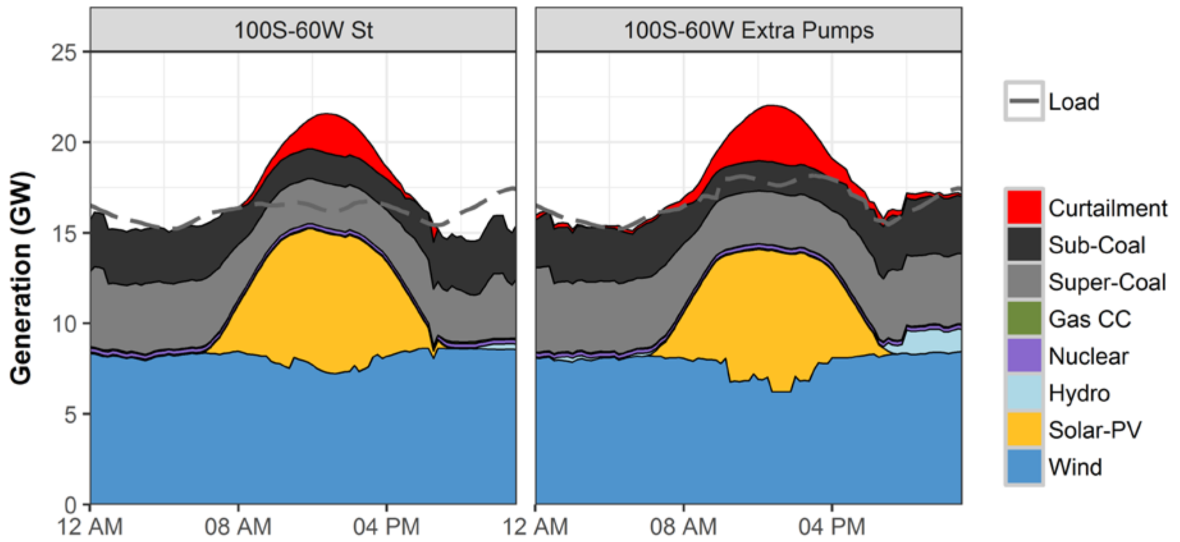


Figure 47. Comparison of dispatch in Gujarat on 22 June, with and without extra pumps

Summary

The economic and operational insights available from a production cost model can be much broader or if necessary, much more detailed, than the simple applications exemplified here. The primary challenge is selecting the scenarios and sensitivities that will satisfy the various stakeholders impacted by changes to the system. Another challenge, as in all power systems analysis, is assigning impacts to the various actors. A comprehensive and successful planning process will take these issues into account early in the process so modeling outcomes reflect reality and satisfy those impacted.

APPENDIX B: TRANSMISSION ENFORCEMENT AND ADDITIONS IN THE REGIONAL STUDY

A model that enforces all 1,215 lines at or above 400 kV inside the Western region, Southern region, and Rajasthan (hereafter: focus area) runs slowly. To improve run-times, we tested a number of potential speed-up measures.

One such successful speed-up strategy was the enforcement of only a subset of the 1,058 400-kV lines inside the focus area, such that their enforcement constrains the system in a way approximately equivalent to enforcing all 1,058.[21] The rationale that enforcing some 400-kV lines constrains flows on other 400-kV lines is identical to the rationale in Section 1.1 that enforcing 400-kV lines constrains flows on nearby 220-kV lines. For example, two lines in series will always have the same flows when using DC optimal power flow. Two lines in parallel with equal reactances will also always have the same flows. In each case, it is only necessary to enforce one to constrain flows on the other. In a more complex system, if two lines have similar power transfer distribution factors relative to nearby power injections and withdrawals, then enforcing one is approximately equivalent to enforcing both. While it is impossible to find a strict subset of the 400-kV lines whose enforcement is exactly equivalent to enforcing all 400-kV lines, we found that enforcing 223 of the 1,058 400-kV lines inside the focus area delivers a very good approximation of enforcing all.

To find the above subset, we first identified three weeks with particularly extreme system conditions from the national study runs: 20–26 June for its high RE generation and 9–15 July and 24–30 September for their high interregional flows. Beginning with only the 765-kV lines enforced, we simulated each of the three weeks multiple times at 2-hour resolution with varying amounts of RE and different transmission aggregations. The resulting set of solutions constituted iteration 0. After examining iteration 0, we identified 184 400-kV lines inside the SR, WR, or Rajasthan that exceeded their flow limits in more than one 2-hour interval across all solutions. The subsequent iteration 1 reran the same weeks with the 184 400-kV lines enforced. After examining the results of iteration 1, we identified a further 131 400-kV lines to enforce and proceeded to iteration 2.

If a line overloaded in iteration n-1, was subsequently enforced and then never reached its flow limit in iteration n, we unenforced it in iteration n+1.Because the line would not have overloaded in iteration n even if it had been unenforced, we considered the line's flow constraints adequately represented by the other lines enforced in iteration n-1. By the end of iteration 3, we arrived at a core set of 205 400-kV lines to enforce inside the focus area.[22] Table 17 shows the process through iteration 3.

[21] All 765-kV lines inside the focus area remain enforced throughout.

[22] The model parameters varied between iterations. In the first iteration we considered only No New RE and focused on the SR and WR separately. In later iterations we considered the 100S–60W and 60S–100W RE buildouts and focused on the SR and WR simultaneously.

Table 17. Lines Enforced and Unenforced in Each Iteration to Test Methods of Improving Computational Times

ITERATION	LINES ENFORCED	LINES UNENFORCED
0	184	-
1	131	74
2	24	37
3	28	5
Aggregate through 3	**205**	**-**

Figure 48 demonstrates that the enforced 400-kV lines do in fact approximately hold the unenforced 400-kV lines in check. Each dot represents line flow as a percentage of flow limit in an interval for a 400+-kV line in July of the 100S–60W scenario. Of the roughly 3.5 million data points on the figure, only 0.09% represent overloaded 400-kV lines, compared to 0.06% for the entire year. No 400+-kV line overloads past 130% of its flow limit during the month.

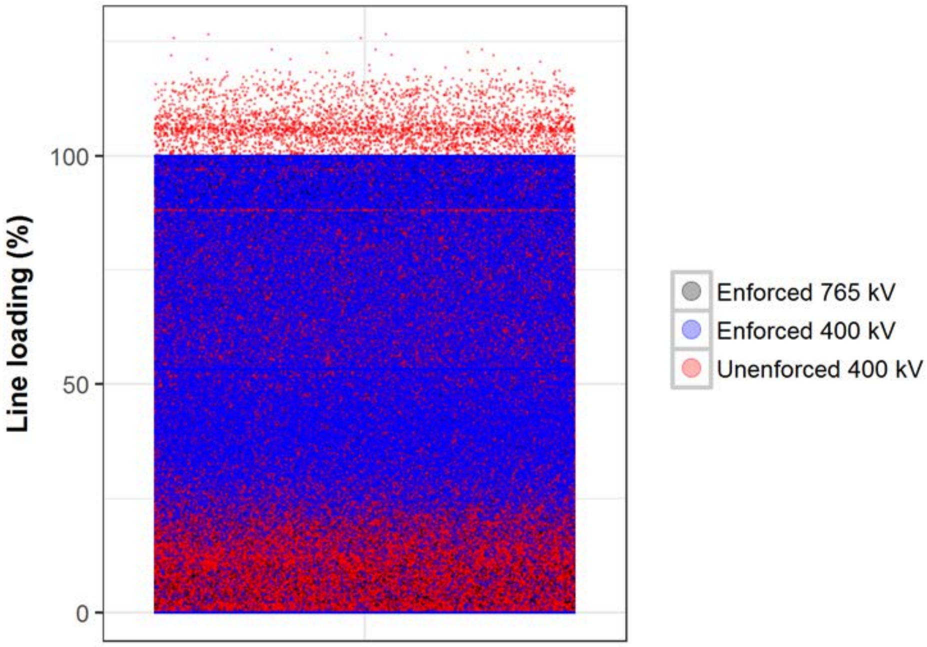


Figure 48. Interval loading of all 400-kV lines inside the focus area in July of the 100S-60W scenario

Iterative Transmission Buildout

In the process of determining the subset of 400-kV lines to enforce, it became apparent that several nodes in SR, WR, and Rajasthan were curtailing significant amounts of RE relative to their neighbors because of transmission constraints on the newly enforced 400-kV lines. RE generators are located on 237 different nodes in the 100S–60W scenario of the Regional Study as opposed to 30 nodes in the National Study. Because we sited new RE installations based on best resource locations and did not have up-to-date information on intrastate transmission lines, our model can be ineffective at representing system operations at the nodal level. As such, instances of extremely high localized curtailment are likely byproducts of our modeling process rather than indications of actual system conditions. To reduce curtailment caused by line-specific congestion, we selectively added new lines in parallel with existing congested 400-kV lines after iterations 3, 4, 5, and 6. We based iteration 6 off of year-long, instead of week-long, runs. All new lines were automatically set to 400 kV, enforced, shared the physical parameters of their twins, and were selected using the procedure below.

If a node curtailed at least 40% (or 20% in iteration 6) of its available capacity totaling at least 5 GWh (0 GWh in iteration 6) across all solutions in an iteration, we designated it a TCN (transmission curtailing node). For each TCN, we asked the following four questions:

1. Does the line have at least one end point inside the TCN's state?
2. Is the line already enforced?
3. Is the line 400 kV?
4. In at least 50% of the intervals where the TCN curtails energy, is the line also congested?

For all lines where the four questions above are satisfied, we built a twin line in parallel, effectively doubling the capacity of the flowgate.

We layered the transmission buildout procedure on top of the existing selective enforcement of transmission and continued the iterations. Table 18 shows the state of the transmission system after the final iteration 6.[23]

Table 18. Iterations of Lines Enforced, Unenforced, and Built as Part of the Process to Expand Transmission

ITERATION	LINES ENFORCED	LINES UNENFORCED	LINES BUILT
0	184	-	-
1	131	74	-
2	24	37	-
3	28	5	8
4	11	-	3
5	1	-	5
6	6	-	10 (400 kV) + 1 (765 kV)
Aggregate through 6	**223**	**-**	**27**

In aggregate, we enforced 223 of 1,058 400-kV lines and all 157 765-kV lines inside the SR, WR, and Rajasthan. We also built 27 new lines, primarily in WR and Rajasthan.

Convergence Criteria

As noted above, there is no strict subset of 400-kV lines that, when enforced, exactly match the constraint of enforcing all 400-kV lines. Instead we allowed some 400 kV-lines to violate flow limits, as in Figure 49, in exchange for improvements to computation time.

Instead of using a formal convergence criterion we decided the enforcement of only several additional lines in iteration 6—despite basing the iteration off a year-long simulation—signaled we had arrived

[23] After iteration 3 we stopped unenforcing lines to simplify the algorithm and speed its convergence.

at the approximate subset of 400-kV lines that would produce results reflective of complete 400-kV enforcement.

Figure 49 shows a real example of the iterative process in a small section of the Rajasthan network. We enforced the green 400-kV lines over the course of iterations 0–3, which in turn drastically increased curtailment at the red nodes (Panel 1). In response, we reduced transmission-induced curtailment by adding the blue 400-kV lines in parallel with previously enforced lines over iterations 3–5 (Panel 2). However, as a result of the new blue lines, previously unenforced lines whose flows were held in check by the green lines began to significantly overload. We respond by enforcing the orange lines in iterations 4 and 5 (Panel 3).

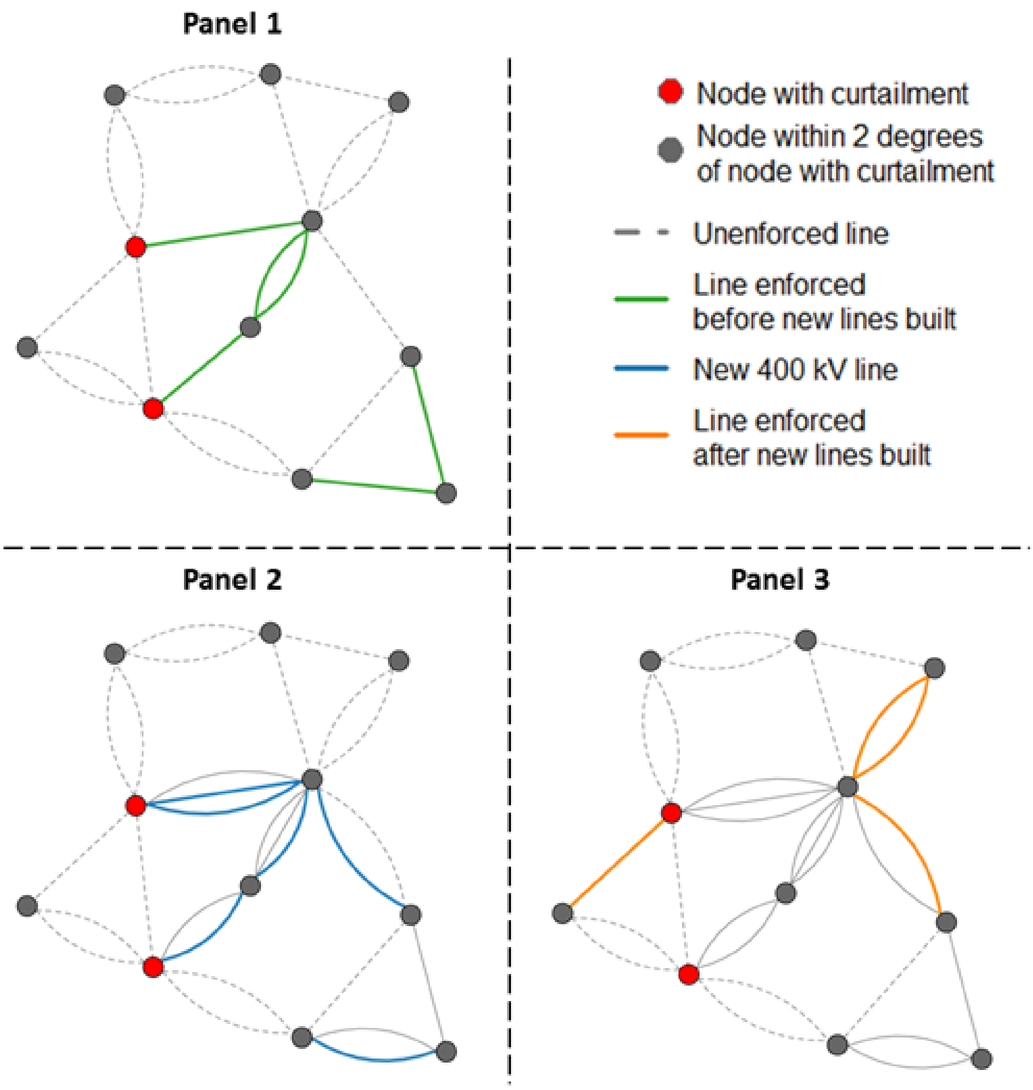


Figure 49. Example of the iterative process of adding and enforcing lines in a small section of the Rajasthan network

Table 19 lists the newly built lines and their properties. Interstate additions differ from intrastate additions in that they also contribute to the flow limits of their respective interfaces.

Table 19. Intrastate and Interstate Transmission Additions in the Model to Address RE Curtailment

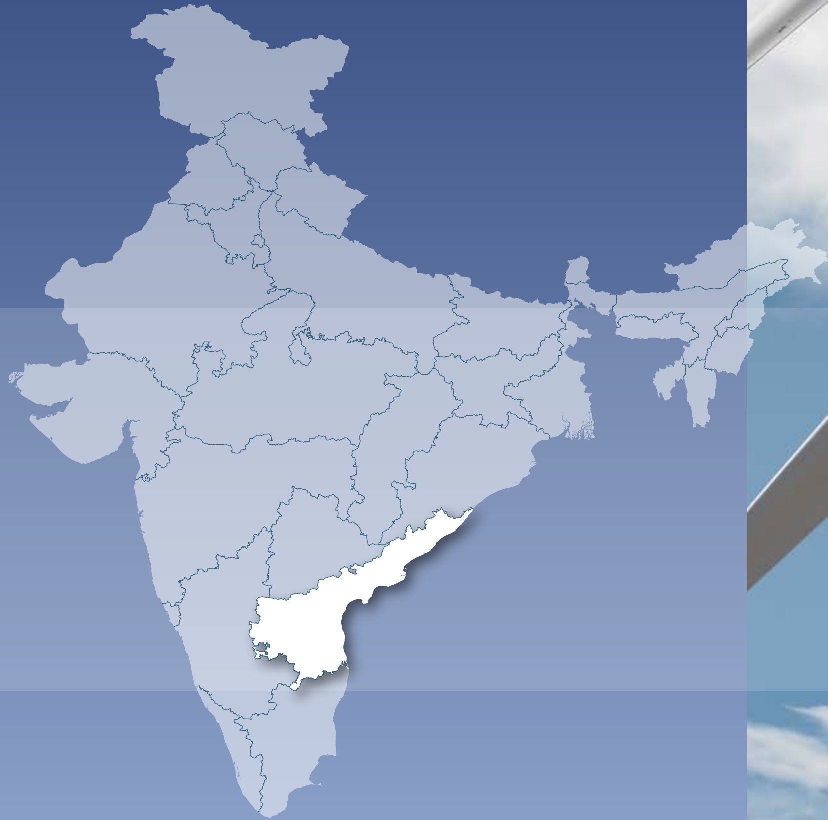
`					
NEW LINE	**REGION FROM**	**REGION TO**	**TYPE**	**VOLTAGE**	**LIMIT (MW)**
164400_164433_3_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164401_164433_2_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164401_164433_3_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164402_164413_2_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164402_164413_3_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164413_164433_3_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164433_184404_2_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
164433_184404_3_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
184445_184921_3_CKT	RAJASTHAN	RAJASTHAN	AC	400	517
354002_354009_2_CKT	GUJARAT	GUJARAT	AC	400	517
354003_354017_3_CKT	GUJARAT	GUJARAT	AC	400	560
354009_354021_2_CKT	GUJARAT	GUJARAT	AC	400	517
354017_354036_2_CKT	GUJARAT	GUJARAT	AC	400	550
364003_364010_2_CKT	MADHYA PRADESH	MADHYA PRADESH	AC	400	517
364009_364026_3_CKT	MADHYA PRADESH	MADHYA PRADESH	AC	400	560
374001_374042_2_CKT	MAHARASHTRA	MAHARASHTRA	AC	400	517
374006_374012_7_CKT_DC	MAHARASHTRA	MAHARASHTRA	DC	400	700
524002_524003_2_CKT	KARNATAKA	KARNATAKA	AC	400	517
544026_544027_3_CKT	TAMIL NADU	TAMIL NADU	AC	400	550
548127_548129_3_CKT	TAMIL NADU	TAMIL NADU	AC	765	48
INTERSTATE ADDITIONS					
NEW LINE	**REGION FROM**	**REGION TO**	**TYPE**	**VOLTAGE**	**LIMIT (MW)**
184403_354019_2_CKT	RAJASTHAN	GUJARAT	AC	400	517
184403_354019_3_CKT	RAJASTHAN	GUJARAT	AC	400	517
314001_364008_3_CKT	CHHATTISGARH	MADHYA PRADESH	AC	400	517
374050_524015_3_CKT	MAHARASHTRA	KARNATAKA	AC	400	675
514011_514013_2_CKT	TELANGANA	ANDHRA PRADESH	AC	400	517
534954_544006_3_CKT	KERALA	TAMIL NADU	AC	400	517
544016_534999_43_CKT_DC	TAMIL NADU	KERALA	DC	400	1000

APPENDIX C: STATE CHAPTERS

The objective of the state chapters is to provide modeling assumptions, results, and next steps to use and improve the model specific to each state. The model has inherent uncertainties, particularly in how the intrastate transmission network and RE generation projects will develop (e.g., locations, capacities). The model also does not include information on contracts or must-run status of particular plants for reliability purposes. By providing details on modeling assumptions, system planners and operators in each state can better understand how to interpret the results based on the existing assumptions and customize the model to answer additional questions.

The state chapters are included below in the following order: Andhra Pradesh, Gujarat, Karnataka, Maharashtra, Rajasthan, and Tamil Nadu.

Greening the Grid



Andhra Pradesh

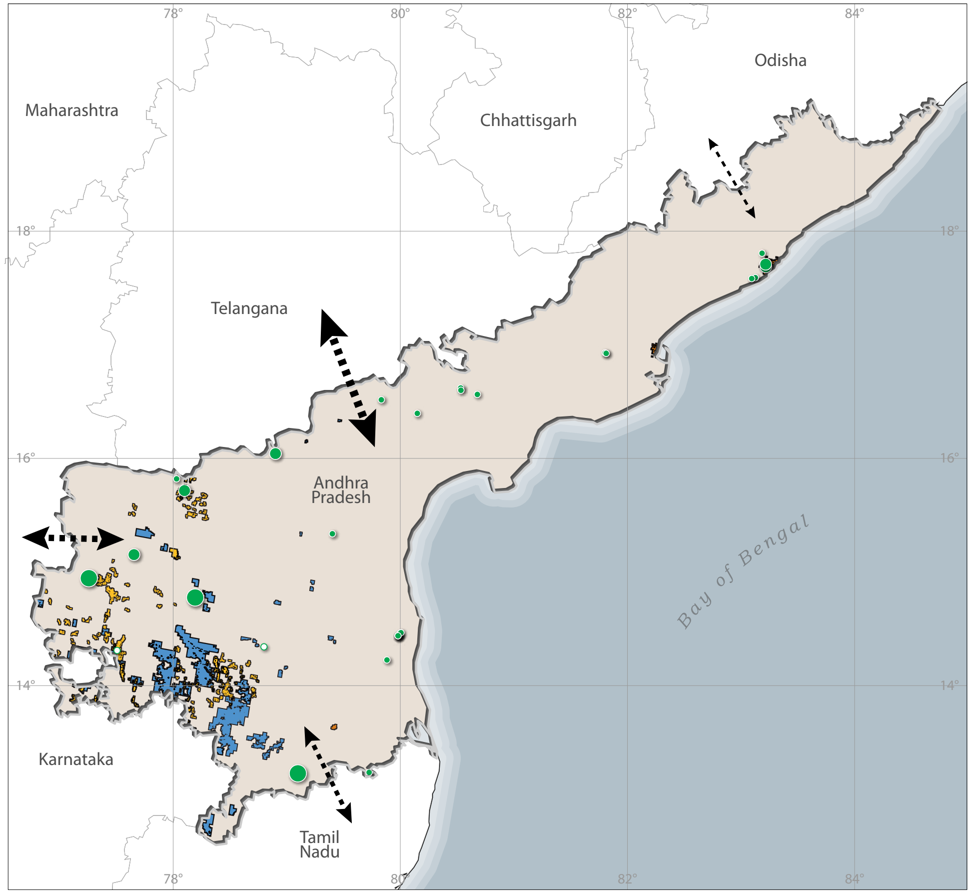
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

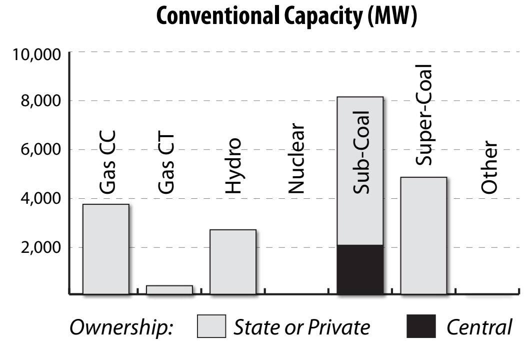
State-specific results from Volume II, which includes all of India. The full reports include detailed explanations of modeling assumptions, results, and policy conclusions.

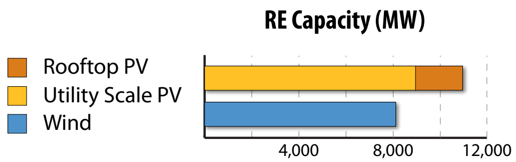
www.nrel.gov/india-grid-integration/

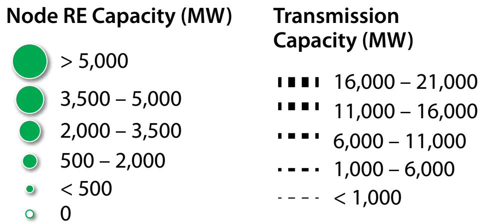
Assumptions About Infrastructure, Demand, and Resource Availability in 2022

Assumptions about RE and conventional generation and transmission in Andhra Pradesh in 2022









Peak load (GW)	12
Total annual load (TWh)	160
Installed non-RE capacity (GW)	20
Installed RE capacity (GW)	19
Total import/export capacity (GW)	47

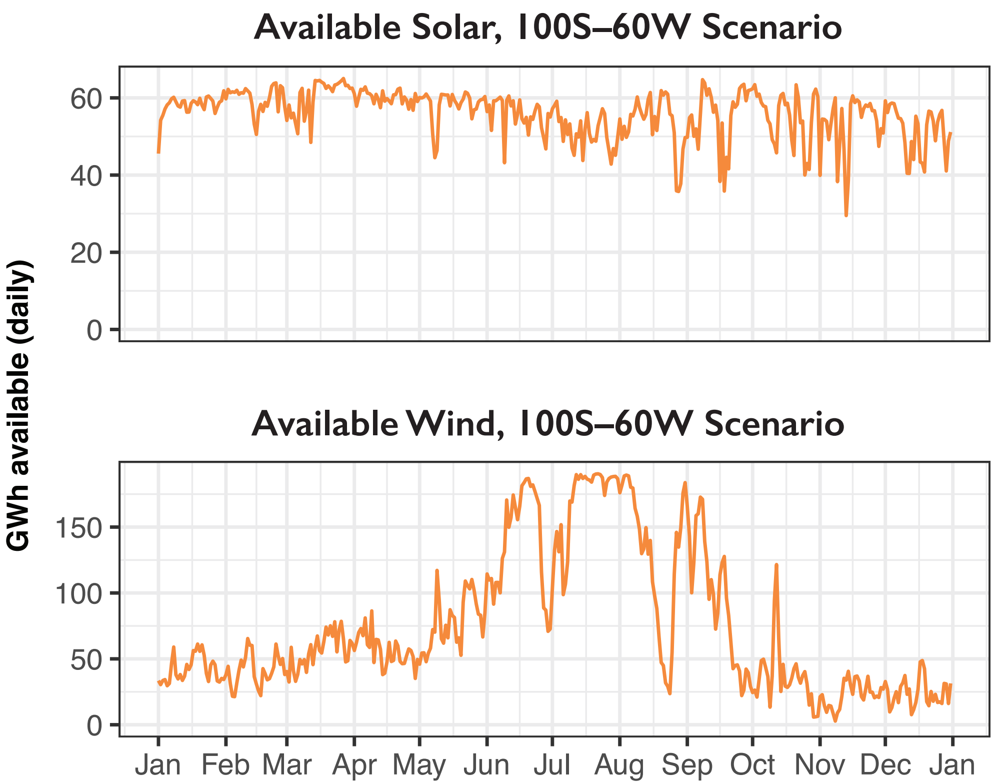
Andhra Pradesh has 50 tie-lines connecting it to other states in this model.

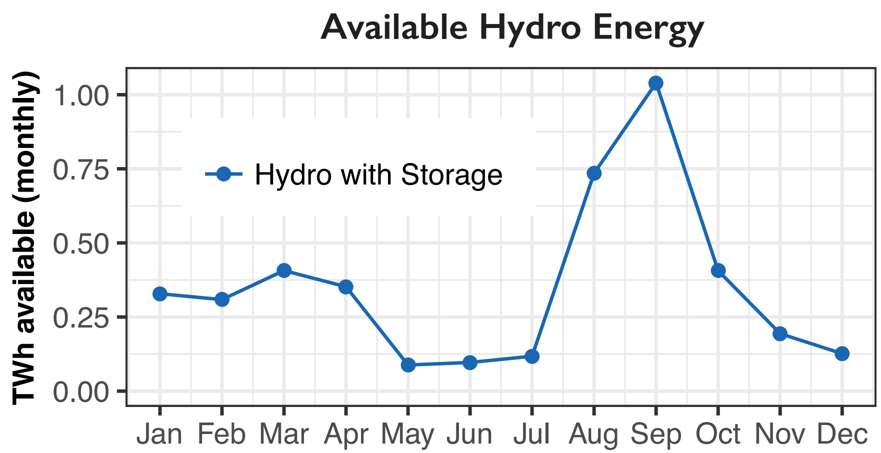
NREL and LBNL selected RE sites based on the methodology explained in Volume 1 of this report, which is available at www.nrel.gov/docs/fy17osti/68530.pdf.

Rooftop PV has been clubbed to the nearest transmission node.

Andhra Pradesh Resource Availability in 2022

Available wind, solar, and hydro energy throughout the year in Andhra Pradesh





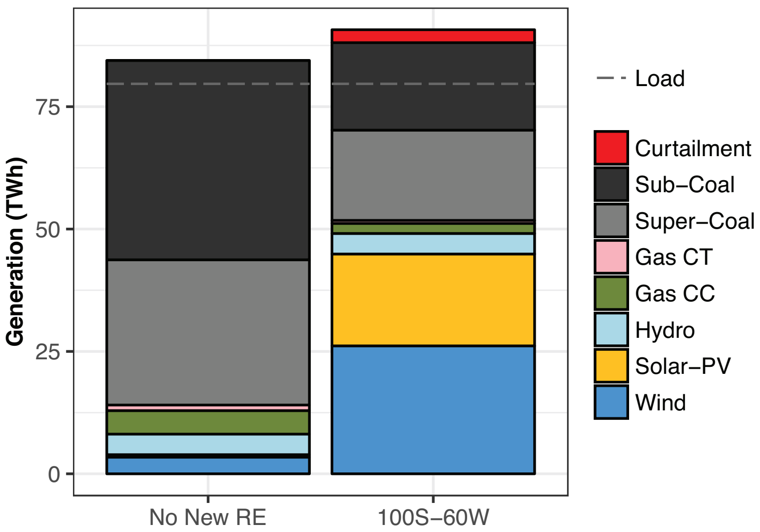
Daily solar energy is relatively consistent throughout the year, while wind energy varies seasonally.

Note: Y-axis is different for each resource

Operation in Andhra Pradesh with Higher Levels of RE: RE Penetration in 2022

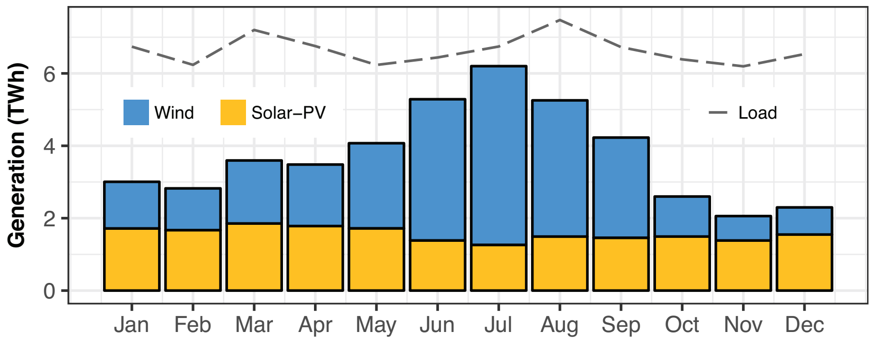
Increased amounts of RE available in Andhra Pradesh change Andhra Pradesh's generation mix and therefore the operation of the entire fleet.

Annual energy generation in Andhra Pradesh



19 GW of wind and solar power generates 45 TWh annually.

Monthly RE generation and load in Andhra Pradesh in the 100S-60W scenario



Wind and solar produce 51% of total generation in Andhra Pradesh and meet 56% of load.

RE penetration by load and generation

	100S-60W
Percent time RE is over 50% of load	54
Peak RE as a % of load	180
Percent time RE is over 50% of generation	51
Peak RE as a % of generation	98

Coal generation falls by 48% and gas by 55% between No New RE and 100S-60W.

Operation in Andhra Pradesh with Higher Levels of RE: Imports and Exports

Increased RE generation inside and outside of Andhra Pradesh affects flows with surrounding states.

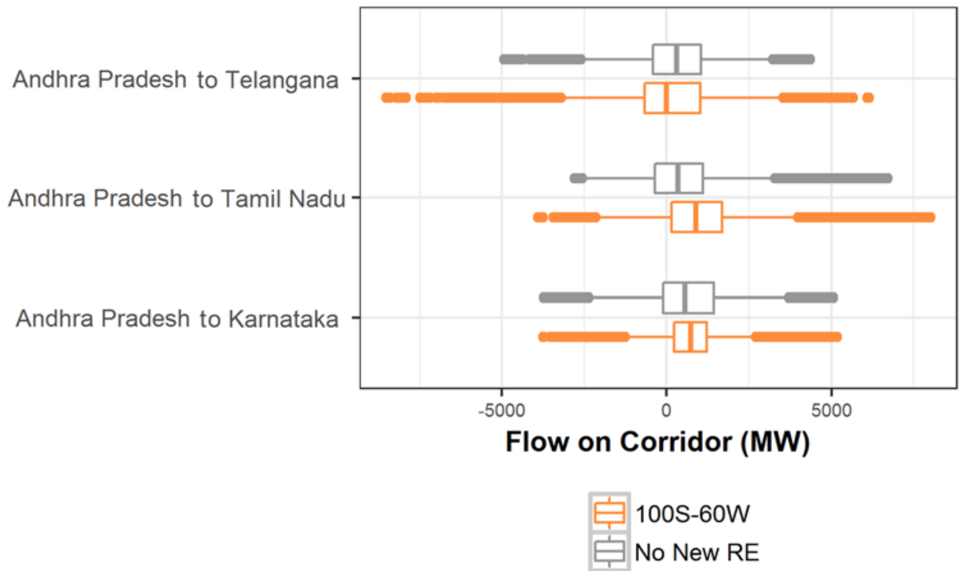
Andhra Pradesh's net exports are nearly double in the 100S-60W scenario compared to No New RE. A large portion of the increase in exports is to Tamil Nadu, which is able to decrease its imports from Chhattisgarh as a result.

Imports fall by **6.6%** annually

Exports rise by **5.0%** annually

SCENARIO	NET EXPORTS (TWh)	
No New RE	4.8	net exporter
100S-60W	8.4	net exporter

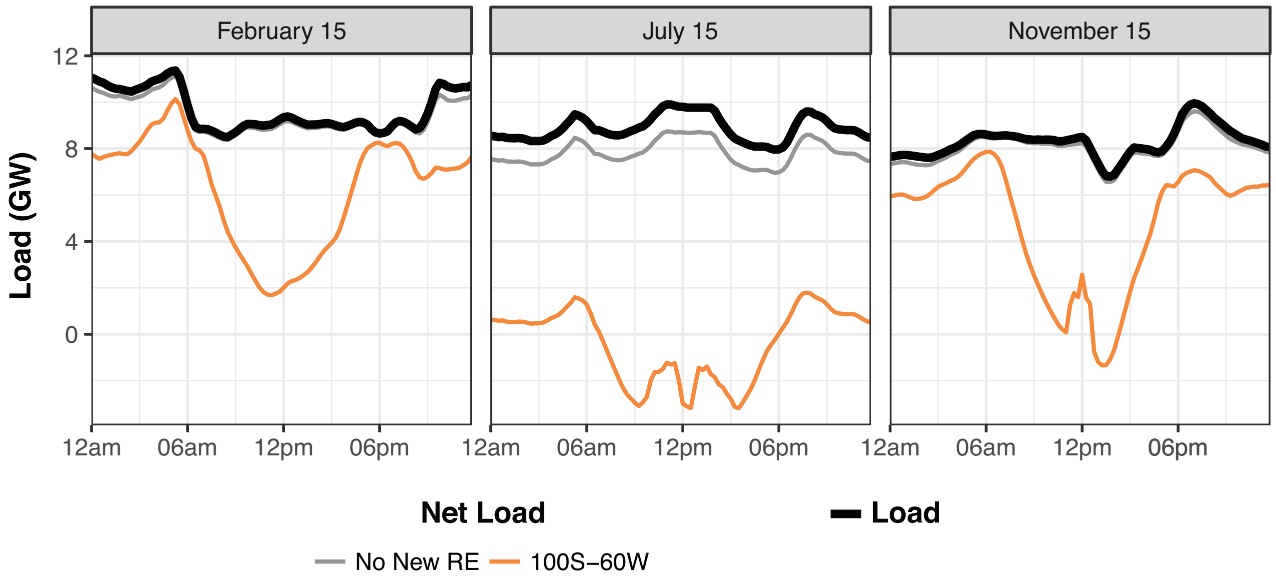
Distribution of flows across state-to-state corridors



Operation in Andhra Pradesh with Higher Levels of RE: Rest of the Fleet

The addition of RE in Andhra Pradesh changes net load, which is the load that is not met by RE and therefore must be met by conventional generation. Due to changes in net load, hydro and thermal plants operate differently in higher RE scenarios.

Example days of load and net load in Andhra Pradesh



Increased daytime solar generation causes a dip in net load, which requires Andhra Pradesh to increase net exports, turn down its thermal generators, or curtail RE. For much of the day on 15 July, increased wind generation drives Andhra Pradesh's daytime net load below zero (>100% RE penetration).

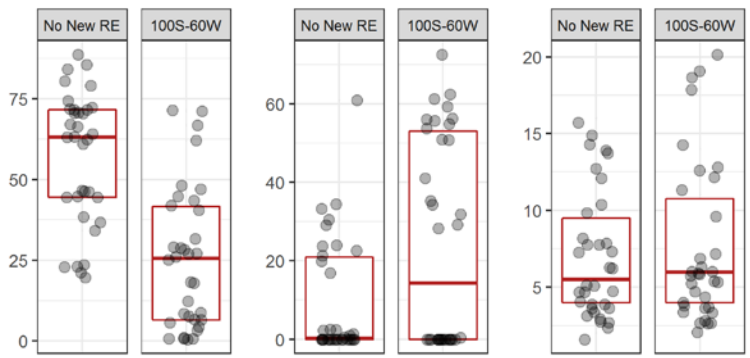
Hourly net load ramps for all periods of the year, ordered by magnitude

Peak 1-hour net load up-ramp in the **100S-60W scenario is 9.1 GW**, up from **2.1 GW in the No New RE scenario.**

Maximum net load valley-to-peak ramp is **13 GW in the 100S-60W scenario**, up from **4.0 GW in the No New RE scenario.**

Changes to Andhra Pradesh's Coal Fleet Operations

Operational impacts to coal



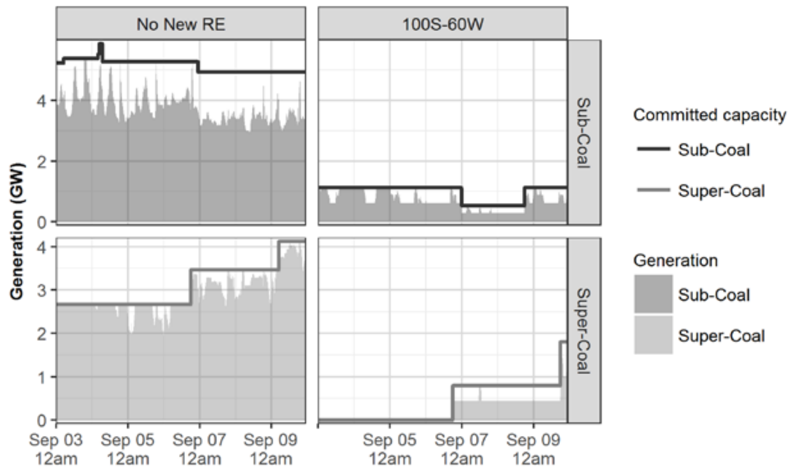
Coal plant load factors (PLFs) are lower in the 100S-60W scenario due to more frequent cycling and operation at minimum generation levels.

While coal PLFs are lower fleetwide in 100S-60W, generators with higher variable costs are impacted more.

Average PLF of coal generators in Andhra Pradesh, disaggregated by variable cost

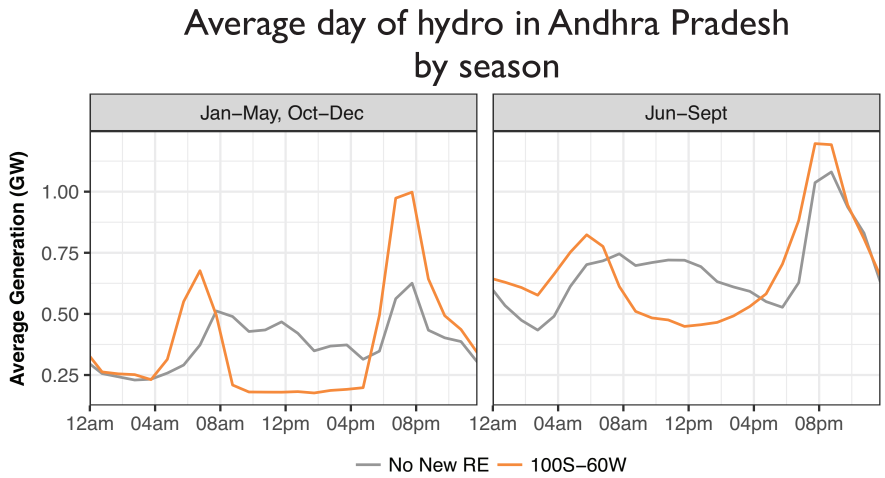
RELATIVE VARIABLE COST	NO NEW RE	100S-60W
Lowest 1/3	73	46
Mid 1/3	55	16
Highest 1/3	27	1.6
Fleetwide	63	32

One week of coal operation in Andhra Pradesh



The coal fleet is committed much less and operates at or near minimum generation more in the 100S-60W scenario.

Changes to Andhra Pradesh's Hydro Fleet Operations



Minimum generation levels during the monsoon season hinder the ability of hydro to shift generation to net load peaks as it does more fully in the months outside of the monsoon.

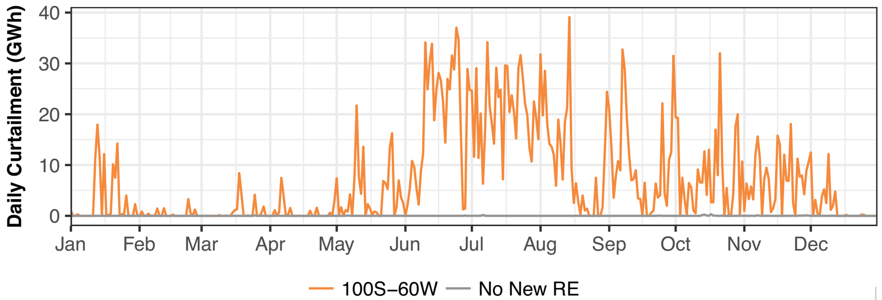
Hydro plants follow a more pronounced two-peak generation profile due to availability of solar power during the middle of the day.

How Well Is RE Integrated?
Curtailment and Operational Snapshots

Curtailment levels indicate how efficiently RE is integrated. Large amounts of curtailment signal inflexibility in the system, preventing grid operators from being able to take full advantage of the available renewable resources.

5.6% of wind and solar is curtailed annually.

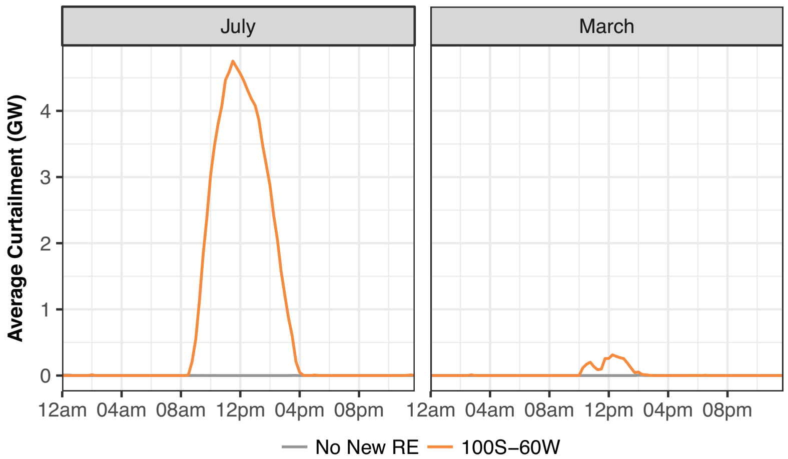
Total daily curtailment throughout the year in Andhra Pradesh



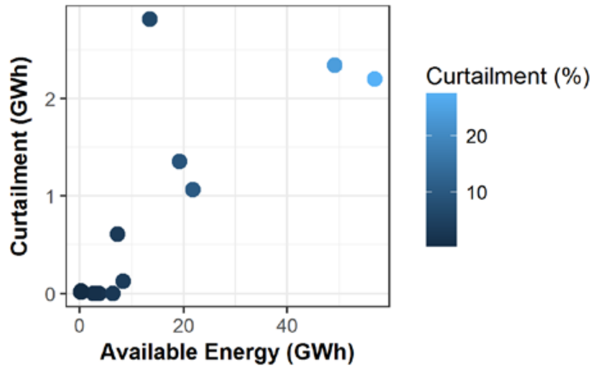
Curtailment is highest in June and July when wind energy is highest. Monthly curtailment is higher than 6% June through November.

Almost all RE curtailment occurs in 7.1% of periods in the year.

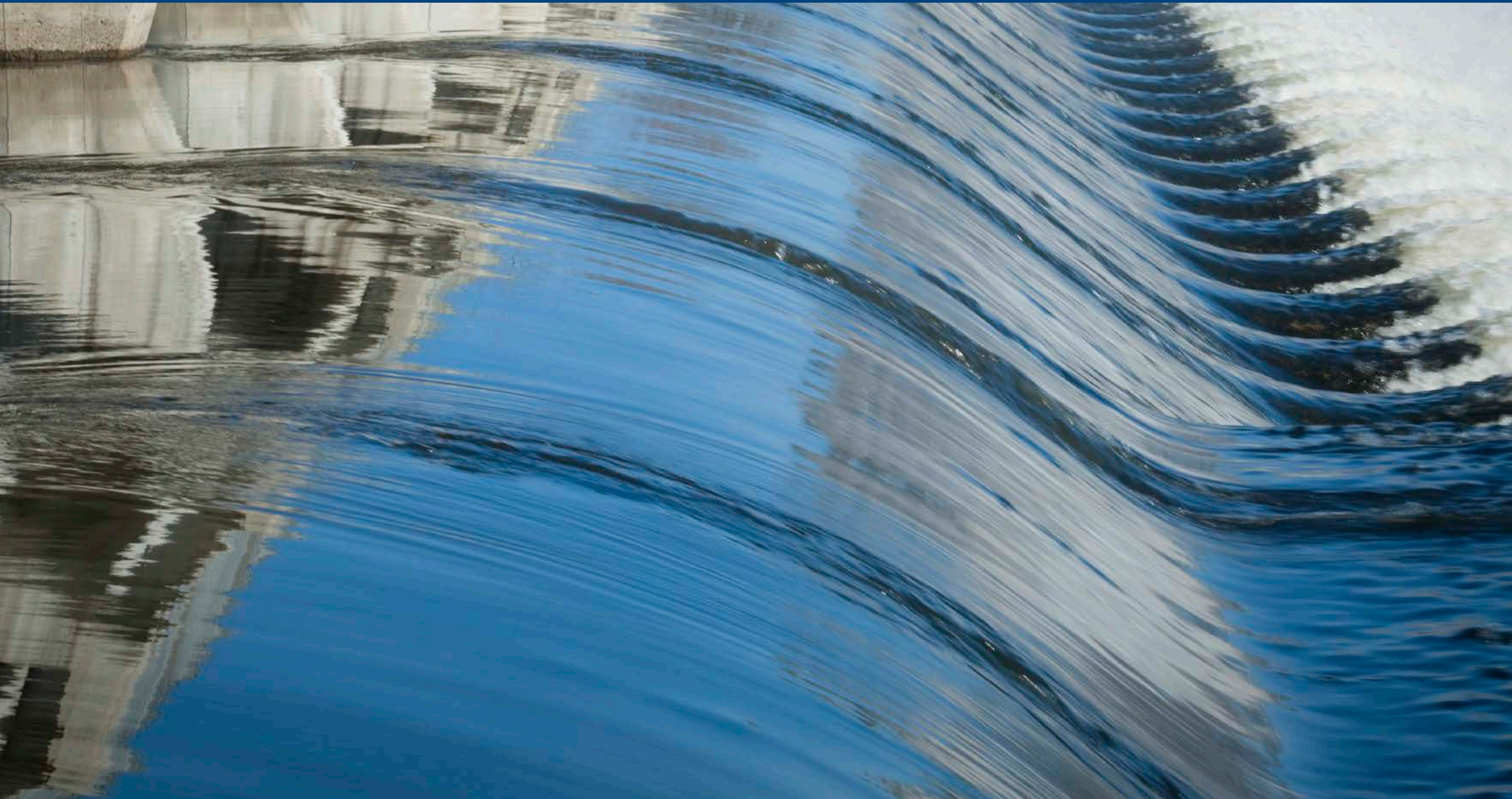
Average daily curtailment in March and July in Andhra Pradesh



RE curtailment as a percent of available energy by substation (each dot represents a substation)



Examples of Dispatch During Interesting Periods in Andhra Pradesh

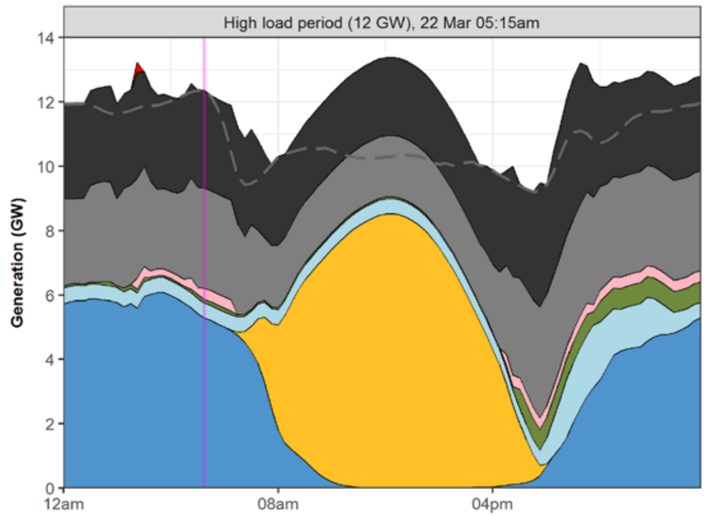


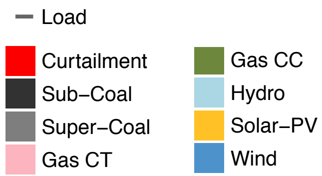
The following pages show dispatch in Andhra Pradesh during several interesting periods throughout 2022. The vertical magenta line highlights the dispatch interval associated with the figure title.

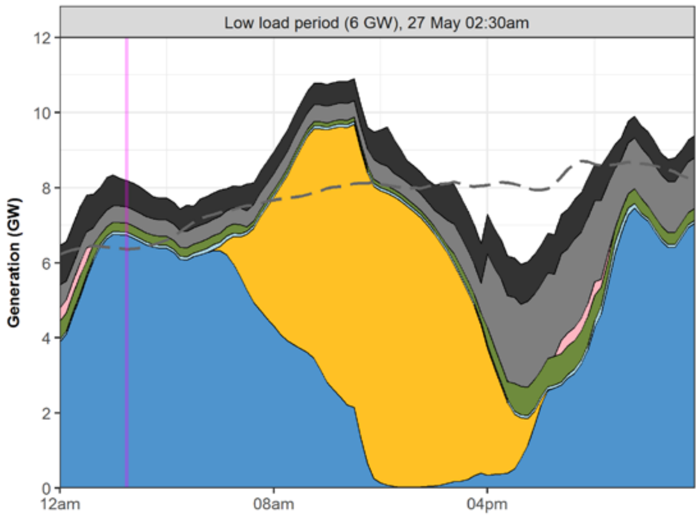
High load period: Generation, load, and interchange (values in GW unless otherwise specified)

22 March 5:15 am

LOAD	CURTAILMENT	HYDRO	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
12.4	0	0.5	6.1	0.5	5.3	0	43







Low load period: Generation, load, and interchange (values in GW unless otherwise specified)

27 May 2:30 am

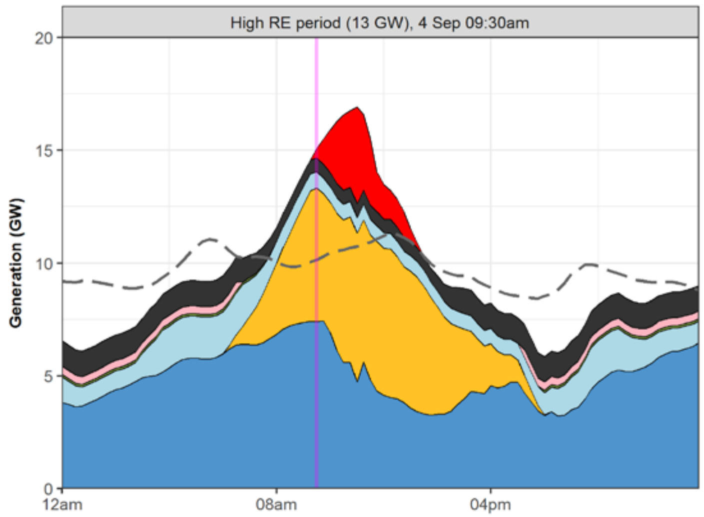
LOAD	CURTAILMENT	HYDRO	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
6.4	0	0.1	1.1	0.2	6.7	1.8	106

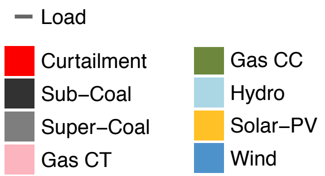
Example Dispatch Days

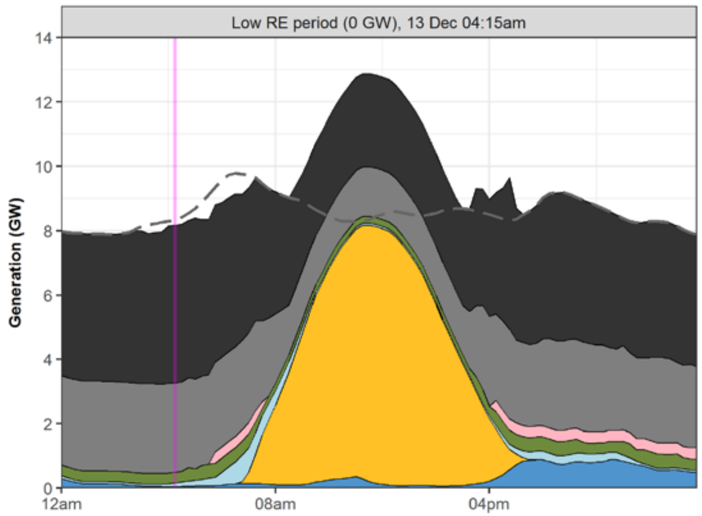
High RE period: Generation, load, and interchange (values in GW unless otherwise specified)

4 September 9:30 am

LOAD	CURTAILMENT	HYDRO	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
10.1	0.4	0.7	0.6	0	13.3	4.5	131



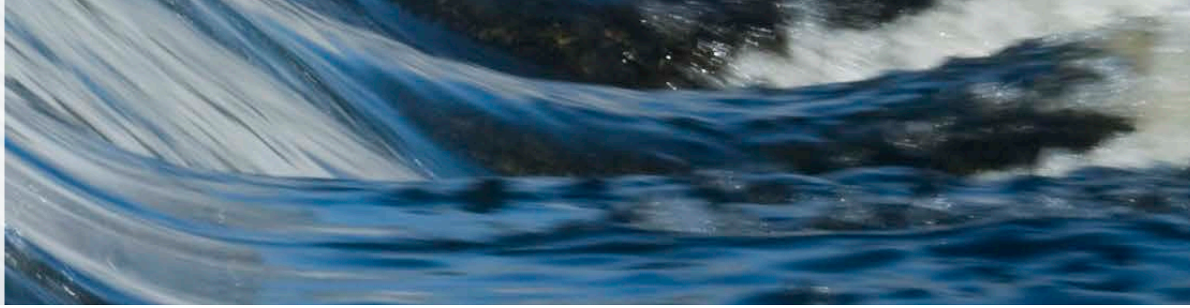




Low RE period: Generation, load, and interchange (values in GW unless otherwise specified)

13 December 4:15 am

LOAD	CURTAILMENT	HYDRO	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
8.3	0	0.1	7.7	0.3	0	0.2	0.5

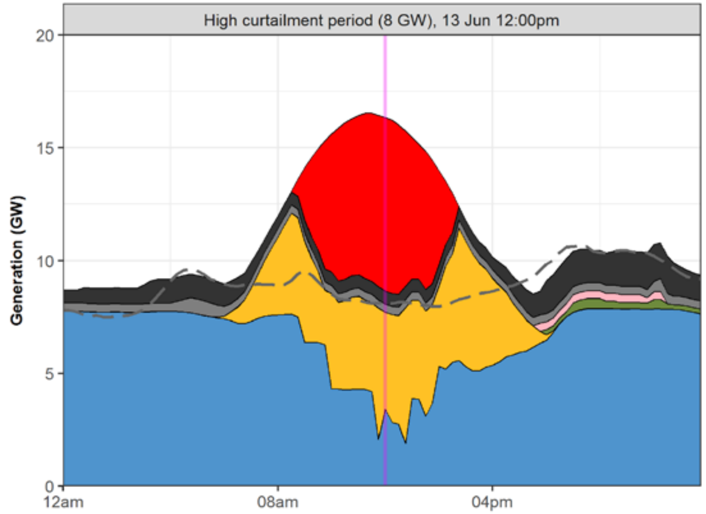


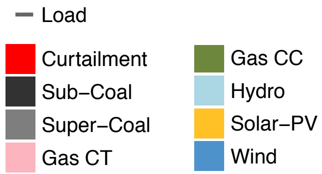
Example Dispatch Days

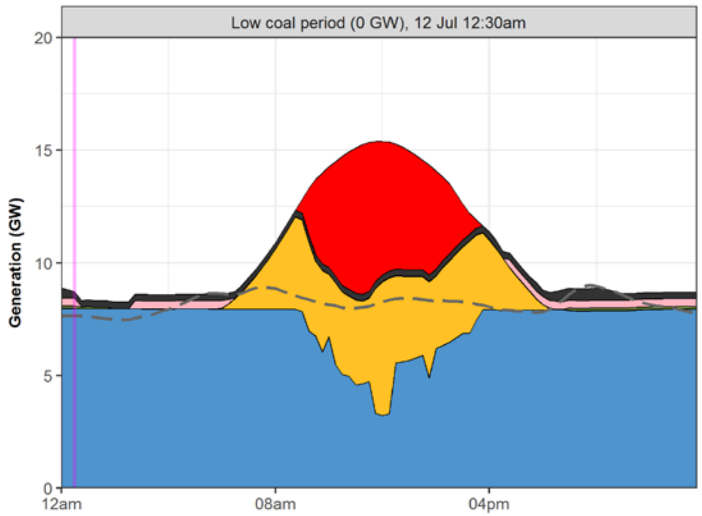
High curtailment period: Generation, load, and interchange (values in GW unless otherwise specified)

13 June 12:00 pm

LOAD	CURTAILMENT	HYDRO	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
8.1	7.7	0	0.9	0	7.7	0.5	95







Low coal period: Generation, load, and interchange (values in GW unless otherwise specified)

12 July 12:30 am

LOAD	CURTAILMENT	HYDRO	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
7.6	0	0	0.3	0.5	7.9	1.1	104

Conclusions

Based on this study's assumptions about demand and installed generation and transmission capacity in Andhra Pradesh and nationwide, Andhra Pradesh can integrate the equivalent of 51% of its total generation in 2022, with 5.6% annual wind and solar curtailment. The RE changes the way Andhra Pradesh's grid must operate. Compared to a 2022 system with no new RE, net exports rise by 75% annually and the PLF of the coal fleet falls from 63% to 32%.

Andhra Pradesh has the highest RE penetration of any state and relatively high RE curtailment. As a result of large amounts of low-cost RE, energy exports to interconnected states increase dramatically in the 100S-60W scenario.

What can the state do to prepare for higher RE futures?

Establish process for optimizing locations and capacities for RE and transmission; inadequate transmission has a large effect on RE curtailment in the model. This requires good information on possible areas for RE locations.

Match or exceed CERC guidelines for coal flexibility. Reducing minimum operating levels for coal plants has the largest impact to RE curtailment among all integration strategies evaluated.

Consider mechanisms to better coordinate scheduling and dispatch with neighbors, which can reduce production costs and allow each state to better access least-cost generation, smooth variability and uncertainty, and better access sources of system flexibility.

Create a new tariff structure for coal that specifies performance criteria (e.g., ramping), and that addresses the value of coal as PLFs decline.

Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks.

Use PPAs to require RE generators to provide grid services such as automatic generation control and operational data.

Create policy and regulatory incentives to access the full capabilities of existing coal, hydro, and pumped storage.

Require merit order dispatch based on system-wide production costs; supplementary software may be required.

Improve the production cost model built for this study to address state-specific questions.

Institute organization and staff time to maintain the model over time.

Update power flow files to include more information related to high RE futures; conduct dynamic stability studies.

Adopt state-of-the-art load and RE forecasting systems.

Address integration issues at the distribution grid, including rooftop PV and utility-scale wind and solar that is connected to low voltage lines.

For a broader set of policy actions, see the executive summary for the National Study at www.nrel.gov/docs/fy17osti/68720.pdf.

Ways to use the model for state planning

You can use this model for operational and planning questions such as:

What is the effect on operations of different reserve levels?

How will changes to operations or new infrastructure affect coal cycling?

What is the impact on dispatch of changes to market designs or PPA requirements?

How will different RE growth scenarios affect fuel requirements and emissions targets?

How does a new transmission line affect scheduling and costs?

What are plant-specific impacts (PLFs, curtailment) based on different scenarios?

What are critical periods for follow-up with a power flow analysis, and what is the generation status of each plant during these periods?

What flexibility is required of the system under different future scenarios?

What technologies or systematic changes could benefit the system most?

The production cost model built for this study is ready for you to use!

Next Steps to Improve the Model for State Planning

The production cost model used in this study has been built to assess region- and nationwide trends, and lacks some of the plant-specific detail that will be more important if the model is used for planning at the state level. Further improvements are suggested for use at the state level:

Input load specific to each substation level

Current model allocates a statewide load to each substation proportionate to peak

Modify load shapes to reflect expected changes to appliance ownership and other usage patterns

Current model uses 2014 load shape, scaled up to 2022 peak demand

Revise RE locations and transmission plans as investments evolve

Current model uses best RE locations within the state based on suitable land availability; transmission plans are based on CEA's 2021–2022 PSS/E model and do not reflect anticipated changes to in-state transmission to meet new RE

Improve generator-specific parameters (e.g., variable costs, minimum up/down time, hub heights, must run status)

Current model uses generator-specific information when available, but also relies on averages (e.g., all utility PV employs fixed tracking)

Create plant-specific allocations of central generations

Current model allocates all central plant generating capacity to the host state

Allocate balancing responsibility for new RE plants to host state versus offtaker state or central entity

Current model allocates responsibility for balancing to host state

Create an equivalent but computationally simpler representation of transmission in states or regions where operations do not affect focus area

Current model includes level of detail for the country that may be unnecessary for a specific state, creating computational challenges

Appendix

Supplemental information on study assumptions

Total generation capacity in Andhra Pradesh (GW) in the 100S-60W scenario		
	OWNERSHIP	**TOTAL CAPACITY (GW)**
Gas CC	State/Private	3.7
Gas CT	State/Private	0.3
Hydro	State/Private	2.6
Sub-Coal	State/Private	6.1
Sub-Coal	Central	2.0
Super-Coal	State/Private	4.8
Total non-RE		19.5
Solar-PV	State/Private	11.0
Wind	State/Private	8.1
Total RE		19.1
Total capacity		**38.6**

Total capacity (surge impedance limit [SIL]) of transmission lines connecting Andhra Pradesh to other states
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Andhra Pradesh to Karnataka	220	2
Andhra Pradesh to Karnataka	400	16
Andhra Pradesh to Karnataka	765	2
Andhra Pradesh to Odisha	400	4
Andhra Pradesh to Odisha	765	2
Andhra Pradesh to Tamil Nadu	230	2
Andhra Pradesh to Tamil Nadu	400	9
Andhra Pradesh to Tamil Nadu	765	6
Andhra Pradesh to Telangana	132	5
Andhra Pradesh to Telangana	220	11
Andhra Pradesh to Telangana	765	8
Andhra Pradesh to Telangana*	400	17
Total import/export capacity		**84**

Total capacity (SIL) of transmission lines within Andhra Pradesh
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

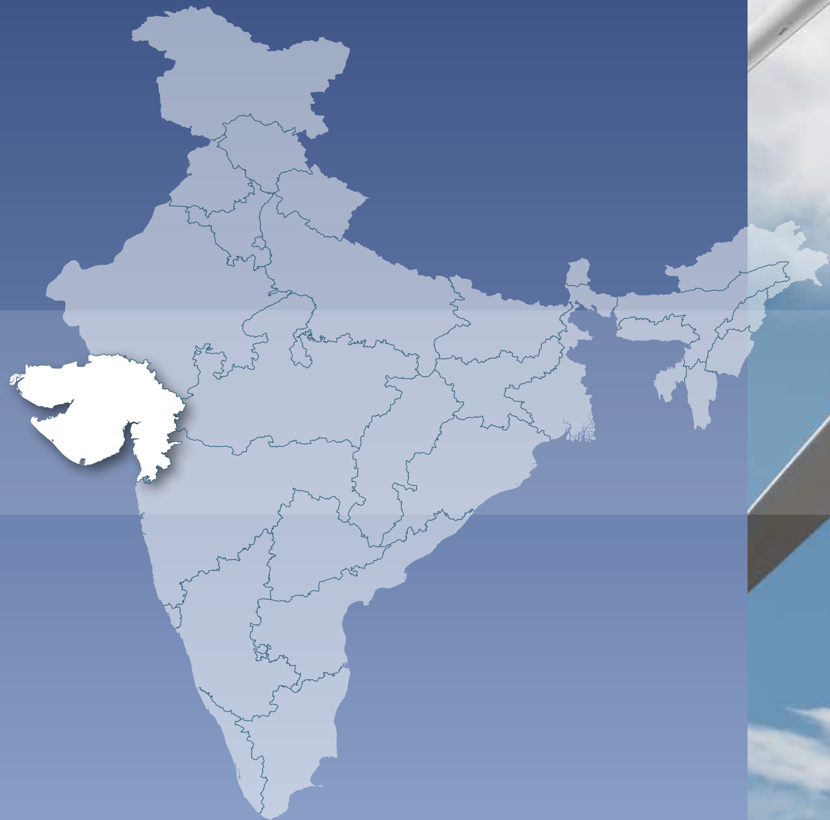
CONNECTING	VOLTAGE (kV)	NO. LINES
Intrastate	220	139
Intrastate	400	117
Intrastate	765	16
Total intrastate capacity		**271**

RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
512019_NELL_220	0	27
512109_RAMAGIRI_220	2,967	2,550
512132_KONDPRM-W_220	285	1,441
512133_URVKND_220	1,612	100
512136_MOGULV2_220	0	34
512137_BRMPLI_220	0	12
514006_GAZW_400	891	0
514007_CUDP_400	2,464	2,307
514008_GOOT_400	615	281
514013_KURNOOL4_400	975	0
514024_CHITOR_400	212	1,359
514028_KURL-NEW_400	32	0
514096_GMR-OA_400	376	0
514098_HINDJ-OA_400	519	0
Total RE capacity	**10,948**	**8,111**

Annual energy generation fuel type, No New RE and 100S–60W		
	NO NEW RE (TWh)	100S–60W (TWh)
Gas CC	2	5
Gas CT	1	1
Hydro	4	4
Solar-PV: rooftop	4	0
Solar-PV: utility scale	15	1
Sub-Coal	18	41
Super-Coal	18	30
Wind	26	3
Total Generation	88	84
Imports	27	29
Exports	36	34
RE Curtailment	3	0

Greening the Grid



Gujarat

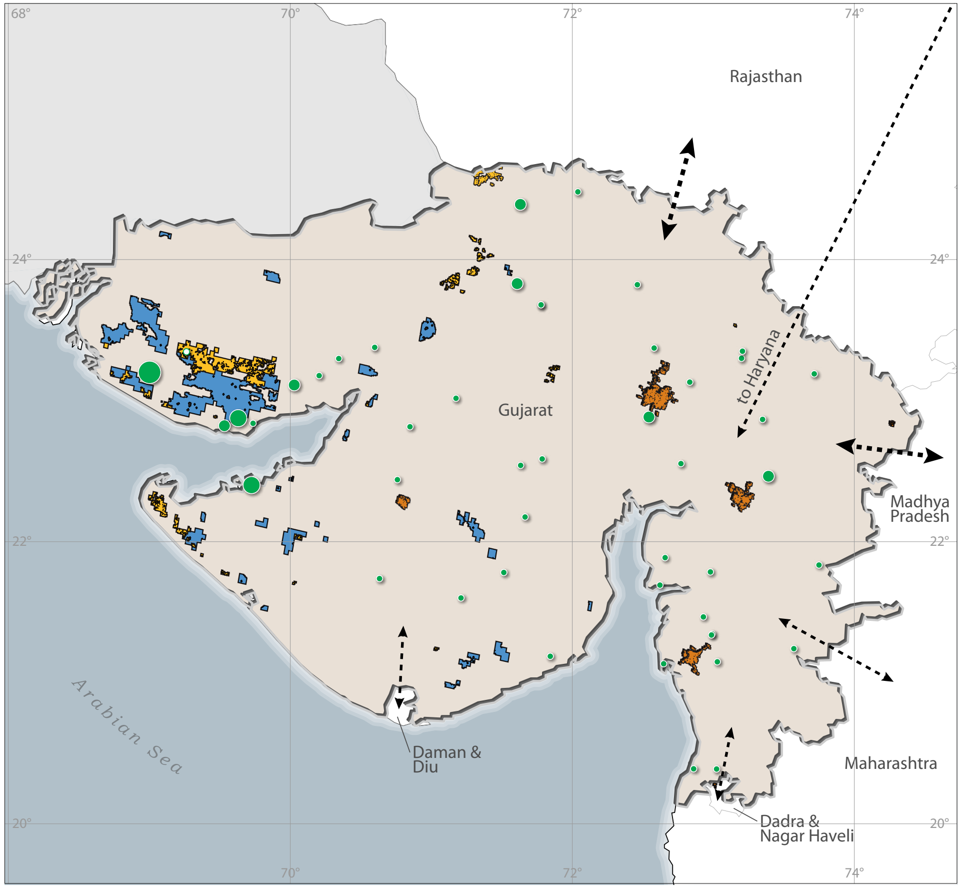
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

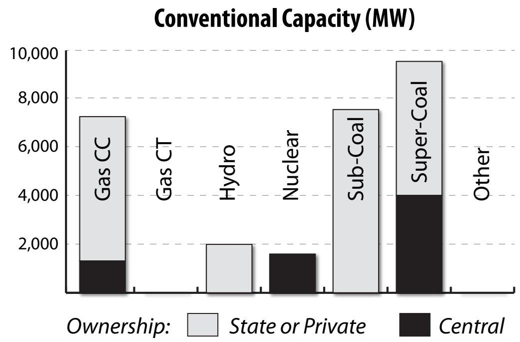
State-specific results from Volume II, which includes all of India. The full reports include detailed explanations of modeling assumptions, results, and policy conclusions.

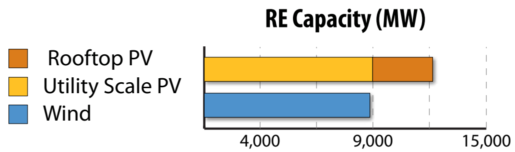
www.nrel.gov/india-grid-integration/

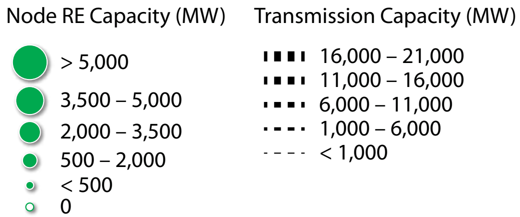
Assumptions About Infrastructure, Demand, and Resource Availability in 2022

Assumptions about RE and conventional generation and transmission in Gujarat in 2022









Peak load (GW)	23
Annual load (TWh)	287
Installed non-RE capacity (GW)	27
Installed RE capacity (GW)	21
Total import/export capacity (GW)	25

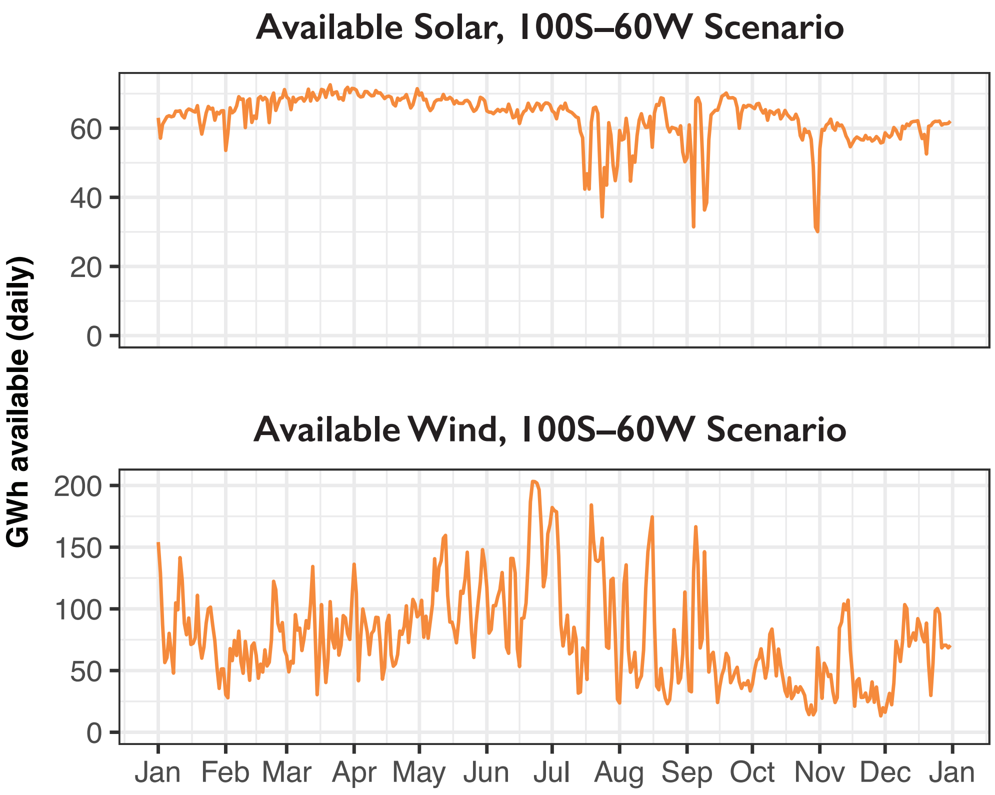
Gujarat has 28 tie-lines connecting it to other states in this model.

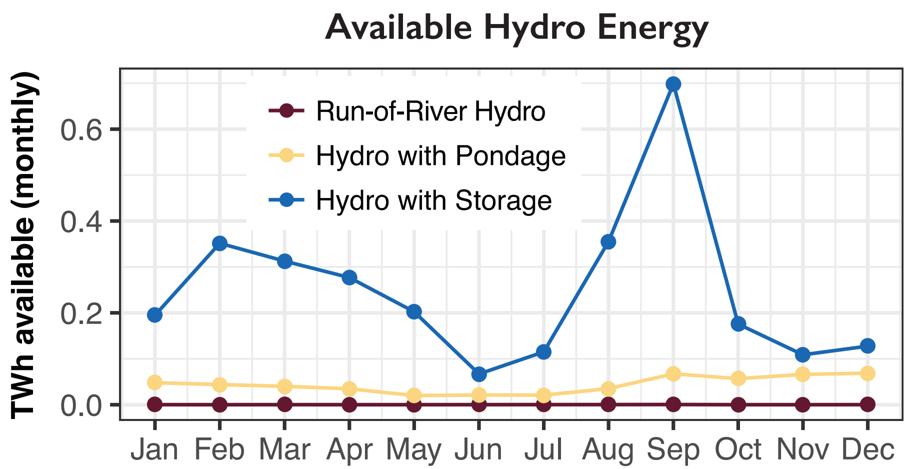
NREL and LBNL selected RE sites based on the methodology explained in Volume I of this report, which is available at www.nrel.gov/docs/fy17osti/68530.pdf.

Rooftop PV has been clubbed to the nearest transmission node.

Gujarat Resource Availability in 2022

Available wind, solar, and hydro energy throughout the year in Gujarat





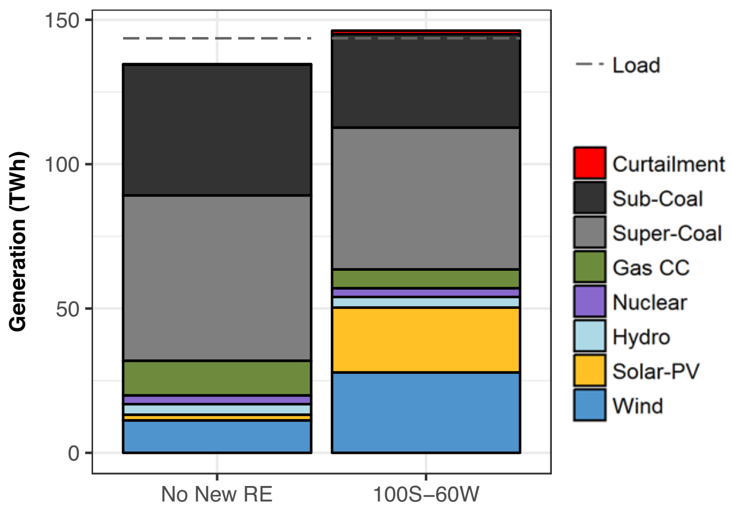
Daily solar energy is relatively consistent throughout the year while wind energy varies seasonally.

Note: Y-axis is different for each resource

Operation in Gujarat with Higher Levels of RE: RE Penetration in 2022

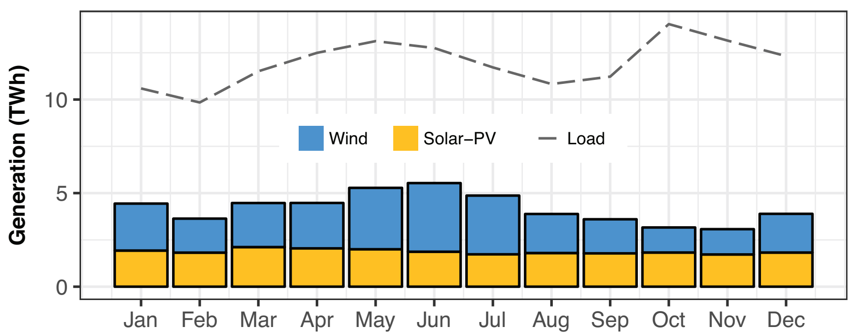
Increased amounts of RE available in Gujarat change Gujarat's generation mix and therefore the operation of the entire fleet.

Annual energy generation in Gujarat



21 GW of wind and solar power generates 50 TWh annually.

Monthly RE generation and load in Gujarat in the 100S-60W scenario



Wind and solar produce 35% of total generation in Gujarat and meet 35% of load.

RE penetration by load and generation

	100S-60W
Percent time RE is over 50% of load	23
Peak RE as a % of load	110
Percent time RE is over 50% of generation	19
Peak RE as a % of generation	81

Coal generation falls by 21% and gas by 46% between No New RE and 100S-60W.

Operation in Gujarat with Higher Levels of RE: Imports and Exports

Increased RE generation inside and outside of Gujarat affects flows with surrounding states.

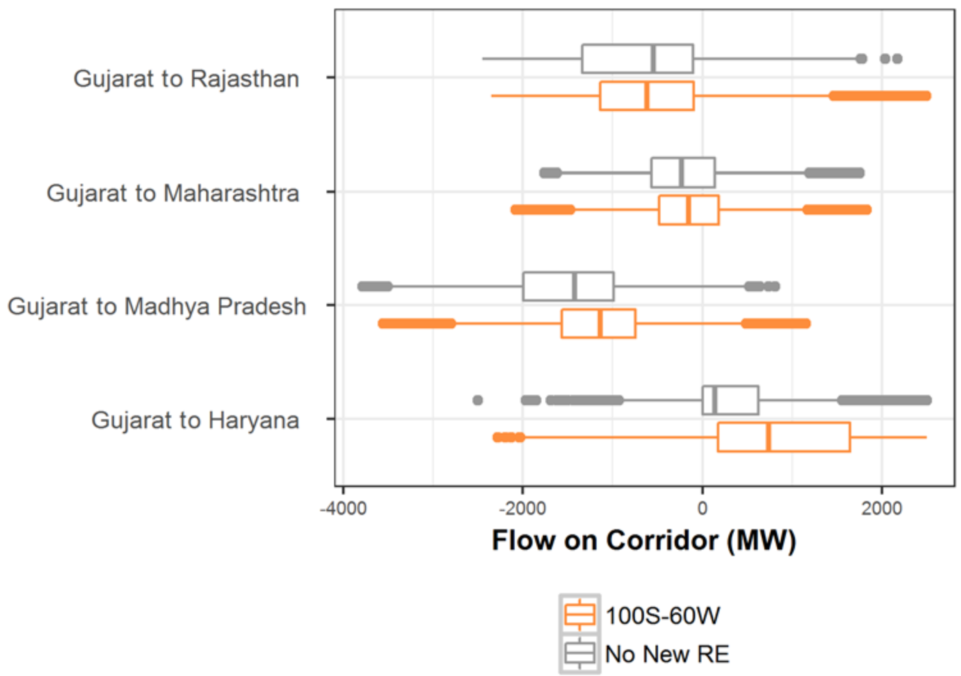
Gujarat transitions from a net importer in the No New RE scenario to net exporter in 100S-60W. This is largely driven by increased exports to Haryana, which is also associated with frequent congestion along that corridor.

Imports fall by **11%** annually

Exports rise by **44%** annually

SCENARIO	NET EXPORTS (TWh)	
No New RE	-9.1	net importer
100S-60W	1.5	net exporter

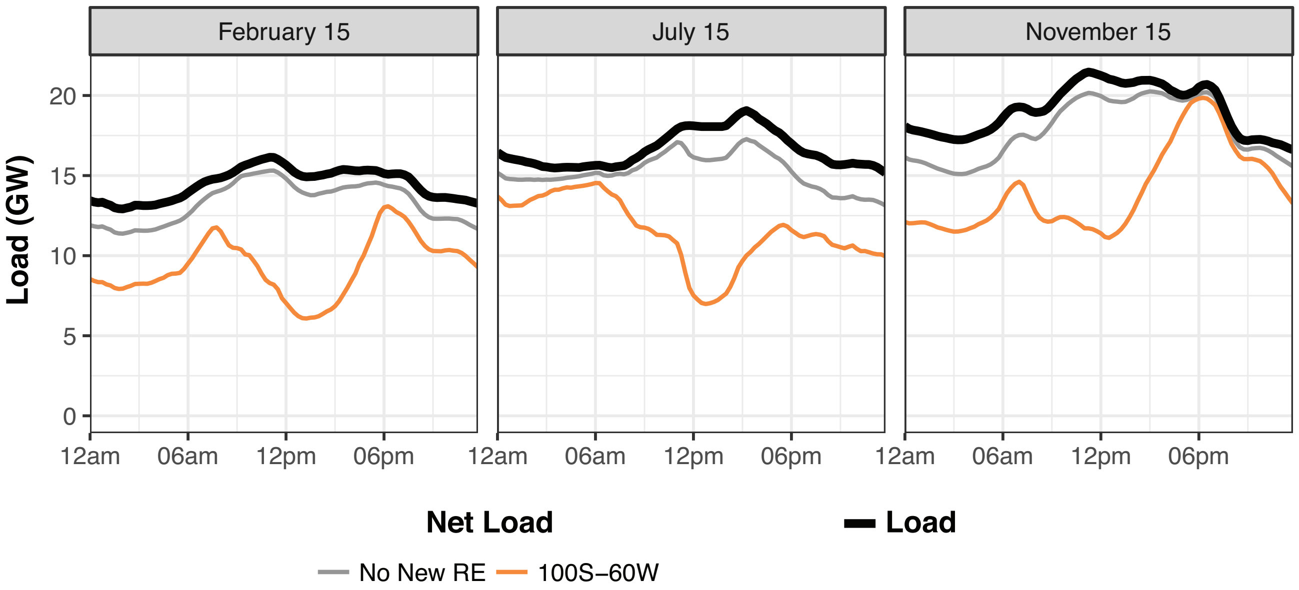
Distribution of flows across state-to-state corridors



Operation in Gujarat with Higher Levels of RE: Rest of the Fleet

The addition of RE in Gujarat changes net load, which is the load that is not met by RE and therefore must be met by conventional generation. Due to changes in net load, hydro and thermal plants operate differently in higher RE scenarios.

Example days of load and net load in Gujarat

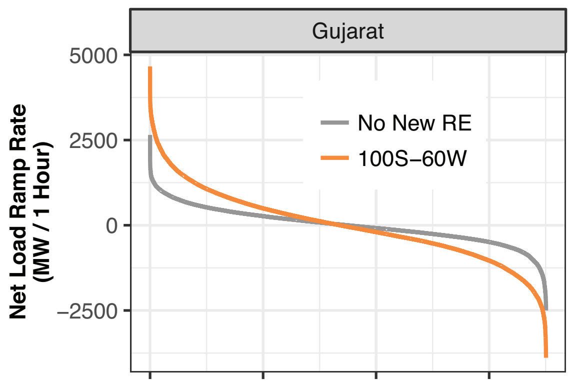


Increased daytime solar generation causes a dip in net load, which requires Gujarat to either increase net exports, turn down its thermal generators, or curtail RE.

Peak 1-hour net load up-ramp in the **100S-60W scenario is 4.7 GW**, up from **2.7 GW in the No New RE scenario.**

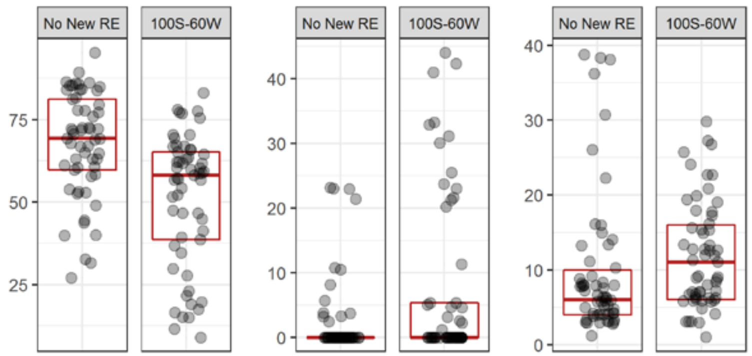
Maximum net load valley-to-peak ramp is **12 GW in the 100S-60W scenario**, up from **6.9 GW in the No New RE scenario.**

Hourly net load ramps for all periods of the year, ordered by magnitude



Changes to Gujarat's Coal Fleet Operations

Operational impacts to coal



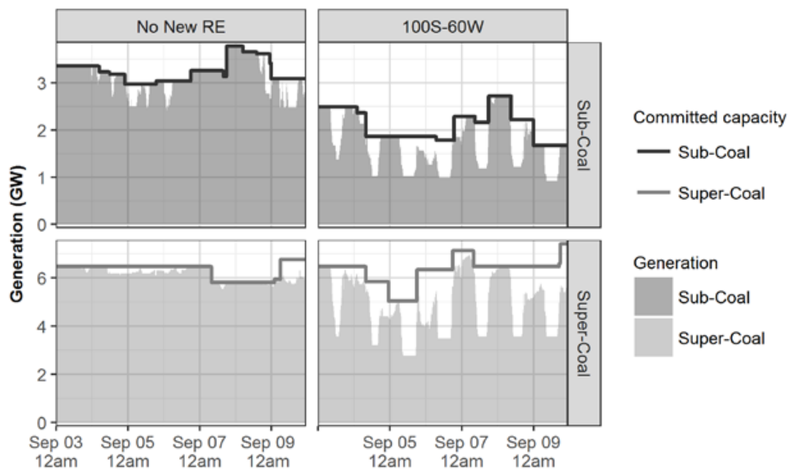
Coal plant load factors (PLFs) are lower in the 100S-60W scenario due to more frequent cycling and operation at minimum generation levels.

While coal PLFs are lower fleetwide in 100S-60W, the most expensive generators experience the greatest drop in PLF.

Average PLF of coal generators in Gujarat, disaggregated by variable cost

RELATIVE VARIABLE COST	NO NEW RE	100S-60W
Lowest 1/3	67	58
Mid 1/3	76	65
Highest 1/3	59	29
Fleetwide	69	55

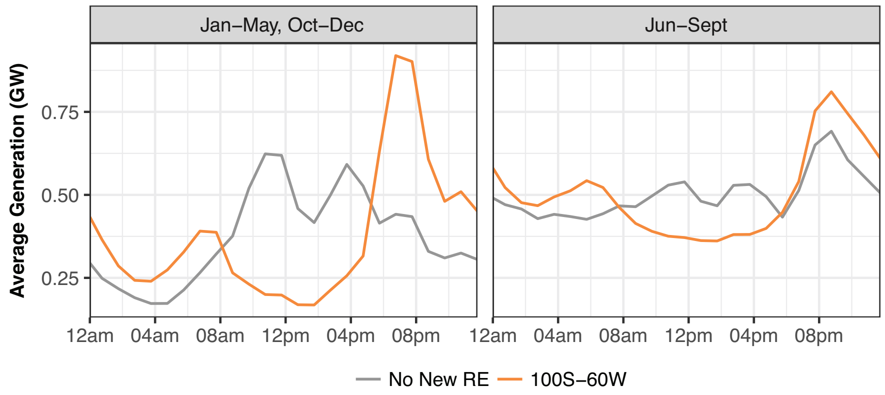
One week of coal operation in Gujarat



The coal fleet is turned off more and its output varies daily due to midday availability of solar power in the 100S-60W scenario.

Changes to Gujarat’s Hydro Fleet Operations

Average day of hydro in Gujarat by season



Minimum generating limits during the monsoon season hinder the ability of hydro to shift generation to net load peaks as it does more fully in the months outside of the monsoon.

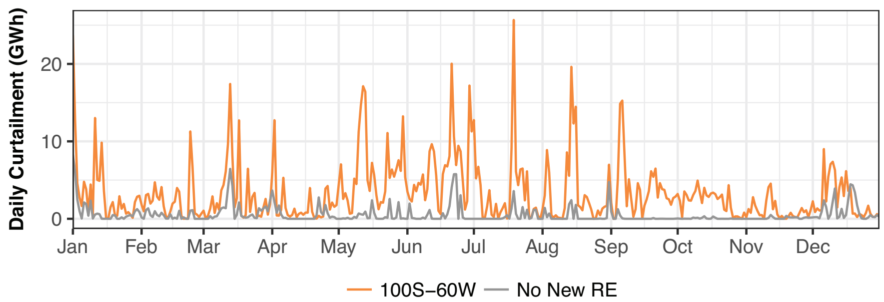
Hydro plants follow a more pronounced two-peak generation profile due to availability of solar power during the middle of the day.

How Well Is RE Integrated? Curtailment and Operational Snapshots

Curtailment levels indicate how efficiently RE is integrated. Large amounts of curtailment signal inflexibility in the system, preventing grid operators from being able to take full advantage of the available renewable resources.

2.4% of wind and solar is curtailed annually.

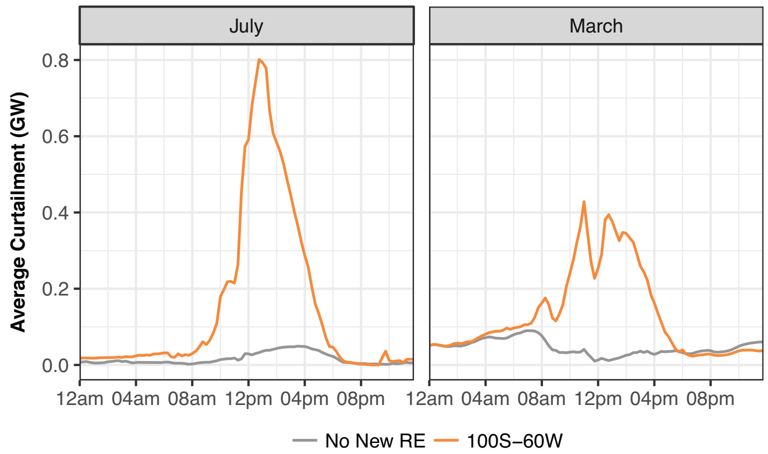
Total daily curtailment throughout the year in Gujarat



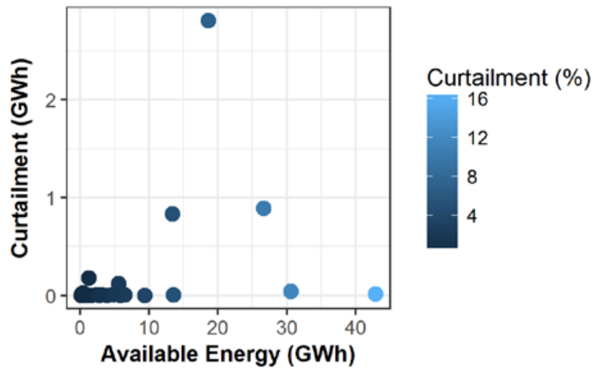
Gujarat's RE curtailment in 100S-60W primarily occurs in only three substations. RE curtailment also occurs in the No New RE scenario when the Western region has flexible thermal capacity available, implying that a portion of Gujarat's RE curtailment is caused by transmission congestion.

Almost all of RE curtailment occurs in 19% of periods in the year.

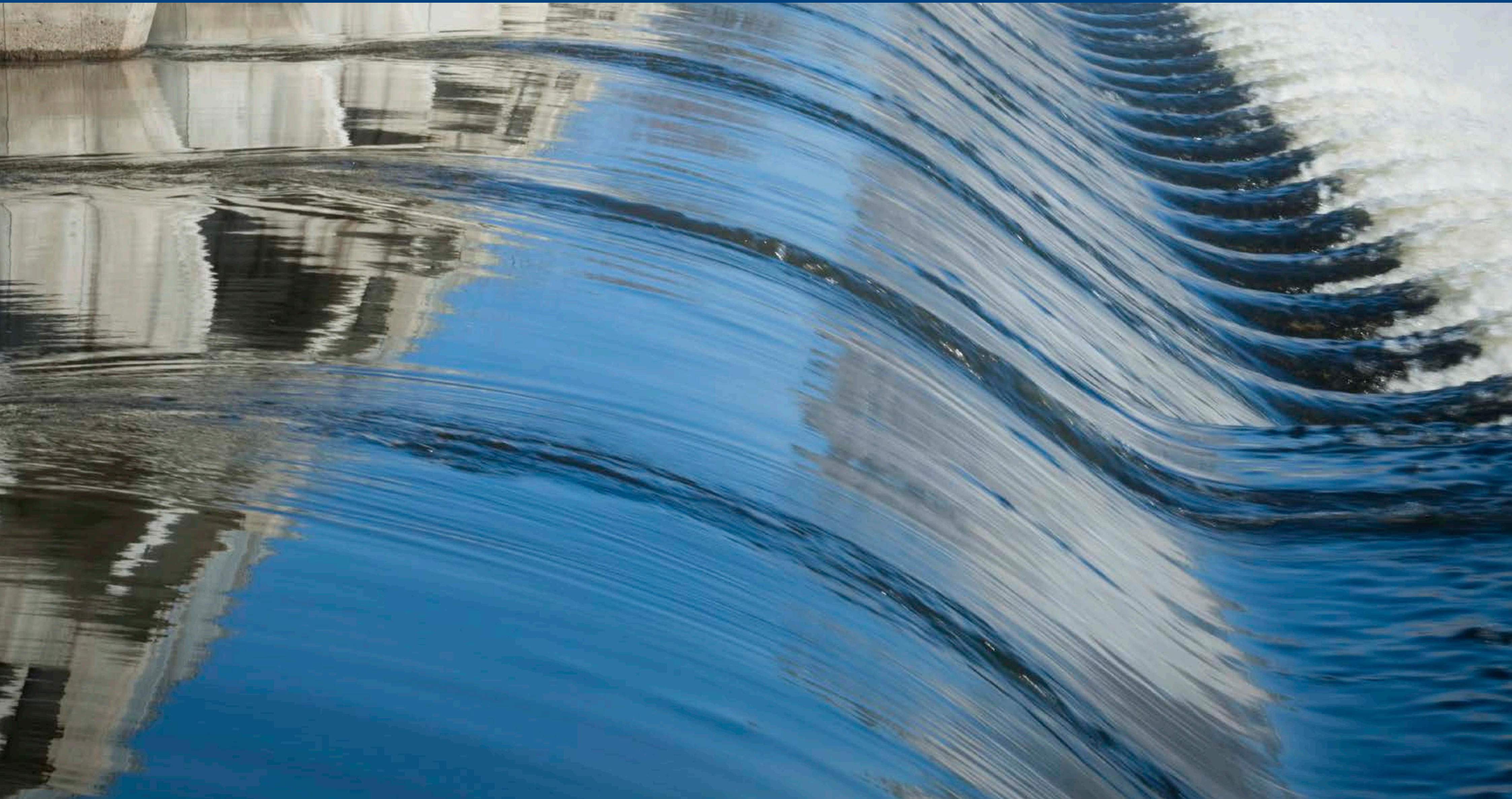
Average daily curtailment in March and July in Gujarat



RE curtailment as a percent of available energy by substation (each dot represents a substation)



Examples of Dispatch During Interesting Periods in Gujarat

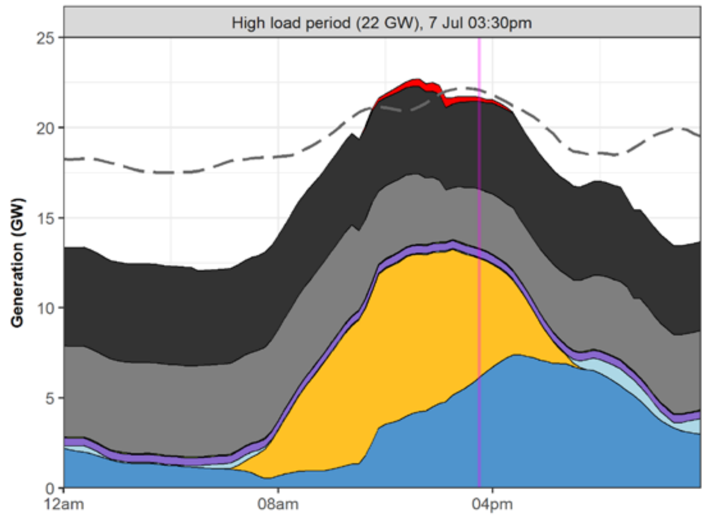


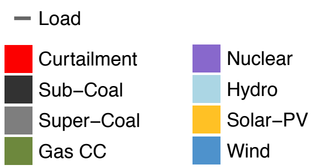
The following pages show dispatch in Gujarat during several interesting periods throughout 2022. The vertical magenta line highlights the dispatch interval associated with the figure title.

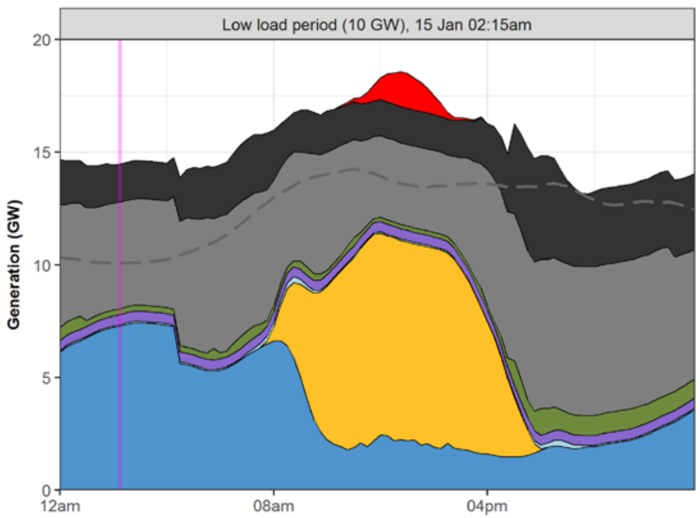
High load period: Generation, load, and interchange (values in GW unless otherwise specified)

7 July 3:30 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
22.1	0.2	0.1	0.4	8.1	0.1	12.7	0.6	58







Low load period: Generation, load, and interchange (values in GW unless otherwise specified)

15 January 2:15 am

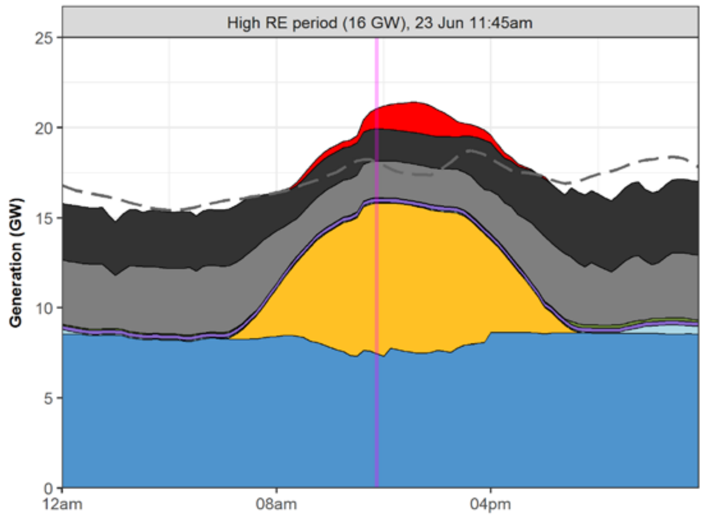
LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
10.1	0	0.1	0.4	6.4	0.3	7.3	4.4	72

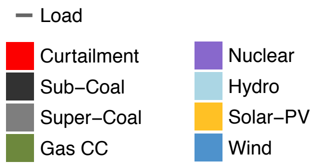
Example Dispatch Days

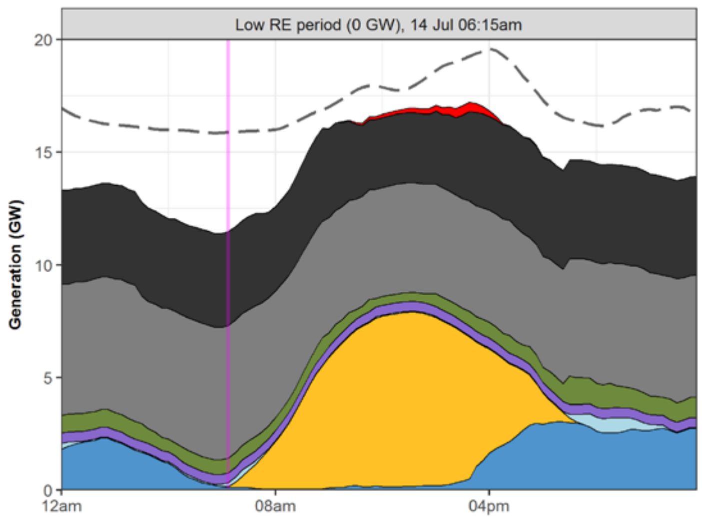
High RE period: Generation, load, and interchange (values in GW unless otherwise specified)

23 June 11:45 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
18.1	1.1	0.1	0.2	3.8	0	15.8	1.9	87



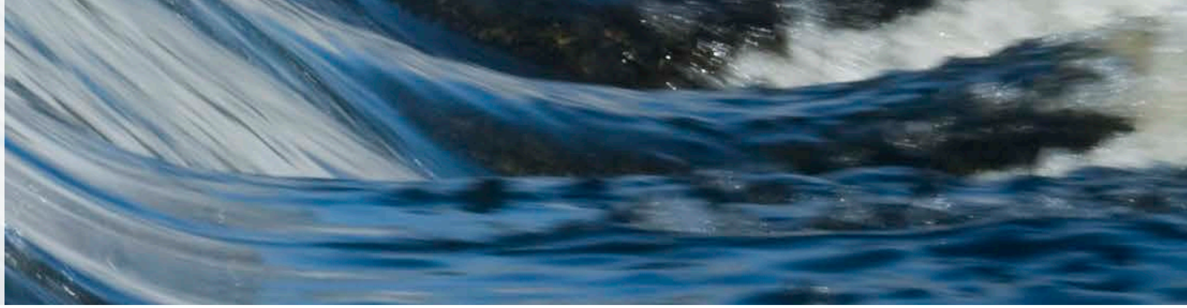




Low RE period: Generation, load, and interchange (values in GW unless otherwise specified)

14 July 6:15 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
15.9	0	0.2	0.4	10.1	0.6	0.2	4.4	1

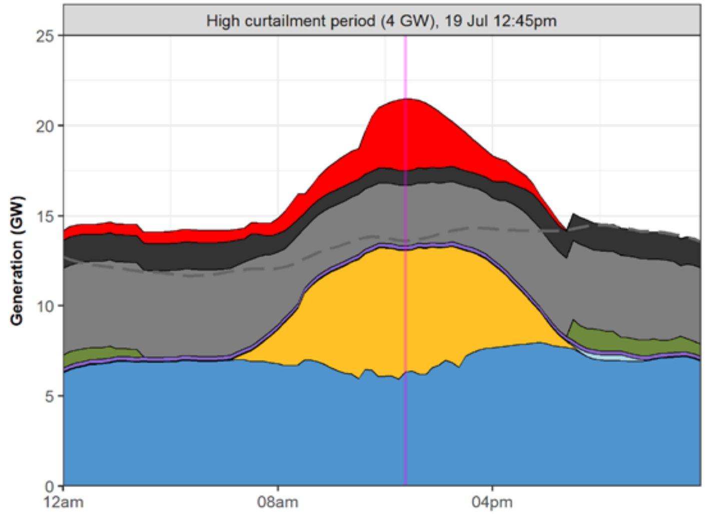


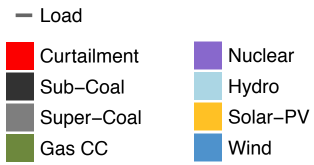
Example Dispatch Days

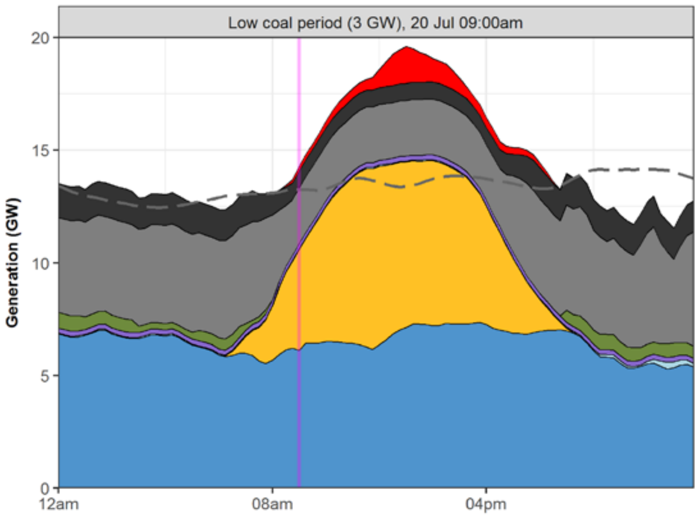
High curtailment period: Generation, load, and interchange (values in GW unless otherwise specified)

19 July 12:45 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
13.6	4	0	0.2	4.2	0	13.1	3.9	96







Low coal period: Generation, load, and interchange (values in GW unless otherwise specified)

20 July 9:00 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
13.3	0.2	0	0.2	3.2	0	10.6	0.8	80

Conclusions

Based on this study's assumptions about demand and installed generation and transmission capacity in Gujarat and nationwide, Gujarat can integrate the equivalent of 35% of its total generation in 2022 with 2.4% annual wind and solar curtailment. The RE changes the way Gujarat's grid must operate. Compared to a 2022 system with no new RE, net exports rise by 117% annually, and the PLF of the coal fleet falls from 69% to 55%.

Coordinated planning between intrastate transmission and locations of new RE can alleviate the risk of RE curtailment. As the highest RE state in the Western region, sufficient transmission will be necessary to not only evacuate RE, but also enable the full use of flexible resources such as coal or hydro.

What can the state do to prepare for higher RE futures?

Establish process for optimizing locations and capacities for RE and transmission; inadequate transmission has a large effect on RE curtailment in the model. This requires good information on possible areas for RE locations.

Match or exceed CERC guidelines for coal flexibility. Reducing minimum operating levels for coal plants has the largest impact to RE curtailment among all integration strategies evaluated.

Consider mechanisms to better coordinate scheduling and dispatch with neighbors, which can reduce production costs and allow each state to better access least-cost generation, smooth variability and uncertainty, and better access sources of system flexibility.

Create a new tariff structure for coal that specifies performance criteria (e.g., ramping), and that addresses the value of coal as PLFs decline.

Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks.

Use PPAs to require RE generators to provide grid services such as automatic generation control and operational data.

Create policy and regulatory incentives to access the full capabilities of existing coal, hydro, and pumped storage.

Require merit order dispatch based on system-wide production costs; supplementary software may be required.

Improve the production cost model built for this study to address state-specific questions.

Institute organization and staff time to maintain the model over time.

Update power flow files to include more information related to high RE futures; conduct dynamic stability studies.

Adopt state-of-the-art load and RE forecasting systems.

Address integration issues at the distribution grid, including rooftop PV and utility-scale wind and solar that is connected to low voltage lines.

For a broader set of policy actions, see the executive summary for the National Study at www.nrel.gov/docs/fy17osti/68720.pdf.

Ways to use the model for state planning

You can use this model for operational and planning questions such as:

What is the effect on operations of different reserve levels?

How will changes to operations or new infrastructure affect coal cycling?

What is the impact on dispatch of changes to market designs or PPA requirements?

How will different RE growth scenarios affect fuel requirements and emissions targets?

How does a new transmission line affect scheduling and costs?

What are plant-specific impacts (PLFs, curtailment) based on different scenarios?

What are critical periods for follow-up with a power flow analysis, and what is the generation status of each plant during these periods?

What flexibility is required of the system under different future scenarios?

What technologies or systematic changes could benefit the system most?

The production cost model built for this study is ready for you to use!

Next Steps to Improve the Model for State Planning

The production cost model used in this study has been built to assess region- and nationwide trends, and lacks some of the plant-specific detail that will be more important if the model is used for planning at the state level. Further improvements are suggested for use at the state level:

Input load specific to each substation level

Current model allocates a statewide load to each substation proportionate to peak

Modify load shapes to reflect expected changes to appliance ownership and other usage patterns

Current model uses 2014 load shape, scaled up to 2022 peak demand

Revise RE locations and transmission plans as investments evolve

Current model uses best RE locations within the state based on suitable land availability; transmission plans are based on CEA's 2021–2022 PSS/E model and do not reflect anticipated changes to in-state transmission to meet new RE

Improve generator-specific parameters (e.g., variable costs, minimum up/down time, hub heights, must run status)

Current model uses generator-specific information when available, but also relies on averages (e.g., all utility PV employs fixed tracking)

Create plant-specific allocations of central generations

Current model allocates all central plant generating capacity to the host state

Allocate balancing responsibility for new RE plants to host state versus offtaker state or central entity

Current model allocates responsibility for balancing to host state

Create an equivalent but computationally simpler representation of transmission in states or regions where operations do not affect focus area

Current model includes level of detail for the country that may be unnecessary for a specific state, creating computational challenges

Appendix

Supplemental information on study assumptions

Total generation capacity in Gujarat in the 100S-60W scenario		
	OWNERSHIP	**TOTAL CAPACITY (GW)**
Gas CC	Central	1.3
Gas CC	State/Private	5.9
Hydro	State/Private	2.0
Nuclear	Central	0.4
Sub-Coal	State/Private	7.5
Super-Coal	State/Private	5.5
Super-Coal	Central	4.0
Total non-RE		26.6
Solar-PV	State/Private	12.0
Wind	State/Private	8.8
Total RE		20.8
Total capacity		**47.4**

Total capacity (surge impedance limit [SIL]) of transmission lines connecting Gujarat to other states
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Gujarat to Dadra & Nagar Haveli	66	5
Gujarat to Dadra & Nagar Haveli	220	5
Gujarat to Dadra & Nagar Haveli	400	2
Gujarat to Daman & Diu	66	3
Gujarat to Daman & Diu	220	2
Gujarat to Daman & Diu	400	2
Gujarat to Haryana	400	2
Gujarat to Madhya Pradesh	400	8
Gujarat to Madhya Pradesh	765	2
Gujarat to Maharashtra	220	4
Gujarat to Maharashtra	400	5
Gujarat to Maharashtra	765	1
Gujarat to Rajasthan	765	2
Gujarat to Rajasthan*	400	4
Total import/export capacity		**47**

Total capacity (SIL) of transmission lines within Gujarat
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Intrastate	132	130
Intrastate	220	326
Intrastate	765	2
Intrastate*	400	122
Total intrastate capacity		**580**

RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
352016_ANJAR2_220	926	468
352028_RAJKOT2_220	267	36
352054_DHANS2_220	15	0
352062_THARAD_220	811	0
352069_NAKH2_220	3,170	1,397
352086_MORBI_220	26	17
352104_RADHANPR_220	804	50
352109_SHIVLAKH_220	0	424
352113_DHASA_220	0	310
352114_BOTAD_220	0	35
352117_OTHA_220	0	213
352124_SUTHARI_220	29	0
352135_BHUJPOOL_220	1,123	1,353
352201_BHACHUNDA_220	493	2,073
354001_ASOJ4_400	790	0

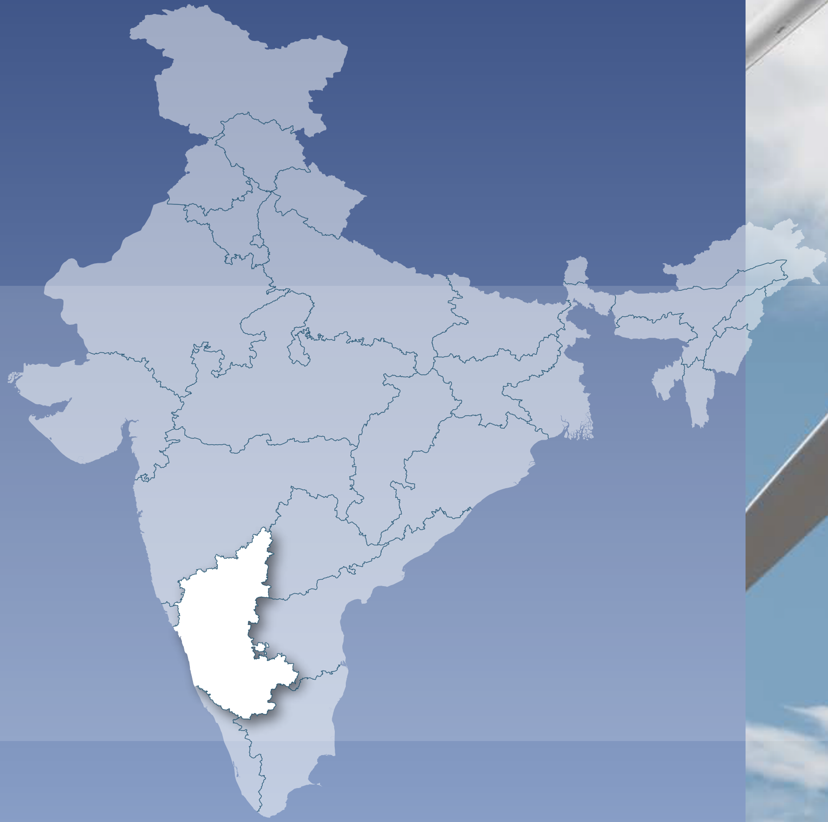
RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
354003_DEHGM4_400	101	0
354005_SOJA4_400	141	0
354008_JET4_400	16	20
354012_SUGEN4_400	209	0
354014_PIRANA_P_400	1,266	0
354015_MUNDRA4_400	153	329
354016_SAMI4_400	172	0
354020_AMRELI4_400	28	211
354022_HAZIRA4_400	214	0
354023_CGPL_400	435	777
354024_BACHAU_400	0	15
354025_VERSANA_400	0	38
354026_VADINAR_400	779	1,021
354034_NAVSARI_400	179	0
354036_HALVADNEW_400	0	21
Total RE capacity	**12,147**	**8,808**

Annual energy generation fuel type, No New RE and 100S-60W		
	NO NEW RE (TWh)	**100S-60W (TWh)**
Gas CC	12	7
Hydro	4	4
Nuclear	3	3
Solar-PV: rooftop	0	6
Solar-PV: utility scale	2	17
Sub-Coal	45	32
Super-Coal	57	49
Wind	11	28
Total Generation	134	145
Imports	27	24
Exports	18	26
RE Curtailment	0	1

Greening the Grid

Karnataka



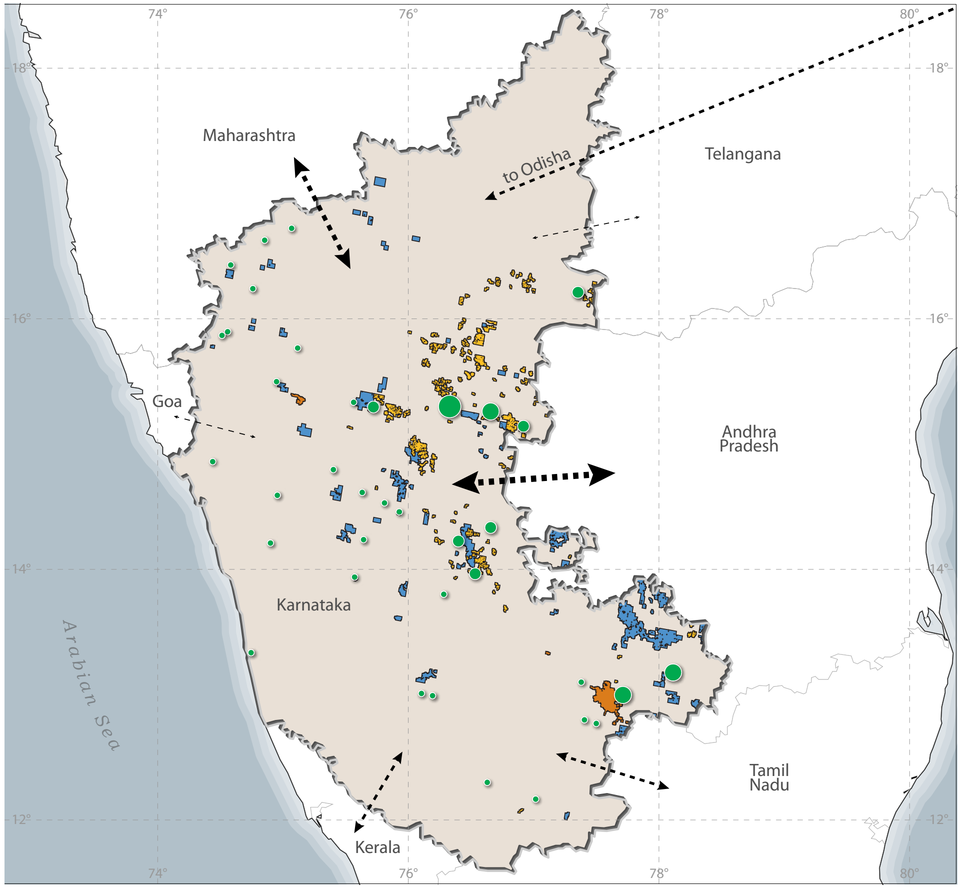
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

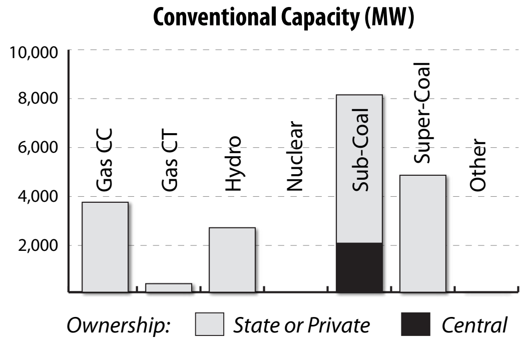
State-specific results from Volume II, which includes all of India. The full reports include detailed explanations of modeling assumptions, results, and policy conclusions.

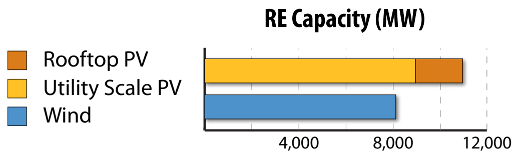
www.nrel.gov/india-grid-integration/

Assumptions About Infrastructure, Demand, and Resource Availability in 2022

Assumptions about RE and conventional generation and transmission in Karnataka in 2022







Peak load (GW)	14
Total annual load (TWh)	150
Installed non-RE capacity (GW)	14
Installed RE capacity (GW)	17
Total import/export capacity (GW)	27

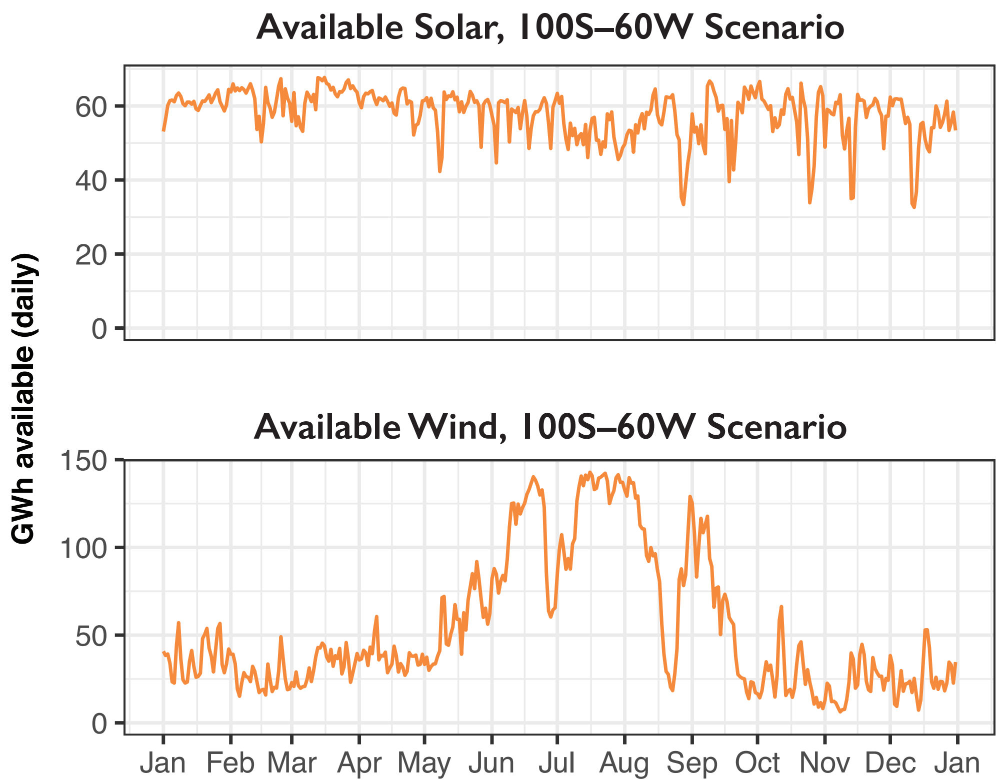
Karnataka has 35 tie-lines connecting it to other states in this model.

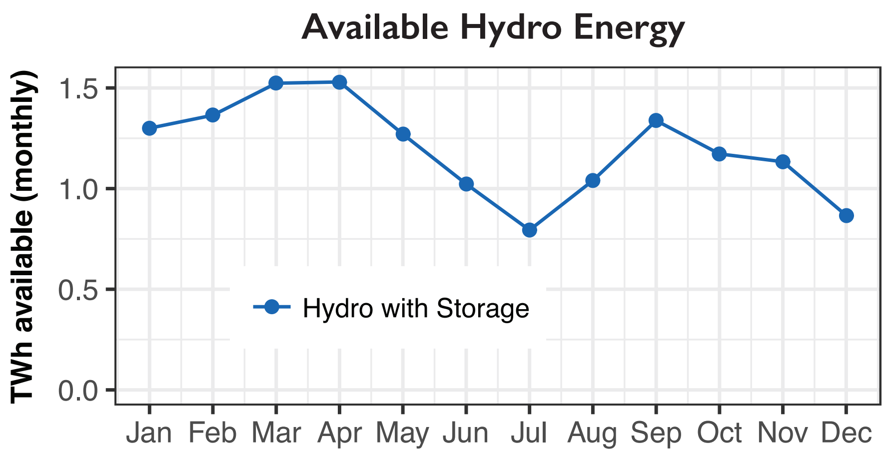
NREL and LBNL selected RE sites based on the methodology explained in Volume 1 of this report, which is available at www.nrel.gov/docs/fy17osti/68530.pdf.

Rooftop PV has been clubbed to the nearest transmission node.

Karnataka Resource Availability in 2022

Available wind, solar, and hydro energy throughout the year in Karnataka





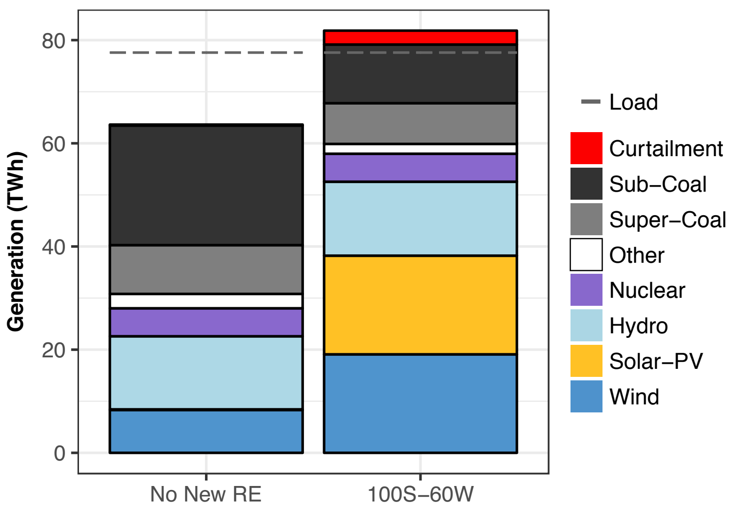
Daily solar energy is relatively consistent throughout the year, while wind energy varies seasonally.

Note: Y-axis is different for each resource

Operation in Karnataka with Higher Levels of RE: RE Penetration in 2022

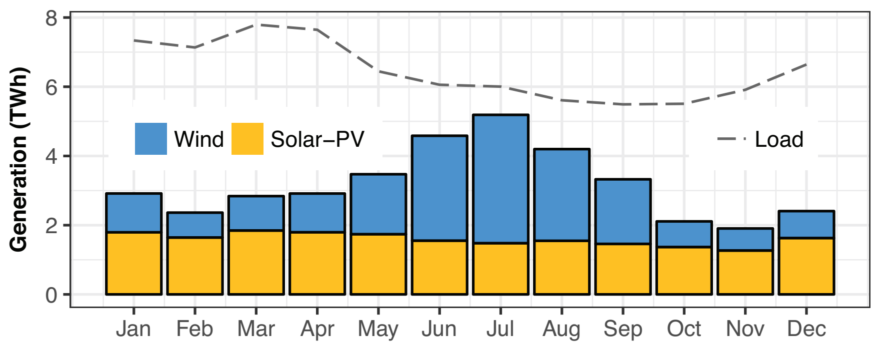
Increased amounts of RE available in Karnataka change Karnataka's generation mix and therefore the operation of the entire fleet.

Annual energy generation in Karnataka



17 GW of wind and solar power generates 38 TWh annually.

Monthly RE generation and load in Karnataka in the 100S-60W scenario



Wind and solar produce 48% of total generation in Karnataka and meet 49% of load.

RE penetration by load and generation

	100S-60W
Percent time RE is over 50% of load	47
Peak RE as a % of load	160
Percent time RE is over 50% of generation	45
Peak RE as a % of generation	93

Coal generation falls by 41% between No New RE and 100S-60W.

Operation in Karnataka with Higher Levels of RE: Imports and Exports

Increased RE generation inside and outside of Karnataka affects flows with surrounding states.

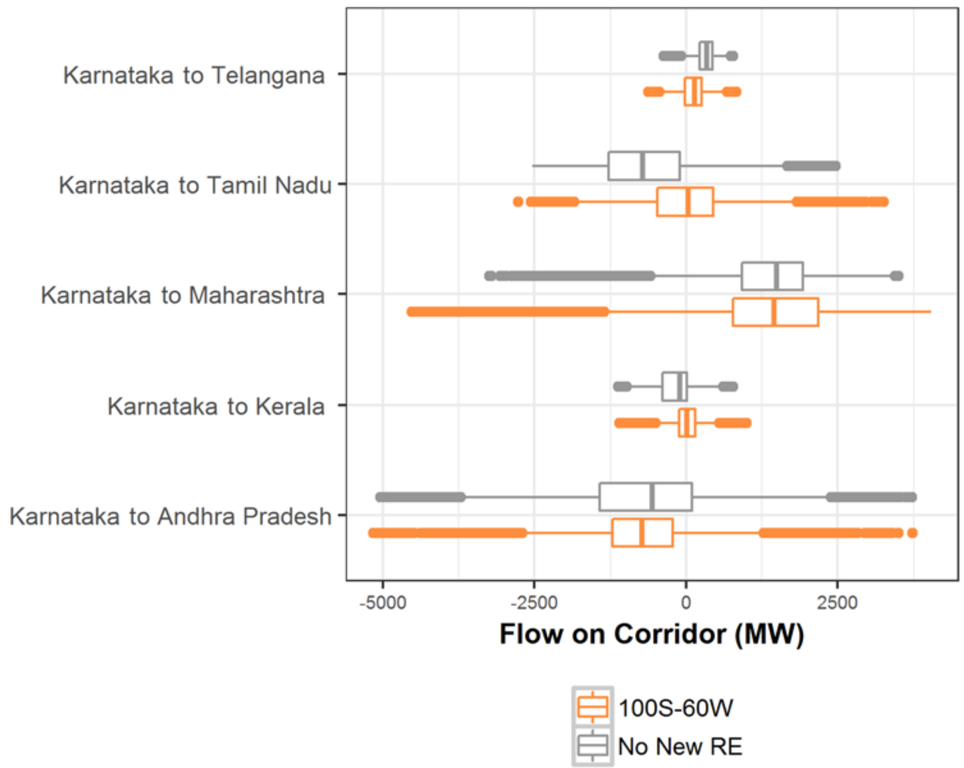
Karnataka is responsible for a large portion of the Southern region's exports to the Western region. It changes from a net importer in the No New RE scenario to a net exporter in the 100S-60W scenario, driven primarily by accepting fewer imports from Tamil Nadu, which in turn imports less from Chhattisgarh.

Imports fall by **36%** annually

Exports rise by **1.9%** annually

SCENARIO	NET EXPORTS (TWh)	
No New RE	-14	net importer
100S-60W	1.6	net exporter

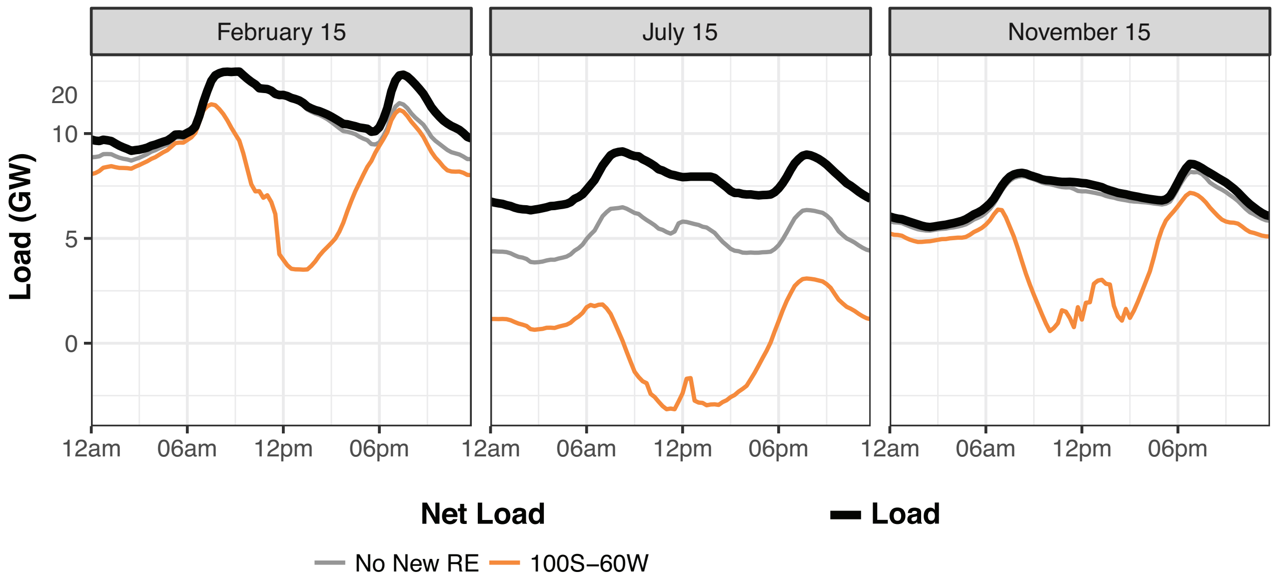
Distribution of flows across state-to-state corridors



Operation in Karnataka with Higher Levels of RE: Rest of the Fleet

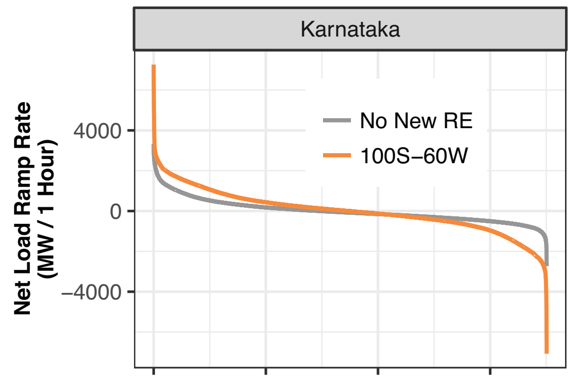
The addition of RE in Karnataka changes net load, which is the load that is not met by RE and therefore must be met by conventional generation. Due to changes in net load, hydro and thermal plants operate differently in higher RE scenarios.

Example days of load and net load in Karnataka



Increased daytime solar generation causes a dip in net load, which requires Karnataka to either increase net exports, turn down its thermal generators, or curtail RE. On 15 July, increased monsoon season wind generation drives Karnataka's daytime net load below zero (>100% RE penetration) for several hours. However, despite its lower RE penetration, 15 November has the larger nationwide valley-to-peak net load ramp, and RE curtailment on that day is higher.

Hourly net load ramps for all periods of the year, ordered by magnitude

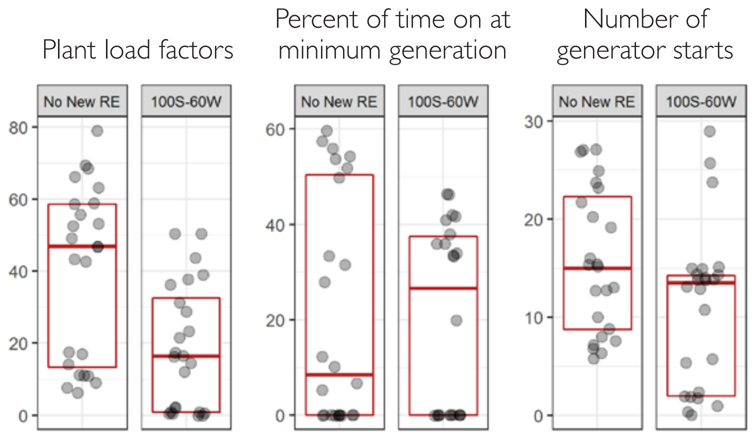


Peak 1-hour net load up-ramp in the **100S-60W scenario is 7.3 GW**, up from **3.3 GW in the No New RE scenario.**

Maximum net load valley-to-peak ramp is **10 GW in the 100S-60W scenario**, up from **6.2 GW in the No New RE scenario.**

Changes to Karnataka's Coal Fleet Operations

Operational impacts to coal



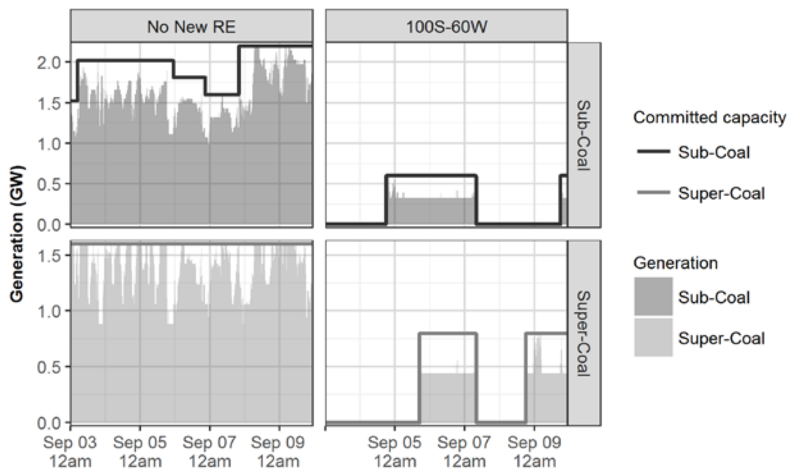
Coal plant load factors (PLFs) are lower in the 100S-60W scenario due to more frequent cycling and operation at minimum generation levels.

While coal PLFs are lower fleetwide in 100S-60W, generators with higher variable costs are impacted more.

Average PLF of coal generators in Karnataka, disaggregated by variable cost

RELATIVE VARIABLE COST	NO NEW RE	100S-60W
Lower 1/3	56	41
Mid 1/3	53	18
Higher 1/3	9.0	0.30
Fleetwide	47	28

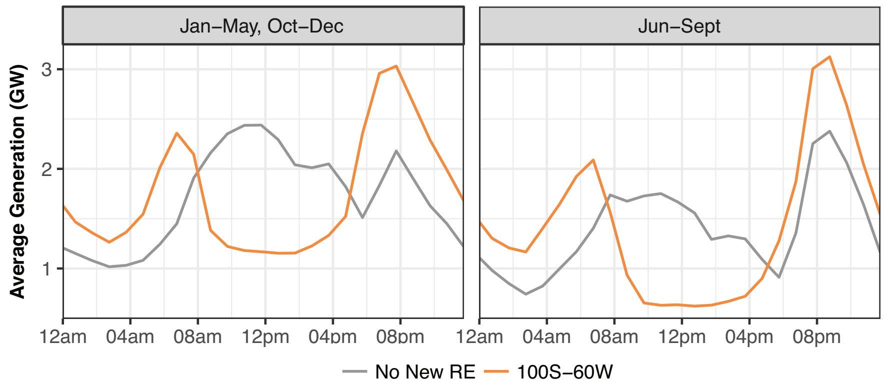
One week of coal operation in Karnataka



The coal fleet is committed much less and operates at or near minimum generation more in the 100S-60W scenario.

Changes to Karnataka's Hydro Fleet Operations

Average day of hydro in Karnataka by season



Minimum generation limits and higher hydro energy availability during the nonmonsoon season hinder the ability of hydro to shift generation to net load peaks as it does more fully in June through September.

Hydro plants follow a more pronounced two-peak generation profile due to availability of solar power during the middle of the day.

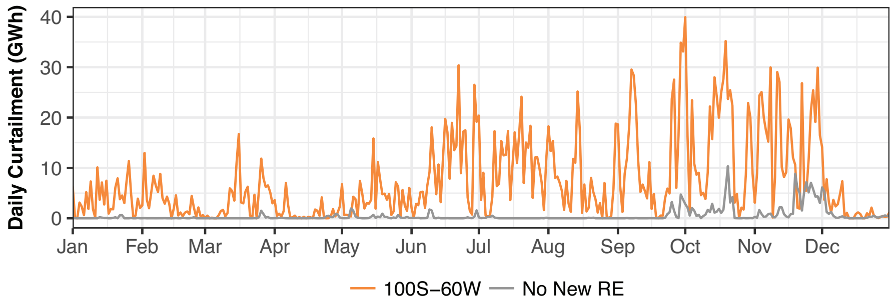
How Well Is RE Integrated?
Curtailment and Operational Snapshots

Curtailment levels indicate how efficiently RE is integrated. Large amounts of curtailment signal inflexibility in the system, preventing grid operators from being able to take full advantage of the available renewable resources.

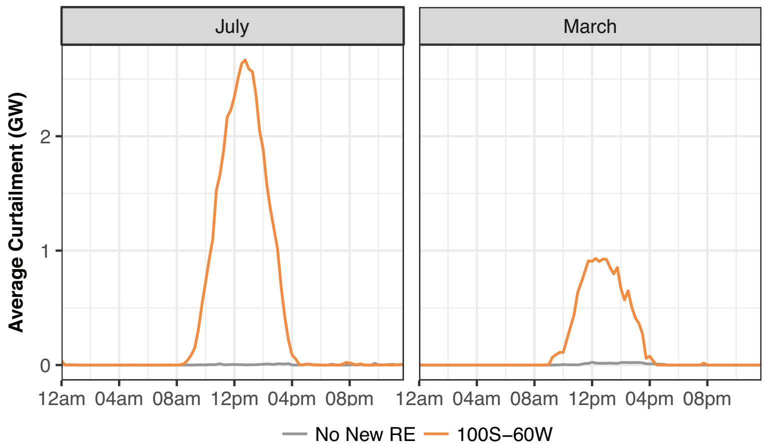
6.6% of wind and solar is curtailed annually.

Almost all of RE curtailment occurs in 11% of periods in the year.

Total daily curtailment throughout the year in Karnataka

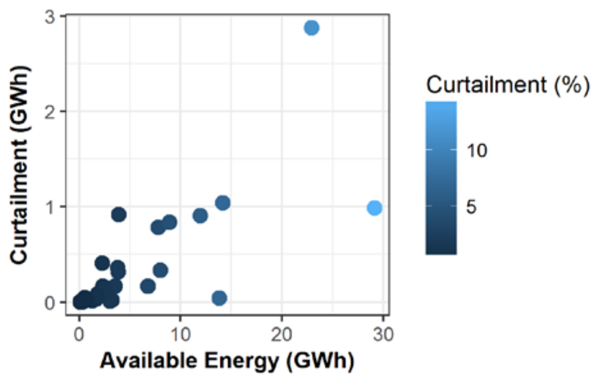


Average daily curtailment in March and July in Karnataka

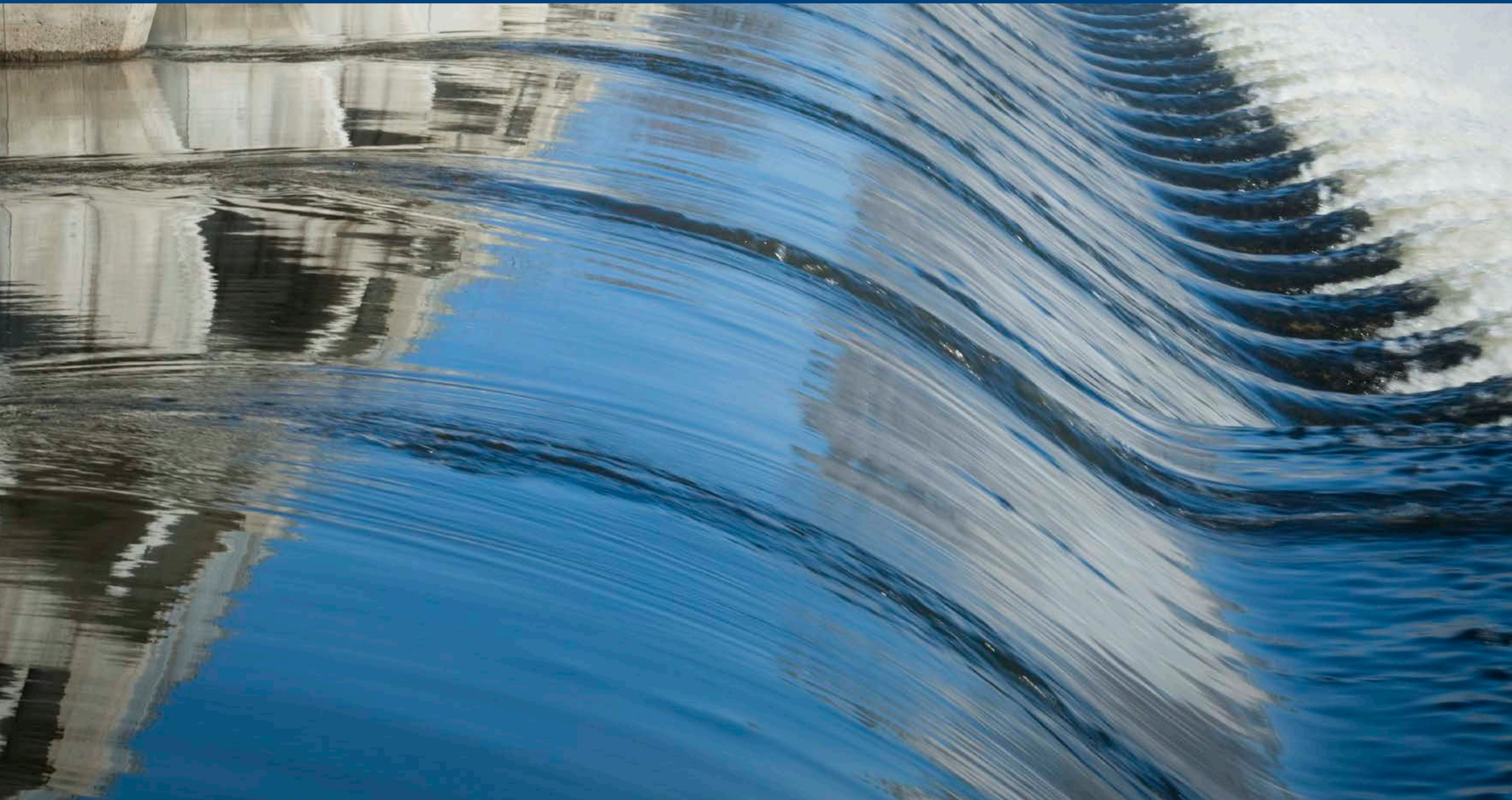


Karnataka experiences the highest RE curtailment as a percent of available capacity in the Southern region, particularly in October and November when curtailment exceeds 18%. It has the lowest ratio of thermal to RE capacity in the region, making curtailment sensitive to minimum coal generation levels, transmission constraints, and trade barriers.

RE curtailment as a percent of available energy by substation (each dot represents a substation)



Examples of Dispatch During Interesting Periods in Karnataka

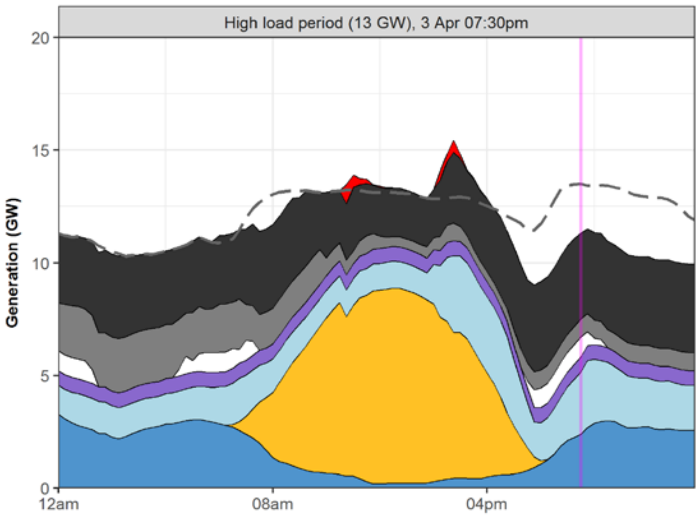


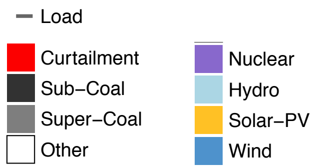
The following pages show dispatch in Karnataka during several interesting periods throughout 2022. The vertical magenta line highlights the dispatch interval associated with the figure title.

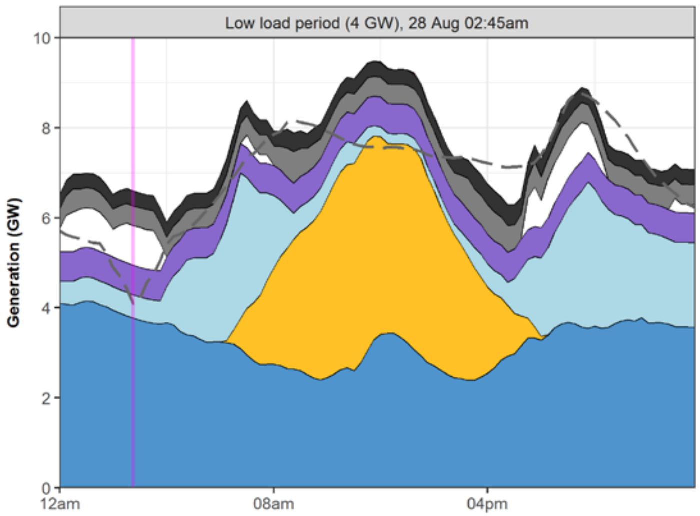
High load period: Generation, load, and interchange (values in GW unless otherwise specified)

3 April 7:30 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	RE	NET IMPORTS	RE PENETRATION (%)
13.5	0	2.8	0.7	0.9	4.6	2.4	2.2	18







Low load period: Generation, load, and interchange (values in GW unless otherwise specified)

28 August 2:45 am

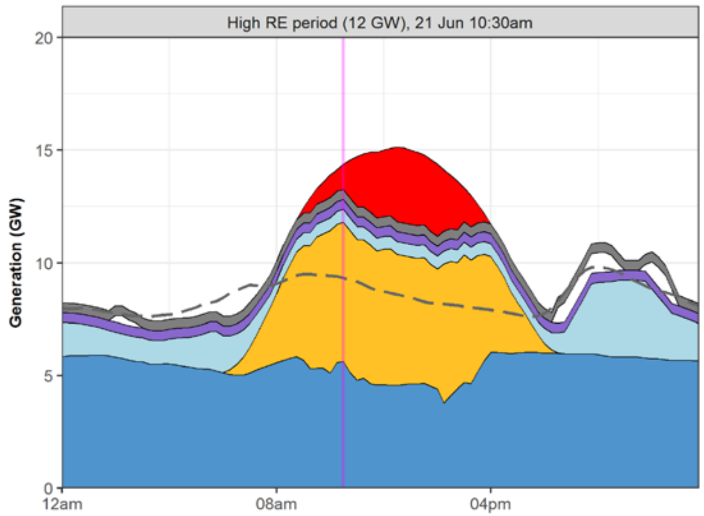
LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	RE	NET EXPORTS	RE PENETRATION (%)
4.1	0	0.5	0.7	0.9	0.8	3.8	2.5	92

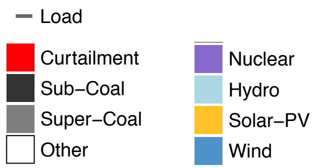
Example Dispatch Days

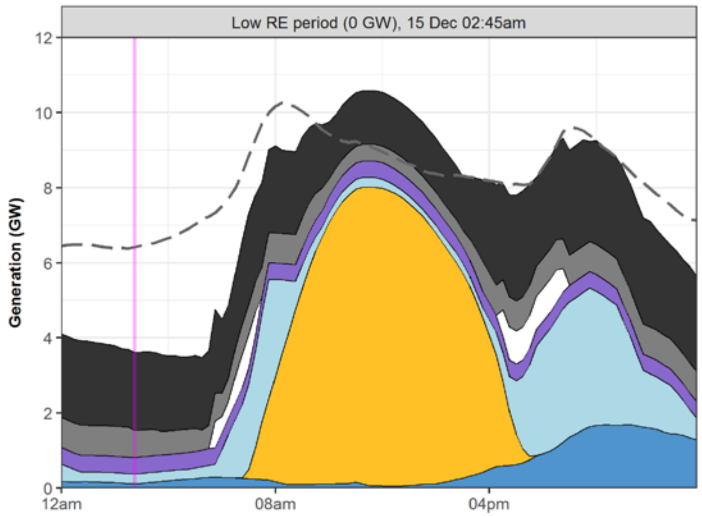
High RE period: Generation, load, and interchange (values in GW unless otherwise specified)

21 June 10:30 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	RE	NET EXPORTS	RE PENETRATION (%)
9.3	1.1	0.6	0.4	0	0.4	11.8	3.9	126







Low RE period: Generation, load, and interchange (values in GW unless otherwise specified)

15 December 2:45 am

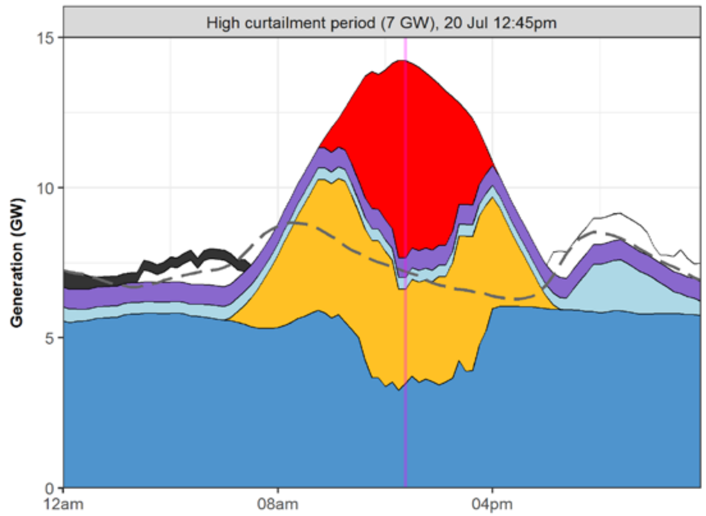
LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	RE	NET IMPORTS	RE PENETRATION (%)
6.4	0	0.3	0.4	0	2.8	0.1	2.8	1.9

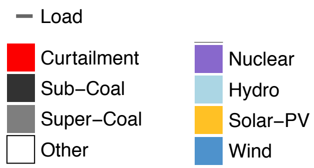
Example Dispatch Days

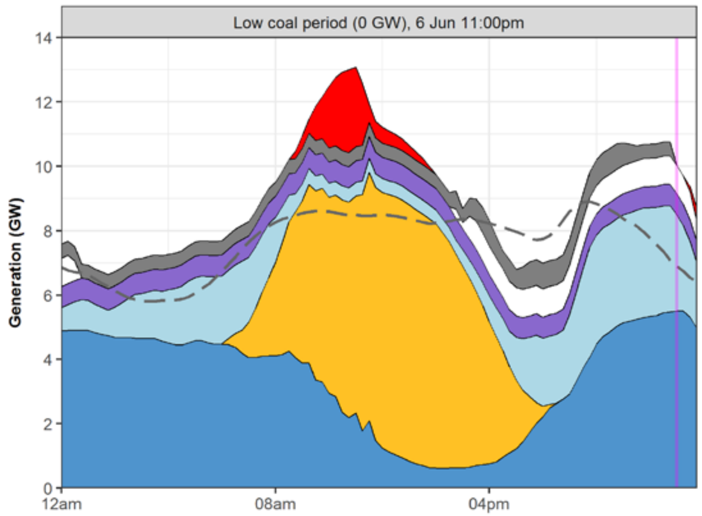
High curtailment period: Generation, load, and interchange (values in GW unless otherwise specified)

20 July 12:45 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	RE	NET EXPORTS	RE PENETRATION (%)
7.2	6.6	0.4	0.7	0	0	6.6	0.4	92







Low coal period: Generation, load, and interchange (values in GW unless otherwise specified)

6 June 11:00 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	RE	NET EXPORTS	RE PENETRATION (%)
6.9	0	3	0.7	0.9	0	5.5	3.1	80

Conclusions

Based on this study's assumptions about demand and installed generation and transmission capacity in Karnataka and nationwide, Karnataka can integrate the equivalent of 48% of its total generation in 2022 with 6.6% annual wind and solar curtailment. The RE changes the way Karnataka's grid must operate. Compared to a 2022 system with no new RE, net exports rise by 111% annually, and the PLF of the coal fleet falls from 47% to 28%.

Lowering coal minimum generation levels from 70% to 55% in all states particularly helps Karnataka in reducing the risk of RE curtailment. Karnataka also benefits from added transmission capacity (beyond Central Electricity Authority 2021–2022 plans) to Maharashtra, which typically has flexible thermal capacity available.

What can the state do to prepare for higher RE futures?

Establish process for optimizing locations and capacities for RE and transmission; inadequate transmission has a large effect on RE curtailment in the model. This requires good information on possible areas for RE locations.

Match or exceed CERC guidelines for coal flexibility. Reducing minimum operating levels for coal plants has the largest impact to RE curtailment among all integration strategies evaluated.

Consider mechanisms to better coordinate scheduling and dispatch with neighbors, which can reduce production costs and allow each state to better access least-cost generation, smooth variability and uncertainty, and better access sources of system flexibility.

Create a new tariff structure for coal that specifies performance criteria (e.g., ramping), and that addresses the value of coal as PLFs decline.

Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks.

Use PPAs to require RE generators to provide grid services such as automatic generation control and operational data.

Create policy and regulatory incentives to access the full capabilities of existing coal, hydro, and pumped storage.

Require merit order dispatch based on system-wide production costs; supplementary software may be required.

Improve the production cost model built for this study to address state-specific questions.

Institute organization and staff time to maintain the model over time.

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The production cost model used in this study has been built to assess region- and nationwide trends, and lacks some of the plant-specific detail that will be more important if the model is used for planning at the state level. Further improvements are suggested for use at the state level:

Input load specific to each substation level

Current model allocates a statewide load to each substation proportionate to peak

Modify load shapes to reflect expected changes to appliance ownership and other usage patterns

Current model uses 2014 load shape, scaled up to 2022 peak demand

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Current model uses best RE locations within the state based on suitable land availability; transmission plans are based on CEA's 2021–2022 PSS/E model and do not reflect anticipated changes to in-state transmission to meet new RE

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Current model allocates all central plant generating capacity to the host state

Allocate balancing responsibility for new RE plants to host state versus offtaker state or central entity

Current model allocates responsibility for balancing to host state

Create an equivalent but computationally simpler representation of transmission in states or regions where operations do not affect focus area

Current model includes level of detail for the country that may be unnecessary for a specific state, creating computational challenges

Appendix

Supplemental information on study assumptions

Total generation capacity in Karnataka in the 100S-60W scenario

	OWNERSHIP	TOTAL CAPACITY (GW)
Hydro	State/Private	3.7
Nuclear	Central	0.9
Other	State/Private	0.9
Sub-Coal	State/Private	5.6
Super-Coal	Central	2.4
Total non-RE		13.5
Solar-PV	State/Private	11.0
Wind	State/Private	6.2
Total RE		17.2
Total capacity		**30.7**

Total capacity (surge impedance limit [SIL]) of transmission lines connecting Karnataka to other states
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Karnataka to Andhra Pradesh	220	2
Karnataka to Andhra Pradesh	400	16
Karnataka to Andhra Pradesh	765	2
Karnataka to Goa	220	2
Karnataka to Kerala	220	1
Karnataka to Kerala	400	7
Karnataka to Maharashtra	220	2
Karnataka to Maharashtra	765	4
Karnataka to Maharashtra*	400	3
Karnataka to Odisha	400	2
Karnataka to Tamil Nadu	230	1
Karnataka to Tamil Nadu	400	10
Karnataka to Telangana	220	2
Total import/export capacity		**55**

Total capacity (SIL) of transmission lines within Karnataka
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Intrastate	220	430
Intrastate*	400	120
Total intrastate capacity		**550**

RE capacity by substation and type

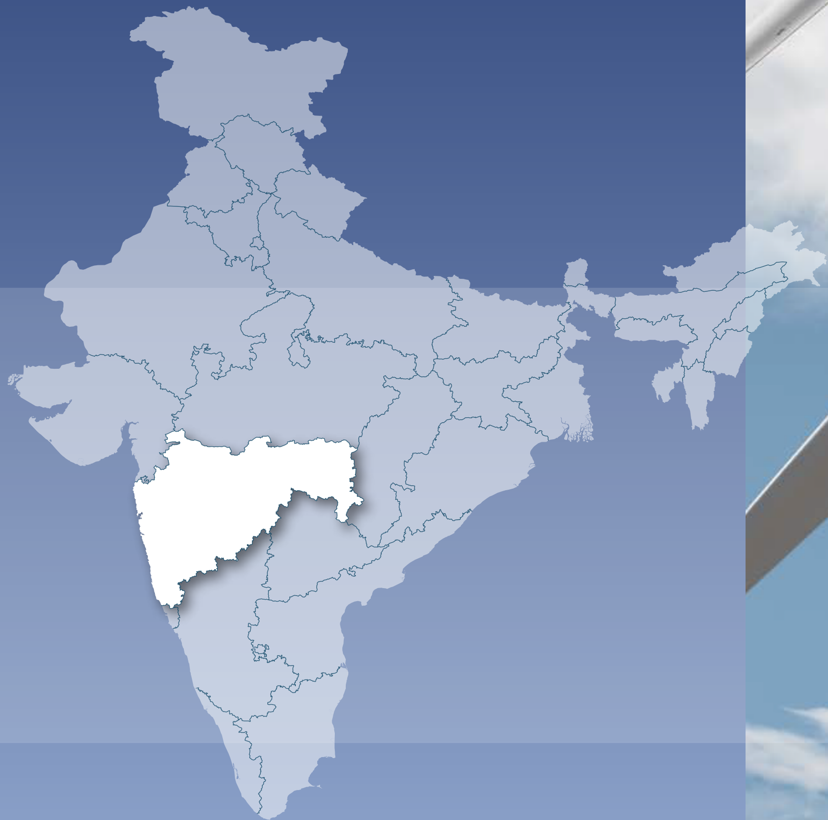
SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
522023_KUDUCHI_220	0	56
522024_ATHANI_220	0	294
522025_SOUNDATI_220	0	53
522026_CHIKKODI_220	0	72
522027_GHATPRBH_220	0	20
522033_BELG_220	0	11
522036_DAVA_220	272	164
522041_HAVR_220	0	223
522058_MLNG_220	28	28
522068_SHIM_220	44	0
522072_TALLAK_220	239	366
522104_CHITRDRG_220	391	379
522113_RANIBNNR_220	16	34
522115_HONNALI_220	0	161
522136_DHONI_220	913	414
522137_HARTI2_220	24	131
522143_KANABRGI_220	0	47

RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
522154_HASSAN-KAR_220	0	110
522203_HOSUDURGA_220	15	118
524001_SMNH_400	171	142
524002_MNRB_400	2,806	132
524003_RAIC_400	525	0
524004_DAVAN4_400	30	333
524005_HOODI4_400	1,598	134
524007_NELMANG4_400	309	50
524009_HASSAN4_400	0	15
524011_KOLAR_400	209	2,058
524013_RAIC-NEW_400	304	0
524044_HIRY_400	738	177
524047_NAREND-4_400	156	106
524076_TORNGL4_400	1,451	263
524077_BIDADI_400	15	0
524082_BELLARY_400	992	108
Total RE capacity	**11,246**	**6,199**

Annual energy generation fuel type, No New RE and 100S-60W		
	NO NEW RE (TWh)	**100S-60W (TWh)**
Hydro	14	14
Nuclear	5	5
Other	2	3
Solar-PV: rooftop	4	0
Solar-PV: utility scale	15	0
Sub-Coal	11	23
Super-Coal	8	9
Wind	19	8
Total Generation	79	63
Imports	27	42
Exports	28	28
RE Curtailment	3	0

Greening the Grid



Maharashtra

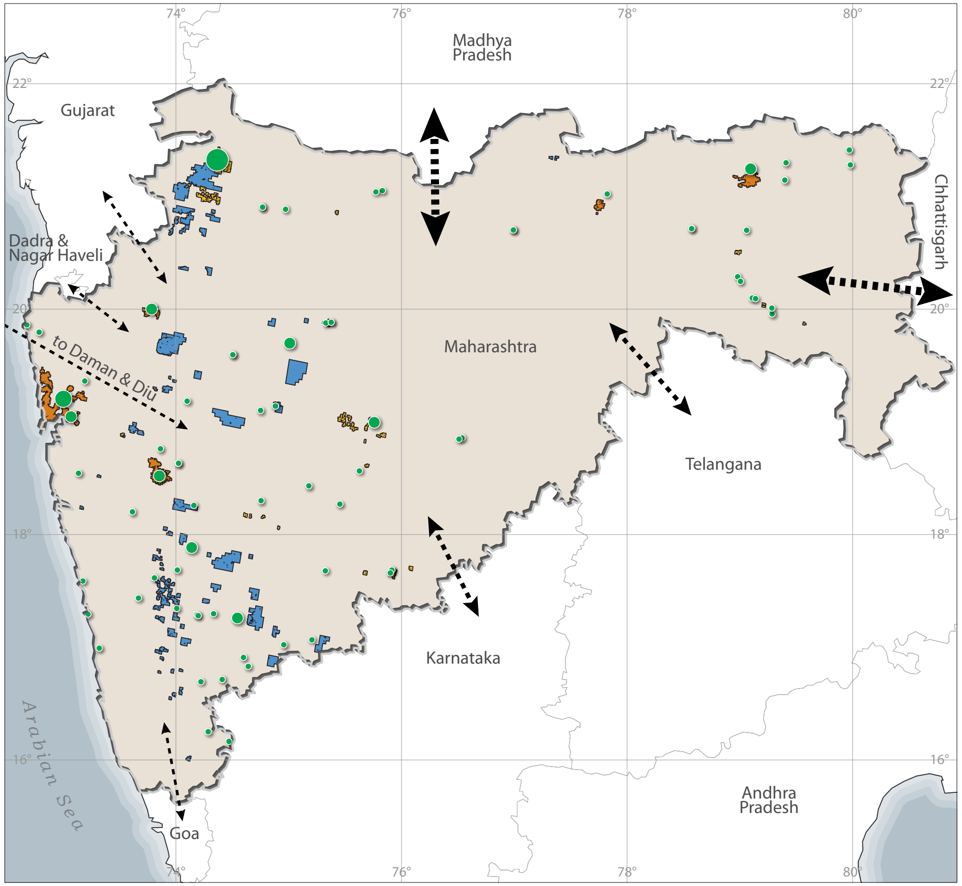
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

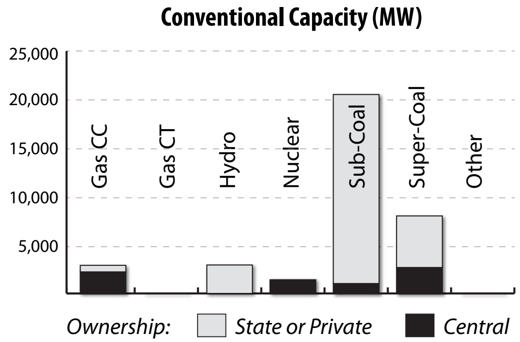
State-specific results from Volume II, which includes all of India. The full reports include detailed explanations of modeling assumptions, results, and policy conclusions.

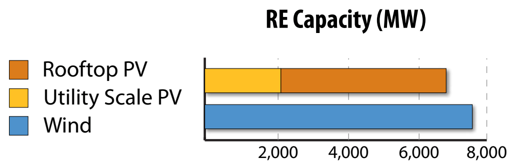
www.nrel.gov/india-grid-integration/

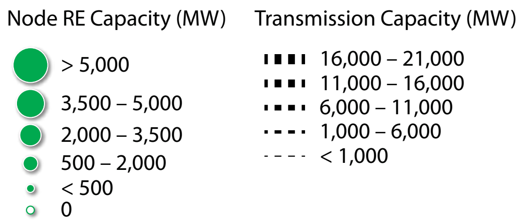
Assumptions About Infrastructure, Demand, and Resource Availability in 2022

Assumptions about RE and conventional generation and transmission in Maharashtra in 2022









Peak load (GW)	34
Total annual load (TWh)	420
Installed non-RE capacity (GW)	35
Installed RE capacity (GW)	14
Total import/export capacity (GW)	61

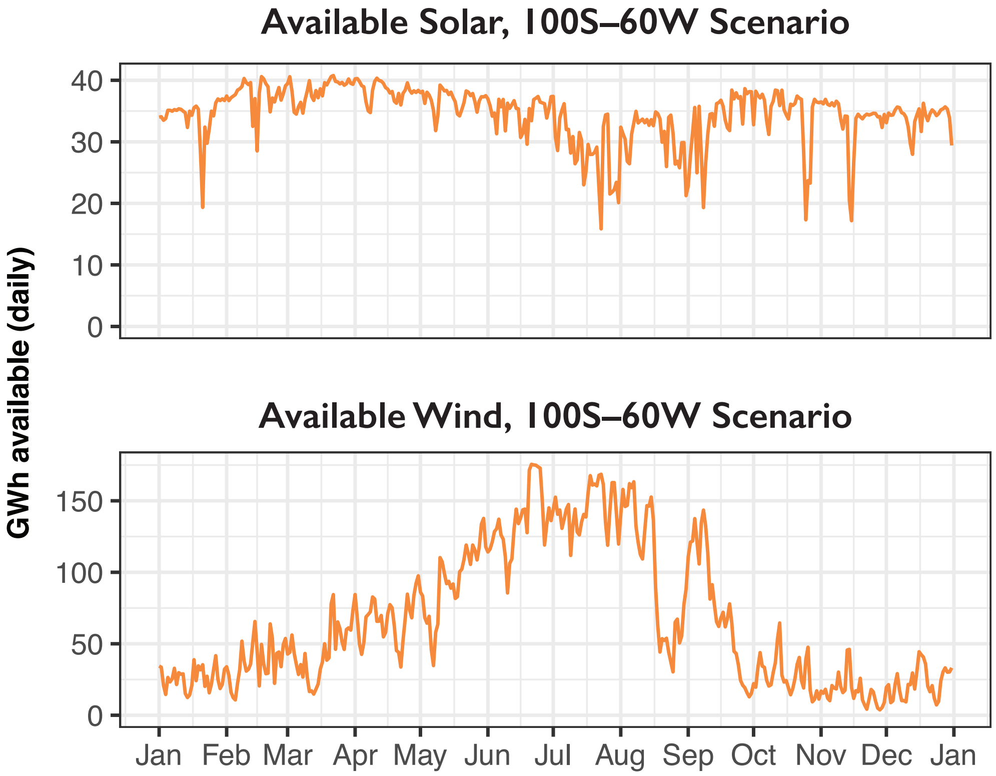
Maharastrha has 41 tie-lines connecting it to other states in this model.

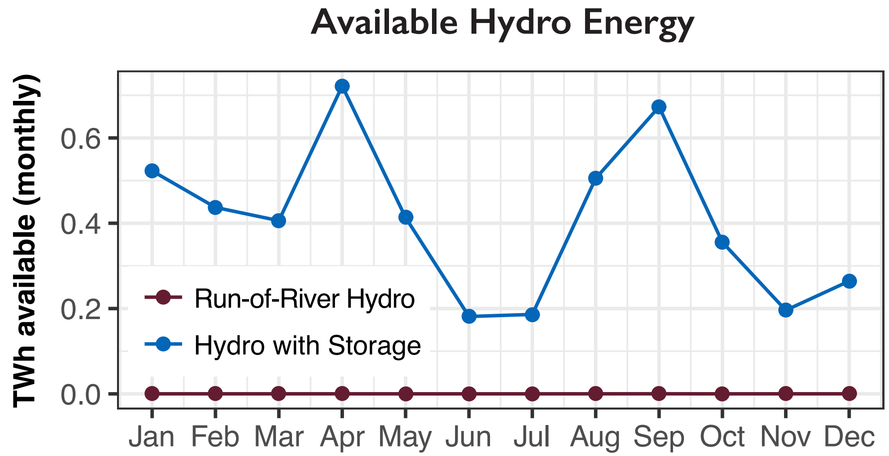
NREL and LBNL selected RE sites based on the methodology explained in Volume 1 of this report, which is available at www.nrel.gov/docs/fy17osti/68530.pdf.

Rooftop PV has been clubbed to the nearest transmission node.

Maharashtra Resource Availability in 2022

Available wind, solar, and hydro energy throughout the year in Maharashtra





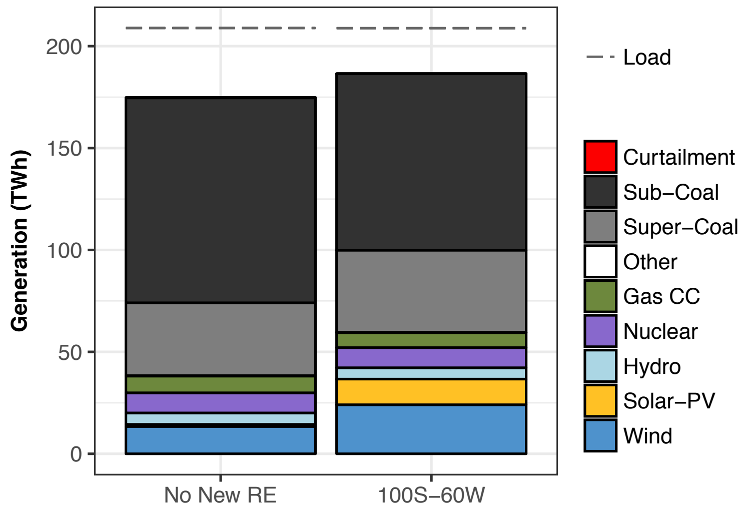
Daily solar energy is relatively consistent throughout the year, while wind energy varies seasonally.

Note: Y-axis is different for each resource

Operation in Maharashtra with Higher Levels of RE: RE Penetration in 2022

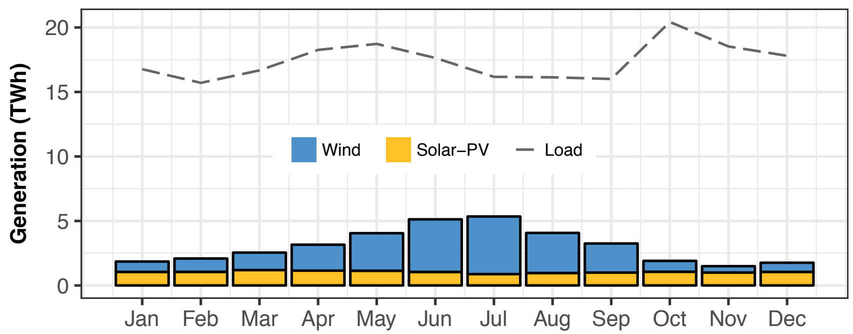
Increased amounts of RE available in Maharashtra change Maharashtra's generation mix and therefore the operation of the entire fleet.

Annual energy generation in Maharashtra



14 GW of wind and solar power generates 37 TWh annually.

Monthly RE generation and load in Maharashtra in the 100S-60W scenario



Wind and solar produce 20% of total generation in Maharashtra and meet 17% of load.

RE penetration by load and generation

	100S-60W
Percent time RE is over 50% of load	0.80
Peak RE as a % of load	60
Percent time RE is over 50% of generation	1.7
Peak RE as a % of generation	61

Coal generation falls by 6.9% and gas by 10% between No New RE and 100S-60W.

Operation in Maharashtra with Higher Levels of RE: Imports and Exports

Increased RE generation inside and outside of Maharashtra affects flows with surrounding states.

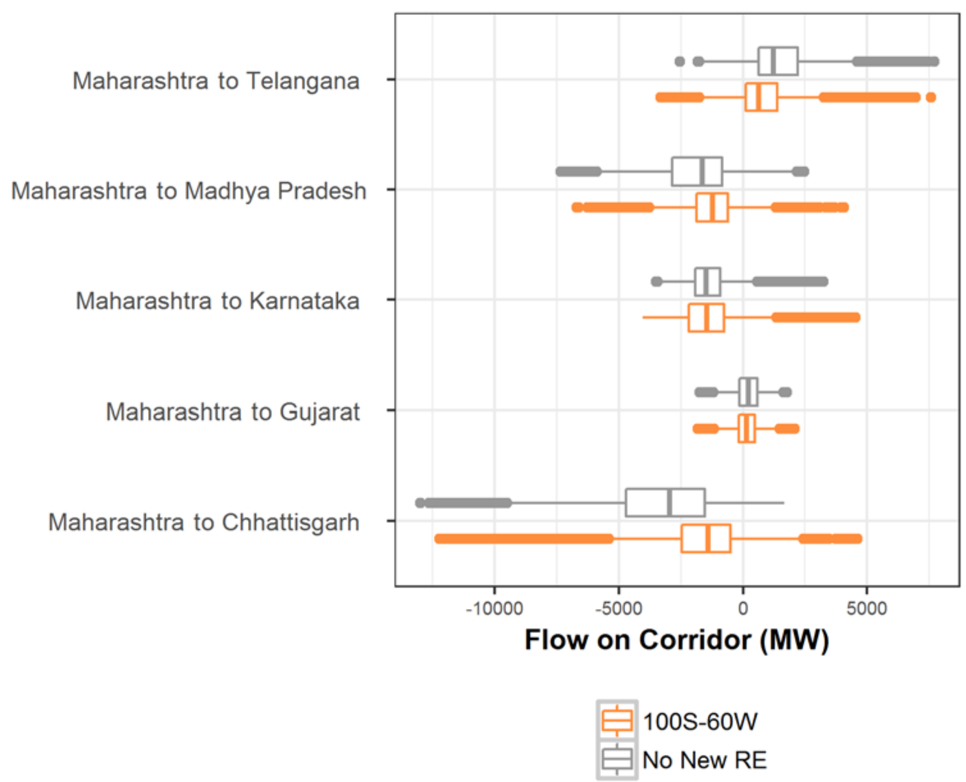
Maharashtra's imports and exports both fall in the 100S-60W scenario because all states with RE rely more on local generation to serve load. Maharashtra imports less thermal generation from Chhattisgarh and Madhya Pradesh and reduces its exports to Telangana.

Imports fall by **27%** annually

Exports fall by **19%** annually

SCENARIO	NET EXPORTS (TWh)	
No New RE	-33	net importer
100S-60W	-22	net importer

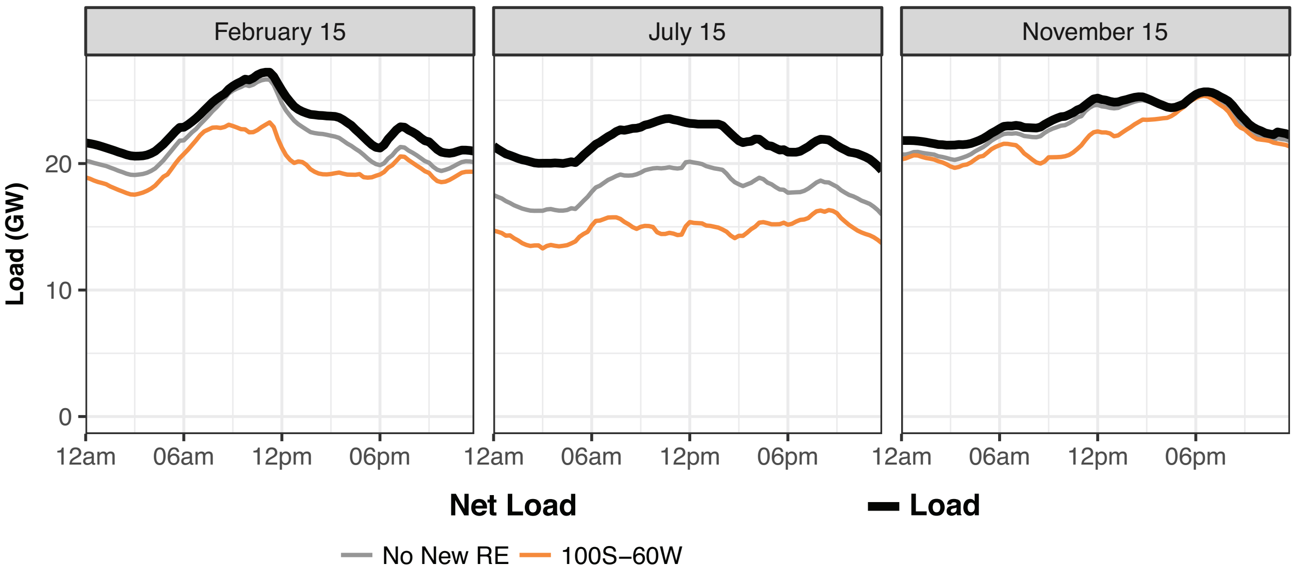
Distribution of flows across state-to-state corridors



Operation in Maharashtra with Higher Levels of RE: Rest of the Fleet

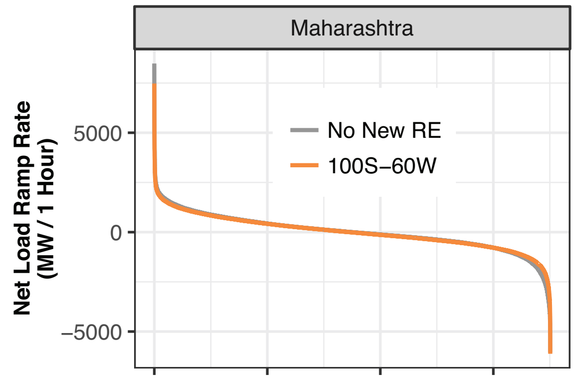
The addition of RE in Maharashtra changes net load, which is the load that is not met by RE and therefore must be met by conventional generation. Due to changes in net load, hydro and thermal plants operate differently in higher RE scenarios.

Example days of load and net load in Maharashtra



Because of its large size and high wind capacity relative to solar in the 100S-60W scenario, Maharashtra experiences less severe daytime net load ramps than other high-RE states. Its load often peaks midday, as on 15 February and 15 July, during which solar generation smooths the net load profile.

Hourly net load ramps for all periods of the year, ordered by magnitude

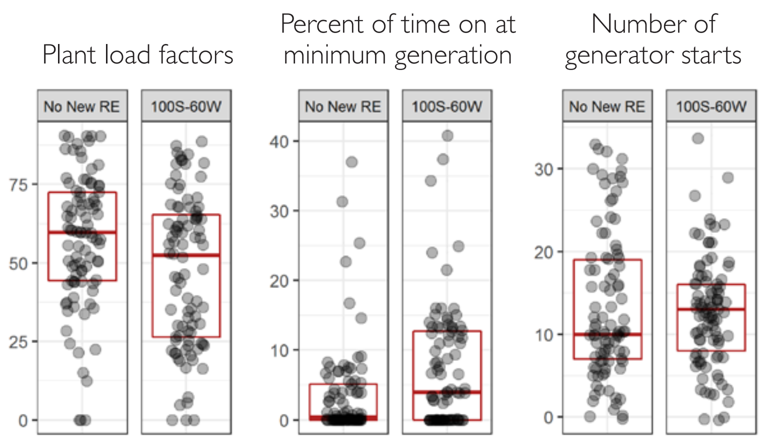


Peak 1-hour net load up-ramp in the **100S-60W scenario is 7.5 GW**, down from **8.5 GW in the No New RE scenario.**

Maximum net load valley-to-peak ramp is **11 GW in the 100S-60W scenario**, down from **12 GW in the No New RE scenario.**

Changes to Maharashtra's Coal Fleet Operations

Operational impacts to coal



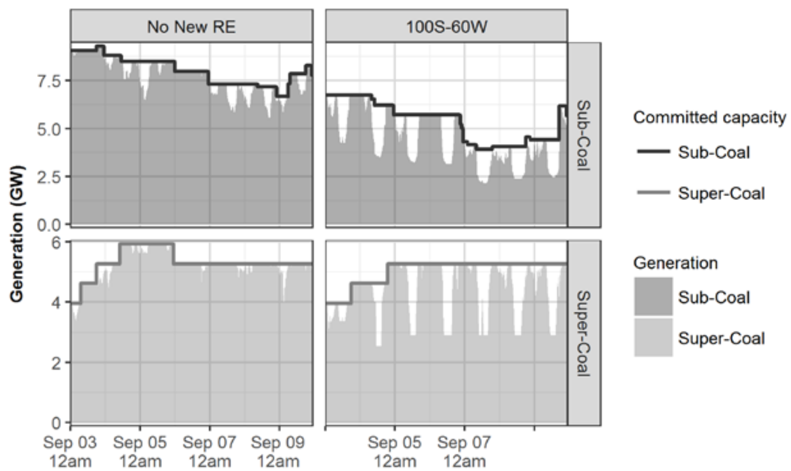
Coal plant load factors (PLFs) are lower in the 100S-60W scenario due to more frequent cycling and operation at minimum generation levels.

While coal PLFs are lower fleetwide in 100S-60W, the most expensive generators experience the greatest drop in PLF.

Average PLF of coal generators in Maharashtra, disaggregated by variable cost

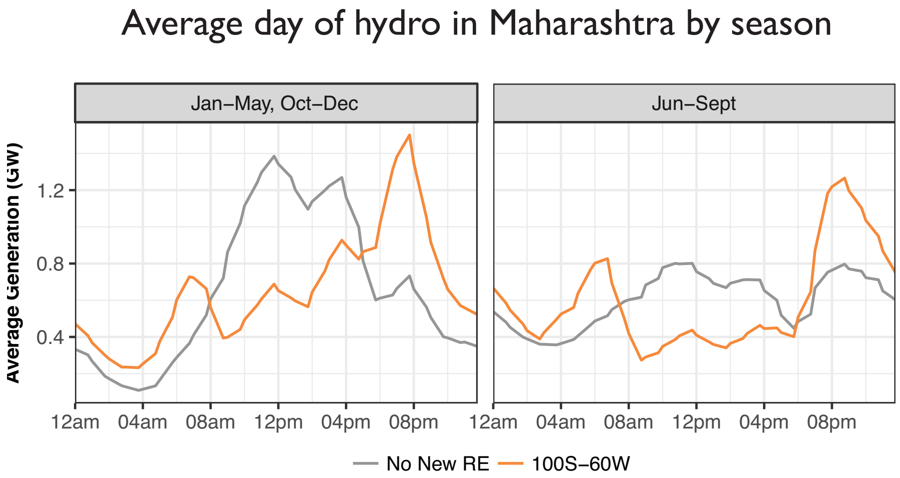
RELATIVE VARIABLE COST	NO NEW RE	100S-60W
Lower 1/3	63	68
Mid 1/3	44	33
Higher 1/3	55	30
Fleetwide	56	52

One week of coal operation in Maharashtra



The coal fleet is turned off more and its output varies daily due to midday availability of solar power in the 100S-60W scenario.

Changes to Maharashtra's Hydro Fleet Operations



Minimum generation levels during the monsoon season hinder the ability of hydro to shift generation to net load peaks as it does more fully in the months outside of the monsoon.

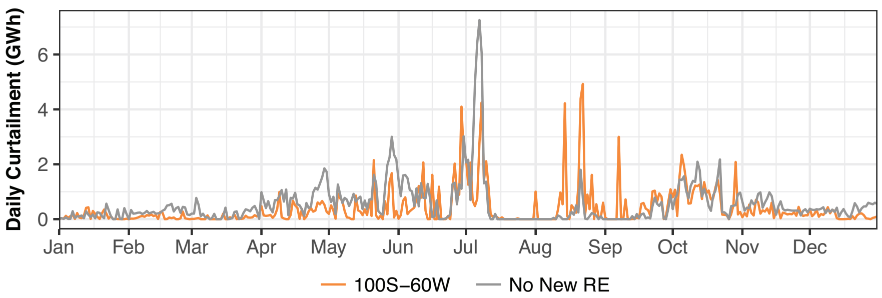
Hydro plants follow a more pronounced two-peak generation profile due to availability of solar power during the middle of the day.

How Well Is RE Integrated?
Curtailment and Operational Snapshots

Curtailment levels indicate how efficiently RE is integrated. Large amounts of curtailment signal inflexibility in the system, preventing grid operators from being able to take full advantage of the available renewable resources.

0.4% of wind and solar is curtailed annually.

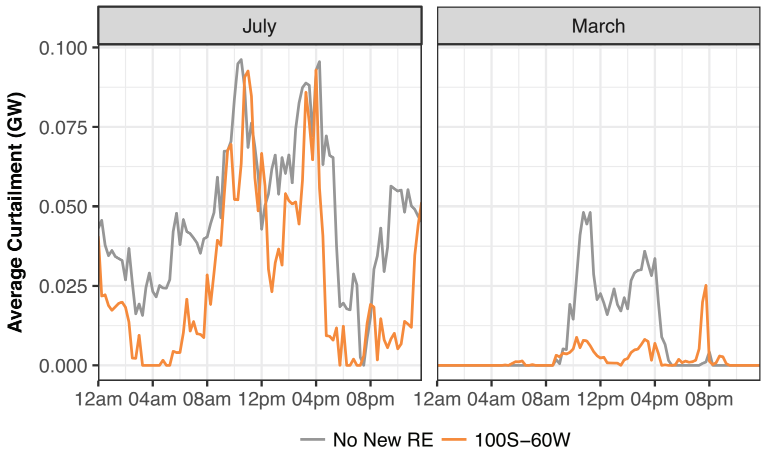
Total daily curtailment throughout the year in Maharashtra



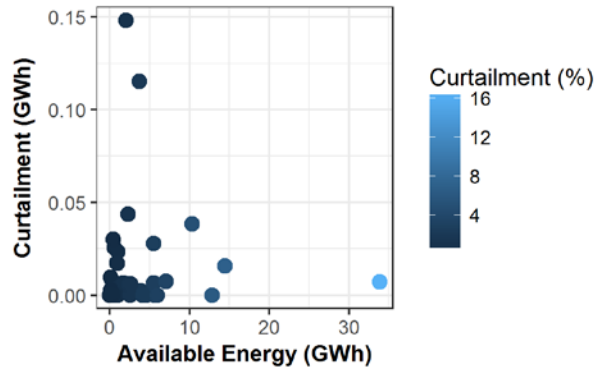
Maharashtra experiences the lowest RE curtailment of any state with significant RE capacity. Its thermal fleet is fully constrained only 0.2% of the year in the 100S-60W scenario, indicating that the RE curtailment that does happen is caused primarily by transmission congestion and trade barriers.

Almost all of RE curtailment occurs in 9.9% of periods of the year.

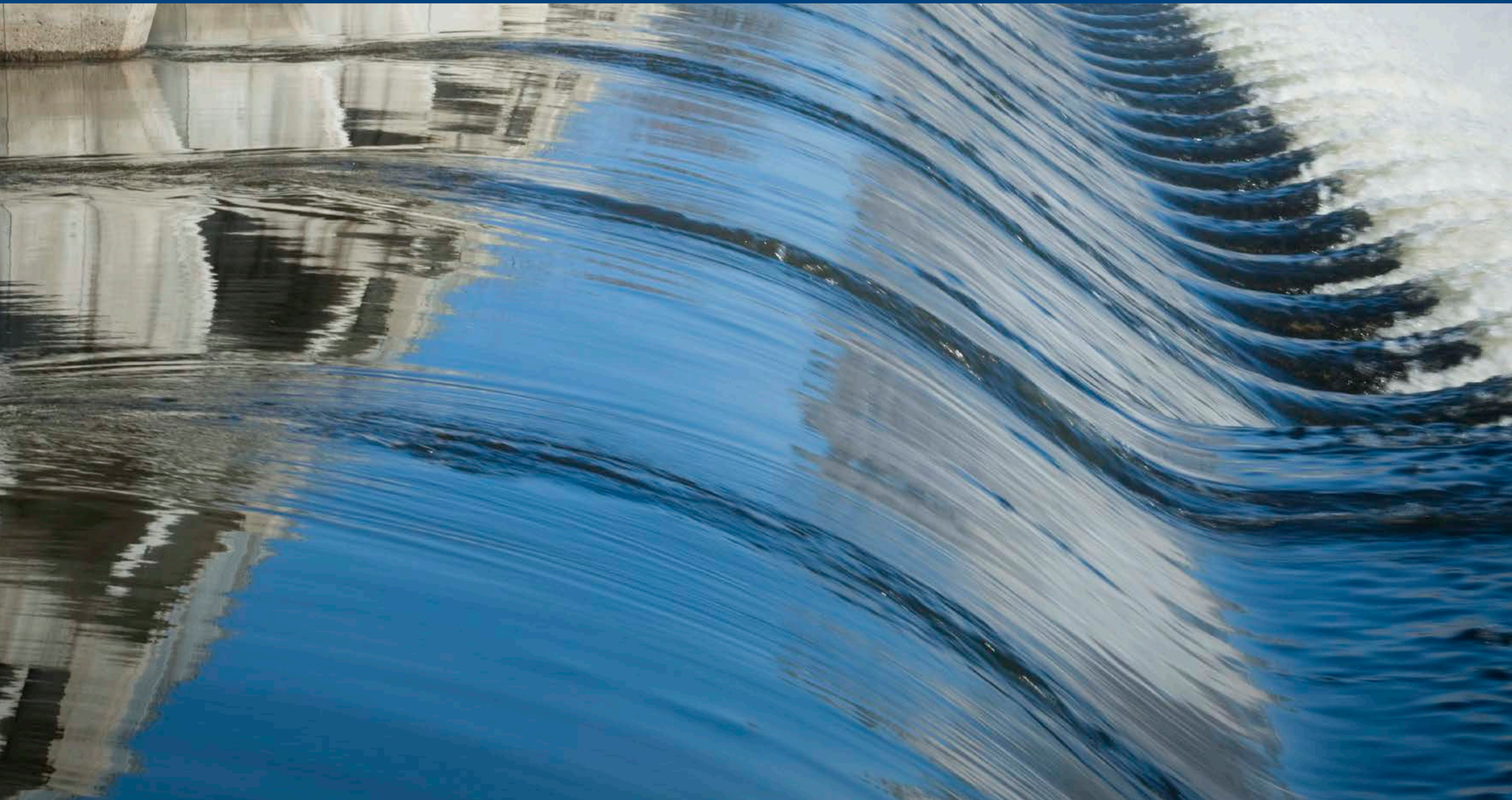
Average daily curtailment in March and July in Maharashtra



RE curtailment as a percent of available energy by substation (each dot represents a substation)



Examples of Dispatch During Interesting Periods in Maharashtra

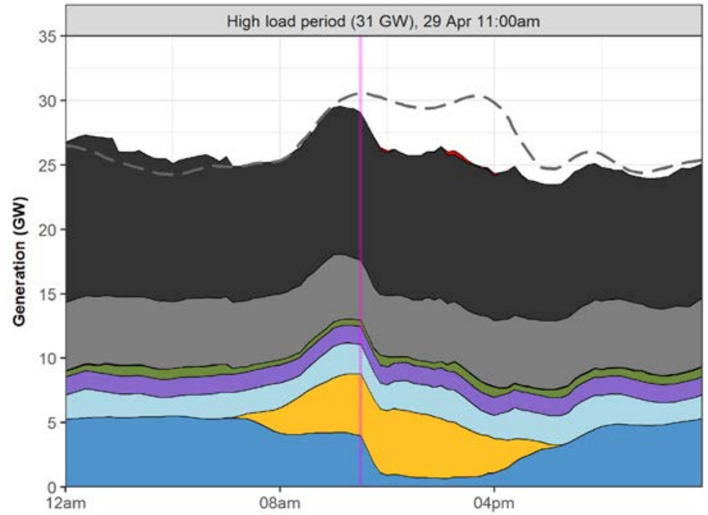


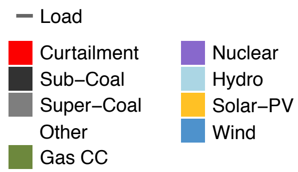
The following pages show dispatch in Maharashtra during several interesting periods throughout 2022. The vertical magenta line highlights the dispatch interval associated with the figure title.

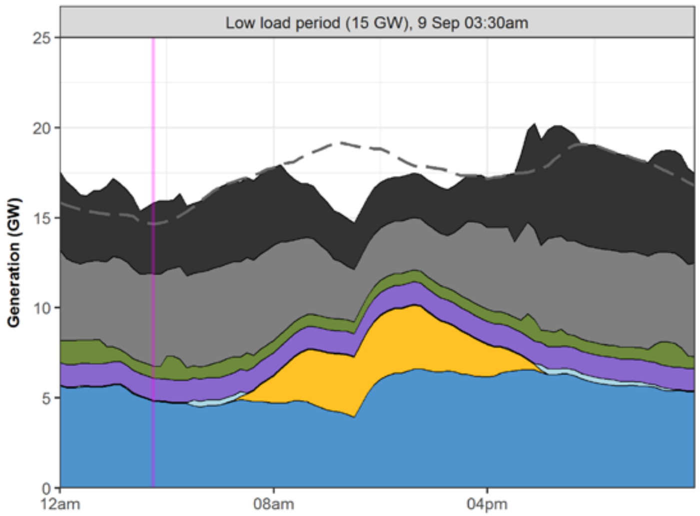
High load period: Generation, load, and interchange (values in GW unless otherwise specified)

29 April 11:00 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
30.6	0	2.3	1.4	0	16.1	0.5	8.8	1.5	29







Low load period: Generation, load, and interchange (values in GW unless otherwise specified)

9 September 3:30 am

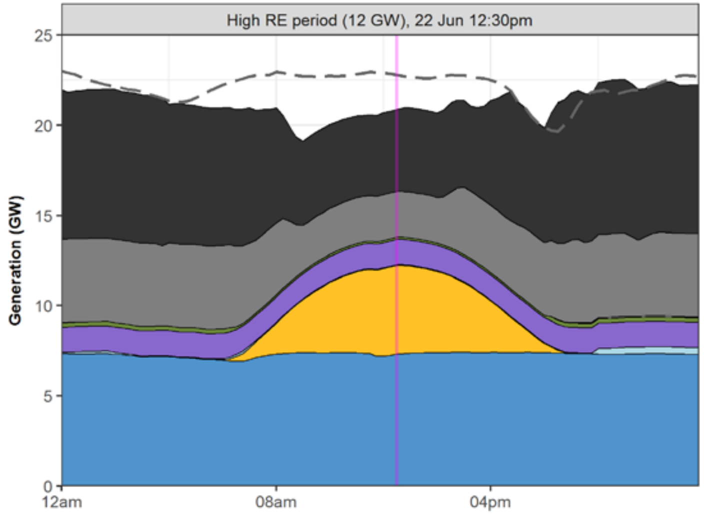
LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
14.6	0	0	1.2	0	9.1	0.7	4.8	1.2	33

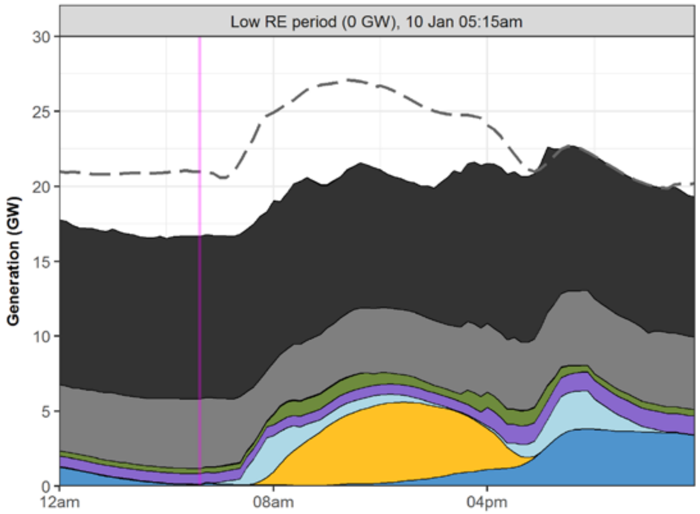
Example Dispatch Days

High RE period: Generation, load, and interchange (values in GW unless otherwise specified)

22 June 12:30 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
22.8	0	0	1.4	0	7.1	0.1	12.2	1.9	54





Low RE period: Generation, load, and interchange (values in GW unless otherwise specified)

10 January 5:15 am

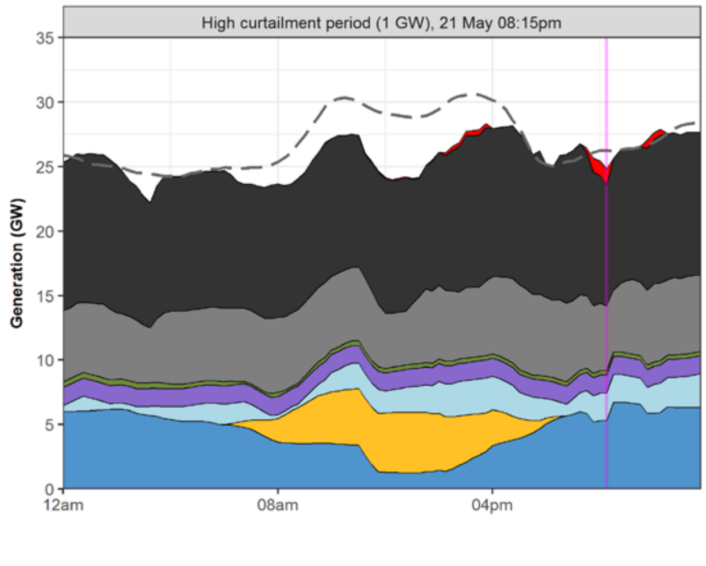
LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
21	0	0	0.7	0	15.5	0.3	0.1	4.3	0.4

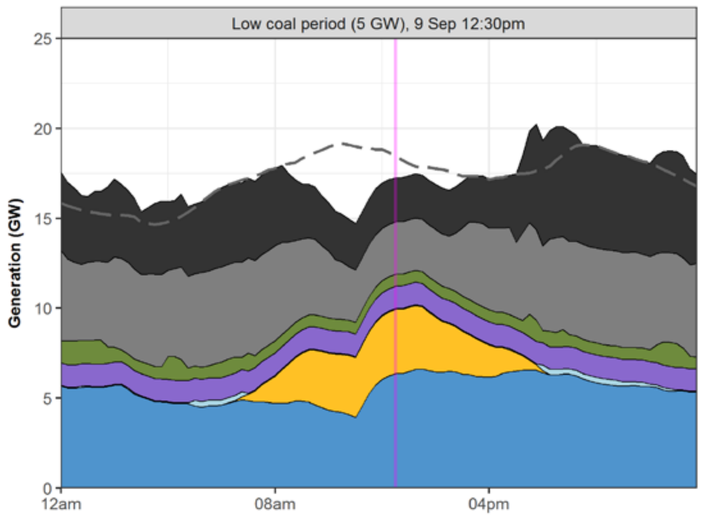
Example Dispatch Days

High curtailment period: Generation, load, and interchange (values in GW unless otherwise specified)

21 May 8:15 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
26.2	1.3	2.1	1.4	0	14.4	0.3	5.3	2.7	20





Low coal period: Generation, load, and interchange (values in GW unless otherwise specified)

9 September 12:30 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
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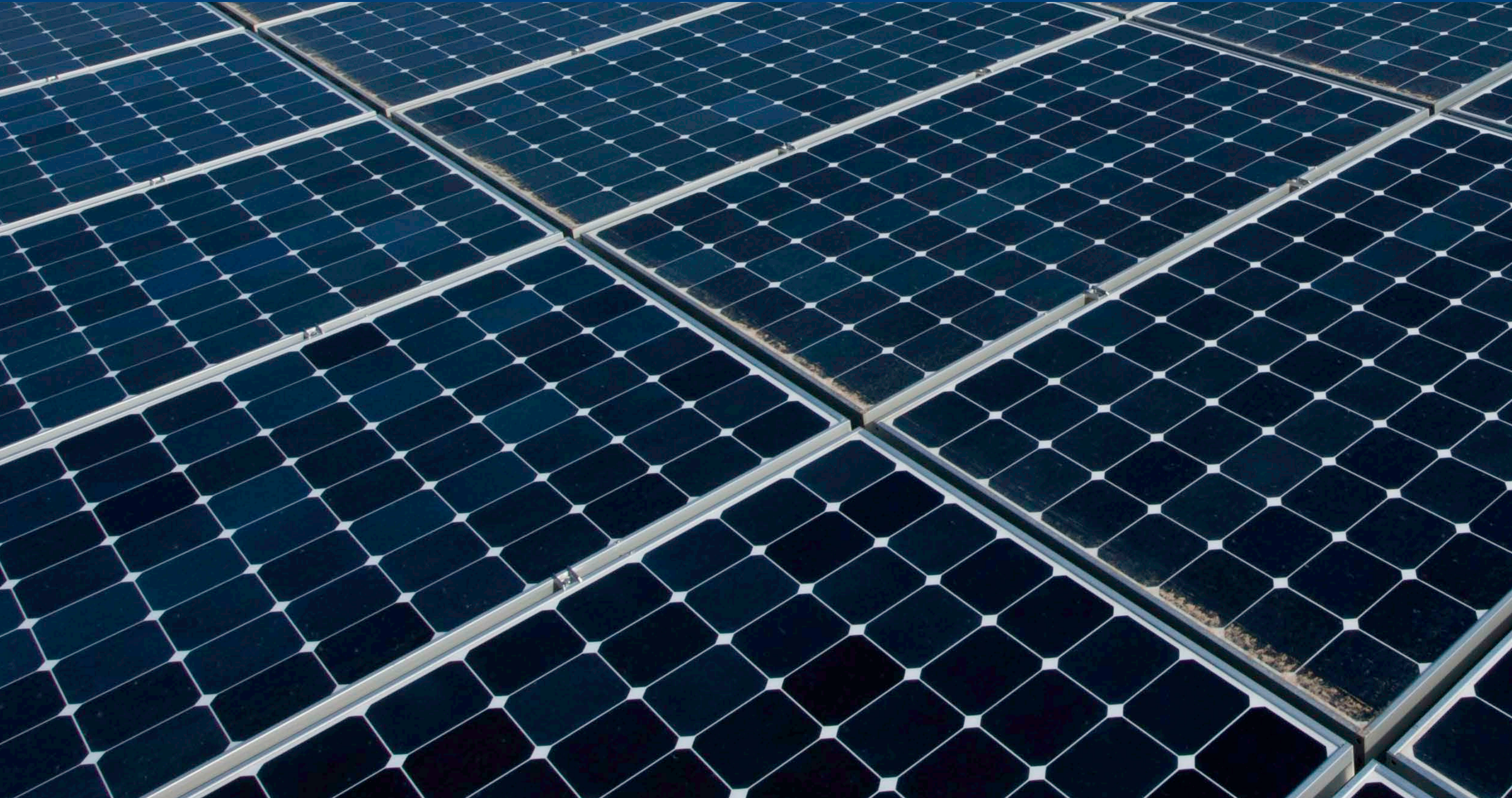
Conclusions



Based on this study's assumptions about demand and installed generation and transmission capacity in Maharashtra and nationwide, Maharashtra can integrate the equivalent of 20% of its total generation in 2022 with 0.4% annual wind and solar curtailment. The RE changes the way Maharashtra's grid must operate. Compared to a 2022 system with no new RE, net exports rise by 33% annually, and the PLF of the coal fleet falls from 56% to 52%.

Maharashtra often has sufficient flexible thermal capacity online to facilitate RE generation with minimal RE curtailment. However, strategies for coordination with neighboring states may benefit Maharashtra, as thermal flexibility is needed to balance changes to net load regionwide.

What can the state do to prepare for higher RE futures?

Establish process for optimizing locations and capacities for RE and transmission; inadequate transmission has a large effect on RE curtailment in the model. This requires good information on possible areas for RE locations.

Match or exceed CERC guidelines for coal flexibility. Reducing minimum operating levels for coal plants has the largest impact to RE curtailment among all integration strategies evaluated.

Consider mechanisms to better coordinate scheduling and dispatch with neighbors, which can reduce production costs and allow each state to better access least-cost generation, smooth variability and uncertainty, and better access sources of system flexibility.

Create a new tariff structure for coal that specifies performance criteria (e.g., ramping), and that addresses the value of coal as PLFs decline.

Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks.

Use PPAs to require RE generators to provide grid services such as automatic generation control and operational data.

Create policy and regulatory incentives to access the full capabilities of existing coal, hydro, and pumped storage.

Require merit order dispatch based on system-wide production costs; supplementary software may be required.

Improve the production cost model built for this study to address state-specific questions.

Institute organization and staff time to maintain the model over time.

Update power flow files to include more information related to high RE futures; conduct dynamic stability studies.

Adopt state-of-the-art load and RE forecasting systems.

Address integration issues at the distribution grid, including rooftop PV and utility-scale wind and solar that is connected to low voltage lines.

For a broader set of policy actions, see the executive summary for the National Study at www.nrel.gov/docs/fy17osti/68720.pdf.

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Other	State/Private	0.1
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Sub-Coal	Central	1.0
Super-Coal	Central	2.6
Super-Coal	State/Private	5.3
Total non-RE		35.2
Solar-PV	State/Private	6.8
Wind	State/Private	7.6
Total RE		14.4
Total capacity		**49.6**

Total capacity (surge impedance limit [SIL]) of transmission lines connecting Maharashtra to other states
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Maharashtra to Chhattisgarh	220	1
Maharashtra to Chhattisgarh	400	9
Maharashtra to Chhattisgarh	765	6
Maharashtra to Dadra & Nagar Haveli	400	2
Maharashtra to Daman & Diu	400	2
Maharashtra to Goa	220	2
Maharashtra to Goa	400	4
Maharashtra to Gujarat	220	4
Maharashtra to Gujarat	400	5
Maharashtra to Gujarat	765	1
Maharashtra to Karnataka	220	2
Maharashtra to Karnataka	765	4
Maharashtra to Karnataka*	400	3
Maharashtra to Madhya Pradesh	132	2
Maharashtra to Madhya Pradesh	220	1
Maharashtra to Madhya Pradesh	400	5
Maharashtra to Madhya Pradesh	765	8
Maharashtra to Telangana	400	2
Maharashtra to Telangana	765	6
Total import/export capacity		**69**

Total capacity (SIL) of transmission lines within Maharashtra
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Intrastate	100	54
Intrastate	132	385
Intrastate	220	436
Intrastate	765	27
Intrastate*	400	173
Total intrastate capacity		**1,075**

RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
372004_KARAD2_220	0	96
372039_AHMED2_220	0	437
372055_MIRAJ2_220	0	20
372065_ALEPHAT_220	0	303
372076_MALHRPTH_220	0	444
372077_WANKUSWD_220	1,248	1,830
372078_MUMEWADI_220	0	15
372084_BEED2_220	523	0
372110_VITA2_220	0	568
372126_BHIGWAN_220	97	15
372142_GHATNDAR_220	30	0
372160_WATHAR_220	0	761
372180_GANGAPUR_220	0	627
372181_SATARA_220	0	17
372301_ALKUD_220	0	203
372402_JATH_220	0	190
372403_KHANDAKE_220	0	247
372407_KADEGAON_220	0	138
374001_KALWA4_400	1,740	0
374002_KHARGAR_400	634	0
374006_CHNDR4_400	30	0
374008_DHULE4_400	0	76

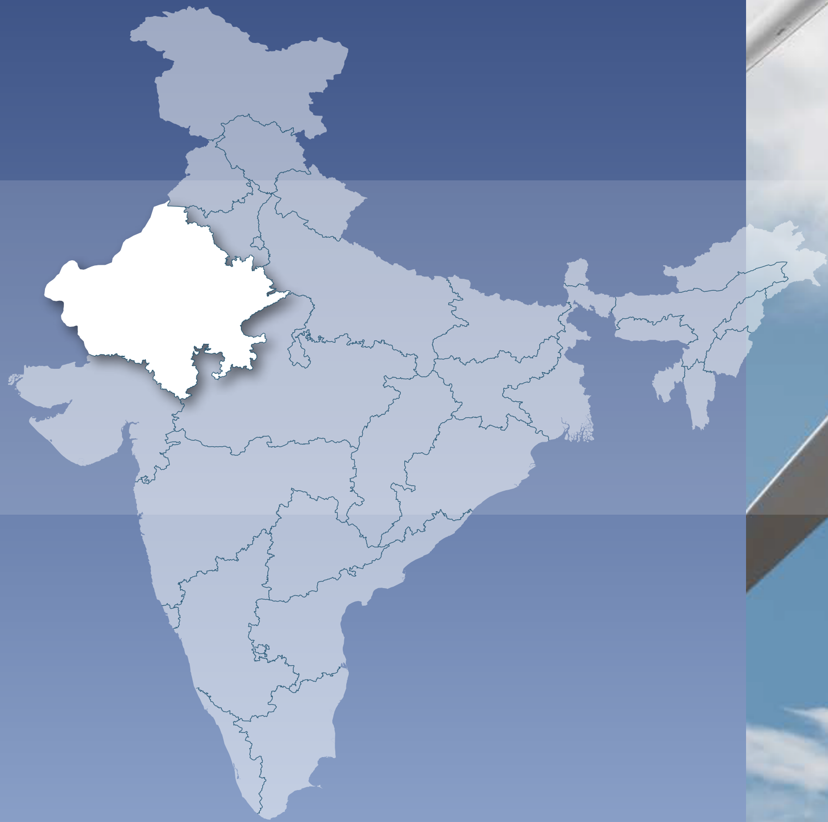
RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
374009_KORADI-I_400	579	0
374010_BHUSAWAL-I_400	28	0
374012_PADGH4_400	145	0
374013_KOLHAPUR_400	0	71
374014_AURANGBD-I_400	37	0
374015_JEJ4_400	0	273
374016_SHOL4_400	141	0
374018_BOIS4_400	3	0
374025_NKOY4_400	0	11
374026_KOY4-4_400	0	181
374028_NGTHANE_400	0	14
374029_CHAKAN_400	78	122
374035_IEPL_400	63	0
374036_AMRAVATIIBL_400	189	15
374037_CHANDRPR-II_400	16	0
374040_SHOLAPUR-PG_400	80	0
374042_PUNE-PG-AIS_400	756	0
374045_PUNE-PG-GIS_400	40	0
374047_AURANGABD-II_400	38	19
374055_SINNARTPP_400	313	896
374090_SOLAPURSTPP_400	39	0
Total RE capacity	**6,847**	**7,589**

Annual energy generation fuel type, No New RE and 100S-60W		
	100S-60W (TWh)	NO NEW RE (TWh)
Gas CC	7	8
Hydro	6	6
Nuclear	10	10
Other	0	0
Solar-PV: rooftop	9	0
Solar-PV: utility scale	4	1
Sub-Coal	87	101
Super-Coal	40	36
Wind	24	13
Total Generation	186	175
Imports	55	73
Exports	33	39
RE Curtailment	0	0

Greening the Grid

Rajasthan



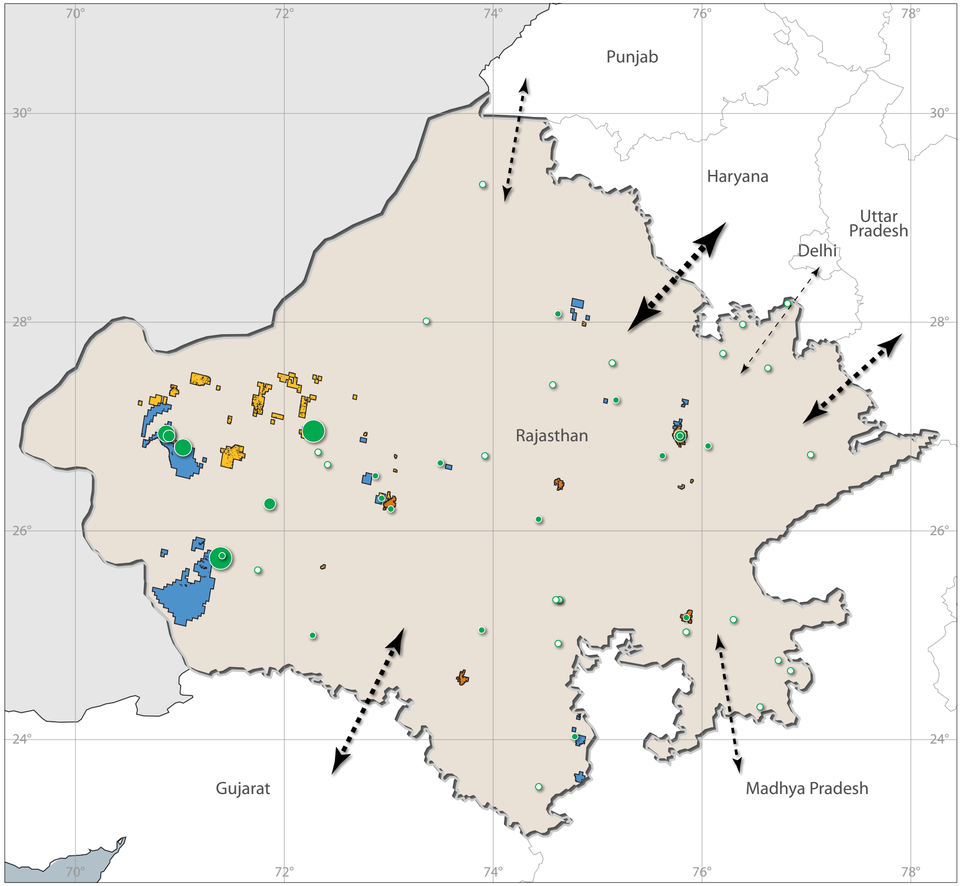
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

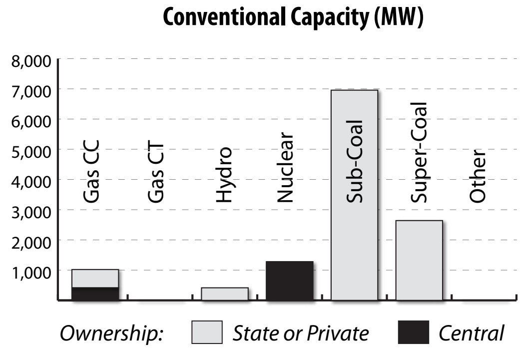
State-specific results from Volume II, which includes all of India. The full reports include detailed explanations of modeling assumptions, results, and policy conclusions.

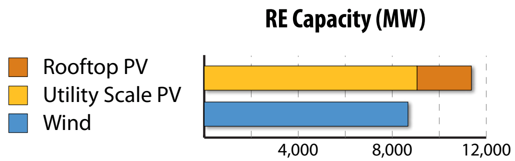
www.nrel.gov/india-grid-integration/

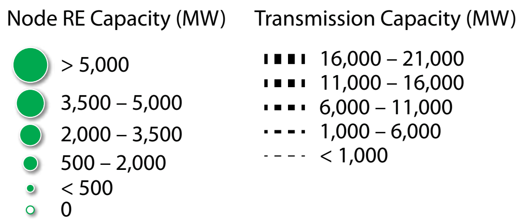
Assumptions About Infrastructure, Demand, and Resource Availability in 2022

Assumptions about RE and conventional generation and transmission in Rajasthan in 2022









Peak load (GW)	17
Total annual load (TWh)	191
Installed non-RE capacity (GW)	12
Installed RE capacity (GW)	20
Total import/export capacity (GW)	36

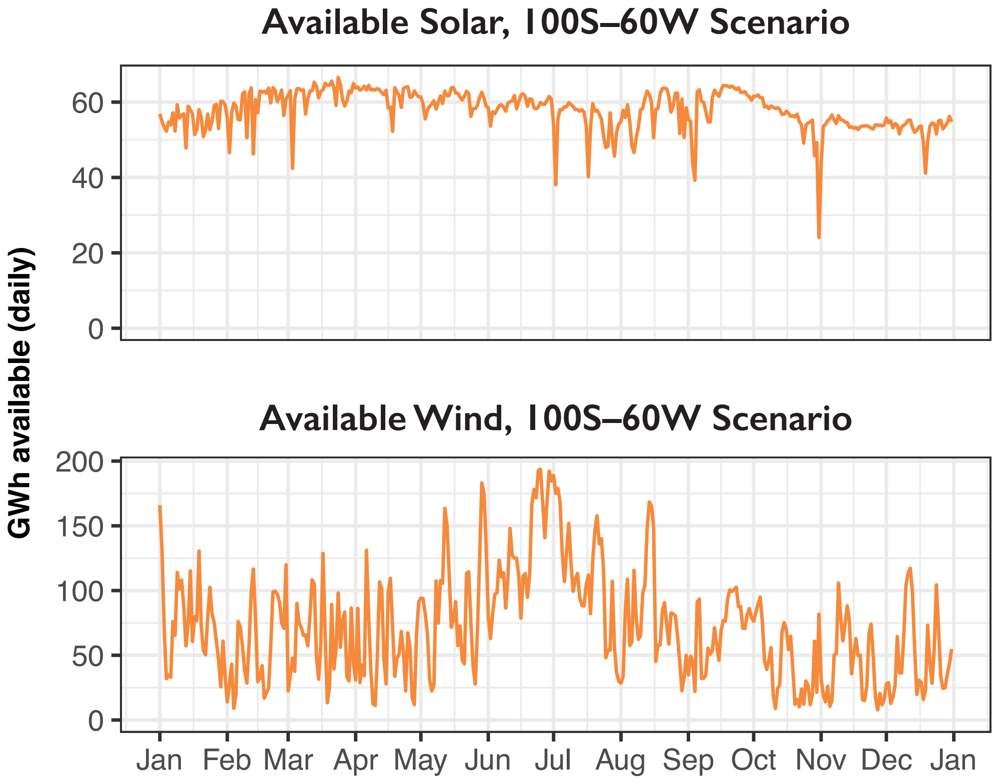
Rajasthan has 30 tie-lines connecting it to other states in this model.

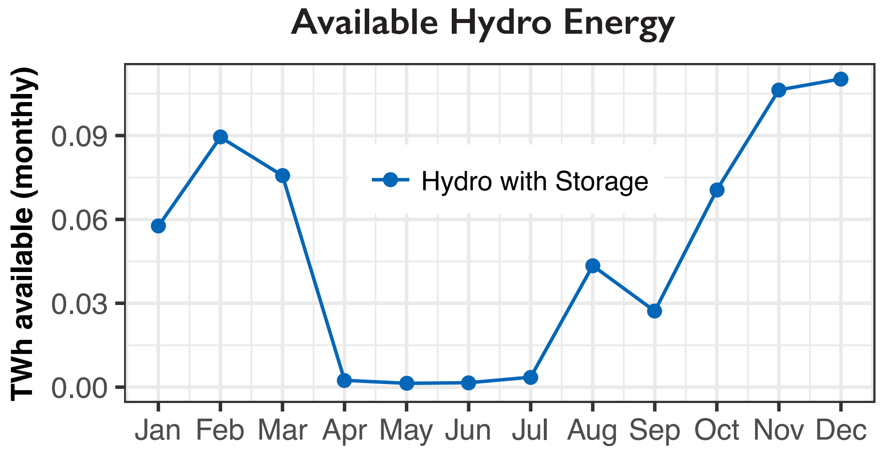
NREL and LBNL selected RE sites based on the methodology explained in Volume 1 of this report, which is available at www.nrel.gov/docs/fy17osti/68530.pdf.

Rooftop PV has been clubbed to the nearest transmission node.

Rajasthan Resource Availability in 2022

Available wind, solar, and hydro energy throughout the year in Rajasthan





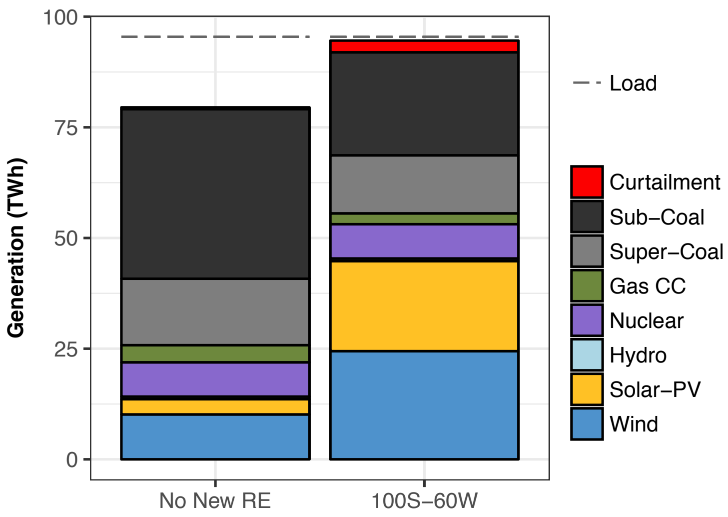
Daily solar energy is relatively consistent throughout the year while wind energy varies seasonally.

Note: Y-axis is different for each resource

Operation in Rajasthan with Higher Levels of RE: RE Penetration in 2022

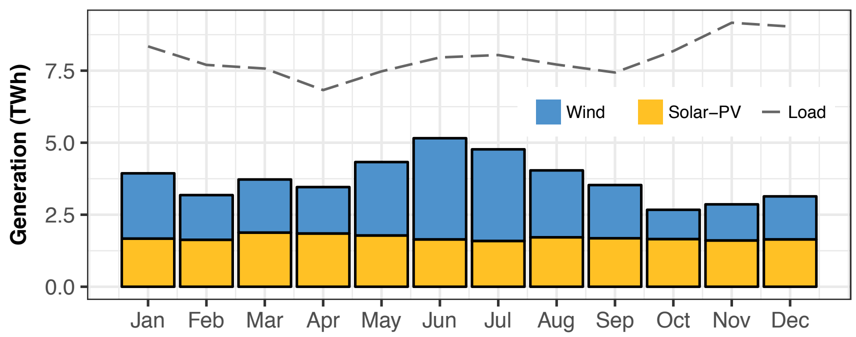
Increased amounts of RE available in Rajasthan change Rajasthan's generation mix and therefore the operation of the entire fleet.

Annual energy generation in Rajasthan



20 GW of wind and solar power generates 45 TWh annually.

Monthly RE generation and load in Rajasthan in the 100S-60W scenario



Wind and solar produce 49% of total generation in Rajasthan and meet 47% of load.

RE penetration by load and generation

	100S-60W
Percent time over 50% of load	50
Peak RE % of load	134
Percent time over 50% of generation	50
Peak RE % of generation	83

Coal generation falls by 32% and gas by 37% between No New RE and 100S-60W.

Operation in Rajasthan with Higher Levels of RE: Imports and Exports

Increased RE generation inside and outside of Rajasthan affects flows with surrounding states.

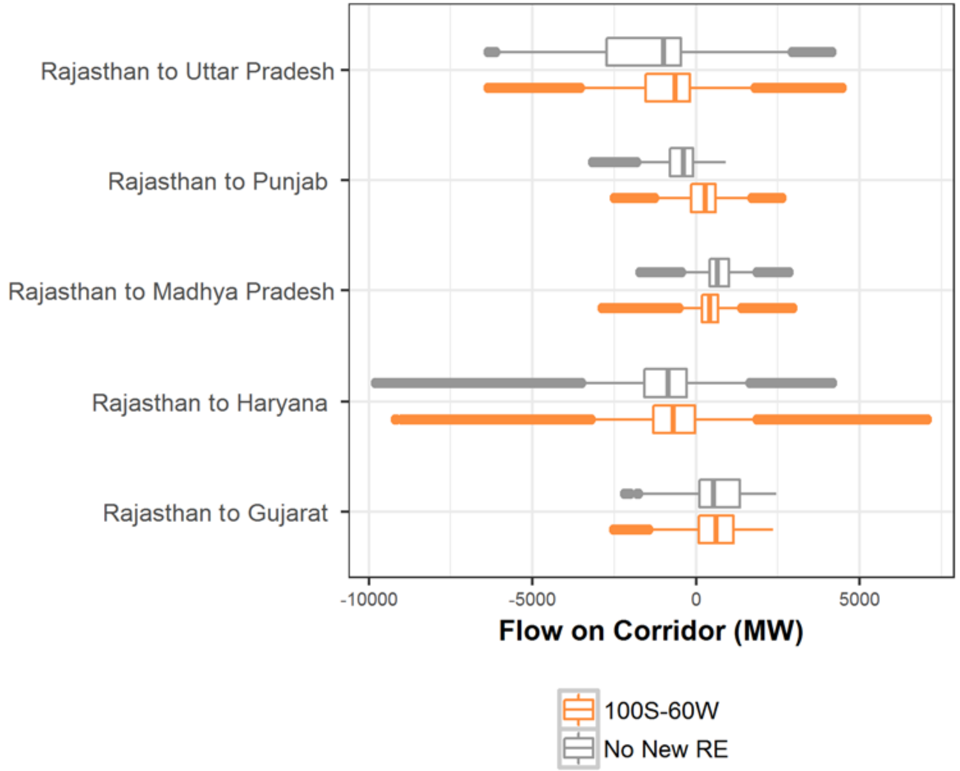
Rajasthan's increased RE generation in the 100S-60W scenario allows it to rely less on imports from the rest of the Northern region, particularly Punjab, Haryana, and Uttar Pradesh.

Imports fall by **22%** annually

Exports rise by **11%** annually

SCENARIO	NET EXPORTS (TWh)	
No New RE	-16	net importer
100S-60W	-3.5	net importer

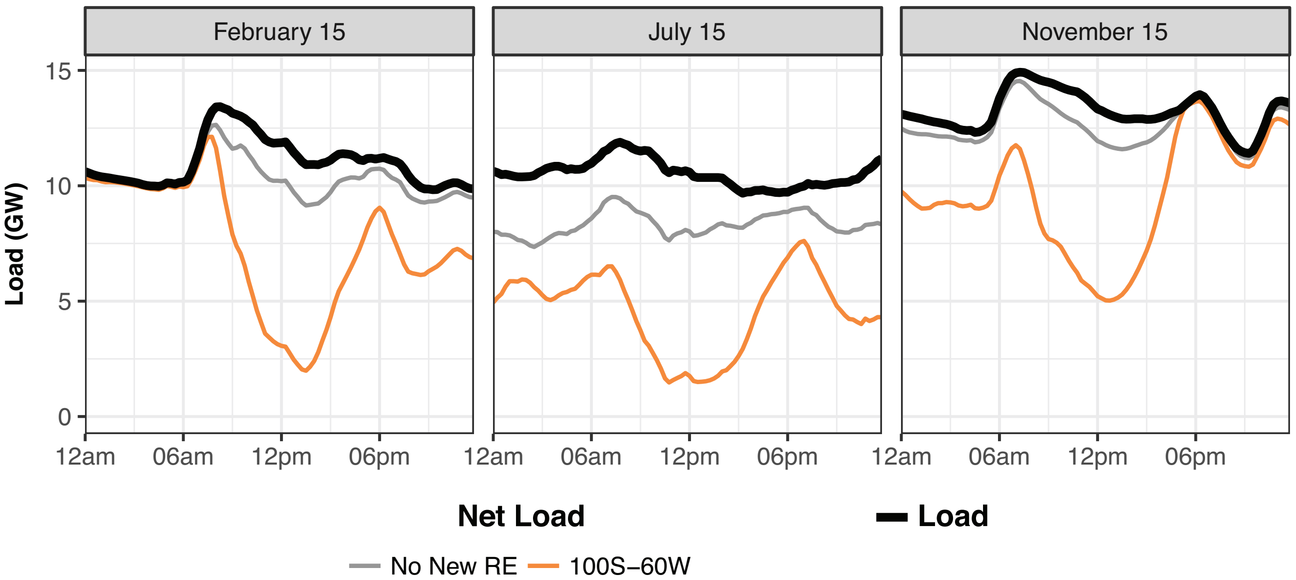
Distribution of flows across state-to-state corridors



Operation in Rajasthan with Higher Levels of RE: Rest of the Fleet

The addition of RE in Rajasthan changes net load, which is the load that is not met by RE and therefore must be met by conventional generation. Due to changes in net load, hydro and thermal plants operate differently in higher RE scenarios.

Example days of load and net load in Rajasthan

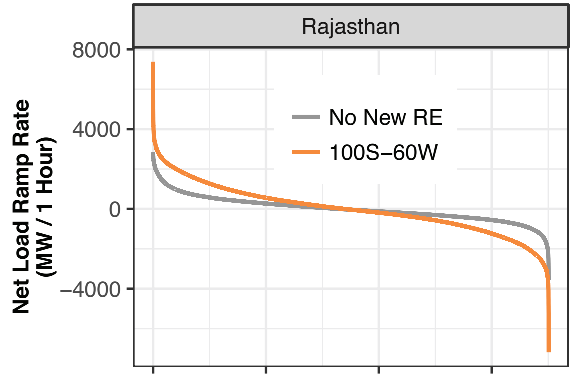


Increased daytime solar generation causes a dip in net load, which requires Rajasthan to either increase net exports, turn down its thermal generators, or curtail RE. On 15 July, increased monsoon season wind generation shifts Rajasthan's net load curve downward during all hours of the day.

Peak 1-hour net load up-ramp in the **100S-60W scenario is 7.4 GW**, up from **2.8 GW in the No New RE scenario.**

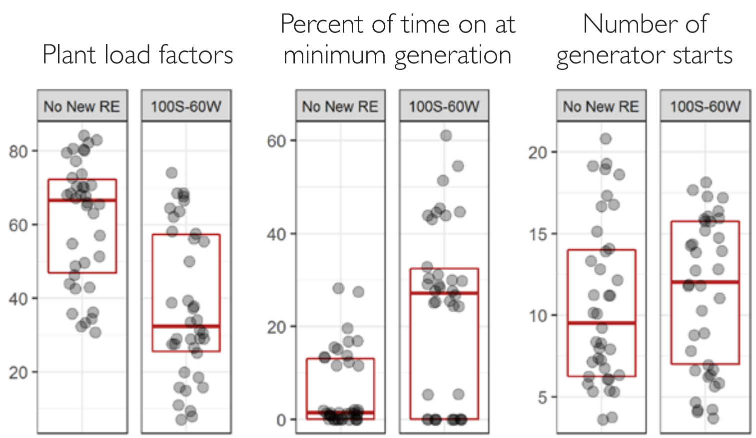
Maximum net load valley-to-peak ramp is **13 GW in the 100S-60W scenario**, up from **8.0 GW in the No New RE scenario.**

Hourly net load ramps for all periods of the year, ordered by magnitude



Changes to Rajasthan's Coal Fleet Operations

Operational impacts to coal



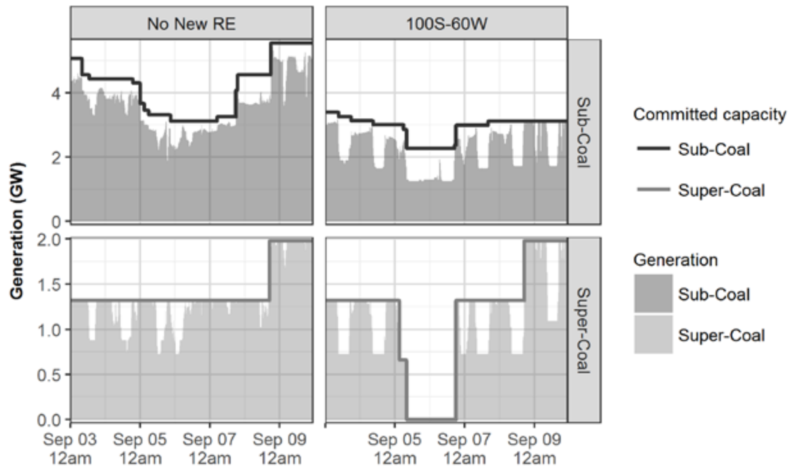
Coal plant load factors (PLFs) are lower in the 100S-60W scenario due to more frequent cycling and operation at minimum generation levels.

While coal PLFs are lower fleetwide in 100S-60W, the most expensive generators experience the greatest drop in PLF.

Average PLF of coal generators in Rajasthan, disaggregated by variable cost

RELATIVE VARIABLE COST	NO NEW RE	100S-60W
Lower 1/3	58	51
Mid 1/3	60	50
Higher 1/3	54	14
Fleetwide	63	43

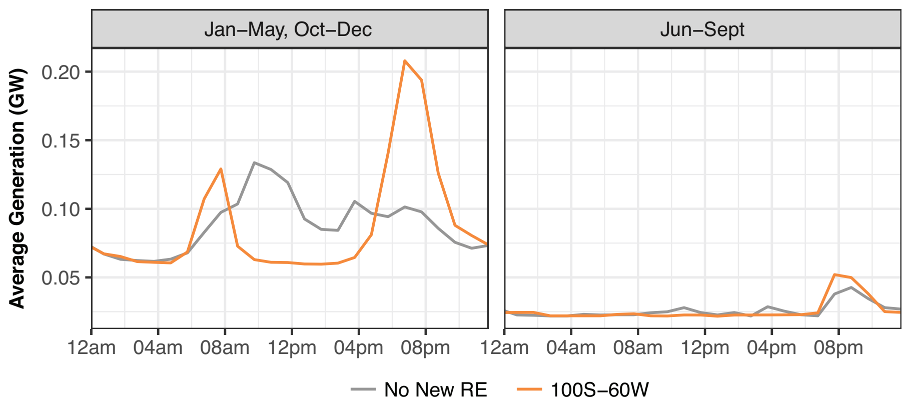
One week of coal operation in Rajasthan



The coal fleet is turned off more and its output varies daily due to midday availability of solar power in the 100S-60W scenario.

Changes to Rajasthan's Hydro Fleet Operations

Average day of hydro in Rajasthan by season



Low hydro availability in Rajasthan limits its effectiveness in helping to balance changes to net load.

Hydro plants follow a more pronounced two-peak generation profile due to availability of solar power during the middle of the day.

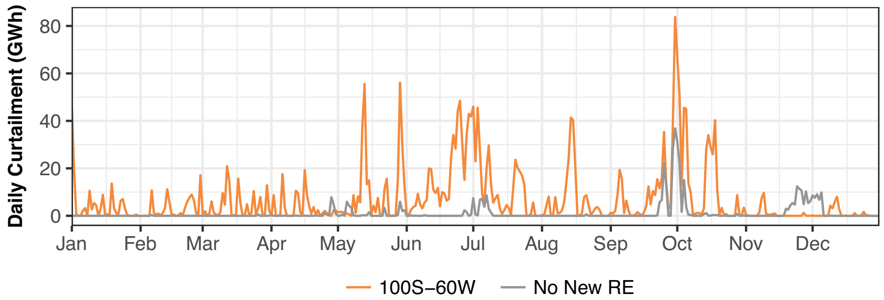
How Well Is RE Integrated? Curtailment and Operational Snapshots

Curtailment levels indicate how efficiently RE is integrated. Large amounts of curtailment signal inflexibility in the system, preventing grid operators from being able to take full advantage of the available renewable resources.

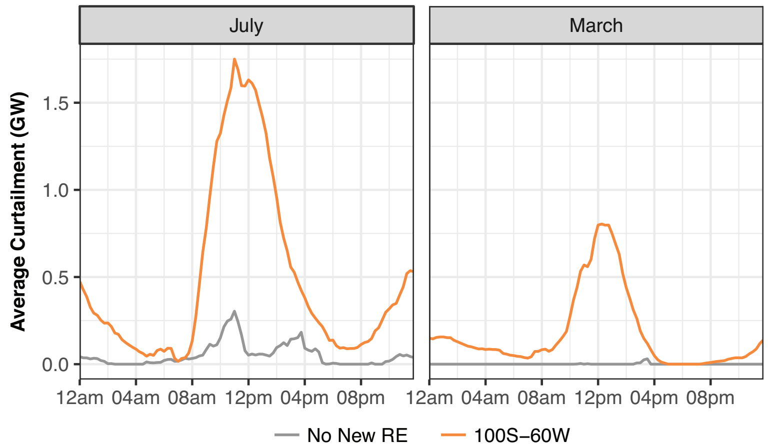
5.6% of wind and solar is curtailed annually.

Almost all of RE curtailment occurs in 15% of periods in the year.

Total daily curtailment throughout the year in Rajasthan

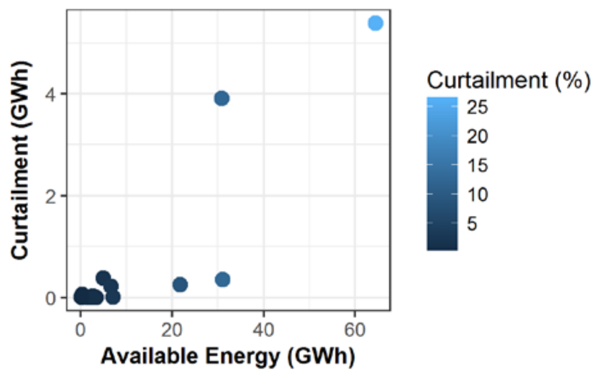


Average daily curtailment in March and July in Rajasthan

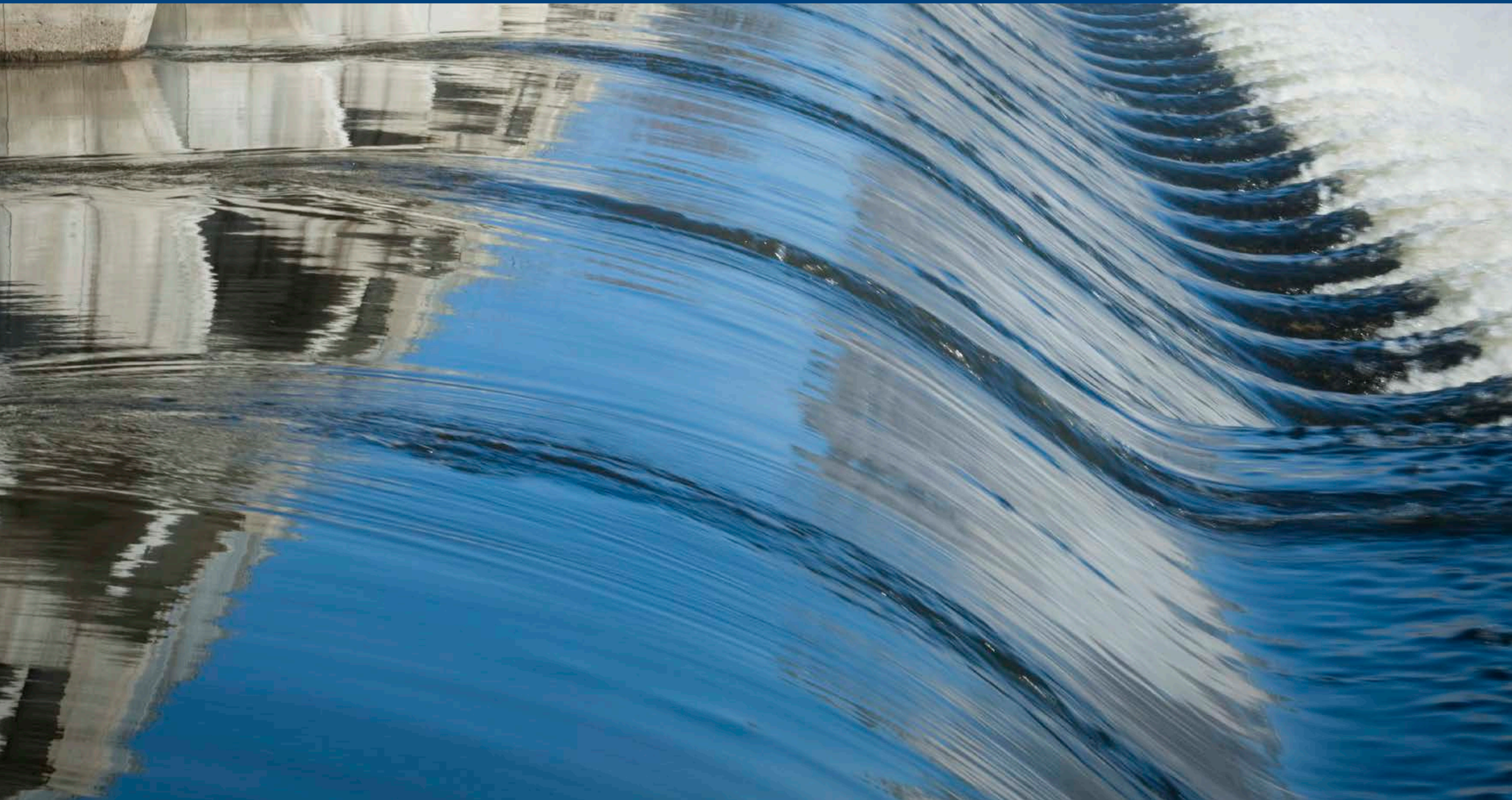


Two substations contribute the majority of Rajasthan's RE curtailment, despite the addition to this model of nine in-state lines to reduce curtailment. This suggests that thorough in-state transmission planning will be necessary for Rajasthan to effectively consume and export RE generation.

RE curtailment as a percent of available energy by substation (each dot represents a substation)



Examples of Dispatch During Interesting Periods in Rajasthan

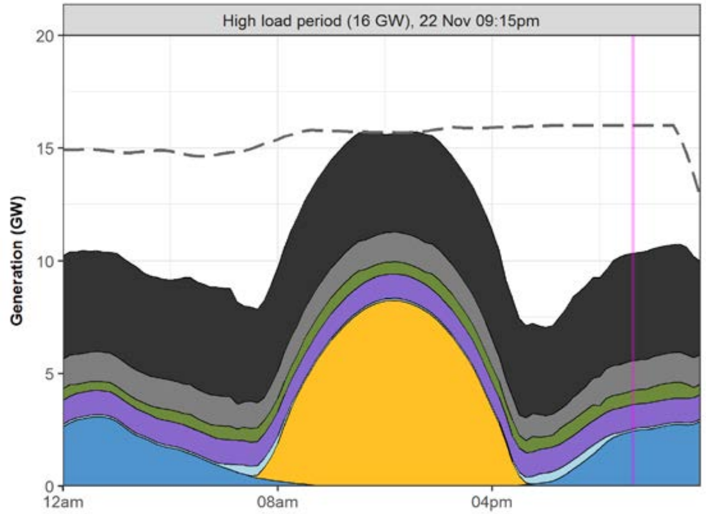


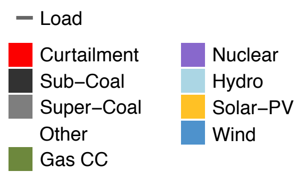
The following pages show dispatch in Rajasthan during several interesting periods throughout 2022. The vertical magenta line highlights the dispatch interval associated with the figure title.

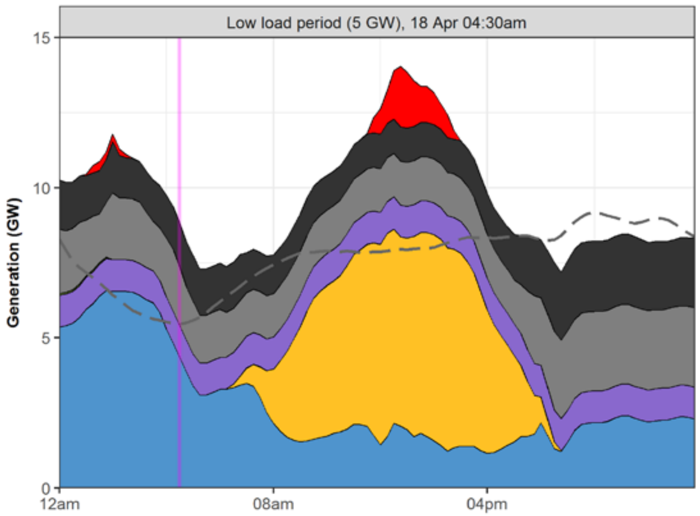
High load period: Generation, load, and interchange (values in GW unless otherwise specified)

22 November 9:15 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
16	0	0.1	1.1	6.1	0.6	2.5	5.7	15







Low load period: Generation, load, and interchange (values in GW unless otherwise specified)

18 April 4:30 am

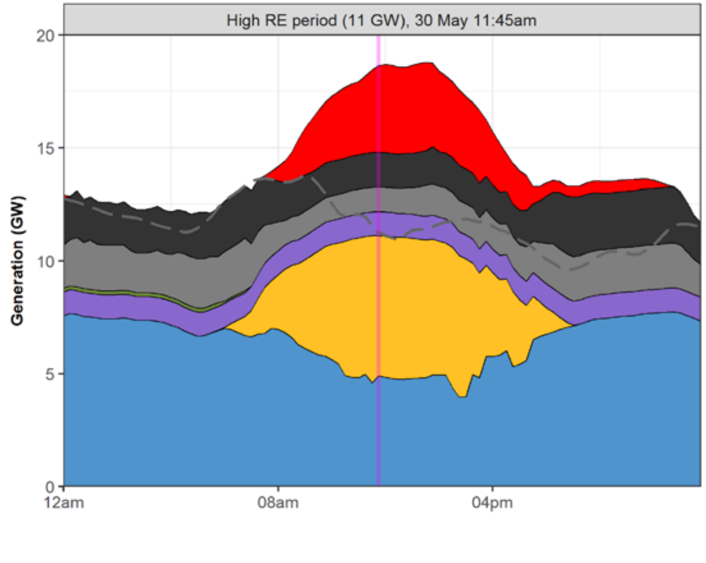
LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
5.5	0	0	1.1	3.4	0	4.4	3.4	80

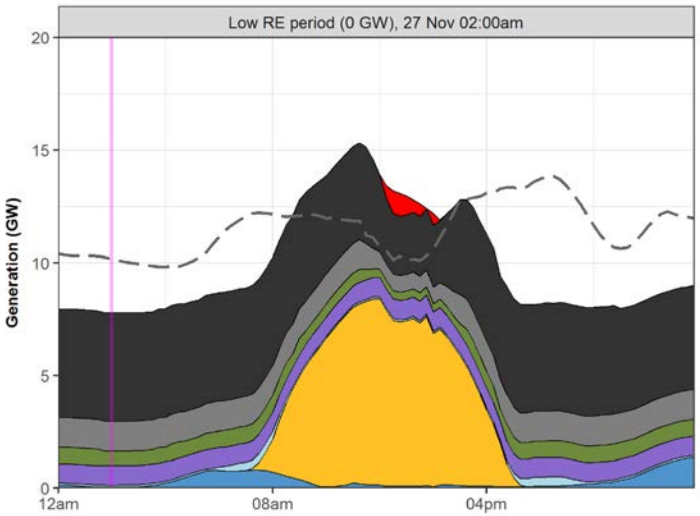
Example Dispatch Days

High RE period: Generation, load, and interchange (values in GW unless otherwise specified)

30 May 11:45 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
11.3	3.8	0	1.1	2.6	0	11.1	3.6	99

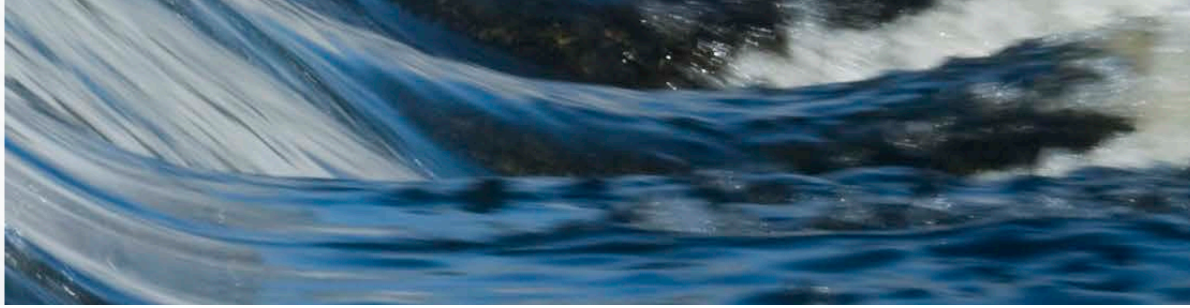




Low RE period: Generation, load, and interchange (values in GW unless otherwise specified)

27 November 2:00 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
10.2	0	0.1	0.9	6.1	0.7	0	2.4	0.4

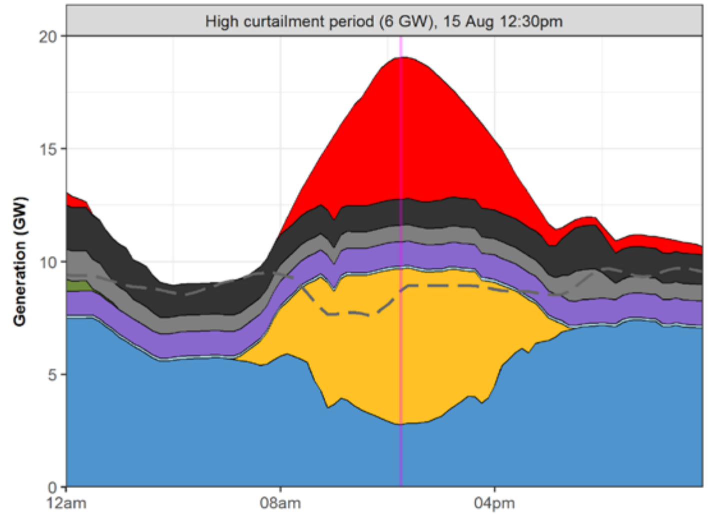


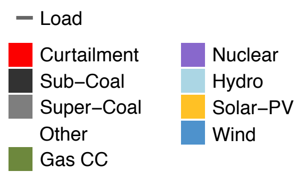
Example Dispatch Days

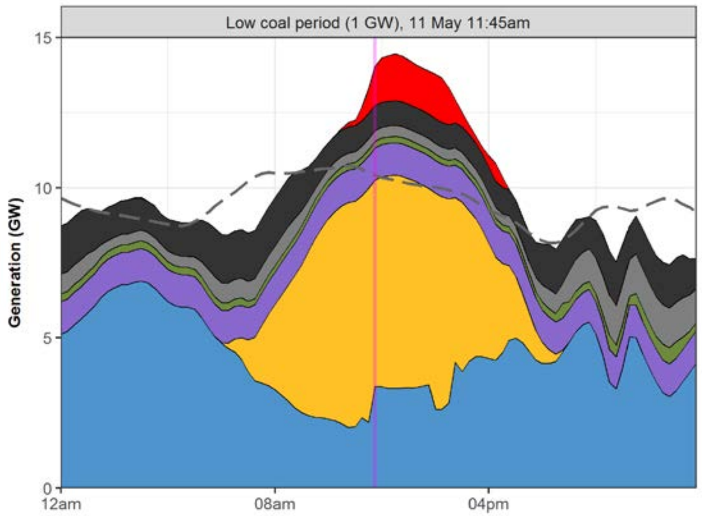
High curtailment period: Generation, load, and interchange (values in GW unless otherwise specified)

15 August 12:30 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
8.7	6.3	0.1	1.1	1.9	0	9.7	4	111





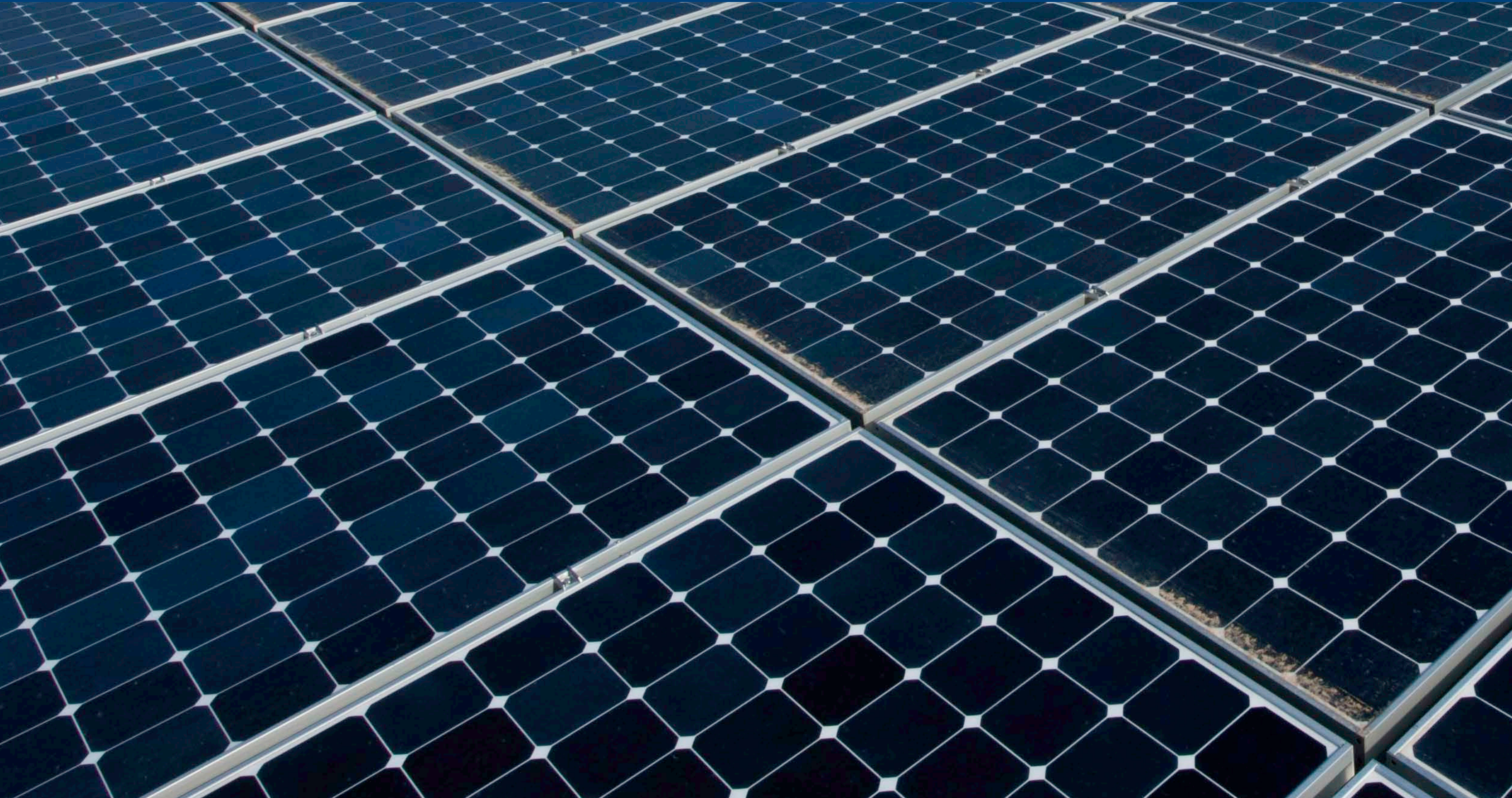


Low coal period: Generation, load, and interchange (values in GW unless otherwise specified)

11 May 11:45 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
10.4	1.3	0	1.1	1.2	0.2	10.3	2.3	98

Conclusions



Based on this study's assumptions about demand and installed generation and transmission capacity in Rajasthan and nationwide, Rajasthan can integrate the equivalent of 49% of its total generation in 2022 with 5.6% annual wind and solar curtailment. This changes the way Rajasthan's grid must operate. Compared to a 2022 system with no new RE, net exports rise by 79% annually and the PLF of the coal fleet falls from 63% to 43%.

Rajasthan has the largest percentage of RE capacity outside the Southern region. Coordinated planning between intrastate transmission and locations of new RE can alleviate the risk of RE curtailment. Sufficient transmission will be necessary to not only evacuate RE, but also enable the full use of flexible resources such as coal or hydro.

What can the state do to prepare for higher RE futures?

Establish process for optimizing locations and capacities for RE and transmission; inadequate transmission has a large effect on RE curtailment in the model. This requires good information on possible areas for RE locations.

Match or exceed CERC guidelines for coal flexibility. Reducing minimum operating levels for coal plants has the largest impact to RE curtailment among all integration strategies evaluated.

Consider mechanisms to better coordinate scheduling and dispatch with neighbors, which can reduce production costs and allow each state to better access least-cost generation, smooth variability and uncertainty, and better access sources of system flexibility.

Create a new tariff structure for coal that specifies performance criteria (e.g., ramping), and that addresses the value of coal as PLFs decline.

Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks.

Use PPAs to require RE generators to provide grid services such as automatic generation control and operational data.

Create policy and regulatory incentives to access the full capabilities of existing coal, hydro, and pumped storage.

Require merit order dispatch based on system-wide production costs; supplementary software may be required.

Improve the production cost model built for this study to address state-specific questions.

Institute organization and staff time to maintain the model over time.

Update power flow files to include more information related to high RE futures; conduct dynamic stability studies.

Adopt state-of-the-art load and RE forecasting systems.

Address integration issues at the distribution grid, including rooftop PV and utility-scale wind and solar that is connected to low voltage lines.

For a broader set of policy actions, see the executive summary for the National Study at www.nrel.gov/docs/fy17osti/68720.pdf.

Ways to use the model for state planning

You can use this model for operational and planning questions such as:

What is the effect on operations of different reserve levels?

How will changes to operations or new infrastructure affect coal cycling?

What is the impact on dispatch of changes to market designs or PPA requirements?

How will different RE growth scenarios affect fuel requirements and emissions targets?

How does a new transmission line affect scheduling and costs?

What are plant-specific impacts (PLFs, curtailment) based on different scenarios?

What are critical periods for follow-up with a power flow analysis, and what is the generation status of each plant during these periods?

What flexibility is required of the system under different future scenarios?

What technologies or systematic changes could benefit the system most?

The production cost model built for this study is ready for you to use!

Next Steps to Improve the Model for State Planning

The production cost model used in this study has been built to assess region- and nationwide trends, and lacks some of the plant-specific detail that will be more important if the model is used for planning at the state level. Further improvements are suggested for use at the state level:

Input load specific to each substation level

Current model allocates a statewide load to each substation proportionate to peak

Modify load shapes to reflect expected changes to appliance ownership and other usage patterns

Current model uses 2014 load shape, scaled up to 2022 peak demand

Revise RE locations and transmission plans as investments evolve

Current model uses best RE locations within the state based on suitable land availability; transmission plans are based on CEA's 2021–2022 PSS/E model and do not reflect anticipated changes to in-state transmission to meet new RE

Improve generator-specific parameters (e.g., variable costs, minimum up/down time, hub heights, must run status)

Current model uses generator-specific information when available, but also relies on averages (e.g., all utility PV employs fixed tracking)

Create plant-specific allocations of central generations

Current model allocates all central plant generating capacity to the host state

Allocate balancing responsibility for new RE plants to host state versus offtaker state or central entity

Current model allocates responsibility for balancing to host state

Create an equivalent but computationally simpler representation of transmission in states or regions where operations do not affect focus area

Current model includes level of detail for the country that may be unnecessary for a specific state, creating computational challenges

Appendix

Supplemental information on study assumptions

Total generation capacity in Rajasthan (GW) in the 100S-60W scenario

	OWNERSHIP	TOTAL CAPACITY (GW)
Gas CC	State/Private	0.6
Gas CC	Central	0.4
Hydro	State/Private	0.4
Nuclear	Central	1.3
Sub-Coal	State/Private	7.0
Super-Coal	State/Private	2.6
Total non-RE		12.3
Solar-PV	State/Private	11.0
Wind	State/Private	8.6
Total RE		19.6
Total capacity		**31.9**

Total capacity (surge impedance limit [SIL]) of transmission lines connecting Rajasthan to other states
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Rajasthan to Delhi	220	1
Rajasthan to Gujarat	765	2
Rajasthan to Gujarat*	400	4
Rajasthan to Haryana	132	3
Rajasthan to Haryana	220	5
Rajasthan to Haryana	400	12
Rajasthan to Haryana	765	2
Rajasthan to Madhya Pradesh	220	2
Rajasthan to Madhya Pradesh	400	2
Rajasthan to Madhya Pradesh	765	4
Rajasthan to Punjab	765	2
Rajasthan to Uttar Pradesh	220	1
Rajasthan to Uttar Pradesh	400	9
Total import/export capacity		**49**

Total capacity (SIL) of transmission lines within Rajasthan
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Intrastate	132	601
Intrastate	220	296
Intrastate	765	10
Intrastate*	400	113
Total intrastate capacity		**1,020**

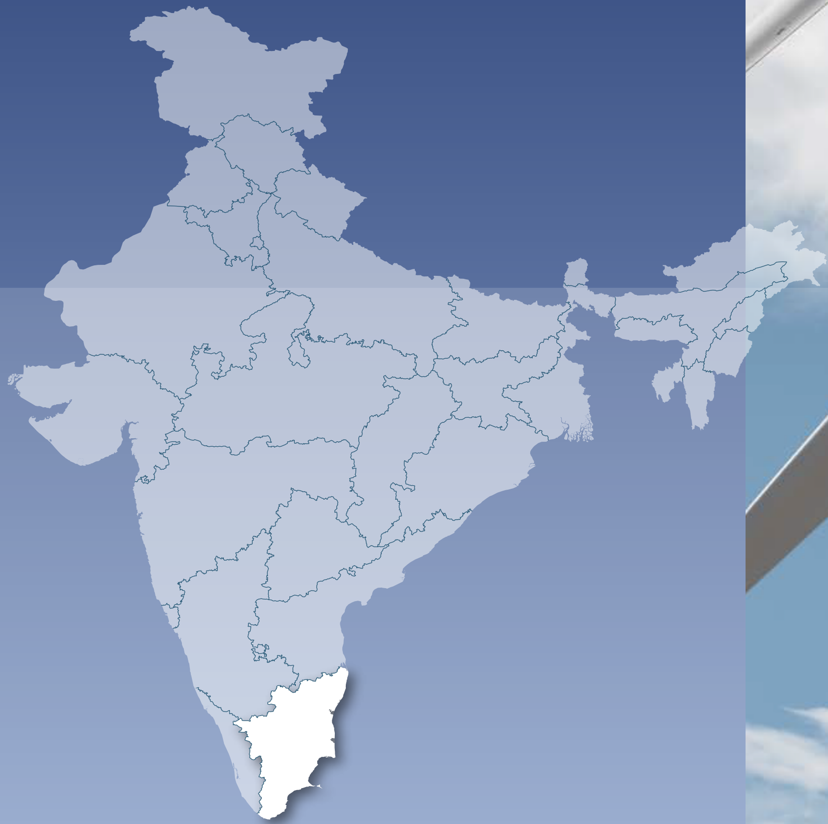
RE capacity by substation and type		
SUBSTATION (NUMBER_NAME_VOLTAGE)	**SOLAR-PV (MW)**	**WIND (MW)**
162216_BARMER_220	0	15
162237_AMARSAGAR-W_220	1,552	935
162238_TINWARI-WS_220	67	202
162240_BHOPALGA_220	0	40
162284_BARLI_2_220	158	113
162395_SANWREEJ-WS_220	4,151	0
162760_PRATAPGARH-W_220	0	312
164110_JAISALMER_400	573	192
164401_AKAL-4_400	1,700	1,511
164402_BARMER-4_400	0	4,912
164403_RAMGARH_400	0	19
164406_HERAPU-4_400	46	0

RE capacity by substation and type		
SUBSTATION (NUMBER_NAME_VOLTAGE)	**SOLAR-PV (MW)**	**WIND (MW)**
164408_RATANGAR_400	41	242
164413_RAJWEST_400	658	0
164433_JODHPU-4_400	456	0
164451_JAIPUR_RS_400	836	107
184403_BHINMAL_400	43	0
184404_KANKROLI_400	309	0
184407_KOTA_400	382	0
184430_BASSI_400	16	0
184458_SHRECEM_400	233	0
184473_JAIPUR_PG_400	56	0
Total RE capacity	**11,277**	**8,600**

Annual energy generation fuel type, No New RE and 100S-60W		
	100S-60W (TWh)	NO NEW RE (TWh)
Gas CC	2	4
Hydro	1	1
Nuclear	8	8
Solar-PV: rooftop	4	0
Solar-PV: utility scale	16	3
Sub-Coal	23	38
Super-Coal	13	15
Wind	24	10
Total Generation	92	79
Imports	34	44
Exports	31	28
RE Curtailment	3	0

Greening the Grid

Tamil Nadu



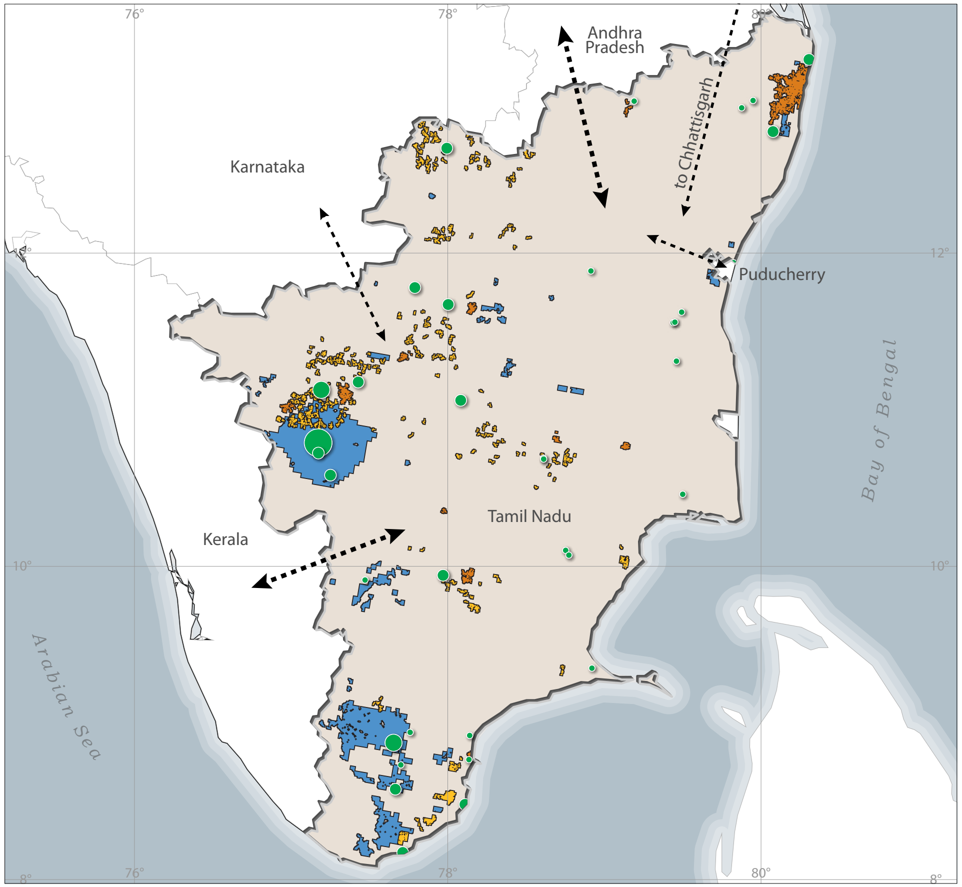
Pathways to Integrate 175 Gigawatts of Renewable Energy into India's Electric Grid

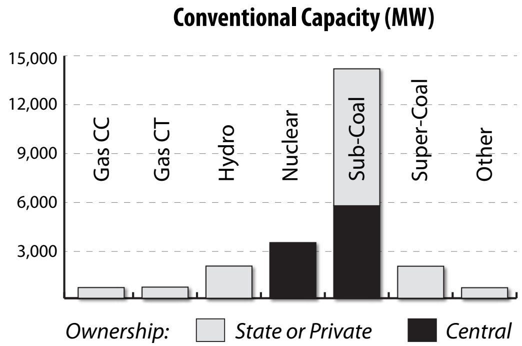
State-specific results from Volume II, which includes all of India. The full reports include detailed explanations of modeling assumptions, results, and policy conclusions.

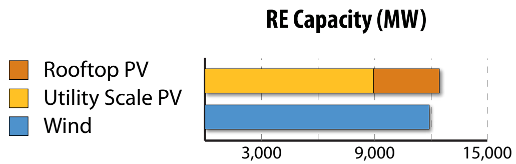
www.nrel.gov/india-grid-integration/

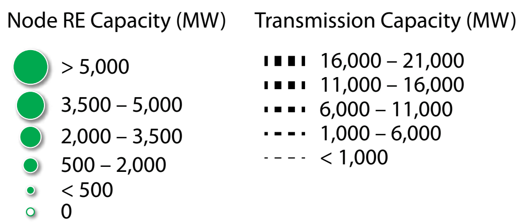
Assumptions About Infrastructure, Demand, and Resource Availability in 2022

Assumptions about RE and conventional generation and transmission in Tamil Nadu in 2022









Peak load (GW)	25
Total annual load (TWh)	316
Installed non-RE capacity (GW)	24
Installed RE capacity (GW)	24
Total import/export capacity (GW)	29

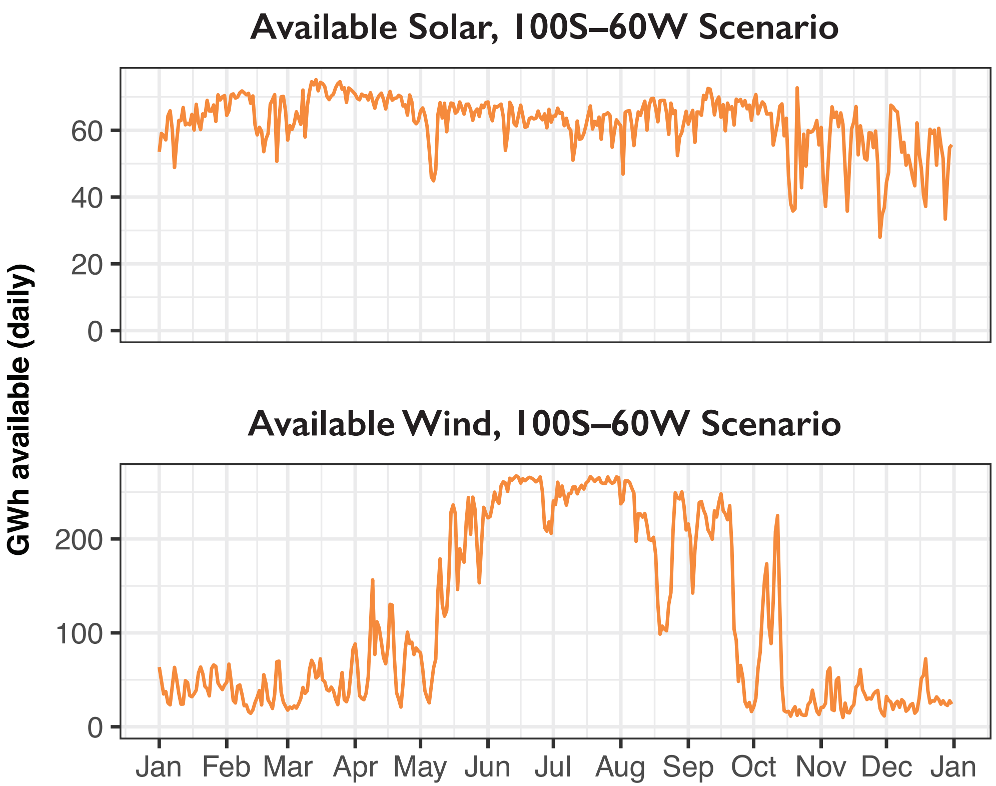
Tamil Nadu has 35 tie-lines connecting it to other states in this model.

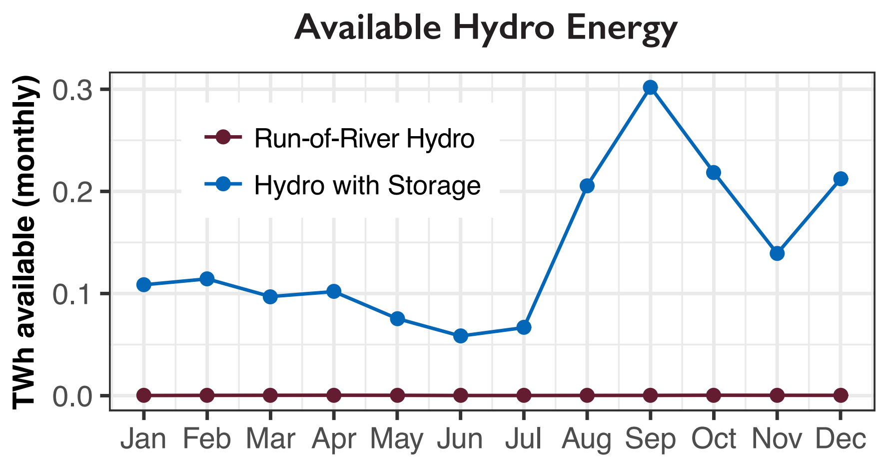
NREL and LBNL selected RE sites based on the methodology explained in Volume I of this report, which is available at www.nrel.gov/docs/fy17osti/68530.pdf.

Rooftop PV has been clubbed to the nearest transmission node.

Tamil Nadu Resource Availability in 2022

Available wind, solar, and hydro energy throughout the year in Tamil Nadu





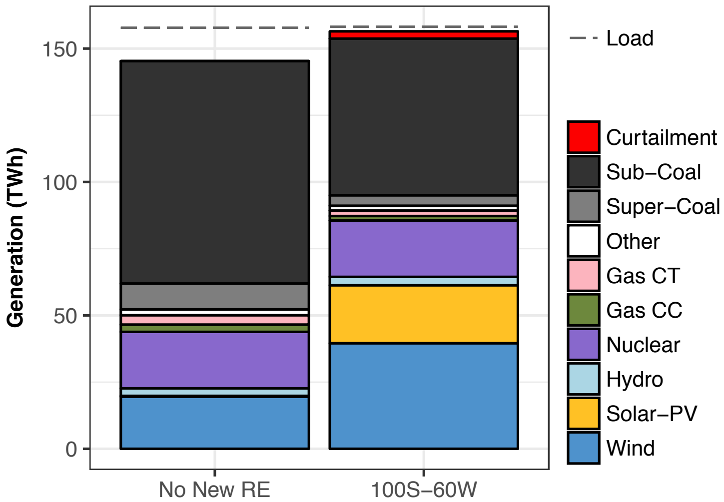
Daily solar energy is relatively consistent throughout the year while wind energy varies seasonally.

Note: Y-axis is different for each resource

Operation in Tamil Nadu with Higher Levels of RE: RE Penetration in 2022

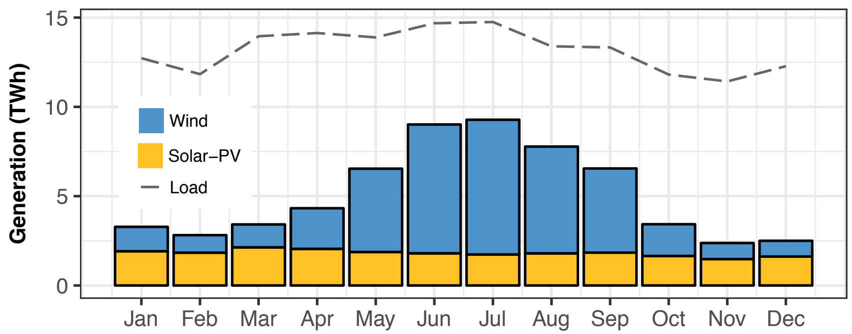
Increased amounts of RE available in Tamil Nadu change Tamil Nadu's generation mix and therefore the operation of the entire fleet.

Annual energy generation in Tamil Nadu



24 GW of wind and solar power generates 61 TWh annually.

Monthly RE generation and load in Tamil Nadu in the 100S-60W scenario



Wind and solar produce 40% of total generation in Tamil Nadu and meet 39% of load.

RE penetration by load and generation

	100S-60W
Percent time over 50% of load	33
Peak RE % of load	100
Percent time over 50% of generation	37
Peak RE % of generation	82

Coal generation falls by 33% and gas by 41% between No New RE and 100S-60W.

Operation in Tamil Nadu with Higher Levels of RE: Imports and Exports

Increased RE generation inside and outside of Tamil Nadu affects flows with surrounding states.

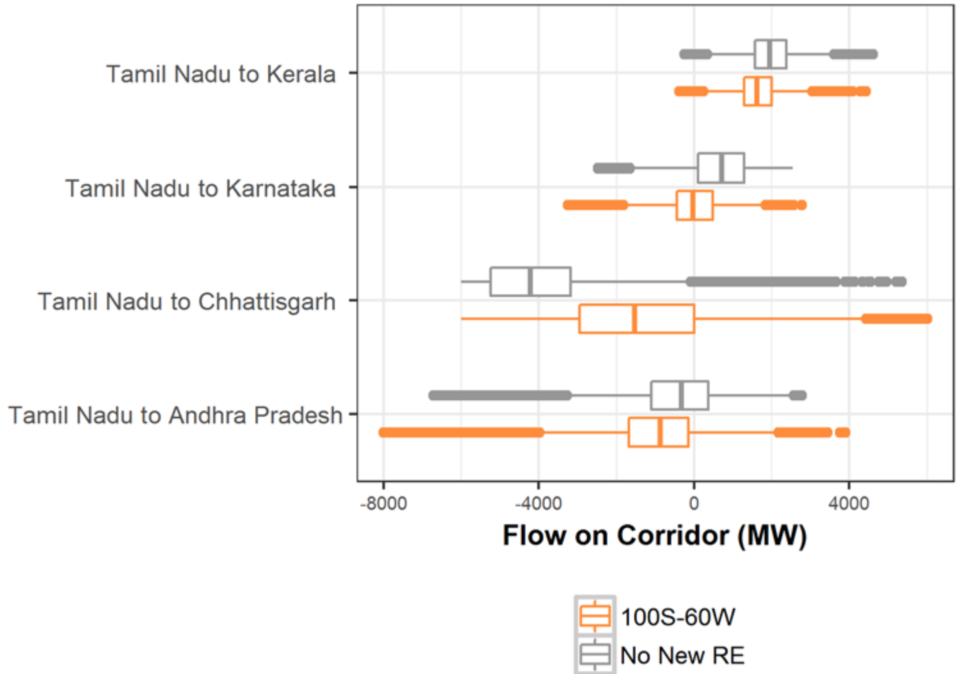
Tamil Nadu's increased RE generation allows it to reduce imports from Chhattisgarh. The state also reduces its net exports to Karnataka, Kerala, and Andhra Pradesh, which likewise are relying more on their local RE generation. The shift in flows away from traditional corridors contributes to a 56% increase in periods when in-state congestion affects dispatch.

Imports fall by **11%** annually

Exports fall by **16%** annually

SCENARIO	NET EXPORTS (TWH)	
No New RE	-12	net importer
100S-60W	-4.4	net importer

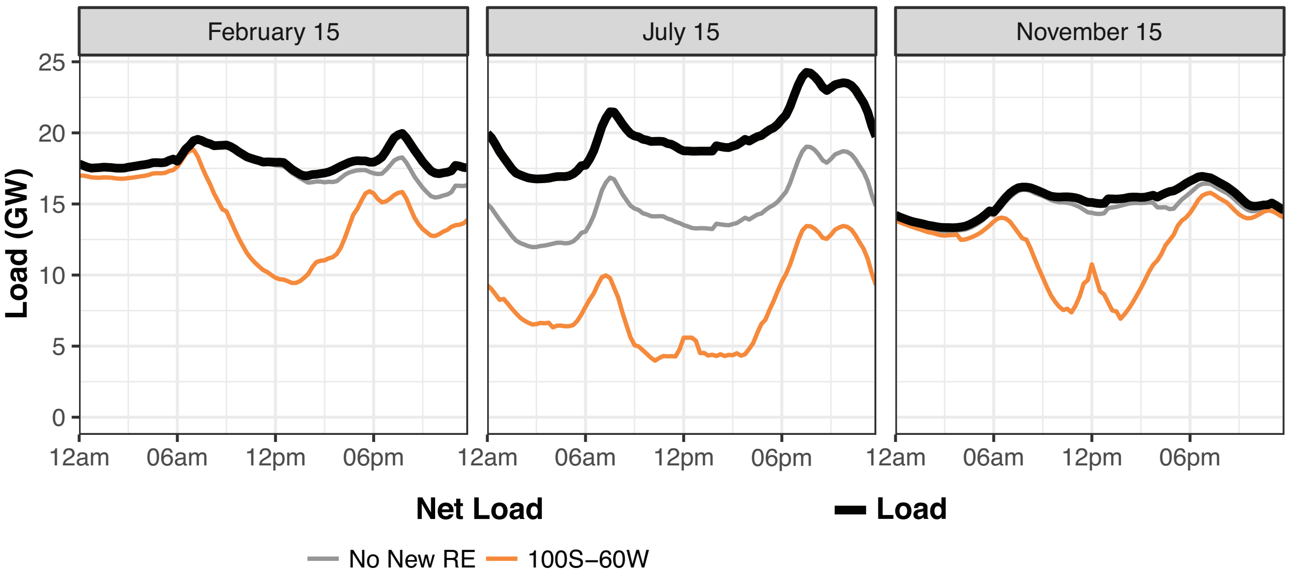
Distribution of flows across state-to-state corridors



Operation in Tamil Nadu with Higher Levels of RE: Rest of the Fleet

The addition of RE in Tamil Nadu changes net load, which is the load that is not met by RE and therefore must be met by conventional generation. Due to changes in net load, hydro and thermal plants operate differently in higher RE scenarios.

Example days of load and net load in Tamil Nadu

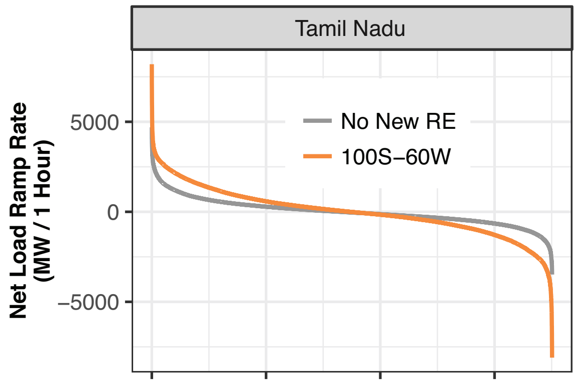


Increased daytime solar generation causes a dip in net load, which requires Tamil Nadu to either increase net exports, turn down its thermal generators, or curtail RE. On 15 July, increased monsoon season wind generation reduces Tamil Nadu's net load throughout the day.

Peak 1-hour net load up-ramp in the **100S-60W scenario is 8.2 GW**, up from **4.7 GW in the No New RE scenario.**

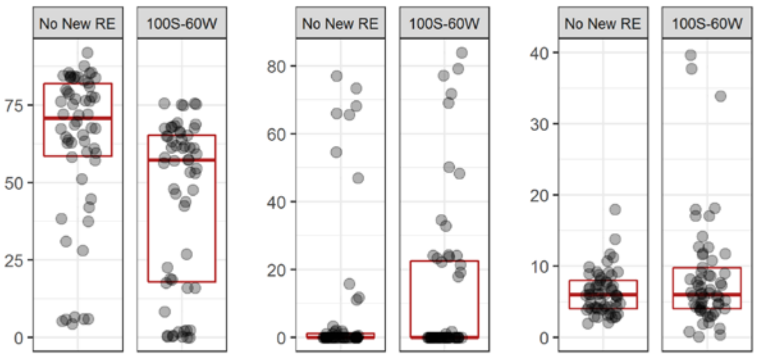
Maximum net load valley-to-peak ramp is **14 GW in the 100S-60W scenario**, up from **8.6 GW in the No New RE scenario.**

Hourly net load ramps for all periods of the year, ordered by magnitude



Changes to Tamil Nadu's Coal Fleet Operations

Operational impacts to coal



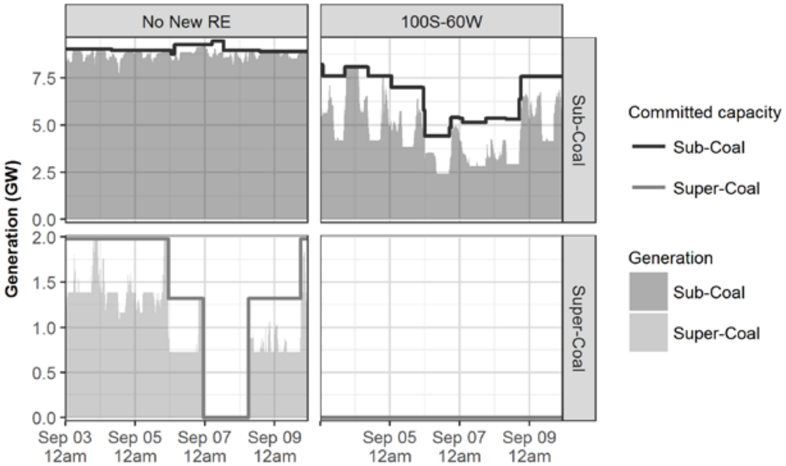
Coal plant load factors (PLFs) are lower in the 100S-60W scenario due to more frequent cycling and operation at minimum generation levels.

While coal PLFs are lower fleetwide in 100S-60W, the most expensive generators experience the greatest drop in PLF.

Average PLF of coal generators in Tamil Nadu, disaggregated by variable cost

RELATIVE VARIABLE COST	NO NEW RE	100S-60W
Lower 1/3	76	66
Mid 1/3	79	58
Higher 1/3	43	12
Fleetwide	66	44

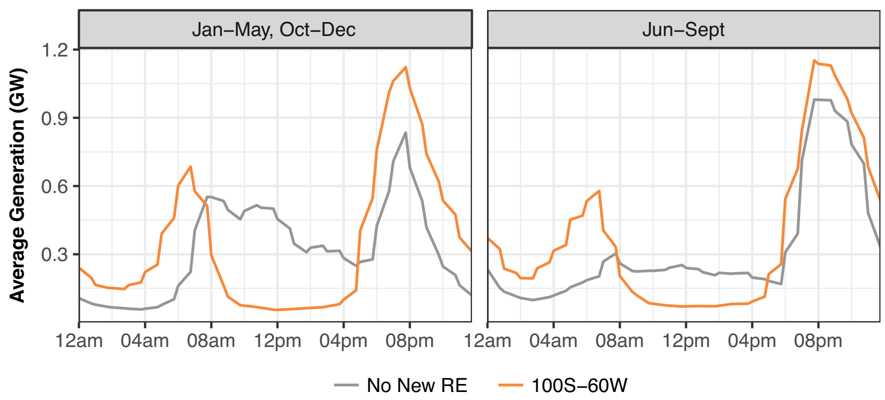
One week of coal operation in Tamil Nadu



The coal fleet is turned off more and its output varies daily due to midday availability of solar power in the 100S-60W scenario.

Changes to Tamil Nadu's Hydro Fleet Operations

Average day of hydro in Tamil Nadu by season



Tamil Nadu is able to utilize most of the flexibility available in hydro in both nonmonsoon and monsoon seasons. This is partially aided by the flexibility supplied from pumped hydro.

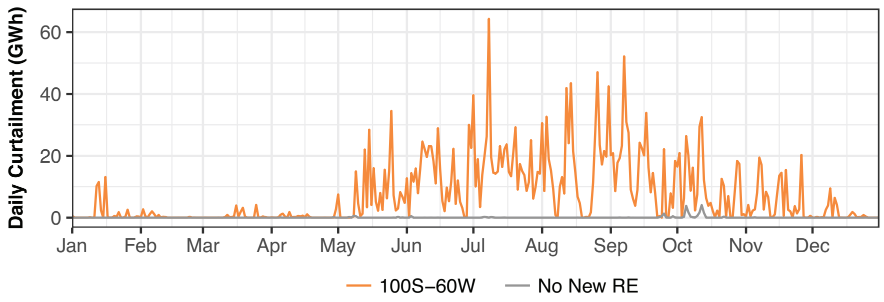
Hydro plants follow a more pronounced two-peak generation profile due to availability of solar power during the middle of the day.

How Well Is RE Integrated?
Curtailment and Operational Snapshots

Curtailment levels indicate how efficiently RE is integrated. Large amounts of curtailment signal inflexibility in the system, preventing grid operators from being able to take full advantage of the available renewable resources.

4.3% of wind and solar is curtailed annually.

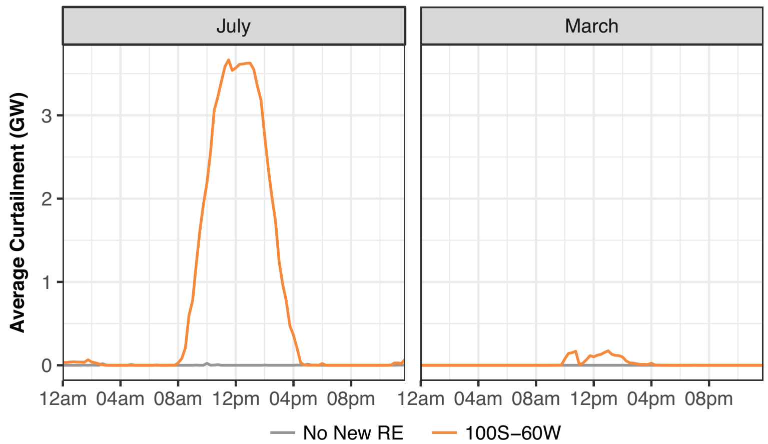
Total daily curtailment throughout the year in Tamil Nadu



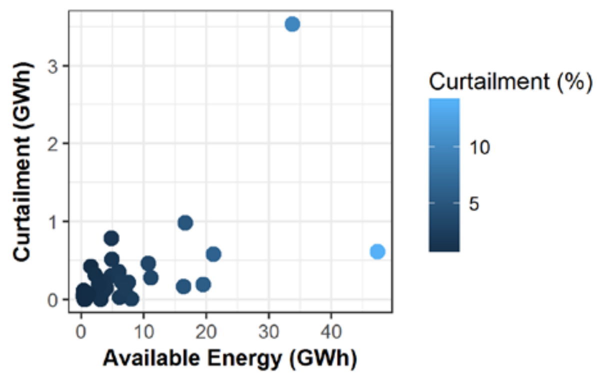
Tamil Nadu's RE curtailment is relatively low from January through April but rises during the monsoon season, and this persists through November. In-state congestion affects its dispatch for 56% of the year, and for 13% of the year its thermal fleet is fully inflexible. Both of these factors contribute to RE curtailment. Tamil Nadu's geographic location can restrict access to external markets, making adequate local thermal and transmission flexibility especially important.

Almost all of RE curtailment occurs in 8.4% of periods in the year.

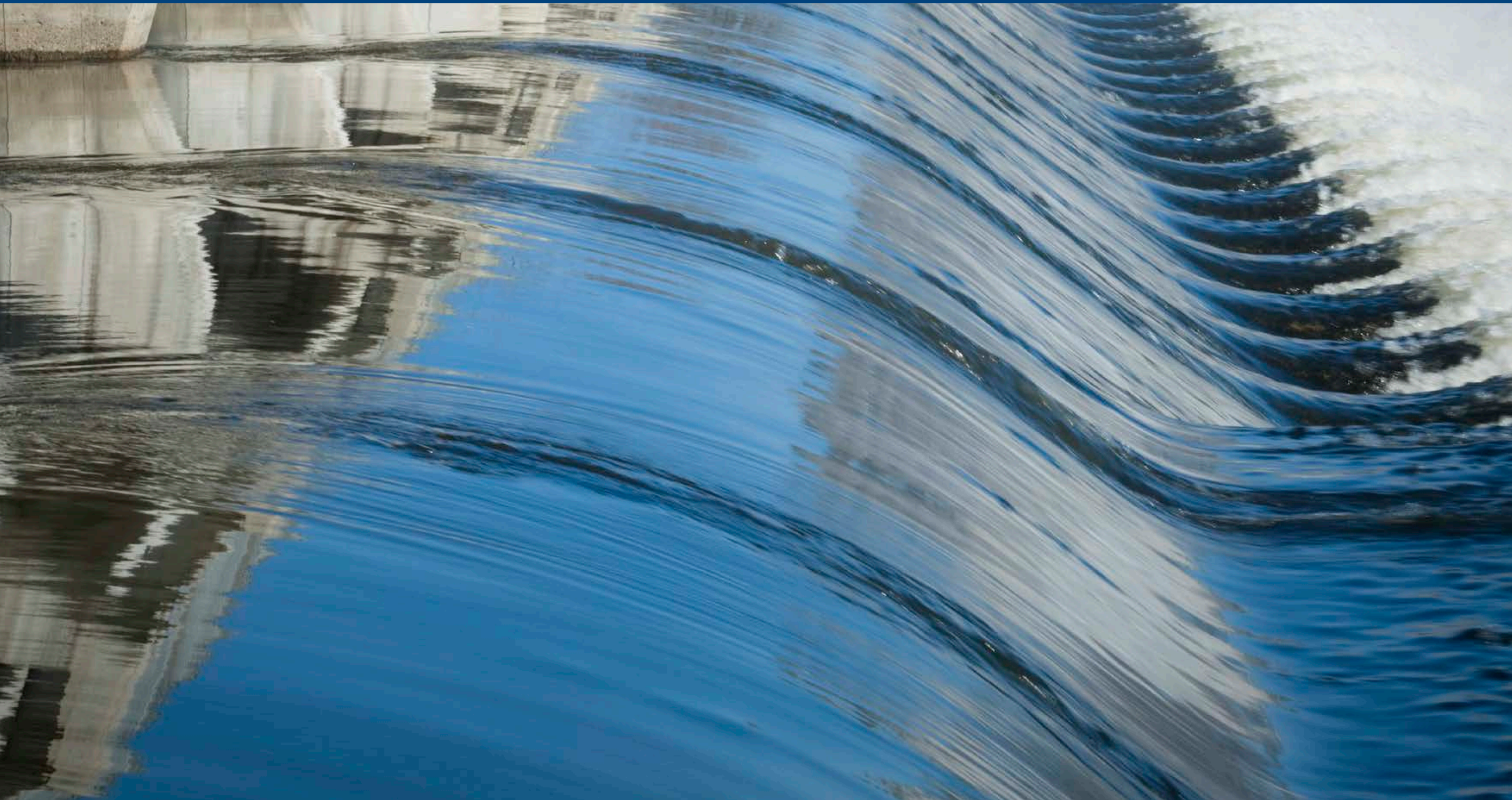
Average daily curtailment in March and July in Tamil Nadu



RE curtailment as a percent of available energy by substation (each dot represents a substation)



Examples of Dispatch During Interesting Periods in Tamil Nadu

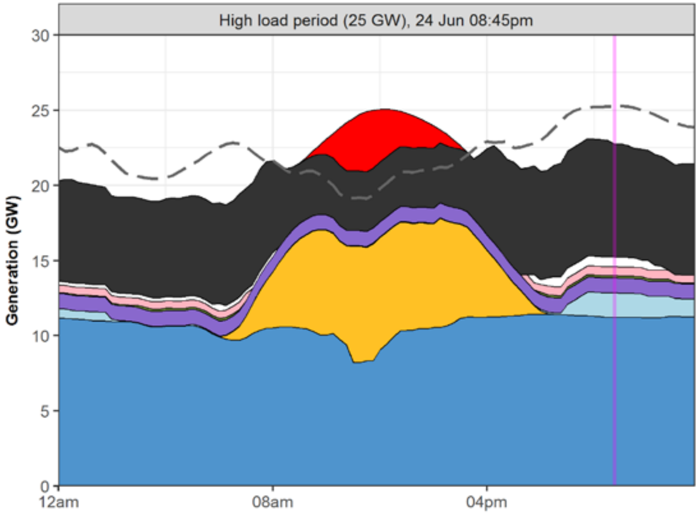


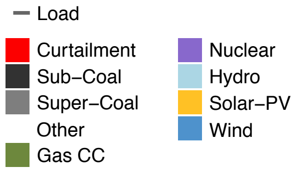
The following pages show dispatch in Tamil Nadu during several interesting periods throughout 2022. The vertical magenta line highlights the dispatch interval associated with the figure title.

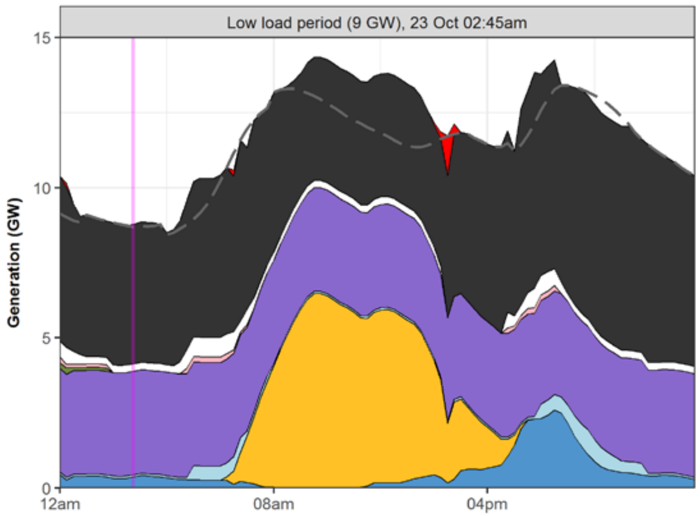
High load period: Generation, load, and interchange (values in GW unless otherwise specified)

24 June 8:45 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET IMPORTS	RE PENETRATION (%)
25.3	0	1.6	1	0.6	7.5	0.7	11.2	2.5	44







Low load period: Generation, load, and interchange (values in GW unless otherwise specified)

23 October 2:45 am

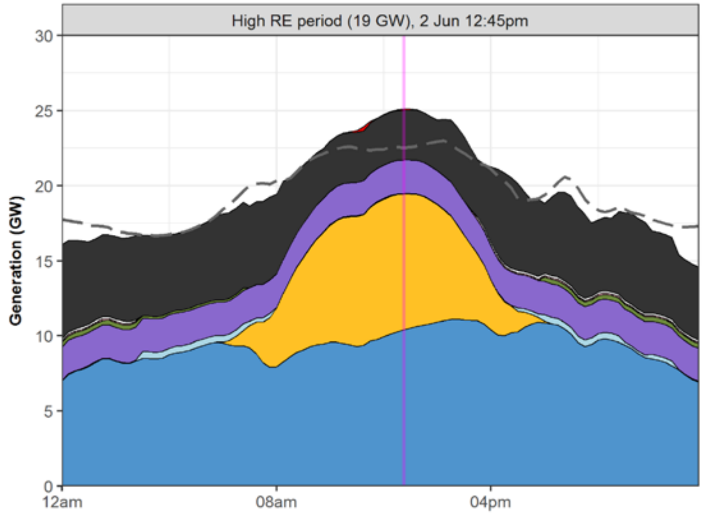
LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
8.7	0	0.1	3.4	0.2	4.6	0	0.4	0.1	4.2

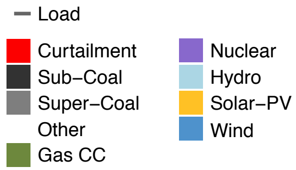
Example Dispatch Days

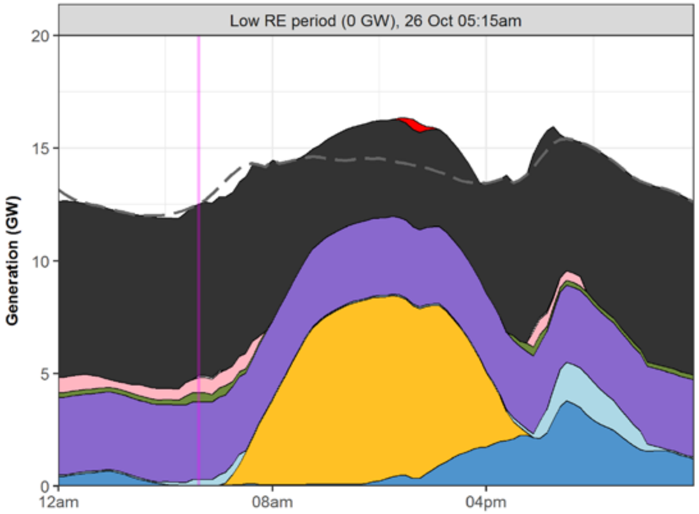
High RE period: Generation, load, and interchange (values in GW unless otherwise specified)

2 June 12:45 pm

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
22.5	0.1	0	2.2	0	3.3	0	19.4	2.5	86





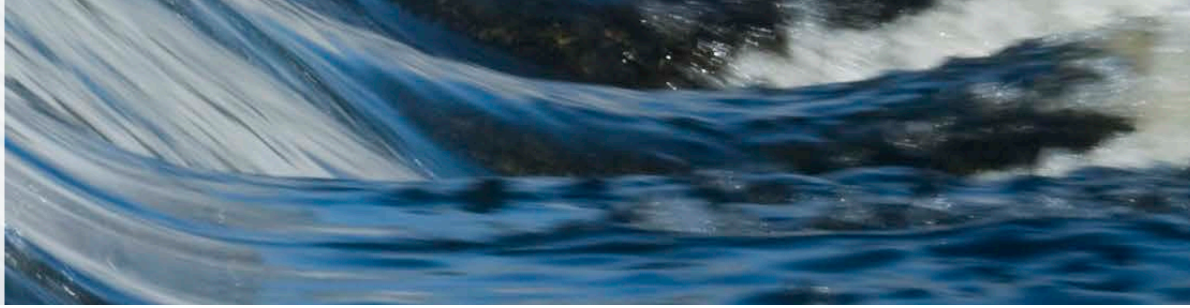


Low RE period: Generation, load, and interchange (values in GW unless otherwise specified)

26 October 5:15 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
12.5	0	0.3	3.4	0.1	7.6	1.1	0	0	0.2

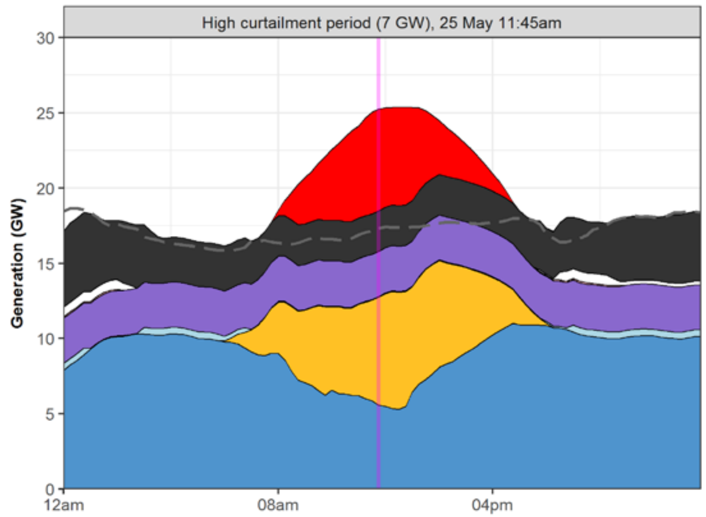
Example Dispatch Days

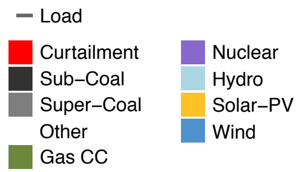


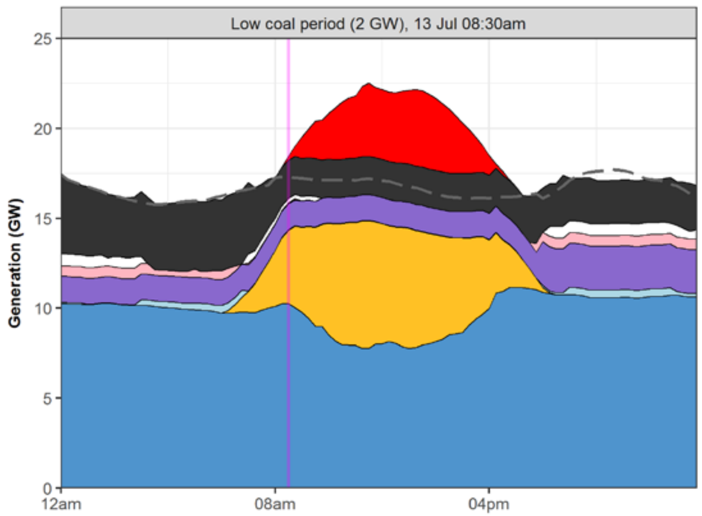
High curtailment period: Generation, load, and interchange (values in GW unless otherwise specified)

25 May 11:45 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
17.3	6.8	0	3	0	2.7	0	12.7	1.2	74







Low coal period: Generation, load, and interchange (values in GW unless otherwise specified)

13 July 8:30 am

LOAD	CURTAILMENT	HYDRO	NUCLEAR	OTHER	COAL	GAS	RE	NET EXPORTS	RE PENETRATION (%)
17.3	0.2	0	1.4	0.2	2.1	0.1	14.4	0.9	83

Conclusions

Based on this study's assumptions about demand and installed generation and transmission capacity in Tamil Nadu and nationwide, Tamil Nadu can integrate the equivalent of 40% of its total generation in 2022 with 4.3% annual wind and solar curtailment. This changes the way Tamil Nadu's grid must operate. Compared to a 2022 system with no new RE, net exports rise by 36% annually, and the PLF of the coal fleet falls from 66% to 44%.

Because Tamil Nadu borders the ocean with limited interstate transmission capacity, it is especially affected by constraints in Andhra Pradesh, in Karnataka, and on the Southern-to-Western-region interface. Regionwide solutions will be especially impactful to Tamil Nadu because of these factors.

What can the state do to prepare for higher RE futures?

Establish process for optimizing locations and capacities for RE and transmission; inadequate transmission has a large effect on RE curtailment in the model. This requires good information on possible areas for RE locations.

Match or exceed CERC guidelines for coal flexibility. Reducing minimum operating levels for coal plants has the largest impact to RE curtailment among all integration strategies evaluated.

Consider mechanisms to better coordinate scheduling and dispatch with neighbors, which can reduce production costs and allow each state to better access least-cost generation, smooth variability and uncertainty, and better access sources of system flexibility.

Create a new tariff structure for coal that specifies performance criteria (e.g., ramping), and that addresses the value of coal as PLFs decline.

Create model PPAs for RE that move away from must-run status and employ alternative approaches to limit financial risks.

Use PPAs to require RE generators to provide grid services such as automatic generation control and operational data.

Create policy and regulatory incentives to access the full capabilities of existing coal, hydro, and pumped storage.

Require merit order dispatch based on system-wide production costs; supplementary software may be required.

Improve the production cost model built for this study to address state-specific questions.

Institute organization and staff time to maintain the model over time.

Update power flow files to include more information related to high RE futures; conduct dynamic stability studies.

Adopt state-of-the-art load and RE forecasting systems.

Address integration issues at the distribution grid, including rooftop PV and utility-scale wind and solar that is connected to low voltage lines.

For a broader set of policy actions, see the executive summary for the National Study at www.nrel.gov/docs/fy17osti/68720.pdf.

Ways to use the model for state planning

You can use this model for operational and planning questions such as:

What is the effect on operations of different reserve levels?

How will changes to operations or new infrastructure affect coal cycling?

What is the impact on dispatch of changes to market designs or PPA requirements?

How will different RE growth scenarios affect fuel requirements and emissions targets?

How does a new transmission line affect scheduling and costs?

What are plant-specific impacts (PLFs, curtailment) based on different scenarios?

What are critical periods for follow-up with a power flow analysis, and what is the generation status of each plant during these periods?

What flexibility is required of the system under different future scenarios?

What technologies or systematic changes could benefit the system most?

The production cost model built for this study is ready for you to use!

Next Steps to Improve the Model for State Planning

The production cost model used in this study has been built to assess region- and nationwide trends, and lacks some of the plant-specific detail that will be more important if the model is used for planning at the state level. Further improvements are suggested for use at the state level:

Input load specific to each substation level

Current model allocates a statewide load to each substation proportionate to peak

Modify load shapes to reflect expected changes to appliance ownership and other usage patterns

Current model uses 2014 load shape, scaled up to 2022 peak demand

Revise RE locations and transmission plans as investments evolve

Current model uses best RE locations within the state based on suitable land availability; transmission plans are based on CEA's 2021–2022 PSS/E model and do not reflect anticipated changes to in-state transmission to meet new RE

Improve generator-specific parameters (e.g., variable costs, minimum up/down time, hub heights, must run status)

Current model uses generator-specific information when available, but also relies on averages (e.g., all utility PV employs fixed tracking)

Create plant-specific allocations of central generations

Current model allocates all central plant generating capacity to the host state

Allocate balancing responsibility for new RE plants to host state versus offtaker state or central entity

Current model allocates responsibility for balancing to host state

Create an equivalent but computationally simpler representation of transmission in states or regions where operations do not affect focus area

Current model includes level of detail for the country that may be unnecessary for a specific state, creating computational challenges

Appendix

Supplemental information on study assumptions

Total generation capacity in Tamil Nadu (GW) in the 100S-60W scenario

	OWNERSHIP	TOTAL CAPACITY (GW)
Gas CC	State/Private	0.7
Gas CT	State/Private	0.7
Hydro	State/Private	2.0
Nuclear	Central	3.4
Other	State/Private	0.6
Sub-Coal	Central	5.7
Sub-Coal	State/Private	8.5
Super-Coal	State/Private	2.0
Total non-RE		23.6
Solar-PV	State/Private	12.0
Wind	State/Private	12.0
Total RE		24.0
Total capacity		**47.6**

Total capacity (surge impedance limit [SIL]) of transmission lines connecting Tamil Nadu to other states
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Tamil Nadu to Andhra Pradesh	230	2
Tamil Nadu to Andhra Pradesh	400	9
Tamil Nadu to Andhra Pradesh	765	6
Tamil Nadu to Chhattisgarh	400	2
Tamil Nadu to Karnataka	230	1
Tamil Nadu to Karnataka	400	10
Tamil Nadu to Kerala	230	5
Tamil Nadu to Kerala*	400	19
Tamil Nadu to Puducherry	230	6
Tamil Nadu to Puducherry	400	2
Total import/export capacity		**62**

Total capacity (SIL) of transmission lines within Tamil Nadu
**To evacuate new RE capacity, transmission was added in this study to supplement CEA plans for 2022.*

CONNECTING	VOLTAGE (kV)	NO. LINES
Intrastate	110	87
Intrastate	230	423
Intrastate*	400	194
Intrastate*	765	25
Total intrastate capacity		**729**

RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
542014_ARASUR2_230	808	2,881
542015_JAMBNNPRM2_230	303	94
542064_THENI2_230	0	487
542105_KNARPT-W_230	91	2,369
542112_VALUTHUR2_230	58	0
542114_ANIKDV-W_230	0	1,119
542118_SADAYMPLYM-W_230	1,131	238
542170_SANKARPURI_230	24	10
544003_SALE_400	773	156
544004_TRIC_400	301	0
544005_MADURAI4_400	793	15
544006_UDMP_400	0	1,344
544007_HOSUR4_400	1,417	17
544010_NEYEXTN4_400	0	120
544012_NAGAPTNM4_400	86	0

RE capacity by substation and type

SUBSTATION (NUMBER_NAME_VOLTAGE)	SOLAR-PV (MW)	WIND (MW)
544013_PUGALUR4_400	549	68
544014_ARSUR4_400	1,740	596
544017_KARAIK_400	206	0
544018_TIRUNEL4_400	0	232
544021_KUDAN4_400	416	877
544025_TIRUNVLPOOL_400	0	642
544027_KAYATHAR4_400	16	351
544041_METTUR4_400	536	5
544071_TUTICORN_400	600	37
544086_MALEKTT_400	707	107
544087_TIRUVLM_400	63	0
544088_VALLURTPS_400	1,091	10
544095_TUTI-POOL_400	284	116
544133_GUINDY4_400	434	0
Total RE capacity	**12,427**	**11,891**

Annual energy generation fuel type, No New RE and 100S-60W

	100S-60W (TWh)	NO NEW RE (TWh)
Gas CC	2	3
Gas CT	2	4
Hydro	3	3
Nuclear	21	21
Other	2	2
Solar-PV: rooftop	6	0
Solar-PV: utility scale	15	0
Sub-Coal	59	83
Super-Coal	4	10
Wind	40	20
Total Generation	154	145
Imports	37	52
Exports	33	39
RE Curtailment	3	0

Access both volumes of the *Greening the Grid* India grid integration report at **www.nrel.gov/india-grid-integration/.**

About USAID

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About the Ministry of Power, Government of India

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.

About NREL

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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