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A Study Under the Flexible Resources Initiative of the
U.S.-India Clean Energy Finance Task Force

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Summary for Policymakers

Achieving India's goal of 500 GW of non-fossil capacity (predominantly renewable) is the least-cost and most economical pathway to meet India's rising electricity demand, while safeguarding grid reliability, as long as renewable energy (RE) can be supplemented by flexible resources including 252 GWh (63 GW) of grid-scale battery storage and storage costs continue to decline. If adequate storage and RE capacity are not deployed at scale, substantial additional thermal capacity may be required to meet the rising demand. Deploying storage and renewables at scale will require addressing supply chain challenges and securing adequate financing.

Using comprehensive grid simulations, the study assesses the technical and economic implications of RE deployment at a scale similar to India's ambitious target of 500 GW of non-fossil capacity by 2030. Key findings from the study are as follows:

1. **Achieving India's goal of 500 GW of non-fossil capacity (predominantly renewables) can be the least-cost and most economical pathway to meet the rising electricity demand.** This will require 252 GWh (63 GW) of battery storage and steps to ensure grid balancing and stability. Given the rapid increase in the power demand, India will still require a modest net increase in the fossil fuel based capacity – albeit its share in the installed capacity and electricity generation mix will decline substantially. There will be higher infrastructure financing requirements for the economy, given the large-scale expansion of transmission and storage. The increase in thermal capacity is primarily required to meet the increase in night-time base load net of the reduction achieved by the ongoing shifting of nighttime agricultural consumption to the daytime. A net increase of 23 GW of thermal capacity through 2030 is required under study's modeled cost-optimal scenario assuming an increase in power demand of 70 percent by 2030.

2. **Additional thermal capacity by 2030 will be required if adequate storage (63 GW/252 GWh) cannot be deployed.** If the cost of battery storage does not decline and it becomes difficult to deploy storage at such scale, additional fossil fuel based capacity beyond the 23 GW net additions in the primary cost-optimal scenario will be needed through 2030 to meet evening peak demand, but these plants will operate at low capacity factors.

3. **A decline in storage costs will be required for 500 GW of non-fossil capacity to be the least-cost and most economical pathway by 2030.** Such declines are consistent with historical trends and credible future projections by third-party experts, as well as India's Central Electricity Authority.

4. **Deploying battery storage and renewables at such a significant scale will likely require addressing supply chain challenges and securing adequate financing.**

Executive Summary

India has set ambitious installed renewable energy (RE) capacity targets of 175 GW by 2022 and 450-500 GW by 2030. Dramatic cost reductions over the last decade for wind, solar, and battery storage technologies position India to leapfrog to a more flexible, robust, and sustainable power system—much of which is yet to be built—for delivering affordable and reliable power to serve demand that will nearly double by 2030. As India's grid attains higher penetrations of renewables, balancing generation variability through a spectrum of flexible resources becomes increasingly important for ensuring the affordability, stability, and reliability of grid power.

This study assesses a least-cost and operationally feasible pathway for India's electricity grid through 2030 that validates—and surpasses—India's 2030 target of 500 GW of installed non-fossil capacity. The study uses the latest RE and battery cost data, an industry-standard power system modeling platform (PLEXOS), and exhaustive analytical methods (optimal capacity expansion and power plant-level hourly grid dispatch simulations).

The study highlights the critical role of enhancing system flexibility and maintaining grid dependability through a spectrum of flexible resources, such as energy storage, demand response (load shifting), existing natural gas power plants used more flexibly, and electricity markets. Specifically, we find that the least-cost resource mix to meet India's load in 2030 (the "Primary Least Cost Case") consists primarily of a combination of RE and flexible resources as follows: 465 GW of RE (307 GW_{DC} solar, 142 GW wind, and 15 GW other RE), 63 GW (252 GWh) of battery storage, 60 GW of load shifting to solar hours (50 GW agricultural + 10 GW industrial), and flexible operation of the existing natural gas fleet of 25 GW. A coal power plant capacity of 229 GW (23 GW net addition over 2020) is found to be cost-effective (Table ES-1). The study signals investment opportunities that could spur creation of a robust pipeline of flexible resources, most notably battery storage. For example, the total investment required by 2030 for battery storage alone is Rs 300,000 Cr ($40 billion) for 63 GW (252 GWh) of batteries. If low-cost energy storage is not deployed at such scale, additional thermal investments beyond the 23 GW of net additions will be needed through 2030 to meet peak demand, but such assets will operate at low capacity factors.

Importantly, the study shows that between 2020 and 2030 the average cost of electricity generation drops by nearly 8-10% owing to the inflation-proof, low-cost renewable power and improved capacity factors of existing coal power plants. Despite a near doubling of electricity demand between 2020 and 2030, the emissions intensity of electricity generation drops by 43-50%, while total CO_2 emissions from the power sector stay almost the same as 2020 levels (Table ES-1). Also, India's coal consumption in the power sector by 2030 is comparable to the 2020 level, implying that the clean energy transition may not lead to loss of coal mining/supply chain jobs in the near to medium term, potentially giving India sufficient time to prepare for a long-term transition.

For India to achieve the least-cost resource mix indicated in this study, a modest decline in the current RE (5-10% by 2030) and a more pronounced decline in the current storage costs (30-40% by 2030), consistent with historical trends and projections by other studies, will be required. Also, deploying RE and storage at such a significant scale will likely require addressing supply chain challenges and securing adequate financing. Finally, critical policy and regulatory changes such as a long-term resource adequacy framework for system planning and procurement, a regulatory framework for energy storage that values its full functionality, and natural gas reforms that promote flexible and efficient operations of the gas pipelines and power plants should be implemented.

Key Study Findings:

1. India's incremental electricity demand through 2030 is largely met by new investments in RE and energy storage along with existing thermal assets.

- The **Primary Least Cost Case** combines 465 GW of RE (307 GW_{DC} solar, 142 GW wind, and 15 GW other RE), 63 GW (252 GWh) of battery storage, 60 GW of load shifting to solar hours (50 GW agricultural + 10 GW industrial), flexible operation of the existing natural gas fleet of 25 GW, and 140 GW of additional interstate/interregional power transfer capacity (Table ES-1). A coal power plant capacity of 229 GW (23 GW of net additions over 2020) will be needed by 2030. Total non-fossil capacity by 2030 would be 545 GW.

- Under a **Low-RE Cost Case**, which assumes that RE and battery costs continue to decline at historical rates (with the solar levelized cost of energy at the best sites dropping to Rs 1.5/kWh by 2030), the capacity of RE and battery storage in the least-cost mix increases to 547 GW of RE (385 GW_{DC} solar, 147 GW wind, and 15 GW other RE) and 84 GW (336 GWh), respectively(Table ES-1). Coal power plant capacity of 206 GW at 2020 levels remains stable in 2030.

Table ES-1: Installed capacities, average costs of generation, and emissions in India (2020 and 2030)

Property	Technology	Actual (2020)	Primary Least Cost (2030)	Low-RE Cost (2030)
Installed Capacity (GW)	Coal	206	229	206
	Natural gas	25	25	25
	Nuclear	7	19	19
	Hydropower	43	62	62
	Wind	38	142	147
	Solar	35	307	385
	Other RE	15	15	15
	Storage	0	63	84
	Total	**369**	**862**	**943**
Average Cost of Generation (Rs/kWh)		**3.90***	**3.59**	**3.50**
Power-Sector CO_2 Emissions (MT/yr)		**1,008**	**1,080**	**981**
Emissions Intensity(kg CO_2/kWh)		**0.82**	**0.47**	**0.41**

* This number is a model estimate and close to the actual number.

- In the Primary Least Cost Case, coal's share of total electricity generation decreases from 73% in 2020 to 48% in 2030, while the share from solar plus wind increases to 35%. The total share of electricity generation from non-fossil resources, including hydropower and nuclear, is 50% in 2030. In the Low-

RE Cost Case, wind and solar resources provide 42% of total electricity generation by 2030, while the total non-fossil share increases to 58%.

- Inflation-proof, low-cost RE and battery storage are the primary drivers of these results. Battery storage obviates the need for building thermal capacity to meet morning and evening peak loads, while agricultural and industrial load shifting from evening to solar hours significantly reduces the nighttime load and, in turn, the requirement for new baseload coal-fired capacity.

- The average generation cost in 2030 in the Primary Least Cost Case is 8% lower than in 2020 owing to the inflation-proof, low-cost RE and improved coal capacity factors for existing units (Table ES-1).

2. Flexible resources help prevent the stranding of coal capacity while maintaining grid dependability and enabling existing coal assets to operate more efficiently.

- In the absence of flexible resources, particularly battery storage and agricultural load shifting, India may need to build significant new coal resources primarily as a firm capacity resource, as other studies suggest. For example, CEA (2020) shows that, by 2030, India would need a net coal capacity addition of 60 GW beyond the 2020 levels. However, such a coal buildout—in tandem with the RE buildout—would likely cause the average fleet-level coal capacity factor to drop to 56% (gross), with over 100 GW of coal capacity (mostly existing plants with high variable cost) operating at capacity factors of 15%–40% (gross). This result could put such assets at increased risk of being stranded and needing regulatory support.

- Deploying flexible resources can prevent the stranding of coal capacity by reducing the new coal buildout while maintaining grid dependability and enabling existing coal assets to operate more efficiently. In the Primary Least Cost Case, the average fleet-level coal capacity factor increases to 65% (gross) in 2030, from less than 60% in 2020. However, 20–36 GW of existing coal capacity with high variable costs may still operate at capacity factors below 40%.

3. With large additions of RE and battery storage capacity, India's electric grid remains dependable

- Existing and under-construction thermal power plants combined with hydropower, nuclear, and new battery storage capacity enable India to meet electricity demand dependably—in every hour of the year in each state—with 465 GW of installed RE capacity in 2030.

- India's RE generation, particularly wind generation, is highly seasonal. Flexible resources work in tandem to maintain grid dependability throughout the year, including times of high system stress such as periods with peak annual load, high RE variability, and high net load.

- During high RE generation seasons (June through September for wind, March through June for solar), energy storage and agricultural load shifting provide diurnal grid balancing. Batteries charge during the day (coincident with solar generation) and discharge during morning and evening peak periods (4–6 total hours each day). Batteries also help meet steep system ramps. Shifting agricultural load to solar hours increases the daytime load by 30–60 GW depending on the season, while reducing the nighttime load and thereby the baseload capacity requirement by 30–50 GW. As a result, only 180 GW of coal capacity are dispatched, mainly as a baseload resource (Figure ES-1).

Figure ES-1: Average hourly dispatch for key months in 2030 in the Primary Least Cost Case

- During the low RE generation season (October through February), the 25 GW of existing natural gas capacity (in lieu of coal-fired assets) play a crucial role providing seasonal balancing, with most of this capacity dispatched during these months.

- If low-cost energy storage is not deployed at such scale, additional thermal investments beyond the 23 GW of net additions will be needed through 2030 to maintain grid reliability, but such assets will operate at low capacity factors.

4. An additional interstate electricity transfer capacity buildout of 140 GW is cost-effective.

- Under the Primary Least Cost Case, about 140 GW of new electricity transfer capacity must be built by 2030: 40 GW on interregional corridors and 100 GW on interstate corridors. Because of an anticipated doubling of India's electricity load between 2020 and 2030, significant additional transmission capacity investments will be needed irrespective of RE expansion.

5. Between 2020 and 2030, the emissions intensity of electricity generation drops 43%–50%.

- By 2030, the average CO_2 emissions intensity of the Indian power sector drops from 0.82 kg/kWh in 2020 to 0.47 kg/kWh in the Primary Least Cost Case (43% reduction), and to 0.41 kg/kWh in the Low-

RE Cost Case (50% reduction). Total power-sector CO_2 emissions fall 3%—from 1,008 MT/yr in 2020 to 981 MT/yr in 2030—in the Low-RE Cost Case; emissions increase by only 7% (to 1,080 MT/yr) in the Primary Least Cost Case, despite the near doubling of electricity demand. Importantly, under the Primary Least Cost Case, nearly 80% of the net incremental generation between 2020 and 2030 is from new clean energy assets, including new RE, nuclear, and hydropower assets. Under the Low-RE Cost Case, new clean energy assets contribute about 90% of the net incremental generation.

6. In the near to medium term, India's clean energy transition is unlikely to cause a loss of jobs in coal mining and transportation.

- By 2030, India's total coal consumption from the power sector is 750 MT/yr in the Primary Least Cost Case and 667 MT/yr in the Low-RE Cost Case—comparable to 2020 consumption (647 MT/yr). Thus, the clean energy transition may not lead to loss of coal mining/supply chain jobs in the near to medium term, potentially giving India sufficient time to prepare for a long-term transition.

We tested the sensitivity of these results to other parameters and policies, as summarized below:

- <u>Impact of Market-Based Economic Dispatch (MBED)</u>: If India implements a national wholesale electricity market by 2030 as outlined in the MBED proposal by the Central Electricity Regulatory Commission, the resulting efficient thermal dispatch saves Rs 14,000 Cr/yr ($2 billion/yr) or 6% in thermal power plant variable costs, albeit with a significant increase in interstate electricity trade.

- <u>Impact of Low Demand Growth</u>: If the economic recovery from the COVID 19 pandemic is slow and demand growth between 2020 and 2030 decreases by 20% (2030 peak load is 290 GW, compared with 340 GW in the Primary Least Cost Case), no new coal capacity is cost-effective, while the cost-effective RE capacity decreases to 355 GW, from 465 GW in the Primary Least Cost Case.

  <u>Impact of Low Liquefied Natural Gas (LNG) Price</u>: If the LNG price drops to $4.5/MMBTU (landed) by 2030, LNG starts competing with expensive coastal coal power plants. Although building new gas-fired assets still is not cost-effective, generation from gas power plants fueled primarily by LNG increases to about 120 TWh/yr by 2030 (compared with about 50 TWh/yr in the Primary Least Cost Case). LNG consumption increases to about 14 bcm (10 million tons) per year by 2030.

- <u>Impact of Postponed Coal Retirements</u>: The Primary Least Cost Case assumes the retirement of about 25 GW of existing coal assets by 2027 per the National Electricity Plan. If this coal capacity does not retire as planned, total cost-effective coal capacity by 2030 would be 238 GW. An installed RE capacity of 453 GW (301 GW_{DC} solar, 137 GW wind, and 15 GW other RE), along with flexible resources, is still more cost-effective than operating some of the inefficient coal capacity with high variable costs. However, the risk of potentially stranding some of the older coal capacity increases significantly.

This study indicates several key policy and regulatory strategies in the power and gas sectors, which we assess in a separate report and summarize in Section 6 of this report.

1 Introduction

1.1 Background and Objectives

India has set an ambitious clean energy target for the power sector, namely 175 GW of renewable energy (RE) installed capacity by 2022. In 2021, Prime Minister Modi increased this ambition by announcing a target of 500 GW of installed non-fossil capacity by 2030. India has made rapid progress towards achieving these goals. Between 2015 and 2021, India's renewable energy capacity more than doubled from 40GW to 100GW, supplying nearly 10% of the total electricity generated in the fiscal year 2021 (CEA, 2021). Over the last decade, India has been successful in achieving some of the lowest RE costs in the world. Between 2010 and 2020, it saw the largest reduction in country-level solar levelized cost of energy (LCOE), 85%, while the average solar tariff in 2020 was 34% lower than the global weighted average. India also had the lowest country-level installed cost for solar and wind in 2020 (BNEF, 2020a) (Figure 1).

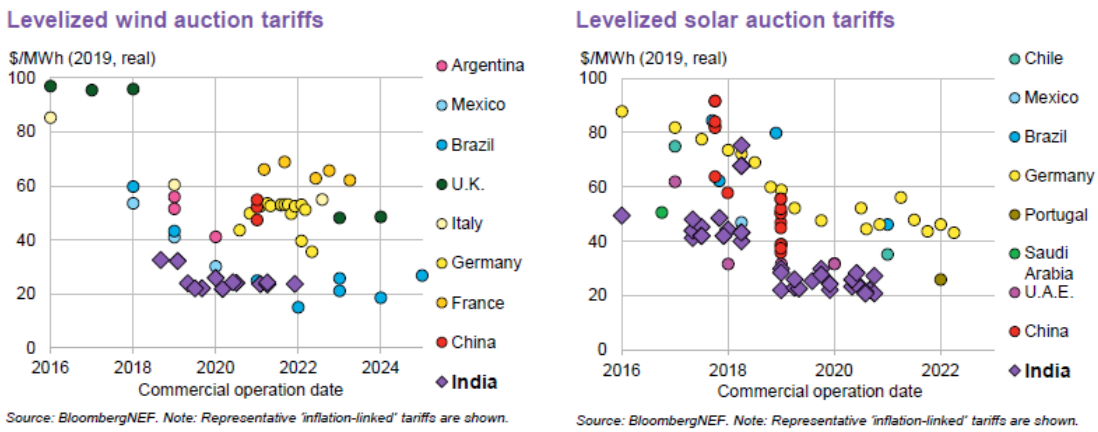

Figure 1: Solar and Wind energy prices in key countries, including India.

Source: BNEF (2020a)

It is well accepted that renewable electricity costs have dropped below coal costs on a levelized basis. Nonetheless, many countries around the world, including India, continue to invest in new coal power plants primarily because: (a) RE generation is intermittent and may need significant system flexibility for grid integration, (b) RE generation does not coincide with peak electricity demand periods which is in the evening for India, and (c) legacy planning and regulatory frameworks that may not fully capture the value and capabilities of RE and energy storage technologies. In this context, the dramatic decline in battery storage costs — 90% cost reduction at the battery pack level since 2010 — could serve as a turning point, because it enables the cost-effective supply of low-cost renewable electricity during peak times (Figure 2). Notably, several large utility scale RE + storage projects are underway globally and, in several cases, offer electricity generation prices well below that from fossil power plants. For example, a recent solar + storage auction by Los Angeles Department of Water and Power (LADWP) resulted in a combined PPA price of $39/MWh (Rs 3/kWh) for storing over 50% of the solar energy in batteries (effective capacity factor of over 40%) (Figure 2). Similarly, in India, the recent RE + storage peaking power auction resulted in a levelized tariff of Rs 3.5/kWh, which is cost-competitive with the higher variable cost of 40 GW of India's existing coal units.

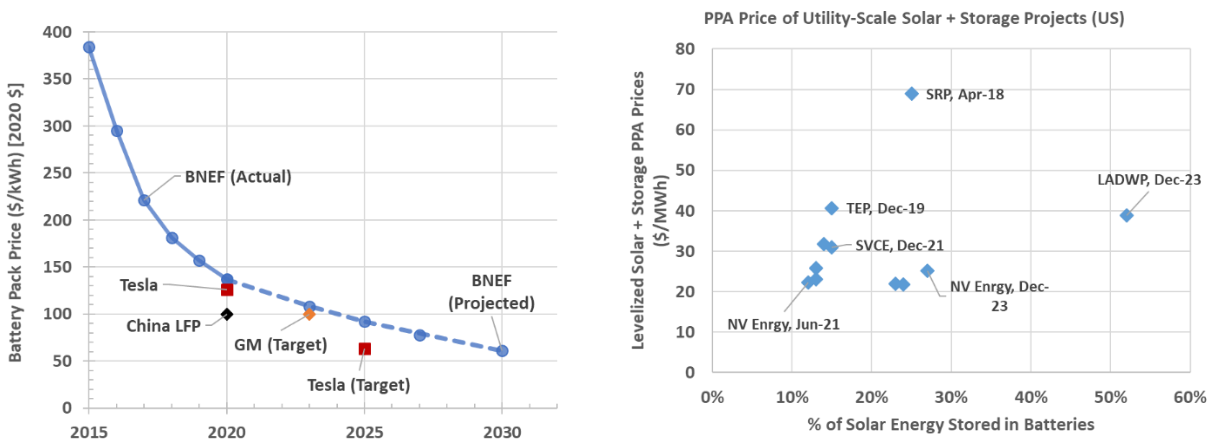

Figure 2: Global average battery pack price over years (left) and Solar + Battery Storage PPA prices in the United States (right)

Data Source: BNEF (2020b) and Deorah, et al (2020).

Indian utilities are also using several other flexible resources such as demand response for integrating renewable energy. Several states (e.g., Karnataka, Maharashtra, and Gujarat) have already shifted a major part of their agricultural load from night time to solar hours (over 6 GW total in 2020). Electricity market reforms in India, falling global natural gas prices, and demand response also offer some important flexibility options to the grid.

Given that a large part of India's electricity grid infrastructure is yet to be built, such cost reductions offer India a unique opportunity to leapfrog to a more flexible, robust, and sustainable power system. The objective of this study is to assess the least-cost resource mix for India to meet its load reliably through 2030, with a particular focus on key flexible resources such as energy storage, load shifting, gas, and electricity markets, to support India's low-carbon energy transition over the next decade. Several recent studies have assessed a similar question (e.g., CEA (2020), NREL (2020 & 2021b), TERI (2020), BNEF (2020a), and IEA (2021)). However, most of the recent studies either do not consider the recent dramatic decline in the clean energy and storage costs, or account for significant changes to the daily demand pattern of agricultural load, or provide spatial and temporal granularity to assess in detail the technical and economic impacts on the power system. Our study attempts to build on the existing literature and address some of these gaps by (a) developing a spatially and temporally resolved capacity expansion and economic dispatch model using an industry standard platform, PLEXOS, that assesses the least cost resource mix at the state level, interstate transmission requirement, and power plant level hourly economic dispatch, (b) using the latest renewable energy and storage cost estimates and trends, informed by prices observed in the market, and (c) including demand side resources, in particular, shifting of the agricultural load from night-time to solar hours, which many Indian utilities are practicing.

1.2 Summary of Recent Studies

Our study draws from and expands on a growing body of literature and methodologies that assess an optimal resource mix for India to meet its load in the medium to long run. All these studies grapple with a number of key issues, such as rapidly changing costs and capabilities of new energy technologies such as wind, solar and battery storage and operations of a state or national power system.

For example, TERI (2020) focuses on the operational strategies for integrating the 450GW of renewable capacity by 2030. CEA (2020) assesses a least-cost resource mix for 2030 and validates the technical feasibility of this resource mix by simulating hourly dispatch. However, they not conduct a spatially resolved analysis (state / regional / other sub-national level) and assess the impact of agricultural load shifting. NREL (2020) conducts long-term capacity expansion modeling (2047 timeframe) at the state level and NREL (2021b) quantifies the energy storage opportunities in South Asia, including India, by assessing the storage requirement and operational strategies. While BNEF (2020a) uses recent renewable energy auction prices, its results are not spatially resolved, and it is unclear whether they model hourly grid dispatch. Moreover, none of the studies model the role of demand side resources, such as shifting agricultural loads from evening to solar hours. IEA (2021) focuses on renewable grid integration issues and do not conduct an optimal capacity expansion analysis. They use production cost models – the five-region India Regional Power System Model and the Gujarat State Power System Model, to assess the flexibility challenges and solutions specific to the India context. Table 1 shows projected generating capacity by resource type from studies of India's resource mix in the timeframes indicated below, as compared with the Primary Least Cost Case.

Table 1: Installed capacity (GW) – 2020 (actual) and 2030 projections from recent studies (India total)

Technology	Actual (2020)	CEA (2030)	NREL (2030)	BNEF (2030)	TERI (2030)
Coal	206	267	170	234	238
Natural gas	25	25	49	25	25
Nuclear	7	19	11	33	17
Hydro	54	61	54	81	84
Wind	38	140	200	109	169
Solar	36	280	250	204*	229
Battery storage	0	27 (4-hour)	16 (2-hour) 68 (4-hour)	#N/A	60 (2-hour)
New pumped storage	N/A	10	1.5	0	0
Load Shifting		0	0	0	0
Other RE	15	15			
Total	**381**	**844**	**824**	**734**	**822**

*AC capacity with an Inverter Loading Ratio of 1.30, implying the DC capacity to be approximately 265GW.
Note: Each study uses a different set of assumptions on technology costs, baseline year, and operational parameters. Therefore, the comparison across studies is shown for illustrative purposes only and should be interpreted carefully.

Data Sources: CEA (2020a), CEA (2020b), NREL (2021b), BNEF (2020a), TERI (2020)

TERI (2020) examines various scenarios of RE penetration on the Indian grid in 2030, and they run an hourly production cost model to determine unit commitment, system costs, and transmission flows. They conclude that the system cost of a high-RE pathway (32% of generation from solar and wind) is comparable to the cost of the baseline case (26% of generation from solar and wind). They explore system flexibility requirements by examining options for coal flexibility and incorporating battery storage into the resource mix. However, they do not conduct least-cost, capacity-expansion modeling.

NREL (2021b) uses the Regional Energy Deployment System (ReEDS) model to assess cost-effective opportunities for grid-scale energy storage deployment in South Asia both in the near term and the long term, including a detailed analysis of energy storage drivers, potential barriers, and the role of energy storage in system operations. They conduct scenarios-based capacity expansion modeling and find that India's market for grid scale storage will be in the range of 50 GW to 120 GW by 2030, mostly from lithium-ion battery storage.

BNEF (2020a) estimates that the least-cost resource mix in 2030 includes 313 GW_{ac} of solar and wind (26% of generation) and 234 GW of coal (55% of generation) out of a total estimated installed capacity of 734 GW. By 2034, RE capacity would grow rapidly to reach 450 GW, while coal capacity would be 252 GW; flexible resources, including peaker gas, pumped hydro, batteries etc., would contribute a total of over 90 GW.

Building on the existing literature, our study attempts to address some of these gaps by (a) developing a spatially and temporally resolved capacity expansion and economic dispatch model that assesses the least cost resource mix at the state level, interstate transmission requirement, and power plant level hourly economic dispatch, (b) using the latest renewable energy and storage cost estimates and trends, informed by prices observed in the global and Indian markets, and (c) including demand side resources, in particular, shifting agricultural load from night-time to solar hours, which many Indian utilities are practicing.

The remainder of this report is organized as follows. In section 2, we summarize our key assumptions, scenarios, and data. In section 3, we present the key findings followed by sensitivity analysis in section 4 and key conclusions and policy implications in section 5. In section 6, we summarize the policy and regulatory recommendations (assessed in detail separately) that would enable India's transition to a flexible, robust, and cleaner power system. Section 7 provides key caveats in using this analysis and identifies the future work. Appendix I provides detailed assumptions and data sources. Appendix II shows additional results on system operations and transmission investments, including some state level findings. In appendix III, we offer a high level comparison of the economics of battery storage and pumped hydro systems in India.

2 Methods, Data, and Assumptions

We use PLEXOS[1] to build a capacity-expansion model to assess the least-cost ("optimal") generation mix at the state level and interstate/inter-regional transmission investments for each year between FY 2020 and FY 2030.[2] The model minimizes total generation cost (fixed plus variable costs) for the entire system, including existing and new generation capacity and transmission networks. We assess the optimal resource mix under a range of scenarios examining technology costs, natural gas prices, coal plant retirements, demand growth, electricity market design, demand response, and supply chain challenges. For FY 2030, we also model economic dispatch at the power plant level to ensure that the grid can run reliably for all 8,760 hours in the year, including the hours when the system is most constrained.

We model the Indian electricity grid using 36 nodes: one node for each state/Union Territory (Figure 3). Figure 4 depicts our overall method and the various data components.

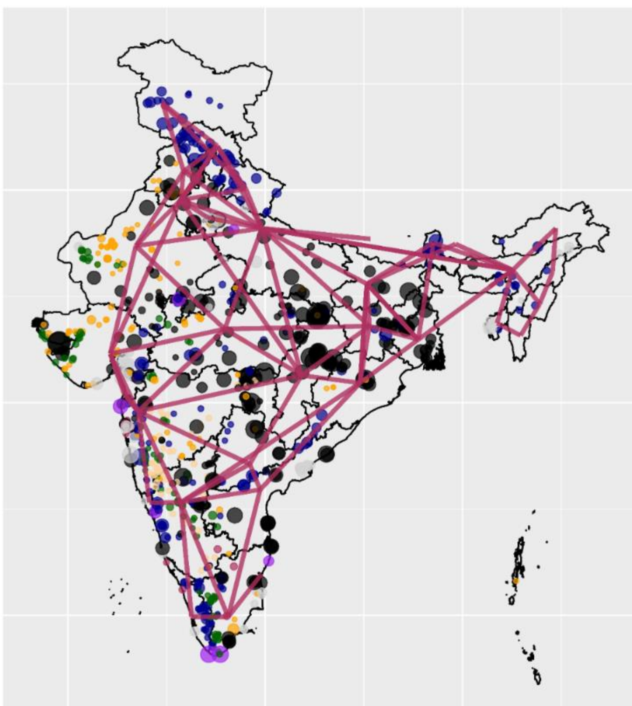

Figure 3: Representation of India's transmission network with a simplified interstate network (36 nodes) along with the location of existing power generation plants

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[1] For more information on PLEXOS, see www.energyexemplar.com. PLEXOS uses deterministic or stochastic, mixed-integer optimization to minimize the cost of meeting load given physical (e.g., generator capacities, ramp rates, transmission limits) and economic (e.g., fuel prices, start-up costs, import/export limits) grid parameters. Moreover, PLEXOS simulates unit commitment and actual energy dispatch for each hour (or at 1-minute intervals) of a given period. As a transparent model, PLEXOS makes available to the user the entire mathematical problem formulation.

[2] The fiscal year in India runs from April 1 through March 31. For example, FY 2030 runs from April 1, 2029 to March 31, 2030. In this report, we use the terms fiscal year and year interchangeably. Any reference to a year implies fiscal year, unless specified otherwise.

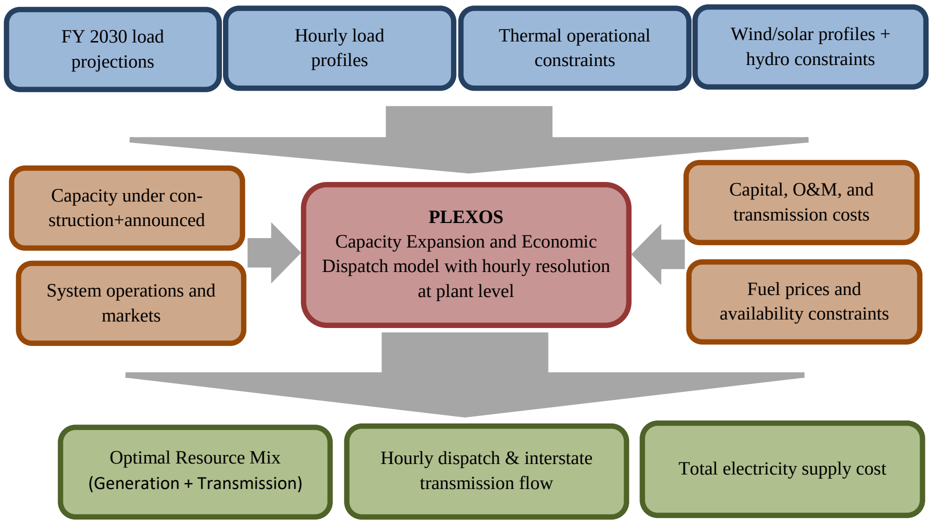

Figure 4: Overview of the modeling framework

We assess the following two primary scenarios:

1. **Primary Least Cost:** This scenario assumes a mid-cost trajectory for clean technologies, 60 GW of load shifting to solar hours, state-level balancing, and a base cost for liquefied natural gas (LNG).
2. **Low-RE Cost:** This scenario assumes RE and storage cost reduction through 2030 in line with the historical trends. Assumptions about load shifting, system balancing, and LNG costs are the same as the Primary Least Cost.

Important assumptions and data sources are as follows (see Appendix I for details):

- **Clean technology costs:** We model three cases (low, mid, and high) of solar, wind, and battery cost trajectories (Figure 3). See Appendix I for details.
  - The base or ***mid-cost (or base-cost)*** case in the Primary Least Cost Case assumes the cost reductions for solar and wind technologies over the next decade are half the observed historical rate. Average solar LCOE drops from Rs.2.8/kWh in 2020 to Rs.2.0/kWh in 2030 while wind LCOE goes from Rs.3.2/kWh in 2020 to Rs.3.0/kWh in 2030. Note that these projections are somewhat more conservative compared to other global projections such as BNEF or NREL ATB (moderate cost case) (BNEF, 2021; NREL, 2021a). Our assumptions for Li-ion battery levelized cost of storage (LCOS), based on our previous bottom-up cost analysis, are Rs.6.0/kWh in 2020 and Rs.3.7/kWh in 2030 for 4-hour storage (Deorah et al, 2020).[3]
  - The ***low-cost*** case in the Low-RE Cost Case assumes cost reductions are in line with historical trends, with the average LCOE in 2030 dropping to Rs.1.5/kWh for solar, Rs.2.5/kWh for wind. These projections are more in line with other global forecasts such as BNEF and NREL ATB (moderate cost case) (BNEF, 2021; NREL, 2021a). For batteries, we assume that the LCOS of a 4-hour storage project drops to Rs.3.0/kWh by 2030.

[3] In particular, battery pack life is assumed to be 3,000 cycles or 10 years, while the project life is assumed to be 20 years meaning that there will be one battery pack replacement in year 11.

- The ***high-cost*** case assumes the cost trajectory of clean technologies is higher than in the base case (solar and wind LCOE of Rs 2.3/kWh and Rs 3.1/kWh by 2030, respectively and 4-hour battery LCOS of Rs 4.9/kWh by 2030), which could occur for various reasons, such as slower reductions in global prices, restrictions on imports, or solar and battery supply chain disruptions that limit the capacity that could be installed in the first few years of the decade (10 GW/yr). We assume domestic manufacturing catches up by middle of the decade, and new installations are not constrained beyond 2025. Under this scenario, India does not achieve its 175-GW RE target by 2022.

- **Demand forecast:** We use state-level demand projections from CEA's 19th Electric Power Survey (EPS) (CEA, 2017b). India's peak load is expected to grow from 180 GW in 2020 to 340 GW in 2030, while the total energy demand (bus-bar) increases from 1,357 TWh to 2,363 TWh per year over the same period (CEA, 2017b). Using the state level hourly load data in 2018, we project the hourly load pattern for future years. We also run a Low Demand Growth case, which assumes a 25% lower demand growth, implying a 2030 peak load of 290 GW and a total energy demand of 2,000 TWh per year.

- **RE generation profiles:** We assess hourly wind generation profiles and hydro dispatch constraints using historical generation data (for the load synchronized 2018 weather year). For solar, we create hourly generation profiles using Global Horizontal Irradiance (GHI) or Direct Normal Irradiance (DNI) data for key sites within each state (Deshmukh et al 2019; Abhyankar et al, 2016).

- **Agricultural (Ag) and industrial demand response:** Several states have separated distribution feeders for agricultural consumers from other feeders, and some states (e.g., Karnataka, Maharashtra, and Gujarat) have already shifted a major part of the agricultural load to solar hours (over 6 GW total in 2020) (KPTCL, 2020; MSLDC, 2020). We assume the same trend to continue in the future, and by 2030, about 50 GW of agricultural load and 10 GW of industrial load could be shifted from night-time to solar hours.

- **Coal capacity:** We incorporate the coal capacity that is already under construction per CEA progress reports (about 38 GW between 2021 and 2025 - 23 GW until 2022 and 15 GW between 2023 and 2025) (CEA, 2021). The NEP stipulates that about 8 GW of existing coal capacity would retire by 2022, and about 25 GW retires by 2027 — this includes plants that have surpassed their useful life or plants that are/will be unable to meet required emission standards (CEA, 2018b). The Primary Least Cost Case accounts for all these additions and retirements. We also simulate a case in which the 25 GW of capacity (planned to be retired between 2022 and 2027) do not retire as anticipated.

- **Regulatory framework for balancing:** We treat each state as an independent balancing area with a certain import-export capacity. This is the current practice under which distribution utilities, often termed as Discoms, "self-schedule" the generation they have under contracts (including the central sector plants). Currently, limited electricity trade occurs between states, except for occasional bilateral contracts, or in the day-ahead wholesale electricity market. We simulate the limited interstate electricity trade (except for the central sector plants) by applying an economic hurdle of Rs 1.5/kWh to all electricity that a state would import from other states. Central-sector generating stations under contract would not face such hurdle rate because most of them already have contracts with multiple states. We also model as a separate scenario a national or centralized pool-based dispatch pursuant to CERC and MOP's Market Based Economic Dispatch (MBED) proposal (CERC, 2018; MOP, 2021).

- **Conventional fixed costs and cost of capital:** We use CERC generation tariff regulations, CEA assumptions, and industry consultations for estimating the capital cost and fixed operations and maintenance (O&M) costs for each conventional technology (coal, natural gas, hydro, biomass, and diesel) (CERC, 2019; CEA, 2020). Regulatory norms for coal capital costs exclude additional investments required to meet new pollution standards for particulate matter, SOx, and NOx emissions.

- **Weighted Average Cost of Capital:** We assume the real (inflation-adjusted) weighted average cost of capital (WACC) of 8%, which is equivalent to a nominal WACC of 11.6% (nominal interest rate of 11% and return on equity of 14%, assuming a debt-to-equity ratio of 80:20).

- **Variable costs of existing power plants:** We take the variable costs of existing interstate generating stations (ISGS) from reports available under the Reserves Regulation Ancillary Services (RRAS) mechanism (POSOCO, 2021). Variable costs for state generators and IPPs are from tariff orders by the respective state electricity regulatory commissions for FY 2020, where available. Variable costs for power plants with no recent regulatory data (nearly 5% or 10GW of the existing thermal power plants) are taken either from the MERIT website or assumed to be regional / state level average.

- **Coal prices for new power plants:** We assume a pithead coal price of Rs 2000-2500/ton (incl taxes), which is equivalent to a variable cost of Rs 1.59/kWh, increasing at 1% per year (half the historical growth rate of Coal India Limited's actual coal prices per CIL (2020)) between 2020 and 2030. Imported coal prices are taken from global market reports at the Indonesian hub. Although imported coal prices are higher than domestic coal prices, they improve plant heat rates.

- **Natural gas prices:** We assume that domestic gas availability for power sector will remain the same as 2020 (8.4 bcm/yr or 23 mmscmd) (MOSPI, 2020). Total LNG import capability increases from 15 million tons per annum (MTPA) in 2020 to 50 MTPA in 2030. Domestic gas price in 2030 is assumed to remain almost the same as 2020 ($4.2/mmbtu). We examine two LNG price scenarios: 1) a landed price of $5.5/MMBTU (plus regasification cost of $0.6/mmbtu and pipeline charges, as applicable) which is in line with current prices, and 2) a lower price of $4.5/MMBTU (plus regasification cost of $0.6/mmbtu and pipeline charges, as applicable).

- **Operational parameters:** We take key operational parameters for thermal power plants (ramp rates, technical minimum generation levels, auxiliary consumption, forced outage and planned maintenance rates, warm/cold start times, secondary fuel use, start cost, etc.) from the prevalent regulations, performance data, and normative values used by system operators and provided in the

CEA Thermal Performance Review (CEA, 2020; CEA 2018; CERC, 2019). Coal power plant technical minimum generation level is assumed to be 55% for central sector generating stations and IPPs per CERC regulations, while it is assumed to be 70% for state-level owned generating stations (CERC, 2019).

- **Heat rates:** We use actual heat rate data for every power plant based on several sources, such as regulatory filings, CEA Thermal Performance Review, CEA CO_2 Emissions Baseline, MERIT[4] data on variable costs, etc (CEA, 2018; CEA 2021; MERIT, 2021). We model the heat rate as a function of generator loading, as per CERC regulations on compensating for partial load operations.

- **Reserves:** For capacity-expansion modeling**,** we assume a 5% planning reserve margin. For dispatch modeling, we include 5% spinning reserves. We also model forced and planned maintenance outages for all power plants, using the actual values for existing capacity per CEA Thermal Performance Review and where such values are not available, we use normative values per CERC tariff norms (CEA, 2018; CERC, 2019; CEA, 2020).

- **Hydropower plants:** We divide the hydro plants in each state into three categories: (i) reservoir, (ii) run-of-river, and (iii) pumped hydro. Reservoir hydro plants are modeled using a monthly energy budget approach using the actual monthly generation / capacity factors in weather year 2018 (CEA, 2020; CEA, 2019). For run-of-river plants, hourly output is assumed to be constant throughout the week/month subject to the energy budget constraint. Pumped storage capacity is optimally dispatched subject to head/tail reservoir storage capacities.

- **Inter-annual variability in wind, solar, and hydropower generation:** Choosing a specific weather year for modeling wind, solar, and hydropower generation could miss capturing the low-probability risks due to very large inter-annual variability in generation. In order to assess the impact of such variations during the periods of highest system stress, we simulate the hourly dispatch during the peak load and the net load peak weeks by assuming solar and wind output to be 20% and 50% lower, respectively, based on the similar assessments in the US by Shaner et al (2018) and Phadke et al (2020).

- **Transmission network:** We model the interstate (400kV and above) transmission network using a reduced form 36-node model (one node for each state / Union Territory), which allows us to assess the transmission flows and requirements at the interstate level.

[4] Merit Order Dispatch of Electricity for Rejuvenation of Income and Transparency (MERIT), an application of Ministry of Power: http://meritindia.in

3 Key Findings

3.1 Incremental demand through 2030 could largely be met by new investments in RE plus storage and existing thermal assets. A coal power plant capacity of 229 GW (23 GW net addition over 2020) will be needed by 2030.

(a) The least-cost resource mix in 2030 includes 465 GW of RE, 63 GW of energy storage, 60 GW of load shifting, and 229 GW of coal capacity

Despite demand nearly doubling between 2020 and 2030, meeting most incremental demand by building new solar, wind, and flexible resources is cost optimal. Under the Primary Least Cost Case (mid-RE cost), about 23 GW of new coal capacity, mostly at pit-head locations in the eastern and western regions — beyond the coal capacity currently under construction is cost-effective. If low-cost energy storage is not deployed at such scale, additional thermal investments beyond the 23 GW of net additions will be needed through 2030 to meet peak demand. In the Low RE Cost Case, the least-cost mix of resources in 2030 includes over 530 GW of solar and wind capacity, coupled with 84 GW of energy storage. Table 2 and Figure 5 show the installed power mix over time in the Primary Least Cost and Low RE Cost Cases.

Table 2: Installed capacity in 2020 vs. 2030 in the Primary Least-Cost and Low-RE Cost scenarios

Technology	Installed Capacity (GW)		
	Actual (2020)	**Primary Least Cost (2030)**	**Low-RE Cost (2030)**
Coal	206	229	206
Natural gas	25	25	25
Nuclear	7	19	19
Hydro	43	62	62
Wind	38	142	147
Solar	35	307	385
Other RE (Small Hydro + Biomass)	15	15	15
Battery Storage*	0	63 (252 GWh)	84 (336 GWh)
Total	**369**	**862**	**943**
Average Generation Cost Rs/kWh	3.90**	3.59	3.50

* Modeled as standalone battery energy storage systems.

** This is estimated by the model and is very close to the actual number. The national average cost of power purchase estimated by CERC in April 2021 is Rs 3.85/kWh (CERC, 2021).

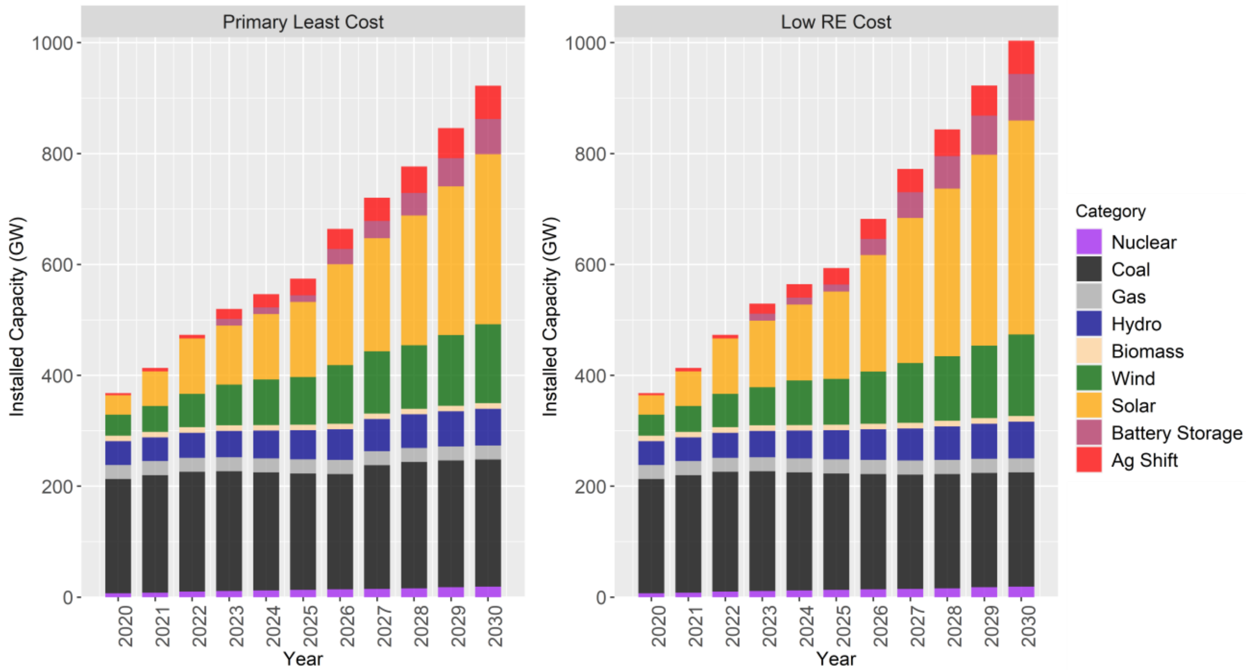

Figure 5: Installed capacity by resource type in Primary Least-Cost (left) and Low-RE cost (right), 2020–2030

With this mix, the share of non-fossil resources in total installed capacity is 545 GW or 63% in the Primary Least Cost case (or 50% share in annual generation) and 628 GW or 67% in the low-RE cost case (or 56% share in annual generation).

Figure 6 shows the wind and solar sites in the Primary Least-Cost scenario in 2030. The sites are chosen using multiple criteria, such as resource quality and proximity to the existing road and transmission infrastructure, while excluding agricultural lands, sensitive areas, water bodies, urban bodies, forests, etc.[5] The total land footprint of solar plants in 2030 is about 1.7 million acres, or 0.2% of total land area, compared with 0.16 million acres of direct footprint (0.02% of total land area) for wind capacity.[6]

[5] All underlying data and other assumptions are available at http://mapre.lbl.gov.

[6] For wind energy, 0.16 million acres is the direct footprint on the ground. Total land area requirement would be higher, but most of that land could be utilized for other applications including agriculture.

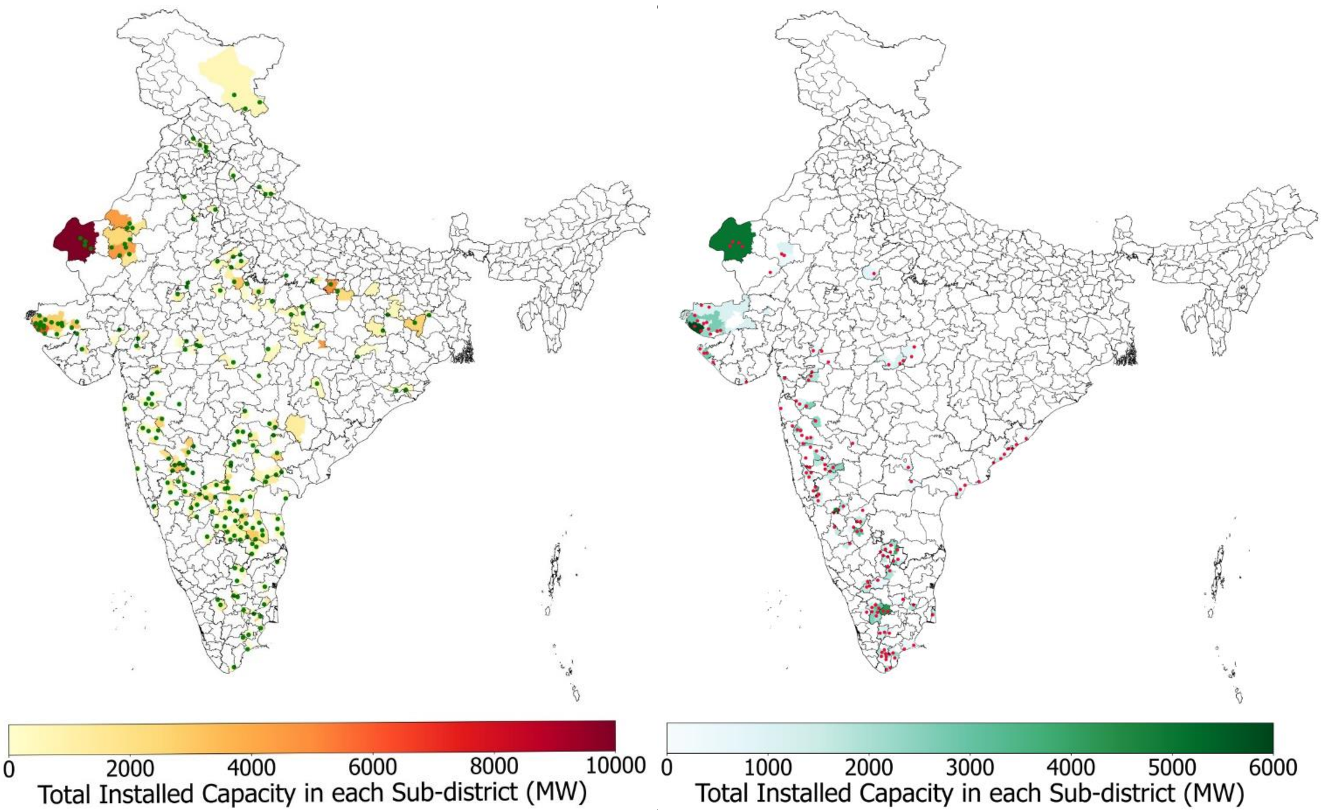

Figure 6: Sites for installation of solar (left) and wind (right) plants in Primary Least Cost Case, 2030

The resource mix in the base case is least cost due to three main reasons:

1. ***Plummeting costs of solar, wind, and batteries drive the system average cost down.*** Average cost of generation (including interstate transmission) is lower in FY 2030 under the Primary Least Cost Case than 2020 levels. The average cost of generation in FY 2030 under the Primary Least Cost case is estimated to be Rs.3.59/kWh, which is 8% lower than the estimated 2020 average cost of Rs.3.90/kWh. Lower generation costs would translate into lower retail electricity prices, assuming electricity distribution costs do not change significantly in the Primary Least Cost Case. The primary reason for the cost declines is low RE and storage costs make them competitive with thermal power generation throughout the country, even in regions previously considered resource-poor for renewable energy generation. For example, over 150GW of existing coal capacity in India has a variable cost of more than Rs 2/kWh, the lowest solar PPA price in 2020. Even after adding a storage cost of Rs 1/kWh (for 20-25% solar PV energy stored in batteries), the cost of evening-peaking solar power would be Rs 3/kWh, which is lower than the variable cost of over 80 GW of the existing coal capacity.[7] This implies that utilities will be better off building new solar + storage projects for diurnal balancing and not dispatching expensive coal plants, while still paying their fixed costs.

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[7] Based on global market trends and bottom costs in India, Levelized cost of co-located storage is Rs 6/kWh in 2020, dropping to Rs 3.7/kWh by 2030. By 2024-25, the costs drop to Rs 4.8-5/kWh. For 20-25% of solar energy to be stored in batteries, the net storage adder when spread over the solar generation from the project would 20-25% of Rs 4.8-5/kWh or about Rs 1-1.2/kWh.

2. ***60 GW of demand response reduces the night-time baseload requirement.*** Shifting of agricultural load, which is primarily supplied during night hours (10 PM to 6 AM), to solar hours would reduce significantly the night-time baseload power requirement typically met by coal power plants. Shifting 60GW of load away from night hours reduces the need for baseload coal capacity by over 30 GW.[8] Such load shift to solar hours also facilitates cost-effective grid integration of 30GW of new solar capacity.

3. ***Cheap grid-scale battery storage enhances the capacity value of solar.*** India's load is evening peaking usually around 7 or 8 pm, implying low-capacity value for solar in the Indian grid. Batteries change this dynamic by storing excess solar energy produced during the afternoon and discharging it during the evening peak hours. This interplay between solar and batteries also enables clean sources to provide firm capacity and meet the reserve margin requirements. The storage capacity required on the grid is about 10% of the average daily RE generation by 2030, equivalent to 63 GW x 4 hours = 252 GWh.[9]

(b) About 23 GW of net addition to the coal capacity is economical

Between 2020 and 2030, beyond the coal capacity currently under construction (38 GW) and planned retirements (33GW), we find 23 GW of new coal capacity to be cost-effective under the Primary Least Cost Case. This means about 229 GW of coal capacity will be required in 2030, compared with 206 GW in 2020. In the Low RE Cost Case, we find no new coal capacity beyond the capacity already under construction is cost-effective.

(c) Non-fossil resources contribute to over half of electricity generation by 2030, with solar and wind constituting a third of total 2030 electricity generation

The Primary Least Cost mix suggests a five-fold increase in total RE capacity, from 90 GW in 2020 to 465 GW in 2030. This increase is aided by the plummeting cost of Li-ion batteries, because storage enhances the value of solar energy to the grid. By 2030, solar and wind resources provide 36% (about 850 TWh) of total electricity generation in this scenario (Figure 7). The share of generation from non-fossil resources, including hydro and nuclear, increases from 24% in 2020 to 50% in 2030 —demonstrating that India can make major gains in reducing emissions and local air pollution from its power sector, while reducing costs for utilities and end consumers.

Between 2020 and 2030, coal's share of total electricity generation drops from 73% to 48%, while total coal generation increases from 988 TWh to 1,145 TWh, implying coal power plant operations at better capacity factors. We also infer that coal consumption from the power sector is unlikely to decrease over the next decade; in fact, in the Primary Least Cost Case, it increases by 15%, from 647 MT in FY 2020 to 750 MT in FY 2030. Even in the Low RE Cost Case, where the RE and non-fossil share in total electricity generation increases to 42% and 56% respectively, the total coal consumption remains as high as 659 MT

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[8] Coal capacity reduction is lower than 60GW because of the seasonal variation in agricultural consumption.
[9] Note that we have modeled battery storage as a standalone resource and not co-located with a renewable energy generator.

by FY 2030. Therefore, the clean energy transition may not lead to loss of coal mining/supply chain jobs in the near to medium term, giving India sufficient time to prepare for a long-term transition.

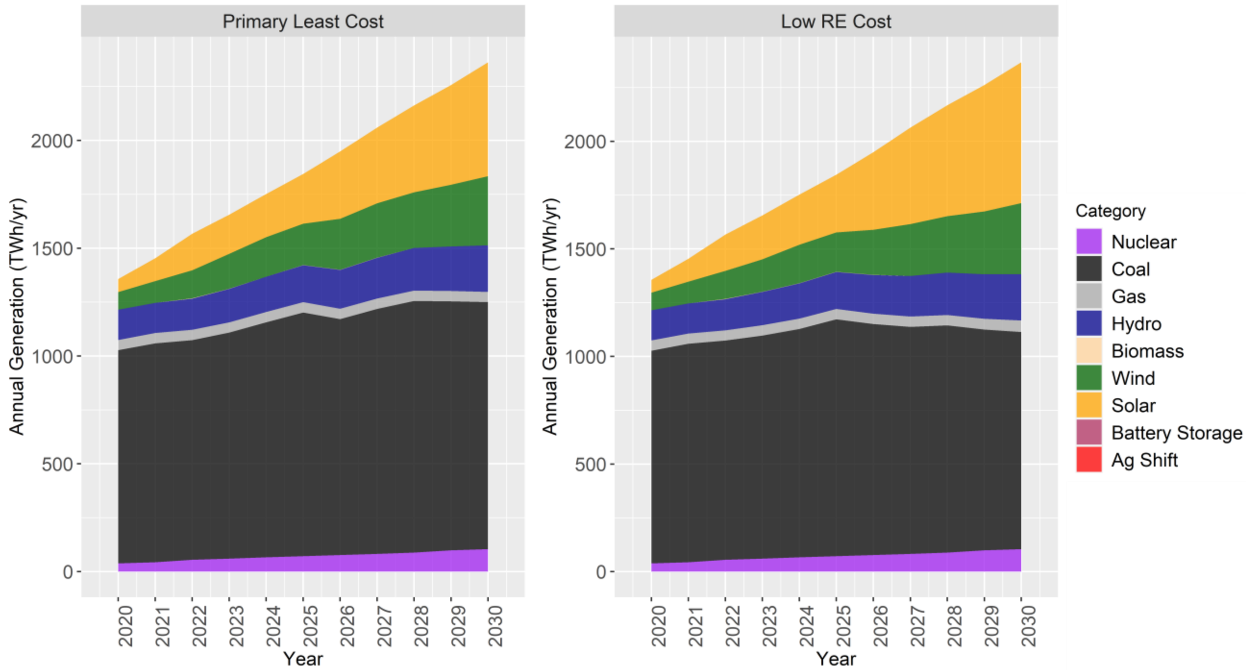


Figure 7. Annual generation by resource type in Primary Least-Cost (left) and Low-RE Cost scenarios (right), 2020–2030

(d) Coal power plants operate at improved plant load factors (PLFs), reducing their financial and operational stress

In the absence of flexible resources, particularly battery storage and agricultural load shifting, India may continue to build significant new coal resources primarily as a firm capacity resource, as other studies suggest. However, such coal buildout, in tandem with RE buildout, may cause the average fleet-level coal capacity factor to drop to 56%, with over 100 GW of existing coal capacity high variable cost operating at 15-40% capacity factors, potentially placing such assets at an increased risk of technical and financial stress and stranding. At 40% PLF, the average cost of generation increases to about Rs.6.0/kWh, while such cost rises to about Rs.10.0/kWh at 15% PLF.

In the Primary Least-Cost Case, the average PLF of the coal fleet increases to 63% (gross), which is higher than the gross PLF of 61% in 2020 (Figure 8). PLFs across the coal fleet still vary, but the quantum of capacity operating at very low PLFs reduces significantly. In 2030, about 36 GW of capacity, consisting mostly of existing plants with high variable cost, operates at less than 40% PLF. These plants may need certain regulatory support because of the stranding risk.

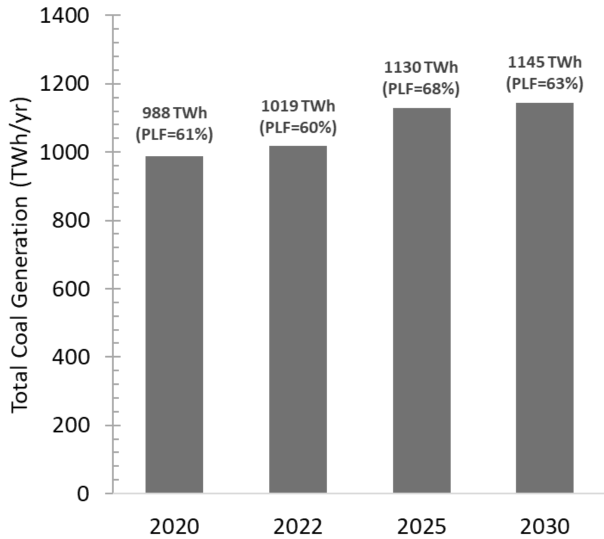


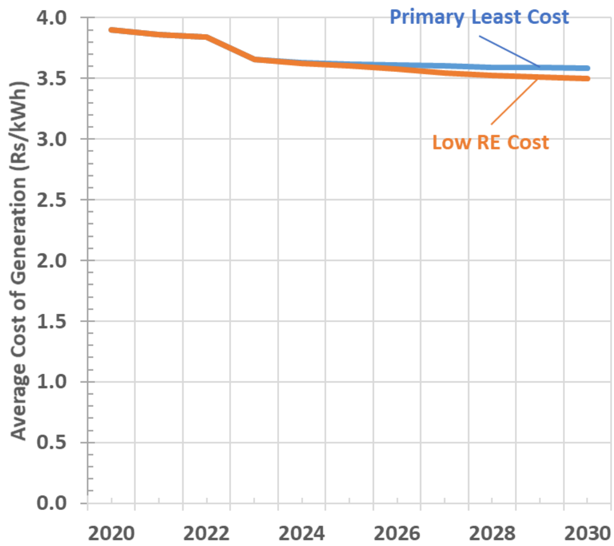
Figure 8: Coal generation and gross PLF in the Primary Least-Cost scenario

(e) The average cost of electricity generation is lower than today's cost of generation

The average cost of electricity includes the fixed costs (annualized capital service and O&M) of all existing and new power plants, battery assets (including battery pack replacement costs), and the transmission network, fuel costs of thermal, biomass, and nuclear generators, and any startup/shutdown costs. We model the heat rate of thermal power plants using CERC's heat rate curve, which implies that, if thermal power plants operate at low loads, the thermal efficiency decreases.

As Figure 9 shows, the average cost of generation decreases from Rs.3.90/kWh (5.20 cents/kWh) in 2020 to an estimated Rs.3.59/kWh (4.78 cents/kWh) in 2030 in the Primary Least-Cost Case, a drop of about 8%. In the Low RE Cost Case, the average cost of generation drops to Rs 3.50/kWh (4.67 cents/kWh), or 10% by 2030.[10] These drops result from two factors. First, the LCOE of most new capacity additions (solar and wind) is much lower and follows a decreasing trend over the decade. Second, the PPAs are fixed in nominal terms for 25 years, making a huge portion of power procurement inflation proof. With a decreasing share of coal power in the mix, the inflation-related increase in average cost (fuel and transportation costs, labor costs, O&M costs) is mitigated.

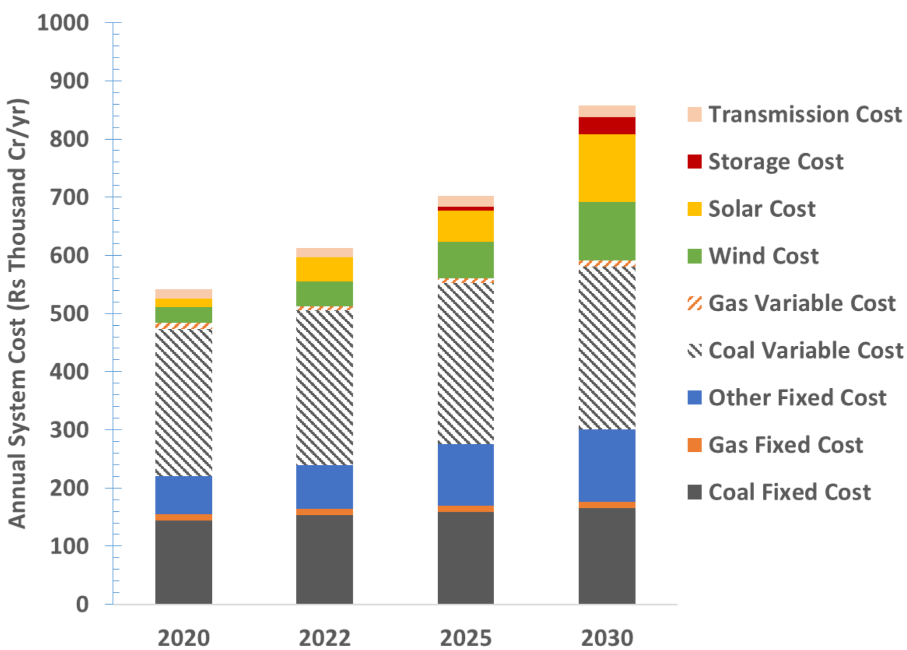
[10] These are the costs implied from the capacity expansion model. If one uses the production costs from hourly dispatch model, the fuel costs may be slightly different. These average cost numbers should not be taken for their absolute value, but more for the trend between 2020 and 2030.



Note: All cost numbers expressed as 2020 real.

Figure 9: National average generation cost, 2020 through 2030, in the Primary Least-Cost and Low RE Cost scenarios

Figure 10 shows the drivers of total system cost in 2020 and in the 2030 Primary Least-Cost Case. In 2030, the fixed and variable costs of coal-fired generation still account for 52% of the total system cost. On the other hand, wind, solar, and storage costs jointly account for 29% of the total, while providing 36% of the annual energy generation. The cost of new transmission buildout will be Rs 0.09/kWh (0.11 cents/kWh), if spread over the entire generation base.



Note: All cost numbers expressed as 2020 real.

Figure 10: Total system cost and cost drivers in 2020 and 2030 in the Primary Least-Cost scenario

3.2 The grid is dependable in every hour of the year

Our dispatch modeling validates that the optimal resource mix can meet demand in every hour of the year in 2030. There is no loss of load, even during days when the system is stressed, such as days of peak load, highest net load, highest RE variability, etc. Figure 11 shows average hourly system dispatch in FY 2030 for key months in the Primary Least Cost Case. The flexible resources work in tandem to maintain grid dependability. Agricultural load shifting and energy storage together are critical for diurnal balancing of the grid, while natural gas plants are critical for seasonal balancing. Agricultural load shifting reduces the nighttime baseload requirement by about 30-50 GW, such that during the evening (7-9PM) and morning (6-8 AM) peaks, baseload coal's contribution is minimal. Energy storage, including batteries and pumped hydro, charges during the day and discharges during evening and morning peak hours, while also providing the ramping support during the most critical ramp events. Natural gas plants operate mostly during the low RE season (October through February) and are critical for seasonal balancing of the grid. There is small amount of renewable energy curtailment (0.2% annually), mostly occurring during high wind season (June-September). The curtailment is found to be small because of the following two reasons: (a) significant quantum of flexible resources such as energy storage, agricultural load shifting, and flexible operation of gas power plants enable cost-effective grid integration, and (b) we do not model any intra-state transmission constraints, which is mainly responsible for RE curtailment that is currently observed in India. Additional dispatch results are shown in Appendix II.

Figure 11: Average hourly dispatch for key months in 2030 in the Primary Least-Cost scenario

(a) Agricultural load shift helps reduce the nighttime load

Figure 12 shows the projected load curves for May and October in FY 2030. The dotted curve shows the optimally shifted load curve, if 60 GW of load (50 GW of agricultural load and 10 GW of heavy industrial load) shifts to solar hours by FY 2030. As mentioned earlier and demonstrated in Appendix II, states such as Karnataka, Gujarat, and Maharashtra have already shifted significant agricultural load to daytime (6 GW in total), and several other states are following suit. Given the seasonal and regional variations in agricultural load, on average, such a shift would reduce the nighttime load by 30 GW nationally.

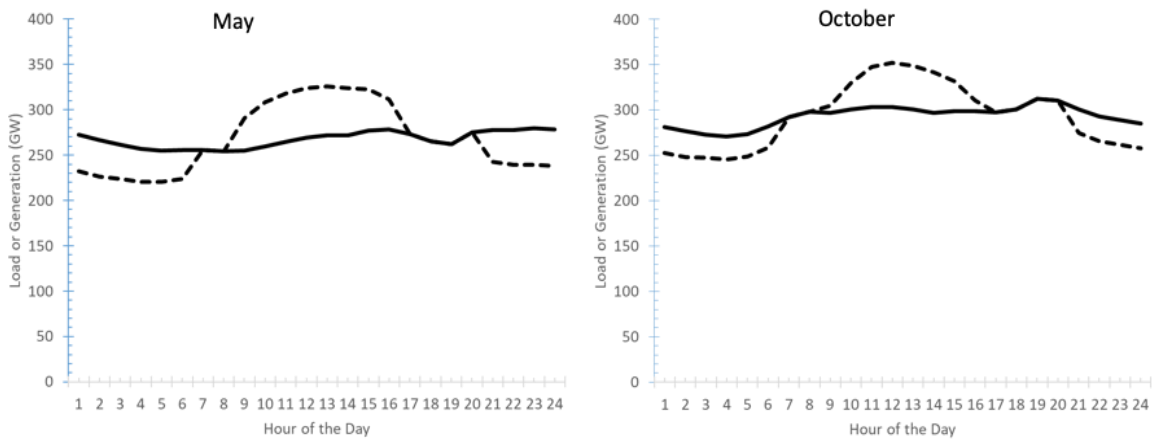


Figure 12: Average load (solid line) and shifted load (dotted line) curves, FY 2030, in the Primary Least-Cost scenario. Annually, 122TWh of agricultural and heavy industrial load gets shifted from night hours to solar hours.

(b) About 60 GW (250 GWh) of energy storage helps meet morning and evening peak loads

Energy storage is crucial for diurnal balancing of variable RE generation (i.e., shifting the RE generation to morning and evening peak demand hours (6–8 am and 7–10 pm)) and avoiding build-out of new thermal capacity that would be required primarily for meeting the peak load.[11] Figure 13 shows charging and discharging hours for batteries for an average day during 4 months of the year in 2030. The batteries typically charge during the day and discharge over 6-8 hours during the morning and evening peak hours. During winter months between October and January, batteries also charge at night. This is mainly because batteries are unable to fully charge during the day due to the steep reduction in wind generation during winter.

Fast responding batteries are crucial for meeting the grid's morning and evening ramp requirements in 2030. These ramps are timed with the large on-ramp of solar generation between 7 and 8 am, and off-ramp around 6 pm. Batteries also help reduce the ramping stress on thermal plants. Storage would be a critical source of flexibility starting as early as 2023, especially in states with high solar deployment and low hydro resources such as Rajasthan and Gujarat. Table 4 shows the optimal battery storage requirement in the intermediate years between 2020 and 2030.

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[11] In some states/Union territories, such as Delhi, the peak load is shifting to even later in the night (about 11 pm to midnight) in the summer, driven by residential space cooling demand.

Table 4: Battery Storage Requirement in the Primary Least Cost Case

	2025	2027	2030
Battery Storage Requirement (All-India)	12 GW/ 48 GWh	31 GW/ 125 GWh	63 GW/ 252 GWh

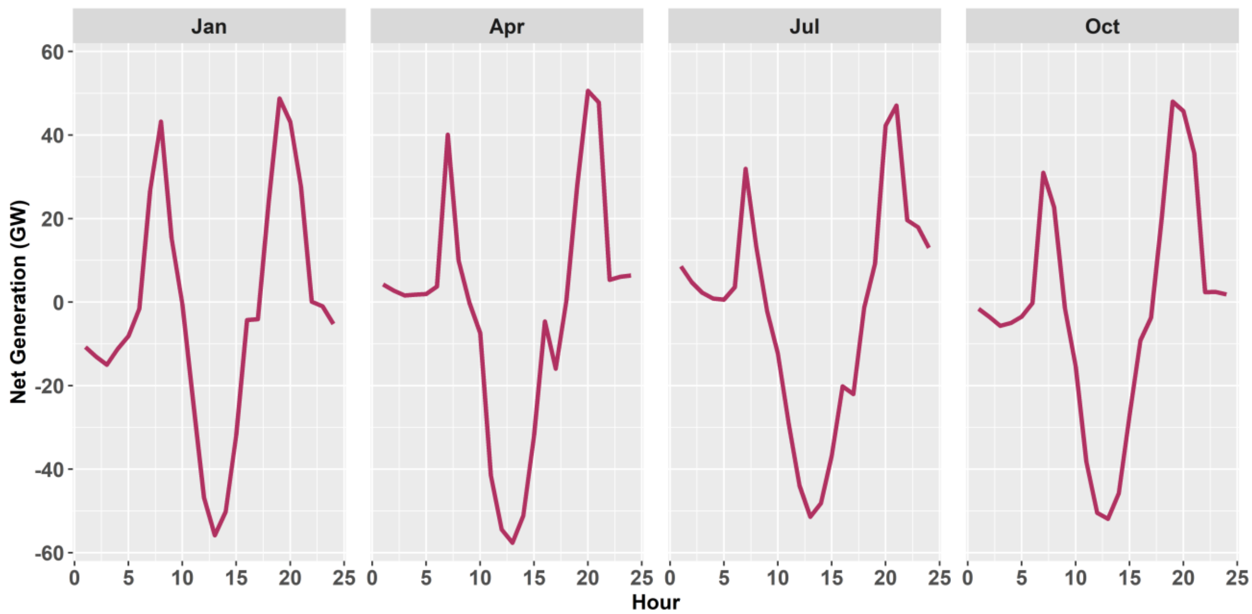


Figure 13: Average hourly net generation from batteries in FY 2030 in the Primary Least-Cost Case

Note: Positive values imply battery discharge while negative values imply batteries charging

Batteries and agricultural load shift provide diurnal balancing but cannot address RE's seasonal mismatch with electricity demand. Nationally, the electricity demand peaks in September-October, but RE output peaks between June and September (monsoon), mainly due to high wind generation. Between October and February, wind generation drops significantly (reaching an average capacity factor as low as 10%–15%, vs. 50%–60% during monsoon season), while solar generation also drops. Natural gas power plants play a crucial role in providing such seasonal energy balancing.

If low-cost energy storage could not be deployed at such a scale, additional thermal investments beyond the 23 GW net additions will be needed through 2030 to maintain grid reliability, but such assets will operate at low capacity factors.

(c) Existing natural gas power plants assist in seasonal balancing.

Even if the domestic natural gas allocation to power sector remains the same (8 bcm/yr), flexible operation of India's existing natural gas assets (25GW) could be crucial for maintaining grid dependability, especially during low-RE months. From October to the end of January, as the monsoon wind wanes and solar output drops, the grid needs significant additional energy which the batteries are unable to supply due to low RE generation. We find that the existing natural gas plants can fill this gap cost-effectively relative to building new coal power plants operating at low PLFs to meet such seasonal loads. However, seasonal, flexible operation of gas power plants, and by corollary gas pipelines, would require coordinated regulatory interventions in the power as well as gas sector, which are discussed in a separate report.

Optimal utilization of hydro power resources, particularly the 20-25 GW of reservoir-based capacity, would also be important for seasonal balancing, especially for meeting the evening peak demand during the low RE season. However, several restrictions on hydro power dispatch such as maintaining the water flows in key river basins, the cascaded and multipurpose nature of hydro power projects etc., limit their value to the grid.

(d) Flexible resources help manage thermal ramps.

Figure 14 shows coal ramps in the Primary Least-Cost Case and the CEA case.[12] Given higher flexibility in the system, coal ramps decrease significantly in the Primary Least-Cost Case, even though both cases have a similar amount of RE capacity on the grid. Batteries, hydropower resources, and natural gas plants (if operated in open-cycle mode) are best suited to tackle the steep ramp up and down from the midday solar generation. The maximum system ramp requirement in 2030 is 60 GW/hour. While batteries perform most of this ramping, coal power plants are required to ramp at less than 25 GW/hour (Figure 14). Without sufficient battery capacity, coal plants may have to meet over 50 GW/hr of the ramp requirement as seen in the CEA case, leading to lower heat rates, additional wear and tear and increasing variable and O&M costs.

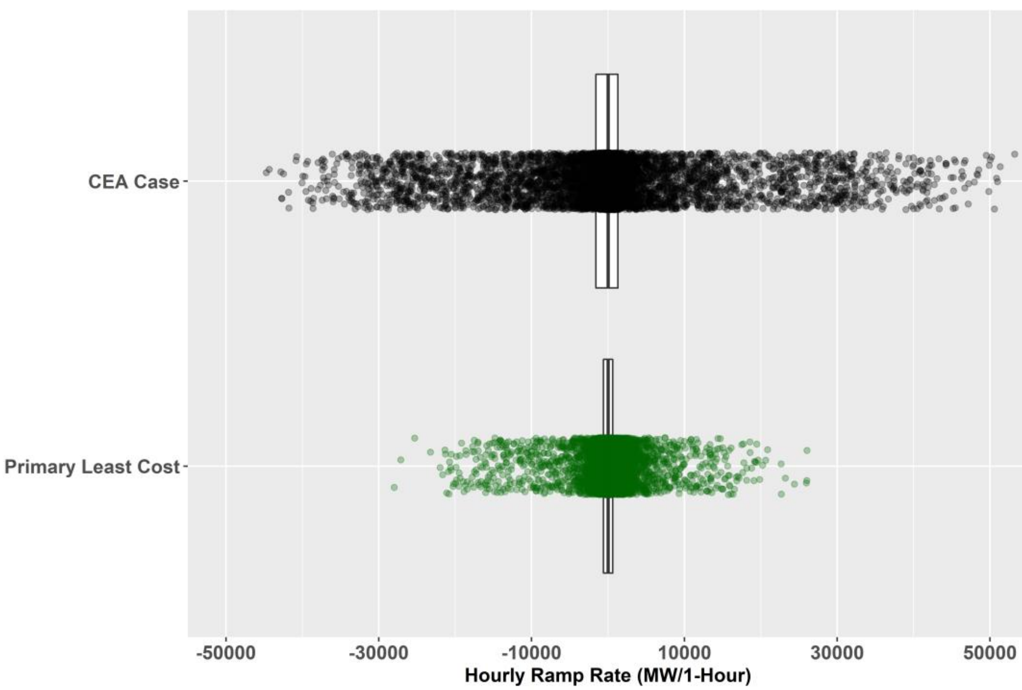


Figure 14: Hourly coal ramps in the Primary Least-Cost Case and CEA Case in 2030. Each point shows total coal fleet ramping per hour.

[12] Note that the CEA Case shows the results of hourly dispatch simulations assuming the capacity addition envisaged in CEA's Optimal Capacity Expansion report. Our assumptions on operational parameters, generation capacity siting, transmission buildout etc would be somewhat different from those used by CEA in their study. Therefore, the CEA case results should be interpreted as indicative only.

(e) The grid has sufficient capacity to run dependably during "high-stress" periods.

Here we look at how grid reliability is met during days of excessive stress, examining dispatch results for each of the peak load week, the highest net load week, and the highest system ramps week.

1. ***Peak Load:*** Nationally, the system load peak of 340 GW in FY 2030 would occur on September 15 at 7 pm (Figure 15). At this time, wind generation is as high as 50 GW (~33% capacity factor). Coal plants (ex-bus generation of 170GW) and nuclear plants (ex-bus generation of 13GW) will operate at near full capacity, providing mostly the base load support. Peak support is provided by 60 GW of batteries combined with 40 GW of hydropower. Natural gas plants also generate during the evening peak and continue to operate through the night.

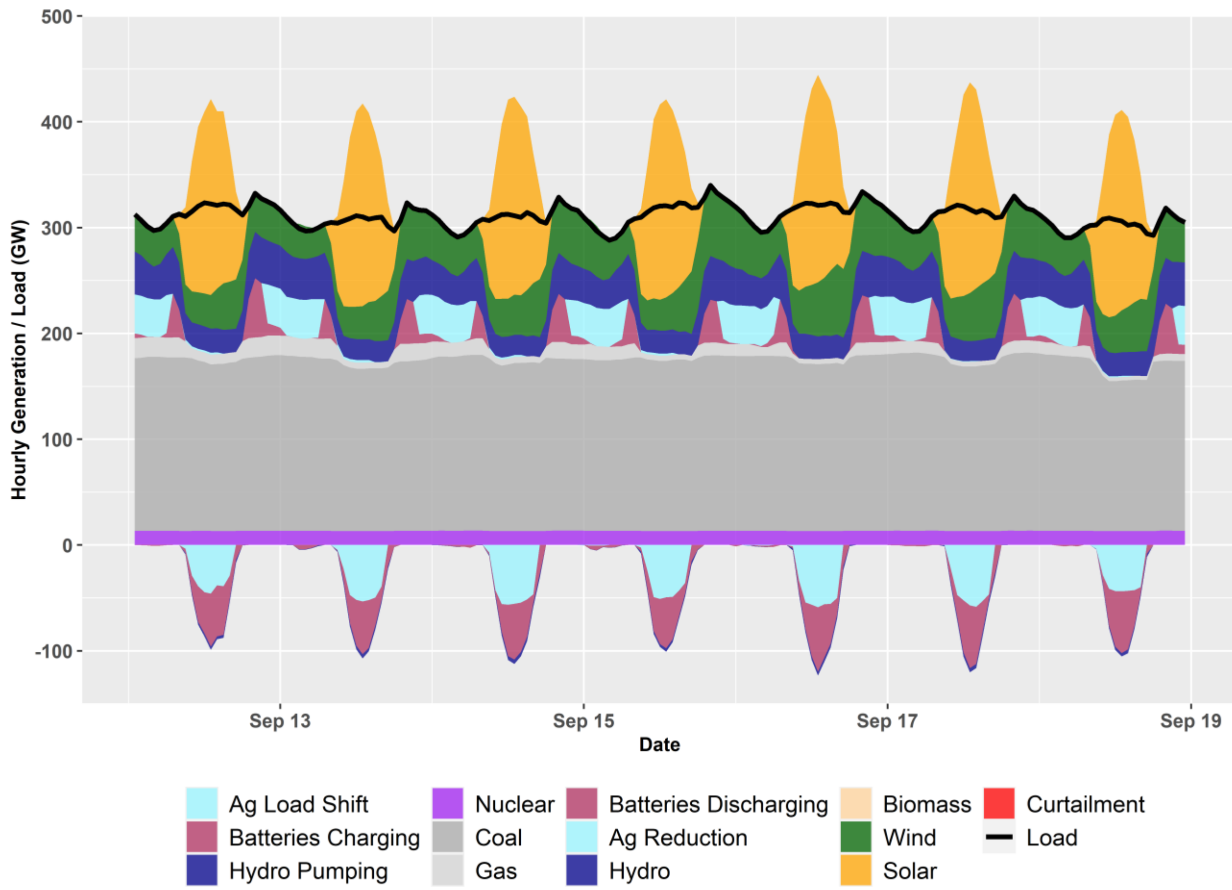


Figure 15: Hourly dispatch in the peak load week (2030) in the Primary Least-Cost scenario

2. ***Net Load Peak:*** Net load (or residual load) is defined as load minus the output from variable RE sources (solar and wind). Net load is critical from the system planning and operations perspective because it is the effective load that the rest of the system resources, such as thermal, nuclear, and hydropower, have to meet. The highest net load (national) occurs in October, when the system load is still high but the wind generation has reduced drastically (Figure 16). In FY 2030, net load peak of 312 GW occurs on October 13. Similar to the peak load week, all resources operate at near full capacity during net load peak. For example, coal (ex-bus generation of 175 GW) and Nuclear

(ex-bus 13 GW) provide the base load support while batteries (58 GW) and hydropower (40 GW including small hydro) provide the evening peaking support. Natural gas power plants run at a capacity factor of over 60% providing the seasonal balancing.

The highest net load peak day would still have a buffer of 20 GW of undispatched coal (ex-bus capacity of 15 GW, after accounting for forced outages and auxiliary consumption) and about 5 GW of battery capacity, which would provide the operating reserves needed to cover any contingencies, such as errors in day-ahead RE or load forecasts.

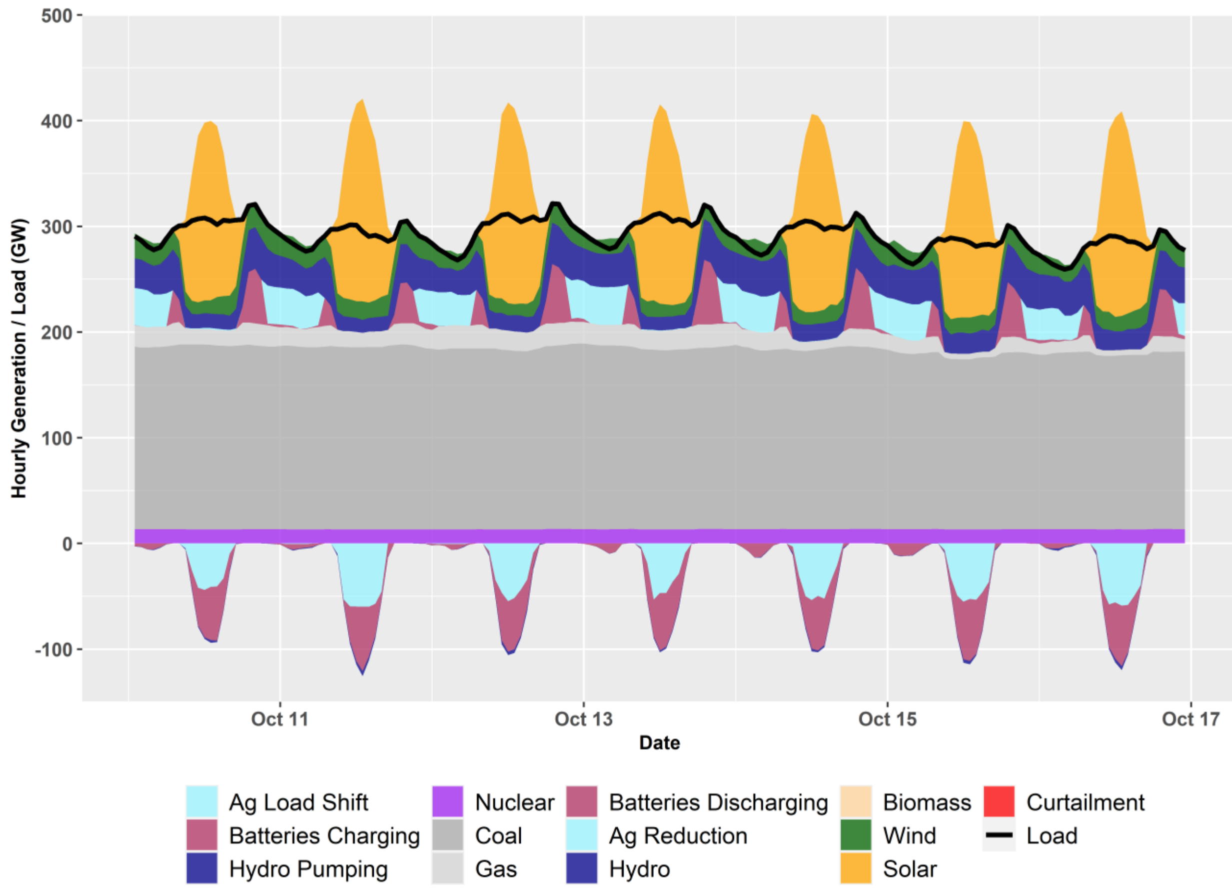


Figure 16: Hourly dispatch in the highest net load week (2030) in the Primary Least-Cost scenario

3. ***Highest System Ramps:*** Given the steep reduction in solar generation coupled with load increase right after sunset, the system ramping requirements increase significantly by 2030 owing to high solar installed capacity. The highest system ramp of about 61 GW/hour occurs on March 26 at 7 pm. The system can meet these ramps with the large battery capacity, ramping at 45-50 GW/hr and dispatchable hydropower capacity, ramping at 10-15 GW/hr, with support of 2-5 GW/hr provided by gas power plants and 5-10 GW/hr provided by coal power plants (Figure 17).

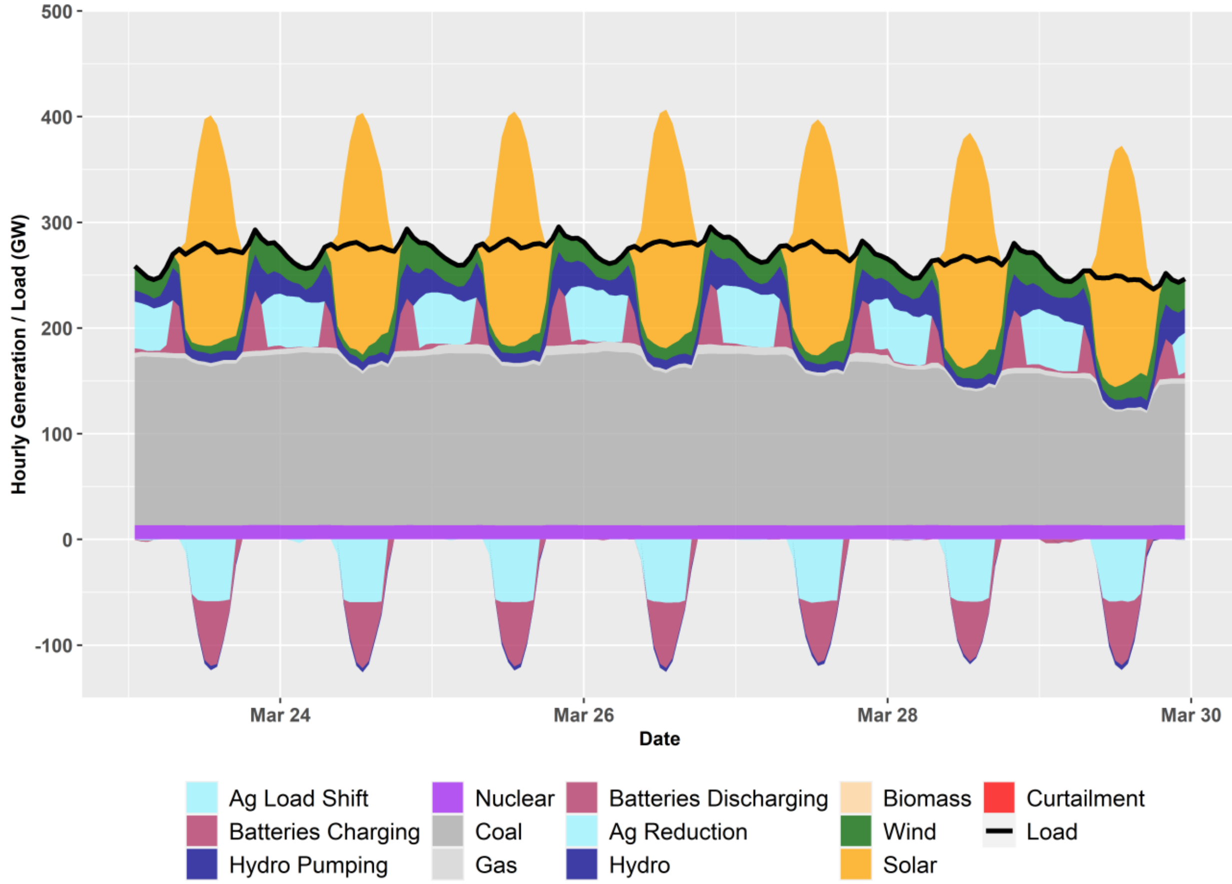


Figure 17: Hourly dispatch in the highest RE variability week (2030) in the Primary Least-Cost Case

Additional dispatch results are shown in Appendix II.

4. **Inter-annual variation in renewable energy generation:** If solar and wind energy resources experience significantly reduced output over several consecutive days, there is a significant risk that RE generation and stored electricity may not be able to meet demand, especially during peak or net load peak periods. Such a situation does not arise in our simulation year (2018 weather year), and, for every hour of the year, the Indian power system operates dependably even when about 80% of India's instantaneous load is met by renewable energy. However, simulating one specific weather year deterministically may not capture the low-probability, high-cost event of extremely low RE generation during high demand periods that may occur once every several years. Assessing the period 1981–2015, Shaner et al (2018) find the lowest solar output aggregated over the continental United States on any day is at most 20% lower than the mean solar output on that day of the year, whereas the wind output can be as much as 50% lower. They also find the temporal correlation in solar generation decreases relatively weakly with distance, implying limited diversity benefits of aggregation over a larger area.

   Unfortunately, no such assessment exists in India. As a first approximation, we believe that the solar output aggregated over India on any day likely will be at most 20% lower than the mean solar output on that day, similar to what is observed in the United States (much bigger land mass compared with India). In order to assess the impact during the periods of highest system stress, we simulate the hourly dispatch during the peak load and the net load peak weeks by assuming solar and wind output to be 20% and 50% lower, respectively.

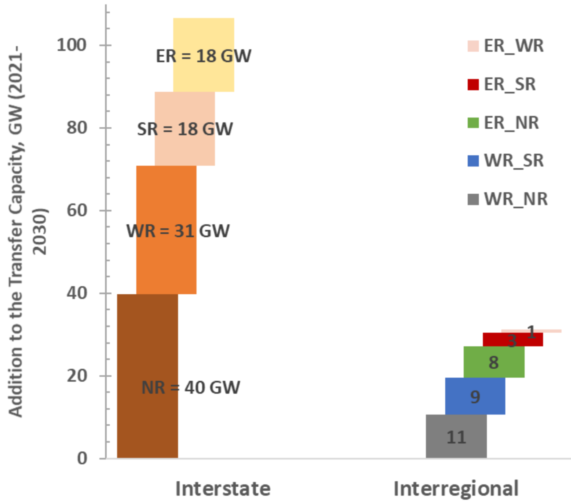
We find that during both weeks, the system was able to meet such deep drops in the renewable generation. During the peak load hour (September) the system still has significant slack in coal capacity (25 GW of undispatched available capacity that is not generating) and gas capacity (5 GW of undispatched available capacity). Since solar generation is almost zero during evening peak hours, if wind generation drops by 50% (from 33 GW to 16 GW), there is enough slack firm capacity in the system that could compensate for such drop and meet the demand. During the net load peak week (October), the wind energy generation has already dropped significantly (generating about 15 GW during the net load peak hour), system is able to handle an additional 7 GW (50%) drop in wind generation. As shown previously, coal and batteries still have about 20-25 GW undispatched available capacity that helps fill in the drop in wind generation.
From the energy balance perspective, the system is still able to handle such drops because batteries could be charged using coal or gas based generation during sustained periods of reduced generation from renewable energy resources.

It is important to understand that the study has simulated hourly grid operations using a DC Optimal Power Flow formulation. This implies that some of the operational issues that may arise in an AC power system such as reactive power compensation, impact on line voltages and grid frequency etc. could not be assessed in this study. Deeper analyses using appropriate simulation tools (such as Power System Simulator for Engineering (PSSE) etc.) would be needed to fully understand such impacts. Also, while we include 5% spinning reserves in our production cost model, we have not explicitly modeled RE or load forecast errors and some additional work would be needed for a more nuanced assessment. However, with state of the art forecasting techniques

3.3. By 2030, about 140 GW of additional transfer capacity buildout is found economical

Between 2020 and 2030, about 140 GW of additional transfer capacity needs to be built in the Primary Least-Cost Case, of which about 33 GW are required on interregional corridors and 107 GW on interstate corridors (Figure 18). The required transmission capacity buildout could be approximately twice as high i.e. 280GW. The transmission corridors that need the most additions are as follows: Maharashtra to Chhattisgarh, Uttar Pradesh to Delhi, Maharashtra to Karnataka, Rajasthan to Haryana, Rajasthan to Punjab, Gujarat to Madhya Pradesh, Madhya Pradesh to Uttar Pradesh etc. Appendix II provides additional insights on which transmission corridors would be strengthened.

The average transmission buildout cost by FY 2030 would be around Rs.0.08–0.10 /kWh (0.11-0.13 cents/kWh). In 2020, the total interstate and inter-regional transmission capacity was about 200 GW.



ER = Eastern Region, SR = Southern Region, NR = Northern Region, WR = Western Region

Figure 18: Transmission buildout in the Primary Least-Cost Case (2020–2030)

Importantly, the additional interstate / inter-regional transmission investments are not primarily driven by the RE capacity addition. Because India's load is expected to almost double over the decade, significant additional transmissions investments would be required irrespective of the resource mix. In fact, we find that because of the deep reduction in solar and battery prices, and generally good solar resource quality in most states, it is feasible to spread out RE and storage investments throughout the country, which may not be feasible with coal power plants that need to be sited near the coal mines to achieve low costs. We ran a hypothetical "No New RE" scenario, where no new renewable energy or storage capacity is built and all incremental load (2021-2030) is met only by building additional coal power plants, and found that the total interstate / inter-regional transmission buildout to be 10% higher than the Primary Least Cost case.

We have not assessed in detail the investments in spur-lines that connect RE pooling substations with the main transmission network. Nonetheless, initial estimates suggest that Rs.10,500 crore[13] of investment in the spur-line infrastructure may be required by 2030, which is equivalent to a cost adder of Rs.0.01/kWh (0.01 cents/kWh) of RE generation.

Table 5 shows interregional interchange for the Primary Least-Cost Case. Given the lower reliance on coal-fired power plants concentrated in a few regions, the net interchange decreases in the Primary Least-Cost Case, especially between western and northern regions, and eastern and southern regions.

Figure 19 plots hourly line loading for key interstate lines during 2030. In general, because of the significant battery storage capacity, we do not find any significant / consistent congestion on the key interstate / inter-regional corridors except for the Chhattisgarh-Haryana corridor. However, more nuanced assessment using more detailed transmission network, sub-hourly resolution, and AC power flow analysis would be needed to assess the true impact on the transmission system operations.

[13] Assuming the average length of spur-lines to be 20 km, the average cost of spur-lines to be Rs.15,000/MW-km, and the life of lines to be 40 years.

Table 5: Interregional interchange in Primary Least-Cost Case TWh/yr (2030)

Inter-regional corridor	Net Annual Interchange (TWh/yr)
ER-NR	27.6
WR-NR	56.2
WR-SR	-0.4
ER-WR	1.9
ER-SR	23
ER-NER	7.1

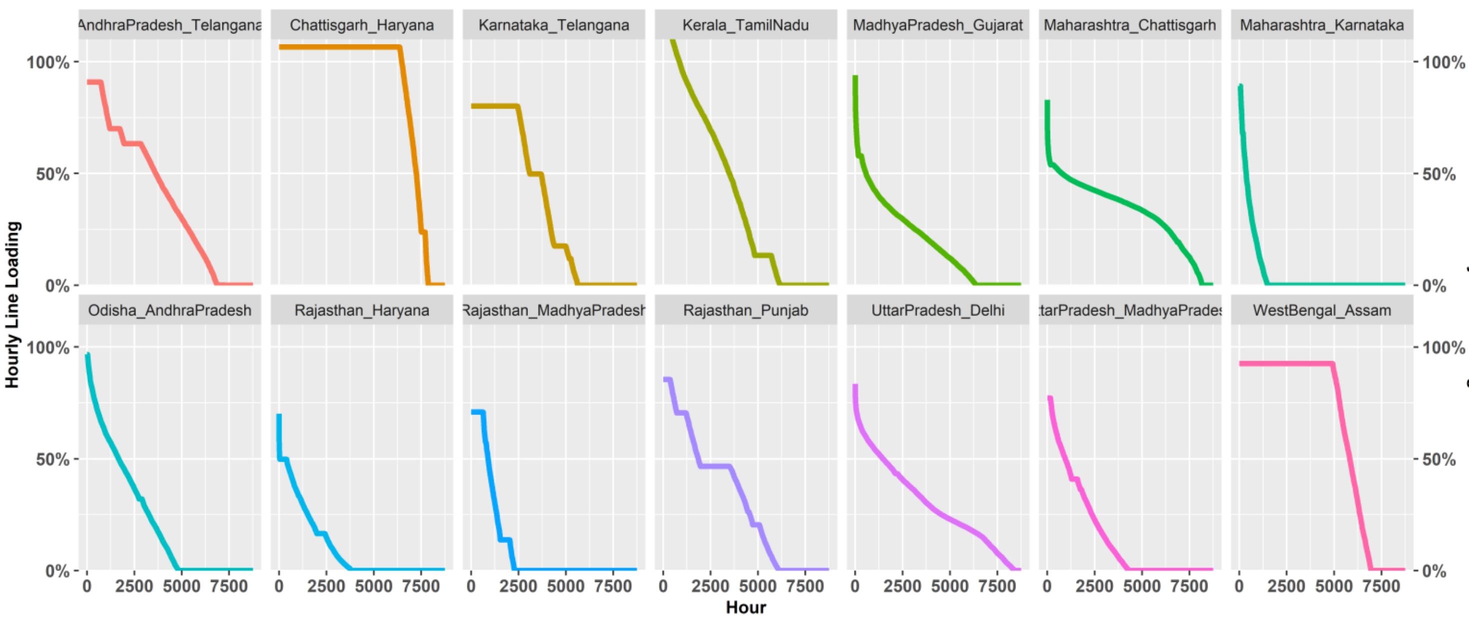


Figure 19: Hourly line loading for key interfaces, Primary Least-Cost Case (2030)

3.4 Emissions intensity of power generation drops by 43-50%

By 2030, the average CO_2 emissions intensity of the Indian power sector drops from 0.82 kg/kWh in 2020 to 0.47 kg/kWh in the Primary Least Cost case (43% reduction), and to 0.41 kg/kWh in the Low RE Cost case (50% reduction). Relative to the 2020 levels (1008 MT/yr), total CO_2 emissions from power sector in 2030 drop by 3% in the Low-RE Cost case (981 MT/yr) and increase only by 7% (1081MT/yr) in the Primary Least Cost case, despite near doubling of the electricity demand (Figure 20).

Importantly, under the Primary Least Cost case, nearly 80% of the net incremental generation between 2020 and 2030 will be contributed from new clean energy assets, including new RE, nuclear, hydropower assets. Under a Low-RE Cost case, new clean energy assets contribute about 90% of the net incremental generation. The avoided coal generation due to solar and wind generation has immense health benefits in the form of avoided air pollution. The resultant benefits due to reduced mortality and morbidity are significant and need to be assessed in more detail.

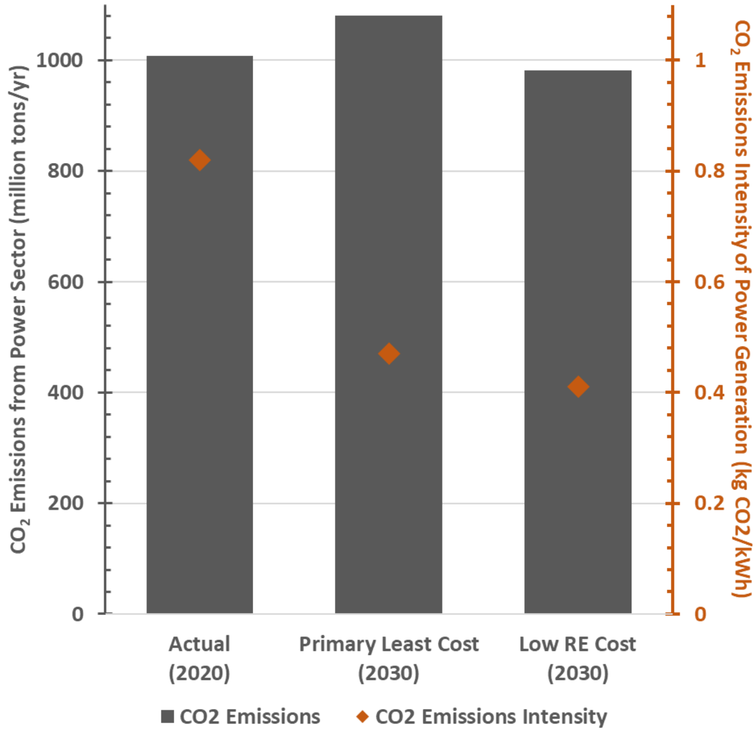


Figure 20: Carbon-dioxide emissions and intensity in 2020 and 2030

4 Sensitivity Analysis

We assess the sensitivity of our results on the key assumptions: (1) clean technology costs and disruptions to the solar / batteries supply chain or additional safeguard duties to reduce imports, (2) LNG prices, (3) utilities' unwillingness to retire their existing coal assets, (4) demand growth, and (5) implementation of a national electricity market like the proposed Marked Based Economic Dispatch. Table 6 summarizes these alternate pathways, and key insights set forth below.

Table 6: Summary of results in different sensitivity cases (2030)

	Scenario	Scenario Description	Coal (GW)	Gas (GW)	Solar (GW_{DC})	Wind (GW)	Storage (GW)	Avg Cost (Rs/kWh)
1	**Low Demand Growth**	Load growth is 25% lower (2030 Peak = 290GW)	206	25	230	109	32	3.64
2	**No Coal Retirement**	25GW coal (NEP) does not retire per plan	238	25	301	137	57	3.62
3	**High RE Cost** (with supply chain constraints)	Significantly higher cost and deployment constraints for solar and batteries	242	45	220	142	32	3.63
4	**Low LNG Price**	LNG price = \$4.5/MMBTU (landed)	224	28	308	132	66	3.58
5	**MBED**	National level economic dispatch	232	25	302	151	59	3.56

5.1 No new coal capacity beyond what is under construction is cost-effective if demand growth is lower than expected

If the post-COVID economic recovery takes longer than expected and the rate of load growth through 2030 drops to 4.7% per year (instead of 6.3% per CEA's 19th EPS assumed in the Primary Least-Cost Case i.e., if peak load in 2030 would be 290 GW), no new coal capacity addition is found to be economical. The system would only need a total of 355 GW of total RE capacity to meet the lower demand:

- Solar: 230 GW
- Wind: 109 GW
- Other RE: 15 GW
- Battery storage: 32GW/128 GWh

The average cost of generation in this Low Demand Growth case is Rs.4.08/kWh, slightly higher than in the Primary Least-Cost scenario, mainly because of the lower asset utilization of the existing assets.

5.2 If 25 GW of coal plants do not retire as planned, 438 GW of solar and wind capacity would still be cost-effective, though the average cost of generation would increase to Rs 3.62/kWh as compared to Rs 3.59/kWh under the Primary Least Cost Case

In the latest NEP, CEA identified about 25 GW of aging coal capacity for retirement between 2022 and 2027. We analyze a scenario in which state utilities do not retire any of this capacity by 2030. The model in this case builds 8 GW of additional coal capacity beyond the capacity under construction resulting in 238 GW of installed coal capacity, 301 GW of solar, 137 GW of wind, and 57 GW of battery storage to be cost-effective (Table 6). Generation from coal plants increases marginally to 1,168 TWh/yr (49% of generation), while solar and wind sources provide 35% of total generation.

5.3 With high RE costs due to higher duties and/or supply chain constraints, additional coal and natural gas capacity is needed, increasing the average electricity cost by Rs.0.047/kWh

In the high RE cost scenario, in addition to the high capital cost / import taxes on solar and batteries, we also assume significant supply chain challenges leading to only a limited deployment of these resources. As a result, coal and natural gas expand significantly to meet the increasing demand. The resource mix is 220 GW_{DC} of solar, 142 GW of wind, 35 GW of batteries, 242 GW of coal, and 45 GW of natural gas (Table 6). Coal provides over half of the annual generation in 2030, and solar and wind account for about 30%. The average electricity cost by 2030 would be Rs 3.63/kWh, which is 1.4% higher than in the Primary Least-Cost Case. This boundary case shows the potential consequences of serious trade or supply disruptions.

5.4 If the LNG price drops to $4.5/MMBTU, flexible operation of gas-fired generation starts competing with expensive coal power plants

The Low LNG Price scenario assumes the LNG price (delivered on the Indian shore) drops to $4.5/MMBTU, while the domestic natural gas price stays the same. While this price drop is still not enough to justify buildout of new natural gas power plants, gas generation increases to about 120 TWh/yr by 2030, compared with 50 TWh/yr in the Primary Least-Cost Case. There is no change in coal capacity, but about 42 TWh of expensive coal generation is replaced by natural gas generation. The following is the resource mix for this scenario:

- Solar: 308 GW
- Wind: 132 GW
- Battery storage: 66 GW/264 GWh

Domestic gas availability for the power sector is about 8.5 bcm/yr (23 mmscmd) by 2030, and LNG consumption is about 14 bcm/yr (10 MTPA).

5.5 Effects of Market-Based Economic Dispatch (MBED)

For FY 2030, we simulate a national wholesale electricity market or Market Based Economic Dispatch (MBED) proposed by CERC to assess the impact on system operations and costs in a RE heavy grid. To simulate MBED, we use the resource mix in our Primary Least-Cost Case and run the grid dispatch simulation by removing the economic hurdles that states face for importing / exporting electricity to other states. The physical limits of the transmission system and standard transmission wheeling charges would still apply.

1. ***More efficient dispatch:*** Figure 21 shows the annual PLF vs. variable cost of each individual coal power plants dispatched under the Primary Least-Cost Case and MBED scenario. In the MBED scenario, the system dispatches the plants with lowest variable cost at the highest PLFs, while the PLF continues to drop as the variable cost increases. With MBED, although national coal generation remains almost the same as in the Primary Least-Cost Case (with state-level balancing), the distribution among states changes significantly. Because the utilization of cheaper thermal assets increases significantly, the total variable cost of generation (coal plus natural gas) decreases by 5% or Rs 14,000 Cr/yr (~$2 billion/yr) by FY 2030 (Table 7) and the total CO_2 emissions from the power sector reduce by 5% relative to the Primary Least Cost case.

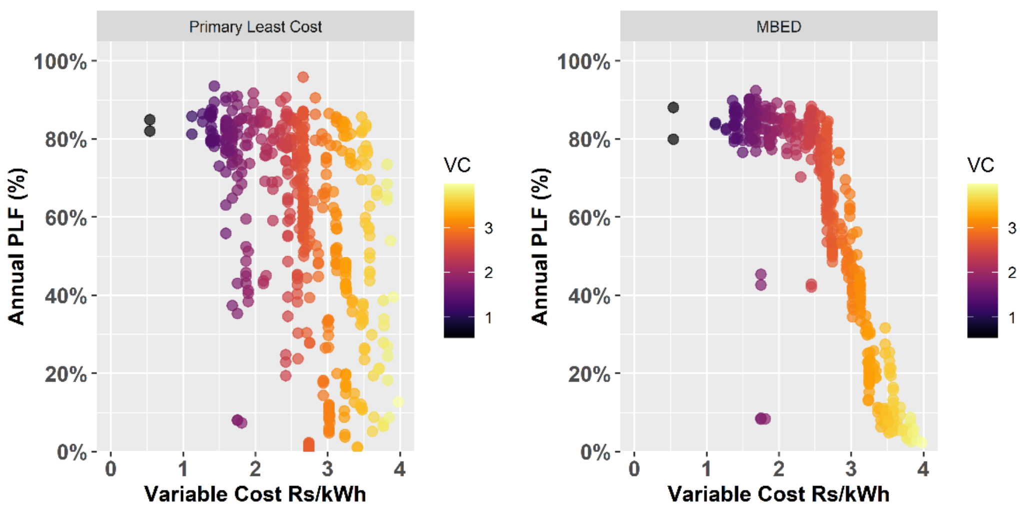


Figure 21: PLF vs. variable cost (VC) of coal plants in the Primary Least-Cost Case (left) and MBED (right) scenario. Color of the point shows the variable cost of each power plant.

Table 7: Total system variable cost (Rs Thousand Cr/yr) in 2030 for the Primary Least-Cost (state balancing) and MBED scenarios

	Primary Least Cost (State Balancing)	MBED
Coal Variable Cost	285	276
Gas Variable Cost	18	13
Total	**303**	**289**

2. ***Change in power flows and transmission congestion:*** Figure 22 shows duration curves for line loading on certain key interfaces in the MBED scenario. MBED increases the possibility of congestion on certain interfaces, so transmission requirements should be assessed in detail.

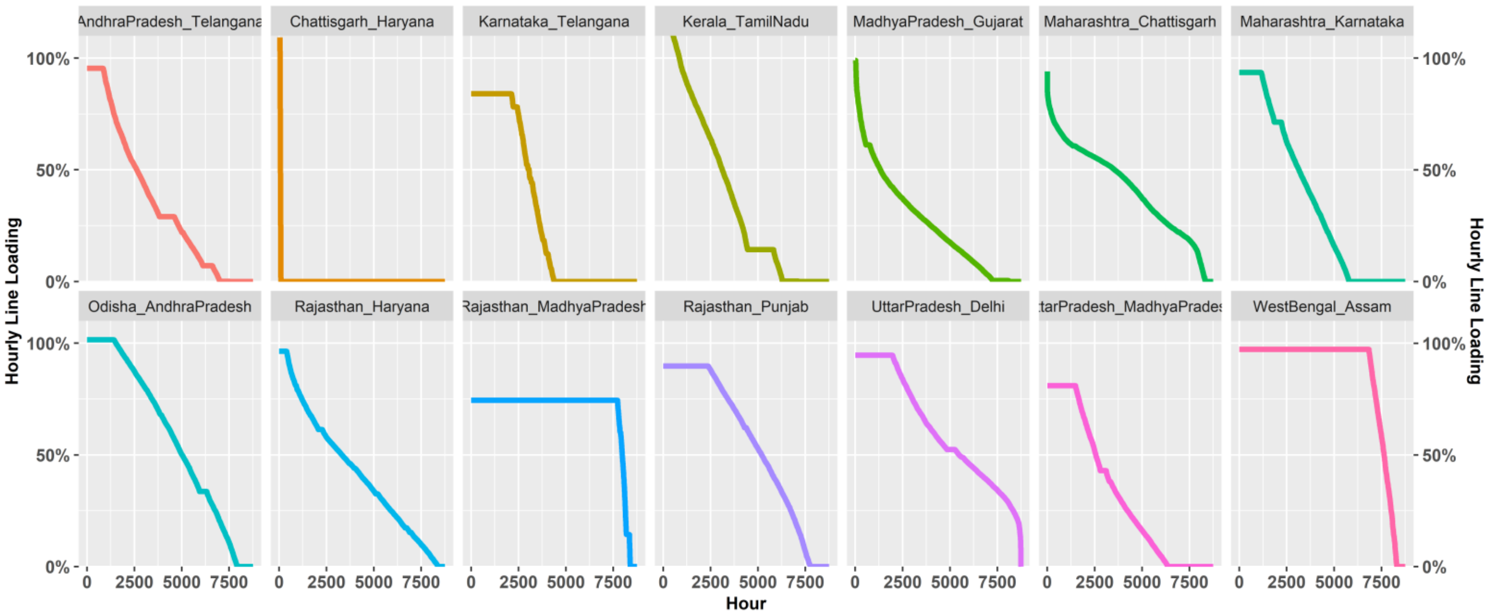


Figure 22: Hourly loading on key line interfaces in the MBED scenario

As shown in Table 7, in the Primary Least-Cost Case with state-level balancing, there is significant interregional exchange, mainly because most RE capacity is concentrated in the west and south. In the MBED scenario, the interregional exchanges increase significantly (Table 8). This is expected as the system tries to dispatch the cheapest resources available across the country. The transmission capacity is enough to handle these flows, but congestion becomes more pronounced.

Table 8: Interregional transmission flows (TWh/yr) in FY 2030

Net Interregional Exchange (TWh/yr)	Primary Least-Cost	MBED
ER-NR	27.6	67.2
WR-NR	56.2	106.2
WR-SR	-0.4	5.9
ER-WR	1.9	7.8
ER-SR	23	46.9
ER-NER	7.1	9.7

5 Conclusions

Dramatic cost reductions over the last decade for wind, solar and battery storage position India to leapfrog to a more flexible, robust, and sustainable power system — much of which is yet to be built — for delivering affordable and reliable power to serve a nearly doubling power demand by 2030. In this study, we assess a cost-effective and operationally feasible investment pathway for India's electricity grid by enhancing system flexibility and robustness through renewable energy (RE) and a spectrum of flexible resources, such as energy storage, demand response (load shifting), natural gas, and electricity markets. The study achieves this objective by using an industry standard power system modeling platform (PLEXOS) and comprehensive electricity grid data at the individual power plant level.

We find that the least cost resource mix to meet India's load in 2030 (the "Primary Least Cost Case") consists primarily of a combination of RE and flexible resources as follows: 465 GW of RE (307 GW_{DC} solar, 142 GW wind, and 15 GW other RE), 63 GW (252 GWh) of battery storage, 60 GW of load shifting to solar hours (50 GW agricultural + 10 GW industrial), flexible operation of the existing natural gas fleet of 25 GW. About 23 GW of net new thermal capacity investments are found to be cost effective between 2020 and 2030 – making the total coal capacity requirement in 2030 to be 229 GW. If RE and storage prices drop per historical trends (Low RE Cost Case), the least cost mix includes 547 GW of RE (385 GW_{DC} solar, 147 GW wind, and 15 GW other RE), 84 GW/336 GWh of battery storage, and 206 GW of coal capacity. Note that if low-cost energy storage could not be deployed at such a scale, additional thermal investments beyond the 23 GW net additions will be needed through 2030 to meet the peak demand, but such assets will operate at low capacity factors.

This implies that India's incremental electricity demand through 2030 will largely be met by new investments in renewable energy (RE) and energy storage and existing thermal assets. As a result, between 2020 and 2030, despite near doubling of India's electricity demand, the total CO_2 emissions from the power sector remain almost the same while emissions intensity of electricity generation drops by 43%-50%. Also, total coal consumption in the power sector remains almost the same as that in 2020, implying clean energy transition is unlikely to lead to loss of coal mining and transportation jobs in the near- to medium-term.

Continued build-out of new coal-fired assets will cause significant financial and technical stress on the existing coal power plants. About 23 GW of new thermal investments beyond the capacity that is already under construction is found to be economical. We also find that India's electric grid with massive RE and battery storage capacity will be dependable in every hour of the year. Between 2020 and 2030, average cost of generation is found to reduce by 8-10% because of the falling renewable energy and storage prices. The interstate transmission investment is found to be modest - 140 GW of additional interstate transfer capacity buildout through 2030.

Overall, as India's grid attains higher penetrations of renewables, balancing its variability through a spectrum of flexible resources – such as energy storage, demand response (agricultural load shifting), flexible operation of gas power plants, and becomes increasingly important for ensuring the affordability, stability, and reliability of grid power. The flexible resources work in tandem to maintain the hourly supply-demand balance. During the high RE generation season (June through September for wind and March through June for solar), energy storage and agricultural load shifting provide diurnal grid balancing.

Batteries charge during the daytime (coincident with solar generation) and discharge during the morning and evening peak periods (4-6 hours total each day). They also help to meet steep system ramps. Shifting agricultural load to solar hours increases the day-time load by 40-60 GW while reducing the night-time load and thereby the baseload capacity requirement by 30-50 GW. As a result, only 180GW of coal capacity is dispatched mainly as a baseload resource. During the low RE generation season (October through February), the 25 GW of existing natural gas capacity (in lieu of coal-fired assets) plays a crucial role in providing the seasonal balancing with most of their dispatch occurring during these months. Widening and deepening of the electricity markets, such as implementation of the MBED, can provide additional flexibility in system dispatch while reducing the thermal variable costs and CO_2 emissions by 5% in 2030.

For India to achieve the least-cost resource mix indicated in this study, a modest decline in the current RE (5-10% by 2030) and a more pronounced decline in the current storage costs (30-40% by 2030), consistent with historical trends and projections by other studies, will be required. Also, deploying RE and storage at such a significant scale will likely require addressing supply chain challenges and securing adequate financing. Finally, critical policy and regulatory changes must be expeditiously implemented in order for India to move on to the least-cost pathway. These changes include, among other things, a nuanced long-term resource adequacy framework for system planning and procurement, a regulatory framework for energy storage that values and compensates this resource for its full functionality, and gas reforms that promote flexible operations and increased utilization of India's gas pipeline system to enable cost-effective, flexible operation of India's existing 25 GW fleet of gas-fired power plants for seasonal and diurnal grid balancing.

We conducted a separate analysis of specific policy and regulatory changes that may be needed, which are summarized in the next section.

6 Policy and Regulatory Recommendations

This study points to an investment pathway for India's transition to a flexible, robust, and cleaner power system while meeting its growing load reliably and at least cost. Strong policies and regulatory interventions – particularly, around three main areas: resource adequacy (RA), state resource planning and procurement, and short-term markets and system operations would be required for achieving the projected 2030 resource mix and changes in system operations, are summarized in this section. A separate report provides an in-depth discussion on each of the following policy and regulatory recommendations.

Resource Adequacy (RA)

- *Nearer-term (1–3 years)*. Develop a national RA mechanism that requires a reserve margin study, mandates standards for state load forecasting, creates RA requirements for states, defines transparent methods for capacity crediting, develops markets for RA capacity, and implements deficiency penalties for non-compliance and incentives for generator availability.

- *Longer-term (4–10 years)*. Develop transparent pricing for mechanisms to provide RA and probabilistic methods for capacity crediting (demand response, solar, storage, wind).

Resource Planning and Procurement

- *Nearer-term (1–3 years)*. Integrate RA requirements into state and Discom resource planning and procurement, pilot all-source competitive procurement in a few states, and build the capacity of states/Discoms to conduct economic modeling needed to support all-source competitive solicitations.

- *Longer-term (4–10 years)*. Develop national guidelines for competitive procurement and expand all-source competitive procurement to all states.

Markets and System Operations

- *Nearer-term (1–3 years)*. Complete implementation of current market reforms and review market participation rules for energy storage to ensure that its full flexibility and functionality can be utilized and compensated through markets.

- *Longer-term (4–10 years)*. More closely align short-term markets and power system operation by implementing locational marginal price-based (LMP-based) security constrained economic dispatch (SCED) in real-time markets.

Flexible operation of the existing gas power plants

To operate gas power plants flexibly, existing gas-fired generators will need access to fuel and the ability to change the amount of fuel consumed to increase or decrease output. The specific policy and regulatory changes needed in the gas sector to enable such operational flexibility and better gas-electric sector coordination are provided in the table below.

Table 9: Policy and regulatory recommendations for gas-electric coordination

#	Key gas-electric coordination topics	Specific Policy & Regulatory Innovation
1	Information transparency to ensure physical access and availability of gas to power plants	Require establishment of an electronic bulletin board that provides information on pipeline capacity availability, critical notices of system outages and natural gas pipeline tariffs.
2	Enabling contractual flexibility in commodity gas/LNG supply agreements	Commodity supply agreements should include flexible pricing and volume optionality
3	Enabling flexibility in pipeline gas transportation agreements	Enable flexibility in gas transportation by eliminating take-or-pay (ship-or-pay) provisions, thereby supporting commodity contracts on flexible terms
		Amend pipeline access code to require pipeline operators to offer interruptible transportation services in addition to firm service
		Require pipeline operators to offer value-added no-notice, hourly, non-ratable flow, and line pack derived storage services that are related to transportation flexibility
		Allow intra-day gas capacity nominations and require pipeline operators to move initial nomination schedules to one day before flows
		Allow resale of firm transportation service to third parties
		Require pipeline operators to provide flexibility in entry/exit (receipt/delivery) points
		Amend pipeline access code to require pipeline operators to offer standardized gas transportation agreement terms and conditions
4	Wholesale gas market, pricing and structural reforms	Facilitate commercial and operational unbundling of pipeline transportation, commodity gas sales and marketing functions and allow open access to third party shippers
5	Rationalization of natural gas pipeline tariff structure	Amend tariff regulations to move towards a two-part tariff for firm transportation service and interruptible services on volumetric basis

7 Caveats and Future Work

Although we assess an operationally feasible least cost pathway for India's power system using weather-synchronized load and generation data, further work is needed to advance our understanding of other facets of a power system with high RE penetration. First, this report primarily focuses on renewable-specific technology pathways and does not explore the full portfolio of clean technologies that could contribute to future electricity supply. First, issues such as loss of load probability, system inertia, and alternating-current transmission flows need further assessment. Options to address these issues have been identified elsewhere (for example, Denholm, 2020). Second, our assessment does not fully address the operational impacts of day-ahead / intra-day forecast errors in RE and load. However, several studies have shown that with state of the art forecasting techniques, the impact of such forecast errors appears to be small (for example, Hodge, 2015; Martinez-Anido, 2016).

Although this analysis does not attempt a full power-system reliability assessment, we perform scenario and sensitivity analysis to ensure that demand is met in all periods, including during extreme weather events and periods of low renewable energy generation. This modeling approach provides confidence that integrating over 450GW of renewable energy into the grid is technically feasible and economically desirable by FY 2030. This is critical, because power sector decarbonization can be the catalyst for decarbonization across all economic sectors via electrification of vehicles, buildings, and industry. Owing to the global nature of renewable energy and battery markets, our study indicates the possibility that cost-effective decarbonization can be a near-term reality.

Finally, although this report describes the system characteristics needed to accommodate high levels of renewable generation, it does not address the institutional, market, and regulatory changes that are needed to facilitate such a transformation. Our complementary analysis, presented in a separate report and summarized in the policy recommendations section, identifies many of these solutions (Deorah et al, 2021). Further details on the key assumptions and results can be found in the appendices.

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8 Appendix I: Key Assumptions and Data

8.1 Wind, solar, and battery storage costs

For the fiscal year 2019-20, we use actual reverse auction results for assessing the solar and wind levelized cost of energy. To account for the impact of safeguard duty on imported components, we increase the 2019-20 solar auction prices by 10% based on several Central Electricity Regulatory Commission (CERC) and Maharashtra Electricity Regulatory Commission (MERC) tariff orders allowing for the pass-through of safeguard duty. For example, average solar reverse auction price in FY 2019-20 was found to be Rs 2.51/kWh; by applying the safeguard duty, the corrected LCOE comes to about Rs 2.76/kWh, for an average resource quality region with DC capacity factor of 19%. We adjust LCOE per resource quality in a region. For example, in Rajasthan and Gujarat, we adjust the 2020 LCOE to Rs 2.4/kWh, which reflects the better resource quality and an average DC capacity factor of 22%. Battery storage capital costs have been taken from our previous analysis that assesses the grid-scale battery storage costs in India (Deorah et al, 2020). For projecting the future costs of wind, solar, and battery storage through 2030, we create three scenarios – low-, base-, and high-. The ***low-cost*** case assumes cost reductions between 2020 and 2030 are in line with historical trends in India. The base or ***mid-cost*** case assumes cost reductions between 2020 and 2030 to be half the observed historical rate. The ***high-cost*** case assumes the cost trajectory of clean technologies is higher than in the base case, which could occur for various reasons, such as slower reductions in global prices, restrictions on imports, or solar and battery supply chain disruptions that limit the capacity that could be installed in the first few years of the decade (10 GW/yr). We assume domestic manufacturing catches up by middle of the decade, and new installations are not constrained beyond 2025. Table A1 lists our wind, solar, and battery storage cost assumptions.

Table A1: Assumptions on Average Levelized Cost of Energy for Wind and Solar and Levelized Cost of Storage for Standalone Battery Energy Storage Systems (Rs/kWh)

	High Cost			Mid (or Base) Cost			Low Cost		
	Wind	**Solar**	**Battery (4-hour)**	**Wind**	**Solar**	**Battery (4-hour)***	**Wind**	**Solar**	**Battery (4-hour)**
2020	3.2	2.8	6.0	3.2	2.8	6.0	3.2	2.8	6.0
2021	3.2	2.7	5.9	3.2	2.7	5.8	3.2	2.6	5.6
2022	3.2	2.7	5.8	3.2	2.6	5.5	3.1	2.4	5.2
2023	3.2	2.6	5.7	3.2	2.5	5.2	3.0	2.3	4.9
2024	3.2	2.6	5.6	3.1	2.4	5.0	2.9	2.1	4.5
2025	3.2	2.5	5.4	3.1	2.3	4.7	2.8	2.0	4.2
2026	3.1	2.5	5.3	3.1	2.3	4.5	2.8	1.9	4.0
2027	3.1	2.4	5.2	3.0	2.2	4.3	2.7	1.8	3.7
2028	3.1	2.4	5.1	3.0	2.1	4.1	2.6	1.7	3.4
2029	3.1	2.3	5.0	3.0	2.1	3.9	2.6	1.6	3.2
2030	3.1	2.3	4.9	3.0	2.0	3.7	2.5	1.5	3.0

Note: Wind and solar LCOEs are shown for typical projects with average capacity factors of 26% and 19.2%, respectively.

8.2 Conventional power plant fixed costs

Conventional technology (coal, natural gas, hydro, biomass, and diesel) capital and fixed O&M costs have been taken from multiple sources including CERC tariff norms, CEA's optimal capacity expansion report, and industry consultations. Table A2 summarizes the assumptions.

Table A2: Assumptions on Fixed Costs of Conventional Technologies

Technology	Capital Cost of New Capacity (Rs Cr/MW)	Fixed O&M Cost (Rs Cr/MW-yr)
Coal (Ultra super-critical)	7.85	0.188
Gas (CCGT)	4.5	0.113
Hydro	#N/A	0.15
Nuclear	#N/A	0.15
Biomass	#N/A	0.113

Note: Hydro, Nuclear, and Biomass capacities are not optimized and the current CEA / DAE plans are taken as given.

We assume the real (inflation-adjusted) weighted average cost of capital (WACC) of 8%, which is equivalent to a nominal WACC of 11.6% (nominal interest rate of 11% and return on equity of 14%, assuming a debt-to-equity ratio of 80:20).

8.3 Coal prices and variable costs

For existing coal power plants, we take the variable costs of existing interstate generating stations (ISGS) from reports available under the Reserves Regulation Ancillary Services (RRAS) mechanism. Variable costs for state generators and IPPs are from regulatory orders by Indian state commissions. For plants with no recent data available from regulatory orders, we use power the variable cost data from Ministry of Power's MERIT database. For power plants with no data available (less than 5 GW), we use the average variable costs for that technology and size in their state / region. Between 2020 and 2030, we assume a 1% per year of real increase in the variable costs, which is half the historical growth rate of Coal India Limited's actual coal prices. Figure A1 shows the supply curve of the coal fleet (at individual unit level) for FY 2020. Each point on the chart represents a thermal power plant unit in the country; the horizontal axis shows cumulative total installed capacity of the fleet in MW while the vertical axis shows the variable cost in Rs/kWh.

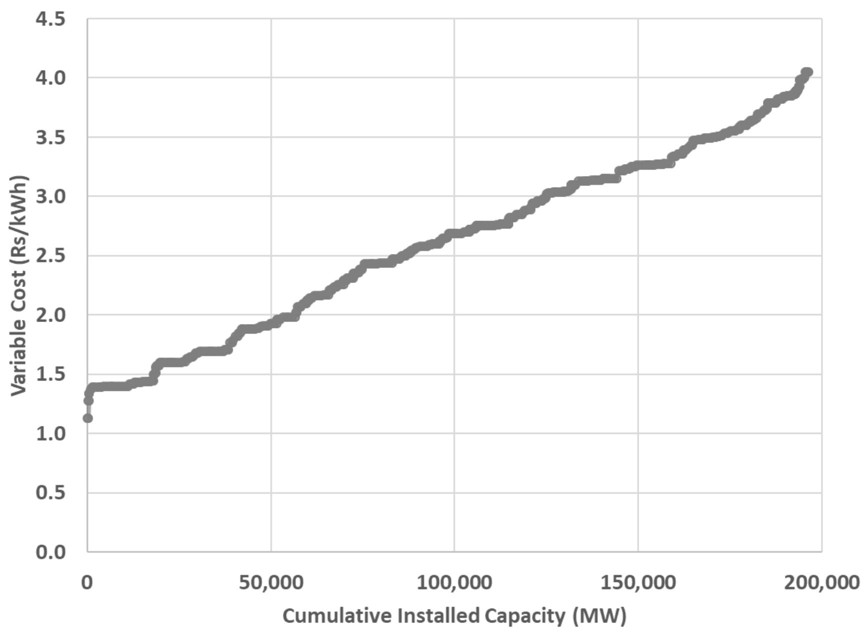


Figure A1: Supply Curve of the Existing Coal Capacity in FY 2020

It is interesting to note than in FY 2020, nearly 90 GW of the coal capacity had a variable cost of higher than Rs 2.76/kWh, the average solar reverse auction price including the safeguard duty. For new coal power plants, we assume a pithead coal price of Rs 2000-2500/ton (incl taxes), which is equivalent to a variable cost of Rs 1.59/kWh, increasing at 1% per year (half the historical growth rate of Coal India Limited's actual coal prices) between 2020 and 2030. Imported coal prices are taken from global market reports at the Indonesian hub. Average delivered price imported coal is assessed to be $70/ton in FY 2020 increasing at 1% per year, which is equivalent to a variable cost of Rs 3.5/kWh for coastal power plants, after accounting for the improvement in heat rates due to imported coal.

8.4 Gas prices and supply constraints

We assume that the total domestic gas availability for power sector will remain constrained at the 2020 levels (8.4 bcm/yr or 23 mmscmd). Total LNG import capability would increase from 15 million tons per annum (MTPA) in 2020 to 50 MTPA in 2030. Domestic gas price in 2030 is assumed to remain almost the same as 2020 ($4.2/mmbtu). LNG price in 2020 is assumed to be $3.5/mmbtu (FOB) or $4.5/mmbtu (landed). For 2030, we examine two LNG price scenarios: 1) Base LNG price: landed price of $5.5/MMBTU (plus regasification cost of $0.6/mmbtu and pipeline charges, as applicable), and 2) Low LNG price: landed price of $4.5/MMBTU (plus regasification cost of $0.6/mmbtu and pipeline charges, as applicable).

8.5 Operational parameters

Operational parameters such as ramp rates, technical minimum levels, auxiliary consumption, minimum up and down times etc have been taken from the actual data from CEA thermal performance review reports, regulatory norms, and expert / industry consultations. They are summarized in Table A3.

Table A3: Assumptions on Operational Parameters of Power Plants

	Coal (new)	Coal (existing)	Gas CCGT	Gas CT	Hydro	Nuclear	Biomass	Wind	Solar	Battery	Pumped Hydro
Planned Outage rate	5%	8-12%	5%	5%	5%	10%	10% (Availability is seasonal)	1%	1%	1%	5%
Forced Outage rate	5%	7-8%	5%	5%	5%	10%	10%	1%	1%	1%	5%
Technical Minimum Level %	55%	Central & IPP = 55% State = 70%	40%	20%	0%	90%	70%	0%	0%	0%	0%
Cold-start time (hours)	24	24	12	1	#N/A	96	24	0	0	0	#N/A
Minimum up-time (hours)	12	12	6	1	0	96	12	0	0	0	0
Minimum down-time (hours)	6	6	3	1	0	96	6	0	0	0	0
Cold-start Cost ($/MW)	100	100	30	1	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A
Ramping (% of installed capacity per minute)	1%	0.50%	2%	10%	100%	#N/A	1%	#N/A	#N/A	100%	100%
Auxiliary Consumption	7%	7-8%	5%	2%	1%	10%	10%	0.5%	0.5%	0.5%	1%
Roundtrip Efficiency	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	90%	80%
Heat Rate kCal/kWh	2262	2214-2819 (actual)	1810	2857	#N/A	#N/A	3000	#N/A	#N/A	#N/A	#N/A

8.6 Heat rates

We use actual heat rate data for every power plant using several sources such as regulatory filings, CEA Thermal performance review, CEA CO_2 Emissions Baseline etc. We model the heat rate as a function of generator loading, meaning that as the power generation from a unit drops, the heat rate will increase. The heat rate function is taken from the CERC regulations on compensating the generators for partial load operations. Figure A2 shows the heat rate function used for a new 660 MW super-critical power plant.

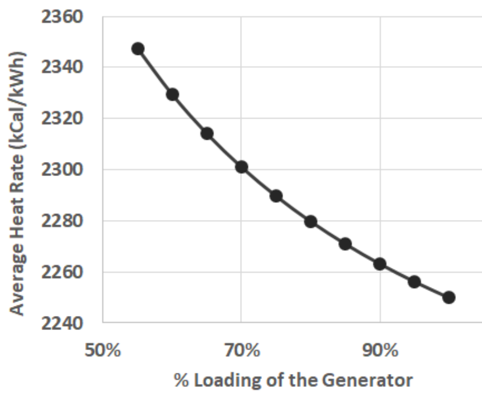


Figure A2: Average heat rate of a coal unit (660 MW super-critical) as a function of unit loading

At technical minimum level of 55%, the heat rate increases by over 4% of the design heat rate at rated capacity.

8.7 Agricultural and industrial demand response

Several states have separated distribution feeders for agricultural consumers from other feeders, and some states (e.g., Karnataka, Maharashtra, and Gujarat) have already shifted a major part of the agricultural load to solar hours (over 6 GW total in 2020). For example, Karnataka, which was traditionally an evening peaking system, has its peak load in the afternoon mainly due to shifting of agricultural load to solar day-time hours, as seen in the charts in Figure A3.

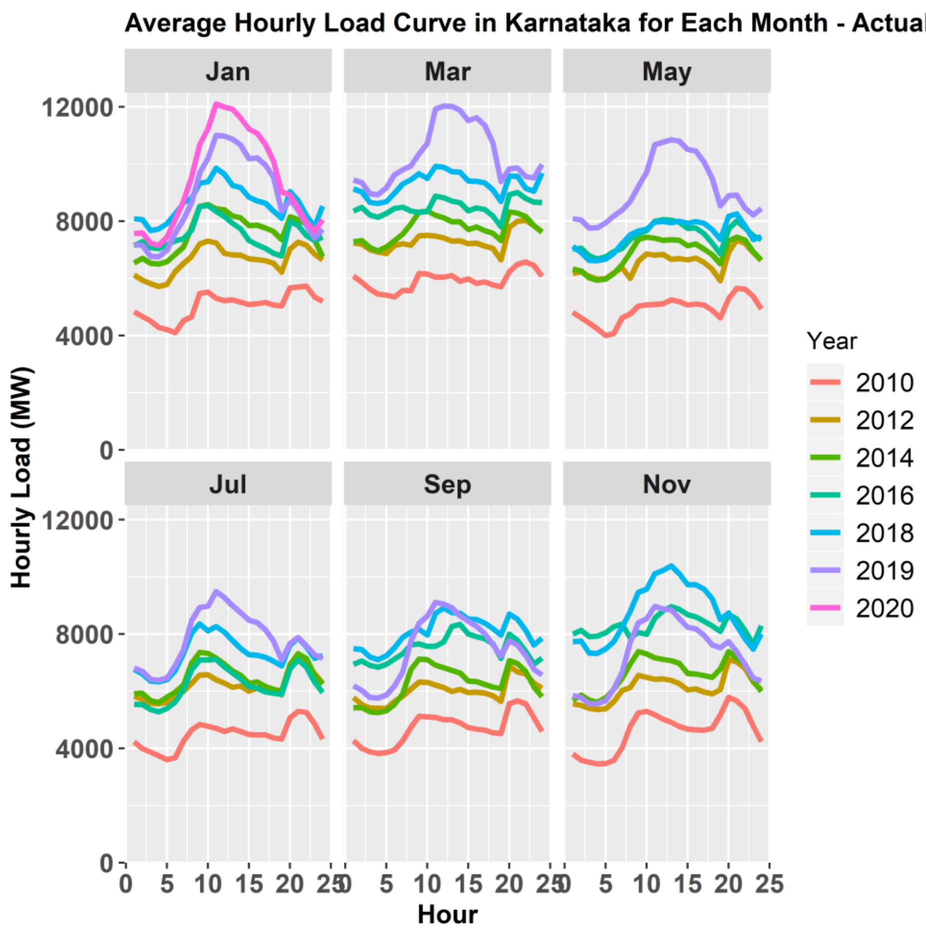


Figure A3: Actual average hourly load met in Karnataka in selected months for 10 years

Data source: KPTCL (2020)

We assume the same trend to continue in the future, and by 2030, about 50 GW of agricultural load and 10 GW of industrial load could be shifted from night-time to solar hours.

9 Appendix II: Additional Results

9.1 Seasonal nature of renewable energy generation in India

As shown in Figure A4, wind generation is highly seasonal in India with majority of the generation occurring in monsoon (June – September). Solar generation more uniformly distributed across the year, with some drop in winter; albeit electricity demand also reduces in winter. The system load (national aggregate) peaks in September and October. As a result, the net load (load minus renewable energy generation) peaks in October as wind generation starts dropping rapidly beyond September.

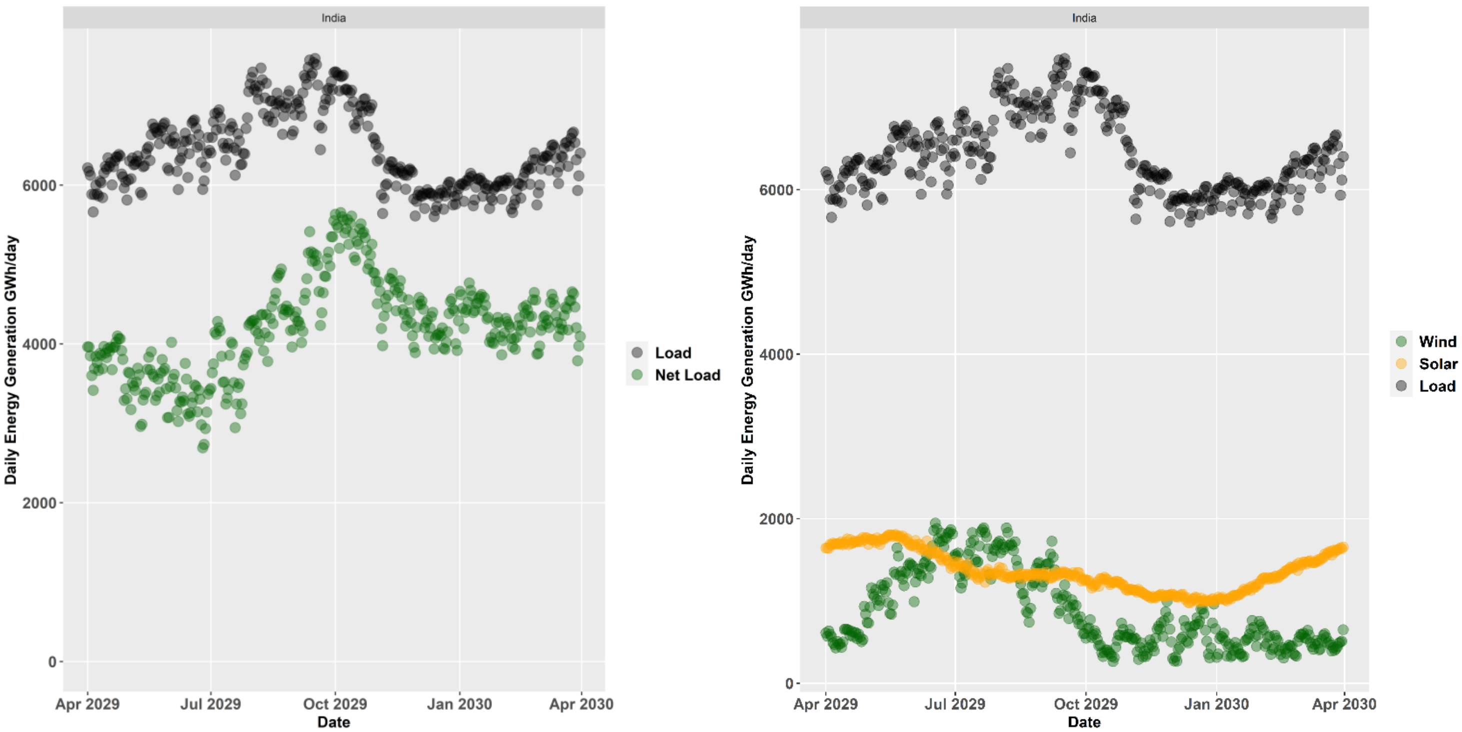


Figure A4: Daily load and net load energy (left) and daily load and RE generation (right) in FY 2030 in the Primary Least Cost case

9.2 Impact of increasing RE penetration on system ramping requirements

As RE capacity increases, the system ramping requirement increases significantly as shown in Figure A5.

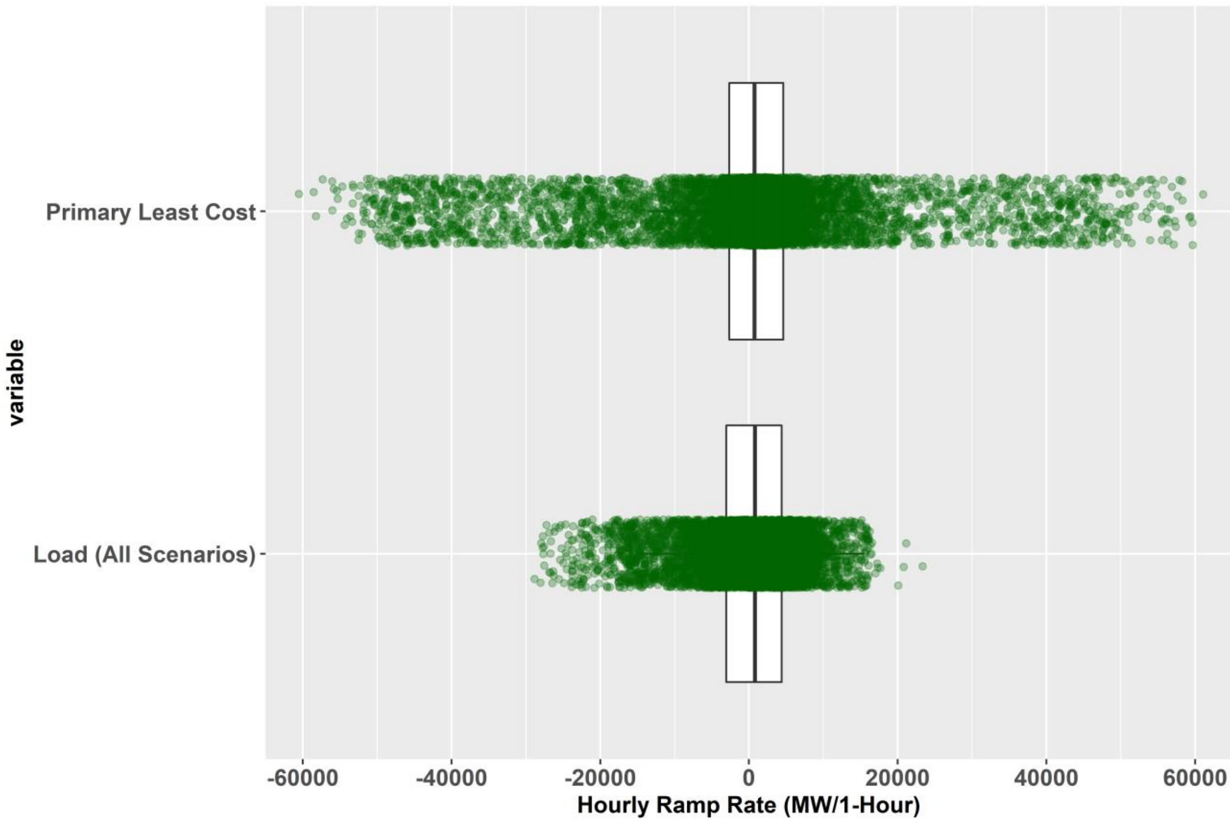


Figure A5: Hourly load-only ramps and net-load ramps for the Primary Least Cost case in FY 2030

9.3 Where is new RE capacity and storage capacity built ?

India's wind energy potential is highly geographically concentrated while solar energy potential is more uniformly spread out. Top-10 states, mostly in the western and southern region (Table A4), would have over 90% of the installed RE capacity by 2030; specific sites where solar and wind capacities could be sited are shown in Figure A6. Battery storage installations are found to be optimal in states with significant solar capacities and with limited other flexibility options such as agricultural load shifting, hydro, and gas. Because of the highly seasonal nature of the wind generation .

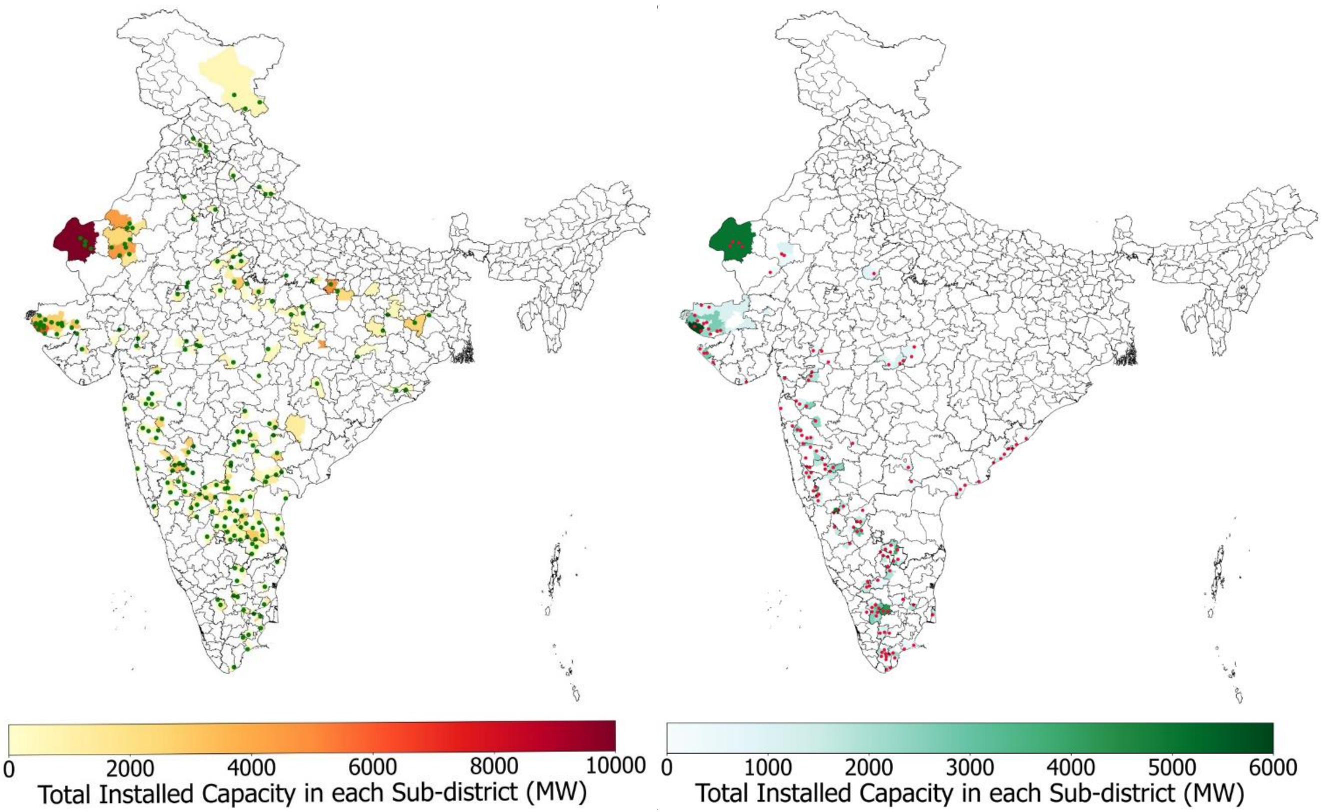


Figure A6: Sites for installation of solar and wind plants in Primary Least Cost Case, 2030

Table A4: State level wind, solar, and battery storage installed capacities (GW) in the Primary Least Cost case

State	2020 (Actual)			2030		
	Solar	**Wind**	**Battery Storage**	**Solar**	**Wind**	**Battery Storage (x4-hr)**
Rajasthan	5.2	4.3	-	57.4	6.3	20.1
Gujarat	3.1	7.6	-	35.8	22.3	4.3
Maharashtra	1.9	5.0	-	30.2	35.2	0.3
Karnataka	7.3	4.8	-	24.7	34.9	4.1
Tamil Nadu	3.9	9.3	-	17.7	30.8	3.9
Andhra Pradesh	3.6	4.1	-	37.6	6.7	8.3
Madhya Pradesh	2.3	2.5	-	31.7	4.1	9.6
Telangana	3.7	0.1	-	20.4	1.1	3.8
Uttar Pradesh	1.2	-	-	16.7	-	4.8
Uttarakhand	0.3	-	-	10.1	-	1.9
Other States	2.7	0.1	-	24.6	0.7	2.6
All-India	**35.1**	**37.8**	**-**	**306.9**	**142.2**	**63.4**

9.4 Which transmission corridors need strengthening ?

Table A5: New Transfer Capacity Buildout through FY 2030 in the Primary Least Cost Case

Interface	Additional Transfer Capacity Buildout GW (2021-2030)
Maharashtra_Chattisgarh	15.7
UttarPradesh_MadhyaPradesh	8.7
MadhyaPradesh_Gujarat	8.3
Rajasthan_Haryana	8.3
Bihar_UttarPradesh	7.6
Maharashtra_Karnataka	7.1
Punjab_UttarPradesh	6.1
Rajasthan_Punjab	5.6
UttarPradesh_Delhi	5.1
TamilNadu_Karnataka	4.9
WestBengal_Bihar	4.4
WestBengal_Odisha	4.2
WestBengal_Jharkhand	4.1
Karnataka_Telangana	3.7
Kerala_Karnataka	3.4
Odisha_AndhraPradesh	3.3
Haryana_HimachalPradesh	2.9
Bihar_Odisha	2.4
Uttarakhand_Haryana	2.4
AndhraPradesh_TamilNadu	2.3
WestBengal_Bhutan	2.1
HimachalPradesh_Punjab	2.0
AndhraPradesh_Telangana	1.9
Maharashtra_Telangana	1.9
Haryana_Delhi	1.5
Punjab_JammuandKashmir	1.4
Uttarakhand_UttarPradesh	1.3
AndhraPradesh_Karnataka	1.2
Uttarakhand_JammuandKashmir	1.2
Maharashtra_MadhyaPradesh	1.1
Jharkhand_Bihar	1.1
Odisha_Bihar	1.0
Other interfaces	11.7
Total	**139.9**

9.5 Hourly coal and gas generation

Maximum coal generation of about 180 GW (ex-bus) occurs during the net load peak season of October (Figure A7).

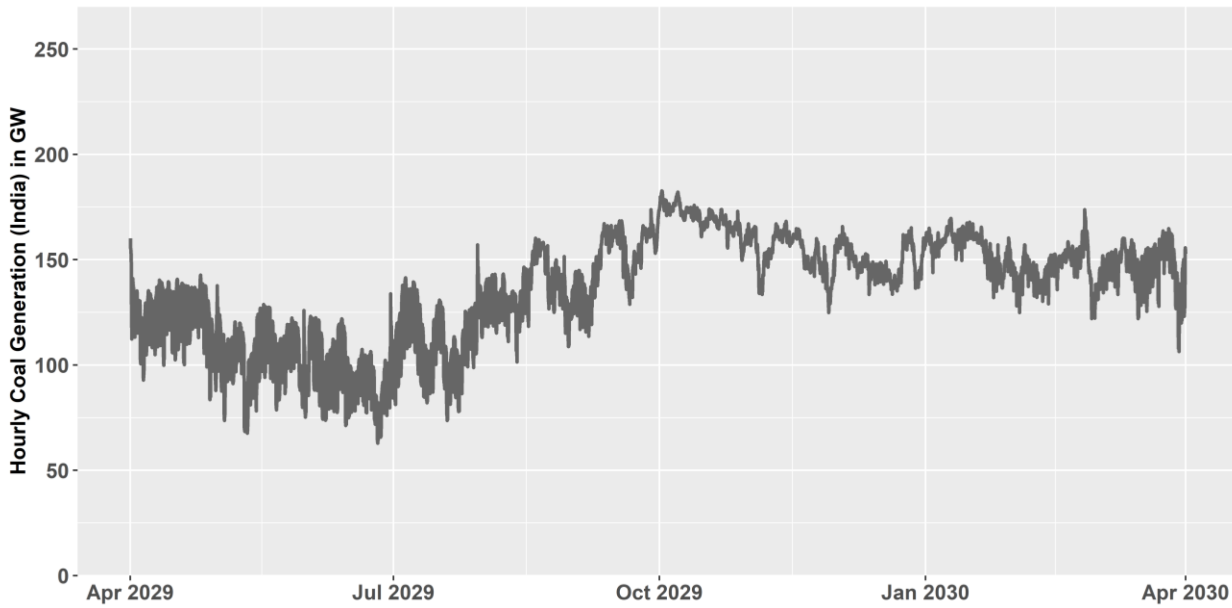


Figure A7: Hourly coal generation (national aggregate) in the Primary Least Cost Case (FY 2030)

Most of the gas generation occurs in the low RE season (between October and February) providing the much needed seasonal balancing to the grid (Figure A8).

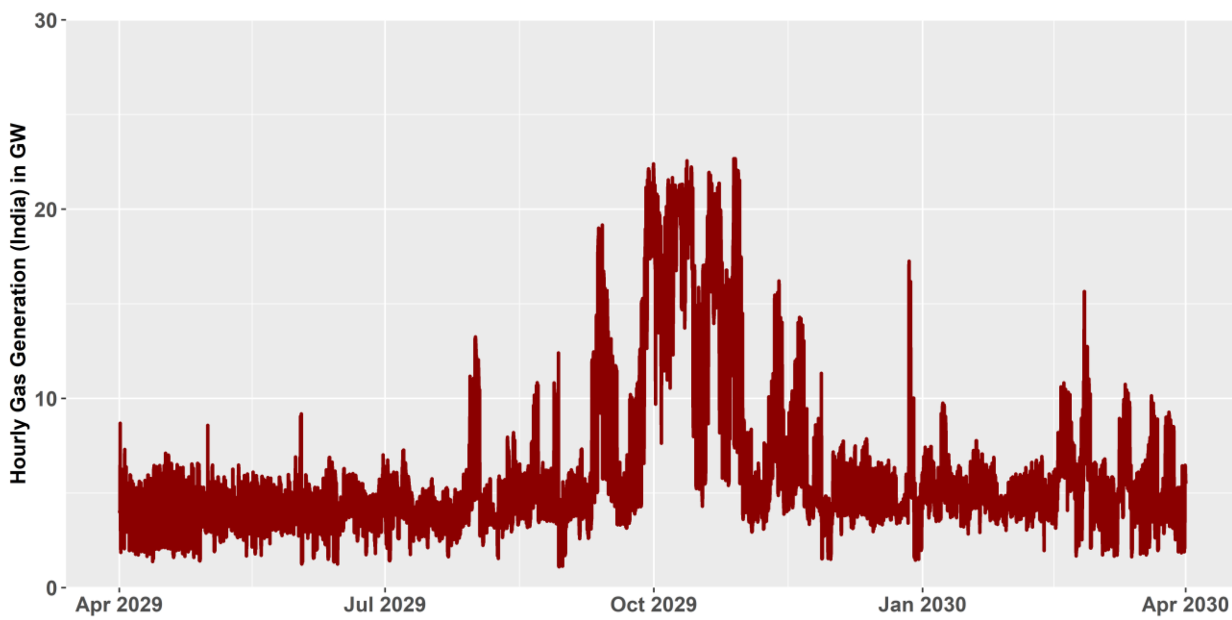


Figure A8: Hourly gas generation (national aggregate) in the Primary Least Cost Case (FY 2030)

9.6 How does hydropower contribute to system flexibility

Since the reservoir based fully dispatchable hydroelectric projects are only ~25GW, the diurnal ramping support provided by the hydro capacity is limited to ~20-25GW/hour, as shown in the Figure A9. Dispatchable hydro power plants mainly generate during the morning and evening peak demand periods.

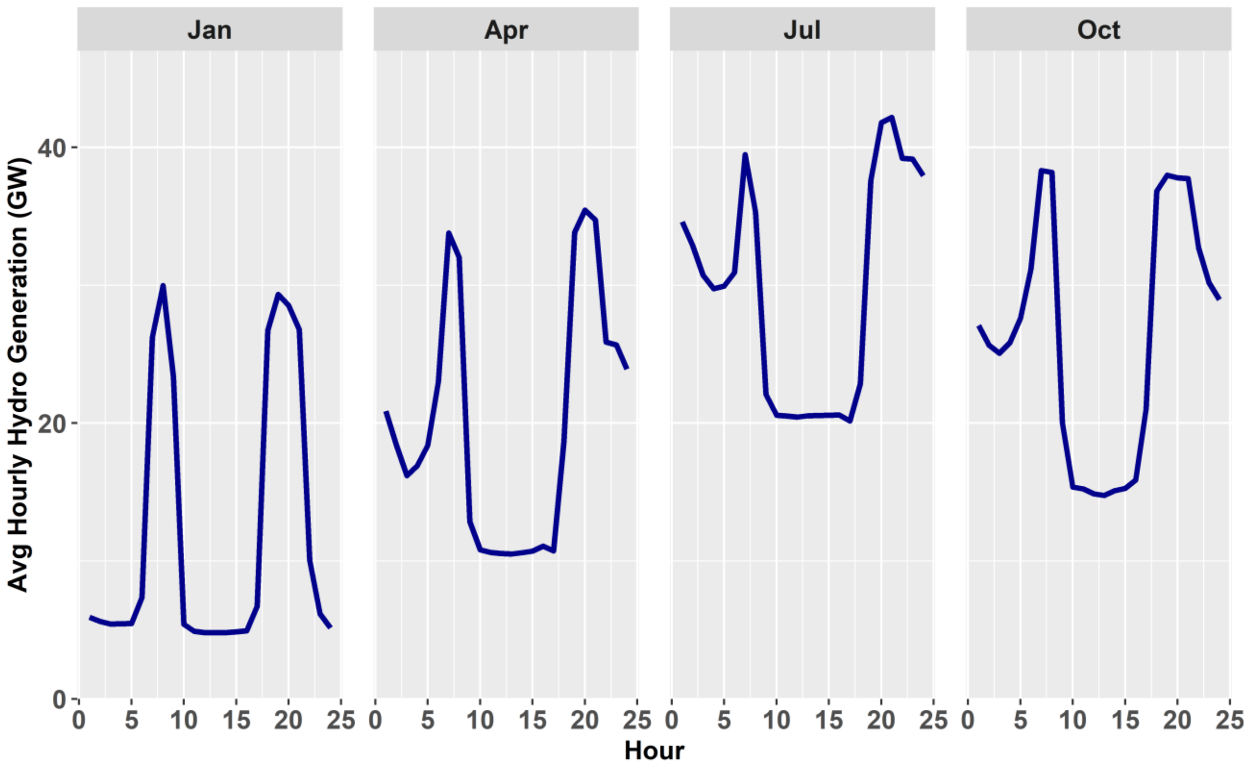


Figure A9: Average hourly hydro generation (including small hydro) in FY 2030 in the Primary Least Cost case

9.7 State level generation and annual transmission flows

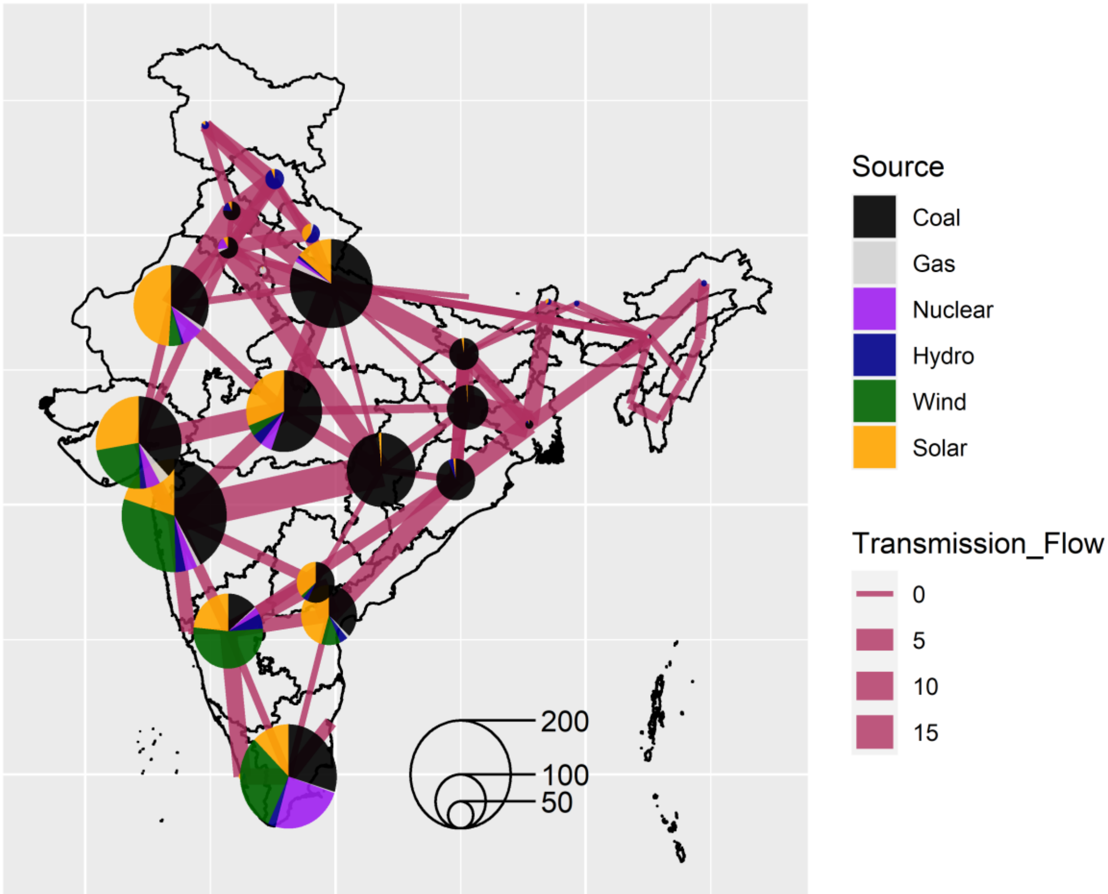


Figure A10: State level generation and transmission flows (TWh/yr) in FY 2030 in the Primary Least Cost case

Notes:
1. All numbers in TWh/yr.
2. The individual state pie charts do not include imports / allocations from the central sector generating stations.

9.8 National dispatch during maximum RE generation week

In FY 2030, the instantaneous maximum contribution of RE in meeting the load is as high as 73% of the instantaneous load, typically occurring at 12 or 1 PM in late-June when wind generation has picked up and solar generation in the west and north has not dropped much (Figure A11). In RE rich states such as Karnataka or Tamil Nadu, the instantaneous maximum RE generation in FY 2030 could be as high as 90%.

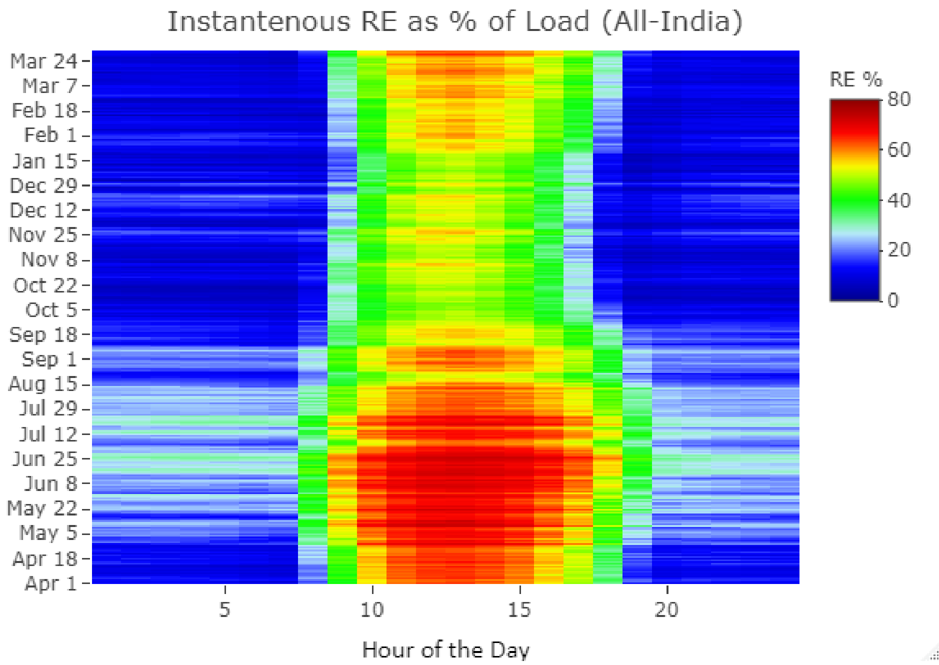


Figure A11: Instantaneous RE generation as % of the instantaneous load in the Primary Least Cost case (FY 2030)

Figure A12 shows national dispatch during the week of the maximum daily RE generation in FY 2030, which occurs in early monsoon when solar generation has not dropped significantly. There is small curtailment observed during this period, but it is mostly concentrated in the wind rich states such as Karnataka or Tamil Nadu.

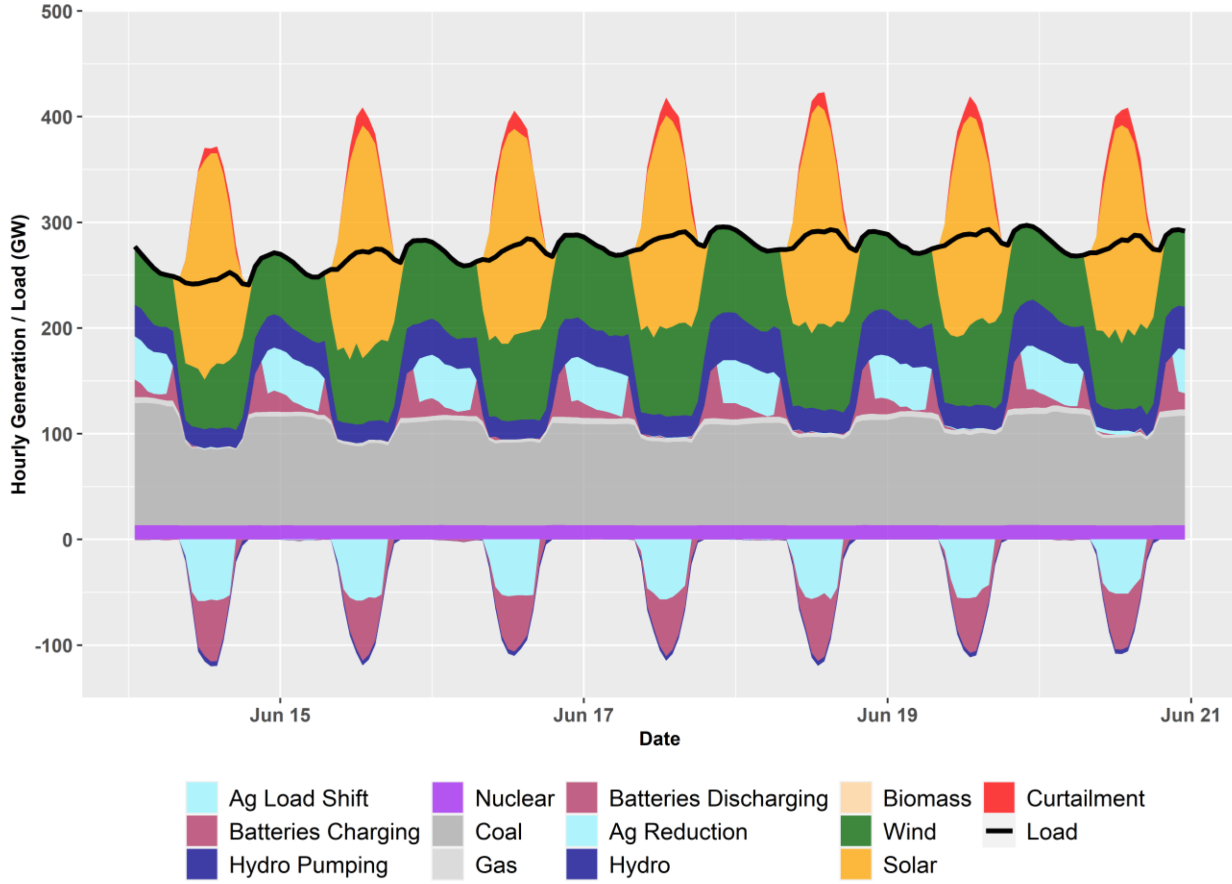


Figure A12: National hourly dispatch during the maximum RE integrated week in the Primary Least Cost case (FY 2030)

9.9 National dispatch during minimum load week

In winter, the wind generation drops significantly but electricity demand also drops. With the help of other resources, the demand is reliably met in each hour but the manner in which energy storage operates is different from other seasons. During low demand periods, energy storage charges twice in each day – majority of the charging still happens during the solar hours but small amount of charging also happens during the demand troughs in the early morning hours (1-5 AM). Figure A13 shows the national dispatch during minimum load week.

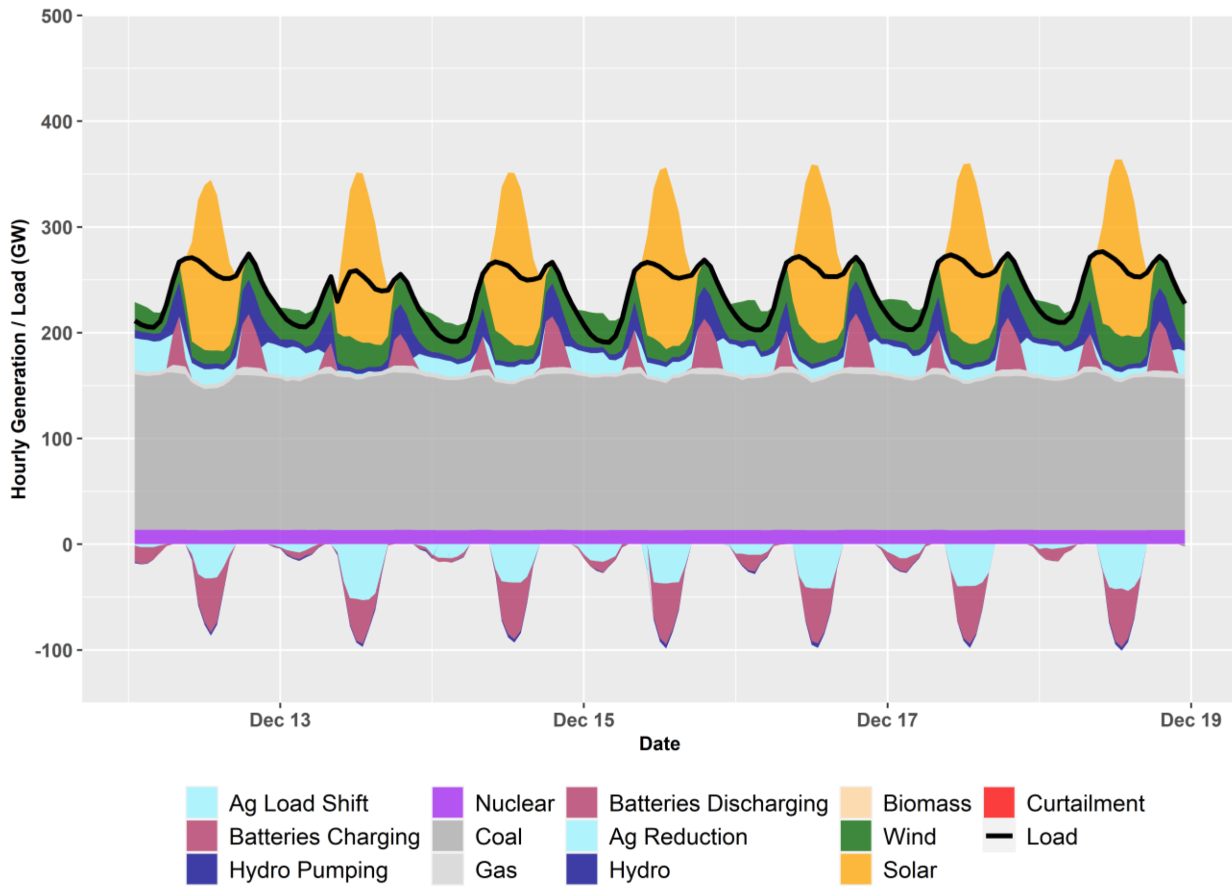


Figure A13: National hourly dispatch during the minimum load week in the Primary Least Cost case (FY 2030)

9.10 Dispatch in Key RE Rich States

The following charts show average hourly dispatch in key RE rich states in FY 2030 for the Primary Least Cost case. The difference between load and total generation are the imports / exports from the state (including central sector allocations and bilateral / market transactions).

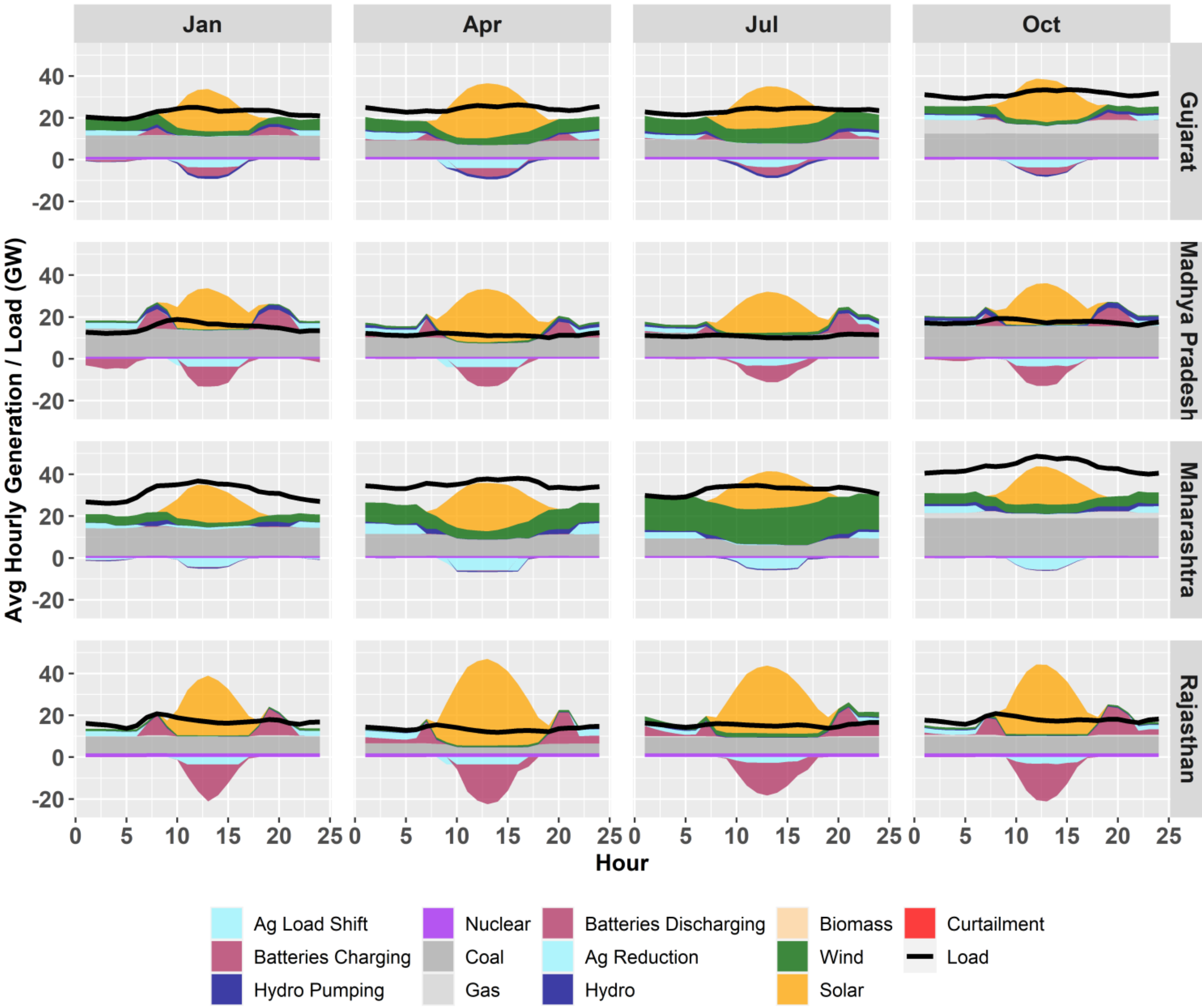


Figure A14: Average hourly dispatch in key western & northern RE rich states in Primary Least Cost (FY 2030)

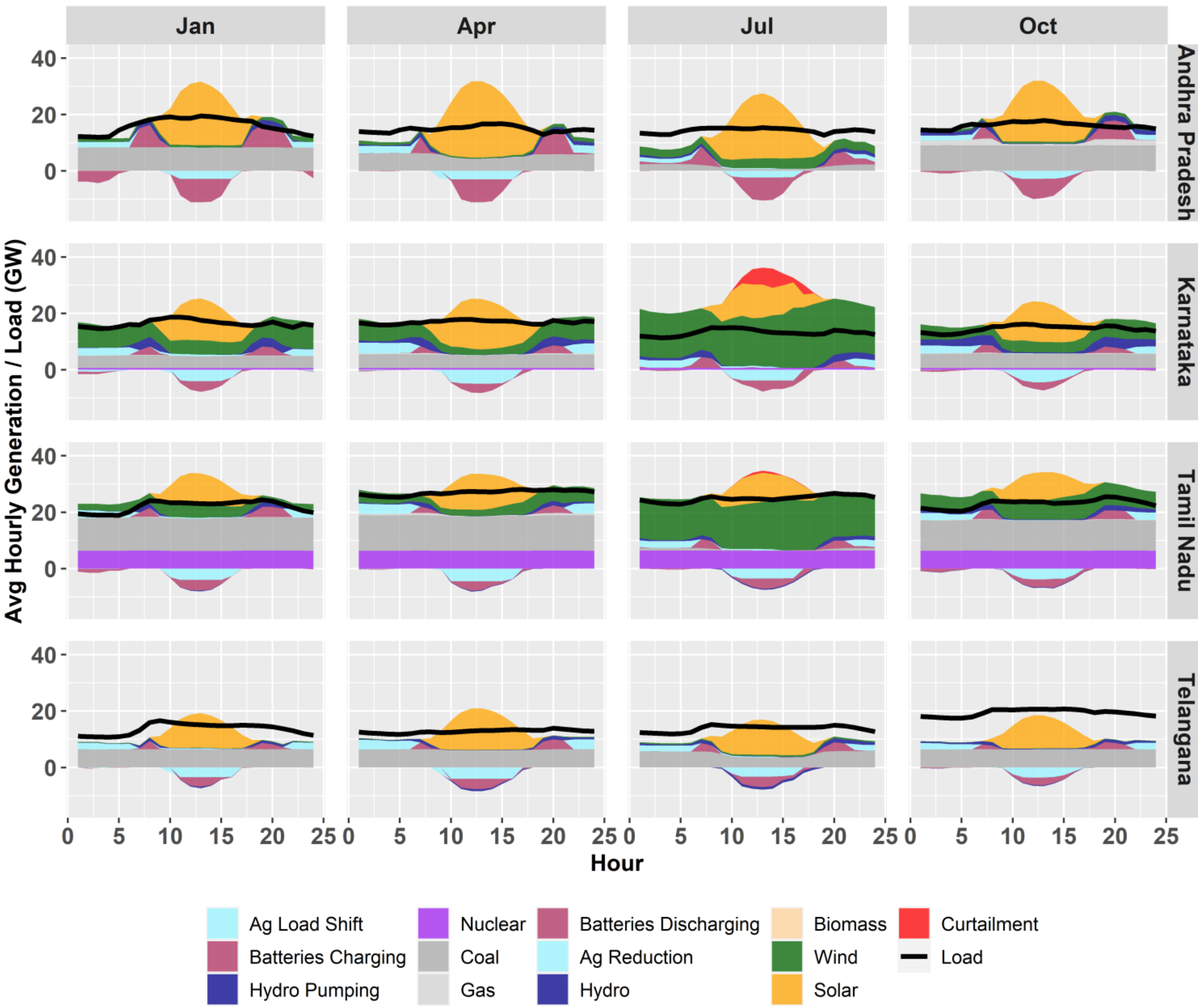


Figure A15: Average hourly dispatch in key southern RE rich states in the Primary Least Cost case (FY 2030)

9.11 What are the transmission flows on key corridors ?

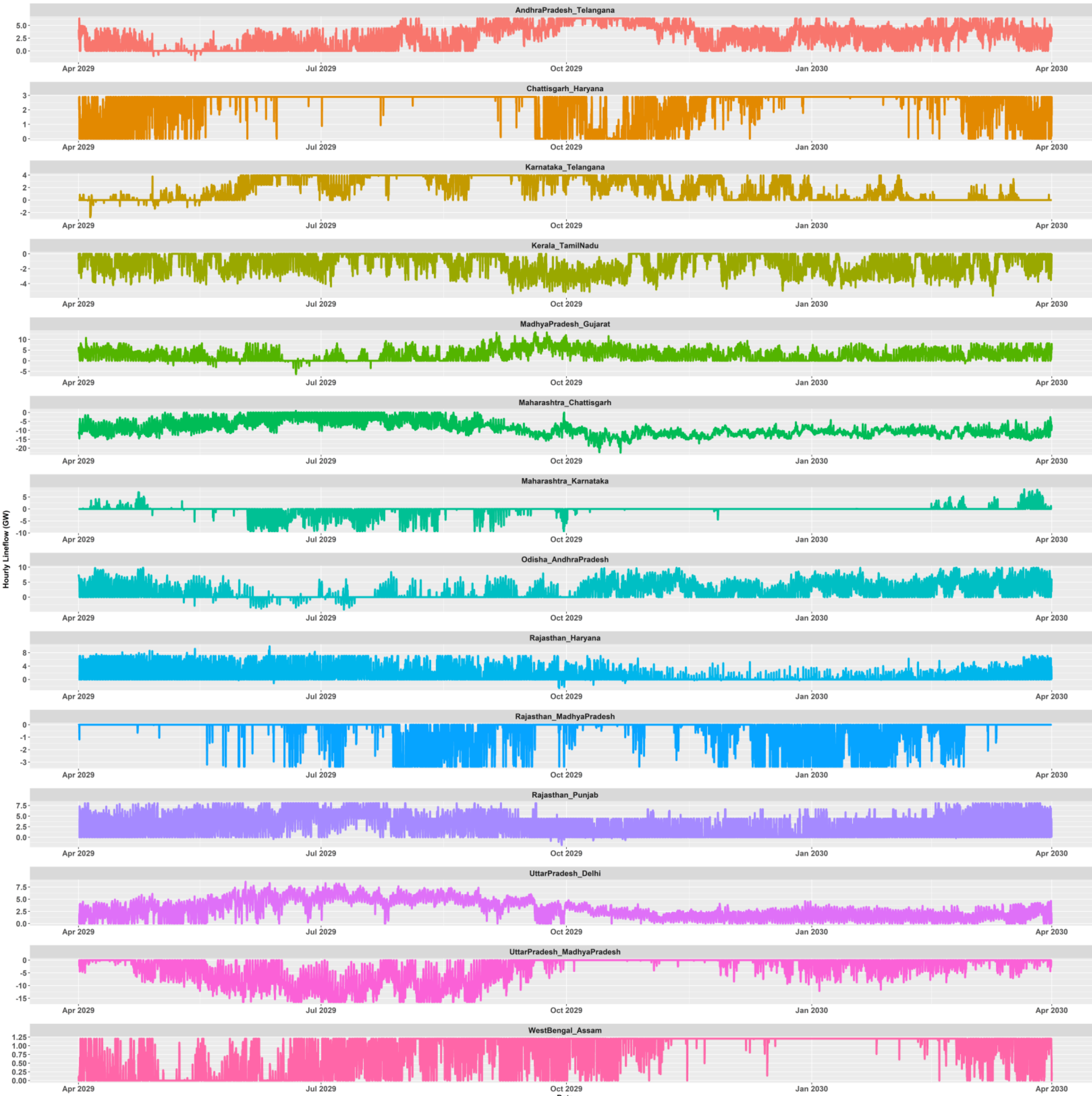


Figure A16: Hourly transmission flows on key corridors in the Primary Least Cost Scenario (FY 2030)

10 Appendix III: Comparative Economics of Pumped Hydro and Battery Storage

Pumped hydro storage system and battery storage systems are considered to be the two major alternatives for diurnal storage in India. In this appendix, we present comparative economics of pumped hydro and battery storage systems in India. Our key assumptions are given in the following tables:

Table A6: Capital cost, life, construction time, and land requirement of pumped hydro systems

	Addition of pump system to existing hydro reservoirs	New pumped hydro plant
Capital Cost (Rs Cr/MW)	7.5	12
Economic Life	25 years	25 years
Technical Life	50 years	50 years
Construction time	3-4 years	8-10 years
Land requirement	2-5 acres/MW (Assuming 300m net head)	

Given the maturity of the pumped hydro technology, its capital cost is assumed to stay the same over years. Capital costs of the battery storage systems, however, is expected to reduce rapidly in the future, as shown in the following table.

Table A7: Capital cost, life, and construction times of battery storage system

	Co-located battery storage system			Standalone battery storage system		
	2020	**2025**	**2030**	**2020**	**2025**	**2030**
Battery pack price ($/kWh)	143	88	62	143	88	62
BOS, EPC and other costs ($/kW)	176	136	124	240	184	164
Technical and Economic Life	Pack life = 10 years (3000 cycles) BOS life = 25 years			Pack life = 10 years (3000 cycles) BOS life = 25 years		
Construction time	6 months			6 months		

Note: All cost numbers are expressed as 2020 real, unless specified otherwise.
Data source: Deorah et al (2020)

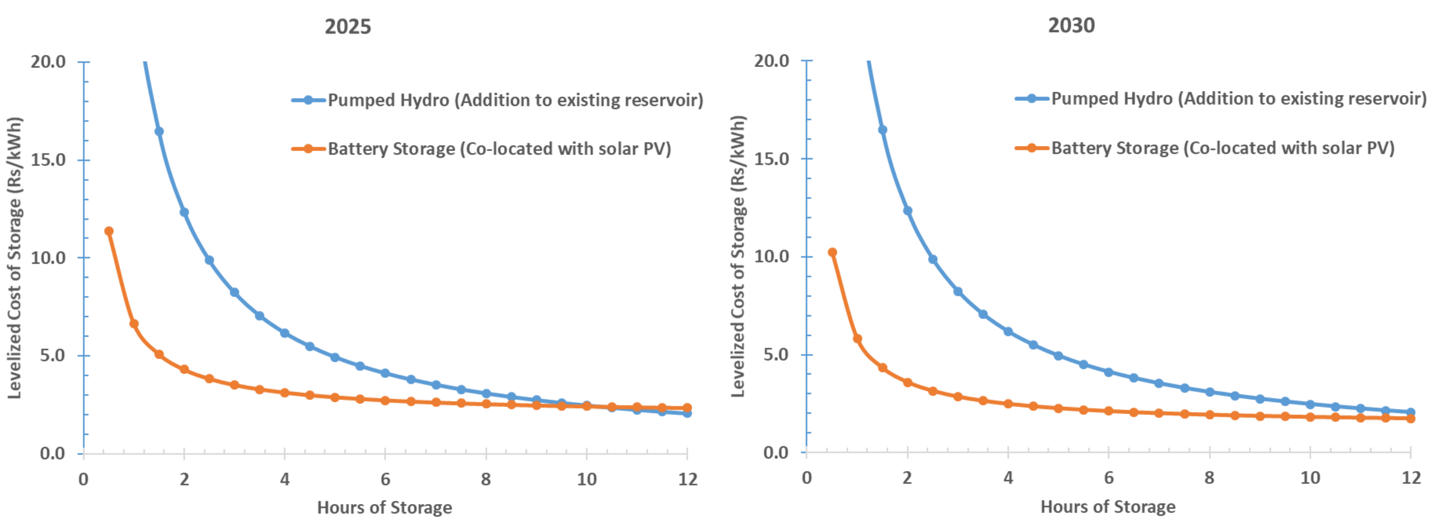
As shown in the previous sections, we find 4-6 hours of diurnal storage to be cost-effective in India through 2030. The following table shows the levelized cost of storage for pumped hydro and battery storage for a 4-hours of diurnal storage (1 MW/4MWh system).

Table A8: Levelized cost of storage for 1MW/4MWh pumped hydro and battery storage systems in India (Rs/kWh, 2020 real)

	2020	2025	2030
Pumped Hydro (Addition to existing reservoirs)	6.18	6.18	6.18
Pumped Hydro (new project)	8.24	8.24	8.24
Battery storage (co-located with RE)	4.57	3.13	2.49
Battery storage (standalone)	4.93	3.40	2.71

Note: All cost numbers are expressed as 2020 real, unless specified otherwise.
Other economic assumptions: WACC = 8% (real); Full charge / discharge cycles = 300 cycles/year.

The levelized cost of storage depends on the hours of storage (i.e. MWh to MW ratio). The following chart shows the levelized cost of storage in 2025 and 2030 for pumped hydro and battery storage systems.



Note: All cost numbers are expressed as 2020 real, unless specified otherwise.

Figure A17: Levelized cost of storage for pumped hydro and battery storage systems in 2025 (left) and 2030 (right) as a function of hours of storage

It can be seen from Figure A17 that by 2025, co-located battery storage systems are cheaper up to 10 hours of diurnal storage, when compared with adding pumped systems to existing hydro reservoirs. As hours of storage increase, pumped hydro becomes more economical. However, as battery costs continue to reduce in the future, by 2030, batteries are found to be cheaper than pumped hydro, irrespective of the hours of storage. As mentioned previously, we find that by 2030, 4-6 hours of diurnal energy storage is found to be cost-effective in India, implying that batteries are a more cost-effective storage option in India.