Energy Storage in South Asia: Understanding the Role of Grid-Connected Energy Storage in South Asia's Power Sector Transformation

Ilya Chernyakhovskiy, Mohit Joshi, David Palchak, and Amy Rose

National Renewable Energy Laboratory

Produced under direction of the U.S. Department of State by the National Renewable Energy Laboratory (NREL) under Interagency Agreement No. IAG-17-02055.

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Contract No. DE-AC36-08GO28308

Strategic Partnership Project Report
NREL/TP-6A20-79915
July 2021

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Suggested Citation

Chernyakhovskiy, Ilya, Mohit Joshi, David Palchak and Amy Rose. 2021. *Energy Storage in South Asia: Understanding the Role of Grid-Connected Energy Storage in South Asia’s Power Sector Transformation*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-79915. https://www.nrel.gov/docs/fy21osti/79915.pdf.

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Golden, CO 80401
303-275-3000 • www.nrel.gov

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Acknowledgments

This study was funded by the U.S. Department of State Bureau of Energy Resources. The authors are greatly indebted to Mark Pituch and Dan Birns (U.S. State Department) for their feedback and guidance throughout the project. The authors also wish to thank several individuals for their thoughtful reviews and insightful comments:

Reviewer	Organization
Praveen Gupta	Central Electricity Authority (CEA)
Sushanta Chatterjee	Central Electricity Regulatory Commission (CERC)
Vijay Meghnani	CERC
S R Narasimhan	Power System Operation Corporation Limited
Anjan Kumar Sinha	National Thermal Power Corporation
Pankaj Batra	Integrated Research and Action for Development
Deepak Krishnan	World Resources Institute
Binoy Saranji	ReNew Power Private Limited
Alam Mondal	International Food Policy Research Institute
Sarah Lawson	Unites States Agency for International Development (USAID)
Ashwin Gambhir	Prayas Energy Group
Phillip M. Hannam	The World Bank

Reviews are provided in a personal capacity and do not indicate a formal endorsement from affiliated organizations. We also wish to thank Wesley Cole, Will Frazier, Jennie Jorgenson, and Jaquelin Cochran at the National Renewable Energy Laboratory (NREL) for their thoughtful reviews and guidance. And thanks to Isabel McCan, Liz Breazeale, and Elizabeth Stone for communications, editing, and design support. Any errors or omissions are solely the responsibility of the authors.

List of Acronyms

ATB	annual technology baseline
BESS	battery energy storage systems
CBET	cross-border electricity trade
CEA	Central Electricity Authority
CEM	capacity expansion model
CERC	Central Electricity Regulatory Commission
LCOE	levelized cost of electricity
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
PCM	production cost model
PSH	pumped storage hydropower
PV	photovoltaic
RE	renewable energy
ReEDS-India	Regional Energy Deployment System India
reV	Renewable Energy Potential tool
ROR	run-of-river
VC	variable cost

Executive Summary

During the last decade, the cost of energy storage technologies, primarily lithium-ion battery energy storage systems (BESS), has declined rapidly and is projected to decline further over the next decade (BloombergNEF 2019). This comes at a time when electricity grid flexibility is being recognized as an essential resource for reliable operations and for integrating high amounts of renewable energy (RE). In India, flexibility has been referred to as the "new currency for the use of energy" (Soonee and Kumar 2020). Energy storage has the technical potential to provide some of this grid flexibility. However, questions remain about the opportunities for energy storage in India and other South Asia countries, including Bangladesh, Bhutan, and Nepal. Uncertainty remains about the technology costs, as well as rules governing energy storage operations, ownership, and compensation mechanisms.

Objective and Scope

This study provides a first-of-its-kind assessment of 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. We conducted scenarios-based capacity expansion modeling to assess when, where and how much energy storage can be cost-effectively deployed in India through 2050. The analysis relies on state-of-the-art modeling approaches to uncover and compare the value streams of battery storage with different durations, as well as pumped storage hydropower (PSH). We also ran hourly simulations of system operations in India, Bangladesh, Bhutan, and Nepal as a single South Asia interconnection with no institutional barriers to cross-border electricity trade (CBET). Simulations are run for 2030 and 2050 to understand how energy storage will be utilized by system operators to help integrate RE, reduce operating costs, optimize CBET, and optimize the use of domestic resources.

This study does not seek to identify a single optimal scenario for power sector growth and energy storage deployment. Instead, scenario analysis is used to assess the range of possible least-cost pathways for India's power sector and the potential role for energy storage. Nor does this study consider the challenges that may be faced in scaling up energy storage from a manufacturing, materials, land-use, or supply chain perspective. Finally, this study does not evaluate the potential for future breakthroughs in long-duration energy storage technologies such as power-to-gas hydrogen applications or gravity energy storage.

Key Findings

Energy storage can provide a range of grid services and has the potential to play an important role in the development of a cost-effective power sector for India. Storage can also provide benefits to Bangladesh, Bhutan, and Nepal individually and collectively to the South Asia grid (see Figure ES-1). Energy storage in Nepal and Bhutan can help in optimizing exports to India, thereby helping the South Asia grid to accommodate more hydro and RE in the system. Energy storage in Bangladesh can help displace fuel oil generation, reduce the production cost, and provide balancing services.

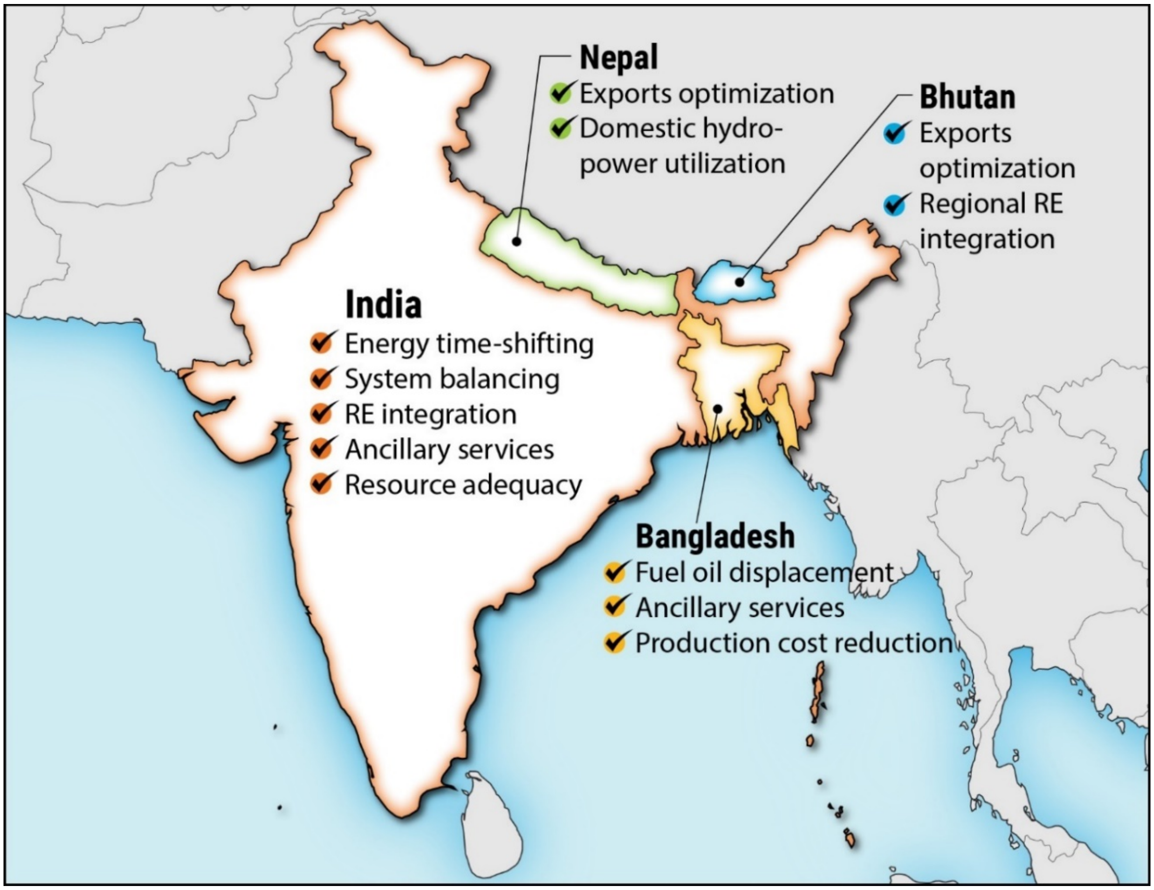

Figure ES-1. Primary sources of value of energy storage

Cost-Effective Energy Storage Opportunities for Various Grid Services Are Right Around the Corner

We find that energy storage becomes cost-competitive with other technologies due in part to projected cost declines through 2030. Results show that cost-effective energy storage capacity grows quickly with an average year-over-year growth rate of 42% between 2020 and 2030. Initial deployments are primarily 2-hour duration battery systems. Beginning in the mid-2020s, 4-hour battery storage deployments dominate the energy storage landscape. Pumped-hydro development is limited to those projects that are currently under construction or planned as per the Central Electricity Authority (CEA) (CEA 2021). Battery storage investments are found to be cost-effective in 26 of the 34 states and union territories by 2030. In the Reference Case, which represents the standard set of assumptions used in this study, three states have over 10 GW of battery storage capacity by 2030: Jammu and Kashmir, Gujarat, and Karnataka.

Across All Scenarios, Energy Storage Technologies Play an Increasing Role in India's Power System

We evaluate the investment potential for energy storage under several scenarios representing different trajectories for technology costs, regulatory rules, and policy changes. In all cases, energy storage grows to play a significant role in India's power system. The capacity of storage technologies reaches between 180 GW and 800 GW, representing between 10% and 25% of total installed power capacity by 2050. Energy capacity of storage reaches between 750 GWh and

4,900 GWh by 2050. Figure ES-2 shows the range of storage deployment results across all scenarios.

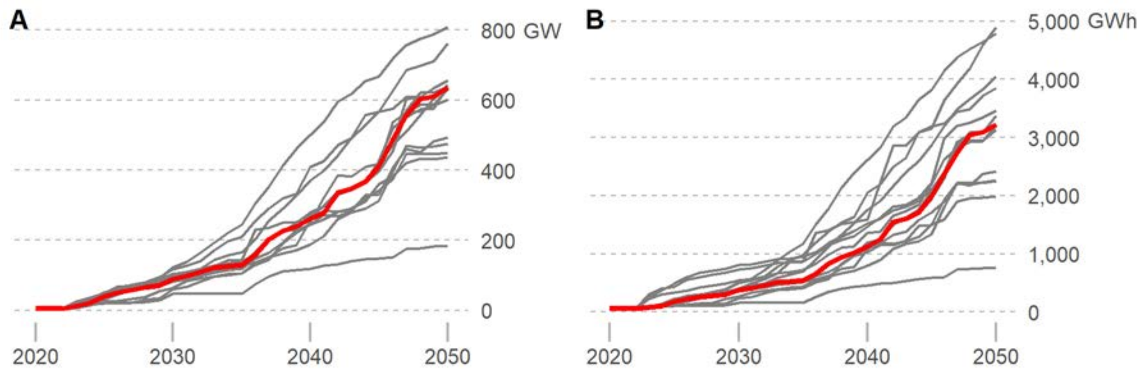

Figure ES-2. Energy storage power (A) and energy (B) capacity deployment in India to 2050

Note: Each line represents one modeled scenario. The Reference Case is highlighted in red.

The Reference Case is not designed to forecast what is most likely to happen. Rather, the Reference Case is designed as a launching point to examine the key drivers for energy storage deployment and allow us to examine these drivers through additional scenarios. The scenarios analyzed in this study, summarized in Figure ES-3, help identify conditions that lead to higher or lower energy storage deployment in India.

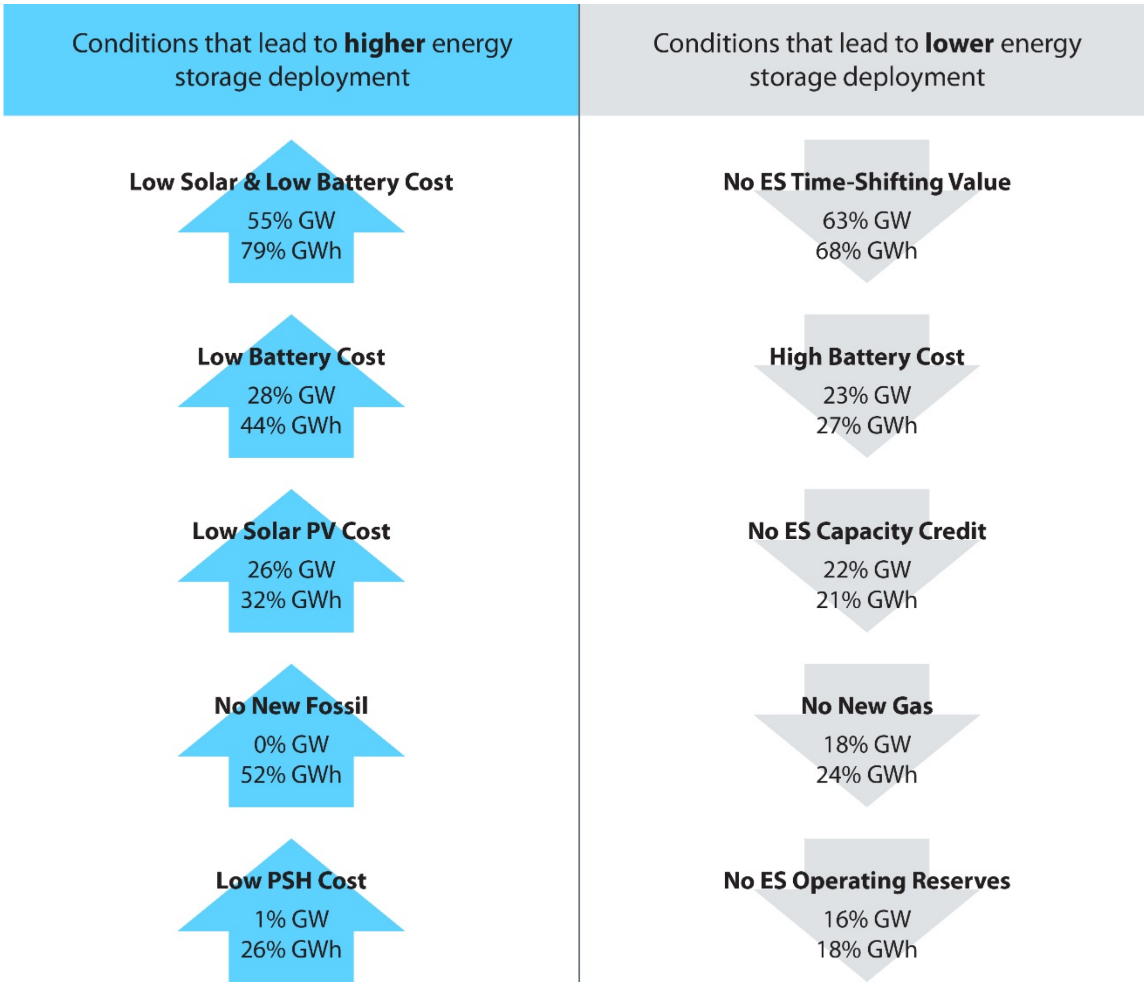

Figure ES-3. Conditions that lead to higher and lower energy storage deployment in India

No ES Time-Shifting Value: energy storage is not valued for shifting energy to different times of day; No ES Capacity Credit: energy storage is not valued for contributions to resource adequacy; No ES Operating Reserves: energy storage does not provide operating reserves.

Energy Time-Shifting and Capacity Services Are the Largest Source of Value for Energy Storage Both in the Near and Long Term

Energy storage can provide multiple services to the grid, and the value for providing these services changes over time as the generation mix and patterns of electricity demand change. Across all scenarios evaluated in this study, energy time-shifting and capacity services make up the lion's share of value for energy storage. We find that the ability for energy storage to provide diurnal energy time-shifting has the largest impact on both near-term and long-term storage deployment (Figure ES-3).[1] And the value of energy time-shifting is likely to increase over time as anticipated growth in electricity demand and RE deployment results in increased variability in daily net load patterns. In the scenario where energy storage cannot receive revenue for energy time-shifting, overall investments in energy storage technologies fall by 65%. This scenario

[1] We evaluate the time-shifting value of energy storage on an hourly timescale. Sub-hourly timescales are outside the scope of this study.

could happen in a contract structure in which there is a single tariff that does not correctly account for the changing price of energy throughout the day.

Valuing Energy Storage for a Range of Grid Services Helps Achieve a Least-Cost Power System

The Reference Case assumes that energy storage devices can receive revenue equal to the full value of grid services they provide. Scenario analysis is used to evaluate the impacts of removing certain revenue streams. Total systems costs are higher when energy storage does not provide certain grid services (Figure ES-4). In the scenario where energy storage cannot receive revenue for energy time-shifting, system costs are 4% higher compared to the Reference Case. This is due, in part, to differences in the capacity and generation mix, with less RE and more high-operations and maintenance (O&M) cost thermal investments. The No ES Capacity Credit scenario, where storage devices are not compensated for their contribution to capacity reserve requirements, also leads to a 4% increase in total system costs. In this scenario, more underutilized thermal capacity is needed to meet capacity reserve margins compared to the Reference Case. And when energy storage does not provide operating reserves, system costs are 3% higher. Increased system costs in this scenario are driven primarily by higher fuel consumption and O&M costs for conventional generators.

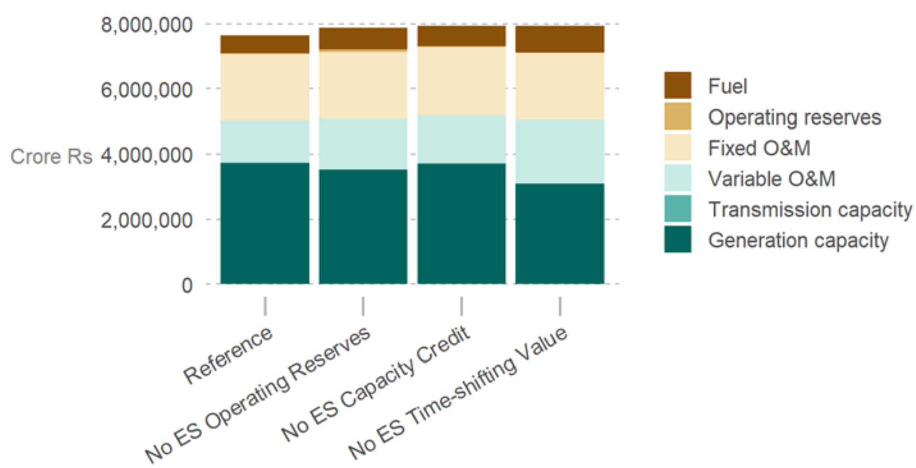

Figure ES-4. Present value of total system costs for 2020 to 2050 in Reference Case and energy storage regulatory scenarios

Note: The currency conversion rate for Indian Rupees (₹) to United States Dollars ($) is taken as ₹70.2 per $1.

Four-Hour Battery Storage has the Largest Potential to Provide Peaking Capacity for Long-Term Capacity Adequacy

Energy storage can provide a reliable source of peaking capacity, contributing to long-term capacity adequacy. However, the ability of storage to provide peaking capacity depends on the storage duration and the shape of the net demand curve. We find that 4-hour battery storage has the largest potential to provide peaking capacity with a 100% capacity credit (67 GW in 2030 and 140 GW in 2050) in the Reference Case. We also find the ability of energy storage to count towards long-term capacity adequacy requirements has the second-largest impact on overall storage deployment. In scenarios where energy storage cannot receive revenue for capacity adequacy, overall investments in energy storage technologies fall by 22%.

New PSH Capacity Can Be Cost-Effective in the Near Term

Cost scenarios show that in the near term, new PSH at 6.9 Crore ₹/MW (0.93 million $/MW) is cost-competitive with battery storage technologies. Further reductions in PSH costs result in more PSH capacity and delayed investments in BESS projects. PSH capacity reaches 52 GW with 630 GWh energy capacity by 2030 in the Low PSH Cost scenario (4.9 Crore ₹/MW in 2020). This buildout represents over half of the potential PSH capacity that has been identified by CEA (P. K. SHUKLA 2017). However, given rapidly declining costs for BESS, longer-term opportunities for economic PSH investments are limited. We see no new investments in PSH projects after 2030 across the capacity expansion scenarios evaluated for this study. However, upgrading existing reservoir storage with pumping capacity may be cost-effective, but is not considered in this study.

There Is a Strong Synergy Between Battery Storage and Solar Photovoltaic (PV) Deployment

We find significant reductions in solar PV deployment when battery storage costs are higher. In the High Battery Cost scenario, by 2030 there is 25 GW (110 GWh) less energy storage capacity and 19 GW less solar PV capacity, reductions of 30% and 7.6%, respectively, compared to the Reference Case. The same trend persists in the long term. By 2050, energy storage capacity is 20% lower and solar PV capacity is 19% lower in the High Battery Cost scenario compared to the Reference Case. We also explore the impacts of different assumptions for the future costs of solar PV technologies. The Low Solar PV Cost scenario has more investment in both solar PV and energy storage in the near- and long-term. There is 25% more energy storage capacity in the Low Solar PV Cost scenario by 2050 compared to the Reference Case. We also see a substantial reduction in wind capacity by 2050, declining by 30% in the Low Solar PV Cost scenario compared to the Reference Case. This result indicates that policies aimed at lowering the cost of solar PV may have important implications for the battery storage and wind power sectors as well.

Energy Storage Technologies Can Provide a Majority of Operating Reserve Requirements in 2030, if Allowed to Do so.

Operational modeling of the 2030 power system shows energy storage can play a major role in providing operating reserves in the future power system and there are significant system benefits to allowing these technologies to do so. Energy storage provides 80% of the annual operating reserves in 2030 in the Reference Case. We see a 3.3% increase in annual production cost in 2030 when storage is not allowed to provide operating reserves. This is because more thermal and gas machines are committed to provide reserves. Further, the average cost of providing reserves increases from around \$7/MWh to \$60/MWh. Allowing energy storage to provide operating reserves also reduces the need for fossil-fuel based plants to remain committed. On average, 7% more gas-fired units and 4% more coal-fired units are scheduled to run throughout the year when energy storage is not allowed to provide operating reserves.

Energy Storage Provides System Balancing, Ramping, and RE Integration Services

Storage can support the system by providing balancing services and help integrate more RE. Results show that by 2030, India's maximum hourly net load ramp could reach 60 GW. Energy storage can meet the majority of these needs by storing excess generation during high-RE periods and discharging to meet evening ramp needs (see Figure ES-5). The role of storage to integrate RE becomes increasingly important by 2050, when coal, gas and hydro contribute only

20% toward the country's generation mix. The results also show that energy storage is primarily charged during the daytime, enabling higher penetration of solar. Further, on some days, storage reduces its generation during the evening when wind generation picks up, helping to absorb higher levels of wind in the grid.

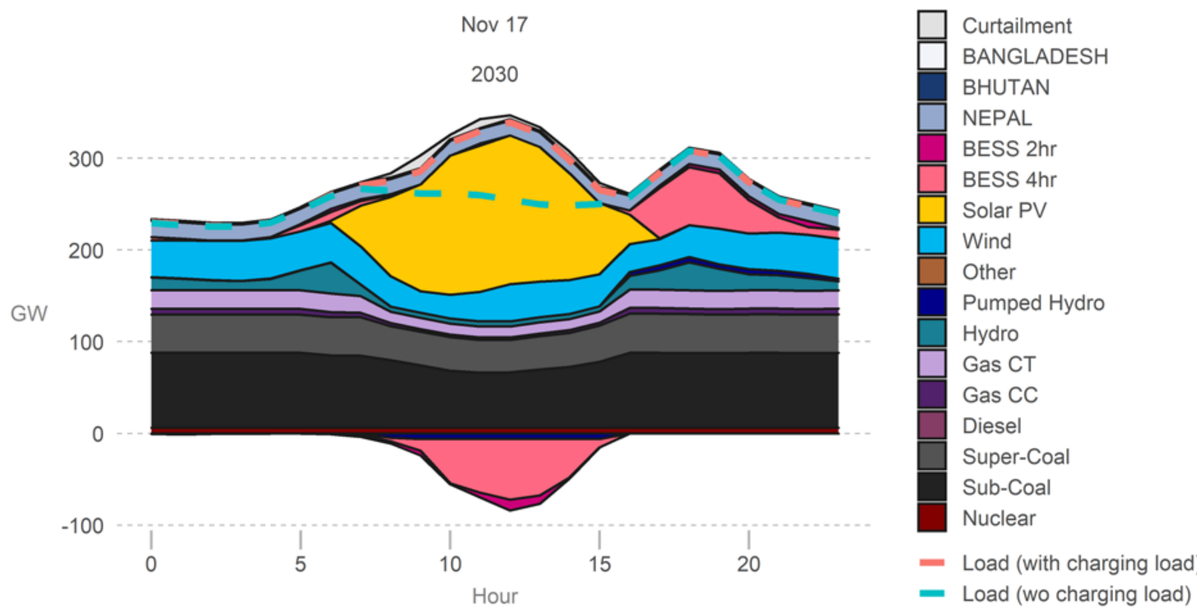

Figure ES-5. Dispatch stack for one day with the highest net load ramp in 2030

Energy Storage and RE Capacity Grows More Slowly in the Long Term When New Investments in Gas-Fired Capacity Are Restricted

In the No New Gas scenario, where investments in new gas-fired capacity are not allowed, long-term energy storage capacity grows slower and ends 38% lower in 2050 compared to the Reference Case. This result is somewhat unexpected, given that energy storage can serve similar peaking capacity functions as gas-fired power plants. Instead, we see that gas-fired capacity from the Reference Case is replaced primarily by super-critical coal capacity in the No New Gas scenario. With more coal in the capacity mix, the energy time-shifting value for energy storage decreases due to a lower electricity price differential between the low-value and high-value periods. By 2050, the average energy time-shifting value of energy storage is 28% lower compared to the Reference Case. With reduced time-shifting value, less energy storage is cost-effective. And with less cost-effective energy storage, there is less opportunity for cost-effective solar PV deployment in the No New Gas scenario compared to the Reference Case.

The Results Point to Several Trends That Can Inform Regulations, Policies, and Market Rules for Energy Storage in South Asia

- Establishing a level playing field for energy storage to compete with conventional technologies can lead to increased RE integration and reduced air emissions from the power sector. Modeling results show that when energy storage can compete directly with conventional resources to provide various system services, more energy storage becomes cost-effective, which results in increased solar PV deployment and reduced generation from fossil-fueled resources. Leveling the playing field can include new ways to value the performance of generating resources to meet system needs, such as ramp rates, response time, and minimum generation level.

- Energy storage systems can achieve their full economic potential if they are able to provide and monetize multiple system services. In the South Asia context, this means that new regulatory proceedings at the national and state levels may be needed to enable energy storage projects to participate as a source of both load and generation, and to provide multiple grid services. For utility-owned energy storage devices, where costs are recovered under a cost-of-service regulation, utilities and regulators can establish agreed-upon methods to quantify and compensate the full system value that energy storage provides to the power system.
- Access to cost-reflective energy markets, with daily price fluctuations, is a key revenue stream that can enable energy storage to be cost-competitive with conventional resources. Regulators can consider allowing energy storage to participate in the wholesale and real-time energy market. In the absence of markets, tariffs structures that reflect system value, such as rewarding energy storage for discharging during high-value periods, can help storage devices monetize the energy time-shifting value they provide to the system.
- Energy storage can be a significant source of reliable capacity for India's power system. Valuing the capacity contribution of energy storage, through tariff design or other mechanisms such as capacity auctions or capacity payments, can enable cost-effective energy storage to compete with fossil-fueled capacity resources. Regulators can begin by establishing clear and agreed-upon methods to quantify and compensate all resources (including energy storage devices) for contribution to reliable capacity.
- Energy storage can help meet operating reserve requirements and therefore reduce commitments of thermal generators. However, providing operating reserves is a relatively small portion of the full value of energy storage for the power system. Regulators can help ensure that market rules governing operating reserves and other ancillary services enable energy storage to provide multiple grid services from the same device. In India, for example, the Central Electricity Regulatory Commission (CERC) has issued draft regulations explicitly allows energy storage to participate in the proposed ancillary services markets (CERC 2021).
- There is a strong synergy between energy storage and solar PV deployment. Policymakers can include energy storage in national energy policies and master plans and acknowledge the complementarity between solar PV targets and increasing opportunities for energy storage technologies.

Table of Contents

List of Figures

List of Tables

1 Introduction

During the last decade, the cost of energy storage technologies, primarily lithium-ion battery energy storage systems (BESS), has declined rapidly and is projected to decline another 50% over the next decade. Several landmark utility-scale projects around the globe, such as the 150-MW/194-MWh Hornsdale Power Reserve in South Australia and the 250-MW/250-MWh Gateway Energy Storage project in California, have demonstrated that energy storage can provide a cost-effective source of flexibility and reliability services for the electric grid (LS Power 2020; AEMO 2018). At the same time, questions remain about the opportunities for energy storage in India and other South Asia countries. India, one of the world's largest synchronized power systems serving over one billion people, plans to increase the deployment of variable renewable energy (RE) resources to 175 GW in 2022 and further to 450 GW by 2030. To cost-effectively integrate increasing levels of RE, India's power system could require substantially more supply and demand-side flexibility. The International Energy Agency (IEA) in its India Energy Outlook 2021 noted that "India has a higher requirement for flexibility in its power system operation than almost any other country in the world" (IEA 2021). While energy storage has garnered increased interest from policymakers as a potential source of flexibility, uncertainty remains about the technology costs, as well as rules governing energy storage operations, ownership, and compensation mechanisms.

This study provides a first-of-its-kind assessment of 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 value streams, potential barriers, and the role of energy storage in system operations. We conducted scenarios-based capacity expansion modeling to assess when, where, and how much energy storage can be cost-effectively deployed in India through 2050. The analysis relies on state-of-the-art modeling approaches to uncover and compare the value streams of 2-hour, 4-hour, 6-hour, 8-hour, and 10-hour battery storage, as well as pumped storage hydropower (PSH). We also run hourly simulations of system operations in 2030 and 2050 to understand how energy storage will be utilized by system operators to help integrate RE and reduce operating costs. For Bangladesh, Nepal, and Bhutan, we use operational simulations to explore how increasing deployment of energy storage can help optimize the use of domestic resources and cross-border electricity trade (CBET).

This study is conducted under a broader program focused on identifying opportunities and barriers for energy storage in South Asia. Other publications in this series include:

- *A Framework for Readiness Assessments of Utility-Scale Energy Storage* (Rose, Koebrich, et al. 2020)
- *Policy and Regulatory Environment for Utility-Scale Energy Storage: India* (Rose, Wayner, et al. 2020)
- *Policy and Regulatory Environment for Utility-Scale Energy Storage: Bangladesh* (forthcoming)
- *Policy and Regulatory Environment for Utility-Scale Energy Storage: Nepal* (forthcoming).

2 Modeling Approach

The modeling approach for this study relied on several interlinked modeling tools and multiple scenarios to assess different aspects of energy storage opportunities in India, Bangladesh, Bhutan, and Nepal.

2.1 Modeling Tools

Figure 1 illustrates how different modeling tools were linked to analyze the opportunities for energy storage in South Asia.

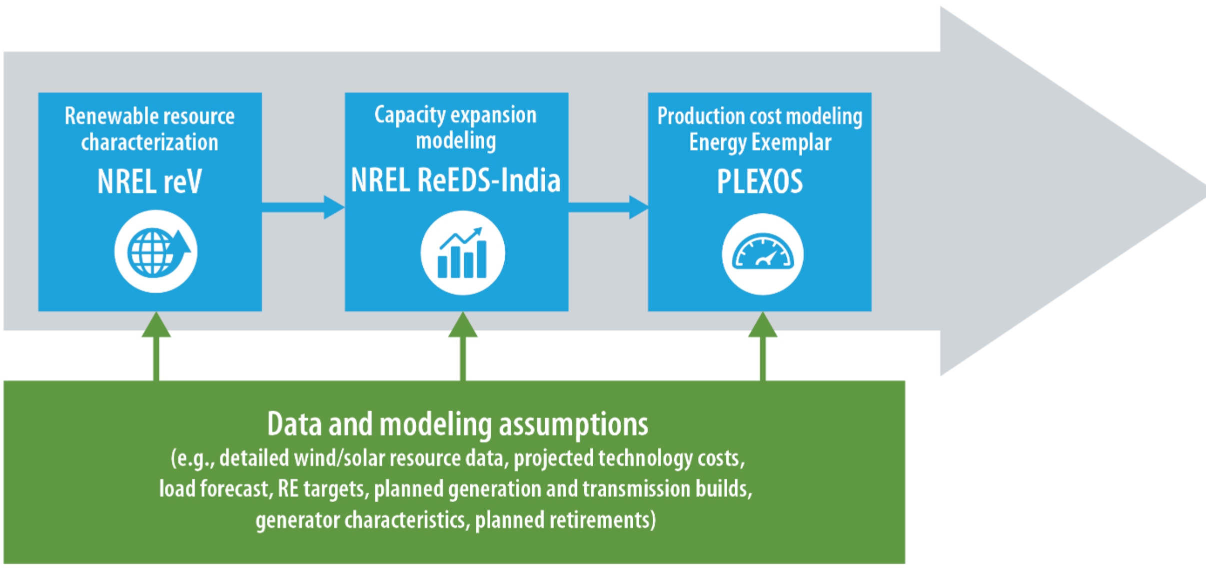

Figure 1. Modeling tools used in this study

The Renewable Energy Potential (reV) tool is a detailed spatio-temporal modeling tool that is used to assess renewable resource potential, technical potential, generation, and cost based on geospatial intersection with grid infrastructure and land-use characteristics. Coupled with NREL's System Advisor Model, the reV model's generation module estimates system performance based on technology parameters, including solar panel tilt angle, azimuth, inverter load ratio, efficiency, and others. Wind systems are defined based on their hub height, rotor diameter, power curve, and other wind-specific configurations. The resource potential identified in reV is input into the Regional Energy Deployment System India (ReEDS-India) capacity expansion model (CEM) to identify the least-cost mix of generation, storage, and transmission infrastructure required to meet system needs, including needs for energy and reserves.

The ReEDS-India model is the cornerstone of the modeling framework for this study, informing where, when, what types and how much energy storage is cost-effective for deployment in each year between 2020 and 2050. The model includes three levels of spatial resolution: regions, balancing areas, and resource regions. Regions include the five operating regions that make up the all-India interconnection, namely the Northern region, Northeastern region, Eastern region, Southern region, and Western region. Bangladesh, Bhutan, and Nepal are represented as single nodes that trade power with respective transmission-connected states in India. We considered 34 total balancing areas in India. Each balancing area represents a state or union territory with aggregated electricity demand, conventional generation capacity, and transmission. We assumed there are no hurdles to electricity trade among balancing areas. Finally, within each balancing area, there are multiple resource regions designed to capture differences in RE resources at a higher level of granularity. There is a total of 146 resource regions.

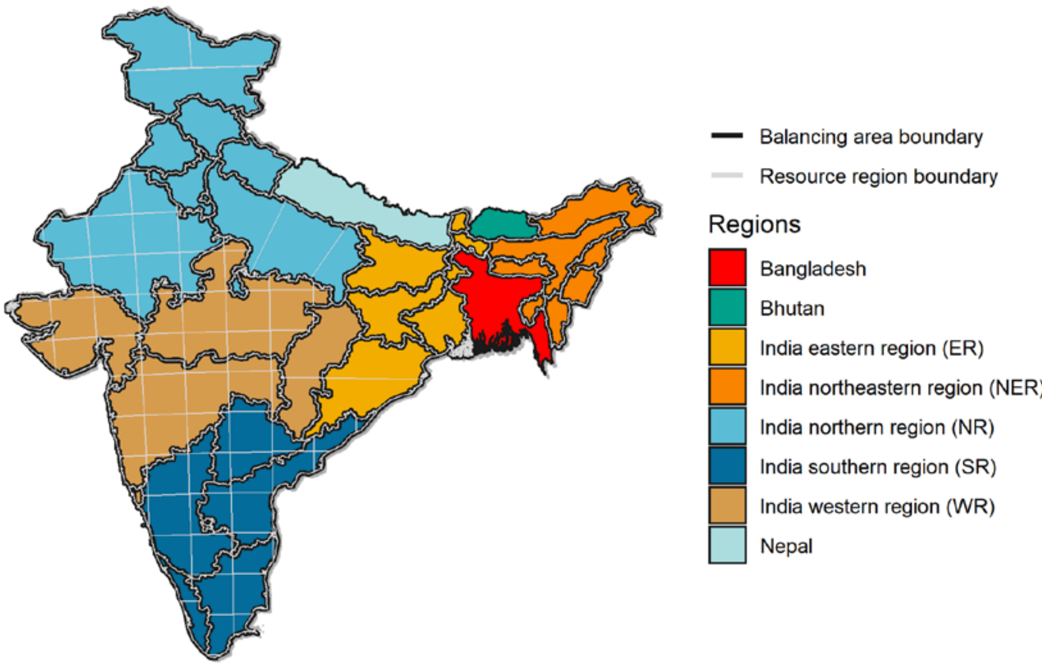

Figure 2. Balancing areas and RE resource regions

State-wise electricity demand is represented using 35 representative periods or “time slices” per year. The time slices capture changes in seasonal and daily demand patterns, as well as variability in renewable generation. The transmission network is represented as the aggregate transfer capacity between balancing areas. Energy flows on the transmission network are represented as pipe-flow energy transfers in each time slice. There are 77 transmission corridors represented in the model. Operational reserves are modeled as 5% of load. See Appendix A for more details about the modeling approach and inputs.

The model includes several updates and new features for representing energy storage since the initial ReEDS-India release, as described in (Rose, Chernyakhovskiy, et al. 2020). First, we expanded the set of options for energy storage investments. The model selected among six different configurations of stand-alone BESS between 1 and 10 hours of duration, as well as PSH with 12 hours of duration. For each energy storage technology, we calculated the capacity credit, or the contribution that different energy storage durations can provide to meeting capacity adequacy requirements. The methods used to calculate energy storage capacity credit are described in Frazier et al. (2020). Further, we added a dispatch simulation to calculate the potential revenue that different energy storage technologies can receive for shifting energy to different periods of the day. Storage time-shifting revenue includes the value to the system of shifting the time of supply from low-value to high-value periods. In India, this can mean shifting energy from the middle of the day when there is abundant solar energy to high-demand periods in the early morning and/or late evening. At the same time, storage time-shifting helps to avoid startup costs for conventional generators and to reduce RE curtailment. See Frazier et al. (2021) for further details on the method used to calculate time-shifting revenues in this study.

Using the capacity expansion results from ReEDS-India, we created a production cost model (PCM) in PLEXOS® for select years to evaluate how energy storage is operated on an hourly timescale. [2] Several assumptions were necessary to translate the CEM scenarios from ReEDS-India into the PCM. First, we "broke up" state-wise capacity investments from the CEM into unit-wise representations using a state-wise average size of existing generating units. This enabled detailed simulation of unit constraints and operational constraints, including ramp rates, minimum generation level, start-up and shut-down times, and minimum up/down time. Operational characteristics for new fossil-fueled units are based on average state-wise values of generators built between 2015 and 2020. Next, we added transmission investments by duplicating existing lines until total interstate transmission capacity matched the CEM buildout. We also updated regional transfer capacities to capture new state-to-state transmission capacity that crossed regional boundaries. Finally, we translated wind and solar buildout for each resource region into site-wise hourly generation profiles using NREL's reV tool (Rossol, Buster, and Spencer 2021). The resulting site-wise profiles were aggregated to the state level to create hourly state-wise wind and solar generation profiles for the PCM dispatch simulation. This process ensured that the geographic diversity of wind and solar resources was preserved when modeling system operations at the state level.

Box 1. Treatment of Energy Storage in the PCM

The PCM optimizes the operation of storage to achieve least-cost operations at the system level in each day of the year. The decision to charge, discharge, or provide reserves is based on the least-cost strategy for the day. The storage would generally charge during hours when the prices are relatively low and discharge during high-price periods. The decision is calculated by co-optimizing the provision of energy and ancillary services. Operations of storage devices are constrained by the storage duration and the maximum capacity. All storage technologies are assumed to be half-charged at the start of year. Constraints that are routinely discussed as being enforced in reality, such as depth-of-discharge and number of cycles, are not modeled to allow for insight about whether these constraints are necessary, given optimal system operations (Smith et al. 2012).

2.2 Scenario Design

Scenarios for this study are designed to understand the drivers for energy storage investment and assess the potential role for energy storage on the South Asia power system. Table 1 describes each scenario evaluated in this study. The Reference Case formed the basis for all the scenarios. All other scenarios were formed by making a change to the Reference Case. We used the Reference Case result from the ReEDS-India CEM to create the South Asia PCM for 2030 and 2050. We used the South Asia PCM to evaluate several scenarios of energy storage in Bhutan, Nepal, and Bangladesh. The methodology and results for South Asia scenarios are discussed in Section 3.6.

[2] We used PLEXOS version 7.4 using the Xpress-MP solver in this study. Operating reserves, represented as 5% of load on a regional basis, are co-optimized with energy.

Table 1. Scenarios Evaluated

Scenario Name(s)	Description	Scenario Category
Reference Case	The Reference Case represents standard assumptions about technology costs, policies, and regulations for energy storage through 2050.	Reference scenario
No ES Operating Reserves	Energy storage does not provide spinning reserves.	Regulatory scenarios
No ES Capacity Credit	Energy storage is not valued or compensated for its contribution to resource adequacy.	
No ES Time-Shifting	Energy storage is not valued or compensated for shifting energy supply to different times of day.	
No New Gas	No new investments in gas-fired capacity above what is currently planned.	Fossil-fuel policy scenarios
No New Fossil	No new investments in fossil-fueled capacity above what is currently planned.	
Low Battery Cost	Installed costs for BESS start lower and decline faster compared to the Reference Case.	Cost scenarios
High Battery Cost	Installed costs for BESS start higher and decline slower compared to the Reference Case.	
Low Solar PV Cost	Installed costs for solar PV decline faster compared to the Reference Case.	
Low Solar and Battery Cost	Combined Low Solar PV Costs and Low Battery Cost scenario	
Low PSH Cost	Installed costs for PSH are 50% lower than in the Reference Case.	
Nepal, Bhutan, and Bangladesh Operational Simulations	PCM scenarios for Nepal, Bhutan, and Bangladesh with incrementally increasing amounts of energy storage capacity.	South Asia regional scenarios

2.2.1 Reference Case

The Reference Case is not designed to forecast what is most likely to happen in the future. Rather, the Reference Case is designed as a launching point to examine the key drivers for energy storage deployment and allow us to examine these drivers through additional scenarios. Cost projections and performance characteristics for storage technologies are middle of the road based on several projections analyzed (see Section 2.3). Additionally, the regulatory environment created for the Reference Case is somewhat optimistic, allowing storage to receive credit for capacity and to participate in energy markets as both a source of electricity demand and generation, which is not currently allowed, but for which there is regulatory momentum to make these changes (Rose, Wayner, et al. 2020).

2.2.2 Data and Assumptions

This study followed the same input data and set of assumptions presented by (Rose, Chernyakhovskiy, et al. 2020) for the ReEDS-India CEM, with several key modeling advances noted in this section. The PCM used the same input data and assumptions presented by (J. D. Palchak et al. 2019). Input data and assumptions were updated in three categories:

- Energy storage technologies
- Projections for electricity demand growth considering the 2020–21 global COVID-19 pandemic
- CBET among Bangladesh, Bhutan, India, and Nepal.

Additionally, we added a target for India to reach 450 GW of installed RE capacity by 2030. Detailed inputs for the CEM and PCMs are presented in Appendix A and Appendix B, respectfully. The remainder of this section summarizes inputs and assumptions that were uniquely developed for this study.

2.3 Battery Storage Technologies

The estimates for current and future costs for BESS vary widely. Figure 3 shows cost projections for 4-hour lithium-ion BESS from various published sources, with 2020 costs ranging from $812/kW to $1,455/kW ($203/kWh to $364/kWh). BESS technologies based on other chemistries such as sodium-sulfur were not evaluated in this study. We used the BloombergNEF 1H 2020 cost projection for 4-hour lithium-ion BESS for the Reference Case. The BloombergNEF 1H 2020 cost is selected as a reasonable mid-range projection among the various published sources. Notably, the BNEF 1H 2020 projection is lower than NREL's 2020 Annual Technology Baseline (ATB)–Low scenario for BESS costs in the United States.

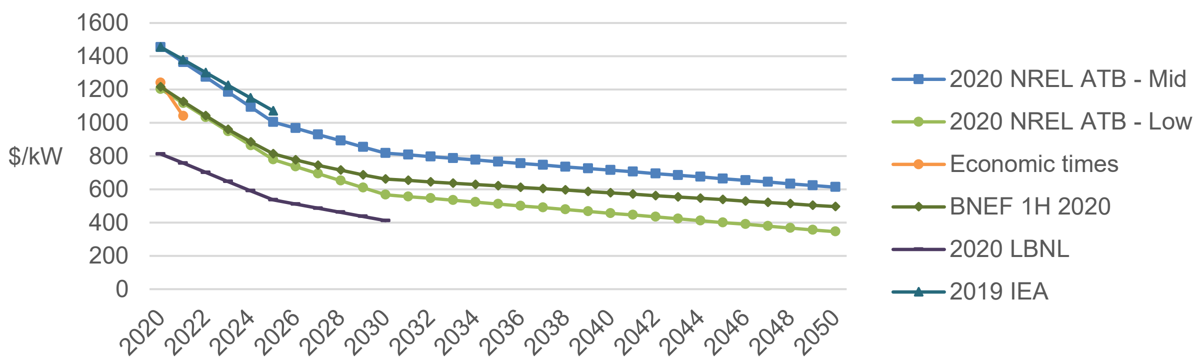

Figure 3. Select published projections for the installed costs of 4-hr BESS

Sources: 2020 NREL ATB: (NREL 2020); Economic times: (The Economic Times 2020); BNEF 1H 2020: (BloombergNEF 2020); 2020 LBNL: (Deorah et al. 2020); 2019 IEA: (IEA 2019)

For other duration BESS, there are fewer cost projections available. Therefore, we scaled the cost for different BESS durations from the 4-hour BESS cost using scaling factors derived from (Cole and Frazier 2020). We also followed (Cole and Frazier 2020) for assumptions about BESS lifetime, O&M costs, and efficiency (see Table 2).

Table 2. BESS Inputs and Assumptions

Reference Case Assumption	BESS 1-hr	BESS 2-hr	BESS 4-hr	BESS 6-hr	BESS 8-hr	BESS 10-hr
Power Capacity Cost in 2020 (Crore ₹/MW)	2.9	4.9	8.5	12	15	19
Energy Capacity Cost in 2020 (Crore ₹/MWh)	2.9	2.5	2.1	2.0	1.9	1.9
Fixed O&M Cost in 2020 (Crore ₹/MW-year)	0.21					
Lifetime	15 years					
AC-AC Round-Trip Efficiency	85%					

We developed two additional BESS cost curves for the scenario analysis presented in Section 3.5. Costs for the High Battery Cost scenario are based on the 2020 NREL ATB Mid Case. The Low Battery Cost scenario is based on the 2020 LBNL projection for BESS costs in 2030, extended to 2050 using the same year-over-year cost decline as the Reference Case. Figure 4 presents the cost curves across different BESS durations and scenarios. The large range of costs across different scenarios, both in the near-term and through 2050, reflects current uncertainty about battery costs for grid-scale applications in South Asia.

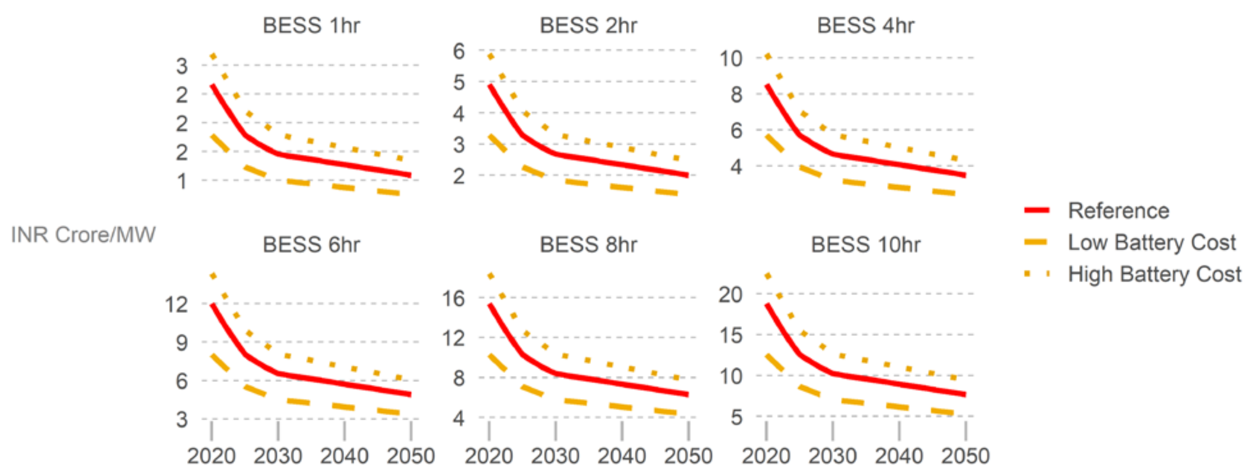

Figure 4. Cost scenarios for battery storage

2.4 PSH Potential

Special considerations are needed when implementing PSH in CEM because the feasibility of such projects is limited by geographic conditions and land-use constraints. Therefore, we limited the state-wise potential for PSH deployment based on a hydro-electric potential study carried out by CEA (P. K. SHUKLA 2017). According to the CEA report, total PSH potential in India is 96.5 GW. For existing PSH capacity, we included commissioned and planned PSH plants from the latest CEA report *Pumped Storage Development in India* as of this writing (CEA 2021).

Additionally, several simplifying assumptions are made to represent investment opportunities for PSH in the CEM. Table 3 presents the key assumptions for new investments in PSH plants. We assumed a uniform cost for the construction of a PSH plant across all Indian states.[3] We also assumed that all potential new PSH plants have a 12-hour duration (i.e., 12 hours of energy at full power output). Finally, we made a simplifying assumption that potential new PSH plants are closed loop, have no natural inflows, and can store energy from grid power only.

Table 3. PSH Assumptions

Input	Value
Installed Cost	9.9 Crore ₹/MW
Fixed O&M Cost	0.29 Crore ₹/MW
AC-AC Round-Trip Efficiency	80%
Duration	12 hours

We explored five alternative scenarios for PSH investment costs (see Table 4). One option to develop PSH in India is to upgrade existing reservoir storage plants. Upgrading existing plants is estimated to be a lower-cost option compared to building a new PSH facility. Therefore, we evaluate a range of PSH cost scenarios that are lower than the reference. These scenarios are designed to discover the cost at which PSH is cost-competitive with other resources, including battery storage. Results for PSH cost scenarios are presented in Section 3.5.

Table 4. PSH Cost Scenarios

Scenario	Installed Cost Relative to Reference Case
PSH Cost (10%)	10% lower
PSH Cost (20%)	20% lower
PSH Cost (30%)	30% lower
PSH Cost (40%)	40% lower
Low PSH Cost	50% lower

2.5 Electricity Demand Growth

Our assumptions for state-wise electricity demand growth were based on the 19th Electric Power Survey, with several important adjustments (CEA 2018a). First, due to the 2020 global pandemic, we assumed both energy and peak demand in 2020 remained at the same level as 2019 for all states. After 2020, we assumed that demand growth rates will return to pre-pandemic levels after 2025. Between 2020 and 2025, we used the Energy And Resources Institute's forecasts for electricity sector demand growth recovery under a V-shaped scenario (Spencer

[3] Site-specific cost assessment for new PSH plants is outside the scope of this study.

2020). Second, because the 19th Electric Power Survey was published several years ago, we updated historic state-wise electricity demand with actual energy and peak demand observed from January 2016 to December 2019 using annual reports published by CEA (CEA 2016b; 2017b; 2018c; 2019b; 2016a; 2017a; 2018b; 2019a). Finally, we extended the Electric Power Survey state-wise demand projections for all years between 2025 and 2050. After 2026, the 19th Electric Power Survey provides demand projections in 5-year increments until 2036. We assumed linear growth in annual energy and peak demand in the intervening years. For 2036–2050, we assume the same rate of demand growth as the previous 5 years. Table 5 presents the assumptions for all-India energy and peak demand in 2020, 2030, 2040, and 2050.

Table 5. Projections of Annual Energy and Peak Demand in India for Select Years

Year	National Energy Demand (TWh)	National Peak Demand (GW)	National Load Factor (%)
2020	1,300	180	82.9%
2030	2,300	310	82.5%
2040	3,200	450	81.9%
2050	4,200	580	81.5%

Demand growth projections were used to create hourly state-wise load profiles for each from 2020 to 2050, using the actual hourly state-wise load from 2014 as the base year.

2.6 Future Power System Buildout for South Asia

Because development of a CEM for Bangladesh, Bhutan, and Nepal is beyond the scope of this study, alternate methods are used to evaluate opportunities for energy storage in these countries and account for changing patterns of CBET in the ReEDS-India model. We used the national plans for generation and cross-border transmission capacity additions in each country and interpolated intermediate values for years that are not available. Projections for demand growth beyond the timeframe in official plans were based on the average growth rate from the previous 3 years. No new generation or cross-border interconnection was added beyond the official plans.

Bhutan: Bhutan's power system almost exclusively comprises run-of-river (ROR) type hydropower plants. As a result, the country's generation supply is highly seasonal with limited flexibility. Bhutan has cross-border links with India, and all surplus generation in the existing and planned system is exported to India. The load, generation, and cross-border interconnection projections for Bhutan through 2040 are based on the National Transmission Grid Master Plan, 2018 (Department of Hydropower & Power Systems 2018). We assumed all hydropower capacity additions were ROR and used hourly profiles of hydropower generation and load to calculate the hourly CBET to India in every year to 2050. Power transfers are modeled as fixed flows and proportionally distributed to the states that are connected with Bhutan based on the ratio of expected transmission capacity.

Nepal: Most of the existing hydropower plants in Nepal are ROR with a few reservoir hydropower plants as well. These hydropower plants are seasonal in nature with limited flexibility. The present CBET between India and Nepal is limited to contracted quantum between the two countries. Although Nepal imports from India at present to meet daily and seasonal balancing needs, it is expected that Nepal's planned expansion of its domestic hydropower resources will enable it to become a net exporter to India in the future. The future generation capacity in Nepal till 2028 is considered based on the Ministry of Energy's white paper (Ministry of Energy, Water Resources and Irrigation 2018) and the generation capacity for 2040 is based on Transmission System Development Plan of Nepal (Rastriya Prasaran Grid Company Limited 2018). The total reservoir hydropower capacity for 2040 was calculated based on individual proposed plants mentioned in the transmission system development plan. All other hydropower capacity was assumed to be ROR type. For intermediate years until 2040, a linear growth was assumed for ROR and reservoir hydropower based on existing and 2040 projected capacity. Projections for electricity demand from 2015 to 2040 was based on the reference scenario published in (Water and Energy Commission Secretariat 2017). CBET between India and Nepal is represented by two components: (a) fixed flow generators; and (b) generators with monthly energy limits. We used hourly profiles of ROR hydropower generation and load to calculate the hourly fixed flow component of CBET to India in every year to 2050. Fixed flows are proportionally distributed to the Indian states, which are connected with Nepal based on the ratio of planned interconnection capacity. For the second component, we used monthly energy limits of reservoir hydropower generation.

Bangladesh: The existing generation mix in Bangladesh is comprised of gas, fuel oil, coal, hydropower, and diesel-based generation. Although the system has some level of flexibility, costly fuel oil and diesel generators are a substantial part of the generation mix, which contributes significantly towards production costs and emissions. We assumed future generation buildouts follow the latest power system master plan, low case of revisiting Power Sector Master Plan 2016 of Bangladesh, which includes coal generation, nuclear generation, gas generation, and imports from other South Asian countries (Ministry of Power, Energy & Mineral Resources 2016). Concerns about domestic gas availability in the future are incorporated in the modeling (see further details in Appendix B). Projections for electricity demand to 2040 and cross border interconnections were also based on the Power Sector Master Plan report. To represent CBET, we used the Power Sector Master Plan to calculate the total transfer capacity between India and Bangladesh for every year through 2041 and assumed no additional transfer capacity from 2042 to 2050. Monthly available transfer capacity was moderated using the monthly ratio of actual transfers and maximum possible transfer based on actual monthly power transfer for 2019 (Power System Operation Corporation Limited 2019). The moderated hourly transfer capacity for each year through 2050 is proportionally distributed to the Indian states where these interconnections are planned based on the ratio of expected transmission capacity.

Notably, there are no utility-scale energy storage projects operating in any of these countries. However, changes in technology costs and system needs are prompting increased interest in energy storage technologies. In Nepal, the government is supporting the development of a PSH pilot project to meet peak demand needs and increase the flexibility of the country's power system, and the Nepal Electricity Authority is undertaking an economic feasibility study on the potential for utility-scale battery storage in the country (NEA 2016a; 2016b; Water and Energy Commission Secretariat 2017). In Bangladesh, the draft National Solar Energy Action Plan recommends a policy for industrial storage systems for peak shifting, load management, and balancing for variable RE generation (Chowdhury 2020).

See Appendix B for further details about modeling assumptions.

3 Results: Opportunities for Energy Storage

Across all scenarios, energy storage technologies are expected to play an increasing role in India's power system. Figure 5 shows that power capacity of storage technologies reaches between 180 GW and 800 GW, representing between 10% and 25% of total installed power capacity in 2050. Energy capacity of storage reaches between 750 GWh and 4,800 GWh in 2050.

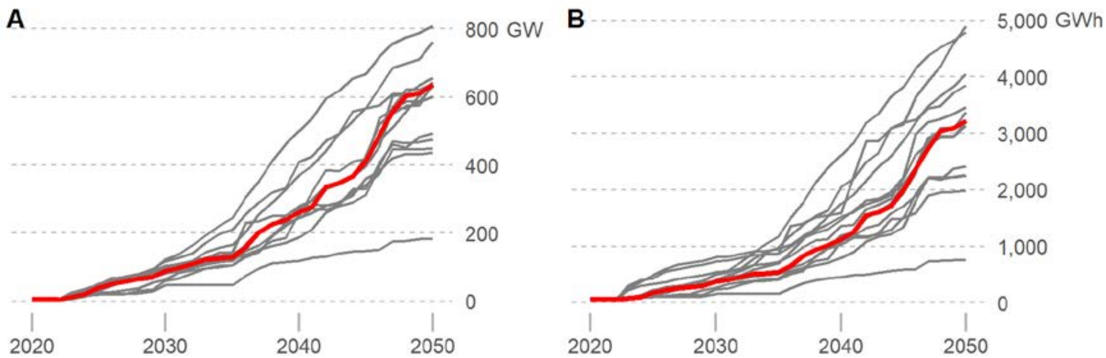

Figure 5. Energy storage power (A) and energy (B) capacity deployment in India to 2050

Each line represents one modeled scenario. The Reference Case is highlighted in red.

The remainder of this section will discuss: (1) the Reference Case results and key drivers for energy storage in India; (2) the role of energy storage in system operations; (3) scenario results; and (4) the regional South Asia result.

3.1 Reference Case Results

Energy storage has the potential to reach 23% of the installed power capacity in India by 2050. Table 6 provides the installed capacity and share of energy storage in total power capacity under the Reference Case in key years.

Table 6. Energy Storage Deployment in Reference Case for Select Years

	2020		2030		2040		2050	
Energy Storage Technology	**GW**	**Share of Installed Capacity**	**GW**	**Share of Installed Capacity**	**GW**	**Share of Installed Capacity**	**GW**	**Share of Installed Capacity**
PSH	4.8	1%	6.3	0.8%	6.3	0.4%	6.3	0.2%
BESS 2-hr	0	0%	16	2%	0	0%	0	0%
BESS 4-hr	0	0%	68	8%	240	16%	350	13%
BESS 6-hr	0	0%	0	0%	17	1%	240	9%
BESS 8-hr	0	0%	0	0%	0	0%	40	1%
Total	**4.8 (57 GWh)**	**0%**	**90 (380 GWh)**	**11%**	**260 (1,100 GWh)**	**17%**	**640 (3,200 GWh)**	**23%**

3.1.1 What Types of Energy Storage Are Cost-Effective in the Near Term?

Under Reference Case assumptions, energy storage deployment grows quickly with an average year-over-year growth rate of 42% between 2020 and 2030. Figure 6 shows deployment of different energy storage technologies from 2020 to 2030 in the Reference Case. Investments in large-scale battery storage are cost-effective beginning in 2023, the first year when economic investments are allowed in the model.[4] Initial investments are primarily 2-hour duration battery systems. Beginning in the mid-2020s, 4-hour battery storage dominates the energy storage landscape.

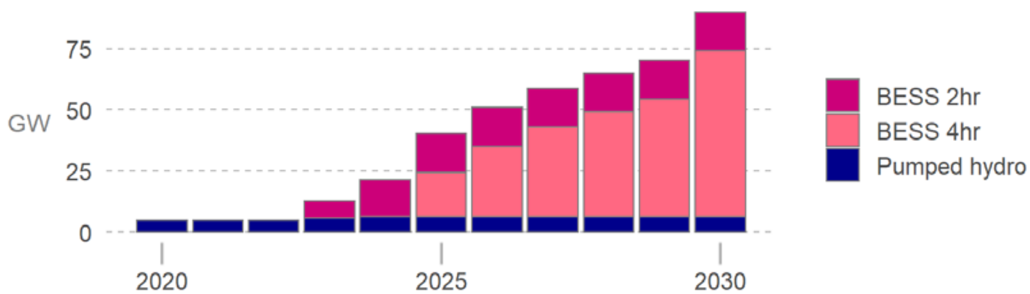

Figure 6. Energy storage investments to 2030, Reference Case

We see energy storage investments spread across all regions in India. Figure 7 shows the geographic distribution of energy storage deployed through 2030 in the Reference Case. Pumped-hydro deployment is limited to those projects that are currently under construction or planned, as per CEA (CEA 2021). Battery storage investments are found to be cost-effective in 26 states. Three states have over 10 GW of battery storage capacity by 2030: Jammu and Kashmir, Gujarat, and Karnataka.

[4] The model includes a mix of planned and economic investments in generation and transmission capacity. Planned investments are capacity additions from the 13th National Electricity Plan, including 175 GW of RE by 2022 (CEA 2018d), as well as 450 GW of RE by 2030. Due to the 2019–2020 global pandemic, we assumed that conventional capacity additions planned for 2020 would be delayed by 1 year to 2021. Economic investments are capacity additions chosen within the model optimization. We allowed the model to choose economic investments beginning in 2023.

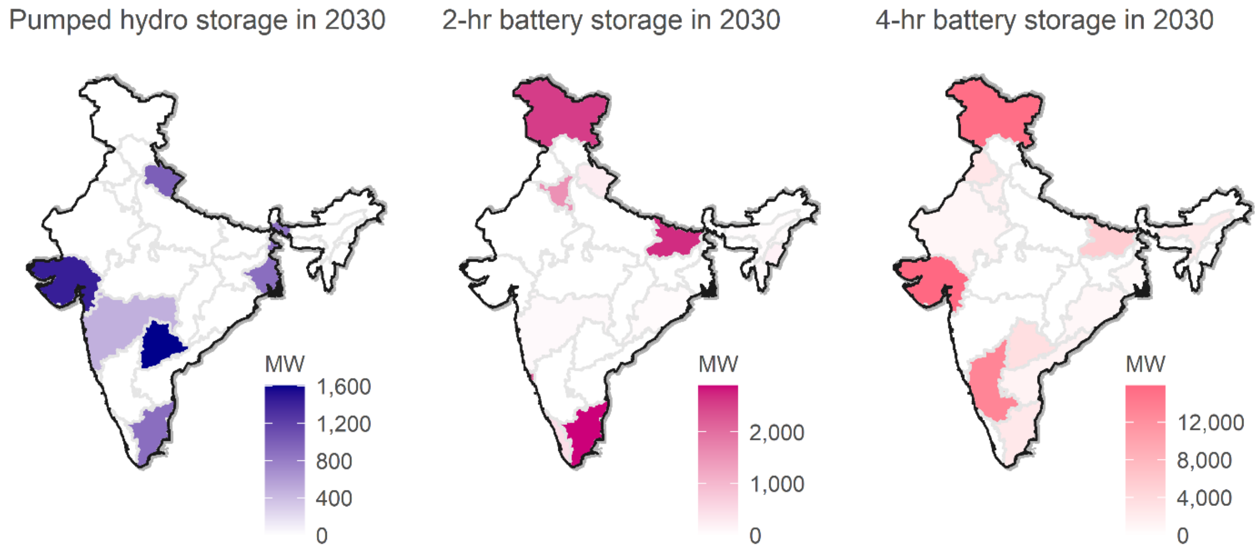

Figure 7. State-wise energy storage deployment to 2030, Reference Case

Energy storage opportunities at the state level are dependent on several interrelated factors. Existing flexible resources such as hydro, gas, and certain coal-burning units can diminish the cost-effectiveness for new battery systems in some states. Existing pumped-hydro facilities may also decrease the cost-effectiveness for longer-duration batteries. Interstate electricity transmission capacity and trade can also impact energy storage opportunities. For example, states like Karnataka and Jammu and Kashmir that have abundant RE resources and rely on out-of-state generation resources for supply-demand balancing show investments in battery storage to avoid costly upgrades in interstate transmission capacity.

3.1.2 How Much Energy Storage Is Cost-Effective in the Long Term?

In the longer term, energy storage investments continue to grow with every year. Figure 8 shows the investments in energy storage technologies through 2050 in the Reference Case. Total energy storage deployment reaches 635 GW. This represents 23% of total installed capacity in 2050. The total energy capacity of energy storage reaches 3,220 GWh, with an average storage duration of 5 hours across all devices. Four-hour battery storage is the only cost-effective storage technology from the mid-2020s through the late 2030s. All 2-hour storage devices are retired by 2039, having reached the end of their technical and financial life. There are no additional investments in 2-hour batteries after they are fully retired. Beginning in 2039, 6-hour batteries are cost-effective in certain locations. Beyond 2040, 6-hour batteries have the highest growth of any storage technology. Eight-hour batteries start to become cost-effective in the mid-2040s. Under Reference Case assumptions, we did not see additional investment in PSH beyond what is currently under construction or planned.

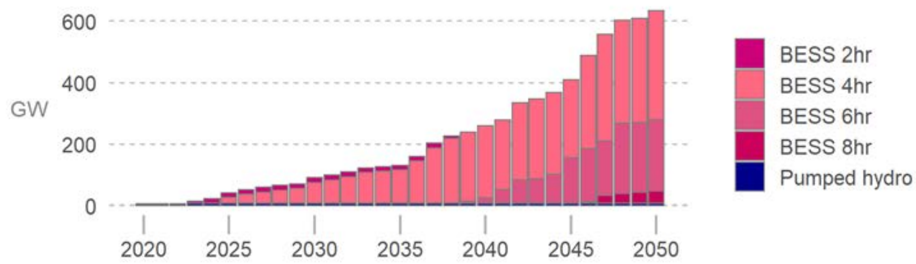

Figure 8. Energy storage investments to 2050, Reference Case

By 2050, we see a large concentration of battery storage in Northern and Western Region states, particularly in Rajasthan and Gujarat. These states have the highest total battery storage deployment, with 1,060 GWh and 680 GWh of battery energy capacity, respectively. Figure 9 shows the state-wise buildout of battery storage technologies to 2050.

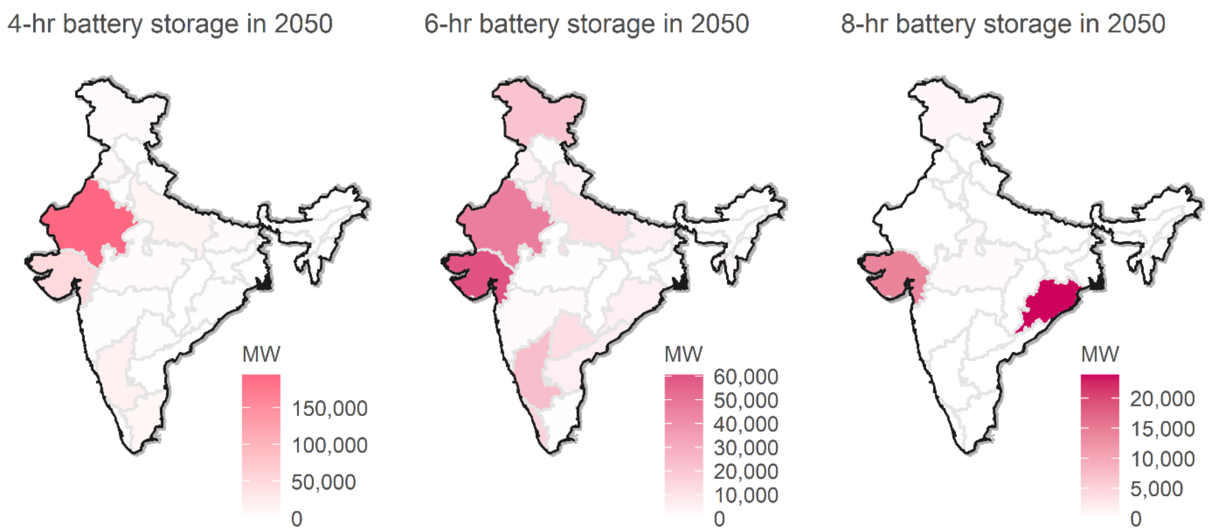

Figure 9. State-wise energy storage deployment to 2050, Reference Case

In the long term, states with the largest investments in battery storage also have high concentrations of solar PV deployment. Rajasthan and Gujarat have the highest battery capacity as well as the highest capacity of solar PV in India, with 450 GW and 270 GW installed by 2050, respectively. Odisha stands out with 24 GW of 8-hour BESS deployed by 2050. Although Odisha is not currently considered a high-solar state, by 2050 we see 37 GW of economic solar PV deployment in the state. The results also show a high value for 8-hour BESS to provide capacity in Odisha (see Section 3.1.3 for a detailed discussion of energy storage value streams).

Furthermore, of the top 10 states for solar PV capacity, seven of them are in the top 10 for battery storage deployment in 2050. Overall, battery storage and solar PV deployment across all states in India has a correlation coefficient of 97%. Excluding Rajasthan and Gujarat, which may be outliers due to those states' high concentrations of solar PV deployment, the correlation coefficient is 66%. While a combination of factors affects the deployment of solar PV and battery storage, the presence of a positive correlation indicates that there is a positive relationship between balancing areas with high-quality solar PV resources and cost-effective battery storage investments. While it may be natural to interpret that more energy storage "enables" higher levels of cost-effective solar PV, the opposite is also true—more solar PV can create more opportunities for energy arbitrage *and* shifts the timing of peak demand to enable a higher capacity credit for shorter-duration storage devices. This trend is well documented in the U.S. context (Denholm et al. 2019; A. W. Frazier et al. 2020; Denholm and Mai 2017; Denholm and Margolis 2018).

3.1.3 What Are the Drivers for Energy Storage in the Reference Case?

Like conventional resources, energy storage projects can provide multiple services to the power system. The same battery storage facility, for example, can help reduce operational costs by performing energy time-shifting, provide reliable capacity for long-term capacity adequacy, and *also* provide essential grid services (i.e., ancillary services) to help maintain grid reliability. We refer to these services as the **value streams** for energy storage investments. Table 7 shows three major categories of value streams from energy storage evaluated in this study.[5] In the Reference Case, we assumed that energy storage operations are fully coordinated to maximize the total value that they provide to the grid. This means that the state of charge is managed in such a way that energy storage devices are available when they are cost-effective to charge and dispatch energy for grid needs. It also means that, in the Reference Case, we assumed that energy storage projects can receive full compensation for the multiple services they provide to the grid. These assumptions are explored in Section 4.5.

Table 7. Value Streams for Energy Storage Evaluated in This Study

Energy Storage Service	Description
Capacity adequacy	Energy storage provides a reliable source of peaking capacity.
Energy time-shifting	Energy storage is used to shift energy between low-value and high-value periods.[6]
Operating reserves	Energy storage is used to provide operating reserves (i.e., spinning reserves).

By looking at the value provided to the system for different services, we can learn about the drivers for energy storage investments. Figure 10 shows the average value streams provided by different types of energy storage projects in the CEM.

[5] Transmission and distribution network upgrade deferral and congestion management are other potential categories of energy storage value. However, assessing opportunities for energy storage to defer or avoid transmission equipment upgrades or help alleviate distribution network issues requires detailed power flow modeling that is outside the scope of this study.

[6] Another common term for this service is energy arbitrage.

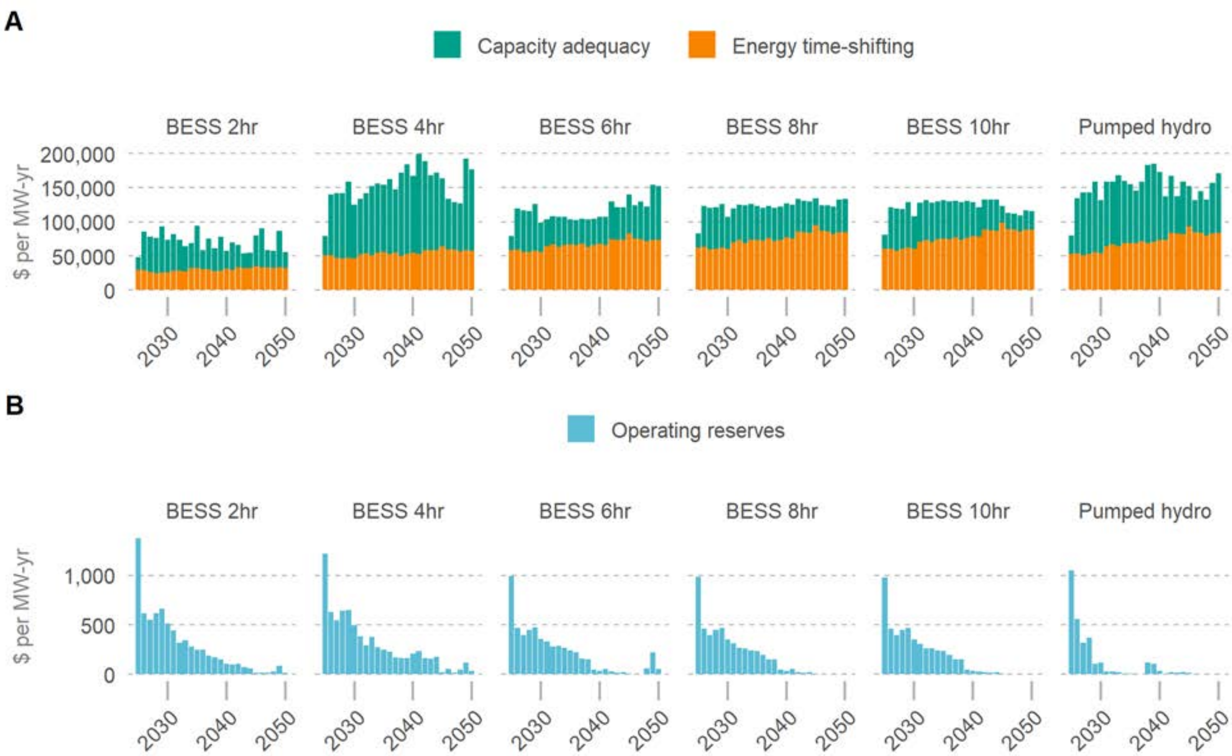

Figure 10. Average value streams for energy storage in the Reference Case

Note: Y-axis scales differ between categories.

Energy time-shifting and capacity services are the largest source of value for energy storage, both in the near and long term. The value of energy storage to provide operating reserves, on the other hand, is relatively small and declines over time. While operating reserves are an essential grid service, the total requirement is relatively small when compared to requirements for energy and capacity services. In the near term, new energy storage devices can capture much of the operating reserves requirement and reduce the overall cost of providing operating reserves by displacing fossil-fueled generation, which is required to start up and maintain headroom to contribute to operating reserves. However, as new energy storage is added to the grid over time, the value for a unit of energy storage to provide operating reserves declines rapidly as the requirement is satisfied by existing resources.

In general, differences in value streams between different years and storage durations are driven by several interrelated factors, including the penetration of RE in the generation mix, the shape of the demand curve, planned retirements of conventional generators, and the amount of energy storage deployed in any given year.

The remainder of this section will explore each category of value streams in further detail.

Capacity Adequacy

The contribution of generation resources to long-term capacity adequacy, often referred to as a generator's "firm capacity" (measured in MW), can also be expressed as a **capacity credit.** The capacity credit is the percentage of a generator's installed capacity that can reliably provide energy to meet peak demand.

Box 2. Capacity Credit for Energy Storage

Peak demand is often defined with a length of time that a regulator or utility decides that they need reliable capacity. Being able to reliably provide power for this amount of time is what determines a resource's capacity credit. For energy storage resources, the capacity credit depends on the duration of the storage and the duration of the peak demand that must be met. In a hypothetical example depicted in Figure 11, up to 200 MW of a 2-hour storage device can serve peak demand with a capacity credit of 100%. In this example, the 2-hour storage discharges 100 MWh at 2 p.m.–3 p.m., 200 MWh at 3 p.m.–4 p.m., and 100 MWh at 4 p.m.–5 p.m. to reduce the net peak demand by 200 MW. The new peak demand after accounting for the storage discharge is now 200 MW over a 5-hour period. A longer duration storage device would be needed to reduce the peak further, as seen in Panel B. This example shows how the capacity credit of energy storage declines as more storage devices are added to the grid. This is because each additional unit of energy storage "flattens" the demand curve, requiring a longer duration of energy discharge. See (Frazier et al. 2020) for a detailed demonstration and analysis of the relationship between energy storage capacity credit, the shape of the net demand curve, and energy storage deployment.

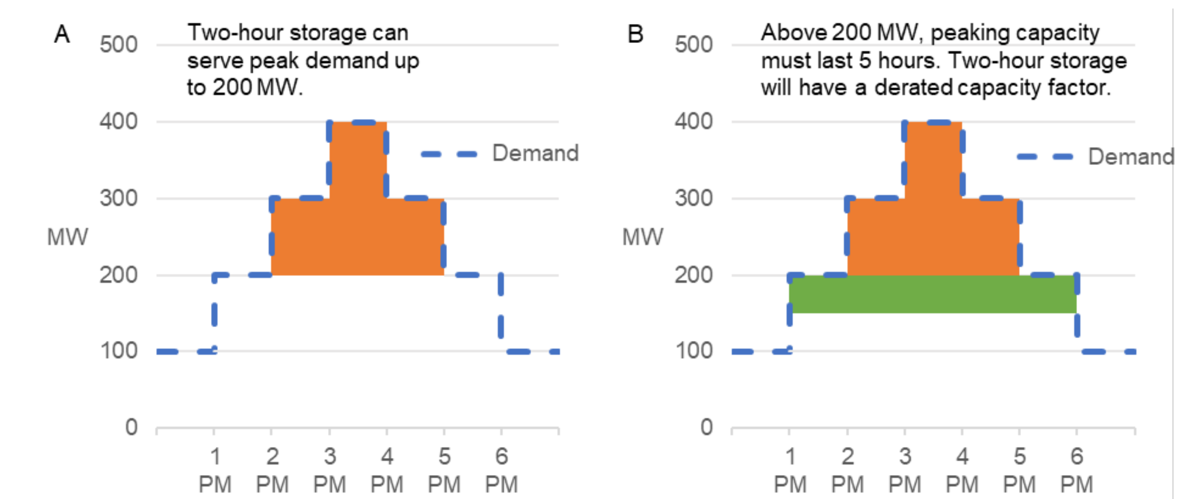

Figure 11. Illustrative example of energy storage capacity credit

Note: Figure adapted from Frazier et al. 2020.

As part of the modeling for this study, we identified the total amount of energy storage with different durations that can provide peaking capacity with a 100% capacity credit. The result of this analysis for select years is depicted in the left panel of Figure 12. The left panel shows the total potential (i.e., upper bound) for energy storage with 100% capacity credit, in GW, based on the load curve in each of India's balancing areas in 2030, 2040, and 2050. Intervening years are not shown to allow easier visual comparisons. The right panel shows the total energy storage capacity that is optimally built in the Reference Case. Comparing results from the left panel with the Reference case buildout provides insights into the value of different storage durations for resource adequacy. When the bar in the left panel is higher than the buildout, this indicates that additional storage capacity at 100% capacity credit could be built but is not cost-effective in the

Reference Case. When the bar in the left panel is lower than the buildout, this indicates that energy storage is cost-effective and is receiving a derated capacity credit in the Reference Case.

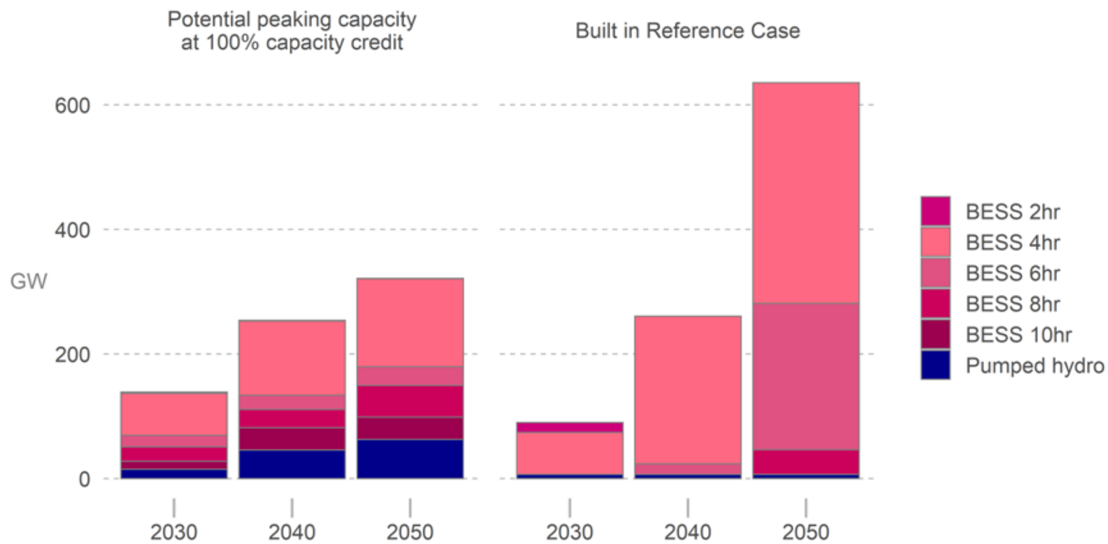

Figure 12. Peaking potential and built capacity for energy storage in the Reference Case

Note: Selected years displayed for ease of visual comparison.

Four-hour BESS has the largest potential to provide peaking capacity with a 100% capacity credit across the entire model horizon. Notably, as shown in the right panel of Figure 12, more 4-hour BESS is built in the model than the peaking potential at 100% capacity credit. This indicates that other factors, including energy-time shifting and operating reserves value, make it economic to deploy 4-hour BESS for purposes other than resource adequacy. The same is true for 6-hour BESS in 2050. Other technologies, including 10-hr BESS and pumped hydro, also have significant peaking potential in the long-term. However, as shown in the right panel of Figure 12, no new l0-hour BESS or pumped hydro is built in the model. This indicates that the value of 10-hour BESS and pumped hydro to provide capacity adequacy does not outweigh other factors such as the cost of investment and availability of other, lower-cost resources that can provide peaking capacity.

Over time, energy storage plays an increasing role in meeting India's capacity reserve margin requirements.[7] Compared to 2020, by 2030, coal-fired capacity still provides the bulk of the capacity reserve margin, but there are growing and significant contributions from diverse resources, including hydro, gas-fired capacity, wind, and solar PV, as well as energy storage, as seen in Figure 13. Energy storage, almost exclusively 4-hour battery storage, provides 15% of the capacity reserve margin in 2030 in the Reference Case. In the longer term, the share of coal in the capacity reserve margin declines as more gas-fired capacity, energy storage, and RE resources are deployed. While the total share of energy storage in the capacity reserve margin increases over time, reaching 31% in 2050, the average capacity credit declines as more storage is deployed, as shown in Table 8. The same trend of declining capacity credits is true for wind

[7] The capacity reserve margin requirement is assumed to be 15% above peak demand in each season.

and solar resources, which provide small additions to the capacity reserve margin despite large growth in total capacity.

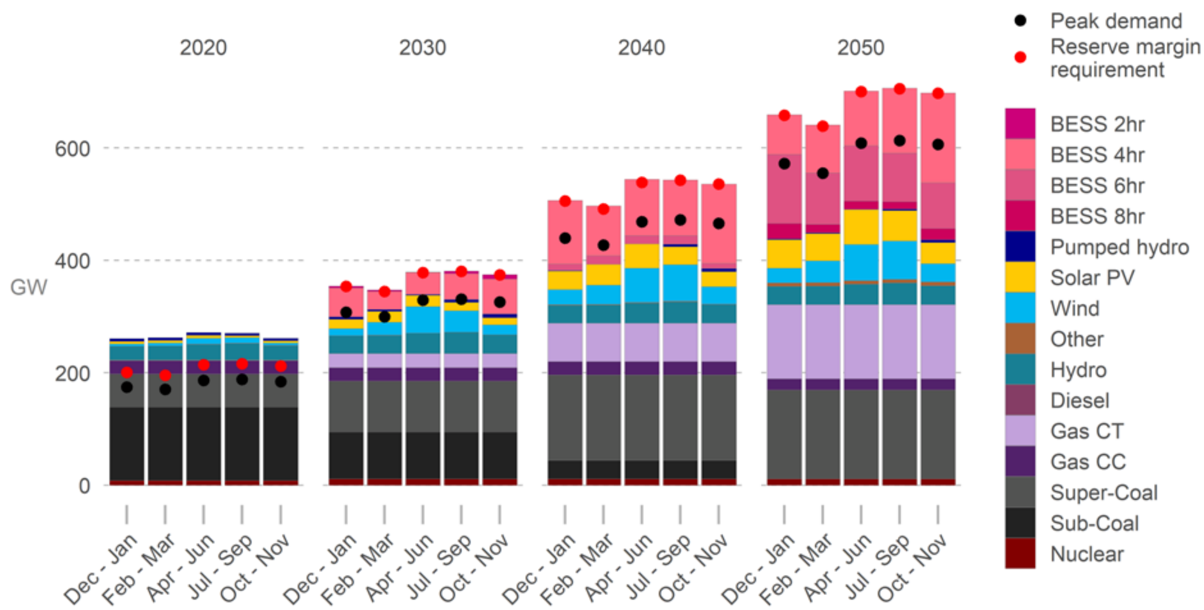

Figure 13. Contribution of different technologies to India's reserve margin by season for select years in the Reference Case

Table 8. Contribution of Energy Storage to the Reserve Margin Requirement

	2030	2040	2050
Proportion of Reserve Margin Requirement Met by Storage	15%	22%	31%
Total Energy Storage Capacity (GW)	90	260	640
Energy Storage Capacity Contributing to Capacity Reserve Margin (GW)	56	120	220
Average Capacity Credit of Energy Storage	62%	46%	34%

The declining capacity credit of energy storage is an important factor that contributes to the cost-effectiveness of nonstorage capacity resources in the long term. In the Reference Case, nonstorage capacity is primarily provided by new gas-fired capacity. The potential impacts of energy storage capacity credit are explored further in the No ES Capacity Credit scenario in Section 3.3.

Energy Time-Shifting

Energy time-shifting refers to moving low-value energy to high-value periods (otherwise known as energy arbitrage). This can help in reducing RE curtailment, reducing the number of thermal unit starts, and ensuring greater utilization of low-cost generation resources.

To get a detailed view of the opportunities for energy time-shifting in the operational timeframes, we employed the PLEXOS operational model, which allowed for hourly comparisons of energy prices. We calculated energy time-shifting revenue of energy storage as the difference between per-unit revenue received for discharging and per-unit price paid for charging. We found that the energy time-shifting revenue is around $31/MWh in 2030. Figure 14 shows the average daily price differential in each month and the resultant energy time-shifting revenue of energy storage in 2030.

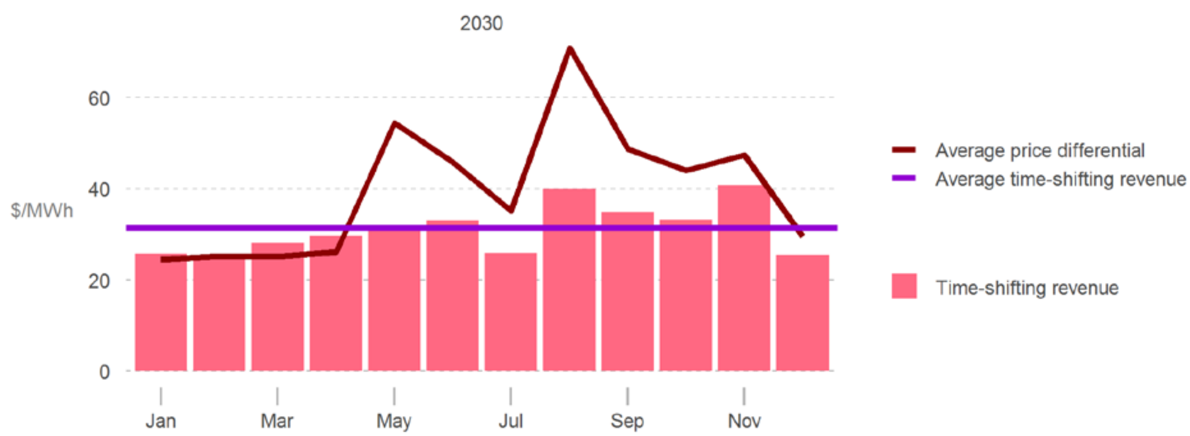

Figure 14. Average energy-shifting revenue for energy storage and monthly average price differential in 2030, Reference Case

We see more energy time-shifting opportunities during June to November in 2030. This seasonal trend is due to higher price differential in these months caused by dispatch of costly gas generation and transmission congestion. This trend also correlates with the actual price differential observed during these months in power exchange prices in 2018 and 2019 (Rose, Wayner, et al. 2020).

We also calculated the energy time-shifting value of energy storage in 2050. We found that the energy time-shifting value varies from $14/MWh to $99/MWh, depending upon whether the transmission constraints were enforced or not. It is important to understand here that the energy time-shifting value is dependent upon the daily price differential. This price differential during any day varies with the level of transmission constraints, variable charges of the costliest marginal generator, and penetration of zero variable charge generation such as solar, wind and hydro. Because a lot of uncertainties are involved in these factors, the numbers presented here should be taken as a possible future scenario that may vary.

Operating Reserves

Another role for energy storage in the power system is to provide ancillary services in the form of operating reserves, which we assumed to be 5% of load procured at the regional level. Providing operating reserves has proven to be a key entry point for recent energy storage development in the United States, in part because of the ability for energy storage to respond rapidly to control signals (Bowen, Chernyakhovskiy, and Denholm 2019). Operations modeling of India showed that energy storage technologies will provide up to 81% of total reserve requirements in 2030, increasing to 97% in 2050 in the Reference Case (see Figure 15). Six-hour storage provides 49% of the total reserve requirements in 2050, whereas 4-hour storage provides a significant share of reserve requirements in both 2030 (70%) and 2050 (39%).

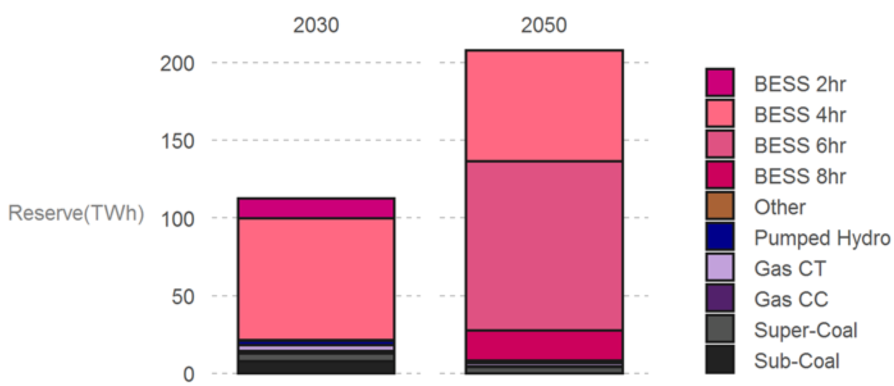

Figure 15. Generation technologies contributing to operating reserves in 2030 and 2050 in the Reference Case

On some days in 2050, energy storage can provide all reserve requirements. Figure 16 shows the reserve provision of one such day when energy storage provides 100% of reserve requirements. Overall, in 2050, energy storage provides more than 85% of reserves in all days and more than 95% of reserve requirements for 63% of the days in the year.

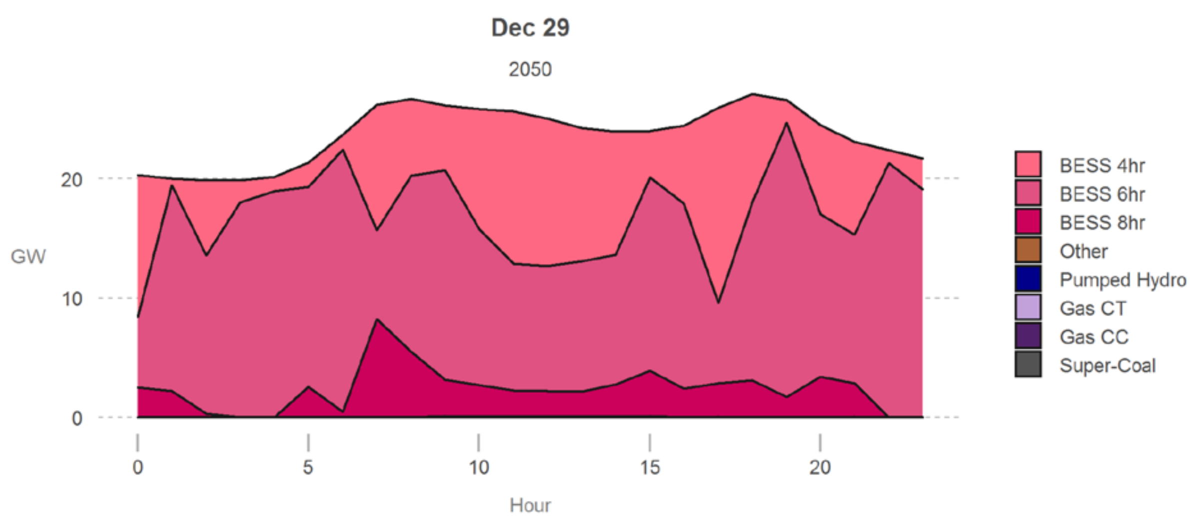

Figure 16. Generation technologies contributing to operating reserves on a day when storage provides 100% of reserve requirements in 2050, Reference Case

Although energy storage provides over 90% of operating reserve requirements in 2050, this service represents a small portion of the overall storage capacity. It can be seen from Table 9 that the capacity factor, or utilization factor, of energy storage for operating reserves goes down from 13% in 2030 to 4% in 2050. The capacity factor for reserve provision is calculated as the ratio of total reserve energy provision and maximum energy it can generate, assuming total capacity generating around the clock. Although energy storage cannot provide generation around the clock at full capacity, this number gives a good indication regarding energy storage capacity utilization for providing reserves.

Table 9. Reserve Provision Capacity Factor (%) for Energy Storage in 2030 and 2050, Reference Case

Type	2030	2050
BESS 2-hr	9.1	-
BESS 4-hr	13	2.3
BESS 6-hr	-	5.3
BESS 8-hr	-	5.7
Pumped Hydro	22	13

3.1.4 How Does the Generation Mix in India Change as Storage Is Deployed?

Solar PV and wind power have the highest growth in installed capacity among generating technologies over the next several decades, with a combined year-over-year growth rate of 40% between 2022 and 2050. Figure 17 shows the deployment of generation capacity through 2050 in the Reference Case.[8] Solar PV sees particularly high growth from the mid-2030s to the late 2040s. Wind grows rapidly from the mid-2020s to the mid-2030s, after which deployment levels off around 330 GW. There is a dip in wind capacity in the 2040s when many existing wind power plants are retired at the end of their economic life, although new deployments make up for retirements by 2050. There are no economic investments in hydropower or nuclear capacity beyond planned additions, reaching 54 GW and 11 GW in 2023, respectively. We also see relatively small increases in biomass and waste heat recovery capacity in later years, reaching a combined 6.5 GW in 2050 (not shown in Figure 17).

Reference Case results show gas-fired plant capacity growing significantly, both in the near term and long term. All new gas-fired capacity is simple cycle combustion turbine technology. These are peaking units that are designed to run for a small percentage of the year. There is also 24 GW of existing combined cycle gas that begins to retire in the 2030s, falling to less than 20 GW by 2050.

[8] The Reference Case includes RE capacity targets of 175 GW by 2022 and 450 GW by 2030.

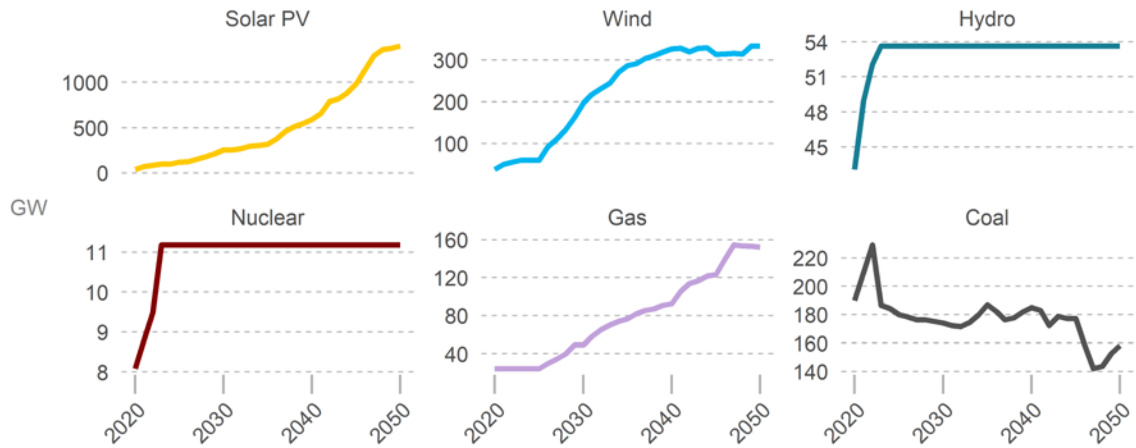

Figure 17. Deployment of generating technologies in India to 2050, Reference Case

Note difference in y-axis scales. Plot does not include biomass.

Total installed capacity in India reaches 2,700 GW by 2050. Figure 18 shows the installed capacity (Panel A) and the capacity mix (Panel B) by technology through 2050, and Table 10 provides numbers for select years. Solar PV represents the largest share of the capacity mix in the long term, with 1,400 GW found to be cost-effective by 2050 in the Reference Case.

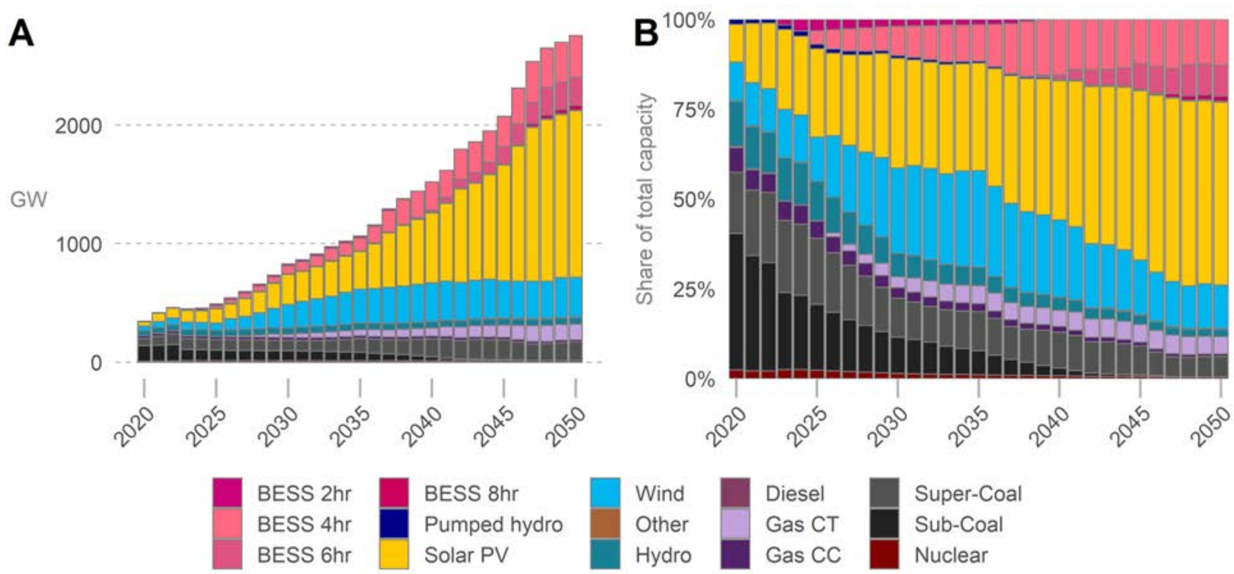

Figure 18. Reference Case installed capacity (A) and capacity mix (B)

Table 10. Capacity of Generation Technologies in India for Select Years, Reference Case

	2020		2030		2040		2050	
Technology	**GW**	**Share of Installed Capacity**	**GW**	**Share of Installed Capacity**	**GW**	**Share of Installed Capacity**	**GW**	**Share of Installed Capacity**
Solar PV	37	11%	250	31%	590	47%	1,400	51%
Wind	37	11%	200	24%	330	22%	330	12%
Hydro	43	12%	54	6.5%	54	3.5%	54	1.9%
Nuclear	8.1	2.3%	11	1.4%	11	<1%	11	<1%
Gas	24	7%	49	5.9%	49	6.1%	150	5.5%
Coal	190	55%	170	21%	180	12%	160	5.7%

Finally, we see several major expansions of interstate transmission capacity by 2050. Figure 19 depicts the transmission investments between 2020 and 2050 in the Reference Case.

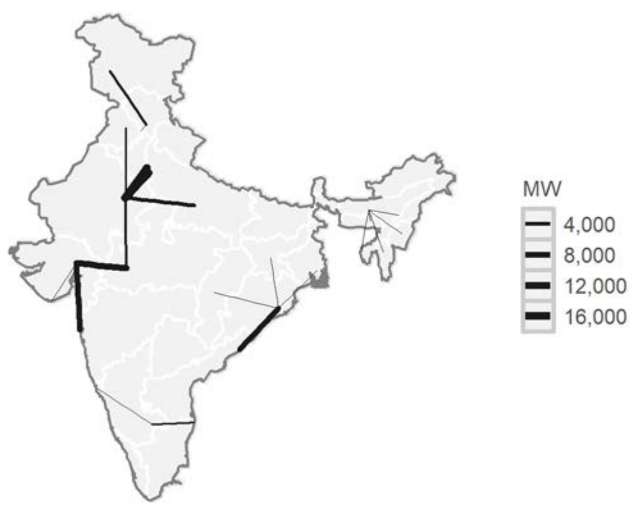

Figure 19. Transmission capacity investments through 2050, Reference Case

The bulk of new transmission investments are in the Northern region. Rajasthan and Gujarat see the most investments in new transfer capacity with neighboring states, which is needed to evacuate solar energy. Jammu and Kashmir also has increased transfer capacity with Himachal Pradesh to evacuate solar energy to high-demand states. We also see substantial investments in transmission between the Southern region and Northern region via the Gujarat-to-Maharashtra corridor, and the Southern region and Eastern region via the Andhra Pradesh-to-Odisha corridor.

3.2 How Will System Operators Utilize Energy Storage?

Storage operations change over time as the generation mix evolves and energy storage proliferates. To understand how storage resources will be optimally utilized in operations (i.e., commitment and dispatch) we used the hourly operations from the PLEXOS operations model. Results for 2030 showed that energy storage charges during the middle of the day and discharges primarily during morning and evening peaks. The energy storage utilization becomes more consistent in 2050 where storage again charges during the middle of the day but discharges through the peaks and into the nighttime hours. In both model years, energy storage followed a seasonal pattern of charging during earlier daylight hours in the summer months.

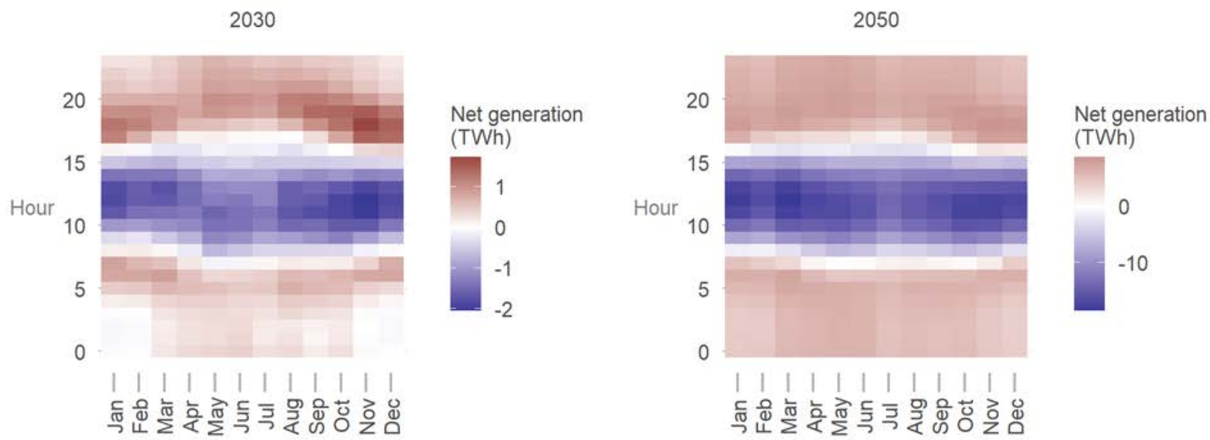

Figure 20. Diurnal monthly charging and discharging pattern for storage in 2030 and 2050, Reference Case

Note: Cells represents average net generation for the combined storage capacity (charging-discharging).

The shifting patterns of utilization between 2030 and 2050 are enabled by longer-duration energy storage that becomes economic in the late 2030s. In 2030, besides the 6.2 GW of PSH, the largest source of storage is 4-hour BESS. By 2050, PSH still has 6.2 GW, but there are now 275 GW of battery storages with 6 hours or more. This shift to longer durations allows energy storage to discharge longer into the nighttime hours and play more of a load-following role in 2050 as opposed to the peaking resource seen in 2030.

Another indicator about the operational requirements from storage is the number of operational cycles and starts per day. Cycles are related to degradation of energy storage; therefore, it is expected that metrics of cycling will be of interest to developers and operators going forward (Smith et al. 2012). We found that, on average, storage devices performed less than one full operational energy cycle per day in all months, both in 2030 and 2050. One full operational cycle means storage is providing generation corresponding to its total energy storage capacity.

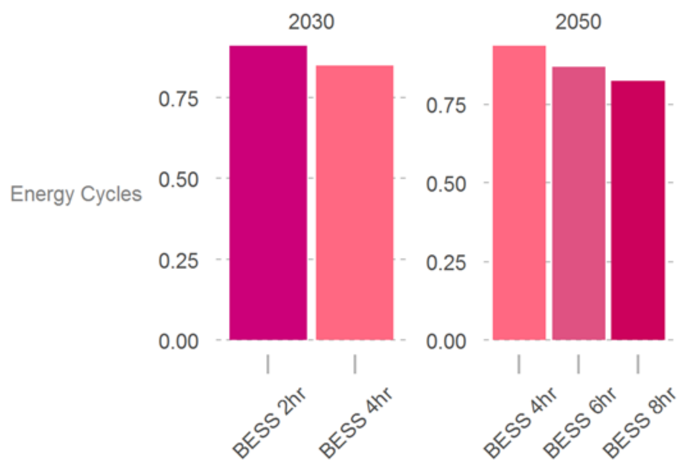

Figure 21. Average energy cycles per day for storage in the Reference Case

We observe that the average daily starts of storage devices (excluding PSH) increases from 3 in 2030 to 4 in 2050. Although additional constraints can be included in the model to limit the number of starts, it is important to understand the unconstrained needs of the system. This will provide useful indications for development of storage devices in the future.

3.2.1 What Role Does Energy Storage Play in Day-to-Day Operations in 2030?

Energy storage supports the system by providing balancing services and helping integrate more RE generation by avoiding curtailment through energy time-shifting. It does this in part by bolstering ramping capabilities to meet net load ramp requirements. Figure 22 shows the dispatch on one of the highest net load ramp days in 2030. The maximum net load ramp of around 60 GW occurs at 1700 hrs. The BESS and PSH is charging during the middle of the day and discharging mostly during the evening peak time, but also during the morning ramp up in load.

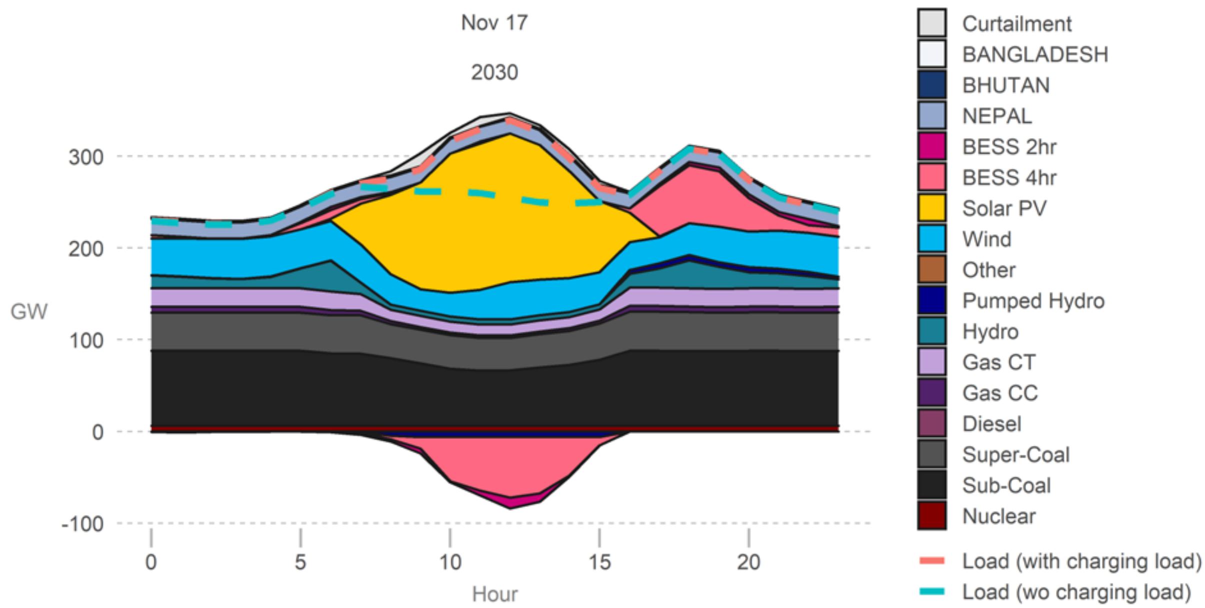

Figure 22. Dispatch stack for one day with the highest net load ramp in 2030

Note: Generation below zero indicates that energy storage is charging. Load (with charging load) includes the charging of energy storage from the grid as a load. Load (without charging load) only includes the demand from electricity customers.

Ramp rate analysis of the same day revealed that storage provided a majority of the ramping requirements throughout the day (see Figure 23).

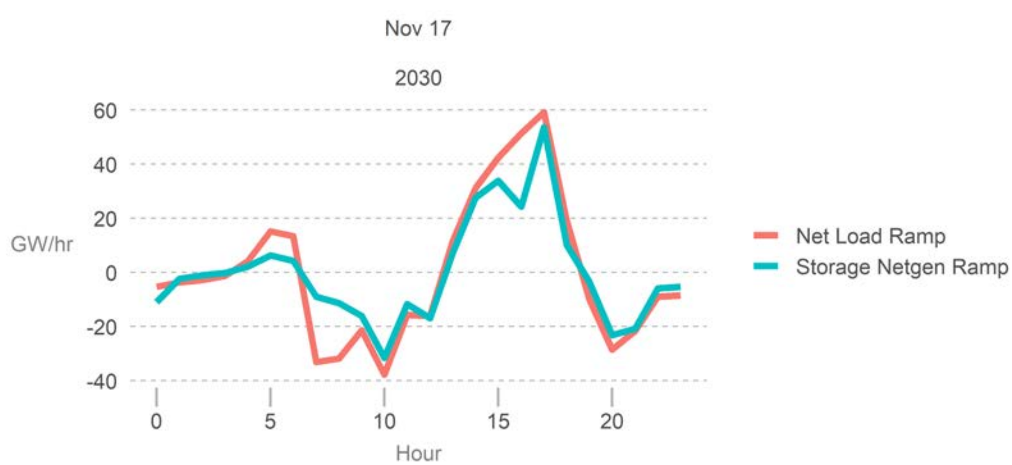

Figure 23. Comparison of net load ramp and storage net generation ramp during the day with highest net load ramp in 2030 Reference scenario

The correlation between the hourly net load ramp and storage net generation ramp was also consistent throughout the year (Figure 24) with an annual correlation of 0.95.

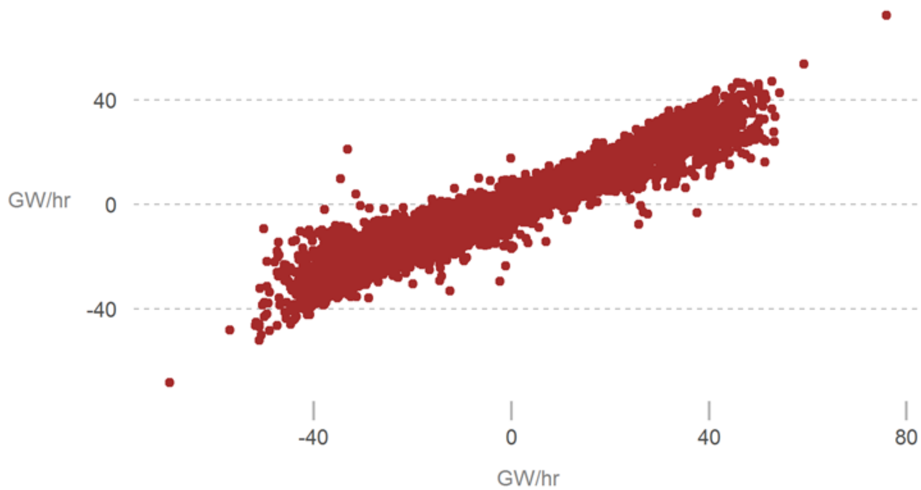

Figure 24. Daily correlation between net load ramp (x-axis) and storage discharge ramp (y-axis) in 2030 Reference scenario

Storage can also help system operators in absorbing more RE to lower the costs of operations. Figure 25 shows the dispatch stack for May 5, 2030. Typically, storage is charged during the daytime and helps to shift energy to the evening hours when it is needed. This impacts the whole generation stack, while at the same time allowing a greater absorption of solar energy, decreasing the backdown requirements of coal, and reducing the potential need for more thermal peaking resources. Additionally, on this day, some energy storage continues charging during the evening peak time to accommodate more wind in the system.

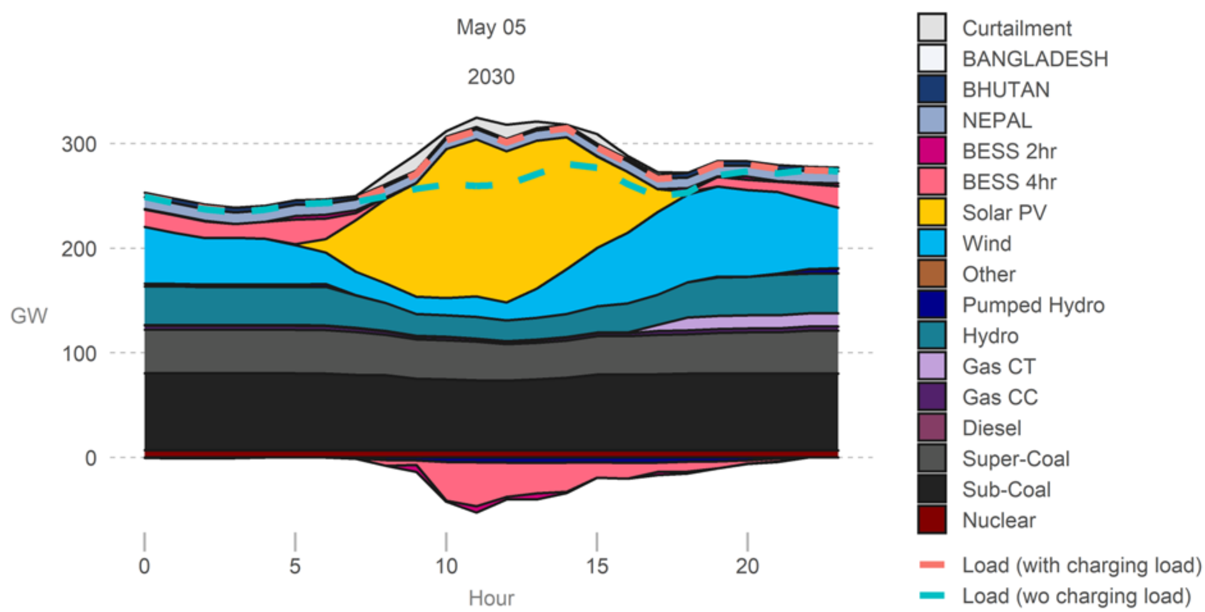

Figure 25. Dispatch stack of one day in 2030 when storage helps absorb more RE

Energy storage can also support balancing the RE variability. In Figure 26, storage devices continue discharging in the morning hours, after the start of solar generation, to compensate for the variability of wind generation. At 0800 hrs, wind generation reduces by 28 GW, which is partially compensated by storage devices helping the system mitigate this supply-side variability.

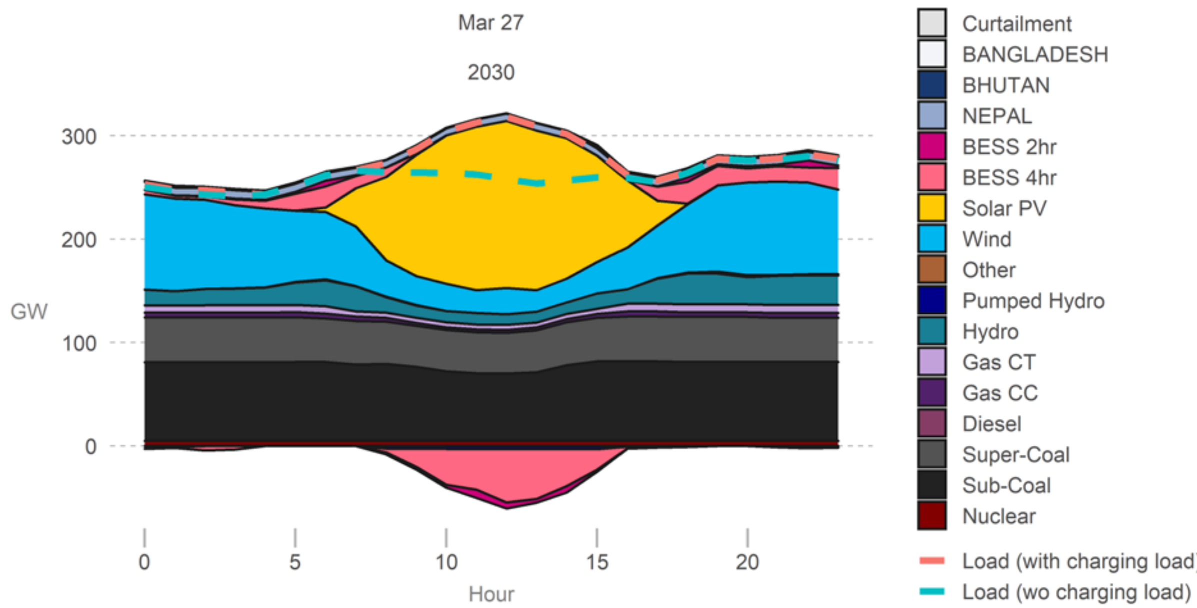

Figure 26. Dispatch stack of one day in 2030 when energy storage helps manage variability of RE

3.2.2 What Role Does Energy Storage Play in Day-to-Day Operations in 2050?

Energy storage, along with other non-fossil fuel energy resources (solar, wind, hydro and nuclear), can meet the bulk of energy requirements in 2050, supplying more than 80% of the total generation annually.[9] For 10% of the days in the year, the penetration of non-fossil fuel energy resources is greater than 90%. And on some days, these resources can provide almost 100% of energy requirements, as seen during a week of September (Figure 27). Ramping support from energy storage is especially critical in 2050, providing the bulk of ramping needs for the system.

[9] This study did not evaluate the inertia requirements and the impact of high penetration of inverter-based resources on the dynamic stability of the transmission system, which is an area for further research.

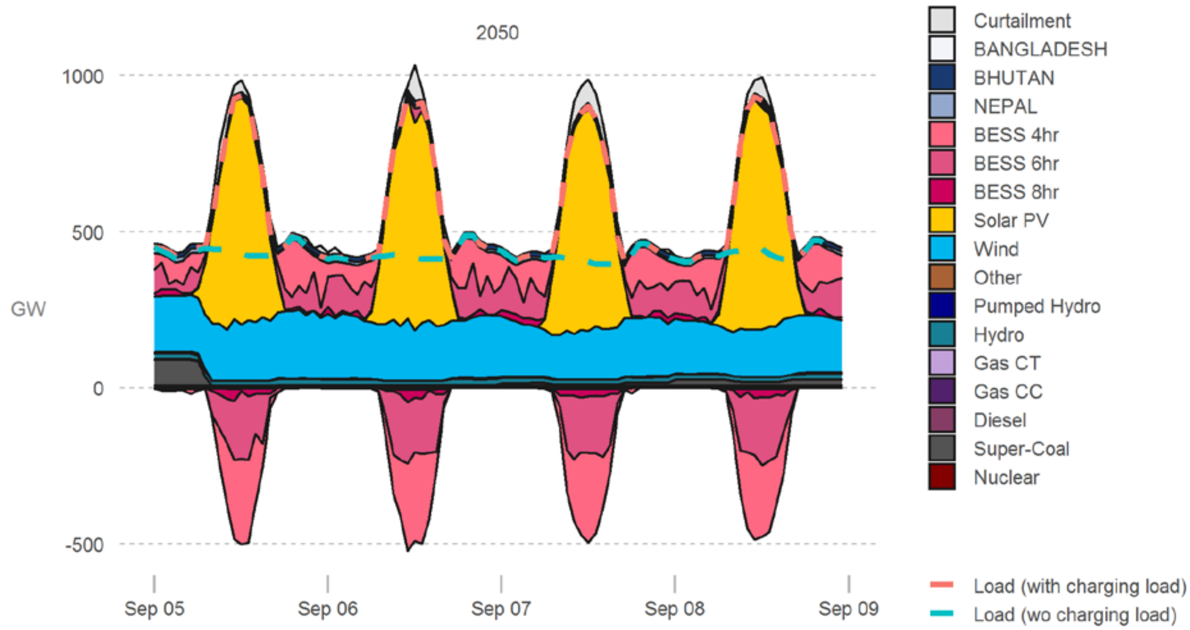

Figure 27. Dispatch stack of four days in 2050 when non-fossil fuel sources provide close to 100% of energy requirements, Reference Case

Energy storage provides most of the balancing for the 2050 Reference Case. Solar energy is largely coincident with ramping requirements; however, the flexibility gained from energy storage during ramping periods in the morning and evening plays a critical role. Additionally, the longer duration storage from PSH, BESS 6- and 8-hour is providing the energy requirement through the night. Four-hour storage also continues to discharge through the night. The typical operations scheme for storage is to charge for 8–10 hours in the middle of the day and then discharge for 12–14 hours until the morning ramp up in load. Figure 28 shows the operations of different durations of BESS for two states, Gujarat and Odisha.

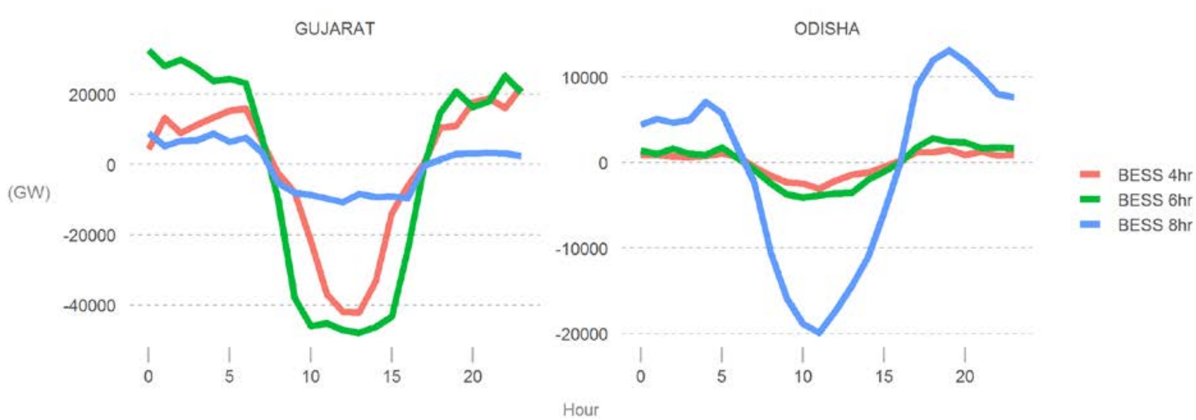

Figure 28. Average storage operations for Gujarat and Odisha during April–June in 2050

3.2.3 Storage Helps in Balancing RE Forecast Errors

Energy storage can play a key role in balancing RE forecast errors. We study this aspect by running a day-ahead and real-time operational scenario. The day-ahead scenario is run with hourly RE forecast values. The results from the day-ahead scenario are passed to real time with actual 15-minute RE profiles. The mean absolute error between day-ahead forecast and real-time generation for utility solar PV, distributed PV, and wind in the model was 1.73%, 1.83%, and 5.71%, respectively. In our PCM, the commitment of coal, combined cycle gas, and hydro unit commitment was fixed in the real-time model based on the day-ahead optimization. There are three primary modes of flexibility to manage balancing in the real time: (1) storage redispatch, (2) thermal unit redispatch, (3) quick-start unit (e.g., gas combustion turbines) commitment and dispatch, and (4) curtailment of RE.

A sample day shown in Figure 29 indicates the role of energy storage in balancing RE forecast errors. During the morning hours when there is a negative forecast error in real time, storage increases its discharge to balance the deficit. Similarly, during the afternoon, storage charges to manage overgeneration. A similar pattern is observed during the evening when storage discharges to compensate for reduced RE generation. The role of energy storage in balancing RE forecast errors was found to be consistent throughout the year.

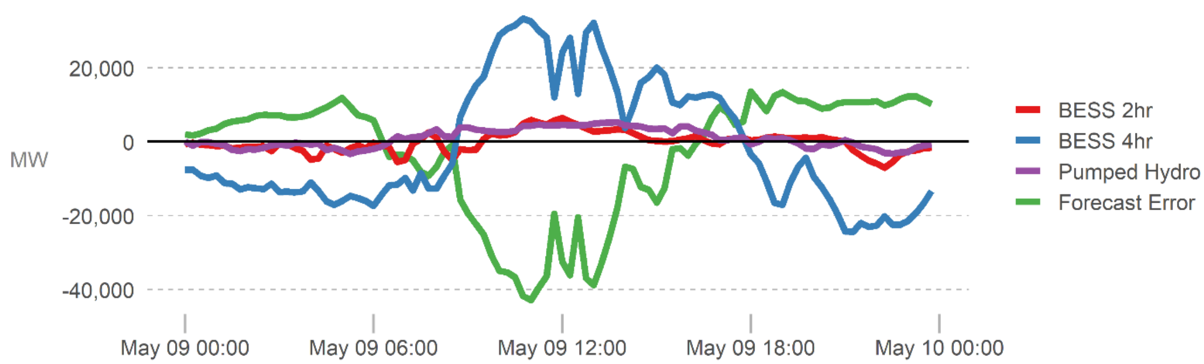

Figure 29. Change in storage dispatch to balance RE forecast error during one day in 2030

3.3 What Are the Regulatory Drivers for Energy Storage Opportunities?

We used scenario analysis to understand how regulations that enable energy storage to provide various grid services impact energy storage investment potential. Figure 30 shows the evolution of energy storage capacity in India from 2020 to 2050 under the Reference Case and three scenarios that vary the regulatory environment.

Electricity sector regulations establish what types of electricity technologies can provide different grid services and receive compensation for those services. To determine an appropriate compensation scheme, utilities and regulators need agreed-upon methods to identify the value that technologies, including energy storage, will provide to the power system. Because energy storage is a novel technology, utilities and regulators may need to further develop tools and expertise to assess the full value that energy storage can provide. The goal of the regulatory scenarios is to indicate which regulations might be best suited for innovation to enable a fair environment for energy storage. In the case of a market-based electricity sector, utilities and independent power producers rely on market prices to reflect the value of different grid services. However, market regulations may exclude (either explicitly or by omission) energy storage from participating in certain markets. In practice, the electricity sector has a mix of cost-of-service tariffs and market-based products that may or may not reflect the full value that different technologies provide to the power system. In India, while most grid services are compensated through cost-of-service tariffs, there is increasing interest in moving toward market-based products (The Financial Times 2020).

The three scenarios discussed in this section provide insight into potential consequences of undervaluing energy storage for specific services and/or excluding energy storage from participating in markets for certain grid services (see Table 1 for scenario descriptions). By design, the scenarios represent extreme or "edge" cases in which energy storage does not receive any value or compensation for the service under consideration.

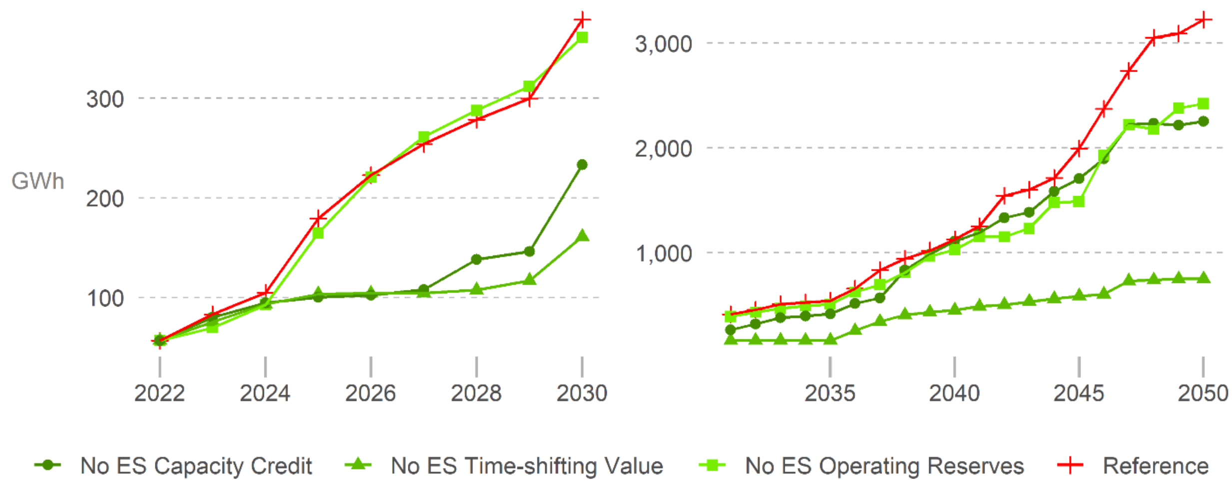

Figure 30. Energy storage capacity under regulatory scenarios through 2030 (left) and 2050 (right)

Note: Y-axis scale changes between left and right panels.

The ability of energy storage to receive compensation for energy time-shifting (i.e., buy low, sell high) has the largest impact on both near-term and long-term storage deployment. By 2030, the energy capacity of storage technologies is 57% lower in the No ES Time-shifting Value scenario compared to the Reference Case and 76% lower by 2050. This scenario represents an environment in which energy storage projects are not able to monetize (i.e., receive revenue) for the time-shifting service that they provide to the grid. This scenario could happen in a contract structure in which a single tariff does not correctly account for the changing price of energy throughout the day.

When energy storage does not receive time-shifting revenue, the investment and operating costs of energy storage projects must be covered with other services to make the investment cost-effective. Because time-shifting is a significant source of value for energy storage in India (see Section 3.1.3), removing this value stream significantly limits the investment potential for storage technologies. Moreover, removing the energy time-shifting value stream for storage has significant impact on the long-term capacity and generation mix in India. Figure 36 shows the difference in capacity and generation in the No ES Time-shifting Value scenario relative to the Reference Case.

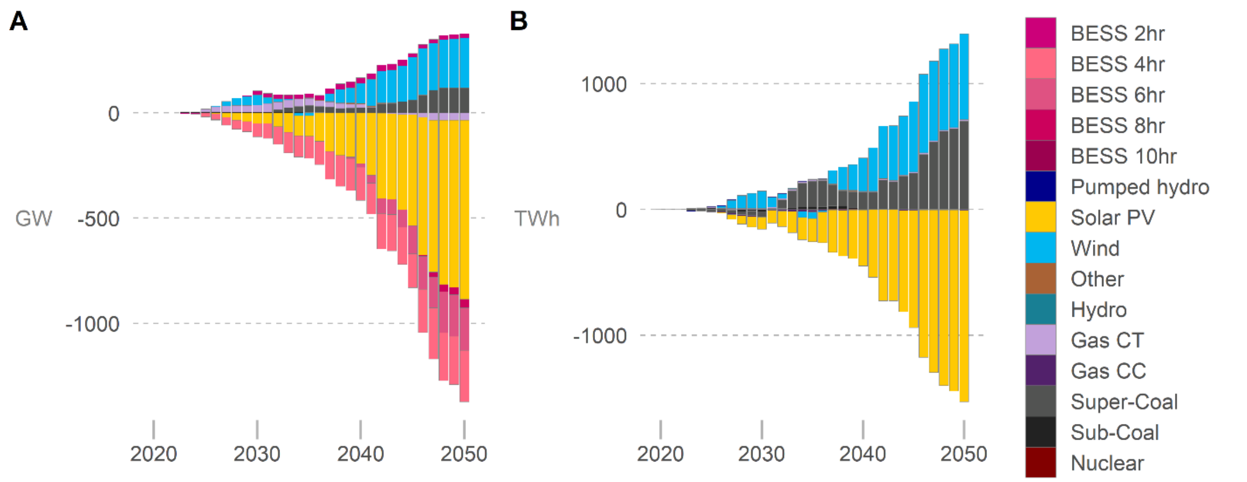

Figure 31. Difference in capacity (A) and generation (B) in the No ES Time-Shifting Value scenario relative to Reference Case

Solar PV deployment is substantially lower by 2050, decreasing 60% from 1,400 GW to 550 GW. In the long term, with less cost-effective energy storage and solar PV, a combination of wind and supercritical coal capacity are deployed to offset reduced generation from solar PV. Notably, new investments in coal increases the national coal capacity to 280 GW by 2050, up from 160 GW in the Reference Case, and generation from coal-fired capacity increases by 120% in 2050. This results in a 120% increase in CO_2 emissions in 2050, more than doubling relative to the Reference Case, and a 20% increase in total CO_2 emissions from the power sector between 2020 and 2050. Emissions in the regulatory scenarios are discussed in greater detail below.

The No ES Capacity Credit scenario also had a significant impact on the results, with 38% less energy storage deployed by 2030 and 30% less by 2050 compared to the Reference Case. Without a revenue stream for their contribution to capacity adequacy, the investment potential for energy storage is reduced. While energy storage is technically capable of providing reliable capacity, evaluating its contribution to the planning reserve margin requires a systems-level approach. This is because the capacity contribution of energy-limited storage depends on the shape of net demand during peak (or possibly other high stress times), which may change over time as new wind and solar resources are added to the grid as demand evolves. Other factors, including the availability of other peaking resources and the state of charge of the storage device, also impact the capacity contribution.

The No ES Capacity Credit scenario evaluated the impact of reducing the capacity credit of energy storage technologies to zero. When energy storage is not allowed to contribute toward the power system's capacity adequacy requirement, other resources are needed to meet the planning reserve requirement, as seen in Figure 32.

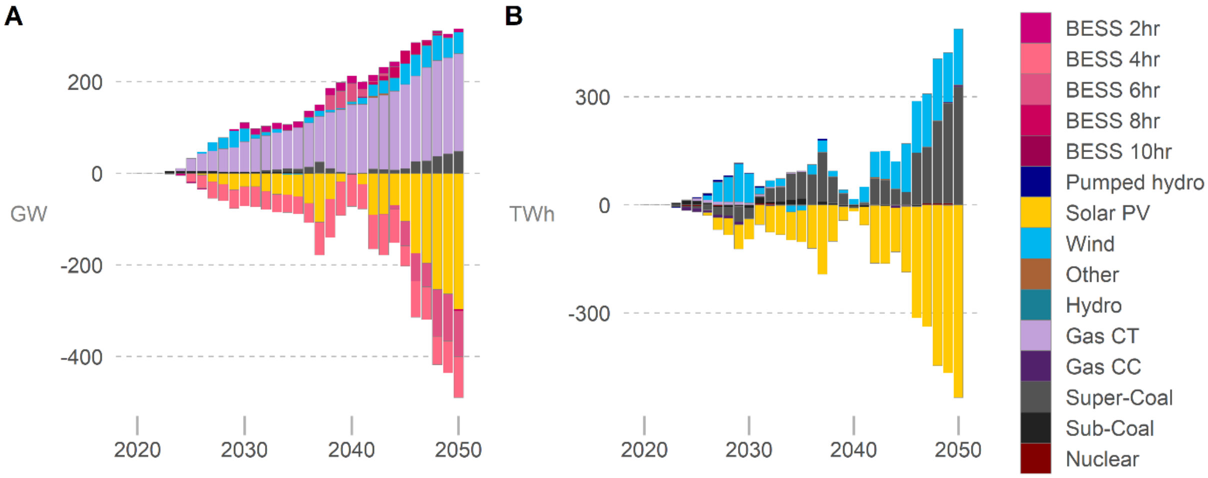

Figure 32. Difference in capacity (A) and generation (B) in the No ES Capacity Credit scenario relative to Reference Case

Gas combustion turbine capacity is the most cost-effective source of peaking capacity when energy storage does not contribute to capacity adequacy. We also see a shift toward wind and supercritical coal and away from solar PV generation compared to the Reference Case, though this trend was less pronounced than in the No ES Energy Time-Shifting Value scenario. Additionally, the gas combustion turbine built for capacity as a replacement for energy storage have a capacity factor of 28% in 2030 and 3.9% in 2050, starting up only for a few extreme events in a year. Emissions are also increased because of the reduced energy storage and solar PV capacity, as well as the resultant increase in coal and gas generation.

The No ES Operating Reserves scenario, on the other hand, tracked installed capacity closely with the Reference Case in the near term, with storage deployment essentially unchanged through 2040 (Figure 30). In the near term, existing and planned conventional capacity is sufficient to supply operating reserves, and the value of providing operating reserves from energy storage is low. As discussed in Section 3.1.3, operating reserves represent a small portion of the total value that energy storage provides to the power system. However, after 2040, the No ES Operating Reserves scenario begins to diverge from the Reference Case. The rate of growth for energy storage deployment slows, and total capacity is 25% less in 2050 compared to the Reference Case. This is because, with energy storage barred from contributing to operating reserves, new conventional resources are needed to meet the operating reserve requirement. And because new conventional capacity is built, there is less opportunity for energy storage to provide energy time-shifting and capacity services past 2040 compared to the Reference Case.

We also quantified the system-level operational impacts of the No ES Operating Reserves scenario using PLEXOS for hourly dispatch modeling. We saw a 3.3% increase in annual production cost when storage did not provide operating reserves in 2030. Further, the average reserve price increased from around $7/MWh to $60/MWh. This is because there is a greater need for thermal and gas plants to start and be committed for longer periods to provide reserves. On average through the year, 26 more gas-fired units and 22 more coal-fired units are scheduled to run, compared to the Reference Case with energy storage providing operating reserves (Figure

33). This leads to a 1.5% increase in total emissions from electricity generation in 2030.

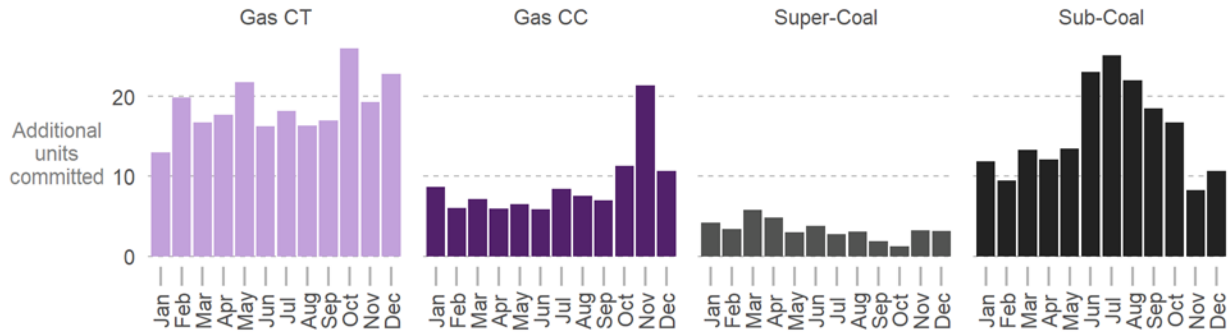

Figure 33. Difference in the average number of units committed when energy storage does not provide operating reserves

A key insight from the regulatory scenarios is that energy storage projects require remuneration for a range of services to achieve their full investment potential. In the Indian context, this means that new regulatory proceedings at the national and state levels may be needed to enable energy storage projects to provide multiple grid services and to establish agreed-upon methods to quantify and compensate the full value that energy storage provides to the power system. Regulators can also consider allowing energy storage to participate in the wholesale and real-time energy market.

Another key insight from the regulatory scenarios is that the level of energy storage deployment can have significant implications for the long-term CO_2 emissions from the power sector in India, as seen in Figure 34. In the near term, annual CO_2 emissions increase as demand grows, then decline after 2025 as more wind and solar is deployed to meet the 450 GW by 2030 target. While CO_2 emissions fall in the long run in the Reference Case, across the three regulatory scenarios, annual CO_2 emissions remain at the same level or increase significantly in 2050 compared to 2020. As described previously, the No ES Time-Shifting Value scenario has the largest increase in emissions due to increased coal generation in the long term.

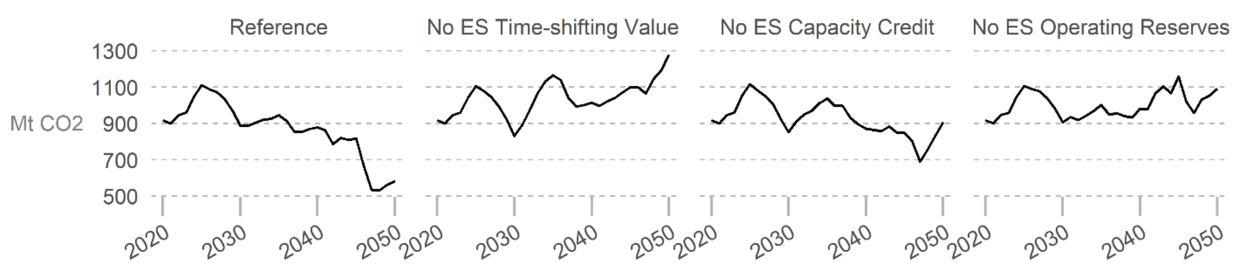

Figure 34. CO2 emissions from the power sector in the Reference Case and regulatory scenarios

Finally, total systems costs are higher when energy storage does not provide certain grid services (Figure 35). System costs were 4% higher in the No ES Time-Shifting Value scenario compared to the Reference Case. The No ES Capacity Credit scenario, in which storage devices are not compensated for their contribution to capacity reserve requirements, also led to a 4% increase in total system costs. And when energy storage did not provide operating reserves, system costs were 3% higher. Increased system costs are driven primarily by higher fuel consumption and variable O&M costs for conventional generators.

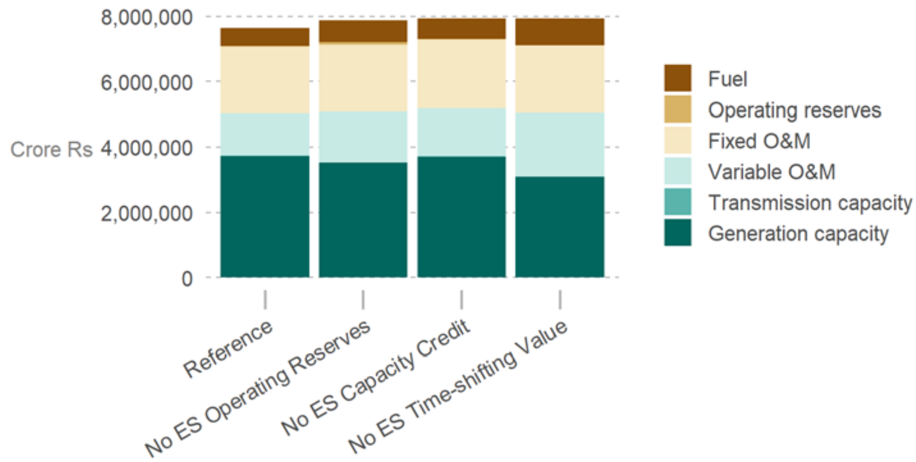

Figure 35. System costs in Reference Case and energy storage regulatory scenarios, 2020–2050

3.4 How Do Fossil Fuel Policies Impact Energy Storage Opportunities?

This section explores how potential national policies for fossil-fueled technologies would impact the near-term and long-term investment opportunities for energy storage in India.[10] Exploring these policy scenarios helps shed light on potential impacts of policies that target specific technologies or on future economic conditions that might preclude certain technologies from being built. Figure 36 shows the deployment of energy storage in the Reference Case, No New Gas, and No New Fossil scenarios. The left panel shows deployment through 2030, and the right panel shows results to 2050.

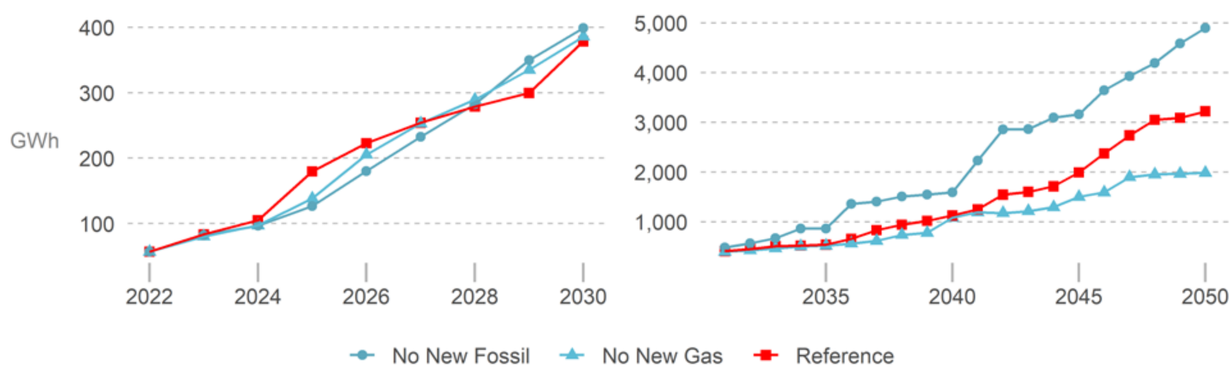

Figure 36. Energy storage capacity in Reference Case and fossil fuel policy scenarios through 2030 (left) and 2050 (right)

Note: Y-axis scale changes between left and right panels.

In the near term, policies restricting investments in gas and fossil-fueled capacity have negligible impacts on energy storage deployment. Both policy scenarios showed a similar growth in energy storage investments to 2030 compared to the Reference Case. In the long term, potential policies around fossil-fuel technologies have a significant impact on the amount of cost-effective energy

[10] The No New Gas and No New Fossil scenarios explored in this report do not reflect existing or proposed policies in India of which the authors are aware.

storage. There are also important implications for the least-cost generation mix in the long-term. Figure 37 shows the difference in total installed capacity compared to the Reference Case. In both cases, substantial differences in the least-cost mix become apparent only after 2030.

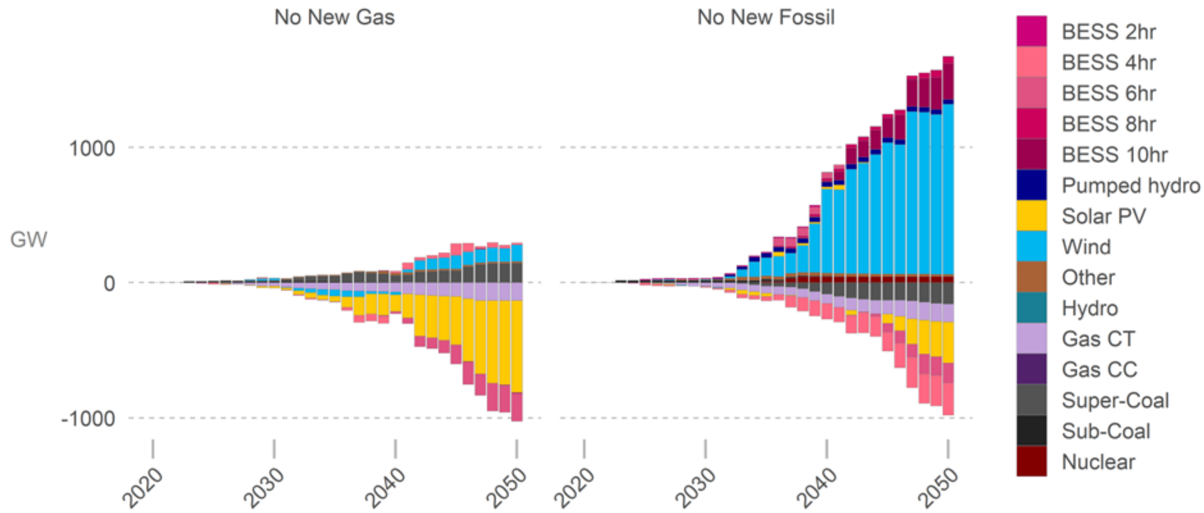

Figure 37. Capacity difference in fossil fuel policy scenarios compared to the Reference Case

In the No New Gas scenario, long-term energy storage capacity grew slower and leveled off around 2,000 GWh, ending 38% lower in 2050 compared to the Reference Case. This result is somewhat unexpected, given that energy storage can serve similar peaking capacity functions as gas-fired power plants. Instead, we see that gas-fired capacity from the Reference Case is replaced primarily by supercritical coal capacity in the No New Gas scenario. Increased deployment of coal has significant implications for the RE sector, primarily for solar PV, which sees 120 GW (20%) less capacity by 2040 and 680 GW (50%) less capacity by 2050 compared to the Reference Case. The reduction in solar PV capacity is partially offset by increased wind deployment, which has 130 GW (27%) more capacity by 2050 in the No New Gas scenario. The net effect is a 20% decrease in RE supplied in 2050, with RE penetration falling from 80% in the Reference Case to 62% in the No New Gas scenario.

To understand why restricting new gas capacity leads to less energy storage and less solar PV deployment, we can look at the role of gas-fired capacity in the Reference Case. In Figure 38, Panel A shows the average dispatch of generating technologies to meet demand during each time slice in the July–September season in 2030. In the Reference Case, gas combustion turbine generation is dispatched to help meet the peak demand. At the same time, gas-fired capacity contributes to capacity adequacy year-round (Panel B). By 2030, gas-fired capacity provides 13% of the reserve margin in the Reference Case. In the No New Gas scenario, the contribution of gas-fired capacity falls to 6%, with the difference made up by delayed retirements of coal capacity. Overall, restricting investments in gas-fired capacity results in more coal capacity needed to meet peak demand and reserve margin requirements.

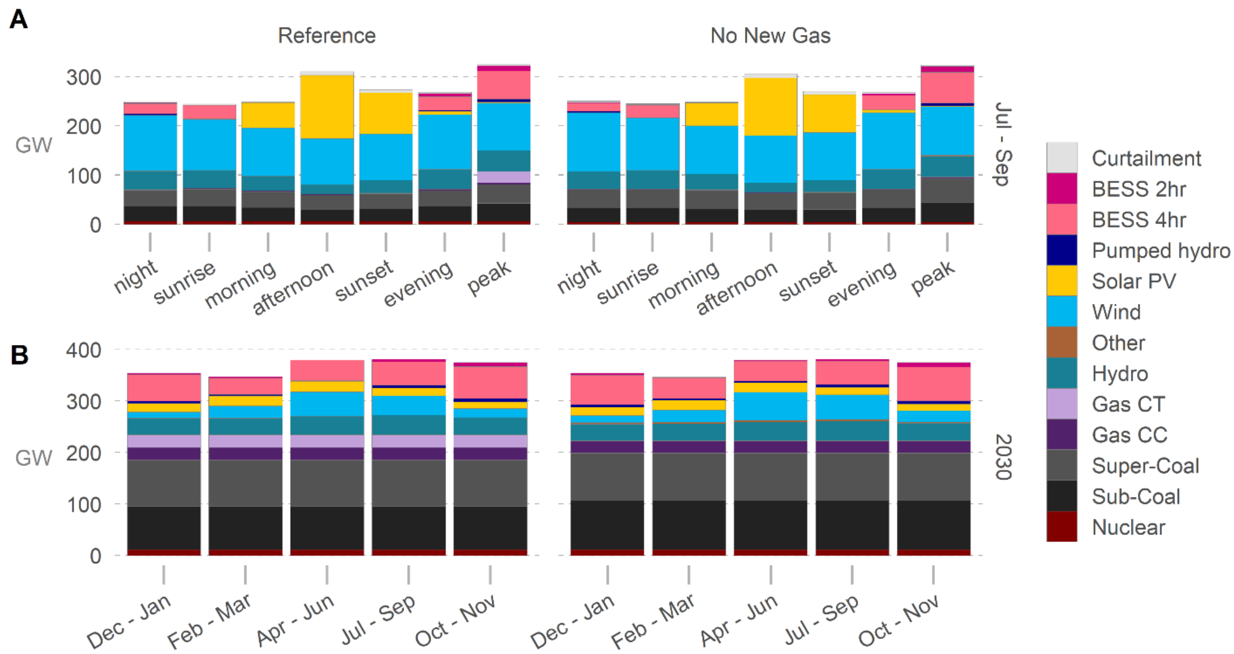

Figure 38. Average generation dispatch for one season (A) and firm capacity by season (B) in 2030 in the Reference Case and No New Gas scenario

Delayed retirement of coal capacity, which is cost-effective when gas investments are restricted, leads to a less flexible generation mix and repercussions to the revenue potential for energy storage. With more coal in the capacity mix, the energy time-shifting value for energy storage decreases because coal capacity has a higher minimum generation level and lower operating cost compared to gas-fired plants, resulting in a lower differential between the low-value and high-value periods. This trend of reduced time-shifting value of energy storage in the No New Gas scenario grows over time (see Figure 39). By 2050, the average energy time-shifting value of energy storage is 28% lower compared to the Reference Case. With reduced time-shifting value, less energy storage is cost-effective, as discussed previously in Section 3.3. And with less cost-effective energy storage, there is less opportunity for cost-effective solar PV deployment in the No New Gas scenario compared to the Reference Case.

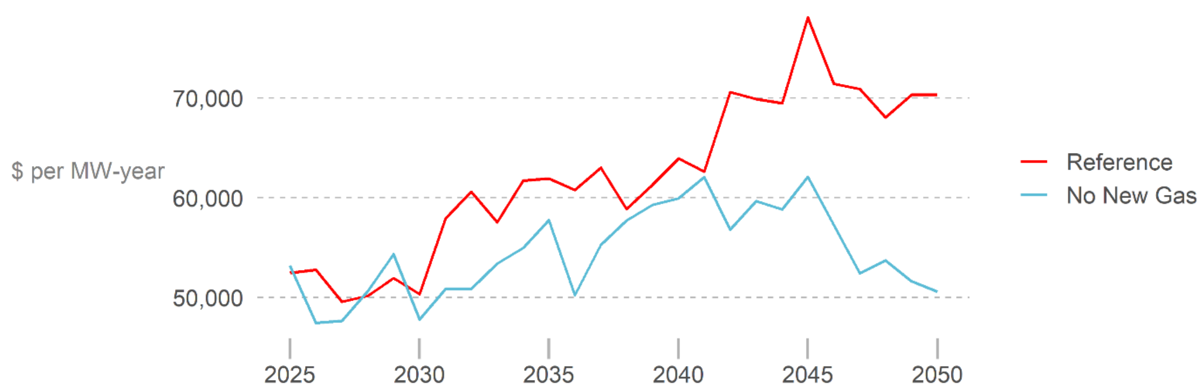

Figure 39. Average energy time-shifting value of energy storage in Reference Case and No New Gas scenario

In the No New Fossil scenario, coal- and gas-fired capacity is retired when many existing plants reach the end of their economic life, starting in the late 2030s. Figure 40 shows the total installed capacity by year and technology in the Reference and No New Fossil scenarios. By 2050, there is no coal-fired capacity and 20 GW gas-fired capacity remaining. Coal and gas retirements drive an increasing need for alternative sources of reliable capacity. Longer-duration storage plays a major role in filling this gap. Energy storage capacity grows to 4,900 GWh in 2050, 50% higher compared to the Reference Case. This difference is driven by substantial amounts of longer-duration storage, with 260 GW of 10-hour battery projects, as well as 46 GW of pumped hydro by 2050. We also see 50 GW of new nuclear and 18 GW of biomass capacity by 2050.[11,12] Notably, wind power grows rapidly after 2035, reaching 1,600 GW by 2050, far more than in any other scenario evaluated in this study.

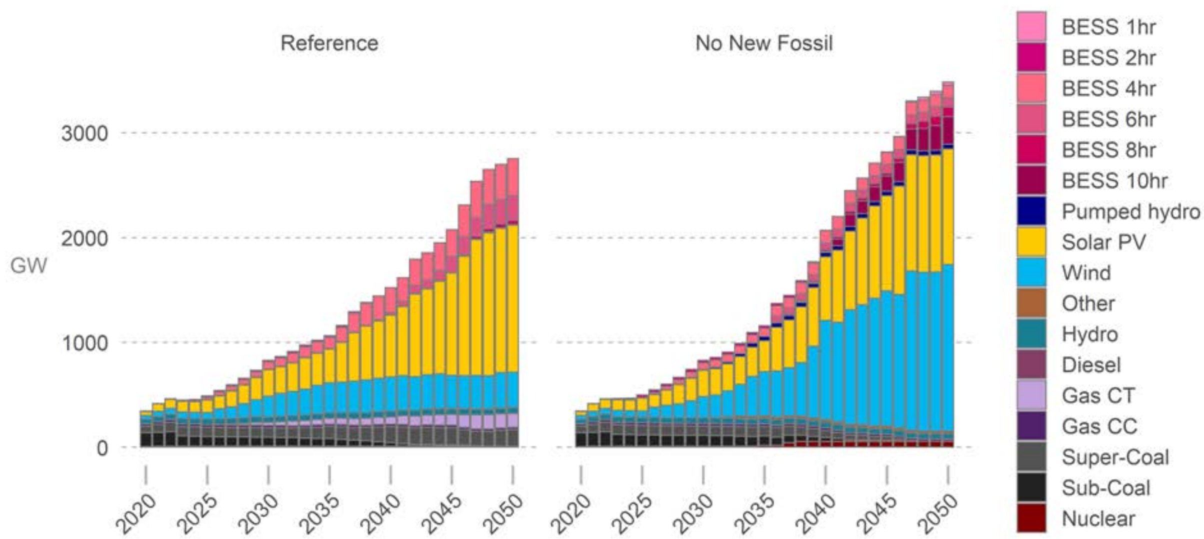

Figure 40. Installed capacity in the Reference Case and No New Fossil scenarios

Overall, restricting investments in fossil-fueled capacity results in more total capacity. By 2050, there is 3,500 GW of installed generation and storage capacity in the No New Fossil scenario, compared to 2,800 GW in the Reference Case. We also see high levels of RE curtailment, averaging 20% annually in the No New Fossil scenario, meaning that 20% of the potential energy from RE resources goes unused. This result of large capacity additions without large energy needs indicates that the planning reserve margin is a key driver for capacity investments, more so than energy requirements, when investments in fossil-fueled capacity are restricted. More total capacity is needed to meet the planning reserve margin because non-fossil resources with full capacity credit (i.e., nuclear and biomass) are fully built out, and the remaining cost-effective technology options (i.e., wind, solar PV, and energy storage) have reduced capacity credits. By 2050, wind, solar PV, and energy storage have average capacity credits of 12%, 5%, and 47%, respectively, in the No New Fossil scenario. Given current cost projections of RE, curtailing RE could be a cost-effective option. However, future studies can explore alternative

[11] State-wise nuclear capacity is limited in the model based on numbers taken from Department of Atomic Energy (2019). The limit for nuclear capacity in India, 56 GW, is reached in 2038 in the No New Fossil scenario.
[12] State-wise biomass capacity is limited in the model based on numbers taken from CEA (2018d). The limit for biomass capacity in India, 18 GW, is reach in 2033 in the No New Fossil scenario.

emerging technology options, such as green hydrogen, carbon capture and storage, and synthetic fuels, that can meet planning reserve margin requirements while meeting air emissions and decarbonization targets.

3.5 How Do Technology Costs Impact Energy Storage Opportunities?

This section describes results from scenarios that explore how energy storage opportunities change with different assumptions about the future costs of specific technologies.

Battery Cost Scenarios

Exploring different assumptions for battery costs helps to assess the potential impact of significant uncertainties for both current and future installed costs of utility-scale battery storage projects in South Asia (Figure 3). See Section 2.3 for details on the input data for the battery cost scenarios. Figure 41 shows the difference in installed capacity in the two battery costs scenarios compared to the Reference Case.

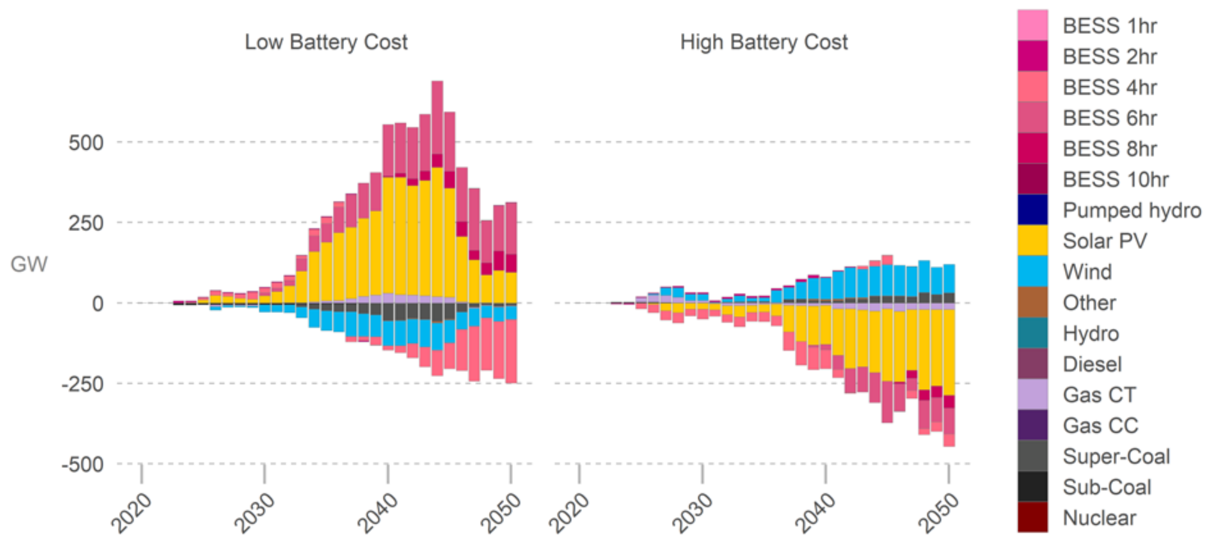

Figure 41. Capacity difference in battery cost scenarios compared to the Reference Case

Results showed significantly more investment in longer-duration battery storage in later years under the Low Battery Cost scenario compared to the Reference Case. By 2040, there is 150 GW more installed capacity from 6-hour duration BESS, increasing the energy capacity of storage devices to 2,060 GWh. After 2040, increased deployment of 6-hour and 8-hour duration BESS is offset by reduced deployment of 4-hour duration BESS. While total power capacity of BESS is essentially unchanged by 2050, the energy capacity of storage devices increases by 630 GWh (20% more) in the Low Battery Cost scenario relative to the Reference Case. We also found that availability of lower-cost batteries shifted the timing of solar PV deployment to earlier years, with significantly more solar PV investment from the mid-2030s to the mid-2040s. By 2045, there is 240 GW (35%) more solar PV capacity, although this difference falls to 95 GW (7%) by 2050. Long-term investments in conventional technologies are unchanged; however, early retirements of coal plants in the 2030s and early 2040s combined with the higher PV capacity leads to an emissions decrease of 12% by mid-century under the Low Battery Cost scenario.

As expected, the High Battery Cost scenario showed less overall investment in BESS. We also saw significant reductions in solar PV investment, which was offset by additional wind deployment, compared to the Reference Case. By 2030 there is 25 GW (110 GWh) less energy storage capacity and 19 GW less solar PV capacity, reductions of 30% and 7.6%, respectfully. Wind capacity offsets the reduction in solar PV deployment to meet the 450 GW RE target for 2030. The same trend, with less energy storage, less solar PV, and more wind capacity, persists in the long term. By 2050, energy storage capacity is 20% lower, solar PV capacity is 19% lower, and wind capacity is 26% greater, compared to the Reference Case. Apart from a trade-off between gas combustion turbine and combined cycle gas capacity, with more legacy combined cycle gas plants staying online and less new investment in new gas combustion turbines, long-term investments in conventional technologies remains unchanged in the High Battery Cost scenario.

Solar PV Cost Scenarios

We further explored synergies between energy storage and solar PV deployment in two scenarios. The Low Solar Cost scenario assumed the installed cost of solar PV technologies will decline faster in the near term and level off at a lower cost in later years relative to the Reference Case (Table 11).[13] All other technology costs and assumptions were held constant from the Reference Case.

Table 11. Capital Cost of Solar PV Technologies

	Utility PV Capital Cost (Crore ₹/MW)		**Rooftop PV Capital Cost (Crore ₹/MW)[14]**	
	Reference Case	Low Solar Cost	Reference Case	Low Solar Cost
2020	4.5	4.4	11	11
2030	3.8	3.1	6.8	5.2
2040	3.4	2.7	5.6	4.1
2050	3.1	2.3	5.3	3.7

We used one additional scenario, Low Solar & Battery Cost, to assess the combined impact of lower-cost solar PV technologies and lower-cost BESS. Figure 42 shows the installed capacity of energy storage, solar PV, and wind technologies in the Reference Case and two low-cost solar PV scenarios.

13 Solar PV costs in the Low Cost Solar scenario are based on cost declines from the 2020 ATB 2020–Low case (NREL 2020) .
14 Starting values for rooftop PV costs are based on BloombergNEF (2017).

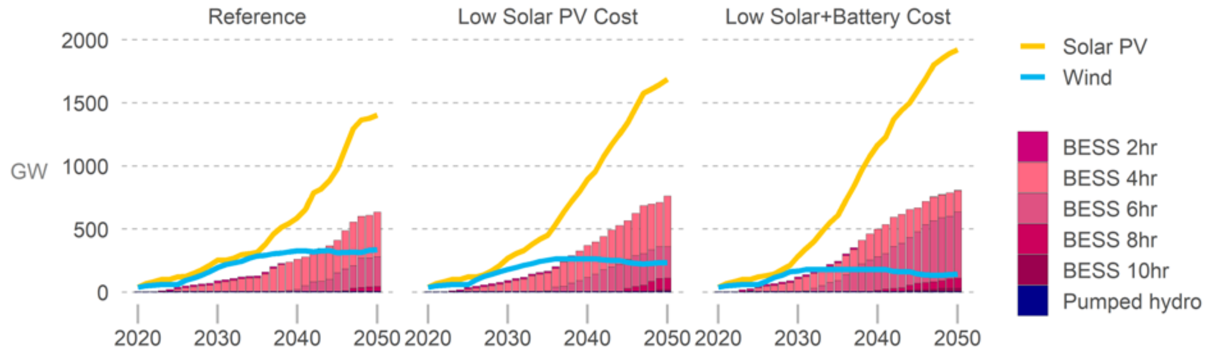

Figure 42. Energy storage, solar PV, and wind capacity in solar cost scenarios

The Low Solar PV Cost scenario has more investment in both solar PV and energy storage in the near- and long-term. There is 4,050 GWh of energy storage capacity in the Low Solar PV Cost scenario in 2050, a 25% increase over the Reference Case and a 5% increase over the Low Battery Cost scenario. We also saw a substantial reduction in wind capacity by 2050, declining by 100 GW from 330 GW in the Reference Case to 230 GW in the Low Solar PV Cost scenario. This result indicates that policies aimed at lowering the cost of solar PV may have important implications for the battery storage and wind power sectors as well.

The combined Low Solar & Battery Cost scenario, as expected, resulted in more investment in both solar PV and longer-duration battery storage capacity in the long term. Wind capacity does not grow after 2030, and 16 GW of legacy wind power is retired in the mid-2040s.

PSH Cost Scenarios

The PSH cost scenarios were designed to examine the cost of PSH that will be competitive.[15] Modeling results showed increasing opportunities for PSH investments when capital costs were lower (see Figure 43). In the near term, a 30% cost reduction compared to the Reference Case, at 6.9 Crore ₹/MW, is the tipping point for PSH to be competitive with battery storage technologies.[16] Further reductions in PSH costs result in a greater PSH capacity and delayed investments in BESS projects. PSH capacity reaches 52 GW with 630 GWh energy storage capacity by 2030 in the Low PSH Cost scenario. This buildout represents over half of the potential PSH capacity identified by CEA (P. K. SHUKLA 2017). However, given rapidly declining costs for BESS, longer-term opportunities for economic PSH investments are limited. We see no new in investments in PSH projects after 2030 across the capacity expansion scenarios evaluated for this study.

[15] Hydro resources, including PSH, have the potential to serve many functions beyond supplying power, such as recreational opportunities, irrigation, or flood control. These scenarios are meant to encompass both economic incentives through policies as well as the potential benefits outside the power sector that could offset the capital costs. However, examining the exact mechanisms for incentive or the value of other benefits is outside the scope of this study.

[16] Assumptions about the efficiency, duration, and operations of PSH plants were kept the same across cost scenarios evaluated for this study. Further investigation into site-specific plant characteristic, land-use and water constraints, and local environmental impacts would be needed to assess whether specific potential PSH projects would be cost-effective.

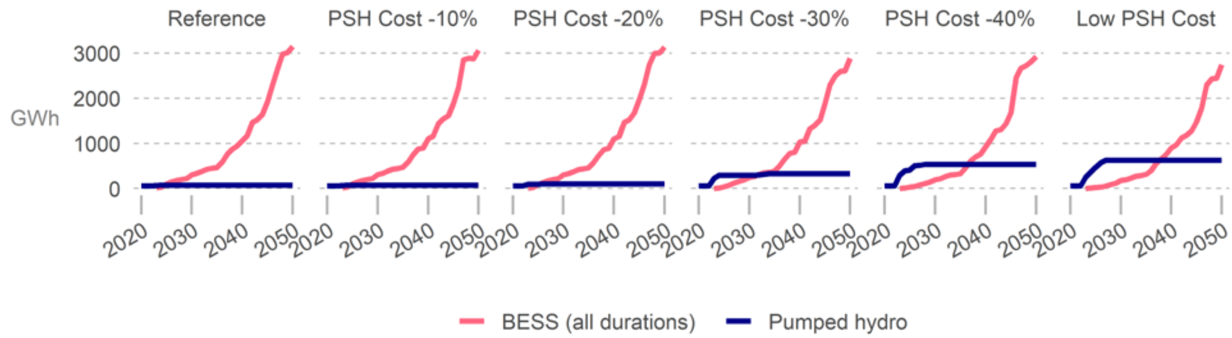

Figure 43. Pumped storage and battery capacity in PSH cost scenarios

3.6 South Asia Regional Opportunities for Energy Storage

We also studied the impact of energy storage on the operation of other South Asian countries, including Bangladesh, Bhutan, and Nepal. As of now, there are no commissioned energy storage projects, and countries are in early stages of evaluating the technical and economic feasibility of energy storage in their systems. Therefore, we analyzed multiple scenarios of energy storage buildout in each country by adding an incremental quantum of 4-hour energy storage to examine the impact and potential value of energy storage on operations. Given that we did not evaluate the least-cost generation mix for countries outside of India, the energy storage added to Bangladesh, Bhutan, and Nepal is not specific to a technology, so could be BESS, PSH facilities, or converting existing hydro storage to pump storage plants wherever possible, which will provide similar benefits. Each of the country analysis changed only the energy storage within the country, and all other aspects of the model stayed the same while using an unchanged Reference Case from the India capacity expansion scenarios.

3.6.1 Energy Storage in Bangladesh Can Displace Costly Thermal Generation, Reduce Emissions and Provide Operating Reserves

Bangladesh currently imports power from India mostly through a 1,000-MW high-voltage DC interconnection. Additional high-voltage DC interconnections are planned with an objective of importing power from India, Nepal, and Bhutan. Using a similar approach to Nepal of adding incremental quantum of energy storage in subsequent scenarios, we studied the value of energy storage for Bangladesh. Results showed that energy storage can reduce costly fuel oil and diesel generation, reduce emissions, and provide operating reserves to Bangladesh. Table 12 compares the results from the storage buildout scenarios for Bangladesh. With the addition of only 300 MW of 4-hour energy storage, annual production costs in 2030 reduce by over 1%, driven largely by the reduction in fuel oil generation. Adding 5,000 MW reduces production costs by 8.3% driven again by reductions in fuel oil of 34%. This amount of energy storage also drives a reduced cost for reliability by reducing the price of operating reserves by 46%. For perspective, in this scenario, India has 68,000 MW of 4-hour energy storage in 2030 based on the results of the least-cost capacity expansion in the Reference Case.

Table 12. Change in Annual Operational Metrics in Bangladesh With Incremental Energy Storage Builds

	ES-100 MW	ES-300 MW	ES-500 MW	ES-1000 MW	ES-2000 MW	ES-5000 MW
Production Cost	-0.5%	-1.1%	-1.7%	-2.9%	-5.4%	-8.3%
Fuel Oil Generation	-1.2%	-3.1%	-5.4%	-11%	-22%	-34%
Energy Storage Share in Operating Reserves	0.4%	1.2%	1.9%	3.5%	11%	26%
Reserve Price	No significant change	No significant change	No significant change	-6%	-13%	-46%

Figure 44 shows the operation of energy storage in all scenarios of energy storage addition for Bangladesh. The pattern is similar in all where energy storage is discharging during the evening peak and charging at all other times.

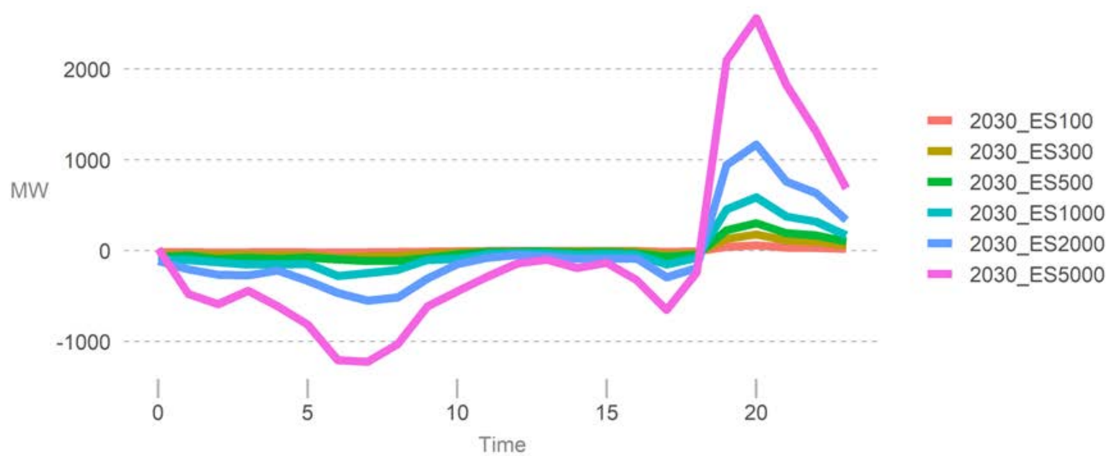

Figure 44. Average net generation pattern of energy storage devices in Bangladesh in the energy storage addition scenarios (ES100 = 100 MW, ES200 = 200 MW, etc.)

Note: Negative values indicate that the storage is charging from the grid.

3.6.2 *Energy Storage in Bhutan Can Shift Exports to Times That Are Beneficial for Regional RE Integration*

In present-day operations, all excess hydro generation from Bhutan is exported to India. The present contracts between India and Bhutan for various hydro projects located in Bhutan are based on total export potential rather than a specific power quantum. Therefore, in our modeling, exports from Bhutan to India were not associated with transmission wheeling or other charges. This ensured that all the excess power from Bhutan was exported to India. As shown in Figure 45, adding energy storage shifted exports more to the evening hours as well as increasing export during times of solar ramp up and down. This helps to balance the grid in India, allowing for ramping support and optimizing Bhutan's resources. Additionally, increasing amounts of energy storage in Bhutan lead to reduced daytime RE curtailment in India by reducing export during the middle of the day when solar is high and shifting it to the evening peak. Between the scenario with 500 MW and 1,000 MW energy storage in Bhutan, an additional 150 GWh of RE was accommodated on India's grid for the year.

Figure 45. Average export pattern from Bhutan to India in 2030 without energy storage additions (2030) and with incremental energy storage builds in Bhutan (ES100 = 100 MW, ES200 = 200 MW, etc.)

3.6.3 Energy Storage Helps Nepal to Reduce Hydro Curtailment, Exporting More Energy to India and Providing Operating Reserves

Most of the existing and planned hydropower projects in Nepal are ROR type, except a few that have storage. Because ROR plants cannot modulate their output, Nepal may not be able to maximize the use of domestic hydropower resources during periods when domestic demand and exports to India are not sufficient to absorb the ROR generation. In our production cost modeling of hourly system operations in 2030, we observed that 0.6% of Nepal's hydropower generation was curtailed due to insufficient flexibility.[17] Adding 4-hour energy storage in Nepal helped shift hydro generation to periods when it is needed, reducing hydro curtailment, and increasing exports to India in 2030. Table 13 shows that adding up to 500 MW of 4-hour energy storage reduces curtailment substantially and increases the opportunities for exporting formerly curtailed power to India. We also tested scenarios with 1,000 MW, 2,000 MW, and 5,000 MW of storage capacity but did not see much further increase in exports to India.

[17] ROR hydropower has very low or zero marginal costs to operate. Therefore, curtailing power, which is done by allowing water to flow past the dams, is wasting very low-cost energy that cannot be recovered.

Table 13. Change in Annual Nepal Export to India With Incremental Energy Storage Additions

4-hr Energy Storage Capacity	Change in Exports to India (GWh)	Hydro ROR Curtailment
0 MW	-	0.6%
100 MW	293	0.48%
300 MW	432	0.36%
500 MW	728	0.13%

Figure 46 shows the changes in the export of power to India for all scenarios of energy storage addition. Energy storage enables Nepal to shift daily exports to India to evening peak hours when India's demand is higher and solar generation in India is low or zero. Increasing the capacity of energy storage increases the export during evening peak.

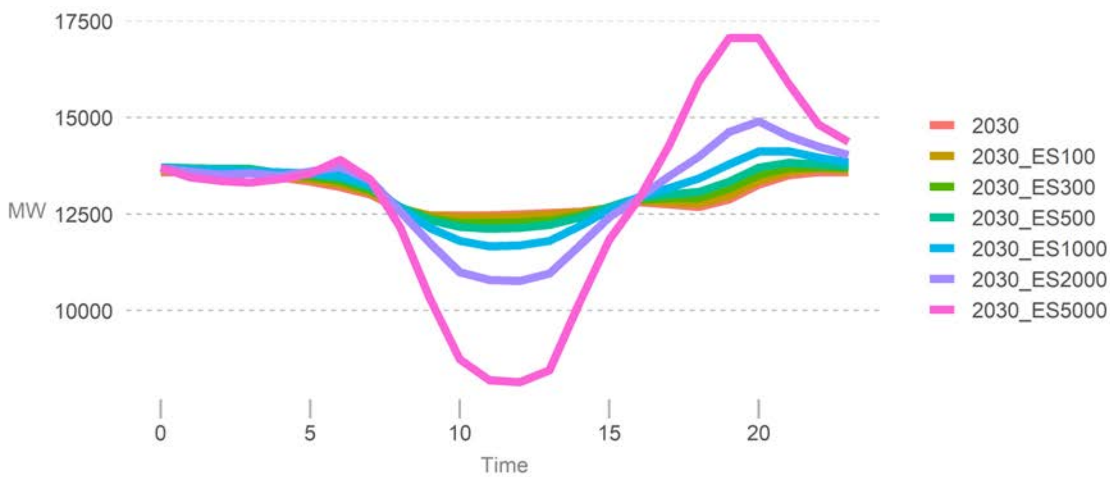

Figure 46. Average export pattern from Nepal to India in 2030 without energy storage additions (2030) and with incremental energy storage builds in Nepal (ES100 = 100 MW, ES200 = 200 MW, etc.)

We also studied the role of energy storage in providing operating reserves in Nepal.[18] Adding 500 MW of energy storage can provide 69% of total reserve requirements. Adding 100 MW of energy storage can provide 44% of total reserve requirements. The remainder of reserve requirements is fulfilled by reservoir-based storage hydro plants**.** This indicates that if energy storage with 4-hour duration is added to Nepal's power sector, it could increase reliability by contributing to operating reserves while having multiple value streams that it could access if the necessary regulations were in place.

[18] Though there are no existing regulations related to operating reserves in the country, we assumed 5% of load as the reserve requirement for this analysis.

4 Summary

We found that grid-scale energy storage plays an important role in the development of a cost-effective power sector for India and is a key enabler for cost-effective solar PV deployment and reduced air emissions from India's power sector in the long term. Additionally, energy storage has the potential to increase efficiency and lower the costs of operations for Bangladesh, Bhutan, and Nepal. The system growth scenarios analyzed in this study, summarized in Figure 47, helped identify factors that lead to higher or lower energy storage deployment in India.

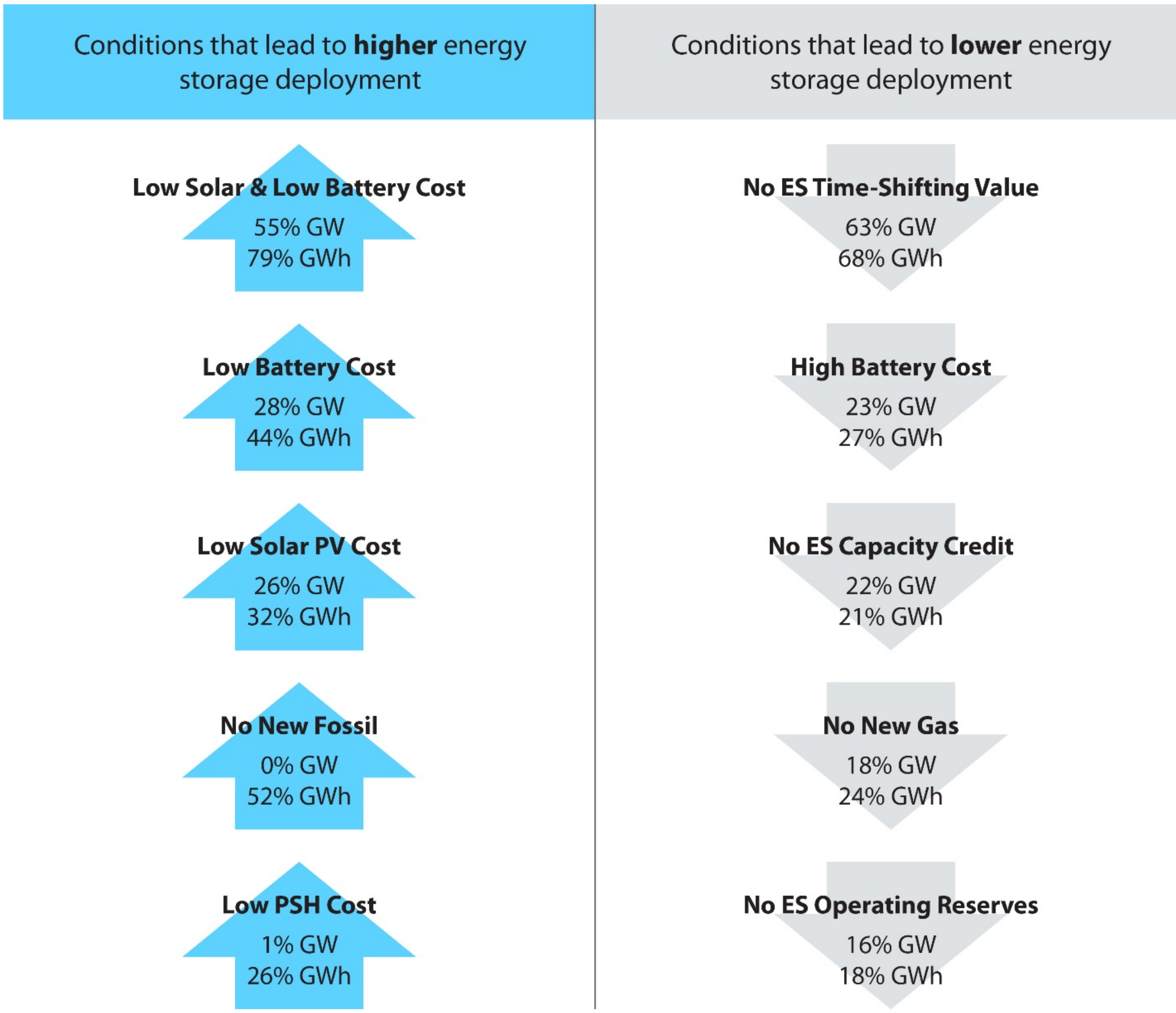

Figure 47. Conditions that lead to higher and lower energy storage deployment in India

No ES Time-shifting Value: Energy storage is not valued for shifting energy to different times of day; No ES Capacity Credit: energy storage is not valued for contributions to resource adequacy; No ES Operating Reserves: energy storage does not provide spinning reserves.

The results point to several trends that can inform regulations, policies, and market rules for energy storage in South Asia:

- Establishing a level playing field for energy storage to compete with conventional technologies can lead to increased RE deployment and reduced air emissions from the power sector. Modeling results showed that when energy storage can compete directly with conventional resources to provide various system services, more energy storage becomes cost-effective, which results in increased solar PV deployment and reduced generation from fossil-fueled resources. Leveling the playing field can include new ways to value the performance of generating resources to meet system needs, such as ramp rates, response time, and minimum generation level.
- Energy storage systems can achieve their full economic potential if they are able to provide and monetize multiple system services. In the South Asia context, this means that new regulatory proceedings at the national and state levels may be needed to enable energy storage projects to participate as a source of both load and generation and to provide multiple grid services. For utility-owned energy storage devices, where costs are recovered under a cost-of-service regulation, utilities and regulators can establish agreed-upon methods to quantify and compensate the full system value that energy storage provides to the power system.
- Access to cost-reflective energy markets, with daily price fluctuations, is a key revenue stream that can enable energy storage to be cost-competitive with conventional resources. Regulators can consider allowing energy storage to participate in the wholesale and real-time energy market. In the absence of markets, tariff structures that reflect system value, such as rewarding energy storage for discharging during high-value periods, can help storage devices monetize the energy time-shifting value they provide to the system.
- Energy storage can be a significant source of reliable capacity for India's power system. Valuing the capacity contribution of energy storage, through tariff design or other mechanisms such as capacity auctions or capacity payments, can enable cost-effective energy storage to compete with fossil-fueled capacity resources. Regulators can begin by establishing clear and agreed-upon methods to quantify and compensate all resources (including energy storage devices) for contribution to reliable capacity.
- Energy storage can help meet operating reserve requirements and therefore reduce commitments of thermal generators. However, providing operating reserves is a relatively small portion of the full value of energy storage for the power system. Regulators can help ensure market rules governing operating reserves and other ancillary services enable energy storage to provide multiple grid services from the same device. In India, for example, CERC has issued draft regulations that explicitly allow energy storage to participate in the proposed ancillary services markets (CERC 2021).
- There is a strong synergy between energy storage and solar PV deployment. Policymakers can include energy storage in national energy policies and master plans and acknowledge the complementarity between solar PV targets and increasing opportunities for energy storage technologies.

The results also point to significant opportunities for energy storage in Bangladesh, Bhutan, and Nepal. In Bangladesh, energy storage can substitute costly thermal generation used for energy and operating reserves. With each incremental addition of energy storage in Bangladesh, we saw reductions in the annual production cost, as well as lower costs for operating reserves. In Bhutan, energy storage can be used to shift hydropower generation from the middle of the day, when solar generation in India is highest, to evening hours when exports are most valuable. In Nepal, energy storage can help reduce hydro curtailment, help maximize energy exports to India, and provide operating reserves.

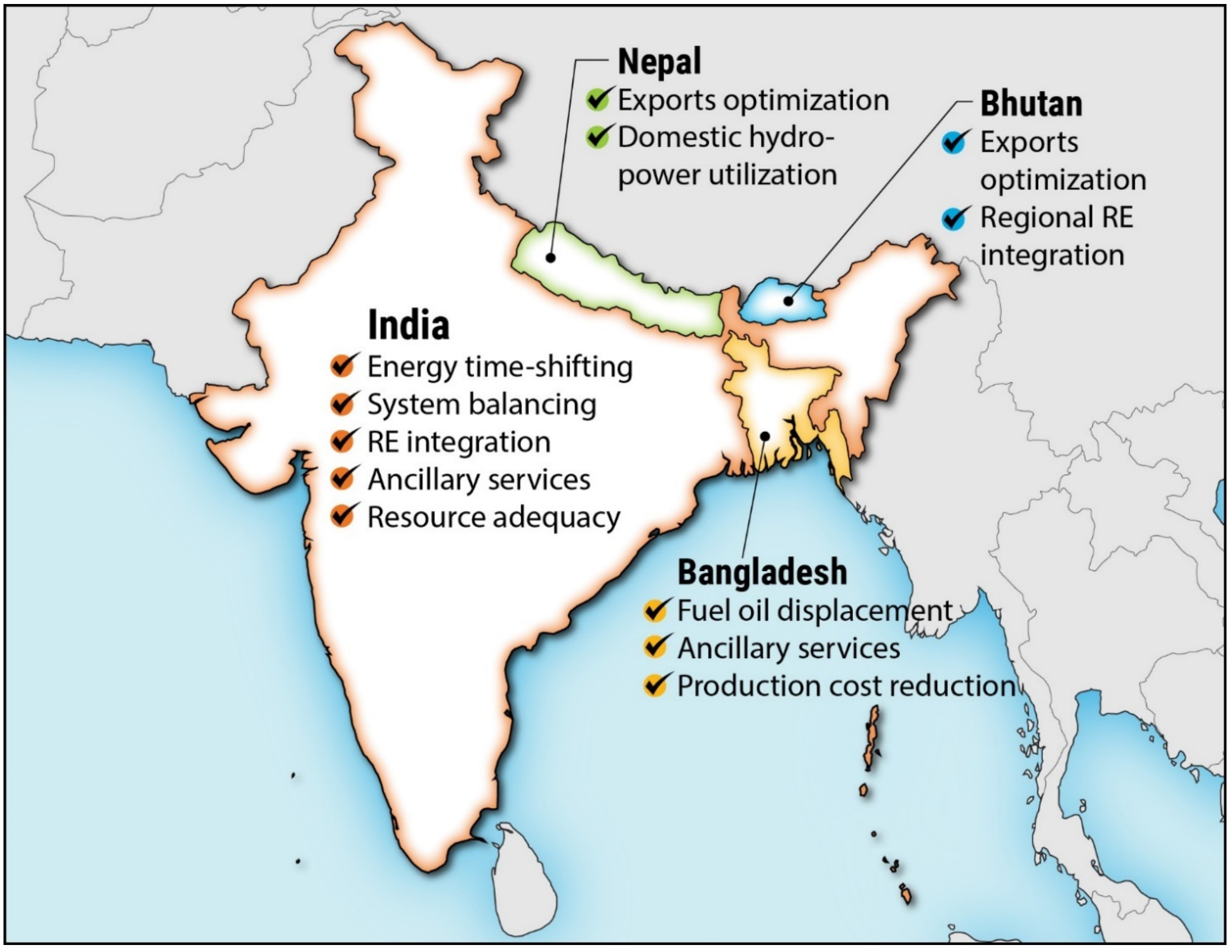

Figure 48. Summary of potential energy storage services in South Asia

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Appendix A. CEM Inputs

Model Regions

The model included three levels of spatial resolution: regions, balancing areas, and resource regions. Regions included the five operating regions of India, namely the Northern region, Northeastern region, Eastern region, Southern region, and Western region. Each region is composed of balancing areas representing states and union territories connected by the transmission network. We considered 34 total balancing areas. Finally, within each balancing area, there were multiple resource regions designed to capture differences in RE resources at a higher level of granularity. There were a total of 146 resource regions.

Electricity Demand Representation

Electricity demand in ReEDS is represented by a set of time slices that capture changes in seasonal and daily demand patterns, as well as interactions between demand and renewable generation.

The ReEDS-India model represents annual demand with 35 time slices. The time slices include five seasons (Winter, Spring, Summer, Rainy, and Autumn) with seven times of day per season (Night, Sunrise, Morning, Afternoon, Sunset, Evening, Peak). Figure A- 1 shows how the demand in each hour is allocated to a particular time slice.

<table>
<tr><th></th><th>January</th><th>February March</th><th>April May June</th><th>July August September</th><th>October November</th><th>December</th></tr>
<tr><th></th><th>Winter</th><th>Spring</th><th>Summer</th><th>Rainy</th><th>Autumn</th><th>Winter</th></tr>
<tr><td>1</td><td rowspan="5">Night</td><td rowspan="4">Night</td><td rowspan="3">Night</td><td rowspan="4">Night</td><td rowspan="4">Night</td><td rowspan="5">Night</td></tr>
<tr><td>2</td></tr>
<tr><td>3</td></tr>
<tr><td>4</td><td rowspan="3">Sunrise</td></tr>
<tr><td>5</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td></tr>
<tr><td>6</td><td rowspan="3">Sunrise</td><td rowspan="3">Sunrise</td></tr>
<tr><td>7</td><td rowspan="5">Morning</td></tr>
<tr><td>8</td><td rowspan="4">Morning</td><td rowspan="4">Morning</td><td rowspan="4">Morning</td></tr>
<tr><td>9</td><td rowspan="3">Morning</td><td rowspan="3">Morning</td></tr>
<tr><td>10</td></tr>
<tr><td>11</td></tr>
<tr><td>12</td><td rowspan="4">Afternoon</td><td rowspan="4">Afternoon</td><td rowspan="5">Afternoon</td><td rowspan="4">Afternoon</td><td rowspan="4">Afternoon</td><td rowspan="4">Afternoon</td></tr>
<tr><td>13</td></tr>
<tr><td>14</td></tr>
<tr><td>15</td></tr>
<tr><td>16</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td><td rowspan="3">Sunset</td></tr>
<tr><td>17</td><td rowspan="3">Sunset</td></tr>
<tr><td>18</td></tr>
<tr><td>19</td><td rowspan="4">Evening</td><td rowspan="4">Evening</td><td rowspan="4">Evening</td><td rowspan="4">Evening</td><td rowspan="4">Evening</td></tr>
<tr><td>20</td><td rowspan="3">Evening</td></tr>
<tr><td>21</td></tr>
<tr><td>22</td></tr>
<tr><td>23</td><td rowspan="2">Night</td><td rowspan="2">Night</td><td rowspan="2">Night</td><td rowspan="2">Night</td><td rowspan="2">Night</td><td rowspan="2">Night</td></tr>
<tr><td>24</td></tr>
</table>

Figure A- 1.Time Slices in the ReEDS-India Capacity Expansion Model

Sunrise and sunset periods were determined based on 2022 solar generation profiles developed by NREL. They represent the first and last 3 hours of the day when solar generation is available, respectively. Peak period time slices are not depicted in Figure A- 1 because the peak hours vary by state. Seasonal peak load in each state was based on the highest 40 demand hours.

After every hour of the year was allocated to one of the 35 time slices, the demand was calculated as the mean load from all hours assigned to that time slice. We used hourly state-wise load data from 2014 as the baseline for all demand calculations to align with the available weather data for 2014.

Generation Technologies

The generation fleet is represented by a number of different technology types, each with their own techno-economic parameters. Table A- 1 contains the generation technologies considered in the model.

Table A- 1. Generation Technologies Considered in the Model

Conventional	Renewable
Combined Cycle Gas Turbine	Distributed PV
Combustion Turbine Gas	Hydro pondage
Cogeneration Bagasse	Hydro ROR
Diesel	Hydro storage (reservoir)
Nuclear	Onshore wind
Subcritical Coal	Utility PV
Subcritical Lignite	
Subcritical Oil	
Supercritical Coal	
Waste Heat Recovery	

Input data for exogenously defined capacity include existing capacity, planned capacity additions, and planned retirements. These were sourced from the Greening the Grid database, CEA's National Electricity Plan, and consultations with CEA.

Operating Parameters

The operational inputs and assumptions were designed to capture the cost and performance characteristics of each technology type used to generate electricity. In some cases, these were assumed to remain constant across all balancing areas and model years while others were disaggregated based on location, technology type, or year. Unless otherwise stated, all inputs were taken from the Greening the Grid database.

Table A- 2 contains the input parameters assumed to remain constant for all model years and balancing areas.

Table A- 2. Input Parameters that Remain Constant Across Model Years and Balancing Areas

Technology	Ramping Limits (%/min)	Minimum Loading Fraction	Planned/ Unplanned Outage (%)	Co2 Emissions (ton/GJ)[19]
Combined Cycle Gas Turbine-Gas	3%	0.5	2.4/8.5	0.0486
Combined Cycle Gas Turbine Liquified Natural Gas	3%	0.5	2.4/8.5	0.065
Combined Cycle Gas Turbine-Naptha	3%	0.5	2.4/8.5	0.065
Cogeneration Bagasse	1%	0.5	2.4/8.5	-
Combustion Turbine-Gas	5%	0	4.1/4.3	0.0486
Diesel	2%	0.5	4.1/4.3	0.068
Distributed PV	NA	0	0/0	-
Hydro Pondage	10%	0	0/0	-
Hydro Pumped	10%	0.2	0/0	-
Hydro ROR	10%	0	0/0	-
Hydro Storage	10%	0	0/0.71	-
Nuclear	0.5%	1	2.3/8.3	-
Subcritical-Coal	1%	0.55	5.1/10	0.0892
Subcritical-Lignite	1%	0.55	5.1/10	0.0989
Subcritical-Oil	1%	0.55	5.1/24.7	0.0708
Supercritical-Coal	1%	0.55	5.1/8	0.0892
Utility PV	NA	0	0/0	-
Waste Heat Recovery	1%	0	5/8.5	-
Wind	NA	0	0/0	-
BESS	100%	0	0/0	-

Variable Costs (VCs)

The total VCs for generators in ReEDs are represented by the following equation:

[19] Based on fuel emissions factors in table in Appendix B pg. 31 of "CO2 Baseline Database for the Indian Power Sector --- User Guide" from CEA (http://cea.nic.in/reports/others/thermal/tpece/cdm_co2/user_guide_ver10.pdf).

$$VC = Heat\ rate \times Fuel\ cost + VOM$$

VOM is the variable O&M costs that do not include fuel costs, such as labor. The source for this data was the publicly available variable tariffs for central and state-owned generators as of early 2016, which was collected for the Greening the Grid study. The plants that did not have variable charges publicly available were assigned the average for the technology and state, or region if a state does not already have a certain plant type. Disaggregating the VC into the components of the equation above is required to be able to design scenarios with different fuel costs while maintaining plant-specific characteristics. The following sections focus on the source for these VC components and how plant-wise variability is maintained within these assumptions.

VC Representation

Maintaining a tractable optimization problem requires that individual plants be simplified into representative parameters. To achieve this, each balancing area, technology type, and year was assigned a specific VC based on the existing capacity. The VC parameter was defined separately for two types of capacity: (1) existing or planned capacity exogenously prescribed in the model, and (2) newly built capacity endogenously built by ReEDS. These costs were derived from the total VC as explained above.

For exogenously prescribed capacity, that which already exists or is known to be added based on the National Electricity Plan or Greening the Grid database, the model managed the number of variables and overall size of the model by clustering units in each balancing area into "performance bins" based on their VC. We stipulated that each bin must have at least 5 units and the minimum deviation in average VC between bins must exceed 200 ₹/MWh.

For new capacity endogenously built in ReEDS, VC varied by state based on capacity-weighted average costs. In cases where state-level data were not available (e.g., no plants of a certain type exist), VCs were based on regional or national averages. Table A- 3 contains the average VC assumed for each technology.

Table A- 3. Average Variable Cost by Technology

	Combined Cycle Gas Turbine-Gas	Combined Cycle Gas Turbine-Liquified Natural Gas	Cogeneration-Bagasse	Combustion Turbine-Gas	Nuclear	Supercritical-Coal	WHR
Average VC for new builds (₹/MWh)	3,932	6,065	4,869	8,020	2,498	2,473	3,770

Distributed PV, hydropower plants, utility PV, and wind plants were assumed to have no VCs. All VCs were assumed to remain constant over the model period.

Heat Rate

Plant heat rates are distinguished based on the type of technology and include some assumed efficiency improvements over time. Table A- 4 contains the heat rate and assumed efficiency improvements over time for all technologies.

Table A- 4. Heat Rate and Efficiency Improvement Over Time by Technology

Technology	2022 Heat Rate (GJ/MWh)[20]	Efficiency Improvement[21]
Combined Cycle Gas Turbine-Gas	7.22	0.2% annual improvement until 2030
Combined Cycle Gas Turbine-Liquified Natural Gas	7.22	0.2% annual improvement until 2030
Combined Cycle Gas Turbine-Naptha	7.22	0.2% annual improvement until 2030
Cogeneration Bagasse	12.3	None
Combustion Turbine-Gas	10.94	0.6% annual improvement until 2030
Diesel	11.48	None
Subcritical-Coal	11.12	None
Subcritical-Lignite	12.3	None
Subcritical-Oil	11.12	None
Supercritical-Coal	11.08	0.05% annual improvement until 2030

Fuel Cost

Fuel costs were broken into a variable component and a static component to allow for flexibility in modeling. The static component was determined by the fuel cost assumptions in the following table, which was roughly the cost of fuel in 2016.[22] The variable component captured the cost differences between plants by representing the total landed cost of fuel at a plant, which included costs for transportation, long-term contracts, quality of the fuel, and plant efficiency.

All fuel costs other than coal were assumed to remain constant over the model period.[23] Coal fuel cost has an additional annual escalation rate of 2%, in addition to the annual inflation rate. Note that nuclear plants were not assigned a fuel cost. All nuclear fuel cost is represented with its single variable tariff, as their operation is largely dictated outside of economic dispatch decisions.

[20] Value assumed for all plants commissioned in or before 2017. Source: CERC norms.
[21] Based on NREL 2018 ATB (https://atb.nrel.gov).
[22] Exact estimates of fuel costs are not required with this method if VCs at the plant level are captured.
[23] All calculations of future cost include a uniform inflation rate.

Table A- 5. Fuel Prices

Fuel	Price (₹/GJ)
Gas	200
Coal	50 (increasing 2% annually)
Oil	20
Diesel	400
Lignite	50
Naphtha	200
Bagasse	205[24]

Fuel Supply Limits

Fuel supply limits were imposed on gas technologies based on historic domestic and imported gas supplies. For 2017 and 2018, gas supplies were assumed to reflect current gas supply condition. For 2019–2024, the gas supply situation was assumed to gradually improve. The maximum available gas supply is reached in the year 2024, after which the gas fuel limit remains constant through 2047.

Table A- 6. Gas Fuel Supply Limits

Year	Gas Limit (MMSCMD)[25]	Gas Limit (GJ/yr)
2020	68.27	927,959,975
2021	86.32	1,173,304,600
2022	104.37	1,418,649,225
2023	122.42	1,663,993,850
2024	140.472	1,910,000,000
2025–2050	140.472	1,910,000,000

Capital Costs

Capital costs included all overnight costs to build a new power plant, excluding construction period financing. Unless otherwise stated, all capital costs assumptions were taken from CEA National Electricity Plan 2018 table “Assumptions for Estimating Capital Costs of Power Projects” (pg. 11.4).

[24] See CERC RE Tariff Order 2017-18 (http://www.cercind.gov.in/2017/orders/05.pdf). Estimate for bagasse costs in “all other states” is given as 1964.71 ₹/ton. A conversion factor of 9.6 GJ/ton is used to calculate a fuel cost of 204.647 ₹/GJ.

[25] MMSCMD = million metric standard cubic meters per day. Conversion for GJ/yr: MMSCMD * (365 days/yr) * (10^6 m^3/million m^3) * (1/26.853 GJ/m^3) = GJ/yr.

Table A- 7. Capital Costs

Technology	2020 capital cost (crore/MW)	Notes
Combustion Turbine-Gas	4	CEA (2016)[26]
Combined Cycle Gas Turbine-Gas	4.68	Use NREL ATB[27] assumption that CC units are 17% more expensive that CT units
Combined Cycle Gas Turbine-LNG	4.68	Assume same as Combined Cycle Gas Turbine-Gas
Combined Cycle Gas Turbine-Naphtha	4.68	Assume same as Combined Cycle Gas Turbine-Gas
Cogeneration-Bagasse	5.7	
Concentrated Solar Power	6.08	Based on CERC benchmark capital cost[28]
Diesel	4	NREL 2018 ATB value for CT-Gas
Distributed PV (rooftop)	11	Bloomberg New Energy Finance (2017)[29] value for commercial rooftop PV
Hydro - Pondage	10	
Hydro - Pumped	10	
Hydro - ROR	6.5	
Hydro – Storage	10	
Nuclear	10.2	
Subcritical Coal	6.5	
Subcritical Lignite	6.5	
Subcritical Oil	6.4	Assume same as Diesel
Supercritical Coal	7.9	
Solar PV (Utility)	5.5	
Waste Heat Recovery	5.7	Assume same as cogeneration-bagasse
Onshore Wind	6	NREL 2020 ATB.
BESS 2-hour	4.9	NREL 2020 ATB.
BESS 4-hour	8.5	NREL 2020 ATB.
BESS 6-hour	11.9	NREL 2020 ATB.
BESS 8-hour	15.4	NREL 2020 ATB.
BESS 10-hour	18.8	NREL 2020 ATB.

[26] CEA. Draft National Electricity Plan (Volume 1) Generation. December 2016. http://www.cea.nic.in/reports/committee/nep/nep_dec.pdf.

[27] NREL (National Renewable Energy Laboratory). 2018. 2018 Annual Technology Baseline. Golden, CO: National Renewable Energy Laboratory. http://www.nrel.gov/analysis/data_tech_baseline.html.

[28] Central Electricity Regulatory Commission (CERC). Petition No. 17/SM/2015: Determination of Benchmark Capital Cost Norm for Solar PV power projects and Solar Thermal power projects applicable during FY 2016-17. March 23, 2016.

[29] Bloomberg New Energy Finance (BNEF). "Accelerating India's Clean Energy Transition: The future of rooftop PV and other distributed energy systems in India." November 2017.

Changes in Capital Costs Over Time

For all technologies, both mature and emerging, there is a learning rate that results in changes in capital costs over time. We adopted the same learning rates used in NREL's 2020 ATB. Table A-8 presents the assumed cost reductions and underlying data sources used to derive these values. These changes in capital costs are separate from anticipated changes in labor and material costs, which are anticipated to increase in India over the planning period. This increase is captured by the inflation rate included in ReEDS financial assumptions.

Table A- 8. Change in Capital Cost Over Time

Technology	Annual Reduction in Capital Cost (%)	Source
Combustion Turbine-Gas	0.39	U. S. Energy Information Administration (EIA). 2018. Annual Energy Outlook 2018 with Projections to 2050. Washington, D.C: U.S. Department of Energy. February 6, 2018.
Combined Cycle Gas Turbine-Gas	0.37	Same source as Combustion Turbine-Gas
Combined Cycle Gas Turbine-Liquified Natural Gas	0.37	Assumed same as Combustion Turbine-Gas
Combined Cycle Gas Turbine-Naphtha	0.37	Assumed same as Combustion Turbine-Gas
Cogeneration-Bagasse	0.24	Same source as Combustion Turbine-Gas
Concentrated Solar Power	1.5	Feldman, David, Jack Hoskins, and Robert Margolis. 2017. Q2/Q3 2017 Solar Industry Update. U.S. Department of Energy. NREL/PR-6A42-70406. November 13, 2017. https://www.nrel.gov/docs/fy18osti/70406.pdf.
Diesel	0.39	Assumed same as Combustion Turbine-Gas
Distributed PV (rooftop)	4.0: 2017-2030 1.0: 2031-2040 0.5: 2041-2050	Same source as Concentrated Solar Power
Hydro - Pondage	0	DOE (U.S. Department of Energy). 2016. Hydropower Vision: A New Chapter for America's Renewable Electricity Source. Washington, D.C.: U.S. Department of Energy. DOE/GO-102016-4869. July 2016. https://energy.gov/sites/prod/files/2016/10/f33/Hydropower-Vision-10262016_0.pdf.
Hydro - Pumped	0.26	Same source as Hydro - Pondage
Hydro - ROR	0	Same source as Hydro - Pondage
Hydro – Storage	0.26	Same source as Hydro - Pondage
Nuclear	0.46	Same source as Combustion Turbine-Gas
Subcritical Coal	0.26	Same source as Combustion Turbine-Gas
Subcritical Lignite	0.26	Same source as Combustion Turbine-Gas
Subcritical Oil	0.39	Assumed same as Diesel
Supercritical Coal	0.26	Same source as Combustion Turbine-Gas
Solar PV (Utility)	6.8: 2017-2021 1.1: 2022 – 2050	Multiple sources. See NREL 2020 ATB.
Waste Heat Recovery	0.24	Assumed same as Cogeneration-Bagasse
Onshore Wind	0.82 in 2017 declining linearly to 0 in 2050	Wiser, Ryan, Karen Jenni, Joachim Seel, Erin Baker, Maureen Hand, Eric Lantz, and Aaron Smith. 2016. Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts. Berkeley, CA: Lawrence Berkeley National Laboratory. LBNL-1005717. June 2016. https://emp.lbl.gov/publications/forecasting-wind-energy-costs-and.
BESS	Cost reductions based on NREL 2020 ATB.	See NREL 2020 ATB.

Plant Lifetime

The plant lifetime is the maximum age of the plant. When a plant reaches the maximum age, it must be either retired or refurbished.

Table A- 9. Plant Lifetime

Technology	Plant Lifetime
Combustion Turbine-Gas	55
Combined Cycle Gas Turbine-Gas	55
Combined Cycle Gas Turbine-Liquified Natural Gas	55
Combined Cycle Gas Turbine-Naphtha	55
Cogeneration-Bagasse	45
Concentrated Solar Power	30
Diesel	55
Distributed PV (rooftop)	30
Hydro - Pondage	100
Hydro - Pumped	100
Hydro - ROR	100
Hydro – Storage	100
Nuclear	70
Subcritical Coal	25
Subcritical Lignite	25
Subcritical Oil	25
Supercritical Coal	25
Solar PV (Utility)	30
Waste Heat Recovery	45
Onshore Wind	24
BESS	15

First Year for Economic Builds

The first year for economic builds is the initial year when new capacity can be built based on economic criteria. Prior to the first year, only prescribed additions can be built by the model. All technologies begin economic builds in 2023.

Absolute Growth Limit

An absolute growth limit in MW is imposed on hydro, biomass, and waste heat recovery technologies. The state-wise limits were based on CEA National Electricity Plan 2018 Annexure-6.1 "State-Wise Details of Estimated Potential for Renewable Power in India" (pg. 6.24-6.25).

Weather Data

To estimate electricity output, we used spatio-temporal weather data to calculate electricity output of various PV and wind turbine systems across multiple years, if available. For this study, we used the National Solar Radiation Database (NSRDB) and India WIND Toolkit (WTK). The characteristics of these data sets are below:

Table A- 10. Characteristics of Weather Data

Data Set	Spatial Resolution	Temporal Resolution	Observation Period
NSRDB	10 km	Hourly	2000–2014
WTK	3 km	Hourly	2014

RE Generator System Configurations

PV System Configuration

There are two types of possible PV systems that have separate supply curves in ReEDs: utility-scale or distributed systems. Specific locations were assigned the appropriate supply curves based on geographic information (i.e., rural versus urban; see *Land Exclusions* below). The following table gives the configuration parameters for utility-scale PV.

Table A- 11. Solar PV System Configuration

Parameter	Value
System Capacity	1,100 kWdc
DC to AC Ratio	1.1
Losses	14 %
Inverter Efficiency	96 %
Array Type	Fixed open rack
Tilt	Tilt = latitude
Azimuth	180 degrees (South facing)
Model Type	Standard
Ground Cover Ratio	0.40

PV systems were assigned generation profiles based on the quality of the resource at a specific location. Each 10-km^2 grid cell is assigned a resource class based on the annual average irradiance for that location based off hourly 8,760 profiles from the NSRDB database.

Wind System Configuration

Wind turbine classes are designated for each location based on the annual average wind speed in the following table:

Table A- 12. Wind System Configurations

IEC Class	Annual or Multiyear Mean Wind Speed
Class I	> 9 m/s
Class II	> 8 m/s & <= 9 m/s
Class III	<= 8 m/s

Below are the system configurations for each class of turbine.

Table A- 13. System Configuration for Wind Turbine Classes

Parameter	Class I Turbine	Class II Turbine	Class III Turbine
Rated Output	2,000 kW	2,000 kW	2,000 kW
Hub Height	80 m	80 m	80 m
Rotor Diameter	77 m	82.5 m	100 m
Shear Coefficient	0.14	0.14	0.14
Total Losses	16.7 %	16.7 %	16.7 %

Power Density

To assign a maximum available installable capacity for PV and wind developments, we used a single value for PV and wind as the power density in MW/km^2, as denoted below:

Table A- 14. Power Density of Solar PV and Wind Technologies

Technology	Power Density (MW/km^2)
Utility-Scale PV	32
Wind	3

Land Exclusions

To model locations that are available for development, we used geospatial data that helped inform land characteristics, uses, and cover (Table A- 15).

Table A- 15. Land Exclusions

Technology	Utility-Scale PV	Distributed Utility-Scale PV	Wind
Slope Included (deg)	< 5%	n/a	< 20%
Urban	Exclude	Include	Exclude
Rural	Include	Exclude	Include
Protected Areas	Exclude	n/a	Exclude
Croplands	Exclude	n/a	Include
Forest	Exclude	n/a	Exclude
Grassland	Include	n/a	Include
Bare	Include	n/a	Include
Wetland	Exclude	n/a	Exclude
Water Bodies	Exclude	n/a	Exclude
Airports	Include	n/a	Exclude

Capacity Factors

The maps below show the resulting annual mean (wind) and multiyear mean (PV) capacity factors using the weather data and system configurations outlined above. These capacity factors are used for calculating the site levelized cost of electricity (LCOE), which contributes to the overall cost of a new system when added to the transmission LCOE.

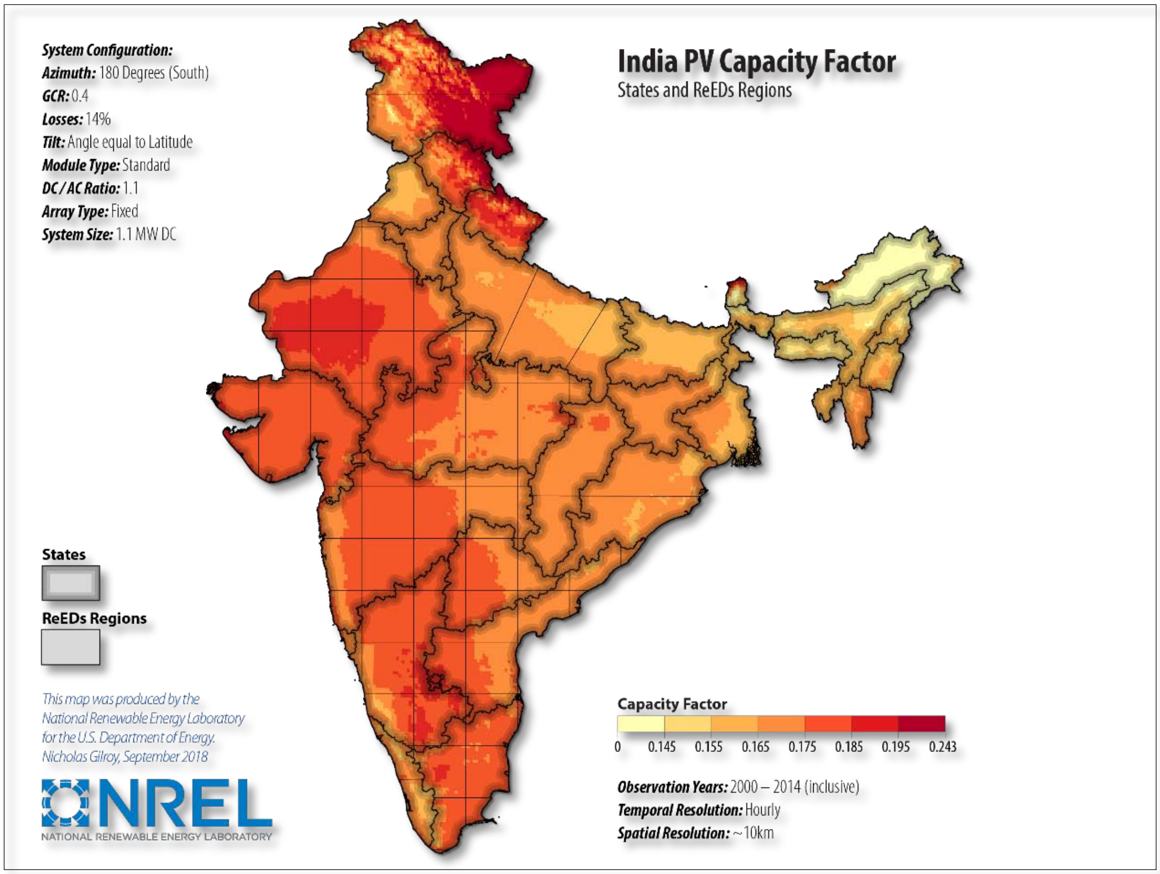


Figure A- 2. Map of Capacity Factors for Solar PV in India

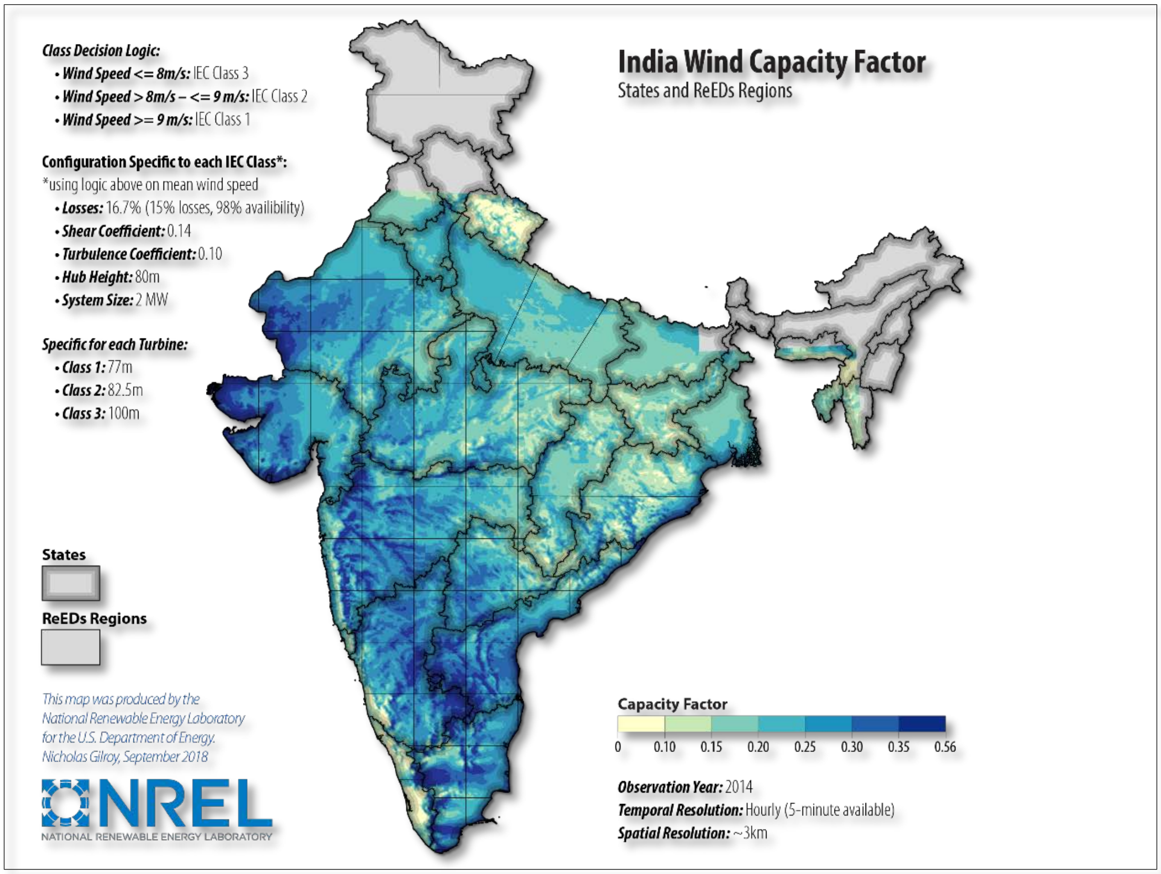


Figure A- 3. Map of Capacity Factors for Wind in India

ReEDs uses supply curves of wind and solar to characterize the potential sites available for development and directly evaluates the investments of these generation sources using the curves. These supply curves are estimated from detailed weather data, geospatial constraints, and economic assumptions.

Supply curve cost inputs are used to calculate site and transmission LCOE for new wind and PV developments. The components that comprise the LCOE are: capital costs, fixed operating costs, and grid integration costs (i.e., transmission), as well as other financing costs.[30] The following table gives the assumptions of the transmission line components of the LCOE:

Table A- 16. Transmission Spur Line Cost

Technology	Transmission line ($/MW-mile)
PV	423
Wind	423

[30] Based on Heimiller, Donna, Philipp Beiter, Nick Grue, Galen Maclaurin, and July Tran. 2018. South Asia Wind and Solar Supply Curves. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-71679. https://www.nrel.gov/docs/fy19osti/71679.pdf.

The capital cost represents an expense for a specific piece of equipment or installation service that applies in year zero of the cash flow. The fixed operating costs represent the cost of operating the plant over its lifetime. The transmission line cost is only added to the LCOE if current substation capacities are not sufficient for the new capacity.

Transmission

Existing Transmission Capacity

Transfer capacity between states was calculated based on Greening the Grid transmission capacity, which included all plans from PowerGrid out to 2022 (as of March 2016), separately for AC and DC lines.

Cost for New Transmission Investment

Transmission investment costs were based on the cost list provided by CEA (as of February 2017):

Table A- 17. Transmission Capital Costs

Line Type	Cost (Lakhs ₹/km)
765 KV	413
400 KV	124
220 KV	51

ReEDS-India uses both distance and energy capacity to assess the total capital cost of a transmission line. To convert ₹/km to ₹/MW/km, we estimated the state-wise total carrying capacity based on average line capacity for the highest voltage lines. The final ₹/MW/km values were obtained by dividing the costs in Table A- 17 by the average carrying capacity of the highest voltage lines in each state.

Table A- 18. Average Cost for New Transmission by Voltage Class

Line Type	Average Cost (₹/MW/km)
765 KV	18025
400 KV	21915
220 KV	23181

Total cost for new transmission investment between any two states was calculated as the average cost multiplied by the approximate distance between states. Distance between states was estimated using the largest population center of each state.

Substation Supply Curves

The substation supply curves are designed to capture the cost of stepping up the voltage within a balancing area to reach the voltage of the inter-balancing area transmission line within ReEDS. It is an attempt to estimate the costs of distributing the power from large, high-voltage, inter-balancing area lines that are built by ReEDS to the existing intra-balancing area infrastructure. For example, if ReEDS builds enough transmission between two balancing areas to require two 500-kV lines, the two lines can go to different 500-kV buses if they already exist at no extra cost. However, if only one 500-kV bus is available, the second 500-kV line may need to be split between two 345-kV stations, with the added cost of two transformers. If no voltage change is required and the carrying capacity of the transmission infrastructure is large enough to accommodate more energy flowing through the system, the cost to distribute the power will be assumed to be negligible.

In the case of adding generation within a balancing area, it is assumed that new renewables can use existing infrastructure to step-up the voltage to the high-voltage buses to get the power out. If there are not enough buses in an area to distribute/collect the power, the cost of purchasing new infrastructure to step up the voltage from the output of each generator to transmission level voltages will be added to the total transmission infrastructure cost.

The supply curves were created based on the following input data: (1) count of buses by voltage in each balancing area, (2) cost of transformers (₹/MW) at different voltage levels, and (3) estimate of how much new line capacity (MW) can be tied into a specific bus by voltage. All data for the number of buses by balancing area and the max voltage for inter-balancing area connections are based on the Greening the Grid database. After a review of Greening the Grid data and Volume II Transmission of the National Electricity Plan, we reduced the number of possible voltages to 765 kV, 400 kV, 220 kV, and 132 kV.

Table A- 19. Substation Cost and Carrying Capacity by Voltage Class

Voltage	Substation Cost (Lakh)	Carrying Capacity (MW)[31]	Notes
765 kV	1,500	2250	Substation cost per bay
400 kV	1,500	691	Substation cost for 2 bays
220 kV	440	132	Substation cost per bay

These two values, the substation cost and carrying capacity, were used to calculate the cost of new substations in ₹/MW. The final supply curve consists of a carrying capacity (MW) and marginal cost (₹/MW) for each voltage class by balancing area. The carrying capacity is calculated as the number of substations in each balancing area at a specified voltage times the carrying capacity for that voltage. The marginal cost to distribute power in each balancing area is equal to the cost to step up the voltage from each class to the voltage for inter-balancing area transmission lines.

Planning and Operating Reserves

The planning reserve margin requirement was based on 15% of peak demand by region in each year. The planning reserve must be held within each region, with trade allowed for reserve capacity between regions.

Operating reserves were held at 5% of total national demand in each time slice. The contribution of different technologies to the operating reserve requirement is limited by the ramping

[31] Based on POSOCO SIL data for transmission lines (Table 3) http://nerldc.org/Docs/DEC14/NER%20REACTIVE%20POWER%20MANAGEMENT%20MANUAL%202014.pdf

capability for the given technology. The assumptions for operation reserve costs and technology-specific contributions were based on U.S. ReEDS assumptions.

Table A- 20. Operating Reserve Parameters

Technology	Cost for Providing Operating Reserve (₹/MW)	Contribution of Capacity to Operating Reserve Capacity
Combined Cycle Gas Turbine-Gas	421.2	30%
Combined Cycle Gas Turbine-Liquified Natural Gas	421.2	30%
Combined Cycle Gas Turbine-Naphtha	421.2	30%
Combustion Turbine-Gas	280.8	30%
Diesel	280.8	20%
Hydro – Pumped	140.4	100%
Hydro – Storage	140.4	100%
Subcritical Coal	702	10%
Subcritical Lignite	702	10%
Subcritical Oil	280.8	10%
Supercritical Coal	1,053	10%

Generation Availability

Seasonal Capacity Factors for Hydro Technologies

To account for regional and seasonal changes in water availability for hydropower generation, ReEDS includes seasonal capacity factors by state for each type of hydro plant.[32] Using CEA's monthly generation data for over 350 hydropower plants during 2015–2016 and 2016–2017, we calculated average seasonal capacity factors for each plant in the report. Using the hydro plant database from Greening the Grid and other publicly available sources, we classified each plant as ROR, pondage, storage, or pumped.

The tables below contain the inputs used in the ReEDS-India for average hydropower capacity factors by season, state, and plant type.

Notes on capacity factor data:

- Seasonal capacity factors are only calculated for combinations of states and technology types where hydropower plants currently exist, are under construction, or could be built in the future.
- In cases where historic generation data for particular states were not available, we used regional averages for plants of the same type.

[32] As per CEA's recommendation, seasons are defined as follows: Winter: December-January, Spring: February-March, Summer: April-June, Rainy: July-September, Autumn: October-November.

- Given the potentially high variability in seasonal and interannual weather patterns, we would ideally consider more than 2 years of generation data but were limited by available data.

Table A- 21. Seasonal Capacity Factors for Storage Plants

State	Autumn	Rainy	Spring	Summer	Winter
Andhra Pradesh	0.11	0.12	0.19	0.08	0.14
Arunachal Pradesh	0.67	0.81	0.22	0.38	0.47
Assam	0.67	0.81	0.22	0.38	0.47
Chhattisgarh	0.37	0.44	0.03	0.14	0.03
Goa	0.27	0.32	0.18	0.17	0.17
Gujarat	0.18	0.31	0.12	0.13	0.04
Himachal Pradesh	0.15	0.38	0.14	0.24	0.13
Jammu Kashmir	0.29	0.41	0.24	0.20	0.30
Jharkhand	0.01	0.10	0.00	0.03	0.00
Karnataka	0.14	0.25	0.24	0.18	0.12
Kerala	0.28	0.41	0.32	0.38	0.24
Madhya Pradesh	0.30	0.31	0.24	0.13	0.32
Maharashtra	0.25	0.21	0.31	0.28	0.30
Manipur	0.94	0.94	0.28	0.43	0.70
Meghalaya	0.40	0.69	0.16	0.34	0.24
Mizoram	0.67	0.81	0.22	0.38	0.47
Nagaland	0.67	0.81	0.22	0.38	0.47
Odisha	0.21	0.37	0.17	0.23	0.11
Punjab	0.31	0.59	0.21	0.38	0.27
Rajasthan	0.38	0.26	0.37	0.01	0.47
Sikkim	0.00	0.00	0.08	0.00	0.00
Tamil Nadu	0.24	0.27	0.15	0.14	0.22
Telangana	0.16	0.10	0.08	0.00	0.07
Uttar Pradesh	0.39	0.34	0.20	0.08	0.36
Uttarakhand	0.24	0.50	0.30	0.30	0.29
West Bengal	0.67	0.96	0.22	0.43	0.31

Table A- 22. Seasonal Capacity Factors for ROR Plants

State	Autumn	Rainy	Spring	Summer	Winter
Arunachal Pradesh	0.42	0.76	0.10	0.40	0.14
Assam	0.58	0.73	0.14	0.39	0.23
Bihar	0.49	0.64	0.15	0.37	0.18
Chhattisgarh	0.25	0.35	0.16	0.14	0.19
Gujarat	0.14	0.33	0.07	0.03	0.10
Haryana	0.35	0.59	0.30	0.43	0.29
Himachal Pradesh	0.27	0.82	0.15	0.65	0.15
Jammu Kashmir	0.33	0.48	0.37	0.46	0.24
Jharkhand	0.49	0.64	0.15	0.37	0.18
Karnataka	0.31	0.35	0.12	0.17	0.17
Kerala	0.43	0.58	0.30	0.41	0.27
Madhya Pradesh	0.45	0.43	0.24	0.20	0.28
Maharashtra	0.17	0.28	0.18	0.18	0.19
Manipur	0.42	0.76	0.10	0.40	0.14
Meghalaya	0.26	0.78	0.06	0.41	0.05
Mizoram	0.42	0.76	0.10	0.40	0.14
Nagaland	0.42	0.76	0.10	0.40	0.14
Odisha	0.49	0.64	0.15	0.37	0.18
Punjab	0.56	0.69	0.57	0.48	0.57
Rajasthan	0.35	0.59	0.30	0.43	0.29
Sikkim	0.42	0.74	0.12	0.33	0.18
Tamil Nadu	0.22	0.17	0.13	0.13	0.13
Tripura	0.42	0.76	0.10	0.40	0.14
Uttar Pradesh	0.22	0.33	0.16	0.12	0.19
Uttarakhand	0.36	0.64	0.23	0.44	0.27
West Bengal	0.55	0.54	0.18	0.42	0.17

Table A- 23. Seasonal Capacity Factors for Pondage Plants

State	Autumn	Rainy	Spring	Summer	Winter
Andhra Pradesh	0.21	0.33	0.26	0.35	0.16
Arunachal Pradesh	0.23	0.60	0.12	0.28	0.11
Assam	0.58	0.85	0.21	0.56	0.24
Gujarat	0.41	0.43	0.33	0.16	0.44
Himachal Pradesh	0.22	0.68	0.15	0.49	0.12
Jammu Kashmir	0.33	0.66	0.39	0.66	0.21
Jharkhand	0.58	0.85	0.21	0.56	0.24
Karnataka	0.12	0.19	0.30	0.39	0.12
Kerala	0.30	0.47	0.22	0.30	0.20
Madhya Pradesh	0.40	0.39	0.26	0.19	0.35
Maharashtra	0.40	0.41	0.29	0.17	0.40
Meghalaya	0.58	0.85	0.21	0.56	0.24
Odisha	0.58	0.85	0.21	0.56	0.24
Punjab	0.29	0.83	0.27	0.67	0.17
Sikkim	0.69	0.93	0.28	0.63	0.32
Tamil Nadu	0.21	0.33	0.26	0.35	0.16
Telangana	0.21	0.33	0.26	0.35	0.16
Uttar Pradesh	0.36	0.74	0.17	0.54	0.23
Uttarakhand	0.24	0.62	0.15	0.41	0.15
West Bengal	0.46	0.76	0.15	0.49	0.16

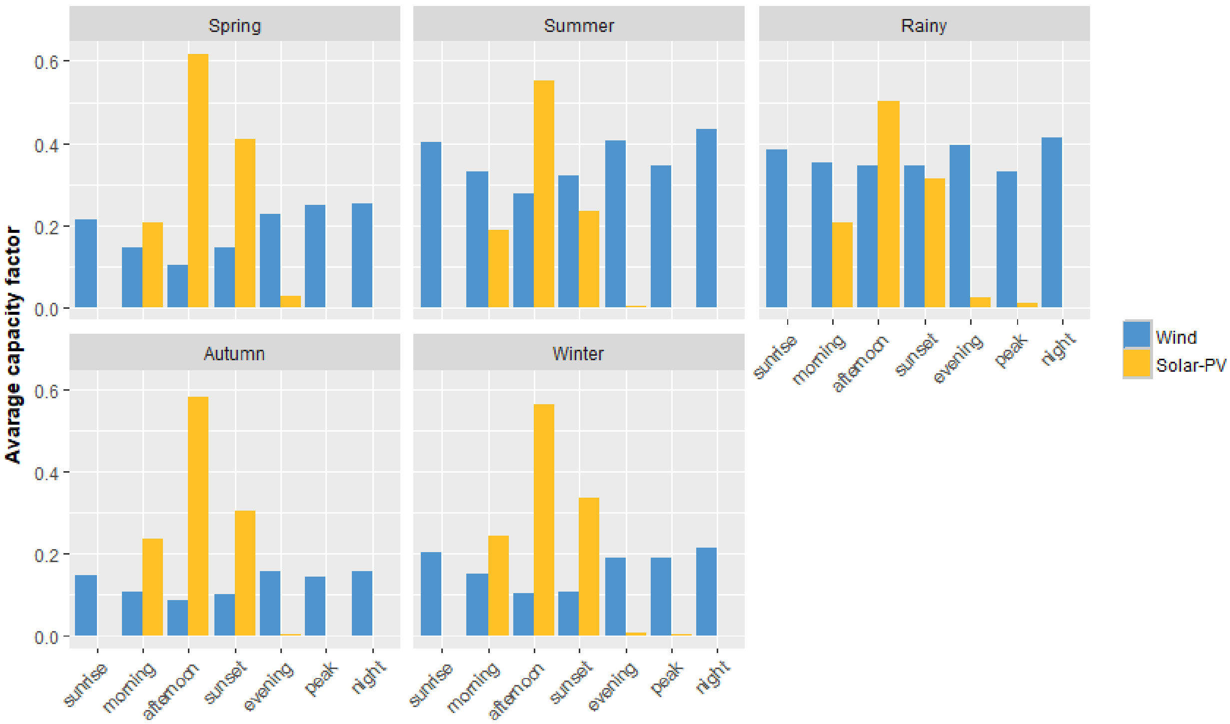
Table A- 24. Seasonal Capacity Factors for Pumped Storage Plants

State	Autumn	Rainy	Spring	Summer	Winter
Jharkhand	0.13	0.15	0.13	0.11	0.14
Karnataka	0.17	0.17	0.15	0.08	0.14
Kerala	0.17	0.17	0.15	0.08	0.14
Maharashtra	0.14	0.13	0.14	0.12	0.23
Odisha	0.13	0.15	0.13	0.11	0.14
Tamil Nadu	0.09	0.08	0.13	0.09	0.11
Telangana	0.04	0.05	0.04	0.01	0.04
West Bengal	0.13	0.15	0.13	0.11	0.14

RE Capacity Factor by Time Slice

Capacity factors for wind and solar technologies were estimated for each time slice based on the resource data for each resource region. The figures below show the average for each season and time slice; however, each resource region has a unique capacity factor when input to the model.

Table A- 25. National Average Capacity Factors for RE Technologies, by Season and Time Slice



Financial

Construction Schedule

The construction schedule is the percentage of the plant that is completed in each year of construction. The schedules were based on the CEA National Electricity Plan 2018 Annexure 11.2 "Assumptions For Estimating Capital Cost Of Power Projects" (pg. 11.5).

Table A- 26. Construction Schedules

Technology type	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Total
Coal	10%	10%	20%	30%	30%					100%
Hydro (pumped, storage)	20%	25%	25%	20%	10%					100%
Solar PV (Utility)	80%	20%								100%
Wind	60%	40%								100%
Biomass; Hydro (pondage, ROR)	30%	40%	30%							100%
Nuclear	3%	1%	4%	5%	10%	15%	21%	26%	15%	100%
Gas	40%	50%	10%							

For technologies not given in the CEA table, the following assumptions were used:

- Distributed PV (rooftop) and BESS: 1 year construction schedule
- Diesel and Subcritical-Oil: same construction schedule as gas technologies
- Waste Heat Recovery: same construction schedule as biomass
- Concentrated Solar Power: same construction schedule as solar PV (utility)

- Subcritical-Lignite: same construction schedule as coal.

Financial Parameters

Table A- 27. Financial Parameters

Financial Parameter	Value	Notes
Real Discount Rate	9%	CEA 2018 National Electricity Plan Table 5.6
Nominal Interest Rate	11.5%	CEA 2018 National Electricity Plan Table 5.6
Federal Tax Rate	34.6%	Based on corporate tax rate for 2015-2018 (https://tradingeconomics.com/india/corporate-tax-rate)
Inflation Rate	4.5%	Based on average inflation rate for 2015-2018 (https://tradingeconomics.com/india/inflation-cpi)
Debt Coverage Ratio	1.4	Based on U.S. ReEDS assumption
Initial Debt Fraction	70%	CEA 2018 National Electricity Plan Table 5.6
Financial Lifetime	Same as plant lifetime	Except for hydro technologies, which are given 100 year financial lifetime. This is based on the assumption used in U.S. ReEDS.
Depreciation Schedule	12 years for all technologies	CEA 2018 National Electricity Plan Table 5.6
Finance Period	Coal and nuclear: 20 years Pumped hydro: 30 years All other technologies: 15 years	Based on U.S. ReEDS assumptions

Appendix B. PCM Inputs

The PCMs developed by NREL in previous studies formed the basis of this study (D. Palchak et al. 2017; McBennett et al. 2019; Joshi, Hurlbut, and Palchak 2020). The assumptions remained the same for the base network in 2022, and the PCM is developed for future years based on publicly available data and certain assumptions discussed later. The assumptions regarding load projections and generation buildouts for all South Asian countries (including India) has been discussed in Sections 3.3 and 3.4, respectively. Considering the various uncertainties associated with commissioning of any new power plant, we have considered the new generators available from the next year of its expected commissioning year. This may lead to some differences between the generation capacity numbers mentioned in the various master plans of each country and the numbers considered in this study. Standard technical parameters have been used for future interconnections between South Asian countries based on the proposed conductor type wherever available The other assumptions used for building this PCM are given below.

ReEDS to PLEXOS and India PCM

We translated the output of ReEDs-India to PLEXOS for doing production cost analysis. While ReEDS-India outputs a continuous value of capacity, for most resources (excluding solar and wind), PLEXOS requires generators to be discrete units. The attributes for future buildouts (such as generator size, forced outage rate, mean time to repair, minimum stable level, VO&M charges, fuel charges, and transport charge) were assigned average value by state or region when possible and assigned country-wide historical average when state/regional data was unavailable or nonexistent. For transmission buildouts, we identified the largest existing transmission lines between states and replicated these lines when constructing new capacity for a given corridor. ReEDs-India also provided cumulative capacity by state/fuel/class for each year. We retired generators by construction date.

Load

Bhutan: The monthly average load shape for Bhutan was assumed similar to 2019 based on quarterly reports of Bhutan Power System Operator.

Bangladesh: The load shape for Bangladesh was assumed similar to 2018–2019.

Load: The load shape for Nepal was assumed based on our previous study ((McBennett et al. 2019).

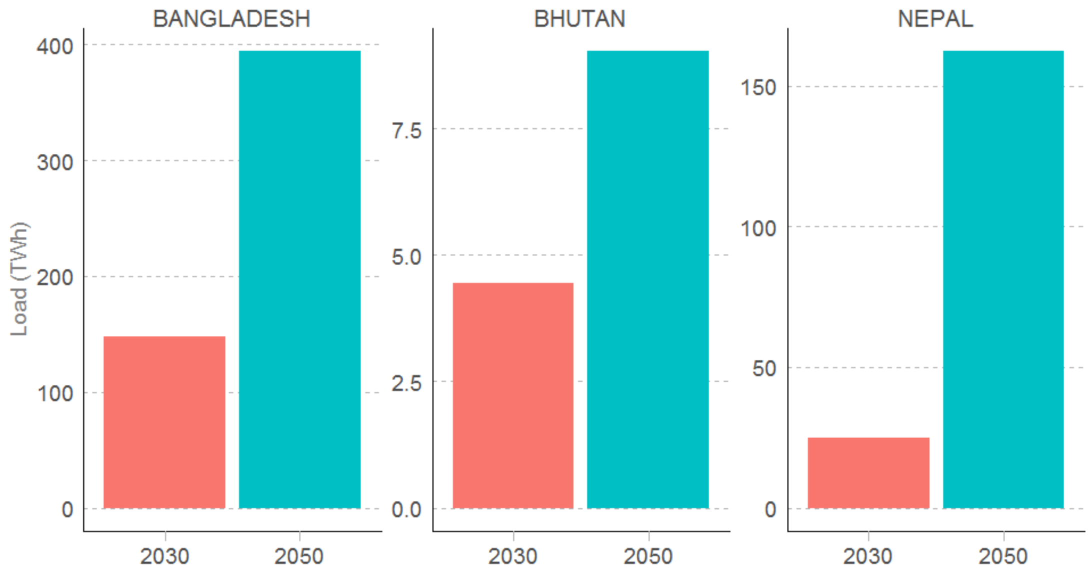


Figure B- 1. Electricity Demand in Bangladesh, Bhutan, and Nepal

Generation

Bhutan: We modeled all the existing generators of Bhutan and added future buildouts (transmission and generation) based on the transmission master plan of Bhutan. The technical attributes such as ramp rate, minimum stable level, etc., for existing and future generators have been assumed based on the similar generators from India. Because all of the existing generators are ROR type and there is no indication of any storage type generator in future plans, we have assumed future buildouts to be ROR type as well. All the generators are modeled with daily energy limits, minimum generation level, and maximum possible generation based on monthly average numbers provided in the 2019 quarterly reports published by Bhutan Power System Operator. For future generators, energy, minimum and maximum generation limits were assumed similar to the nearby existing generator in the same river basin. In the absence of any nearby existing generator, the average of whole Bhutan was assumed for that generator.

Bangladesh: The technical attributes (such as forced outage rate, mean time to repair, minimum stable level, ramp rate, etc.) of existing and future generators were based on the average of similar existing plants in India. Future buildouts were based on the power system master plan of Bangladesh. The variable charges of existing generators were assumed based on the annual report of Bangladesh Power Development Board for 2018–19. Considering the availability of domestic gas and share of imported gas in future, we used the following cost projections:

Table B- 1. Natural Gas Price Assumptions

Year	Simulated Price of Domestic Natural Gas ($/MMBTU)	Simulated Blended Price of Domestic Natural Gas and Imported Liquified Natural Gas, Assuming That Liquified Natural Gas Offsets Decreases in Domestic Production
2020	$1.43	$1.93
2021	$1.43	$1.93
2022	$1.43	$1.93
2023	$1.46	$2.06
2024	$2.03	$3.71
2025	$2.22	$4.12
2026	$2.43	$4.51
2027	$2.55	$4.73
2028	$2.82	$5.14
2029	$2.93	$5.28
2030	$3.01	$5.38
2031	$3.12	$5.51
2032	$3.18	$5.57
2033	$3.37	$5.77
2034	$3.41	$5.81
2035	$3.87	$6.16
2036	$3.92	$6.19
2037	$4.18	$6.33
2038	$4.29	$6.38
2039	$4.45	$6.44
2040	$4.45	$6.44

Source: Projections done by David Hurlbut, NREL

Variable charges of coal/diesel/fuel oil-based generators for the future were assumed based on the power system master plan of Bangladesh.

Nepal: The future projected generation capacity was assumed based on Nepal's Ministry of Energy's white paper and the transmission system development plan of Nepal. The total storage-based hydro capacity for 2040 was calculated based on individual proposed plants mentioned in the transmission system development plan of Nepal. All other hydro capacity was assumed to be ROR type. A linear growth was assumed for ROR and storage-based hydro based on existing and 2040 projected capacity, duly considering the total capacity projections.

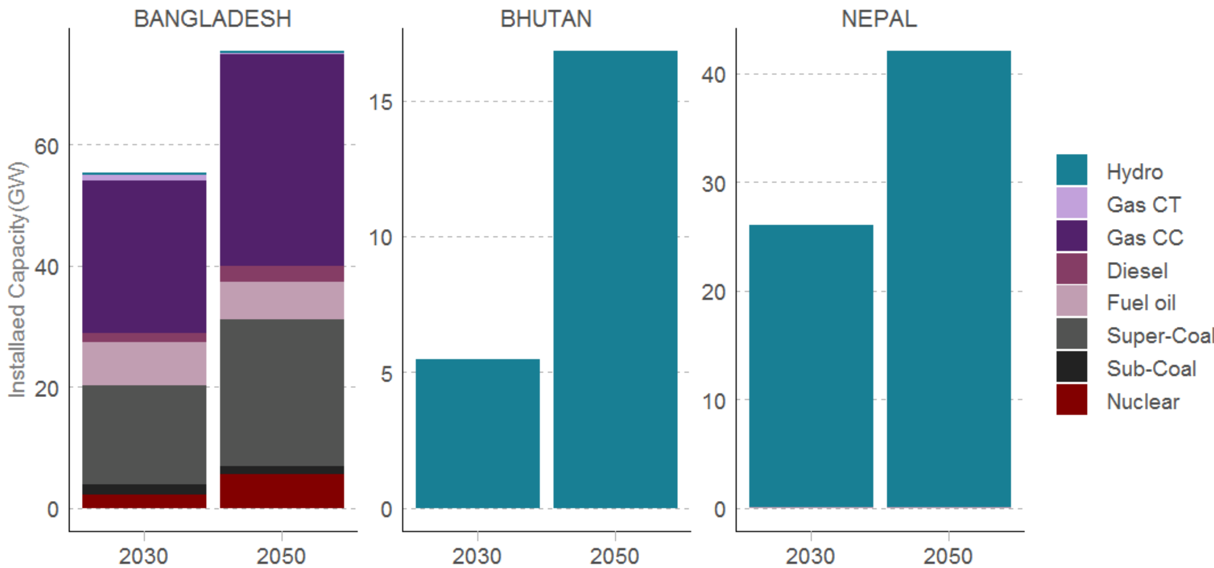


Figure B- 2. Installed Capacity in Bangladesh, Bhutan, and Nepal

Transmission

We have added the future interconnections between the South Asian countries based on various official plans mentioned in Section 3.4. The interconnection capacity between the South Asian countries in 2030 and 2050 scenario is given below:

Table B- 2. Transmission Capacity Between South Asian Countries

	2030	2050
India-Bhutan	6.6 GW	12.9 GW
India-Nepal	8.2 GW	14.7 GW
India-Bangladesh	3.5 GW	11 GW