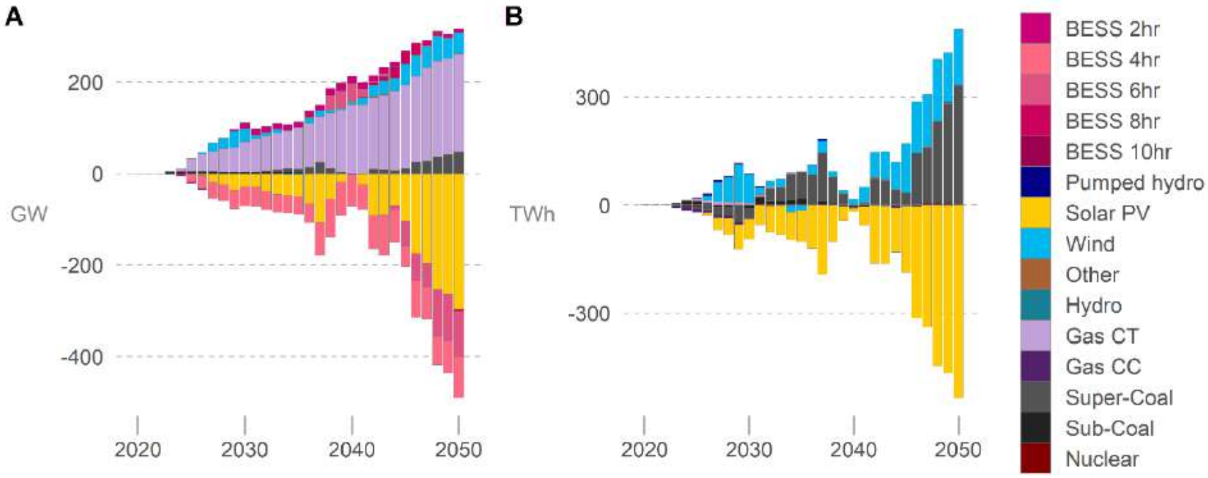

Figure 32. Difference in capacity (A) and generation (B) in the No ES Capacity Credit scenario relative to Reference Case

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.

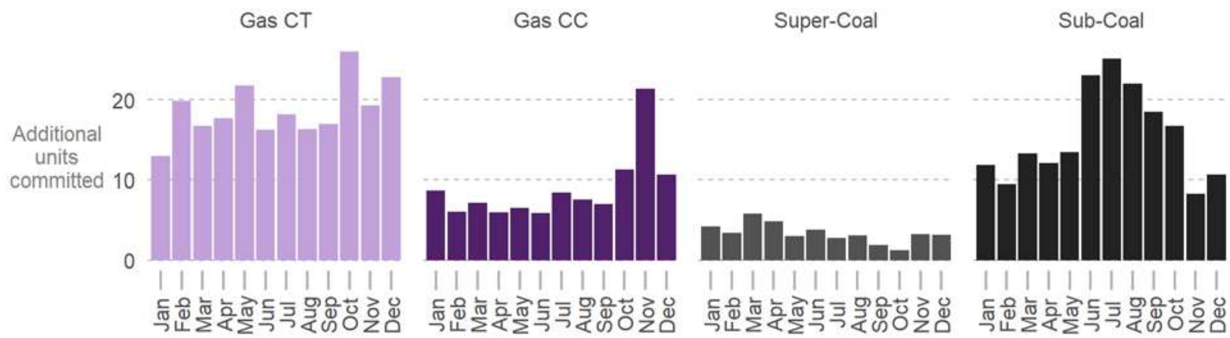

Figure 33. Difference in the average number of units committed when energy storage does not provide operating reserves

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.

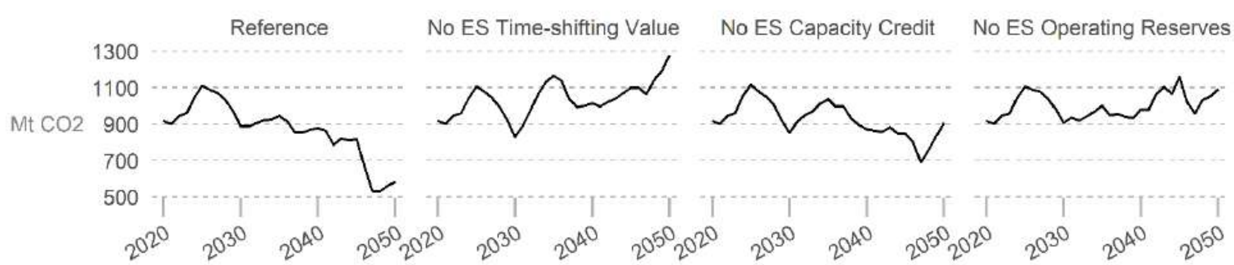

Figure 34. CO2 emissions from the power sector in the Reference Case and regulatory scenarios

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.

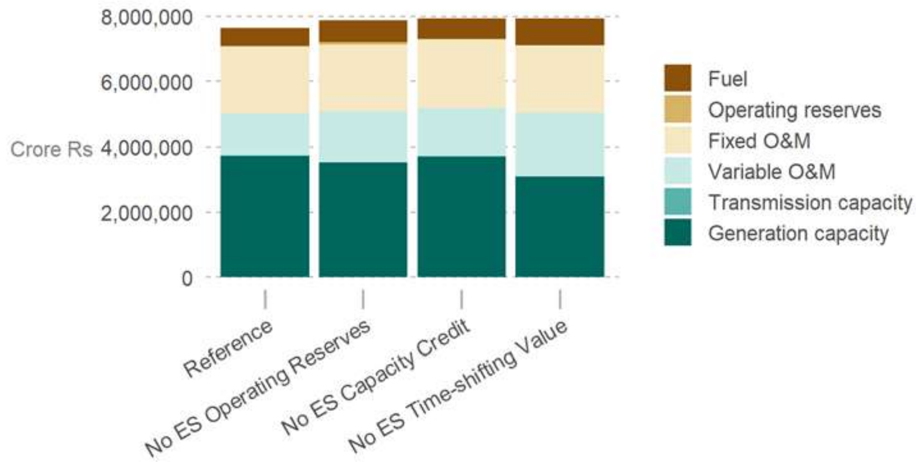

Figure 35. System costs in Reference Case and energy storage regulatory scenarios, 2020–2050

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.

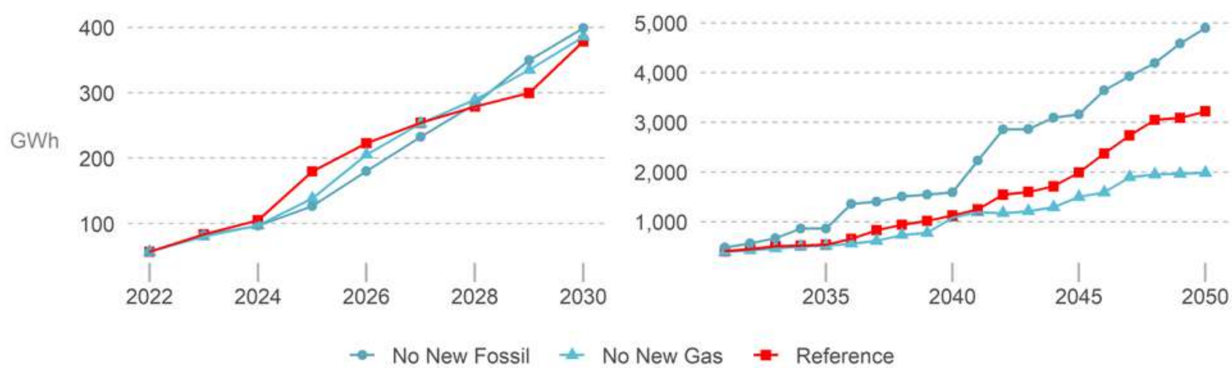

Figure 36. Energy storage capacity in Reference Case and fossil fuel policy scenarios through 2030 (left) and 2050 (right)

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.

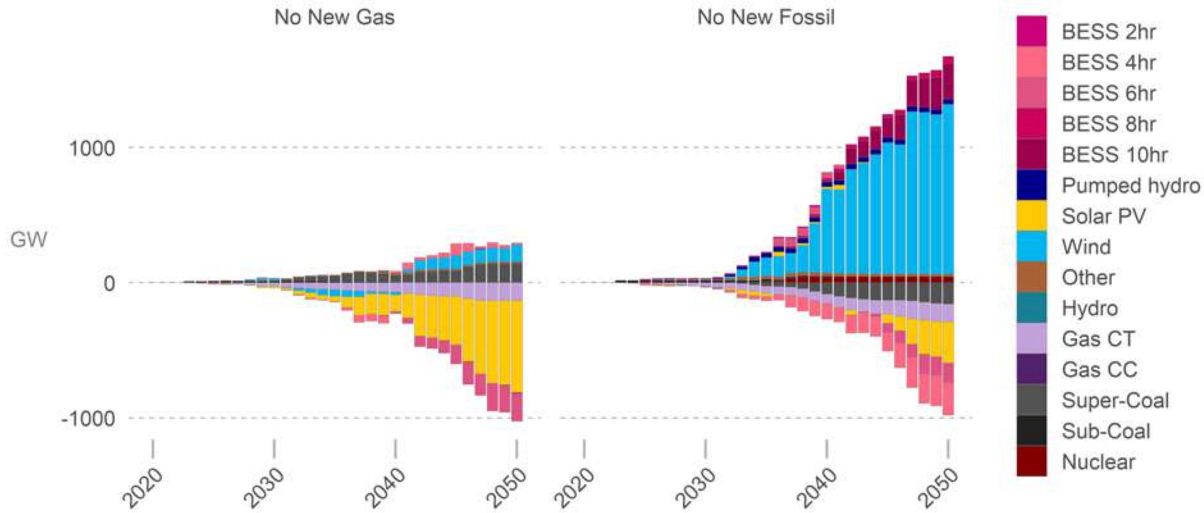

Figure 37. Capacity difference in fossil fuel policy scenarios compared to the Reference Case

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.

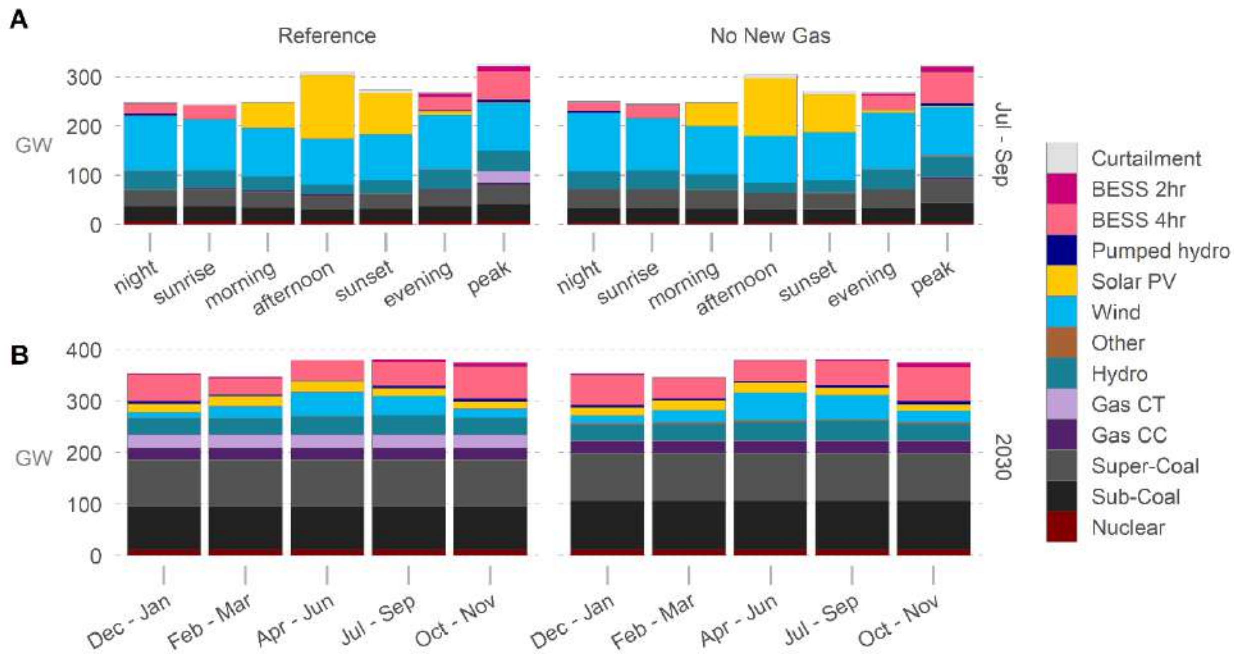

Figure 38. Average generation dispatch for one season (A) and firm capacity by season (B) in 2030 in the Reference Case and No New Gas scenario

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.

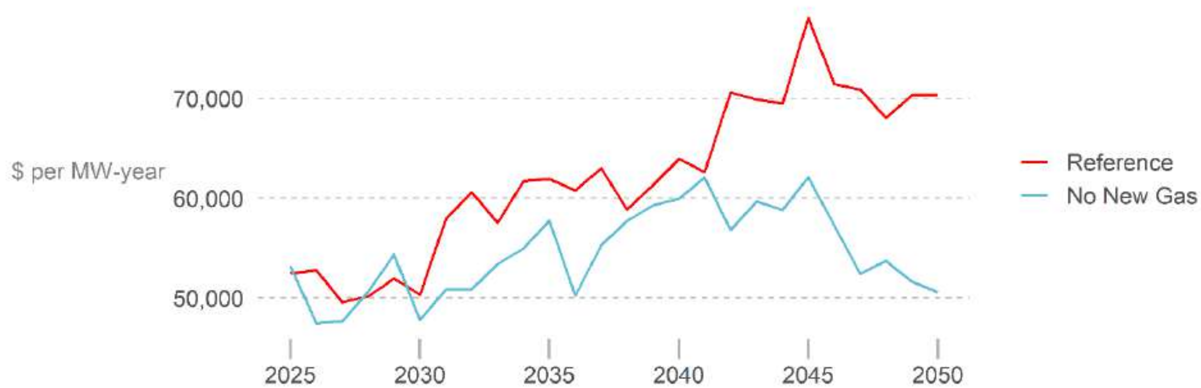

Figure 39. Average energy time-shifting value of energy storage in Reference Case and No New Gas scenario

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.

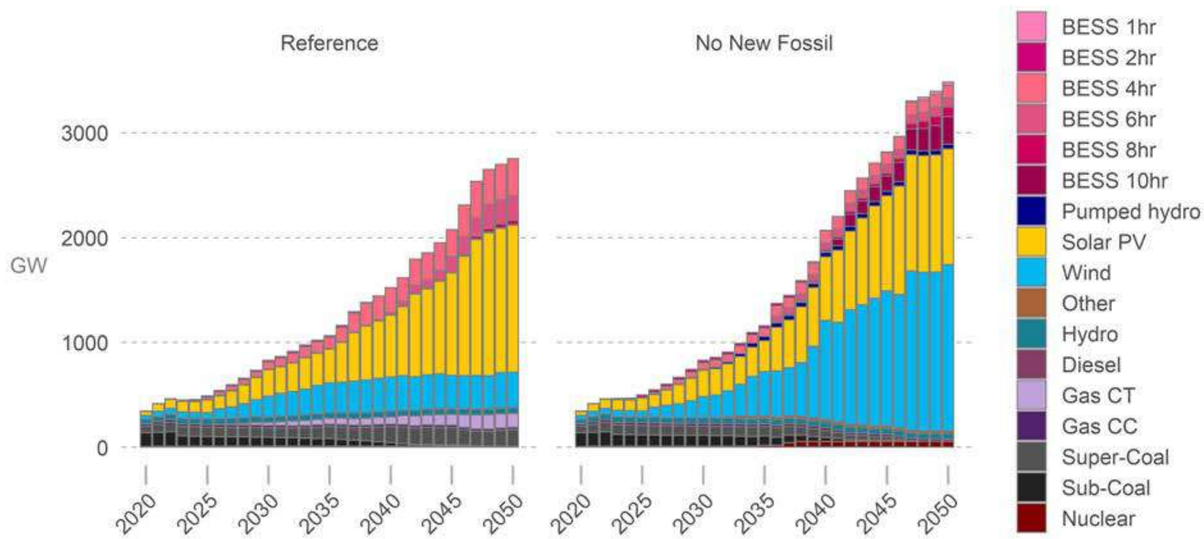

Figure 40. Installed capacity in the Reference Case and No New Fossil scenarios

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.

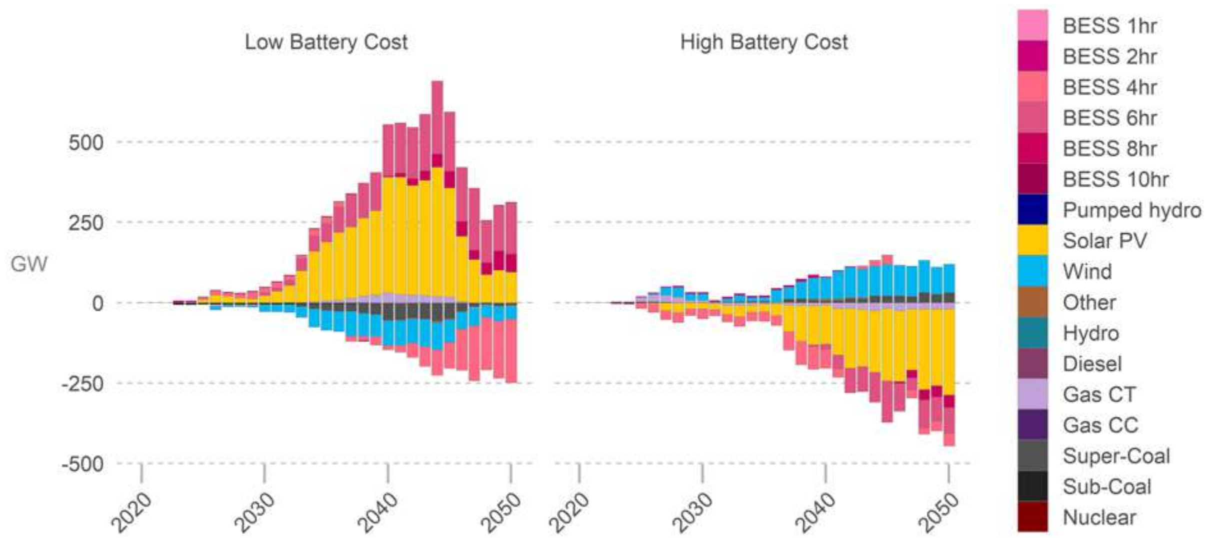

Figure 41. Capacity difference in battery cost scenarios compared to the Reference Case

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).

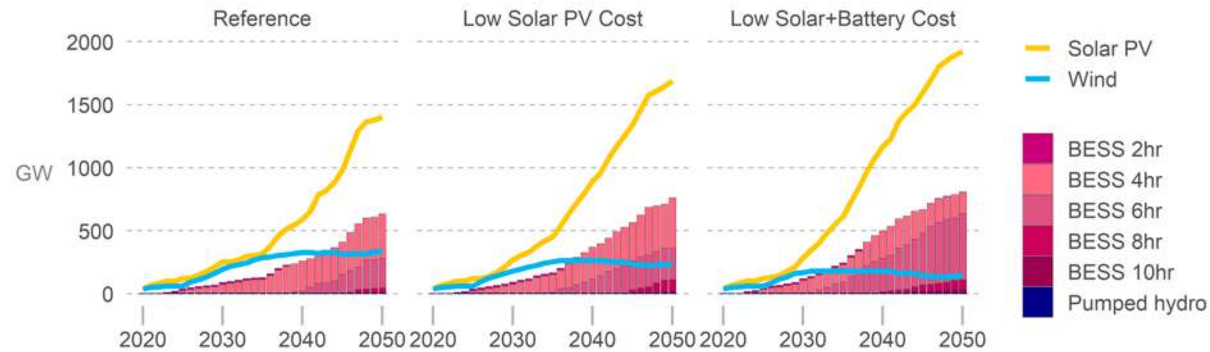

Figure 42. Energy storage, solar PV, and wind capacity in solar cost scenarios

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.