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Developing a roadmap to a flexible, low-carbon Indian electricity system: interim findings

Udetanshu
Brendan Pierpont
Saarthak Khurana
David Nelson

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A CPI interim paper

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Insights contained in this paper represent CPI Energy Finance's interim findings based on demand and supply scenarios published in parallel by TERI in reports, Analysing and Projecting Indian Electricity Demand to 2030 and Exploring Electricity Capacity Scenarios to 2030: Scenario Framework. We will publish a full report later in the year.

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Descriptors

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Region	India
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Contact	Udetanshu Udetanshu@cpilondon.org
	Felicity Carus felicity.carus@cpilondon.org

About CPI

Climate Policy Initiative works to improve the most important energy and land use policies around the world, with a particular focus on finance. An independent organization supported in part by a grant from the Open Society Foundations, CPI works in places that provide the most potential for policy impact including Brazil, China, Europe, India, Indonesia, and the United States. Our work helps nations grow while addressing increasingly scarce resources and climate risk. This is a complex challenge in which policy plays a crucial role.

CPI's Energy Finance practice is a multidisciplinary team of economists, analysts and financial and energy industry professionals focused on developing innovative finance and market solutions that accelerate the energy transition.

India flexibility: interim report

India can successfully integrate 390GW of wind and solar generation by 2030, an increase of more than 40% above the current renewable energy trajectory, at a total system cost that is lower than that of the current trajectory. By making both electricity supply and electricity demand more flexible, India can achieve these higher levels of clean energy, creating a modern, low cost energy system, while reducing carbon emissions. Working with the Energy Transitions Commission India (ETC India), Climate Policy Initiative (CPI) has found that ample technology and system concepts exist to create the flexibility required to build and operate a reliable, low cost, low carbon system, but implemention is among the biggest challenges facing energy transition in India. Increasing flexibility needs can be met cost effectively using a combination of investment, incentives and technologies that:

1. Change how and when consumers use energy,
2. Increase the flexibility of power generation, and
3. Encourage development of new energy storage options.

India must address several flexibility needs, each of which will grow under any scenario

Modern electricity systems must balance electricity demand and supply at every instant, and at every location, to avoid outages and damaging swings in voltage and frequency. Adding supplies whose output depends on gusting wind levels, or fades as the sun sets, increases the difficulty of making this continuous match. In India, this addition of wind and solar power only adds to a problem that was already growing as the share of increased household demand relative to more constant and predictable industrial demand. To make a continuous match of supply and demand, system operators must:

- **Reserve** some powerplant capacity to replace energy lost if a powerplant or transmission line suddenly fails, or to meet an unexpected surge in demand.
- **Ramp** (increase) output fast enough to meet expected sharp increases in demand, such as when the sun sets and consumers turn their lights on at once.
- **Balance daily** demand and supply over the course of each day, for example, balancing lower demand in the middle of the night against higher solar energy production in the middle of a sunny day.

Figure 1: Growth in key flexibility needs

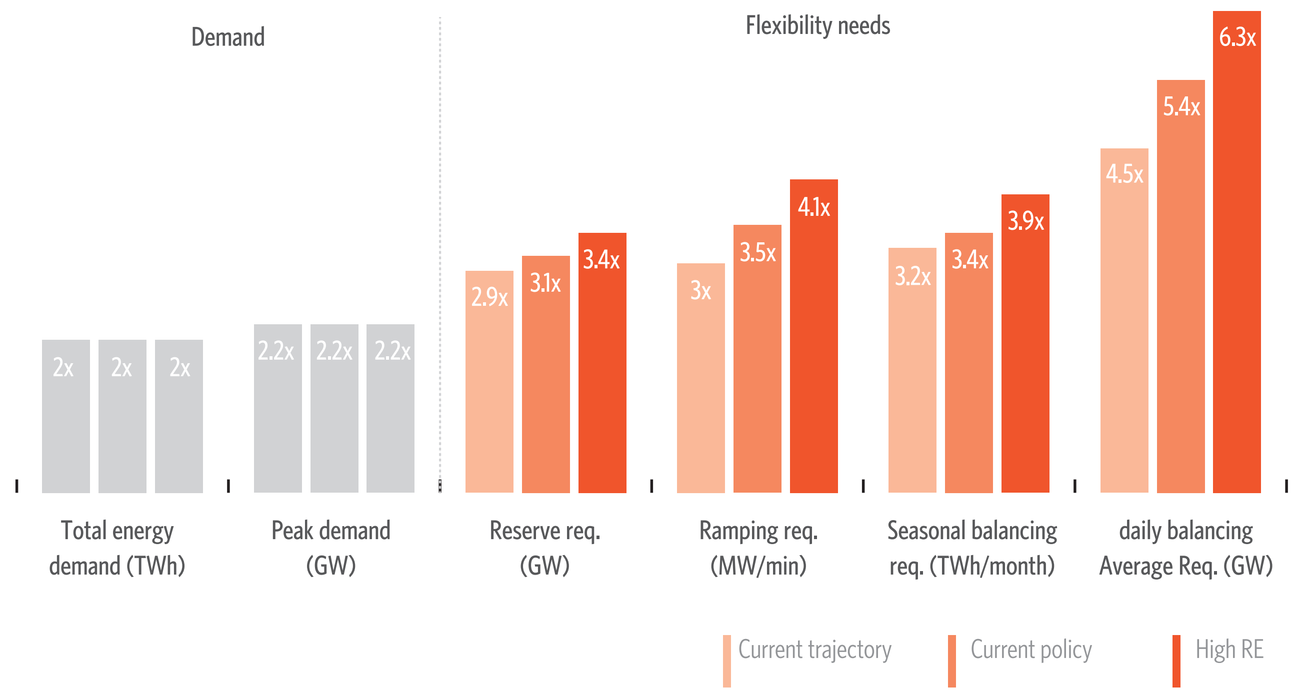
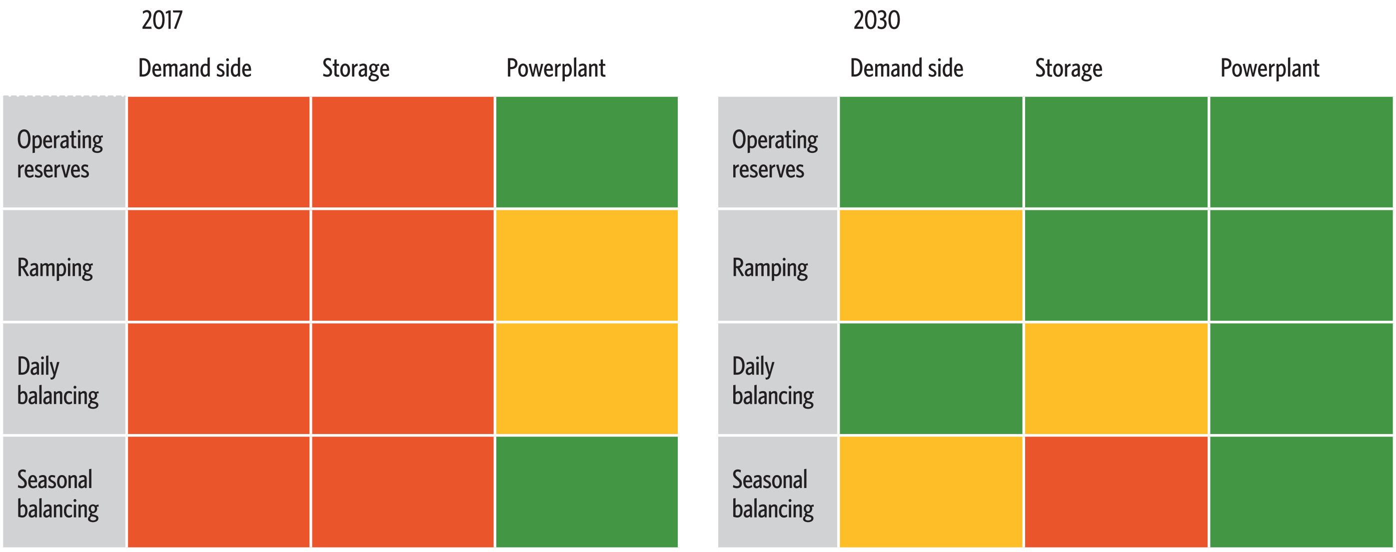


Figure 2: Readiness of flexibility option to **deliver flexibility**



- **Balance seasonal** supply and demand to meet annual cycles, for instance, when cold winters or hot summers drive up electricity demand, or rainy, sunny or windy days drive up energy supply.

While there are many variations of each of these flexibility needs, we have used these four main categories to summarise our analysis of flexibility needs and supplies. As shown in figure 1 on the preceeding page, the combination of changing demand and added renewable energy supply will increase flexibility needs far faster than either energy demand or peak demand.

In the Figure 1 above, the three bars for each of the flexibility needs represent the three scenarios we use in the analysis: a current trajectory scenario based on forecasts of future renewable energy deployment following current trends[1]; a current policy scenario where India meets the government's current renewable energy targets; and a high renewable energy scenario that follows ETC India's high RE scenario. Flexibility needs increase significantly in all three scenarios, indicating that improving system flexibility should be a priority, regardless of the level of India's clean energy ambitions.

India will need to develop new types of flexibility to meet growing needs

Historically, India has relied on thermal and hydro powerplants to balance supply with demand, turning these plants up or down in response to varying demand. When flexibility demands were too high for the powerplants to cover, power quality dipped and outages were forced across the system. In recent years, India has reduced unplanned outages through load shedding, where system operators have planned reduced service and curtailments to groups of customers in order to improve power quality. Responding to planned service interruptions is also less costly to consumers than unexpected interruptions.

Meanwhile, consumers have assumed that supply would adapt to their consumption patterns. Even though small changes in their consumption patterns could significantly reduce total system costs, consumers have been given little or no information on how to shift their demand nor have incentives to vary their demand to meet supply. Powerplants, for their part, have options that would significantly increase the amount of flexibility they can offer to the system, but they also lack incentives to cover capital costs and higher operating costs of providing this flexibility, even though the lower system costs would more than make up for their higher costs. Meanwhile, the cost of energy storage, including batteries, is falling rapidly, while the capability is increasing.

1 Exploring Electricity Supply Mix Scenarios to 2030: Scenario Framework (TERI). Current trajectory includes 274GW of wind and solar generation capacity, plus 68GW of hydro capacity by 2030, while current policy reflects current targets of 322GW for solar and wind based generation along with 83GW of hydro capacity, and the High RE scenario includes 390GW of solar and wind generation capacity and 81GW hydro capacity.

Figure 2 shows that, although the systems and incentives are not in place today to offer the various types of flexibility to the system, by 2030 each of the three general sources of flexibility will contribute most to flexibility needs, if these resources are developed over the coming years.

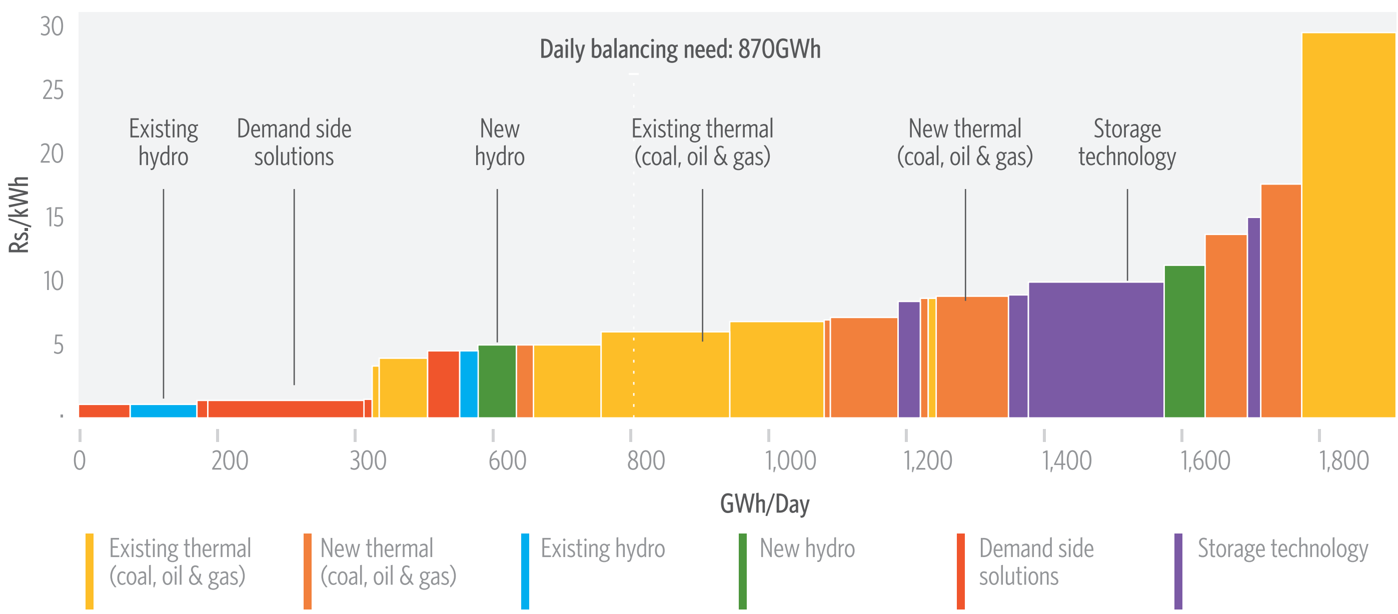
All three of these flexibility options need to be pursued for India. Developing all three enables the lowest total system cost and offers backup to the system in case one or another of them develops less slowly than forecast. Integrating these options to achieve the lowest cost and most reliable supply is an important task both in balancing the development effort between the options, and in developing systems that incentivize and dispatch these resources.

Integrating these flexibility options is the key to keeping costs low

To assess this balance and estimate the cost of integrating higher levels of renewable energy on the system, CPI has developed a series of supply curves for each of the four flexibility needs, and some important variations of each type of flexibility. These supply curves are based upon a series of models where CPI has estimated the cost, including capital and financing costs, operating and fuel costs, not factored in, and energy losses (each where applicable). This cost, when allocated to the kWh shifted over the course of the day, is represented by the height of the bar in figure 3 below. The width of the bar represents our estimate of the potential that could be available in India by 2030 and is based on conservative estimates of ownership of equipment and the share of that equipment that could be made available for offering the service. Figure 3 shows an example of an average day of daily shifting. Note how demand measures and existing hydro provide the cheapest means of meeting this particular need, but existing powerplants will be required, including some increase in flexibility of existing plant. If demand side management and new hydro are not developed successfully, newer powerplants and batteries might be needed.

Another perspective would be to look at how generation profiles and renewable energy curtailment[2] affect the dispatch of powerplant across a day, week or year. Figure 4 on the following page shows output from our model of how the mix of flexibility options affects powerplant operation and curtailment. The dark line near the top shows demand across a week. Note how in the left hand of figure 4, where demand flexibility and storage are included, thermal powerplants operate much more steadily, which increases their efficiency. On the right, without demand flexibility and new storage, powerplants are more strained and more energy – the energy above the lines - is curtailed. Our analysis shows that the mixed portfolio has 82% to 97% less energy wasted, 5% to 8% lower total system costs, and 8% to 12% lower total carbon emissions.

Figure 3: 2030 supply and demand for daily balancing (on an average day for 6 hours of energy shift)



[2] Renewable energy curtailment occurs when constraints prevent the powerplants from backing down enough to absorb all renewable energy production. In such cases the excess energy and its economic value is discarded.

Figure 4: Demand flexibility and storage allow thermal plant to operate more efficiently

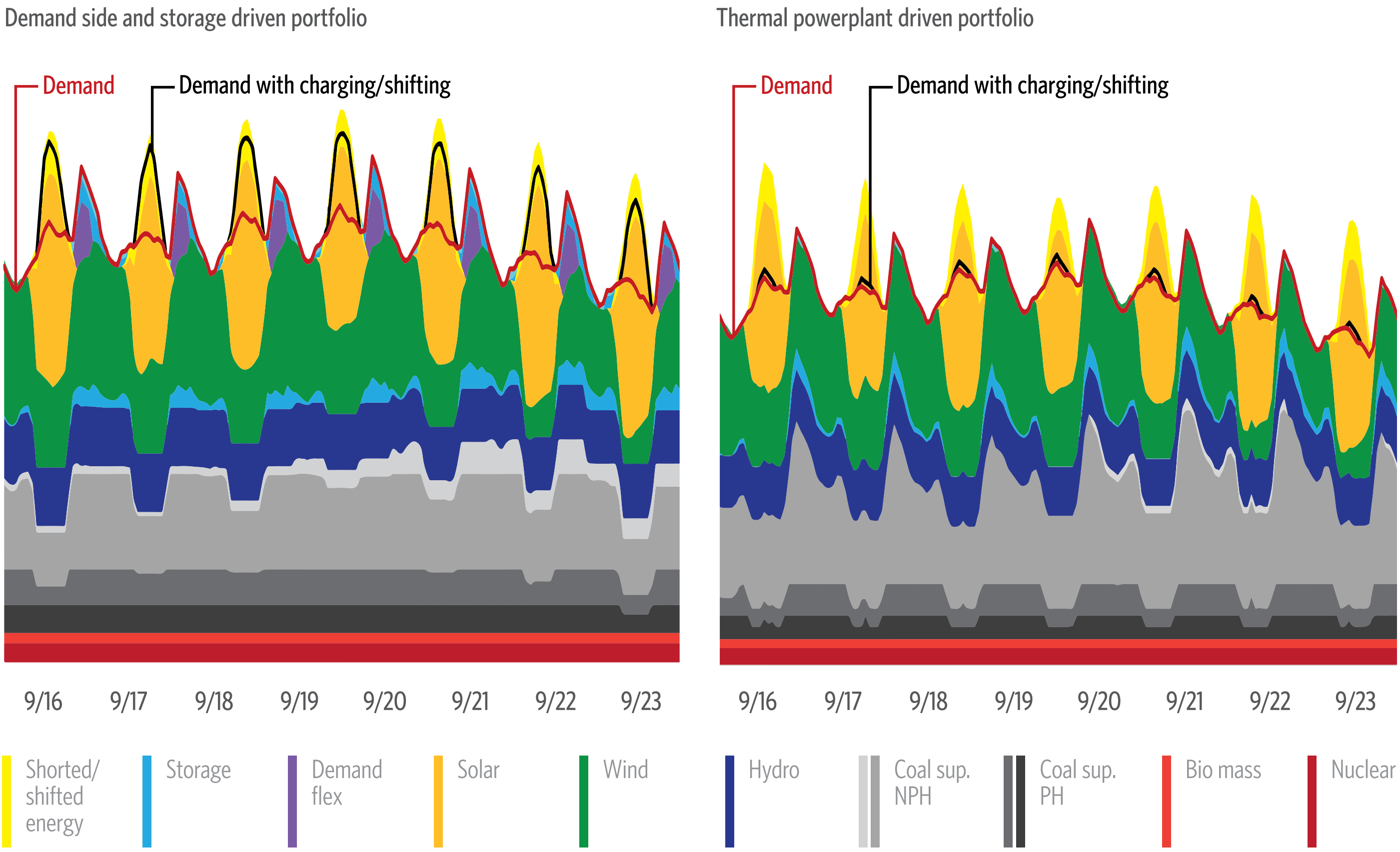
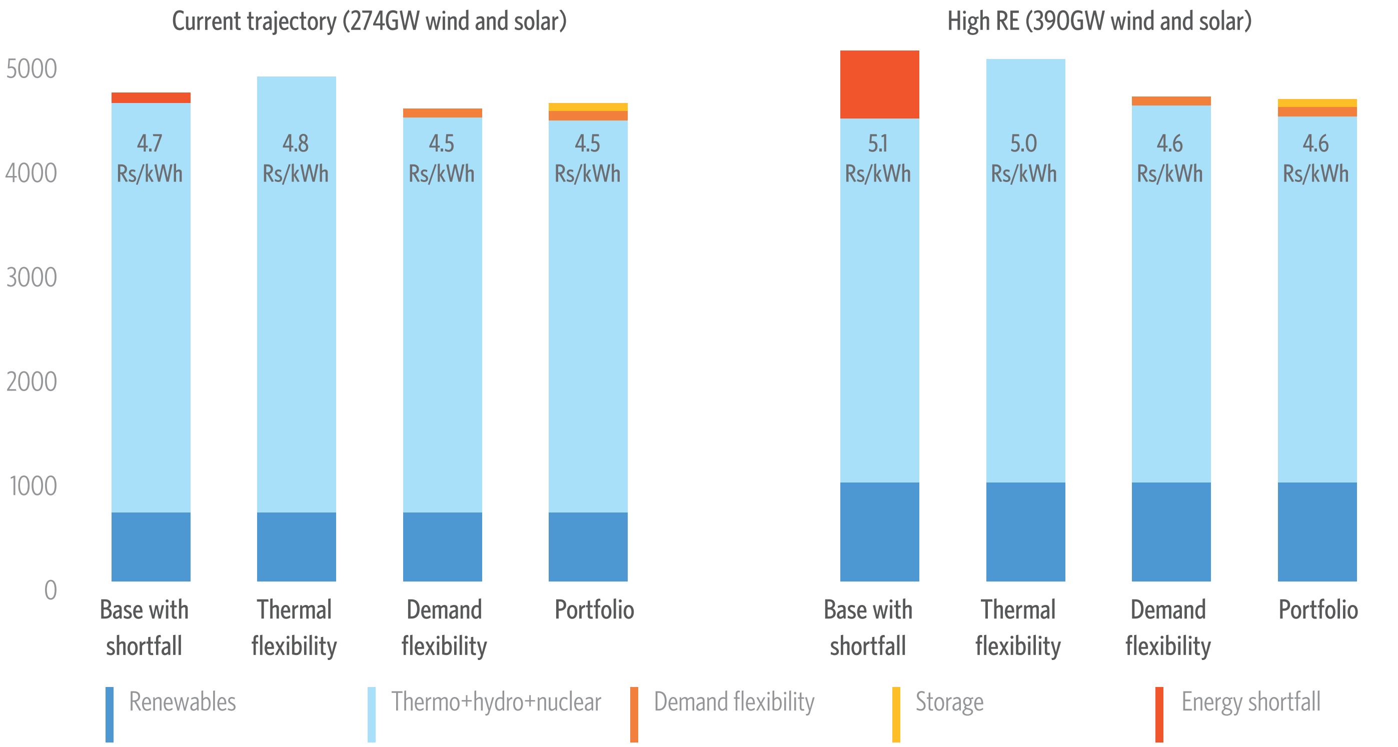


Figure 5: System cost including flexibility



A mixed portfolio of flexibility sources is the lowest cost option

Figure 5 on the previous page shows further detail on the cost simulation runs for the complete system, including a breakdown of renewable energy costs (both capital and operating costs), powerplant costs, the costs of demand flexibility and storage, and, in red, the cost of energy shortfalls that would be met by diesel generation. For both the current trajectory and the high RE scenarios, we have modelled average total system costs (in today's money), for different portfolios of flexibility options.

- The base option includes flexibility as it is used today.
- The thermal flexibility meets flexibility through powerplant dispatch, including investments to increase the flexibility of existing powerplants.
- The demand portfolio relies primarily on demand flexibility, but uses existing thermal flexibility to balance the overall system.
- The portfolio approach uses the lowest cost mix of all three options, including storage.

The average system cost for the High RE case is below the current trajectory costs with either the base flexibility, or the enhanced powerplant flexibility. Also, added demand flexibility and storage reduce costs, even at relatively modest renewable energy ambitions. Finally, note that base levels of flexibility lead to energy outages in either scenario, even though enough energy is produced in these scenarios to meet demand.

The needs and challenges will be different in different regions across India

The analysis in figures 4 and 5 treats Indian electricity supply and demand as a single unit, unhindered by transmission costs or constraints. The reality is different as India is a large and diverse country with significant transmission costs and constraints. An important consideration in developing a flexible Indian electricity system is a tradeoff between building additional local flexibility or building transmission to harness excess flexibility in one region to use in another. Local flexibility can involve building batteries or prioritising demand side or powerplant options in one area, whereas pan-India flexibility might enable balancing loads between regions with disparate needs. For example, regions with excess generation during the monsoon season may balance those that have excess solar production at different times of the year.

A complete evaluation of transmission requirements would require detailed assessment of demand and powerplant options in each state and an India-wide transmission model to forecast costs and constraints. This analysis is beyond the scope of this study, but given the range of uncertainties in the estimates of option availability in 2030, it is unlikely that the detailed analysis would provide a great deal of valuable insight. Instead, we have investigated the flexibility needs of four individual states – with different electricity supply and consumption characteristics and flexibility needs – to ascertain how limiting interstate exchange of flexibility might affect the results, and to evaluate how transmission planning and interstate exchanges and markets should be incorporated into a dedicated flexibility development policy.

In isolation, some Indian states will face greater flexibility needs than India as a whole, while others will face less. High renewable energy states will often face particular challenges, whereas thermal generation heavy states could have an opportunity to reduce their electricity costs by harnessing and exporting demand flexibility.

CPI looked at four states with different mixes of energy:

- **Tamil Nadu** where wind is already close to 30% of the capacity mix faces seasonal balancing challenges. By 2026/27, nuclear and renewable generation at approximately 42GW are expected to outstrip demand during the monsoon season. In the absence of flexibility measures the state will face the dual economic impact of curtailment of must-run renewables and compensating thermal generation for capacity not called. The left side of figure 6 shows how by 2030 the residual demand after renewables and must-run hydro, which must be met mainly by thermal generation, falls to 1% in the lowest month of the year. That is, powerplants in Tamil Nadu would be, effectively, completely shut down in the absence of sufficient transmission export capacity. This figure compares to 30% for India as a whole.
- **Karnataka's** renewable capacity today represents half of its total; by 2026/27 solar at 18.8GW will make up 40% of its capacity mix. Solar energy output declines rapidly around sunset. Karnataka, with its growing household wealth and energy demand, sees its energy demand increasing during those same evening hours. The result is that the rate

at which the thermal and hydro power would need to increase – that is the ramp rate – is growing rapidly. By 2030, Karnataka will need to increase its capacity by 30% of its peak demand in just one hour. This figure is double our forecast for India on average. In the absence of flexibility measures, the significant mismatch between the daytime generation and evening peak load will lead to demand for substantial ramping needs of about 11GW.

- **Uttar Pradesh** meets its demand largely through contracted thermal capacity and has relatively low renewable energy ambitions. Simultaneously Uttar Pradesh has a relatively well-established industrial base and has a diverse potential for demand flexibility, 12GW spread across AC, agriculture pumping and industry. With access to adequate transmission and distribution infrastructure, the state could look at exporting the flexibility, especially if it is able to harness its demand flexibility potential.

- **Bihar** is a thermal generation heavy state with 4.3GW of contracted capacity faces internal challenges of its power deficit and balancing its own system as demand grows rapidly from a relatively small base. Managing transmission links internally and to other states could help it tap into over 1.5GW of demand flexibility by 2026/27 could contribute substantially in addressing the deficit and also reducing bills

- Regions and states will ultimately require different mixes of flexibility options to address their specific challenges, tap into the flexibility potential of individual states while creating trading opportunities on a regional and pan-India basis. Figure 8 shows how different combinations of flexibility drivers, such as demand profiles and generation sources, and flexibility options would lead to each state being a flexibility importer or exporter.

Figure 6: Regional examples of seasonal balancing and ramping needs

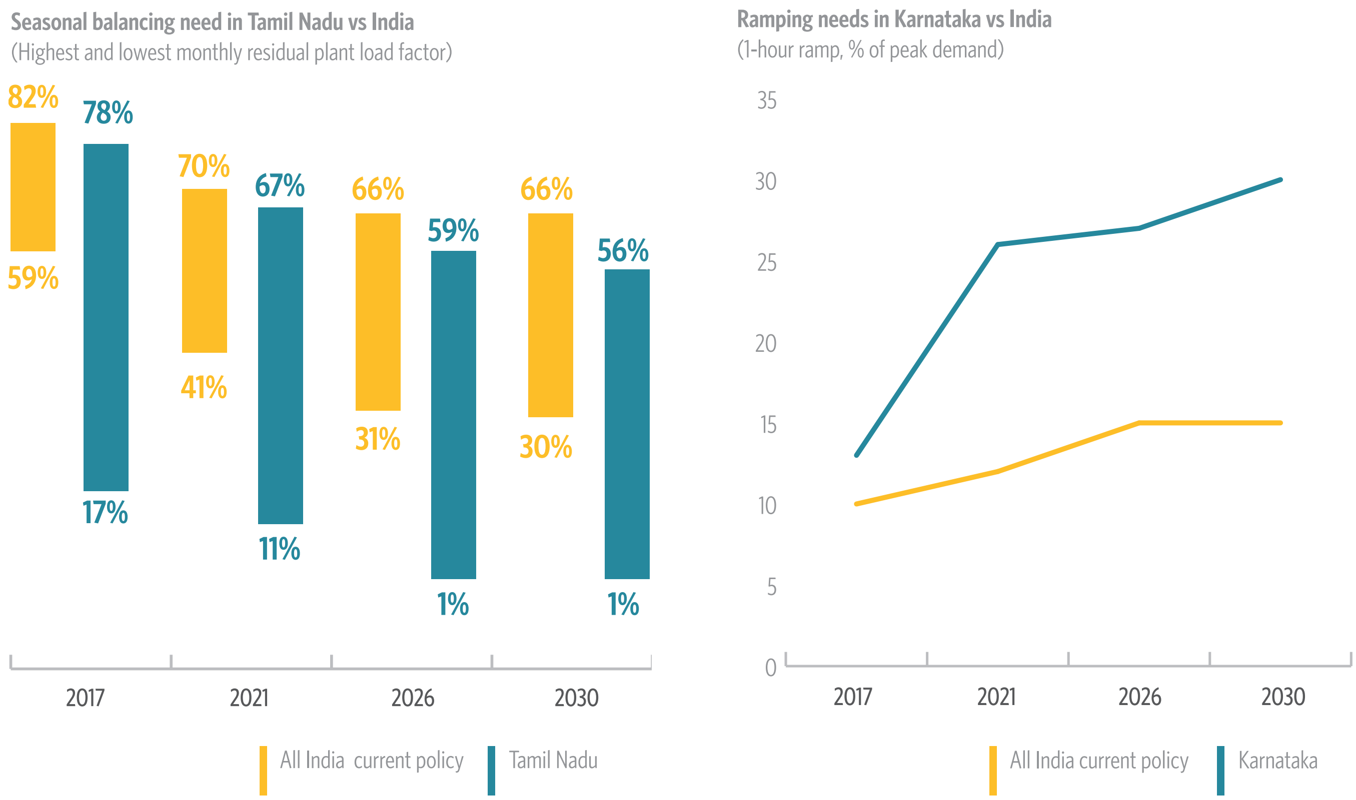
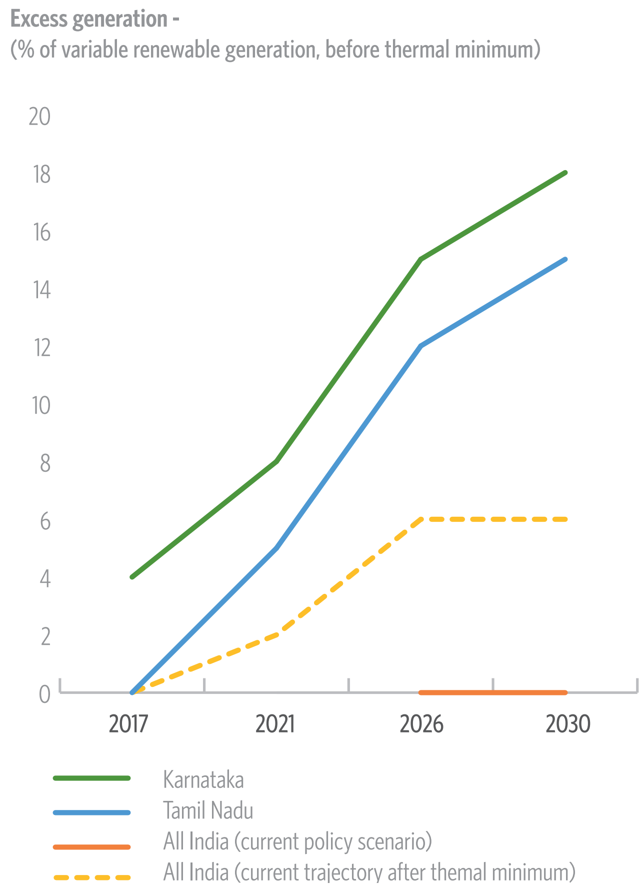
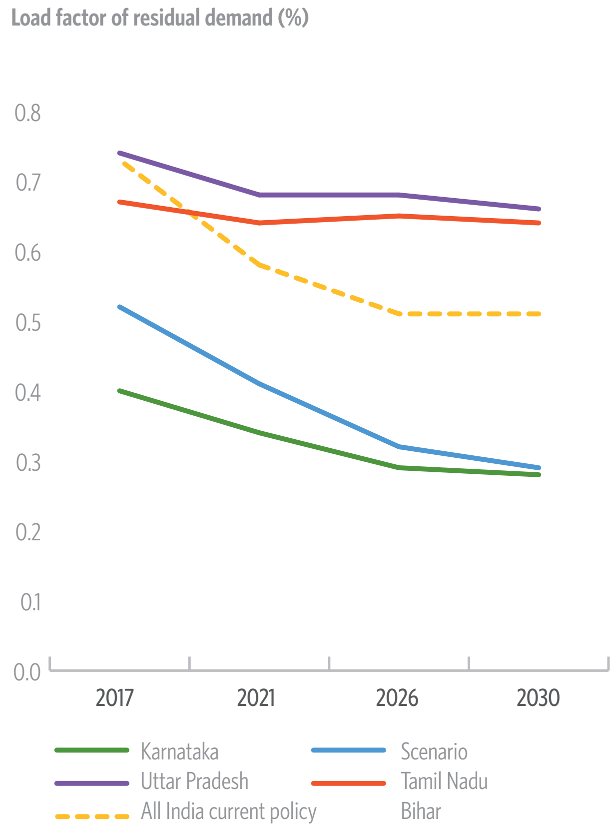


Figure 7: Growth in flexibility needs and flexibility potential is not evenly distributed





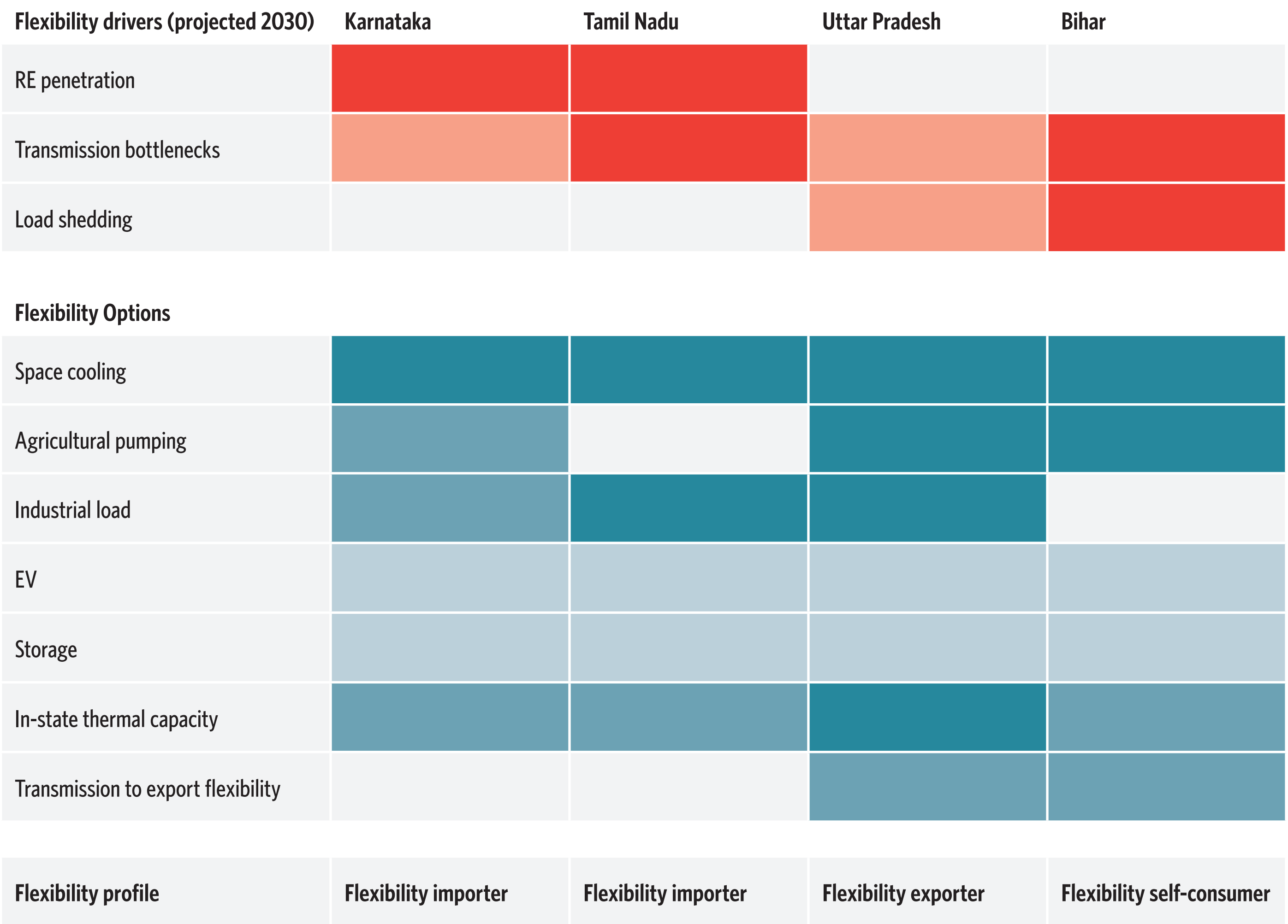
India can pursue ambitious renewable energy targets, but concerted action on data, market design, development, investment, consumer behaviour and infrastructure is essential

Our analysis has shown that flexibility should be addressed urgently to reduce costs and improve the quality of electricity supply, regardless of renewable energy ambitions. However, once flexibility is addressed, the cost of integrating variable renewable energy falls significantly, making clean energy a low-cost option.

Developing and integrating each of the categories of flexibility options will require concerted action along the following lines:

1. **Data and information**. Balancing supply and demand continuously is a data intensive exercise. A first step to creating this balance is to build a comprehensive set of data on both the value/ cost of flexibility over time and location, and the potential and cost of each flexibility option.
   - On the **need for flexibility**, data from the dispatch centres and trading markets form the core of required data, but more complete and comparable data will be needed.
   - On the **supply of flexibility**, a central catalogue of the capabilities of all India powerplants – and their potential upgrade – would be an important step, while estimates of daily demand, consumption patterns by end use (for example, agricultural pumping or residential air conditioning), and alternative consumption models are essential before we can develop programmes and incentives to shift these patterns.
2. **Incentives and markets**. While the data identifies the need and potential options, incentives and markets are needed to encourage providers to provide the lowest cost flexibility option, when it is needed, and to work to reduce the costs of each option. For example, more liquid wholesale electricity markets that create a transparent price signal, more time-varying and dynamic retail prices would encourage demand flexibility, new contract

Figure 8: Regions and states may require differing flexibility profiles



structures with powerplants, demand flexibility aggregators, storage assets that value flexibility characteristics.

3. **Development and cost reduction.** Since flexibility has not been a priority in India, several of the options remain underdeveloped.

    - **Batteries and other energy storage** options are developing rapidly internationally, and costs are falling, but local costs, including balance of system, installation, and operation, are an important part of the total costs. India needs to begin deploying batteries soon, so that costs fall enough by the time the technology can be applied at scale and at low cost.

    - **Thermal powerplants** can significantly increase the flexibility they offer, in part by reducing the minimum level at which they operate. A lower minimum increases the amount each plant can ramp, and also increases the amount of renewable energy that can be absorbed, thus reducing costly renewable energy curtailment. Lowering minimum generation levels requires investment in plant equipment and monitoring and could increase operating costs. India will need to work with existing plant owners to reduce this investment and these costs.

    - **Demand side options**. Harnessing demand flexibility requires metering, controls, and incentives. It will also require customer acquisition, which is difficult if consumers are uncertain of the benefits and costs of consuming energy and operating more flexibly. Working with consumers to develop these programmes and be comfortable with the results will require time.

4. **Investment**. Batteries, plant upgrades, information technology and metering for consumers, may require smaller, individual investments than new, large powerplants, but collectively they will still represent significant investment for India. The investment patterns, time horizons, risks, and the investors themselves, will often be distinct from typical power sector investors. Likewise, investment during the development phase for these options will have different patterns and needs than once the options become mainstream. These differences need to be addressed early in order to accelerate development.

5. **Behaviour**. Many of the options presented here are new to Indian electricity consumers or producers. Thus, they may break entrenched practices that have developed over many years. While incentives may provide an economic case, changing behaviour – for example to change the hours of agricultural pumping, to accept operating powerplants at lower minimum levels, or changing how a house is cooled – often requires different mechanisms than pure incentives including utility and customer education, development of new business models, creation of new market participants, political will and new policy frameworks.

6. **Policy interventions and frameworks.** A number of the current market structures, incentives and the policy framework that underpin them are structured to support old generation and consumption models. Transitioning into the new behaviours, new market models and incentivizing evolution of operational and financing models will require not just the creation of new pathways (eg, markets can find the right price for ancillary and balancing services, real-time markets, market aggregators and deployment of control and measurement infrastructure to facilitate demand side flexibility) but also amendment existing contracts and agreements (eg, adjustment of existing thermal generation contracts to compensate for financial and operational cost of flexible operations).

7. **Infrastructure**. Finally, some of the new investment and systems lie with neither producers or consumers, but rather the infrastructure in between. We have already seen how more centralised data might help pursue these ambitions, but there are other common infrastructure needs to accessing greater flexibility:

   - **Transmission and distributio**n are central elements of delivering and rationalizing flexibility resources. Planning and building these elements will likely increase and need to consider carefully the flexibility needs and resources.

   - **Information technology and meterin**g will drive markets, incentives, payments, and new programme development. Information is a key to balancing this system and creating the infrastructure to gather and use this data is an important step to minimizing costs.

Summary

Regardless of how far India moves on its clean energy ambitions, additional flexibility in demand, powerplants and storage will lower the cost and increase the reliability of its electricity supply. Building a programme to improve the capacity and cost competitiveness of storage options in India is an important step that requires development in the near term and deployment programmes in the longer term. Improving demand flexibility through further test programmes, development programmes and market reform and incentives is another step that can provide significant value to India under any circumstances, but they will need to start as soon as is practical to ensure that the flexible capacity is available for when it is needed in the future. With all three categories developed – demand management, thermal and and storage – flexibility will be the key enabler for reducing system costs, increasing power quality, and transitioning the India power sector into a low cost, low carbon, sustainable system which can support and facilitate increasing renewable energy and lower emissons.

Annexes

1. Framework and methodology
2. Flexibility needs
3. Flexibility options
    a. Demand side
    c. Powerplants
    c. Storage and batteries
4. Portfolio analysis
5. Regional case studies

Annex 1. Framework and methodology

The following annexes lay out the methodology we have used to calculate the cost, potential and options required to address India's electricity system flexibility needs under different scenarios. This methodology and the supporting analysis will be laid out in more detail in the final report to be released in April 2019.

Each of the scenarios is based upon the work of The Energy Resources Institute India (TERI) and the Energy Transitions Commission India (ETC India) in evaluating the changes to Indian electricity supply and demand between now and 2030. In addition to a base scenario, these scenarios include different mixes of variable renewable energy and thermal powerplant, as these are the two most important determinants of how much flexibility the system will need. Specifically, we use three scenarios:

1. A ***current trajectory*** scenario based on forecasts of future renewable energy deployment following current trends;
2. A ***current policy*** scenario where India meets the government's current renewable energy targets; and
3. A ***high renewable energy*** scenario that follows the ETC India High RE scenario, maximizing renewable energy by 2030 with no new coal additions beyond current pipeline.

Note that trends fall short of current targets, although meeting today's policy targets should be considered a "base case" as there is a strong potential for India to increase its renewable energy targets, as outlined in TERI/ETC India's demand work.

Using the scenarios as a base, we undertake several steps:

1. **Analysis of flexibility requirements.** As outlined in annex 2, for each of the three scenarios, we have assessed the development of different types of flexibility needs between now and 2030. The assessment is based on ETC India's supply and demand modelling, analysis of the Indian load shape and how it will be affected by changing usage patterns, analysis of system modelling, and application of Indian system operation guidelines. The flexibility requirements we have assessed include:
    - **Short-term reserves** to meet sudden, unexpected changes in either supply or demand.
    - **Ramping** requirements where the limiting factor is not how much energy can be provided, but how fast the system can react to increasing (or decreasing) demand or decreasing supply (for example from solar PV) over a period of 15 minutes to three hours. In many electricity systems, the number of plants that need to be brought online over the course of the day can depend on the maximum system ramp, rather than peak capacity. That is, in some cases more plants than are needed for peak need to be online to provide a sufficient system ramp rate.
    - **Daily balancing** to match excess production during the day (or during the night) with higher demand at night (or day). For example, when excess solar energy produced during the day needs to be shifted to nighttime hours, or when baseload plant needs to be turned down at night and replaced by daytime peaking plant.
    - **Seasonal balancing** where high wind generation during the monsoon, needs to be shifted by months to times of the year when there is lower generation or higher demand.
2. **Analysis of India flexibility options.** Options to provide flexibility fall into three groups.
    - **Demand flexibility** (annex 3a)**.** The biggest opportunity and uncertainty is the amount of demand flexibility India can harness. A lack of comprehensive data on the amount of energy consumed by different end uses, the appliances owned by different types of consumers, the load patterns of the different consumers and end uses, price sensitivity, customer attitudes, and other data needs hampers a complete analysis of demand potential. We have focused on developing preliminary estimates that can help determine the role and potential importance of demand side flexibility as an input to decision-making on the level of prioritization India should set for demand flexibility. To this end, we focused our analysis on a subset of end uses (commercial and residential air conditioning, agricultural pumping, electric vehicle charging, and industrial demand response) where data is available and where consumers are most likely to be receptive

to demand side opportunities. For these end-use/consumer combinations, we estimate potential and use these as proxies to identify potential barriers and requirements for implementation. Even applying conservative estimates to potential penetration rates, these end uses provide enough flexibility to the system to have a major impact on costs, reliability, and the ease at integrating higher levels of variable renewable energy.

- **Powerplant flexibility** (annex 3b). Most flexibility today is provided by thermal and hydroelectric powerplants. These plants are capable of delivering all types of flexibility, although there are both limits and costs. At the basic level, operating plants flexibly reduces plant efficiency, increases fuel costs and can increase operating costs. To provide reserve, extra plant need to be built and kept online, again increasing costs. We compare these costs for each type of flexibility using incremental costs to deliver the service. Additionally, we have found that most plant on the India system can deliver significantly more flexibility than they are currently offering. Without modification, engineers suggest that the plants can offer more flexibility. Investments can also significantly increase the amount of flexibility each plant can offer. We worked with ETC India member, Siemens, to evaluate the cost and potential of retrofits and to include those options in our system modelling.
- **Energy storage** (annex 3c). Battery prices are falling dramatically across the world, and these cost reductions will help India lower costs. Batteries and other storage options like pumped storage hydro can provide all of the flexibility service, but the cost of doing so is highly dependent on the capital cost of the batteries, the full cycle efficiency and the life of the batteries. We used estimates of each of these variables, and the investment return required, to calculate the cost of providing flexibility services through storage options at today's costs, and at costs and operating characteristics we forecast for 2030.

3. **Modelling and evaluation of integrated flexibility option portfolios** (annex 4). As outlined above, for each of the flexibility options we have modeled potential supply and its cost for each of the flexibility needs. By ranking these flexibility resources, we can create supply curves to show which flexibility resources would be dispatched at what cost to serve each flexibility need. Then, using these supply curves and forecasts for annual hourly load shapes for India, we evaluate the "dispatch" of different sets of flexibility options to meet the various flexibility needs of the system. The aim is to both assess the cost of integrating various levels of renewable energy into the system, as well as to evaluate how the availability of different supply side options affects cost and overall dispatch. Thus, we have used our model to understand the costs and dispatch of the Indian system for each of the three energy mix scenarios outlined above, with the following mixes of flexibility resources:
   - **A base case** – where only the existing sources of flexibility are used.
   - **Powerplant driven portfolios** - where the flexibility required by the system is provided entirely by thermal and hydroelectric powerplants. Where it is economic, these plants are upgraded to increase their flexibility and new plant are added to the system if it is economic to do so.
   - **Demand side driven portfolios –** the third portfolio uses existing sources of flexibility combined with only demand side options at the scale and cost from the demand side flexibility analysis.
   - **Storage driven portfolios –** similar to the demand driven option, but using storage instead of demand with existing options.
   - **Combined portfolio of all options** – our final portfolio combines all flexibility options to determine which options would be used and at what scale, and to assess what the lowest cost would be if all flexibility programmes were successful.
4. **Case studies of regional differences** (annex 5). Much of our analysis takes India as a single unit. The underlying assumption would be that there are no transmission constraints or costs and that flexibility resources can be used to supply flexibility across India. While this is a first approximation, it is far from the reality we have now or could expect by 2030. Transmission constraints between states and regions create differences in pricing and dispatch, which are exacerbated by differences between states in weather, economies and, as a result demand patterns, energy supply and resources, including both

renewable energy and conventional energy. To understand how these constraints and regional differences could affect flexibility costs and resource requirements, we have studied four different states, with distinct energy needs and resources. We evaluate these regions on their own, and then in the context of how each state/region could benefit from or be affected by the trading of flexibility resources. The state differences provide initial indications of the needs for interregional/ multi-regional trading and national level policy. The regions we studied in detail are:

- **Karnataka –** Karnataka combines a strong, growing, and reasonably wealthy economy with high renewable energy ambitions and ample solar resources. This combination could lead Karnataka to experience some of the strongest ramping needs in the country, as well as potential excess generation during the day.
- **Tamil Nadu –** Another strong economy, Tamil Nadu's strong renewable energy ambitions have focused more strongly on its wind resources. The strong seasonal variation of wind production, combined with seasonal patterns in neighbouring states and limited national transmission options, could lead Tamil Nadu to experience a seasonal flexibility problem, including excess production during the monsoon season.
- **Bihar –** Bihar is one of the less developed states, with many areas in need of greater electrification and power supply. Bihar enables us to study the impact of energy access and initial electricity system growth on flexibility needs.
- **Uttar Pradesh –** Uttar Pradesh is also a developing economy, but one that is characterized by a large share of industrial consumption and a good supply of conventional thermal powerplants to meet demand. Uttar Pradesh is an example of a state that has more flexibility resources than it will need, and therefore could have an opportunity to export its flexibility.

5. **Assessment of finance, technology, strategy, planning and market design needs.** Finally, based on the portfolio analysis and the regional analyses, we identify the key factors and policy areas that will be needed to drive a more flexible, lower cost, and potentially lower carbon system for India's future.

Annex 2. India's growing flexibility needs

Electricity systems need to balance electricity supply with demand at each moment at each point of the network. Failure to do so results in poor power quality that damages equipment – such as voltage drops or frequency fluctuations – and can cause outages and system failure. The cost of outages or poor power quality drives consumers and producers to install expensive backup generation and power conditioning equipment, or to bear the costs and consequences of unreliable supply.

Changing patterns of consumer demand make this matching process more complex and difficult. Demand is shifting in India, as it has elsewhere, from a larger share of industrial consumers who tend to have more continuous and stable demand to an increasing share of households and commercial consumers, whose heating and air conditioning demand tends to vary with the weather, and whose lifestyle can often include an evening demand peak when lights and appliances are turned on in the evening. Adding wind and solar, whose output depends on weather, rather than being controllable by system operators, adds to the difficulty of continuously matching supply and demand.

The key to making this match is to increase the flexibility of both energy supply and demand, so that each can be adjusted to meet the other at the lowest cost. This annex outlines how we have defined and measured the needs for flexibility in India and how they will change under different scenarios. This measurement serves as a critical input in determining how much and what combination of of flexibility resources (annexes 3a, b, c) will be required by the optimum, lowest cost, portfolio of flexibility resources (annex 4) to meet India's future needs under different scenarios.

Defining different types of flexibility

While electricity system operators need to match supply and demand at each instant, to do so they need to make decisions across many time frames. Thermal powerplants take time to start up, so decisions about which plant will be running at various times need to be made hours or a day in advance. Demand varies across the year, so decisions about scheduled plant maintenance and fuel procurement to match these variations need to take place months in advance. New plant or storage systems can take years to build, so some decisions must be made years in advance. At the same time, a large transmission line or powerplant can suddenly go down, or a commercial break in a popular television programme can prompt a sudden surge of demand, so system operators need to make decisions instantaneously, and over the course of a few minutes, to restore the balance.

Different types of flexibility, that is different responses from the system operator, and electricity suppliers and consumers, are needed across these time frames shown in number one of the slides that follow For our analysis we have modelled four main types of flexibility needs:

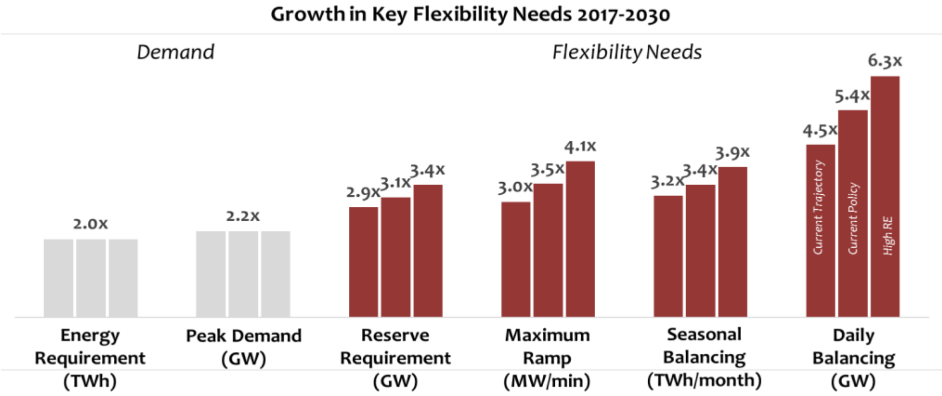
- **Operating reserve** is the capacity to replace energy if a powerplant or transmission line suddenly fails, or to meet a surge in demand. We have grouped the short-term flexibility needs, including spinning reserve, load following, frequency response, short term reserve, into a single category, as these are the areas that are most well equipped to meet the growing flexibility needs (see slide 1).
- **Ramping** addresses the need to increase (or decrease) output (or demand) fast enough to maintain a balance of supply and demand when demand is expected to increase at its fastest rate. For example, when the sun sets and consumers turn their lights on at once – particularly if solar generation falls off at the same time – the limiting constraint to an electricity system may not be the capacity to meet the daily peak, but rather having enough capacity that can ramp up (increase capacity) fast enough to maintain a continuous match of supply and demand. It is not uncommon for a system to require extra powerplants to be dispatched beyond what is needed to meet peak demand, just to have enough ramping capacity to meet the day's maximum ramp rate. Finding demand or storage solutions to meet ramping can decrease the amount of powerplants that need to be online, and increase the overall efficiency of the powerplants that are dispatched.
- **Daily (intraday) balancing** matches demand and supply across the entire day. For example, adjusting for lower demand in the middle of the night when using baseload generation, or shifting higher solar energy production in the middle of a sunny day to meet lighting needs in the evening or night time.

- **Seasonal (interday) balancing** matches supply and demand to meet annual cycles, for instance, when cold winters or hot summers drive up electricity demand, or rainy, sunny or windy days drive up energy supply.

Assessing flexibility needs

To assess these needs under each scenario we need to assess supply and demand on an hourly basis (and sometimes less) over the course of this and future years. To address the twin effects of changing demand profiles and higher renewable energy production, we use a net load, or net demand, approach (see slide 2). In this analysis, we forecast future hourly load profiles based upon the TERI/ETC India demand models, and then net off the must run, or undispatchable generation from all sources, including wind, solar, nuclear, must run hydro. The resulting net demand is the load that must be met by dispatchable generation or altered through demand flexibility. In our analysis we treat demand flexibility as an energy supply option akin to flexible generation.

At the broadest level, our analysis indicates that the demand for flexible resources will intensify in the push to meet the government's target of 160GW installed capacity for wind and solar by 2022 and the years after that target date. But even as demand doubles over the timeframe of our analysis (2017-2030) flexibility needs such as daily balancing will increase by 6.3 times under a high renewable scenario, and even 4.5 times under a conservative scenario (current trajectory).



While this analysis shows the challenge of increasing flexibility needs, for our portfolio and option modelling we require more detailed analysis, as below.

Net Peak demand

Peak demand will grow with growing energy demand and changing demand profile. More generation will be built to meet this peak demand, but depending on the scenario, more of that energy may be from renewable energy, which has relatively less available and reliable production at peak. As a consequence, net peak demand will increase almost 75% faster than peak demand (slide 3). Meanwhile, net peak will shift to low wind, low run of river hydro days, most likely in October (slide 4).

Short term reserves

Indian system operators manage several different levels of reserves across different time frames (slide 5), yet these are the least affected by changing demand and growing renewable energy mainly because the largest instantaneous risks are often the largest single failure, such as a large powerplant or transmission line. Since renewable energy and consumer demand are a series of smaller items, simultaneous failure is unlikely to grow as fast. Exceptions are either transmission line failure when delivering significant renewable energy, or sudden output variations due to weather (eg, wind gusts or lulls, or cloud cover). Nevertheless, the scale of these events is likely to be small compared to major powerplant outages. Furthermore, system operators have invested significantly into resolving the short-term reserve problem (slide 6). Our estimates of reserve requirements are based on national standards and include the larger of a single plant or transmission failure, or 3% of peak demand (to address simultaneous unexpected demand shocks and forecast errors) plus 5% of peak renewable energy production (to address weather and forecast errors).

Ramping

Ramping requirements increase as demand becomes peakier and as solar energy reduces output in the evening. In fact, growth in solar energy is expected to shift (and in some case has shifted) maximum ramping requirements from the morning to the evening. Our analysis, which is based on the evaluation of net load profiles to identify the highest likely ramp rates within a year shows that even under current renewable energy targets (current policy scenario), maximum ramp rates will not only increase by more than 3x between 2017 and 2030, but that there will be a much wider spread of maximum ramp rates across the year (slide 7).

Daily Balancing

Quantifying daily balancing needs is less straightforward. In extreme cases, there is the need to shift excess energy generated in one hour to hours where more energy is needed. Most of the time, daily balancing can be shifting energy across the day to smooth the residual load that must be met by thermal powerplant to improve the efficiency of these plants and reduce the costs of starting up powerplants for a few hours. There are also important differences between, say, 1000MWh of excess that needs to be shifted occurring all in one hour to 100MWh per hour over 10 hours, to 1MWh per hour over 10 hours over 100 days. Although each of those shift the same amount of energy, each has very different consequences on generation costs and the cost of flexibility options. The 1000MWh in one hour, for example, benefits from a lower capital cost solution, while for the 1MWh over 1000 hours, it would be more cost effective to invest in capital to shift the 10MWh/day 100 times.

As such, our analysis is based on net load profiles, rather than daily balancing metrics, to incorporate the mix of high capital costs/low variable cost and high variable cost/low capital cost options that would optimize the portfolio for a lowest cost.

Despite the intricacies, slides 8 and 9 show clearly how daily balancing needs will increase over the next 13 years as the variability over the day, and the eventual excess energy production in the middle of the day, increase over time.

Seasonal Flexibility

Indian daily electricity demand is higher in September than it is in April or November (slide 10) and this difference will increase by 2030 as demand grows (bottom chart slide 10). However, the largest impact on the variation of net daily load across seasons is growth in renewable energy. In India, where solar resource is more constant across the year, the increase in wind and must run generation from hydro is the major contributor to seasonal variation in net load. The load factor of net load relative to net peak demand for the lowest month will fall from 65% to close to 30% (slide 11), or lower, depending on the scenario.

Like daily balancing, the intricacies of meeting seasonal balancing depend upon the specific shape of seasonal needs, rather than a single metric, and therefore must be assessed through the broader model. Additionally, variations in how daily balancing is met will reduce seasonal balancing needs. For example, during months with a supply deficit, a greater share of daily balancing needs will be met by peak generation, where added generation will fill both daily and seasonal balancing needs. Conversely, daily balancing need during the months of surplus supply will be met by demand flexibility and storage.

Our models indicate that with a moderate amount of daily balancing, seasonal variation alone will not lead to excess energy production until well after 2030. Wind generation is more likely to be limited by seasonal factors while solar would be more limited by daily balancing capacity.

For each of the flexibility needs we have evaluated scenarios with different mixes and quantities of renewables. In each scenario, we have used the model in the portfolio analysis described in annex 4, but the simple metrics laid out above provide a good perspective on how needs could evolve.

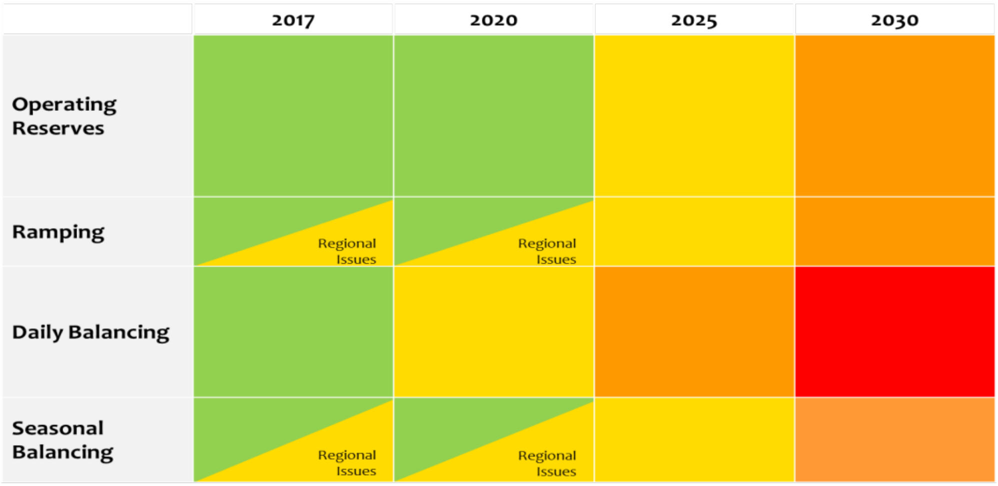
Geographical differences

In a country as geographically vast and diverse as India, there are some extreme variations in the need for flexible capacity, and flexibility needs may intensify sooner than in some other regions. These differences are particularly profound in those states that have the highest shares of renewable energy generation. Solar mainly affects ramping and daily balancing, so we can see that by 2030 Karnataka will have ramping needs that are double that of India on average (slide 13). Either transmission will need to import flexibility to Karnataka, or energy will be spilled on some days. Wind mainly affects seasonal balancing. Tamil Nadu, which has a large share of wind generation in its mix, already sees load factors of 17% for net load during the highest RE generation month, compared to 59% for India as a whole. This figure will fall to 1% by 2026.

Initial comparison to available flexibility

An initial comparison of flexibility needs under the TERI High Renewable Energy Scenario with the flexibility currently available in India suggests that by 2025 India will need additional sources of flexibility across all all four categories, with daily balancing becoming critical. By 2030, all flexibility needs will become critical without additional sources (below and slide 14).

Indian electricity system's ability to deliver key types of flexibility
Under TERI high renewable energy scenario



Flexibility needs: Implications for policy and investment

Analysis of flexibility needs generates initial conclusions, including policy and investment implications, that feed into the wider study:

1. **Growth in reserves needs may be modest, but implementation is incomplete**
   - Operational incentives that ensure availability of reserve capacity (not just pay for dispatch costs)
   - Expansion of reserve mechanisms to allow reserves provision from demand-side and storage resources
2. **Ramping needs will grow significantly, driven by high shares of solar**
   - Mechanisms to ensure ramping resources are online when needed
   - Incentives for development of new resources that reflect future need for fast-ramping resources
3. **Daily balancing needs will grow substantially by 2030, and will require new resources and approaches**
   - Contracts and markets to provide meaningful signals as to value of energy at different times of day
   - Incentives for development of new resources that reflect future need for low utilization peaking resources and energy shifting
4. **Seasonal flexibility needs will be apparent first in specific regions, but eventually will impact India-wide utilization patterns**
   - Contracts and markets to incentivize seasonal availability and utilization
   - Enhanced interregional exchange to mitigate more severe regional challenges

Need for flexibility: There are several distinct types of flexibility needs, and variable renewable energy will have different impacts on these four main categories

		Type of flexibility	Impact of a increasing variable renewable energy on flexibility needs
Real-time Operations	<1 min 5 min	Spinning and load-following	**Low to moderate** *Modest increases in forecast error with more variable generation*
	15 min	Short-term reserve	
Scheduling and forecasting	hour	Ramping	**Moderate to high** *Daily patterns (eg, sunset) lead to substantial ramping needs*
	day	Intraday / daily balancing	**Moderate to high** *Misalignment between generation and load drives hourly over/under-production*
Planning	season Year(s)	Interday / seasonal balancing	**Moderate to high** *Dependent on resource mix, seasonality of renewable resource*

CLIMATE POLICY INITIATIVE

Need for flexibility: Approach - CPI Net Demand Analysis

Scenario modelled

- Figures based on the current policy scenario supply scenario and base demand scenario
- Consumption grossed up for grid losses using 19th EPS projections

	2017	2021	2026	2030
Total Load (TWh)	1,193	1,555	1,941	2,428
Utility PV (GW)	19	60	110	150
Rooftop PV (GW)	3	40	40	40
Wind (GW)	34	60	100	132
Hydro (GW)	50	56	71	83
Nuclear baseload (GW)	6	9	14	14

Approach

Net Load Analysis
- Calculate hourly renewable energy production, plus baseload nuclear assuming constant generation when online
- Calculate hourly demand
- Calculate difference between demand and variable renewable energy supply for each hour
- Summarize key statistics and key graphs

Demand
- Demand shape estimated from 2015-16 year, from POSOCO Demand Pattern Analysis study (daily energy, shaped using typical load curves by month)
- Demand pattern scaled to equal total generation need estimated by TERI.

Supply
- Wind and solar profiles based on NREL Greening the Grid data – India-wide average weighted by "high RE scenario" locational capacities
- Minimum hydro by day from MOP "Large Scale Integration" study, smoothed using a 7-day moving average
- Nuclear baseload production assumes constant output at expected load factor of 66% (2017) to 75% (2030)

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Peak demand: Peak demand net of renewable energy will grow from today's total peak demand

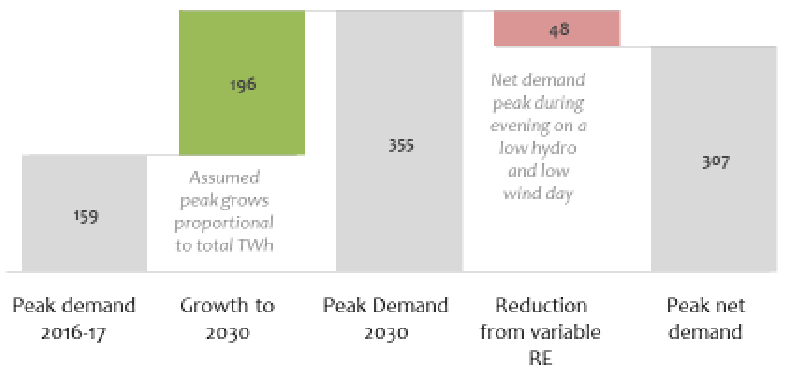
Description

- Capacity to meet peak demand
- Considering wind, solar, must-run hydro coincidence with peak

Drivers

- Demand growth
- Wind and solar penetration
- Wind and solar production uncertainty
- Hydro and thermal availability uncertainty

Changes in Peak Demand and Net Peak Demand (GW)

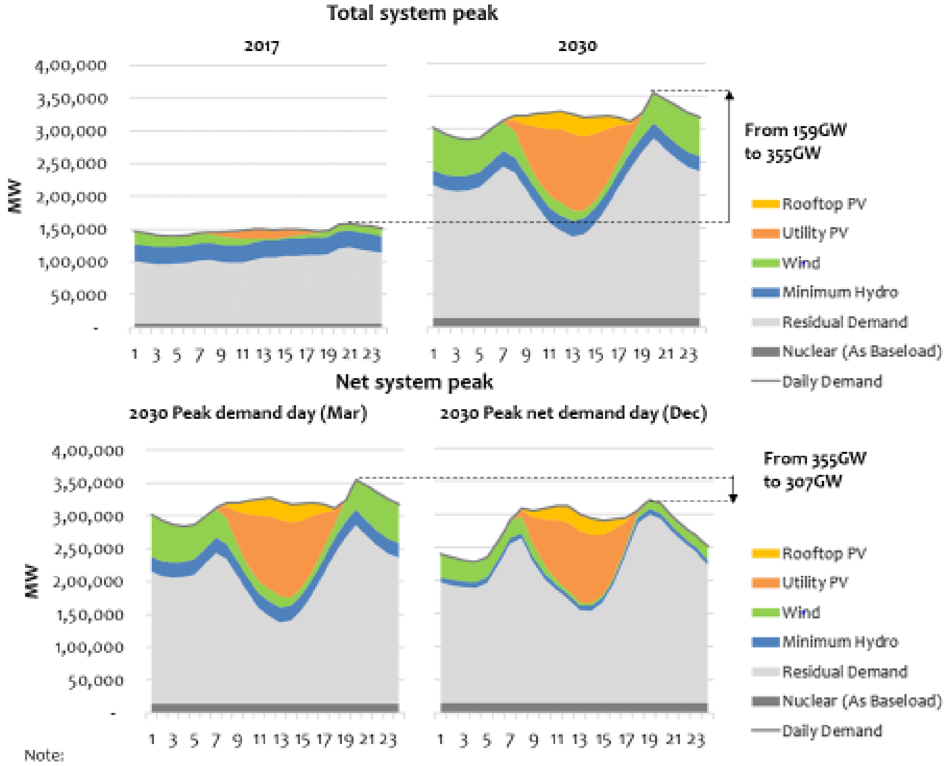


Note:
Assumes 2015-16 demand profile, scaled up to 2030 generation requirement with no change in shape

CLIMATE POLICY INITIATIVE

3

Peak demand: But net peak demand will shift to low wind, low run-of-river hydro days



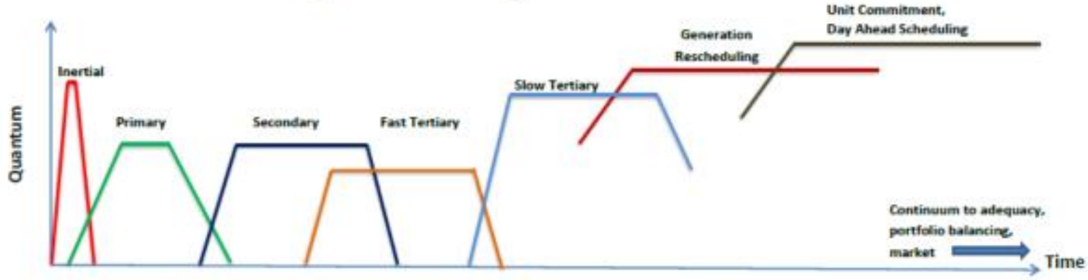
Note:
Assumes 2015-16 demand profile, scaled up to 2030 generation requirement with no change in shape

CLIMATE POLICY INITIATIVE

4

Reserves options in India at varying levels of development

System Balancing in India – A Schematic



Response → Attribute ↓	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC / RLDC	NLDC	NLDC / SLDC	RLDC / SLDC	RLDC / SLDC
Manual / Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	Ancillary Regulations	Ancillary Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Yet to start	Yet to start	Existing	Existing	Existing

Source: POSOCO, Power System Operation and Ancillary Services, Presentation, Dec 2017

CLIMATE POLICY INITIATIVE 5

Operating reserve: Some growth foreseen, as well as near-term technical implementation and compensation challenges

	Drivers	Current Need	Implementation	Growth
Primary reserve (sec – 5 min)	Largest system contingencies (failure of large power plant or transmission line)	~ 4 GW	Partial • Per 2010 Grid Code, thermal generators over 200MW equipped with governor control to independently respond to frequency changes	Minimal growth
Secondary reserve (< 1 min – 15 min)	Contingencies, load forecast error, wind and solar forecast error, congestion management	~ 4 GW	Partial • Requires automatic generation control • Currently being tested at some generators and LCDs	Proportional or slower growth than peak demand • Function of demand growth, wind and solar growth, forecast accuracy, scheduling practices
Tertiary reserve (5 min – 60 min)	Contingencies, load forecast error, wind and solar forecast error, congestion management	~4-5 GW	Implemented • Reserve Regulation Ancillary Services program started operation in 2016 with Inter-State Generating Stations • 55GW of participating generators • Dispatches available (undispatched) capacity based on merit order	Proportional or slower growth than peak demand • Function of demand growth, wind and solar growth, forecast accuracy, scheduling practices

Overlap with National Electricity Policy (NEP) target of 5% spinning reserve

Sources: CERC, Explanatory Memorandum on Introduction of Ancillary Services in India, 2015; Posoco, Power System Operation and Ancillary Services, Presentation, Dec 2017, CPI Analysis

CLIMATE POLICY INITIATIVE 6

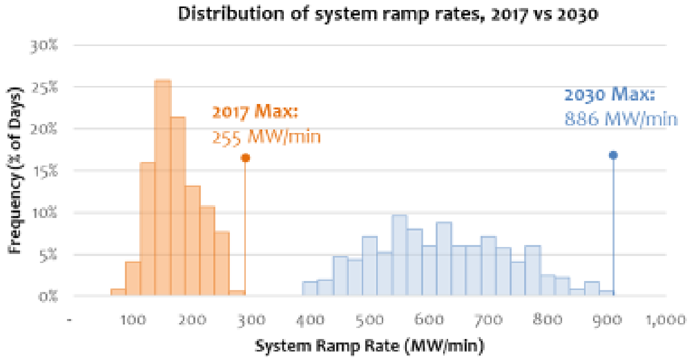
Ramping: Even under the current policy scenario, system ramp rates will increase by more than 3x, and will be more variable across the year

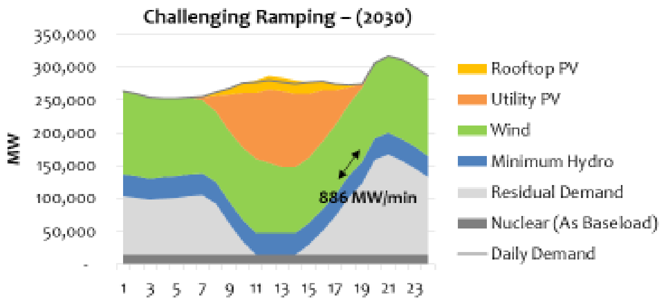
Description

- Ability to increase or decrease generation rapidly in response to changing demand and variable renewables output

Drivers

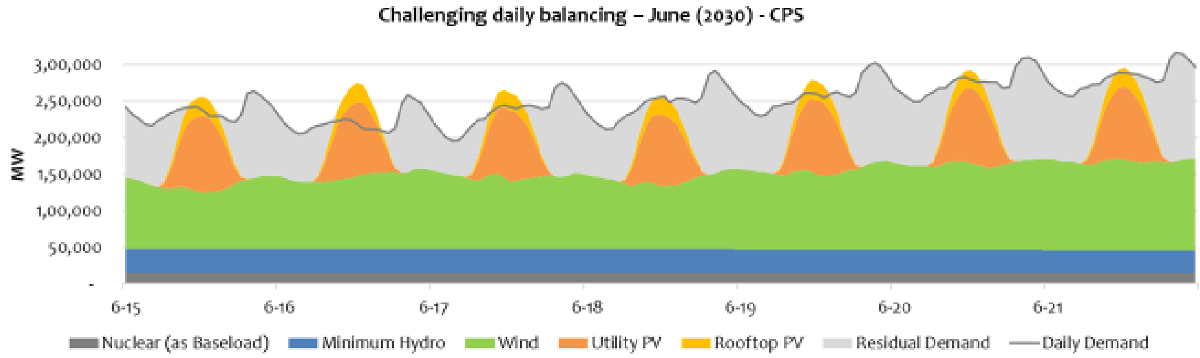
- Wind and solar penetration, and changes in "net load" after wind and solar
- Alignment of wind and solar production with demand pattern
- Amount of mid-day curtailment of solar (which could reduce size of ramps)





CLIMATE POLICY INITIATIVE 7

Daily balancing: Significant energy shifting will be needed from mid-day solar to evening peak



Description

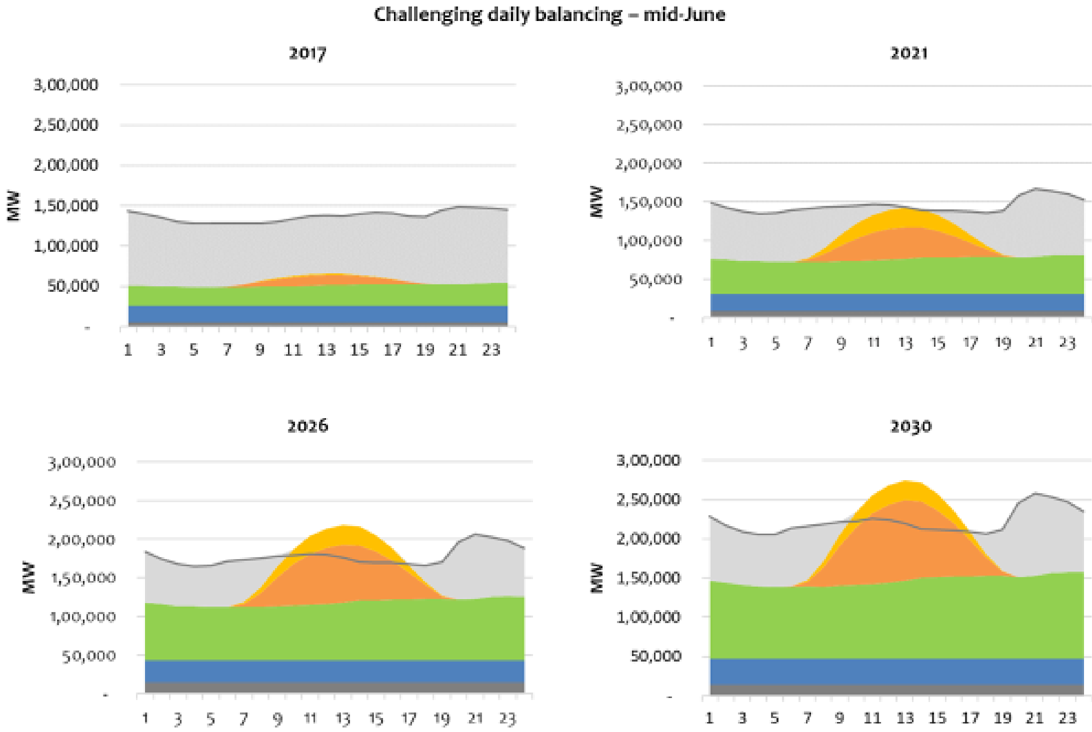
- Ability to shift energy from one time of day to another, either through altering energy production and consumption times, when to consume energy, or storing energy

Drivers

- Wind and solar penetration, and changes in "net load" after wind and solar
- Coincidence of solar and wind production with demand
- Constraints imposed by high minimum generation levels of online generators
- Changing demand profile (eg, air conditioning penetration increasing peak demand)

CLIMATE POLICY INITIATIVE 8

Daily balancing: Daily balancing becomes a significant challenge by 2026



CLIMATE POLICY INITIATIVE

9

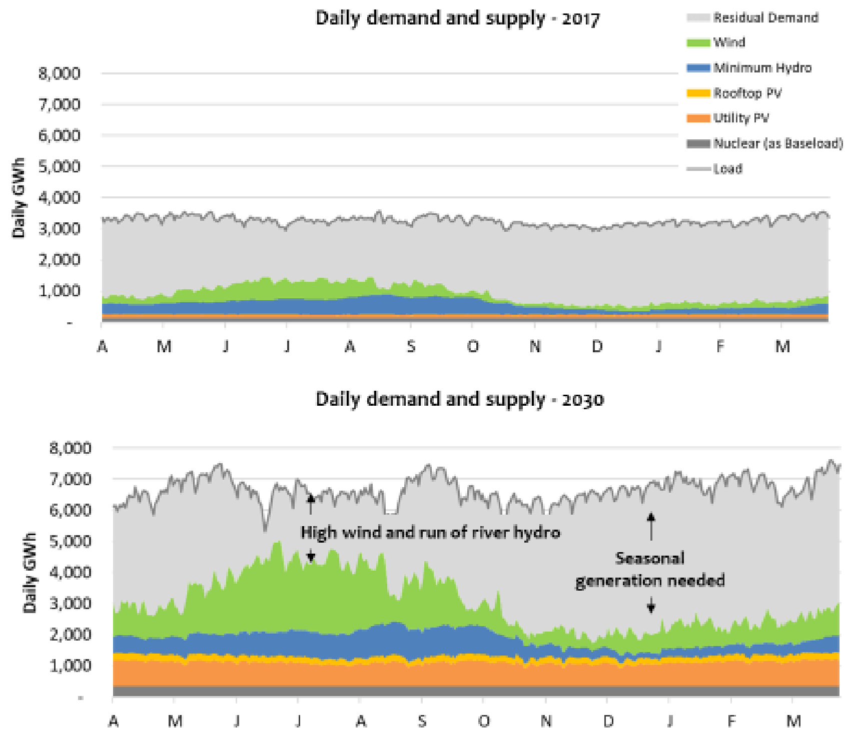
Seasonal balancing: Seasonal wind and hydro will drive greater seasonality in need for dispatchable generation

Description

- Ability to shift energy from one day, week or month to another, either through changing when to produce energy, when to consume energy, or storing energy

Drivers

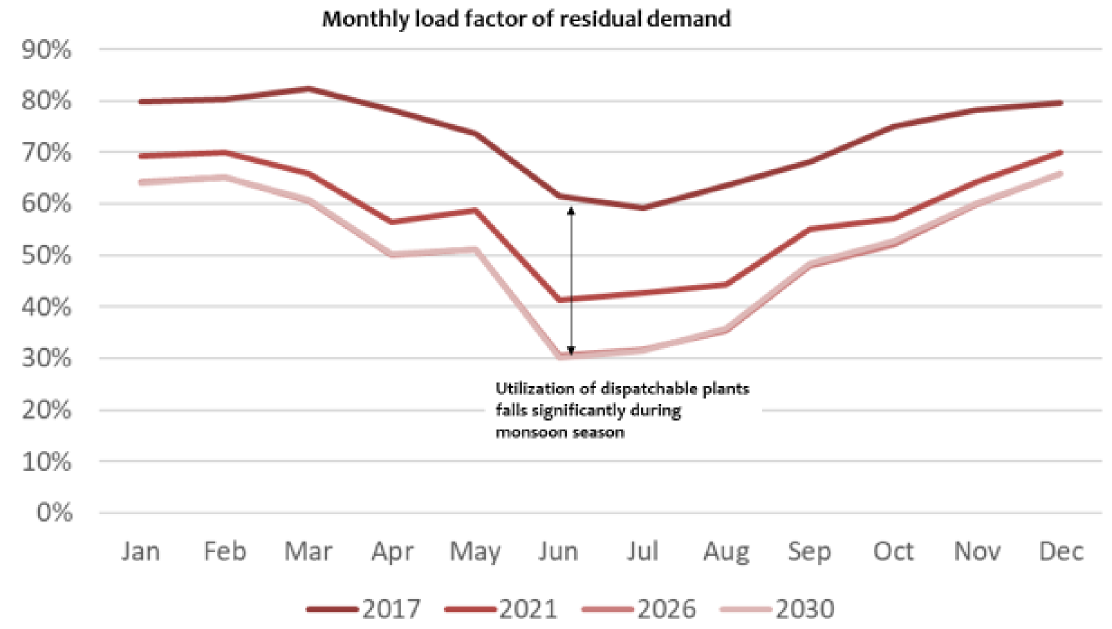
- Wind and minimum hydro flows are highly seasonal, driven by monsoon weather patterns – low wind and low hydro periods coincide
- Solar production is relatively consistent throughout the year



CLIMATE POLICY INITIATIVE

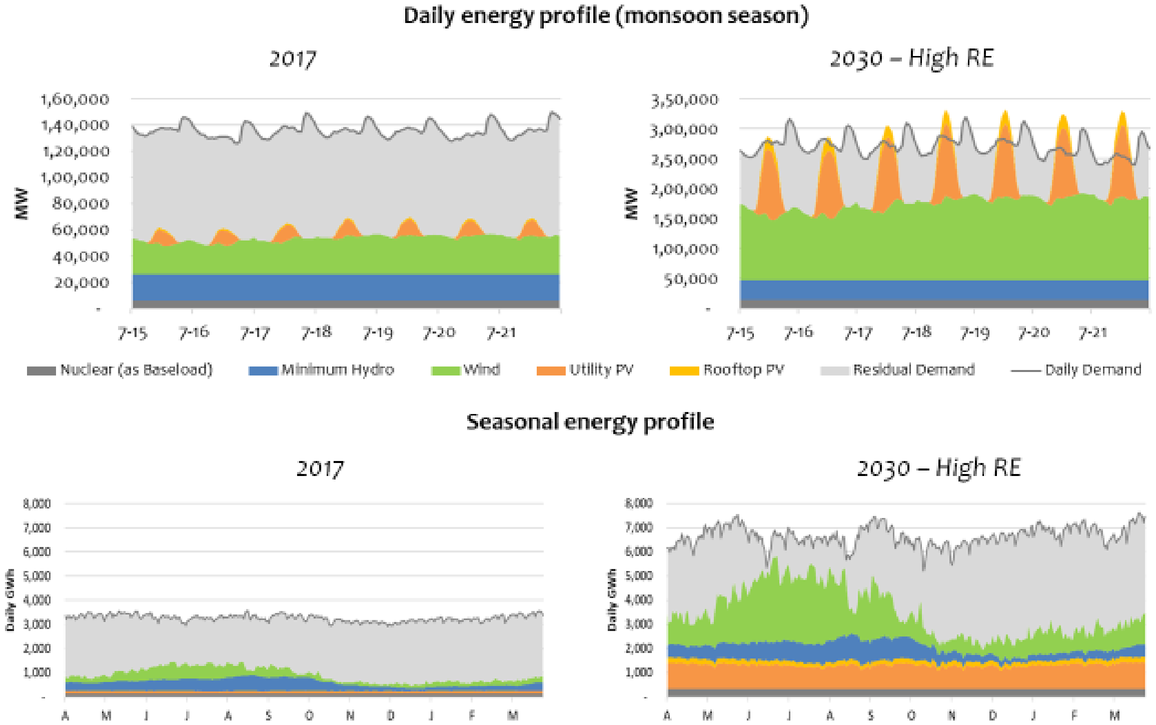
10

Seasonal balancing: Seasonal wind and hydro will drive greater seasonality in need for dispatchable generation



CLIMATE POLICY INITIATIVE

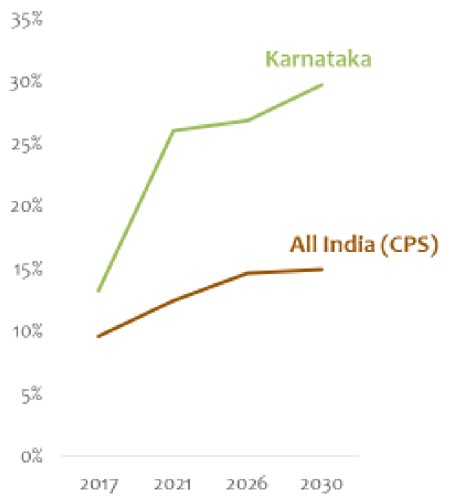
Flexibility needs will increase faster than electricity demand, driven by increased variable generation and changing consumption patterns



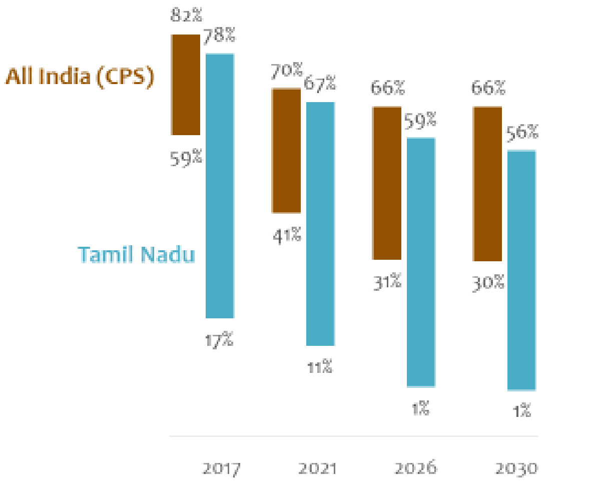
CLIMATE POLICY INITIATIVE

High RE states will face particular challenges that vary from one region to the next

Ramping needs in Karnataka vs. India
(1-hour ramp, % of peak demand)



Seasonal balancing need in Tamil Nadu vs. India
(Highest and lowest monthly residual PLFs)



Note: Represents PLF of generation resources, so excludes hours of negative residual load.

CLIMATE POLICY INITIATIVE 13

Need for flexibility: Without technology and/or policy changes, flexibility could become an issue in the next few years

Preliminary evaluation of current Indian electricity system's ability to deliver key types of flexibility
Under TERI high renewable energy scenario

	Key challenges	2017	2020	2025	2030
Operating Reserves	• Operating reserve needs likely to grow as reserve products are defined and implemented, and as total system size grows • Increased RE forecast uncertainty may drive increased need for reserves, but may be offset by improvements in RE forecasting • May need new resources to provide these reserves if thermal plants that currently provide them are no longer online every day • Further study needed				
Ramping	• Ramp rates will increase by 4.1x (vs. demand growth of 2x) • Likely to be mostly handled by existing thermal and hydro resources	Regional Issues	Regional Issues		
Daily Balancing	• High mid-day solar output, plus high output of wind and hydro will lead to generation in excess of demand during certain hours by 2025-2030 • High minimum generation levels of thermal fleet will accelerate the issue • Result is either curtailment of solar, or need for daily flexibility resources				
Seasonal Balancing	• Residual generation will become increasingly seasonal, driven by high wind and hydro output during monsoon months • Likely to be more severe in specific high-wind states (e.g. Tamil Nadu)	Regional Issues	Regional Issues		

CLIMATE POLICY INITIATIVE 14

Annex 3a. Meeting flexibility needs with demand side options

As our analysis shows, demand flexibility could provide some of the lowest cost options to meet India's growing electricity system flexibility needs. However, compared to using powerplant flexibility or energy storage, demand flexibility is both less developed, and conceptually less well understood. As a result, building a useful share of low-cost demand flexibility will take time, and the potential scale of demand flexibility is significantly more uncertain than powerplants or storage. Nevertheless, achieving large scale demand flexibility could be transformational for India in terms of reducing electricity costs, improving electricity supply quality, and enabling the integration of even higher levels of variable renewable energy. Planning for incorporating demand flexibility into the future system requires an understanding of how demand can meet the system needs, the experience that India has had so far with demand flexibility, the sources of flexibility and their costs, and how these sources fit within the overall portfolio of electricity flexibility.

Harnessing demand flexibility in India

The concept that electricity supply should adapt to consumer demand – rather than consumers using electricity when supply is available – is one of the most widespread and enduring notions of the electricity industry in India, as it is in most places. This view holds despite advances in information technology and electricity market design that could enable demand management at low cost, with very little noticeable impact on the services provided to the consumer.

The systems required, the impact on consumers and the cost depend on the type of flexibility offered (see slide 1). In general, there are many ways to encourage flexibility, starting with time of day pricing, or real time pricing where consumers respond to price signals and extending to agreements for voluntary demand reduction or curtailment, peak demand limiters or automated control systems. The costs involved include incentives to consumers, communications equipment, relevant information technology and customer management. The consumer may wish to invest in equipment such as insulation to enable shifting of air-conditioning timing, water storage to shift pumping timing, or warehousing to store product.

Experience in India with demand response

While demand response programmes and real-time pricing have been tried and tested in many countries since the 1980s, India's efforts are more recent and preliminary (see slide 2). While these efforts show that demand flexibility has potential, they also point to how long it will be before demand response can be a staple of the India power system, unless there is a concerted effort in the area. Indian forays into real time pricing and time of day pricing have also been limited. There are wholesale trading markets, but these prices affect very little of the overall energy supply, and the price signals almost never reach consumers. Time of day pricing exists predominantly for industrial consumers in most Indian states with plans for introduction of ToD pricing for commercial consumers being considered.

Load shedding has been one costly, but effective, exception. Historically, India has managed flexibility, peak demand, ramping and energy shortage issues by cutting off customers when supplies, capacity, or flexibility ran short (slide 3). Consumers, not knowing when the shedding might occur, often had to invest in expensive back-up systems and operate in ways that would reduce the impact of load shedding (slide 4). More recently, India has moved to a system where the timing of shedding is usually planned and advised in advance. With advance warning, consumers can manage their usage in ways that reduces the cost of disruption. As a result, power quality has improved and consumer costs have fallen. The next step is voluntary shedding, where consumers could opt to shed load at certain times for an incentive. In theory, those consumers that would be least affected by the shedding would volunteer, lowering overall system costs. This first step into active demand management will require some IT systems but leads to a much lower overall cost.

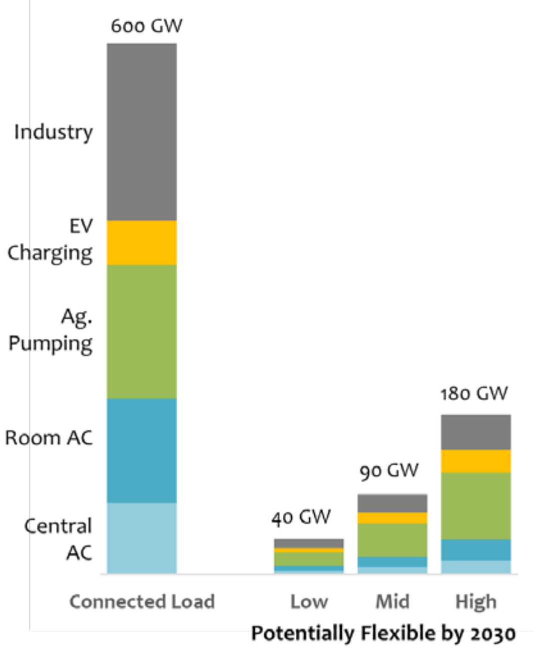
Demand flexibility by sector

The potential for demand flexibility depends on who the consumer is and what they are using the energy for. In general, the net economic benefit to the consumer of providing flexibility must be material and the inconvenience of delivering the service low. Thus, consumers must see the cost of a particular energy use as being significant enough to bother with and must see easy and convenient ways to provide the flexibility. The key to demand flexibility is identifying the significant energy costs while providing convenient systems to develop the flexibility. For agriculture (pumping), commercial and residential (air-conditioning), and transport (future EV charging), we have identified the electricity service that will provide the best combination of these two and analyzed the size of the market they comprise (slide 5). Experience shows that opening a first avenue of demand response reduces the cost and inconvenience of subsequent end-uses. However, within our 2030 timeframe, to be conservative we have chosen to focus on these first end-uses. Industrial demand response is more complex, with a broad array of unique, plant-level response opportunities that depend on the production process, market, and other factors. Thus, we have chosen to estimate industrial demand response at a sectoral level.

Within these end-use/sector combinations there are clear opportunities to provide most of the flexibility services (slide 7), with the path to many options being reasonably well defined (slide 8). Altogether, these end-use/sector combinations represent a peak load of 600GW, with between 40GW and 180GW capable of being operated flexibly. The mid case represents 84% of the potential flexible capacity offered by coal fired powerplants in the High RE scenario, with additional end uses yet to be included. These end uses contribute to each of the flexibility needs, representing 30% of total operating reserve, 42% of ramping, 18% of daily shifting. Industrial demand flexibility is a key potential contributor to seasonal flexibility, but this capacity will require more detailed study, and is unlikely to be needed until well after 2030.

For each of the sector/end-use combinations we have estimated the cost per unit of flexibility offered as well as the potential scale discussed above (below and slide 8).

Flexibility potential for demand by end uses

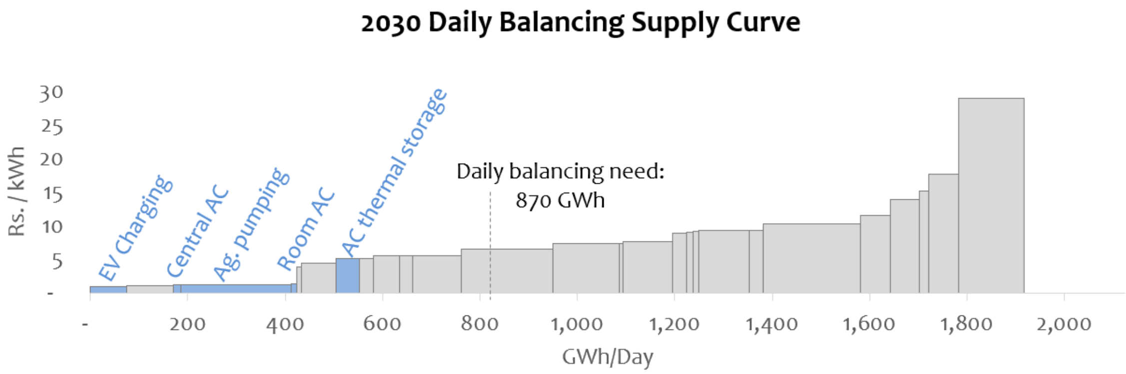


2030 Flexibility	Operating Reserve	Ramping Flexibility	Daily Flexibility	Seasonal Flexibility
Industry	20 GW	20 GW/hr	20-120 GWh/day	Possible, Not Quantified
EV Charging	12.5 GW	12.5 GW/hr	75 GWh/day	-
Agri Pumping	37.7 GW	37.7 GW/hr	226.3 GWh/day	-
Space Cooling	19.8 GW	19.8 GW/hr	27.8 GWh/day	-

More details on the calculations and assumptions will be included in the final CPI report on India flexibility to be published in April 2019. A summary of some key data points and issues around flexibility for each of these end uses is included in slides 10-13.

Comparing demand flexibility to powerplant flexibility and storage

Although demand flexibility will require time, effort and patience to develop, by 2030 demand flexibility could be a significant contributor to lowering electricity system costs and improving service quality. We have developed supply curves for each flexibility type, ranking options from lowest cost to highest cost, showing how different levels of flexibility needs could be met at different costs. While demand flexibility is likely to have only a small impact on short term reserves – which are already reasonably well covered -- demand could significantly reduce the costs of daily balancing and ramping (below and slides 13 and 14).



There is significant potential for demand response to surpass these estimates as they focus on only a subset of demand response opportunities. Specifically, they do not include spill over opportunities in residential, commercial or agriculture, once the systems and culture of demand response enter these sectors. Further, lacking specific detail about individual industrial demand response opportunities, that sector has not been included in this analysis, despite ample opportunity.

Developing systems and overcoming barriers to access demand flexibility

The electricity system has been built around assumptions of supply flexibility for many decades. Adding demand flexibility will require developing new systems, measurement and monitoring, and relationships that will take time to develop. Demand flexibility will also require overcoming barriers, many of which have developed as consumers adapted to the way electricity has traditionally been supplied. Some of these barriers are physical. Inadequate building stock insulation makes it difficult to shift the timing of cooling, for instance. Measurement provides more barriers. To provide effective demand response, we need to understand the energy consumption pattern for a particular end use and observe how that patter changes with incentives. In cases like agricultural pumping, efficient demand response will require separate metering along with the completion of the supply feeder separation. There are tested business models and incentives that can help overcome these barriers (slide 15). However, development will take time and move in stages as technology, incentives and business models improve and develop in response to the demand flexibility levels delivered.

Annex 3a will show that India can meet its flexibility needs to 2030 using just powerplants and storage, but it will also show how much money can be saved by employing demand flexibility and how much more clean energy India will be able to use in 2030 and after. Demand flexibility will take time and effort to develop, but the reward will be high.

Consumers can meet each of the flexibility needs with a combination of investment, control and communications equipment, and incentives to make it worthwhile

	How consumers can provide flexibility	What is needed and what could it cost
Spinning reserves and load following	Consumers would need to give system operators control to vary consumption/ processes continuously on a minute by minute basis	• These needs are well met by powerplants (and storage) • Sophisticated monitoring and control is needed, so demand contribution only makes sense for large equipment that can respond quickly (mostly industrial, but also EV charging)
Short-term reserves	Consumers give system operators the (limited) option to reduce demand when capacity runs short	• Requires simpler equipment than load following, for example signalling that triggers automated demand reductions (for example for air-conditioning turn down for a limited period) • Consumers will need communications/control equipment, metering, and incentives to use them
Ramping	Consumers shift their consumption slightly, for instance by beginning to cool homes early, or delaying evening consumption	• Either type of action above can be used by system operators to meet ramping needs, although the load following provides more value • Systems/agreement to adjust daily consumption patterns (eg, prescheduling of AC demand) can also provide value on a daily basis
Daily balancing	Consumers shift their daily energy consumption patterns, for example, by rescheduling when they use appliances	• Requires metering, monitoring and incentives • Consumers may have to invest in different types of equipment or timing • Time of use tariffs, or hourly pricing can provide incentives
Seasonal balancing	Consumers shift demand over the year. Can include greater energy conservation during peak seasons, or rescheduling or production	• Metering, communication, monitoring and incentives are needed. • Incentives will need to be provided contractually, in advance, to ensure shifting can be incorporated into planning • Consumers will need to invest to shift timing of maintenance (over the year), or to store production for times of lower energy use

CLIMATE POLICY INITIATIVE

Demand flexibility: Case studies in India

Tata Power - Delhi
- 354 consumers participated, 17 events
- Reduced 34MW of load

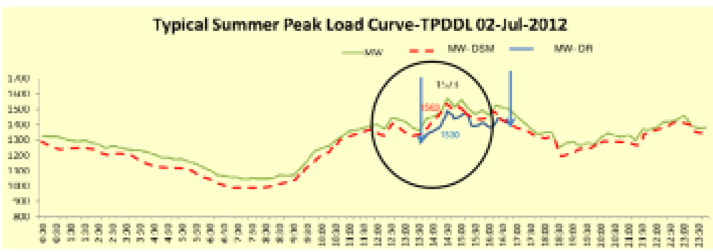
BSES - Delhi
- Ran pilot for largest 500 customers
- Reduced 17 MW of load

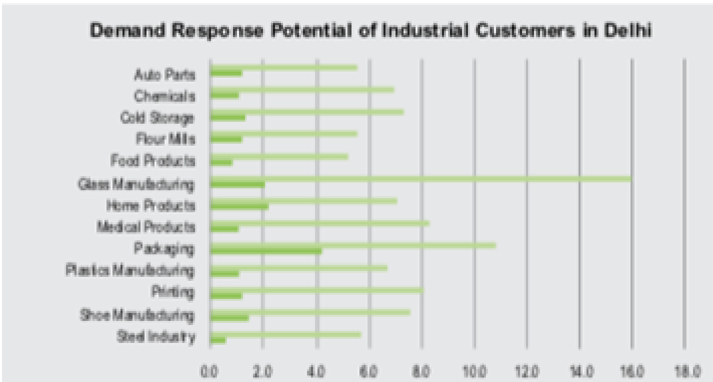
→ Plans 2-5% peak shaving (30-75MW)

Tata Power - Mumbai
- 27 customers participated, 18 events
- Reduced over 15MW of load
- 18.157MWh of load shifted

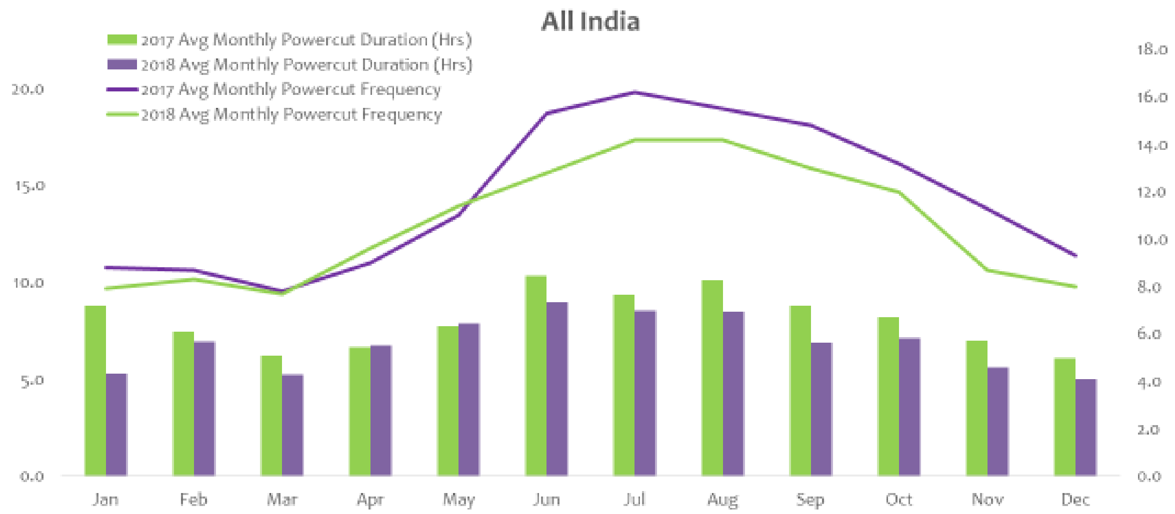
JVVNL - Jaipur
- 17 participating consumers across 3 industrial areas, 4 events
- Reduced approx. 22MW of load

Thermal Energy storage – Tata
- Thermal storage capacity of 15K Tons enrolled





India has also been using involuntary load shedding to balance demand



India has historically managed flexibility, peak demand, ramping and energy shortage issues by cutting off customers when supplies, capacity, or flexibility ran short – using load shedding, an expensive tool for demand management.

CLIMATE POLICY INITIATIVE 3

Load shedding has a significant economic cost

Power replaced at additional cost

Diesel gensets
90GW
Variable Rs. 17/ KWh

Inverter batteries
+ 5GW p.a.
Variable Rs. 4/ KWh

Power lost

???

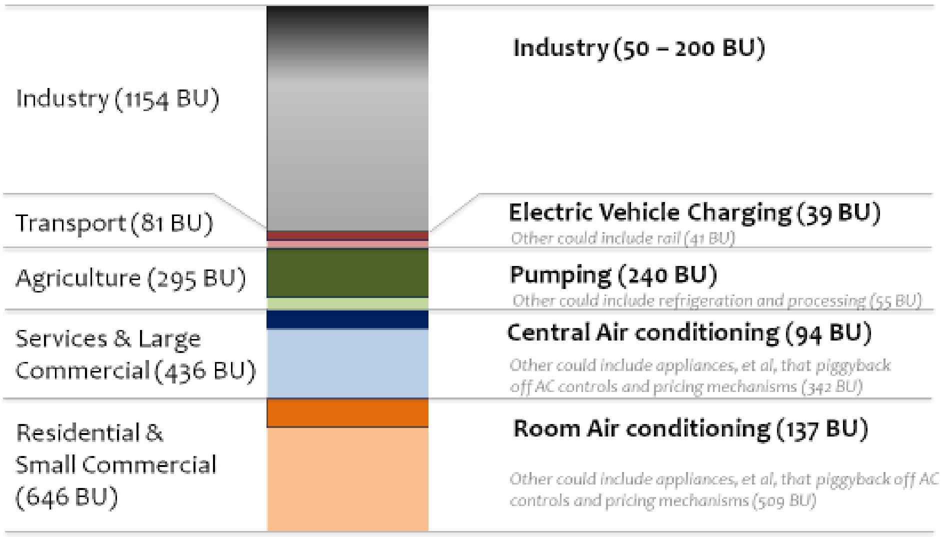
Economic cost of load shedding

- Building of expensive redundancies in the system through the accumulation of DGs and Inverter-Batteries
- Damage to equipment
- Payment to workers for downtime
- Waste of raw materials due to interrupted processes
- Wastage of food in households

CLIMATE POLICY INITIATIVE 4

We have concentrated on the most accessible and potentially highest value demand shifting opportunities within each sector for our evaluation

Estimated energy demand by sector and key flexibility options
(of estimated **2030** electricity consumption)



… but once demand measures are adopted, subsequent opportunities will grow, so estimates could be low

Source: TERI (Baseline Scenario) and CPI Analysis

CLIMATE POLICY INITIATIVE 5

Ag. pumping, space cooling and industry are currently the major sources and offer different types of flexibility, EVs are expected to be a major source in the future

		Air conditioning	Agri pumping	Electric vehicles	Industry*
Potential Connected Load**	**2018**	75 GW	106 GW	N/A	86 GW
	2030	198 GW	151 GW	50 GW	200 GW
Spinning and load following		Central cooling solutions can offer limited spinning and load following capabilities by turning off equipment chillers for a few minutes through automated DR	Upon separation, the agri feeders can be temporarily turned off to reduce immediate load and therefore reduce requirement of spinning capacity	Can provide limited spinning capacity through v2g operations for charger connected vehicles. Real world use cases currently in testing phases	Potential for providing load following capabilities using auto DR for certain equipment (pumps, compressors, etc.).
Short-term reserve		Smart air-conditioners and smart plugs through DR can shut down the compressor to free up MW. But installing smart systems currently bear a significant cost		May provide short term reserve capability by temporarily interrupting charging with appropriate price incentives to the vehicle owner/operator	Turning off some of the non essential equipment temporarily can help free up energy for short term balancing
Ramping		Central AC load may be shifted to off peak hours using thermal storage or temperature raising in a central AC fleet (only part of the fleet's temp raised for a time block). Room ACs may not offer flexibility to reduce ramping	Supplying agri feeders during the peak generation or low demand periods can reduce ramping needs	Charging cars during high generation and off peak consumption hours can reduce additional ramping needs	Non process industries, (running morning to evening) may exaggerate the ramping need – However future ramping need driven by solar could be partially covered by backing down some of the batch operations
Intraday balancing		Central air-conditioners through thermal energy storage can shift peak cooling load to off peak durations creating a flatter load curve	Through the segregation of feeders, agri pumping operations can be shifted to off peak hours thereby flattening the load curve	Charging of the batteries during off peak hours can help flatten the load curve	By shifting some of the batch manufacturing activities to off peak times from peak hours, industries can provide intraday balancing
Seasonal flexibility		May contribute to local needs for seasonal flexibility	Contributes to the need for seasonal flexibility	PHEVs have some potential to provide seasonal flexibility by shifting to gasoline based operations during high peak months	Can help meet seasonal flexibility need by scheduling planned outages and maintenance during periods of high demand/low generation

CLIMATE POLICY INITIATIVE 6

*including captive capacity; ** non-coincident capacity of equipment

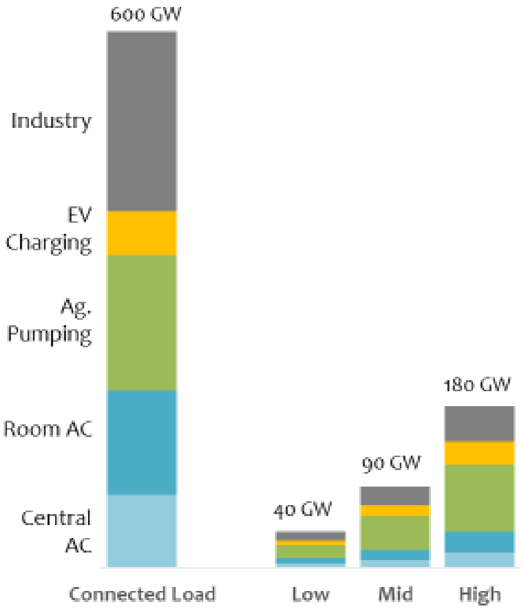
There are low hanging fruits in demand flexibility which can be tapped at relatively low cost

	Costs	Areas needing investment
Agricultural pumping	12,200 INR / kW (derived from cost per connection)	• Dedicated agricultural feeders • Distribution monitoring and automation systems
Space cooling	5,000-15,000 INR/kW up front additional cost Ongoing cost of < 700 INR/kW-yr	• Smart AC controls • Fleet control, optimization and dispatch software • Thermal energy storage systems
EV charging	5,000-10,000 INR/kW up-front cost Ongoing cost of < 700 INR/kW-yr	• Additional batteries to enable battery swapping for 2- and 3- wheelers • Additional charging points for cars • Fleet control, optimization and dispatch software
Industry	Costs are industry dependent ranging from very low for batch manufacturing industries with high technical potential e.g. packaging to very high for even partial; back down of process based industries e.g. steel	• Control systems for isolating and shifting loads • Fleet control, optimization and dispatch software • Equipment R&M for sustaining flexible operation

CLIMATE POLICY INITIATIVE 7

Significant low-cost potential for demand flexibility may be challenging to unlock

Flexibility potential for demand by end uses



2030 Flexibility	Operating Reserve	Ramping Flexibility	Daily Flexibility	Seasonal Flexibility
Industry	20 GW	20 GW/hr	20-120 GWh/day	Possible, Not Quantified
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CLIMATE POLICY INITIATIVE 8

Key Data Points – Agricultural pumping

	2017	2030
Number of Grid Connected Pump sets	20,000,000	28,368,794
National irrigation load (GW)	106	151
Energy Consumed by Pump sets (BU) [avg. pumpset of 5.3kW running for 4.36 Hrs daily]	169	240
Annual national cost of electricity for irrigation (Rs. bn) [With current avg. cost of power procurement rising 5% annually]	677	1,812

- Program to switch to high energy efficient pumps has been initiated
- The cost per connection to an agricultural user is Rs 65,000 and it costs ~ Rs 0.24 Million per km for installation of a separate agricultural feeder
- With the cost of each new connection at Rs 65,000; the per kW cost of shifting pumping load to new agricultural feeders is ~Rs 12,200 (using avg. 5.3 kW pumpsets)
- The Solar Irrigation Pump program envisages 1.75 million diesel power pump sets and 1 million grid connected pump sets will be replaced by solar powered pump sets
- The replacement of grid connected pump sets by solar powered pump sets is expected to cost ~Rs 600 billion, reducing the total load on the grid by ~3.7GW (which requires ~Rs 165 Billion to set up – Utility PV)
- This reduced agriculture pumping load on the grid also reduces flexibility potential

CLIMATE POLICY INITIATIVE 9

Key Data Points – Air conditioning

Room AC	2017	2030
Number of Units	30,000,000	124,000,000
Total Installed Capacity (Million Tons)	43	177
National room air conditioning load (GW)	42	117
Annual Electricity Consumption per AC of 1.35 Ton (kWh)	2286	1044
Annual Electricity Expense per AC (INR) [With avg. tariff across consumer categories rising 5% annually]	13,715	11,809

- Smart Room ACs which can help with automated DR are available from major manufacturers but cost ~Rs 53,000 per AC (1.5 Tons) and the current models are not the most energy efficient
- Smart ACs cost over Rs. 15,000/kW (1 Ton cooling capacity~ 1kW load) more than similar non smart ACs currently available
- Smart Plugs for non-smart room ACs can enable automated DR at a cost of ~ Rs 5,000/kW

Central AC	Current	2030
Installed Capacity (Million Tons)	33	122
Annual Power Consumption (BU)	55	94
National central air conditioning load (GW)	32	81

- Central ACs have a capital cost of ~Rs 25,000 per ton and consume ~1700 kWh/ton of energy annually
- They can also be candidates for load shifting through addition of thermal energy storage systems at no additional cost, when added at initial installation.
- They are more suited for flexibility need response than room ACs due to the size of each unit

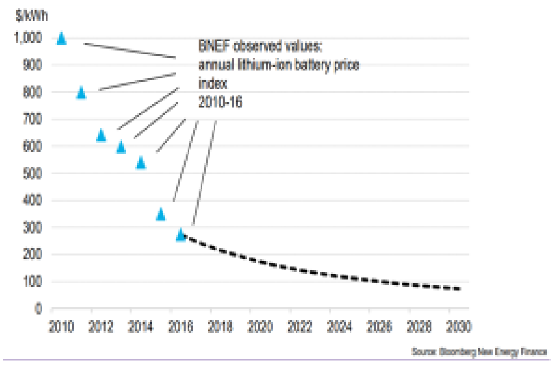
CLIMATE POLICY INITIATIVE 10

Key Data Points – EV Charging

Vehicle Type	Share of EVs in new vehicle sales (%)	Total Electricity demand from EVs – Existing and New Sales - (GWh)
4 Wheelers	5%	7,626
2&3 Wheelers	20%	11,152
Buses	10%	12,630
Light Duty Freight Vehicles	5%	9,726
Total		**41,134**

Source: TERI (Baseline Scenario)

- Fleet vehicles such as buses and taxis are expected to have higher rate of adoption due to their higher utilization rate accruing savings and benefits quicker
- BNEF calculates that producing a battery in a Korean manufacturing plant in 2017 cost $162/kWh, dropping to $74/kWh by 2030
- As per consensus estimates, the cost of BoS, Soft Costs and EPC currently form up to 70% of the total system costs, expected to to decline rapidly to 50% by 2030
- At 4hrs of system utilisation, we estimate system costs ~Rs 10,000/kW, dropping to ~Rs 5,000/kW by 2030
- We have assumed that only 25% of the EV capacity will be available to dispatch flexibly



CLIMATE POLICY INITIATIVE

Key Data Points - Industry

	2001	2015	2030
Total Industrial Electricity Demand (GWh)	1,59,507	4,23,523	11,53,916
- Supplied through grid (GWh)	1,07,296	2,85,696	7,96,897
- Met through captive generation (GWh)	52,211	1,37,827	3,57,019

Source: TERI

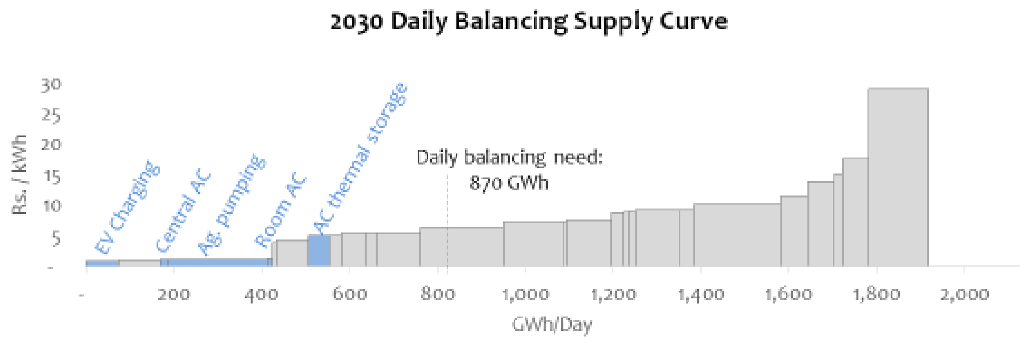
- The total capacity installed to meet the industrial demand ~200 GW (including backup DG sets)
- As per the mid scenario, the flexibility potential of this connected load is 10% (20GW)
- Electro intensive industries like Textile, Metals, Cement, Paper etc offer the largest flexibility potential amongst industries

Industry	Flexibility potential	Processes offering flexibility
Textile	8-12%	Stentor, jiggers, humidifiers and centrifuges
Iron & Steel	5-7%	Material preparation, waste metal recovery , sand reclamation unit
Paper and Pulp	3-4%	Chip plant, ETP, pulp preparation
Cement	2-3%	Grinding

Note: Lacking specific detail about individual industrial demand response opportunities, that sector has not been included in our individual supply curves yet.

CLIMATE POLICY INITIATIVE

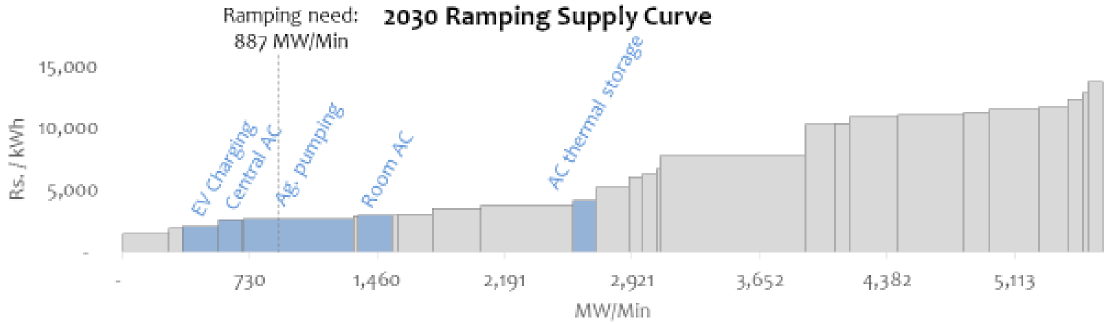
Demand side measures have high potential and low cost

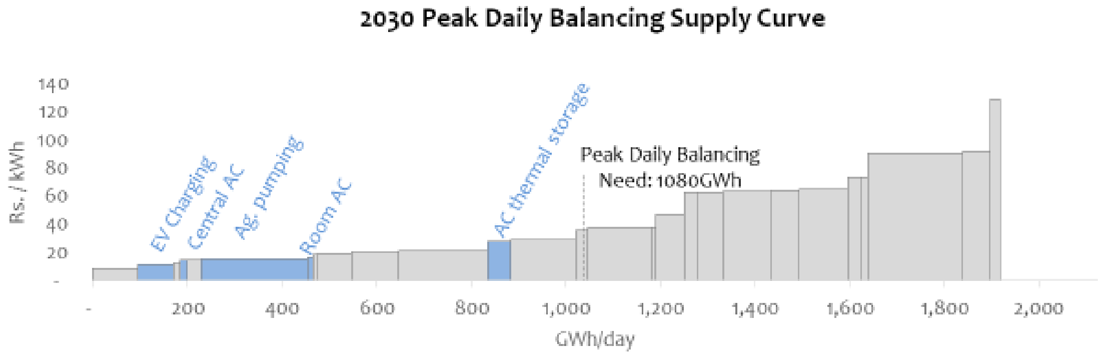


CLIMATE POLICY INITIATIVE

13

Demand side measures have high potential and low cost





CLIMATE POLICY INITIATIVE

14

Some barriers exist in realizing the potential which can be overcome through price signals, incentives, contracting structures and granular data on flexible sources

	Barriers	Potential business models	Incentives needed
Agricultural pumping	• Existing structure of common feeders for rural domestic consumption and agricultural demand • Political sensitivities around charging agricultural customers • Lack of discom incentives to invest in feeder separation to isolate agricultural demand	• Separation of all agricultural feeders which can provide load shifting opportunities • Metered and billed usage for non - agricultural rural consumption	• Continued push for completion of feeder separation program • Direct benefit transfer schemes
Space cooling	• Fleet of existing fixed speed room air conditioners with no "smart" features • Poor building insulation limits inherent thermal storage in buildings • Lack of data on regional AC penetration or usage profile to predict available flexible loads • High cost of efficiency retrofits in central ACs • Behavioral barriers to changing temperatures • Fragmented control over AC investment and operational decisions	• Aggregation and dispatch of fleet of AC systems by discom or third party • Shift to high efficiency ACs with pay back through savings • Use of thermal energy storage in greenfield central AC installation to lower opex and provide load shifting • Smart controls for DR linked savings through marginal temperature raising • Unlocking demand response value through smart AC or Smart Plugs • Thermal storage systems to replace DG sets as backup during power outages	• Time of day tariffs for residential and commercial customers • Prioritization of high efficiency smart ACs (NCAP) • Building guidelines for central ACs to include thermal storage • Sharing of DR linked saving between discom and market participants
EV charging	• Prediction of charging profiles and available charging load • Lack of ubiquitous, standardized charging infrastructure • Charging patterns likely to be driven by consumer needs and convenience, not electricity pricing • Uncertainty around EV market potential	• Aggregation of EV charging demand participating in electricity markets • EV charging subscription plans with discounts for greater flexibility	• Location-based and time of use pricing for EV charging
Industry	• High cost impact of halting supply line based or process based industries • Fragmented nature of industry demand (over 2/3 consumers outside electro-intensive sectors)	• Earning through sharing of discoms saving by shifting planned maintenance to high electricity demand season • Unlocking demand response through local targeting of non-process industries with high technical potential	• Regulatory mechanism to facilitate sharing of savings

CLIMATE POLICY INITIATIVE 15

Annex 3b. Meeting flexibility needs with thermal and hydro powerplants

Thermal and hydroelectric powerplants, along with load shedding, provide most of the flexibility needed by India's electricity system today. Existing powerplants could provide more flexibility across all types of flexibility needs than they do today. However, there are limits to how much flexibility they can provide and there are costs to provide it. Optimizing India's electricity system will need this flexibility and to achieve the lowest cost and most robust system, it will need to optimize the integration of powerplant flexibility options with the demand and storage options. To assess integration opportunities, we need to start with how powerplants provide flexibility and the limitations and costs.

Limits to flexibility from thermal powerplants
Within limits, powerplants are dispatchable. That is, system operators can turn plants on or off, up or down. The limits are significant.

- **Minimum generation –** Powerplants cannot operate stably below a certain level of peak capacity. Below that level output will become unsteady and the equipment cannot handle the operating parameters. The level of minimum generation is a function of the plant itself, as well as the control equipment and system or plant owner operating policy (designed to maintain a stable electricity system). The range for offering flexibility services such as ramping or daily balancing, is limited to the "flexible range" between maximum and minimum load. For example, a 200MW plant with a 55% minimum operating level could offer 90MW of ramping or, in many cases, daily balancing.
- **Ramp speed –** Just as an automobile requires time to accelerate from 0-100km/h, powerplants require time to raise temperatures to provide steam and increase output. To meet increasing, or ramping, demand as factories start up or lights are turned on (or solar PV output decreases) a system will bring on as many powerplants needed to address two constraints: how much total ramp will be needed and how fast that ramp will be needed. A single powerplant can contribute the difference between its minimum and maximum as its total ramping, and contribute its rate of acceleration (MW/min) to the peak ramp. Often the number of powerplants dispatched in a system will depend upon the maximum acceleration required (adding up all of the maximum ramp rates of the plants available to ramp), rather than the number of plants required to meet peak load.
- **Start-up time –** Depending on how long a plant has been idle, it will require time to get the plant up and operating, even to minimum output. Startup times generally last for several hours, requiring notification to the plant operator of when the plant will be needed well in advance. More often, plants need to be left at minimum generation so that they are available later in the day for peak times or peak ramping needs.
- **Minimum down time –** Likewise, most plants cannot be shut down for a few minutes or an hour and then re-started. Minimum down times also lead to plants running at minimum or less than maximum output for parts of days.
- **Load following/frequency response/other –** Finally, powerplants can be asked to make smaller adjustments on a real time basis to help manage supply and demand balance. Providing these services requires more sophisticated control systems and sometimes plant modification.

Slide 1, provided by ETC India member Siemens, shows how a typical powerplant could offer various flexibility services to the system. The black line represents the potential flexibility offered from a typical powerplant before it is made more flexible through investment, changes to operating practices, renegotiation of contracts that limit flexible operation or provide disincentives to do so, and enhanced control systems.

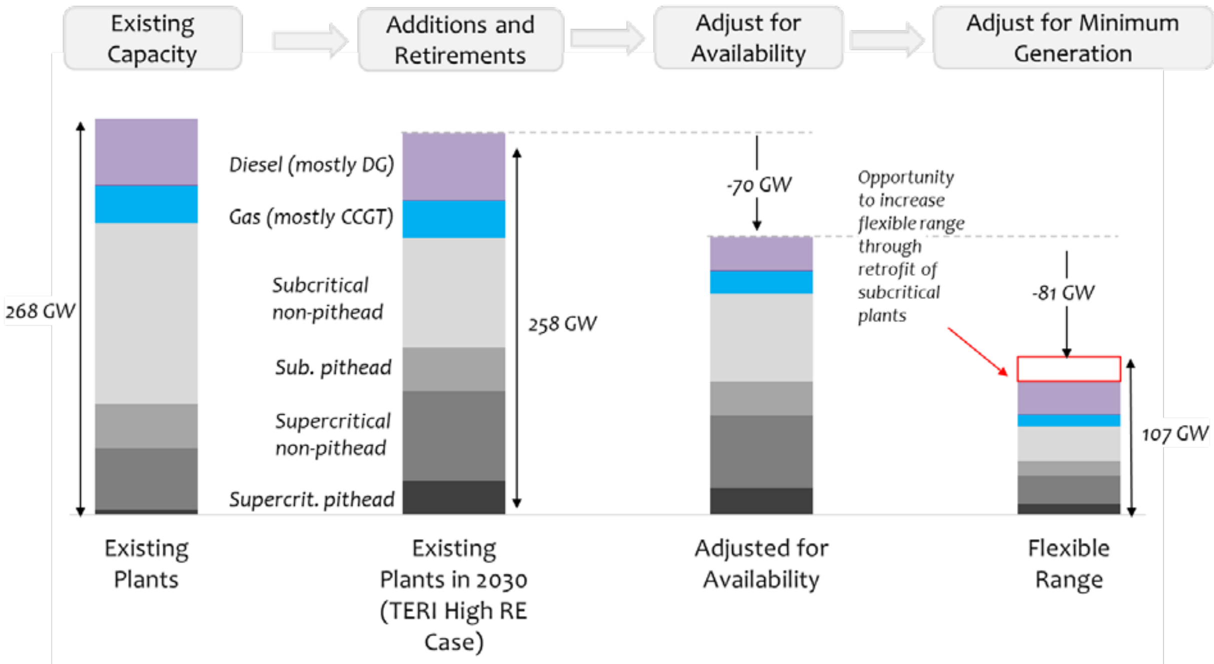
Costs of providing flexibility from thermal powerplants
Although the powerplants that provide flexibility are already running, there are at least five ways that offering flexibility could increase the costs to the powerplant and to the system:

1. **Efficiency penalty.** Thermal powerplants are less efficient when they operate below their maximum rated capacity. Slide 2, also provide by Siemens, shows how the heat rate[1] of a 500MW coal fired powerplant would decline at lower load factors. This plant could operate at a minimum load of 50% or 250MW. We factor in 10% efficiency loss at part load.
2. **Operating costs.** Operating plants more flexibly requires changes in temperature and starting and stopping equipment, all of which puts strain on the equipment, requires increased maintenance, and requires additional monitoring. Additionally, plant failures and repairs may be more likely. How much costs, maintenance and failures increase is controversial, as is how much investment and changed operating procedures can reduce these costs. Nevertheless, there is certainly some additional costs. We have not factored in any increase in operating costs, separate to the penalty already factored in through efficiency losses above.
3. **Capacity.** Providing some flexibility services, such as short-term reserve, requires powerplants to operate at less than maximum capacity so that they can increase output quickly in response to sudden surges in net demand. Not only does operating below maximum increase fuels costs as above, system-wide additional plants may be needed.
4. **Start-up costs.** While fuel is saved by shutting a plant down, restarting a plant and bringing it back online incurs extra costs including fuel, operating costs, etc.
5. **Upgrade costs.** Many plants are not operating as flexibly as they could. Increasing flexibility for these plants requires changes in operating practices, guidelines and incentives. Additional flexibility can be added to the system through investment. Slide 2 shows one example of how a plant upgrade, adding 200MW of capacity to a 500MW plant, could increase flexibility by 50% from 240MW (490-250) to 360MW, and decrease the fuel cost penalty from close to 2.5%, to around 1.5%.

Estimating available thermal powerplant flexibility

We estimate how much flexibility is available by identifying which plants could provide flexibility, adjusting these numbers over time for additions and retirements, then adjusting for availability (that is, maintenance and repair down time), and then adjusting for minimum generation, as in the figure below.

Figure 3b-1 Potential flexible capacity from existing thermal power plants



[1] The heat rate of a powerplant is a measure of efficiency expressed as units of fuel divided per unit of electricity output. In India, a typical plant will have a heat rate in the region of 10,000. Thus, a decline in heat rate of 100, represents about a 1% increase in fuel costs per kWh produced.

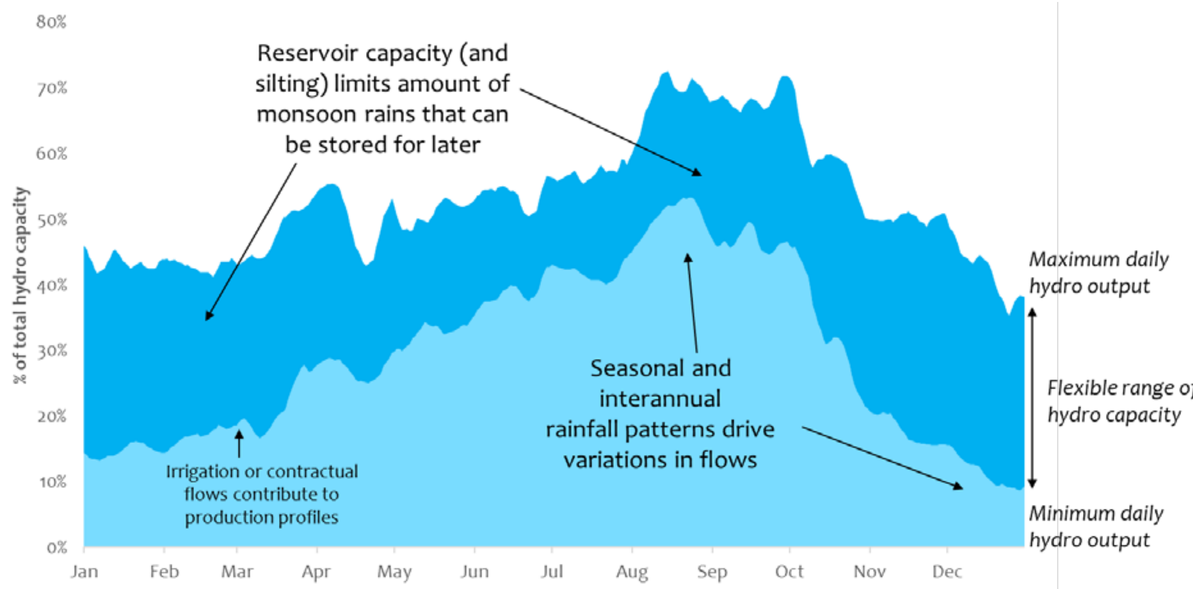
After these adjustments, powerplants can provide 107GW of flexibility to the system, of which about 20GW would require significant plant upgrades and investment.

Hydroelectric powerplant flexibility

Hydroelectric powerplants with large reservoirs are often much more flexible than thermal powerplants. They can start up almost instantaneously, with little startup costs; they have almost no minimum generation limits and can operate at almost any level of output with little efficiency loss. Running below maximum output saves energy for later use, and these plants can easily follow load. For these reasons, hydro powerplants are often the first source of flexibility.

However, there are certain complications. Rainfall drives potential output, so output and flexibility provision are seasonal. At times, plants must operate at high output to avoid water spillage, at others they must operate at least enough to ensure that rivers flow to supply irrigation and keep wildlife alive. Seasonal flexibility is limited by the size of the reservoirs and the rainfall patterns. At the same time, there are many hydroelectric generators that have limited or no reservoirs and therefore offer only limited levels of flexibility. Figure 3b2 shows how hydro flexibility varied in 2014 for India.

Figure 3b2 India-wide minimum and maximum daily hydro production, 2014 (CEA)

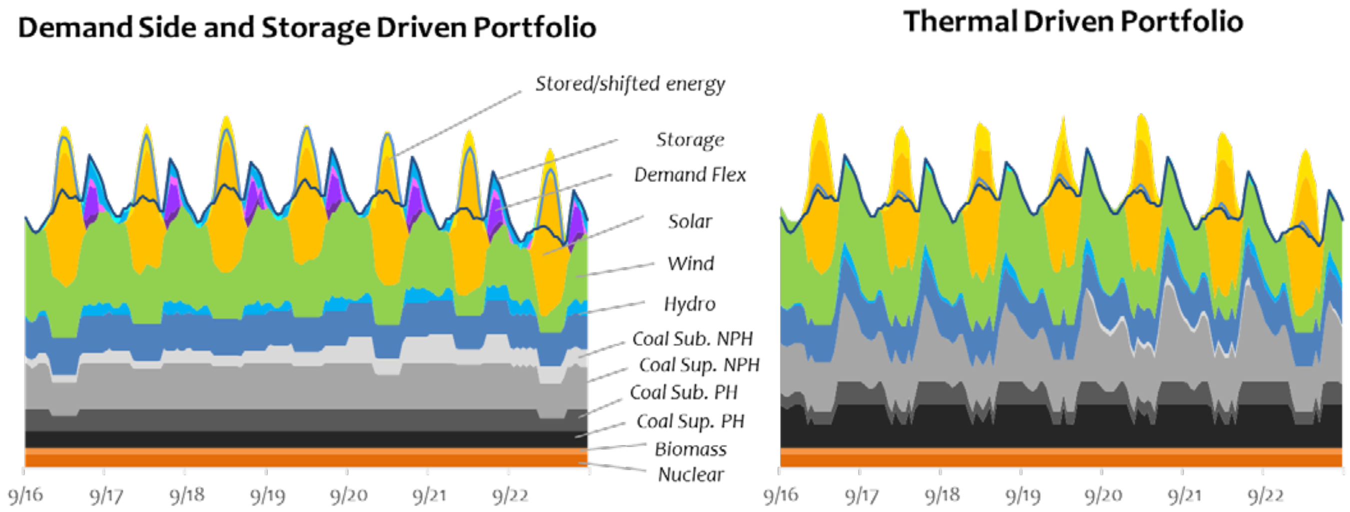


Meeting specific flexibility needs

Each of the flexibility needs incurs different costs for the powerplants and different capacity availabilities. Slides 3-6 show where thermal and hydro powerplant fit within the flexibility supply options. Hydro is among the lowest cost options for all flexibility needs, but only for reserves is there usually enough existing hydro capacity to come close to fulfilling India's needs. Thermal powerplant will play an increasing role in daily balancing, ramping and seasonal balancing, providing almost all of the latter at a reasonable cost. Captive diesel (slide 5) gensets, owned by consumers, will also be able to contribute to meeting the peak daily balancing needs, if adequate controls and incentives can be built to harness their capacity at the right time.

To meet these requirements, thermal powerplant will need to operate more flexibly, with lower minimum generation and more frequent start-ups, variations in generation across the day, and seasonal shutdowns when less thermal capacity is needed. However, given the availability of many lower cost demand and storage flexibility options, the operation of thermal powerplants will depend upon how much of these sources develop. The chart below, which foreshadows the analysis of the portfolio section, shows how thermal powerplant of different types will operate differently in a system with fully developed demand flexibility and storage, compared to a system where powerplants are the only source of flexibility.

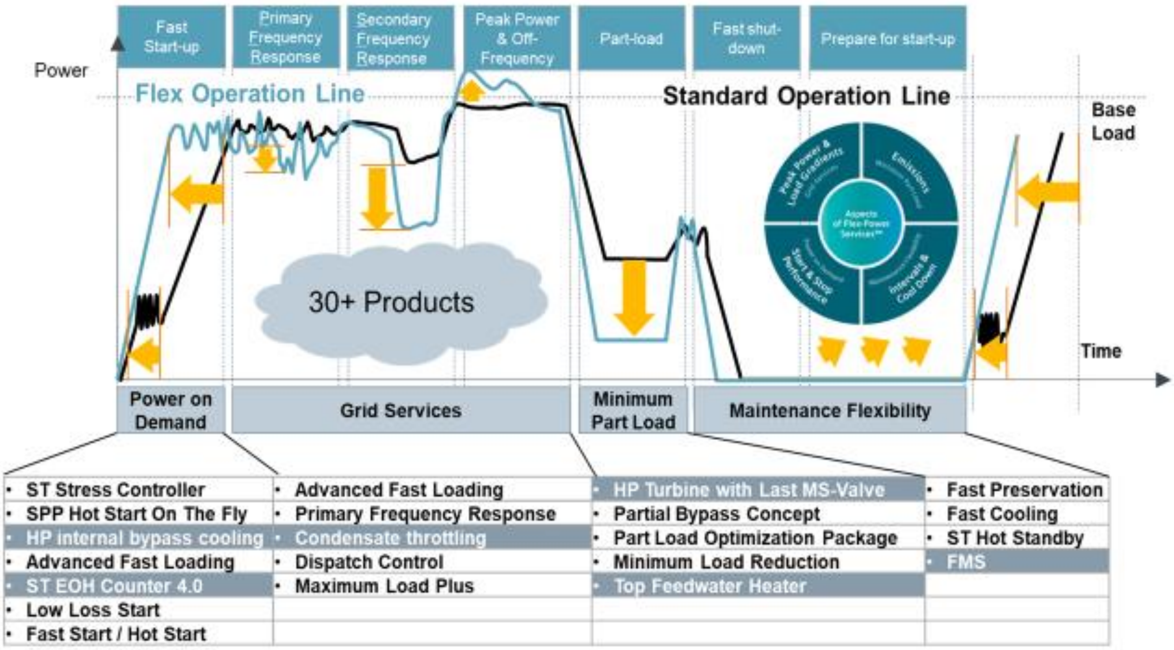
Figure 3b Thermal power plant contribution to flexibility depends on interactions with other system resources3



Thermal Asset Roles:
- Cheapest pithead plants turn down infrequently
- Limited intraday ramping and balancing
- Relatively flat profile
- Storage and demand shifting absorb most mid-day solar production and follow changes in load / RE

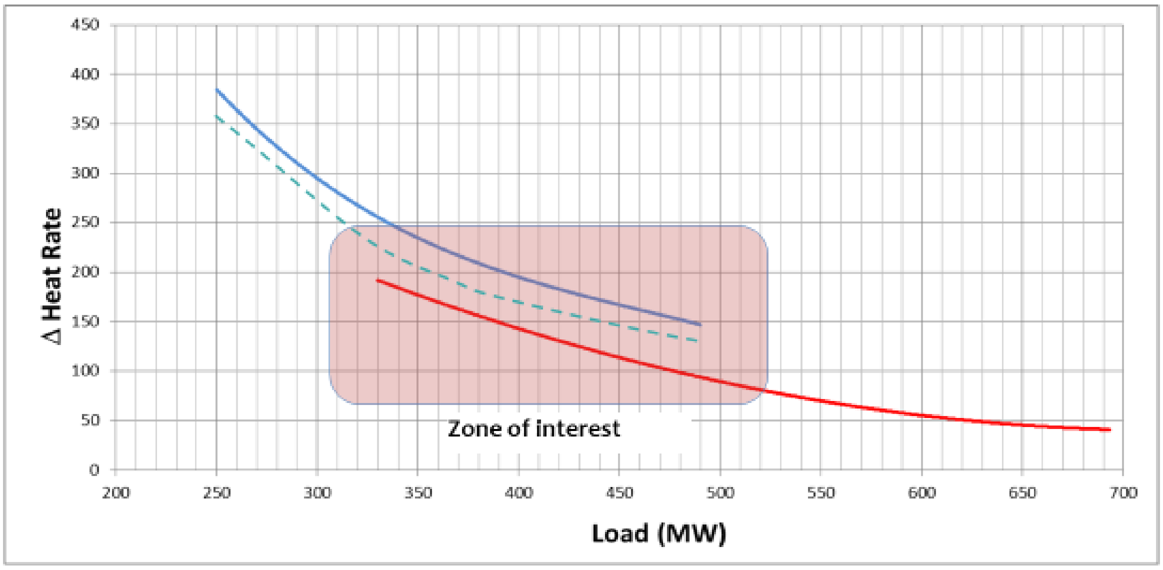
Thermal Asset Roles:
- Even cheapest pithead plants turning down daily
- More expensive non pithead plants ramping substantially to balance supply and demand
- High minimum generation levels contribute to substantial mid-day excess energy production

How coal-fired powerplants contribute to flexibility services (courtesy of Siemens)



CLIMATE POLICY INITIATIVE

Impact of lower generation on efficiency (courtesy of Siemens)



A typical 200 MW modernization would lead to 25 paisa savings in cost of generation with payback period of ~3 years

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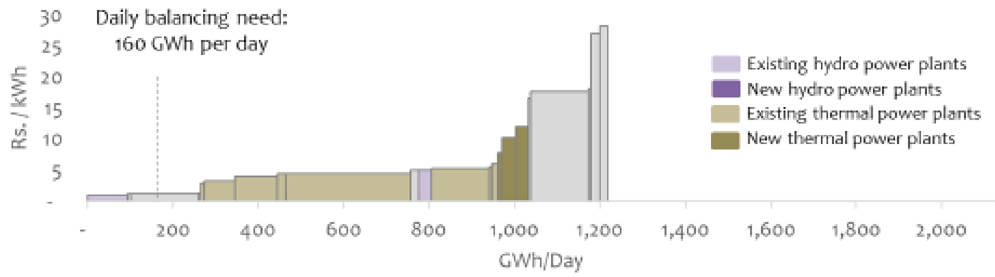
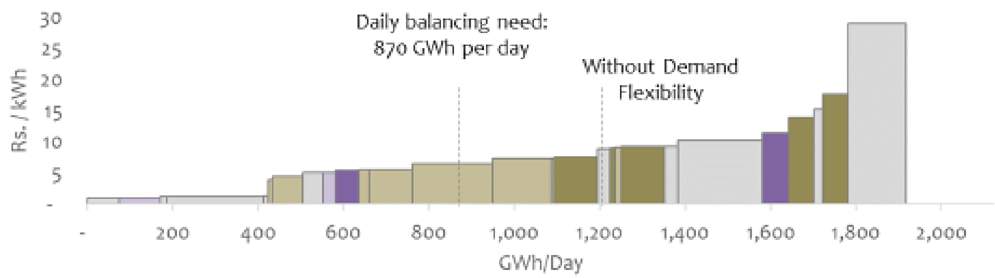
Existing power plants are a cost-effective source of many flexibility needs (1)

2017 Daily Balancing Supply Curve



2030 Daily Balancing Supply Curve

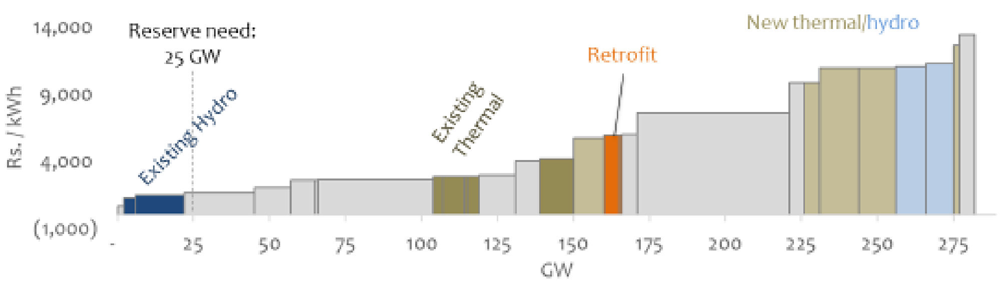


CLIMATE POLICY INITIATIVE

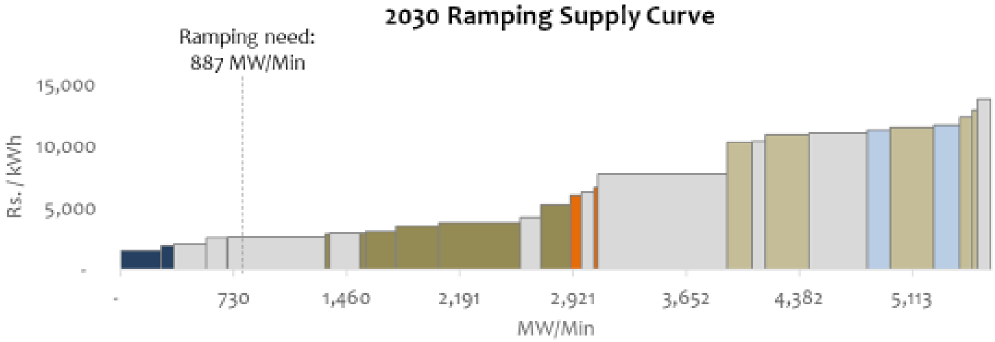
3

Existing power plants are a cost-effective source of many flexibility needs (2)

2030 Reserve Supply Curve



2030 Ramping Supply Curve

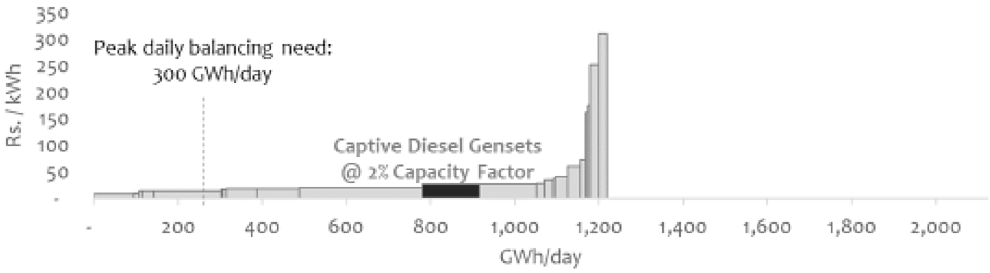


CLIMATE POLICY INITIATIVE

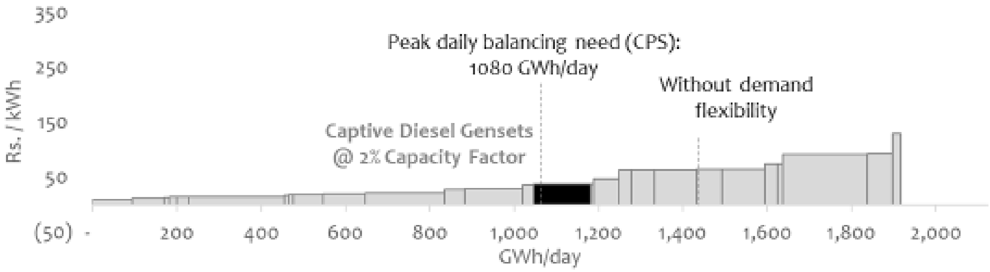
4

Integrating captive diesel generation into grid operations for flexibility may be an important option to meet peak daily balancing needs

2017 Peak Daily Balancing Supply Curve



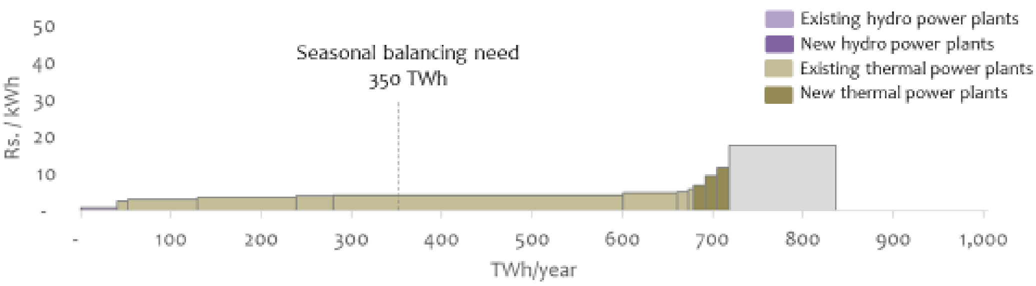
2030 Peak Daily Balancing Supply Curve



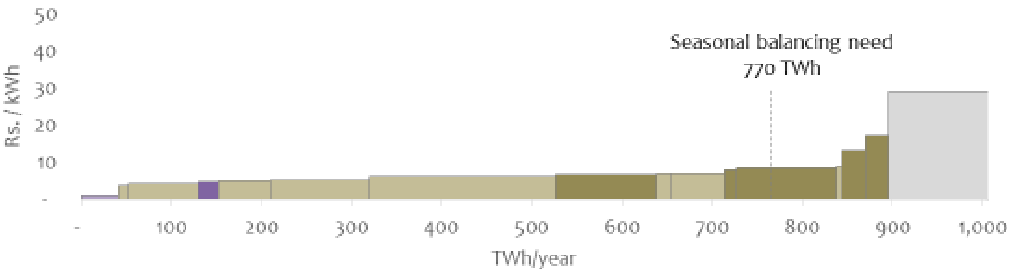
CLIMATE POLICY INITIATIVE 5

New resources will be needed to meet seasonal generation needs, due to growth of the system, but expected coal development would be sufficient

2017 Seasonal Balancing Supply Curve



2030 Seasonal Balancing Supply Curve



CLIMATE POLICY INITIATIVE 6

Annex 3c. Meeting India's flexibility needs with energy storage and batteries

The difficulty and cost of storing AC electricity is the reason there is a flexibility issue for electricity systems. Inexpensive, instantaneously accessible storage could be the system reserve capacity, it could smooth out demand ramps, follow load variations, balance demand over the course of the day and, if the capital cost of the storage were nearly free, it could store energy from one season to use in the next.

Until recently, storing energy in the form of water behind dams in hydro powerplants, and pumped storage hydro powerplants, was the only widespread, cost-effective method of storing AC electricity. Even hydro storage is usually expensive when capital costs are included, and its potential is limited by geography and water availability. India has good existing reserves of hydro capacity, but increasing that capacity is challenging to grow significantly from its current level of 41GW in spite of potential, due to complexity of approvals, social and development factors and construction timelines.

Recently, however, lithium ion batteries and inverters have been developing in capability and falling in cost to the point where they may soon contribute substantially to AC power system flexibility. Low-cost batteries could provide benefits beyond even those provided by pumped storage hydro, as batteries are scalable at almost any level, they could be located where needed to reduce transmission and distribution costs and constraints, they could be integrated into equipment, and they could be used for multiple purposes, such as balancing and transport.

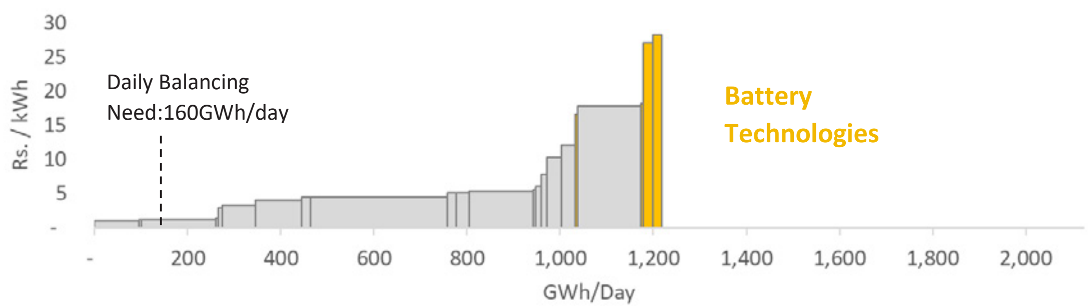
Whether pumped storage, li-ion batteries, or other technologies are used for storage, they will need different cost and operating characteristics that depend on the flexibility need.

Figure 3c-1 Storage requirements by flexibility need

	Reserves and Frequency Response	Ramping	Daily Balancing	Seasonal Balancing	EV / Transport	Distributed / Household
Long Storage Duration			✔	✔		
Long life under frequent cycles	✔	✔	✔		✔	
High Round-Trip Efficiency	✔		✔	✔	✔	✔
Low Capital Cost	✔	✔	✔	✔	✔	✔
High Energy Density					✔	✔

As we have seen, powerplants and demand flexibility can also provide these services at a cost. Today, those costs are much lower than the cost of batteries for many of the flexibility needs as demonstrated by the example in figure 3c-2.

Figure 3c-2 The position of li-ion batteries in the 2017 Daily Balancing supply curve at 2017 costs



The key, then, to the storage revolution for India is to develop a package of lower costs, efficiency, life and operating characteristics, and business models with incentives, that delivers these services more cost effectively than powerplants of demand management. The evidence that this can be done for at least some of the flexibility needs is positive, but work on developing the manufacturing, technology, business models and incentives needs to start now to deliver the capacity when it will be needed.

Declining costs of energy storage

By 2030, the cost of stationary energy storage systems using lithium-ion batteries in India may decline by as much as 75%. Lithium ion batteries are quite versatile in the flexibility services they provide – they are most cost effective for short-term, fast-response and daily flexibility needs. There are other battery storage technologies, but flow batteries and sodium sulphur are less mature while lead acid batteries are more limited in capability(slide 3)

The cost of the batteries themselves continue to decline dramatically, driven by global development focused on electric vehicles. By 2030 forecasted global EV sales of over 20 million cars per year implies annual battery need of at least 1,000 GWh per year. Indian EV demand is highly uncertain, but may be a contributor to falling battery costs in India and driver of how India's energy storage industry develops. (slide 1)

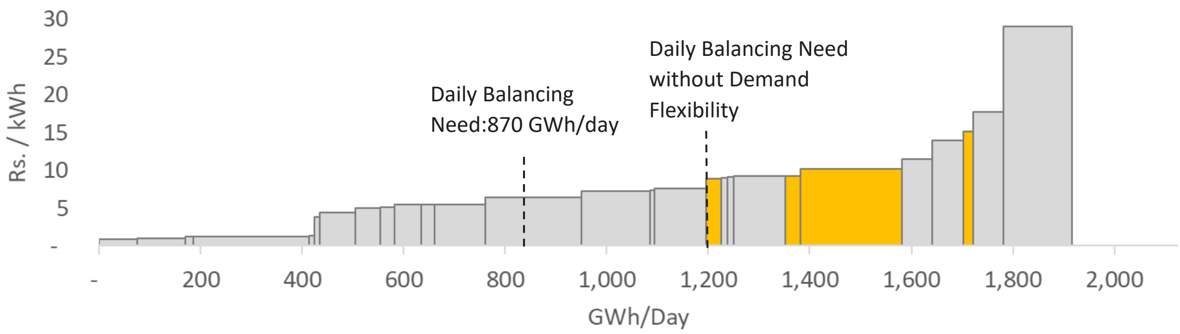
Simultaneously, the cost of the balance of system (BOS), including foundations, installation, connections and soft costs like financing and project development, are also falling. Taken together, we forecast a global decline in total costs for stationary storage systems to fall from $587/kWh in 2017 to $142kWh in 2030. (Slide 2)

Unlike the battery packs, where much of the cost trajectory is determined by global factors, BOS and soft costs depend more strongly on the local market. In general, BOS costs typically fall as local developers and installers learn how to optimize these costs as the local industry develops. In India, the BOS and soft costs are typically lower, but will only stay lower if India begins a substantial program of developing and installing stationary battery systems.

The role of lithium ion batteries in the power system

Even with those levels of cost reductions, batteries will remain uncompetitive with powerplants and demand flexibility for many flexibility requirements, if the batteries are built exclusively to address that one flexibility need alone. However, the costs are much closer, see for example, Figure 3c-3.

Figure 3c-3The position of batteries in the daily balancing supply curve at 2030 costs



In this scenario, daily balancing needs are easily covered by powerplant and demand side options without batteries. Even if no demand flexibility enters the picture (the shift of the balancing need line) there are still less expensive options to deliver flexibility.

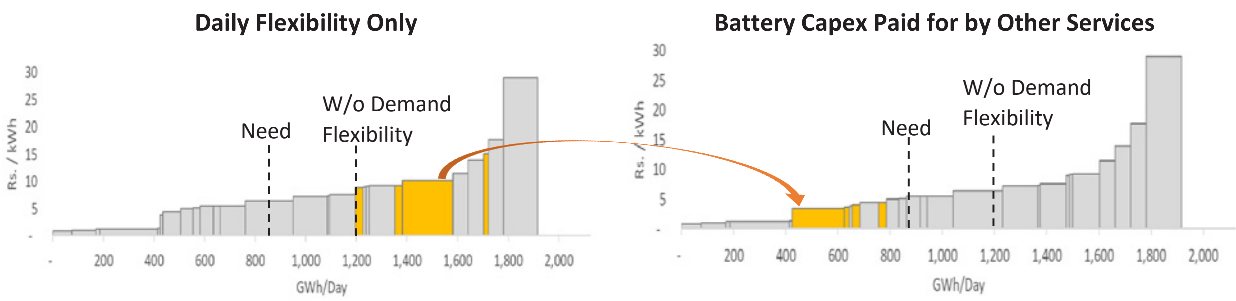
This picture underestimates the potential for batteries in three very important ways:

1. Battery storage, using li-ion or other technologies, is expected to continue to decline in relative costs well beyond 2030, and there is room to expect that 2030 prices may be lower than those assumed here.
2. As thermal powerplants retire, their ability to offer more flexibility will decline, while batteries provide a scalable source of flexibility that can increase with needs.
3. Most significantly, battery storage is much better equipped to provide multiple sources of flexibility. For instance, locating batteries behind transmission constraints can eliminate that constraint,

batteries can be used to develop new electricity and service delivery models, and batteries are controllable to the extent that it is easier to mix reserves, ramping and daily balancing in one asset.

The last of these three will make batteries competitive much sooner. The cost curve in figure 3c-3 assumes that the entire capital cost of the battery is allocated to the daily balancing. However, if the battery is already needed, say to provide local system security or to reduce distribution system costs, then the capital cost will not need to be covered by daily balancing, as the battery has already been built and paid for (just as existing powerplants have been paid for and new powerplants would cost more to deliver flexibility if they are built solely for that purpose). The impact is to improve the competitiveness of batteries dramatically, as in figure 3c-4, where batteries provide a significant share of daily balancing needs.

Figure 3c-4 The impact of multiple services on battery flexibility costs (2030 costs)



A similar picture plays out in all the flexibility needs except seasonal storage, where batteries become more cost-effective as multiple uses are considered. Providing seasonal storage can be expensive as a battery might be used only one or two cycles a year. However, even here we see a role for batteries, as we expect that batteries would provide more flexibility services such as ramping and daily balancing when renewable energy and demand are more closely in balance, while powerplants will provide more flexibility during those seasons where additional energy is needed.

Understanding and modelling all the potential interplays between the different uses of batteries requires analysis of transmission, distribution, and consumer needs beyond the capability of our model. Furthermore, much of the potential will depend on market design, incentive programmes, and technology and control system development. Thus, our modelling is likely to significantly underestimate the potential of battery storage and over estimate the cost. To access these future benefits, India will need to develop the battery market and the market incentives that will enable the technology to flourish and provide the value it can to the system.

Globally, grid applications are expected to reach 300+GWh of cumulative deployment by 2030 globally, of which around 25 GWh is expected in India (BNEF). Our expectation is that if India can solve the incentive, market, and flexibility service integration issues, storage can provide even greater levels of cost savings well into the 30s and 40s.

New pumped hydro

Batteries are not the only energy storage option. There is significant potential for pumped hydro in India – the Central Electricity Authority estimates 63 sites with over 96 GW of potential capacity, of which only around 5 GW has been developed to date. (Slide 4) But pumped hydro can be challenging and costly to develop, due to complexity of project approvals, development and construction, and the pipeline of projects that could be delivered by 2030 (given long development and construction timelines) is relatively modest. For our analysis, we based our models on a forecast of 10GW additional pumped hydro by 2030.

New markets require new incentives

Energy storage for the grid will not develop on its own. There are a number of market and policy barriers that need to be overcome to unlock flexibility from storage:

- **Value discovery**: the value of energy storage can be very location-specific and time-dependent, but electricity pricing is not nearly granular enough to reveal the value of storage at different points on the grid at defined time intervals. The characterization and cost of distribution grid constraints are also very opaque, making it difficult to show where energy storage may have value in avoiding distribution grid upgrades, and stacking this value with energy shifting and grid services values.
- **Immature value chain**: The grid energy storage industry in India is nascent and underdeveloped. Project developers and system integrators are undercapitalized, and standards / expectations for project quality have yet to emerge. The industry will need to mature significantly to be capable of deploying energy storage at scale and attract sufficient financing.

The main areas that India's policymakers could address to overcome these barriers are:

- Markets to allow electricity price arbitrage
- Market products or contracts for fast frequency response
- Locationally granular markets to reveal the value of local grid constraints
- Tariff constructs for stand-alone storage
- Tariff constructs for solar + storage that would incentivize flexibility and reflect locational value

More details of the calculations and assumptions will be included in the final CPI report on India flexibility to be published in April 2019.

Development of battery manufacturing in India will be linked with development of the electric vehicle market, but the rest of the value chain will remain separate

- Demand for batteries in the electric vehicle sector could greatly exceed demand in the grid sector
- Likely that domestic battery manufacturing would be linked primarily with EV supply chain
- Grid battery and EV battery value chains may diverge at the cell manufacturing level (e.g. different chemistries), and will have separate value chains for pack assembly, systems integration, installation, etc.
- Reducing non-pack costs for grid batteries likely requires local learning by doing in pack assembly, system integration, installation and project development

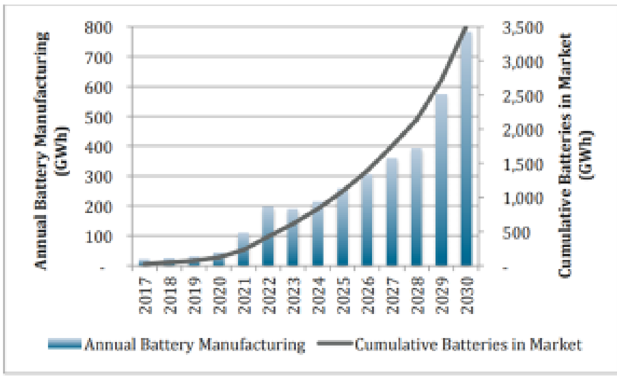
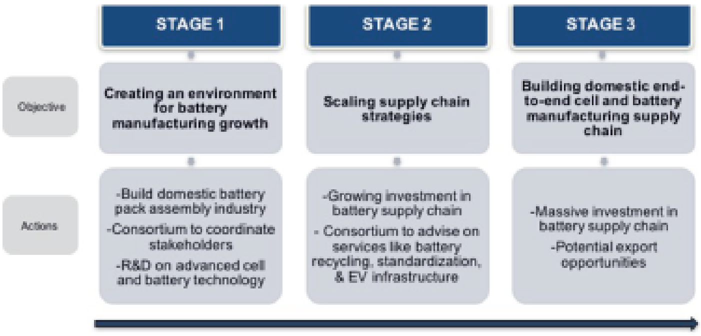


FIGURE 1: ANNUAL AND CUMULATIVE BATTERY REQUIREMENTS TO MEET INDIA'S EV AMBITIONS



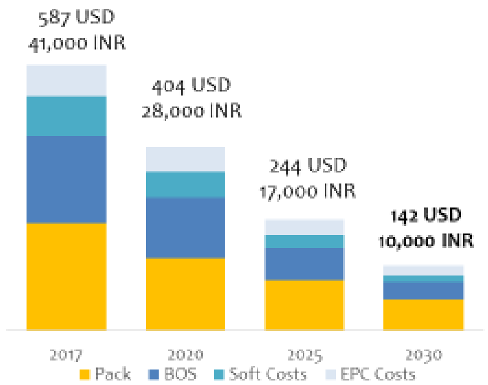
http://niti.gov.in/writereaddata/files/document_publication/India-Energy-Storage-Mission.pdf

CLIMATE POLICY INITIATIVE

1

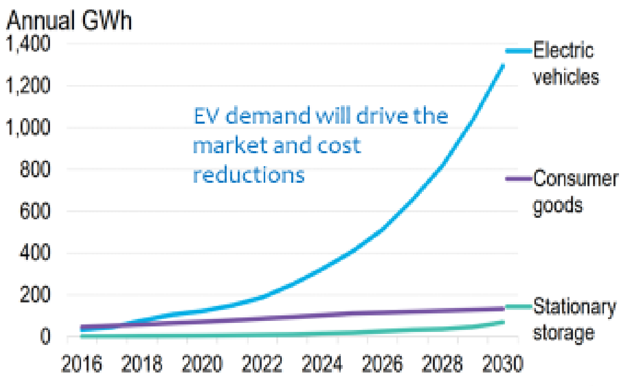
Battery costs are declining rapidly as manufacturing capacity scales driven by the electric vehicle market

Lithium Ion Battery Storage System Capex Cost (per kWh of energy storage capacity)



Based on McKinsey figures, assuming India BOS discount of 25% by 2030, increasing from no discount in 2017. 2030 extended based on 2017-2025 CAGR. Exchange rate - 70 INR/USD.

Global Lithium Ion Battery Demand (GWh/yr)



Source: BNEF 2018, assumes 100% of stationary storage demand met by lithium ion.

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2

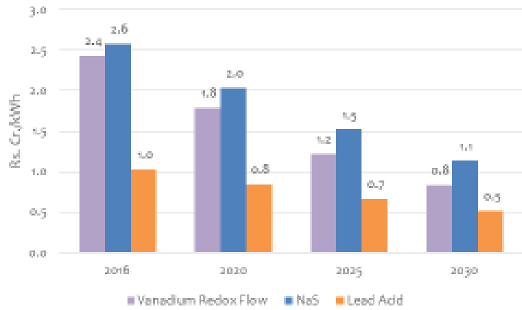
Other potential energy storage technologies also have promise, but technologies are much less mature

Flow Batteries
- Energy capacity can be scaled independently from power capacity, allowing longer-duration storage
- Low (70%) round-trip efficiencies
- Long cycle life and no depth of discharge limitations
- Some chemistries use highly toxic electrolytes
- Potentially higher operating cost due to pumps / other moving parts
- Various chemistries – Vanadium Redox, Zinc Bromine, Iron, etc – highly immature technology not yet produced at scale

Sodium Sulfur
- High temperature battery cell, based on inexpensive materials
- Higher efficiency (~80%), and long cycle life
- Corrosive material and high operating temperature mostly limit applications to grid scale
- Minimal commercial deployment, mostly in US and Japan.

Lead Acid
- Mature supply chain, well-understood technology, with minimal opportunity for future cost reductions
- Higher efficiency (~82%) than other alternative chemistries
- Limited cycle life and limited depth of discharge makes economics more challenging

Capex of alternative energy storage technologies



CPI analysis based on IRENA, http://www.irena.org/-/media/Files/IRENA/Agency/Publication/2017/Oct/IRENA_Electricity_Storage_Costs_2017.pdf

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3

Pumped hydro may be a promising option, but project development faces significant challenges

- Typical cost of new Pumped Hydro Storage plants: Rs 6-10 Cr/MW
- Possible to retrofit existing dispatchable hydro dams for Rs 3-4 Cr/MW
- Longer duration possible compared with batteries, e.g. 8-12 hours depending on the site
- Relatively low efficiency, ~70%
- Development can take 5-10+ years, with significant risks associated with land acquisition for reservoirs, financing challenges, regulatory approvals, etc.

Status of Pumped Storage Potential

Identified Sites: 63
Probable Installed Capacity: 96,524 MW

Region	Potential Capacity (MW)	Capacity Developed (MW)	Capacity under Construction (MW)
Northern	13,065 (7 sites)	0	1,000 (1 site)
Western	39,684 (29 sites)	1,840 (4 sites)	80 (1 site)
Sothern	17,750 (10 sites)	2,006 (3 sites)	0
Easter	9,125 (7 sites)	940 (2 sites)	0
North Eastern	16,900 (10 sites)	0	0
Total	96,524 (63 sites)	4,786 (9 sites)*	1,080 (2 sites)

* In addition, 2 capacities namely Paithan (12MW) & Ujjainin (12 MW) are under operation in Aurangabad and Solapur respectively

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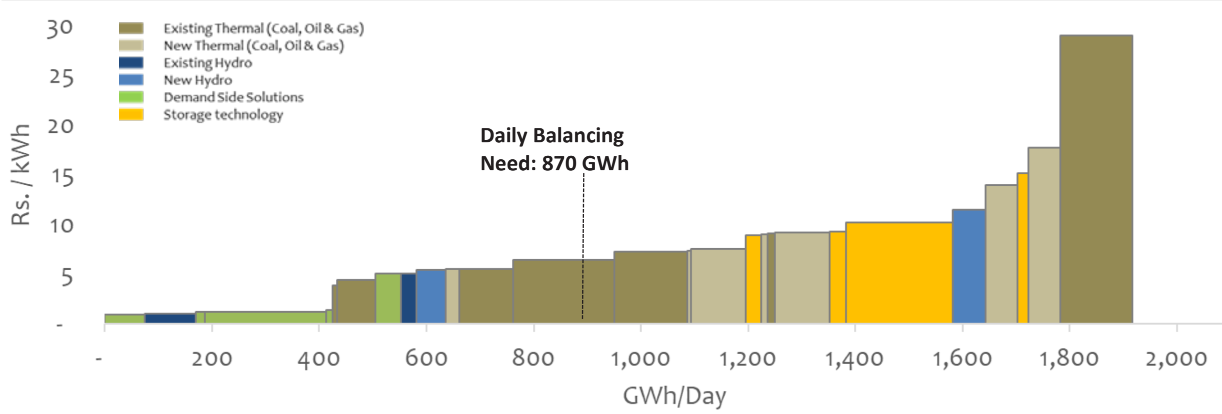
4

Annex 4. Integrated flexibility portfolios

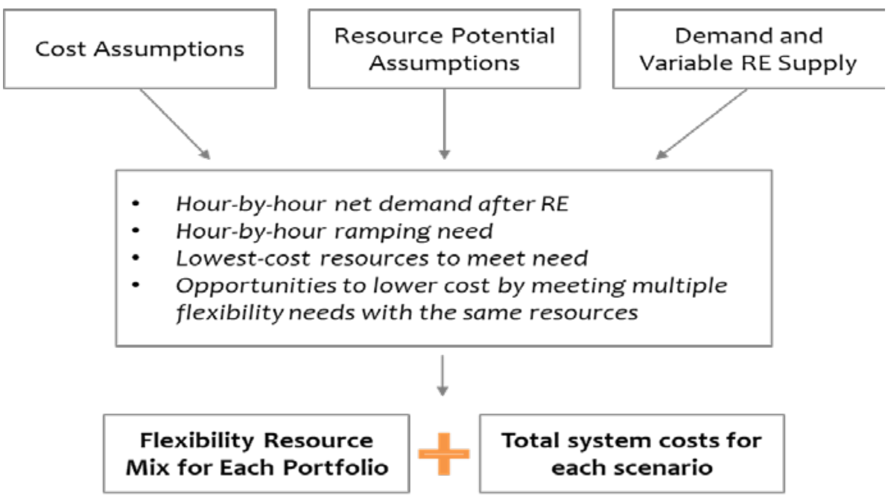
Annexes 3a-c set out supply curves that indicated how cost competitive each flexibility option was in providing each flexibility need. Putting all of these components together, as in figure 4-1 demonstrates that the lowest cost mix of options is likely to include demand, powerplant and storage options. In this example, existing hydro, new hydro, existing powerplants and demand measures would all constitute low costs options to meet the average daily 6-hour balancing need of 870 GWh, If the capital costs of battery storage are amortized for another need, storage too would be among the low-cost options.

Figure 4-1. 2030 Demand for daily balancing (on an average day for 6 hours of demand shift)



But an electricity system's flexibility needs are not a series of independent markets, rather they are linked together to meet the overall system requirements. Thus, to understand which options will be used, and how procuring these options will impact total systems cost, we have built different portfolios of flexibility options, using the supply curves as a guide, and used these options to calculate total system cost over the course of a full year's hourly demand profile. While these are not complete system optimization models, which would require an India wide transmission and dispatch models, these models should provide results that are accurate within the constraints of the assumptions around load, costs, interest rates, resource potential, renewable energy supply, weather conditions, and so forth for 2030. Our model fits the various assumptions from the flexibility supply curves, resources potential, and load shapes for demand and renewable energy supply together in one model as depicted in the figure below.

Figure 4-2. Integrating assumptions into a flexibility portfolio model



Flexibility Portfolios

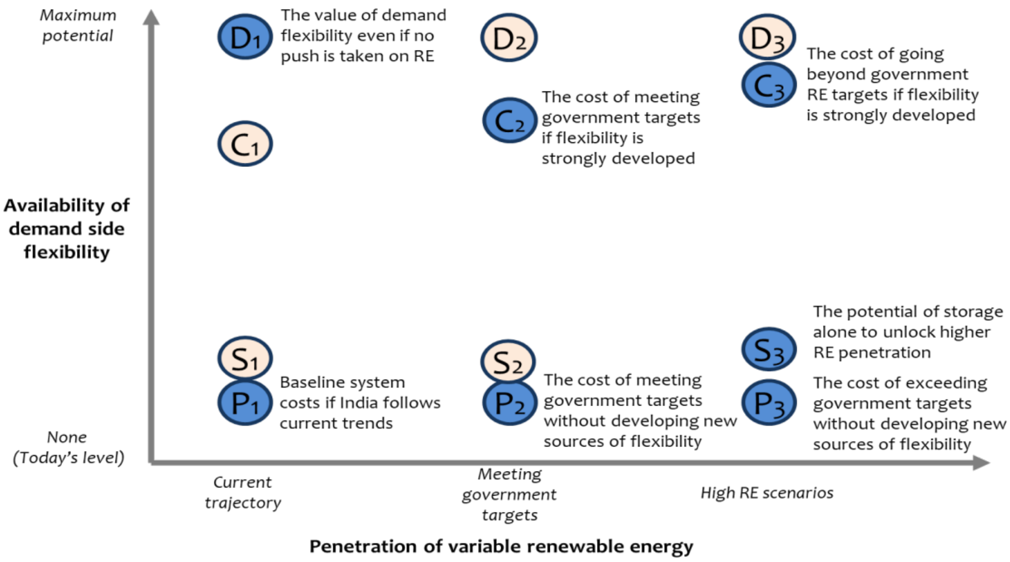
This flexibility analysis should provide answers to three questions that policy makers should be asking in an India transition to a cleaner India electricity system with higher levels of variable renewable energy:

- How much variable renewable energy can India integrate into its electricity system?

- How much should consumer driven demand flexibility contribute to meeting flexibility needs?
- How much will flexibility add to the system costs under high renewable energy scenarios?

To some degree, both the amount of renewable energy and the amount of demand flexibility are variables that policymakers can influence. Since these two variables are also key determinants of system costs and the cost and source of flexibility, our portfolios have been designed to test how each of these two variables will affect flexibility options and cost.

Figure 4-3 Portfolios built to assess the impact of demand flexibility and RE ambition



Our portfolios fall into 4 different sets, dependent upon RE ambition and demand flexibility achievements.

P. **Powerplant driven portfolios** – System flexibility is provided entirely by thermal and hydro electric powerplants. Plants are upgraded and new plants added to the system if needed and economic to do so

D. **Demand side driven portfolios** – System flexibility provided by existing sources of flexibility and combined with demand side options. Limited new thermal capacity may be added if needed and economic to meet any balance demand

S. **Storage driven portfolios** – System flexibility provided by exiting resources of flexibility combined with storage options. Limited new thermal capacity may be added if needed and economic to meet any balance demand

C. **Balanced portfolios of all options** – System flexibility met with a combination of all flexibility options, to determine which options would be used and at what scale to meet the needs at the lowest cost if all flexibility programmes were successful

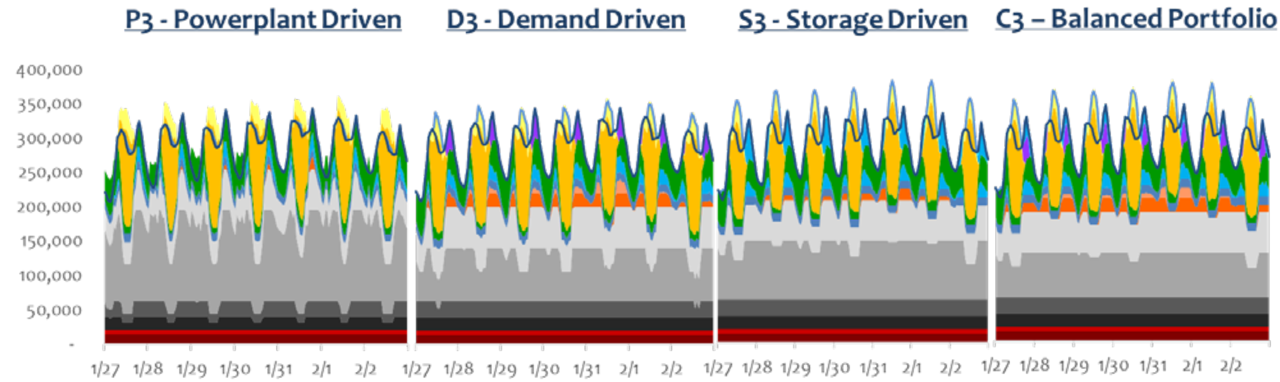
In figure 4-3, the scenarios highlighted (D1, P1, P2, C2, C3, S3, and P3) each offer valuable insight into one of the key questions outline above, as described in the figure.

In our summary report, figure ES-4 shows the impact of the flexibility portfolio composition on the generation profile of thermal plants and curtailment of renewable energy. In the table below, we have compared the different flexibility portfolios above for both the Current Trajectory and High RE scenario.

Below is another set of outputs from our model, which looks at the dispatch profile for each of the portfolios side-by-side. The dark line on the top of the graph is the demand across the week.

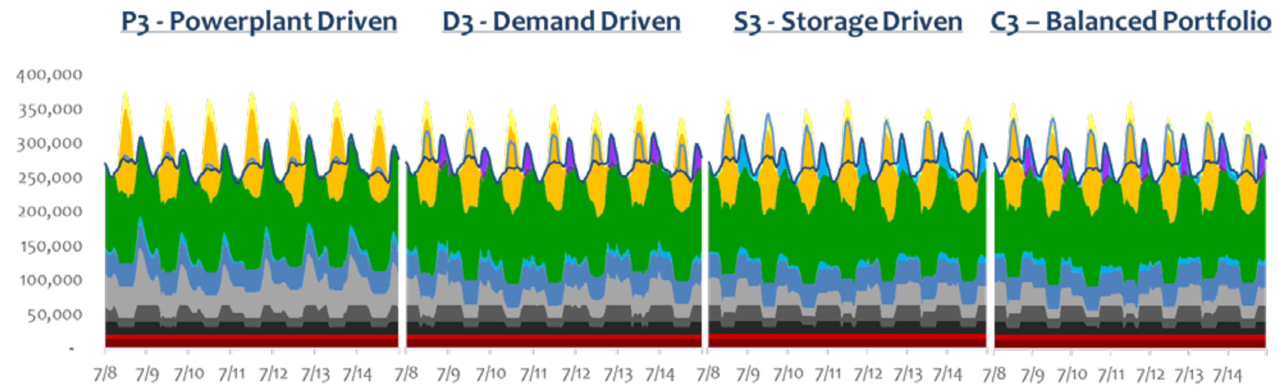
For the week in January, only the powerplant driven portfolio on the left sees, the thermal plants strained and maximum curtailment of both solar and wind energy, while the rightmost balanced portfolio has the least constrained power plant generation profile and almost no curtailment of renewable energy.

Figure 4-4 Dispatch profile for High RE scenario – Late January



When we move on to a week in July, we see the same comparative impact, exaggerated by increased renewable generation. Power plants are constrained across all portfolios during this week but more variable in the leftmost power plant flexibility scenario and renewable curtailment is minimum for the Balanced portfolio.

Figure 4-5 Dispatch profile for High RE scenario – July



The impact of these different portfolios can be seen clearly in figure 4-5, which compares current trajectory and High RE scenarios for each of the flexibility portfolios. The balanced portfolio shows an overall lower curtailment in both the High RE (97%) and Current trajectory (82%) scenarios. It also delivers 6 to 9 % lower system cost and 8 to 12% lower carbon intensity than the base case.

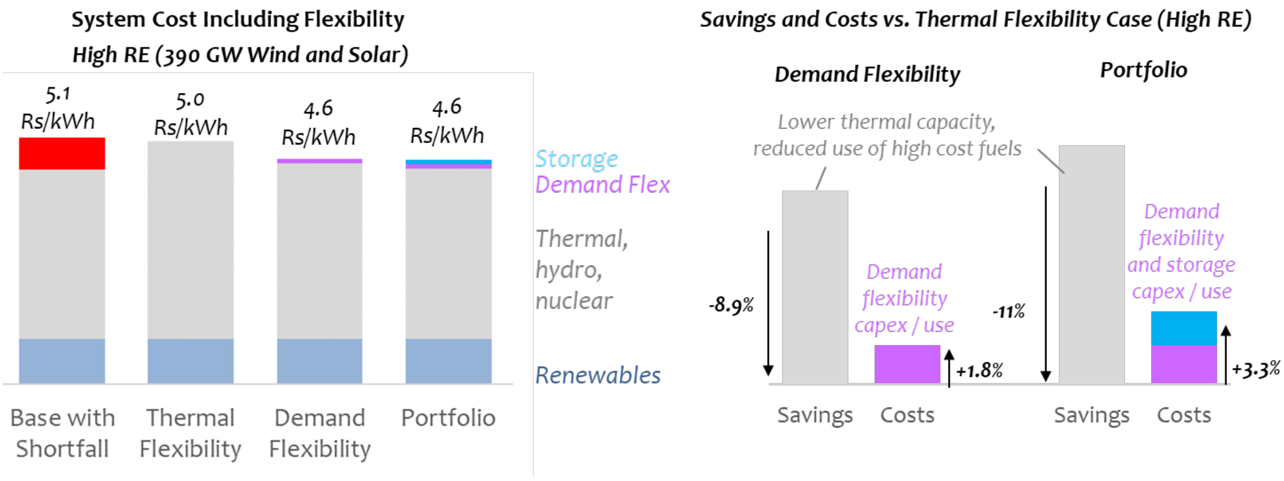
Figure 4-5 Balanced portfolio of demand, storage and powerplant flexibility perform best on most metrics and are least risky

Scenario	Target Met?	Excess Energy	Total Cost	Carbon emissions
Power-plant Driven	Yes	10%	4.8 (Rs/kWh)	0.6 (t/MWh)
Demand Flex Driven	Yes	-83%	-6%	-6%
Storage Driven	Yes	-95%	-4%	-6%
Balanced Portfolio	Yes	-97%	-5%	-8%

Scenario	Target Met?	Excess Energy	Total Cost	Carbon emissions
Power-plant Driven	Yes	13.8%	5.0 (Rs/kWh)	0.5 (t/MWh)
Demand Flex Driven	Yes	-63%	-7%	-9%
Storage Driven	Yes	-80%	-5%	-10%
Balanced Portfolio	Yes	-82%	-8%	-12%

As in the summary report, figure ES-5, the average total system cost (in today's money) is lowest for the balanced portfolios for both the Current Trajectory and the High RE scenarios, with the High RE portfolio system cost (Rs 4.6/ kWh) lower than the system cost for base case (Rs. 4.7/ kWh) or thermal flexibility portfolio (Rs 4.8/ kWh) in the Current Trajectory cases.

The chart below shows the system cost for different portfolios under the High RE scenario, and also the savings and cost advantage the demand side portfolio and balanced portfolio provide over the powerplant driven option.



As outline in the summary, several important insights emerge:

- **Demand side is important in High RE scenarios** - Portfolios that include more demand flexibility in combination with powerplant and storage (D3 and C3), are significantly less expensive than those that rely on powerplants only (P3).
- **Balanced and demand flexibility portfolios significantly reduce costs even at low RE ambitions –** As portfolios D1 and C1 have lower costs than the baseline P1, even with no increase in RE from the current trajectory. This result implies that demand side flexibility should be pursued whatever the RE policy is pursued.
- **A flexible high RE system is less expensive than an inflexible low RE system -**With all of the flexibility options in place, total costs of the high RE system are below what we could expect from the baseline scenario. That is, adding flexibility to the system lowers costs of a high RE ambition to below the costs that would be expected if neither RE nor flexibility is pursued with greater urgency.

The following pages present inputs to and outputs from our model, providing a detailed overview of how each of the portfolios perform on different metrics under different scenarios and the portfolio composition across generation and flexibility resources.

Flexibility portfolios yield numerous insights

General
- Storage and demand flexibility largely meet the same daily balancing need and are substitutes with different cost, deliverability, availability characteristics

Costs
- Costs across portfolios with very different mixes only vary by around 10%
- Demand flexibility is the key to lower costs, while storage costs are offset by reduced thermal capacity and fuel use

Carbon
- Demand flexibility and storage can lower grid carbon emissions by roughly 10%, given the same renewable energy capacity

Curtailment
- All high renewable cases involve substantial excess energy production (3% to 14% of wind and solar output); the financial risk around curtailment needs to be managed or it will raise the cost of capital and reduce investment in renewable energy
- Demand flexibility and storage can lower excess energy production from 14% to 3% of total VRE (while shifting this energy to offset high cost thermal production)

Coal
- Portfolios with high degrees of demand flexibility and storage reduce the amount of ramping, cycling, and part-load generation needed from coal
- In the high RE scenario, a portfolio of demand flexibility and storage can almost completely offset the need for new coal capacity vs. today – without demand flexibility and storage, significantly more thermal / dispatchable capacity is needed

Demand Side
- AC flexibility is not always available when needed, and its' contribution is minimal in key pinch points (e.g. January capacity needs)
- Agricultural pumping flexibility is enormously valuable if it is available throughout the year
- EV charging flexibility largely serves to absorb excess energy production from wind and solar, but likely won't help meet peak capacity needs
- Harnessing India's fleet of backup diesel generators is a key strategy to access a significant amount of capacity for a limited number hours per year – utilities will need tariffs and programs specifically targeted at unlocking this resource

| CLIMATE POLICY INITIATIVE

1

P1 Current Trajectory – Thermal Powerplant driven flexibility portfolio

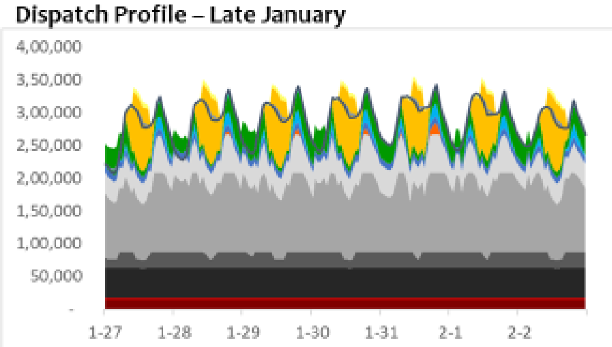
Portfolio Statistics

System Cost (Rs/kWh)	5.0
Excess Production (% of VRE)	10.0%
Emissions Intensity (tonnes CO_2/MWh)	0.60
Coal Capacity (GW)	312
Coal Capacity Factor (%)	54%
Average Coal Loading When Running (%)	71%
Demand Flexibility Capacity (GW)	N/A
Battery Capacity (GW)	N/A
Pumped Hydro Capacity (GW)	5.9
Captive Diesel Generators Capacity (GW)	N/A

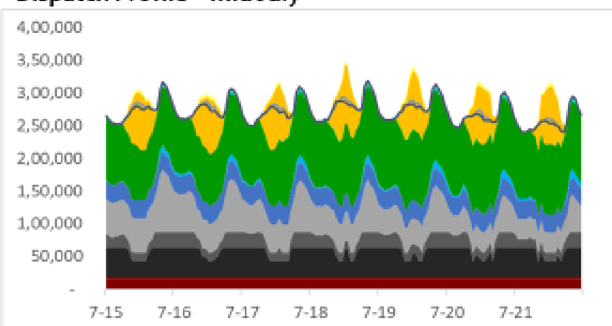
Key Implementation Risks
- High levels of excess energy production drive need to manage curtailment risk
- Coal fuel availability, allocation, and seasonal storage are critical to reliability
- Political / social appetite for coal-related pollution may be a challenge

Operational Challenges
- Daily ramping, part-load operation, cycling of many coal plants
- Substantial excess production
- Infrequent, seasonal use of gas
- Seasonality of coal use requiring extended shut down periods

Dispatch Profile – Late January



Dispatch Profile – Mid July



| CLIMATE POLICY INITIATIVE

2

P1 Current Trajectory – Thermal Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	123.0	16.3%	36.6%	7,000	-
Solar PV	141.0	10.8%	21.3%	4,700	-
Rooftop PV	10.0	0.7%	20.4%	7,050	-
Hydro	68.0	8.5%	34.8%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	5.0	1.2%	65.0%	14,700	7.47
Super Coal - Pithead	58.3	16.2%	76.9%	10,503	2.31
Sub Coal - Pithead	29.6	7.5%	70.5%	9,771	2.92
Super Coal - Non Pithead	151.0	32.0%	58.8%	10,503	4.07
Sub Coal - Non Pithead	74.0	5.4%	20.4%	9,771	4.46
Gas CCGT	22.1	0.0%	0.2%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	-	0.0%		1,685	28.21
Air Conditioning	-	0.0%		2,948	-
Ag Pumping	-	0.0%		3,601	-
Industry	-	0.0%		-	5.00
EV Charging	-	0.0%		1,849	-
Battery	-	0.0%		7,562	-
Pumped Hydro	5.9	-0.1%	-3.6%	11,062	-
Captive Diesel	-	0.0%		1,685	28.21

D1 Current Trajectory – Demand Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.7
Excess Production (% of VRE)	1.7%
Emissions Intensity (tonnes CO2/MWh)	0.56
Coal Capacity (GW)	243
Coal Capacity Factor (%)	65%
Average Coal Loading When Running (%)	86%
Demand Flexibility Capacity (GW)	70
Battery Capacity (GW)	N/A
Pumped Hydro Capacity (GW)	5.9
Captive Diesel Generators Capacity (GW)	24

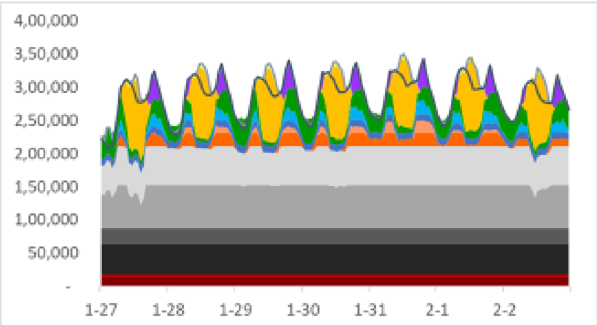
Key Implementation Risks

- Accessing sufficient demand side flexibility, requiring new regulatory approaches, market mechanisms and business models

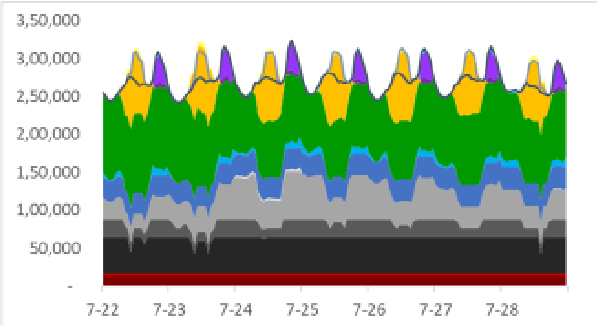
Operational Challenges

- Forecasting and managing RE and demand flexibility availability
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns

Dispatch Profile – Late January



Dispatch Profile – Late July



D1 Current Trajectory – Demand Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	123.0	16.3%	36.6%	7,000	-
Solar PV	141.0	10.8%	21.3%	4,700	-
Rooftop PV	10.0	0.7%	20.4%	7,050	-
Hydro	68.0	8.7%	35.7%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	5.0	1.2%	65.0%	14,700	7.47
Super Coal - Pithead	58.3	16.7%	79.4%	10,503	2.31
Sub Coal - Pithead	29.6	8.2%	77.1%	9,771	2.92
Super Coal - Non Pithead	81.0	20.6%	70.5%	10,503	4.07
Sub Coal - Non Pithead	74.0	11.7%	43.7%	9,771	4.46
Gas CCGT	24.9	0.9%	9.7%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	3.7%	1,685	28.21
Air Conditioning	19.8	0.3%	3.7%	2,948	-
Ag Pumping	37.7	-0.1%	-0.7%	3,601	-
Industry	-	0.0%		-	5.00
EV Charging	12.5	-0.3%	-7.0%	1,849	-
Battery	-	0.0%		7,562	-
Pumped Hydro	5.9	0.0%	-1.8%	11,062	-
Captive Diesel	23.9	0.1%	1.1%	1,685	28.21

CLIMATE POLICY INITIATIVE

5

S1 Current Trajectory – Storage Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.8
Excess Production (% of VRE)	0.5%
Emissions Intensity (tonnes CO2/MWh)	0.56
Coal Capacity (GW)	256
Coal Capacity Factor (%)	63%
Average Coal Loading When Running (%)	89%
Demand Flexibility Capacity (GW)	NA
Battery Capacity (GW)	60
Pumped Hydro Capacity (GW)	15
Captive Diesel Generators Capacity (GW)	NA

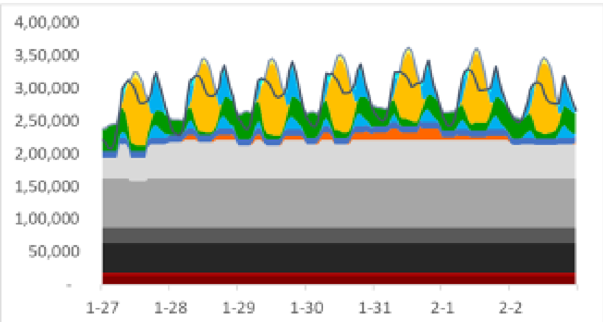
Key Implementation Risks

- Building battery storage supply chain to deliver 60 GW of storage by 2030
- Development of 10 GW additional pumped hydro by 2030

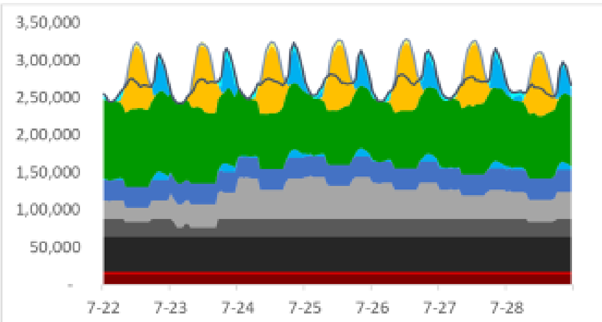
Operational Challenges

- Forecasting and managing RE availability
- Optimizing storage dispatch profile against multiple sources of value (customer, distribution, transmission systems)
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE

6

S1 Current Trajectory – Storage Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	123.0	16.3%	36.6%	7,000	-
Solar PV	141.0	10.8%	21.3%	4,700	-
Rooftop PV	10.0	0.7%	20.4%	7,050	-
Hydro	68.0	8.5%	34.8%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	5.0	1.2%	65.0%	14,700	7.47
Super Coal - Pithead	58.3	16.8%	79.8%	10,503	2.31
Sub Coal - Pithead	29.6	8.4%	79.1%	9,771	2.92
Super Coal - Non Pithead	94.0	23.8%	70.2%	10,503	4.07
Sub Coal - Non Pithead	74.0	9.3%	34.7%	9,771	4.46
Gas CCGT	24.8	0.2%	2.2%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	-	0.0%		1,685	28.21
Air Conditioning	-	0.0%		2,948	-
Ag Pumping	-	0.0%		3,601	-
Industry	-	0.0%		-	5.00
EV Charging	-	0.0%		1,849	-
Battery	60.0	-0.3%	-1.3%	7,562	-
Pumped Hydro	15.0	-0.5%	-8.6%	11,062	-
Captive Diesel	-	0.0%		1,685	28.21

CLIMATE POLICY INITIATIVE 7

C1 Current Trajectory – Balanced Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.7
Excess Production (% of VRE)	0.3%
Emissions Intensity (tonnes CO2/MWh)	0.55
Coal Capacity (GW)	228
Coal Capacity Factor (%)	68%
Average Coal Loading When Running (%)	94%
Demand Flexibility Capacity (GW)	70
Battery Capacity (GW)	25
Pumped Hydro Capacity (GW)	10
Captive Diesel Generators Capacity (GW)	25

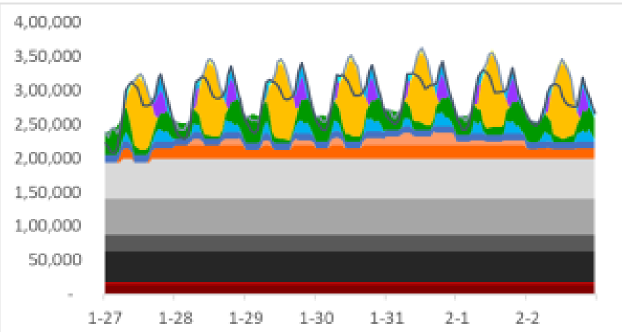
Key Implementation Risks

- Accessing sufficient demand side flexibility, requiring new regulatory approaches, market mechanisms and business models
- Building battery storage supply chain to deliver 25 GW of storage by 2030

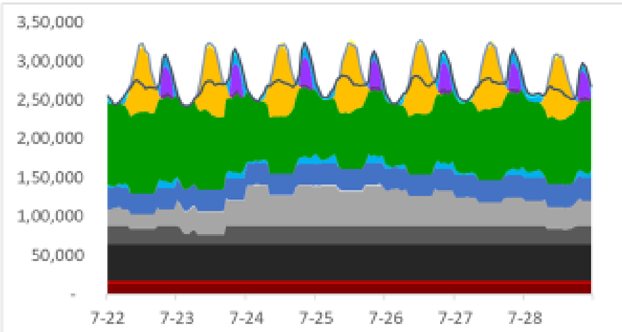
Operational Challenges

- Forecasting and managing RE and demand flexibility availability
- Optimizing storage dispatch profile against multiple sources of value (customer, distribution, transmission systems)
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns
- Ensuring availability of gas, demand-side diesel when called

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE 8

C1 Current Trajectory – Balanced Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	123.0	16.3%	36.6%	7,000	-
Solar PV	141.0	10.8%	21.3%	4,700	-
Rooftop PV	10.0	0.7%	20.4%	7,050	-
Hydro	68.0	8.7%	35.7%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	5.0	1.2%	65.0%	14,700	7.47
Super Coal - Pithead	58.3	16.8%	79.8%	10,503	2.31
Sub Coal - Pithead	29.6	8.4%	79.2%	9,771	2.92
Super Coal - Non Pithead	66.0	17.6%	73.8%	10,503	4.07
Sub Coal - Non Pithead	74.0	13.3%	49.9%	9,771	4.46
Gas CCGT	24.9	1.7%	18.6%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	8.7%	1,685	28.21
Air Conditioning	19.8	0.3%	3.7%	2,948	-
Ag Pumping	37.7	-0.1%	-0.7%	3,601	-
Industry	-	0.0%		-	5.00
EV Charging	12.5	-0.3%	-7.0%	1,849	-
Battery	25.0	-0.1%	-1.3%	7,562	-
Pumped Hydro	10.0	-0.3%	-8.2%	11,062	-
Captive Diesel	24.7	0.2%	2.6%	1,685	28.21

CLIMATE POLICY INITIATIVE 9

P2 Current Policy – Thermal Powerplant driven flexibility portfolio

Portfolio Statistics

System Cost (Rs/kWh)	5.1
Excess Production (% of VRE)	11.2%
Emissions Intensity (tonnes CO2/MWh)	0.54
Coal Capacity (GW)	294
Coal Capacity Factor (%)	52%
Average Coal Loading When Running (%)	70%
Demand Flexibility Capacity (GW)	N/A
Battery Capacity (GW)	N/A
Pumped Hydro Capacity (GW)	5.9
Captive Diesel Generators Capacity (GW)	N/A

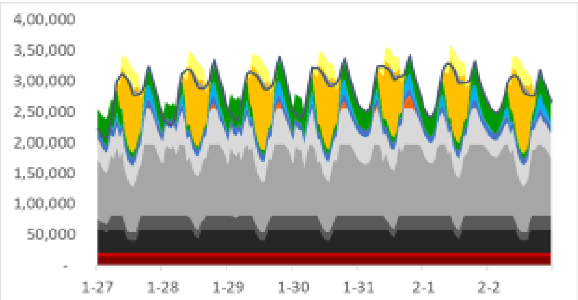
Key Implementation Risks

- High levels of excess energy production drive need to manage curtailment risk
- Coal fuel availability, allocation, and seasonal storage are critical to reliability
- Political / social appetite for coal-related pollution may be a challenge

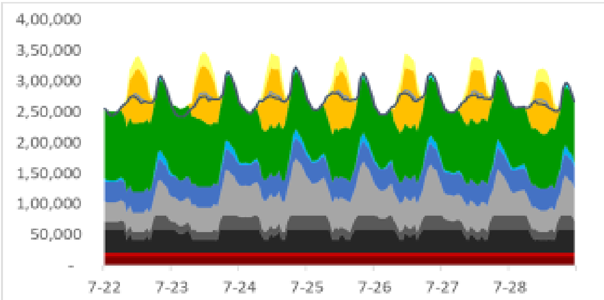
Operational Challenges

- Daily ramping, part-load operation, cycling of many coal plants
- Substantial excess production
- Infrequent, seasonal use of gas
- Seasonality of coal use requiring extended shut down periods

Dispatch Profile – Late January



Dispatch Profile – Mid July



CLIMATE POLICY INITIATIVE 10

P2 Current Policy – Thermal Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	132.0	17.4%	36.6%	7,000	-
Solar PV	150.0	11.5%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	83.3	10.6%	35.3%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	46.3	12.3%	73.4%	10,503	2.31
Sub Coal - Pithead	29.6	7.2%	67.9%	9,771	2.92
Super Coal - Non Pithead	144.5	29.7%	56.9%	10,503	4.07
Sub Coal - Non Pithead	74.0	5.6%	20.8%	9,771	4.46
Gas CCGT	24.9	0.0%	0.4%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	0.0%	1,685	28.21
Air Conditioning	-	0.0%		2,948	-
Ag Pumping	-	0.0%		3,601	-
Industry	-	0.0%		-	5.00
EV Charging	-	0.0%		1,849	-
Battery	-	0.0%		7,562	-
Pumped Hydro	5.9	0.0%	-2.1%	11,062	-
Captive Diesel	-	0.0%		1,685	28.21

CLIMATE POLICY INITIATIVE 11

D2 Current Policy – Demand Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.7
Excess Production (% of VRE)	2.7%
Emissions Intensity (tonnes CO_2/MWh)	0.49
Coal Capacity (GW)	214
Coal Capacity Factor (%)	64%
Average Coal Loading When Running (%)	87%
Demand Flexibility Capacity (GW)	70
Battery Capacity (GW)	N/A
Pumped Hydro Capacity (GW)	5.9
Captive Diesel Generators Capacity (GW)	25

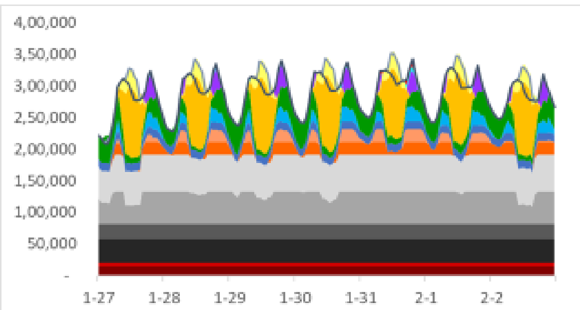
Key Implementation Risks

- Accessing sufficient demand side flexibility, requiring new regulatory approaches, market mechanisms and business models

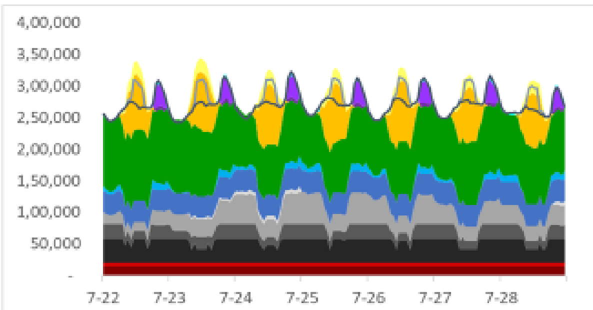
Operational Challenges

- Forecasting and managing RE and demand flexibility availability
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE 12

D2 Current Policy – Demand Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	132.0	17.4%	36.6%	7,000	-
Solar PV	150.0	11.5%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	83.3	10.9%	36.4%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	46.3	13.0%	78.0%	10,503	2.31
Sub Coal - Pithead	29.6	8.0%	74.7%	9,771	2.92
Super Coal - Non Pithead	64.0	15.7%	67.9%	10,503	4.07
Sub Coal - Non Pithead	74.0	12.7%	47.6%	9,771	4.46
Gas CCGT	24.9	1.3%	14.9%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	8.4%	1,685	28.21
Air Conditioning	19.8	0.3%	3.7%	2,948	-
Ag Pumping	37.7	-0.1%	-0.7%	3,601	-
Industry	-	0.0%		-	5.00
EV Charging	12.5	-0.3%	-6.3%	1,849	-
Battery	-	0.0%		7,562	-
Pumped Hydro	5.9	-0.1%	-2.4%	11,062	-
Captive Diesel	25.0	0.3%	3.9%	1,685	28.21

CLIMATE POLICY INITIATIVE 13

S2 Current Policy – Storage Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.9
Excess Production (% of VRE)	1%
Emissions Intensity (tonnes CO_2/MWh)	0.49
Coal Capacity (GW)	270
Coal Capacity Factor (%)	53%
Average Coal Loading When Running (%)	80%
Demand Flexibility Capacity (GW)	NA
Battery Capacity (GW)	60
Pumped Hydro Capacity (GW)	15
Captive Diesel Generators Capacity (GW)	NA

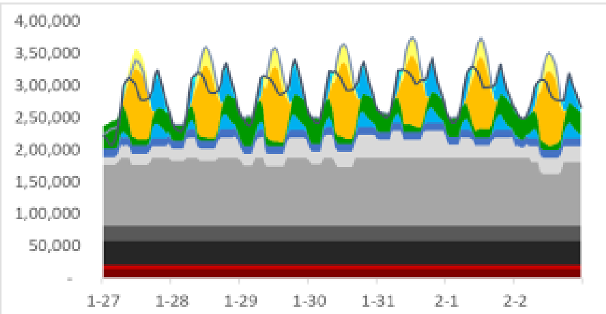
Key Implementation Risks

- Building battery storage supply chain to deliver requisite storage by 2030
- Development of additional pumped hydro by 2030

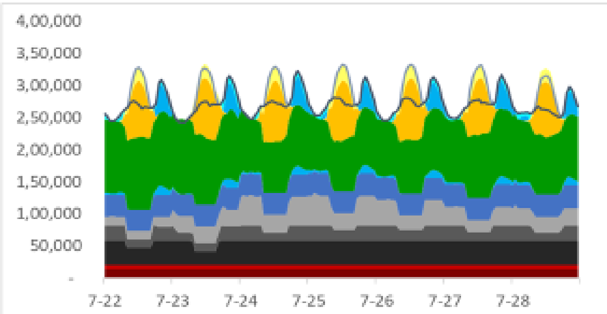
Operational Challenges

- Forecasting and managing RE availability and optimizing storage dispatch profile against multiple sources of value (customer, distribution, transmission systems)
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE 14

S2 Current Policy – Storage Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	132.0	17.4%	36.6%	7,000	-
Solar PV	150.0	11.5%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	83.3	10.6%	35.3%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	46.3	13.2%	79.0%	10,503	2.31
Sub Coal - Pithead	29.6	8.2%	76.9%	9,771	2.92
Super Coal - Non Pithead	133.1	27.6%	57.4%	10,503	4.07
Sub Coal - Non Pithead	60.5	2.4%	10.8%	9,771	4.46
Gas CCGT	-	0.0%		9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	-	0.0%		1,685	28.21
Air Conditioning	-	0.0%		2,948	-
Ag Pumping	-	0.0%		3,601	-
Industry	-	0.0%		-	5.00
EV Charging	-	0.0%		1,849	-
Battery	60.0	-0.3%	-1.3%	7,562	-
Pumped Hydro	15.0	-0.5%	-8.5%	11,062	-
Captive Diesel	-	0.0%		1,685	28.21

C2 Current Policy – Balanced Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.7
Excess Production (% of VRE)	0.9%
Emissions Intensity (tonnes CO2/MWh)	0.49
Coal Capacity (GW)	211
Coal Capacity Factor (%)	65%
Average Coal Loading When Running (%)	91%
Demand Flexibility Capacity (GW)	70
Battery Capacity (GW)	25
Pumped Hydro Capacity (GW)	10
Captive Diesel Generators Capacity (GW)	25

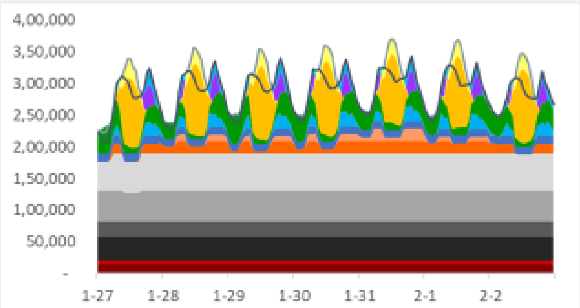
Key Implementation Risks

- Accessing sufficient demand side flexibility, requiring new regulatory approaches, market mechanisms and business models
- Building battery storage supply chain to deliver 25 GW of storage by 2030

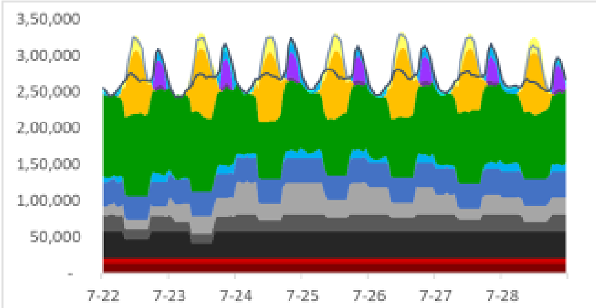
Operational Challenges

- Forecasting and managing RE and demand flexibility availability
- Optimizing storage dispatch profile against multiple sources of value (customer, distribution, transmission systems)
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns
- Ensuring availability of gas, demand-side diesel when called upon

Dispatch Profile – Late January



Dispatch Profile – Late July



C2 Current Policy – Balanced Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	132.0	17.4%	36.6%	7,000	-
Solar PV	150.0	11.5%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	83.3	10.9%	36.4%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	46.3	13.2%	79.0%	10,503	2.31
Sub Coal - Pithead	29.6	8.2%	77.2%	9,771	2.92
Super Coal - Non Pithead	61.4	15.5%	69.9%	10,503	4.07
Sub Coal - Non Pithead	74.0	12.2%	45.8%	9,771	4.46
Gas CCGT	24.9	1.4%	15.1%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	6.3%	1,685	28.21
Air Conditioning	19.8	0.3%	3.7%	2,948	-
Ag Pumping	37.7	-0.1%	-0.7%	3,601	-
Industry	-	0.0%		-	5.00
EV Charging	12.5	-0.3%	-6.3%	1,849	-
Battery	25.0	-0.1%	-1.3%	7,562	-
Pumped Hydro	10.0	-0.3%	-8.4%	11,062	-
Captive Diesel	25.0	0.2%	1.9%	1,685	28.21

CLIMATE POLICY INITIATIVE 17

P3 High RE – Thermal Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	5.1
Excess Production (% of VRE)	13.8%
Emissions Intensity (tonnes CO_2/MWh)	0.50
Coal Capacity (GW)	292
Coal Capacity Factor (%)	48%
Average Coal Loading When Running (%)	68%
Demand Flexibility Capacity (GW)	N/A
Battery Capacity (GW)	N/A
Pumped Hydro Capacity (GW)	5.9
Captive Diesel Generators Capacity (GW)	N/A

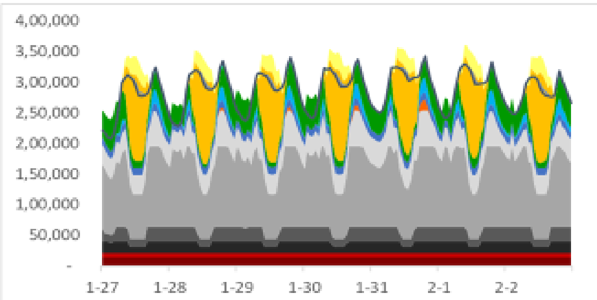
Key Implementation Risks

- High levels of excess energy production drive need to manage curtailment risk
- Coal fuel availability, allocation, and seasonal storage are critical to reliability
- Political / social appetite for coal-related pollution may be a challenge

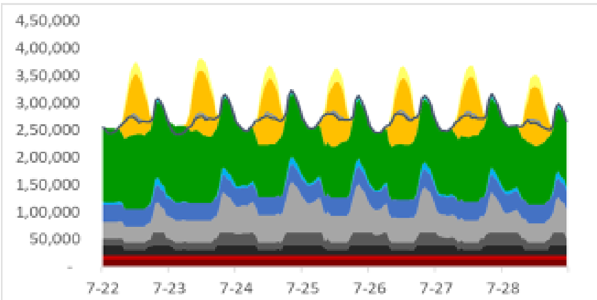
Operational Challenges

- Daily ramping, part-load operation, cycling of many coal plants
- Substantial excess production
- Infrequent, seasonal use of gas
- Seasonality of coal use requiring extended shut down periods

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE 18

P3 High RE – Thermal Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	160.0	21.1%	36.6%	7,000	-
Solar PV	190.0	14.6%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	80.5	10.4%	35.8%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	23.1	5.9%	70.6%	10,503	2.31
Sub Coal - Pithead	29.6	7.2%	67.1%	9,771	2.92
Super Coal - Non Pithead	165.7	32.2%	53.8%	10,503	4.07
Sub Coal - Non Pithead	74.0	4.9%	18.5%	9,771	4.46
Gas CCGT	23.1	0.0%	0.3%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	-	0.0%		1,685	28.21
Air Conditioning	-	0.0%		2,948	-
Ag Pumping	-	0.0%		3,601	-
Industry	-	0.0%		-	5.00
EV Charging	-	0.0%		1,849	-
Battery	-	0.0%		7,562	-
Pumped Hydro	5.9	0.0%	-1.4%	11,062	-
Captive Diesel	-	0.0%		1,685	28.21

CLIMATE POLICY INITIATIVE 19

D3 High RE – Demand Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.7
Excess Production (% of VRE)	5.2%
Emissions Intensity (tonnes CO2/MWh)	0.45
Coal Capacity (GW)	222
Coal Capacity Factor (%)	56%
Average Coal Loading When Running (%)	80%
Demand Flexibility Capacity (GW)	70
Battery Capacity (GW)	N/A
Pumped Hydro Capacity (GW)	5.9
Captive Diesel Generators Capacity (GW)	25

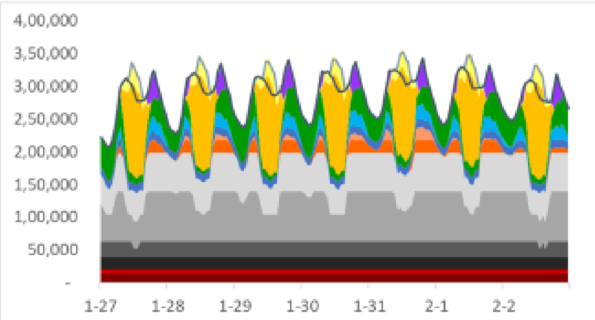
Key Implementation Risks

- Accessing sufficient demand side flexibility, requiring new regulatory approaches, market mechanisms and business models

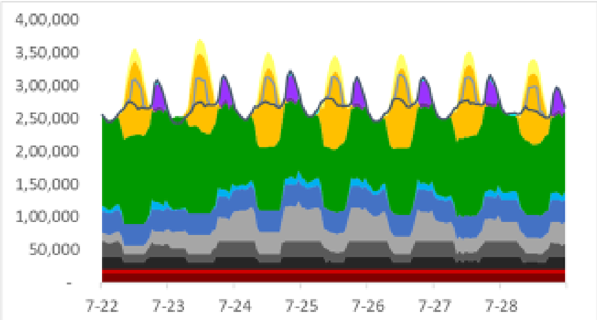
Operational Challenges

- Forecasting and managing RE and demand flexibility availability
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE 20

D3 High RE – Demand Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	160.0	21.1%	36.6%	7,000	-
Solar PV	190.0	14.6%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	80.5	10.7%	37.0%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	23.1	6.3%	75.5%	10,503	2.31
Sub Coal - Pithead	29.6	7.7%	71.9%	9,771	2.92
Super Coal - Non Pithead	95.7	21.4%	61.9%	10,503	4.07
Sub Coal - Non Pithead	74.0	9.8%	36.8%	9,771	4.46
Gas CCGT	24.9	0.6%	6.7%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	2.5%	1,685	28.21
Air Conditioning	19.8	0.3%	3.7%	2,948	-
Ag Pumping	37.7	-0.1%	-0.7%	3,601	-
Industry	-	0.0%		-	5.00
EV Charging	12.5	-0.3%	-6.1%	1,849	-
Battery	-	0.0%		7,562	-
Pumped Hydro	5.9	-0.1%	-2.7%	11,062	-
Captive Diesel	24.9	0.1%	0.8%	1,685	28.21

CLIMATE POLICY INITIATIVE

21

S3 High RE – Storage Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.8
Excess Production (% of VRE)	2.8%
Emissions Intensity (tonnes CO_2/MWh)	0.45
Coal Capacity (GW)	232
Coal Capacity Factor (%)	54%
Average Coal Loading When Running (%)	80%
Demand Flexibility Capacity (GW)	N/A
Battery Capacity (GW)	60
Pumped Hydro Capacity (GW)	15
Captive Diesel Generators Capacity (GW)	N/A

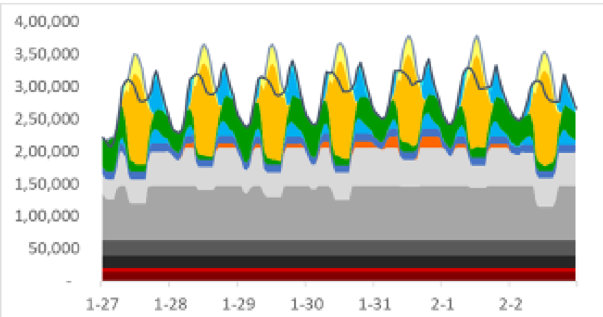
Key Implementation Risks

- Scaling battery supply chain in India
- Overcoming barriers to pumped hydro development

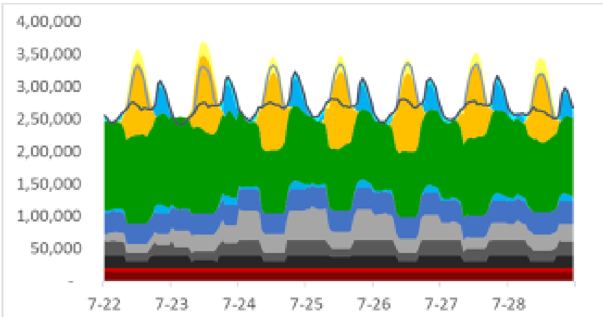
Operational Challenges

- Managing and optimizing storage across multiple sources of value
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns

Dispatch Profile – Late January



Dispatch Profile – Late July



CLIMATE POLICY INITIATIVE

22

S3 High RE – Storage Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	160.0	21.1%	36.6%	7,000	-
Solar PV	190.0	14.6%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	80.5	10.4%	35.8%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	23.1	6.5%	77.7%	10,503	2.31
Sub Coal - Pithead	29.6	8.0%	74.9%	9,771	2.92
Super Coal - Non Pithead	105.7	23.7%	62.0%	10,503	4.07
Sub Coal - Non Pithead	74.0	7.3%	27.5%	9,771	4.46
Gas CCGT	24.9	0.1%	1.4%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	0.0%	1,685	28.21
Air Conditioning	-	0.0%		2,948	-
Ag Pumping	-	0.0%		3,601	-
Industry	-	0.0%		-	5.00
EV Charging	-	0.0%		1,849	-
Battery	60.0	-0.3%	-1.3%	7,562	-
Pumped Hydro	15.0	-0.4%	-7.1%	11,062	-
Captive Diesel	-	0.0%		1,685	28.21

C3 High RE – Balanced Flexibility Portfolio

Portfolio Statistics

System Cost (Rs/kWh)	4.7
Excess Production (% of VRE)	2.5%
Emissions Intensity (tonnes CO2/MWh)	0.44
Coal Capacity (GW)	207
Coal Capacity Factor (%)	59%
Average Coal Loading When Running (%)	86%
Demand Flexibility Capacity (GW)	70
Battery Capacity (GW)	25
Pumped Hydro Capacity (GW)	10
Captive Diesel Generators Capacity (GW)	22

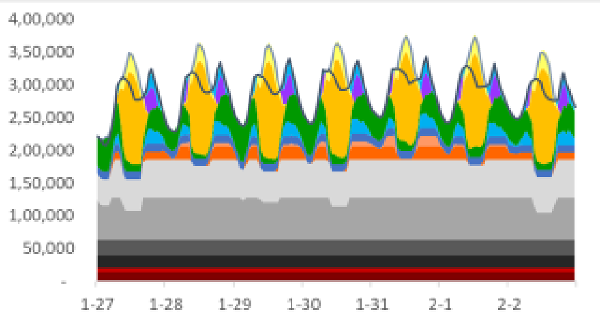
Key Implementation Risks

- Accessing sufficient demand side flexibility, requiring new regulatory approaches, market mechanisms and business models
- Building battery storage supply chain to deliver 25 GW of storage by 2030

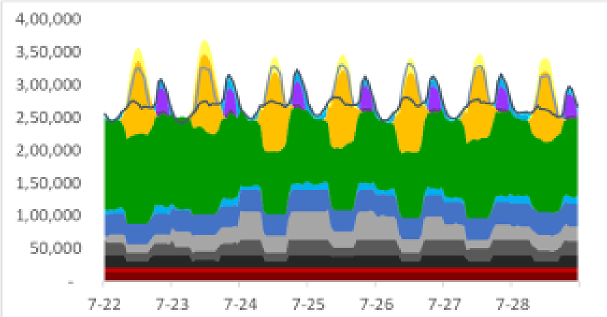
Operational Challenges

- Forecasting and managing RE and demand flexibility availability
- Optimizing storage dispatch profile against multiple sources of value (customer, distribution, transmission systems)
- Managing regional interchange to avoid underutilizing transmission
- Seasonality of some coal and gas capacity, including extended shutdowns
- Ensuring availability of gas, demand-side diesel when called upon

Dispatch Profile – Late January



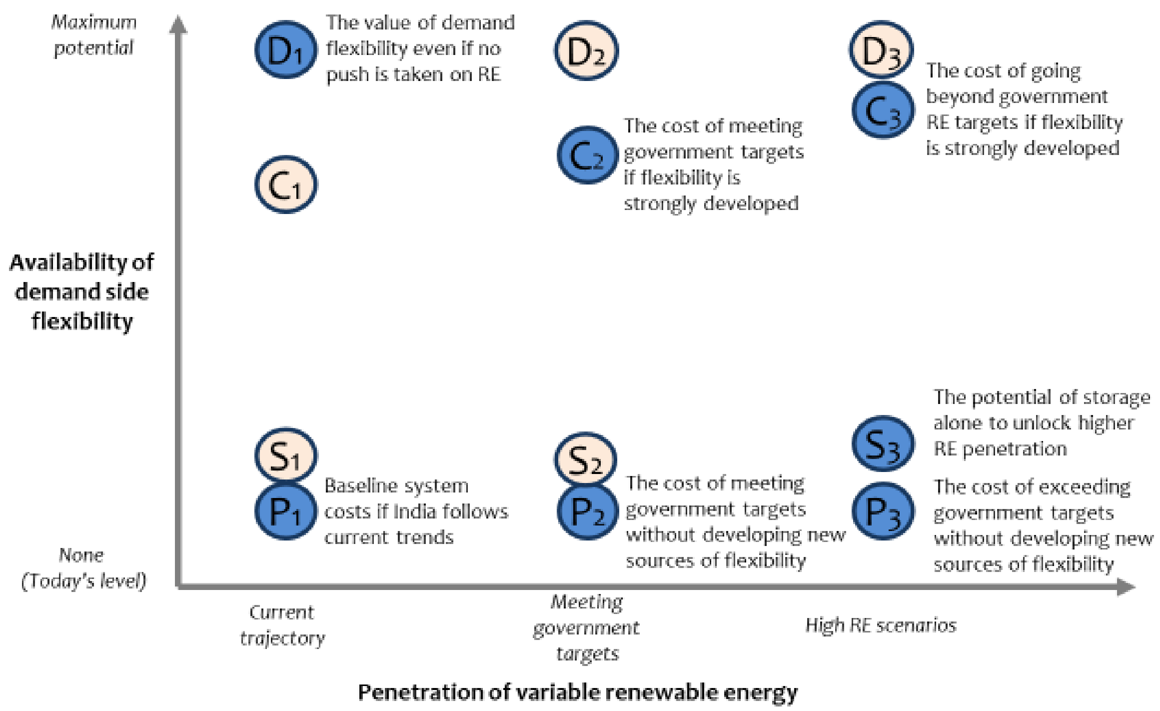
Dispatch Profile – Late July



C3 High RE – Balanced Flexibility Portfolio (Detailed Data)

	Capacity (GW)	Energy Share (%)	Capacity Factor (%)	Fixed Cost (Rs/kW-yr)	Variable Cost (Rs/kWh)
Wind	160.0	21.1%	36.6%	7,000	-
Solar PV	190.0	14.6%	21.3%	4,700	-
Rooftop PV	40.0	2.9%	20.4%	7,050	-
Hydro	80.5	10.7%	37.0%	11,062	0.26
Nuclear	16.9	4.9%	80.0%	25,000	0.50
Biomass	10.4	2.4%	65.0%	14,700	7.47
Super Coal - Pithead	23.1	6.5%	77.8%	10,503	2.31
Sub Coal - Pithead	29.6	8.0%	75.1%	9,771	2.92
Super Coal - Non Pithead	80.7	19.0%	65.1%	10,503	4.07
Sub Coal - Non Pithead	74.0	10.5%	39.4%	9,771	4.46
Gas CCGT	24.9	0.8%	9.1%	9,256	5.32
Gas OCGT	-	0.0%		5,620	8.66
Diesel (Grid)	0.8	0.0%	3.3%	1,685	28.21
Air Conditioning	19.8	0.3%	3.7%	2,948	-
Ag Pumping	37.7	-0.1%	-0.7%	3,601	-
Industry	-	0.0%		-	5.00
EV Charging	12.5	-0.3%	-6.1%	1,849	-
Battery	25.0	-0.1%	-1.3%	7,562	-
Pumped Hydro	10.0	-0.3%	-7.3%	11,062	-
Captive Diesel	22.4	0.1%	1.0%	1,685	28.21

The cost and construction of optimal flexibility portfolios will depend on the level of variable renewable energy and the availability of demand side flexibility



Annex 5: Flexibility needs and challenges will be different in different regions across India

Much of the analysis in this report and previous annexes has treated India as a single, fully integrated electricity system. This level of analysis yields numerous insights as to the potential and cost of pursuing India-wide renewable energy targets and flexibility initiatives. Within the uncertainty of demand forecasts, policy and technology development, we believe that the conclusions are relatively robust. However, as India moves down the path of greater flexibility and renewable energy, there are at least four reasons why we should go beyond the India level analysis to look at regional constraints and differences.

1. **Transmission constraints** and costs restrict the exchange of energy, and therefore flexibility and excess renewable energy, between regions. The effect is that many states and regions are, at times, effectively separate systems for the purposes of balancing energy and meeting system reliability needs. For flexibility, the implication is that flexibility resources in one part of the country might not be useful to meet the flexibility needs in another. In the longer term, the decision is one of transmission costs versus providing flexibility locally or nationally. However, in the shorter-term transmission might not be available, while even in the long term, there are likely to be many cases where it is cheaper to provide flexibility locally rather than investing in more transmission.
2. **The local economy, energy consumption** practices and equipment will lead to significant differences in the availability of local demand side and supply side flexibility resources. Once transmission constraints take their effect, the value and need of flexibility resources in one area may be higher than in another, but also the ability to deliver them might require different incentives.
3. **Weather** has a profound impact on flexibility needs as weather drives both the variability of demand – given temperature driving heating and air conditioning demand – as well as renewable energy output that can be driven by monsoons or sunshine. As long as there are transmission constraints, local climate and weather will have significant impacts on local and state level flexibility needs.
4. **Renewable energy output and ambitions –** While weather affects the output profile from RE, the ambitions are a function of local policy. Nevertheless, with transmission constraints the result of changing local flexibility needs is similar. Further, understanding how regions or states cope that have high renewable energy today, can help us understand how India might cope when higher levels of RE are reached nationally. Of course, states with higher RE penetration tend to have better RE resources, so we could expect that they will continue to have a higher share of the total as India's RE increases.

To start evaluating the potential impact of transmission constraints and regional differences, we have evaluated the needs and potential in four geographically disperse states with different weather patterns, wind and solar capacity levels, susceptibility to powercuts (representing current power shortages), and agricultural and industrial capacity, which represent different types of demand, and demand flexibility potential.

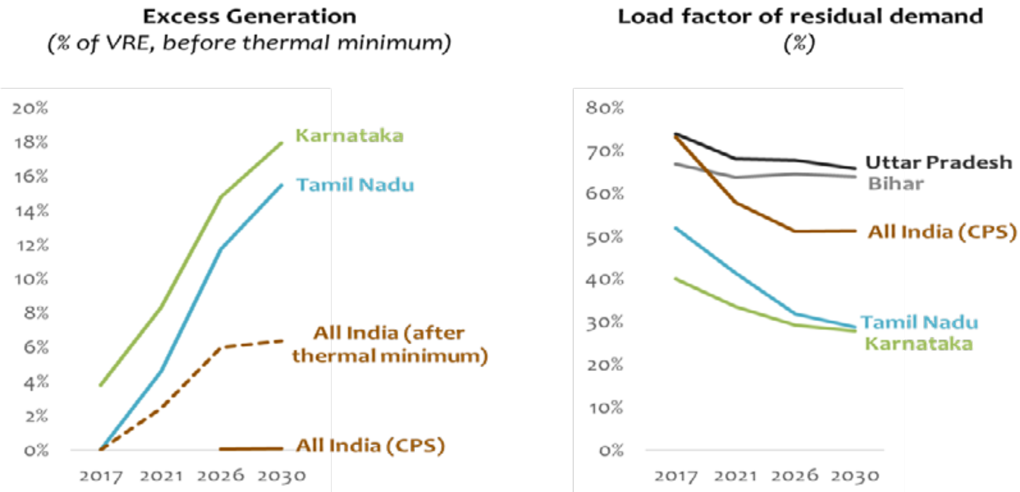
Figure 5-1. States with maximum need and impact were selected for the analysis

Maximum Installed Solar Capacity	Karnataka (5,198 MW)	Telangana (3,284 MW)	Andhra Pradesh (2,282 MW)	Rajasthan (2,300 MW)
Maximum Installed Wind Capacity	Tamil Nadu (9,792 MW)	Gujarat (5,705 MW)	Karnataka (4,791 MW)	Maharashtra (4,785 MW)
Industry and Agricultural Irrigation	Tamil Nadu (37,378 Factories)	Maharashtra (29,123 Factories)	Gujarat (22,876 Factories)	Uttar Pradesh (14,463 Factories)
	1.61 Million Hectares of ground water irrigated land	3.12 Million Hectares of ground water irrigated land	3.1 Million Hectares of ground water irrigated land	10.64 Million Hectares of ground water irrigated land
Annual Powercut Frequency and Population	Jharkhand (717.6)	Uttaranchal (557.5)	Bihar (444.1)	Nagaland (346.9)
	3,29,98,134 Individuals	1,00,86,292 Individuals	10,40,99,452 Individuals	19,78,502 Individuals

For our four case studies we have chosen states with largest wind based installed capacity (Tamil Nadu 9,792 MW) and solar installed capacity (Karnataka 5,198 MW). Additionally, in Uttar Pradesh, we have chosen a state with lower RE, but with the highest level of irrigated land and large industrial base. Finally, Bihar has the largest population affected by power cuts and thus represents states that are faced with inadequate supply, transmission and distribution shortages, or large number of power cuts affecting a substantial chunk of population. For the purpose of this study, the states were considered in isolation and not as a part of a larger system to identify the flexibility challenge faced by each state.

The challenges are, indeed, very different. The two RE heavy states will face significant excess of energy supply, almost triple that of the India average by 2030 (see figure 5-2), if these states have no access to interstate transmission and if flexibility resources are not increased in the coming decade.

Figure 5-2. Flexibility needs would evolve sooner and be more significant in certain states



The chart on the right is even more telling, residual demand, that is the demand that must be met by flexible powerplants, falls to near 30% in the RE heavy states, while staying near current levels in Uttar Pradesh and Bihar. Without transmission constraints, the average load factor would stay somewhere in between across India.

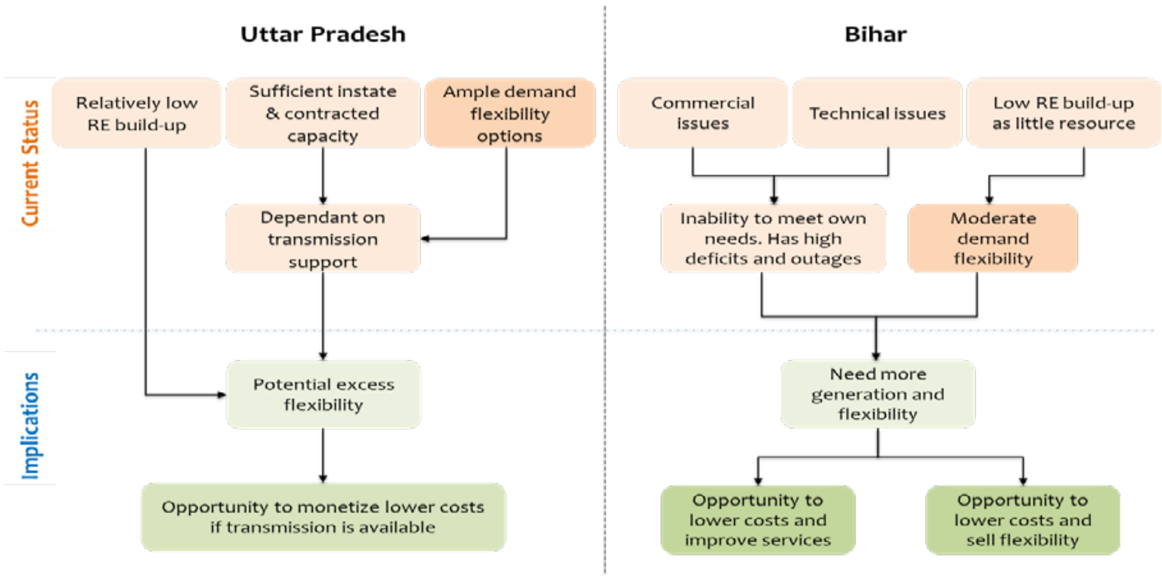
Additional findings at the state level provide further national insight:

- **Tamil Nadu** - the need for seasonal flexibility is expected to rise sharply by 2030 due to the highly seasonal nature of wind-based generation that peaks in monsoon period and slumps during the months of spring. By 2030, the residual PLFs are expected to drop to zero for a period of 3-4 months (see slide 1) which, without interstate trading and/or additional seasonal flexibility, could put the financial viability of the generating assets under pressure. We note that the neighbouring states to Tamil Nadu often face similar issues and timing, so the issue is a regional and national one, rather than just a Tamil Nadu state level issue.
- **Karnataka** - daily ramping requirements are expected to rise significantly as solar energy increases within the state’s energy mix (see slide 1). By 2030, the ramping need is expected to rise to 30% of peak demand from its current levels of 14%. Again, interstate exchange and additional flexibility resources are required.
- **Uttar Pradesh** faces a 10% peak power deficit and the electricity demand is expected to surge with the implementation of 24x7 power for all program. The state electricity board is under financial stress and depends heavily on import of power from generators outside the state to meet the rising power needs. Potential transmission bottlenecks may restrict the states capacity to import increasing quantum of power which is currently used to meet the flexibility needs and the electricity board may not be able to afford installation of fresh peaking power capacity within the state aggravating the peak shortage. Despite these near term issues, UP’s large industrial base, agricultural energy use, and reliance on flexible thermal generation implies that if regulation , pricing, markets and incentives were

fixed, UP will have significant levels of excess flexibility to cover all of its needs and those in other states. Appropriate markets supported by transmission infrastructure and trading mechanisms could enable a significant source of value for UP in selling its flexibility to other states and regions.

- **Bihar** - The demand for power in Bihar has surged more than 150% in the past decade and is expected to rise further with the electrification program. But the supply of power faces repeated disruptions due to poor infrastructure which is unable to cope with peak demands and high level of AT&C losses in the system leading to involuntary flexibility through load shedding which would need to be reduced to meet the 24x7 power for all program targets. Bihar faces near and medium term challenges stabilizing an adequate supply for its own needs. Improving flexibility will help, but is unlikely to lead to significant revenues from selling flexibility until internal supply is secured.

Figure 5-3 Coal dependent states have an opportunity to reduce costs by harnessing demand flexibility



Taken together, the transmission position, RE ambitions, load shedding issues, as well as the availability of flexibility options should make Tamil Nadu and Karnataka importers of flexibility, with UP as an exporter, while Bihar develops more resources for its own use.

Figure 5-4. States may emerge as net importer or exporter of flexibility

Flexibility Drivers (Projected 2030)	**Karnataka**	**Tamil Nadu**	**Uttar Pradesh**	**Bihar**
RE Penetration				
Transmission bottlenecks				
Load shedding				
Flexibility Options	**Karnataka**	**Tamil Nadu**	**Uttar Pradesh**	**Bihar**
Space Cooling				
Agriculture Pumping				
Industrial load				
EV				
Storage				
In state thermal capacity				
Transmission Capacity to Export Flexibility				
Flexibility Profile	***Flexibility Importer***	***Flexibility Importer***	***Flexibility Exporter***	***Flexibility Self-Consumer***

Regional insights for India flexibility

The regional analysis highlights at least five areas where flexibility needs and analysis will need to be incorporated in electricity industry reform and modernization in India.

1. **Incorporating all flexibility needs into transmission planning and development**
   The large differences between states and regions in India highlight the value of transmission. A robust transmission system reduces the needs for flexibility in the first place, by averaging the impacts of diverse weather and consumption effects across the country. At the same time, transmission can increase the amount of flexibility available at lower costs.

   India has an ambitious transmission expansion and development programme underway already. The flexibility benefits achieved from this expansion support this programme. Additionally, while the programme's focus is reducing energy costs by enabling access of low-cost supplies from across India, the programme also aims to improve the quality and security of electricity supplies across India, an important flexibility need.

   Beyond these two objectives, the flexibility work indicates that flexibility more generally represents a third important value stream for transmission. In planning and further development of the transmission system, the growing importance of flexibility, including seasonal and daily balancing and ramping, suggest that transmission planners and developers need to incorporate flexibility benefits in decision making.

   For generators, demand and supply aggregators, energy consumers, or flexibility service providers, an important question will be whether to build or buy flexibility services locally or import them from other states. Clear transmission planning, pricing, and consideration of flexibility requirements is an important part of making this decision.

2. **Building and reforming interstate electricity markets and trading**
   Improving transmission systems will help reduce flexibility needs, but the access to interstate flexibility resources is only possible if there are adequate price signals, incentives, and trading arrangements. Operators in UP, for example, will only develop significant industrial flexibility resources if they see, and can rely on, markets for their flexibility that they can access at a reasonable cost.

   Building this capability suggests not only more comprehensive markets with higher participation, and guaranteed third party access, but also better data provision, and the possibility of long term markets and longer term contracts to justify the investment in flexibility development.

3. **State level planning and regulation**
   As long as transmission has a cost or there are transmission losses, there will be differentiated needs between states and the need for developing local flexibility. Each state thus needs to include flexibility needs, development and procurement into planning and development of intrastate transmission and distribution, generation, storage, and demand side flexibility development. In an ideal world, where there are reliable interstate markets, this planning should include buying and selling flexibility and generation into the markets.

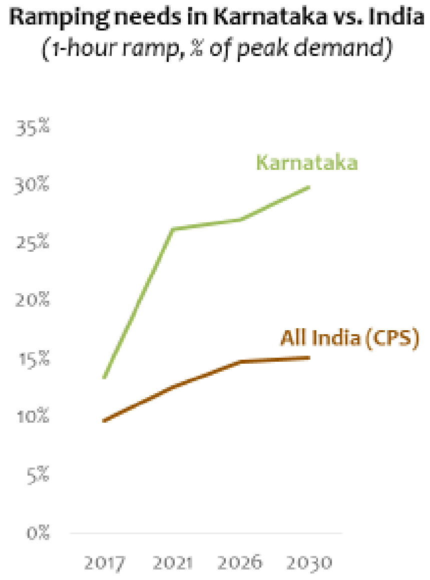
   Even before developing local capabilities, there are actions that states can take to unlock flexibility that is currently inaccessible due to regulatory and commercial barriers. For example, must run levels for thermal power plants are higher than what is technically possible even without modification; contracts often give some thermal plants must run status, or higher priority, which prevents them from offering valuable flexibility to the system. Contracts and business practices prevent powerplants from even considering seasonal mothballing or two shift operation, which could help with local and national seasonal and daily balancing/ramping, respectively. Of course, without interstate trading and markets, there is currently little incentive to make these changes, unless the issues are in state.

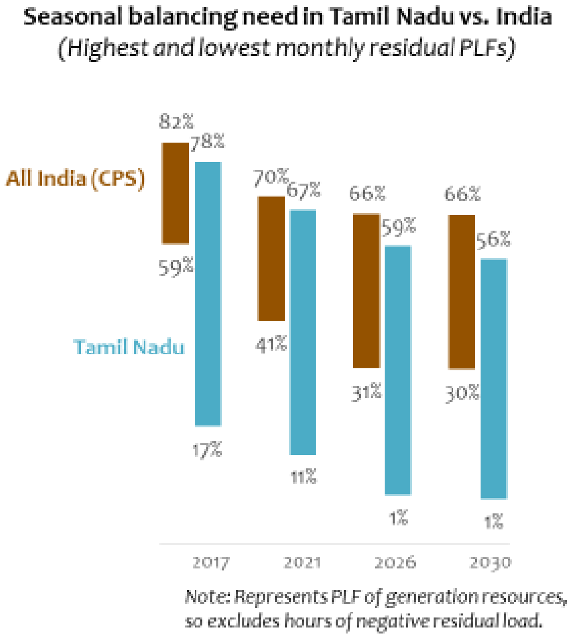
4. **State level energy and flexibility markets**
   Efficient access to intrastate flexibility options also requires tradeoffs between differing resources and transmission or distribution. As at the national level, state level markets, that allow consumers,

distributed generators, storage owners, and powerplants to each offer services to the market, is essential in accessing and integrating the widest range – and therefore lowest cost and most diverse – of flexibility options.

5. **State level flexibility programmes and beta testing**
   Finally, we have noted that costs, resources, and local practices will vary enough between states such that programmes from one state or region might not be applicable in another. The differences will be particularly acute in the demand side area, but storage and generation will also see marked differences. In order to develop programmes that address these difference, each state should begin developing and testing flexibility resources programmes that are tailored to each states needs and resources.

High RE states will face particular challenges that vary from one region to the next





CLIMATE POLICY INITIATIVE

Tamil Nadu will need seasonal balancing due to high wind generation variability

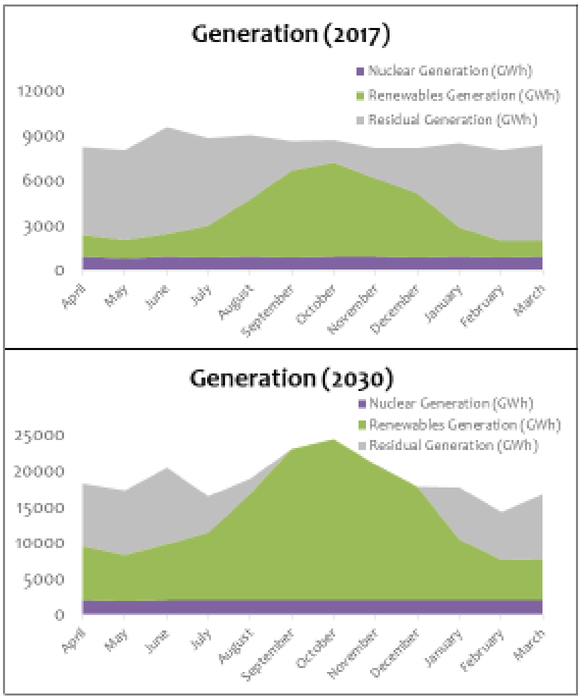
Tamil Nadu is expected to see massive capacity addition in renewables (40GW) while share of coal generation capacity in its energy mix is expected to drop from ~50% in 2017-18 to ~20% in 2030-31

The state currently uses banking agreements to meet its seasonal flexibility needs

With the growth in must-run wind capacity, residual load on thermal powerplants will be impacted by wind seasonality, facing up to a few months shut down

High financial cost of curtailment and of powerplant turn down under current contracts

Potential transmission bottlenecks at state-national grid inter-connect as well as inter regional grid level can threaten banking arrangements with other states



CLIMATE POLICY INITIATIVE

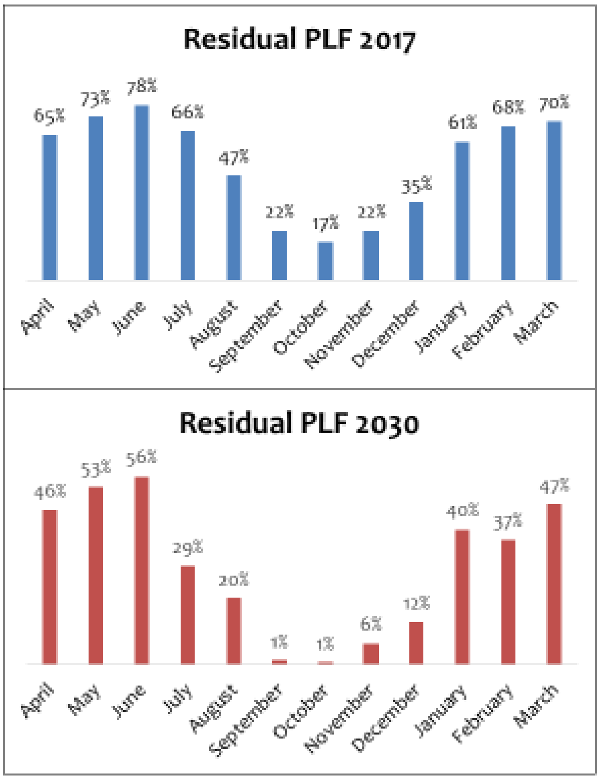
Thermal PLFs in Tamil Nadu are expected to decline drastically and would require new solutions

With the rise in seasonal wind generation, thermal capacity is expected to face shut downs during high wind seasons

Market mechanisms will be needed to incentivise seasonal operation of thermal powerplants – e.g. capacity payments, mothballing of plants for certain months of the year

Industrial demand flexibility could be developed through incentives for energy incentive manufacturing sectors to high wind season

Market instruments for trading up to 500MW of excess seasonal wind generation would provide momentum to help facilitate interstate trading at size



CLIMATE POLICY INITIATIVE

Karnataka will face daily ramping requirement due to high solar generation

Karnataka already has a large share of renewables in its generation mix , ~47%

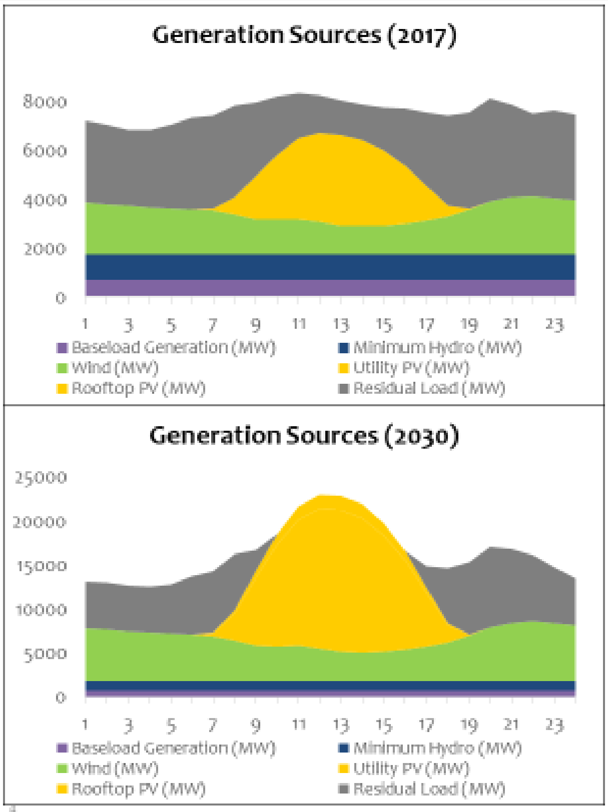
By 2030, over two thirds capacity is expected to come from renewable resources, with solar alone contributing 40% of the capacity mix

Technical limitations of thermal powerplants (high min. technical and low ramp rates) create limitations on their ramping potential

Must run status of renewables raise cost of curtailment

Limited flexible capacity from hydro powerplants due to priority of agriculture commitments and monsoon flows

High price of storage systems means they can be only selectively applied.



CLIMATE POLICY INITIATIVE

Evolving plant operations and new technology can help meet rising ramping need

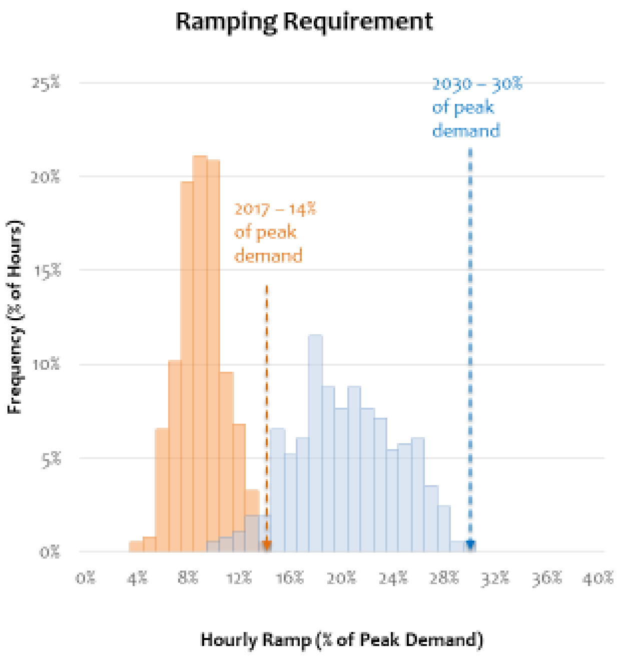
With the increased solar contribution to generation mix, ramping requirement in in Karnataka is expected to rise from 14% of peak demand in 2017 to 30% of peak demand in 2030

Undertaking retrofiring of existing thermal capacity (~10 GW) can improve ramp rates and reduce minimum technical and help meet ramping need

Ensuring all upcoming thermal capacity (~3GW) can support 2 shift operations would support the flexibility needs

Incentives such as VGF to make storage solutions competitive on price would help open the market in early stages

Improving interstate grid infrastructure would support export of power during peak solar generation and reverse flows during monsoons



CLIMATE POLICY INITIATIVE

5

Uttar Pradesh can reduce import dependency for peak demand periods by tapping into demand flexibility

Uttar Pradesh suffers a peak power deficit of c.10%

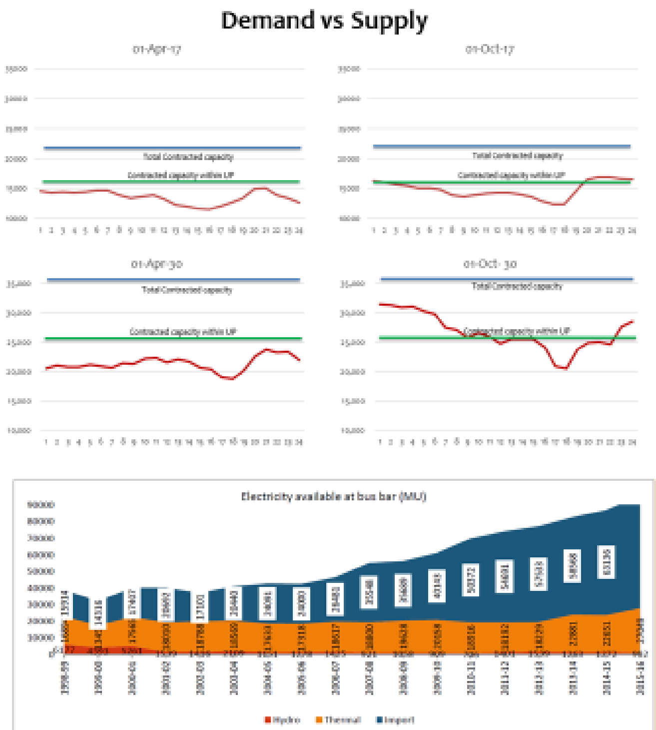
About a quarter of UP's contracted generation capacity lies outside state borders and this is likely to increase by 2030–31

Peak shortage may get aggravated with the rising demand through the 24x7 power for all plan

Potential bottle-necks could arise at the state grid - national grid interconnect with rising import

Weak financials of discoms make it challenging to afford gas based peaking plants or expensive storage

Large no of factories in the state (14,463) and large agriculture consumption (18% of total), with only 15% feeder separation – potential for demand flexibility



Source: 24x7 Power For All - Uttar Pradesh, GoI, GoUP,Crisil

CLIMATE POLICY INITIATIVE

6

Bihar will need solutions to reduce load shedding amidst rising demand

Bihar's peak electricity demand grew by 168% from 2009 to 2016

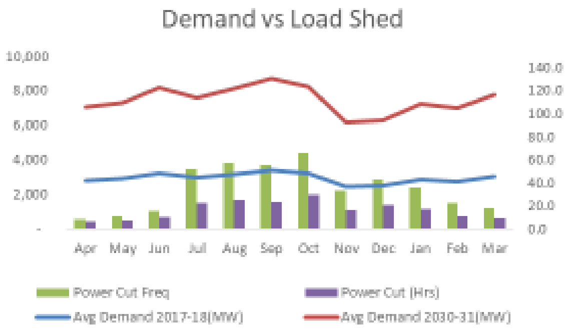
Per capita power consumption at 228.8 kWh is 75% less than the national average and is expected to rise sharply with power for all program

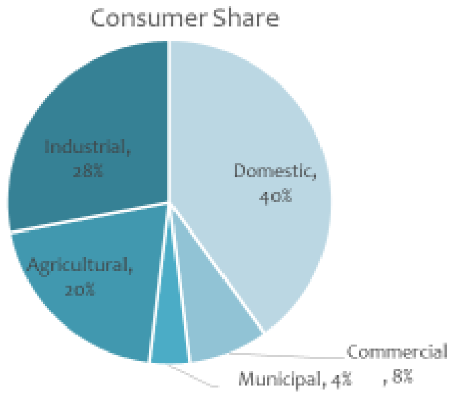
Load shedding in the state has a positive correlation to demand and rises significantly during the high demand period of monsoon in this agricultural state

Poor metering and collection efficiencies (~40% AT&C losses) make it more economical for the discom to shed load than procure costly peaking power

Poor infrastructure being unable to cope with growing load leads to failure during peak demand periods

Only 4% agriculture feeder segregation completed, limiting the load shifting potential





CLIMATE POLICY INITIATIVE 7

In low RE states, demand side solutions offer a low cost option

	Technology	Potential	Effectiveness	Cost
Supply Side	Gas Based Peaker Plants	*Low gas availability*		*High cost of gas*
	Hydro Storage Solutions	*Limited hydro Resource that can be tapped*		*High capex*
	Battery Storage Solutions	*Unproven technology*	*Unproven technology*	*High capex*
Demand Side	Agricultural Demand Response			
	Industrial Demand Response	*Limited to batch production*		*Cost of changing work shifts*
	Cooling Load Shifting	*Limited by seasonality*	*Thermal comfort requirement limits duration*	
	Municipal Demand Response	*Limited potential*		

CLIMATE POLICY INITIATIVE 8

Both Uttar Pradesh and Bihar offer large potential for demand side flexibility

Uttar Pradesh

- Through agri feeder separation, combined agri consumption of ~25 BUs can be shifted to low demand hours by 2030
- Building only 20% of new central AC capacity with thermal storage at no additional cost can help offset the peak demand by 1.5 GW
- Using DR to shift some of the heavy industrial load (10%) by a few time blocks can help shift 3 BU of power demand

Bihar

- Shifting of 10% of industrial load by a few time blocks can shift 183 MU power demand, thereby reducing net peaking power required
- Shifting agricultural load through separate feeders can help move ~300 MUs of consumption to off peak hours
- Thermal storage system for 25% of upcoming central ACs can shift 1GW of peak load to off-peak hours at no additional cost

CLIMATE POLICY INITIATIVE 9

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Climate Policy Initiative Energy Finance

19 Hatfields, London, SE1 8DJ, United Kingdom

Office No. #254-255, 1st Floor, DLF South Court, Saket,
New Delhi – 110017, India