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

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Executive Summary

Over the next decade, India's electricity sector can take advantage of continued declines in renewable energy (RE) and battery storage costs and improvements in the utilization of flexible generation resources to lower costs, enhance reliability and resilience to events like the COVID-19 pandemic, and reduce air pollution and carbon emissions. Enabling the transition to this more flexible, robust, and sustainable power system will require changes in policy and regulation.

National modeling by Lawrence Berkeley National Laboratory (LBNL)[1] found that least-cost, operationally feasible pathways for India's power sector through 2030 consist primarily of investments in renewable energy and flexible resources, including: renewable generation (450-530 GW_{DC} solar and wind, 15 GW other RE), energy storage (60-85 GW), load shifting (60 GW), interstate transmission (140 GW), more flexible operation of existing natural gas generation (25 GW), and development of a more liquid national electricity market. The LBNL national study illustrates that with increases in power system flexibility, India can meet — or even exceed — Prime Minister Modi's announced target of 500 GW of installed non-fossil fuel capacity by 2030, while reducing costs and increasing power system reliability.

While the modeling study provides a long-term vision, the recommendations in this report seek to address the nearer term policy and regulatory changes needed to achieve that vision. For the electricity sector, recommendations[2] focus on three main areas:[3] **resource adequacy (RA)**, state **resource planning and procurement**, and short-term **markets and system operations**.

With respect to RA, resource planning and procurement, and markets and system operations, India's electricity sector faces three main challenges:

1) LBNL estimates that India's national electricity system had approximately 35 GW of excess generation capacity in 2020, relative to what would be needed if existing resources could be used efficiently, and will not return to an efficient, cost-effective load-resource balance until fiscal year 2023 or 2024. Procurement of thermal capacity to meet peak load without taking into account renewables or other flexible resources results in an oversized system and inflated costs.

2) The current practice of procuring thermal and renewable resources through separate solicitations makes it difficult to determine the most economic capacities of different resources to procure, particularly during periods of rapid changes in technology costs, hourly electricity system costs, and demand profiles.

3) Increases in solar and wind generation will likely increase system ramping needs, shift system balancing needs closer to real-time, and increase transmission congestion.

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[1] Abhyankar, Nikit et al., "Least Cost Pathway for India's Power System Investments: Renewable Energy and Flexible Resources Offer a Technically Feasible and Cost-Effective Alternative to New Coal-Fired generation*,"* forthcoming.

[2] Recommendations for the gas sector under Flexible Resources Initiative (FRI) are published as a separate report and focus on flexible utilization of gas assets.

[3] For each area, in consultation with the U.S. Department of State and the Federal Energy Regulatory Commission (FERC), as co-leads under the Flexible Resources Initiative of the U.S.-India Clean Energy Finance Task Force, LBNL developed nearer and longer-term recommendations for India's electricity sector, which were deliberated upon with the Ministry of Power (MOP), the Central Electricity Regulatory Commission (CERC), and Power System Operation Corporation (POSOCO).

Well-designed system planning and RA frameworks, coordinated with state-level resource planning and procurement and supported by electricity markets, are critical to scaling renewables deployment with less curtailment and less financial and operational stress on conventional assets. System planning and RA analysis can help facilitate generation capacity sharing among states, increasing utilization of existing generation assets. They also ensure that electricity supply remains reliable and resilient in response to extreme weather events (e.g., heat and cold waves) and as higher capacities of variable renewable generation are added to the Indian electricity system. Electricity markets and system operations provide the connective tissue, assuring that all planned and procured RA capacity will be available when needed and will be operated when economic to do so. In the longer term, markets must be more closely aligned with real-time operations and facilitate energy storage participation.

Absent well-designed RA frameworks connected to state-level planning and procurement, and reinforced by electricity markets, India risks overbuilding resources, making uneconomic investments, using resources inefficiently, and failing to retire uneconomic plants, all of which will hinder its transition to a low-carbon electricity system.

Proposed Regulatory Framework

The recommendations form a coherent framework of RA planning, resource planning and procurement, and markets and system operations. Figure ES-1. illustrates how the different pieces of this framework fit together, potential roles and responsibilities, and the modeling tools used at each stage. Table ES-1 is a synthesis of all nearer-term and longer-term recommendations.

- This framework begins with annual **state load forecasts** (*Recommendation 1*) and an annual or biennial **national reserve margin study** (*Recommendations 2, 3, 4*), which provides the target RA capacity for resource planning by state joint procurement centres (states) or power distribution companies (Discoms).
- Based on RA requirements, **resource plans** (*Recommendation 9*) identify how much short-term and longer-term capacity the state/Discom needs to procure.
- States/Discoms meet these resource needs through short-term **market procurement** (*Recommendation 5*) and **all-source competitive solicitations** for the longer term (*Recommendation 10*). Short-term RA contracts enable market-based capacity sharing among states/Discoms. Regulators enforce RA requirements (*not pictured, Recommendation 6*).
- States/Discoms evaluate bids in all-source solicitations ("**bid evaluation**") and market procurement ("**market evaluation**") using modeling tools (*Recommendation 11*). This framework would ensure states/Discoms procure a least-cost mix of different types of resources to meet load, including demand response, renewables, and storage.
- **Day-ahead and real-time markets for energy and ancillary services** (*Recommendations 13, 14*) provide price signals that can be used in market and bid evaluation.
- In resource planning and procurement and RA planning, the recommendations presume the pervasive use of industry standard modeling tools. Indian electricity regulators have an important role to play in encouraging the development and use of state-of-the-art modeling tools in implementing resource planning, procurement, and RA planning.

Figure ES-1. Illustration of how Recommendations fit in an Interactive Framework

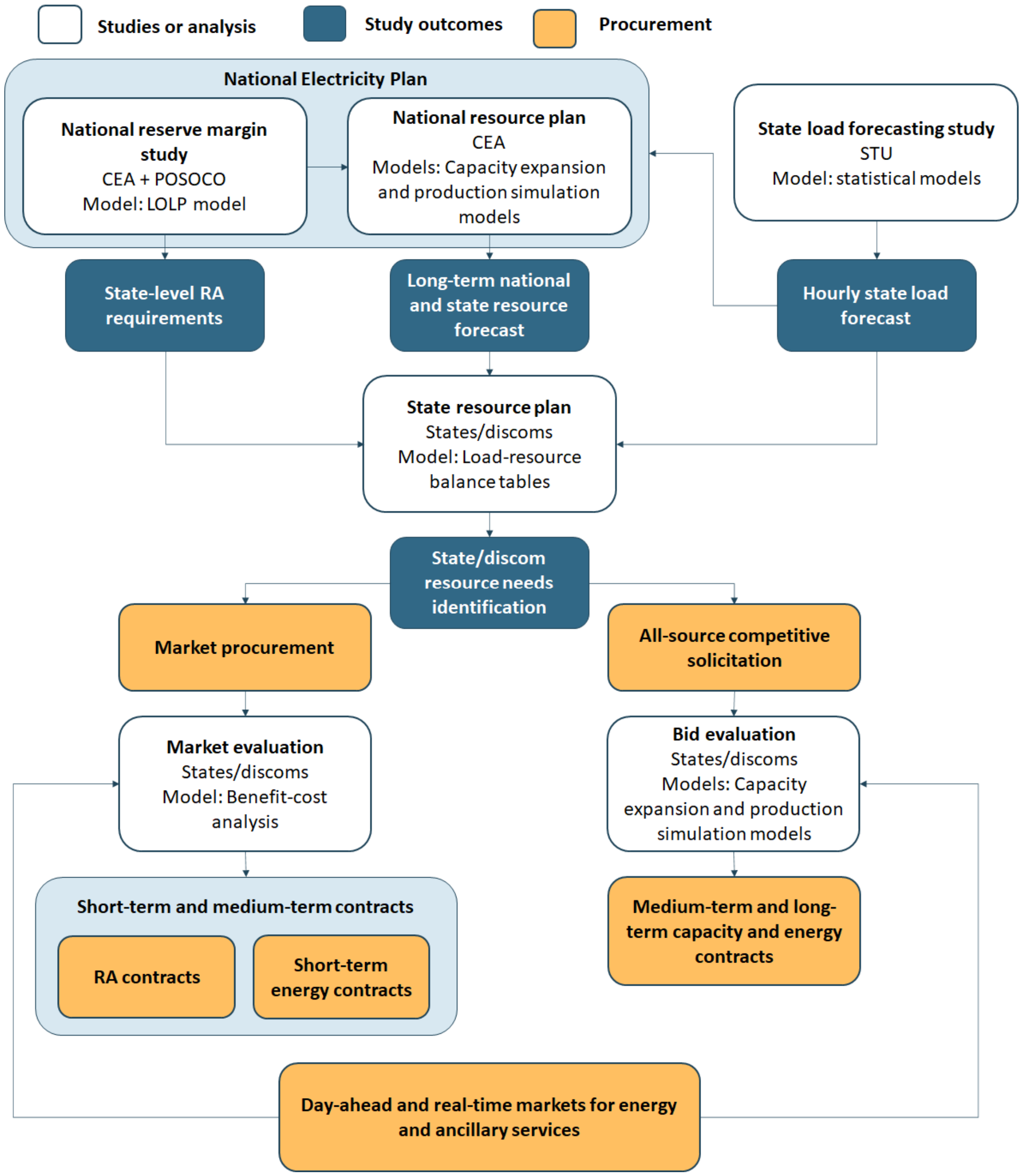

Table ES-1. Synthesis of Recommendations

Nearer-Term	Longer-Term
Resource Adequacy	
1. Create national planning guidelines for state load forecasts, to ensure a consistent national load forecast.	**7.** Adapt RA mechanism to changes in electricity markets, industry structure, and emerging technologies. For example, this might include developing a national RA market for capacity-only contracts.
2. Develop an annual or biennial reserve margin study that sets a national RA requirement.	
3. Allocate the national RA requirement to states with year-ahead compliance.	
4. Develop transparent methods for calculating the contribution of different kinds of resources to RA requirements.	**8.** Develop probabilistic methods for capacity crediting.
5. Allow states and Discoms to comply with RA requirements through self-supply and bilateral markets for RA capacity that transfer scheduling rights in the nearer term, to facilitate sharing of capacity resources.	
6. Develop RA deficiency penalties to enforce compliance with RA requirements and incentives to ensure generator availability.	
Resource Planning and Procurement	
9. Integrate RA requirements into state/Discom determination of resource needs.	**12.** Expand all-source competitive procurement nationwide and integrate long-term procurement, short-term market prices, and transmission expansion
10. Pilot an all-source competitive procurement process, in which all eligible resources, including energy storage and demand-side resources, compete in a single competitive solicitation.	
11. Build the capacity of states/Discoms to use engineering-economic models to evaluate the economics of different resources, including energy storage and demand-side resources, in planning and procurement.	
Markets and System Operations	
13. Complete implementation of day-ahead and ancillary service market reforms.	**15.** More closely align short-term markets and power system operation, by implementing locational marginal price-based (LMP-based) SCED and in real-time markets.
14. Review scheduling and market participation rules for energy storage to ensure that its full functionality can be recognized, utilized and compensated through markets.	

These recommendations aim to support the goals of a lower cost, cleaner, and more reliable and resilient electricity sector. Implementing a more formal, systematic RA framework in India could help to reduce future overcapacity, facilitate generation capacity sharing among states, reduce the risk of free riding on system reliability by individual states or Discoms, increase utilization of existing generation resources, increase the resiliency of the power system to extreme events, and maintain power system reliability as the penetrations of solar and wind generation increase. LBNL's analysis shows that avoiding overcapacity and enabling capacity sharing among states could have reduced total generation capacity by around 45 GW in 2020, leading to approximately Rs 34,000 crore (US$5 billion) per year in annual fixed cost savings.[4] Regulatory interventions can help India's power sector achieve higher reliability at a lower cost.

Enhancing state-level resource planning and procurement practices would enable states/Discoms to construct least-cost portfolios of renewable, thermal, and storage resources that meet national RA requirements. Continued improvements to electricity markets, including the implementation of market-based economic dispatch (MBED) and the creation of markets for ancillary services, would help to increase system flexibility and ensure low-cost operation of India's electricity grid.

[4] The analysis uses forecasted demand for 2020 and does not include the effects of the COVID-19 pandemic. See Appendix A for more detail on the calculations behind this estimate.

Policy and Regulatory Recommendations for India's Electricity Sector

Background

India's power sector is on the cusp of transitioning from a system predominantly powered by thermal, nuclear, and hydro sources, to a grid with increasing penetration of renewable energy from sources such as solar and wind. India currently has about 95 GW of renewables-based capacity[5] and is striving for 175 GW of installed renewable capacity by 2022. Furthermore, Prime Minister Modi has announced an ambitious goal of 500 GW of non-fossil fuel capacity by 2030. Concurrently, the sector is undergoing an array of regulatory changes. Recent regulations have focused on activating real-time markets and ancillary services markets, as well as proposed Market Based Economic Dispatch (MBED) in future. Additionally, how should battery storage be integrated into the current market design has been a topic of debate.

In the United States, and indeed globally, power markets and regulatory frameworks are evolving to incorporate increasing levels of renewables and energy storage. Across U.S. electricity markets, renewable sources and energy storage are now integrated into resource adequacy processes and day-ahead and real-time energy markets. For regulated utilities, all-source procurement, in which different types of resources, including thermal, renewables and batteries, compete to provide to meet utility resource needs, is gaining popularity.

In India, with rapidly falling renewable energy costs, the financial viability of new coal generation is doubtful. LBNL's national modeling study[6] concludes that the least-cost pathway to meet the load in 2030 comprises of mainly renewable energy and storage buildout along with optimum utilization of flexible resources: renewable generation (450-530 GW_{DC} solar and wind, 15 GW other RE), energy storage (60-85 GW), load shifting (60 GW), interstate transmission (140 GW), more flexible operation of existing natural gas generation (25 GW), and implementation of market-based economic dispatch (MBED). Additionally, the variable cost of 80-100 GW of existing coal capacity is higher than the levelized cost of new solar, at 2 Rs/kWh. However, renewables have limited capacity contribution, as load in most regions peaks in the mornings and evenings.

At the same time, procurement of thermal capacity to meet peak load without taking into account renewables or other flexible resources has resulted in an oversized system and inflated costs for several states. A coordinated framework that accurately determines the capacity needs for estimated load, along with mechanisms that allow sharing of resources among states to maximize diversity benefits, would result in a more cost-effective and robust system. Planning and procurement practices that enable the least cost mix of resources would complement this framework at the state level. Enhancing system flexibility through markets would better manage balancing and congestion issues in future. Thus, our policy and regulatory recommendations focus on three broad areas: **resource adequacy (RA)**, state **resource planning and procurement**, and short-term **markets and system operations**.

The objective of this report is to recommend regulatory frameworks that would support these changes, building upon the reform processes that are currently underway in India's power sector.

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[5] See https://mnre.gov.in/the-ministry/physical-progress.

[6] Abhyankar et al., forthcoming.

Five appendices provide supporting background and analysis on:

- Appendix A: India resource adequacy analysis
- Appendix B: Resource adequacy mechanisms in the United States
- Appendix C: Capacity market auction designs in the United States
- Appendix D: U.S. experience with resource planning and procurement
- Appendix E: Market participation models for energy storage in California

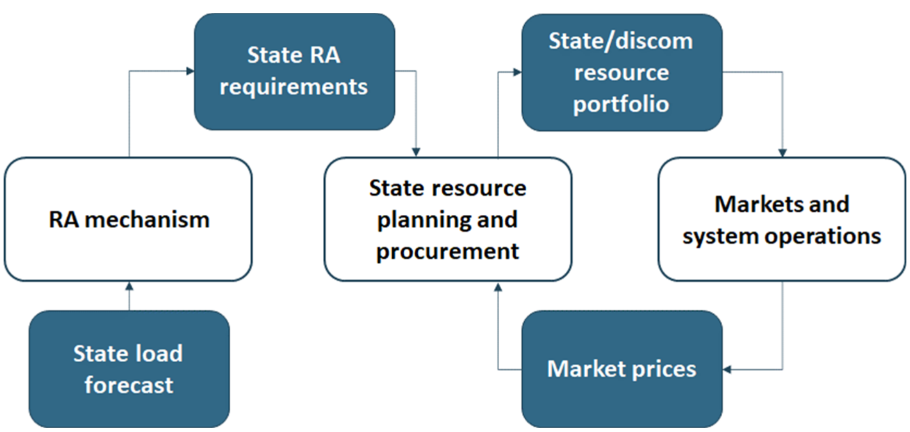
Policy and Regulatory Recommendations Overview

Our policy and regulatory recommendations focus on three areas:

- **System planning and RA** mechanisms — planning and mechanisms that aim to ensure that adequate resources including generation, demand response, efficiency measures, and storage will be available to meet demand, and that resources can be shared among load serving entities (LSEs)[7]
- **State resource planning and procurement** — processes through which states plan for and procure capacity and energy resources at the lowest possible cost, subject to public policy objectives related to environmental or other goals
- **Markets and system operations** — day-ahead and intraday markets for energy and ancillary services and their interaction with the physical operation of the power system

These three areas are interactive (Figure 1.). A national RA mechanism determines RA requirements that are used in state resource planning and procurement. State load forecasts from state resource planning are used in national RA planning. State resource procurement leads to portfolios of resources that are scheduled by load dispatch centres and may participate in energy and ancillary services markets. Prices from these markets can help to guide state resource planning and procurement.

Figure 1. Interactions Among RA Mechanism, Resource Planning and Procurement, and Markets and System Operations



For each area, recommendations are categorized into nearer-term and longer-term recommendations. Nearer-term recommendations can be implemented within the next one to three years, whereas longer-

[7] LSEs primarily refer to distribution companies (Discoms) for the purposes of this document, but also include open access customers.

term recommendations can be implemented within the next four to ten years. Nearer- and longer-term recommendations are intended to form a continuum, with longer-term recommendations building on nearer-term recommendations.

Resource Adequacy Recommendations

- An RA mechanism transparently determines the total amount of resource capacity that includes all supply and demand side options needed to meet a reliability target and allocates responsibility for procuring that target capacity to load serving entities based on their coincident peak electricity consumption, with penalties for non-compliance.
- Although an RA mechanism will not directly address existing overcapacity, it can help to avoid future overcapacity by more efficiently using existing capacity, facilitating procurement of the minimal amount cost-effective new resources to meet future needs, and improving generation capacity sharing among states, thereby reducing the total costs to meet electricity demand.

Indian Context

- LBNL's analysis shows that India has an estimated 35 GW of excess generation capacity, relative to what is needed to meet individual state peak demands for electricity (see Appendix A).
- Enabling states to share generation capacity would further reduce India's total generation capacity needs by around 10 GW.
- In total, avoiding overcapacity and enabling capacity sharing could have reduced generation capacity by 45 GW in 2020 (fiscal year), leading to approximately Rs 34,000 crore (US$5 billion) per year in annual fixed cost savings.[8] Over the next decade, the potential for generation capacity sharing will increase due to continued load growth, reaching around 20 GW by 2030.[9]
- The RA recommendations seek to build upon the draft Indian Electric Grid Code (IEGC) and CEA's national electricity planning process.[10]
- The RA recommendations also seek to improve upon current resource sharing practices in India, including banking of power (typically between states with disparate peak load months), short-term power contracts, as well as revision of scheduling rights amongst beneficiaries of a central generating station.

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[8] Overcapacity here is defined as total RA-credited net generation capacity minus the sum of state peak demands. Capacity sharing savings are defined as the sum of state peak demands minus non-coincident peak plus a 15% planning reserve margin. Capacity credits for coal, gas, oil, nuclear, and biomass generation were assumed to be 100% of net nameplate capacity; tertiary reserves to address generator forced outages are embedded in the planning reserve margin. The cost savings estimate assumes that coal is the marginal capacity resource and uses an annual fixed cost of 7,500 Rs/kW-yr and an exchange rate of 70 INR/USD. All years are fiscal years unless otherwise noted.

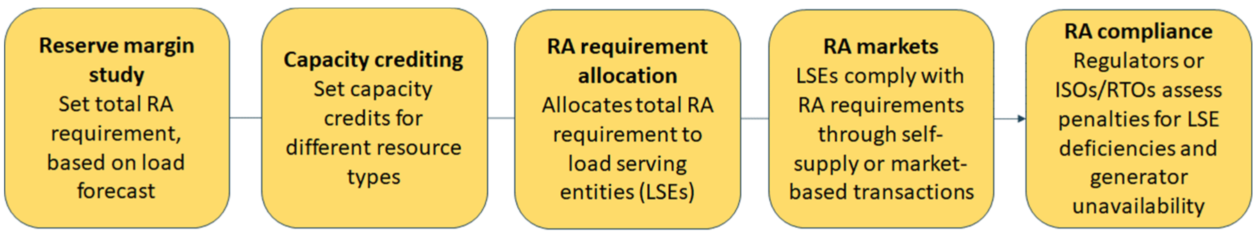
[9] See Appendix A for documentation of the assumptions, methods, and full results of LBNL's RA analyses.

[10] The draft IEGC proposed that, "Each distribution licensee shall ensure demonstrable resource adequacy as specified by the respective SERC [State Electricity Regulatory Commission] for the next five (5) years." *Report of the Expert Group: Review of Indian Electric Grid Code*, 2020, https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf, p. 20. CEA's National Electricity Plan includes elements of a reserve margin study, including national targets for loss-of-load probability and energy not served. See CEA, 2018, *National Electricity Plan*, https://cea.nic.in/wp-content/uploads/2020/04/nep_jan_2018.pdf.

U.S. Context

- Six of the seven independent system operators/regional transmission organizations (ISOs/RTOs)[11] in the United States have some form of an RA mechanism.
- The design of these RA mechanisms differs significantly across ISOs/RTOs.[12]
- For instance, four ISOs/RTOs (MISO, ISO-NE, NYISO, PJM) have regular auctions for RA capacity in which the ISO/RTO acts as the buyer, whereas two ISOs/RTOs (CAISO, SPP) have bilateral markets for complying with RA requirements.[13]
- However, despite differences in the details of RA mechanism design across ISOs/RTOs, these mechanisms share a similar underlying process (Figure 2.).

Figure 2. General Steps in the RA Process



- The RA recommendations are based on this process, tailored to the Indian context and market design.

Recommendations

<u>Nearer-Term (1-3 years)</u>

1. Create national planning guidelines for state load forecasts, to ensure a consistent national load forecast.

- Load forecasts are the most critical input to reserve margin studies and RA requirements.
- The draft IEGC stipulates that the national load forecast will be based on state load forecasts by state transmission utilities (STUs), adjusted by the Central Transmission Utility (CTU). However, there is currently significant variation in methodologies used in state load forecasts and the forecasts' accuracy.
- National planning guidelines for state load forecasts would create more consistency across different state forecasts, leading to a more robust national load forecast. These guidelines could specify acceptable forecasting methodologies, weather-year assumptions, explanatory variables, and data input sources.

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[11] ISOs/RTOs are not-for-profit system operators that operate bulk power systems and electricity spot markets in the United States. The primary distinction between an ISO and RTO is that ISOs within a single state, whereas RTOs are multi-state. The seven U.S. ISOs/RTOs include the California ISO (CAISO), Electric Reliability Council of Texas (ERCOT), Midcontinent ISO (MISO), PJM, ISO-New England (ISO-NE), New York ISO (NYISO), and Southwest Power Pool (SPP).

[12] See Appendix B for a detailed description of RA mechanism designs and design tradeoffs in the United States.

[13] Even among the four ISOs/RTOs that have capacity auctions, RA mechanism and auction designs are quite different (see Appendices A and B).

- CTU could develop state load forecasting guidelines in consultation with CERC and review state forecasts for statistical accuracy and rigor.
- U.S. RTO load forecasting guidelines could provide a useful reference for Indian regulators and CTU, in terms of balancing the need for greater rigor and standardization in utility forecasting, while preserving state jurisdiction and autonomy over reliability.[14]

2. Develop an annual or biennial reserve margin study that sets a national RA requirement.

- A reserve margin study would calculate a national system-wide planning reserve margin (PRM), which is the amount of resource capacity, in addition to forecasted national coincident peak (CP) demand, that is needed to meet a bulk system reliability target, such as a loss-of-load expectation (LOLE) target.[15]
- The PRM accounts for operating reserve needs, expected forced outage rates, and load forecast error due to deviations from expected weather and changing macroeconomic conditions.
- The reserve margin study would set a national RA requirement, equal to forecasted national CP plus the PRM, which would then be allocated to states (Recommendation 3).
- Distribution companies or state-level aggregate of Discoms would be required to demonstrate that they have adequate resources to meet the RA requirement or pay a deficiency penalty (Recommendation 6).
- A national RA requirement would take advantage of the significant load diversity between India's Western, Eastern, and Southern grid regions, lowering overall generation capacity needs.
- Load diversity refers to the fact that the peak demands of different states and regions will occur at different times. In 2019, for instance, India's national CP was 171,690 MW whereas the sum of state peak demands — the minimum amount of generation capacity required if each state met its needs independently — was 208,393 MW.
- A mandatory RA requirement would shift the main incentive for ensuring that LSEs have adequate generation capacity to meet demand from real-time imbalance penalties, through the deviation settlement mechanism (DSM), to a year-ahead basis.
- One of the main goals of shifting incentives would be to facilitate more systematic sharing of generation capacity resources and their fixed costs across Discoms and states.

3. Allocate the national RA requirement to states on a year-ahead basis, with seasonal or monthly RA requirements.

- A key issue for allocating RA requirements in India will be how to encourage more generation capacity sharing across states, reducing overall generation capacity needs and costs.
- Generation capacity sharing is limited, in part, due to the "self-scheduling" protocol followed by Discoms and the load dispatch centres — the Discom has complete control over the generation it schedules for meeting its load.

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[14] As an example, see MISO's *Peak Forecasting Methodology Review*, https://cdn.misoenergy.org/Peak%20Forecasting%20Methodology%20Review%20Whitepaper173766.pdf.

[15] "Bulk system" refers to the high voltage transmission system. In the United States, bulk system reliability targets are based on an LOLE metric, which is defined as the total duration during which load exceeds available generation over some time period. Traditionally, the target LOLE in U.S. electricity industry has been 1 day in 10 years (0.1 days per year).

- In principle, the national RA requirement could be allocated to states based on their share of national CP.
- In about 75% of states (assuming a 15% PRM), this RA requirement would have been lower than state peak demand in 2019 because of load diversity (see Appendix A).
- For instance, under this approach, Punjab's share of national CP in 2019 (5.4%) would have given it a 10,615 MW RA requirement in 2019, 1,758 MW less than its 12,372 MW peak demand.
- During Punjab's peak demand hour (in July), India's national demand was 154,626 MW. With a 15% PRM, a national RA requirement would have resulted in 197,443 MW of generation capacity in 2019, suggesting that the national electricity system would have had more than enough unutilized generation (42,817 MW) during Punjab's peak demand hour to provide the additional generation (1,758 MW) needed to meet Punjab's demand in that hour.
- Currently, states/Discoms can procure power to meet their short-term energy needs through short-term (monthly, daily, intraday) power markets. However, with current low levels of power market liquidity, there is no guarantee that adequate power would be available when a state/Discom needs it.
- Additionally, states/Discoms that are paying the fixed costs for their generation might be hesitant to make it available to other states/Discoms in the market without some fixed cost compensation.
- Thus, in the short-run, given the current market framework, state/Discom RA requirements could be based on seasonal or monthly state/Discom peak demands, rather than share of national CP.
- This approach would require states/Discoms to demonstrate, on a year-ahead basis, that they have adequate resources to meet their forecasted seasonal or monthly peak demands, plus a share of the PRM.
- This would still enable states/Discoms to lower their costs of meeting seasonal peak demand by procuring from other states/Discoms who might have excess capacity during that season, instead of signing on new resources for the whole year (Recommendation 5).
- With seasonal or monthly requirements, states/Discoms would have an additional incentive to pay for part of the fixed costs of shared generation, but this approach may come at a cost of higher regulatory complexity and effort.
- In the long run, the allocation of state RA requirements should ideally be based on proportional share of national CP to meet the load at least possible cost (Recommendation 7).

4. Develop transparent methods for calculating the contribution of different kinds of resources to RA requirements.

- Capacity crediting refers to the process of determining the percentage of the net installed (nameplate) capacity of different resources that will be counted toward RA requirements.
- For thermal generation, capacity credits should include, at a minimum, weather-related capacity derates, supported by semi-regular testing to benchmark unit performance.
- Non-thermal resources — energy storage, demand response, hydropower, solar, and wind generation — will generally be credited based on their anticipated contribution to RA requirements. This value is typically lower than the net installed capacity of the resource. Accurately accounting for the contribution of resources towards RA requirements avoids incenting excess generation capacity and in turn higher costs relative to what should be needed to meet a reliability target. It also avoids under-procurement of resources to maintain RA.

- Initially, methods for calculating capacity credits for non-thermal resources in India could be based on capacity factor during peak demand periods (hydropower, solar, wind) or duration requirements (storage, demand response) and can transition to probabilistic methods over time.
- This staged approach is consistent with U.S. ISO/RTO experience. It allows for relatively simple but reasonably accurate approaches to be developed first, and for more sophisticated approaches to be developed over time.
- For use in a national RA program, capacity credit values should reflect regional resource diversity but can be calculated using a standardized methodology. These capacity credits can be adjusted to account for a changing resource and load shapes every few years.

5. Allow states and Discoms to comply with RA requirements through self-supply and markets for RA capacity, to facilitate sharing of capacity resources.

- Markets for RA capacity enable Discoms and generators that have surplus generation capacity (are long) to sell that capacity to Discoms that do not have adequate capacity to meet their RA requirements (are short).
- Thus, rather than signing contracts for new generation at full fixed cost to meet their RA requirements, Discoms that are short on RA capacity can procure it from existing resources at what should, in most cases, be a lower cost.
- In the United States, capacity-only RA contracts are only used by LSEs to demonstrate compliance with RA requirements and have no energy component.
- Under current self-scheduling practice in India, states/Discoms must have the scheduling rights to generation that they use to meet their electricity needs, which precludes the use of capacity-only RA contracts.
- Although capacity-only RA contracts can be an efficient way to facilitate fixed cost sharing for RA compliance, they require a liquid energy market and potentially must-offer obligations (Recommendation 7) to ensure that the generation in these contracts is available to the electricity system when needed.
- As an alternative, Discom-to-Discom capacity sales could be through RA contracts that transfer scheduling rights to generation, and generator-to-Discom capacity sales could be through short-term RA capacity and energy contracts.
- In RA contracts that transfer scheduling rights, the fixed cost component could be market-based while the variable cost component could remain unchanged from the existing contract.
- Such a contract between Discoms might be more effective if the generator is also a party and is aware of availability incentives (Recommendation 6).
- In the short run, markets for RA capacity could be through competitive solicitations by the procuring state/Discom or through new products on existing platforms, for instance the Discovery of Efficient Electricity Price (DEEP) portal or power exchanges (IEX/PXIL).

6. Develop RA deficiency penalties to enforce compliance with RA requirements and incentives to ensure generator availability.

- If Discoms are not able to demonstrate adequate capacity to meet their RA requirements, they would be assessed a deficiency penalty.
- Deficiency penalties should be high enough to encourage compliance, even when available generation capacity is scarce and capacity prices are high. In U.S. ISOs/RTOs, compliance penalties

are typically set at a multiple (e.g., 1.5x) of the marginal capacity resource (e.g., a natural gas combustion turbine).

- Availability incentives seek to ensure that generators that have been counted toward RA requirements are available to perform when needed.
- Availability incentives can be designed to be revenue neutral to loads, with penalties for non-availability paid to generators that exceed their availability targets, or can be integrated into capacity crediting by basing credits on historical forced outage rates during peak demand periods.[16]

Longer-Term (4-10 years)

7. Adapt RA mechanism to changes in electricity markets, industry structure, and emerging technologies.

- Implementation of a more liquid national market, such as the proposed market-based economic dispatch (MBED), would facilitate generation capacity sharing in an RA mechanism, for instance through capacity-only RA contracts that could be traded in a national auction-based exchange.
- To ensure the generation that is being counted toward RA requirements is available when needed, this generation should have a must-offer obligation in at least the day-ahead energy market.
- Five of the six U.S. ISOs/RTOs that have RA mechanisms (CAISO, ISO-NE, MISO, NYISO, PJM) have must-offer obligations for generation that is counted toward RA compliance.
- Additionally, a streamlined capacity sharing mechanism would enable allocation of RA requirements on the basis of national coincident peak, instead of states holding resources up to their state (non-coincident) peaks. This would significantly bring down the costs of meeting load, taking advantage of India's synchronized grid.
- Changes in industry structure and technological change may also require significant adaptations in future RA mechanism design.
- The most important changes in industry structure and technology that would require changes in an RA mechanism would be growth in competitive retail supply and distributed energy resources (DERs). With competitive retail supply, there must be a way of ensuring that all suppliers, including small retailers with small loads, are able to fairly and competitively meet their RA obligations. DERs must be accounted for in determining RA requirements.
- Expansion of competitive retail supply may warrant the development of a centralized capacity market, where the system operator (POSOCO) acts as the buyer in a capacity auction and buys capacity on behalf of load serving entities (LSEs) that are capacity short, with the costs allocated to LSEs based on their share of demand. Having the system operator act as a "backstop" buyer on behalf of LSEs allows for a more competitive retail market, by reducing transaction costs for smaller retail providers.

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[16] The CAISO's availability incentive mechanism, for instance, charged/credited generators that were 2.5% below/above monthly forced outage rates for the previous 3 years, with charges based on the marginal cost of new generation capacity. In other ISOs/RTOs, availability incentives are integrated into the calculation of capacity credits (unforced capacity, or UCAP, as opposed to installed capacity, or ICAP), based on historical forced outage rates during peak demand periods, and in some cases through performance incentives that penalize/reward generators for unavailability/availability during periods of operating reserve scarcity. Using UCAP rather than ICAP requires reducing the total RA requirement to account for the fact that forced outage rates are already being accounted for in generation capacity credits.

- Expansion of DERs would require consideration of how these resources will fit into RA studies and reserve margin determination, either on the supply side through capacity crediting or on the demand side through load forecasts.

8. Develop probabilistic methods for capacity crediting.

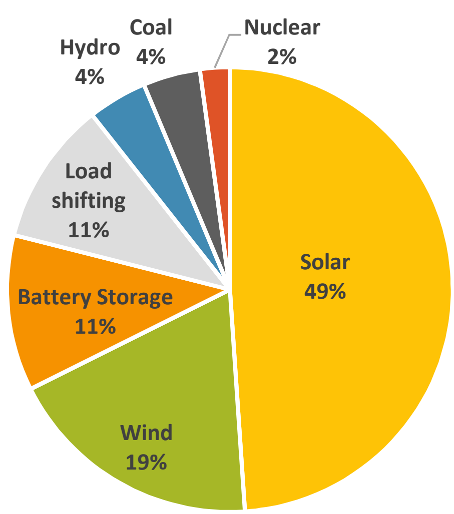
- As solar, wind, and solar penetrations rise, more probabilistic methods will be needed for assessing the capacity credit of solar, wind, storage, and demand response resources in bulk system reliability planning.
- Most U.S. ISOs/RTOs are now moving toward an effective load carrying capability (ELCC) methodology for determining the capacity credit of these resources.
- ELCC is the incremental amount of firm load that can be met by a resource, while maintaining a reliability target.
- Developing a more accurate methodology for calculating the capacity credits of different resources — including solar, wind, storage, and demand response but also thermal, nuclear, and hydropower — will be important for bulk system reliability planning regardless of India's choice of longer-term RA mechanism.

Resource Planning and Procurement Recommendations

Indian Context

- LBNL's national capacity expansion modeling projects that the least-cost investment pathway for India's electricity sector over the next decade will consist mainly of new renewable generation and flexible resources, such as storage and load shifting. (Figure 3.).

Figure 3. Shares of New Resource Capacity from 2020 to 2030 in LBNL National Modeling Study[17]



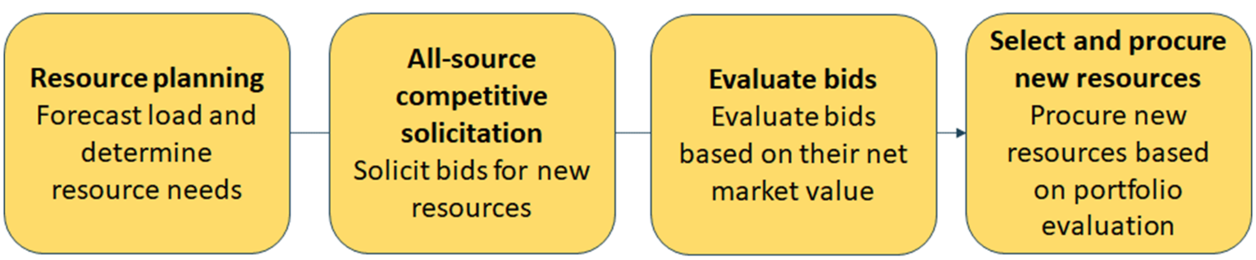
[17] These shares are based on the Primary Least Cost scenario.

- LBNL's modeling projects that a least-cost investment strategy would include a significant amount of cross-state resource sharing, to take advantage of diversity in the timing of loads and resources and regional differences in solar and wind resource quality.
- Resource diversity refers to the fact that weather-dependent resources will generate at different times in different regions; for instance, solar in Western India will have a different generation profile than solar in Northeastern India.
- The projected least-cost investment strategy shown in Figure 3. is the result of low solar, wind, and battery costs and changing electricity system economics.
- Changing economics are driven by interactions among solar, wind, hydropower, demand response (e.g., agricultural load shifting), and batteries: low-cost solar and wind generation and shifting hydropower generation to evenings will reduce the value of new baseload generation.
- LBNL's modeling study finds that for India's projected load, which includes 60 GW of agricultural and industrial load shift to solar hours, batteries would be a lower cost way of providing required capacity for meeting morning and evening peak than new coal or natural gas generation.[18]
- Long-term resource planning in India is currently undertaken every five years by the Central Electricity Authority (CEA) through the National Electricity Plan (NEP), but procurement is under state jurisdiction and undertaken annually or semi-annually by individual Discoms or state procurement agencies that represent multiple Discoms.
- Within this framework, no entity is responsible for determining the least-cost amounts of different kinds of resources that states/Discoms should procure.
- Enhancements to India's resource planning and procurement framework could help to ensure least-cost investments over the next decade.

U.S. Context

- For U.S. electric utilities, resource planning and procurement is a multi-step process that includes load forecasting, resource planning to identify resource needs, competitive solicitations for new resources, evaluation of solicitation bids, and selection and procurement of new resources (Figure 4.).

Figure 4. General Steps in the Resource Planning and Procurement Process



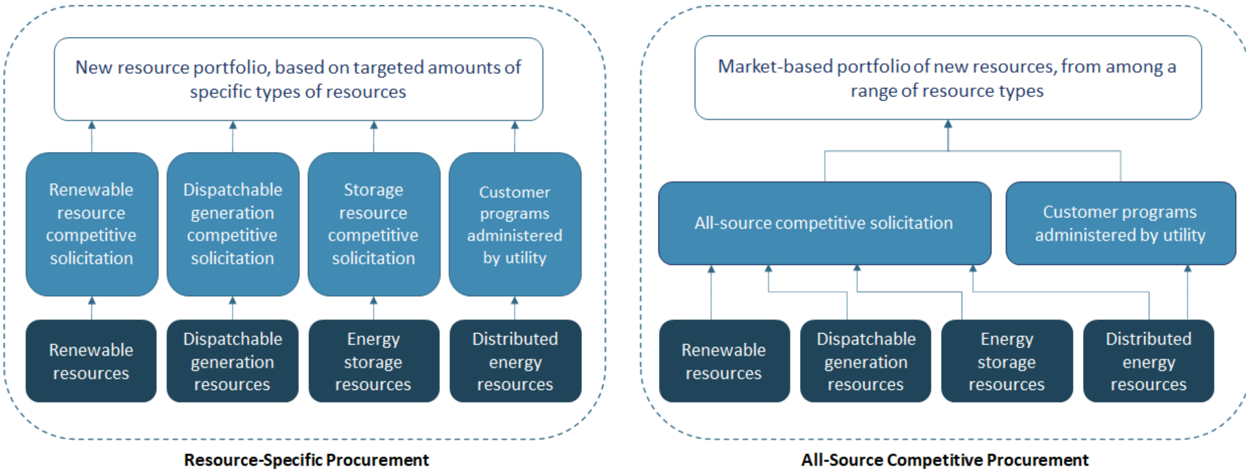
- Rapid declines in renewable and storage costs have led to changes in utility resource planning and procurement frameworks in the United States.
- A growing number of utilities are using all-source competitive solicitations, where all eligible resources compete in a single solicitation, rather than having separate solicitations for different

[18] Abhyankar et al., forthcoming.

kinds of resources, as this leads to a lower overall cost than procuring resources in silos of "traditional" and renewable resources.

- Figure 5. below illustrates the difference between all-source competitive procurement, where utilities procure all or most of their resources in a single solicitation, and resource-specific procurement, where utilities procure different resources in different solicitations.

Figure 5. Illustration of Resource-Specific Procurement and All-Source Competitive Procurement



Recommendations

Nearer-Term (1-3 years)

9. Integrate RA requirements into state/Discom determination of resource needs.

- RA requirements are the amount of credited capacity that each state/Discom will need to own or have under contract to avoid paying a deficiency penalty.
- RA compliance would be on a year-ahead basis (Recommendation 3), while the resource planning horizon is typically much longer (e.g., 5-10 years).
- In resource planning, RA requirements are the benchmark for determining resource needs — the quantity of new or existing resources that the state/Discom will need to procure.
- For instance, if a state had 10,000 MW of credited resources in 2020 and RA requirements of 10,500 MW, 11,500 MW, and 13,000 MW in 2021, 2022, and 2023, it would need to secure 500 MW, 1,000 MW, and 1,500 MW of additional resources by 2021, 2022, and 2023, respectively, assuming that existing resources are retained.[19]
- States/Discoms could meet incremental resource needs through a combination of short-term market purchases and long-term contracts for new resources, to create an economically diversified portfolio that leads to lower expected costs and manages price and performance risk.

[19] If the state/discom met part of its RA requirements through short-term market purchases, its additional resource needs in any given year might be higher. For instance, if the state/discom met the 500 MW incremental RA requirement in 2021 with through short-term (< 1-year) contracts, for the 2022 compliance year it would need to procure 1,500 MW of RA resources.

10. Pilot an all-source competitive procurement process, in which all eligible resources compete in a single competitive solicitation.

- Because of rapid changes in relative generation technology costs over the past five years, India's current framework for resource procurement faces three key challenges.
- First, it is difficult to translate from the least-cost resource portfolios identified in the NEP to actual state resource procurement; unlike the NEP, state procurement does not account for the interactions among different resources.
- Second, with increasingly diverse resource options, it is more difficult to compare different resources on an equivalent basis in terms of their levelized (Rs/kWh) costs and the lowest cost option may not yield the most value.
- Third, the costs of solar PV, wind, and energy storage are rapidly changing, which affects optimal investment strategies and creates investment risk.
- The first two challenges require further description.

Challenge 1: Translating least-cost portfolios to least-cost procurement

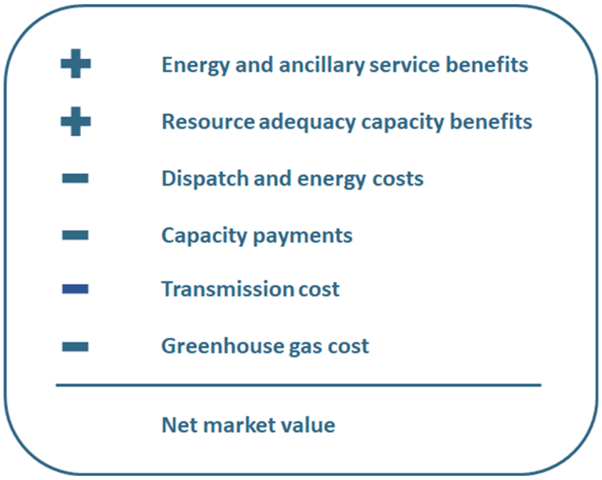
- States/Discoms currently procure new resources through separate competitive solicitations: they procure renewable generation to meet state renewable purchase obligations (RPOs), coal and other thermal generation to meet load growth, and they are not yet procuring standalone battery storage.
- With continued declines in renewable generation and storage costs, however, it may be cost-effective for states to procure more renewable energy and begin to procure battery storage on a large scale, as shown in the LBNL modeling results.
- To determine least-cost amounts of different resources, state procurement would need to account for interactions among demand response, hydropower, solar, thermal, wind, and storage, as well as changes in load profiles.
- These interactions will affect RA capacity credits and capacity value (Recommendations 4 and 8), but will also affect the energy value of different resources.
- For instance, optimal investments in battery storage will depend on the amount and cost of solar procurement; optimal investments in coal generation will depend on how much agricultural load is shifted to solar hours and how much peak hour demand batteries are able to meet.

Challenge 2: Evaluating resources with different characteristics on an equivalent basis

- To determine which resources are most valuable, net market value (benefits minus costs) is a more appropriate metric for comparison than is levelized cost.
- Figure 6. illustrates the U.S. state of California's framework for calculating net market value. In this framework, net energy and ancillary service market benefits can be quantified as the market value of the resource (projected generation and reserves multiplied by projected market prices or system marginal costs) less the dispatch and energy costs of the resource when it operates.
- Net resource adequacy benefits are the market value of the resource (capacity credit multiplied by projected market capacity price), less the cost of capacity payments to the resource.
- Transmission cost quantifies the cost of additional transmission needed to make the capacity deliverable to the utility; resources closer to load generally require less transmission than resources far from load.

- Greenhouse gas cost quantifies the cost of allowances for greenhouse gases under California's cap-and-trade system; for a zero emissions source like solar, wind, or hydropower, these costs are zero.

Figure 6. Illustration of California's Net Market Value Framework[20]



All-Source procurement as a solution to challenges

- To address these three challenges, states/Discoms will need a procurement framework that can determine a least-cost mix of different kinds of new resources, identify new resources that have the highest net market value to a state/Discom, and provide relatively frequent price discovery. All-source competitive procurement could provide such a framework.
- All-source competitive procurement would consist of regular (e.g., biennial) solicitations in which all eligible resources can participate. All suppliers, including national, state, and private companies, could submit offers for generation or storage beginning commercial operation in the procurement window (e.g., the next 3-5 years).
- States/Discoms would evaluate different bids based on their net market value and qualitative ("non-price") factors. Economic evaluation of bids would use engineering-economic (capacity expansion, production simulation) models (Recommendation 11), using actual bids rather than assumed costs as inputs to these models.
- States/Discoms could incorporate their RPOs in their resource evaluation and selection as minimum constraints, without having to procure renewables in a "silo."
- Within this framework, Discoms can also evaluate the benefits and costs of agricultural load shifting and other demand response programs. Discoms can include agricultural load shifting and other demand response programs in capacity expansion models, as selectable resources, or can evaluate these resources separately and then adjust demand forecasts to account for demand response.

[20] This figure is based on the net market value framework used in Southern California Edison's 2013 all-source solicitation. California utilities also include the cost of "debt equivalence" (not shown in the figure) in their calculations. Debt equivalence refers to the potential increase in utility borrowing costs that results from long-term contractual liabilities.

- Out-of-state resources could participate in the solicitations, and states/Discoms could include incremental transmission upgrade costs in their resource evaluations where appropriate, as discussed in the context of Figure 6..
- All-source procurement would complement NEP, as NEP would continue to play an important role in providing information and visibility to suppliers on expected long-term national and state trends. While NEP would give direction on a potential least-cost resource mix for states to meet projected load, a planning and procurement process as suggested above would ensure that the states determine and procure the quantum of required resources to meet their load at minimum cost.

11. Build the capacity of states/Discoms to use engineering-economic models to evaluate the economics of different resources in planning and procurement.

- In an all-source procurement framework, states/Discoms would need to evaluate the economics of resources with vastly different operating characteristics — for instance batteries versus coal generation — on an equivalent basis. As discussed in Recommendation 10, this requires common valuation metrics.
- In the United States, electric utilities undertake these comparisons using engineering-economic models: capacity expansion models and production simulation (cost) models.
- Capacity expansion models are used to project least-cost portfolios of resources over a longer time horizon (e.g., 10 years), using a limited snapshot of system dispatch; production simulation models are used to simulate the operating cost of a given portfolio of resources across a shorter time horizon (e.g., one year), using more detailed dispatch.
- In India, building the capacity of states/Discoms to use capacity expansion and production simulation models would be an essential foundation for all-source procurement. This would also enable them to do their own long-term resource planning using modeling tools, as a complement to the NEP.
- State-level long-term resource planning could provide an additional source of information and visibility for independent power producers on the kinds of resources that states are likely to procure in an upcoming all-source competition solicitation.
- CERC and the Forum of Regulators (FOR) could play an important role in supporting capacity building on, and setting industry standards for, state/Discom modeling tools.

Longer-Term (4-10 years)

12. Expand all-source competitive procurement nationwide and integrate long-term procurement, short-term market prices, and transmission expansion.

- Based on the results of pilots, all-source competitive procurement could be enhanced and expanded to all states over the longer term.
- CERC and FOR could promote convergence in state/Discom all-source procurement practices through national guidelines that lay out best practices and minimum requirements.
- In the longer term, integrating market pricing and transmission planning with procurement will be important for providing coordination, so that decentralized procurement by states/Discoms approximates what could be achieved by a nationwide optimization of resources.

- In the United States, RTO markets have played an important role in coordinating utility procurement across states, by providing locational price signals and transparent methods for calculating incremental transmission costs for new cross-state resources in the interconnection process.
- In India, with increases in market liquidity, national market prices could also be incorporated into resource evaluations, to help guide investments, which further makes the principles in Recommendation 10 easier to implement. Market price forecasts can be integrated into planning and procurement models.
- Similar to U.S. RTOs, the CTU can estimate the incremental transmission costs required to fully or partially deliver resources, including cross-state resources, to different areas, and these cost estimates can be included in bids in all-source solicitations.

Markets and System Operations

Indian Context

- CERC has already undertaken several initiatives to reform existing electricity markets, including the creation of a real-time market (operational since June 2020) and proposals for MBED, participation of renewable generation in day-ahead and real-time energy markets, and tertiary (operating) and secondary (regulation) reserve markets.
- In addition, POSOCO is piloting security-constrained economic dispatch (SCED), CTU is conducting pilots for battery storage, and CERC drafted a white paper on issues around the introduction of energy storage in India's electricity markets.
- Two important issues that have not yet been addressed in these initiatives include (1) questions around energy storage participation in electricity markets and (2) how to manage transmission congestion and balancing energy needs as the penetration of intermittent solar and wind generation increases.
- Additionally, issues surrounding gas-electric coordination, to enable gas generation to operate more flexibly, have yet to be addressed in the context of market and system operations. A separate set of recommendations under Flexible Resources Initiative (FRI) provides considerations for enhancing gas-electric coordination.

U.S. Context

- India and the United States have fundamentally different electricity market designs and traditions for integrating market and system operation.
- In India, power exchanges operate electricity markets and load dispatch centres are responsible for the operation of the electricity system (markets and operations are housed in separate organizations, which must coordinate).
- In the United States, independent system operators operate spot markets for electric energy and ancillary services and are also responsible for operating the electricity system (markets and operations are integrated both organizationally and functionally).
- The market and system operations recommendations reflect U.S. experience, while being cognizant of these fundamental differences in market design between the United States and India.

Recommendations

Nearer-Term (1-3 years)

13. Complete implementation of day-ahead and ancillary service market reforms.

- MBED would make participation in day-ahead and real-time energy markets mandatory.
- This approach is similar to market rules in much of the United States, which require participation and settlement in real-time, rather than day-ahead, markets.[21]
- MBED promises to increase the liquidity of India's electricity markets, strengthen price signals, and enable day-ahead co-optimization of energy and tertiary reserves.
- MBED will also support greater resource sharing for RA, by making states/Discoms more comfortable with resource sharing through markets and enabling capacity-only contracting.
- For instance, a Discom that had a 200 MW shortfall in RA resources could meet this need through short-term capacity-only RA contracts and rely on the electricity market to meet any shortfalls in energy.
- Lastly, MBED could promote greater interstate development of resources, through greater price transparency.
- U.S. experience has been that reforms like MBED require the development of value propositions to secure the buy-in of states and Discoms, and that these kinds of reforms require significant lead time.
- For instance, all participants in the U.S. Western Energy Imbalance Market (EIM) conducted benefit-cost analysis to determine the value proposition of joining the EIM before they joined.
- In India, similar benefit-cost analysis studies could inform state participation in MBED, with support from CERC and the Forum of Regulators.

14. Review scheduling and market participation rules for energy storage to ensure that its full functionality can be recognized, utilized, and compensated through markets.

- Energy storage is a broad category of resources that includes electrochemical (e.g., battery), mechanical (e.g., pumped hydropower), and thermal storage (e.g., ice storage).
- Energy storage is a unique resource: it can act as a generator or load, is highly flexible, and can provide an array of market and non-market services, but it is also energy limited.
- Electricity market rules may need adjustment to enable storage to provide and be compensated for its full functionality. CERC's white paper on energy storage (2017) identified the lack of a policy and regulatory framework for storage as a key obstacle to investment in storage.
- Reviewing scheduling and market participation rules could be an important part of efforts to establish a regulatory framework for storage. FERC's Order 841 can provide a useful reference point for this kind of review.
- Although differences in electricity market design mean that energy storage participation in India's electricity markets will be different from that in the United States, FERC's criteria for storage participation can still provide a useful reference.

[21] This difference is primarily due to differences in market design. Both countries share a similar rationale in their mandatory participation and settlement rules, which is to increase liquidity and improve price signals in markets that are dominated by regulated utilities.

- FERC's criteria stipulate that energy storage should (a) be able to provide the full range of services that it is technically able of providing, (b) be eligible to participate in markets for RA, energy, and ancillary services, (c) be able to set market clearing prices as a buyer and seller, and that (d) market and dispatch rules should account for physical and operating characteristics of storage (e.g., state of charge management).
- The United States has just over 20 GW of pumped hydropower storage, most of which was built in the 1970s to help balance nuclear power plants and provide peak load management.[22] Since the early 2000s, battery storage has accounted for most investments in electricity storage in the United States. The highest wholesale market value for battery storage has thus far been for providing regulation reserves, and expected to be followed by their capacity value, rather than for energy arbitrage.[23]
- In India, over medium to long term, real value of battery storage would be to provide RA capacity support for evening peak hours (by charging with solar power in the afternoon). Our national modeling study concludes that deploying batteries would be cheaper than building new coal plants to meet the peak load in 2030. In the short term though, providing secondary and tertiary reserves and reducing DSM charges are likely to be high value applications for energy storage. The regulatory framework for storage in India could initially prioritize these applications.

Longer-Term (4-10 years)

15. More closely align short-term markets and power system operation, by implementing locational marginal price-based (LMP-based) SCED in real-time markets.

- In the United States and Europe, two important challenges from rising penetrations of solar and wind generation include: (1) increased real-time balancing and ramping needs arising from solar and wind variability and uncertainty, and (2) increased transmission system congestion, resulting from changing power flows on the transmission system.
- In Europe, efforts to address these challenges are ongoing. The European Network of Transmission System Operators for Electricity's (ENTSO-E's) *Vision on Market Design and System Operations Towards 2030* (2019) explored solutions to the need for "better alignment of market operation to power system operation, as well as on better coordination of congestion management and balancing" arising from greater reliance on solar and wind generation, but left solutions to individual countries and TSOs.[24]
- In the United States, existing ISO/RTO market designs, and in particular real-time markets with LMP-based, 5-minute SCED, have helped to pre-emptively address the real-time balancing and congestion challenges identified in ENTSO-E's *Vision.*
- In India, cost-effectively integrating higher levels of renewable generation will also require closer alignment between markets and system operations. Two areas of alignment will be particularly important: security constraints and transmission congestion.

[22] More specifically, the highest value for batteries has been for secondary reserves (frequency regulation in the U.S. context) and, to a lesser extent, RA. Data are from the U.S. Energy Information Administration (EIA), www.eia.gov.

[23] For an overview, see EIA, 2020, *Battery Storage in the United States: An Update on Market Trends*, https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

[24] ENTSO-E, 2019, *Vision on Market Design and System Operation towards 2030*, https://vision2030.entsoe.eu/wp-content/uploads/2019/11/entsoe_fp_vision_2030_web.pdf.

- Closer alignment on security constraints would avoid the need for system operator re-dispatch to meet transmission security (reliability) and generator operating constraints by incorporating these constraints into market clearing and dispatch.
- Implementation of SCED in real-time markets could address this first area, building on POSOCO's SCED pilot and experience with the recent implementation of the real-time market.
- Combined with more liquid real-time markets, implementation of SCED would also enable real-time co-optimization of energy and ancillary services, which allows the system operator to change which generators hold reserves as conditions change over the course of a day.
- Closer alignment on transmission congestion would avoid the need for costly redispatch to relieve transmission constraints and reduce the potential for strategic behavior (gaming) in markets, by incorporating transmission constraints into market clearing and dispatch.
- Day-ahead and real-time markets in India incorporate interregional (zonal) transmission constraints and allow for regional pricing when the interregional transmission system is congested.
- Incorporation of a larger set of transmission constraints into market operations could build incrementally on existing practices and ultimately be incorporated into SCED.[25]
- Continued improvements in grid management infrastructure, including telemetry, metering, and settlement systems, is a prerequisite for greater alignment between market and system operations.

Conclusion

- Over the next decade, India's electricity sector can take advantage of continued declines in renewable generation and battery storage costs and improvements in the utilization of flexible generation resources to lower costs, enhance reliability and resilience to events like the COVID-19 pandemic, and reduce air pollution and carbon emissions.
- Enabling the transition to this more flexible, robust, and sustainable power system will require changes in policy and regulation. Our recommendations seek to support these changes, focusing on three areas: RA, resource planning and procurement, and markets and system operations.
- Implementing a more formal, systematic RA framework in India could help to reduce future overcapacity, facilitate generation capacity sharing among states, reduce the risk of free riding on system reliability by individual states and Discoms, increase utilization of existing generation resources, increase the resiliency of the power system to extreme events, and maintain power system reliability as the penetrations of solar and wind generation and energy storage increase.
- Enhancing state-level resource planning and procurement practices would enable states/Discoms to construct least-cost portfolios of renewable, thermal, and storage resources that meet national RA requirements.
- Continued improvements to electricity markets, including the implementation of MBED and the creation of markets for ancillary services, would help to increase system flexibility and ensure low-cost operation of India's electricity grid.

[25] More granular locational pricing would require the development of financial products that allow market participants to hedge locational market risk.

Appendix A: India Resource Adequacy Analysis

To support the RA recommendations, LBNL undertook several quantitative analyses:

- **Load-resource balance** analyses for fiscal years 2020 and 2030,[26] including an analysis of when India will return to load-resource balance.
- Analysis of different **RA mechanism design options**, including an illustrative example of RA planning in Uttar Pradesh.

This appendix provides documentation of these analyses.

Load-Resource Balance Analyses

The load-resource balance analyses examined generation capacity relative to different measures of peak demand in 2020 and 2030, as well as the year in which India's national electricity system will return to load-resource balance. These analyses do not incorporate transmission constraints.[27]

Analysis of 2020 load-resource balance

The 2020 analysis sought to assess the current level of overcapacity in India's electricity system and the potential for generation resource sharing among states. The analysis used two measures of peak demand to determine RA requirements: (case 1) the sum of state non-coincident peak (NCP) demands, (case 2) national coincident peak (CP) demand plus a 15% planning reserve margin (PRM).

The first measure of peak demand (sum of state NCPs) was used to assess regional and national overcapacity.[28] The second measure of peak demand (CP plus PRM) was used to assess generation capacity needs if states can fully share generation resources. The difference between these two measures (case 1 minus 2) is the potential for generation resource sharing among states (in MW).

The 2020 analysis used capacity credits that were consistent with those used in LBNL's capacity expansion modeling, state-level hourly load forecasts for 2020, installed capacity data from CEA (as of June 2020), and renewable generation capacity data from MNRE.[29] In case 2 (CP plus PRM), state RA requirements were based on state shares of national CP.

Table A-1. shows the 2020 analysis results. As of June 2020, India had 257,294 MW of total RA credited resources relative to forecasted case 1 peak demand (sum of state NCPs) of 223,162 MW.[30] Based on this metric, India's electricity system had 34,131 MW of excess generation resources in 2020. If states can share generation resources (case 2), overcapacity would have reached 45,916 MW, suggesting that the

[26] All years in this appendix are fiscal years, unless otherwise noted.

[27] Including transmission constraints will tend to increase RA requirements, to ensure that generation resources being counted toward RA requirements are deliverable when and where they are needed.

[28] Using state NCPs rather than state NCPs plus a reserve margin assumes operating reserve sharing among states, which is currently done through the Reserve Regulation Ancillary Services (RRAS) mechanism.

[29] CEA data are from http://cea.nic.in/reports/monthly/installedcapacity/2020/installed_capacity-06.pdf; MNRE data are from https://mnre.gov.in/img/documents/uploads/file_s-1594347424972.xlsx.

[30] Generator self-consumption inputs were assumed to be 8% for coal, 3% of gas, 5% for oil, 10% for nuclear, and 10% for biopower. All other resources were assumed to have negligible self-consumption. Large hydro was credited at 50% of net nameplate capacity, small hydro at 40%, wind at 10%, solar at 0%, and all other resources were credited at 100% of net nameplate capacity.

potential for resource sharing among states was on the order of 10 GW (11,784 MW = 45,916 MW – 34,131 MW) in 2020.

Table A-1. Results of 2020 Load-Resource Balance Analysis

Summary Results								
			Northern	Western	Southern	Eastern	Northeastern	National
Total available RA resources		MW	71465	88904	65420	28089	3416	257294
Sum of State NCPs								
RA requirement		MW	74247	66710	56057	22442	3707	223162
Surplus/shortfall (+/-)		MW	-2782	22194	9363	5647	-291	34131
National CP + 15% PRM								
RA requirement		MW	69108	63376	52236	23162	3496	211378
Surplus/shortfall (+/-)		MW	2357	25528	13185	4927	-81	45916

Analysis of the timing for a return to load-resource balance

To assess when India's national electricity system would return to load-resource balance, the analysis considered four cases:

- **Case 1**: Load-resource balance year is defined as the fiscal year in which the sum of state annual non-coincident peak (NCP) demands exceeds base (June 2020) RA.
- **Case 2**: Load-resource balance year is defined as the fiscal year in which national coincident peak (CP) demand plus a planning reserve margin (PRM) exceeds base (June 2020) RA capacity plus planned coal additions (2021-2024).
- **Case 3**: Load-resource balance year is defined as the fiscal year in which the sum of state annual NCPs exceeds base (June 2020) RA capacity plus planned coal additions/retirements (2021-2024).
- **Case 4**: Load-resource balance year is defined as the fiscal year in which national CP demand plus a PRM exceeds base (June 2020) RA capacity plus planned coal additions/retirements (2021-2024).

Analysis of these four cases used the same data sources and assumptions as the 2020 load-resource balance analysis. The results, shown in Table A-2., suggest that India's national electricity system will return to load-resource balance between 2023 and 2025, depending on assumptions. The differences in regional timing underscores the potential for generation resource sharing across regions.

Table A-2. Fiscal Year in Which India's National and Regional Electric Grids Return to Load-Resource Balance

Summary Results					
Load-Resource Balance Year (Fiscal Year) by Region and Case					
		Case 1	Case 2	Case 3	Case 4
India		2024	2025	2023	2024
Northern		2020	2022	2020	2021
Western		2025	2026	2024	2025
Southern		2026	2027	2022	2025
Eastern		2027	2027	2026	2026
Northeastern		2020	2020	2020	2020

Analysis of 2030 load-resource balance

The 2030 analysis applied an RA framework to the results of LBNL's national capacity expansion modeling work, to examine the implementation of an RA program in 2030. In particular, the 2030 analysis sought to examine how generation resource sharing among states and regions would optimally evolve, in a least-cost way, to 2030.

As in the capacity expansion modeling, the 2030 analysis assumed that generation capacity is built to meet an RA requirement that is equal to forecasted national CP in 2030 plus a 15% PRM. This RA requirement was allocated to individual states based on their forecasted share of national CP in 2030. The self-consumption and capacity credit assumptions used for different resources were generally the same as in the 2020 analysis.[31]

In 2030, India's forecasted national CP was 339,970 MW, and applying a 15% PRM resulted in a total RA requirement of 390,966 MW. The sum of state peak (NCP) demands was 412,447 MW, which implies a capacity savings of 21,481 MW in 2030, based on the approach in the main text.

Table A-3. shows available RA capacity by region by month in 2030, where available RA capacity is defined as a region's total RA credited resources minus the sum of RA requirements for individual states. Table A-3. illustrates the significant amount of regional generation resource sharing in 2030 under an optimal expansion planning framework. The Southern, and to a lesser extent Western, regions rely on imports from the Northern region to meet their reliability needs.

Table A-3. Projected Available RA Capacity (Credited RA Capacity Minus RA Requirement) by Region in 2030

Available RA Capacity by Region					
Month	Northern	Western	Southern	Eastern	Northeastern
1	37,823	4,551	-7,991	5,989	985
2	38,690	4,986	-12,923	5,554	1,622
3	41,719	4,571	-17,496	763	1,759
4	38,927	9,840	-9,008	3,741	2,073
5	22,231	5,524	-3,823	2,315	1,926
6	10,473	10,432	-3,672	3,093	1,527
7	14,030	15,861	-7,293	1,873	1,468
8	18,308	10,730	-5,545	2,012	1,215
9	25,964	1,425	-9,507	1,841	1,192
10	35,149	-5,280	-11,896	2,302	1,606
11	44,823	1,073	-7,519	5,245	2,145
12	37,583	4,010	-8,737	8,720	1,804

The results in Table A-3. strengthen the rationale for an RA mechanism that facilitates generation resource sharing among states and regions. As the penetrations of solar and wind generation increase, regional generation resource sharing through an RA mechanism will be increasingly important for maintaining reliability and managing costs.

RA Mechanism Design Analysis

The RA mechanism design analysis examined several different designs for a nearer-term RA mechanism in India. As described in the main text, these mechanism designs assume that (a) the incentive for maintaining adequate generation resources is shifted to a mandatory forward (e.g., year-ahead) RA

[31] Batteries were given net consumption of 12%, reflecting roundtrip losses. The capacity credit for solar PV was 5% rather than 0%.

requirement, and (b) any RA mechanism will need to enable states/discoms to have the rights to schedule generation up to their peak (NCP) demands ("energy scheduling constraint").

Analysis of RA mechanism designs

The RA mechanism design analysis considered five different design options, which differed in terms of their scope (national versus regional) and approach to compliance (annual, seasonal, monthly).

- With a **national** RA mechanism, RA requirements are set based on a national CP forecast plus a PRM.
- With a **regional** RA mechanism, RA requirements are set based on regional CP forecasts plus a PRM.
- With **annual** compliance, states/discoms are required to demonstrate RA compliance for an entire year.
- With **seasonal** compliance, states/discoms are required to demonstrate RA compliance for summer and winter seasons.
- With **monthly** compliance, states/discoms are required to demonstrate RA compliance for each month.

A national RA mechanism will require less total generation capacity than a regional RA mechanism, because national CP will always be less than the sum of regional CPs due to load diversity. However, a regional RA mechanism may be more politically feasible than a national RA mechanism.

The most important difference in approaches to compliance is their implications for generation resource sharing. Because of the energy scheduling constraint, annual compliance limits opportunities for resource sharing, if states/discoms must maintain adequate generation resources under contract for an entire year to meet their NCP demands. Seasonal compliance expands opportunities for resource sharing, and monthly compliance further expands these opportunities.

The analysis of different design options considered five alternatives: (1) a national RA mechanism with monthly compliance, (2) a national RA mechanism with seasonal (summer/winter) compliance, (3) a national RA mechanism with annual compliance, (4) a regional RA program with annual compliance, and (5) a state RA mechanism with annual compliance. The analysis used fiscal year 2019 load data and assumed a 15% PRM. In the seasonal design, summer and winter periods were defined to maximize generation resource sharing.[32]

Table A-4. shows the total RA requirements and "effective national PRM" under each of the five options, where effective national PRM is the actual margin of capacity credited resources, relative to 2019 national CP.[33] The national / monthly design had the lowest total RA requirement (197 GW), consistent with national CP plus a 15% PRM. The national / seasonal design had a slightly higher RA requirement (199 GW)

[32] Summer was defined as April through September. This captures the main diversity benefit between the Northern region, which has several strongly summer peaking states (Punjab, Uttar Pradesh, Delhi), and the Western region, in which Madhya Pradesh is strongly October peaking. Extending the definition of summer through October would eliminate this diversity and increase the total RA requirement to 203 GW.

[33] That is, effective national PRM is $\frac{Capacity\ resources - National\ CP}{National\ CP} - 1$.

and a 16% effective PRM. The seasonal design has a higher RA requirement because the season-long compliance requirement loses some of the monthly load diversity among states.

Table A-4. Total RA Requirement and Effective National PRM for the Five RA Mechanism Design Options

Synthesis of Results			
Approach		Total RA Requirement (MW)	Effective National PRM (%)
National / monthly		197,443	15%
National / seasonal		199,742	16%
National / annual		208,393	21%
Regional / annual		220,225	28%
State / annual		239,652	40%

The national / annual mechanism is equivalent to the sum of state NCPs (208 GW, 21% effective PRM), because it assumes that states are required to hold sufficient resources under contract to meet their annual NCPs due to the energy scheduling constraint. The regional / annual mechanism is unable to take advantage of interregional load diversity, and thus has a significantly higher RA requirement (220 GW, 28% effective PRM) than the national / annual mechanism. The state / annual mechanism has the highest RA requirement (239 GW, 40% effective PRM).

In principle, an RA mechanism with annual RA requirements could be designed so that states/discoms are only required to demonstrate year-ahead compliance during the national CP month. This approach assumes that states/discoms that have low coincidence factors (CP/NCP) would be able to secure the resources they need to meet their NCP demands in short-term energy markets. As an extreme case, for instance, Madhya Pradesh would have had a 10,656 MW RA requirement in 2019, under a load ratio share approach to RA requirement allocation (it accounted for 5.4% of the 171,690 MW national CP in 2019). Madhya Pradesh's peak demand of 13,655 MW occurred in December. If Madhya Pradesh only had adequate generation capacity to meet its RA requirement (i.e., 10,656 MW), it would have needed to find an additional 2,999 MW (= 13,655 – 10,656 MW) to meet its energy demand in December. The system as a whole would have had ample resources to support this — during Madhya Pradesh's peak demand hour the system would have had as much as 41,584 MW of unutilized capacity — but this assumes that this capacity could be made available to Madhya Pradesh without additional incentive mechanisms. If it could, the "national / annual" and the "national / monthly" approaches converge.

Because India has a nationally synchronous electricity grid, neither the regional nor the state RA mechanism design is fundamentally consistent with the underlying physics of the system. The national LDC is ultimately what in the United States is referred to as the balancing area authority, and the design of the RRAS mechanism and proposals for operating reserve markets reflects this fact.

Although the national / monthly mechanism has the lowest RA requirement, it would presumably require the most regulatory effort, because regulators would need to ensure state/discom compliance with monthly RA requirements.

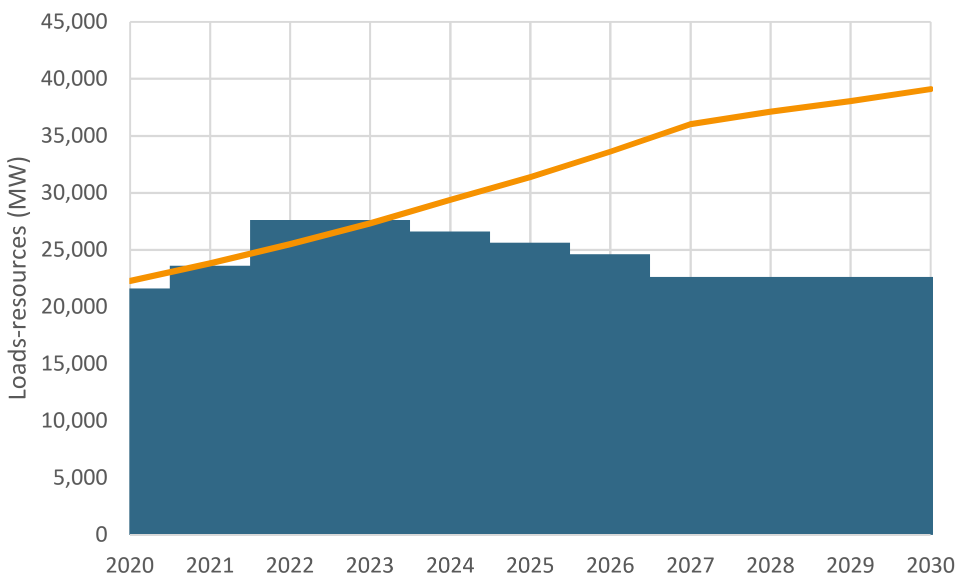
Any of the compliance designs could be transitioned to a capacity-only contracting approach once MBED is in place and the energy scheduling constraint can be relaxed. Under this approach, the total RA requirement would be national CP plus the PRM and the energy market would facilitate energy resource sharing. Resources that are counted toward the national RA requirements would have a must-offer obligation in the day-ahead and real-time energy and the ancillary services markets.

Illustrative analysis of RA mechanism implementation in Uttar Pradesh

The implementation analysis sought to illustrate how an RA mechanism could be implemented at a state level, using Uttar Pradesh as an example. The analysis assumed a national RA mechanism with a 15% PRM, in which state RA requirements are set based on state share of national CP. For Uttar Pradesh, this resulted in a 1.9% PRM above state peak demand forecast, based on fiscal year 2019 data.

The analysis used traditional load-resource balance tables to assess the gap between Uttar Pradesh's available RA (capacity credited) resources and the state's forecasted RA requirement through 2030. Figure A-1. shows the projected net available RA capacity and RA requirement for Uttar Pradesh from 2020 to 2030. The gap between available RA resources and the RA requirement is the resource need.

Figure A-1. Projected Load-Resource Balance for Uttar Pradesh from 2020 to 2030



The analysis assumed that Uttar Pradesh Power Corporation Limited (UPPCL) procures a combination of (a) short-term RA resources on an annual basis through procurement portals (e.g., DEEP) or the exchanges, and (b) long-term RA resources through competitive solicitations and longer-term contracts. Competitive solicitations were assumed to have a five-year procurement horizon, meaning that UPPCL would procure new resources to meet any needs identified over this five-year horizon.

In the illustrative table below, UPPCL begins 2021 with a total of 21,601 MW of RA resources. It has 2,000 MW of planned (already under construction) coal additions in 2021, providing a total of 23,808 MW in RA resources and leaving it 672 MW short of its RA requirement. UPPCL meets this gap with annual RA procurement. In 2021, UPPCL also conducts a competitive solicitation for up to 6,000 MW of new resources to meet RA gaps from 2021 to 2025 (31,380 MW RA requirement in 2025 plus 2,000 MW of net planned coal retirements minus 27,601 MW of available RA resources, including planned coal additions).

Table A-5. Dynamic Load-Resource Balance for UPPCL from 2021-2030

Dynamic Load-Resource Balance											
	Unit	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Net available RA capacity in previous year	MW	21,601	23,601	27,601	27,601	29,276	31,176	30,176	28,176	28,176	28,176
Net planned additions and retirements	MW	2,000	4,000	0	-1,000	-1,000	-1,000	-2,000	0	0	0
Short-term RA procurement	MW	207	0	0	87	205	0	0	0	0	0
New RA capacity	MW	0	0	0	2,675	2,900	0	0	0	0	0
Total available RA capacity at beginning of year	MW	23,808	27,601	27,601	29,363	31,381	30,176	28,176	28,176	28,176	28,176
Annual RA obligation	MW	23,808	25,509	27,331	29,363	31,380	33,622	36,016	37,116	38,047	39,103
Surplus or shortfall	MW	0	2,092	270	0	0	-3,446	-7,840	-8,940	-9,871	-10,927

Through this solicitation, UPPCL procures 5,575 MW of new RA resources, with 2,675 MW scheduled to begin commercial operation in 2024 and 2,900 MW scheduled to begin in 2025. UPPCL plans to make up any remaining RA shortfalls from 2023 to 2025 with annual RA procurement, based on its assessment of the short-term RA market. In 2023, UPPCL will conduct another competitive solicitation, and may change its annual procurement strategy based on the results of that solicitation.

UPPCL may find itself long and able to sell capacity as well. In 2022, for instance, UPPCL adds 4,000 MW of planned coal capacity, bringing its total available RA capacity to 27,601 MW relative to its 25,509 MW RA requirement (a 2,092 MW surplus). UPPCL can sell this excess capacity on a short-term basis to other discoms.

Appendix B: Resource Adequacy Mechanisms in the United States

The recommendations in the main text draw on U.S. experience with resource adequacy (RA) mechanisms. This appendix provides a more detailed overview of RA mechanism design questions and tradeoffs in the United States. The appendix is organized around two questions:

(1) *What should the building blocks of an RA mechanism in India be, and what should be the roles and responsibilities of different organizations in developing and running this mechanism?*
(2) *What are India's options for RA markets and what are the tradeoffs among different options?*

1. What should the building blocks of an RA mechanism in India be, and what should be the roles and responsibilities of different organizations in developing and running this mechanism?

- Except for Texas' (ERCOT's) energy-only market, all organized electricity markets in the United States have some form of RA mechanism. Utilities that do not participate in organized markets also have RA requirements, but these are typically requirements that state regulators impose on individual utilities.
- Across markets, RA mechanisms share a similar process that is differentiated primarily by roles and responsibilities, how LSEs comply with resource adequacy obligations, and the role of the independent system operator (ISO)[34] in backstop procurement to resolve any LSE deficiencies. In an Indian context, LSEs would refer primarily to discoms.

1.1 Five main steps in U.S. RA mechanisms

- In general, ISO RA mechanisms have five main steps:[35]
    1. **<u>The ISO establishes system-wide and zonal (local) RA requirements</u>**, based on load forecasts and a reserve margin study that establishes a planning reserve margin (PRM, in % of peak load) needed to meet a loss-of-load expectation (LOLE) target. LOLE is the sum of hourly loss-of-load probabilities (LOLPs). Most ISOs use a 1-day-in-10-years (1-in-10) LOLE target as defined by the North American Electric Reliability Corporation (NERC). The RA requirement (RAR) is

$$\text{RAR} = \text{forecasted peak demand} \times (1 + \text{PRM})$$

    2. **<u>The ISO determines capacity credits for different resources</u>**. This step determines the amount (in MW) of energy-limited resources (run-of-river hydro, wind, solar, energy storage) that will count toward RA requirements.[36]
    3. **<u>The ISO allocates system-wide and zonal RA requirements to LSEs</u>**. These requirements are mandatory, meaning that if LSEs are "deficient" (do not have adequate capacity), they

[34] In this appendix, the term "ISO" refers broadly to both regional transmission organizations (RTOs) — MISO, ISO-NE, PJM, and SPP — and single state ISOs — CAISO, ERCOT, and NYISO.
[35] In California, the first three steps are done by the state regulator rather than the ISO.
[36] Some ISOs also derate the capacity credit awarded to thermal and other resources based on historical forced outage rates. This provides generators with an incentive to reduce their forced outage rates. In these cases, the ISO will also adjust the total resource adequacy requirement by an average, system-wide forced outage rate to ensure accounting consistency between the RA requirement and RA resources.

will be subject to deficiency penalties or the ISO will procure RA capacity on their behalf through capacity auctions and assign them an appropriate share of the costs. In most cases, LSE RA requirements will be based on “load ratio share” (LSE share of ISO coincident peak demand), which helps to take advantage of load diversity.

4. **LSEs comply with their RA requirements**. LSEs can typically comply using resources that they own, resources with which they have long-term contracts, and resources with which they have short-term contracts. Short-term contracts may be only for RA compliance purposes (i.e., only for capacity and not energy). This approach means that the RA mechanism will cover both existing and new resources.
5. **ISOs and/or state regulators ensure compliance with LSE obligations and provide incentives for resources that have been counted toward resource adequacy to be available (and able to perform) when needed for reliability**. In some ISOs, the ISO is responsible for acquiring any resources needed to resolve LSE deficiencies through backstop procurement. Backstop procurement refers to the procurement of resources in cases where LSEs do not have sufficient capacity to meet their RA requirements. How LSE deficiencies are dealt with varies across ISOs, discussed in more detail in Section 2. Availability is typically enforced through must-offer requirements in day-ahead markets and intraday commitment processes, as discussed below. ISOs may also have additional incentives for availability.

1.2 RA mechanism design considerations

- Often, but not always (see below), RA requirements are set at a regional level, to take advantage of load diversity. In a U.S. context, load diversity refers to the fact that the system-wide coincident peak (CP) demand will be lower than the sum of non-coincident peak (NCP) demand for all LSEs in the region. Load diversity will reduce the total costs of meeting a reliability target.
- Zonal capacity requirements establish a minimum capacity obligation for transmission-constrained zones. They complement the system-wide requirement. Having zonal requirements is important because transmission constraints may mean that generation in one zone is not actually deliverable to another during peak demand periods. LSEs can contract with resources in other zones to provide capacity so long as there is available transmission capability, but if not, the resource may have to pay for any incremental transmission upgrades necessary to deliver its contracted output to the LSE’s zone.
- RA mechanisms have a commitment and forward period. The commitment period refers to the period over which LSEs will be required to comply with the resource adequacy requirement. For most ISOs, the commitment period is annual (based on a peak demand period) or seasonal (NYISO). California has a monthly commitment period. The forward period refers to how far in advance of the commitment LSEs will need to take action to begin demonstrating compliance. Both PJM and ISO-NE use three-year forward windows (i.e., the auction for 2023 compliance will be conducted in 2020). California requires year-ahead compliance. New York requires month-ahead compliance. MISO runs its Planning Reserve Auction two months prior to the year-long compliance period.

1.3 Roles and responsibilities in RA mechanisms

- Roles and responsibilities for each step in the RA process vary across ISOs. The table below removes step 4 from above ("LSE compliance") and splits enforcement of LSE compliance and availability requirements on RA resources into separate steps, for clarity.

Table B-1. RA Roles and Responsibilities

	Forecast peak load and set planning reserve margin	**Determine capacity credits for different resources**	**Allocate resource adequacy requirement to LSEs**	**Enforce LSE compliance**	**Enforce resource availability and performance**
California	State regulator and state energy agency	State regulator	State regulator	ISO responsible for backstop procurement; regulator responsible for compliance enforcement	ISO
SPP	Utilities forecast and conduct reliability studies; ISO sets reserve margin	ISO	No explicit allocation; implicit allocation based on utility peak load forecast plus reserve margin	No backstop procurement; ISO responsible for assessing penalties	ISO
MISO	ISO (states can set higher or lower reserve margins)	ISO	ISO	ISO	ISO
NYISO	Non-profit organization (NYSRC)	ISO	ISO	ISO	ISO
PJM and ISO-NE	ISO	ISO	ISO	ISO	ISO

- PJM and ISO-NE are responsible for all five of the steps in the above table. Both ISOs procure capacity on behalf of LSEs. In other words, the ISO is the buyer in the capacity auction and LSEs do not bid their demand directly into the capacity auctions. However, LSEs can bid in reductions to forecast demand on the demand-side of the market (PJM only) or offer demand reductions on the supply-side of the market and the demand curve that clears the auction is based on an ISO demand forecast and other parameters. Capacity beyond the PRM has value and may be committed at lower prices through downward sloping demand curves. LSEs have the option to self-supply and not participate in the auction and can hedge against capacity market price risk through forward procurement.

- In New York, step 1 in the above table is done by the New York State Reliability Council (NYSRC), an independent, non-profit organization that was created as part of the agreement that established the NYISO. The use of an independent organization to conduct the reliability study and establish capacity requirements addresses concerns that the ISO might be overly influenced by generation companies, which are represented on its governing board. The NYISO is responsible for steps 2-5. It conducts a voluntary auction six months before compliance periods, a voluntary month-ahead auction 15 days before the beginning of a compliance month, and then conducts a mandatory spot capacity market 4-5 business days before the beginning of a compliance month. In the spot market, the NYISO procures any residual capacity needed to meet the NYSRC's forecasted capacity need.
- In California, the California Public Utilities Commission (CPUC) is responsible for administering the state's RA program, based on final load forecasts from the California Energy Commission (CEC) and local capacity requirements from the CAISO based on transmission studies. The CPUC is responsible for all steps except for backstop procurement and availability penalties and incentives, for which the CAISO is responsible. This separation of RA program administration and backstop procurement has led to duplicative rules between the CPUC and CAISO and, during tight supply conditions, bilateral market prices converging to the CAISO backstop price. CPUC and CAISO responsibilities also have conflicting jurisdiction, with the RA program subject to state (CPUC) jurisdiction, but the CAISO backstop procurement and availability incentives subject to FERC jurisdiction.
- In MISO, MISO is responsible for determining system-wide and zonal RA requirements for LSEs. Individual states within MISO can set reserve margins that are higher or lower than MISO's. MISO determines the number of resource adequacy zones based on a range of factors, including the physical transmission system, utility service territories, and state boundaries. MISO operates a voluntary capacity market for RA compliance, but the capacity auction is only voluntary in the sense that LSEs can opt-out through demonstrating RA compliance or by paying a deficiency penalty. MISO sets the opt-out deficiency penalty price at a multiple of the estimated cost of new entry (CONE) in each zone.
- In SPP, SPP sets the planning criteria (planning reserve margin, capacity credits for resources) but requires individual transmission providers (utilities) to conduct the reliability studies that inform the planning reserve margin. Each LSE's capacity obligation is its forecasted demand plus the planning reserve margin. SPP sets a penalty price for deficiencies, at a multiple of the estimated cost of new entry (the all-in fixed costs of a new gas-fired peaker plant). Penalty revenues are provided to LSEs or generators that can resolve the shortfall. SPP has a single transmission tariff, which avoids transmission rate pancaking for resources wanting to provide capacity across utility service territories. SPP coordinates the RA process and verifies that the total resources LSEs count toward RA do not exceed available resources. The lack of a more centralized reliability study and capacity obligation allocation process means that SPP does not capture the load diversity benefits of regional long-term reserve sharing.

1.4 Other resource adequacy design considerations

- As the SPP approach illustrates, ISO procurement of RA capacity is not strictly necessary. System operators and regulators can address the potential for deficiencies through penalties and a process through which LSEs are required to resolve any deficiencies. Penalties are always revenue neutral. Penalties collected from LSEs that are deficient are often paid out to LSEs that have excess resources. When supply is tight, this approach may lead to perverse incentives depending on design of the allocation mechanism.
- In all ISO markets, resources with capacity awards (i.e., that are counted toward resource adequacy) are required to offer (either self-schedule or submit an economic bid) in the day-ahead and real-time markets, as well as in intraday unit commitment processes. This must-offer requirement provides an assurance that resources that are being paid to provide resource adequacy are available to provide it. Resources pay implicit or explicit penalties for non-availability or non-performance when needed.
- Both PJM and ISO-NE have also created performance incentives for generators with capacity awards, with high penalties for non-performance (in addition to availability penalties), based on operating reserve levels or emergency conditions.
- California is the only jurisdiction in the United States to have a flexible resource adequacy requirement, which is an additional requirement (i.e., in addition to system and local capacity) in its resource adequacy program. This requirement is based on the largest forecasted three-hour system ramp for the following year.

2. What are India's options for resource adequacy markets and what are the tradeoffs among different options?

- RA markets refer to markets for compliance with RA requirements. For instance, if an LSE is short 500 MW of capacity, does it need to build this capacity itself, can it acquire the capacity bilaterally or through power exchanges, or can it resolve resource adequacy deficiencies through a centralized auction?
- The United States has a spectrum of resource adequacy markets, including centralized capacity markets (ISO-NE, NYISO, PJM), voluntary capacity markets combined with bilateral markets (MISO), and bilateral RA markets (California, SPP).
- ERCOT (Texas) does not have an RA program. Instead, ERCOT's energy-only market relies on an operating reserve demand curve (ORDC) as the primary means of raising energy market prices to levels that are high enough to induce good generator performance demand response during reserve shortage conditions. Over time persistent high prices due to the ORDC incent new entry and retain existing resources.
- Individual utilities also do not have formal RA programs, though they have RA requirements that they must meet in a resource planning process.

2.1 Tradeoffs among different approaches to markets for maintaining adequate resources

- At a high level, the tradeoffs among these approaches are straightforward, as described in the table below.

Table B-2. Pros and Cons of Different Approaches to Markets for Maintaining Adequate Resources

Approach	Pro	Con
Centralized capacity auctions	Price transparency and ISO backstop procurement help support retail competition	Complex; significantly expands the role of the ISO in electricity markets and may limit the role of LSEs, as capacity auctions are cleared using ISO demand curves that are administratively determined
Bilateral market with voluntary centralized auctions	Relatively simple; provides some amount of price transparency through voluntary market	Prices in the voluntary market may not be meaningful if the market is not liquid; same cons as bilateral market
Bilateral market	Relatively simple	Lack of price transparency; larger utilities may be able to exercise market power; backstop procurement may be complex
Energy-only with ORDC	Sends more efficient price signals for supply and demand (pays for performance) in real-time operation	Very high prices may be needed to ensure adequate generation; reserve margins can be volatile and low creating political problems
Individual utilities	Often status quo	Does not achieve reserve sharing benefits, utilities pay pancaked transmission charges for firm imports, and lack of coordination may lead to regional capacity shortages

- The reasons why different ISOs took different approaches to RA markets are rooted in history.

2.2 RA markets in the Eastern ISOs

- The Eastern ISOs (ISO-NE, NYISO, PJM) developed ISO-operated capacity markets to accommodate retail competition. In each ISO region, several states had begun to allow retail competition by the late 1990s. The mandatory, auction-based nature of these centralized capacity markets increased price transparency and reduced the likelihood that larger utilities would be able to exercise market power. The main shortcomings of these markets have been their complexity and the challenge of integrating diverse states and LSEs in a single capacity market. For instance, since its creation in 2009, ISO-NE's Forward Capacity Market has been in a state of nearly perpetual redesign through filings at FERC. The same is also true of PJM where there has only been one time since 2008 that auctions were run under the same rules in consecutive years. A key design issue has been the tradeoff between using the capacity market to provide efficient price signals for entry and exit, and allowing more traditional LSEs (regulated utilities, municipal utilities, rural cooperatives) the flexibility to build their own resources and sign long-term contracts. Traditional LSEs are not subject to retail market competition. If a utility builds its own above-market resources, it may artificially suppress capacity prices below competitive levels and make it difficult for the capacity market to attract the merchant generation needed to serve competitive retail providers.

2.3 RA markets in California and SPP

- California developed its resource adequacy program in the aftermath of the California electricity crisis, to address the insufficient forward contracting that contributed to the crisis. After the crisis, the utilities remained the primary LSEs but most of their generation had already been divested to independent power producers. Utilities could sign long-term (typically 10-year) contracts for any new resources identified through a biennial long-term procurement planning process. Utilities were also allowed to sign short-term bilateral contracts to demonstrate compliance with resource adequacy obligations. In the mid-2000s, the California Public Utilities Commission (CPUC) considered transitioning its resource adequacy program to a centralized capacity market. Ultimately, the CPUC decided to continue with a bilateral market, both due to jurisdictional concerns (a centralized capacity market would be subject to FERC jurisdiction) and because California did not have significant retail competition at the time. The opening up of California's retail sector over the 2010s and the tightening of electricity supply have led to pressure on its bilateral capacity markets. With a larger number of smaller LSEs and a tightening bilateral market, the frequency of LSE deficiencies has increased. When LSEs are deficient, the CAISO procures the capacity to resolve the deficiency using its backstop procurement mechanism, which is based on an administratively set price and is much higher than prevailing market prices. With tightening supply, generators may be withholding capacity in the market to receive the administrative price. The future of California's RA program is currently under debate at the CPUC. California's experience illustrates the difficulties of bilateral markets for resource adequacy in competitive retail markets.
- SPP is by most measures a newer ISO. FERC approved its resource adequacy program in 2018. All SPP LSEs are regulated utilities, municipal utilities, or rural cooperatives. As described above, SPP sets resource adequacy requirements on the basis of LSE demand forecasts plus a system-wide reserve margin, rather than setting a system-wide reserve requirement. LSEs comply with their obligation through resource planning, in which they determine long-term resource needs, and bilateral markets for short-term compliance. Bilateral markets provide a complement to long-term resource planning, by enabling LSEs that are short to procure capacity from LSEs that are

long. The main shortcoming of this resource planning + bilateral market approach is its lack of price transparency and the potential for market power when supply conditions tighten.

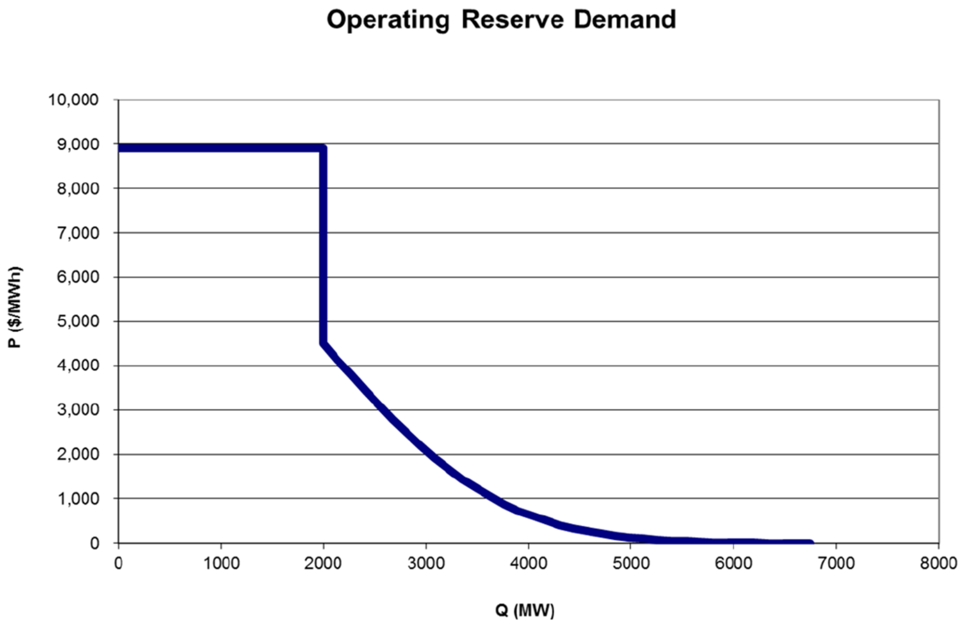
2.4 RA markets in MISO

- Unlike the Eastern ISOs and like SPP, MISO members are primarily utilities and cooperatives that are vertically integrated. Only two states in MISO have retail competition (Illinois and limited amount in Michigan). In part to accommodate these states, MISO developed a voluntary capacity market in 2009 that allowed LSEs to procure capacity in a transparent, auction-based market. Bidding in this voluntary auction was double-sided, meaning that LSEs could choose to whether to participate and were the buyers in the auction. MISO's original RA market was thus a hybrid between centralized and bilateral capacity markets. The main shortcoming of this approach is whether the voluntary auction can produce meaningful prices and meaningfully address the potential for market power in bilateral markets.
- In 2013, MISO transitioned to its current planning reserve auction framework, in which LSEs can choose among four options: (1) submit a fixed RA plan demonstrating RA compliance and opt-out of the capacity market, (2) self-schedule capacity and bid it into the auction at a price of zero, (3) have MISO procure on their behalf through annual auctions, or (4) pay a deficiency charge. MISO acts as the buyer in the planning reserve auction.

2.5 ERCOT's energy-only market

- ERCOT took a different route than the other six ISOs, preferring to use the threat of very high prices to incentivize load serving entities to make forward procurement decisions that would lead to adequate overall resources. Realizing that the market would not lead to desired reserve margins, ERCOT later implemented the ORDC, which is a price adder that is tied to operating reserve levels. When operating reserves fall below a specified level, energy market prices rise non-linearly to a maximum value based on an estimate of the value of avoided outages (lost load), which acts as a price cap. The figure below illustrates ERCOT's ORDC, with Q in the x-axis being ERCOT's operating reserves.

Figure B-1. ERCOT's Operating Reserve Demand Curve



- ERCOT's experience was unique, because it is not regulated by FERC (as an asynchronous grid entirely within Texas), and was able to set its price cap at a much higher level ($9,000/MWh) that the price cap for FERC-jurisdictional ISOs. In contrast, FERC-jurisdictional ISOs have market-based offer caps of $1,000/MWh, and cost-based caps of $2,000/MWh. That being said, all U.S. ISOs have some form of reserve shortage pricing like the ORDC, though reserve shortage prices are capped at lower levels than in ERCOT. Energy-only markets with reserve shortage pricing are defended by some as more efficient than capacity markets, but this efficiency comes at a cost of high price volatility and long-term reserve margin volatility.

2.6 Utilities outside of ISO markets

- Outside of ISO markets, utilities do resource adequacy planning on an individual basis as part of their resource planning processes. Utilities can procure some capacity from other utilities to meet their resource adequacy needs and may share some operating reserves. However, individual utilities will need to procure more capacity than they would have needed to if they were part of a regional RA program, utilities will often need to pay "pancaked" transmission charges for firm capacity imports (each external utility will charge the utility for transmission, meaning that the utility may pay the full cost of multiple transmission systems), and bilateral procurement will not be coordinated. Lack of coordination can mean, for instance, that utilities are relying on more imported RA capacity than is actually available in the aggregate. This situation has recently occurred in the Pacific Northwest.

2.7 Goals of RA mechanisms

- Across all of the RA mechanisms described above, the goal of all mechanisms is the same — to enable reserve sharing that captures the benefits of load and resource diversity but at the same time providing incentives that mitigate free riding and ensure that there will be adequate resources for system reliability. Free riding is a problem because, to meet peak demand, LSEs will need to collectively own, have contracts with, or pay spot prices for a significant amount of generation capacity that is very infrequently used and is thus very expensive on a $/MWh basis (i.e., to recover its fixed costs, it will need to charge very high prices). There is a strong incentive for LSEs to try to avoid paying these costs and lean on the rest of the system for reliability.

Appendix C: Capacity Market Auction Designs in the United States

This appendix provides high-level background on capacity market auction design. The nearer-term recommendations focus on establishing an RA program in India that has self-supply and more decentralized markets for compliance. The longer-term focus on developing more transparent pricing for an RA mechanism. Capacity auctions could be one approach to more transparent pricing.

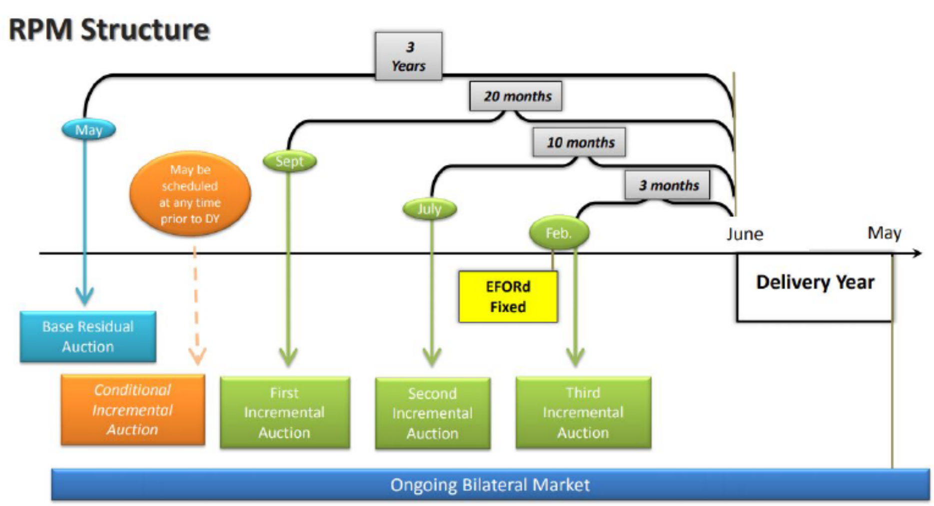
Four of the six U.S. ISOs that have RA programs conduct auctions for RA compliance (ISO-NE, NYISO, MISO, PJM). The remaining two – SPP and CAISO – have bilateral markets for compliance with RA obligations. The discussion below addresses six key elements of auction design that are common across all capacity auctions.

1) Forward period
2) "Voluntary" versus "mandatory "auctions
3) Procurement responsibilities
4) Auction mechanism (sealed bid, uniform price; descending clock)
5) Demand curve (vertical or downward sloping)
6) Locational constraints and pricing.

1. Forward period

Forward period refers to the amount of time before the compliance (commitment) period that the auction is conducted. The figure below shows the timeline for PJM's capacity auction (reliability pricing model, or RPM), which occurs three years before the compliance period ("delivery year" in the figure).[37] Because supply and demand conditions will change in the three years between the auction and the compliance period, PJM conducts "incremental" auctions that let suppliers and PJM adjust their positions and updates based on changes to the load forecast.

Figure C-1. PJM's Reliability Pricing Model for Capacity Auction



[37] Figure is from https://www.pjm.com/~/media/documents/manuals/m20.ashx.

Both PJM and ISO-NE have three-year forward auctions, while MISO conducts year-ahead auctions and NYISO conducts multiple auctions and a spot auction one month period prior to delivery. The rationale for three-year forward auctions is to provide enough time for a merchant developer to build a new resource knowing it has cleared an auction rather than starting construction before knowing if the resource is needed. This does not mean development costs have not yet been incurred to get permits, financing, or interconnection costs settled. On average the time to develop a new combined cycle gas project, which can in some cases be a marginal capacity resource, from initial interconnection request to in-service date is 5-8 years.

From an economic and financial perspective, a three year forward commitment reduces the value of the real option to wait for better information in that it provides a revenue stream that is known three years ahead.

The rationale for a shorter forward period prior to commitment (year or months ahead like MISO and NYISO) is that such decisions have already been made, and that it is the series of annual or monthly payments in total that provides the signal to enter or exit the market. This is especially true in the MISO context as most utilities remain vertically integrated and regulated. In the NYISO context, they do not see the load growth that other ISO/RTOs are seeing, making the longer forward period potentially less important.

Designing the capacity market so that a merchant generator provides the marginal resource to meet resource adequacy needs is due to the need to accommodate retail competition. In an Indian context, a year-ahead or shorter forward period auction would likely be sufficient to start.

2. “Voluntary” versus “mandatory” auctions

In a voluntary capacity auction, generators and LSEs can offer “uncommitted” (no capacity contract or commitment through other means) capacity into the capacity market but do not have a requirement to do so. Prior to a voluntary auction, LSEs may contract uncommitted capacity to meet their RA requirements and to hedge their compliance and market risks. LSEs that do not have adequate resources can bid their demand for capacity into the market. Utilities that have excess capacity can sell capacity. The market clears where supply meets demand. A voluntary market complements LSE self-supply and must be paired with a deficiency penalty for LSEs that do not have adequate capacity. MISO had monthly voluntary capacity auctions between 2009 and 2013 but moved to a more mandatory framework in 2013 due to concerns that prices were too low to attract investment in new capacity needed to maintain resource adequacy and to satisfy competitive retail programs in Illinois and Michigan.

In a mandatory capacity auction, the system operator (or another procurement entity) acts as the agent that determines demand and the agent that buys capacity for load in the auction. LSEs are required to either self-supply (as they would in a voluntary auction framework) and place the offsetting supply and demand into the auction or let the system operator procure on their behalf. In some cases, LSEs can demonstrate RA compliance to the ISO through “RA plans” and opt out of the mandatory auction. PJM, ISO-NE, NYISO, and MISO all operate “mandatory” auctions. The term “mandatory” is a bit of a misnomer in that the ability to self-supply through bilateral contracts or self-owned generation remains a large portion of satisfied demand. But the amount of demand exposed to market clearing price is larger in PJM, NYISO, and ISO-NE due to the prevalence of retail competition and the need for a provider of last resort

("POLR") to have access to capacity even though they will not know their capacity obligation until the time it is needed.

3. *Procurement responsibilities*

In mandatory auctions, the system operator may procure all or only the residual capacity needs. PJM, ISO-NE, and MISO procure all of the capacity needs. In these markets, the ISOs' demand curve is based on the total RA requirement, in some cases subtracting out RA requirements and capacity supply for LSEs that submit RA plans. All resources are settled at the capacity market clearing price. Bilateral and self-supply contracts effectively appear as contracts for differences or offsetting transactions that net to zero. Through accounting mechanisms, LSEs show they have complied with meeting the capacity obligation. In other words, the procurement responsibility resting with the ISO/RTO does not free the LSE from its underlying capacity obligation, but it reduces transactions costs of ensuring those obligations are met.

LSEs can choose to procure capacity outside the auction, but it is more of a financial arrangement than a physical arrangement and is done for financial risk mitigation and hedging and takes place in all markets. In effect, whether ISO auctions are categorized as "voluntary" or "mandatory", the ISO/RTO arranges to procure the residual capacity needs. It subtracts the capacity that LSEs have already procured from the total system and zonal capacity needs and then procures the remainder in a spot market. Only residual capacity resources are "settled" at the market clearing price.

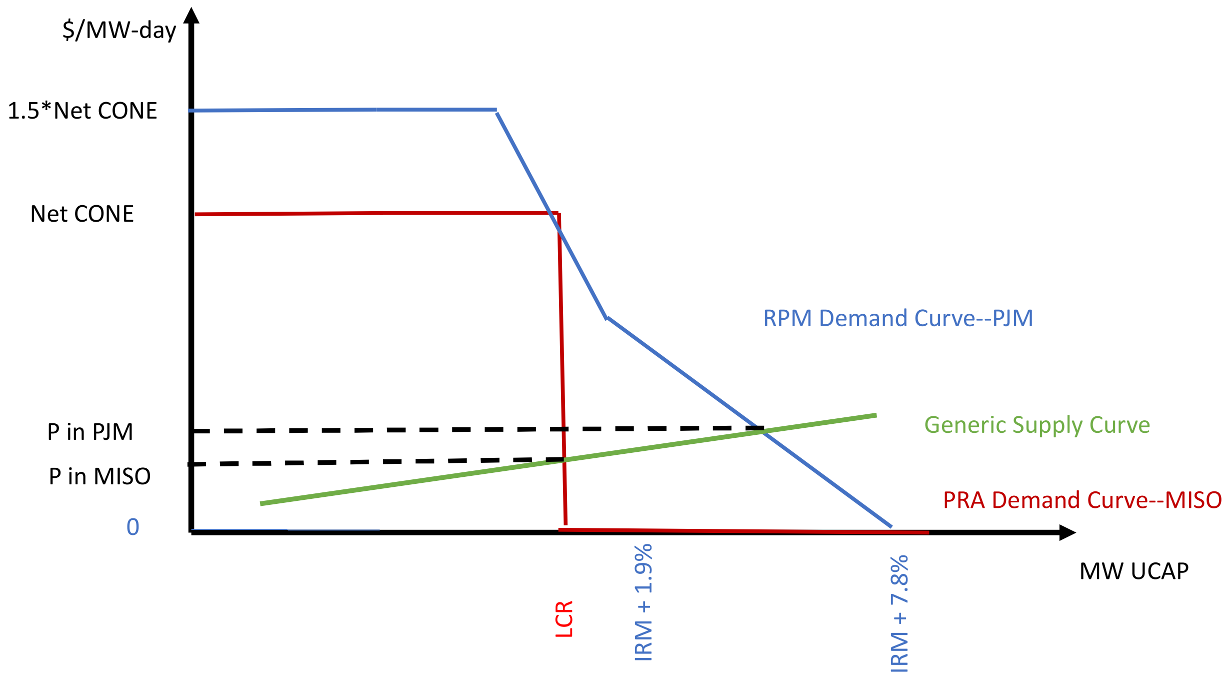
4. *Auction mechanism*

Most of the capacity auctions in the United States are sealed-bid, single-round auctions that clear at uniform price by location, except for ISO-NE. ISO-NE uses a multi-round descending clock auction format, where the ISO issues a price, generators bid in capacity at that price, and then the ISO continually reduces its price until the quantity supplied equals the quantity the ISO wishes to procure according to their demand curve. Prices and quantities are also locational in ISO-NE. The descending clock format is intended to promote better price discovery but has been criticized as being prone to gaming/strategic bidding behavior. The kind of strategic behavior is through "price signaling" whereby in each round, generation owners can signal to other generators about their intent and ability to withhold capacity at a certain price through what they offer which has the potential to lead to prices above competitive levels.

5. *Demand curve*

In economics, the demand represents the marginal willingness to pay for a good or service. The demand for capacity is no different. Implicitly, LSEs and the entire load on the system have a willingness to pay for capacity to ensure resource adequacy. If the price of capacity is high, LSEs are likely to not want to buy as much capacity. But when prices are low, they are willing to buy more capacity. This may even mean that LSEs are willing to buy capacity beyond the target reserve margin if it is cost-effective to do so. It could also mean they are willing to not buy capacity to satisfy the target reserve margin because it is too expensive, and the value of lost load is lower than the cost of capacity.

Figure C-2. Demand Curves for Capacity Auctions (PJM/MISO)



In the U.S. context, ISO/RTOs that conduct "mandatory" auctions have moved to downward sloping demand curves, like the demand curve in blue for PJM in the figure above. Only MISO uses a vertical demand curve, as shown in red in the figure above.

Vertical demand curves tend to lead to boom and bust cycles of building and retirements and can observe extreme price volatility over time, because each MW beyond the demand curve has zero value. The use of downward sloping demand curves is intended to reduce volatility in capacity prices. Moreover, as shown in the figure above, for the same supply curve (shown in green), prices with a vertical demand curve tend to be lower, and the quantity of committed capacity tends to be lower given history and experience.

The vertical demand is placed at the point of the forecast peak demand plus the planning reserve margin adjusted for forced outage rates so that demand for capacity is expressed in Unforced Capacity terms (UCAP). In the MISO vertical demand context, the market is willing to pay up to the Net Cost of New Entry (Net CONE) for a reference resource that has low capital costs, is quick to build, and generally higher running costs. This turns out to be a gas-fired combustion turbine (CT). Net CONE includes the entire sunk capital costs, assumed returns to investment, and fixed, going forward costs less net energy market and ancillary service market revenues. At the Net CONE price, MISO is willing to let a zone "go short" on its Local Capacity Requirement (LCR). MISO has recently seen this happen in Michigan Zone 7 for the 2020/2021 year.

In contrast, the downward sloping demand curve will not exhibit extreme boom and bust cycles in new entry, retirements, and pricing. As shown in the figure above, price tends to be higher (all else equal) and quantities committed higher (all else equal) for the blue PJM downward sloping demand curve than seen in the vertical demand curve case. Additionally, PJM will procure capacity up to 7.8 percent above the installed reserve margin (IRM) target and will pay up to 1.5 Net CONE (as defined above), but does not reach that point until committed capacity is 1.2 percent below the IRM. The two key features of a downward sloping demand are: 1) capacity above IRM has value; and 2) if capacity above IRM is procured, the overall cost to LSEs declines. This means procuring extra capacity is cost-effective for LSEs.

Both demand curves, vertical or downward sloping, anchor their demands at the reserve margin target at a price of Net CONE. It is at this quantity of exactly meeting the IRM as it is called in PJM, or PRM as it is called in MISO, that the price should incentivize the reference resource to enter the market to ensure resource adequacy.

6. Locational Requirements

All ISO/RTO capacity market have locational constraints modeled, and potentially separate prices, to account for transmission limits that prevent enough capacity to be delivered into load pockets or other constrained areas. These types of locational limits have local resource requirements that mandate a certain percentage of capacity be located within the constrained area and model the available transmission transfer capability. Each of the modeled constrained areas will have a demand curve for capacity on its own that interacts with the overall demand for capacity.

Appendix D: U.S. Experience with Resource Planning and Procurement

This appendix provides an overview of U.S. experience with resource planning and procurement, focusing on two distinct case studies: (1) a vertically integrated utility in Colorado, (2) California's integrated resource planning process. These two examples illustrate different approaches to planning and procurement processes, as well as to coordination between state resource planning and resource planning by load serving entities (LSEs).

Colorado Case Study

Utility procurement and all-source competitive solicitation in a non-market environment

Public Service of Colorado (PSCo) is an operating subsidiary of Xcel Energy Inc, a utility holding company. PSCo is regulated by the Colorado Public Utilities commission (COPUC).

PSCo has not historically participated in a Regional Transmission Organization (RTO), but has recently announced, along with three other electric utilities in Colorado, plans to join the Western Energy Imbalance Market (WEIM) beginning in 2021. PSCo has cited improved renewables integration and reduced customer costs as reasoning for joining the WEIM.

Colorado's ERP Process

PSCo is required to submit an Energy Resource Plan (ERP) every four years to the COPUC. There are two phases of the ERP. In Phase I, the COPUC establishes the state's resource needs over the planning horizon, called the Resource Acquisition Period (RAP), as well as the modeling methodology and assumptions that PSCo and other LSEs must use in bid solicitations and evaluations. The following information gets developed in accordance to COPUC guidelines and reported in PSCo's ERP:

- PSCo's electric demand and energy forecast
- A description of existing transmission resources and PSCo's identified future transmission needs
- PSCo's development of metrics and criteria to assess its system's reliability
- PSCo's assessment of need for additional resources
- PSCo's Resource Acquisition Plan, which is PSCo's plan for acquiring these resources
- PSCo's Request for Proposals (RFP) and model contracts for use in its competitive acquisition process

In Phase II, PSCo issues a 120-Day Report, which presents the results of the All-Source Solicitation evaluations and requests approval from the COPUC of PSCo's preferred resource portfolio.[38] PSCo is also required to file annual progress reports with an updated load forecast and assessment of resource needs. In annual progress reports, PSCo must also provide updates on the implementation of any approved resource plans.

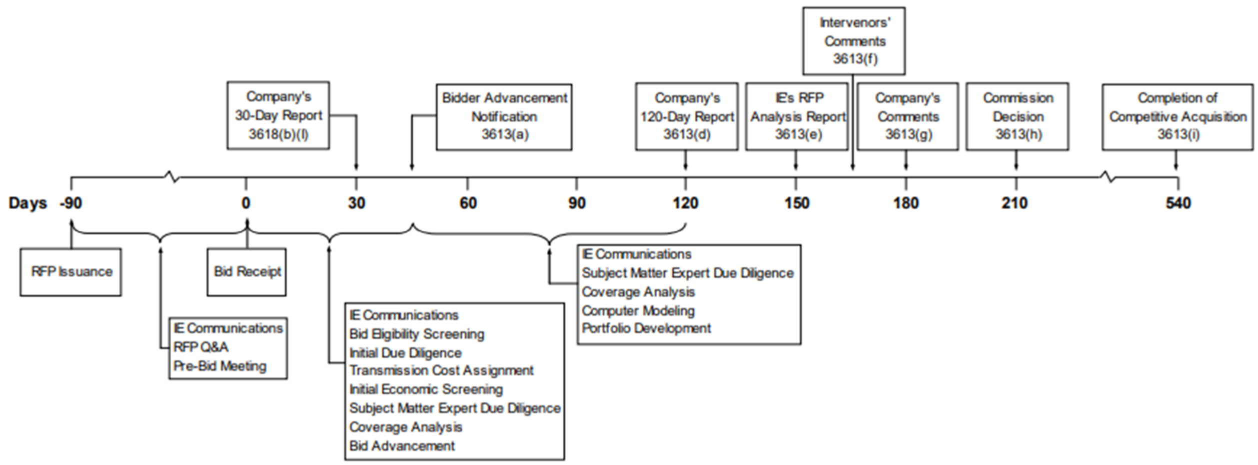
PSCo's Procurement Process

PSCo can issue its COPUC-approved RFPs and evaluate bids using the methodology outlined in its ERP. The methodology includes inputs and assumptions approved by the COPUC for use in the evaluation of bids.

[38] 2018 Update to 2016 ERP (filing system down): https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=16A-0396E

At the end of its procurement process, PSCo must receive approval from the COPUC to enact its selected resource portfolio.

Figure D-1. Overview of PSCo's procurement process



The COPUC can also enact requirements around the procurement process. The COPUC has the authority to decide whether PSCo must use competitive solicitation in its procurement of certain resources. The COPUC can also require PSCo to meet specified resource and renewable targets, which impacts PSCo's procurement process.

In 2016, PSCo included four different RFPs in its ERP: a Dispatchable Resources RFP, a Renewable Resources RFP, a Semi-Dispatchable Renewable Capacity Resources RFP, and a Company Ownership RFP.

PSCo issues bids for contracts varying from 1 to 25 years in length. PSCo prefers bids that use fixed prices. Bidders can, however, submit a second, alternative pricing schedule that varies on a "published and widely recognized" index and PSCo can choose between the fixed price and alternative pricing schedule for its evaluation of the bid. PSCo evaluates the contribution of an offered resource by adjusting the name plate capacity of the project by its resource-specific ELCC.

PSCo's bid evaluation follows a series of steps, outlined below:

- **Step 1: Bid Eligibility Screening.** Bids must satisfy a set of minimum requirements set by PSCo in order to be considered in further steps. These requirements include specification of pricing terms, compliance with power delivery requirements, acceptable level of development and technology risk, and security requirements. Additionally, in order for PSCo to consider a supplier's bid, the supplier must have successfully completed the development, construction, and commissioning of at least one other utility-scale project with a similar technology.[39]
- **Step 2: Interconnection assessment and initial economic evaluation**

[39] PSCo 2016 Electric Resource Plan Vol 3 https://www.xcelenergy.com/staticfiles/xe/PDF/Attachment%20AKJ-3.pdf

- **Step 2A: Electric interconnection cost estimates.** For projects that have had interconnection costs estimated in the studies required to sign a Large Generator Interconnection Agreement (LGIA) or Small Generator Interconnection Agreement (SGIA), PSCo verifies the interconnection cost estimates. For projects without studies previously conducted that have determined interconnection costs, PSCo determines the interconnection cost estimates. Bidders are responsible for procuring transmission service up to the Point of Delivery on the PSCo system and PSCo is responsible for any transmission costs beyond the Point of Delivery. The cost of transmission upgrades beyond the Point of Delivery do not get included in the bid cost.
- **Step 2B: Transmission and distribution upgrade schedule assistant.** Any necessary transmission and/or distribution upgrades get evaluated to assess the time requirements of general siting, permitting, and construction.
- **Step 2C: Initial economic screening.** PSCo ranks each bid by technology type. PSCo considers the "all-in" levelized cost of energy (LEC) that is calculated in each bid. In addition to costs provided in the bid, PSCo also estimates incremental costs or benefits that get converted to a variable rate. Components that go into the incremental costs/benefits may include electrical interconnection costs and network upgrades, resource integration costs (wind and solar resources only), avoided line loss credits, fuel delivery costs incurred by PSCo, and wind curtailment benefits (storage resources only).

  For dispatchable generation resources, LECs are calculated by converting fixed costs to variable \$/MWh costs based on annual capacity factor, average annual heat rate, and wheeling losses assumptions. Start charges also get converted to a variable \$/MWh cost based on the assumed number of hours that a unit will run at full output after being started. Capacity payments are estimated assuming a 5% Equivalent Forced Outage Rate (EFOR). Bids proposing secondary fuels are only evaluated based on their primary fuel. PSCo does not attribute any incremental benefits for quick start or faster ramp rates Regardless of LEC calculations, eligible bids move to the next computer modelling stage.

- **Step 3: Non-Price Factor Analysis.** PSCo assesses non-economic characteristics of bids, such as supplier characteristics, environmental permitting and compliance, technology viability, community reactions to the project, and ability for the project to meet reliability needs.
- **Step 4: Bidder Notification.** PSCo must notify bidders if their bids have moved on to computer modeling stage within 45 days after bids are received. If the bid has not moved to the computer modeling stage, PSCo must provide an explanation.
- **Step 5: Computer-Based Modeling of Bid Portfolios.** PSCo deploys its internal Strategist planning model, which is the same capacity expansion model used for resource planning in the ERP. The model simulates the operation of bids with PSCo's existing resources and is used to identify the portfolios that have the lowest NPV of revenue requirements through a long-term planning horizon.
- **Step 6: Evaluation of bids between 100 kW and 10 MW.** Bids of this size are too small for the computer model; instead, these bids' LECs get compared to the LECs of the most expensive larger bids selected in the least-cost portfolio in Step 5. If the LEC of a small bid is lower than the most expensive large bid selected, then the small bid gets included in the portfolio. If total capacity exceeds the necessary capacity after the addition of all cost-effective small bids, then the ability for small bids to displace more expensive large bids gets tested. If there are no comparable

technologies considered in Step 5 for a small bid to be compared against, the overall effect of including the small bid on the revenue requirement is tested; if the revenue requirement decreases as a result of including the small bid, then the small bid is added to the least-cost portfolio.

- **Step 7: Phase II report to the Commission.** PSCo submits a 120-day report to the COPUC that includes selection of PSCo's preferred resource plan as a result of the above steps. PSCo can ultimately select the amount of generation it seeks to acquire from the RFP process based on the bids as well as external factors such as changes in forecasts, regional transmission availability, and regulatory and/or legal requirements.

PSCo must conduct its RFP process in 18 months unless granted an extension. After PSCo files its 120-day report, an Independent Evaluator assesses PSCo's bid evaluation and determines whether the bid process was done fairly and in accordance with the COPUC's rules and decisions in Phase I of the ERP. The COPUC then issues a decision approving, modifying, or rejecting PSCo's resource plan.

Short-term Procurement

For smaller resource needs, PSCo has historically relied on short-term contracts with existing generation rather than procure new resources. PSCo has considered contracts to be short-term if they do not extend more than 7-14 years beyond the RAP. In its 2011 ERP, PSCo cited several reasons for its preference for short-term contracts with existing generation, or what PSCo also refers to as the "opportunistic approach". In the early 2010s, capacity expansions and reduced demand left WECC with excess capacity in the near term (through 2019); reserve margins in WECC were above 30%, which is significantly over target PRMs. In addition, PSCo was facing several uncertainties during the development of its 2011 ERP, which helped to make short-term contracts more attractive. PSCo was facing uncertainties regarding future environmental regulations, changing technologies (particularly cost declines), tax credits and their impacts on technology cost-effectiveness, fuel prices, and economic growth of their service territory. Additionally, the City of Boulder alerted PSCo in the early 2010s that it would be considering becoming a muni and no longer taking service from PSCo, which would have significant impacts on PSCo's load. Short-term contracts offered flexibility to reassess the changing and uncertain conditions several years later. [40]

PSCo identified two types of short-term contracts: 1) Contracts with Company-owned facilities, which would continue their operation under a short-term contract and 2) Short-term PPAs with facilities owned by IPPs or other utilities. Typically, resources require longer-term PPAs to support their construction and financing. However, existing resources with expired initial longer-term PPAs may be more likely to agree to shorter-term contracts and may also be able to offer lower prices than new resources. [41]

To make contracts with existing generators viable, PSCo has previously requested in its ERP to not be subject to renewable or Company-owned targets for new resource acquisitions. Although PSCo emphasized short-term contracts with existing generation in its 2011 ERP, PSCo also allowed bids for short-term contracts with new resources and bids for expansions of Company-owned generation to

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[40] PSCo 2011 ERP Vol 1 https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Exhibit-No-KJH-1-Volume-1.pdf

[41] PSCo 2011 ERP Vol 1 https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Exhibit-No-KJH-1-Volume-1.pdf

compete with bids with existing generators in its All-Source Solicitation. In addition to soliciting bids for short-term contracts, PSCo also procured long-term contracts in its 2011 ERP.[42]

California Case Study

Statewide IRP coordination and utility procurement in a bilateral capacity market

California's IRP Process

The CPUC's Integrated Resource Planning (IRP) process was created by SB 350 in 2015. The IRP process is the main mechanism by which the CPUC organizes long-term resource planning. The IRP process is focused on ensuring that California's electric sector "meets its GHG reduction goals while maintaining reliability at the lowest possible cost."[43]

The IRP process occurs in two-year cycles and is made up of two year-long phases. In the first half of the IRP cycle, the CPUC sets a GHG emission planning target for California's electric sector that is aligned with CARB's Scoping Plan and the state's economywide GHG targets. In addition to the GHG target set in this phase, the CPUC may identify additional GHG targets that serve as sensitivities to the selected GHG target. For example, although the CPUC selected a 46 MMT target for its current IRP process, the CPUC also asked LSEs to submit plans for a 38 MMT target in their 2020 filings.[44] The first half of the IRP culminates in the development of the Reference System Plan (RSP), which identifies the optimal state-wide electricity resource mix to meet the state's emissions and reliability goals. Throughout this phase, capacity expansion modeling, production simulation modeling, and economy-wide GHG emissions modeling are done to inform optimal electricity resource mixes and strategies for achieving GHG targets.[45]

In the second half of the IRP cycle, LSEs develop their own IRPs in which they identify resource needs and procurement strategise over a 10-year planning horizon based on the RSP. LSEs may use any model they choose to develop their own resource portfolio, but use standardized CPUC reporting templates and emissions calculator. The CPUC then reviews the individual resource plans submitted by each LSE and aggregates these LSE plans into one single system-wide portfolio. Individual LSE resource plans must sum to meet all resource needs determined in the RSP as well as collectively meet the state's GHG targets. The aggregated LSE plans, after approval from the CPUC, form the Preferred System Plan (PSP).

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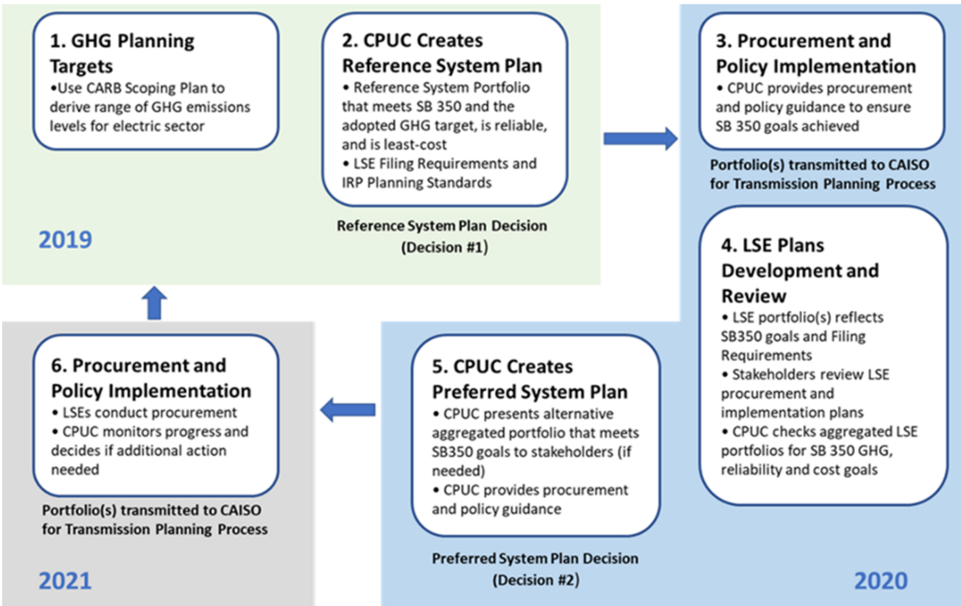
[42] PSCo 2011 ERP Vol 1 https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/PSCo-ERP-2011/Exhibit-No-KJH-1-Volume-1.pdf

[43] CPUC, "Fact Sheet: Decision on 2019-20 Electric Resource Portfolios to Inform Integrated Resource Plans and Transmission Planning" (2020). https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442464699

[44] "Final Decision [on RSP]" https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M331/K772/331772681.PDF

[45] E3's RESOLVE model and the SERVM Production Simulation model are used in the development of the RSP. CARB used the E3 PATHWAYS model to inform its 2017 Scoping Plan.

Figure D-2. Overview of the IRP 2019-2021 Process



Load Forecasting in the IRP

The CPUC aligns its load forecasts with the CEC's Integrated Energy Policy Report (IEPR) peak demand and energy consumption forecasts. IEPR projects demand and energy forecasts on a statewide level and includes separate hourly profiles for "demand-side modifiers," which include electric vehicles, building electrification, other electrification, BTM PV, non-PV self-generation (predominantly BTM CHP), EE, and TOU rate impacts.

In the IRP, the CPUC allocates load forecasts, including demand-side modifier load forecasts, among LSEs and each LSE must use the load forecast assigned to them in developing their resource plan. LSEs use default load shapes from IEPR unless an LSE proposes to use alternative load shapes. The annual load of alternative load shapes must still sum to the CPUC-assigned annual load. In the development of the PSP, LSE load forecasts used in individual LSE resource plans get aggregated back up to a statewide level.[46]

IEPR forecasts get developed biennially using several California models. The models used in IEPR convert forecasts of annual energy use to hourly demand forecasts by applying load shapes for different end-uses as well as demand-side resources such as energy efficiency, EV charging, and PV generation.

The load shapes used in the models originally come from data provided by California's utilities and databases of customer energy usage and are distinguished by end use, sector, and geographic area.[47]

[46] "Proposed Inputs & Assumptions: 2019-2020 Integrated Resource Planning" https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/Prelim_Results_Proposed_Inputs_and_Assumptions_2019-2020_10-4-19.pdf

[47] "California Investor-Owned Utility Electricity Load Shapes" https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03

Resource Procurement

California's IRP process does not include bid evaluation. Bid evaluation may be authorized or ordered by the CPUC based on results of IRP planning, but LSEs are responsible for organizing their own solicitations and determining the criteria by which they evaluate bids. IOUs typically procure new resources through competitive request for offers (RFOs). IOUs evaluate supplier offers based on preset quantitative and qualitative criteria.

Quantitative criteria may vary between RFOs and IOUs. For example, the PG&E Demand Response Auction Mechanism (DRAM) RFO issued in 2019 used Net Market Value (NMV) in units of $/kW-contract term in its quantitative evaluation of offers. The NMV is calculated as:

Net Market Value = Benefits – Costs

Benefits are calculated using PG&E's forecast capacity market value of each type of product in the offer. Costs are calculated by multiplying the monthly price per product and the volume of each product per month. [48] In its quantitative assessment of RPS bids, SCE used the benefit-to-cost ratio of projects, which divides total benefits by total costs associated with the project. The benefits used in this calculation are calculated as the sum of capacity and energy benefits. The costs are the sum of the contract price, integration costs, transmission costs, and debt equivalence. Prior to summing the costs and benefits used in the calculation, SCE discounts the annual benefit and cost streams to a common base year.[49]

Quantitative assessment uses the Qualifying Capacity estimates provided by the bidder. The IOU evaluating the bid may also calculate the net capacity value of the proposed resource using a resource-specific methodology. For example, the capacity of renewable resources is assigned based on ELCC values.

Qualitative criteria can also vary by RFO. In its qualitative evaluation of its DRAM RFO, PG&E developed a qualitative assessment scoring matrix and used the Qualitative Factor Adjustment derived from the scoring matrix in an Adjusted Cost calculation, as shown below:

*Adjusted Cost = Cost * Qualitative Factor Adjustment*
where:
*Qualitative Factor Adjustment = 1 + ∑(Score * Weight)*

The Scoring Matrix used by PG&E in its DRAM Solicitation is shown below:

[48] "2020 DRAM Requests for Offers Solicitation Protocol" https://www.pge.com/pge_global/common/pdfs/save-energy-money/energy-management-programs/demand-response-programs/2020-demand-response/2020_DRAM_Protocol.pdf

[49] "SCE's Written Description of RPS Bid Evaluation and Selection Process and Criteria ("LCBF Written Report")" http://www3.sce.com/sscc/law/dis/dbattach1e.nsf/0/FF5993694F4D086E882573FE00706547/$FILE/APPENDIX+B--R.06-05-027+RPS-OIR-SCE+Written+Description+of+RPS+Bid+Eval+and+Sel+Process+and+Criteria.pdf

Table D-1. Qualitative Evaluation Scoring Matrix

	Answer	Score: Yes	Score: No	Weight: PG&E	Weighted Score (Score x Weight)
Small Business					
Are you a certified Small Business?*	Yes/No	1	0	-1%	
Prior Experience					
Have you willfully terminated or defaulted on your most recent DRAM PA? *or* Have you submitted offers that demonstrated bidding behavior providing clear evidence of market manipulation or collusion?[8]	Yes/No	1	0	15% cost if any or multiple of these conditions are met	
Have you not signed a DRAM PA when extended a shortlist offer on your most recent submitted offer? *Or* If you currently have or previously had a 2019, 2018-2019, or 2017 DRAM contract, have you delivered Supply Plans to the IOUs for DRAM totaling, in aggregate, less than 50% of the contracted capacity for all months in your most recent DRAM contract term, at the time of offer submittal?[9]	Yes/No	1	0	5% cost if any or multiple of these conditions are met	

*For information about Small Business standards, please refer to one of the following sites:
(1) California Department of General Services
(2) Small Business Administration

SCE's qualitative evaluation of RPS bids considers project and technology viability, timing and progress towards gaining transmission access, and the seller's qualifications. SCE also uses qualitative attributes such as interconnection location, ability to dispatch during on-peak periods, environmental impacts on water quality and use, resource diversity, benefits to minority and low-income communities, and local reliability to break ties between offers.[50]

Resource Adequacy in the IRP

Following the Energy Crisis in the early 2000s, the CPUC adopted a Resource Adequacy (RA) policy framework to ensure the reliability of California's electric grid and services. The RA program ensures that there are sufficient resources available to allow for safe and reliable operation of the grid. In real-time, the RA program ensures that resources can be dispatched as needed to the California Independent System Operator (CAISO). The RA program also ensures future reliability by guiding resource procurement in the IRP to meet future needs. Each LSE has its own RA obligations that must satisfied by its resource plans. LSE RA requirements are based on the CEC's state-wide demand forecasts and LSE demand forecasts. The CEC reviews LSE forecasts and adjusts the statewide coincident system peak based on LSE forecasts.

[50] "SCE's Written Description of RPS Bid Evaluation and Selection Process and Criteria ("LCBF Written Report")" http://www3.sce.com/sscc/law/dis/dbattach1e.nsf/0/FF5993694F4D086E882573FE00706547/$FILE/APPENDIX+B--R.06-05-027+RPS-OIR-SCE+Written+Description+of+RPS+Bid+Eval+and+Sel+Process+and+Criteria.pdf

There are three components of the RA program that have their own distinct requirements set by the CPUC:

1. System RA requirements. System RA requires LSEs to have enough resources to meet their peak demand plus a PRM, set at 15% in California. Obligations for each LSE are determined based on an LSE's monthly peak forecast, with forecasts derived from a 1-in-2 (average) weather year.
2. Local RA requirements. A certain amount of an LSE's RA must be served by resources in "locally constrained areas" to meet contingency needs. Local RA requirements are determined by annual CAISO studies that use a 1-in-10 weather year and an N-1-1 contingency. Local RA obligations are divided among LSEs based on load ratios in the local area's peak month.
3. Flexible RA requirements. A certain amount of an LSE's RA must be served by "flexible" resources that can ramp up or down quickly to maintain grid reliability with variations in load and/or intermittent resource generation. Flexible RA requirements are determined by annual CAISO studies that evaluate the largest three-hour ramp of generation required each month to keep the system running reliably.[51,52] Flexible RA requirements are allocated among LSEs based on monthly load ratio shares.[53]

Contribution of each resource towards meeting RA requirements is dependent on the resource type. Thermal and hydro resources' contributions are based on the Net Qualifying Capacity (NQC), which are calculated by the CPUC and CAISO. Solar and wind resources' contributions are calculated based on their Effective Load Carrying Capability (ELCC), which are calculated in the capacity expansion model used by the CPUC in developing its RSP and can be informed by CPUC assumptions. The contribution of Demand Response is based on a forecast of 1:2 peak load impact. The CPUC sets limitations on imports' ability to contribute to RA; in the most recent IRP planning cycle, the CPUC revised imports' contribution to RA to reflect increasing resource scarcity in neighboring regions. In its recent IRP, the import assumptions were a key driver of results, and therefore, the CPUC ran sensitivities of imports' contribution to RA.[54]

The CPUC issues decisions adopting Local and Flexible RA obligations the year before going into effect. The RA program requires LSEs to submit monthly and annual filings to the CPUC to demonstrate RA compliance and procurement of a specified portion of RA resources for the upcoming year or month. System and Flexible RA only requirement procurement one year in advance, but Local RA requires procurement compliance up to three years in advance. As load forecasts change throughout the year, LSEs must revise their procurement and demonstrate their updated procurement in monthly filings.

LSEs can count their own resources and longer-term contracts toward their RA obligations, provided they meet RA availability requirements. LSEs can then meet residual ("net short") capacity needs with annual or monthly RA contracts with generators and demand response and storage providers. Most (83-86% in 2018) of the contracts used to meet System RA obligations are bilateral contracts for generation. The

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[51] Gridworks, "Resource Adequacy – What Is It and Why Should You Care?" https://gridworks.org/2018/06/resource-adequacy-what-is-it-and-why-should-you-care/.

[52] CPUC, "Resource Adequacy" https://www.cpuc.ca.gov/ra/

[53] "RA Program Orientation Slides" https://www.cpuc.ca.gov/ra/

[54] "2019-20 IRP: Proposed Reference System Plan" https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019%20IRP%20Proposed%20Reference%20System%20Plan_20191106.pdf

remaining System RA obligation is met through imports (5-8% in 2018) and DR resources (3-5% in 2018).[55] This total does not include hydropower and nuclear facilities, which receive RA credit but do not have separate RA contracts.

Contracts for RA must have a "must-offer obligation" (MOO) to be eligible to meet the LSE's RA obligation. A must-offer obligation requires owners of resources to submit self-schedules or bids into the CAISO market and have the resources available for dispatch by CAISO.

If LSEs do not meet their RA obligation, the CAISO procures backstop resources on their behalf and allocates the costs to the deficient LSEs. There are two ways in which CAISO can exercise backstop procurement in two ways: 1) the Capacity Procurement Mechanism (CPM), which is triggered when an LSE does not meet its RA obligation and 2) Reliability Must Run (RMR) contracts with resources that must prolong retirement to provide reliability. LSEs are charged penalties for not satisfying their RA obligations unless they can demonstrate that they met one of the criteria for penalty waivers.

Figure D-3. Steps in California's RA Procurement Process

There are annual RA proceedings held by the CPUC to refine the RA program as needed. Therefore, requirements for the RA program are constantly changing and being updated to reflect changing conditions of the grid and the services required to ensure its reliability. For example, in California, the rise of CCAs and increased penetration of renewables have spurred recent modifications to the RA program.[56] In addition, the CPUC can require additional RA procurement after the PSP has been adopted.

[55] "2018 Resource Adequacy Report" https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Electric_Power_Procurement_and_Generation/Procurement_and_RA/RA/2018%20RA%20Report%20rev.pdf

[56] CPUC, "Resource Adequacy" https://www.cpuc.ca.gov/ra/

Appendix E: Market Participation Models for Energy Storage in California

This appendix provides an overview of market participation models for energy storage in the California Independent System Operator (CAISO) market. CAISO is expecting significant amount of new storage over the next decade and has been a leader among ISOs in developing participation models for standalone and hybrid (paired with a generation resource) energy storage.

To allow storage more fully participate in the ISO market, CAISO introduced the Non-generator Resource (NGR) model in 2012. NGRs are defined as "resources that have a continuous operating range from a negative to a positive power injection." NGRs can be dispatched along their entire capacity range.[57] NGRs are also constrained by a MWh limit to generate energy, curtail energy consumption for demand response, or consume energy.[58] NGRs can include Limited Energy Storage Resources (LESRs), but NGRs are not limited to storage resources. There is a subset of NGRs that have Regulation Energy Management (REM), an option in which NGRs are optimized to only provide regulation and only participate in CAISO's regulation markets.[59]

Over the past decade, CAISO has created rules and processes around NGR to allow NGRs to participate in the CAISO energy and AS markets similarly to traditional generators.[60] CAISO outlined two phases of NGR integration into the ISO markets. In Phase I, CAISO created an initial model for storage to participate in the ISO market. In Phase II, CAISO enabled dispatchable DR to participation in Regulation markets.[61] The guidelines for the operation of NGRs are continuously getting updated, with changes being reflected in CAISO's Market Operations Business Practice Manual (BPM).

CAISO Rules for NGRs

The bidding process and rules for NGRs is similar to that of other resources. Bids for NGRs can be submitted in the Day-Ahead Market for charging or discharging in MW and can range from P_{min} to P_{max}. In the bidding process, NGR scheduling coordinators can submit day-ahead hourly Self-Schedule quantities for supply and/or demand. The day-ahead self-schedules become binding in the RTM. Self-scheduled bids can be in addition to or without economic bids. There are different types of Self-Scheduled bids that can be submitted and the bid type determines the order in which bidded resources get dispatched. NGRs are only able to submit Price Taker Self-Scheduled bids, which are the lowest in the dispatch order.[62]

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[57] "Non-Generator Resource (NGR) and Regulation Energy Management (REM) Overview – Phase 1" http://www.caiso.com/Documents/NGR-REMOverview.pdf

[58] BPM Market Operations https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/BPM_for_Market%20Operations_V68_redline.pdf

[59] "Non-Generator Resource (NGR) and Regulation Energy Management (REM) Overview – Phase 1" https://www.caiso.com/Documents/NGR-REMOverview.pdf

[60] BPM Market Operations https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/BPM_for_Market%20Operations_V68_redline.pdf

[61] "Non-Generator Resource (NGR) and Regulation Energy Management (REM) Overview – Phase 1" http://www.caiso.com/Documents/NGR-REMOverview.pdf

[62] "CAISO SIBR – Scheduling Coordinator Users Guide" https://www.caiso.com/Documents/SIBR_SchedulingCoordinatorUserGuideFrameworkUpgrade.pdf

In addition to submitting bid amounts, NGRs can submit Lower and Upper Charge Limits for each day, which are the lowest and highest amount of stored energy that the resource is permitted to store, respectively. NGRs can also submit an initial State of Charge (SOC) in MWh to indicate the amount of energy that is available from the resource in the first interval of the day. There are default values that are used if a Scheduling Coordinator does not submit values for the Charge Limits and initial SOC.[63]

CAISO has considered the implementation of spread bids to enhance storage resources' ability to economically bid in the ISO market. The "spread" refers to the difference in energy price at which a storage device charges and discharges. Since storage devices profit off the relative difference between the prices at which it can consume and sell energy, the price at which a storage resource is willing to participate depends on the "spread" of its buying and selling prices, rather than one set buying and/or selling price.[64] Spread bidding has not yet been implemented.

NGRs must meet several additional requirements to participate in the ISO market in addition to having to meet the requirements for traditional generators. NGRs must be scheduled in accordance with feasibility limits pertaining to upper and lower charge limits and the resource's operational ramp rate. NGRs must meet a 10-minute ramping requirement and Regulation Up and down must satisfy the 15-minute continuous energy delivery and consumption requirements. To meet the requirements for CAISO-issued certification to provide Regulation, Spinning, Non-Spinning, and maximum capacity, NGRs must be dispatchable on a continuous basis for at least 60 minutes. NGRs must also meet the continuous energy AS procurement requirement (60 minutes for Day-Ahead Regulation Up/Down, 30 minutes for Real-Time Regulation Up/Down, and 30 minutes for Spin and Non-Spin).[65]

Emerging Rules for Hybrid Resources

Hybrid resources refer to resources that have both a generation and storage components and are behind a single point of interconnection. For example, solar + storage is classified as a hybrid resource. Hybrid resources are currently managed by CAISO as a single resource and participate in CAISO markets as a single resource. This distinguishes hybrid resources from co-located resources, which are located behind a single point of interconnection but participate in CAISO markets and are managed by CAISO as separate resources. Scheduling coordinators of hybrid resources self-manage the intermittency of the resources and can optimize the resources' output and submit a single bid for the resource accordingly.
CAISO then dispatches hybrid resource as non-intermittent and dispatchable. [66]

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[63] "Business Practice Manual for Market Instruments" CAISO https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Instruments/BPM_for_Market%20Instruments_V62_redline.pdf

[64] "Energy Storage and Distributed Energy Resources Initiative: Second Revised Straw Proposal" CAISO http://www.caiso.com/InitiativeDocuments/Presentation-Day2-EnergyStorage-DistributedEnergyResourcesPhase4-SecondRevisedStrawProposal.pdf

[65] "Non-Generator Resource (NGR) and Regulation Energy Management (REM) Overview – Phase 1" http://www.caiso.com/Documents/NGR-REMOverview.pdf

[66] "Hybrid Resources – Technical Conference Comments of the CAISO Corporation" FERC proceeding http://www.caiso.com/Documents/Sep24-2020-CAISO-Comments-Technical-Conference-HybridResources-AD20-9.pdf

The amount of hybrid and co-located resources in CAISO has increased drastically over the past few years. Of the active interconnection requests submitted in 2020, 58% were hybrid or co-located projects. Most of these interconnection requests were for solar + storage, with a few solar + wind projects.[67] The existing rules and regulations for generating resources pose some challenges for integration of hybrid resources and CAISO is currently considering and developing modifications to allow hybrid resources to participate in the CAISO market.

One area of modification is in CAISO's methodology for determining a resource's maximum allowable output. Current resources are constrained to their interconnection rights; applying the same constraint to hybrid resources could artificially limit their output. Therefore, CAISO has proposed an aggregate capability constraint that would allow the combined capacity of the hybrid resource components to exceed the resource's interconnection capacity but would still limit output of the resource to its interconnection capacity.[68]

There are several challenges that arise from the treatment of hybrid resources as a single resource and CAISO is considering how to best address these challenges. It is difficult for CAISO to accurately forecast output from a hybrid resource since CAISO cannot distinguish between the generating and charging contributions of the resource. The lack of visibility into the different components of a hybrid resource also poses challenges for how CAISO operates the resource. CAISO does not know a storage component's state of charge when dispatching resources, which limits CAISO's ability to knowledgably dispatch a hybrid resource. Additionally, because hybrid resources are treated like traditional dispatchable resources, their bids can only be updated once an hour at 75 minutes prior to the operating hour. Given the intermittent nature of the generating components of hybrid resources, this advanced commitment presents a risk for over commitment or prevents the resource from producing at its maximum capability.

In order to forecast and operate hybrid resources more accurately, CAISO is considering ways in which it can gain more visibility into the different components of hybrids. One potential solution that CAISO has endorsed is issuing the generating and storage components of the hybrid separate resource IDs, which would effectively present the resource as two separate entities to CAISO.[69]

Hybrid resources are able to participate in the AS market, but existing requirements present some challenges to hybrid resource participation in the AS market. Therefore, CAISO is considering modifications to AS requirements that will apply to hybrid resources. CAISO is considering changes to the timing for power output changes and methods for determining the potential output of the resource to allow hybrid resources to provide Spinning and Non-Spinning Reserves. CAISO is also considering several modifications to sizing requirements. Current AS requirements require resources to be 0.5 MW or larger to participate in the AS market, but CAISO is considering modifying this requirement to allow resources that are smaller than 0.5 MW, but paired together to form a hybrid resource, to participate. To ensure that a storage device can provide Regulation services, CAISO is considering enacting a minimum storage

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[67] "Hybrid Resources – Technical Conference Comments of the CAISO Corporation" FERC proceeding http://www.caiso.com/Documents/Sep24-2020-CAISO-Comments-Technical-Conference-HybridResources-AD20-9.pdf

[68] "CAISO Corporation Hybrid Resource Phase 1 Amendment Docket No. ER20-____-000" http://www.caiso.com/Documents/Sep16-2020-Tariff-Amendment-Hybrid-Resources-Phase-1-ER20-2890.pdf

[69] "Hybrid Resources Issue Paper" CAISO http://www.caiso.com/Documents/IssuePaper-HybridResources.pdf

generation sizing requirement.[70] CAISO is also considering requirements for additional telemetry to communicate the necessary data from the hybrid resource to CAISO. For example, CAISO would need improved telemetry to be able to accurately assess whether a resource should be issued payment rescissions if they received an AS award but were unable to provide the committed service.[71]

CAISO is also working to develop rules and methodology to allow hybrid resources to participate in RA. CAISO has proposed a new methodology to count hybrid resources' eligibility for RA; the exceedance approach that CAISO proposed "measures the minimum amount of generation produced by the resource in a certain percentage of hours" based on historic production data. CAISO is also assessing Must Offer Obligation (MOO) provisions that reflect any updates to the counting methodology.[72]

In order for hybrid resources to qualify for RPS, CAISO must be able to report meter data. The metering for hybrid resources may need to be modified to make them eligible for RPS. The CEC has developed guidelines for hybrid resources' RPS eligibility; the CEC has determined that any storage charging and discharging from renewables qualifies as the amount of renewable energy produced from the generating resource net any losses from storage.[73]

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[70] This would require that the storage facility be greater than or equal to 10% of the overall hybrid resource interconnection rights with a capability to provide the minimum required capacity output for at least 30 minutes.
[71] "Hybrid Resources Issue Paper" CAISO http://www.caiso.com/Documents/IssuePaper-HybridResources.pdf
[72] *Ibid.*
[73] *Ibid.*