Reforms in electricity market design

Comments on the CERC Staff Paper on Capacity Market for Electricity in India

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1 Context

The Central Electricity Regulatory Commission (CERC or the Commission) released a staff paper on the introduction of a capacity market in India in April 2026 (CERC, 2026). Currently, capacity is procured through long term contracts such as power purchase agreements where distribution companies (discoms) hold scheduling rights. The staff paper argues that this arrangement prevents the dispatch from being market-based and does not reliably ensure that this capacity will be available during hours of stress. The paper proposes to change this by introducing a capacity obligation in the long term, a short term capacity market for existing capacities and a reserves market.

This note is a response to the proposals outlined in the staff paper. We identify the gaps in the current framework for procurement of capacity which clearly establish the need for reforming the market for reserves through the reform of the market for ancillary services. We argue that the reforms for the procurement of reserve capacity are well timed, but they exclude a crucial segment (primary reserves) from market based procurement of reserves.

Next we tackle the proposals related to capacity remuneration mechanisms and argue that the case for introducing one in the Indian context is not eminently clear. Given that the legacy contracts in India are inherently capacity contracts, proposals for capacity remuneration mechanism need to be grounded in rich empirical evidence on resource adequacy assessments. The current proposal while outlining three options for a capacity obligation, does not sufficiently engage with the underlying parameters needed to justify the introduction of a capacity remuneration mechanism in the Indian context. The parameters should include — the construction of the demand curve, the net cost of new entry, eligibility criteria and market power and have been discussed in this response.

The response is structured as follows. Section 1 sets out the context for the CERC's proposals, explaining what capacity markets are and identifying the market failures — principally the missing money problem and the free rider problem — that are used to justify their introduction. Section 2 describes India's current framework for capacity procurement, which is built around long-term contracts and does not address concerns related to the financial burden that fixed capacity charges place on distribution companies, and the absence of any obligation on generators to be available during

periods of system stress. Section 3 identifies gaps in the proposed design — the absence of a market-based mechanism for primary reserves, and the documented disuse of the market mechanism for tertiary reserves. Section 4 addresses the CERC's proposal for a long-term capacity obligation and identifies the design elements that require further elaboration before a capacity market can be introduced, including the choice of capacity remuneration mechanism, the methodology for setting the resource adequacy requirement, the construction of the demand curve, the estimation of the Net Cost of New Entry, the eligibility of technologies including storage and demand response, and the risks of market power in capacity markets. Section 5 sets out the note's recommendations, divided into near-term steps for improving the ancillary services market and longer-term conditions that should be satisfied before a capacity obligation is introduced.

1.1 Rationale for capacity markets

What is capacity?

Typically, electricity is bought and sold as energy i.e. in kWh or MWh. The market to sell energy is known as an energy only market. Energy should be distinguished from the capability to generate electricity which is measured in units of kW or MW as the case may be. Under this mechanism, generating stations are compensated for their availability to produce electricity with the goal of constantly satisfying the demand.

What are capacity markets?

Capacity market is created alongside an energy market where maintenance of capacity is explicitly traded and compensated. It is introduced to ensure security of supply in the medium term and long term periods.

Reliability remains the underlying goal of electricity market design and regulation. Meeting this objective requires sufficient investment in supply capacities.

What are the underlying market failures that justify introduction of a capacity market?

A review of economic literature reveals that introduction of capacity markets is justified on account of the 'missing money' problem and the 'free rider' problem (Cramton et al., 2013; Keppler, 2017). Energy only markets do not compensate

the participants adequately for them to meet the medium and long term investments into reliability, this is referred to as the 'missing money' problem (Aagaard & Kleit, 2022a; Bublitz et al., 2019). Additionally, increasing penetration of renewable energy sources reduces prices in the short term markets. Renewable energy sources due to their intermittency also require additional backup generating capacity in times of peak load (Schreiber, 2018).

As a consequence policy makers are concerned whether existing compensation mechanisms will generate the right price signals to incentivise long term investments in generation capacity. This is compounded by the lack of participation from the demand side responses, and resource adequacy in the long term remains a supply side burden (Bublitz et al., 2019). The inelastic nature of the demand curve implies that as the system approaches scarcity situations and the supply curve also becomes inelastic due to limited capacity, energy markets may not clear as demand and supply fail to intersect (Cramton et al., 2013).

The other issue is the 'free rider' problem. The shared nature and resemblance to public good characteristics of the electricity network complicates price signalling for it is impossible to differentiate between consumers who contract for reliable supply and those who do not (Bublitz et al., 2019; Keppler, 2014).
However, there is no consensus on whether energy-only markets suffer from the market failures that effectively threaten security of supply (Keppler, 2014; Schreiber, 2018). Markets across the world use different combinations including different variations within energy-only and capacity market designs, suggesting that the chosen market design should be tailored to country specific requirements (Chattopadhyay & Suski, 2022).

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2 Current framework

Currently, the majority of base load capacity in India is tied up in cost plus long term contracts with two-part tariffs where investment in capacity is recovered as a component of the two-part tariff structure (IGEP, 2015). The fixed or capacity charge is calculated on the basis of annual fixed costs, which are composed of the return

on equity, the interest on loans and working capital, depreciation and operations and maintenance expenses. Generators are entitled to recover their entire fixed charge if they declare their capacity available to their contracted state's system operator, known as the State Load Dispatch Centre, for at least 85% of the time in a month (Khanna, 2025).

For renewable energy sources, contracts include a single part fixed tariff, which hinges on payment for actual energy delivered. These contracts also provision for under performance and over-performance in the form of penalties and incentives. In addition to long term contracts, India has an illiquid energy only market (approximately 13%).

2.1 Recovery of fixed costs

Buyers (discoms) must pay a fixed capacity charge regardless of whether they use the capacity. The financial burden of fixed costs especially when the demand has not coincided with the projections has made the discoms financially vulnerable given that they are constrained by their procurement decisions and cannot exit them.

Importantly, discoms recover the investment into fixed costs (which include capacity payments to thermal generating stations) through the variable energy charges linked to electricity consumption. Even if electricity demand falls or discoms lose commercial and industrial consumers and revenue collections decline, the fixed obligations remain unchanged. Fixed capacity charges under long term contracts therefore pose a significant financial risk to discoms.

This form of procurement, given that the tariffs are settled for a long period, is also vulnerable to mismatches in developing generation capacity and long term demand due to the uncertainty related to forecasting of demand. The reluctance on part of the discoms in signing long term contracts can be seen in the stranded tendered capacity, especially in the context of renewable energy resources.

2.2 Unresponsive to system stress

Apart from the problem of stranded fixed costs, power generators have no obligation to support the power system in terms of 'capacity' and 'ancillary services' when system is in stress either due to higher-than-expected demand or lower-than-forecast renewable

generation. Under the conventional contracts, such generators are assured of their fixed costs based on availability calculated on an annual basis.

In this framework, the discoms are entitled to schedule despatch of power and a system wide mechanism for scheduling does not exist. This forecloses the market from using the pool of generation capacity and as a consequence, there may be surplus and deficits in different regions even when aggregate capacity may be adequate. Lack of an obligation to become available during times of system stress needs to be urgently attended to. While the ancillary services regulations have ensured market based procurement of tertiary reserves, there are gaps in its design and implementation.

We discuss how to enhance the reserve capacity market based on the proposal outlined in the CERC, 2026 staff paper in the following section.

3 Enhanced reserve capacity market

The Commission contemplates advance procurement of reserves. It proposes a forward auction held once a year to contract capacity specifically for reserve provision, before the delivery period. It suggests that separate auctions be held for secondary and tertiary reserves where eligibility is governed by the ancillary services regulations. The framework does not address the lack of market based mechanism for primary reserves and the disuse of market based mechanism for tertiary reserves. These concerns have been outlined below.

3.1 Inefficiency

Primary reserves would continue to be procured through the mandatory obligation provided for in the Indian Electricity Grid Code. The lack of a market based mechanism for PRAS, effectively excludes storage technologies from participation even though these technologies are well-suited to provide these services. Under the current framework, thermal generators provide these services and consequently entail high operational costs on account of increased cycling and ramp up. NLDC can procure PRAS from standalone energy storage systems, but such procurement would have to be approved by the relevant Regulatory Commission. Moreover, an obligation-based system does not differentiate between low-cost and high-cost providers and may result in inefficient

dispatch of expensive units.

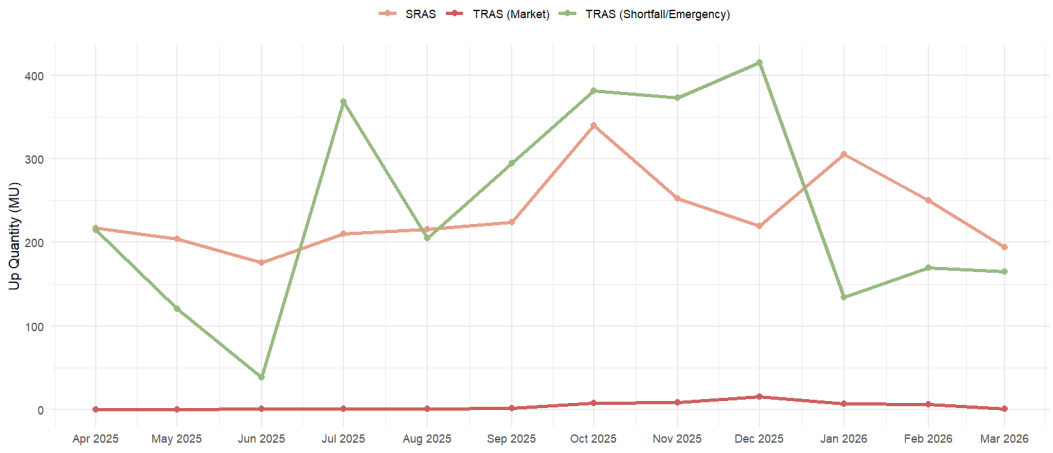
The proposed framework does not include PRAS in the market based procurement. We recommend that reforms should include the transition away from the mandatory regulated obligation for primary reserves. A market-based procurement mechanism for primary reserves would require careful consideration of the procurement method, pricing mechanism, remuneration structure and cost allocation. These design choices should align with PRAS's technical requirements and enable participation by the most efficient providers.

3.2 Market disuse for tertiary reserves

A related concern is the disuse of the market for tertiary reserves. The data from Grid India reveals that the procurement of tertiary reserves is done through the shortfall or the emergency route . Figures 1 and 2 show the procurement of secondary and tertiary reserves, and amplify that the tertiary reserves are chiefly procured via the shortfall or emergency route.

Figure 1 Ancillary services Up procurement

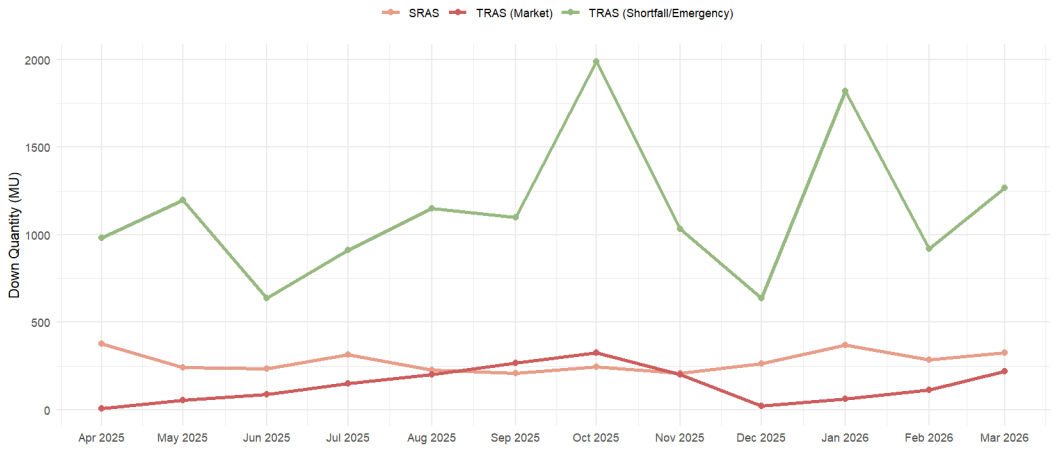
The graph shows the procurement of SRAS, TRAS Up from the market and through the shortfall or emergency route.



Source: Grid India, Monthly Ancillary Reports

Figure 2 Ancillary services Down procurement

The graph shows the procurement of SRAS, TRAS Down from the market and through the shortfall or emergency route.



Source: Grid India, Monthly Ancillary Reports

In this context, a study which explores the reasons for the procurement of tertiary reserves through the shortfall or emergency route instead of the market based mechanism should be conducted. The results of the study can inform the design of reforms for market based procurement of SRAS and TRAS.

The reserves market can be reformed and made operational in the near term. With the increased deployment of renewable energy generating stations, a capacity remuneration mechanism will add complementary value in the long term. However, the introduction of such a mechanism should be justified on strong empirical evidence and transparently set parameters. There are market design elements that need careful consideration, these have been discussed in the section that follows.

4 Capacity obligation

In the long term, the development of a capacity remuneration mechanism should be based on the characteristics of the electricity market it is being designed for. The table in Annexure C compares the options provided by the Commission for introducing a capacity obligation. The three options can be distinguished on the basis of how much

autonomy they accord to the discoms in the obligation framework. Option 2, which endorses a decentralised framework protects the scheduling rights of the discoms.

The staff paper does not adequately justify the need to introduce a capacity remuneration mechanism, nor does it provide evidence related to parameters on which the obligation would depend. Other jurisdictions demand that the introduction of capacity remuneration mechanism be grounded in a medium to long-term resource adequacy assessment, and may only be introduced where adequacy concerns cannot be resolved by removing existing market distortions (European Parliament and the Council of the European Union, 2024; Government of United Kingdom, 2015).

In this context, we specify the elements that need deeper consideration.

4.1 Capacity remuneration mechanism

Capacity remuneration mechanisms are devised to encourage investments into generation adequacy, in order to avoid shortages. The mechanisms provide income to the capacity providers on top of the money that they make by selling energy in the markets. The capacity prices are either derived from market based principles or decided in advance administratively.

Capacity remuneration mechanisms are broadly classified into *volume-based* mechanisms, where a specific capacity sufficient to guarantee the desired level of system adequacy is set and *price-based* mechanisms, where the amount of the procured capacity is steered by setting a target price. There are various ways in which capacity can be remunerated, the dominant forms are discussed below, in table 1 (Bublitz et al., 2019; Schreiber, 2018).

Table 1 Different capacity remuneration mechanisms

This table documents the different remuneration mechanisms used by countries to compensate capacity providers.

Mechanism	Description
Tendering	Construction of new capacity is financially supported, capacity providers are granted support, long term PPAs are an example.
Strategic reserve	A specified quantity of capacity is contracted and reserved outside the energy market. This reserve capacity is used only under certain conditions, for example if a shortage arises.
Central buyer	A central level authority determines the required capacity and procures it through a central bidding process. The price is determined through a market driven competitive process.
Targeted capacity payment	A central level authority pays particular technologies or new capacities a predetermined price
Decentralised obligation	Load serving entities are obligated to procure the capacity they need, individually. Suppliers will either tender or negotiate contracts with capacity providers in this scenario.
Capacity payment	A centrally determined capacity price is paid to all the capacity providers in the market. The price is determined on the basis of estimated required capacity.
Administrative reserve scarcity pricing	A dynamic type of capacity payment, it offers an adder to wholesale prices, reflecting the combined demand for energy and reserves and the resulting marginal value of an additional unit of supply during periods of reserve scarcity.

A suitable capacity mechanism will need to take into account the country specific nature of the market failures described in the preceding section. Keppler notes,

> "In matters of capacity remuneration, there is thus no one design fits all countries or situations. A mechanism for France needing large amounts of additional capacity for less than 200 hours a year will differ from Germany, which especially in the South needs to keep existing capacity designed for up to 2 000 hours per year on stand-by, or from the United Kingdom, which urgently needs large amounts of new baseload capacity (Keppler, 2014)."

Designing a capacity remuneration mechanism for a country like India would be a challenge for it is dependent on other criteria, such as the target to be achieved, the

demand curve, eligibility of technologies amongst others. The introduction of a capacity obligation or capacity markets should be preceded by a transparent discussion on the methodologies and parameters that are used to develop the elements of market design. These parameters are discussed in the sections that follow. The remuneration mechanisms and parameters relied upon in other countries or jurisdictions have been summarised in Table A.

4.2 Resource adequacy

Setting a target for system availability follows the decision to introduce a capacity remuneration mechanism. A rigorous adequacy assessment measured against a well-defined economic reliability standard is necessary for identifying risks to the security of supply and for determining the necessary size of any capacity mechanism. This will in turn substantially reduce the risk of over-procurement and help to limit the distortions of competition that capacity mechanisms create. This is the capacity requirement for the system and in some jurisdictions like the Pennsylvania-New Jersey-Maryland Interconnection (PJM), it is derived from three parameters. These include (Aagaard & Kleit, 2022a):

- Annual peak load forecast, which estimates peak electricity demand in a time period where the capacity is due to be delivered;
- Reserve margin, which is an assessment of the amount of capacity above the peak load forecast which is needed to provide the level of reliability desired by the system;
- Resource outage rate which suggests that some capacity will not be able to contribute.

The level of reliability is measured by a metric called the loss of load expectation (LOLE), which reflects the expected frequency of outages when the supply falls short of demand. The system can set a high level of reliability, for example the United States has set the LOLE at one outage in ten years. This indicates a very high reliability goal.

The capacity requirement and errors in forecasting could lead to under- or over-investment of capacity. Aagaard and Kleit (2022a) compared forecasted and actual demand for PJM and ISO New England for 2009 to 2018 and found that forecasts were biased upwards. This could lead to overbuilding capacity and increased costs

for consumers. One way to account for this is to reduce the forecast windows, while accounting for planning and construction timelines of different technologies (Batlle et al., 2014). Determining the period is a crucial first step before introducing capacity markets alongside establishing detailed methodologies for forecasting and setting the LOLE.

The Indian framework for resource adequacy is outlined in Annexure D. Resource adequacy planning in India is anchored in the Guidelines issued by the Ministry of Power, in June 2023. This combined with the mandate under the Grid Code has made it obligatory on each state to have a framework for resource adequacy. Currently, 20 states have notified these frameworks, while the rest are in consultation stages. (Ministry of New and Renewable Energy, 2025) Broadly, the notified frameworks of all the states impose a binding obligation on distribution licensees to make resource adequacy plans. Given how recent these plans are, it is clear that discoms are just beginning to consider resource planning. However, the reliability metrics prescribed by the Guidelines need to be modified to make them more suitable for the renewable energy rich system of the future (Singh & Chitnis, 2024).

4.3 Demand curve

Capacity markets clear at the intersection of the demand and supply curves, which determines the quantum of capacity procured and the market-clearing price. The supply curve is drawn by stacking the sell bids from generators, lowest to highest, and is not directly controlled by the system operator. The demand curve thus becomes an important design element that determines market outcomes.

When the system operator sets a fixed capacity requirement (say Q^*) that is to be procured from the market, the demand curve becomes a vertical line $Q^d = Q^*$ independent of the price. However, the inelasticity in this case could lead to high price volatilities (Li et al., 2024), and so system operators often impose a price cap on the vertical demand curve (Aagaard & Kleit, 2022a). This price cap is typically equal to the value of lost load, which is an estimate of the amount consumers are willing to pay to avoid supply interruptions during blackouts (Cramton & Ockenfels, 2012).

There are various challenges in constructing the demand curve. A vertical curve does not reflect the fact that the marginal benefits of an additional MW of capacity on grid

reliability decrease as the quantity increases. This is better reflected in a downward-sloping demand curve, which also reduces price volatilities (Li et al., 2024). Additionally, this system demand curve is not a simple aggregation of individual demand curves of buyers. Grid reliability is a public good which entails that benefits accrue to all entities. This leads to the problem of individual buyers undervaluing grid reliability compared to the socially optimal level. The demand curve is thus administratively determined. However, system operators may have incomplete information regarding the marginal reliability benefits of additional capacity, and construct the curve based on three parameters: i) a capacity requirement based on forecasted peak load demand, reserve margin and accounts for outages of existing capacity, ii) the net CONE and iii) a slope determined by the desired price elasticity (Aagaard & Kleit, 2022b). The staff paper notes that the demand curve would be set up based on net CONE, but greater clarity is needed on how the slope of the curve would be determined and the methodology that would guide its design.

4.4 Net CONE

The net cost of new entry (CONE) is another important determinant of the demand curve as it acts as a vertical anchor, pinning the demand curve to the point that passes through (Q^*, Net CONE). The Net CONE is also used to determine the price cap, often as a multiple of it (Bublitz et al., 2019). Arriving at the Net CONE however involves several judgments and assumptions, starting from the assumption of a hypothetical reference resource for which the CONE is estimated, and then considering project-level factors, the annual fixed and operating costs, discounting factors, and the potential revenue generation from energy and ancillary services markets (Aagaard & Kleit, 2022a) For instance, given that different technologies have different entry costs, net CONE is based on a reference technology, often a gas-fired peaking plant, but others argue one should use a mix of technologies rather than a single one (Jenkin et al., 2016). Moreover, the estimates are determined for a future date when the plant would be commissioned, which depends on the auction period, as well as involving various kinds of forecasting. Moreover, estimating annual revenues from energy and ancillary markets would depend on future energy and ancillary market prices, heat rate of the resource, and assumptions on how often the plant would be dispatched (Aagaard & Kleit, 2022a). This makes estimating net CONE a complex exercise: Aagaard and Kleit (2022c) find that net CONE values for PJM have been systematically overesti-

mated from 2010 to 2022, leading to higher prices. Designing a capacity market for India would thus first require identifying an independent entity responsible for estimating the net CONE, alongside establishing the methodologies to be used. This is further complicated by the relatively low liquidity of India's existing wholesale energy market, and the fact that a significant share of ancillary services procurement happens outside a competitive market framework (see Section 3.2). Other jurisdictions conduct consultations for deciding on the calculation of net CONE (SEM Committee, 2023).

4.5 Eligible technologies

Capacity markets when they were introduced favoured conventional generation given the firm and despatchable nature of their power. Given that the Indian energy mix would incline towards high share of variable energy resources, capacity mechanisms need to factor in incentives for flexibility. Storage technologies can contribute to the reliability of the system during short supply.

Additionally, new market participants should be encouraged to participate in the remuneration mechanism depending on their capacity accreditation and be exposed to the same incentives as other generation technologies. In this context, consumption can also be incentivised to respond to price signals. This would factor demand response and can shift demand during peak hours (IRENA, 2019). Demand response has been experimented with in the forward capacity markets at PJM (IRENA, 2019). Demand response should be included in the coverage of options because it constitutes a potential alternative to building new generation capacity and works on the understanding that during times of generation scarcity there are consumers who might be willing to reduce their demand in return for financial compensation (Apostolopoulou & Poudineh, 2024).

It would be important to ensure that the market design for capacity is not unduly privileging the requirements of conventional technologies and large generating stations. The needs of storage technologies and demand response should be factored in from the inception.

Another important question to resolve is whether capacity remuneration should co-exist with support and subsidy given to renewable technologies.

4.6 Market power

Compared to other markets, electricity capacity markets are more vulnerable to exercise of market power wherein some participants can manipulate market prices away from competitively efficient levels. This stems from relative inelasticity of both demand and supply in capacity markets. In fact, Aagaard and Kleit (2022a) show that even when the Herfindahl-Hirschman index (HHI), a commonly used measure of market concentration, does not indicate concentration, the nature of capacity markets could lead to uncompetitive behaviour and gaming.

For instance, in case of a vertical demand curve at a required capacity of say 110 MW, we have fifty sellers each of 2 MW, and one seller with 20 MW. If the 20 MW seller restricts 11 MW from the market, it would drive up the price all the way to the maximum at which the vertical curve is capped. Abuse of market power here implies that a generator can withhold capacity, and if that drives up the price, it could sell reduced capacity at higher price and earn more even after sacrificing part of its capacity. There could also be instances of tacit collusion wherein firms restrict output rather than competing, thereby increasing prices (Aagaard & Kleit, 2022a).

If traditional methods like HHI are unable to indicate market concentration, other measures involve pivotal supplier test which tests if one generator or multiple-generators together have the capacity necessary to meet market demand, for instance the 20 MW generator in the above example. This has been adopted by PJM where the Independent Market Monitor has to submit reports on whether entities pass the pivotal supplier test by analysing whether any group of three together have the ability to meet market demand and thereby become pivotal: in the auction for the delivery year 2021-22, all resources failed the test and price caps were imposed. On the other hand, as per the New York ISO, any firm that is necessary to clear the market are deemed pivotal (Aagaard & Kleit, 2022a). It is worth noting that the determination of an entity as pivotal depends on the available capacity, wherein the chances of failing the pivotal test increase during periods of scarcity (Cramton & Ockenfels, 2012). For instance, New England ISO's internal market monitor conducts one-firm pivotal test for all supply bidders, and in 2019-2020, lack of capacity had deemed all entities as failing the test, but number of pivotal firms fell over the years as capacity increased. (Aagaard & Kleit, 2022a).

The next step following detection involves setting a price cap to ensure anticompetitive behaviour is not occurring, alongside measures to expand capacity supply, increase demand response and encourage long-term contracts (Aagaard & Kleit, 2022a). Another possible way may be in the design of the demand curve wherein it is allowed to be more elastic near the target requirement (Cramton & Ockenfels, 2012). Reducing the ability of generators to misuse market power should also be a key consideration while designing India's capacity markets.

5 Recommendations

Recommendations

5.1 Near term

Enhance the ancillary services market by transitioning away from mandatory procurement of PRAS. PRAS should be added as a new service procured through the market.

Carry out a study exploring the reasons for the disuse of market based mechanism for TRAS. The reform of the reserves market should be based on the results on the study.

5.2 Long term

A capacity remuneration mechanism will be of complementary value and can correct the inefficiencies in the current long term framework of procurement of capacity in India. However, the need for its introduction is not immediately apparent from the staff paper and needs to be justified on strong empirical evidence and careful consideration of parameters.

The concerns with the market design elements have been outlined above in Section 4. Before the introduction of the market, there should be clear evidence presented on resource adequacy, and the objectives that are sought by the introduction of the market.

It is useful to pay attention to the rules and regulations of countries which specify the disclosure and transparency requirements regarding setting up of parameters

which will drive the auction/obligation process (Government of United Kingdom, 2015).

The capacity remuneration mechanism should ensure that parameters and concerns related to the design elements discussed in Section 4 are publicly and periodically deliberated. Table A in the annexures presents the approaches used in other jurisdictions.

A International experience: Design parameters

Jurisdiction	CRM	Net CONE	Resource adequacy	Demand Curve
United Kingdom	Central buyer auctions	Net-CONE defined as the cost of a new entrant after accounting for wholesale and ancillary market revenues and requires (1) *reference technology*; i.e. the likely new entrant technology of choice, and (2) *capital*, operating and other appropriate costs of this technology and its expected operating performance	Amount of capacity to target through the Capacity Market is made each year on the basis of evidence and an accompanying recommendation provided by National Grid, scrutinised	Auction parameters determining the shape of the demand curve (price cap, price-taker thresholds, target capacity tolerances), are set with reference to the level of net-CONE
California	Decentralised obligation	No Net CONE, but a levelised going-forward fixed cost which includes insurance, ad-valorem taxes, fixed operations and maintenance costs for a reference plant is used as a soft-cap on prices (California ISO, 2023)	California Public Utilities Commission gives load service entities year-ahead RA obligations (CPUC, 2025)	NA (because bilateral contracting)
PJM	Central buyer	Net CONE based on levelised capital recovery dependent on capital costs, levelisation method, length of project development, taxes, and annualised operating and maintenance costs dependent on size and trajectory of fixed operating costs (Newell et al., 2025)	Three years in advance (PJM Interconnection, 2025)	Downward sloping demand curve anchored to Net CONE

Jurisdiction	CRM	Net CONE	Resource adequacy	Demand Curve
Ireland	Central auction	Based on capital investment and annual fixed costs of the selected reference technology	Capacity requirement is also expressed in terms of de-rated MWs. The requirement is calculated using the same approved methodology and takes account of a wide range of future demand scenarios, generator reliability and renewable energy output	Demand Curve set by the Regulatory Authorities, which has been adjusted accordingly for reserves, non-participating capacity and capacity to be procured in future auctions

B International experience: Accounting and settlement

Parameter	Ireland CRM Single Electricity Market	US PJM RPM Reliability Pricing Model	GB Capacity Market Electricity Market Reform
Introduced	Current CRM under SEM framework	2007 (replaced short-term model)	2014 (EMR programme)
Auction Types	T-4 (bulk procurement) and T-1 (top-up) held four and one year(s) prior to the capacity year respectively	Base Residual Auction (BRA) held 3 years ahead; Incremental Auctions (IAs) allow position adjustments up to delivery year	T-4 (bulk, ≈95% of capacity) and T-1 (top-up based on revised demand forecasts)

Parameter	**Ireland CRM** Single Electricity Market	**US PJM RPM** Reliability Pricing Model	**GB Capacity Market** Electricity Market Reform
Auction Format	Pay-as-clear; bids stacked lowest to highest against a decremental demand curve set by the NRA	Pay-as-clear; bids stacked ascending against the Variable Resource Requirement (VRR) curve	Descending-clock; auctioneer lowers price each round until aggregate supply equals demanded volume
Capacity Metric	De-rated MW (MWd); price in €/MWd or £/MWd	Unforced Capacity (UCAP); nameplate adjusted downward by each unit's forced outage rate	De-rated MW; technology-specific de-rating factors applied; payments scaled accordingly
Penalties for Non-delivery	If a capacity provider does not run during high system stress (high MRP), it still owes the Difference Charge but earns no energy revenue, creating a double financial penalty that incentivises dispatch when most needed	Non-Performance Charge based on MW shortfall × Net CONE rate ($2,013/MW-h in 2026/27)	Under-delivery penalty (capped at 100% of annual capacity revenues)

Parameter	**Ireland CRM** Single Electricity Market	**US PJM RPM** Reliability Pricing Model	**GB Capacity Market** Electricity Market Reform
Price Caps	**APC** = 1.5× Net CONE **ECPC** = 0.5× Net CONE (existing units) **USPC** available for new capacity with proven high going-forward costs	Maximum bid = 1.5× Net CONE Net CONE = first-year revenue required by a new peaking unit, net of energy & ancillary revenues	**Auction Price Cap** = 1.0× Net CONE Demand curve anchored to Net CONE of a reference peaking plant; no bids above this level permitted

C CERC proposal: Options for capacity obligation

Parameter	Option 1	Option 2	Option 3
Design	Decentralised auction	Decentralised auction	Central auction
Bid structure	Single-part, capacity charge only	Two-part, capacity charge and variable energy charge	Single-part, capacity charge only
Demand curve basis	Net-CONE, drawn by discom	Not explicitly Net-CONE; total cost bid	Net-CONE, drawn by central agency
Price discovery	Pay-as-cleared at intersection of supply and demand curves	Pay-as-cleared; MCP determined in energy market	Pay-as-cleared at intersection of supply and demand curves
Contract duration	15 years	15 years	10–15 years
Scheduling rights	Discom has no scheduling rights	Discom retains scheduling rights until DAM window opens; dispatch thereafter through market	Buyers have no scheduling rights

Energy market dispatch	Both discom and generator bid independently into DAM/RTM	Both bid into DAM/RTM; discom's bid for contracted volume set above price cap to guarantee supply	Both generator and buying entity bid into DAM/RTM
Energy cost settlement	Discom pays MCP in energy market; no bilateral adjustment	MCP paid through market; difference between MCP and contracted total cost settled bilaterally outside market (Contract for Difference)	Buying entity pays MCP in energy market; no bilateral adjustment
Free-rider protection	Discom's demand curve drawn slightly above price cap to secure contracted volume in energy market	Discom's demand curve set above price cap; CfD settlement prevents windfall for generator	Market dispatch and price-taker rule serve as primary disciplines
Stress-hour obligation	Generator must bid as price taker during NLDC-notified peak/stress hours	Generator must bid as price taker during NLDC-notified peak/stress hours	Generator must bid as price taker during NLDC-notified peak/stress hours
Non-performance penalty	1.5× discovered capacity charge	1.5× discovered capacity charge	1.5× discovered capacity charge

D Resource Adequacy Planning in India

D.1 National Level

In 2023, the Guidelines for Resource Adequacy Planning Framework for India were issued the MoP and MNRE to provide a uniform approach for advance planning and procurement of adequate power resources across the country.

D.2 Obligations under RA Guidelines 2023

A. Demand Forecasting Distribution licensees must estimate demand across long-term, medium-term, and short-term horizons, using various forecasting methods (trend, time series, econometric, etc.), and include detailed daily load curves. State Transmission Utilities consolidate licensee forecasts for state-wide demand estimations.

B. Planning Reserve Margin and RAR: As per the recommendations in the Resource Adequacy Guidelines and the IEGC, all discoms need to calculate their Planning Reserve Margin on the basis of LOLP and NENS. Once, the PRM has been computed by the DISCOM and approved by the commission, it is used to find out the Resource Adequacy Requirement.

$$\text{RAR} = \text{Coincident Peak Contribution} \times (1 + \text{PRM})$$

Example: So if a DISCOM's share of the national peak is 5,000 MW and the PRM is 15%, its RAR is 5,750 MW. That is the total capacity it must have contracted at any given time.

$$\text{RAR} = 5{,}000 \text{ MW} \times (1 + 0.15) = 5{,}750 \text{ MW}$$

C. Contracting of adequate capacity: Under the guidelines, at least 75-80% of RAR must be covered by long-term contracts, 10-20% by medium-term contracts, and the remainder by short-term bilateral contracts.

D.3 State Level

The obligation to have a state level resource adequacy framework, while originally recommended under the previously mentioned guidelines, has been legally mandated under the Indian Electricity Grid Code 2023 on all SERCs and JERC.

According to the latest ministry data, 20 States have notified their final State Resource Adequacy (SRA) Frameworks through their respective State Electricity Regulatory Commissions (SERCs),while 4 States have issued draft frameworks for stakeholder consultation. The rest of the States are in the process of initiating notification of their SRA Frameworks. All Union Territories have published their Resource Adequacy Planning documents through the respective Joint Electricity Regulatory Commissions (JERCs). (Ministry of New and Renewable Energy, 2025)

SERC regulations have transcribed the obligations under the IEGC into binding state-level law. However, as the IEGC does not mandate the exact methodology of compu-

tation of the PRM, RAR and the share of capacity contracts, states have used both the Central guidelines and the FoR recommendations for guidance.

For example, the Madhya Pradesh Electricity Regulatory Commission's RA regulations specify that MPPMCL shall keep the share of long-term contracts in the range of 75–80% of the Resource Adequacy Requirement and medium-term contracts in the range of 10–20%, with the rest through short-term contracts, and that power procurement through the Day-Ahead Market shall not be considered towards contribution for meeting the RAR. (MPERC, 2023)

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