**Comments of The Energy and Resources Institute on the CERC Discussion Paper: "Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India"**

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## Introduction and general observations

The issue of electricity market reform and design is of crucial importance to the objectives of the Indian power sector, namely the provision of affordable, reliable and sustainable electricity. The growth of cheap renewables requires the consideration of reforming power markets, but there are many benefits of such reforms beyond the grid integration of renewables.

The Commission's discussion paper is to be commended for highlighting several important issues with regard to the current framework for scheduling and dispatch, and proposing an ambitious way forward. TERI is supportive of the general thrust of the discussion paper.

This being said, TERI is of the view that the transition to a market based economic dispatch (MBED) is a highly complex issue, and should be conducted in successive steps and learnings from experience.

## Objectives of the Reform

The objectives of the reform should be clearly stated. TERI believes that the objectives of such a reform could be summarized as follows:

- Lower power procurement costs by ensuring optimal dispatch of a larger pool of generating stations based on marginal costs.
- Increase the transparency and clarity of price formation, and allow better locational and temporal market signals to be created, to inform decisions both on system operation and investment, including in transmission.
- Facilitate the grid integration of variable renewables through stronger price signals for desirable system and generator characteristics such as flexibility.
- Facilitate grid integration of renewables through the creation of larger balancing areas for scheduled imbalances between RE supply and demand

## Implementing Market Based Mechanisms in The Context of Imperfect Markets & Institutional Capacities

While the benefits of market based economic dispatch are clear in theory and through simulation, consideration needs to be given to the implementation of such mechanisms in the context of a developing country still building its institutional and market-related capacities. These issues include:

- Upstream distortions regarding coal availability and supply.
- Downstream distortions regarding retail pricing, cross-subsidy and imperfect price pass through.
- Planning process for cross-border transmission capacity, and absent planning processes for mid-term capacity additions taking into account the potentials for cross-border resource optimisation.
- Political economy distortions related e.g. to the financial position of discoms or the desire of state political agent to retain control over a strategically important sector.
- Lack of institutional capacities among market players, e.g. discoms.

- Large computational and market monitoring capacity of the system operator, to solve the daily economically optimal dispatch and monitor the market

Certainly, greater market-based prices can help to provide signals to resolve such distortions. But the functioning of the market and its ability to provide appropriate signals may also be affected. In addition, it is likely that the transition to market based economic dispatch would have an impact on the asset value of plants, to the extent that current dispatch deviates from the market discovered optimum. The political economy of this asset revaluation needs to be studied and understood, in order to bring stakeholders on board and analyse any system implications of this transition.

**Settlement and Counter Party Risk**

A major issue in the power sector to date is the issue of counter party risk given revenue recovery and liquidity issues faced by DISCOMS. Currently this is managed through bilateral contracting, which can in some cases favour certain actors over others (such as state-owned plants). The settlement arrangements for the market do not seem clear from the discussion paper:

- "The buyers will be supplied electricity as per their load and the generators will get dispatched in merit order up to the point where the total system load is met; and the contracts would be settled bilaterally." (p. 26)
- "All the buyers will pay to the market operator at MCP for the day-ahead demand". (p. 27)

The nature of the settlement arrangement should be clear, and consideration should be given to its implication for who bears counterparty risk. Throughout the rest of the text it appears to be the proposal that pay-in/pay-out pooled system would be used, in which case the Market Operator bears counterparty risk. The reference to bilateral settlement appears to pertain to the bilateral compensation mechanism, but clarity should be given in this regard.

**Impacts of the Proposed Compensation Mechanism on Market Incentives and Behaviour**

The Commission proposes a mechanism to compensate for any differences between the market clearing price and the contracted price (PPA price). In the context of non-optimising agents facing e.g. liquidity constraints, what incentives would the bilateral compensation mechanism create for agents to deviate from the theoretical market optimum behaviour (bidding on marginal costs)? For example, if a DISCOM has a contracted capacity with a high variable cost, why not bid strategically at low variable cost and withhold the due compensation payment for 6 months in order to improve the liquidity position, assuming that the DISCOM were confident that its bid would be satisfied? Or consider the example of a generator with high variable costs: why not bid low to ensure schedule, and then rely on the bilateral settlement mechanism to ensure the bids are financially viable, assuming that the generator were confident that its bid would be satisfied? These examples are hypothetical, and somewhat facile, but the point holds from experience: electricity markets provide ample avenue for manipulation, and proposed compensation mechanism, by increasing complexity, would likely multiply opportunities for such behaviour.

A second issue that needs to be considered is whether the shift to MBED would justify the continuation of the variable cost terms of PPAs. Such a contractual structure was appropriate when coal contracting and delivery were also considered to be conducted on a largely bilateral long-term contract basis, mirroring the structure of PPAs. However, under a MBED dispatch schedule would significantly change (indeed, this is the promise of its purported efficiency gains: it must change dispatch significantly to realise these gains), and therefore the process for coal allocation and delivery would also have to evolve. The delivery of coal would have to evolve to an "as needed basis", rather than "as contracted" basis, and this change in delivery patterns would likely have impacts on the costs of supply for each plant. In the future, therefore, it would likely be desirable that coal pricing and allocation be done on a more market-driven basis. Given that variable costs is supposed to be a pure cost passthrough mechanism, with RoI delivered through fixed cost component, what is the rationale for retaining bilateral variable cost contract components under the proposed MBED. The risks this poses in terms of manipulation and dampening of the price signal for optimal coal pricing, allocation and delivery need to be considered.

Finally, there is likely to be objections from DISCOMS that retain the burden of fulfilling fixed price contracts, but no longer benefit, under the MNED, from the offtake of the capacity thus acquired. This issue needs to be given careful consideration in the context of an environment of growing demand which will, before very long, create the need for new investment. If capacity continues to be procured out of market (see below), what is the incentive for DISCOMS to procure new capacity? Why not continue to procure energy in the wholesale market, given that that market doesn't internalize capital costs, and freeride on the procurement of others? In theory, capital costs could be amortized for existing and new investment, in a market based on variable costs, *provided that inframarginal rents are large enough.* However, it can be questioned whether this would be the situation in Indian wholesale markets, where the variable cost supply curve is fairly flat, and the missing money problem exacerbated by the unwillingness / incapacity of DISCOMS to pay high marginal prices for the last units of supply required, where load shedding is still an option.

**Impacts on Investment**

The history of liberalized electricity markets shows that they have tended to function well in environments with large quantities of dispatchable capacities and relatively stagnant investment / demand. Here marginal cost, market-based dispatch has helped to optimize dispatch. There is less evidence, however, that liberalized wholesale markets have helped to generate new investments (see recent numbers from the IEA on the share of new generation investments under a regulated model). India, however, is a dynamic demand country, and will likely require new investments. For zero marginal cost technologies, one could expect the current model of long-term auction-based contracts to continue. In the case of dispatchable capacities and flexibility options (e.g. storage), it may be unlikely that the wholesale market, in the short- to mid-term, would provide sufficient price signals for investment. This is particularly the case in India where the supply curve in the market is fairly flat being dominated by coal, and where load shedding still imposes an implicit price cap. In the current exchange-based day-ahead market, the trough to peak averages about 1 Rs/kWh, while the average inframarginal rent across all time blocks would be less. If one considers that the fixed cost of a new coal plant is in the order of 1.7 Rs/kWh (levelized as normative PLF of 85%, for a plant operating at part load it would be more); whereas the fixed cost of battery storage operating as energy arbitrage is in the order of 25 Rs/kWh,[1] then its becomes clear that in the foreseeable future the market alone can provide signals, but not an investment case, for the kinds of investments that the Indian system may require in the future. In this case, out-of-market options may be required in order to attract the right investment. These could include capacity auctions for different kinds of desirable capacities based on e.g. flexibility characteristics.

But there needs to be a deeper analysis of the interlinkages between energy only markets, and capacity markets, and India's requirements in respect of both.

[1] Assuming discounted capital costs and lifetime discounted fixed costs are amortized only over discounted lifetime kWh of energy shifted, and not other system services.

**Transition Pathways to Market Reform**

TERI is supportive of the thrust of the proposed transition to a market-based day ahead dispatch. However, in view of the ambitious scope of the reform and the state of readiness, TERI believes it would be advisable to outline a transition pathway consisting of smaller manageable steps. Such a pathway could consist of the following kinds of steps (initial thoughts from TERI, subject to further analysis, they are presented here to illustrate the principle of a transition pathway rather than what its ultimate constituents should be):

- Further study and simulation of the potential implications and barriers of implementation.
- Further efforts to increase transparency and availability of data regarding dispatch and scheduling practices.
- Interim steps to deepen the existing day ahead market, including through:
  - facilitating market based open access,
  - discouraging the signature of new PPAs for capacities without PPAs and rather encouraging their participation in the existing exchanges to deepen the market,
  - ensuring un-requisitioned capacities can participate in the wholesale market, if necessary through benefit sharing and policy intervention regarding interpretation of existing PPAs
- Enforcement of gate-closure even as part of the current self-scheduling arrangements
- Use of pilot projects with willing DISCOMS, in addition to the pilot on security constrained economic dispatch of central plants.
- Exploration of a European style approach of development of state-level markets and progressively coupling these with regional / the national market
- Overarching narrative and framework for the desired mid-term (2025-2030) market design and the role and interactions of its various components.

As a closing note, TERI would like to note that it welcomes and appreciates the efforts of CERC to advance policy on electricity markets in India, and stands ready to continue to contribute to this important policy agenda.