Comments and Suggestions on MoP Discussion Paper MBED

Prayas (Energy Group) *30th June 2021*

Summary of comments

Ministry of Power released a discussion paper on Market Based Economic Dispatch (MBED) seeking public comments[1]. Ensuring economic dispatch of capacity at the national level can result in savings when compared to current scheduling practices but the savings with the proposed framework need to be evaluated with potential impacts, risks and implementation issues. The existing proposal, to be initiated in a phase-wise manner over the next couple of years will have significant techno-economic, contractual, legal and policy implications on the sector. The discussion draft circulated by the Ministry of Powers raises more questions than it answers and fundamentals of the proposals are not detailed adequately. For example, there is lack of clarity on

— DISCOMs self- scheduling in the MBED mechanism,
— whether MBED will be combined with existing DAM or operate as a separate market,
— bidding strategies for inflexible demand of DISCOMs as well as for must-run capacity,
— whether BCS settlements would be provided by the DISCOMs to the generators in some cases.

Additionally, some of the concerns raised by stakeholders before the CERC during the consultation process for their staff paper on MBED[2] have also not been addressed/ detailed. For example,

— the demand for transparent sharing of data, assumptions and detailed results from studies used to estimate benefits from MBED,
— articulation and detailing of the price and volume risk due to technical minimum, start/stops transmission constraints,
— need for market monitoring mechanisms and detailing of potential regulatory, contract and policy changes to implement MBED.

Considering all this, adoption of the MBED, even in the first phase, must be based on evaluation of the benefits after considering implementation issues as well as legal/ contractual risks. For example,

— **Impact on working capital of DISCOMs due to delay in BCS payments in generators in MBED. Presently there is an absence of mechanisms to prevent delays in settlement of BCS claims by DISCOMs**, especially in cases where MCP is much higher than the contracted VC (as is likely in case of inflexible/ fixed demand)
— **If BCS settlements are provided by DISCOMs to thermal generators who bid less than VC and clear in MBED, the risks undertaken during bidding by the generators are hedged by the DISCOMs. This protection could result in risky bidding strategies. This should be avoided by explicitly clarifying that BCS settlements by DISCOMs to generators will not be provided.**

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[1] https://powermin.gov.in/sites/default/files/webform/notices/Seeking_comments_on_Discussion_Paper_on_Market_Based_Economic_Dispatch_MBED.pdf

[2] https://cercind.gov.in/2018/draft_reg/DP31.pdf

— Possibility of litigations due to lack of clarity on which entity pays for PLF incentives, fuel price variation etc. post MBED,
— Implications of MBED participation with the implementation of the 2019 LC order by the MoP,
— Without market coupling, possibility of MBED participation if there is no agreement among multiple beneficiaries on which exchange to participate in.
— Treatment of short-term contracts under MBED

While considering the proposal, it must also be kept in mind that with the associated risks and costs, future capacity addition of coal-based capacity will be muted. Future demand growth (driven by economic growth and end-use electrification trends) and increasing viability of storage would also reduce the extent of 'surplus capacity'/ 'backed down' capacity contracted by DISCOMs[3]. As more contracted capacity gets scheduled with increase in demand, the savings from MBED will reduce over time. The MBED proposal and required changes should also be evaluated in this context over time.

The current proposal suggests a cautious, phase-wise implementation and its evaluation before large-scale rollout. While we support phase-wise implementation, it is not clear if a pilot with the NTPC block of generators will bring to light the gamut of potential issues that can arise with the scheme design. Ideally, issues related to contract, BCS, scheduling and fuel availability related issues can only be evaluated with participation from state-owned and private generating company participation as well. This was also highlighted during SCED implementation as private capacity implementation challenges were different from NTPC stations[4].

To evaluate risks and benefits, it is suggested that multiple pilots with the aim of economic dispatch at the national level be tried out to evaluate the best design, suited to ground realities. Some of these could include:

— Implementation of MBED at a regional level (say western region) for a period of 2 months with incentives provided for DISCOMs to participate on a voluntary basis.
— Compulsorily requiring sale of URS power in the DAM if power not scheduled by DISCOMs.
— Expanding the scope of SCED by mandating it for all generators contracted by DISCOMs and implementing look ahead and unit commitment for a three day ahead demand forecast by SLDC.

Of course, for all these initiatives the DISCOMs should agree to suspend their right to recall during the period of operation of the mechanism and can be incentivised to do so. Such approaches will help better understanding of various risks and to develop appropriate mitigation mechanisms.

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[3] Many states which have existing 'surplus' contracted capacity (such as Maharashtra, Gujarat, Chhattisgarh) have already committed to no net capacity addition of coal based generating stations.

[4] Jhabua power, an IPP is a participant under SCED and has PPAs with Kerala utilities and MP utilities. The terms for heat rate compensation, accounting of fixed and variable costs vary between the two PPAs. With MBED approach, a mechanism would be required to manage BCS settlement and scheduling for the plant based on different PPA provisions. This is because a weighted average variable charge as in SCED cannot be used in such cases with BCS. For more details, please see: http://posoco.in/wp-content/uploads/2021/04/POSOCO_SCED_Expanded_Pilot_Detailed_Feedback_Report_Mar_2021.pdf

Detailed comments

PEG's detailed comments and suggestions below focus on estimated savings from MBED, possible risks faced by participants and sector agencies, and implementation challenges which need to be addressed before Phase 1 of MBED in launched.

Areas where further clarity and steps are needed to mitigate risk

1 Operationalisation of BCS

1.1 BCS and Self-Scheduling

As per Page 6 of the paper, DISCOMs can continue to self-schedule under MBED as long as both DISCOMs and generators mandatorily participate in the DAM segment. The paper also mentions that BCS would be carried out taking into account the self-scheduled quantum. **It is not clear whether generators which have not been scheduled by the DISCOM would be able to avail BCS or not.** This should be clarified and should ideally be restricted to generators scheduled by the DISCOMs alone. This would help resolve some of the contractual issues and risks in MBED.

1.2 Must-run bidding strategies and BCS

The current proposal, for Phase 1, is designed with thermal generators and two-part tariffs in mind. However, there will be participation of must-run capacity as well under MBED going forward. As must run plants have single part tariffs, it is not clear how the variable cost for must run plants will be determined for BCS.

— Would variable cost for all must run capacity be set at 0 avoiding the need for BCS?
— As must-run capacity has to be scheduled, it is likely that the generator's bidding strategy would be to bid as low as possible to clear the market. In such a case, how will BCS settlement take place if Tariff> MCP as illustrated in Table 1? In such case, would the DISCOMs pay BCS to the generator?

Table 1: Bidding strategies and BCS for must run capacity

Particulars	Rs. /kWh
Tariff	3
Buyer Bid	3
Seller bid	0
MCP	2.5
BCS (MCP- VC)	(-)0.5

1.3 BCS for thermal generators

As generators are expected to bid based on self-determined ECR, there could be scenarios where the generator bids less than variable cost for certain periods. For example, it is likely that thermal generators given technical constraints such as technical minimum, ramp rate and start/stops may decide to bid lower than VC in some time blocks to ensure adequate quantum is cleared in all time blocks to meet technical constraints. Currently in DAM, these risks are part of the bidding strategies of the generators. These risks might be more challenging to mitigate in a market with greater liquidity.

However, it is also likely that generators bid lower than variable cost with the anticipation of clearing and generating at higher PLFs. If BCS is provided by the DISCOMs to thermal generators in this case, it implies that the risks undertaken during bidding by the generators are hedged by the DISCOMs, as illustrated in the example in Table 2.

Table 2: Risk with BCS payments to generators

Particulars (Rs. /kWh)	Generator bids below VC and DISCOM bids at VC
Variable cost for generator as per PPA	3
Seller Bid	1.5
Buyer bid	3
MCP	3
If BCS payments by DISCOMs to generators is permitted	Generator will get full schedule. However, entire risk and BCS for generation to be borne by contracting DISCOM.

It must be explicitly clarified that thermal generator who bid less than their variable cost and clear in the DAM would not be provided any BCS by the DISCOMs.

Other measures would be needed to address the technical constraints of generators, without which the savings from MBED would reduce significantly and generators would be unable to operate efficiently under MBED.

1.4 Operationalisation of BCS with Market Splitting

The bilateral contract settlement is supposed to take place outside the exchange between the contracted generator and the DISCOM. With congestion in particular areas, market splitting would be required for MBED transactions. In such cases, as the area clearing price would be different from the market clearing price, having bilateral contract settlements at the market clearing price would also not compensate the parties for actual payment as illustrated in Table 3. In such a case, would the congestion revenue collected by the power exchange be utilized for BCS settlements as well? The mechanism to compensate parties in case of congestion is not clear. This should be clarified before the launch of the scheme.

Table 3: Illustrative example for market splitting in MBED

Scenario 2	DAM	
Particulars (Rs. /unit)	**Buyer 1**	**Seller 1**
Market Clearing Price (MCP)	5	
Variable cost	3	
BCS (MCP-VC)	2	
Area Clearing Price (ACP)	6	4
Congestion revenue (ACP-MCP)	**1**	
	Buyer pays higher than MCP but receives BCS at MCP	**Seller receives payment less than MCP but has to pay BCS at MCP**

1.5 Short-term contracts on MBED

There is also lack of clarity on treatment of short-term contracts (< 1 year) which have single part tariffs, in the MBED mechanism. It is not clear if the single part tariff be treated as a variable cost with no fixed cost obligations. If the treatment is such, then it would be difficult to adjust BCS payments through fixed cost adjustments for this capacity as envisaged in the proposal and jurisdictional issues with SEBI for BCS could arise. An alternate mechanism should be detailed for such capacity even for Phase 1, especially if NTPC capacity is being traded with DISCOMs on the DEEP portal.

2 Delay in payments and impact on working capital

In the first phase, provision of 45 days line of credit would help mitigate challenges with delay in payments to some extent. However, if payments to PFC and REC are delayed, the working capital borrowing and interest build up would be significant for DISCOMs. This is especially the case if BCS payments are not made by generators to DISCOMs in time. If DISCOMs are bidding high rates for inflexible bids, the MCP and consequently the BCS payments to be made would be substantial. In some cases, it could be higher than the fixed cost payments themselves.

The present proposal has no provision to address the risk faced by DISCOMs due to delayed payment in BCS. Specific terms and conditions would be required to ensure that BCS settlements are cleared within a stipulated period (say, 3- 5 days) from the transaction. Letter of credit should be provided to DISCOMs by the generators to guarantee timely payments. This would require a separate enforceable agreement with stipulated penalties for non-compliance between the procurer and the contracted generators for BCS.

3 Inflexible bids

Page 6 of the document specifies that the DISCOMs may chose to submit 'Fixed Demand' in each block, which has to be served. This demand is price inelastic. To specify a price inelastic fixed demand in any block, it is not clear if:

- The DISCOM specifies the bid at the highest price (say, Rs. 20/unit) in order to ensure the bid clears *or*
- The DISCOMs specifies quantum without specifying price such that the fixed quantum is traded at the MCP discovered with inflexible bids alone.

This is critical to market operations and price shifts and should be clarified in the paper.

4 Implementation of LC order

As per Para 6 of the 28th June 2019 order of the Ministry of Power on Letter of Credit (LC)[5], LDCs are to ensure that DISCOMs have no access to power exchanges and are not granted STOA unless LC is opened for the appropriate quantum. With MBED, majority of the transactions will take place via STOA on the power exchanges. Without adequate LC being provided for any of the contracted capacity, it would mean that MBED participation would not be possible. In such a case, can the DISCOMs continue to schedule contracted power directly? If so, the savings from MBED would reduce. Alternatively, if DISCOMs lose right to contracted capacity due to non-participation in MBED, there could be potential legal and contractual issues. This risk needs to be mitigated by providing clarity.

[5]https://powermin.gov.in/sites/default/files/webform/notices/Opening_and_maintanig_of%20adequate_Letter_of_Credit_as_Payment_Security_Mechanism_under_Power_Purchase_Agreements.pdf.

5 Operations of the power exchanges

Several aspects of the operations of power exchanges are unclear in the existing proposal.

For one, it is not clear if **MBED will operate as a separate contract or will be combined with the existing day-ahead market**. As this would have significant impacts on other participants of the existing DAM, it should be clarified. If all MBED trades take place on the existing DAM, open access consumers would have to pay at MCP without a BCS hedge. If inflexible bids raise the MCP significantly, this would subject such consumers to price risks.

Further as all generators clear at MCP, it is also likely that a merchant plant without BCS arrangements would clear at MCP. In such a case, DISCOMs, would have to pay at MCP without the guarantee of BCS for power. As most power exchange trades take place on the DAM, it is important to ensure availability of other contracts and instruments for open access consumers to trade on. Further it is crucial to protect DISCOMs from such price risks.

Secondly, it is not clear if **Minimum Quantity Block Bid and Profile Bids** will be applicable on MBED bids. Further if **G-DAM** is introduced, it is not clear if RE capacity scheduled by the DISCOM will be cleared first under G-DAM and the rest will be cleared on DAM.

Another related concern is whether **changes are required in the existing DAM algorithm** to operationalise MBED, especially with flexible/ inflexible bids, scheduling must-run generators.

Mechanism for **changing the margins and contribution to the settlement guarantee fund** with increased transaction volume with MBED is also unclear.

6 Choice of power exchange in the absence of coupling

In order to operationalise MBED in the absence of coupling, the paper suggests that procurers and generators, mutually agree to submit bids on one power exchange. This is to ensure that both parties are subject to the same MCP to operationalise BCS. In case of multiple beneficiaries, it is not clear what would occur if the generator and any DISCOM do not agree to participate in the same exchange. Would the present arrangement under self-scheduling be allowed to continue? Without the DISCOM's guarantee to provide BCS, the generator also may not be willing to bid in MBED. The mechanism to ensure consensus in such cases would be necessary especially given preferences of multiple beneficiaries.

7 Self-determined energy charges and variable cost

Page 6 of the document states that:

'Generators shall be required to offer their capacities in the DAM based on self-determined ECR with no adjustments for retrospective revisions in fuel and other charges.'

As DISCOMs are self-scheduling these generators, it should be clarified whether:

— along with provision of BCS, any adjustment in retrospective revisions in fuel and other charges for the scheduled capacity will be settled by the contracting DISCOM by increasing the variable charge to that extent.

— such settlements would include PLF incentives, fuel price variation charges, compensation due to heat rate degradation for the sale of power to other entities under MBED which could be applicable on a retrospective basis.

Page 11 of the document mentions that the BCS settlement would be based on the difference between the contract price and MCP. Presumably, this refers to variable charges. As BCS settlements would need to take place on a regular basis and variable charges can change on a month to month basis, there should be clarity on the variable charge considered for settlement. The document should clearly state whether it would be based on variable charges as per tariff orders or as mutually agreed between the buyer and the seller reflective of revision in costs (as in the case of SCED).

8 Price risks, planning and need for improved market monitoring

In order to participate effectively in MBED, DISCOMs whose business has been defined by long term power procurement contracts, would have to bid for power on a daily basis and would need to trade in RTM in case they are unable to meet flexible demand under MBED. This would entail DISCOMs significantly improving and depending on their capacity as traders to operate under MBED. DISCOMs would also need to anticipate bidding strategies of generators to ensure clearing at the margin.

Even with overall system benefits under MBED, gains from the scheme for specific DISCOMs would depend on existing PPAs, loading of fixed and variable cost payments and efficiency of contracted generators. Such varied benefits would also have impacts on medium term capacity addition and infrastructure planning.

As mentioned earlier price risks for open access consumers and DISCOMs will also be possible in some scenarios with wider participation in DAM. These concerns need to be addressed and mitigation strategies detailed before rollout of Phase 1.

As the proposed mechanism is new and would entail significant scaling up of the DAM segment on the power exchange, **it is important to track price trends and volatility across exchanges, URS trades post MBED, BCS payment dues, pending dues with PFC/ REC due to MBED line of credit, congestion management, difference between VC and MCP for all scheduled generators etc**.

Participating DISCOMs, generators and POSOCO can be mandated to provide such critical information on a **quarterly basis which should be published by CERC** (the regulatory authority for power exchanges).

Further, MoP/ CERC can also **constitute a market monitoring committee** with representation from POSOCO, power exchanges, ERCs, DISCOMs, generators etc., which can highlight critical areas requiring attention and suggest action.

The recommendations of the market monitoring committee as well as the data provided by DISCOMs and generators should be available in the **public domain in consumer interest.**

9 Amendments in regulations, contracts and policies required

The paper provides a broad overview of the mechanism for MBED without details of implementation. To ensure consensus building, clarity in implementation and reduced litigation, it is imperative along with the paper, the Ministry also share:

- **Amendments necessary in state and central regulations for MBED implementation**: This would include specific changes in *tariff regulations, grid code, open access regulations, sharing of Inter-state transmission charges and* losses, power market regulations, transmission pricing, grant of connectivity and GNA, MBED market monitoring etc.
- **Contractual and regulatory clarity** on treatment of retrospective costs, stipulation and payment of incentives and penalties, role of power exchanges, obligations of generators, contracting DISCOMs and beneficiaries of power under MBED.
- **Provisions in supplementary PPA** between generator and DISCOM to operationalise MBED

Need for more analysis on potential benefits from MBED

As significant efforts from central and state sector actors are required for MBED, it is important that the assessment of potential benefits is analytically rigorous, representative and reflective of present operations. It is also important that the assumptions and methodology used for assessment of benefits is transparently shared with all stakeholders to aid deliberation. In the present proposal, without sharing adequate data and assumptions, it is challenging for stakeholders to assess benefits from the scheme based on the implementation changes, risks and costs involved. Some of these issues are discussed below:

1 Evidence required to make a case for MBED

The rationale for MBED in the paper is based on a nation-wide analysis to show that costlier units are committed while cheaper units are not fully scheduled. However, data has not been provided to detail the extent (in MW or MU terms) for such displacement at the national level.

Further, the paper details that there have been instances of violation of MoD by utilities but no details have been provided for this, especially from recent years. This is relevant especially if MoD violation had taken place due to transmission constraints or other technical reasons, which cannot be avoided even with MBED.

Additionally, the paper highlights that VRE deployment over a larger balancing area would provide flexibility and enable sharing of reserves. However, data or evidence for the extent of such benefits have not been detailed in the paper.

2 Benefits assessment from studies

The paper mentions the CERC study of 5 states in FY17 which estimates benefits of Rs. 6220 crores from MBED. The data and detailed assumptions used for this study are not shared. As per the CERC staff paper, the benefits from the year-long assessment for 5 states does not account for unit-tripping, forced outages, transmission network overloading/ constraints. Further the analysis uses declared capacity which may not be available at certain times and would affect savings. The benefits need to be evaluated based on these constraints. The Detailed Feedback Report on the SCED pilot in March 2021 notes that:

'With the optimal fuel supply arrangements and rationalization of coal stock, the spread of variable charges is reducing pan-India. The reduction of spread of variable charges appears to be one of the causes for lowering of SCED savings in 2020 vis-a-vis 2019.'

As FY17 was a year where many states were reeling under coal shortages, it is likely that the savings will be less today for these states where critical challenges with coal shortages have been addressed.

In addition to this, MoP ran a simulation exercise for 5 representative days to assess benefits from MBED. Based on assessment of NTPC capacity, the savings with MBED is assumed to be 4% of energy cost. When extended to all generators in the country, this translates to Rs. 12,295 crores. Unlike the CERC study, the estimation is based on 5 days in a year (FY21) with COVID-related lockdowns. To estimate benefits, ideally the simulation should have run for a 1 year period in a recent year. The savings assessment from NTPC stations alone is extended to the whole country on a linear basis. However, the savings may not materialize on a linear basis as the generators and their performance vary. The paper also notes that unit commitment would increase the savings from 4% to 12-15%. It is not clear if the simulation with 4% savings was only with committed generators (like in the case of SCED) and 12-15% savings was assuming entire scheduled generation fleet. The assumptions and changes made in scenarios with and without unit commitment should be clarified.

The benefits from the recent 5 day study was depicted in the paper as benefits due to system cost optimisation and additional revenue from sale of URS power. Under the current MBED mechanism, it is not clear how the two are differentiated. If URS power implies sale of power which is unscheduled it is unclear as to how that would account for 40-50% of benefits as depicted in Figure in page 9 of the paper.

To ensure consensus building, it is suggested that simulation studies be run for multiple years with a wider sample of generators with different assumptions and along with sensitivity analysis (especially on variable costs) to assess extent of benefits.

As savings would reduce with technical constraints (accounting for technical minimum, ramp rate, start/stops etc.), market splitting, the simulation studies should estimate impact of such reduction to give a sense of variation in potential savings. Further, if MBED transactions take place in multiple exchanges, fragmentation of the market and having multiple MCPs will also reduce savings.

3 Right to revise analysis and assumptions

As participant DISCOMs forgo their right to revise schedules, the paper outlines a study in August 2020 for slot-wise scheduling for Maharashtra and Gujarat to indicate that DISCOMs have a tendency to overschedule and thus forgoing right to recall would not subject DISCOMs to significant risks. However, this study is not representative and does not inspire confidence. The study was conducted for Maharashtra and Gujarat, states which have been having sustained surplus capacity and negligible shortages for the past five years, especially in the monsoon month of August, when demand is low. Further, the study was conducted in a low-demand month when both states were facing covid-19 related lockdown restrictions. The analysis should be presented for states such as Karnataka, Uttar Pradesh, Tamil Nadu, Bihar and Punjab for at least a year covering periods with peak demand as well. This would have helped determine and understand whether DISCOMs overschedule and the role of right to recall better.

4 Lessons from international experience

The paper should have also included international experience on voluntary versus mandatory participation in power exchanges, role of price signals in energy only markets, size of spot markets and measures to protect from price and volume risks, transmission and scheduling challenges along with the proposal. This would have helped understand critical issues, implementation risks and mitigation strategies better.

Conclusion

The changes proposed in the paper are fundamental changes with significant ramifications on sector operations. Thus, they need to be implemented cautiously and would require time for consensus building and implementation. The proposal outlined in the paper needs further analysis before launch of Phase 1, especially to ensure:

— Estimation of potential savings based on multiple studies
— Assessment of potential risks to DISCOMs, Generators and grid users
— Detailing of mechanisms to address potential risks
— Analysis of legal and institutional changes needed to operationalise mechanism and implications of the same, particularly in the context of:
    - Amendments to existing regulations and power procurement contracts
    - Role and powers of power exchanges, LDCs and market monitoring institutions
    - Capacity which needs to be built within DISCOMs, ERCs, LDCs, transmission companies and state owned generators to ensure effective market functioning

Along with these efforts it is also critical to ensure initiatives to rationalize coal costs and capacity addition, integrate RE in a cost-optimal manner based on DISCOMs requirements, broaden and deepen market to provide price certainty to open access and captive consumers are given adequate attention.

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