No. 23/16/2020-R&R
Government of India
Ministry of Power

Shram Shakti Bhawan, Rafi Marg,
New Delhi, 01st June, 2021

To,

1. Secretary, MNRE, New Delhi
2. The Chairperson, Central Electricity Authority, Sewa Bhavan, R.K. Puram, New Delhi
3. The Secretary, Central Electricity Regulatory Commission (CERC), Janpath, New Delhi
4. Principal Secretaries/Secretaries (Power/Energy) of all State Governments/UTs
5. Secretaries of All State Electricity Regulatory Commissions/JERCs.
6. Chairman/CMDs of all PSUs under administrative control of Ministry of Power
7. CMD, SECI, New Delhi
8. CMDs/MDs of Discoms/Gencos of all State Governments
9. CMD, IEX LTD New Delhi & MD/CEO, PXIL , Mumbai
10. DG, Association of Power Producers, New Delhi.
11. President, FICCI, House No. 1, Tansen Marg New Delhi
12. President, CII, New Delhi
13. President, PHDCCI, New Delhi
14. ASSOCHAM, Chanakyapuri, New Delhi
15. Member, PRAYAS Energy Group, Pune
16. DG, Electric Power Transmission Association (EPTA), New Delhi
17. Chairman Indian Wind Power Association, New Delhi
18. Chairman, Indian Wind Turbine Manufacturers Association, New Delhi
19. Director General, National Solar Energy Federation of India (NSEFI), New Delhi.
20. Registrar, APTEL, New Delhi.

Subject: Seeking comments on Discussion Paper on Market Based Economic Dispatch(MBED) -Reg

Sir/Madam,

I am directed to forward herewith the Discussion Paper on Market Based Economic Dispatch (MBED), with the request to provide your comments, if any, to this Ministry by 30-06-2021. The comments may be emailed at debranjan.chattopadhyay@nic.in.

2. This issues with the approval of Competent Authority.

Encl: as above

Yours faithfully

1/6/2021

(Ghanshyam Prasad)
Joint Secretary to the Govt. of India
Ph: 011-2371 0389

Copy for information to: PS to Hon'ble MOSP, Sr. PPS to Secy.(P), Sr. PPS to JS(R&R) MOP

Copy to: Technical Director, NIC Cell for uploading on MOP's website under "Current Notices " with the heading of "**Discussion Paper on Market Based Economic Dispatch(MBED)**"

Development of Power Market in India

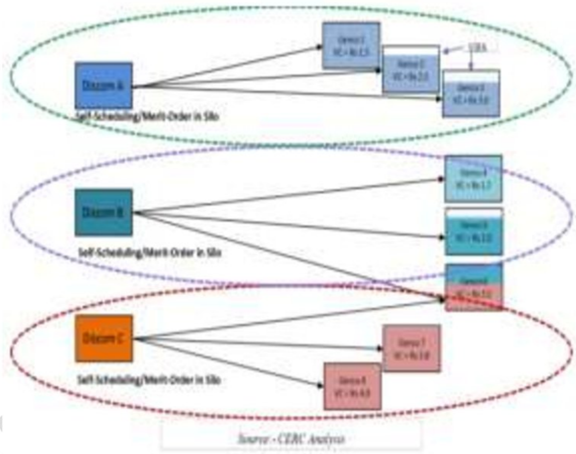
Phase 1: Implementation of Market based economic dispatch (MBED)

May 2021

Contents

Section 1: Rationale for Market based economic dispatch in day ahead

Distribution companies (Discoms) in India currently schedule generation on a day-ahead basis from amongst their portfolio of contracted generators. This practice is referred to as self-scheduling and is a sub-optimal outcome for the power system in the country, with relatively higher costs being borne by Discoms and consumers. Following are the key issues in the extant mechanism:



- A Discom goes by only its contracted portfolio **without visibility of possible lower cost generation** in other States being still under-utilized / available
- All India analysis shows that the country very often ends up committing and utilizing **costlier generation** plants while cheaper generation plants are not fully scheduled / utilized
- Instances of states violating the **merit order** even within their own contracted portfolio of generators is commonly noticed
- There is an **absence of uniform price for procurement of power** across the country, despite having one unified and integrated grid. Representations from States have been received to have one price of power ie ONE NATION ONE PRICE as we already have ONE NATION, ONE GRID, ONE FREQUENCY. This was also deliberated in the Standing committee of Energy.
- An inflexible aspect of self-scheduling within state control areas is **the inability to share reserves** across states leading to technical constraints in the extent of variable renewable energy (VRE) a state can deploy within its boundaries. A centralized, market-based scheduling and dispatch will ensure enlarging the balancing area from the state boundaries to regional / national boundaries and bringing in the desired flexibility for reliably deploying much higher levels of VRE.

These constraints were analysed and highlighted in CERC's Discussion Paper on Market Based Economic Dispatch published in December 2018, which proposed a re-design of the day-ahead scheduling and operation of the electricity markets in India.

Need for market-based / integrated dispatch in day ahead horizon

India has attained the status of **'One Nation, One Grid, One Frequency'** and there are hardly any constraints today in the inter-regional transfer of electricity. The true benefit of physical integration is realisable only when India transits to a national merit-order and a country-wide balancing area instead of the siloed self-scheduling and balancing mechanisms currently followed. It is also possible to move towards a **"One Nation, One Grid, One frequency, *One Price*"** framework by adoption of a market based economic dispatch, which will lead to discovery of uniform clearing prices in the day-ahead market. It is a desirable next step in India's transition to an integrated national framework for electricity and will help individual states and retail consumers to benefit from integrated operations and sharing of each other's resources.

Several jurisdictions worldwide have embraced and realized the benefits of a centralized / integrated scheduling & dispatch framework. A study[1] carried out by CAISO and PacifiCorp of a centralized Energy

[1] https://www.caiso.com/documents/pacificorp-isoenergyimbalancemarketbenefits.pdf

Imbalance market i.e. an intra-day market which utilizes security constrained economic dispatch of generation to meet load across a wider geographic region highlights the following key advantages.

- Reduction in wind and solar generation variability due to geographic diversity inherent across a wide area
- Better generation-load balancing through sharing of reserves
- Substantial yearly production cost savings (in excess of $ 300 million)
- Reduction in requirement for flexible reserves

Countries in UK and the EU region have historically adopted de-centralized scheduling and dispatch. However, there too the emphasis has been on cross-border integration, primarily to derive benefits of reserves sharing across the EU region through larger balancing areas. As per this target electricity model[2], the benefits to be realized upon successful EU wide integration are around €2.5bn to €4bn per year. About 58%-66% of these benefits have already been achieved due to the level of integration in large electricity markets of north-western Europe and the Nordic region. The EU region's primary initiative of integrating electricity markets has been based on two broad principles viz.

- Energy only regional markets where generator revenues depend on price of marginal unit of energy supplied, and,
- Integration of electricity markets and discovering single day-ahead prices for each area / country

It is in this backdrop that a Market Based Economic Dispatch (MBED) framework was proposed in a Discussion Paper released by the Central Electricity Regulatory Commission in December 2018, with substantial system cost savings, which would benefit end consumers. The key advantages of MBED for key stakeholders can be highlighted as below:

Particulars	Benefits
Discoms	• Dispatch optimization through MBED framework increases utilization of low-cost generators while reducing and backing down in certain cases, the expensive generators. • Additional revenue received from market by cheaper generating stations would be shared with Discoms • Discoms and consumers benefit as the overall procurement cost reduces
Generators	• Mechanism inherently promotes cheaper and efficient plants • Pit head stations runs to its full capacity. Less requirement of coal movement and thus saving in the coal transportation cost. Decongestion of railway traffic. • Generators, who sell their URS power, will earn additional revenues (to the extent of cap, as decided suitably by the Commission) through this mechanism
Others	• Demand for reserves (Ancillary Services) could be assessed suitably • Mechanism would lead to enhanced RE integration due to enlargement of balancing area from state to national level. This will lead to reduced RE curtailment. As more RE gets added in the portfolio, overall system cost and power procurement cost reduces. Enhanced RE also leads to reduced dependence on imported fuel and increase in energy security of the country • Improved discipline would be achieved in merit-order based scheduling and transparency of system marginal price • The proposed mechanism would be a key step in enabling uniform clearing price for procurement of power and transitioning towards the concept of **"One Nation, One Grid, One Price"**

The proposed MBED mechanism would be a key step in enabling uniform clearing price for procurement of electricity and transitioning towards a **"One Nation, One Grid, One Price"** phenomenon. It also paves the way for the wider market reforms like introduction of co-optimization of Ancillary Services with energy, capacity market and increased RE integration.

MBED is a fundamental redesign of the electricity market and requires significant changes to operations, infrastructure and systems for market participants and enabling agencies such as the power exchanges and POSOCO. It thus calls for a consensual approach amongst the key stakeholders with due regards to time required for preparatory actions. The Central Electricity Regulatory Commission is empowered under

https://www.nrel.gov/docs/fy13osti/57115.pdf

[2] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/05/The-EU-Target-Model-for-electricity-markets-fit-for-purpose.pdf

Report for Directorate-General Energy European Commission by Booz & Company, revised July 2013

Section 66 of the Electricity Act, 2003 to promote electricity market development in the country through appropriate regulations.

Ministry of Power shall support this initiative in joining efforts with CERC in driving consensus amongst key stakeholders, providing enabling policy framework where required, and in addressing any administrative roadblocks to implementation of MBED in the country.

This paper, based on inputs from key stakeholders on the subject, outlines a phased introduction of MBED with Phase 1 involving only the thermal fleet of NTPC to test the efficacy of the MBED mechanism, identify deficiencies or potential issues that need to be addressed prior to a nation-wide rollout, familiarize all key stakeholders with the framework and allow for necessary infrastructure and systems to be built out and tested before scale up. The Ministry of Power intends to hold wider consultations now with all states to arrive at a consensual way forward on implementing Phase 1 of MBED from 1st April 2022.

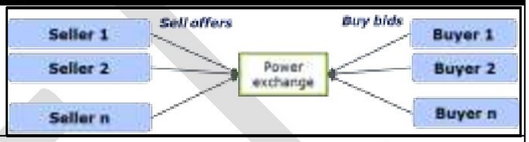
Section 2: Overview and proposed mechanism for implementation of MBED

Background

In December 2018, the staff of CERC issued a Discussion Paper (DP) on Market Based Economic Dispatch (MBED), proposing redesign of the Day-ahead Market (DAM) in India highlighting the advantages and benefits of the same. Subsequently, the Commission received several comments and suggestions from various stakeholders which have been deliberated and analysed in detail. It was recognized that the implementation of full-fledged MBED (with State, Central and Private power generators) requires several policy, regulatory and operational changes in the existing practice of power procurement. Further, there is a need for amendments to various regulations. A key feedback from stakeholders was to implement MBED in a phased-wise manner starting with a limited set of generators to restrict the commercial exposure of Discoms and to gain experience prior to a full-fledged implementation.

Salient features of MBED as per CERC's Discussion Paper

The proposed Market Based Economic Dispatch (MBED) is expected to function on a day-ahead time horizon and enable scheduling and dispatch of all generation on economic principles, subject to plant and network constraints. Following are the salient features of the MBED mechanism in day-ahead horizon:-

<table>
<tr><th>Details</th><th>Particulars</th></tr>
<tr><td>Pooling of buy / sell bids</td><td>
• Sellers and buyers submit their offers and bids on a day ahead basis
• Offers and bids (quantum and price) are pooled


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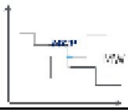
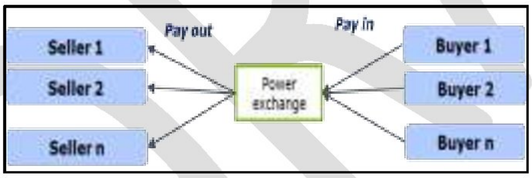
<tr><td>Price discovery, scheduling & dispatch</td><td>
• National merit order stack is prepared
• Market Clearing Price (MCP) is discovered as per common merit order for each time block of upcoming day

</td></tr>
<tr><td>Payments and settlement</td><td>
• Cleared buyers would pay MCP to the Power exchange which will in turn pay the MCP to the cleared sellers
• Final settlement would be as per contract for the portion of demand cleared in relation to contracted MW. Gains realized due to URS sale will be shared with beneficiaries as stipulated by the Commission
• The buyers would still continue to pay the fixed costs outside the market.


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Security Constrained Economic Dispatch and key differences with MBED

An extension of the MBED concept is the Security Constrained Economic Dispatch (SCED), which was implemented by POSOCO from April, 2019 with a smaller set of generators to begin with. SCED optimizes the production cost of electricity from primarily Inter-State Generating Stations (ISGS) stations (and other participating IPPs and state generating companies) after final schedules are prepared and post gate-closure in the Real Time Market (RTM). The implementation of the SCED has been extended till September, 2021 by the CERC. The primary means of optimisation is re-arranging the dispatch of scheduled generators in a merit order, such that the generators with lower operating cost are booked to the full before generators with higher operating costs are dispatched, subject to technical constraints.

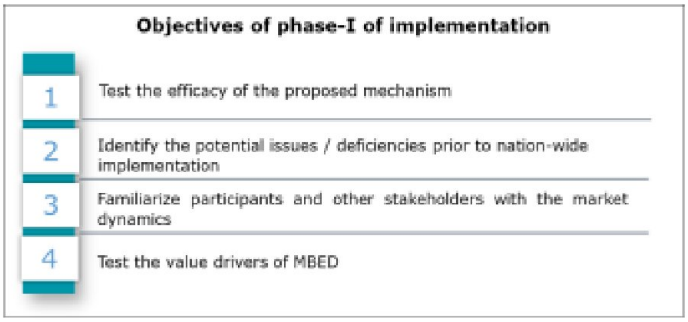
The scope of SCED covers system cost optimisation only after final schedules are prepared and units are committed (based on schedules received on day-ahead basis from entitled Discoms). The framework does not alter the commitment of generating units on a day-ahead basis and thus costlier generators once committed, continue to be operated and cannot be backed down below their technical minimums (e.g., below 55% of rated capacity for ISGS thermal units). On the other hand, the proposed MBED mechanism shall schedule and commit generation on the day-ahead time-frame, purely on economic principles subject to technical constraints. This will lead to further optimisation, as marginal generating units which are committed currently may not be scheduled at all under MBED, leading to additional system cost savings. An illustration of additional optimization possible when we transit from SCED to MBED is highlighted in ***Annexure 1***.

Additionally, MBED proposes a market-based mechanism, which will lead to discovery of uniform system-wide marginal prices, essential for encouraging market-based generation capacity additions in the future.

Parameter	SCED	Proposed MBED mechanism
Time frame and mode of operation	Undertaken after right to revision of schedule of ISGS ends and final schedules are prepared **Mode- Administered by POSOCO**	Proposed to be undertaken once day-ahead schedules are provided by Discoms and post which generating stations offer their capacities into the market. **Mode- Market based**
Objective	Ensures system cost optimization for the portion of demand contracted from ISGS & other participating regulated generators by the following measures: • Optimize schedules and generation from the list of committed generators (generators on bar and having schedules), subject to ramp and technical minimum constraints • The optimization kicks in only after the final schedules are prepared (after RTM)	Ensures system cost optimization by the following measures: • Optimizes schedules and dispatch from all stations through market based dispatch principles • Doesn't ensure unit commitment and hence costlier plants may not get cleared • Market-based, uniform system marginal prices under MBED will establish the basis for market-based generation capacity additions in the future

Proposed Phase 1 of MBED Implementation

Recognising the significant changes in operating environment for both Generators and Discoms under MBED, a phased approach has been proposed by stakeholders to implement MBED. Accordingly, it is proposed that implementation of MBED shall start with the fleet of NTPC thermal stations (Phase -I) from 1 April 2022. This will also help participants, power exchanges and regulators, gain experience from the process and keep disruptions at minimum, while also limiting the commercial exposure of Discoms.



Key changes for introduction of MBED Phase 1

To implement the first phase of MBED i.e. for NTPC thermal stations only, following are the key changes / modifications envisaged to the existing practice of power procurement and scheduling:

S No.	Existing mechanism of procurement of power and scheduling	Changes due to MBED implementation
Scheduling mechanism		
1.	The Discoms self-schedule the NTPC generators based on their entitlements and access the Power Exchanges for the balance of their energy requirements	Discoms can still self-schedule the generators, however both Discoms and the generators have to mandatorily participate in the Day-ahead market segment of Power exchanges for bidding. Bilateral contract settlement would be carried out taking into account the quantum of power which is self-scheduled
2.	NTPC generators are scheduled by Discoms / LDCs based on their declared capabilities and states' requirements.	Generators shall submit offers and shall be cleared based on the total demand bid into the day-ahead market Once the bids and offers are received, the market clearing engine will seek to optimize the dispatch of generation sources taking technical constraints into account.
3.	Discoms do not have visibility of cheaper options outside the states and hence several low-cost generation capacities remain partially or sub-optimally utilized. Discoms tend to run costlier generation capacity at its technical minimum in off peak period even at the cost of backing down of cheaper generation	The entire demand from NTPC stations shall be met by dispatching the least-cost generation mix while ensuring that security of the grid is maintained. Cheaper NTPC plants shall be dispatched to the maximum extent whereas costlier plants will run optimally as required.
Actions by buyers, sellers & Power exchange		
4.	Generators are scheduled based on the merit order which considers variable charges as determined by the Commission under section-62 of the Act.	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. National merit order shall be formed and all generators would be subsequently dispatched.
5.	Discoms / SLDC communicate the dispatch schedule to RLDCs for their contracted generators.	Discoms / buyers shall be required to submit bids for all the time-blocks of the upcoming day. Discoms may choose to submit 'Fixed Demand' in each Block, which is price inelastic and "has to be served". Further, Flexible Demand by the Discom, over and above the 'Fixed demand' in each block will be price sensitive.
6.	Generators declare their capabilities for next day to RLDCs which then communicates entitlements to SLDCs. SLDCs review their requirements and communicate drawal schedule to RLDCs.	Buyers and sellers, based on their mutual preference, shall submit bids and offers on a particular Power exchange.

S No.	Existing mechanism of procurement of power and scheduling	Changes due to MBED implementation
	RLDCs compute the corresponding dispatch schedule for the Generators.	
7.	Self-scheduling of generators by Discoms often leads to sub-optimal merit order stack for scheduling and despatch. True marginal cost of the system doesn't get discovered	Once the bids and offers are received, the market clearing engine of the Power exchanges will schedule the generating stations following optimal despatch principles. Market Clearing Prices shall be discovered for each 15 min time block of the upcoming day.
Schedule revisions		
8.	As per extant practice, both the generator and the Discom can revise their schedule 7/8 time blocks prior to delivery without any financial liability.	Right to Revision (RTR) for the complete fleet of NTPC plants shall cease to exist for the period until the results of DAM are announced, and such RTR will be reinstated in respect of the quantum not cleared in the DAM from those candidate plants. Further, if there is any need for beneficiaries to buy / sell additional power closer to real-time, they can participate in the Real Time market (RTM) and correct their day-ahead positions suitably.
Payment and settlement		
9.	Discoms pay the variable charges to scheduled generators based on the quantum of energy scheduled.	Discoms / buyers will pay to the market operator at MCP for the day-ahead demand. Similarly, all the generators will be paid at the MCP according to execution of their selected bids. Buyers, under LT contracts, will be refunded the difference between the market clearing price and the contracted price as per the quantum of power self-scheduled through the Bilateral Contract Settlement (BCS)
10.	NTPC generators who have a long-term contract are paid the fixed cost separately outside the market	NTPC generators who have a long-term contract will continue to be paid the fixed cost separately outside the market
11.	URS power of NTPC generators can be availed by a Discom which is not the original beneficiary of the generators. Such beneficiaries can meet demand through this URS after exhausting their share of contracted power in such ISGS. The fixed cost liability to the extent of URS scheduled by such beneficiaries would rest with them and not on original beneficiaries.	NTPC generators can sell the URS power in the market. Net revenue earned by NTPC generators by selling their URS power will be shared with concerned beneficiaries in the ratio of 50:50 subject to a ceiling of 7p/kWh to the generator and balance to the concerned beneficiary.

Section 3: Benefits estimation of proposed mechanism

Benefits of MBED mechanism

The CERC staff, in the discussion paper on MBED, carried out the benefits modelling for 5 states viz. (Andhra Pradesh, Telangana, Maharashtra, Karnataka and Chhattisgarh) for FY 2016-17 based on actual scheduling and dispatch data of State, Central and private generators, obtained on a 15 -minute basis. The benefits demonstration exercise showcased (see below) the following overall benefits of MBED in a day-ahead timeframe.

Net benefits for all the states	All figures in Rs crs		
	Total cost of generation		
	Base case	With Market based economic dispatch	Net benefits
For FY 2016-17	58948	52728	6220

Total benefits to discoms

Net benefits for the state	All figures in Rs crs					
	AP	Chhattisgarh	Maha	Telangana	Karnataka	Total
Total	**708**	**218**	**3391**	**234**	**76**	**4627**
As % of procurement cost	6.0	6.6	11.8	2.7	0.8	7.4

In addition to the above, further modelling was carried out by the Consultants recently to analyse the quantum of benefits, if only NTPC thermal stations were to participate in the Phase I implementation rollout of MBED.

Data used for simulation

Virtual power market runs in DAM and RTM are simulated to analyse the gain/loss situations of all the market participants (Discoms, Gencos). The data used for the analysis include:

- Declared Capacity of NTPC stations and their scheduled generation
- Actual demand, discom-wise, from the NTPC stations
- Variable costs and fixed costs of NTPC stations
- Market participation data – Buy and Sell bid quantum and price

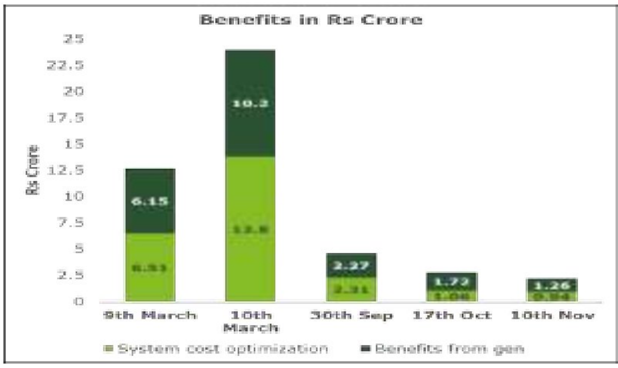
The simulation was run for the following days in the year in 2020:

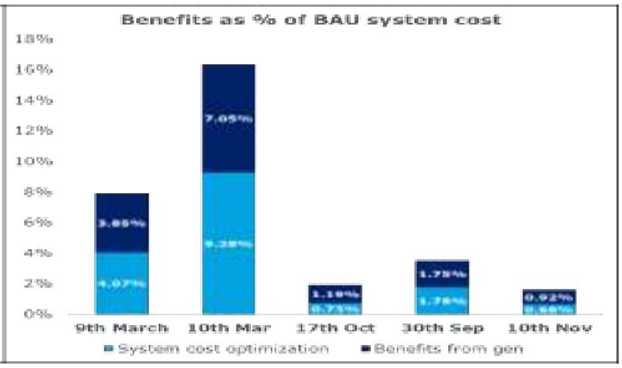
Day	Reason for selection
9th March	For pre-covid day benefits estimation
10th March	Festival day – Holi
30th September	Low demand day
17th October	High demand day
10th November	ISGS demand in between levels observed on 17th October and 30th September

Results and inferences

a. **Overall benefits**

The comparison of benefits on the select days is highlighted as below:





The total benefits for a day were categorised into two components:

- Benefits from system cost optimization due to optimization of dispatch (increase in generation from cheaper resources and reduction in / backing down generation from expensive stations)
- Benefits from generators – Additional revenue from sale of URS power distributed to discoms based on the methodology devised by the commission.

b. <u>Key inferences</u>

- ***On an average, MBED yields ~4% of benefits[3] in power procurement cost. The optimization benefits can be much higher (to the tune of ~12-15%), if unit commitments related benefits are additionally captured in day-ahead.***
- Proposed MBED pilot with all ISGS stations is expected to yield benefits more than ~ INR 5 crores per day for the entitled states (~INR 1825 crores per year reduction in power procurement cost)
- If the entire generation in the country is mandated to participate, total estimated savings could be to the extent of ~ Rs 12,000 crores as shown below:-

Total Energy Generation (2019-2020)	Weighted average price of plants	Average benefits form MBED	Total estimated benefits from MBED
1393 BU	Rs 2.36/kWh	3.74%	12295 Cr

As per the "Feedback Report of SCED pilot" issued by POSOCO, the total reduction in variable cost of generation due to SCED was Rs 1624 Crores during the period from April 2019 – January 2021 i.e. an average of ~ Rs 900 crs per year. There are thus substantial additional optimisation benefits to be harnessed through the implementation of MBED.

[3] 1 Calculated by taking average of benefits simulated for all days except 10th March, as benefits estimated for 10th March is exceptionally high; Benefits are estimated without offering rebates. With rebates, the benefits will go up further.

Section 4: Key issues and suggested mitigation measures

Relinquishment of Right to Revise schedule by Discoms

With the implementation of MBED, the participating Discoms will forego the right to revise schedules of the NTPC thermal stations and as such some Discoms had pointed out that they may face risk of not being able to meet demand through the day ahead market. With the introduction of Real-Time Market, the Discoms have access to an additional avenue to correct their positions, which makes the continuance of Right to revise untenable in the longer term. An analysis was carried out by the Consultants for two representative states (Maharashtra and Gujarat) over two representative months in 2020 (January and August) to understand the impact of right to revise schedules in meeting demand. Based on the analysis, the following inferences could be drawn:

1. There was recall of power (upward revision) for less than ~ 35% of all slots analysed (less than 25% for recall from tied-up ISGS). Recalled quantum of greater than 200 MW occurred for less than 10 % of slots.
2. Downward revisions occurred for more than ~ 60% of the slots (~ 75% of downward revision from tied-up ISGS).
3. It is observed that much larger share of revisions are downward revisions, indicating that the Discoms tend to over schedule on a day ahead basis and then correct their positions closer to real-time. This analysis may have further skewed with the introduction of Real-Time Markets.

Suggested measure: To further minimize the exposure and impact, it is proposed that the Right to Revision (RTR) for NTPC plants shall cease to exist only for the period until the results of DAM are announced and such RTR will be reinstated in respect of the generation quantum not cleared in the DAM from these plants. Discoms shall be able to meet their day-ahead demand reliably by placing price inflexible bids.

Working capital management for Discoms

As per extant practice of payment for the quantum of power procured, a monthly invoice for the aggregated amount of electricity sold to the Discom by the generator in a month gets issued in the first week of the ensuing month and the Discom has 45 days from the invoice date to pay the dues. With the implementation of MBED, it is expected that the entire power tied up with NTPC thermal stations would be transacted on the power exchanges. This would call for upfront payment of margin money by Discoms to the Power exchanges for the quantum of power procured.

It is expected that with the implementation of MBED for full fleet of NTPC thermal stations, following would be the overall funding requirement on a yearly basis.

Average daily energy transacted (MUs)	Weighted average cost of selected plants * (Rs / kWh)	Approximate funding requirement – daily (Rs crs)	Approximate funding requirement – yearly (Rs crs)
650-700	2.14	140-150	51000-55000

**Discoms would be required to pay MCP for each slot and would receive adjustments against fixed charges, so the net cost of power procured will be at the variable / bid cost.*

Suggested measure: To ensure that Discoms are not burdened with such huge upfront payments, a centrally designated agency viz. PFC or REC could provide a line of credit to Discoms who require such working capital. The Discom / borrowers could repay such amount along with interest within a maximum period of 45-60 days from the date of disbursement of each tranche/disbursement. Following are the expected benefits of such a mechanism.

Stakeholder	Benefits
Generators	• Ensures payments to generators as per the rules and bye-laws of the power exchanges
Discom	• Provides the necessary working capital support needed • Provides adequate timeframe for Discoms to repay back the amount to the designated agency
Exchange	• Addresses counterparty risk of exchanges
PFC / REC	• Provides opportunity to increase their loan book size and revenues from power markets

Those Discoms who are financially sound and does not require the help of financial institutions will tend to save more. The generation cost is likely to reduce as there will not be any working capital requirement by the generating company.

Need for Price coupling

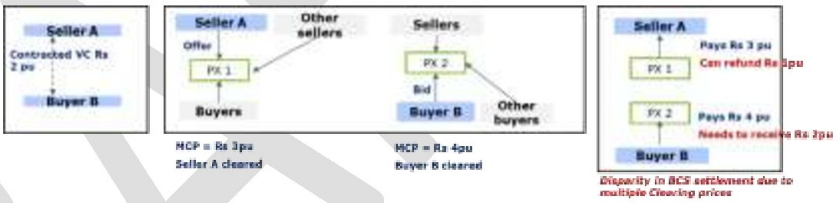
CERC Regulations allow for multiple power exchanges to ensure competition in Day-Ahead markets. Structurally the same can continue. However, for better system efficiency, there would be a need to combine the bids and offers of both the exchanges to arrive at the following outcomes:

1) Discovery of uniform Area clearing prices (instead of multiple ACPs due to multiple power exchanges)
2) Achieving higher social welfare as compared to the sum of maximum social welfare in multiple power exchanges

Following are the key issues which are expected to arise in case a seller and a buyer, who are tied up through LT PPAs, go to separate exchanges without coupling of exchanges being implemented:

1) **One entity gets cleared whereas the other does not**: For instance, say seller A is tied up with buyer B for a variable cost of Rs 3pu. Seller A places an offer in PX 1 and buyer B places an inflexible bid in PX 2. Buyer B gets cleared in PX 2 however, seller A, due to lack of liquidity, does not get cleared in PX 1. In this case, Buyer B pays Rs 4 pu as MCP and is expected to get a refund of Rs 2 pu (MCP-contract price). However, BCS is not possible for Buyer B since its corresponding seller has not been cleared with whom BCS needs to be done. Had there been price coupling which could have allowed Seller A to get cleared in case MCP is more than Rs 3 pu, the BCS mechanism would have been possible and the buyer would have got the refund of Rs 2 pu.

2) **Both entities get cleared at different Clearing prices leading to disparity in BCS settlement**: For instance, say seller A is tied up with buyer B at a variable / energy price of Rs 2 / kWh. Seller A places an offer in PX 1 and buyer B places an inflexible bid in PX 2 for the same quantum. Buyer B gets cleared in PX 2 at a MCP of, say, Rs 4 / kWh however, seller A, gets cleared in PX 1 at a MCP of, say, Rs 3 / kWh.
In this case, Buyer B pays the MCP of Rs 4 / kWh and need to obtain a BCS refund of Rs 2 / kWh (Rs 4/kWh – Rs 2/ kWh). However, the seller has received an MCP of Rs 3 / kWh, i.e. an additional revenue of Rs 1 / kWh only and hence it will not be able to refund back Rs 2 / kWh to the buyer.



Suggested measure: As an interim measure of resolving the above issue, it is suggested that the buyers and corresponding sellers, based on their mutual preference, would need to submit bids and offers on a particular Power exchange. This would ensure that both the parties are subject to the same clearing price and liquidity. However, CERC / MoP is exploring the feasibility of undertaking price coupling and the same could also be implemented in due course of time, as envisaged under the Power Market Regulations, 2021.

Additional relief for upfront payments by Discoms

As per extant mechanism, a 1.5% rebate is provided to the Discoms, if the payment is made to the Gencos within 5 days from the invoice date and 1% rebate if the payment is made with 30 days from the invoice date. Since with the implementation of MBED, Discoms would be paying upfront for the cost of power procurement, they would need to be incentivized by granting additional rebates for such upfront payment.

Suggested measure: It has been analysed that a total rebate of 2% could be offered to Discoms on the payment for the quantum of power procured through exchange. ***Details of the calculations are provided in Annexure 2. An additional analysis (Annexure 5) has been carried out to include the overall benefits of this offered rebate against the additional working capital burden for depositing margin money.***

Treatment of Bilateral Contract settlement

As per the proposed mechanism, the final settlements between generators and Discoms would be executed as per the terms of the contract through the Bilateral Contract Settlement. The Ministry of Power vide order dated 26th October, 2018 had constituted a

committee on "Efficient Regulation of Electricity Derivatives" for resolving the jurisdictional issue between SEBI and CERC with regard to various forms of contracts of electricity and examine the technical, operational and legal framework for electricity derivatives. Accordingly, the Committee has recommended the adjoining terms and conditions (as shown alongside) regarding the regulatory jurisdiction of electricity derivatives products as agreed upon by CERC and SEBI.

Suggested measure: For the pilot with NTPC thermal stations, this could be achieved through a regulatory order outlining the process of adjustment of market-based payments against fixed charges to be paid by the Discoms. An illustration of this mechanism has been reproduced in ***Annexure 3***.

Relaxation/ reduction of transaction charges levied by Power Exchanges

MBED would result in increase in electricity volumes, traded through the power exchanges. The transaction charges, as levied by the power exchanges, is also expected to go up substantially as volume increases. This would put additional pressure on the profitability and working capital requirement of Discoms. Moreover, the current transaction charges levied by Indian Power exchanges is substantially higher than their European counterparts (as highlighted in ***Annexure 4***).

Suggested measure: The below alternatives could be explored and appropriate regulatory interventions could be taken by CERC based on merits and further discussions/ consultations with stakeholders.

Alternatives	Liability of transaction charges for quantum of power self-scheduled	Liability of transaction charges for quantum of power procured above self-scheduled quantum
1	Nil	As per reduced / concessional transaction charges per unit
2	As per reduced / concessional transaction charges per unit	As per reduced / concessional transaction charges per unit

Applicability of transmission charges

Currently, Short Term Open Access (STOA) charges and transmission losses are applicable for trade in the power exchange. The STOA charges get adjusted from the payment received by the generators for their cleared volumes. As MBED would include trade of medium/ long term power through power exchanges, there is a need to relook the existing mechanism of recovery of LT and ST charges. The entities who have long term access should not be liable to pay the ST charges, for the quantum of electricity, contracted under LT access, and traded through power exchanges.

Suggested measure: Payment of LT Charges could be adjusted against the STOA charges paid by the generators, having long term access for their contracted volumes traded in power exchange. As a long-term measure and reforms, CERC has issued the Draft Notification for Grant of Connectivity and **General Network Access** to the inter-State transmission system in November 2017.

Section 5: Way forward

This discussion note is intended to elicit viewpoints and comments from stakeholders on the overall mechanism and key issues perceived to be faced by market participants if MBED were to be implemented for NTPC thermal fleet. Following is the way forward contemplated for the implementation of MBED:

S No.	Activity	Timeline
1.	Receiving comments from stakeholders on the Discussion paper by MoP	May 2021
2.	Analysing stakeholder comments	May 2021
3.	National level workshop on MBED: • Overview and proposed mechanism for phase 1 of implementation • Discussion on key challenges perceived by stakeholders • Devising mitigation mechanism and obtaining suggestions	June 2021
4.	Preparing draft regulations, stakeholder consultations and final regulations by CERC	September 2021
5.	• Formulation of procedures by POSOCO • Operational changes to be effected by Power exchanges • Addressing key issues in implementation	March 2022
6.	Conduct of mock exercise	March 2022
7.	Go-LIVE of phase 1 of MBED	1st April 2022

Annexure 1: Optimization possible on transiting from SCED to MBED

Consider a total demand to be met of 70 MW across four states. Each state is tied up with one generator. All the generators have a Declared Capacity of 25 MW and technical minimum of 10 MW (say). Considering self-scheduling done for a particular slot for each of the four generators, the increase in optimization possible as we move from SCED to MBED is highlighted below:

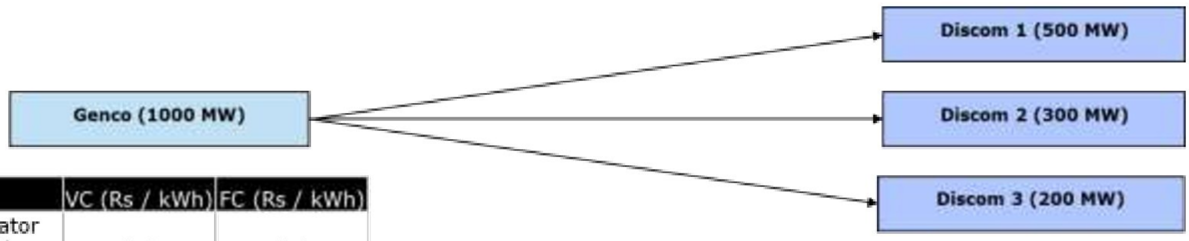
Generators (with variable cost)	**DC (MW)**	**Schedule as per self-scheduling mechanism (MW)**	**Revised schedules as per SCED (MW)**	**Revised schedules as per MBED (MW)**
Gen 1 @ Rs 1 / kWh	25	20	25	25
Gen 2 @ Rs 2 / kWh	25	20	25	25
Gen 3 @ Rs 3 / kWh	25	15	10	20
Gen 4 @ Rs 4 / kWh	25	15	10	-
Total system cost (Rs)		20x1+20x2+20x3+20x4= Rs 200	25x1+25x2+10x3+10x4= Rs 145	25x1+25x2+20x3+0x4= Rs 135

Annexure 2: Illustration of a formulation for Rebate (%)

Power Sale Day	Days from Invoice Date	Additional Rebate (%)	Total Rebate (%)	Proposed Rebate (%)
1	35	0.97%	2.47%	~2% (Avg)
2	34	0.95%	2.45%	
3	33	0.92%	2.42%	
4	32	0.89%	2.39%	
5	31	0.86%	2.36%	
6	30	0.83%	2.33%	
7	29	0.81%	2.31%	
8	28	0.78%	2.28%	
9	27	0.75%	2.25%	
10	26	0.72%	2.22%	
11	25	0.70%	2.20%	
12	24	0.67%	2.17%	
13	23	0.64%	2.14%	
14	22	0.61%	2.11%	
15	21	0.58%	2.08%	
16	20	0.56%	2.06%	
17	19	0.53%	2.03%	
18	18	0.50%	2.00%	
19	17	0.47%	1.97%	
20	16	0.44%	1.94%	
21	15	0.42%	1.92%	
22	14	0.39%	1.89%	
23	13	0.36%	1.86%	
24	12	0.33%	1.83%	
25	11	0.31%	1.81%	
26	10	0.28%	1.78%	
27	9	0.25%	1.75%	
28	8	0.22%	1.72%	
29	7	0.19%	1.69%	
30	6	0.17%	1.67%	

Annexure 3: Adjustment of fixed charges against BCS liability

Consider a generator with a declared capacity of 1000 MW tied up with 3 discoms as shown below (Ratio of 5:3:2)



	VC (Rs / kWh)	FC (Rs / kWh)
Generator details	2.0	1.1

The discoms undertake scheduling of the generator on a day-ahead basis. Assuming the above scheduling profile for a particular slot, following are the payments which would be made to the generator for a particular 15-min time block (as per extant practice of self-scheduling):

Payments to Generator for a particular 15 min time block		Discom 1 (500 * 1000 * 15*2/60)	Discom 2 (300 * 1000 * 15*2/60)	Discom 3 (200 * 1000 * 15*2/60)	Total
Variable cost payment	Rs	2,50,000	1,50,000	1,00,000	5,00,000
Fixed cost payment	Rs	1,37,500	82,500	55,000	2,75,000
Total payments by the discoms	Rs	**3,87,500**	**2,32,500**	**1,55,000**	**7,75,000**

Let us assume that this generator participates in MBED and sells 1000 MW in DAM for the same slot of the upcoming day. Discoms place bid equal to their allocated share in the genco. Following is the overall scenario of quantum self-scheduled by discoms, bidding and market clearing for a particular 15-min time block:

Day ahead schedule	
Genco	1000
Discom 1	500
Discom 2	300
Discom 3	200

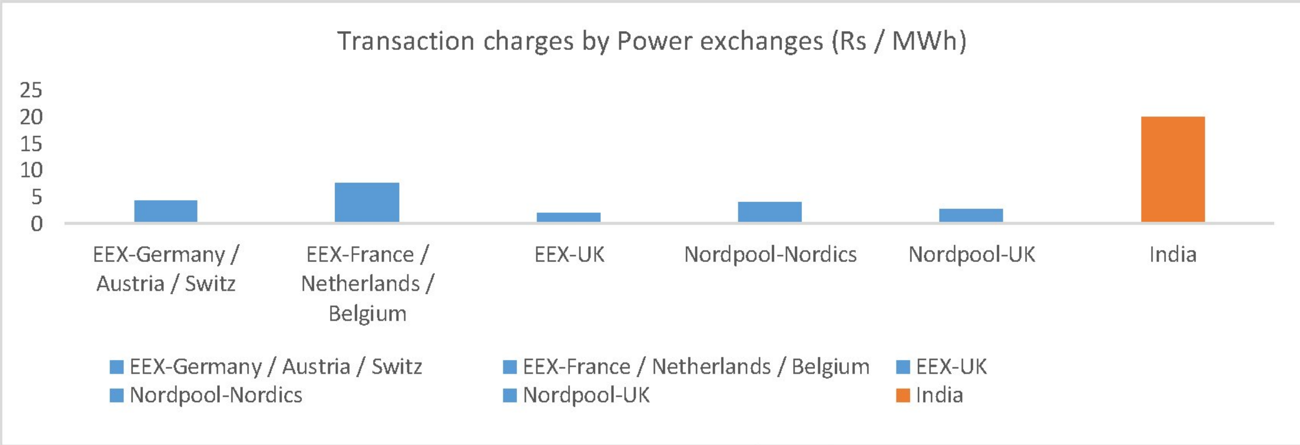
	Rs / kWh
MCP in DAM	2.5

Market results	
Genco	1000
Discom 1	500
Discom 2	300
Discom 3	200

Following is the summary of payment and settlements in case the amount to be refunded back as BCS to discoms is netted off against their fixed cost liability.

Payments to / from Generator		Particulars (Rs)
Payment from Market operator @ MCP	a = 1000 * 250 * 2.5	6,25,000
BCS liability of genco	b = 1000 *250* (2.5-2)	1,25,000
Gains realized for URS power	c	0
Fixed cost liability of discoms	d	2,75,000
Adjusted fixed cost liability of discoms	e=d-b	1,50,000
Adjusted Fixed cost payment by discoms		**Discom 1: 75,000** **Discom 2:, 45,000** **Discom 3: 30,000**
Total payment received by generator	f=a+e	7,75,000

Annexure 4: Transaction charges levied by Power exchanges



Annexure 5: Impact analysis on buyers for upfront payment

Distribution companies will be procuring power through power exchanges and hence, the power will be procured through advance payments / margin money and generating companies will be realizing the payment against the power sold on the same day. A rebate of ~2% has been proposed for such advance payment by discoms.

However, since the distribution companies would be utilizing the mechanism of working capital from Designated agencies to make such upfront payments, it is essential to understand and compare the interest cost liability to be incurred by Discoms in availing the working capital facility vis-à-vis the additional relief in the form of rebates for upfront payments. Discoms would be incentivized to participate in MBED if the additional relief suitably compensates them for the interest cost incurred.

The approximate funding requirement by Discoms, on a daily basis, would be ~ Rs 150 crs (Section 4, main document). Based on the following assumptions, the table below computes the benefits and costs incurred by the Discoms, because of the MBED scheme.

1. A working capital rate of SBI MCLR (1 year MCLR of 7%) + 350 basis points
2. A maximum tenure of 45 days for Discoms to repay back the working capital loan, and,
3. Proposed rebate of 2.00% on the procurement value

Approximate funding requirement – daily (Rs crs) (1)	**SBI MCLR 1-year (%) (2)**	**Interest rate on WC loan (3)=(2)+3.5%**	**Interest cost (Rs crs) (4) = (3)*(1)*45/365**
~150	7%	10.5%	~ 1.95

Approximate funding requirement – daily (Rs crs) (1)	**Rebate offered (%) (2)**	**Rebate (Rs crs) (3)=(2)x(1)**
~150	2%	3.0

Net benefits are represented herein:

Rebate provided for upfront payment (Rs crs) (1)	**Interest cost incurred for upfront payment through working capital loan (Rs crs) (2)**	**Net benefits (Rs crs) (3)=(2)-(1)**
3.0	1.95	1.05

It can be thus assumed that irrespective of paying upfront for the cost of power procured through exchanges, the distribution companies would realize net benefits if additional rebate of 2% is offered. Furthermore, the Ministry of Power vide No. 23/22/2019-R&R had already directed distribution companies to open and maintain adequate letter of credit as Payment Security mechanism under the PPAs signed by such distribution companies. NLDC and RLDCs were also directed to dispatch power after suitable intimation from generators and distribution companies that such Letter of credits for the desired quantum of power have been opened and copies of the same supplied to NLDC / RLDCs. The concerned generating company is entitled to encash the LC after 45-60 days as provided in the PPA. As such, the proposed MBED mechanism is already in line with the existing requirement of upfront payment and does not aim to alter the status quo with respect to such provision.