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No/CGM/C-3/MPPMCL/18-19/136 **Bhopal Dated. 31 / 01 /19**

To,
The Secretary
Central Electricity Regulatory Commission
3rd and 4th Floor, Chanderlok Building
36 , Janpath, New Delhi

Subject:- Comments on discussion paper on Market Based Economic Dispatch of Electricity: Re-designing of Day-ahead Market (DAM) in India

Please find attached herewith the Comments of M.P. Power Management Co. Ltd. on subject cited discussion paper. Submitted for your kind perusal please.

Encls:- **As Above**

CGM (Comm.-3)

Copy to:

1. PS to MD (MPPMCL), Shakti Bhawan , Rampur, Jabalpur
2. OSD (Energy) Energy Department GoMP, Vallabh Bhawan , Bhopal.

Encls:- **As Above**

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CGM (Comm.-3)

Comments on some of the major issues related to proposed MBED

CERC has issued discussion paper on market based economic dispatch (MBED) to optimize scheduling and dispatch of generation capacity available in Indian power market. It is a welcome step forward.

One of the major trigger points necessitating this discussion paper is that available un-requisitioned surplus (URS) power available from many plants with cheaper variable cost (VC) is not utilized, while power from many plants with costlier VC are dispatched. This may be attributable either to separate MODs of different States or to obligation to maintain technical minimum (TMM) of plants in the entitlement bucket of a State.

MBED envisages national merit order dispatch (NaMOD) based on variable cost (VC) of generation. Proposed MBED deals broadly with two aspects of market- a) scheduling and dispatch and b) settlement.

However, the following are some of the issues which need exhaustive assessment and stakeholder consultations before implementation of MBED or other market reforms as in pipeline:

1. **Increasing flexibility requirement:** How to handle increasing flexibility requirement due to increasing RE capacity and penetration?

   <u>Comments</u>

   India has about 89 GW RE installed capacity (wind- 56%, solar- 28% and rest- 16%). A 10% fluctuation in renewable generation during peak generation (when both wind and solar resources are available either simultaneously or individually), the implication on grid would be 5-10 GW. With additional capacity of 80-90 MW coming up in future, the implications would be even higher. This requirement would further get complicated with increasing penetration of solar rooftop systems across length and breadth of geographies. This would require more efforts to improve not only forecasting of RE generation but also availability of balancing power at par i.e. availability and flexibility of balancing power (mostly, non-RE or storage system) to match the requirement, which may vary every 5 minute (time block). Thus, the requirement of non-RE power to manage flexibility and un-certainty associated with RE generation would increase. Proposed MBED or other discussion papers on Real Time Market (RTM) or Ancillary Services Market (ASM) etc. have to address this aspect adequately before embarking on market reforms such as MBED etc.

2. **State specific impact analyses**: What would be comparative benefit of 100% despatch of low cost (VC) power versus loss in maintaining costlier power at TMM versus opportunity loss?

   <u>Comments</u>

   Implementation of MBED targets to maximize utilization of cheaper URS power, which otherwise presently suffer due compulsion to maintain technical minimum (TMM) of entitlement plants. However, this proposal has to be assessed for two fold implications for power surplus States like Madhya Pradesh-

a) Economic trade-off: States need to assessed trade-off between maximum/ full utilization of lower VC plants vis-à-vis shaving off the burden of higher VC paid to maintain TMM of entitlement plants as per State specific experience and plans. Further, recommendations of all States must be examined before finalization of MBED;
b) Loss off opportunity: Potential URS plants with lower VC or plants running at TMM are utilized to maximize revenue of utilities, which, in turn, is utilized to off-set fixed cost (FC) burden of utilities towards surplus capacity. This aspect needs to be examined as per State specific experience and their recommendations before implementation of MBED.

3. **PPA moderation:** Examining the need of periodic re-alignment of PPAs with lower MOD (higher VC).

Comments

There are many States like MP have sufficient capacity tie up i.e. about 25-30% more than present peaking demand. Also, there is wide range in peaking demand of lean season and peak season. Further, such surplus power situation is expected to prevail over next 3-5 years. Given this scenario, some surplus capacity of these States may be declared entitlement of deficit States for appropriate medium term time horizon (say, 1 year or 2 years etc.) after due stakeholder consultations. This would not only reduce FC burden on surplus States, thus improving financial health of distribution companies but also add vibrancy in capacity market, a plank to MBED. Hence, market reform should also assess and address this aspect before implementation of MBED.

4. **PPAs nationalization**: Prospecting rationalization of RTC PPAs to 12 hourly PPAs or even smaller duration.

Comments

As standard practice, most of long term and medium term PPAs are/ have been signed for round-the-clock (RTC) supply. However, with increasing RE capacity and penetration, there impending need to rationalize both existing and upcoming PPAs for smaller durations, say, 12 hourly or 4 hourly. As a natural consequence, all existing PPAs (especially, long term PPAs) would have to be nationalized in such a way that generators' FC revenue stream remains unaffected and utilities' FC burden gets optimized. Also, this exercise would also lead to optimization of NaMOD, a basic plank of MBED as proposed. It is suggested that this aspect should be assessed before implementation of MBED or any of its variants.

5. **Change in treatment to RE:** How would RE scheduling and despatch be aligned in respect of the following:

a) To explore possibility of RE being incorporated in NaMOD;
b) To assess possibility of separate MOD for RE;
c) To optimize RE power procurement (avoid curtailment and ensure maximum despatch)?

Comments

Presently, solar and wind projects enjoy must run status. These projects have associated natural pattern of generation and associated operational as well as commercial implications. Given the underlying principle of MBED being push for more efficient and vibrant operation of power market, it would be worthwhile to explore answer to above possibilities in order to make RE sector more innovative and provide RE poor States with opportunity to meet their renewable power obligation (RPO) targets.

6. **Real-time constraints:** If all generators from entitlement of a State get accommodated in NaMOD but actual power does not flow due to transmission constraints, the following issues need to be addressed under MBED:

    a) How would concerned State get power, supposing that such requirement is significant and beyond the scope of ASM or demand response market (DRM)? The MBED needs to provide for dealing with such situations and fix accountability on system operator (SO) or market operator (MO) to ensure supply in such situations;
    b) How would interest of both generator and State be protected i.e.

        i. Would financial implications on buyer utility be mitigated from congestion fund or some other pooled fund? In such situations, utilities may face implications in terms of cost of alternative supply, FC burden, minimum off-take guarantee burden and UI/DSM etc. MBED needs to address this aspect before its implementation.

        ii. Would generator share any benefit resulting from trading (in TAM, RTM or ASM) of such un-despatched capacity (attributable to such constraints) in some other market? MBED model needs to provide a mechanism which helps not only energy market of MBED but also helps lessen burden on distribution licensees.

7. **Utilization of URS capacity issues:** Actual schedule of URS capacity may not be practicable to implement

    Comments

    URS power sale would be subject to market clearance. This could lead to scheduling of power in the range of zero to full URS quantum. However, if such power is scheduled with many spikes, the same may be demotivating for a generator and pose practical difficulties in operation of its plant. In such circumstances, generators may not be interested in honoring the schedule, leading to both operational and contractual issues. This aspect needs to be addressed under MBED model.

8. **Netting off the payment** to generator i.e. hedging platform to be handled by MO

    Comments

    The hedging mechanism described under proposed MBED model encourages not only procedural delays but also makes it prone to cost ineffective from buyer's perspective. Instead of money going to generator's account followed by generator crediting back to buyer's account, it would be more efficient and cost effective that market operator (MO) operates the hedging account and debits or credits net-off money from or to buyer's account on T+1 or T+2 day. It is suggested that MBED model should address this aspect accordingly so as to avoid procedural redundancies without compromising with efficiency in market.

9. **Verification of variable cost (VC):** As the MBED shall operate on VC, verification of VC becomes critical

   Comments

   MBED model is proposed to be based on variable cost (VC) of generation. Prevalent practice of VC determination is primarily dependent upon declarations of concerned generators. It is pertinent that VC is dependent upon a host of factors affecting fuel cost (both primary and secondary). In such scenario, it unquestionability of VC becomes cornerstone to efficiency and success of MBED. Hence, MBED should adequately address this very pivotal aspect of it.

10. **Real time grid balancing:** Who shall handle real-time grid balancing issues?

    Comments

    As the whole country evolves into one capacity and one energy market, it would be a challenge to address real time grid balancing. The same cannot be left on to deviation settlement mechanism (DSM). MBED needs to specify role and accountability of MO or SO in respect of real time grid balancing.

11. **Role of system operator (SO)** in ensuring supply and mitigating transmission related risks

    Comments

    As suggested in the MBED discussion paper, RTM, ASM and MBED shall operate in appropriate tandem to achieve overall objective of market reforms. However, discussion papers concerning to MBED, RTM and ASM do not adequately address as to who shall ensure supply in period after gate closure or during exigencies emerging out of transmission constraints in real-time? MBED needs to specify roles and obligations of SO and/or MO in this regard.

12. **Right to recall:** If MCP > VC, how to protect interests of distribution licensees in case generator fails/ unwilling to supply

    Comments

    Proposed MBED model envisages buyer's right to recall in real time before gate closure. It triggers a scenario wherein the generator may not be willing to arrange buy-out power at buyer's/ beneficiary's request under right to recall [***Scenario:*** *There are chances that some URS capacity of a plant may get scheduled in day ahead market (DAM). But, given need of hour, beneficiary utility having right to recall may exercise its right anytime. It such cases, the generator would evaluate its cost economics of arranging buy-out power or not arranging. In case the market clearing price (MCP) is more than the VC of its generation, there are chances that the generator may indulge in not honouring right-to recall (R2R), leading to inherent risk for buyer*]. The proposed

MBED needs to delve deeper on such aspects of potential market dynamics and provide appropriate mechanism to address these issues.

13. **Mechanism for benefit sharing:** What if unscheduled DC (due to transmission issues) gets despatched at MCP more than VC?

    Comments

    The model proposes a NaMOD. However, there may come a situation wherein curtailment or restriction may be imposed due to transmission system un-availability. In such situations, the declared capacity (DC) or a part thereof may get scheduled in term ahead market (TAM) or real time market (RTM), which may fetch higher than VC. A mechanism needs to be evolved to address profit sharing between generator and original beneficiaries.

14. **Delivery point related issues:** What shall be structure of transmission losses and charges and who shall bear those?

    Comments

    Generally every contract has specified delivery point. Accordingly, transmission losses and charges are owned/ paid by parties to a transaction, which is now aligned to point of contact (PoC) philosophy. Under MBED model, whole nation is, ideally and theoretically, envisaged to be one boundary. In such scenario, MBED needs to address this issues for all PPAs, which may require different treatment as per time horizon of contract i.e. long term, medium term or short term.

15. **OA market:** How would OA market find place under MBED scheme of things?

    Comments

    In general, open access market (OAM) operates on single part tariff. Also, OA agreements have bilateral nature and executed for short term or medium term period (majority of cases). Further, OA consumers have multiple sources (discom, bilateral and power exchange) and fuels (wind, solar, other RE and conventional) of supply. All this would add new dimensions to MBED and needs to be addressed before implementation of MBED.

16. **Two rates by generators**: How to address issues attributable to two rates quoted by generators?

    Comments

    Plants running around or willing to operate at TMM capacity may bid at two rates- one for capacity up to TMM and another for capacity beyond TMM. In such scenario, how the power shall be allocated when only a part of DC gets cleared [***Scenario:*** *Plant "A" has PPAs for 90% of its capacity (40% with one State & 50% with another State). Upon actual finalization of bid, only 55% gets cleared (TMM capacity). In such scenario, how would the market cleared capacity be allocated among both beneficiaries? Also, how would both beneficiary States get remaining power? Further, how would beneficiary States be compensated for losses, if any, in terms of URS compensation* *emanating due to such exigencies?*]. Discussion on MBED would have to address these issues before implementation.

17. **Implementation of supplementary PPAs:** Issues related to implementation of supplementary PPAs in respect of existing PPAs under Section 63 needs to be addressed.

18. **UI & DSM:** Any issues related to UI & DSM needs to be addressed.