NTPC Limited

Comments of the Discussion paper on "Market Based Economic Dispatch (MBED): Re-designing the Day Ahead Market"

The current Discussion Paper on "Market Based Economic Dispatch (MBED): Re-designing the Day Ahead Market" is the fourth one in the series of proposals by Hon'ble Commission issued recently towards promoting market mechanisms in the country and real time balancing.

The other relevant Regulations/ Discussion papers released recently are:

1) Linkage of DSM price to the market price (Regulations introduced since 1st January)
2) Re-designing of the Real Time Market and
3) Re-designing of the Ancillary Market.

Whereas all of the above mentioned proposals have intended to bring out market mechanism in a limited way, the current paper intends to introduce a new concept having wider ramifications for the entire Power sector.

This paper on the Market Based Economic Dispatch (MBED) aims at changing the existing scheduling and dispatching process from a decentralized mechanism to a centrally coordinated mechanism. The power sale in India is predominantly based on the Power Purchase Agreements signed between the generators and the distribution utilities and the proposed mechanism need to preserve the sanctity of these contracts. This paper has attempted to do this through the mechanism of Bilateral Contract Settlement (BCS) scheme.

The concept of Market Based Economic Dispatch is intended to bring in optimization of the system cost and result in savings to the distribution utilities. It is noteworthy that recently two more papers have been floated with similar intended objectives.

1) Govt of India vide communication no 23/21/2018-R&R dated 30.08.2018 has issued the policy of "Flexibility in generation and Scheduling of Thermal Power Stations to reduce the cost of power to the consumers". The main approach followed in this paper is optimization of the power generation cost of a generating company through a Bucket Filling Approach to maximize generation from cheaper stations.

2) POSOCO in a similar manner has proposed the concept of Security Constrained Economic Dispatch (SECD) whereby it has been proposed to optimize the cost of the generation of all the Inter State Generating Stations considering the constraints such as technical minimum limit of operation, ramp rate, transmission constraints etc. Subsequently Hon'ble Commission has issued an order for a pilot study for a period of six months starting from 01.04.2019.

Hon'ble Commission has proposed the MBED approach with the similar objectives. Hence multitude of concepts have been floated for the same objective.

It is understood that the MBED concept when implemented will be done through a separate Regulations issued for this purpose or suitable amendments in the existing Regulations. At this stage the comments of NTPC are limited to broad principles regarding this new concept. We have also tried to highlight some of the market design issues which can have implications on the sector. The Hon'ble Commission may consider these while framing the Draft Regulations. NTPC would like to submit its detailed comments/ suggestions as and when the Draft Regulations are issued to this effect.

NTPC's Comments:

1) It may be pertinent to point out that optimization of the power procurement cost can be achieved even without resorting to market mechanism. The RLDCs may be entrusted with required authorizations for carrying out optimization exercise so that cheaper stations are utilized to the maximum extent possible, in line with the concept proposed under Security Constrained Economic Dispatch. This mechanism with appropriate gain sharing of the savings between the generators and discoms will result in lowering the power procurement cost.

2) As we move towards a market based system, it may be pertinent to consider some of the critical issues such as ensuring reliability of supply of power at all times without compromising on the efficiency in price discovery process and at the same time implement proper risk mitigation mechanism for all the market participants, to have a stable, sustainable and equitable market regime.

3) The proposed mechanism aims to clear all the power transaction in the country at a common platform. This common platform will be used by two sets of generators; one set of generators, who have set up plants based on prior long term agreements/ contracts signed with the buyers and have envisaged for sale at regulated rates. The

other set of generators who have set up their plant without any prior agreements/ contracts with any buyer and have envisaged to sell at market rates in the market space outside long term contracts. The proposed mechanism will open the entire market space to the set of generators not having any prior agreement; due to this it is likely that scheduling from some of the costlier stations, lying lower in the merit order stack, will reduce despite having prior agreements. In essence the proposed mechanism provides a platform to the merchant generators, who do not have any prior agreement for setting up a power plant to take some market share at the cost of others. This will increase the risks of the regulated generators, as the paper itself has recognized in the *Clause 7.5* about realigning of the capacity contract strategy in the future.

4) It is felt that the proposed mechanism does not provide an equitable *'level playing field'* to the different categories of generators as described above. The generators, set up based on prior agreements with buyers are regulated by the Hon'ble Commission at the central and state level. The ECR (marginal costs of generation) of these stations are published through the orders of the Hon'ble Commission and are known in the public domain, as opposed to the generators which are purely merchant in nature. Hence the flexibility of the regulated generators to decide a bidding strategy is limited as compared to others.

5) The paper discusses about the legacy contracts and has proposed the BCS mechanism to preserve these contracts. But it is silent about any new bilateral agreement/ contract between a generator and buyer. It is not clear about the process to be followed for a new agreement is entered into between a generator and buyer for a new capacity.

6) The BCS mechanism proposed is expected to be implemented through Supplementary Agreements for the already signed PPAs. Successful implementation of this mechanism depends on agreement of the stakeholders on these agreements. These would be standard agreements issued by the Hon'ble Commission to be signed by the stakeholders as has been done while implementing the POC mechanism for sharing of transmission charges.

7) **Participation by the generators:**

    a. Generators, particularly thermal generators are typically constraints by their technical limitations such as technical minimum limit of operation and ramp rate. While clearing the stations through the proposed mechanism, these aspects must be taken into account. At any point of time, only a small part of a generating station may get cleared to meet the total demand; then other lower cost units need to be backed down to accommodate technical minimum limit of this unit. For example, in some block 100 MW from the costliest station (say 500 MW capacity) may get cleared in the market. But as the minimum loading has to be 275 MW, 175 MW will have to be backed down from cheaper stations.

Similarly during the peak hours, to meet the demand, higher cost generators may be cleared in the market. These stations will not be cleared in the off-peak hours due to lower clearing price. Hence they may need to be kept running at the technical minimum limit during the off peak hours. To accommodate these units, the cheaper station though cleared fully in the market will need to be backed down. This consideration may also need to be continued for a continuous period of 5-7 days to avoid frequent start/ stops.

b. Similar situation will also arise due to their limited ramp rates. To accommodate the limiting ramp rates of a lower cost unit, a costlier station may be required to be run in place of a cheaper station.

c. These events will cause a deviation in the cost from the minimum cost criteria. But the question that needs to be answered is how to derive the market clearing price on such occasions. From the marginal cost perspective, the additional units can be obtained from the cheaper stations which has some spare capacity to accommodate the costlier stations' technical limitation. But the Market Clearing Price is set at the Marginal cost will not clear the costlier stations which are required to be run. Hence the MCP has to deviate from the marginal cost and has to be equal to the price of the costlier station.

d. Similarly generators also have other associated cost elements such as the start-up costs in addition to the variable costs. While taking the bidding decisions for the next day (Day Ahead) in case of the units which are under shutdown, the startup costs if added to the variable cost will make the generators uncompetitive in the Day Ahead Market. Hence the Market Design should have the provision to take care of these kinds of nonlinear costs.

e. Though this paper has referred to these difficulties in clause 5.17 (page 40), this being an important aspect for the generators needs to be deliberated and discussed in more detail. Most of the market designs around the world try to solve this issue through various approaches. In the approach followed by the many Power Pools, this issue is addressed through the concept of Side Payments. In that approach the bidding can happen based on the variable costs and other costs such as start-up costs can be paid separately. Similarly the technical minimum and ramp rate limitation can be sorted out to the concerned generators with the help of an additional payment (make-whole payments). In the beginning India can adopt a Security Constrained Economic Dispatch along with a side payment system which will consider the technical constraints and additional cost elements while deciding the dispatch decision.

~~f.~~ While it is envisaged that any additional earning above the ECR would be refunded by the generators to the distribution utilities, it is silent about the actual cost of energy of the generators participating in the market. The 'Strike Price' of the contract between the generator and the distribution utility here is considered as the regulated variable cost, which is based on the normative efficient parameters. The actual parameters could be different and the actual cost may be different from the regulated variable cost.

g. As far as technical minimum limit is concerned, currently these standards are different for central generators and state generators. This is one of the factors which is posing a problem for minimizing the cost currently. As per the current practice it is possible that a cheaper unit is backed down to 55% level where as a costlier unit is backed down to 75%-80% level. With this mechanism a uniform approach of 55% technical minimum limit may be adopted.

h. There should be provision of revision of schedule of the generator, particularly in case of unit outages. Unit outage is an unforeseen event which cannot be predicted.

8) BCS Mechanism:

a. The BCS mechanism proposed is one-sided i.e.it only covers the risks of the distribution utilities against increase in their power purchase costs from the market vis-à-vis the contracts entered with the generators. On the other hand, due to implementation of the MBED mechanism, as submitted at 3) above the risks will increase substantially for huge number of generators particularly the non-pit head stations having relatively higher ECR. These stations in spite of having bilateral contracts (PPAs), will not dispatch many times.

b. The Bilateral Contract Settlement scheme described in this paper is based on the premise that generators having PPAs would submit their bids at the marginal cost, which would be the variable cost and in case of regulated generators this is considered equal to the variable cost or ECR. But there may be many occasions when the bidding will not be at the marginal cost. But sometimes to maximize their clearance in the market, a generator may bid at a lower rate and clear the market. So in this case it is not clear how the BCS will be administered.

c. For example a generator with variable cost of Rs 2.5/ kWhr may decide to bid at Rs 2.4/kWhr. The issues involved here as follows:

   i. Here if the MCP is say Rs 2.48/kWhr, he will clear the market but will make loss of Rs 0.02/kWhr for every unit sold. It should be compensated from the BCS mechanism, where there should be some provision for refund from the discoms to the generators.

   ii. If the MCP is Rs 3.0/kWhr, how much will be refund, will it be the difference between ECR and the MCP or between the Bidding price and MCP.

9) Participation by Renewable projects:

a. Renewable projects have single –part tariff in India and the cost is recovered based on the units scheduled from the RE projects. RE projects have zero or negligible marginal cost of generation. It makes economic sense to schedule the entire generation from the RE projects and hence they are accorded "must run"' status. Though the cost of RE projects have seen significant decline from very high levels in the recent years, most of the RE projects commissioned before 2-3 years have very high cost. It is not very clear how the BCS mechanism will operate in case of RE projects, particularly for the older projects.

b. For example a RE project with cost of say Rs 8.0/kWhr can only recover from the market at rate of the MCP. If the RE projects bids at the 'Zero' Marginal cost, it will clear the market but will only get the MCP from the market. So there has to be mechanism to recover the difference between the contracted price of say Rs 8 and the MCP (say Rs 4.0/kWhr); ideally this has to be refunded by the distribution utility to the RE project developer. Since the proposed mechanism is only one-sided i.e. it has dealt with the situation where only the risks of the distribution utilities are protected. This would necessitate payment of the difference between the agreed price (regulated feed-in tariff) and the Market Clearing Price by the distribution utilities to the RE project developers.

10) Participation by the distribution utilities:

a. Financial condition of the Distribution Sector has been a cause of serious concern for long. Outstanding dues of the discoms on the generators is posing serious threat on the viability sector. Participation in the market by the Discoms to meet their power requirement would require sufficient liquidity. A daily power demand of 3500 MU when procured through the market would necessitate a payment (in advance) of Rs 1200 to Rs 1500 Cr (depending on the average MCP).

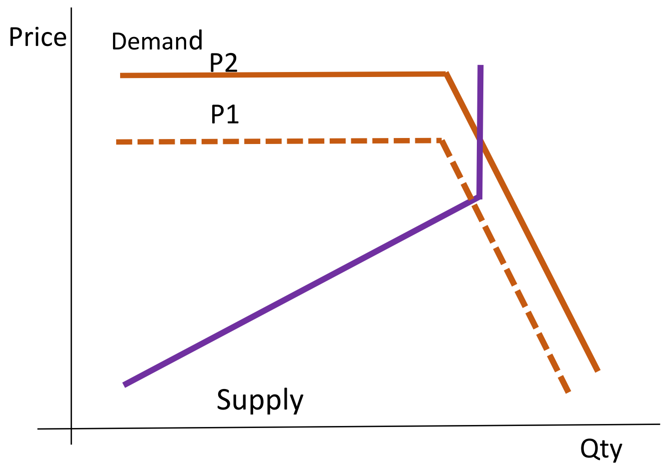
b. As far as the bidding mechanism is considered, it is proposed in the paper to follow a double-sided bidding with participation by both the generators and disocms. Once the MBED is in service, Discoms will have to submit bids to buy all their power requirements from the market. Even if they schedule from the generating stations with which they have contracts, actual clearance in the market will decide how much they are be get from the market. But in reality, in most cases Discoms cannot afford to not supply power to the retail conusmers due to not clearing the market. Hence to meet the mandated ‘Universal Service Obligation’, they will have to buy power from the market through aggressive bidding.

   Probably this is the reason why it has been proposed in the paper that Discoms are expected to submit a ‘Fixed Bid’ to meet the base level requirement of power and then can have a price sensitive bid for the additional quantity. It is expected that for the “Fixed Bid” quantum, Discoms will bid for the base demand at the maximum price (Rs 20/kWhr currently) and the additional quantity through a price sensitive bid. It is apprehended that this may have serious consequences for the price discovery process in the bidding, as illustrated the below paragraphs.

c. In this context, attention is drawn to price peaks observed during the October 2018. It was found out that prices are reaching at that level mainly because some discoms are bidding at the highest price level to ensure that they are able to get power from the market.

A look the Aggregate Supply and Aggregate Demand curve of IEX for the time block of 19:00 – 19:15 Hrs of 04.10.2018 indicates that probably one of the main reasons of the price peak of Rs 18.2 was because nearly 8500 MW demand was bid at the maximum price (Rs 20/kWhr). Due to this, even if the marginal price of the highest generator was around Rs 12.0/kWhr, the AS and AD curves actually cut at the vertical segment of the AS curve and the price discovered was very high i.e. Rs 18.2.

As can be seen from the adjoining graph, if the maximum Bid price is reduced from P2 to P1, the equilibrium point shifts downwards and does not fall on the vertical segment of the supply curve.



So in peak seasons or in case of any unexpected shortfall in RE or hydro generation, when supply is barely sufficient to meet the demand, it is likely to result in very high prices i.e. much higher than the marginal cost of generation.

d. As an alternate approach, in some developed markets like National Electricity Market, Australia single side bids are used where only the suppliers bids their quantum and price and total forecasted demand is used to decide the marginal supplier and the price gets discovered in the process. In this case though the demand will be price-taker, they will not participate in the bidding unlike the proposed double-sided bidding where they can influence the price level through the Fixed Bid submitted at the highest price.

e. It goes without saying that accurate demand forecasting is one of the pre-requisites for any market mechanism. At present, demand forecasting has not matured in the country. This can be undertaken at a centralized level and should be available publicly for all the stakeholders.

11) Transaction fees and Charges:

a. Currently Short Term Open Access charges and transmission losses are applicable for trade in the power exchange. The bidding price of the sellers and the buyers include these statutory charges. Once the entire energy is exchanged through the Power Exchange, these additional charges may not be applicable for the entities having Long Term Access.

b. Similarly there are some other charges such as client membership charges, PX fees, scheduling and application fees which are applicable in case of participation in the power exchanges. There should not be any such charges when participating in the market becomes mandatory for the generators/ buyers and all the power gets transacted in the power exchanges.

c. If the total generation in the country, of around 1200 BU is to be transacted through the power exchanges at the current rates it will translate to the additional cost of Rs 4800 Cr. Even if the PX fees are reduced to 1 paise/ unit, this would still be as high as Rs 1200 Cr for the sector.

d. *Clause 7.12* has discussed the critical issue of price coupling due to existence of multiple power exchanges; currently there are two power exchanges operating in the country. Going forward, the mechanism should have provisions to take care of the situation with more than two power exchanges.

12) Payment Security and Settlement System:

a. As the clearance will be done through the market, pay-in and pay-out will be made on everyday basis. Considering the poor state of the distribution sector, currently many Discoms are not able to make timely payments to the generators; in some cases payments are lying unpaid for much beyond the stipulated payment period of 60 days. Once MBED mechanism is implemented, Discoms may have to deposit advances in the Power Exchanges.

b. So though the Energy Charge of the generators will be recovered from the market, payment security for the Fixed Charges has to be ensured. It is proposed that generator while making the refund through the BCS mechanism should adjust this against the outstanding dues of the Discoms beyond the due date. There should be a reconciliation mechanism with the distribution companies considering all the payments including the Fixed Charge payments.

c. It is not clear how regulation of power supply will be implemented in case of non-payment by a distribution company toward the payment of the generators.

13) Incentive of generators beyond 85% scheduling

a. Currently, as per the Tariff Regulations, the generating stations which are scheduled beyond the Normative PLF level are entitled to get incentive @50 paise/ unit. This mechanism should continue and incentive payment for the generators should be linked to the original schedule given by the discoms. If a generator is in the incentive zone as per the original schedule given by the discoms, as defined the Tariff Regulations should get the incentive. Otherwise implementation of the Scheme would impact the Generators adversely.

14) Transition towards a market based system:

a. In *Clause 5.19 to 5.21* of the paper, the brief roadmap for the transition phase has been discussed. It is suggested in the paper that in the transition phase only the URS power which is not requisitioned by 09:45 Hrs can be transacted in the market and gradually after the transaction phase, all the power may be transacted in the market. It is submitted that to implement this, there is a need to shift the scheduling timeline to 09:45 Hrs. Currently the discoms can finalize the schedule only in the evening after closure of the markets. Hence the URS power which is permitted to be sold in the DAM is based on a conservatively estimated expected URS. By shifting the scheduling timeline to the morning will facilitate participation of the URS power in the bidding.

b. The Power Exchanges in India have completed almost a decade of their operation in the country. Different generators and as well as Discoms might have gained experiences to varying degrees about the process of participation and the risks involved. Excluding the merchant generators, other generators' participation would be limited to sell the URS power in the market. Similarly the extent of participation by the Discoms could be buying power to a very limited extent and sometimes selling their surplus power. The MBED concept being discussed is far larger in scope and coverage and would necessitate proper awareness of the process and the risks involved. The price discovery process which is currently being done for about 3% of the power in the country is envisaged to be scaled up to cover 100% of the power transaction.

c. While participating in the market based bidding, both buyers and sellers have to be very careful, considering the stakes involved. Any lapse can have serious implication for the generator or the distribution utility. Hence wide spread awareness has to be created among all the stakeholders to educate them about the bidding process, possible risks etc. before the mechanism is rolled out completely.

d. It is submitted that before the actual roll out of the mechanism in the country, there should be a pilot roll out for a period of at least six to twelve months, without any commercial implications. Based on the results of this pilot study, the actual roll out mechanism may be decided.

Further, there are some other areas which require clarifications. Some of them are as follows:

- Will there be a separate entity to carry out BCS or same has to be settled between Gencos & Discoms themselves?
- Who will calculate & distribute the Congestion Revenue for the PPA tied quantum in case of market splitting?

In view of the above, it is submitted that the Security Constrained Economic Dispatch mechanism, as per the order of Hon'ble Commission in the Petition No. 02 /SM/2019 (Suo-Motu) dated 31.01.2019 may be implemented and based on the experiences gained through the implementation of SCED, implementation of the Market Based Economic Dispatch mechanism may be considered.

xxxxxxx