Comments on "Draft Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) (Fourth Amendment) Regulations, 2018"

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1. **Market-based DSM Pricing:** Inadequate planning for short-term power procurement supported with a reliable short-term demand forecast, renewable energy generation forecast and inadequacy of the ancillary services 'market' are some of the main reasons for persistence of deviations from schedule. In response to the Draft "Deviation Settlement Mechanism and related matters" Regulations, 2013 (enclosed as Appendix A), comments submitted by the author suggested the adoption of market-based prices to reflect the relative value of electricity, which varies across time and space.

2. **Area-specific Market Clearing Price (MCP):** While a clear migration is being attempted by adopting market-linked deviation pricing, we should take this opportunity to implement a more direct correspondence with market clearing price based on the market areas demarcated by power exchanges. In the case of a state being represented by more than one market area, average of area clearing prices could be used for the purpose. Respective State Electricity Regulatory Commissions (SERCs), in deciding the deviation price for the inter-state ABT mechanism, could adopt the differentiated area-specific prices for constituents (distribution utilities, state generators, etc.) in those market areas.

3. **Final Destination for Deviation Settlement Mechanism:** It is important to highlight that the deviation settlement mechanism is designed to address the first three primary reasons identified above, whereas the ancillary services market is expected to address the residual deviations that have not been taken care of by adequately. In an ideal world, the deviations from schedule should become 'irrelevant', with a well-functioning ancillary services 'market' that can address the issues 'beyond the reasonable control of the system constituents'.

4. **Beyond Area Clearing Prices:** It must be understood that the area clearing price(s) as determined on power exchanges, though reflect the competitive outcome of interplay between demand and supply, are only a reflection of the interaction between the two to the extent of the 'cleared' volume on the exchange.

   If the constituents, who deviate in real-time, were to actually participate in the DAM, they would have influenced the market prices. By directly adopting the area clearing price(s), it is being assumed that the market would have exhibited an inelastic response and would have absorbed any amount of demand and/or supply at the cleared price. This is an area of further debate, discussion and analysis.

5. **Renewable Rich States:** The regulations, by defining an exception for a Renewable Rich State, make an artificial exception to address an anomaly that should have been adequately addressed under the regulations applicable to renewable energy. Strengthening of existing regulations for addressing RE balances may obviate the need for such an action in future.

   The definition of a 'Renewable Rich State' remains dynamic and is subject to artificial limits. Further, a renewable rich state may actually have a significant RE capacity under PPA with entities outside the state. The regulations should adequately address this.

6. **Role of Ancillary Services and Hedging Instruments:** A vibrant ancillary services market and scheduling inaccuracy instrument for risk hedging of deviations could help reduce the risk exposure of the constituents to scheduling inaccuracy. Ancillary services could allow the system operator to seek system support at a shorter notice after the hour ahead schedule forecast is provided by RE generators.

   It should also be possible to design hedging instruments to cover for uncertainty in forecast of RE schedule as well as the deviation charges applicable for the same. However, such instruments should only be available initially to the constituents directly exposed to risk rather than being an instrument for financial speculation.

7. Certain corrections for the amended provisos are identified below in **<u>bold and underlined</u>** text.

   The following sub-clause shall be added after sub-clause (c) of clause (1) of Regulation 2 of the Principal Regulations:

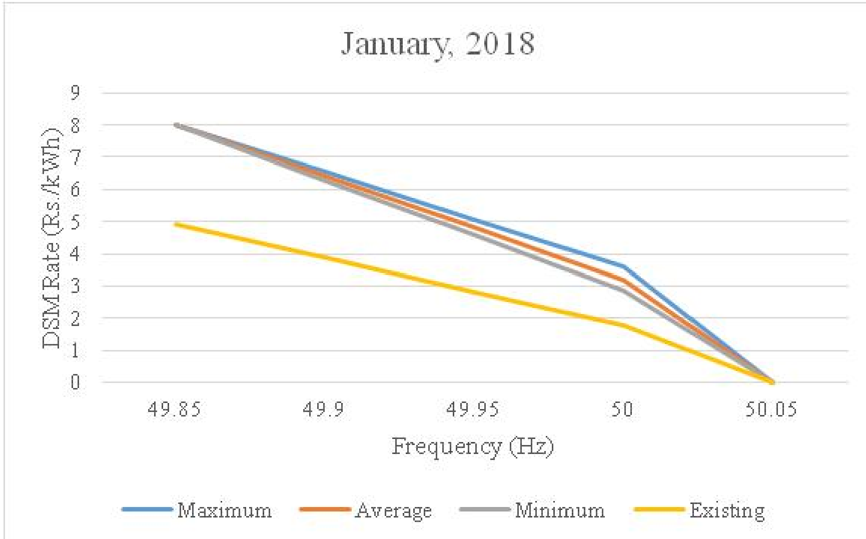
   "(ca) "Area Clearing Price (ACP)" means the price of 15-minute time block electricity contract established on the **<u>Power</u>** Exchange arrived at after considering all valid purchase and sale bids in particular area(s) determined after market splitting, i.e. dividing the market across constrained transmission corridor(s)."

   After the existing proviso to clause (1) of Regulation 7 of the Principal Regulations, a new proviso shall be added as under:

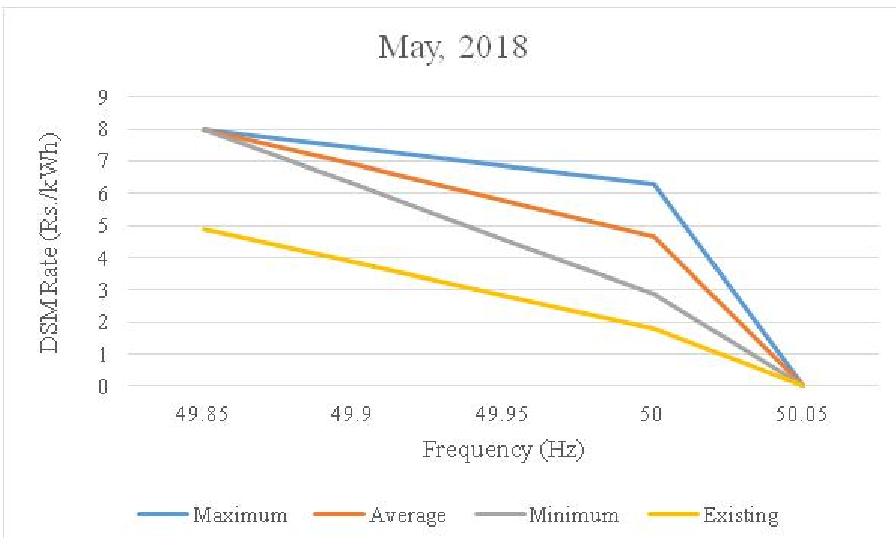
   "Provided also that the total **<u>inter-state</u>** deviation from schedule in energy terms during a day shall not be in excess of 3% of the total schedule for the drawee entities and 1% for the **<u>ISGS</u>** generators and additional charge of 20% of the daily base DSM payable / receivable shall be applicable in case of said violation."

   [It is important to clarify that the additional charge of 20% would be applicable to the 'incremental' deviation beyond the limits identified (i.e. in a telescopic manner), rather than for all the deviation (i.e. in a non-telescopic manner).]

8. **Short-term Impact of the Proposed Changes:** The daily average, minimum and maximum prices of DAM against the prevailing deviation prices (truncated to the proposed second limit of 49.85 Hz) for the month of January and May 2018 are depicted in the following graphs.



So: Analysis by Energy Analytics Lab (EAL), IIT Kanpur (eal.iitk.ac.in)



So: Analysis by Energy Analytics Lab (EAL), IIT Kanpur (eal.iitk.ac.in)

It can be noted that adoption of area clearing prices would make the deviation price curve much steeper than the existing one. There may be a short-term spike in the deviation-related penalty, hence requiring significant preparatory work by state-level entities. Further, this would also necessitate fuel supply agreements that address the quality of coal supplied and the timeliness of its supply to thermal power plants.

9. **Need for an Analogous and More Effective Intra-state ABT Regime:** The 'one' Indian grid reflects the overall deviation from schedule irrespective of the fact that such deviations originate at an inter-state or an intra-state level. However, the existing military framework for addressing deviations from schedule leaves significant gaps which can be attributed to the absence of (i) intra-state ABT in some states, (ii) exclusion of distribution utilities from the existing intra-state ABT, and (iii) adoption of non-analogous

price vector for intra-state ABT with respect to the deviation price vector applicable for inter-state deviations. There is a need to ensure that the 'one' Indian grid also values the deviations through the same price vector, with the exception of the congestion reflected in market splitting (as discussed above).

10. **Strengthening Mechanisms to Address RE Imbalances:** A steeper price vector for deviations applicable for non-RE generation, would accentuate direct (socialised) burden of deviations on account of RE generation. In the context of a vibrant 'one' Indian grid, the current regulatory framework for addressing RE imbalances should also be strengthened.

11. **Need for Institutional Strengthening of SLDCs and Distribution Utilities:** The effectiveness of a more stringent market-based price vector for frequency-deviation would significantly depend on the ability of the distribution utilities to develop a consistent and reliable framework for short-term demand forecasting, RE generation forecasting, demand-side management (including time of day tariff and curtailable tariff) and scheduling through institutional strengthening of SLDCs as well as state-owned distribution utilities.

12. **Economics of Imbalances Vs Flexible Generation and Storage:** Growing RE penetration, especially that behind the meter, raises significant uncertainty for balancing the grid. In the absence of visibility of behind the meter data (generation and consumption), it would be a greater challenge to address imbalances. There may be a need to incentivise flexible generation andstorage including that from Electric Vehicles (V2G). The market conditions, that would guide deviation price, may justify business case for such technological initiatives.

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1. **Change in Philosophical approach to reduce reliance on UI mechanism:**

   The key reasons for deviation from schedule are

   a. Technical/operational reasons that result in load loss, generation loss, fault/congestion in transmission and distribution network

   b. Change in load profile due to user behavior, change in weather etc.

   c. Change in generation profile due to change in weather, fuel supply, fuel quality etc.

   d. Inadequate planning for short-term procurement and sale of power.

   The last factor is relatively ignored from the underlying philosophy of draft regulations. Do these regulations give incentive for short-term power procurement or sale? UI market with lucrative 'prices' seem to assure 'sale' of excess power and leaves little incentive for transactions through bilateral contracts, traders or PXs.

   The draft regulations should embrace a philosophical shift by maintaining / increasing penalty for over-drawal and under-injection, and reduce incentive for under-drawal and over-injection. This should provide appropriate incentive to system constituents to reduce reliance on UI mechanism and shift towards short-term transactions through bilateral contracts, trading and PXs.

   UI charge should ideally reflect the value/cost of the deviation to the system rather than direct cost/benefit of the constituents. Existing regulations for deviations have followed a pre-defined 'price curve' for deviations. The proposed price curve seems complex and it would become difficult for a buyer (utility) /seller (generator) to assimilate this 'price' information in its decision making. It is desirable that the 'structure' of UI and additional charges be simplified.

2. **Strategy for Short-term Power Procurement:** The gap arising out of forecasted load and generation capability from existing contracts should be first planned to be met through short-term procurement. Similarly, any surplus should be planned to also be sold through available short-term bilateral contracts, short-term options like trading and PXs. The inability of utilities to develop a Short-term Power Procurement Strategy is reflected in greater reliance on the UI mechanism. While few steps have been undertaken by utilities in this direction, consistent behavior of utilities vis a vis the UI mechanism suggests otherwise. Uncleared volume (without congestion) on PXs would be a testimony to the availability of electricity at a price which was not sought after by the utilities facing shortages. Another critical issue in the context of short-term power procurement is the procedural rigidity and lack of transparency at the state level. Unless

such issues are addressed at the state level, the regulator's and system operator's task of maintaining grid frequency and its stability would continue to face challenges.

3. **Unsymmetric Deviation limit for under-injection / over-injection:** The "12% or 150 MW" volumetric band for under-drawal/over-drawal by buyers and under-injection/over-injection by sellers should also be unsymmetrical due to the following reasons,

   - The frequency band itself is un-symmetrical with a greater frequency range (49.9 – 50.0 Hz) below 50 Hz than the frequency range (50.0 – 50.05 Hz) above 50 Hz.
   - Buyers (especially distribution utilities) have lesser flexibility than generation plants.
   - The problem of under-frequency is greater than that for over-frequency i.e. instances and probability of frequency deviation below 50 Hz are greater than those above 50 Hz.
   - Higher band gives greater incentive for gaming for under-drawal by buyers and over-injection by sellers

   A lower deviation band for under-drawal by buyers and over-injection by sellers would ensure that there are less incentives for gaming. Further, 12% deviation allowance for a generator is a relatively high as it is expected that generators are able to exercise better control on generation than the utilities can do on the load.

4. **Differential Frequency Steps for inter-state and intra-state deviation:** The proposal to lower the frequency step from 0.02 Hz to 0.01 Hz is welcome as this provides greater granularity for the tightening frequency band. While metering infrastructure capable of 0.01 Hz frequency step is under implementation at inter-state interface points, a time bound plan should be rolled out to make adequate changes to the metering infrastructure at the intra-state level including those with the eligible consumers. In the absence of the same, there would be difference in UI settlement at the inter-state and the intra-state level. A rollout plan for installing meters enabled with frequency measurement at 0.01 Hz step is required for implementation at the state level. Forum of Regulators can take initiative towards the same.

5. **Volumetric limits on Deviation and Additional UI Charges:** The prevalent UI mechanism incorporates frequency based penalty/incentive. The application of volume based limits is to reduce greater volatility in the system frequency (independent of system frequency). While the volumetric limits are expected to address this volatility, it should also address potential gaming with reference to under-drawal by buyers and over-injection by sellers. However, it is noted that the limits/sub-limit steps and the related UI charges for the volumetric deviation across time blocks and over a day are rather complex. It may present a challenge to utilities and the generators to assimilate these in their decision making.

   Notwithstanding the above, one of the advantages of additional UI charge above volumetric limits (and which are not related to frequency anymore) would be some degree of separation between the system frequency and deviation. It is to be seen if these volumetric limits would bring about desirable changes in the behaviour of the system participants. **A 6-month evaluation exercise should be undertaken after implementation of these regulations.**

6. **Choice and Impact of Volumetric limits on Deviation:** While volumetric limits, given the frequency deviations and the grid disturbances, are justified the choice of steps for these limits

(i.e. “12%” or 150 MW, 20% or 200 MW) should be justified and their distribution impact be examined. These limits place an unsymmetrical limit on buyers/sellers with scheduled load/generation of above and below 1000 MW. It should be possible to evaluate the impact of these limits on grid participants under different conditions. This would help decide appropriate volumetric limits.

7. **Remove Additional UI Charge for higher ‘under-drawal’ / ‘over-injection’:** High additional UI charge would further lower incentive for the buyers and sellers to participate in short-term power market through bilateral contracts, traders or PXs. There should not be any need to promote under-drawal by buyers and over-injection by sellers beyond the 12% (150 MW) limit. Additional UI charge payable for higher limit steps would encourage gaming for under-drawal by buyers and over-injection by sellers.

8. **Market Monitoring to investigate gaming with under-drawal / over-injection:** CERC should undertake regular exercise to investigative if there is gaming with under-drawal / over-injection. These should also include RE based plants with/without captive consumption. The report of the same should be made available on the CERC website along with relevant action taken report.

9. **‘Deviations’ due to Transmission Constraints and ‘Locational/Congestion UI Charge’:** There are numerous instances when transmission constraints between NEW and Southern regional grids would hinder the ability of the system to reach the desired frequency. The draft regulations do not seem to identify and address this issue. It would be useful to examine if transmission constraints have indeed contributed to the above concern. Appropriate measures can then be explored to introduce **‘location-specific UI charge’, or ‘congestion UI charge’**. Associated implementation challenges are discussed below.

10. **Locational Bias in UI Charge:** Locational differentiation in UI price is theoretically justified only in case of congestion in a transmission corridor. To implement such a procedure, relative value of congestion must be built into the differential UI charge and known beforehand to the system constituents. Further, differential UI charges can only be implemented ex-post due to the fact that congested corridor would only be known in real time. Alternatively, market splitting information from the Day Ahead Market (DAM) of the PXs can be used as a proxy for locational UI bias, if required. Incorporation of real-time congestion charge would be very challenging as this would leave little room for the system constituents to respond to the ‘new’ locational UI charges.

11. **Role of in-firm power:** There are reasons to allow certain .. for in-firm power. If possible, a sense of discipline or organised’ testing can be brought by encouraging injection of inform power during identifying hours of the day (possibly non-peak hours to avoid volatility in system frequency). With addition of large unit sizes of 660, 800 and 1000 MW, in-firm power (its injection and non-injection) can bring significant deviation in a vulnerable system. It would also be useful to analyse historical data on in-firm power ‘schedule’ and injection to understand their role in the system deviation (especially during vulnerable periods) and opportunities to address this in future.

12. **Load Forecasting, adequacy planning and load management**: Lack of missing or inadequate load forecasting, adequacy planning and proactive load management is perhaps the main reason for the dependence on the UI mechanism to address these gaps. In philosophical terms, long-term regulatory attention should be on improving utility’s skill for load forecasting, adequacy planning

and fine-tuning of UI mechanism should be a short-term objective only. Unless the above mentioned capabilities of the utilities are improved, the need for enhanced regulatory attention to UI mechanism or its alternate would remain. If the long-term goal is to evolve a better mechanism in future, greater attention should be paid to improve load forecasting, adequacy planning and load management.

13. **Demand Side Management (DSM), market based tariff and reliability based tariff:** The elasticity of response of utilities to the dynamic grid situation can improve if distribution utilities adopt demand side management tools like time-of-day (TOD) tariff with premium for peak hours and discount for off-peak hours. Further, partial linking of tariff for large consumers with market prices (or average UI rate faced) can also improve load response and help utilities pass on additional cost due to UI charges to large customers contributing partially to the same. Another DSM option would be to introduce 'reliability based tariff' which would allow the utility to reduce curtailable demand in case of significant deviation from schedule.

14. **Renewable Energy and System Volatility:** Natural dependency of renewable energy plants especially Wind and solar based plants contribute to the volatility in the system frequency. Renewable Regulatory Fund (RRF) mechanism has been activated this month. However, the scheme it does not address a greater context of improving forecasting capability of wind and solar plants. The draft regulations do not refer to the RRF scheme. In fact, there is a need to further tighten the tolerance for efficient forecasting by reducing range of forecasting error. There has been inadvertent delay in implementing the same. Given that the country would have larger RE capacity based on wind and solar technology in future, it is more important that **RE generators improve generation forecasting capability** and, hence, improve greater acceptability of the RE capacity in the grid in future.

15. **Linking UI Charge to Area Clearing Price on PXs:** Theoretically, deviations should be priced as per their market value. However, implementation of the same with 'real time' prices is not feasible. The suggestion to link the same to DAM prices is also challenging as this may not reflect the value of deviation in real time.

    Alternatively, if most of the potential deviations are converted to planned short-term transactions, only residual 'imbalances' need redressal through the UI mechanism. This would equivalently mean that majority of 'potential deviations' would now face the area clearing prices. Hence, emphasis should be placed on shifting 'potential deviations' away from UI mechanism to the shrt-term transactions through bilateral, trading and PXs.

16. **Review of UI price Vector:** Peak UI price should be related to those plants which are able to respond in short-term. There is very limited DG capacity that can be used for supporting inter-state grid. DG capacity connected to the intra-state grid would respond only if there is adequate mechanism in place. Unless large eligible consumers (with adequate DG capacity) face UI deviations under an analogous intra-state mechanism, the UI price vector may not able to ensure that DG based capacity is used by system constituents to avoid deviation from drawal schedule. There is a need to gather evidence to that effect.

    A number of gas based power plants have unutilised capacity due to unavailability of domestic gas. Use of imported R-LNG is expensive and there are may not be potential buyers for such expensive power on consistent basis. In case, gas based capacity is better placed to respond, it should be reflected in the UI price vector.

The statement of reasons does not clarify the use of 'median' value of coal/lignite based plants. How does this impact generation plants above and below median?

17. **Dis-incentivise under-drawal vis a vis short-term transactions:** Incentives for under-drawal by buyers, makes this 'potential capacity' unavailable for short-term transactions through bilateral transactions, traders and PXs. Hence, deviation limit on under-drawal should be limited to 5-8 % at most. This would give appropriate signal to utilities with excess capacity to undertake develop a strategy for sale of excess power through non-UI avenues.

18. **No increase in over/under-injection limit by Generating Plants:** As per prevailing regulations, a generating plan can under/over-inject upto 105% of the installed capacity of the station in a time block or 101% of the installed capacity over day. The proposal to give a more lenient limit of 12% or 150 MW would encourage generating stations to indulge in gaming to a greater extent and derive undue benefits by under-scheduling in a shortage scenario. This proposal should be reconsidered.

19. **Energy Charge to be UI Charge for Generation:** Is there is evidence of generators reducing generation when UI charge is lower than their energy charge? It should be presented first. **If an attempt is made to provide 'energy charge' as minimum UI charge to generators, there would be no incentive to forecast generation and stick to it.** If a generator faces lower UI charge than its energy charge, it should have been providing better scheduled to the system operator. In any case, even if there is any evidence of the holding up generation, it would happen only at very small band below 50 Hz (i.e. between 50.0 to 49.99 Hz). I feel that this additional largess could be avoided. This would benefit those plants which have much higher energy charge, may perhaps be associated with newer plants with better generation forecasting and control capability. Plants with energy lower energy charge would still continue to face incentive as previously.

20. **Lower Cap Rate for over-injection for Generating Station using coal: Why should the cap rate for generating stations (for over-injection) using domestic coal be linked to imported coal?** All coal based generating stations whose average variable charge is below Rs. 3.05 per kWh would benefit. Based on average variable charges, this would give undue benefit to 33 out of 34 NTPC/NLC plants (listed in Annexure-I of Statement of Reasons). Similarly, private sector generating plants based on domestic coal whose variable charge is below Rs. 3.05 per kWh would also benefit. (Note: Only variable charge would be under consideration as fixed charges would already have been taken care of through fixed part of the tariff)

21. **Lower Cap Rate for under-drawal by Buyer: The c**ap rate for deviation for under-drawal by buyer should be lower than that for energy charge based on imported coal. This should provide appropriate incentive to buyers to shift towards short-term transactions through bilateral, trading and PXs.

22. **Need for an objective definition of 'gaming':** The definition for gaming needs to be improved as it does not seem to provide a robust definition and could be challenged legally due to,

    - What would qualify **as** 'intentional' mis-declaration and how can the system operator or CERC prove it?

    - What would be called an 'undue' commercial gain? If a generating station would get monetary benefits 'due' to it as per the prevailing UI charges, what would be called 'undue'?.

- Has any instances of suspected gaming been ever investigated from the data available?

If the regulations have to provide a credible threat to desist from gaming, a more objective and implementable definition of 'gaming' should be provided. **This definition should relate to a pattern or consistency in the behaviour of the system participants. This definition should also account for gaming behaviour of the buyers/utilities. The anti-gaming provisions should also define a penalty over and above the 'undue' benefits derived, perhaps as a multiplier over the 'undue' benefits to deter such behaviour.**

A more robust definition for gaming would also provide incentive for better forecasting and, perhaps, planning for sale/purchase through short-term transactions.

23. **Include 'Buyers' also within the ambit of gaming:** The draft regulations exclude 'buyers' from the provision of gaming. A buyer is as much a suspect for gaming as a seller or a generating station. While this is an issues open to further examination, it may be feasible, that many utilities or other buyers may have been deriving 'undue' benefits by engaging in consistent under-drawal especially during the periods of low frequency (high UI charges). Hence, introducing such a provision would safeguard against such practices and enable monitoring of such behavior.

24. Sub clauses 2(c) and e(d) under regulation 5 (Charge for Deviation) can be merged as these are analogous except that these point to two adjacent frequency bands.

25. Last para above 'Note' under regulation 5 (Charge for Deviation): There is a need to clarify what kind of sorting from highest to lower is being suggested across fuels. Which 'fuels' are being referred to?