CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

Coram:
Shri Jishnu Barua, Chairperson
Shri Ramesh Babu V., Member

No. L-1/260/2021/CERC **Dated: 15th November, 2024**

In the matter of
Central Electricity Regulatory Commission (Deviation Settlement and Related Matters) Regulations, 2024 – Statement of Objects & Reasons (SOR) thereof.

STATEMENT OF REASONS

1. Introduction

1.1 The Central Electricity Regulatory Commission (hereinafter referred to as the "CERC" or "the Commission") initiated the process of notifying CERC (Deviation Settlement and Related Matters) Regulations, 2024 (hereinafter referred to as "the DSM Regulations 2024") in exercise of powers conferred under Section 178 read with clauses (c) and (h) of sub-section (1) of Section 79 of the Electricity Act, 2003 (36 of 2003) (hereinafter referred to as the "the Act") and all other powers enabling it in this behalf. On April 30, 2024, the Commission issued the Draft Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 (hereinafter referred to as the "Draft Regulations"). Subsequently, the Commission also issued the Explanatory Memorandum for the same wherein the reasons and analysis relied upon for framing the Draft Regulations were explained.

1.2 **Comments/suggestions/objections** were sought from the stakeholders and interested persons on the Draft Regulations by May 24, 2024, which was extended till June 3, 2024, based on the request of stakeholders. In response, the Commission received submissions from eighty-nine (89) stakeholders. Subsequently, a Public Hearing on the Draft Regulations was conducted on June 19, 2024, via video conferencing. The list of stakeholders who presented during the Public Hearing is attached as **Annexure I.** The Commission, on request received during the public hearing by the stakeholders, allowed the submission of further comments along with relevant information. Accordingly, the Commission received submissions from ninety-seven (97) stakeholders. The list of the stakeholders is attached as **Annexure II** to this document.

1.3 The Commission, complying with the provisions of the Act and the Electricity (Procedure for Previous Publication) Rules, 2005, proceeded to finalize the DSM Regulations 2024. The Commission considered the comments of the stakeholders on the Draft Regulations, views of the participants in the Public Hearing as well as their written submissions received during and after the Public Hearing. The Regulations have been finalized after due consideration of various issues raised. The analysis of the issues and findings of the Commission thereon are discussed in the subsequent paragraphs.

1.4 It may be noted that all the suggestions given by the stakeholders have been considered, and the Commission has attempted to elaborate on all the suggestions as well as the Commission's decisions on each suggestion in the Statement of Reasons. However, if any suggestion is not specifically elaborated, it does not mean that the same has not been considered. Wherever possible, the comments and suggestions have been summarised clause-wise, along with the Commission's analysis and ruling on the same. However, in some cases, due to overlapping of the issues/comments, two or more clauses have been combined in order to minimise repetition.

1.5 The main issues raised during the public consultation process and the Commission's analysis and decisions on the issues that underlie the Regulations as finally notified, are given in the subsequent paragraphs.

2. Definitions and Interpretation

2.1. Definition of Available Capacity (Regulation 3(1)(g))

Commission's Proposal

2.2. The Commission had proposed the following definition of Available Capacity in Regulation 3(1)(g) of the Draft Regulations:

*(g) **'Available Capacity'** for generating station based on wind or solar or hybrid of wind-solar resources, which are regional entities, is the cumulative capacity rating of wind turbines or solar inverters that are capable of generating power in a given time*

block;

Comments received

2.3. **India Power Corporation Ltd (IPCL)** suggested modifying the definition to include only the cumulative capacity rating of wind turbines or solar inverters **in operation** that are capable of generating power in a given time block.

Analysis and Decision

2.4. The Commission is of the view that the definition already covers the aspect highlighted by the stakeholder in that the wind turbines or solar inverters that are capable of generating power in a given time block would need to be considered as available capacity. The Commission would like to reiterate the available capacity would be equal to the Installed Capacity, unless one or more turbines/inverters are under maintenance or shutdown. Any attempt at misdeclaration, that is, declaration of capacity when it is actually not available due to reasons of maintenance or shutdown, etc, would be treated as gaming and would be liable to action under appropriate provisions of the Act or the Regulations.

2.5. Definition of Contract Rate (Regulation 3(1)(j))

Commission's Proposal

2.6. The Commission had proposed the following definition of Contract Rate in Regulation 3(1)(j) of the Draft Regulations:

*(j) '**Contract rate'** means the tariff for sale or purchase of power, as determined under Section 62 or adopted under Section 63 or approved under Section 86(1)(b) of the Act by the Appropriate Commission or the price as discovered in the Power Exchange, as the case may be; and in the absence of a tariff or price as above, contract rate shall mean the weighted average ACP of the Day Ahead Market segments of all Power Exchanges for the respective time block;*

Comments received

2.7. **EDF Renewable** and **Solar Park** suggested excluding High price DAM in the definition, while **Manikaran Analytics** suggested bringing clarity on the price as discovered in the Power Exchange in the definition. **BRPL** suggested linking the Contract rate with the RTM as the deviation is managed on a real time basis, and also to reduce gaming by the generator.

2.8. Stakeholders such as **IPCL, WIPA, O2 Power, Sembcorp, and Amplus Solar** suggested including the price as indicated under Bilateral Power Purchase Agreements, signed between Consumers (including group captive and captive consumers) and generators in the definition. **Amplus** suggested that in the absence of an affidavit or contract copy under the bilateral arrangement, the contract rate may be considered as the average price of concluded tenders of ISTS-connected project tenders over the last year for respective technologies, i.e., Solar/Wind/Wind-Solar Hybrid, etc. or National APPC tariff determined by CERC.

2.9. **Re New** suggested defining the contract rate as equal to the weighted average of the contract rates of all individual WS seller(s) opting for aggregation at the pooling station and linking the contract rate with national APPC in cases where the contract rate at the pooling station is absent. **CER IIT-K** suggested including the prices discovered from other market segments**,** such as other products traded on power exchanges, Discovery of Efficient Electricity Price (DEEP), and Surplus power portal (PUShP) in the definition of Contract Rate.

2.10. **RPC and Grid India** suggested providing clarity regarding the method of calculation of contract rate in cases where the general Seller (operating under section 62 or otherwise) is selling only a quantum of power under PPA and the remaining part in the market. **IEX** suggested providing clarity regarding the calculation of contract rate in cases where an RE Generator participates in multiple transactions such as GDAM, DAM, GTAM, and TAM in different time blocks. **Sekura** Energy requested clarity regarding the 'Power exchange' price being referred to the first instance of the definition. **Grid India** suggested providing clarity on the calculation of contract rate when the single PPA itself has different rates for different points of time in the day, e.g. in Peak power contracts, different rates for peak and off-peak hours. It also pointed out that the rate is adjusted based on the penalty and incentive on a monthly basis.

Analysis and Decision

2.11. The Commission has noted the suggestion(s) provided by the stakeholders and made suitable changes in the definition of "Contract Rate" in the final regulations (DSM Regulations, 2024).

2.12. Bilateral contracts between discoms and generators are generally approved under section 86(1) (b) of the Act and hence covered under the definition. The treatment of Group Captive and Captive Consumption and of multiple transactions in the Market have also been dealt with in the final regulations. Regarding prices discovered in other market segments, such as DEEP and PUShP, it is clarified that any power purchase through these market platforms has to undergo the approval of the Appropriate Commission; therefore, these are suitably taken care of in the definition.

2.13. It is imperative that a seller be incentivised or penalised for its deviation in terms of the rate at which it is selling its power under various contracts. Therefore, when a seller participates in any segment of the power exchange, including High Price-DAM, the contract rate for the purpose of calculation of deviation charges should be aligned with the prices discovered (Collective or continuous, as the case may be) in those respective segments. Further, contracts cleared under the High Price Day Ahead Market (HP-DAM) offer a true representation of the market situation of high demand. As such, the Commission is of the view that the prices discovered in HP-DAM must be included in the definition, as they reveal actual market behaviour during critical periods.

2.14. On the suggestion of linking the contract rate only to the RTM price of the respective time block, the Commission is of the view that though the Real-Time Market is an organized market operating closest to actual delivery, liquidity in this market segment is limited. Hence, the suggestion to link the contract price only to RTM prices is not being considered at this stage.

2.15. For the captive consumption of a captive generating plant based on renewable energy sources, contract rates are not approved or determined by the appropriate commission and may not be available with the system operator. Accordingly, the Commission is of the view that for contract rates for captive consumption or third-party sale of power, the weighted average ACP of the integrated-Day Ahead Market (I-DAM) segment of all power exchanges for the respective time block is to be considered. Further, contracts between discoms and generators under DEEP or PUSHP platforms are generally approved under section 86(1) (b) of the Act and hence covered under the definition.

2.16. As regards the suggestion to provide clarity on the methodology for the calculation of contract rate under multiple contracts or transactions in a time block by an entity, the Commission would like to clarify that in case an entity is selling power through multiple modes, e.g., under PPA or through Power Exchanges (PXs), the contract rate for the purpose of deviation for such entity, for a given time block, would be the weighted average of contract rates considering schedules under each contract or transaction (including power exchange transactions). For further clarity on the provision, the Commission has provided an example below to illustrate the calculation of contract rate for multiple contracts or transactions in a time block:

Example: Consider Generator 'A' has an installed capacity of 500 MW. Out of this, it has a PPA of 300 MW at a tariff of Rs. 3/kWh, and the remaining untied capacity (i.e.200 MW, in this case) is available for selling in the power exchange. Suppose, in a given time block, Generator 'A' has provided a schedule of 280MW under the PPA (with tariff of Rs. 3/kWh) and the same generator has sold its untied capacity of 200MW in the power exchanges such that it got cleared for 90 MW in DAM at Rs. 5/kWh and 80 MW in RTM at Rs. 4/kWh, in the given time block. Accordingly, the total schedule of Generator 'A' in the given time block is equal to (280MW + 90 MW + 80 MW), i.e., 450 MW. If the actual injection by Generator 'A' in the given time block is 440 MW, the contract rate for such generator 'A,' in the given time block, for under injection of 10MW would be [(280 X 3) + (90 X 5) + (80 X 4)] / (280 + 90 + 80) = **Rs. 3.58/kWh.**

2.17. Accordingly, the Commission has suitably modified the definition of 'Contract Rate' in order to bring further clarity, as under: -

*" (j) **'Contract rate'** means (i) in respect of a WS seller or a MSW Seller or such other entity as applicable, whose tariff is determined or adopted or approved under Section 62 or Section 63 or Section 86(1)(b) of the Act, Rs/kWh tariff as determined or adopted or approved by the Appropriate Commission; or (ii) in respect of a WS seller or a MSW Seller or such other entity as applicable, whose tariff is not determined or adopted or approved under Section 62 or Section 63 or Section 86(1)(b) of the Act, and selling power through power exchange(s), the price as discovered in the Power Exchange for the respective transaction; or (iii) in case of captive consumption of a captive generating plant based on renewable energy sources, the weighted average ACP of the Integrated-Day Ahead Market segments of all Power Exchanges for the respective time block; (iv) in case of multiple contracts or transactions including captive consumption, the weighted average of the contract rates of all such contracts or transactions, as the case may be."*

2.18. Definition of Deviation (Regulation 3(1)(k))

Commission's Proposal

2.19. The Commission had proposed the following definition of Deviation in Regulation 3(1)(k) of the Draft DSM:

*(k) '**'Deviation'** in a time block for a seller of electricity means its total actual injection minus its total scheduled generation, and for a buyer of electricity, it means its total actual drawal minus its total scheduled drawal, and shall be computed as per Regulation 6 of these regulations;*

Comments received

2.20. **Assam Distribution Company and IPCL** suggested that deviation due to CTU Constraint/ corridor constraint should not be included in deviation.

Analysis and Decision

2.21. The Commission has noted the suggestion. However, the Commission would like to underscore that this is a subject matter of the Grid Code and beyond the scope of the DSM Regulations. The issue has been dealt with in detail under Sub Regulation (3) of Regulation 49 of the Grid Code, 2023.

2.22. Definition of General Seller (Regulation 3(1)(m))

Commission's Proposal

2.23. The Commission had proposed the following definition of General seller in Regulation 3(1)(m) of the Draft DSM Regulations:

*(m) **''General seller'** means a seller in case of a generating station based on other than wind or solar or hybrid of wind-solar resources;*

Comments received

2.24. **IPCL** suggested adding a hybrid of wind-solar resources or the thermal generators participating under the scheme for Flexibility in the Generation and Scheduling of Thermal Power Stations in the definition. **Mr. Shishir Kumar Pradhan** opined that there is a general apprehension that the general seller means seller except those involved in solar, wind, or hybrid of wind-solar resources. **JSW** suggested widening the ambit of definition by including the term "with or without ESS" after "..wind or solar or hybrid of wind-solar resources" in the definition.

Analysis and Decision

2.25. The Commission has noted the suggestion provided by the stakeholders. The Commission is of the view that the definition is self-explanatory and does not require any modification.

2.26. **Definition of Integrated Day Ahead Market (Regulation 3(1)(o))**

Commission's Proposal

2.27. The Commission had proposed the following definition of Integrated Day Ahead Market in Regulation 3(1)(o) of the Draft DSM:

*(o)**Integrated Day Ahead Market** means a market where Day Ahead Contracts are transacted on the power exchanges, including collective transactions under Day Ahead Market (DAM), Green Day Ahead Market (Green DAM), and High Price Day Ahead Market (HP-DAM);*

Comments received

2.28. **TNPPA, BRPL,** and **EDF RE India Private Limited** suggested that as the price discovered in the HP-DAM segment would always be higher, the inclusion of HP-DAM in the definition will negatively affect both buyers and sellers who are actually not participating in the HP-DAM market segment. **BRPL** suggested that coupled prices discovered from all power exchanges of only the DAM segment should be considered.

Analysis and Decision

2.29. The Commission has carefully noted the stakeholders' suggestion to exclude the price discovered in the HP-DAM segment from the definition. However, the Commission would like to emphasize that this dedicated market segment was introduced specifically for high-cost generators, who were previously unable to participate in the day-ahead market due to the prevailing price cap in the Day-Ahead Market (DAM). The HP-DAM enables such generators to be available during periods of high demand, addressing power shortages that were not possible to manage earlier. This has been introduced keeping in mind the market realities and ensuring a level playing field across segments and across buyers and sellers intending to transact in various segments based on their requirements and availability.

2.30. It has been observed that the HP-DAM Market is getting volume generally only in situations of high demand and shortage of supply. Therefore, any contract cleared under HP-DAM accurately reflects the value of electricity being transacted in such situations of high demand and shortage of supply in the sector. Given this, the prices discovered in HP-DAM must be included in the definition, as they play a crucial role in revealing market behaviour during critical periods. This inclusion ensures that both sellers and buyers are impacted based on their actions—whether supporting grid stability or contributing to violations. As such, the market signals provided by HP-DAM prices should influence regional entities accordingly, reflecting their behaviour during these high-demand periods. Accordingly, the Commission does not find any need for revisiting this definition.

2.31. Definition of Regional Entity (Regulation 3(1)(u))

Commission's Proposal

2.32. The Commission had proposed the following definition of Regional Entity in Regulation 3(1)(u) of the Draft DSM:

*(u) '**Regional Entity'** means a person whose metering and energy accounting are done at the regional level by the Regional Load Despatch Centre;*

Comments received

2.33. **Mr. Shishir Kumar Pradhan** suggested modifying the definition of Regional Entity as "the entity which is in the RLDC control area and whose metering and energy accounting is done at the regional level," which is in alignment with the IEGC Regulations, 2023. Whereas **IPCL** suggested modifying the definition as "an entity whose scheduling, metering and energy accounting is done at the regional level by the concerned RLDC as defined in the Central Electricity Regulatory Commission (Fees and Charges of Regional Load Despatch Centre and other related matters) Regulations."

Analysis and Decision

2.34. The Commission has reviewed the comments and is of the view that the definition is adequate and self-explanatory and does not require any changes.

2.35. Definition of Renewable Rich State (Regulation 3(1)(v))

Commission's Proposal

2.36. The Commission had proposed the following definition of Renewable Rich State in Regulation 3(1)(v) of the Draft Regulations:

*(v) **'Renewable Rich State'** or '**RE-rich State**' means a State whose combined installed capacity of solar and wind generating stations under the control area of the State is 1000 MW or more but less than 5000 MW;*

Comments received

2.37. **Assam Distribution Company, and HPSEBL** suggested including hydro generators in the definition, as hydro power is recognized as a renewable source of energy under various regulations issued by the Hon'ble CERC. **IPCL** suggested modifying the definition as "a State whose combined installed capacity of solar and wind and hybrid of wind-solar with or without BESS and hydro generating stations under the control area of the State or the contracted capacity of RE by all entities connected to the State is 1000 MW or more but less than 5000 MW."

2.38. **MP SLDC** suggested categorising the Renewable Rich states as 'Renewable Rich State', 'Renewable Rich State -1' 'Renewable Rich State -2' with combined installed capacity being "1000 MW or more but less than 4000 MW", "4000 MW or more but less than 7000 MW" and "7000 MW or more but less than 10000 MW" respectively;

2.39. **BRPL** suggested that the definition of RE-rich State should be based on the % of RE contracted capacity as the RE capacity installed in the state may be high, but the capacity may be supplying to Other State beneficiaries under a long term PPA. **Tata Power** suggested that the states may be categorised as RE Most Rich State-1 with combined installed capacity being more than 10,000 MW but less than combined installed capacity being more than 10,000 MW MW and RE Most Rich State -2 with combined installed capacity being more than 10,000 MW.

2.40. Assam Discom also wanted clarification as to whether the term "control area" includes generators from CSGS with which DISCOMs have PPA, or is it limited solely to solar plants connected to the STU.

Analysis and Decision

2.41. The Commission has noted the suggestions and would like to clarify that the definition of RE Rich State, along with the special dispensation, has been specifically developed to address the variability inherent in wind and solar resources and to manage the unique challenges they present. Consequently, the Commission does not intend to extend this definition to include other types of renewable energy resources beyond wind and solar. Further, the definition does encompass wind-solar hybrids or wind or solar with ESS. Regarding the inclusion of contracted capacity of all entities under the State control area in the definition, the Commission emphasizes that renewable energy generation is inherently variable and requires precise management to address deviations effectively. Regarding clarification of the term 'control area', it is clarified that it will have the same meaning as specified in the Grid Code. By focusing on installed capacity within the control area of the State, the Commission seeks to factor in the challenges of managing variable renewable energy, thus providing a more accurate and practical basis for regulatory measures. Accordingly, the Commission decided to retain the definition of Renewable Rich State as proposed in the draft Regulations.

2.42. Definition of Renewable Super Rich State (Regulation 3(1)(w))

Commission's Proposal

2.43. The Commission had proposed the following definition of Renewable Super Rich State in Regulation 3(1)(w) of the Draft Regulations:

*(v) **'Renewable Super Rich State'** or '**RE Super-rich State**' means a State whose combined installed capacity of solar and wind generating stations under the control area of the State is 5000 MW or more;*

Comments received

2.44. **IPCL** suggested modifying the definition as **"**a State whose combined installed capacity of solar and wind and hybrid of wind-solar with or without BESS and hydro generating stations under the control area of the State or the contracted capacity of RE by all entities connected to the State is 5000 MW or more."

2.45. Some of the stakeholders suggested that the installed capacity range for RE super-rich state should be 10000 MW or more (MP SLDC)/ 5000 MW & less than 10000 MW, which should include rooftop solar (**AEMIL**). **KPTCL, Gujarat SLDC, and AEMIL suggested adding the definition of RE as** the Most Super state/ultra-rich state with an installed RE capacity range of more than 10000 MW. **Maharashtra SLDC** suggested including new definitions, i.e., 'Renewable Most Rich State-1' (with an installed capacity of more than 10000 MW but less than 15000MW) and 'Renewable Most Rich State-2' (combined installed capacity of 15000 MW or more).

2.46. **CER (IIT-K)** suggested that categorization of RE-rich and super RE-rich could be on RE injection rather than RE capacity and could be differentiated across high/low RE injection periods of the day.

Analysis and Decision

2.47. The Commission has noted the suggestions of the stakeholders. The Commission would like to reiterate that Renewable Energy (RE) integration requires adopting effective measures rather than simply relaxing the DSM bands. To facilitate the transition to a large-scale penetration of variable RE sources, special provisions for RE-rich States were already made in the previous DSM Regulations. The Commission has further allowed an additional category of RE Super Rich State in these Regulations with higher dispensations. The Commission emphasizes the importance of improved forecasting, scheduling, and balancing to address the intermittent nature of RE. The existing AS Regulations and the Real-Time Market are also designed to enhance grid management and handle the integration of variable RE capacity more effectively. India is also aiming for the ambitious national target of adding 500 GW of RE capacity by 2030; as such, it is expected that most States with significant RE potential will exceed the 5000 MW threshold as well. Consequently, the Commission believes that further sub-categorizing States based on varying levels of RE penetration is unnecessary. Such categorization would not provide additional benefits but could complicate the regulatory framework. Instead, maintaining the current categorization ensures a manageable and coherent approach to integrating RE while addressing the challenges associated with variable generation.

2.48. On the suggestion that categorization of RE-rich and super RE-rich should be on RE injection rather than RE capacity, the Commission is of the view that the installed capacity is a fixed number, whereas generation/injection could vary, and as such categorisation based on injection/generation would be difficult to implement, especially for wind and solar generation resources embedded in a State control area. Therefore, the Commission considers it appropriate to categorize States based on installed RE capacity, as this factors in the challenges of integrating variable renewable energy into the grid.

2.49. Definition of Reference Charge Rate (Regulation 3(1)(x))

Commission's Proposal

2.50. The Commission had proposed the following definition of Reference Charge Rate in Regulation 3(1)(x) of the Draft Regulations:

*(x) '**Reference Charge Rate'** or 'RR' means (i) in respect of a general seller whose tariff is determined under Section 62 or Section 63 of the Act, Rs/ kWh energy charge as determined by the Appropriate Commission, or (ii) in respect of a general seller whose tariff is not determined under Section 62 or Section 63 of the Act, the daily weighted average ACP of the Day Ahead Market segments of all the Power Exchanges, as the case may be;*

Comments received

2.51. **Tata Power, ITPCL** suggested including the 'benchmark rate' determined by the MoP Committee for generating plants operating under Section 11 directions by the Ministry of Power (MoP) in the definition. **IL&FS Tamil Nadu Power Company Limited (ITPCL)** further sought clarification on the reference rate for generating stations whose tariff has been adopted under Section 63 but is operating under Section-11 directions of the MoP with ECR determined by the MoP Committee. It was also mentioned that the tariff notified by the MoP when the power plant is being directed under section 11 as the ECR notified on a particular date by the MoP (revised on a fortnightly basis) is effective from a few days before the notification itself and real-time 'RR' may be unknown for some of the days.

2.52. **Dhariwal Infrastructure and MB Power** suggested that the charges of deviation for the different categories of entities should be designed in such a manner that it penalizes or incentivizes the entities for hurting or helping the grid to the same extent, irrespective of the power sale portfolio of the generator and tariff, i.e., whether under Section 62 or Section 63 or merchant route. Thus, the Hon'ble Commission may consider capping the charges for deviation for the general sellers whose tariff is not determined under Section 62 or Section 63 of the Act. **CER (IIT – K)** suggested that the RR for merchant power plants should be caped to avoid gaming through over-injection when the frequency is below 50 Hz.

2.53. **ReNew** Pvt. Ltd. suggested defining the 'Reference Charge Rate' separately for General Seller, standalone ESS, and ESS co-located with WS Seller and indicated that the RR of ESS co-located with WS Seller would be the daily weighted average ACP of the DAM segments of all the Power Exchange as specified in the footnote (a) of Regulations 8 (6).

2.54. **NTPC** suggested computing the energy charge for generating stations under Section 62 projects as per the provisions and formulations in Tariff Regulations on a month-to-month basis. Accordingly, the definition may be modified**.**

Analysis and Decisions

2.55. The Commission has examined the suggestions of the Stakeholders. Regarding the inclusion of plants operating under Section 11, it is clarified that Section 11 of the Act stipulates that in extraordinary circumstances, the Appropriate Government may direct a generating company to operate and maintain any generating station. The Reference Charge rate for calculation of deviation charges for such generating station will however, be adopted or approved by the Appropriate Commission and hence effectively would be governed by the provisions as laid down under Regulation 3 (1) (y) of these Regulations.

2.56. Many stakeholders have suggested providing a cap on the Reference Charge Rate against the merchant capacity. The Commission would like to clarify that the reference charge rate for the merchant capacity is linked to the prices discovered in the power exchanges. Since price discovery in the power exchange is driven by demand and supply in the market, it reflects the market reality in a given situation. In addition, the respective price caps prevalent in the market segment will automatically apply while determining the reference charge rate, and as such separate capping is not required.

2.57. Regarding defining 'Reference Charge Rate' separately for General Seller, Standalone ESS, and ESS co-located with WS Seller, the Commission is of the view that the principles for the determination of deviation charges for different regional entities have been provided in these Regulations and shall apply accordingly.

2.58. Further, the Commission has suitably modified the definition of 'Reference Charge Rate' to align the structure with the definition of 'Contract Rate' in order to bring further clarity, as under: -

" (y) ***'Reference Charge Rate' or 'RR'*** *means (i) in respect of a general seller whose tariff is determined or adopted or approved under Section 62 or Section 63 or Section 86(1)(b) of the Act, Rs/ kWh energy charge as determined or adopted or approved by the Appropriate Commission, or (ii) in respect of a general seller whose tariff is not determined or adopted or approved under Section 62 or Section 63 or Section 86(1) (b) of the Act, and selling power through power exchange(s), the price as discovered in the power exchange for the respective transaction; or (iii) in case of captive consumption of a captive generating plant based on resources other than renewable energy sources, the weighted average ACP of the Integrated-Day Ahead Market segments of all the Power Exchanges for the respective time block; or (iv) in case of multiple contracts or transactions including captive consumption, the weighted average of the reference rates of all such contracts or transactions."*

2.59. **Definition of Run-of-River Generating Station (Regulation 3(1)(y))**

Commission's Proposal

2.60. The Commission had proposed the following definition of Run-of-River Generating Station in Regulation 3(1)(v) of the Draft Regulations:

*(y)**Run-of-River Generating Station**' or '**RoR generating station**' means a hydro generating station which does not have upstream pondage;*

Comments received

2.61. **IPCL** suggested including small hydro projects with pondage of about 3 hours in the definition.

Analysis and Decisions

2.62. The Commission has noted the suggestion and would like to clarify that the definition of RoR generating station has been adopted from the CERC Tariff Regulations and does not warrant any change.

2.45 Definition of WS seller (Regulation 3 (1) (cc)

Commission's Proposal

2.63. The Commission had proposed the following definition for WS Seller in Regulation 3(1)(cc) of the Draft Regulations:

***(cc) 'WS seller'** means a seller in the case of a generating station based on wind or solar or a hybrid of wind-solar resources.*

Comments received

2.64. JSW suggested that the definition of WS seller may be modified as "means a generating station based on wind or solar or hybrid of wind and solar resources with or without ESS."

Analysis and decision

2.65. The Commission has noted the suggestion and made suitable changes in the definition of "WS seller" in the final regulations (DSM Regulations 2024).

2.66. **Additional Definition for DIC**

Comments received

2.67. **EDF Renewable Pvt Ltd, Amplus Solar,** and **WBSEDCL** suggested incorporating the definition of DICs and Pooling Station

Analysis and Decisions

2.68. The Commission is of the view that the words 'Pooling Station' and 'DICs' will have the same meaning as provided in the Grid Code and CERC Sharing Regulations, 2020. As such, these terms are not required to be defined in the DSM Regulations.

3. Scope (Regulation 4)

Commission's Proposal

3.1. The Commission had proposed the following in Regulation 4 of the Draft Regulations: *These regulations shall be applicable to all grid connected regional entities and other entities engaged in inter-State purchase and sale of electricity.*

Comments received

3.2. **Assam DISCOM** suggested implementing the new draft DSM Regulations only after full implementation of the SAMAST Project.

3.3. **O2 Power and Azure Power** suggested making effective the proposed Regulations only on new projects as existing projects with fixed tariffs face worsening profitability and viability issues due to further tightening of DSM bands, whereas the new projects can factor in the impact of the new Regulations in their tariff bids. Alternatively, the revised DSM can be recognized as a "Change in Law" event so that the existing wind and solar power plants can claim compensation for the extra financial impact incurred due to the implementation of new regulations.

3.4. **MSPL** suggested that it basically represents the retrospective operation of these Regulations, and all WS projects will now have to follow these Regulations. Such retrospective tightening of the bands should be avoided, and the existing operational plants, including plants that have been bid out on the day of notification of these draft regulations, should be excluded from the applicability of these regulations. It is analysed that the impact is two times higher in DSM numbers compared to the existing regulation.

Analysis and Decision

3.4 In response to the concerns raised regarding the application of new regulations to the existing renewable energy (RE) projects or to treat it as a 'Change in Law,' the Commission would like to reiterate that the regulatory measures, such as the Deviation Settlement Mechanism (DSM), are essential for maintaining grid discipline and cannot be considered as permanent exemptions or rights for any party. The purpose of DSM is to deter violations and ensure stability in the grid, and it is necessary that all projects, both existing and new, adhere to these standards.

3.5 Moreover, the regulations are subject to change over time, and investors should be aware of this. The new regulations do not infringe upon any fundamental rights of stakeholders but are rather a part of the evolving regulatory landscape. Therefore, the Commission believes it is appropriate to apply these regulations uniformly across both the existing and the future RE projects.

3.6 On the suggestion of deferring the implementation of DSM Regulations until full implementation of SAMAST in the State, the Commission would like to clarify that the implementation of SAMAST falls under the jurisdiction of the State Commissions and the DSM framework has been in place for inter-state transactions for more than a decade now. Accordingly, the Commission does not find any merit for deferral of DSM implementation till SAMAST implementation. Further, the Commission has been actively engaging with the State Commissions through the Forum of Regulators to emphasize the importance of proper scheduling and deviation settlement mechanisms at the State level, which are crucial for ensuring grid security.

4. Adherence to Schedule and Deviation (Regulation 5)

Commission's Proposal

4.1. The Commission had proposed the following in Regulation 5 of the Draft Regulations:

(1) For the secure and stable operation of the grid, every grid-connected regional entity shall adhere to its schedule as per the Grid Code and shall endeavour not to deviate from its schedule.

(2) Deviation shall generally be managed through the deployment of Ancillary Services, and the computation, charges, and related matters in respect of such deviation shall be dealt with as per the following provisions of these regulations.

Comments received

4.2. **IPCL/Assam Discom** suggested adding a new clause that Deviation caused due to transmission constraints/corridor constraints may not be considered as deviation. Further Deviation caused during Ramping up (synchronisation or else) and Ramping down may also not be penalised.

4.3. **The Association of Power Producers** commented that the expectation from a generating station to strictly adhere to its schedule is unrealistic and objected that keeping frequency as the only consideration for DSM may not be realistic. It was requested that a penalty free deviation band may be considered.

4.4. **BRPL** suggested that RLDC should display on a day-ahead basis slot-wise capacity being deployed under the Ancillary service without any load curtailment for public use as Ancillary service is a proposed market mechanism to manage deviation.

Analysis and Decision

4.5. The Commission has noted the suggestions of the Stakeholders. On the issue of deviation due to transmission constraint/corridor constraint, as stated earlier, the Commission would like to reiterate that this is a subject matter of the Grid Code and beyond the scope of the DSM Regulations. The issue has been dealt with in detail under Sub Regulation (3) of Regulation 49 of the Grid Code, 2023.

4.6. The Commission does share the understanding that it may not be technically or operationally feasible for the generators to ensure zero deviation all the time and has accordingly made suitable provisions in the final regulations to address this concern. However, the effort of all the grid-connected entities should be to adhere to and not deviate from the schedule. On the suggestion of displaying the capacity deployed under Ancillary Services in advance, the Commission would like to point out that this is beyond the scope of these regulations and can be dealt with under the Ancillary Service Regulation, if required.

4.7. The Commission would like to reiterate that load generation balance is the prime objective of system operation. This requires the generators and the drawee entities to adhere to their schedule. The Sellers and buyers can avail of various avenues enabled by the policy and regulatory framework to buy and sell electricity closer to the actual time of delivery. After all such avenues are over, i.e., after the gate closure, the system operator takes over and manages the imbalance or deviation through the deployment of ancillary services. The proposed regulations framed on this philosophy provide that all grid-connected entities shall adhere to their schedules and deviation, if any, shall be managed by the system operator through ancillary services, and charges for such deviation shall be governed by the proposed DSM Regulations. Accordingly, the Commission does not find any reason to modify the provisions.

5. Computation of Deviation (Regulation 6)

Commission's Proposal

5.1. The Commission had proposed the following in Regulation 6 of the Draft Regulations:

(1)Deviation in a time block for general sellers shall be computed as follows:

Deviation-general seller (DGS) (in MWh) = [(Actual injection in MWh) – (Scheduled generation in MWh)].

Deviation-general seller (DGS) (in %) = 100 x [(Actual injection in MWh) – (Scheduled generation in MWh)] / [(Scheduled generation in MWh)].

(2)Deviation in a time block for WS sellers shall be computed as follows:

Deviation-WS seller (DWS) (in MWh) = [(Actual Injection in MWh) – (Scheduled generation in MWh)].

Deviation-WS seller (DWS) (in %) = 100 x [(Actual Injection in MWh) – (Scheduled generation in MWh)] / [(Available Capacity)].

(3)Deviation in a time block for buyers shall be computed as follows:

Deviation- buyer (DB) (in MWh) = [(Actual drawal in MWh) – (Scheduled drawal in MWh)].

Deviation- buyer (DB) (in %) = 100 x [(Actual drawal in MWh) – (Scheduled drawal in MWh)] / [(Scheduled drawal in MWh)].

Comments received

5.2. Many stakeholders, such as **NRPC, IPCL, TNPPA, PCKL, KPTCL, MSEDCL, AP Discoms, and APSLDC** suggested reconsidering available capacity in the denominator for computation of deviation for WS sellers. It has been highlighted that in many states, the total WS Seller capacity has already exceeded more than 50% of total capacity, and it is now a mature technology and hence should be treated at par with other sellers. It has been claimed that even with advanced technologies available in the global market, the WS sellers are unwilling to invest in technologies to increase the accuracy of forecasts. Every user in the nation should always be measured using the same standard. Accordingly, it was requested to consider 'scheduled generation' in the denominator instead of 'available capacity' as 'available capacity' in the denominator creates a disparity between the thermal and wind-solar plants. According to these stakeholders, using scheduled generation in the denominator would encourage

WS sellers to estimate wind-solar generation schedules at more accurate levels. More accurate forecasting technologies are now available, which provide data regarding wind speed and cloud coverage on a daily basis. Further, it was also pointed out by MSEDCL and Prayas that the Tamil Nadu Electricity Regulatory Commission (TNERC) has notified "Tamil Nadu Electricity Regulatory Commission (Forecasting, Scheduling and Deviation Settlement and related matters for Wind and Solar Generation) Regulations, 2024" wherein the Commission has incorporated formula for Deviation of WS seller with scheduled generation in the denominator. Prayas, in its comments, also suggested moving quickly towards a new formulation with scheduled generation in the denominator. **Maharashtra SLDC** suggested considering (X% of scheduled generation in MWh + Y% of Available Capacity in MWh) in the denominator for calculating the Deviation % for WS seller. **Gujarat SLDC, AEML, and UPSLDC** suggested that to give equal weightage to available capacity and scheduled generation in the denominator while computing deviation error in % for WS sellers.

5.3. **PFI** suggested linking the deviation of Wind/Solar sellers and RoR generating stations with frequency and having the Charges for Deviation for these sellers the same as General Sellers provided the Deviation band for Wind sellers is increased to 15%. **PFI** also suggested that alternatively, Deviation (in %) of WS seller should be on a Scheduled generation basis with the proviso that if scheduled generation is less than 10% of Available capacity, then 10% of Available capacity should be considered as scheduled generation in the denominator for the calculation.

5.4. **MNRE and Solarpack** suggested bringing uniformity in the units of the parameters. **IPCL** suggested that the deviation for WS sellers/buyers should be computed on a regional basis, and the net deviation charges should be apportioned among the WS sellers/ buyers of respective regions.

5.5. **NTPC** suggested defining **S**cheduled Generation as the sum of beneficiary Schedule, SCED, Market operation Schedule, TRAS, and SRAS to ensure uniformity in DSM accounts issued by different RPCs.

5.6. **CER (IIT-K**) suggested using a true or near-true definition of scheduling (forecasting) error. It was also suggested that as a transition, the Commission may consider a graded path for implementation of a weighted average of the available capacity and schedule generation for the denominator.

Analysis and Decision

5.3 The Commission has considered the suggestions of the stakeholders. Some of the stakeholders have suggested using ‘Scheduled Generation’ in the denominator for the calculation of deviation % for WS seller, while some have suggested using both ‘Available Capacity’ as well as ‘Scheduled Generation’ in the denominator with a certain weightage allotted to it. The Commission acknowledges the importance of shifting from a deviation formula based on available capacity to one based on scheduled generation. This change is necessary to encourage more accurate forecasting and scheduling by renewable energy (RE) generators. With advancements in technology and the availability of real-time data on wind speeds and cloud coverage, the ability to predict generation levels has significantly improved, thereby reducing the margin for error between actual and scheduled generation. India's ambitious goal of achieving 300 GW of renewable energy capacity by 2030 underscores the need for stricter deviation criteria to ensure grid stability. As renewable energy plays a larger role in the energy mix, grid security becomes increasingly critical. Deviations in variable renewable energy generation can pose significant challenges to grid stability, and transitioning to a schedule-based deviation mechanism is essential for mitigating these risks.

5.4 The Commission recognizes that while RE generators have historically been given certain advantages in DSM due to the intermittent nature of their output, the landscape has evolved over the period. With improvement in forecasting techniques and the growing importance of grid security, it is appropriate to gradually align the deviation criteria for RE generators with those applicable to conventional generators. However, the Commission also understands the inherent complexities in forecasting wind and solar generation. Therefore, the Commission believes that providing some relaxations—over and above those available to general sellers— continues to remain necessary. As such, the Commission has decided that the existing formula, as provided in the draft, will continue to be effective up to 31.03.2026. Post this, the formula of deviation will be replaced from available capacity to scheduled generation in a phased manner, for which separate Order(s) will be issued by the Commission after due consultations with stakeholders.

5.5 On the suggestion of providing an additional formula for deviation in respect of ‘WS Buyer’ by replacing Scheduled Generation to Available Capacity in the denominator, the Commission would like to clarify that Buyers are already categorized based on the

RE installed capacity within the State, as RE Rich State and Super RE Rich State. For such States, the DSM Regulations have already provided for additional relaxation by way of allowing broader deviation volume bands compared to General Buyers. Therefore, no further modification in the definition of percentage deviation is deemed necessary. Further, these DSM Regulations are applicable to the grid connected regional entities and other entities engaged in inter-State purchase and sale of electricity. Hence, it is apt to calculate deviation entity-wise and not region-wise.

5.6 Some stakeholders have suggested that deviations resulting from transmission constraints should not be considered deviations, while some of the stakeholders suggested that deviations occurring during ramping up and ramping down should not be penalised. One stakeholder also sought clarity on the schedule, which should, include SCED and Ancillary Schedule for calculation of deviation. The Commission would like to clarify all these issues have been dealt with in the IEGC regulations adequately and are, beyond the scope of these regulations. Deviation under the DSM Regulations will be calculated based on the schedule or any revised schedule finalized in accordance with the Grid Code.

5.7 Based on the suggestions received, the Commission has modified the formula for Deviation of WS Seller as under: -

" *Regulation 6 (2): Deviation in a time block for WS sellers shall be computed as follows:*

a) For the period from the date of commencement of these regulations to 31.03.2026

Deviation-WS seller (D_{WS}) (in MWh) = [(Actual Injection in MWh) – (Scheduled generation in MWh)];

Deviation-WS seller (D_{WS}) (in %) = 100 x [(Actual Injection in MWh) – (Scheduled generation in MWh)] / [(Available Capacity)];

b) For the period from 01.04.2026 onwards

Deviation-WS seller (D_{WS}) (in MWh) = [(Actual Injection in MWh) – (Scheduled generation in MWh)];

Deviation-WS seller (D_{WS}) (in %) = 100 x [(Actual Injection in MWh) – (Scheduled generation in MWh)] / [(X% of Available Capacity) + (100 - X) % of Scheduled Generation):

Provided 'X' shall be stipulated by the Commission through separate order(s) after public consultation"

6. Normal Rate of Charges (Regulation 7)

Commission's Proposal

6.1. The Commission had proposed the following in Regulation 7 of the Draft Regulations:

(1) The Normal Rate (NR) for a particular time block shall be equal to the sum of:

(a) 1/3 [Weighted average ACP (in paise/kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges];

(b) 1/3 [Weighted average ACP (in paise/kWh) of the Real-Time Market segments of all the Power Exchanges]; and

(c) 1/3 [Ancillary Service Charge (in paise/kWh) computed based on the total quantum of Ancillary Services deployed and the net charges payable to the Ancillary Service Providers for all the Regions].

Provided that in cases where there is no despatch of Ancillary services in a time block or where the net charges for Ancillary services are receivable in Deviation and Ancillary Service Pool Account, the Ancillary Service Charge shall not be considered for computation of Normal Rate (NR). Further, 50% weight shall be considered for ACP (in paise/kWh) of the Integrated-Day Ahead Market segments, and 50% weight shall be ACP (in paise/kWh) of the Real-Time Market segments of all the Power Exchanges:

Provided further that in case of non- availability of ACP for any time block on a given day, ACP for the corresponding time block of the last available day shall be considered.

(2) The normal rate of charges for deviation shall be rounded off to the nearest two decimal places.

Comments received

6.2. Various stakeholders such as **Gujarat SLDC, Maharashtra SLDC, GUVNL, UPSLDC, RUVNL (RUVITL), APSLDC, AP Discom, MPSLDC, PCKL, etc** suggested capping the Normal Rate of Charge (NR) at Rs 10/kWh, while some stakeholders such as, **Tata Power, Ayana Renewable Power Private Limited** suggested to cap the NR rate at Rs 12/kWh. Stakeholders like **HPSEBL, Amplus Solar, and Vena Energy** also advocated capping of NR rate as the price of the market depends on external factors such as the availability of coal, increasing coal prices, seasonality, etc., over which buyers have no control and the 1/3 weightage of the ACP of AS will also be on a high side. At the same time, Prayas indicated that the price cap in DAM and RTM segments does not fully reflect the real value/price of power in the short term.

6.3. **Maharashtra SLDC** suggested that for computation of normal rate of charge (NR), equal weightage to DAM, RTM, and Ancillary Services should not be given. Indian Chamber of Commerce (ICC) suggested that till the ancillary services market becomes stable and predictable, the weighted average ACP of Integrated DAM and RTM with equal weightage may only be considered. **Prayas**, **CER and IIT-K** suggested giving higher weightage to the RTM being closer to the actual delivery of power.

6.4. **Gujarat SLDC, DVC, GUVNL, etc.** suggested considering only DAM and RTM prices since Ancillary Prices are not available on a real time basis, while **Assam Discom, IPCL, EMA Solutions, etc.** suggested setting a minimum of all prices discovered across I-DAM, and RTM NR as NR.

6.5. **IPCL** suggested that the NR rate should be published prior to the commencement of each respective time block.

6.6. **Adani Power Limited (APL), MPSEX Utility Ltd (MUL), and Torrent Power Ltd (TPL)** suggested that while computing the Normal Rate, a weighted average of price as well as volume traded across these segments should be considered.

6.7. **Jindal Power Ltd (JPL)** suggested that NR should be equal to the average cost of supply of power through all the fuel sources.

6.8. **Indian Energy Exchange (IEX),** in its comments, suggested that AS charges to be considered for computation of NR should be on a gross UP & DOWN basis for over-drawl & under-drawl, respectively, as the net AS charge (in paise/kWh) can be often too low to elicit a rational behaviour from the participants. On the other hand, **WBSLDC** suggested incorporating receivable net block wise charges for AS in the computation of AS.

6.9. **Indi Grid** suggested considering the weighted average price for the TAM market segment across all exchanges and also for the computation, as liquidity in the Term Ahead Market (TAM) segment has increased significantly and stood at 21.95% in January 2024.

6.10. **ERPC,** in its comment, suggested that for non-availability of ACP for any time block on a given day, ACP for the corresponding time block of the last available day may be considered **(ERPC)** or the All India ACP for the corresponding time block may be considered. Issues have been faced in the existing methodology when, for many days, there are no ACPs for that area for a particular time block.

6.11. **IPCL** suggested that in cases where there is no despatch of Ancillary services in a time block or where the net charges for Ancillary services are receivable, the Ancillary Service Charge should not be considered for computation of Normal Rate, whereas **Mr. Shishir Pradhan and ERPC** suggested to consider the Ancillary Service Charge for the corresponding time block of the last available day.

6.12. **Grid India** highlighted that the ACP of DAM, GDAM, and HPDAM are different in a single exchange and suggested that regulations should mention that to arrive at IDAM, the weighted average rate of DAM, GDAM, and HPDAM have to be calculated. They also suggested that Ancillary Service Charge (in paise/kWh) should be computed based on the net quantum of Ancillary Services deployed and the net charges payable to the Ancillary Service Providers for all the Regions. Grid India requested to designate the NLDC as a Nodal Agency for notification of NR for the calculation of DSM charges.

6.13. **SRIPL, Sembcorp, and Solar Park** suggested that daily block-wise ancillary service charges should be published in detail. It was also suggested that these data should be made available in advance in a manner accessible to all the stakeholders to understand the conditions under which Ancillary Service will be utilised for grid support. **KPTCL** suggested making DSM rates available ex ante by the system operator and proposed to add one more proviso suggesting that NLDC/RLDCs should link the Normal rates for a particular block in real time SCADA.

6.14. **Ravi Sankar** suggested that the proposed NR formulation may be modified as a weighted average instead of basing the formulation of 1/3 weightage on all components.

6.15. **New Age Market in Electricity (NAME)** commented that electricity transacted on power exchanges only reflects a small portion of the total supply of energy in the country and, hence, is not a true and fair representation of the overall supply. Entities that are not participating in the power exchanges are being charged on the price in power exchanges, which is not fair. It is proposed that all entities need to be mandated to report about the electricity transacted by them, irrespective of the medium. Accordingly, regulation may reserve the authority to amend the method of price determination as outlined in these regulations by combining various market segments to have the price of a true reflection of the market, and such amendment may be considered necessary in furtherance of the objective of these regulations.

Analysis and Decision

6.16. The Commission would like to reiterate that the objective of the regulations is that all grid connected entities should adhere to schedule and that the deviation should only be inadvertent to be managed by the system operator through the deployment of ancillary services. Hence, charges for deviation should be such that the cost of deploying ancillary services is recovered. The Commission believes that, ideally, the NR should be computed based on the total charges payable to Ancillary Services deployed for all the regions for respective time blocks. However, the Ancillary Service Market still lacks adequate liquidity. On the other hand, the system operator is forced to deploy high-cost resources like gas based generating stations for managing the reserve requirement during evening peak on certain days. The Commission is of the view that the charges for deviation should be such that they may act as a deterrent and discourage the grid connected entities from resorting to using DSM for meeting their energy demand. This, in turn, would encourage the grid connected entities to procure power adequately in advance. The discoms need to improve their forecasting technique and plan their power procurement accordingly. The competitive price discovery mechanism in DAM and RTM segments on power exchange has gained confidence and acceptance with the market participants. The prices in the DAM and RTM reflect the demand-supply situation. Further, Area Clearing Price (ACP) in DAM and RTM represents locational and temporal elements, including transmission congestion. Accordingly, the Commission has considered DAM and RTM for the computation of the NR rate. The rationale behind linkage to the highest of different market prices is to create a deterrent and discourage the grid connected entities from resorting to DSM for meeting their energy need. Further, it has been observed that with a shortfall in reserves, the system operator has deployed costlier RLNG-based gas generating stations since last year during consistently high demand in order to mitigate the likely capacity shortfall. The payment for all such Ancillary Services is made through the Deviation and Ancillary Services Pool Account, which is way above the selling price in the power Exchanges, resulting in a deficit in the DSM Pool Account. Hence, the Commission believes that the NR rate should also reflect Ancillary Service Prices with appropriate weightage reflecting the prices of imbalance closer to the real time.

6.17. Accordingly, the Commission has modified the Regulation as follows:

"Regulation (7) (1) : The Normal Rate (NR) of charges for deviation for a particular time block shall be the highest of (A), (B) or (C), where (A), (B) and (C) are as follows:

(A) the weighted average ACP (in Paise /kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges;

(B) the weighted average ACP (in Paise /kWh) of the Real Time Market segments of all the Power Exchanges;

(C) the sum of:

1/3 [Weighted average ACP (in paise/kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges];

1/3 [Weighted average ACP (in paise/kWh) of the Real-Time Market segments of all the Power Exchanges]; and

1/3 [Ancillary Service Charge (in paise/kWh) computed based on the total quantum of Ancillary Services (SRAS UP and TRAS UP) deployed and the net charges payable to the Ancillary Service Providers for all the Regions]:

…."

6.18. On the issue of capping the NR rate, the Commission is of the view that whenever Ancillary Service (AS) Charge is less than the weighted average ACP of DAM or RTM, the highest of the weighted average ACP of DAM or RTM price would be setting the NR rate and hence price ceiling applicable for DAM and RTM would automatically be applicable to DSM charge for these time-blocks. Hence, the Commission believes that a separate price ceiling is not required for deviation charges during such time blocks. The Commission believes that the Component (C) of Regulation 7(1) would set the NR price during a shortage of capacity or when the system operator has deployed costly generation resources. During such a period, it is important that the weightage of the Ancillary Services Charge should adequately reflect the DSM price and, at the same time should also avoid price shocks in the system. The Commission also directs NLDC to make DSM charges available on their website along with the methodology of computation of NR for each time block.

7. Charges for Deviation (Regulation 8)

7.1. Regulation 8(1): Charges for Deviation, in respect of a general seller other than an RoR generating station or a generating station based on municipal solid waste

or WS seller

Commission's Proposal

7.2. The Commission had proposed the following in **Regulation 8(1)** of the Draft Regulations:

*(1) Charges for Deviation, in respect of a **general seller other than an RoR generating station or a generating station based on municipal solid waste or WS seller** shall be as under:*

Deviation by way of over injection (Receivable by the Seller)	***Deviation by way of under injection (Payable by the Seller)***
(I) For Deviation up to [10% D_{GS} or 100 MW, whichever is less] and f within f_{band}	
(i) @ RR when f =50.00 Hz	*(iv) @ RR when f =50.00 Hz*
(ii) When [50.00 Hz < f ≤50.05 Hz], for every increase in f by 0.01 Hz, charges for deviation for such seller shall be reduced by 10% of RR so that charges for deviation become 50% of RR when f = 50.05Hz	*(v) When [50.00 Hz < f ≤50.05 Hz], for every increase in f by 0.01 Hz, charges for deviation for such seller shall be reduced by 3% of RR so that charges for deviation become 85% of RR when f = 50.05Hz*
(iii) When [49.90 ≤ f < 50.00 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such seller shall be increased by 1.5% of RR so that charges for deviation become 115% of RR when f = 49.90Hz	*(vi) When [49.90 ≤ f < 50.00 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such seller shall be increased by 5% of RR so that charges for deviation becomes 150% of RR when f = 49.90Hz*
(II) For Deviation up to [10% D_{GS} or 100 MW, whichever is less] and f outside f_{band}	
(i) @ zero when [50.05 Hz < f < 50.10 Hz]: Provided that such seller shall pay @ 10% of RR when [f ≥ 50.10 Hz]	*(iii) @ 85 % of RR when [f > 50.05 Hz]*
(ii) @ 115 % of RR when [f < 49.90 Hz]	*iv) @ 150 % of RR when [f < 49.90 Hz]*

(III) ***For Deviation beyond [10% D_{GS} or 100 MW, whichever is less] and f within and outside f_{band}***	
*(i) Such seller shall be paid back @ zero when (**f** < 50.10 Hz):* *Provided that such seller shall pay @ 10% of RR when [f ≥ 50.10 Hz]*	*(ii) Such seller shall pay @ RR when [f ≥ 50.00 Hz];* *(iii) @ 150% of RR when [49.90Hz ≤ f < 50.00 Hz]; and* *(iv) @ 200% of RR when [f < 49.90 Hz]*

Note: System frequency = f and f_{band} = [49.90Hz ≤ f ≤50.05 Hz]

Comments received

7.3. **NTPC** submitted that inadvertent and natural deviations are part of the operation of thermal power plants, and these are beyond the reasonable control of an operator. NTPC highlighted some Technical and Operational difficulties, such as the response of the control system, frequent changes in schedule, Free Governor Mode Operations, etc., in achieving 'Zero Deviation.' It was suggested that an operational Margin of +/-5% may be provided in the frequency range of 49.90 Hz =<Freq =< 50.05 Hz for thermal generators to take care of natural and inadvertent deviations which are beyond the reasonable control of the operator. Within this Margin of +/-5%, any over-injection and under-injection should be settled at the rate of Reference charge rate of the stations.

7.4. **NTPC** also proposed that the DSM charges may be specified in such a way that incentive opportunities and penalty provisions are balanced and equitable, and the incentive for supporting the grid by over-injection or under-injection may be increased up to 50% of the Reference charge rate.

7.5. Stakeholders, such as **JPVL, Adani Power, Jindal Power, SJVN, NTNPL, APP, NHPC,** etc., suggested bringing symmetry in charges for deviation. It was commented that the deviation charges are higher in case **of penalt**y while **lower for incentive**.

7.6. **SJVN, Dhariwal Infra, and BALCO** requested to remove the volume limit beyond the operative frequency band of (49.90Hz to 50.05Hz) and incentivise the seller adequately in line with the existing provisions.

7.7. **Jindal India Thermal Power Ltd (JITPL)** suggested that, technically, it is not possible for generators to maintain the exact schedule. Therefore, a deviation of 10 MW must be allowed without any additional financial impact.

7.8. **ERPC** requested clarification on DSM charges by way of over-injection when a general seller who has given zero schedule or has given drawal schedule is actually injecting firm power into the grid.

7.9. **AP Discom** suggested that the charges for Deviation for a seller, other than RoR, need to be similar to that of a buyer, i.e., instead of RR, the seller needs to pay at the normal rate.

7.10. **THDCIL** suggested that the variation in generation due to FGMO should be compensated to the generator, and the generator should be incentivised for over-injection due to FGMO.

7.11. **Dhariwal** suggested that deviations arising to maintain an up-to-technical minimum should not be charged any additional penalty at any frequency.

7.12. **SJVN** suggested that pondage type of Hydro Power stations should not be penalized for supporting the grid by under injection when the frequency is higher than 50 Hz during high inflow season. SJVN proposed that inherent deadband of +/- 0.03 Hz with respect to a frequency of 50Hz (i.e., 49.97Hz to 50.03 Hz) may be considered in such a way that receivable/ payable by the seller on account of over-injection or under-injection within this deadband maybe @ RR. Beyond the deadband frequency, the increase or decrease in percentage may be varied accordingly.

7.13. **Tata Power** requested clarity on the methodology for the computation of charges for Deviation when the actual deviation of the seller exceeds the volume limit of the seller in a particular time block.

7.14. **APRAAVA** suggested having a constant reference charge rate for a band of frequency close to 50Hz (like 49.98 to 50.02 Hz). It was argued that steep reductions in receivables for marginal variation in the frequency of 0.1 Hz over 50.0 Hz are onerous to the seller as managing a 0.01 Hz frequency gap would be practically impossible.

7.15. **Jaiprakash Power Venture Ltd (JPVL), APL** suggested that the incentive and penalty rate should be the same for under-injection and over-injection for all the three frequency bands or should be RR (or increased and decreased at a similar rate) within the dead band of 49.97 Hz < = f<= 50.03 Hz. While **SJVNL and Tata Power** suggested that deviation charges should be constant when $49.95 \leq f \leq 50.03$ Hz.

7.16. **APL** requested zero penalties on generators for deviation up to a certain margin of over-injection or under-injection when operating at a technical minimum. APL suggested that the generator should not be penalized in case of under-injection when the f > 50 Hz, as the generator is supporting grid frequency, and remove the volume limit of 10% in case of over-injection when grid frequency is less than 49.90 Hz. Further, it was suggested that the existing dispensation when the grid frequency is below 49.90 Hz be continued for the sake of the benefit of grid stability.

7.17. **Jindal power, JITPL** proposed that when [49.90 ≤ f < 50.00 Hz], for every decrease in f by 0.01 Hz, for over injection, the charges for deviation should increase by 10% of RR, while **Indi Grid** proposed that it should be increased by 1.5% of RR till f becomes 49.94 Hz beyond which it should be increased by 5% of RR till f reaches 49.90 Hz. **NHPC** suggested that deviation charges for **over-injection** should increase **by 5% of RR** for hydro generating station as the ECR of hydro generation plant is very low.

7.18. **NLC Tamil Nadu Power Limited** suggested that when f is in the range of 50.00 Hz < f < =50.05 Hz for every increase in f by 0.01 Hz, charges for deviation for over-injection shall be (a) reduced by 3% of RR. **Tata Power** suggested that when 50.03 Hz < f ≤50.05 Hz, the charges for deviation for such seller shall be 50% of RR.

APP, BRPL, NHPC JPVL, etc. suggested that when f ≤ 49.90 Hz, the receivable for over-injection should be 150% of RR. When 50.05 Hz < f, the receivable for over-injection should be zero (**BRPL**), payable for under-injection should be 75% of RR (**NHPC**), and for under-injection when 50.05 Hz < f < 50.10 Hz the deviation charge should be 85% of RR (**WBSEDCL, NLC Tamil Nadu Power Limited);** when f > 50.01 Hz it should be zero **(WBSEDCL)**, 85% of RR (**NLC Tamil Nadu Power Limited);** when f = 50.05 Hz the deviation charges should be 85% of RR **(APP).**

7.19. **APRAAVA** argued that the charges for deviation beyond the 10% DGS or 100 MW and when the frequency is beyond the operative band of 49.90 Hz and up to 50.05 Hz, for under-injection, the deviation charges are very high and should be lower than 200% of RR. According to **MB Power,** only the incremental Deviation of 1% (i.e., 11% -10%) beyond 10% should be governed by Regulation.

7.20. **Dhariwal, SJVN** suggested that the DSM charges for over-injection beyond 10% may be @ 115% of RR without any volume limit, while NSL Group suggested that the DSM charges should be 150% of RR when f ≤ 49.90 Hz. Charges of deviation for **over injection** when f < 49.90 may be kept at 115% of RR (**SJVN, Dhariwal),** 150% of RR (**NSL Group);** when 49.90< f < 49.95 Hz should be 120% of RR (**NSL

Group); when f < 50.0 Hz should be at RR and when 50.00 Hz≤f < 50.10 Hz should be zero (**NHPC**); when f < 50.10 Hz should be paid back 115% of RR (**BALCO**); when f => 50.10 Hz should be zero (**JITPL**), should be paid back to pool at 10% of RR (**BALCO, NHPC).**

7.21. **JVPL, BALCO** suggested that the charges of deviation for **under-injection** when f < 49.90 Hz should be 150% of RR, and when 49.90Hz ≤ f <49.95 Hz such seller should pay at RR (**BALCO**); when 49.90 Hz < = f < 50.00 Hz should be 125% of RR (**JVPL),** 125% of RR **(APP),** 115% of RR **(NLC Tamil Nadu Power Limited);** when 50.00 Hz< f <50.10 Hz **should be at RR (WBSEDCL);** when f ≥ 50.0 Hz such seller shall pay at RR (**BALCO**); when 49.95Hz ≤ f <50.00 Hz **at** 150% of RR; **when** f ≥ 50.05 Hz such seller shall pay at 85% of RR (Dhariwal); **when f > 50.10 Hz** should be zero **(WBSEDCL).**

Analysis and Decision

7.22. The Commission has examined the comments submitted by the stakeholders. The Commission would like to reiterate that a general seller (other than an RoR, MSW, or WS seller) has better control over its generation. However, as pointed out by the stakeholders in their comments, there could be some deviation due to technical reasons such as FGMO, etc. Accordingly, the Commission has provided a frequency band of [49.97 Hz to 50.03 Hz] in which the general seller would be revenue neutral and would be charged at a Reference Rate up to its 10% of schedule or 100MW, whichever is less.

7.23. On the issue of treatment of generating stations running below the minimum turn-down level, the Commission is of the opinion that the contractual issues between a generator and the beneficiaries cannot be grounds for allowing interference with the grid stability and beyond the scope of these regulations.

7.24. On the question of providing higher incentives and reducing penalties, the Commission would like to reiterate that the responsibility to maintain grid frequency and grid security lies with the system operator. The system operator is expected to utilise the ancillary services to maintain grid security, while grid connected entities are expected to adhere to the schedule. DSM is not a trading mechanism, and its design cannot be built around the concept of incentivising any entity. Further, it is important to design the commercial mechanism under DSM in such a way that the cost of deployment of ancillary services could be recovered through DSM and the Ancillary

Service Pool Account. Accordingly, the charges for general sellers **<u>other than</u> an RoR generating station and a generating station based on municipal solid waste** have been specified in the final regulations as follows:

"Regulation 8 (1): Charges for Deviation, in respect of a **general seller (<u>other than</u> an RoR generating station and a generating station based on municipal solid waste)** shall be as under:

Deviation by way of over injection (Receivable by the Seller)	**Deviation by way of under injection (Payable by the Seller)**
(I) **For Deviation up to [10% D_{GS} or 100 MW, whichever is less] and f within f_{band}**	
(i) @ RR when [49.97 Hz $\le$ f $\le$50.03 Hz]	(iv) @ RR when [49.97 Hz $\le$ f $\le$50.03 Hz]
(ii) When [50.03 Hz < f $\le$50.05 Hz], for every increase in f by 0.01 Hz, charges for deviation for such seller shall be reduced by 25% of RR so that charges for deviation become 50% of RR when f = 50.05Hz	(v) When [50.03 Hz < f $\le$50.05 Hz], for every increase in f by 0.01 Hz, charges for deviation for such seller shall be reduced by 7.5% of RR so that charges for deviation become 85% of RR when f = 50.05Hz
(iii) When [49.97 Hz > f $\ge$ 49.90 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such seller shall be increased by 2.15% of RR so that charges for deviation become 115% of RR when f = 49.90Hz	(vi) When [49.97 Hz > f $\ge$ 49.90 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such seller shall be increased by 7.15% of RR so that charges for deviation becomes 150% of RR when f = 49.90Hz
(II) **For Deviation up to [10% D_{GS} or 100 MW, whichever is less] and f <u>outside f_{band}</u>**	
(i) @ zero when [50.05 Hz < f < 50.10 Hz]: Provided that such seller shall pay @ 10% of RR when [f $\ge$ 50.10 Hz]	(iii) @ 85 % of RR when [f > 50.05 Hz]
(ii) @ 115 % of RR when [f < 49.90 Hz]	(iv) @ 150 % of RR when [f < 49.90 Hz]
(III) **For Deviation beyond [10% D_{GS} or 100 MW, whichever is less] and f within and outside f_{band}**	
(i) @ zero when (***f*** < 50.10 Hz): Provided that such seller shall pay @ 10% of RR when [f $\ge$ 50.10 Hz]	(ii) @ RR when [f $\ge$ 50.00 Hz]; (iii) @ 150% of RR when [49.90Hz $\le$ f < 50.00 Hz]; and (iv) @ 200% of RR when [f < 49.90 Hz]

"

7.25. Regulation 8(2): Charges for Deviation, in respect of a general seller being an RoR generating station

Commission's Proposal

7.26. The charges for deviation in respect of a general seller being an ROR generating station were proposed in **Regulation 8(2)** of the Draft Regulations as under:

"(2) Charges for Deviation, in respect of a general seller being an RoR generating station, shall be without any linkage to grid frequency, as under:

Deviation by way of over injection (Receivable by the Seller)	**Deviation by way of under injection (Payable by the Seller)**
(i) @ RR for deviation up to [*10% D_{GS} or 100 MW, whichever is less*]; (ii) @ Zero for deviation beyond [*10% D_{GS} or 100 MW, whichever is less*]	(iii) @ RR for deviation up to [*10% D_{GS} or 100 MW, whichever is less*]; (iv) @ 105% of RR for deviation beyond [*10% D_{GS} or 100 MW, whichever is less*] and up to [*15% D_{GS} or 150 MW, whichever is less*]; (v) @ 110% of RR for deviation beyond [*15% D_{GS} or 150 MW, whichever is less*].

Comments received

7.27. **NHPC** provided details of various incidents wherein the operation of ROR plants in the Cascade model depends on upstream plants. It was argued that the upstream station controls the water flow to the downstream, allowing inadequate time for schedule adjustment and, consequently, leading to over injection frequently. Accordingly, it was suggested that the over-injection limit of RoR power station might be enhanced to at least 25%, and the generator should be paid @RR up to 25% or 200MW, whichever is less, as over-injection due to interdependency between two cascading hydro stations is beyond the control of such seller. Similarly, it was suggested that the percentage of deviation limit might be increased in case of under-injection, as the inflow of water is beyond the control of such sellers.

7.28. **Stakeholders** suggested that charges of Deviation for under-injection beyond [15% D_{GS} or 150 MW, whichever is less] should be @105 % of RR (**JPVL, APP).**

NHPC suggested decreasing or eliminating penalties and increasing the % of the deviation volume limit as the inflow of water is beyond the control of the RoR generating station from 10% to 20% and from 15% to 30%.

Analysis and Decision

7.29. The Commission noted the suggestions of the stakeholders for providing a higher band for ROR projects being dependent on many external factors. The Commission agrees with the views of the stakeholders and decides to give special dispensation by increasing the tolerance band from 10% to 15%. Accordingly, the charges for deviation in respect of a general seller and RoR generating station as under*:*

" Regulation 8 (2): Charges for Deviation, in respect of a **general seller being an RoR generating station,** shall be **<u>without any linkage to grid frequency</u>**, as under:

Deviation by way of over injection (Receivable by the Seller)	**Deviation by way of under injection (Payable by the Seller)**
(i) @ RR for deviation up to [*15% D_{GS} or 150 MW, whichever is less*]; (ii) @ Zero for deviation beyond [*15% D_{GS} or 150 MW, whichever is less*]	(iii) @ RR for deviation up to [*15% D_{GS} or 150 MW, whichever is less*]; (iv) @ 105% of RR for deviation beyond [*15% D_{GS} or 150 MW, whichever is less]* and up to [*20% D_{GS} or 200 MW, whichever is less*]; (v) @ 110% of RR for deviation beyond [*20% D_{GS} or 200 MW, whichever is less*].

7.30. <u>Regulation 8(3): Charges for Deviation in respect of a general seller being a generating station based on municipal solid waste</u>

Commission's Proposal

7.31. The charges for deviation in respect of a general seller being a generating station based on municipal solid waste were proposed in **Regulation 8(3)** of the Draft Regulations as under:

" (3) Charges for Deviation, in respect of a general seller being a generating station based on municipal solid waste, shall be without any linkage to grid frequency, as under:

Deviation by way of over injection (Receivable by the Seller)	***Deviation by way of under injection (Payable by the Seller)***
(i) @ contract rate for deviation up to [20% D_{GS}]; *(ii) @ Zero for deviation beyond [20% D_{GS}];*	*(iii) @ 50% of contract rate for deviation up to [20% D_{GS}];* *(iv) @ RR for deviation beyond [20% D_{GS}].*

Comments received

7.32. **Abellon** suggested that the Contract Rate ("CR") be considered as defined in the Power Purchase Agreement, which is inclusive of the Viability Gap Funding and the Tariff component payable by Discoms. Accordingly, the payment on scheduled energy and the actual energy injection are to be made to the WTE Project Developer at the contract rate. It was suggested that the charges for deviation (without linkage to grid frequency) for over-injection and under-injection should be as indicated below:

Over Injection

(i) Upto 20% D_{WTE} :- Receivable by the Seller for Actual injection (©Contract rate ("CR")

(ii) Beyond 20% D_{WTE}: Receivable by the Seller for Actual injection @CR

Under Injection

(i) Upto 20% D_{WTE} :- Seller to pay @50% of CR on Scheduled Energy

(ii) Beyond 20% D_{WTE}: Receivable by the Seller for Actual injection @CR

7.33. **GUVNL, IIT-Kanpur** commented that the proposed charges in case of under injection @ 50% of contract rate may enable WtE generators to indulge in gaming for availing undue commercial gain. It was suggested that the charges may be aligned with RoR generating station as proposed in the draft regulations.

Analysis and Decision

7.34. The Commission has noted the comments submitted by the stakeholders and is of the view that the MSW projects should be seen in the context of processing and disposal of waste, and their contribution to social and environmental causes. MSW-based generating stations operate with a heterogeneous combination of solid waste, which is inherently variable, and the same cannot be predicted. If the waste quality varies or is poor, the operating parameters are varied even at the cost of electricity generation to achieve environmental parameters and compliance since the primary objective is to ensure the processing of waste. Accordingly, the Commission is of the view that MSW-based generation stations should be given special dispensation, and accordingly, the tolerance band is retained at 20% for over-injection and under-injection. Further, agreeing with the views of the stakeholders, the Commission has kept the tolerance band revenue neutral for MSW-based generating stations while making sure that in case of under injection up to 20%, the MSW-based generation stations shall pay back the @contract rate. The Regulations have been finalised accordingly as follows:

"Regulation 8 (3): Charges for Deviation, in respect of a **general seller being a generating station based on municipal solid waste,** shall be without any linkage to grid frequency, as under:

Deviation by way of over injection (Receivable by the Seller)	**Deviation by way of under injection** **(Payable by the Seller)**
(i) @ contract rate for deviation up to [*20% D_{GS}*]; (ii) @ Zero for deviation beyond [*20% D_{GS}*];	(iii) @ contract rate for deviation up to [*20% D_{GS}*]; (iv) @ 110% of contract rate for deviation beyond [*20% D_{GS}*].

7.35. **Regulation 8(4): Charges for Deviation, in respect of a WS Seller being a generating station based on wind or solar or hybrid of wind–solar resources, including such generating stations aggregated at a pooling station through QCA**

Commission's Proposal

7.36. For WS seller, the Commission proposed the following in **Regulation 8(4)** of the Draft Regulations:

"(4) Charges for Deviation, in respect of a WS Seller being a generating station based on wind or solar or hybrid of wind–solar resources, including such generating stations aggregated at a pooling station through QCA shall be without any linkage to grid frequency, as under:

Deviation by way of over injection (Receivable by the Seller)	***Deviation by way of under injection (Payable by the Seller)***

(i) for VL_{WS} (1) @ contract rate; *(ii) for VL_{WS} (2) @ 90% of contract rate* *(iii) for VL_{WS} (3) @ 50% of contract rate,* *(iv) beyond VL_{WS} (3) @ Zero;*	*v) for VL_{WS} (1) @ contract rate;* *(vi) for VL_{WS} (2) @ 110% of contract rate;* *(vii) for VL_{S3} @ 150% of contract rate;* *(viii) beyond VL_{WS} (3) @ 200% of contract rate.*

Note: Volume Limits for WS Seller :

WS Seller	***Volume Limit***
A generating station based on solar or a hybrid of wind –solar resources or aggregation at a pooling station	*VL_{WS} (1) = Deviation up to 5% D_{WS}* *VL_{WS} (2) = Deviation beyond 5% D_{WS} and up to 10% D_{WS}* *VL_{WS} (3) = Deviation beyond 10% Dws and up to 20% D_{WS}*
A generating station based on wind resource	*VL_{WS} (1) = Deviation up to 10% D_{WS}* *VL_{WS} (2) = Deviation beyond 10% D_{WS} and up to 15% D_{WS}* *VL_{WS} (3) = Deviation beyond 15% Dws and up to 25% D_{WS}*

Note: In case of aggregation of WS sellers at a pooling station through QCA,

(a) the contract rate for the purpose of deviation shall be equal to the weighted average of the contract rates of all individual WS seller(s) opting for aggregation at the pooling station;
(b) Available Capacity shall be equal to the cumulative capacity rating of wind turbines or solar inverters that are capable of generating power in a given time block;
(c) depooling of deviation charges for WS seller(s) connected to the pooling station shall be as per the methodology mutually agreed upon between the QCA and such individual WS seller(s)".

Comments received

7.37. Some of the stakeholders, such as **RUVNL, Azure Power, Adani Power,**

WIPPA, TPL, Indi Grid, ESPL, Amplus Solar, WIPA, Ayana Renewable power, Apraava, etc., suggested continuing with the existing band as better accuracy of forecasting requires technological breakthrough or at least 1-2 year should be provided to the developers and forecasting agencies to adapt to the change and improve the accuracy. It was also suggested to broaden the DSM band from the proposed level as the narrow band encourages the developers to under schedule. **Amplus Solar** suggested that the new DSM regime should not be introduced at this time, as the last DSM Regulations were introduced less than 14 months ago. The developers are still struggling to adjust themselves to the DSM introduced earlier **. SRIPL** suggested that any changes/amendments to the DSM regime should not be undertaken before 3 years from the introduction of the previous amendment. **MSPL** suggested gradual tightening of the band. **Adani Power** argued that in the case of over-injection, though the generator is not getting paid, the consumers have consumed the power and are paying for it.

7.38. **CEA** suggested that the present Regulations may be continued till this financial year (31st March 2025), after which a trajectory for tightening the deviation limits may be specified with this amendment so that developers can take action accordingly. Further, the dead band should not be relaxed from a pre-existing level as it gives conflicting signals. The band outside the dead band should remain symmetrical. Further, due to the inherent nature of wind generation and the difficulty in forecasting associated with it, the deviation limits for wind generators should be liberal as compared to solar and hybrid generators

7.39. **Ayana Renewable Power, Apraava** suggested that the existing band be continued for a year to understand the impact of aggregation before making changes in the methodology for calculation of the charges for deviation. **WIPPA**, **Apraava** suggested the existing band should continue for existing projects, while **RE Connect** suggested that aggregation of schedules should be allowed in line with the provisions of the IEGC 2023.

7.40. Some of the stakeholders suggested that charges for deviation settlement should be computed at polling stations with aggregation (**Adani Power),** at areas larger than pooling stations **(MNRE),** at multiple PSS level **(JSW),** at company level (**NTPC**), zonal level with each state having 3-4 zones **(Azure power)** or at regional level **(WIPPA, TPL, O2 Power)** for improved grid stability. Some of the stakeholders suggested that the de-pooling of deviation charges for WS seller(s) connected to the pooling station should be as per the methodology approved by the Commission

(WIPPA, Tata Power, Re New, O2 Power, MNRE) as **a** mutual agreement on the procedure between RE developers, will delay the process and will result in multiple litigations in future. **WIPPA, O2 Power, Sembcorp, Tata Power, Re New, and PHDCCI** suggested that such de-pooling methodology may be prepared by NLDC and should be approved by the Commission within 4 weeks. **Azure Power** suggested that the nominal charges for each QCA for aggregation of schedules and co-ordination with RLDC should be fixed by the Commission so as to avoid steep price hikes by any one QCA. **NTPC** suggested that a procedure may be formulated to facilitate company-wide Aggregate scheduling for all the generators falling under a single Regional Load Despatch Centre.

7.41. **Manikaran Analytical Limited, Regent Climate Connect, EDF Renewable India, TPL, and Ayana Renewable Power** suggested that aggregation should be implemented after the finalisation of the detailed procedure for aggregation. While **Azure Power, Prayas** suggested that the proposed deviation bands for Wind should be made applicable to all the RE generators choosing to aggregate their schedules at a pooling station. **Manikaran Analytical Limited** also requested for clarity on the method of calculation of deviation charges in case of aggregation and de-pooling of the same to different generators if there are multiple contract rates and in cases where any generator decides against aggregation at the station. **Adani Power Limited** suggested that QCA/Generator be mandated to furnish the contract rates on affidavit to respective RPC for the purpose of preparation of deviation charge account.

7.42. **EDF Renewable, O2 Power, VENA Energy, Tata Power, MSPL, and Manikaran Analytical Limited** suggested that for Seller based on a hybrid of WS resources deviation band of the technology having higher installed capacity should be applicable. However, **Apraava** suggested that such deviation of hybrid WS resources should be treated as wind resources. In contrast, **WIPA** suggested that in case of aggregation, the applicable Volume limit should be based on a higher quantum of Wind or Solar at the aggregation level. **Grid India** suggested that in the case of a hybrid of Wind-Solar if a hybrid plant initially commissions a wind component (pending commissioning of Solar plant), suitable provision may be added to treat it as a wind source until such time the plant commissions the other component. **Prayas** suggested that the Commission should review the deviation bands after 15 months of effectiveness of the regulation (after considering data for at least 12 months) and should also carry out a separate analysis for hybrid generators.

7.43. **Sustainable Energy Infra Trust (SEIT)** proposed to reduce the deviation charges a penalty for volume limit – $VL_{WS}(3)$ and beyond $VL_{WS}(3)$ such that for VL_{WS} (3) and beyond VL_{WS} (3), deviation charge for over injection could be at 75% and 50% of CR respectively and that for Under injection at 120% and 130% of CR respectively. Mr. Shishir Pradhan suggested reducing the penalty for under injection for VLwS (3) and VLwS (4) at 130% and 150% of CR, respectively.

7.44. **Apraava** suggested that for penalty bands 10-15% and 15-25%, there should be a graded increase in penalty for each 1% increase in penalty rather than a step up increase for the 5% band range or 10% band range for RE projects. In line with the Charges for Deviation of general sellers beyond the dead band, the Charges for Deviation for RE generators should be increased in a graded fashion with a step of 1% volume deviation.

7.45. **KPTCL** suggested similar to conventional generators, treatment for gaming should be included for wind/solar/hybrid generators also. It was suggested that in such cases of gaming, the amount of penalty should be payable by the QCA(s)/Generator(s) to the State Deviation Settlement Mechanism (DSM) Pool as per the procedure to be issued by the RLDC. In case of repeated events of misdeclaration, the RLDC may, after giving due notice, cancel the registration of the QCA.

7.46. Some of the stakeholders suggested to have the following deviation band (Volume Limits) for solar :

i) Dead band/ revenue neutral band ($VL_{WS}(1)$): +/-10% (**Manikaran)**,

ii) Dead band/ revenue neutral band ($VL_{WS}(1)$): +/- 7.5% (**Shishir Pradhan**)

iii) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$ $VL_{WS}(3)$) : 0-10%, 10% - 15%, 15% - 20% (**WIPPA, O2 Power Re Ne, PHDCCI and Juniper, MNRE, SEMBCORP, Solar Park, Sembcorp, RE connect**)

iv) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0-10%, 10% - 15%, 15% - 25% (**Juniper**)

v) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0-10%, 10% - 20%, 20% - 30% (**RE Connect**) with 100% charges for Deviation beyond 30%.

vi) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0- 15%, 15% - 25%, 25% - 30% (**NTPC**)

vii) VLwS (3) should be 10% - 15%, (**AP Discom**)

viii) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0-2.5%, 2.5% - 5%, 5% - 10% (**MP SLDC)**

ix) Maximum limit should be 15% (**MSEDCL**) so that accuracy can be built into the schedules of generators

7.47. Some stakeholders suggested the following deviation band (Volume Limits) for **wind** :

i) Dead Band ($VL_{WS}(1)$): +/-15% (**Manikaran Analytical Limited, EDF Renewable India**),

ii) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$) : 0-15% at No penalty; 15%-25% Deviation at10% of PPA; 25% - 35% Deviation at 20% of PPA; more than 35% Deviation at 30% of PPA (**Ayana Renewable Power)**

x) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0-15%, 15% - 20%, 20% - 25% (**WIPPA, MNRE, O2 Power Re Ne, PHDCCI, SEMBCORP, Solar Park and Juniper**) as most of the improvement in forecasting has happened in the deviation range of > 20% and in more than 85% of time blocks error remains within ±10% for solar and hybrid.

iii) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0- 15%, 15% - 25%, 25% - 30% (**NTPC**)

iv) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0-15%, 15% - 20%, beyond 20% (**RE Connect**) with Charges for Deviation for over injection being CR, 90% of CR and Nil respectively and for under injection being CR, 110% of CR and 150% of CR respectively.

v) VL_{ws} (3) should be 15% - 20% (**AP Discom**)

vi) Band Range ($VL_{WS}(1)$, $VL_{WS}(2)$, $VL_{WS}(3)$): 0-5%, 5% - 10%, 10% - 15% (**MP SLDC)**

vii) Maximum limit should be 20% (**MSEDCL)** so that accuracy can be built in the schedules of generators.

7.48. **Kreate technologies** suggested that the loss in revenue of the generators due to the implementation of the draft DSM regulations would be more than 5% on an annual basis. According to **Kreate technologies**, in the case of over-injection, revenue losses are more than the revenue loss in the existing regulation for deviation up to 19%, while in the case of under-injection, revenue losses are up to 2 times as compared with the existing regulations. **RE Connect** submitted that the introduction of an additional accuracy band and deviation rate(s) increasing from 50% to 100% in case of under-injection indicates that the impact on the Charges for Deviation for wind plant would be approximately 50% more while on solar plant would be 90% more than the current regulatory level based on the simulation of 200 MW wind plant and 340 MW Solar plant. **SRIPL** submitted that the result of the simulation of solar and wind plants, both on an individual and aggregation basis, indicated that the impact on an individual basis increases the charges for Deviation from 90% to 125% and that on an aggregation basis, increases from 3% to 17%. **JSW, SEIT** suggested that the impact of the proposed DSM regime would be detrimental to renewable energy capacity addition and counterproductive to the Hon'ble Prime Minister of India's vision of achieving 500 GW of renewable energy by 2030.

7.49. **Apraava** suggested that in case of sudden changes in weather conditions, generators should be allowed to revise the schedule immediately after 2nd or 3rd time block instead of restricting revision to become effective from 7th or 8th time blocks as mentioned in the Indian Electricity Grid Code (IEGC) 2023 (**Apprava**). **CER (IIT – K)** suggested that the generators should be allowed to revise their schedule from 4 time blocks.

7.50. **MSPL suggested that** gradual tightening in the band may be undertaken, and as the WS seller has been able to consistently perform with +/-15% deviation in most of the time blocks, the band should be kept at 10% for solar and 15%, for Wind generators.

7.51. **WIPPA** suggested that the revised DSM should be applied prospectively, with a clear implementation date, to ensure a smooth transition and clarity for all existing generators or to recognize the revised DSM as a "Change in Law" event. It was further suggested that per unit impact on account of the implementation of the new Regulation may be determined to allow the existing generators to claim compensation for the extra financial impact incurred due to the change in the new deviation band rate.

7.52. **RUVNL** suggested that states with abundant RE resources should be exempted from DSM charges to the extent of over-drawal by the state due to deviations from RE sources.

7.53. **KPTCL** also suggested that if the scheduled generation is zero but there is actual generation in a particular 15-minute block by the wind/solar generator(s), the deviation settlement charges should be collected from those generator(s) at 125% of the capped price for such energy injected.

7.54. **Adani Power Limited (APL)** submitted that various solar and wind developer associations (viz. NSEFI & WIPA) have challenged the DSM Regulations 2022 and the draft DSM Regulations 2024, and the Hon'ble Delhi High Court has granted an interim relief to RE generators by way of no-coercive action while implementing the DSM Regulations, 2022. In view of this, the Commission may keep the public consultation process on the draft DSM Regulations, 2024 in abeyance and await the outcomes of the Writ Petitions filed by RE associations challenging the DSM Regulations, 2022 and the Draft DSM Regulations, 2024 in the Delhi High Court. It is contended that the draft DSM Regulations, 2024 override the Interim Order dt. 12.01.2033 issued by the Hon'ble Delhi High Court in which no coercive action was assured for WS sellers under DSM Regulations, 2022.

Analysis and Decision

7.55. The Commission has examined the comments received from the stakeholders. Some stakeholders have objected to the tighter band proposed in the draft Regulations for WS sellers by arguing that this would have an adverse financial impact on RE developers, while some stakeholders have advocated for tightening the deviation bandwidth. Some have suggested continuing with the tolerance band provided in the interim order in Petition No 01/SM/2023. Some have argued to apply the new regulation prospectively or allow change in law for managing revenue loss due to tighter band. Some have requested to reconsider the zero charges for over injection above certain limits as it will go against the promotion of RE power. Some stakeholders have advocated for aggregation at multiple pooling stations, at the regional level, etc., in order to reduce the impact of the tighter band proposed and have requested the Commission to direct the system operator to formulate a procedure for aggregation along with de-pooling methodology by QCA. Some sought clarity on the methodology of computation at the aggregation level and suggested required checks and balances to be in place for any dispute resolution among the parties. Some stakeholders have requested to apply the tolerance band of wind for hybrid projects, while some stakeholders have requested to reduce the existing gate closure of 7^{th} – 8^{th} time blocks to 4 time-blocks for WS sellers to better forecast their schedule.

7.56. The Commission is of the view that the generation from wind and solar based generating stations is variable in nature, and as such, they have been given special dispensation while ensuring that variability could be minimised for proper forecasting. The forecasting and scheduling framework for WS sellers has been in place since 2017, and it is expected that based on the experience gained over the period, there would be an improvement in forecasting techniques, which could be deployed in the larger interest of grid security. The Commission believes that with an increase in penetration of Wind and Solar into the grid, a large tolerance band coupled with a relaxed error/deviation formula for such resources would have a serious operational impact on grid management and a financial impact on the other grid connected entities. Further, with a significant decrease in the cost of energy storage technologies, the Commission believes the deployment of energy storage technologies would also need to be considered by the RE developers to reduce the impact on grid security arising out of their intermittency. However, the Commission also agrees with the stakeholders that sufficient time may be given to adjust to necessary realignment with the DSM band at par with other generators. Accordingly, the Commission has decided to continue with the existing tolerance band of 15% and 10% for Wind and Solar based power projects, respectively, for some more time, i.e., till 31.03.2026. Subsequently, the tolerance band of 10% and 5% for Wind and Solar would be implemented from 01.04.206 onwards.

7.57. Accordingly, the Commission has decided to continue with the existing volume limits till 31.03.2026 but with the removal of asymmetry in the charges for deviation for deviation 'beyond $VL_{WS}(2)$' in accordance with the suggestion of the Expert Committee. From 01.04.2026, the new bandwidth for the deviation calculation shall come into effect. The Commission also feels that there must be a balance between the wrong doing and the penalty imposed against such wrong doing, and the deterrent charges stipulated under the DSM Regulations 2022 should be sufficient to ensure grid discipline. The Commission feels that continuation of the existing volume limits till 31.03.2026 will provide sufficient time for the WS sellers to take necessary measures and make a realignment to adhere to the new DSM bandwidth applicable from 01.04.2026 onwards.

7.58. As regards the suggestion of applicability of the reduced exemption band to the new projects only and continuation of the existing band for the existing projects for their project viability and for the treatment of the DSM as a 'change in law event' for the existing projects, the Commission is of the view that this contention does not sustain as it does not apply against legislative action. The principles of estoppel cannot override the provisions of a statute or law. Where a statute imposes a duty by positive action, estoppel cannot prevent it. In the instant case, DSM is in the nature of a deterrent against violation of grid discipline and a special dispensation in regard to payment of DSM charges cannot be claimed to be a promise or a right in perpetuity. Furthermore, by these regulations any substantive rights of the stakeholders are not getting infringed. The Regulations are subject to periodic change and the investors are expected to factor in these realities before making any investment.

7.59. Regarding the suggestion of the stakeholders to provide for compensation for the deviation even beyond the volume limits, the Commission would like to reiterate that DSM is not a trading platform, nor is it a mechanism that guarantees fixed revenue for any project. DSM is a deterrent mechanism, and as such, basing project viability on revenue from DSM cannot be considered a sound business decision. It's common knowledge that the Regulations are subject to change periodically, and it is expected that the project developers duly factor in these realities while conceptualising a project.

7.60. The Commission is of the view that the benefits of developments are equally available to the existing projects as well as the new projects. As such, the Commission is not inclined to consider the suggestion of continuing with the exemption band of +/- 15% for the existing WS sellers while applying the new norms only for the new projects.

7.61. Regarding the suggestions of the stakeholders to consider aggregation at the larger area for WS Seller, the Commission would like to highlight that the IEGC has enabled aggregation at the pooling station through QCA for WS Seller. Detailed provisions for aggregation at a pooling station are already made in the IEGC, and the developers should make the best use of these provisions to reduce error and consequent DSM impact. There is no specific need for the developers to wait for any detailed procedure for aggregation at the pooling station in view of the explicit provisions in this regard in the IEGC. As such, the Commission does not find any merit in the argument that the new tolerance band should be introduced after the publication of a detailed procedure on aggregation at a pooling station. The Commission would like to clarify that the IEGC provides a detailed procedure for the pooling of pooling stations, which is not a pre-condition for aggregation at the pooling station. However, the Commission directs Grid-India to suggest, based on the experience gained on aggregation at pooling stations, the methodology for aggregation of multiple pooling stations for approval of the Commission as per the Grid Code.

7.62. Regarding the suggestions of the stakeholders to provide clarity in the methodology for calculation of charges for Deviation under various scenarios and for the methodology for de-pooling for aggregation, etc., the Commission would like to clarify that de-pooling and commercial settlement between the QCA and the WS sellers are private arrangements between the parties, and the Commission would not like to intervene on these aspects at this stage.

7.63. Regarding the suggestions of the stakeholders for allowing the revision in the schedule effective in 4th time blocks rather than 7th or 8th time block, the Commission is of the view that the matter is related to the Grid Code and beyond the scope of the DSM Regulations.

7.64. On the issue of keeping the DSM Regulations in abeyance in view of the Writ Petitions in the Hon'ble High Court challenging DSM Regulation, 2022 and the draft DSM Regulations, 2024, the Commission would like to clarify that the said interim order dt 12.01.2023 in W.P. (C) 270/2023 & CM APPL. 1074/2023 (filed by NSEFI) passed by the Hon'ble Delhi High

Court not to take coercive steps on the Petitioner therein, pursuant to the DSM Regulations, 2022, cannot be construed as an order staying the implementation of the said regulations. Even otherwise, the said order does not bar the statutory obligation of CERC to frame the Regulations and/ or exercise its legislative function. Further, the Hon'ble High Court has not granted any stay in the Writ Petition No. 8283 of 2024, whereby the draft DSM Regulations 2024 have been challenged. The DSM Regulations, 2024, have been issued in exercise of the power conferred under Section 178, read with clauses (c) and (h) of sub-section (1) of Section 79 of the Electricity Act, 2003 (36 of 2003). The said Regulations have been issued after following the due process of extensive stakeholder consultation.

7.65. Provision 8(4) in the final regulations, accordingly, reads as under:-

"Regulation 8(4): Charges for Deviation, in respect of **a WS Seller,** including such generating stations aggregated at a pooling station through QCA shall be <u>without any linkage to grid frequency</u>, as under:

Deviation by way of over injection (Receivable by the Seller)	**Deviation by way of under injection (Payable by the Seller)**
(i) for $VL_{WS}(1)$ @ contract rate; (ii) for $VL_{WS}(2)$ @ 90% of contract rate (iii) beyond $VL_{WS}(2)$ @ Zero;	iv) for $VL_{WS}(1)$ @ contract rate; (v) for $VL_{WS}(2)$ @ 110% of contract rate; (vi) beyond $VL_{WS}(2)$ @ 200% of contract rate'

Note-1: Volume Limits for WS Seller (VL_{WS}):

(i) Volume limits of a WS Seller for the period from **the date of commencement of these regulations** to 31.03.2026 shall be as under:

WS Seller	**Volume Limit**
A generating station based on solar or a hybrid of wind –solar resources	$VL_{WS}(1)$ = Deviation up to 10% D_{WS} $VL_{WS}(2)$ = Deviation beyond 10% D_{WS} and up to 15% D_{WS}
A generating station based on wind resource	$VL_{WS}(1)$ = Deviation up to 15% D_{WS} $VL_{WS}(2)$ = Deviation beyond 15% D_{WS} and up to 20% D_{WS}

(ii) Volume limit of a WS Seller for the period from 01.04.2026 onwards:

WS Seller	**Volume Limit**
A generating station based on solar or a hybrid of wind –solar resources	$VL_{WS}(1)$ = Deviation up to 5% D_{WS} $VL_{WS}(2)$ = Deviation beyond 5% D_{WS} and up to 10% D_{WS}
A generating station based on wind resource	$VL_{WS}(1)$ = Deviation up to 10% D_{WS} $VL_{WS}(2)$ = Deviation beyond 10% D_{WS} and up to 15% D_{WS}

Note-2: In case of aggregation of WS sellers at a pooling station through QCA

(a) the contract rate for the purpose of deviation shall be equal to the weighted average of the contract rates of all individual WS seller(s) opting for aggregation at the pooling station;

(b) Available Capacity shall be equal to the cumulative capacity rating of wind turbines or solar inverters that are capable of generating power in a given time block;

(c) de-pooling of deviation charges for WS seller(s) connected to the pooling station shall be as per the methodology mutually agreed upon between the QCA and such individual WS seller(s)."

7.66. **Regulation 8 (5): Charges for Deviation, in respect of a Standalone Energy Storage System (ESS),**

Commission's Proposal

The Commission had proposed the following in **Regulation 8(5)** of the Draft Regulations:

"(5) Charges for Deviation, in respect of a Standalone Energy Storage System (ESS), shall be at par with the charges for Deviation for a ***general seller*** ***other than*** ***an RoR generating station or a generating station based on municipal solid waste or WS seller*** *as specified in Clause (1) of this Regulation."*

Comments received

7.67. **CER (IIT – K), Ayana Renewable Power, and Amplus Solar** suggested that separate treatment needs to be provided for the ESS based on Pumped Storage Projects (PSP), as the size of PSP is comparatively higher than that of the BESS.

7.68. **Sekura, Azure Power, and ReNew Power** commented that treating standalone ESS at par with general sellers would hamper the development of ESS and may be treated at par with RE.

7.69. **MNRE** suggested providing charges for both drawal and supply of energy for standalone ESS. **ICC, WIPPA, Sembcorp, HFE, and SRIPL** suggested that the Charges for Deviation specified in the proposed Regulation may be applicable for Standalone ESS operating in generation mode only. However, for drawl of power while charging the standalone ESS, the applicable charges at par with the Buyer except for Renewable Energy (RE) Rich or Super RE Rich States may be provided. **Greenko** suggested that the Charges for Deviation for

Standalone ESS in charging mode may be considered at par with a WS seller, where Over-Injection may be considered as Under Drawal and Under-Injection as Over- drawal. While requesting for clarity on the treatment of deviation in case of drawal schedule of ESS for charging, **Tata Power** also requested clarity with respect to the treatment of behind-the-meter storage technologies.

7.70. **Indi Grid** suggested that Charges for Deviation for standalone ESS should be exempted for ESS being utilised for Ancillary services. It was also suggested by **Indi Grid** that the volume limit should be provided as "15% DGS or 150 MW, whichever is less."

Analysis and Decision

7.71. The Commission has examined the suggestions of the stakeholders and based on discussion held with the experts on the subject, the Commission has decided to bring clarity on the treatment of deviation in both the charging and discharging modes of a standalone ESS. The Commission noted that ESS can engage in both drawl and supply of energy When an ESS is supplying power, the charges for deviation in respect of a general seller should be applied for standalone ESS being firm in its despatch. The Standalone ESS, being BESS or PSP, can readily adhere to its schedule during generation mode and hence can be treated at par with a general seller (other than an RoR generating station or a generating station based on municipal solid waste) or WS seller. However, during the charging mode, especially with PSP technologies, it has been pointed out that the fixed-speed PSP turbines cannot operate at partial load and can run only at 100% load in pumping mode. It has been pointed out that various PSP projects that would be commissioned in the near future are based on the fixed speed turbine technology and would require a facilitative framework in the initial phase of development to gain some operational experience. Taking into consideration the technical difficulties and the possibility of evolving various flexible contracts that may evolve with the commissioning of PSP projects, the Commission is of the view that till 31.03.2026, a standalone ESS, being PSP, can be given some special dispensation by treating it at par with a WS Seller during charging mode. Further, to bring clarity on the treatment for drawal and supply for a standalone ESS, the Commission has decided to add one proviso in the final regulations to provide that during charging mode of an ESS, deviation by way of over drawal shall be treated as under injection and deviation by way of under drawal shall be treated as over injection and the charges for deviation would be settled accordingly. This implies that during charging mode, the deviation charges for PSP would be calculated by taking into account the capacity capable of drawing power during the respective time block. To illustrate the same with an exam ple, let’s assume a PSP with a drawl capacity of 210 MW has a drawal schedule of 200 MW in a time block. As against this drawal schedule, now let’s assume that the actual drawal by the PSP during the time block is 150 MW. Then, the computation of deviation charges by way of under-drawal of 50MW (i.e., 200MW - 150 MW) in the respective time-block would be estimated by considering the drawl Capacity of 210MW as a proxy for AvC for calculation of deviation charges in Percentage (%) for this respective time-block.

7.72. Accordingly, Regulation 8 (5) has been finalized as follows:

“*Regulation 8 (5): Charges for Deviation, in respect of a Standalone Energy Storage System (ESS), shall be the same as applicable to* ***a general seller (other than an RoR generating station and a generating station based on municipal solid waste)*** *as specified in Clause (1) of this Regulation:*

Provided that in the charging mode, deviation by way of over drawal shall be treated as under injection and deviation by way of under drawal shall be treated as over injection and the charges for deviation shall be settled accordingly:

Provided further that the charges for deviation including the formula for computation of Deviation, in respect of charging of a standalone ESS being pumped hydro storage plant shall be the same as applicable to a WS seller being a generating station based on solar resources, for the period from ***the date of commencement of these regulations to 31.03.2026***.”

7.73. Regulation 8 (6): Charges for Deviation in respect of an ESS co-located with WS Seller(s) connected at the same interconnection point

Commission’s Proposal

7.74. The Commission had proposed the following in **Regulation 8(6)** of the Draft Regulations:

(3) Charges for Deviation Charges for Deviation, in respect of an ESS co-located with WS Seller(s) connected at the same interconnection point, shall be as follows:

i)Such seller shall provide a separate schedule for WS and ESS components through the Lead generator or QCA at the interconnection point;

ii)Deviation corresponding to WS component shall be charged at the same rates as applicable for WS Seller being a generating station based on solar or hybrid of wind-solar resource in accordance with clause (4) of this regulation; and *iii)Deviation corresponding to the ESS component shall be charged at the same rates as applicable for a standalone ESS in accordance with clause (5) of this regulation.*

Deviation by way of over injection (Receivable by Lead generator)	***Deviation by way of under injection (Payable by the lead generator)***
(I) Any over injection up to 5% or 50 MW shall be receivable as per RR and for under generation shall be payable zero up to 5% or 50MW.	
(II) For Deviation from 5% to 10% D_{GS} or greater than 50 MW up to 100 MW, whichever is less] and f within f_{band}	
(i) @ RR when f =50.00 Hz	*(iv) @ RR when f =50.00 Hz*
(ii) When [50.00 Hz < f ≤50.05 Hz], for every increase in f by 0.01 Hz, charges for deviation for such seller shall be reduced by 10% of RR so that charges for deviation become 50% of RR when f = 50.05Hz	*(v) When [50.00 Hz < f ≤50.05 Hz], for every increase in f by 0.01 Hz, charges for deviation for such seller shall be reduced by 3% of RR so that charges for deviation become 85% of RR when f = 50.05Hz*
(iii) When [49.90 ≤ f < 50.00 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such seller shall be increased by 1.5% of RR so that charges for deviation become 115% of RR when f = 49.90Hz	*(vi) When [49.90 ≤ f < 50.00 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such seller shall be increased by 5% of RR so that charges for deviation becomes 150% of RR when f = 49.90Hz*
(III) ***For Deviation up to [10% D_{GS} or 100 MW, whichever is less] and f outside f_{band}***	
(i) @ zero when [50.05 Hz < f < 50.10 Hz]: *Provided that such seller shall pay @ 10% of RR when [f ≥ 50.10 Hz]*	*(iii) @ 85 % of RR when [f > 50.05 Hz]*
(ii) @ 115 % of RR when [f < 49.90 Hz]	*iv) @ 150 % of RR when [f < 49.90 Hz]*
(IV) ***For Deviation beyond [10% D_{GS} or 100 MW, whichever is less] and f within and outside f_{band}***	

Deviation by way of over injection ***(Receivable by Lead generator)***	***Deviation by way of under injection*** ***(Payable by the lead generator)***
*(i) such seller shall be paid back @ zero when (**f** < 50.10 Hz):* *Provided that such seller shall pay @ 10% of RR when [f ≥ 50.10 Hz]*	*(ii) such seller shall pay @ RR when [f ≥ 50.00 Hz]; @ 150% of RR when [49.90Hz ≤ f < 50.00 Hz]; and @ 200% of RR when [f < 49.90 Hz]*

Note : (a) Reference rate (RR) of such generators would be the daily weighted average ACP of the Day Ahead Market segments of all the Power Exchange.

(b) The DSM shall be computed based on the Net schedule, i.e., the sum of all generator schedule injecting/drawing power and net actual injection/drawal at the interconnection point

(c) Each generator shall be metered with SEM so that individual actual injection/drawal can be captured;

(d) Schedule shall be prepared separately for each type of generator. This shall help to understand the different profiles of each generator.

Comments received

7.75. **ICC, JSW, and PFI** commented that the table given under clause (6) of Regulation 8 does not have any connection with paragraphs 6 (i), (ii), and (iii) above and requested clarification. **Grid India** pointed out that note (b), which mentions that DSM shall be computed based on the 'Net schedule at the interconnection point,' is apparently in contradiction with Clause 8.6. (i), (ii), (iii), which provides that the schedules and Deviations corresponding to the WS component and ESS component are to be computed separately. Thus, note (b) to the Clause.8.6. may be deleted if it is envisaged to prepare separate schedules for WS and ESS components by the QCA/Lead Generator.

7.76. **Prayas Energy Group and VENA Energy** requested clarification on the methodology for calculation of Deviation for ESS on the DC side of the inverter and when it shares a common inverter with the WS component or when the hybrid project of wind and solar, co-located with ESS component, are injecting power at one interconnection point for connecting with the Grid.

7.77. Suggesting that aggregations of ESS with WS may help smoothen deviations, **MNRE** requested clarification on the applicability of DSM regulations for Round the Clock Power

(Solar Wind Hybrid + Storage) Central Pool, Peaking Power (Solar Wind Hybrid + Storage) Central Pool, Firm and Dispatchable RE Power.

7.78. **Adani Power, PFI,** requested clarification on the methodology for the calculation of Deviation as the computation of DSM charges on the net schedule renders the process of providing separate schedules for the RE component and ESS component redundant. Many stakeholders, including **PFI** suggested that if ESS is being used by the WS Seller(s) to regulate its schedule/generation, there will not be any separate schedule (injection/drawal) of ESS. **RE Connect**, **Azure Power, and HYGENCO** suggested that the Band Width for the Energy Storage System (ESS) may be considered under the same band as the rest of the Hybrid Renewable Energy projects or Green Amonia projects, as ESS acts as complementary support by absorbing fluctuations and enabling the WS projects in providing grid stability. Thus, the Charges for Deviation for WS seller(s) with Co-located ESS, which are connected at the same interconnection point, should be de-linked from GRID frequency.

7.79. **TPL, O2 Power, JSW, VENA Energy, Sekura** suggested that the whole purpose of installing ESS to reduce the variability of the wind /solar technology and make the grid more stable would be defeated if the deviation of ESS is treated separately or in line with the general seller and would also impact the inflow of fund for ESS development in the country. **HYGENCO** suggested that treating both standalone ESS and ESS co-located with WS seller, on similar lines is not justifiable and is counterproductive, especially when co-located ESS is being used for the production of green ammonia and green hydrogen.

7.80. **EDF RE India, TPI** suggested having a combined schedule for WS and ESS Components for the computation of Deviation and not to link the Charges for Deviation for ESS with the frequency (**TPI**). Some of the stakeholders suggested that the deviation for BSS co-located with WS sellers should be at par with the WS deviation band (**Manikaran Analytical Limited, Ayana Renewable Power Private Limited, Juniper**, Sembcorp, **Indi Grid, and THDCIL)** to which the ESS is co-located with **(WIPPA)**. Re New suggested that the co-located ESS resources should be provided a tolerance band of +/- 10% or 100MW without any linkage with system frequency; however, beyond such tolerance band, it could be treated like a general seller.

7.81. **Indi Grid** suggested that in case the Commission continues with frequency-linked charges for Deviation for the ESS component, the bandwidth for deviation should be as indicated below:

(i) Over injection up to 10% or 100 MW shall be receivable as per RR and for under generation shall be payable zero up to 10% or 100 MW.

(ii) For Deviation from [10% to 15% DGS or greater than 100 MW up to 150 MW, whichever is less] and f within f band

(iii) For Deviation up to [15% DGS or 150 MW, whichever is less] and f outside fband

(iv) For Deviation beyond [15% DGS or 150 MW, whichever is less] and f within and outside f band

7.82. **Greenko** suggested that the Co-located projects should provide cumulative or separate schedules to QCA, and the charges for Deviation should be for the bandwidth 0% - 10%, 10% -15%, 15%- 20% at RR, 90% of RR, 50% RR respectively in case of over injection/ under drawal and at 100% of RR, 110% of RR and 150% of RR respectively for under injection/ over drawal.

7.83. **GUVNL** suggested providing clarity on the Reference Rate applicable for the calculation of charges for Deviation, as the Reference Rate has been defined in Regulation 3 (x) and also in Note (a) of Regulation 8 (6).

7.84. **MSPL** suggested that the methodology for the calculation of charges for DSM in cases where the ESS co-located with Thermal/ Hydro generating stations may also be provided as the MoP scheme dated 12.04.2022 for flexibility in Generation and Scheduling of Thermal/ Hydro power stations provided for co-location of RE and ESS with Thermal/Hydro generating stations as an option.

Analysis and Decision

7.85. The Commission has noted the suggestions received from the stakeholders and held discussions with the subject experts to bring clarity to the treatment of deviation charges for co-located ESS with other resources. The Commission had proposed, based on the recommendation of the Expert Committee in the draft regulation, for further consultation before specifying the deviation treatment for such innovative technology, which can act both as a seller and as a buyer. The Commission agrees with the views of the stakeholders that the table provided in the draft regulations would not be required if deviation for WS and ESS components are treated separately; accordingly, the table provided in the draft regulation has been removed. On the issue of providing a schedule at interconnection points through a lead generator or QCA, the Commission is of the view that the same has been explained in the Grid Code and beyond the scope of the DSM regulations. As far as the calculation of deviation is concerned, each generator and ESS would need to be metered with a Special Energy Meter (SEM) so that individual injections or drawals could be captured. On the issue of contract rate or reference rate for the co-located ESS with solar or wind, the Commission is of the view that the definitions of 'Contract Rate' and 'Reference Rate' are adequate to compute the respective rates.

7.86. The Commission believes that with global trend of decrease in storage cost and recently concluded tenders such as Round the Clock Power (Solar Wind Hybrid + Storage), Firm and Dispatchable RE Power (FDRE) many wind and solar projects co-located with ESS are expected to be commissioned.

7.87. The Commission notes that various business models are emerging with respect to utilisation of ESS. Such resources can sell/lease/rent out storage space in whole or in part to any utility or may use such storage space itself. The Commission agrees with the stakeholders that ESS would reduce the variability of the wind solar technology and make the grid more stable. While in the initial phase, the development of ESS needs to be supported with the complementary regulatory framework, the Commission believes that being firm in nature deviation framework needs to be specified while taking into consideration the technical capabilities of such resource. Further, it is envisaged that co-located ESS with any generation resource can be owned by the same generator with which it is co-located or it can be owned by a third party also, which shall be as specified while seeking Connectivity for such resource under the GNA Regulations.

7.88. Modalities of connectivity and flexibility in the contracts can vary depending on the business models adopted by the ESS and the multiple applications used. Accordingly, after detailed consultation with the subject experts, the Commission has stipulated treatment of deviation, taking into consideration various scenarios. If an ESS is co-located with a WS Seller with the same interconnection point, for any time block in which the WS seller is injecting power, the charges for deviation would be as applicable to the respective category, such as solar or wind, or hybrid. In case only ESS is injecting the power into the grid during these time blocks, the charges applicable to such entity would be as per standalone ESS. In cases wherein co-located ESS has given a drawal schedule from the grid, deviation charges for ESS would be at par with standalone ESS. This implies that each generator and ESS would need to be metered with a Special Energy Meter (SEM) so that individual injection or drawal could be captured. Accordingly, the Commission has finalised the provision for co-located ESS with solar or wind or hybrid resources as follows:

"(6) Charges for Deviation including the formula for computation of Deviation, in respect of a WS Seller with ESS connected at the same interconnection point shall be the same (i)

as applicable to a WS seller of respective category during the period solar or wind or hybrid generating station is injecting power, (ii) as applicable to a standalone ESS as per sub-clause (5) of this Regulation, when only ESS is injecting power, and (iii) as applicable to a standalone ESS for drawl by ESS based on drawal schedule from the grid as per sub-clause (5) of this Regulation.

Note :

Each generator and ESS shall be metered with Special Energy Meter (SEM) so that individual actual injection/drawal can be captured."

Illustrations:

Suppose a WS seller 'A' has been granted Connectivity for 300 MW at a specific substation at 220 kV bay with following configuration:

Wind: 200 MW, Solar: 100 MW, ESS: 50 MW

1. Suppose 'A' has given generation schedule for time block 12.00-12.15 PM as 250 MW with Available capacity(AVC) as 300 MW.

   Suppose Actual generation is 280 MW for this time block out of which Solar was injecting 80 MW, Wind was injecting 150 MW and ESS was injecting 50 MW , the deviation shall be calculated as (280-250)/300 = 10%. The injection from ESS shall be counted as behind the meter, injection from WS seller itself where AVC shall not include ESS capacity.

2. Suppose 'A' has Schedule generation for 40 MW during time block 11PM-11.15. PM when there is no solar and no wind. Actual generation is 50 MW. The deviation shall be calculated as (50-40)/40 = 25%.

3. Suppose 'A' has Schedule generation for 250 MW during time block 12.00-12.15 pm and a drawl schedule of 45 MW (at the interface point of ISTS) for the ESS.

   Suppose actual generation for solar and wind components works out as 260 MW and actual drawl by ESS works out as 50 MW. The deviation for WS seller shall be = (260-250)/300 = 3.33%

   Deviation for ESS shall be = (50-45)/ 45 = 11.11%.

4. Suppose ‘A’ has Schedule generation for 200 MW during time block 7PM-7.15. PM when there is no solar. The AvC at such time shall be taken as that of Wind component only i.e 200 MW. Actual generation is 190 MW. The deviation shall be calculated as (190-200)/200 = -5%.

8. Deviation Charges by Buyers (Regulation 8(7))

Commission’s Proposal

8.1. The Commission had proposed the following in **Regulation 8 (7)** of the Draft Regulations:

*(7) Charges for Deviation, in respect of **a Buyer,** shall be receivable or payable as under:*

Deviation by way of under drawal (Receivable by the Buyer)	***Deviation by way of over drawal (Payable by the Buyer)***
(I) ***For VL_B (1) and f within f_{band}***	
i) @ 85% of NR NR when f =50.00 Hz;	*iv) @ NR when f =50.00 Hz;*
ii) When 50.00 Hz < $f \leq$50.05 Hz , for every increase in f by 0.01 Hz, charges for deviation for such buyer shall be decreased by 7% of NR so that charges for deviation become 50% of NR when f = 50.05Hz;	*v) When 50.00< $f \leq$50.05 Hz , for every increase in f by 0.01 Hz, charges for deviation for such buyer shall be reduced by 5% of NR so that charges for deviation become 75% of NR when f = 50.05Hz;*
iii) When 49.90 $\leq f <$ 50.00 Hz, for every decrease in f by 0.01 Hz, charges for deviation for such buyer shall be increased by 1 % of NR so that charges for deviation become 95% of NR when f = 49.90Hz;	*vi) When 49.90 $\leq f <$ 50.00 Hz, for every decrease in f by 0.01 Hz, charges for deviation for such buyer shall be increased by 5% of NR so that charges for deviation become 150% of NR when f = 49.90Hz.*
(II) ***For VL_B (1) and f outside f_{band}***	
(i) @ zero when [50.05 Hz < f < 50.10 Hz]: *Provided that such buyer shall pay @ 10% of NR when [$f \geq$ 50.10 Hz];*	*(iii) @ 50% of NR when [50.05 Hz < f < 50.10 Hz]:* *(iv) @ zero when [$f \geq$ 50.10 Hz];*
(ii) @ 95% of NR when [f < 49.90 Hz];	*(v) @ 150 % of NR when [f < 49.90 Hz].*
(III) ***For VL_B (2) and f within and outside f_{band}***	
(i) @ 80% of NR when $f \leq$ 50.00 Hz; *(ii)@ 50% NR when [50.00 Hz < $f \leq$ 50.05 Hz]; @ zero when [50.05 Hz < f < 50.10 Hz]:* *Provided that such buyer shall pay @ 10% of NR when [$f \geq$ 50.10 Hz];*	*(iii) @ 150% of NR when $f \leq$ 50.00 Hz;* *(iv) @ NR when [50.00 Hz $\leq f \leq$ 50.05 Hz];* *@ 75% NR when [50.05 Hz < f < 50.10 Hz];* *@ zero when [$f \geq$ 50.10 Hz].*

*(IV) **For VL_B (3) and f within and outside f $_{band}$***	
(i) @ zero when f < 50.10 Hz: Provided such buyer shall pay @ 10% of NR when [f ≥ 50.10 Hz];	*(ii) @ 200% of NR when f <50.00 Hz; (iii) @ 110% of NR when [f ≥ 50.00 Hz].*

Note: Volume Limits for Buyer :

Buyer	***Volume Limit***
Buyer <u>other than</u> (the buyer with a schedule less than 400 MW and the RE-rich State)	*VL_B(1) = Deviation up to [10% D_{BUY} or 100 MW, whichever is less]* *VL_B(2) = Deviation [beyond 10% D_{BUY} or 100 MW, whichever is lower] and up to [15% D_{BUY} or 200 MW, whichever is lower]* *VL_B(3) = Deviation beyond [15% D_{BUY} or 200 MW, whichever is less]*
Buyer (with a schedule up to 400 MW)	*VL_B(1) = Deviation [20% D_{BUY} or 40 MW, whichever is less]* *VL_B(2) = Deviation beyond [20% D_{BUY} or 80 MW, whichever is less]*
Buyer (being an RE Rich State)	*VL_B (1) = Deviation up to 200 MW* *VL_B (2) = Deviation beyond 200 MW and up to 300 MW* *VL_B (3) = Deviation beyond 300 MW*
Buyer (being Super RE Rich State)	*VL_B (1) = Deviation up to 250 MW* *VL_B (2) = Deviation beyond 250 MW and up to 350 MW* *VL_B (3)= Deviation beyond 350 MW*

Comments received

8.2. **IPCL, IEX** suggested that the penalties should be such as to act as a deterrent for the participants to deviate and drive them to utilize the market for energy balancing. **IEX** suggested linking the NR with the highest of DAM, RTM, or Ancillary Services as the proposed calculation of NR based on the weighted average cost of DAM, RTM, and AS would, in several instances, be non-reflective of the energy cost being despatched through the Ancillary Services and would encourage the buyers to lean on DSM rather than to purchase energy from HP DAM. Whereas **IPCL** suggested treating under-drawal by the buyer as an Ancillary Service and compensating the buyer for the quantum of under-drawal energy at the cost of procurement of power.

8.3. While requesting for the Charges for Deviation to be line with the existing charges for

Deviation, **EDG** highlighted that the proposed receivable of only 85% to 90% of the Normal Rate (NR) in case of under-drawal, while payment of 100% to 125% of NR for over-drawal in the frequency range of 50.00Hz to 49.95Hz would lead to substantial loss to the states/ buyers and thus would discourage the states/ buyers for extending grid support

8.4. **ICC** appreciated linking the deviation charge rate to Normal Rate and grid frequency as these measures would encourage the states/buyers to a more accurate forecast of demand and to take proactive action to schedule power from DAM and RTM and also maintain reserves to maintain drawl closer to the schedule.

8.5. **O2 Power** suggested that the introduction of a new clause of a 10% NR penalty for under-drawal at frequencies of 50.10 Hz or higher should not be implemented and also suggested creating a separate Category for buyer purchasing power under the GNA- RE mechanism. **GRIDCO** suggested permitting over-drawal at Rs 0/ Kwh when the frequency > 50.05 Hz. **HPSEBL** suggested that during the peak generation period, the state will have to back down its hydro generation to counter the sudden load loss by spilling water, which otherwise is a national loss. **Karnataka** suggested that Charges for Deviation, in respect of a Buyer, should be zero for under-drawal when the frequency is >= 50.10Hz as the state is RE rich.

8.6. Various suggestions by stakeholders on the deviation charges for different frequency bands and volume limits are summarised below:

(I) When within f band for $\underline{VL_B\ (1)}$

(i) When f ≥ 50.5 Hz the charges of deviation could be 50% of NR for under drawal (**BALCO**), 50% of NR for over drawal upto 50.1 Hz and zero for over drawal when f ≥ 50.10 Hz

(ii) When f < 49.90 Hz the charges of deviation could be 95% of NR for under drawal (**BALCO**) and 150% of NR for Over drawal

(iii) When f = 50.0 Hz: the receivable and payable due to under drawal and over drawal should be 100% of NR in line with the provision for general seller (**GUVNL, Adani Power, MUL, AP Discom**) as the condition depicts equilibrium in the system (**MUL)**

(iv) When 50.00 Hz < f ≤ 50.05 Hz: The charges deviation for

a. under drawal: when f = 50.05 Hz should be 65% of NR (**GUVNL, MUL),** 50% of NR **(Amplus Solar),** 75% of NR (**AP Discom**)

(v) When 49.90 <= f < 50.00 Hz: the charges deviation for

a. under drawal: when f = 49.90 Hz should be 100% of NR (**WBSLDC**), 110% of NR (**GUVNL, MUL),** 120% of NR (**AP Discom**)

b. over drawal: when f = 49.90 Hz should be 120% of NR (**Gujarat SLDC, AP Discom** and **APSLDC**)

c. Encourage buyers as much as possible to under draw in order to support the grid (**Adani Power)**

(II)For VL_B (1) and f outside f band

(i) When f < 49.90 Hz: The charges for deviation for

a. under drawal: should be 110% of NR (**TPL),** 115% of NR (**WBSEDCL),** 120% of NR **(BRPL, AP Discom),** 150% of NR (**Assam Discom),**

b. over drawal: should be 120% of NR (**AP Discom**)

(ii) When 49.90 ≤ f ≤ 50.00 Hz: The charges for deviation for

a. over drawal: should be 80% of NR **(AP Discom)**

(iii)When 50.00 Hz < f ≤ 50.05 Hz: The charges for deviation for

a. over drawal: should be 100% of NR (**TPL**), 50% of NR (**Assam Discom**)

(iv)When 50.05 Hz < f ≤ 50.10 Hz: The charges for deviation for

a. over drawal: should be 50% of NR **(TPL),** zero **(Assam Discom)**

(v) When f ≥ 50.10 Hz: The charges for deviation for

a. under drawal: 10% of NR should not be levied as sudden loss in load due to weather condition is beyond control (**BRPL, AP Discom**),

b. over drawal: 20% of NR (**Assam Discom**)

III) For VLB (2) and f within and outside f band

(i) When f < 49.90 Hz: The charges for deviation for

a. under drawal: 100% of NR **(TPL),** 120% of NR **(AP Discom)**

b. over drawal: 150% of NR when f = 49.90 Hz (**Gujarat SLDC, AP SLDC, GRIDCO**), 120% of NR (**AP Discom**)

(ii) When f ≤ 50.00 Hz: The charges for deviation for

a. under drawal:

b. over drawal: 125% of NR when f = 50.00 Hz (**BRPL, GRIDCO**), 120% of NR (**Gujarat SLDC, AP SLDC**) or 80% of NR **(AP Discom)** when 49.90 Hz <= f < 50 Hz

(iii)When 50.00 Hz < f ≤ 50.05 Hz: The charges for deviation for

a. under drawal:

b. over drawal: 50% of NR **(AP Discom)**

(iv)When 50.05 Hz < f ≤ 50.10 Hz: The charges for deviation for

a. under drawal:

b. over drawal: 50% of NR (**TPL**), Zero **(AP Discom)**

(v) When f ≥ 50.10 Hz: The charges for deviation for

a. under drawal: 10% of NR should not be levied as sudden loss in load due to weather condition is beyond control (**BRPL, AP Discom)**

b. over drawal: 20% of NR

<u>IV) For For VLB (3) and f within and outside f band</u>

(i) When f < 49.90 Hz: The charges for deviation for

a. under drawal: No volume limit should be applicable as the buyer shall be supporting the grid under these circumstances **(UP SLDC),** 100 % when f ≤ 49.95 Hz (**GRIDCO**)

b. over drawal: 200%of NR **(Gujarat SLDC, APSLDC, AP Discom)** , 200% of NR when f = 49.90 Hz **(GRIDCO)**

(ii) When f ≤ 50.00 Hz: The charges for deviation for

a. under drawal: Zero when f ≤ 49.95 Hz (**GRIDCO**)

b. over drawal: 150% of NR when 49.90 Hz <= f < 50 Hz **(Gujarat SLDC, APSLDC, BRPL, AP Discom),** 150% of NR when f = 50.00 Hz **(GRIDCO),** 175% of NR **(TPL)**

(iii)When 50.00 Hz < f ≤ 50.05 Hz: The charges for deviation for

a. under drawal: 25% of NR **(AP SLDC, Gujarat SLDC),** Zero when 49.95 < f < 50.10 Hz (**GRIDCO**), Zero **(Adani Power)**

b. over drawal: 110%of NR **(Gujarat SLDC, WBSEDCL, BRPL, AP Discom),** 75% of NR **(APSLDC),** 100% of NR **(TPL)**

(iv)When 50.05 Hz < f ≤ 50.10 Hz: The charges for deviation for

a. under drawal: 50% of NR **(AP SLDC, Gujarat SLDC),** Zero when 49.95 < f < 50.10 Hz (**GRIDCO)**, 110%of NR **(Gujarat SLDC)**

b. over drawal: NR **(Gujarat SLDC),** 110%of NR **(WBSEDCL),** Zero **(Adani Power),** 50% of NR **(APSLDC),** 75% of NR **(TPL),** 100% of NR **(AP Discom)**

(v) When f ≥ 50.10 Hz: The charges for deviation for

a. under drawal: No reverse charges should be levied **(BRPL, UPSLDC, WBSEDCL)**

(vi) over drawal: 20% of NR **(AP Discom)**, 50%of NR **(Gujarat SLDC),** Zero **(WBSEDCL, Adani Power),** Zero **(BRPL)**

8.7. **Grid India** suggested that in Point No. (III) "For VL_B (2) and f within and outside f band" of the table in Clause 8.7, pertaining to Charges for Deviation, in respect of Buyer, 50Hz is covered at both sl.(iii) as well as sl.(iv). This may be corrected.

8.8. Various stakeholders suggested separate categorisation for RE rich States as follows:

i) Add new Volume limit for “most superior RE rich states” with Deviation up to 400 MW, beyond 400 MW, and up to 500 MW, and beyond 500 MW as VL_B (1), VL_B (2), VL_B (3), respectively **(Gujarat SLDC)**

ii) Add new Volume limit for “RE rich states” with Deviation up to 300 MW, beyond 300 MW and up to 400 MW and beyond 400 MW as VL_B (1), VL_B (2), VL_B (3) respectively, and for “RE rich states” with Deviation up to 350 MW, beyond 350 MW and up to 450 MW and beyond 450 MW as VL_B (1), VL_B (2), VL_B (3) respectively **(Maharastra SLDC)**

iii) Volume limit for *“RE rich states (installed capacity between 1000 MW and 5000 MW)”* with Deviation up to 200 MW, beyond 200 MW and up to 300 MW and beyond 300 MW as VL_B (1), VL_B (2), VL_B (3) respectively and for *“Super RE rich states (installed capacity between 5000 MW and 10000 MW)”* with Deviation up to 300 MW, beyond 300 MW and up to 400 MW and beyond 400 MW as VL_B (1), VL_B (2), VL_B (3) respectively and for *“Most Super RE rich states (installed capacity between 5000 MW and 10000 MW)”* with Deviation upto 400 MW, beyond 400 MW and upto 500 MW and beyond 500 MW as VL_B (1), VL_B (2), VL_B (3) respectively **(AEML)**

iv) According to **MSEDCL** super RE rich states should be clubbed in three categories:

(a) Super RE rich states – I (installed capacity between 5000 MW and 7500 MW) with Deviation up to 300 MW, beyond 300 MW and up to 400 MW, and beyond 400 MW as VL_B (1), VL_B (2), VL_B (3) respectively

(b) Super RE rich states – II (installed capacity between 7500 MW and 10000 MW) with Deviation upto 350 MW, beyond 350 MW and up to 450 MW and beyond 450 MW as VLB (1), VLB (2), VLB (3) respectively

(c) Super RE rich states – II (installed capacity above 10000 MW) with Deviation upto 400 MW, beyond 400 MW and up to 500 MW, and beyond 500 MW as VLB (1), VLB (2), VLB (3) respectively

v) Consider only one category for RE Rich State with the deviation limit being VL_B (1) = 100MW+5% of RE installed capacity of the state, VL_B (2) = VL_B (1) + 100 MW, and VL_B (3) = beyond VL_B (2) **(AP SLDC)**

8.9. **Amplus Solar** suggested changing the phrases “Buyer (being an RE Rich State)” and “Buyer (being Super RE Rich State)” to “Buyer (located in an RE Rich State)” and “Buyer (located in a Super RE Rich State)" respectively for better clarity.

Analysis and Decision

8.10. The Commission has examined the submissions of the stakeholders. It is noted that some stakeholders suggested making the changes of Deviation more stringent so as to decrease/ eliminate the leaning of the buyer on DSM for meeting their demand. Whereas some stakeholders suggested treating under-drawal by the buyers as an Ancillary Service. While some stakeholders argued that the proposed charges would discourage the State/Buyer from extending its support to complement the grid operation, some appreciated the proposed charges by citing that these measures would encourage the states/ buyers to more accurate forecast of demand and to take proactive action to schedule power from DAM and RTM and also maintain reserves to maintain drawl closer to the schedule. Some stakeholders advocated permitting over-drawal at Rs 0/ kWh when the frequency is above 50.05 Hz. Some of the stakeholders suggested modification in the charges of deviation for over-drawal and under - injection. It was suggested that the buyer may be paid @NR when the system frequency is at 50Hz. It was suggested that the incentive for under-drawal may need to be increased further and bring symmetry in incentive and penalty for Buyer. It was also suggested that there should not be any volume limit beyond the operative frequency band *[i.e. 49.90Hz < f < 50.05 Hz]*. Some stakeholders suggested to create a separate Category for buyer purchasing power under GNA- RE mechanism. Some stakeholders suggested reconsidering the introduction of a penalty clause @ 10% NR at frequencies of 50.10 Hz or higher.

8.11. The Commission has examined the submissions of the stakeholders in detail. On the question of providing higher incentives and reducing penalties, the Commission would like to reiterate that the responsibility to maintain grid frequency and grid security lies with the system operator. The system operator is expected to utilise the ancillary services to maintain grid security, while the grid connected entities are expected to adhere to a schedule. DSM is not a trading mechanism, and its design cannot be built around the concept of incentivising any entity. Further, it is important to design the commercial mechanism under DSM in such a way that the cost of deployment of ancillary services could be recovered through DSM and the Ancillary Service Pool Account.

8.12. The Commission feels that there has to be a balance between the incentive and penalty that may be imposed on the buyer to support the grid and for inadvertent drawal of power due to the uncontrolled nature of demand. The Commission is of the view that the incentive and penalty imposed under the regime are sufficient to ensure that the buyers are not overly penalised or incentivised. It is to be noted that the Ancillary service requirements and procurement are to be carried out by the grid operator. As such, instead of treating ‘unscheduled’ under drawal as an Ancillary Service, the Commission would like the discoms to participate under ‘scheduled’ Ancillary Services requisitioned by the system operator.

8.13. The Commission recognises the role which the buyers can provide in grid stability. However, the Commission also has to ensure that DSM is not treated by the buyer as a market for energy trade. However, considering the comments received, the Commission has increased the receivable of buyers for under-drawal within the volume limit from 85% of NR to 90% of NR at 50 Hz and from 90% to 100% of NR at 49.90 Hz. Below the system frequency of 49.90Hz, the charges would be constant. However, it should be noted that for any deviation beyond VLB (1), the charges would be flat in different frequency ranges but relatively less than that of VLB (1) so that a buyer is encouraged to participate in the Ancillary Service Mechanism rather than leaning on the DSM. Thus, the Commission feels that the charges for Deviation specified in the final regulation will ensure the stability of the grid.

8.14. Regarding the suggestion of some stakeholders to create a separate category for the buyer purchasing power under the GNA-RE mechanism, the Commission would like to clarify that the mechanism of GNA deals with access to transmission networks and is relevant primarily for waiver of transmission charges. On the other hand, DSM deals with deviation from schedule irrespective of any kind of access (GNA, GNA-RE, or T-GNA). Thus, the Commission feels that there is no need for the creation of any separate category of buyer based on GNA.

8.15. On the suggestion of further categorisation of the RE rich States, the Commission feels that the proposed categorisation is adequate and further categorisation would increase the complexity further with some additional burden on the DSM and Ancillary Pool Account. Given the ambitious target of RE capacity addition in the country, most of the States would very soon have substantial RE capacities installed within their control areas, and the categorisation of states would lose relevance.

8.16. On the issue of the penalty of 10% of NR at Frequency 50.10Hz, the Commission believes that the same is required to discourage the buyer from under-drawal at high frequency. The Commission believes that the approach of the Commission will balance the interests of the States, including the RE-rich States as well as the RE generators, while at the same time ensuring grid security.

8.17. Regulation 8 (7) dealing with a deviation of Buyers, as specified in the final regulations, is as under: -

*"(7) Charges for Deviation, in respect of **a Buyer,** shall be receivable or payable as under:*

Deviation by way of under drawal (Receivable by the Buyer)	***Deviation by way of over drawal (Payable by the Buyer)***
(V) ***For VL_B (1) and f within f_{band}***	
i) @ 90% of NR when f =50.00 Hz;	*iv) @ NR when f =50.00 Hz;*
ii) When 50.00 Hz < f ≤50.05 Hz , for every increase in f by 0.01 Hz, charges for deviation for such buyer shall be decreased by 8% of NR so that charges for deviation become 50% of NR when f = 50.05Hz;	*v) When 50.00 < f ≤ 50.05 Hz , for every increase in f by 0.01 Hz, charges for deviation for such buyer shall be decreased by 5% of NR so that charges for deviation become 75% of NR when f = 50.05Hz;*
iii) When [50.00 Hz > f ≥ 49.90 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such buyer shall be increased by 1 % of NR so that charges for deviation become 100% of NR when f = 49.90Hz;	*vi) When [50.00 Hz > f ≥ 49.90 Hz], for every decrease in f by 0.01 Hz, charges for deviation for such buyer shall be increased by 5% of NR so that charges for deviation become 150% of NR when f = 49.90Hz.*
(VI) ***For VL_B (1) and f outside f_{band}***	
(i) @ zero when [50.05 Hz < f < 50.10 Hz]: Provided that such buyer shall pay @ 10% of NR when [f ≥ 50.10 Hz];	*(iii) @ 50% of NR when [50.05 Hz < f < 50.10 Hz]:* *(iv) @ zero when [f ≥ 50.10 Hz];*
(ii) @ NR when [f < 49.90 Hz];	*(v) @ 150 % of NR when [f < 49.90 Hz].*
(VII) ***For VL_B (2) and f within and outside f_{band}***	
(i) @ 80% of NR when f ≤ 50.00 Hz; *(ii)@ 50% NR when [50.00 Hz < f ≤ 50.05 Hz];* *(iii) @ zero when [50.05 Hz < f < 50.10 Hz]: Provided that such buyer shall pay @ 10% of NR when [f ≥ 50.10 Hz];*	*(iv) @ 150% of NR when f < 50.00 Hz;* *(v) @ NR when [50.00 Hz ≤ f ≤ 50.05 Hz];* *(vi) @ 75% NR when [50.05 Hz < f < 50.10 Hz];* *(vii)@ zero when [f ≥ 50.10 Hz].*
(VIII) ***For VL_B (3) and f within and outside f_{band}***	

(i) @ zero when f < 50.10 Hz: Provided such buyer shall pay @ 10% of NR when [f ≥ 50.10 Hz];	*(ii) @ 200% of NR when f <50.00 Hz; (iii) @ NR when [50.00 Hz ≤ f < 50.10 Hz] (iv) @ 50% of NR when [f ≥ 50.10 Hz].*

Note: Volume Limits for Buyer :

Buyer	***Volume Limit***
Buyer other than (the buyer with a schedule less than 400 MW and the RE-rich State)	*VL_B(1) = Deviation up to [10% D_{BUY} or 100 MW, whichever is less]* *VL_B(2) = Deviation [beyond 10% D_{BUY} or 100 MW, whichever isless] and up to [15% D_{BUY} or 200 MW, whichever isless]* *VL_B(3) = Deviation beyond [15% D_{BUY} or 200 MW, whichever is less]*
Buyer (with a schedule up to 400 MW)	*VL_B(1) = Deviation [20% D_{BUY} or 40 MW, whichever is less]* *VL_B(2) = Deviation beyond [20% D_{BUY} or 40 MW, whichever is less]*
Buyer (being an RE Rich State)	*VL_B (1) = Deviation up to 200 MW* *VL_B (2) = Deviation beyond 200 MW and up to 300 MW* *VL_B (3) = Deviation beyond 300 MW*
Buyer (being Super RE Rich State)	*VL_B (1) = Deviation up to 250 MW* *VL_B (2) = Deviation beyond 250 MW and up to 350 MW* *VL_B (3)= Deviation beyond 350 MW*

”

9. Deviation Charges for injection of infirm power (Regulation 8(8))

Commission's Proposal

9.1. Treatment for infirm power was proposed in **Regulation 8 (8)** of the Draft Regulations is follows:

(8) The charges for deviation for injection of infirm power shall be zero: Provided that upon such infirm power being scheduled, the charges for deviation for such power shall be as applicable for a general seller or WS seller, as the case may be.

Comments received

9.2. **Adani Power** welcomed the levy of Charges for Deviation of RE generators injecting scheduled infirm power as per the charges applicable for the WS seller.

9.3. **BRPL** suggested that WS sellers should not be allowed to inject infirm power beyond one week without certification of RLDC, and further, to avoid gaming, such sellers should not be allowed to sell or schedule infirm power in the market before COD. **BRPL** suggested that **s**ince infirm power injected into the grid is for the purpose of testing and commercial operation certification, the Charges for Deviation should be Zero or 50% of RR or 50% of contract rate so as to reduce gaming or delay in declaration of COD by the generator or seller.

9.4. **NTPC and THDCIL** suggested that in the absence of compensation for infirm power, the entire fuel cost would be capitalised during commissioning activities, thereby pushing up the total capacity cost of a project and increasing the AFC burden on the beneficiary States.

9.5. **Mr. Shishir Pradhan** suggested that the charges for deviation for injection of infirm power should be allowed up to 50 MW or 10% of the installed capacity of the project/ unit. **SJVN** suggested that the Charges for Deviation should be linked with the frequency of the grid.

9.6. **PCKL** requested clarification on the charges for deviation if the infirm power is not scheduled.

9.7. **Grid India** suggested that the denominator of the formulae for calculation of Deviation in percentage should have "Scheduled Power" instead of "AvC," especially for the WS, which schedules infirm power through short-term market prior to COD. Citing that presently, many WS sellers are not doing trial runs and COD within the stipulated time, thereby delaying the process of trial run, **Grid India** also suggested that in cases where the infirm power is being scheduled, the charges for deviation for such power should be as applicable for a general seller.

Analysis and Decision

9.8. Some stakeholders sought clarification regarding the computation of deviation charges when infirm power is not scheduled. While some stakeholders welcomed the provision for allowing the scheduling of infirm power by treating it at par with the respective seller category, some stakeholders objected to the scheduling of infirm power since infirm power is for the purpose of testing and commercial operation certification and should not be strictly allowed to be monetised. Some of the stakeholders suggested compensating the injection of infirm power at contract or reference rate, while some suggested the generator should not be compensated for the injection of infirm power. The system operator highlighted difficulties in ascertaining capacity that is capable of generation prior to the trial run and suggested that the charges for deviation for such infirm power be applicable at par with a general seller.

9.9. Infirm power is defined in the Grid Code as the electricity injected into the grid prior to the date of commercial operation (COD) of a unit of the generating station. A generating station is required to inject infirm power before COD to test its equipments. For a thermal generating stations, such injection is required to be carried out over a longer period of time due to multiple rotating machines that need to be commissioned and proved. Injection of Infirm power is also required to tune various control loops for smooth and reliable operation of the plant in order to achieve successful trial run. However such is not the case for a WS seller. The Commission would like to reiterate that injection of infirm power is akin to over-injection and should be used only for the intended purpose. Prolonged injection of infirm power, without adequate safeguards could pose threat to Grid security and also lead to load-generation imbalance. The Commission also notes that it is difficult to ascertain the Available Capacity of generating stations before the trial run which are WS sellers. Hence, the Commission is of the view that the scheduling of infirm power needs to be discouraged, especially before a successful trial run. Further, there have been instances of high frequency due to over-injection of infirm power. The injection prior to successful trial run should be strictly carried out in terms of Grid Code solely for the purpose of testing and not for scheduling of such power.

9.10. Accordingly, the Commission has finalised the regulation in this context as follows:

"*Regulation 8 (8) : The charges for deviation by way of injection of infirm power shall be zero:*

Provided that if infirm power is scheduled after trial run as specified in the Grid Code, the charges for deviation over the scheduled infirm power shall be as applicable for a general seller or WS seller, as the case may be."

10. Deviation Charges for start-up power (Regulation 8(9))

Commission's Proposal

10.1. The Commission had proposed the following in **Regulation 8 (9)** of the Draft Regulations:

(9)The charges for deviation for drawal of start-up power before the COD of a generating unit or for drawal of power to run the auxiliaries during the shut-down of a generating station shall be payable at the reference charge rate or contract rate or in the absence of reference charge rate or contract rate, the weighted average ACP of the Day Ahead Market segments of all Power Exchanges for the respective time block, as the case may be.

Comments received

10.2. **THDCIL** suggested capping charges for Deviation for start-up power drawn from the grid by generating stations.

10.3. **NLC** suggested providing clarity as to whether these Regulations shall also be applicable for deviation from scheduled power purchased from the Power Exchange during shutdown to run its auxiliaries.

10.4. **GUVNL** suggested that it would be more appropriate to link the deviation charges for drawl of start-up / auxiliary power with the weighted average ACP of the Day Ahead Market segments of all Power Exchanges for the respective time block only as the tariff determined by Commission under section 62 or adopted under section 63 is for long term duration whereas drawl of power for start-up and for auxiliary are momentary/temporary in nature.

10.5. **Amplus Solar** requested clarification on whether the charges for deviation for the drawal of power to run auxiliaries during non-solar hours should be categorized under Regulation 8(9) of the Draft DSM Regulations, 2024, or shall be treated under Regulation 8 (6). It was also suggested that a separate provision specifically addressing the charges for deviation for the drawal of power to run auxiliaries during the non-solar hours. Further, **PCKL** suggested that as the contract rate of the plant, which has been under shutdown for a period of more than one month, is not available, the contract rate applicable for the preceding month should be considered.

10.6. **NHPC** suggested that no regulation has been proposed for over-injection against zero schedules during start up, restoration of machines, and shut down of the machine. In this regard, it is submitted that while synchronizing Unit (s), the generators normally synchronize their unit (s) just ahead of the scheduled time block during ramping Up to meet the injection schedule of a particular time block. A similar phenomenon occurred during the de-synchronisation of the machine or ramping down of the Unit(s). In such cases, the over -injection and under-injection of more than 10% should be considered, and there should be a penalty for injecting power in a time block against zero schedules.

10.7. **NTPC suggested that** suitable provisions may be incorporated for the settlement of over-injection or under-injection from the schedule till the Minimum Turn Down Level (MTL) is achieved and that the charges for Deviation for such Deviation should be at a Reference charge rate irrespective of frequency.

Analysis and Decision

10.8. Some stakeholders suggested charging the start-up power at a contract or reference rate, while some suggested capping the rate of start-up power. Some stakeholders sought clarity on the drawal of power during non-solar hours to run auxiliaries. Some stakeholders suggested that the charges for deviation for start-up power should be linked with the temporary tariff specified by the respective SERC.

10.9. The Commission is of the view that the drawal of start-up power from the grid without schedule is not desirable. Drawal of (start-up or auxiliary) power from the grid without schedule would lead to system imbalances in the absence of a corresponding level of generation in the system. The Commission is of the view that the generators have sufficient avenues of procuring power to meet their requirement of start-up power and auxiliary power, including that during the night hours, and they should explore these avenues to ensure scheduled transactions without affecting the grid. If they fail to do so, they would be subjected to a deviation charge at the reference rate or contract rate as the case may be. Further, in the absence of a Reference rate or contract rate, such an entity should be charged at the weighted average ACP of the Day Ahead Market segments of all Power Exchanges for the respective time block. On the issue of treatment of deviation during the restoration of machines and shut down of machines, the Commission believes that the provision made under the respective category of seller is adequate and clear. Accordingly, the Commission decided to retain the same as follows:

"Regulation 8 (9) : The charges for deviation for drawal of start-up power before the COD of a generating unit or for drawal of power to run the auxiliaries during the shut-down of a generating station shall be payable at the reference charge rate or contract rate or in the absence of reference charge rate or contract rate, the weighted average ACP of the Day Ahead Market segments of all Power Exchanges for the respective time block, as the case may be."

11. Deviation Charges in respect of cross-border transactions (Regulation 8(11))

Commission's Proposal

11.1. The Commission had proposed the following in **Regulation 8 (11)** of the Draft Regulations:

(11) The charges for deviation in respect of cross-border transactions caused by way of over drawal or under drawal or over injection or under-injection shall be payable or receivable at the deviation charge rates and subject to volume limits as applicable to a seller (of the respective category) or to a buyer (other than a RE-rich State or a Super RE-rich State), as the case may be.

11.2. **Grid India** suggested that the neighbouring countries may be treated like 'state' & categorized under the 'buyer' category.

Analysis and Decision

11.3. The Commission noted the suggestion and is of the view that the provision made in the regulation is adequate. The NLDC may incorporate further detailing with regard to accounting and for deviation based on the existing framework of the cross-border mechanism through the settlement nodal agency (SNA).

12. Deviation Charges for forced outage of a seller (Regulation 8(12))

Commission's Proposal

12.1. The Commission had proposed the following in **Regulation 8 (12)** of the Draft Regulations:

(12) Notwithstanding anything contained in Clauses (1) to (5) of this Regulation, in case of forced outage of a seller, the charges for deviation shall be @ the reference charge rate for a maximum duration of eight time blocks or until the revision of its schedule, whichever is earlier.

Comments received

12.2. **Adani Power** suggested that the charges for Deviation under forced outage condition should be waived off as the condition of forced outage is beyond the control of the generator. **Adani Power, TPC, and NTPC** suggested that in case of a partial outage also, the charges for Deviation applicable for a forced outage should be applied. **JITP** suggested that until the revision schedule, the charges for deviation should be at the reference charge rate, whereas **Mr. Shishir Kumar Pradhan** suggested that the charges for Deviation should be linked to the reference charge rate for infirm generators. **APP** suggested that for collective transactions, the charges for Deviation may be kept at the reference charge rate for the entire period of forced shutdown.

12.3. **UPSLDC, JITPL, KPTCL, NLC, NTPC, and THDCIL** suggested that the revision of the schedule should not be restricted to 8 time blocks and the provisions to revise the schedule/ DC from the earliest possible block should be considered. **Adani Power** suggested that the RLDC may revise the schedule based on the actual generation starting from the event to normalized condition or restoration of the evacuation system. **Amplu Solar** suggested that revisions in generation schedules for Sellers contained in Clauses (1) to (5) should be permitted in accordance with the CERC (Indian Electricity Grid Code) Regulations, 2023.

12.4. **APRAAVA** suggested allowing for the partial forced outage condition also the charges for deviation @ the reference charge rate for a maximum duration of eight time blocks or until the revision of its schedule

12.5. **KPTCL** suggested that in case of a Force Majeure event, such as GD-5, the actual drawal should be replaced with the drawl schedule of the affected entities.

12.6. Grid India requested f clarification on the rate of deviation charges applicable after 8 blocks if the generator fails to revise the schedule.

Analysis and Decision

12.7. The Commission has noted the suggestions made by the stakeholders. Many stakeholders have suggested modifications in the provisions on schedule revision. It is clarified that schedule revision is beyond the scope of the present Regulations, and the stakeholders shall be guided by the provisions of the Grid Code. The Commission would like to clarify that the specified timelines have been adopted from the Grid Code in order to ensure consistency and alignment across regulations. Consequently, the Commission believes that the existing provisions are adequate and do not require any change.

12.8. The Commission also acknowledges NTPC's submission regarding the operational challenges faced by thermal stations, which can lead to partial outages and necessitate revisions in Declared Capacity (DC). Given the complexities involved, the Commission had previously allowed limited DC revisions for reasons such as partial outages, fuel quality variations, or other technical factors, as detailed in its Suo-motu order 18/SM/2023 dated 18.12.2023. In light of these challenges, the Commission agrees that it is essential to align the treatment of partial outages with that of forced outages. Therefore, the Commission has modified the relevant provisions in the final regulations to reflect this alignment. It is also clarified that such dispensation shall be permitted for downward revision of DC due to such partial outage which is permitted under Suo-Motu order 18/SM/2023 dated 18.12.2023 or subsequent amendment to the Grid Code.

12.9. Regarding the request for clarification of deviation charges applicable after 8 blocks if the generator fails to revise the schedule, it is clarified that under such circumstances, charges as applicable to a General Seller shall apply, including the impact of frequency and volume limits.

13. Multiple Contracts (Regulation 8(13))

Commission's Proposal

13.1. The Commission had proposed the following in Regulation 8 (13) of the Draft Regulations:

(13) In case of multiple contracts, the contract rate or the reference rate referred to in this Regulation shall be the weighted average of the contract rates of all such contracts.

Comments received

13.2. **ITPCL** requested clarification on whether the calculation of RR should include the tariffs of Short-Term (ST) Contracts also when power is being supplied under some ST Contracts, in addition to the long-term (LT) Contract, as some of the ERC Orders approving of such power procurement by the Utilities under ST Contracts do not specifically mention about adoption/determination under Section 63 of the Act.

13.3. **ICC** seeks clarification as to how the untied capacity of a general seller, which is partly or fully scheduled in DAM segments or RTM or Ancillary Services market, will be accounted for in the calculation of the Reference Rate of such general seller.

13.4. **Dhariwal** suggested incorporating necessary provisions regarding the computation of reference charge rate for the general seller having multiple contracts for which tariffs are determined under Section 62 or Section 63 of the Act and the seller also has merchant capacity.

13.5. **Grid India** suggested adding a proviso: "Provided that in case of scheduling of both Firm (after COD) & Infirm Power (prior to COD) by a seller from the different part capacities of the plant, the reference rate shall be the weighted average of contract(s) for the capacity that has achieved COD and the daily weighted average ACP of the I-DAM of all the Power Exchanges for the infirm power scheduled from the capacity that has not achieved the COD.

Analysis and Decision

13.6. The Commission has carefully reviewed the submissions made by the stakeholders and accordingly made suitable modifications to the definitions of 'Contract Rate' and 'Reference Charge Rate' in the final Regulations. As already mentioned in the earlier sections, it is reiterated that any contract for procurement of power has to be approved by the Appropriate Commission. Consequently, the rate specified in such contracts will be considered for the calculation of the contract rate or reference rate. In cases where a seller transacts power on a power exchange across multiple segments, each transaction in a different segment will be treated as a separate contract. The Contract Rate or Reference Charge Rate for that time block will be determined as the weighted average of the rates discovered across those cleared segments. For sellers who have achieved COD for only part capacity, the reference rate or contract rate shall be the weighted average of contract(s) for the capacity that has achieved COD. For the infirm power scheduled from the capacity that has not achieved the COD, the weighted average of the rates at which the seller has sold power in the market, as explained above, shall be considered.

14. Reference Charge Rate for Under-Injection in HP-DAM (Regulation 8(14))

Commission's Proposal

14.1. The Commission had proposed the following in Regulation 8 (14) of the Draft Regulations:

(14) For a Seller whose bids are cleared in the HP-DAM, the 'reference charge rate' for

deviation by way of 'under-injection' for the quantum of power sold through HP- DAM shall be equal to the weighted average ACP of the HP-DAM Market segments of all the Power Exchanges for that time block;

Comments received

14.2. **Mr. Shishir Kumar Pradhan** requested clarification on the calculation of Deviation and RR of a seller that sells 10 MW in HP-DAM, schedules 100 MW & actually generates 85 MW.

14.3. **MP SLDC** requested clarification whether, for a Seller bidding in HP-DAM, the 'reference charge rate' for deviation by way of 'under-injection' shall be equal to the weighted average ACP of the HP-DAM Market segments of all the Power Exchanges for that time block.

14.4. **ERPC** requested clarification whether the segregation of the deviation occurred due to the quantum of power sold through HP-DAM is to be calculated in respect of the total deviation that occurred in a time block or, alternatively, the weighted reference charge is to be calculated in a time block by considering the weighted average ACP of the HP-DAM Market segments of all the Power Exchanges for the part of schedule cleared through HP-DAM and for the remaining part of schedule at reference rate of the seller. ERPC also requested clarification on whether the above should be applicable in case of over-injection by a seller or not.

Analysis and Decision

14.5. The Commission has noted the comments from the stakeholders. In the case where a seller's sell bid is cleared in the HP-DAM, the reference charge rate for that seller will be determined as the weighted average Area Clearing Price (ACP) of the HP-DAM market segments across all Power Exchanges for the corresponding time block.

14.6. In the scenario highlighted by Mr. Pradhan, the total under-injection quantum by the seller is 15 MW, and the quantum sold in HP-DAM is 10 MW. In the instant case, if the system frequency during the relevant time block in which the HP-DAM transaction occurred was 50 Hz, and the weighted average ACP of all Power Exchanges' HP-DAM market segments for that time block was Rs. X/kWh, the seller will be required to pay back for 10 MW under-injection quantum at the rate of Rs. X/kWh, and the remaining 5 MW at reference charge rate calculated as per relevant provision of these Regulations. It should be noted that these calculations are subject to the actual system frequency and the applicable volume limits.

15. Deviation Charges for the states having net injection (Regulation 8(15))

Commission's Proposal

15.1. The Commission had proposed the following in Regulation 8 (15) of the Draft Regulations:

(15) In case of a State having net injection at the regional periphery, the deviation charges for such State shall be as applicable to a buyer.

Comments received

15.2. **Mr. Shishir Kumar Pradhan** suggested that necessary provisions may be incorporated while publishing the final DSM Regulation 2024 for generators giving drawl schedules. Grid India requested to provide clarity for the generators in case they have a drawal schedule from the grid.

Analysis and Decision

15.3. The Commission has noted the suggestion. The Commission is of the view that a generator can have a drawal schedule in specific situations where it is necessary for the generator to draw power from the grid to run its auxiliaries. The treatment of such generating stations is already covered under Regulation 8(9) of the draft notification. The Commission feels that the provisions are adequate and do not need any further modification.

16. Accounting of Charges for Deviation and Ancillary Service Pool Account (Regulation 9)

Commission's Proposal

16.1. The Commission had proposed the following in **Regulation 9** of the Draft Regulations:

9. Accounting of Charges for Deviation and Ancillary Service Pool Account

(1)By every Thursday, the Regional Load Despatch Centres shall provide the data for deviation calculated as per Regulation 6 of these regulations for the previous week ending on Sunday midnight to the Secretariat of the respective Regional Power Committees.

(2)After receiving the data for deviation from the Regional Load Despatch Centre, the Secretariat of the Regional Power Committee shall prepare and issue the statement of charges for deviation prepared for the previous week to all regional entities by ensuing Tuesday:

Provided that transaction-wise DSM accounting for intra-State entities shall not be carried out at the regional level.

(3)Separate books of accounts shall be maintained for the principal component and interest component of charges for deviation by the Secretariat of the Regional Power Committees.

(4) There shall be a Deviation and Ancillary Service Pool Account to be maintained and operated by the Regional Load Despatch Centre for the respective region:

Provided that the Commission may, by order, direct any other entity to operate and maintain the Deviation and Ancillary Service Pool Account.

(5) The Deviation and Ancillary Service Pool Account shall receive credit for:

(a) payments on account of charges for deviation referred to in Regulation 8 of these regulations and the late payment surcharge as referred to in Regulation 10 of these regulations;

(b) payments made by:

(i) SRAS Provider for the SRAS-Down despatched under the Ancillary Services Regulations;

(ii) TRAS Provider for the TRAS-Down despatched under the Ancillary Services Regulations; and

(iii) such other charges as may be notified by the Commission.

(6) Deviation and Ancillary Service Pool Account shall be charged for:

(a) payment to the seller for over injection as referred to in clause (1) of Regulation 8 of these regulations;

(b) payment to the buyer for under drawal as referred to in clause (2) of Regulation 8 of these regulations;

(c) the full cost of despatched SRAS-Up, including the variable charge or the energy charge or the compensation charge, as the case may be, for every time block on a regional basis, as well as the incentive for SRAS, payable to the concerned SRAS Provider as referred in the Ancillary Services Regulations;

(d) the full cost towards TRAS-Up, including the charges for the quantum cleared and despatched and the commitment charge for the quantum cleared but not despatched as referred in the Ancillary Services Regulations; and

(e) such other charges as may be notified by the Commission.

(7)In case of deficit in the Deviation and Ancillary Service Pool Account of a region, the surplus amount available in the Deviation and Ancillary Service Pool Accounts of other regions shall be used for settlement of payment under clause (6) of this Regulation:

Provided that in case the surplus amount in the Deviation and Ancillary Service Pool Accounts of all other regions is not sufficient to meet such deficit, the balance amount shall be recovered from the drawee DICs - (i) for the period from the date of effect of these regulations till 31.03.2025, in the ratio of [50% in proportion to their drawal at the regional periphery] and [50% in proportion to their GNA]; and (ii) from 01.04.2025, in the ratio of the shortfall of reserves allocated by NLDC to such DICs in accordance with the detailed procedure to be issued in this regard by the NLDC with the approval of the Commission.

Comments received

16.2. **Mr. K.K. Das** suggested modifying the design of DSM so that payment to RLDC should always be equal to payment from RLDC. **Mr. Shishir Kumar Pradhan** suggested that the Reactive Energy Charges & Congestion charges should also be accounted for in the Deviation & AS Pool. **NSL Group** suggested that the State Power Committee should collate transaction-wise DSM accounting for intra-State entities engaged in inter-state sale of electricity from SLDC & RLDC and issue charges on a monthly basis.

16.3. **GUVNL** suggested that it would be apt to devise a mechanism based on the ‘causer pays’ principle, and the DIC should not be burdened for payment of deficit in relation to their GNA as individual entities causing the Deviation would already have been incentives/ penalized in respect of its deviation.

16.4. **Some stakeholders, including RUVNL,** submitted that it may not be fair to recover deficits in the Pool Accounts from Discoms, especially when such deviations may not have been caused by them. It was highlighted that under RLDC fees and charges Regulations, 2019, the Discoms are already burdened with the payment of a portion of RLDC fees and charges for ISGS as per the TSA and PPA. **WBSEDCL, DVC** suggested that pool deficit should be shared with all ISTS Connected Utilities and should not be limited to the drawee DICs only. **DVC** also suggested that such charges may be recovered based on the injection/drawl quantum of all the pool participants.

16.5. Some stakeholders, including **KPTCL and AEML** suggested that in case of a deficit in the Pool Account of a region, the surplus amount available in the Pool Accounts of other regions should be used for settlement of payments.

16.6. However, if the deficit still exists, **AP Discom** suggested that the amounts may be adjusted from the PSDF funds, and if the same is also not sufficient, receivables from the pool may be reduced on a pro-rata basis based on the amount available. **KPTCL**, **AMEL, and BALCO** suggested that such deficit amount, if any, should be recovered from the drawee DICs & the sellers in the ratio of [50% in proportion to their drawal at the regional periphery] and [50% in proportion to their GNA to the schedule of seller] from the date of effect of these regulations till 31.03.2025, and 01.04.2025 onwards in the ratio of the shortfall of reserves allocated by NLDC to such DICs in accordance with the detailed procedure to be issued in this regard by the NLDC with the approval of the Commission. **Grid India** suggested that the shortfall may be recovered from Regional Entities (Buyers), in the ratio of [50% in proportion to their drawal at the regional periphery] and [50% in proportion to their GNA, which includes the GNA of drawee DICs located in the state] and that NLDC may be mandated to prepare detailed procedure (with prior approval of the Hon'ble Commission) for outlining the modalities for recovery of shortfall charges as mentioned in Para 9.7 of the regulation. It was highlighted by Grid India that the drawee DICs include the intra-state buyers like Central Railway Maharashtra (intra-state entity of Maharashtra), MPSEZ Utilities Ltd., Mundra (intra-state entity of Gujarat), etc., who have been granted GNA as per GNA Regulations. Further, the deviation mechanism at the interstate level is applicable only for regional entities whereas, in the draft DSM 2024, the deficit amount is proposed to be recovered from all the drawee DICs, which include intra-state entities, which may not be justifiable. As deviation accounting at the interstate level is being done only for Regional Entities, the intra-state entities, which are drawee DICs, need to be excluded. The GNA quantum of these intra-state drawee DICs may be added to the State's GNA for this purpose.

16.7. **MSEDCL** suggested avoiding recovery from the pool participants who have not caused the deficit and should be limited to the participants responsible for deviations, including RE generators. The deficit should be recovered by levy of additional charges from the Regional Entities (buyers and sellers) in proportion to Net Deviation Charges Payable by the concerned regional Entity for the applicable weekly settlement period through supplementary bills.

16.8. **ReNew** suggested that the deficit amount may be recovered from the drawee DICs. However, the amount recovered from DICs should not be allowed as pass through in their respective ARR. If the deficit recovered is allowed as pass through, the amount should not be recovered from renewable energy generators.

16.9. **Grid India** commented that in the settlement of inter-regional Deviation to and fro, payment of a substantial amount is done by Regional Entities as per their deviation accounts prepared by the respective RPCs. Inter-regional deviation charges are generally a circular flow of money and are notional. Thus, it was suggested that Inter-Regional deviations could be computed for indicative purposes only in the RPC accounts, and no physical fund transfer should be made within regions. Further, in order to have a simpler settlement system for faster settlement and for assessment of pool account surplus/deficit on an India basis, it was suggested that there should be one National pool account where the surplus from all Deviation and Ancillary Service Pool Accounts shall be transferred after settlement of all accounts in the concerned region on accrual basis such as Deviation, ancillary, reactive, congestion, etc. NLDC, based on the surplus on an actual basis, shall transfer the amount to deficit regional pool accounts in proportion to their net deficit. In addition, Grid India has also suggested some modifications/additions under Regulation 9.

Analysis and Decision

16.10. Many stakeholders have suggested that the deficit amount should be recovered from all ISTS-connected utilities, both injecting and drawee entities. Stakeholders have also proposed various recovery methods, including proportional recovery based on absolute deviation charges, Net Deviation Charges, or the causer pays principle and use of PSDF Funds with any remaining shortfall adjusted on a pro-rata basis from receivables.

16.11. As mentioned in the explanatory memorandum, the Commission acknowledges the critical importance of maintaining grid reliability, particularly in the context of anticipated significant growth in demand. Ideally, States should maintain adequate reserves to manage increasing demand and ensure grid stability. However, given the current challenges in identifying the shortfall on the part of the States against their allocated share of reserves, the Commission has determined that it is not feasible to allocate deficits solely based on the shortfall of reserves by individual States at this time.

16.12. The Commission recognizes that a framework for tracking reserve deficiencies will take time to develop and implement. Therefore, a deadline of March 31, 2026, has been set for the operationalization of this framework. This framework will enable the Commission to allocate deficits more precisely to the entities responsible for not maintaining adequate reserves. Until this framework is in place, deficits will continue to be recovered as outlined in the draft regulations.

16.13. In the meantime, to address the recovery of the current deficit, Grid India is directed to develop a detailed procedure and seek the Commission’s approval. This procedure should ensure an effective and transparent method for managing and recovering deficits.

16.14. Some stakeholders have suggested that charges like Reactive Energy Charges, Congestion Charges, and charges for SCUC and Black Start should also be accounted for in the Deviation & AS Pool. It is clarified that these charges fall outside the scope of the current regulations and will be governed by the provisions of the Grid Code. Regarding the uniformity in the settlement cycle of different pool accounts, it is reiterated that the present regulation addresses only the timelines for payment of deviation charges. The timelines for payment of other charges will be governed by the respective regulations pertaining to those charges.

16.15. In response to the issue raised by Grid India regarding the complexity of the current DSM settlement process, which results in a circular flow of funds between regions due to notional inter-regional transactions, the Commission has accepted the suggestion to establish a National Pool Account for centralizing surpluses from regional accounts. However, the Commission acknowledges that transitioning from regional pool accounts to a national pool will involve significant implementation challenges, particularly in developing and managing the necessary procedures. To address these concerns and ensure a smooth transition, the Commission has decided to allow Grid India a one-year period to formulate a comprehensive procedure and seek approval from the Commission. This will facilitate the effective implementation and operation of the National Pool Account. The Commission has accordingly made suitable changes in the final regulations.

16.16. Regarding DSM accounting for intra-State entities, the Commission would like to clarify that these are State specific matters and will be dealt with in the State Regulations.

16.17. Regulation 9, as specified in the final regulations, is as under: -

"9. Accounting of Charges for Deviation and Ancillary Service Pool Account

(1) By every Thursday, the Regional Load Despatch Centres shall provide the data for deviation calculated as per Regulation 6 of these regulations for the previous week ending on Sunday midnight to the Secretariat of the respective Regional Power Committees.

(2) After receiving the data for deviation from the Regional Load Despatch Centre, the Secretariat of the Regional Power Committee shall prepare and issue the statement of charges for deviation prepared for the previous week to all regional entities by ensuing Tuesday:

Provided that transaction-wise DSM accounting for intra-State entities shall not be carried out at the regional level.

(3) Separate books of accounts shall be maintained for the principal component and interest component of charges for deviation by the Secretariat of the Regional Power

Committees.

(4) There shall be a Deviation and Ancillary Service Pool Account to be maintained and operated by the Regional Load Despatch Centre for the respective region:

Provided that the National Load Despatch Centre (NLDC) shall formulate detailed procedure for implementation, maintenance and operation of the National Deviation and Ancillary Services Pool account after due consultation with stakeholders within 1 (one) year from the date of commencement of these Regulations and seek approval of the Commission.

(5) The Deviation and Ancillary Service Pool Account shall receive credit for:

(a) payments on account of charges for deviation referred to in Regulation 8 of these regulations and the late payment surcharge as referred to in Regulation 10 of these regulations;

(b) payments made by:

(i) SRAS Provider for the SRAS-Down despatched under the Ancillary Services Regulations;

(ii) TRAS Provider for the TRAS-Down despatched under the Ancillary Services Regulations; and

(iii) such other charges as may be notified by the Commission.

(6) Deviation and Ancillary Service Pool Account shall be charged for:

(a) payment to the seller for over injection as referred to in Regulation 8 of these regulations;

(b) payment to the buyer for under drawal as referred to in Regulation 8 of these regulations;

(c) the full cost of despatched SRAS-Up, including the variable charge or the energy charge or the compensation charge, as the case may be, for every time block on a regional basis, as well as the incentive for SRAS, payable to the concerned SRAS Provider as referred in the Ancillary Services Regulations;

(d) the full cost towards TRAS-Up, including the charges for the quantum cleared and despatched and the commitment charge for the quantum cleared but not despatched as referred in the Ancillary Services Regulations; and

(e) such other charges as may be notified by the Commission.

(7) In case of deficit in the Deviation and Ancillary Service Pool Account of a region, the surplus amount available in the Deviation and Ancillary Service Pool Accounts of other regions shall be used for settlement of payment under clause (6) of this

Regulation:

Provided that in case the surplus amount in the Deviation and Ancillary Service Pool Accounts of all other regions is not sufficient to meet such deficit, the balance amount shall be recovered from the drawee DICs - (i) for the period from the date of effect of these regulations till 31.03.2026, in the ratio of [50% in proportion to their drawal at the ISTS periphery] and [50% in proportion to their GNA]; and (ii) from 01.04.2026, in the ratio of the shortfall of reserves allocated by NLDC to such DICs:

Provided further that the NLDC shall prepare, with the approval of the Commission, a detailed procedure for recovery of charges in case of deficit in the Deviation and Ancillary Service Pool Accounts, and for the methodology of computation of shortfall of reserves and allocation of deficit amongst DICs."

17. Schedule of Payment of Charges for deviation (Regulation 10)

Commission's Proposal

17.1. The Commission had proposed the following in **Regulation 10** of the Draft Regulations:

10. Schedule of Payment of Charges for deviation

(1) The payment of charges for deviation shall have a high priority, and the concerned regional entity shall pay the due amounts within 7 (seven) days of the issue of the statement of charges for deviation by the Regional Power Committee, failing which late payment surcharge @ 0.04% shall be payable for each day of delay.

(2) Any regional entity which at any time during the previous financial year fails to make payment of charges for deviation within the time specified in these regulations shall be required to open a Letter of Credit (LC) equal to 110% of their average payable weekly liability for deviations in the previous financial year in favour of the concerned Regional Load Despatch Centre within a fortnight from the start of the current financial year.

(3) In case of failure to pay into the Deviation and Ancillary Service Pool Account within 7 (seven) days from the date of issue of the statement of charges for deviation, the Regional Load Despatch Centre shall be entitled to encash the LC of the concerned regional entity to the extent of the default and the concerned regional entity shall recoup the LC amount within 3 days.

Comments received

17.2. **Adani Power** suggested that any discrepancy should be resolved before the due date of DSM payment otherwise, the due date should be extended. Alternatively, the RPC may publish a preliminary/provisional DSM account for the purpose of resolving discrepancies, if any, and then upload the final DSM account.

17.3. **RUVNL** suggested keeping the provision for paying the outstanding amount within a 12-day period, while NLC, AEML, and Tata Power suggested keeping it at 10 days in line with earlier practice. Some stakeholders suggested that with added validation of details to be complied by QCA, the time provided for making the payment be increased to 7 working days **(NTPC),** 10 days (**MNRE, WIPPA, NTPC**), 12 days (**RUVNL, Adani Power**), or 15 days **(Re New)** or.

17.4. **THDCIL** suggested that in case the last day is an official holiday, the due date of payment shall be construed as the immediate succeeding working day.

17.5. Some stakeholders suggested that in the case of generating stations aggregated at a pooling station through QCAs, the late payment surcharge should only apply to individual generators that have failed to make timely payments for deviation charges **(SRIPL, HFE, Re New, PHDCCI)**.

17.6. **Tata Power** suggested that the LPS applicable to the regional entities for the delay in payment should also be applicable to the RPC for the delay in receivable by the regional entity under the principle of equitable treatment. **WBSLDC, MUL** suggested that the Receivable amount should be credited to that entity within 7 days of the publishing of the bill, failing which the entity should receive 0.04% per day interest for each day of delay as LDC is recovering LPS at the same rate from defaulting entity.

17.7. **IPCL** suggested that the entity should have the right to withhold the payment in case of dispute on the computation of the payable amount.` **Tata Power** indicated that on a few occasions, the statements issued by RPC were erroneous. In such cases, RPCs have to be intimated to correct the error and verify the same. Thus, a delay in payment due to the error in the statement of RPC should not be subject to any consequences like LPS as per Regulation 10 (1).

17.8. **Grid India** indicated that as per SRAS Procedure, SRAS Providers are directed to pay back the amount payable to the Pool Account within 10 days, while TRAS providers are required to make the necessary payment to the Pool Account within 7 days from the date of issuance of corresponding statements by RPC. Similarly, as per the IEGC Annexure – 4 Sl no 2 in case of reactive energy, the concerned regional entities are mandated to make the payment to the Pool Account within 10 days of issuance of the statement and as per the Regulations of 2009 on Measures to Relieve congestion in Real**T**ime Operation, the Regional Entities liable to pay congestion charge are directed to deposit the amount in Congestion Charge Account within 10 days of issue of statement by RPC. Thus, to have a clear picture of the net surplus available in respective regional Deviation and Ancillary Service Pool Accounts at any given point in time, there is a need to have a common payment cycle for all the transaction heads. Further, there is a need to have to and fro payment to the Entities on a net basis to net off the numerous bi-directional transactions, or else this would lead to a circular flow of money. On similar lines, reactive energy and congestion charges may be clubbed together, and the timeline of all payments may be aligned through amendments in relevant regulation(s) or through devising "a separate procedure" for the same. **Grid India** indicated that a few states are persistent defaulters, and no regulatory tool is available for strict clearance of outstanding DSM. It was also proposed that in case of non-payment of dues for more than one month after the due date by the regional entity or in case of non-maintenance of LC, the scheduling of the supply of electricity to the defaulting entity shall be regulated. It was also indicated that there is no provision for opening of LC for new Pool members in the financial year as for such new pool members, average payable weekly liability for deviations in the previous financial year is not available. So, practically, it is not possible to open LC for a new entity if it defaults in the current year. Thus, Grid India suggested that the regulation of access of defaulting entities may be included in sub Regulation (10).

17.9. **Tata Power** suggested that at least 15 working days should be provided from the date of issue of the RE DSM bill before the LC encashment can kick in. It was highlighted that some states are providing considerable time [e.g. 60 days as per the (Procedure for Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2015' of KERC] before LC encashment can kick in.

Analysis and Decision

17.10. Many stakeholders have suggested increasing the due date of payment from 7 days to 10 days or 12 days to account for the time required for data validation and de-pooling processes. The Commission has accepted the suggestions of the stakeholders and has modified the payment due date to 10 days in the final regulations. However, discrepancies in the DSM statement issued by the RPCs shall be mutually settled between the RPCs and the Entity and guided by the principles laid down in these Regulations.

17.11. Some stakeholders have suggested the need for clear guidelines on the timeline for receiving payments from the DSM pool to ensure timely credits. It is clarified that payments to the receiving entities are to be made within the same timelines specified for the paying entities.

17.12. Some stakeholders have also suggested providing clarity on the sharing of charges among individual generators in case of aggregation at a pooling station through QCAs. As explained in the earlier sections, the de-pooling of deviation charges for WS seller(s) connected to the pooling station shall be as per the methodology mutually agreed upon between the QCA and such individual WS seller(s).

17.13. Regarding the suggestion from Grid India on the need to have a common payment cycle for all transaction heads, it is clarified that the jurisdiction of these Regulations is only up to transactions related to deviation charges. Payment cycle of all other transactions will be dealt with as per the provision of respective Regulations. Further, regulation of Power supply to defaulting entities is beyond the purview of the instant Regulation. Regarding the provisions on LC, the Commission is of the view that there is no need for any change in this regard, and hence, the provision as proposed in the draft Regulations has been retained.

17.14. Regulation 10. as specified in the final regulations is as follows:-

"10. Schedule of Payment of charges for deviation

(1)The payment of charges for deviation shall have a high priority, and the concerned regional entity shall pay the due amounts within 10 (ten) days of the issue of the statement of charges for deviation by the Regional Power Committee, failing which late payment surcharge @ 0.04% shall be payable for each day of delay.

(2)Any regional entity which at any time during the previous financial year fails to make payment of charges for deviation within the time specified in these regulations shall be required to open a Letter of Credit (LC) equal to 110% of its average payable weekly liability for deviations in the previous financial year in favour of the concerned Regional Load Despatch Centre within a fortnight from the start of the current financial year.

(3)In case of failure to pay into the Deviation and Ancillary Service Pool Account within 10 (ten) days from the date of issue of the statement of charges for deviation, the Regional Load Despatch Centre shall be entitled to encash the LC of the concerned regional entity to the extent of the default and the concerned regional entity shall recoup the LC amount within 3 days."

18. Additional Comments

18.1. In addition to the regulation specific comments, some stakeholders submitted general comments not directly related to specific provisions of the regulations. These comments emphasized the need for more flexibility in schedule revisions, a reduction in the implementation time for revised schedules, and a shorter gate closure time in the Real-Time Market (RTM) to improve deviation management, etc. Suggestions also included provisions for declaring the duration of force majeure events, adjusting scheduling for transmission constraints or weather disruptions, addressing impacts on buyers or beneficiaries during grid disturbances, and ensuring that energy supplied by RE generators under certain services is credited toward RPO and HPO compliance.

18.2. The Commission has noted the suggestions/additional comments submitted by the stakeholders. However, the suggestions are beyond the scope of these regulations.

Sd/-	**Sd/-**
(Ramesh Babu V.)	**(Jishnu Barua)**
Member	**Chairperson**