REPORT OF THE CERC EXPERT COMMITTEE

ON

ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS

January 2024

Central Electricity Regulation Commission

Expert Group on

"Analyzing the Causes of Inadequate Primary and Secondary Response with Respect to Implementation of DSM Regulations"

The Central Electricity Regulatory Commission, vide letter No. RA-14018 (11)/1/2023-CERC/8140 dated 27th February 2023 constituted an Expert Committee for analyzing the causes of inadequate primary and secondary response with respect to implementation of DSM Regulations 2022 under the Chairmanship of Shir I.S. Jha, Member, Central Electricity Regulatory Commission.

The Scope of Work of the Expert Committee outlined for the Expert Committee included behavioral analysis of regional entity, review of adequacy of reserves and design related issues of DSM. This report is an outcome of extensive consultation and valuable inputs from Committee members along with special invitees on various aspects of maintaining adequate reserves for managing grid frequency and operational feedback on DSM implementation. This report documents deliberation of the Expert Committee constituted for the purpose and key recommendations on remedial measures for ensuring participation of the grid connected entities in providing primary, secondary, and tertiary reserves and on design aspects of Deviation Settlement Mechanism (DSM). The Committee, hereby, submits the report to the Central Electricity Regulatory Commission.

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Abbreviations

ACE	Area Control Error
AGC	Automatic Generation Control
AvC	Available Capacity
CAISO	California Independent System Operator
CERC	Central Electricity Regulatory Commission
DAM	Day-Ahead-Market
DRE	Distributed Renewable Energy
DSM	Deviation Settlement Mechanism
ERPC	Eastern Regional Power Committee
F&S	Forecasting and Scheduling
FGMO	Free Governor Mode Operation
FRO	Frequency Response Obligations
IEGC	Indian Electricity Grid Code
KERC	Karnataka Electricity Regulatory Commission
MNRE	Ministry of New and Renewable Energy
MW	Mega Watts
MWh	Mega Watt-hours
NERPC	North Eastern Power Committee
NLDC	National Load Despatch Center
NRPC	Northern Regional Power Committee
OD	Over Drawal
OI	Over Injection
RE	Renewable Energy
RE	Renewable Energy
RGMO	Restricted Governor Mode Operation
RLDC	Regional Load Despatch Centers
RLNG	Regasified Liquefied Natural Gas
ROR	Run Of River
RPC	Regional Power Committee
RRAS	Reserve regulatory ancillary service
Rs	Rupees
RTM	Real-Time Market
SAREP	South Asia Regional Energy Partnership
SLDC	State Load Dispatch Centre
SOW	Scope of Work
SRAS	Secondary Reserve Ancillary Services
SRPC	Southern Regional Power Committee
TB	Time Blocks
TRAS	Tertiary Reserve Ancillary Services

UD	Under Drawal
UI	Under Injection
UP	Uttar Pradesh
UPERC	Uttar Pradesh Electricity Regulatory Commission
USA	United States of America
USAID	United States Agency for International Development
WRPC	Western Regional Power Committee

Acknowledgement

The Expert Committee would like to thank Hon'ble Commission for constitution of the Committee and creating a platform for deliberating on vital aspects of primary, secondary, and tertiary response with respect to implementation of DSM Regulations. The members acknowledge the extensive support provided by their parent organizations for accomplishment of the assignment.

The Expert Committee also acknowledges the wealth of information available in the literature & international experience in different countries which has provided deep insights into the finer aspects of primary, secondary, and tertiary market products and services in India.

The Expert Committee acknowledges the inputs from Sh. S.S Barpanda, Director (Market Operation), Grid-India and Sh. S.C. Saxena, Executive Director, NLDC, Shri Ravindra Kadam, Senior Advisor (RE), CERC and the USAID supported SAREP (RTI and Idam team), which helped in analysis and providing inputs for remedial measures required in DSM Regulations 2022.

The contribution of Sh. Vivek Pandey, Sh. K.V.N. Pawan Kumar, Sh. Anupam Kumar, Sh. Rahul Shukla, Sh. Phanisankar Chilukuri, Sh. Anmol Sharma, Sh. Aman Gautam, for their valuable contribution in analysis of primary, secondary, and tertiary response. The contribution of Ms. Sukanya Mandal, Shri Saurabh, Prof. Nicholas Ryan, and Sh. Yashwanth Reddy in behavioural analysis is also duly acknowledged.

1 Introduction

The Central Electricity Regulatory Commission (CERC) notified the Deviation Settlement Mechanism (DSM) Regulations in 2014 (DSM Regulations 2014) followed by an amendment in 2016 (DSM Regulations Amendment 2016)[1] with the objective of ensuring grid discipline for the grid connected entities. CERC subsequently issued the DSM Regulations in March 2022 (DSM Regulations 2022)[2] which came into effect on 05 December 2022, repealing the DSM Regulations, 2014 as amended from time to time.

After the DSM Regulations 2022 came into effect, it was observed that while the number of frequency excursions decreased, frequency fluctuations outside the operative band increased by almost 20%. It was also noted that there was tendency to over-inject to avoid payment of deviation charge for over-drawal/under-injection (OD/UI). In the wake of this operational experience, the Commission notified an intervening Order on 26 December 2022 vide suo-motu Petition No. 16/SM/2022, stipulating inter-alia certain regulatory measures to contain frequency within the operating band and reduce wide frequency fluctuations. Notably, the Commission put a cap of 12 Rs/kWh on the normal rate of charges for deviation[3].

The Commission continued to monitor the performance and received further operational feedback from Grid-India and other stakeholders post 26 December 2022. Grid-India noted that the frequency profile did improve but still continued to be of concern. Other stakeholders noted that ancillary services were not being deployed as envisaged. Based on the above feedback and consultation, the Commission issued directions vide its Suo Motu Order 01/SM/2023 dated 06 February 2023 to remove difficulties in the implementation of DSM Regulations 2022, as an interim measure, to ensure smooth and secure grid operations[4].

In addition, on 27 February 2023, the Commission issued directions to form an Expert Committee to conduct detailed monitoring and analysis of performance. The Commission noted in the said Order that *"frequency excursions have revealed, inter alia inadequate primary response from the generators through their governors as mandated under the IEGC. Further, secondary response through AGC was expected to correct the area control error (ACE) which has an element of both frequency control and tie-line flow control. Performance of neither has been satisfactory as is reflected in the Grid-India report and revealed from interaction with the generators and other stakeholders. The Commission accordingly decided to form a high-level committee of*

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[1] https://cercind.gov.in/2016/regulation/14.pdf
[2] https://cercind.gov.in/Regulations/168_reg.pdf
[3] https://cercind.gov.in/2022/orders/16-SM-2022.pdf
[4] https://cercind.gov.in/2023/orders/1-SM-2023.pdf

experts to go into detail the causes for inadequate primary and secondary response and suggest remedial measures."

1.1 Constitution and ToR of Expert Committee

As per the order of the Commission, the Competent Authority constituted an Expert Committee with the following composition:

1. Shri I. S. Jha, Member, CERC – Chairman
2. Shri S. R. Narasimhan, CMD, Grid Controller of India Limited – Member
3. Shri K. K. Sharma, Former Member, UPERC – Member
4. Shri B. B. Mehta, Director, SLDC Orissa – Member
5. Shri Satyanarayan S., Member Secretary, WRPC – Member
6. Shri Sushanta Kumar Chatterjee, Chief (RA), CERC – Member Secretary

The scope of Work of the Expert Committee constituted by the Commission is as follows:

1. Review and analysis of operational behaviour of grid-connected buyers and sellers post 05.12.2022.
2. Examine the performance of the regional entity generators in terms of providing primary response and AGC support to manage grid frequency.
3. Review operation of RRAS and status of implementation of TRAS.
4. Review the practice of maintaining reserves by states and status of implementation of ancillary services at the state level.
5. Suggest remedial measures for deployment of adequate reserves (primary, secondary, and tertiary) for reliable grid operation.
6. Any other matter related to above, including design related issues on DSM and ancillary services.

Shri Bhanu Bhushan, former Member, CERC and Shri Rakesh Nath, former Member, APTEL were invited as special invitees for their expert opinion.

USAID offered technical support to the CERC Expert Committee through its subcontractors under the SAREP Program. As a part of this technical support, Idam Infrastructure Advisory Pvt. Ltd. through its contractor RTI International has supported the Expert Committee (EC) through its analysis, deliberations, and preparation of this report.

2 Summary of Deliberations of the Expert Committee

2.1 First Meeting on 06 March 2023

The first meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations" was held on 06 March 2023 at CERC Conference Hall under the chairmanship of Shri I.S Jha (Member, CERC). The agenda of the first meeting was to analyze the causes for inadequate primary and secondary response with respect to the implementation of DSM Regulations 2022.

The need for detailed analysis of supply- and demand-side issues before the suggestive remedial measures was highlighted. Regulatory roadmap for ancillary services was discussed. Grid-India submitted that the concept of dead band of ripple filter is creating a confusion among the vendors, designing the controls for primary response in generating stations. Ripple filter implementation at current tracking frequency is the logic in frequency controller that restricts governor to respond within ripple filter band range calculated with respect to the current tracking/running frequency. Grid-India further added that frequency excursions has become more dominant in post period of 5th December 2022. It was opined that existing provisions of Restricted Governor Mode Operation (RGMO) needed review along with consideration of substitution of RGMO with Free Governor Mode Operation (FGMO). It was decided to carry out supply- and demand-side performance pre and post 05 December 2022 and to consult generating stations in subsequent meetings.

2.2 Second Meeting on 05 April 2023

The Second Meeting of the Expert Committee was held on 05 April 2023 at CERC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). The main agenda of the meeting was supply- and demand-side performance analysis pre and post 05 December 2022 along with interaction with subject matter experts.

A detailed analysis of the performance of buyers and sellers was presented by the Consultant. 3 - 4 buyers and sellers were selected across WRPC, SRPC, and NRPC and one representative week was selected for each month from January 2022 to March 2023. Analysis of 15-min frequency, actual, and schedule was presented, and it was observed that there was very little correlation between frequency and deviation. However, since this analysis was done at 15-min interval, there was a chance that finer behavioral trends might get missed out.

Sh. Bhanu Bhushan (Ex-Member, CERC) remarked that for 15 February 2023 and 24 March 2023, there were four distinct peaks in one hour potentially due to scheduling in steps of 15-min and absence of FGMO. He suggested analyzing a step-less approach to scheduling.

Sh. Rakesh Nath (Ex-Member, APTEL) expressed that unless states are well equipped, DSM cannot solve the issue of frequency fluctuations, but that frequency linkage is better than no linkage. He noted that resource adequacy planning should be ensured by the state regulators at the state-level. He further noted that the whole scheme should be looked at while formulating solutions.

Grid-India presented the primary response of generating units during high and low frequency periods. It was highlighted that the generating plants were not providing primary response in both instances of high and low frequency. However, an analysis of the same unit's response during contingency events, such as generation loss, demonstrated a positive primary response. The suggested reason for the unit's failure to provide primary response during hourly boundaries, especially in high and low-frequency periods, revolves around the implementation of the ripple filter logic in the frequency controller. This logic, tied to the current tracking frequency, may be constraining the governor's response by limiting it within the ripple filter band range calculated based on the current frequency and slower tracking rate.

2.3 Third Meeting on 26 April 2023

The Third Meeting of the Expert Committee was held on 26 April 2023 at NLDC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC).

Sh. Bhanu Bhushan (Ex-Member, CERC) gave a detailed overview of the operation of the governor and explained that the key functions of a governor are reducing frequency change, load sharing, and safety of the machine. NTPC made a presentation on ‘Operational Aspects of Governor Control in a Generating Station/Unit’. In this presentation, NTPC representative explained that RGMO lets frequency increase within 49.90-50.00 Hz but if it is reduced in that band then it steps in. It was discussed that FGMO comes into the picture before and after RGMO’s band. It was noted that RGMO is set at 5% to avoid hunting. Grid-India made a presentation on analysis of power plants response with and without AGC. Case studies of Sipat and Rihand units were presented, wherein it was presented that the AGC response from thermal units is helping in containing the frequency excursions in power system.

2.4 Fourth Meeting on 14 August 2023

The Fourth Meeting of the Expert Committee was held on 14 August 2023 at NRLDC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). The main agenda of the meeting was discussion on trial operation with AGC, and option analysis of DSM framework.

Shri. S. R. Narasimhan (CMD Grid-India) made a presentation on trial operation with AGC. In the presentation, he explained frequency fluctuations, AGC response in contingencies, grid operation and response of AGC for thermal and hydro plants. Case studies were shown to explain the effect of AGC by comparing grid operation with and without AGC. In the end, he explained feedback received, modes of control area trial operation, frequency control, and way forward.

Shri Bhanu Bhushan (Ex-Member, CERC) explained DSM framework development and DSM charges. Further option analysis was presented by the consultant in the presentation. In the presentation, the consultant explained the current DSM framework for the buyers and the sellers, the explanation of ACE and FRO, and the three-option analysis. The option analysis is done for the buyers and the sellers compared with the existing DSM charges.

NLDC explained that Market based procurement of reserves through Tertiary Reserve Ancillary Services (TRAS) has been implemented from 1st June 2023. TRAS allows the system operator to procure reserves from the day ahead ancillary services market and real time ancillary services market. However, very low or nil participation has been observed from the sellers in TRAS.

2.5 Fifth Meeting on 21 September 2023

The Fifth Meeting of the Expert Committee was held on 21 September 2023 at CERC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). The main agenda of the meeting was discussion on design principles and proposed revisions to the DSM framework and analysis of performance of reserves and potential causes for frequency fluctuations.

Mr. Nicholas Ryan made a presentation on design principles and suggested revision to the DSM framework. He noted that historical performance analysis highlighted the tendency of solar and wind sellers to over-schedule and under-inject, and tendency of thermal sellers to under-schedule and over-inject, both behaviours driven by the asymmetrical pricing structure. He further added that buyers also displayed similar behaviour due to asymmetrical pricing. Given the above observations, Mr. Ryan proposed the following changes to the DSM Regulations: 1) tighter tolerance band of +/- 5% for sellers to encourage accuracy of forecasts; 2) symmetrical and linear charges for general sellers and buyers; and 3) removal of incentive/penalty parameters for UI/OD to avoid any perverse incentive.

Representatives of Grid-India made a presentation on performance of reserves and potential causes for frequency fluctuations. They presented that the generating units have implemented droop settings in four different ways. First is droop at MCR with 5% limitation of MCR, second one is droop at current generation (CG) with 5% limitation of CG, third one is droop at MCR with 5% limitation of CG , fourth one is droop at MCR, with 5% limitation of CG for below 50 Hz & 5% limitation of MCR for above 50 Hz. This difference in understanding of droop logics is restricting the primary response from generating units. They also presented the issue of ripple filter implementation, some units have ripple filter implementation on running/current tracking frequency, some have implemented w.r.t fixed 50 Hz, and some have at current tracking frequency for f<50 Hz and at fixed 50 Hz for f>50 Hz and vice-versa. They remarked that a time lag of 15-20 seconds was observed in output change of generators after receiving signal, due to high scan rate and other technical reasons related to boilers. Also, it was presented that units responding to consecutive changes in frequency as per droop but no response while ramp back is in action and also some units responds to first frequency change and does not respond to any further changes in frequency. Additionally, they highlighted that some thermal plants were not able to give primary response due to technical constraints. They remarked that a clear difference in controller logic could be seen in July 2022 and February 2023, likely due to revisions in DSM. They explained that while the generators were behaving as per the technical characteristics, the control signal had been modified. The EC deliberated on whether this manual control settings on PRAS and SRAS were causing frequency excursions.

2.6 Sixth Meeting on 26 October 2023

The Sixth Meeting of the Expert Committee was held on 26 October 2023 at CERC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). The main agenda of the meeting was discussion on recommended remedial measures for reserves and DSM Regulations.

At the outset of the meeting, Shri. B. B. Mehta (Director, SLDC, Odisha) made a presentation on technical and administrative aspects relating to reserves and DSM. He explained that many generators need refurbishment but have no provision under O&M for the same. To ensure primary control functionality on all participating generators, he suggested that generators may be supported through PSDF. He presented additional suggestions on rates for over-injection/under-drawal, fast-track implementation of storage, model-based scientific demand forecasting with periodically accurate weather input, and DSM for reactive power.

The Committee Members went through a compilation of feedback received from Members and stakeholders during the course of the Committee meetings. They discussed suggestion of stepless scheduling and deliberated that while it makes theoretical sense, it may be difficult to implement. It was discussed that though scheduling is in 15-minutes steps but practically the load & generation in the system would vary smoothly barring agriculture load rosters & bringing in & out of hydro units which creates spikes in the frequency at the 15-minute boundary. Step-less scheduling would necessitate moving from the current 15-minute average MW scheduling to schedules at various instant of time (0000 hrs,0015 hrs. & so on) with linear interpolation. It would need to start from Declaration of Capacity (DC), requisitions filled by States, bilateral contracts, DAM and RTM & necessary software changes at all utilities which would necessitate a wider discussion with all stakeholders.

Thereafter, recommended remedial measures for reserves and DSM Regulations were presented by the Consultant on behalf of USAID. Recommendations for reserves were centred around roadmap for FGMO and AGC compliance, review of compensation/incentive to encourage SRAS and TRAS, resource adequacy, and alignment with IEGC/GNA. Recommendations for DSM Regulations were based on key principles of symmetrical and uniform pricing, avoiding over-incentivizing, promoting participation in ancillary services, and capturing FGMO compliance. The Committee Members discussed recommended formulations for general sellers, wind/solar/hybrid sellers, and RE-rich/non-RE-rich buyers. Each formulation was discussed in detail and suggestions from Committee Members were noted for further iteration and incorporation.

3 Evolution of DSM Framework

The Central Electricity Regulatory Commission (CERC) notified the Deviation Settlement Mechanism (DSM) Regulations in 2014 (DSM Regulations 2014) followed by an amendment in 2016 (DSM Regulations Amendment 2016), with the objective of ensuing grid discipline for the grid connected entities. These Regulations were essentially linked with the frequency and volume limits in certain cases. CERC subsequently issued the DSM Regulations in March 2022 (DSM Regulations 2022) which came into effect on 05 December 2022 which has delinked the frequency and also removed the volume limits. The overarching differences between DSM Regulations Amendment 2016 and DSM Regulations 2022 were:

1. The DSM Regulations 2022 envisage that all grid-connected entities shall adhere to their schedules and inadvertent deviation, if any, shall be managed by the system operator through ancillary services.
2. To manage uncertainty in demand and possible unanticipated changes in generating station conditions, the load-serving entities and the generators may resort to organised market platforms like Real Time Market (RTM) and other avenues of energy trade closer to real-time.
3. DSM charges were delinked from frequency as it was felt that the existence of both the centralised mode of frequency regulation through Ancillary Services and the decentralised mode of controlling frequency through frequency-linked DSM could lead to avoidable conflict in system operation.
4. The System Operator should have the responsibility of managing the system frequency.
5. The grid-connected entities can continue to play the same role (of helping restore frequency within the operating band) but at the instruction of the system operator by participating in the Ancillary Services mechanism, rather than acting on their own driven by the price signals linked to frequency.

In the wake of the operational experience and feedback post 05 December 2022, the Commission notified intervening orders on 26 December 2022 with the following key modification:

- From an analysis of Grid-India for the first two weeks after DSM implementation, there were instances of high frequency and frequency remaining outside of the operating band of 49.9 HZ to 50.05 Hz, and the combined effect of OI and UD. To contain this trend, the Commission decided as follows:
    - For frequency of 50.05 Hz or above, the general seller other than an ROR generating station or a generating station based on municipal solid waste shall be paid from the Deviation and Ancillary Service Pool Account @

zero, for deviation by way of over injection in such time-block and similarly shall pay back to the Deviation and Ancillary Service Pool Account for the shortfall in energy against its schedule in any time block due to under injection @ 50% of the reference charge rate.

- The buyer shall be paid back from the Deviation and Ancillary Service Pool Account @ zero, for deviation by way of UD in such time-block.
- For frequency of 49.90 Hz or below, the general seller other than a ROR generating station or a generating station based on municipal solid waste shall be paid back from the Deviation and Ancillary Service Pool Account @ 150% of reference charge rate for deviation by way of over-injection in such time-block.

With continued operational experiences and feedback, the Commission issued the intervening Order on 06 February 2023 for general sellers and buyers. Additionally, the Commission clarified provisions regarding the following aspects:

1. Treatment of deviation charges for infirm power, start-up power, power to run auxiliaries during shutdown of a generating station and during a forced outage of a generating station, and deviation with regard to Cross-Border Transactions and for inter-regional deviation.
2. Highlighted that the required support from the buyers and the sellers in the form of Reserves and Ancillary Services, as was envisioned, under the Ancillary Services Regulations dated 31.01.2022, has not been forthcoming.
3. The Commission reiterated that the basic intent of the Ancillary Service Regulations 2022 was to transit the same sets of buyers and sellers, who were acting based on 'commercial considerations', to provide support for grid operation through an organized mechanism of Ancillary Services.
4. Frequency excursions have revealed inter-alia inadequate primary response from the generators through their governors as mandated under the IEGC. Further, a secondary response through AGC was expected to correct the area control error (ACE) which has an element of both frequency control and tie-line flow control. Performance has not been satisfactory as is reflected in the Grid-India report and revealed from interaction with the generators and other stakeholders.
5. Against this backdrop, the Commission in this Order highlighted the need for a detailed investigation into the causes of frequency fluctuations and deviations. The Commission accordingly constituted the Expert Committee to go into detailed causes for inadequate primary and secondary response and suggest remedial measures.

The following Figure 1 depicts the evolution of DSM Regulations:

Figure 1: Evolution of DSM Framework

3.1 Current DSM Framework (06 Feb 2023)

The following schematic (Figure 2) depicts the current DSM framework for general sellers as introduced through the Order dated 06 February 2023:

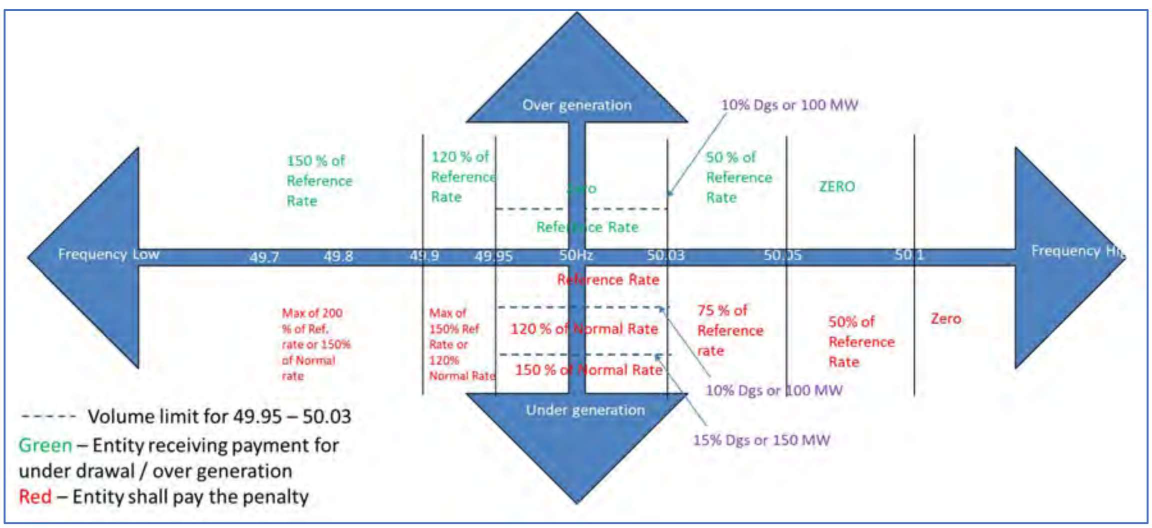


Figure 2: 06 February 2023 Framework - General Sellers

The current framework places a volume limit of lesser of 10% D_{gs} or 100 MW, up to lesser of 15% D_{gs} or 150 MW. Reference rate is used till the first volume limit, after which normal rate is used for deviation while there is no incentive for OI beyond the first volume limit. Beyond the volume limit range, a mix of reference and normal rates is used.

The following schematic (Figure 3) depicts the framework for wind/solar/hybrid sellers:

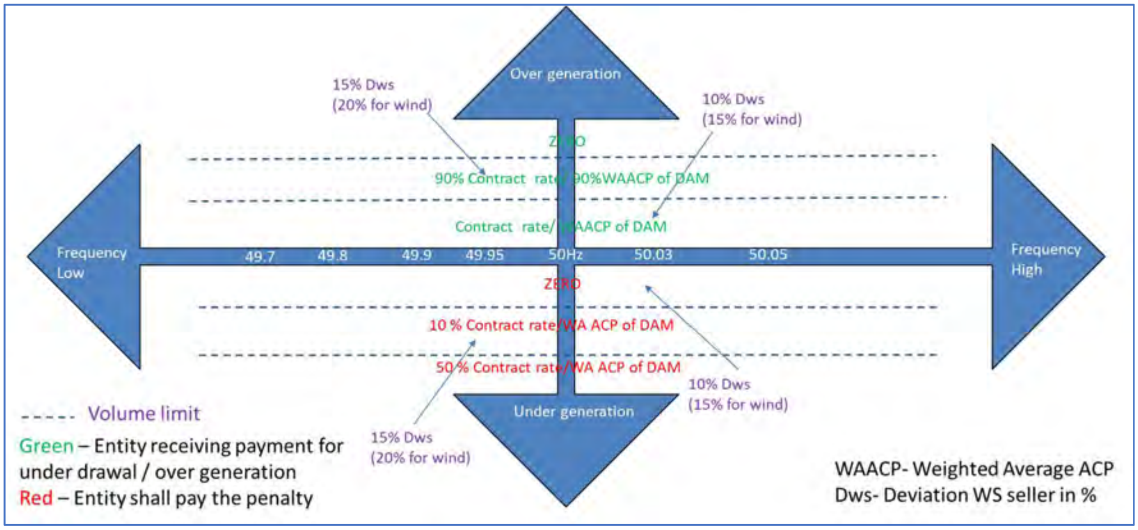


Figure 3: 06 February 2023 Framework - Solar, Wind, Hybrid Sellers

For the Wind and Solar projects, volume limit is applicable across the entire frequency range. There is a volume limit of 10% D_{ws} for solar, going up to 15% D_{ws}, while for wind it is from 15% to 20% D_{ws}. The DSM rate is linked to the contract rate of weighted average day-ahead market price.

The following schematic (Figure 4) depicts the framework for buyers:

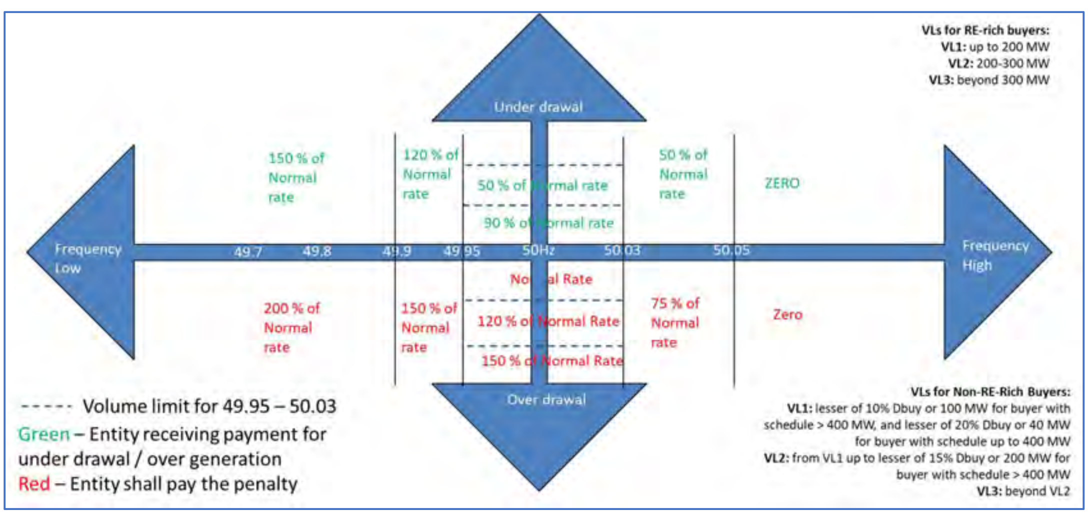


Figure 4: 06 February 2023 Framework - Buyers

For non-RE-rich buyers, there are different volume limits for buyers with schedules greater than 400 MWs, and for buyers with schedules up to 400 MWs. For RE-rich buyers, the first volume is up to 200 MW, the second volume limit is 200-300 MW, and the third volume limit is beyond 300 MW. For all volume limits and frequency bands, ratios of normal rates are applied as DSM charges.

4 Stakeholder Feedback

4.1 Operational Feedback on DSM Regulations 2022

The Commission recognized that wide frequency fluctuations had occurred post 05 December 2022. While some improvements were observed post 26 December 2022 and then post 06 February 2023, the performance was still short of expectations. Many states were not responding to bring frequency back into operating band but rather continuing under-drawal in high frequency periods and over-drawal in low-frequency periods.

The following Figure 5 shows changes in frequency excursions pre- and post- DSM Regulations 2022 including post 06 February 2023:

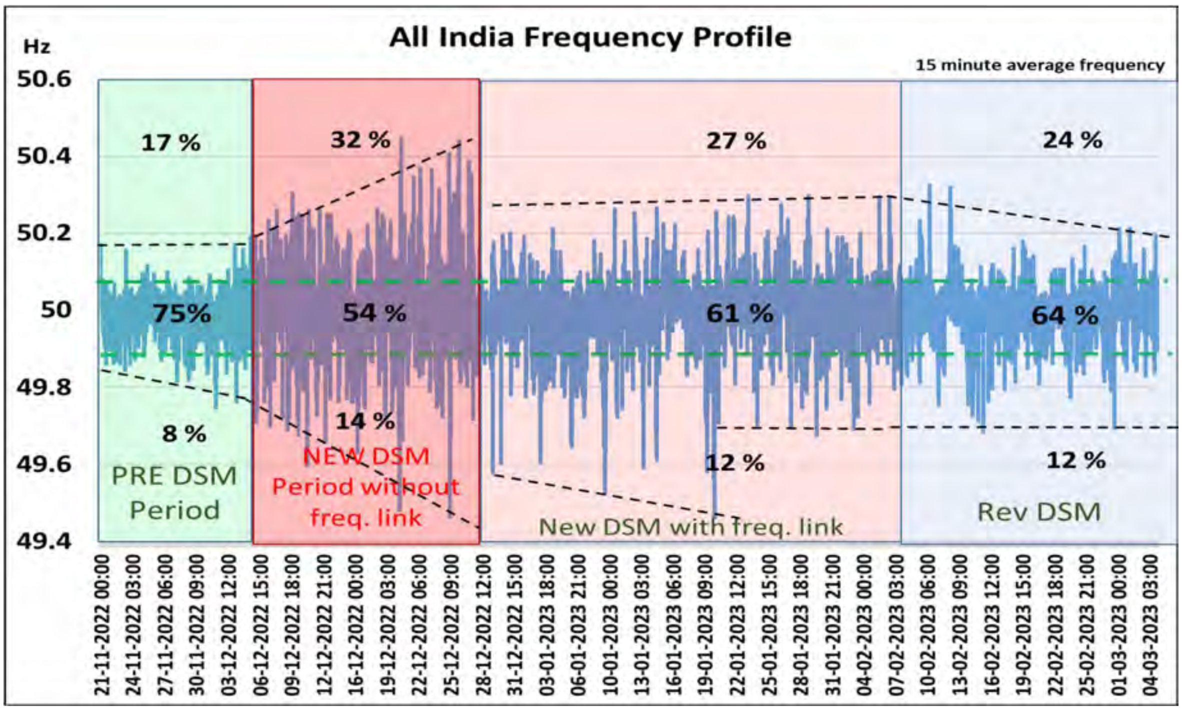
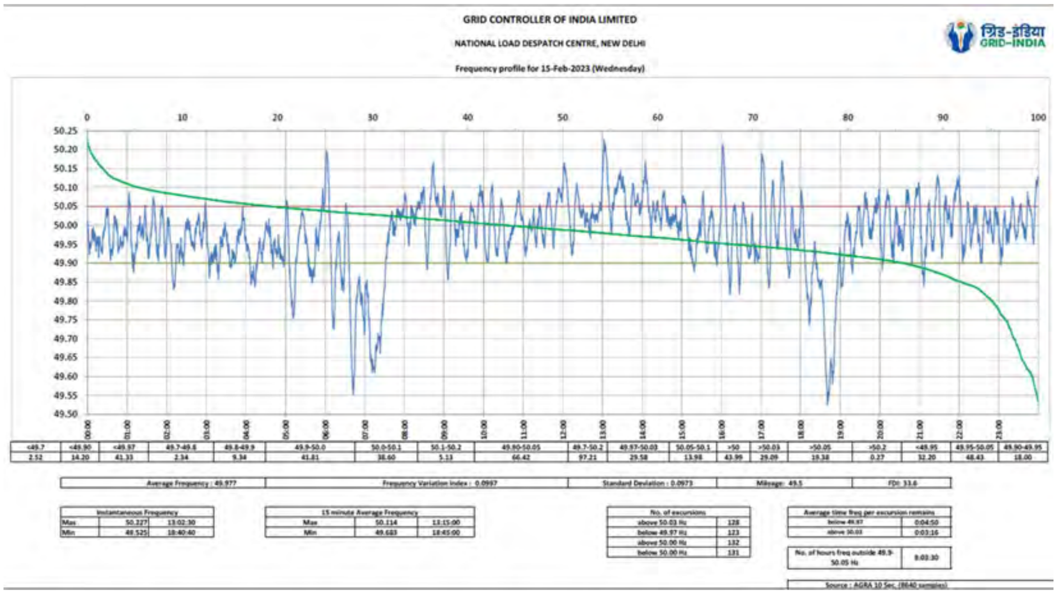


Figure 5: All-India Frequency Profile

The Committee deliberated on frequency excursions in detail and decided to undertake a 15-minute frequency and behavioural analysis over the course of subsequent meetings, which is covered in Section 5.

4.2 Feedback on Scheduling

Shri. Bhanu Bhushan (Ex-Member, CERC) highlighted that for 15 February 2023 and 24 March 2023, four distinct frequency peaks were observed in one hour, as depicted below:



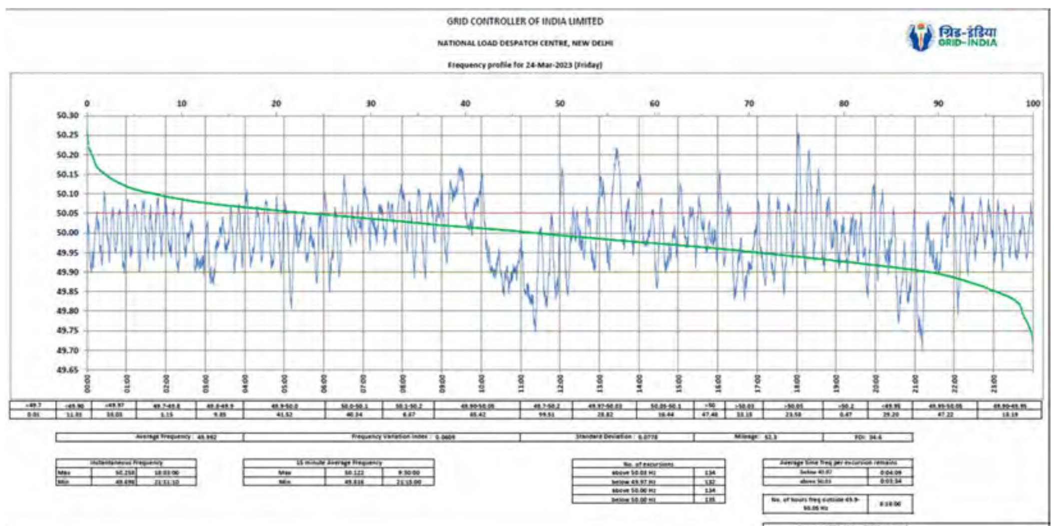


Figure 6: Frequency Peaks per Hour

He remarked that the potential reasons behind these fluctuations could be:

1. Absence of free governor operation or primary response, without which SRAS or TRAS may not be effective.
2. Scheduling in steps of 15-minutes.

He explained that while demand & generation ramp is a gradual curve / straight line, the schedule is in steps which leads to fluctuations. He opined that by making the schedule to "float" or be "step-less" into a gradual curve / straight line may reduce fluctuations. A recommended way of implementing "step-less" scheduling would be to allow entities to declare schedule by factoring for ramp rate instead of a sudden step change. Further, once governors are put into action, reserves (primary, secondary, tertiary) may be considered.

It was noted that while schedule is in steps, actual is similar to demand in the sense that it is a gradual curve / straight line. Participants discussed whether and to what extent, the change in methodology of declaring schedules would help in controlling frequency fluctuations. It was also noted that scientifically driven demand forecasting is critical to control deviation and frequency fluctuations. Additionally, it was noted that states would need support to implement free governor mode of operation of intra-state generators.

Shri. Satyanarayan remarked that SLDCs can correct schedules only within internal resources, while the central sector cannot change schedules for 7-8 blocks (~2 hours). This leads to under-utilization of unused schedules/reserves from the central sector. Additionally, he remarked that correction by gas is a costlier alternative. He further added that runway frequency was a time-block problem, and that avg. 2-hr delay and resource-wise under-utilization of central schedules/reserves should be corrected. For the same, he proposed introducing SLDC and RLDC corrections in schedules without disturbing the overall structure, by allowing SLDC to use all resources (including central) for their corrections.

It was discussed that Grid-India should explore the feasibility of 5-min scheduling and stepless scheduling and develop a roadmap for the same.

4.3 Feedback on Response of Reserves

It was noted that generators' response through primary and secondary reserve participation was not adequate. Availability of secondary reserves was not adequate due to limited availability of down/up margins, communication issues at regional level, stability issues by some generator in particular lignite-based plants, and non-participation of UMPPs. It was also observed that many states were not responding to bring frequency back into the operating band but rather continuing Under Drawal (UD) in high-frequency periods and Over Drawal (OD) in low-frequency periods.

Grid-India conducted detailed analyses of performance of PRAS and SRAS, and highlighted the following observations:

1. Generating units have implemented droop settings in four different ways:
    a. Droop at MCR with 5% limitation of MCR
    b. Droop at current generation (CG) with 5% limitation of CG
    c. Droop at MCR with 5% limitation of CG

    d. Droop at MCR, with 5% limitation of CG for below 50 Hz & 5% limitation of MCR for above 50 Hz.

   This difference in understanding of droop logics is restricting the primary response from generating units.

2. Generating plants have implemented the Ripple filter in three different ways:
    a. Implementation on running/current tracking frequency
    b. Implemented w.r.t fixed 50 Hz
    c. current tracking frequency for f<50 Hz and at fixed 50 Hz for f>50 Hz and vice-versa.

   This logic, tied to the current tracking frequency, may be constraining the governor's response by limiting it within the ripple filter band range calculated based on the current frequency and slower tracking rate.

3. Some units exhibited restrictions in their response capabilities (e.g., fixed MW change for any change in frequency, no response for consecutive change in frequency, restricted response for frequency changes above 50 Hz, fixed response hold time irrespective of the duration of frequency event etc.) which compromise their contribution to grids stability during contingency.
4.
5. There was a restricted response holding time for F > 50 Hz.

The following potential reasons behind inadequate frequency response were stated:

1. The difference in understanding of droop logics is restricting the primary response from generating units.
2. The logic, tied to the current tracking frequency, may be constraining the governor's response by limiting it within the ripple filter band range calculated based on the current frequency and slower tracking rate.
3. Time lag of 15-20 seconds in generation output change after receiving signal was observed due to high scan rate and other technical reasons related to boilers. Delayed response initiation can potentially defeat the purpose of PFR because of higher overall response initiation time.
4. Manual interventions were noted in certain instances to achieve an ideal response - Higher Pressure setpoint maintained for steps below 50Hz & Lower Pressure setpoints. These interventions could introduce delays and uncertainty in restoring grid frequency.
5. Mechanical backlash in hydro units, pressure correction compensation in thermal units and response stability issues in super critical units etc. were identified as system bottlenecks affecting the efficient delivery of frequency response.
6. Some of the generating units were incapable to provide PFR for subsequent fall in simulated frequency and also for large frequency steps. This may probably be

due to valve-wide operation which can be observed from the trends of valve positions.

7. Generators were behaving as per technical characteristics but there was a clear difference in controller logic between July 2022 and February 2023, likely due to DSM revisions.
8. Manual control/parameter settings on PRAS and SRAS at some generating stations.

The Committee held detailed discussions on performance of reserves and corrective measures taken by the Grid-India.

4.4 Feedback on AGC and RGMO/FGMO Operations

Shri. Bhanu Bhushan (Ex-Member, CERC) explained about the change in frequency with change in load. He remarked that as load increases, more fuel input is required into the boiler which produces more steam which in turn gives more output and governors takes less than 30 seconds to restore balance. He explained that there are limits permitted by standards for the governor to sense considering the example of standard governor droop of 4-5% wherein generation goes from full load to zero when the frequency increases by 4-5% (~2 cycles) subject to limitation of generator loading limits. He explained that the key functions of the governor are reducing the frequency change, load sharing, and safe operation of the machines. It was discussed that if frequency changes by 0.001 cycles, the governor may not act so there are some limits set for governor to sense change.

NTPC expressed that the operating band for Restricted Governor Mode of Operation (RGMO) is from 49.5 – 50.0 Hz. If frequency increases within that band, RGMO doesn't operate and lets the frequency reach 50 Hz. If frequency reduces in that band, RGMO kicks in for steps of 0.03 Hz. Free Governor Mode of Operation (FGMO) comes into picture beyond the operating band of RGMO and kicks in to reduce drop in frequency below 49.5 Hz. or increase in frequency above 50 Hz. However, within a 15-minute time block, if frequency drops, the generators are supposed to give more output to support the grid as per the DSM framework as well as if the generator is part of ancillary services. This can create a conflict between the DSM and ancillary schemes.

NHPC presented about primary and secondary response of their generators, and particularly expressed challenges in RGMO and AGC operations, as described below:

1. Challenges in RGMO operations:

   a. Ageing of generating units and increase in winding temperature during overloading of units for longer time.
   b. Higher response time of governor during governor action.
   c. Manual switching ON the RGMO operation, especially in case of frequent start/stop
2. Challenges in AGC operations:
   a. Reduced AGC performance due to RGMO effect.
   b. Communication Link Failure.
   c. AGC metering Error.
   d. Out of dual controller, single controller is being used.
   e. Hanging of AGC set points due to communication failure.
   f. Getting lower command continuously even if frequency is low.

The Committee noted that NTPC had taken corrective actions to reduce conflict between DSM and AS regimes. NTPC had changed control logic to help resolve the conflict between DSM and Ancillary Services regime, and that it was proving effective to a certain extent. They explained that as per the new logic, when AGC set-point and unit load set-point are in different directions, ramp rate of correction has been reduced to 0.5% which has reduced fatigue in boiler parameters. Further, Grid-India noted that NTPC has increased ramp rate of various units (1.5-2%) for AGC while schedule will still be at 1%. The Committee Members discussed that Grid-India will share a summary of discussions and measures taken with NTPC along with impacts.

4.5 Feedback on DSM for RE-Rich States

KERC noted that 51% of Karnataka’s installed capacity is RE, with more additions expected in the following years. ISTS schedules during high RE generation and low state demand vary significantly. The schedule goes below the normal Inter-State schedule due to surplus trading of power outside the State through exchange.

Given the above challenges and deviations, KERC recommended the following solutions till the emergence of techno-commercial viable options:

1. Replacing volume limits based on solar + wind installed capacity for RE-rich and Super RE-rich states.
2. Replacing available capacity (AvC) with scheduled generation for calculating deviation.
3. Excluding STOA transactions while calculating deviations.

KERC recommended the following volume limits shown in Table 1 below:

Sr. No.	Combined Solar + Wind IC (MWs)	Volume Limit (MWs)
1	Up to 5,000	200

Sr. No.	Combined Solar + Wind IC (MWs)	Volume Limit (MWs)
2	> 5,000 up to 10,000	300
3	> 10,000	500

Table 1: KERC's Suggestion for Volume Limits of RE-Rich States

The Committee noted KERC's feedback and felt that replacement of AvC by scheduled generation might yield unrealistic deviation errors ranging from zero to infinity even with a small difference between schedule and actual generation. Given the uncertainty of solar and wind resources this might cause undue hardship and commercial impact for such generators. However, endeavor should be made to improve forecasting and make wind and solar dispatchable in future, especially by using energy storage systems. CERC should draw a road map for this and gradually move towards error definition for wind and solar to be at par with other generators.

4.6 Feedback on DSM Accounting

SRPC sought clarifications on the following:

1. DSM calculation for hybrid WS seller with energy storage.
2. DSM calculation for BESS/PSH as standalone project/ integrated with RE projects and their status as buyer or seller.
3. Contract rate to be considered for integrated RE with storage plant when such plant has multiple contracts for various capacities.
4. Scheduling of non-co-located hybrid project with multi-point injection and drawal.
5. Scheduling of co-located WS and storage hybrid project with different peak and off-peak tariff.

4.7 Feedback on DSM Design Issues

Mr. Nicholas Ryan, Associate Professor of Economics at Yale University had undertaken an analysis of the DSM design issues in India and made a presentation before the Expert Committee. He highlighted that the idea of DSM is to strictly be an imbalance pricing mechanism by putting penalty on deviations. He explained that this was attempted with the notification of DSM Regulations, 2022 but frequency fluctuations were found to increase, and ancillary services were not mature enough to pick up the slack.

He explained that data analysis of historical performance (29 August 2022 to 16 April 2023) was carried out to observe performance of various sellers and buyers under the revised Regulations. He remarked that revisions had lessened accuracy of RE forecasts, thereby increasing the need for balancing. He further added that there was still incentive for some generators to deviate from schedules. Additionally, he highlighted that balancing provided by DSM was not very high, ~194 MWs per 0.1 Hz change in frequency. Frequency fluctuations can be seen in the Figure 7 below:

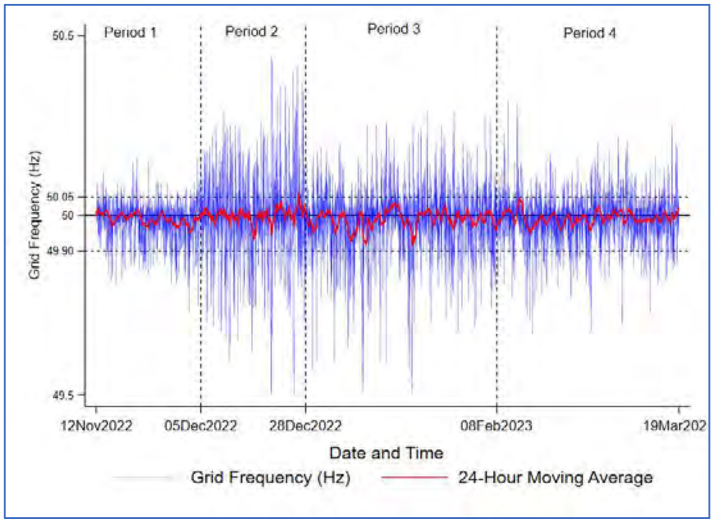


Figure 7: Frequency Fluctuations

He remarked that solar and wind sellers were observed to over-schedule and under-inject, with magnitude of this behaviour higher for wind than for solar. He remarked that tightening the tolerance band down to +/- 5% would avoid this behaviour and encourage accurate forecasting. He further recommended a much lesser per unit charge for deviations from solar and wind sellers. The members deliberated on whether reducing the price so much would incentivize deviations since the penalty would be very less. Mr. Ryan recommended an additional voluntary feature of opting for public forecasts by REMC, in which case sellers would be exempt from deviation charges. The members deliberated that solar and wind sellers currently have the option to opt for public forecasts but presently most of them don't, and that forecasts from developers are found to be much more accurate.

He highlighted that thermal sellers in some parts were seen to under-schedule and over-inject, likely due to asymmetry in structure and switching between normal and reference rates. Applying a tighter tolerance band and symmetrical and linear charges would avoid such behaviour.

Mr. Ryan highlighted that buyers also showed similar behaviour due to asymmetry in charges. This in turn had potential to cannibalize the ancillary services.

Impact of this asymmetry in pricing structure is depicted in the Figure 8 below:

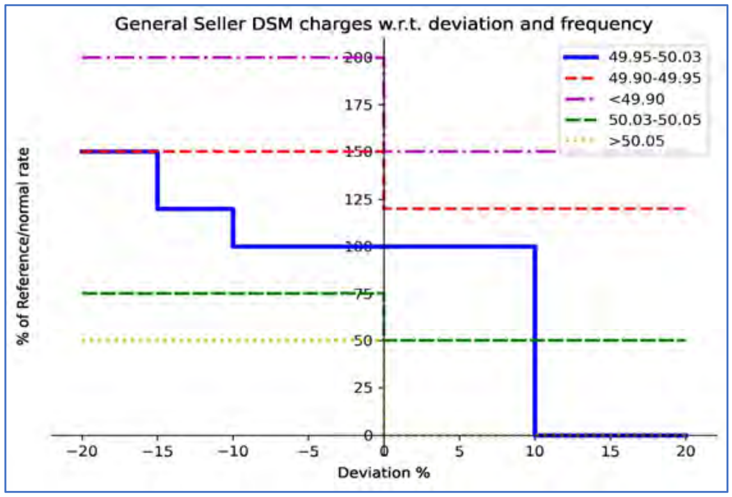


Figure 8: Asymmetry in Pricing Structure for General Seller

Figure 9 below shows asymmetry in pricing structure for Solar/Hybrid Sellers:

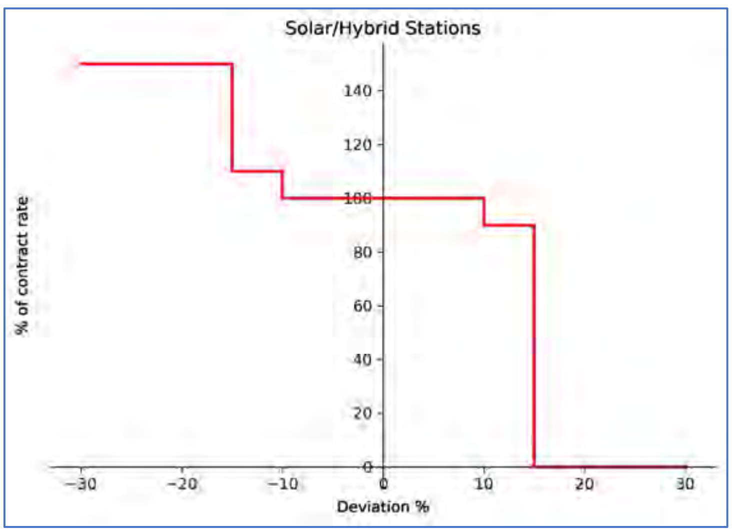


Figure 9: Asymmetry in Pricing Structure for Solar/Hybrid Sellers

Figure 10 below shows asymmetry in pricing structure for Solar/Hybrid Sellers:

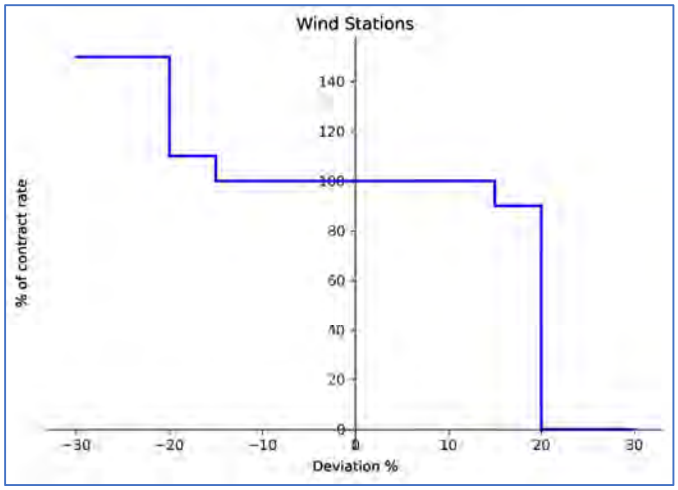


Figure 10: Asymmetry in Pricing Structure for Solar/Hybrid Sellers

Given the above observations, Mr. Ryan presented the following proposed changes to DSM Regulations, 2022:

1. Tighter tolerance band of +/- 5% for sellers to encourage accuracy of forecasts.
2. Symmetric and linear charges for general sellers and buyers within tolerance band and for under-injection/drawal and over-injection/drawal to avoid any perverse incentive.
3. Removal of incentive/penalty parameters for over-injection/under-drawal during low frequency and under-injection/over-drawal during high frequency to encourage reliance on ancillary services.

The Committee discussed the all the issues in great detail and the recommendation are detailed in Section 6.

5 Behavioural Analysis and Outcomes

In the wake of wide frequency fluctuations post 05 December 2022, the Expert Committee felt it important to look at behaviour of the buyers and the sellers pre and post 05 December 2022, in terms of deviations with respect to grid frequency. This was conducted by means of frequency and four-quadrant analysis. For frequency analysis, the spread of 15-minute frequency data was observed for the past year. To analyze the performance of buyers and sellers, 15-minute data on frequency, actual, and schedule was collected for sample weeks from the respective RPC websites, and behaviour (UD/OD and UI/OI) in times of low/high frequency was observed.

5.1 Frequency Analysis

To perform frequency analysis, 15-minute data for approximately one year from 11 April 2022 to 01 January 2023 was collected. A scatter plot was created to see variation in frequency over time. Additionally, a funnel graph was created to observe the spread in frequency.

The following Figure 11 depicts the frequency analysis for 17 January 2022 – 01 May 2022:

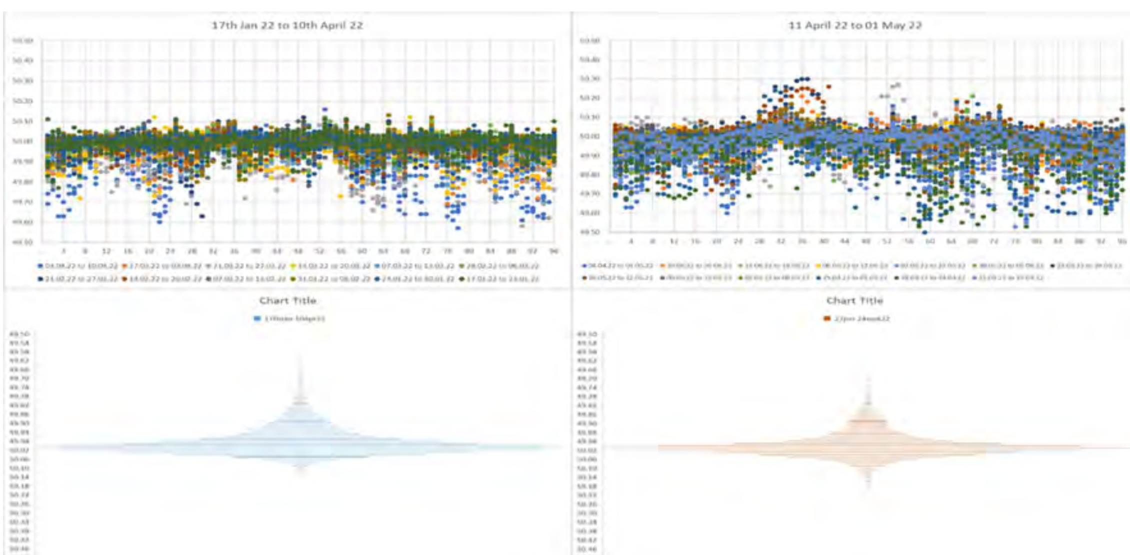


Figure 11: Frequency Profile from 17 Jan to 10 Apr '22

For the scatter plots, frequency is on the y-axis from lower to higher magnitude, while for the funnel plots, frequency is on the y-axis from higher to lower magnitude. The graphs on the left are from 17 January to 10 April 2022, while the ones on the right are from 11 April to 01 May 2022. It can be seen that there were more instances of low frequency than of high frequency for approx. the first four months of 2022.

The following Figure 12 depicts the frequency analysis for 27 June to 04 December 2022:

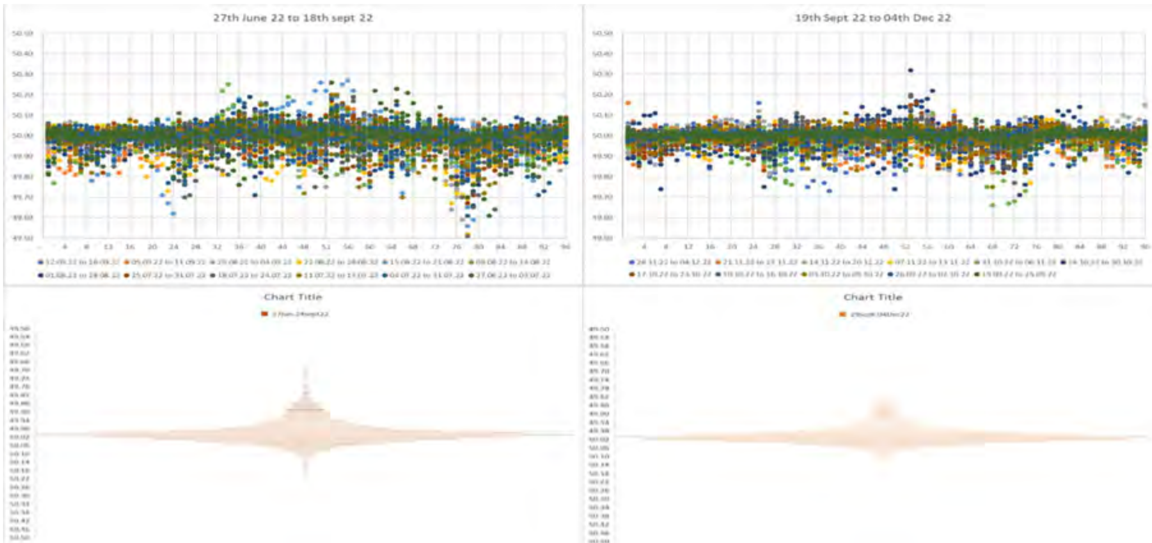


Figure 12: Frequency Profile from 27 Jun to 04 Dec '22

For the remainder of 2022 as well, there continued to be more instances of lower frequency than that of higher frequency. The same plots were created for the period post 05 December 2022 as well as post 06 February 2023, as depicted in Figure 13:

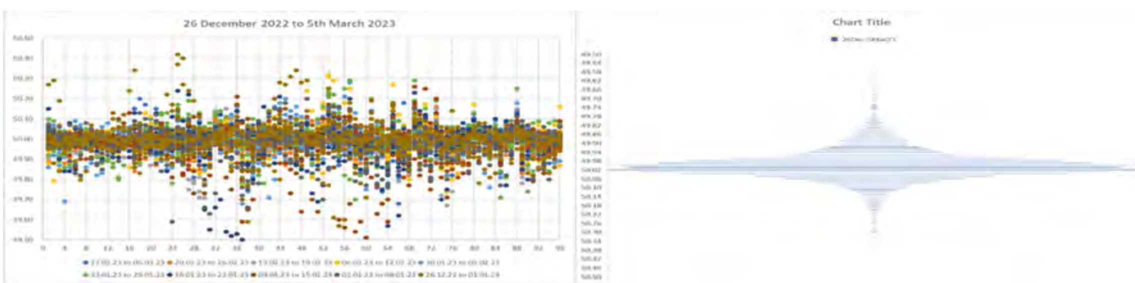


Figure 13: Frequency Profile from 26 Dec to 05 Mar '23

5.1.1 Key Takeaways of Frequency Analysis

Frequency analysis of the past one year showed that the system generally depicted low frequency (< 50 Hz) prior to notification of DSM Regulations 2022 on 05 December 2022. This trend seemed to have shifted post 05 December 2022 since frequency excursions in both directions significantly increased.

5.2 Four-Quadrant Analysis

The main objective of four-quadrant analysis was to observe tendency of buyers and sellers across different regions to UD/OD or UI/OI with respect to prevalent frequency situation in the grid, and to check whether the behaviour was directionally aligned towards bringing/keeping the frequency at 50 Hz. For this, representative states and generators from five regions (WRPC, SRPC, NRPC, ERPC, and NERPC) were selected and relevant 15-min data on frequency, schedule, actual, charges etc. was collected and compiled for one sample week per month for the past 19 months. In particular, the following computations were carried out:

1. Minimum and maximum deviation
2. Range/ Spread of Deviation
3. Correlation of Freq < 50 with Deviation
4. Correlation of Freq >= 50 with Deviation
5. Count of TBs in 49.90 <= F <= 50.05 Case
6. Count of TBs in 49.90 <= F <= 50.05 and -250/-150<= Dev <= 250/150 Case
7. % of TBs in 49.90 <= F <= 50.05 Case
8. % of TBs in 49.90 <= F <= 50.05 and -250/-150 <= Dev <= 250/150 Case
9. Sum of Deviation by Quadrant Count of Time blocks by Quadrant

Following Table 2 shows the selected buyers and sellers for each region:

Regions	Selected Buyers	Selected Sellers	Data Period
WRPC	• Maharashtra • Gujarat • Madhya Pradesh	• VSTPS • BALCO • SASAN • SIPAT	January 2022 to March 2023
SRPC	• Tamil Nadu • Karnataka • Andhra Pradesh	• SIMHADRI • RSTPS • KUDGI • NLC	January 2022 to March 2023
NRPC	• Rajasthan • Punjab • Uttar Pradesh	• NJHEP • RIHAND • TEHRI • SINGRAULI	January 2022 to March 2023
ERPC	• Bihar • Orissa • West Bengal	• BARH-I • FSTPP- I&II • KHSTPP-II	December 2022 to March 2023
NERPC	• Assam • Meghalaya • Tripura	• AGBPP • BGTPP • KAMENG	April 2022 to March 2023

Table 2: Selected sellers and Buyers for Four Quadrant Analysis

Solar and wind sellers in WRPC and SRPC, namely AlfanarWind_SECI-III, ArinSun_RUMS, GIWEL_SECI-III_RE, ESPL, NTPC_NPKUNTA, Tata_Pavagada, Orange_Tuticorin, and Ostro were also analyzed.

For each buyer and seller and each sample week, each time block was categorized into one of the four quadrants as defined below:

1. Quadrant I (Q1): frequency above 50 Hz and deviation +ve.
2. Quadrant II (Q2): frequency below 50 Hz and deviation +ve.
3. Quadrant III (Q3): frequency below 50 Hz and deviation -ve.
4. Quadrant IV (Q4): frequency above 50 Hz and deviation -ve.

The behaviour of the sellers and the buyers are analyzed and presented in the following sub-sections.

5.2.1 Interpretation of Quadrants for Sellers

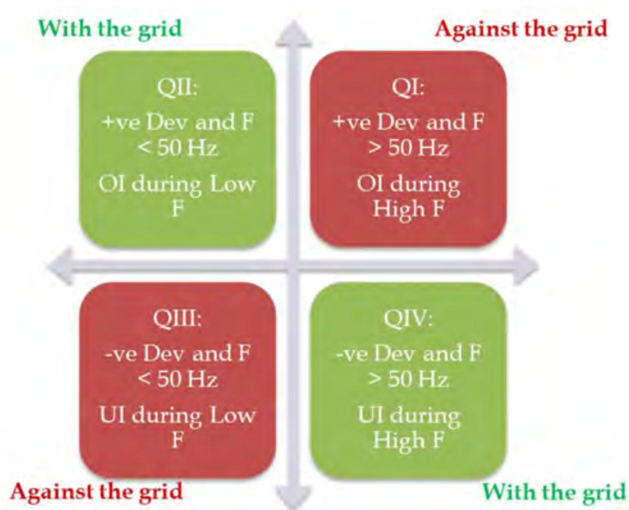


Figure 14: Four Quadrant Analysis Matrix for Sellers

For sellers, the operation in the 2nd and the 4th quadrant would benefit the grid which is shown in green color in Figure 14. In the 2nd quadrant, when the frequency is less than 50 Hz, the generator over-injecting will limit the frequency fall as generation increases to meet the required load. In the 4th quadrant, when the frequency is greater than 50 Hz, the generator under-injecting will reduce the frequency so as to maintain load generation balance and these operations help stabilize the grid.

When data points are in the 1st and 3rd quadrants, the operation is not in the interest of the grid as deviation and frequency correlation is not supporting the grid. In the 1st quadrant, when the frequency is greater than 50 Hz the generator over-injecting in the grid will further increase the frequency, and similarly in the 3rd quadrant, when the frequency is less than 50 Hz the generator under-injecting in the grid will further decrease the frequency.

5.2.2 Interpretation of Quadrants for Buyers

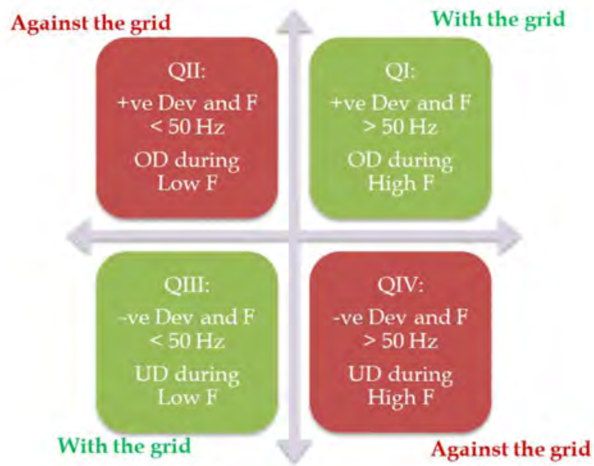


Figure 15: Four Quadrant Analysis Matrix for Buyers

The data points for buyers are divided into four quadrants as shown in Figure 15. The data points support the grid when they are in the 1st and 3rd quadrants.

In the 1st quadrant, when the frequency is greater than 50 Hz, the buyer over-drawing increases the demand to attain load-generation balance. This will help to reduce frequency deviation and to maintain frequency at 50 Hz. Similarly, for the 3rd quadrant when the frequency is less than 50 Hz, the buyer under-drawing reduces the demand to create favorable load-generation balance. So, in both quadrants, the buyer is helping the grid to reduce the frequency in the 1st quadrant and increase the same in the 3rd quadrant to stabilize the grid. For this reason, the buyer is supporting the grid which is shown in green in Figure 15.

The operation of data points against the grid for buyer when its data points are in the 2nd and the 4th quadrants. In the 2nd quadrant, when the frequency is less than 50 Hz, the buyer over-drawing increases the demand and hence further reduces the frequency. In the 4th quadrant, when the frequency is greater than 50 Hz, the buyer under-drawing further reduces the demand and hence further increases the frequency.

5.2.3 Outcomes of Four Quadrant Analysis

The above-mentioned analysis was carried out for each of the buyers and sellers identified in Table 2. The sample results below are shown for Maharashtra and Sasan, while the rest of the results can be found in **Appendix-1**.

5.2.3.1 Four Quadrant Analysis of Maharashtra

Relevant deviation data for 15 weeks from 31 January 2022 to 27 February 2023 was collected. Each time block was segregated into four quadrants as defined above, and quantum of deviation as well as count of instances of deviation in each time block were studied. Instances in support of and against the grid frequency were quantified and correlation between deviation and frequency was checked. Supportive operation in Q1 and Q3 was depicted in light green, while counteractive action in Q2 and Q4 was depicted in light red.

The following Figure 16 shows the analysis from 31 Jan 22 – 11 Apr 22 for the State of Maharashtra:

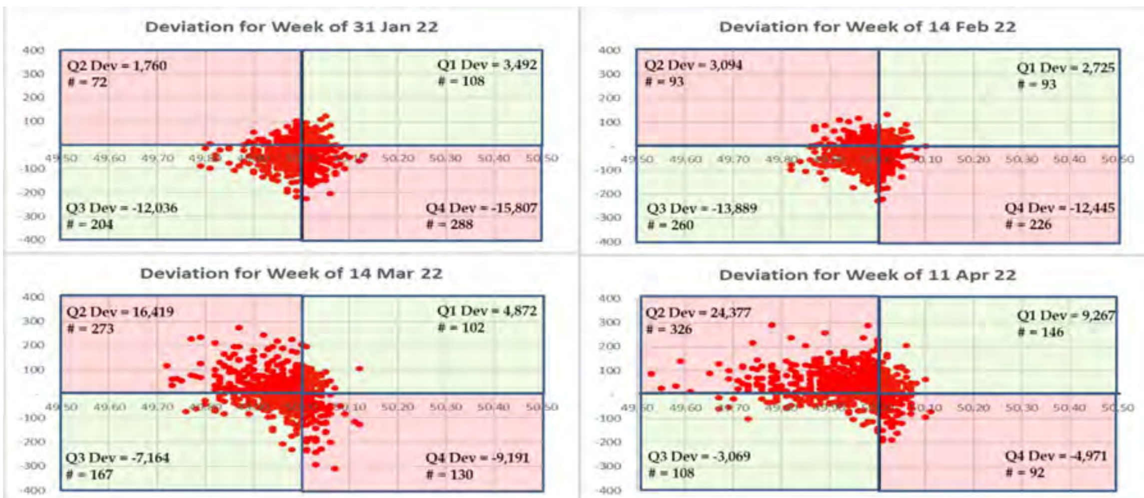


Figure 16: Maharashtra Four Quadrant Analysis: 27 Jan 22 - 11 Apr 22

It can be seen from the graph that the number of instances of deviation are generally higher in Q2 and Q4, indicating that there is over-drawal in times of low frequency or under-drawal in times of high frequency, thereby going against the grid frequency.

The following Figure 17 shows the analysis from 16 May 22 – 15 Aug 22:

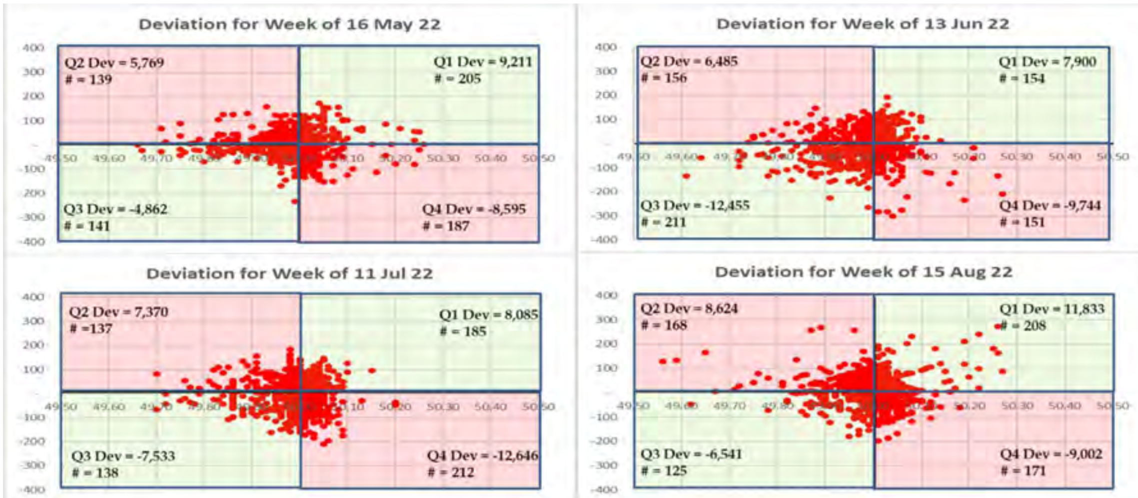


Figure 17: Maharashtra Four Quadrant Analysis: 16 May 22 - 15 Aug 22

The following Figure 18 shows the analysis from 12 Sep 22 – 26 Dec 22:

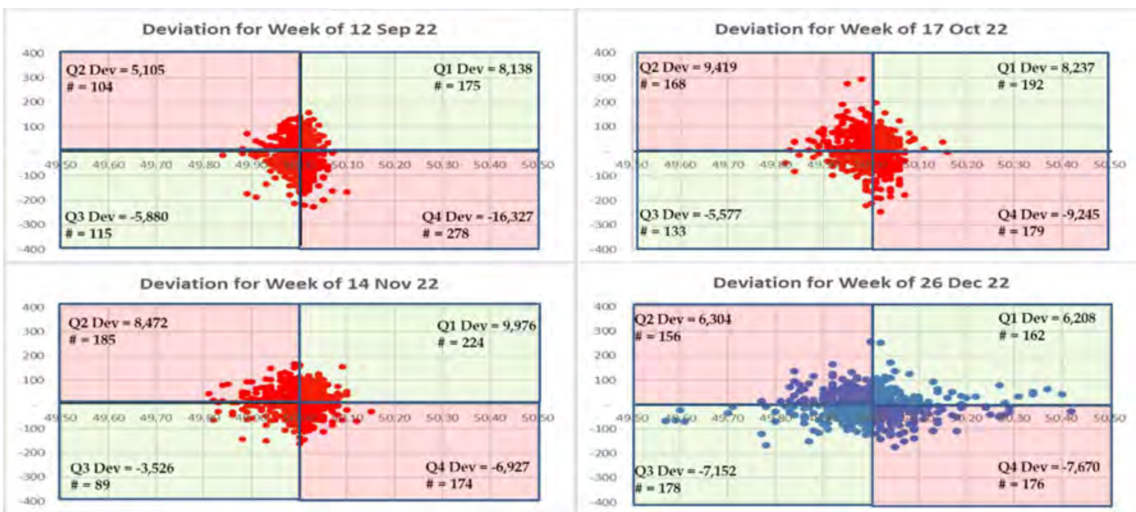


Figure 18: Maharashtra Four Quadrant Analysis: 12 Sep 22 - 26 Dec 22

The following Figure 19 shows the analysis from 26 Dec 22 – 27 Feb 23:

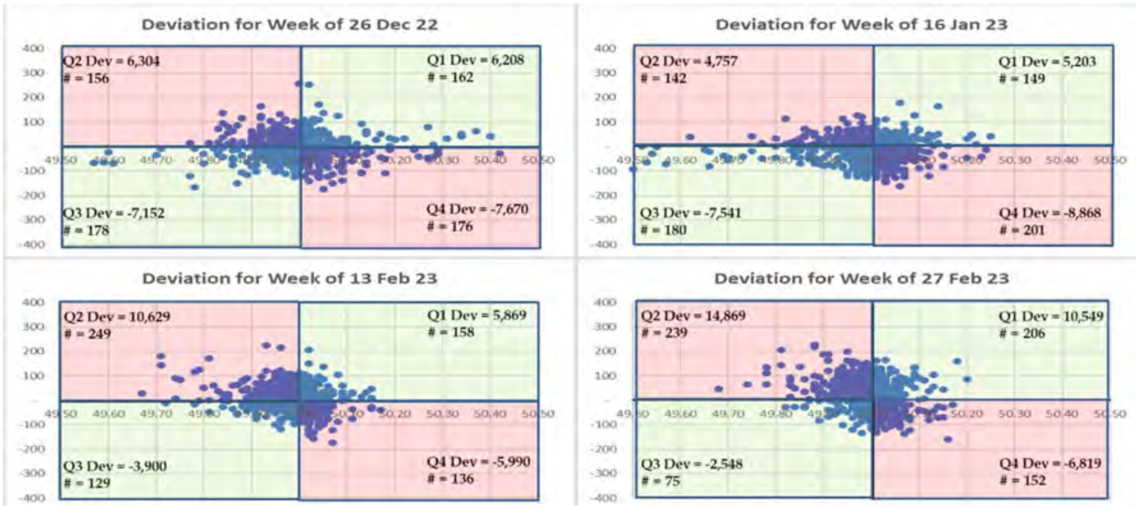


Figure 19: Maharashtra Four Quadrant Analysis: 26 Dec 22 - 27 Feb 23

Table 3 below gives the summary of the four-quadrant analysis for all the sample weeks from 31 January 2022 to 27 February 2023. Computations for maximum UD/OD, deviation spread, correlation of frequency less/greater than 50 Hz with deviation, and percent of time blocks in between 49.9 and 50.05 Hz with deviation +/- 250 was evaluated for each sample week and summarized. Very little correlation was observed between frequency and deviation.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-225	-228	-310	-191	-233	-302	-209	-198	-227	-246	-162	-173	-162	-173	-159
Max. OD	123	133	274	290	172	192	183	273	158	293	166	257	179	224	226
Deviation Spread (Max-Min)	348	361	584	481	405	494	392	471	385	539	328	431	341	397	385
Correlation of Freq < 50 Hz with Deviation	0.08	-0.02	-0.24	-0.01	-0.01	0.15	-0.01	-0.14	0.12	-0.07	0.04	0.10	0.05	-0.15	-0.15
Correlation of Freq >= 50 Hz with Deviation	-0.06	0.16	-0.22	-0.16	0.05	-0.22	-0.02	0.22	-0.12	-0.03	0.02	-0.03	0.04	-0.09	-0.05

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	93%	94%	84%	73%	83%	80%	85%	81%	98%	93%	92%	77%	78%	88%	86%

Table 3: Summary of Four Quadrant Analysis for Maharashtra Buyer

5.2.3.1.1 Four Quadrant Analysis of Sasan

Relevant deviation data for 15 weeks from 31 January 2022 to 27 February 2023 was collected. Each time block was segregated into four quadrants as defined above, and the quantum of deviation as well as count of instances of deviation in each time block were studied. Instances in support of and against the grid frequency were quantified and correlation between deviation and frequency was checked. Supportive operation in Q2 and Q4 was depicted in light green, while counteractive action in Q1 and Q3 was depicted in light red.

The following Figure 20 shows the analysis from 31 Jan 22 – 11 Apr 22:

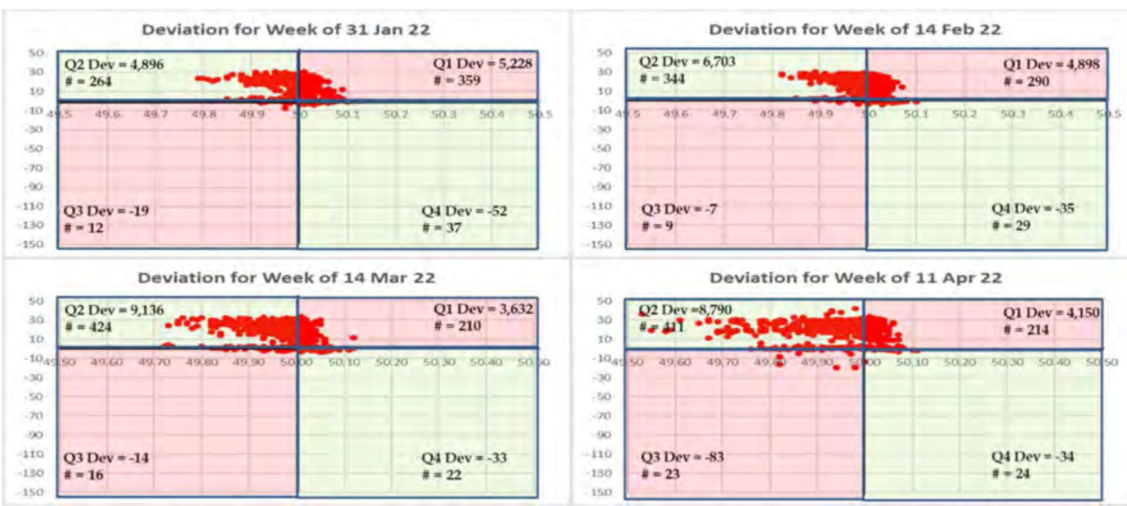


Figure 20: Sasan Four Quadrant Analysis: 31 Jan 22 - 11 Apr 22

It can be seen from the graph that the number of instances of deviation are generally higher in Q2 and Q4, indicating that there is OI in times of low frequency, thereby supporting the grid frequency. Overall, there was persistent OI as against UI.

The following Figure 21 shows the analysis from 16 May 22 – 15 Aug 22:

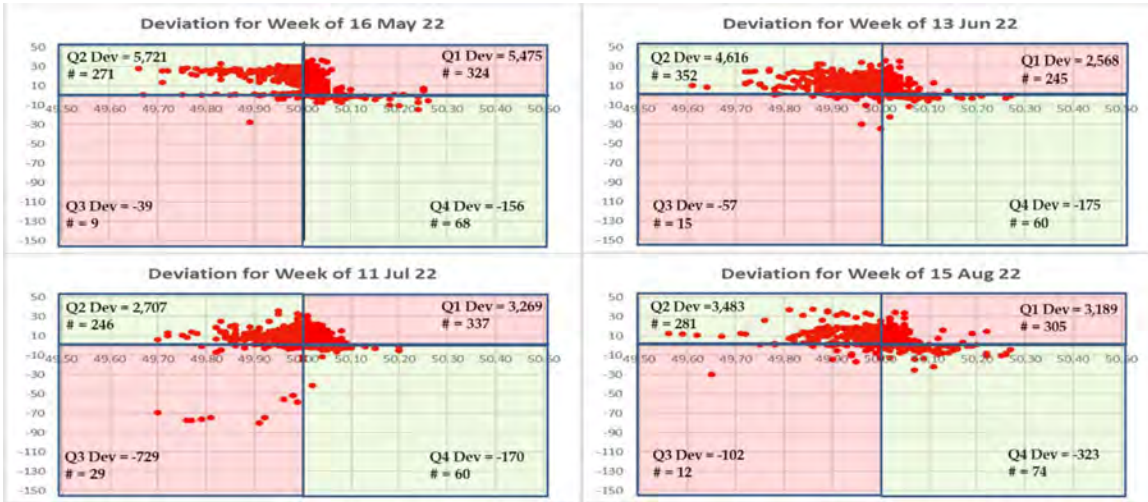


Figure 21: Sasan Four Quadrant Analysis: 16 May 22 - 15 Aug 22

It can be seen that Sasan continues to behave in a direction that supports grid frequency towards 50 Hz. However, instances of deviation in extreme low/high frequency increased. Overall, there was persistent OI as against UI.

The following Figure 22 shows the analysis from 12 Sep 22 – 26 Dec 22:

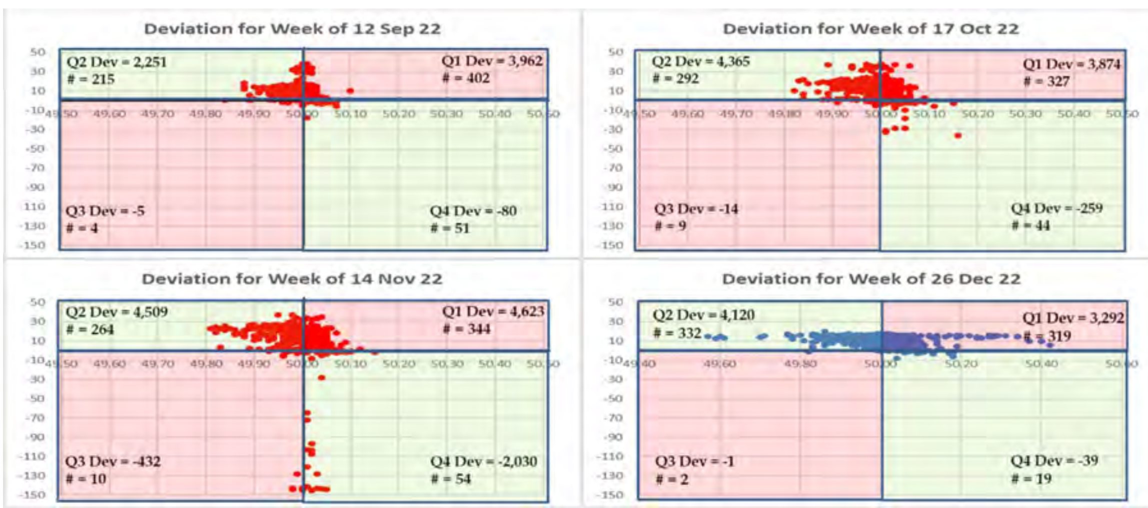


Figure 22: Sasan Four Quadrant Analysis: 12 Sep 22 - 26 Dec 22

It can be seen that instances against the grid slightly increased, and instances of extreme low/high frequency increased post notification of DSM Regulations 2022 on 05 December 2022. Overall, there was persistent OI as against UI.

The following Figure 23 shows the analysis from 26 Dec 22 – 27 Feb 23:

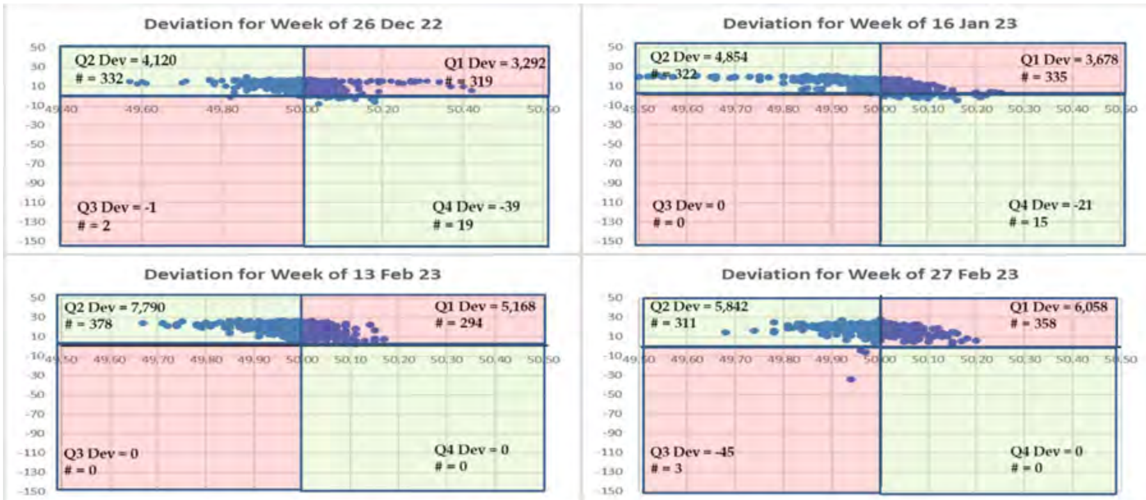


Figure 23: Sasan Four Quadrant Analysis: 26 Dec 22 - 27 Feb 23

Table 4 below gives the summary of the four-quadrant analysis done for all the sample weeks from 31 January 2022 to 27 February 2023. Computations for maximum UI/OI, deviation spread, correlation of frequency less/greater than 50 HZ with deviation, and percent of time blocks in between 49.9 and 50.05 Hz with deviation +/- 250 was evaluated for each sample week and summarized. Very little correlation was observed between frequency and deviation.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-7	-4	-3	-20	-27	-34	-80	-30	-18	-36	-145	-8	-5	3	-34
Max OI	31	30	127	42	55	36	36	38	38	38	37	20	21	28	28
Deviation Spread (Max – Min)	38	34	130	62	82	70	116	67	56	74	183	28	26	25	63
Correlation of Freq < 50 Hz with Deviation	-0.06	-0.07	-0.06	0.05	-0.04	-0.07	0.27	0.08	0.08	0.05	-0.12	-0.12	-0.42	-0.20	-0.09
Correlation of Freq >= 50 Hz with Deviation	-0.42	-0.41	-0.41	-0.39	-0.53	-0.36	-0.40	-0.47	-0.41	-0.43	-0.10	-0.05	-0.61	-0.39	-0.46

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table 4: Summary of Four Quadrant Analysis for SASAN Seller

6 Analysis of Reserves & Recommended Remedial Measures

The Indian Electricity Grid Code, 2023 (IEGC 2023) defines ancillary services as "*in relation to power system operation, means the services necessary to support the grid operation in maintaining power quality, reliability and security of the grid and includes Primary Reserve Ancillary Service, Secondary Reserve Ancillary Service, Tertiary Reserve Ancillary Service, active power support for load following, reactive power support, black start and such other services as defined in these regulations*". Broadly, ancillary services refer to functions that address imbalances between supply and demand in real-time, maintain flow and direction, help the system recover after any event, and help grid operators maintain system reliability and stability. There are three main types of ancillary services:

1. Frequency control
2. Voltage control
3. Black start

Mismatch between supply and demand causes frequency fluctuations, for which ancillary support is necessary. This can be provided by three types of reserves:

1. Primary reserve
   IEGC 2023 defines it as, "*...the maximum quantum of power which will immediately come into service through governor action of the generator or frequency controller or through any other resource in the event of sudden change in frequency as specified in clause (10) of Regulation 30 of these regulations*".
2. Secondary reserves
   IEGC 2023 defines it as, "*...the maximum quantum of power which can be activated through secondary control signal by which injection or drawal or consumption of an SRAS provider is adjusted in accordance with Ancillary Service Regulations*".
3. Tertiary reserves
   IEGC 2023 defines it as, "*...the quantum of power which can be activated in order to take care of contingencies and to cater to the need for replacing secondary reserves*".

The following Figure 24 shows the purpose of each of the three reserves:

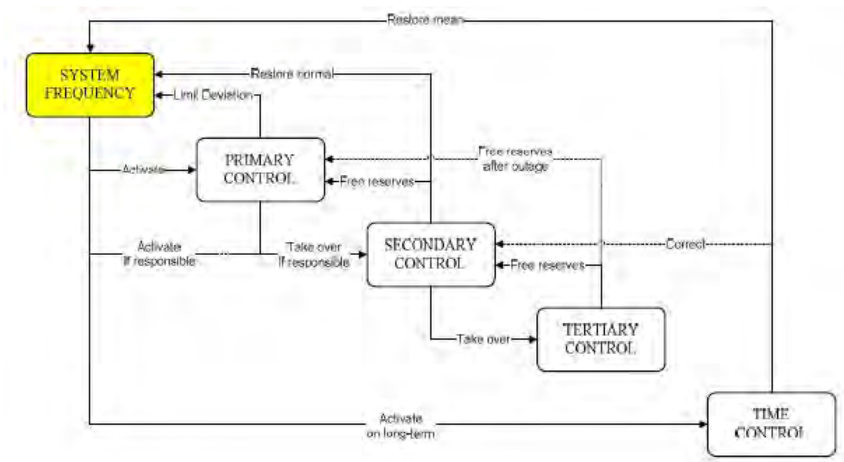


Figure 24: Purpose of Reserves

Primary reserves are mandated by IEGC 2023 for all the generators on bar except renewable and small generators, while secondary reserves are regulated through Secondary Reserve Ancillary Service Provider (SRAS Provider). Tertiary reserves are market-based through Tertiary Reserve Ancillary Service (TRAS).

The following Figure 25 shows the activation times and sustainability of the three types of reserves:

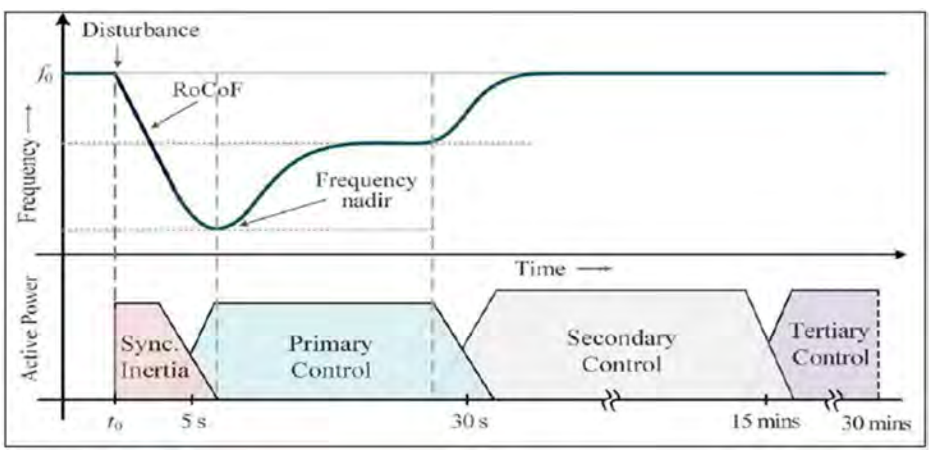


Figure 25: Activation Times and Sustainability of Reserves

Primary response kicks in instantaneously after frequency crosses dead-band and can reach full availability within 30 seconds. This can be sustained for up to 5 minutes and can be provided by all generators and energy storage.

Secondary response kicks in within 30 seconds and can reach full availability within 15 minutes. This can be sustained up to 30 minutes or till replaced by tertiary reserves, and can be provided by all generators, energy storage and also by demand response.

Tertiary response kicks in and can reach full availability within 15 minutes, can be sustained up to 60 minutes, and can be provided by all generators, energy storage, and also by demand response.

6.1 Primary Response

According to Ancillary Service Regulations 2022, primary reserve ancillary service (PRAS) comes into service through governor action of the generator or through any other resource in the event of sudden change in frequency.

The operating band for Restricted Governor Mode of Operation (RGMO) is from 49.5 – 50.0 Hz. If frequency increases within that band, RGMO doesn't operate and lets the frequency reach 50 Hz. If frequency reduces in that band, RGMO kicks in for steps of 0.03 Hz. Free Governor Mode of Operation (FGMO) comes into picture beyond the operating band of RGMO and kicks in to reduce drop in frequency below 49.5 or increase in frequency above 50 Hz. However, within a 15-minute time block, if frequency drops, generators are supposed to give more output to support the grid as per the DSM framework.

Analysis of primary frequency response of thermal and hydro units was conducted by Grid-India with the help of telemetered governor control signal being received in NLDC AGC system. It was noted that the frequency response of most of the thermal units was reasonably good for fast change in frequency and the frequency response was negligible/sluggish/delayed/inadequate for slow changes in frequency. The Figure 26 below shows typical governor control instructions in a thermal unit towards slow frequency changes:

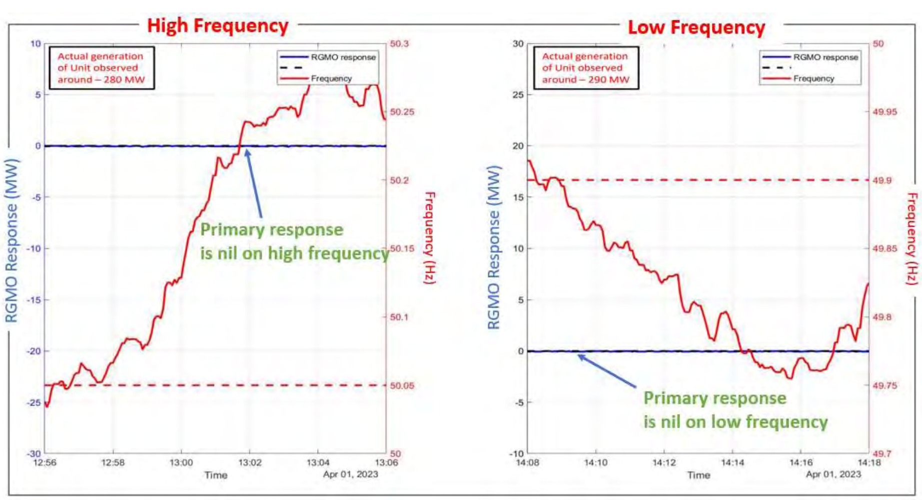


Figure 26: Typical Governor Control Instructions in a Thermal Unit towards Slow Frequency Changes

The Figure 27 below shows typical governor control instructions in a thermal unit towards fast frequency changes:

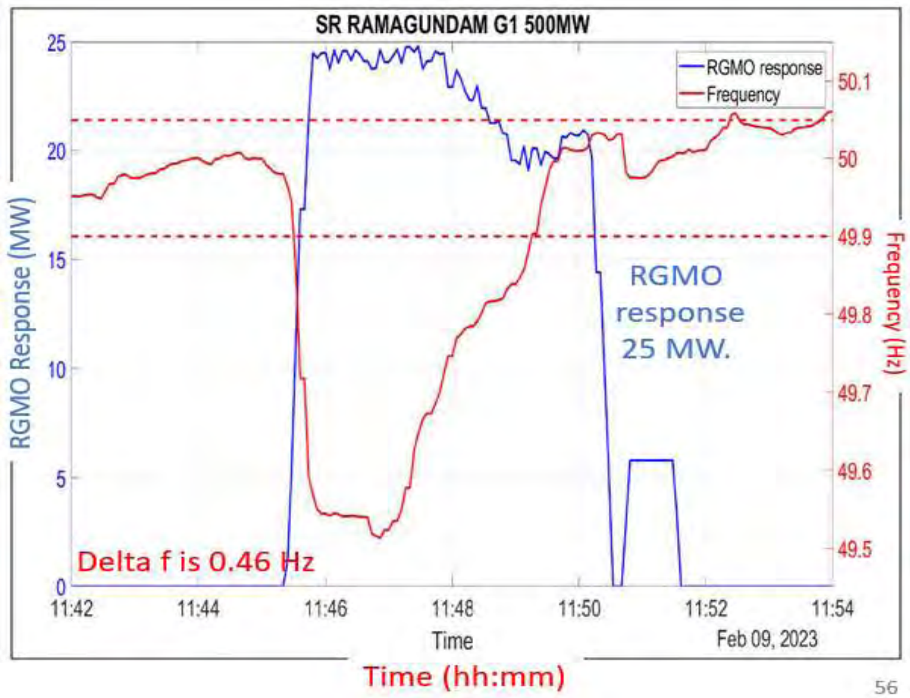


Figure 27: Typical Governor Control Instructions in a Thermal Unit towards Fast Frequency Changes

Additionally, a third-party assessment of 240 generating units was carried out, with observations as under:

1. Summary of thermal units
   Primary Frequency Response (PFR) from most of the thermal units were as per droop characteristics. Most of the tested units have given initial response but the overall MW contribution, stability of response and response to further fall in frequency found to be varying by dynamic conditions such as pressure correction compensation in MW, quality of fuel, type of unit, tuning of boilers and related control loops and disparity in logic implementations.
2. Summary of hydro units
   Hydro units demonstrated primary frequency response as per their droop characteristics, full response time for majority of hydro units were obtained within 45 seconds. Stability of the response depends upon the forbidden zone and status of adjacent units during the event of frequency changes.
3. Summary of gas units
   Gas based units has shown quick full response time and stable response in terms of holding the MW correction but limited by mode of operation and dead band/ripple filter implementation. It has been observed that gas turbines running

in combined cycle with steam turbine provide the primary frequency response only by the MW changes of gas turbine generator, on the other hand the steam turbine response comes after a delay of 5 to 10 minutes hence do not contribute in PFR in terms of MW contribution.

It is learned that response from the units varies, depending upon the droop implementation, implementation of ripple filter logic, different governor scan time, MW contribution limited by diverse implementation of limiters in frequency control logic, restrictions in response in terms of maximum MW contribution, units' instability issues and manual innervations during the test to achieve desirable response.

Response from governor is automatically driven by manually entered controller settings. It was observed that there was a clear difference in controller logic prior and post DSM Regulation 2022 likely due to the constructs. Additionally, a time lag of 15-20 seconds was observed in output change of generators after receiving signal, due to high scan rate and other technical reasons related to boilers, which impedes the operation of primary response. It was also highlighted that some thermal plants were not able to give primary response due to technical constraints. These could be potential reasons behind inadequate primary response.

These studies and findings highlighted some major areas of concern:

1. Logics
    a. Droop implementation in controller logic with limiters
        i. Droop at MCR with 5% limitation of MCR
        ii. Droop at current generation (CG)
        iii. Droop at MCR with 5% limitation of CG
        iv. Droop at MCR, with 5% limitation of CG for below 50 Hz & 5% limitations of MCR for above 50 Hz
    b. Ripple filter implementation
        i. Implementation on running/current tracking frequency.
        ii. Implementation w.r.t 50 Hz
        iii. At current tracking frequency for $f < 50$ Hz and at fixed 50 Hz for $f > 50$ Hz and vice-versa
    c. Response in consecutive changes in frequency
        i. Units responding to consecutive changes in frequency as per droop.
        ii. Units responding to consecutive changes in frequency as per droop but no response while ramp back is in action.
        iii. Units respond to the first frequency change and does not respond to any further changes in frequency.

   iv. Units respond to frequency changes from f<50 Hz to f>50 Hz and vice versa.
   v. Restricted response holding time for frequency above 50 Hz.
  d. RGMO implementation for both below and above 50Hz
  e. Fixed % change in MW for any change in frequency
  f. Restriction in response hold time
  g. Scan time of governor frequency controller & intentional delay
2. Unit operations
  a. System bottlenecks w.r.t Super-critical units.
  b. Pressure correction affecting the sustainability of response.
  c. Coal quality
  d. Manual interventions to achieve desired response during test - Higher Pressure setpoint maintained for steps below 50Hz & Lower Pressure setpoints maintained during steps above 50Hz.
  e. Base load Vs MCR understanding for Gas based units.
  f. Overshoot, mechanical backlash and oscillations in MW when operating near forbidden zone w.r.t hydro units.
3. Controller tuning
  a. Governor frequency controller tuning.
  b. CMC controller tuning.
  c. Boiler tuning.

The above analyses and findings highlight the need for standardization in logic implementation, understanding the system bottlenecks, and taking corrective measures for the improvements in the primary frequency response of generating units across India. Implementing the recommended measures will contribute to a more resilient and stable power grid, enhancing overall system reliability and performance. The detailed report of Grid India study is enclosed in Appendix-2 (separate report). Specific recommendations for primary response are covered in the section below.

6.1.1 Potential Remedial Measures for Primary Response

6.1.1.1 Operational Remedial Measures

1. Standardization of droop settings
   The test revealed significant disparities in droop implementation across generating units, such as droop implemented on MCR, droop implemented on units current generation, droop implemented on MCR but capped or limited by 5% of current generation, droop implemented on current generation and capped with 5% of current generation. The different way of implementation gives different MW contribution during the event. These variations in droop settings have the potential to impact grid stability during frequency deviations.

Definition of Governor Droop in IEGC states in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from no load to full load, which is Hz/MW from full load to no load, hence the droop should be implemented on unit MCR without any limiters. It is recommended to implement standardized droop settings for generating units to ensure consistent frequency response.

2. Ripple filter implementation
   Inconsistencies in PFR due to different ripple filter logic implantation is noted, such as different responses from the units in consecutive frequency changes, variation in responses during the transition of frequency from below 50 Hz to above 50 Hz and vice versa, less than desired MW correction during frequency changes etc. These variations are due to the implementation of ripple filter logic differently among the generators. For those generating units where the ripple filter logic is implemented with respect to fixed frequency of 50 Hz contributes in PFR as per droop with respect to frequency change whenever frequency deviates beyond the rippler filter range (which mostly observed is 0.03 Hz). However, units where the ripple filter logic is implemented on running frequency or current tracking frequency, it has been noticed that the response from the unit during the frequency changes depends on the running frequency value and may not be adequate. Furthermore, this small decline in frequency may remain undetected by the governor, which could affect the unit's ability to contribute in PFR. The concept of ripple filter has been eliminated in the IEGC 2023 which states 'The inherent dead band of a generating unit or frequency controller shall not exceed +/- 0.03 Hz'. Hence in order to verify that ripple filter logic is removed, and governor action is with respect to reference frequency of 50 Hz, it is recommended to retest the units for PFR.
3. Response restrictions
   Some units exhibited restrictions in their response capabilities (e.g., fixed MW change for any change in frequency, no response for consecutive change in frequency, restricted response for frequency changes above 50 Hz, fixed response hold time irrespective of the duration of frequency event etc.) which may compromise their contribution to grids stability during contingency. It is suggested to identify and resolve response restrictions in units to enhance their contribution to primary frequency response.
4. Manual intervention
   Manual interventions were noted in certain instances to achieve an ideal response. These interventions could introduce delays and uncertainty in restoring grid frequency. Hence it is recommended to have well-tuned coordinated master control logic implementations among such units to achieve uniform responses during grid disturbances.

5. System bottlenecks
   Mechanical backlash in hydro units, pressure correction compensation in thermal units and response stability issues in super critical units etc. were identified as system bottlenecks affecting the efficient delivery of frequency response. Hence it is recommended to mitigate these issues as far as possible.
6. Different scan time / intentional delay
   From the PFR tests it is observed that the response initiation time, subjected to change in frequency steps, are different for different generating units. How quickly unit start to respond depends on the scan time in the governor's frequency control logic. From the test results it has been noticed response initiation time varies from less than a second to 6 - 7 seconds. Delayed response initiation can potentially defeat the purpose of PFR because of higher overall response initiation time. It is recommended to address this issue and standardize scan time in the governor for enabling them to provide quick initiation of response to avoid the intentional delay and for achieving optimal delivery time of PFR.

6.1.1.2 Remedial Measures for Plant Owners

1. Logic modification and tuning
   To achieve robust PFR, it is essential to tune controller logic, including governor frequency controllers, CMC controllers, and boiler tuning, to enhance PFR capabilities.
2. Address pressure correction
   Identify and address issues related to pressure correction that affect the sustainability of PFR.
3. No valve-wide operation
   It has been observed from the PFR test, some of the generating units were incapable to provide PFR for subsequent fall in simulated frequency and also for large frequency steps. This may probably be due to valve-wide operation which can be observed from the trends of valve positions. Therefore, it is advisable to avoid valve-wide operation and maintain sufficient margin for PFR.
4. Fuel quality management
   Ensure the quality of fuel used to maintain stable PFR response.
5. Minimize manual interventions
   Manual interventions were noted during the test in certain instances to achieve an ideal response. These interventions could introduce delays and uncertainty during actual grid events. Hence it is recommended to have well-tuned coordinated control (CMC) among such units to achieve uniform responses during grid disturbances.
6. Hydro and gas-based units response optimization

For some of the hydro units, implementation of dead band, slow response, non-uniformity in logic implementation has been observed. For gas-based units, dead band and the mode of operation (when operating in base load) restricting PFR has been observed. Hence it is recommended to implement uniform logics in order to have consistent speed of response, quantum of MW change as per droop and response stability during frequency changes.

6.2 Secondary Response

As per Ancillary Services Regulations 2022, Secondary Reserve Ancillary Service (SRAS) comprises of SRAS-Up and SRAS-Down which is activated and deployed by the secondary control signal. This secondary control signal drives the Automatic Generation Control (AGC) mechanism. Following are some key aspects of AGC:

1. Automatic and supplementary control mechanism, 24x7, to control frequency and tie-line flows.
2. Helps replenish the exhausted primary reserves.
3. Acts as efficient and automatic frequency control during high RE periods.
4. Improves the reliability of the power system.

Automatic Generation Control (AGC) has been in operation in India since 21st July 2021 with 44 power plants with an installed capacity of 41,900 MW. At present, 185 generating units from 70 power plants comprising of thermal (57.7 GW), gas (3.2 GW) and hydro (6.4 GW) with an installed capacity of 67,337 MW are wired under AGC. AGC implementation is a multi-stakeholder project. All the 185 units have been integrated under AGC after rigorous testing.

From 5th Dec 2022, AGC has been implemented as Secondary Reserve Ancillary Service (SRAS) in line with CERC (Ancillary Services) Regulations, 2022. A detailed operating procedure for SRAS is hosted on the NLDC website, which serves as a guideline for the power plants in operating AGC under different use cases. Accounting and settlement of the services provided by the AGC power plants are done on a weekly basis.

Out of the total capacity wired, typically a capacity of around 40 GW would be operating under AGC, out of the on-bar generation. These plants together offer up/down regulation of +/-2000 MW for secondary frequency control at around 200-300 MW/minute ramp rate combined. The power number of the Indian grid is around 10000 – 15000 MW/Hz, and hence AGC can roughly control grid frequency up to 0.1 Hz - 0.15 Hz. The details of the plants are mapped in Figure 28:

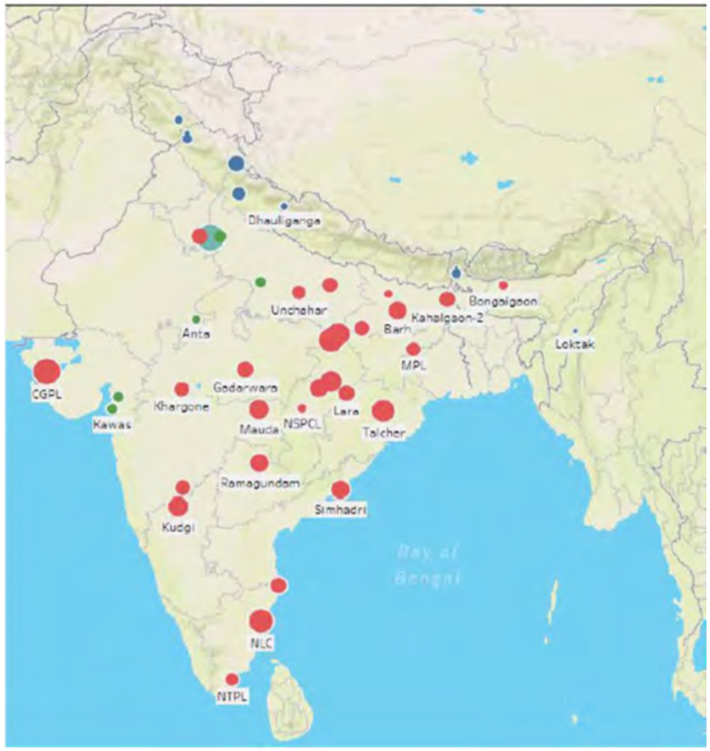


Figure 28: SRAS Status Pan-India

Availability of secondary reserves continued to be inadequate, and the following potential reasons were highlighted for the same:

1. Limited availability of up/down margins on account of 5% limits on the response provided by the power plant.
2. Constraints in participation in SRAS by generating stations due to communication-related issues.
3. Non-participation by lignite-based thermal stations due to stability issues.
4. Non-participation of UMPP CGPL due to commercial issues.
5. Non-participation of UMPP Sasan due to delay in establishing necessary infrastructure of AGC.
6. Demand for a higher performance-based incentive for participation in SRAS by generating stations to compensate for the increased fatigue.

Grid-India has been taking remedial measures to help the situation, such as:

1. Further integration planned under AGC:
    a. Telangana STPP, North Karanpura, Farakka-1, and Ramagundam-1, DVC plants.
    b. Motivated towards intra-state AGC with regular workshops. Workshops conducted for Maharashtra, West Bengal, Uttar Pradesh, Delhi, Haryana, and Telangana.

2. BESS/Pumped Hydro envisaged under AGC/SRAS.
3. Increased ramp rate of 1.5-2% per minute on more plants (60/185 units covered).
4. Operate gas plants under AGC more regularly.
5. Increase integration time as required (presently 300s) in stages.
6. Facilitate reduced fatigue cycling of thermal power plants.
7. DeltaP reversal control settings (implemented in 4 plants and others in a phased manner).

A detailed report of Grid India "Learnings from the Trial Operations with Automatic Generation Control (AGC) in Indian Power System" is enclosed as Appendix 3 (separate report).

6.3 Tertiary Response

Tertiary Reserve Ancillary Services (TRAS) have been made operational in the Indian power system since 1st June 2023 as per the directions of the Hon'ble Commission. TRAS has been rolled out through a combination of in-house development, incorporation of TRAS process in the National Open Access Registry (NOAR) and integration of these applications. NLDC, has been placing the Up and Down reserve requirement up to 4000 MW in the DAM-AS / RTM-AS. Since the launch of TRAS, very few supply bids have been received through the Power Exchanges.

The TRAS Regulations implemented from 1st June 2023 do not explicitly provide for bringing units on bar from cold start up. Emergency dispatch provisions under TRAS provide that any generator can be dispatched under emergency conditions. However, the emergency dispatch provisions are for a short duration and cannot be used for meeting day-to-day shortfall in reserves. Considering the fact that high demand growth is being experienced along with wide variations on account of weather changes and RE variations, it has become imperative to maintain more spinning reserves.

Requisition of power by constituents depends on various factors such as availability of power in the electricity market and this sometimes leads to delays in the unit commitment decision. During some periods the available spinning reserves are low, and it has become imperative on the part of NLDC/RLDCs to intervene and bring thermal/gas units on bar so as to create and maintain spinning reserves for grid security reasons. Once the unit commitment decision is made and units are brought on bar, constituents also provide requisition as per their requirement. In case requisitions are not received, TRAS support to maintain technical minimum generation was being provided in the interest of secure grid operations.

Dispatch of reserves under TRAS has provided support for facilitating secure operation of the grid. Presently, the ancillary dispatch requirements of the grid are presently being fulfilled by the secondary reserve ancillary services (SRAS / AGC) and the 'Shortfall' provisions of the TRAS regulations, which allow utilization of un-requisitioned reserves from the section-62 generators.

In view of the above, thermal (coal, gas) units under Section 62 / MOP directions have been committed in advance, based on anticipated grid conditions and availability of spinning reserves (in section 62 generators), under the TRAS shortfall provisions. In this manner, as per the grid situation, the requisite generation under cold reserve have been synchronized to replenish the available reserves in the grid. Also, in case of unit likely to go under reserve shut down and there is a requirement for ensuring adequate spinning reserves, TRAS support is being given to retain the unit at technical minimum level for grid security reasons. The technical minimum support given in 2023 is depicted in Figure 29.

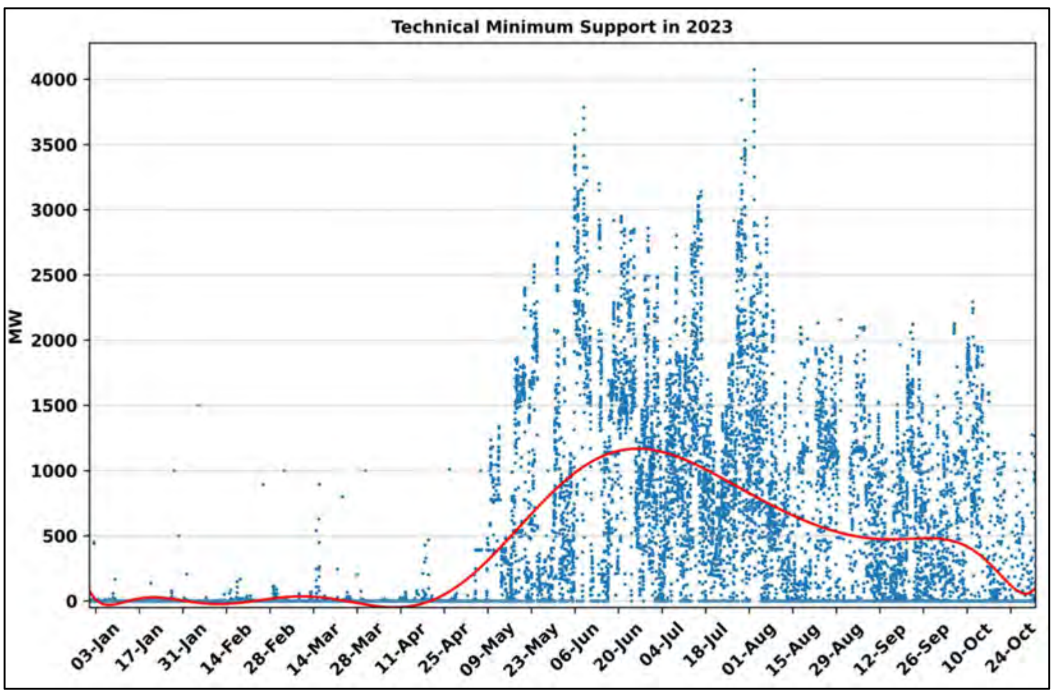


Figure 29: Technical Minimum Support given through Ancillary Services

The TRAS block wise dispatch and TRAS duration curve between Jan 1st 2023 to November 30th 2023 is depicted in Figure 30 and Figure 31 below.

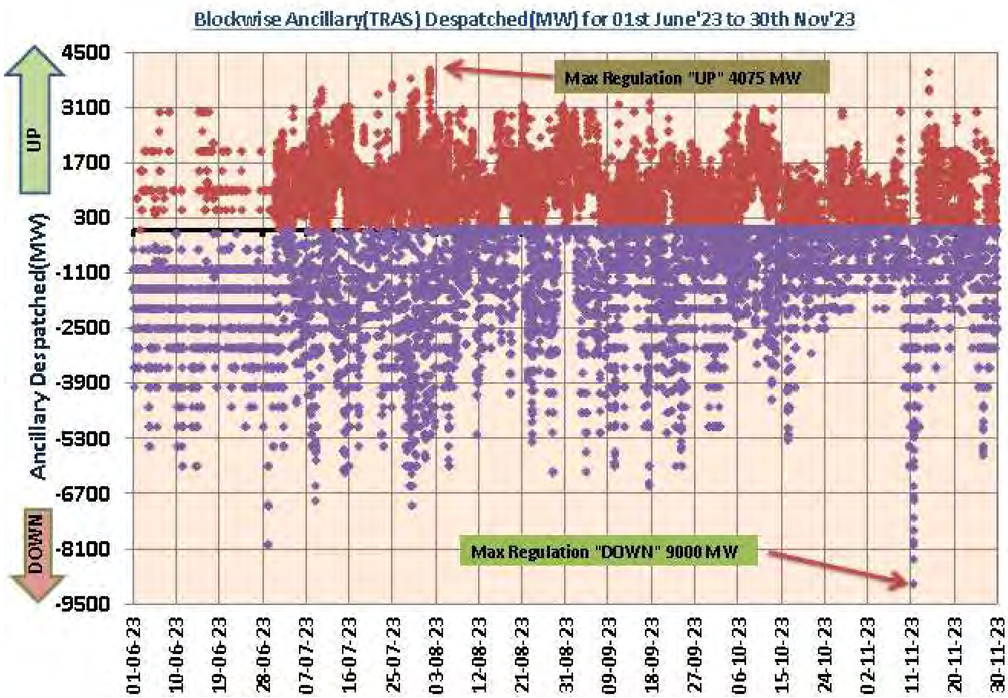


Figure 30: Blockwise TRAS Dispatched (MW between 1st June 2023 to 30th November 2023

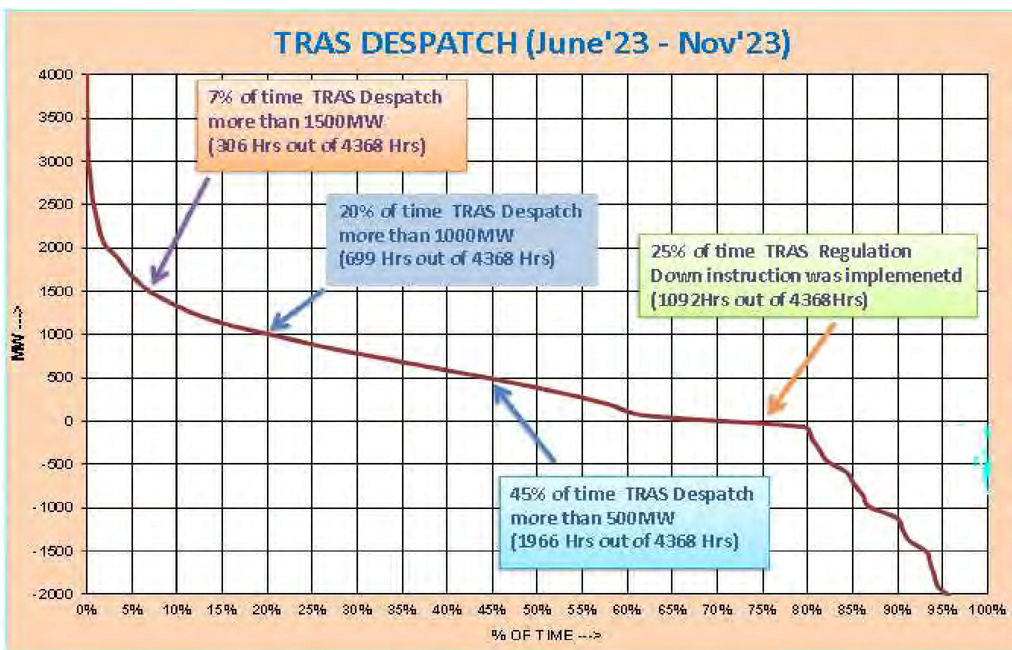


Figure 31: TRAS Dispatch duration curve between 1st June 2023 to 30th November 2023

6.4 Summary of Recommended Remedial Measures for Reserves

The Expert Committee recommends the following remedial measures for ensuring adequate integration and participation from primary, secondary, and tertiary reserves:

1. Primary reserves
    a. Standardization of droop settings
        i. Recommended to implement standardized droop settings for generating units to ensure consistent frequency response and frequent testing of compliance.
    b. Ripple filter implementation
        i. Recommended to have ripple filter logic is implemented with respect to fixed frequency of 50 Hz only.
    c. Minimize manual intervention
        i. Recommended to have well-tuned coordinated master control logic implementations in large power plants (capacity > 1,000 MW) to achieve uniform responses during grid disturbances.
    d. No valve-wide operation
        i. It is advisable to avoid valve-wide operation and maintain sufficient margin for PFR.
    e. Fuel quality management
    f. Ensure the quality of fuel used to maintain stable PFR response.
        i.
    g. Other issues
        i. Recommended to mitigate system bottlenecks and to standardize the scan time of governor to provide quick initiation along with tuning of all the controllers as far as possible.
2. Secondary reserves:
    a. Further integration under AGC at state level with a clear mandate by the State Commissions.
    b. BESS and storage plants can be a part of AGC/SRAS.
    c. Increasing the ramp rate of 1.5-2% per minute.
    d. Increase integration time from the present level of 300s to the requisite level as per NLDC operational feedback.
    e. DeltaP reversal control settings to be implemented on a case-to-case basis in a phased manner.
    f. Thermal power plants may increase reserves offered for SRAS/AGC from the present +/- 5% to a higher quantum.
3. Tertiary Reserves
    a. Enabling TRAS at state-level and implementing state-level ancillary projects in line with the national TRAS market.
    b. Review the compensation/ incentive structure to encourage AS participation.
    c. Enabling advance procurement of AS by the system operator.

   d. Incentive structure to encourage high ramping resources like ESS and demand response.

4. Miscellaneous
   a. Strict alignment with and implementation of FGMO.
   b. SOP for testing of FGMO compliance.
   c. In compliance with Grid Code requirements, a spinning reserve up to 5% may be mandated through the State Grid Code Amendment.
   d. Cost recovery through regulatory process.
   e. State-level implementation of and adherence to RA standards and necessary finance could be arranged through PSDF wherever possible.
   f. Movement towards shorter scheduling and settlement periods up to 5 minutes.

7 Analysis of DSM Design & Recommended Remedial Measures

The Expert Committee (EC), in a span of six meetings, undertook detailed analysis of historical frequency profile, behaviour of buyers and sellers under different system frequencies, and performance of reserves. The EC held detailed discussions on potential remedial measures going forward, and identified the following key elements of design:

1. Avoiding asymmetry in pricing structure.
2. Avoiding over-incentivizing for deviation.
3. Promoting participation in ancillary services.
4. Not making DSM as another market mechanism.
5. Making provision to capture operation of generator in FGMO as per latest IEGC provisions.

The following subsections describe the EC's recommendations for immediate interventions and changes to DSM Regulations 2022 (as per Order dt. 06 February 2023).

7.1 Recommendations for General Sellers

The current dispensation (as per Order dt. 06 February 2023) has one volume limit of lesser of 10% Dgs or 100 MW for OI, and three limits of lesser of 10% Dgs or 100 MW, 15% of Dgs or 150 MW, and beyond for UI. The EC recommends only one volume limit of lesser of 10% Dgs or 150 MW for general sellers and uniform for OI and UI.

The current dispensation charges OI at reference rate, while UI for VL1 is charged at reference rate, UI for VL2 and VL3 is charged at normal rate, low frequencies are charged at reference/normal rate, and high frequencies at reference rate. The EC recommends applying only the reference rate for all volume limits and frequencies instead.

The recommended construct for general sellers is depicted in the Table 5 below:

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	(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

Deviation by way of over injection (Receivable by the Seller)	**Deviation by way of under injection (Payable by the Seller)**
charges for deviation become 50% of RR when f = 50.05Hz	charges for deviation become 85% of RR 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 seller shall be increased by 1.5% of RR so that charges for deviation become 115% of RR when f = 49.90Hz	(vi) When [$49.90 \leq f < 50.00$ 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]; @ 150% of RR when [49.90Hz ≤ f < 50.00 Hz]; and @ 200% of RR when [f < 49.90 Hz]

Table 5: Recommended Intervention for General Sellers

Note: system frequency = f and f_{band} = [$49.90Hz \leq f \leq 50.05$ Hz].

For under injection of seller/generator selling in HP-DAM the following provision may be added to avoid any gaming:

"Provided that for a Seller whose bid is cleared in the HP-DAM, the deviation charge by way of 'under-injection' for a time block shall be equal to the highest of the weighted average ACP of the HP-DAM Market segments of all the Power Exchanges; or the RR for that time block in which the seller has sold power though HP-DAM."

OI during high frequency by general sellers, is not supportive to the grid and it is important to penalize or sellers operating in this quadrant. As a result, the recommended design pays the seller from the pool at 100% of RR at 50 Hz, which becomes zero from 50.05 Hz to 50.10 Hz. Beyond the very high frequency of 50.1 Hz, there is a flat penalty or negative pricing in which the seller has to pay back to pool at 10% of RR. By paying lesser than 100% of RR, there is an indirect penalty imposed on the seller. These charges within VL1 and in between the frequency points are dependent on a sloping price vector. While these charges are for deviation within VL1, there are no additional charges for deviation beyond VL1, except for very high frequencies beyond 50.1 Hz which continue to be penalized at 10% of RR.

OI during low frequency by general sellers, is supportive for the grid and it is important to appropriately incentivize while avoiding over-incentive. It is also important to ensure encouragement for participation in reserves. Hence, the EC recommends paying the seller from the pool at 100% of RR at 50 Hz and gradually sloping up to 115% of RR by 49.9 Hz and staying constant at 115% of RR thereafter. This constant incentive avoids over-incentivization. These charges within VL1 and in between the frequency points are dependent on a sloping price vector. While these charges are for deviation within VL1, there are no additional charges for deviation beyond VL1.

UI during low frequency by general sellers, is not in support of the grid and should be appropriately penalized. Hence, the EC recommends the seller to pay into the pool at RR till VL1 and flat RR beyond VL1 at 50 Hz, gradually sloping up to 150% of RR by 49.9 Hz till VL1 and flat 150% of RR when system frequency fall below 49.9 Hz. Further beyond VL1 deviation rate would be flat 150% of RR between 50.50 Hz and 49.90 Hz and flat 200% of RR when frequency fall down below 49.90Hz . These charges within VL1 and in between the frequency points are dependent on a sloping price vector.

UI during high frequency by general sellers is supportive for the grid and shouldn't be severely penalized. Hence, EC recommends the seller to pay into the pool at RR for 50 Hz, gradually going down to 85% of RR by 50.05 Hz, staying flat at 85% thereafter. While this is within VL1, the EC recommends the seller to pay flat RR for frequency greater than 50 Hz. By paying back into the pool at less than 100% of RR for frequencies higher than 50 Hz, there is an indirect incentive for the seller.

Besides the sloping price vector, two more important changes are the application of only one volume limit for general sellers and that too across the entire frequency range.

7.2 Recommendations for Wind, Solar, and Hybrid Sellers

The current dispensation (as per Order dt. 06 February 2023) has volume limit of 10% Dws for solar and 15% Dws for wind, going up to 15% Dws for solar and 20% Dws for wind. The EC slightly tighter VL1 and an additional volume limit, i.e., VL3:

1. Volume limit 1 (VL1): 5% Dws for solar and 10% Dws for wind
2. Volume limit 2 (VL2): from VL1 up to 10% Dws for solar and 15% Dws for wind
3. Volume limit 3 (VL3): from VL2 up to 20% Dws for solar and 25% Dws for wind
4. Beyond VL3

The current dispensation charges OI at contract rate or weighted average market rate up to VL2, with no incentive for VL3. On the other hand, there is no penalty for VL1 and then penalty of contract rate or weighted average market rate beyond VL1. The EC recommends applying a uniform and symmetrical pricing structure with UI beyond VL3 charged at 200% of contract rate or weighted average market rate, while OI beyond VL3 paid zero.

While the applicable charges are same as 06 February 2023, i.e., contract rate or weighted average ACP of the market, the EC recommends an additional volume limit (VL3) and uniformity of pricing structure for OI and UI.

The recommended construct for wind, solar, and hybrid sellers is depicted below Table 6:

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 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% D_{WS} 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% D_{WS} and up to 25% D_{WS}

Table 6: Recommended Framework for Wind, Solar, and Hybrid Sellers

7.3 Recommendations for Buyers

The current dispensation (as per Order dt. 06 February 2023) has one volume limit of lesser of 10% Dbuy or 100 MW for buyers with schedules greater than 400 MW, and lesser of 20% Dbuy or 40 MW for buyers with schedule up to 400 MW. There is a second volume limit of 15% Dbuy or 200 MW for buyer with schedule greater than 400 MW, followed by penalty structure for deviation beyond the second volume limit in case of OD. The EC recommends the following symmetrical volume limits across OD and UD:

Volume Limit	Non-RE-Rich Buyer with Schedule > 400 MW	Non-RE-Rich Buyer with Schedule up to 400 MW	RE-Rich Buyer with Solar + Wind IC from 1,000 – 5,000 MW	RE-Rich Buyer with Solar + Wind IC > 5,000 MW
VL1	Lesser of 10% Dbuy or 100 MW	Lesser of 20% Dbuy or 40 MW	200 MW	250 MW
VL2	from VL1 to lesser of 15% Dbuy or 200 MW	Beyond VL1	200 – 300 MW	250 – 350 MW
VL3	Beyond VL2	-	Beyond VL2	Beyond VL2

Table 7: Recommended Volume Limits for Buyers

Three important changes with regards to the volume limit are: two volume limits for all buyers and across the entire frequency range, and segregation of RE-rich states into RE-rich and Super RE-Rich states, depending on total solar + wind installed capacity in state.

The current dispensation has asymmetrical charges for UD and OD within the volume limit. For instance, OD up to VL1 is charged at normal rate while UD up to VL1 is incentivized at 90% of the normal rate. The EC recommends applying only the normal rate across all frequencies and volume limits for all buyers.

The recommended construct for buyers is depicted in the Table 8 below:

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 when f =50.00 Hz	iv) @ NR when f =50.00 Hz
ii) 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 7% 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 reduced by 5% of NR so that charges for deviation become 75% of NR 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 % of NR so that charges for deviation become 95% of NR 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 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 ≥ 50.10 Hz]	(iii) @ 50% of NR when [50.05 Hz < f < 50.10 Hz]: (iv) @ zero when [f > 50.10 Hz]

(ii) @ 95 % of NR when [$f < 49.90$ Hz]	iv) @ 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. @ 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]	(ii) 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 [$f \geq 50.10$ Hz]	(ii) @ 200% of NR when f<50.00 Hz; (iii) @ 110% of NR when [$f \geq 50.00$ Hz].

Table 8: Recommended Intervention for Buyers

UD during high frequency by buyers is not supportive for the grid and it is important to appropriately penalize. As a result, the recommended design pays the buyer from the pool at 85% of NR at 50 Hz, gradually reducing to 50% by 50.05 Hz. Thereafter, payment to buyer is zero till 50.1 Hz. For very high frequencies beyond 50.1 Hz, the buyer has to pay a penalty of 10% of NR. While this is within VL1 and VL2, there is no payment in VL3 and beyond till 50.1 Hz, after which the 10% penalty applies. By paying lesser than 100% of NR, there is an indirect penalty imposed on the buyer.

UD during low frequency by buyers is supportive to the grid and it is important to appropriately incentivize while avoiding over-incentivization. As a result, while the recommended design pays the buyer from the pool at 85% of NR at 50 Hz, this gradually goes up to 95% of NR at 49.90 Hz, thereafter, staying the same. While this is within VL1, the buyer is paid at 80% of NR within VL2, and there is no payment in VL3.

OD during low frequency by buyers is not supportive to the grid and should be appropriately penalized. Hence, the EC recommends a payment by buyer to pool of NR at 50 Hz, gradually going up to 150% of NR till 49.90 Hz, thereafter staying the same. For VL2, the buyer has to pay 130% of NR till 49.90 Hz, and then 150% of NR thereafter. For VL3, buyer has to pay 200% of NR below 50 Hz.

OD during high frequency by buyers is supportive to the grid and should be appropriately incentivized while avoiding over-incentivization. Hence, the EC recommends a payment by buyer to pool of 100% of NR at 50 Hz, gradually going down to 75% of NR by 50.05 Hz, becoming 50% by 50.10 Hz, and then zero thereafter. By paying less than 100% of NR back into the pool, there is an indirect incentive for the buyer. For VL2, buyer has to pay back at NR till 50.05 Hz, 75% of NR till 50.10 Hz, and zero thereafter. For VL2, buyer has to pay back 110% of NR for all frequencies. This avoids over-incentivization beyond certain limits.

The EC further clarifies that:

Charges for deviation, in respect of a Standalone Energy Storage System (ESS) or an ESS co-located with wind or solar generating station or both, 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**.

7.4 Recommendations for Normal Rate of Charges for deviation

The current dispensation (as per Order dt. 06 February 2023) has provided that the Normal Rate of Charges for Deviations for a time block shall be equal to the higher of [the weighted average ACP of the Day Ahead Market segments of all the Power Exchanges; and the weighted average ACP of the Real Time Market segments of all the Power Exchanges, for that time block] subject to a ceiling of Rs 12 per kWh, until further orders.

Subsequently, in view of the introduction of high Price DAM segment, the Commission further revised the Normal Rate of Deviation charges for sellers cleared in the HP-DAM market as follows:

“The Normal Rate of Charges for Deviation by way of ‘under-injection’ for a time block shall be equal to the highest of [the weighted average ACP of the HP-DAM Market segments of all the Power Exchanges; or the weighted average ACP of the Day Ahead Market segments of all the Power Exchanges; or the weighted average ACP of the Real Time Market segments of all the Power Exchanges, for that time block] for the quantum of power sold though HP- DAM. and

(ii) In para 27 of the said Order dated 06th February, 2023 (Relaxation of Regulation 8 of the DSM Regulations, 2022), for a seller whose bids are cleared in the HP-DAM, ‘reference charge rate’ specified for deviation by way of ‘under-injection’ shall be equal to [the weighted average ACP of the HP-DAM segments of all Power Exchanges, for that time block] for the quantum of power sold through HP-DAM.”

The EC recommends the following definition of Normal Rate of Charges for Deviation:

“The Normal Rate (NR), for a particular time-block, shall be equal to the Weighted Average of:

(a) ACP (in paise/kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges

(b) ACP (in paise/kWh) of the Real Time Market segments of all the Power Exchanges

(c) 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 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.

Provided further that in case of no despatch of Ancillary services in a time block or net charges for Ancillary services (due factoring Up and Down cost) is receivable in Deviation and Ancillary Service Pool Account, in that case Ancillary Service Charge and volume shall not be considered for computation of Normal Rate (NR)."

Alternatively,

> "In order to capture the impact of Ancillary despatch in a time block, it is proposed that the Normal Rate (NR), for a particular time-block, shall be equal to the:
>
> (a) ACP (in paise/kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges (1/3rd weight)
>
> (b) ACP (in paise/kWh) of the Real Time Market segments of all the Power Exchanges (1/3rd weight)
>
> (c) 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 (1/3rd weight)

Provided further that in case of no despatch of Ancillary services in a time block or net charges for Ancillary services (due factoring Up and Down cost) is receivable in Deviation and Ancillary Service Pool Account, in that case Ancillary Service Charge and volume 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."

7.5 Scheduling and DSM Accounting of Hybrid RE Seller with Energy Storage

The Committee has gone through the representation of some developers for cases where different type of generating stations such as wind, solar, pump storage and BESS are injecting power in grid through a common Bus in inter-state system. Scheduling and DSM accounting of hybrid RE seller with energy storage was deliberated. The Expert Committee recommended the following:

1. These hybrid entities shall be considered as a seller.
2. During injection schedule or drawal schedule in case of drawing pumping power/charging power from grid shall be considered as generator only.
3. Schedule shall be prepared separately for each type of generator. This shall help to understand the different profile of each generator.
4. Each generator shall be metered with SEM so that individual actual injection/drawal can be captured.
5. The DSM shall be computed based on the Net schedule i.e. sum of all generator schedule injecting/drawing power and net actual injection/drawal at common bus.
6. There shall be a lead generator who shall take responsibility of scheduling and DSM payment liabilities towards pool on behalf of all the generators.
7. The net payable or receivable shall be further distributed among the generator through any of the below given option in proportion of their:
    a. Deviation from the schedule;
    b. Schedule; or
    c. Actual generation
8. This is a case of multiple generators and having different sets of contract, so it may be difficult to derive a common reference rate(RR). So it is proposed to keep Reference rate (RR) of such generators as the weighted average DAM price.

<table>
<tr><th>Deviation by way of over injection
(Receivable by Lead generator)</th><th>Deviation by way of under injection
(Payable by the lead generator)</th></tr>
<tr><td></td><td></td></tr>
<tr><td colspan="2">(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.</td></tr>
<tr><td colspan="2">(II) For Deviation from 5% to 10% D_{GS} or greater than 50 MW upto 100 MW, whichever is less] and f within f_{band}</td></tr>
<tr><td>(i) @ RR when f =50.00 Hz</td><td>(iv) @ RR when f =50.00 Hz</td></tr>
<tr><td>(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</td><td>(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</td></tr>
<tr><td>(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</td><td>(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</td></tr>
</table>

Deviation by way of over injection (Receivable by Lead generator)	**Deviation by way of under injection (Payable by the lead generator)**
charges for deviation become 115% of RR when $f = 49.90$Hz	charges for deviation becomes 150% of RR when $f = 49.90$Hz
(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}**	
(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]

Table 9: Recommended Framework for Hybrid RE Seller with Energy Storage

Accordingly, the draft Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 have been recommended by the EC which is attached as Annexure 8

8 Summary of Recommendations

8.1 Recommendations on Reserves

The Expert Committee recommends the following remedial measures for ensuring adequate integration and participation from primary, secondary, and tertiary reserves:

1. Primary reserves
    a. Standardization of droop settings
        i. Recommended to implement standardized droop settings for generating units to ensure consistent frequency response and frequent testing of compliance.
    b. Ripple filter implementation
        i. Recommended to have ripple filter logic is implemented with respect to fixed frequency of 50 Hz only.
    c. Minimize manual intervention
        i. Recommended to have well-tuned coordinated master control logic implementations in large power plants (capacity > 1,000 MW) to achieve uniform responses during grid disturbances.
    d. No valve-wide operation
        i. It is advisable to avoid valve-wide operation and maintain sufficient margin for PFR.
    e. Fuel quality management
    f. Ensure the quality of fuel used to maintain stable PFR response.
    g. Other issues
        i. Recommended to mitigate system bottlenecks and to standardize the scan time of governor to provide quick initiation along with tuning of all the controllers as far as possible.
2. Secondary reserves:
    a. Further integration under AGC at state level with a clear mandate by the State Commissions.
    b. BESS and storage plants can be a part of AGC/SRAS.
    c. Increasing the ramp rate of 1.5-2% per minute.
    d. Increase integration time from the present level of 300s to the requisite level as per NLDC operational feedback.
    e. DeltaP reversal control settings to be implemented on a case-to-case basis in a phased manner.
    f. Thermal power plants may increase reserves offered for SRAS/AGC from the present +/- 5% to a higher quantum.
3. Tertiary Reserves
    a. Enabling TRAS at state-level and implementing state-level ancillary projects in line with the national TRAS market.

   b. Review the compensation/ incentive structure to encourage AS participation.
   c. Enabling advance procurement of AS by the system operator.
   d. Incentive structure to encourage high ramping resources like ESS and demand response.
4. Miscellaneous
   a. Strict alignment with and implementation of FGMO.
   b. SOP for testing of FGMO compliance.
   c. In compliance with Grid Code requirements, a spinning reserve up to 5% may be mandated through the State Grid Code Amendment.
   d. Cost recovery through regulatory process.
   e. State-level implementation of and adherence to RA standards and necessary finance could be arranged through PSDF wherever possible.
   f. Movement towards shorter scheduling and settlement periods up to 5 minutes.

8.2 Recommendations on Design Aspects of Deviation Charges

The EC held detailed discussions on potential remedial measures going forward, and identified the following key elements of design:

1. Avoiding asymmetry in pricing structure.
2. Avoiding over-incentivizing for deviation.
3. Promoting participation in ancillary services.
4. Not making DSM as another market mechanism.
5. Making provision to capture operation of generator in FGMO as per latest IEGC provisions.

Based on the above principles, the EC made the following recommendations on the design aspects of DSM:

- Normal Rate of charges for deviation should be weighted average of collective transactions on the power exchanges and net charges for Ancillary services in a time block.
- The deviation charges should be graded within the operative frequency band i.e. 49.90 Hz to 50.05 Hz; however, beyond the operative band the deviation charges should be flat irrespective of frequency.
- Graded deviation charges should be limited to initial volume limit of respective buyers and sellers beyond which the charges should be flat with additional disincentive for any further deviation so that the respective buyers and sellers are encouraged to participate in the Ancillary Services Mechanism.

- Deviation Charges should be such that a general seller receives or pays at its reference rate when the frequency is at 50.00 Hz and the charges decrease when the system frequency is higher than 50.00 Hz and increase or remain the same when the system frequency is less than 50.00 Hz within its volume limit. Beyond volume limit the deviation charges for over-injection should be zero while for under-injection the deviation charges should be with additional penalty. The recommended construct for general seller has been explained in Table 6 of the previous section.
- Over injection by general sellers during high frequency, is not supportive to the grid and should penalized. Accordingly, the seller should receive payment from the pool at RR at 50 Hz and should be paid less than RR when the frequency increases such that the rate of deviation charge becomes zero when the frequency increases to 50.05 Hz and would remain zero till 50.10 Hz. Beyond the very high frequency of 50.1 Hz, there is a flat penalty or negative pricing in which the seller has to pay back to pool at 10% of RR. While these charges are for deviation within VL1, there are no additional charges for deviation beyond VL1, except for very high frequencies beyond 50.1 Hz which continue to be penalized at 10% of RR.
- Over injection by general sellers during low frequency, is supportive for the grid and it is important to appropriately incentivize while avoiding over-incentive. It is also important to ensure encouragement for participation in reserves. Hence, the EC recommends paying the seller from the pool at 100% of RR at 50 Hz and gradually sloping to 115% of RR at 49.9 Hz and staying constant at 115% of RR thereafter. This avoids over-incentivization. These charges within VL1 and in between the frequency points are dependent on a sloping price vector. While these charges are for deviation within VL1, there are no additional charges for deviation beyond VL1.
- Under Injection by the general sellers during low frequency, is not in support of the grid and should be appropriately penalized. Hence, the EC recommends the seller to pay into the pool at RR till VL1 and flat RR beyond VL1 at 50 Hz, gradually sloping to 150% of RR by 49.9 Hz till VL1 and flat 150% of RR when the system frequency falls below 49.9 Hz. Further beyond VL1 deviation rate would be flat 150% of RR between 50.50 Hz and 49.90 Hz and flat 200% of RR when the frequency falls below 49.90Hz .
- Under Injection by general sellers during high frequency, is supportive for the grid and should be incentivised. Hence, the EC recommends the seller to pay into the pool @ RR at 50 Hz, gradually going down to 85% of RR to 50.05 Hz, staying flat at 85% thereafter. While this is within VL1, the EC recommends the seller to pay flat RR for frequency greater than 50 Hz. By paying back into the pool at less than 100% of RR for frequencies higher than 50 Hz, there is an indirect incentive for the seller. Accordingly, the charges for deviation for a general seller are depicted in Table 6 of the previous section.
- For intermittent sources like wind and solar the deviation charges should not be linked with frequency. The EC noted that Central Commission has notified the IEGC

2023 and made it effective since 01.10.2023. As the IEGC 2023 has provided for aggregation at the pooling station for inter-state wind and solar generating stations, the EC recommends the need of modifying the tolerance band for wind and solar generating stations. In view of the intermittent nature of wind and solar resources, the EC recommends to increase the deviation band further for wind and solar generating stations. Accordingly, the EC recommends modified construct for wind and solar based generating station with an option of aggregation as proposed in Table 7 of the previous section.

- RE-rich States should be further segregated into RE-rich and Super RE-Rich states, depending on the total solar + wind installed capacity in state. Any State with more than 5000MW of installed capacity should be categorised as super RE-rich State. Volume limits for super RE-rich States should be 250 MW, 250-350 MW and beyond 350MW for VL_1, VL_2 and VL_3 as depicted in the Table 8 of the previous section.
- UD by buyers during high frequency is not supportive for the grid and should be appropriately penalized. Accordingly, the buyer should be paid for under drawal from the pool at 85% of Normal Rate of charge for deviation (NR) at 50 Hz while gradually reducing to 50% of NR at 50.05 Hz. Thereafter, payment to buyer should be zero till 50.1 Hz. For very high frequencies beyond 50.1 Hz, the buyer should pay a penalty of 10% of NR. While this is within VL1 and VL2, there is no payment in VL3 and beyond till 50.1 Hz, after which the 10% penalty applies.
- Under Drawal by a buyer during low frequency, is supportive to the grid and it is important to appropriately incentivize while avoiding over-incentivization. As a result, while the recommended design pays the buyer from the pool at 85% of NR at 50 Hz, this gradually goes up to 95% of NR at 49.90 Hz, thereafter, staying the same. While this is within VL1, the buyer is paid at 80% of NR within VL2, and there is no payment in VL3.
- Over Drawal by a buyer during low frequency is not supportive to the grid and should be appropriately penalized. Hence, the EC recommends a payment by buyer to pool @ NR at 50 Hz, gradually going up to 150% of NR at 49.90 Hz, thereafter staying at the same level. For VL2, the buyer has to pay 130% of NR till 49.90 Hz, and then 150% of NR thereafter. For VL3, the buyer has to pay 200% of NR below 50 Hz.
- Over Drawal by a buyer during high frequency is supportive to the grid and should be appropriately incentivized while avoiding over-incentivization. Hence, the EC recommends a payment by buyer to pool of 100% of NR at 50 Hz, gradually going down to 75% of NR at 50.05 Hz, becoming 50% of NR by 50.10 Hz, and then zero thereafter. For VL2, the buyer has to pay back at NR till 50.05 Hz, 75% of NR till 50.10 Hz, and zero thereafter. For VL2, the buyer has to pay back 110% of NR for all frequencies. This avoids over-incentivization beyond certain limits. Above Charges for buyers are depicted in Table 8 of the previous section.

- Being despatchable in nature, the charges for deviation, in respect of a Standalone Energy Storage System (ESS) or an ESS co-located with wind or solar generating station or both, shall be at par with the charges for deviation for a general seller.

9 Recommendations for Long-Term Interventions

Sufficient frequency response is necessary to stabilize frequency within an Interconnection immediately following the sudden loss of generation or load. System frequency in general reflects the instantaneous balance between generation and load. Reliable operation of a power system depends on maintaining frequency within predetermined boundaries. Most frequency response is provided by the automatic and autonomous actions of turbine-governors, with some response being provided by changes in demand due to changes in frequency. However, with large-scale renewable energy, modern invertors and the wind turbines are also capable of providing frequency response in particular downside requirements. It is also possible for upside generation requirement based on frequency drop under special situations as per the requirements of grid.

As per IEGC 2023, section 30 clause 10(f), specifies that *"The minimum All India target frequency response characteristics (FRC) shall be estimated and based on such target FRC, the frequency response obligation of each control area shall be assessed by NLDC as per Annexure-2, giving due consideration to generation and load within each control area and details as given in Table 4 under sub-clause(g) of this clause. The same shall be informed to all control areas by 15tth of March every year for the next financial year."*

It is noted that all the entities may have to respond to the frequency deviation immediately as per their response characteristics but also remain in the same state till recovery of the frequency to its schedule limits. In this regard, as a long term for DSM, it would be preferable to move towards the framework of frequency response obligation (FRO) for each of the entities and as per the mandate of grid code annexure II for each of entities (buyers, sellers, designated balancing authorities (in future to with higher RE penetration), open access consumers with threshold limits etc.,).

For buyers & drawing entities, area control error (ACE) which is in existence for AGC calculation would be an appropriate measure, whereas for generators, the second part of the ACE, i.e., FRO, could be based on droop characteristics. ACE has been defined and implemented for many years as part of the automatic governor controlled (AGC) mechanism.

The recently notified Indian Electricity Grid Code (IEGC 2023) specifies the calculation of ACE for the control area and outlines the condition in Clause 11(d) that the ACE of each state or regional control area shall be auto calculated at the control center of NLDC/RLDC/SLDC based on telemetered values and external inputs. ACE is a net difference between schedules and actual, i.e., deviation, combined with frequency regulation of demand, i.e., FRO (Frequency Response Obligations). ACE accounts for both deviation in power flow as well as changes in generation/demand-based frequency variation for the control area.

In general, ACE is calculated for the control area defined as:

ACE = (Ia-Is)-10*(Bf*Pf)*(Fa-Fs)

Where:

Bf – Frequency Bias (MW/0.1Hz); say, 12000 to 15000MW/Hz (assumption)

Pf – Participation Factor of the control area

Fa – Actual Frequency

Fs – Scheduled Frequency; 50Hz

In the above formulation, (Ia-Is) represents the deviation while 10*(Bf*Pf)*(Fa-Fs) represents the FRO. Notably, ACE is defined differently for drawing and generating entities. The above formulation represents ACE for drawing entities. In the interconnected system, the frequency bias and participation factors are well-recognized concepts and can be clearly defined. However, there is no condition of specifying ACE for generators rather there is the concept of frequency response obligation (FRO) that can be applicable to generators. As an application of ACE for generators, droop characteristics may be considered. as follows:

ACE for generator = (Ia-Is)-(-Pmax) *(Fa-Fs)/(Fs*Droop)

Where:

Ia – Actual Power Flow (+ve for export)

Is – Scheduled Power (+ve for export)

Pmax – Maximum possible generation (Rated capacity of generating plant)

Fa – Actual Frequency

Fs – Scheduled Frequency; 50Hz

Droop – Generation Droop; 5%

Pmax is the maximum generation rated capacity (equivalent to MCR) on bar and droop is generation droop which can be stipulated for characteristics/types of generators. For simplicity of operation of the FRO concept and for the sake of uniformity, the same can be considered as 5%, to begin with.

ACE is calculated and applied as a balancing metric and for AGC calculation in many international markets such as CAISO and SPP in the USA and across Europe[5].

Considering the experiences and insights from analysis of past DSM frameworks and also upon review of international approaches, three formulations for DSM treatment have been analyzed as potential modifications to the current operational DSM framework, as under:

9.1 Suggested ACE Design for DSM

The following Table 10 shows penalty/incentive structure for ACE-based DSM:

Frequency	DSM Pricing Framework
< 49.95 Hz	ACE * DAM
49.95 < F < 50.05	0 for ACE > 0 and F > 50; ACE * 0.5 * DAM
50.05 < F < 50.10	0
>50.10	ABS(ACE) * 0.5 * DAMT

Table 10: ACE DSM Charges

The following Figure 32 shows the formulation for ACE based approach:

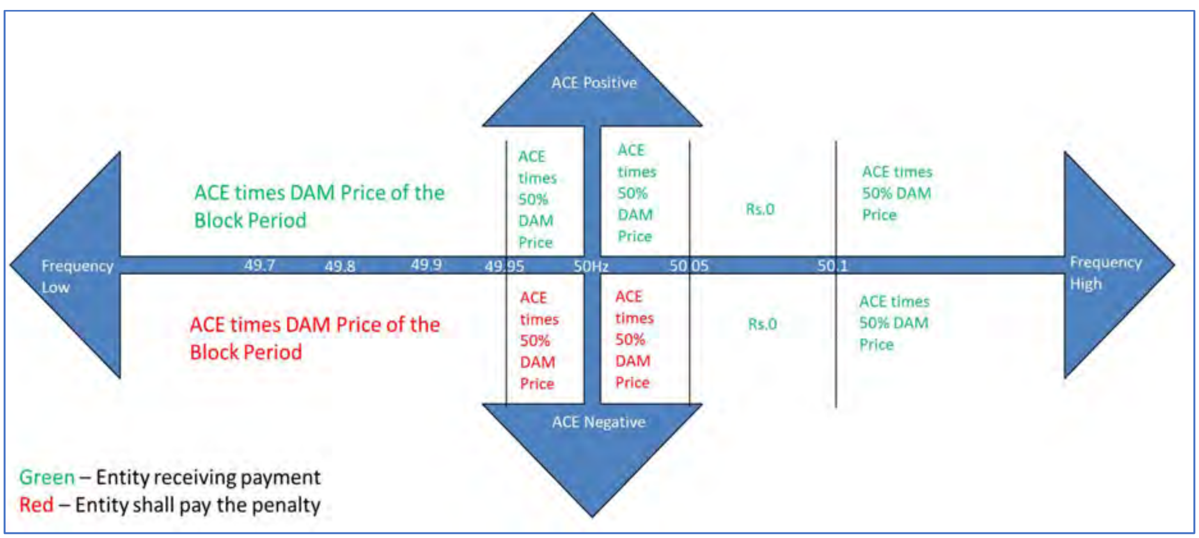


Figure 32: Schematic for ACE-Based DSM

[5] NERC; CAISO; SPP; Europe

9.2 Key Takeaways for Long-term Interventions

The Consultant to the Expert Committee carried out illustrative computations of the ACE-based DSM approach. While it was found to be technically sound, it would be challenging to implement in a short timeframe. The Expert Committee recommended investigating these approaches further.

10 Bibliography

1. Central Electricity Regulatory Commission (Deviation and settlement Mechanism and related matters) Regulations, 2014 https://cercind.gov.in/2016/regulation/14.pdf
2. Central Electricity Regulatory Commission (Deviation and settlement Mechanism and related matters)(Third Amendment) Regulations, 2016 https://cercind.gov.in/2016/regulation/Noti123.pdf
3. Central Electricity Regulatory Commission (Deviation and settlement Mechanism and related matters) Regulations, 2022 https://cercind.gov.in/Regulations/168_reg.pdf
4. Petition No. 16/SM/2022, Date order on 26th December 2022 https://cercind.gov.in/2022/orders/16-SM-2022.pdf
5. Petition No. 01/SM/2023 Date order on 06th February 2023 https://cercind.gov.in/2023/orders/1-SM-2023.pdf

11 Annexures

11.1 Annexure 1

-2-

5. The scope of work of the Expert Committee would be as under: -

(a) Review and Analysis of operational behavior of grid connected buyers and sellers post 05.12.2022.

(b) Examine the performance of the regional entity generators in terms of providing primary response and AGC support to manage grid frequency.

(c) Review operation of RRAS and status of implementation of TRAS.

(d) Review the practice of maintaining reserves by States and status of implementation of Ancillary Services at the State level.

(e) Suggest remedial measures for deployment of adequate reserves (primary, secondary and tertiary) for reliable grid operation.

(f) Any other matter related to above, including design related issues on DSM and Ancillary Services.

6. The Expert Committee may co-opt any expert as Member and also avail the services of a consultant/ consulting-firm/ research organisation in the process of examining the issues related to the subject matter.

7. Central Electricity Regulatory Commission shall provide secretariat services to the Expert Committee.

(Harpreet Singh Pruthi)
Secretary

<u>Copy to</u>

Members of the Expert Committee.

<u>Copy for information to:</u>

a. Sr. Exec.(O) to Chairperson, CERC.
b. Sr. PPS to Secretary, CERC.
c. Sr. Exec.Steno (O) to Chief (RA), CERC.
d. PS to Deputy Chief (RA), CERC.

ii.	Shri S.R. Narsimhan, Managing Director, Grid Controller of India Limited	-	Member
iii.	Shri K.K. Sharma, Former Member, UPERC	-	Member
iv.	Shri B.B. Mehta, Director, SLDC, Orissa	-	Member
v.	Shri Satyanarayan.S, Member Secretary, WRPC	-	Member
vi.	Shri Sushanta Kumar Chatterjee, Chief (RA), CERC	-	Member Secretary

11.2 Annexure 2

Minutes of Meeting (MoM) for the 1st Meeting of the FOR Working Group

MINUTES OF THE FIRST MEETING OF THE EXPERT COMMITTEE FOR ANALYSING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS

Venue	**: CERC 3rd floor Conference Room, 36 Janpath, Chanderlok building 36, New Delhi**
Date & Day	**: 6th March, 2023 (Monday);**
Time	**: 1500 Hrs**

1. The first meeting of the Expert Committee for analyzing the causes for inadequate primary andsecondary response with respect to implementation of CERC DSM Regulation, 2022 was held on 6th March, 2023 at CERC Conference Hall under the chairmanship of Shri I.S Jha (Member,CERC). At the outset, the Chairperson welcomed all the participants and highlighted the importance of maintaining reserves at regional as well as at State level to enhance stability of the system. He highlighted the mandate of the Committee which reads as follows, and requestedthe members to give their views and suggestions on each of the issues listed for deliberation bythe Committee:
   (a) Review and Analysis of operational behavior of grid connected buyers and sellers post05.12.2022
   (b) Examine the performance of the regional entity generators in terms of providing primaryresponse and AGC support to manage grid frequency.
   (c) Review operation of RRAS and status of implementation of TRAS
   (d) Review the practice of maintaining reserves by States and status of implementation ofAncillary Service at the State level.
   (e) Suggest remedial measures for deployment of adequate reserves (primary, secondary andtertiary) for reliable grid operation.
   (f) Any other matter related to above, including design related issues on DSM and AncillaryService.
2. Chief RA (CERC) while explaining the genesis of the constitution of the Committee highlightedthat the supply side issues such as inadequate support by way of primary and secondary response from the generators; and the demand side issues involving analysis of the behavior of discoms with respect to different levels of incentives/disincentives under DSM need be examined

in detail before suggesting remedial measures to contain frequency fluctuations.

3. CMD Grid-India appreciated the issue of reserves raised by Shri Jha and briefed about the regulatory roadmap established by the Commission for primary, secondary and Tertiary Ancillary Services in the Indian power sector. He further emphasized on the resource adequacy measures required in view of the possible high demand in the ensuing summer and also stated that there should be a provision for procurement of reserves up to three months in advance.
4. The Committee discussed the existing provisions for providing primary response from the inter-state generators in the Grid Code. The members opined that the existing provision of RestrictedGovernor Mode Operation (RGMO) in the Grid Code needs review, as it restricts the primary response from the generators to the desired level in response to frequency fluctuations. This should be substituted by FGMO and enforced strictly to ensure the governors in the generating stations respond to frequency excursions.
5. Director, SLDC, Orissa mentioned that the DSM charges without any volume limit leadgenerators to over-inject and discoms to under-draw for monetary gain and this results in wide frequency fluctuation. Hence, DSM rates may be linked proportionate to frequency as in earlierregime. He further emphasized that performance of regional entity generating stations inproviding primary response may be examined.
6. He also added that state gencos, which constitute 60% of the total installed capacity in the country have no primary response capability. It's because machines are old, and technology is not available. He further opinioned that mandatory provision of primary response may also be extended to State generating stations with PSDF support. He also suggested to provide some volume limit for the generators in the existing DSM framework.
7. Representative of WRPC stated that fluctuation in frequency is being caused due to variation in load including the variation due to renewable energy sources. State entity is finding it challenging to match the variation in intermittent sources in the grid.

8. The Committee Chairman emphasized that in order to ensure the grid security, suitable provisions may be explored so that each State entity keeps reserves on daily basis and intimate the same to national system operator in advance to ensure resource adequacy.
9. It was suggested that the generators should also be given opportunity to present their view beforethe Committee. It was also suggested that the Committee may consult experts for remedial measures.

Action points/ Decisions

- It was decided that the behavior analysis from supply side and demand side may be carried out based on the data analysis pre and post implementation of the DSM Regulations 2022. The Grid-India may provide all required support from the same.
- The Committee may consult experts in the subsequent meetings;
- The Committee may consult generating stations and discoms in the subsequent meeting forbehavior analysis;

The meeting ended with a vote of thanks to the Chair.

LIST OF PARTICIPANTS AT THE FIRST MEETING OF THE EXPERT COMMITTEE FORANALYSING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS

Members

Shri I S Jha, Member CERC
Shri S. R. Narasimhan, CMD Grid-India
Shri K.K. Sharma, Former Member
UPERC (virtual)Shri B.B. Mehta,
Director, SLDC, Orissa
Shri Satyanarayan S., Member
Secretary, WPRC Shri Sushanta
Kumar Chatterjee, Chief (RA),
CERC

Other participants

Shri Harpreet Singh Purthi, Secretary CERC
Shri Awdhesh Kumar Yadav,
Chief (Engg), CERCSmt Shilpa
Yadav, Joint Chief (Engg),
CERC
Shri Sameer Saxena, ed, Grid -India
Sh. Ravindra Kadam,
Advisor (RE), CERCSmt
Sukanya Manal, AC
(RA), CERC

<u>Note-2</u>

<u>Review and analysis of operational behavior of grid connected buyer and seller post 05.12.2022</u>

- As DSM rate is max(DAM,RTM), which is known in advance, therefore prompt gamingleading to wide range frequency variation.
- Viz : - Buyer will try to under draw at high DSM rate and vice versa
  and Seller will try to over inject simultaneously causing rise in frequency.

  Remedy: -

  Link DSM rate proportionate to frequency.
  DSM rate for over injection by seller should be capped around Rs 3.00 or less.

Examine the performance of regional entity generators in terms of providing primary responseand AGC support to manage grid frequency.

- Refurbishment of mandatory primary response for state Genco (contributing more than60% in Pan India) with PSDF support.

Review operation of RRAS and status of implementation of TRAS

- Compulsory schedule of power to over drawing beneficiary state as per meritorder/SCED before RRAS up instruction and vice versa.

Review the practice of maintaining reserves by states and status of implementation ofAncillary Services at the state level.

- SLDC is not able to maintain 50% reserve on bar of State's highest capacity generator.
    - It is proposed that state should maintain 5% reserve of the operatingdemand.
- There is no resource adequacy at state level during peak season for all 96 blocks.
- No ancillary service regulation at state level.

Suggest remedial measures for deployment of adequate reserves (primary, secondaryand tertiary) for reliable grid operation.

- SERC may encourage additional PPA as back up reserve barring its cost impact onconsumers.
- State Govt. may direct Captive Generating Plant to sell surplus power to StateDISCOM at mutually agreed tariff as needed.
- SERC may allow fuel and power purchase cost adjustment to DISCOM.

Any other matter related to above, including design related issues on DSM and AncillaryServices.

- Over drawl above 50.05Hz should be proportionately incentivized and for under drawlduring high frequency (i.e. 50.10Hz and above) should be penalized.
- Introduction of sign change violation for non-supportive grid operation (i.e. UD at highfrequency and vice versa) at change over block.
    - State A is overdrawing since last five block
    - At 6th block if frequency is high then A will not be penalised for sign changeviolation because it is supporting the grid.
- Rationalize DSM rate for under drawl with volume cap up to 50.03 Hz and no volumecap at frequency between 50.03 Hz to 50.05 Hz.

- UD up to 50.03 Hz volume limit is 100 and 200 MW.
- But above 50.03 Hz and up to 50.05 Hz no volume limit !!!

- As present, cost of renewable is equal to or less than conventional, therefore DSMregulation should be uniform with less DSM rate for RE.
- Removal of anomaly for effect of revision between RE and conventional power.

Further Suggestions: -

- Fast Track Implementation of storage solutions for balancing to be funded byPSDF/Govt. grant.
- Model based demand forecasting with periodically accurate weather input.
- Implementation of intra state DSM.

11.3 Annexure 3

Minutes of Meeting (MoM) for the 2nd Meeting of the FOR Working Group

MINUTES OF THE SECOND MEETING OF THE "EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Venue	:	CERC, New Delhi
Date	:	05 April 2023
List of Participants	:	Annexure-1 (Enclosed)

1. The Second Meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations" was held on 05 April 2023 at CERC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). Chief, RA (CERC) welcomed all members and participants and highlighted the following two takeaways from the 1st

meeting: data analysis of buyers and sellers over the past one year and invitation to subject experts for the 2nd meeting. Chief, RA (CERC) gave an overview of the data analysis conducted by Consultant to the Expert Committee. One sample week per month was considered for the past 15 months and frequency, schedule, and actual at 15-min intervals was analyzed for key buyers and sellers in WRPC, SRPC, and NRPC. The Chairperson highlighted that the main objective was to analyze if there has been any change in behaviour of buyers and sellers before and after the DSM Regulations 2022 came into effect. The Chairperson also highlighted that while frequency fluctuations were manageable, what was worrisome was the increase in extremes and peaks in frequency with the new regime.

Agenda 1: Minutes of the First Meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations".

1. The minutes were confirmed with no changes or further discussions.

Agenda 2: Behavioural Analysis of Buyers and Sellers before and after DSM Regulations, 2022

2. The Consultant presented a detailed data analysis of behaviour of buyers and sellers before and after DSM Regulations 2022. 3 sellers and 4 buyers from each of WRPC, SRPC, and NRPC were identified for analysis. One sample week per month was considered for the previous 15 months (January 2022 – March 2023) and 15-min data of frequency, scheduled drawal/injection, and actual drawal/injection was compiled. Analysis was computed w.r.t deviation, correlation of frequency with deviation, and deviation in times of low and high frequencies.
3. It was discussed that correlation between frequency and deviation is less than +/- 0.5 for most months across all entities, and however the frequency within the bandwidth of 49.9 to 50.05 has been less than 80% post regulation as compared to previous months except in the month of April 22.
4. It was expressed that there is general agreement among generators that during the previous regime, they would proactively do small manual interventions when the frequency would fluctuate, which would have a collective effect on stabilizing the frequency. However, it would be difficult to demonstrate this behaviour through data analysis. Hence, it would be important to look at data analysis with this context.

Agenda 3-A: Presentation by Shri. Bhanu Bhushan (Ex-Member, CERC)

5. Shri. Bhanu Bhushan (Ex-Member, CERC) remarked that for 15 February 2023 and 24 March 2023 that there are consistently four frequency peaks in one hour. He highlighted the following two potential reasons behind frequency fluctuations:
    a. No free governor operation or primary response, without which there is little point of secondary and tertiary response.
    b. Scheduling in steps of 15-minute intervals.
6. He explained that while demand & generation ramp is a gradual curve / straight line, but the schedule is in steps which leads to fluctuations. He opined that by making the schedule to "float" or be "step-less" into a gradual curve / straight line may reduce fluctuations. A recommended way of implementing "step-less" scheduling would be to allow entities to declare schedule by factoring for ramp rate instead of a sudden step change. Further, once governors are put in action, then reserves (primary, secondary, tertiary) may be considered.
7. It was noted that while schedule is in steps, actual is similar to demand in the sense that it is a gradual curve / straight line. Participants discussed whether and how much changing the methodology of declaring schedules would help in controlling frequency fluctuations.
8. It was also noted that scientifically driven demand forecasting is critical to control deviation and frequency fluctuations.
9. Additionally, it was noted that states would need support to implement free governor mode of operation of intra-state generators.

Agenda 3-B: Shri. Rakesh Nath (Ex-Member, APTEL)

10. Shri. Rakesh Nath expressed that the situation wasn't bad in the old regime and while change may have been necessary, it was sudden and drastic.
11. He noted that the area control error correction is with states and unless and until the states are well equipped, DSM cannot solve everything.
12. He noted that a new resource adequacy planning has to be ensured by state regulators at state level as the old method may not work with increasing RE penetration.
13. He expressed that frequency linking may not solve everything but was still better than no linkage at all.
14. He expressed that it would be important to look at the whole scheme and formulate solutions.

Action Points/Decisions

1. Next meeting is tentatively scheduled for 26 April 2023 @ Grid-India to discuss the following:
    a. Simulation of "step-less" scheduling for one sample historical day/week.
    b. Analysis of 1-min data before and after DSM Regulations 2022.
    c. Contribution of RE towards deviations.
    d. Structure of incentives/disincentives beyond tolerance band of 49.90 – 50.05 Hz.
2. Generators may be invited for discussions.

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ANNEXURE-1

LIST OF PARTICIPANTS AT THE "EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Members

Shri. I. S. Jha, Member CERC

Shri. S. R. Narasimhan, CMD Grid-India

Shri. K. K. Sharma, Former Member UPERC (virtual)

Shri. B. B. Mehta, Director, SLDC, Orissa

Shri. Satyanarayan S., Member Secretary, WPRC

Shri. Sushanta Kumar Chatterjee, Chief (RA), CERC

Subject Experts

Shri. Bhanu Bhushan, Ex-Member, CERC

Shri. Rakesh Nath, Ex-Member, APTEL

Other Participants

Shri. Harpreet Singh Pruthi, Secretary CERC

Shri. Awdhesh Kumar Yadav, Chief (Engg), CERC

Smt. Shilpa Agarwal, Jt. Chief (Engg), CERC

Shri. Sameer Saxena, ED, Grid-India

Smt. Rashmi Nair, Dy. Chief (RA), CERC

Shri. Ravindra Kadam, Advisor (RE), CERC

Shri. Ajit Pandit, Consultant on behalf of USAID

Dr. K. Balaraman, Consultant on behalf of USAID

Smt. Richa Karve, Consultant on behalf of USAID

11.4 Annexure 4

Minutes of Meeting (MoM) for the 3rd Meeting of the FOR Working Group

MINUTES OF THE THIRD MEETING OF THE "EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Venue	:	NLDC, New Delhi
Date and Day	:	26 April, 2023
Time	:	1100 Hrs.
List of Participants	:	Appendix-I **(Enclosed)**

2. The Third Meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations" was held on 26th April, 2023 at NLDC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). He highlighted that the focus of the meeting is on operational aspects of governor control in a generating station/unit. Chief, RA (CERC) welcomed all members and participants and went over the agenda items and action points.

Agenda 1: Confirmation of Minutes of the Second Meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations" held on 05 April 2023.

3. The minutes of the second meeting were confirmed.

Agenda 2: Update on the Action Points from the Previous Meeting.

4. CMD, NLDC appraised the Committee that the simulation of "Step-Less" scheduling for sample data is under process and will be done with subject expert parallelly as it is beyond the terms of reference of the Committee. Chief RA Chief, RA (CERC) updated that 1-minute analysis for a sample day is underway and the consultant will present the analysis in the subsequent meetings.

Agenda 3: Presentation by Shri. Bhanu Bhushan on "DSM and Operation of Turbine Governor".

5. Shri. Bhanu Bhushan (Ex-Member, CERC) explained about the role of turbine governor operation in thermal generating stations along with required coordinated control system (CCS) to manage generation load imbalance in a generating station. He briefed on the governor action in all three modes namely 'Boiler Follow Turbine', 'Turbine Follow Boiler' and 'coordinated'. He remarked that as load increases, more fuel input is required into the boiler which produces more steam which in turn gives more output and governors take less than 30 seconds to restore balance. He explained that there are limits permitted by standards for the governor to sense and when load goes from full load to zero the standard governor droop is 4-5%.

6. He explained that the key functions of the governor are reducing the frequency change, load sharing, and safe operation of the machines. It was discussed that a turbine governor can be made effective by manipulating the setting of load limiter and MW set point. A copy of his presentation is attached at Annexure-I

7. He explained the current fluctuations in the system frequency may need to be studied in detailed for which stepwise scheduling practice may be examined. He further stated that he would like to submit his view on the contemporary design of deviation settlement mechanism in the next meeting.

Agenda 4: Presentation on "Operational Aspects of Governor Control in a Generating Station/Unit".

8. Representatives of the NTPC, NHPC and SJVN made presentation on 'Operational aspects of Coal based Thermal Power Plant Governor Control' highlighting the current practice of RGMO and FGMO in the coal based generating stations. In this presentation, differences between RGMO and FGMO were discussed in detail.

9. It was highlighted that the operating band for RGMO is 49.5 – 50.0 Hz. If frequency increases in that band, governor automatically respond to change in frequency. If

frequency reduces in that band, governor starts responding in steps of 0.03Hz change in frequency. FGMO comes into picture beyond the operating band of RGMO and kicks in case of drop in frequency below 49.5 Hz and increase in frequency above 50.0 Hz. The logic behind introduction of RGMO was to avoid "hunting". It was informed that load set point in a generator is independent of Governor correction through RGMO or FGMO. It was informed that as and when system frequency change is beyond 0.03 Hz, governor of the generating station will kick in. However, under RGMO if the frequency is increasing towards 50Hz from the lower frequency, governor correction would not be activated. Hence, the governor logic is built in such a way that when grid frequency is above reference frequency of 50 Hz primary response would be provided through FGMO as against that when grid frequency is below reference frequency of 50Hz, primary response would be provided through RGMO. Under RGMO governor action has been restricted in case frequency is increasing towards reference frequency from lower system frequency.

10. In response to the query on shifting the governor action mode through FGMO only, it was informed that this may increase the hunting of the generating stations by continuously responding for change in system frequency. It was informed that for handling the mismatch in turbine load and boiler response nowadays calorific value corrections take place automatically. Few concerns were highlighted during the meeting such as AGC correction in some time blocks may be opposite to the schedule ramp requirement. On some occasions AGC correction signals by default negate the DSM intervention required from the generation in case the frequency is beyond operating band. It was suggested that presently implemented AGC system be modified to simplify the telemetered correction as direct deltaP from AGC instead of difference between NLDC common LSP and sum of individual ULSP.

11. CMD Grid-India highlighted that adequate primary response is not being provided in response to routine grid frequency variation observed in most of the days. Primary response is being observed only during contingency events in the grid.

Action Points

1. Generators may submit their observations, and recommendations on the governor response mechanism presently deployed in the generating stations.

2. Grid India may consult NTPC, NHPC and SJVN to address the concerns over primary response and outcomes may be discussed in the next meeting.

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APPENDIX-I

LIST OF PARTICIPANTS AT THE "EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Members

Shri I. S. Jha, Member, CERC

Shri S. R. Narasimhan, CMD, Grid-India

Shri K. K. Sharma, Former Member, UPERC (virtual)

Shri B. B. Mehta, Director, SLDC, Orissa

Shri Satyanarayan S., Member Secretary, WPRC

Dr. Sushanta Kumar Chatterjee, Chief (RA), CERC

Subject Experts

Shri Arun Goyal, Member, CERC

Shri Bhanu Bhushan, Ex-Member, CERC

Shri Rakesh Nath, Ex-Member, APTEL

Other Participants

Shri Harpreet Singh Pruthi, Secretary, CERC (Virtual)
Shri Awdhesh Kumar Yadav, Chief (Engg), CERC
Smt. Shilpa Agarwal, Jt. Chief (Engg), CERC
Smt. Rashmi Nair, Dy. Chief (RA), CERC (Virtual)
Shri Ravindra Kadam, Senior Advisor (RE), CERC
Shri Sameer Saxena, ED, NLDC, Grid-India
Shri Rajeev Porwal, ED, NRLDC, Grid India
Shri Neeraj Kumar, GM, Grid India
Shri Suraj Dhiman, GM (O &M), NHPC
Shri Vijay Kumar, GSM, NHPC
Shri G. S. Rao, GM (OS- SIIS) NTPC
Shri C.K. Samasta, CGM, NTPC

Shri S.K. Meena, GSM (E), NHPC
Shri J. Pani, NTPC
Shri Rajeev Agarwal, DGM, SJVN
Shri Ajit Pandit, Consultant on behalf of USAID
Smt. Richa Karve, Consultant on behalf of USAID
Shri Devesh Khattar, SAREP

11.5 Annexure 5

Minutes of Meeting (MoM) for the 4th Meeting of the FOR Working Group

MINUTES OF THE FOURTH MEETING OF THE "EXPERT COMMITTEE FOR

ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY

RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Venue : NRLDC, New Delhi

Date : 14 August, 2023

Time : 1100 Hrs.

List of Participants : Appendix-I (Enclosed)

1. The Fourth Meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations and suggesting remedial measures" was held on 14 August, 2023 at NLDC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). Chief, RA (CERC) welcomed all members and participants and went over the agenda items.

Agenda 1: Confirmation of Minutes of the Third Meeting of the "Expert Committee for Analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations" held on 26th April, 2023.

2. The minutes of the third meeting were confirmed by the members of the expert committee.

Agenda 2: Presentation by Shri Bhanu Bhushan on "DSM"

3. Shri. Bhanu Bhushan (Ex-Member, CERC) delivered a presentation (***Annexure – I***) on DSM covering its inception and essential features. He further delved into the methodology for accounting deviations and the criteria for pricing them and explained the rationale behind the utilization of 15-minute time-blocks in DSM calculations. He stated that in the original scheme of Availability Tariff and UI, frequency was used as the universal indicator of the SMP, since it was a measure of the maximum of the variable costs of the power plants, arranged as per merit-order, which had to be run. Now that the frequency is maintained at around 50.0 Hz and is no longer an indicator of SMP, it will not be logical to use it in pricing of deviations in any manner. He suggested that the frequency should be managed through governor control by the generator and better load forecasting by the discoms. He further added that the pricing of deviation should be based on System Marginal Price (SMP), and also suggested incentive/disincentive for load forecasting of the discoms and frequency response of the generators to achieve the desired result of frequency within operating band.

4. The members of the expert committee noted the observations and suggestions of Shri Bhanu Bhushan.

Agenda 3: Update on operational aspect of governor control by Grid-India

5. CMD, NLDC appraised the Committee that there has been improvement in the system frequency. He highlighted that the frequency of the grid is now being maintained within the operative band for 87% of the time. The performance of AGC has improved due to various initiatives taken by NLDC in consultation with AGC enabled generators. He also highlighted that variation in the availability of wind and solar generation due to weather condition is putting stress on the system operations and Recourse Adequacy still remain a major concern to maintain the reserves in the system. Further, the scheduled maintenance of the thermal stations has also led to scarcity of the resources. During the week starting 6th August, the system has seen instances when all the resources available at disposal were utilised completely to meet the demand.

6. Thereafter, representatives from NLDC made the presentation (***Annexure – II***) on the steps taken by the NLDC to meet the demand and the Trial Run carried by NLDC to improve the performance of AGC which has been providing the following services:-
    1) Generation changes in response to outages
    2) Load following during RE integration (morning and evening peak following)
    3) Minute to minute regulations

7. It was informed that as directed in the 3rd Meeting of the Expert Group, several meetings were also carried with members of NTPC to understand their concerns and to discuss the step – by- step modifications needed to improve performance of AGC. It has been decided that NLDC shall operate the control areas in flat frequency control mode by default, for ensuring economy in the grid. In case of congestion or anticipated congestion, with flows from or towards any area exceeding or nearing the Available Transfer Capability (ATC) limits, the Nodal Agency shall operate such areas in tie-line bias mode. If there are any radial control areas with commercial or technical requirements of strict adherence to tie-line schedules, such areas can be operated in flat tie-line control mode. Also, the Nodal Agency shall operate one or more power plants or control areas, in suspended mode, for reasons like intermittent communication, reboots, software updations, etc.

8. It was also informed that NLDC has carried trial runs based on 20 plants of NTPC, to assess the performance of AGC under the following mode of operations:
    1) Response delays of thermal power plants (29th April to 2nd May, 2023)
    2) Tie-line bias mode of operation (14th May, 2023)
    3) Constant frequency mode of operation with revised settings (30th May, 2023 to 5th June, 2023)
    4) Constant frequency mode of operation with improved settings (7th July to 2nd August, 2023)

9. During the presentation the results of the trial runs along with the observations of the NLDC on the trail runs were also discussed in detail. NLDC informed that due to the various steps identified under trial runs the response time of AGC has improved considerably and the ramp rate of the power plants has also been increased from 1% to

1.5%for super critical units and up to 2% for sub critical units. It was informed that without ancillary support the frequency remained within the band for about 26.8% of the time (with 84 nos. of 50 Hz crossing) while with SRAS support the frequency remained within the band for about 73.1% of the time (with 184 nos. of 50 Hz crossing) and that with SRAS and TRAS support the frequency remained within the band for about 83.8% of the time (with 379 nos. of 50 Hz crossing). The Committee appreciated the efforts of NLDC and Generators to improve the performance of Secondary reserves services and suggested to follow similar approach to address the concerns regarding primary reserves services.

Agenda 4: Presentation on the alternative proposal of FRO linked DSM

10. A presentation was made (***Annexure – III***) on the alternative proposal of FRO linked DSM, by the USAID supported consultant assisting the Expert Group. The members deliberated on the proposal and noted their concern related to using a power plant as a control area. The members suggested that it may not be possible for the power plant to perform frequency response obligation (FRO) for improving the area control error when the plant is already running under full schedule condition as there will not be any spare capacity available to meet the FRO.

11. The members suggested the consultant to explore other solutions through which the plants may be motivated to provide primary response.

Action Points:

12. The members of the expert committee directed the NLDC to:
    a) analyse the primary response and AGC support provided by all plants and to present its report during the next meeting.
    b) explore the possibility of including the state-owned generation plants to provide primary support in the interest of grid and the incentive and penalty mechanism thereof.

13. The meeting ended with a vote of thanks to the chair.

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Appendix-I

LIST OF PARTICIPANTS AT THE "FOURTH MEETING OF THE EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSEWITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Members

Shri. I. S. Jha, Member CERC
Shri. S. R. Narasimhan, CMD Grid-India
Shri. K. K. Sharma, Former Member UPERC (virtual)
Shri. B. B. Mehta, Director, SLDC, Orissa (virtual)
Shri. Sushanta Kumar Chatterjee, Chief (RA), CERC

Subject Experts

Shri. Bhanu Bhushan, Ex-Member, CERC
Shri. Rakesh Nath, Ex-Member, APTEL

Other Participants

Shri. Harpreet Singh Pruthi, Secretary, CERC
Shri. Awdhesh Kumar Yadav, Chief (Engg), CERC
Smt. Shilpa Agarwal, Jt. Chief (Engg), CERC
Shri. Sameer Saxena, ED, Grid-India
Shri Rajeev Porwal, ED, NRLDC, Grid-India
Shri Vivek Pandey, GM, Grid-India
Shri Phanisankar Chilukuri, CM, NLDC, Grid-India
Shri. Ravindra Kadam, Advisor (RE), CERC (virtual)
Smt. Sukanya Mandal, AC (RA), CERC
Dr. K. Balaraman, Idam Infra Consultant on behalf of USAID
Shri. Saurabh, PRO, CERC (virtual)
Smt. Nausheen, RA, CERC

11.6 Annexure 6

Minutes of Meeting (MoM) for the 5th Meeting of the FOR Working Group

MINUTES OF THE FIFTH MEETING OF THE "EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Venue	:	CERC, New Delhi
Date and Day	:	21 September 2023
Time	:	1100 Hrs
List of Participants	:	Annexure-1 (Enclosed)

12. The Fifth Meeting of the "Expert Committee for analyzing the Causes of Inadequate Primary and Secondary Response with respect to Implementation of DSM Regulations" was held on 21 September 2023 at CERC, New Delhi, under the chairmanship of Shri. I. S. Jha (Member, CERC). Chief, RA (CERC) welcomed all members and participants and went over the agenda items and action points.

Agenda 1: Presentation by Prof. Nicholas Ryan on "Deviation Settlement Mechanism: Design Principles and Proposed Revisions".

13. At the start of the presentation, Prof. Ryan highlighted that the DSM is an imbalance pricing mechanism by putting incentive and disincentive mechanism on deviations. He explained that data analysis of historical performance (29 August 2022 to 16 April 2023) was carried out to observe performance of various sellers and buyers under the DSM Regulations 2022.

14. He remarked that solar and wind sellers were observed to over-schedule and under-inject, with magnitude of this behaviour higher for wind than for solar. He remarked that tightening the tolerance band down to +/- 5% would avoid this behaviour and encourage accurate forecasting. He further recommended a much lesser per unit charge for deviations from solar and wind sellers. Prof. Ryan also recommended an additional voluntary feature of opting for public forecasts by REMC, in which case sellers would be exempt from deviation charges.

15. Prof. Ryan highlighted that thermal sellers in some parts were seen to under-schedule and over-inject, likely due to asymmetry in structure and switching between normal and reference rates. Applying a tighter tolerance band and symmetrical and linear charges would avoid such behaviour. He highlighted that similar asymmetry in charges for buyers which in turn had potential to cannibalize the ancillary services.

16. Given the above observations, Prof. Ryan presented the following proposed changes to DSM Regulations, 2022:

    a. Tighter tolerance band of +/- 5% for sellers to encourage accuracy of forecasts.

    b. Symmetric and linear charges for general sellers and buyers within tolerance band and for under-injection/drawal and over-injection/drawal to avoid any perverse incentive.

    c. Removal of incentive/penalty parameters for over-injection/under-drawal during low frequency and under-injection/over-drawal during high frequency to encourage reliance on ancillary services.

17. The members noted the suggestions of Prof Ryan on the nature of asymmetric charges in the current DSM design. The members also deliberated that solar and wind sellers currently have the option to opt for public forecasts but presently most of them don't, and that forecasts from developers are found to be much more accurate. However the Members appreciated the efforts put by Prof Ryan on the behavioural analysis of the entity under current DSM Regulations and recommended further deliberation on the symmetric nature of DSM charges in the subsequent meeting.

Agenda 2: Presentation by Shri. Satyanarayan S. on "Correcting the Runway Frequency Problem – Tools at our Hands".

18. In the presentation, Shri. Satyanarayan remarked that since schedules can be changed every 15 minutes, there is bound to be frequency fluctuation. He highlighted that SLDCs can correct schedules only within internal resources, while the central sector cannot change schedules for 7-8 blocks (~2 hours). This leads to the under-utilization of unused schedules/reserves from the central sector. Shri. Satyanarayan further added that runway frequency was a time-block problem, and that avg. 2-hr delay and resource-wise under-utilization of central schedules/reserves should be corrected.

19. For the same, he proposed introducing SLDC and RLDC corrections in schedules without disturbing the overall structure, by allowing SLDC to use all resources (including central) for their corrections.

20. The members noted the suggestions of Shri Satyanarayan.

Agenda 3: Presentation by Grid-India on "CERC Expert Group to Review the Principles of DSM".

21. In the presentation, representatives of Grid-India highlighted that a time lag of 15-20 seconds was observed in output change of generators after receiving signal, due to high scan rate and other technical reasons related to boilers, which defeated the purpose of primary response. Additionally, they highlighted that some thermal plants were not able to give primary response due to technical constraints.

22. They remarked that a clear difference in controller logic could be seen in July 2022 and February 2023, likely due to revisions in DSM. They explained that while the generators were behaving as per technical characteristics, the control signal had been modified. However, they added that they were getting good response in times of contingency and that the underlying challenge was resource adequacy.

23. Grid-India highlighted that further integration under AGC has been planned and workshops are being conducted for interested states and their ISTS generators. However, they added that there is a need for establishing real-time communication between SLDC software and Grid-India.

24. They remarked that while PRAS and SRAS response is automatically driven by controller settings, TRAS signal was entirely with Grid-India. The members deliberated on whether manual control settings on PRAS and SRAS were causing frequency excursions.

Action Points:

25. The Members of the Committee decided to deliberate in the next meeting as follows:

    3. Formulations on suggested remedial measures to be deliberated in the next meeting.

    4. Recommendations to be presented (Draft PPT and Draft Report) in next Expert Committee meeting .

26. The Meeting ended with vote of thanks to the Chair.

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ANNEXURE-1

LIST OF PARTICIPANTS AT THE "EXPERT COMMITTEE FOR ANALYZING THE CAUSES OF INADEQUATE PRIMARY AND SECONDARY RESPONSE WITH RESPECT TO IMPLEMENTATION OF DSM REGULATIONS"

Members

Shri. I. S. Jha, Member CERC
Shri. S. R. Narasimhan, CMD Grid-India
Shri. S. S. Barpanda, Grid-India
Shri. Sameer Saxena, Grid-India
Shri. K. K. Sharma, Former Member UPERC (virtual)
Shri. Satyanarayan S., Ex-Member Secretary, WPRC (virtual)
Shri. Sushanta Kumar Chatterjee, Chief (RA), CERC

Subject Experts

Shri. Arun Goyal
Shri. Kaushal Kishore Sharma (virtual)

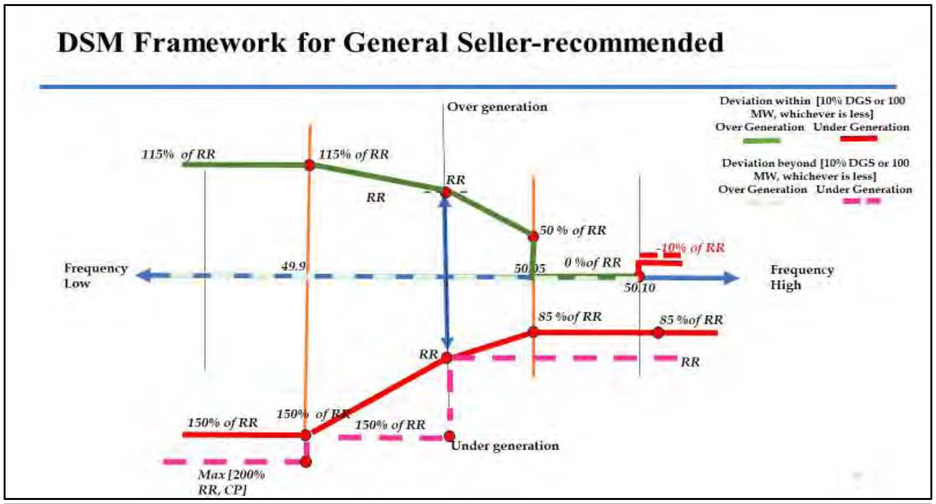
Special Invitees

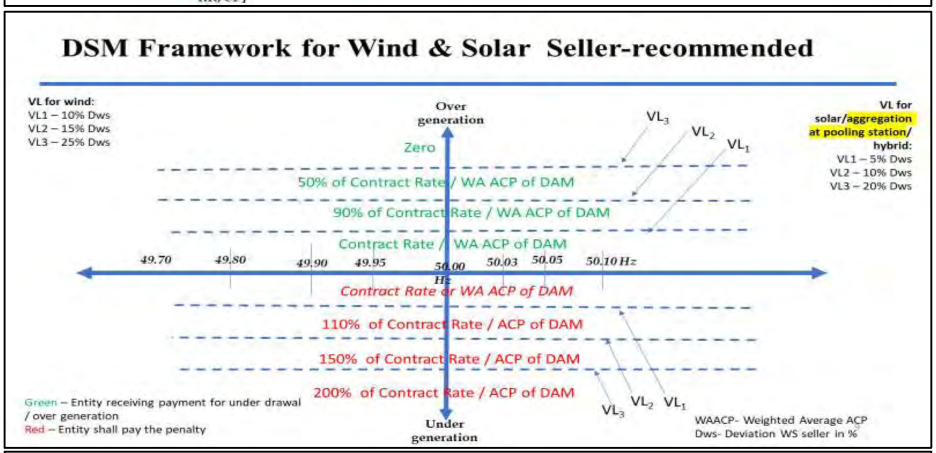
Shri. Nicholas Ryan (virtual)
Shri. Yashwanth Reddy

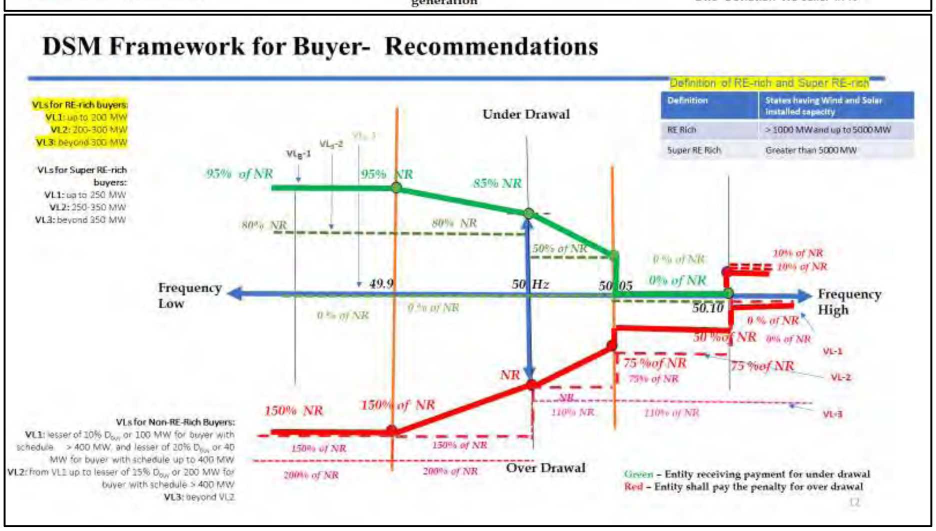
Other Invitees

Shri P.D. Lone, Director, WRPC
Shri. Harpreet Singh Pruthi, Secretary CERC (Virtual)
Shri. Awdhesh Kumar Yadav, Chief (Engg), CERC
Smt. Shilpa Agarwal, Jt. Chief (Engg), CERC
Shri. Ravindra Kadam, Advisor (RE), CERC
Shri. Saurabh Derhgaven, CERC
Shri. Ajit Pandit, Consultant on behalf of USAID
Smt. Richa Karve, Consultant on behalf of USAID

11.7 Annexure 7 Simple Schematic of Recommendation on Design Aspect







11.8 Annexure 8

Draft Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024

CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

No. L-1/260/2021/CERC Dated: ** December, 2023

Preamble

Whereas it is necessary to provide for a regulatory mechanism for treatment and settlement of deviation from schedule of drawal or injection of electricity in the interest of reliability, security and stability of the grid, it is hereby specified as follows:

NOTIFICATION

No. L-1/260/2021/CERC - In exercise of the 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), and all other powers enabling it in this behalf, and after previous publication, the Central Electricity Regulatory Commission hereby makes the following regulations, namely:

1. **Short title and commencement**

(1) These regulations may be called the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2024.

(2) These regulations shall come into force on such date as may be notified by the Commission separately.

2. **Objective**

These regulations seek to ensure, through a commercial mechanism, that users of the grid do not deviate from and adhere to their schedule of drawal and injection of electricity in the interest of security and stability of the grid.

3. Definitions and Interpretation

(1) In these regulations, unless the context otherwise requires, -

(a) **'Act'** means the Electricity Act, 2003 (36 of 2003);
(b) '**actual drawal'** in a time block means the electricity drawn by a buyer, measured by the interface meters;

(c) **'actual injection'** in a time block means the electricity injected by the seller, measured by the interface meters;

(d) **'Ancillary Services'** means the Ancillary Services as defined in the Ancillary Services Regulations;

(e)**'Ancillary Services Regulations'** means the Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 as amended from time to time and shall include any re-enactment thereof;

(f) **'Area Clearing Price' or 'ACP'** means the price of electricity contract for a time-block transacted on a Power Exchange after considering all valid buy and sale bids in particular area(s) after market-splitting;

(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;

(h)'**Buyer**' means a person purchasing electricity through a transaction scheduled in accordance with the Grid Code;

(i) **'Commission'** means the Central Electricity Regulatory Commission referred to in sub-section (1) of Section 76 of the Act;

(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;

(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 means its total actual drawal minus its total scheduled drawal, and shall be computed as per Regulation 6 of these regulations;

(l) **'Deviation and Ancillary Service Pool Account'** means the Account to be maintained and operated by the concerned Regional Load Despatch Centre in each region as per Regulation 9 of these 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;

(n)**'Grid Code'** means the Grid Code specified by the Commission under clause (h) of sub-section (1) of Section 79 of the Act;

(o) **'Interface meters'** means interface meters as defined under the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time and any re-enactment thereof;

(p)**'Load Despatch Centre'** means National Load Despatch Centre, Regional Load Despatch Centre or State Load Despatch Centre, as the case may be;

(q)**'Normal Rate of Charges for Deviation (NR)'** means the charges for deviation (in paise/kWh) as referred to in Regulation 7 of these regulations;

(r) **'Open Access Regulations'** means the Central Electricity Regulatory Commission (Open Access in inter-State Transmission) Regulations, 2008 as amended from time to time and shall include any re-enactment thereof;

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

(t) **'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;

(u) **'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;

(v)**'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;

(w) '**Run-of-River Generating Station**' or '**RoR generating station**' means a hydro generating station which does not have upstream pondage;
'Scheduled generation' or 'Scheduled injection' for a time block or any period means the schedule of generation or injection in MW or MWh ex-bus including the schedule for Ancillary Services given by the concerned Load Despatch Centre;

(x)**‘Scheduled drawal’** for a time block or any period means the schedule of drawal in MW or MWh ex-bus including the schedule for Ancillary Services given by the concerned Load Despatch Centre;

(y)**‘‘Seller’** means a person, including a generating station, supplying electricity through a transaction scheduled in accordance with the Grid Code;

(z) **‘Time Block’** means the time block as defined in the Grid Code;

(aa) **‘WS seller’** means a seller in case of a generating station based on wind or solar or hybrid of wind-solar resources.

(2) Save as aforesaid and unless repugnant to the context or the subject matter otherwise requires, words and expressions used in these regulations and not defined, but defined in the Act, or any other regulation of this Commission shall have the meaning assigned to them respectively in the Act or any other regulation.

4. Scope

These regulations shall be applicable to all grid connected regional entities and other entities engaged in inter-State purchase and sale of electricity.

5. Adherence to Schedule and Deviation

(1) For a 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 to not deviate from its schedule.

(2) Deviation shall generally be managed through 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.

6. Computation of Deviation

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

Deviation-general seller (D_{GS}) (in MWh) = [(Actual injection in MWh) – (Scheduled generation in MWh)].

Deviation-general seller (D_{GS}) (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 (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)].

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

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

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

7. Normal Rate of Charges for Deviations

(1) The Normal Rate (NR), for a particular time-block, shall be equal to the Weighted Average of:

(a) ACP (in paise/kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges

(b) ACP (in paise/kWh) of the Real Time Market segments of all the Power Exchanges

(c) 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 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.

Provided further that in case of no despatch of Ancillary services in a time block or net charges for Ancillary services (due factoring Up and Down cost) is receivable in Deviation and Ancillary Service Pool Account, in that case Ancillary Service Charge and volume shall not be considered for computation of Normal Rate (NR).

Alternatively,

The Normal Rate (NR), for a particular time-block, shall be equal to:

(a) ACP (in paise/kWh) of the Integrated-Day Ahead Market segments of all the Power Exchanges (1/3rd weight)

(b) ACP (in paise/kWh) of the Real Time Market segments of all the Power Exchanges (1/3rd weight)

(c) 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 (1/3rd weight)

Provided further that in case of no despatch of Ancillary services in a time block or net charges for Ancillary services (due factoring Up and Down cost) is receivable in Deviation and Ancillary Service Pool Account, in that case 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.

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

8. Charges for Deviation

(1) Charges for Deviation, in respect of a **general seller <u>other than</u> 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 upto [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 upto [10% D_{GS} or 100 MW, whichever is less] and f <u>outside</u> 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]

<table>
<tr><td>(ii) @ 115 % of RR when [f < 49.90 Hz]</td><td>iv) @ 150 % of RR when [f < 49.90 Hz]</td></tr>
<tr><td colspan="2">(III) For Deviation beyond [10% D_{GS} or 100 MW, whichever is less] and f within and outside f_{band}</td></tr>
<tr><td>(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]</td><td>(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]</td></tr>
</table>

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

For under injection of seller/generator selling in HP-DAM the following provision may be added to avoid any gaming:

"Provided that for a Seller whose bid is cleared in the HP-DAM, the deviation charge by way of 'under-injection' for a time block shall be equal to the highest of the weighted average ACP of the HP-DAM Market segments of all the Power Exchanges; or the RR for that time block in which the seller has sold power though HP-DAM.

(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 [*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*].

(3) Charges for Deviation, in respect of a **general seller being a generating station based on municipal solid waste** 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) @ 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}].

(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 <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) 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 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% D_{ws} 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% D_{ws} and up to 25% D_{WS}

(5) Charges for Deviation, in respect of **a WS Seller being a generating station based on wind or solar or hybrid of wind with storage**

(a) The net payable or receivable shall be further distributed among the generator through

Actual generation.

(b) This is a case of multiple generators and having different sets of contract, the Reference rate (RR) of such generators shall be the weighted average DAM price.

Deviation by way of over injection (Receivable by Lead genrator)	**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 paybale zero up to 5% or 50MW.**	
(II) **For Deviation from 5% to 10% D_{GS} or greater than 50 MW upto 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}**	
(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]

(6) 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 ≤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 ≤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 ≤ 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 ≤ 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 ≥ 50.10 Hz];	(iii) @ 50% of NR when [50.05 Hz < f < 50.10 Hz]: (iv) @ zero when [f ≥ 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 ≤ 50.00 Hz; (ii)@ 50% NR when [50.00 Hz < f ≤ 50.05 Hz]; @ zero when [50.05 Hz < f < 50.10 Hz]: Provided that such buyer shall pay @ 10% of NR when [f ≥ 50.10 Hz];	(iii) @ 150% of NR when f ≤ 50.00 Hz; (iv) @ NR when [50.00 Hz ≤ f ≤ 50.05 Hz]; @ 75% NR when [50.05 Hz < f < 50.10 Hz]; @ zero when [f ≥ 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 other than (the buyer with 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 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

(7) Charges for Deviation, in respect of a Standalone Energy Storage System (ESS) or an ESS with co-located with wind or solar generating station or both, shall be at par with the charges for Deviation for a **general seller <u>other than</u> an RoR generating station or a generating station based on municipal solid waste or WS seller** as specified in Clause (1) 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 upto 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 <u>outside</u> f_{band}**	
(i) @ zero when [50.05 Hz < f < 50.10 Hz]:	(iii) @ 85 % of RR when [f > 50.05 Hz]

Deviation by way of over injection (Receivable by Lead generator)	**Deviation by way of under injection (Payable by the lead generator)**
Provided that such seller shall pay @ 10% of RR when [f ≥ 50.10 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}**	
(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:

(i) These hybrid entities shall be considered as a seller.
(ii) During injection schedule or drawal schedule in case of drawing pumping power/charging power from grid shall be considered as generator only.
(iii) Schedule shall be prepared separately for each type of generator. This shall help to understand the different profile of each generator.
(iv) Each generator shall be metered with SEM so that individual actual injection/drawal can be captured.
(v) The DSM shall be computed based on the Net schedule i.e. sum of all generator schedule injecting/drawing power and net actual injection/drawal at common bus.
(vi) There shall be a lead generator who shall take responsibility of scheduling and DSM payment liabilities towards pool on behalf of all the generators.
(vii) The net payable or receivable shall be further distributed among the generator through any of the below given option in proportion of their:
   a. Deviation from the schedule;
   b. Schedule; or
   c. Actual generation
(viii) Reference rate (RR) of such generators as the weighted average DAM price

(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.

(9) The charges for deviation for drawal of start-up power before COD of a generating unit or for drawal of power to run the auxiliaries during 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.

(10) The charges for inter-regional deviation caused by way of over drawal or under drawal or over injection or under-injection shall be payable or receivable, as the case may be, at the normal rate of charges for deviation.

(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 respective category) or to a buyer (other than an RE-rich State or a Super RE-rich State), as the case may be.

(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.

(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.

(14) 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.

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 mid-night 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 regulation;

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

(b) payment to 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, 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 in the ratio of [50% in proportion to their drawal at the regional periphery] and [50% in proportion to their GNA][6].

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 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 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.

11. Power to Relax

The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these regulations on its own motion or on an application made before it by the affected party.

12. Power to Remove Difficulty

If any difficulty arises in giving effect to these regulations, the Commission may on its own motion or on an application filed by any affected party, issue such practice directions as may be considered necessary in furtherance of the objective of these regulations.

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[6] Or as may be decided by the Commission from time to time.

13. Repeal and Savings

(1) Save as otherwise provided in these regulations, the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022 shall stand repealed from the date of commencement of these Regulations.

(2) Notwithstanding such repeal, anything done or any action taken or purported to have been done or taken including any procedure, minutes, reports, confirmation or declaration of any instrument executed under the repealed regulations shall be deemed to have been done or taken under the relevant provisions of these regulations.

Secretary

12 Appendix

12.1 Appendix 1

12.1.1 Western Region Buyers

This section consists of the summary of the four-quadrant operation for selected Buyers from the Western region.

12.1.1.1 Maharashtra:

Table A1-1 shows the summary of the four-quadrant analysis of Maharashtra buyers from the Western region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-225	-228	-310	-191	-233	-302	-209	-198	-227	-246	-162	-173	-162	-173	-159
Max. OD	123	133	274	290	172	192	183	273	158	293	166	257	179	224	226
Deviation Spread (Max – Min)	348	361	584	481	405	494	392	471	385	539	328	431	341	397	385
Correlation of Freq < 50 Hz with Deviation	0.08	-0.02	-0.24	-0.01	-0.01	0.15	-0.01	-0.14	0.12	-0.07	0.04	0.10	0.05	-0.15	-0.15
Correlation of Freq >= 50 Hz with Deviation	-0.06	0.16	-0.22	-0.16	0.05	-0.22	-0.02	0.22	-0.12	-0.03	0.02	-0.03	0.04	-0.09	-0.05
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	93%	94%	84%	73%	83%	80%	85%	81%	98%	93%	92%	77%	78%	88%	86%

Table A1-1: Summary of Four Quadrant Analysis for Maharashtra Buyer

12.1.1.2 Gujarat

Table A1-2 shows the summary of the four-quadrant analysis of Gujarat buyers from the Western region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-200	-187	-350	-221	-408	-227	-372	-421	-444	-275	-196	-326	-232	-236	-314
Max. OD	155	298	162	147	33	190	245	309	185	178	147	227	230	307	305
Deviation Spread (Max – Min)	355	484	512	367	441	417	618	730	629	453	343	552	462	543	619
Correlation of Freq < 50 Hz with Deviation	-0.05	-0.04	-0.11	-0.16	-0.08	-0.03	-0.15	-0.16	-0.11	-0.07	-0.01	-0.11	-0.20	-0.19	-0.02
Correlation of Freq >= 50 Hz with Deviation	-0.17	-0.20	-0.31	-0.12	-0.20	-0.09	-0.09	-0.03	-0.34	-0.03	-0.13	-0.02	-0.20	-0.18	-0.07
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	93%	94%	83%	73%	74%	81%	84%	78%	95%	93%	92%	77%	78%	88%	85%

Table A1-2: Summary of Four Quadrant Analysis for Gujarat Buyer

12.1.1.3 Madhya Pradesh:

Table A1-3 shows the summary of the four-quadrant analysis of Madhya Pradesh buyers from the Western region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-236	-254	-146	-194	-309	-192	-199	-286	-306	-245	-226	-156	-312	-162	-212
Max OD	117	123	235	277	302	202	131	279	164	118	128	115	163	251	186
Deviation Spread (Max – Min)	352	377	380	471	610	394	330	565	470	363	354	271	475	413	398
Correlation of Freq < 50 Hz with Deviation	-0.11	-0.05	-0.06	-0.31	0.11	0.09	-0.03	-0.15	-0.24	0.05	-0.25	0.09	-0.27	-0.23	-0.13

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Correlation of Freq >= 50 Hz with Deviation	0.02	-0.05	0.04	-0.26	-0.14	-0.06	-0.03	-0.17	-0.11	-0.28	-0.16	-0.10	-0.13	-0.13	-0.12
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	93%	94%	84%	73%	81%	81%	85%	81%	98%	94%	92%	77%	78%	88%	86%

Table A1-3: Summary of Four Quadrant Analysis for Madhya Pradesh

12.1.2 Western Region Sellers

This section consists of the summary of the four-quadrant operation for selected Sellers from the Western region.

12.1.2.1 VSTPS:

Table A1-4 shows the summary of the four-quadrant analysis of VSTPS Seller from the Western region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-15	-42	-46	-47	-27	-13	-19	-37	-36	-51	-40	-18	-9	-6	-24
Max OI	28	41	27	15	55	23	30	55	67	51	13	34	2	6	5
Deviation Spread (Max – Min)	43	83	73	62	82	36	49	93	103	101	53	52	11	12	30
Correlation of Freq < 50 Hz with Deviation	0.02	-0.06	0.02	0.17	-0.15	-0.16	-0.05	-0.06	0.11	0.14	0.05	-0.06	-0.26	-0.31	-0.16
Correlation of Freq >= 50 Hz with Deviation	-0.17	-0.17	-0.02	-0.24	0.08	-0.38	-0.34	0.36	0.01	0.04	-0.08	-0.20	-0.19	-0.37	-0.23

% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-4: Summary of Four Quadrant Analysis for VSTPS Seller

12.1.2.2 BALCO:

Table A1-5 shows the summary of the four-quadrant analysis of BALCO Seller from the Western region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-58	-15	-46	-67	-27	-62	-21	-28	-56	-68	-37	-36	-80	-29	-16
Max OI	42	23	19	10	87	16	16	20	9	13	11	27	58	14	24
Deviation Spread (Max – Min)	100	38	65	77	113	78	38	48	65	81	48	62	138	43	39
Correlation of Freq < 50 Hz with Deviation	0.02	0.08	-0.01	0.14	0.11	-0.06	-0.00	-0.09	0.16	0.13	-0.14	-0.02	-0.01	0.05	0.04
Correlation of Freq >= 50 Hz with Deviation	-0.10	0.05	0.02	0.17	0.09	0.12	-0.09	0.05	-0.06	-0.11	-0.03	-0.10	-0.00	-0.12	-0.03
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-5: Summary of Four Quadrant Analysis for BALCO Seller

12.1.2.3 SASAN

Table A1-6 shows the summary of the four-quadrant analysis of SASAN Seller from the Western region.

Parameter	31 Ja	14 Fe	14 Ma	11 Ap	16 Ma	13 Ju	11 Ju	15 Au	12 Se	17 Oc	14 No	26 De	16 Ja	13 Fe	27 Fe

	n 22	b 22	r 22	r 22	y 22	n 22	l 22	g 22	p 22	t 22	v 22	c 22	n 23	b 23	b 23
Max UI	-7	-4	-3	-20	-27	-34	-80	-30	-18	-36	-145	-8	-5	3	-34
Max OI	31	30	127	42	55	36	36	38	38	38	37	20	21	28	28
Deviation Spread (Max – Min)	38	34	130	62	82	70	116	67	56	74	183	28	26	25	63
Correlation of Freq < 50 Hz with Deviation	-0.06	-0.07	-0.06	0.05	-0.04	-0.07	0.27	0.08	0.08	0.05	-0.12	-0.12	-0.42	-0.20	-0.09
Correlation of Freq >= 50 Hz with Deviation	-0.42	-0.41	-0.41	-0.39	-0.53	-0.36	-0.40	-0.47	-0.41	-0.43	-0.10	-0.05	-0.61	-0.39	-0.46
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-6: Summary of Four Quadrant Analysis for SASAN Seller

12.1.2.4 SIPAT

Table A1-7 shows the summary of the four-quadrant analysis of SIPAT Seller from the Western region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-14	-20	-28	-13	-52	-26	-59	-140	-81	-117	-160	-41	-45	-38	-84
Max OI	6	5	5	3	8	4	120	64	98	57	26	24	38	7	7
Deviation Spread (Max – Min)	20	25	33	16	60	30	179	204	178	174	187	65	82	45	91
Correlation of Freq < 50 Hz with Deviation	-0.45	-0.33	-0.30	-0.30	-0.22	-0.28	-0.19	-0.23	-0.07	-0.27	-0.16	-0.38	-0.40	-0.43	-0.36

Correlation of Freq >= 50 Hz with Deviation	-0.60	-0.47	-0.44	-0.64	-0.44	-0.55	-0.03	0.16	-0.14	-0.07	-0.26	-0.14	-0.55	-0.53	-0.25
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	92%	59%	86%	90%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-7: Summary of Four Quadrant Analysis for SIPAT Seller

12.1.3 Southern Region Buyer

This section consists of the summary of the four-quadrant operations for selected Buyers from the Southern region.

12.1.3.1 Tamil Nadu

Table A1-8 shows the summary of the four-quadrant analysis of Tamil Nadu Buyer from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-102	-205	-266	-344	-339	-286	-283	-348	-318	-197	-26	-352	-219	-242	-307
Max. OD	293	116	185	167	240	394	392	284	333	169	246	138	283	258	175
Deviation Spread (Max – Min)	394	321	451	511	580	680	675	632	652	366	272	490	502	500	482
Correlation of Freq < 50 Hz with Deviation	-0.09	-0.06	-0.06	-0.02	0.12	-0.17	-0.15	-0.10	0.01	-0.14	-0.05	0.11	-0.24	-0.19	-0.06
Correlation of Freq >= 50 Hz with Deviation	-0.14	-0.16	-0.10	-0.35	-0.35	-0.20	-0.27	0.11	-0.16	-0.23	-0.01	-0.45	0.09	-0.17	-0.10
% of TBs in 49.90 <= F <=	92%	94%	84%	73%	81%	80%	84%	81%	97%	94%	92%	77%	78%	88%	84%

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
50.05 and Deviation +/- 250															

Table A1-8: Summary of Four Quadrant Analysis for Tamil Nadu Buyer

12.1.3.2 Karnataka

Table A1-9 shows the summary of the four-quadrant analysis of Karnataka Buyer from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-177	-203	-161	-304	-403	-310	-195	-180	-218	-265	-176	-232	-243	-282	-332
Max. OD	364	217	159	211	167	187	332	165	156	192	247	243	212	253	138
Deviation Spread (Max – Min)	540	420	321	515	570	497	527	345	375	457	423	476	455	535	470
Correlation of Freq < 50 Hz with Deviation	-0.35	-0.04	-0.08	-0.20	0.08	-0.01	0.06	0.16	0.05	-0.27	-0.12	-0.04	0.05	-0.17	-0.07
Correlation of Freq >= 50 Hz with Deviation	-0.03	0.12	0.09	-0.09	-0.12	0.00	0.23	0.21	0.27	-0.00	0.09	0.05	0.02	-0.02	-0.09
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	92%	94%	84%	73%	82%	81%	85%	82%	98%	94%	92%	77%	78%	87%	85%

Table A1-9: Summary of Four Quadrant Analysis for Karnataka Buyer

12.1.3.3 Andhra Pradesh

Table A1-10 shows the summary of the four-quadrant analysis of Andhra Pradesh Buyer from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-177	-203	-161	-304	-403	-310	-195	-180	-218	-265	-176	-232	-243	-282	-332
Max. OD	364	217	159	211	167	187	332	165	156	192	247	243	212	253	138
Deviation Spread (Max – Min)	540	420	321	515	570	497	527	345	375	457	423	476	455	535	470
Correlation of Freq < 50 Hz with Deviation	-0.35	-0.04	-0.08	-0.20	0.08	-0.01	0.06	0.16	0.05	-0.27	-0.12	-0.04	0.05	-0.17	-0.07
Correlation of Freq >= 50 Hz with Deviation	-0.03	0.12	0.09	-0.09	-0.12	0.00	0.23	0.21	0.27	-0.00	0.09	0.05	0.02	-0.02	-0.09
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	92%	94%	84%	73%	82%	81%	85%	82%	98%	94%	92%	77%	78%	87%	85%

Table A1-10: Summary of Four Quadrant Analysis for Andra Pradesh Buyer

12.1.4 Southern Region Sellers

This section consists of the summary of the four-quadrant operations for selected Sellers from the Southern region.

12.1.4.1 Simhadri

Table A1-11 shows the summary of the four-quadrant analysis of Simhadri seller from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-31	-36	-30	-73	-29	-31	-24	-129	-43	-58	-21	-25	-28	-56	-122
Max. OI	100	32	18	5	27	28	92	53	19	11	25	15	24	23	20
Deviation Spread	130	68	49	78	56	59	116	181	63	69	45	40	52	79	142

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
(Max – Min)															
Correlation of Freq < 50 Hz with Deviation	-0.05	-0.07	-0.13	-0.22	-0.15	-0.21	-0.14	0.07	-0.13	0.07	0.10	-0.22	-0.18	-0.07	-0.08
Correlation of Freq >= 50 Hz with Deviation	-0.21	-0.19	-0.09	-0.32	0.09	-0.03	0.13	0.15	0.00	-0.13	-0.14	-0.17	-0.37	-0.35	-0.11
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-11: Summary of Four Quadrant Analysis for Simhadri Seller

12.1.4.2 RSTPS

Table A1-12 shows the summary of the four-quadrant analysis of RSTPS seller from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-138	-59	-37	-53	-49	-44	-68	-134	-89	-67	-46	-42	-27	-129	-122
Max. OI	391	97	78	75	72	76	92	198	126	111	77	64	89	157	147
Deviation Spread (Max – Min)	529	155	115	128	122	120	160	332	215	179	123	107	116	286	269
Correlation of Freq < 50 Hz with Deviation	-0.12	-0.02	-0.38	-0.37	-0.39	-0.24	0.07	0.09	-0.12	0.15	0.12	-0.16	0.11	-0.20	-0.24
Correlation of Freq >= 50 Hz with	-0.09	-0.33	-0.45	-0.40	-0.05	-0.06	0.00	0.00	-0.04	-0.10	-0.16	-0.15	-0.28	-0.26	-0.28

Deviation															
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	92%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-12: Summary of Four Quadrant Analysis for RSTPS Seller

12.1.4.3 Kudgi

Table A1-13 shows the summary of the four-quadrant analysis of Kudgi seller from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-68	-53	-76	-75	-83	-109	-72	-69	-63	-6	-45	-66	-62	-155	-51
Max. OI	146	94	132	145	140	183	126	109	115	6	73	138	114	217	119
Deviation Spread (Max – Min)	214	148	208	220	224	292	199	177	178	12	118	204	176	372	170
Correlation of Freq < 50 Hz with Deviation	0.00	-0.04	-0.07	-0.12	-0.25	-0.09	-0.17	-0.01	-0.20	0.16	0.03	-0.27	-0.12	-0.32	-0.16
Correlation of Freq >= 50 Hz with Deviation	0.02	-0.16	-0.32	-0.29	0.00	-0.12	-0.13	-0.12	-0.22	0.02	-0.15	-0.17	-0.38	-0.36	-0.28
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-13: Summary of Four Quadrant Analysis for Kudgi Seller

12.1.4.4 NLC

Table A1-14 shows the summary of the four-quadrant analysis of NLC seller from the Southern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UI	-29	-11	-49	-29	-30	-10	-22	-47	-28	-32	-8	-4	-10	-4	-30
Max. OI	52	34	67	46	55	31	49	72	57	49	24	10	27	22	42
Deviation Spread (Max – Min)	80	46	116	75	85	41	70	119	86	82	32	14	38	26	72
Correlation of Freq < 50 Hz with Deviation	-0.10	0.07	0.03	-0.04	0.14	-0.06	0.02	-0.07	0.13	0.14	-0.02	0.05	-0.05	-0.01	0.01
Correlation of Freq >= 50 Hz with Deviation	0.06	-0.04	-0.05	-0.22	0.03	-0.15	-0.01	0.02	0.14	-0.15	0.03	-0.09	-0.12	-0.11	-0.01
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 150	93%	94%	84%	73%	83%	81%	85%	82%	98%	94%	92%	77%	78%	88%	86%

Table A1-14: Summary of Four Quadrant Analysis for NLC Seller

12.1.5 Northern Region Buyers

This section consists of the summary of the four-quadrant operations for selected Buyers from the Northern region.

12.1.5.1 Rajasthan

Table A1-15 shows the summary of the four-quadrant analysis of Rajasthan buyer from the Northern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-268	-192	-286	-278	-458	-455	-434	-384	-233	-231	-190	-236	-342	-209	-217
Max. OD	226	243	188	259	378	232	307	222	177	210	181	131	146	134	139
Deviation Spread	495	434	474	536	836	687	741	606	410	441	372	368	488	343	356

(Max – Min)															
Correlation of Freq < 50 Hz with Deviation	0.08	-0.10	0.02	0.10	-0.00	0.17	0.12	0.11	0.14	0.04	0.13	0.11	0.01	0.16	0.09
Correlation of Freq >= 50 Hz with Deviation	-0.02	0.03	-0.04	0.16	0.28	-0.29	-0.13	0.01	-0.11	-0.15	-0.03	-0.09	-0.27	0.04	-0.05
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 250	92%	94%	84%	73%	82%	81%	84%	81%	89%	94%	92%	77%	78%	88%	86%

Table A1-15: Summary of Four Quadrant Analysis for Rajasthan Buyer

12.1.5.2 Punjab

Table A1-16 shows the summary of the four-quadrant analysis of Punjab buyer from the Northern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-154	-156	-221	-443	-210	-968	-405	-134	-157	-117	-92	-150	-125	-128	-139
Max. OD	92	96	112	145	119	101	174	79	91	96	73	100	88	93	99
Deviation Spread (Max – Min)	246	251	333	588	329	1,068	579	212	247	213	166	250	213	221	238
Correlation of Freq < 50 Hz with Deviation	-0.04	-0.09	0.00	-0.06	0.16	-0.07	-0.05	0.20	0.23	0.00	-0.07	0.07	0.20	-0.08	0.02
Correlation of Freq >= 50 Hz with Deviation	-0.06	-0.23	-0.05	-0.37	-0.00	-0.05	-0.26	0.15	-0.03	0.00	-0.01	0.18	-0.00	-0.05	0.02

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 200	93%	94%	84%	72%	83%	76%	82%	82%	89%	94%	92%	77%	78%	88%	86%

Table A1-16: Summary of Four Quadrant Analysis for Punjab Buyer

12.1.5.3 Uttar Pradesh

Table A1-17 shows the summary of the four-quadrant analysis of Uttar Pradesh buyer from the Northern region.

Parameter	31 Jan 22	14 Feb 22	14 Mar 22	11 Apr 22	16 May 22	13 Jun 22	11 Jul 22	15 Aug 22	12 Sep 22	17 Oct 22	14 Nov 22	26 Dec 22	16 Jan 23	13 Feb 23	27 Feb 23
Max UD	-318	-279	-298	-283	-578	-315	-335	-453	-331	-216	-190	-263	-182	-233	-394
Max. OD	205	177	169	204	279	483	199	241	288	285	181	166	182	340	184
Deviation Spread (Max – Min)	523	456	467	487	857	798	534	693	619	501	372	428	364	574	578
Correlation of Freq < 50 Hz with Deviation	-0.02	-0.06	-0.16	0.07	-0.11	0.08	0.16	0.01	-0.07	-0.22	0.13	0.01	0.24	-0.01	-0.04
Correlation of Freq >= 50 Hz with Deviation	-0.09	-0.18	-0.19	-0.05	-0.12	0.08	-0.12	-0.31	-0.14	-0.14	-0.03	-0.02	-0.13	-0.12	-0.13
% of TBs in 49.90 <= F <= 50.05 and Deviation +/- 200	91%	93%	82%	72%	79%	79%	85%	81%	88%	94%	92%	77%	78%	87%	82%

Table A1-17: Summary of Four Quadrant Analysis for UP Buyer

12.2 Appendix- 2

GRID – INDIA

Major Findings & Observations Report Based on Primary Frequency Response Test

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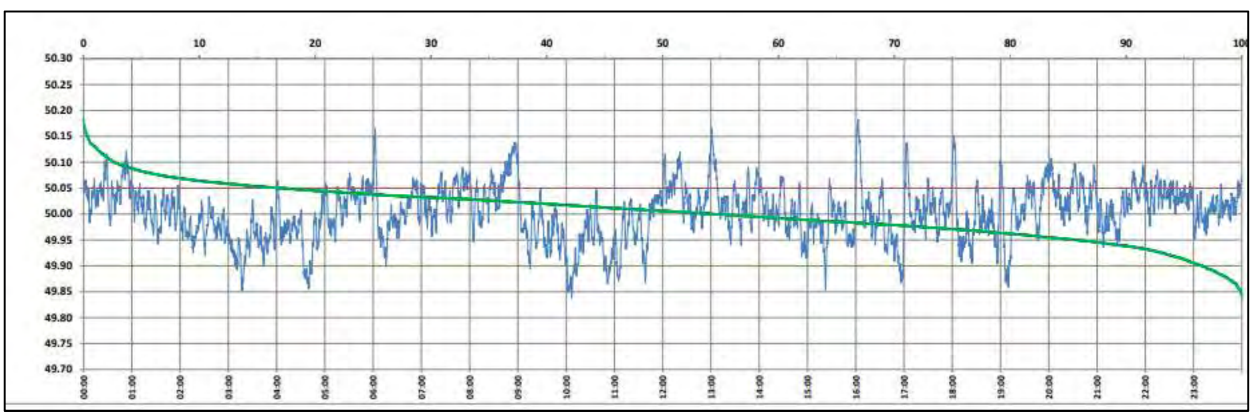
Executive Summary

Indian Electricity Grid Code 2023 mandates 50 Hz as reference frequency with permissible operating band of 49.90 – 50.05 Hz. Maintaining grid frequency within the predetermined boundaries around 50 Hz is critical for the reliability of large and complex Indian power system network. The rotational kinetic energy and the automatic primary frequency response (through droop characteristics) of synchronous machines play a critical role in frequency stability.

Frequency response is a measure of a power systems "ability to arrest and stabilize frequency deviations following the sudden loss of generation or load''. The amount of frequency response in an interconnection is affected by the collective responses of generation and load resources throughout the entire interconnection.

IEGC mandates that all thermal units of 200 MW and above, all hydro units of 25 MW and above as well as all gas turbines of 50 MW to provide primary frequency response. Nuclear generating stations and hydro generating stations (with pondage up to 3 hours or Run of the river projects) are exempt from mandatory primary response. They may provide the primary response to the extent possible, considering the safety and security of machines and humans.

In compliance to directions from Hon'ble CERC vide its order 47/MP/2012 (dated 03.05.2013) and subsequently as mandated in IEGC-2023, NLDC/RLDCs have been assessing and reporting the frequency response characteristics of all regional entities for all grid events involving generation/load loss of more than 1000 MW or frequency change of 0.1 Hz. The FRC of the All India grid has been observed to be in the range of 18000 MW/Hz - 25000 MW/Hz. Notwithstanding the above large excursions in frequency during hour boundary and sustained period large deviations from nominal frequency are often observed in the power system.



Review of frequency profile post implementation of DSM regulation 2022 indicates that the frequency has remained within the IEGC band only for around 57% of time during 5th Dec 2022-6th Feb 2023. In order to analyse the possible reasons for poor frequency profile, the primary frequency response of thermal and hydro units was analyzed with the help of telemetered governor control signal being received in NLDC AGC system. It was noted that the frequency response of most of the thermal units was reasonably good for fast change in frequency and the frequency response was negligible/sluggish/delayed/inadequate for slow changes in frequency.

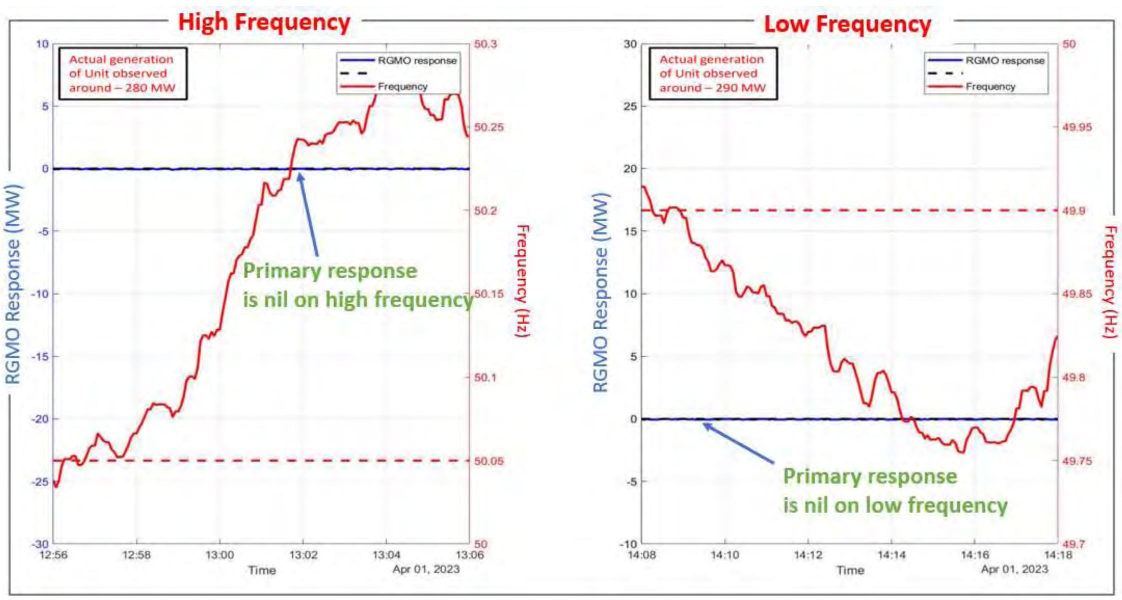


Figure 33:Typical governor control instructions in a thermal unit towards slow changes in frequency

Further regulation 5.2 (g) of Part 5 of the principal IEGC-2010 mandated that – "provided that periodic check-ups by third party should be conducted at regular interval once in every 2 years through independent agencies selected by RLDCs or SLDCs as the case may be..." In compliance to the above testing of 232 out of identified 240 generating units was conducted by third parties.

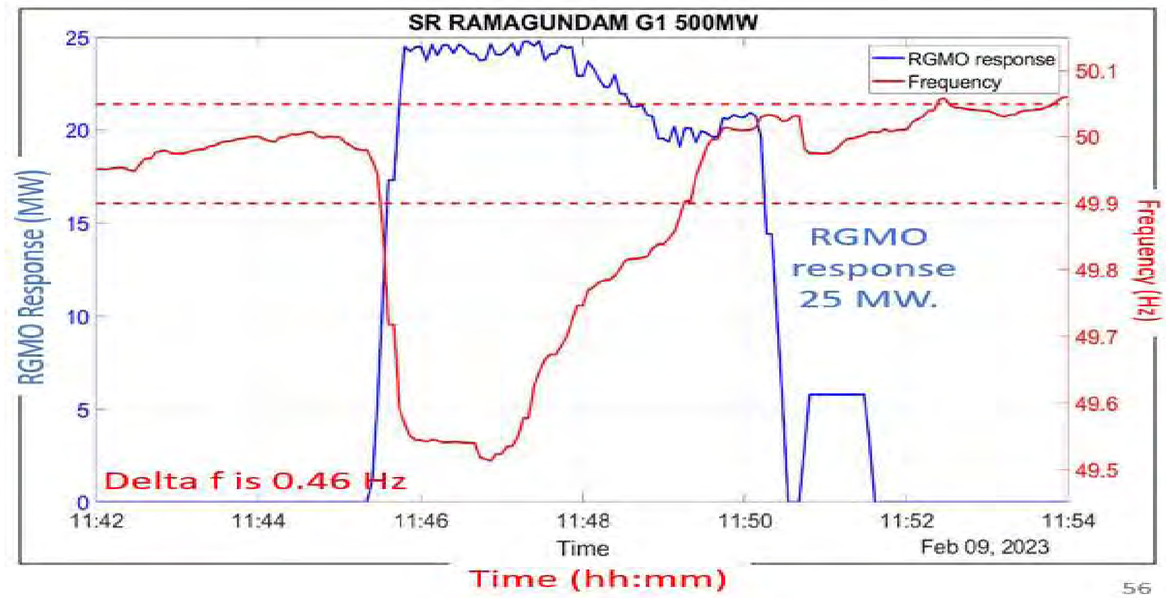


Figure 34: Typical governor control instruction of a thermal unit towards fast change in frequency during contingency

The test reports submitted by the third party were studied to assess the performance of the governing system. Summary of observations are as below:

Summary of thermal units:

Primary Frequency Response (PFR) from most of the thermal units were as per droop characteristics. Most of the tested units have given initial response but the overall MW contribution, stability of response and response to further fall in frequency found to be varying by dynamic conditions such as pressure correction compensation in MW, quality of fuel, type of unit, tuning of boilers and related control loops and disparity in logic implementations.

Summary of hydro units:

Hydro units on the other hand demonstrated primary frequency response as per their droop characteristics, full response time for majority of hydro units were obtained within 45 seconds. Stability of the response depends upon the forbidden zone and status of adjacent units during the event of frequency changes.

Summary of gas-based units:

Gas based units has shown quick full response time and stable response in terms of holding the MW correction but limited by mode of operation and dead band/ripple filter implementation. It has been observed that gas turbines running in combined cycle with steam turbine provide the primary frequency response only by the MW changes of gas turbine generator, on the other hand the steam turbine response comes after a delay of 5 to 10 minutes hence do not contribute in PFR in terms of MW contribution.

It is learned that response from the units varies, depending upon the droop implementation, implementation of ripple filter logic, different governor scan time, MW contribution limited by diverse implementation of limiters in frequency control logic, restrictions in response in terms of maximum MW contribution, units' instability issues and manual innervations during the test to achieve desirable response. The major areas of concerns from the findings of the test results are mentioned below:

<u>Major areas of concern related to PFR:</u>

i. **<u>Logics related:</u>**

Diverse logic implementations were identified, leading to non-uniform responses across units. This may supress the coordinated efforts during system disturbances in overall PFR.

- **Droop implementation in controller logic with limiters**
  - Droop at MCR with 5% limitation of MCR
  - Droop at current generation (CG)
  - Droop at MCR with 5% limitation of CG
  - Droop at MCR, with 5% limitation of CG for below 50 Hz & 5% limitations of MCR for above 50 Hz
- **Ripple filter implementation**
  - Implementation on running/current tracking frequency.
  - Implementation w.r.t. 50 Hz
  - At current tracking frequency for f < 50 Hz and at fixed 50 Hz for f > 50 Hz and vice-versa
- **Response in consecutive changes in frequency**
  - Units responding to consecutive changes in frequency as per droop.
  - Units responding to consecutive changes in frequency as per droop but no response while ramp back is in action.

- Units respond to the first frequency change and does not respond to any further changes in frequency.
- Units respond to frequency changes from f<50 Hz to f>50 Hz and vice versa.
- Restricted response holding time for frequency above 50 Hz.

➢ **RGMO implementation for both below and above 50Hz**

➢ **Fixed % change in MW for any change in frequency**

➢ **Restriction in response hold time**

➢ **Scan time of governor frequency controller & intentional delay**

ii. <u>Unit operation related:</u>

- System bottlenecks w.r.t Super-critical units.
- Pressure correction affecting the sustainability of response.
- Coal quality
- Manual interventions to achieve desired response during test - Higher Pressure setpoint maintained for steps below 50Hz & Lower Pressure setpoints maintained during steps above 50Hz.
- Base load Vs MCR understanding for Gas based units.
- Overshoot, mechanical backlash and oscillations in MW when operating near forbidden zone w.r.t. hydro units.

iii. <u>Controller tuning related:</u>

- Governor frequency controller tuning.
- CMC controller tuning.
- Boiler tuning.

Analysis from the of Primary Frequency Response test, highlights the need for standardization in logic implementation, understanding the system bottlenecks and take corrective measures for the improvements in the primary frequency response of generating units across India. Implementing the recommended measures will contribute to a more resilient and stable power grid, enhancing overall system reliability and performance. To address these issues, the following measures are recommended:

a) Recommendations

- **Standardization of Droop Settings**

  The test revealed significant disparities in droop implementation across generating units, such as droop implemented on MCR, droop implemented on units current generation, droop implemented on MCR but capped or limited by 5% of current generation, droop implemented on current generation and capped with 5% of current generation. These different way of implementation gives different MW contribution during the event. These variations in droop settings have the potential to impact grid stability during frequency deviations. Definition of Governor Droop in IEGC states ***in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from no load to full load***, which is Hz/MW from full load to no load, **hence the droop should be implemented on unit MCR without any limiters**. It is recommended to implement standardized droop settings for generating units to ensure consistent frequency response.

- **Ripple filter implementation**

  Inconsistencies in PFR due to different ripple filter logic implantation is noted, such as different responses from the units in consecutive frequency changes, variation in responses during the transition of frequency from below 50 Hz to above 50 Hz and vice versa, less than desired MW correction during frequency changes etc. These variations are due to the implementation of ripple filter logic differently among the generators. For those generating units where the ripple filter logic is implemented with respect to fixed frequency of 50 Hz contributes in PFR as per droop with respect to frequency change whenever frequency deviates beyond the rippler filter range (which mostly observed is 0.03 Hz). However, units where the ripple filter logic is implemented on running frequency or current tracking frequency, it has been noticed that the response from the unit during the frequency changes depends on the running frequency value and may not be adequate. Furthermore, this small decline in frequency may remain undetected by the governor, which could affect the unit's ability to contribute in PFR. The concept of ripple filter has been eliminated in the IEGC 2023 which states '***The inherent dead band of a generating unit or frequency controller shall not exceed +/- 0.03 Hz'.*** Hence in order to verify that ripple filter logic is removed, and governor action is with respect to reference frequency of 50 Hz, it is recommended to retest the units for PFR.

- **Response restrictions**

  Some units exhibited restrictions in their response capabilities (e.g., fixed MW change for any change in frequency, no response for consecutive change in frequency, restricted response for frequency changes above 50 Hz, fixed response hold time irrespective of the duration of frequency event etc.) which may compromise their contribution to grids stability during contingency. It is suggested to identify and resolve response restrictions in units to enhance their contribution to primary frequency response.

- **Manual intervention**

  Manual interventions were noted in certain instances to achieve an ideal response. These interventions could introduce delays and uncertainty in restoring grid frequency. Hence it is recommended to have well-tuned coordinated master control logic implementations among such units to achieve uniform responses during grid disturbances.

- **System bottlenecks**

  Mechanical backlash in hydro units, pressure correction compensation in thermal units and response stability issues in super critical units etc. were identified as system bottlenecks affecting the efficient delivery of frequency response. Hence it is recommended to mitigate these issues as far as possible.

- **Different scan time/intentional delay**

  From the PFR tests it is observed that the response initiation time, subjected to change in frequency steps, are different for different generating units. How quickly unit start to respond depends on the scan time in the governor's frequency control logic. From the test results it has been noticed response initiation time varies from less than a second to 6 - 7 seconds. Delayed response initiation can potentially defeat the purpose of PFR because of higher overall response initiation time. It is recommended to address this issue and standardize scan time in the governor for enabling them to provide quick initiation of response to avoid the intentional delay and for achieving optimal delivery time of PFR.

b) Recommendations to Plant owners

- **Logic modification and tuning**: To achieve robust PFR, it is essential to tune controller logic, including governor frequency controllers, CMC controllers, and boiler tuning, to enhance PFR capabilities.

- **Address pressure correction**: Identify and address issues related to pressure correction that affect the sustainability of PFR.
- **No valve-wide operation:** It has been observed from the PFR test, some of the generating units were incapable to provide PFR for subsequent fall in simulated frequency and also for large frequency steps. This may probably be due to valve-wide operation which can be observed from the trends of valve positions. Therefore, it is advisable to avoid valve-wide operation and maintain sufficient margin for PFR.
- **Fuel quality management**: Ensure the quality of fuel used to maintain stable PFR response.
- **Minimize manual interventions**: Manual interventions were noted during the test in certain instances to achieve an ideal response. These interventions could introduce delays and uncertainty during actual grid events. Hence it is recommended to have well-tuned coordinated control (CMC) among such units to achieve uniform responses during grid disturbances.
- **Hydro and gas-based units response optimization**: For some of the hydro units, implementation of dead band, slow response, non-uniformity in logic implementation has been observed. For gas-based units, dead band and the mode of operation (when operating in base load) restricting PFR has been observed. Hence it is recommended to implement uniform logics in order to have consistent speed of response, quantum of MW change as per droop and response stability during frequency changes.

The Hon'ble Central Electricity Regulatory Commission (CERC), vide notification dated 12th April 2017, had notified Indian Electricity Grid Code (Fifth Amendment) Regulations, 2017. As per this notification, following proviso has been added at the end of Regulation 5.2(g) of part 5 of the principal Indian Electricity Grid Code (IEGC) Regulations:

"Provided that periodic checkups by third party should be conducted at regular interval once in two years through independent agencies selected by RLDCs or SLDCs as the case may be. The cost of such tests shall be recovered by RLDCs or SLDCs from the generators. If deemed necessary by RLDCs/SLDCs, the test may be conducted more than once in two years."

In compliance to the regulation mentioned above, National Load Despatch Centre (NLDC) on behalf of RLDCs formulated a procedure for carrying out the primary frequency response tests, the details of which was intimated vide POSOCO letter dated 12th Oct 2018.

1.1. Primary Frequency Response Test Objective

The purpose of these tests was to record and verify the following capabilities on the specified generating units as per IEGC guidelines.

- Primary Frequency Response in normal operation under Restricted Governor Mode (RGMO) as well as in Free Governor Mode (FGMO) as specified in regulation 5.2 (f) & 5.2 (g) of the Indian Electricity Grid Code.
- The adopted test procedure should be a proven and viable way of performing primary frequency response when the generating units is operating in synchronism with the grid. Model validation testing to derive and validate the turbine governing system dynamic model and parameters.
- Apart from the testing, the response for any past event in the grid to further validate the test results has to be carried out.

2. Requirements & Procedure for conducting the Primary Response Testing

2.1. Requirements on the test methodology

The test methodology and the equipment deployed shall be such as to enable assessment/evaluation of the power plant frequency control capability in normal grid connected operation (frequency response test- Restricted Governor Mode and Free Governor Mode). The desirable features of the methodology were as under:

i. The generating unit under test shall be subjected to simulated frequency variation to assess its capability to contribute in the system frequency control while operating in synchronism with the grid.

ii. During the test, unit under test shall remain synchronized with the main grid.

iii. Critical parameters such as drum level, steam pressure and steam temperature etc. in the plant process shall be monitored and supervised during the period of test.

iv. There must be features in the test equipment to automatically abort the test if plant operating conditions indicate abnormal behaviour consequential to test.

v. The power plant shall have the authority to order abortion of any ongoing test and requisition for retaking of test in case the plant or grid conditions so demand.

vi. All existing protection systems must be kept in operation during the entire test in order to protect the plant if the tests unexpectedly fail.

vii. After the completion of the tests, the initial settings (before the tests) shall be restored by the test conducting agency.

viii. Prior to the commencement of the test, permission from the concerned Regional Load Despatch Centre shall be obtained. The POSOCO will assign its representative(s) from RLDC/NLDC for witnessing the testing procedure at site as well as for smooth coordination between parties involved.

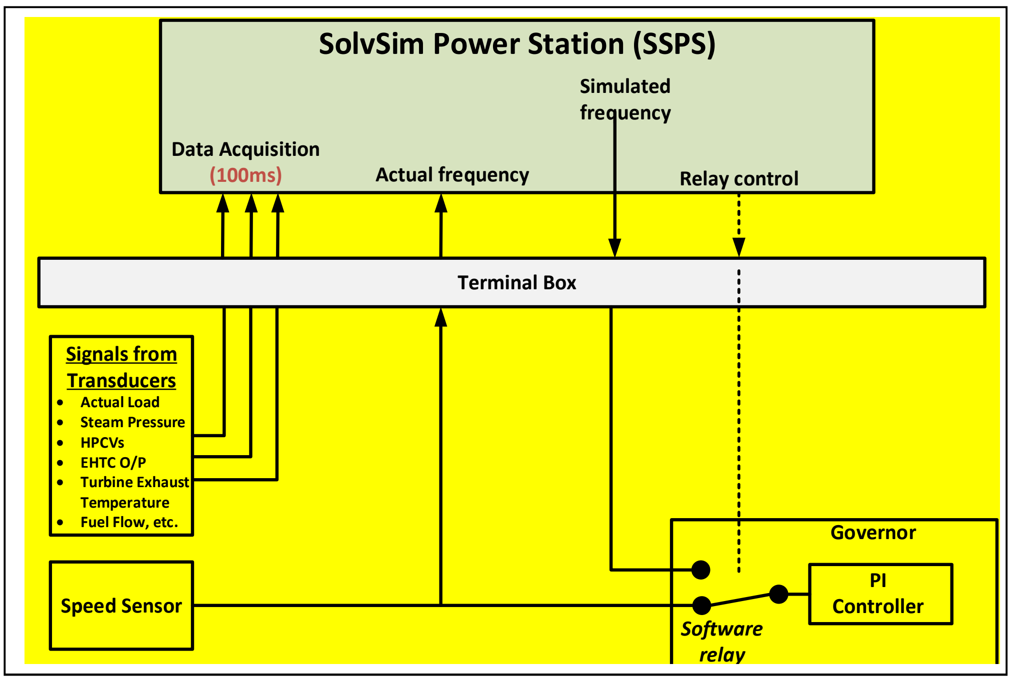
ix. Prior to the test, the testing agency undertaking the work shall submit a format for documenting the test readings/ results before the tests to be performed on each of the identified units.

x. After the completion of the tests, the filled formats shall be authenticated jointly by the parties concerned and POSOCO representative, including the representative of the plant owner, which shall become a part of the report to be submitted by the agency for the release of payments.

2.2. Procedure for conducting the Primary Response Testing

In order to fulfil the compliance with the Terms of Reference (TOR), a comprehensive test program outlining all the details of the test methodology was prepared. Additionally, a signal list, enumerating all the necessary signals to be acquired and injected was prepared as part of the testing process. Before proceeding with the tests at the respective unit, an initial site meeting was convened with the generating station along with respective RLDC, during which the test program and the signal list was shared and discussed to ensure alignment and understanding of the project's objectives and procedures.

Figure 35 Block diagram for test methodology



The generating unit under the test was subjected to simulated frequency variation with est equipment *Solv Sim Power Station (SSPS)* while the unit remained in synchronism with the grid as shown in Figure 35. The simulated frequency signal was injected to the governor's frequency control system. The test was carried out at three load levels, specifically near the technical minimum, part load and full load. The selection of load levels was made in a manner that allowed the turbine to increase or decrease the load within the operational capability of the unit being tested.

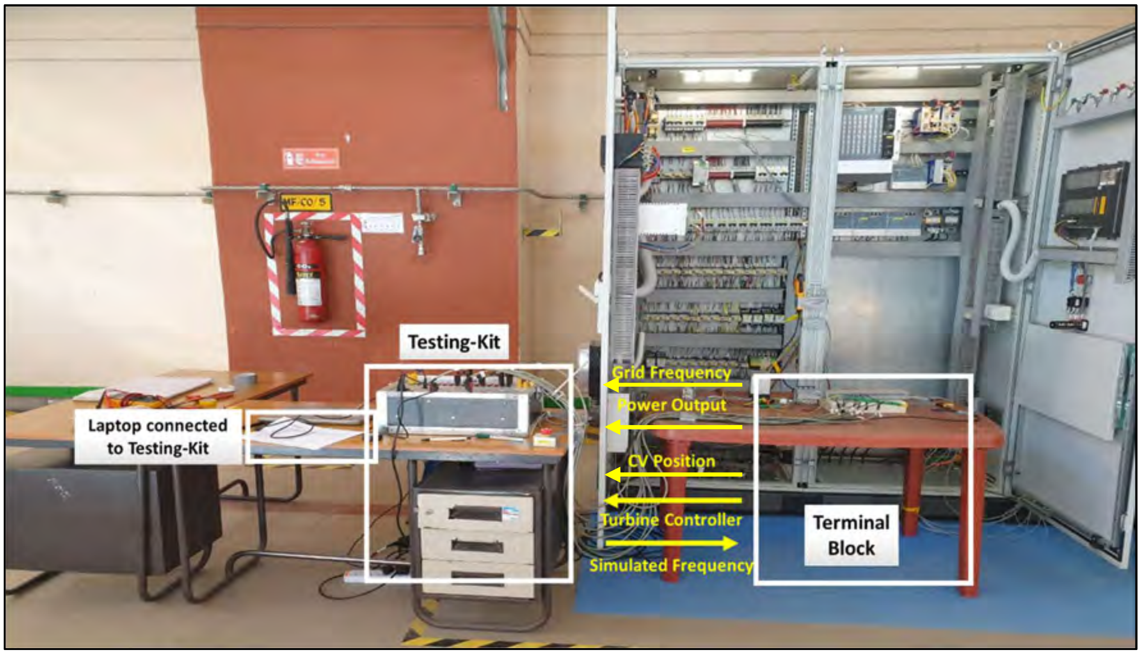


Figure 36 Test setup - SSPS

The simulated frequency steps were injected as step signal and as precautionary measure, the test was initiated with small frequency changes, and were gradually increased in the presence of operation leader form plant. The frequency steps were applied as per the test program until the frequency step corresponding to 5% or 10% of the unit's Maximum Continuous Rating (MCR) was reached.

The response was analysed based on following key performance indicators:

- **Time (Speed) of Response:** i.e., the time taken to deliver full MW contribution.
- **Quantum of Response**: i.e., the MW and MW/Hz contribution delivered in steady state.
- **Stability of the Response**: i.e., the time duration in seconds for which the response sustained.

In order to analyse the test results, signals such as simulated frequency, active power and other signals (as per the signal list for thermal, hydro and gas), were recorded with a sampling rate of 10 Hz. The response was observed for 3-5 minutes and more for each simulated frequency step in order to assess the unit's performance comprehensively, spanning from the initial transient states to final steady-state conditions.

3. Major Findings & Observations

3.1. Ripple Filter and Dead Band Implementation

It is required to implement ripple filter in frequency control logic as per IEGC clause 5.2 (f)(ii-b) which states that,

"Ripple filter of +/-0.03 Hz shall be provided so that small changes in frequency are ignored for load connection, in order to prevent governor hunting".

At the same time, IEGC prohibits the implementation of dead band as per the clause 5.2 (g) which states that,

"Facilities available with/in load limiters, Automatic Turbine Run-up System (ATRS), Turbine supervisory control, coordinated control system, etc., shall not be used to suppress the normal governor action in any manner and no dead bands and/or time delays shall be deliberately introduced except as specified in para 5.2(f) above".

However, dead band is implemented instead of ripple filter in some of the power plants.

3.1.1. Ripple filter

Implementation of ripple filter in frequency control logic restricts the governor to respond for the frequency changes lie within its range. However, for frequency changes outside ripple filter range, the governor responds to the actual change in grid frequency with respect to 50 Hz as represented in

Figure 37, resulting in desired MW contribution from the unit.

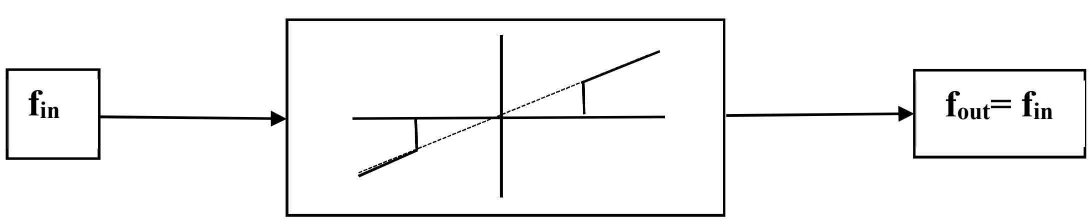


Figure 37 Block diagram representation of logic for ripple filter.

It has been observed from PFR test results that ripple filter has been implemented in different ways in different power plants which can be categorized as:

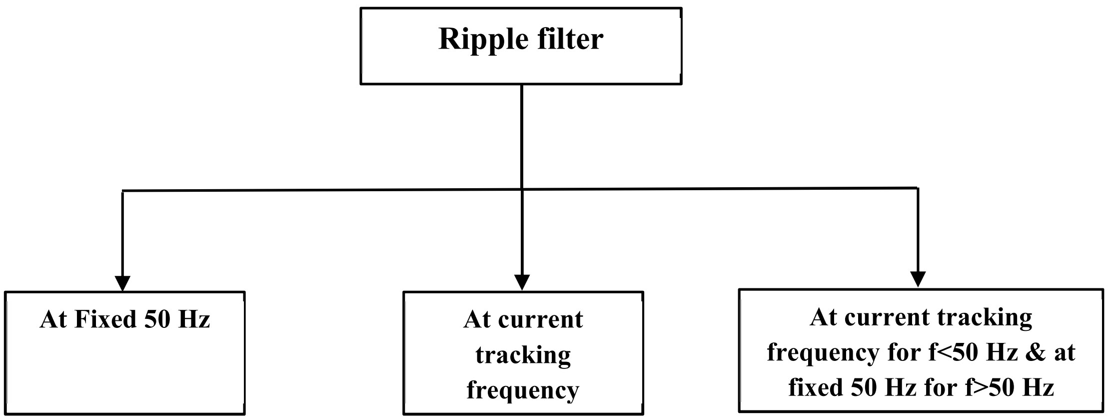


Figure 38 Categorisation of ripple filter implementation.

3.1.1.1. Ripple filter at current tracking/running frequency.

Ripple filter implementation at current tracking frequency is the logic in frequency controller that restricts governor to respond within ripple filter band range calculated with respect to the current tracking/running frequency.

e.g., KSK Mahanadi unit 4, where ripple filter at current tracking frequency is verified by performing special step tests for frequency below & above 50 Hz respectively.

i. 50.00 → 49.94 → 49.92 Hz: For frequency below 50 Hz, a special step test is performed where governor responds as per the droop for simulated frequency steps except for the frequency step change of -0.02 Hz from 49.94 to 49.92 Hz which implies that ripple filter is implemented at current tracking frequency.
ii. 50.00 → 50.04 → 50.06 Hz: For frequency above 50 Hz, a special step test is performed where governor responds as per the droop for simulated frequency steps except for the frequency step change of +0.02 Hz from 50.04 to 50.06 Hz which implies that ripple filter is implemented at current tracking frequency.

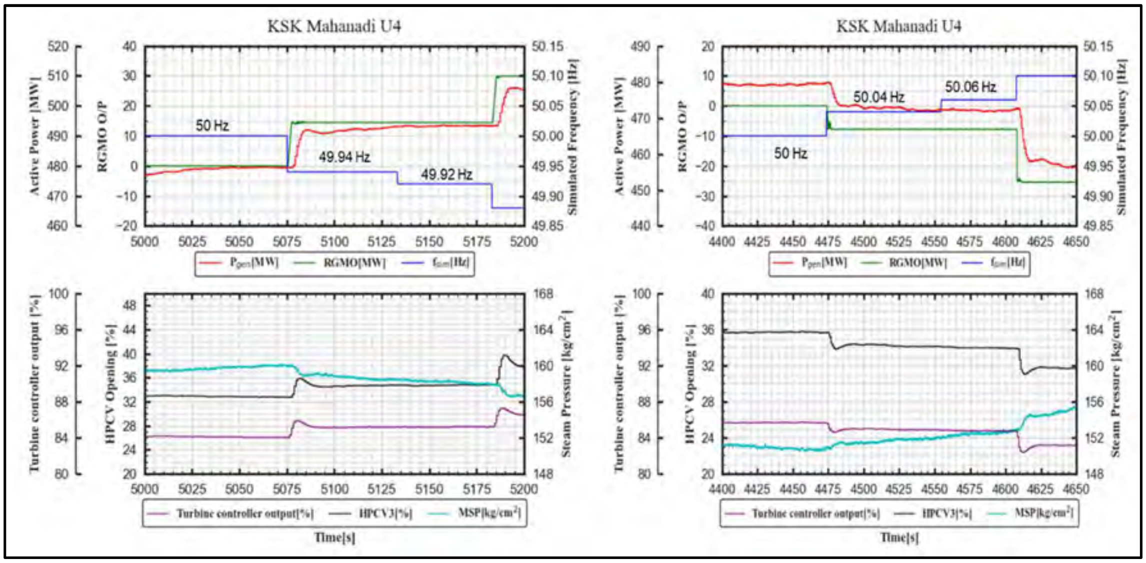


Figure 39 Ripple filter implementation at current tracking frequency at KSK Mahanadi unit 4.

3.1.1.2. Ripple filter at current tracking frequency for f<50 Hz & at fixed 50 Hz for f>50 Hz

A logic in frequency controller that restricts governor to respond within ripple filter band range calculated with respect:

i. To the current tracking/running frequency for frequency less than 50 Hz.
ii. To the fixed 50 Hz for frequency greater than 50 Hz

e.g., NTPC Ramagundam unit 5, where the above-mentioned logic is verified by performing special step tests for frequency below and above 50 Hz.

i. 50.00 → 49.96 → 49.94 Hz: For frequency below 50 Hz, a special step test is performed where governor responds as per the droop for simulated frequency steps except for the frequency step change of -0.02 Hz from 49.96 to 49.94 Hz which implies that ripple filter is implemented at current tracking frequency that can be seen in Figure 40.
ii. 50.00 → 50.04 → 50.06 Hz: For frequency above 50 Hz, a special step test is performed where governor responds as per the droop for simulated frequency step change of +0.02 Hz from 50.04 to 50.06 Hz which implies that ripple filter is implemented at fixed 50 Hz that can be seen in Figure 40.

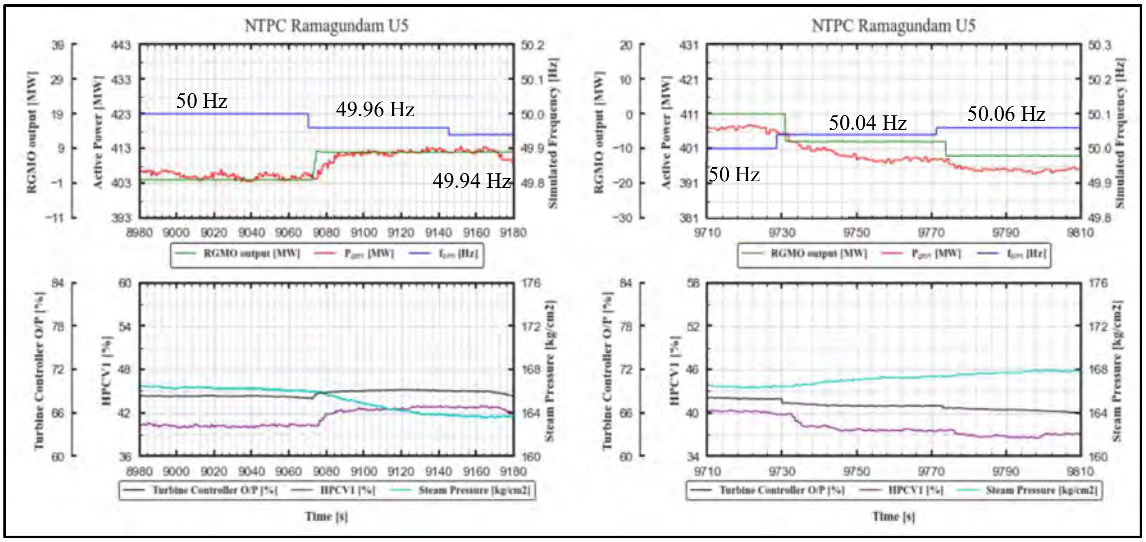


Figure 40 Ripple filter implementation at current tracking frequency for f<50 Hz & at fixed 50 Hz for f>50 Hz at NTPC Ramagundam unit 5.

3.1.2. Dead band

Implementation of dead band in frequency control logic restricts the governor to respond for the frequency changes lie within its range. Furthermore, for frequency changes outside dead band range, the governor responds to the difference between actual grid frequency and the dead band value as represented in Figure 41, resulting in less MW contribution from the unit than the desired contribution.

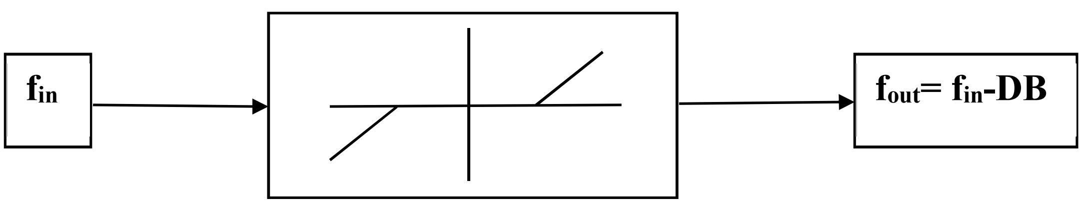


Figure 41 Block diagram representation of logic for dead band.

****NOTE: This type of dead band (i.e., without step implementation) is classified based on the observations and findings during PFR testing.**

i. Considering UGT-1 at NTPC Dadri GPS, where dead band of +/-0.03 Hz is implemented which can be seen in Figure 42 where no change on frequency controller output (FGMO) and actual load is observed during step tests of -+0.03 Hz & +-0.03 Hz.

   And for the step tests -+0.13 Hz & +-0.13 Hz governor responds to the frequency values of -+0.10 Hz & +-0.10 Hz i.e., difference between actual simulated frequency (-+0.13 /+-0.13) and the dead band value (-+0.03 Hz) resulting in less MW contribution of (5.20MW) than the desired MW (6.76 MW) which can be seen in Figure 43.

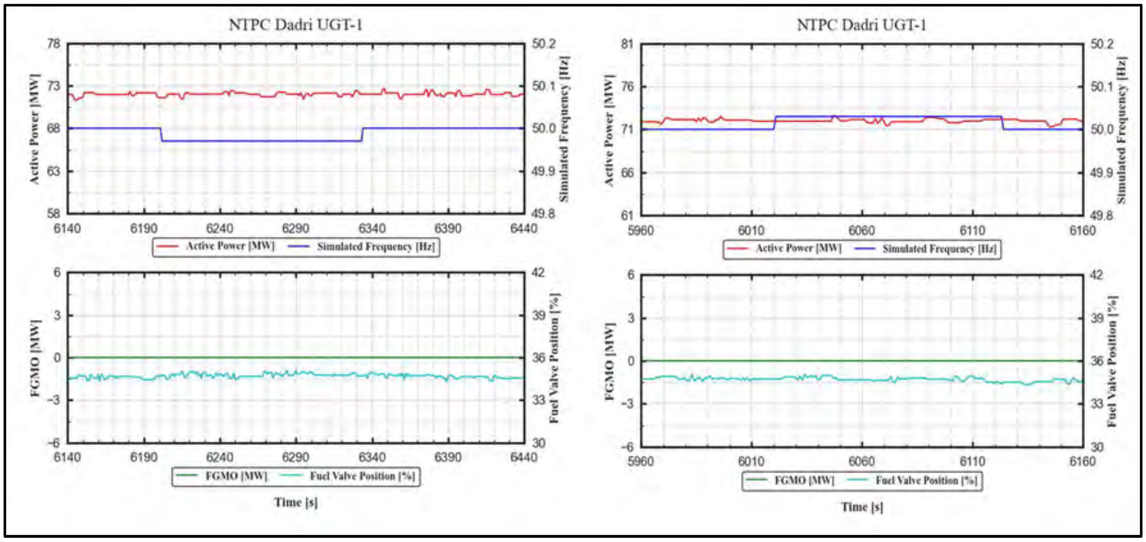


Figure 42 Ripple filter test of -+0.03 Hz & +-0.03 Hz at NTPC Dadri GPS

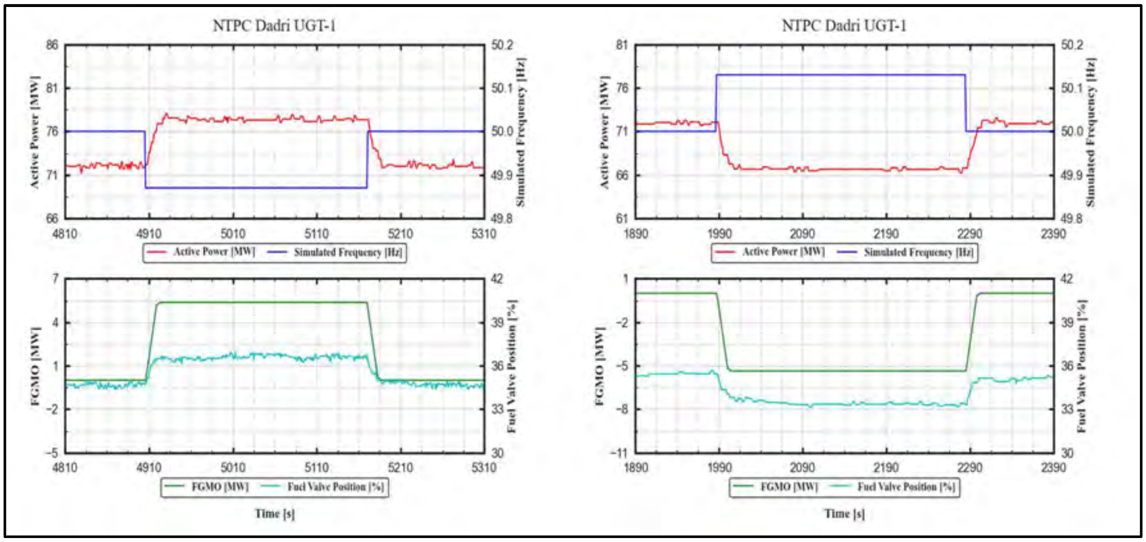


Figure 43 Step test of -+0.13 Hz & +-0.13 Hz at NTPC Dadri GPS UGT 1

ii. Considering unit 1 at NHPC Chamera-II, where dead band with a large value of +/-0.10 Hz is implemented which can be seen in Figure 42 where no change on guide vane position and actual load is observed during step tests of -+0.10 Hz & +-0.10 Hz which can be seen in Figure 44 .

And for the step tests -+0.23 Hz & +-0.23 Hz governor responds to the frequency values of -+0.13 Hz & +-0.13 Hz i.e., difference between actual simulated frequency (-+0.23 /+-0.23) and the dead band value (-+0.10 Hz) resulting in less MW contribution (5.2 MW) than desired MW contribution (9.2 MW) as shown in Figure 45.

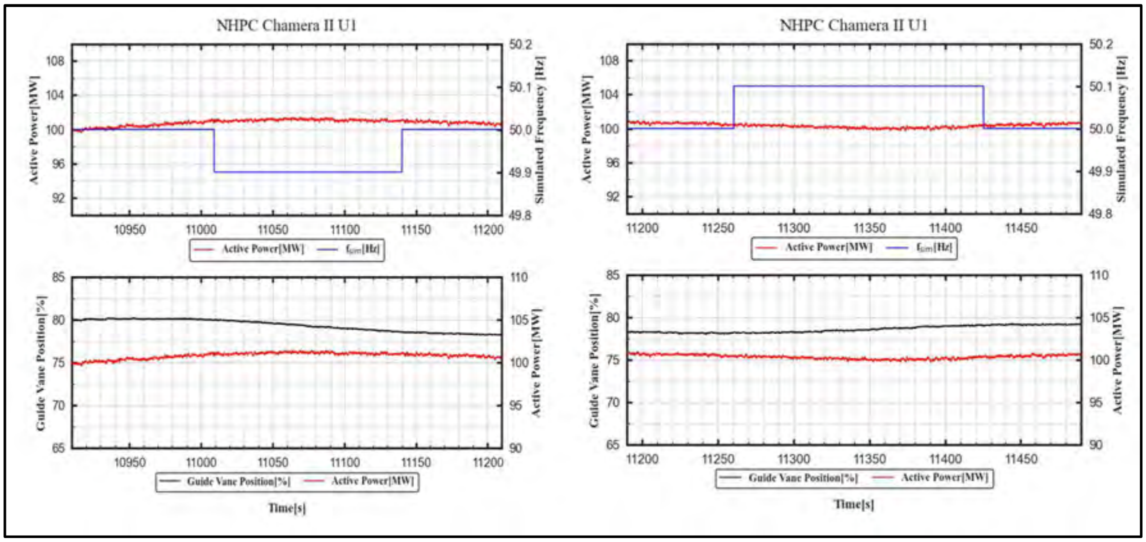


Figure 44 Dead band verification test of -+0.10 Hz & +-0.10 Hz at NHPC Chamera-II unit 1

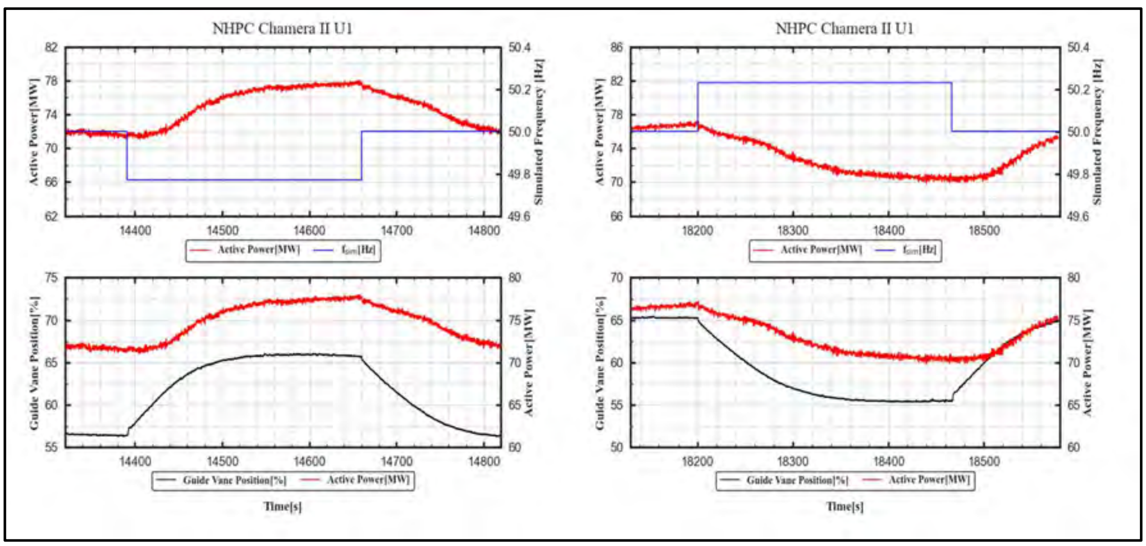


Figure 45 Dead band verification test of -+0.23 Hz & +-0.23 Hz at NHPC Chamera-II unit 1

3.2. Droop implementation in controller logic with limiters

IEGC prohibits the implementation of droop in frequency control logic with any kind of limiter that restricts the natural response of the governor & the unit as per the clause 5.2 (g) which states that,

"Facilities available with/in load limiters, Automatic Turbine Run-up System (ATRS), Turbine supervisory control, coordinated control system, etc., shall not be used to suppress the normal governor action in any manner and no dead bands and/or time delays shall be deliberately introduced except as specified in para 5.2(f) above".

It has been observed from PFR test results that droop has been implemented in different ways in different power plants which can be categorized as:

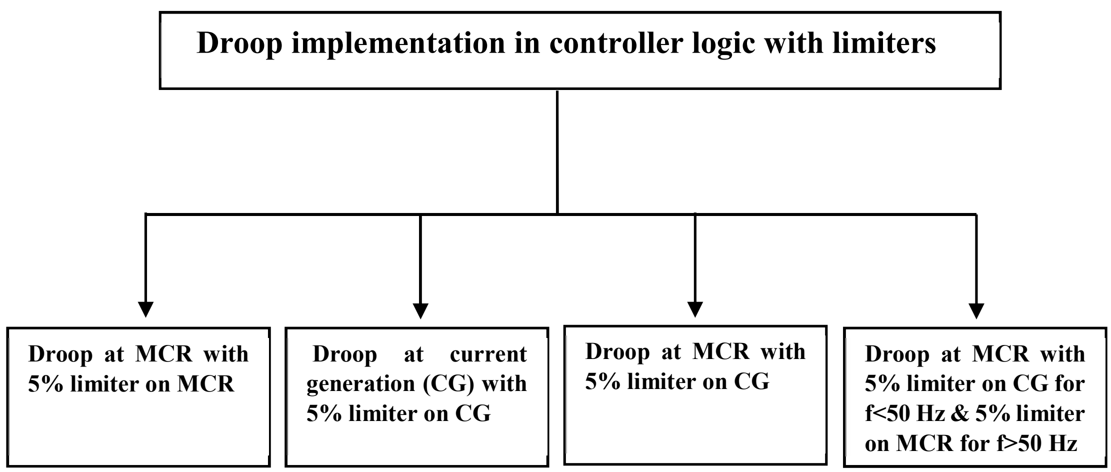


Figure 46 Categorization of droop implementation in governor control logic with limiters

Different droop implementation with limiters in governor control logic restricts the PFR since the unit contributes less MW correction than the desired MW correction corresponding to a particular frequency change, which can be seen from the bar graph Figure 47.

Calculation for the MW correction with respect to the step size of 0.13 Hz is based on the droop formula for each category of droop implementation as explained below:

$$Droop = \frac{\Delta f}{f} X \frac{P}{\Delta P} \quad (1)$$

where,

Δf = Change in frequency

f = Base frequency of 50 Hz

P = Machine's continuous rating (MCR) (3.2.1, 3.2.3, 3.2.4)

= Current generation (CG) (3.2.2)

In the bar graph Figure 47, different MW corrections are represented for all the categories of droop implementation for simulated frequency change of -/+0.13 Hz (below 50 Hz) & +/-0.13 Hz (above 50 Hz) at 325 MW load level.

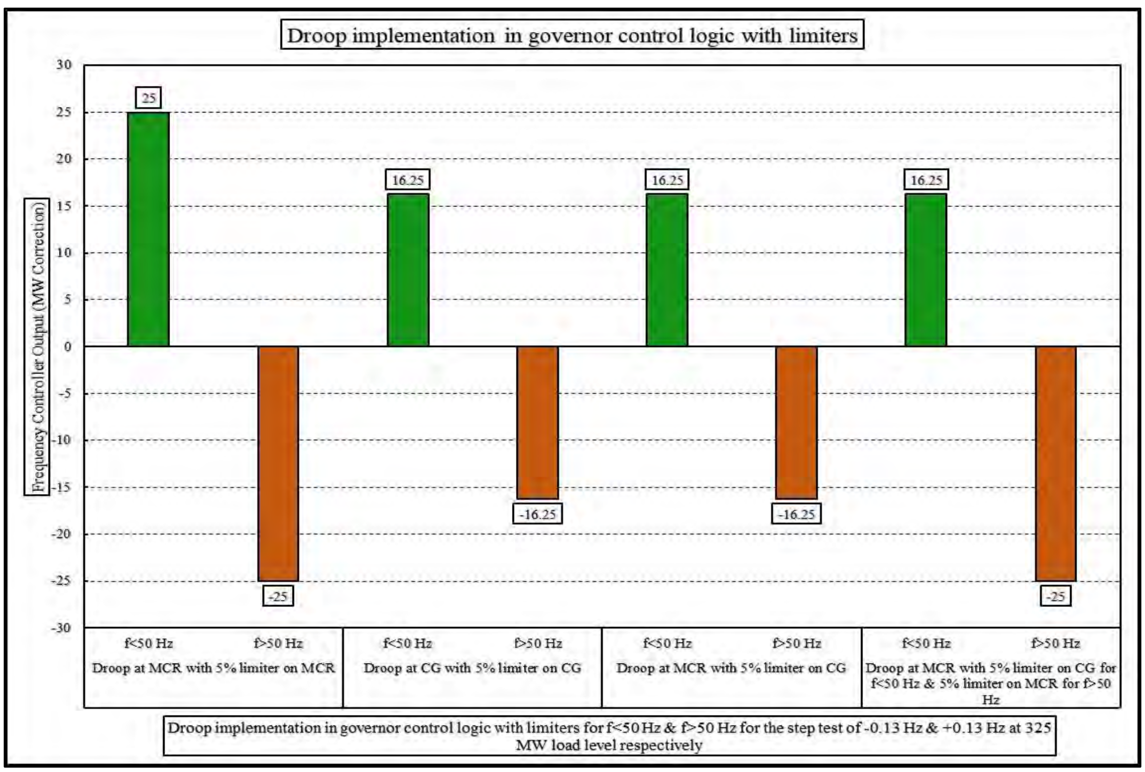


Figure 47 Droop implementation with limiters for the step test of -0.13 Hz & +0.13 Hz

3.2.1. Droop at MCR with 5% limiter on MCR

Droop is implemented on unit's machine's continuous rating (MCR) in frequency control logic and the maximum change in actual load is limited to 5% of unit's MCR.

Considering the step tests of 0.1 Hz & 0.13 Hz for below & above 50 Hz at NTPC Ramagundam unit 4 at 400 MW load level with unit's MCR of 500 MW:

i. During both the step tests of -+0.10 Hz & +-0.10 Hz, MW correction i.e., RGMO Output (20 MW) is observed as per the set droop of 5%, as shown in Figure 48.

ii. While during the step tests of -+0.13 Hz & +-0.13 Hz, the MW correction (+25 MW & -25 MW) obtained is less than the desired MW correction of +26 MW & -26 MW since a limiter of 5% on unit's MCR (500 MW) is limiting the correction to 25 MW, as shown in Figure 49.

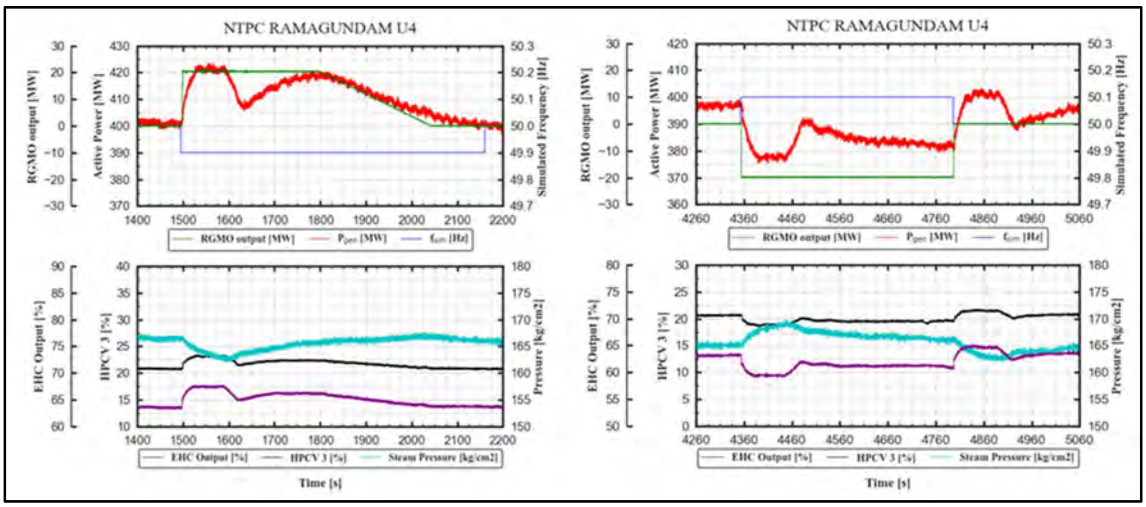


Figure 48 Step tests of -+0.10 Hz & +-0.10 Hz at NTPC Ramagundam unit 4 at 400 MW load level

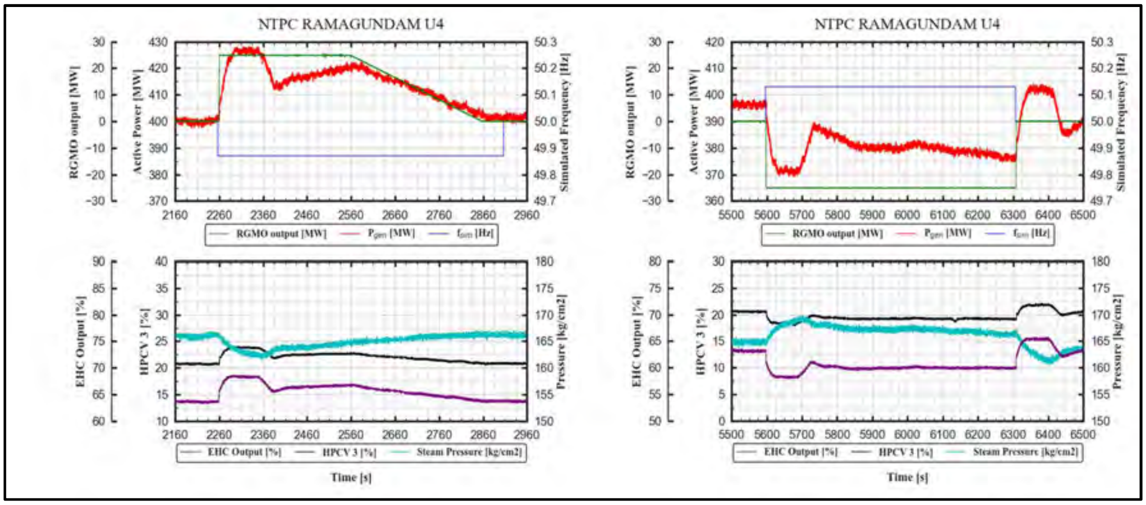


Figure 49 Step test of -+0.13 Hz & +-0.13 Hz at NTPC Ramagundam unit 4 at 400 MW load level

3.2.2. Droop at current generation (CG) with 5% limiter on CG

Droop is implemented on unit's current generation (CG) in frequency control logic and the maximum change in actual load is limited to 5% of unit's CG.

Considering the step tests of 0.10 Hz & 0.13 Hz for below & above 50 Hz at SEIL Nellore P1 U1 at 440 MW load level with unit's MCR of 660 MW:

i. During both the step tests of -+0.10 Hz & +-0.10 Hz, MW correction i.e., RGMO Output (17.6 MW) observed is equals to the desired MW correction of 17.6 MW as shown in Figure 50 since the droop is implemented at current generation.

ii. During both the step tests of -+0.15 Hz & +-0.15 Hz, MW correction i.e., RGMO Output (22 MW) observed is less than the desired MW correction of 26.4 MW, since a limiter of 5% on unit's CG (440 MW) is implemented which is limiting the correction to 22 MW, as shown in **Figure 51**.

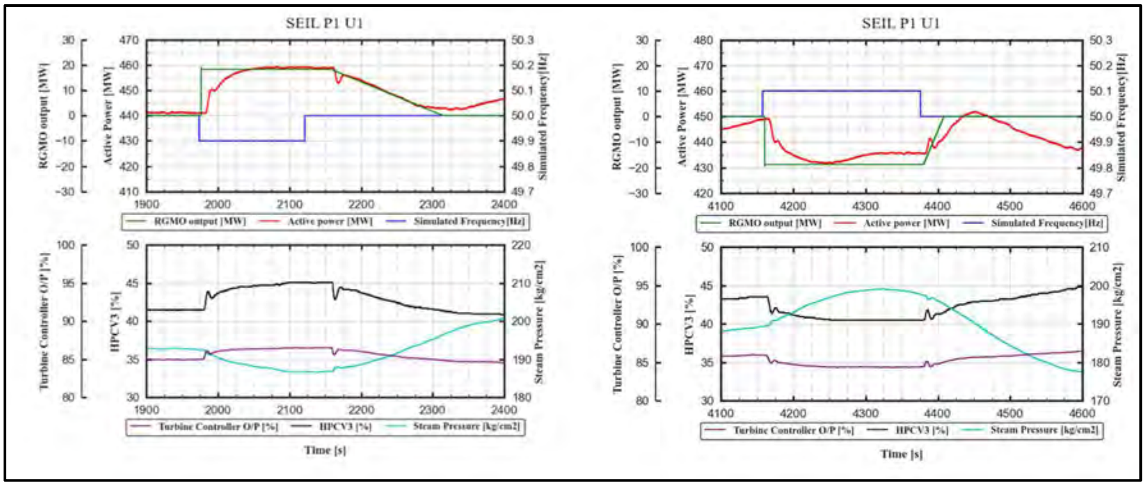


Figure 50 Step test of -+0.10 Hz & +-0.10 Hz at SEIL Nellore unit P1 U1 at 440 MW load level

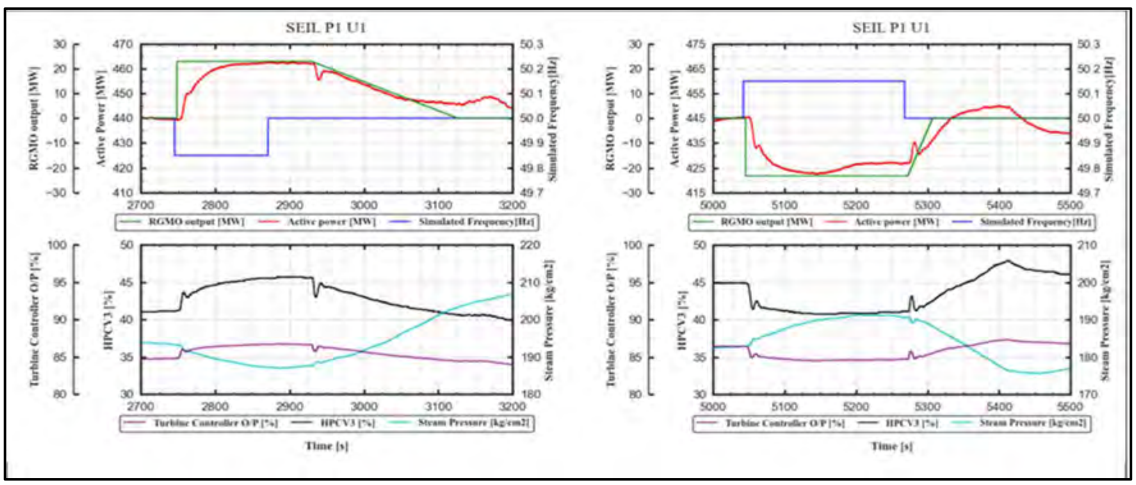


Figure 51 Step test of -+0.15 Hz & +-0.15 Hz at SEIL Nellore unit P1 U1 at 440 MW load level

3.2.3. Droop at MCR with 5% limiter on current generation (CG)

Droop is implemented on machine's continuous rating (MCR) in frequency control logic with the maximum change in actual load is limited to 5% of unit's CG.

Considering the step tests of 0.1 Hz & 0.13 Hz for below & above 50 Hz at APCPL Jhajjar unit 1 at 400 MW load level with unit's MCR of 500 MW:

i. During both the step tests of -+0.10 Hz & +-0.10 Hz, MW correction i.e., RGMO Output (20 MW) is observed as per the set droop of 5%, as shown in Figure 52.

ii. While during the step tests of -+0.13 Hz & +-0.13 Hz, the MW correction (+20 MW & -20 MW) obtained is less than the desired MW correction of +26 MW & -26 MW since a limiter of 5% on unit's CG (400 MW) is limiting the correction to 20 MW, as shown in Figure 53.

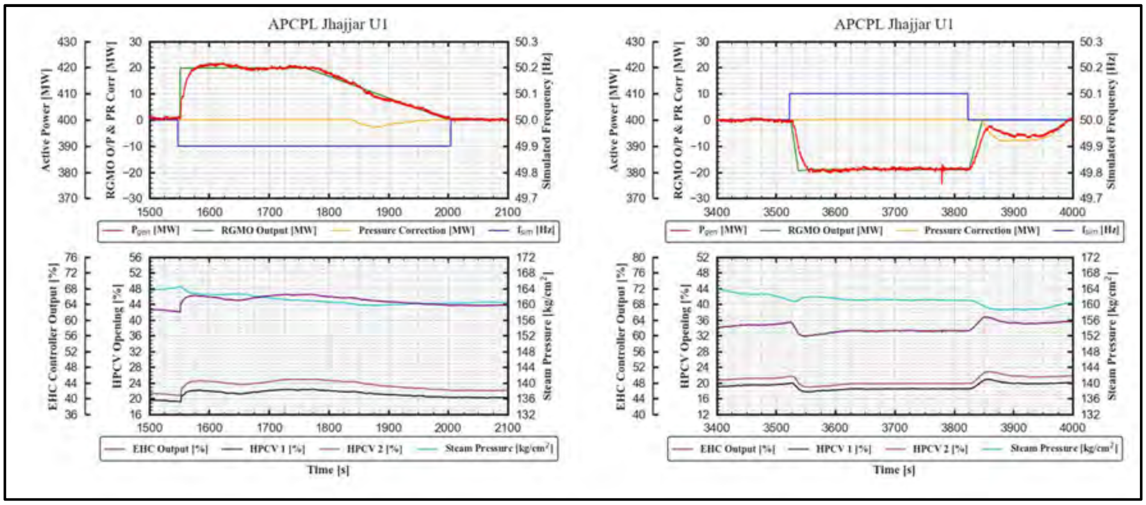


Figure 52 Step tests of -+0.10 Hz & +-0.10 Hz at APCPL Jhajjar unit 1 at 400 MW load level

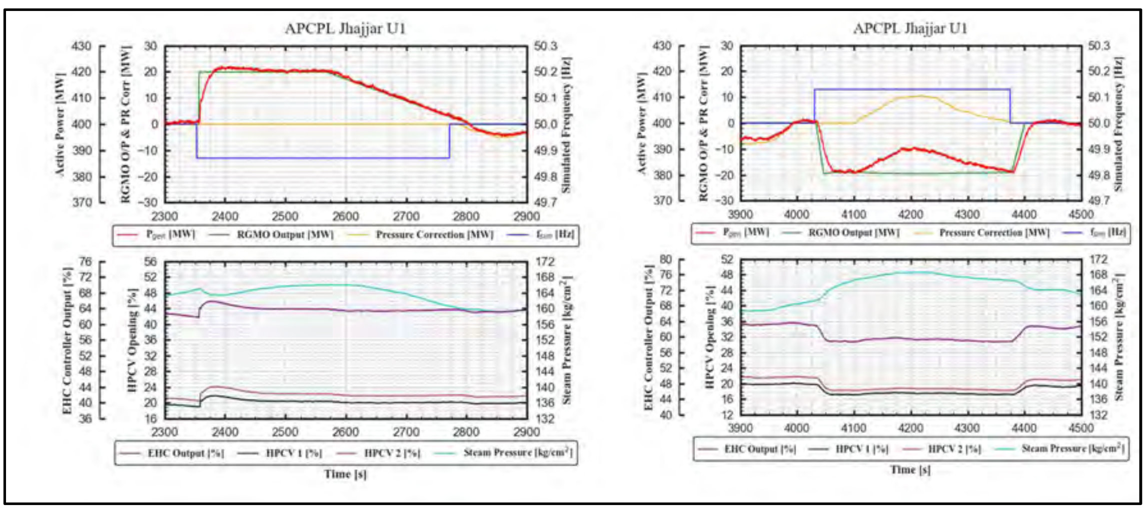


Figure 53 Step tests of -+0.13 Hz & +-0.13 Hz at APCPL Jhajjar unit 1 at 400 MW load level

3.2.4. Droop at MCR with 5% limiter on CG for frequency less than 50 Hz & on MCR for frequency greater than 50 Hz.

Droop is implemented on machine's continuous rating (MCR) in frequency control logic with the maximum change in actual load is limited to 5% of unit's CG for frequency less than 50 Hz & on MCR for frequency greater than 50 Hz.

Considering the step tests of 0.1 Hz & 0.13 Hz for below & above 50 Hz at NTPC Sipat at 528 MW load level with unit's MCR of 660 MW:

i. During both the step tests of -+0.10 Hz & +-0.10 Hz, MW correction i.e., RGMO Output (26.4 MW) is observed as per the set droop of 5%, as shown in Figure 54.

ii. While during the step tests of -+0.13 Hz & +-0.13 Hz, the MW correction (+26.4 MW & -33 MW) obtained is less than the desired MW correction of +34.32 MW & -34.32 MW since a limiter of 5% on unit's CG (528 MW) for frequency less than 50 Hz & a limiter of 5% of unit's MCR (660 MW) is limiting the correction to +26.4 MW & 33 MW respectively, as shown in Figure 55.

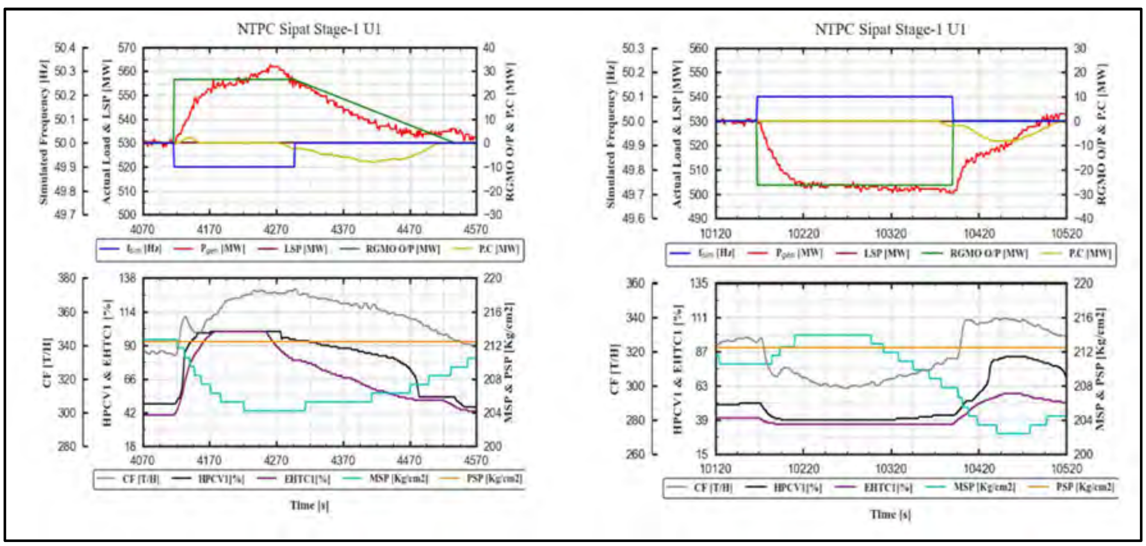


Figure 54 Droop at MCR with 5% limiter on CG for f< 50 Hz & on MCR for f>50 Hz at NTPC Sipat unit 1

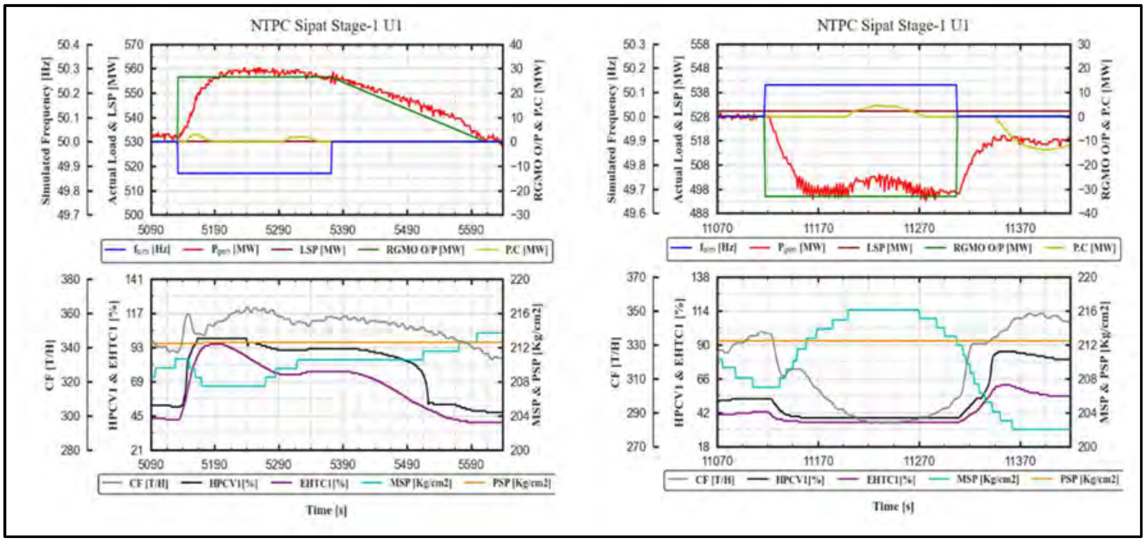


Figure 55 Droop at MCR with 5% limiter on CG for f< 50 Hz & on MCR for f>50 Hz at NTPC Sipat unit 1.

3.3. Initial response of the frequency controller output during frequency changes

Based on the initial response of the frequency controller output i.e., RGMO output in terms of MW with the change in frequency, units are categorized as:

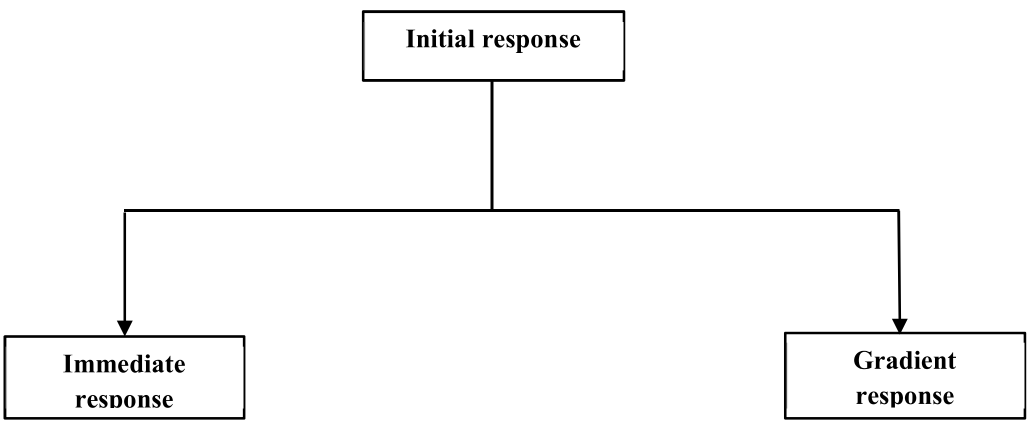


Figure 56 Categorisation of logic implemented for initial response.

3.3.1. Immediate response

Immediate response is the instant rise in frequency controller output with the applied change in frequency resulting in faster response from the unit.

Considering the step changes -+0.10 Hz & +- 0.10 Hz at 420 MW load level at NTPC Kahalgaon unit-6, where instant rise in frequency controller output resulting in faster response from the unit.

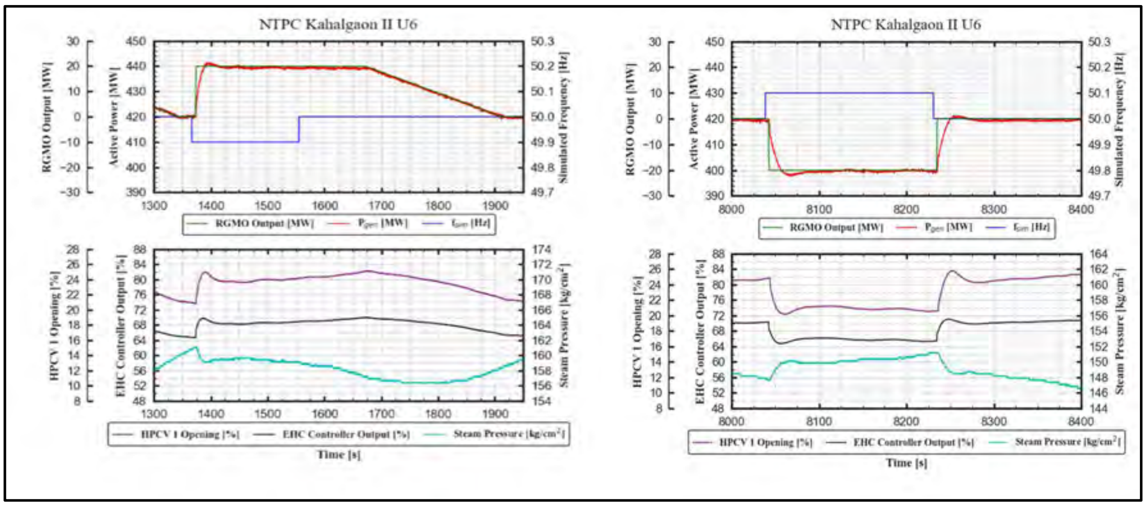


Figure 57 Immediate response at NTPC Kahalgaon unit-6.

3.3.2. Gradient response

Gradient response is the rise in frequency controller output (RGMO Output) in gradient form (i.e., rate of change of RGMO signal in MW with respect to time) with the applied change in frequency resulting in slower response from the unit.

Considering the step changes -+0.10 Hz & +- 0.10 Hz at 200 MW load level at NTPC Dadri Stg-II unit-1, where frequency controller output rises with gradient resulting in slower response from the unit.

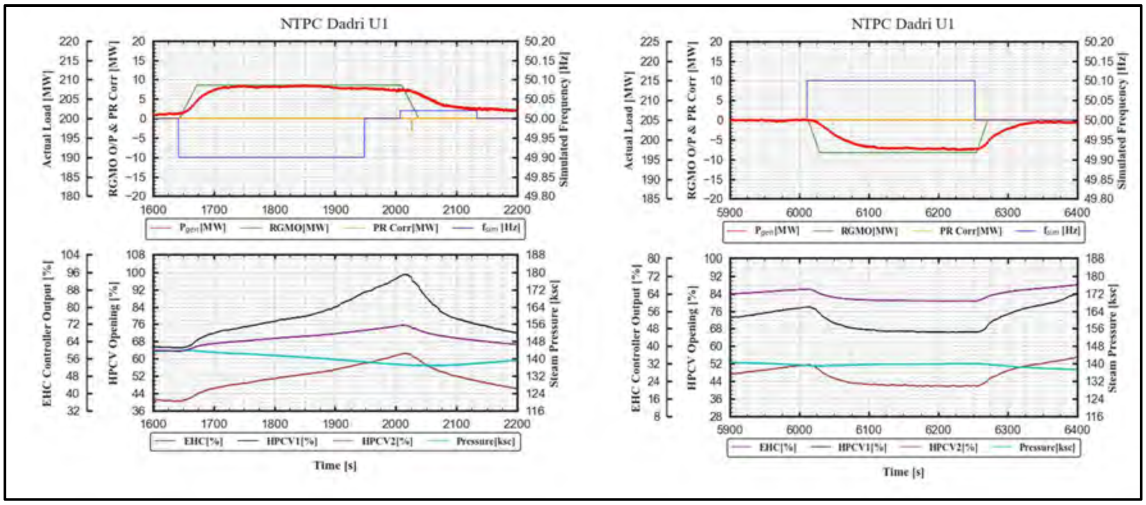


Figure 58 Gradient response at NTPC Dadri Stg-II unit-1.

3.4. Ramp back rate

Ramp back rate is the rate implemented in frequency controller logic to withdraw the MW correction in case of continued operation is not sustainable.

It was observed from the results of PFR testing that in different power plants, different ramp back rates are implemented in frequency control logic for frequency below 50 Hz, which is not as per IEGC clause 5.2 (h) which states that,

"After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute, in case continued operation at the increased level is not sustainable. Any generating unit not complying with the above requirements, shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of RLDC."

Based on the observations ramp back rate (other than 1 % per minute) can be categorized as:

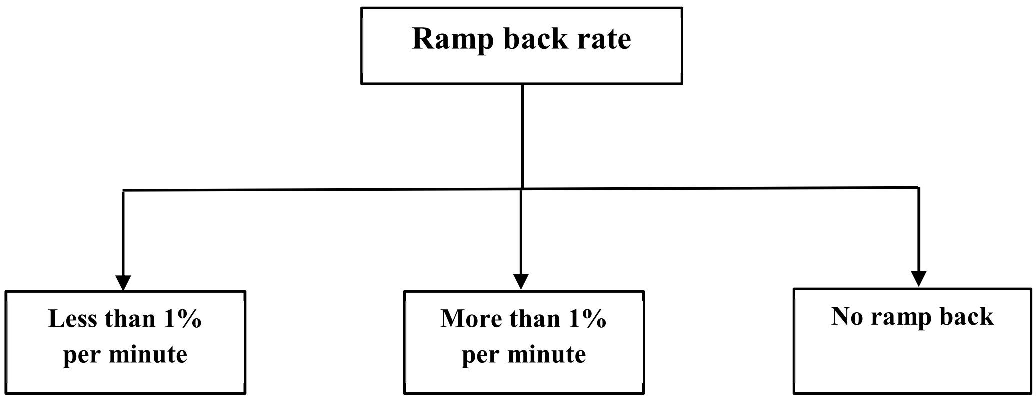


Figure 59 Categorisation of logics implemented for ramp back rate.

3.4.1. Ramp back rate less than 1%

Ramp back rate less than 1% per minute results in slow withdrawal of MW correction (RGMO output) in comparison to the withdrawal with 1% per minute.

Considering the step test of -+0.06 Hz at 200 MW load level at BRBCL unit-2, unit responds as per the droop, holds the MW correction for 180 seconds and then starts ramping back with the rate less than 1 % per minute resulting in complete withdrawal of MW correction in 300 seconds as shown in Figure 61

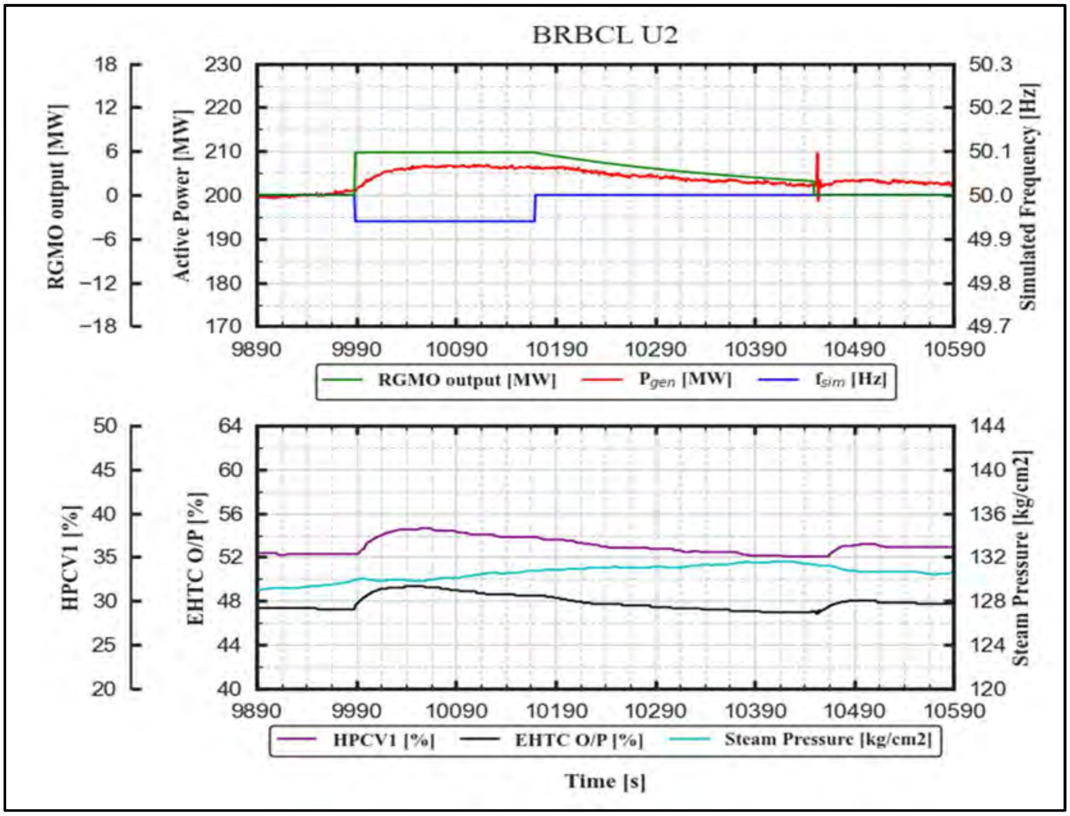


Figure 60 Ramp back rate less than 1% per minute at BRBCL unit 2.

3.4.2. Ramp back rate more than 1% per minute

Ramp back rate more than 1% per minute results in fast withdrawal of MW correction (RGMO output) in comparison to the withdrawal with 1% per minute.

Considering the step test of -+0.10 Hz at 450 MW load level at NTPC Talcher unit 6, unit responds as per the droop, holds the MW correction for 300 seconds and then starts ramping back with the rate more than 1 % per minute resulting in complete withdrawal of MW correction in around 50 seconds as shown in Figure 61.

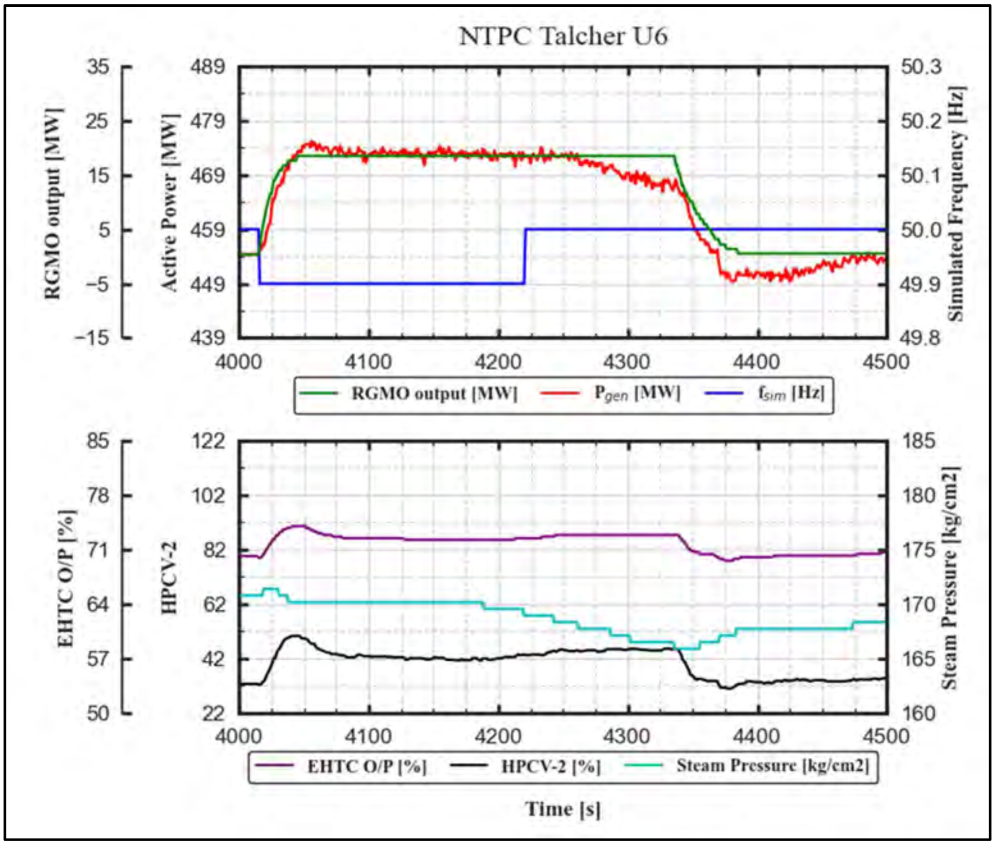


Figure 61 Ramp back rate more than 1% per minute at NTPC Talcher unit 6.

3.4.3. No ramp back.

In some of the tested units, instant withdrawal of MW correction is observed instead of ramp back rate.

Considering step test of -0.13 Hz at 580 MW load level at Jhabua power unit 1, no ramp back is implemented, and unit automatically withdraws the MW correction instantly after holding correction for 300 seconds as shown in Figure 62.

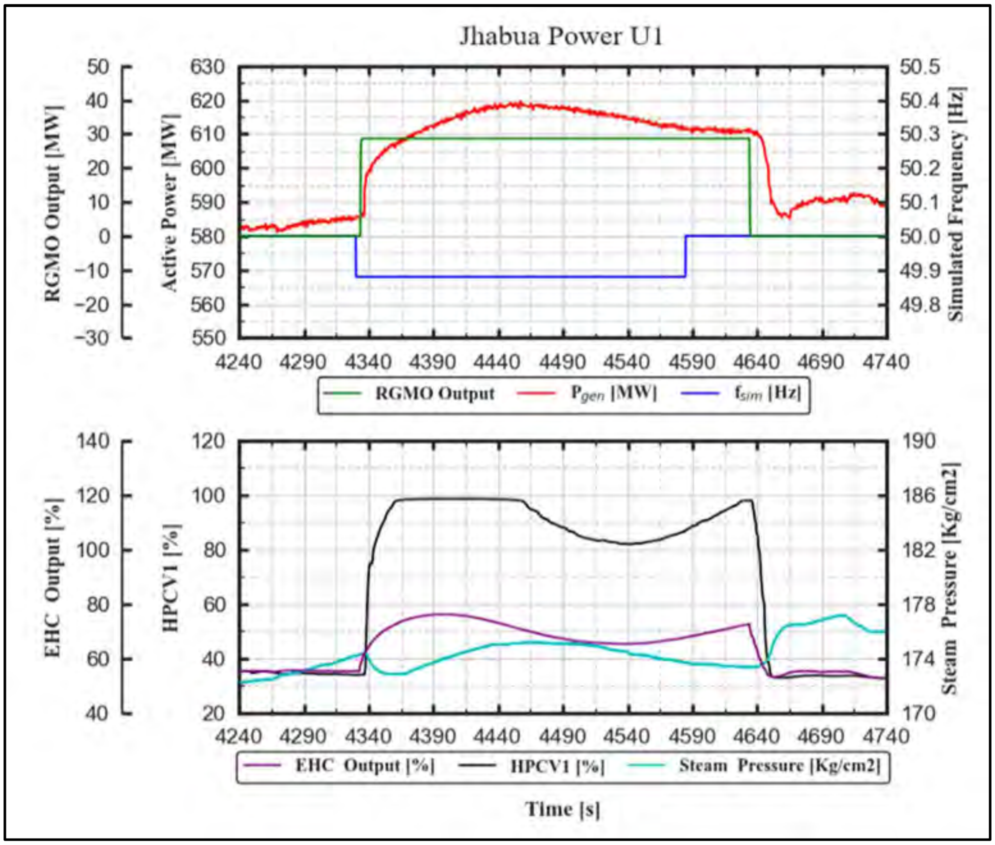


Figure 62 No ramp back logic at Jhabua power unit 1.

3.5. Pressure correction

Pressure deviation occurs during loading and unloading the generating unit. Therefore, in order to maintain the main steam pressure within the desired limits, pressure correction logic is implemented at most of the stations. It compensates actual load (MW) in order to maintain the main steam pressure.

Pressure correction logic affects the sustainability of primary response and also restricts the full primary frequency response since it maintains the steam pressure near to its setpoint by compensation in actual load (MW).

Based on primary frequency response testing logics implemented for pressure correction can be categorised as:

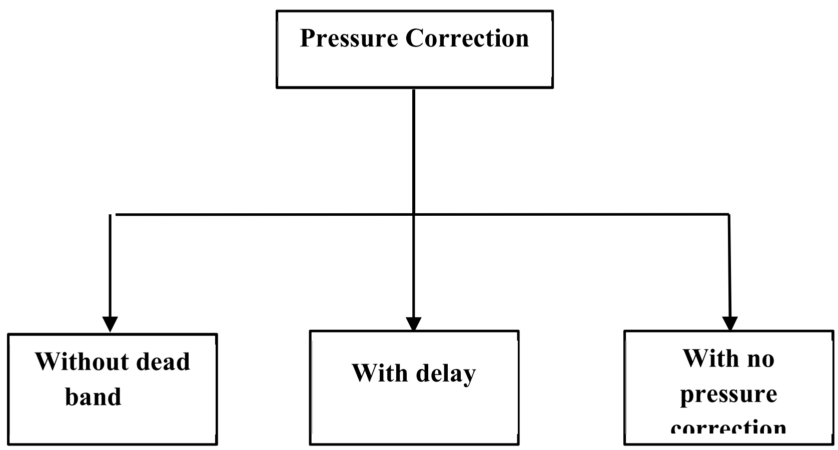


Figure 63 Categorisation of logics implemented for pressure correction.

3.5.1. Without dead band

Pressure correction without dead band is the logic implemented in controller for steam pressure control, activates whenever steam pressure before control valves deviates from the pressure setpoint and results in compensation in actual load (MW) by controlling the valve positions and fuel flow.

Considering step test of +/-0.10 Hz at 740 MW load level at NTPC Kudgi, where due to immediate activation of pressure correction and its compensation in MW with the deviation in main steam pressure, PFR is not sustaining as shown in Figure 64.

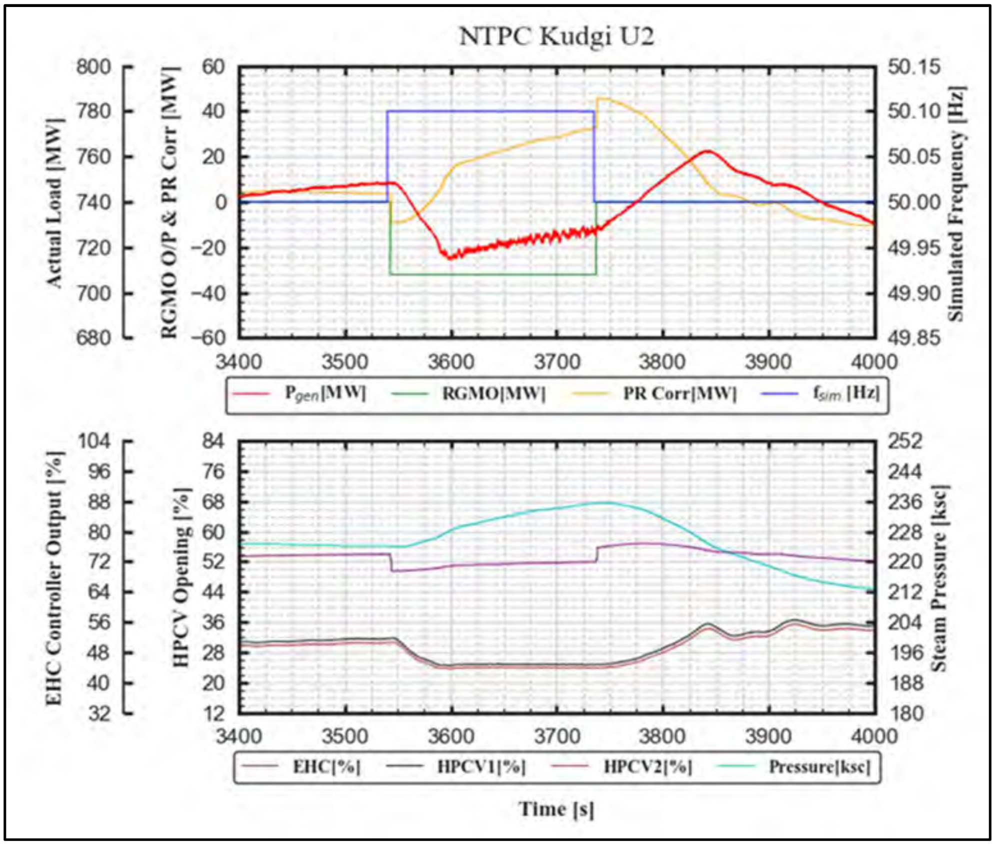


Figure 64 – Pressure correction without dead band at NTPC Kudgi unit 2.

3.5.2. With delay

Pressure correction with delay is the logic implemented in controller for steam pressure control, which activates after a delay whenever steam pressure deviates from its setpoint leads to compensation in actual load (MW) by controlling the valve positions and the fuel flow.

Considering the step tests of -/+0.13 Hz & +/-0.13 Hz at 500 MW load level performed at NTPC Ramagundam unit 6 where, unit restricts the PFR due to activation of pressure correction in terms of MW only after providing the full response for 90 seconds as shown in Figure 65.

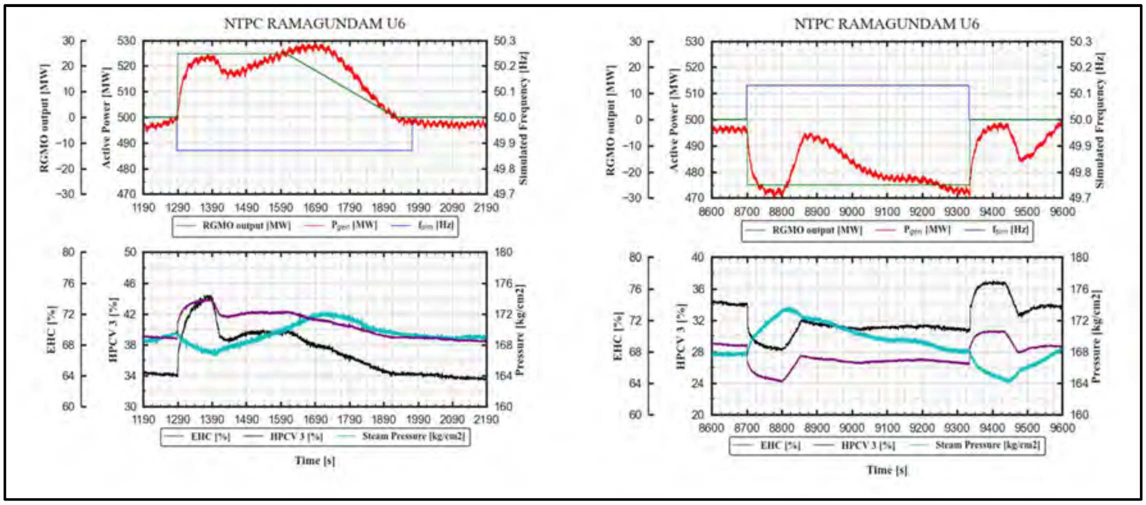


Figure 65 Pressure correction with delay at NTPC Ramagundam unit 6.

3.5.3. Deactivation of pressure correction

Deactivation of pressure correction loop results in no correction or compensation in actual load (MW) with the deviation in steam pressure.

It was observed during PFR testing that the units with above mentioned logic for steam pressure control contributes to PFR and holds the desired MW correction for the longer duration but without considering the effect of steam pressure deviation.

Considering the step tests of -/+0.10 Hz & +/-0.10 Hz at 325 MW load level at NLC NNTPS unit 1, where with the change in simulated frequency step, steam pressure deviates from its setpoint with the change in actual load but no change in pressure correction (in MW) signal was observed as shown in Figure 66.

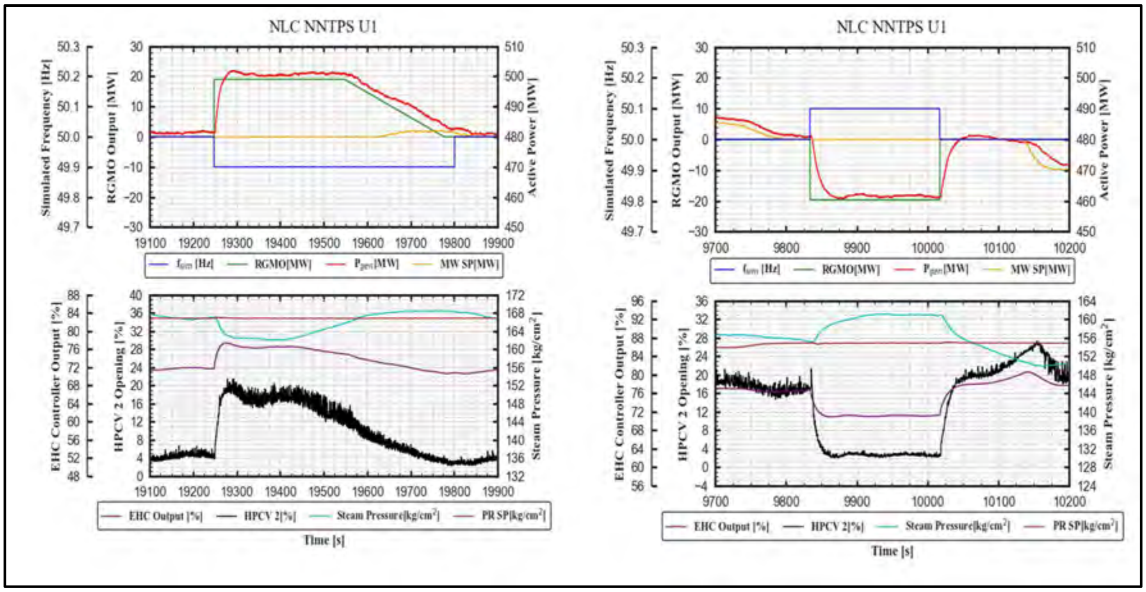


Figure 66 Deactivation of pressure correction at NLC NNTPS Unit 1

3.6. Scan time and the intentional delay

Scan time is the time taken to process the complete cycle of scanning includes getting inputs, execute control logics & generating the output by distributed control system.

And the intentional delay is defined as the time delay in frequency controller to generate the governor output corresponding to the applied change in frequency.

Considering the governor outputs of all the coal-based units in eastern region, where delay due to both scan time and the intentional delay varies from milliseconds up to 6.6 seconds. Due to combined effect of both scan time and intentional delay, each unit initiates PFR at different point of time with respect to same frequency change as shown in Figure 67.

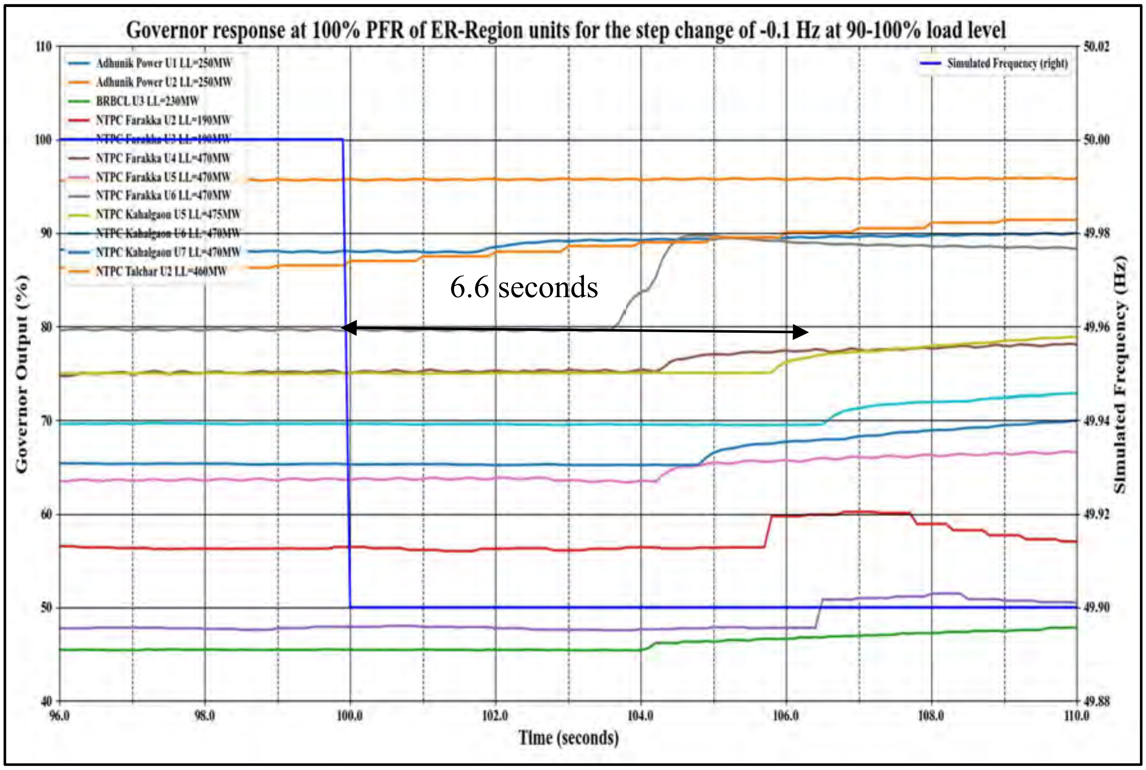


Figure 67 Combined effect of scan time and intentional delay in governor's output of ER region coal-based units.

Due to the delay in governor's output, delay in response initiation for different units is observed as shown in Figure 68.

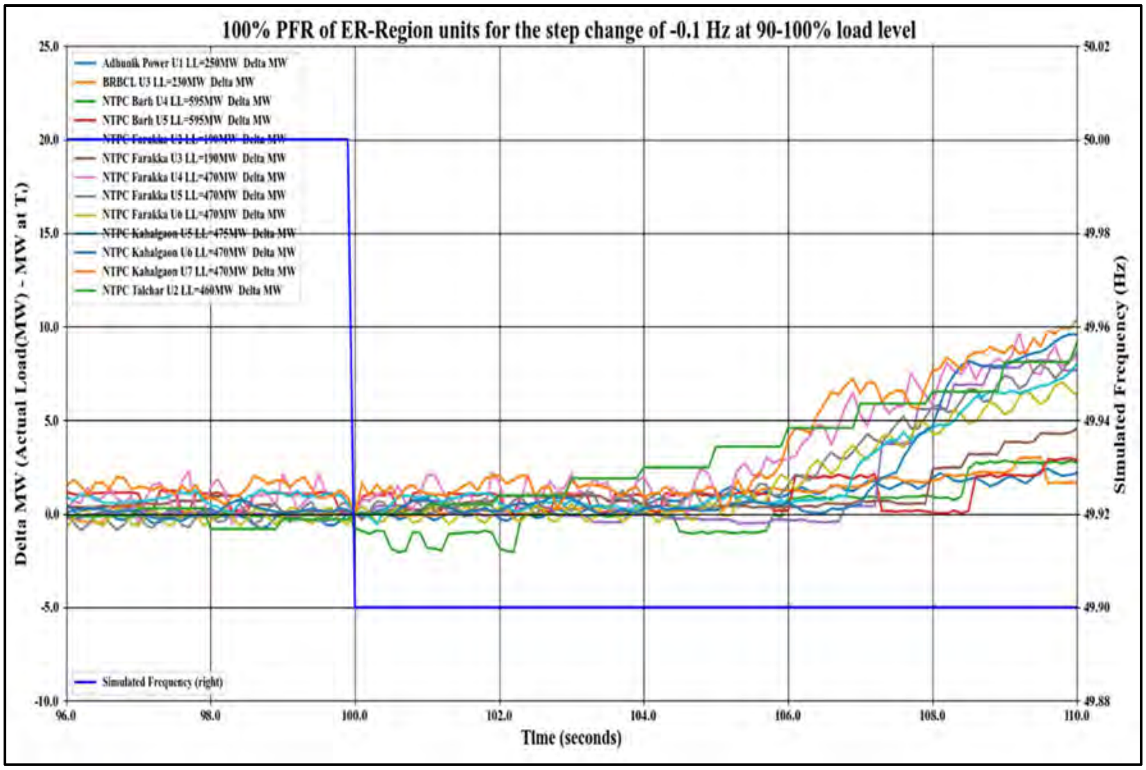


Figure 68 Combined effect of scan time and intentional delay in actual load of ER region coal based units.

3.7. Manual interventions during the test

It has been observed in most of the tested units that manual interventions and favourable test conditions were created in order to achieve the desired response.

Based on the PFR tests observation manual interventions can be categorised as:

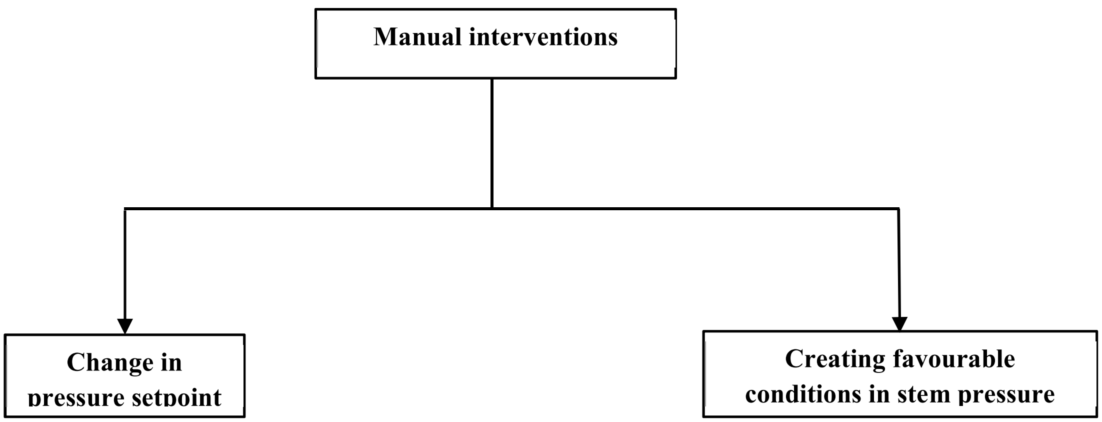


Figure 69 Categorisation of manual interventions

3.7.1. Change in pressure setpoint

Changes in pressure setpoint were observed during PFR testing to achieve the desired response from the unit.

Considering the step of +-0.10 Hz at 500 MW load level at JPL(Stage 2) unit 1, where it was observed that main steam pressure is less than its setpoint value and is in decreasing trend before the step change indicates the manual intervention to achieve the desired response as shown in Figure 70.

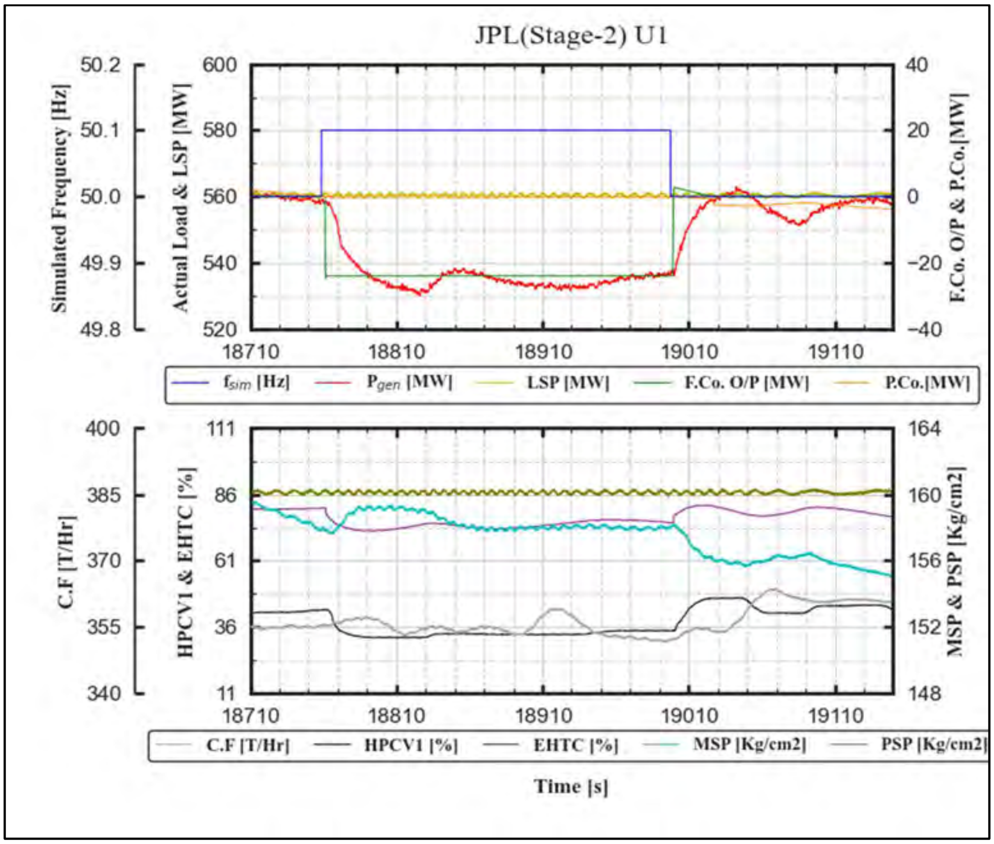


Figure 70 Step test of +-0.10 Hz at 560 MW load level at JPL (Stage 2) unit 1.

3.7.2. Creating favourable conditions in steam pressure

Favourable condition of main steam pressure was maintained prior to the injection of simulated frequency steps in order to achieve the desired response. Rising trend of steam pressure was observed for some of the units when simulated frequency step change for below 50 Hz was applied and vice versa as shown in Figure 71 step tests of -+0.13 Hz & +-0.13 Hz at 430 MW load level at Sasan Power Limited unit 5.

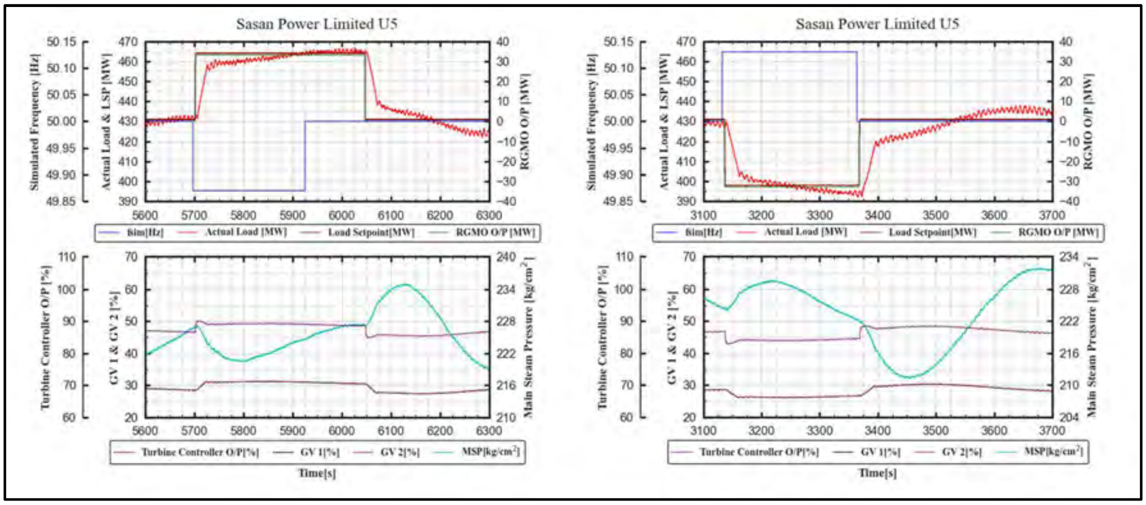


Figure 71 Step tests of -+0.13 Hz & +-0.13 Hz at 430 MW load level at Sasan Power Limited unit 5.

3.8. Restriction in response

From the PFR test results it has been observed that logics in some of the tested units are restricting the PFR such as RGMO logic for frequency above 50 Hz, fixed change in actual load irrespective of frequency change etc which is not as per the IEGC clause 5.2 (g) which states that,

"Facilities available with/in load limiters, Automatic Turbine Run-up System (ATRS), Turbine supervisory control, coordinated control system, etc., shall not be used to suppress the normal governor action in any manner and no dead bands and/or time delays shall be deliberately introduced except as specified in para 5.2(f) above".

Based on test results, restriction in response can be categorised as:

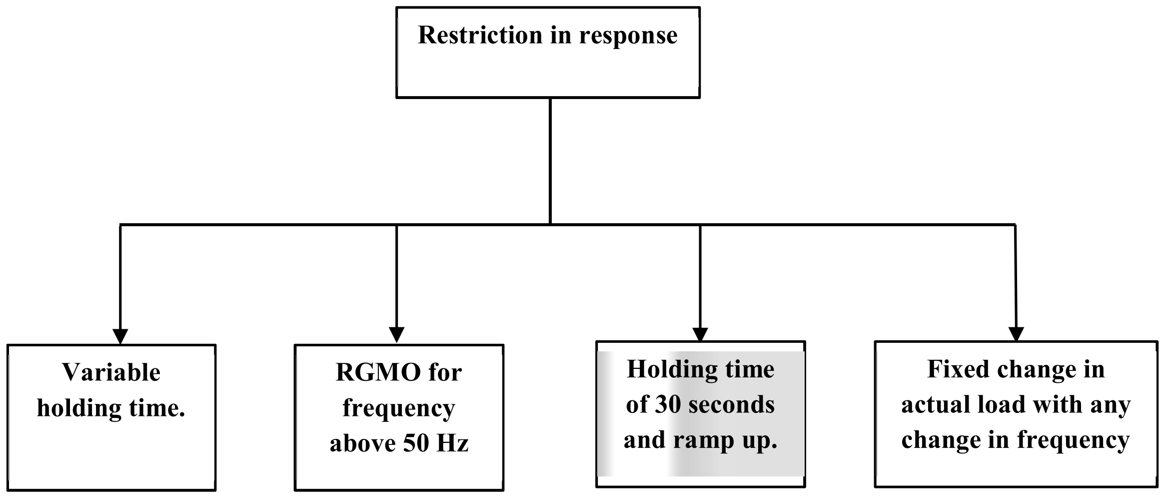


Figure 72 Categorisation of logics implemented for restriction in response.

3.8.1. Variable holding time.

During PFR tests variable holding time of frequency controller output (RGMO output) is observed in controller's logic depending on the deviation in main steam pressure, unit started ramping back instantly resulting in variable holding time.

Considering the Step test of -+0.10 Hz and -+0.08 Hz at 780 MW and 760 MW load level at NTPC Kudgi , where variable hold time of 100 and 225 seconds of frequency controller output (RGMO O/P) is observed due to deviation in steam pressure from its setpoint as shown in Figure 73.

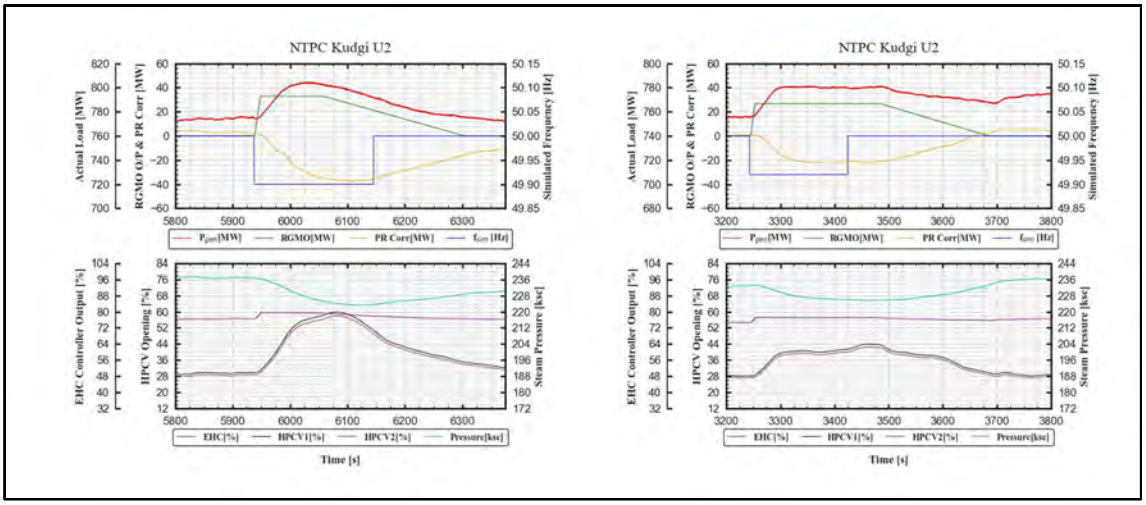


Figure 73 Variable holding time at NTPC Kudgi unit 2.

3.8.2. RGMO for frequency above 50 Hz

In some of the PFR tested units restricted governor mode of operation is implemented for frequency above 50 Hz, where no MW correction is observed when the frequency is improving towards 50 Hz from the value above 50 Hz resulting in restriction of natural response of the governor which is not in line with IEGC clause 5.2. (g).

Considering the step test of +-0.10 Hz at 780 MW load level at Tata Power MTPS unit-20, where with the step change of +0.10 Hz, MW correction (RGMO Output) increases to -30 MW. And when the frequency improves to 50 Hz, no MW correction is observed. After holding this correction for 300 seconds unit starts ramping up with the rate of 1% per minute.

Such response for frequency changes above 50 Hz indicates the restriction in response.

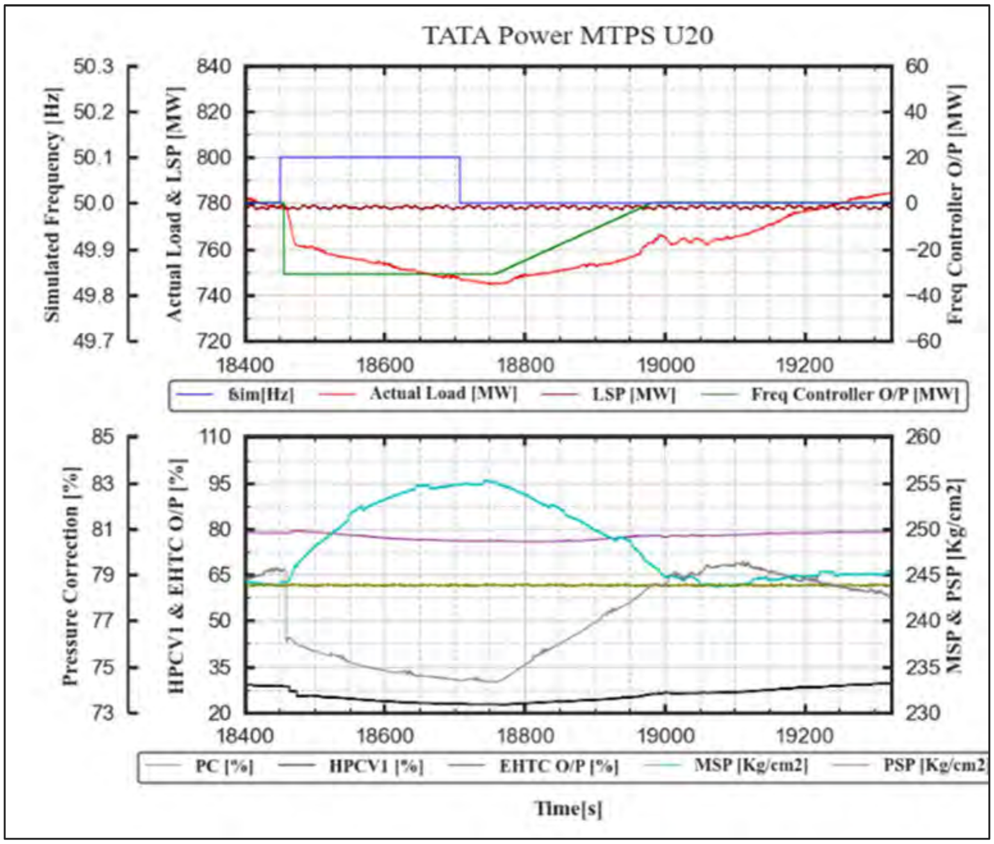


Figure 74 RGMO for frequency above 50 Hz at Tata Power MTPS unit 20.

3.8.3. Holding time of 30 seconds and ramp up.

In some of the tested units restricted governor mode of operation is implemented for frequency above 50 Hz with the holding time of 30 seconds in controller's logic resulting in restriction of natural response of the governor which is not in line with IEGC clause 5.2. (g).

Considering the step test of +-0.10 Hz at 486 MW load level at NTPC Dadri Stage 2 unit-6. When the frequency step of +0.10 Hz is applied, frequency controller output (RGMO O/P) decreases to -22.86 MW and then after holding MW correction for only 30 seconds, unit starts ramping up with a rate of 1% per minute irrespective of the frequency.

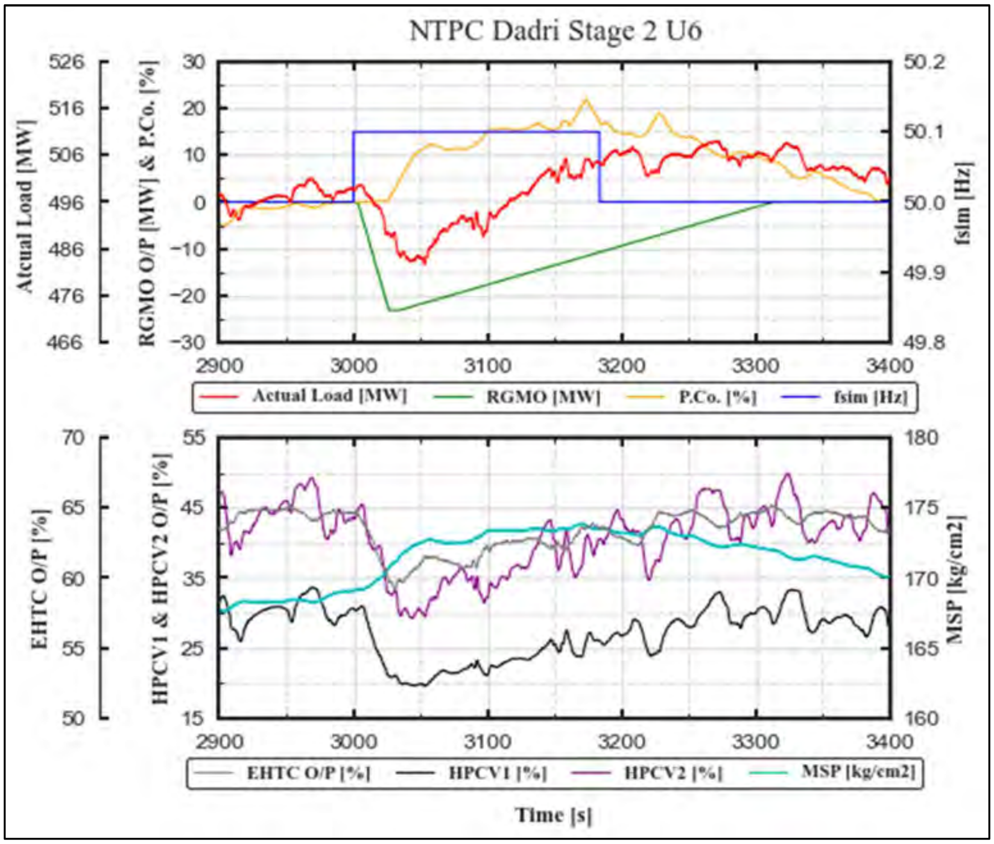


Figure 75 Holding time of 30 seconds and ramp up at NTPC Dadri Stage-2 unit 6.

3.8.4. Fixed change in actual load for any change in frequency

During PFR in some of the tested hydro units, fixed percentage change in actual load of either MCR or current generation with any change in frequency was observed, resulting in restriction of natural response of the governor as per the droop which is not in line with IEGC clause 5.2. (g).

Considering the step tests 0.13 Hz and 0.10 Hz for frequency below and above 50 Hz at 50 MW load level at NCA CHPH unit 1 where, with the change in simulated frequency step, 5% change of unit's MCR (2.5 MW) for both the step tests of 0.10 Hz & 0.13 Hz as shown in Figure 76 & Figure 77 respectively.

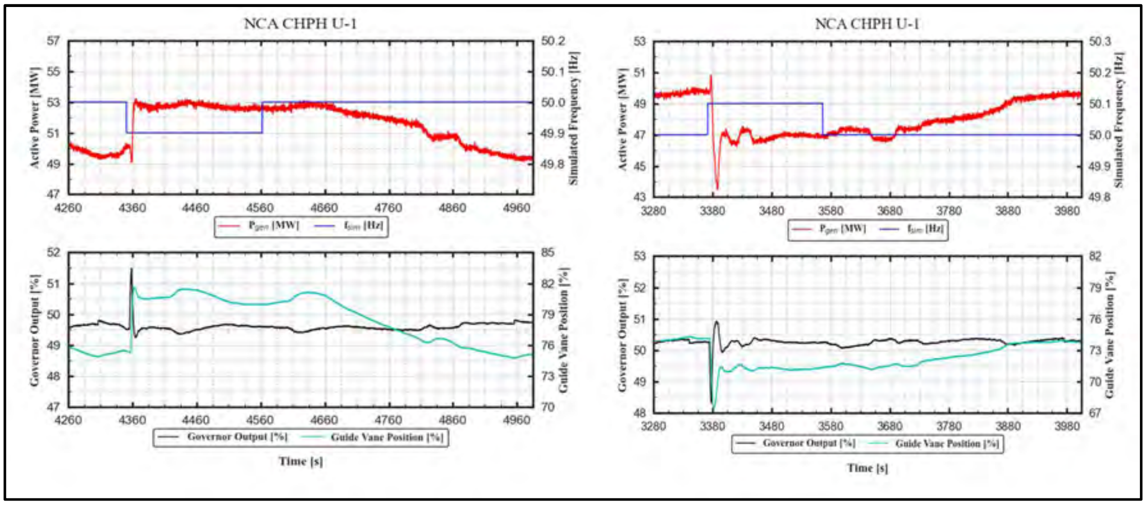


Figure 76 5% of MCR change in actual load for -/+0.10 & +/- 0.10 Hz at NCA CHPH unit 1

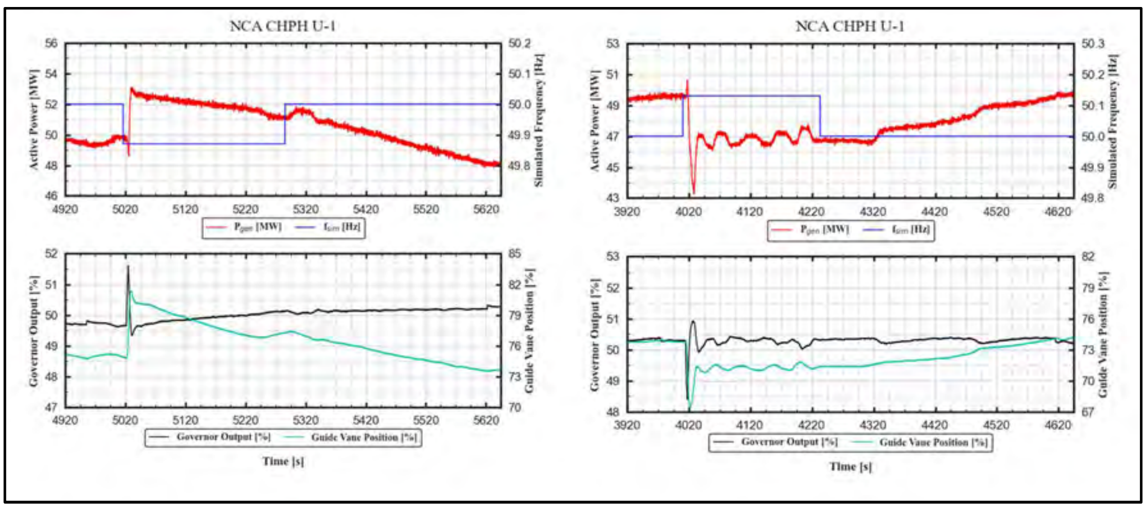


Figure 77 5% of MCR change in actual load for -/+0.13 & +/- 0.13 Hz at NCA CHPH unit 1

3.8.5. Valve wide operation

In some of the tested units, restriction in response was observed due to wide valve operation of the unit which is prohibited by IEGC clause 5.2 (h) which states that:

"*The generating station shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load and shall ensure that there is margin available for providing Governor action as primary response.*"

Considering step test of -+0.13 Hz, initially with the applied step change, MW correction (RGMO output) increases as per droop resulting in increase in actual load. However, increase in actual load is around 20 MW which is less than the desired MW correction of 30 MW due to wide valve operation (i.e., valve is operating at around 100% results in no margin left to support PFR) as shown in Figure 78.

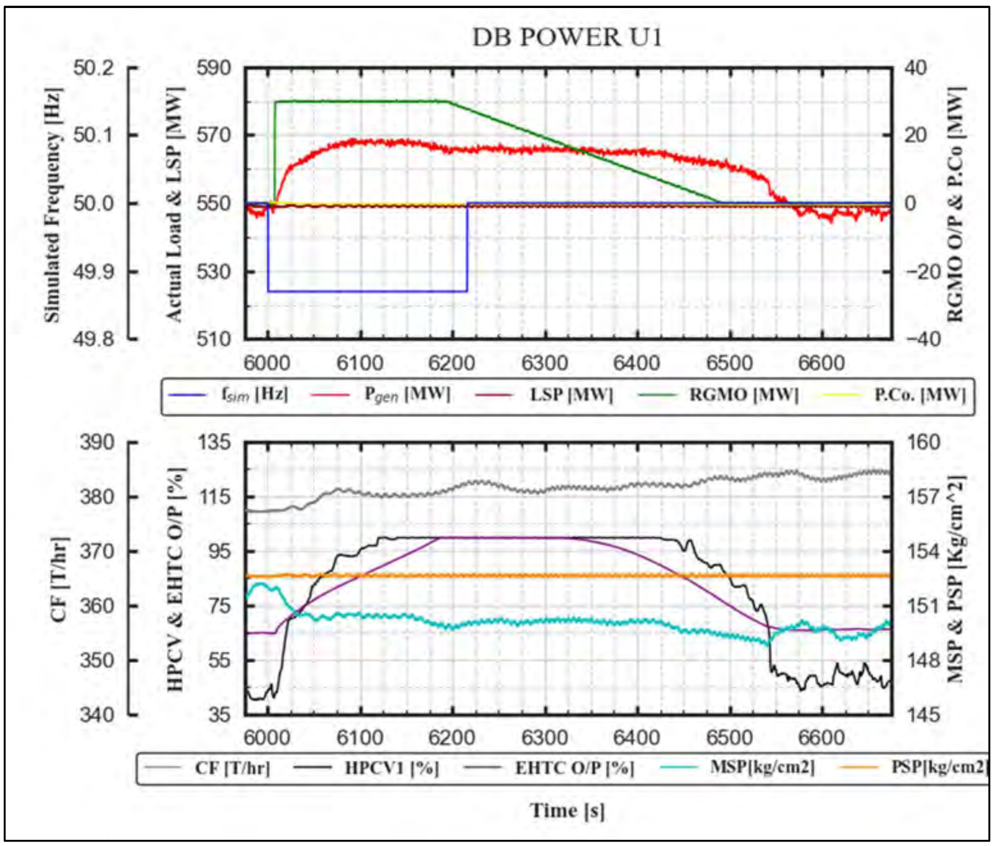


Figure 78 Valve wide operation at DB Power unit 1.

3.9. Dynamic turbine-governor model validation and past event simulation

After the completion of PFR tests of all the units, dynamic turbine-governor models are developed including the provision of ripple filter and restricted governor mode of operation (RGMO), then the developed models were validated with the test results.

Furthermore, a past event simulation study is performed for each tested units, response of the units during a frequency event is compared with the response from the validated model. It is noticed that, though the response during testing is as per the droop yet the response from the units is less than the desired response in most of the grid frequency events.

With the help of validated models such studies can be carried out in order to analyse the actual response in comparison to the desired response of the unit.

e.g., Model validation performed at SEIL Nellore P1 unit 1, where unit's response is matching with the results of dynamic simulation performed for the same frequency step test as shown in Figure 79.

However, in case of a grid event dated 21.10.2021, unit response is not adequate in comparison to the desired response represented as simulated power (i.e., power obtained after performing simulation for the same frequency event in the validated model) in the Figure 80.

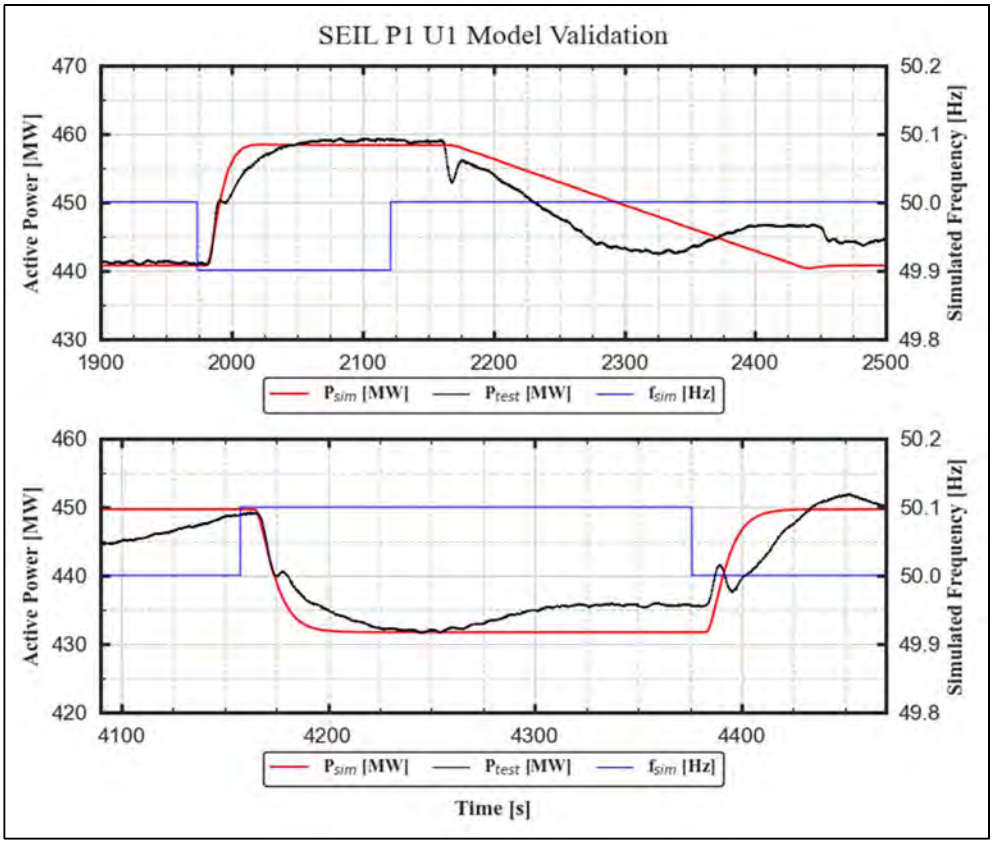


Figure 79 Step response validation for ±0.10 Hz at 440 MW at SEIL Nellore P1 unit 1.

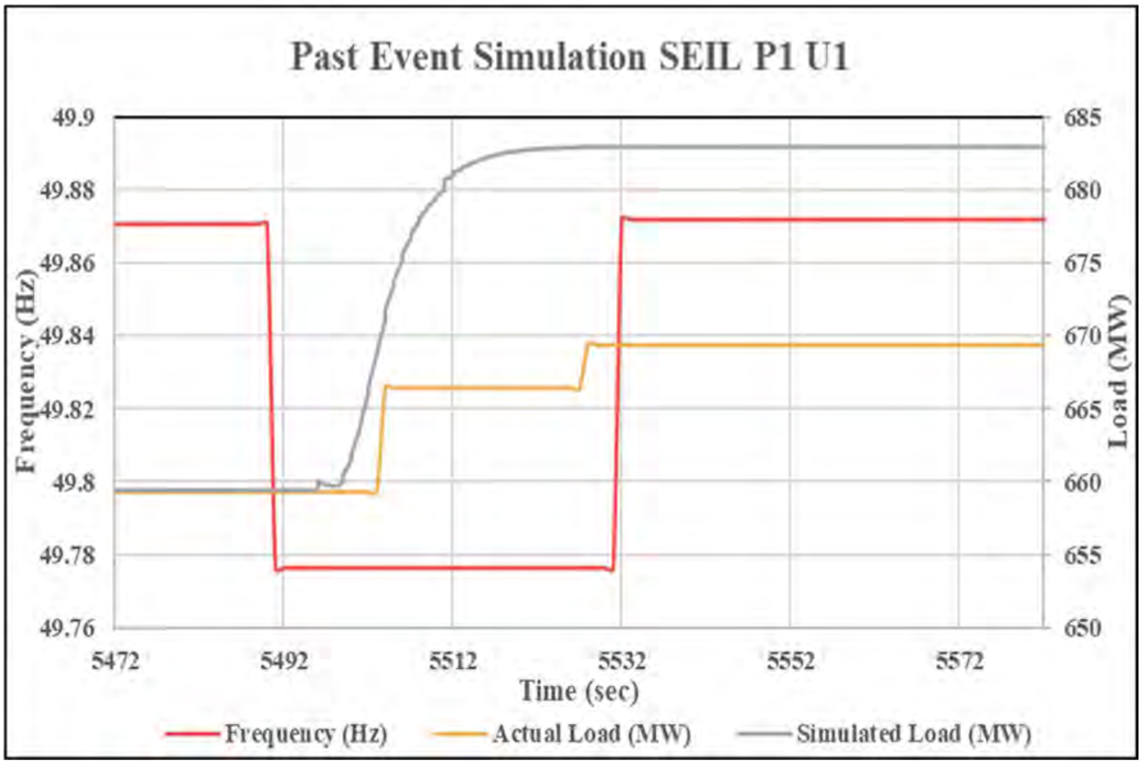
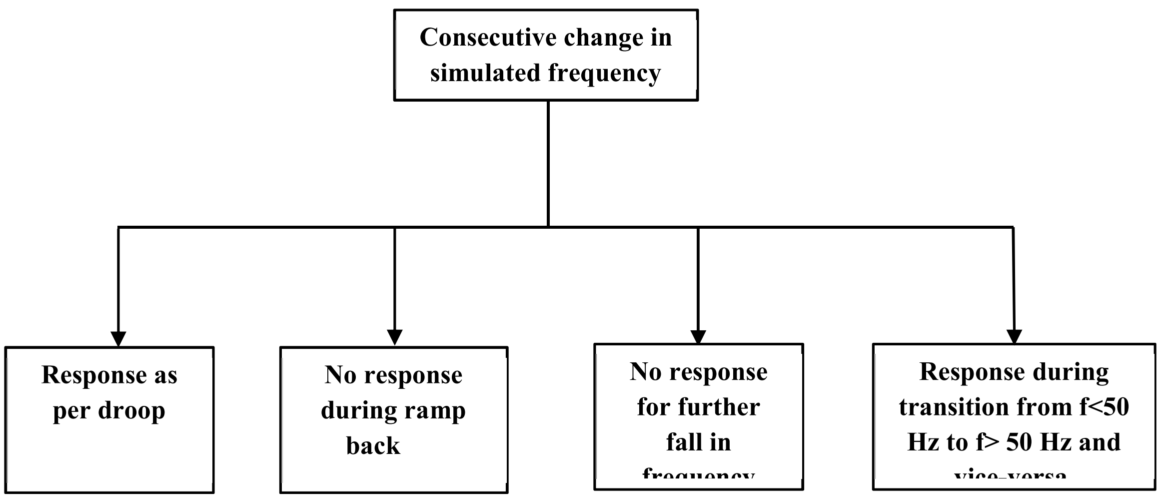


Figure 80 Past event simulation at SEIL Nellore P1 unit 1

3.10. Consecutive changes in simulated frequency

In some of the units during PFR testing special steps were applied to observe the response from the unit with the consecutive changes in simulated frequency.

Based on these special steps applied, response from the units is categorised as:



3.10.1. Response as per droop.

From the PFR test results it is observed in some of the units that the response is as per droop for all the consecutive change in frequency steps. Examples for the above-mentioned category for frequency below and above 50 Hz are as follows:

i. Considering the consecutive changes in simulated frequency for KSK Mahanadi Unit-4 from 50 Hz to 49.94 Hz unit gives the MW correction as per droop, for the further fall in frequency from 49.94 Hz to 49.92 the unit does not respond to the fall in frequency which shows that ripple filter is implemented at current tracking frequency. Further fall in frequency from 49.92 to 49.87 unit gives the MW correction as per droop. Further when the frequency is increased from 49.87 Hz to 49.98 Hz unit does not respond to the rise in frequency and when it is further increased from 49.98 Hz to 50 Hz the unit does the respond which can be seen in the Figure 81.

ii. Considering the consecutive changes in simulated frequency for KSK Mahanadi Unit-4 from 50 Hz to 50.04 Hz unit gives the MW correction as per droop, for the further increase in frequency from 50.04 Hz to 50.06 the unit does not respond to the rise in frequency which shows that ripple filter is implemented at current tracking frequency. Further rise in frequency from 50.06 to 50.10 unit gives the MW correction as per droop. Further when the frequency is improved towards 50 Hz from 50.10 Hz to 50 Hz unit responds as per droop which can be seen in the Figure 81

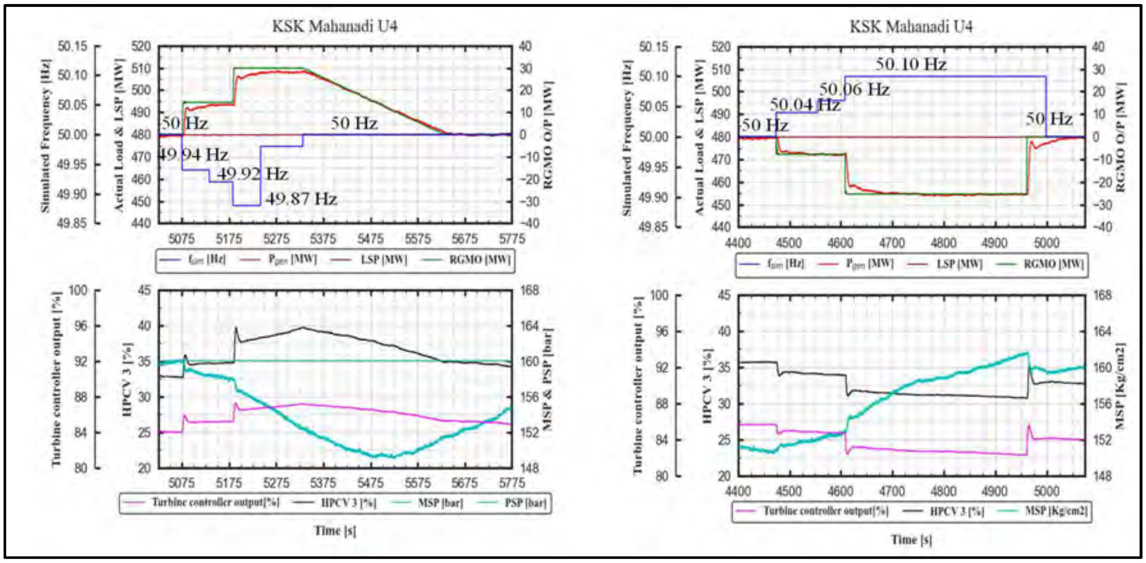


Figure 81 Special step test for frequency below 50 Hz & above 50 Hz.

3.10.2. No response during ramp back

From the PFR test results it is observed in some of the units that the response is as per droop for all the consecutive change in frequency steps. However, no response is observed for the further fall in frequency during ramp back. Example for the above-mentioned category is as follows:

Considering the consecutive changes in simulated frequency for NTPC KSTPS Unit-3 from 50 Hz to 49.96 Hz unit gives the MW correction as per droop, for the further fall in frequency from 49.96 Hz to 49.94 the unit responds to the fall in frequency as per droop. Further fall in frequency from 49.94 to 49.87 unit does not respond while the MW correction is ramping down at the rate of 1% per minute. Further when the frequency is increased from 49.87 Hz to 50 Hz unit does not respond to the rise in frequency which can be seen in the Figure 82.

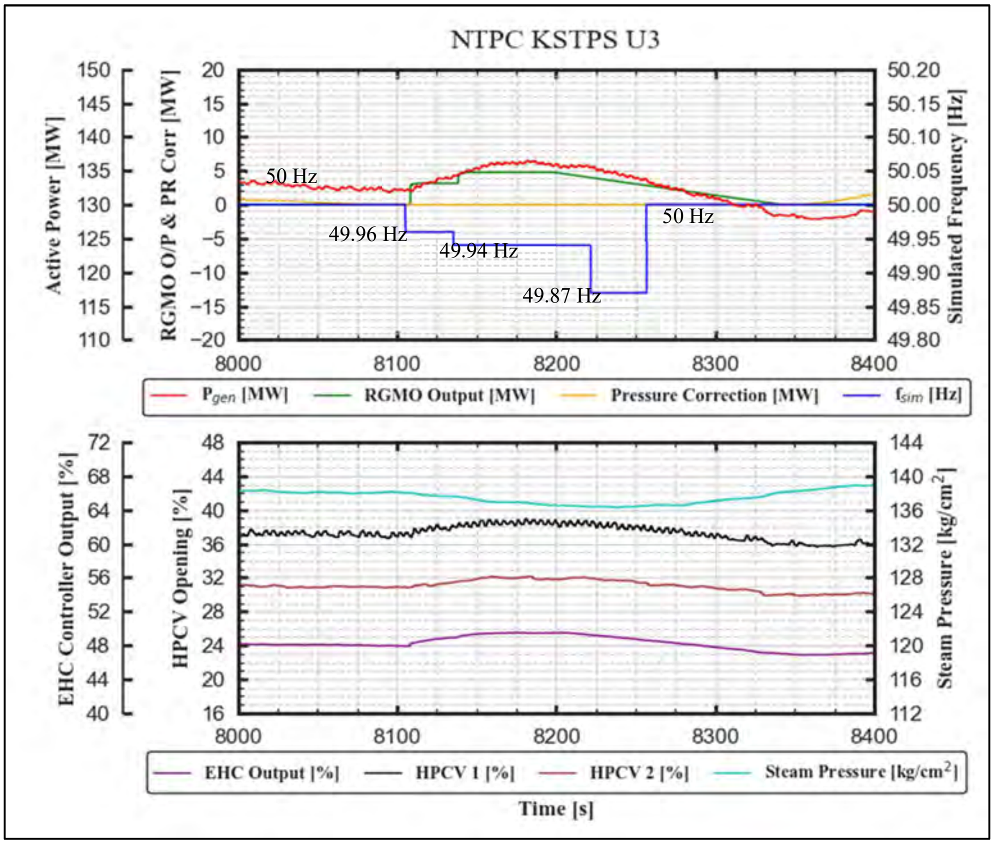


Figure 82 Special step test of consecutive changes in frequency from 50Hz→49.96Hz→49.94Hz→49.87 Hz→50 Hz.

3.10.3. No response for further fall in frequency

It is observed from the PFR test results that some units do not respond for the consecutive change in frequency. Example for the above-mentioned category for frequency is as follows:

Considering the consecutive changes in simulated frequency for SEIL P1 Unit-2 from 50 Hz to 49.96 Hz unit gives the MW correction as per droop, for the further fall in frequency from 49.96 Hz to 49.92 the unit does not respond to the fall in frequency. Further when the frequency is increased from 49.92 Hz to 49.965 Hz unit does not respond to the rise in frequency and starts to ramp back with a rate more than 1% per minute. Further when the frequency is increased from 49.965 Hz to 50 Hz there is no response from the unit which can be seen in the Figure 83.

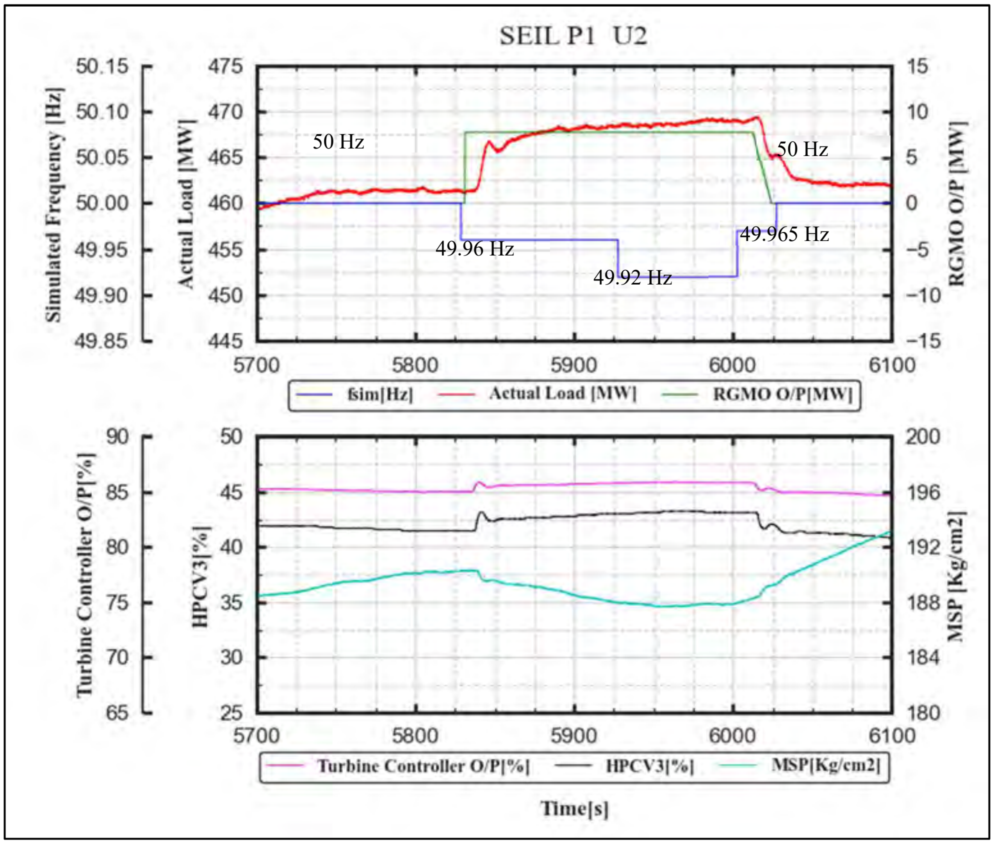


Figure 83 Special step test of consecutive changes in frequency from 50Hz→49.96Hz→49.92Hz→49.965 Hz→50Hz.

3.10.4. Response during transition from f<50 Hz to f> 50 Hz and vice-versa.

In some of the units, special steps are applied to observe the response during transition of frequency from below 50 Hz to above 50 Hz and vice versa. Examples for the above-mentioned category for frequency below and above 50 Hz are as follows:

i. Considering the consecutive changes in simulated frequency for NLC Tamil-Nadu Power Ltd unit-2 from 50 Hz to 49.95 Hz unit gives the MW correction as per droop, for the further fall in frequency from 49.95 Hz to 49.92 the unit responds to the fall in frequency as per droop. Further when the frequency is increased from 49.92 Hz to 50.05 Hz unit does not respond to the rise in frequency due to the implementation of the timer block and the MW correction withdraws at the rate of 1% per minute. Further when the frequency is increased from 50.05 Hz to 50.04 Hz unit responds as per droop with respect to 50 Hz and further when frequency is improved from 50.04 Hz to 50 Hz the unit withdraws the MW correction completely as per droop which can be seen in the Figure 84.

ii. Considering the consecutive changes in simulated frequency for NTPC Ramagundam Unit-5 from 50 Hz to 49.96 Hz unit gives the MW correction as per droop, for the further fall in frequency from 49.96 Hz to 49.94 the unit does not respond to the fall in frequency which shows that the ripple filter is implemented at current tracking frequency. Further when the frequency is decreased from 49.94 Hz to 49.87 Hz unit responds as per droop with respect to the 49.94 Hz. Further when the frequency is increased from 49.87 Hz to 49.98 Hz there is no response from the unit. Further when the frequency is increased from 50 Hz to 50.04 Hz unit immediately withdraws approx. 5 MW of response and the unit continued its ramp back. Further when frequency is improved from 50.04 Hz to 50 Hz the unit immediately increased the MW correction and ramped back at the rate of 1% per minute till actual Load setpoint which can be seen in the Figure 84.

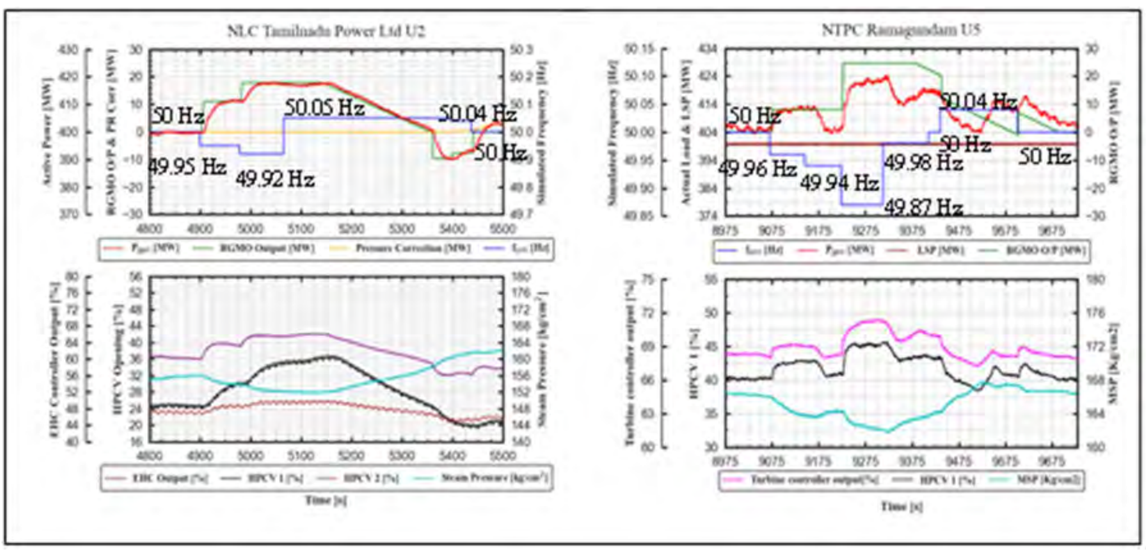


Figure 84 Special step test for frequency below 50 Hz & above 50 Hz.

3.11. System bottlenecks

3.11.1. Mechanical backlash

One of the system's bottlenecks found during PFR tests is the mechanical backlash which delays the change in actual load even after the change in frequency. This delay is due to the mechanical constraints involved actuator system of hydro power plants.

Considering the step tests of +-0.10 Hz, where a delay is observed in change in actual load with respect to the applied simulated frequency step due to the mechanical backlash in the actuator system of the unit as shown in Figure 85.

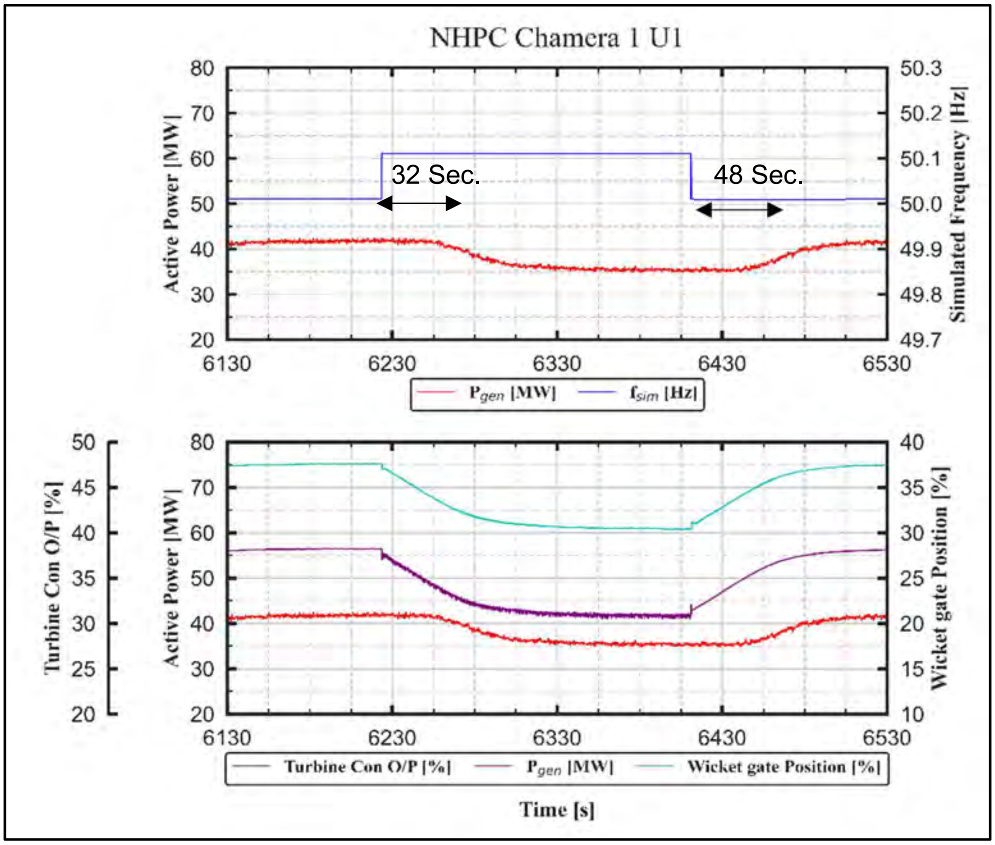


Figure 85 Step test of +-0.10 Hz at 32 MW load level at NHPC Chamera-I unit 1.

3.11.2. Unit stability of super-critical units

It has been observed during PFR tests of supercritical units that, due to deviations in main steam pressure, the actual load is non-sustainable at the desired value due to activation of pressure correction.

Considering step test of -+0.13 Hz performed at supercritical unit 1 of NPGCL Aurangabad at 610 MW load level with unit's MCR of 660 MW, where with the increase in MW after applying simulated frequency step, steam pressure deviates from its setpoint resulting activation of pressure correction. This activation of pressure correction results in non-sustainability of actual load at desired value as shown in Figure 86.

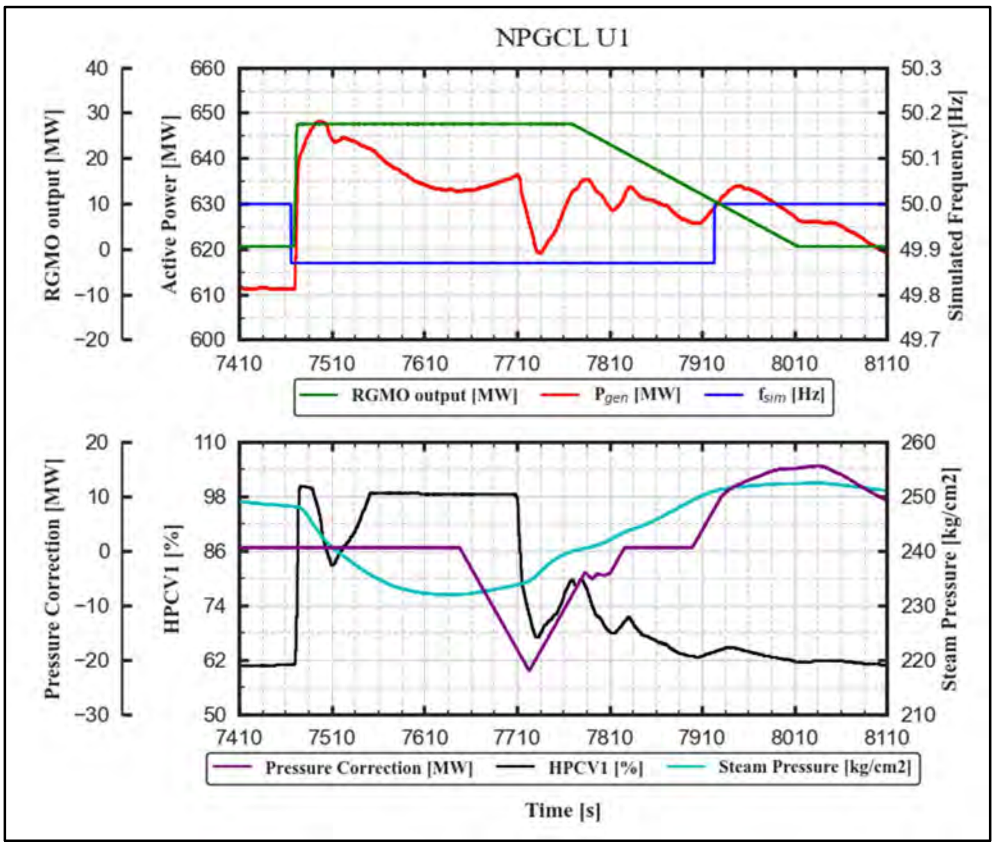


Figure 86 Non-sustainable PFR response at NPGCL Aurangabad unit 1.

3.11.3. Unit stability

In some of the tested coal-based unit, although the logics are as per the IEGC, yet the unit behaviour is not stable. Reason for this unstable behaviour is the unstable response from the boiler.

Considering the PFR tests performed at NTPC Bongaigaon, where during testing performed unit remains unstable due to the unstable response from the boiler as shown in Figure 87.

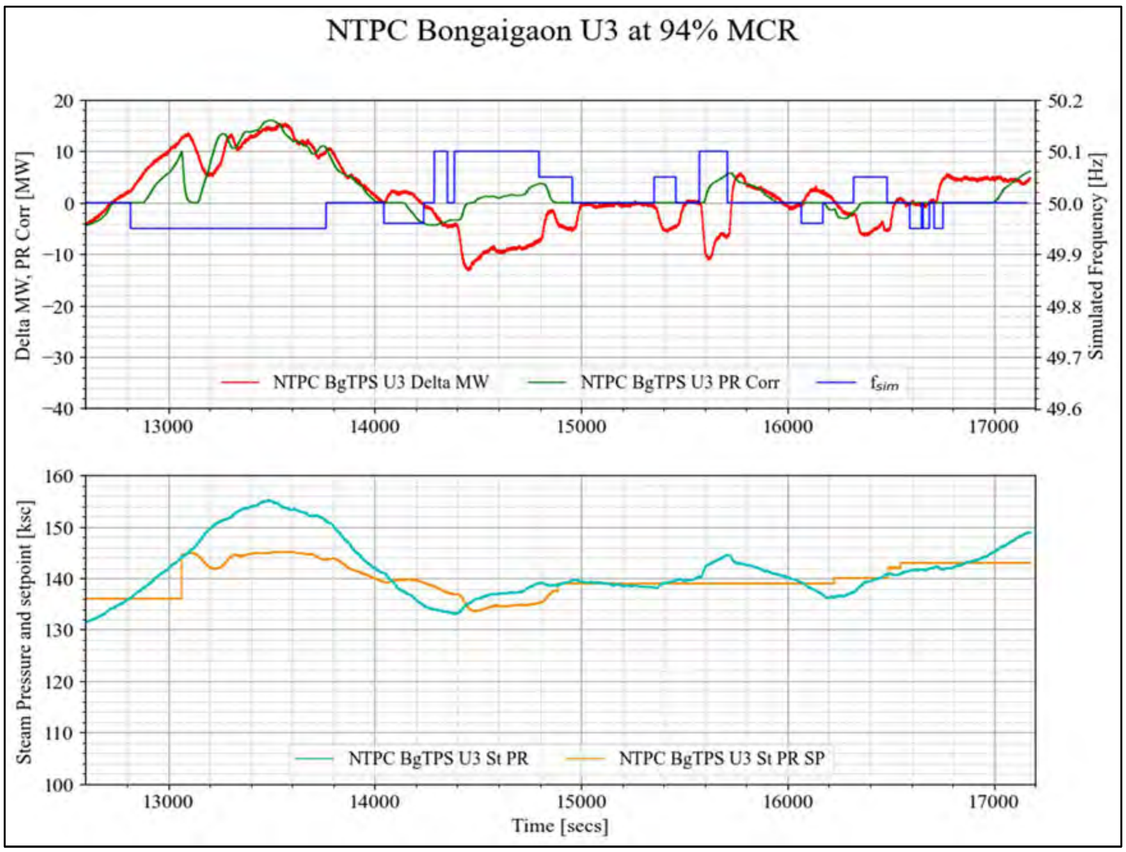


Figure 87 Step tests at NTPC Bongaigaon

3.12. Primary Response Analysis for the same set of units for a normal hour boundary as well as contingency

- **Ramagundam Unit 1 : 500 MW**

The RGMO response input from Ramagundam Thermal Unit 1 reveals a remarkable absence of primary response during high and low-frequency periods, as illustrated in Figure 88. In instances of high frequency, the frequency exceeded 50.05 Hz after 12:56 hrs, reaching nearly 50.27 Hz by 13:04 hrs, and remained above the IEGC band thereafter. Throughout this high-frequency period, the RGMO input directly provided to the governor consistently registered zero, indicating a lack of frequency support from the thermal unit. Similarly, during a sustained low-frequency period, where the frequency dipped below 49.90 Hz at 14:08 hrs and reached a minimum of 49.75 Hz at 14:16 hrs, the RGMO response remained persistently zero. Notably, no primary response was observed in both instances of high and low frequency. However, an analysis of the same unit's response during contingency events, such as generation loss, demonstrated a positive primary response. In a specific disturbance event (**Figure 89**), where the frequency net change recorded was 0.46 Hz, the RGMO response from the unit was 25 MW, aligning with the ideal response within the 5% limit on MCR.

The suggested reason for the unit's failure to provide primary response during hourly boundaries, especially in high and low-frequency periods, revolves around the implementation of the ripple filter logic in the frequency controller. This logic, tied to the current tracking frequency, may be constraining the governor's response by limiting it within the ripple filter band range calculated based on the current frequency and slower tracking rate.

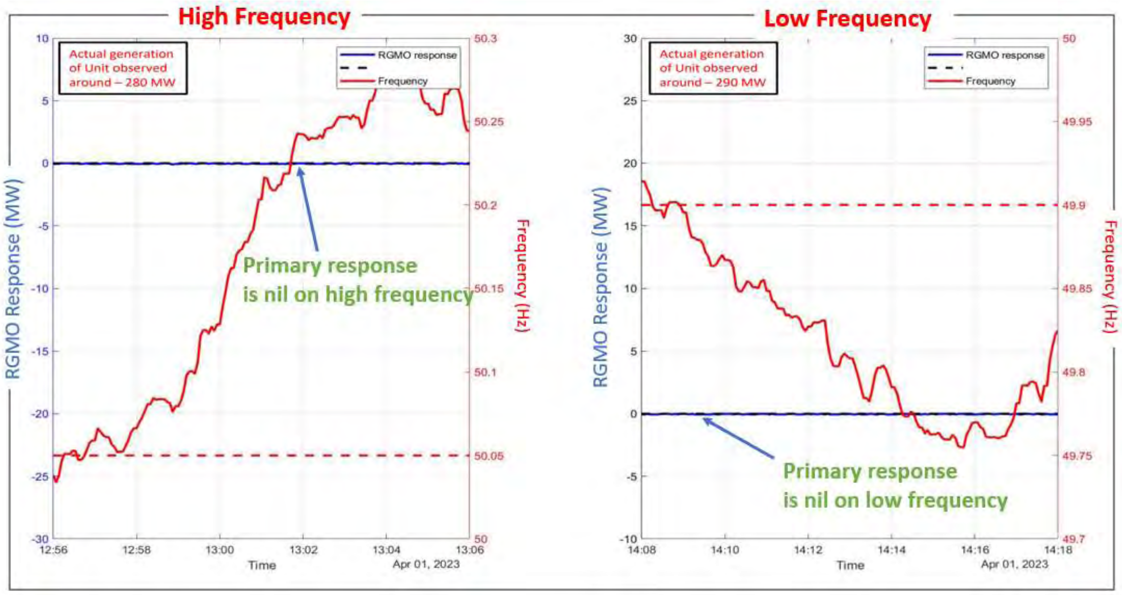


Figure 88: RGMO response for thermal unit during high and low frequency period

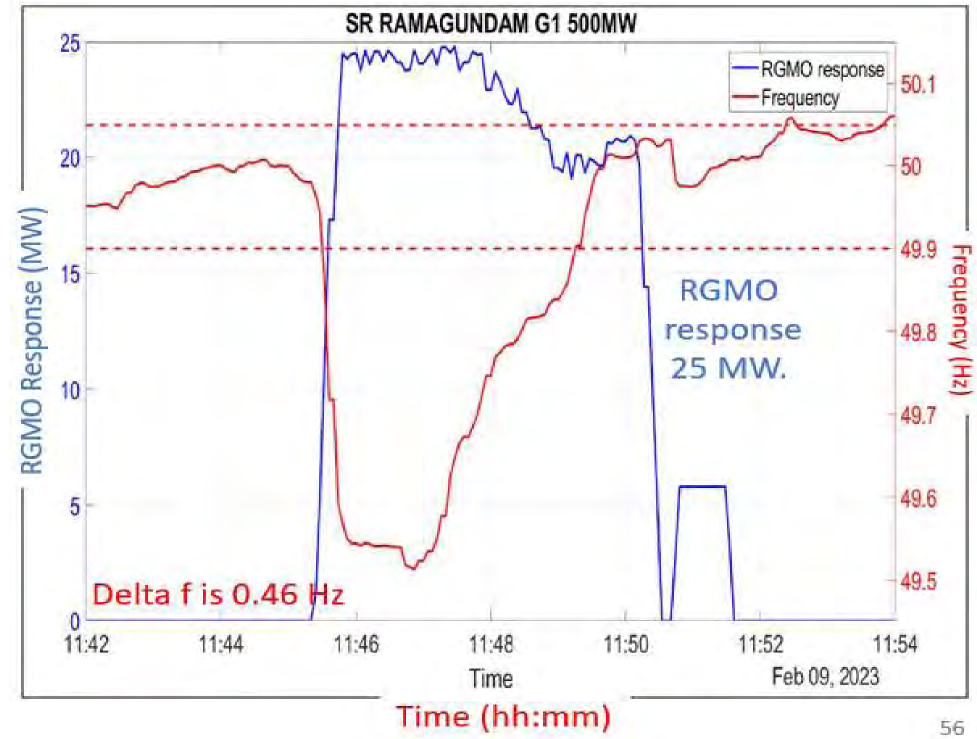


Figure 89: RGMO response for thermal unit during generation loss events

3.13. Summary of thermal, hydro & gas-based units.

After performing PFR tests, analysing the results and the data, it was observed that different logics were implemented based on the different interpretations of the clauses mentioned in Indian Electricity Grid Code (IEGC) clause 5.2.

The different logics can be categorised as:

3.13.1. Dead band and ripple filter

Variations in frequency control logic for ripple filter has been observed among the tested generating units. Furthermore, in some of the units, dead band was implemented instead of ripple filter.

Due to such inconsistencies in logics, non-uniform response was observed among the units. Variations in logics of dead band and ripple filter is shown below:

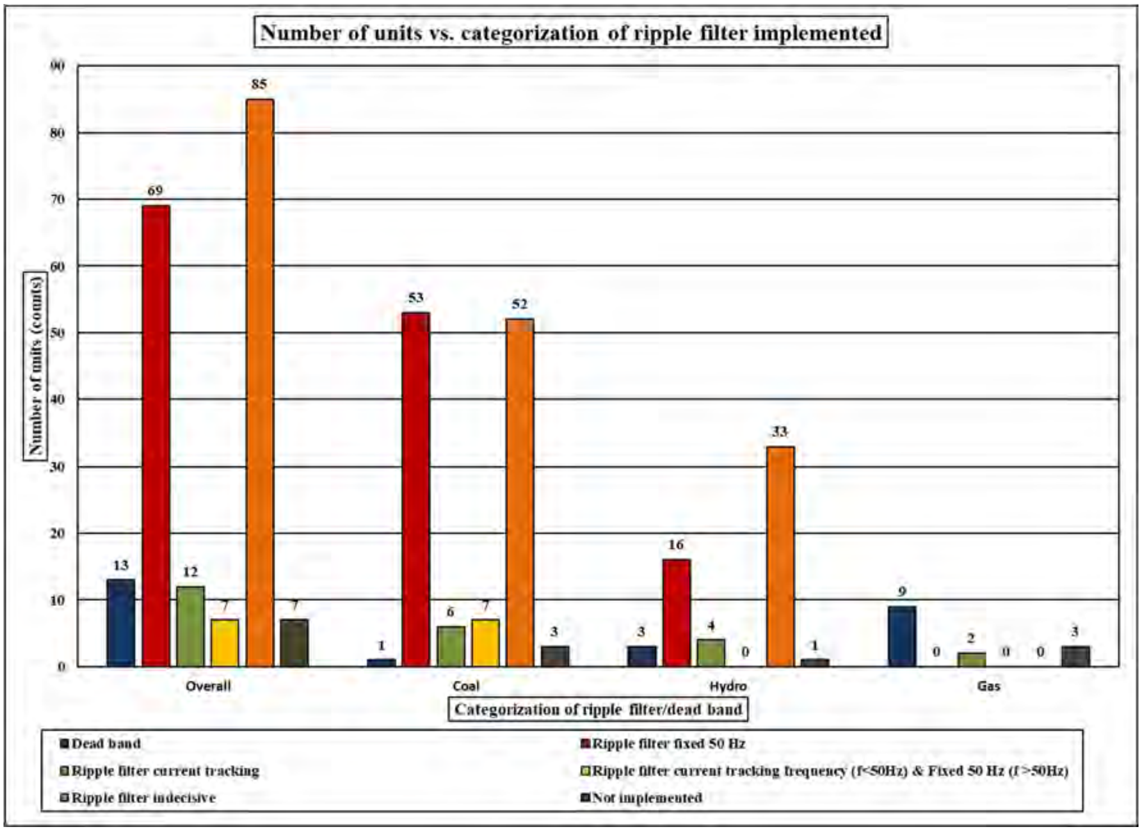


Figure 90 Bar graph representing number of units vs. categorisation of ripple filter/dead band.

Note: Category of ripple filter indecisive includes those units, **where ripple filter is implemented** in frequency control logic but status of ripple filter being implemented whether at fixed 50 Hz or current tracking frequency is unknown.

From the statistics obtained from the PFR test data it is concluded that dead band is implemented in 13 units (1-coal, 3- hydro & 9- gas-based units).

3.13.2. Droop implemented.

Variations in frequency control logic for implemented droop has been observed among the tested generating units resulting in different frequency controller output (RGMO output/MW correction), affecting the MW contribution from the unit simultaneously.

Variations in logics for implemented droop is shown in Figure 91 below:

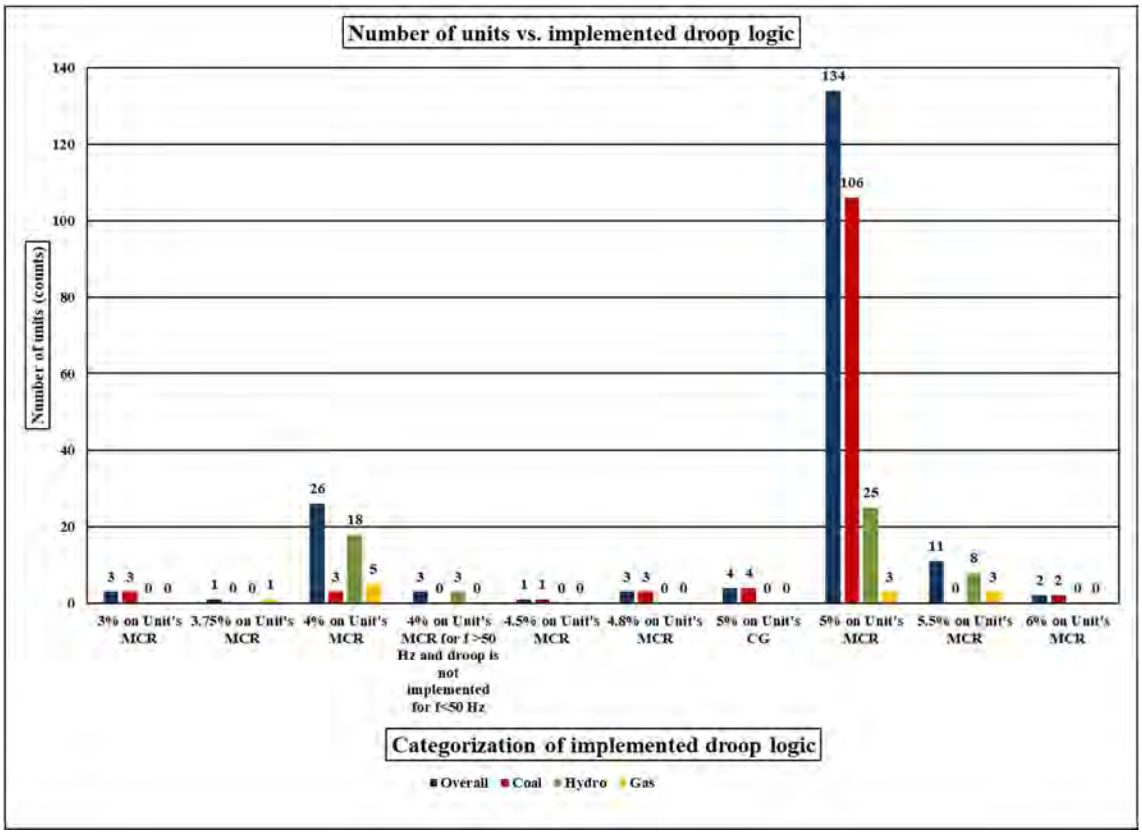


Figure 91 Bar graph representing number of units vs. implemented droop logic.

3.13.3. Limiters implemented.

From the analysis of PFR test results, it has been observed that different implemented limiters in frequency control logic restricts the maximum MW contribution from the units leading to lesser contribution than the desired.

Categorization of implemented logic for the limiters are shown in the Figure 92 below:

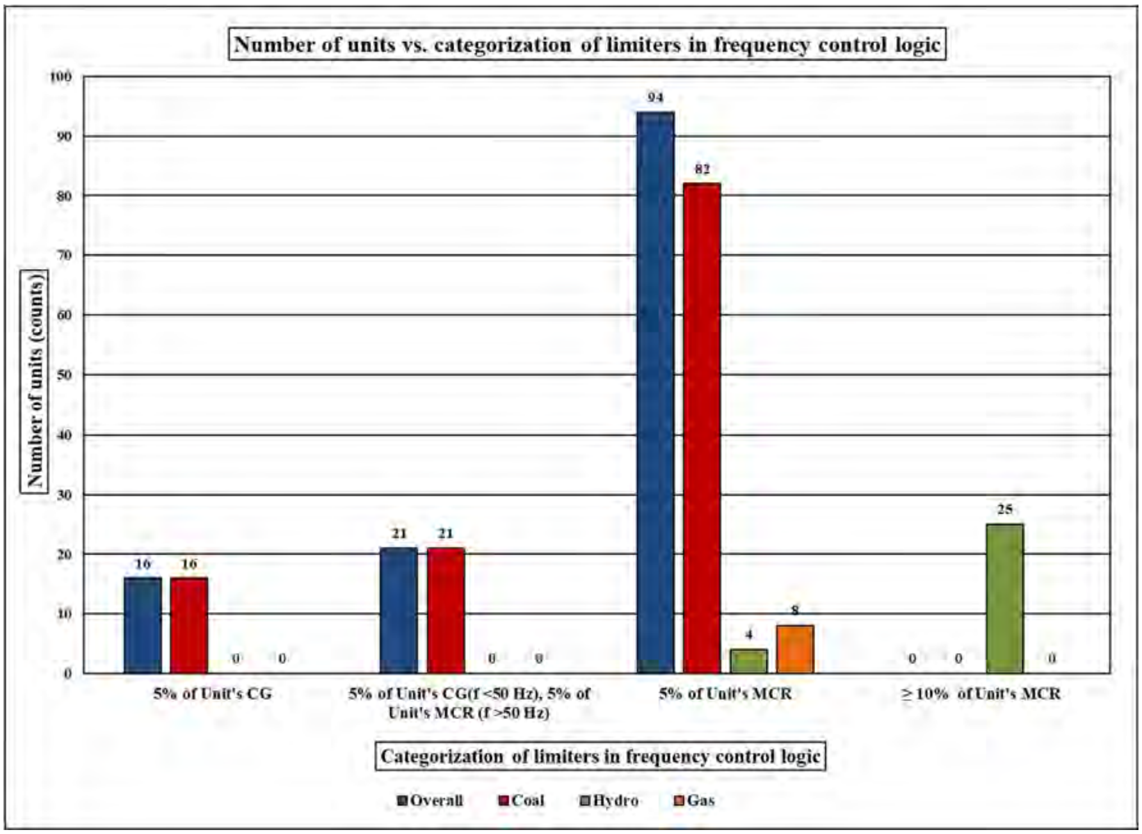


Figure 92 Bar graph representing number of units vs. categorization of different limiters in frequency control logic.

3.13.4. Scan time and the intentional delay

Variable scan time and intentional delay led to delay in governor's response initiation, resulting a time lag in MW correction.

Delay in governor's output (i.e., due to scan time and intentional delay) varies in a range of milliseconds to 12 seconds are shown below in Figure 93.

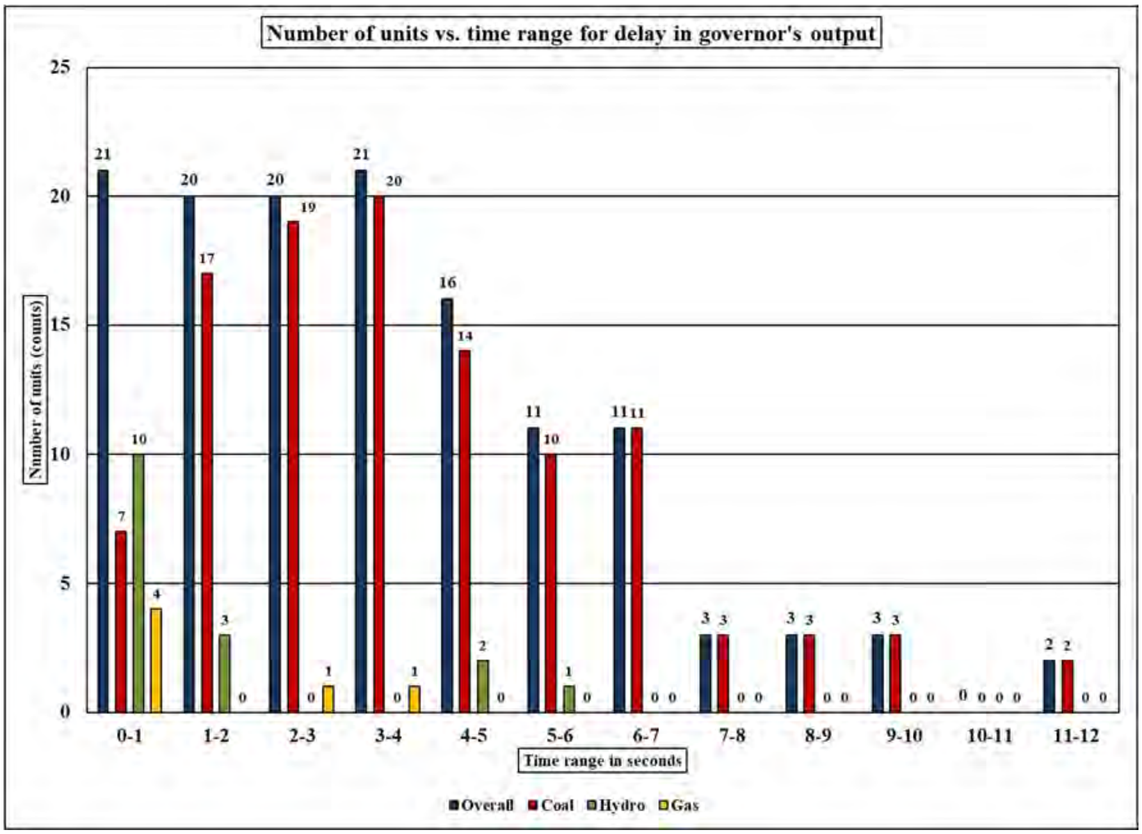


Figure 93 Bar graph representation of number of units with different time delays.

3.13.5. Time constant (τ), Rise time (Tr) & Full response time (T).

Dynamic response behaviour of the unit can be analysed using all these three parameters i.e., time constant (τ), rise time (Tr) & full response time (T) where time constant corresponds to the **rate** at which response reaches to its steady state while rise time signifies the **duration of the response to reach from initial value to specified final value**. And full response time indicates the **time taken to reach a new steady state value after a step disturbance**.

Detailed description and analysis from the PFR step tests performed are as follows:

3.13.5.1. Time constant (τ)

It is defined as the time taken by the unit to achieve the 63.2 % of full response*. Time constant has been calculated for all the tests performed.

Time constant for all the units for the frequency step of -/+0.10 Hz lies within the range of 150 seconds. A bar graph for number units vs. time range in seconds for time constant is shown in Figure 94.

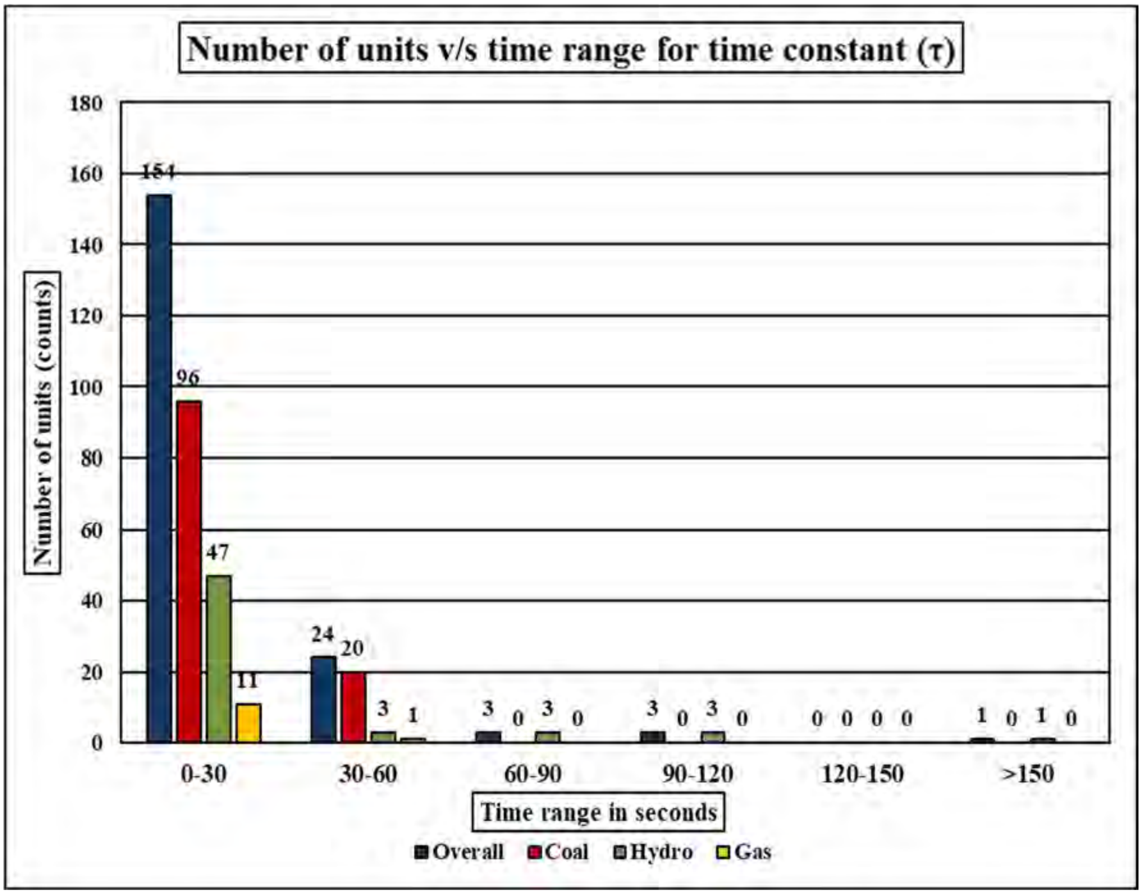


Figure 94 Bar graph representation of number of units vs. time range for time constant.

From the represented bar graph for time constant, it can be concluded that:

- 154 units (96-coal, 47-hydro & 11-gas units) out of 193 units i.e., **80% units are contributing 63.2% of full response* within 30 seconds.**
- Even 178 units (116-coal, 50-hydro & 12-gas units) out of 193 units i.e., **92 % units are contributing 63.2% of full response* within 60 seconds.**
- **Signifies that the majority of units are responding fast up to 63.2 % of the full response.**

3.13.5.2. Rise time (Tr)

It is defined as the time taken by the unit to rise from 10% to 90% of the full response*. Rise time has been calculated for all the tests performed.

Rise time for all the units for the frequency step of -/+0.10 Hz lies within the range of 240 seconds. A bar graph for number units vs. time range in seconds for rise time is shown in Figure 95.

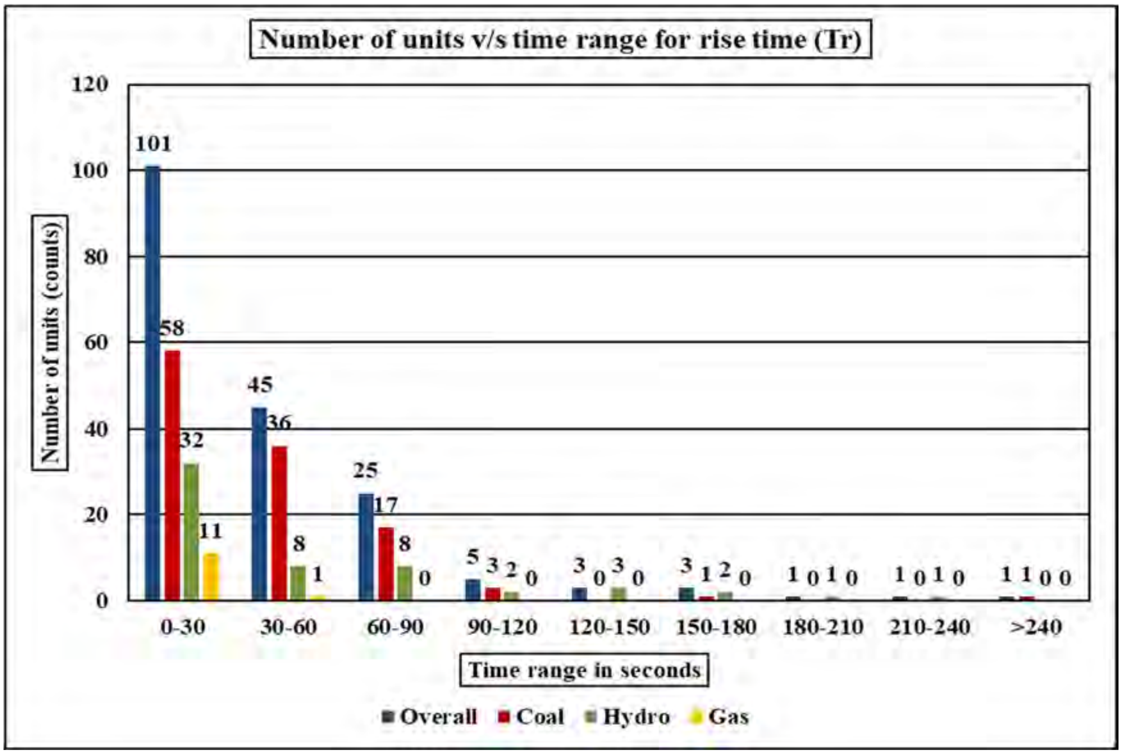


Figure 95 Bar graph representation of number of units vs. time range for rise time.

From the represented bar graph for rise time, it can be observed that:

- 101 units (58-coal, 32-hydro & 11-gas units) out of 193 units i.e., **52% units are contributing 10% to 90% of full response* within 30 seconds.**
- 146 units (94-coal, 40-hydro & 12-gas units) out of 193 units i.e., **76 % units are contributing 10% to 90 % of full response* within 60 seconds.**

- Even 171 units (111-coal, 48-hydro & 12-gas units) out of 193 units i.e., **89 % units are contributing 10% to 90 % of full response* within 90 seconds.**
- Signifies that the majority of units are responding from 10% to 90% of the full response within 90 seconds.
- Unlike time constant, **rise time values are slightly higher indicating units are responding fast with the change in frequency but taking time to reach up to 90% of the full response* value.**

3.13.5.3. Full response time (T)

It is defined as the time taken by the unit to achieve the full response*. Full response time has been calculated for all the tests performed.

Full response time for all the units for the frequency step of -/+0.10 Hz lies within the range of 330 seconds. A bar graph for number units vs. time range in seconds for full response time is shown in Figure 95.

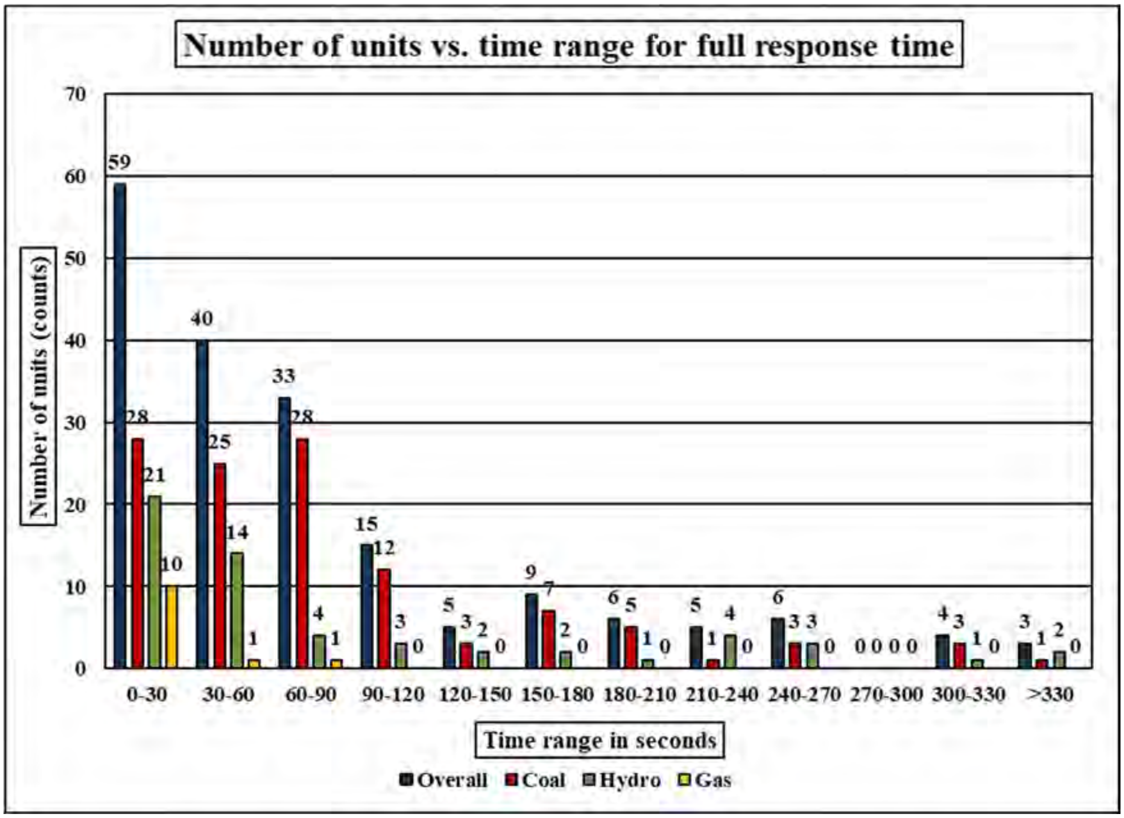


Figure 96 Bar graph representation of number of units vs. time range for rise time.

From the represented bar graph for rise time, it can be observed that:

- 59 units (28-coal, 21-hydro & 10-gas units) out of 193 units i.e., **31% units are contributing full response* within 30 seconds.**
- 99 units (53-coal, 35-hydro & 11-gas units) out of 193 units i.e., **51% units are contributing full response* within 60 seconds.**
- 132 units (81-coal, 39-hydro & 12-gas units) out of 193 units i.e., **68% units are contributing full response* within 90 seconds.**
- 147 units (93-coal, 42-hydro & 12-gas units) out of 193 units i.e., **76% units are contributing full response* within 120 seconds.**
- It can be observed from statistics specifically **number of units for time constant, rise time and full response time within first 30 seconds are in decreasing trend** (i.e., 154 units-

time constant, 101 units- rise time & 59 units- full response time within first 30 seconds) as shown in Figure 97.

- This decreasing trend signifies that although the units are responding **fast initially but slow down considerably after achieving 63.2% of response**, resulting in longer time to reach 90% of full response*.
- **Furthermore, units after reaching 90% of full response become even slower, which adds to more time to reach the full response***.

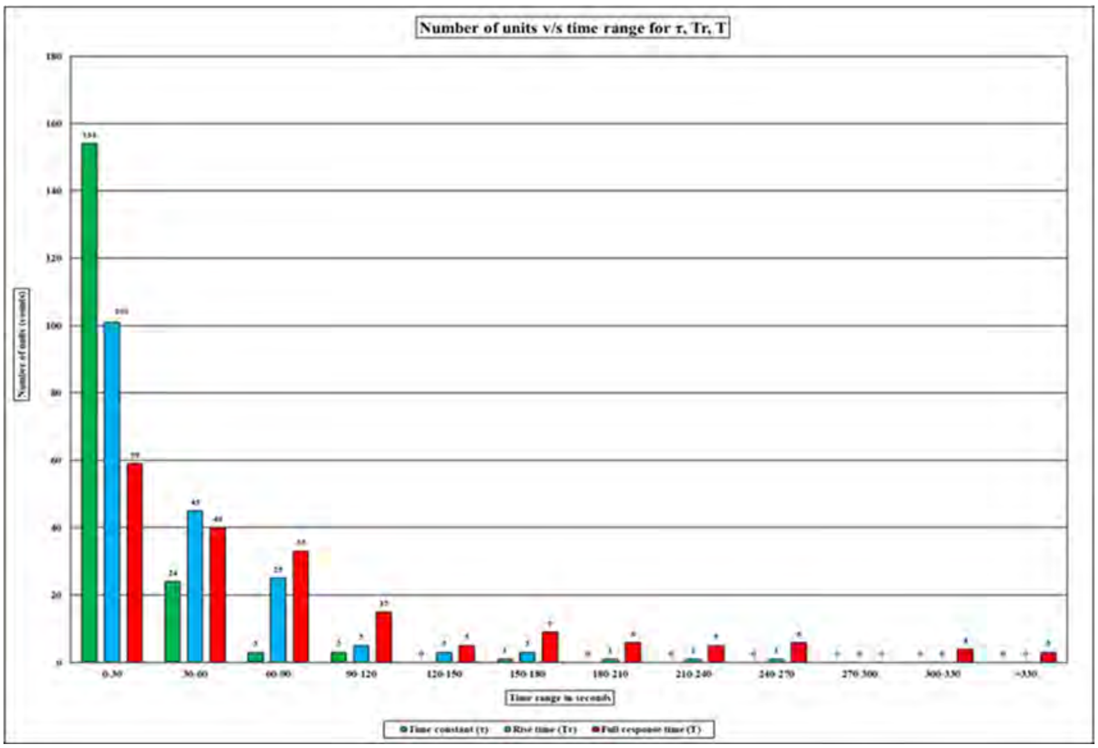


Figure 97 Bar graph representation for number of units vs. time range for τ, Tr, T.

***Full response:** It is defined as the MW contribution (RGMO output in MW) by the unit for the applied frequency step when MW change in actual load is greater than or equals to RGMO output.

In case when change in actual load is less than the RGMO output, maximum change in actual load is considered as full response of the unit.

4. Recommendations

Based on the findings from the PFR test results, key areas of concern were identified, and recommendations were given for improving the primary frequency response in compliance to IEGC clause 5.2.

From the tests result analysis, ambiguities in logic and system bottlenecks were identified. In some of the cases logic corrections and tuning were made during onsite testing to improve the response. In the units where logic correction was not possible during onsite test, recommendations were given in the final test reports submitted to RLDC's and generators. However, these recommendations should now be considered along with the understanding of the new grid code IEGC 2023 .

Periodic testing along with model validation of the generating unit for PFR is important for grid code compliance.

It was learned from the test of 193 units that PFR for individual units varies because of the non-uniformity in logic implementation due to different interpretation of grid code among the generator owners, tuning of related control loops, system bottlenecks etc. However, complying with the regulations is necessity for generating units and robust PFR delivery is crucial for stability of the grid. Hence following are recommended:

4.1. Standardization of Droop Settings

The test revealed significant disparities in droop implementation across generating units, such as droop implemented on MCR, droop implemented on units current generation, droop implemented on MCR but capped or limited by 5% of current generation, droop implemented on current generation and capped with 5% of current generation. These different way of implementation gives different MW contribution during the event. These variations in droop settings have the potential to impact grid stability during frequency deviations. Definition of Governor Droop in IEGC states ***in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from no load to full load***, which is Hz/MW from full load to no load, **hence the droop should be implemented on unit MCR without any limiters**. It is recommended to implement standardized droop settings for generating units to ensure consistent frequency response.

4.2. Ripple filter implementation

Inconsistencies in PFR due to different ripple filter logic implantation is noted, such as different responses from the units in consecutive frequency changes, variation in responses during the transition of frequency from below 50 Hz to above 50 Hz and vice versa, less than desired MW correction during frequency changes etc. These variations are due to the implementation of ripple filter logic differently among the generators. For those generating units where the ripple filter logic is implemented with respect to fixed frequency of 50 Hz contributes in PFR as per droop with respect to frequency change whenever frequency deviates beyond the rippler filter range (which mostly observed is 0.03 Hz). However, units where the ripple filter logic is implemented on running frequency or current tracking frequency, it has been noticed that the response from the unit during the frequency changes depends on the running frequency value and may not be adequate. Furthermore, this small decline in frequency may remain undetected by the governor, which could affect the unit's ability to contribute in PFR. The concept of ripple filter has been eliminated in the IEGC 2023 which states '***The inherent dead band of a generating unit or frequency controller shall not exceed +/- 0.03 Hz'.*** Hence in order to verify that ripple filter logic is removed, and governor action is with respect to reference frequency of 50 Hz, it is recommended to retest the units for PFR.

4.3. Response restrictions

Some units exhibited restrictions in their response capabilities (e.g., fixed MW change for any change in frequency, no response for consecutive change in frequency, restricted response for frequency changes above 50 Hz, fixed response hold time irrespective of the duration of frequency event etc.) which may compromise their contribution to grids stability during contingency. It is suggested to identify and resolve response restrictions in units to enhance their contribution to primary frequency response.

4.4. Manual intervention

Manual interventions were noted in certain instances to achieve an ideal response. These interventions could introduce delays and uncertainty in restoring grid frequency. Hence it is recommended to have well-tuned coordinated master control logic implementations among such units to achieve uniform responses during grid disturbances.

4.5. System bottlenecks

Mechanical backlash in hydro units, pressure correction compensation in thermal units and response stability issues in super critical units etc. were identified as system bottlenecks affecting the efficient delivery of frequency response. Hence it is recommended to mitigate these issues as far as possible.

4.6. Different scan time/intentional delay

From the PFR tests it is observed that the response initiation time, subjected to change in frequency steps, are different for different generating units. How quickly unit start to respond depends on the scan time in the governor's frequency control logic. From the test results it has been noticed response initiation time varies from less than a second to 6 - 7 seconds. Delayed response initiation can potentially defeat the purpose of PFR because of higher overall response initiation time. It is recommended to address this issue and standardize scan time in the governor for enabling them to provide quick initiation of response to avoid the intentional delay and for achieving optimal delivery time of PFR.

12.3 **Appendix-3**

Learnings from the Trial Operations with Automatic Generation Control (AGC) in Indian Power System

GRID CONTROLLER OF INDIA LIMITED (GRID-INDIA)
Formerly Power System Operation Corporation Limited (POSOCO)

December 2023

Contents

1. 1.0 Background

Automatic Generation Control (AGC) has been in operation in India since 21st July 2021. 24x7 operations of AGC pan India started with 44 power plants with an installed capacity of 41,900 MW on 21st July 2021. Presently, 185 generating units from 70 power plants comprising of thermal (57.7 GW), gas (3.2 GW) and hydro (6.4 GW) with an installed capacity of 67337 MW are wired under AGC. AGC implementation is a multi-stakeholder project. All the 185 units have been integrated under AGC after rigorous testing.

From 5th Dec 2022, AGC has been implemented as Secondary Reserve Ancillary Service (SRAS) in line with CERC (Ancillary Services) Regulations, 2022. A detailed operating procedure is hosted on the NLDC website, which serves as a guideline for the power plants in operating AGC under different use cases. Accounting and settlement of the services provided by the AGC power plants are done on a weekly basis.

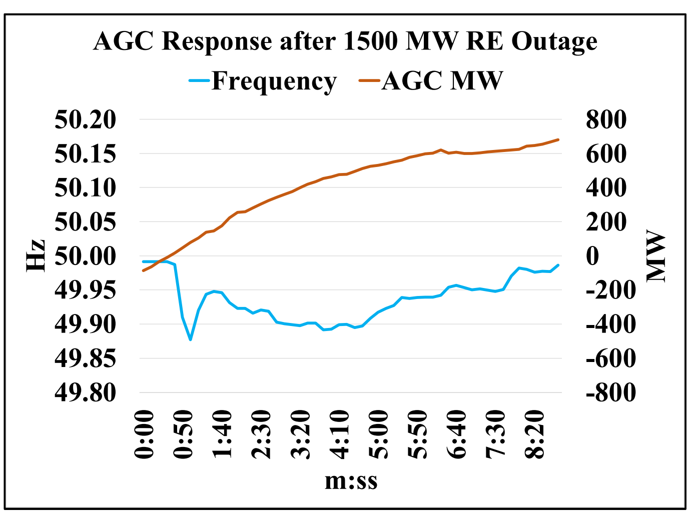
Out of the total capacity wired, typically a capacity of around 40 GW would be operating under AGC, out of the on-bar generation. These plants together offer up/down regulation of +/-2000 MW for secondary frequency control at around 200-300 MW/minute ramp rate combined. The power number of the Indian grid is around 10000 – 15000 MW/Hz, and hence AGC can roughly control grid frequency up to 0.1 Hz - 0.15 Hz.

1.1 AGC operation summary

The services offered by AGC could be broadly classified into three types -

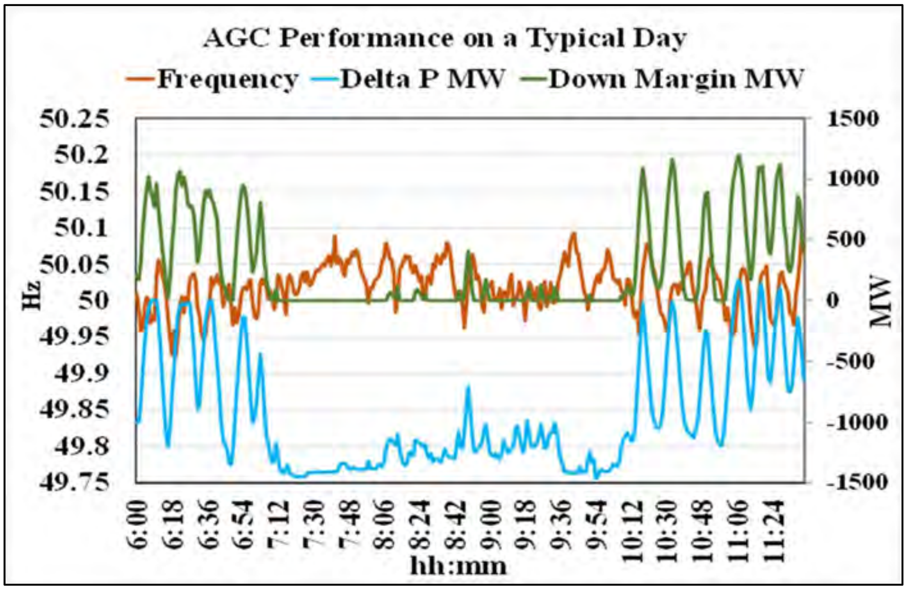
1.1.1 Support during contingencies

During contingencies like generation loss or load loss, AGC quickly increases or decreases generation to restore the frequency to 50 Hz.



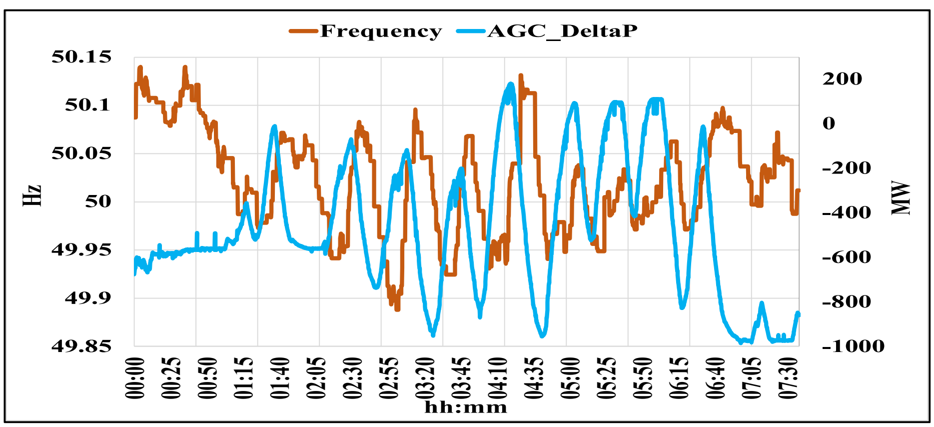
1.1.2 Support during sustained frequency deviations

During sustained frequency deviations, AGC provides a sustained support of Up or Down, to the extent spinning reserves are available under AGC wired plants.



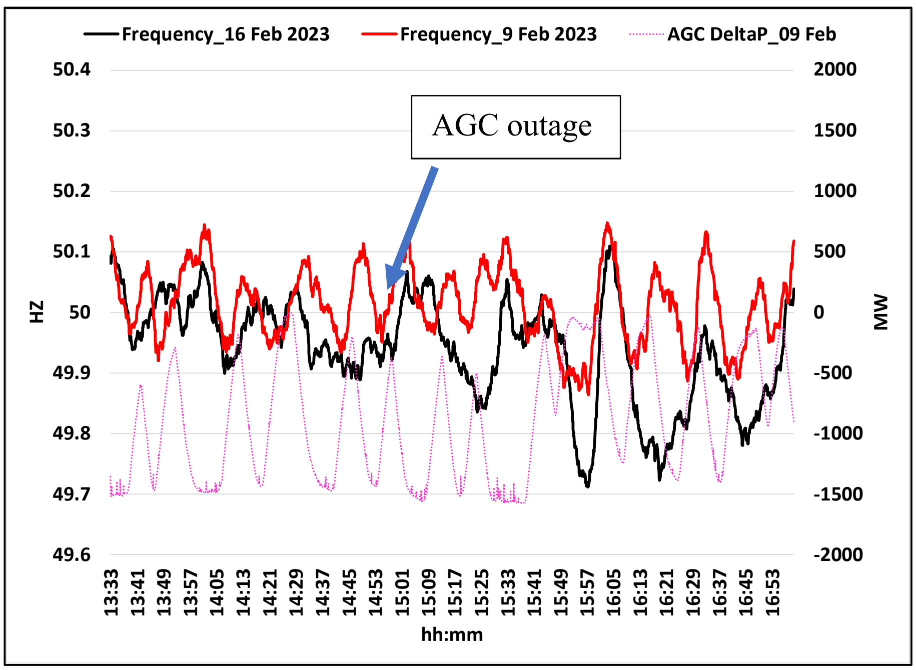
1.1.3 Support during minute-to-minute variation of frequency

During cyclic variation of frequency around 50 Hz, AGC increases or decreases the generation, intended to restrict the magnitude of frequency deviations.



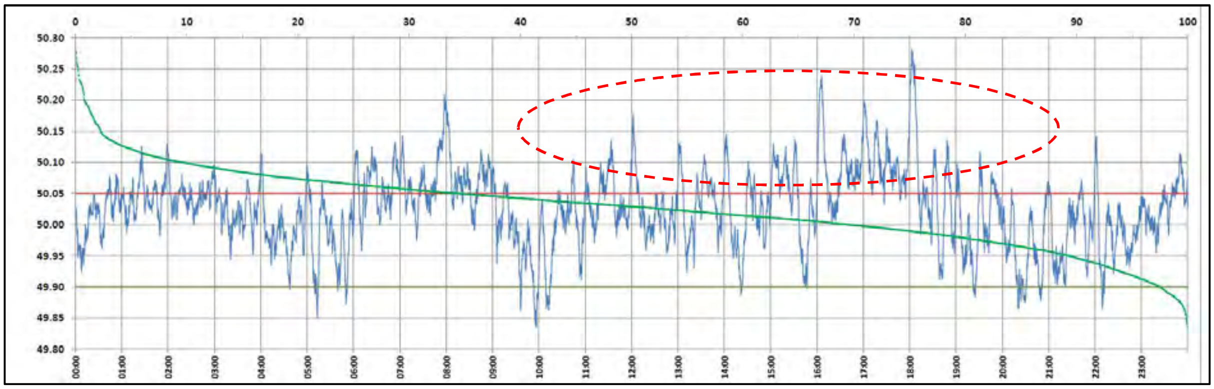
1.2 Impact of AGC on frequency profile

A typical day frequency profile with and without AGC operating in the grid is given below. On 16th February, AGC was under outage for technical reasons at NLDC from 1515 hrs. The effect of AGC on improvement of frequency could be clearly observed.



1.3 Feedback from the DSM Committee

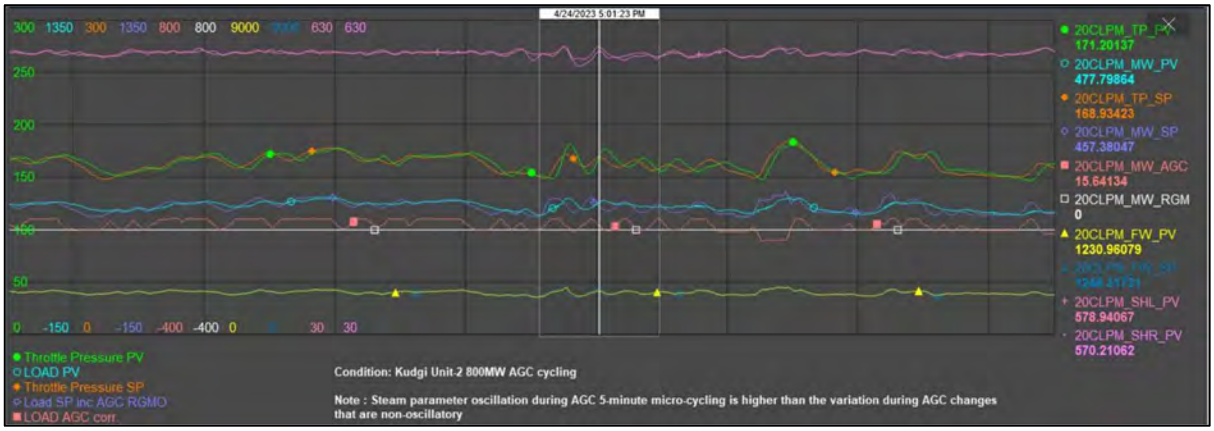
Based on the deliberations of the DSM Committee, suggestions were made by esteemed members to explore increasing the efficacy of the operation of AGC in containing the magnitude of the frequency fluctuations happening with a beat period of around 5 minutes.



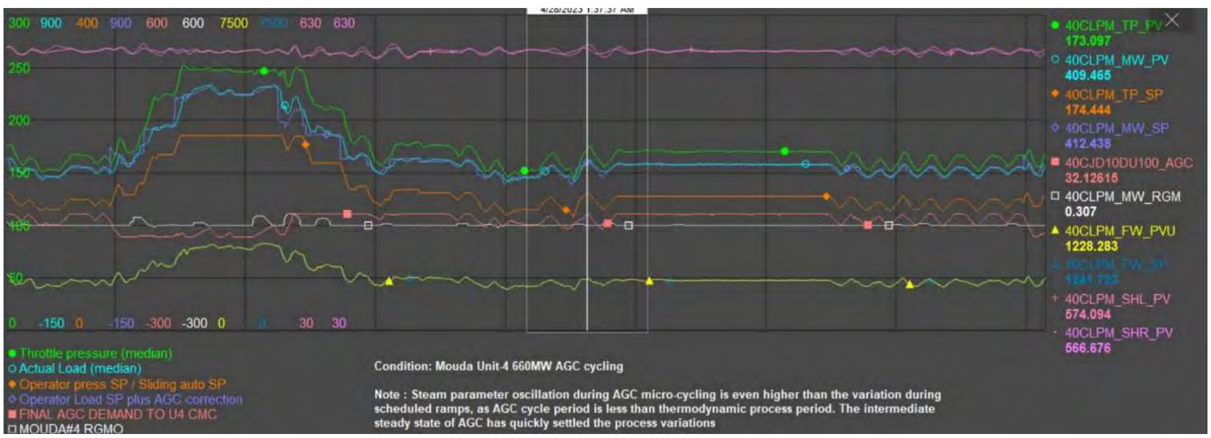
Suggestions were provided by the committee members to quantify the delay by the power plant in responding to the AGC signals. Thermal power plants have an inherent delay from the boiler side in responding to the AGC signals sent from NLDC. The time delay could be in minutes, where the power plants are operating in Coordinated Master Control (CMC) mode of operation. Ideally, this time delay in response should be covered by the response from governors of the power plants. It was also suggested check whether the governors are responding to slow minute to minute changes in frequency.

1.4 Feedback from NTPC (before issue resolution efforts)

NTPC has provided feedback on a few issues. The main feedback was that the cyclic operation of AGC while delivering the service “in Section 1.1.3” mentioned above is resulting in the micro-cycling of steam and temperature parameters. NTPC submitted that this micro-cycling cumulatively adds to mechanical stress over a period and might result in fatigue induced boiler tube leakage related tripping.



NTPC has submitted that the plant steam parameters are stable during continuous operation of AGC in a sustained direction. Plant tuning already supports operation during large changes of load, during schedule changes, contingencies and sustained frequency deviations.



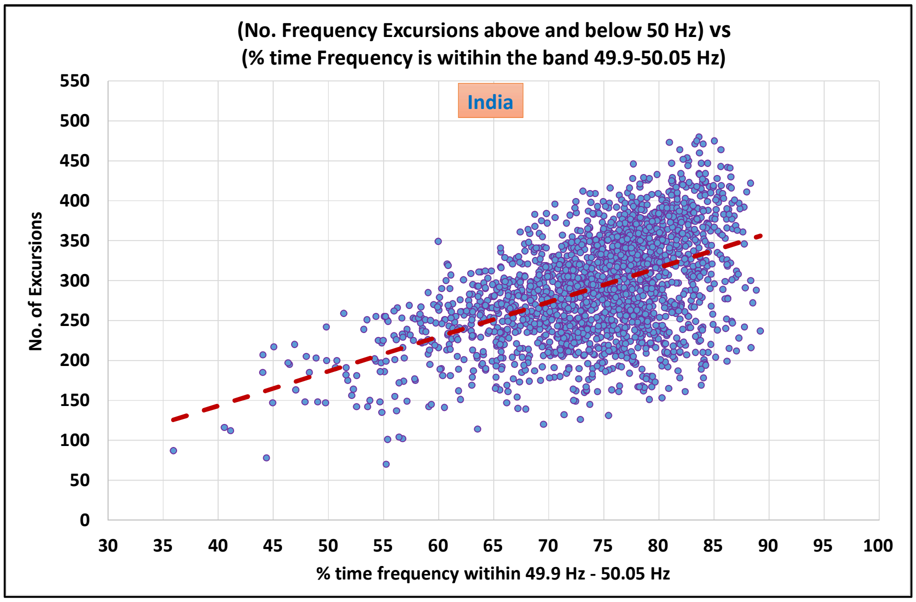
Another issue raised by NTPC was that in response to grid frequency, DeltaP sometimes remains in the opposite direction to scheduled ramps. This results in a reduced momentum than required while feeding coal to the boiler (note that the momentum is established by the legacy controller at the plant CMC. The controller tuning was done by the plant considering the non-linear behaviour of the boiler response). This was agreed to be handled at power plant level. The solution presented by NTPC is that during the periods when AGC DeltaP is in opposite direction to Scheduled ramping of the plant, DeltaP ramp rate would be limited to 0.5%/minute. Trial settings have been deployed at Jhajjar and the results would be analysed, before further steps/replication.

Multiple meetings were held between NTPC and NLDC on 9th May 2023, 05th June 2023, 08th June 2023, 10th July 2023, 12th July 2023, 18th July 2023, 25th July 2023, 21st August 2023, 10th October 2023 and 31st October 2023 to discuss the step-by-step modifications needed in AGC at plants and NLDC, to improve performance.

1.5 Interplay between Frequency within the band and Frequency Excursions around 50 Hz

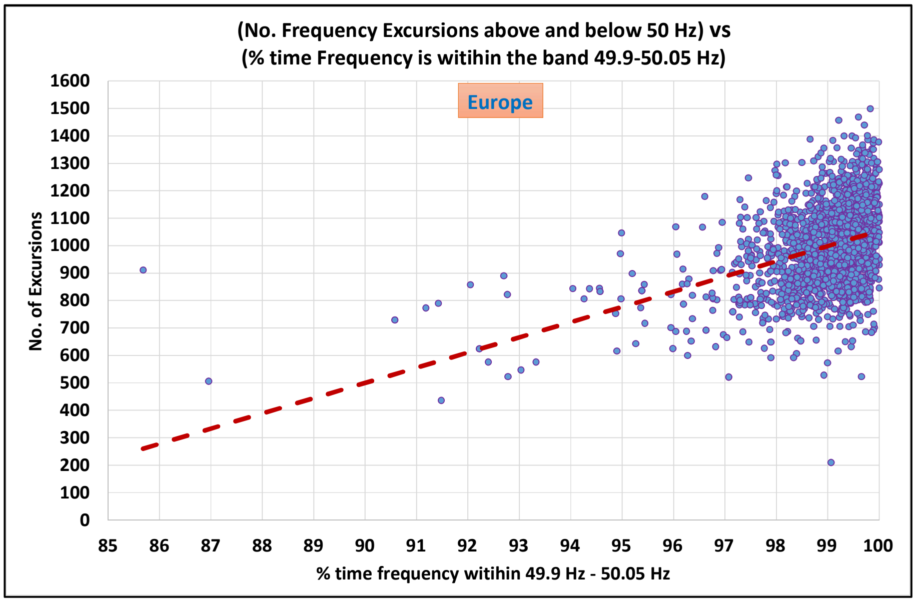
Frequency crosses the 50 Hz line 300 times per day on an average. On better days this is of the order of 380-390 times. A high degree of interplay (not direct correlation) has been observed between frequency remaining within the band and frequency excursions around 50 Hz. If the excursions around 50 Hz are higher, then there is a greater chance that frequency remains within the band on the same day. Apart from the number of 50 Hz crossings, the magnitude of frequency deviation from 50 Hz is also important.

For Indian grid, scatter plot has been plotted below between frequency excursions across 50 Hz and frequency remaining within 49.9 Hz-50.05 Hz, for a time period of 5 years (2018-2023), using 10s Frequency data. Frequency moving on an average 300 times per day above and below 50 Hz would mean and average of 1440/300 = 4 minutes 48 seconds for the frequency to return to the band.



1.5.1 Comparison with Continental Europe

For Continental Europe, the 50 Hz line is crossed 800 to 1100 times a day which means 1 minute 20 seconds on an average. Please find below a scatter plot for Continental Europe, between frequency excursions across 50 Hz and frequency remaining within 49.9 Hz-50.05 Hz. Primary frequency response in CE recognizes deadbands, frequency insensitivity etc. In India's case the way ripple filter and other mechanisms used to ensure that primary response is available only for sudden changes in frequency and not minute to minute. This explains the hourly boundary fluctuations, to some extent.



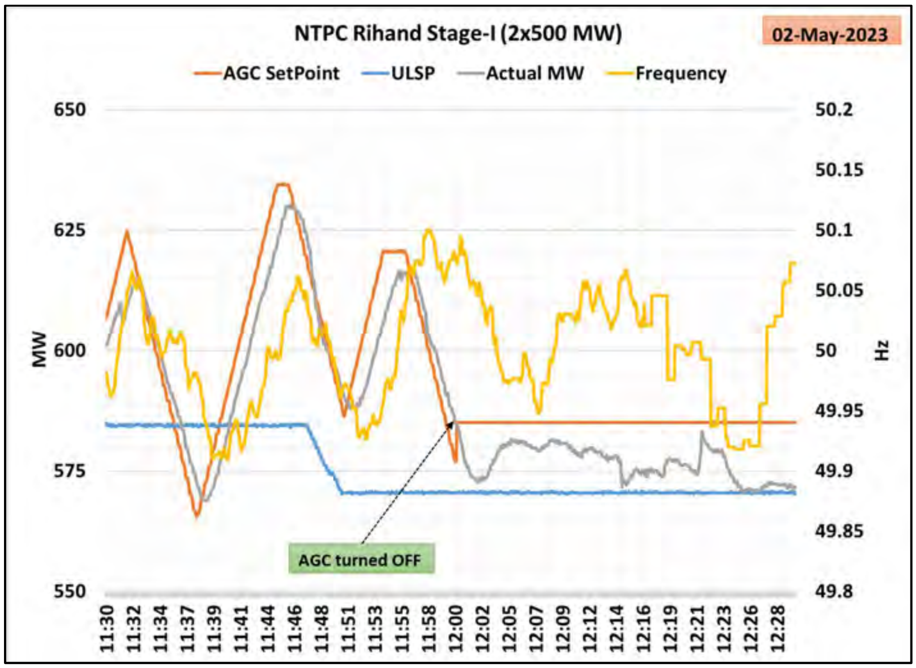
Large power systems like Europe, China, US have AGC existing in their power systems by design. North American and European AGC systems largely have hydro-based and gas-based resources providing secondary frequency control. India and China on the other hand have large coal-based power plants in their generation mix, and are operating them under AGC. It is common knowledge that gas and hydro resources are more flexible than coal-based generation. Hence, adoption of international operating practices of AGC in India may need slight improvements and changes.

2. 2.0 Summary of issues and suggestions

Based on the discussions, the issues were decided to be addressed. The members of the DSM Committee have suggested a few trial operations to get insights into the behaviour of power plants and the grid. They are listed below:

2.1 Study of the plant delays by switching AGC ON/OFF at selected plants

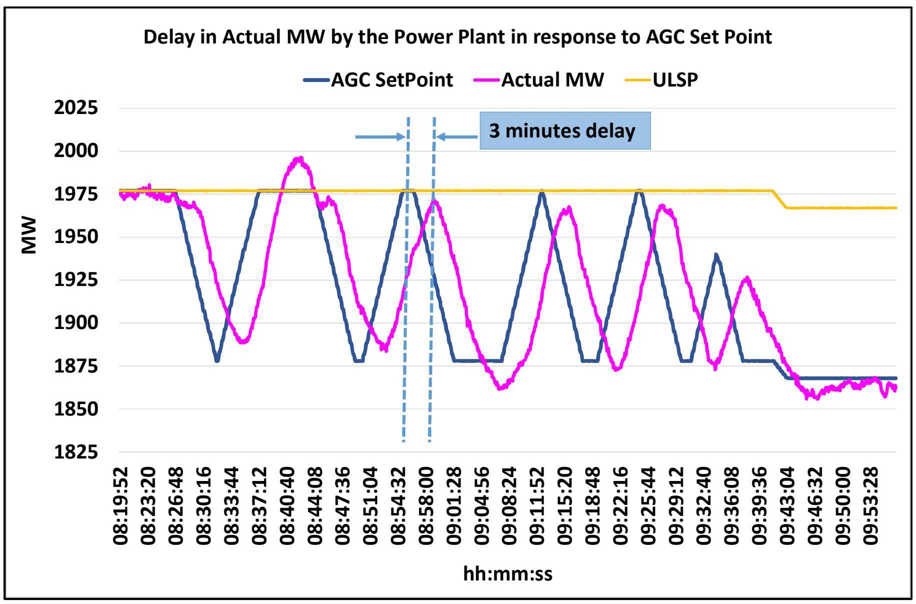
It was opined that the delay because of the boiler lag at the power plant side and the NLDC side was resulting in accentuating the frequency fluctuations. It was suggested to conduct a trial operation by switching AGC ON and OFF at selected power plants, for some time period, to study the difference and delays. A detailed report on these experiments is attached as **Annexure-1.**



The summary of experiments recorded in Annexure-1 is given below:

- When AGC is switched off, the power plants (viz., Rihand (0600-0630 , 02 May 2023) and Singrauli (1200-1230, 29 Apr 2023)) are generating close to their injection schedule irrespective of frequency variations.
- Freq is below 50 Hz, between 1207 - 1229 hrs on 29 Apr 2023, Injection schedule of Singrauli is at tech minimum, no increase in generation is seen implying that primary response to slow variations in frequency is poor at Singrauli
- Frequency is above 50 Hz between 0616 to 0621 hrs on 02 May, injection schedule of Rihand -I is at Pmax, no decrease in generation is seen, implying primary response to slow variations in frequency is poor at Rihand-I.

- Between 1230 to 1300 hrs, on 02 May 2023, Rihand-I generation appears to be sensitive to frequency variations. When AGC is switched ON Rihand is unable to follow the AGC set points.
- When AGC is in remote, Rihand (1130 - 1200 hrs on 02 May) and Singrauli (1300 - 1330 hrs on 29 Apr) can follow the AGC set points with delay of ~ 1-2 minutes.
- When AGC is in remote (0700 - 0730 hrs, 01 May), Sipat follows the AGC set points with delay of ~ 3 minutes.



The above experiments established that the time delay of the response of power plants to AGC signals is in the range of 2-3 minutes. The absence of free governor at the power plants is also understood.

2.2 Tie line Bias mode of Operation

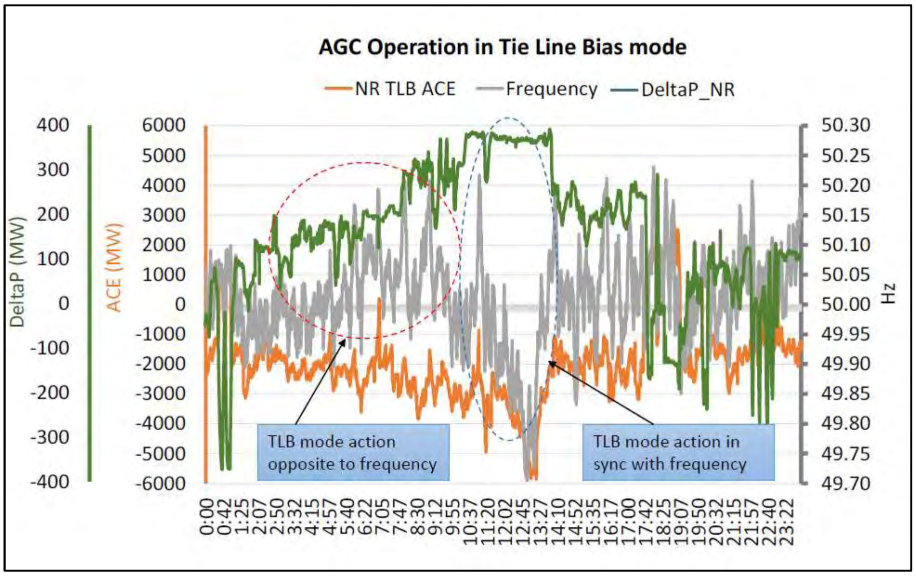
Ideally, true free-governor action on all the generating units, with no time delays in generation change (through adoption of turbine-follow mode, etc) is desired. In the absence of free-governor action (which happens in less than a minute) and adoption of unit controls which delay the frequency response, the AGC commands have less productive effect on frequency. AGC commands @ 1% per minute are too slow to curtail the present frequency fluctuations, and they are based on whether the frequency is below 50.0 Hz or above 50.0 Hz, disregarding whether the frequency is rising or falling.

In addition to the ramp constraint of 1% per minute, the aggregate response by any NTPC unit to AGC_up / AGC_down signals are limited to +/- 5%. It may also be noted that optimization of ISGS-thermal generation through SCED operation mops up the scattered reserves in stations with low ECR and shifts it on stations with higher ECR. Thus, the available ramping reserves available is inadequate to restore the ACE to zero / frequency to 50 Hz.

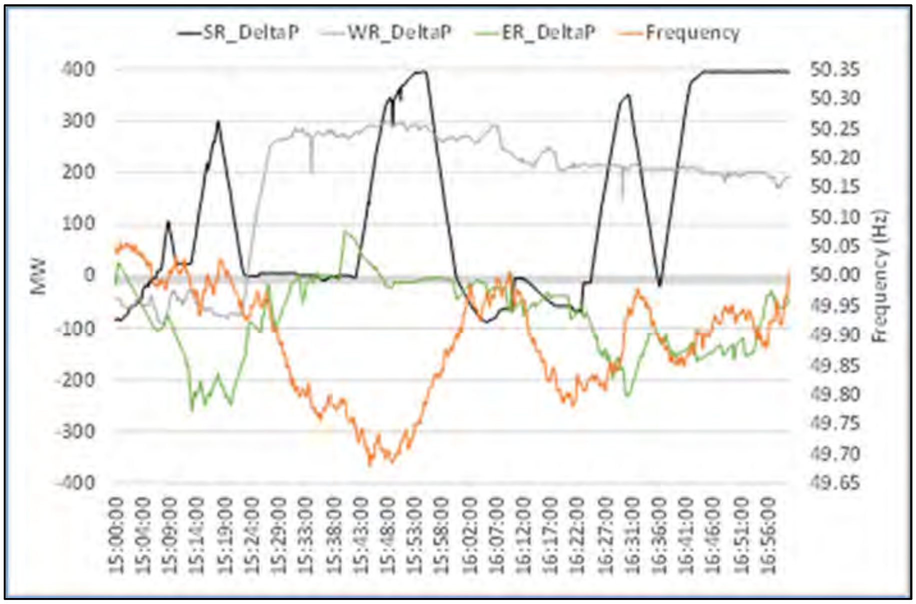
One solution to overcome the above was suggested by the DSM Committee to operate AGC in tie line bias mode of operation.

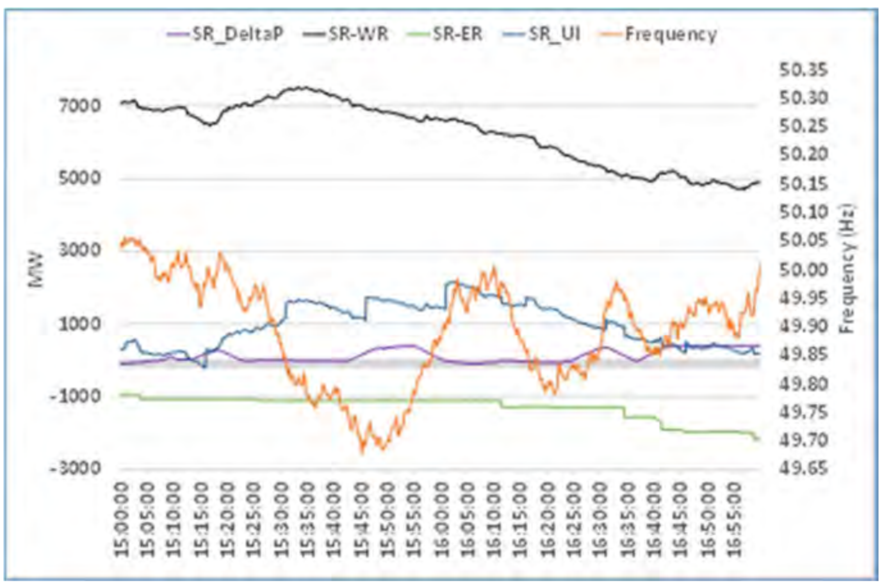
Hence, AGCs of all the control areas viz., NR, WR, SR, ER and NER were operated in tie-line bias mode on a trial basis on 14th May 2023. The detailed data of the tie-line bias mode of operation is provided as **Annexure-II**. A sample depiction of the operation in tie line bias mode using the NR data is given below. It was observed that plants operating under TLB AGC mode underwent reduced cycling on 14th May when compared with similar day operation (Sunday) of plants under CF AGC mode on 07th May.

However, Area Control Error in TLB mode is observed to be in counter-intuitive direction with frequency for around 50% of the time. It may contribute negatively to frequency control, particularly during periods of sustained low frequency/high frequency. Also, this operation may not be economical for the Indian grid during congestion-free periods (which account for 99% time of grid operation), as tie line bias mode doesn’t utilize the reserves to the full extent harnessing diversity.



AGC of SR, WR, and ER has been operated in tie-line bias mode (TLB mode) from 1500 hrs to 1652 hrs on 12 Sep 2022. During this period, NR and NER have been operated in Constant Frequency (CF) mode. Some plots depicting the operation in TLB mode have been given below.





It has been observed that during periods when SR is over injecting into the grid and was placed in tie-line bias mode, the generators in SR have been given down regulation by AGC, which helped relieve congestion on the SR-WR corridor. It has been observed that even during periods of low frequency, as SR was placed in TLB mode, generators in SR have been give down regulation based on the value of net SR ACE. This down regulation was compensated to some extent by WR and NR, whose generators were given up regulation by AGC.

It was proposed that during periods of congestion (say morning 1100 hrs -1400 hrs and evening 2200-2400 hrs), SR, WR and ER shall be placed in TLB mode. The associated risk is that the up reserves in SR may not get utilized when the frequency is low and SR is over injecting. However, if congestion alleviation is the priority, it is suggested to place SR, WR and ER in TLB mode from CF mode. If frequency associated risk needs to be balanced, only SR may be kept in TLB mode.

Conclusions from TLB mode of trial operation of AGC are as below:

<u>Merits:</u>

- Less stress on steam parameters of thermal plants due to reduced cyclic regulation
- Effective mode for congestion alleviation

<u>Demerits:</u>

- Smooth ACE can be in counterintuitive direction of frequency for ~50% time
- Probability of below par utilization of available reserves during contingencies and sustained frequency deviations, which may not be economical.

2.3 Constant Frequency control mode of operation with revised settings

The overall delay between the frequency deviation and the response by the grid has 2 major components –

1. Delay at NLDC side introduced by the AGC PID controller
2. Delay introduced by the power plants because of CMC/boiler lag

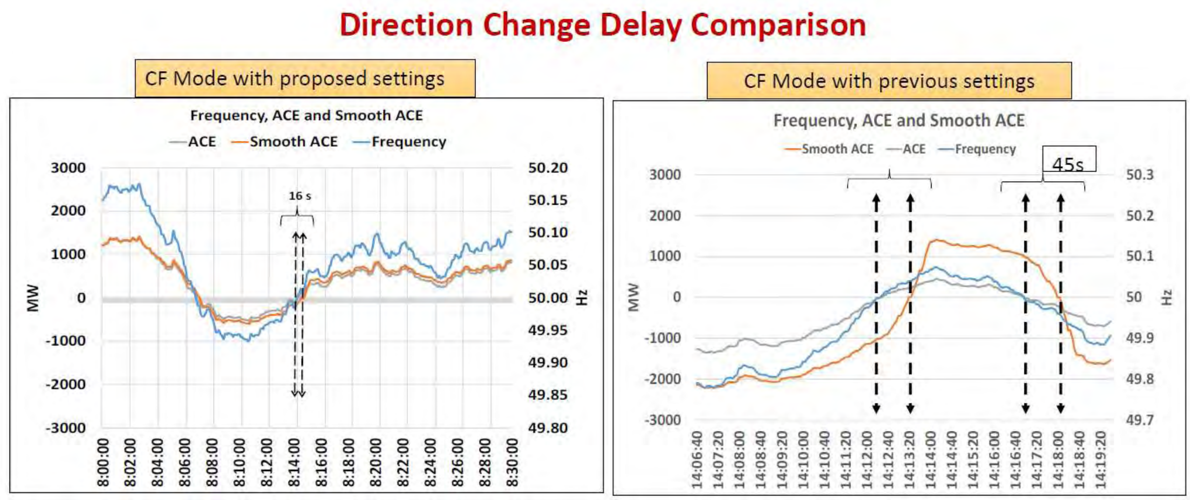
While the delay from power plant has been thoroughly understood using the trials in May 2023, the delay from NLDC side has been proposed to be reduced using controller tuning at NLDC. AGC settings have been revised on a trial basis from 30th May 2023 to 05th June 2023, to address the issue of steam parameter micro cycling issue cited by NTPC. Broadly three changes were made in the AGC software settings at NLDC –

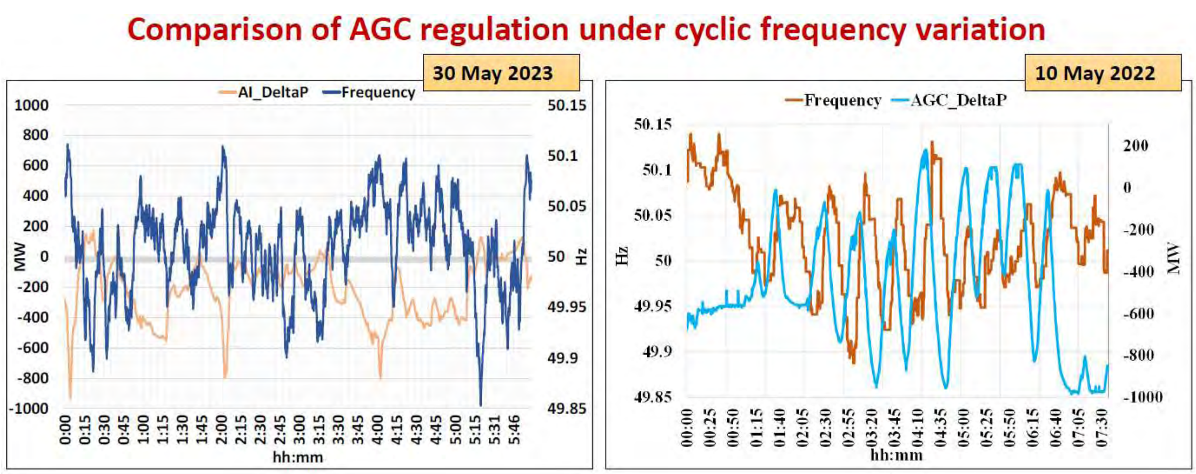
i) dead band has been introduced over smooth ACE,
ii) integration time has been increased and
iii) anti-windup limit has been decreased.

The changes have been made based on simulation studies and past observations. The settings are as below:

- Increased Dead band on SmoothACE for each region to +/-FRC*0.1 MW from +/-10 MW
    - +/-610 MWdeadbandforNR
    - +/-265 MW dead band for ER
    - +/-800MWdeadbandforWR
    - +/-620 MW dead band for SR
    - +/-32MWdead band for NER
- Increased integration time
    - To 40 s from 10s
- Decreased anti-wind up limit
    - To 5000 MW from 10000 MW

The above settings resulted in reduced micro cycling (up to 50%) of power plants, and at the same time ensured similar performance as earlier during sustained frequency deviations and contingencies. The complete analysis has been provided as **Annexure-III**. The delay in the change of direction of Smooth ACE (and DeltaP) in response to frequency change from NLDC side has reduced to around 15s from the earlier 45s.





NTPC's feedback on revised settings

NTPC has provided feedback about AGC operation with revised PID controller settings at NLDC from 30th May 2023 to 05th June 2023, in comparison with earlier settings. It has been confirmed by NTPC that steam parameter cyclic variations reduced significantly across units, with less AGC micro-cycling. It has been requested by NTPC to continue with similar settings, except for AGC dead band.

It was also suggested that, assuming a typical power plant response delay of 90-120 sec (coupled with the fact that majority of AGC participants at present are thermal), the AGC integration time is required to be brought to at least this range, with gain gradually adjusted upwards.

Undesired effect of Dead band

However, introduction of any dead band against narrow control target (i.e. 49.90 to 50.05 Hz) compromises frequency control due to inaction within the dead band, especially with the slower response of AGC being applied at thermal power plant CMC level. Consequently, average line of frequency would drift undesirably inside the set AGC dead band. This effect was visible in the frequency profile in the 00:00-06:00 hrs period.

2.4 Constant Frequency control mode of operation with improved settings

After the trial operation, and feedback from the power plants and the grid, further improvement was desired to be made in the settings. Regular meetings were also held with NTPC. The aim has been to get the steam parameter oscillations under control, and to improve the performance of the AGC at the same time. As NTPC's CMC tuning is a fixed PID tuning, the new understanding was to make NLDC AGC settings amicable to the power plant controller settings and steam parameters.

NTPC intimated that large magnitude of MW deviations in response to small frequency changes is of more concern, than the zero crossings of AGC DeltaP.

A combination of settings which can make AGC effective for handling minute to minute load variations were proposed, learning from the trial operations made during April-July 2023. Another trial operation started from 1830 hrs of 7th July 2023. The below changes were made -

1. Integration time increased from 10s to 120s. This results in quick change in direction of Smooth ACE in response to frequency or ACE.

2. Proportional gain increased from 0.9 to 1. This results in better performance during contingencies. This is coordinated to match other settings.

3. Antiwindup limits have been reduced to match the reserves available under AGC. This results in integrator not getting over saturated during sustained frequency deviations, which was resulting in a delay of 45s earlier. Now the delay from NLDC side has been virtually made zero. The delays in CMC at the power plants remain the same at over 2 minutes. This also results in smaller MW changes to small frequency deviations and vice versa. Antiwindup limits are as follows for different regions NR - 600 MW, WR - 800 MW, SR - 600 MW, ER - 700 MW, NER - 100 MW.

4. Smooth ACE dead band to remain same as 10 MW

5. Ramp rate has been increased by NTPC from 1% per minute to 1.5%/minute and 2% per minute from 1800 hrs of 10th July 2023 on 09 selected plants.

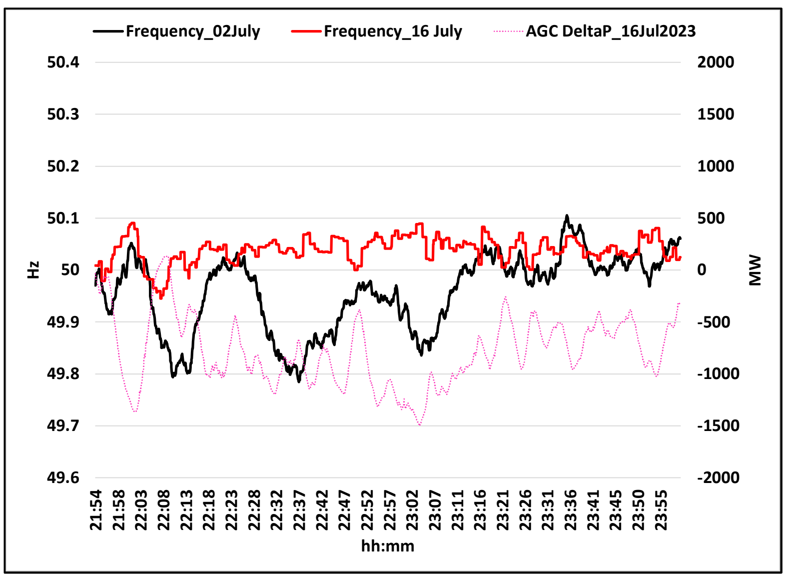
Ramp rate of the selected plants (as per the trailing mails) has been increased w.e.f. 1805 hrs of 10th July 2023. The increased ramp rate and the corresponding plant are as follows:
Ramp rate increased from 1% to 2% at Sipat-2, Jhajjar, Ramagundam-3, Mouda-1, Vallur. Ramp rate increased from 1% to 1.5% ramp rate at Kudgi, Solapur, Mouda-2, Gadarwara.

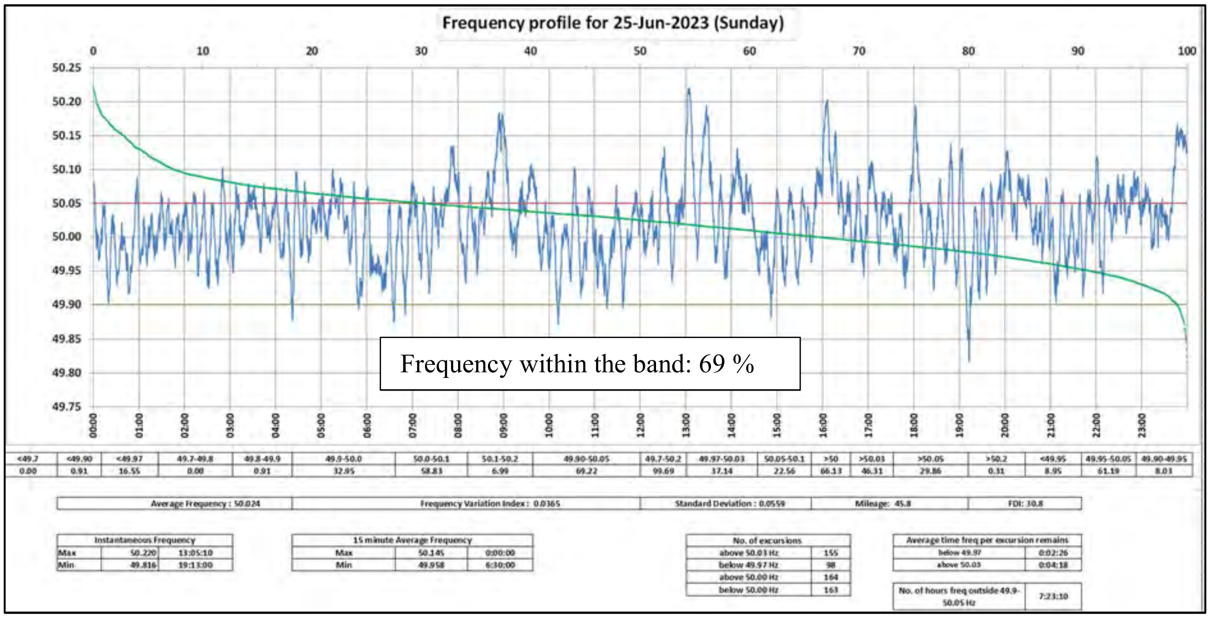
Subsequently, integration time has been further increased from 120s to 360s in the steps of 60s between 02nd August 2023 and 11th October 2023. During this period, ramp rate has been increased on a total of 40 units out of 185 units, providing higher ramp rate of 1.5% - 2%/min under AGC.

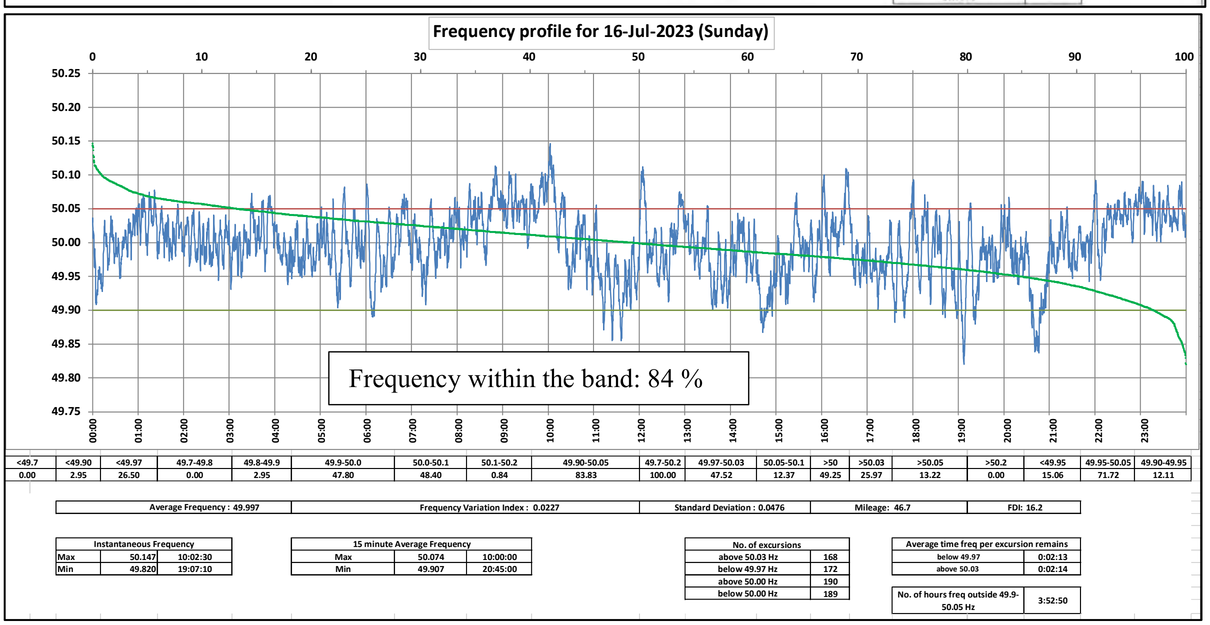
With the above changes, some positive effects were observed on frequency. It has been observed that frequency profile on Sundays in particular, has been better than other days of the week. The improvement in overall frequency profile is because of the effective combination of the below:

- RE and Load forecasting, scheduling
- Improved availability of spinning reserves for primary, secondary and tertiary frequency control
- Minimized load shedding and unit outages
- Easing of harsh seasonal effects after the onset of the monsoon

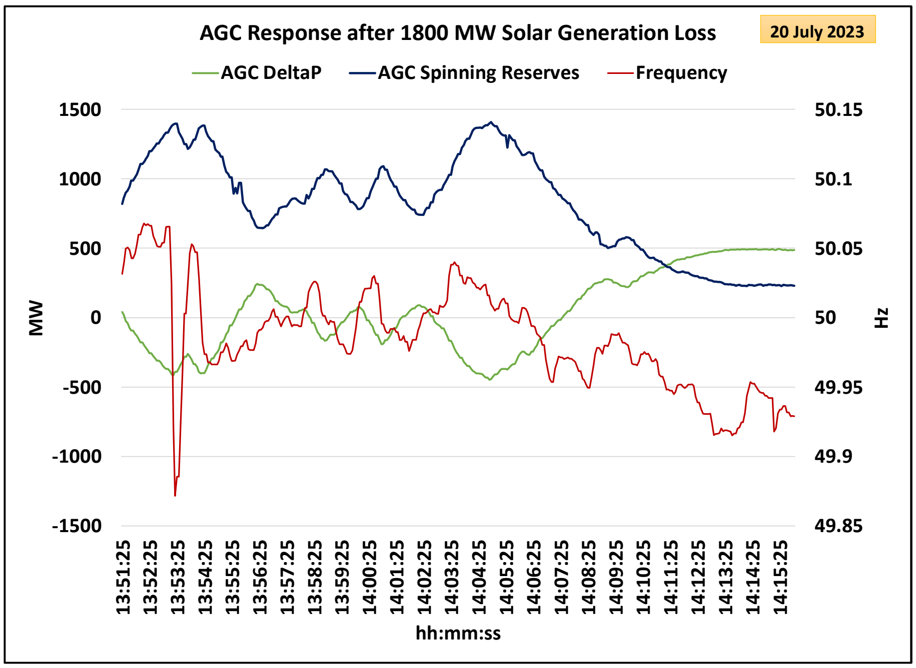
The effect of AGC on the power system can be understood from the graphs with and without AGC as produced below. On 02nd July 2023, AGC was placed under outage due to outage of communication links from around 2154 hrs. It can be observed that frequency variation was significant without AGC until restoration of AGC around 2315 hrs. This effect is much pronounced than the effect without AGC on 16th Feb 2023 (given in this report earlier).







AGC response to contingencies and sustained frequency deviations has been equally effective as earlier during this period of trial settings. On 20th July 2023, there was a sudden loss of 1800 MW Solar generation. The effect of quick restoration of solar coupled with primary response is visible in the first several seconds after the contingency. AGC provided Up regulation at a ramp rate of 325 MW/minute during the first few minutes of the contingency. A total of 650 MW Up regulation has been issued to the power plants under AGC in a span of 2 minutes following the plant ramp rate. During the period of sustained frequency deviation after 1406 hrs on 20th July 2023, AGC exhausted 750 MW up reserve within 7 minutes and sustained the support for the next several minutes.



The percentage of time frequency remained within the band with support from Ancillary Services (SRAS/AGC and TRAS) has been 83.83% on 16th July 2023. However, if the support from SRAS & TRAS are discounted assuming a fixed power number of 10000 MW/Hz, then the frequency remains within the band only for 26.8% of the time. Contribution of TRAS is mainly from energy balancing perspective, that the frequency has been pulled back to hover around 50 Hz, increasing the number of 50 Hz crossings.

S.No.	With & without Ancillary Support	% time frequency remained within the band	No. of 50 Hz crossings
1	Without Ancillary support	26.8 %	84
2	With SRAS support	73.1 %	184
3	With SRAS & TRAS support	83.8 %	379

Counter-intuitive action of AGC DeltaP with frequency (around 50 Hz) has come down to the range of 15% with the revised AGC settings. This number used to be in the range of 30-35% with the older settings. Counter-intuitive action of AGC DeltaP with frequency beyond 49.97-50.03 Hz has come down to the range of 3% with the revised AGC settings. The range of counter-intuitive action of TRAS with frequency compared to other days remained same as earlier while making this comparison.

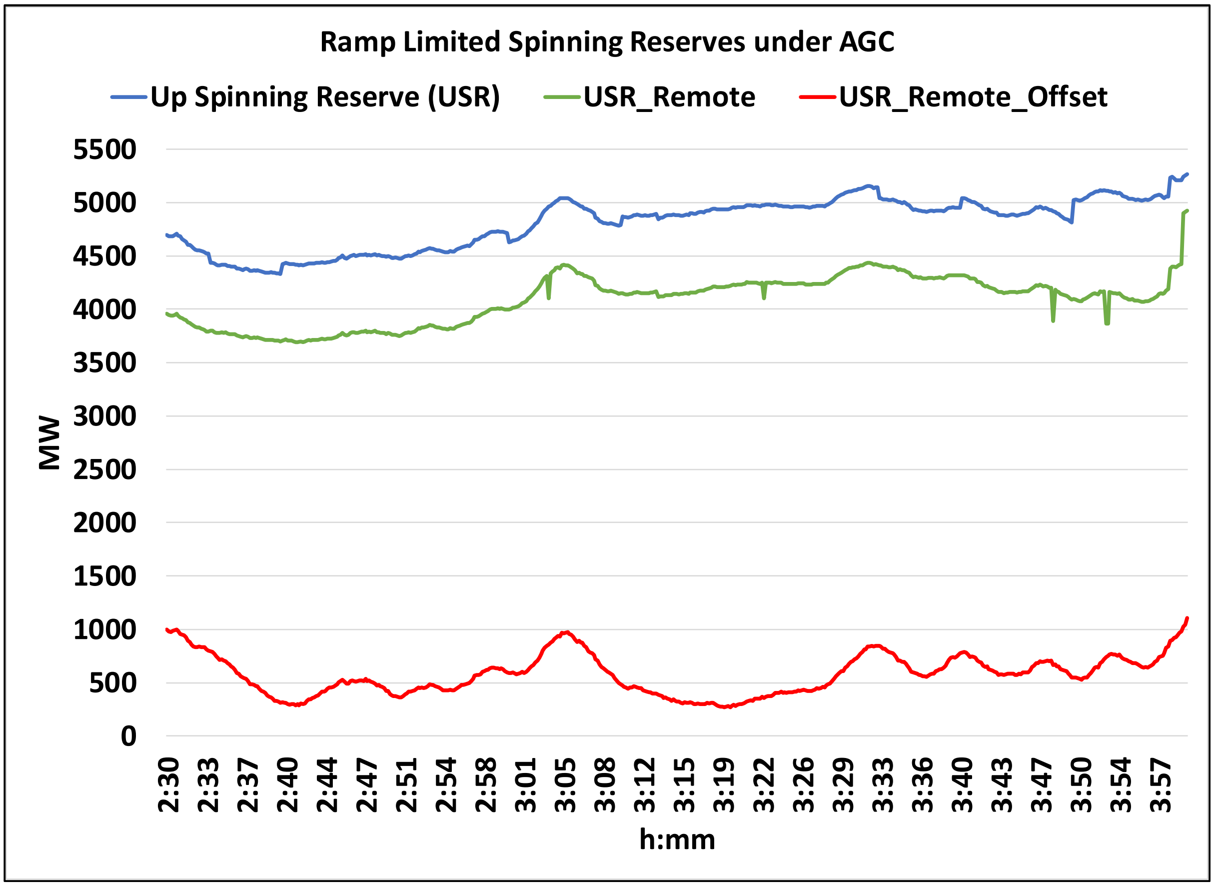
Counter-intuitive action	Frequency vs TRAS MW	Frequency vs AGC DeltaP
for 50 Hz	**58%**	**15%**
Beyond 49.97 - 50.03 Hz	**20%**	**3%**

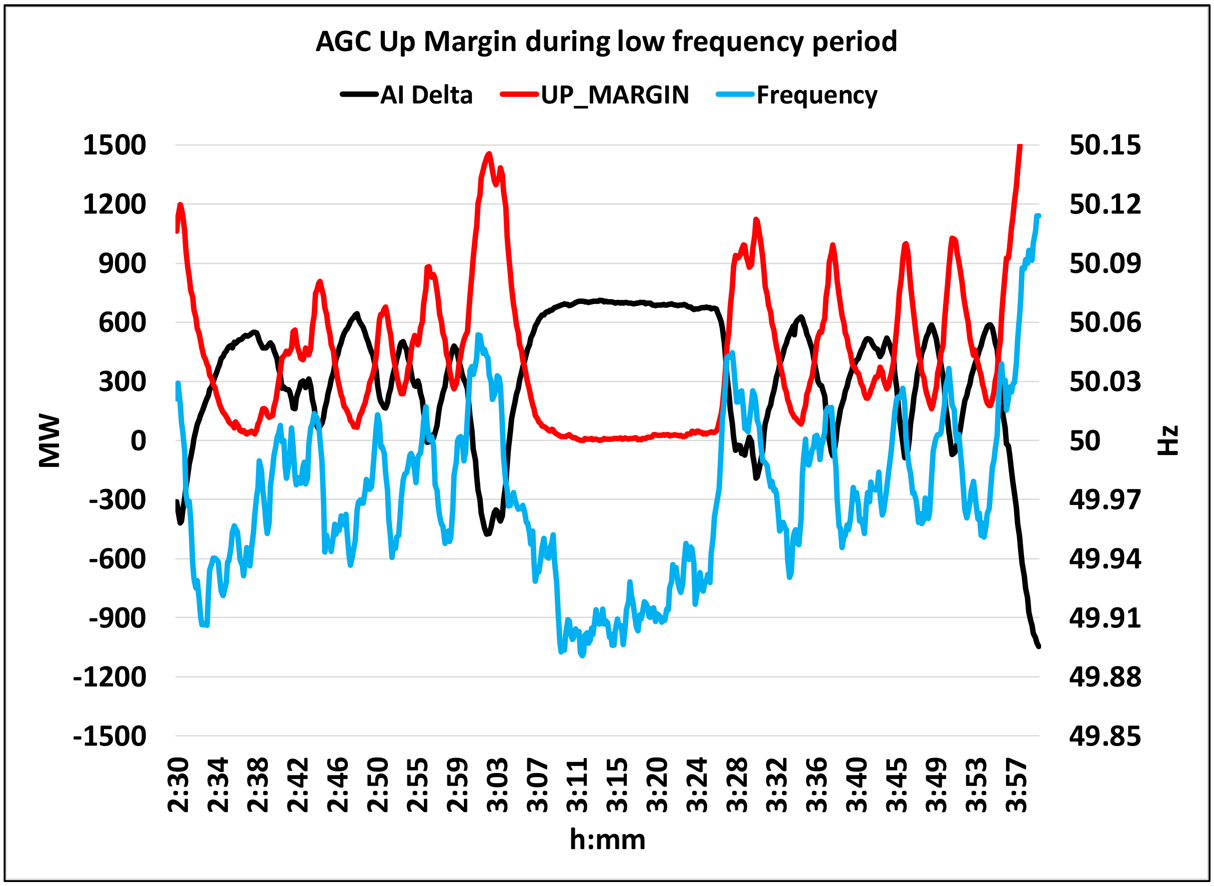
1500 MW of maximum Up & Down regulation has been done by AGC with a net zero net energy (-0.1 MU) on some days. As a result of the new settings, there has been an increased number of 50 Hz crossings and the average time per excursion reduced.

2.5 Spinning Reserves and 15-minute Ramp Limited Spinning Reserves

Please find the plots of reserves under AGC calculated below for a particular day. Up to 5000 MW 15-minute ramp limited spinning reserves are on bar under AGC at 0315 hrs. Out of the 5000 MW, more than 4000 MW reserves are under AGC remote. However, due to the +/-5%*IC limit per unit imposed by the power plants on the delivery of the spinning reserves under AGC, only up to 800 MW reserves are available for real-time despatch through AGC. It could be observed that around 800 MW have been despatched by AGC during the low frequency period at 0315 hrs. The Up margin available with the AGC generators has become zero, mainly because of the 5%*IC limit imposed by the generators on the delivery of spinning reserves.

It can be inferred from the long-term analysis of spinning reserves and 15-minute ramp limited spinning reserves that during some periods the 15-minute spinning reserves are almost zero. Obviously, during those periods, the power plants under AGC don't have sufficient reserves for frequency control. It is important to keep a larger pool of power plants pan India under AGC. This would allow for higher availability of reserves and increased ramping resources operating under AGC.


Ramp Limited Spinning Reserves under AGC
Up Spinning Reserve (USR)
USR_Remote
USR_Remote_Offset
MW
5500
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
2:30
2:33
2:37
2:40
2:44
2:47
2:51
2:54
2:58
3:01
3:05
3:08
3:12
3:15
3:19
3:22
3:26
3:29
3:33
3:36
3:40
3:43
3:47
3:50
3:54
3:57
h:mm



2.6 Feedback from NTPC

A meeting was held with NTPC at NLDC, on 18th Jul 2023. NTPC analysed temperature and pressure data of different power plants. NTPC provided the feedback that they have faced less micro cycling of steam parameters (which can result in mechanical fatigue) with the present trial settings. They opined that the frequency profile is also getting better. NTPC have confirmed that as the magnitude of DeltaP variations has subsided, power plant steam parameters remain stable even with increased zero crossing of frequency around 50 Hz.

Another issue of DeltaP reversal during schedule ramps, raised consistently by

NTPC since March 2023, was also discussed. In response to grid frequency, DeltaP sometimes remaining in the opposite direction to scheduled ramps. This results in a reduced momentum than required while feeding coal to the boiler (note that the momentum is established by the legacy controller at the plant CMC. The controller tuning was done by the plant considering the non-linear behaviour of the boiler response). This was agreed to be handled at power plant level. The solution presented by NTPC is that during the periods when AGC DeltaP is in opposite direction to Scheduled ramping of the plant, DeltaP ramp rate would be limited to 0.5%/minute. Trial settings have been deployed at Jhajjar. and the deployed settings are helping the power plant in smooth manoeuvring during scheduled ramps, as per the feedback received from NTPC. The trial settings have been replicated at other plants as well namely Ramagundam-3, Mouda-1, Vallur, Kudgi, Gadarwara, Ramagundam-2, Dadri, Lara, NPGC, Korba-2, Korba-3, Mauda-2, and Unchahar-4. The other remaining plants where ramp rate has been increased would be subsequently covered with the trial settings.

Coal-based power plants have expressed inability to increase the quantum of AGC correction (regulation range) above +/-5%, due to additional +/-5% already reserved for primary response, along with mill auto firing margin constraints. Further in the context of AGC movement of units operating under free governor mode, there were apprehensions that routine frequency variations can amplify the requirements from +/-5% to +/-10%, when operating in mid-range. The fatigue related micro-cycling can be further amplified by free governor and AGC operating together.

2.7 Cost of SRAS (Jun'23-Nov'23)

Month	Up Regulation due to SRAS (MU)	Down Regulation due to SRAS (MU)	Net Energy (MU)	Variable Charges (Rs. in Cr)	Markup Charges as per CERC (Rs. in Cr)	Total Charges (Rs. in Cr)
June'23	269.463	518.024	-248.557	-29.152	33.115	3.963
July'23	170.133	326.024	-155.888	-18.165	18.309	0.144
Aug'23	110.979	297.665	-186.683	-25.871	25.860	-0.011
Sept'23	116.626	267.774	-152.531	-32.738	15.028	-17.710
Oct'23	139.401	365.727	-226.326	-50.374	19.209	-31.165
Nov'23	100.474	204.212	-103.738	-15.264	10.786	-4.479
Total	907.076	1979.426	-1073.723	-171.565	122.308	-49.257

3. Summary of the Trial Operations and Inferences

Summary of the Trial Operations with Automatic Generation Control (AGC)				
S. No.	**Period of Trial**	**Trial operation objective**	**Changes / Activity done**	**Observations**
1	29-Apr-23 to 02-May-23	Study of the plant delays	Switching AGC ON/OFF **at selected power plants**	• Time delay of the response of power plants to AGC signals is in the range of 2-3 minutes • Absence of free governor at the power plants – primary response to slow variations in frequency is poor
2	14-May-23	Tie line Bias mode of Operation	**At NLDC:** AGC control mode changed from Constant Frequency	• Less stress on steam parameters of thermal plants due to reduced cyclic regulation

Summary of the Trial Operations with Automatic Generation Control (AGC)				
S. No.	**Period of Trial**	**Trial operation objective**	**Changes / Activity done**	**Observations**
			(CF) to Tie Line Bias (TLB)	• Effective mode for congestion alleviation • Smooth ACE can be in counterintuitive direction of frequency for ~50% time • Probability of below par utilization of available reserves during contingencies / sustained frequency deviations, which may not be economical
3	30-May-23 to 05-Jun-23	CF control mode of operation with revised settings	**At NLDC** i) Increased Dead band on SmoothACE for each region to +/- FRC*0.1 MW from +/-10 MW ii) integration time increased to 40s from 10s iii) anti-windup limit decreased to 5000 MW from 10000 MW	• Reduced steam parameter cyclic variations, with less AGC micro-cycling – feedback from NTPC • Compromise on frequency control due to inaction within the dead band – visible in the frequency profile in the 00:00-06:00 hrs period • Integration time can be further increased to the level of a typical power

Summary of the Trial Operations with Automatic Generation Control (AGC)				
S. No.	**Period of Trial**	**Trial operation objective**	**Changes / Activity done**	**Observations**
				plant response delay of 90-120 sec
4	07-Jul-23 to date	CF control mode of operation with improved settings	**At NLDC (w.e.f. 07-Jul-23):** i) Integration time increased from 10s to 120s ii) Proportional gain increased from 0.9 to 1 iii) Anti-windup limits have been reduced to match the reserves available under AGC **At Power plants (w.e.f. 10-Jul-23):** Ramp rate has been increased by NTPC from 1% per minute to 1.5%/minute and 2% per minute on 09 selected plants (20 units)	• AGC response to contingencies and sustained frequency deviations has been equally effective as earlier • Counter-intuitive action of AGC DeltaP with frequency (around 50 Hz) has come down • Increased number of 50 Hz crossings and the average time per excursion reduced • Increase in percentage of time frequency remaining within the band • Less micro cycling of steam parameters – feedback from NTPC

Summary of the Trial Operations with Automatic Generation Control (AGC)				
S. No.	**Period of Trial**	**Trial operation objective**	**Changes / Activity done**	**Observations**
			At NLDC (w.e.f. 02-Aug-23): Integration time increased from 120s to 180s **At Power Plants (w.e.f. 10-Aug-23):** Ramp rate has been increased by NTPC from 1% per minute to 1.5%/minute and 2% per minute on 06 selected plants (20 units) **At NLDC (w.e.f. 18-Aug-23):** Integration time increased from 180s to 240s **At NLDC (w.e.f. 29-Aug-23):** Integration time increased from 240s to 300s	

Summary of the Trial Operations with Automatic Generation Control (AGC)				
S. No.	Period of Trial	Trial operation objective	Changes / Activity done	Observations
			At NLDC (w.e.f. 11-Oct-23): Integration time increased from 300s to 360s **At NLDC (w.e.f. 14-Nov-23):** Integration time increased from 360s to 420s **At Power Plants (w.e.f. 22-Nov-23):** Ramp rate has been increased by NTPC from 1% per minute to 1.5%/minute and 2% per minute on 14 selected plants (20 units: Total – 60 units operating with higher ramp rate)	

3.1. Way Forward

Below way forward has been proposed towards achieving a better frequency profile:

- Integrate more power plants under AGC. There was very less interest shown by other than section-62 plants, regional entity IPPs, and state sector generators for integration under SRAS till date. Performance-based incentives to the power plants may be re-looked at for roping in more participants.
- Continue with amicable settings for the system operator and power plants. Review integration time settings suitably.
- Increase ramp rate on more plants (60 units out of 185 units are providing higher ramp rate of 1.5%-2%/min).
- Implement DeltaP reversal trial settings on remaining units
- Explore increase in +/-5% limit at selected plants on a trial basis to increase the reserves operating under AGC.
- Tendering work is ongoing for power plants that are planned to be wired under AGC viz., Telangana STPP, North Karanpura, Farakka-1, and Ramagundam-1. Integrating Jhabua may also be targeted.
- Maharashtra, West Bengal, Uttar Pradesh, Delhi, Haryana have shown interest in proceeding towards intra-state AGC. Tendering work is ongoing for intra-state AGC in West Bengal. Workshops have been conducted to Maharashtra, West Bengal, Uttar Pradesh, and Telangana on AGC/SRAS.
- There are ongoing initiatives w.r.t. AGC implementation and pilot projects on Battery Energy Storage Systems (BESS), Solar, and Pumped Hydro.