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विषय: POSOCO inputs on Draft CERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2021

संदर्भ: 1. CERC Public Notice No. L-1/260/2021/CERC dated 07th September, 2021
2. CERC Public Notice No. L-1/260/2021/CERC Dated: 08th October, 2021

महोदय,

With reference to above, the POSOCO inputs on Draft CERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2021 are enclosed herewith for kind consideration of the Hon'ble Commission and further directions.

The delay in submission of the comments may be condoned.

सधन्यवाद,

भवदीय,

देबाशिस दे
25/10/21

कार्यकारी निदेशक

संलग्न - ऊपरोक्त अनुसार

**POSOCO Suggestions, on behalf of RLDCs/NLDC, on
CERC (Draft) Deviation Settlement Mechanism and Related Matters
Regulations, 2021**

Introduction.....	2
Section A – Implications of the Proposed Mechanism on the Grid Security and Behaviour of Market Players	3
A.1 Collectively Distributed Responsibility to maintain Integrated Grid Security and Reliability	3
A.2 Challenges towards Clean Energy Transition	3
A.3 Delinkage of deviation with frequency would deteriorate the primary response	4
A.4 Case Study of Maharashtra – Imbalance Pricing delinked with frequency a non-starter	4
A.5 Frequency delinked DSM would delay intra-state ABT implementation pan-India	6
A.6 Uncertainty of Ancillary Services Despatch.....	6
A.7 Schedule Leaps due to Market Processes leading to Imbalance.....	7
A.8 Need to Pay for Deviations in any direction by all grid connected entities.....	8
A.9 Mechanism for priority of payments and handling defaults.....	10
A.10 Need to delink DSM Regulatory Pool Account and Revenue Stream of NLDC/RLDCs through RLDC Fees & Charges.....	11
Section B – Requirements for an Efficient and Effective Imbalance Handling Approach in Indian Power System	12
B.1 Need for Hybrid Approach of Active and Passive balancing.....	12
B.2 Need for Long Term Resource Adequacy Assessment – Portfolio Management	13
B.3 Need for development of Forecasting as Primary Faculty in LDC.....	14
B.4 ‘Deviation’ and ‘Settlement’ – Need for Integrated Approach	14
B.5 DSM is an integral part of Grid Code – Need for Grid Code Amendment / Revision	14
B.6 Need for Frequency linkage with Charges for Deviation.....	14
B.7 Sufficiency of funds for Ancillary Services – Need for differential DSM rates	16
B.8 Availability of Generation Reserves – Need for Security Constrained Unit Commitment (SCUC) mandate.....	16
B.9 Need for Monitoring and Tight Control of Area Control Error (ACE)	18
B.10 Need for Narrower Symmetrical Frequency Bands	19
B.11 Need for Declaration of transfer capability by State control areas	20
B.12 Need for metrics for measuring portfolio management diligence of all market players ..	20
B.13 Need for Linkage of DSM Charges to Market Discovered Prices.....	21
B.14 Need for Retaining and tightening Volume limits.....	23
B.15 Need for a National Deviation Pool Account.....	26
Section C – Proposal for revised DSM mechanism with New Price Vector	26

Introduction

POSOCO believes that the time is ripe for deeper discussions on Deviation Settlement Mechanism (DSM) in the light of various developments in power system operations and the emerging electricity market realities in the Indian power sector. Deviation settlement i.e., imbalance handling is one of the four essential pillars of market design; the other three being scheduling & despatch, ancillary services and congestion management.

In the recent past, there have been major paradigm shifts having impact on power system operations and electricity markets including DSM such as Secondary Frequency Control through Automatic Generation Control (AGC), Reserve Regulation Ancillary Services (RRAS), Real Time Market (RTM) and pilot on Security Constrained Economic Despatch (SCED) which resulted in changed scenario.

As per our understanding, the draft regulation has the following fundamental changes:

- A.** Imbalance pricing delinked from frequency even before full implementation of resource adequacy, reserves and frequency control framework
- B.** It is assumed that exact delivery in electricity would be there as per schedule, however, perfect forecasting and scheduling is impossible and deviations inevitable
- C.** Rates for deviation are proposed to be determined on post facto basis rather than ex-ante
- D.** Absence of mechanism for priority of payments and handling defaults
- E.** Mixing of system operator revenue stream with regulatory pool account funds managed as custodian

The above-mentioned proposed changes would have implications on the grid security and behaviour of market players which have been detailed in **Section A**. Further, in **Section B**, need for certain features (some existing in present mechanism too) has been highlighted which are necessary to be incorporated in the proposed DSM for an efficient and effective imbalance handling mechanism. Lastly, a proposal for DSM mechanism with new price vector has been elaborated in **Section C** which would complement the proposed mechanism by Hon'ble Commission with incorporation of the desired features like '*indication*' of surplus/deficit, '*coordinated*' and '*secure*' system operation along with '*true*' deviation pricing.

Section A – Implications of the Proposed Mechanism on the Grid Security and Behaviour of Market Players

A.1 Collectively Distributed Responsibility to maintain Integrated Grid Security and Reliability

If an individual state control area were to operate in isolation, frequency management by the control area would have to be solely done by it through generation reserves or demand response within the state else there would be serious risk of frequency instability leading to cascading failure and blackouts. Intra-state ancillary services need to be implemented in the states to facilitate despatch of reserves & real time balancing.

The grid security and reliability are of paramount importance to system operators at state, regional and national level. For an integrated power system with several control areas (with no single control area being able to influence frequency significantly), Area Control Error (ACE) has been the bed rock mechanism and is in vogue for more than five decades in all the interconnected power system through. out the world. **'What frequency is to the interconnection, Area Control Error (ACE) is to the control area' is the basic principle on which the frequency control and its various performance metrics are designed.** In Indian power system, frequency is collectively controlled and democratically stabilized. All the 36 LDCs at state/UT levels with 6 LDCs at regional and national level are equitably responsible for maintaining grid parameters such as frequency, voltage etc. and contribute in integrated decentralized Indian power system operations.

Traditionally, ACE would be controlled through the full suite of Resource Adequacy, optimal portfolio management, ensuring adequate generation reserves and implementing the same through the Frequency Control Ancillary Services mechanism. None of these (barring primary response through IEGC to some extent), is existing firmly on the ground at intra state level. At the interstate level too, these provisions need to be strengthened through the Grid Code but it is still elusive.

The frequency linked DSM in vogue now actually gave a signal for slow tertiary control to be exercised at the intra state level. **De-linking the frequency part from DSM without putting in place the full suite of Resource Adequacy, optimal portfolio management, generation reserves and Ancillary Services would lead to insecure operating conditions in the grid.**

A.2 Challenges towards Clean Energy Transition

National Electricity Policy, 2005 emphasized on the need to create adequate reserve capacity margin. It mandated creation of spinning reserve of at least 5%, at national level to ensure grid security, quality and reliability of power supply. Indian power system has moved from shortage situation to adequacy scenario in recent times. It has been observed, world-over, that during clean

energy transition and especially during pandemic times, there have been certain bumps in the journey in terms of energy security, resource adequacy, market design, costs of compliance to standards and grid codes, market prices, ramping reserves, storage etc. ***There seems general consensus that the move to a more integrated balancing model would be gradual and proceed in a stepwise fashion.*** Therefore, India would also get through the various challenges in the journey with various gradual steps towards clean energy transition with market mechanisms 'to complement' and 'not compromise' grid security.

A.3 Delinkage of deviation with frequency would deteriorate the primary response

In place of restricted governor mode of operation (RGMO), the draft Grid Code submitted by Expert Group in 2020 has proposed free governor mode of operation (FGMO) for all generating units in the country in order to arrest steady fall in the frequency in the event of a major grid disturbance. The primary response shall be provided by the generating machines immediately up to five minutes by which time the secondary response shall take over through automatic generation control to recover the frequency.

There is an inherent 'inadvertent deviation' by the conventional generators because of design and control characteristics. Delinkage of frequency from DSM would remove the incentive to provide any primary response by the conventional generators, as the power generated through governor response might get treated as deviation. Reduction in primary response would be detrimental to grid security. ***Therefore, conventional generators may get penalized for the 'inadvertent deviation' in the proposed mechanism even after providing primary response in line with IEGC and other design characteristics.***

A.4 Case Study of Maharashtra – Imbalance Pricing delinked with frequency a non-starter

Maharashtra Electricity Regulatory Commission (MERC) issued the Order on 17 May, 2007 in Case No.42 of 2006 regarding "Introduction of Availability Based Tariff Regime at State level within Maharashtra and other related issues" (Intra-State ABT Order). The imbalance settlement was based on "Weighted Average System Marginal Price" (WASMP). Final Balancing and Settlement Mechanism (FBSM) was implemented on 1 August, 2011 after approval of MERC on 23 August, 2009 and after overcoming the constraints in its implementation.

MSLDC filed a Petition (Case No. 56 of 2012) before MERC on 08.06.2012 for removal of difficulties in the matter of operation and implementation of the Intra-State ABT Order in Case No. 42 of 2006. The issues were as follows:

- i. Control of Intra-state STOA transactions under State MOD.
- ii. Constraint of ramping rate of thermal generators in operation of State MOD on 15 min block basis.
- iii. Real time MOD & control of hydro stations like Koyna.

- iv. Surplus scenarios in monsoon/winter.
- v. Consideration of wind, hydro and other generators in net UI-II.
- vi. State's imbalance in the pool & its relation with deviations in net UI-I & II.
- vii. Treatment of OA generators frequently changing status between Inter-State/Intra-State transactions.
- viii. Allocation of additional UI (penal UI charges for frequency below 49.50 Hz).
- ix. Sharing of TPC generation between TPC-D & BEST.
- x. Metering of Unit wise generation.
- xi. Difference in rates of UI at Regional level & Intra-State W ASMP.
- xii. Migrated consumers of R-Infra to TPC.
- xiii. POC deviation bills (RTDA) & Congestion Charges.
- xiv. Incorporating RRF settlements in pool.
- xv. Implementation of governor response.
- xvi. MOD principle and position of generators contracted with Mumbai utilities

MSLDC stated that the prevailing Three Stage Settlement Mechanism is too complex and is difficult to comprehend. A simple Single Stage Settlement mechanism where all the participants are brought on a level playing field and the unscheduled interchanges with the Regional grid is treated at par with the Central UI Regulations in force is essential for the state.

In order to address the issues raised by MSLDC and utilities, MERC, vide Order dated 28.03.2013, formed a Committee under the Chairmanship of Dr. S. A. Khaparde, Professor (Electrical Dept.), IIT, Mumbai and various representatives from stakeholders in the State of Maharashtra. The scope of work for the above referred Committee was to carry out a Zero Base Review of Balancing and Settlement Mechanism for Intra-State ABT In Maharashtra as compared to the system prevalent for Inter-State ABT in Rest of India. The Commission after considering the recommendations of the Committee on Zero Base Review and comments/ suggestions of distribution licensees & MSLDC on the Committee Report issued an Oder vide its order dtd 11.04.2014. The summary of this Order was as follows:

- (a) Implementation of de-centralized scheduling and frequency linked deviation settlement mechanism in Phase I; and
- (b) Implementation of State level customization in Phase II, for improving balancing and settlement mechanism after ensuring successful implementation of Phase-I.

Underlying frequency linkage in deviation design could act as a back stop to ensure resilient and sustainable settlement system, it helps in forward / backward integration and ease of implementation at intrastate as well as microgrid level (homeostatic control). Frequency linked DSM has been implemented in Maharashtra since 01st October, 2021.

A.5 Frequency delinked DSM would delay intra-state ABT implementation pan-India

Robust metering, accounting and settlement is a fundamental requirement for effective RE integration. A Technical Committee of Forum of Regulators (FOR) has been constituted to evolve roadmap for implementation in November, 2015. Accordingly, implementation of Scheduling, Accounting, Metering and Settlement of Transactions (SAMAST) in Electricity in the States has been taken up by the Technical Committee of the Forum of Regulators. The recommendations covered, inter alia, Facilitating Economic Despatch, Ensuring Interface Meter Adequacy, Implementation of Scheduling Mechanism, Real-Time Generation Despatching, Implementation of Energy Accounting System, Implementation of Settlement System, Transparency, Integrity and Probity of Accounts, HR Skill Development, Human Resource and Logistics. Further deployment and implementation of framework on forecasting, scheduling and deviation settlement of wind & solar generating stations at the state level, Introduction of Ancillary Services, Reserves and Automatic Generation and primary control within States is still under initial stage. ***The DSM delinkage with frequency being proposed in the draft regulations would lead to confusion and further delays in implementation for intra-state ABT.***

A.6 Uncertainty of Ancillary Services Despatch

There are time-blocks during certain periods when there is no RRAS Up despatch as the load generation balance is maintained. In fact, there are several days wherein continuous RRAS Down instructions are given to control high frequency situations in the grid. As observed from Ancillary Services despatch over the years (Fig. 1), on an average, around 25-48 blocks in a day, Ancillary Services is not despatched. Further, recently for past few years, on an average, Ancillary Services 'Down' is given for 33 – 45 time-blocks in a day.

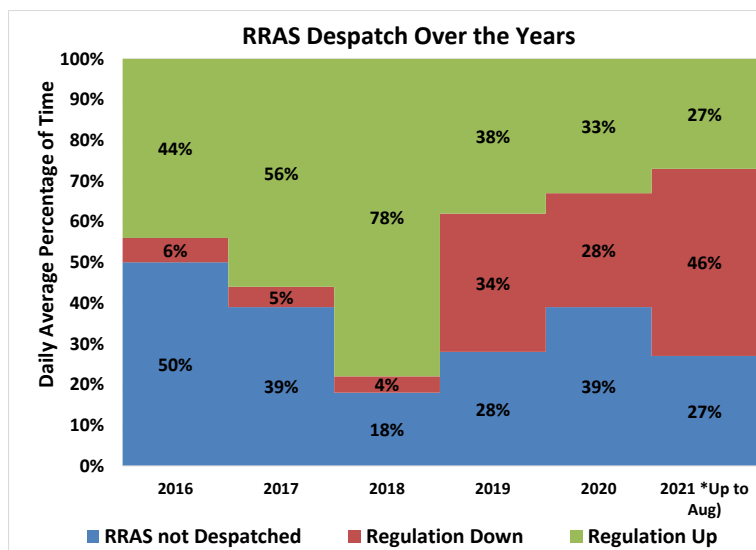


Figure 1: RRAS Despatch over the years

Therefore, there would be complex issues with pricing of deviation linked with Ancillary Services despatch as in some time blocks in a day when Ancillary Service “Up” may not be required to be deployed or only “Down” may have been deployed. Further, it would be limited to a particular set of generators which would not represent the true marginal cost.

A.7 Schedule Leaps due to Market Processes leading to Imbalance

In the modern power systems, imbalances could be attributed to the following factors:

- i. Forced/unplanned outage (Generation loss or load loss)
- ii. Load forecast error
- iii. Forecast error of RES (Wind & Solar) generation
- iv. Extreme Weather Conditions/Abnormal Event
- v. Difference between scheduled and actual generation

Deviation of the frequency from the nominal value is a consequence of the above imbalances. This implies that in a given time block, the interchange schedule would never match the demand or supply perfectly – it would either be ‘over-scheduled’ or ‘under scheduled’. Thus, the deviation of actual interchange from the interchange schedule are inevitable in a power system. These deviations are sometimes referred as ‘schedule leaps’. Schedule leaps are quite significant at the boundary of the defined time blocks due to step changes in the schedule. The schedule leaps are also reflected in the frequency profile of the grid as depicted in Fig. 2.

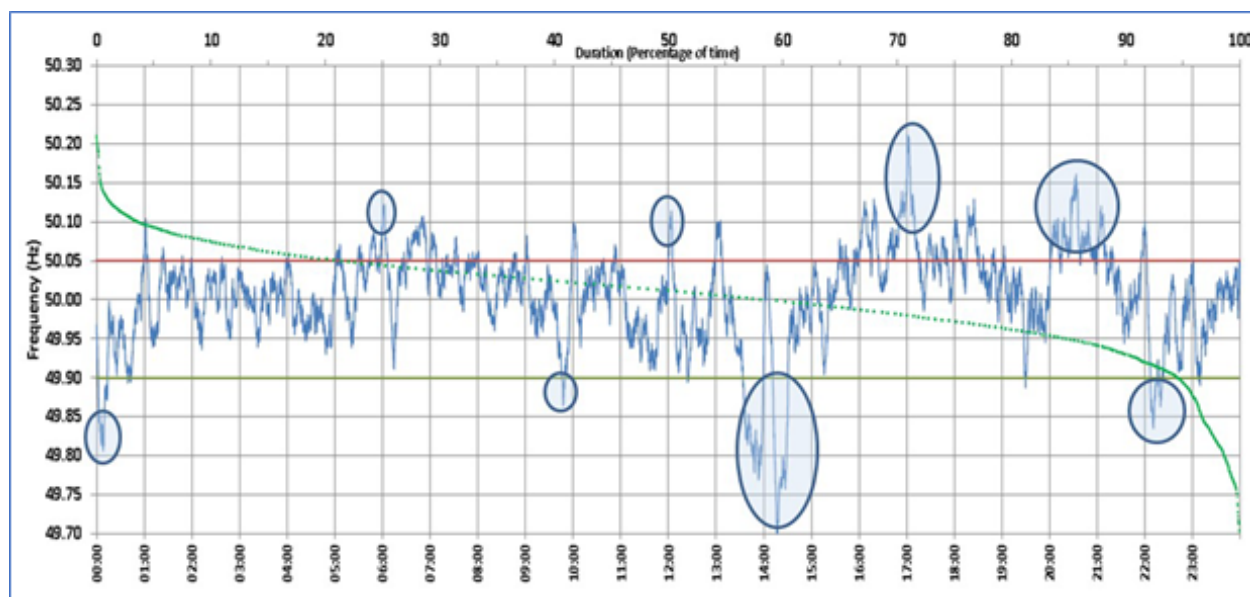


Figure 2: Typical Day Frequency Profile

The changes in the physical supply or the demand are generally gradual (except under contingency). However, in the electricity market, the interchange schedules are specified as discreet step functions in hourly or sub-hourly intervals (15-minute in India) as depicted below. In

the short-term markets such as day-ahead and real time, bids don't factor the ramping constraints as it is assumed that it would be implicitly factored by the bidding entity. It has been observed that due to non-clearing of short-term trades in day-ahead and real time markets, there is excessive leaning on the grid by the entities. It results in sudden change in schedules leading to huge deviations of grid entities. **Hence, factoring of ramping constraints in the short-term market bidding along with focus on ramping reserves needs to be there.**

These drawbacks have to be removed through provisions in the Grid Code with respect to scheduling; delinking the frequency component in DSM without adequate provisions in the former would create insecure conditions.

A.8 Need to Pay for Deviations in any direction by all grid connected entities

In current regulation, any over-injection/under drawal of electricity in a time block an additional charge for deviation is applicable for frequency 50.10 Hz and above. However, in the proposed regulations, deviation charge for over-injection/under drawal has been made zero. The frequency pattern above 50.05 Hz (15-minute average) for period January'2020 - October'2021 is given in Fig.3 below. On an average on 15-minute basis, around 9.7 % of time, frequency remained above 50.05 Hz. There are even some days when more than 45 % of time frequency remained above 50.05 Hz.

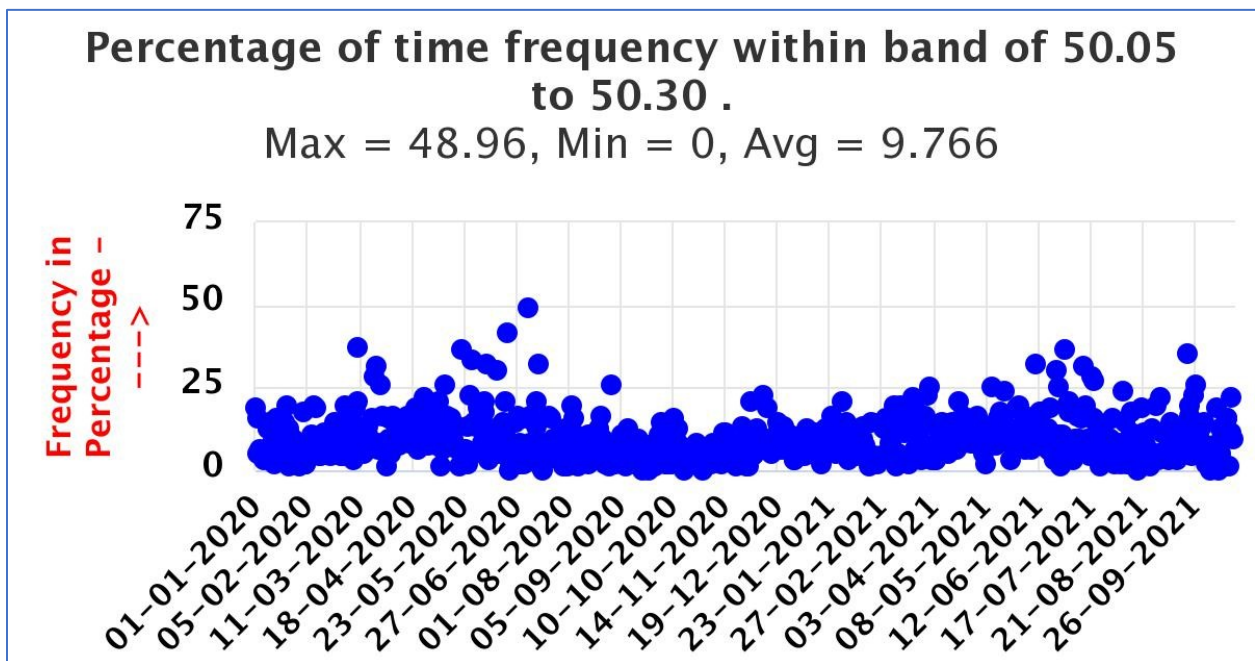


Figure 3: Percentage of Time frequency above 50.05 Hz from January, 2020 - October, 2021

There could be aspects of gaming involved too if the deviation charge for over-injection/under drawal would be made zero. There are several cases in the recent past (depicted in Fig. 4) there was sustained deviation with possibility of under-delivery by few generating stations.

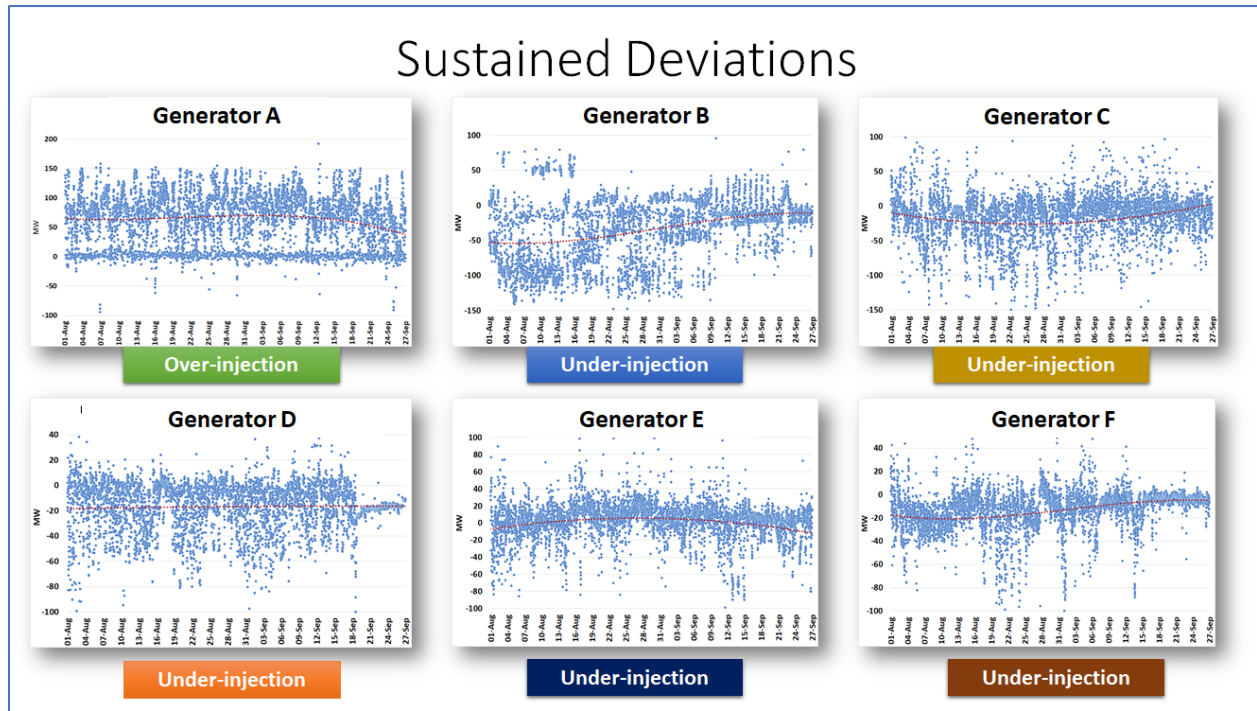


Figure 4: Cases of Sustained Deviation by Sample Generators

When frequency is above the IEGC band, there would be requirement of 'Down' Ancillary Services. The over injecting generators would not get any price signal to follow schedule with proposed mechanism. If those generators were given 'Down' Ancillary Service instruction, they may not contribute, however, they would get compensated for getting schedule for 'Down' Ancillary Service.

In the absence of any price signal and in the scenario of shortfall in procurement of 'Down' Ancillary services by Nodal Agency, it would be detrimental to grid security. Further, zero deviation charge payable for under-drawals would lead to a sharp increase in Renewable Energy (RE) curtailment from commercial considerations alone rather than technical reason.

The provision in the draft for having zero deviation charge for under-drawals / over-injections needs to be revisited. **Hence, deviation in any direction by all grid entities must be priced at all times in the interest of grid security. Any Under Drawal/Over Injection above 50.10 Hz and for Over Drawal/Under-Injection below 49.90 Hz, additional charges for deviation would need to be considered.**

A.9 Mechanism for priority of payments and handling defaults

It is being observed that a number of regional entities are persistently defaulting in payment of 'deviation charges' as well as in opening the requisite letters of credit (LC) against the default. As per CERC order in 142/MP/2012, RLDCs may invoke regulation 25A of Open Access Regulations & deny open access to such entities whenever they willfully & persistently default in payment of regulatory charges including DSM charges. As per the said order such default trigger date is defined as 90 days from the due date of payment. Consequently, the defaulting regional entities are taking advantage of the 90 days default trigger date provision for initiating the regulatory measures by RLDCs and willfully delaying in payment of weekly DSM charges to 30-40 days. Thus, by making payments after 30-40 days, these entities are avoiding to get regulated by RLDCs and continuing with the same cycle for each weekly DSM account. Further, RLDC can invoke this clause (25A of Open Access Regulations) only to stop STOA transactions & not the LTA & MTOA transactions.

It may be appreciated that the amount of weekly deviation charges are very less when compared with the payable generation and transmission charges. Accordingly, to address this issue of dealing with persistent delay/default in DSM charge payment, it is suggested that if any regional entity defaults the DSM payments for a long period (i.e. beyond 30 days), RLDCs shall curtail/restrict their schedules (LTA/MTOA/STOA) in a graded fashion say 25% restriction for first week of default, followed by 50% the next week and so on.

Further the draft regulations have a provision for opening letter of credit against any failure to pay DSM charges during previous FY. The LC amount is 110% of average weekly DSM payment liability. It is felt that instead of 110% of average weekly DSM payment liability, we may consider making it as 110% of maximum weekly DSM payment liability so as to bring more seriousness amongst the regional entities. This might serve as a better deterrent against default in payment of weekly DSM charges. Further, in a few cases where the regional entity generators have filed for insolvency resolution before the NCLT and are under the custody of the Insolvency Resolution Professional (IRP), they have expressed legal difficulties in opening the LCs. They have sought permission to open Bank Guarantee instead. Accordingly, we may consider allowing such entities to either open LCs or BGs.

The extant DSM regulation allows a deviation volume limit of 12% for overdrawing buyers. Accordingly, we may consider having a provision where the new **regional entity buyers are may be advised to open Letter of Credit (LC)/Bank Guarantee (BG) equivalent to the energy charge corresponding to for 12% of their contacted capacity/installed capacity. Further, the LCs must be made unconditional, revolving and irrevocable so that RLDCs can encash them whenever the default continues beyond a defined period in case of default in payment of weekly DSM charges by such entities.**

A.10 Need to delink DSM Regulatory Pool Account and Revenue Stream of NLDC/RLDCs through RLDC Fees & Charges

In India, since inception of availability-based tariff two decades back, DSM pool account is a regulatory pool account. RLDCs have been given the mandate to operate this pool account as a custodian for collection & disbursement amongst the beneficiaries as per the Grid Code & DSM Regulations. The volume of transactions in DSM pool neither appears in the books of accounts of RLDCs nor is any tax liability attached to RLDCs for handling these regulatory funds.

RLDC Fees & Charges are collected by the RLDCs from the users (viz. Generating Stations/Sellers, Buyers/DISCOMs, Transmission Licensee and others) as per provisions under section 28(4) of the Electricity Act and the CERC (RLDC Fees & Charges) Regulations 2019. The same is booked as their revenue in their financial books of accounts viz. Balance Sheet & Profit & Loss Accounts etc. It is used for computation of income tax and dividend payment liability of POSOCO (RLDCs/NLDC).

The methodology of computation & treatment of DSM charges & RLDC Fees & Charges are driven by separate regulations and they serve entirely different purposes. While DSM pool fund is used for imbalance settlement & for funding the cost of procuring ancillary services, the RLDC Fees & Charges serves as the revenue stream for RLDCs/NLDC. It is subject to approval of the proposed expenditure by the Commission for a period of 5 years with due prudence check. The same is again subjected to truing up annually and at the end of the 5 year control period followed by refund/recovery to/from the users as per approval of the Commission.

The pool members who pay DSM charges are basically the regional entity generators and the DISCOMs, whereas a wide range of users share the approved RLDC Fees & Charges viz. Generators/Sellers, Buyers/DISCOMs, Transmission Licensees, SPPDs/WPPDs, etc as defined in the CERC (RLDC Fee & Charges) Regulations 2019. The deviation charges are required to be paid by the defaulting entities. A defaulting entity may be a buyer of electricity as well as the seller/the generator. Further, the amount from the pool account may be received by the buyer as well as the seller/the generator. These entities may insist on deducting TDS while making payment to Deviation and Ancillary Service Pool Account and/or also charge TCS while raising bills for deviation charges. It may create less payment in Regulatory Pool Account and also create TDS/TCS related issue for POSOCO.

Thus, if the RLDCs start collecting the deficit amount in DSM & ancillary account through RLDC fees & charges, it would lead to a lot of disputes and litigations with respect to accounting, taxation and audit. Even, at present, with introduction of GST regime, RLDCs are facing multiple audit queries on their tax liability for handling current DSM pool account funds.

Similarly, the volume of transactions are widely different when we compare the monthly RLDC Fees & Charges amount (~ ₹ 5 Crores) with the transaction volume in the regional Deviation pool

accounts which is of the order of a few hundred crores per week. It is observed that a significant number of entities default in payment of DSM charges for which RLDCs keep following up in various RPC forums and at times file petitions before the commission (Eg. WRLDC vs Essar Mahan, WRLDC vs Vandana Vidhyut Ltd., in 2015-16, ERLDC Vs Ind Barath in 2018-19 etc.). Fortunately, the default or delay in payment of RLDC charges is rarely observed due to the meagre amount of payment liability towards this. Such default in DSM payment at times takes years to recover and in some cases the matter is still pending for resolution before the NCLT. If both DSM & RLDC Fees & Charges collection accounts are merged and the entities start defaulting in payment of RLDC Fees & Charges for years like they do for Deviation charges, it would directly impact the revenue stream of RLDCs. In the long run it may threaten the financial sustainability of RLDCs/NLDC.

Further, Regulation 9(4) of the draft DSM Regulations 2021 has a provision where in Commission may by order direct any other entity to operate and maintain the Deviation and Ancillary Service Pool Account. Thus, in future if any other entity other than RLDCs operate the Deviation and Ancillary Service Pool Account, the said entity may not be able to meet the deficit through RLDC Fees & Charges. Thus, this provision is apparently in contrast to the provision for meeting deficit in Deviation Pool account as given at clause 9(7) of the draft.

Currently, RLDC fees & charges as shown as “exempt supply” for GST compliance which are part of POSOCO’s revenue. Mixing DSM receipts with RLDC fees & charges revenue may also create problem in GST turnover reconciliation of POSOCO in future.

Internationally, in ISO model, like PJM in the USA, the energy and Ancillary Services market payments are a separate pool account and the amounts not routed through PJM balance sheet.

Source: <https://www.pjm.com/-/media/committees-groups/committees/fc/2021/20210325/20210325-annual-financial-report.ashx>

Thus, it is suggested to keep the two accounts i.e. RLDC Fees & Charges account and the DSM & Ancillary pool account separate for all purposes, which is in line with intent and the spirit of the Electricity Act as well as the accompanying regulations of the Hon’ble Commission.

Section B – Requirements for an Efficient and Effective Imbalance Handling Approach in Indian Power System

B.1 Need for Hybrid Approach of Active and Passive balancing

Deviations are unavoidable, however, unchecked deviations are a threat, no matter how much transfer capacity is added. World over, system operators have tools to actively balance the system by sending a dispatch signal to the suppliers of balancing power and passively balance the system by sending a price signal to utilities/entities. In India, the shift in balancing paradigm is depicted in Fig. 5 as below:

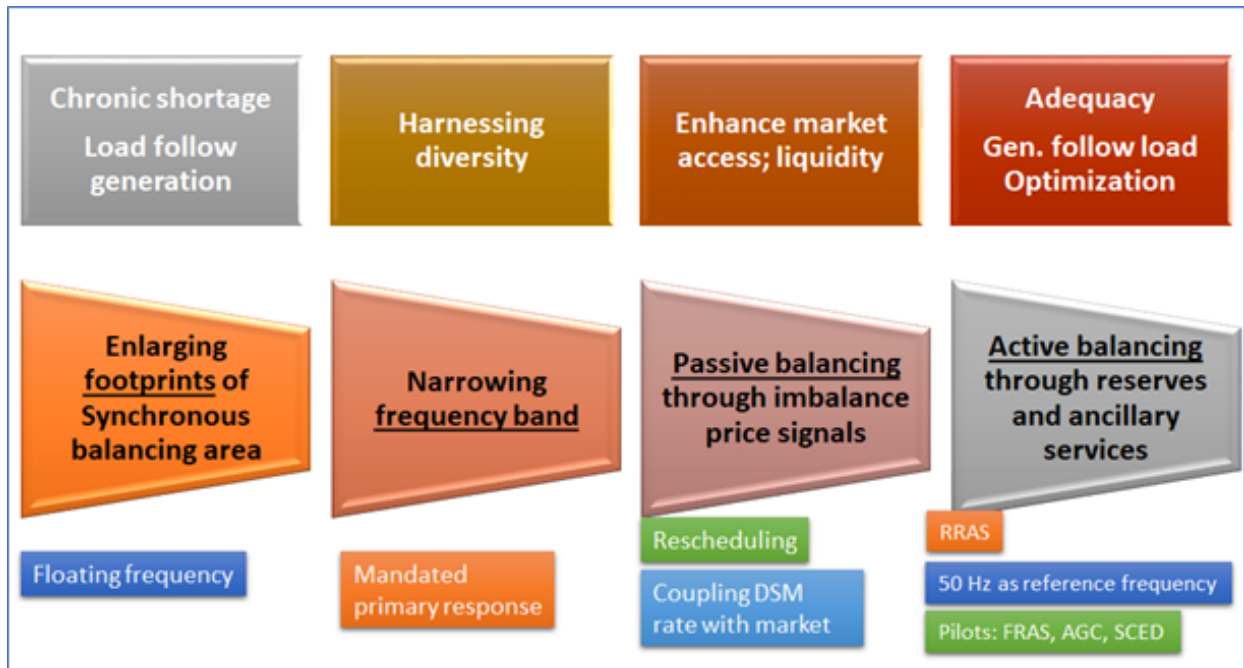


Figure 5: Balancing Paradigm in Indian Power System

The timely publication of the imbalance price and the ability of entities to respond to the price signal is pre-requisite for passive balancing. Passive balancing is a close substitute for active balancing, especially for slow reserves. Moreover, deterministic imbalances – such as schedule leaps at hourly boundaries in Indian case – could be efficiently targeted by passive balancing. ***In India, there is need for hybrid approach of distributed passive balancing (through frequency linked DSM) as back-up to integrated active balancing by LDCs.***

B.2 Need for Long Term Resource Adequacy Assessment – Portfolio Management

There is a need to implement a more formal, systematic resource adequacy framework in India essential for balancing. It would facilitate generation capacity sharing among states as load serving entities, reduce the risk of free riding on system reliability by individual states and Discoms thereby lesser deviations, increase utilization of existing generation resources, increase the resiliency of the power system to extreme events, and maintain power system reliability as the penetrations of solar/wind generation and energy storage increase. Electricity markets don't bring adequacy is being realized in all parts of the world including India.

Globally, capacity adequacy studies are conducted by the perspective planners. The resource adequacy is important for planning power procurement in long term. ***The respective distribution licensees need to publish yearly adequacy statement of generation (basket of resources) & transmission on a rolling basis.*** These statements need to consider reasonable margins for generation and transmission to take care of contingencies. The determination of resource adequacy guidelines for each region is important including LoLP (Loss of Load Probability), VoLL

(Value of Lost Load) and Optimal Reserve Margin. These provisions need to be strengthened through the National Electricity Policy and the Indian Electricity Grid Code and implementation enforced through the SERCs.

B.3 Need for development of Forecasting as Primary Faculty in LDC

The load and RE forecasting would be necessary for all-India/Regional/State level entities in different time horizons at granular resolution. As per the CERC approved detailed procedure for Ancillary Services, in accordance with the stipulations in Clause 5.3 of the IEGC regarding demand estimation, each SLDC has to prepare the block wise daily forecast of demand on day-ahead basis by 1500 hrs of current day for next day taking into account various factors such as historical data, weather forecast data, outage plan of units / transmission elements, etc. Each state control area may also give block-wise reserves quantum. This provision to be given in the regulations for enforcement and compliance. ***Robust forecasting would be key for activation and deployment of reserves to tackle the deviations, by the system operators.***

B.4 'Deviation' and 'Settlement' – Need for Integrated Approach

DSM, per-se, does not balance the system; it is simply an ex-post mechanism for defraying the costs of balancing and at the same time incentivizing good contracting and portfolio management behaviour on the part of grid entities. Therefore, ***deviation (as physical 'real time' manifestation in grid having impact on grid security and reliability) and settlement (commercial impact of deviation whether helping the grid or otherwise with incentive/dis-incentive) are two different yet complementary aspects.***

B.5 DSM is an integral part of Grid Code – Need for Grid Code Amendment / Revision

In earlier avatar, DSM as Unscheduled Interchange (UI) was conceptualized as part of commercial mechanism in the first grid code in year 2000. Thereafter, for some period, UI was made part of Terms and Conditions of Tariff Regulations. It was felt that due to limitations in revisions of tariff on dynamic basis, a separate regulation was carved out for UI in 2009. However, the enabling provisions related to UI/DSM have been suitably incorporated in the Grid Code amended from time to time for past two decades. Grid Code is the foundation on which the market edifice stands. **Therefore, DSM has been recognized an integral part of Grid Code and hence, any change in fundamentals of DSM would necessitate amendment in the Grid Code a-priori.**

B.6 Need for Frequency linkage with Charges for Deviation

An important aspect of the Indian electricity market is the decentralized nature of scheduling & despatch decisions. Frequency leads to independent and 'real time' behaviour in collective interest. Frequency linked DSM borrows from the basic philosophy of homeostatic control,

proposed by Fred C. Schweppe et.al., in which the supply (generation) and demand (load) respond to each other in a cooperative fashion. The emerging technologies such as peer to peer trading through blockchain technologies would require real time price signal which is only possible through frequency linked deviation pricing easily measurable at consumer premises with variety of technologies. Frequency is the fastest guide for interconnect-wide price adjustment.

Frequency an inseparable component of deviation. In complex system like power system anywhere in the world, with thousands of entities, there is not a one to one relationship between system operator actions and the imbalance positions of individual grid entities. Hence, the frequency control component, represents the value of the response and underlying reserves activation used to deliver the balancing energy necessary to offset unscheduled energy by individual entities.

In addition to frequency control component, the deviation also consists of the energy component, representing the value of the energy included in the Inadvertent Interchange and translated in the energy price. There is another component i.e. the transmission component, representing the reliability value of the transmission congestion and which is in the form of energy price. Hence, **world over, any deviation settlement mechanism would have to factor the three components of energy, reliability and frequency control for deviation handling (security) and formulating suitable commercial aspects.** (Reference Literature and International Practices placed at **Annexure – 1**)

Internationally, such as in Europe (having similar attributes with Indian grid), resource adequacy, portfolio management, Frequency Containment Reserves and Frequency Restoration Reserves have played vital role for frequency control. Recently, the shortages of fuel and LNG as well as increased prices have been witnessed in Europe. However, there was no perceptible change in European frequency profile as compared to Indian grid frequency profile though the balancing costs are reported to have doubled. The comparison of frequency related parameters for the period 01 January 2020 – 15 October 2021 is as follows:

Table 1: Comparison of Frequency Parameters of Europe and India

	Europe (ENTSO-E)	India
Daily Average Frequency	Max. – 50.017 Hz, Min. – 49.986 Hz	Max. – 50.058 Hz, Min. – 49.932 Hz
Daily Maximum Frequency	Max. – 50.158 Hz, Min. – 50.047 Hz	Max. – 50.393 Hz, Min. – 50.094 Hz
Daily Minimum Frequency	Max. – 49.946 Hz., Min. – 49.753 Hz	Max. – 49.892 Hz, Min. – 49.502 Hz
Frequency Variation Index	Max. – 0.008, Min. – 0.002	Max. – 0.132, Min. – 0.014
Standard Deviation	Max. – 0.027, Min. – 0.014	Max. – 0.093 Min. – 0.035

The European (ENTSO-E) frequency data (Source: RTE-France) comparison with Indian frequency data for sample days is placed at **Annexure- 2**.

It can be inferred that that there is a long journey ahead in terms of stabilization of frequency profile with international standards. It is a fact that there is improvement in power system operation (in terms of stable operation and frequency remaining within a close band) over the years with various regulatory interventions by Hon'ble Commission. Still, there are large frequency excursions experienced on daily basis with constraints in the demand and supply with frequency touching 49.50 Hz as recently as 07th October, 2021.

B.7 Sufficiency of funds for Ancillary Services – Need for differential DSM rates

Worldwide, the system balancing costs are typically 1-2% of the energy costs. So, in India too, it would be in the range of Rs 5000-10000 crores in the medium to long term. This amount is across all the load despatch centres in the country. At an All India level, the RLDCs despatch typically 45% of the country's generation and so NLDC/RLDCs would need to spend amounts in the range of ₹ 2000-5000 crores annually. ***The DSM regulatory pool account must have sufficient funds to facilitate ancillary services despatch and the differential DSM rates would be needed to capture this aspect.***

B.8 Availability of Generation Reserves – Need for Security Constrained Unit Commitment (SCUC) mandate

It has been observed that RRAS Up despatch during critical periods has been quite low (depicted in Fig. 6) during which reserves situation is also unfavorable at times (depicted in Fig. 7).

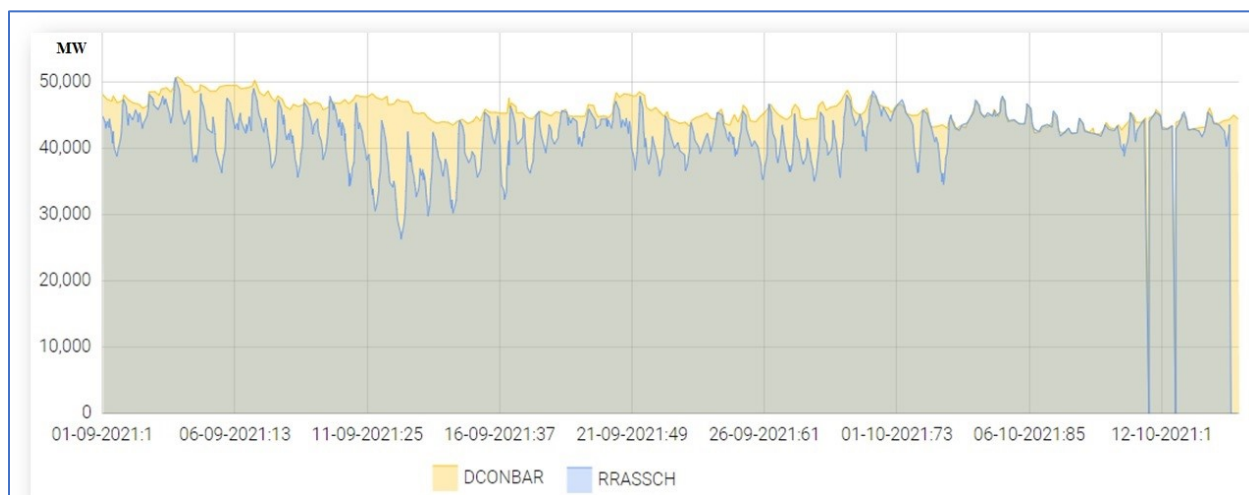


Figure 6: DC-on-bar and RRAS Despatch

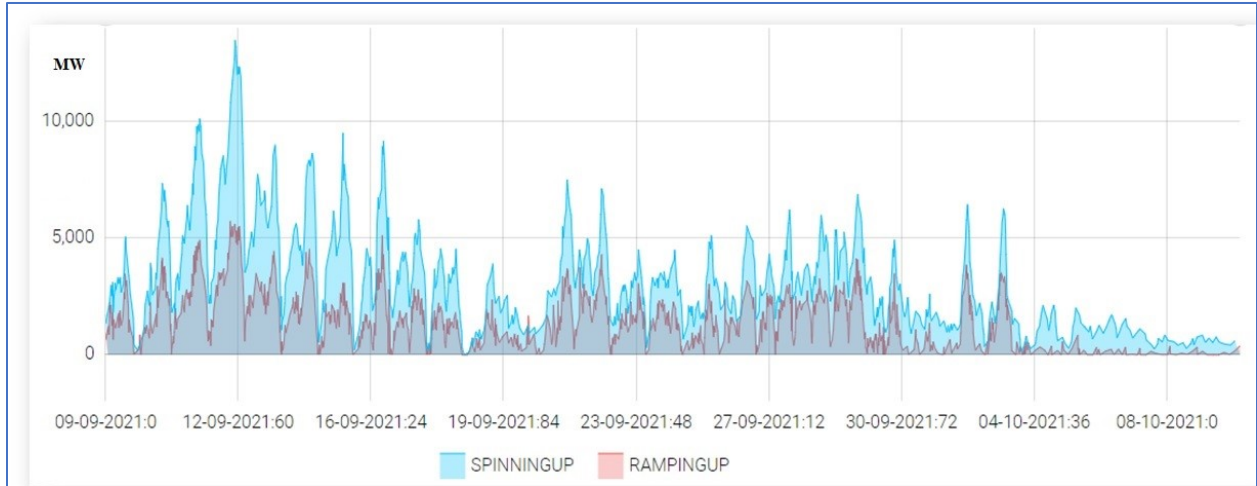


Figure 7: Spinning Reserves and Ramping Reserves

At present, especially during the late evening peak and night hours, the buy bids are consistently and significantly higher than the sell bids in the day ahead market indicating the limitation in the quantum of generation available from non-regulated sources/merchant sources. A sample plot of buy-sell on IEX power exchange for delivery date of 09th October, 2021 is as below in Fig. 8.

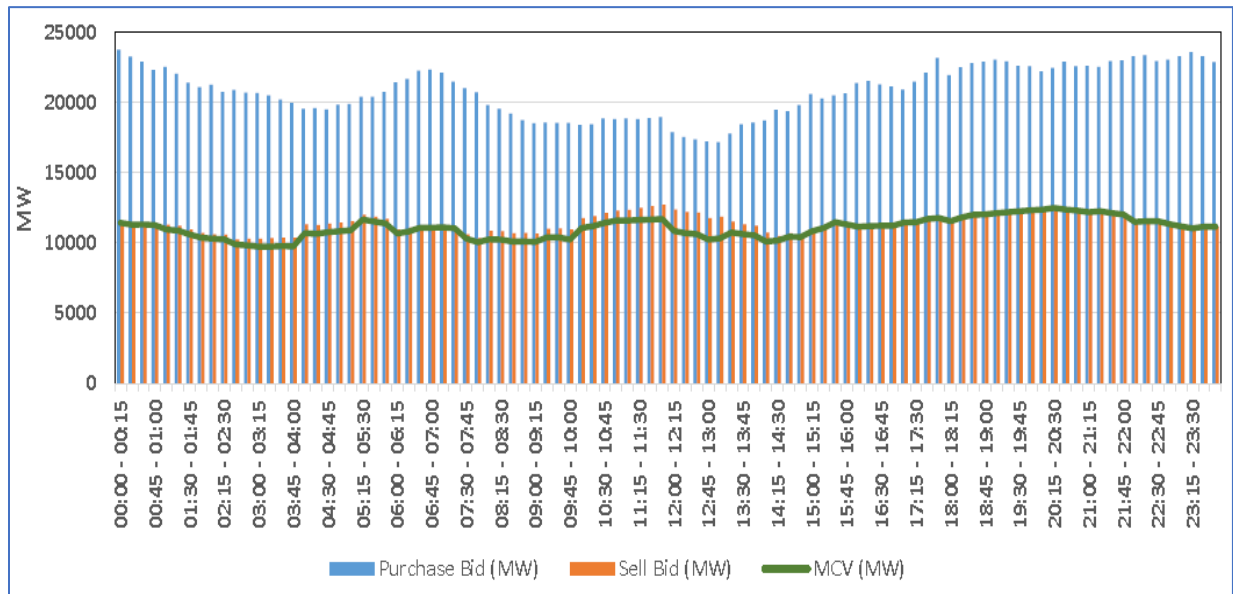


Figure 8: Purchase Bid and Sell Bid on Power Exchange

At present, SCED optimization is taking place after unit commitment has taken place based on requisitions by constituents. Unit commitment is being handled in accordance with the approved operating procedure for taking units under Reserve Shutdown which is ad-hoc in approach.

Formulation for Security Constrained Unit Commitment has been operational in offline mode since June 2020, and its results over an eight month period were shared in the SCED detailed feedback report submitted to Hon'ble Commission. The formulation is continuing to run in testing

mode and the modelling has been improved over time with incorporation of gas and hydro stations in the model.

The Expert Group constituted by the Central Commission to review Indian Electricity Grid Code also proposed that the Security Constrained Unit Commitment (SCUC) exercise may be carried out to facilitate reliability of supply to the regional entities/beneficiaries taking into account optimal cost, adequate reserves, ramping requirements factoring security constraints. ***In order to ensure availability of adequate secondary and tertiary reserves with sufficient ramping capability, there is a need to identify the generating unit for purpose of unit commitment at the national level on at least 3-day rolling basis.***

In addition to the above, subjects like more frequent declaration of variable charges, declaration of incremental heat rate curves, need for lower turn down level, mandate for reserves, national pool account, and optimization considering full transmission network have been flagged in the Pilot on SCED detailed feedback report. There is a need for more flexibility from the generating stations in terms of two shift operations and need to lower the turn down level i.e. technical minimum level, especially at intra-state level, with more machines on bar.

B.9 Need for Monitoring and Tight Control of Area Control Error (ACE)

Balancing systems are meant to balance both the synchronous system and each balancing area. The synchronous system is balanced if frequency is at its nominal value (50Hz). What frequency is to the interconnection, Area Control Error (ACE) is to the control area is the basic principle on which the frequency control and its various performance metrics are designed.

ACE reflects the control area power balance. ACE signal includes the interconnection frequency error and the interchange power error with the grid. The definition and formula for ACE has been provided in the report of the Expert Group to review Indian Electricity Grid Code in January 2020.

Presently, the states try to restrict their deviations through limited avenues like manual rescheduling, market based transactions, and load management. As AGC and Tertiary Frequency control are absent in most of the states, the functions of these frequency control mechanisms are presently upheld by leaning over DSM and the state operator's manual interventions. Several messages are being issued from the NLDC/RLDCs control rooms to the states to maintain ACE within limits. In the absence of AGC and control over ACE, delinking DSM from frequency might lead to further deviation from schedule and hamper grid security.

In the light of the above, maintaining ACE within limits is an immediate requirement for grid security. Automatic control mechanisms like AGC at the interstate level can only work effectively if the states maintain ACE within reasonable limits. The culture of maintaining reserves also has to be adopted by every control area. ***There is a need for a paradigm change from monitoring of simple deviations to monitoring of "Area Control Error (ACE)".***

B.10 Need for Narrower Symmetrical Frequency Bands

The purpose of implementing the various provisions of the DSM Regulations is to ensure a better frequency and secure & reliable power system operation. In this context, it is pertinent to mention that the monitored frequency band is asymmetrical i.e., 49.90-50.05 Hz considering a short supply position. However, in view of the fact that the nominal frequency for Indian Electricity Grid has been declared as 50 Hz and with improved generation & transmission infrastructure adequacy, the frequency band to be monitored should be "above 50 Hz" and "below 50 Hz" with a symmetrical tolerance band around 50 Hz.

Hence, as also recommended in the "Report of Expert Group to review and suggest measures for bringing power system operation closer to National Reference Frequency (Volume – I)", **the operational frequency band should be changed to 49.95 – 50.05 Hz.** The comparison of percentage of time frequency within the band of 49.95 – 50.05 Hz for Indian grid (Fig. 9) and ENTSO-E (main Continental Europe which is twice the size of the Indian grid) (Fig. 10) is as below:

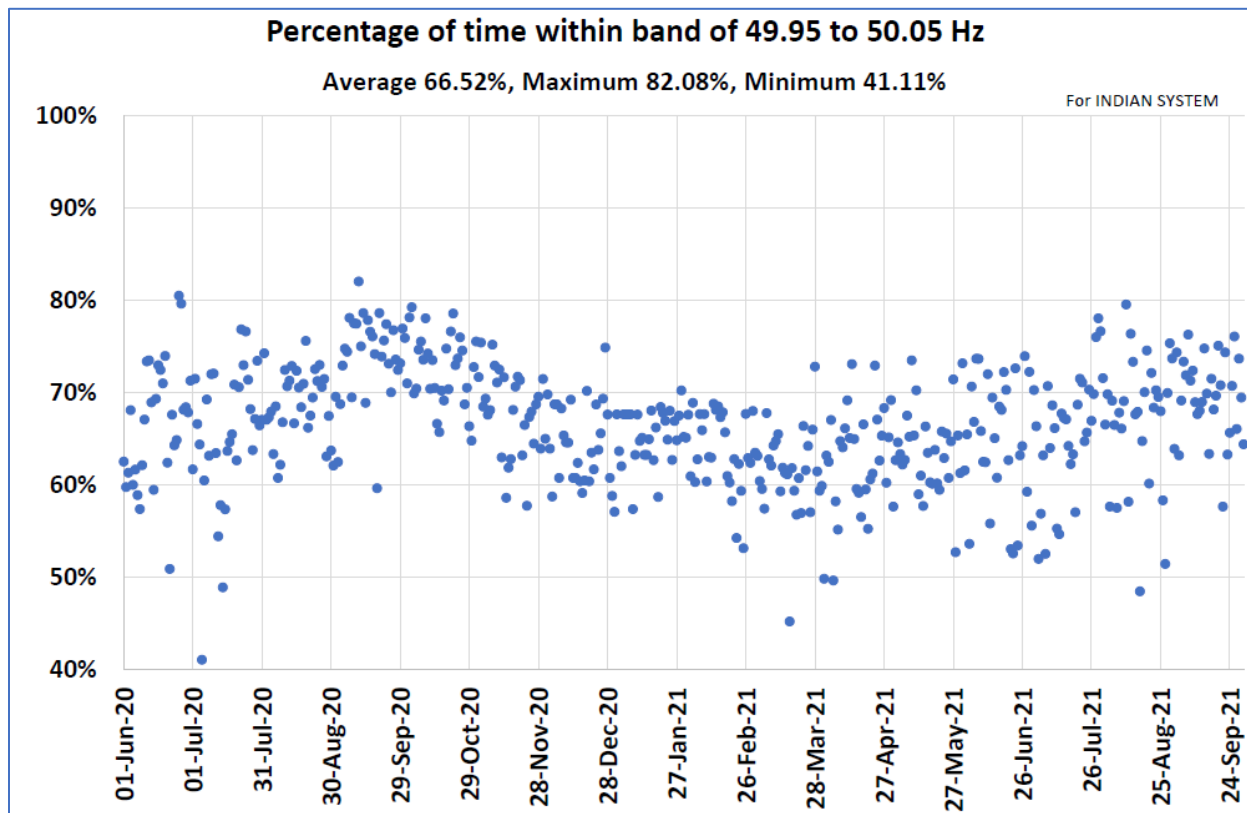


Figure 9: Percentage of Time within band of 49.95 - 50.05 Hz in Indian Grid

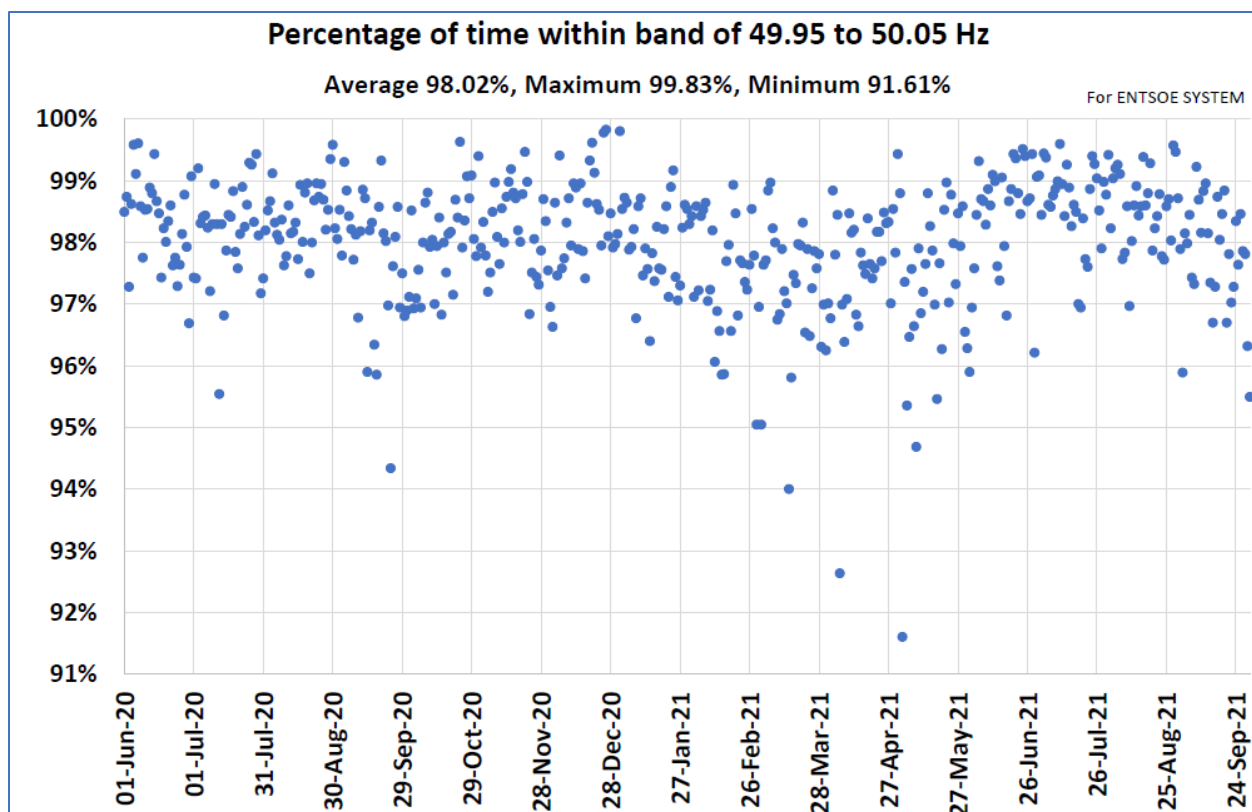


Figure 10: Percentage of time within band of 49.95 - 50.05 Hz (ENTSO-E grid)

There is a need for putting in place the complete framework of Resource Adequacy, portfolio management and balancing through generation reserves as available in all developed systems worldwide before we de-link frequency from DSM.

B.11 Need for Declaration of transfer capability by State control areas

In order to facilitate the administration of the market trades, another essential requirement is the ***need for assessment of transfer capability on a state-wise basis in advance***. Few states such as Punjab, Kerala, Uttar Pradesh, etc. have started declaring the TTC/ATC. However, majority of the states are yet to start the assessment and declaration of TTC/ATC. This would have to then translate to creation of more bid areas in the PX (with each state control area as a bid area). Only this would make the Area Control Prices more robust and factor network congestion.

B.12 Need for metrics for measuring portfolio management diligence of all market players

There are instances in the recent past wherein states have procured upto 18 % of their demand through day-ahead market and upto 10.9 % from real time market. Further, certain states had drawal schedule consisting of more than 40 % through day-ahead market and upto 14.5 % from real time market. The plot of sample states for the September- October, 2021 period is placed at

Annexure – 3. There is an urgent need to review the thresholds regarding relative proportion of energy procured in long-term and short-term markets including real time market.

The dependence of the states on day ahead market and real time market as mode of last minute procurement poses a threat to grid security. Such high volumes would also lead to price volatility in the market. State utilities must be able to demonstrate resource adequacy till clearing of day ahead markets. This resource adequacy would include reserves too. Any contingency thereafter may be handled through real time market.

Instead of tweaking the deviation pricing, there is a need for market instruments for deploying peaking power/ramping resources. In the recent times, the failure of electricity market to ensure resource adequacy has been felt globally and in India too. ***There is a pervasive grid security threat arising from inflexibility of contracts at the state level with over reliance on short term markets. There is a need for metrics such as resource adequacy for measuring portfolio management diligence of all market players.***

B.13 Need for Linkage of DSM Charges to Market Discovered Prices

The view of the imbalance price primarily from a cost allocation perspective, i.e. as a mechanism to recover the cost of utilizing balancing reserves. However, from an efficiency perspective, the crucial role of the imbalance price as an economic incentive to entities is to avoid (or not avoid) imbalances. The entities can reduce imbalances in many ways: by improving forecast tools, updating forecasts more frequently, shifting to faster scheduling intervals, trading more actively on intra-day markets, and dispatching assets more accurately. Rational entities invest in such imbalance management measures up to the point where the marginal cost of reducing imbalances equals the marginal benefit of doing so, i.e. the imbalance spread. For statically and dynamically efficient resource allocation, the imbalance price should reflect the marginal economic costs of solving imbalances by means of balancing power. In India, the day-ahead market and real-time market price discovery process would ideally reflect the marginal costs of particular set of generators on pan-India basis.

The paying capacity and lack of decision-making power of the entities has been a major challenge in handling energy imbalances. Entities are resorting to imbalance as it is a risk-free option and payments are not required to be made before the delivery unlike other types of short-term contracts. The other challenge is pertaining to handling real time scenario which may be different than the anticipated scenario while price discovery in Power exchange. This may be either due to either load crash or any other unforeseen circumstances. The evaluation of DSM price vector based on the market prices would correctly evaluate the opportunity cost based on the expectations of buyers and sellers. This adequate compensation would help to extract the demand response and contribute positively towards system reliability.

In the initial UI formulation in 2001-02, the ceiling was linked to diesel generation prices. Even today if a customer is disconnected due to load shedding, the replacement power cost considering 0.25 litres per kWh and Rs 100/- per litre of diesel would be Rs 25 per kWh. In the current stressed conditions in the grid due to fuel supplies, the Power Exchange prices have clocked Rs 20 per kWh (ceiling) continuously for many blocks in Oct 2021.

While running SCED optimization, the SMP is derived based on about 45-50 GW coal capacity which is 25% of the All-India demand. But SMP for the 25% coal fleet, under SCED optimization, was of the order of Rs 4 per kWh (max. regulated variable cost in the SCED stack) which is not reflective of the actual scenario.

The correlation between the DAM price and RTM price for June, 2020 – September, 2021 period is depicted in Fig. 11.

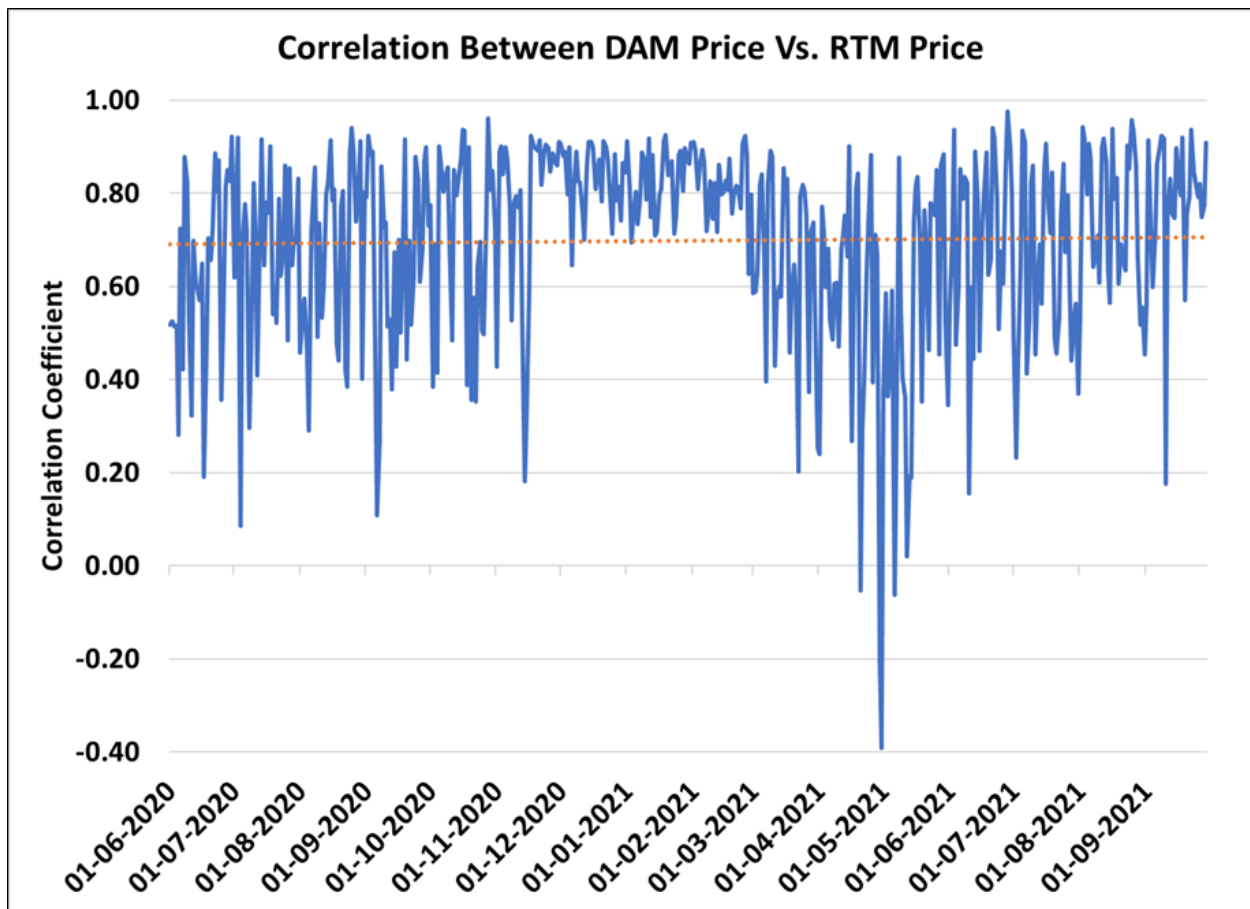


Figure 11: Correlation of DAM and RTM Prices (Jun, 2020 - Sep, 2021)

Hence linkage of DSM rates to market prices would be more appropriate. The base charges for deviation must be linked with 'ex-ante' market discovered prices. The Commission may also like to review the Rs 20 per kWh ceiling currently in vogue at the PX.

B.14 Need for Retaining and tightening Volume limits

The present DSM mechanism defines volume limits beyond violation of which attracts penalties in terms of additional charges varying from 20% to 100% of the applicable DSM rate for that time block. The utilities have been representing that there are instances such as generating unit tripping etc. and, in such cases, the volume limits get violated. However, during such an event, the violations can occur in the initial few blocks and the utility must quickly respond by taking actions to achieve balance once again. Another contention is that the deviation limits are violated because of variability of renewable generation. It needs to be appreciated that variation of renewables does not happen in the few-minute time frames and variability of renewables can be handled with better load and RE forecasting techniques as is being done elsewhere in the world.

The volume limits for RE rich states have been relaxed by CERC based on the level of RE penetration and these vary from 150 MW to 250 MW. In this regard, Explanatory Memorandum issued by CERC along with the proposed amendment states the following:

“Taking into consideration the time required to put the above recommendations in place, and the difficulties of the States under existing DSM limits, the Commission is proposing a revised set of DSM limits for the States, as outlined below, as a one-time measure. It must be noted that these relaxations are being offered only until 1st April 2017, by which time the Commission expects the States to have attained significant progress on all dimensions of robust grid management, as summarized in the Roadmap above.”

Every state control area needs to monitor its ACE and have appropriate tools to minimize the deviations. The regional level ACE for the October, 2020 – September, 2021 is attached at **Annexure – 4**. The state-wise ACE for September, 2021 is placed at **Annexure – 5**. It is felt that even if the top 10 states with high demand implement AGC at intra-state level, majority of the issues with the ACE may be addressed.

Internationally, like in Continental Europe, TSOs specify Frequency Restoration Control Error Target Parameters or ‘FRCE’. FRCE means the control error for the Frequency Restoration Process (FRP) which is equal to the ACE of a Load Frequency Control (LFC) area or equal to the frequency deviation where the LFC area geographically corresponds to the synchronous area. Level 1 and Level 2 limits are defined and FRCE has to be within the target values. Level 1 and level 2 are the limit values for the ACE. The ACE shall not exceed these values for more than:

- Level 1: 30 % of the time intervals of the year.
- Level 2: 5 % of the time intervals of the year.

The level 1 and level 2 parameters must not be exploited in order to reduce reserves or reserves activation. These parameters should rather be interpreted as an absolute warning limit that shows that quality of ACE is below the required standard and that respective countermeasures have been reported and will be implemented urgently. The level 1 and level 2 Frequency Restoration Control

Error Target Parameters for some of the LFC blocks within Continental Europe are provided in Table 2.

Table 2: FRCE Target Parameters in Europe

Sl no	Country	LFC-Block	belonging LFC-Areas	Demand (MW)	Level 1 (MW)	Level 2 (MW)
1	Austria	APG	APG	10000	78	148
2	Belgium	Elia	Elia	12 870	88	166
3	Bulgaria	ESO	ESO	6600	63	119
4	Czech Republic	CEPS	CEPS	10000	86	163
5	Germany	TNG+TTG+AMP+50HZT+EN+CREOS	TNG+TTG+AMP+50HZT+EN+CREOS	75000	248	468
6	Spain	REE	REE	41 381	187	354
7	France	RTE	RTE	94 190	226	427
8	Greece	IPTO	IPTO	8000	64	121
9	Hungary	MAVIR	MAVIR	6500	52	98
10	Italy	TERNA	TERNA	50000	159	301
11	Poland	PSE	PSE, Western WPS	25000	125	236
12	Portugal	REN	REN	8000	73	139
13	Slovak Republic	SEPS	SEPS	4500	49	93

Source:

1. https://docstore.entsoe.eu/Documents/nc-tasks/SOGL/SOGL_A118.1_180808_CE%20SAOA%20part%20B_final_180914.pdf
2. <https://transparency.entsoe.eu/dashboard/show>

In India too, similar limits may be mandated in order to control ACE and maintain frequency profile close to 50 Hz.

A sample indicative exercise on the lines of the above mentioned FRCE target parameters was conducted for the Indian states. The K_{SA} (Frequency Response Characteristics of synchronous Indian Power system based on observed value) & K_{FCR} (Primary response required for reference contingency of largest possible loss of generation) value considered for Indian system is 15000 MW/Hz & 4500 MW respectively. $K_{FCR,i}$ is considered as Frequency Response Obligation (FRO) for each state expressed as ratio of its maximum demand and generation with all India maximum demand and generation multiplied by K_{SA} . The FRCE limits for the respective Indian states are as tabulated in Table – 3 below:

Table 3: Indicative FRCE limits for Indian states/UTs

State	K _{FCRi} (taken FRO)	Level 1 (MW)	Level 2 (MW)
Chandigarh	5	15	28
Delhi	113	66	125
Haryana	184	84	159
Himachal Pradesh	38	38	72
Jammu & Kashmir	48	43	81
Punjab	259	100	189
Rajasthan	293	106	201
Uttar Pradesh	426	128	242
Uttarakhand	42	40	76
Chhattisgarh	99	62	117
Daman & Diu	5	13	25
Dadra & Nagar Haveli	11	20	38
Gujarat	417	127	240
Goa	8	18	34
Madhya Pradesh	257	100	188
Maharashtra	549	145	275
Andhra Pradesh	231	94	179
Karnataka	263	101	190
Kerala	77	55	103
Puducherry	6	15	28
Tamilnadu	347	116	219
Telangana	233	95	179
Bihar	73	53	101
DVC	117	67	127
Jharkhand	22	29	55
Odisha	112	66	124
Sikkim	2	8	15
West Bengal	200	88	166
Arunachal Pradesh	4	12	22
Assam	27	32	61
Manipur	3	10	19
Meghalaya	11	21	40
Mizoram	2	8	15
Nagaland	10	19	37
Tripura	7	16	31

In the interest of secure grid operation, all the volume limits along with associated additional charges for violating the deviation limits should be retained in the proposed market linked DSM price mechanism. The deviation limits also need to be reduced to the approximate values of FRCE Level 1 given in Table-3 above. There is a need for explicit mention of responsibility/accountability of different entities. There is a need to evolve metrics for measuring grid indiscipline and non-compliance. The explicit definition of essential reliability services / flexibility services is required.

B.15 Need for a National Deviation Pool Account

There is a need of national pool account to avoid transfer of fund to deficit region from surplus region while making payment to the recipients of Deviation Pool Account. The disbursement can be done in an integrated manner from the national pool without any procedural delay. A proposal prepared by NLDC submitted to National Power Committee in this regard highlighting the circular flow of money is attached as **Annexure-6** for the consideration by Hon'ble Commission.

Section C – Proposal for revised DSM mechanism with New Price Vector

A proposal for revised DSM mechanism with new price vector containing the following features is submitted for kind consideration of Hon'ble Commission as follows:

- There would be linkage with the frequency and DSM rate
- The operational frequency band would be changed to 49.95 Hz – 50.05 Hz.
- DSM rate would be linked to 'ex-ante' market discovered prices
- In the interest of secure grid operation, all the volume limits along with associated surcharge/additional surcharge would be retained in the proposed market linked DSM price mechanism. Volume limits would be based on monitoring of ACE
- Any Under Drawal/Over Injection above 50.10 Hz and for Over Drawal/Under-Injection below 49.90 Hz, additional charges for deviation would be applied.
- It is proposed that time-block wise Base DSM Rate at 50 Hz may be equal to Weighted Average Time-block wise DAM and RTM discovered ACP of multiple PX.
- There would be suitable slope of DSM rate in steps of every 0.01 Hz till 49.90 Hz
- Below 49.90 Hz, the DSM rate would be equal to two times Base DSM Rate at 50 Hz or a floor price whichever is higher as decided by CERC.
- There would also be suitable slope of DSM rate in steps of every 0.01 Hz till 50.05 Hz
- Between 50.05 Hz and 50.10 Hz, there would be zero DSM rate
- Above 50.10 Hz, the DSM rate would be equal to negative Base DSM Rate at 50 Hz
- The deficit in the DSM pool account would not be mixed with RLDC Fees and Charges
- There would be a national deviation pool account

The proposed DSM rate vector is depicted in Fig. 12 below.

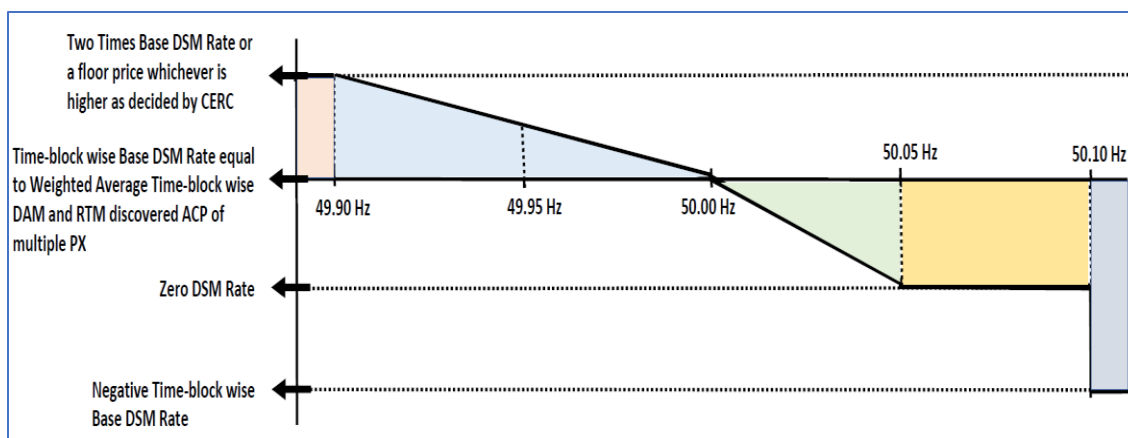


Figure 12: Proposed DSM Rate Vector

The Table-4 below describes the above proposal:

Table 4: Proposed Frequency and DSM Rate

Average Frequency of the time block		Base Rate for Deviation (Paise/kWh)
Below	Not below	
	50.10	Negative Time-block wise Base DSM Rate
50.10	50.09	0
50.09	50.08	0
50.08	50.07	0
50.07	50.06	0
50.06	50.05	0
50.05	50.04	1*(P/5)
50.04	50.03	2*(P/5)
50.03	50.02	3*(P/5)
50.02	50.01	4*(P/5)
50.01	50.00	P (Time-block wise Base DSM Rate equal to Weighted Average Time-block wise DAM and RTM discovered ACP of multiple PX)
50.00	49.99	1.1 *(Pmax-P)
49.99	49.98	1.2 *(Pmax-P)
49.98	49.97	1.3 *(Pmax-P)
49.97	49.96	1.4 *(Pmax-P)
49.96	49.95	1.5 *(Pmax-P)
49.95	49.94	1.6 *(Pmax-P)
49.94	49.93	1.7 *(Pmax-P)
49.93	49.92	1.8 *(Pmax-P)
49.92	49.91	1.9 *(Pmax-P)
49.91	49.90	Pmax = Two Times Base DSM Rate or a floor price, whichever is higher, as decided by CERC
49.90		

Differential Rates

- In order to discourage the treatment of balancing mechanism as trading mechanism by sellers and buyers and inhibit scope for gaming, there is need to introduce dual pricing for both under-drawal/over-injection and over-drawal/under-injection depending on the grid frequency.
- With this hysteresis, the trading through market-based instruments would be encouraged. Otherwise, for the same rate, trade cleared through market-based instruments would have to pay additionally for loss and transmission charges including scheduling charges etc. which is absent through the deviation settlement mechanism.
- Therefore, it is proposed that over-drawals/under-injection would have to pay 110% of the DSM rate as worked out from the above table. The under-drawals/over-injection would get paid @90% of the DSM rate as worked out from the Table-4.

Volume Limits

- There would be an additional multiplier of 1.2 or 0.80 for volume limits.
- Volume limits for state control areas need to be much lower than the 12%/150 MW/250 MW currently allowed and in line with the limits worked out in section B.14 above.
- For generators, it may be at +/-3% to take care that the primary response is in no way discouraged.

Deviation Treatment of Renewable

- The deviation of renewables may be continued as delinked from frequency as per present mechanism in vogue.
- **Definition of “Fixed 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. In the absence of a contract rate/fixed rate, the rate of the Area Clearing Price of the Day Ahead Market for the respective time block would be taken as proposed in the draft regulations.
- It is suggested that for Wind and Solar plants, the present mechanism available in extant regulations could be retained with the 15% error band reduced to 10% as per Table-5 below:

Table 5: Proposed Deviation Charges for WS Sellers

Deviation (%) in time-block	Deviation Charges in case of over Injection	Deviation Charges in case of under Injection
< = 10%	At the Fixed Rate for excess energy upto 10%	At the Fixed Rate for the shortfall energy upto 10%
>10% but <= 20%	At the Fixed Rate for excess energy upto 10% + 90% of the Fixed Rate for excess energy beyond 10% and upto 20%	At the Fixed Rate for the shortfall energy upto 10% + 110% of the Fixed Rate for balance energy beyond 10% and upto 20%
>20% but <=30%	At the Fixed Rate for excess energy upto 10% + 90% of the Fixed Rate for excess energy beyond 10% and upto 20% + 80% of the Fixed Rate for excess energy beyond 20% and upto 30%	At the Fixed Rate for the shortfall energy upto 10% + 110% of the Fixed Rate for balance energy beyond 10% and upto 20% + 120% of the Fixed Rate for balance energy beyond 20% and upto 30%
> 30%	At the Fixed Rate for excess energy upto 10% + 90% of the Fixed Rate for excess energy beyond 10% and upto 20% + 80% of the Fixed Rate for excess energy beyond 20% and upto 30% + 70% of the Fixed Rate for excess energy beyond 30%	At the Fixed Rate for the shortfall energy upto 10% + 110% of the Fixed Rate for balance energy beyond 10% and upto 20% + 120% of the Fixed Rate for balance energy beyond 20% and upto 30% + 130% of the Fixed Rate for balance energy beyond 30%

Balancing of deemed renewable purchase obligation (RPO) compliance of buyers with respect to schedule

- As per the extant regulations, deviations by all wind and solar generators which are regional entities shall first be netted off for the entire pool on a monthly basis and any remaining shortfall in renewable energy generation must be balanced through purchase of equivalent solar and non-solar Renewable Energy Certificates (RECs), as the case may be, by NLDC by utilising funds from the Pool Account.
- For positive balance of renewable energy generation, equivalent notional RECs shall be credited to the DSM Pool and carried forward for settlement in future. This provision is proposed to be retained in the amended DSM framework.

Reference Literature and International Practices for Imbalance Handling

S.No.	Author/Source	Relevant Extract
1.	<p>NERC Joint Inadvertent Interchange Task Force (JIITF)</p> <p><i>White Paper, Recommendations for the Wholesale Electric Industry of North America, May 2002 [6]</i></p>	<p><i>"...Inadvertent Interchange consisted of three components. The first component, the "Energy Component", represented the value of the energy included in the Inadvertent Interchange and is represented in the energy price. The second component, the "Transmission Component", represents the reliability value of the transmission congestion and in present markets this is also included in the energy price. The third component, the "Frequency Control Component", represents the value of the response and underlying reserves used to deliver the balancing energy necessary to offset unscheduled energy..."</i></p> <p><i>"...The proposed standard addressing frequency control contribution will have incentives and penalties that will reward good control and penalize poor control. The incentives and penalties need to be sufficient to promote good performance..."</i></p> <p><i>"...Zero UI is a coincidence rather than expectation..."</i></p>
2.	<p>Mark Lively</p> <p><i>Consulting Economist, to Federal Energy Regulatory Commission, USA</i></p> <p><i>Article - "Creating an automatic market for unscheduled electricity flows"[7][8]</i></p>	<p><i>"...Unscheduled market has not only allowed the new players in the market to participate economically in the inadvertent market between utilities but also offered the customers an alternative way to buy their electricity. The customer being able to buy electricity in the unscheduled market would diminish any market power that the local utility has. Further even the customers can assume a role of a seller in this market by under-drawing from the grid during shortages. Generators need not sell their output at a price lower than the UI rate. Similarly, customers need not agree to buy electricity at any price higher than the value (tangible or intangible) of feeding that loads. A win-win situation for everyone!</i></p> <p><i>"Market is somewhat of a masonry wall. We have bricks with cement around it. Sometimes these bricks are maybe a 100-megawatt contract for an hour or for a day. If you want the wall to stay up, you've got to have this masonry, this mortar, cement to fill up the seams and also a way to price it. Else the wall will fall down. I noticed</i></p>

		<p><i>that about a year and a half ago, India decided that they were going to put in a way to price what they call unscheduled interchange where they provided liquidity for the market and improved their operations by a factor of 5 or 10."</i></p>
<p>3.</p>	<p>Robert Blohm</p> <p><i>Solving the Crisis in Unscheduled Power Public Utilities Fortnightly August 2004</i></p> <p>&</p> <p><i>'Economist's Assessment' North American Electric Reliability Council Joint Inadvertent Interchange Taskforce 10th April 2002[7][9]</i></p>	<p><i>"...Inadvertent interchange isn't a standard commodity transaction: It occurs without specific mutual consent. The total inadvertent interchange on an interconnected system always sums to zero because a single reading of a common meter on any tie-line is counted twice, once as one BA's outflow and again as the other BA's inflow. Since inadvertent interchange always clears, its price must be driven by something else...."</i></p> <p><i>"...True economic dispatch decisions for reliability are based not just on energy cost, but also on Frequency Contribution Component (FCC) cost. Two-part pricing of inadvertent interchange (into energy and FCC) makes the price of inadvertent interchange greater when there is under-frequency than when there is over-frequency...."</i></p> <p><i>"...Inadvertent interchange flows reflect the sudden loss of resources as well as the sudden deployment of resources...."</i></p> <p><i>"...Unscheduled power occupies the interface between markets and reliability; real-time is the proper domain for management of honest scheduling error, not for markets for energy. A market for FCC is the only market needed for incenting reliable behavior. Markets for energy alone do not efficiently incent behavior that is compatible with good frequency control. Moreover, allowing suppliers to increase real-time risk by taking real-time energy delivery risks in an energy-only spot market winds up unfairly penalizing customers if there are no resources available...."</i></p> <p><i>"Inadvertent and energy imbalance are "unscheduled energy" which is two things: (i.1) the "energy" part, and a related (i.2) transmission congestion (loading component, and (ii) the "unscheduled aspect". The unscheduled part is the "inconvenience" factor, "hassle" factor, or degree of suddenly needing the energy."</i></p>

		<i>"...The California market meltdown may be attributed in significant part to improper pricing of unscheduled power..."</i>
4.	Steven Stoft <i>'Power System Economics'- Chapter-Power Supply and Demand & Chapter-The Two-Settlement System [7]</i>	<i>"Because frequency indicates the discrepancies between supply and demand, frequency is the right guide for interconnection-wide price adjustment. When frequency is high price should be reduced; when frequency is low price should be raised. This is the classical adjustment process for keeping supply equal to demand." "In a competitive market the real time prices are true marginal cost prices, and the forward prices are just estimates"</i>
5.	Arthur Berger & F.C Schweppe <i>'Real time pricing to assist in load frequency control' (IEEE Transactions on Power Systems, Vol.4, No. 3, August 1989)[7]</i>	<i>"A key feature of this pricing scheme is that the independent power plants can themselves monitor the frequency deviations and thus no real time signal needs to be sent by the electric utility. This eliminates the problem of how the utility could compute and transmit the price faster than the time scale to be controlled."</i>
6.	Sally Hunt <i>'Making Competition Work in Electricity' Chapter - Trading Arrangements Section – Imbalances & Chapter- Trading Arrangements Section-Imbalances [7]</i>	<i>"The right price for imbalances is a market-based price. A market-based price for imbalance energy is incentive-compatible... It means...that if price is low, it is a good thing that the generator reduces output from its contracted level because imbalance market is a cheaper provider of energy. It means that if the price is high, it is a good thing that the generator increases output from its contracted level because it is a cheaper provider of energy than the alternative imbalance energy providers. And it means equivalent signals are sent to loads." "If the imbalance price is too low, generators would produce less and rely on the imbalances to meet their customers' load. A cheap generator might be better off backing down, creating further imbalance"</i>
7.	Sally Hunt & Graham Shuttleworth <i>'Competition & Choice in Electricity' Chapter- Spot Market & Organization of Trade[7]</i>	<i>"The market for imbalances competes with longer-term transactions as a means for trading electricity." "The imbalances must be settled as if they were instantaneous spot transactions i.e. sales of electricity arranged at (infinitesimally) short notice for immediate delivery."</i>

		<p><i>"There must be some pricing rules for imbalances...These pricing rules become central to the character of the whole electricity market"</i></p> <p><i>"The main tool available to the Market Operator to encourage efficiency is the price charged or paid for imbalances between contracts and actual flows."</i></p> <p><i>"If these imbalances are priced at punitive rates, generators may be reluctant to offer any flexibility of output. The task of maintaining system security would then be rendered difficult, if not impossible."</i></p>
8.	<p>Howard F. Illian <i>"Defining Good and Bad Inadvertent" Jan 2002[7]</i></p>	<p><i>"A market requires an a priori determination of Good and Bad Inadvertent."</i></p>
9.	<p>LDK Consultants <i>FINAL REPORT - Study on Development of Best Practice Recommendations for Imbalance Settlement – January, 2013[10]</i></p>	<p><i>The best practice recommendations for allocation of balancing costs in the 8th Region include:</i></p> <ul style="list-style-type: none"> • <i>Gross model for energy imbalance settlement.</i> • <i>Single Imbalance price.</i> • <i>Average price of accepted bids in system imbalance direction but long term aim to move to a marginal price.</i> • <i>Weight activated reserve bids by reservation fee.</i> • <i>Remove Transmission constraint resolving bids and make the TSO pay for them.</i> • <i>Non Delivery Rule for high price Offers and low price accepted Bids.</i> • <i>RES to be exposed to imbalance settlement on an equal basis to other system users.</i>

International Literature survey on Real Time Balancing of electricity market

United Kingdom:

National Grid uses the term "Balancing Services" to refer to the range of products it uses "to balance demand and supply and to ensure the security and quality of electricity supply across the GB Transmission System." National Grid currently procures over 20 different balancing services products across the categories of System Security, Reserve, Frequency Response, and Reactive Power.

The Imbalance Price is the price of electricity that generators or suppliers pay for imbalance on the UK electricity grid.

In the UK generators and suppliers (known as Parties) contract with each other for the supply of electricity. Generators sell electricity to suppliers who then sell electricity to residential, commercial and industrial customers.

As System Operator National Grid handles real time balancing of the UK grid. Parties submit details of their contracts to National Grid one hour before delivery. This allows National Grid to understand the expected imbalance.

National Grid will then take actions to correct any predicted imbalance. For example, the Balancing Mechanism allows Parties to submit Bids or Offers to change their position by a certain volume at a certain price.

National Grid also has the ability to balance the system using actions outside the Balancing Mechanism, such as:

- Short Term Operating Reserve.
- Frequency Response plants used to balance real time.
- Reserve Services.
- In more drastic scenarios National Grid may call upon closed power plants or disconnect customers.

Short Term Operating Reserve: - STOR allows to have extra power in reserve for when they need it. It helps them to meet extra demand at certain times of the day or if there's an unexpected drop in generation. They award firm STOR contracts to providers on a Committed or Flexible basis across six annual seasons. Non-Balancing Mechanism (NBM) providers can also offer their assets (where eligible) on the day via the Optional STOR service.

Payment to Providers:

- **Availability payments** – Paid (£/MW/Hr) for the hours in which the committed firm service has been made available.
- **Utilisation payments** – Applicable to firm and Optional service. Paid £/MWh for the energy delivered.

Fast Reserve (Optional): Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of a dispatch instruction from the ESO. Optional Fast Reserve is contracted on the day by instruction from the ESO for a Fast Reserve Unit to be available for instruction under the Optional service.

Payment to Providers:

- Availability payments in £/hours – paid for a unit to be available to supply Fast Reserve
- Utilisation payments in £/MWh – paid for the energy delivered under the service

Firm Frequency Response (FFR) Firm Frequency Response is a service they use to keep the system frequency close to 50Hz. Fast acting generation and demand services are held in readiness to manage any fluctuation in the system frequency, which could be caused by a sudden loss of generation or demand. There are three types of frequency response known as "primary", "secondary" and "high". The difference between primary and secondary is the speed at which they act to recover the system frequency. Both primary and secondary react to low frequency conditions, and high response reacts to high system frequency conditions, restoring the frequency to normal operational limits.

Payments to Providers: an availability fee on a £/Hr basis to providers for the MW and hours in which the firm service has been Contracted through the monthly tender. There is no utilisation payment for the FFR service

National Grid attempts to minimize balancing costs within technical constraints. Parties submit their expected positions one hour before delivery. For a number of reasons parties do not always meet their contracted positions.

A supplier may underestimate their customer's demand. A power plant might face an unexpected outage. The difference between the contracted and actual position is charged using the Imbalance Price.

ELEXON uses the costs that National Grid incurs in correcting imbalance to calculate the Imbalance Price. This is then used to charge Parties for being out of balance with their contracts.

There are two Energy Imbalance Prices for each Settlement Period. These are:

- System Buy Price (SBP)
- System Sell Price (SSP)

The System Sell Price (SSP) and System Buy Price (SBP) are the 'cash-out' or 'Energy Imbalance' prices. These are used to settle the difference between contracted generation, or consumption, and the amount that was actually generated, or consumed, in each half hour trading period. However now there is a single price calculation, so SBP will equal SSP in each Settlement Period.

- Parameters used in the calculation of System Prices (Energy Imbalance Price):
 - NIV – Net Imbalance Volume
 - PAR – Price Average Reference Volume
 - DMAT – De Minimis Acceptance Threshold
 - CADL – Continuous Acceptance Duration Limit
 - MIDS – Market Index Definition Statement
 - LoLP – Loss of Load Probability
 - VoLL – Value of Loss Load
 - RSVP – Reserve Scarcity Price
 - Utilisation Price

References:

<https://adagefficiency.com/what-is-the-uk-imbalance-price/>

<https://www.elexon.co.uk/operations-settlement/balancing-and-settlement/imbalance-pricing/>

<https://www.nationalgrideso.com/document/191721/download>

ENTSO-E (Europe):

With the Balancing Guideline entering into force, design of the balancing energy markets is shifting from the national grid operators and regulators' desks to the European associations such as the ENTSO-E and ACER.

The security of an energy supply requires the continuous adjustment of power generation and consumption and vice versa. As forecasting errors (e.g. load and renewable generation) and technical disturbances (e.g. power plant outages) cannot be avoided, the TSOs engage in load-frequency control (hereafter LFC) processes in order to maintain the system frequency within permissible limits. Figure illustrates the load-frequency control processes in accordance with Commission Regulation (EU) 2017/1485 of 2 August 2017, establishing a guideline on electricity transmission system operation (hereafter SO regulation).

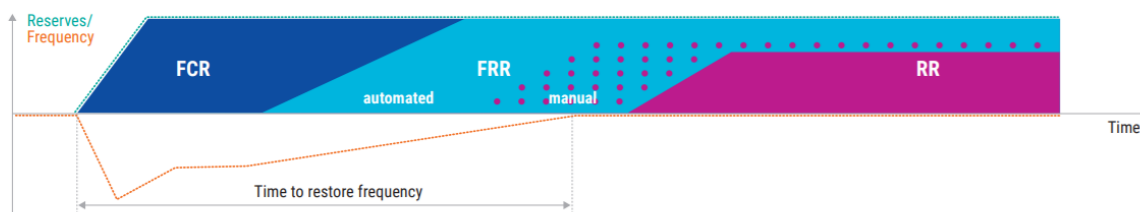


Figure 1 Load Frequency Control and Balancing Markets

During the first seconds following the occurrence of an imbalance (e. g. a power plant outage), the frequency containment reserves (hereafter FCR) are activated in the entire synchronous area with respect to the measured frequency deviation in order to stabilize the frequency at a value below 50 Hertz (in case of generation shortage). The FCR activation is performed in a decentralized way by control devices which are implemented in the respective generating or demand units and activate the FCR pro-rata.

The task of restoring the frequency to 50 Hertz is performed by automatic frequency restoration reserves (hereafter aFRR) and manual frequency restoration reserves (hereafter mFRR). Because power imbalances lead to additional load flows, which can exceed the available transmission capacity, the imbalances are compensated regionally by TSOs within load frequency control areas⁷ (hereafter LFC areas). As the basis for these processes, the TSO continuously calculates the deviation between the measured power exchange of the LFC area (corrected by its FCR activation) and its scheduled exchange, which corresponds to the energy import or export obligation of the given area. The resulting value, the so-called frequency restoration control error (hereafter FRCE), serves as an input to a frequency restoration controller, which operates with a control cycle of a few seconds and requests aFRR activation until the FRCE reaches zero or all available aFRR are fully activated. Additionally, some TSOs use replacement reserves (RR) in order to support or release FRR activation.

In the terminology of the EB regulation, 'balancing capacity' stands for the volumes of the reserves (FCR, aFRR, mFRR and RR) for which market participants commit to submit corresponding balancing energy bids, while the term 'balancing energy' applies to the energy resulting from the activation of aFRR, mFRR and RR.

Balancing Energy Pricing:

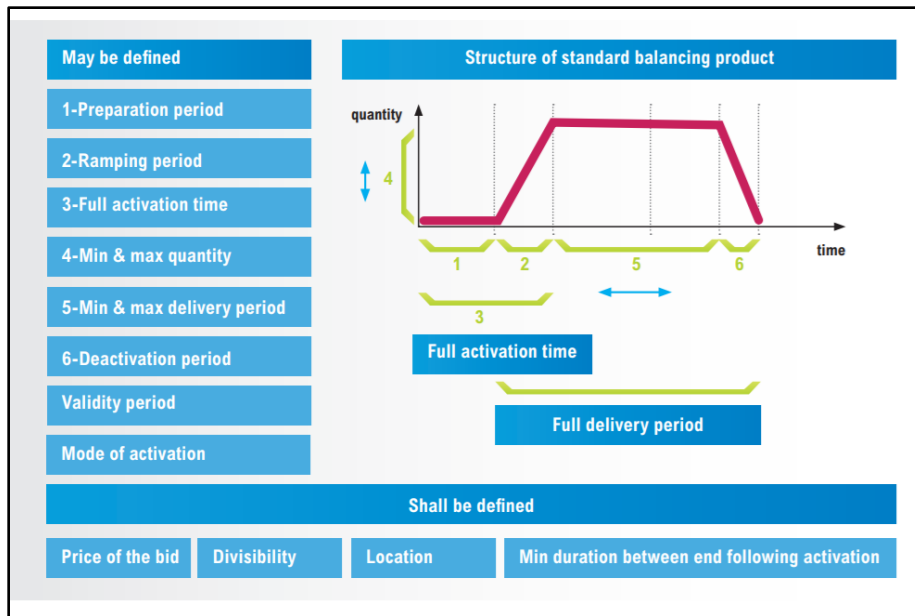


Figure 2 Standard Product characteristics

Each TSO shall set up rules to calculate the imbalance price, which can be positive, zero or negative, as defined in the table:

	Imbalance price positive	Imbalance price negative
Positive imbalance	Payment from TSO to BRP	Payment from BRP to TSO
Negative imbalance	Payment from BRP to TSO	Payment from TSO to BRP

The rules pursuant to above shall include a definition of the value of avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

Each TSO shall determine the imbalance price for:

- (a) each imbalance settlement period;
- (b) its imbalance price areas;
- (c) each imbalance direction.

The imbalance price for negative imbalance shall not be less than, alternatively:

- (a) the weighted average price for positive activated balancing energy from frequency restoration reserves and replacement reserves;
- (b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

The imbalance price for positive imbalance shall not be greater than, alternatively:

- (a) the weighted average price for negative activated balancing energy from frequency restoration reserves and replacement reserves;

(b) in the event that no activation of balancing energy in either direction has occurred during the imbalance settlement period, the value of the avoided activation of balancing energy from frequency restoration reserves or replacement reserves.

References

(https://ec.europa.eu/energy/sites/ener/files/documents/informal_service_level_ebgl_16-03-2017_final.pdf)

https://eepublicdownloads.entsoe.eu/clean-documents/Network%20codes%20documents/NC%20EB/entso-e_balancing_in%20 europe report Nov2018_web.pdf

(https://eepublicdownloads.azureedge.net/clean-documents/Publications/Market%20Committee%20publications/ENTSO-E_Balancing_Report_2020.pdf#page=9&zoom=100,0,0)

Australian Electricity Market (NEM):

The Australian Energy Market Operator (AEMO) manages the electricity system so power supply and demand is matched simultaneously. The physics of the power system means the electricity supplied by generators must exactly match how much electricity is being used by consumers, or blackouts can happen.

The spot market is the mechanism that AEMO uses to match the supply of electricity from power stations with real time consumption by households and businesses. All electricity in the spot market is bought and sold at the spot price.

The spot price tells generators how much electricity the market needs at any moment in time to keep the physical power system in balance.

When the spot price is increasing, generators ramp up their output or more expensive generators turn on to sell extra power to the market. For example, a gas peaker or pumped hydro plant may jump in, or a fast-response battery may discharge electricity. When the spot price is decreasing, more expensive generators turn down or off.

Spot prices are currently updated every thirty minutes but this will move to every five minutes in 2021. Prices are usually low in the early hours of the morning, before people wake up and businesses and factories start operating. Spot prices are usually higher in the mid afternoon or evenings, when people and businesses are generally using the most power.

Generators submit offers to AEMO, signalling their willingness to generate electricity. AEMO's central dispatch engine orders the generators' offers from least to most expensive and determines which generators will be dispatched. In this way, the expected demand for electricity is supplied by the lowest cost mix of generators. In delivering electricity, AEMO dispatches electricity every five minutes, so generators are required to bid to supply electricity in five-minute blocks. For the purposes of settlement, the price is then averaged out over 30 minutes. The spot price for a 30-

minute trading interval is therefore the average of the six dispatch interval prices. All generators dispatched in that trading interval receive the spot price.

In delivering electricity, AEMO dispatches electricity every five minutes, so generators are required to bid to supply electricity in five minute blocks. For the purposes of settlement, the price is then averaged out over 30 minutes. The spot price for a 30 minute trading interval is therefore the average of the six dispatch interval prices. All generators dispatched in that trading interval receive the spot price.

AEMO uses the spot price as the basis for the settlement – that is, the transfer of money for electricity supplied to the market and consumed by end users.

References

<https://www.aemc.gov.au/energy-system/electricity/electricity-market/spot-and-contract-markets>

<https://www.energy.gov.au/government-priorities/energy-markets/national-electricity-market-nem>

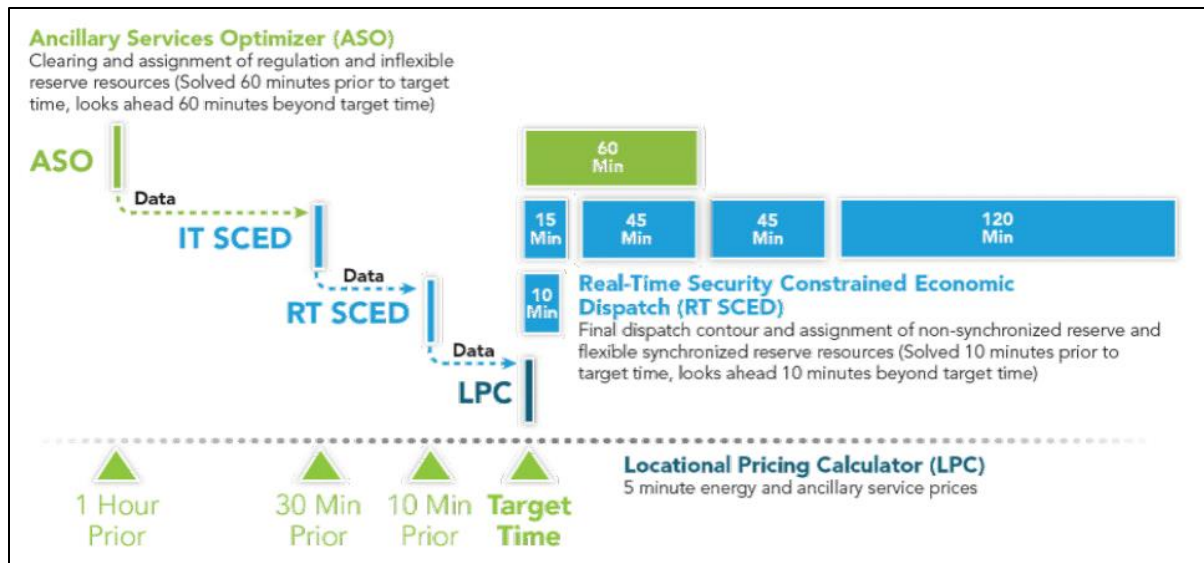
Nord Pool Spot:

Internationally, Nord Pool Spot operates the leading markets for buying and selling power in Europe. It operates Elbas which is a continuous balancing market where power trading takes place until one hour before the power is delivered. Members can adjust their power production or consumption plans close to delivery. Every day, transmission system operators publish their power transmission capacity to Elbas. Members „offer“ how much power they want to sell and buy and at what price. Trading is then set based on a first-come, first-served basis between a seller and a buyer. If transmission capacity is available, neighbouring countries can also trade on the Elbas market.

PJM, USA:

The PJM RTO operates in accordance with NERC Resource and Demand Balancing (i.e., BAL) standards to ensure its capability to utilize reserves to balance resources and demand in real time and to return interconnection frequency within defined limits following a Reportable Disturbance.

To dispatch energy, and ensure adequate reserves in real-time and regulation in near time, a multi-module software platform is used by PJM



Real Time Market Application Process Flow

The real-time market application consists of the following:

- Ancillary Service Optimizer (ASO): The Ancillary Services Optimizer (ASO) performs the joint optimization function of energy, reserves and regulation. The main functions of ASO are the commitment of all regulation resources and inflexible reserve resources for the next operating hour.
- Real-Time Security Constrained Economic Dispatch (RT SCED): The Real-Time Security Constrained Economic Dispatch (RT SCED) application is responsible for dispatching resources to maintain the system balance of energy and reserves over a near-term look-ahead period. Historical and current system information is used to anticipate generator performance to various requests, and to provide accurate information regarding generator operating parameters under multiple scenarios. RT SCED will jointly optimize energy, regulation and reserves on online, dispatch able resources to ensure system needs are maintained. The results from the RT SCED are energy basepoints and Tier 2 and Non-Synchronized reserve commitments that are sent to resource owners in real-time. All quantities may change with each solution based on system economics and reserve needs. RT SCED determines reserves shortages.
- Intermediate Term Security Constrained Economic Dispatch (IT SCED): The Intermediate Term Security Constrained Economic Dispatch (IT SCED) application is used by PJM to perform various functions over a 1–2-hour look-ahead period. Historical and current system information is used to anticipate generator performance to various requests, and to provide accurate information regarding generator operating parameters under multiple scenarios.
- Locational Price Calculator
 - Produces financially binding LMPs and reserve market clearing prices
 - Calculates LMPs for the entire PJM network model and Regulation MCPs and reserve MCPs for each locale
 - Uses the latest approved RT SCED case as its reference case
 - Uses the input files from the RT SCED case

- EMS inputs
- Constraint Control

References:

<https://www.pjm.com/library/manuals>

CAISO, USA - Energy Imbalance Market (EIM)

CAISO maintains a real time Energy Imbalance market which allows participants to buy and sell Energy when needed. Balancing authority areas are allowed to buy and sell the final few megawatts of power to satisfy demand within the hour it's needed.

Utilities will maintain control over their assets and remain responsible for balancing requirements while sharing in the cost benefits the market produces for participants. The EIM does not participate in the Day Ahead market. For Optimization CAISO employs a 15 minute "RTPD" optimization and then within each 15 minutes there is a 5-minute CAISO despatch optimization. Out of the RTPD comes the commitment and the LMP and the 5-minute process is the one that sets the dispatch instruction. Every 5 minutes the security constrained economic dispatch runs along with a contingency analysis to ensure no reliability constraints are being violated.

References

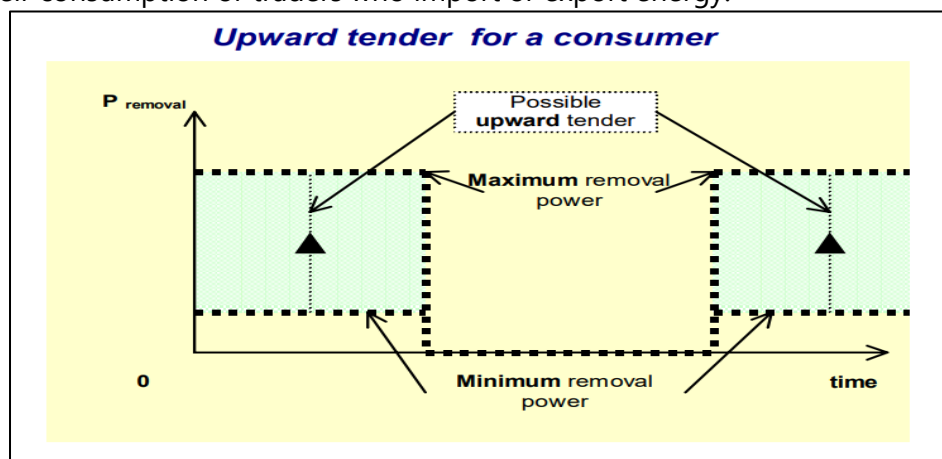
<https://transform.ru/articles/pdf/SIGRE/c5-107.pdf>

France

The French transmission system operator RTE employs a balancing mechanism in which the TSO calls on the tenders in the order of economic precedence, and allowing for the operating conditions of the electrical system. These Tenders are a set of conditions proposed by a player to modify the injection or extraction of power on the RTE system at the level of a consumption and/or production and/or interconnection site (or of a group of sites). These tenders are of 2 types:-

- Upward tenders: production increase, consumption decrease, imports
- Downward tenders: production decrease, consumption increase, exports.

In advance, the player has supplied RTE with its production programme for D-1 or a consumption reference. The players are producers who modulate their production, consumers who may remove some of their consumption or traders who import or export energy.



At half-hourly intervals, the system trend is determined by evaluating the energy volume corresponding to the downward balancing and to the upward balancing. The trend is then upward if the volume of upward balancing is greater than the volume of downward balancing.

The balancing mechanism is based on the global vision of all the imbalances seen from the electric system and thus enables the emergence, for each half-hourly step, of a reference price applicable for the settlement. This reference price is calculated on the basis of the average weighted prices of the upward balancing tenders (AWPu) and the downward balancing tenders (AWPd) unless the imbalance of the balance responsible reduces the global imbalance of the system, in which case the Powernext price applies.

The following table sums up the prices applied to imbalances in France:

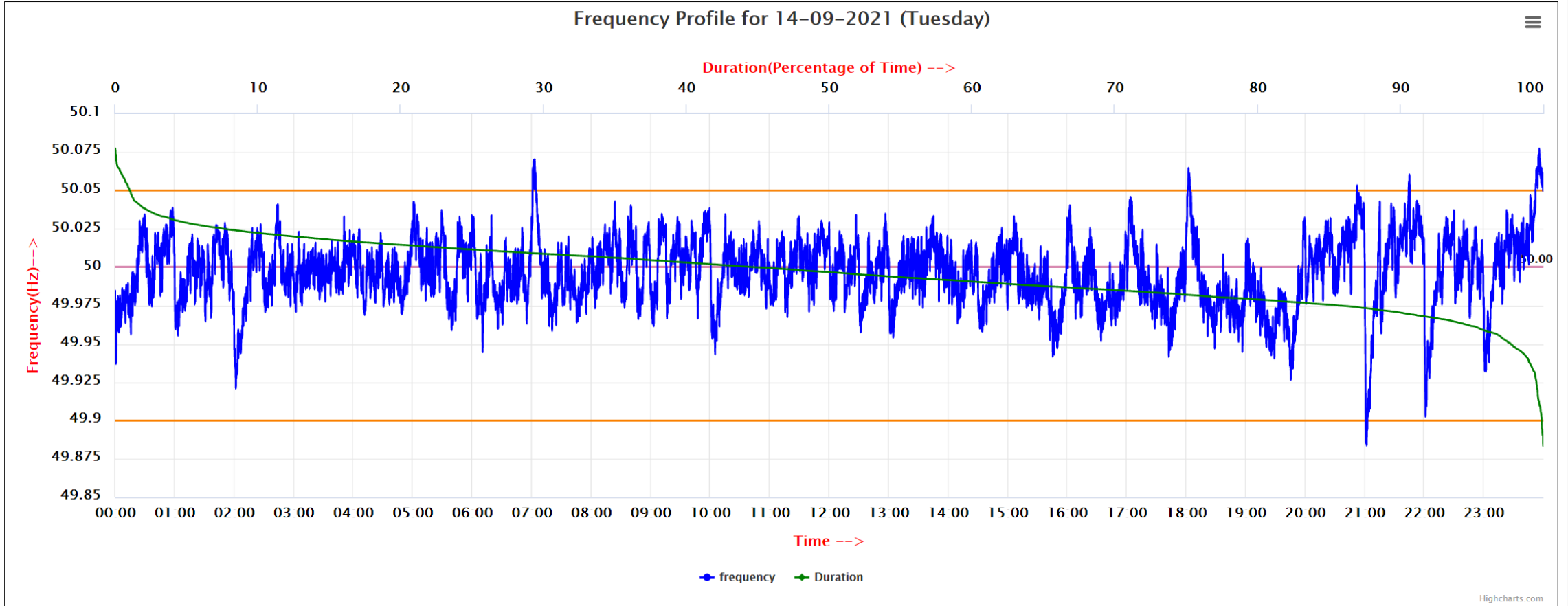
	Upward balancing trend	Downward balancing trend
Positive imbalances ($I > S$) RTE pays Bal. resp.	Powernext spot price	AWPd / (1+k)*
Negative imbalances ($I < S$) Bal. resp. pays RTE	AWPu x (1+k)**	Powernext spot price

*upper limit is Powernext spot price/ ** Powernext spot price is lower limit / k weighting factor k=0,2

Entsoe Day Wise Reports for high market prices days



Entsoe Frequency Report



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0.12	9.78	0	0.12	55.15	44.93	0	98.88	100	85.74	1.03	44.73	4.48	1.01	0	2.29	96.7	2.2

Average Frequency : 50	Frequency Variation Index : 0.005	Standard Deviation : 0.022	Mileage : 53.15	FDI : 1.12
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Instantaneous Frequency		
Max	50.08	23:55:50
Min	49.88	21:01:50

15 minute Average Frequency		
Max	50.0459	23:45:00
Min	49.9508	21:00:00

No. of excursion	
above 50.03 Hz	115
below 49.97 Hz	193
above 50.00 Hz	495
below 50.00 Hz	490

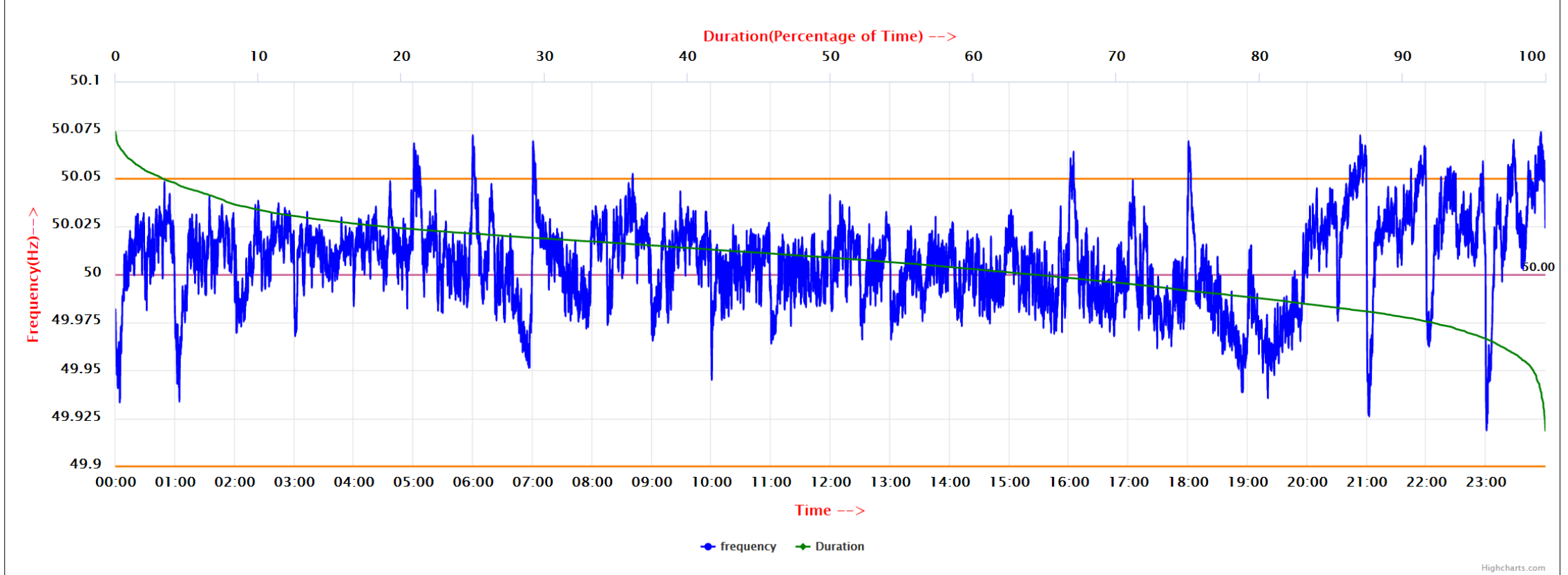
Average time freq per excursion remains	
below 49.97	00:00:43
above 50.03	00:00:33

No. of hours freq outside 49.9-50.05 Hz	0:16:07
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Entsoe Frequency Report

Frequency Profile for 14-09-2020 (Monday)



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0	5.54	0	0	36.11	64.18	0	96.76	100	81.54	3.28	63.89	12.92	3.24	0	0.86	95.9	0.87

Average Frequency : 50.01	Frequency Variation Index : 0.0056	Standard Deviation : 0.0227	Mileage : 48.84	FDI : 3.24
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Instantaneous Frequency		
Max	50.07	23:55:30
Min	49.92	23:00:30

15 minute Average Frequency		
Max	50.0537	20:45:00
Min	49.96	19:15:00

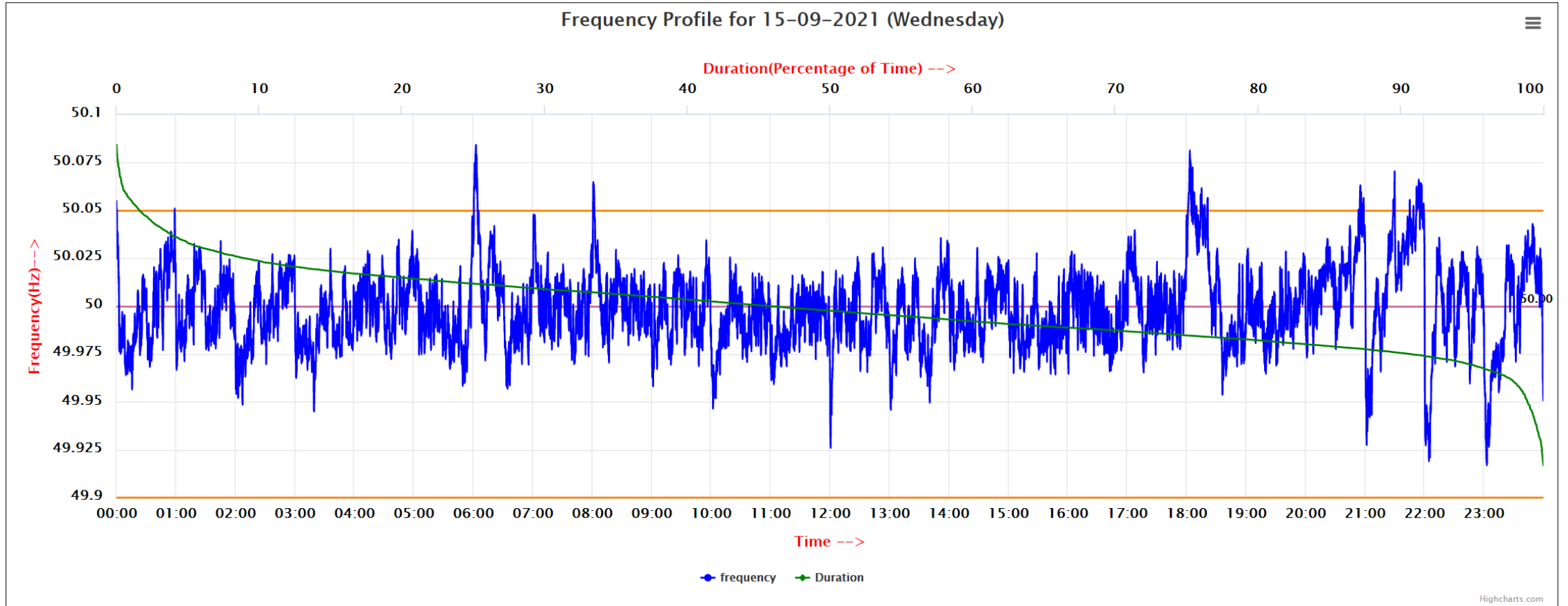
No. of excursion	
above 50.03 Hz	213
below 49.97 Hz	96
above 50.00 Hz	419
below 50.00 Hz	417

Average time freq per excursion remains	
below 49.97	00:00:49
above 50.03	00:00:52

No. of hours freq outside 49.9-50.05 Hz	0:46:39
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Entsoe Frequency Report



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0	5.37	0	0	54.35	45.81	0	98.4	100	88.41	1.6	45.65	6.22	1.6	0	1.12	97.28	1.12

Average Frequency : 50	Frequency Variation Index : 0.0042	Standard Deviation : 0.0205	Mileage : 49.55	FDI : 1.6
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Instantaneous Frequency		
Max	50.08	06:02:40
Min	49.92	23:03:40

15 minute Average Frequency		
Max	50.0493	18:00:00
Min	49.957	23:00:00

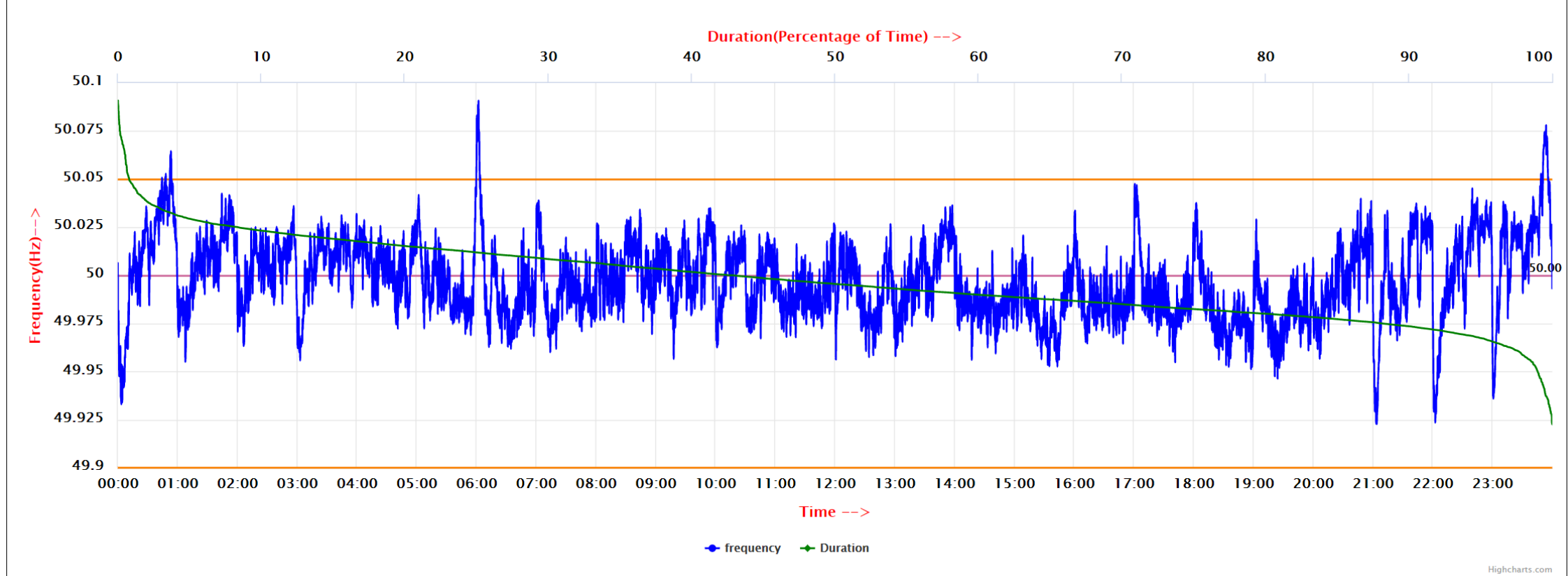
No. of excursion	
above 50.03 Hz	94
below 49.97 Hz	118
above 50.00 Hz	482
below 50.00 Hz	487

Average time freq per excursion remains	
below 49.97	00:00:39
above 50.03	00:00:57

No. of hours freq outside 49.9-50.05 Hz	0:23:02
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Entsoe Frequency Report

Frequency Profile for 15-09-2020 (Tuesday)



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0	6.82	0	0	57.47	42.95	0	99.21	100	88.54	0.79	42.53	4.64	0.79	0	1.02	98.19	1.02

Average Frequency : 50	Frequency Variation Index : 0.0043	Standard Deviation : 0.0205	Mileage : 48.67	FDI : 0.79
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Instantaneous Frequency		
Max	50.09	06:02:00
Min	49.92	21:03:00

15 minute Average Frequency		
Max	50.0446	23:45:00
Min	49.9655	22:00:00

No. of excursion	
above 50.03 Hz	99
below 49.97 Hz	168
above 50.00 Hz	427
below 50.00 Hz	428

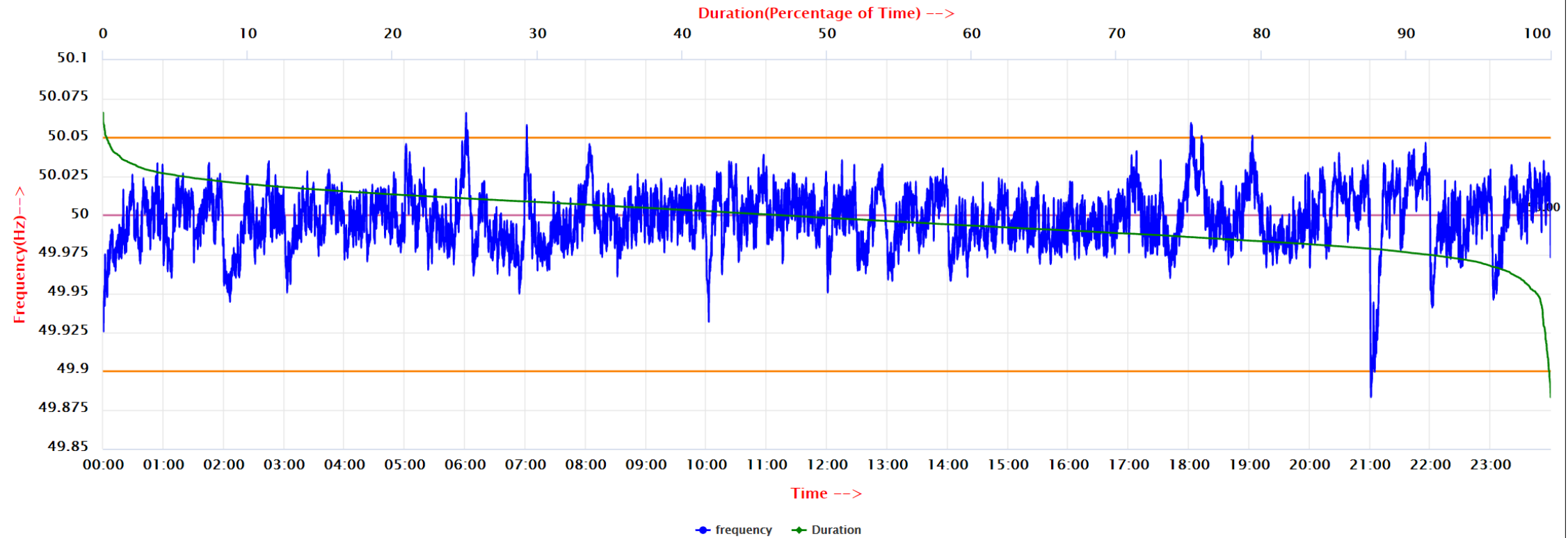
Average time freq per excursion remains	
below 49.97	00:00:35
above 50.03	00:00:40

No. of hours freq outside 49.9-50.05 Hz	0:11:22
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Entsoe Frequency Report

Frequency Profile for 16-09-2021 (Thursday)



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0.12	5	0	0.12	52.81	47.26	0	99.62	100	92.16	0.27	47.07	2.84	0.27	0	1	98.74	0.89

Average Frequency : 50	Frequency Variation Index : 0.0035	Standard Deviation : 0.0185	Mileage : 50.9	FDI : 0.38
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Instantaneous Frequency		
Max	50.07	06:01:10
Min	49.88	21:01:10

15 minute Average Frequency		
Max	50.0338	18:00:00
Min	49.9494	21:00:00

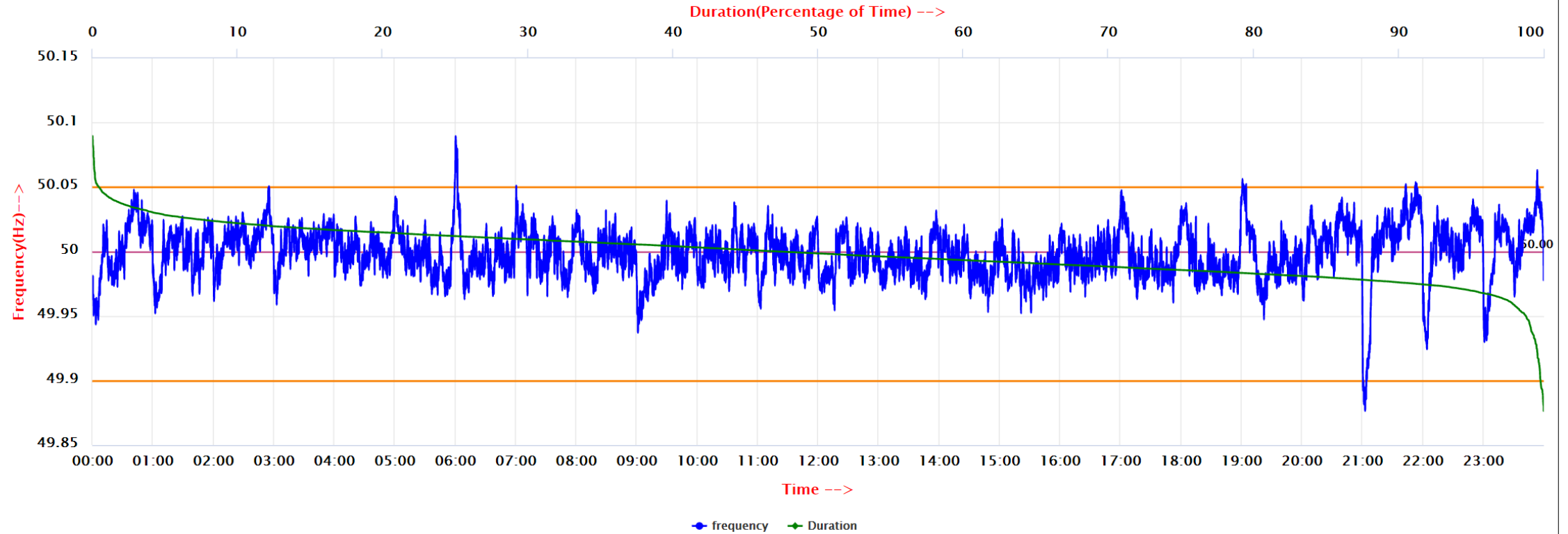
No. of excursion	
above 50.03 Hz	82
below 49.97 Hz	118
above 50.00 Hz	583
below 50.00 Hz	586

Average time freq per excursion remains	
below 49.97	00:00:36
above 50.03	00:00:29

No. of hours freq outside 49.9-50.05 Hz	0:05:28
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Entsoe Frequency Report

Frequency Profile for 16-09-2020 (Wednesday)



Highcharts.com

<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0.22	5.09	0	0.22	52.52	47.59	0	99.34	100	90.62	0.47	47.26	4.28	0.44	0	1.24	98.32	1.02

Average Frequency : 50	Frequency Variation Index : 0.004	Standard Deviation : 0.0198	Mileage : 50.26	FDI : 0.66
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Instantaneous Frequency		
Max	50.09	06:00:30
Min	49.88	21:02:30

15 minute Average Frequency		
Max	50.0325	21:45:00
Min	49.949	21:00:00

No. of excursion	
above 50.03 Hz	87
below 49.97 Hz	103
above 50.00 Hz	521
below 50.00 Hz	518

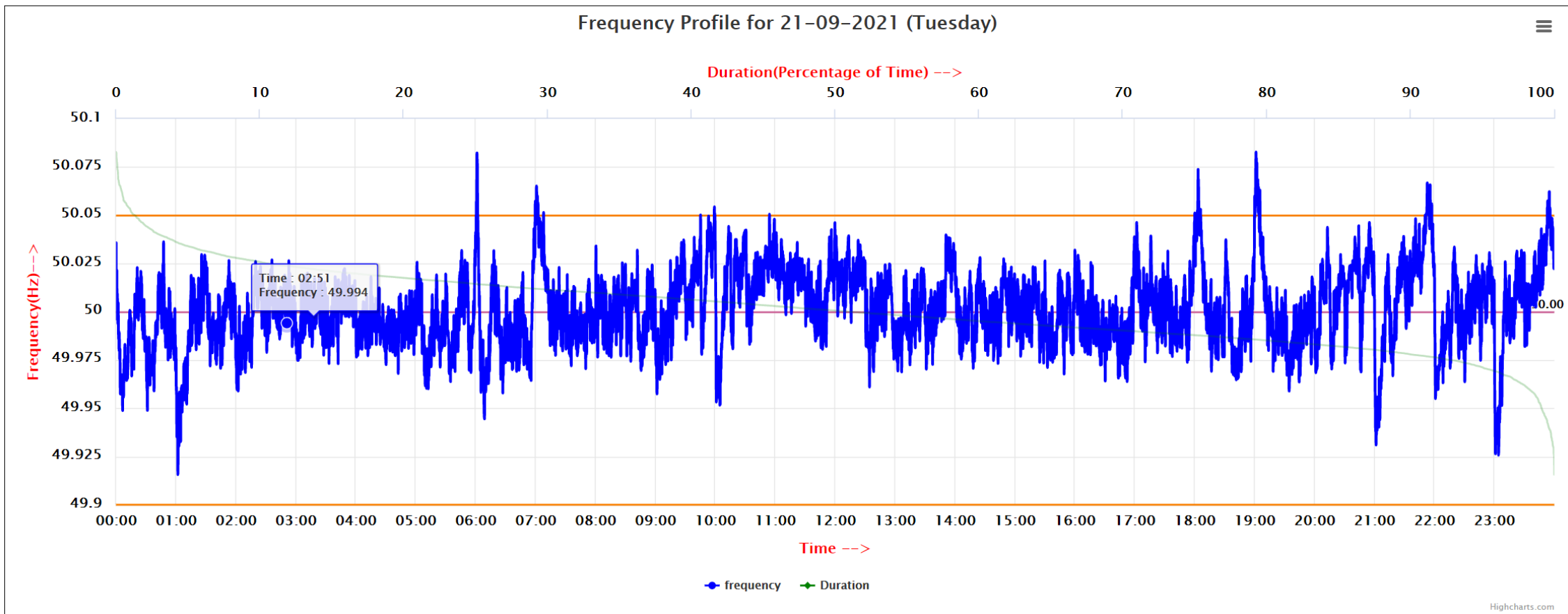
Average time freq per excursion remains	
below 49.97	00:00:42
above 50.03	00:00:42

No. of hours freq outside 49.9-50.05 Hz	0:09:30
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Entsoe Frequency Report

Frequency Profile for 21-09-2021 (Tuesday)



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0	4.47	0	0	49.12	51.08	0	98.69	100	88.54	1.31	50.88	6.99	1.31	0	0.88	97.81	0.88

Average Frequency : 50	Frequency Variation Index : 0.004	Standard Deviation : 0.0199	Mileage : 52.87	FDI : 1.31
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Instantaneous Frequency		
Max	50.08	19:01:20
Min	49.92	01:01:20

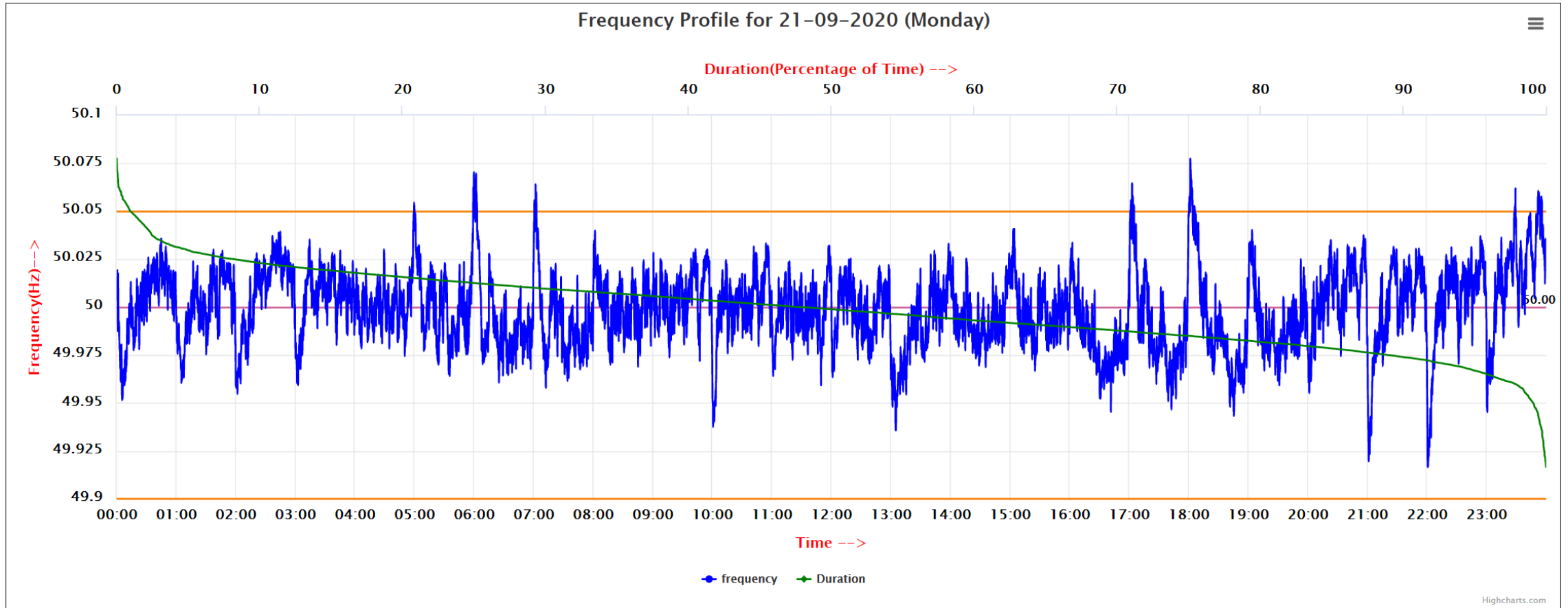
15 minute Average Frequency		
Max	50.0402	21:45:00
Min	49.9619	1:00:00

No. of excursion	
above 50.03 Hz	134
below 49.97 Hz	110
above 50.00 Hz	539
below 50.00 Hz	539

Average time freq per excursion remains	
below 49.97	00:00:35
above 50.03	00:00:45

No. of hours freq outside 49.9-50.05 Hz	0:18:51
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Entsoe Frequency Report



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	50.2	<49.95	49.95-50.05	49.90-49.95
0	0	6.71	0	0	52.41	48.07	0	99.06	100	88.43	0.98	47.59	4.86	0.94	0	0.91	98.15	0.91

Average Frequency : 50	Frequency Variation Index : 0.0041	Standard Deviation : 0.0201	Mileage : 49.07	FDI : 0.94
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Instantaneous Frequency		
Max	50.08	18:01:30
Min	49.92	22:00:30

15 minute Average Frequency		
Max	50.0355	23:45:00
Min	49.9625	13:00:00

No. of excursion	
above 50.03 Hz	97
below 49.97 Hz	149
above 50.00 Hz	510
below 50.00 Hz	515

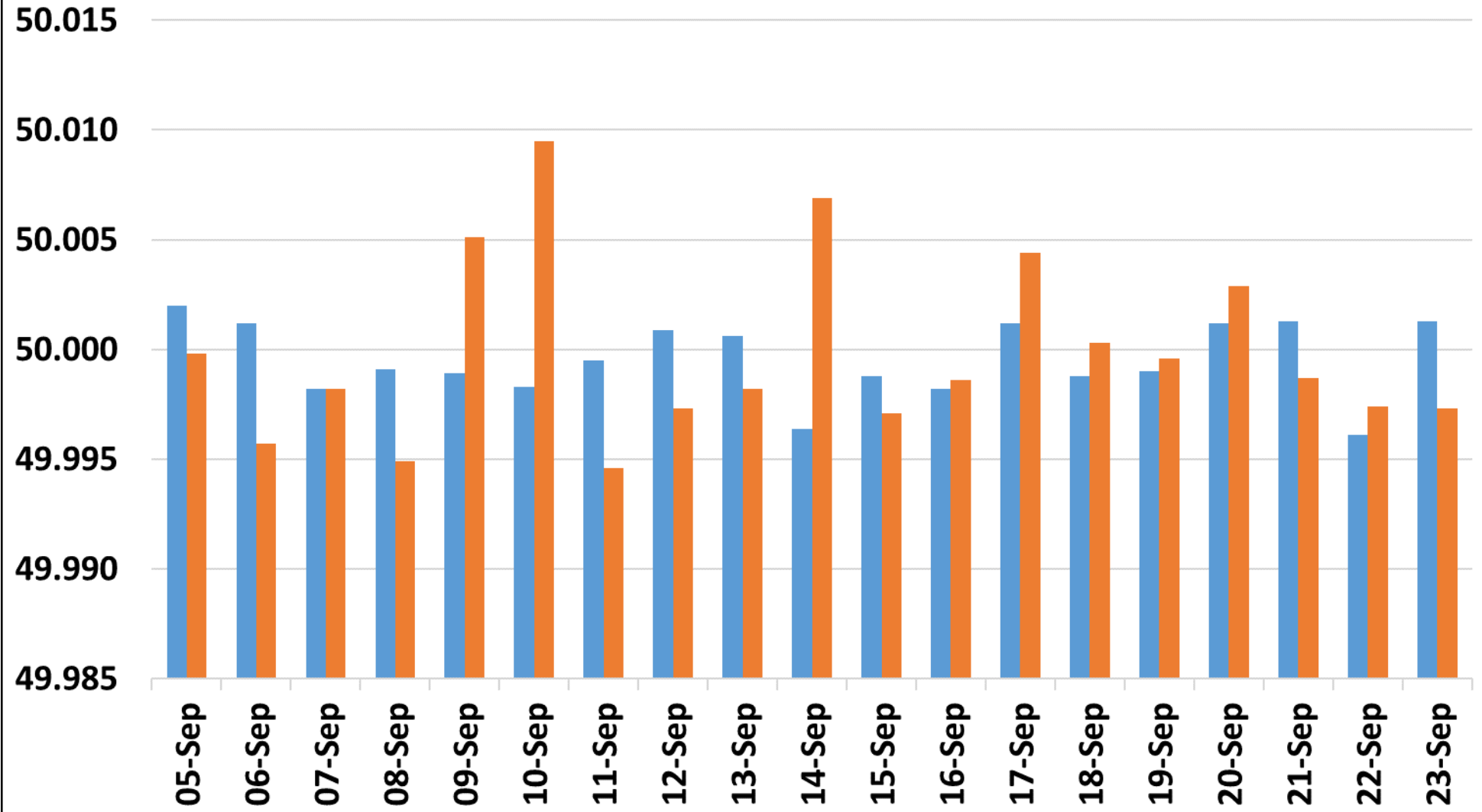
Average time freq per excursion remains	
below 49.97	00:00:38
above 50.03	00:00:43

No. of hours freq outside 49.9-50.05 Hz	0:13:32
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Frequency comparison from
date 5 sep to 23 sep 2021 with
same dates of year 2020.

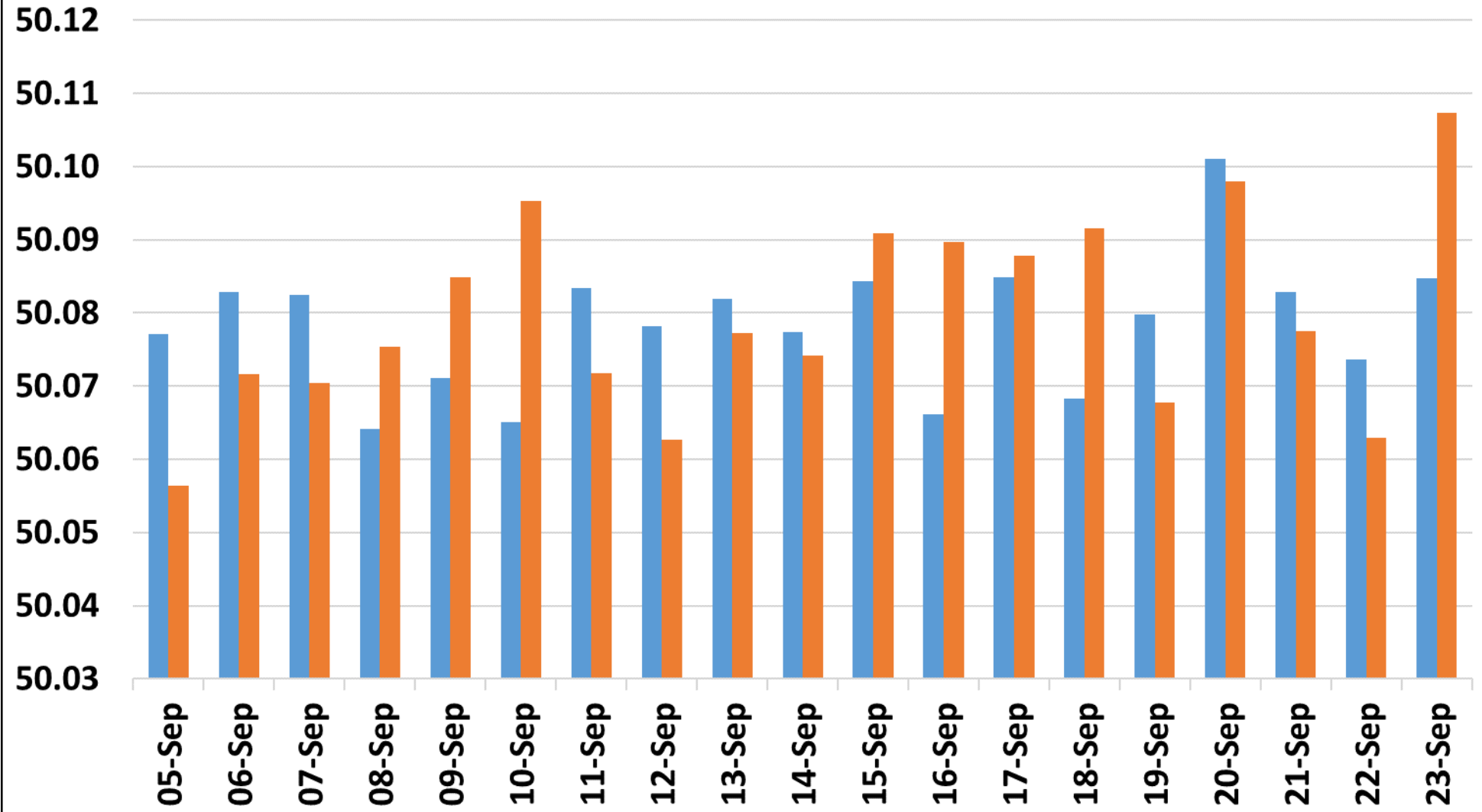
Average Frequency (Hz)

■ 2021 ■ 2020



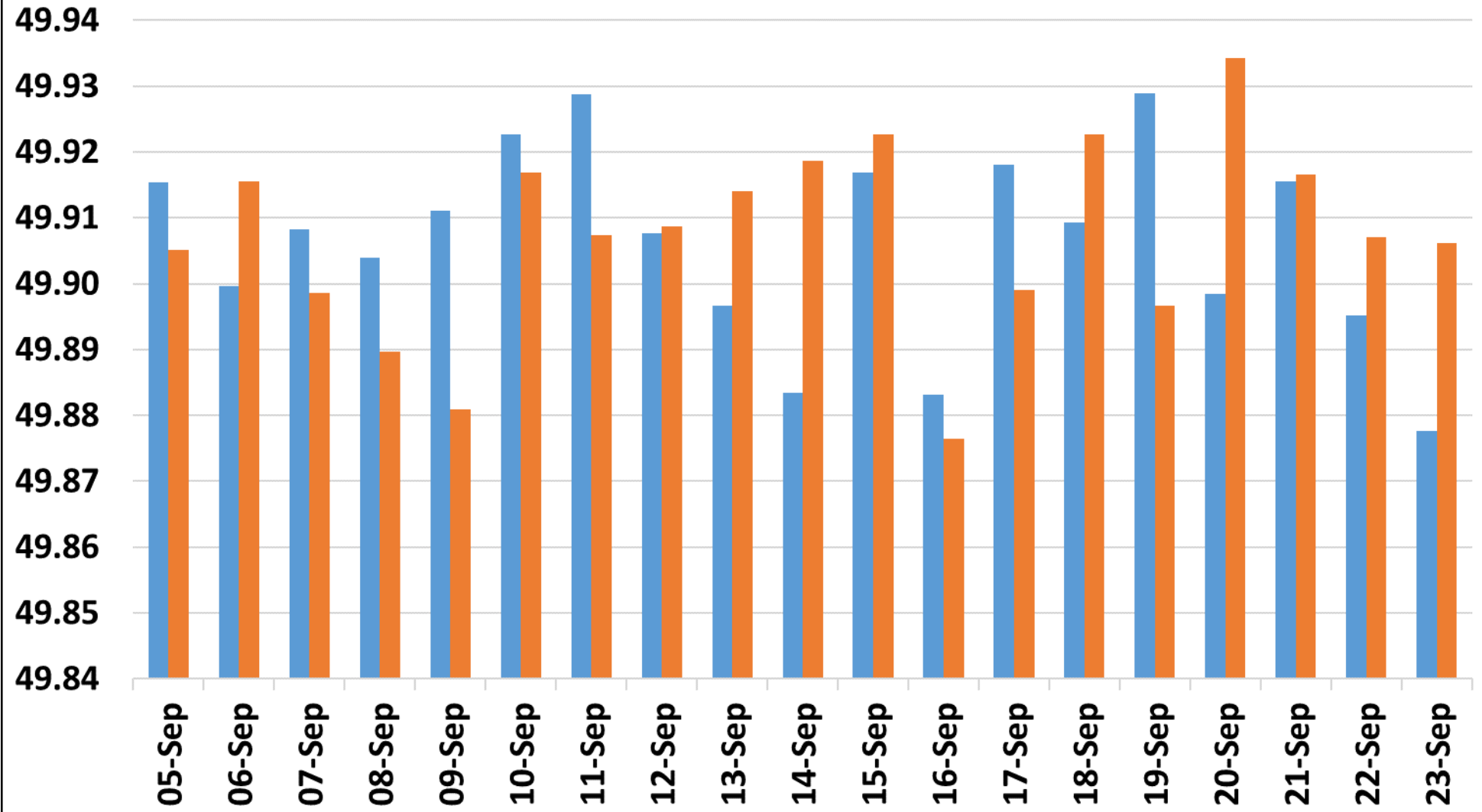
Maximum Frequency (Hz)

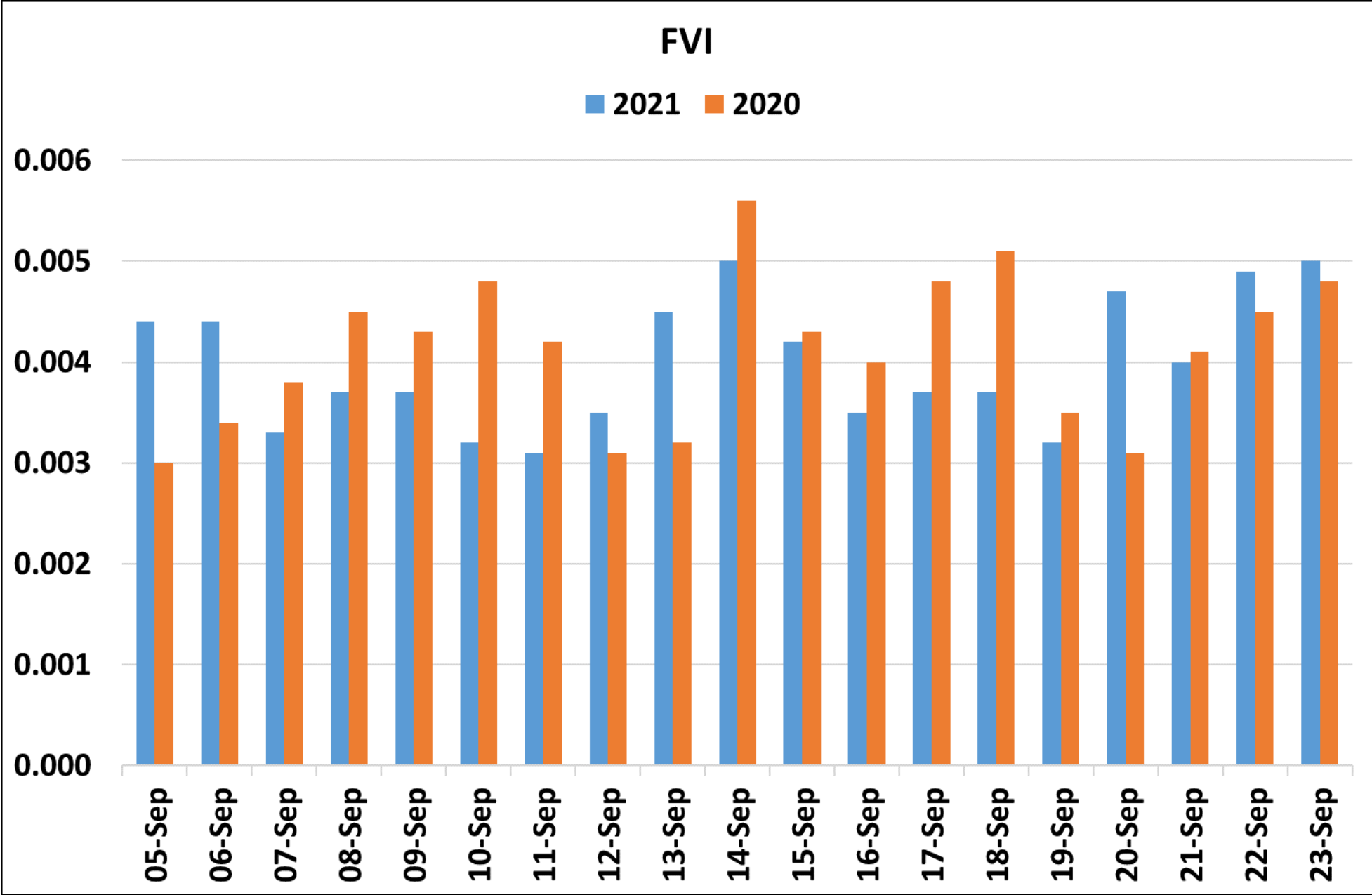
2021 2020



Minimum Frequency (Hz)

2021 2020





STD

2021 2020

0.025

0.020

0.015

0.010

0.005

0.000

05-Sep

06-Sep

07-Sep

08-Sep

09-Sep

10-Sep

11-Sep

12-Sep

13-Sep

14-Sep

15-Sep

16-Sep

17-Sep

18-Sep

19-Sep

20-Sep

21-Sep

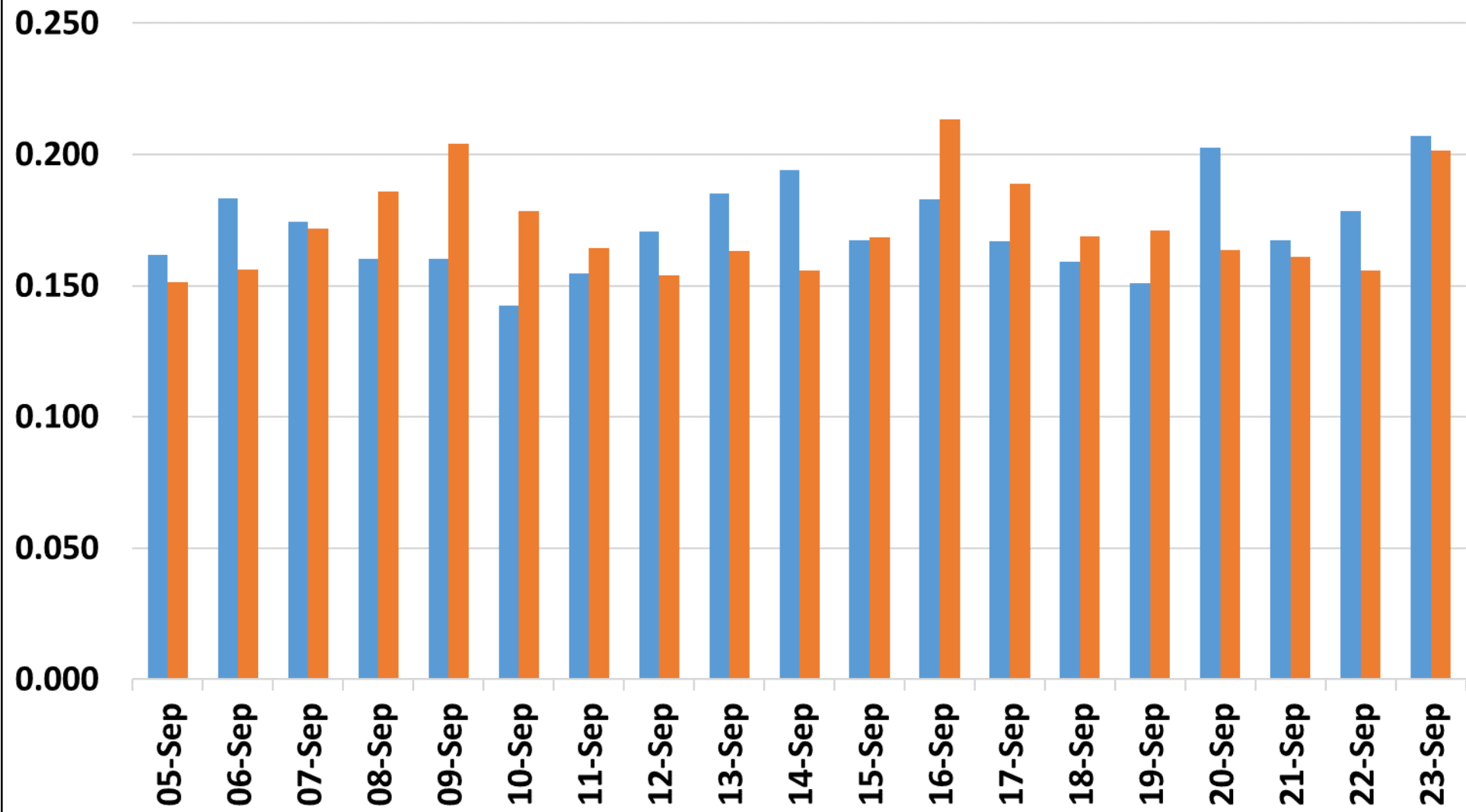
22-Sep

23-Sep



(Max - Min) Frequency

2021 2020



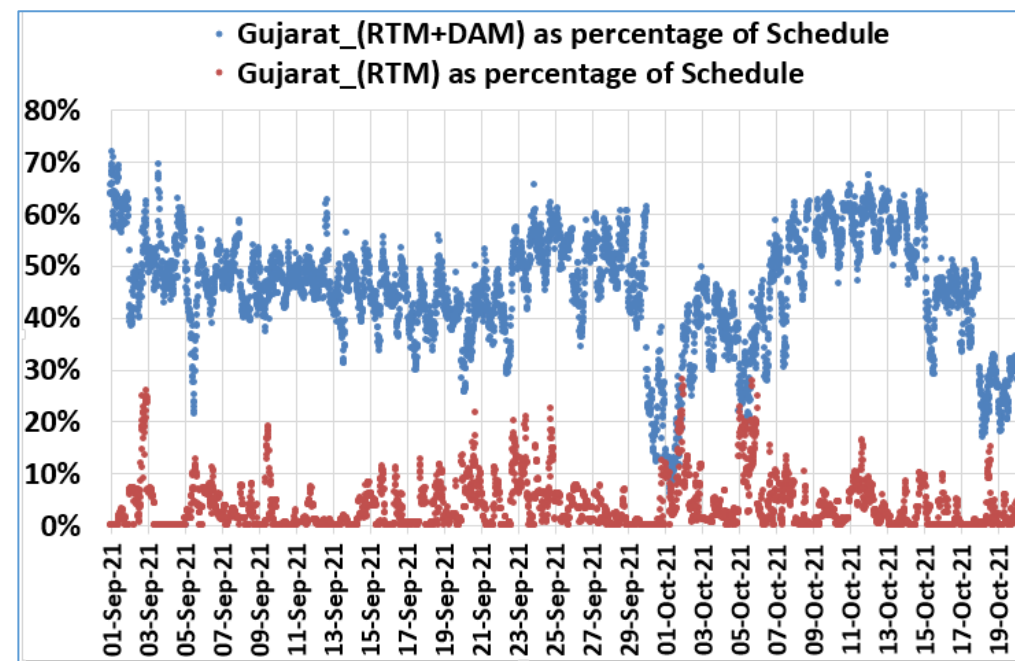
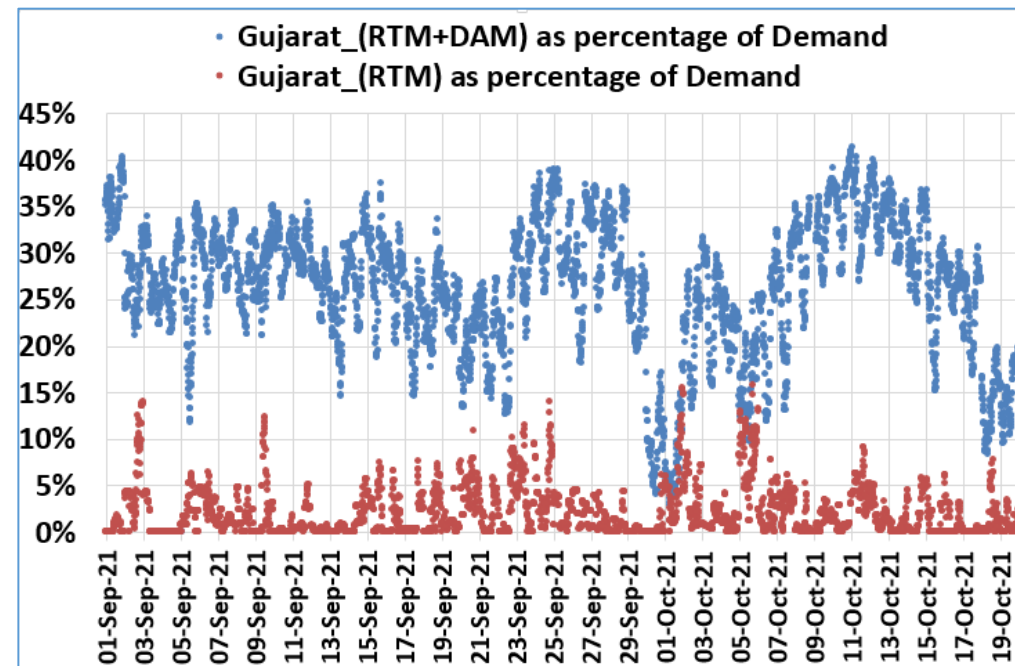
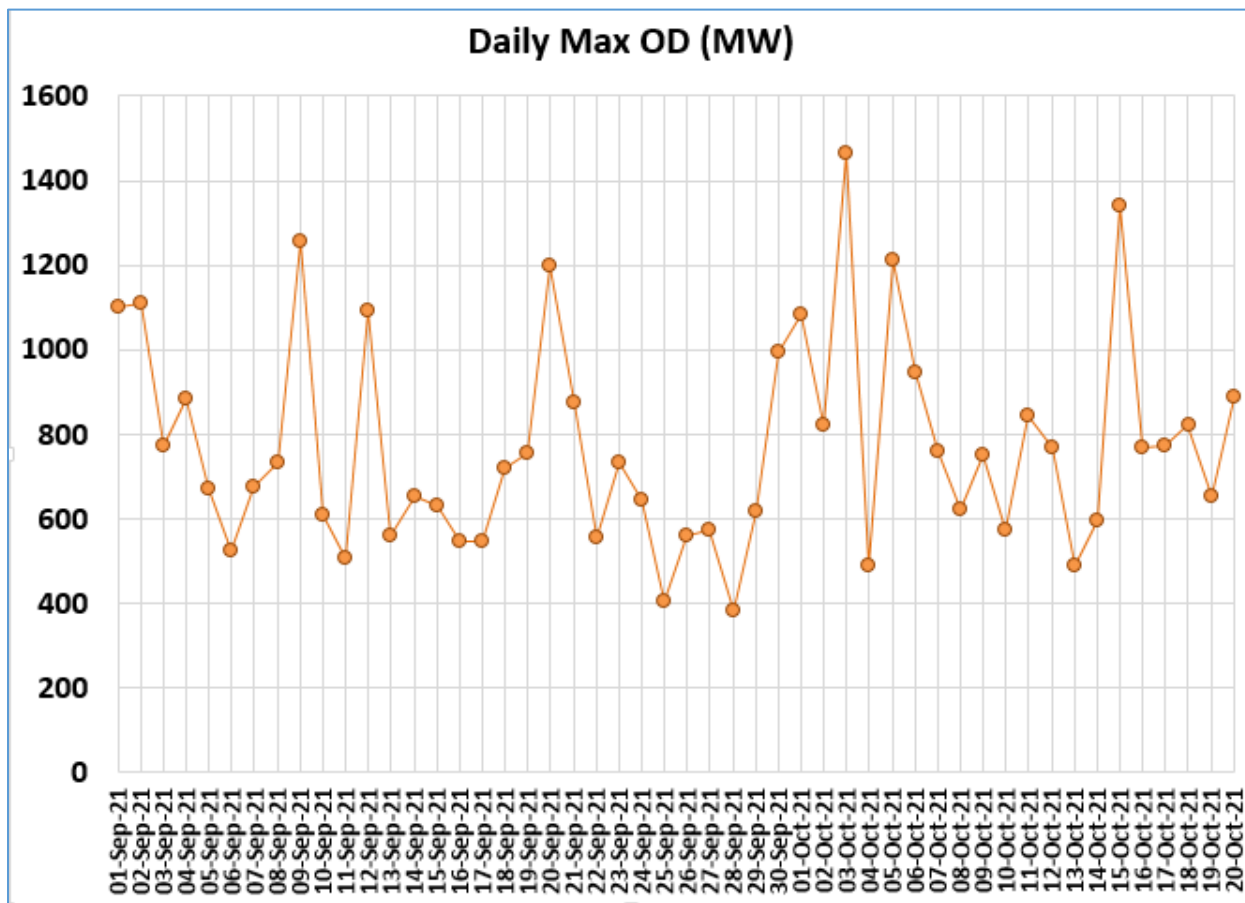
Annexure - 3

DAY AHEAD MARKET								
S.no	STATE	Date	Time block	Power Purchased from DAM (MW)	Schedule (MW)	Demand Met (MW)	DAM Purchase As Percentage of Schedule	DAM Purchase as a percentage of Demand met
1	Gujarat	18-10-2021	47	1443	8697	16849	16.59	8.56
2	Rajasthan	12-10-2021	47	1800	4453	12873	40.42	13.98
3	Maharashtra	13-10-2021	76	713	6401	22053	11.14	3.23
4	Andhra pradesh	17-09-2021	39	868	4120	10372	21.07	8.37
5	Uttar Pradesh	06-09-2021	84	2102	12668	23237	16.59	9.05
6	Tamil Nadu	14-09-2021	76	1247	7676	15970	16.24	7.81
7	Madhya Pradesh	09-10-2021	77	18	6097	10925	0.30	0.16
8	Haryana	06-09-2021	79	395	7507	9098	5.26	4.34
9	Karnataka	20-09-2021	41	0	3064	12016	0.00	0.00
10	Bihar	10-09-2021	81	249	5426	5783	4.59	4.31
11	Telangana	18-09-2021	34	2280	5086	12472	44.83	18.28

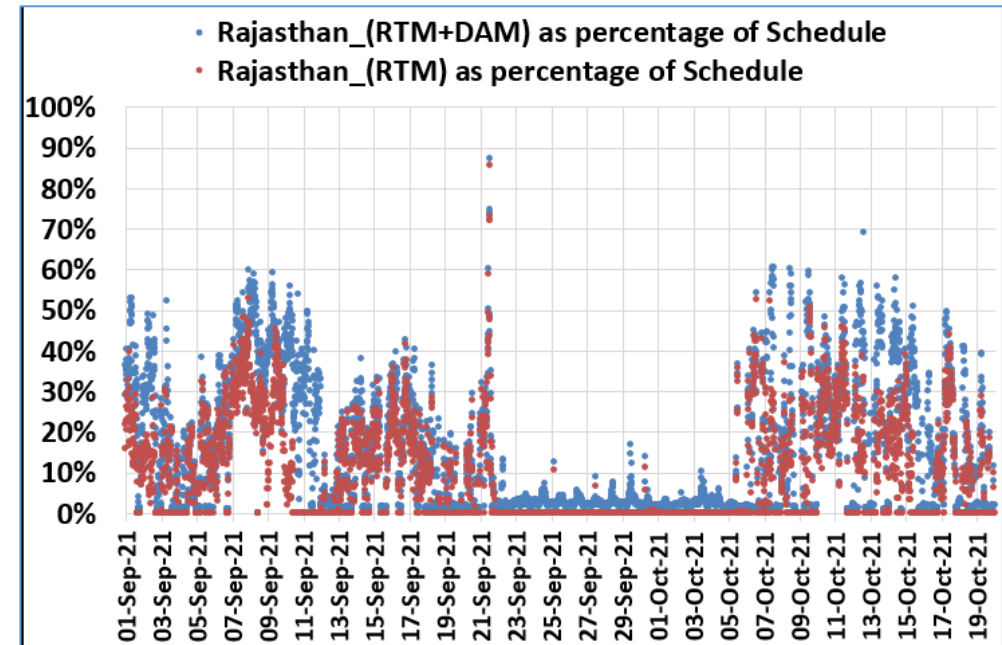
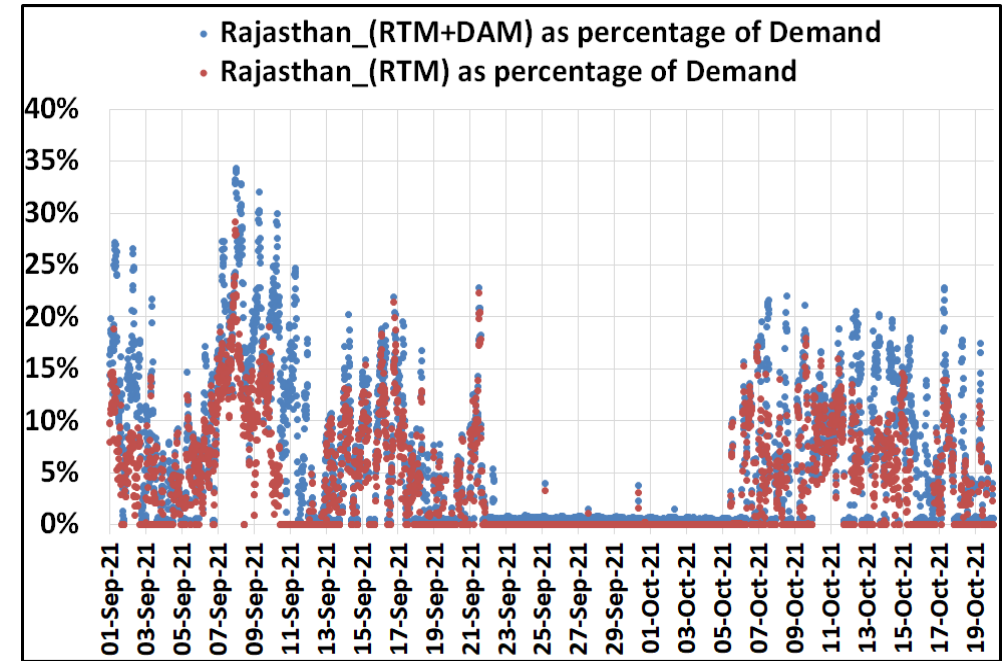
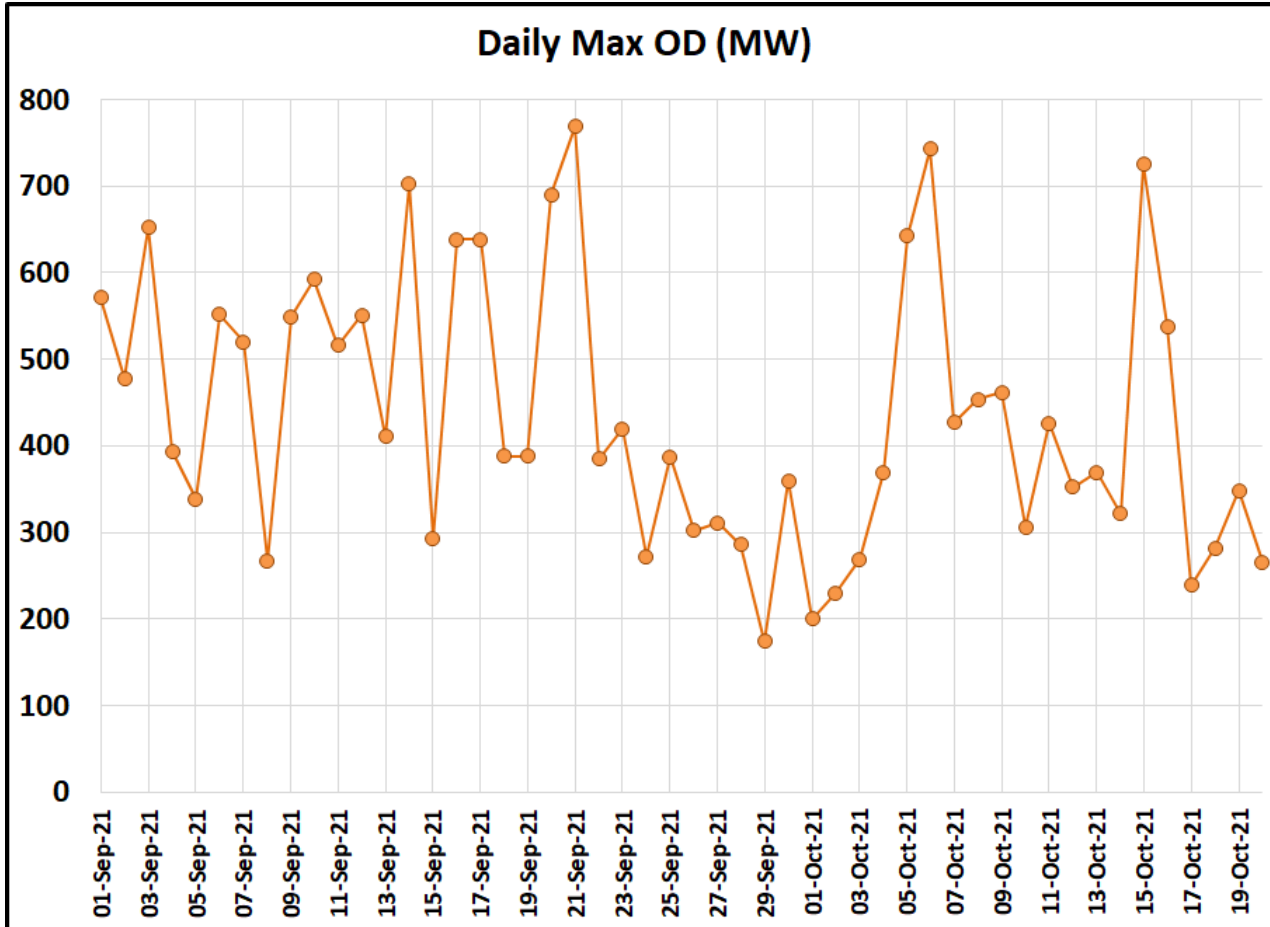
REAL TIME MARKET

S.no	STATE	Date	Time block	Power Purchased from RTM (MW)	Schedule (MW)	Dem and Met (MW)	RTM Purchase As Percentage of Schedule	RTM Purchase as a percentage of Dem and met
1	Maharashtra	18-10-2021	47	782.17	8697	16849	8.99	4.64
2	Gujarat	12-10-2021	47	649.11	4453	12873	14.58	5.04
3	Karnataka	13-10-2021	76	75.08	6401	22053	1.17	0.34
4	Tamil Nadu	17-09-2021	39	254.8	4120	10372	6.19	2.46
5	Uttar Pradesh	06-09-2021	84	1393.81	12668	23237	11.00	6.00
6	Rajasthan	14-09-2021	76	558.4	7676	15970	7.27	3.50
7	Madhya Pradesh	09-10-2021	77	7.61	6097	10925	0.12	0.07
8	Telangana	06-09-2021	79	1000	7507	9098	13.32	10.99
9	Andhra pradesh	20-09-2021	41	0	3064	12016	0.00	0.00
10	Haryana	10-09-2021	81	146.2	5426	5783	2.69	2.53
11	Bihar	18-09-2021	34	12.2	5086	12472	0.24	0.10

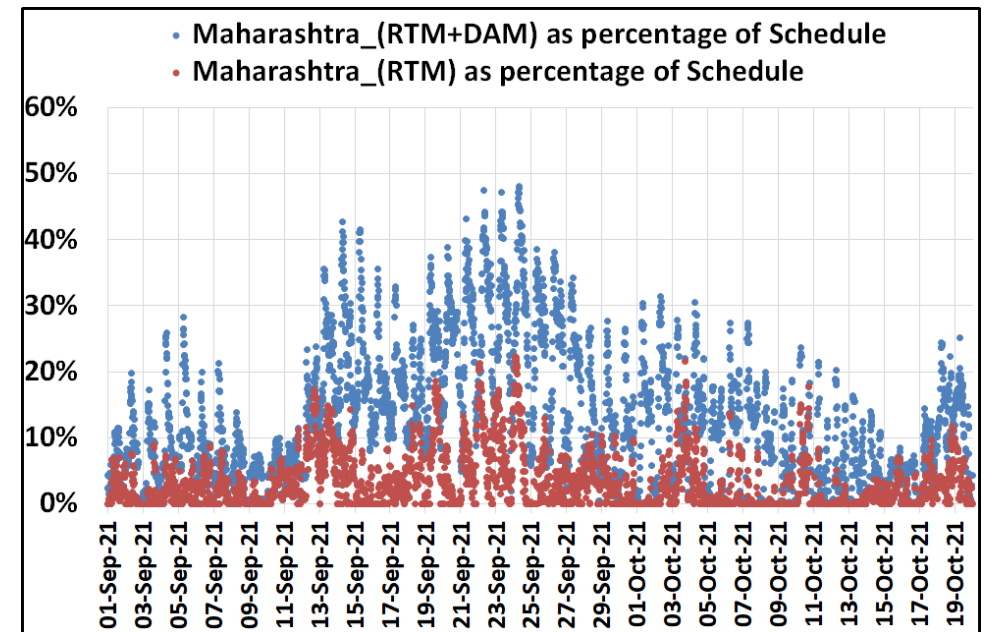
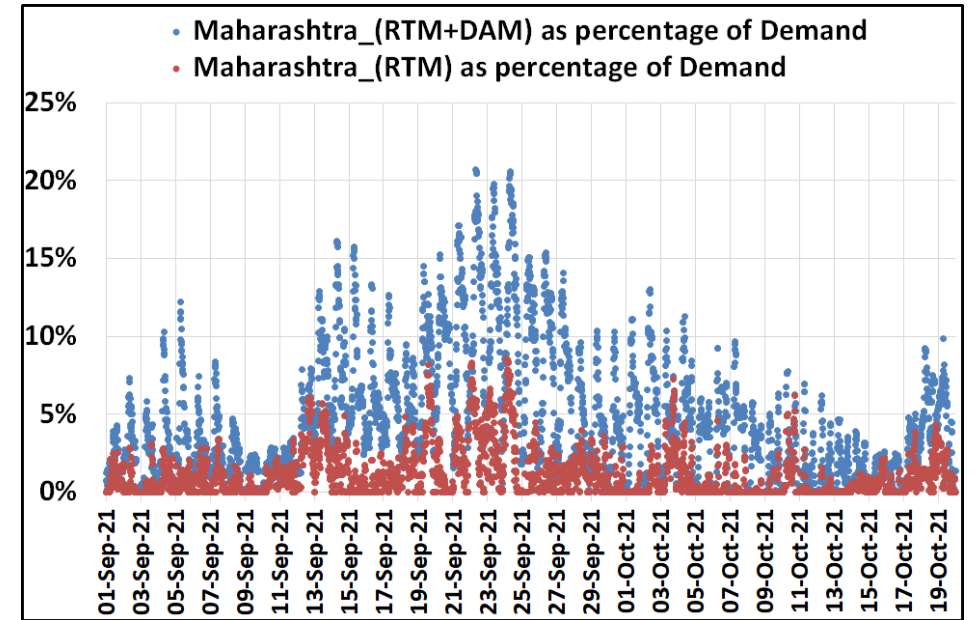
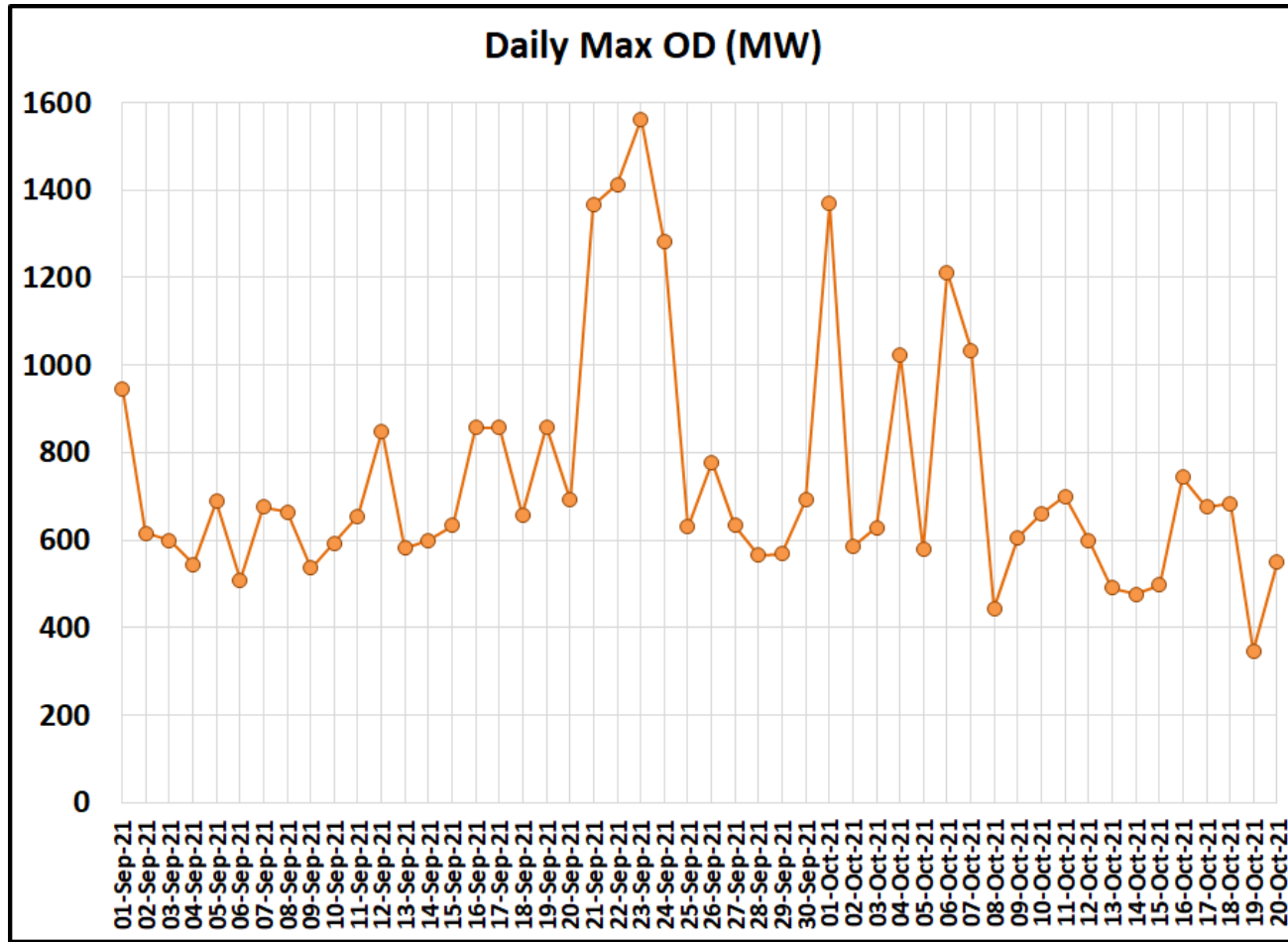
Gujarat



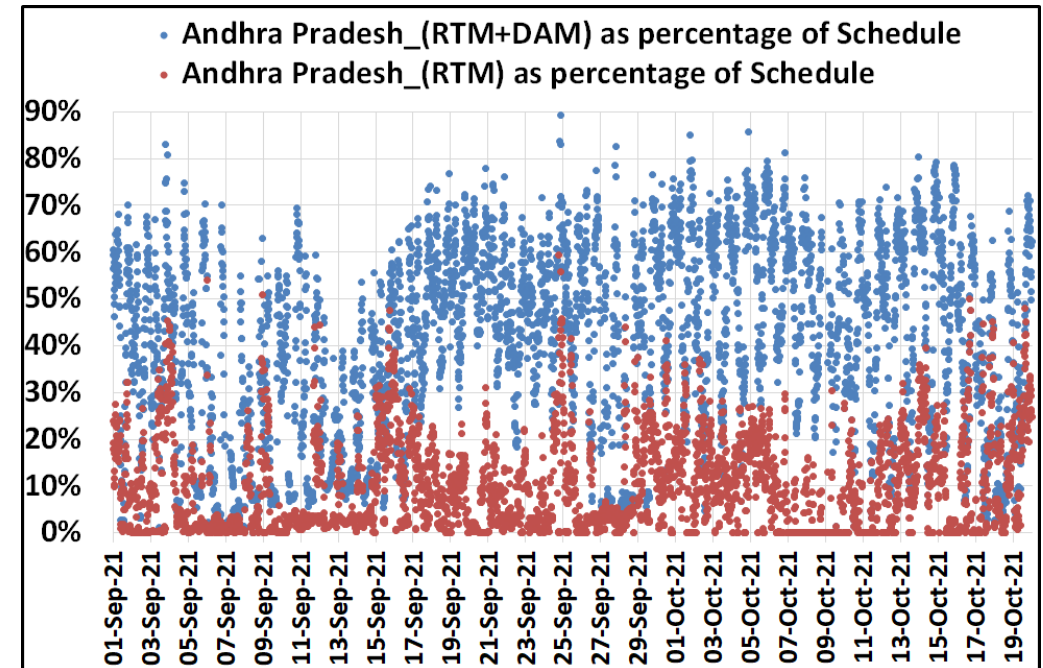
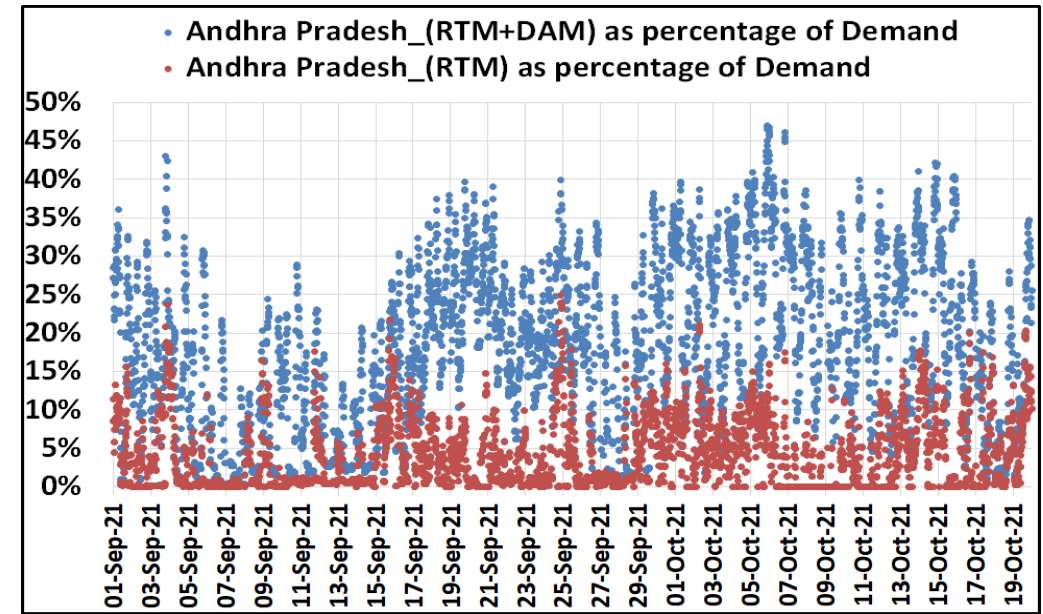
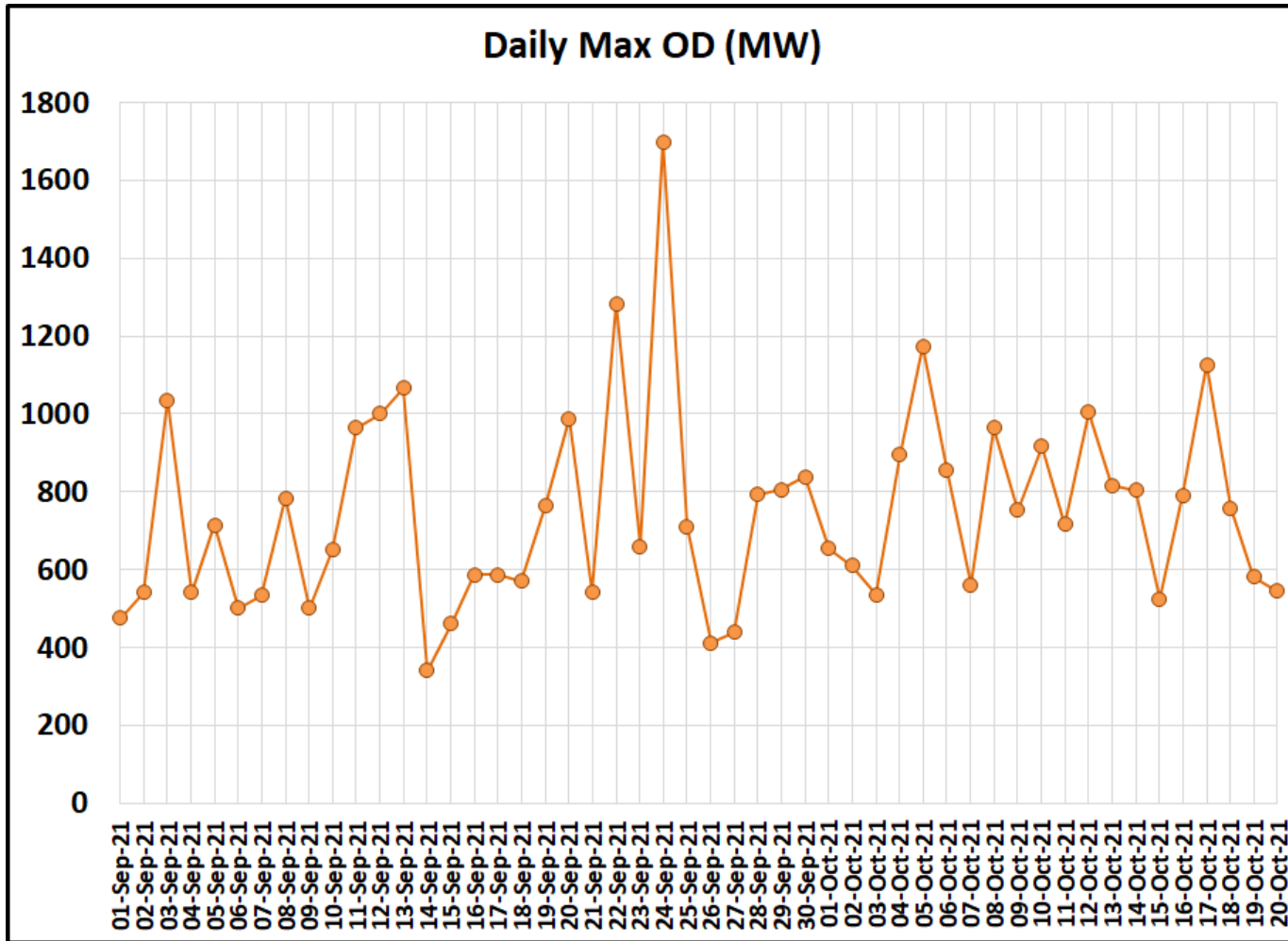
Rajasthan



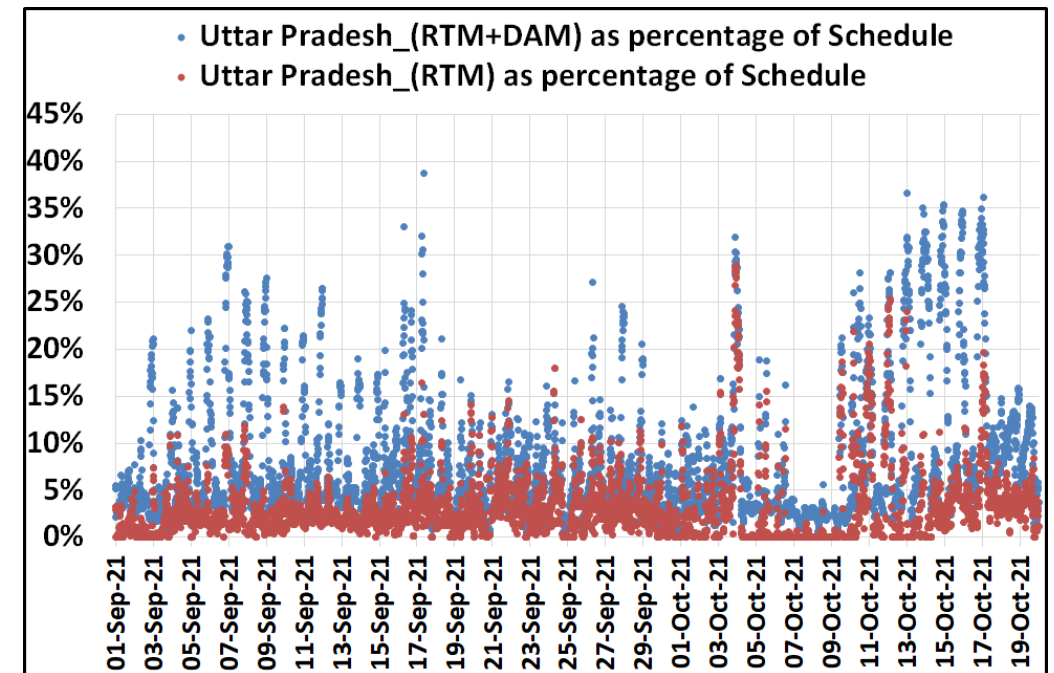
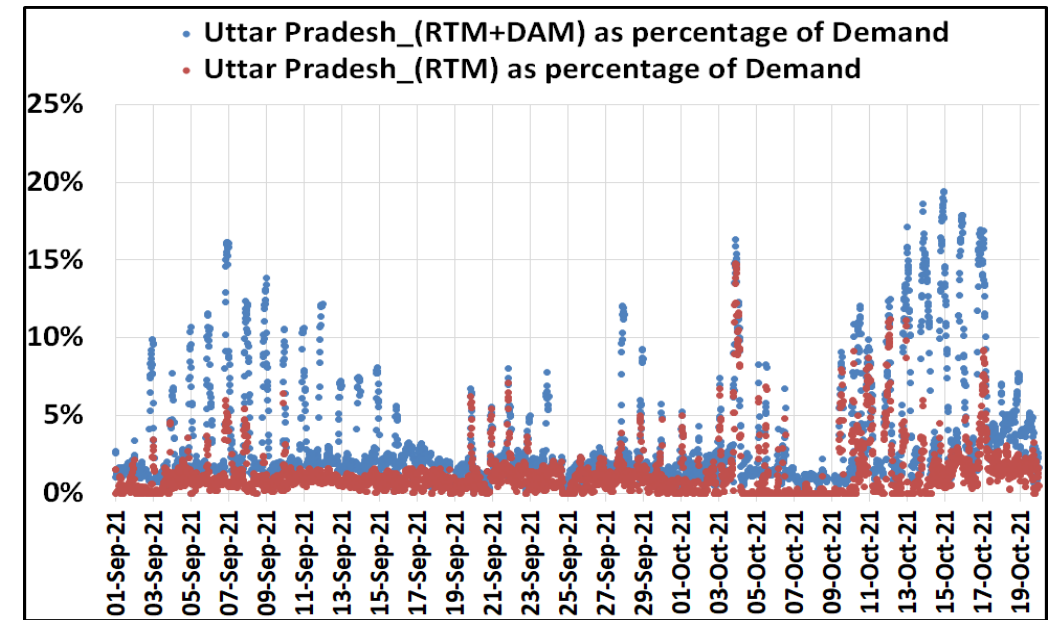
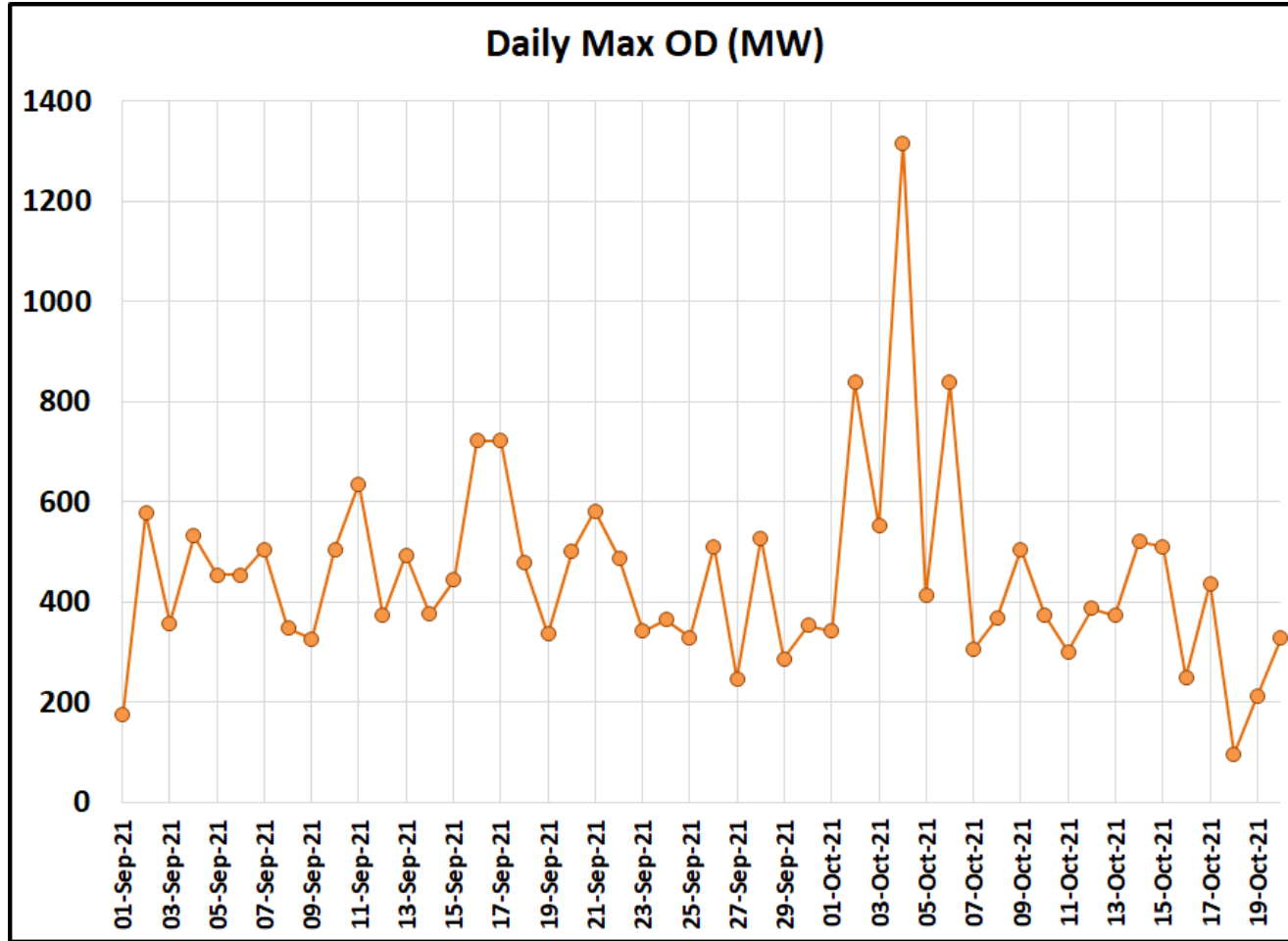
Maharashtra



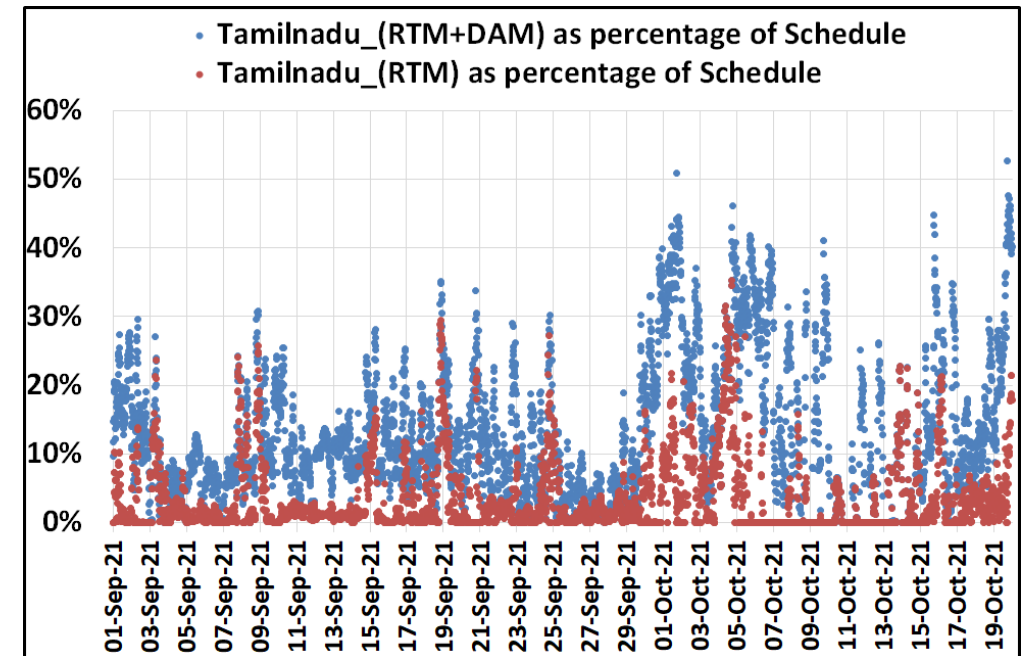
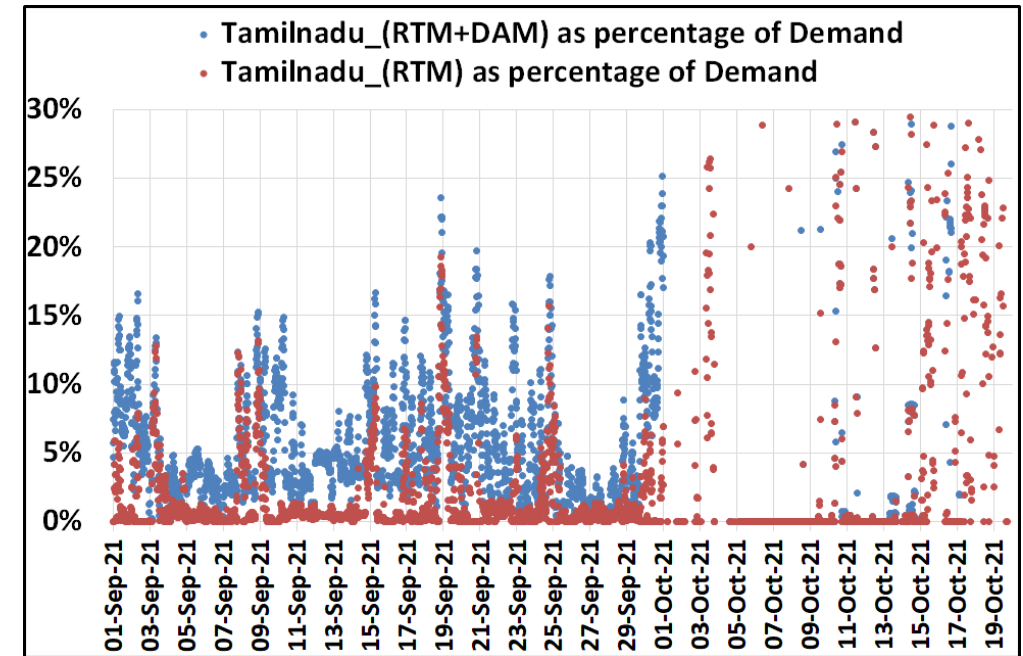
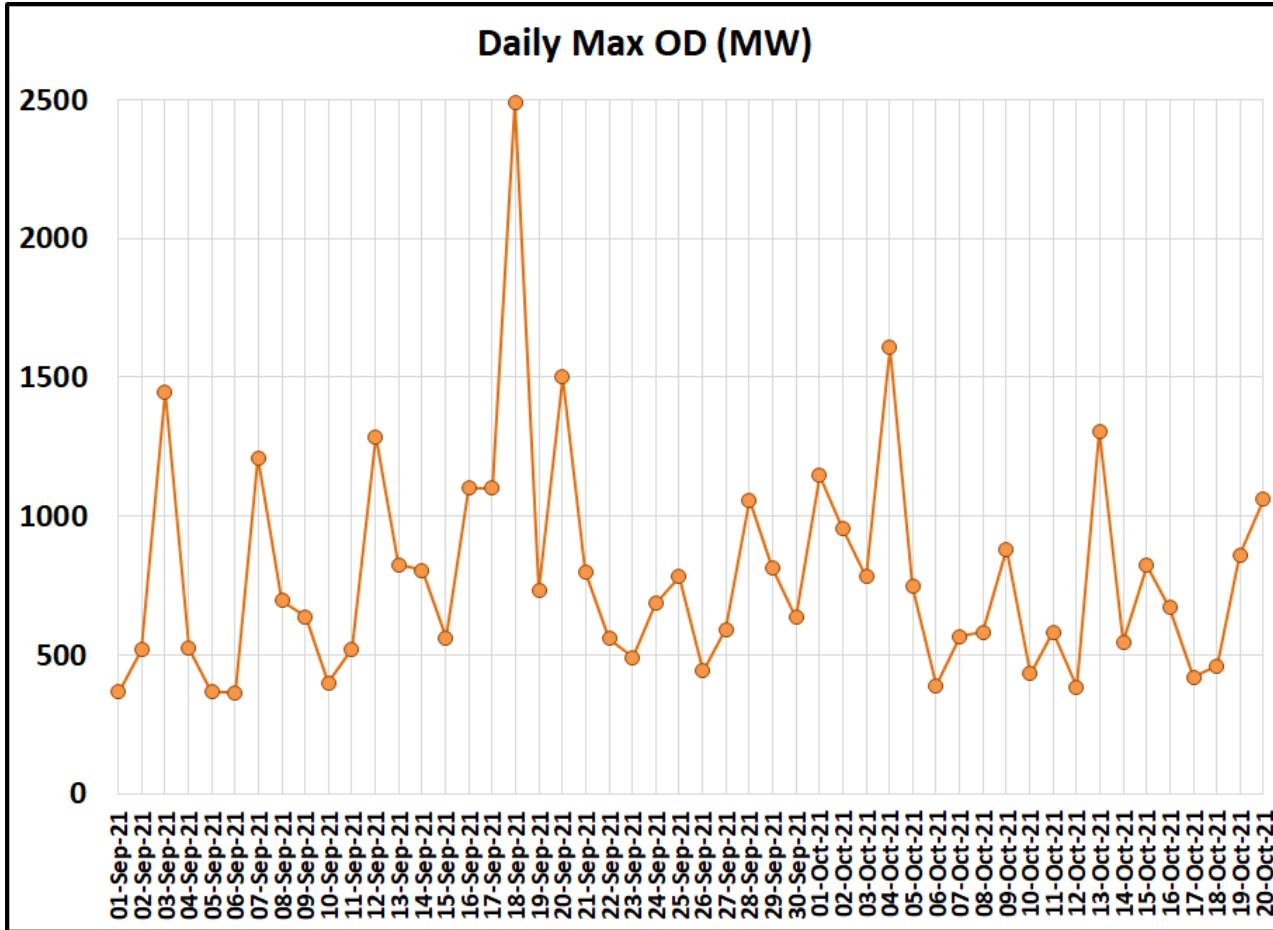
Andhra Pradesh



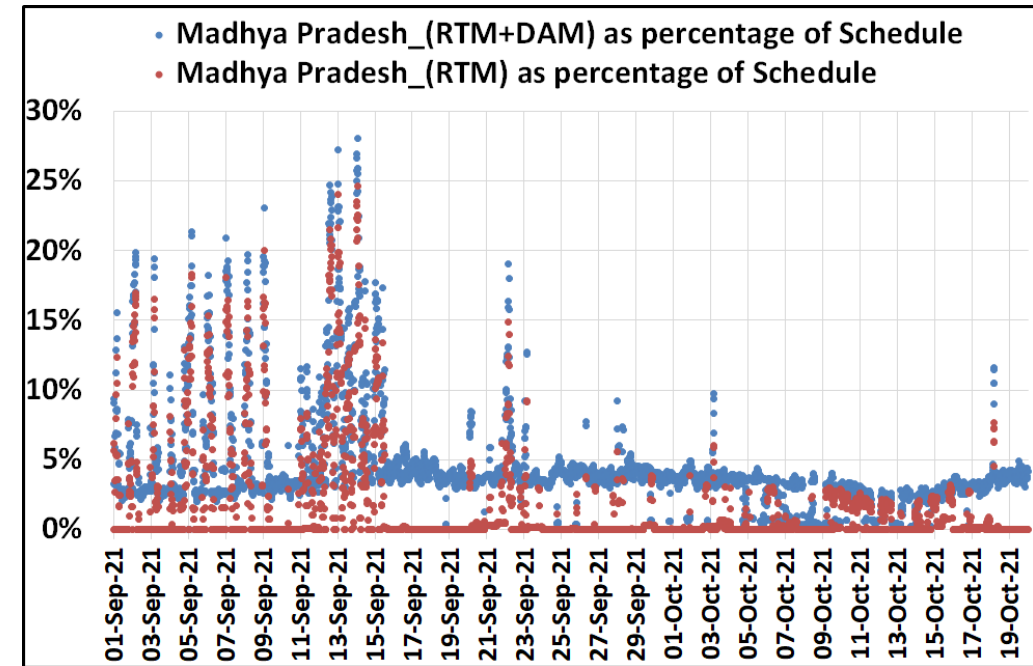
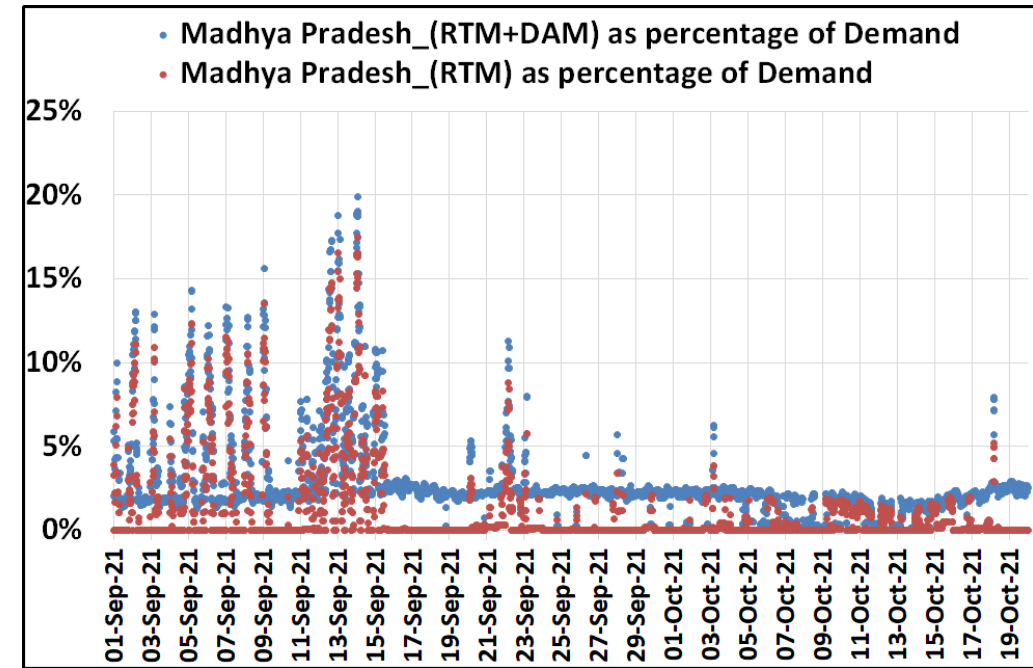
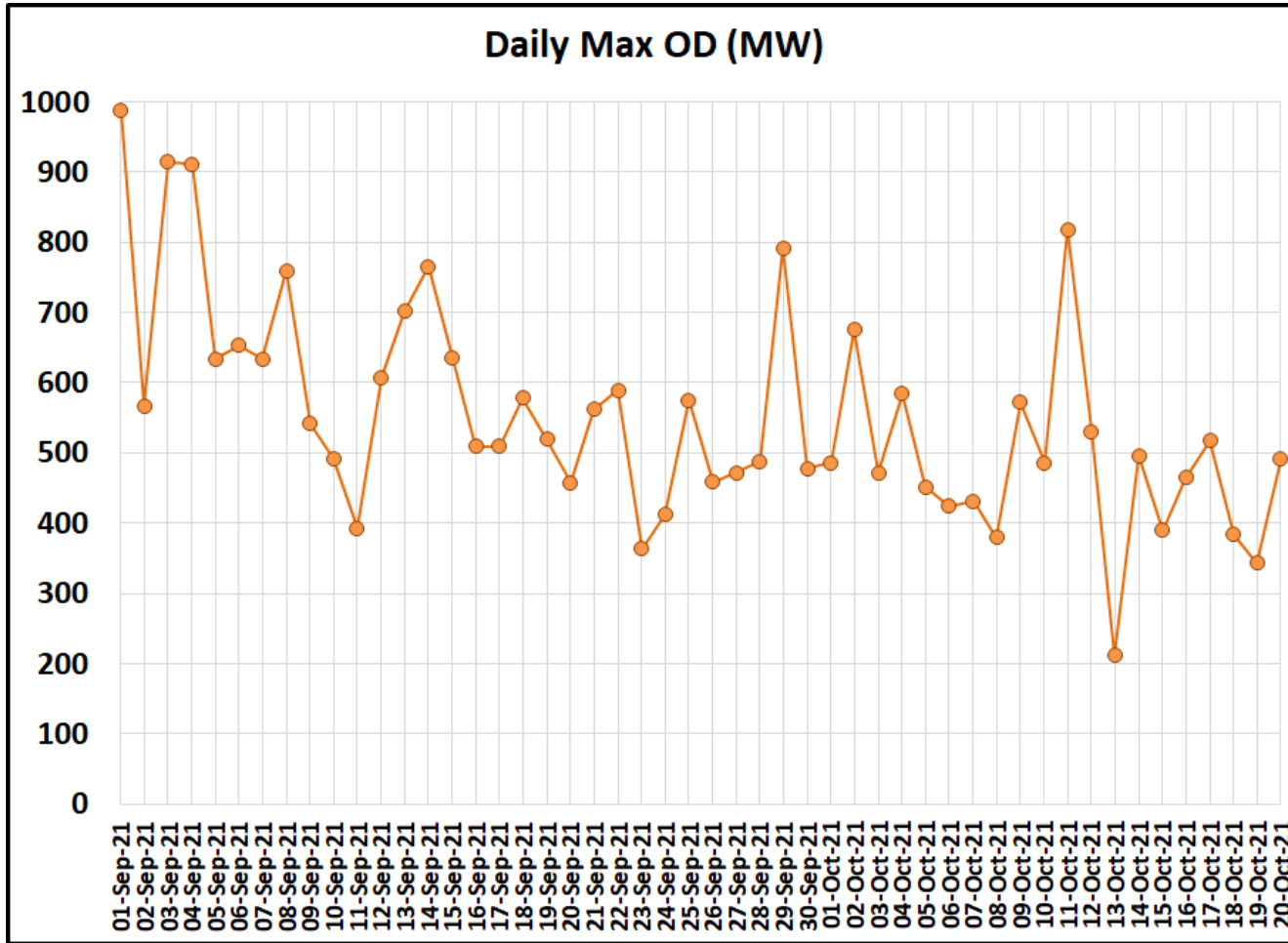
Uttar Pradesh



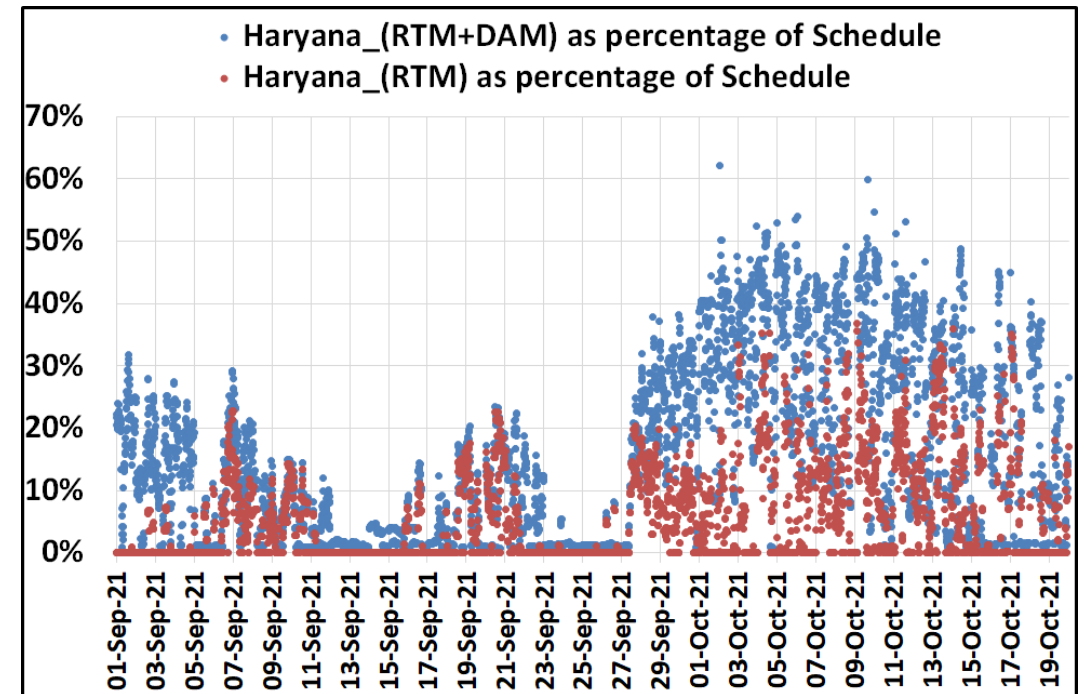
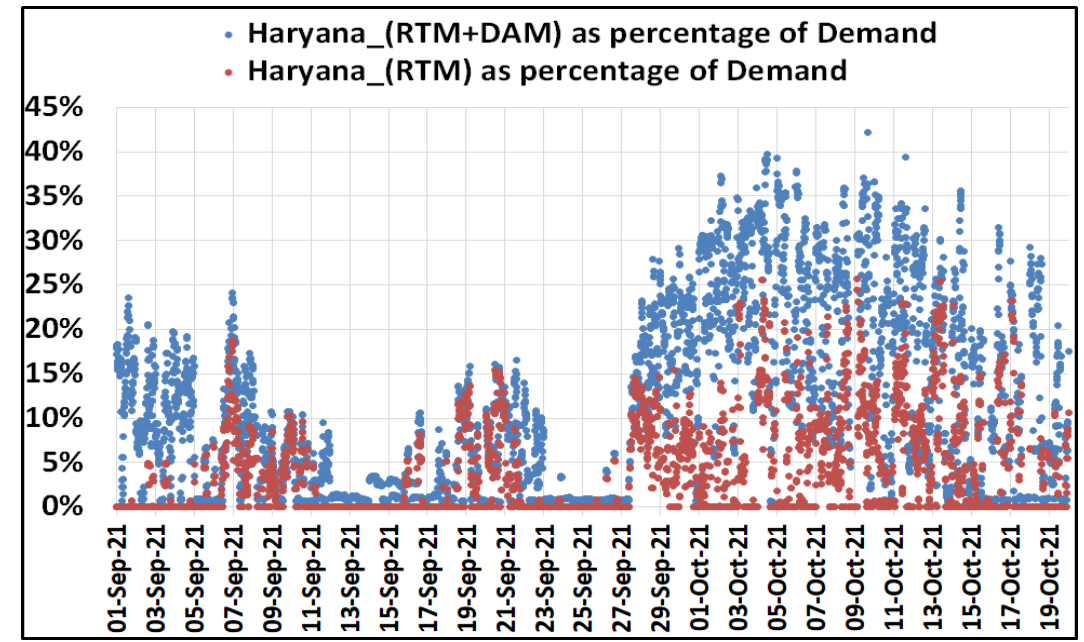
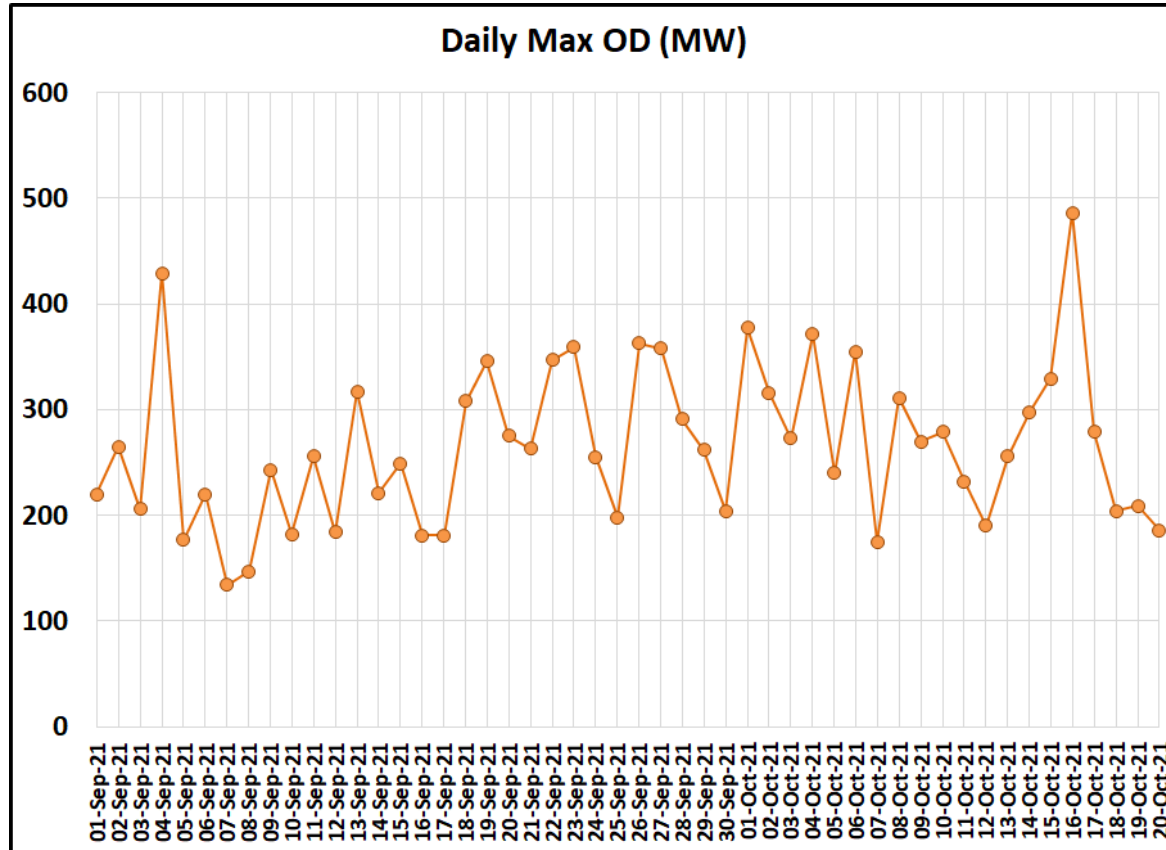
Tamil Nadu



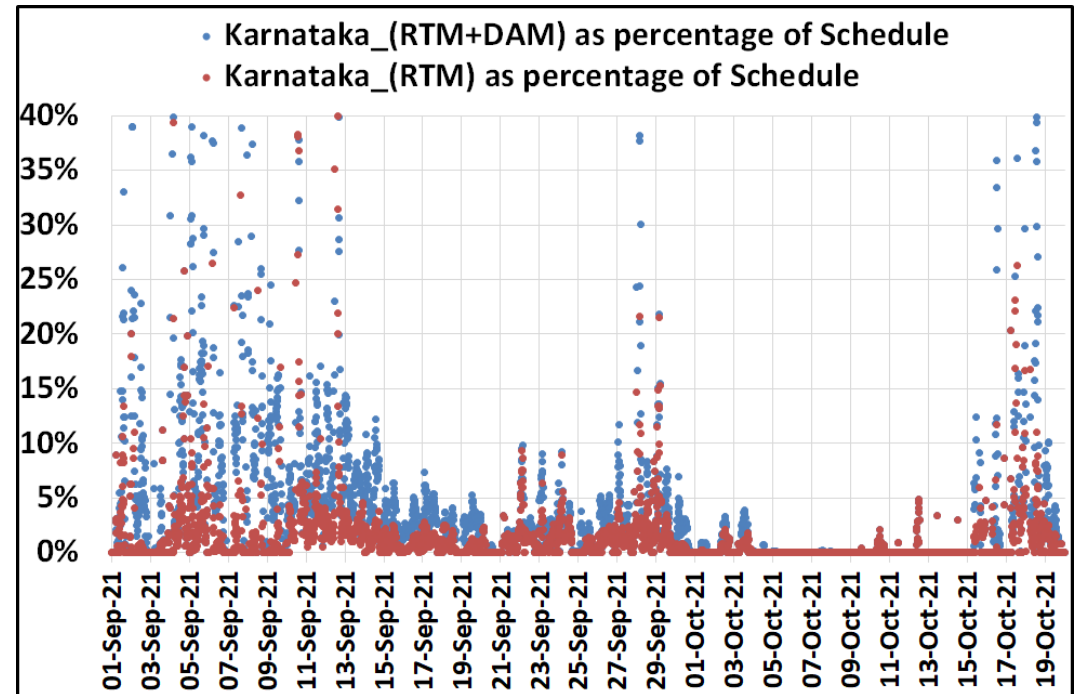
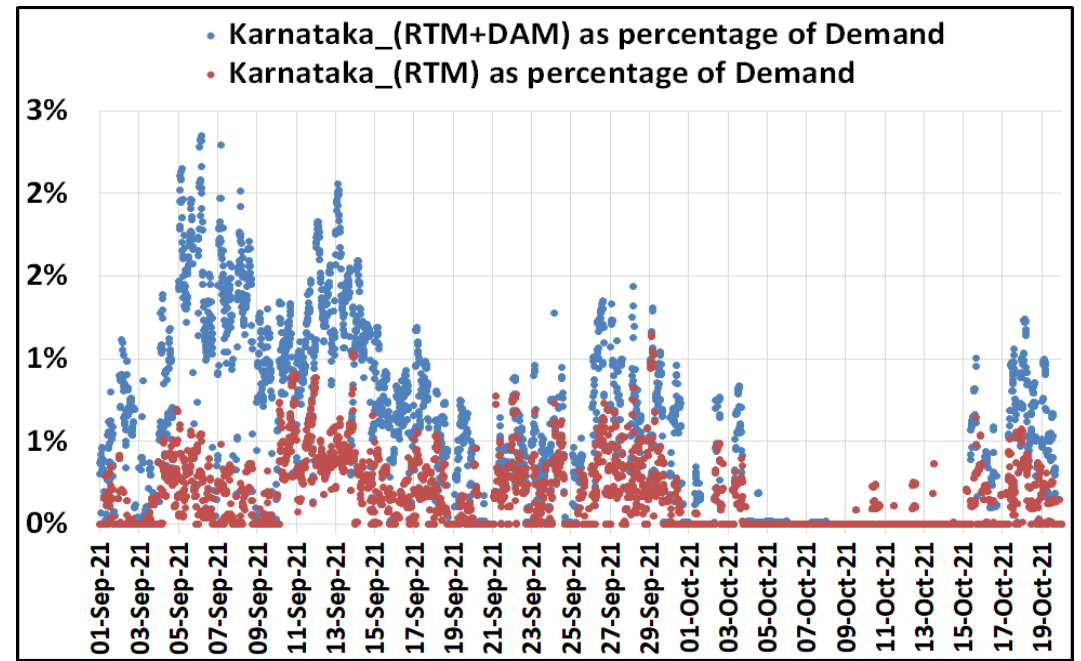
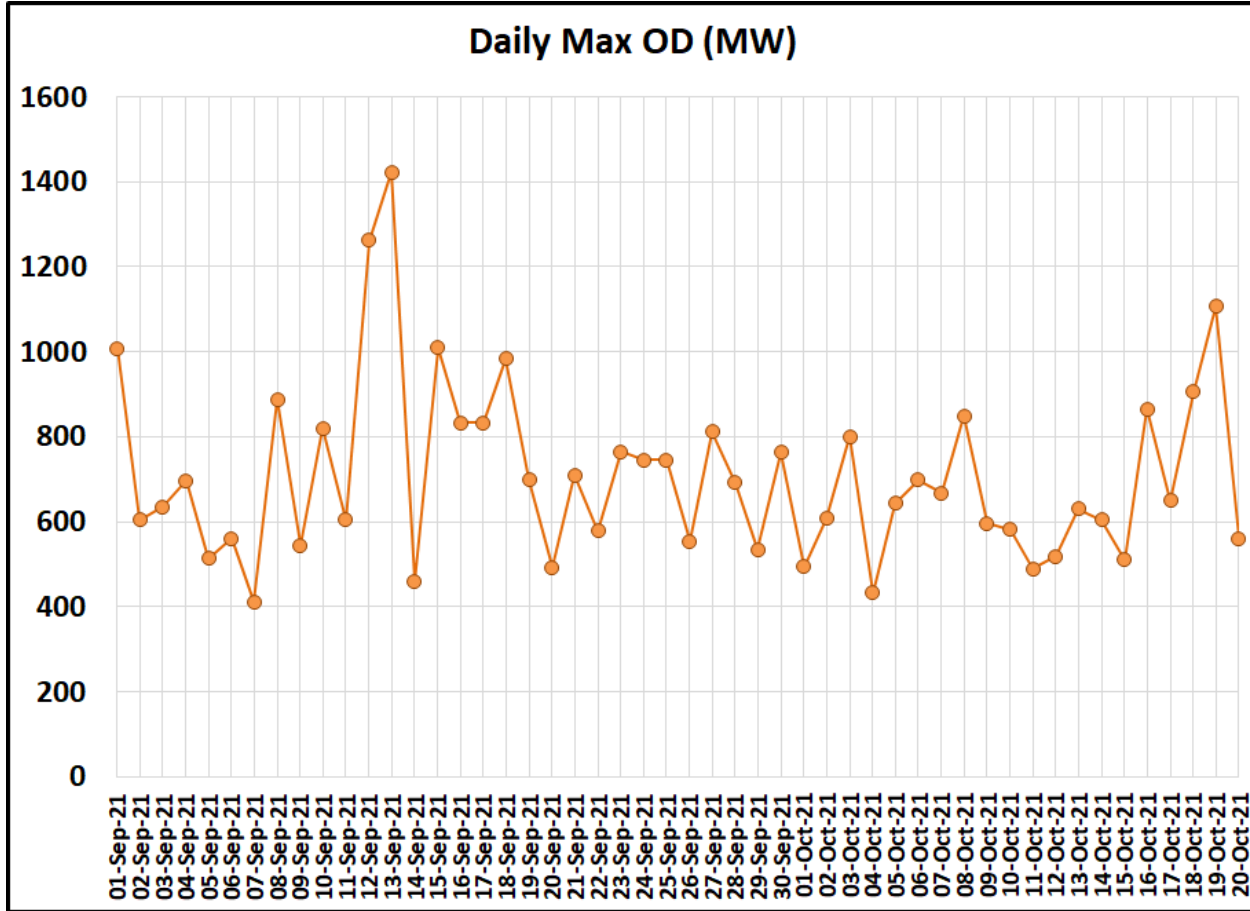
Madhya Pradesh



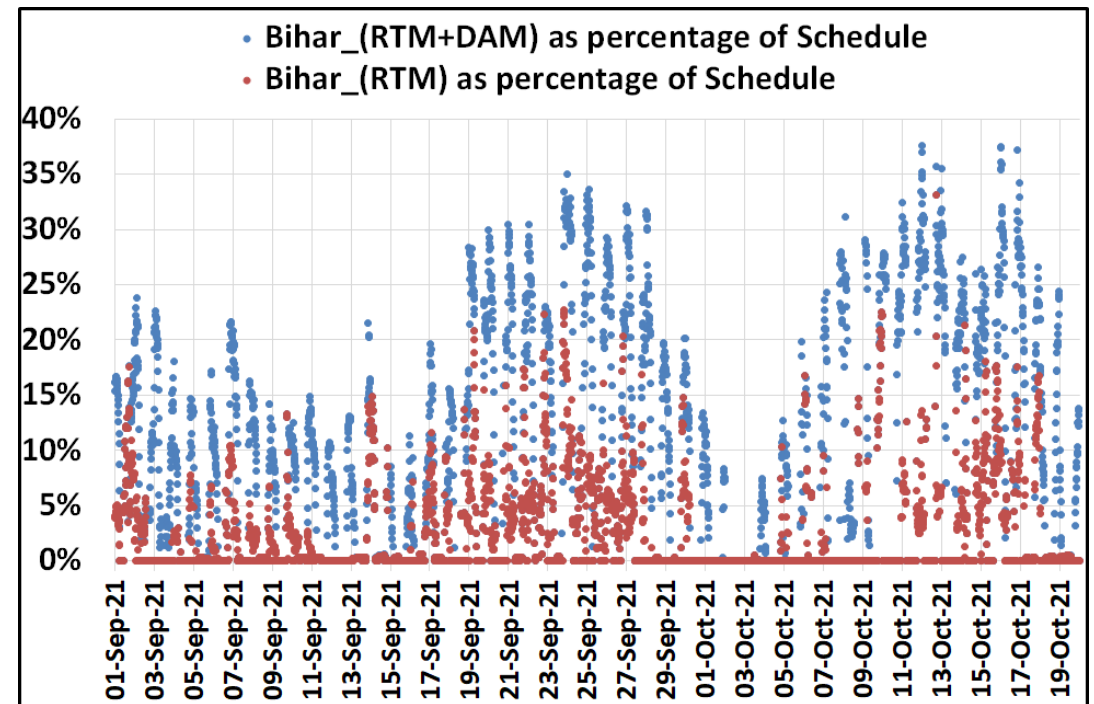
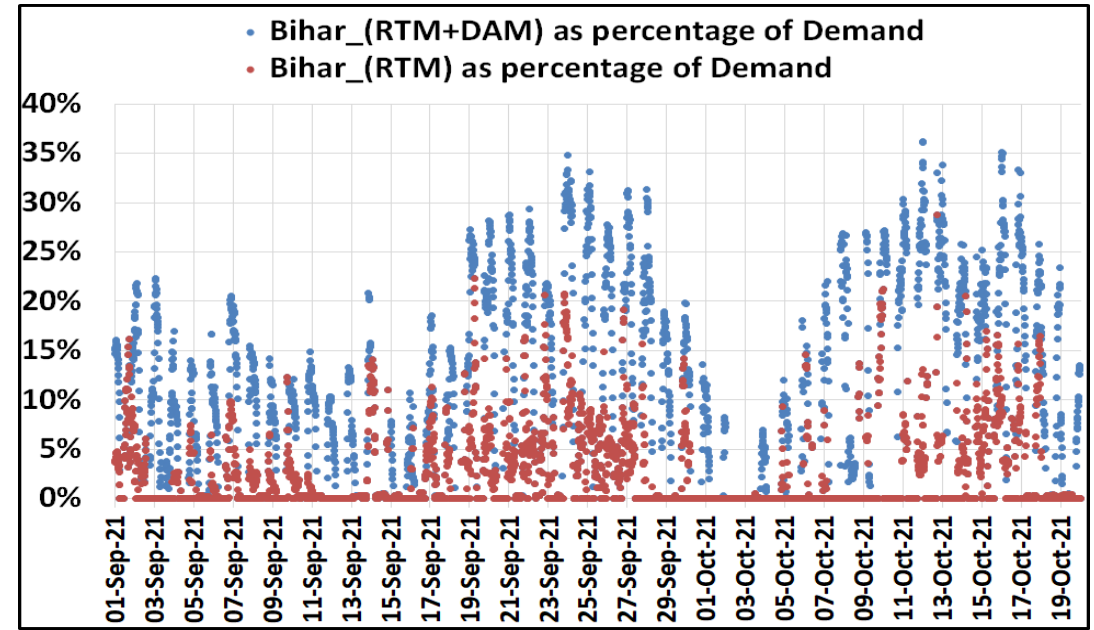
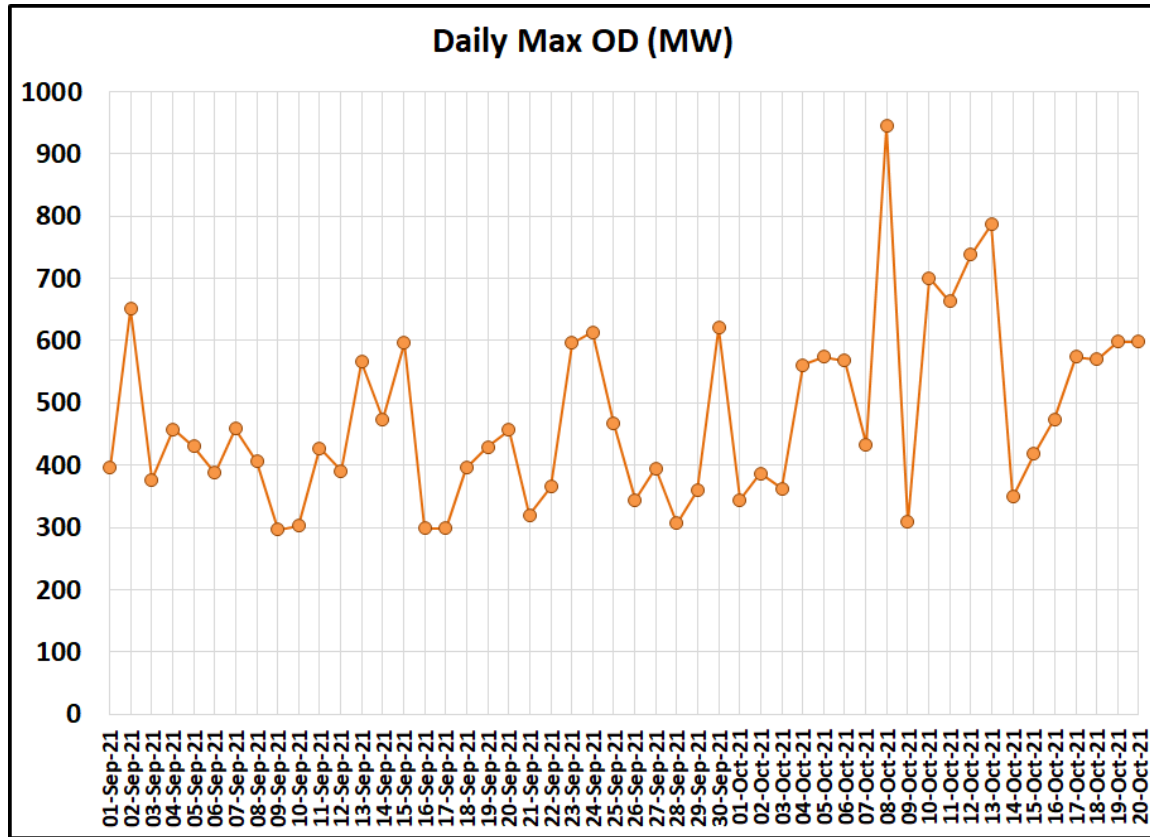
Haryana



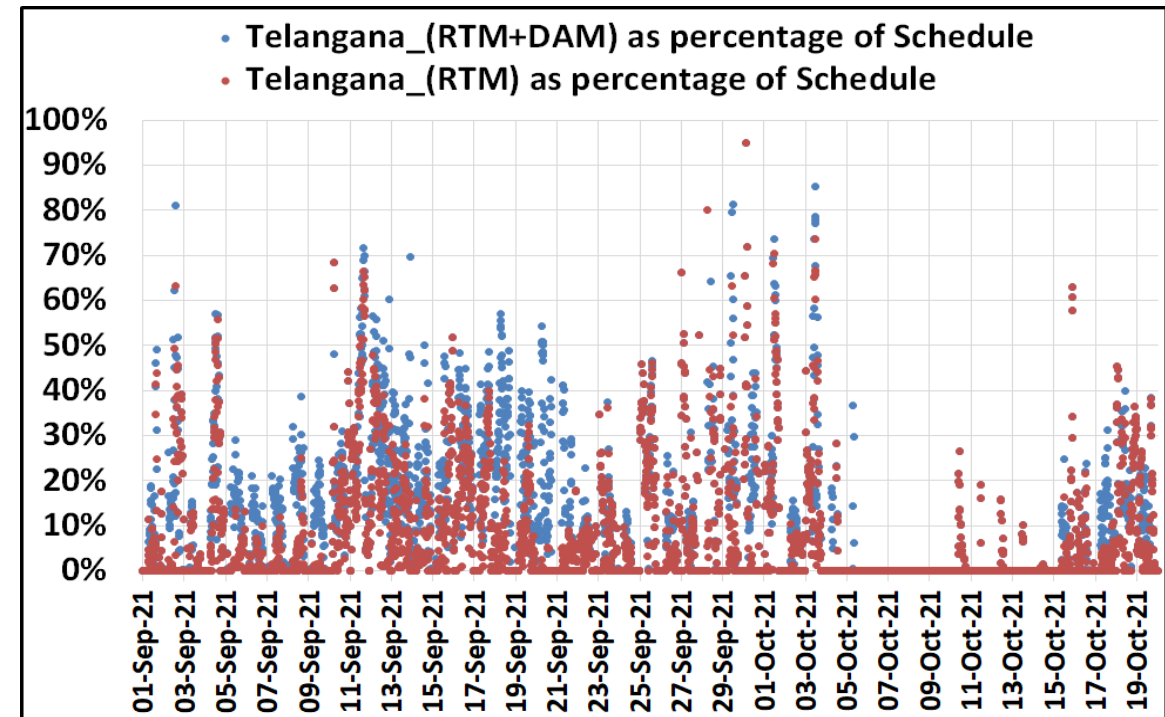
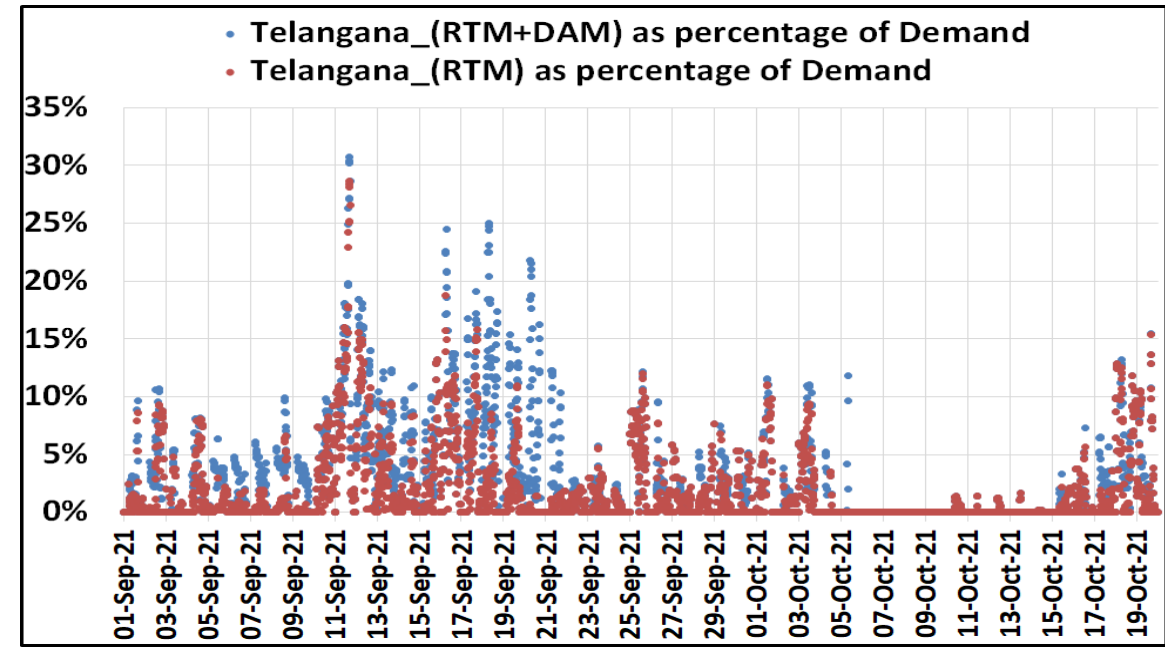
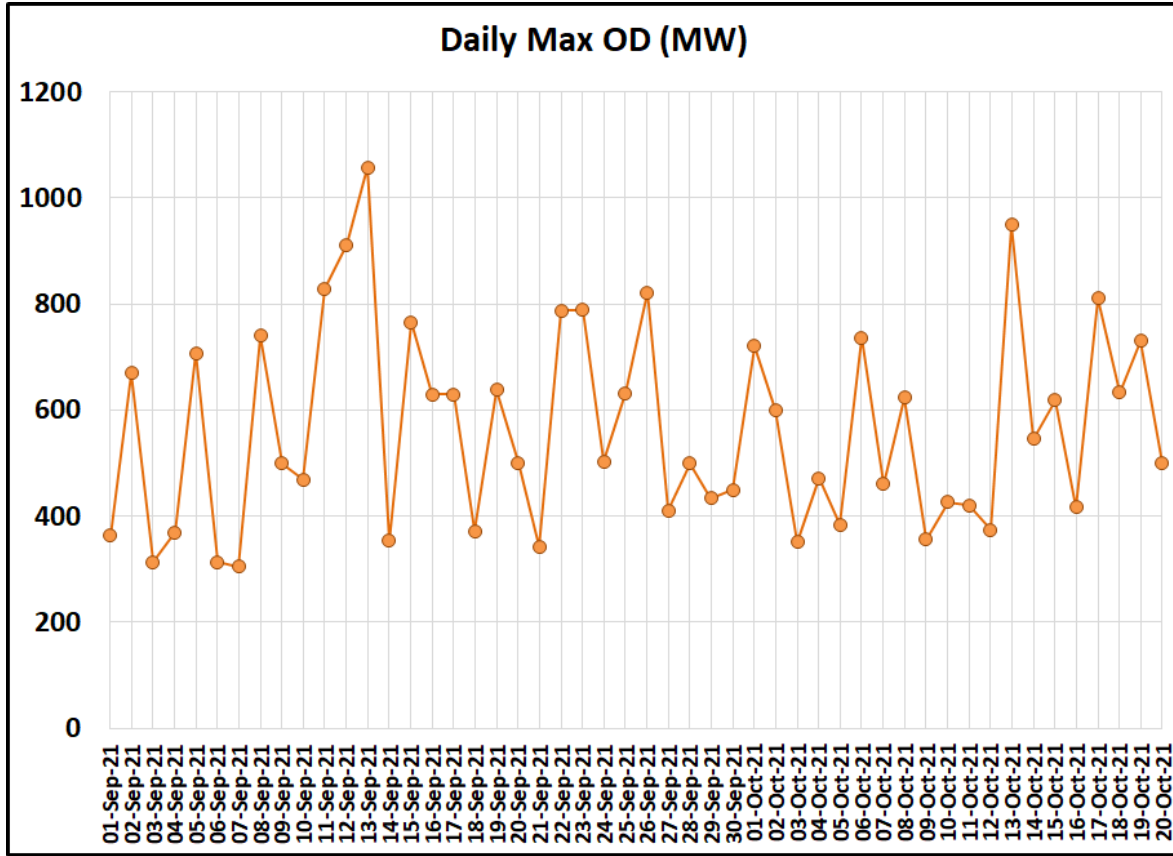
Karnataka

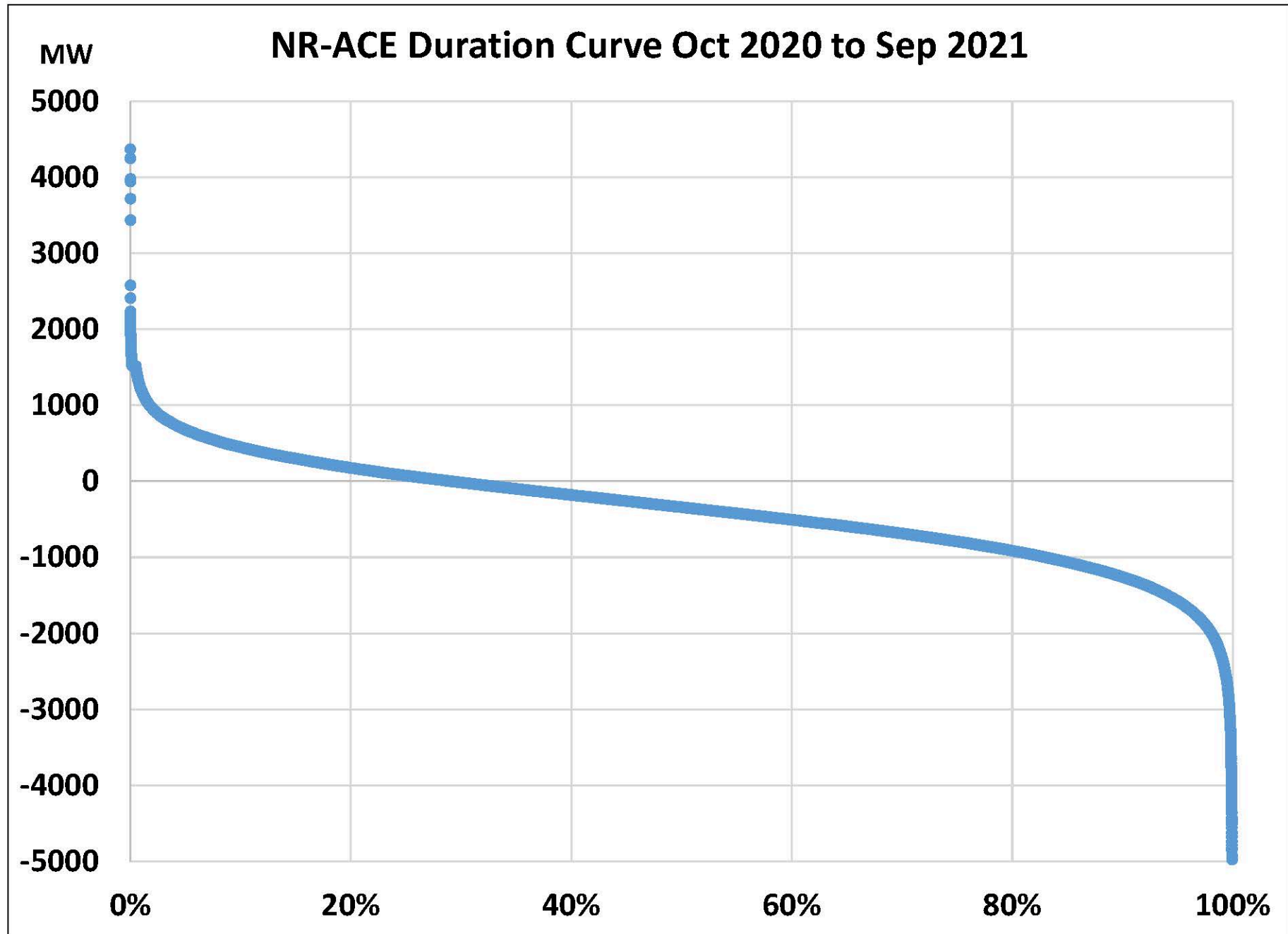


Bihar

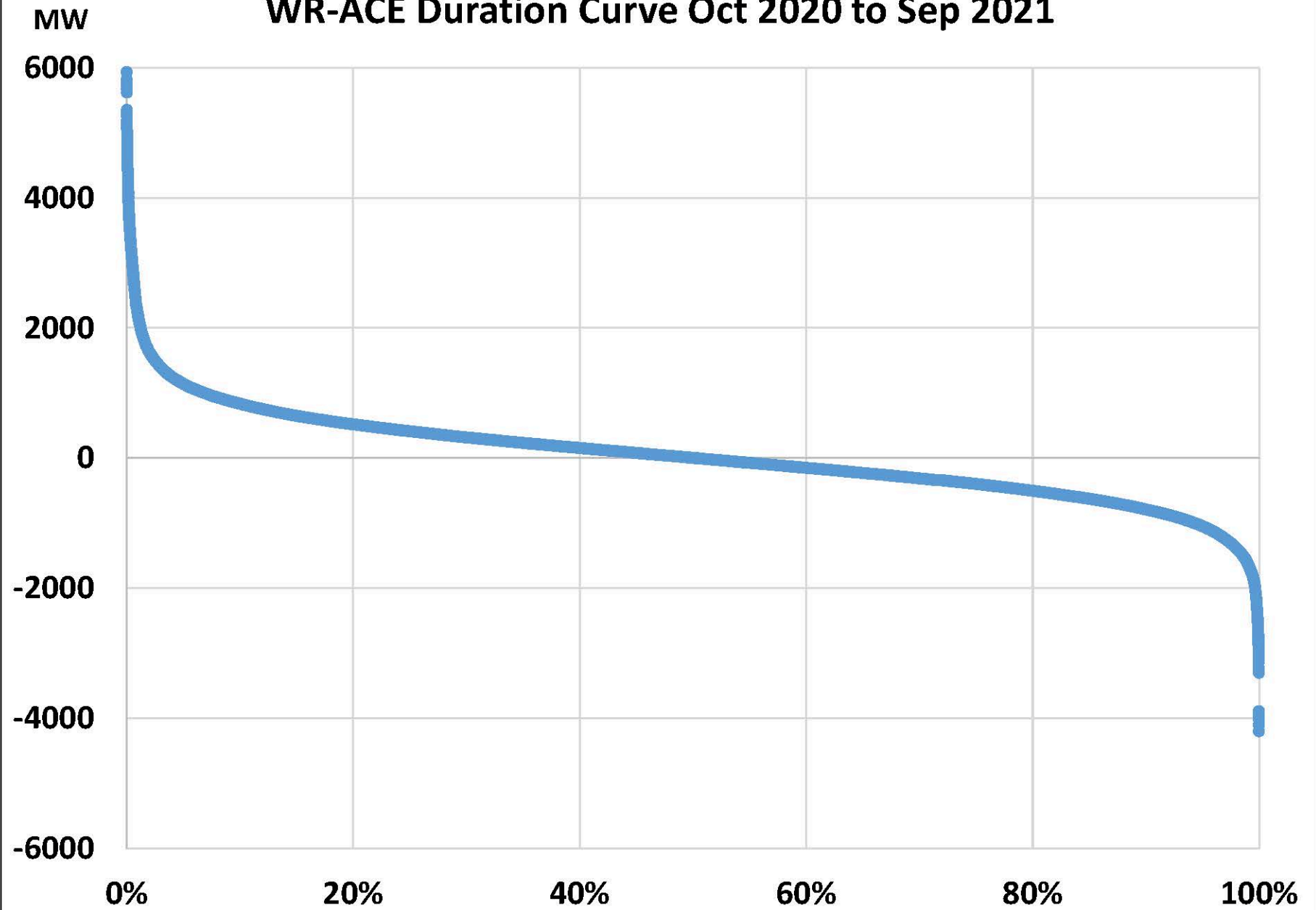


Telangana

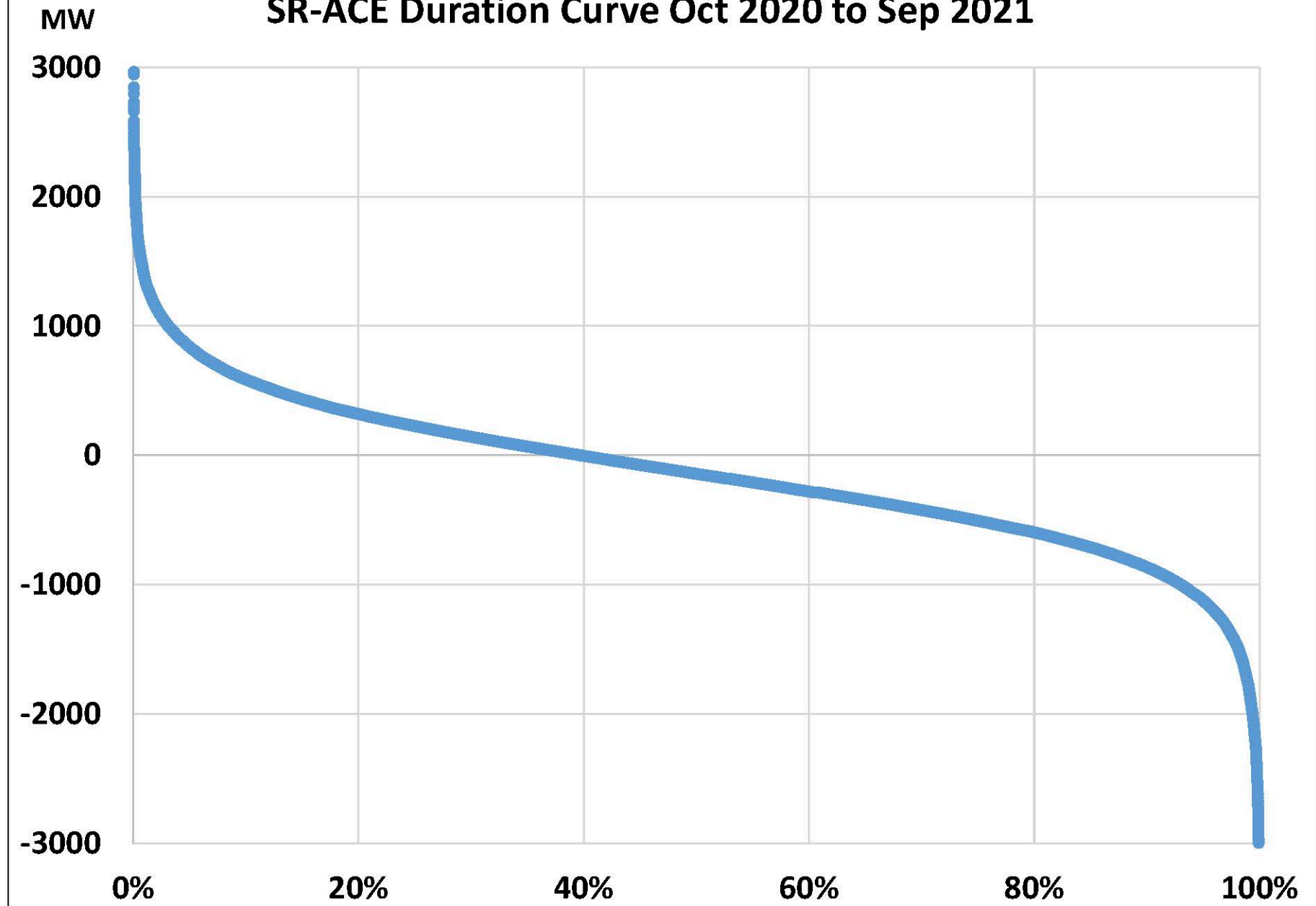




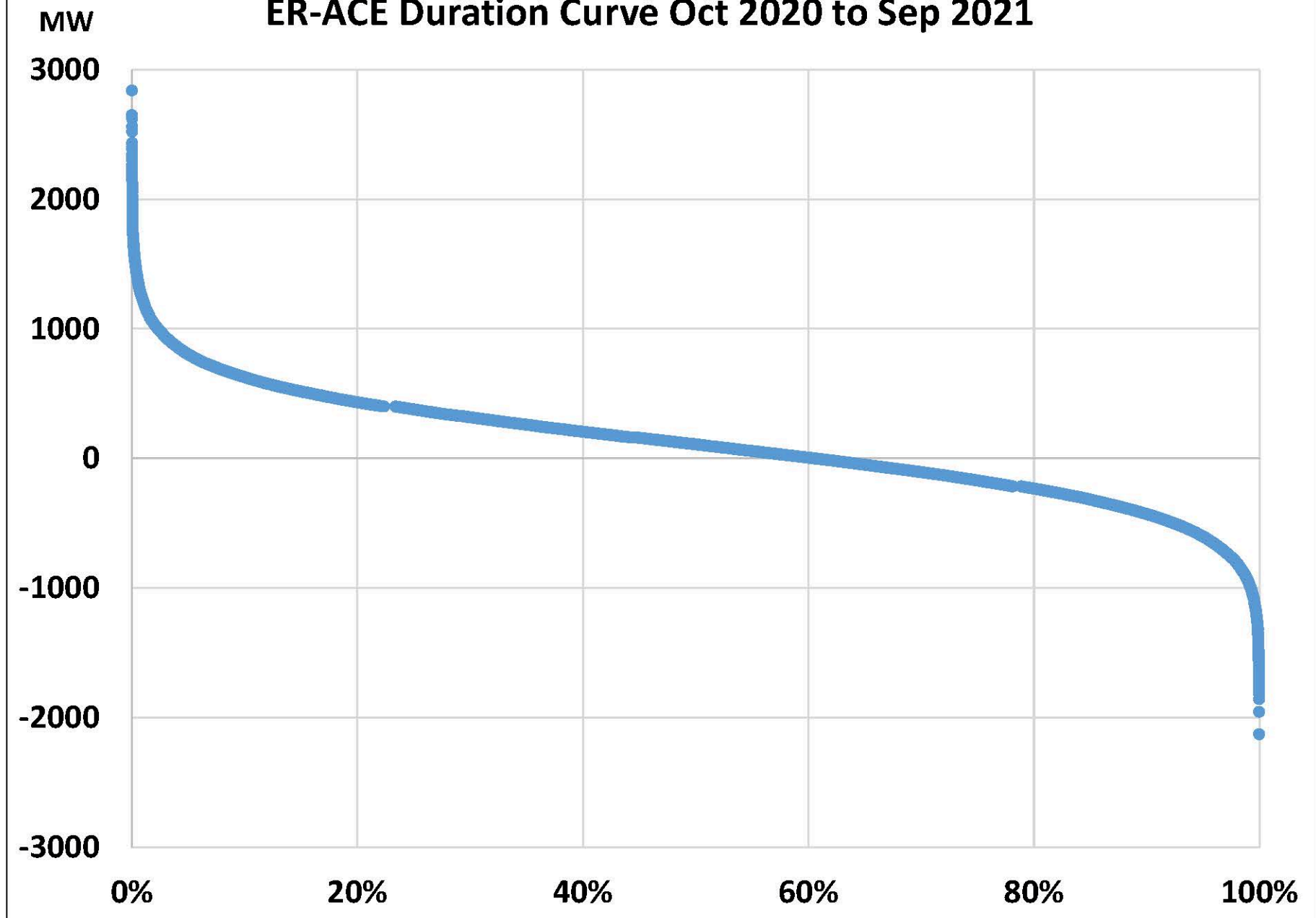
WR-ACE Duration Curve Oct 2020 to Sep 2021



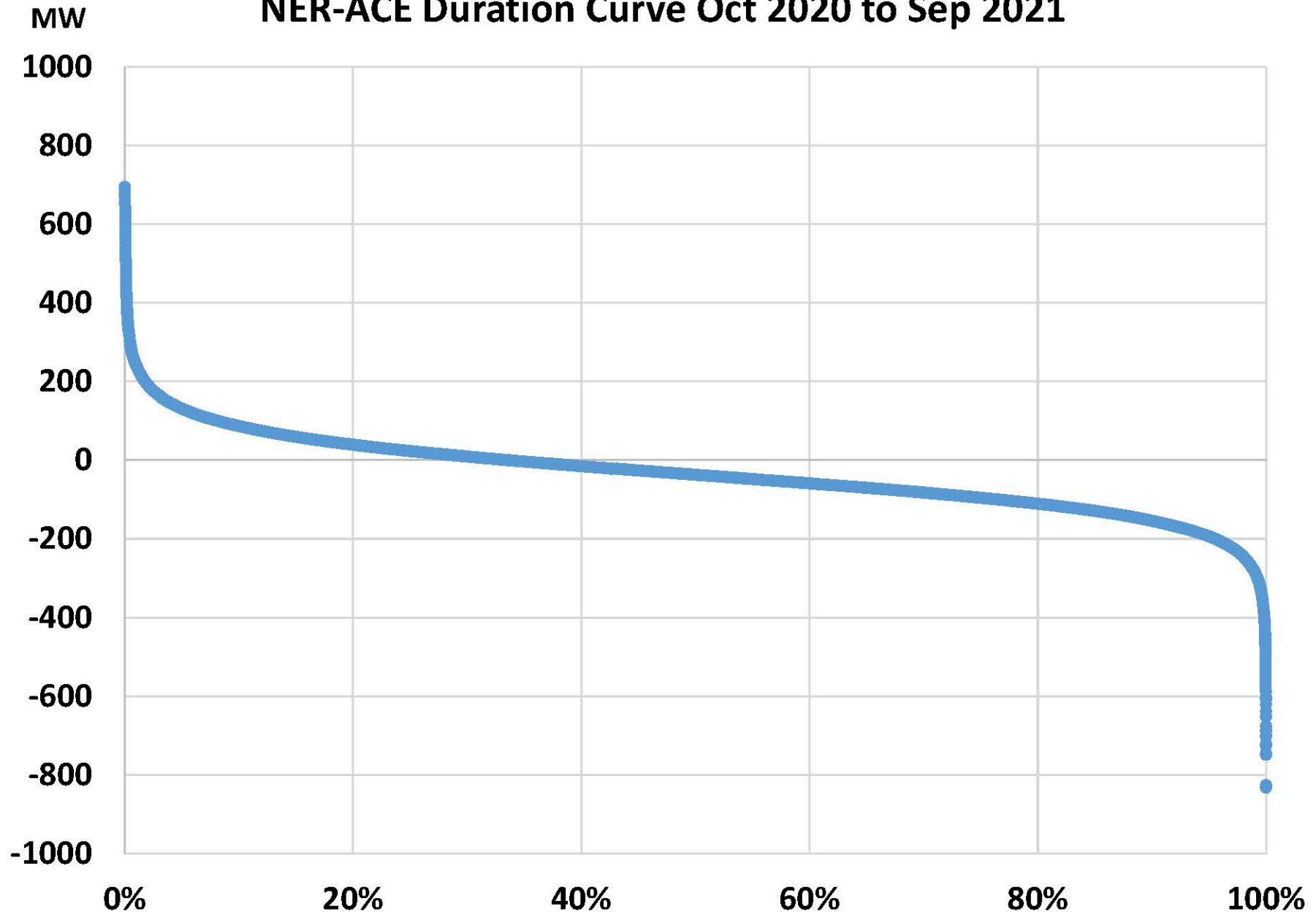
SR-ACE Duration Curve Oct 2020 to Sep 2021



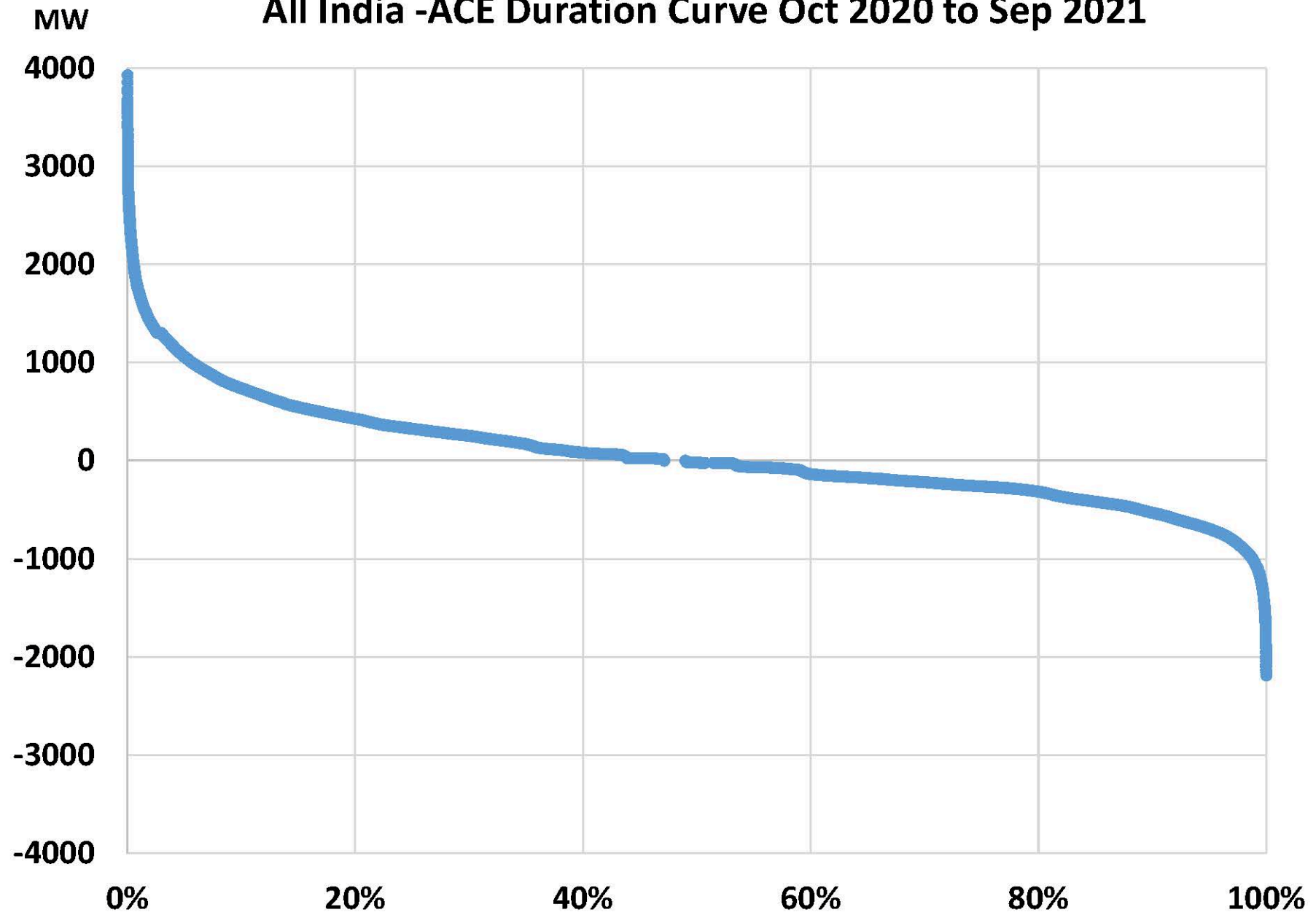
ER-ACE Duration Curve Oct 2020 to Sep 2021



NER-ACE Duration Curve Oct 2020 to Sep 2021



All India -ACE Duration Curve Oct 2020 to Sep 2021



ACE Ranking of all states based on September & October 2021 Data					
S.No.	State	Percentage of time ACE above 150 MW when the frequency is below 50 Hz.	Percentage of time ACE above 150 MW	Percentage of time ACE above 250 MW	99 percentile ACE
1	Gujarat	17.5%	34.2%	21.8%	766
2	Rajasthan	16.0%	32.8%	21.1%	716
3	Maharashtra	13.3%	28.3%	15.6%	593
4	Andhra Pradesh	12.8%	26.3%	14.4%	666
5	Uttar Pradesh	11.6%	23.1%	13.8%	658
6	Tamil nadu	10.8%	22.0%	12.5%	811
7	Madhya Pradesh	10.4%	23.1%	11.0%	499
8	Haryana	10.1%	20.5%	8.2%	452
9	Karnataka	7.7%	18.0%	8.1%	563
10	Bihar	7.6%	15.8%	3.8%	342
11	Telangana	7.0%	14.8%	7.4%	550
12	DVC	6.8%	12.8%	4.5%	396
13	Jammu & Kashmir	5.5%	11.4%	2.4%	304
14	Punjab	4.5%	8.9%	2.8%	346
15	West Bengal	4.0%	12.2%	3.6%	366
16	Orissa	2.8%	7.7%	1.7%	285
17	Chattisgarh	2.5%	5.4%	0.8%	237
18	Uttarakhand	1.1%	2.5%	0.3%	190
19	Himachal Pradesh	1.0%	1.8%	0.3%	181
20	Jharkhand	0.8%	1.3%	0.0%	158
21	Kerala	0.6%	2.3%	0.2%	173
22	Delhi	0.5%	1.0%	0.0%	149
23	Assam	0.2%	0.4%	0.0%	126
24	Pondy	0.1%	0.1%	0.1%	35
25	Chandigarh	0.0%	0.0%	0.0%	79
26	Sikkim	0.0%	0.0%	0.0%	75
27	DNH	0.0%	0.0%	0.0%	66
28	D&DIU	0.0%	0.0%	0.0%	83
29	GOA	0.0%	0.0%	0.0%	52
30	Meghalaya	0.0%	0.0%	0.0%	35
31	Tripura	0.0%	0.0%	0.0%	78
32	Manipur	0.0%	0.0%	0.0%	27
33	Mizoram	0.0%	0.0%	0.0%	18
34	Nagaland	0.0%	0.0%	0.0%	21
35	Arunanchal Pradesh	0.0%	0.0%	0.0%	35

Note: Calculations are based on States ACE of September & October 2021 Data (Resolution of data is one minute). Data of October is considered till 20 Oct 2021.

पावर सिस्टम ऑपरेशन कॉर्पोरेशन लिमिटेड

(भारत सरकार का उद्यम)

POWER SYSTEM OPERATION CORPORATION LIMITED

(A Govt. of India Enterprise)



पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी-9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली-110016
Registered & Corporate Office : 1st Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.posoco.in, E-mail : posococc@posoco.in, Tel.: 011- 41035696, Fax : 011- 26536901

संदर्भ संख्या:पोसोको/एनएलडीसी/2021/97

दिनांक: 12th फरवरी, 2021

सेवा मे,

**Chief Engineer,
National Power Committee,
Central Electricity Authority,
01st Floor, Wing-5, West Block-II,
R.K.Puram, New Delhi-66**

विषय: **NPC Agenda on National Energy Account(NEA).**संदर्भ: 1. **POSOCO Communication: पोसोको/एनएलडीसी/2018/329 dated 09th Nov'2018**2. **NPC email National Energy Account (NEA)_9th NPC meeting follow up-reg. dated 29th Jan'2021**

महोदय,

In order to streamline and harmonize the accounting and settlement at the national level, POSOCO has submitted the agenda of "National Energy Account (NEA)" for discussion on 08th National Power Committee (NPC) (Annex-1).

As per the above-mentioned proposal, it is envisaged that NPC shall prepare the National Energy Account (NEA) comprising of the interregional and trans-national transactions. The NEA shall reflect the payables/receivables for each region on a net-basis and this amount shall be payable/receivable to the National Deviation Pool Account which shall be operated by NLDC. The NEA shall also reflect the cross-border or transnational transactions and the neighbouring countries shall be paying/receiving to/from the National Deviation Pool Account operated by NLDC.

National Energy Account (NEA) & National Pool Account related feedback have been submitted to Honourable CERC through various feedback report from time to time. CERC being a quasi-judicial body, does not normally respond to such feedback through letters etc. A petition may be required to be filed either suo-moto or by respective parties, for getting the appropriate directions from CERC. It may also be appreciated that introduction of the NEA needs the notification of the Regulatory Framework by CERC through appropriate Regulations, which also needs pre-publication, stakeholder consultation and final notification.

In this regard, it is pertinent to mention that CERC has mentioned the National Pool account in SCED order Petition No. 02 /SM/2019 (Suo-Motu) Date of Order: 31st of January, 2019. The same is reproduced below

Quote

"10.(c) POSOCO has suggested implementation of the National Pool Account to take care of changes in injection schedule for each region due to optimisation process. There would be a need for pay-in/pay-out from the National Pool Account for incremental changes in schedules (Up/Down). As per the present mechanism, the generators receive their variable charges based on the schedules issued by the concerned RLDC. Optimization would result in incremental/decremental changes in the existing schedules of generators and these would need to be settled through the National Pool Account mentioned above."

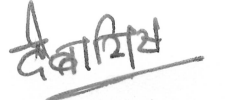
Unquote

As per the direction of CERC, National Pool Account (SCED) is maintained and operated by NLDC for settlement of SCED. Similarly National Deviation Pool Account for Deviation Settlement (DSM) can also be maintained/operated by NLDC in case of any direction received from the appropriate Commission.

In 08th NPC Meeting it was decided that RPCs may provide their observation/views after deliberations in the respective RPCs meeting. Accordingly, it is suggested that considering the suggestions received from the RPCs, a framework for implementation of NEA/National Pool Agenda can be finalized in the next NPC Meeting. Once this is agreed upon, POSOCO would submit the necessary feedback once again to the Hon'ble CERC for consideration & further directions.

सादर धन्यवाद,

भवदीय



देबाशिस दे

कार्यपालक निदेशक, रा.भा.प्रे.के.

Enclosures: As above

पावर सिस्टम ऑपरेशन कॉर्पोरेशन लिमिटेड

(भारत सरकार का उद्यम)

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संदर्भ संख्या: पोसोको/एनएलडीसी/2018/ 329

दिनांक: 09th November, 2018

सेवा मे,

Director,
National Power Committee,
NRPC Building,
3rd Floor, Katwaria Sarai,
New Delhi-110016

(Kind Attn: Sh. Irfan Ahmad)

विषय: Agenda Note on National Energy Account & National Deviation Pool Account for 8th Meeting of National Power Committee.

संदर्भ: NPC letter no: 4/MTGS/NPC/CEA/2018/1122-1123 dtd. 01st Nov, 2018

महोदय,

With reference to the above mentioned NPC communication dated 01st November 2018, an Agenda note on National Energy Account & National Deviation Pool Account for the forthcoming 8th Meeting of National Power Committee is enclosed.

सादर धन्यवाद,

भवदीय,

समीर सक्सेना
09/11/18

(एस. सी. सक्सेना)

उप महाप्रबंधक (एन एल डी सी)

Encl: As above

Copy to: Chief Engineer, National Power Committee, NRPC Building, 3rd Floor,
Katwaria Sarai, New Delhi-110016

National Energy Account & National Deviation Pool Account
Agenda Note for 8th Meeting of the National Power Committee (NPC)
30th November 2018, Guwahati

1. Establishment of National Grid

In the sixties, the country's electricity grid was demarcated into five electrical regions and Regional Electricity Boards were formed. In order to facilitate inter-state power transactions and the development of regional grids, Govt. of India funded construction of a number of inter-state lines. Subsequently multi-beneficiary Central Sector generating stations were developed by utilities like NTPC, NHPC etc. along with associated transmission system for evacuation of power. The concept of regional energy accounting (earlier known as global accounting) was developed with boundary metering of all control areas.

Till late nineties, power system was planned on regional self-sufficiency basis and there were very few inter-regional links. With more and more inter-regional inter-connections coming up, the focus now shifted to formation of a strong National Grid. Initially, HVDC was used to interconnect two regions, e.g., NR-WR, NR-ER, WR-SR, etc. Gradually, AC interconnections also came up and by August 2006, all regional grids except SR were interconnected synchronously into two synchronous systems known as NEW and SR Grids. The strong HVDC links connecting the NEW grid to Southern region are extensively used for optimizing power flows in the NEW grid. With strong AC connections between the regions constituting the NEW grid as well as extensive use of HVDC links in real time operation, inter-regional schedules lost any physical relevance. All the five regional grids in the country were progressively interconnected using AC links and these are now operating as one synchronism system since December 2013. The situation has become more complicated with direct HVDC connections between NER and NR.

2. Existing Scheduling, Metering, Accounting and Settlement Systems

Availability Based Tariff (ABT) was implemented in stages, starting with Western Region in July 2002. With implementation of ABT, the concept of Unscheduled Interchange (UI) pool came up and all RLDCs started operating regional UI pool accounts, which were subsequently known as the "Regional Deviation Accounts". Deviations from the schedules are computed using the net injection/drawal for using boundary metering for each control area. Based on deviations from schedule, utilities pay UI charges to or receive UI charges from the regional UI pool account.

Short-term open access in inter-state transmission was introduced in May 2006 and with this, scheduling of market-based trades/transactions also commenced. Further, in 2008, multiple Power Exchanges were also implemented. Corridor wise margin declaration for market-based transactions was carried out along with net import/export capability for regions for administering the short-term open access transactions. Later from 2009 onwards, long-term and medium-term transactions also commenced within one region and between different regions. Corresponding scheduling on the inter-regional links was carried out for these transactions on a corridor-wise basis e.g., WR-NR, ER-SR, etc. Presently, while corridor wise TTC/ATC are being declared, net import/export margins for the region are being used for administration of short-term transactions.

Special energy meters have been installed at both ends of inter-regional / inter-state tie lines and all inter-connections of CTU system with ISGS as well as states / other entities whose accounting is done at regional level. As specified in the IEGC, meter readings are sent to respective RLDCs by different sub-stations of CTU / ISGS / states. The meter readings are processed at RLDCs and forwarded to respective RPC secretariat for preparation of weekly deviation account. The RPC secretariats issue deviation accounts based on which different utilities pay /receive deviation charges to / from deviation pool account. These also included settlement of inter-regional deviations between neighboring regions. The regional UI pools are being operated satisfactorily and have successfully served the purpose for the last many years.

The deviation rate vector is declared upfront by the CERC from time to time. Prior to 2008, with uniform rates for deviation, the total payable and receivables were supposed to be equal making it a zero-sum game. However, due to difference in estimated loss and actual loss as well as metering errors, total UI/deviation charges payable did not match with total UI/deviation charges receivable. Based on methodology decided in RPC forum, suitable adjustment is done to make total UI charges payable equal to the UI charges receivable. Thus, the UI pool accounts had been zero balance accounts traditionally since introduction of ABT up to 2008.

Regional UI pool accounts became a non-zero sum game since 7th January 2008 with introduction of UI rate cap for Central generating stations with coal or lignite firing and stations burning only APM gas. UI rate cap was retained in the UI regulations, 2009. Further, as per the UI regulations, 2009, additional UI charge is payable by over-drawing or under-injecting utilities based on specified volume limits and frequency bands. Thus a surplus is generated in the UI/deviation pool.

An important feature of the UI accounts issued by RPCs is treatment of inter-regional transactions. The following methodology is followed by the RPCs in this regard:

- No adjustment is done in UI charges payable to / receivable from other regions (otherwise this may lead to an iterative process)
- UI charges payable to other regions has highest priority i.e. UI charges received in UI pool account is used first to clear dues to other regions.

Schedules are reconciled between RLDCs and thereafter final schedules are issued. Moreover, same meter readings are used by both connected regions for computation of UI/deviations. Hence it is expected that normally there should not be any mismatch between UI charges payable / receivable by adjacent regions connected through AC links.

At present, RPCs of each region prepare and issue UI/deviation accounts considering neighboring region as control areas (similar to states within the region). Sometimes, there are cases of mismatch between UI/deviation payable/receivable as per accounts issued by two RPCs of adjacent Regions and reconciliation of accounts by RPCs prior to issuance is required to be done.

Settlement of UI/deviation charges is done between the regions on one to one basis. For example, UI/deviation pool of ER has to pay to or receive from 4 different UI pools (NER, NR, SR, WR). This leads to multiple financial transactions in terms of money flow between regions. There are

instances of circular flows of funds between regions which needs to be avoided. An example of such circular flow of funds between the regions is illustrated in Annex – 1.

The above methodology is gradually losing its relevance with the five regions connected synchronously as power can flow from one region to another via a third region leading to circular and multiple fund transactions. These ‘tandem’ money transactions between the regions at times also leads to issues in disbursement within the regions.

3. Mandate for NLDC

Section 26 of Electricity Act, 2003 mandates the following:

“Section 26. (National Load Despatch Centre): --- (1) The Central Government may establish a centre at the national level, to be known as the National Load Despatch Centre for optimum scheduling and despatch of electricity among the Regional Load Despatch Centres.

(2) The constitution and functions of the National Load Despatch Centre shall be such as may be prescribed by the Central Government:

Provided that the National Load Despatch Centre shall not engage in the business of trading in electricity.

(3) The National Load Despatch Centre shall be operated by a Government company or any authority or corporation established or constituted by or under any Central Act, as may be notified by the Central Government.”

Subsequently vide notification dated 2nd March 2005, the Central Government has notified National Load Despatch Centre Rules 2004, which prescribes functions of NLDC. The functions include following (relevant extracts):

- *Scheduling and dispatch of electricity over inter-regional links in accordance with grid standards specified by the Authority and Grid Code specified by the Central Commission in coordination with Regional Load Despatch Centres.*
- *Coordination with Regional Load Despatch Centres for achieving maximum economy and efficiency in the operation of National Grid.*
- *Supervision and control over the inter-regional links as may be required for ensuring stability of the power system under its control*
- *Coordination with Regional Load Despatch Centres for the energy accounting of inter-regional exchange of power*
- *Coordination for trans-national exchange of power*

From the above mandate it is evident that just as the RLDCs/RPCs are responsible for scheduling, metering, accounting and settlement at the Regional level, NLDC has been made responsible at the inter-regional and trans-national levels. The corresponding roles pertaining to inter-regional and trans-national transactions accounting and settlement need to be taken up at the National level by the NLDC and NPC.

4. Trans-National/Cross-Border Interconnections

At present, India has cross-border interconnections with Nepal, Bhutan, Bangladesh and Myanmar. Briefly, the connectivity of these countries with various regional grids in India is as follows:

- Nepal: With Northern region and Eastern Region
- Bhutan: With Eastern region
- Bangladesh: With Eastern region and North-Eastern region
- Myanmar: With North-Eastern region

In future, other neighboring SAARC countries like Bangladesh and Pakistan may have connectivity with two different regions of India. For the purpose of cross-border interconnections, the country needs to be treated as a single control area for the purpose of transnational exchanges and transactions have to be reconciled on National basis. Further, in line with the mandate provided, NLDC is responsible for all trans-national exchanges.

5. Changing Scenario & Increasing Complexities

A vibrant electricity market is functioning in the country and many regulatory changes have been implemented to address new challenges from the changing scenario which is also leading to increased complexities. Some of the significant changes that have already been implemented at the National level and some future challenges are briefly discussed below.

- Collective Transactions through Power Exchanges:** Open Access Regulations, 2008 issued by CERC paved the way for functioning of power exchanges. As per the Regulations and procedures issued pursuant to the Regulations, collective (i.e. power exchange) transactions are coordinated by NLDC. Two Power Exchanges are functioning at present and another is in the offing. NLDC accepts scheduling request for collective transactions after checking for congestions, and forwards the same to RLDCs for scheduling. Curtailment, if any, has to be done by NLDC in coordination with RLDCs. Accounting and settlement of the Collective Transactions is carried out by NLDC.
- Ancillary Services (RRAS):** The Regulatory Framework for implementation of Ancillary Services has been provided by the Hon'ble CERC in August 2015 and these have been implemented from April 2016. As per the present framework for ancillary services, available generation (thermal) reserves are dispatched by NLDC across regions on a pan-India basis. In the scheduling process, a virtual entity has been created in each regional pool to act as a counterparty to the ancillary schedules (beneficiaries schedules are not disturbed in the ancillary despatch process). Settlement of ancillary transactions is carried out on a regional basis from the DSM Pool. There are times, when the regional DSM pool faces shortfall and NLDC facilitates transfer of funds from a surplus regional pool to the deficit regional pool as per the provisions of the relevant CERC regulations. Again, this involves multiple fund transfers at times.
- Fast Response Ancillary Services (FRAS):** CERC vide suo-motu order dated 16th July 2018 has directed the implementation of FRAS and pilot project for 5-minute metering. The framework for FRAS provides for fast response ancillary services using the flexibility of hydro generation. The dispatch under FRAS is with the primary objective of obtaining regulation services from hydro while at the same time honoring all the hydro constraints. Scheduling, accounting and settlement of FRAS is to be carried out by NLDC across multiple regions (NR, ER and NER).

- (d) **Secondary Frequency Control through Automatic Generation Control (AGC):** Based on the directions of CERC a pilot project for AGC has been implemented at Dadri – Stage II in January 2018. The AGC signals are being sent to the generating station from NLDC and the accounting and settlement for the AGC is being facilitated by NLDC. Based on the experience gained by this pilot project, AGC implementation is being taken up at one generating station in each of the other regions. A second pilot implementation of AGC is expected to be commissioned at Simhadri in November 2018. Implementations in other regions are also coming up progressively. Accounting and settlement of all such implementations have to be facilitated at the national level.
- (e) **Proposals under various stages of implementation/deliberations:** Some of the other proposals which are under various stages of deliberations or implementation are as follows:
- Replacement of thermal generation by RE generation (Ministry of Power, April 2018)
 - Real Time Markets (CERC, July 2018) for facilitating balancing closer to the time of delivery
 - Flexibility in scheduling of thermal generation (Ministry of Power, August 2018) to achieve economy in despatch at the national level
 - Security Constrained Economic Despatch (POSOCO, September 2018) to achieve economy in despatch at the national level

Almost all of the above-mentioned proposals are intended for scheduling, despatch, accounting and settlement at the national level. The complexity in settlement needs to be streamlined at the national level keeping in view the changing paradigm and new challenges.

6. National Energy Account and National Deviation Pool Account

In order to streamline the accounting and settlement at the national level there is a need for implementing a National Deviation Pool based on the National Energy Account. In this regard, the following methodology is proposed.

- (a) **Scheduling:** Corridor-wise (e.g., ER-NR, etc.) scheduling of inter-regional transactions is presently being carried out. However, actual power flows as per the laws of physics. In case of collective transactions, one to one correspondence of source and sink is not there and scheduling on a particular inter-regional corridor may at best be notional. Hence, there is a need to migrate to scheduling inter-regional transactions on a net basis for each region. However, while accepting the transactions for scheduling, corridor-wise TTC/ATC/available margin etc. may be duly taken care of. Inter-regional corridor-wise schedules may also be continued based on the physical power flow patterns as the same is useful for grid security monitoring and checking for any discrepancies. NLDC shall communicate the net inter-regional schedules to the NPC for the purpose of accounting.

Schedules for cross-border transactions shall also be prepared by NLDC on a net-basis to facilitate accounting of cross-border transactions by the NPC. However, individual schedules of

the concerned neighboring country with different region regions shall also be continued at RLDC level for the purpose of grid security monitoring and checking for discrepancies.

- (b) **Metering:** The existing practice for metering of the inter-regional points shall continue as per the IEGC and the SEM data shall be collected by the RLDCs, processed and made available to the RPCs. In addition, the processed meter data shall also be made available to the NPC through NLDC. A similar practice shall be adopted for the cross-border metering locations, where the processed meter data shall be provided by the respected RLDCs to the RPCs and NPC (through NLDC).
- (c) **Accounting & Settlement:** Based on the scheduling and meter data provided, NPC shall prepare the National Energy Account (NEA) including the National Deviation Account for the inter-regional and trans-national transactions. The NEA will reflect the payables/receivables for each region on a net-basis and this amount shall be payable/receivable to the National Deviation Pool Account which shall be operated by NLDC. The NEA shall also reflect the cross-border or trans-national transactions and the neighboring countries shall be paying/receiving to/from the National Deviation Pool Account operated by NLDC. Payment to the National DSM Pool shall have the highest priority.

In the future, multi-lateral transaction between neighboring countries are also envisaged under the SAARC framework e.g., Bangladesh may purchase power from Nepal or Bhutan through India. Neighboring countries may also participate in a designated Power Exchange for cross-border transactions in the future. For scheduling and settlement of such transactions, the all-India loss figures would need to be declared upfront by NLDC.

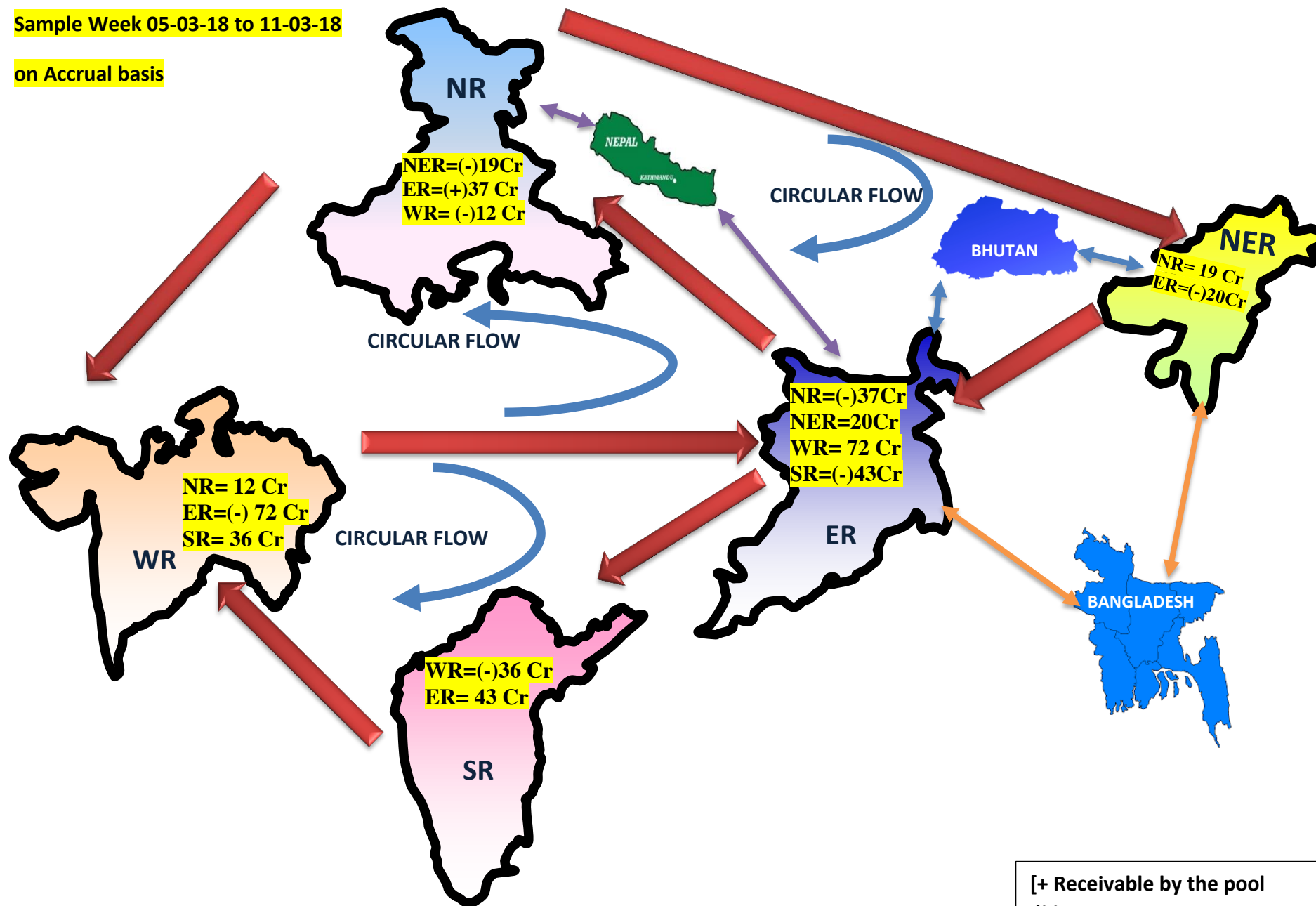
- (d) **Handling Surplus/Deficit in Regional Pool Accounts and transfer of residual to PSDF:** As has already been mentioned above, sometimes the regional DSM pool may face shortfalls on account of disbursements for reliability support such as RRAS, FRAS, AGC, etc. in accordance with the relevant regulations of CERC. Once the National DSM Pool becomes operational, all residual/surplus amount in the regional DSM pools shall be transferred to the National DSM pool account. The NPC accounts would also facilitate the transfer of funds from the surplus available in the National DSM pool to the deficit regional DSM pool accounts as a single transaction thereby simplifying the process. Once all liabilities have been met, any residual in National DSM Pool shall be transferred periodically to the PSDF in accordance with the extant CERC Regulations.

A sample illustration of the flow of funds between different regional DSM pool accounts to the national DSM pool account and that with the neighboring countries is shown at Annex – II.

Suitable changes/modifications are required to be carried out in the IEGC and DSM Regulations and the functions of NPC also need to be recognized in the regulatory framework.

Sample Week 05-03-18 to 11-03-18

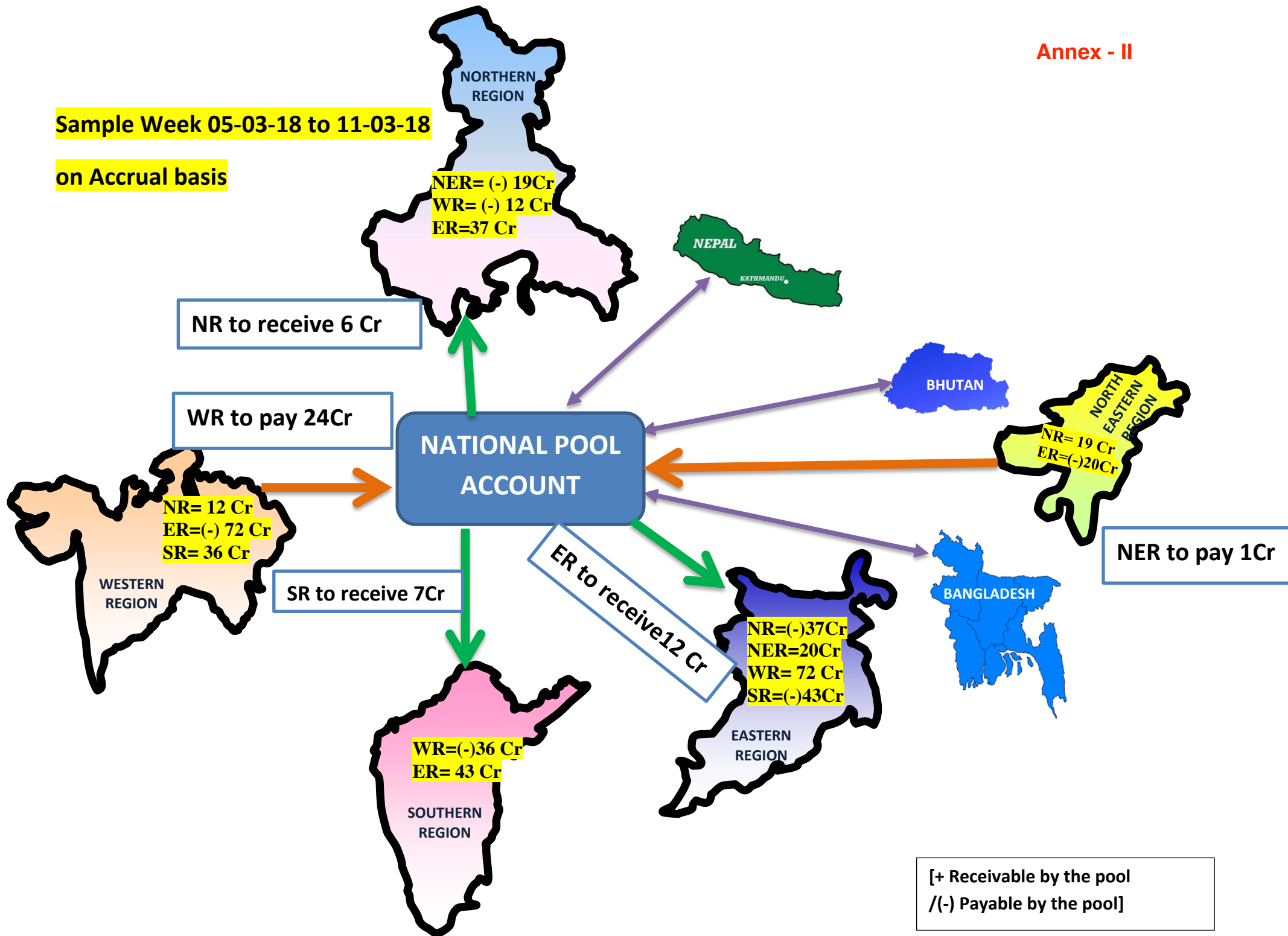
on Accrual basis



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Sample Week 05-03-18 to 11-03-18

on Accrual basis



[+ Receivable by the pool
 /(-) Payable by the pool]