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संदर्भ संख्या: पोसोको/एनएलडीसी/**2021/** **दिनाँक: 15th July, 2021**

सेवा मे,

Secretary
Central Electricity Regulatory Commission
3rd & 4th Chanderlok Building 36,
Janpath Rd, New Delhi - 110001

विषय: POSOCO Inputs on Draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2021.

संदर्भ: **1.** Public Notice No. RA-14026(11)/3/2019-CERC dated 29th May, 2021 on Draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2021

2. Public Notice No. RA-14026(11)/3/2019-CERC dated 30th June, 2021 on extension of date for seeking comments/ suggestions on draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2021

महोदय,

With reference to above, POSOCO inputs on Draft Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2021 are enclosed herewith for kind consideration.

सधन्यवाद,

देबाशिस

(देबाशिस दे)

संलग्नक: उपरोक्त अनुसार

कार्यपालक निदेशक, रा. भा. प्रे. के.

POSOCO Suggestions on

CERC (Draft) Ancillary Services Regulations, 2021

Ancillary services is one of the four essential pillars of market design; the other three being scheduling & despatch, imbalance handling and congestion management. POSOCO supports the Hon'ble Commission in its initiative towards market-based paradigm for ancillary services. The forward-looking measures of encouraging energy storage resources and demand-side resources would help to harness ancillary services from new and emerging technologies. It is a welcome step for promotion of the participation of intra-state resources which would expand the ambit of ancillary services providers.

The suggestions on the draft Ancillary Services regulations have been demarcated into following four sections containing the key/major points viz. Generic Suggestions, Specific Suggestions on SRAS, Specific Suggestions on TRAS and Proposal of Voltage Control Ancillary Services (VCAS). The clause-wise suggestions on draft Ancillary Services Regulations are placed at ***Annexure-1***.

1) Generic Suggestions

a) Data analysis of Area Control Error (ACE) towards assessment of reserves needed

The objective of SRAS and TRAS is to minimize the Area Control Error (ACE). In the draft grid code as submitted by the Expert Group constituted by Hon'ble Commission in January, 2020, one of the methodologies proposed towards assessment of reserves needed involved positive and negative ACE respectively of that control area. The regional ACE during October, 2020 - June, 2021 period is placed at ***Annexure – 2***. The key inferences are as follows:

i. Positive ACE is observed in Northern Region for about 30 % of the time with maximum upto 4500 MW. The negative ACE is observed upto 5000 MW.
ii. Positive ACE is observed in Western Region for about 40 % of the time with maximum upto 6000 MW. The negative ACE is observed upto 4000 MW.
iii. Positive ACE is observed in Southern Region for about 30 % of the time with maximum upto 3000 MW. The negative ACE is also observed upto 3000 MW.
iv. Positive ACE is observed in Eastern Region for about 60 % of the time with maximum upto 3000 MW. The negative ACE is observed upto 2000 MW.
v. Positive ACE is observed in North-Eastern Region for about 30 % of the time with maximum upto 700 MW. The negative ACE is observed upto 700 MW.

b) Data analysis of reserves availability and despatch of RRAS up/down

The data analysis of reserves and RRAS between October, 2020 - June, 2021 has been carried out and placed at ***Annexure – 3.*** The key inferences are as follows:

vi. The availability of the All India spinning reserves up is limited during the peak and high demand periods. It is below 1000 MW for about 15% of the time.
vii. There is sufficient availability of the All India spinning reserves down. There is availability of more than 4000 MW for almost 100 % of the time.

viii. The availability of the All India ramping reserves up is limited during the peak and high demand periods. It is below 500 MW for about 20% of the time and 'Nil' for about 10 % of the time.

ix. There is sufficient availability of the All India ramping reserves down. There is availability of more than 500 MW for almost 100 % of the time.

x. In the hour-wise duration curve of spinning reserves, it is observed that there is depletion of 'Up' spinning reserves especially during morning (0900-1000 hrs) and night (1800-2300 hrs).

xi. In the hour-wise duration curve of ramping reserves, it is observed that there is depletion of 'Up' ramping reserves especially during evening and aggravated during night (1800-2400 hrs).

xii. RRAS Up was despatched for around 20 % of time with maximum upto 1500 MW.

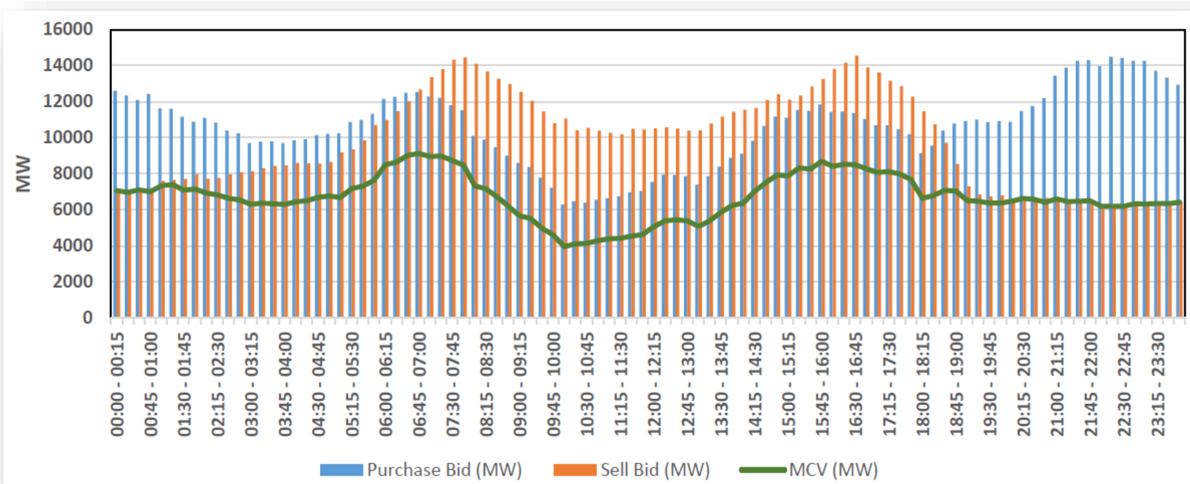
xiii. RRAS Down was despatched for around 50 % of time with maximum upto 5000 MW.

xiv. All India Cold Reserves of around 2000 MW were available for almost 100 % of the time with maximum upto 17000 MW.

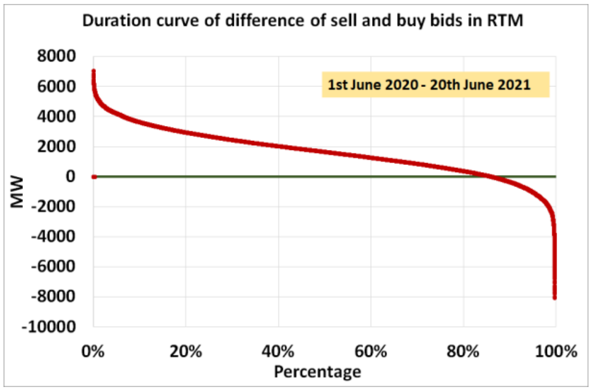
xv. All India RRAS System Marginal Price remain below ₹ 2.5/kWh for around 40 % of the time and between ₹ 2.5 - 3/kWh for around 45 % of the time.

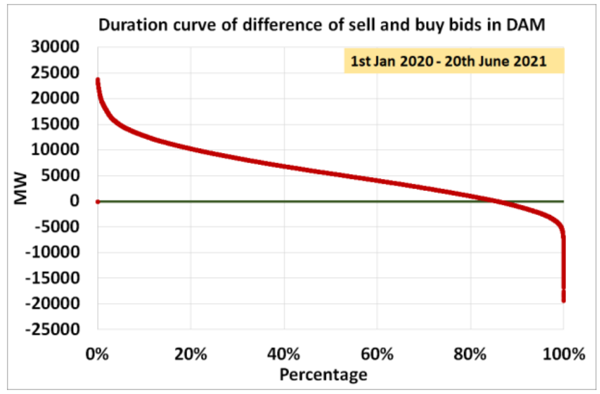
c) Availability of Generation Reserves – Need for SCUC mandate

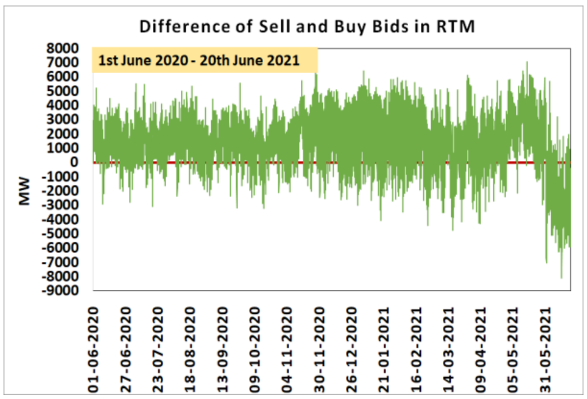
At present, especially during the late evening peak and night hours, the buy bids are consistently and significantly higher than the sell bids in the day ahead market indicating the limitation in the quantum of generation available from non-regulated sources/merchant sources. A sample plot of buy-sell on IEX power exchange for delivery date of 23rd June, 2021 is as below:

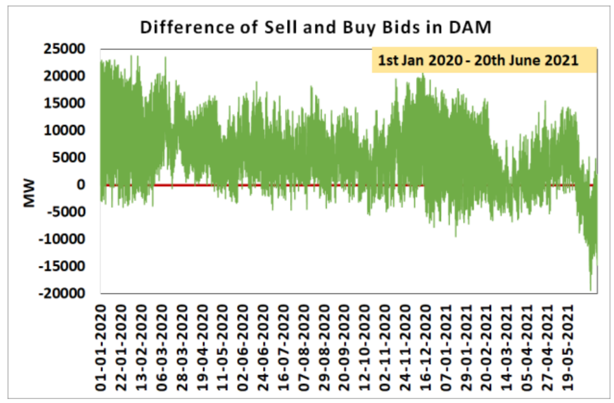


The duration curve of difference of sell and buy bids in DAM and RTM for January, 2020 – May, 2021 period is as below. It indicates that there are not enough sell offers i.e. committed generation for around 20 % of the time during peak hours both in DAM and RTM.









Hence, there is need for mandate for Security Constrained Unit Commitment (SCUC) on the day ahead basis for the creation of reserves as also recommended by the expert group on IEGC. 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.

d) Estimation and Assessment of Reserves

The draft IEGC recommended by the expert group has provisions for generation reserve estimation and frequency control (***Annexure – 4)***. Hon'ble Commission may direct the Nodal Agency, in coordination with RLDCs and SLDCs, to estimate the quantum of requirement of SRAS and TRAS for such period and based on such methodology as specified in the draft IEGC by the expert group. This would pave the way forward for the estimation and assessment of reserves in a transparent and holistic manner.

e) Mandatory participation in SRAS

Hon'ble Commission, vide order in the Petition No. 319/RC/2018 directed that in the interest of reliable and safe grid operation, all the ISGS stations whose tariff is determined or adopted by CERC shall be AGC-enabled and provide the ancillary services including secondary control through AGC. It is proposed that in the Ancillary Services regulations too, similar to the aforesaid order, all the ISGS stations whose tariff is determined or adopted must be made to mandatorily participate in SRAS.

f) Distributed Maintenance of Reserves

As per the expert group on IEGC, it is desirable that reserves should be provided locally by the control area. The responsibility to provide reserve response should be shared by all Control Areas in a distributed manner in the interest of grid security and in a participative manner so that there is no tendency to pass on the responsibility to other entities. The relevant portions on power system reserves from Report of the expert group on IEGC is placed at ***Annexure – 5.***

g) Ancillary Services Despatch from units under reserve shutdown

The extant RRAS regulations and procedure have the provisions for revival of units under reserve shutdown and despatch under RRAS. This scenario requires that adequate lead time shall be allowed by the Nodal Agency while scheduling the RRAS. A minimum dispatch duration of ninety six (96) time blocks i.e., twenty four (24) hours has to be given by the Nodal Agency to the thermal (coal based) RRAS providers from the time the unit is scheduled for providing RRAS. A minimum dispatch duration of twelve (12) time blocks i.e., three (3) hours has to be given by the Nodal Agency to the gas/RLNG/liquid based RRAS providers from the time the unit is scheduled for providing RRAS. Due consideration shall also have be given to ramp rates and congestion. In case beneficiaries of the station requisition power from those units which are brought into service under RRAS, the same shall be scheduled to the respective constituents and the RRAS schedule shall be revised to that extent.

In the present draft Ancillary Services regulations, although there are provisions for Ancillary Services despatch under emergency conditions, there is no mechanism available to revive and despatch the cold reserve units under TRAS as per the grid conditions. Further, the need for mandate for Security Constrained Unit Commitment (SCUC) on the day ahead basis is reiterated for the creation of reserves as also recommended by the expert group on IEGC.

h) Need for Communication Providers

CERC (Communication System for inter-State transmission of electricity) Regulations, 2017 laid down the rules, guidelines and standards to be followed by various persons and participants in the system for continuous availability of data for system operation and control including market operations. However, there is a need for separate functions and responsibility mandated by the Ancillary Services regulatory framework for the Communication Providers (CTUIL, PGCIL etc.) in case of SRAS. This aspect has not been dealt with in the 2017 communication regulations.

Communication Providers would need to provide end to end redundant communication system between SRAS Provider and Nodal Agency ensuring route diversity and dual communication. In case of multiple Communication Providers involving CTUIL and STU, both the Communication Providers would need to coordinate to arrange communication between SRAS Provider and Nodal Agency. Communication Providers would also need to have Network Management System for monitoring and troubleshooting communication links on a 24x7 basis. Assessment and maintenance of communication system has to be done by Communication Providers in real-time to maintain the availability of communication system. Communication Providers need to coordinate with their infrastructure providers/maintenance providers/vendors/OEMs to provide end to end communication between SRAS provider and Nodal Agency.

i) Resource Adequacy – Optimal Reserve Margin

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.

j) Forecasting

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 **(Format AS4 attached at *Annexure - 6*)** 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 by the system operators.

k) Simultaneous Notification of Revised IEGC and Ancillary Services Regulations

Hon'ble Commission had constituted an Expert Group to review IEGC submitted its report along with draft revised IEGC in January, 2020. There are various provisions in the draft ancillary services regulations which are incumbent on the notification of the revised IEGC as various entities responsibilities, time-lines and settlement systems would undergo significant changes. The important mandate of estimation and assessment of reserves along with SCUC is also to be given by the revised grid code. Therefore, it is requested that simultaneous notification of the revised IEGC and Ancillary Services Regulations may be considered by the Hon'ble Commission for harmonious and dispute-free operationalization of SRAS and TRAS.

In case of limited time for simultaneous notification, it is requested that a broad guideline may be given in the regulations for enunciation in detailed procedure by the Nodal Agency, which may be subsequently considered in revised IEGC, regarding bidding process, time-lines, settlement system etc.

l) Uniform declaration of technical parameters and market surveillance

There is need for suitable market surveillance and monitoring mechanism to ensure that the generating station which is providing SRAS, TRAS and normal energy scheduling must declare uniform technical parameters across all the segments.

As per Hon'ble Commission approved Detailed Procedure for Ancillary Services Operations, the Variable Charges (VC) shall be the variable charges for the previous month as per bill raised by the RRAS Provider for the generating stations, or in case that is not available then last available month bill. In case of SRAS, there is need for VC declaration by the respective SRAS provider. There is a need to clarify the basis for VC as in vogue for present RRAS. Further, the validity of the consent with start date and end date needs to be there. There may be monthly/weekly update which may be needed to clarified in the regulations. There would also be separate declaration formats of technical and commercial parameters for different types of resources such as Thermal, Hydro, BESS, Demand Side Response etc.

There would be interplay between DAM-TRAS and RTM-TRAS prices. Market monitoring and surveillance needs to be strengthened along with the internal process of the entities involved. The surveillance function needs clarity for the responsible entity. Further, there would be rare cases of MCP-Energy-Up-DAM being equal to the MCP-Energy-Up-RTM for TRAS.

m) Accounting and Settlement

Accounting of TRAS shall be done by the Regional Power Committee (RPC) on a weekly basis. The account/statement for TRAS may be prepared along with the weekly DSM account. The payment to TRAS provider shall be made from the surplus available in respective regional DSM Pool account where the TRAS provided is geographically located.

TRAS/SRAS account of intra-state entities also need to be prepared by respective RPCs. The deviation account for the state is to be prepared by the respective RPC. Deviation account for individual SRAS/TRAS Providers need to be prepared by the SLDC/State agency.

It may be clarified in the regulations that the compensation due to Part Load Operation or any other charges not specified in the Ancillary Services Regulations, 2021, would not be payable to the SRAS and TRAS providers for providing Ancillary Services. Further, the quantum of schedule under SRAS and TRAS (for both up and down) would not be considered for the purposes of incentive calculation for the generating station by the concerned RPC.

In the draft regulation, "Deviation and Ancillary Service Pool Account" means the Regional Deviation Pool Account Fund referred to in the DSM Regulations, or any such Account as may be specified by the Commission. The change in name entails legal, procedural and taxation related issues and hence, Hon'ble Commission may consider to retain the existing name "Regional Deviation Pool Account Fund".

The guidelines for sequencing of payment (say first DSM payment, SRAS payment, then incentive for SRAS, then TRAS payment/commitment charge) for weekly accounting and settlement of TRAS may also be clarified in the regulations.

The charges to be collected by Power Exchanges and traders on behalf of TRAS providers may be specified and regulated by Hon'ble Commission.

n) Handling deficit in pool accounts

Due to different payment due date amongst the RPCs pool account statements, there may be case wherein there may be shortfall in cash available in DSM pool account even if there is surplus available as per DSM statement. In this case, it may not be possible to transfer the surplus available in one regional DSM Pool to another regional DSM Pool account which is in deficit, for payment towards SRAS/TRAS. In order to address such issues, the surplus available in other Regulatory Pool account maintained by RLDCs/NLDC like Congestion Revenue may also be considered by the Hon'ble Commission for utilization towards the payment to SRAS/TRAS provider.

The requirement for SRAS/TRAS may vary season wise. During high demand period/season, the requirement of TRAS Up may be more compared to the lean period/season when TRAS Down requirement is more. In order to address the seasonal requirement which may lead to shortfall towards payment of SRAS/TRAS provider, the surplus available in Regional DSM pool account may be transferred to PSDF on quarterly/half yearly basis instead of monthly basis. Accordingly, PSDF regulations may have to be amended.

o) Charges for Deviation

Contract-wise/product wise deviation is impossible as there is only a single meter reading. The settlement of deviation from schedule by the AS Provider first against the Ancillary Services schedule statement is not needed in the regulations as the deviations are treated at same rate irrespective of the type of transaction / schedule.

Further, there is a strong possibility of the DSM pool deficit under the envisaged mechanism with payment of commitment charges. There is a need for review and re-design of DSM vector and pool with differentiated rates for over-drawal/under-drawal. The recommendations of the CERC Expert group, in 2018, which reviewed the principles of deviation settlement mechanism (DSM) pricing including its linkage with the frequency in light of the emerging market realities may be considered. The weblink of the report is as follows: https://cercind.gov.in/2018/Reports/ASB.pdf

p) Transmission charges and losses for SRAS Provider and TRAS Provider

It may be explicitly mentioned that there would be no inter-state transmission system (ISTS) transmission charges and losses for SRAS and TRAS. Further, when there is participation of the intra-state entities, it may be clarified that the respective SERCs/JERC may need to specify the intra-state transmission charges and losses for intra-state SRAS and TRAS providers.

q) Intra-state entity scheduling to settlement to be done by SLDC/SPC

The draft regulations have envisaged participation of the intra-state entities in the SRAS/TRAS. Therefore, the coordination of concerned SLDC with regard to scheduling, metering, accounting and settlement assumes significant importance. It may be clarified that the scheduling, metering, along with the deviation accounting and settlement for intra-State transmission system connected SRAS/TRAS providers would be done by respective SLDC/State Power Committee (SPC).

It may also be clarified that whichever entity is participating in TRAS, Nodal Agency should have net injection/drawal of that entity in real time. All the SRAS and TRAS providers may be mandated to compulsorily register with respective RLDC in addition to SLDC.

There is a need for detailed definition for all the envisaged AS providers viz. demand side resources and storage resources etc. other than generating stations. There is a need for clarity as to whether storage and DR as entity must be pure or could it be a portfolio too. It may also be clarified whether a Discom can be considered as a demand side resource. Further, it may be clarified whether an EV aggregator also qualify as a demand side resource.

If the intra state entities participate in the AS, there should be direct communication of the intra state entity with the NLDC/RLDC for performance evaluation since at the state/SLDC level the actual performance of the AS provider may not get reflected whereas the deviation needs to be calculated at the periphery of state. Hence clarification is required in this case regarding provision of AS by a particular entity and measurement as well as monitoring of performance.

It may also be provided for phased implementation of SRAS/TRAS for regional entities and intra-state entities. The detailed procedure may be revised with detailed methodology for intra-state entities, including entities having energy storage resources and demand side resources qualified to provide Ancillary Services as provided in the AS regulations, after discussion and finalization of modalities of interfacing and integration of intra-state entities in consultation with SLDCs and other intra-state entities within six months of implementation of SRAS and TRAS for regional entities.

r) Despatch of SRAS/TRAS during Emergency Conditions

If there are SRAS and TRAS Providers who could not provide ancillary services in view of technical or commercial issues during emergency, there is a need for clarity through regulatory provisions to deal with such type of situation.

s) Black Start Ancillary Services

FOR model regulations on Intra-State Hydro Generating Stations Regulations were endorsed at the 61st FOR Meeting held on 22nd Sept 2017. The minutes of the meeting is available at http://www.forumofregulators.gov.in/Data/Meetings/Minutes/61.pdf . The key highlights for black-start ancillary services include:

- Demonstration of Blackstart at least once every year
- Testing of Diesel Generator sets (BSDG) for black start on weekly basis
- Fuel stock (useable under black out conditions) to be maintained in sufficient quantity to operate at full for a minimum of 20 hours and/or at 50% of accredited capacity for 40 hours
- Reimbursement of O&M expenses incurred during Blackstart
- Lumpsum incentive of Rs. 0.5 Lakh for successful demonstration of Blackstart capability by the Station subject to certification by the SLDC

2) Specific Suggestions on SRAS

a) Data analysis of pan-India AGC Continuous Operations w.e.f 14 June, 2021

The continuous operation of AGC has begun from 14th June 2021 for limited time every day for the AGC-enabled generating plants of around 35 GW capacity. Mainly down-regulation has been imposed by AGC daily (~ -1000 MW peak) based on frequency. The data analysis for first few days of the AGC operations is attached at ***Annexure – 7.***

b) Operating Modes

It has been provided in the draft regulations that Nodal Agency may operate SRAS in any of the three control modes viz., tie-line bias, flat frequency or flat tie-line depending on grid requirements. The three operating modes may be defined in the definition section for better understanding & appreciation of all stakeholders.

c) Performance Incentive

The bands of actual performance vis-à-vis secondary control signal for an SRAS Provider could be made simpler to begin with and gradually tightened over the course of time.

All measurements of secondary control signals from the Nodal Agency to the control centre of the SRAS Provider and actual response of SRAS Provider would be carried out on post-facto basis using SCADA data.

In view of maiden introduction of SRAS, the Hon'ble Commission has proposed to take liberal approach by allowing incentive upto 20% performance of SRAS provider and irrespective of the energy delivered by the SRAS. It is felt that 20% minimum performance benchmark has been set too low. There is a need for at least 50 % performance benchmark for getting the desired response. Further, in the long run, the minimum performance benchmark of at least 70% may be set and a roadmap may be given.

d) Intra-state demand side and storage resources

There is a need for detailed definition for all the envisaged AS providers viz. demand side resources and storage resources etc. other than generating stations. The principles as to how the other AS providers would declare their available SRAS capability and how nodal agency would identify and compute SRAS obligation for them needs to be clarified. Similarly, the scheduling and energy accounting principles also need to be clarified. The performance monitoring and measurement of other AS providers under SLDC jurisdiction along with calculation of deviation account of state as a whole needs further clarification.

e) Performance measurement of SRAS Provider

While 4 seconds data is stored in the historian, maintaining and retrieving 4 seconds data and backups transparently for the purpose of performance-related calculations can be challenging in the long run. The 5 minutes average data would have the advantages over 4 seconds data in terms of lesser memory usage (KB vs MB), fast retrieval and smoothened over 5 minutes, thereby avoids inevitable SCADA noise. 5 minutes data usually results in 1%-5% better (optimistic number) performance as a result of smoothening.

The Appedix-1 may not be required as part of the regulations. These would be provided in sufficient clarity in the detailed procedure of Nodal Agency as this is an operational and software aspect. Alternatively, a more accurate example of what the AGC software does is provided below for Up regulation. The example and notes may be slightly modified in Table-I and Table-II of Appendix – 1 as below. AGC Set Point moves up and down with a small ramp rate every 4 seconds. It does not take a 15 min leap. AGC setpoint always looks at its previous state and moves to the next state with a step size of 4 seconds.

Example for Up Regulation

Plant name	Declared Capacity Pmax (MW)	Schedule (MW)	UP Reserve (MW)	Rate Factor (MW/min)	Cost Factor (paise/kWh)	Normalized Rate Participation Factor	Normalized Cost Factor	Custom Participation Factor (CPF)	Normalised Custom Participation Factor (NCPF)	SRAS-Up Requirement (MW) (assumed)	SRAS-UP Capacity with NCPF	SRAS Desired Signal	4-second ramp rate(MW/min)	SRAS Control signal for the next 4 seonds	SRAS Control signal after 8 seconds$	Time to achieve Desired SRAS@ at "m" (minutes)
	(a)	(b)	(c)=(a)-(b)	(d)	(e')	(f) = [(d)/sum(d)]	(g) = [(e)/sum(e)]	(h) = [(f)/(g)]	(i) = [(h)/sum(h)]	(k)	(l) = (i)x(k)	(m) = (l) subject to (c)	(n)=(d)*4/60	(o)=(n)	(p)= (o)+/-(n)	(q)=(m)/(d)
A	4150	4000	150	41.5	194	0.16	0.15	1.0	0.19	340	66	65.8	2.8	2.8	5.5	1.58
B	400	250	150	100	231	0.38	0.18	2.1	0.39		133	149*	6.7	6.7	13.3	1.49
C	1050	950	100	10.5	264	0.04	0.21	0.2	0.04		12	12.2	0.7	0.7	1.4	1.62
D	1000	900	100	100	265	0.38	0.21	1.8	0.34		116	100#	6.7	6.7	13.3	1.00
E	1320	1200	120	13.2	314	0.05	0.25	0.2	0.04		13	12.9	0.9	0.9	1.8	0.98

Note:

(i) "#" SRAS desired signal of 16 MW clipped from SRAS Provider D, considering the SRAS-Up reserves available with SRAS Provider D.

(ii) "*"SRAS desired signal of 16 MW clipped from SRAS Provider D is allocated to the SRAS Provider with the highest normalised Custom Participation Factor first and so on - in this case, it is allocated to SRAS Provider B.

(iii) "$" AGC shall follow desired signal with ramp rate (n) if ACE (k) is in the same direction (+); (-) means oppsite direction like -340

(iv)"$"ACE (column k) can change direction frequently and so does (m); However, (p) changes only based on previous (o)+/-(4 second ramp rate)

(v)@ Assuming that ACE is the same direction for those many minutes

f) Cyber Security

Suitable regulatory provisions may be mandated for cyber security so that the SRAS Providers would take the necessary cyber security measures for the purpose of grid security and plant safety. SRAS Providers would need to ensure that no extra devices are connected to the AGC equipment and regular monitoring may be ensured. SRAS Providers would also need to submit the required undertaking before the start of Closed Loop Tests with the Nodal Agency.

3) Specific Suggestions on TRAS

a) Demarcation between energy market (DAM/RTM) and TRAS Market (DAM/RTM)

As the same power would be available for bidding by a generator in both energy market and TRAS market, simultaneous clearance of both markets is a challenge. It is proposed that the bidding and clearing for TRAS (DAM) may be done post energy (DAM) clearing on day-ahead basis. The bidding process of TRAS (RTM) and Energy (RTM) may be done simultaneously as per the existing timelines.

b) Specification of Reserve Requirement instead of Buy-bid by Nodal Agency

There would be specification of reserve requirement, per se, by the Nodal Agency and hence, no buying bid/rate would be quoted. It would be simple stacking and matching of the merged/masked bids from the multiple power exchanges which nodal agency would match against the TRAS requirement. National Load Despatch Centre has been debarred from engaging in the business of trading in electricity by Electricity Act, 2003. Bidding would be construed as trading activity. Therefore, buy bid by Nodal Agency in respect of TRAS may be deleted from the regulations.

c) Provisions for Non-delivery of TRAS

There may be provisions to measure and monitor non-delivery of TRAS as there is scope for gaming for TRAS providers. There may be regulatory provisions, as in present case of RRAS, wherein TRAS Providers performance would be monitored and debarred if persistently defaulting. Similar provisions have been provided for SRAS providers too.

d) Technical and Ramping constraints of TRAS Providers

The technical and ramping constraints of TRAS providers would need to be suitably considered at the time of bidding. Hence, suitable regulatory provisions would be needed keeping the grid security intact.

e) Congestion Management

While the provision of SRAS has been mandated at regional level, the TRAS providers are on national basis. Existing RRAS framework has the congestion management feature with out-of-merit despatch during congestion scenario. There is a need for distributed diversified set of TRAS providers across regions mandated by regulatory framework. It would help to relieve congestion in the times of stressed conditions in a particular region/transmission corridor. It would also mean separate prices for TRAS Providers in various regions in case of requirement of out-of-merit despatch of the TRAS generators. TRAS despatch has to be subjected to available margins and grid security constraints. Enabling regulatory provisions may be provided to enable the congestion management feature in TRAS framework.

f) Eligibility for TRAS Provider

It has been specified in the draft regulations that TRAS Provider must be capable of providing TRAS within 15 minutes and sustaining the service for at least next 60 minutes. However, the bids for TRAS-Up and TRAS-Down would be submitted for a minimum of 30 minutes. There is need for specifying the verification methodology for the minimum 60 minutes capability of the TRAS provider.

g) Bidding

It may be clarified whether TRAS down bids can be used as an instrument for purchase of power from grid by generators. There would be opportunity of arbitrage for the generators who participate in multiple markets in multiple time-frames. It may be clarified that the non-overlapping would be in a single product or the sequential markets.

4) Proposal of Voltage Control Ancillary Services (VCAS)

In addition to frequency control ancillary services, expanding the ambit to other forms of ancillary services for voltage control and black-start is also important. The charging for reactive energy exchange was introduced first time as the part of maiden Indian Electricity Grid Code (IEGC) issued in December, 1999. The charges were fixed at 4 paise/kVArh, which is to be escalated by 5% per year thereafter. The assumption was Rs 5 lakhs/Mvar capital cost for capacitors and duration of 6 hours operation in a day. Payment and recovery for VAr exchanges by beneficiary during voltages going beyond 3% in either direction i.e. more than 103% or less than 97% was stipulated. The amount was to be kept in a separate regional reactive energy account. Further, ISGS were mandated to generate/absorb reactive power as per instructions of RLDC, within capability limits and without any extra charges to be paid for it. The above-referred IEGC was revised in March 2006, issued as a CERC regulation and came into effect from 01.04.2006. Provisions regarding reactive power were substantially the same. The new (updated) rate was specified as 5 paise/kVArh with effect from 01.04.2006, with an annual escalation of 0.25 paise/kVArh.

The Grid code of 2006 was replaced by the extant version in the year 2010. The provisions regarding reactive power and voltage control in the new IEGC were the same as those in the IEGC of 2006, except that the rate for reactive energy was increased to 10 paise/kVArh with an annual escalation of 0.5 paisa/kVArh, and the word 'beneficiaries' was replaced by 'regional entities except generating stations' throughout the section.

POSOCO has recently submitted a report on Reactive Power Management and Voltage Control Ancillary Services (VCAS) in India (attached at ***Annexure – 8***) to the Hon'ble Commission in March 2021 which has suggested a detailed road map and commercial framework for rolling out VCAS. The recommendations, inter-alia, include:

i. Commercial framework for reactive support from generators
ii. Communication and metering requirements
iii. Renewable generation reactive support during "no generation" period
iv. Synchronous condenser operation of hydro generators
v. Utilizing pumped storage hydro stations for reactive support
vi. Conversion of retired thermal power plants to synchronous condenser
vii. Treatment of inter-state tie lines reactive power exchange
viii. Mechanism for transformer tap changing
ix. Reactive power market
x. Distribution side reactive power needs
xi. Mobile reactive resources

The existing provisions in the Grid Code were introduced looking at the low voltage conditions prevailing at that point of time and installation of shunt capacitors was a thrust area. The exemption of generators for reactive charge payments was on account of the fact that the thermal and hydro power plants connected to the Inter State Transmission System (ISTS) were located far off from the load centres and the reactive power generation at these plants would have had little impact on the load centre voltages.

The situation has changed over the last decade with the commissioning of an extensive 765 kV and 400 kV system. The power demand has however not kept pace with the projections in Electric Power Survey (EPS) issued by CEA and the system has started experiencing high voltage for a significant period of time as brought out in the above POSOCO's report too. Many bus reactors are being planned and installed at the 400 kV and 765 kV level. The transmission system related to the wind and solar generation is also under loaded for a significant portion of the day adding to the high voltage problem. The Reactive Energy (RE) pool account system has also been relatively less effective as the pool becomes a deficit one with high voltage in many pockets.

Inverter Based Resources (IBRs) have also become more prominent with more wind and solar being added to the system. In case of solar parks, the high voltage (above 103%) would generally be during the non-solar hours and low voltage would generally be during high solar hours. The provision of 'night mode' operation whereby the inverters can act as STATCOM have been demonstrated world-wide and also demonstrated in field trials carried out by SRLDC at Pavagada solar park. The provision of voltage control ancillary services by renewables through var control may enable enhanced grid support.

POSOCO Report on Pilot project – Five Minute Metering and Accounting in India was submitted to Hon'ble Commission in January, 2021 (https://posoco.in/wp-content/uploads/2021/02/Report-on-Pilot-project-%E2%80%93-Five-Minute-Metering-and-Accounting-in-India.pdf). New IEMs are capable of recording the 05-minute reactive energy and the voltage. CEA (Installation and Operation of Meters) Amendment Regulations, 2019 applicable from 23 December, 2019 also mandated to have this feature for all the meter going to be procured from the date of implementation of the said regulation. The major hurdle for implementation of Voltage Control Ancillary Services is the measurement of the reactive power actually absorb/supplied to the grid as per the requirement. With the new IEM installation pan India, the implementation of Voltage Control Ancillary Services would be implementable in a short time frame.

While more refined Voltage Control Ancillary Services (VCAS) may be designed as suggested in the POSOCO report above, these would take some time and require installation of interface meters with revised set of specifications besides amendments in Regulations, it is suggested that the following steps could be take right away with minimal amendments to the Grid Code and some other regulations. These are outlined below.

1) Section 6.6 (1) of the IEGC may be amended as under:

"6.6 Reactive Power and Voltage Control

1. Reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The Regional Entities ~~except Generating Stations~~ are therefore expected to provide local VAr compensation/generation such that they do not draw VArs from the EHV grid, particularly under low-voltage condition. To discourage VAr drawals by Regional Entities ~~except Generating Stations~~, VAr exchanges with ISTS shall be priced as follows: -

- *The Regional Entity ~~except Generating Stations~~ pays for VAr drawal when voltage at the metering point is below 97%*
- *The Regional Entity ~~except Generating Stations~~ gets paid for VAr return when voltage is below 97% -*

- *The Regional Entity ~~except Generating Stations~~ gets paid for VAr drawal when voltage is above103%*
- *The Regional Entity ~~except Generating Stations~~ pays for VAr return when voltage is above 103%*

~~Provided that there shall be no charge/payment for VAr drawal/return by a Regional Entity except Generating Stations on its own line emanating directly from an ISGS~~"

2) As explained above, high voltages are being experienced for significant period and bus reactors are being planned and installed at a number of locations. As per the POSOCO report mentioned above, the capital cost of a bus reactor at 765 kV level based on various CERC tariff orders comes to approximately Rs 8 lakhs/MVAr. The annual tariff for such a bus reactor would be of the order of Rs 1.6 lakhs/MVAr. If the reactor is kept switched on for twelve (12) hours a day for nine months in a year, the MVArh generated would be 3240 MVArh and if the fixed costs are spread over this reactive energy, it works out to approximately 5 paise/kVARh. It is therefore suggested that section 6.6 (2) may be modified as under:

"2. The charge for VArh shall be at the rate of ~~10~~ 5 paise/kVArh w.e.f. ~~1.4.2010~~ 1st January 2022 and this will be applicable between the Regional Entity, ~~except Generating Stations,~~ and the regional pool account for VAr interchanges. This rate shall be ~~escalated at 0.5paise/kVArh per year thereafter, unless otherwise~~ ~~revised~~ reviewed periodically by the Commission. Any shortfall or surplus in the Reactive Energy Pool Account would be adjusted on quarterly basis through the Monthly Transmission Charges (MTC) as per the CERC (Sharing of Inter State Transmission Charges and Losses) Regulations 2020"

Further, all references to 'Reactive Energy Charges' in the CERC (Power System Development Fund) Regulations, 2019 may be removed.

3) The words 'except generating stations' may be removed from sections 6.6.3, 6.6.4 and 6.6.7.

4) The sentence "No payments shall be made to the generating companies for such VAr generation/absorption" may be removed from section 6.6.6.

5) A new section 6.6.2(A) may be added as under:

"6.6.2(A) The above scheme would be mandatorily applicable to all the regional entities (including hydro generators operating in synchronous condenser mode) and the interface meters installed at the point of interconnection would be used for accounting the reactive energy. All the Inverter Based Resources (IBRs) covering wind, solar and energy storage would need to ensure that they have the necessary capability all the time including night hours for solar. The active power consumed by these devices when operating under synchronous condenser/night-mode, would be treated as transmission losses in the ISTS. For IBRs of capacity 50 MW and below not coming directly to the point of interconnection but through the pooling at the Power Park Developer end, the Power Park Developer would act as aggregator for the Reactive Energy Charges for payments to and fro from the Pool Account at RLDC level. The de-pooling of Reactive Energy charges amongst the individual wind and solar would be done by the Power Park Developer."

It is suggested that the above changes may be considered for notification at the earliest by the Hon'ble Commission so that the system is secure and transmission investments are made optimally.

<u>Annexure – 1</u>

<u>Clause-wise POSOCO Comments/Suggestions on CERC Draft Ancillary Services Regulations, 2021</u>

S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
1.	3. Definitions and Interpretation	*i. "Compensation charge" means the price declared by an SRAS Provider other than a generating station for participation in SRAS;*	*"Compensation charge" means the price declared by an SRAS Provider other than a generating station* ***with two part tariff*** *for participation in SRAS*	There may be a methodology to determine the compensation charge (say any state is participating as load serving entity) with provisions for capping for compensation charge. Few state hydro generating stations or RE stations (maybe captive) who may wish to participate in SRAS doesn't have two part tariff.
2.	3. Definitions and Interpretation	*r. "Nodal Agency" means the National Load Despatch Centre which shall be responsible for implementation of the Ancillary Services at the inter-State level through the Regional Load Despatch Centres;*	*r. "Nodal Agency" means the National Load Despatch Centre which shall be responsible for implementation of the Ancillary Services at the inter-State level through the Regional Load Despatch Centres* ***and in coordination with State Lod Despatch Centres****;*	When intra-state entities are being envisaged for participation in the SRAS/TRAS, the consent/coordination of concerned SLDC with regard to scheduling, metering, accounting and settlement may also be required.
3.	3. Definitions and Interpretation	*ae. "Un-Requisitioned Surplus" or "URS" means the capacity in a*	*ae. "Un-Requisitioned Surplus" or "URS" means the capacity in a generating station that has not been requisitioned*	The declaration of capacity (DC) is for Section 62/63 plants. The merchant / Captive Power Plants

S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
		generating station that has not been requisitioned and is available for despatch, and is computed as the difference between the declared capacity of the generating station and its total schedule.	*and is available for despatch, and is computed as the difference between the* ***normative*** *declared capacity* **or maximum possible generation (Pmax) as the case may be** *of the generating station and its total schedule.*	don't declare DC. There is need for On-bar/off-bar DC for reserves assessment. There is a need for declaration of either normative On bar declared capability or maximum possible generation (Pmax) as the case may be. As per definition URS is the difference between the declared capacity of the generating station and its total schedule. In case of temporary reallocation of URS, margin calculated based on the difference between requisition + DA power sell & DC. Therefore, in this regulation it can be renamed as USS (Unscheduled surplus) to avoid confusion between two products.
4.	7. Eligibility for an SRAS Provider	*(b) is AGC-enabled, in case of a generating station;*	*(b) is AGC-enabled, in case of a generating station and* ***energy storage system****;*	The energy storage systems also need to be AGC-enabled in order to receive and respond to AGC signals.
5.	8. Activation and	*(1) SRAS shall be activated and deployed by the Nodal Agency on*	*(1) SRAS shall be activated and deployed by the Nodal Agency on account of the following events to*	It is understood that SRAS shall be activated and deployed by Nodal Agency when ACE for a region

S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
	Deployment of SRAS	*account of the following events to maintain or restore grid frequency within the allowable band as specified in the Grid Code and replenish primary reserves:* *(a) Area Control Error (ACE) of the region deviating from zero (0) and going beyond the minimum threshold limit of ±10 MW;* *(b) Such other events as specified in the Grid Code.*	*maintain or restore grid frequency within the allowable band as specified in the Grid Code and replenish primary reserves:* *(a) Area Control Error (ACE) of the region* ***~~deviating from zero (0) and~~*** *going beyond the minimum threshold limit of ±10 MW;* *(b) Such other events as specified in the Grid Code.*	becomes above +/-10MW, thus mentioning of "deviating from zero" may be superfluous.
6.	8. Activation and Deployment of SRAS	*(3) Frequency Bias Coefficient (Bf) shall normally be based on median Frequency Response Characteristic during previous financial year of each region and refined from time to time.*	*(3) Frequency Bias Coefficient (Bf)* ***shall be assessed and declared by Nodal Agency as per detailed procedure****. It would normally be based on median Frequency Response Characteristic during previous financial year of each region and refined from time to time.*	It may be clarified that frequency bias coefficient would be assessed and declared by Nodal Agency as per detailed procedure.
7.	8. Activation and Deployment of SRAS	*(4) Offset shall be used to account for metering errors and shall be decided by the Nodal*	*(4) Offset shall be used to account for ~~metering~~* ***measurement*** *errors and shall be decided by the Nodal Agency for the respective region.*	The term 'measurement' would broaden the scope of different types of errors at different points.

S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
		Agency for the respective region.		
8.	10. Selection of SRAS Providers and Despatch of SRAS	*(8) Secondary control signal for SRAS-Up and SRAS-Down shall be sent to the control centre of the SRAS Provider every 4 seconds by the Nodal agency.*	*(8) Secondary control signal for SRAS-Up and SRAS-Down shall be sent to the control centre of the SRAS Provider every* ***2 – 10*** *seconds by the Nodal agency.*	The time period of 4 seconds can be further fine-tuned with experience of full-fledged AGC pan-India in due course of time. Therefore, a range of 2-10 seconds would be helpful.
9.	10. Selection of SRAS Providers and Despatch of SRAS	*New proposed clause*	***(13) SRAS Provider can take the generating unit into AGC 'Local' operation from AGC 'Remote' operation and vice versa based on the guidelines furnished in the Detailed Procedure. Suitable codes shall be exchanged between the Nodal agency and the SRAS Provider. AGC for the power plant can be disabled by the Nodal agency based on requirements like communication failure, scheduled maintenance, request of the power plant, etc.***	Suitable provisions may be specified for taking the SRAS providers into AGC 'Local' operation from AGC 'Remote' operation and vice versa based on the guidelines in the Detailed Procedure.
10.	11. Payment for SRAS	*(3) SRAS Provider shall be eligible for incentive based on performance*	*SRAS Provider shall be eligible for incentive* ***and shall be paid from the Deviation and Ancillary Service Pool***	The source of payment of incentive may be clarified.

S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
		as per Regulation 12 of these regulations.	***Account based on performance*** *as per Regulation 12 of these regulations.*	
11.	12. Performance of SRAS Provider and incentive	*(2) Performance of the SRAS Provider shall be measured by the Nodal Agency by comparing the actual response measured against the secondary control signals for SRAS-Up and SRAS-Down sent every 4 seconds to the control centre of the SRAS Provider. The methodology for measurement of performance of SRAS Provider shall be as specified in Appendix-II of these regulations.*	*12(2). Performance of the SRAS Provider shall be measured by the Nodal Agency by comparing the actual response measured against the secondary control signals for SRAS-Up and SRAS-Down sent every* ***2-10*** *seconds to the control center of the SRAS Provider* ***using 5-minute average data.*** *The methodology for measurement of performance of SRAS Provider shall be as specified in Appendix-II of these regulations.*	While 4s data is stored in the historian, maintaining and retrieving 4s data and backups for the purpose of performance-related calculations can be challenging in the long run over a period of years. Whereas, 5 minutes average data will have the advantages of a.Small memory usage (KB vs MB), b.Fast retrieval, c.Is smoothened over 5 minutes, thereby avoids inevitable SCADA noise. Roughly 40 GB excel content per year would be generated for handling 4s data (of 80 power plants) as against 4 GB for handling 5 min average data. At least 151200 data points per power plant per week ((60/4)*60*24*7) have to be handled. This will cross 6,00,000 per plant including other necessary check signals like CB ON/OFF, Local/Remote, etc. 5 minutes data usually results in 1%-5% better (optimistic) performance as a result of smoothening.

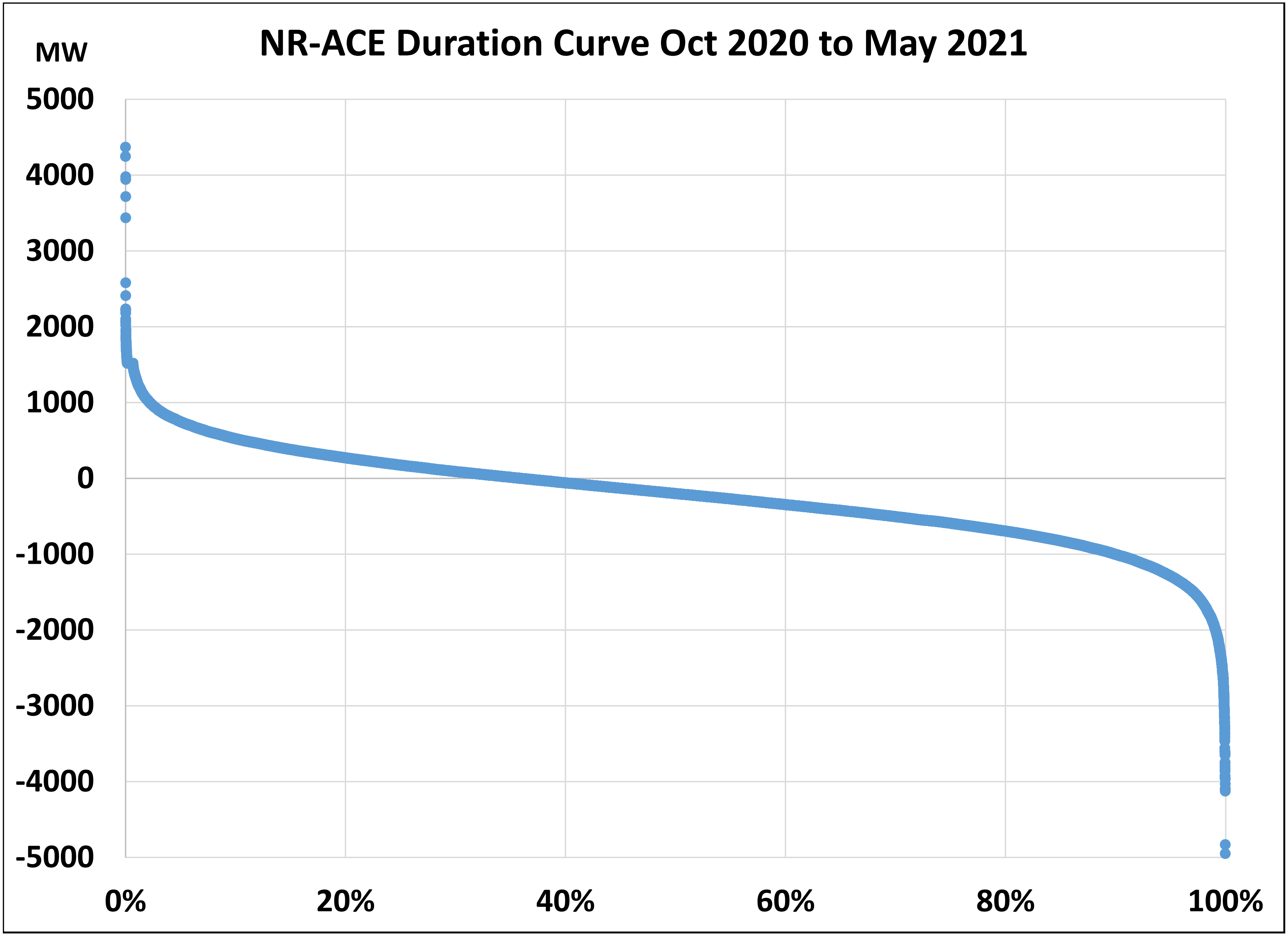
S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
12.	15. Activation and Deployment of TRAS	*(b) Such other events as specified in the Grid Code.*	*(b) Such other events as specified* ***~~in the Grid Code~~ as under:*** • ***Extreme weather forecasts and/or special day;*** • ***Generating unit or transmission line outages;*** • ***Intra-day load forecast or Trend of load met;*** • ***Trends of frequency and area control error;*** • ***The trend of the utilization of reserves through secondary frequency control.*** • ***Any abnormal event such as an outage of hydro generating units due to silt, Coal supply blockade etc.;*** • ***Excessive loop flows leading to congestion;*** • ***such other events.***	There is a need for clarity on the triggering events for operationalization of TRAS.
13.	16. Procurement of TRAS	*Buy Bid: The Nodal Agency shall communicate to the power exchange(s), the quantum of requirement of TRAS-Up and TRAS-Down on day-ahead basis before commencement of the*	***~~Buy Bid~~ Reserve Requirement:*** *The Nodal Agency shall* ***~~communicate to the power exchange(s),~~ declare*** *the quantum of requirement of TRAS-Up and TRAS-Down on day-ahead basis before commencement of the Day Ahead Market and incremental requirement, if any, over and above the procurement in the Day Ahead Market,*	There would be no buy bid, per se, by the Nodal Agency and hence, no buying rate would be quoted. It would be simple stacking and matching of the merged/masked bids from the power exchange which nodal agency would match against the TRAS requirement for every time-block. National Load Despatch

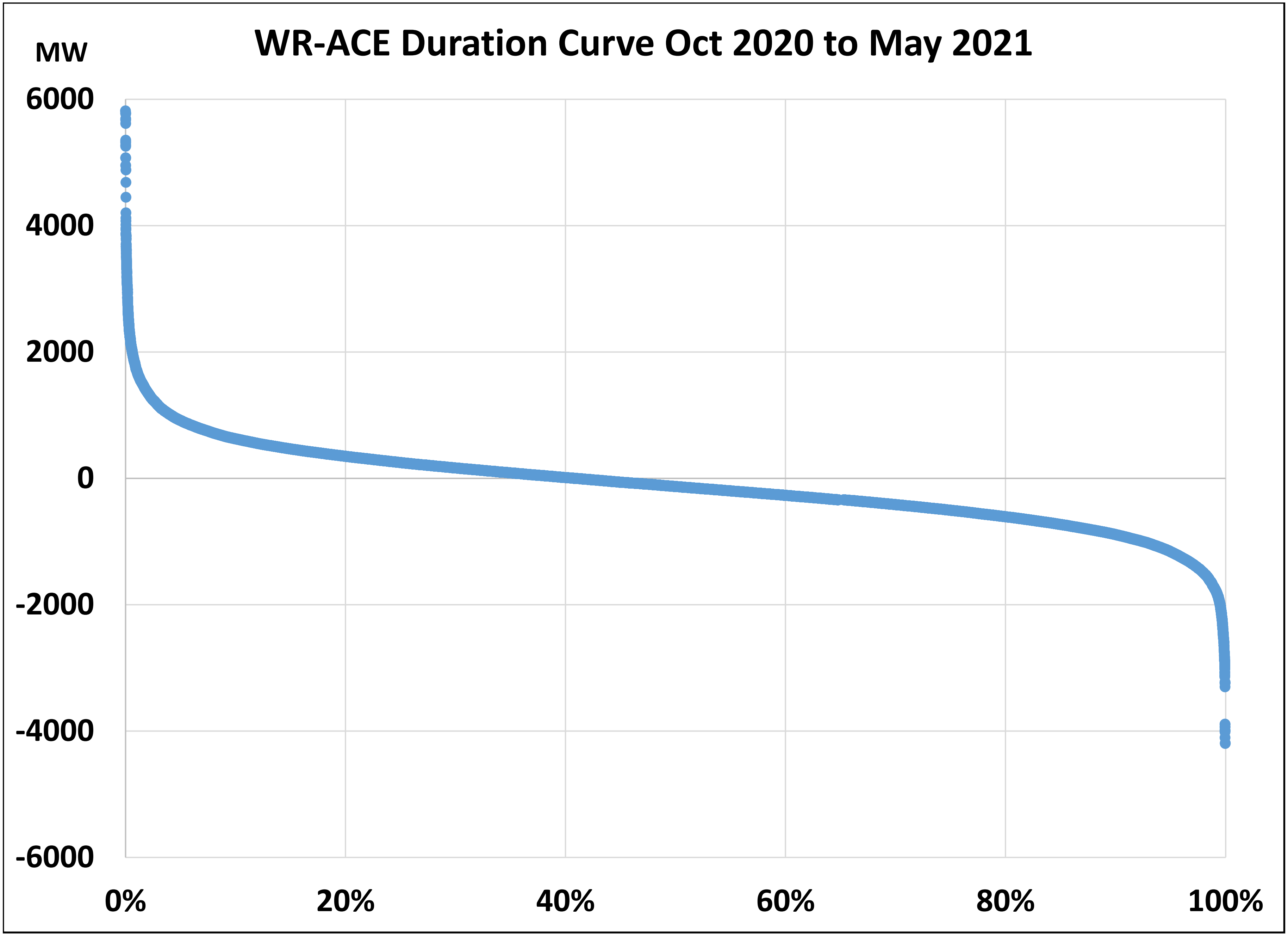
S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
		Day Ahead Market and incremental requirement, if any, over and above the procurement in the Day Ahead Market, on real-time basis, before the commencement of the Real Time Market:	***reviewed*** *on real-time basis, before the commencement of the Real Time Market:*	Centre has been debarred from engaging in the business of trading in electricity by Electricity Act, 2003. Bidding would be construed as trading activity. Therefore, buy bid by Nodal Agency in respect of TRAS may be deleted from the regulations.
14	19. Payment for TRAS	*(2) TRAS-Up Provider shall receive commitment charges at the rate of ten percent of the MCP-Energy-Up-DAM or the MCP-Energy-Up-RTM, as the case may be, subject to the ceiling of 20 paise/kWh for the quantum of TRAS-Up cleared in the Day Ahead Market or the Real Time Market as the case may be, but not instructed to be despatched by the Nodal Agency.*	***19 A.1. In case of forced outage of a unit of a TRAS provider which has been cleared Day Ahead Market, the TRAS shall promptly inform the same to the Nodal Agency. If required, Nodal agency shall procure the corresponding TRAS quantum of power in Real Time Market. The TRAS provider shall receive all payments based on the reduced quantum of power. In case of forced outage of the complete plant, the generating station shall be excluded from TRAS on receipt of the outage information from the generating station and no payment shall be made to such generating stations. Provided that no such provision shall be available for the TRAS***	Sometimes a TRAS provider may have committed to provide TRAS-UP or TRAS-Down service, but, during real-time operation due to unit tripping/partial outage/transmission constraint/other reasons, actual power reserve may not be available with the TRAS Provider for dispatch by the Nodal Agency. In such cases, it needs to be clarified whether the TRAS Provider would get any commitment charge or not.

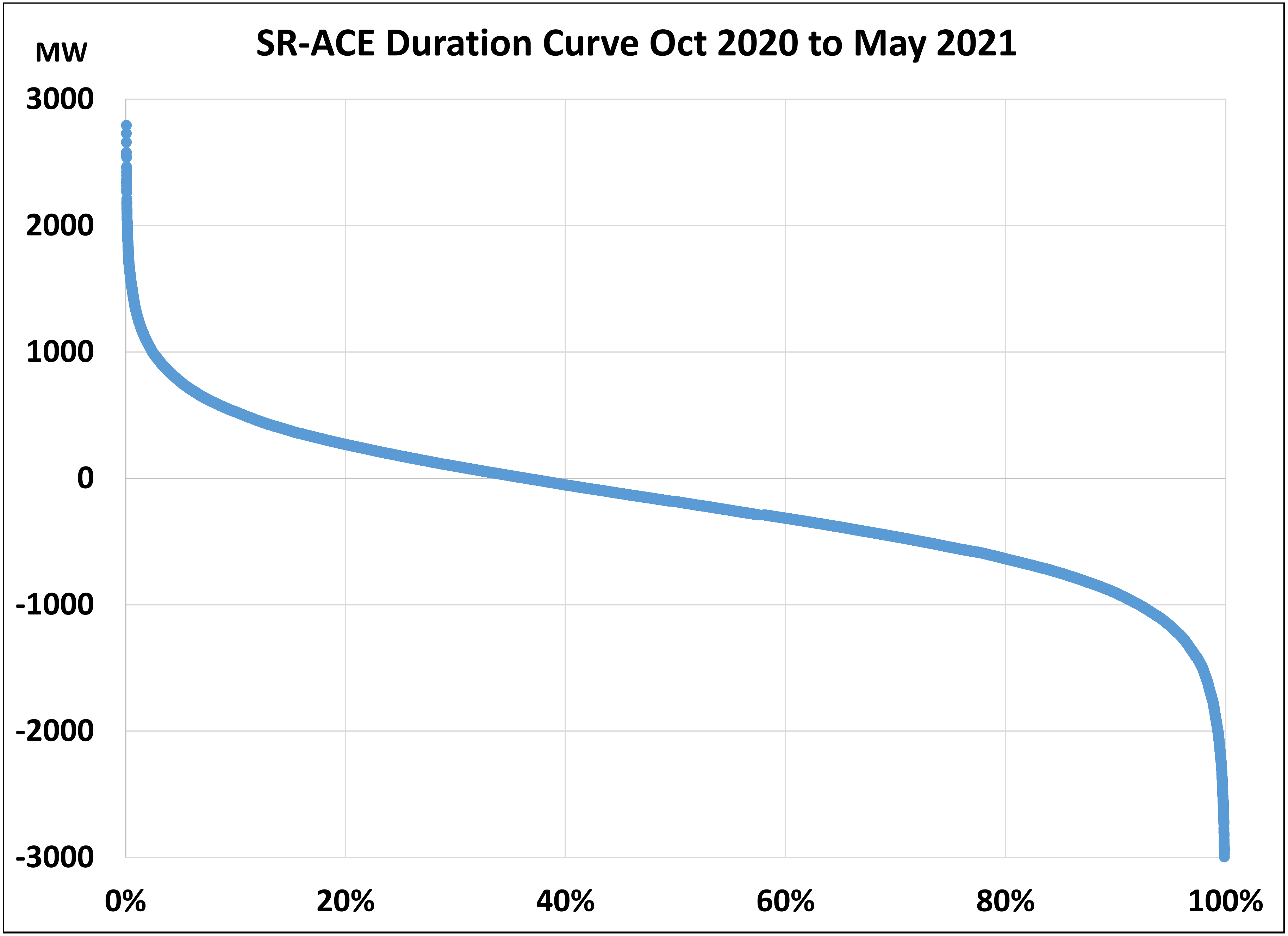
S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
			providers which have been cleared in Real Time Market. ***19 A.2 In the case of a TRAS provider is affected by bottleneck in evacuation of power or Grid Disturbance, in line with Regulation 6.5.16 and 6.5.17 of IEGC 2010, such TRAS providers shall be excluded from TRAS, and they shall only receive payment on account of commitment charges as per clause 19.2 of these regulations.***	
15.	21. Accounting and Settlement of SRAS and TRAS	*(2) Accounting of TRAS shall be done by the Regional Power Committee on a weekly basis, based on interface meter data and schedules.*	*(2) Accounting of TRAS shall be done by the Regional Power Committee on a weekly basis, based on* ~~***interface meter data and***~~ *schedules.*	The accounting of TRAS is not dependent on interface meter data. The respective SLDCs would need to provide interface energy meter data of Intra-State TS connected entities.
16.	21. Accounting and Settlement of SRAS and TRAS	*Provided that deviation from schedule by the AS Provider shall be settled first against the Ancillary Services schedule*	~~***Provided that deviation from schedule by the AS Provider shall be settled first against the Ancillary Services schedule***~~	This statement is not needed in the regulations as the deviations are treated at same rate irrespective of the type of transaction / schedule.

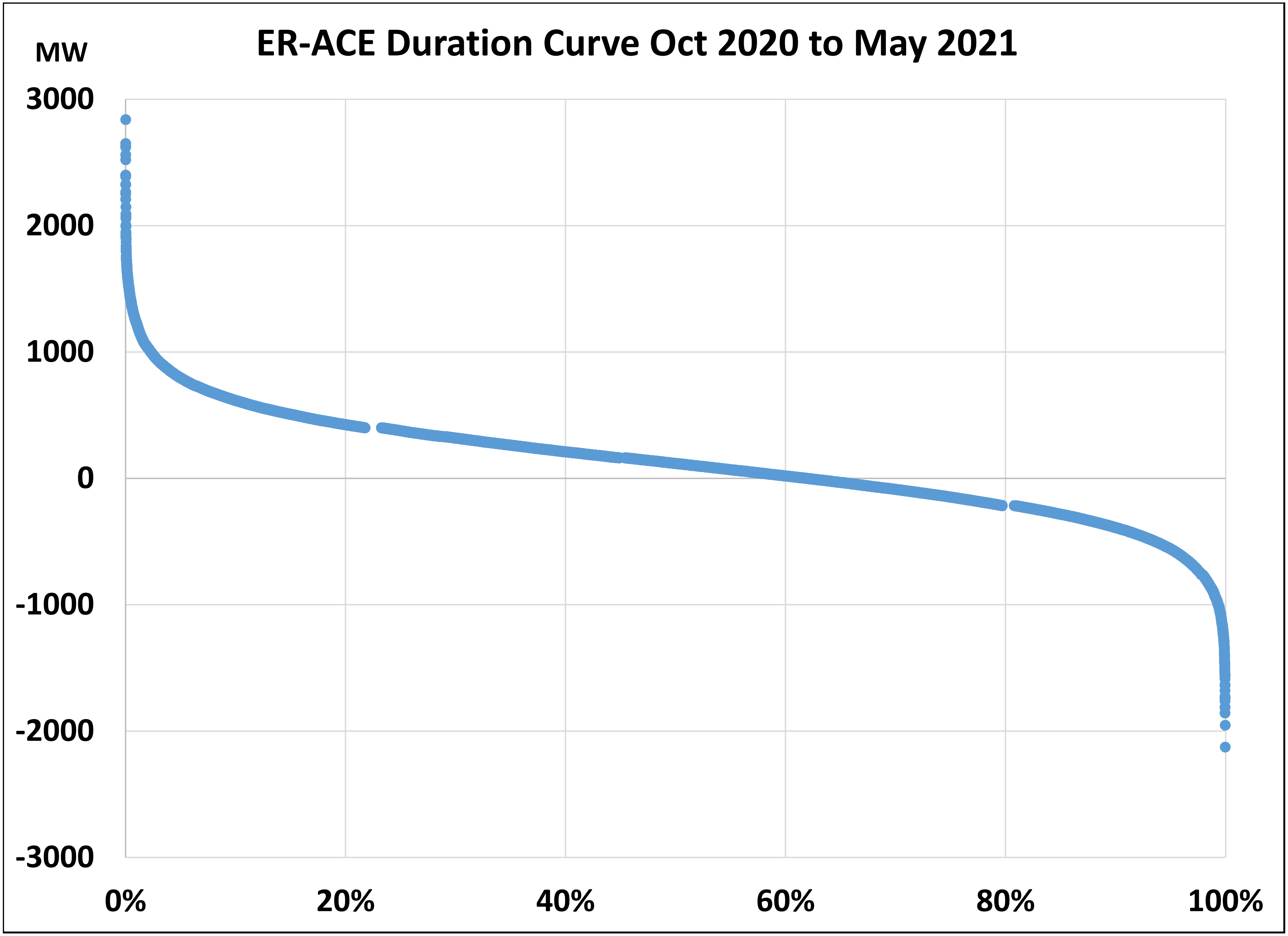
S.No.	Section	Clause in Draft Regulations	Proposed Change / Revised Clause in the Regulations	Rationale/Remark
17.	*23. Detailed Procedure*	*(2)(i). "methodology of payment to SRAS and TRAS providers in case of deficit in the concerned Deviation and Ancillary Service Pool Account as referred to in clause (5) of Regulation 21 of these regulations";*	*(2)(i). "methodology of payment to SRAS and TRAS providers in case of deficit in the concerned Deviation and Ancillary Service Pool Account as referred to in* ***~~clause (5)~~ Clause (8)*** *of Regulation 21 of these regulations";*	Correction of clause.
18.	*Appendix-I . Table-2*	*# SRAS signal of 84 MW and 96 MW clipped from SRAS Providers B and D, resp. considering ramp limited SRAS UP reserves available with SRAS Providers B & D".*	**The Appedix-1 may altogether be deleted from regulations.** *# SRAS signal of 84 MW and 96 MW clipped from SRAS Providers B and D, respectively considering ramp limited* ***~~SRAS UP~~ SRAS-Down*** *reserves available with SRAS Providers B and D".*	The calculations would be provided in sufficient clarity in the detailed procedure of Nodal Agency as this is an operational and software aspect.
19.	*Appendix-II Methodology for Measurement of Performance of SRAS Provider*	*(1) A scatter X-Y plot shall be plotted for each SRAS Provider for comparing the actual response provided by the SRAS Provider against the secondary control signal sent every 4 seconds by the Nodal Agency on post-facto basis using SCADA data for each day.*	*(1) A scatter X-Y plot shall be plotted for each SRAS Provider for comparing the actual response provided by the SRAS Provider against the secondary control signal sent every 4 seconds by the Nodal Agency on post-facto basis using* ***5-minute average*** *SCADA data for each day.*	The rationale has been mentioned in the earlier comment too. Weekly accounting and performance evaluation is needed for settlement of energy and incentive. There would be 2016 (=60*24*7/5) scatter plot dots for each week per power plant.

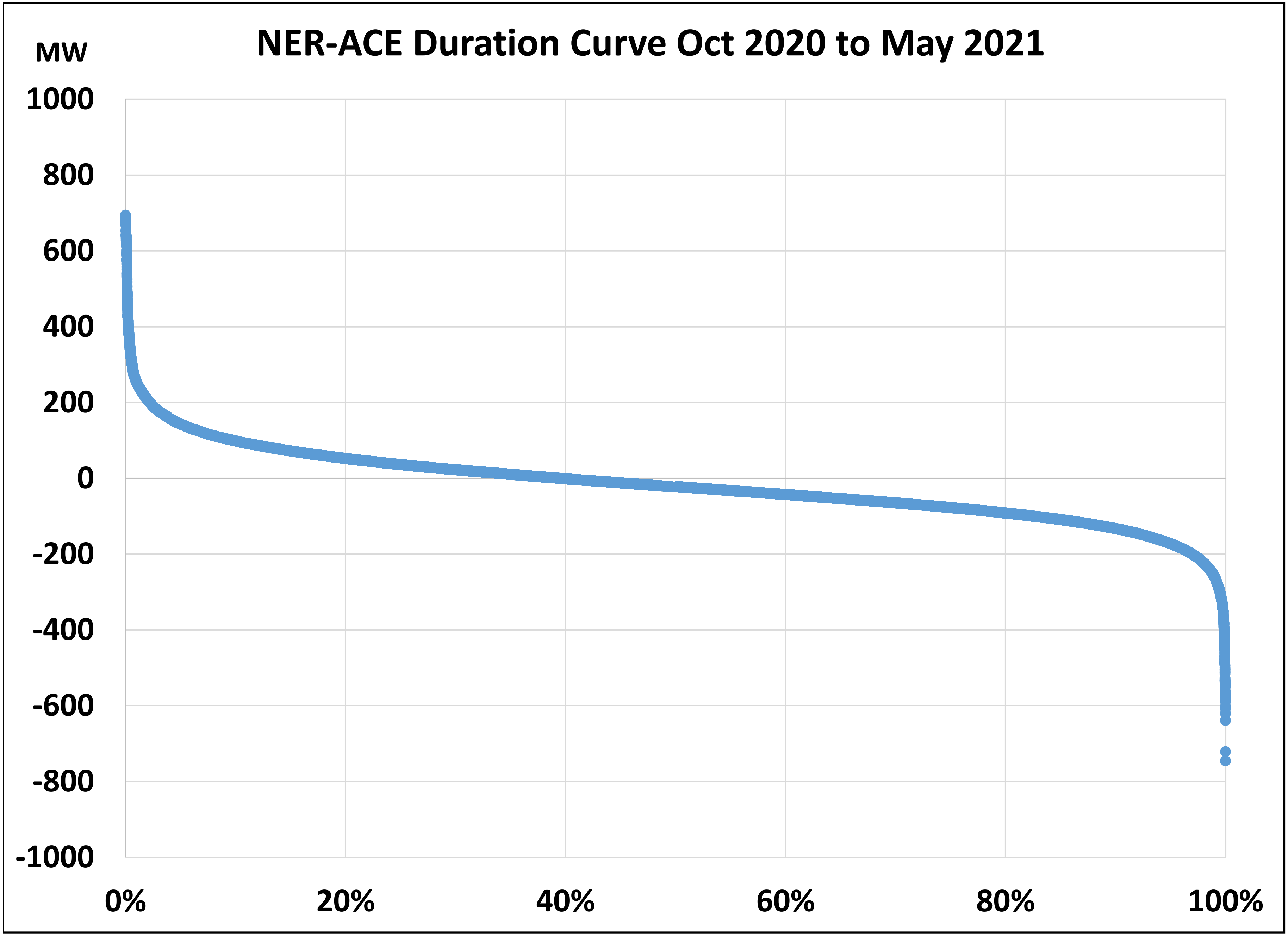
Annexure - 2


NR-ACE Duration Curve Oct 2020 to May 2021
MW
5000
4000
3000
2000
1000
0
-1000
-2000
-3000
-4000
-5000
0%
20%
40%
60%
80%
100%


WR-ACE Duration Curve Oct 2020 to May 2021
MW
6000
4000
2000
0
-2000
-4000
-6000
0%
20%
40%
60%
80%
100%

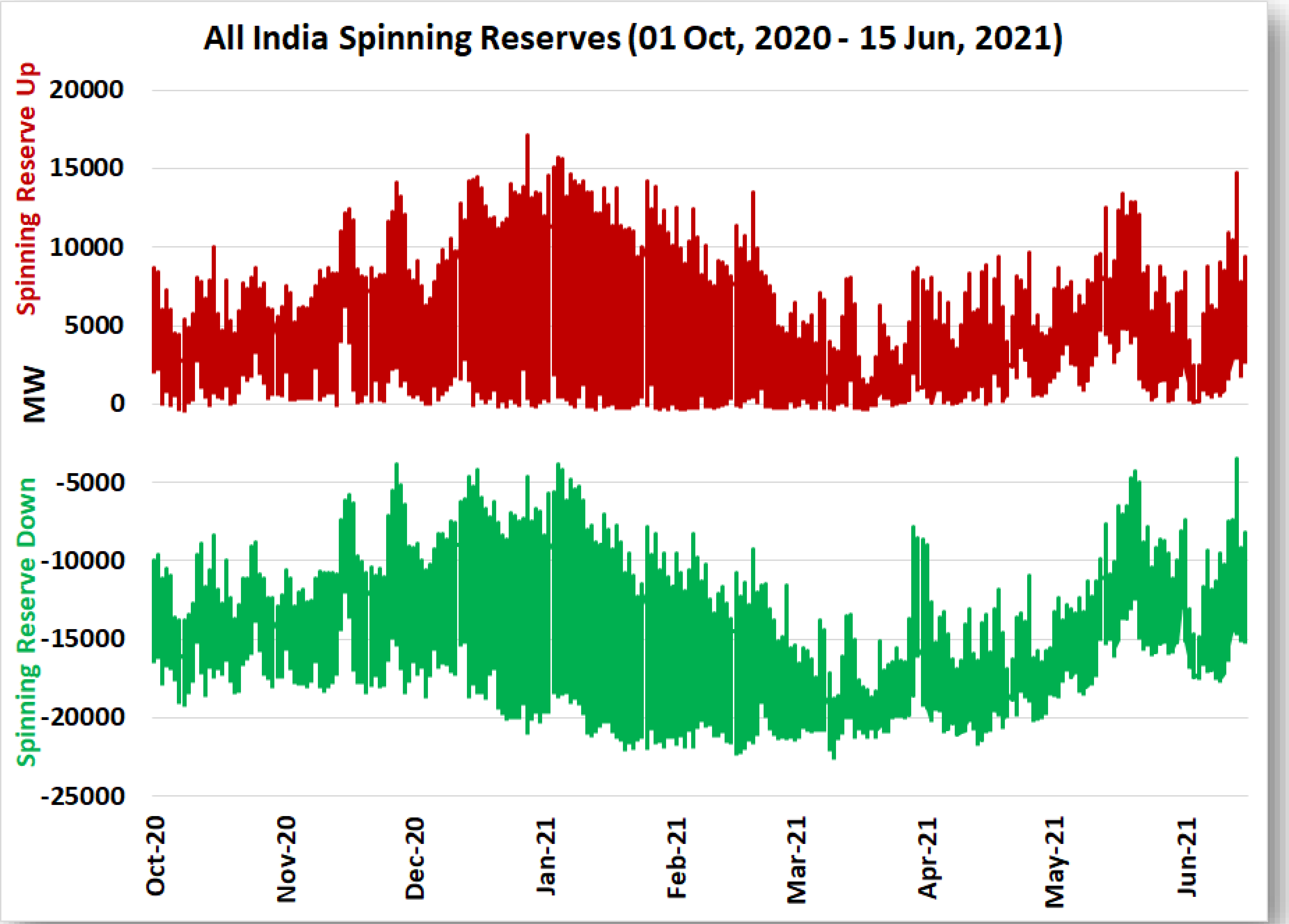

SR-ACE Duration Curve Oct 2020 to May 2021
MW
3000
2000
1000
0
-1000
-2000
-3000
0%
20%
40%
60%
80%
100%

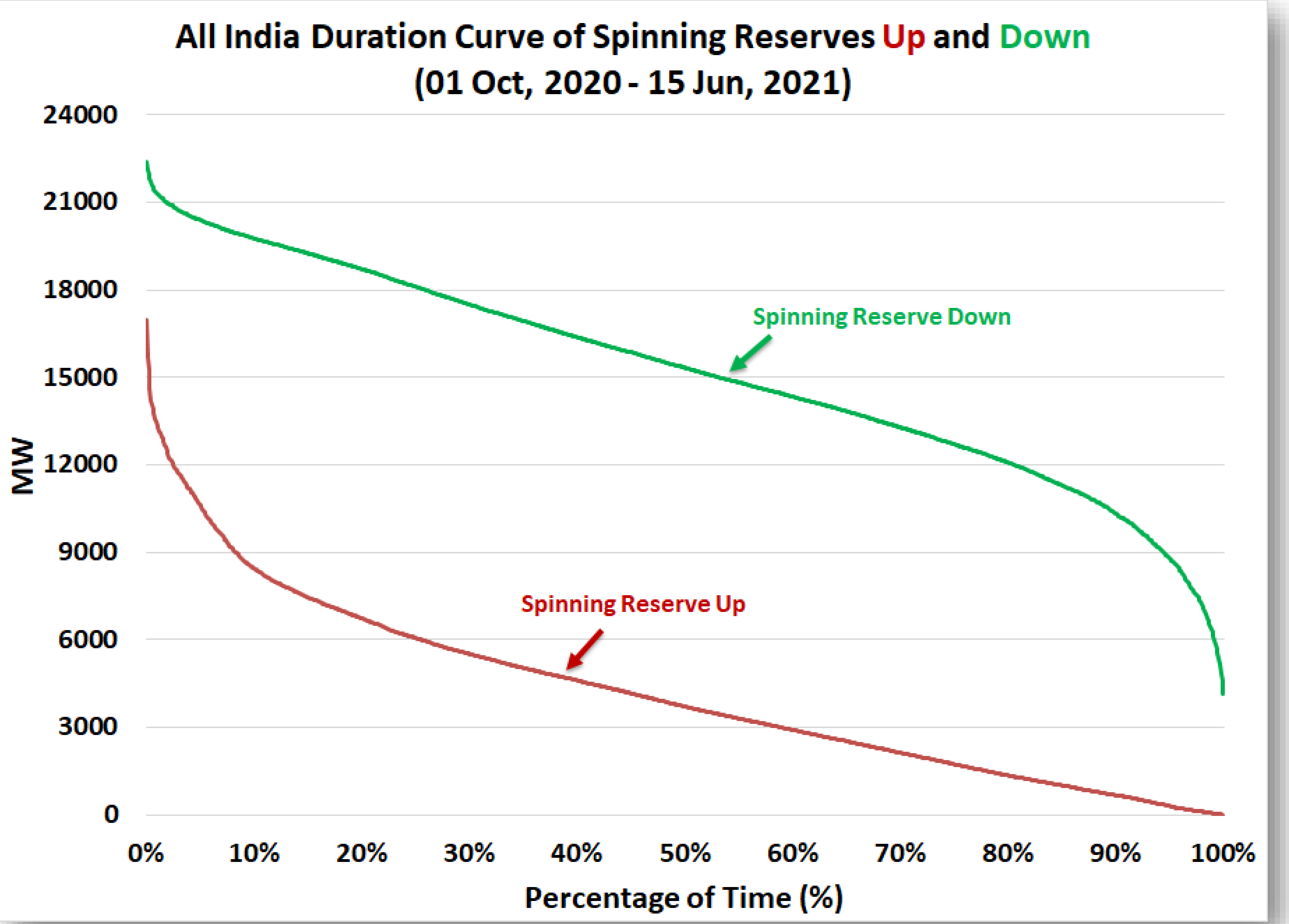

ER-ACE Duration Curve Oct 2020 to May 2021
MW
3000
2000
1000
0
-1000
-2000
-3000
0%
20%
40%
60%
80%
100%

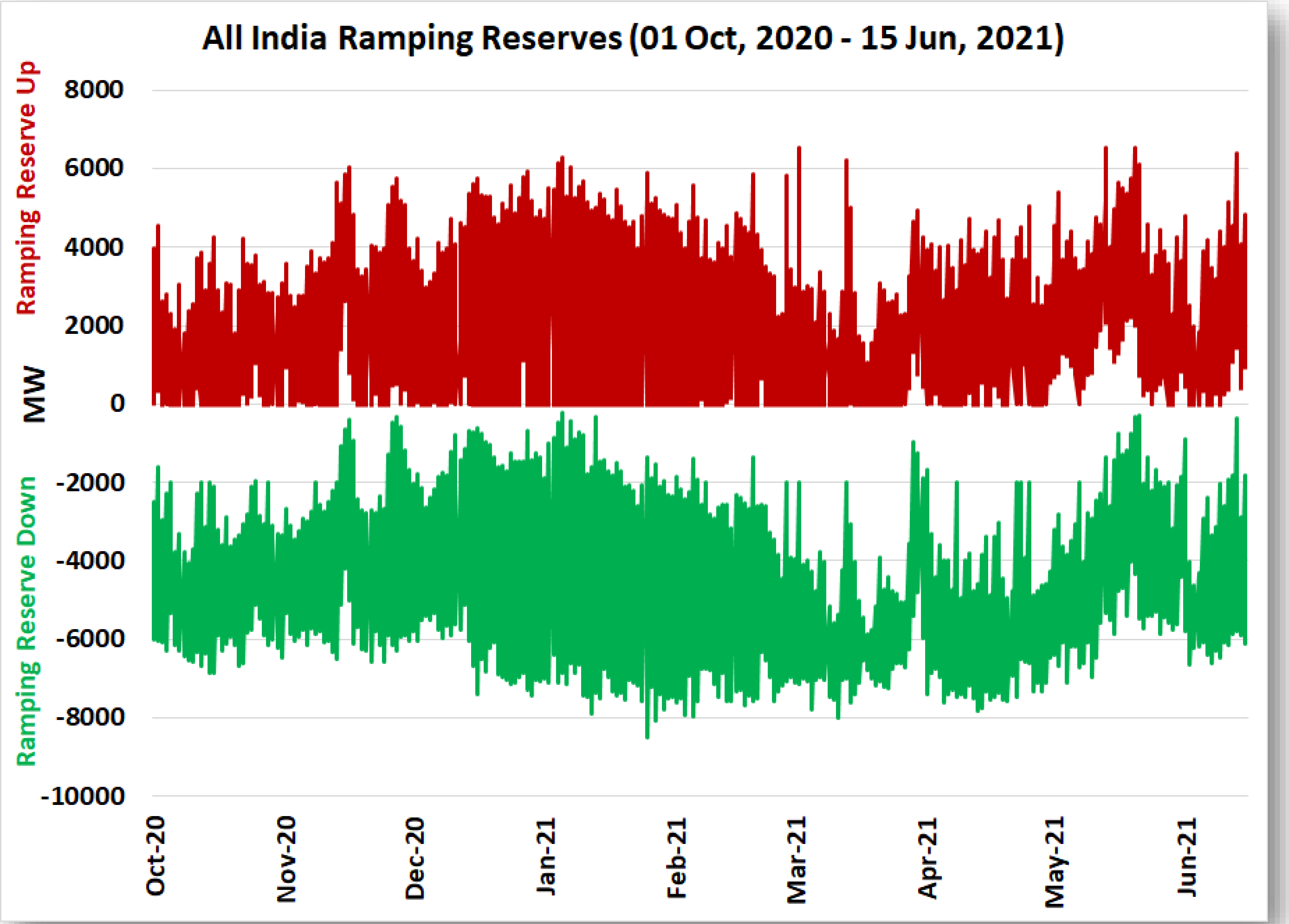

NER-ACE Duration Curve Oct 2020 to May 2021
MW
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
0%
20%
40%
60%
80%
100%

Annexure - 3

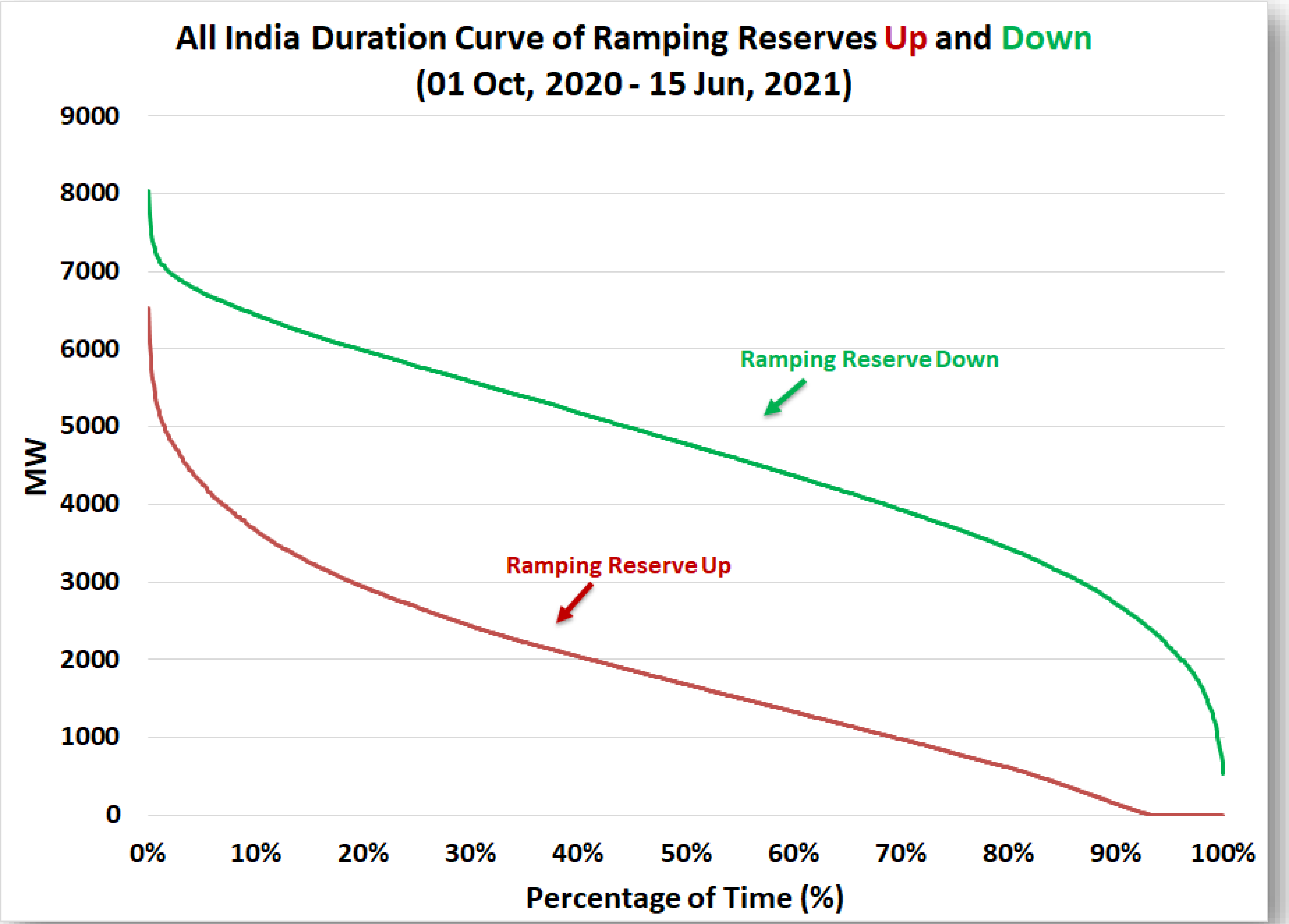
Data analysis of Reserves and RRAS (Oct,20 – Jun,21)


All India Spinning Reserves (01 Oct, 2020 - 15 Jun, 2021)
Spinning Reserve Up
Spinning Reserve Down
MW
20000
15000
10000
5000
0
-5000
-10000
-15000
-20000
-25000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

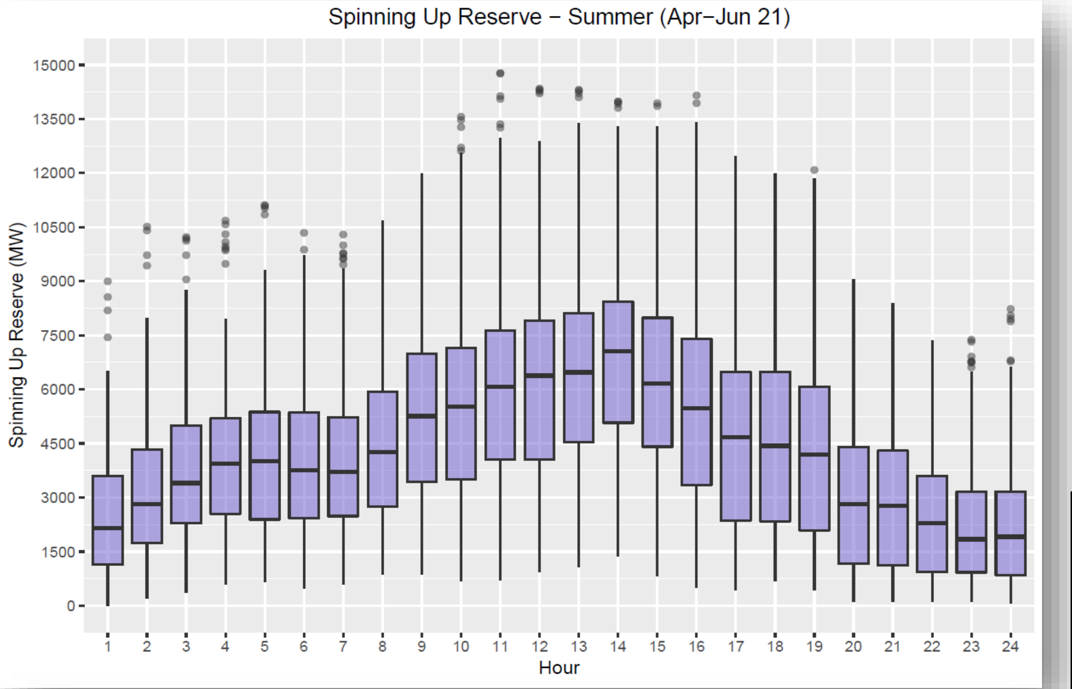

All India Duration Curve of Spinning Reserves Up and Down
(01 Oct, 2020 - 15 Jun, 2021)
24000
21000
18000
15000
12000
9000
6000
3000
0
MW
Spinning Reserve Down
Spinning Reserve Up
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percentage of Time (%)

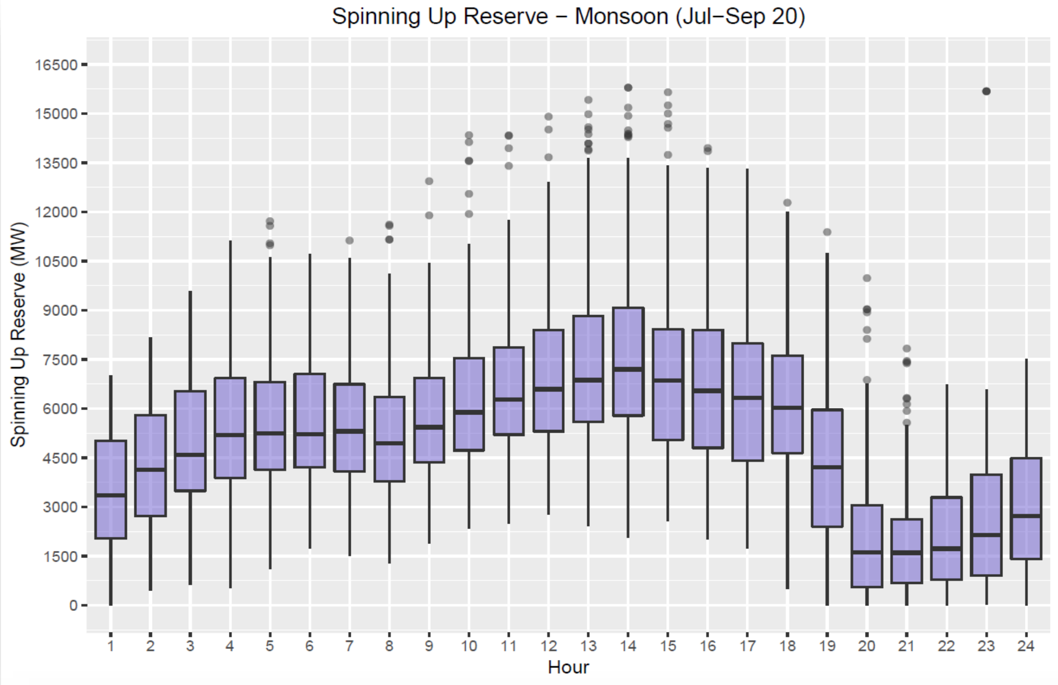


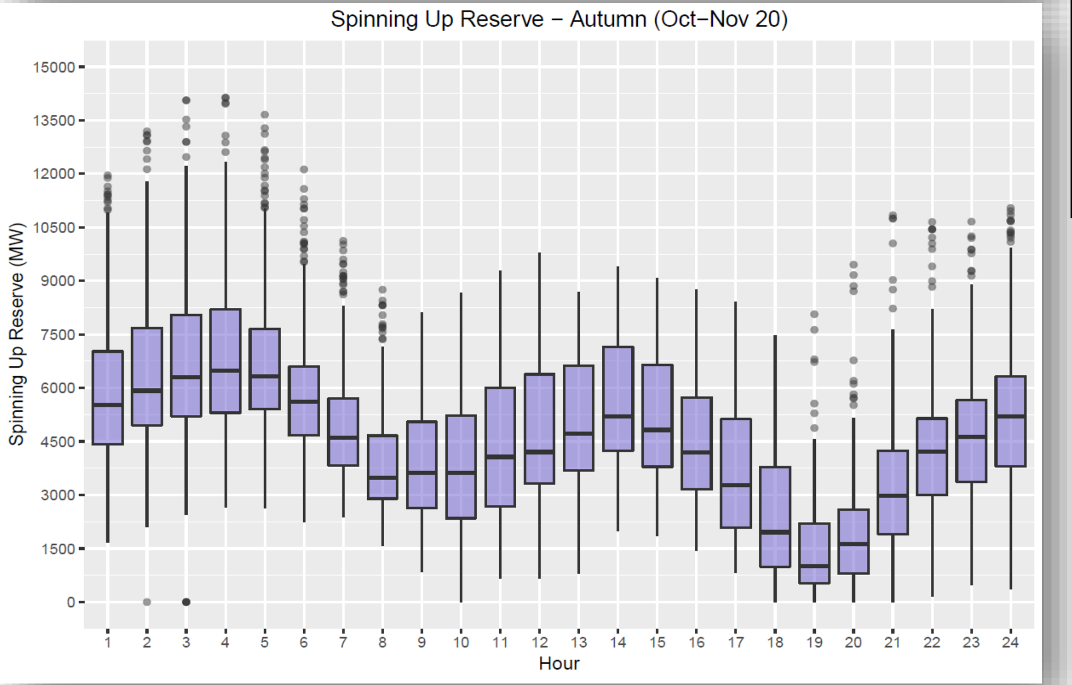
All India Ramping Reserves (01 Oct, 2020 - 15 Jun, 2021)
Ramping Reserve Up
MW
Ramping Reserve Down
8000
6000
4000
2000
0
-2000
-4000
-6000
-8000
-10000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

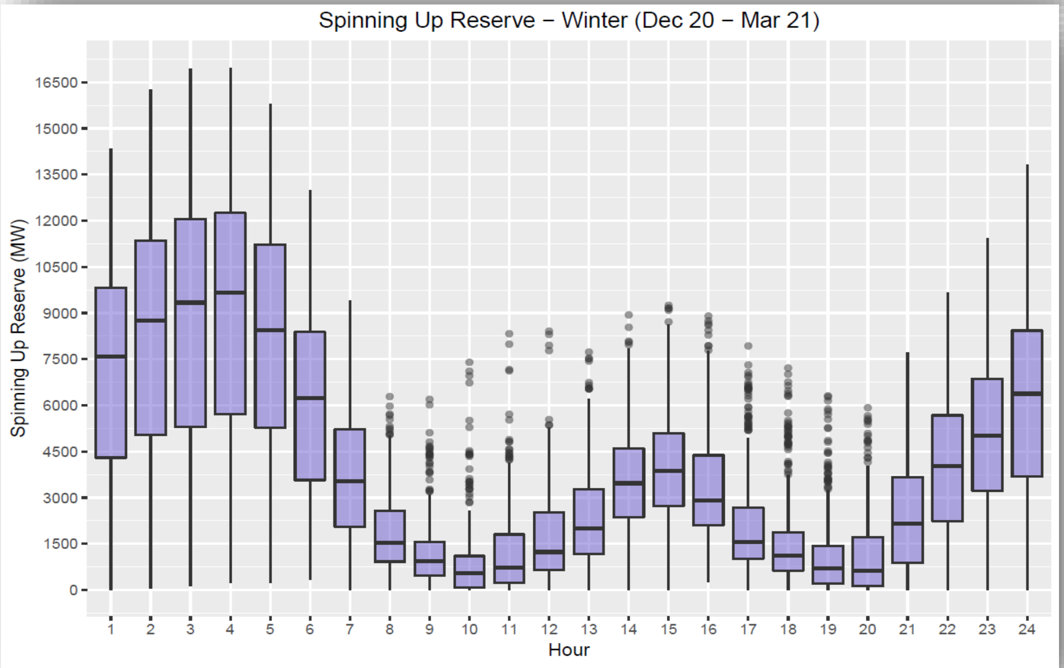

All India Duration Curve of Ramping Reserves Up and Down
(01 Oct, 2020 - 15 Jun, 2021)
9000
8000
7000
6000
5000
4000
3000
2000
1000
0
MW
Ramping Reserve Down
Ramping Reserve Up
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percentage of Time (%)

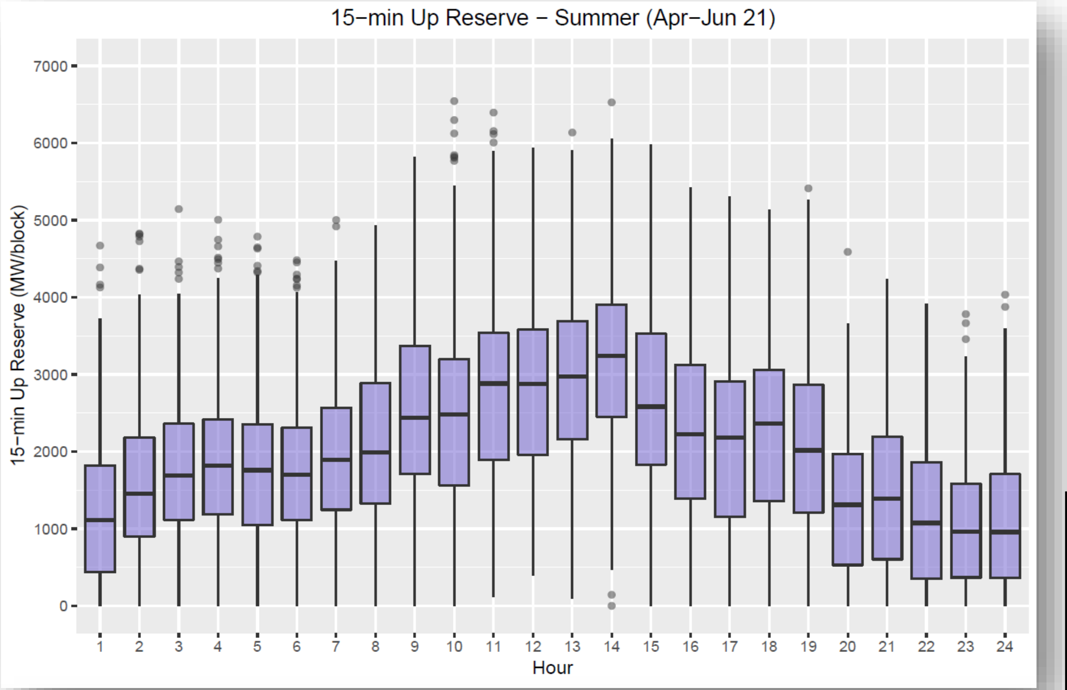
Spinning Up Reserve Hourly Distribution with Seasonal Pattern



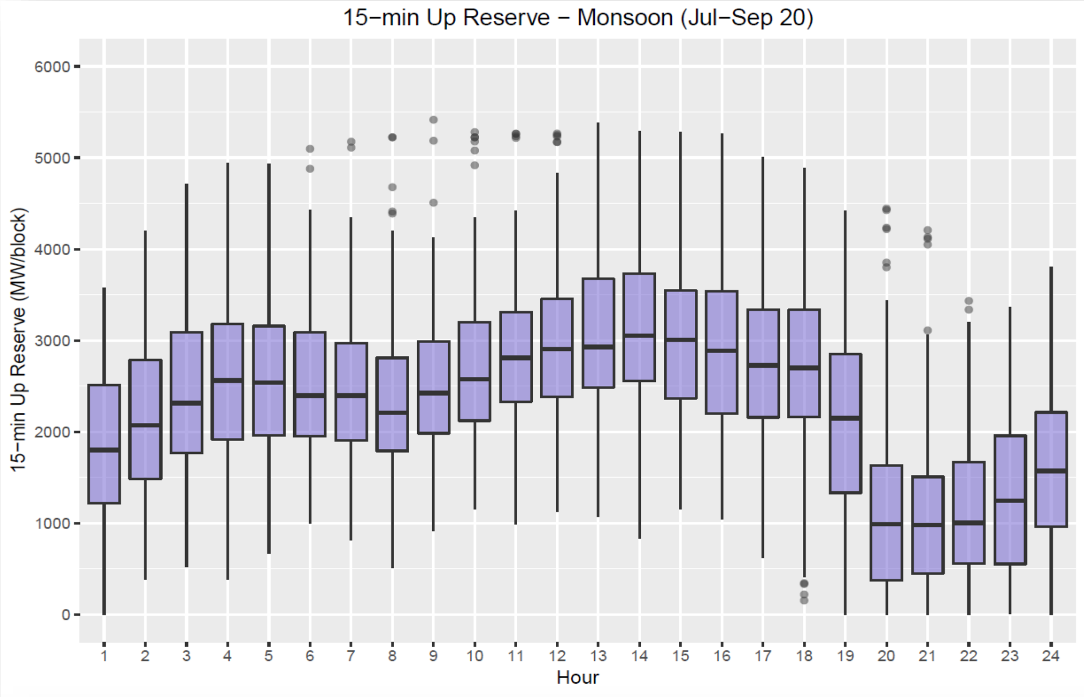


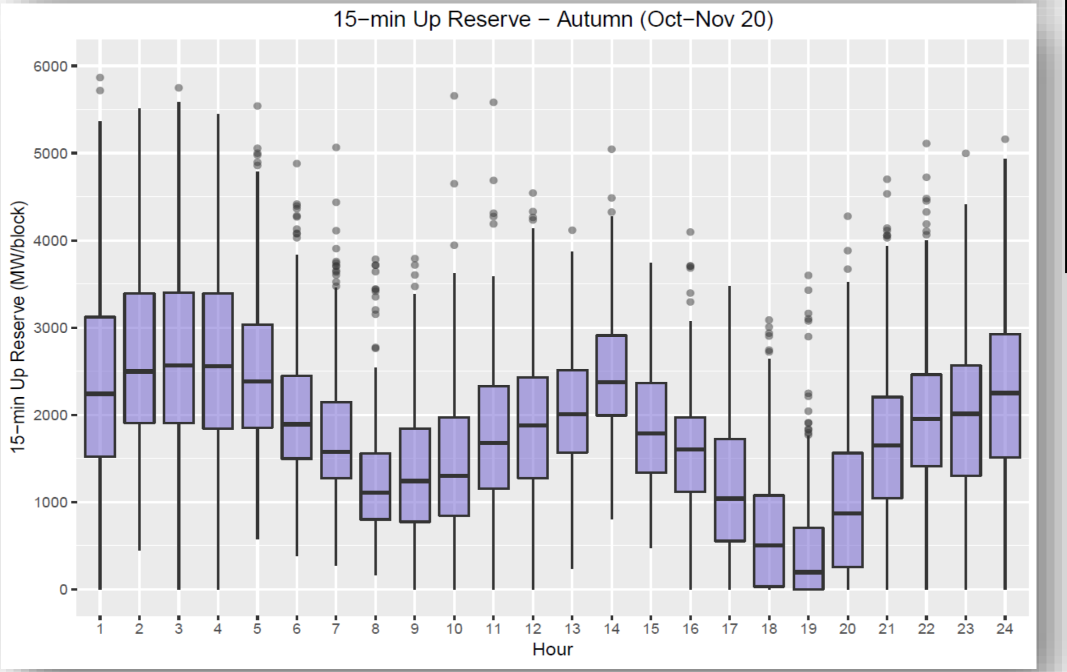


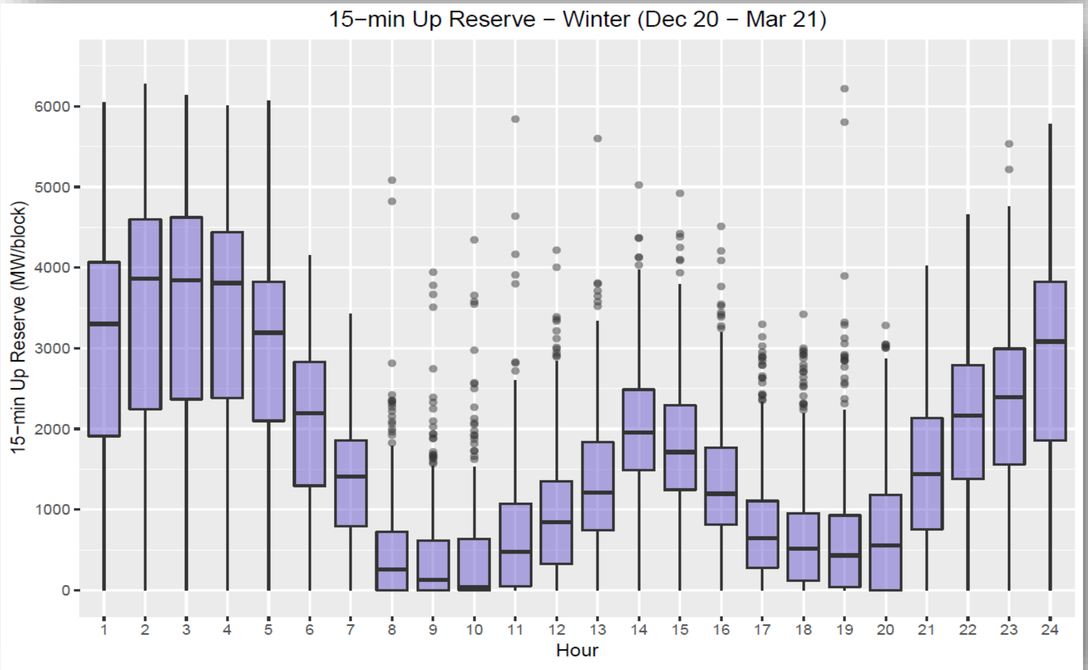


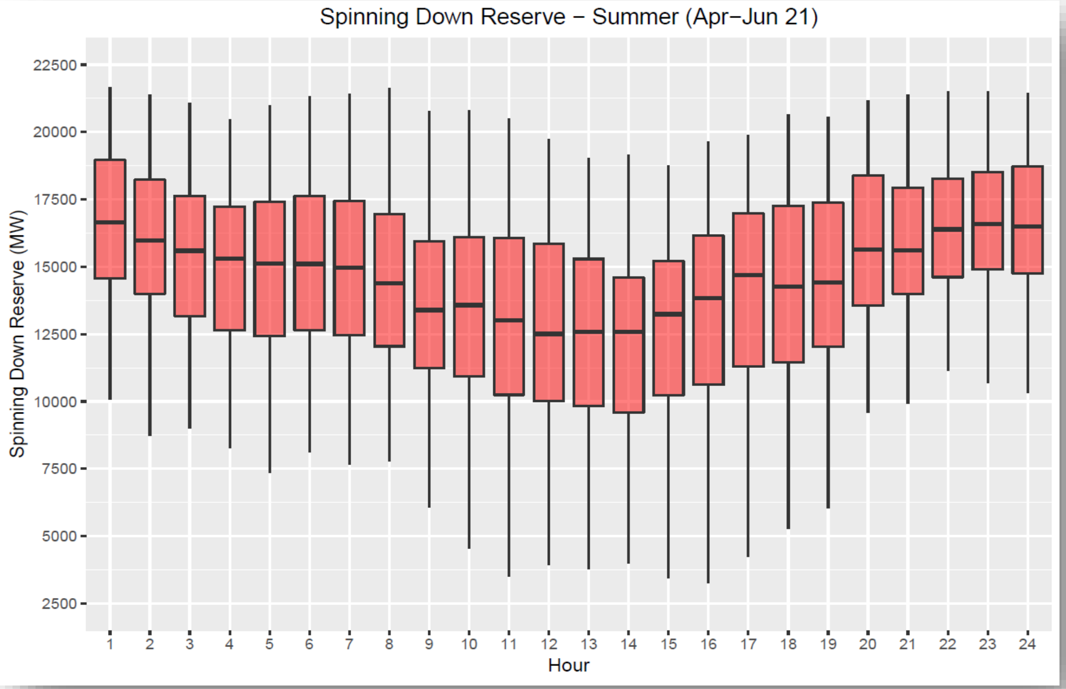


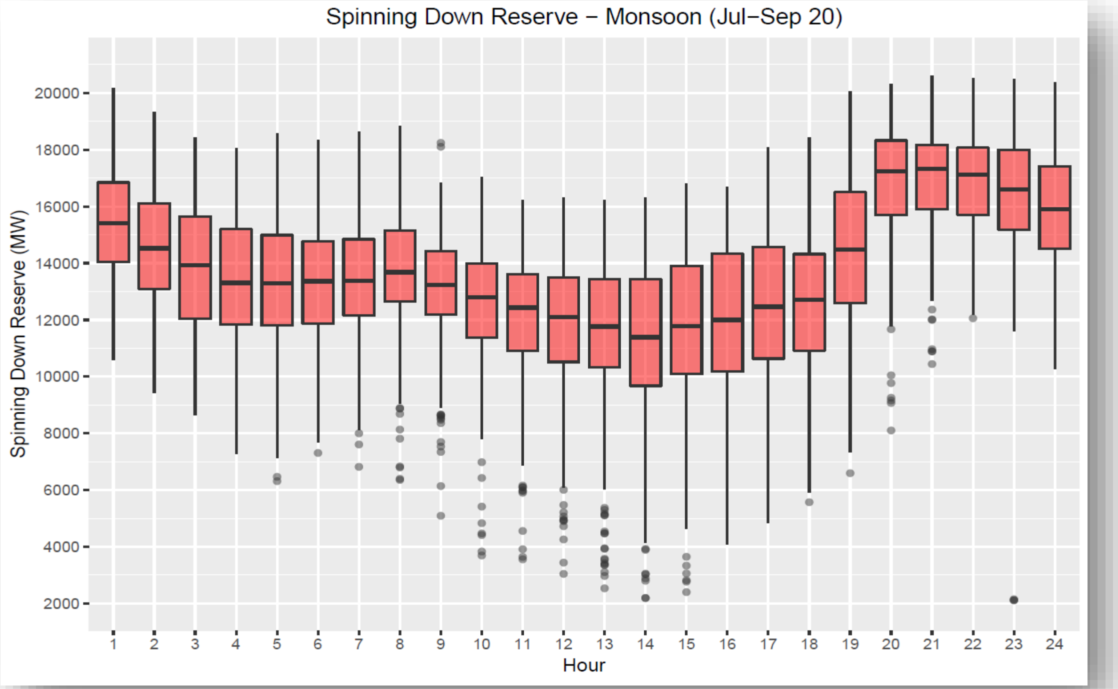
15-minute Spinning Up Reserve Hourly Distribution with Seasonal Pattern



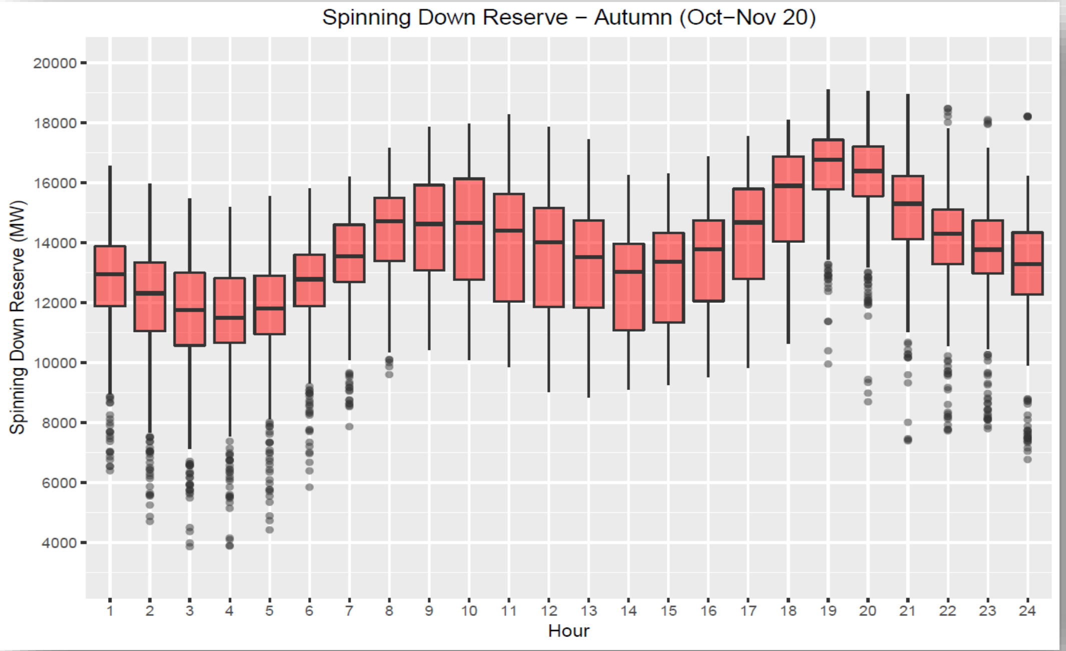


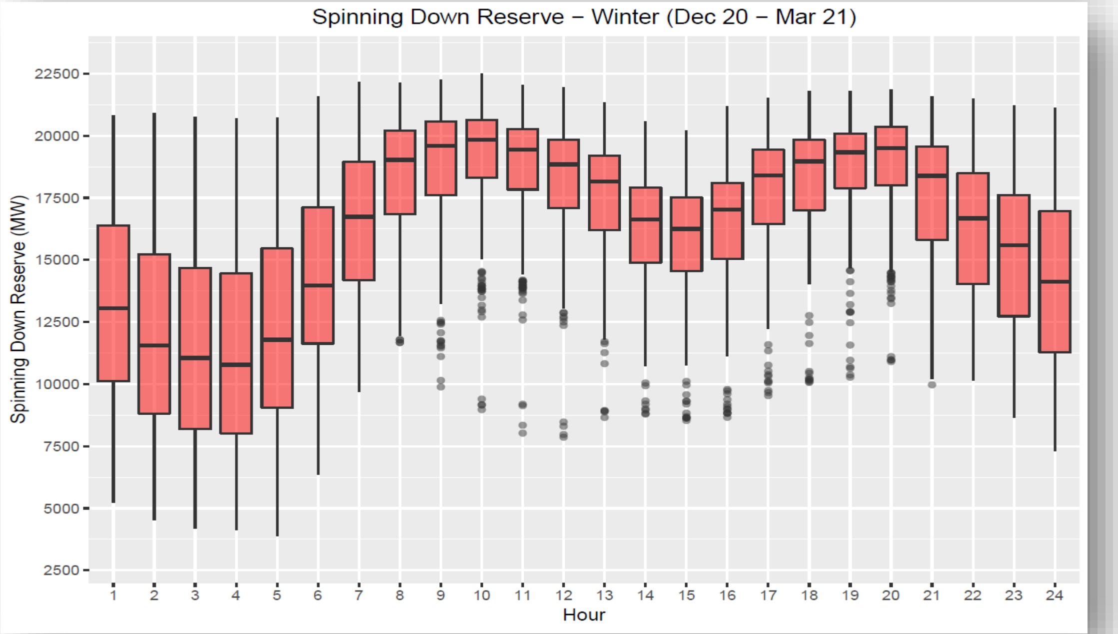




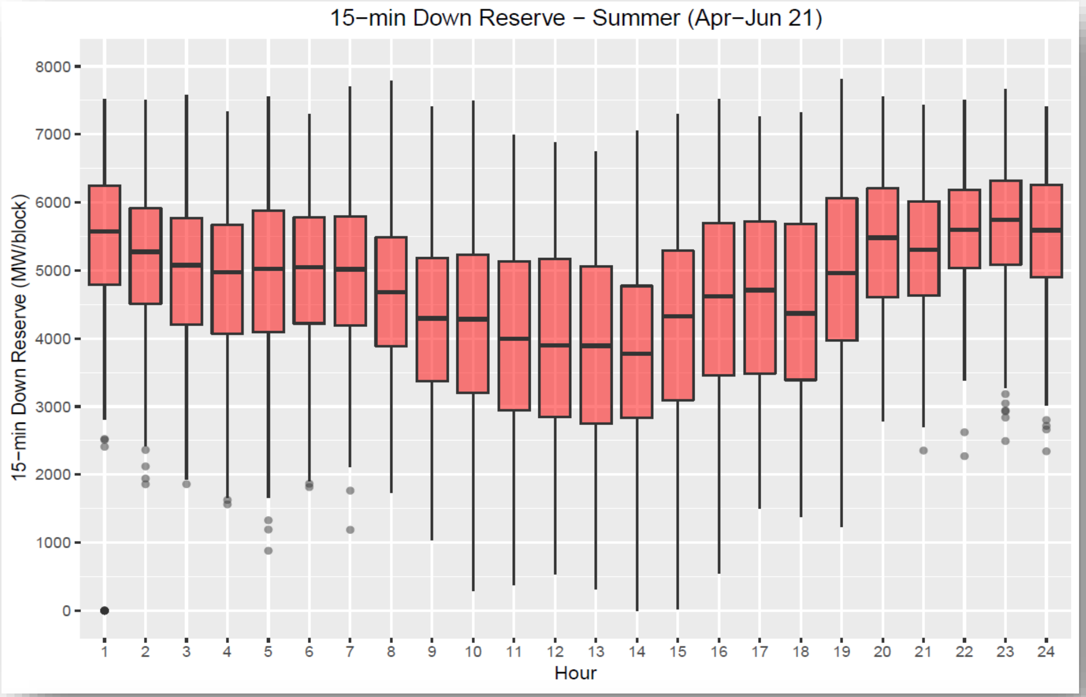


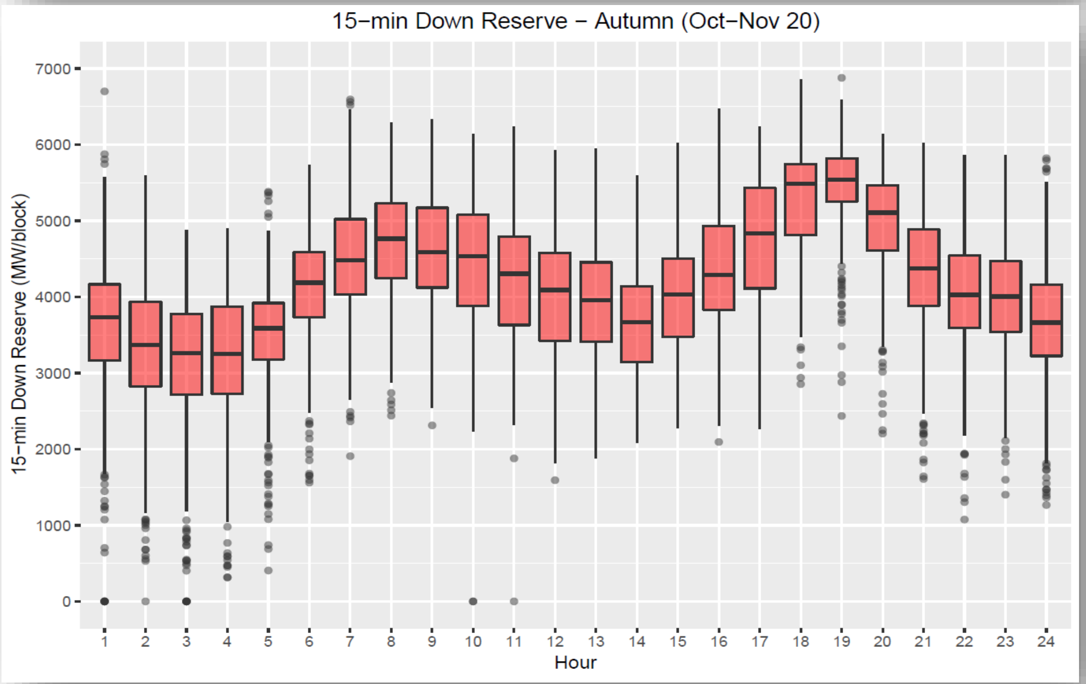
Spinning Down Reserve Hourly Distribution with Seasonal Pattern

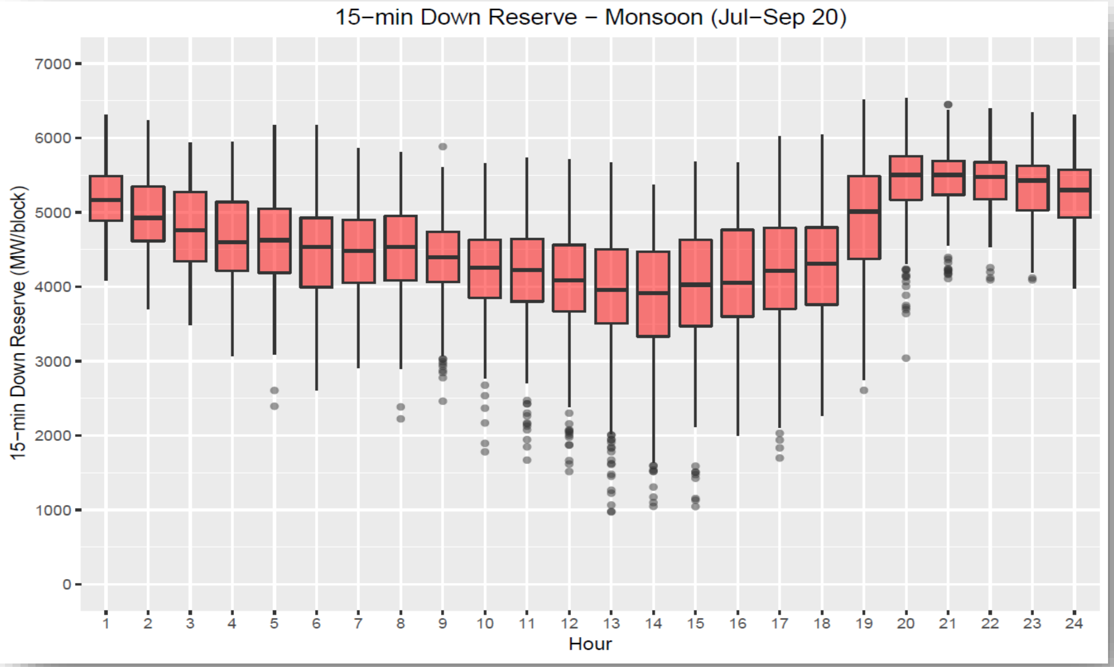


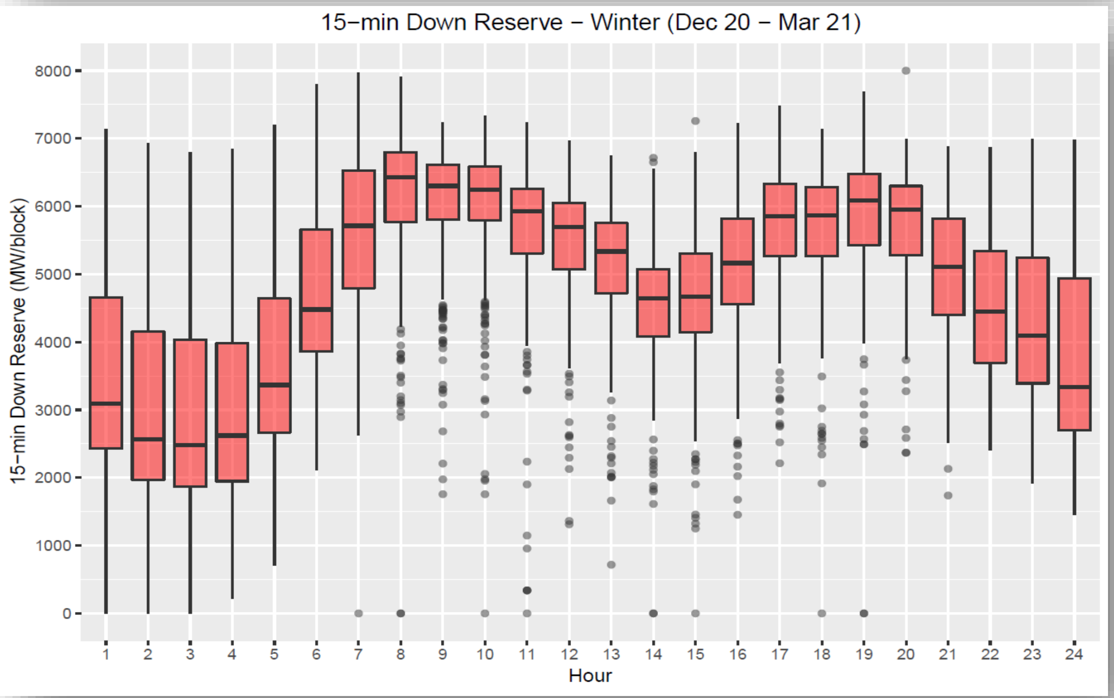


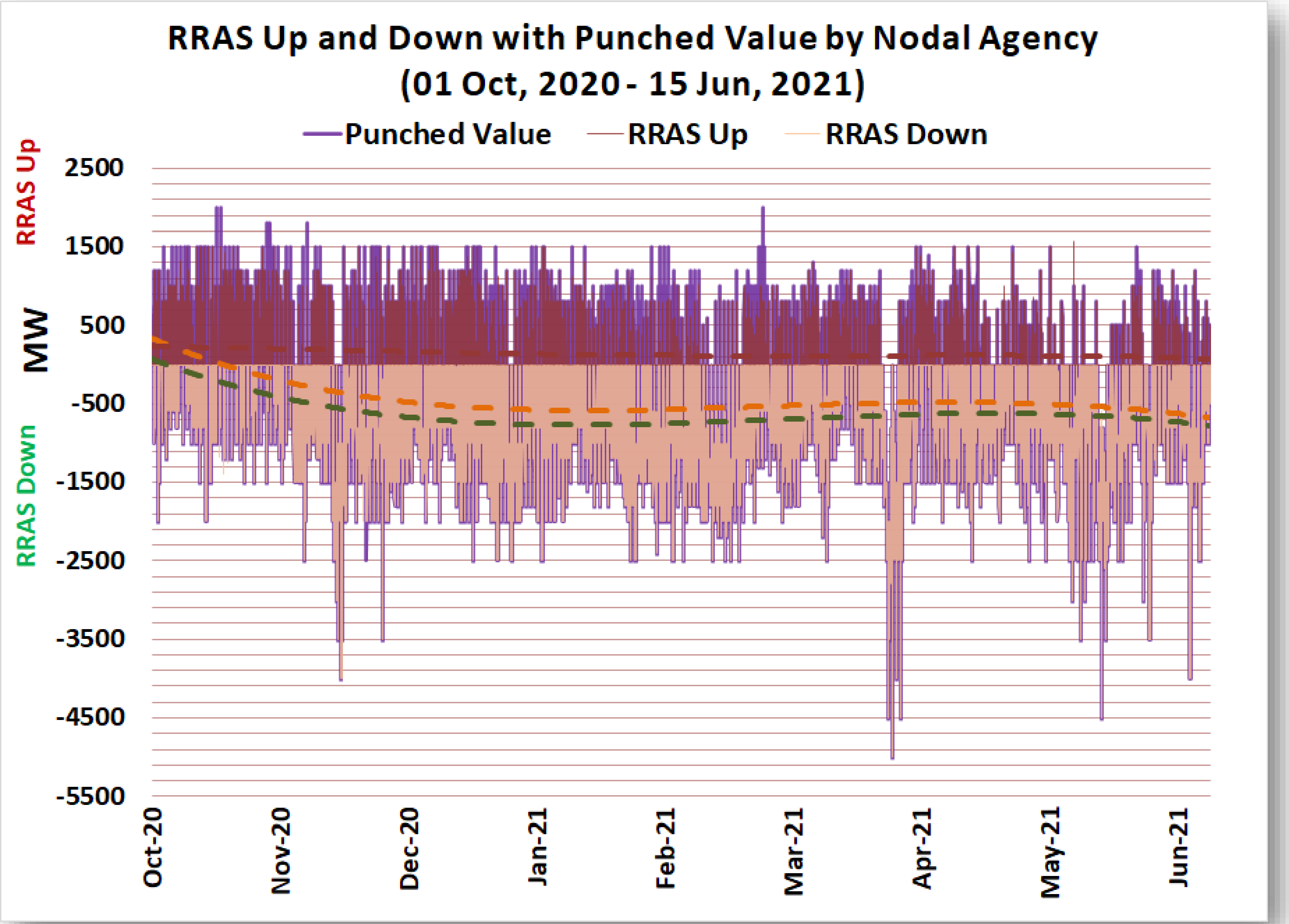
15-minute Spinning Down Reserve Hourly Distribution with Seasonal Pattern

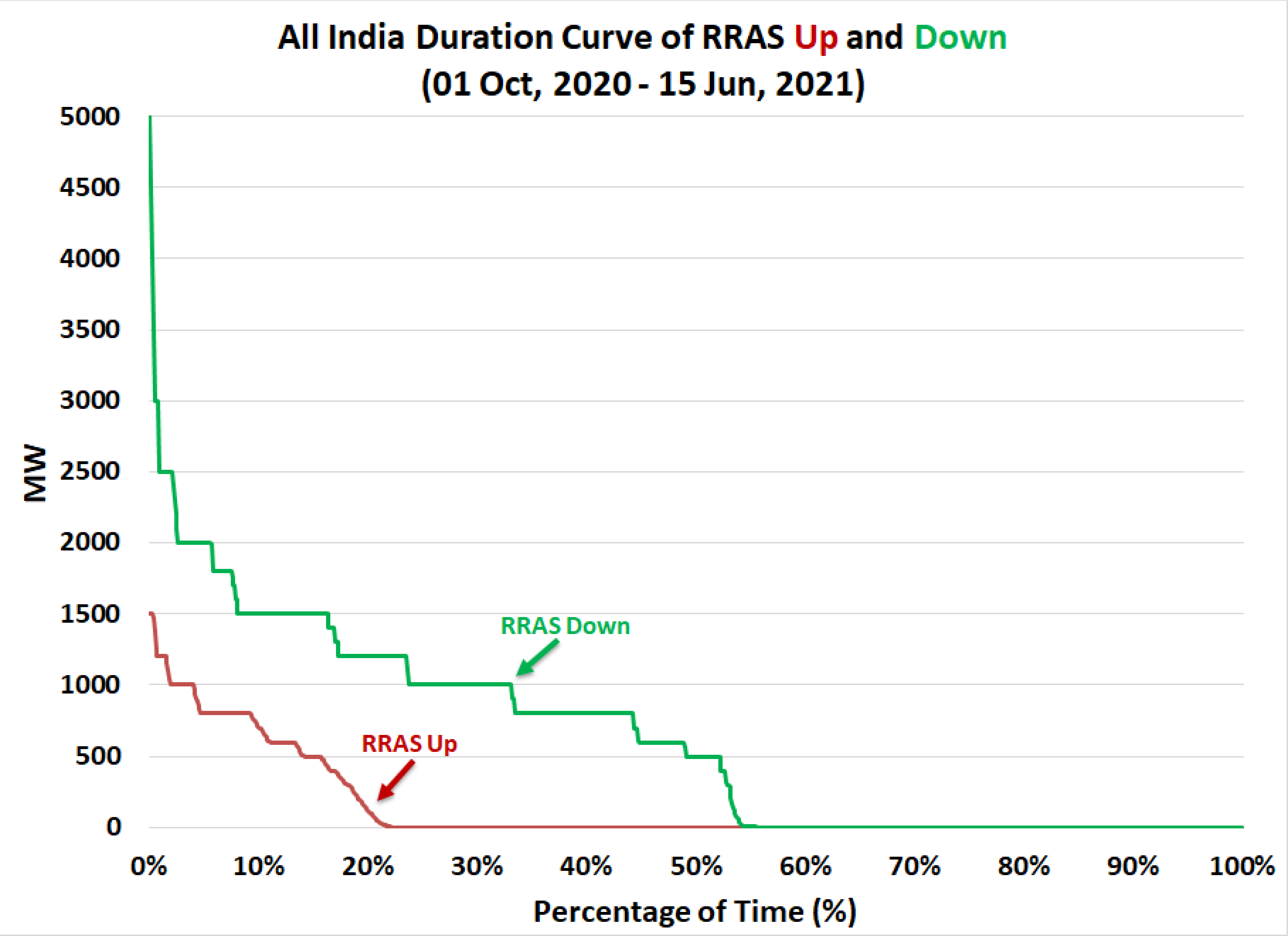


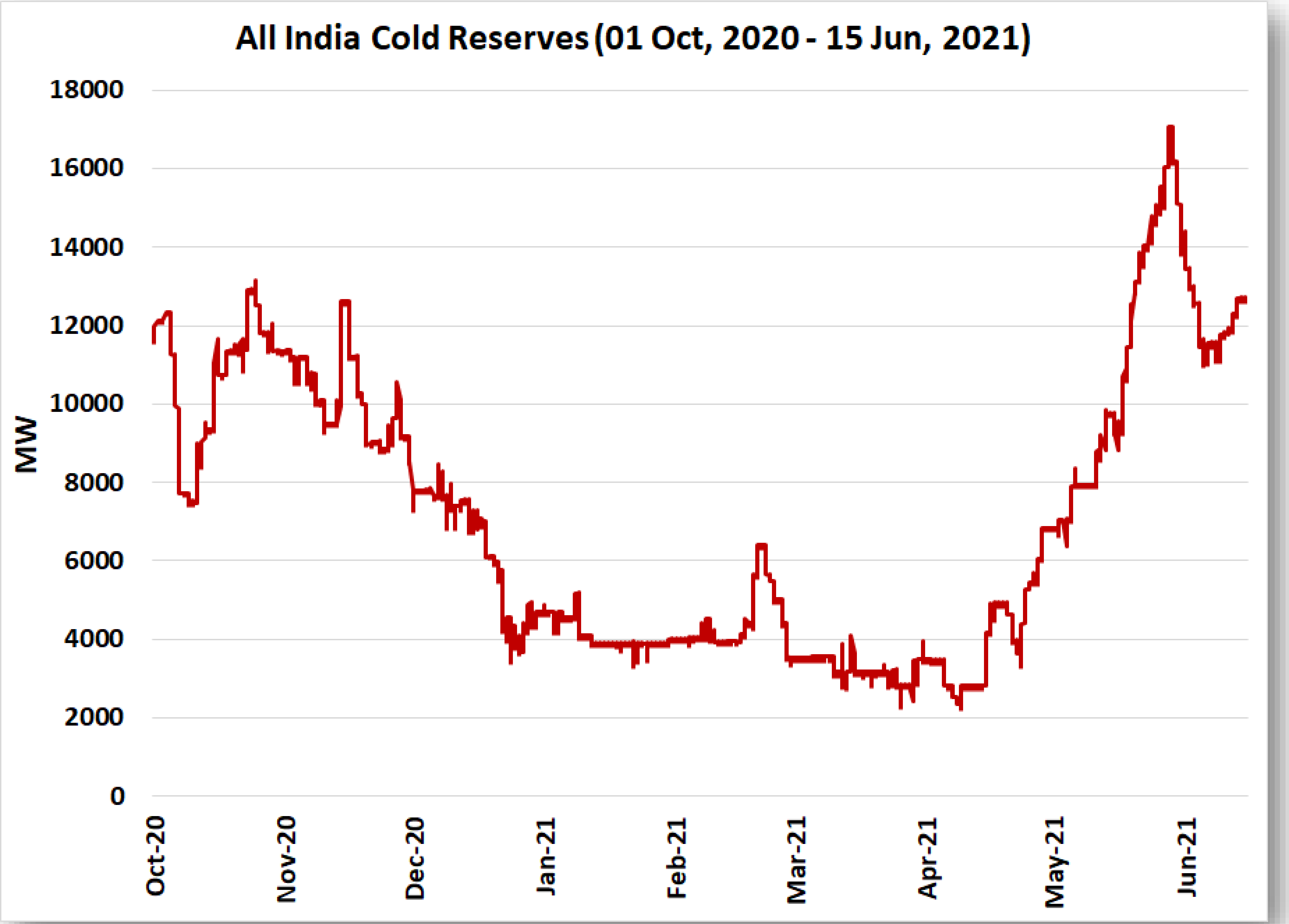


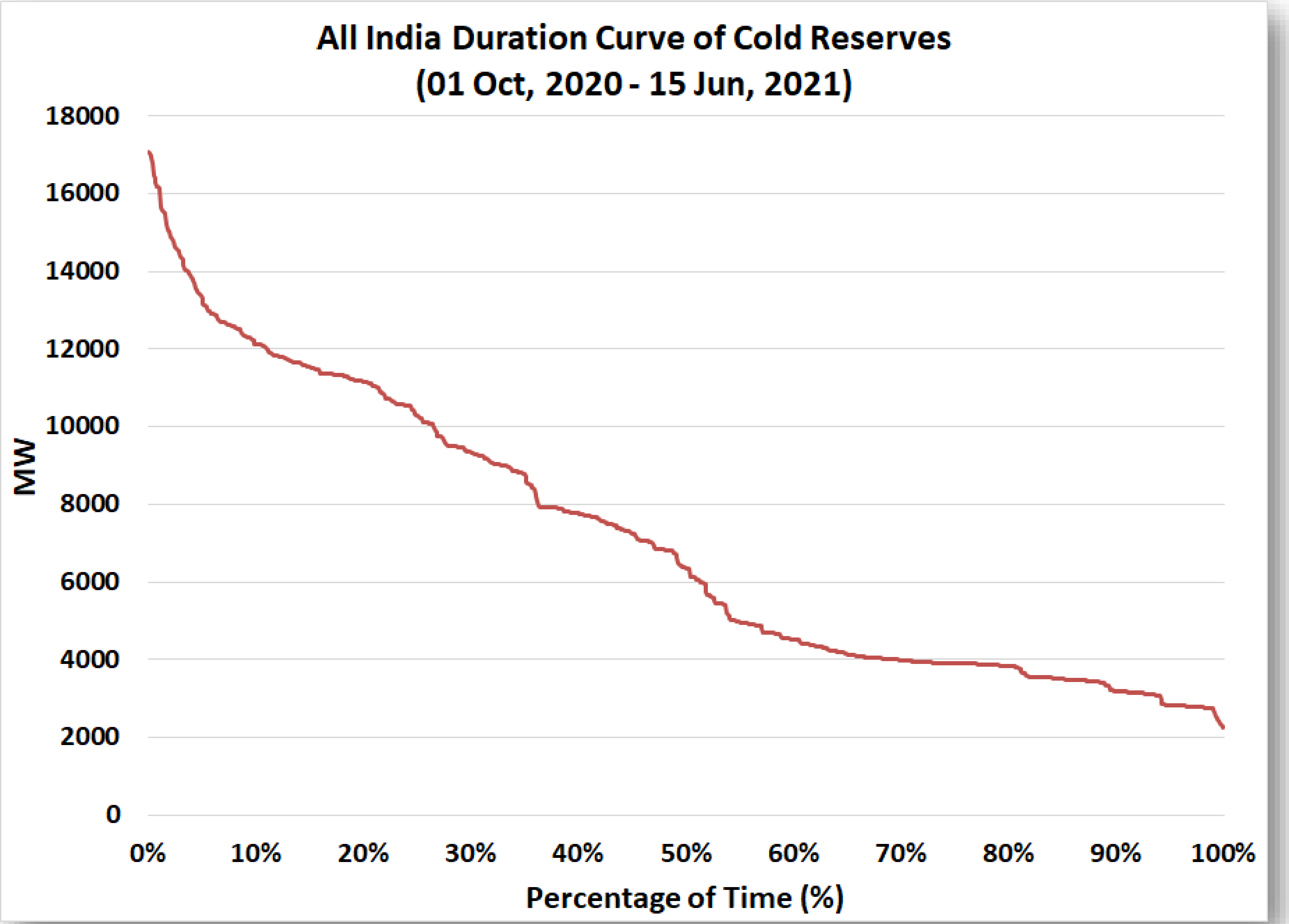


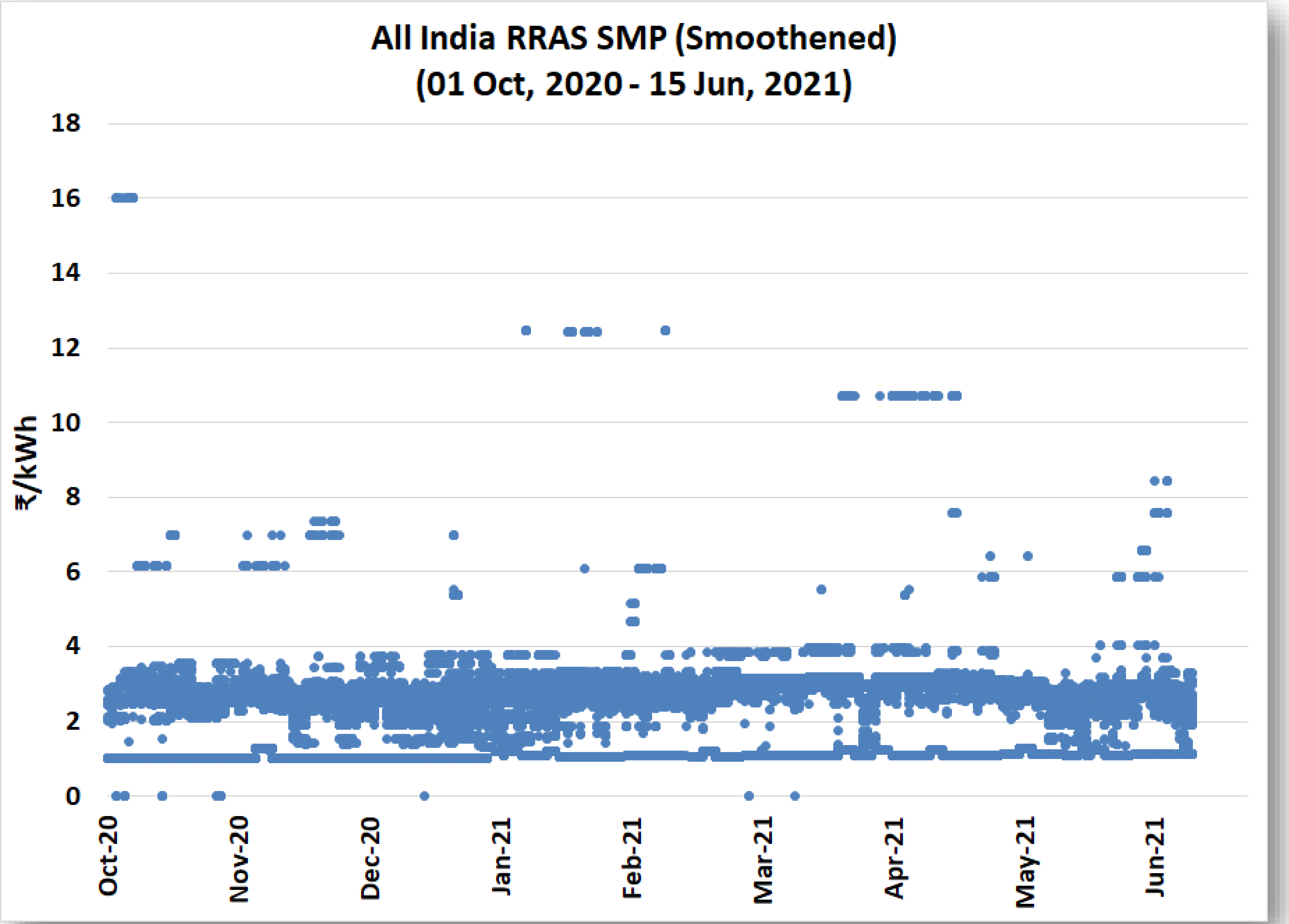


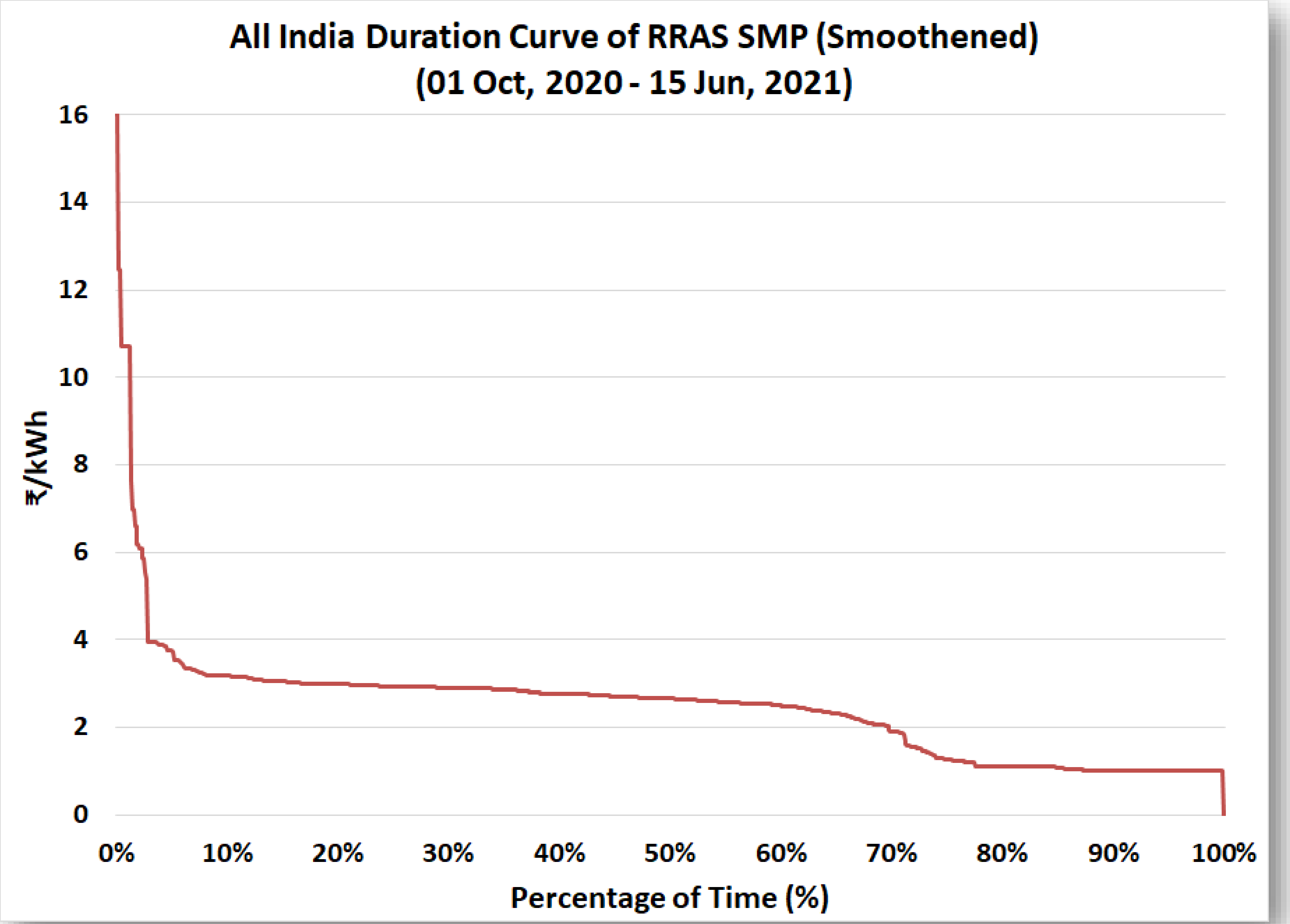

RRAS Up and Down with Punched Value by Nodal Agency
(01 Oct, 2020 - 15 Jun, 2021)
Punched Value
RRAS Up
RRAS Down
RRAS Up
RRAS Down
MW
2500
1500
500
-500
-1500
-2500
-3500
-4500
-5500
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

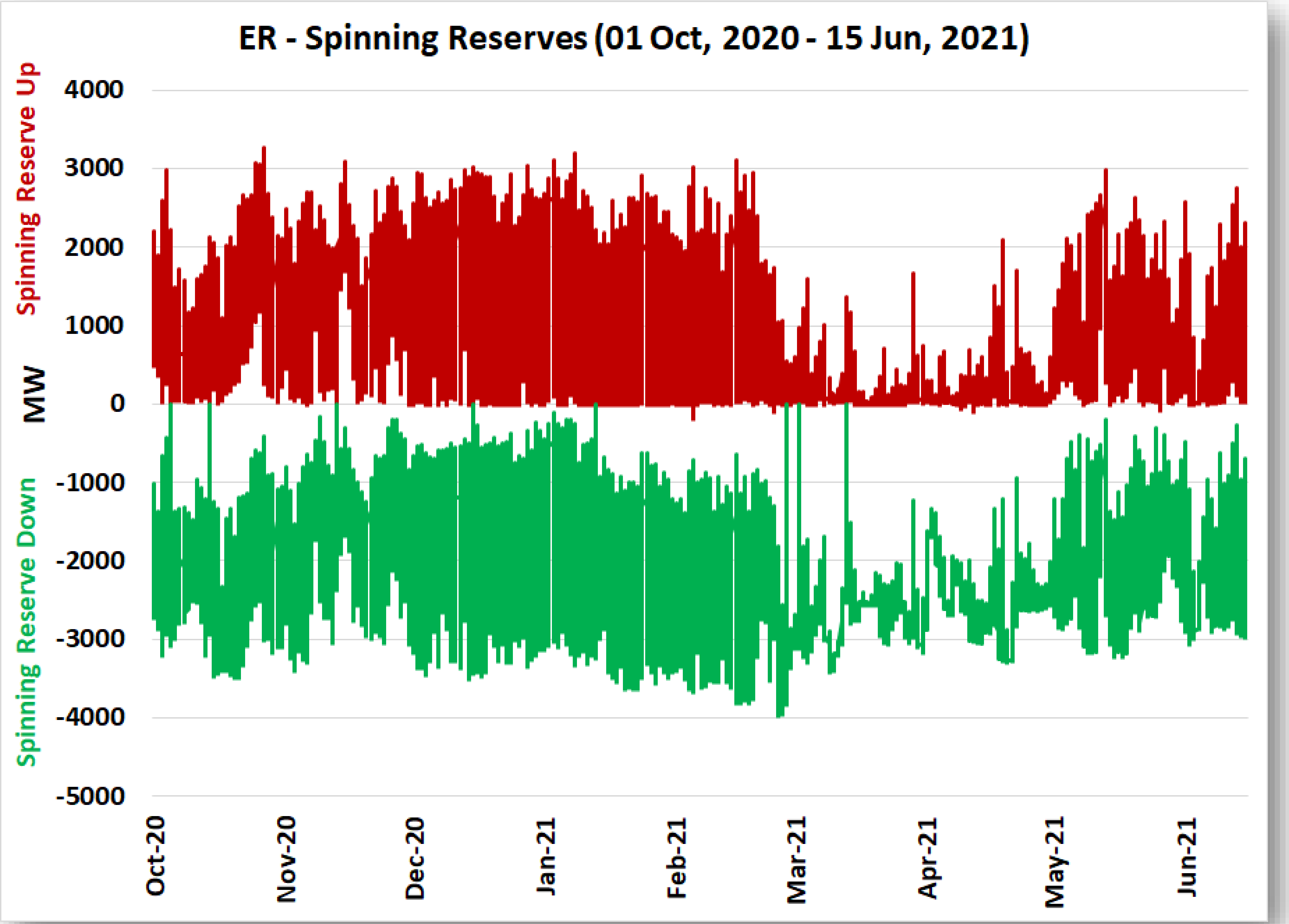

All India Duration Curve of RRAS Up and Down
(01 Oct, 2020 - 15 Jun, 2021)
MW
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percentage of Time (%)
RRAS Down
RRAS Up

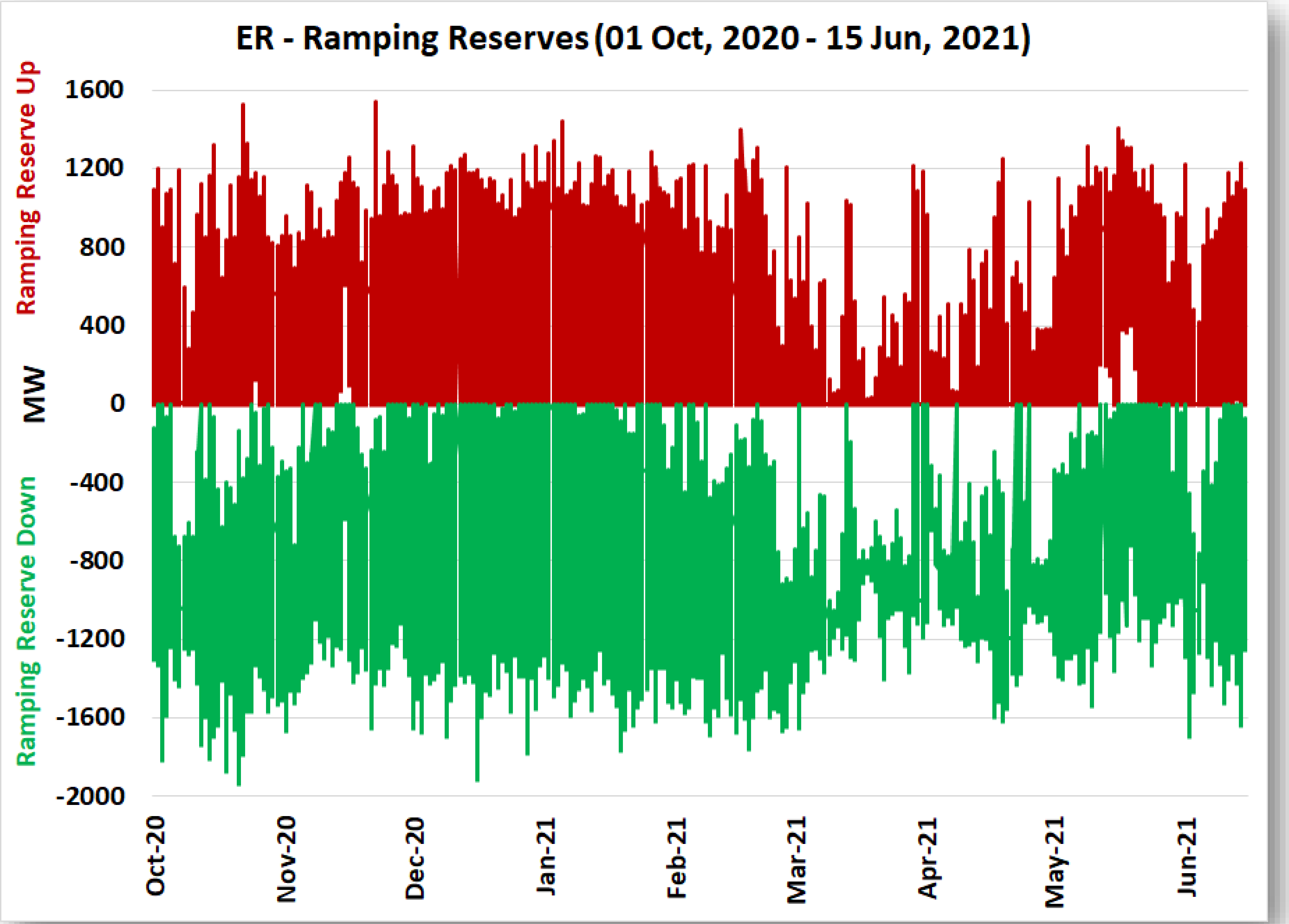

All India Cold Reserves (01 Oct, 2020 - 15 Jun, 2021)
MW
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

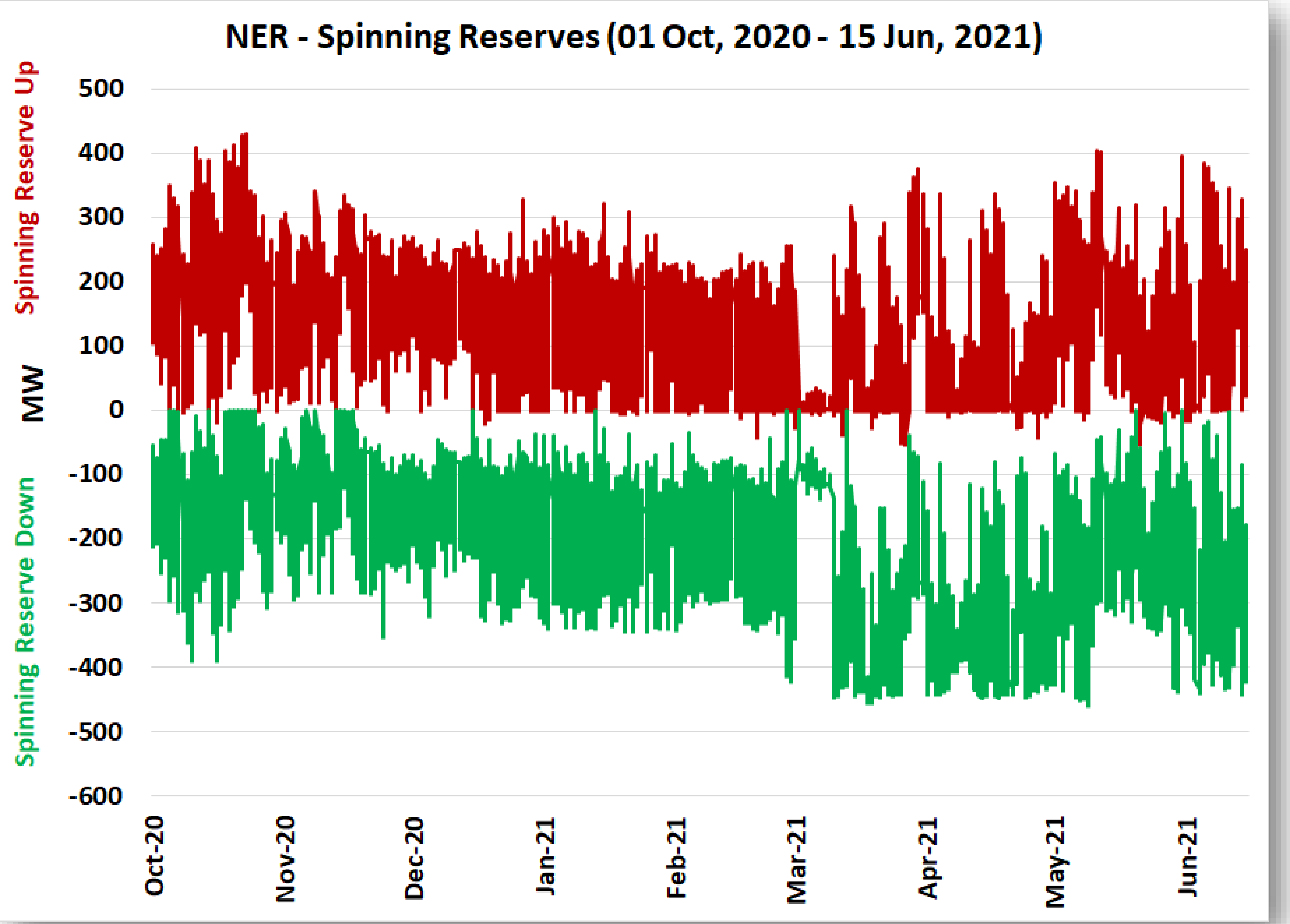

All India Duration Curve of Cold Reserves
(01 Oct, 2020 - 15 Jun, 2021)
MW
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percentage of Time (%)


All India RRAS SMP (Smoothened)
(01 Oct, 2020 - 15 Jun, 2021)
₹/kWh
18
16
14
12
10
8
6
4
2
0
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

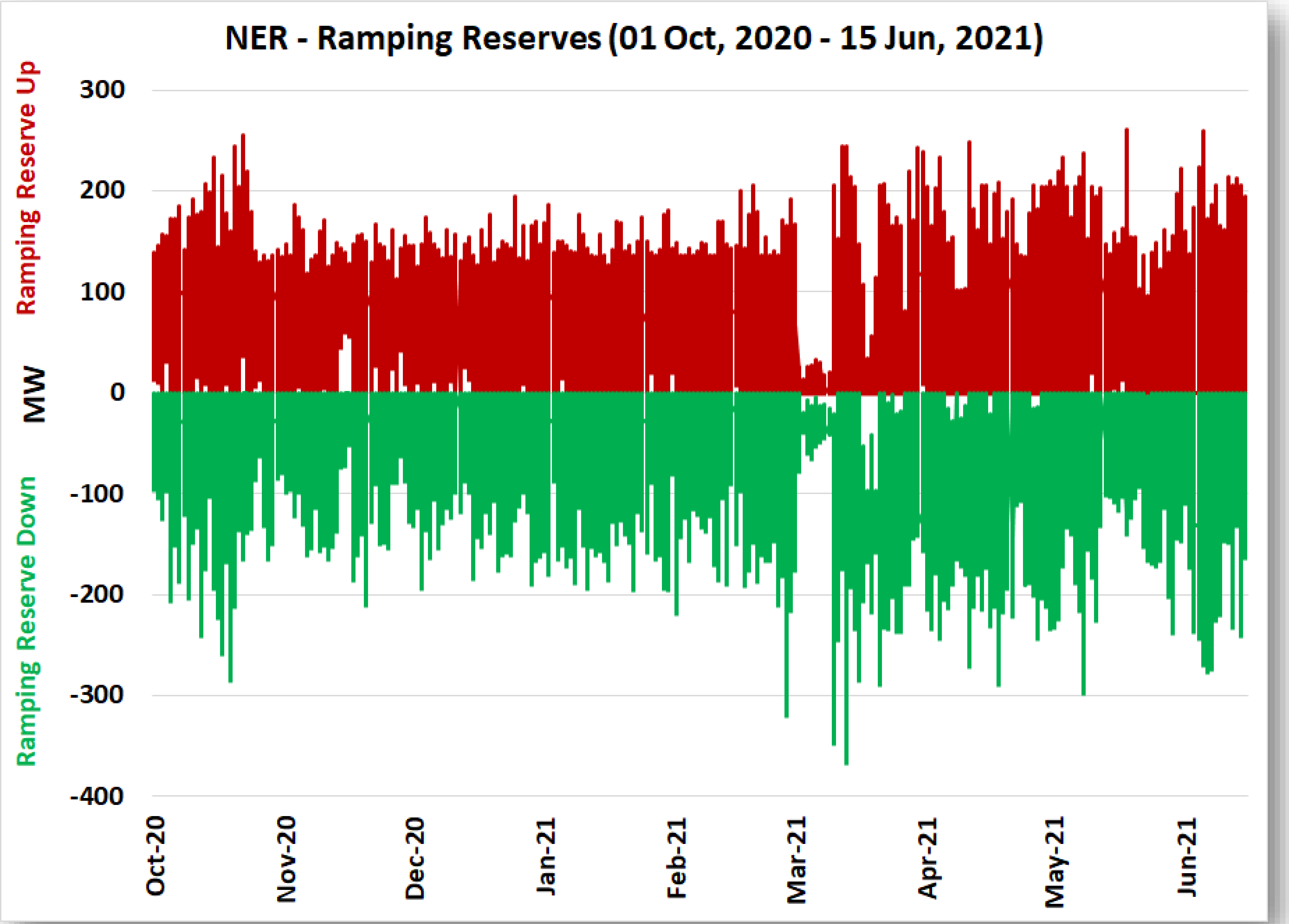

All India Duration Curve of RRAS SMP (Smoothened)
(01 Oct, 2020 - 15 Jun, 2021)
₹/kWh
16
14
12
10
8
6
4
2
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Percentage of Time (%)


ER - Spinning Reserves (01 Oct, 2020 - 15 Jun, 2021)
Spinning Reserve Up
MW
Spinning Reserve Down
4000
3000
2000
1000
0
-1000
-2000
-3000
-4000
-5000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

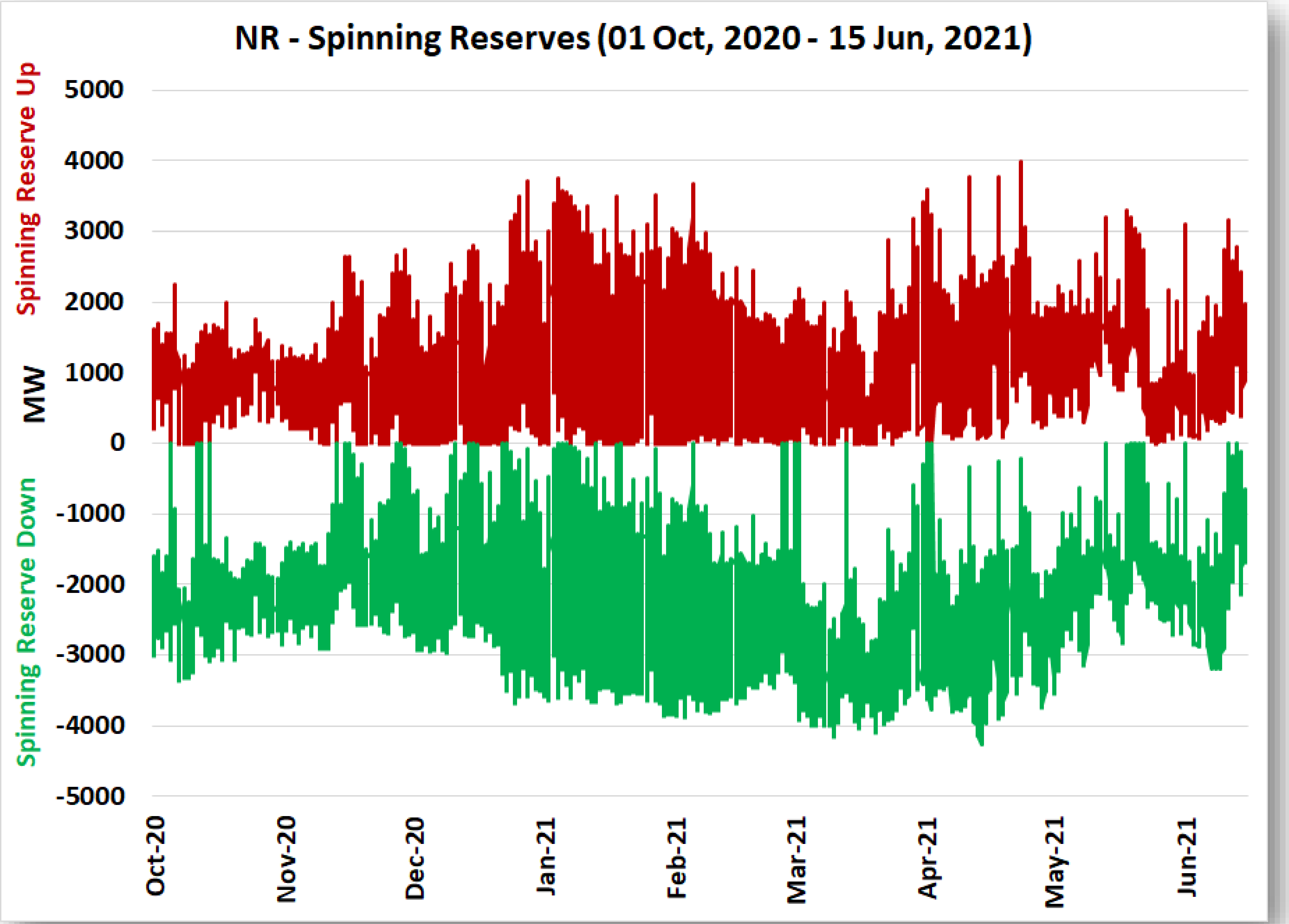

ER - Ramping Reserves (01 Oct, 2020 - 15 Jun, 2021)
Ramping Reserve Up
MW
Ramping Reserve Down
1600
1200
800
400
0
-400
-800
-1200
-1600
-2000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

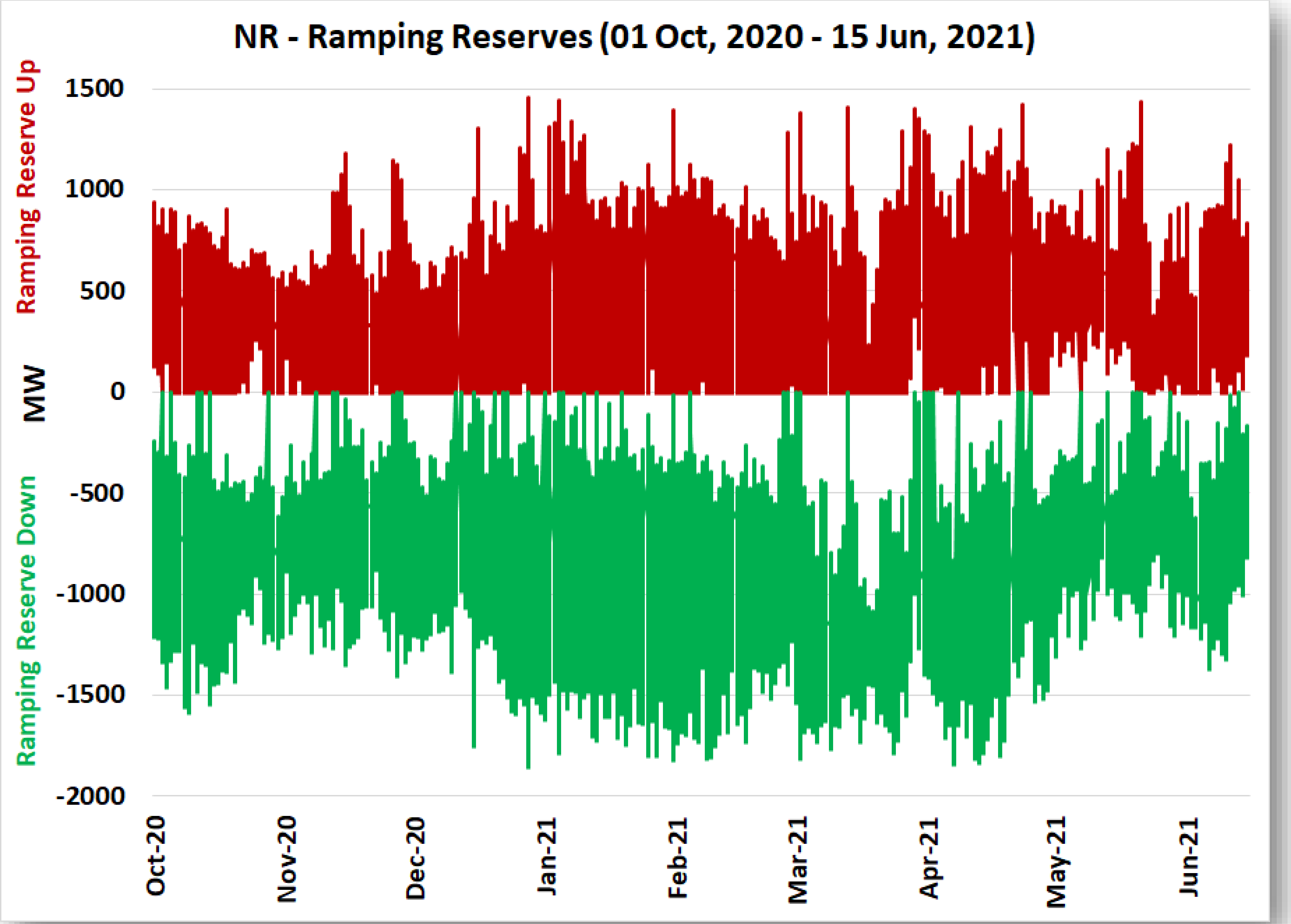


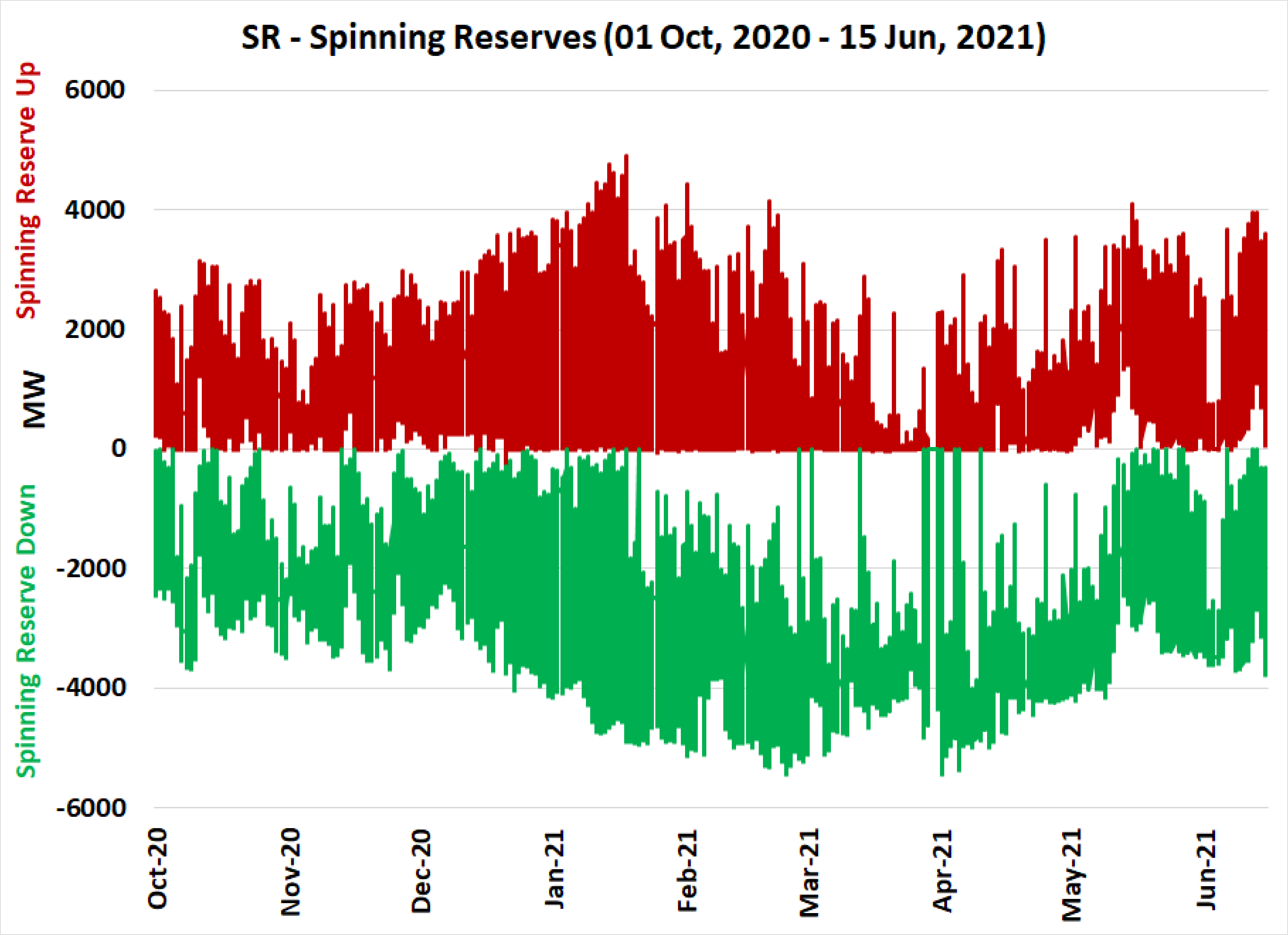
NER - Spinning Reserves (01 Oct, 2020 - 15 Jun, 2021)
Spinning Reserve Up
MW
Spinning Reserve Down
500
400
300
200
100
0
-100
-200
-300
-400
-500
-600
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

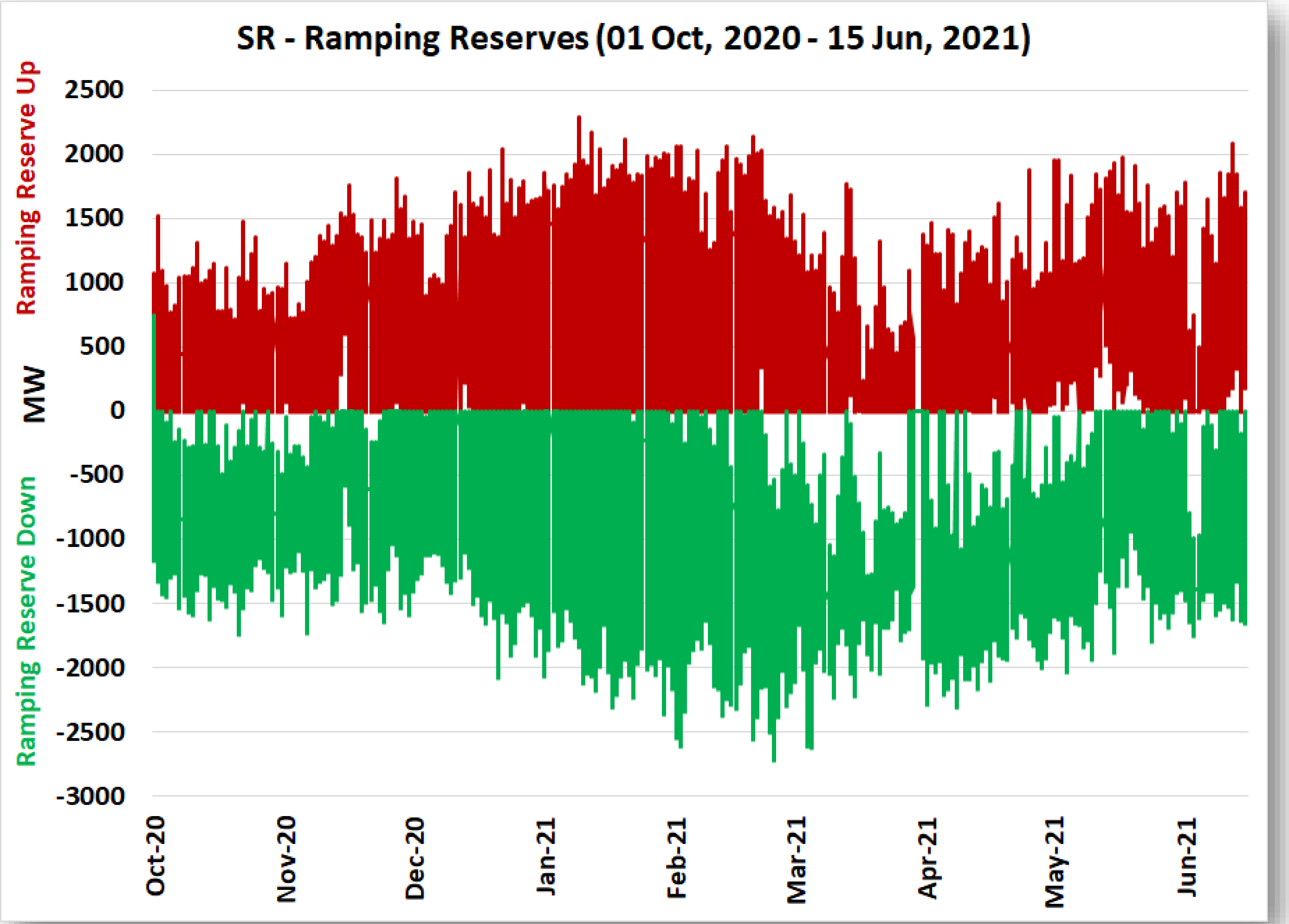


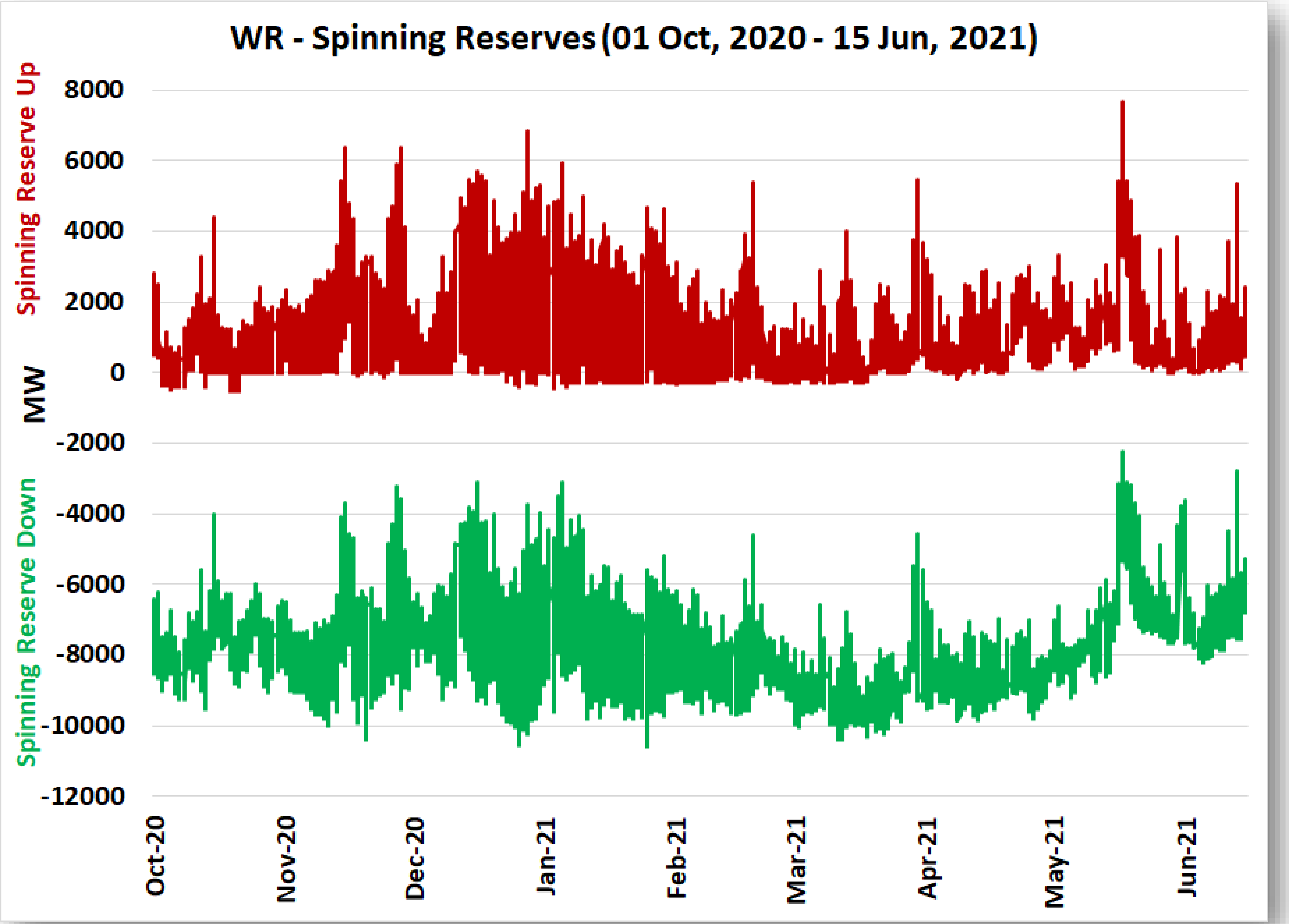
NER - Ramping Reserves (01 Oct, 2020 - 15 Jun, 2021)
Ramping Reserve Up
MW
Ramping Reserve Down
300
200
100
0
-100
-200
-300
-400
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

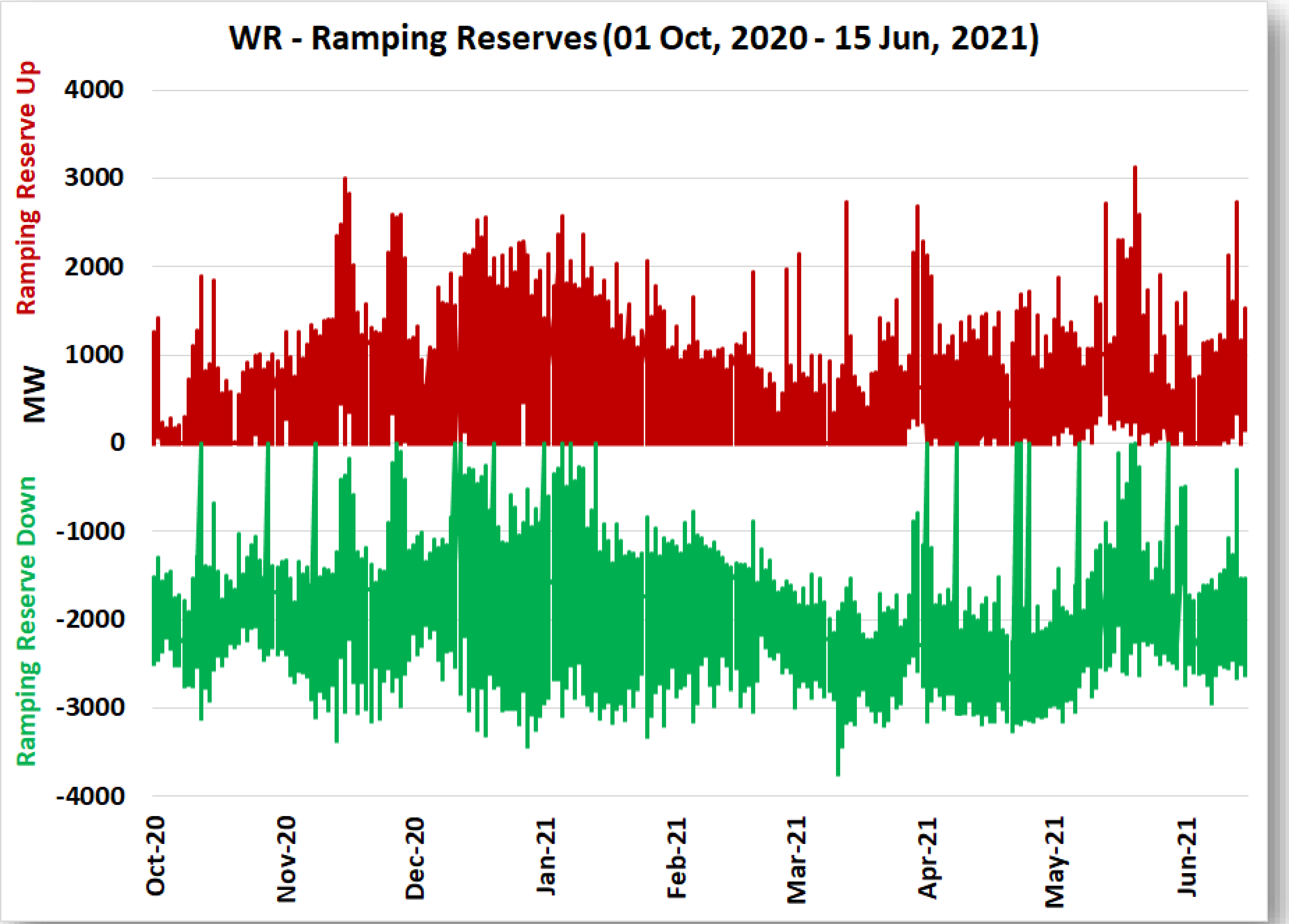

NR - Spinning Reserves (01 Oct, 2020 - 15 Jun, 2021)
Spinning Reserve Up
MW
Spinning Reserve Down
5000
4000
3000
2000
1000
0
-1000
-2000
-3000
-4000
-5000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21


NR - Ramping Reserves (01 Oct, 2020 - 15 Jun, 2021)
Ramping Reserve Up
MW
Ramping Reserve Down
1500
1000
500
0
-500
-1000
-1500
-2000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21


SR - Spinning Reserves (01 Oct, 2020 - 15 Jun, 2021)
Spinning Reserve Up
MW
Spinning Reserve Down
6000
4000
2000
0
-2000
-4000
-6000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21


SR - Ramping Reserves (01 Oct, 2020 - 15 Jun, 2021)
Ramping Reserve Up
MW
Ramping Reserve Down
2500
2000
1500
1000
500
0
-500
-1000
-1500
-2000
-2500
-3000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21


WR - Spinning Reserves (01 Oct, 2020 - 15 Jun, 2021)
Spinning Reserve Up
MW
Spinning Reserve Down
8000
6000
4000
2000
0
-2000
-4000
-6000
-8000
-10000
-12000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21


WR - Ramping Reserves (01 Oct, 2020 - 15 Jun, 2021)
Ramping Reserve Up
MW
Ramping Reserve Down
4000
3000
2000
1000
0
-1000
-2000
-3000
-4000
Oct-20
Nov-20
Dec-20
Jan-21
Feb-21
Mar-21
Apr-21
May-21
Jun-21

Voltage – (kV rms)		
Nominal	**Maximum**	**Minimum**
220	245	198
132	145	122
110	121	99
66	72	60
33	36	30

Appropriate LDC will take suitable measures to control the voltage as per its operating procedure.

(14) All users, transmission licensee shall provide adequate defence mechanism through under-voltage load shedding scheme (UVLS) as finalized by RPC, to prevent voltage collapse and shall ensure its effective application to prevent voltage collapse/ cascade tripping.

35. GENERATION RESERVE ESTIMATION AND FREQUENCY CONTROL

(1) The National Reference Frequency is 50.000 Hz. All Users, SLDCs, RLDCs and NLDC shall measure the grid frequency with a resolution of +/-0.001 Hz. The frequency data shall be archived at the rate of one sample every second.

(2) All Users, SLDCs, RLDCs, and NLDC shall take all possible measures to ensure that the grid frequency remains within the 49.95-50.05 Hz band.

(3) All possible endeavor shall be made by NLDC, RLDCs and SLDCs to bring the frequency back within the above band within fifteen (15) minutes of the start of excursion beyond the band through despatch of secondary and tertiary reserves.

(4) There shall be different levels of reserves such as primary, secondary and tertiary for the purpose of frequency control and regulating area control error. The reserves shall be deployed by each control area connected with the grid.

- Provision for primary reserve (governor droop response) shall be mandatory as per this code. The primary response of machines shall be verified by the load despatch centres during grid events.
- Secondary reserves (automatic generation control) shall be deployed by a control area as per this code.
- Tertiary reserves shall be deployed by control area as per this code.
- Any other type of reserves required to be deployed in the interest of grid security as per the direction of the SLDC, RLDC or NLDC.
- ESS reserves may be deployed by SLDC, RLDC or NLDC if required depending on the impact of variability of renewable generation and the need for frequency control.

(5) Primary Control

(a) Primary control is local automatic control in a generating unit for the purpose of adjusting its active power output in response to frequency excursion. Primary control is immediate automatic control implemented through turbine speed governors or frequency controllers. The generating units shall have their governors in operation at all times with droop settings of 3-6 % as per the requirements mentioned separately for each category in Table-2.

TABLE 2: PRIMARY RESPONSE RANGE OF VARIOUS TYPES OF GENERATING UNITS

Fuel/ Source	Min. Capacity /Requirement to fall in Primary Response purview	Upper ceiling limit (% of MCR)
Coal/Lignite Based	200 MW and above	105
Hydro	25 MW and above & non-canal based	110
Gas based	Gas Turbine above 50 MW	105 (corrected for ambience temperature)
Wind/ Solar (commissioned between 6th Aug 2019 -31st March 2022)	Capacity of Generating station more than 10 MW and connected at 33 kV and above	110 (subject to availability of capacity and commensurate wind speed in case of wind generating stations and solar insolation in case of solar generating stations)
Wind/ Solar/Hybrid (commissioned after 31st March 2022)^	Capacity of Generating station more than 10 MW and connected at 33 kV and above	105

^*Wind/ Solar/Hybrid plant commissioned after 31st March 2022 shall have the option to provide primary response individually through BESS or through a common BESS installed at its pooling station.*

(b) The normal governor action shall not be suppressed in any manner through load limiter, Automatic Turbine Run-up System (ATRS), turbine supervisory control, coordinated control system and no time delays shall be deliberately introduced. In case of renewable energy generating unit, reactive power limiter or power factor controller or voltage limiter shall not suppress the primary frequency response within its capability. The inherent dead band of a generating unit/frequency controller shall not exceed +/- 0.03 Hz.

Provided that for solar and wind generator (commissioned between 6th Aug 2019 to 31st March 2022) the dead band of frequency controller shall not exceed +0.05 Hz/-0.03 Hz.

(c) All generating stations mentioned in Table-2 above shall provide primary response shall have the capability of (and shall not in any way be prevented from) instantaneously picking up to minimum 105% of their operating level or 105% or 110% of their MCR, as the case maybe, when the frequency falls suddenly. After an increase in generation as above, a generating unit may ramp back to the original level at a rate of about one percent (1%) per minute, in case continued operation at the increased level is not sustainable. Any generating unit not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of RLDC.

(d) The thermal/hydro generating unit shall not resort to Valve Wide Open (VWO) operation of units whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response.

(e) The minimum primary reserve required for reference contingency shall be declared by NLDC at the start of each financial year.

(f) The primary reserves shall be activated immediately (within few seconds) when the frequency deviates from 50 Hz and the maximum steady state frequency deviation should not cross 0.30 Hz for the reference contingency.

(g) The power system must be operated at all the times with a minimum inertia to be specified by NLDC so that minimum nadir frequency post reference contingency stays above threshold set for UFLS. NLDC shall do the study in this regard and reschedule the generation (including curtailment of wind, solar and wind-solar hybrid generation) in coordination with RLDC/SLDC to maintain the minimum inertia.

(h) The primary reserve response shall start immediately and attain its peak in less than thirty (30) seconds, and shall sustain up to five (5) minutes.

(i) The minimum All India target frequency response characteristics and frequency response obligation of each control area shall be assessed by NLDC giving due consideration to generation and load within each control area and factors in Table 2 above. The same shall be informed to all control areas by 15th of March every year for the next financial year.

(j) The procedures at **Annexure-1** provides the methodology for the following:

- assessment of reference contingency,
- All India minimum target frequency response characteristics,
- calculation of frequency response obligation of each control area,
- criteria for reportable event and
- calculation of actual frequency response characteristics of control area
- calculation of frequency response performance

(k) NLDC in consultation with RLDC shall calculate actual frequency response characteristic of all the control areas. The performance of each control area in providing frequency response characteristic shall be calculated for each reportable event. Each control area shall separately assess their frequency response characteristic and share with RLDC along with high resolution data of at least one

(1) second for regional entity generating stations and ten (10) second for state control area.

(l) Each control area shall be graded based on median Frequency Response Performance annually (considering at least 10 events) as per following criteria:

TABLE 3: FREQUENCY RESPONSE CRITERIA

	Performance	Grading
i.	FRP ≥ 1	Excellent
ii.	0.85 ≤ FRP < 1	Good
iii.	0.75 ≤ FRP < 0.85	Average
iv.	0.5 ≤ FRP < 0.75	Below Average
v.	FRP < 0.5	Poor

(6) <u>Secondary and Tertiary Control</u>

(a) Secondary control is area-wise automatic generation control which regulates reserve power to bring area control error close to zero (0), consequentially restoring the frequency.

(b) Secondary control signals are generated at control centre (NLDC, RLDC, SLDC) as the Area Control Error (ACE) deviates from zero (0) and transmitted to generating stations/units within the control area jurisdictions for responding with desired change in generation.

(c) ACE of each control area/region shall be calculated as per following formula:

$$\mathbf{ACE = (I_a - I_s) - 10 * B_f * (F_a - Fs) + Offset}$$

Where,

I_a = Actual net interchange in MW (positive value for export)

I_s = Scheduled net interchange in MW (positive value for export)

B_f = Frequency Bias Coefficient in MW/0.1 Hz (negative value)

F_a = Actual system frequency in Hz

Fs = Schedule system frequency in Hz

Offset = means provision for compensating measurement error

Tie-line bias mode means AGC is correcting ACE according to the above equation, factoring deviation in area interchange **(I_a - I_s)** as well as frequency deviation **(F_a - Fs).**

i. Frequency Bias shall normally be equal to median FRC during previous financial year of each control area and refined from time to time.

ii. Offset shall be used to account for metering errors and shall be decided by SLDC/RLDC for its respective control area.

iii. Schedule system frequency (Fs) would normally be reference frequency of 50.000 Hz unless otherwise specified by NLDC for time correction.

iv. If AGC is operating in frequency sensitive mode only ignoring difference in area interchange i.e. (I_a - I_s), it would mean *flat frequency control.*

v. If AGC is operating in area interchange sensitive mode only ignoring difference in frequency i.e. (F_a - F_s), it would mean *flat tie-line control.*

(d) SLDC/RLDC/NLDC shall compute the ACE of respective control area in real time based on telemetered data. ACE data should be archived at the interval of 10 seconds or better if adequate measurement is available through synchro-phasor measurement.

(e) The secondary reserves through automatic generation control shall start responding within thirty (30) seconds of ACE of a particular control area going beyond the minimum threshold limit of +/- 10 MW.

(f) The required secondary reserves through automatic generation control shall be fully delivered within fifteen (15) minutes and shall be capable of sustaining for the next thirty (30) minutes thereafter.

(g) The secondary reserve capacity shall be computed by NLDC, RLDC, SLDC as per any of the following methodologies:

The positive and negative secondary reserve capacity for any control area for a financial year shall be equal to 99 percentile of positive and negative ACE respectively of that control area during the previous financial year,

OR

The secondary reserves capacity for any control area shall be equal to the 110 % of largest unit size in that control area plus load forecast error plus wind forecast error plus solar forecast error.

Provided that the All India secondary reserves capacity shall be equal to the reference contingency.

(h) This reserve capacity as per above regulation shall be calculated by respective control area by 15th February every year for next financial year and submitted to NLDC. NLDC would work out the minimum quantum of secondary reserves to be maintained at inter-state level (region-wise at regional entity generating station) and intra-state level for each control area. NLDC will publish the information on its website by 1st March every year which will be implemented for next financial year from 1st April onwards by control areas.

(i) The secondary reserves shall be maintained in regional entity generating stations for activation by RLDC/NLDC and Intra-state generating stations for activation by respective SLDC. Energy Storage Systems (ESS) and/or demand response may also be deployed for providing adequate secondary response,

(j) Secondary control through automatic generation control shall be provided by generating stations/ ESS as per the following Table:

S. No.	**Generating unit/ ESS category**	**Control Centre for supervision**	**Start Date for Application**
1	Regional entity generating stations with CERC regulated or adopted Tariff (Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW)	NLDC	On or before 1st Apr 2020
2	Other Regional entity generating stations not covered under Sl.No.1(Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW) and ESS for providing secondary response	NLDC	To be notified by Commission
3	State (having annual Peak demand more than 10 GW or renewable energy rich states) generating stations (Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW) and ESS for providing secondary response	SLDC	On or before 1st Apr 2021
4	State (not covered under Sl. No. 3) generating stations (Thermal with rated capacity more than 200 MW and Hydro with rated capacity more than 25 MW) and ESS for providing secondary response	SLDC	To be notified by the Commission or earlier if agreed by State. However secondary reserves within the state shall be activated manually till the implementation of AGC.

(k) Similar mechanism shall be implemented at state level for intra-state generating station. NLDC, RLDC or SLDC would indicate the short fall in secondary reserves and announce emergency alerts for such periods.

(l) Normal mode of operation of AGC would be tie-line bias control. NLDC may also operate select region/country automatic generation control on flat frequency control mode during anticipated congestion free period or flat tie-line mode.

(m) Tertiary reserves maybe arranged from the generating stations, ESS and/or demand response. Tertiary reserve shall be greater or equal to secondary reserves to take care of contingencies, and shall be maintained at both regional entity level as well as state control area. Tertiary reserves activation would restore the secondary reserves to the desired level.

(n) The tertiary reserve shall be fully activated within fifteen (15) minutes of operator's instructions from appropriate load despatch centre and shall be capable of delivering until next 60 minutes. Instruction for tertiary reserve activation shall be given by appropriate load despatch centre based on the following:

   i. When area control error (more than 100 MW) persists for more than fifteen (15) minutes in one direction;

   ii. In the event of loss of generation or loss of load of more than 100 MW in the control area;

   iii. In case the secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW, then tertiary reserves shall be triggered in order to replenish the secondary reserve;

iv. Any other condition such as mitigating local congestion due to transmission lines.

(o) Each state control area shall keep reserve capacity one day in advance and inform RLDC as outlined in the scheduling code.

(p) The secondary and tertiary reserves shall be arranged by the RLDC and SLDC according to the mechanism decided by the appropriate commission.

(q) The control area wise performance of secondary and tertiary control shall be evaluated in accordance with the detailed procedure prepared by NLDC.

36. OPERATIONAL PLANNING

(1) <u>Introduction</u>

(a) Operational planning for ensuring reliable and secure operation in real time shall be carried out in advance by the concerned agency as per the following time table:

Time Horizon	**Agency**
Monthly/Yearly	RPC/CTU/STU/NLDC/RLDC/SLDC
Weekly	NLDC/RLDC/SLDC
Day Ahead	NLDC/RLDC/SLDC
Intra-day	NLDC/RLDC/SLDC

(b) NLDC and RLDC shall issue a procedure for all users, CTU and STU for:

i. Operational planning analysis,

ii. Real-time monitoring,

iii. Real-time assessments and

iv. Format for data submission and updating

Annexure - 5

Major Highlights on Power System Reserves from Report of the Expert Group: Review of Indian Electricity Grid Code

1. Planning code has been made exhaustive to cover the following:
    i. Demand Forecasting
    ii. Generation resource planning (flexibility, ramping, minimum turndown level),
    iii. Requirements of energy storage system
    iv. System reserves
    v. System-inertia for grid stability
    vi. Inter-state system planning (including re-optimization system study, adequacy, enhancement of total transfer capability (TTC) across inter-regional boundaries as well as ISTS interfaced with STU network)

2. Connection code made applicable to the generators as well as the transmission licensees. The code specifies the tests required before trial run to asses technical capabilities of the elements.
3. A new chapter on protection and commissioning code has been added which also lists flexibility required by generators before declaration of commercial operation.
4. The nominal frequency band has been narrowed from 49.90- 50.05 Hz to 49.95-50.05 Hz band.
5. Frequency response via primary, secondary and tertiary response has been added. The primary response (via Free Governor Mode of Operation) 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.
6. The quantum of reserve capacity required to be maintained for grid security is related to credible contingency including net error in the forecasts of demand and renewable generation.
7. An institutional mechanism (Qualified Coordinating Agency) for the composite scheduling and common deviation settlement of renewable generating stations at one or more pooling stations has been provided.
8. Report mandates adequacy of generation resources for round the clock supply to all consumer categories. It proposes load shedding through demand response contracts or through special protection schemes in the event of an emergency situation.

9. In the event of transmission or system security constraint, the renewable generation may be curtailed after harnessing available flexible resources including energy storage systems.
10. SLDC/RLDC shall calculate the desired secondary reserve to be kept in their control areas at the beginning of each financial year and submit to NLDC.
11. The quantum of reserves earmarked for secondary would be based on the data of last year ACE , will be taking care of exceptional high values due to weather related phenomenon or any other exceptional circumstances.
12. The AGC need to act as early as possible after the event, a time of 30 seconds has been provided for activation of secondary reserves. The secondary control thus activated will be deployed fully within 15 minutes and continue at this level for next 30 minutes.
13. It is desirable that reserves should be provided locally by the control area. The responsibility to provide reserve response should be shared by all Control Areas in a distributed manner in the interest of grid security and in a participative manner so that there is no tendency to pass on the responsibility to other entities.
14. Tertiary reserves may be arranged from the generating stations, ESS and/or through demand response. Tertiary reserve shall be greater or equal to secondary reserves to take care of contingencies, and shall be maintained at both regional entity level as well as state control area.
15. The Security Constrained Unit Commitment (SCUC) exercise shall 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, Provided that, the payment of carrying cost for the generation reserves committed through SCUC shall be as specified by the commission.
16. In order to ensure availability of adequate secondary and tertiary reserves with sufficient ramping capability, NLDC shall identify the generating unit for purpose of unit commitment at the national level three (3) days in advance of actual day of scheduling for regional entity generating stations on a rolling basis. NLDC, through RLDC shall advise the regional entity generators to commit or de-commit the unit.

---------x--------

Table-1: References in Draft Grid Code (as per recommendations of Expert Group)

S.No.	Subject	Clause No.	Page No.
1	Reserve in planning dimensions	15 , (i) (c)	37
2	Reserve in resource planning	15, (2) (b)	39
3	Generation Reserve Estimation	35	71
4	Reserve in LGBR	37	86
5	Reserve adequacy in Demand management	41, (i) (b)	96
6	Reserves in control area jurisdiction	49 (1)	107
7	Reserves in functions of control area	50 (g)	109
8	Reserves in SCUC	52 (2)	123

Annexure - 6

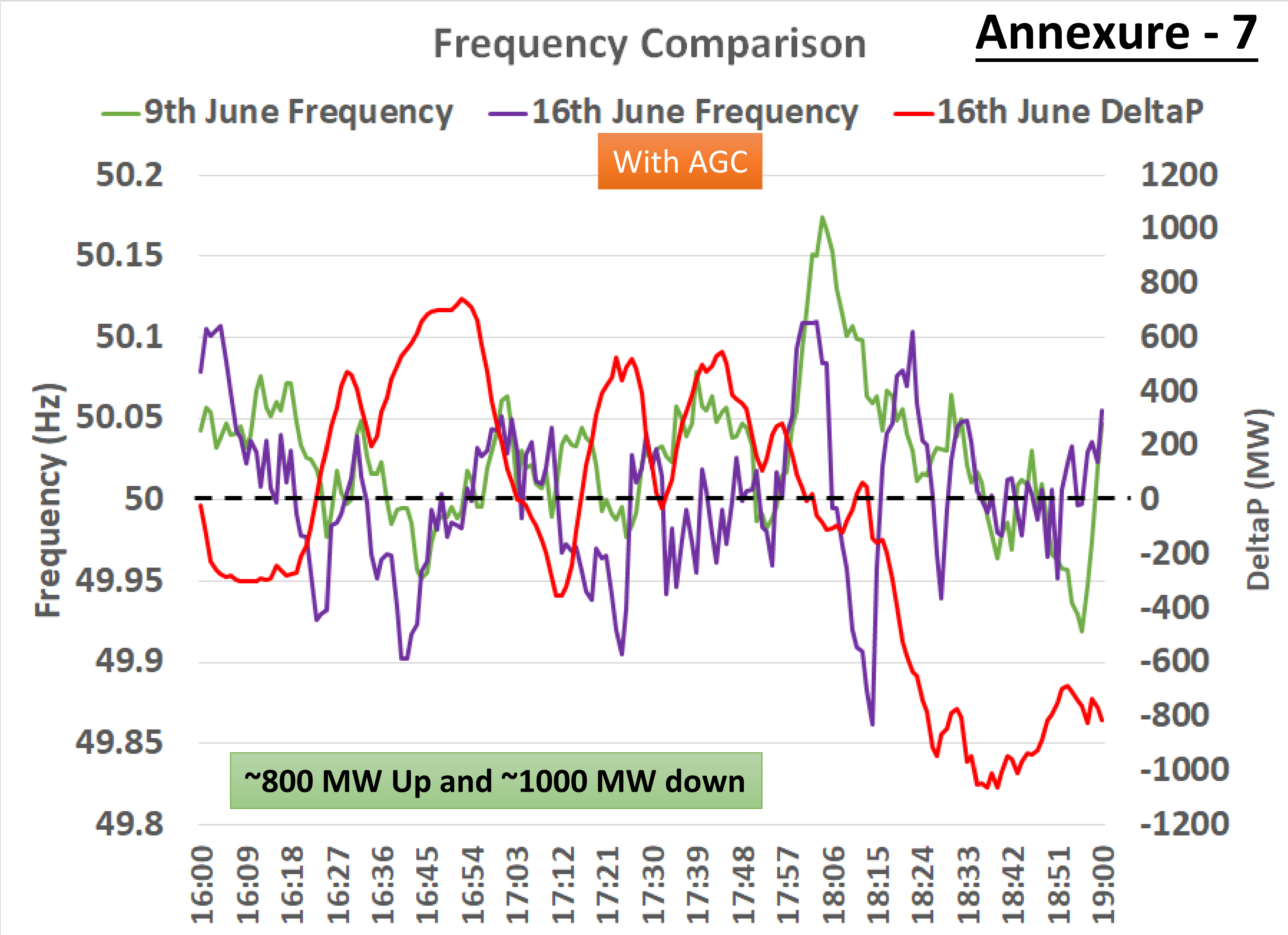
Format-AS4:Day Ahead Load Forecast by SLDC

State: ....

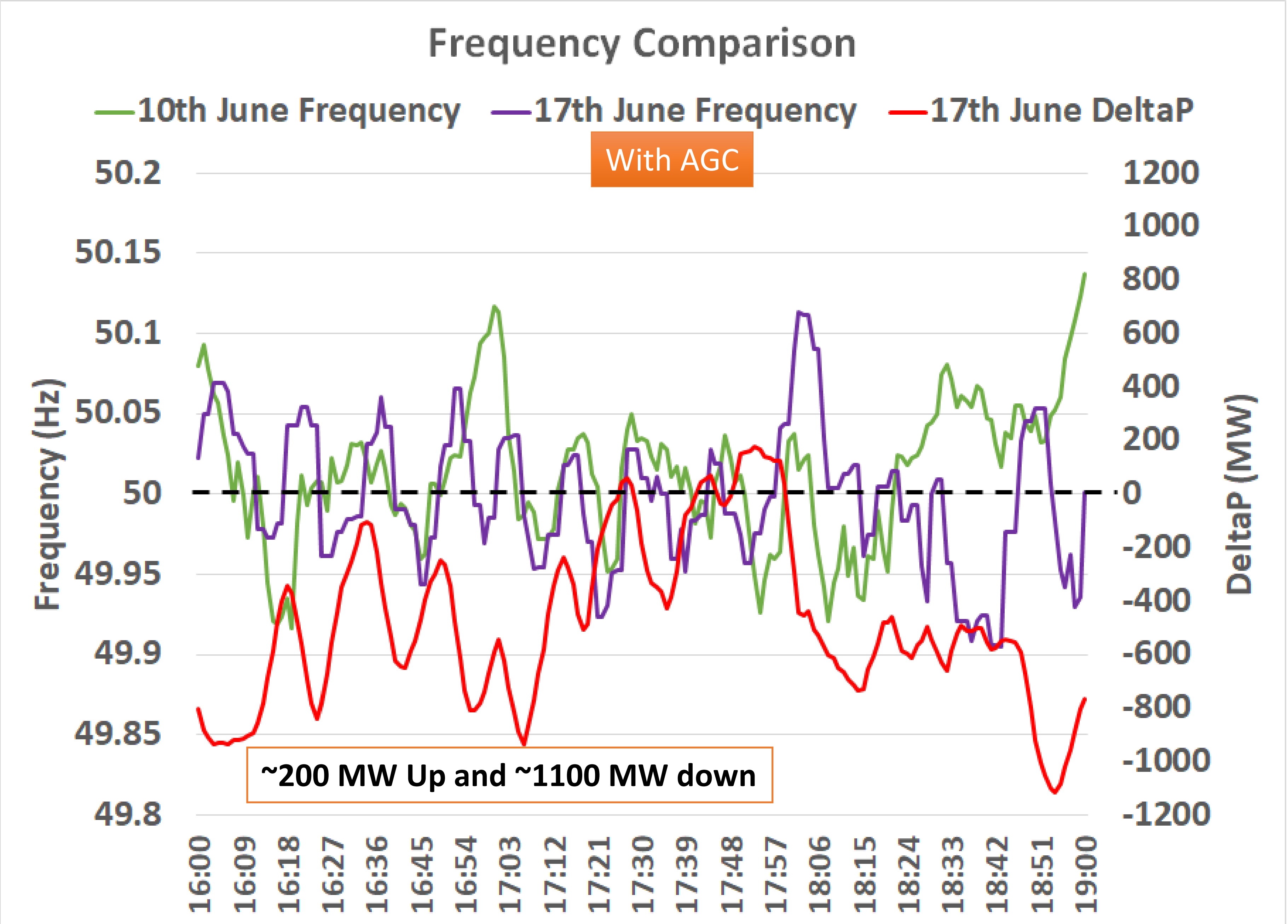
Forecast Done on Date (D):.................. **Forecast for Date (D+1):................**

Time Block	Actual Demand met for day D-1 (MW)	Forecasted Load for day D+1 (MW) (X)	Total Quantum tied up to meet forecasted demand in Net MW				
			Own Generation (A)	ISGS/Long Term (B)	Medium Term (C)	Short Term (D)	Total tied up Y = (A+B+C+D)
1							
2							
3							
.							
.							
.							
.							
.							
95							
96							

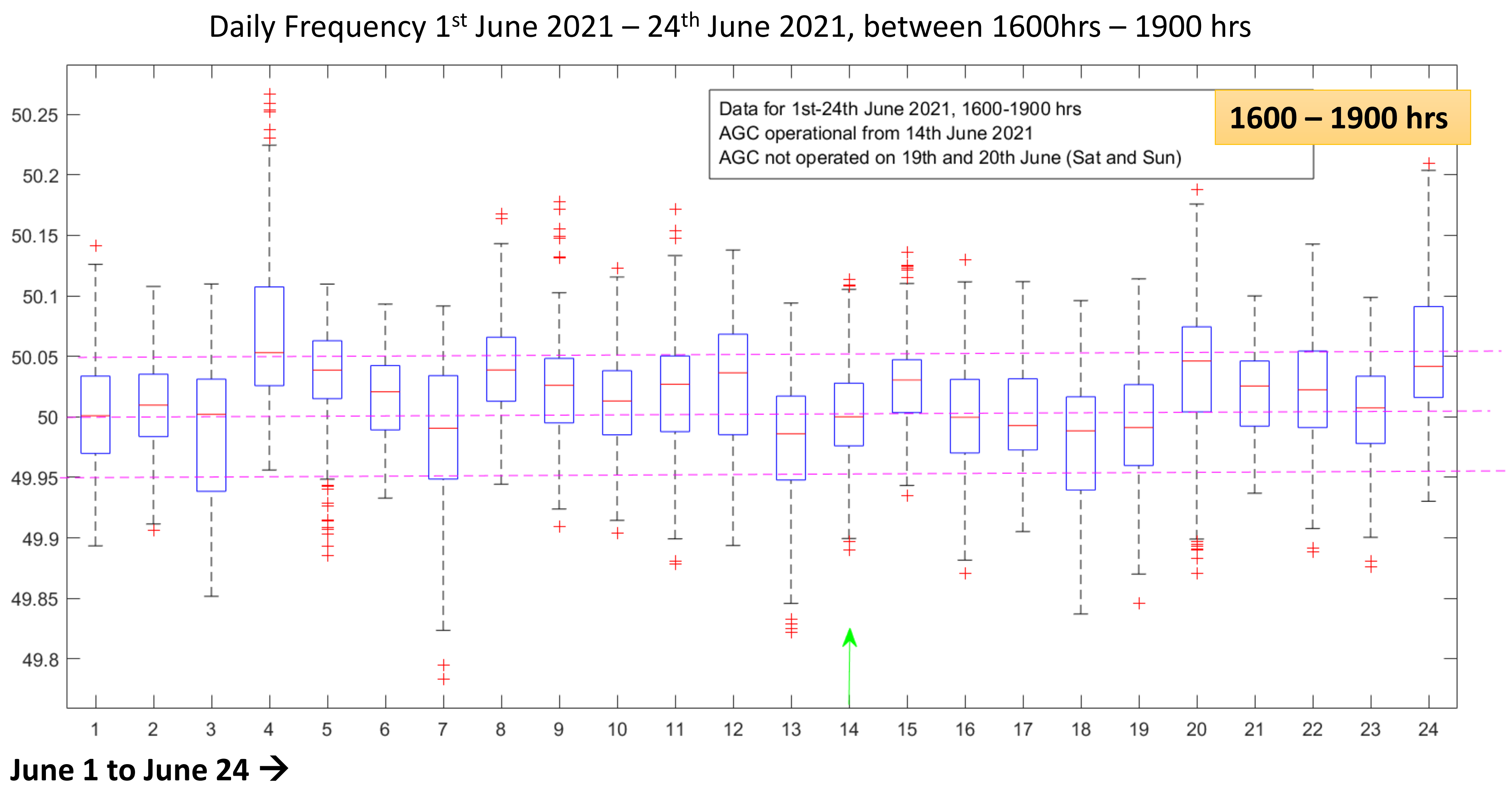
(To be transmitted to concerned RLDC electronically)

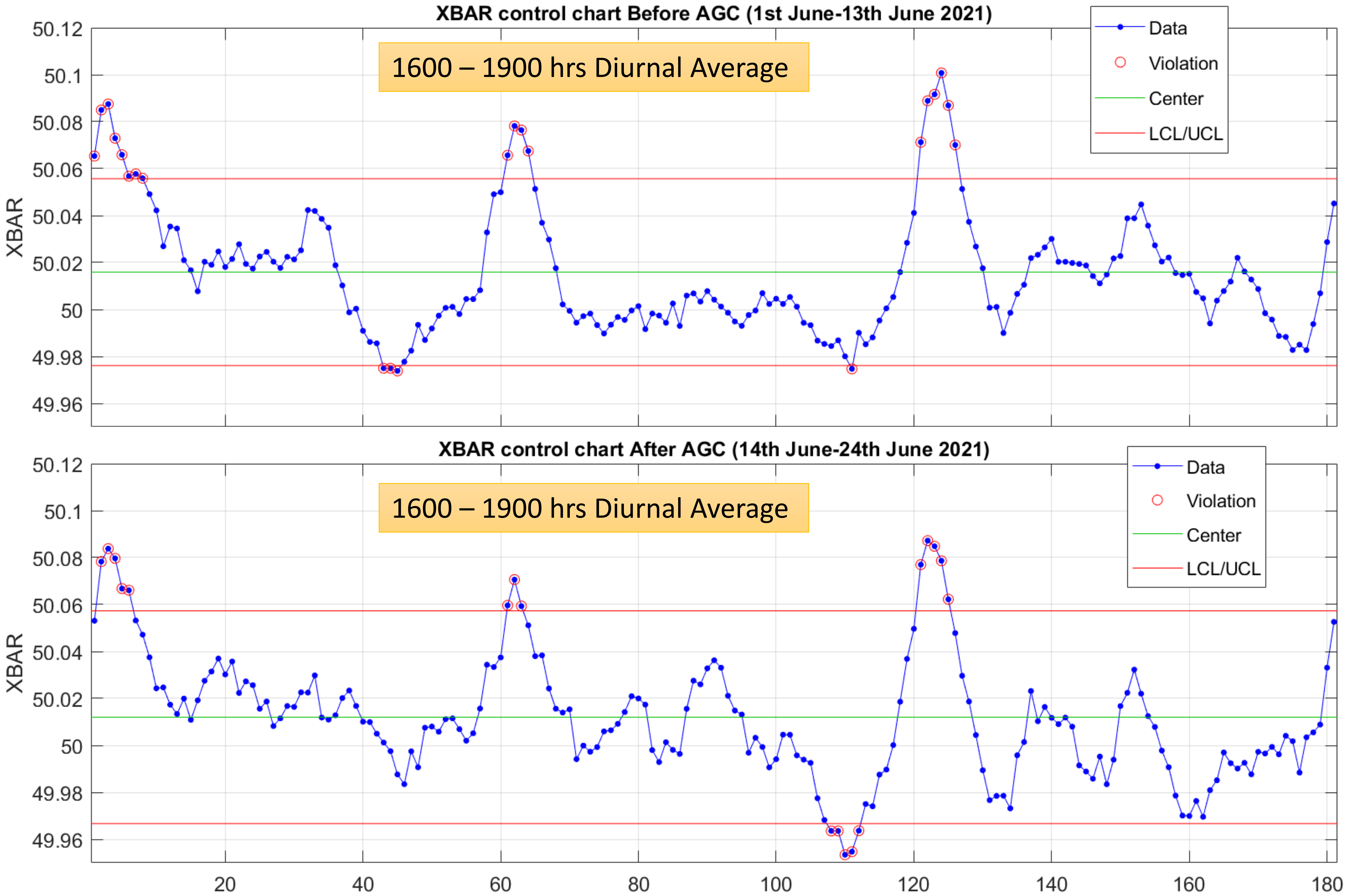


Annexure - 7
Frequency Comparison
9th June Frequency
16th June Frequency
16th June DeltaP
With AGC
~800 MW Up and ~1000 MW down
Frequency (Hz)
DeltaP (MW)
50.2
50.15
50.1
50.05
50
49.95
49.9
49.85
49.8
1200
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
-1200
16:00
16:09
16:18
16:27
16:36
16:45
16:54
17:03
17:12
17:21
17:30
17:39
17:48
17:57
18:06
18:15
18:24
18:33
18:42
18:51
19:00



Frequency Comparison
10th June Frequency
17th June Frequency
17th June DeltaP
With AGC
~200 MW Up and ~1100 MW down
Frequency (Hz)
DeltaP (MW)
50.2
50.15
50.1
50.05
50
49.95
49.9
49.85
49.8
1200
1000
800
600
400
200
0
-200
-400
-600
-800
-1000
-1200
16:00
16:09
16:18
16:27
16:36
16:45
16:54
17:03
17:12
17:21
17:30
17:39
17:48
17:57
18:06
18:15
18:24
18:33
18:42
18:51
19:00


Daily Frequency 1st June 2021 – 24th June 2021, between 1600hrs – 1900 hrs
Data for 1st-24th June 2021, 1600-1900 hrs
AGC operational from 14th June 2021
AGC not operated on 19th and 20th June (Sat and Sun)
1600 – 1900 hrs
50.25
50.2
50.15
50.1
50.05
50
49.95
49.9
49.85
49.8
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
June 1 to June 24 →

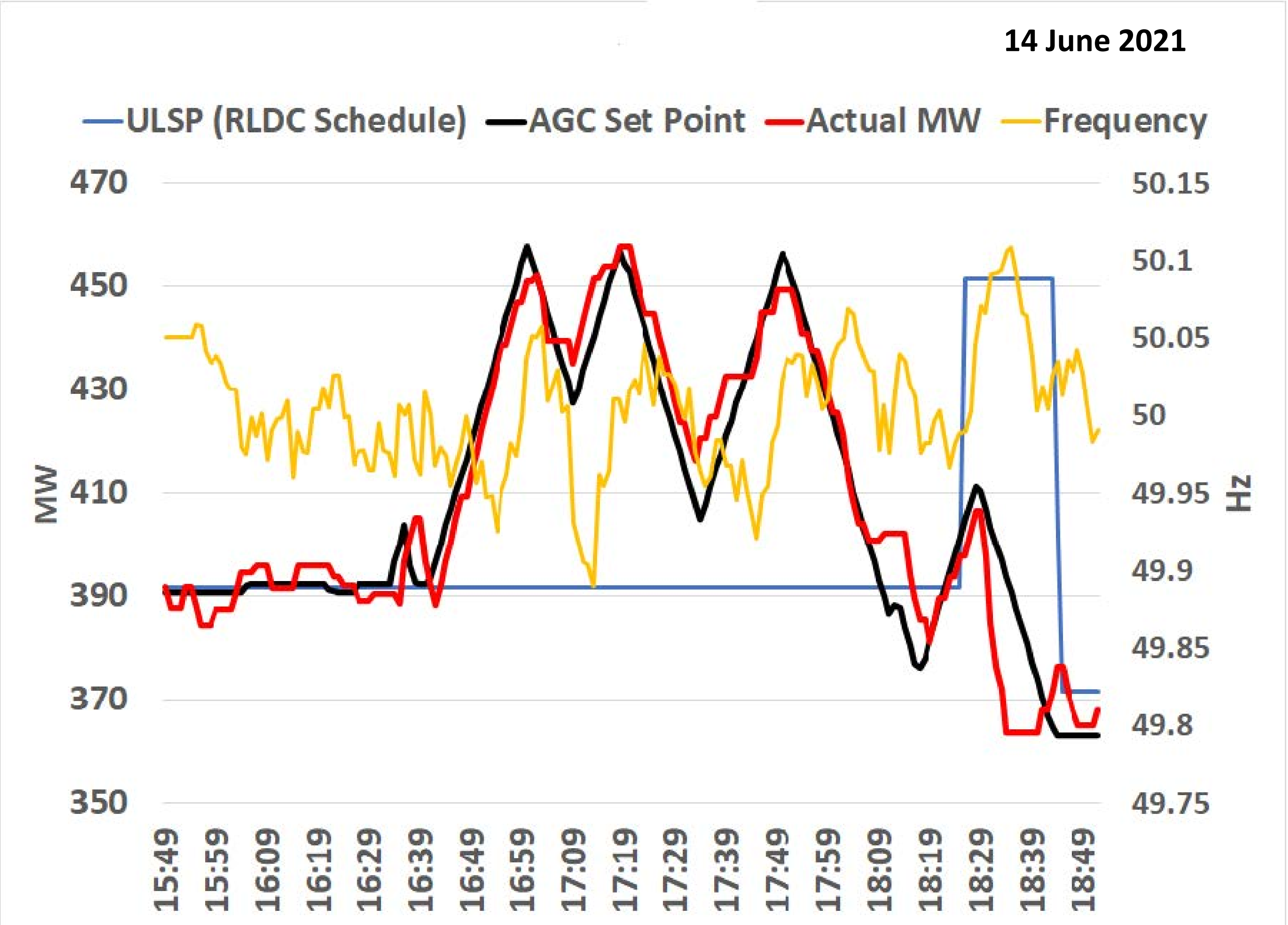


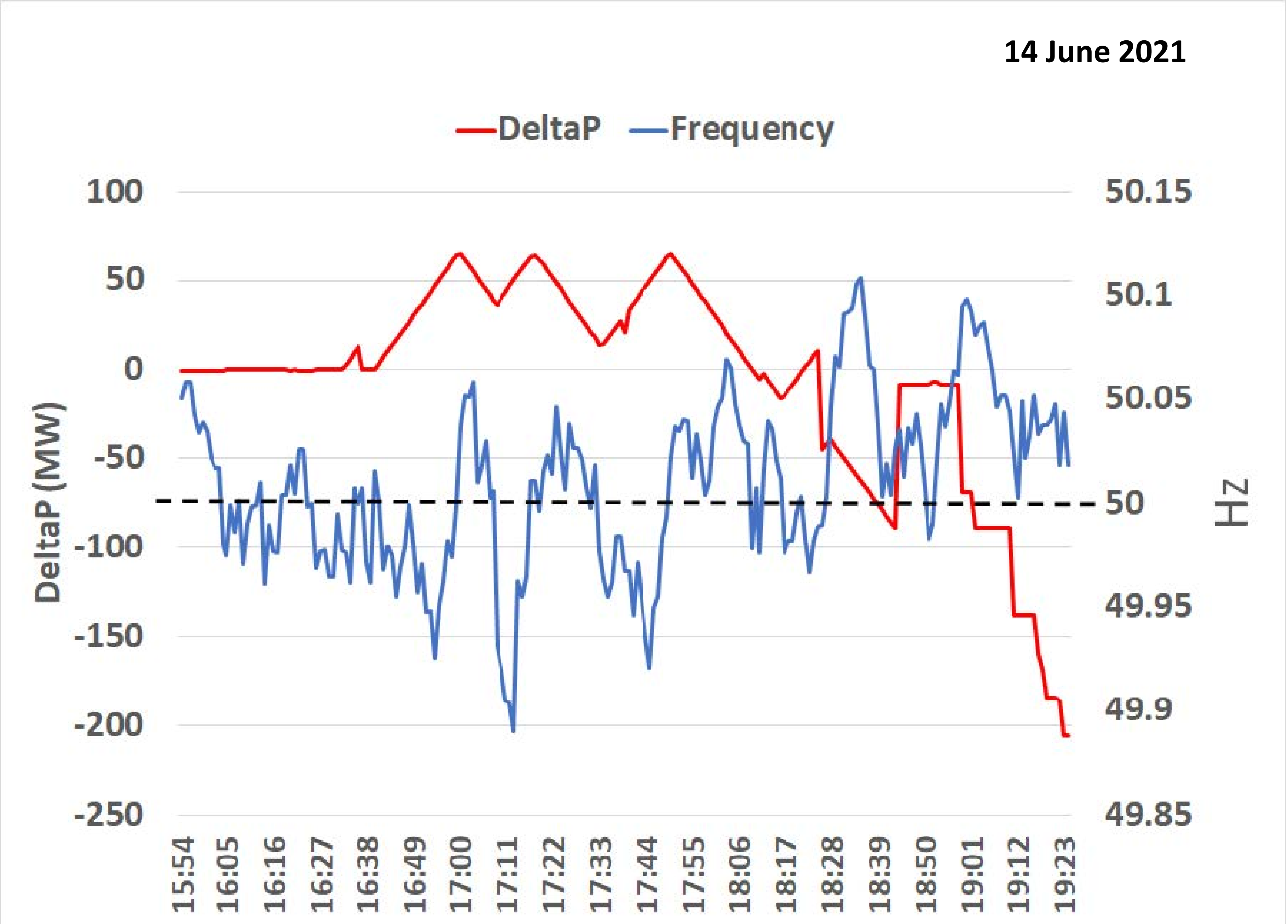
XBAR control chart Before AGC (1st June-13th June 2021)
1600 – 1900 hrs Diurnal Average
Data
Violation
Center
LCL/UCL
XBAR
50.12
50.1
50.08
50.06
50.04
50.02
50
49.98
49.96
XBAR control chart After AGC (14th June-24th June 2021)
1600 – 1900 hrs Diurnal Average
20
40
60
80
100
120
140
160
180

XBAR Control Chart

- The chart plots the “mean” of the data in time order.
- Center line (CL) is at the average of the mean.
- UCL and LCL (+/-3 sigma) lines are drawn in such a way that 99.7% of the data points fall between them.
- Measurements crossing LCL/UCL are marked as violations and drawn with a red circle.

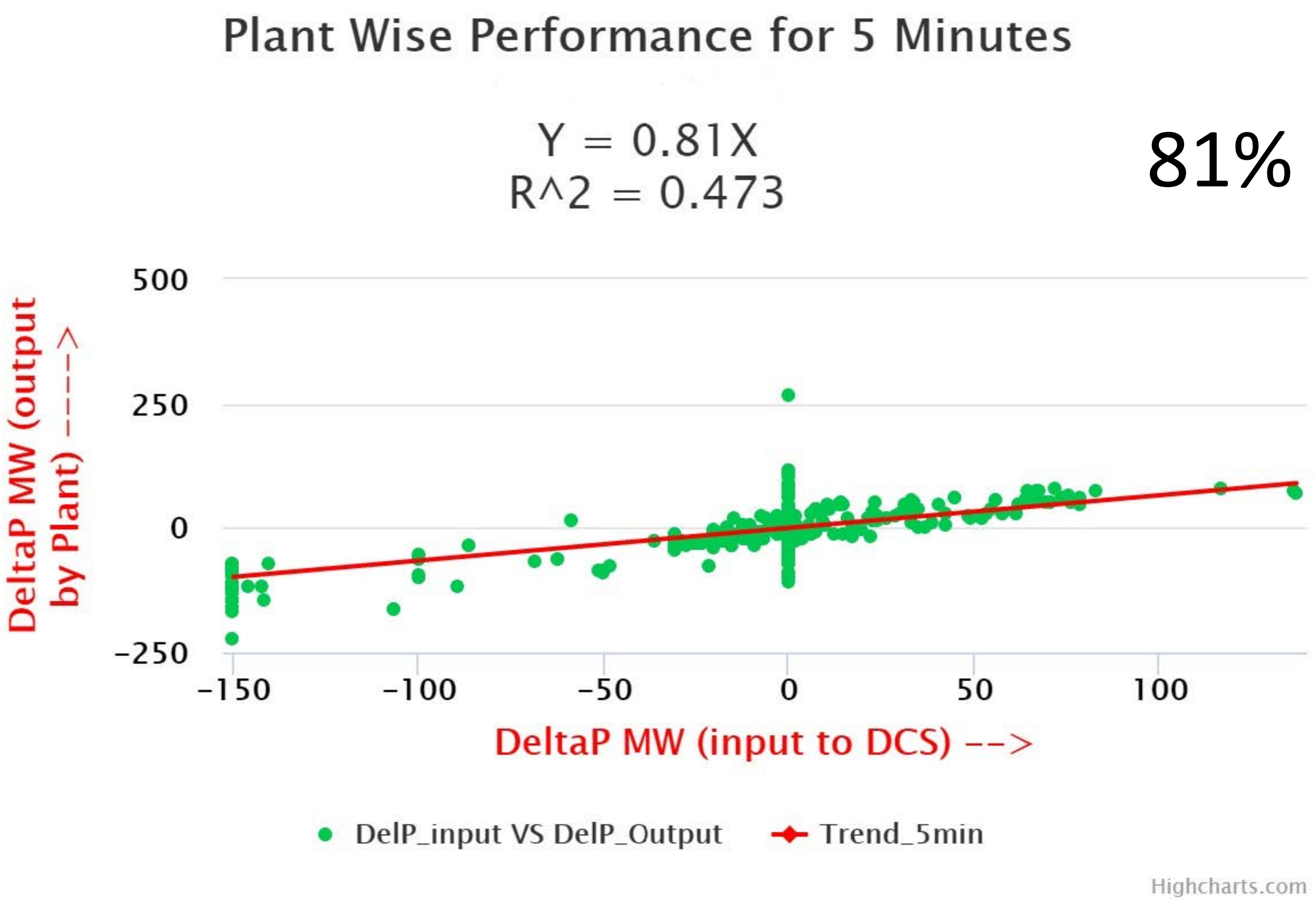
Sample Plant Response to AGC signals


14 June 2021
ULSP (RLDC Schedule)
AGC Set Point
Actual MW
Frequency
MW
Hz
470
450
430
410
390
370
350
50.15
50.1
50.05
50
49.95
49.9
49.85
49.8
49.75
15:49
15:59
16:09
16:19
16:29
16:39
16:49
16:59
17:09
17:19
17:29
17:39
17:49
17:59
18:09
18:19
18:29
18:39
18:49


14 June 2021
DeltaP
Frequency
100
50
0
-50
-100
-150
-200
-250
DeltaP (MW)
50.15
50.1
50.05
50
49.95
49.9
49.85
Hz
15:54
16:05
16:16
16:27
16:38
16:49
17:00
17:11
17:22
17:33
17:44
17:55
18:06
18:17
18:28
18:39
18:50
19:01
19:12
19:23

Sample Plant AGC Performance

Using 5 min Average data



81%

पावर सिस्टम ऑपरेशन कॉर्पोरेशन लिमिटेड
(भारत सरकार उद्यम)
POWER SYSTEM OPERATION CORPORATION LIMITED
(A Government of India Enterprise)

केन्द्रीय कार्यालय : 61, आई एफ सी आई टावर, 8 एवं 9वी मंजिल, नेहरू प्लेस, नई दिल्ली-110019
Corporate Office : 61, IFCI Tower, 8 & 9th Floor, Nehru Place, New Delhi - 110019
CIN : U40105DL2009GOI188682, Website : wwwposoco.in, E-mail : posococc@posoco.in, Tel.: 011-40234672

Date: 22nd March, 2021

The Secretary,
Central Electricity Regulatory Commission
Chandra Lok, 36, Janpath,
New Delhi

Sub: Report on Reactive Power Management and Voltage Control Ancillary Services in India

Dear Sir,

Reliable operation of electricity grids necessitates proper voltage control measures and management of reactive power flows in the network. Given the long transmission lines designed for power transfer to load centers and intra-day/seasonal variations in demand, the management of reactive power becomes highly challenging for system operators and utilities in India. For more than last four decades, reactive power requirements have been dealt by planning shunt reactors, capacitors and mandatory support from conventional generators. These schemes have paid rich dividends till now, however there is a need to bring in a different approach as more wind and solar get integrated to the system with the accompanying variability and intermittency leading to large change in network flows.

In this connection, a study has been undertaken by POSOCO and a report in this regard is enclosed which may be helpful in introduction of Voltage Control Ancillary Services in Indian power system. This is for kind information of the Hon'ble Commission and suitable directions in the matter.

Thanking you,

Yours faithfully,

बाबा

(KVS Baba)
Chairman & Managing Director

Reactive Power Management and Voltage Control Ancillary Services (VCAS) in India

Power System Operation Corporation Ltd.

(A Government of India Enterprise)

March 2021

TABLE OF CONTENT

1. List of Tables

2. List of Figures

3. List of Acronyms

RRAS: Reserves Regulation Ancillary Services
FRAS: Fast Response Ancillary Services
AGC: Automatic Generation Control
VCAS: Voltage Control Ancillary Services
ISTS: Inter State Transmission System
NREB: Northern Regional Electricity Board
ECC: ECC INC.
IEGC: Indian Electricity Grid Code
ISGS: Inter State Generating Station
RLDC: Regional Load Despatch Centre
WRLDC: Western Regional Load Despatch Centre
ERLDC: Eastern Regional Load Despatch Centre
SRLDC: Southern Regional Load Despatch Centre
NRLDC: Northern Regional Load Despatch Centre
NERLDC: North Eastern Regional Load Despatch Centre
NLDC: National Load Despatch Centre
SLDC: State Load Despatch Centre
RMS: Root Mean Square (RMS)
CERC: Central Electricity Regulatory Commission
CEA: Central Electricity Authority
EHV: Extra High Voltage
HVDC: High Voltage Direct Current
HV: High Voltage
LV: Low Voltage
STATCOM: Static Synchronous Compensators
SVC: Static VAr Compensators
VSC: Voltage-Sourced Converter
SEM: Special Energy Meter
SAMAST: Scheduling, Accounting, Metering and Settlement of Transactions in Electricity
DC: Direct Current
AC: Alternating Current
MW: Mega-Watts
ER: Eastern Region
WR: Western Region
SR: Southern Region
NER: North-Eastern Region
NR: Northern Region
UEL: Under Excitation Limiter

Over Excitation Limiter
SC: Synchronous Compensator / Series Capacitor
POI: Point of Interconnection
RE: Renewable Energy
TCR: Thyristor Controlled Reactor
SIL: Surge Impedance Loading
ICT: Inter-Connecting Transformer
IEC: International Electro Technical Commission
FERC: Federal Energy Regulatory Commission
AVR: Automatic Voltage Regulator
ISO: Independent System Operators
NERC: North American Electric Reliability Corporation
SEB: State Electricity Board
TSO: Transmission System Operator
ENTSO-E: European Network of Transmission System Operators for Electricity
ERCOT: Electric Reliability Council of Texas
CAISO: California Independent System Operator
PPM: Power Park Module
MCR: Maximum Continuous Rating
FACTS: Flexible Alternating Current Transmission Systems
ISTS: Inter State Transmission System
ISGS: Inter-State Generating Station
ISO-NE: ISO New England
AEP: American Electric Power
NYISO: New York Independent System Operator
MISO: Midcontinent Independent System Operator
CAISO: California Independent System Operator
SCL: Short-circuit level
PV: Photo-voltaic
PPC: Power Plant Controller
GT: Generator Transformer
HV: High Voltage
LV: Low Voltage
NREL: National Renewable Energy Laboratory
UAT: Unit Auxiliary Transformer
TCC: Technical Coordination Sub-committee
NRPC: Northern Regional Power Committee
OLTC: On Load Tap changer
BESS: Battery Energy Storage System
USAID: United States Agency for International Development

GTG: Greening the grid
VRE: Variable Renewable Energy
DSM: Deviation Settlement Mechanism
CTU: Central Transmission Utility
DER: Distributed Energy Resources
PT: Potential Transformer
CVT: Capacitive Voltage Transformer
POD: Point of Delivery
IC: Installed Capacity
DISCOM: Distribution Companies

4. Executive Summary

The reactive power management conundrum continues to challenge the power systems around the world. The variability, localized nature of reactive power and affecting/getting affected by almost all the facets of power system viz. generation, transmission, distribution and consumption make reactive power a unique and vital parameter.

The voltage control ancillary services are a part of many power grids around the world. However, in the Indian power system, for the last two decades, instead of direct ancillary service stature for voltage control, reactive power requirements are managed by mandatory support from grid-connected generators. Further, there is a charge for reactive exchanges, depending on the voltage conditions. Though these schemes have paid dividends in past, there is a need to bring in a different approach to reinforce the present and future in view of unprecedented and ongoing renewable integration. This report looks into the introduction of such an approach via voltage control ancillary services in the Indian power system.

In India, during the early seventies to early nineties, the voltages at the transmission level used to be so low, even the synchronization of generating unit with the grid or start of synchronous condensers used to face hindrance. However, with the introduction of proper checking mechanisms and expansion of the transmission network, the voltage deviations were curbed to some extent.

At present, the grid is experiencing seasonal high voltages, predominantly during winter and lean load hours. For instance, the Indian grid experiences voltages higher than operating limits at more than half of the nodes for 10-20% of the time. On an average, around sixty-five (65) lines at 400 kV level and above are opened on daily basis to control high voltages and in a few instances tripping incidents are reported on account of over-voltage and over-flux. In India, different regions have different demand characteristics depending largely on the weather, type of load (Industrial/Household/Commercial, etc.), population, events/festivals, etc. The power system has been planned to cater peak or high demand. Thus, during off peak or low demand hours, a large portion of the transmission network remains offloaded rendering net generation of reactive power (VAr) from transmission lines leading to high voltages. On the other hand, during peak hours, high line loading and low load power factor lead to low voltages. Further, as more and more renewable generation (low inertia) is replacing the conventional generators, the diminishing system inertia is posing new challenges to the grid stability and growing concern to the grid operators. This report highlights the voltage stability issues and explores the optimum/effective utilization of various reactive resources available in the system to provide voltage support. Voltage control ancillary services in Indian power system is one of the approach discussed in this report.

If we look at the financial compensation for voltage control ancillary services, many of the deregulated markets are yet to establish a mechanism for the same. The report extensively covers an analysis of these kinds of market mechanisms in place across different grids worldwide.

In the end, a framework is proposed which could be implemented for enhancing reactive support to the grid. This includes:

- Payment mechanism for conventional as well as renewable resources
- Exploiting synchronous condenser operation of hydro plants and reactive support from renewable plants' operation during "no generation" period
- A separate regulation for addressing the voltage control related matters among others.

Reactive power is like the *chlorophyll* for the GREEN future and this document is aimed at preserving the pigmentation.

1. Introduction

A power grid caters to various electricity needs, while experiencing a lot of ongoing dynamics. The real power essentially does the useful work. However, the reactive power is the one which builds the voltages at nodes, travels across the power system, supplies fault currents and keeps voltages in check, if managed optimally. Reactive power directly influences voltages in the grid, which, if not kept within limits, may lead to local or large-scale disturbances. Large disturbances across the world indicate inadequate reactive power compensation as one of the prime reasons[1]; several steps have been taken world over to address this issue.

In India, right from the very first grid code in year 2000 (IEGC), reactive power has been given due importance. After the 2012 grid collapse, the enquiry committee also suggested few proactive measures to tackle reactive power needs in the system.[2] Since the existing governing grid code, notified in 2010, the Indian power system has evolved monumentally and is continuing the evolution. The generation capacity has more than doubled whilst transmission has seen a growth of around 80%.

It is pertinent to mention that demand profile, in terms of seasonal and diurnal variations, has also been experiencing large variations. Introduction of renewable energy resources also added its impact on loading of transmission system, manifested into reactive power needs. Managing reactive power varying needs in such a mammoth grid has been achieved through disposal of various resources in the grid.

Table 1 shows reactive power resources available pan India. Though more and more resources are being added with time, there is always scope for effectively managing reactive power in the grid at present as well as in future.

[1]TECHNICAL BACKGROUND AND RECOMMENDATIONS FOR DEFENCE PLANS IN THE CONTINENTAL EUROPE SYNCHRONOUS AREA, ENTSOE- https://eepublicdownloads.entsoe.eu/clean-documents/pre2015/publications/entsoe/RG_SOC_CE/RG_CE_ENTSO-E_Defence_Plan_final_2011_public_110131.pdf

[2]Report of inquiry committee on grid disturbance https://powermin.nic.in/sites/default/files/uploads/GRID_ENQ_REP_16_8_12.pdf

Table 1: Reactive power assets / resources, pan India (As on 31st Oct 2020)

Reactive power assets/resources	Installed capacity/ Number	Reactive power (MVAr)	
		Absorbing	Injecting
Static Resources			
Bus Reactor (400kV & above)	640 nos	74155	--
Capacitors at distribution level	--	--	80738
Line Reactor (400kV & above)	864 nos	105294	
Dynamic Resources			
		Q_{min} (Absorption)	Q_{max} (Generation)
Thermal generating units	237440 MW	71233	142464
Hydro generating units (Including units run in Synchronous condenser mode)	45397 MW	10895	21791
Synchronous condenser hydro	3872 MW	929	1859
Renewable generation at ISTS	4800 MW	1578	1578
SVC	05 nos	1180	1580
STATCOM	13 nos	3300	4100
Total		268564	254110

At present, voltages at more than half of the nodes remain higher than the specified limit for 10-20% of time. On an average around Sixty-five (65) lines at 400 kV and above are opened on daily basis to control high voltages and several tripping incidents are also reported on account of over voltage and over flux. To go a step ahead in addressing the current problem, the utilization of existing resources could be boosted. For instance, exploiting full dynamic reactive power capability of conventional as well as Renewable generators, utilizing synchronous condenser operation of generators, converting retiring thermal units to synchronous condensers etc. could be carried out.

On the other hand, in view of the ambitious targets of 175GW renewable integration in the grid by 2022 and a non-fossil based installed generation capacity of 40% by 2030, commensurate addition of reactive capacity seems indispensable. Moreover, the dynamic reactive power resources, coupled with versatile support from synchronous condensers, would help in coping up with the variable nature of renewables and associated minimal inertial support.

This document covers the following:

- Available resources of reactive power in the grid at present.
- Issues being faced in effectively deploying these resources.
- Current regulations and standards in respect of reactive power.
- Need for more resources especially dynamic reactive resource.
- Proposed framework for reactive power as ancillary services.

2. Background

2.1. Reactive Power

In an alternating current power system, power comprises of two components, active power and reactive power. Reactive power is an essential component for the smooth flow of the real power in the power networks. Reactive power is produced and/or absorbed by all major elements of the power system. Reactive power flows primarily govern the voltages across the power system. The control of reactive power in a small power system is straight forward, particularly when the load is reasonably steady and stable. However, it becomes highly challenging in large power systems, where the power network consists of long-distance power lines and variable load due to widely varying seasonal as well as diurnal conditions.

Unlike system frequency, which is consistent throughout an interconnected system, voltages at different points in the grid form a "voltage profile" uniquely related to local generation and demand at that instant, and is also affected by the prevailing system network configuration.

As a localized phenomenon, voltage changes in the system can be best addressed by providing reactive power support locally. Unlike real power, reactive power cannot be transferred across long distances in a bulk power system. Long distance and unchecked reactive power flows can give rise to substantial voltage variation across the system. Thus, it becomes necessary to maintain reactive power balances between sources of generation and points of demand on a 'zonal basis'. The type of resource selected to mitigate any reactive power is an output of techno-economic analysis depending upon the system characteristics. In some situations, static shunt compensation is adequate to alleviate voltage conditions whereas in others, dynamic reactive support is necessary to ensure reliable pre and post contingency voltage levels and a robust response following a disturbance.[3]

2.2. Ancillary Services

Ancillary services are those functions performed by the equipment and people that generate, control, transmit, and distribute electricity to support the basic services of generating capacity, energy supply, and power delivery. Ancillary services are the tools that enable the system operator to maintain the demand-supply balance, helps in regulating the voltage and the frequency within prescribed limits and thus preventing a system collapse in case of contingencies, and would even help in restoring the system following a collapse. Ancillary services have always been a part of the electricity industry worldwide. However, technical specification and procurement methods are dependent on the ancillary service to be pursued as well as on

[3] Kankar Bhattacharya and Jin Zhong "Reactive Power as an Ancillary Service" IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 16, NO. 2, MAY 2001

differences in operating, and regulatory methodologies that exist among Transmission System Operators (TSOs) and countries. At present, it has been observed that worldwide, frequency support ancillary services and its market is well established. In India also, regulators have strengthened the system operation by introducing various frequency support ancillary services i.e. Reserves Regulation Ancillary Services (RRAS), Fast Response Ancillary Services (FRAS) etc. for balancing active power and real-time cost optimization. Secondary control of frequency through Automatic Generation Control (AGC) has also been introduced on pilot basis with a system-wide rollout in the pipeline.

2.3. Voltage control ancillary services

As discussed earlier, unlike frequency, voltages across an integrated system may have wider variation. It is so localized that even voltage at adjacent stations connected to a transmission line may have substantial difference. Thus, voltages at different nodes across the system form a "voltage profile" which is primarily governed by the reactive power flow near to the node.

Managing reactive power in a power system is complicated. Reactive power, in contrast to active power, can't travel long distances. Moreover, it produces high system losses while travelling through the transmission network. The dynamics of electrical system also increases complications as far as reactive power is concerned. The very carrier of electricity i.e. transmission lines, behaves as a source or sink of reactive power under different loading conditions. The ideal situation would be a unity power factor at all points in a network i.e. reactive power production and consumption balance out at every point in the system. However, such ideal situation is neither economical nor practical. System voltage control is used to maintain voltages within prescribed limits at various points in the grid and to compensate for the reactive requirements of the grid. Injection and absorption of reactive power is also required to maintain system stability, in particular to protect against contingencies that could lead to voltage collapse. Adequate amount of reactive power capacity must be available to achieve expected voltage profile along with reserve margins for contingencies. Thus, voltage control ancillary services are indispensable requirement. The report of the Enquiry committee[4] on grid disturbance on July 30, 2012 and July 31, 2012 gave the following relevant recommendations with respect to reactive power and voltage control:

- In order to avoid frequent outages/opening of lines under over voltages and also providing voltage support under steady state and dynamic conditions, installation of adequate static and dynamic reactive power compensators should be planned.
- The regulatory provisions regarding absorption of reactive power by generating units needs to be implemented.

[4] https://powermin.nic.in/sites/default/files/uploads/GRID_ENQ_REP_16_8_12.pdf

3. History of Reactive energy charges at Inter State Transmission System (ISTS)

In early 70's, supply voltage used to be so low that the bulbs glowed dimly, fans spun slowly and the tube-lights did not light up. Low voltage issues were not limited to only distribution system rather it was major issues at transmission level also. At many instances, thermal units failed to synchronize due to low voltage in the system. At that time, grid was in nascent stage, transmission system was limited and short circuit levels were quite low. Large chunks of power was being transmitted through pit head generating station or hydro station over long lines and caused wide voltage fluctuations throughout the system. The developing but limited power system infrastructure for both active and reactive power management were causing large excursion of voltage and frequency. In addition, installation of capacitors remained a low priority area for the state utilities during those days. A considerable reactive power was flowing through the transmission lines, transformers etc. causing additional voltage drops and avoidable transmission losses.

To address the low voltage issues, Northern Regional Electricity Board (NREB) introduced power factor linked pricing of reactive charge in **1975** and in **1983**, NREB proposed charges for reactive energy exchanges under normal and below normal voltages. Both the initiative was challenged due to lack of metering arrangement or technology advancement in those times. In late **eighties,** an approach similar to the frequency linked pricing of deviations from schedule was proposed for reactive energy exchanges pricing linked to voltage, however it also faced difficulty in implementing.

The next crucial development regarding charging for and pricing of reactive energy came during the ECC exercise in **1993**. In their final report of February **1994** which endorsed the need for it, a reactive power charge was recommended by ECC as a component of the transmission tariffs, the same is enclosed in Annexure 1. In March **1999**, POWERGRID (as directed by CERC) formally circulated its specific proposal regarding charging for reactive energy exchange, and filed a petition with the Commission including the backup calculation for the proposed rate of 4.0 paise per kVArh, in May 1999. The same is attached at Annexure 2.

The proposal was extensively commented and debated before being accepted in totality. The relevant points of the Indian Electricity Grid Code (IEGC) dated December 1999 are summarized below:

- Payment and recovery for VAr exchanges by beneficiary during voltages going beyond 3% in either direction i.e. more than 103% or less than 97%.
- Charges fixed at 4 paise/kVArh, which is to be escalated by 5% per year thereafter.
- The amount is to be kept in a separate regional reactive energy account.
- ISGS to generate/absorb reactive power as per instructions of RLDC, within capability limits and without any extra charges to be paid for it.

As the electronic meter became available in market in **nineties**, which offered the possibility of computing many parameters of a circuit in one compact unit, the reactive power computation became part of the specification. It was specified that the meter should also compute VAr and integrate the reactive energy (VArh) algebraically into two separate registers, one for the period for which the average RMS voltage is 103.0% or higher, and the other for below 97.0%. Incorporation of the above functional requirement in these meters was to enable implementation of the reactive energy charge scheme at regional level.

The above scheme proved to be a boon bringing about dramatic improvement in grid voltages throughout the country within a relatively short period. The state utilities installed capacitors in their respective systems because of the perpetual commercial incentive it provides.

There was barely perceptible development in the matter over the next **five years** as charge for reactive energy exchange could only be an accessory in the overall rationalization of inter-utility tariff, which was making hardly any progress.

The above-referred IEGC was revised in **March 2006**, issued as a CERC regulation and came into effect from 01.04.2006[5]. Provisions regarding reactive power were substantially the same. The new (updated) rate was specified as 5 paise/kVArh with effect from 01.04.2006, with an annual escalation of 0.25 paise/kVArh. It had also been noticed during the intervening years that depending on the general voltage profile over a regional grid, the total pay-outs from the regional reactive energy accounts did not equal the total payments received from the beneficiaries, leading to a surplus or deficit in the account. The 'Complementary commercial mechanisms' clause thus added to deal with this anomaly.

The grid code of 2006 was replaced by a new version in the **year 2010**. The provisions regarding reactive power and voltage control in the new IEGC were the same as those in the IEGC of 2006, except that the rate for reactive energy was increased to 10 paise/kVArh with an annual escalation of 0.5 paisa/kVArh, and the word 'beneficiaries' was replaced by 'regional entities except generating stations' throughout this section.

With the accelerated expansion of grid over the past twenty years, commissioning of new EHV lines, HVDC etc. over previous years also helped in improving the grid voltage and 'low-voltage' issues were reduced considerably. Instead, 'high-voltage' became the new problem.

[5] Indian Electricity Grid code, 2006 (repealed) http://www.cercind.gov.in/11122006/Reg_on_Grid_Code.pdf

4. Reactive Power Assets in India

Reactive power sources are categorized as Static and Dynamic resources. Static resources are mainly the Fixed Shunt Devices and Switched Shunt Devices while Dynamic resources include exclusive resources like Static Synchronous Compensators (STATCOM), Static VAr Compensators (SVC) and other resources like Synchronous Generators**,** Synchronous Condensers, VSC based HVDC, Non-Synchronous Generators (Renewable Generators), Battery energy storage systems. The reactive support from static resources is somewhat constant and depends upon the static inductance and capacitance value. The dynamic resources, on the other hand, have capability to vary reactive output over a wide range. Though dynamic resources are preferred over static, the low cost of static resources is the main reason for their higher population.

A transmission line consisting of distributed inductances and capacitances. The static and dynamic resources of reactive power can be deployed on operator's discretion. On the contrary, a transmission line behaves as source or sink of reactive power based on the loading of the line.

Transformers with tap changer, though essentially not a source or sink of reactive power, redistribute the reactive power flow.

Thus, transmission lines and transformer tap changers also plays key role in reactive power management. The following sections brief about the general performance of these assets along with their standing in the Indian grid.

4.1. Performance of various reactive power resources

As already mentioned in other sections, reactive power management is an important consideration both in planning and operation of power grids. Reactive power shortage has led to various voltage collapses and has been a cause of several major power outages worldwide.

The problem statement i.e. managing reactive power, is very evident and simple. However, the solution is diversified and applicable on case to case basis. Various resources of reactive power have different performance under different scenarios of grid, and therefore it is necessary to plan the reactive power compensation based on the system requirement under different scenarios and contingencies. Performance of reactive resources as per literature survey and industry experiences is listed below in Table 2

Table 2: Performance of reactive resources[6]

	Reactor	Shunt Capacitor	SC	SVC	STATCOM	TCR	TSC
Reactive Power Absorption	M	–	M	M	H	L	L
Reactive Power Generation	–	M	M	M	H	L	L
Voltage Control	M	L	M	H	H	–	L
Voltage Stability improvement	M	M	M	M	H	–	–
Increases transfer capability of lines	L	L	M	M	M	L	L

H: High, M: Medium, L: Low, D: Depends, SC: Series capacitor, SVC: Static VAr compensator, TCR: Thyristor controlled reactance

4.2. Cost analysis of various reactive power resources

Reactive power can be supplied from various sources. Static reactive power resources cannot rapidly vary the reactive power outputs and their reactive power production drops when the voltage level at their terminals drops. Capacitors/inductors supply/consume reactive power based on their terminal voltages. Dynamic reactive power resources can quickly change their VAr output fairly independent of their terminal voltage. Both variable and fixed costs of reactive power sourced from static resources are lower than those from dynamic ones. Table 3 depicts a cost comparison between various reactive power resources.

Table 3: Cost of various reactive resources[7]

S. No.	Name of Element	Rating (MVAr)	Total Cost (₹ in Lakhs)	₹ (Lakhs) /MVAr
1	Capacitor at 132kV			1.2-2.0
2	Capacitor at 220kV			2.5-4.0
3	Bus reactor at 400kV	125	770	6
4	Bus reactor at 765kV	240	1900	8
5	SVC at Ludhiana	+600/-400	20329	34
6	SVC at New Wanpoh	+300/-200	18172	60
7	SVC at Kankroli	+400/-300	17990	45
8	STATCOM at Lucknow	±300	21464	72
9	STATCOM at Nalagarh	±200	16849	84

[6] Ali Mehdipour Pirbazari, Chalmers University of Technology, Gothenburg, Sweden "Ancillary Services Definitions, markets and practices in the world" *2010 IEEE/PES Transmission and Distribution Conference and Exposition: Latin America*

[7] CERC tariff Orders and capacitor installation tenders from distribution companies.

4.3. Static reactive resources

Static resources have fixed reactive power output at their nominal voltage, and their capability mainly varies in proportion to square of terminal voltage. These devices are switched in and out of service based on system conditions. Switching action can be manual or automatic, but this type of resource provides a fixed nominal contribution of reactive power to the grid once connected. Static reactive resources generally include the following:

4.4. Fixed Shunt Devices

Fixed shunt reactive devices include shunt capacitors and reactors. These devices have a fixed nominal rating and their reactive power production or consumption is dependent on terminal voltage. While these types of devices are relatively cheaper, their operating characteristic and inability to manually switch in/out quickly enough to provide dynamic support limits their applicability to steady-state operation only. The details are given in Table 4 and 5.

Table 4: Bus reactors at 400kV & above and Shunt Capacitors at distribution level (Pan-India) (As on 31st Oct 2020)

Region	Installed capacity, generation (GW)	Number of 400kV & above nodes (AC)	Bus reactor (400kV & above) #		Capacitors at distribution level (MVAr)
			Nos	MVAr	
ER	37.5	91	113	13086	1321
NER	4	11	21	1593	273
NR	89	238	221	26211	33660
SR	114.4	171	126	13730	13344.7
WR	124.5	222	191	24552	30208
All India	369.4	733	672	79172	78806.7

#few bus reactors also present at lower transmission voltage levels

Table 5: Line reactors at 400kV & above pan India (As on 31st Oct 2020)

Region	Installed capacity, generation (GW)	Number of 400kV & above lines (AC)*	Total Line reactor (400 kV & above)		Line reactor (out of total) convertible/usable as Bus reactor	
			Nos	MVAr	Nos	MVAr
ER	37.5	278	132	12089	87	9616
NER	4	28	27	1515	13	711
NR	89	556	232	29139	137	19739

Region	Installed capacity, generation (GW)	Number of 400kV & above lines (AC)*	Total Line reactor (400 kV & above)		Line reactor (out of total) convertible/usable as Bus reactor	
			Nos	MVAr	Nos	MVAr
SR	114.4	433	132	12716	86	11034
WR	124.5	586	373	52419	143	28959
All India	369.4	1817	896	107878	466	70059

*Inter-regional lines included in each region

4.5. Switched Shunt Devices

Switched shunt capacitors and reactors are simply fixed shunt devices that have the capability to automatically be switched in service based on control settings or operator action. These devices may have shorter switching times than the fixed shunt devices, but their inability to smoothly vary reactive power output differentiates them from dynamic reactive devices.

4.6. HVDC transmission lines

HVDC transmission link (both bipolar and back-to-back) are being used for bulk transfer of power over long distances and to connect asynchronous systems for power transfer. Power flow control in HVDC is easy, fast and reliable. HVDC system mainly comprises of convertor and invertor station, convertor transformers, smoothening reactor, AC and DC filter to control harmonics etc. Reactive power is required in the AC to DC / DC to AC conversion. The AC harmonic filters provide some amount of reactive power. The additional supply may also be obtained from shunt capacitors, synchronous phase modifiers and static VAr systems. The choice depends on the speed of control desired. The reactive power consumption of an HVDC converter depends on the active power, the transformer reactance and the control angle. It increases with increasing active power, the DC voltage selected for operation (in case of Reduced Voltage Operation mode). A common requirement to a converter station is full compensation or overcompensation at rated load. Thus, by changing the power order, respective reactive power or filter bank switching can be controlled accordingly. Details of HVDC links and back-to-back stations present in Indian grid are included in Table 6.

Table 6: HVDC links and back-to-back station (Pan-India)

S. No.	HVDC link	Region	No. of poles	Capacity (MW)	Filter capacity (MVAr) at each terminal
1	Rihand-Dadri*	NR	2	1500	627
2	Ballia-Bhiwadi*	NR	2	2500	1260
3	Chandrapur*-Padghe	WR	2	1500	800
4	Biswanath Chariali / Alipurduar-Agra* MTDC	NER/ER/NR	4	6000	3630
5	Champa-Kurukshetra*	WR/NR	4	6000	2054
6	Mundra-Mohindergarh*	WR/NR	2	2500	1410
7	Talcher-Kolar*	ER/SR	2	2000	914
8	Raigarh-Pugalur	WR/SR	2	3000	1260
9	Pugalur-Thrissur	SR	2	2000	-
Back to Back stations					
1	Bhadravathi	WR/SR	2	1000	742
2	Gajuwaka	ER/SR	2	1000	808
3	Vindhyachal	WR/NR	2	500	335
4	Pusauli	ER/NR	1	500	465

*Filter capacity at this end

4.7. Dynamic reactive resources

4.7.1. Synchronous Generators

Synchronous generators are currently the primary source of active power in the electric power system and can inject or absorb large amounts of reactive power as well. This is driven by the excitation voltage provided to the rotor of the machine, similar to a synchronous condenser. Limits on reactive power exchange capability are dependent on stator winding rating, field current rating, terminal voltage rating, cooling of machine, and the active power output of the machine. By convention, generator consuming lagging VArs is said to be in leading mode while one injecting lagging VArs said to be in lagging mode. The leading mode of generator is associated with under excitation whereas the lagging mode is with over excitation. The generator excitation limiters are intended to limit operation of the generator to within its continuous capabilities. Generally, the setting of the under-excitation limiter (UEL) will be coordinated with the steady-state stability limit of the generator. The over excitation limiter (OEL) limits generator operation in the overexcited region to within the generator capability curve. There are examples where reactive power capability can be increased, such as increasing pressure in the hydrogen cooling system, but the excitation limiter should be adjusted to actually utilize that additional capability. An all-India level generation summary is shown in Table 7 and 8.

Table 7: Thermal generators and MVAr capability (Pan-India) (As on 31st Oct 2020)

S. No.	Installed capacity (GW)	Number of Thermal units (50MW and above)					
		No.	Size		MW (Pmax)	#Qmax in MVAr (+60% of Pmax)	#Qmin in MVAr (-30% of Pmax)
			< 500MW	> = 500MW			
ER	37.5	111	82	29	31550	18930	-9465
NER	4	10	8	2	2606	1564	-782
NR	89	113	90	24	52697	31618	-15809
SR	114.4	146	101	45	55199	33199	-16559
WR	124.5	251	164	87	90960	54576	-27288
All India	369.4	631	445	187	233012	139887	-69903

#As per CEA transmission planning criteria (sec 11.6

Table 8: Hydro generators & MVAr capability (Pan-India) (As on 31st Oct 2020)

S. No.	Total generation Installed capacity (GW)	Number of Hydro units (50MW and above)			
		No.	MW (Pmax)	#Qmax in MVAr (+48%) of Pmax	#Qmin in MVAr (-24% of Pmax)
ER	37.5	38	4942	2372	-1186
NER	4	24	1427	685	-342
NR	89	98	12536	6017	-3008
SR	114.4	92	8507	4083	-2041
WR	124.5	62	7547	3623	-1811
All India	369.4	314	38495	18477	-9238

#As per CEA transmission planning criteria (sec 11.6)

4.7.2. Synchronous Condensers

A synchronous condenser is a synchronous machine whose shaft is not driven by a prime mover; rather, the shaft spins freely and the field voltage is controlled to produce or consume reactive power by adjusting set point voltage. Thus, this contributes to overall power factor correction or/and local voltage control.

Besides providing reactive power support, a synchronous condenser has other advantages like contributing to system short-circuit capacity, short term overload capability, system inertia etc. Performance and advantage of synchronous condenser operation is detailed in Annexure 3.

The synchronous condenser technology is best suited to handle the reactive power dynamics and local harmonic concerns and appears advantageous from a long-term life of product support standpoint.

In India, there are a lot of hydro stations which are suited for synchronous condenser operation however, due to technical and other issues, only few are operated in condenser operation during requirement. The present synchronous condenser capable machine details pan India are shown in Table 9.

Table 9: Synchronous condenser mode of Hydro machine operational in India

Region	No. of Hydro stations (50MW & above)	No. of stations operational as synchronous condenser operation			Remarks
		No.	Units	Capacity (MW)	
ER	38	1	1	225	Each unit is synchronized one by one at an interval of 30min and for a period of 30min of operation period in SC mode (One unit at a time)
NER	24	0	0	0	
NR	141	4	7	840	Larji and Chamera-2 machine are trial tested and have some issues in continuous operation
SR	150	3	11	1363	Some units can be put in condenser mode with time gap
WR	62	4	12	1444	All the four generating stations are being used for synchronous mode operation as and when required
All India	415	12	31	3872	

Unit wise details are enclosed in Annexure 4

4.7.3. Non-Synchronous Generators

Non-synchronous generators include induction generators (e.g., Type I, II, and III wind plants) and electronically coupled resources (e.g., Type IV wind plants and solar). These may or may not have the capability to provide reactive power and voltage control. Interconnection requirements demands for a plant to have reactive capability for voltage control, such as reactive support corresponding to ± 0.95 power factor (pf) lead/lag[8]. However, the individual units within a plant may have limited capability, thus additional reactive resources (e.g. small STATCOMs or SVCs) may be required to maintain a power factor or voltage control set point at the Point of Interconnection (POI).

[8] Central Electricity Authority (Technical Standards for Connectivity to the Grid) (Amendment) Regulations, 2019

A key distinction between non-synchronous and synchronous resources is that non-synchronous reactive capability is different from that as described in terms of a "D-curve". In case of conventional synchronous generator. Reactive capability in non-synchronous resources is often based on the number of individual units (e.g., number of wind turbines or photovoltaic panels) online for the plant as well as the plant-level reactive power controls. A list of RE generators currently present in the country at Inter State Transmission System (ISTS) level is included in Table 10.

Table 10: Renewable generators connected to ISTS and respective MVAr capability (As on 31st Mar 2020)

Region	Type of Renewable generation (Wind/Solar)	Number of Plants	Rating in MW	$MVAr capability considering +/-0.95 power factor
ER	Solar	1	10	±3
NR	Solar	9	1040	±342
SR	Solar	29	3252	±1008
SR	Wind	4	856	±266
WR	Solar	3	750	±247
WR	Wind	5	1650	±542
All India		28	4800	±1578

$: As per CEA connectivity standards

4.7.4. Static VAr Compensators (SVC)

This is a FACTS device that consists of thyristor-controlled reactors (TCRs), thyristor-switched capacitors (TSCs), and fixed capacitors acting as a harmonic filter. The TCR consists of reactors in series with thyristor valves that continuously control the reactive power output by varying the current flow through the reactor. The fixed capacitor is part of the filter that absorbs the harmonics generated by the thyristor switching, supplying a fixed reactive power to the grid.

4.7.5. Static Synchronous Compensators (STATCOM)

A STATCOM is a voltage source converter (VSC) device and part of the FACTS family that consists of a DC voltage source behind a power electronic interface connected to the AC grid through a transformer. This results in a controllable voltage source and hence reactive power output. Summary of SVC and STATCOM present in the country is shown in Table 11.

Table 11: SVC and STATCOM (Pan-India) (As on 31st Oct 2020)

S. No.	SVC			STATCOM		
	No.	MVAr (Generation)	MVAr (Absorption)	No.	MVAr (Generation)	MVAr (Absorption)
ER	0	0	0	4	2000	-1200
NER	0	0	0	0	0	0
NR	5	1580	-1180	2	500	-500
SR	0	0	0	3	500	-500
WR	0	0	0	4	1100	-1100
All India	5	1580	-1180	13	4100	-3300

4.7.6. VSC HVDC

A VSC HVDC uses a voltage source on the DC side of conversion, enabling direct control of active as well as reactive power output on each end of the converter. Reactive power output takes a constant-current characteristic and is directly proportional to voltage. Reactive power capability tends to decrease as active power increases (similar to a traditional generator D-curve). India's first VSC based HVDC system from Pugalur to Thrissur in southern region is under commissioning and expected in operation shortly.

4.7.7. Transmission lines

Lines produce reactive power due to their natural capacitance, and the amount produced is dependent on the capacitive reactance (X_C) of the line and the voltage. On the other hand, lines also consume reactive power due to their inductive reactance (X_L), and the amount consumed depends upon the current in the line. Transmission lines have an operating characteristic known as the surge impedance loading (SIL), which is the active power loading at which reactive power produced and consumed by the line are balanced. The SIL is that value of loading when VArs produced equal VArs consumed. The details are given in Table 12 and 13. Transmission lines that are compensated with fixed series capacitor are enclosed in Annexure 5.

Table 12: 220kV and above transmission lines and Charging MVAr (Pan-India) (As on 31st Oct 2020)

Sl. No.	Transmission lines (400kV & above) *	Ckm	Charging MVAr (400kV & above)	Transmission lines (220kV)	Ckm	Charging MVAr (220kV & above)
ER	278	36955	33458	452	22795	33204
NER	28	4312	2703	39	3043	3132
NR	556	74990	64855	1426	55980	72748

Sl. No.	Transmission lines (400kV & above) *	Ckm	Charging MVAr (400kV & above)	Transmission lines (220kV)	Ckm	Charging MVAr (220kV & above)
SR	433	49764	39583	1370	53273	47491
WR	586	82704	98020	207	8954	98020
All India	1817	234415	216293	3479	142565	232020

*Inter-regional lines included in each region

Table 13: 132kV and above cable (Pan-India) ***(As on 31st Oct 2020)***

Regions	132kV			220kV		
	No. of cable lines	Ckm	Charging MVAr	No. of cable lines	Ckm	Charging MVAr
ER	46	246	262	6	34	105
NER	----	----	----	----	----	----
NR	----	----	----	39	203	----
SR	42	116	----	24	125	----
WR	----	----	----	40	162	473
All India	88	362	262	109	524	578

Number of cable lines including lines that have partial cable too

4.7.8. Tap change in transformer

By means of changing taps of Inter-Connecting Transformer (ICT) thereby regulating the flow of reactive power through the transformer, reactive power exchange can be manually controlled up to certain extent. Reactive Power management is being done by tap optimization at 765/400kV and 400/220kV ICT nodes at RLDC/NLDC level[9]. Number of 765/400kV and 400/220kV nodes pan India is as follows:

Table 14: Statistics of Inter-connecting transformer (ICT) at 400kV & above in India ***(As on 31st Oct 2020)***

Region	765/400kV Nodes	Nos of ICTs	MVA rating	400/220kV Nodes	Nos of ICTs	MVA rating
ER	7	17	22500	49	121	42740
NER	-	-	-	6	13	4235
NR	24	60	81900	138	349	129715

[9] A. SINGH, R. SHUKLA, S. REHMAN, S.R. NARASIMHAN, K.V.S. BABA “Transformer Tap Optimisation exercise in Indian Power System” *CIGRE Symposium 2017 Dublin, Ireland*

Region	765/400kV Nodes	Nos of ICTs	MVA rating	400/220kV Nodes	Nos of ICTs	MVA rating
SR	10	20	30000	110	283	103962
WR	36	74	107000	185	284	104270
All India	77	171	241400	488	1050	384922

To summarize, at all India level, the transmission grid is having close to 250 billion VArs both at absorption and injection levels. Incidentally, the charging VAr of 220kV and above transmission lines is also nearly the same.

5. Existing Provisions for Reactive Power Management

5.1. Operating voltage range

Indian Electricity grid code (IEGC) and Central electricity authority (CEA) have specified the operating voltage range at various voltage level of grid as given below.

Table 15: Operating voltage range as per IEGC[10] & CEA planning criteria[11]

S. No.	Nominal System Voltage (RMS in kV)	Maximum (RMS in kV)	Minimum (RMS in kV)
1	765	800	728
2	400	420	380
3	220	245	198
4	132	145	122
5	110	121	99
6	66	72	60
7	33	36	30

5.2. Requirements for generators

The Indian Electricity Grid code (IEGC) specifies following requirements:

"All generating units shall normally have their automatic voltage regulators (AVRs) in operation. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained."

"SLDC/RLDC may direct a wind farm to curtail its VAr drawl/injection in case the security of grid or safety of any equipment or personnel is endangered."

"During the wind generator start-up, the wind generator shall ensure that the reactive power drawl (inrush currents in case of induction generators) shall not affect the grid performance."

"The ISGS and other generating stations connected to regional grid shall generate/absorb reactive power as per instructions of RLDC, within capability limits of the respective generating units that is without sacrificing on the active generation required at that time. No payments shall be made to the generating companies for such VAr generation/absorption."

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[10] Indian Electricity Grid Code, http://cercind.gov.in/2016/regulation/9.pdf

[11] CEA Planning Criteria, https://cea.nic.in/reports/others/ps/pspa2/tr_plg_criteria_manual_jan13.pdf

The CEA construction standard[12] specifies the following:

"The rated current of the excitation system shall be at least 110% of the machine excitation current at the rated output of the machine. The rated voltage shall be at least 110% of the machine excitation voltage."

The CEA connectivity regulation[13] specifies the following:

"...All generating units commissioned on or after 01.01.2014, shall be capable of operating at rated output for power factor varying between 0.85 lagging (over-excited) to 0.95 leading (under-excited)." (Generating units includes conventional synchronous generators)

"Hydro generating units having rated capacity of 50 MW and above shall be capable of operation in synchronous condenser mode, wherever feasible.

Provided that hydro generating units commissioned on or after 01.01.2014 and having rated capacity of 50 MW and above shall be equipped with facility to operate in synchronous condenser mode, if necessity for the same is established by the interconnection studies."

"The generating station shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits of 0.95 lagging to 0.95 leading." (For inverter based resources connected to the grid after 15.04.2014)

5.3. Transmission licensee/utilities obligatory requirements

IEGC specifies the following:

"Reactive Power compensation and/or other facilities shall be provided by STUs, and Users connected to ISTS as far as possible in the low voltage systems close to the load points thereby avoiding the need for exchange of Reactive Power to/from ISTS and to maintain ISTS voltage within the specified range."

"Each SLDC shall develop methodologies/mechanisms for daily/ weekly/monthly/yearly demand estimation (MW, MVAr and MWh) for operational purposes."

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[12] CEA (Technical standards for construction of electric plants and electric lines) Regulations, 2010, https://www.cea.nic.in/reports/regulation/tech_std_reg.pdf

[13] Central Electricity Authority, Technical Standards for Connectivity to the Grid, (Amendment), regulations, 2012, http://cea.nic.in/reports/regulation/grid_connectivity_12112013.pdf

The CEA construction standards specify the following:

"Shunt reactors, wherever provided, shall comply with relevant standards in general. Shunt reactors up to 420 kV rated voltage shall have linear voltage vs current (V/I) characteristics up to 1.5 per unit voltage. 800 kV Shunt reactors shall have linear V/I characteristics up to 1.25 per unit voltage."

"Capacitor banks of adequate rating shall be provided preferably at voltages below 33kV and definitely not at voltages higher than 132kV. Suitable redundancy shall be provided in the number of Capacitor units to avoid reduction in reactive compensation due to failure of the Capacitor units. The objective shall be to ensure that voltage received by the consumers remain within the permissible limits."

5.4. Reactive Energy Charges

As per IEGC, reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption point as possible. To discourage VAr drawls by regional entities except generating stations, VAr exchanges with ISTS is priced as per following criteria:

i. Regional Entity pays for VAr drawl when voltage at the metering point is below 97%.
ii. Regional Entity gets paid for VAr return when voltage is below 97%.
iii. Regional Entity pays for VAr return when voltage is above 103%.
iv. Regional Entity gets paid for VAr drawl when voltage is above103%.

With an unprecedented, fast paced large renewable penetration in Indian Grid, would come the need of controlling its inherent intermittency and dynamic nature. Renewable energy generation is variable in nature (diurnal, seasonal, weather dependent). Implementation of ancillary services would facilitate smooth integration of renewable energy generation in the country. For instance, voltage control ancillary services will certainly help in controlling the dynamics of voltage caused due to variability of renewable generation, presently concentrated in certain parts of the country. Though, latest technology of inverter based Solar P-V panel has wide range of reactive power generation and absorption capability that can be utilized with suitable mechanism in place.

6. Reactive Power Management – Need of the Hour

6.1. Need for managing reactive power

In India, different regions have different demand characteristics depending largely on weather, type of load (Industrial/Household/Commercial etc.), population, events/festivals etc. The power system has been planned to cater for peak or high demand scenario. Thus, during peak hours, high load and consequent high line loadings causes low voltages whereas during off-peak hours, lightly loaded transmission lines and cable network cause high voltages in the system. Inadequate reactive support in both the situations can lead to stressed operation of power system and may result in system disturbance either of localized nature or at large scale. An operational feedback[14] is also prepared by the system operator at transmission level to highlight such issues of voltage deviations.

6.1.1. Impact of wide load variations on voltage

- A decrease in load is generally accompanied by increased voltage levels and vice versa. For instance, high voltages are observed in Northern Region of the country on account of winter season/load crash events due to thunderstorm/hailstorm/dust storm whereas low voltages are observed during high demand periods of extreme hot summer season.
- In load crash events, Extra High Voltage (EHV) lines often trip on over voltage protection rendering system weak and with reduced reliability.
- Power transformers also experience over flux alarm and at times tripping also occur on account of prevailing high voltages coupled with low frequency conditions.
- During winter season especially in Northern Region, generations at most of the hydro stations (mainly snow-fed hydro stations) are at their minimum level which also results in high voltages during off peak hours because of lightly loaded long connecting links to these hydro stations.

6.1.2. Impact of Renewable Energy on voltage

- At or near to Renewable Energy (RE) plant, diurnal variation of voltages is observed. For instance, high generation in daytime by solar plant lead to low voltages in the vicinity areas whereas no generation in night hours coupled with reactive power injection by cables present in the plant lead to high voltages.

[14] Operational Feedback, https://posoco.in/documents/operational-feedback-on-transmission-constraints/

6.1.3. Nature of load affecting voltage

Certain types of load e.g. agricultural loads can draw high reactive power thereby causing extreme low voltage profiles in the network. These loads are more prominent during monsoon season in Northern region and at some places, such load occur in winter too.

6.2. Voltage profile

As frequency indicates active power balance in the grid, voltage indicates reactive power balance locally. Voltages across the grid have different values. Maintaining voltages within permissible limits requires meticulous reactive power management. Moreover, different voltage pattern can be observed at same location during different time of the day/week/month/year. Figure 1 shows the voltage duration curve for a well-connected 400kV bus in the Indian grid. Table 16 indicates voltage pattern observed in 2018-19. Figure 2 shows voltage pattern across the country for different scenarios.

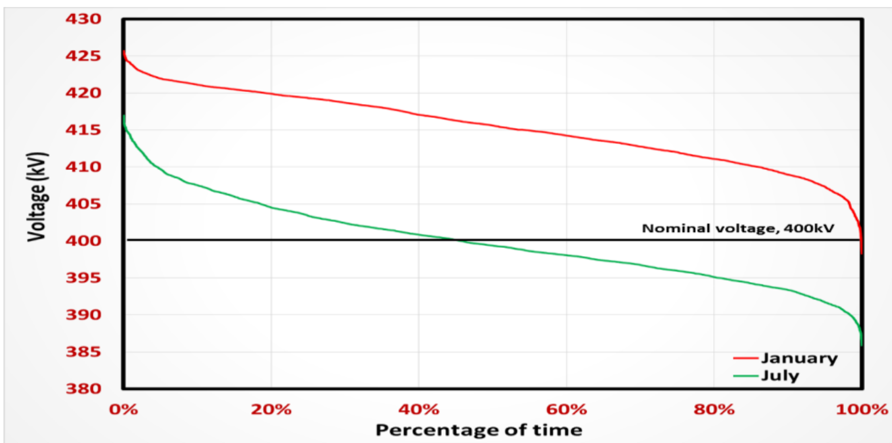

Figure 1: Voltage duration curve for a 400kV bus

Table 16: Voltage profile outside the IEGC upper band (>420 kV) (2018-19)

S.No.	No. of 400kV and above Nodes	Monitored Nodes	No. of nodes with > 420kV (HV case) and % of time of violation							
			Q1		Q2		Q3		Q4	
			No. of nodes	% of time	No. of nodes	% of time	No. of nodes	% of time	No. of nodes	% of time
ER	82	77	51	3%	18	4%	32	4%	21	8%
NER	11	11	9	1%	6	1%	6	2%	7	3%
NR	227	170	165	9%	145	7%	155	20%	162	25%
SR	148	148	138	13%	138	16%	138	16%	138	15%
WR	212	38	27	10%	30	18%	29	19%	31	23%
All India	680	444	390	10%	337	11%	360	17%	359	20%

Table 17: Voltage profile outside the IEGC lower band (<380) (2018-19)

S.No.	No. of 400kV and above Nodes	Monitored Nodes	No. of nodes with < 380kV (LV case) and % of time of violation							
			Q1		Q2		Q3		Q4	
			No. of nodes	% of time	No. of nodes	% of time	No. of nodes	% of time	No. of nodes	% of time
ER	82	77	5	3%	2	0%	0	0%	0	0%
NER	11	11	0	0%	4	0%	0	0%	0	0%
NR	227	170	162	1%	55	1%	86	1%	95	1%
SR	148	148	10	0%	10	0%	10	0%	10	0%
WR	212	38	0	0%	0	0%	0	0%	0	0%
All India	680	444	177	1%	71	2%	96	2%	105	2%

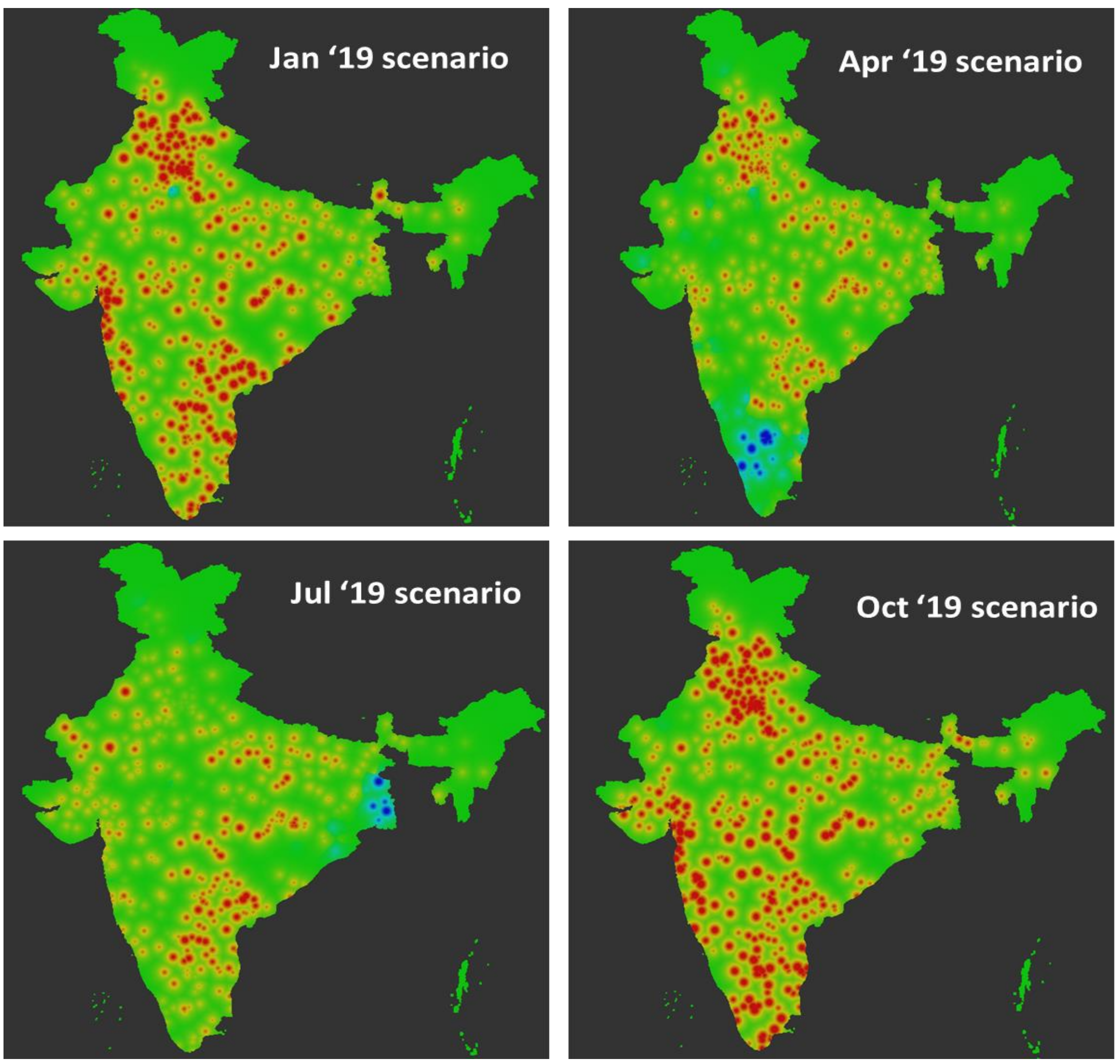

Figure 2: Voltage Profile of Indian HV grid during different scenarios (Blue: low voltage; Red: high voltage)

The voltage variation that an electrical bus experiences is closely linked to its fault level and the apparent power handled by the bus. Ratio of fault level to transformation capacity connected at a bus can be an indicator of the vulnerability of a bus to wider voltage variations. Figure 3 depicts the fault level, transformation capacity and ratio of fault level to transformation capacity for high voltage nodes in Indian power system. Table 29 at Annexure 6 contains nodes on which this ratio came out to be lowest implying they are most likely to experience wide voltage variations.

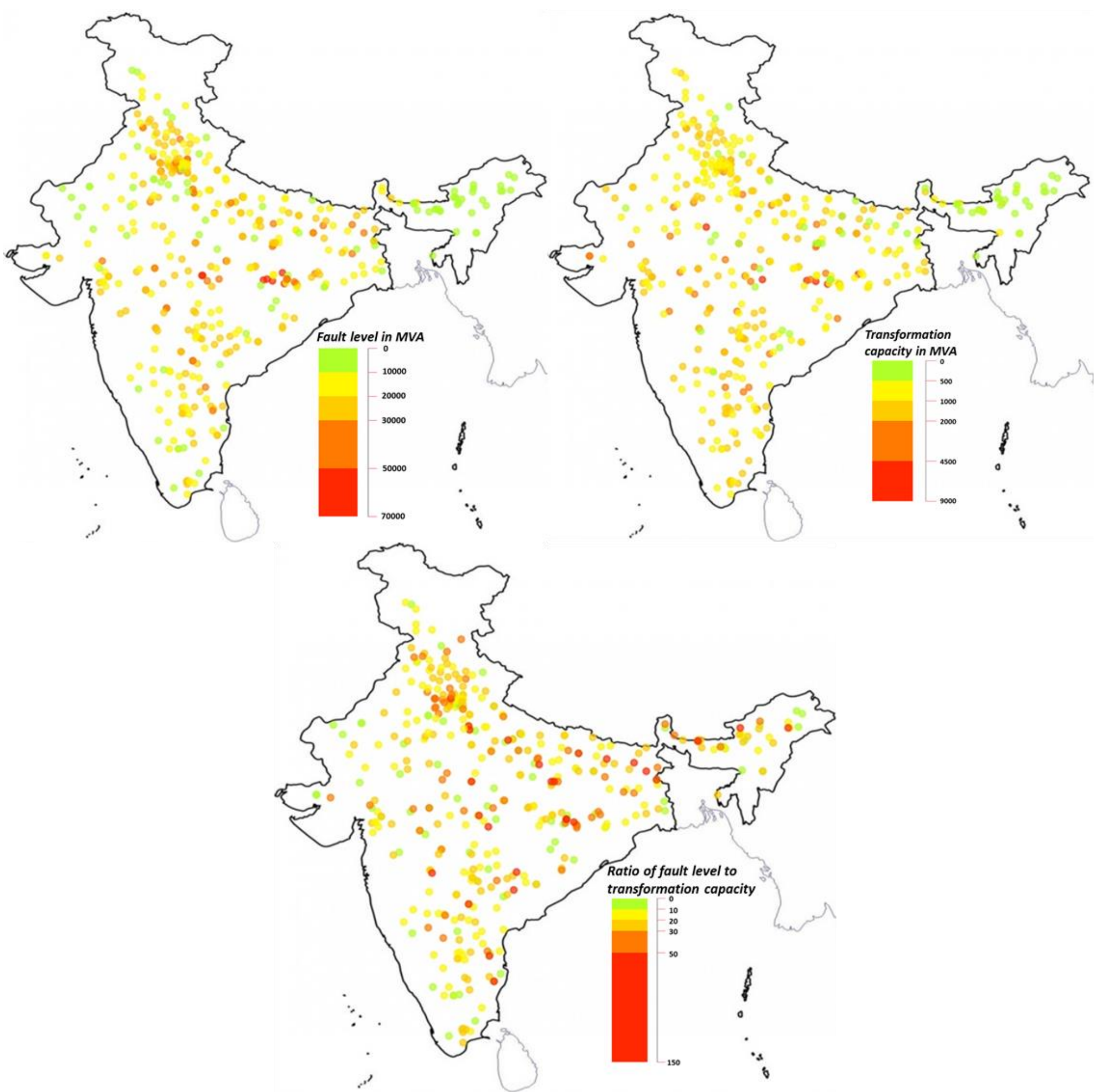

Figure 3: Fault level, transformation capacity and ratio of fault level to transformation capacity for high voltage nodes pan-India

Another contributor to voltage variation is system frequency[15]. It has been observed that system wide voltages more or less follow the system frequency. The load flow analysis usually used in system studies considers strong relationship of *reactive power with voltage* and *real power with angle*. The method is applied for steady state analysis which means the frequency is invariable. However, in practical ever dynamic grid conditions, the frequency variation is inevitable and its effect can be seen in system voltages throughout the grid. This aspect is covered in [ii] and [v]. The studies done in [ii] shows a 1% variation in frequency causes variation of 6% to 12% in reactive power exchange of generator.

Figure 4 shows a plot of EHV lines tripped on over voltage in Northern Region and prevailing frequency at that time. It can be observed that most of the lines tripped during the time when frequency was high.

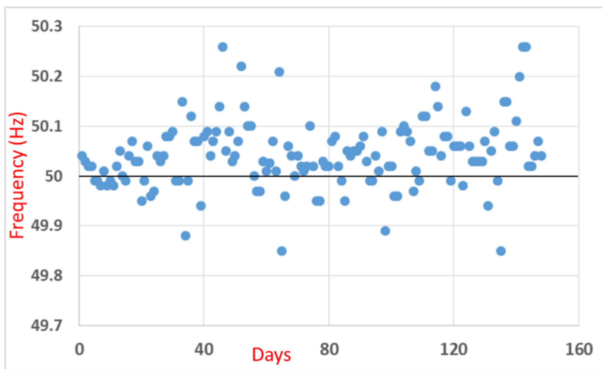

Figure 4: EHV lines tripped on over voltage in Northern Region

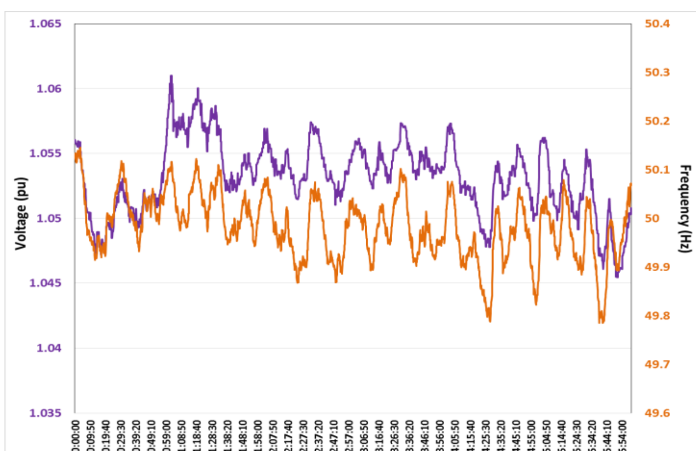

Figure 5: Voltage variation vis-a-vis frequency variation

[15] Central Electricity Generating Board, Modern Power System Practices, Vol. L (System Operation)

The frequency based variation of voltage is also corroborated by Figure 5 which depicts variation of voltage with respect to frequency for a brief period.

Thus, a better reactive power management goes hand in hand with a better active power balance. Further, as suggested in [ii], considering a better frequency dependent load modelling both at planning as well as operational stage would also help in specifying system's active and reactive needs.

6.3. Steady-state simulation

A simulation study of off-peak hour scenario during winter season of Northern Region has been carried out. With this scenario, load generation balance of reactive power has been assessed and represented in Table 17 and Table 18. Dynamic Reactive power reserve requirement and its assessment technique need attention. For voltage stability under steady state and contingency conditions, some dynamic reactive reserve should be made available to avert any voltage collapse.

Table 18: Load generation balance of reactive power for off-peak winter Scenario (High voltages)

Region	Generation		Load		Bus reactor	Line reactor	Line Charging	Losses		Tie line exchange
	MW	MVAr	MW	MVAr	MVAr	MVAr	MVAr	MW	MVAr	MVAr
ER	20345	-3935	17266	6251	4279	9144	27192	469	4050	-466
NR	32706	-273	45009	16336	10268	25035	70630	1364	17255	1463
NER	2069	-493	1887	678	336	1656	3517	45	296	59
SR	32232	-7190	35931	12612	7256	13958	50300	986	9832	-549
WR	57055	-5652	40129	14428	12678	44793	91553	1300	14245	-244
Trans-national	426	-302	441	160	187	45	478	6	48	-263
All India	144833	-17844	140662	50464	35004	94632	243670	4169	45726	0

Table 19: Load generation balance of reactive power for peak summer Scenario (Low voltages)

Region	Generation		Load		Bus Shunt	Line reactor	Line Charging	Losses		Tie-line exchange
	MW	MVAr	MW	MVAr	MVAr	MVAr	MVAr	MW	MVAr	MVAr
ER	28816	81	22558	6721	3811	8760	26435	818	6969	254
NR	49858	6077	61911	18387	5907	23651	67199	1857	25340	-9
NER	3067	-295	2962	913	-217	1636	3419	82	537	255
SR	41069	-3522	46549	15534	4239	13911	50209	1597	14065	-1062
WR	67269	-4532	50106	16330	7564	47289	95737	1855	19275	747
Trans-national	1548	-125	1315	135	-18	45	193	16	98	-191
All India	191627	-2315	185401	58020	21287	95291	243191	6225	66284	-6

6.4. Measures for voltage control

Voltage is being controlled through available static and dynamic resources based on the system requirement. The following measures are being taken for voltage control[16]:

1. Switching in or out line reactor / Bus reactor
2. Switching in or out shunt capacitors at lower voltage level
3. Optimizing dynamic resources e.g. SVC, STATCOM, reactive power from generators
4. Synchronous condenser operation (limited resources)
5. Optimizing Transformer taps
6. Using line reactor as bus reactor while line is out of service
7. Opening of High voltage lines (as a last resort with due consideration of reliability and security of the grid)

Switching of bus reactors, line reactors are done as frequently as twice in a day at same location. For instance, during peak hours, voltages being on lower side, reactors are switched off while during off peak hours, reactors are brought into relieve high voltages.

[16] As per operating procedures of various RLDCs, available at respective RLDC websites

Capacitors switching is done primarily at lower voltage levels. The dynamic reactive power resources like generators, SVC, STATCOM keep on changing the VAr value as per system requirement or system operator's instructions. Tap optimization is being done mainly on seasonal basis.

Manual opening of high voltage line is also carried out as a last resort to alleviate alarming high voltages in the system. As a perspective, as per table 12, the charging VAr produced by all 220kV and above lines is 2,31,577 MVAr for national grid. The security and reliability of the system is taken into account while opening transmission lines on voltage regulations. Figure 6 shows the number of high voltage lines opened during year 2018-19. On an average, 65 lines opened on daily basis. On a particular day, the number also went up to 135 lines opening i.e. 270 operations (charging and discharging) in a single day.

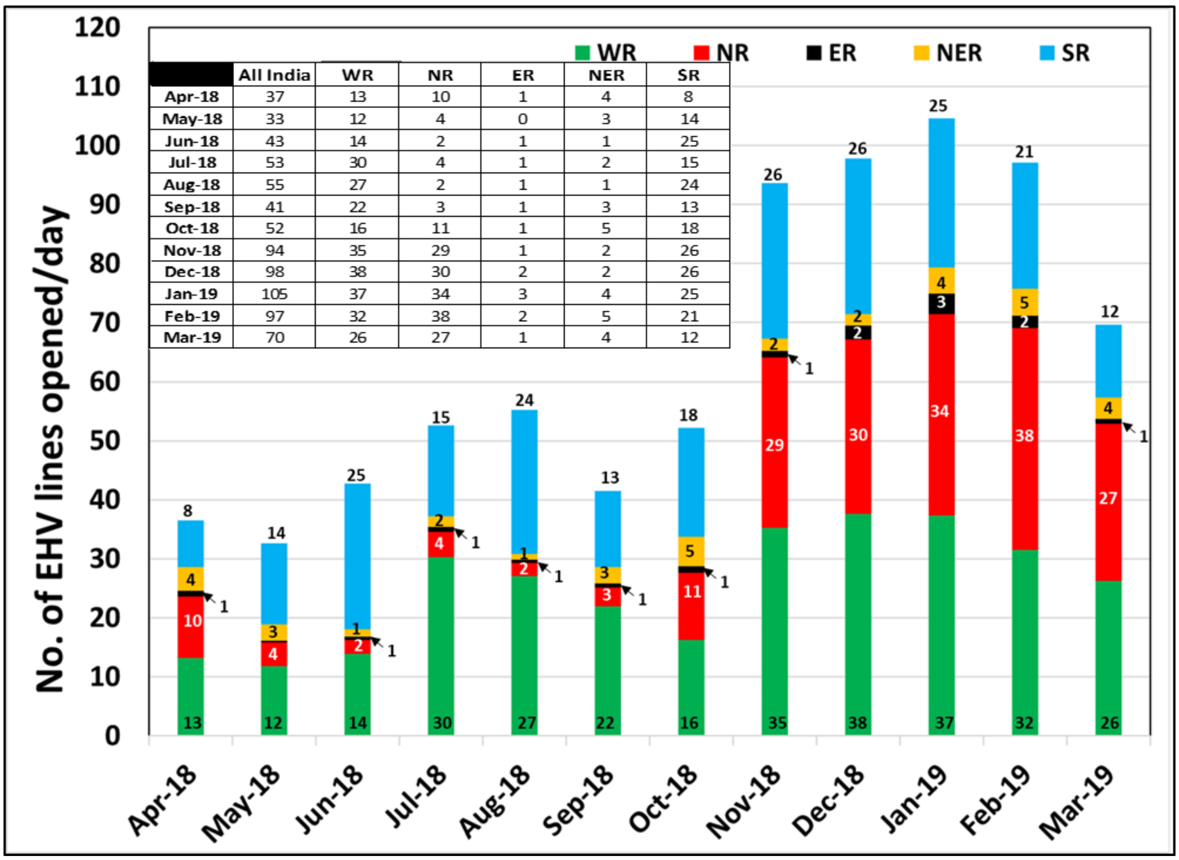

Figure 6: EHV line opening during High voltage scenario (2018-19)

7. Reactive Energy Account and Settlement

It is expected that beneficiaries/utilities will provide local VAr support such that they do not draw VAr from the EHV grid, particularly under low voltage condition. To discourage VAr drawls by beneficiaries, VAr exchanges with Inter State Transmission System (ISTS) are priced. Any regional entity except generating stations pays for VAr drawl in case of voltage at the metering point is below 97% or VAr injection in case the voltage is above 103% and on other hand gets paid for VAr drawl in case of voltage at the metering point is above 103% or VAr injection in case the voltage is below 97%.

At present, monitoring of reactive power exchange across tie points is being done through Special Energy Meter (SEM). SEMs installed at various metering points across the country are compliant with IEC 687 / IEC-62053-22:2003 standard and have accuracy class of 0.2S. Detailed specification of SEM is attached at **Annexure *7***.

These SEMs register VAr whenever the voltage goes below 97% or above 103% only. However, with the implementation of proposed SAMAST recommendation[17], new meter should record average voltage as well as net reactive energy exchange at every 5min/15-min irrespective of voltage level.

Details of tie point and SEMs installed pan India is given in Table 20 and summary of SEMs installed in each region is included in Table 21.

Table 20: Metering/Tie points in India (Except interface points for Generators)

Regions	**Tie points at 400kV and above**	**Tie points at 220kV and below**
NR	232	330
ER	82	70
WR	394	152
SR	192	93
NER	10	72
All India	910	717

[17] Report on Scheduling, Accounting, Metering and Settlement of Transactions in Electricity (SAMAST), http://www.forumofregulators.gov.in/Data/WhatsNew/SAMAST.pdf

Table 21: Summary of SEMs installed in different regions

Region	No. of Meter Locations	No. of Meters
NR	325	2070
WR	193	1839
SR	185	1500
ER	185	1280
NER	82	457
All India	945	7047

7.1. Reactive energy settlement

The charge for VArh was fixed at 10 paise/kVArh w.e.f. 01.04.2010. It is applicable for Regional Entity except Generating Stations as per the Indian electricity grid code. This rate has been escalated at 0.5paise/kVArh per year thereafter. The present rate is 15 paise/kVArh.

7.2. Status of reactive energy pools

Figure 7 to 12 shows the reactive energy pool accounts summary for 2018-19. Figure 7 shows the virtual All India account which is indicative as there is no inter-regional pool exchange at present. From this account, it is observed that the virtual all India pool is not balanced and remained highly negative for 2018-19. Thus, suggesting the present scheme of settlement needs review.

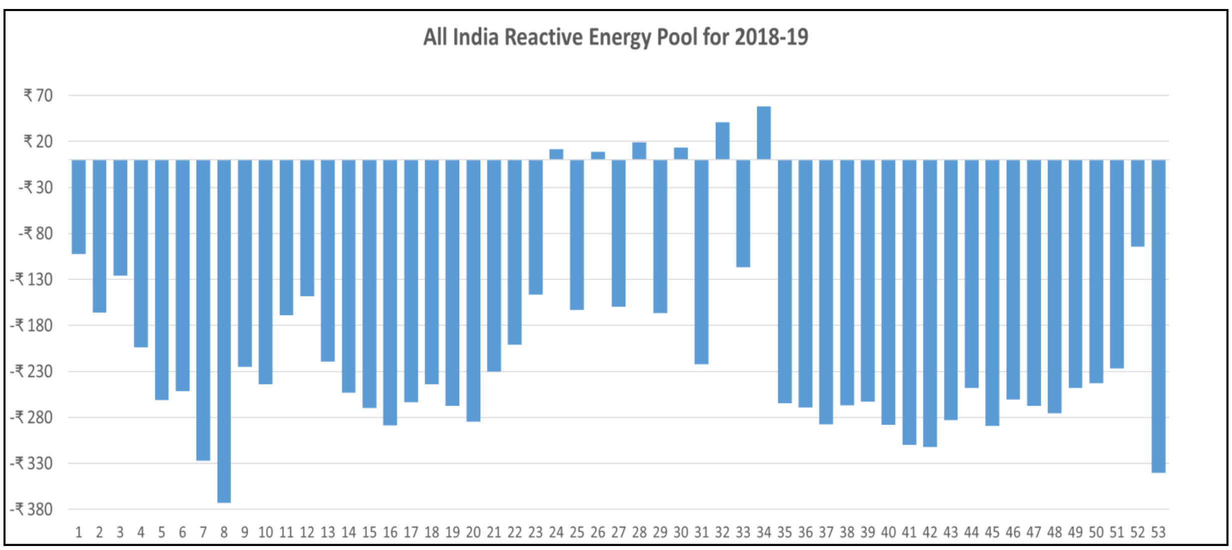

Figure 7: Week wise all India reactive energy pool 2018-19 (In Lakhs)

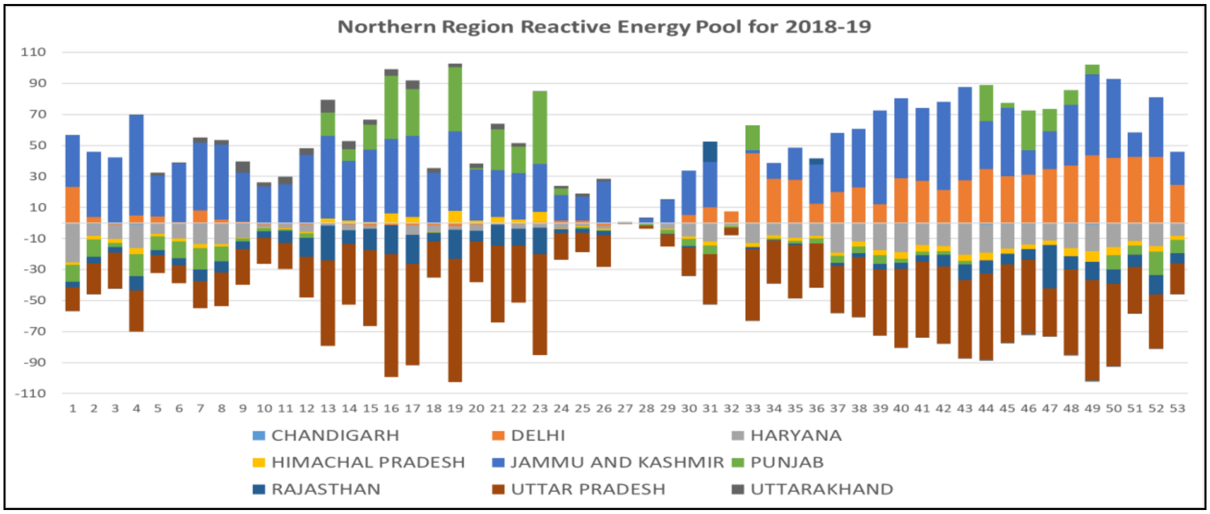

Figure 8: Week wise Reactive energy pool of NR 2018-19 (In Lakhs)

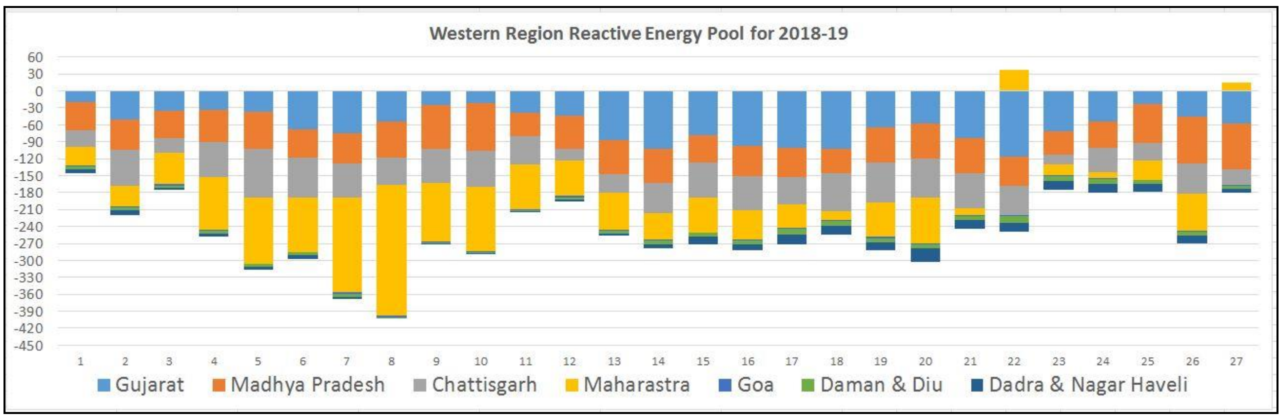

Figure 9: Week wise Reactive energy pool of WR 2018-19 (In Lakhs)

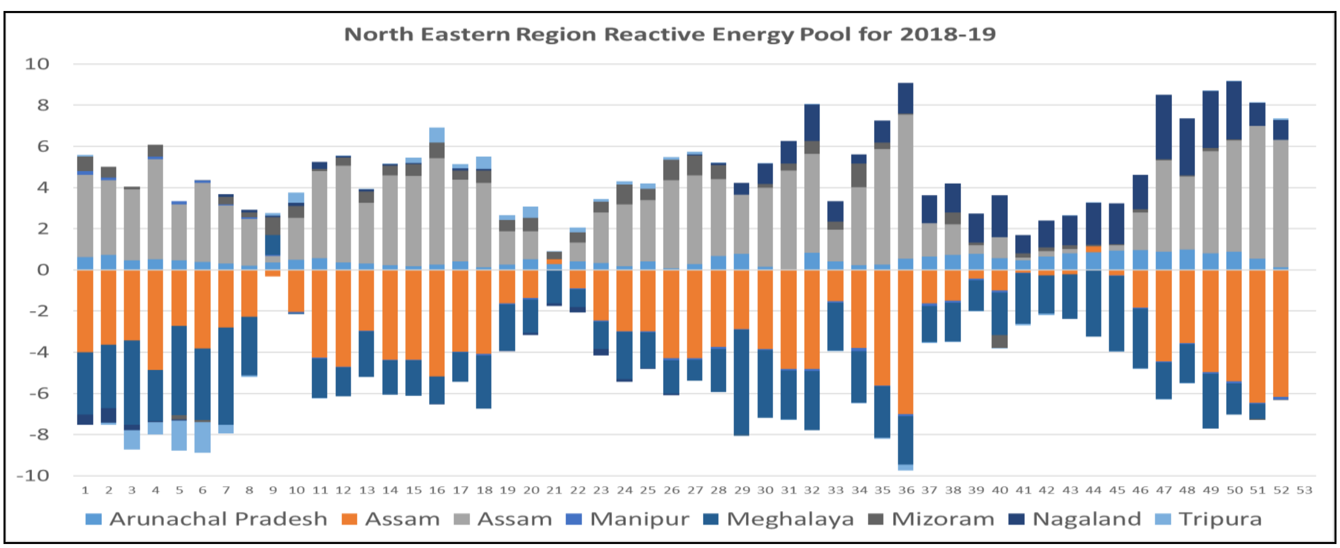

Figure 10: Week wise Reactive energy pool of NER 2018-19 (In Lakhs)

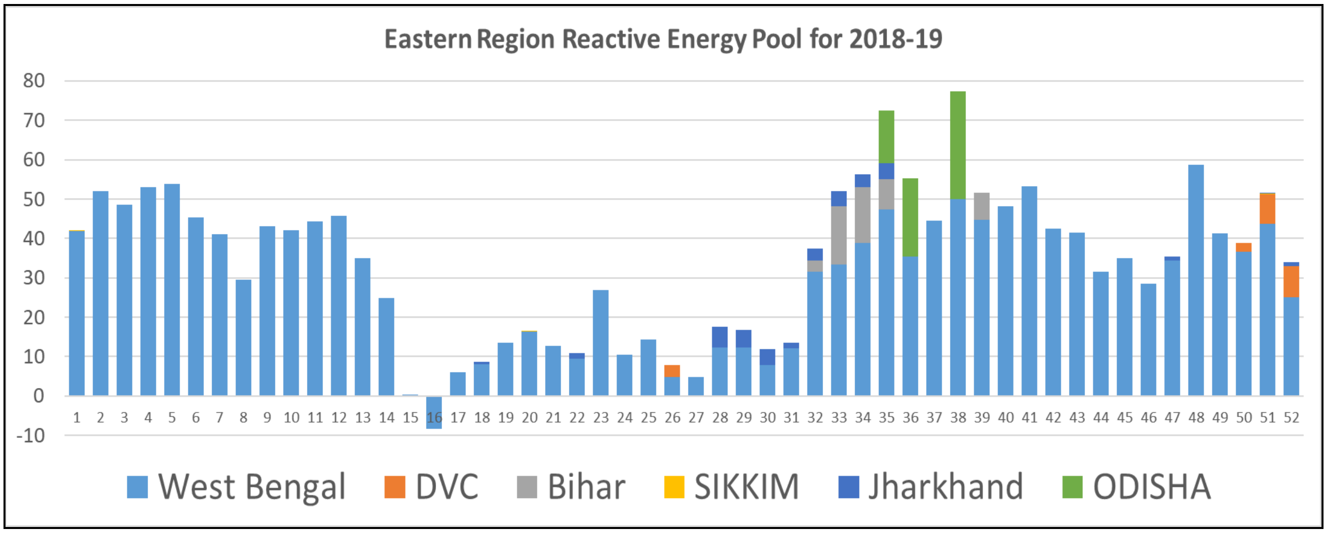

Figure 11: Week wise Reactive energy pool of ER 2018-19 (In Lakhs)

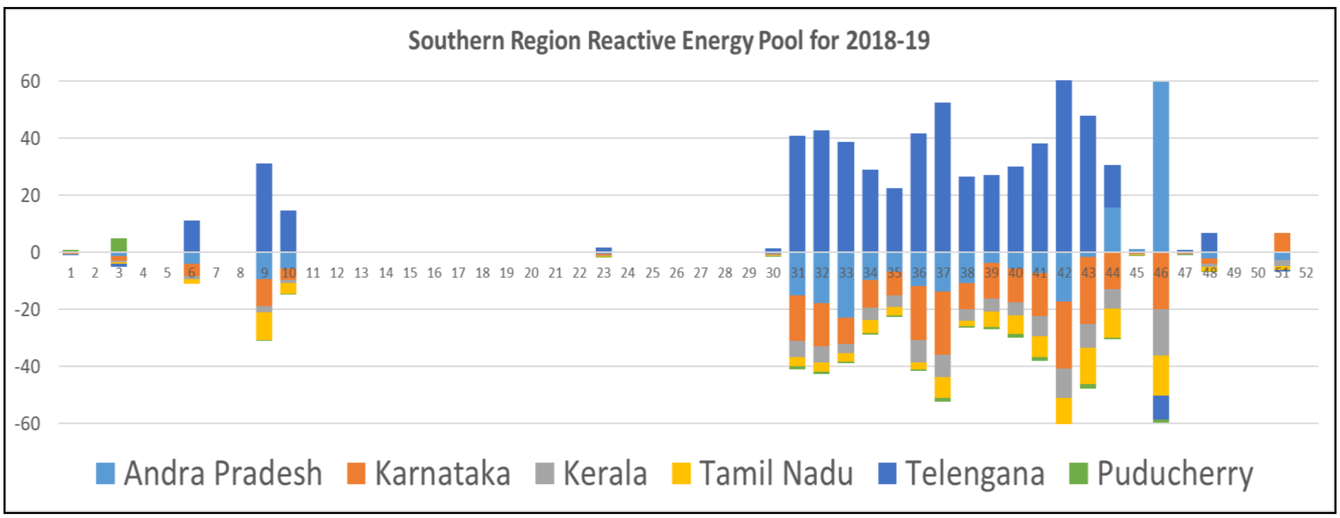

Figure 12: Week wise Reactive energy pool of SR 2018-19 (In Lakhs)

8. International Practices for Voltage Regulation

8.1. Regulatory provisions

As per the worldwide practices, various grid codes describe the voltage support as critical requirement for secure operation and planning in synchronous grid. For this, majority of grid codes first describe operating voltage range, reactive power requirement, reactive power capabilities, etc. In addition, many grid codes specify the action for voltage management under normal and emergency condition along with remuneration for reactive support.

8.2. Technical requirements

Federal Energy Regulatory Commission (FERC) (North America) adopted the power factor requirement of 0.95 leading to 0.95 lagging for all the transmission system customers. Transmission operators have to specify a system-wide voltage schedule (either a range or a target value with an associated tolerance band) as part of its plan to operate within defined limits and should schedule sufficient reactive resources to regulate voltage under normal and contingency conditions. Generator should operate in AVR mode or in different mode as per instruction of TSO/ISO and should comply with TSO/ISO step-up transformer tap change directives. Most TSOs define a +/- 0.95 power factor baseline requirement for renewable generator at the Point of Interconnection (POI).[18]

ERCOT specifies a required power factor range of 0.95 lead/lag at maximum power output, which must be supplied at the POI. At partial power, reactive capability must be up to the VAr range at rated power, or at least the required range at rated power scaled by the ratio of active power to rated power.

As per ENTSOE regulations for system operation, in case of conventional generator, system operator shall specify a U-Q/Pmax-profile within the boundaries of which the synchronous power-generating module shall be capable of providing reactive power at its maximum capacity. An agreement would be made between generator and TSO which shall cover the specifications and performance of AVR with regard to steady-state voltage and transient voltage control and the specifications and performance of the excitation control system. [19]

[18] NERC Reliability Guidelines
https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

[19] ENTSO-E Network Code for Requirements for Grid Connection applicable to all Generators

The CAISO tariff rule[20] entails Participating Generators to operate their generating units at specified points within their power factor ranges. Participating Generators receive no compensation for operating within these specified ranges. If the CAISO requires additional Voltage Support, it procures this either through Reliability Must-Run Contracts or by instructing a Generating Unit to move its VAr output outside its mandatory range. Only if the Generating Unit must reduce its MW output in order to comply with such an instruction will it be eligible to recover its opportunity cost as compensation.

In case of renewable generators, in addition to above requirement, the relevant system operator may specify supplementary reactive power to be provided if the connection point of a power park module is not located at the high-voltage terminals of the step-up transformer. Also, relevant system operator in coordination with the relevant TSO and the Power Park Module (PPM) owner have the right to choose which of the reactive power control mode (voltage control, reactive power control and power factor control) is to be applied. Other countries e.g. Great Britain, Australia, New Zealand, also specify the power factor ranges for generators in view of reactive support to the Grid.

8.3. Commercial settlement

In many regions interconnection Customer (Generators) are not compensated for reactive power when operating its generating facility within the established power factor range, since it is only meeting its obligation. Over and above obligatory requirements reactive power rates paid to generators are filed in individual rate cases.

[20] https://www.caiso.com/Documents/CalPeakandMalagaCommentsReactivePowerRequirementsandFinancialCompensationRevisedStrawProposal.pdf

Table 22: Comparison of the rates and details of various regions in North America[21]

Region	Rate charged	Capability Rate	Capability Rate Calculation Method	Payment for actual reactive power	Qualification Process in place	Specific Provisions for Non-generator sources
ISO-NE	Formula in tariff, allocated based on load ratio	$2.19/kVAr- year	Settlement (based on American Electric Power (AEP) method)^^	Yes	Yes	Yes
NYISO	Formula in tariff, allocated based on load ratio	$3919/MVAr-year	Settlement	Yes	Yes	Yes
PJM	Varies by zone, allocated based on load ratio	Yes, individual resource revenue requirement	AEP methodology	Yes, based on LMP	None	None
MISO	Varies by zone, allocated based on load ratio	Yes, individual resource revenue requirement	AEP methodology	Yes	Yes	None
CAISO	N/A	N/A	N/A	Yes, LMP or RMR	Yes	None

^^ AEP methodology identifies three components of a generation plant related to the production of reactive power:

(1) The generator and its exciter.

(2) Accessory electric equipment that supports the operation of the generator-exciter.

(3) The remaining total production investment required to provide real power and operate the exciter.

Because these plant items produce both real and reactive power, AEP developed an allocation factor to sort the annual revenue requirements of these components between real and reactive power production. The factor for allocating to reactive power, developed by AEP, is MVAr ^{2}

[21] FERC, Payment for Reactive Power, Commission Staff Report, 2014, https://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf

/MVA² where MVAr is megavolt amperes reactive capability and MVA is megavolt amperes capability at a power factor of 1.

Further details regarding reactive power compensation in various above-mentioned TSO/ISO are given at Annexure 8.

It is difficult to design an adequate equivalent to balancing markets (which deal with frequency issues) for voltage control. One of the main reasons is the localized characteristic of voltage and its treatment. Reactive power cannot be transmitted efficiently over a long distance. At some instances, this can cause just a few generators to provide the necessary reactive power flows, leading to monopolistic behavior. Further details on reactive power requirements and remuneration methods in North America are attached at Annexure 9.

8.4. Synchronous condenser operation of retired/old conventional sources[22]

Few countries have opted for converting power plant units to synchronous condensers. Ensted thermal power plant in Denmark, commissioned in 1979 with electrical capacity of 626 MW, stopped active power production in 2013 in view of increasing share from renewable energy thereby rendering fewer shares in the plant. The Ensted power plant now contributes to the stability of the national Danish electricity grid when required. The outcome of this project is the innovative reuse of deactivated power plant, improved grid stability due to the generation of reactive power and short circuit power accompanied with low investment and operational costs.

The two units at the Zion nuclear power station near Chicago were converted to synchronous condensers in 1997. In 2013 and 2014, units 4 and 5 at the FirstEnergy Eastlake plant in Ohio, USA were converted into synchronous condensers. The local area around Cleveland, Ohio still required dynamic voltage support, so various options were considered. The synchronous condenser conversion was selected in view of the static and dynamic voltage support it provides, as well as advantages of the installed infrastructure at the Eastlake plant.[23]

In one more case in California, USA, units 3 and 4 steam turbine generators (retired since 1995) at the Huntington Beach Generating Station have been converted to synchronous condensers to provide voltage support to the Southern California grid after the unexpected retirement of the San Onofre Nuclear Generating Station. [24]

Converting an obsolete synchronous generator to a synchronous condenser is a viable, economical alternative to retiring the unit. As the condenser is a rotating device, it can also

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[22] https://spectrum.ieee.org/energy/the-smarter-grid/zombie-coal-plants-reanimated-to-stabilize-the-grid

[23] C.R. SLATTERY, J.M. FOGARTY "Synchronous Condenser Conversions at FirstEnergy Eastlake Plant" *CIGRE US National Committee 2015 Grid of the Future Symposium*

[24] http://cacurrent.com/subscriber/archives/22112

provide short circuit support in addition to reactive power capacity. While converting the unit requires a system-level approach and custom engineering, the result can greatly extend the generator's useful lifespan. For the community, a conversion to a synchronous condenser can provide electrical system voltage support resulting in a stable source of electric power.[25] Conversion cost of Old thermal machines for synchronous condenser operation is around 40000-50000 US dollars /MVAr (Price in year 2014) in Indian Rupees about 30-40 lakhs /MVAr.[26]

CEA, India has also recommended utilizing retiring thermal units as synchronous condensers for supplying reactive power as well as short circuit support in its report on Flexible operation of thermal power plant for Integration of renewable generation.[27]

8.5. Standalone Synchronous condenser and Hybrid Synchronous condensers

Standalone Synchronous condensers (SCs) are now being considered in many countries as it provides two main system services that power electronic FACTS devices cannot adequately provide, which are inertia and short-circuit level (SCL). Even with the constantly evolving electricity network and many innovative power system technologies inertia and SCL remain essential for security of power system, as thyristor based HVDC systems and existing protection systems require a minimum SCL for efficient operation and inertia is required for stability. The challenge lies in lack of commercial mechanisms to financially incentivise a standalone SC installation. Ofgem is considering Phoenix project[28] deploying Synchronous Compensator (SC) with innovative hybrid co-ordinated control system combined with a static compensator (STATCOM) referred to as Hybrid Synchronous Compensator (H-SC). The project cost is approximately ₹ 196 Crores. The use of these devices is expected to mitigate serious system issues that are being encountered on the GB transmission network as a result of the progressive closure of synchronous generation plants.

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[25] https://www.power-eng.com/2011/10/01/converting-existing-synchronous-generators-into-synchronous-condensers/#gref

[26] FERC, Principles for Efficient and Reliable Reactive Power Supply and Consumption, staff report, 2005, https://www.ferc.gov/CalendarFiles/20050310144430-02-04-05-reactive-power.pdf

[27] Flexible operation of thermal power plant for Integration of renewable generation, A CEA report, http://www.cea.nic.in/reports/others/thermal/trm/flexible_operation.pdf

[28] GB Phoenix project - https://www.ofgem.gov.uk/ofgem-publications/107861

9. Reactive Power Support from Renewable Generators

India has envisioned 175 GW of renewable power by 2022. Out of this 175 GW, Solar (utility-scale, distributed, off-grid/mini-grid) is 100 GW, Wind (utility-scale) is 60 GW, Small hydro is 5 GW and Bioenergy is 10 GW. With RE's increased proportion to the generation mix, the grid's reliability, stability, and power quality needs immediate attention.

A typical solar photovoltaic (PV) power plant as well as type 3 and type 4 wind turbine generators consists of multiple power electronic inverters and can contribute to grid stability and reliability through sophisticated controls. It may in this way mitigate the impact of its variability on the grid, and contribute to important system requirements more like traditional generators[29]. However, their reactive power capability differs from those of conventional synchronous machines because they are normally not power-limited, as synchronous machines are, but are limited by internal voltage, temperature, and current constraints[30].

9.1. Solar PV

Capability of solar plant based inverters can be used to provide voltage support during critical system needs on continuous basis and during night the entire inverter capacity can be used for reactive power support. During the critical voltage condition in day time the leftover inverter capability apart from active power generation can be utilised without any real power curtailment[31]. Similarly, type-3 and 4 based wind power plants can also support the grid during no real power output.

Figure 13 shows a typical and actual solar PV inverter capability curve. It can be observed that 1406kVAr i.e. 56% reactive support is available almost at all real power level.

[29] Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants - https://www.nrel.gov/docs/fy16osti/65368.pdf

[30] Reactive Power Performance Requirements for Wind and Solar Plants - A. Ellis, Senior Member, IEEE, et. al.

[31] Reactive power control strategies for solar inverters, Ram Krishnan et al. - https://regridintegrationindia.org/wp-content/uploads/sites/14/2019/11/10A_1_RE_India19_141_paper_Krishan_Ram.pdf

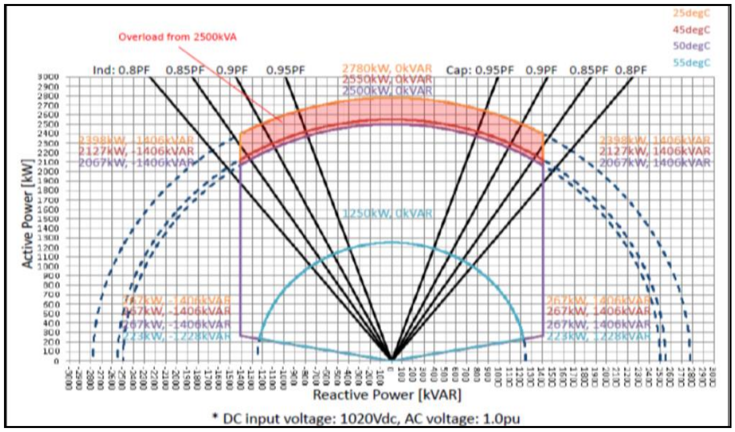

Figure 13: Capability Curve of a 2500 kVA inverter

As far as PV inverters are concerned, they generally have three modes of operation w.r.t. reactive power:

1. **Voltage control mode** in which voltage of the reference point is monitored by inverters/PPC and reactive power drawl/ injection is varied accordingly w.r.t a voltage set point.
2. **Reactive Power or Q-control mode** in which inverter supplies/absorbs a fixed amount of reactive power from the grid.
3. **Power Factor control mode** is one in which inverter operates within a defined power factor range.

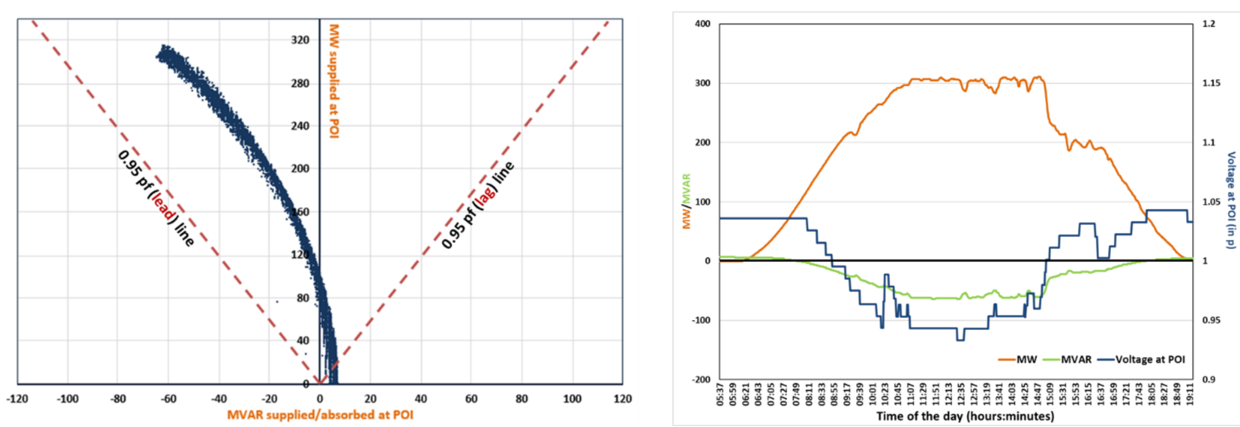

Figure 14: PQ curve of a PV plant (operating in power factor mode) and its typical day's behavior

Figure 14 shows PQ curve built up from actual data of real and reactive power received at POI alongside the trend of P, Q and V at POI for a particular day. It can be seen from the figure that the reactive power absorption of solar plant is increasing with increase in generated active power. Though the plant is running within 0.95 lead lag power factor limits at POI, the effect of this plant along with others operating in same manner i.e. at lagging pf, is absorption of reactive power at POI proportional to real power output resulting in reduction of voltage to critically low levels during peak solar generation.

To meet the CEA standard of 0.95 lead/lag p.f. the solar plant operators are generally running in power factor control mode and maintaining unity p.f. at inverter terminals. This scenario is leading to all the reactive power required by inverter transformers, plant power transformers and dedicated line being absorbed from grid.

A way out from this situation is to operate all the PV plants and other inverter based resources in voltage control mode (taking POI voltage as reference voltage) thereby regulating reactive power injection/drawl as per grid condition.

As an example, shown in Figure 15 is PQ curve of a typical solar generator operating in voltage control mode, the typical day behavior could also be seen.

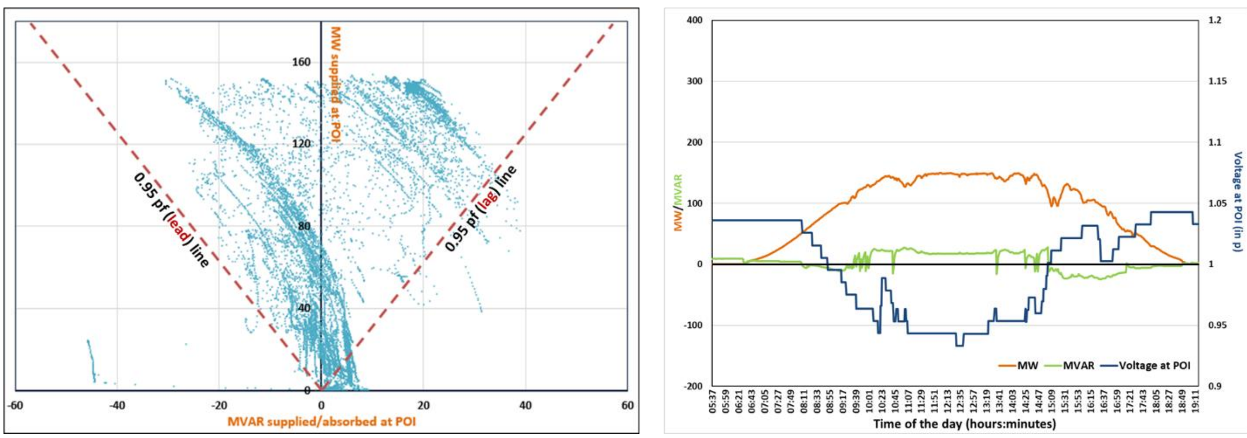

Figure 15: PQ curve of a PV plant (operating in voltage control mode) with constant Q and typical day's behavior

In voltage control mode solar plant is dynamically supporting the grid by injecting/absorbing reactive power based on local voltage. As can be seen from the figure, during peak solar generation period, the plant is injecting VArs to the POI to boost the dip in voltage.

9.2. Wind Plants

Some typical examples, illustrating wind plants current operating philosophies and challenges are illustrated.

9.2.1. Wind Plant-1

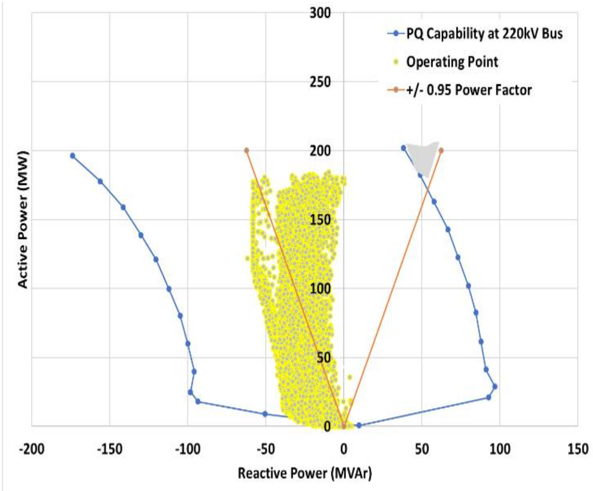

Figure 16: PQ Curve of Wind Plant – 1

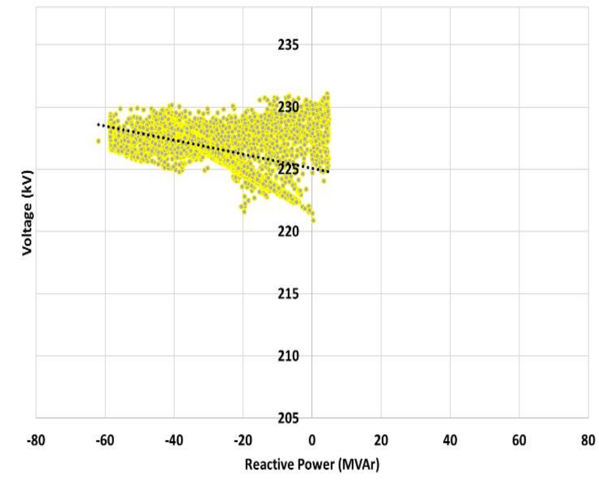

Figure 17: VQ Curve of Wind Plant – 1

- PQ curve shows, plant was mostly absorbing reactive power from the Grid. Reactive power absorption capability is more than -0.95 pf.
- From the VQ curve, it can be seen that plant is operating in voltage control mode as when voltage increases, reactive power absorption increases and attains a value to the tune of 60 MVAr when voltage is around 230 kV. Voltage is above 220kV most of the times.

9.2.2. Wind Plant-2

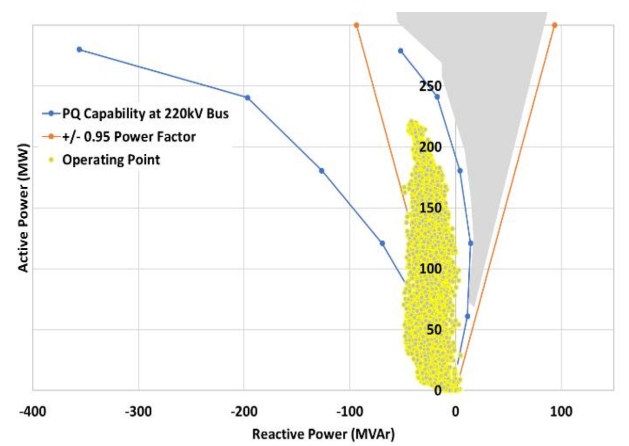

Figure 18: PQ Curve of Wind Plant – 2

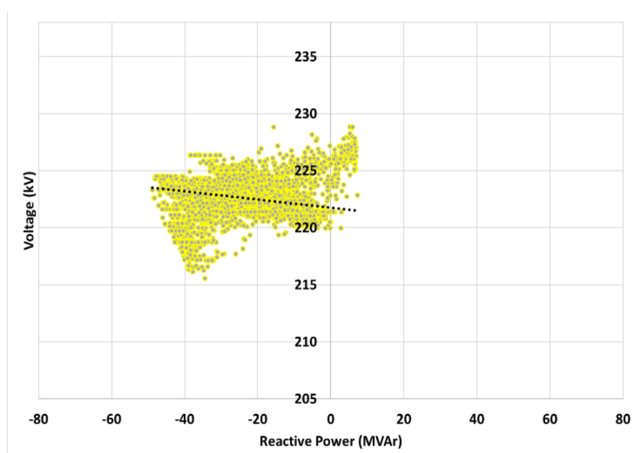

Figure 19: VQ Curve of Wind Plant – 2

- From the PQ curve, it can be seen that wind farm was generally drawing reactive power from the Grid.
- Maximum absorption was observed when voltages were high and reactive power absorption was in decreasing trend with decrease in voltages.

- PQ capability is compromised, indicated by gray area in PQ curve. When generation is above 175MW, plant cannot supply MVAr to the Grid.

Considering the performance of solar and wind plants in view of existing standards, the following consideration may improve the situation:

- Operation of solar/wind plants and other inverter based resources in voltage control mode (taking POI voltage as reference voltage) thereby regulating reactive power injection/drawl as per grid condition.
- In situations where voltage control operation is not possible, solar/wind developer must provide shunt compensation devices so that they don’t have to depend on grid for reactive power support. In view of this, **it is suggested that prior to granting grid connectivity, reactive power assessment shall be done which would help in installation of sufficient VAr compensation devices at plant level by RE developers**.
- A voltage based reactive support requirement could be introduced by doing away with any linking of reactive power output w.r.t. power factor.

10. Managing reactive power in a grid

This section discusses about various challenges associated with voltage control along with other important aspects.

The prescribed operational voltage range is covered in most of the grid codes, operational guidelines around the world. The basic reactive power requirement, which is the so called “obligatory response” is also covered, though the following need to be contemplated:

10.1. Choice of site for reactive support:

For conventional generators, the reactive power capability is defined at generator terminal. The general requirement for power factor based reactive support is also stated at generator terminal except in few cases (the South African grid code stipulates power factor based reactive support at HV side of GT[32]). The metering and telemetry (in most cases) are available at the grid interconnection point which is the high voltage side of generator or step-up transformer. Since, there is substantial reactive drop across the GT leakage reactance, monitoring and accounting of actual VAr exchange by a generator calls for **metering as well as telemetry at generator terminal**.

The other alternative could be to set the requirements at HV side of GT or the grid interconnection point as it is covered in some grids. The Maharashtra’s grid code[33] also specifies such a requirement at HV side generator bus voltage. This would also simplify monitoring as well as metering. The monitoring in real time would be easier for system operator as the existing telemetry available at grid interconnection could help in assessing the performance of generator. The metering, on the other hand, would also be taken care of by the existing metering arrangement in place.

10.2. Point of reactive support:

The power factor based requirement of reactive support is generally captured in operational documents of high voltage grids. However, it may become ambiguous as to where such requirement is needed. For instance, In India, as per the CEA grid connectivity standards, the power factor capability requirement for the conventional generators is specified but the point of measurement i.e. generator terminal or grid interconnection point is not clear. This ambiguity assumes magnitude because of generator transformer consuming lagging VArs. For example, even if the power factor at generator terminal is maintained at unity, reactive drop across

[32] https://nersa.org.za/

[33] Maharashtra Electricity Regulatory Commission (State Grid Code), Regulations, 2020 https://www.merc.gov.in/mercweb/faces/merc/common/outputClient.xhtml

generator transformer reactance needs to be compensated. As a result, the power factor at grid interconnection point would not be unity. Such a case is not there with renewable/inverter-based generation for which the requirement is defined at Point of Interconnection (POI).

10.3. Power factor to voltage based:

A typical capability curve of generator would depict that at rated real power or beyond, the reactive support is least. This means at any other real power output less than the rated or maximum level, the reactive power support from generator exceeds the corresponding value at rated power output. This could also be corroborated from Figure 20 which depicts the typical PQ characteristic "D-curves" of different types of machines.

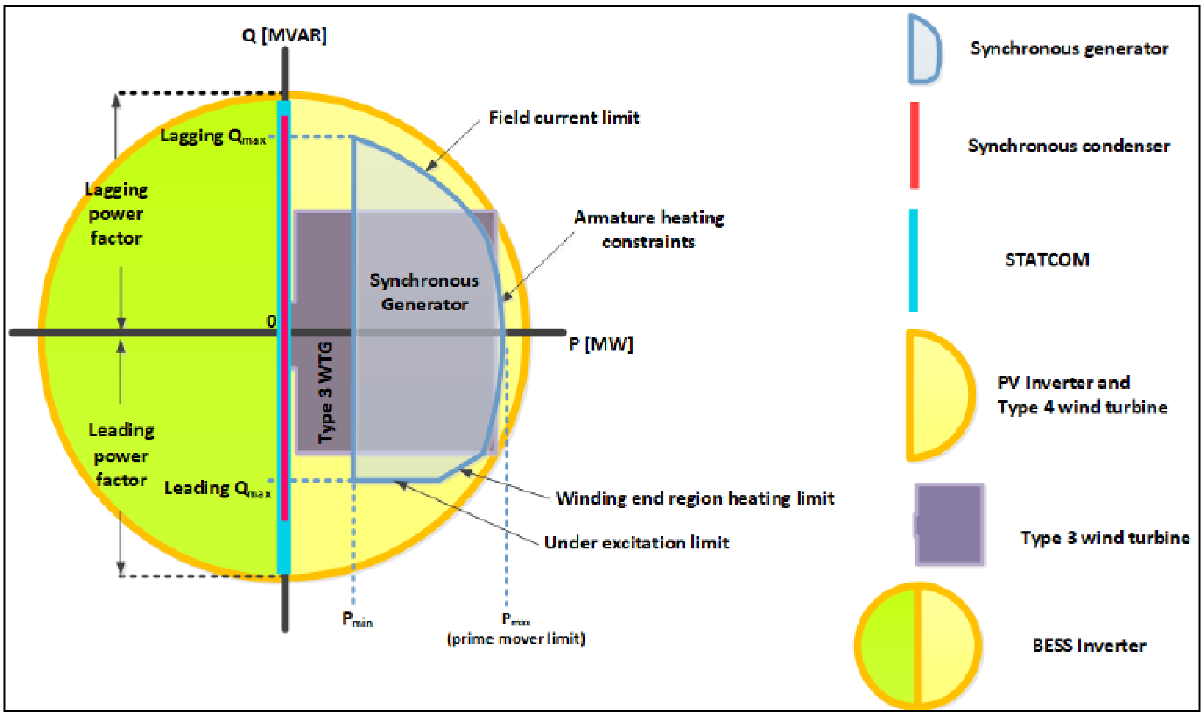

Figure 20: PQ or Capability curve of different generators (Reference: NREL)

In few grids,[34] less complicated reactive power requirement is expected as they only define the minimum and maximum reactive power capability band instead of power factor based limits. Thus, if unit is on bar or synchronized, it could be capable of providing certain minimum level of reactive power support as desired by system operator. This **delinking of reactive power requirement from power factor** ensures that the focus shifts towards voltage and based on the voltage, the reactive power is dispensed.

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[34] Active and Reactive Power Control of a PV Generator for Grid Code Compliance, https://www.mdpi.com/1996-1073/12/20/3872

As for the commercial mechanism, it would be advantageous for grid operation to link reactive energy pricing to voltage. The similar linking is advocated in SAMAST[35] report wherein Reactive Energy pricing at inter utility level was recommended to be linked to voltage instead of power factor.

10.4. Remuneration

- There are different ways to compensate reactive support from generators. The response is generally categorized in two ways viz. mandatory or obligatory and beyond obligation. The response beyond obligation is once again divided based on whether the VAr support led to any real power reduction or not. In case VAr support lead to real power reduction, an opportunity cost is generally paid to the generator.
- The general tendency for payments to generators in lieu of reactive support is fixed payments.
- The obligatory reactive response in most grids is not compensated. Moreover, there is no penalty in case such mandatory service is not provided by generator with few exceptions like Switzerland wherein penalty is imposed[36]. **The lack of direct penal provision could lead to non-compliance of obligatory response**.
- The response beyond obligation or stipulated level is also dealt differently in different power grids. In few grids, it is not remunerated at all, in others, remunerated on the basis of energy or availability or on the basis of both. For instance, in Spain, the remuneration is based on availability as well as reactive energy provided.
- In vintage FERC, 2005 report[37], the availability-based payments to generators is contested as it would not align incentives with desired generator locations for reliability. For example, payments based on the number of hours a unit is online would tend to increase payments to baseload units which may be located far from load while decreasing payments to intermediate or peaking units that may provide reactive power where and when it is most needed. Moreover, the stressed nature of merchant generators also corroborates the notion of not basing the reactive payments on availability as these plants must be on bar for a reasonable time of the year to receive any fixed payment.
- The payment based on quantity or reactive energy would also result in paying more to generators in areas with weak transmission than to generators in areas with stronger transmission. Though if penal provisions would be set for non-compliance, the generators

[35] Report on Scheduling, Accounting, Metering and Settlement of Transactions in Electricity (SAMAST), http://www.forumofregulators.gov.in/Data/WhatsNew/SAMAST.pdf

[36] https://www.swissgrid.ch/dam/swissgrid/customers/topics/tariffs/Tabelle-Tarife-en.pdf

[37] FERC, Principles for Efficient and Reliable Reactive Power Supply and Consumption, staff report, 2005, https://www.ferc.gov/CalendarFiles/20050310144430-02-04-05-reactive-power.pdf

which tend to get higher penalty would also be the one who are located near weak transmission zone.

10.5. Implementation aspects

- The basic requirement for getting reactive support from generators are:
  - AVR to be in auto mode.
  - Set point of voltage in AVR control mode to be set in consultation or as instructed by system operator.
  - Generator transformer tap ratio to be communicated to system operator and may be changed based on instruction from system operator.
- These more or less static data monitoring even ensures optimum **dynamic reactive support** from generators.
- For renewable generating plants, the set point and mode of operation needs to be communicated to the system operator. Voltage control mode is preferred mode of operation.

10.6. Synchronous condenser operation

- A typical hydro plant generator is made to run in condenser mode in the following general manner:
  - Firstly, the unit is started as a synchronous generator and loaded up to a set point
  - Water is depressed from the turbine by injecting compressed air
  - Condenser mode operation starts
- The generation mode results in real power generation for few minutes. This can be compensated by either providing the determined tariff-based pricing or in other cases where such tariff is not present, by any other mechanism.
- The power consumed while in condenser mode or during changeover could be treated as transmission loss.
- The maintenance cost of equipment involved during the condenser operation along with manpower cost and relevant auxiliary consumption not directly tapped from grid could be compensated by an energy-based pricing.
- The maintenance cost of equipment's during changeover to condenser mode could either be paid as one time charge every time the unit is brought on bar for condenser operation or once a machine is brought in for condenser operation, it could be paid for at least full capacity VAr support for a minimum amount of time.
- The additional advantage of synchronous condenser in providing inertial and SCL (Short circuit level) support to the grid.

10.7. Reactive support from renewable plants in "no generation" period

The solar and wind plants don't produce power during whole day. Where solar is much more predictable, the wind is intermittent. These inverter-based plants especially solar and type -3 and

4 wind plants have capability for reactive support[38]. Thus, a proper pricing mechanism could help in utilizing these dynamic reactive resources even when there is no generation.

10.8. Reactive power reserves

While dealing with voltage stability, the reactive power reserves or at places termed as dynamic reactive power reserves need to be factored in. These are necessary to keep voltages in check in case of contingencies like faults, switching surges and also address stability. Some grid operators define the amount of reserves to be kept. For e.g. in Finland, 50% of maximum available reactive power that can be injected or absorbed by the plant has to be kept as reserve[39] whereas in some cases the decision is left to operator to assess in real time[40]. While keeping the fixed amount of reserves reduces complexity, the analysis based figures means only optimum amount of reserves are kept.

10.9. Other issues

- The Unit Auxiliary Transformer (UAT) or Unit Transformer (UT) of a generator is connected between the GT and unit stator windings. The typical rating of UAT corresponds to auxiliary consumption of plant. For e.g. in hydro power plants, the rating is around 1% whereas in thermal plants it is around 8%. The existing metering provision at HV side of GT would not exclude the VAr exchange through UAT. This would also need to be taken care of. The other way round is the provision of metering at LV side of GT. This would mean installation of new meters at LV side of all eligible or chosen generators which in turn may delay any immediate measures.
- As per [44], **Hunting** may occur if multiple resources are attempting to control scheduled voltages at a common substation. Thus, different RE developers having common POI may in attempt to control the voltage experience hunting. Although, the choice of appropriate voltage droop characteristics, latency may mitigate the problem of hunting to some extent.
- The AVR mode or the voltage control mode of a generator is an important requirement enabling plant to handle reactive power demand of the grid. Therefore, it becomes imperative to **monitor the healthiness of AVR or other voltage control related equipment at a plant** and have periodic checking of reactive response by a generator, in case the desired output is not realized.

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[38] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Item_4a._Integrating%20_Inverter-Based_Resources_into_Low_Short_Circuit_Strength_Systems_-_2017-11-08-FINAL.pdf

[39] https://www.fingrid.fi/globalassets/dokumentit/en/customers/grid-connection/supply-of-reactive-power-and-maintenance-of-reactive-power-reserves_2017.pdf

[40] https://www.nerc.com/comm/PC_Reliability_Guidelines_DL/Reliability%20Guideline%20-%20Reactive%20Power%20Planning.pdf

11. Roadmap for Voltage Control Ancillary Services

In view of large-scale renewable integration, decreasing system inertia, wide variation of load and generation mix, the threat to voltage stability is growing along with the issues of system stability and quality of power. As a result, more stringent and proactive measure for voltage support becomes the need of the hour.

11.1. Separate regulation for Reactive power management

All the provisions with respect to managing reactive power in the grid could be covered in a separate regulation viz. planning; resources; mandate or obligatory response from Generators; guidelines for renewables generators; voltage range under normal and emergency system condition; dynamic reactive reserves assessment and planning; monitoring; mechanism for deriving reactive charges for penalties, rewards; commercial settlement mechanism considering scope of reactive energy accounting.

The previous chapters addressed the challenges associated with certain regulatory provisions in bringing the reform to strengthen the reactive support in the system. Moreover, the proposed recommendations also indicate reviewing these regulations and standards. These aspects may also be addressed by a separate regulation dealing with reactive support to the grid.

11.2. Commercial framework for Reactive support from generators

The IEGC mandates that the reactive support has to be extended to the grid by grid connected ISGS and other generators. However, it has been observed that reactive power response from generating stations is inadequate and large reactive reserves remain underutilized during the system requirement. To address this, the following commercial framework for reactive support from conventional generators as well as inverter based generators is proposed:

- Voltage (POI voltage) > 1.02pu, generator to be paid for VAr absorption greater than 20% of generating unit MCR (Maximum Continuous Rating) at POI and to be charged for any VAr injection.
- Voltage (POI voltage) < 0.98pu, generator to be paid for VAr injection greater than 20% of generating unit MCR at POI and to be charged for VAr absorption.
- Charges, both remuneration and pe
- nalty, may be set as ***15 paise / kVArh*** **(say)** and to be escalated at ***0.5 paisa / year*** **(say)** synonymous to the corresponding existing charges of regional entities (except generators).
- AVR auto mode or voltage control mode to be the preferred mode of operation unless otherwise specified by system operator. Any problem in running in above mode shall be immediately communicated to RLDC by respective plant.
- The GT tap ratio, voltage set point to be communicated to RLDC before making any change or changes are to be made in consultation with RLDC.

- The payments are made for the reactive support over and above 20% of generating unit MCR. For e.g., if V > 1.02 and machine is absorbing 25% of VAr, the payment would be made for 5% (25%-20%) response.
- For any reactive support beyond 40% of MCR, the payment is capped at 40%. For instance, if reactive support in intended direction is 55% of MCR, the payment would be made for 20% (40%-20%) of response.
- The interpreted obligatory reactive support from CEA's Grid Connectivity Standards corresponds to a maximum 0.95 power factor i.e. reactive power output of around 33% of active power production. Owing to accuracy of measurement, UAT reactive requirement, drop across GT, the figure of 20% of machine MCR is chosen.
- The voltage dead band may be chosen as 2% i.e. no change from 98% to 102%. The idea to choose a dead band is measurement error and reactive support remuneration only when it is required.
- The framework may be mandated only in case the unit is on bar.
- In the long run, arrangements shall be made to communicate the POI voltage to the AVR of generating unit or the Power Plant Controller of solar or wind farm. Pending this, local voltage could be used for feedback which could be periodically corrected.

11.3. Communication and metering requirements

At present, meter data is available for tie points only and meters register reactive energy exchange when voltage is below 0.97 / beyond 1.03 p.u. The following characteristic of metering to be employed for smooth implementation of proposed commercial mechanism:

- Meters to measure reactive power on each time block.
- Meters as per SAMAST committee recommendation.
- Metering at LV side of GT with due consideration of UAT location in appropriate time frame.

Further, for proper monitoring in real time, the following data shall be provided to respective regional control centers:

- Telemetry of control mode of operation viz. voltage control, reactive control, power factor control or any other control mode in case of renewable plants and AVR on/off status in case of conventional generator.
- Telemetry of voltage set point.

11.4. Support from grid connected Renewable Energy Sources during "no generation" period

As discussed in previous sections, inverter based RE resources can provide reactive support even when not producing any real power output. An exercise was carried out in consultation with a solar plant (150 MW) in order to calculate various additional costs/ charges incurred in providing reactive power with no real power output. The calculation is as under:

Typical cost of operating solar inverters in SVC mode during "no generation" period:

- Additional maintenance cost = **₹ 0.02 / kVArh**
- Reactive power generation is around **33%** of installed capacity (AC)
- Active power consumed during "no generation" period is around **4%** of installed capacity (AC)
- The running time is assumed to be from 6 P.M. to 6 A.M.

To utilize RE generation during no active power generation, the following framework similar to the synchronous condenser operation is proposed:

- Variable charges to be paid for RE plant providing reactive support in absence of real power output.
- The real power consumed during the operation of plant for reactive support to be treated as transmission losses.
- Q (Reactive Power) schedule to be provided by RLDC to generators. There shouldn't be any significant variation from schedule except voltage droop based (as per voltage control mode). Remuneration is based on scheduled VAr. Any variation beyond a certain tolerance or threshold limit to be dealt accordingly **OR** Voltage (POI) schedule can be provided wherein the reactive support is based on the voltage droop setting and set point.
- Voltage control mode is the preferred mode of operation unless any other mode of operation is desired by respective RLDC. Any problem in running in above mode shall be immediately communicated to RLDC by respective plant.
- The voltage set points to be communicated to RLDC before making any change or changes are to be made in consultation with RLDC.

11.5. Synchronous condenser (SC) operation

As per CEA mandate, hydro station of capacity 50MW or above shall be capable of synchronous condenser (SC) operation, wherever feasible. However, it has been experienced that additional auxiliary consumption and other related issues impact the performance of machine during condenser operation. Due to such issues, and other technical and commercial aspects, many of hydro generating plants resort to not operating in synchronous condenser (SC) mode.

SCs can provide AC system strength in the form of inertia and short circuit power thereby inherently providing dynamic voltage control. The FACTS devices on the other hand are mostly limited to fast voltage control. Also, SCs combined with a BESS or gas turbine can play a role in Black Start strategies.[41]

As mentioned earlier, the usage of synchronous condenser is not only limited as a dynamic reactive source which is why we have seen examples of usage of synchronous condenser in various parts of the world. In order to mandate the CEA standards and to exploit the dynamic response of synchronous condenser operation in addition to other features, suitable incentives or compensation needs to be introduced to encourage synchronous condenser operation. Task Force on Power System Analysis under Contingencies constituted by Ministry of Power, in its report[42] submitted in August 2013 inter-alia, mentioned that:

"Additionally arrangements may need to be made for allowing operation of hydro generators in synchronous condenser mode. In fact, the CEA (Technical Standards for Connectivity to Grid) Regulation 2007, specifies synchronous condenser operation as a desirable feature in hydro generators of 50MW and above. To encourage synchronous condenser operation of hydro generators, CERC may like to consider some tariff incentives to these generators".

In 35th TCC & 39th NRPC Meetings[43] (01st and 02nd May, 2017), TCC opined that "CERC may be approached at appropriate time for compensation to generators for operation of units under synchronous condenser mode". An exercise was carried out in consultation with a hydro plant to calculate various additional costs/charges incurred by generator for operating machine in synchronous condenser mode. The calculation methodology is attached at Annexure 10.

Table 23: SC Cost calculation

Description/ Head	**Cost in INR (₹)**
Per hour running maintenance cost of one unit in SC mode	4226
Per hour running maintenance cost of compressed air system	603
One man-hour rate of semi-skilled manpower	209
One man-hour rate of skilled manpower	280
Total Cost/Hr.	5319
Reactive power capability of Unit in SC mode	100 MVAr
Reactive energy generated in 01 hour	100 MVArh
Cost incurred per kVArh	5.3 Paise

[41] https://www.ofgem.gov.uk/ofgem-publications/107861

[42] http://erpc.gov.in/wp-content/uploads/2016/10/Ramkrishna-report_power_system_analysis.pdf

[43] https://nrpc.gov.in/wp-content/uploads/2017/12/35TCC-39NRPC_MN.pdf

With enhanced telemetry of MVAr and new meter as per SAMAST committee, monitoring and accounting would improve to handle the commercial aspect of the problem. The following framework is proposed:

- Fixed and variable charges to be paid for generator running in condenser mode of operation.
- The real power generation before going into condenser mode to be treated as being scheduled or would be given appropriate generated energy charges.
- The real power consumed during condenser operation to be treated as transmission losses.
- Once a machine is brought in for condenser operation, it is to be paid equivalent to at least full capacity VAr generation/absorption for an hour as recovery for changeover cost.
- Q (Reactive Power) schedule to be provided by RLDC to generators. There shouldn't be any significant variation from schedule except voltage droop based (as per AVR). Remuneration is based on scheduled VAr. Any variation beyond a certain tolerance or threshold limit to be dealt accordingly. **OR** Voltage (HV side) schedule can be provided wherein the reactive support is based on the voltage droop setting and set point.
- AVR to be in auto mode. Any problem in AVR shall be immediately communicated to RLDC by respective plant.
- The GT tap ratio, voltage set point to be communicated to RLDC before making any change or changes are to be made in consultation with RLDC.

11.6. Utilizing Pumped storage hydro stations for reactive support

Guidelines for pumped storage hydro station needs to be issued for four quadrant operation and the commercial settlement mechanism for different quadrant operation needs to be put in place.

11.7. Conversion of retired thermal plants to synchronous condenser

When old thermal generator switched from conventional generation to synchronous condenser operation mode, they substantially reduced air emission since synchronous condenser mode doesn't burn fuel to provide reactive power and also helps in reducing the carbon footprint. In addition, many thermal generators are located at load centers. The conversion of such generators to synchronous condenser would help in integrating more RE power to the system as this would enhance the stability of the system.

Adequate incentives for such retired thermal generator machine to run as a synchronous condenser operation may be provided. However, the cost of conversion in India is yet to be discovered as it may depend on various factors.

As per international experience, retired or less utilized thermal station may be proposed for synchronous condenser operation after doing cost-benefit analysis. At various places around the world retired generating units were converted into synchronous condenser.

The cost of conversion was also less than putting a dynamic device like SVC or STATCOM at place with benefits surpassing the later[44]. Many of the old thermal stations in India have also been retired or are on the verge of retirement. These retired thermal stations may be opted suitably for synchronous condenser operation. Majority of the units are at 220kV level i.e. relatively near to load, a favorable coincidence. Utilization of these plants as synchronous condenser would provide the necessary reactive power support, strengthen the network and provide overall benefit in both voltage and efficient active power flows. Summary of thermal stations that have been retired is given in Table 23. Details are given at Annex 11.

Table 24: Retired thermal / Gas based units

Region	Generating units	Capacity, MW	MVAr capability (+60% / -30%)
ER	39	2671	1603 / -801
NER	7	140	84 / -42
NR	23	2604	1562 / -781
SR	12	940	564 / -282
WR	22	2705	1623 / -812
All India	103	9060	5436 / -2718

11.8. Settlement of interstate reactive energy exchanges

Suitable mechanism needs to be put in place for treatment of inter-state tie lines reactive power exchanges.

11.9. Mechanism for Transformer tap optimization

OLTC feature is available in almost all ICTs at 220kV and above. However, frequent online tap switching is being avoided. The OLTC (On load) tap changing frequency could be as high as 5000 operations per year as compared to seasonal operation of off load tap changing currently being carried out. There are different aspects related to transformer taps viz. number of taps, frequency of tap changing, tap staggering, On load or Off load tap changers, frequent utilization of GT taps. In addition, optimum tap changes in a grid results in appreciable reduction in transmission losses. **Thus, a mechanism needs to be devised in consultation with stakeholders to look into aspects like frequency of tap operation, OLTC (On load) tap operation, GT tap operation, tap staggering, optimum operation of taps etc.**

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[44]FERC, Payment for Reactive Power, Commission Staff Report, 2014, https://www.ferc.gov/legal/staff-reports/2014/04-11-14-reactive-power.pdf

11.10. Regulatory frame work for reactive power pricing

Various types of reactive power resources are available in the system. System operators often take the decision for reactive power dispatch based on the grid requirement however it may not be at an optimum cost. As in case of active power wherein optimization or economic or merit order dispatch is likely to be considered, reactive power dispatch is not passed through these checks. **Regulatory framework for reactive power pricing and later on market design would help system with optimum dispatch of reactive power.**

11.11. Reactive support from Distribution system

Voltage support is best dealt at local level. In view of more variability expected due to DERs, the reactive power management at distribution level becomes all the more important.

11.12. Mobile reactive resources

As reactive power can't travel long distances and it should be compensated locally for effective and efficient use, location of reactive power also keeps changing with varying load scenarios. **In such cases, exploring and encouraging the mobile reactive resources could be useful particularly for location where reactive power requirement is for short duration only**. Re-locatable SVCs are having modules that can be transported with normal transportation equipment (truck, train, boat). The modules have prefabricated cables and bus work for easy interconnection. Currently, re-locatable SVCs are being used in Japan, Switzerland, Australia and the United Kingdom[45].

11.13. Battery Energy Storage System (BESS)

BESS are being adopted worldwide at both Medium voltage & Low Voltage level for active and reactive power support apart from other associated benefits. BESS helps in providing a range of power system services e.g. Connect/disconnect function – adaptive settings (grid-connected and islanded), Maximum generation limit – peak power limiting, fixed power factor function – Intelligent Volt-Var function, Low/high voltage ride-through – Low/high frequency ride-through, Dynamic reactive power/current support etc. With the high penetration of renewable at grid or HV level, BESS are coming with features like droop-controlled voltage regulation along with frequency response services. BESS now a days are being designed to provide voltage and frequency support and improve the stability of the grid. Thus, BESS are offering a wide range of

[45] FERC, Principles for Efficient and Reliable Reactive Power Supply and Consumption, staff report, 2005, https://www.ferc.gov/CalendarFiles/20050310144430-02-04-05-reactive-power.pdf

grid supported services which may be helpful in smooth integration & operation with large renewable power.

Battery Energy Storage System (BESS) seems a promising technology option for reliably integrating a large proportion of VRE into large power grids. In India, energy storage has been the subject of study by a technical committee and task force constituted by the Ministry of Power (Large Scale Integration of Renewable Energy), and by Central Electricity Regulatory Commission (Staff paper – "Introduction of Electricity Storage System in India", in January 2017).

Already a pilot project is going under USAID, GTG (Greening the grid) -RISE initiative to study the technical and economic effectiveness of grid-connected BESS in providing dynamic frequency regulation and other ancillary services; capacity firming and energy time shift of VRE generators, peak shaving and load following; and dynamic reactive compensation and voltage support. Based on the study, specific recommendations for operation of battery energy storage system and required enhancements based on Indian grid conditions would be proposed. Based on feedback, suitable mechanism may be adopted for reactive support services from BESS.

11.14. Recovery of shortfall in reactive pool account

Reactive pool account may be supplemented from other pools, if there is any shortfall so that it can be made sufficient for the compensation to the entities for their reactive power support.

11.15. Cross border exchange, Reactive power and Voltage management

Indian grid is connected with Bhutan, Bangladesh and Nepal at 400 kV level and 220 kV level. The connection with Nepal and Bhutan is synchronous while with Bangladesh is asynchronous.

Bhutan usually injects power into the Indian Grid which normally peaks in monsoon season during the month of July-September, since most of the power plants in Bhutan are run of the river based hydro plants. During the month of December to March, generation remains very low, which causes high voltage issues at some nodes of the Indian grid. To control high voltages during this period, lines are being opened between Binaguri(India) and Tala (Bhutan) as well as Alipurdwar(India) and Jigmeling(Bhutan).

Indian grid is connected to Bangladesh though 2 x 500 MW HVDC B-T-B blocks Bahrampur(India) -Bheramara (Bangladesh). Presently voltage at Bahrampur normally remains under control even during high or low drawl scenario.

Nepal keeps part of their system radially connected with Indian grid, both at ISTS and tie points with Bihar and Uttarakhand. Nepal drawl remains high during winter and early summer while it decreases significantly during monsoon season.

Due to radial exchanges of power, reactive power and voltage issues are being faced during system operation and the same are being discussed regularly in the coordination meetings. Voltage control ancillary services may be extended for cross border power exchange.

12. Conclusion

Reactive power support is important in view of voltage stability, efficiency of transmission network, power quality, equipment safety and above all, the grid stability and continuity of power. This report strived to introduce voltage control ancillary services for reactive power management in Indian power system. The idea has been to utilize reactive resources already present in the system and motivate the current and future stakeholders to provide reactive support.

Indian power system has been increased many fold in past two decades. India has envisioned 175GW of renewable power by 2022, with the in surge of such large renewable power, thrust on reactive power management has been becoming equally important as of active power. Reactive power assets e.g. static sources like Bus reactor, line reactor, capacitor banks etc. and dynamic sources like SVC, STATCOM, Synchronous condenser operation of generating stations, Reactive power response (Capability curve) of conventional generator, Invertor based resources etc. are important and their monitoring for availability, utilization, performance, response time etc. has become inevitable for reactive power management. Dynamic reactive resources e.g. Generators, SVC, STATCOM etc. play vital role in primary & secondary response of reactive power support under other than normal conditions. Therefore, response of reactive power support may also be categorized as primary, secondary and tertiary as in case of active power and suitable mechanism may be introduce for its monitoring and accounting. For primary response, role of AVR is important and it should be mandatory to keep it enable all the time.

Further, reactive power support beyond the obligatory response could be incentivized so as to encourage entity (Ancillary services) to extend support in reactive power management during normal and contingency condition. For this, monitoring (Real-time as well as metering) of all such reactive assets is pre-requisite for accounting (Penalty /Incentives) the availability, performance and response time among others.

Treatment of deviation of reactive power (performance of reactive power assets) could also be in line with current DSM (Deviation Settlement Mechanism) for regional entity in case of active power. To incorporate all the above recommendation in view of reactive power management, a suitable chapter or separate regulation on reactive power may be introduced.

The approach discussed above would help in enhancing the reactive power support in the grid and may also pave the way for reactive power markets in future. Though, the localized nature of voltage may lead to market power, suitable regulations and guidelines may take care for this aspect.

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15. Annexures

Annexure-I: ECC 1994 recommendation

ECC recommendation

Quote:

"When actual voltage is too low relative to nominal voltage at the customer's terminal with the Power Grid grid, consumption of reactive power will be charged for at a multiple of the per MVAr or MVArh equivalent of an average carrying cost for capacitors. This multiple will increase as the ratio of actual to nominal voltage decrease. The same rate will be paid to customers who inject MVAr under this condition. If actual voltage is greater than nominal at the SEB terminal with the Power Grid grid, consumption of reactive power will be paid for at the rate described above and injection of MVAr will be charged for at the same rate. The actual formulation of this charge for tariff purposes should be determined based on a careful consideration of the nature and structure of the Regions comprising the Indian electricity sector.

In light or heavy loading situations, the grid itself can create reactive power problems by producing of consuming MVAr. The resolution of such problems can range from taking a line out of service to installing capacitors or reactors. The choice of solution is highly dependent upon the specific situations. For example, it may not be possible to take lightly loaded line out of service without adversely affecting system security. These decisions are Power Grid's responsibility. It is not practical to devise an incentive because of the uncertainty of resolution. The study team recommends that Power Grid's performance be reflected in the rate of return on equity as deemed appropriate by the regulatory authority. All revenues raised under this rate element are to be held in an escrow account. The proceeds of the account are to be used only for investment in additional system compensation within the Region.

Because of the potential complexity of implementing this charge, Power Grid may wish to impose the charge only on customers that do not efficiently respect to consumption and injection of MVAr. In addition, implementation could be delayed to allow Power Grid time to develop all necessary systems and to allow customers time to respond to the possibility of such charges by installation appropriate". The proposed formula for reactive energy pricing was as follows:

Reactive power charge = $CC \times \Sigma_i RF_i \times VAR_i$, where:

CC = Average carrying cost of capacitors prorated on a per MVARh basis,

$$RF_i = \begin{cases} 1.5 \text{ if } VU < 0.97 \\ 1.0 \text{ if } 0.97 < VU < 0.985 \\ 0.5 \text{ if } 0.985 < VU < 0.995 \\ 0.0 \text{ if } 0.995 < VU < 1.005 \\ -0.5 \text{ if } 1.005 < VU < 1.015 \\ -1.0 \text{ if } 1.015 < VU < 1.03 \\ -1.5 \text{ if } VU > 1.03 \end{cases}$$

Where 'i' is hour

VU: ratio of actual to nominal voltage at each Central Sector (POWERGRID) to SEB terminal

VAR_i = MVARh consumed (+) or injected (-) in hour i

Note: *funds generated from reactive power charges are placed in an escrow account to off-set payments for reactive likely due in next 18 months and for purchase of compensation for system at load centers.*

Annexures-2: CTU proposal on Reactive Power, 1999.

Form-1

BEFORE THE CENTRAL ELECTRICITY REGULATORY COMMISSION
NEW DELHI

FILING NO.

CASE NO.

IN THE MATTER OF :

Proposal by Power Grid Corporation of India Limited (CTU), regarding charging for Reactive Energy drawals by and exchanges between beneficiaries pursuant to Section 7.7 of IEGC draft.

AND

IN THE MATTER OF :

PETITIONER

1. NAME : POWER GRID CORPORATION OF INDIA LIMITED

2. ADDRESS : B-9, INSTITUTIONAL AREA, KATWARIA SARAI, NEW DELHI – 110 016

The Petitioner humbly states that :

BACKGROUND :

1. Ideally, all reactive load should be compensated locally, so that reactive energy does not have to be conveyed through the long EHV lines and sub transmission system This basically requires installation of sufficient quantity of capacitors in the Beneficiaries'/State Electricity Boards' distribution systems. Since such capacitor installation does not bring any extra revenue to the SEBs, it has been getting a low priority, which has resulted in a very substantial backlog. As a consequence, the SEBs draw large amounts of MVARs from the EHV grid, causing voltage drops of 70-80 kV along 400 kV transmission system, avoidable transmission losses, and considerable MVAR generation at remote stations. To encourage the SEBs to expedite capacitor installation and thereby reduce their MVAR drawal from the EHV grid, it is proposed to charge for Reactive Energy drawals/exchanges as per the following.

PROPOSAL BY POWERGRID REGARDING CHARGING FOR REACTIVE ENERGY EXCHANGES

2. A nominal charge is proposed for the MVAR drawal, at a rate of four (4.0) paise per kVARh, while the voltage at the drawal point is below 97% of rated. The metering point for this purpose would be same as the metering point identified for determination of the net drawal of active energy for the SEB. The charge would be bi-directional, that is if an SEB injects reactive power into the EHV grid while the voltage at the drawal point is below 97%, the SEB would get paid for the kVARh injected, at the same paise per kVARh rate.

3. There are also off-peak hour situations when the voltages at the EHV substations rise beyond the rated/permissible levels due to a combination of various factors. Such voltage rise can be restricted if the SEBs increase their reactive power drawal under such conditions, by switching off more capacitors and/or by operating their own generating units at leading power factors. To induce the SEBs to take these measures, the above described reactive energy charge is proposed to be reversed when the voltage is above 103%, that is the SEBs would get paid for drawing MVARs, and would pay for injecting MVARs when the voltage is above this threshold.

4. The voltage range of 97 to 103% is to be treated as a deadband for reactive charge purpose. Reactive energy exchange need not even be measured while the voltage at the drawal point is in this range. The paise per kVARh rate is to be such that the reactive charge amount an SEB would save (when this scheme is in operation) by installing a capacitor would match with the cost of such capacitor installation.

5. The above scheme is basically proposed for the inter-utility exchanges of reactive energy, primarily focussed on SEBs' drawals from the regional EHV grid. Whether reactive energy should be charged/paid for within an SEB's system e.g. exchanges with licencees, has to be decided by that SEB only. Reactive energy drawals by SEBs directly from the busbars of Central generating stations are not proposed to be charged, since such drawal does not cause any voltage drops on EHV lines. Also, the Central generating stations would not be paid separately for any reactive energy supply/absorption, since they would be fully compensated through their tariff for active energy.

6. Since supply of reactive energy does not involve any extra incremental expenditure on the part of any utility, no body need be compensated for the same. The scheme proposed above (to induce SEBs to install capacitors) would therefore result in the collection of a fund, which is proposed to be utilised for further system improvement/augmentation. The EHV transmission system owner (POWERGRID) would not be paid or be required to pay for any reactive energy exchanges. The scheme would also be applied for inter-state exchanges on the SEB-owned lines, where one SEB would pay the applicable reactive energy charge directly to the other.

7. ILLUSTRATIVE COMPUTATION OF RATE FOR REACTIVE ENERGY CHARGE

Suppose a one kVAR capacitor is installed in an SEB's system, on an industrial motor which is to run for 6 hours a day for 300 days in a year. The installation of this capacitor would bring down the reactive energy drawal of the SEB from the regional grid by about 1800 kVARh per year. Suppose the rate for reactive energy charge is 4.0 paise/kVARh for the first year, and is to be escalated @ 5.0% per year thereafter. The corresponding savings due to the above reduction of reactive energy drawal from year to year, and their present worth (considering a reasonable discounting factor of 12% per year) would then be as tabulated below :

Year	kVARh drawal Reduction	Proposed rate (paise per kVARh)	Resultant saving (Rupees)	Present worth (Rupees)
1st	1800	4.00	72.00	67.92
2nd	1800	4.20	75.60	63.68
3rd	1800	4.41	79.38	59.70
4th	1800	4.63	83.34	55.96
5th	1800	4.86	87.48	52.45
6th	1800	5.11	91.98	49.23
7th	1800	5.36	96.48	46.11
8th	1800	5.63	101.34	43.25
9th	1800	5.91	106.38	40.53
10th	1800	6.21	111.78	38.03
			TOTAL	516.86

The total installed cost of the above one kVAR capacitor at the present price level is around Rs. 500/-. It would, therefore, be reasonable to conclude that the proposed rate for reactive energy drawals would provide savings to an SEB commensurate with its expenditure on capacitor installation under the assumptions made, i.e an average capacitor installation life of ten years, zero salvage value, negligible O&M expenditure and 1800 hours of operation per year (during which the voltage at the metering point is below normal, which would be generally the case). Where the voltage remains below normal for a period longer than six hours per day, the above reactive energy charge would provide an additional inducement for capacitor installation.

PRAYER : The above may kindly be considered during the deliberations on IEGC draft.

Annexure-3: Performance of Synchronous Condenser

Table 25: Performance of synchronous condenser

S. No.	Characteristics	Performance of Synchronous condenser
1	Additional short circuit power	Enhances grid strength at connection point.
2	Capability over disturbances	Provide voltage support during prolong voltage sags
3	Short term overload capability	Large current - overload capability
4	Low Voltage ride through	Ability to remain connected and provide necessary system benefits under low voltage
5	System Inertia	Due to inertia improved frequency regulation where renewable generation is added or existing generation is retired.
6	Fast response time	Fast enough to meet dynamic response requirements by using excitation and control systems
7	Short circuit contribution	Provides real Short Circuit strength to the grid that improves system stability
8	Minimal harmonic generation	Not a source of Harmonics and even absorbs harmonic currents.
9	Minimal network interactions	It mitigates system control interactions

Table 26: Cost Comparison of reactive power generation equipment and sources [41]

Reactive Power Generating Equipment's and Sources	Investment Cost		
	Capital Cost per kVAr	Operating Cost	Opportunity Cost
Capacitors/Reactors	$10-30	Very Low	No
Synchronous Generators	Difficult to separate	High	Yes
STATCOM	$50-60	Moderate	No
Static VAr compensator	$40-100	Moderate	No
Synchronous Condensers	$10-40	High	No
Distributed Energy Resources (DER) – Inverter	$40-90	High	Yes
Distributed Energy Resources (DER) - Synchronous Generator	$25-40	High	Yes

Annexure-4: List of Synchronous Condensers

Table 27: List of Synchronous Condensers

<table>
<tr><th rowspan="2">S. No</th><th rowspan="2">Generator</th><th rowspan="2">Region</th><th colspan="3">Installed capacity</th><th colspan="4">No. of units operated/operational in Synchronous condenser simultaneously</th><th rowspan="2">Remarks</th></tr>
<tr><th>No. of units</th><th>Rating (MW)</th><th>Total (MW)</th><th>Units</th><th>Capacity (MW)</th><th>MVAr absorption (MVAr)</th><th>Last operated (date)</th></tr>
<tr><td>1</td><td>Pong</td><td>NR</td><td>6</td><td>66</td><td>396</td><td>3</td><td>198</td><td></td><td>On daily basis</td><td></td></tr>
<tr><td>2</td><td>Larji</td><td>NR</td><td>3</td><td>42</td><td>126</td><td>1</td><td>42</td><td></td><td></td><td>Trial run has been done (Some issues in MVAr absorption upto some limit only)</td></tr>
<tr><td>3</td><td>Tehri</td><td>NR</td><td>4</td><td>250</td><td>1000</td><td>2</td><td>500</td><td></td><td>08-12-2019</td><td></td></tr>
<tr><td>4</td><td>Chamera -2</td><td>NR</td><td>3</td><td>100</td><td>300</td><td>1</td><td>100</td><td></td><td></td><td></td></tr>
<tr><td>5</td><td>SSP-RBPH</td><td>WR</td><td>6</td><td>200</td><td>1200</td><td>4</td><td>800</td><td>320</td><td>21-Dec-20</td><td>MVAr Absorption figures are based on SCADA Data</td></tr>
<tr><td>6</td><td>Koyna (IV)</td><td>WR</td><td>4</td><td>250</td><td>1000</td><td>2</td><td>500</td><td>300</td><td>21-Dec-20</td><td>MVAr Absorption figures are based on SCADA Data</td></tr>
<tr><td>7</td><td>TATA-Khopoli</td><td>WR</td><td>3</td><td>24</td><td>72</td><td>3</td><td>72</td><td></td><td>21-Dec-20</td><td>MVAr Absorption figures are not available</td></tr>
<tr><td>8</td><td>TATA-Bhivpuri</td><td>WR</td><td>3</td><td>24</td><td>72</td><td>3</td><td>72</td><td></td><td>21-Dec-20</td><td>MVAr absorption figures are not available</td></tr>
<tr><td>9</td><td>SRISAILAM LEFT BANK</td><td>SR</td><td>6</td><td>150</td><td>900</td><td>6</td><td>900</td><td>360</td><td>15-Aug-20</td><td>All units can be put in condenser mode with time gap</td></tr>
<tr><td>10</td><td rowspan="2">NAGARJUNA SAGAR</td><td>SR</td><td>1</td><td>110</td><td rowspan="2">815.6</td><td></td><td></td><td></td><td></td><td>Unit#1 have no provision for condenser operation</td></tr>
<tr><td></td><td>SR</td><td>7</td><td>100.8</td><td>4</td><td>403.2</td><td>160</td><td>NA</td><td>Four units can be operated in condenser mode simultaneously synchronizing one by one</td></tr>
<tr><td>11</td><td>ALIYAR</td><td>SR</td><td>1</td><td>60</td><td>60</td><td>1</td><td>60</td><td>24</td><td>NA</td><td></td></tr>
</table>

S. No	Generator	Region	Installed capacity			No. of units operated/operational in Synchronous condenser simultaneously				Remarks
			No. of units	Rating (MW)	Total (MW)	Units	Capacity (MW)	MVAr absorption (MVAr)	Last operated (date)	
12	Purulia PSP	ER	4	225	900	1	225	NA	21-06-2020	Each unit will be synchronized one by one at an interval of 30 minutes and for a period of 30 minutes of operation period in SCOP mode
Total			51	1601.8	6841.6	31	3872.2	1164		

Annexure-5: List of Series Capacitors

Table 28: Series capacitors Pan India

S. No.	Line	End at which installed	Compensation
1	400 kV Purnea-Muzaffarpur D/C	Purnea	40% fixed, + 15%/-5% dynamic
2	400 kV Jeypore-Bolangir S/C*	Jeypore	63%
3	400 kV Jeypore-Gajuwaka D/C	Jeypore	40%
4	400 kV Ranchi-Sipat D/C	Ranchi	40%
5	400 kV Rengali – Indravati S/C	Rengali	40%
6	400 kV Seoni-Khandwa-1	Khandwa	40%
7	400 kV Seoni-Khandwa-2	Khandwa	40%
8	400 kV Rajgarh-Kasor-1	Rajgarh	25%
9	400 kV Rajgarh-Kasor-2	Rajgarh	25%
10	400 kV Raigarh-Raipur-3	Raipur	40%
11	400 kV Raigarh-Raipur-4	Raipur	40%
12	400 kV Adani-Sami-1	Sami	40%
13	400 kV Adani-Sami-2	Sami	40%
14	400 kV Raipur-Wardha-1	Wardha	40%
15	400 kV Raipur-Wardha-2	Wardha	40%
16	400 kV Raipur-Raigarh-1	Raipur	40% Fix, +15% / -5% Dynamic
17	400 kV Raipur-Raigarh-2	Raipur	40% Fix, +15% / -5% Dynamic
18	220kV Kishenpur-Ramban	Kishenpur	40%
19	220kV Kishenpur-Mirbazar	Kishenpur	40%
20	400kV Kanpur-Ballabgarh Ckt-1	Ballabgarh	35%
21	400kV Kanpur-Ballabgarh Ckt-2	Ballabgarh	40%
22	400kV Kanpur-Ballabgarh Ckt-3	Ballabgarh	40%
23	400kV Balia-Sohawal Ckt-1	Lucknow(PG)	55%
24	400kV Balia-Sohawal Ckt-2	Lucknow(PG)	55%
25	400kV Karcham- Kala Amb ckt-1	Kala Amb	40%
26	400kV Karcham- Kala Amb ckt-1	Kala Amb	40%
27	400kV Muzaffarpur-Gorakhpur Ckt-1	Gorakhpur(PG)	40% fixed & 5-15% Variable
28	400kV Muzaffarpur-Gorakhpur Ckt-2	Gorakhpur(PG)	
29	400kV Lucknow-Gorakhpur Ckt-1	Lucknow(PG)	30%
30	400kV Lucknow-Gorakhpur Ckt-2	Lucknow(PG)	30%
31	400kV Lucknow-Gorakhpur Ckt-3	Lucknow(PG)	30%
32	400kV Lucknow-Gorakhpur Ckt-4	Lucknow(PG)	30%

S. No.	Line	End at which installed	Compensation
33	400kV Meerut-Bareilley Ckt-1	Bareilley(PG)	30%
34	400kV Meerut-Bareilley Ckt-2	Bareilley(PG)	30%
35	400kV Fatehpur-Mainpuri Ckt-1	Mainpuri	56%
36	400kV Fatehpur-Mainpuri Ckt-2	Mainpuri	56%
37	400kV Unnao-Bareilley(U.P) Ckt-1	Unnao	45%
38	400kV Unnao-Bareilley(U.P) Ckt-2	Unnao	45%
39	400kV Muradnagar-Aligarh line	Muradnagar	40% of Panki-Muradnagar line

Annexure-6: Fault Level and Transformation Capacities

Table 29: Most vulnerable nodes

S.NO	Vol (kV)	SUBSTATION	FAULT LEVEL (MVA)	TRANSFORMATION CAPACITY (MVA)	RATIO OF FAULT LEVEL TO TRANSFORMATION CAPACITY	REGION
1	400	Azara	1530	630	2.43	NER
2	400	Jagdalpur	1791	630	2.84	WR
3	132	Namsai	90	30	3.00	NER
4	765	Ajmer	9803	3000	3.27	NR
5	765	Chittorgarh	9841	3000	3.28	NR
6	400	Noida Sec 148	3375	1000	3.38	NR
7	765	Agra (Fatehabad)	10868	3000	3.62	NR
8	132	Tezu1	110	30	3.67	NER
9	400	Bhadla	5743	1500	3.83	NR
10	400	Kozhikode	4615	1130	4.08	SR
11	132	Roing	130	30	4.33	NER
12	400	Babai	2736	630	4.34	NR
13	765	Bhuj Ps	13094	3000	4.36	WR
14	765	Gaya	27971	6000	4.66	ER
15	400	Thervoikndgi	1475	315	4.68	SR
16	400	Rewa - PG	7222	1500	4.81	WR
17	400	Akal	7087	1445	4.90	NR
18	765	Anta	22742	4500	5.05	NR
19	765	Angul	30877	6000	5.15	ER
20	400	Misa	6792	1315	5.17	NER
21	765	Unnao	16089	3000	5.36	NR
22	765	Ektuni	16095	3000	5.37	WR
23	400	Subhasgram	9547	1760	5.42	ER
24	400	Rasipalyam	6697	1230	5.44	SR
25	765	Bareilly – PG (New)	16742	3000	5.58	NR
26	400	Ramgarh	5670	1000	5.67	NR
27	765	Banaskantha	17049	3000	5.68	WR

On the contrary, Table 30 depicts nodes on which this ratio comes out to be highest implying they are least likely to experience voltage variations.

Table 30: Least vulnerable nodes

S.NO	Vol (kV)	SUBSTATION	FAULT LEVEL (MVA)	TRANSFORMATION CAPACITY (MVA)	RATIO OF FAULT LEVEL TO TRANSFORMATION CAPACITY	REGION
1	400	Mouda - NTPC	18728	400	46.82	WR
2	400	Kabulpur	29774	630	47.26	NR
3	400	Rihand	19375	400	48.44	NR
4	400	Bellary TPS	15577	315	49.45	SR
5	400	Neyveli	25621	500	51.24	SR
6	400	Panki	33492	630	53.16	NR
7	400	Kameng	6464	120	53.87	NER
8	400	Kurnool	33944	630	53.88	SR
9	220	NTPS	2727	50	54.54	NER
10	400	Agra (PG)	36062	630	57.24	NR
11	400	Tiruvalam-TN	36081	630	57.27	SR
12	400	Barh	23065	400	57.66	ER
13	400	Meja	23125	400	57.81	NR
14	400	Kanpur	36534	630	57.99	NR
15	400	Bhiwani	38563	630	61.21	NR
16	400	KTPS - VI	19508	315	61.93	SR
17	400	Solapur - NTPC	25565	400	63.91	WR
18	400	Bawana	41412	630	65.73	NR
19	400	Wardha - PG	50211	630	79.70	WR
20	400	VTS - IV	26298	315	83.49	SR
21	220	Salakti	8380	100	83.80	NER
22	400	Sagardighi	27519	315	87.36	ER
23	400	Kahalgaon	35923	400	89.81	ER
24	400	Bina - PG	28555	315	90.65	WR
25	400	Anpara	27801	300	92.67	NR
26	765	Darlipalli	48269	510	94.65	ER
27	400	JPL Stage-I	30024	315	95.31	WR
28	400	JPL Stage-II	32535	315	103.29	WR
29	400	Bhadrawati	27814	250	111.26	WR
30	400	Farakka	38357	315	121.77	ER
31	400	Singrauli	27639	200	138.20	NR
32	400	Ballia	28493	200	142.47	NR

Annexure-7: Salient Features of SEMs

Table 31: Salient features of SEMs installed at various metering points across country

Energy Meter Type	Static type – Totally Electronic
Compliant with	IEC 687 / IEC-62053-22:2003 standard
Accuracy Class	(0.2S class)
Capability	Capable of measuring Active and Reactive Energy in all 4 quadrants
Connection Type	3 phase-4 wire connection
Harmonics filter	Filters harmonics and measure energy at fundamental frequencies
Auxiliary Power requirements	Operates on self-power from connected PT supply (110V Ph to Ph/ 63.51 V Ph-N)
Current rating	1 Amp (A-type meter) or 5 Amp (B type Meter)
Maximum burden	not more than 10 VA on any of the phases
Time adjustment	Time adjustment facility (in steps of 1 min in a week)
Requirement of calibration	No calibration required due to absence of moving parts.

Annexure-8: Reactive Power requirements and payment mechanisms around the world

Table 32: Reactive Power requirements and Payment mechanisms across the world

ISO/TSO	Absorption capability requirement (lagging)/Production capability requirement (leading)	Estimated absorption /Production requirement at the POD for Pn and Un	Procurement method	Structure of the payment	Settlement Rules	Frequency of Market Clearing	Frequency of review of needs for VCAS	Price caps for VCAS
Germany	pf=0.95 or 0.975 and 0.925 or 0.9 at the POD for Pn and Un	-0.33.Pn or -0.23.Pn/ 0.41Pn or 0.48.Pn	Basic: Compulsory; Enhanced: Bilateral	Enhanced: Opportunity Cost	Basic: None; Enhanced: Discriminatory auction	Enhanced: No Rec.	Enhanced: Unknown	Enhanced: No rec.
France	-0.35.Pn and 0.32 Pn at the POD for Pn and Udim	-0.35/0.32Pn	Basic: Compulsory; Enhanced: Bilateral	Basic: Fixed and Availability; Enhanced: Fixed and Availability	Basic: Discriminatory auction price; Enhanced: Discriminatory auction price	Basic: Every two or three years; Enhanced: Every two or three years	Basic: As soon as generating unit is connected; Enhanced: As soon the unit is connected	Enhanced: None
Spain	pf=0.989 at the POD for Pn and Un (same for both)	-0.15/0.15 Pn	Basic: Compulsory; Enhanced: Tendering Process	Enhanced: Availability and Utilization	Basic: None; Enhanced: Regulated price	Enhanced: Every Year	Enhanced: Every day	Enhanced: None
Netherlands	pf=0.8 at the POD for Pn and Un (same)	-0.75/0.75 Pn						
Belgium	-0.10.Pn at the POD for Pn and Un 0.45.Pn at the POD for Pn and Un	-0.10 / 0.45 Pn						
Great Britain	Pf=0.85 & 0.95 at the terminals for Pn	-0.80/0.17 Pn	Basic: Compulsory and Tendering Process; Enhanced: Tendering Process	Basic: Fixed, Availability and Utilization; Enhanced: Fixed, Availability and Utilization	Basic: Regulated Price, Discriminatory auction price; Enhanced: Discriminatory auction price	Basic: Every Six Month; Enhanced: Every Six Month	Basic: Every Six Month; Enhanced: Every Six Month	Fixed: pffer cap at 999.999 Pount/MVAr/h; Availability: offer cap at 999.999 Pount/MVAr/h; Utilization: offer cap at 999.999 pound/MVArh for both basic and enhanced voltage control

ISO/TSO	Absorption capability requirement (lagging)/Production capability requirement (leading)	Estimated absorption /Production requirement at the POD for Pn and Un	Procurement method	Structure of the payment	Settlement Rules	Frequency of Market Clearing	Frequency of review of needs for VCAS	Price caps for VCAS
Australia			Basic: Compulsory; Enhanced: Tendering Process	Enhanced: Availability and Opportunity Cost	Basic:None; Enhanced: Discriminatory auction price	Enhanced: Every Two years	Enhanced: Every half hour(trading interval)	Enhanced: None
New Zealand			Basic: Compulsory; Enhanced: Bilateral	Basic: Fixed, Availability and Utilization	Basic: Discriminatory auction price	Basic: No Rec.	Basic: Every half hour	Basic: None
PJM			Basic: Compulsory	Basic: Fixed	Basic: Regulated Price	Basic: Every Year	Basic : Unknown	Basic: None
Sweden			Basic: Compulsory		Basic: None			

Annexure-9: Reactive Energy Rates in North America

Details of reactive energy rates for selected transmission Providers of North America

- ISO-NE

ISO-NE operates qualified reactive resources to produce (or absorb) reactive power in order to maintain transmission voltages on the New England Transmission System. These qualified resources are compensated based on four cost components[46]:

1. The lost opportunity cost (LOC) component, which compensates for the value of a generator's lost opportunity in the energy market when a generator that would otherwise be economically dispatched is instead directed by the ISO to reduce real power output to provide more reactive power.

2. The cost of energy consumed (CEC) component, which compensates for the cost of energy consumed by a generator solely to provide reactive power support.

3. the cost of energy produced (CEP) component, which compensates for the cost of energy produced by a generator solely to provide reactive power support.

5. The capacity cost (CC) component, which compensates the generator for the fixed capital costs it incurs with the installation and maintenance of equipment necessary to provide reactive power.

- NYISO

The NYISO calculates payments for voltage support service annually, and makes payments monthly. Suppliers that qualify to receive payments and whose generators are under contract to supply installed capacity receive one-twelfth of the annual payment calculated by the NYISO. Suppliers whose generators are not under contract to supply installed capacity, suppliers with synchronous condensers, and qualified non-generator voltage support resources receive one-twelfth of the annual payment calculated by the NYISO, pro-rated by the number of hours that the generator, synchronous condenser, or qualified non-generator provides voltage support resources[47].

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[46] [ISO-NE Open Access Transmission Tariff, Schedule 2 - Reactive Supply and Voltage Control Service (2012)]

[47] Ancillary Services Manual - https://www.nyiso.com/documents/20142/2923301/ancserv.pdf

- PJM

PJM determines the amount of reactive supply and voltage control that must be supplied by the transmission provider with respect to the transmission customer's transaction based on the reactive power support necessary to maintain transmission voltages within limits that are accepted and adhered to by the transmission provider. The transmission provider administers the purchases and sales of reactive supply and voltage control with PJM designated as a counterparty. Market sellers that provide reactive services at the direction of PJM are credited for such services. Generation or other source owner provide reactive supply and voltage control are paid monthly by the transmission provider, equal to the generation or other source owner's monthly revenue requirement as approved by the Commission.

- MISO

MISO determines the amount of reactive supply and voltage control that generation resources or other services must supply based on the reactive power support necessary to maintain transmission voltages within the voltage range and the resulting reactive power range that are generally accepted in the region and consistently adhered to by MISO. MISO arranges this service with the local balancing authorities that acquire the service for MISO's transmission system. MISO calculates rates for the service for each pricing zone, which represent a pass through of costs, based on the annual cost-based revenue requirements or cost-based rates of qualified generators. Qualified generators file their annual cost-based revenue requirement and/or cost-based rates for voltage control capability with the Commission. MISO collects a charge from each transmission customer monthly by multiplying the applicable rate by the transmission customer's reserved capacity. MISO provides each qualified generator monthly a *pro rata* allocation of the amount collected based upon the qualified generator's share of the rate within its pricing zone[48].

- SPP

SPP requires all qualified generators to maintain reactive supply pursuant to a voltage schedule it provides or one provided by the applicable local balancing authority. SPP does not compensate generators operating within a standard range of 0.95 leading to 0.95 lagging for supplying reactive power. SPP compensates all existing generation owners eligible to collect charges for reactive supply connected to the transmission system under a cost-based rate schedule on file with the FERC as of October 1, 2006. Qualified generators are paid monthly based on actual usage with no true-ups. SPP will post the applicable monthly charges to transmission customers

[48] MISO SCHEDULE 2 - https://cdn.misoenergy.org/Schedule%2002109650.pdf

after it possesses the data necessary to calculate the charges for a transmission customer based on multiplying the applicable rate by the transmission customer's reserved capacity[49].

- CAISO

CAISO determines, on an hourly basis for each day, the quantity and location of voltage support required to maintain voltage levels and reactive margins within NERC and Western Electric Coordinating Council reliability standards. CAISO issues daily voltage schedules to participating generators, transmission owners, and utility distribution companies, which are required to be maintained for reliability. All participating generators that operate asynchronous generating facilities subject to the LGIA shall maintain the CAISO specified voltage schedule if required under the LGIA, while operating within the power factor range specified in their LGIA. CAISO instructs participating Generators to operate their Generating Units at specified points within their power factor range and participating Generators shall receive no compensation for operating within these specified ranges[50].

If CAISO requires additional voltage support, it shall procure this either through reliability-must-run contracts or by instructing a generating unit to move its MVAr output outside its mandatory range. "Only if the Generating Unit must reduce its MW output in order to comply with such instruction will it be eligible to recover opportunity cost.

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[49] Payment for Reactive Power Commission Staff Report April 22, 2014 - https://www.ferc.gov/sites/default/files/2020-05/04-11-14-reactive-power.pdf

[50] CAISO tariff, section 8.2.3.3, Voltage Support

Annexure-10: Cost estimate for SC mode of operation for a hydro plant

Computation of incentive to Generators for operating the unit in SC mode

As of now, the components involved in tariff determination for hydro power plant does not cover the cost incurred by the plant for SC mode of operation. The operation in SC mode is construed as obligatory support to the Grid by Generator. SC mode operation entails additional cost and shall consists of broadly the following components:

1. Cost per unit KVAr support (C_{MVAr}).
2. Additional operational and maintenance Cost (C_{add}) for associated equipment.

1.1 Cost per unit KVAr support (C_{MVAr})

The cost of per unit reactive power support to the system by generator can be can be calculated on the basis of either of the following two methods:

1.1.1 Method – 1: Based on Capital Cost (CF)

The capital cost component in respect of reactive power may be calculated as:

$$CF = \frac{TC}{IC * AF * LF * 8760 * M} \tan(\cos^{-1}(p.f.))(\text{ X 1000 ₹/kVAr/hr}$$

Where TC is the total installation cost of project (in ₹), IC is the installation capacity (MW), AF is the availability factor, LF is the load factor of generating station, p.f. is the power factor, and M is the expected life of power plant in years.

Capital cost (reactive component) C_q in ₹ / h can thus be calculated as:

$C_q = C_F$ X Q

where Q is the reactive power (kVAr) supplied per hour.

1.1.2 Method – 2: Based on existing grid provisions

The actual cost of supplied kVAr by the unit

$Cm = E_{MVAr}$ X T_{MVAr}

where E_{MVAr}= per hour kVAr generated by the unit

T_{MVAr}=Tariff for kVArh

Hence Cost per unit kVAr

$C_{MVAr} = C_q$ or C_m

2.1 Additional operational and maintenance Cost for associated equipment (C_{add})

This cost component shall include changeover cost and running cost in SC mode operation:

2.1.1 Changeover cost: This cost shall again have following components

- Cost of water lost during starting of unit from standstill to SC mode.
- Cost towards wear and tear due to additional no. of operation of mechanical and electrical equipment

2.1.2 Running Cost towards condenser mode operation: This shall depend upon the no of running hours of unit in SC mode and shall be the sum of the following components:

- Cost of wear and tear of mechanical & electrical equipment for additional running hours.
- Cost of energy consumption during condenser mode of operation.
- Cost of deployment of additional man power dedicated for condenser mode of operation.

The methodology proposed for computation of the cost in respect of individual components is given below:

2.1.1.1 Changeover cost (C_{con})

a. Cost of water loss: changeover to SC mode takes place either from standstill state of the machine or when it is running as a generator. During the changeover, loss of water is inevitable as complete water inside turbine needs to be spilled out. Following is the sequence of operation.

- Unit is first started as a synchronous generator,
- Synchronized to the grid
- Machine loaded up to minimum set point i.e 25MW (The set point can be different for different projects depending upon the characteristics of the generating equipment) and run for a duration of approx. 10-15 mins.
- Change over to SC mode after the water is depressed from the turbine by injecting compressed air.

The energy generated during this change over period is not remunerated and may be construed as loss of the water. The cost of the water lost in this process can be treated equivalent to the charges for unscheduled generation of the minimum set point.

Cost of water lost (C_w)=P X t X C_{tar} Where:

P=Generated power (in MW) t=Duration of Power Generation (in hours)

C_{tar}= Energy tariff (in ₹) applicable for the plant as per CERC norms

b. Cost of wear and tear of mechanical & electrical equipment for additional running hours:

It shall basically involve valves associated with SC mode of operation and switching elements like breakers and dynamic switch. This cost can be calculated as under:

- Valves associated with synchronous condenser mode of operation

  Maintenance cost per Operation (C_{val})

  $C_{val}=T_{val}/N_{val}$

  T_{val} : Cost of overhauling of the valves dedicated SC mode operation

  N_{val}: Number of the operations before overhauling

- Switching elements-additional operations dedicated for SC mode

  Maintenance Cost of Per Operation (C_{sw})

  $C_{sw}= (T_{gcb}/N_{gcb} + T_{uaxb}/N_{uaxb} +T_{mvcb}/N_{fcb})$

  Where,

  Tgcb: Cost of major overhauling of the 420kV unit circuit breaker (since major overhauling is performed based on no of operation as per OEM manual).

  Ngcb: Number of operations before major overhauling.

  Tuaxb: Cost of overhauling of Unit Auxiliary Board Circuit Breaker.

  Nuaxb: Number of operations before major overhauling.

  Tmvcb: Cost of overhauling of 11kV feeder CB for dynamic braking.

  Nmvcb: Number of operations before overhauling of 11kV feeder circuit breaker for dynamic braking.

Therefore, the cost involved during changeover process for SC mode operation shall be:

$$Ccon= (C_{valc} +C_{w}+C_{sw}) X N_{sc}$$

Where, N_{sc}: Number of synchronous condenser operation

2.1.2.1 Running Cost towards condenser mode operation:

a. **This component of cost is attributable to wear and tear of mechanical & electrical elements of generating Unit**.
   i. Per running hour maintenance cost for generating unit (Ctg): Ctg=Ttg/ttg

      T_{tg}: Unit maintenance cost in a year, ttg: Running hours of unit in one maintenance cycle.

ii. Per running hour maintenance cost for compressed air system due to frequent operation with increased duty cycle (Ccas):

Ccas=Tcs/tcs

T_{cs} : Overhauling cost of the compressed air system in a year t_{cs}=Running hours before overhauling of the compressed air system in a year.

b. Cost towards auxiliary consumption

i. The energy consumed by auxiliaries such as compressors during SC mode of operation can be calculated as:

Caux1=P_{aux} X t X t_{aux}

P_{aux}: Capacity of the Compressor

T: Time for which compressor runs during one-hour operation in SC mode

t_{aux}: tariff of auxiliary power charged by DISCOMS

ii. Hourly power consumption by the unit during SC mode:

Caux2=Pmot X tdsm

P_{mot}=Power consumed by unit

T_{dsm}=DSM rate

Caux= Caux1+ Caux2

c. Cost towards deployment of additional man power dedicated for SC mode operation:

C_{man}= (T_{ms}XN_{ms} +T_{mss}XN_{mss})/8 (considering 8 working hours in a day)

T_{ms}=One-man day rate of skilled manpower

N_{ms}= no. of skilled manpower deployed during condenser mode

T_{mss}=One-man day rate of semi-skilled manpower

N_{mss}= no. of semi-skilled manpower deployed during SC mode

Per unit per hour running cost implication for SC mode operation C_{rh}=C_{tg}+C_{cas} +C_{aux}+C_{man}

Per unit per hour additional O&M cost for SC mode operation: C_{addn} =C_{con}+C_{rh}

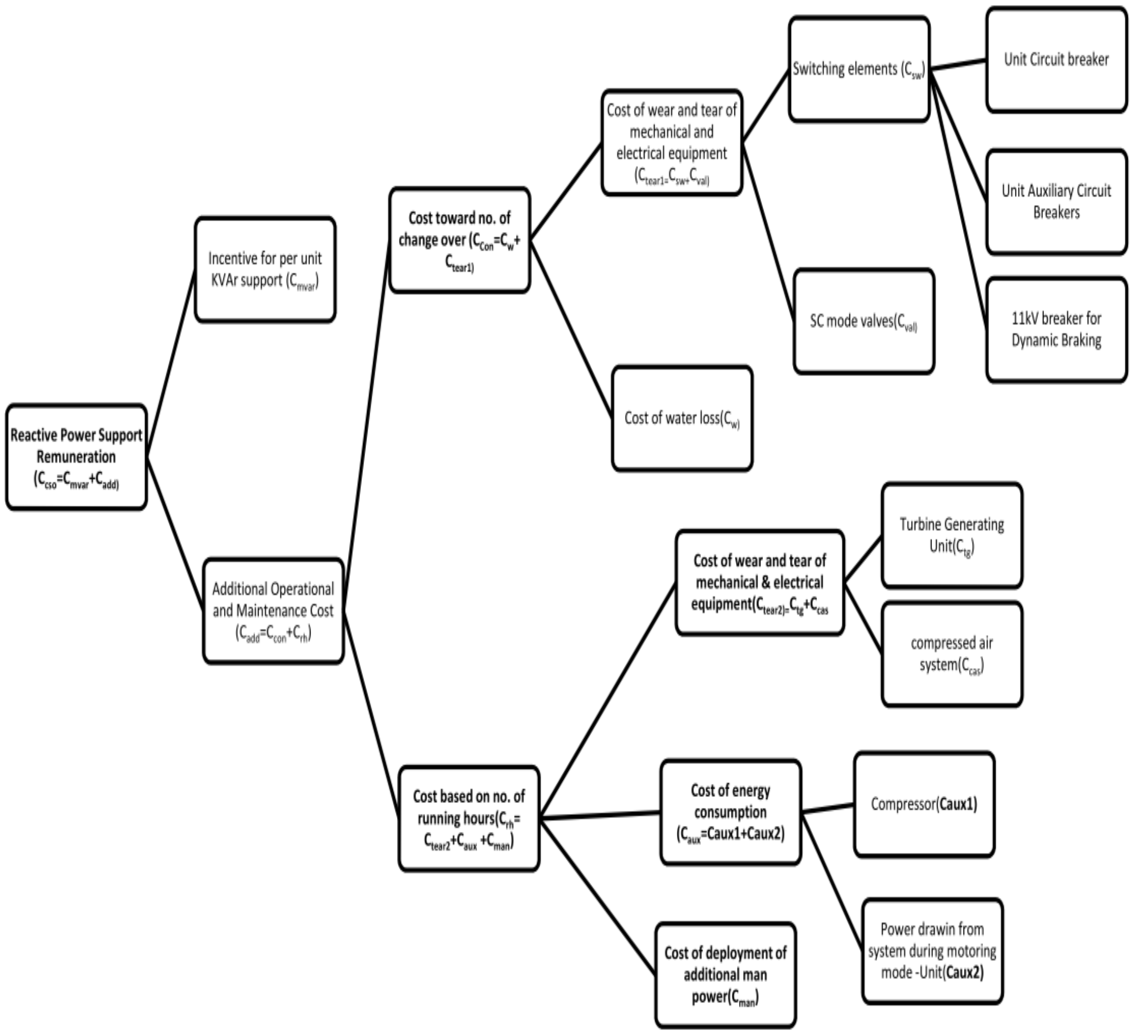
3. Recommendation:

The reactive power support service by the generator can thus be remunerated based on per unit KVAr support charges and additional operational and maintenance cost incurred for SC mode operation. The remuneration in financial terms can be computed for one unit for n no. of operation for t_{rh} hour as:

$C_{cso} = (C_{MVAr} + C_{rh1}) \times t_{rh} + C_{con})$

Data regarding Reactive Power Pricing Mechanism

S.No.	Parameter	Unit	Value	Remarks
1	Total installation cost of Unit	Rs	18244775000	For one unit based on capital cost of the Project as on March'2020, submitted in the Tariff Petition 2019-24 before Hon'ble CERC
2	Average power factor of unit		0.90	
3	Cost of overhauling of unit	Rs	16943063.75	For one unit
4	Average number of Synchronous condenser operation before overhauling	Nos	17	Number of operation for one unit for FY 2019.
5	Maintenance cost per operation for Unit circuit breaker	Rs	1826.15	For one unit circuit breaker
6	Per hour running maintenance cost of generator in SC mode	Rs	4226.26	For one unit
7	Per hour running maintenance cost of compressed air system	Rs	602.93	
8	One man-day rate of semi-skilled manpower	Rs	1675.00	Based on the actual awarded contract rates.
9	One man-day rate of skilled manpower	Rs	2243.00	Based on the actual awarded contract rates.


Reactive Power Support Remuneration (C_{cso}=C_{mvar}+C_{add})
Incentive for per unit KVAr support (C_{mvar})
Additional Operational and Maintenance Cost (C_{add}=C_{con}+C_{rh})
Cost toward no. of change over (C_{Con}=C_w+ C_{tear1})
Cost of wear and tear of mechanical and electrical equipment (C_{tear1}=C_{sw}+C_{val})
Cost of water loss(C_w)
Switching elements (C_{sw})
SC mode valves(C_{val})
Unit Circuit breaker
Unit Auxiliary Circuit Breakers
11kV breaker for Dynamic Braking
Cost based on no. of running hours(C_{rh}= C_{tear2}+C_{aux} +C_{man})
Cost of wear and tear of mechanical & electrical equipment(C_{tear2}=C_{tg}+C_{cas}
Turbine Generating Unit(C_{tg})
compressed air system(C_{cas})
Cost of energy consumption (C_{aux}=Caux1+Caux2)
Compressor(Caux1)
Power drawin from system during motoring mode -Unit(Caux2)
Cost of deployment of additional man power(C_{man})

Annexure-11: Details of Retired Thermal Generating Units

Table 33: Retired thermal generating unit details

Region	Thermal / Gas station retired						
	Name	Nos of Units	Installed capacity	MVAr capability	Location	Voltage level	w.e.f.
NR	Rajghat TPS	2	135	+81 / -40	Delhi	220kV	30.09.2019
NR	Badarpur TPS	5	705	+423 / -211	Delhi	220kV	30.10.2018
NR	Bhatinda	4	440	+264 / -132	Punjab	220kV	31.08.2018
NR	Ropar	2	420	+252 / -126	Punjab	220kV	31.08.2018
NR	Panipat TPS	4	440	+264 / -132	Haryana	220kV	12.04.2016
NR	Panki TPS	2	210	+126 / -63	UP	220kV	16.03.2018
NR	Obra TPS	2	100	+60 / -30	UP	220kV	18.08.2017
NR	Obra TPS	1	94	+56 / -28	UP	220kV	03.04.2018
NR	Harduaganj TPS	1	60	+36 / -18	UP	220kV	18.08.2017
WR	Trombay TPS	1	150	+90 / -45	MH		
WR	Utran CCPS	4	135	+81 / -40	Gujrat		
WR	Amarkantak	2	240	+144 / -72	MP		04.03.2016
WR	Koradi	4	420	+252 / -126	MH		02.08.2016
WR	Koradi	1	200	+120 / -60	MH		24.04.2017
WR	Chandrapur(MSPGCL)	2	420	+252 / -	MH		21.10.2016

Region	Thermal / Gas station retired						
	Name	Nos of Units	Installed capacity	MVAr capability	Location	Voltage level	w.e.f.
				126			
WR	Parli	1	210	+126 / - 63	MH		21.10.2016
WR	Bhusawal	1	210	+126 / - 63	MH		31.08.2017
WR	Gandhinagar	2	240	+144 / - 72	Gujrat		12.01.2017
WR	Sikka	2	240	+144 / - 72	Gujrat		18.08.2017
WR	Ukai	2	240	+144 / - 72	Gujrat		18.08.2017
SR	Maithon GPS	3	90	+54 / -27	Jharkhand		
SR	Ennore	4	340	+204 / - 102	TN		31.03.2017
SR	Ennore	1	110	+66 / -33	TN		12.01.2017
SR	Kothagudem	3	300	+180 / - 90	Telangana		19.03.2019
SR	Neyveli	1	100	+60 / -30	TN		06.02.2019

Region	Thermal / Gas station retired						
	Name	Nos of Units	Installed capacity	MVAr capability	Location	Voltage level	w.e.f.
ER	Santaldih	4	480	+288 / -144	WB		21.12.2016
ER	Bandel	2	120	+72 / -36	WB		20.04.2018

Region	Thermal / Gas station retired						
	Name	**Nos of Units**	**Installed capacity**	**MVAr capability**	**Location**	**Voltage level**	**w.e.f.**
ER	Patratu	5	360	+216 / -108	Jharkhand		21.12.2016
ER	Patratu	5	455	+273 / -136	Jharkhand		23.11.2017
ER	DPL (DPL)	3	220	+132 / -66	WB		20.02.2017
ER	Durgapur(DVC)	1	140	+84 / -42	WB		21.10.2016
ER	Chandrapur(DVC)	1	130	+78 / -39	Jharkhand		17.01.2017
ER	Chandrapur(DVC)	1	130	+78 / -39	Jharkhand		04.09.2017
ER	Bokaro	2	420	+252 / -126	Jharkhand		04.09.2017
ER	New Cossipore	4	160	+96 / -48	WB		
ER	Chinakuri	3	30	+18 / -9	WB		31.08.2017
ER	Dishergarh	4	18	+11 / -5	WB		31.08.2017
ER	Seebpore	4	8.38	+5 / -2	WB		31.08.2017
NER	Chandrapur(APGCL)	2	60	+36 / -18	Assam		18.08.2017
NER	Lakwa GT	4	60	+36 / -18	Assam		
NER	Namrup CCPS	1	20	+12 / -6	Assam		
Total				+5436/2715			

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