Report
of
Expert Group to review and suggest measures
for
bringing power system operation closer
to
National Reference Frequency

(Volume-I)

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केन्द्रीय विद्युत विनियामक आयोग
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A S Bakshi
Chairman of the Expert Group

1 Executive Summary

The Central Electricity Regulatory Commission (CERC) vide order dated 27th April 2017 constituted an Expert Group chaired by Shri A S Bakshi, Member, CERC with representatives from CEA, POSOCO and CTU and others concerned with the mandate to suggest further steps required to bring power system operation closer to the national reference frequency of 50 Hz. The Terms of Reference (TOR) of the Committee are as under:

- Review the experience of grid operation in India.
- Review international experience and practices on grid operation including standards/requirement of reference frequency.
- Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid.
- Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities.
- Any other matter related to above.

The Committee held three meetings on 9th May, 16th June and 3rd Nov 2017. The 2nd meeting had conference calls with experts from PJM, ENTSOE and Professor Anjan Bose, Washington State University, US. This report covers the first three Terms of Reference pertaining to frequency control in India. The fourth item viz. Deviation Settlement Mechanism (DSM) is covered in a separate report. The Expert Group recommends as under:

1) **Frequency Control as a continuum in terms of time horizon**
   Frequency Control in any power system is basically a continuum starting from seconds to a time period of less than an hour. Beyond this time horizon, the problem is basically one of forecasting, unit commitment, scheduling and despatch. Large imperfections in this area would lead to off-nominal frequency or a large quantum of generation reserves requirement which may be suboptimal. **It is therefore recommended that the frequency control continuum chart as given in this report be adopted and included as part of the Indian Electricity Grid Code (IEGC) through an amendment for addendum.**

2) **Reference frequency for the purpose of control**
   Any control system would need a reference value; in case of frequency control, it would be the target frequency or reference frequency. For the Indian system, the same has to be the nominal frequency of 50.0 Hz. **It is therefore recommended that the reference frequency for the purpose of frequency control is considered as 50.0 Hz, and the same is notified in the IEGC.**

3) **Monitoring inertia of the system and inertial response**

The Expert Group recognizes that interconnection of regional grids and formation of an All India electricity grid with 160 GW peak demand has substantially reduced frequency fluctuations in view of large inertia in the system. However, the inertia would gradually reduce in the coming days with increase in static silicon loads, reduction in rotating mass of conventional machines due to higher penetration of wind and solar generation in the system. With 175 GW RE targeted by 2022, the instantaneous penetration of RE in MW could touch as high as 54%, where inertia would be an issue. This would have an impact on the frequency fall immediately following a large contingency (inertial response) and before primary response effect comes into play. **It is therefore recommended that as a first step, inertia of the system be monitored at the regional and All India level in real time so that a baseline is established and monitored for low net load periods. Simulation studies may also be carried out to assess the inertia and any adverse impact on stability due to low inertia. There is a need for suitable provisions for stipulating minimum inertia in Standards and Code in near future besides provision of synthetic inertia from RE resources.**

4) **Primary control**

Primary control from generating units is mandated as per the Indian Electricity Grid Code (IEGC). However, the IEGC has an historical variant of primary control in the form of Restricted Governor Mode of Operation (RGMO). **The Expert Group recommends that RGMO may be phased out by 1st April 2018 and replaced with 'speed control with droop'. Further, the dead band of +/-0.03 Hz(ripple factor in IEGC) may be gradually phased out as is being done in ERCOT Texas and Europe. This could be a voluntary approach initially. The Expert Group also recommends that the Central Electricity Authority (CEA) may notify the Technical Standards for connectivity to the grid in respect of RE generation at the earliest mandating primary control from RE resources also. Primary control testing would also be done periodically in line with provisions of IEGC for which the performance metrics would be defined in the test procedures by CERC.**

5) **Additional parameters to be notified in IEGC**

Apart from the reference frequency, the Expert Group recommends that the IEGC should also notify the following values:

a. **Frequency band permissible: 49.90-50.05 Hz currently, which would be further tightened to 49.95-50.05 Hz by 2020 when secondary and tertiary reserves would be operationalized in substantial quantum both at the inter-state and intra-state level besides more frequent market clearing**
b. **Reference contingency for primary response: 4000 MW UMPP outage**
c. **Minimum frequency (nadir value) following the above reference contingency: 49.50 Hz**

d. **Quasi steady state frequency value after primary response following the above contingency: 49.80 Hz**

The IEGC would also specify the standards for frequency recording and archival at RLDCs/NLDC level for the purpose of further analysis as mentioned in this report.

6) **Frequency Response Characteristics (FRC)**

The Expert Group has noted that the RLDCs and NLDC are computing the Frequency Response Characteristics (FRC) of each control area, region and All India basis. There has been a gradual improvement in FRC from 6000 MW/Hz to 9000 MW/Hz over the last two years. Even then this is much lower compared to systems like the Western Interconnection in US (comparable to India in terms of system size) which have recorded FRC of the order of 20000 MW/Hz despite lower obligation as per BAL-003-1 NERC Reliability Standard. **The Expert group recommends as under:**

a. **RLDCs/NLDC would continue to compute FRC as being done presently. However, the same would also be worked out additionally for All India and region at the 'nadir' frequency (details in the report) so that the impact of inertia can be tracked as indicated in S no 3.**
b. **While no target FRC is required to be prescribed now, the control area wise FRC and percentage of ideal response would be tracked for each event. A minimum response expected is at least 40% of ideal response (based on international experience). Any violation would be reported to CERC for levy of penalty.**

7) **Roadmap for operationalizing reserves**

The Expert Group recommends that the roadmap for operationalizing reserves notified by CERC vide order dated 13th October 2015 be implemented at the earliest so that secondary and tertiary reserves as stated in the order are available for frequency control.

8) **Secondary Control through Automatic Generation Control (AGC)**

As directed by the Commission, POSOCO has already submitted a detailed procedure for implementing secondary control throughout the country through Automatic Generation Control (AGC). A pilot project on AGC with NTPC Dadri Stage-II has been implemented which would be put into operation after approval of the Commission. **The Expert Group recommends that AGC must be implemented throughout the country at the earliest in line with the Commission's recommendation of treating a region as a balancing area. Performance Metrics for such AGC payments may be introduced once sufficient experience is gained through the pilot project. AGC at the intra state level, particularly for large states, can be implemented in line with directions by the Appropriate Commission(s).**

9) **Slow tertiary control through Reserves Regulation Ancillary Service (RRAS)**

Slow tertiary control through Ancillary Services has been implemented pan India since April 2016. **The Expert Group recommends the following:**

a. **Expanding the ambit of RRAS at the inter-state level and refinements based on experience so far.**
b. **Introduction of Performance Metrics for mark-up payments for the slow tertiary Ancillary Services.**
c. **Introduction of slow tertiary Ancillary Services at the intra state level through regulations by Appropriate Commission. This would necessitate implementing the Scheduling, Accounting, Metering and Settlement of Transactions (SAMAST) at the intra state level.**

10) **Fast tertiary control at the Inter State level**

The slow tertiary RRAS at the inter state level leads to a situation where the impact is felt only after 20-30 minutes. The hydro power stations have not been utilized for RRAS so far. **The Expert Group recommends that fast tertiary services through RRAS using hydro could be introduced suitably at the inter state level to start with.**

11) **Monitoring of Area Control Error (ACE)**

It is expected that with all the above steps in place, frequency is expected to be within the IEGC mandated band for nearly 100% of the time. Nevertheless, as stated earlier, for a time horizon beyond one hour, forecasting and scheduling becomes important and any large scale errors here can impact frequency control. Hence monitoring each state control area performance is also important. **The Expert Group recommends as under:**

a. **Each state control area, region and the neighbouring countries would work out the Area Control Error (ACE), display, monitor and archive the same. For the purpose of ACE calculation, the bias could be set as 4% of Area load per Hz which can be refined over time. The inter-state and inter-regional tie line values as well as frequency measurements should be treated as Class A telemetry values and updated at a faster rate than ten (10) seconds at SLDCs/RLDCs/NLDC.**
b. **The ACE, worked out as above, should cross zero value and change sign at least once every hour to start with which would be narrowed down to half an hour. Persistent violation of this condition would render the utility liable for penalties.**
c. **The 15-minute deviations from the schedule as worked out through Special Energy Meter (SEM) data and schedules would be closely monitored for all time blocks where average frequency is below 49.95 Hz and above 50.05 Hz. On a monthly basis, the 90th percentile value of overdrawals below 49.95 Hz and underdrawals above 50.05 Hz**

would be monitored. This should not exceed 150 MW. Any violation could render the utility liable for penalties.

12) **Time Error**

Time error is the difference between the time reported by a synchronous clock, compared to the time reported by a reference synchronous clock. This error signifies the deviation of average frequency from reference frequency. Time error on daily basis (0000-2400 hours) would also be recorded at NLDC level. Standards for cumulative time error would be notified separately by CERC, at an appropriate time based on the experience gained and considering cross border interconnections.

2 Background

The Central Electricity Regulatory Commission (CERC) in its meeting held on 23rd March 2017 resolved to declare national reference frequency as 50 Hz. The Commission observed that all stakeholders should endeavour to maintain this reference frequency. This is required in the larger interest of stability and security of grid operation; for maintaining power quality and as a safeguard against frequency fluctuation which can affect electrical devices. The Commission also decided that a high level Expert Group be constituted consisting of representatives from CEA, POSOCO, CTU, and other concerned with the mandate to suggest further steps required to bring power system operation closer to the national reference frequency as resolved above. The order dated 27th April 2017 constituting the Expert Group and its Terms of Reference is given as **Annexe-I.** The Terms of Reference (TOR) of the Committee are as under:

- Review the experience of grid operation in India.
- Review international experience and practices on grid operation including standards/requirement of reference frequency.
- Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid.
- Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities.
- Any other matter related to above.

The Expert Group held three meetings on 9th May, 16th June and 3rd Nov 2017. Brief details of these meetings are indicated in the foregoing paragraphs.

2.1 Deliberations during the first meeting of the Expert Group

The first meeting was held in CERC on 9th May 2017. The minutes of meeting are enclosed as **Annexe-II.** Members shared similar views on the need for tight frequency control. International references on frequency control were shared by POSOCO**.**

After detailed discussion, the following decisions emerged

1. Experts from academia may be invited in the subsequent meetings for an interaction with the expert group.
2. 50Hz may be recognized as National Reference Frequency for power system operation in India.
3. Interaction with international experts, especially from US & Europe to be organized through Skype or VC on issues regarding reference frequency, operation band of frequency, Area Control Error (ACE), etc.in the next meeting.

4. A questionnaire to be prepared and sent in advance to the identified international experts. Presentation on POSOCO's pilot project on Automatic Generation Control (AGC) and Secondary Reserves may be organized in the next meeting. It was also decided to invite some experts, who can share international experiences on AGC implementation. Feedback of RPCs / RLDCs may be taken on Primary Response.
5. It was decided to gradually phase out the Restricted Governor Mode of Operation (RGMO) by 1st April 2018.
6. Pre-requisites to be prepared for AGC/Secondary Reserves.
7. To work on the framework for next level of interaction on Ancillary Services.

2.2 Deliberations during the second meeting

The 2nd meeting was held on 16th June 2017 at NRLDC, New Delhi. Members from CERC, CEA, POWERGRID and POSOCO were present during the meeting. Sh. Rahul Walawalkar from Customised Energy Solutions India Pvt Ltd. / IESA was Special Invitee to the meeting along with experts from ENTSOE and PJM who attended the meeting through conference call. Prof. Anjan Bose, Regents Professor, Washington State University, US was also connected through web conference as special invitee.

A document highlighting the background on frequency control in India which was circulated ahead of the meeting with the experts. The minutes of the meeting are enclosed as **Annexe-III.** Some specific issues were raised for deliberations with the international experts. The gist of deliberations is given below. :

1) *Defining Reference Frequency : Need & Importance*
   Reference Frequency for PJM, USA is 60 Hz. It is important to define the reference grid frequency from the grid security point of view. In some instances reference frequency is changed from 60 Hz to compensate for time error. Tight compliance to standards in the form of BAAL by NERC is being maintained by PJM. ENTSOE also has similar performance standards applicable in Europe. There is a need for evolving similar standards in India as well.

2) *Permissible Frequency Deviation in your grid and its evolution over the last decade.*
   Frequency is to be maintained at reference 60 Hz in the USA and PJM always endeavours to maintain the frequency between 59.98 Hz to 60.02 Hz. Frequency limits are in relation to operation of UFLS relays and RE generator disconnection in USA / Europe.

3) *Control Area Performance Assessment*
   In USA, BAAL standards were mentioned and Pay as per performance of AGC through FERC order 755 was mentioned.

4) *Types of reserves defined and assessment of requirement thereof*
   Prof. Bose advocated for constant 24x7 secondary reserves to start with as given in the order by CERC. PJM mentioned probabilistic calculations (based on BAAL scores) and a minimum reserve is always ensured.

5) *Procurement methods for reserves, duration and payment thereof*
   Procured by PJM through market based bids for secondary and tertiary. Primary response is mandated and not separately paid for in PJM.

6) *Minimum technical requirements for generators to be eligible for providing AGC services*
   Fast acting reserves and slow acting reserves are classified and procured separately. Requires further detailed discussion.

7) *Deviation Settlement Mechanism; how are imbalances handled as far as accounting is concerned?*
   Methodologies followed differ in different systems.

POSOCO made a presentation on the implementation philosophy of the ready-to-be mock tested AGC Pilot project at NTPC Dadri Stg-II before the CERC Committee.

The 3rd meeting of the Expert Group was held on 19th July 2017 wherein issues pertaining to DSM charges and Ancillary Services were discussed. The minutes of this meeting will be attached with the Vol-II of this report. The draft report of the Expert Group was circulated in the 4th meeting held on 3rd Nov 2017. The minutes of this meeting is attached as **Annexe-IV**. Based on earlier discussion, the portion corresponding to Deviation Settlement Mechanism (DSM) philosophy was circulated as a separate report. This report covers the first three terms of reference related to frequency control which was finalized based on comments received from members.

Chapter 2 covers the journey of Indian electricity grids in so far as frequency control is concerned and the international experience in the area of frequency control. Chapter 3 indicates the suggested frequency control continuum for the Indian grid conditions. Chapter 4 covers the need for monitoring inertia of the system as it impacts the immediate frequency dip following a large contingency. Chapter 5 covers primary control of frequency. Chapter 6 covers secondary control through AGC. Chapter 7 covers tertiary frequency control while Chapter 8 covers the recommendations.

3 Experience of grid operation in the context of frequency control

The Indian electricity grid operates in synchronism with Bhutan and has asynchronous link with Bangladesh besides radial feeds to Nepal, Myanmar and Bangladesh. The peak demand of the Indian grid is of the order of 160 GW with daily electrical energy consumption of the order of 3.4 TWh. POSOCO is responsible for reliable operation of the grid through the five Regional Load Despatch Centres (RLDCs) and National Load Despatch Centre (NLDC).

The nominal frequency of the Indian grid is 50.0 Hz. The All India grid was initially having five regional grids connected through asynchronous links. The regional grids were progressively synchronized in 1991 (East and North East), 2003 (Western Region with East and North East to form Central grid), 2006 (Northern Grid and Central Grid to form the NEW Grid) and 2013 (Southern grid with NEW grid to form All India grid).

The first Indian Electricity Grid Code (IEGC) came into effect with effect from 1st Feb 2000. It prescribed an allowable frequency band of 49.0-50.5 Hz, the frequency range within which all steam turbines conforming to IEC standards can safely operate. Gradually this frequency band was narrowed down and currently stands at 49.90-50.05 Hz w.e.f. Feb 2014. Typical daily frequency profile is available at https://posoco.in/reports/frequency-profile/frequency-profile-2017-18/. Typically, Indian grid frequency is within the band for 70-75% of the time. Minimum frequency touches 49.70 Hz while the maximum touches 50.20 Hz on many days. All generators are mandated to have their speed governors in service with a droop of 3 to 6%. POSOCO works out the Frequency Response Characteristics (FRC) for each Control Area and submits periodic reports to the Central Electricity Regulatory Commission (CERC). From a FRC of 6000 MW/Hz in 2015, grid is gradually getting a FRC of the order of 9000-10000 MW/Hz for the All India grid as a whole.

The Indian grid needs Automatic Generation Control (AGC) now. As per CERC's Order dated 13.10.2015 in the matter of 'Roadmap to operationalise Reserves in the country', each regional grid should have secondary reserves corresponding to the largest size unit in the region which works out to approx. 3600 MW for the country. Further, for the purpose of secondary control, each region would be considered as a control area. CERC has suggested that Central Government owned generators in each region would provide AGC services. However, the modalities of how this 3600 MW reserves would be distributed amongst the generators is under finalization. POSOCO is undertaking the first pilot AGC project for 50 MW secondary control service from a 2 x 500 MW coal fired power plant in Northern Region. In the future, CERC has proposed procurement of secondary reserves from the market. Modalities for payment for AGC services are under consideration.

The state control areas are required to provision tertiary reserves of 50% of the largest sized unit within their control area. This is a guideline by CERC; however the state utilities are yet to provide for the same. Currently, there is some spare capacity in Central Government owned generators which is left unscheduled by the states. This spare capacity is at the disposal of POSOCO which schedules this capacity within 15-30 minutes of any contingency or even otherwise for a period of 2-3 hours. However, the state having a share in this plant can schedule the same at one hour notice. This is a slow tertiary control Reserves Regulation Ancillary Service (RRAS).
The provisions in respect of frequency control and allowable range of its operation as appearing in the Indian Electricity Grid Code (IEGC) and other Standards is enclosed at **Annexe-V.**

3.1 Indian Grid frequency - evolution

Indian grid frequency has come a long way from days of chronic shortages in some regions and chronic surpluses and wide variation. Eastern Region in the past has sustained frequency above 52 Hz while at the same time Southern Region experienced sustained low frequency below 48 Hz **(Annexe-VI)**. The typical pattern of average frequency since 2004 is given in Fig 1 below. Indian power system has come a long way with the average frequency remaining very close to 50.0 Hz since 2014. The variation of maximum and minimum frequency and fluctuation (difference of maximum and minimum frequency) has also decreased over the years as shown in Fig 2 below. A time duration plot of the same is given below. Frequency Variation Index (FVI) also has come down over the years from as high as 7 – 8 to less than 0.05 and below (best FVI achieved is 0.019) as shown in Fig 3 below. Figs 4 -7 indicate box plots for various frequency values. The maximum and minimum frequency are presently touching 50.2 Hz and 49.65 Hz almost on daily basis as can be observed from the graph below.

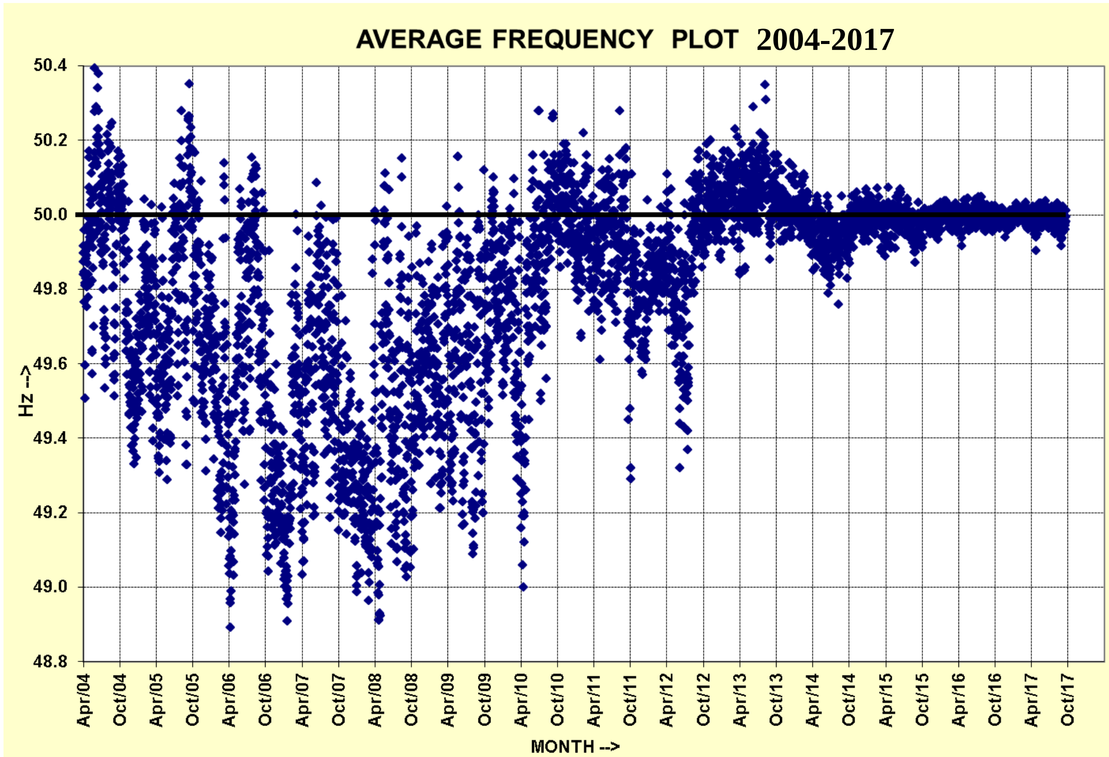


Figure 1: Average frequency of the Indian electricity grid since the year 2004

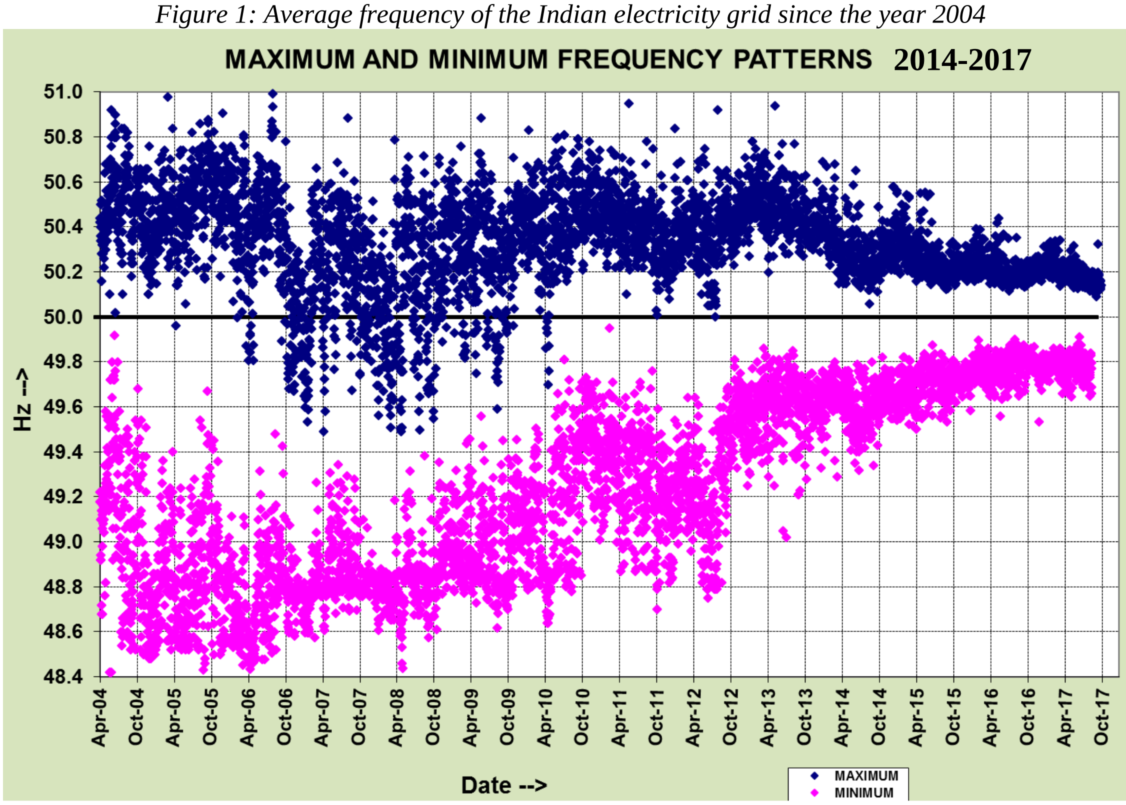


Figure 2: Variation in maximum and minimum frequency of the Indian grid since 2004

2014-2017

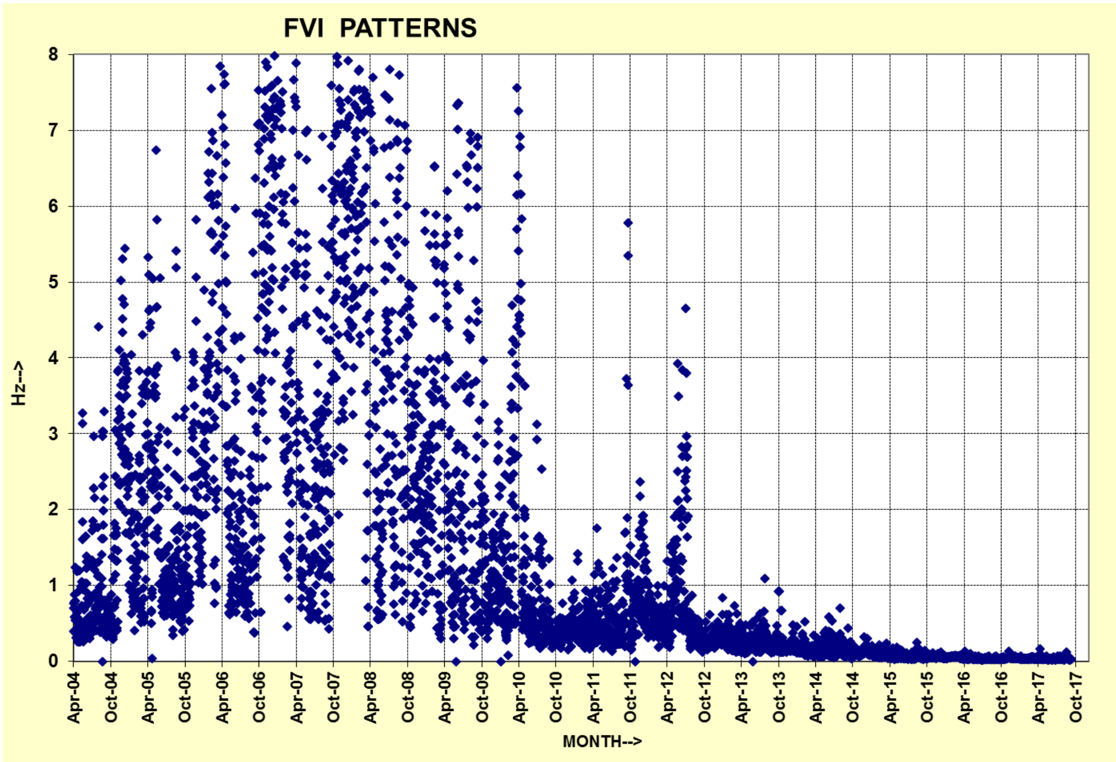


Figure 3: Variation in Frequency Variation Index (FVI) since 2004

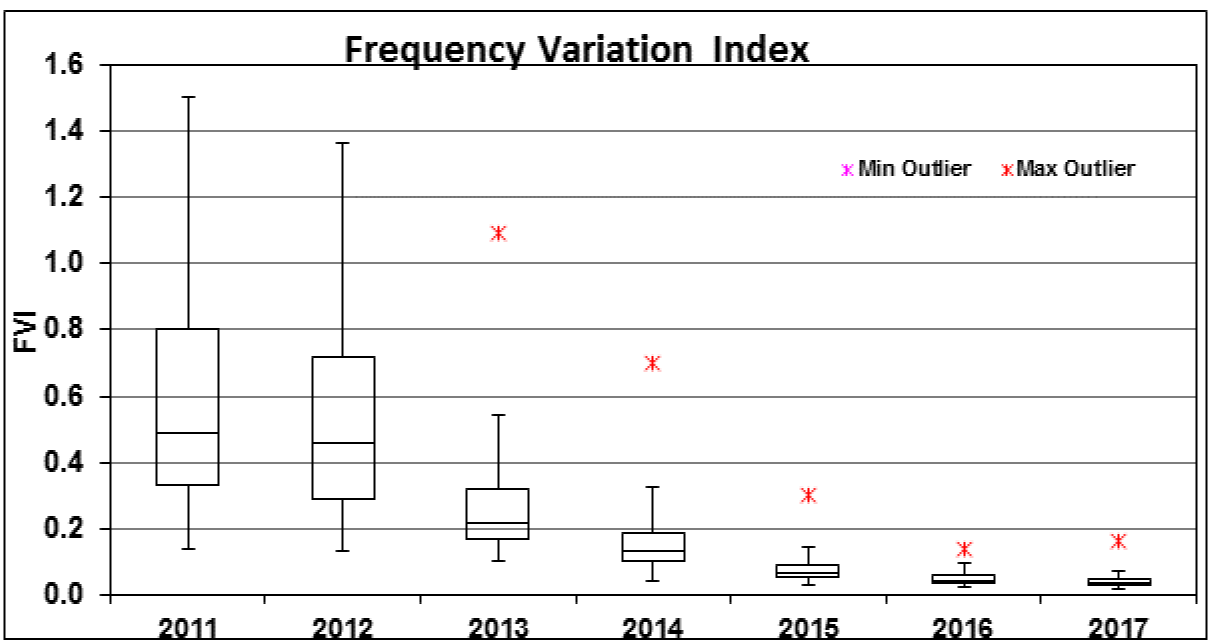


Figure 4: Frequency Variation Index from 2011 to 2017

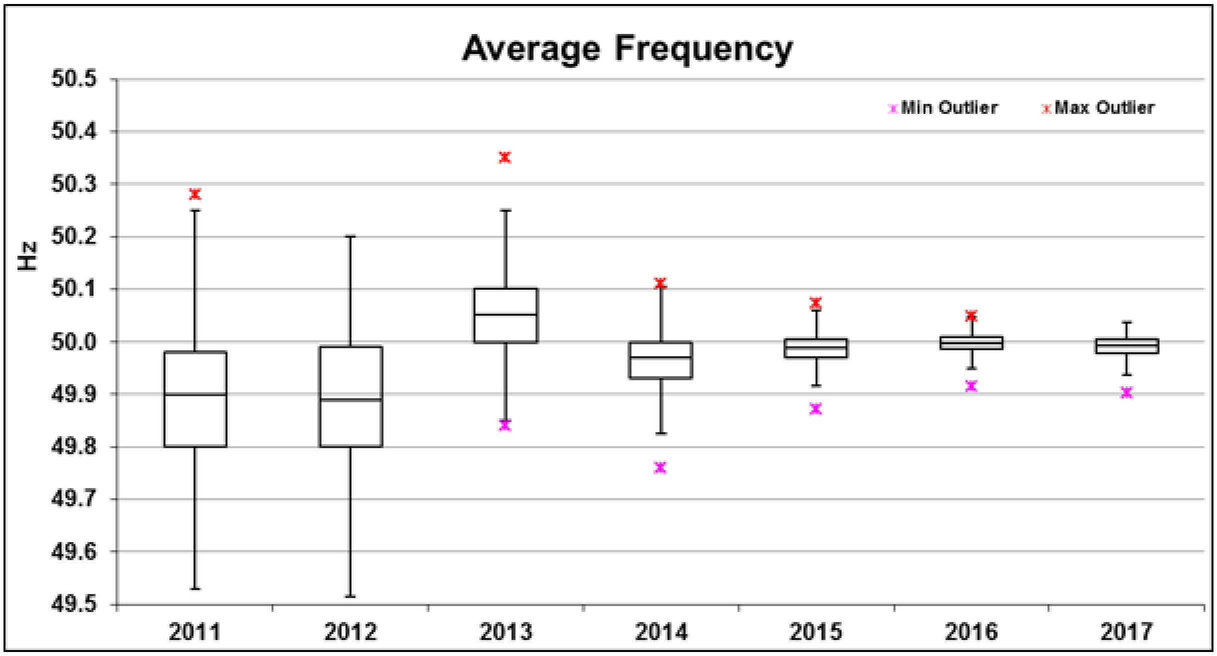


Figure 5 : Average Frequency from 2011 to 2017

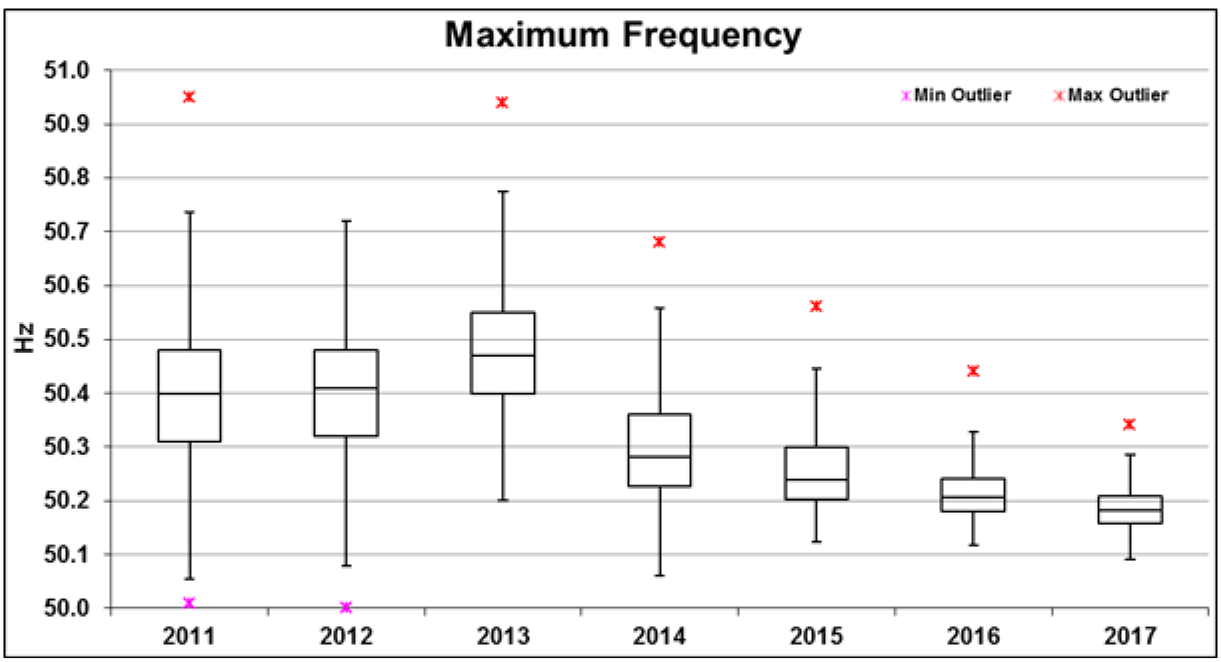


Figure 6: Maximum Frequency from 2011 to 2017

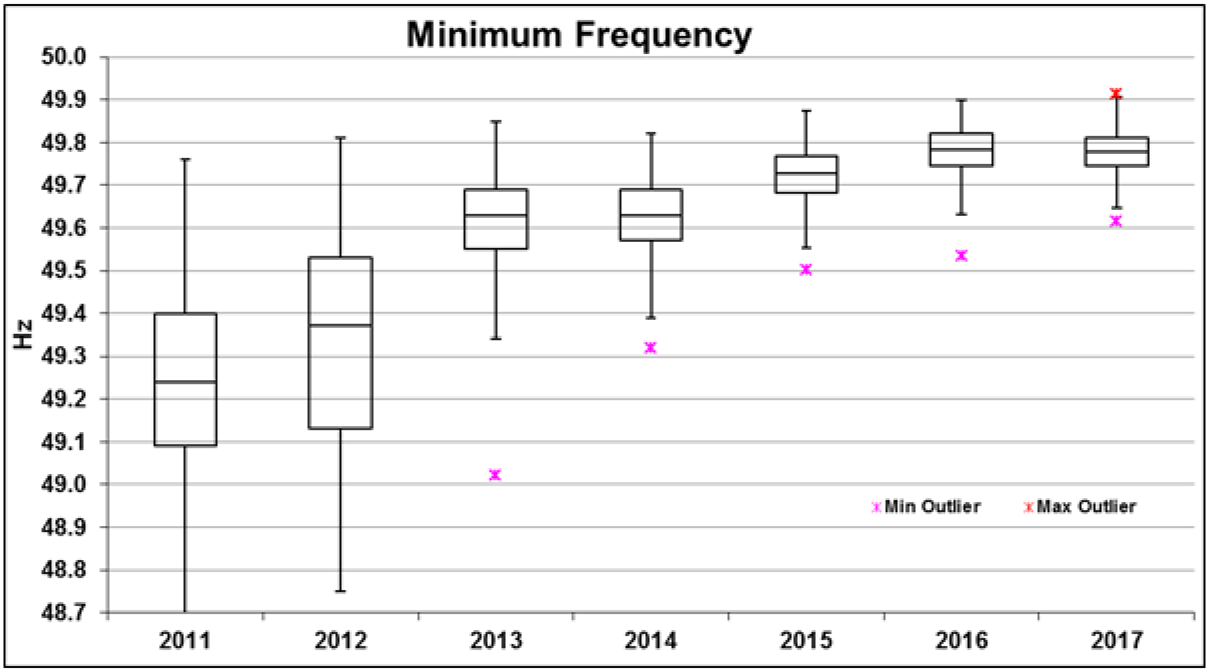


Figure 7: Minimum Frequency from 2011 to 2017

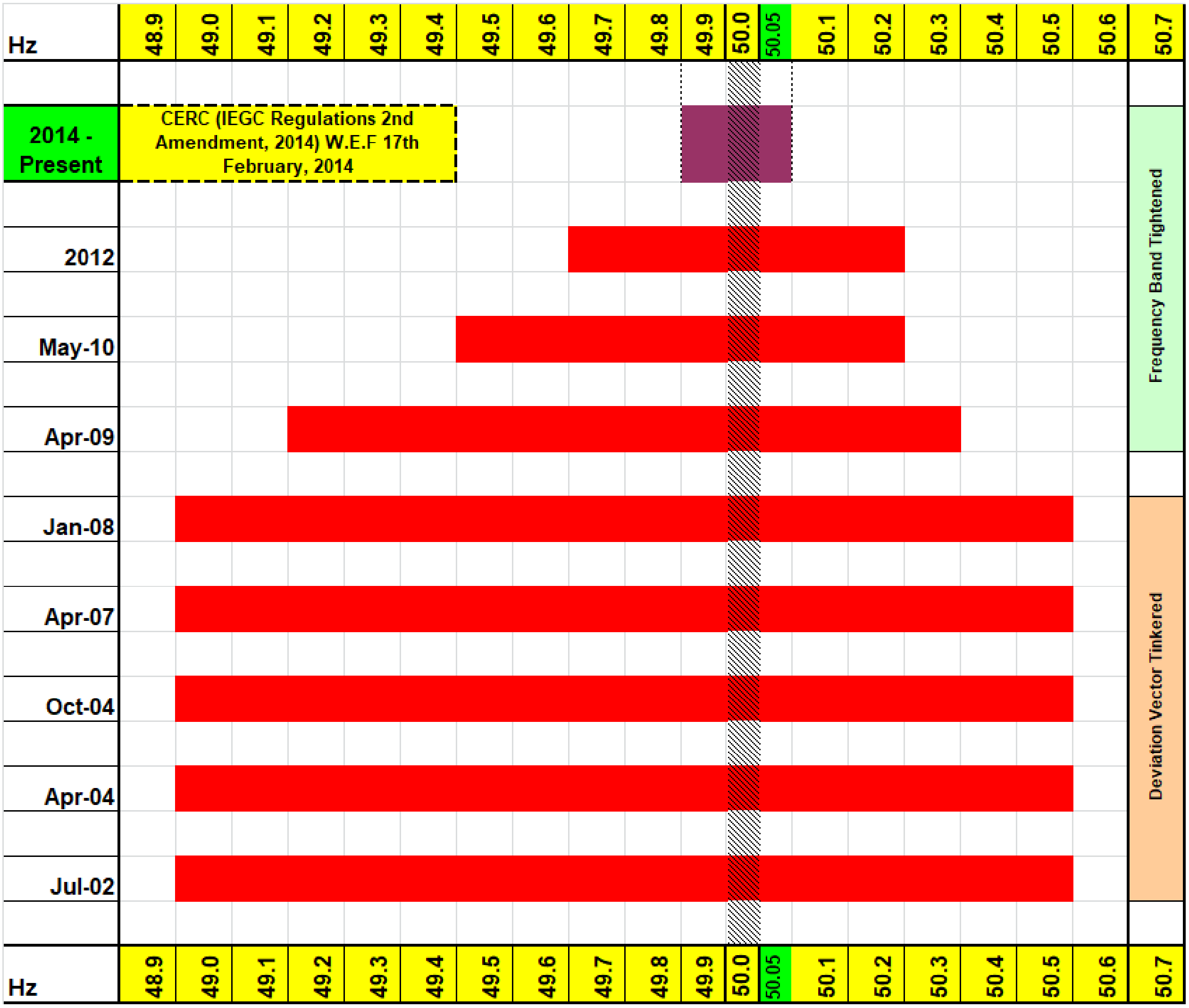


Figure 8: Frequency band specified in the Indian Electricity Grid Code (IEGC) over the years

The Central Commission has through periodic amendments in the Indian Electricity Grid Code (IEGC) tightened the allowable frequency band from a range of 49.0-50.5 Hz in Feb 2000 to the range 49.90-50.05 Hz since February 2014 (as seen in Fig 8). Maintaining frequency profile within the allowable band was mainly through the frequency linked Unscheduled Interchange (UI) or Deviation Settlement Mechanism (DSM) prices. The structural framework of the DSM/UI mechanism as it developed from 2002 onwards is indicated in Fig 9. No automatic controls were available other than mandating primary response for large generators through the IEGC.

Period	Operational Frequency Band	Ceiling Rate (paise/kWh)	Floor Rate (paise/kWh)	Slope (paise/kWh)	Step size
1st July 2002 – 31stMar 2004	49.00 Hz – 50.50 Hz	420	0	5.60	0.02 Hz
1st Apr 2004 – 30th Sep 2004	49.00 Hz – 50.50 Hz	600	0	8.00	0.02 Hz
1st Oct 2004– 29th Apr 2007	49.00 Hz – 50.50 Hz	570	0	9.00	0.02 Hz
30th Apr 2007- 6th Jan 2008	49.00 Hz – 50.50 Hz	745	0	6.00 (50.5-49.8) 9.00 (49.8-49.5) 16.00 (49.5-49.0)	0.02 Hz
7th Jan 2008 – 31st Mar2009	49.00 Hz – 50.50 Hz	1000	0	8 .00 (50.5-49.8) 18.00 (49.8-49.0)	0.02 Hz
1st Apr 2009 – 2nd May 2010	49.20 Hz – 50.30 Hz	735	0	12.00 (50.3-49.8) 17.00 (49.8-49.2)	0.02 Hz
3rd May 2010- 16th Sep 2012	49.50Hz – 50.20 Hz	873	0	15.50 (50.2-49.7) 47.00 (49.7-49.5)	0.02 Hz
17th Sep 2012 - 16th Feb 2014	49.70 Hz – 50.20 Hz	900	0	16.50 (50.2-50.0) 28.50 (50.0-49.8) 28.12 (49.8-49.5)	0.02 Hz
17th Feb 2014 onwards	49.90 Hz – 50.05 Hz	824	0	20.84 (49.70 – 50.00) 35.60 (50.01 – 50.05)	0.01 Hz

Figure 9 : Evolution of Deviation Price (erstwhile UI) Vector

3.2 Comparison of typical Indian frequency with other large power systems

The standard frequency range of Continental Europe (CE) is between 49.95 to 50.05 Hz. For India, the standard range is 49.9 Hz - 50.05 Hz. As can be observed from the pattern of the frequency for a sample day indicated in Fig 5, frequency remains within the band for a large portion of time for Continental Europe. Frequency for CE is very close to 50 Hz for a large portion of the day. For India, there is lot of scope for improvement in terms of grid frequency quality.

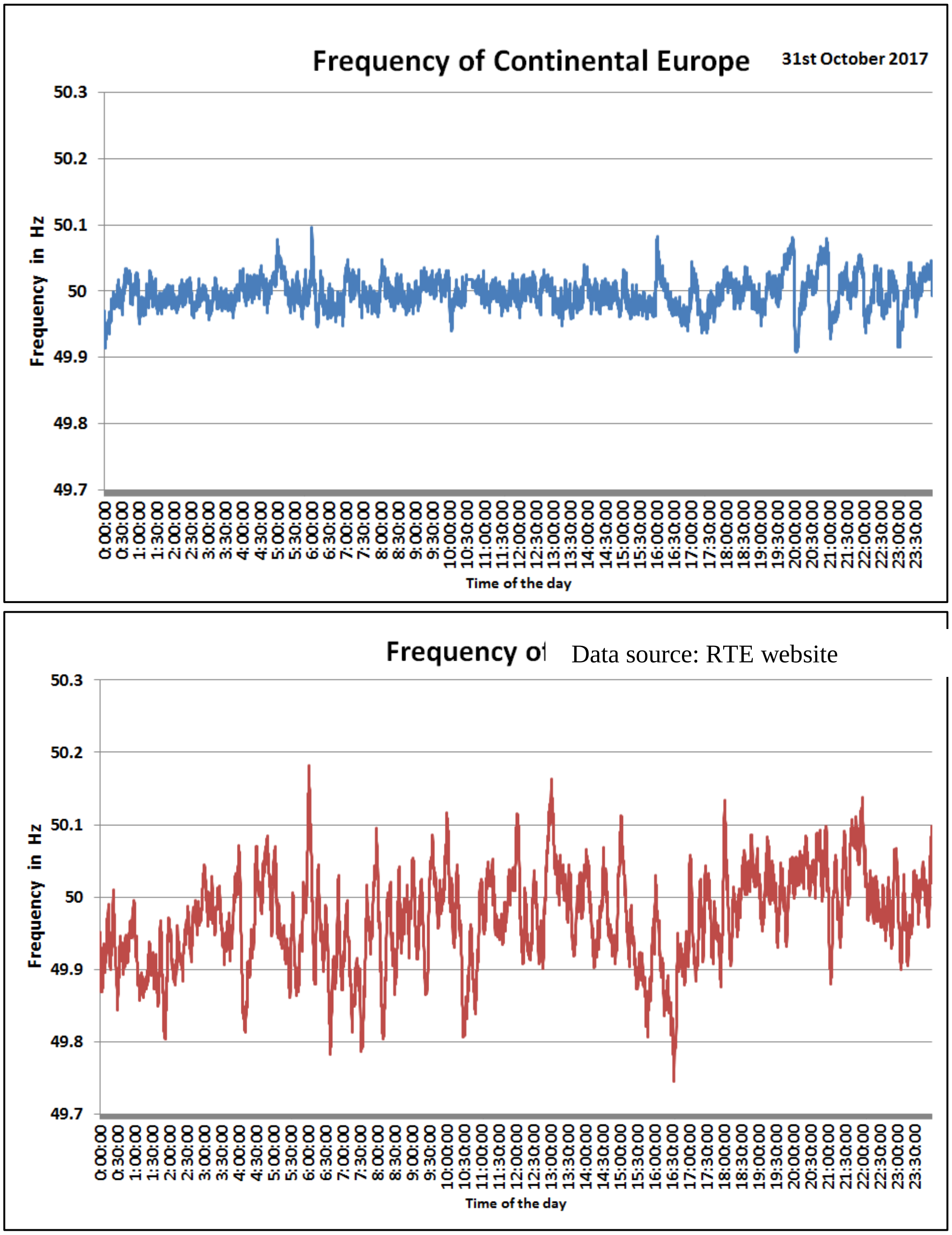


Figure 10: Sample daily frequency profile for Continental Europe & India

Granular data in respect of the frequency of the different interconnections in US are not available in the public domain for a similar plot as Fig 5 for the US systems. However, Fig 11 extracted from the NERC report on 2016 Frequency Response Annual Analysis gives a good indication of the frequency profile of the different grids in US.

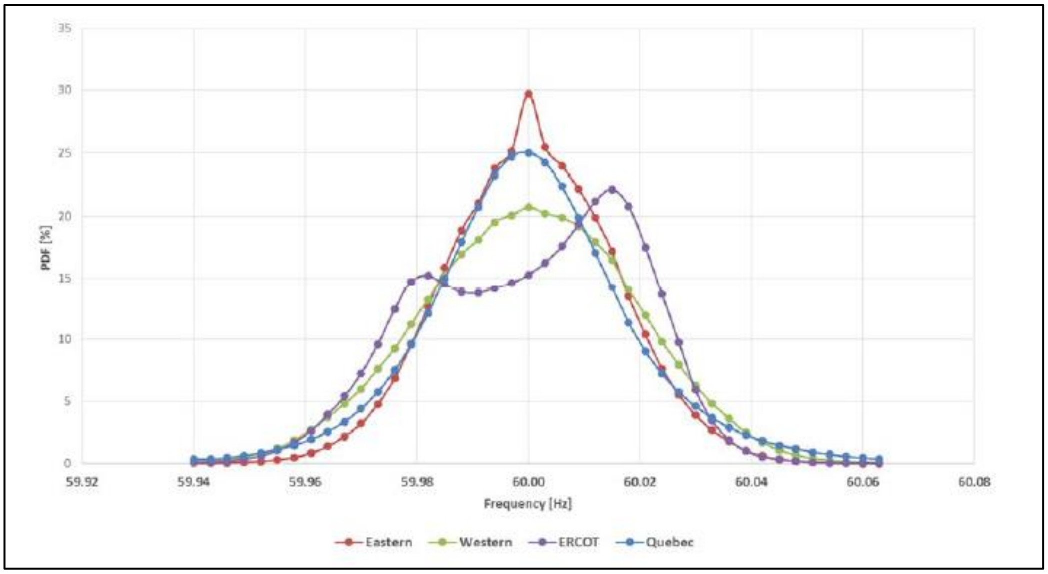


Figure 11: Probability Density Functions (PDFs) of US system frequency from 2012-15

A comparison of the frequency profile of India and Continental Europe (CE) for a typical day (24th Sep 2017) is indicated in the Table below.

Table 1: Comparison of the frequency profile of India and Continental Europe for a typical day

S no	Description	Values for	
		Continental Europe	**India**
2	Standard Deviation (Hz)	0.019	0.042
3	Frequency Variation Index (FVI) in Hz	0.0036	0.020
4	Instantaneous maximum frequency (Hz)	50.060	50.154
5	Instantaneous minimum frequency (Hz)	49.916	49.885
6	15-minute maximum average frequency (Hz)	50.033	50.065
7	15-minute minimum average frequency (Hz)	49.965	49.952
8	% of time frequency remained within 49.90-50.05 Hz	99.61	81.08
9	% of time frequency below 49.90 Hz	0.00	0.06
10	% of time frequency above 50.05 Hz	0.39	18.86
11	Average time frequency remains below 49.97 Hz for every excursion (mm:ss)	00:38	02:10
12	Average time frequency remains above 50.03 Hz for every excursion (mm:ss)	00:33	02:48
13	No of excursions above 50.03 Hz	112	177
14	No of excursions below 49.97 Hz	139	94

The above comparison is only to highlight the need for more automation for the Indian power system as far as frequency control is concerned so that improvements in frequency profile are taken to the next level. For instance, automatic controls such as Automatic Generation Control (AGC) are helping in the frequency restoration to the 49.97-50.03 Hz range within 30-40 seconds in Continental Europe as against over 2 minutes in case of India.

3.3 International scenario in respect of frequency control

For the Indian scenario, it would be worthwhile to look at large systems such as Continental Europe and the US as far as frequency control mechanisms are concerned.

3.3.1 Practices in the North American system for frequency control

The references listed at the end of this report have some NERC references which give a good overview of the various methods deployed for frequency control. *'What frequency is to the Interconnection, Area Control Error or (ACE) is to the Control Area'* is the basic principle on which the Frequency control and its various performance metrics are designed.

In respect of primary response, the NERC Reliability Standards (BAL-003-1) define the Interconnection Frequency Response Obligation (IFRO) which usually considers the largest generation loss possible and the Under Frequency Load Shedding (UFLS) setting. In case of Eastern Interconnection (the largest system in US), this is 4500 MW and 59.5 Hz giving an IFRO of 1002 MW/0.1 Hz. This IFRO is apportioned amongst all entities depending on their load and generation. The actual Frequency Response Characteristics (FRC) observed for the Eastern Interconnection as well as Western Interconnection is much above the IFRO, at least 2.5 to 3 times the IFRO.

Primary response is a mandatory service in the US with no explicit payments made for providing this service. However recently, CAISO in the Western Interconnection has apprehended that under a high RE scenario, it might be difficult for CAISO to even provide the IFRO and a proposal has been placed before the Federal Energy Regulatory Commission (FERC) for payments for primary response. This has been recently approved by the FERC in February 2017 and awaiting implementation.

In respect of secondary control through AGC, termed as regulation services, standards exist for setting the frequency bias (BAL-003-1.1) as well as Control Performance Standard 1 or CPS1. CPS1 is calculated on monthly basis and has to remain above 100 for a Control Area to ensure compliance. CPS1 is mainly calculated from the Area Control Error (ACE). Apart from CPS1, a balancing area must also ensure that its ACE does not exceed the Balancing Authority ACE Limit or BAAL for more than 30 minutes. Violations of CPS1 and BAAL would make the Balancing Authority liable for penalties.

As regards payments to entities for providing regulation services, FERC Order 755 dated 20th October 2011 lays the foundation of pay as per performance. So depending on the extent to which the generators follow the regulation signals, a multiplying factor is added for AGC payments. This multiplication factor would be less than one. Secondary regulation is usually obtained through the market by the Independent System Operators (ISOs).

The third category of reserves deployed as part of any contingency is termed as contingency reserve or supplemental reserve. This is again procured by the ISO through markets.

3.3.2 Practices in the continental Europe for frequency control

The ENTSOE Network Code on Load Frequency Control and Reserves dated 28th June 2013 and the draft European Union (EU) guideline on electricity transmission system operation indicated in the list of references below give an indication of the practices followed in respect of frequency control by Transmission System Operators (TSOs) in Europe.

As would be observed from Fig 12 below, for the Continental Europe (CE), the frequency is expected to be within the 49.95-50.05 Hz band. Following a contingency, the instantaneous frequency could dip to 49.20 Hz and recover to 49.8 Hz through primary response. The frequency, once outside the range, has to be restored to within the 49.95-50.05 Hz band within fifteen (15) minutes.

As per Article 127 of the draft EU Regulation, the frequency can be outside the defined range in Fig 12 for a maximum of 15000 minutes per year. Thus frequency has to be within the band for 49.95-50.05 Hz for 97.15% of the time in a year.

The frequency is maintained within the range with the combined efforts of all the TSOs and obligation to have reserves. Reserves are of the following types:

- Frequency Containment Reserve (FCR) similar to primary control
- Frequency restoration Reserves (FRR) similar to secondary control through AGC
- Restoration Reserves (RR) to replace FRR similar to tertiary control.

	CE	GB	IRE	Nordic
standard frequency range	±50 mHz	±200 mHz	±200 mHz	±100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1000 mHz	1000 mHz
maximum Steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
Frequency Recovery Range	not used	±500 mHz	±500 mHz	not used
time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	±200 mHz	±200 mHz	±100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

Figure 12: Frequency defining quality parameters in Europe as per EU Regulation

For the dimensioning of FCR, the largest contingency considered for continental Europe is +/-3000 MW. The TSOs collectively have to provide this FCR generally in the ratio of their peak loads. However, the TSOs could collaborate jointly to provide the FCR collectively but there are limitations that at least a certain percentage of the agreed FCR has to be provided from within the TSO's area. For the FCR providing generating units, the dead band (inherent plus intentional) must not exceed 10 mHz or 0.01 Hz. Primary response or FCR is generally procured by TSOs from the market. Performance metrics include that 100% of the response has to come within 30 seconds and fully activated by the time frequency drops to 49.80 Hz.

FRR dimensioning by the TSOs consider the statistical values of imbalance or Area Control Error, particularly when frequency goes outside the band and needs to be restored within fifteen (15) minutes. Once the FRR is dimensioned, the TSO has to specify the automatic part and manual part. FRR is also procured by TSOs from the market with performance criteria being the availability of full FRR within 15 minutes.

RR comes next and it must replace FRR, similar to tertiary response. RR is also procured by TSOs from the market. Performance criteria for RR payments is also implemented.

3.3.3 Standards for Measurements of frequency and ACE, archiving of the same:

Frequency Control necessitates handling of frequency and ACE data which is also used for evaluating system performance. Standards exist both in the North American system and Continental Europe for the same.
In the US, the NERC Frequency Monitoring and Analysis (FMA) application whose technical specifications have been formulated by the Consortium for Electric Reliability Technology Solutions (CERTS) specifies standards for recording and archiving of frequency data. For each synchronous system it prescribes at least three (3) frequency measurements from locations reasonably far apart. The frequency data is expected to be stored at the rate of one sample every second as well as 10 seconds. The resolution should be +/-0.001 Hz. ACE data is also required to be stored every 10 seconds.

Similar provisions exist in the EU guidelines.

3.4 Defense Mechanism: UFLS and df/dt Relay operation

Presently, there are four stages of Under-Frequency Load-Shedding (UFLS) relays which are set at 49.2 Hz, 49.0 Hz, 48.8 Hz, and 48.6 Hz in NR, WR, ER, SR, and NER. These settings were last raised in end 2013 before synchronization of Southern region with rest of the grid. In addition to UFLS relays, df/dt relays are also installed in NR, WR, and SR grids. In NR and WR df/dt relays are set to get armed at 49.9 Hz to shed load automatically if the rate of fall of frequency is faster than 0.1, 0.2, or 0.3 Hz/s (i.e., three stages). In SR, however, the frequency at which UFLS is armed and the rate thresholds are 49.5 Hz & 0.2 Hz/s, 49.3 Hz & 0.2 Hz/s, and 49.3 Hz & 0.3 Hz/s for the three stages, respectively.

Table 2: State wise load relief of UFR

All India UFR Status						
Region	States	49.2 Hz	49 Hz	48.8 Hz	48.6 Hz	Total
NR	Punjab	400	402	406	408	1616
	Haryana	308	309	312	314	1243
	Rajasthan	390	392	395	397	1574
	Delhi	258	259	262	263	1042
	UP	551	554	559	561	2225
	Uttarakhand	77	77	78	78	310
	HP	77	77	78	78	310
	J&K	83	84	84	85	336
	Chandigarh	16	16	16	16	64
	Total*	2160	2170	2190	2200	8720
WR	GETCO	580	580	580	590	2330
	MPPTCL	460	460	460	465	1845
	MSETCL*	805	810	815	820	3250
	CSEB	150	150	155	155	610
	Goa	25	25	25	25	100
	DD	10	15	15	15	55
	DNH	30	30	35	35	130
	Total	2060	2070	2085	2105	8320
SR	Andhra Pradesh	392	393	398	399	1582
	Telangana	417	419	424	426	1686
	Karnataka	576	578	586	588	2328
	Kerala	204	205	208	209	826
	Tamil Nadu	740	744	753	756	2993
	Puducherry	21	21	21	22	85
	Total	2350	2360	2390	2400	9500
ER	BSEB	105.5	101.5	115	118.5	441
	JSEB	65	64	63	69	261
	DVC	131.1	133.95	137.75	133.95	537
	OPTCL	181.5	183.5	184	186	735
	WB & CESC	354	351	373	354	1432
	Total	837.1	833.95	872.75	861.45	3405.25
NER	Arunachal Pradesh	5	0	0	0	5
	Assam	55	55	55	55	220
	Nagaland	0	0	5	0	5
	Mizoram	5	5	0	0	10
	Meghalaya	15	15	0	0	30
	Tripura	10	10	0	0	20
	Manipur	0	0	0	0	0
	Total	90	85	60	55	290
ALL India Level		7497.1	7518.95	7597.75	7621.45	30235.25

* All the constituents would plan for 20% more quantum than the agreed for achieving full planned relief from UFRs as per24th TCC and 27th NRPC meeting decision dt. 10-11-2012.

Table 3 : State wise load relief of df/dt relays in Northern Region

	Load Relief in MW			
STATES	**Stage-I 49.9 Hz & 0.1 Hz/sec**	**Stage-II 49.9 Hz & 0.2 Hz/sec**	**Stage-III 49.9 Hz & 0.3 Hz/sec**	**Total**
Punjab	430	490	490	1410
Haryana	280	310	310	900
Rajasthan	330	370	370	1070
Delhi	250	280	280	810
UP	500	280	280	1060
Uttarakhand	70	70	70	210
HP	50	70	70	190
J&K	90	90	90	270
Chandigarh	0	50	50	100
TOTAL	2000	2010	2010	6020

Table 4: State wise load relief of df/dt relays in Western Region

STATE	Stage – I (49.9 / 0.1 Hz / sec)		Stage – II (49.9 / 0.2 Hz / sec)		Stage – III (49.9 / 0.4 Hz / sec)	
	Required Load relief	Implemented Load relief	Required Load relief	Implemented Load relief	Required Load relief	Implemented Load relief
GUJARAT	1006	*	905	1454	1001	1610
MADHYA PRADESH	361	475	355	415	392	445
CHATTISGARH	27	120	37	40	120	40
MAHARASHTRA	546	370	621	1131	686	522
**TPC (Mumbai)	60		82		273	
Total load relief	2000	965	2000	3040	2472	2617

Table 5: State wise load relief of df/dt relays in Southern Region

	Load Relief in MW		
STATES	Stage-I 49.5 Hz & 0.2 Hz/sec	Stage-II 49.3 Hz & 0.3 Hz/sec	Total
Andhra Pradesh	345	855	1200
Telangana	367	912	1279
Karnataka	474	737	1211
Kerala	172	175	347
Tamil Nadu	624	559	1183
Puducherry	18	0	18
TOTAL	2000	3238	5238

During any contingency, the grid frequency will start to drop and UFLS along with df/dt relays (if required) may be activated to arrest its fall. Governor response will play a key role in this regard, as well as in settling at the final frequency. Another important consideration is possible islanding, consequential load shedding and over voltages which might occur due to lightly loaded lines. Thus, excitation systems are equally important, as well as timely switching of shunt reactor/capacitor banks. This aspect is particularly important in the case of Southern Region and North Eastern Region as they are importing regions and there is a stray chance of islanding.

Western grid system experienced a disturbance at 19:22 hours of 12th March 2014 leading to load loss and generation loss. There was a complete black out at CGPL Mundra (UMPP) due to tripping of all evacuating lines from CGPL Mundra leading to a generation loss of 4030 MW (CGPL: 3750 MW + 280 MW wind generation in the vicinity). The grid frequency dipped by 0.67 Hz i.e. from 49.95 Hz to 49.285 Hz. A load loss of 1110 MW was reported during the event out of which 960 MW was due to load shedding through df/dt relays (Gujarat: 630 MW + Maharashtra: 330 MW) and 150 MW due to reduction in export to Bangladesh due to SPS operation. The grid frequency remained above the 1st stage of UFR. There was a total of 960 MW load shedding on account of df/dt relay in Gujarat (636 MW) and Maharashtra (334 MW). df/dt relief has not been reported in other States / Regions.

The review of UFLS schemes is a continuous process at the CEA and Regional Power Committee (RPC) level.

3.5 Metrics on zero crossing and sustained deviation

As per the 2014 Deviation Settlement Mechanism (DSM) regulations in the event of sustained deviation from schedule in one direction (positive or negative) by any regional entity, such regional entity (buyer or seller) shall have to change the sign of their deviation from schedule, at least once, after every 12 time blocks. Though the DSM regulations mention the need for sign change, presently there is no commercial implication for Zero Crossing Violation.

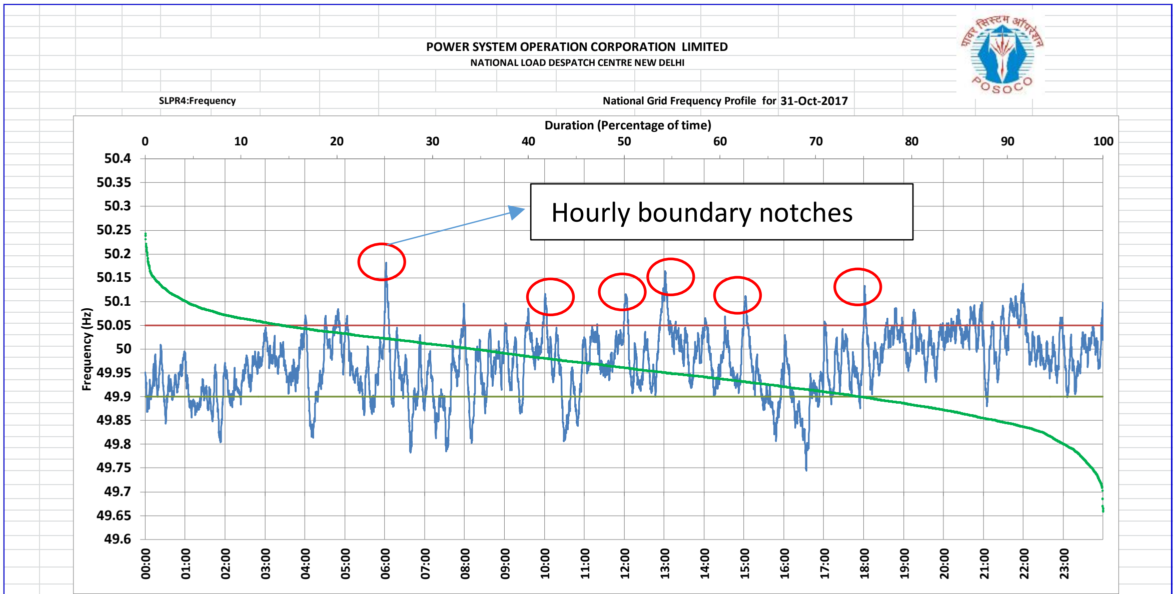
Sustained non-reversal of sign change will lead to a large accumulation of time error. The integral of the Area Control Error (ACE) over a period of time (say the whole day) will also become very high. Both these metrics indicate sustained deviation from schedule (Over Drawl and Under Drawl), and bring out a need for better operational planning along with maintenance and deployment of reserves so as to adhere to the drawl schedule from the grid. Sustained deviations and non-adherence to the schedule are highly detrimental to the secure grid operation and may lead to grid events such as the 2012 grid blackout.

As the sustained level of ACE has an adverse impact on frequency control, there must be suitable provisions in the Grid Code which would encourage utilities to regulate ACE.

3.6 Hourly boundary frequency phenomenon

The demand met in Southern Region (SR) typically starts reducing from around 17:00-17:15Hrs (69th time block) onwards to touch a sharp minima at around 18:00 Hrs on daily basis. A reduction of the order of 4000–5000 MW is generally observed between 17:00 Hrs to 18:00 Hrs and grid frequency also increases to about 50.15–50.20Hz.

Following the sharp notch in demand around 1800 Hrs, a steep ramp in demand profile of several regional entities is observed, which result in fast reduction in grid frequency in the same time block itself. Load changeover also occurs in the time blocks leading to 1800 Hrs, which result in heavy underdrawal by many constituents, which contributes to the sharp dip in demand at 1800 Hrs. Minutes later, the peak load ramp up starts often leading to low frequency. (Fig 13)



<49.7	<49.90	<49.97	49.7-49.8	49.8-49.9	49.9-50.0	50.0-50.1	50.1-50.2	49.90-50.05	49.7-50.2	49.97-50.03	50.05-50.1	>50	>50.03	>50.05	>50.2
0.00	14.97	49.43	0.60	14.36	50.36	32.96	1.71	75.41	100.00	32.69	7.95	34.59	17.88	9.63	0.00

Average Frequency :	49.969	Frequency Variation Index :	0.052	Standard Deviation :	0.065

Instantaneous Frequency			15 minute Average Frequency				
Max	50.182	6:02:10	Max	50.084	22:00:00	No. of excursions above 50.03 Hz	128
Min	49.744	16:33:50	Min	49.849	16:45:00	No. of excursions below 49.97 Hz	121
						No. of excursions above 50.00 Hz	128
						No. of excursions below 50.00 Hz	129

Average time freq remains below 49.97 per excursion	0:05:53	Average time frequency remains above 50.03 per excursion	0:02:01

Figure 13: Sharp fluctuations in frequency at hourly boundary

The short time frame of this phenomenon makes operation of the grid critical.. To prevent such phenomenon, drawal utilities are required to stagger their loads at time-block changes and take all other necessary action in interest of the grid. This also indicates the necessity of grid controls for frequency including primary, secondary and tertiary controls working in synchronism.

3.7 Review of existing frequency band

Expert Group is of the opinion that the present frequency band of 49.9 Hz-50.05 Hz is apt for the Indian power system at present. But, the endeavour should be to be in the frequency band for 100 % of the time. Further tightening of this band without the requisite primary, secondary and tertiary frequency control mechanism in place would be difficult. More frequent runs in the electricity market enabling more opportunity for balancing available to the market participants is also expected to be in place. Moving to a five (5) minute scheduling and settlement interval is also under discussion. The Expert Group is of the view that these changes in the framework would be in place over the next two to three years. Accordingly, a roadmap is suggested to move to an operational frequency band of 49.95 Hz to 50.05 Hz by 2020. Further tightening of the frequency band to this value would also help in valuing flexibility.

With the gradual improvement in frequency profile, the following improvements have taken place leading to a paradigm shift in operations:

i. UFLS relays have not operated in day to day normal operations. Df/dt relays have operated only in case of a major contingency. The flat frequency ULFS have not operated in the integrated All India grid. Only NER system has got islanded in the past leading to some UFLS relays operating but these were inadequate to save the NER system from collapse.

ii. In the past, the fall in frequency to a level of 49.5 Hz and below led to gas turbine output reducing by 2-3% since the air compressor feeding air to the combustion chamber was on the same gas turbine shaft. Due to this reduction in output, the combined cycle power plants were getting some compensation in terms of reduction in schedule to account for the drop in generation. All this is now history and these clauses could be removed now.

iii. In view of tightening of the frequency band, the earlier Special Energy Meters (SEMs) which were recording @0.02 Hz resolution were replaced by a few SEMs recording @0.01 Hz resolution. This has helped in changing the frequency linked pricing mechanism in steps of 0.01 Hz now instead of 0.02 Hz earlier.

3.8 Schematic of reserves, balancing and frequency control continuum

Based on the international experience and our Indian experience, Chapter 4 suggests a schematic of reserves, balancing and frequency control continuum for the Indian conditions. The Expert Group recommends that this schematic could form part of the IEGC through an amendment.

CERC through its order dated 13th October 2015 on roadmap for operationalizing of spinning reserves in the country has already indicated the path which needs to be implemented at the earliest in line with international practices on frequency control. Further, the IEGC must specify the formula for calculating Area Control Error (ACE) as

Area Control Error (ACE) = (Ia - Is) + 10 * Bf * (Fa - 50) + E_σ

- **Ia = Actual net interchange, negative for NR meaning import by NR**
- **Is= Scheduled net interchange, negative for NR meaning import by NR**
- **Bf = Frequency Bias Coefficient in MW/0.1 Hz, positive value**
- **Fa = Actual System Frequency**
- **E_σ = Metering Error**

The frequency bias coefficient Bf could be taken as 4% of area load per Hz initially. ACE positive for a region, say NR means NR is surplus and its internal generation has to back down. ACE negative means NR is deficit and NR internal generation has to increase.

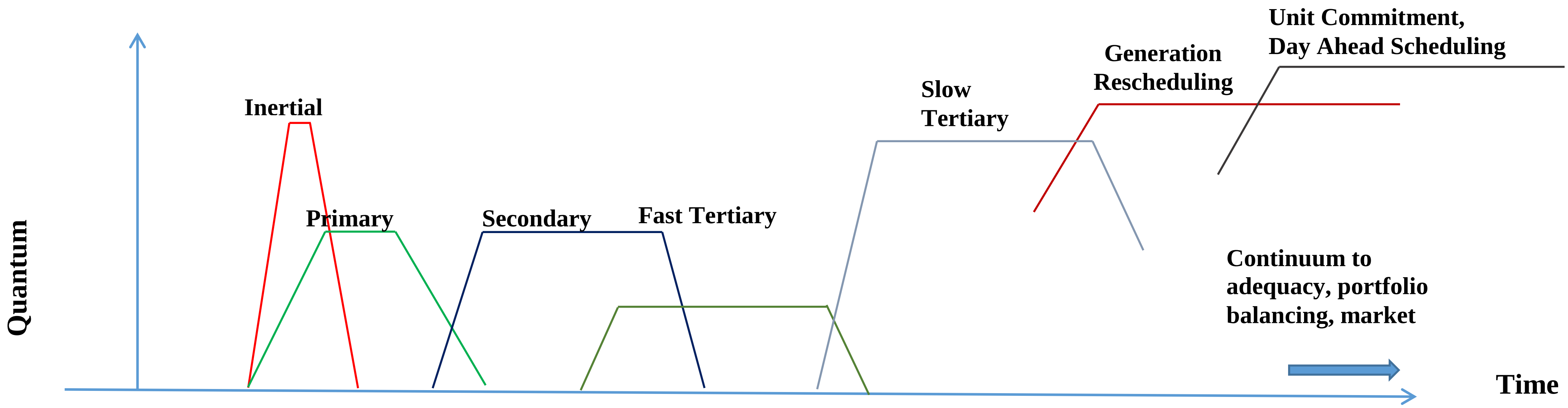
The IEGC could also specify the following additional features in the IEGC as far as frequency control is concerned:

- Reference contingency for primary response: 4000 MW UMPP outage
- Minimum frequency (nadir value) following the above reference contingency: 49.50 Hz
- Quasi steady state frequency value after primary response following the above contingency: 49.80 Hz

3.9 Measurement & Archival of frequency data

Measurement and archival of frequency at 1 second interval and with 0.001 Hz resolution for at least three (3) points in each geographical region could be mentioned in the IEGC. This should be from the Phasor Measurement Unit (PMU) data so that the measurements are time synchronized. Apart from 1 second frequency data, 10 second frequency and ACE data must also be archived at SLDCs, RLDCs and NLDC. The telemetered data to the Control Centres in respect of tie lines used for calculating ACE should have a refresh rate of ten (10) seconds or better for which the required communication facilities should be in place.

4 Schematic of Reserves, Balancing and Frequency Control Continuum in India



Response → Attribute ↓	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling/Market	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC / RLDC	NLDC	NLDC / SLDC	RLDC / SLDC	RLDC / SLDC
Manual / Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	Ancillary Regulations	Ancillary Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Yet to start	Yet to start	Existing	Existing	Existing

Based on the above schematic for frequency control, the system operation in terms of frequency control would be as indicated in Fig 14 below:

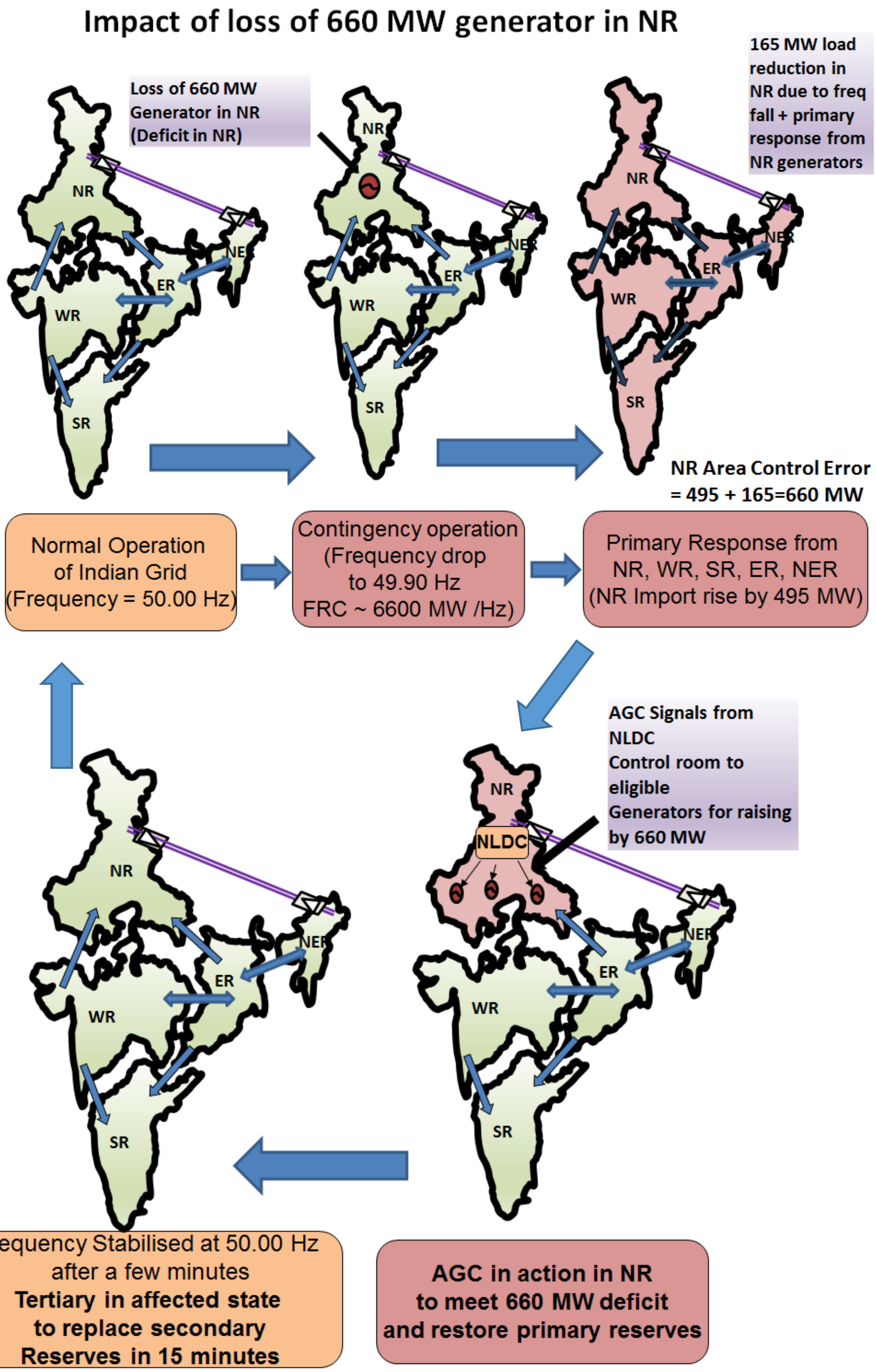


Figure 14: Frequency Control in Indian grid following a 660 MW generation loss in NR

5 Review of inertia monitoring situation in India and world wide

5.1 Following the trip of a generator, the kinetic energy extracted from the rotating mass provides the required power (through rate of change of kinetic energy) to arrest the rate of change of frequency in the system. This is due to the action of Newton's first law of motion and is termed as Inertial response. Inertial response describes the power supplied from the kinetic energy stored in the rotating mass of both generators and motors synchronized to the grid. This consumption of kinetic energy causes the speed of the rotating equipment to decline thereby further reducing the grid frequency. During the initial seconds of the disturbance, the governors do not respond until the frequency decline is detected (both due to measurement delay and due to set dead bands in the governor control loop) and processed in various elements in the governor and prime mover. As the frequency decreases, induction motors slow down and provide some amount of load damping.

5.2 Higher inertia means more kinetic energy and more time for the controls to react to the power deficit and begin restoration of the frequency before the grid frequency hits the under frequency load shed threshold. This high inertia will provide time for the mechanical controls of the plant like governor dead band, main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines to move and provide primary response. During this time delay before the governor response begins, the inertia converted into power limits the rate of change of frequency.

5.3 With higher renewable energy integration in the future, natural directly connected rotating inertia (primarily coal fired thermal generators) will decrease. There is an existing technology to provide synthetic inertia or fast frequency response. The expectation from synthetic inertial response is mainly to minimize the frequency nadir following a disturbance and decrease the rate of change of frequency decline. Hydro Quebec requires that a wind power plant must have an inertia emulation system that acts on major frequency deviations with a performance at least as much as does the inertial response of a conventional synchronous generator whose inertia constant (H) is approximately 3.5 s. Hydro-Québec is revising its synthetic inertia requirement to minimize the risk of a double-dip. A double dip occurs when a wind turbine, after providing kinetic energy immediately after a disturbance, acts as a load on the system to recover its kinetic energy. It plans to limit power reduction during recovery to no more than 20 percent of a wind turbine's capacity. The technology is available but not mandated by many grid codes. For the first time ever, the National Grid has successfully measured and monitored continuous grid stability across an entire network, in a move that could enable renewable energy penetration in the UK. https://www.edie.net/news/8/National-Grid-measures-real-time-system-inertia-for-the-first-time--/

5.4 The 2016 NERC Long Term Reliability Assessment Report also covers the issue of inertia over different time frames. ERCOT Texas monitors the same on a dashboard in the Control Centre in real time. Fig 15 indicates the same. Fig 16 indicates the hour wise analysis to highlight the time when inertia could be a constraint.

Figure 15: ERCOT dashboard to monitor the real time inertia

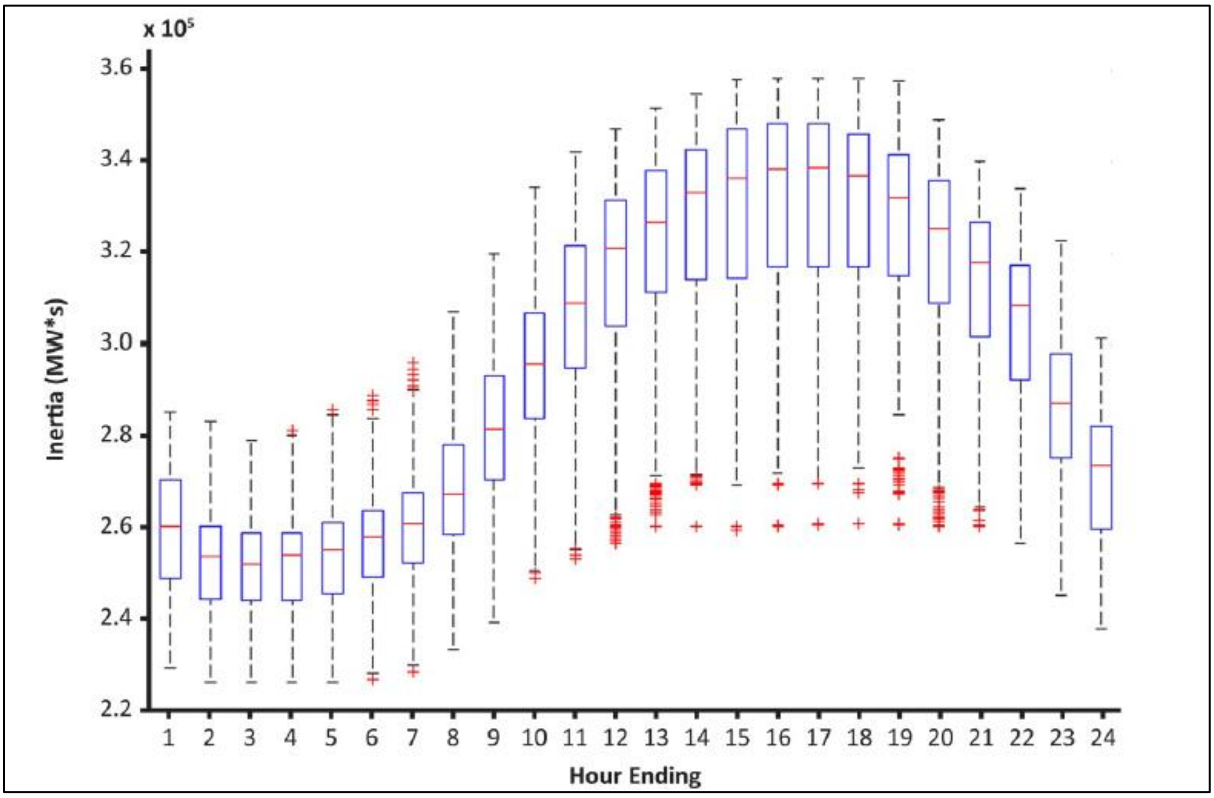


Figure 16: ERCOT inertia by the hour from 1st June to 15th July 2016

5.5 Primary frequency response from renewable energy generators is incorporated in CEA draft standards for connectivity to the grid in respect of Renewable Energy (RE) generators to improve the frequency following a disturbance. Synthetic Inertia or fast frequency response term must be defined and incorporated suitably in the Grid Standards considering the anticipated penetration of renewables to arrest the rate of change of frequency decline. The matter is also important considering that many of the conventional generating units which have crossed 25 years would also be retired over the next few years. These older machines have a much higher inertia of the order of 4 MW-seconds/MVA as compared to the newer units which have inertia of the order of 2.5-3.0 MW-seconds/MVA only. Article 39 of the draft EU Regulation also recognizes the importance of inertia and mandates TSOs to study this aspect within two years of notification of the EU Regulation and indicate whether minimum inertia needs to be specified in the Regulations.

5.6 Various other literature also such as the IEEE Technical Report on Measurement, Monitoring and Reliability issues related to primary frequency response also highlight the importance of inertia and the 'nadir' frequency (the instantaneous frequency drop following a contingency).

5.7 **Considering the importance of the inertia aspect, more so in the coming days with high RE penetration, the Expert Group recommends that POSOCO may also start monitoring the inertia on a real time basis using typical inertia values of machines to start with followed by more technological solutions. Subsequently, if required, the stipulations regarding minimum inertia could also be specified in the Grid Codes/CEA Standards besides provision of synthetic inertia from RE resources**

6 Review of primary frequency response

The Frequency Response Characteristics (FRC) of the All India grid is worked out as

FRC = (MW Generation lost or load lost)/(Change in frequency in Hz) with units of MW/Hz. The FRC value is typically arrived at through recording numerous incidents in the grid. For recording the change in frequency, typically points A and C are used as shown in Fig 17 below.

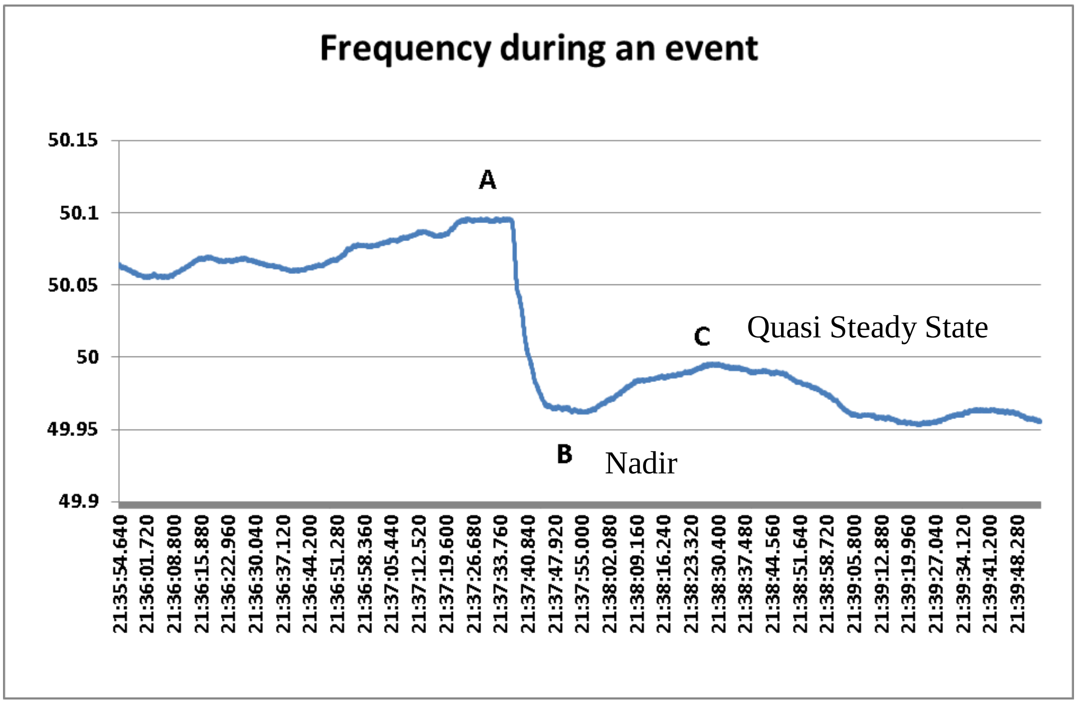


Figure 17: Frequency drop and recovery following a generation loss in the system

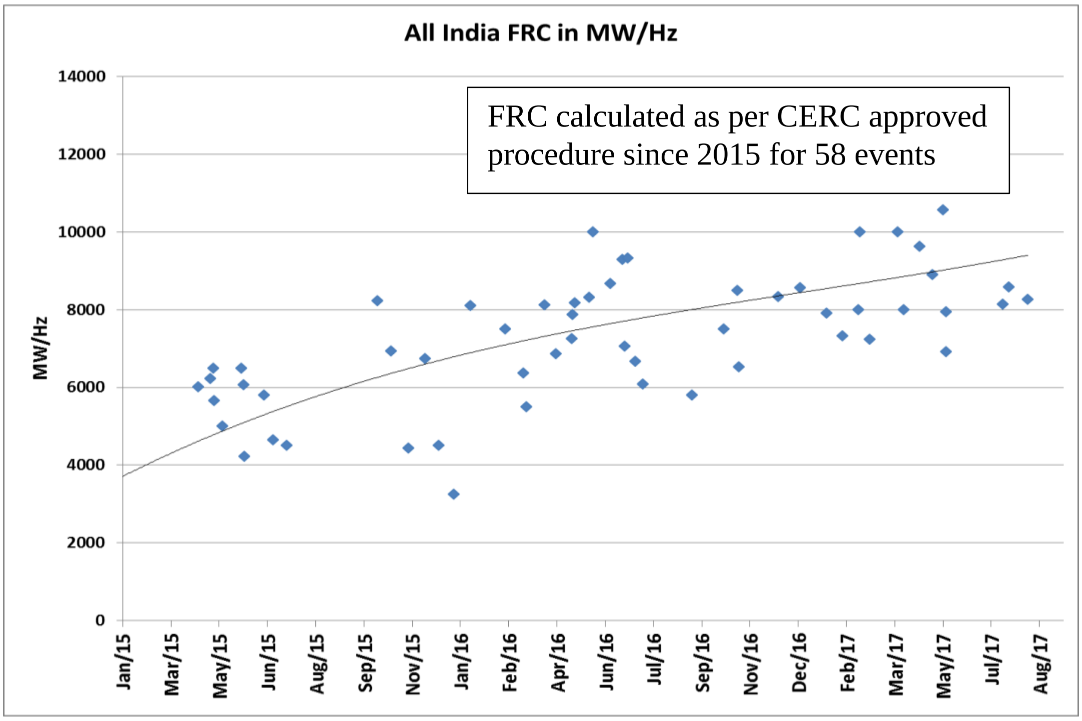


Figure 18: Frequency Response Characteristics (FRC) captured for 58 events (2015-17)

Typical All India FRC at present is of the order of 9000 MW/Hz as indicated in Fig 18 above. The detailed list of FRC calculated since 2015 is attached as **Annexe VII**. The above FRC is available through a mix of load response (typically 4% per Hz) and generator response through governor action. Fig 19 indicates the frequency drop for a similar 1000 MW unit outage in Jan 2015 and Feb 2017; it indicates some improvement in primary response. It has been stated in the CERC order dated 13th Oct 2015 that there should be enough primary response to withstand the loss of 4000 MW generation from a UMPP; one issue that is not explicitly defined is the quasi steady state frequency drop for such an event viz. point C in the above graph.

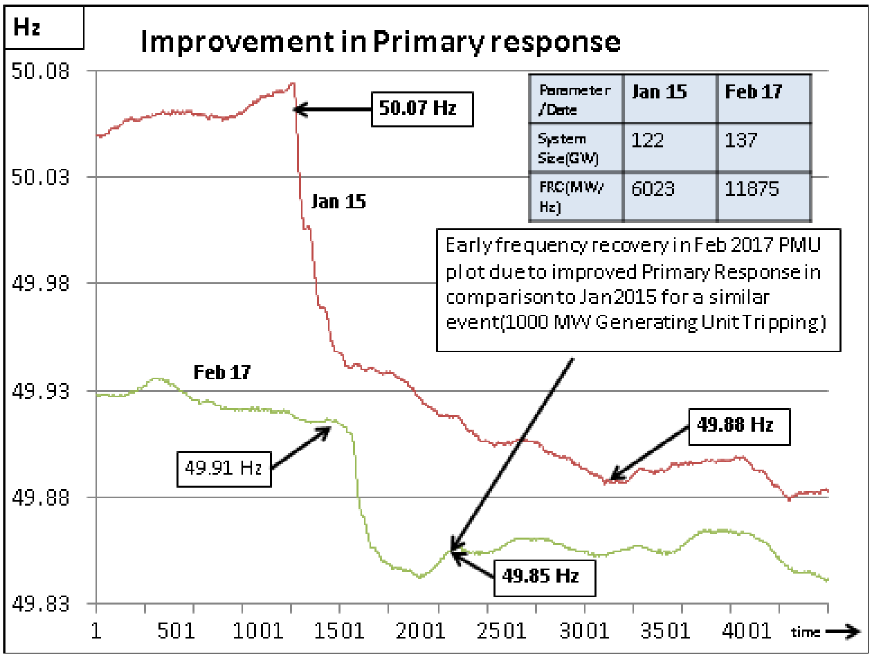


Figure 19: Impact of a 1000 MW unit outage in Jan 2015 and Feb 2017

As indicated in Chapter 4 earlier, inertia is going to be a concern in the coming days. The nadir frequency becomes important. As suggested in several literature, the All India FRC has also been computed using 'nadir' frequency and the same is highlighted in Fig 20 below.

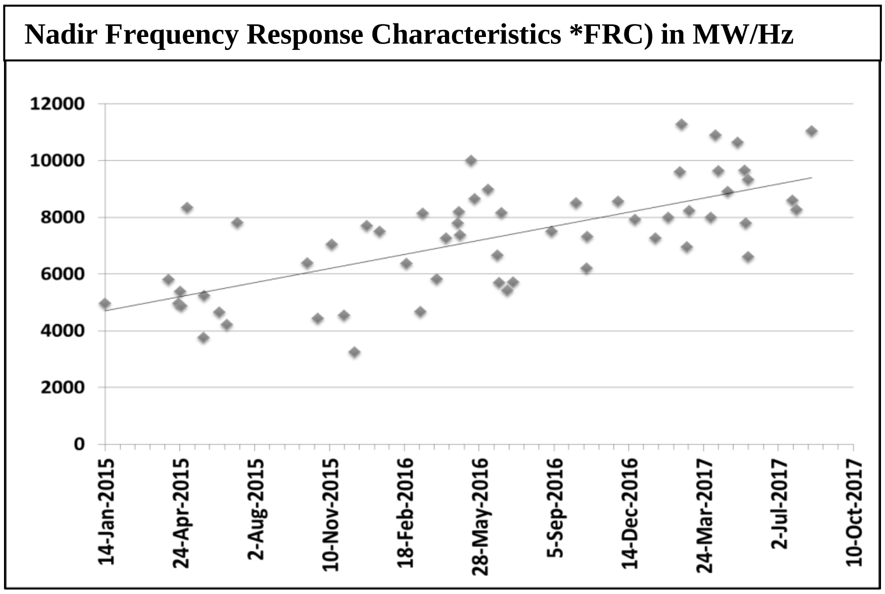
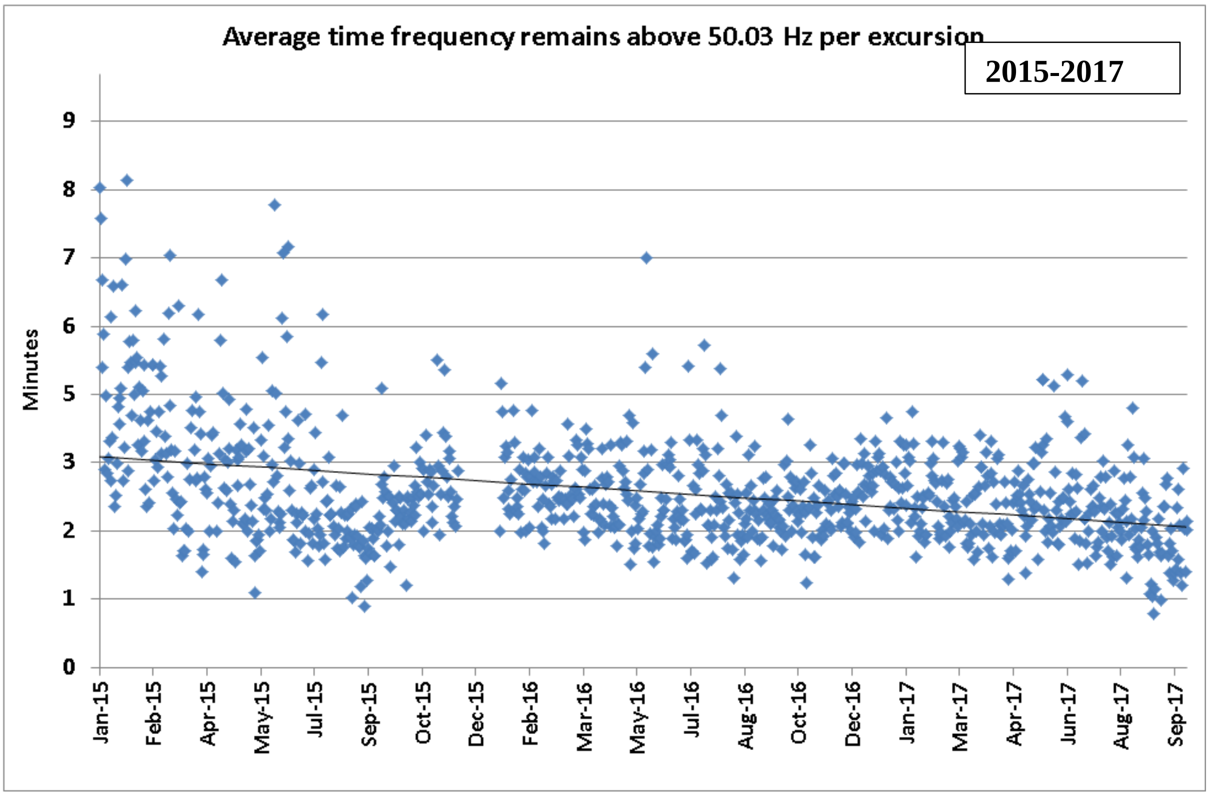


Figure 20: Nadir FRC for 58 events (2015-2017)

The frequency excursion statistics given below show that once the frequency crosses the 49.97-50.03 Hz range, it comes back to this range within 2 to 3 minutes (Fig 21 below) implying that the change in generation due to primary response is required for only 2-3 minutes. These excursions outside the above band happen 140-150 times in a single day (Fig 22 below).



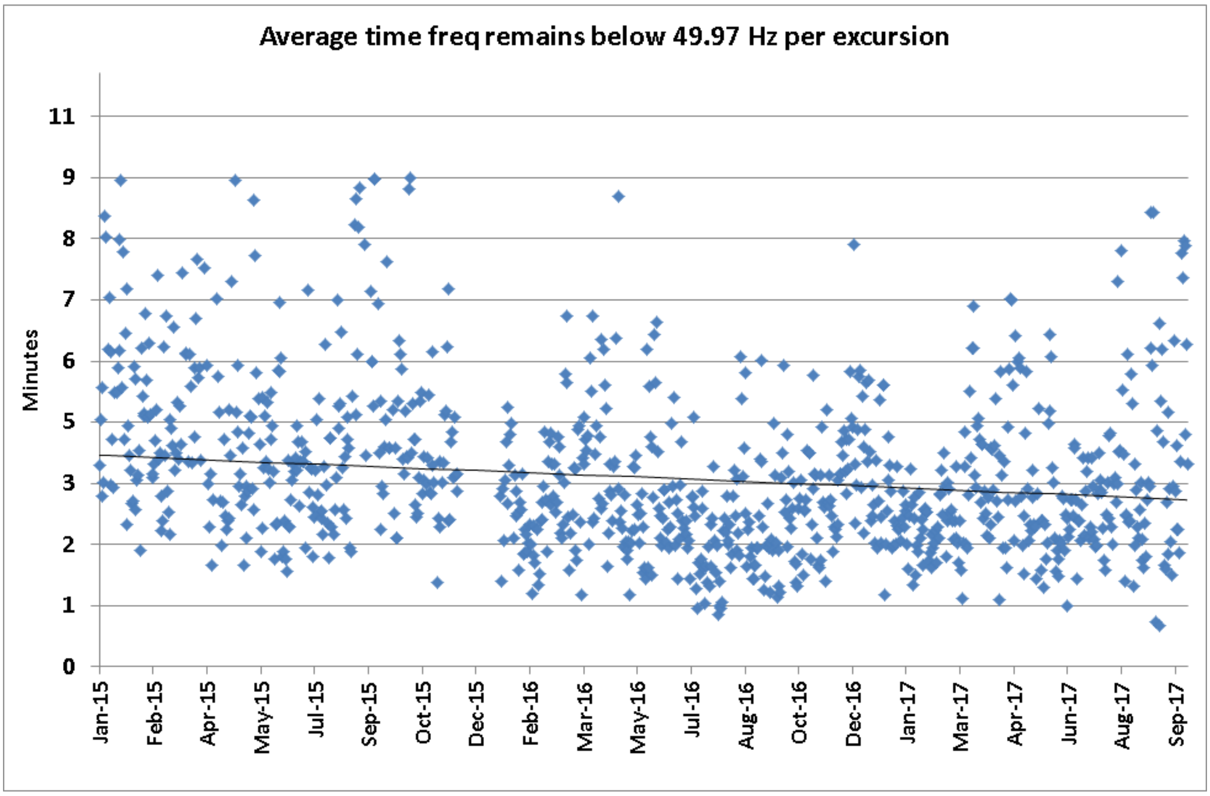
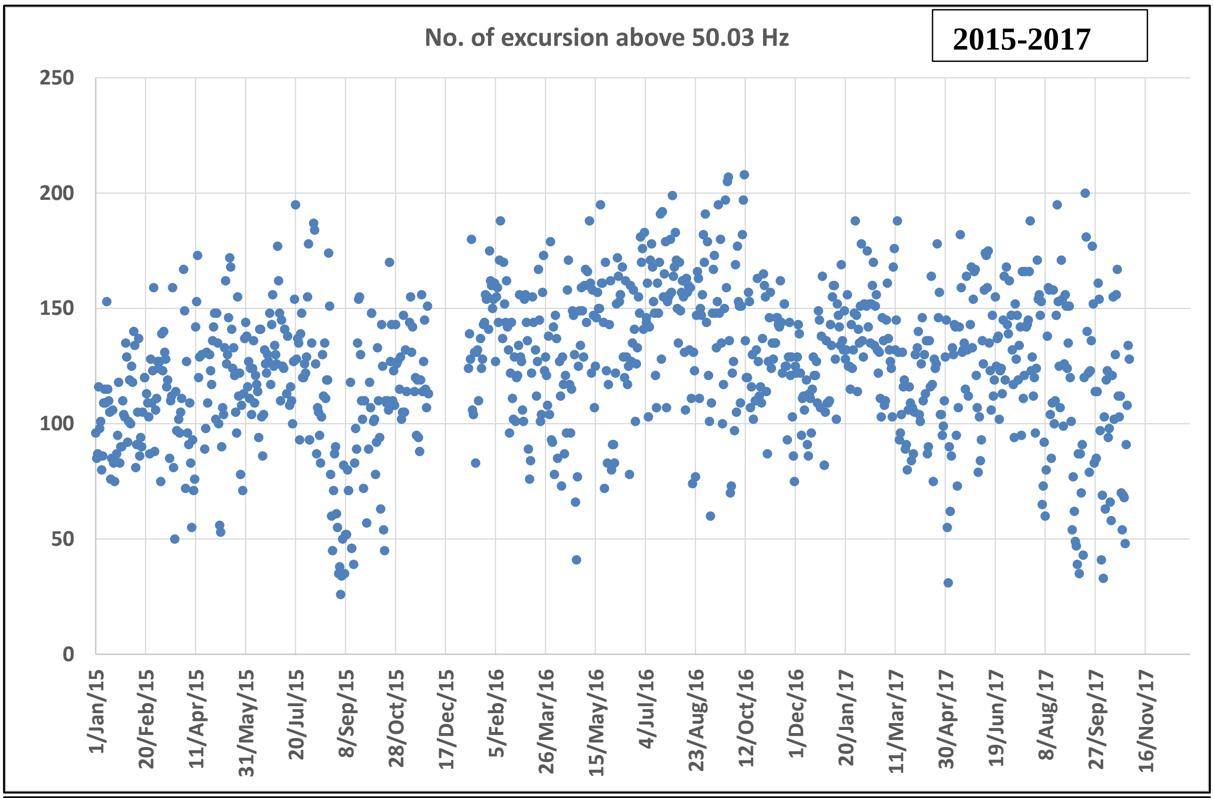


Figure 21: Average time frequency remains outside 49.97-50.03 Hz band da

2015-2017



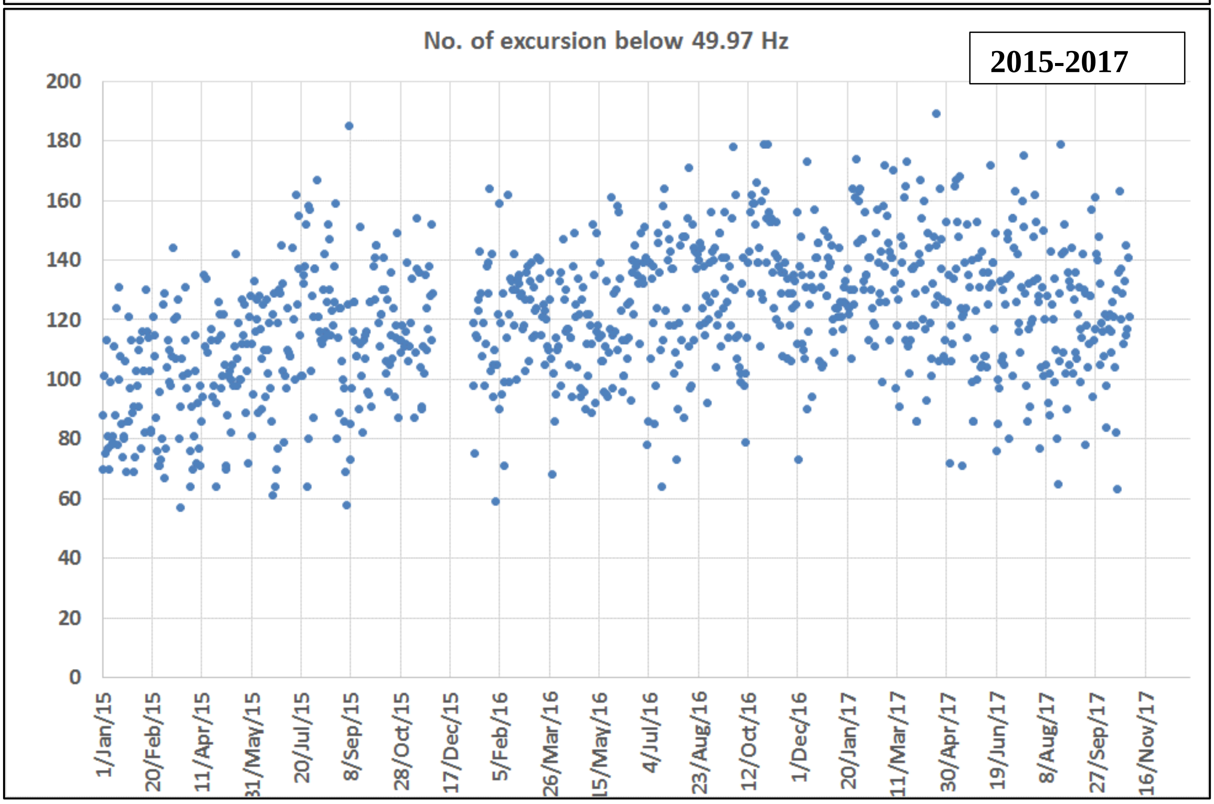


Figure 22: No of excursions below 49.97 Hz and above 50.03 Hz

6.1 Ideal response and worldwide trend

For Continental Europe, the plausible contingency is a 3000 MW generation loss and the quasi steady state frequency drop on this account (point C in the above graph) is defined as 0.2 Hz. 15000 MW/Hz is the minimum value for generator primary response.

Suppose we assume for India point C is 49.8 Hz or 0.2 Hz drop for a 4000 MW generation loss, then the Frequency Response Characteristics (FRC) would be 4000/0.2 Hz or 20,000 MW/Hz, which is the ideal response. Now, out of this 5600 MW/Hz would come from load response (4% per Hz and 140000 MW system size assumptions) and the balance 14,400 MW /Hz ideally should come from generators. So if the All India FRC is 20,000 MW/Hz, then the frequency would stabilize at 49.8 Hz after a 4000 MW generation loss and the load would provide a response of 1120 MW (0.04*0.2*140000) and the generators would provide a response of 2880 MW; so the loss of 4000 MW gets balanced accordingly. Note that frequency would always be less than 50.0 Hz due to governor droop, only secondary control can bring it to 50 Hz.

Similarly, for the US system also, the target FRC is worked out considering contingency and the first level of UFLS setting viz 59.5 Hz. Though this gives a lower target FRC, from the interaction with PJM counterparts as a part of the Expert group deliberations, it was understood that these are minimum levels and they are constantly above the requirement. The actual primary response available is much higher than the target (2.5 to 3 times) as per NERC Reliability Standard as evident from an event in the Western Interconnection, US (Fig 18) which is comparable to the Indian system size.

Considering that the Indian grid is expanding and we have more and more of power stations of 4000 MW capacity (which have a history of station blackouts); secondary control is yet to be implemented, increasing RE penetration leading to less inertia; there is a need to go for a penalty on the defaulting generators mandated for primary response in the event of less overall FRC response from the generators.

Further, Regulation 5.2 (g) of Part 5 of the IEGC states as under:

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

It is suggested that the test procedures finalized by RLDCs should indicate the response time such as 30 seconds for full response and 49.8 Hz for full response (on the lines of EU Regulation) for an objective assessment of compliance by generators.

6.2 Suggested penalty for non-performance of generators

Expert Group suggests that CERC mandates as below:

If the response by generators is less than 40% of the ideal response, there must be heavy penalties imposed on the generators. The ideal response by generator would be the response considering generator droop of 5% which would mean 40% of unit rating change for every 1 Hz change in frequency.

There is an existing penalty for non-performance in RGMO in CERC Terms and Conditions of Tariff,2014.

" the rate of return of a new project shall be reduced by 1% for such period as may be decided by the Commission, if the generating station or transmission system is found to be declared under commercial operation without commissioning of any of the Restricted Governor Mode Operation (RGMO)/ Free Governor Mode Operation (FGMO), data telemetry, communication system up to load dispatch centre or protection system:
as and when any of the above requirements are found lacking in a generating station based on the report submitted by the respective RLDC, RoE shall be reduced by 1% for the period for which the deficiency continues "

6.3 Telemetry issues in FRC computation

Expert Group also realises that telemetry of tie lines should be accurate for calculation of FRC. Refresh rate of the data of the tie lines has to be modified and checked accordingly. Expert Group also understands that for the same data, assessment of FRC would be different based on the choice of point C. The variation is suggested to be handled statistically.

6.4 Suggestion on RGMO

The Expert Group recommends to gradually phase out the RGMO by 1st April 2018 and instead have speed control with droop.

6.5 Review of governor dead band

The 'ripple filter' word was introduced in the May 2010 IEGC. Expert Group suggests that the confusion on governor dead band may be removed by deleting the ripple filter term. Considering that the trend worldwide is to gradually reduce the dead band (inherent plus intentional; Continental Europe specifies it as +/-0.01 Hz), the IEGC could also give a road map for reducing the governor dead band.

7 Review of secondary frequency control

Importance of spinning reserves in the system operation was reiterated by the Commission in several documents and orders, including the last order dated 13th October 2015 on Roadmap to Operationalise Spinning Reserves and the Report of the Committee on Spinning Reserves. This roadmap is consistent with the practices worldwide though the quantum of reserves indicated in the road map could be a starting point and subject to review based on the experience.

Secondary control is the control area wise automatic control which delivers reserve power in order to bring back the frequency and the area interchange programs to their target values. In doing so, the delivered primary control reserves are restored on those machines which have contributed to primary response.

7.1 AGC Pilot project

Members of the Expert Group reviewed the results of the Automatic Generation Control (AGC) pilot project and the mock test. The proposed AGC pilot project is to be operated from NLDC along with the required hardware and software installed at NLDC and NTPC Dadri Stage II. The AGC software was integrated with the existing SCADA system at NLDC and data exchange is taking place accordingly. The modelling of generating station/units with the static and dynamic data was configured along with the desired real-time data in the proposed AGC software.

Secondary control of different control areas viz. five regions in India was proposed for operation from NLDC, considering the future EMS upgradation project at NLDC. During the course of interaction with the vendors, it was observed that that this type of philosophy (5 AGCs located at a single control centre) is almost a first of its kind of experience for all the major vendors. Also, fibre optic communication from the nearest existing communication hub till the Generating Plant to be under AGC was identified as one of the costliest components of the full scale AGC Project. For two way communication, IEC 104 protocol was used. Cyber Security was ensured through appropriate router configurations, firewalls and antivirus software.

A mock test was successfully conducted on 29th June 2017 and it yielded desired results. Results of the mock test and implemented philosophy of the pilot project at NTPC Dadri Stg-II are given in Fig 23 below. The actual generation follows closely the Unit Load Set Point (ULSP) before the mock test. The actual generation follows the AGC set point during the mock test. Petition no. 79/RC/2017 has been filed in this matter by POSOCO with the Commission with the objective of operationalizing AGC control at Dadri Stage-II units on an ongoing basis.

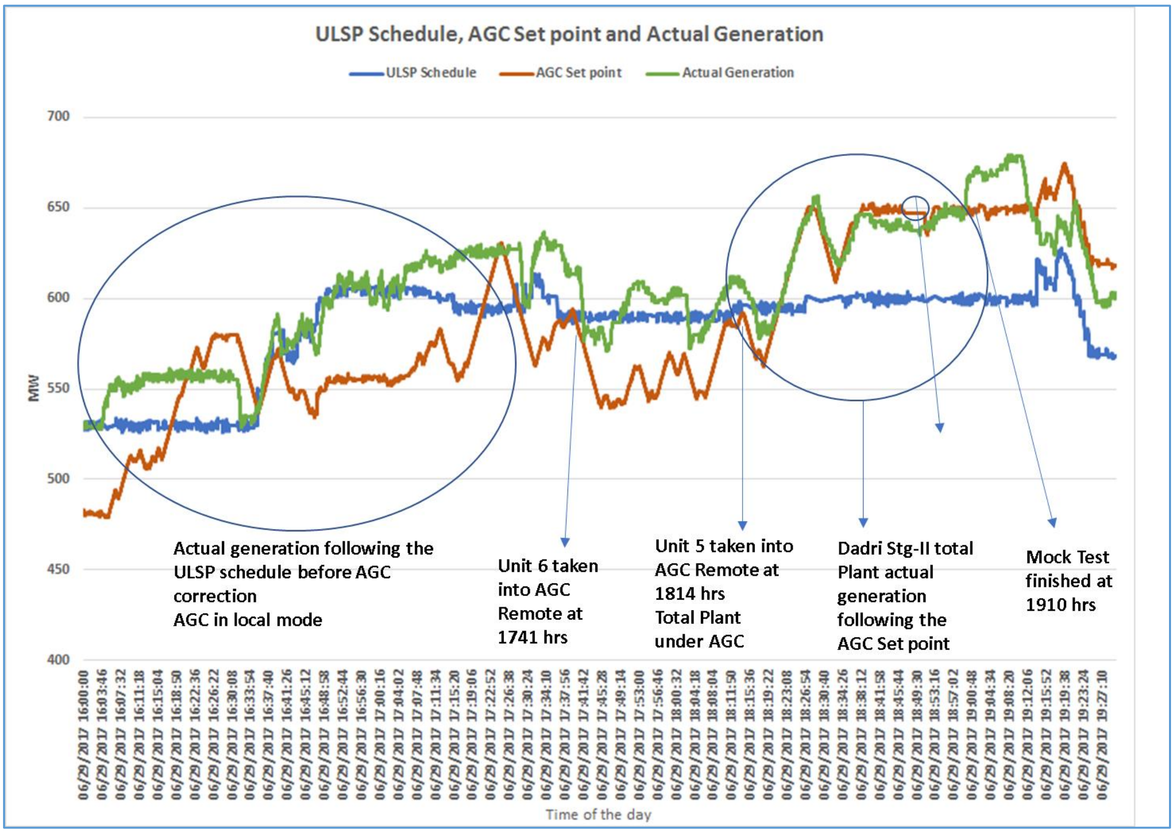


Figure 23: Mock trial of Dadri Stage-II receiving AGC signals from NLDC

The performance of the Dadri Stage-II plants under AGC would be closely monitored so that performance metrics for AGC mileage payments can be worked out.

7.2 *AGC Pilot for Hydro already under consideration by KPCL*

While the secondary control is presently envisaged considering each geographical Region as a Balancing Area and only generators under RLDC jurisdiction covered for the time being to receive AGC signals, the Expert Group feels that there should be no bar in large states also going for secondary control at a later date as and when ordered by the Appropriate Electricity Regulatory Commission. It is understood that under the Greening the Grid (GtG) of USAID, a pilot project for AGC is already being considered for some of the hydro units of KPCL in Karnataka. The Expert Group welcomes these initiatives at the state level.

7.3 AGC for Solar / Wind

Considering the excellent controllability of power electronic devices and the low cost of the Automatic Generation control (AGC) setup, Renewable Energy (RE) resources like wind and solar need to be equipped for AGC. This would be useful for regulation in cases of extreme dispatch scenarios when we run out of secondary reserves and/or emergencies if RE is to be curtailed. Load forecast, Area Control Error (ACE) and Renewable forecast can be together used for deciding the participation of renewables under AGC for a particular time of the day. In the normal operation, the renewables would be dispatched fully. However, in cases of either a network congestion or when the entire coal fired generation is down to the technical minimum generation levels (currently 55%), it might be desirable to curtail RE through down regulation which can be done quickly through AGC signals. This process would also bring in transparency in RE curtailment. Regarding utilizing solar and wind generators for upward regulation, it needs further deliberation with regards to capacity overloading vis-à-vis capacity declared in the Power Purchase Agreement.

The debate on high RE penetration and controllability has started worldwide. Prof. Vijay Vittal has expressed ideas about zero inertia power systems in his blog.
https://www.uvig.org/zero-inertia-power-systems/.
Wind has issues of stress on drive trains and has to be checked through simulations.
http://www.nrel.gov/docs/fy13osti/57820.pdf

On the issue of compensation for such secondary control, the matter would have to be decided by CERC along with suitable provisions in the Power Purchase Agreements.

The Expert Group is of the view that these developments worldwide and the ramping up of RE generation makes it necessary that pilots are undertaken on AGC for wind/solar by NLDC/RLDCs/SLDC at the earliest.

7.4 Suggested modus operandi to operationalise secondary reserves in the country

The Hon'ble Commission directed NLDC/POSOCO to submit a detailed procedure to operationalize reserves in the country vide order dated 13th Oct 2015. This procedure has since been submitted to the Commission and is also available at https://posoco.in/spinning-reserves/ .

The SCADA/EMS upgradation project at NLDC has also been awarded and AGC has also been specified in this project. The Expert Group recommends the detailed modus operandi to operationalise reserves in the country submitted by POSOCO may be examined by the Commission at the earliest and orders passed so that rollout of AGC in the country commences at the earliest.

8 Review of tertiary frequency control and Control Area Performance

Ancillary Services has been implemented with effect from April 2016. In accordance with the directions of the Commission, feedback has been submitted by POSOCO on 17th November, 2016 regarding the experience gained in the operation of Ancillary Services. Further, a feedback on implementation of secondary control through Automatic Generation Control (AGC) pan India and maintenance of reserves was submitted on 14th July, 2017. Some of the issues flagged in the feedback were subsequently addressed in the revised "Detailed Procedures" for Ancillary Services approved by CERC in November, 2016. Subsequently, multiple rounds of discussions were held with the staff of the Hon'ble Commission and it emerged that there is a need for expanding the ambit of ancillary services & introduction of new services.

In this context, a Concept Note for expanding the ambit of ancillary services and introduction of new services is submitted for kind perusal of Hon'ble Commission. Same is attached as **Annexe-VIII**. The Concept Note provides a broad framework for implementation of the additional ancillary services such as Fast Response Ancillary Services (FRAS) from hydro generating stations, and bringing regional entity merchant generators/IPPs under Ancillary Services framework.

8.1 Performance metrics for tertiary control

It is suggested by the Expert Group that some performance metrics may be evolved for validating the performance of generators currently involved in Reserves Regulation Ancillary Services (RRAS) so that the payments could be regulated accordingly.

8.1.1 Control Area Performance

Currently there is no performance metrics for assessing a control area’s performance. There is a sign reversal clause specified in the Deviation Settlement Mechanism (DSM) but there is no commercial mechanism or penalty levied for violation. The Expert Group is of the view that this provision needs strengthening through suitable provisions in the IEGC. The ACE, should cross zero value and change sign at least once every hour to start with which would be narrowed down to half an hour. Persistent violation of this condition would render the utility liable for penalties.

For performance by each control area, RLDCs could also work out the Deviation in MW during Low Frequency/High Frequency (< 49.95 Hz / >50.05 Hz) and the number of blocks for each control area on monthly basis based on energy meter data. That data shall be used to rank the states for performance. The poorly performing states may be penalised as deemed appropriate by the Commission. For instance, the DSM mechanism has provisions that the deviation would not exceed +/-12% of schedule or 150 MW (whichever is lower subject to a minimum of 48 MW). However, while there is a commercial mechanism to handle this deviation in the form of Additional DSM charges, there is a need for classifying the violation. For instance, such violation of the 150 MW level should not exceed, say 10% of the time in a month , to start with, which could be gradually reduced.

The same is indicated in Fig 24 and 25 below for Sep 2017 month for Western Region as a sample.

It would be observed that the states like Gujarat, Chhattisgarh, Maharashtra and MP have exceeded the 150 MW limit for more than 10% of the time. Once the control area performance is monitored and penalised in case of violations, there would be sufficient incentives for the state utilities to put in place a system of primary, secondary and tertiary frequency control within the state and minimize the deviation besides emphasis on reducing load and RE forecast errors.

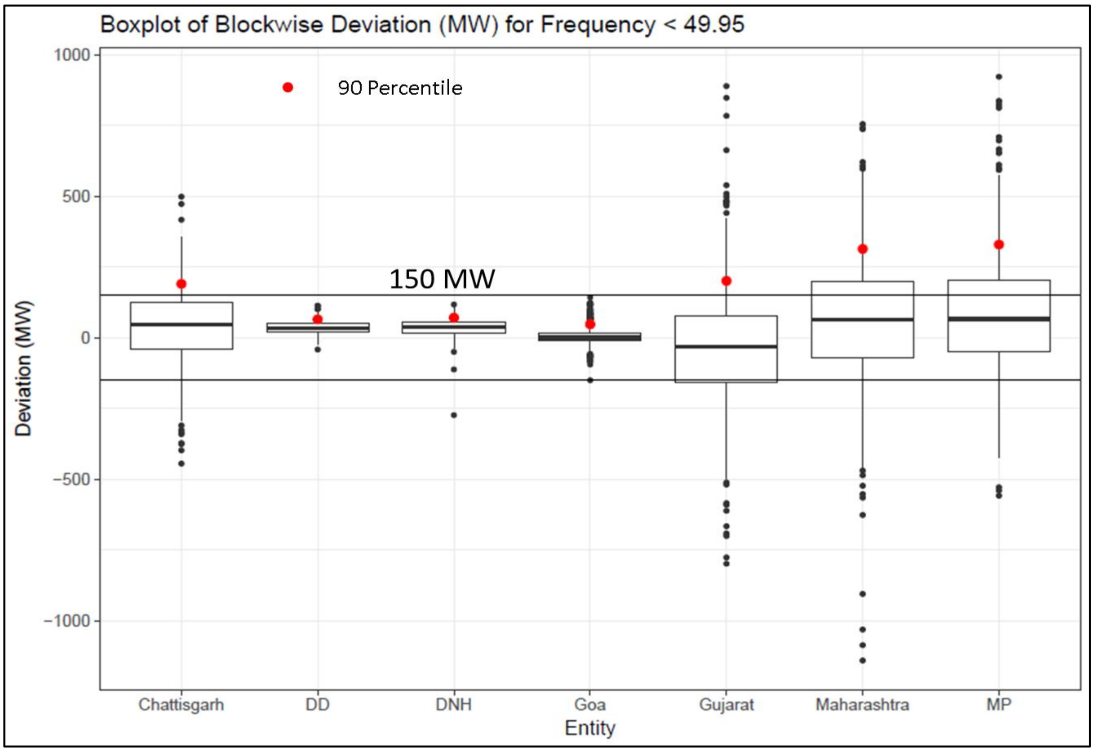


Figure 24 : Deviation from the schedule by WR states in September 2017 below 49.95 Hz

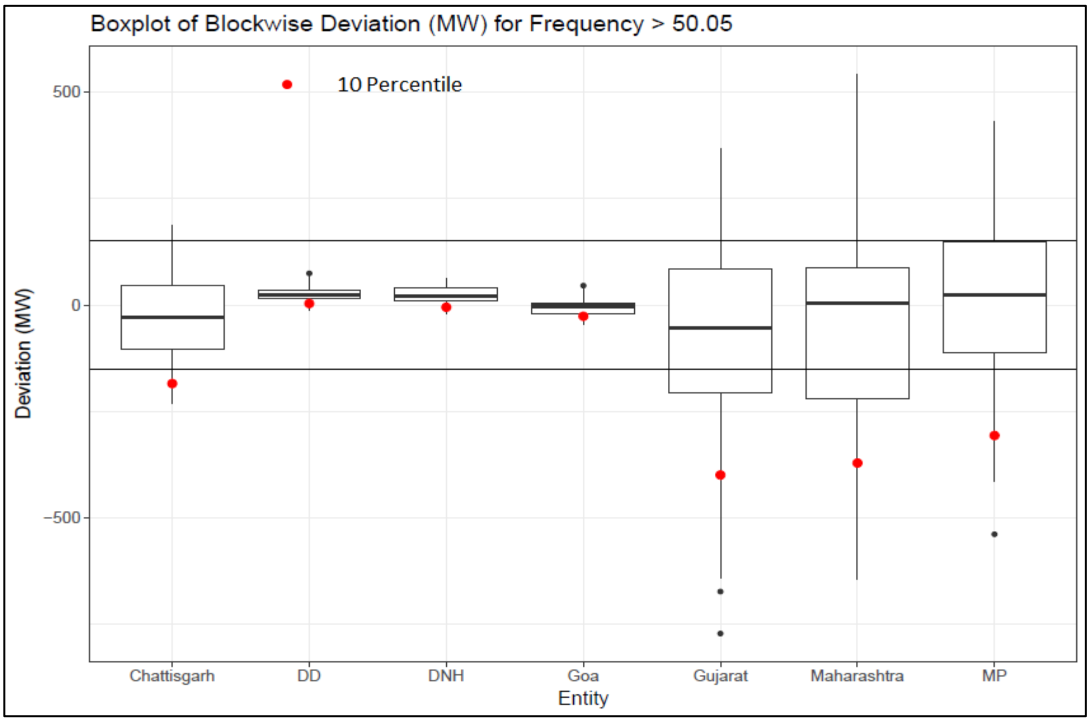


Figure 25: Deviation from the schedule by WR states in September 2017 above 50.05 Hz

8.1.2 Time Error

Apart from the above metrics, the Expert Group feels that the cumulative time error could be worked out on daily basis at the NLDC level. For instance, if frequency runs at 49.9 Hz continuously, a clock running on the electric mains frequency would lose 7.2 seconds every hour. A comparison with world wide trends (Fig 21) show that India has an error on the negative side viz. low frequency leading to slower running of electric clocks as compared to other countries.

Location	Maximum Time Error (Run Fast, Seconds)	Minimum Time Error (Run Slow, Seconds)	Average Time Error (Seconds)
USA, Seattle	+11.14	−09.58	+00.16
USA, Matton	+18.38	−08.05	+00.78
Sweden, Stockholm	+20.52	−12.11	+02.97
USA, San Angelo	+07.15	−05.68	+00.58
Brazil, Itajubá	+80.39	−00.00	+43.02
Japan, Karuizawa	+07.59	−06.75	+00.04
UK, Sheffield	+16.72	−16.10	+03.34
Denmark, Aalborg	+17.88	−10.81	+01.07
China, Shanghai	+333.94	−00.00	+180.70
Australia, Brisbane	+04.43	−05.16	+00.08
India, Kanpur	+00.00	−144.76	−69.83
Latvia, Riga	+02.17	−35.85	−17.37

Fig 21: Yao Zhang et al: Statistical analysis of monthly time error around the world

9 Conclusions and Recommendations

Based on the above, the Expert Group recommends the following with a view to achieving better frequency control in India and prepare for the challenging times ahead.

1) **Frequency Control as a continuum in terms of time horizon**
Frequency Control in any power system is basically a continuum starting from seconds to a time period of less than an hour. Beyond this time horizon, the problem is basically one of forecasting, unit commitment, scheduling and despatch. Large imperfections in this area would lead to off-nominal frequency or a large quantum of generation reserves requirement which may be suboptimal. **It is therefore recommended that the frequency control continuum chart as given in this report be adopted and included as part of the Indian Electricity Grid Code (IEGC) through an amendment for addendum.**

2) **Reference frequency for the purpose of control**
Any control system would need a reference value; in case of frequency control, it would be the target frequency or reference frequency. For the Indian system, the same has to be the nominal frequency of 50.0 Hz. **It is therefore recommended that the reference frequency for the purpose of frequency control is considered as 50.0 Hz, and the same is notified in the IEGC.**

3) **Monitoring inertia of the system and inertial response**
The Expert Group recognizes that interconnection of regional grids and formation of an All India electricity grid with 160 GW peak demand has substantially reduced frequency

fluctuations in view of large inertia in the system. However, the inertia would gradually reduce in the coming days with increase in static silicon loads, reduction in rotating mass of conventional machines due to higher penetration of wind and solar generation in the system. With 175 GW RE targeted by 2022, the instantaneous penetration of RE in MW could touch as high as 54%, where inertia would be an issue. This would have an impact on the frequency fall immediately following a large contingency (inertial response) and before primary response effect comes into play. **It is therefore recommended that as a first step, inertia of the system be monitored at the regional and All India level in real time so that a baseline is established and monitored for low net load periods. Simulation studies may also be carried out to assess the inertia and any adverse impact on stability due to low inertia. There is a need for suitable provisions for stipulating minimum inertia in Standards and Code in near future besides provision of synthetic inertia from RE resources**

4) **Primary control**
Primary control from generating units is mandated as per the Indian Electricity Grid Code (IEGC). However, the IEGC has an historical variant of primary control in the form of Restricted Governor Mode of Operation (RGMO). **The Expert Group recommends that RGMO may be phased by 1st April 2018 and replaced with 'speed control with droop'**. **Further, the dead band of +/-0.03 Hz(ripple factor in IEGC) may be gradually phased out as is being done in ERCOT Texas and Europe. This could be a voluntary approach initially. The Expert Group also recommends that the Central Electricity Authority (CEA) may notify the Technical Standards for connectivity to the grid in respect of RE generation at the earliest mandating primary control from RE resources also. Primary control testing would also be done periodically in line with provisions of IEGC for which the performance metrics would be defined in the test procedures by CERC.**

5) **Additional parameters to be notified in IEGC**
Apart from the reference frequency, the Expert Group recommends that the IEGC should also notify the following values:

a. **Frequency band permissible: 49.90-50.05 Hz currently, which would be further tightened to 49.95-50.05 Hz by 2020 when secondary and tertiary reserves would be operationalized in substantial quantum both at the inter-state and intra-state level.**
b. **Reference contingency for primary response: 4000 MW UMPP outage**
c. **Minimum frequency (nadir value) following the above reference contingency: 49.50 Hz**
d. **Quasi steady state frequency value after primary response following the above contingency: 49.80 Hz**

The IEGC would also specify the standards for frequency recording and archival at RLDCs/NLDC level for the purpose of further analysis as mentioned in this report.

6) **Frequency Response Characteristics (FRC)**
The Expert Group has noted that the RLDCs and NLDC are computing the Frequency Response Characteristics (FRC) of each control area, region and All India basis. There has been a gradual improvement in FRC from 6000 MW/Hz to 9000 MW/Hz over the last two years. Even then this is much lower compared to systems like the Western Interconnection in US (comparable to India in terms of system size) which have recorded

FRC of the order of 20000 MW/Hz despite lower obligation as per BAL-003-1 NERC Reliability Standard. **The Expert group recommends as under:**

a. **RLDCs/NLDC would continue to compute FRC as being done presently. However, the same would also be worked out additionally for All India and region at the 'nadir' frequency (details in the report) so that the impact of inertia can be tracked as indicated in S no 3.**
b. **While no target FRC is required to be prescribed now, the control area wise FRC and percentage of ideal response would be tracked for each event. A minimum response expected is at least 40% of ideal response (based on international experience). Any violation would be reported to the CERC for levy of penalty.**

7) **Roadmap for operationalizing reserves**
The Expert Group recommends that the roadmap for operationalizing reserves notified by the CERC vide order dated 13th October 2015 be implemented at the earliest so that secondary and tertiary reserves as stated in the order are available for frequency control.

8) **Secondary Control through Automatic Generation Control (AGC)**

As directed by the Commission, POSOCO has already submitted a detailed procedure for implementing secondary control throughout the country through Automatic Generation Control (AGC). A pilot project on AGC with NTPC Dadri Stage-II has been implemented which would be put into operation after approval of the Commission. **The Expert Group recommends that AGC must be implemented throughout the country at the earliest in line with the Commission's recommendation of treating a region as a balancing area. Performance Metrics for such AGC payments may be introduced once sufficient experience is gained through the pilot project. AGC at the intra state level, particularly for large states, can be implemented in line with directions by the Appropriate Commission(s).**

9) **Slow tertiary control through Reserves Regulation Ancillary Service (RRAS)**
Slow tertiary control through Ancillary Services has been implemented pan India since April 2016. **The Expert Group recommends the following:**

a. **Expanding the ambit of RRAS at the inter-state level and refinements based on experience so far.**
b. **Introduction of Performance Metrics for mark-up payments for the slow tertiary Ancillary Services.**
c. **Introduction of slow tertiary Ancillary Services at the intra-state level through regulations by Appropriate Commission. This would necessitate implementing the Scheduling, Accounting, Metering and Settlement of Transactions (SAMAST) at the intra state level.**

10) **Fast tertiary control at the Inter State level**
The slow tertiary RRAS at the interstate level leads to a situation where the impact is felt only after 20-30 minutes. The hydro power stations have not been utilized for RRAS so far. **The Expert Group recommends that fast tertiary services through RRAS using hydro could be introduced suitably at the interstate level to start with.**

11) **Monitoring of Area Control Error (ACE)**

It is expected that with all the above steps in place, frequency is expected to be within the IEGC mandated band for nearly 100% of the time. Nevertheless, as stated earlier, for a time horizon beyond one hour, forecasting and scheduling becomes important and any large scale errors here can impact frequency control. Hence monitoring each state control area performance is also important. **The Expert Group recommends as under:**

a. **Each state control area, region and the neighbouring countries would work out the Area Control Error (ACE), display, monitor and archive the same. For the purpose of ACE calculation, the bias could be set as 4% of Area load per Hz which can be refined over time. The inter-state and inter-regional tie line values as well as frequency measurements should be treated as Class A telemetry values and updated at a faster rate than ten (10) seconds at SLDCs/RLDCs/NLDC.**
b. **The ACE, worked out as above, should cross zero value and change sign at least once every hour to start with which would be narrowed down to half an hour. Persistent violation of this condition would render the utility liable for penalties.**
c. **The 15-minute deviations from the schedule as worked out through Special Energy Meter (SEM) data and schedules would be closely monitored for all time blocks where average frequency is below 49.95 Hz and above 50.05 Hz. On a monthly basis, the 90th percentile value of overdrawals below 49.95 Hz and underdrawals above 50.05 Hz would be monitored. This should not exceed 150 MW. Any violation could render the utility liable for penalties.**

12) **Time Error**

Time error is the difference between the time reported by a synchronous clock, compared to the time reported by a reference synchronous clock. This error signifies the deviation of average frequency from reference frequency. Time error on daily basis (0000-2400 hours) would also be recorded at NLDC level. Standards for cumulative time error would be notified separately by CERC, at an appropriate time based on the experience gained and considering cross border interconnections.

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केन्द्रीय विद्युत विनियामक आयोग
CENTRAL ELECTRICITY REGULATORY COMMISSION

सत्यमेव जयते

के वि वि आयोग
CERC

No. 1/2/2017/Exp.Group/CERC 27th April, 2017

Office Order

Sub: Constitution of the Expert Group to review and suggest measures for bringing power system operative closer to national reference frequency.

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The Commission in its meeting held on 23rd March, 2017 resolve to declare national reference frequency as 50 Hz. The Commission observed that all stakeholders should endeavour to ensure maintenance of this reference frequency. This is required in the larger interest of stability and security of grid operation; for maintaining power quality and as safeguard against frequency fluctuation which can affect electrical devices.

2. The Commission also decided that a high level Expert Group be constituted consisting of representatives from CEA, POSOCO, CTU, and other concerned with the mandate to suggest further steps required to bring power system operation closer to the national reference frequency as resolved above.

3. Accordingly, the Competent Authority has constituted a high power Expert Group consisting of the following members:

i)	Shri A.S.Bakshi, Member, CERC	Chairman
ii)	Member (Power System), CEA	Member
iii)	CEO, POSOCO	Member
iv)	Director Operations Incharge, CTU	Member
v)	Shri S.K. Soonee, Advisor, POSOCO	Member
vi)	Shri S.C. Shrivastava, Chief (Engg.),CERC	Member
vii)	Joint Chief (Regulatory Affairs), CERC	Member-Secretary

4. The Chairman may co-opt any other expert person as Member or as a Special Invitee to assist the Expert Group.

..2/-

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5. The Terms of Reference of the Committee would include the following:

- Review the experience of grid operation in India.
- Review international experience and practices on grid operation including standards/requirement of reference frequency.
- Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid.
- Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities.
- Any other matter related to above.

6. The Expert Group shall submit the report to the Commission within the period of three months.

27/04/17
(Sanoj Kumar Jha)
Secretary

To

1. Shri A.S. Bakshi, Member, CERC, New Delhi.
2. Shri K.K. Arya, Member (PS), Central Electricity Authority, Sewa Bhawan, R.K. Puram, Sector – 1, New Delhi – 110066.
3. Shri K.V.S. Baba, CEO, POSOCO, B-9 (1st Floor), Qutab Institutional Area, Katwaria Sarai, New Delhi -110016.
4. Dr. Subir Sen, Executive Director, Incharge, CTU, PGCIL, Saudamini, Plot No.2, Sector 29, Near IFFCO Chowk, Gurgaon (Haryana) - 122001,
5. Shri S.K. Soonee, Advisor, POSOCO, B-9 (1st Floor), Qutab Institutional Area, Katwaria Sarai, New Delhi -110016.
6. Shri S.C. Shrivastava, Chief (Engg.), CERC, New Delhi.
7. Shri S.K. Chatterjee, Joint Chief (Regulatory Affairs), CERC, New Delhi.

MINUTES OF FIRST MEETING OF "EXPERT GROUP TO REVIEW AND SUGGEST MEASURES FOR BRINGING POWER SYSTEM OPERATIVE CLOSER TO NATIONAL REFERENCE FREQUENCY"

Venue	:	3rd Floor Conference Hall, CERC, New Delhi - 110001
Date	:	09-05-2017
List of Participants	:	At **Annexure –I(enclosed)**

The First meeting of Expert Group to review and suggest measures for bringing power system operative closer to national reference frequency was held under the Chairpersonship of Shri A.S. Bakshi, Member, CERC on 9thMay 2017.Shri A.S. Bakshi, Member, CERC, extended a warm welcome to all Members of the Expert Group.

<u>Discussion</u>

1. Shri Bakshi initiated the discussion by referring to the composition of the Committee and Terms of Reference (ToR). The members felt that a lot of ground work needs to be done for meaningful recommendations around the ToR. After discussion it was decided that experts from academia and representatives from Generating companies, Transmission companies and State Regulators may be invited for interaction with the Committee after some broad analysis has been carried out by the Expert Group.

2. Shri Bakshi underscored the need for a National Reference Frequency. Dr. Sushanta K. Charterjee, JC(RA), CERC, informed the group members that the existing literatures (regulations to be specific) do not provide in clear terms that the National Reference Frequency should be 50Hz. The CEA Grid Operation Standards mention it in an oblique way, e.g. "close to 50Hz" and CERC regulations provide for operating band of frequency. The members of the group unanimously endorsed the idea of recognizing 50Hz as National Reference Frequency for power system operations in India.

3. Shri S.R Narasimhan, AGM, POSOCO, shared some international experience on frequency control. He shared the examples of North America, Britain, Ireland and the Nordic and cited how they are balancing the grid frequency. He explained how the North American Electric Reliability Corporation (NERC) Reliability Standards have evolved and informed that Balancing Authority ACE Limit (BAAL) will be replacing Control Performance Standards 2 (CPS 2). A copy of documents is enclosed as **Annexure-II**. The Members of the Expert Group deliberated if the BAAL framework could be replicated in the Indian scenario. Dr. Chatterjee requested POSOCO to further include European/German models before a view could be taken in this regards.

   After discussion it was decided that interaction with international experts, especially from US & Europe be organized through Skype or VC. POSOCO shall facilitate such interaction on issues around reference frequency, operation band of frequency, Area Control Error (ACE), etc. For this purpose, a list of questionnaire should be prepared and sent in advance to the identified international experts before presentations are organized.

4. Shri Bakshi requested the members to deliberate on the measures to ensure adequacy of Spinning Reserves in the country. It was informed that the CERC's regulations already mandate Primary Response to the extent of 5% on installed capacity for all generating stations. The next level of intervention that is required is to roll out Secondary Reserves in the form of Automatic Generation Control (AGC). POSOCO informed that one pilot on AGC is already under trial.

   Dr. Chatterjee brought to the notice of the group the Secondary Reserves requirement as stipulated in the CERC's order on roadmap for implementation of reserves. The order stipulates the requirement of 3600MW of Secondary Reserves in the country. He opined that this support could be provided by some of the generators for which trial operations are already on. However, there is a need for creating appropriate market mechanism to enable market participants to come up with innovative products for implementation of AGC.

After discussion it was decided that in the next meeting, a presentation on the pilot being steered by POSOCO and also interaction with experts, who can share international experiences on AGC implementation can be arranged.

5. POSOCO suggested that the term Restricted Governor Mode of Operation (RGMO) should be removed from the IEGC keeping in view the emerging scenario of power market. The need of the hour was to enforce Free Governor Mode of Operation (FGMO). After discussion it emerged that this should be done in a time bound manner latest by March, 2018.

6. The issue regarding Ancillary Services was also raised. It was informed that POSOCO has submitted a report on operational experience of first six months of operation of Ancillary Services. It has made a number of recommendations as a way forward for strengthening Ancillary Services mechanism in the country. The members felt that Ancillary Services being an integral part of frequency control, it would be desirable for the group to deliberate on it and suggest measures for the next level of regulatory interventions for this mechanism.

<u>Decisions</u>

After detailed discussion, the following decisions emerged:

1. Experts from academia may be invited in the subsequent meetings for an interaction with the expert group. The probable experts could be: Professor Anjan Bose - University of Washington (on Skype Call); Dr. Anil Kulkarni – IIT Bombay; Dr. S.C. Shrivastava - IIT Kanpur; Dr. Abhijit Abyankar-IIT Delhi

Action: Chief (Engg.)/JC(Engg.), (CERC)

2. 50Hz may be recognized as National Reference Frequency for power system operation in India.

3. Interaction with international experts, especially from US & Europe to be organized through Skype or VC on issues regarding reference frequency, operation band of frequency, Area Control Error (ACE), etc.in the next meeting. A questionnaire to be prepared and sent in advance to the identified international experts.

Action: POSOCO

4. Presentation on POSOCO's pilot project on AGC and Secondary Reserves may be organized in the next meeting. It was also decided to invite some experts, who can share international experiences on AGC implementation.

Action: POSOCO

5. Feedback of RPCs / RLDCs may be taken on Primary Response. It was decided to gradually phase out the RGMO by 1st April 2018. Pre-requisites to be prepared for AGC/Secondary Reserves.

Action: Chief (Engg.)/JC(Engg.), (CERC)

6. To work on the framework for next level of interaction on Ancillary Services.

Action: JC(RA), (CERC)

LIST OF PARTICIPANTS ATTENDED THE FIRST MEETING OF "EXPERT GROUP TO REVIEW AND SUGGEST MEASURES FOR BRINGING POWER SYSTEM OPERATIVE CLOSER TO NATIONAL REFERENCE FREQUENCY" HELD ON 09.05.2017 AT CERC OFFICE, NEW DELHI

1	Shri. A. S.Bakshi, Member	CERC
2	Shri R. P Sasmal, Director (Operations)	PGCIL
3	ShriKVS Baba, CEO	POSOCO
4	ShriS R Narasimhan, AGM	POSOCO
5	Shri Kashish Bhambhani, Chief Manager	PGCIL
6	Shri S.C. Shrivastava, Chief (Engg.)	CERC
7	Dr. Sushanta K. Chatterjee, JC(RA)	CERC
8	Smt.Shilpa Agarwal, JC(Engg.)	CERC
9	Shri Siddharth Arora, Regulatory Officer	CERC

International references on frequency control

A. North American Electric Reliability Corporation (NERC) Reliability Standards (as on 8th May 2017)

i. 96 mandatory standards covering 14 areas; 10 standards subject to future enforcement

ii. Nine (9) mandatory standards under BAL series on Resource and Demand Balancing

iii. One (1) BAL standard on Contingency Reserve applicable from a future date

iv. One (1) BAL standard on data requirements for reporting Area Control Error (ACE) pending approval of FERC.

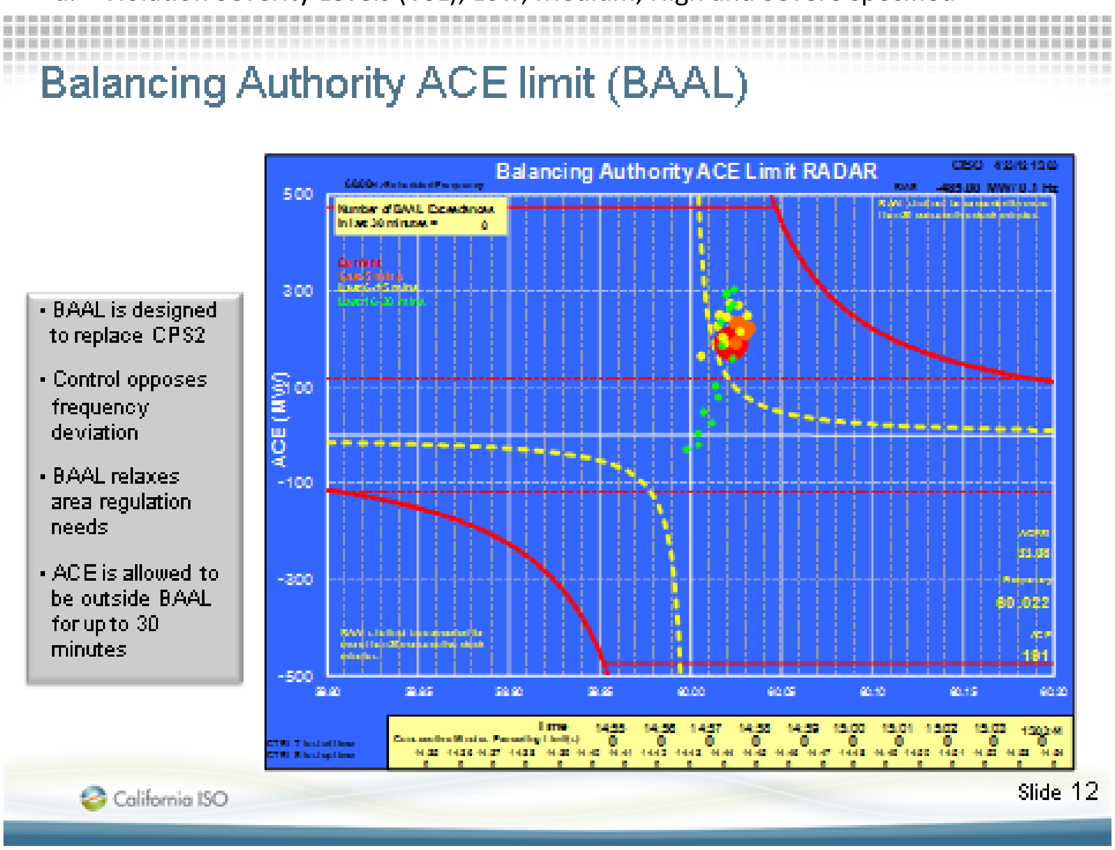
v. BAL-001-2: Real Power Balancing Control Performance

a. Control Performance Standard 1 or CPS1 >100% for the preceding 12 month period

b. Control Performance Standard 2 or CPS2 which says that 1 minute average of ACE should not exceed Balancing Authority ACE Limit or BAAL for more than 30 minutes. (BAAL-Low is calculated if frequency less than nominal and BAAL-High if frequency greater than nominal)

c. Targeted frequency bound for each interconnection (0.018 Hz for Eastern Interconnection, 0.0228 Hz for Western Interconnection, 0.030 Hz for ERCOT and 0.021 for Quebec interconnection)

d. Violation Severity Levels (VSL); Low, Medium, High and Severe specified



vi. **BAL-001-TRE-1: Primary Frequency Response in the ERCOT region**

a. ERCOT works out the Interconnection Minimum Frequency Response (IMFR)
b. Each Generator Owner's Primary Frequency Response is evaluated and rolling average of last 6 events should be more than 0.75 times the Desired Response considering the droop and dead band.

vii. **BAL-002-1: Disturbance Control Performance**

a. ACE to recover within 15 minutes following a contingency (magnitude defined in advance) through quick deployment of contingency reserve
b. Contingency reserve to be restored within 90 minutes

viii. **BAL-002-WECC-2a: Contingency Reserve**

a. Contingency Reserve to be greater of (most severe single contingency) or (3% of integrated hourly load + 3% of hourly integrated generation
b. To be maintained all the time except first 60 minutes following a contingency

ix. **BAL-003-1.1: Frequency Response and Frequency Bias Setting**

a. Interconnection Frequency Response Obligation (IFRO) in MW/0.1 Hz worked out for each Interconnection
b. Frequency Response Obligation (FRO) for each Balancing Area fixed in terms of IFRO, BA's sum of annual load and annual generation as a percentage of the Interconnection annual load and generation.
c. Frequency Bias to be used in ACE calculation should be at least equal to FRO.
d. Frequency Response Measure (FRM) for reportable events should be equal to or more than FRO.

x. **BAL-004-WECC-02: Automatic Time Error Correction**

a. Each BA to ensure that Accumulated Primary Inadvertent Interchange for both the monthly on-peak period and monthly off-peak period are each individually less than or equal to 150% of the previous calendar year's integrated hourly peak demand.

xi. **BAL-005-0.2b: Automatic Generation Control**

a. Specifies requirements for each Balancing Authority regarding the ACE calculations. Each generation, load and transmission facility to be included within the metered boundaries of each Balancing Authority area.

xii. **BAL-006-2: Inadvertent Interchange**

a. Process to ensure that a BA does not excessively depend on other BAs in the Interconnection for meeting their demand or interchange obligations.
b. Hourly Inadvertent Interchange shall be calculated and recorded.

xiii. **BAL-502-RFC-02: Planning Resource Adequacy Analysis, Assessment and Documentation**

a. Calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1 (comparable to 'one day in 10 year criterion).

B. ENTSOE guideline on electricity transmission system operation (Final Provisional)

i. Criteria of Normal State and Alert state with respect to frequency and reserves

   a. Normal State

      i. **active and reactive power reserves are sufficient** to withstand contingencies from the contingency list defined without violating operational security limits

      ii. the **steady state system frequency deviation is within the standard frequency range**; or

      iii. the absolute value of the steady state system frequency deviation is not larger than the maximum steady state frequency deviation and the system frequency limits established for the alert state are not fulfilled;

   b. Alert State

      i. any of the TSO's **reserve capacity is reduced by more than 20% for longer than 30 minutes** and there are no means to compensate for that reduction in real-time system operation

      ii. the **absolute steady state system frequency deviation is not larger than the maximum steady state frequency deviation**; and

      iii. the absolute value of the steady state system frequency deviation has continuously exceeded 50% of the maximum steady state frequency deviation for a time period longer than the alert state trigger time or the standard frequency range for a time period longer than time to restore frequency;

ii. Nominal frequency defined as 50 Hz for all synchronous areas.

iii. All the TSOs to define level 1 Frequency Restoration Control Error (FRCE) range and the level 2 FRCE range

iv. FRCE target parameters:

   a. Outside Level 1 FRCE < 30% of time intervals

   b. Outside Level 2 FRCE < 5% of time intervals

v. FRCE should be made zero within the time to restore frequency.

	CE	GB	IRE	NE
maximum number of minutes outside the standard frequency range	15000	15000	15000	15000

	CE	GB	IRE	Nordic
standard frequency range	±50 mHz	±200 mHz	±200 mHz	±100 mHz
maximum instantaneous frequency deviation	800 mHz	800 mHz	1000 mHz	1000 mHz
maximum Steady-state frequency deviation	200 mHz	500 mHz	500 mHz	500 mHz
time to recover frequency	not used	1 minute	1 minute	not used
Frequency Recovery Range	not used	±500 mHz	±500 mHz	not used
time to restore frequency	15 minutes	15 minutes	15 minutes	15 minutes
frequency restoration range	not used	±200 mHz	±200 mHz	±100 mHz
alert state trigger time	5 minutes	10 minutes	10 minutes	5 minutes

vi. Frequency Containment Reserves (FCR) dimensioning guidelines:

a. the reserve capacity for FCR required for the synchronous area shall cover at least the reference incident
b. reference incident may be calculated based on imbalance caused by loss of largest generating module, largest single demand facility, single HVDC interconnector

c. probabilistic FCR dimensioning approach for CE and Nordic Synchronous area taking into account the pattern of load, generation and inertia, including synthetic inertia as well as the available means to deploy minimum inertia in real-time

vii. Activation of FCR
   a. the activation of FCR shall not be artificially delayed and begin as soon as possible after a frequency deviation
   b. in case of a frequency deviation equal to or larger than 200 mHz, at least 50 % of the full FCR capacity shall be delivered after 15 seconds
   c. in case of a frequency deviation equal to or larger than 200 mHz, 100 % of the full FCR capacity shall be delivered at the latest after 30 seconds;
   d. in case of a frequency deviation equal to or larger than 200 mHz, the activation of the full FCR capacity shall at least rise linearly from 15 to 30 seconds; and
   e. in case of a frequency deviation smaller than 200 mHz the related activated FCR capacity shall be at least proportional with the same time behaviour referred to in points (a) to (d).

viii. Share of the FCR provided per FCR providing unit limited to 5 % of the reserve capacity of FCR required for each the whole CE and Nordic synchronous areas.

ix. Dimensioning of Frequency Restoration Reserves (FRR)
   a. Based on historical imbalance values
   b. Sufficient to respect the current FRCE parameters
   c. FRR + Replacement Reserves (RR) is sufficient to cover imbalance for 99 % of the time based on historical records.

x. Limits on exchange of FCR, FRR and RR
   a. FCR : at least 30 % of their total combined initial FCR obligations, is physically provided inside.
   b. FRR : at least 50 % of their total combined reserve capacity is located inside
   c. RR : at least 50 % of their total combined reserve capacity is located inside

C. FINAL REPORT on Application of Frequency Operating Standards During Periods of Supply Scarcity

Australia (Mainland) Frequency Operating Standards – Interconnected System

Condition	Containment	Stabilisation	Recovery
Accumulated time error	5 seconds		
no *contingency event* or *load event*	49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time	49.85 to 50.15 Hz within 5 minutes	
generation event or *load event*	49.5 to 50.5 Hz	49.85 to 50.15 Hz within 5 minutes	
network event	49 to 51 Hz	49.5 to 50.5 Hz within 1 minute	49.85 to 50.15 Hz within 5 minutes
separation event	49 to 51 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
multiple contingency event	47 to 52 Hz	49.5 to 50.5 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Australia (Mainland) Frequency Operating Standards – Island Operation

Condition	Containment	Stabilisation	Recovery
no *contingency event, or load event*	49.5 to 50.5 Hz		
generation event, load event or *network event*	49 to 51 Hz	49.5 to 50.5 Hz within 5 minutes	
the *separation event* that formed the *island*	49 to 51 Hz or a wider band notified to NEMMCO by a relevant Jurisdictional Coordinator	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
multiple contingency event including a further *separation event*	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

Australia (Mainland) Frequency Operating Standards – Supply Scarcity

Condition	Containment	Stabilisation	Recovery
no *contingency event* or *load event*	49.5 to 50.5 Hz		
generation event, *load event* or *network event* Refer to notes below for specific requirements to be satisfied prior to use this provision.	48 to 52 Hz (Queensland and South Australia) 48.5 to 52 Hz (New South Wales and Victoria)	49 to 51 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes
multiple contingency event or *separation event*	47 to 52 Hz	49.0 to 51.0 Hz within 2 minutes	49.5 to 50.5 Hz within 10 minutes

Column 1	Column 2	Column 3	Column 4
Term	**Normal range (Hz)**	**Island range (Hz)**	**Restoration range (Hz)**
normal operating frequency band	49.85 to 50.15	49.5 to 50.5	49.5 to 50.5
normal operating frequency excursion band	49.75 to 50.25	49.5 to 50.5	49.5 to 50.5
operational frequency tolerance band	49.0 to 51.0	49.0 to 51.0	48.0 to 52.0
extreme frequency excursion tolerance limit	47.0 to 52.0	47.0 to 52.0	47.0 to 55.0

D. Tasmanian Frequency Operating Standard Review

Australia (Tasmania) Frequency Operating Standards

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Accumulated time error (other than multiple contingency events)	15 seconds		
Normal	49.75 to 50.25 Hz, 49.85 to 50.15 Hz 99% of the time	49.85 to 50.15 Hz within 5 minutes	
Load and generation event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.85 to 50.15 Hz within 10 minutes	
Separation event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes
Multiple contingency event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.85 to 50.15 Hz within 10 minutes

Australia (Tasmania) Frequency Operating Standards – Island Operation

CONDITION	CONTAINMENT	STABILISATION	RECOVERY
Normal	49.0 to 51.0 Hz		
Load and generation event	48.0 to 52.0 Hz	49.0 to 51.0 Hz within 10 minutes	
Network event	48.0 to 52.0 Hz	49.0 to 51.0 Hz within 10 minutes	
Separation event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.0 to 51.0 Hz within 10 minutes
Multiple contingency event	47.0 to 55.0 Hz	48.0 to 52.0 Hz within 2 minutes	49.0 to 51.0 Hz within 10 minutes

Term	Normal range (Hz)	Island range (Hz)
normal operating frequency band	49.85 to 50.15	49.0 to 51.0
normal operating frequency excursion band	49.75 to 50.25	49.0 to 51.0
operational frequency tolerance band	48.0 to 52.0	48.0 to 52.0
extreme frequency excursion tolerance limit	47.0 to 55.0	47.0 to 55.0

Minutes of the 2nd Meeting of "Expert Group to Review and Suggest Measures for Bringing Power System Operative Closer to National Reference Frequency"

The 2nd meeting of the "Expert Group to Review and Suggest Measures for Bringing Power System Operative Closer to National Reference Frequency" was held on 16th June 2017 at NRLDC, New Delhi. Members from CERC, CEA, POWERGRID and POSOCO were present during the meeting. Sh Rahul Walawalkar from Customised Energy Solutions India Pvt Ltd was Special Invitee (present in person) to the meeting along with experts from ENTSOE and PJM who attended the meeting through conference call. Prof. Anjan Bose, Regents Professor, Washington State University was also connected through web conference as special invitee. The list of participants is attached as **Annexe-1**. A document highlighting the background on frequency control in India which was given a priori to the experts from PJM and is attached as **Annexe-2.**

Sh. A.S. Bakshi, Member, CERC and Sh. K.V.S. Baba, CEO, POSOCO welcomed the participants to the meeting.

Dr. Rahul Walawalkar from Customized Energy Solutions India Pvt. Ltd., stressed on the necessity of storage solutions for frequency regulation. Apart from the thermal generators, power electronic based solutions must also be explored for frequency regulation considering the large scale integration of renewables in India and the trends world wide. Payment as per the performance of the units under AGC is needed. An aggregator gateway system component for AGC services known as a Remote Intelligent Gateway (RIG) that can be used for transmitting telemetered data and providing direct control of the generating units was proposed in the presentation. The presentation is attached as **Annexe-3.** During discussion the importance of having standards on technical parameters of the power system from basic level came out for further deliberations.

Ms. Danielle Croop, Senior Engineer and Mr. Eric Endress, Engineer from Performance compliance teamof PJM explained the BAAL standards of NERC for Resource and Demand Balancing. BAAL is a performance evaluation standard for maintaining Interconnection frequency within predefined frequency limits (limits more focused on operation of UFLS relays and RE generator disconnection) under all system conditions. They explained that PJM is kicking off an initiative for all generating units to have the capability to provide frequency response. It was also clarified that the primary response is mandatory and not a paid service as of now. The Droop and Deadband settings is in-line with NERC guidelines. Regulation Services (Secondary Control through AGC) in PJM help in the continuous balancing of generation and load so that the interconnection frequency remains at 60 Hz. Two typical signals through AGC were mentioned, viz., Reg-A: Regulation signal sent by PJM to traditional units and Reg-D: Regulation signal set by PJM to fast moving units. Both the signals take into account the unit capabilities of the plants to which the signal is being sent. A plant's performance score under AGC is the weighted average of Precision, Accuracy and Delay. The presentation is attached as **Annexe-4.**

Dr. Konstantin Staschus (Director, Ecofys – a Navigant Company, ENTSO-E Chief Innovation Officer, Chair EU ETIP SNET and CIGRE SC C1) presented on the Institutional aspects regarding frequency control from European TSO/ENTSO-E perspective. He stressed that it is an opportunity for India to define future-oriented rules. He shared the ENTSOE experience since 1951 that International Interconnection needs good cooperation and common rules. The ultimate aim will be increased reliability, reduced costs through trading and shared reserves. But, now market integration and especially Renewable Energy

Systems require stronger common rules. He concluded by stating that requirements for generators need to be in line with operational practice. This requires several interacting sets of rules on system operations, connection conditions (in particular generators of all sizes incl. rooftop PV, but also demand and HVDC interconnectors), and market mechanism. Synchronous link to Bhutan and radial feeds to Nepal, Myanmar and Bangladesh might require contractual and operational clarity for better efficiency. As international interconnections increase, clear operations, connection and market rules will be a crucial enabler for easier contract negotiations and investor certainty. He felt that POSOCO must have requirements to meet standards.

Prof. Anjan Bose pointed out that Reg A signals mentioned by PJM are presently the need of the hour for India as the AGC infrastructure itself is non-existent. This can be gradually improved by including Reg-D signals into AGC at a later stage. He opined that AGC performance can be seen after the infrastructure for AGC has been built in India. Prof. Bose also mentioned that the present CERC mandate of keeping reserves to the tune of largest generator in every region round the clock is a decent way to start keeping reserves.

Thereafter some questions were also asked to the International Experts. The same are listed below along with their response:

1) *Defining Reference Frequency : Need & Importance*
   Reference Frequency for PJM is 60 Hz. It is important from the grid security point of view. In some instances reference frequency is changed from 60 Hz to compensate for time error. Tight compliance standards in the form of BAAL by NERC being maintained by PJM. ENTSOE also has similar performance standards as NERC. Similar standards to be evolved for India as well.

2) *Permissible Frequency Deviation in your grid and its evolution over the last decade.*
   Frequency is to be maintained at reference 60 Hz. PJM always try to maintain frequency between 59.98 Hz to 60.02 Hz. Frequency limits are in relation to operation of UFLS relays and RE generator disconnection.

3) *Control Area Performance Assessment*
   BAAL standards were mentioned. Pay as per performance of AGC through FERC order 755 was mentioned.

4) *Types of reserves defined and assessment of requirement thereof*
   Prof. Bose voted for constant 24x7 secondary reserves to start with as given in the order by CERC. PJM mentioned probabilistic calculations (based on BAAL scores) and a minimum reserve is always ensured (It appeared that the operator decision exists).

5) *Procurement methods for reserves, duration and payment thereof*
   Procured by PJM through market based bids. Similar is the case with ENTSOE.

6) *Minimum technical requirements for generators to be eligible for providing AGC services*
   Not discussed in detail. Fast acting reserves and slow acting reserves are classified and procured separately.

7) *Deviation Settlement Mechanism; how are imbalances handled as far as accounting is concerned?*
   Not discussed in detail.

Towards the end, POSOCO made a presentation on the implementation philosophy of the ready-to-be mock tested AGC Pilot project at NTPC Dadri Stg-II in front of CERC. Verbal consent was sought for the mock tests. A copy of the presentation is attached as **Annexe-5**.

Annexe-1: List of Participants

1. Sh. A.S. Bakshi, Member, CERC
2. Sh. Sushanta Chatterjee, Joint Chief (Regulatory Affairs), CERC
3. Ms. Shruti Deorah, Advisor (RE), CERC
4. Ms. Shilpa Agarwal, Dy. Chief (Engg.), CERC
5. Sh. S. K. Roy Mahapatra, Chief Engineer, CEA
6. Sh. Rajesh Kumar, POWERGRID
7. Sh. S.K. Soonee, Advisor, POSOCO
8. Sh. K.V.S. Baba, CEO, POSOCO
9. Sh. S.R. Narasimhan, AGM, NLDC
10. Sh. S.S. Barapanda, AGM, NLDC
11. Sh. P.K. Agarwal, GM, NRLDC
12. Sh. Devender Kumar, DGM, NRLDC
13. Sh. N.Nallarasan, DGM, NLDC
14. Sh. Samir Saxena, DGM, NLDC
15. Sh. Rajiv Porwal, DGM, NRLDC
16. Sh. Debasis De, AGM, NRLDC
17. Sh. Prabhankar Porwal, Engineer, NLDC
18. Sh. K.V.N. Pawan Kumar, Dy. Mgr., NLDC
19. Ms. Kajal Gaur, Engineer, NLDC
20. Sh. Mohit Joshi, Dy. Mgr., NLDC
21. Sh. Rahul Chakraborty, Sr. Engineer, NLDC
22. Sh. Phanisankar Chilukuri, Sr. Engineer, NLDC

4th Meeting of the Expert Group on Reference Frequency

The 4th meeting of the "Expert Group to Review and Suggest Measures for Bringing Power System Operative Closer to National Reference Frequency" was held on 3rd November 2017 at CERC, New Delhi under the Chairmanship of Shri A.K Bakshi, Member, CERC. Representatives from CEA, POSOCO, CERC and special invitees were present during the meeting. The list of participants is attached as Annexe-1

Sh. A.S. Bakshi, Member, CERC welcomed the participants to the meeting.

Discussions

I. Issues relating to Grid frequency and Related Matters

1. The Commission constituted the Expert Group consisting representatives from CEA, POSOCO and CTU with the mandate to suggest further steps required to bring power systems operation closer to the national reference frequency. The Terms of Reference of the Expert Group were:

- Review the experience of grid operation in India
- Review international experience and practices on grid operation including standards/requirement of reference frequency
- Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid
- Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities
- Any other matter related to above

2. Draft report of the Expert Group covering the first three terms of reference was circulated in advance. Salient points covered in the draft report on measures for bringing power system operations closer to national reference frequency were presented. The transition of average grid frequency from highly volatile in 1990s to a disciplined average grid frequency over the last few years was highlighted.

3. The frequency variation of Indian Grid as compared to European Grid within a particular day was also presented. The graph displayed the high level of disorderliness of the Indian Grid Frequency in a day and stressed on bringing measures to control the indiscipline.

4. The Schematic of Reserves, Balancing and Frequency Control Continuum in India was explained. The features of each measure i.e. Inertial Response, Primary Response, Secondary Control, Fast Tertiary, Slow Tertiary, Generation Rescheduling/Real Time Market were discussed in detail. The schematic also described the response time, control area, quantum etc

of each measure. Based on the presentation and Continuum chart, following recommendations were proposed in the draft report:

a. Frequency Control Continuum chart be included in the IEGC
b. Reference frequency for the purpose of control be considered as 50 Hz
c. Inertia & Inertial response, Frequency Response Characteristics (FRC) and Area Control Error (ACE) should be monitored
d. Frequency band be revised to 49.95 – 50.05 Hz from 49.90 – 50.05 Hz
e. RGMO be phased out and replaced with 'speed control with droop' 'Free Governor Mode of Operation (FGMO)'
f. AGC be implemented throughout the country at the earliest
g. Ambit of Slow tertiary be expanded
h. Hydro be used as Fast tertiary control
i. Standards for cumulative time error be notified at an appropriate time based on the experience gained and considering cross border interconnections.

Decisions

Members of the Expert group unanimously endorsed the draft report with the following broad recommendations; and authorized Chairman of the Expert Group to finalize and present the same to Chairman CERC:

1. Reference frequency for the purpose of frequency control should be considered as 50.0 Hz;
2. Inertia of the system be monitored at the regional and All India level in real time so that a baseline is established, followed by suitable provisions in standards and code as required;
3. Primary Control needs to be implemented at the earliest. RGMO may be phased out at the earliest and replaced with 'speed control with droop';
4. IEGC should notify additional parameters, such as permissible frequency band, Reference contingency for primary response, nadir value, etc;
5. Roadmap for operationalizing reserves notified by the CERC vide order dated 13th October 2015 be implemented at the earliest;
6. AGC must be implemented throughout the country at the earliest;
7. Ambit of Ancillary Services (RRAS) should be expanded, including introduction of performance metrics;
8. Fast tertiary services through RRAS using hydro could be introduced suitably at the interstate level to start with;
9. Area Control Error (ACE) and time error be recorded and monitored

II. Issues Related to DSM Price Vector

1. A presentation was made on the DSM Price Vector and its alignment with DAM Prices. The existing DSM Price Vector follows a regulated price versus frequency curve for any real time deviation from schedule and is independent of Marginal Cost of the system and the location where electricity is being supplied.

2. State utilities are using existing DSM as operational mechanism to over-draw and are optimizing their Day Ahead decisions on the basis of DSM. The price differential between the Day Ahead Market (DAM) and the instant DSM price creates a perverse incentive for the States to rely on the grid to even meet anticipated load requirement, especially as the grid frequency has stabilized resulting in a DSM price of under Rs.2 at most times.

3. The proposed DSM Price Vector links it with the Average Clearing Price (ACP) discovered in the Day Ahead Market (DAM). This will induce the States to plan day ahead and invest in improving their load forecasting techniques.

Decisions

1. The DSM Price at 50 Hz (this will act as reference point) be indexed to the ACP of the DAM at power exchange. The DSM Price vector could extend from 49.85 Hz to 50.05 Hz as against the existing price band covering 49.70 Hz to 50.05 Hz. The DSM price at 49.85 Hz and 50.05 Hz should be fixed at Rs. 8 and Re. 0 respectively. With these conditions, DSM price at each step of 0.01Hz between 49.85 Hz and 50.05 Hz will be determined accordingly.
2. Area Control Error should reverse sign after every 4 time blocks instead of 12 at present. Violation or non-compliance will have 10% additional DSM charge for those four time blocks.
3. The recommendations as above will bring in the desired time & location attributes to DSM Price Vector. Indexation of DSM price to DAM price is being recommended as India still does not have any other Real Time price reference nor does the Ancillary Services Segment, with its limited coverage of generation resources, truly represent last mile system marginal price.

   The Committee felt that indexation of DSM prices to DAM price as also linkage of DSM price vector to frequency should be reviewed on introduction of Real Time market and operationalization of Ancillary Services market.
4. Based on the discussion, a report be finalized and presented by the Chairman of the Expert Group to the Chairman of CERC. This will fulfill the fourth item of TOR of this Expert Group – "*Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities".*

Annexe-1: List of Participants

1. Sh. A.S. Bakshi, Member, CERC
2. Dr. M.K. Iyer, Member, CERC
3. Sh. P.S. Mhaske, Member(PS), CEA
4. Sh. S.K. Soonee, Advisor, POSOCO
5. Sh. K.V.S. Baba, CEO, POSOCO
6. Dr. Sushanta Chatterjee, Joint Chief (Regulatory Affairs), CERC
7. Sh. S.R. Narasimhan, GM, System Opreter, POSOCO
8. Sh. S.C.Saxena, DGM, POSOCO
9. Sh. S.S. Barapanda, AGM, POSOCO
10. Sh. B.S Bairwa, Director CEA
11. Sh. Manish Chaudhari, Dy. Chief (Engg.), CERC
12. Sh. Phanisankar Chilukuri, Sr. Engineer, NLDC
13. Sh. Siddharth Arora, RO, CERC
14. Sh. Puneet Chitkara, KPMG – Special Invitee
15. Sh. Yasir Altaf, KPMG – Special Invitee

Provisions related to Frequency and Frequency Control in CERC Regulations and CEA Standards

1. CERC (Indian Electricity Grid Code), Regulations, 2010

5.2 (f) (ii) a) The restricted governor mode of operation shall essentially have the following features:

a) There should not be any reduction in generation in case of improvement in grid frequency below 50.05 Hz (for example, if grid frequency changes from 49.9 to 49.95 Hz, there shall not be any reduction in generation). For any fall in grid frequency, generation from the unit should increase by 5% limited to 105% of the MCR of the unit subject to machine capability.

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

5.2 (f) (ii) d) After stablisation of frequency around 50 Hz, the CERC may review the above provision regarding the restricted governor mode of operation and free governor mode of operation may be introduced.

5.2 (m) All Users, SEB, SLDCs, RLDCs, and NLDC shall take all possible measures to ensure that the grid frequency always remains within the [49.90-50.05 Hz] band.

5.2 (n) All SEBS, distribution licensees I STUs shall provide automatic under frequency and df/dt relays for load shedding in their respective systems, to arrest frequency decline that could result in a collapse/disintegration of the grid, as per the plan separately finalized by the concerned RPC and shall ensure its effective application to prevent cascade tripping of generating units in case of any contingency. All, SEBs, distribution licensees, CTU STUs and SLDCs shall ensure that the above under-frequency and df/dt load shedding/islanding schemes are always functional. RLDC shall infirm RPC Secretariat about instances when the desired load relief is not obtained through these relays in real time operation. The provisions regarding under frequency and df/dt relays of relevant CEA Regulations shall be complied with. SLDC shall finish monthly report of UFR and df/dt relay operation in their respective system to the respective RPC.

RPC Secretariat shall carry out periodic inspection of the under frequency relays and maintain proper records of the inspection. RPC shall decide and intimate the action required by SEB, distribution licensee and STUs to get required load relief from Under Frequency and Df/Dt relays. All SEB, distribution licensee and STUs shall abide by these decisions. RLDC shall keep a comparative record of expected load relief and actual load relief obtained in Real time system operation. A monthly report on expected load relief vis-a-vis actual load relief shall be sent to the RPC and the CERC.

5.4.2 (e) In order to maintain the frequency within the stipulated band and maintaining the network security, the interruptible loads shall be arranged in four groups of loads, for scheduled power cuts/load shedding, loads for unscheduled load shedding, loads to be shed through under frequency relays/ df/ dt relays and loads to be shed under any System Protection Scheme identified at the RPC level. These loads shall be grouped in such a manner, that there is no overlapping between different Groups of loads. In case of certain contingencies and/or threat to system security, the RLDC may direct any SLDC/ SEE/distribution licensee or bulk consumer connected to the ISTS to decrease drawal of its control area by a certain quantum. Such directions shall immediately be acted upon. SLDC shall send compliance report immediately after compliance of these directions to RLDC.

5.8 (d) The RLDC is authorized during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.

2. <u>CEA (Grid Standards), Regulations, 2010</u>

3. Standards for Operation and Maintenance of Transmission Lines.- (1) All Entities, Appropriate Load Despatch Centres and Regional Power Committees, for the purpose of maintaining the Grid Standards for operation and maintenance of transmission lines, shall,-

   (a) make all efforts to operate at a frequency close to 50 Hz and shall not allow it to go beyond the range 49.2 to 50.3 Hz or a narrower frequency band specified in the Grid Code, except during the transient period following tripping.

3(2) The transmission licensee shall ensure that the voltage wave-form quality is maintained at all points in the Grid by observing the limits given in Table 5 below,-

Table 5

S.No.	System Voltage (kV rms)	Total Harmonic Distortion (%)	Individual Harmonic of any particular Frequency (%)
1	765	1.5	1.0
2	400	2.0	1.5
3	220	2.5	2.0
4	33 to 132	5.0	3.0

Provided that the standard on Harmonic Distortion shall come into force concurrently with clause 3 of Part IV of the Schedule to the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007.

Explanation: For the purpose of this regulation, Total Harmonic Distortion (VTHD) expressed as percentage, shall be calculated as under,-

$$V_{THD} = \sqrt{\sum_{n=2}^{n=40} \frac{V_n^{\ 2}}{V_1^{\ 2}}} X 100$$

'1' refers to fundamental frequency (50 Hz)

'n' refers to the harmonic of nth order (corresponding frequency is 50 x n Hz)

3. CEA (Installation and Operation of Meters), Regulations, 2006

Part II Standards for interface meters

(1) Functional Requirements:

The Interface meters suitable for ABT shall be static type, composite meters, as self –contained devices for measurement of active and reactive energy, and certain other parameters as described in the following paragraphs. The meters shall be suitable for being connected directly to voltage transformers (VTs) having a rated secondary line-to-line voltage of 110 V, and to current transformers (CTs) having a rated secondary current of IA (Model-A: 3 element 4 wire or Model C: 2 element, 3 wire) or 5A (model-B: 3 element, 4 wire or Model D: 2 element 3 wire). The reference frequency shall be 50Hz.

4. CEA (Technical Standards for Construction of Electrical Plants and Electric Lines), Regulations, 2010

PART- B

COAL OR LIGNITE BASED THERMAL GENERATING STATIONS

7. Operating Capabilities of a Unit in the Station- (1) The unit shall give MCR output under the following conditions:

(a) Maximum cooling water temperature at site;
(b) Worst fuel quality stipulated for the unit;
(c) Grid frequency variation of -5% to +3% (47.5 Hz to 51.5 Hz).

PART- B

SUB- STATIONS (33/11 kV, 33/22kV AND 22/11kV)

47. System Parameters- The system shall conform to the design parameters indicated in Table 14 below:

Table 14

Parameter	33 kV	22 kV	11kV
Nominal system voltage (kV)	33	22	11
Highest system voltage (kV)	36	24	12
System earthing	Solidly earthed system	Solidly earthed system	Solidly earthed system
Frequency (Hz)	50	50	50
Lightning impulse withstand voltage (kV_{peak})	170	125	75
Power frequency withstand voltage (dry) (kV_{rms})	70	50	28

43. Salient Technical Particulars and Requirements of Sub-stations and Switchyards

(1) System design parameters

(a) The system design parameters of sub-stations and switchyards shall be as given below in Table 9.

Table 9

Parameter	66 kV	110 kV	132 kV	220 kV	400 kV	765 kV
Highest system voltage (kV)	72.5	123	145	245	420	800
Rated frequency	50Hz	50Hz	50 Hz	50 Hz	50 Hz	50Hz
No. of phases	3	3	3	3	3	3
Rated insulation levels						
(i) Full wave impulse withstand voltage (1.2/ 50 micro sec.) (kV_{peak})	325	550	650	1050*	1425*	2100*
(ii) Switching impulse withstand voltage (250/ 2500 micro sec.) dry and wet (kV_{peak})	-	-	-	-	1050	1550
(iii) One minute power frequency withstand voltage dry (kV_{rms})	140	230	275	460	630	830
Minimum corona extinction voltage (kV_{rms} phase to earth)	-	78	105	156	320	508
System neutral earthing	Effectively earthed					

* for windings of transformers and reactors refer Table 10.

DISTRIBUTION SUB-STATIONS (DSS)

74. **General-** (1) The system shall conform to the design parameters indicated in Table 15 below:

Table 15

Parameter	**33 kV**	**22 kV**	**11kV**	**0.415 V**
Nominal system voltage (kV)	33	22	11	0.415
Highest system voltage (kV)	36	24	12	0.450
System earthing	Solidly earthed system	Solidly earthed system	Solidly earthed system	Solidly earthed system
Frequency (Hz)	50	50	50	50
Lightning impulse withstand voltage (kV_{peak})	170	125	75	-
Power frequency withstand voltage (dry) (kV_{rms})	70	50	28	3

91. **Electrical Design Parameters of the Electric Lines-** (1) The electrical design parameters of the electric lines for altitude upto 1000 m above MSL shall be as indicated in Table 19 below:

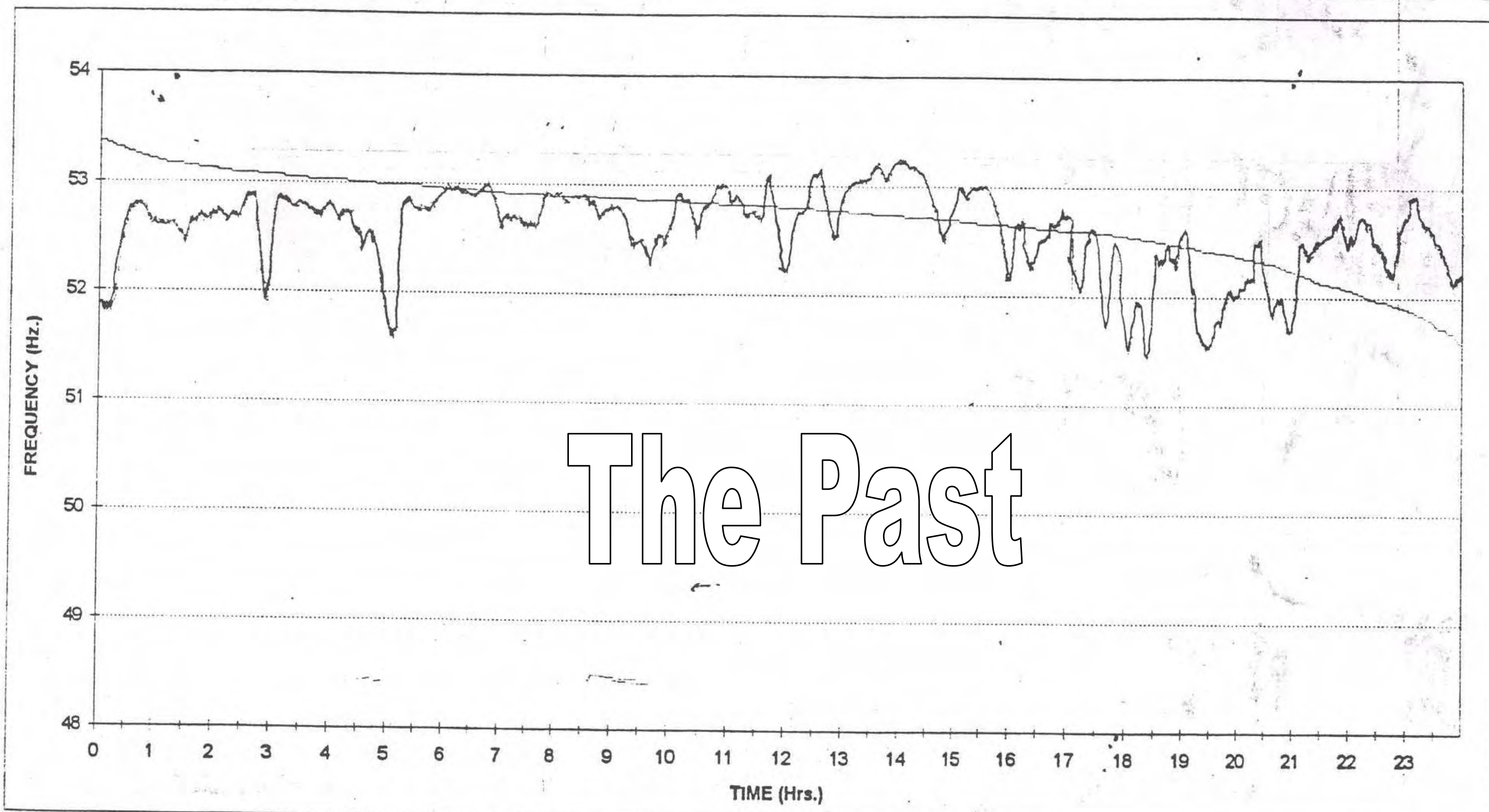
Table 19

Parameter	**33 kV**	**22 kV**	**11 kV**	**0. 415 kV**
Nominal system voltage (kV)	33	22	11	0.415
Highest system voltage (kV)	36	24	12	0.450
System earthing	Solidly earthed system	Solidly earthed system	Solidly earthed system	Solidly earthed system
Frequency (Hz)	50	50	50	50
Lightning impulse withstand voltage (kV_{peak})	170	125	75	-
Power frequency withstand voltage (kV_{rms}) in dry condition	75	50	28	3

FREQUENCY & FREQUENCY DURATION CURVE
DATE : 27/09/98 Sunday

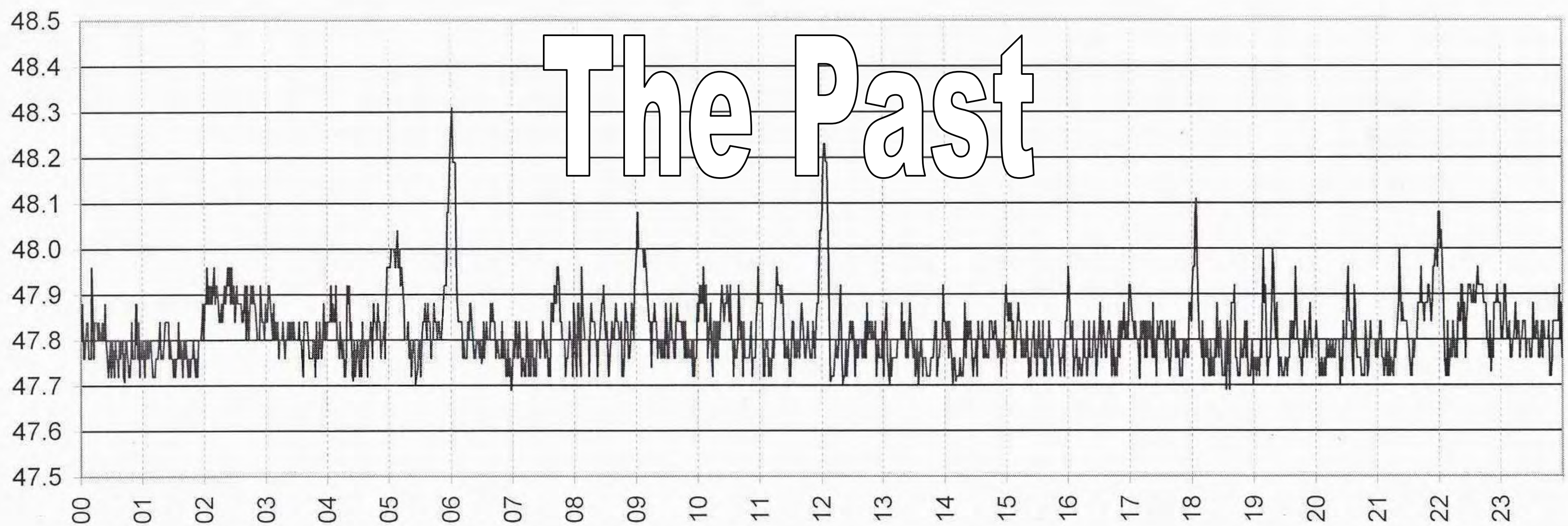
Annexure-VI

FVI : 68.38 **STD : 0.3** **AVG. Freq : 52.6 Hz** **Max. Freq : 53.3 Hz** **Min Freq : 51.4 Hz**



POWER GRID CORPORATION OF INDIA LTD.
SOUTHERN REGIONAL LOAD DESPATCH CENTRE

FREQUENCY ANALYSIS FOR **24-04-2002** **Wednesday**



Frequency Variation based on data integrated over ONE minute interval

	<48.0	48.0 & <48.5	48.5 & <49	49 & <49.5	49.5 & <50	50 & <50.5	50.5 & Above
Minutes	1396	44	0	0	0	0	0
In %	96.9	3.1	0.0	0.0	0.0	0.0	0.0

Average Frequency over the day:	**47.82**	**Standard Deviation:**	**0.08**	**Frequency Variation Index :**	**47.70**

	Instantaneous	
	Freq	Time
Max	48.31	06:01
Min	47.69	18:36

	Quarter Hourly Average	
	Freq	Time
Max	47.97	05:15
Min	47.75	13:45

Annexure VII

Regionwise FRC Calculation(MW/Hz) since Jan 2015				
S.No.	**Date**	**Time**	**Description**	**All India FRC in MW/Hz**
1	14-Jan-2015	19:20	On 14.01.15 at 1920hrs, due to problem in GT Kudankulam Unit-I was tripped. At the time of tripping it was generating 1000MW.	6023
2	9-Apr-2015	12:04	Due to mal operation of Converter transformer R-ph OLTC PRV Limit switch at Kolar end Talcher-Kolar Pole-II tripped. Generation Backing=220MW Load Loss=1303MW	6223
3	22-Apr-2015	10:54	Due to tripping of 400 KV Udumalpet-Palakkad-2, (ckt-1 tripped at 10:52 hrs) Kerala suffered 1575 MW demand loss and 381 MW generation loss	6490
4	25-Apr-2015	11:43	An earthquake with the magnitude of 7.9 on Richter scale occurred with its epicenter in Nepal. The tremors of the same were also felt in Northern, Eastern and North Eastern part of India. Total Load Loss was around 3000MW	5660
5	26-Apr-2015	12:40	An earthquake with the magnitude of 6.9 on Richter scale occurred with its epicenter in Nepal. The tremors of the same were also felt in Northern, Eastern and North Eastern part of India. Total Load Loss was around 2200MW(Approx.)(ER=1500MW,NR=700MW)	5000
6	4-May-2015	21:50	Due to tripping of 400kV Chandrapur(2)-Warora-I&II and 400kV Wardha-Warora-I (Wardha-Warora-II already out under emergency S/D), SPS of Tirora operated resulting tripping of Unit 3 & 5 (generating 1100MW).	6490
7	24-May-2015	19:19	Due to tripping of Talcher - Kolar HVDC and consequently tripping of 765 kV Raichur - Sholapur-1&2, NEW & SR grids got separated.	6078
8	26-May-2015	17:55	Talcher-Kolar HVDC Pole-2 tripped due to DC line fault. Pole 1 survived and went into ground return mode. SPS Action caused generation backing in ER and load shedding in SR.	4230
9	27-May-2015	11:31	HVDC Mundra-Mohindergarh Pole-2 tripped due to DC line fault. HVDC Pole-2 was carrying 1100MW before tripping which reduced to 800MW under RVO mode and ultimately tripped.The SPS operated, causing load loss of 1050 MW	5812
10	16-Jun-2015	19:26	JPNigire - Satna-2 was under planned shutdown. JP Nigire Gen was 1137 MW (as per NLDC SCADA) and was being evacuated through JP Nigire-Satna-1. At 19:26 Hrs JP Nigire-Satna-1 tripped on R-Ph to Earth Fault resulting in outage of JP Nigire due to loss of evacuation	4653

Regionwise FRC Calculation(MW/Hz) since Jan 2015				
S.No.	**Date**	**Time**	**Description**	**All India FRC in MW/Hz**
11	26-Jun-2015	13:16	Due to Emergency Switch Off command from Talcher end, Talcher-Kolar HVDC Pole – II tripped and Talcher – Kolar Pole – I went into metallic return mode	4506
12	10-Jul-2015	16:26	Due to tripping of 765/400KV ICT-2 at Phagi(RRVPNL) (ICT-1 was already in shutdown); Kawai(660MW), Kalisindh (2*500MW) and Chhabara(2*250MW) tripped due to loss of evacuation. Generation Loss of 1800 MW.	8228
13	12-Oct-2015	21:48	R phase CT of Bus coupler at 220 kV Samaypur BBMB blasted. It resulted into bus fault for both the buses and tripping of all 220 kV feeders from Samaypur will all four ICTs at 400/220 kV Ballabgarh(PG). This resulted in load loss of 930 MW in Haryana and generation loss of 150 MW at Faridabad Gas. Fault clearance time was around 800 msec.	6945
14	26-Oct-2015	14:41	An earthquake of 7.5 magnitude(on Richter scale) hit the North East Afghanistan, the tremors were felt in Northern part of India. There was sudden demand reduction and frequency rise during the incident. There was approx. 1200 MW demand reduction in All India and frequency rise by 0.28 Hz.The state of Jammu and Kashmir was affected badly and there was demand reduction of approx. 1000 MW in J & K.	4437
15	13-Nov-2015	23:05	Due to tripping of evacuating 400kV Kalisindh - Anta D/C lines from Kalisindh TPP in Northern Region due to Distance Protection, Generation loss of 1120 MW occurred.	6746
16	30-Nov-2015	17:22	Due to tripping of 400 kV UPCL-Hasan-2 on transient fault both units of UPCL tripped due to SPS operation. This caused an approximate generation loss of 1100 MW.	4506
17	14-Dec-2015	16:54	Fault observed in 400kV Hissar-Bhiwadi ckt2. It resulted into tripping of 400kV Hissar-Bhiwadi ckt-2, Hissar-Fatehabad, Hissar-Bhiwani(PG) ckt2, Hissar-Kaithal ckt2 & at the same time 500kV Mohindergarh-Mundra Pole 2 also tripped due to commutation failure at Mohindergarh end. Load loss observed on behalf of SPS operation in NR	3247
18	30-Dec-2015	06:03	TPCIL Generators (2 X 660 MW) tripped due to Loss of evacuation lines , Loss of generation 1069 MW	8108
19	16-Jan-2016	01:29	765kV Antah-Phagi I tripped leading to tripping of all running units of Kawai, Kalisindh & Chabra and lines 400kV Chabra-Kawai, 400kV Chabra-Hindaun, 400kV Bhilwara-Chabra, this incident led to a generation loss of approx. 2100MW. A load loss of approx. 600MW observed in Rajasthan area. The net interchange coming to 1500 MW.	7500
20	21-Feb-2016	16:46	HVDC Talcher-Kolar Pole-1 tripped due to Valve cooling problem at Kolar end at 16:46 Hrs on 21.02.2016. HVDC pole-2 went into metallic return mode after tripping of HVDC pole-1. SPS signal-1&3 of HVDC Talcher-Kolar operated resulting in 1084MW of load shedding in southern region. In Eastern region, GMR,JITPL and Sterlite generation observed generation backing down of 580 MW in total but since it took place in minutes so the backing down has not been factored in calculations.	6376

Regionwise FRC Calculation(MW/Hz) since Jan 2015				
S.No.	**Date**	**Time**	**Description**	**All India FRC in MW/Hz**
21	11-Mar-2016	00:27	Rajasthan wind generation of 1100MW tripped.	5500
22	14-Mar-2016	01:12	At 01:12hrs, 400KV NTPL-Thootikudi PS tripped on R-N Fault from NTPL end only while synchronizing of this line at 01:36hrs, 400KV NTPL-Thootikudi PS, 400KV NTPL-Coastal, 400KV Thootikudi PS-Coastal and units of NTPL (unit-1 & 2 of 500MW) & Coastal (unit-1 of 600MW) tripped. Total Gen Loss -1350MW.	8132
	2-Apr-2016	13:47	A sharp frequency drop around 0.17 Hz is observed in PMU data. 1100 MW wind generation loss occurred at same time due to loss of evacuation lines on BusBar Protection.	6875
23	14-Apr-2016	13:29	On 14.04.16, at 13:29 hrs 400 kV JP Nigrie-Satna-1 tripped on R-E Fault and JP Nigrie-Satna-2 tripped on DT resulting in loss of evacuating lines and generation loss of 1089 MW.	7260
24	30-Apr-2016	15:01	400 kV Jabalpur-MB power-1 & 2 tripped on Bus Bar differential protection. This led to black out of MB Power.Frequency drop of 0.14 Hz took place during the event (50.06 Hz to 49.92 Hz).Loss of generation of 1024 MW (Unit 1=496 MW, Unit 2=528 MW) took place.	7877
25	1-May-2016	12:24	400 kV JP Nigrie-Satna-1 tripped on R-N fault and circuit-2 tripped on DT receipt.At the time of tripping each circuit was carrying 539 MW (approximately).There was generation loss of 1064 MW due to tripping of Unit-I & II at JP Nigrie station.The frequency fall during the event was 0.13 Hz.	8185
26	3-May-2016	21:07	400kV JP Nigrie -Satna -1 & 2 tripped on R-N fault resulting in generation loss of 1166 MW due to tripping of units on loss of evacuation paths and frequency dip of 0.13 Hz.	8329
27	18-May-2016	17:31	Y&B-phase to phase fault occurred in 400kV Bawana-Mundka ckt-2. At the same time around ~3700MW load loss occurred in Northern Region. Frequeny rose from 50.05Hz to 50.42Hz due to load loss into the system.Major contributors in this load loss are Delhi, Haryana, UP & Punjab. Load loss may be due to stalling of induction motors in the system, AC load & tripping of LT feeders. Frequency returned within IEGC band after a period of 5 minutes.	10000
28	22-May-2016	21:11	400 KV Jhakri-Panchkula II tripped and then Jhakri-Rampur II also tripped. This led to SPS operation resulting in tripping of 2 units each at N.Jhakri (500 MW loss) , K.Wangtoo (500 MW loss) and 5 units at Rampur (300 MW loss).	8669
29	9-Jun-2016	14:27	Y-phase CT of 220kV Samaypur-Palwal ckt-1 bursted. It resulted into bus fault at 220kV Samaypur(BBMB) station. At the same 3890MW load loss observed in NR along with generation loss at BTPS (Badarpur), Pragati generation and Faridabad Gas generation.	9302
30	22-Jun-2016	13:27	400 kV JP Nigree-Satna-1&2 tripped at 13:18 hrs on R-N fault. JP Nigrie U-1 &2 also tripped due to evacuation problem and led to 1200MW gen loss.	7059

Regionwise FRC Calculation(MW/Hz) since Jan 2015				
S.No.	**Date**	**Time**	**Description**	**All India FRC in MW/Hz**
31	24-Jun-2016	02:15	400/220kV 500MVA Patiala ICT #3 tripped due to high winding temperature. 400/220kV 315MVA Patiala ICT #1 & #2 tripped on overloading after tripping of ICT#3.This led to load loss in Punjab area.	6667
32	5-Jul-2016	09:41	Due to 220 kV side jumper snapping of 220/132 kV ICT at Barmer station, busbar protection operated at 220 KV bus of Barmer station. This led to the complete outage of Barmer station and loss of evacuation of wind generation from 400/220 kV Akal station. From initial investigations around 1400 MW wind generation loss in Rajasthan is reported.	6087
33	13-Jul-2016	02:37	While charging 400 kV Bacchau-Varsana-I, multiple tripping at 400 kV CGPL Mundra generating Station occurred. Due to tripping of all evacuation lines, all the four running units i.e. Unit 10,30,40, & 50 which were generating around 2820 MW got tripped and a generation loss of 2820 MW occurred. The fall in frequency was around 0.28 Hz which is indicating operation of df/dt based load shedding in the Indian Grid of the order of approx. 1200 MW(in Western region, yet to be verified).	5800
34	2-Sep-2016	16:03	JP Nigrie-Satna-1 & 2 Tripped on Y-Ph fault resulting loss of evacuation lines of JP-Nigrie and generation loss of 1051 MW	7507
35	5-Oct-2016	23:50	HVDC Talcher-Kolar Pole-1 tripped at 23:50 hrs on 05-10-2016 due to Thyristor failure at Talcher end. Pole-2 successfully changed over to Metallic return mode, with power flow of 920 MW. HVDC Talcher Kolar SPS 1 operated resulting in load shedding of 930 MW in SR.	8503
36	19-Oct-2016	15:39	765/400kV ICT at Fatehabad tripped due to mal-operation of OFS (Oil Flow Switch).After this 765kV Fatehabad-Lalitpur line tripped on over voltage and due to outage of evacuation path, Lalitpur unit #2 generating 630MW along with 220kV lines tripped. Unit #1 came on house load and it also tripped at 15:45hrs. Total generation loss was ~1200MW and load loss was ~150MW.	6529
37	20-Oct-2016	13:11	765/400kV ICT at Fatehabad tripped due to mal-operation of OFS (Oil Flow Switch).After this 765kV Fatehabad-Lalitpur line tripped on over voltage and due to outage of evacuation path, Lalitpur unit #2 generating 630MW along with 220kV lines tripped. Unit #1 came on house load. Total generation loss was ~1000MW and load loss was ~150MW.	8333
38	30-Nov-2016	6:02	All running units in Anpara generation complex tripped most likely due to tripping of 400kV Anpara-Sarnath D/C. Generation loss of 2000 MW occurred. At the same time Vindhyachal Block-1 tripped due to DC Over current protection.	8564
39	23-Dec-2016	1:25	All 400 kV lines from Kishenpur substation tripped except 400 kV Moga-Kishenpur-II which led to complete Valley(Kashmir) system collapse.Total Load loss in J&K was about 1200 MW and Generation loss was of about 250MW(Uri-I-40Mw,Uri-II-38Mw,Baghlihar-125Mw,JK Hydro-30Mw).	7917
40	19-Jan-2017	12:18	Due to break down of 220 kV Akal-Jeerat Y-Phase jumper, all lines emanting from 220 kV Akal s/s got tripped. There was total 1100 MW of wind generation loss in Rajasthan.	7333

Regionwise FRC Calculation(MW/Hz) since Jan 2015				
S.No.	Date	Time	Description	All India FRC in MW/Hz
41	5-Feb-2017	12:26	On 05-Feb-17, at 12:26hrs 765kV Mainpuri-Bara ckt tripped along with both running units at Bara TPS (UP). Generation loss of 1120MW occurred.	8000
42	21-Feb-2017	15:59	On 21.02.17, at 1559 hrs,due to tripping of Kalisindh Unit-I & II the generation loss of 900 MW took place.	10000
43	23-Feb-2017	16:15	On 23.02.17, at 1615 hrs, Kudankulam Unit-II generating 1000 MW went under house load.	11875
44	2-Mar-2017	1:58	On 02.03.17, at 0158 hrs,due to tripping of Krishnapattnam Unit-I & II the generation loss of 1085 MW took place.	7233
45	5-Mar-2017	15:15	On 05.03.17, at 15:15 hrs, full load rejection test(1000 Mw to zero)was carried out for Kudankulam Unit-II by GCB opening.	10000
46	3-Apr-2017	13:10	Yeramarus TPS Unit - 2 tripped due to Boiler Preheater Protection and caused generation loss of 800 MW.	8000
47	9-Apr-2017	08:49	All 400/220 kV ICTs tripped at Biharshariff resulting in load loss of 1000 MW in downstream network.	11743
48	13-Apr-2017	9:36	Due to tripping of Karad & kohlapur ICT's, the Load loss of 1840 MW took place.	9634
49	26-Apr-2017	10:01	Due to tripping of Karad & Kohlapur ICT's, the Load loss of 900 MW took place.	8901
50	9-May-2017	16:42	400KV J.P.Nigri-Satna line -1&2 tripped at 16:19 and 16:41Hrs due to which Unit-1&2 at J.P.Nigri tripped due to loss of evacuation lines. Generation Loss of 1180 MW.	11800

Regionwise FRC Calculation(MW/Hz) since Jan 2015				
S.No.	**Date**	**Time**	**Description**	**All India FRC in MW/Hz**
51	18-May-2017	08:01	Rihand Unit 1,2,4 tripped and at 08:03 Hrs Rihand Unit 3,5,6 also got tripped.Generation Loss was around 2750 MW.	10577
52	20-May-2017	20:06	Complete generation loss of approx. 2150 MW in Chabra/Anta/Kawai/Kalisindh generation complex (Rajasthan) . Load Loss in Rajasthan due to the tripping is approx. 400 MW	7955
53	23-May-2017	18:36	Unit-I of Kudgi STPS tripped due to low air pressure resulting in generation loss of 830 MW.	6917
54	23-May-2017	17:43	Vindhyachal Stage-III tripped reportedly due to fire in GeneratorTransformer LA of Unit-8. Vindhyachal Unit-8,9,10(capacity 500 MW each) tripped.	9333
55	27-Jun-2016	00:15	Load loss of about 1500 MW Occurred due to tripping in Haryana system.	8152
56	21-Jul-2017	21:26	Generation loss of about 1031 MW Occurred at Korba STPS due to tripping of evacuation lines	8592
57	27-Jul-2017	10:08	Generation loss of about 993 MW Occurred at Teesta III & Dikchu due to tripping of evacuation path.	8275
58	16-Aug-2017	12:18	400 kV Rangpo-Teesta (III) line tripped on B-N fault resulting in generation loss of 879 MW and 100 MW in Teesta and Dikchu stations respectively.	10878
			Median	**7507**
			Average	**7552**
** NEW and SR FRC as NEW and SR Grid got separated*				

Expanding the Ambit of Ancillary Services
A Concept Note for Introduction of New Services

Dated: 19th September 2017

1. Background

CERC (Ancillary Services Operations) Regulations, 2015 were notified in August, 2015. National Load Despatch Centre (NLDC) has been designated as the Nodal Agency for despatch of Ancillary Services. After extensive consultations with the stakeholders the "Detailed Procedures" were duly approved in March, 2016 and Reserve Regulation Ancillary Services (RRAS) mechanism was launched in April, 2016. The respective Regional Power Committees (RPCs) are the designated agencies for issuing the RRAS accounts.

Presently, the utilization of un-requisitioned surplus available in the generators, as RRAS Providers, whose tariff is determined or adopted by CERC is being done. All RRAS providers are mandated to submit relevant technical information as per the approved procedures on a monthly basis which is applicable for RRAS despatch during the following month. The present ancillary services framework envisages merit order based despatch (separate stacks for RRAS Up and RRAS Down based on variable charges) which is discounted in case of transmission congestion. Fixed charges, variable charges and an incentive is payable to the participating RRAS providers for 'Up' regulation from the DSM Pool. In case of 'Down' regulation, RRAS providers refund 75% of the variable charges to the DSM Pool, retaining the balance as an incentive for participation.

2. Experience Gained & Feedback on Implementation of Ancillary Services

In accordance with the directions of CERC, a feedback has been submitted by POSOCO on 17th November, 2016 to CERC regarding the experience gained in the operation of Ancillary Services. Further, based on the experience gained, a feedback on implementation of secondary control through Automatic Generation Control (AGC) pan-India and maintenance of reserves was submitted on 14th July, 2017. The key statistics regarding the RRAS despatch during the period April-2016 to August-2017 is enclosed at **Annex – I**.

The feedback submitted by POSOCO also mentioned the implementation related issues, some of which are reiterated as follows:

(a) Need for Primary and Secondary frequency reserves
(b) Participation of Hydro generating stations in the Ancillary Services framework
(c) Review of Deviation Settlement Mechanism (DSM)
(d) Streamlining of settlement and accounting systems, use of funds available in other regulatory pool accounts and operationalization of National Pool Account
(e) Introduction of 'gate-closure' in scheduling
(f) Five-minute scheduling, metering, accounting and settlement
(g) Bringing regional entity merchant generators/IPPs under Ancillary Services framework

Some of the other issues flagged in the feedback were subsequently addressed in the revised "Detailed Procedures" for Ancillary Services approved by CERC in November, 2016. In order to address the other issues raised, the ambit of Ancillary Services needs to be expanded and the implementation of the following is required:

a) Secondary Frequency Control through Automatic Generation Control (AGC)
b) Fast Response Ancillary Services (FRAS) from hydro generating stations
c) Voltage Control Ancillary Service (VCAS) through Condenser mode operation by the hydro generators
d) System Re-start Ancillary Services (SRAS)
e) Bringing regional entity merchant generators/IPPs under Ancillary Services framework

This concept note aims at providing a broad framework for implementation of the above mentioned services.

3. Frequency Regulation

With the introduction of Ancillary Services, there has been a marked improvement in the frequency profile. The average frequency remains very close to 50.00 Hz in a day. The frequency variation index (FVI) has improved to around 0.03-0.05 with the frequency remaining within the IEGC Frequency Band for 75-80% of the time and more. An all-time best FVI of 0.023 with an average frequency of 49.988 Hz was achieved on 17th July 2017. The improvement in frequency profile and the analytics are enclosed at **Annex – II**.

It is clearly observed that while the frequency is remaining within the IEGC specified frequency band close to 50.00 Hz, there are frequency excursions occurring outside the allowed frequency band at the hour boundaries. The frequency excursions are short and sharp in nature and managing these frequency excursions require fast responding resources, such as hydro, which can be pulsated for a short duration and ramped up/down quickly in succession.

Different frequency control mechanisms, namely, primary frequency control, secondary frequency control and tertiary frequency control act in different time frames as shown in the **Figure – 1**.

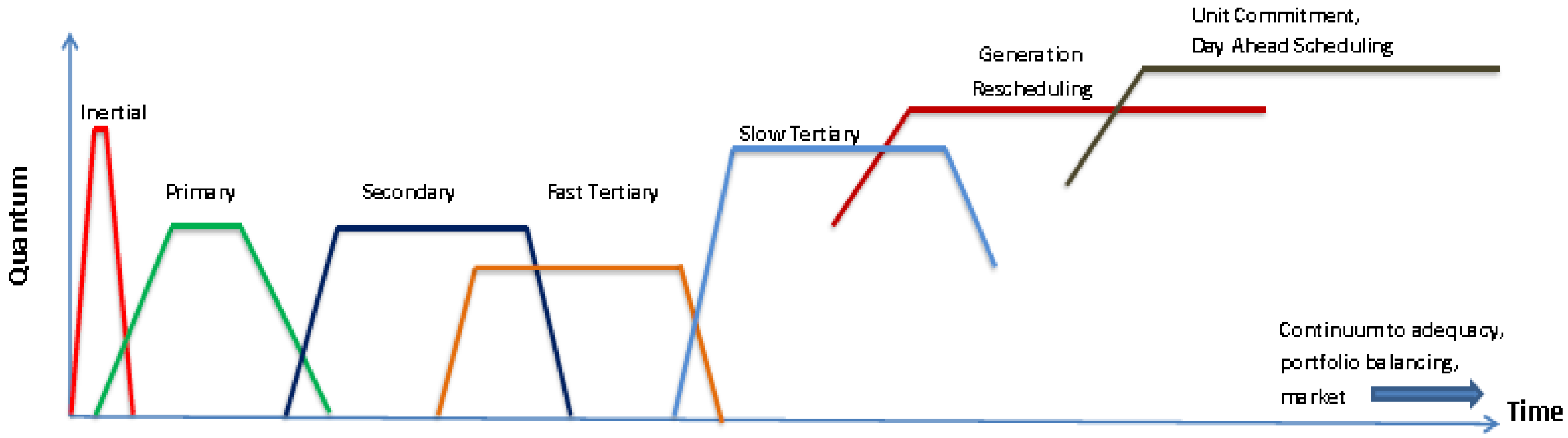
Presently, in India, primary frequency control is mandated and needs to be enforced. A pilot for implementation of secondary frequency control has been implemented. The present Ancillary services implementation falls in the category of tertiary frequency control. Having gained nearly one and half year of experience post implementation of ancillary services, need is felt for further refinements in the existing mechanism and introduction of new products/services under the ambit of ancillary services.

In view of above, new services are being proposed which are discussed hereunder.

4. Secondary Frequency Control or Automatic Generation Control (AGC)

CERC vide order in Suo-motu Petition No. 11/SM/2015 dated 13th October 2015 has given a roadmap for implementation of reserves in the country. Primary, Secondary and Tertiary Reserves have been identified as 4000 MW, 3623 MW and 5218 MW respectively in the road map given by CERC. While primary reserves are to be maintained mandatorily by all generators, secondary reserves are to be maintained at a regional level and the tertiary reserves are to be maintained in a distributed manner in the States.

System Balancing in India – A Schematic



Response → Attribute ↓	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling	Unit Commitment
Time	First few secs	Few sec - 5 min	30 s – 15 min	5 - 30 min	> 15 – 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC / RLDC	NLDC	NLDC / SLDC	RLDC / SLDC	RLDC / SLDC
Manual / Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	Ancillary Regulations	Ancillary Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Yet to start	Yet to start	Existing	Existing	Existing

Figure 1: System Balancing in India - A Schematic

In line with the roadmap given by CERC, a pilot project for implementation of secondary reserves through Automatic Generation Control (AGC) has been undertaken at Dadri Thermal Station in the Northern Region. The proposed commercial mechanism for AGC implementation has also been filed as a petition before CERC (NLDC Petition No. 79/RC/2017) which is presently under consideration of the Hon'ble Commission. The mechanism for AGC implementation as filed before the Hon'ble Commission is available at the web-link https://posoco.in/spinning-reserves/. The details of the proposed scheme are given at **Annex – III**. The detailed modus operandi on operationalization of spinning reserves is available at the web-link: https://posoco.in/download/detailed-modus-operandi-on-operationalization-of-spinning-reserves/?wpdmdl=13461

5. Fast Response Ancillary Services (FRAS) from Hydro Generating Stations

The total present installed capacity of hydropower stations is 44 GW comprising of 15,658 MW regional entity hydropower stations (the balance being intra-state stations). A list of Hydro ISGS is enclosed at **Annex – IV**. Based on plant type the regional entity hydro stations comprise of 3766 MW Storage type, 5678 MW pondage type and 6214 MW run-of-the-river type.

Hydro generating stations are capable of providing fast ramping capability and they can be gainfully utilized for regulation services to meet the system requirements. The present formulation under ancillary services is based on fixed charges, variable charges and a pre-specified markup. This needs to be reviewed for hydro stations because:

(a) Hydro stations are "*energy limited resources*" unlike the thermal stations (coal based) which are "*ramp limited resources*"
(b) Hydro stations are also subject to limitations/constraints in terms of water inflows as well as the quantum of water that can be released based on reasons other than power generation requirements
(c) Hydro stations can respond very quickly and much faster than thermal/gas stations or in other words, these are more suitable for handling sharp changes/fluctuations such as those observed at the hour boundary.
(d) The marginal cost for hydro generation is 'zero' and the segregation of fixed and variable charges in case of hydro is only notional (extract of provisions from the CERC Terms and Conditions of Tariff Regulations 2014-19 enclosed at **Annex – V**). Thus, the present model of ancillary services which relies on payment of fixed charges, variable charges and incentive is unsuitable for hydro stations. The amount of incentive payable to the hydro stations has to be lesser, say 10 paisa per unit.

In view of the special characteristics mentioned above, the following methodology is proposed.

5.1. Triggering and Despatch of FRAS

Triggering of RRAS from hydro stations may only be used for short durations such as handling hour boundary frequency changes, sudden changes in demand, ramp management, grid contingency, etc. As the hydro stations are mainly "*energy limited resources*" it is proposed that the net energy scheduled under RRAS Up and RRAS Down should be made zero for each hydro station within the day. Hydro is fast responding and would help to arrest the frequency spikes. With increasing quantum of renewable penetration, fast response ancillary can also act as a mechanism to handle the variability.

Given the fact that the marginal cost is zero for hydro, a key question that needs to be addressed is how the system operator shall take the despatch decision. This implies that the despatch decision itself should not be based on the variable charges. An alternate mechanism based on the following parameters is required:

- Total energy available declared for the day by the station, E_a
- Total energy scheduled during the day up to the time of despatch, E_g
- Balance energy available for increasing generation, ($E_b = E_a - E_g$)
- Maximum MW that can be delivered, P_{max}
- Minimum MW that needs to be maintained, P_{min}
- Total energy consumed under RRAS Up, E_{up}
- Total energy given as RRAS Down, E_{down}
- Net position of RRAS, $E_{net} = E_{up} - E_{down}$ (should be made zero as early as possible before the end of the day)

The operator may give RRAS Up instruction to the station with maximum E_b upto P_{max}. The RRAS Down instruction may be given to stations with minimum E_b upto P_{min}. Reservoir based stations should be given priority in despatch over pondage based stations. In both cases, a counter instruction is also to be given in due course so as to make the net position, $E_{net} = 0$.

The fast response ancillary services (akin to fast tertiary) from hydro would be despatched normally for a maximum of 2 – 3 time blocks of fifteen-minutes at a time. Subsequently, the despatch under normal RRAS from the thermal based stations (akin to slow tertiary) can replace this fast response ancillary service.

It may so happen that because of despatch of hydro under ancillary (up or down), it becomes necessary to give a counter instruction (down or up) during say hours where frequency is low or congestion is taking place. In such case, despatch under ancillary from thermal (coal / gas based) stations so as to ensure that the E_{net} of hydro becomes zero.

5.2. Scheduling

The present methodology of normal scheduling would be continued as it is. Similar to the existing VAE (which may be referred as VAE-T corresponding to thermal generation), there is a need to delink-the scheduling of hydro under RRAS with the schedules of the beneficiaries. Hence, a "Virtual Ancillary Entity – Hydro or VAE-H" may be created in each regional pool which shall act as the counterparty to the RRAS schedules given to the hydro stations in the concerned region. In effect, all efforts shall be made to make VAE-H equal to zero at the end of the day.

One example where hydro despatch under ancillary is useful is the case of reducing spikes in the frequency at each hour boundary. In such cases, ancillary from hydro can be despatched by giving a down-instruction 5 minutes before the hour boundary and again increasing by giving an up-instruction at 5 minutes after the hour boundary thereby reducing the generation for 10 minutes. In order to implement this feature, the scheduling of FRAS (from hydro) itself can be migrated from 15-minutes to 5-minutes at NLDC. This would be aggregated to 15-minutes, transmitted and interfaced with the existing scheduling software at the RLDCs.

5.3. Communication to the Generating Stations

As the response from hydro stations is quite fast, the despatch instruction (trigger) may be given few minutes in advance of the expected time when the response is required by the operator. The despatch instruction may be incorporated in the software to be put in place by NLDC and communicated telephonically/through emails or through the common SCADA screen to the generating stations. The schedules would continue to be communicated as per existing methodology.

5.4. Accounting and Settlement

For any FRAS instructions given to the hydro stations, the following methodology for payments may be adopted.

- Existing fixed charges and variable charges shall continue to be paid by the beneficiaries for the normal schedules as per existing practice
- No additional fixed charge or variable charges to be paid for the FRAS schedules
- The total energy despatched for hydro under FRAS is expected to be zero
- In case any residual energy is injected under FRAS, then, settlement for this net energy may be done using the variable charges of the station. The cycle time for pondage based stations could be less than 24 hours (say, 6 hours) depending on the pondage available and this needs to be factored suitably in the despatch.
- Incentive may be paid on mileage basis at the rate of say, 10 paise per kWh both for ‘up’ and ‘down’ regulation provided by the hydro station.
- Schedules under FRAS given to the hydro station shall not be included for the purpose of peaking under the Terms and Conditions of Tariff Regulations.

If during the day, the total up regulation is E_{upt} and the total down regulation is E_{downt}, then, the

(a) Net energy is $E_{net} = E_{upt} - E_{downt}$ (in MWh) *(expected to be zero over the day)*

(b) Mileage $E_m = |E_{upt}| + |E_{downt}|$ (in MWh)

6. Voltage Control Ancillary Service (VCAS) using Condenser Mode Operation by Hydro Generating Stations

With increased variability of the load pattern, high voltages are also being experienced in the network which need to be managed by the system operator. A number of hydro generating stations are capable of running in condenser mode and provide reactive power support. A section on Dynamic VAR support – Synchronous condenser operation has been made in the FOLD-POSOCO Report on Operational Analysis for Optimization of Hydro Resources & facilitating Renewable Integration in India.

During condenser mode of operation, the real power production of the unit is ‘nil’ and the unit is required to provide reactive power support (mostly absorb reactive power). Such situations are usually encountered in winter off-peak periods when the water level in the dams is low and active power generation by the unit is not possible.

Generating units with this capability are mostly reluctant to operate in synchronous condenser mode because the tariff received by them is only dependent on their real power output. In addition to this they also have to bear the cost of running their generators by drawing the energy from the grid to meet the friction and windage losses. Typical values of these friction and windage losses are known to be of the order of 1-2 MW/machine for a 120 MW machine. In addition to this, some auxiliary consumption in the form of power drawn by the air compressors etc. shall be considered as system loss.

A source like synchronous condenser has many distinct advantages over a static VAr compensator. The reactive power supplied by a synchronous condenser is dynamic, voltage independent, increases the fault level and also enhances the stability.

It is therefore proposed that a mechanism may be put in place for provision of reactive support ancillary services by condenser mode operation of eligible hydro stations. There should be provision for suitable compensation amount and incentives so that generating units voluntarily make themselves available for synchronous condenser operation.

System operator would advise a generating station to run one or more units in synchronous condenser mode. Remuneration to the generator would be based on duration of operation and reactive power generated / absorbed. It is proposed that a generator who is operating as synchronous condenser will be reimbursed at a rate approved by the Commission (say 25 paisa/kVArh). In addition to this, the losses incurred by generator on account of friction and windage losses and copper losses in generating transformer during synchronous mode operation will factored as pooled losses.

7. System Re-start Ancillary Service (SRAS)

In the event of a blackout, the black start service provided by some identified generators becomes invaluable. Such events are rare and far apart and the identified generating stations capable of providing the black start facility must be in a state of readiness to provide this service. Sometimes due to various reasons, the stations may not be able to provide black start service despite being capable of doing so. From a reliability perspective, it is important to have a mechanism in place, wherein, not only the black start capability gets tested periodically but also, the identified generators are incentivized to maintain the black start facilities voluntarily in a state of readiness to take care of any eventuality.

It is proposed that System restart ancillary services (SRAS) may be introduced to take care of contingency situations like partial/total grid disturbances wherein the electrical system must be restarted in line with the Regional black start procedure. As per clause 5.8(b) of the IEGC, mock exercises for black start must be conducted twice a year by the identified units on demand by the system operator. The black start costs primarily comprise of

(a) the cost of the operators (manpower costs),
(b) the costs associated with routine maintenance and testing of equipment
(c) the cost of fuel used when the service is required
(d) any other contingent expenditure

In addition to the above, the generators should also be incentivized for performing each successful mock exercise. Appropriate payment, say Rs. 0.5 lakhs (including the costs and an incentive) amount may be decided by the Commission per black start, which would be paid to the generator for successfully displaying black start capability in the mock exercise. This amount may also be paid additionally to these stations in case they provide the SRAS during an actual full/partial blackout.

8. Inclusion of Regional Entity Thermal Merchant Generators / IPPs

Presently, only those regional entity generators are included under the RRAS mechanism whose tariff for the full station is determined or adopted by the Central Commission. Thermal Merchant generators / IPPs are excluded from the ambit of ancillary services. These generators also comprise a sizeable chunk and can provide additional reserves for despatch under the ancillary services (List enclosed at **Annex – VI**). The following aspects need to be recognized in respect of these generators:

(a) Merchant/IPP generators are selling power to multiple buyers under long-term, medium-term or short-term contracts and some are also selling in the Power Exchange(s).
(b) Only the despatch schedules are provided by the RLDCs based on the contracts.
(c) Merchant/IPP generators need to provide details of the quantum of reserves available with them for despatch under RRAS on daily basis.
(d) Tariff is not determined and variable charges are not available upfront. Moreover, it may so happen that one IPP could be selling to multiple buyers from the same station at different rates.

Further, in order to facilitate merit order despatch under the ancillary services, each station needs to provide a variable charge based on which the despatch decision could be taken in real time. The following options are available for arriving at the variable charges to be used for merchant generators/IPPs:

a) Regulated Method: The weighted average rate of the long-term contracts entered into by the IPP/MPP or Commission may specify any rate for each plant.
b) Auction Method: Power exchanges may introduce a new segment for reserves. The rate of each station so discovered would be applicable for merit order despatch during the next month.

9. Introduction of Gate Closure in Scheduling

With coordinated multilateral scheduling process and continuous revisions, overlapping of the RRAS instruction and the schedule modifications being carried out by the concerned RLDC is taking place. For example, re-scheduling of un-despatched surplus on the request of one of the beneficiary, tripping of power system elements, natural variations etc. The available URS is thus changing continuously also and simultaneous ancillary dispatch has added another dimension of complexity to the process as there could be overlapping changes by the NLDC (for ancillary) and the RLDCs (schedules).

Therefore, there is need for introduction of gate closure concept in the scheduling process so that system operator has the clarity of the quantum of reserve and resources at hand at any given point of time. Better optimization of the scheduled despatches and the real time ancillary despatch needs to be formulated.

In physical terms, the concept of gate closure would facilitate better system balancing through a thin layer of centralized despatch over decentralized scheduling by the constituents. In order to implement "gate closure", the following is proposed:

(a) The maximum number of revisions in schedule will be restricted to 96 (presently, it goes beyond 100 revisions sometimes). In order to implement this, RLDCs shall implement 'batch processing' of schedule revisions where each batch of schedule revision runs once every 15-minutes.

(b) "Gate Closure", meaning no further revision in schedules (either by beneficiary or the generator) shall be accepted.
(c) Gate closure shall occur 90 minutes (or 6 time blocks of 15-minute each) prior to the time of despatch. It is pertinent to mention that in case of renewables, a maximum of 16 revisions (once every 90 minutes) are allowed. This time could be reduced progressively as more experience is gained and more automation is achieved.
(d) The final schedules would be worked out 60 minutes prior to the time of despatch.
(e) After gate closure, firm information would be available with the NLDC/RLDCs regarding the quantum of reserves available and ancillary despatch can then be undertaken in a more economical way with more certainty.
(f) Despatch under ancillary will be incorporated in the schedules in the next upcoming batch of schedule revision.

10. Way Forward

Implementation of the new products under Ancillary Services will require amendment to the existing CERC Ancillary Services Operations Regulations 2015. Further, before new ancillary services are introduced, certain design modifications are required in the existing framework. Some of the important changes required are mentioned below.

(a) In the present mechanism, fixed charges for RRAS Up instructions are paid from the concerned regional DSM pool account to the RRAS Provider who in turn refunds the fixed charges to the beneficiaries in the ratio of their surrender of power in that station. The original beneficiary(ies) also have the right to recall its un-requisitioned power any time as per provision of Regulations, therefore the ownership and rights remain with original beneficiary and original beneficiary(ies) should continue to pay the fixed charges. This refund of fixed charges, while reducing the fixed charge liability of the beneficiaries, has also created a perverse signal leading to lack of better scheduling of resources in advance. Inclusion of the fixed charges in the payments is indirectly distorting merit order also. Hence, the provision regarding refund of fixed charges needs to be reviewed.

(b) It has been observed in the day to day operations, that many times (specially during periods of high demand and peak hours), there are no available reserves for despatch under the ancillary services. Hence, there is a need for mandating specific quantum of reserves to be maintained. The mandate for maintaining reserves has been given as part of the CERC Order giving the roadmap for reserves. In order to have the force of law, this needs to be made a part of the Ancillary Services Regulations. Once it becomes part of the CERC Regulations, then the necessary steps for enforcement may also be taken up with the States and also at the Central level. Under the present mechanism, the quantum of reserves available keep varying and sometimes for example during peak hours, it becomes zero also. With increasing penetration of renewables, the reserve requirements are set to increase specially as the 'ramping' requirements become more stringent.

(c) Presently, in the process of scheduling all windows for change are open simultaneously and the market participants keep changing requisitions, DC etc. leading to continuous changes in schedules. The existing RRAS mechanism relies on the un-requisitioned surplus available as reserves. This makes it almost impossible to ascertain the quantum of reserves available for despatch under RRAS. Hence, a mechanism for "Gate Closure" is required to be implemented.

(d) In order to refine the existing RRAS mechanism and move ahead with introduction of new services, it is essential that the payment of fixed charges under the existing RRAS mechanism be reviewed and withdrawn. This would also lead to better planning and scheduling by the constituents.

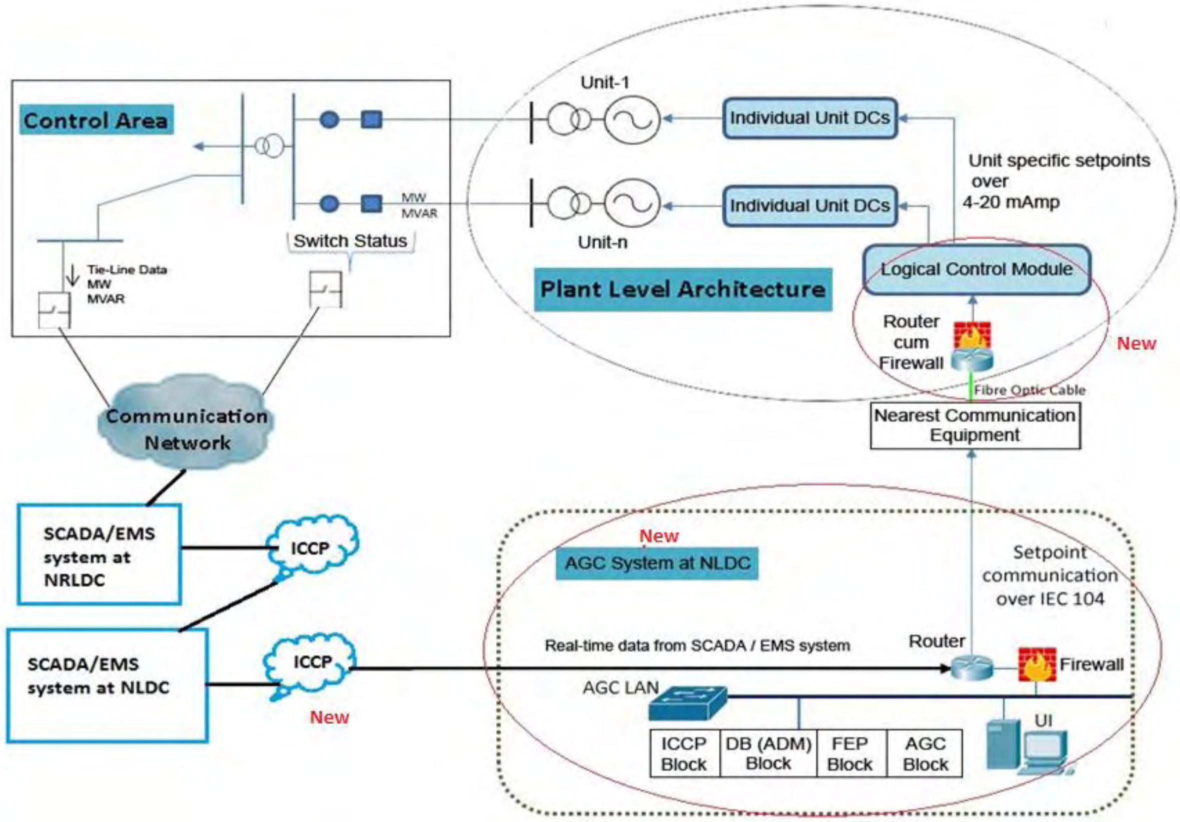
(e) Each of the proposed new services may be added as a separate product under the Ancillary Services.

(f) Deficit in some of the Regional DSM Pools has occurred in the past and as per provisions of the ancillary services regulations, surplus funds from other DSM pools are transferred to the deficit regional pool. However, it has been observed that in some weeks, this is also inadequate to meet the total payment liability for ancillary services. It is proposed that the Regulations may be amended to permit usage of surplus funds in other accounts such as Congestion Revenue as Ancillary Services are also used for congestion management. Hence residual Surplus in all Regulatory accounts (DSM, Reactive, Congestion etc.) may be routed to the National Pool Account, from which all payment liabilities for ancillary despatch are met and any residual amount after meeting the liabilities is transferred to PSDF.

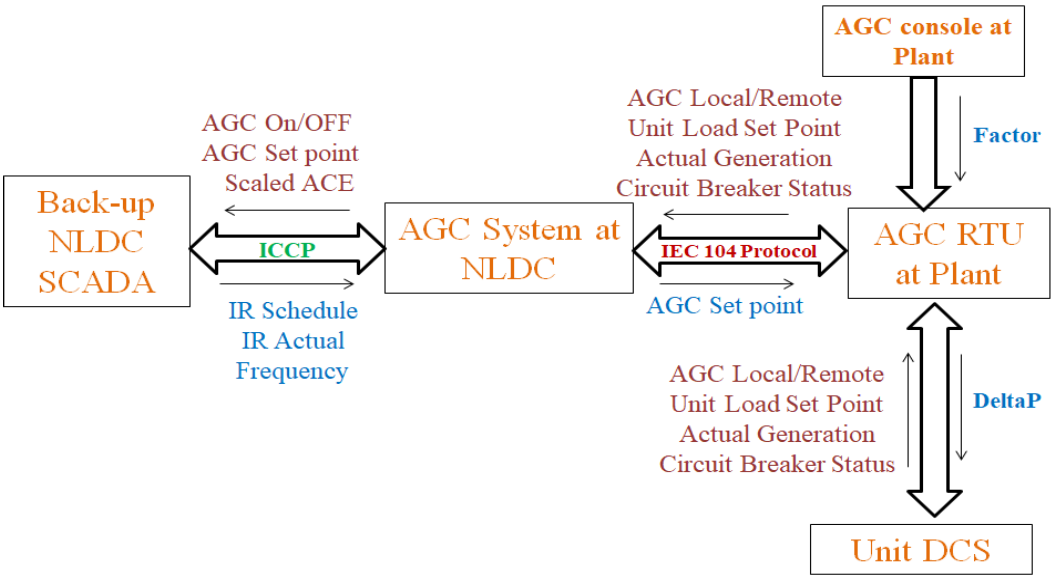
(g) Clear mechanisms for performance monitoring including definition of performance parameters for each type of service needs to be undertaken to ensure quality of service and compliance.

Salient Features of Proposed AGC Implementation Scheme

- All the ISGS generators whose tariff is regulated / adopted by CERC have been proposed to be made capable of participating in secondary control
- **Technical Specifications**



- **Data Flow**



- **Output limit checks**

  A limit is provided to restrict utilization of spinning reserve in a particular generation plant. The plant ramp rate is honoured while giving DeltaP signals. The difference between two successive values of Delta P is computed and restricted to a particular limit by the ramp application at NLDC. Unit

Capabilities are checked at Plant end. Maximum MW limit is also honoured at NLDC and plant ends. Mill availability is ensured manually so that sufficient spinning reserve is available in real time.

- **AGC Implementation Phases**

Phase – 1: The variable cost of generation plants whose tariff is determined/adopted by CERC is already available. There are fewer communication issues and easier to integrate. The availability of the full quantum of reserves as mandated by CERC may be an issue.

Phase – 2: In order to improve the availability of Reserves over and above the Phase-I power stations, regional entities/some Independent Power Producers (IPPs) having part PPA (Power Purchase Agreement) and part merchant contracts can be brought under AGC. Further, their DC and Schedule have to be obtained, similar to Central Sector generating stations, for reserve estimation. Tariff for regional entities/some Independent Power Producers (IPPs) has to be decided and agreed upon apriori. Many of these regional entity generating stations operate in the day-ahead energy market. There can be an issue of low prices on a sustained basis which may lead to many units remaining off the grid.

- **Payment for Energy & Incentive**

The proposed payment mechanism for secondary control is similar to the present RRAS dispensation. The payment will be done on basis of Net energy and Mileage. The total up regulation (E_{upt}) and the total down regulation (E_{downt}) will be calculated on weekly basis. The Net Energy and Mileage is calculated as follows:

(a) Net energy is $E_{net} = E_{upt} - E_{downt}$ (in MWh)
(b) Mileage $E_m = | E_{upt} | + | E_{downt} |$ (in MWh)

The payment for net energy (AGC MWh) generated during a block is proposed to be done at variable charges with mileage markup of 50 paisa to the plant from the respective regional DSM pool. In case of net energy (AGC MWh) reduced during a time block, it is proposed that the plant refunds variable charges to the respective regional DSM pool while retaining the mileage markup of 50 paisa.

- **Handling Deviations in Proposed AGC Implementation Scheme**

The deviation in MWh for every time block will be calculated as:

MWh deviation = (Actual MWh) - (Scheduled MWh) – (Net Energy AGC MWh)

The Net Energy (AGC MWh) can be positive or negative. The Actual MWh and Scheduled MWh will be always positive. The resultant MWh deviation would be settled as per the existing DSM Regulations.