Central Electricity Regulatory Commission

New Delhi

Draft Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022

no. L-1/265/2022/CERC Date:9.10.2022

Explanatory Memorandum

1. Background

1.1. The Central Electricity Regulatory Commission (CERC) (herein after referred as "the Commission") was constituted under the erstwhile Electricity Regulatory Commissions Act (ERC), 1998 and has been deemed to be constituted under the Electricity Act, 2003 (herein after referred as "the Act"), after enactment of the Act. The Commission has been vested with power to specify the regulations pertaining to Grid Code in terms of clause (g) of sub section 2 of Section 178 of the Act read with clause (h) of sub-section (1) of Section 79 of the Act. Accordingly, the Commission notified the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations 2010 on 28.04.2010 (hereafter referred to as '2010 Grid Code'). Till date there have been six amendments to the 2010 Grid Code.

1.2. The 2010 Grid Code contains the provisions regarding the roles, functions and responsibilities of the concerned statutory bodies, generating companies, licensees and any other person connected with the operation of the power systems within the statutory frameworks envisaged in the Electricity Act and the Rules and Notifications issued by the Central Government.

1.3. In the last decade, the National grid as well as entities in the Grid have evolved significantly. There has been significant capacity addition of generation under private sector as well as inter-State transmission system. Further increased focus on renewables poses challenges which are to be addressed through evolving Grid Code. Indian grid has been integrated through cross border interconnections with Nepal, Bhutan, Bangladesh and Myanmar.

1.4. When the first Grid Code was prepared in 1999, Indian electricity grid was divided among regions and was operating at four independent frequencies. Since then the grid has expanded and grown rapidly and has been strongly integrated in to one synchronous grid operating at a common frequency. It has increased the grid stability and its capacity to accommodate the variability of renewable generation. The nominal operating frequency band has been progressively narrowed and charges for deviations from the schedules have been tightened, significantly controlling frequency excursions. Operating an integrated national grid with cross-border interconnections makes the task of grid operation challenging.

1.5. There has been significant progress in the growth of power system including RES in India. As per the Executive Summary on Power Sector for July 2022 published by CEA, the installed capacity of RES (including Small Hydro but excluding Large Hydro) has increased from 1628.39MW around i.e. 0.015% (at the end of 9th Plan) to 114437.37 MW i.e. around 28.31% (up to July, 2022). As per CEA's "Report on Optimal Generation Capacity Mix For 2029-30" in the year 2029-30, non-fossil fuel (solar, wind, biomass, hydro & nuclear) based installed capacity is likely to be about 64% of the total installed capacity (817254 MW) and accordingly, the installed capacity of RES(including Small Hydro but excluding Large Hydro) is likely to be 445306 MW i.e. around 54% of the total installed capacity (817254 MW) during the year 2029-30. Further, the All-India peak electricity demand for the year 2021-22 (as per Peak Power Supply Position Report (Revised) published by CEA) is 203014 MW which is expected to touch around 370462 MW by 2031-32 (as per 19th Electric Power Survey of India report published by CEA).

1.6. Over the years, the Commission has taken several initiatives through laying down required framework for effective and secure grid operations. Few of such initiatives are mentioned hereby for reference.

(a) The Commission vide its order dated 13th October 2015 in 11/SM/2015 provided a roadmap for operationalize reserves in the country. The primary reserves have been ensured through suitable amendments in the Grid Code which require the generating stations to keep such reserves for system security, by not scheduling beyond their installed capacity. For secondary reserves, the Commission has taken phased approach by implementing pilots with a few ISGS (inter-State Generating Stations) and subsequently directing vide Order dated 28.08.2019 in Petition No. 319/RC/2018 that all inter-State generating stations (ISGS) should be AGC enabled. As regards tertiary control, the Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 (in short, 'the RRAS Regulations') has started with administered mode of Ancillary Procurement with idea to shift to market based procurement of Ancillary Service with sufficient experience.

(b) The Commission through suitable amendments facilitated creation of reserves at the regional level by specifying norms for technical minimum and upper limit for scheduling interstate generation stations

(c) Further, keeping in view of the variable nature of generation from wind and solar resources and the effect such variability has on the inter-state grid, the Commission also introduced Forecasting and scheduling framework for wind and solar generating stations along with required framework for Deviation and Settlement Mechanism (DSM) through suitable amendments in the Regulations.

(d) The Commission, over the period, has tightened the operating band of frequency with due regard to the need for safe, secure and reliable operation of the grid. The Commission, in view of emerging market conditions has also reviewed the deviation settlement mechanism (DSM) rates, including their linkages with operational the band of frequency. Further, The Commission, in its meeting dated 23rd March 2017 resolved to declare National Frequency as 50 Hz and also directed to constitute a high-level expert committee 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 of 50 Hz.

(e) The Expert Group (hereafter referred to as "**50 Hz Committee**"), deliberated upon the issues related to grid operation and its existing operational band of frequency and brought out its first volume of the report discussing "review and suggestive measures for bringing power system operation closer to National Reference Frequency". The some of the recommendations of the Committee Report (volume-I) which were considered in the preparing the draft Regulations are listed below for ready reference.

i. Move to an operating frequency band of 49.95 Hz to 50.05 Hz

ii. Establishing the Frequency control continuum for Indian grid conditions detailing out the response time of inertia response, primary response, secondary response and tertiary response and consider Reference frequency of 50 Hz for frequency control

iii. Monitoring of ‘Area Control Error’ and frequency response characteristics (FRC) by Regional Load Despatch Centres (RLDCs)

(f) In view of the intermittency of RE sources, there was a need for an organized market platform to enable buyers and sellers to meet their energy requirements closer to real time of operation. The Commission hence introduced the framework for Real-time Market for Electricity in India (RTM) which came into effect from 1st June, 2020. RTM brought the required flexibility in the market to provide real time balance, while ensuring optimal utilization of the available surplus capacity in the system. The Real Time Market introduced the concept of “Gate Closure”, with an appropriate timeline in consonance with half hourly market. ‘Gate Closure’ implies the point of time after which no trade or revision of schedule is allowed. This is considered necessary for bringing in the desired firmness in schedules during the hours of market operation. After Gate Closure, the system operator takes over the responsibility for balancing the system. The Commission believes that Real Time Market provides an alternate mechanism for Distribution Companies to access larger market at competitive price. On the other hand, generators also benefit by participating in the RTM with their un-requisitioned capacity. The same has been continued through the similar provision in the draft Grid Code.

(g) The Commission has introduced the concept of Security Constrained Economic Despatch (SCED) with a view of ensuring optimization of generation resources at National level though a pilot vide its Orders from time to time. The prime driver behind the pilot is to explore the scope of optimization and therefore the possibility of minimizing the system cost without major structural changes in the existing system. The pilot optimises the injection from generating resources with the objective of minimization of production cost, after the beneficiaries submit their last revision i.e. seven to eight blocks before the actual dispatch of power. The optimisation of generation has been achieved by creating a national level merit order by dispatching cheaper generating station after duly factoring in technical constraints such as technical minimum, maximum generation, ramping constraints, transmission constraints etc. Thus, optimisation at national level is achieved by increasing the lower variable cost pit-head generation while reducing the higher variable cost generation for the generators participating in the pilot. Around 50 generating stations have been participating in the pilot having 120 generating units and capacity of around 53,000 MW in the country. Since its inception in April 2019, SCED has resulted in reduction of variable cost of generation by more than ₹ 2000 crore. In view of this, the Commission has decided to introduce legal framework for the same by incorporating it in the draft Grid Code.

1.7. Further, the Commission envisages that the next decade may see challenges on account of the following aspects:

(a) India has a target to integrate around 500 GW of non-fossil fuel sources in the system by 2030. Due to this addition, issues on account of intermittent generation such as reduction in inertia, ramping requirements and availability of adequate generation to match the variability have to be addressed.

(b) Due to integrated nature of the grid as well as intermittent nature of RE generation, coordination between various stakeholders shall be required to manage any exigency situation.

(c) Due to increased size of the grid including cross border interconnections, in any unforeseen event such as transmission line tripping or generation unit outage may trigger widespread grid collapse, if not managed properly.

Therefore, adequate contingency measures must be made available to cater to unforeseen situations.

(d) Managing physical and cyber security threats.

1.8. In view of the foregoing as well as the requirement to amend the Grid Code due to the recent developments in power sector in India, changes in market structure and future challenges which include high level of renewable penetration in the grid, the Commission appointed an Expert Group (hereafter referred to as "**Expert Group**") chaired by Shri Rakesh Nath to review the provisions of IEGC 2010 and prepare draft IEGC making recommendations for proposed amendment or changes in the existing Grid Code. The Expert Group submitted its report on 9th January 2020 wherein it proposed the Draft Indian Electricity Grid Code. Expert Group Report is available at CERC website at following link:

https://cercind.gov.in/2020/reports/Final%20Report%20dated%2014.1.2020.pdf

1.9. The Expert Groups mainly gave the following recommendations:

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a) *The planning code has been thoroughly overhauled covering all facets of power system planning including demand forecasting, generation resource planning (flexibility, ramping, minimum turndown level), requirements of energy storage system, system reserves, system inertia for grid stability, inter-state system planning (including reoptimization system study, adequacy, enhancement of total transfer capability (TTC) across inter-regional boundaries as well as ISTS interfaced with STU network).*

b) *The Connection Code has been reviewed and made applicable to the generators as well as the transmission licensees. This code specifies the requirements to be fulfilled by the connectivity grantees prior to obtaining the permission of the RLDC/NLDC/SLDC for first time energizing of a new or modified power system element. In addition to above, this code specifies the technical requirements to be complied by a transmission licensee including deemed transmission licensees* *or cross-border entity prior to being allowed by RLDC/NLDC/SLDC to energize a new or modified power system element. The code also specifies the tests required before trial run.*

c) *A new code namely, protection and commissioning code has been added. A centralized data base containing details of relay setting for grid elements shall be maintained by RPC and system wide study twice a year for validating the protection setting shall be carried out by RPC secretariat. The new protection code provides for annual self-audit and third party once in five years. In the commissioning code procedure for trial run and declaration of CoD for renewable generators has been included. Further, to confirm the flexibility of generators for grid security, some necessary tests prior to trial run have been prescribed for different type of conventional and renewable generators.*

d) *The draft IEGC 2020 has suggested frequency response measures to correct the load generation imbalances in an automated manner with the help of primary, secondary and tertiary reserves coupled with demand response as a last resort. In view of the comfortable power supply position, it is now possible to have reserve generating capacity on bar for a quick response. NLDC has already done the preparatory work with regard to automatic generation control or AGC. We are getting initial or primary response at the rate of about 12–14 GW/Hz to contain frequency excursions. In place of restricted governor mode of operation (RGMO), the new Grid Code has proposed free governor mode of operation (FGMO) for all generating units in the country in order to arrest stead fall in the frequency in the event of a major grid disturbances. The primary response shall be provided by the generating machines immediately up to five minutes by which time the secondary response shall take over through automatic generation control to recover the frequency.*

e) *The quantum of reserve capacity required to be maintained for grid security is related to credible contingency including net error in the forecasts of demand and renewable generation. In the draft IEGC 2020, demand forecasting activity has been properly organized and there is a monitoring mechanism for errors in* *demand forecasting. The operating code provides for ensuring and monitoring of availability of reserve capacity.*

f) *In order to minimize forecasting errors of renewable generators, aggregation of renewable energy has been allowed at one or more pooling stations for the purpose of deviation settlement. An institutional mechanism (QCA) for the composite scheduling and common deviation settlement of renewable generating stations at one or more pooling stations has been provided. The role and functions of QCA has been specified in the Grid Code.*

g) *In order to accurately forecast grid behavior in different eventualities it is necessary to validate the performance characteristics of power system elements particularly, generating units. Therefore, field testing of machines for validation of their mathematical models to be used in power system studies has been mandated once in five year.*

h) *The draft IEGC 2020 mandates adequacy of generation resources for round the clock supply to all consumer categories. It proposes load shedding through demand response contracts or through special protection schemes in the event of an emergency situation.*

i) *There is emphasis on continuous re-optimisation of interstate transmission system with a view to achieving economy and efficiency in operation. In addition to inter-regional power transfer capability, both CTU and NLDC shall be required to declare import/export transfer capability at the electrical periphery of a state in coordination with the STU.*

j) *Wind, solar, wind-solar hybrid and hydro plants (in case of excess water leading to spillage) shall be treated as MUST RUN power plants and shall not be subjected to curtailment on account of merit order despatch or any other commercial consideration.*

k) *In the event of transmission or system security constraint, the renewable generation may be curtailed after harnessing available flexible resources including energy storage systems.*

l) In the event of extreme circumstances when any MUST RUN plant has to be curtailed, the details shall be published on the RLDC/SLDC website the following day, as the case may be, giving the date, name of RE generation plant, installed capacity, curtailment quantum in MWh, duration of curtailment and detailed reasons thereof.

m) Flexibility has been granted to the distribution utilities/ buyers having long-term transmission access for scheduling power out of their basket of power purchase agreements, including short-term contracts, up to the approved quantum of LTA. This will facilitate the distribution utilities to optimize their power procurement cost.

n) Distribution utilities/ buyers having short-term bilateral access shall be able to revise their schedule as per the same timelines provided for the long-term or medium-term schedule.

o) With a view to enhancing the flexibility of coal, lignite and gas based thermal generating stations for the emerging scenarios of high renewable energy penetration the compensatory mechanism for below the normative plant load factor has been reviewed and rationalized. The compensation for degradation in performance parameters resulting in higher cost of energy shall be calculated for each time block and settled on monthly basis. However, the extant mechanism has been retained for sharing of efficiency gain for power plants.

A new Code namely, Cyber Security has been added. The code provides for identification of Critical Information Infrastructure, appointment of Information Security Officer as per the Information Technology Rules 2018 and take necessary measures in accordance with guidelines by National Critical Information Infrastructure Protection Centre."

1.10. The Commission, vide its notification dated 31st January 2022 notified the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022 (hereinafter referred to as '2022 Ancillary Service Regulations') which includes the framework of commercial mechanism with respect to the frequency control ancillary services.

1.11. The Commission, vide its notification dated 14th March 2022, notified the Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022 wherein any deviation of schedule shall be dealt according to the provisions of the regulations.

1.12. Subsequently, the Commission on 7th June 2022, notified the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022 (hereinafter referred to as 'GNA Regulations') which dealt with provisions related to Connectivity and Access to the Grid.

1.13. The consequential changes required in 2010 Grid Code keeping in view above stated changes in Regulations has been duly captured in the draft Grid Code. Accordingly, as per the developments considered above, the Central Electricity Regulatory hereby proposes the draft Commission (Indian Electricity Grid Code) Regulations 2022 ('hereinafter referred to as draft Grid Code).

1.14. The draft Grid proposes inclusion of three new chapters viz Protection Code, Cyber Security Code and Monitoring & Compliance Code in addition to specifying the framework for reserves. The salient features of different codes of the draft Grid Code are as follows:

(a) *Resource Planning Code:* The Planning Code has been proposed to be renamed as Resource Planning Code. A bottom up planning approach has been suggested which shall include demand forecasting, generation resource adequacy planning and transmission resource adequacy assessment required for secure grid operation. The resource adequacy planning shall be on a rolling basis of five years to ensure adequacy of generation resources and adequate planning reserve margin.

(b) *Connection Code:* It has been proposed that NLDC shall prepare a detailed procedure for first time energization and integration of new or modified power system elements and SLDC shall prepare the same at intra-State level. NLDC, RLDC or SLDC as the case may be shall carry out joint system study prior to the first time energization of a power system element.

(c) *Protection Code:* Considering the importance of protection protocol and protection audit post 2012 Grid Disturbance, a new code has been introduced in the draft Grid Code covering protection protocol, protection settings and protection audit plan of electrical systems.

(d) *Commissioning and Commercial Operation Code:* In addition to provisions related to trial run and declaration of commercial operation for thermal generating stations, hydro generating stations, transmission system and communication system, provisions related to trial run and declaration of commercial operation of wind, solar, hybrid, pumped storage and ESS stations have been proposed in the draft grid code. Further specific test reports and documents have been specified which shall be submitted prior to declaration of commercial operation by generating stations and transmission licensee.

(e) *Operating Code:* The framework for reserves comprising of primary, secondary and tertiary reserves, Voltage Control Reserves and Black Start Reserves has been proposed in the draft Grid Code. The national reference frequency has been proposed at 50 Hz while allowable frequency band has been proposed to be tightened to 49.95 Hz to 50.05 Hz. The default UFR settings have also been proposed to be amended with an increase of 0.2 Hz at all stages in the existing settings. The compensation for reactive power service and black start service have been proposed in the draft Grid Code.

(f) *Scheduling and Despatch Code:* The scheduling procedure has been modified to align with the GNA regulations. The mechanism for Security Constrained Unit Commitment has also been proposed to ensure adequacy of reserves.

(g) *Cyber Security Code:* A new code has been proposed wherein all users shall conduct Cyber Security Audit as per the guidelines mentioned in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such regulations issued by an appropriate authority, so as to support reliable operation of the grid.

(h) *Monitoring and Compliance Code:* Two methodologies have been followed to ensure compliance: self-audit and compliance audit. The monitoring agency for users shall be the concerned RLDC or SLDC on the basis of their respective control area. The monitoring agency for RLDC, NLDC, CTU and RPC shall be the Commission, and for STUs and SLDCs, shall be the concerned SERC.

2. Definitions

2.1. The following terms have been proposed in the definition of the draft Grid Code:

(a) ‘Alert State’, ‘Emergency State’, ‘Normal State’ and ‘Restorative State’ have been introduced in the draft Grid Code. These are system states on the basis of which power system has been proposed to be categorized in real time as per the Regulation 35. Further, definition of ‘System State’ and ‘Blackout State’ has also been introduced in the draft Grid Code.

(b) The definition of 'Ancillary Services' has been modified in the draft Grid Code. The Commission, vide 2022 Ancillary Services Regulations, had notified Primary Reserve Ancillary Services (PRAS), Secondary Reserve Ancillary Services (SRAS) and Tertiary Reserve Ancillary Services (TRAS) as the ancillary services through which the frequency shall be maintained close to 50 Hz. Accordingly, the same has been modified in the draft Grid Code.

(c) 'Area Control Error' has been introduced in the draft Grid Code since it is the metric for measuring the generation and load imbalance for activating secondary reserve ancillary services.

(d) 'Automatic Generation Control' has been introduced in the draft Grid Code since it is the control system for activating the SRAS and may require modifications on account of proposed regulations.

(e) 'Declared Capacity', 'Cold Start', 'Warm Start', 'Hot Start', 'On-Bar Installed Capacity', 'On-Bar Declared Capacity', 'Off-Bar Declared Capability': The Commission, vide its order dated 5th May 2017 in order No. L-1/219/2017-CERC had notified the aforementioned definitions. As details of these capabilities are proposed to be submitted to RLDC under the draft Grid Code, these definitions have been included in the draft Grid Code.

(f) 'Control Centres' at NLDC, RLDC, REMC, SLDC, Area LDC, Sub-LDC and DISCOM LDC have been included in the draft Grid Code as the control centres are critical for grid operations.

(g) 'Energy Storage System': The Commission has already notified the definition of 'Energy Storage' in the Ancillary Services regulations. The provisions of declaration of COD of ESS has been included in the draft Grid Code.

(h) 'Flat frequency control', 'Flat tie-line control' and 'Tie-line bias control' are three AGC operation modes available to the system operator. Through these modes, the system operator shall be able to deploy SRAS to manage the grid as per the draft Grid Code.

(i) ‘Flow-gate’ are a group of transmission lines whose cascade tripping can lead to loss of generation and load. Due to the critical nature of such corridors, they have a critical role while determining the ATC or while planning the protection schemes. Accordingly, the definition of flow-gate has been included in the draft Grid Code.

(j) ‘Frequency Response Characteristics’, ‘Frequency Response Obligation’, ‘Frequency Response Performance’, ‘Frequency Stability’, ‘Inertia’, ‘Nadir Frequency’, ‘Rate of Change of Frequency’ and ‘Reference contingency’ have been introduced in view of the frequency control mechanism as defined in the draft Grid Code.

(k) ‘Gate Closure’: In IEGC (Sixth Amendment) Regulations, 2019 Gate Closure was termed as “before the window for trade closes for a specified duration”. The Gate Closure is defined in the draft Grid Code to bring clarity and considering its relevance in the scheduling of transaction in Real-time market.

(l) ‘Generating unit’: The definition of generating unit has been expanded in the draft Grid Code and proposed to cover solar, wind and hybrid generation in addition to the turbo-generator.

(m) ‘GNA Regulations’ and ‘GNA Grantee’ have been introduced in the draft regulations to align with the GNA regulations notified by the Commission.

(n) ‘Grid-forming Capability’: Generally the RE based plants are grid following in nature and require voltage reference and rely on a strong grid for synchronizing and thus follow the grid behavior by responding to the measured quantities. The Commission has defined this term and emphasized its importance in system restoration procedure because of unique capability which do not rely on external grid voltage to generate power and can operate without, or with very few, synchronous machines electrically nearby.

(o) 'Infirm Power': The treatment of 'Infirm Power' was earlier in accordance with the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009. As the Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-State Transmission and related matters) Regulations, 2009 ('2009 Connectivity Regulations') are proposed to be repealed after the GNA regulations come in force, the treatment of infirm power has been dealt in the Grid Code and accordingly, the definition is included the draft Grid Code.

(p) 'Merit Order': The term has also been used in the existing Grid Code. In order to have better clarity, the term has been proposed in the draft Grid Code for deciding despatch instruction to the generating stations including SCED.

(q) 'Minimum Turndown Level': 'Technical Minimum' was defined under 2010 Grid Code to indicate the minimum loading required by generating station for safe operations. It has been proposed to rename it as 'Minimum Turndown Level'.

(r) 'Primary Reserve', 'Secondary Reserve' and 'Tertiary Reserve': The Commission vide CERC (Ancillary Services) Regulations 2022 had notified the framework for ancillary services wherein PRAS, SRAS and TRAS were proposed to be deployed to manage any frequency incursion. Accordingly, the 'Primary Reserve', 'Secondary Reserve', 'Secondary Reserve Ancillary Service', 'Secondary Reserve Ancillary Service Provider' and 'Tertiary Reserve' have been defined in the draft Grid Code.

(s) Pooling Station has been introduced in definitions since the power generated from all RE generators shall be pooled in at the pooling station.

Further, all scheduling activities of QCA shall also be carried out at the pooling station.

(t) ‘Qualified Coordinating Agency’: The definition of ‘Qualified Coordinating Agency’ has been introduced in view of their role envisaged in the scheduling and despatch process of generators in the draft Grid Code.

(u) ‘Ramp Rate’: The Ramping Capability is essential for maintaining grid stability especially in high RE Scenario. Further, the Commission has also provided incentive for generators having ramping capability greater than 1% in the Tariff Regulations. Accordingly, ‘Ramp Rate’ has been defined in the draft Grid Code to cater to the commercial and operational implications arising out of ramping capabilities of generators.

(v) ‘Security Constrained Economic Despatch: The Commission vide its suo motu Order dated 31st January 2019 in Petition No. 02/SM/2019, directed Power System Operation Corporation (POSOCO) to implement a pilot on Security Constrained Economic Despatch (SCED) w.e.f. 01.04.2019. The same involves scheduling of power covered under the Grid Code. The framework has been formalized in the draft Grid Code. Accordingly, the definition is included in the draft Grid Code.

(w) ‘Security Constrained Unit Commitment’ has been proposed to address the shortage of reserves under 2022 Ancillary Service Regulations, if any. Accordingly, the same has been introduced in the draft Grid Code.

(x) ‘Settlement Nodal Agency’: The Commission has defined Settlement Nodal Agency in CERC (Cross Border Trade of Electricity) Regulations, 2019. Since SNAs are also envisaged to coordinate grid operations in case of cross border transactions, the definition of SNA has been included in the draft Grid Code.

(y) ‘System Constraint’ has been introduced in the definitions on account of their impact on grid operations.

(z) ‘User’: The definition of ‘User’ has been expanded to include energy storage system, solar park developer, wind park developer and wind-solar photo voltaic hybrid system.

3. Resource Planning Code

3.1. The provisions related to Integrated Resource Planning have been covered under the Chapter 2 of the draft Grid Code. Integrated Resource planning ensures optimal harnessing of available resources in economical and sustainable manner and is essential for secure grid operation with high reliability, high resilience and more flexibility.

3.2. The objective of the Planning Code is to set out principles for planning of generation and transmission resources for reliably meeting the projected demand in compliance with the specified reliability standards for serving the load with optimum generation mix, and to create framework for integration of environmentally benign technologies for electricity generation. It factors large scale absorption of renewable energy in accordance with national policy taking into account measures, including flexible resources, storage systems for energy shift and demand response measures for managing the intermittency and variability of renewable energy sources.

3.3. In the 2010 Grid Code, the scope in the Planning Code was limited to transmission planning and it basically reiterated salient aspects of CEA Transmission Planning Criteria. However, the draft Planning Code comprehensively covers the required details, process and attributes to be captured and to be followed for demand forecasting, generation resource adequacy planning and transmission resource adequacy assessment.

3.4. The Expert Group, in its report in January 2020, had also noted that there was a need for an institutional mechanism for long-term and short-term demand forecasting by each control area as well as ensuring adequacy of transmission and generation resources.

3.5. Stakeholders had also highlighted the requirement of resource adequacy and pointed out that determination of resource adequacy guidelines for each region is important including LoLP (Loss of Load Probability), VoLL (Value of Lost Load) and Optimal Reserve Margin when the Commission had sought comments on the draft CERC (Ancillary Services) Regulations, 2022. The Commission, in its Statement of reasons dated 26th April 2022, observed that since Resource Adequacy is outside the purview of the Ancillary Service regulations, it shall be considered while reviewing the existing Grid Code.

3.6. It has been proposed to adopt the following bottom-up methodology to ensure resource adequacy at control area level as well as national level:

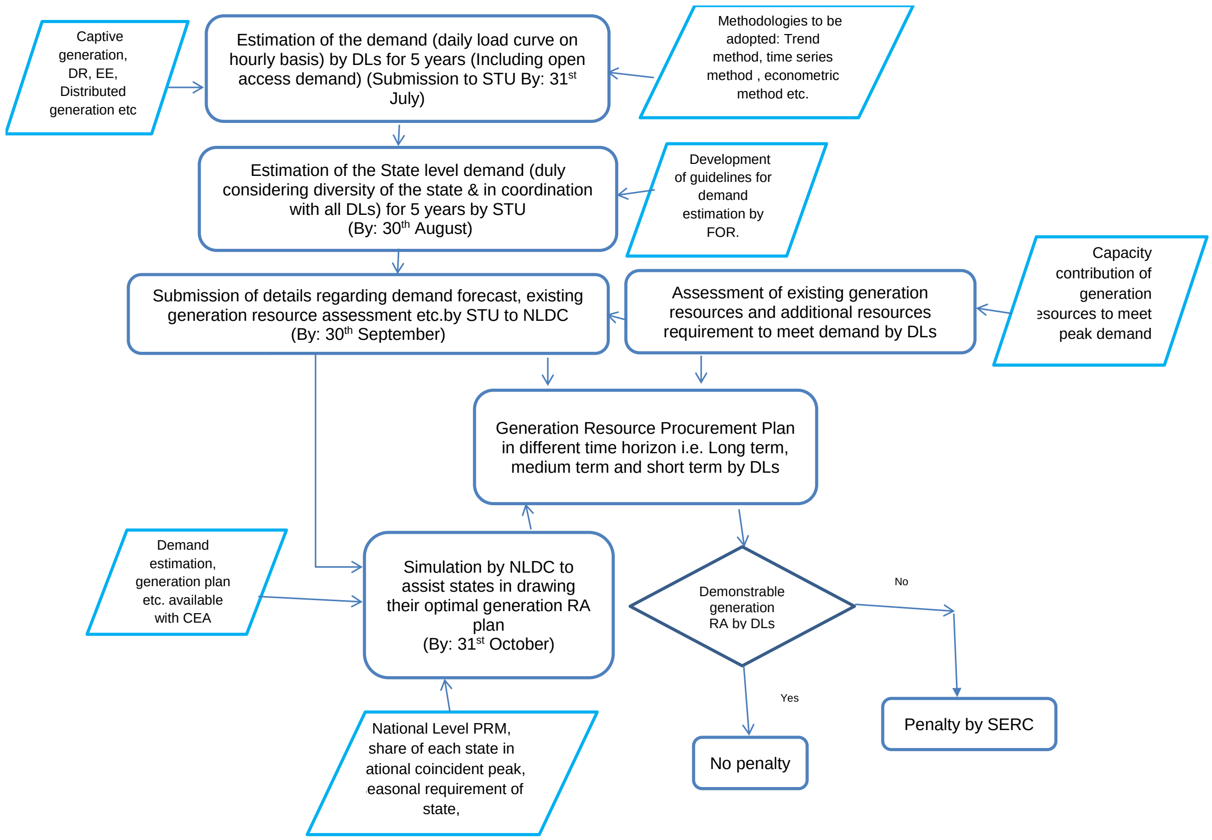


Figure 1: Resource Adequacy flowchart

3.7. Demand Forecasting

The first important requirement *for* ensuring resource adequacy is to have proper demand forecasting over different time horizons. Demand estimation/forecasting is crucial for integrated resource planning because other aspects of planning are dependent on it. Distribution licensees are the major stakeholders which are on the demand side and serve the load. In this Planning Code, the distribution licensees have been assigned the responsibility to estimate the demand in their control areas including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation and demand response. The distribution licensees shall do this demand estimation for the next five (5) years starting from 1st April of the next year and submit the same to the STU by 31st July every year.

(a) For carrying out the demand estimation, the distribution licenses shall use trend method, time series, econometric methods or any state-of-the-art methods and shall include daily load curve (hourly basis) for a typical day of each month. The daily load curve (hourly basis) for a typical day of a month shall be provided in such a way as to depict the clear picture of demand pattern in the control area.

(b) In the Planning Code, STU has been assigned the responsibility to estimate overall demand of the State in co-ordination with all the distribution licensees based on demand estimate. The STU shall estimate by 31th August every year, the demand for the entire State duly considering the diversity for the next five (5) years starting from 1st April of the next year. The STU shall also capture the diversity in demand for all aspects in its demand estimatimation for the State.

(c) To ensure consistency and uniformity in approach across states towards demand estimation, it has been provided that Forum of Regulators (FOR) may develop guidelines for demand estimation considering the factors such as economic parameters, historical data and sensitivity and probability analysis.

3.8. Generation Resource Adequacy Planning

(a) After load is forecasted, the next step is to assess the existing resources based on their capability to contribute to meet the peak demand. This exercise would give an indication about the additional resources that must be procured to meet the forecasted demand.

(b) However, while deciding on the resource procurement plan, it is important not only to factor in the resource gap (between demand and the existing resource capability) but also to ensure availability of adequate reserves for meeting contingencies. For this, there is a need for computing the Planning Reserve Margin (PRM) based on the factors like Loss of Load Probability (LOLP), Energy Not Served (ENS) etc.

(c) Planning Code of the draft Grid Code, therefore, provides that each distribution licensee shall do the assessment of the existing generation resources with due regard to its capacity contribution to meet the peak demand. Further, based on the demand estimate and assessment of the existing generation resources, the distribution licensee shall prepare generation resource procurement plan which shall specify the procurement from resources under State control area and regional control area. Generation resource procurement planning shall be done for different time horizons, namely long -term, medium term and short term as per GNA provisions to ensure:

(d) adequacy of generation resources and

(e) planning reserve margin (PRM) taking into account loss of load probability and energy not served as specified by CEA.

(f) Considering the prevailing thrust on Renewable Energy (RE) generation and steps towards reduction of carbon emission from Power Sector, Generation planning should be done in a way to maximize the harnessing of available RE resources and its economical transmission/dispatch to the load centers. The other factors like available Distributed Energy Resources (DER), RE generation pattern and subsequent requirement of Energy Storage System (ESS), load variations (including sessional load variations) shall also be factored in while planning for optimal harnessing of RE resources.

(g) Distribution licensee shall also factor-in the Renewable Purchase Obligation (RPO) target including Hydro purchase Obligation (HPO), as applicable, in their generation resource adequacy planning and in subsequent generation procurement plan.

(h) Each distribution licensee is expected to carry out these exercises involving demand estimation, existing generation resource assessment, determination of PRM before designing its resource procurement planning. However, empirical evidence shows that if each distribution licensee engages in resource procurement planning only based on its own sets of data (on load forecasting, generation resource assessment and PRM) in isolation, it would lead to sub-optimal planning at the national level leading to excess capacity creation.

(i) As such, it is important that some national level agency carries out a simulation by compiling the data on each of the aforesaid parameters (viz. State /Discom-wise load forecasting, existing resource assessment, PRM etc.) and factor in seasonal load variation across States, share of each State in the national co-incident peak, feasibility of sharing of capacities amongst States etc. Such an exercise can lead to optimal resource adequacy allocation among different States.

(j) The draft Grid Code has sought to entrust this responsibility to NLDC at the national level. This Planning Code specifically mentions that STU on behalf of distribution licensees in the State shall provide to NLDC by 30th September every year, the details regarding demand forecasting, assessment of existing generation resources and such other details as may be required for carrying out a national level simulation for generation resource adequacy for States.

(k) To assist the State in drawing optimal generation resource adequacy plan, NLDC shall carry out a simulation by 31st October every year based on the information received from STU and in consideration with the information related to demand estimation, generation planning and related matters as available with CEA.

(l) However, as the Commission believes in a bottoms-up approach, it has been provided that even after the NLDC has done a national simulation and indicated resource procurement planning for States, it would be desirable for the States to do due diligence at their level. This will ensure that each distribution licensee remains commercially responsible for its own resource procurement strategy which it has to finalize after seeking approval of the concerned SERC.

(m) Distribution licensees shall have the responsibility to demonstrable generation resource adequacy as specified by the respective SERC for the next five (5) years starting 1st April of the next year based on their demand forecasting and the generation resource procurement planning.

(n) The draft Grid Code also highlights the need for proper enforcement of resource adequacy framework developed based on the above principles and accordingly has provided that non-compliance of the resource adequacy target determined as above would make the distribution licensees liable for payment of resource adequacy non-compliance charge as may be determined by the appropriate Commission.

(o) To maintain uniformity and to optimize the State generation resource adequacy, it has been provided that FOR may develop a model Regulation stipulating inter alia the methodology for generation resource adequacy assessment, generation resource procurement planning and compliance of resource adequacy target by the distribution licensees.

3.9. Transmission resource adequacy assessment

(a) As per Section 38 (2) of the Electricity Act 2003, the CTU is responsible for development of an efficient, co-ordinated and economical ISTS system and discharge all functions related to planning and coordination. The Commission notes that such planning should include the assessment of power transfer capability across flow gate, import and export capability across control areas and regions as well transnational exchange of power to ensure that no power gets bottled up on account of requirement of augmentation of transmission system. Further, assessment of such capabilities shall also ensure that the transmission system is being planned optimally.

(b) The CTU shall coordinate with various stakeholders such as CEA, MNRE, state renewable development agencies, STUs, distribution licensee, SLDC, RLDC, NLDC and generation developers to make a comprehensive assessment of inter-state transmission plan covering power evacuation schemes, pooling stations, enhancement of power transfer capability between regions and enhancement of power transfer capability for each STU system.

(c) In addition to the inter-State transmission planning, the CTU shall plan from time to time, system strengthening schemes, need of which may arise to overcome the constraints in power transfer and to improve the overall performance of the grid. The inter-State transmission proposals including system strengthening scheme identified on the basis of the planning studies would be discussed, reviewed and finalized in the meetings of Transmission Planning, in consultation with identified Entities as notified by Government of India from time to time.

(d) Similarly, at state level, STU is responsible for development of an efficient, coordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centres and discharge of all functions related to planning and coordination.

(e) The Transmission planning criterion shall be based on the security philosophy on which the ISTS has been planned. The security philosophy may be as per the Transmission Planning Criteria and other guidelines as specified by CEA from time to time.

(f) CTU shall also factor in the Reactive Power requirement into the Grid as part of inter-State Transmission planning which includes planning studies for Reactive Power compensation of ISTS including reactive power compensation requirement at the generator's /bulk consumer's switchyard and for connectivity of new generator/ bulk consumer to the ISTS in accordance with GNA Regulations.

4. Connection Code

4.1. The Connection Code deals with the technical criteria for connectivity, procedure for connectivity and technical requirements for safe and secured physical connection and integration of either new or modified grid elements, The Indian Power System is one of the largest Grid in the world having interconnection with its neighboring countries. The purpose of this Code is to ensure the safety, stability, integrity and reliability of the Grid while connecting/ integrating new or modified grid elements into the Grid.

4.2. With the penetration of large RE capacity into the Grid there is a need to revamp the Connection Code. The main factors for such a change are as follows:

(a) The current Connection Code needs to be reviewed in light of the newly introduced Connectivity and GNA under the GNA Regulations.

(b) Provisions are required to be incorporated to identify any threat to grid security on introduction of a new or modified power system element including smooth integration of RE.

4.3. The proposed Connection Code comprises of the following sections:

(a) Compliance with existing rules and regulations

(b) Procedure for Connection

(c) Connectivity Agreement

(d) Technical Requirements

(e) Data and Communication Facilities

The key changes are elaborated in subsequent paragraphs.

4.4. Compliance with existing Rules and Regulations

The prevailing Connection Code provides that any user connected or seeking connection to ISTS shall comply with Central Electricity Authority (Technical Standards for connectivity to the Grid) Regulations, 2007 and Central Electricity Regulatory Commission (Grant of Connectivity, Long-term Access and Medium-term Open Access in inter-state Transmission and related matters) Regulations,2009. In the post-GNA regime, the Connectivity Regulations, 2009 shall be repealed and shall be succeeded by the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-StateTransmission System) Regulations, 2022 (GNA Regulations). The Commission observes that the multiple regulations have been notified by various statutory bodies and accordingly all users connected or seeking connection to the grid shall comply with the applicable regulations as specified in the Draft IEGC.

4.5. Provision for Grant of Connectivity

(a) As per the existing regulatory regime, the process for Grant of Connectivity to ISTS is governed by 2009 Connectivity Regulations. Under the GNA Regulations, the grant of Connectivity to the ISTS shall be as per the GNA regulations.

(b) Commission observes that when any new or modified element is integrated into grid there is a need for such an entity to submit technical data for the purpose of studies. POSOCO has already included first time charging Procedure as a part of its Operating Procedure since June 2020. It is clarified that connection of an element after shutdown or tripping shall not be treated as “modified element” and shall not be required to go through first time charging procedure. However, in case the element has been modified, such as a transformer of 300 MVA replaced by 500 MVA, it would be required to go through first time charging procedure.

(c) The Expert Group recommended to include the first time charging procedure as a part of Grid Code. Accordingly, it has been proposed that NLDC shall prepare a detailed procedure covering modalities for first time energization and integration of new or modified power system element. It is important that similar procedure is also developed by SLDC for connection of new or modified element to the grid. Accordingly, it has been proposed that SLDC shall prepare a detailed procedure covering modalities for first time energization and integration of new or modified power system element for intra-state transmission system. The State grids being part of the National grid, are inter-connected and the said detailed procedures would facilitate smooth and integrated grid operation of Indian power system. The Commission has further proposed that in the absence of procedure of concerned SLDC, the NLDC procedure shall be applicable for the elements of 220 kV and above (132 kV and above in case of North Eastern Region).

(d) Users, after completing the all prerequisite requirements as per the prevailing provisions and necessary site tests will approach the concerned RLDC or SLDC, as the case may be, in the NLDC specified format to get the permission for first energization.

4.6. Connectivity Agreement

As per the existing regulatory regime, a Connection agreement is signed by the applicant in accordance with the 2009 Connectivity Regulations. Under the GNA Regulations, the Connectivity agreement shall be signed which shall include all technical details also. However, since transmission licensee does not apply separately for Connectivity, the Connectivity Agreement with such transmission licensee integrating a new element has not been covered under the GNA regulations which was covered under the 2009 Connectivity Regulations. Further, such Connectivity Agreement with transmission licensee under the 2009 connectivity regulations was purely for technical purpose where transmission licensee submitted necessary technical details. Accordingly, it has been proposed that the Connectivity Agreement with transmission licensee shall be signed under the Grid Code. CTU shall specify the formats of submission of technical data by the Transmission licensee and draft Connectivity Agreement to be signed with the transmission licensee.

4.7. Technical Requirements

(a) The Commission feels that connection of a new element to the power system must ensure security of the grid as well as of the element getting connected to the grid as per the CEA Connectivity Standards. It is, therefore, essential to analyze the impact of the element on the power system when the element is transitioning from construction to operation phase. Accordingly, the Commission has proposed that NLDC or RLDC, in consultation with CTU shall carry out a joint system study six (6) months before the expected date of first energization of a new power system element to identify operational constraints. Further, all associated technical data shall be submitted to the CTU and NLDC or RLDC for necessary technical studies to enable CTU/NLDC to accurately forecast the results.

(b) Proposed Connection Code further specifies that SLDC shall also do the similar exercise in consultation with STU for the intra-state system, and specifically for elements of 220 kV and above (132 kV and above in case of North Eastern region) which shall facilitate the SLDCs to identify the operational constraints in their intra-state network and their rectification in a timely manner which shall facilitate smooth and integrated grid operation of Indian power system

4.8. Data and Communication Facilities

(a) For seamless data exchange, safe and secure integration as well as monitoring/supervision of the operation of the grid elements, establishment of reliable speech and data communication systems shall have to be in place. To connect Grid elements into the Grid, users need to comply with the CERC (Communication System for Inter-State Transmission of Electricity) Regulations, 2017 and the Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020. The Commission has proposed the requirement of established Data and Communication facilities in Connection Codes.

(b) In view of large integration of RE and fast dynamic changes in the power system network, visibility of data at various control centers are of growing importance day by day. Data exchange is must for supervision and control of the grid by the System Operators so as to achieve overall secured and integrated operation of the grid.

5. Protection Code

5.1 The protection system plays a pivotal role in ensuring stability of the power system which isolates the faulty section of the power system from the rest of the electrical network and thereby preventing system collapse during disturbances and reducing outage time. The importance of reliable and correct operation of protection system has been brought out in various orders of the commission and reports of various committees from time to time. One of the learning from the 2012 Grid disturbance is requirement of robust protection audit system.

5.2 The failure of protection system may result in incidents of tripping(s), which may further cause cascade tripping of various elements, depletion of network and loss of generation or load in some cases and even partial or complete blackout of the grid. The CEA Grid Standards Regulations provide the classification for events of multiple trippings wherein grid events have been classified into Grid Disturbances and Grid Incidents depending upon the severity and impact of generation/load loss in a region. RLDC releases a list of Grid Events of its region on monthly basis on its website and also submit to the respective RPC and the same is discussed in Protection Sub-committee meetings at RPC level for remedial measures and further actions.

5.3 The Expert Group has observed as follows:

“(1) Protection Code

(a) This code has been newly added to have a common protection philosophy amongst users of the grid, to provide proper co-ordination of protection system in order to isolate the faulty equipment and avoid unintended operation of protection system, to have a repository of protection system and settings at regional level, to have a repository of events, timelines for submission of data and ensure healthiness of recording equipment’s along with time synchronization, to provide for periodic audit of protection system.

(b) It is observed that in absence of a coordinated procedure and specific guidelines of protection systems the desired outcomes are not being witnessed. It is therefore recommended that a coordinated protection setting are adopted by all users of regional grid. The provision of protection philosophy to be adopted at regional level has been added to achieve a uniformity in the procedure for adopting protection settings. The guideline and recommendation provided under various committee Report as constituted under the various orders (Report of the Task Force on Power System Analysis under Contingencies (2013), TASK II PHASE I AND PHASE II – FINAL REPORT (2017), CBIP Manual on Power System Protection (Publication No. 328), Protection philosophy of different RPC (Regional Power Committee)/ NPC

(National Power Committee) and any other as prescribed by commission) may form the basis for finalising the protection philosophy by all RPCs uniformly.

(c) The Protection Code covers the following aspects:
i. Protection philosophy
ii. Protection Settings
iii. Protection Audit Plan
iv. System Protection Schemes (SPS)
v. Recording Instruments"

5.4 Based on the above recommendations, the Commission has proposed inclusion of a new Protection Code in the Draft Grid Code with the following sections:

(a) Protection Protocol
(b) Protection Settings
(c) Protection Audit Plan
(d) System Protection Scheme
(e) Recording Instruments

5.5 **Protection Protocol**

(a) The Commission has proposed that the users connected to the integrated grid shall be guided by uniform protection protocol. The protection protocol shall be evolved by RPC ensuring a common and coordinated approach. In doing this, RPC may be guided by the principal that electrical protection function for equipment connected with the grid shall be provided as per the CEA Technical Standards. However, users may have electrical protection functions over and above or better than the ones specified as per CEA Technical Standards. We observe that each RPC has issued protection philosophy for respective region on its website. Such philosophy at ERPC website dated 2.9.2016 is as under:

PROTECTION PHILOSOPHY OF EASTERN REGION

In the Special meetings of PCC held on 30.12.2014, 10.04.2015 & 20.07.2015 the Protection Philosophy for Eastern Region was agreed as given below:

Sl. No.	Zone	Direction	Protected Line Reach Settings	Time Settings (in Seconds)	Remarks
1	Zone-1	Forward	80%	Instantaneous (0)	As per CEA
2a	Zone-2	Forward	For single ckt- 120 % of the protected line	0.5 to 0.6 - if Z2 reach overreaches the 50% of the shortest line ; 0.35- otherwise	As per CEA
			For double ckt- 150 % of the protected line		As per CEA
2b	Zone-2 (for 220 kV and below voltage Transmission lines of utilities)	Forward	120 % of the protected line, or 100% of the protected line + 50% of the adjacent shortest line	0.35	As per CEA with minor changes
3	Zone-3	Forward	120 % of the (Protected line + Next longest line)	0.8 - 1.0	As per CEA
4	Zone-4	Reverse	10%- for long lines (for line length of 100 km and above) 20%- for shot lines (for line length of less than 100 km)	0.5	As per CEA

Note:

1) ***Zone-2:- Z2 Reach should not encroach the next lower voltage level.***
2) ***Zone-3:- If Z3 reach encroaches in next voltage level (after considering "in-feed"), then Z3 time must be coordinated with the fault clearing time of remote end transformer.***
3) ***Zone-4:- If utility uses carrier blocking scheme, then the Z4 reach may be increased as per the requirement. It should cover the LBB of local bus bar and should be coordinated with Z2 time of the all other lines.***
4) ***The above settings are recommended primarily (exclusively) for uncompensated lines.***

(b) The Draft Grid Code envisages uniform protection protocol. However, each RPC shall develop the protection protocol for the region. The RPCs may coordinate among themselves to ensure uniform protection protocol as far as possible duly considering region specific variations, if any. Further, the protection protocol may vary as per the operational experience and necessary modification/revision as per requirement shall be carried out after approval of the concerned RPC.

5.6 **Protection Settings**

(a) It is observed that multiple agencies are involved for implementation of protection settings such as a line is owned by a transmission licensee and the substation terminating bays of that line may have different owner and hence coordination is required among them for successful implementation and real time operation of the protection system as per the required settings. Accordingly, to evolve a common and coordinated approach, the Commission has proposed that the relay settings shall be discussed and decided at RPC level. To achieve this, a centralized database of relay settings shall be required which will be coordinated with the remote end settings. This data base of settings containing information of various relays has been proposed to be created, updated and verified during the relay audit. The data base shall be maintained with the Regional Power Committees with different levels of access of different users.

(b) The protection group of each entity shall be required to furnish the protection system implemented to the respective RPC in a prescribed format and also obtain approval of the concerned RPC in case of revision in protection setting and implementation of new protection system within specified timeline.

5.7 **Protection Audit Plan**

(a) Periodic audit of the protection system shall be ensured by the user. The audit shall broadly cover the important aspects of protection system, namely the setting and scheme adopted in line with agreed protection philosophy of RPC, the deviations from the RPC protection philosophy, the healthiness of Fault Clearing System etc. It is suggested that each user shall conduct internal audit of their protection system annually and any shortcomings identified shall be rectified and informed to RPC. In order to ensure healthiness of protection system for better grid operation with due weightage for checks and balances in the system, all users shall also conduct third party protection audit of each sub-station (132 kV and above in NER and 220 kV and above for rest of the grid) once in five years or earlier as advised by RPC.

(b) In order to ensure reliability of protection system, certain indices for protection devices and switching devices have been included in the draft Grid Code. The proposed indices have already been notified through the Central Electricity Regulatory Commission (Standards of Performance of inter-State transmission licensees) Regulations, 2012 wherein the inter-state transmission licensees shall furnish prescribed data to enable POSOCO compute the Indices. One such sample submitted by SRLDC for June 2022 is as under:

Annexure-1

PERFORMANCE INDICES CALCULATION AS PER CERC SOP REGULATION FOR June 2022

SN	Name of Transmission Licencee	Nc	Nf	Nu	Ni=Nf+Nu	D= (Nc/Nc+ Nf)	S= (Nc/Nc+ Nu)	R= (Nc/Nc+ Ni)	(1/S)+(1/D)	(1/R)+1
1	KTL	0	0	0	0	Nil	Nil	Nil	Nil	Nil
2	MTL	0	0	0	0	Nil	Nil	Nil	Nil	Nil
3	RSTCL	2	0	0	0	1.000	1.000	1.000	2.000	2.000
4	PGCIL SR-1 (incl.PVTL & PSITSL)	11	0	1	1	1.000	0.917	0.917	2.091	2.091
5	PGCIL SR-2 (incl.PNMTL)	17	0	1	1	1.000	0.944	0.944	2.059	2.059
	NET SR ISTS	30	0	2	2	1.000	0.938	0.938	2.067	2.067

Abbreviations :

Nc :- Number of correct operations

Nf :- Number of failures to operate at internal power system faults

Ni =(Nf+Nu):- Number of incorrect operation & sum of Nu+Nf

Nu :- Number of unwanted operation

D :- Dependability Index.

S :- Secuirty Index.

R :- Reliability Index.

(c) In order to ensure better reliability and security of the protection system, the Commission is of the view that these protection performance indices namely Dependability Index, Security Index and Reliability Index shall be submitted by all users to the respective RPCs on a monthly basis.

(d) As the reliability and security of the system is of paramount importance, the Commission has benchmarked the protection performance indices as unity. Any element operating below unity, the user shall submit the reasons of non-performance as well as a time bound action plan for taking corrective measures to the respective RPC.

5.8 System Protection Scheme (SPS)

SPS are installed to ensure security of the system. There may be a condition where a particular input signal is not working, thereby SPS is not operating when required to do so. Accordingly, it has been proposed that Users shall ensure that SPS shall have redundant system for measurement of input signals and communication path to ensure security and dependability. In order to ensure that SPS operates effectively as and when required, the Commission has proposed that RPC shall conduct regular dynamic studies and mock testing.

5.9 **Recording Instruments**

In order to ensure consistency, uniformity and proper monitoring, it is essential that various attributes be defined and standardized for Digital fault Recorder (DfR) formats. Thus, it has been proposed that a standard template discussed and finalized by RPC shall be followed for recording analog and digital signals. It is also proposed to undertake time synchronization for efficient and correct utilization of DfR records in post events analysis.

6. Commissioning and Commercial Operation Code

6.1. The provisions related to trial run, commissioning and subsequent declaration of commercial operation are dealt in Part-6 (Scheduling and Despatch Code) of the 2010 Grid Code for thermal generators, hydro generators, transmission system and communication system. However under draft Grid Code, a separate Code has been proposed for commissioning, covering conditions for trial run and declaration of commercial operation for transmission and communication system, generating stations including renewable energy sources, Energy Storage System (ESS), Hybrid Generating Station, as well as HVDC, HVAC and STATCOM. The provisions of startup power drawal and infirm injection were included in the 2009 Connectivity Regulations. However, the issues involved are approval by RLDC considering grid security and hence the appropriate regulations covering the provisions for these aspects is included in the Grid Code. Since the drawal of start up power and injection of infirm power are an inherent part of commissioning, it is proposed to be introduced in the draft Grid Code. The Commissioning and Commercial Operation Code shall comprise of the following sections:

(a) Drawl of Start-up power and injection of infirm power
(b) Data to be furnished prior to notice of trial run
(c) Notice of trial run
(d) Trial Run of a generating unit
(e) Trial Run of inter-state transmission system
(f) Documents and Test Reports Prior to Declaration of Commercial Operation
(g) Certificate of successful trial run
(h) Declaration by generating company and transmission licensee
(i) Declaration of Commercial Operation and Commercial Operation Date

The draft provisions are discussed in detail in the subsequent paragraphs.

6.2. Drawal of Start-up power and Injection of infirm Power

(a) The existing provisions related to drawal of startup power have been dealt in Clause (7) of Regulation 8 of the 2009 Connectivity Regulations. Further, the

2009 Connectivity Regulations shall be replaced with the GNA regulations wherein the provisions of drawal of start-up power and injection of infirm power have been cross referred to this Grid Code. Regulation 13 of the GNA regulations provides as follows:

> *"13. Injection of Infirm Power and drawal of Start-up Power Connectivity grantee shall be eligible to inject infirm power and draw start-up power in accordance with the provisions of the Grid Code."*

(b) Accordingly, the provisions for modalities of allowing drawl of start-up power or injection of infirm power have been included in this Code. The provisions related to deviation on account of injection of start-up power have been dealt in the 2022 DSM Regulations and payment of transmission charges have been dealt in the 2020 Sharing Regulations.

6.3. Data to be furnished prior to notice of trial run

A system operator needs to run mathematical simulations before a unit of generating station seeks permission for trial run, to assess the grid conditions and accordingly allow the trial run. This is possible only when the basic details of such generating station proposed to run trial operation are furnished to the system operator. It has been proposed that each regional entity generating station shall be required to submit the details as follows prior to notice of trial run:

Table 1: Details To Be Furnished By Generating Entity Prior To Trial Run

Description	*Units*
Installed Capacity of generating station	*MW*
Installed Capacity of generating station	*MWh*
Number x unit size	*No x MW*
Time required for cold start	*Minute*
Time required for warm start	*minute*
Time required for hot start	*Minute*
Time required for combined cycle operation under cold conditions	*Minute*
Time required for combined cycle operation under warm conditions	*Minute*
Ramping up capability	*% per minute*
Ramping down capability	*% per minute*
Minimum turndown level	*% of ex-bus capacity*

Description	*Units*
Inverter Loading Ratio (DC/AC capacity)	
Name of QCA (where applicable)	
Full reservoir level (FRL)	*Metre*
Design Head	*Metre*
Minimum draw down level (MDDL)	*Metre*
Water released at Design Head	*M^3/ MW*

The Table above contains items applicable for different types of generating stations, hence all the data listed as per above may not be applicable for each generating station. Only the data pertaining to the particular type of generating station need to be furnished.

6.4. Notice of trial run

(a) The 2010 Grid Code includes requirement of trial run as a part of declaration of commercial operation at Regulation 6.3 A as follows:

"1.Date of commercial operation in case of a unit of thermal Central Generating Stations or inter-State Generating Station shall mean the date declared by the generating company after demonstrating the unit capacity corresponding to its Maximum Continuous Rating (MCR) or the Installed Capacity (IC) or Name Plate Rating on designated fuel through a successful trial run and after getting clearance from the respective RLDC or SLDC, as the case may be, and in case of the generating station as a whole, the date of commercial operation of the last unit of the generating station:

Provided that:

(a) Where the beneficiaries / buyers have been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the beneficiaries/buyers and concerned RLDC or SLDC, as the case may be.

(ii) Where the beneficiaries / buyers have not been tied up for purchasing power from the generating station, the trial run or each repeat of trial run shall commence after a notice of not less than seven days by the generating company to the concerned RLDC or SLDC, as the case may be."

As per the above, a minimum notice period of seven days is required to be given to beneficiaries and concerned RLDC or SLDC prior to commencement of trial run. Further, in case of repeat trial run, a seven-day notice is required to be given.

(b) We observe that while running on trial run operation, sometimes the generating unit trips and with minor rectification under hot /warm start condition, repeat trial run can be carried out within 24 hours. A repeat notice of 7 days would require the unit to go under complete shutdown before trial run can be taken up again. Therefore, it has been proposed that if the trial run can be repeated within 24 hours, no fresh notice shall be required. However, the generating station shall coordinate with RLDC or SLDC, as applicable for each such operation. However, if the trial run has failed and cannot be taken up within 24 hours, it shall require fresh appropriate notice to be issued.

6.5. Trial Run of Generating Station

(a) The provisions of the 2010 Grid Code regarding trial run for thermal and hydro generation have been retained as it is.

(b) While running a trial run for a thermal generating station, a unit may trip since various auxiliary systems are running under testing mode. Accordingly, small interruptions have been allowed with corresponding increase in duration of test. In case of hydro generating stations, the plant auxiliaries are not such, which may frequently trip under testing. Further, the trial run timeline is 12 hours for a hydro generating station as compared to 72 hours for thermal generating station. Accordingly, it has been proposed that in case of interruption in trial run for hydro generating station, it shall require repeat trial run.

(c) There may be cases where during a trial run a generating unit is not able to demonstrate its full capacity. The draft Grid Code allows them to de-rate its capacity. However, the generating station is obligated to provide primary response as per the CEA standards. Therefore, in case a generating unit is required to be de-rated, the de-rated capacity shall exclude the margin for primary response. Accordingly, it has been proposed that the de-rated capacity in case of thermal and hydro generating unit shall not be more than 95% (5% margin for primary response) and 90% (10% margin for primary response) of the demonstrated capacity respectively.

(d) **Trial Run for Renewable energy generating Station**

(a) The Expert group has proposed as follows:

"(d) Stakeholders have submitted the necessity to include the same for renewable energy generating stations. It has been observed that the conditions regarding date of commercial operation has been dealt in the PPA which varies from PPA to PPA. Further, the PPAs may not include provision of successful trial operation of renewable energy generating stations. MNRE bidding guidelines allow part commissioning upto 50 MW for both wind and solar generation in ISTS system. Further, any unit partly commissioned becomes eligible for tariff.

MNRE in its bidding guidelines provides as follows:

i. Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Wind Power Projects (Resolution dated: 8th December 2017)

"Part Commissioning: Part Commissioning of the project shall be accepted by procurer subject to the condition that the minimum capacity for acceptance of first part commissioning shall be 50% of project cost or 50 MW, whichever is lower, without prejudice to the penalty, in terms of the PPA on the part which is not commissioned. However, in case of interstate project, minimum capacity for acceptance of first part commissioning shall be atleast 50 MW. A project of capacity 100 MW or less can be commissioned in maximum two parts. The projects with capacity more than 100 MW can be commissioned in parts of atleast 50 MW each, with last part could be the balance capacity, However, the SCD shall not get altered due to part commissioning. Irrespective of dates of part commissioning, the PPA will remain in full force of 25 years from the SCD
or from the date of full commissioning, whichever is earlier.

Early Commissioning: The Wind Power Generator shall be eligible for full commissioning as well as part commissioning even prior to the SCD subject to the availability of transmission Connectivity and Long-Term Access (LTA). In cases of part commissioning, till the achievement of full commissioning or

SCD, whichever is earlier, the Procurer may purchase the generation at 75% (seventy-five percent) of the PPA tariff.

Commercial Operation Date (COD): The commercial operation date shall be considered as the actual date of commissioning of the project as declared by the Commissioning Committee constituted by SNA. In case of part commissioning, COD will be declared only for that part of the project capacity."

ii. Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects (Resolution dated: 3rd August 2017)

"Part Commissioning:
Part commissioning of the Project shall be accepted by Procurer subject to the condition that the Minimum Capacity for acceptance of first and subsequent part(s) commissioning shall be 50 MW, without prejudice to the imposition of penalty, in terms of the PPA on the part which is not commissioned. However, the SCD will not get altered due to partcommissioning.

Irrespective of dates of part commissioning or full commissioning, the PPA will remain in force for a period of 25 (twentyfive) years from the SCD.

Early Commissioning:
The Solar Power Generator shall be permitted for full commissioning as well as part commissioning of the Project even prior to the SCD. In cases of early part-commissioning, till SCD, the Procurer may purchase the generation till SCD, at 75% (seventy-five per cent) of the PPA tariff.

However, in case the entire capacity is commissioned prior to SCD, the Procurer may purchase the generation at PPA Tariff.

Commercial Operation Date (COD):
Commercial Operation Date (COD) shall be the date on which the commissioning certificate is issued upon successful commissioning of the full capacity of the Project or the last part capacity of the Project as the case may be.

(3) Rationale for proposed amendment:

(a) It is necessary to harmonize the criteria for commercial operation date declaration across all generators to maintain consistency and clarity. It is proposed to allow part commissioning for a capacity of 50 MW for both wind and solar generators. This may also benefit the consumers since it will help meet the adequacy targets and RPO obligations.

(b) Provisions for trial run have been included where corroboration of test results with plant parameters have been mandated so that any variability of solar irradiance and wind generation is taken into account.

(c) The date of declaration of commercial operation has been mandated as within fifteen days from date of achieving trial operation. It is observed that there should not be inordinate delays in declaration of COD post declaration of successful trial run.

(d) Stakeholders had requested to specify COD criteria of rooftop solar and offshore wind. As rooftop solar will have connectivity to the state grid, the SERC regulations shall apply. The connectivity of off-shore wind shall be governed in accordance with connectivity to ISTS or state. Hence, no separate provisions have been introduced."

(b) Accordingly, the provisions regarding trial run of wind, solar, hybrid and ESS have been included in the draft Grid Code. The provisions of trial run and subsequent commercial operation for all kinds of generating stations should be harmonized to maintain consistency and clarity. The following key aspects have been proposed in the draft regulations:

a. Part commissioning shall be allowed for a capacity of 50 MW for both wind and solar generators in line with the MNRE bidding guidelines.

b. Provisions have been included where corroboration of test results with plant parameters have been mandated so that any variability of solar irradiance and wind generation is taken into account.

c. For ESS, the testing is limited to one complete cycle of discharging and charging to assess the proper functioning of the battery storage system.

d. Similarly, for a pumped storage system one cycle of turbo generator and pumping has been proposed for trial run.

e. For a hybrid system, the results of successful trial run of individual elements shall be considered before declaring a successful trial run. For instance, in a wind-solar hybrid, the wind generating station and solar generating station shall be required to demonstrate completion of their trial run individually before the trial run of the hybrid station is declared successful.

f. Similar to the provisions in thermal and hydro generating station, the de-rated capacity shall be restricted to 90% of the demonstrable capacity to account for primary response. Further, the de-rated capacity shall also be required to be at least 50 MW in line with the minimum capacity of part commissioning allowed.

(c) It is felt that due to insufficient solar irradiation on account of cloud cover, unavailability of sufficient wind velocity, it might not be possible to demonstrate the rated capacity of the plant at time of trial run. However a unit needs to be declared commercial as per contractual requirement of the date till the time sufficient wind / solar radiation is received. This implies the generating unit is fully capable of producing rated output but for want of natural resources such as wind or solar is not able to demonstrate full capacity output. Accordingly, it has been proposed that such units can declare COD subject to the condition that the same shall be demonstrated immediately when such conditions are met after CoD.

(d) Further, in case of renewable generating stations the panels for unit which has been declared under COD and the ones under trial run are located near to each other. To take care of the situation that trial run has been demonstrated using panels/ turbines of only the unit under trial run, a declaration shall be given by the generating company that no panels has been replaced or added or taken out or design has been altered.

6.6. Trial Run of an Inter-State Transmission System

The provisions of the 2010 Grid Code has been retained. However, it is provided that under exceptional circumstances, transmission element may be charged at a lower nominal voltage after approval of CEA.

6.7. Documents and Test Reports prior to declaration of Commercial Operation

(a) Any element which seeks to get connected to the grid has to comply with the CEA Construction Standards and the Connectivity standards.

(b) Under the 2010 Grid Code, the entities such as generating stations and transmission licensee are required to furnish a certificate certifying that they comply with the applicable CEA Standards. However, with increasing size and complexities of power sector including integration with renewable sources and storage systems, the estimates of system as per simulation studies need to be as close to their real time response as possible. Hence, it has been proposed to take test reports of a few basic identified tests and specified documents to facilitate system studies by the system operator.

(c) In respect of Operational capability of Generators and Transmission System, CEA Technical Standards for Construction provides as follows:

i. *For Coal or Lignite based Thermal Generating Stations*

"7 (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).

……

7 (4) The design shall cover adequate provision for quick start up and loading of the unit to full load at a fast rate. The unit shall have minimum rate of loading or unloading of 3% per minute above the control load (i.e. 50%MCR)."

ii. *For Gas Turbine Based Thermal Generating Stations*

"14 (2) Combined cycle gas turbine (CCGT) module, comprising of gas turbine generator(s) and steam turbine generator, shall give its MCR output at the specified site conditions and the design fuel.

…….

14 (4) The gas turbine, steam turbine and all rotating auxiliaries shall besuitable for continuous operation within the frequency range of 47.5 Hz to 51.5 Hz.

…….

14 (6) Gas turbine rating (ISO) upto 100 MW shall be provided with black start facility."

iii. *For Hydro Electric Generating Stations*

"32 (1) The unit shall be capable of giving the rated output continuously as specified by the manufacturer at the rated design head and rated discharge and shall be capable of operating between the minimum and maximum head specified by the purchaser and ambient temperature at site as specified.

32(2) The maximum continuous overload capacity of the unit at the generator terminals during the. high head conditions or high discharge conditions or both as guaranteed by the manufacturer shall be based on hydraulic parameters of the Station.
32 (3) The unit and all the associated auxiliaries shall be suitable for continuous operation without any restriction within a frequency range of -5% to +3% (47 .5 Hz to 51.5 Hz). All the equipment driven by the electric motors shall give their rated performance even at a power supply frequency of 47 .5 Hz.
……..
32 (8) The Station shall be equipped with facilities for black start of generating unit in the event of grid black- out conditions."

(d) CEA Technical Standards for Connectivity provides as follows:

"

………
A1(4) All generating machines irrespective of capacity shall have electronically controlled governing system with appropriate speed/load characteristics to regulate frequency. The governors of thermal generating units shall have a droopof 3 to 6% and those of hydro generating units 0 to 10%
…..
A1(6) The coal and lignite based thermal generating units shall be capable of generating up to 105% of Maximum Continuous Rating (subject to maximum load capability under Valve Wide Open Condition) for short duration to provide the frequency response.

A1(7) The hydro generating units shall be capable of generating up to 110% of rated capacity (subject to rated head being available) on continuous basis.
….
A1(9) Hydro generating units having rated capacity of 50 MW and above shall be capable of operation in synchronous condenser mode, wherever feasible.

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

A1(13) In case of hydro generating units, self-starting facility may be provided. The hydro generating station may also have a small diesel generator for meeting the station auxiliary requirements for black start.

Provided that hydro generating units shall have black start facilities in accordance with provisions of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 from the date of publication of these Regulations….."

(e) In accordance with the above provisions under the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity and as suggested by the Expert Group, following test reports in respect of Thermal, Hydro and Gas Generator certifying inter alia the following capabilities have been proposed in draft Grid Code:

Type of element	**Capability Required**
Thermal Generator	• Ramping Capability • overload capability with valve wide open as per the CEA Technical Standards for Construction • Primary response • Minimum Ramping capability of 1% • Reactive Power Capability
Hydro Generator	• Primary Response • Reactive Power capability including when operating in synchronous condenser mode • Blackstart capability
Gas turbine	• Primary response • Reactive power capability including when operating in synchronous condenser mode • Blackstart capability

(f) In respect of solar and wind generating stations, the CEA Technical Standards for Connectivity (Amendment, 2019) provides as follows:

i. *For Solar and Wind Generators*

"B2(4) The generating stations with installed capacity of more than 10 MW connected at voltage level of 33 kV and above –

(i) shall be equipped with the facility to control active power injection in accordance with a set point, capable of being revised based on directions

of the State Load Dispatch Centre or Regional Load Dispatch Centre, as the case may be;
(ii) shall have governors or frequency controllers of the units at a droop of 3 to 6% and a dead band not exceeding ±0.03 Hz: Provided that for frequency deviations in excess of 0.3 Hz, the Generating Station shall have the facility to provide an immediate (within 1 second) real power primary frequency response of at least 10% of the maximum Alternating Current active power capacity;
(iii) shall have the operating range of the frequency response and regulation system from 10% to 100% of the maximum Alternating Current active power capacity, corresponding to solar insolation or wind speed, as the case may be;
(iv) shall be equipped with the facility for controlling the rate of change of power output at a rate not more than ± 10% per minute.

B2(5) The generating stations of aggregate capacity of 500 MW and above shall have the provision to receive the signal from the State Load Dispatch Centre or Regional Load Dispatch Centre, as the case may be, for varying active and reactive power output."

(g) In accordance with the above provisions under the CEA Technical Standards for Connectivity and as suggested by the Expert Group, following test reports for Solar and Wind generating stations certifying inter alia the following capabilities have been proposed in draft Grid Code:

Type of element	**Capability Required**
Wind/Solar Generators	• Primary response • Reactive Power Capability • Grid Forming capability during black start operation

(h) For Generating stations based on wind and solar sources, it has been proposed to provide test reports for grid forming capability, wherever provided. Most of the RE based plants are grid following in nature. Grid Following Inverters measure the grid voltage and frequency, and then try to inject the active and reactive power to "follow" the voltage. In contrast, Grid Forming inverters have capability that may be used as black start resource. Grid forming inverters create a local voltage and frequency, then try to move that voltage to cause the correct real and reactive power to flow into the grid. They do not rely on external grid voltage to generate power and can operate without, or with very few, synchronous machines electrically nearby and hence such capabilities exhibit characteristics akin to a synchronous plant as well as can be an alternative blackstart resource. The Commission, has, accordingly proposed this aspect in the draft regulations. However it is not mandated, only the invertors that have the grid forming capability, test report for grid forming capability is required to be submitted.

(i) In respect of Operational capability of HVDC, the CEA Construction Standards provides as follows:

i. For HVDC Terminal/ Stations –

"Schedule – VI

1. System Studies- HVDC control parameters and equipment shall be designed by carrying out the following studies at different stages of the project:

a) Main circuit parameters;
b) Short circuit studies;
c) Insulation co-ordination;
d) AC and DC filter design, rating and performance;
e) Reactive power studies, switching arrangement & logic;
f) Temporary overvoltage;
g) Transient overvoltage, surge arrester stress;
h) Runback and run up studies;
i) Sub- synchronous resonance (SSR) studies;
j) AC breaker transient recovery voltage (TRV) and rate of rise of recovery voltage (RRRV) studies;
k) Overload Study
l) AC equivalent Study
m) Short circuit studies;
………
(zb) ……"

(j) In accordance with the above provisions under the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity and as suggested by the Expert Group, following test reports in respect of HVDC Systems certifying inter alia the following capabilities have been proposed in the draft Grid Code:

Type of element	Capability Required
HVDC	• Minimum load operation. • Ramp rate. • Overload capability. • Black start capability in case of Voltage source convertor (VSC) HVDC

(k) For SVC/STATCOM, Reactive Power Capability test have been proposed as suggested by the Expert Group.

(l) Further, as suggested by the Expert Group following tests are proposed for Energy Storage System:

Type of element	Capability Required
Energy Storage Systems	• Power and energy output capability • Frequency response • Ramping Capability

(m) The various proposed tests under the draft Grid Code are as per requirements in CEA's Technical Standards for Construction, the CEA Technical Standards for Connectivity and as suggested by the Expert Group. However, stakeholders may provide suggestions as to which test reports can be added to the list or modified or deleted considering difficulties, if any in conducting the tests. In such a case, relevant OEM documents needs to be submitted to ensure CEA Standards are complied.

6.8. Certificate of Successful Trial Run

The 2010 Grid Code does not have a specific provision for beneficiaries to raise an objection after completion of a trial run, in case they observe any issues with the trial run. The draft Grid proposes to allow beneficiaries to raise objections to RLDC immediately after completion of trial run so that the RLDC can take such objections into account before deciding on successful completion of a trial run. However, such a period has been restricted to two days in order to prevent any delay in the commissioning process.

6.9. Declaration by generating company and transmission licensee

The 2010 Grid Code provides that the thermal generators, hydro generators and transmission licensees have to declare compliance with the existing CEA technical standards as well as certify that the plant equipment and auxiliary systems are capable of full load operation on sustained basis. These provisions related to thermal generating stations, hydro generating stations and transmission systems have been retained in draft Grid Code. However, RE generators, ESS and the hybrid generating station have also been covered for same.

6.10. Declaration of Commercial Operation and Date of Commercial Operation

(a) The Commission has retained the existing provisions regarding declaration of COD of a generating station and a transmission system. Further, the provisions regarding COD of communication system and Wind / Solar / ESS / Hybrid Generating Station have been included.

(b) With respect to declaration of COD of a transmission system, few additional conditions have been included in the draft grid Code as compared to the 2010 Grid Code, to align it with the 2020 Sharing Regulations and the GNA Regulations. These are listed as follows:

(i) Regulation 2(g) of the 2020 Sharing Regulations defines COD of the Associated Transmission System as COD of the last transmission element of the Associated Transmission System. Accordingly, the first proviso has been proposed wherein the COD of any transmission element which is a part of Associated Transmission System (ATS) shall be declared only after successful trial run of the last element of the said ATS.

(ii) Regulation 13(5) of the 2020 Sharing Regulations states that where some elements of the ATS have achieved COD before the COD of the Associated Transmission System and if such transmission elements are certified by the respective Regional Power Committee(s) as required for improving the performance, safety and security of the grid, the Yearly Transmission Charges for such transmission elements of the Associated Transmission System shall be included under the Pool. Accordingly, the same stance has been included as the second proviso.

(iii) The fourth proviso of Regulation 6.3 (A) (4) of the 2010 Grid Code provides that if a transmission element is prevented from regular service for reasons not attributable to it but on account of delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, it can approach the Commission for approval of the date of commercial operation of such transmission system or an element. Accordingly, the same has been proposed in the fourth proviso. However, in case of declaration of COD of such an element which is not carrying power, the check that the element is otherwise complete is a must to ensure that only completed element has been granted COD. Accordingly, CTU shall certify that the element is complete as per the CEA Technical Standards before such an element may be considered for approval.

(iv) The first proviso of Regulation 6.3(A)(4) of the 2010 Grid Code provides that in case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee shall declare COD of the ISTS in accordance with the provisions of the Transmission Service Agreement. However, under the Draft Grid Code all the transmission elements including that under TBCB shall declare COD after following the requirements stipulated in the draft Grid Code. However, a Transmission licensee under TBCB may declare deemed COD as per provisions of its TSA, subject to completion certificate from CTU. This has been included as fifth proviso.

(c) The fifth proviso of Regulation 6.3 (A) (4) of the 2010 Grid Code stipulates the following:

"An element shall be declared to have achieved COD only after all the elements which are pre-required to achieve COD as per the Transmission Services Agreement are commissioned. In case any element is required to be commissioned prior to the commissioning of pre-required element, the same can be done if CEA confirms that such commissioning is in the interest of the power system."

Regulation 27(1)(c) has been proposed under the draft Grid Code to include the above proviso.

(d) We observe that while planning prerequisites are included by the competent authority after considering the utilisation of such a system. Ideally, delinking with the prerequisites i.e. declared COD of an element without prerequisites in place is against what was planned for unless the conditions of planning vs actual has changed substantially. Any delinking from such pre-requisites should be discussed at RPC where the beneficiaries utilising such system can provide their views vis a vis utilisation of such system in absence of prerequisites. Further, the upstream/downstream system availability can also be discussed along side at RPC. Accordingly, in such a case, RPC may certify that an element is required in the interest of power system prior to its prerequisites before such an element can be considered for COD.

7. Operating Code

7.1. Background

The salient features of the Operating Code are as follows:

(a) Operating Philosophy: The section on Operational Philosophy (Regulation 28) has been retained as per the 2010 Grid Code.

(b) System Security: The section on System Security (Regulation 29) has broadly been retained as per the 2010 Grid Code. However, the aspects of Governor action have been proposed under a separate sub section on Frequency Control and Reserves. The System Security deals with aspects related to isolation, taking out of service and switching off of an element of the grid, sudden reduction of generation output, tuning of AVR and PSS, detailing of islanding schemes, designing of UFR settings as well as voltage range.

(c) Frequency Control and Reserves: The Frequency Control and Reserves is a newly introduced section (Regulation 30) elaborating on frequency control mechanism including Primary, Secondary and Tertiary reserve ancillary services.

(d) Operational Planning: The 2010 Grid Code comprised of section on Demand Estimation for Operational Purposes. Under the draft Grid Code, Operational Planning section (Regulation 31) has been introduced covering aspects related to demand estimation, generation estimation and resource adequacy.

(e) Outage Planning: The section on outage planning process (Regulation 32) covers aspects related to outage planning and has been broadly retained as per the 2010 Grid Code.

(f) System Restoration: The provisions related to system restoration have been dealt within the section recovery procedures under the 2010 Grid Code. The System Restoration section (Regulation 34) under the draft Grid Code deals with aspects related to development of recovery procedures, periodic testing of blackstart units as well as compensation to be provided to blackstart resources.

(g) Real Time Operation: The section on real time operation has been newly introduced in the draft Grid Code (Regulation 35). This section has aspects related to system states, procedures to be followed during an event as well as operational coordination that maybe required.

(h) Demand and Load Management: The 2010 Grid Code primarily dealt with demand disconnection in case the generation in the system is unable to meet the demand. It is observed that demand should be metat all times and should be disconnected only in case of system security. Accordingly the section (Regulation 36) has been modified to include demand side management and load shedding as a last resort.

(i) Post Despatch Analysis: The section on Periodic Despatch Analysis (Regulation 37) has been newly introduced in the draft Grid Code. This section covers aspects related to operational analysis and reporting of events that may have occurred in real time.

(j) Periodic Reports: The section on periodic reports already existed in the 2010 Grid Code. The draft Grid Code (Regulation 38) covers frequency of reporting as well as structure of such periodic reports.

(k) Reactive Power Management: The section on Reactive Power Management is a part of the Scheduling Code in the 2010 Grid Code. However, this section is now included in the operating code (Regulation 39). The section covers aspects related to sourcing of reactive power, measures to regulate reactive power and modalities related to reactive power compensation.

7.2. Operating Philosophy

(a) The grid has evolved from five regional grids to one integrated grid. Additional entities such as QCA, SNA have also been envisaged to be involved in day to day operations. All entities including QCA and SNA are required to act responsibly in coordination with each other to ensure security and stability for integrated operation of the grid so as to achieve maximum economy and efficiency in operation of power system.

(b) The 2010 Grid Code specifies that NLDC, RLDC and SLDC shall be required to specify detailed procedure at national, regional and state level. The same has been retained in the draft Grid Code.

(c) As per the provisions in the existing Grid Code, the control rooms of the NLDC, RLDC, all SLDCs, power plants, substation of 132 kV and above, and other control centers of all regional entities shall be manned round the clock by qualified and adequately trained personnel. Further, over time under the Tariff based competitive bidding multiple transmission licensees have come into being. Many such licensees belong to one parent group in a few cases. In case of any issues with a particular element of a transmission licensee is encountered, system operator should have a contact point for each element. Even for transmission licensees not having their own substation but their transmission line is terminating at substation owned by any other entity, are also proposed to have coordination centre manned by qualified and competent personnel round the clock. Further the role of QCAs and SNAs have been defined such that they are also required to have such coordination center. The Commission, is also of the view, that real time coordination centers are essential to ensure coordinated operation between LDC and the respective entity and for relaying instructions in case of any unforeseen event.

7.3. System Security

(a) The draft Grid Code has retained the following system security provisions from the existing Grid Code viz.:

(i) Provisions regarding isolation and synchronization of the element in the national grid
(ii) Capping the sudden reduction in generation below 100 MW without prior consent of RLDC
(iii) Provisions related to tuning requirement of AVR and PSS
(iv) Preparation of islanding schemes by RPC
(v) Identification of requirement of system protection schemes
(vi) Operational range of voltage

(b) An element in the grid can be taken out only after permission from SLDC or RLDC or NLDC as per respective control area jurisdiction of such an element. However, an important element, even if under control area jurisdiction of SLDC but critical for regional grid operation, can be taken out of service only after prior clearance of respective RLDC. A list of such important grid elements is made available on the website of NLDC/RLDC/SLDC. It has been proposed that the availability of such a list should be restricted only to concerned users in view of safety and security concerns and has it has accordingly been proposed that such a list be made available to concerned entities only.

(c) CEA Technical Standards for Connectivity provides for HVRT AND LVRT capabilities for Solar and Wind generators. It is observed that there is a requirement of periodic tuning including that for HVRT and LVRT capability.

Accordingly, following has been proposed at Regulation 29(7) of the draft Grid Code:

> *"(7) The tuning, including for low and high voltage ride through capability of wind and solar generators or any other requirements as per CEA Connectivity Standards shall be carried out:*
> *– at least once in every five (5) years;*
> *– based on operational feedback provided by the RLDC after analysis of a grid event or disturbance; and*
> *– in case of a major change in excitation system or major network changes/fault level changes near to generating plant as reported by NLDC, RLDC."*

(d) Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers are very critical systems. They need to be tuned properly so that they can perform the required function. Accordingly to bring seriousness in tuning of these systems, it has been proposed to disconnect the erring unit from the grid. Following has been proposed at Regulation 29(8) in the draft Grid Code:

> *"Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers shall be properly tuned by the generating station as per the plan and the procedure prepared by the concerned RPC. In case the tuning is not complied with as per the plan and procedure, the concerned RPC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the generating unit may be disconnected from the grid by the concerned RLDC on receipt of intimation to that effect from the concerned RPC."*

(e) The provisions regarding preparation of islanding schemes by RPCs have been retained as in the 2010 Grid Code. Besides implementation of such scheme, periodic inspections through mock drills are essential to ensure healthiness of the system.

(f) The Expert Group has recommended the inclusion of UFR setting as well as design consideration for implementing UFR and *df/dt* relay scheme in its report. The relevant extract is reproduced as follows:

> *"(a) Considering the All India electricity grid operating as a synchronous grid and being one of the largest grids in the world, the defence plans now need to be looked at from a national level rather than regional level. The same needs to be*

mandated in the IEGC itself rather than any discussion at the RPC level. As indicated in the section on primary response, for the reference contingency of 4500 MW generating station outage, the frequency would dip to 49.50 Hz and quickly recover to 49.70 Hz. So, the chances of the frequency falling below 49.50 Hz in an integrated large power system like India would be rare. The frequency would fall below this value only in case of part separation of systems leading to a generation deficit in one system.

(b) At present, 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."

(g) The Commission notes that minutes of 10th meeting of National Power Committee (NPC) held on 9th April 2021, provides as follows:

"..6.7.2 MS, NPC informed that in the 7th NPC meeting held on 8th September 2017, a need was felt for review of the quantum of load shedding without introduction of additional slabs/stages of frequency. In the 8th Meeting of NPC, it was decided that the frequency settings of AUFLS scheme (with 4 stages) may be raised by 0.2 Hz viz. 49.4, 49.2, 49.0 & 48.8 Hz and quantum of load shedding may be worked out considering the requirement to increase the frequency to 50 Hz.

6.7.3 MS, NPC informed that a Committee was formed (vide dated 19.01.2021-ANNEXURE - X) under the chairmanship of Member Secretary, WRPC, with representatives from POSOCO and all the RPCs to study the AUFLS Scheme and submit its recommendations to NPC.

6.7.4 MS,WRPC informed that in Western Region the frequency settings of AUFLS scheme was raised by 0.2 Hz viz. 49.4, 49.2, 49.0 & 48.8 Hz and implemented as per the 8th NPC decision .

6.7.5 MS, SRPC informed that in Southern Region the state of Telangana had only raised the frequency setting of AUFLS by 0.2 Hz.

6.7.6 MS, ERPC informed that in the Eastern Region, the revised settings were implemented.

6.7.7 SE, NERPC informed that 400 MW was implemented in NER and feeders were identified for revised quantum.

6.7.8 MS, NRPC informed that they would send the status after discussing with the states.

6.7.9 POSOCO also agreed for raising the AUFR settings by 0.2 Hz viz. 49.4, 49.2, 49.0 & 48.8 Hz.

…

6.7.12 After detailed deliberations it was decided that the AUFLS scheme (with 4 stages) viz. 49.4, 49.2, 49.0 & 48.8 Hz with existing quantum of load shedding shall be implemented in all the Regions. The quantum of load shedding would be reviewed based on the recommendation of the Sub- Committee to study the AUFLS scheme."

As per above, the UFR settings (with 4 stages) was decided to be raised by 0.2 Hz. Accordingly, the stages of UFR settings have been proposed in the Draft grid Code as 49.4 Hz, 49.2 Hz, 49.0 Hz & 48.8 Hz (Regulation 29(12)). However, the quantum of load shedding for each Stage of UFR may be worked out in percentage of demand or MW by the respective RPCs.

(h) It has been proposed to monitor the feeders which are mapped with UFR and df/dt regularly so that required response is available in case of contingency. It is also proposed that RPC should carry out random inspection of UFR relays and publish exception report on its website.

7.4. Frequency Control

(a) Indian power system has come a long way from five regional grids to one synchronous grid with one frequency. Over time, the Commission through periodic amendments in the 2010 Grid Code, has narrowed down the frequency band as follows:

- Pre-IEGC 2010:49.0 Hz to 50.5 Hz
- 2010 Grid Code: 49.5 Hz to 50.2 Hz
- First Amendment in 2012 to 2010 Grid Code: 49.7 Hz to 50.2 Hz
- Second Amendment in 2014 to 2010 Grid Code: 49.9 Hz to 50.05 Hz

(b) The national reference frequency has been considered as 50 Hz for power system operation in the larger interest of stability and grid security by the Commission.

i. Commission vide its meeting dated 23.3.2017 resolved to declare national reference frequency as 50 Hz as follows:

“Item No. 1: Frequency for the Indian Grid Decision: Proposal for Frequency for the Indian Grid was considered and endorsed with the following directions:-

- *The Commission noted that the CEA regulations on Grid Standards require all concerned to make all efforts to operate at a frequency close to 50 Hz. Further CERC, IEGC regulations provide for a permissible operating band of 49.90-50.05 Hz. Over the period, because of various measures taken by the Commission including by way of deterrence in terms of the Deviation Settlement Mechanism (DSM) rates, frequency has improved and remains at the present close to 50 Hz.*

- *The Commission, therefore, resolved to declare national reference frequency as 50 Hz.*

- *All stakeholders should endeavour to ensure maintenance of national reference frequency as referred above. 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….”*

ii. The 50 Hz Committee constituted by the Commission has also recommended that the national reference frequency for the purpose of frequency control may be considered as 50 Hz and the same may be notified in the Grid Code.

iii. The Expert Group, in its report, has proposed tightening of frequency band between 49.95 Hz to 50.05 Hz in line with international standards. Further, it has also recommended that 50 Hz be declared as the national reference frequency.

(c) Tightening the operational frequency range have also been complimented with imbalance mechanism through UI / DSM Regulations to manage frequency under the extant grid code. As a result of these interventions over a period there has been a clear improvement in the power system operation with appropriate incentives/disincentives to the grid users. Understanding the need to maintain adequate reserves for a large grid system like India, the Commission vide Order dated 13.10.2015 provided a roadmap to operationalize the reserves in the country. The primary reserves have been made available through suitable amendments in the Grid Code which require the generating stations to keep such reserves for system security, by not scheduling beyond their installed capacity. For secondary reserves, the Commission, vide order dated 28.08.2019, mandated Automatic Generation Control (AGC) to all inter-State Generating Stations. For operationalization of Tertiary reserves, CERC (Ancillary Services Operation) Regulations, 2015 were notified. While these frameworks have served well for setting the context of frequency control and Ancillary Reserves in the Indian power system, the Commission recently has revamped the Ancillary Service Regulations and DSM Regulations to bring out required design changes in the existing system. Accordingly, the Commission has also notified CERC (Deviation Settlement Mechanism and related matters) Regulations, 2022 and CERC (Ancillary Services) Regulations, 2022 wherein the system operator is expected to have adequate reserves at its disposal in order to maintain frequency close to 50 Hz.

(d) In view of the recommendations as well as notification of DSM Regulations 2022 and Ancillary Services Regulations,2022, the Commission has proposed the following in the draft regulations:

   i. National Reference Frequency to be declared at 50.000 Hz
   ii. Frequency shall be measured with a resolution of three decimal places by the system operator
   iii. Allowable frequency band shall be between 49.95 Hz to 50.05 Hz.

(e) Load generation balance is the prime objective of system operation. This requires the generators and the drawee entities to adhere to their schedule.

Given the uncertainty in demand and generation, the Commission has enabled different avenues of energy trade like Real time Market closer to real time. Such avenues would be available for the grid entity to adhere to their schedule. The Commission has introduced the AS Regulations which envisage that after the gate closure, the system operator shall take over and manage the system imbalances or deviations through deployment of ancillary services.

7.5. Reserves

(a) One of the important components for ensuring grid reliability includes achieving adequacy of reserves to maintain the load-generation balance and grid security. Ancillary Services may include a number of different operations such as frequency support through primary control, secondary control and tertiary control; voltage support and system restoration.

(b) The Commission, in the 2022 AS Regulations have notified three Ancillary Services for frequency control viz:

i. Primary Reserve Ancillary Service (PRAS)
ii. Secondary Reserve Ancillary Service (SRAS)
iii. Tertiary Reserve Ancillary Service (TRAS)

(c) Ancillary Services are indispensable part of the power system and very critical for ensuring smooth and effective grid operation, especially in view of large penetration of RE generation into the grid. The 2022 AS regulations specify procurement and deployment aspects regarding SRAS and TRAS. Further, methodology for reserve estimation prepared under the AS Regulations 2022, is an interim methodology till this Grid Code is made effective.

(d) The Commission, in the 2022 AS regulations, had specified that the following aspects shall be covered in the Grid Code:

a) Procurement, deployment and payment of PRAS
b) Estimation of quantum of SRAS and TRAS
c) Events where SRAS and TRAS shall be deployed
d) Scheduling and Despatch of TRAS

The Commission, thus, proposes to deal with the above aspects as well as other related operational aspects within the ambit of the regulation.

(e) **Frequency Control Hierarchy**

For any power system, frequency control continuum depicts frequency control over continuum of time using different resources that have some overlap in timeframe of occurrence. The 50 Hz Committee in its report has recommended the frequency control continuum chart depicting frequency control mechanism to maintain frequency within allowable band under all conditions. The frequency control hierarchy has been proposed to be operationalized through the frequency control continuum as follows:

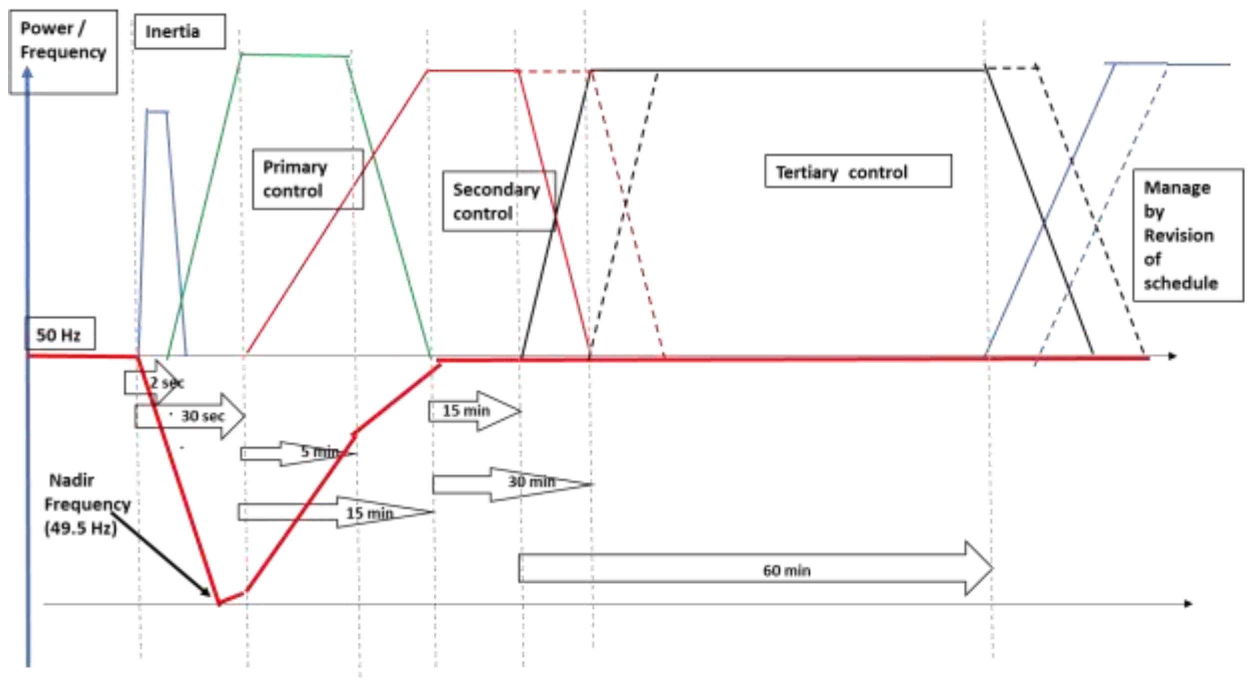


Figure 2: Frequency control continuum as proposed in Draft Grid Code

(i) The frequency control using primary, secondary and tertiary control during an event such as tripping of large generating unit is described below for ease of understanding.

a. Following the tripping 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 viz 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.

b. 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 of the governor and prime mover. As the frequency decreases, induction motors slow down and provide some amount of load damping. Primary response would sense local frequency and inject power automatically after the dead band frequency is crossed. The loss of generation would get balanced. However, this response to arrest frequency drop lasts for short period of up to 30 seconds to 5 minutes, within which secondary control should come into play. The frequency would be less than 50 Hz due to governor droop, only secondary control can bring it to 50 Hz.

c. The secondary control would be deployed automatically once the area control error limit is crossed. The deployment of secondary control reserve would restore the frequency to 50Hz as well as restore the primary response margin.
d. The tertiary controls need to be deployed manually within 15 minutes of application of secondary control to sustain the frequency at 50 Hz and restore the secondary control margins.
e. An Illustrative example is given below to explain the phenomenon:

Consider a simple power system with 4 generators catering a load of 1600 MW. G1 has an installed capacity of 200 MW (dispatched at 100 MW) and G2 to G4 have an IC of 800 MW (dispatched at 500 MW). All the units provide a maximum primary and secondary response of 5% of their IC.

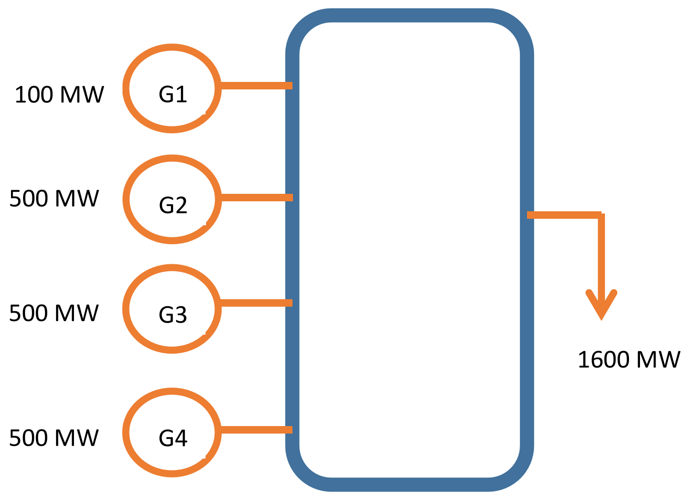


Figure 3: Indicative sample system

Lets assume G1 trips @ 10:00 hrs (denoted as t = 0).

f. Illustrative sequence of Events with respect to Primary, secondary and tertiary reserves coming into play are listed for ease of understanding the overlap and interplay between the three reserves(This may not correspond to a real situation):

t (seconds)	Frequency (Hz)	Event
0	50	G1 trips
1	49.98	Primary response yet to start as dead band of 0.03 Hz is not yet crossed.
2	49.94	Primary response starts within 2 seconds of the frequency crossing the dead band
20	49.70	Nadir frequency is reached. At this time instant the load generation balance is achieved. The total primary response provided by G2 to G4 say 50MW
30	49.80	AGC activation starts in G2 to G4. This combined with the primary response increases the slope of frequency recovery.
32	49.85	Primary response of say 80 MW achieved by G2 to G4.
332	49.95	Primary response starts ramping down as it has been deployed fully for 5 minutes.
400	50	Primary response is zero and the deficit of 100 MW (G1 loss) is fully provided by AGC.
1000	50	Operator dispatches 100 MW tertiary reserves in G2 to G4 to free

		up the deployed AGC. ULSP of the units is increased due to dispatch of tertiary reserves.
1900	50	AGC response is zero and deficit of 100 MW (G1 loss) is fully provided on account of ULSP increase.

*The frequency and MW values shown in the above table are only indicative and for the purpose of understanding

Note:

Above example was for sample generator loss. However secondary control would always be in continuous operation and would get deployed as soon as area control error limits are violated.

The details of each type of response is as follows:

(f) **Inertia**

(i) The inertia is the first step to arrest the fall in frequency following an event and is the fastest and immediate measure to arrest the decline in frequency. Rotating turbine generators and motors store kinetic energy which provides inertial response at the time of contingency. The amount of inertia extracted from the rotating synchronized machines depends on the number of such rotating mass connected to the system. The period during which the inertial response is activated is known as arresting period. This is illustrated in the following figure:

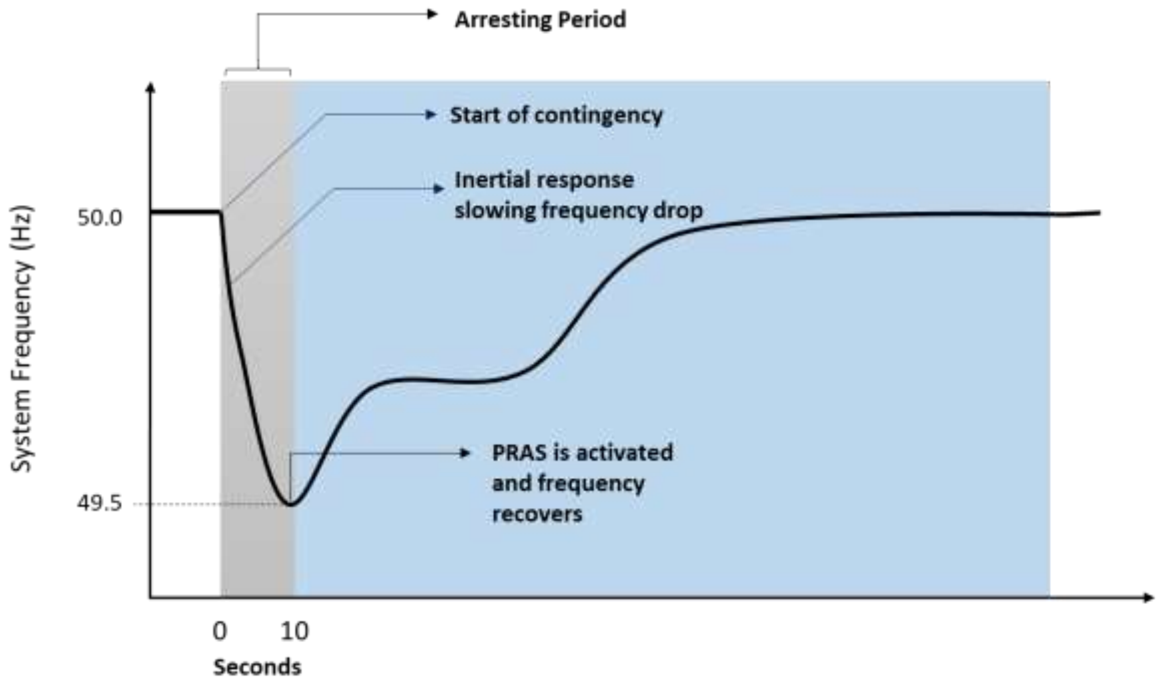


Figure 4: Inertial Response of the system

(ii) The lowest frequency recorded after the event of generation loss has occurred is known as nadir frequency. This nadir frequency shall be different for different events. However, in case of reference contingency, the nadir frequency measured is expected to be lowest in comparison to other events, means for all other contingencies the lowest frequency achieved should be higher. Hence, the inertial response in the system has been proposed to be substantial enough to prevent the fall of frequency below the minimum nadir frequency recorded in the event of reference contingency.

(iii) Internationally, it is observed that the system inertia is monitored in real time. One such example is observed in ERCOT where the system inertia is monitored on real time basis. The dashboard appears as follows:

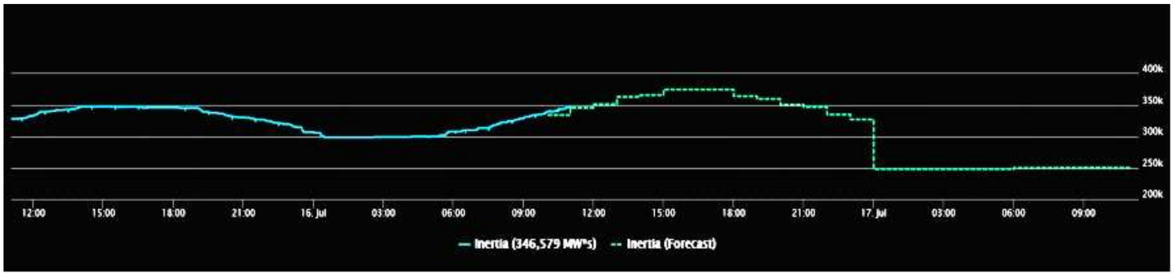


Figure 5: ERCOT dashboard for monitoring system inertia (Source: NERC, Industry Webinar, 2020)

The above figure provides timeline on X-Axis and measurement of inertia on Y Axis. ERCOT's Inertia Monitoring Tool continuously calculates the current total inertia contribution of all online synchronous generators, based on the inertia parameters of individual units in the network model and the online status of the units in the Energy Management System. The tool also is capable of calculating future inertia conditions for the next 168 hours on a rolling basis. This calculation is based on the unit commitment plans (for the next 168 hours) that every generator submits to ERCOT every hour. The tool then identifies any time periods where the expected system inertia is less than the critical level (Source: NERC Whitepaper on Fast Frequency Response Concepts and Bulk Power System Reliability Needs.

(iv) With increase in the intermittent sources of generation into the system in coming years, there would be a need to create appropriate framework to maintain minimum inertia in the system. This would require monitoring the inertial response of the system and to prepare baseline adequate for the Indian power system to simulate and study any adverse impact on the stability of the grid in case of a large contingency. It is envisaged that due to asynchronous nature of renewable machines, inertia of the system may get reduced leading to lower nadir frequency which may lead to under frequency load shedding (UFLS) getting triggered. It is, thus, proposed that NLDC shall be constantly monitoring the system inertia and may curtail RE generation, if required, to maintain inertia in the interest of the grid security. This would facilitate the preparation of baseline for monitoring special periods including the low net load periods.

(v) Internationally, owing to increased penetration of renewable energy, transmission system operators and wind turbine generators are exploring possibility of synthetic inertia for maintaining adequate inertia in the system. As per study done by NERC, synthetic inertia is possible only in Type 3 and Type 4 wind turbines (Source: NERC Whitepaper on Fast Frequency Response Concepts and Bulk Power System Reliability Needs) while in Europe (Entso-E guideline document on Need for synthetic inertia (SI) for frequency regulation), studies are being carried out to determine the effectiveness of synthetic inertia. Currently, there is no such mandate for inertial response from RE Generators as per the CEA Connectivity Regulations. Therefore, no inertial response has been proposed from renewable energy generators currently. The same may be considered once adequate studies have been done in this regard and the relevant technical standards have been notified by CEA.

(g) **Primary Control**

(i) The primary control shall be the next stage in the frequency restoration process wherein response would be provided within a few seconds following a change in frequency through governor action or similar controls which can emulate governor action by using sensing and control action. Primary Control commences automatically within few seconds following a change in frequency. Primary reserves aim at stabilizing the system frequency post contingency. As recommended in the frequency control continuum, Primary reserves respond to frequency signals, typically, within 5-10 seconds and may sustain upto 5 minutes. This is illustrated as follows:

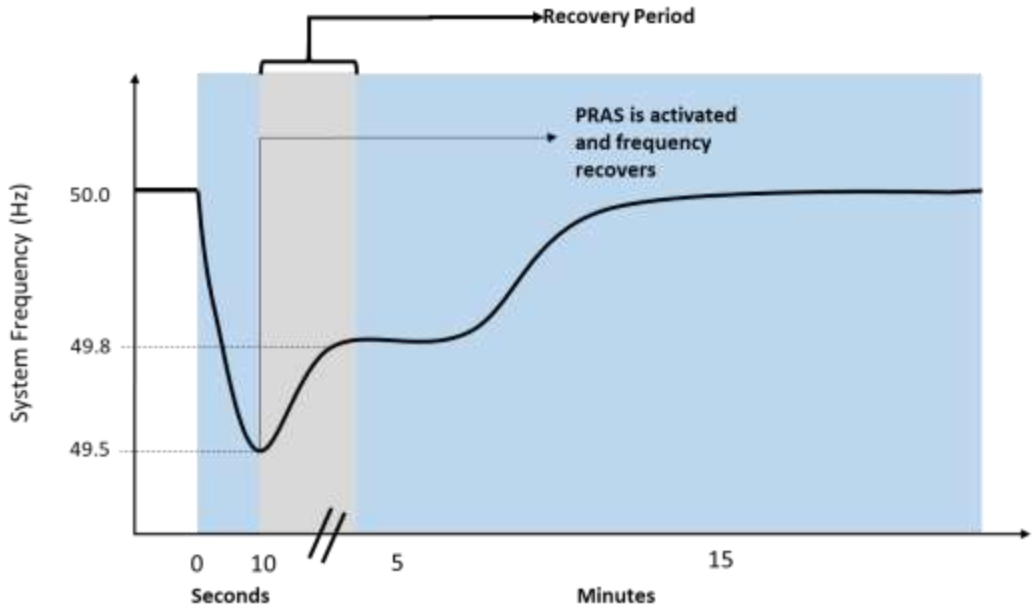


Figure6: Activation of PRAS for recovering system frequency

(ii) Accordingly, the Primary control has been specified as local automatic control in a generating unit or energy storage system or demand side resource for the purpose of adjusting its active power output or consumption, as the case may be, in response to frequency excursion. Resources providing Primary control are called as Primary Reserves Ancillary Services (PRAS) providers.

(iii) **Dimensioning of Primary Response**

a. As notified in the 2022 AS Regulations, the dimensioning of PRAS is to be dealt under the Grid Code. Accordingly, the Commission has proposed that the primary response shall be calculated on the basis of reference contingency as detailed in Annexure-2 of the draft Grid Code and the same would be more than the reference contingency quantum. The procedure for assessment of reference contingency would be discussed separately. It would be pertinent to mention that similar approach has been followed in the European Continent where dimensioning of Frequency Containment Reserves (FCR *(Source: Entso – E, System Operations Code Article 153)* *(PRAS in Indian context)* for a synchronous area requires to cover the reference incident which is the largest imbalance that may result from an instantaneous change of active power. (Source*: Article 153 of the Commission Regulation (EU) 2017/1485*). For Continental Europe reference incident is +/- 3000 MW. Similarly, in the NERC Reliability Standards (BAL-003-1) Interconnection Frequency Response Obligation (IFRO) which usually considers the largest generation loss possible and the Under-Frequency Load Shedding (UFLS) setting. For Eastern system in US, it is 4500 MW. The proposed methodology is in line with international standards/practices.

b. The reference contingency considering the loss of largest Power Plant has been proposed as 4500 MW (as suggested by the Expert group) . The reference contingency may need to be revised in case a larger generation complex gets commissioned post notification of the Grid Code. It has been provided that the reference contingency need to be revised by NLDC from time to time based on the system requirement.

c. It has been proposed that the during any contingency, primary reserves shall be activated immediately (within few seconds) when the frequency deviates from 50 Hz during any contingency of loss of generation. During any contingency, the grid frequency will start to drop and if primary control activation is not enough, UFLS along with df/dt relays (if required) may be activated to arrest its fall even though the Primary control through governor response plays a key role in this regard, as well as in settling at the final frequency. The safe, secure and reliable operation of grid requires that the nadir frequency should be at least 0.1

Hz above the first stage of under frequency load shedding (UFLS) scheme. This implies that the nadir frequency shall be above or 49.5 Hz (considering first stage of under frequency loading shedding setting as 49.4 Hz) for the reference contingency event and the maximum steady state frequency deviation should not cross 0.30 Hz for the reference contingency event.

(iv) **Procurement of Primary Reserves**

a. Commission is of the view that at this stage considering the generation profile of the Country, primary response shall be mandated.

b. As per the present provisions for primary response, the Commission vide the fifth amendment of the 2010 Grid Code dated 12th April 2017 had restricted the scheduling of conventional generators to ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof, so that the overload capacity as per Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 can be utilized for primary control from thermal and hydro generators (non peak season). The same has been retained in the draft Grid Code [Regulation 30 (10) (h)].

c. The Renewable Energy Generating stations have also been mandated to provide primary response in accordance with CEA Technical Standards for Connectivity.

d. CEA vide its amendment dated 6th February 2019 in Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 has provided as follows:

"B. Connectivity standards applicable to the wind generating stations, generating stations using inverters, wind - solar photo voltaic hybrid systems and energy storage systems.

………

B2. For generating station getting connected on or after completion of 6 months from date of publication of these Regulations in the Official Gazette.

(2) The generating unit shall be capable of operating in the frequency range 47.5 to 52 Hz and be able to deliver rated output in the frequency range of 49.5 Hz to 50.5 Hz:

Provided that in the frequency range below 49.90 Hz and above 50.05 Hz, or, as prescribed by the Central Commission, from time to time, it shall be possible to activate the control system to regulate the output of the generating unit as per frequency response requirement as provided in sub-clause (4):

Provided further that the generating unit shall be able to maintain its performance contained in this sub-clause even with voltage variation of up to ±5% subject to availability of commensurate wind speed in case of wind generating stations and solar insolation in case of solar generating stations.

…………

(4) The generating stations with installed capacity of more than 10 MW connected at voltage level of 33 kV and above –

(i) shall be equipped with the facility to control active power injection in accordance with a set point, capable of being revised based on directions of the State Load Dispatch Centre or Regional Load Dispatch Centre, as the case may be;

(ii) shall have governors or frequency controllers of the units at a droop of 3 to 6% and a dead band not exceeding ±0.03 Hz:

Provided that for frequency deviations in excess of 0.3 Hz, the Generating Station shall have the facility to provide an immediate (within 1 second) real power primary frequency response of at least 10% of the maximum Alternating Current active power capacity;

(iii) shall have the operating range of the frequency response and regulation system from 10% to 100% of the maximum Alternating Current active power capacity, corresponding to solar insolation or wind speed, as the case may be;

(iv) shall be equipped with the facility for controlling the rate of change of power output at a rate not more than ± 10% per minute.”

e. As per the above, primary response is mandated for specified Renewable Energy Generating stations getting connected post the specified date. Considering a high percentage of renewable energy generating stations on bar as compared to number of thermal generating stations, the role of renewable energy generating stations to provide primary response becomes very important for grid stability during a contingency. In addition, it is also proposed that NLDC may also identify other resources such as ESS and demand response for providing the primary response, the compensation for the same can be specified separately in the Ancillary Services Regulations.

f. Following has been proposed at Regulation 30(10) in the draft Grid Code:

"(g) The generating units shall have their governors or controllers in operation at all times with droop settings of 3-6 % or as specified in the CEA Technical Standards for Connectivity as per the requirements mentioned in the Table 4.

Table-4: Primary response of various types of generating units

Fuel/ Source	***Minimum unit size/Capacity***	***Up to***
Coal/Lignite Based	*200 MW and above*	*±5%* ***of MCR***
Hydro	*25 MW and above non-canal based*	*±10****% of MCR***
Gas based	*Gas Turbine above 50 MW*	*±5****% of MCR*** *(corrected for ambience temperature)*
Wind/ Solar/ Renewable Hybrid Energy Project (commissioned after the date as specified in the CEA Technical Standards for Connectivity)*^	*Capacity of Generating station more than 10 MW and connected at 33 kV and above*	*10% of the maximum Alternating Current active power capacity in case of frequency deviations in excess of 0.3 Hz*

^*Wind/Solar/Hybrid plant commissioned after the date as specified in CEA Technical Standards for Connectivity shall have the option to provide primary response individually through BESS or through a common BESS installed at its pooling station.*

(h) All generating stations mentioned in Table-4 (under clause (g) of this Regulation) shall have the capability of instantaneously picking up to a minimum 105% of their operating level and up to 105% or 110% of their MCR, as the case maybe, when the frequency falls suddenly and shall provide primary response~~.~~ Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of the concerned RLDC.

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

(j) The thermal and hydro generating units shall not resort to Valve Wide Open (VWO) operation to make available margin for providing governor action."

As per the above, a coal or lignite generating unit is required to provide response upto +/-5% of MCR. Suppose such a generating unit is running at 60% load. It is supposed to pick up loading, subject to droop, as at least 60% + 5% of MCR, in case of drop in frequency beyond dead band. Such a generating unit may be able to provide more than this response based on type of unit, and can provide the same, however the response of +5% of MCR is mandated. Further, for specified renewable energy projects under Table 4 of the draft Grid Code, primary response of 10% of maximum Alternating Current active power capacity is mandated if frequency deviates in excess of 0.3 Hz as per the CEA Standards. Such projects shall have to keep margins so that they can provide primary response. However, it is provided that such projects may provide primary response through BESS or common BESS at its pooling station.

(v) It is further proposed that along with regional entity generating stations, States would also be required to contribute to primary response considering embedded generating stations within the State, to ensure grid security. This frequency response obligation of each control area shall be calculated as

*"FRO = (Control Area average Demand + Control Area average Generation) * minimum all India Target Frequency Response Characteristic/ (Sum of peak or average demand of all control areas + Sum of average generation of all control areas)"*

The proposed methodology is explained in Annexure-2 of the draft Grid Code.

(vi) The above distribution is also in line with the international practices, some of which have been listed as follows:

a. The Entso – E allocates the reserve capacity on FCR (PRAS in Indian context) for each TSO (Transmission System Operators) on the basis of sum of the net generation and consumption of its control area divided by the sum of net generation and consumption of the synchronous area over a period of 1 year

b. The North American Electric Reliability Corporation (NERC) as per BAL-003-2 allocates the Interconnection Frequency Response Obligation between the control areas on the basis of the following formula:

$$\frac{\text{Annual GenBA} + \text{Annual LoadBA}}{\text{Annual GenInt} + \text{Annual LoadInt}} * \text{IFRO}$$

Where

IFRO is the Interconnection Frequency Response Obligation
Annual Gen_{BA} is the total annual "Output of Generating Plants" within the Balancing Authority Area;
Annual $Load_{BA}$ is total annual Load within the Balancing Authority Area
Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection
Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection

A sample example is illustrated as follows:

Assume IFRO of Eastern Connection = (-1015)MW/0.1 Hz, the control area wise FRO is determined as follows:

BA Name (a)	Net Generation (Mwh) (b)	Net Load (Mwh) (c)	Total (Mwh) (d)= (b)+(c)	% of IFRO e=d/Total (d)	Frequency Response Obligation (MW/0.1 Hz) (f)= e*IFRO
Duke Energy	40,197,734	53,858,338	94,056,072	1.53%	-15.521
Florida Municipal Power	16,668,949	17,472,994	34,141,943	0.56%	-5.634
Florida Power and Light	125,032,593	120,976,413	246,009,006	4.00%	-40.595
….	………	……	…..	…..	……..
	3,057,278,181	3,093,684,723	6,150,962,904	100%	-1,015

Figure 1: IFRO Calculation for Eastern Interconnection (Source: NERC IFRO Allocation, 2017)

(vii) Since UTs of Chandigarh, Puducherry, Daman and Diu and Dadra and Nagar Haveli and states of Goa, Sikkim, Manipur, Mizoram, Nagaland and Arunachal Pradesh do not have any intra-state generation, such states may be exempted from providing any frequency response obligation (FRO). However, such States may be required to arrange for such response in accordance with framework which may be specified at an appropriate time.

(viii) The 2010 Grid Code provides that all generators shall ramp up/ramp down based on the governor action. Several stakeholders have approached the Commission to allow generators to operate on Speed Control with Droop Settings in line with international standards. CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007 specify that all governors of thermal generating units shall have a droop of 3% to 6% while hydro generating units shall have a droop of 0 to 10%. The said CEA Standards provides as follows for Generating Stations other than wind and generating stations using inverters:

“(4) All generating machines irrespective of capacity shall have electronically controlled governing system with appropriate speed/load characteristics to regulate frequency. The governors of thermal generating units shall have a droop of 3 to 6% and those of hydro generating units 0 to 10%.”

(ix) It is observed that the frequency profile of the grid has improved over the years. Thus, RGMO can be phased out and governors can be allowed to operate on free governor mode so that they can adjust their output with respect to the grid frequency automatically. Accordingly, provision of RGMO has been done away with.

(x) A monitoring mechanism for Frequency Response Performance has been proposed as follows:

“TABLE 11: FREQUENCY RESPONSE CRITERIA

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

”

(xi) Such a monitoring mechanism is needed in order to ensure that all control areas are in compliance and adequate primary response is available at the time of any contingency. Further, the benchmark performance of 0.75 is in line with international practices, the relevant extract from NERC balancing codes (BAL-001) is reproduced as follows:

“Each GO shall meet a minimum 12-month rolling average initial Primary Frequency Response performance of 0.75 on each generating unit/generating facility, based on participation in at least eight FMEs.”

(xii) The Commission, observes that primary response is a mandatory obligation that must be ensured by the Control areas in order to maintain grid stability during an event. Accordingly, the benchmark norms should be high in line with international standards and accordingly sets the average frequency response in the range of 0.75 to 0.85.

(h) **Secondary Control**

(i) As per the proposed frequency continuum, the Secondary Reserves Ancillary Services (SRAS) shall be deployed to replace the PRAS so that PRAS is available to manage another contingency which may happen anytime. SRAS shall enable the restoration of the system frequency to the reference frequency. As provided in the 2022 AS Regulations, SRAS Providers must have the necessary infrastructure set up so that they can receive and respond to automatic secondary control signal sent by the NLDC through concerned RLDC. Accordingly secondary control has been defined as a centralized automatic function to regulate the generation or load in a control area to replenish deployed primary reserves and to restore the frequency in the allowable band. it is also envisaged that SRAS shall be provided through generating station or an entity having energy storage resource or an entity capable of providing demand response, on standalone or aggregated basis as per the 2022 AS Regulations.

(ii) SRAS is fast response service and hence SRAS providers should be capable of responding to SRAS signal within 30 seconds and providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining at least for the next thirty (30) minutes. This, is illustrated as follows:

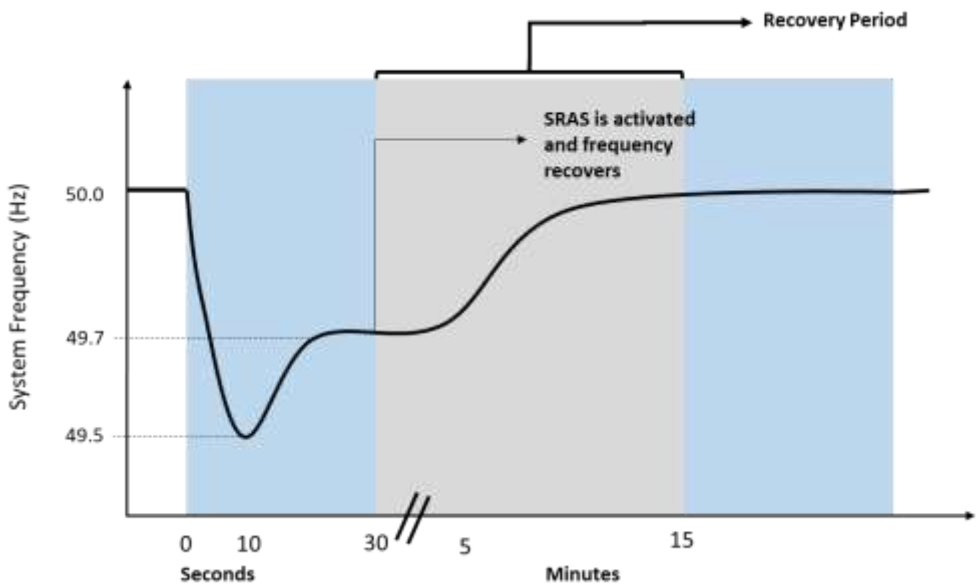


Figure 7: Activation of SRAS in the system

(iii) Secondary reserves are deployed primarily to correct the Area Control Error (ACE). The imbalance in a control area is measured using Area Control Error (ACE), the formula for which is as follows:

ACE= (Ia – Is) – 10 * Bf * (Fa – Fs) + Offset:

(IV) The Area Control Error factors changes on account of tie-line flow between the control areas as well as changes in frequency. ACE has to be driven towards zero for frequency control and grid security. A large positive ACE may indicate over generation and corresponding rise in frequency while a large negative ACE may indicate under generation and corresponding decrease in frequency. While determining the ACE, frequency bias (B_f) is an essential setting in the AGC system as it is used to prevent any premature withdrawal of the primary response following an event.

(v) The bias setting of AGC as stipulated under Frequency Response Intiative Report, 2012 of North American Electric Reliability Corporation (NERC) is as follows:

"If the bias setting is greater than the Balancing Authority's actual frequency response characteristic (FRC), then its AGC will increase generation beyond the primary governor response, which further helps arrest the frequency decline, but increases Inadvertent Interchange. Likewise, if the bias contribution term is less than the actual FRC, its AGC will reduce generation, reducing the Balancing Authority's contribution to arresting the frequency change. In both cases, the resultant control action is unwanted."

(vi) As per the above, if the bias setting is set greater than the actual frequency response characteristics (FRC), the interchange across tie lines would increase whereas if the bias is kept less, the generation may not be enough to restore the frequency. Further, Median is a better choice as the FRC value is susceptible to small number of extreme values or outliers. Accordingly, the value of frequency bias coefficient (B_f) has been proposed as median Frequency Response Characteristics (FRC).

(vii) The ACE can be operated under three modes: tie-line bias mode, flat frequency mode and flat tie-line control mode. These modes are described as follows:

a. The tie line bias mode will be the normal control mode wherein the ACE will be sensitive to both tie line flow as well as frequency.

b. The flat frequency mode will only be sensitive to frequency variations in the grid. This mode may be utilized under system restoration operations in order to maintain frequency of islands which have been isolated from the grid.

c. The flat tie line flow will only be sensitive to changes in tie line flows. This mode may be utilized under system restoration while connecting multiple islands or during cross border operations wherein the system operator is not required to maintain the frequency of the connected grid.

The above scenarios are not exhaustive in nature and may have variations based on grid situations. The draft Grid Code provides that NLDC shall lay down the conditions during which a particular mode shall be chosen and shall necessarily document the reasons for operating in a particular mode. Since Secondary control shall be coming into effect on PAN India basis post effectiveness of this Grid Code, the operation of Secondary control under a particular mode shall need to be learned with experience and documenting the reasons for building up a database to automate at a later point in time when sufficient experience has been built up.

(viii) SRAS is anticipated to operate in automated mode to correct the ACE. Therefore, the ACE shall operate to maintain system frequency close to 50 Hz. A threshold deviation at +/- 10 MW in the ACE have been included for activation of SRAS as suggested by the Expert Group, which may be reviewed as required.

(ix) The Commission has entrusted the responsibility of maintaining the reserves with SLDC and RLDC using probabilistic or deterministic methodology as specified in the draft regulations in line with international experience(Source: SANTULAN-FOR-Report-April2020) and as recommended by the expert group.

(x) Considering that Secondary Reserves have been introduced for the first time in the Grid Code, a flexibility needs to be given to the system operator with regard to dimensioning of Secondary reserves. Accordingly following has been proposed at Regulation 30(11) in the draft Grid Code:

> *"(k)With due regard to the requirement of planning reserve margin and resource adequacy referred to in clause (e) of Regulation 5 of these regulations, and based on the following methodologies, the secondary reserve capacity shall be estimated by RLDCs for their respective regional control areas:*
>
> > *The positive and negative secondary reserve capacity for any control area for a financial year shall be equal to 99 percentile of positive and negative ACE respectively of that control area during the previous financial year (Detailed Procedure shall be as per Annexure-3 to these regulations),*
> >
> > *OR*
> >
> > *The secondary reserves capacity for any control area shall be equal to the 110 % of largest unit size in the respective regional control area or state*

control area plus load forecast error plus wind forecast error plus solar forecast error during the previous financial year.

…

(n)All India secondary reserves requirement for the regional control area and the State control area shall be estimated by NLDC based on reference contingency and other factors such as forecast errors.

All India secondary reserves capacity for the regional control area and the State control area shall be estimated by NLDC based on reference contingency and other factors such as forecast errors.

(o)NLDC shall allocate such All India secondary reserves capacity, to be maintained at regional control area and at State control area, based on the estimated reserves as per clause (k) of this Regulation and publish the information on its website by 1st March every year."

(xi) Due to the integrated nature of the national grid, it has been proposed that NLDC shall estimate the all India reserves requirement and allocate the same between the state control area and regional control area. The reserves requirement shall be declared at the beginning of each financial year so that the states can plan accordingly.

(xii) Since the system operator shall have greater visibility of reserve requirement closer to the actual despatch, it has been proposed that the same shall be re-assessed on day-ahead and real time basis in order to ensure availability of adequate reserves in accordance with the 2022 AS Regulations. However, in case the states are unable to ensure the required quantum of reserves as allocated by NLDC, NLDC shall procure the secondary reserves capacity on behalf of such state and allocate the cost for the same to that state as per methodology specified in the 2022 AS Regulations.

(xiii) Further CEA Technical Standards for Connectivity require that specified renewable energy generating stations shall be equipped with the facility to control active power injection in accordance with a set point, capable of being revised based on directions of the State Load Dispatch Centre or Regional Load Dispatch Centre, as the case may be and accordingly same has been provided in the draft Grid Code.

(i) **Tertiary Control**

(i) As per the proposed frequency continuum, it is envisaged that the secondary reserves will start getting replaced by tertiary reserves at the end of 15 minutes after the occurrence of the contingency to ensure that the secondary reserves are available with the system operator in case of another contingency occurring simultaneously. This is illustrated as follows:

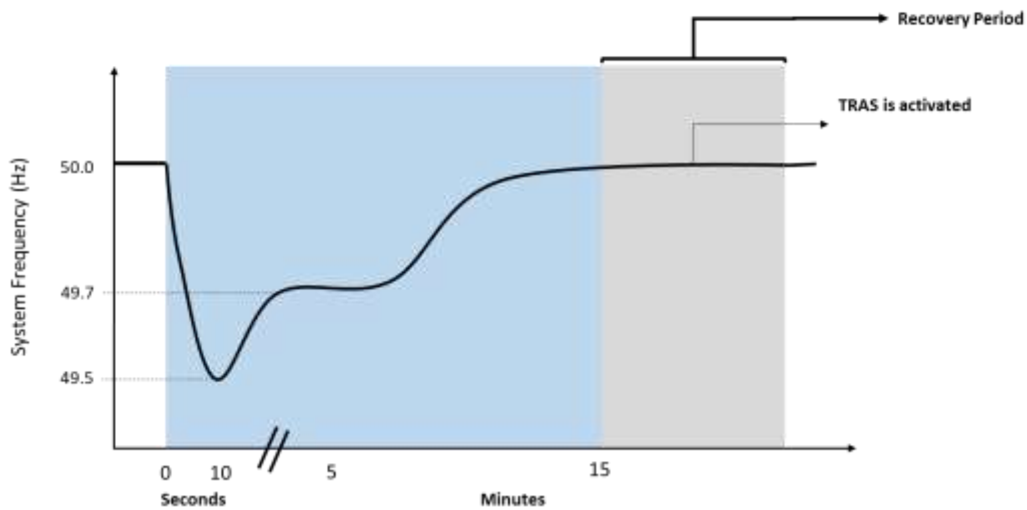


Figure 8: Activation of Tertiary Response in the system

(ii) It has been proposed that tertiary reserve requirement shall be estimated with due regard to the requirement of the planning reserves and resource adequacy to cater to the need of replacing the secondary reserves. The responsibility to provide reserve should be shared by all control areas in a distributed manner in the interest of grid security and in a participative manner. Accordingly, it has been proposed that tertiary reserves shall be maintained at State control area and Regional Control area. In case of shortfall of reserve at the State control area, NLDC shall procure such tertiary reserve capacity on behalf of the concerned state and the cost of procurement for such capacity would be allocated to the concerned State.

(iii) A generating station or an entity having energy storage resource or an entity capable of providing demand response, on standalone or aggregated basis may also provide TRAS. It should be capable of providing TRAS within 15 minutes and have capability to sustain for at least next 60 minutes, as specified in the 2022 AS Regulations.

(iv) The quantum of tertiary reserves shall be estimated by NLDC and distributed between regional and state control areas on a year ahead basis. Since the system operator shall have greater visibility of reserve requirement closer to the actual despatch, it has been proposed that the same shall be re-assessed on day-ahead and real time basis in order to ensure availability of adequate reserves.

(v) The Expert Group has also recommended that tertiary reserves should be deployed where Secondary reserves of more than 100 MW has been deployed in one direction for more than fifteen minutes. Further, tertiary reserves may be deployed in events as affecting Grid Security . Accordingly following has been proposed at Regulation 30(12)(g) in the draft Grid Code:

"Tertiary reserves to be provided by TRAS provider shall be capable of providing TRAS within fifteen (15) minutes of dispatch instructions from RLDC or SLDC, as the case may be, and shall be capable of sustaining the service for at least next 60 minutes. TRAS shall be activated and deployed by the appropriate load dispatch center on account of following events:

i. *To replenish the secondary reserve, in case the secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW;*

ii. *Generation unit or transmission line outages;*

iii. *Any such other event affecting the grid security. "*

(vi) It is also proposed that the NLDC shall prepared a detailed procedure for evaluating the control area wise performance of SRAS and TRAS.

7.5 Operational Planning

(a) It has been proposed that operational planning shall be done by SLDC, RLDC and NLDC on Yearly, Monthly, Weekly, Day Ahead and Real Time basis for ensuring resource adequacy. A bottom up approach of demand estimation has been proposed in the draft Grid Code wherein SLDC has been entrusted to carry out demand estimation at the state level followed by RLDC at the regional level and NLDC at the national level. The sequence of operational planning is as follows:

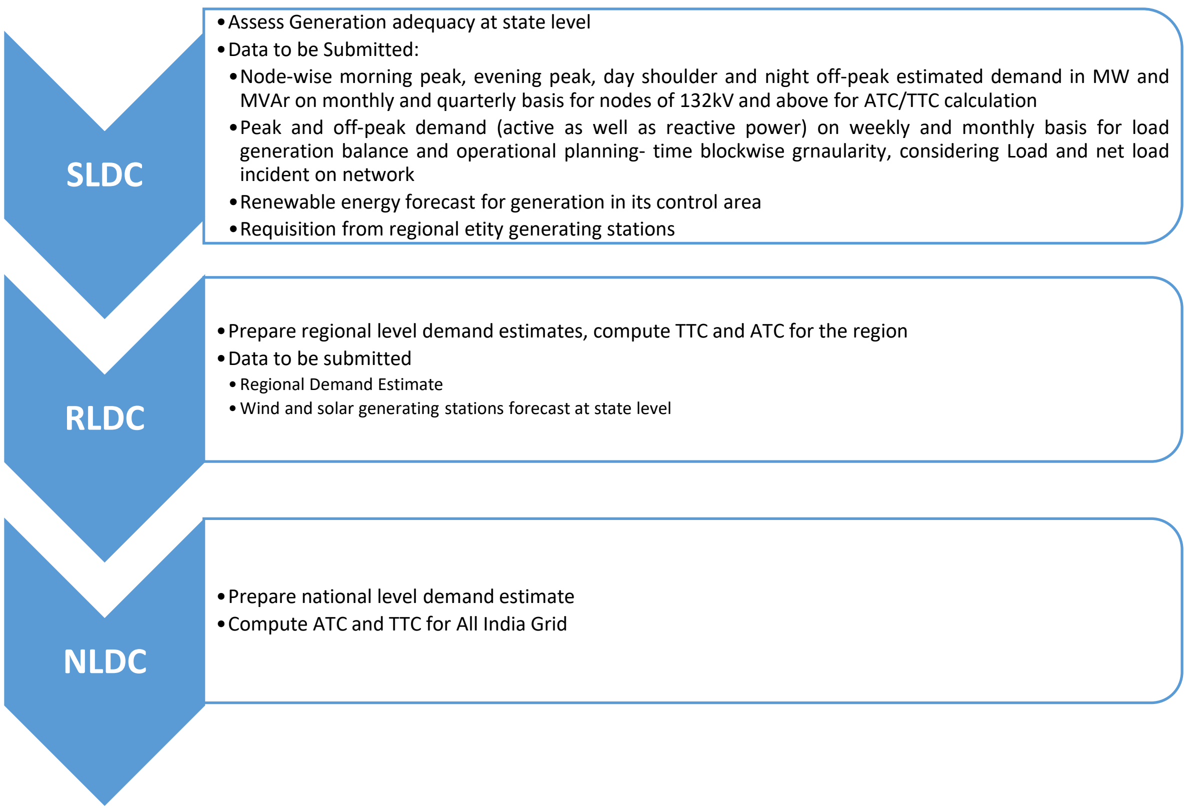


Figure 9: Sequence of Operational Planning

(b) The Commission anticipates that such an elaborate planning approach will result in ensuring resource adequacy during real time operations as well as reduce reliance on reserves as balancing energy. For implementing this bottom up approach, the Commission has proposed that necessary formats shall be introduced by SLDC.

(c) The operational planning on a longer term horizon i.e. monthly and yearly basis is to be carried out in coordination with CTU, RPCs and STUs, as applicable considering the modifications in transmission system being carried out. However, the operational planning on shorter term horizon i.e. intra-day, day ahead and weekly time horizons shall be carried out by NLDC, RLDCs and SLDCs within their control areas.

(d) It has been proposed that there is a requirement to issue Procedure and formats to streamline the operational planning data collection and methodology to be followed while carrying out the operational planning. It is expected that SLDCs may also issue such procedure and formats for data collection for its Control area.

(e) **Demand Estimation**

(i) The demand estimation has been proposed for both active power and reactive power based on details gathered from state level entities since all India adequacy can be achieved if the individual states have adequate resources to balance their load and generation profile. There is requirement for introduction of state of art tools for demand forecasting at the state level.

(ii) It has been proposed that Demand forecasting on day ahead basis should have time block wise granularity for the entire day. The frequency is to be maintained for every block and accordingly reserves are to be kept to maintain the frequency close to National reference frequency at all times. Accordingly, block-wise data of demand is required to be submitted. This data is for the purpose of operational planning only. For weekly and monthly planning, SLDC shall estimate peak and off- peak demand for ensuring adequacy during peak and off-peak time blocks so that the availability of generation capacities can be planned well in advance.

(iii) The timeline for submission of data of daily, weekly, monthly and yearly demand estimation has been specified to ensure that the data is received well in advance.

(iv) The section on operational planning studies proposes various system studies such as:

a. *Inter-regional, intra-regional, inter-state, intra-state total transfer capability/available transfer capability assessment*
b. *Planned outage assessment*
c. *Special scenario assessment*
d. *System protection scheme assessment*
e. *Natural disaster assessment*
f. *Any other study relevant in operational scenario*

(f) While doing the operational studies, emphasis has been placed on real-time network applications available in the EMS SCADA systems at LDCs. Further, such operational studies shall help RLDC to take corrective action well in advance.

(g) Based on operational planning analysis data, operational planning study shall be carried out. It is expected that such study shall help to assess whether the planned operations shall result in deviations from any of the system operational limits as per these regulations and applicable CEA standards so that necessary action may be taken in time bound manner in case of significant deviations.

7.6 Outage Planning

(a) Outage plan shall be prepared in a coordinated and optimal manner keeping in view the grid security so that the overall down time is minimal and the resource adequacy is maintained. A broad outline for outage plan, process and timeline has been proposed to ensure that outage panning shall be conducted in a smooth and well-coordinated manner.

(b) It has been proposed that all users, CTU and STU shall follow the annual outage plan and any deviations from outage plan, as approved by RPC, must be uploaded on the RPC website.

(c) Further in case of grid disturbance, system isolation or other events, which can lead to adverse impact to grid system security due to planned outage, RLDC/NLDC/SLDC can defer the planned outage and may conduct the studies again before giving the outage.

(d) The outage planning procedure shall be prepared and finalized by each RPC.

7.7 Operational Planning Studies

(a) The Expert Group has suggested to include time horizon for operational planning studies clearly as a part of Grid Code so that the same are carried out in a systematic manner.

(b) It has been proposed that real time and intraday studies shall have to be carried out using online tools with not more than 15 minutes interval by SLDCs, RLDCs and NLDC. The provision of offline SCADA/EMS system has been included to cover entities/States where online system is yet to be commissioned. The studies shall corroborate with actual conditions when error free operational data is made available at all times. Further there is a need of feedback system to check if online network estimation tools actually match with real time situation for which its performance shall be reviewed in the monthly meetings at RPC.

(c) The operational studies to be carried out by SLDCs for their control area have been included as a part of Grid Code since under integrated operation, the studies shall have significant impact on the situation of the regional grid.

(d) It has been proposed that NLDC shall declare TTC and ATC for important corridors and inter-State /intra-State interface for 11 months in advance for each month on a rolling basis. The TTC/ATC shall need to be revised from time to time based on commissioning of any new elements. All the assumptions while declaring TTC/ATC or revising TTC/ATC need to be uploaded on website so that stakeholders are aware of the reasons of such revision and hence no disputes arise due to such revision.

7.8 System Restoration

(a) System restoration post partial or total blackout requires adequate planning before such an event occurs. Accordingly, it has been proposed that detailed procedures for restoration shall be prepared by Users, SLDCs and RLDCs for their respective areas. These procedures shall be prepared after due consultations with NLDC, RLDCs, CTU, STUs, SLDCs and RPCs as specified. The Procedures need to be reviewed every year and updated taking into account changes in the system, if any.

(b) In order to ensure better assessment and effective implementation of system restoration, mock trial run of the restoration procedure for different subsystems and generating units have been proposed. Further, simulation studies need to be carried out by each user in coordination with RLDC for preparing, reviewing and updating the restoration procedures.

(c) Regular testing shall be required to ensure healthiness of the black-start facility. Diesel generator sets shall be tested once a week to ensure healthiness since their availability is critical for restarting the auxiliary system of a tripped power plant. However, the sub-systems are proposed to be tested at least once a year to monitor their healthiness.

(d) As per CEA Construction Standards, all hydro units shall be capable of black-start operation while thermal units shall be capable of house load operation. The relevant portion of CEA Construction Standards is quoted as follows:

“ ***PART B:***

COAL OR LIGNITE BASED THERMAL GENERATING STATIONS

7. Operating Capabilities of a Unit in the Station-….

…………………….

(5) The unit shall be capable of automatically coming down to house load and operation at this load in the event of sudden external load throw off.”

“ ***CHAPTER III:***

TECHNICAL STANDARDS FOR CONSTRUCTION OF HYDRO- ELECTRIC GENERATING STATIONS

'32. Operating Capability of the Generating Unit-….

(8) The Station shall be equipped with facilities for black start of generating unit in the event of grid black- out conditions.”

(e) The Commission, therefore, proposes that it is essential to identify the units which have the required capabilities of building a cranking path and has accordingly entrusted the responsible for identification of the same to the respective Load Despatch Centres.

(f) It is observed that there is no well defined commercial mechanism for compensating the generating units extending black start support service. A sample of methodologies following internationally to compensate black start service is as follows:

Country	Procurement Mechanism	Commercial Mechanism
Australia	Market Based	– Availability Charge per 30 -minute interval – Usage Charge per event – Testing Charge (per test)
France	No remuneration	

Country	Procurement Mechanism	Commercial Mechanism
Netherlands	Market Based	– Fixed annual charge – Test cost – Activation Cost – Warming Cost
UK	Market Based/Bilateral	– Availability Charge – Fixed charge to cover capital investment in case some capital works need to be undertaken – Testing costs – Warming costs
New Zealand		– Availability Fee – Event Fee
Ireland	Regulated	Payment for availability which includes cost of maintenance, testing and usage
Belgium	Market Based	– Remuneration for availability – Investment Cost – Testing
North America (ISO-NE)	Regulated	Based on proportional monthly O&M and fixed charges for a black start station
North America (MISO)	Regulated	Fixed Black start Service Costs + Variable Black start Service Costs + Training and Compliance Costs.
North America (NYISO)	Regulated	Cost of service

(g) It is observed that the cost of such black start service is primarily on account of fixed cost for keeping systems such as diesel generator sets and variable cost of fuel used to supply such service. For generating units under Section 62 of the Act, the fixed cost is covered under the capital cost. The situation post an event is such that whichever units are available are required to provide such black start service and need to be incentivized to provide the service, though CEA Standards mandate such a service. Accordingly, compensation to any entity extending black start support service including the units under Section 62 of the Act shall be compensated for providing this service critical for restoration of the Grid.

(h) It has been proposed to compensate the black start service related to deviation charges @ 110 % of normal rate of charges for deviation in accordance with the DSM Regulations for the last block in which the grid was available.

7.9 Real Time Operation

(a) The Expert Group, in its report, has recommended five system states for enabling better grid management. RLDCs under the Operating procedure issued by them has already defined Normal, Alert and Emergency state. The relevant extract of the Operating Procedure for the Northern Region issued by NRLDC for year 2022-2023 is reproduced as follows:

Normal State: All system variables are within the normal range and no equipment is being overloaded.
Alert State: All system variables are within acceptable range, all constraints are satisfied and a further contingency would cause an overloading any equipment.
Emergency State: After the contingency, voltages at many buses are low and/or equipment loadings are exceeds short term emergency ratings.

(b) Further the parameters which are monitored by RLDCs are also provided in the Operating Procedure. The Operating Procedure for Northern Region issued by NRLDC for the year 2022-2023 provides as follows:

"NRLDC shall issue Normal, Alert and Emergency messages on Frequency, Voltage & Loading violation based on values appearing in SCADA. In addition, zero crossing violation & deviation from schedule violation message would also be issued by NRLDC from time to time based on the SCADA data…

Violation Type and Category			Duration for issuance of Message
Frequency Violation	>50.1 Hz or <49.7 Hz	Emergency	Message will be issued if violation continues for atleast 5 minutes
	50.05-50.1 Hz or 49.9 Hz -49.7 Hz	Alert	Message will be issued if violation continues for atleast 15 minutes
	49.9 Hz -50.05 Hz	Normal	
Voltage Violation	> 420 kV or <380 kV	Emergency	Message will be issued if violation continues for atleas 15 minutes
	415 kV - 420 kV or 390 kV - 380 kV	Alert	Message will be issued if violation continues for atleas 15 minutes
	>390 kV to <415 kV	Normal	
Loading Violation	> Thermal Loading under n-1 contingency	Emergency	Message will be issued if violation continues for atleast 5 minutes
	= Thermal Loading under n-1 contingency	Alert	Message will be issued if violation continues for atleast 15 minutes
	< Thermal Limit under n-1 contingency	Normal	
Zero Crossing Violation	1 Failure (issued 14th time Block)	Emergency	
	Issued in 11th time block if the direction not changed for 10 time blocks	Alert	
	Zero Crossing done within 10 time Blocks	Normal	
Deviation Violation	> 20% or 250 MW (whichever lower)	Emergency	Message will be issued if violation continues for atleast 5 minutes
	12%-20% or 150 MW to 250 MW (whichever lower)	Alert	Message will be issued if violation continues for atleast 15 minutes
	<12% or 150 MW (whichever lower)	Normal	

Note:

1. General Approach is to issue Alert Message before reaching Critical level
2. Generally every Alert is considered for maximum of 15 Minutes
3. Generally any Emergency considered for maximum of 5 minutes

”

It can be seen from the above that frequency, voltage, loading, zero cross violation and deviation is monitored currently to categorize a situation as normal, alert or emergency. However, there is a need to design the criteria to categorize system state based on the historical data and grid incidences. Accordingly, the following has been proposed at Regulation 35(2) in the draft Grid Code:

"35 (2) Each RLDC in consultation with NLDC and SLDCs shall carry out the study for the concerned region and based on historical data and grid incidences evolve the detailed criteria to categorise the power system in terms of the above state. The detailed criteria shall be included in respective Detailed Operating Procedure to be issued by RLDCs and NLDC."

(c) Such a practice of defining system state is also being followed internationally in order to respond appropriately to the grid condition. For instance, Entso-E has defined the operational states as follows:

System State	Remarks
Normal State	means a situation in which the system is within operational security limits in the N-situation and after the occurrence of any contingency from the contingency list, taking into account the effect of the available remedial actions
Alert State	means the system state in which the system is within operational security limits, but a contingency from the contingency list has been detected and in case of its occurrence the available remedial actions are not sufficient to keep the normal state
Emergency state	means the system state in which one or more operational security limits are violated
Blackout state	means the system state in which the operation of part or all of the transmission system is terminated

Based on the above classification of system in real time, TSOs are required to undertake remedial actions.

(d) Real time monitoring has become essential especially due to the rapid increase in grid size, integrated operations and intermittent nature of Renewable Energy generators. Accordingly, a uniform system monitoring methodology is required to be evolved across all load despatch centres to monitor system operation in a coordinated manner and has accordingly proposed the following system state classification:

System State	System Condition
Normal State	• Operational parameters are within operational limits. • Equipment are within their respective loading limits. • The power system is secure and capable of maintaining stability under contingencies.
Alert State	• Operational parameters are within operational limits. • Single contingency can lead to violation of security criteria. • The system operator shall take corrective measures to restore the system to normal state.
Emergency state	• Operational Parameters are outside their respective operational limit. • Equipment are above their respective loading limit. • The system operator shall take corrective measures so as to bring back the power system to alert/normal state.
Extreme Emergency state	• Operational parameters are outside their respective operational limit. • Equipment are critically loaded. • The power system may or may not remain intact (splitting may occur)

System State	System Condition
Restorative State	• Control action is being taken to reconnect the system elements and to restore system load.

7.10 Demand and Load Management

(a) The 2010 Grid Code dealt with provisions to effect a reduction of demand in the event of insufficient generating capacity and other specified conditions. Further, the 2010 Grid Code also provides contingency procedures to enable demand disconnection as instructed by the RLDC/SLDC, under contingent conditions.

(b) The Commission, in the entire framework of Grid Operations, has laid emphasis on resource adequacy. This implies that all SLDCs shall ensure availability of power at all times for all as well as utilize the ancillary services in case the system deviates from normal state. Accordingly, it has been proposed that load shedding shall be resorted to as a last resort i.e. after all other options including demand response have been exhausted. This option is restricted only to alert and emergency state as part of contingency measures to be undertaken by RLDC or SLDC.

7.11 Post Despatch Analysis

(a) In a large power system such as India with a large transmission network, events in the generation and transmission system have increased manifold. The post despatch analysis or event analysis is an important step in enhancing reliability of the system so as to identify the root cause of such events and suggest remedial measures to be taken by the concerned utilities so as to avoid such incidents in future. Event reporting makes adequate data available to facilitate event analysis. Further, there is a need to build up database and capability to facilitate decision making for future situations. Accordingly, following has been proposed at Regulation 37(1)(e) in draft Grid Code:

“37(1)(e)For the purpose of analysis and reporting, telemetered data shall be archived with granularity of not more than five (5) minutes and higher granularity for special events. Such data shall be stored by SLDCs, RLDCs and NLDC for at least fifteen (15) years and reports shall be stored for twenty-five (25) years for operational analysis.”

(b) A timeline has been provided for event reporting and event analysis responsibilities of the different agencies and disseminating the lessons learnt.

(c) In the draft Grid Code, under “*Table 8: Report Submission Timeline”,* after the disturbance record and station log data is submitted by the user, detailed report is required to be submitted by the user or SLDC within specified number of days from date of submission of data. A sample for GI-1/GI-2 is timeline of (i)7 days after 24 hours of event, to submit detailed report by the user or SLDC, (ii)RLDC/NLDC to submit the report within 14 days after submission of the report by user/SLDC, (iii) Discussion in protection committee shall be held within 30 days of submission of such report by RLDC/NLDC.

(d) As suggested by the Expert Group, ‘near miss’ events have also been included. The ‘near miss’ event is defined as an incident of multiple failures that had the potential to cause a grid disturbance, power failure or partial collapse but did not result in a grid disturbance shall also be analyzed in addition to the Grid Incidents/Grid Disturbances as per the CEA Grid Standards.

7.12 Periodic Reports

It has been proposed to bring uniformity in reporting structure wherein reports shall now be generated on daily and monthly basis as compared to weekly basis under the 2010 Grid Code. The parameters to be covered under the report have been specified viz Source wise generation for each control area, drawal from the grid and area control error, Demand met (peak, off-peak and average), Demand/Energy unserved in MW and MWh, instances and quantum of curtailment of renewable energy and status of reservoirs etc.

7.13 Reactive Power Management

(a) Reactive Power is an essential component of the system and regulates the voltage profile of the system. Voltage is a local phenomenon and unique to the local generation and demand & system configuration at a particular node. In India, different regions have different generation and demand characteristics depending on weather, load characteristics, population, special events etc. During peak hours, high load and consequent high line loadings cause low voltages whereas during off-peak hours, lightly loaded lines cause high voltages in the system. It is desirable to operate the system within the specified voltage limits as per CEA Technical Standards so as to avoid tripping and sub-optimal operation of the power system.

(b) The conventional sources of energy viz. Thermal and Hydro generating stations have inherent capability of controlling reactive power within their capability limit. The Commission is of the view that that due to integration of renewable energy system in the grid, the reactive power management voltage related issues may become more challenging. For instance, high generation in daytime by solar plant may lead to low voltages in the vicinity areas whereas no generation in night hours coupled with reactive power injection by cables and high voltage transmission lines may lead to high voltages. In view of this, there is a need to incentivize the reactive power support as compared to being a mandated service.

(c) The CEA Connectivity standards specify that all conventional generators shall be capable of operating between 0.85 lagging to 0.95 leading. Further, all inverter based sources shall provide reactive support within limits of 0.95 lagging to 0.95 leading. The relevant regulations are reproduced as follows:

Conventional Generation:

> *"**A. Connectivity Standards applicable to the Generating Stations other than wind and generating stations using inverters***
> *…….*

A1. For Generating stations which are connected on or after the date on which Central Electricity Authority (Technical Standards for Connectivity of the Grid) Regulation, 2007 became effective
Generating Units located near load centre, shall be capable of operating at rated output for power factor varying between 0.85 lagging (over-excited) to 0.95 leading (under-excited) and Generating Units located far from load centres shall be capable of operating at rated output for power factor varying between 0.9 lagging (over-excited) to 0.95 leading (under-excited).

Provided that all generating units commissioned on or after 01.01.2014, (provided also that all hydro-electric generating units, where Techno-Economic Concurrence has been accorded by the Authority under section 8 of the Act, shall be capable of operating at the rated output at the power factor as specified in such techno-economic concurrence.) shall be capable of operating at rated output for power factor varying between 0.85 lagging (overexcited) to 0.95 leading (under excited)."

Renewable Generation:

*"**Central Electricity Authority (Technical Standards for Connectivity to the Grid) Amendment Regulations, 2013 stipulates as follows:***
B2. For generating station getting connected on or after completion of 6 months from date of publication of these Regulations in the Official Gazette.
(1) The generating station shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits of 0.95 lagging to 0.95 leading."

Accordingly, it has been proposed that all generating stations shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits as per the CEA Connectivity Standards.

(d) The CEA Connectivity Standards also specify that all hydro generating units shall be capable of running on synchronous mode. The relevant extract is reproduced as follows:

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

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

POSOCO in its "Report on Reactive Power Management and Voltage Control Ancillary Services in India" dated 22.3.2021 observed that as on date, 1,164 MVAr capacity in hydro units can be utilized for synchronous condenser operation for reactive power support. Accordingly, it has been proposed to harness this capability for providing reactive power support.

(e) As per the existing Grid Code, providing reactive power is an obligation extended to all generators. However, it is observed that the generators despite having reactive power limit within their capability limit which can regulate the voltage, the actual reactive power response from many of such generators is not up to their full capability and thereby large reactive reserves remain underutilized during the system requirement.

(f) SRLDC has issued a "Report on Night Mode Operation (Trial) of PV Inverters at Pavagada Ultra Mega Solar Park)"(Reference https://srldc.in/var/ftp/RemcReports/SRLDC%20Report%20on%20Night%20Mode%20Operation%20(Trial)%20of%20PV%20Inverters%20%20at%20Pavagada%20Ultra%20Mega%20Solar%20Park.pdf) dated January 2022 which has been referred to while proposing the provisions w.r.t reactive power under Annexure-4 of draft Grid Code. The said Report has noted as follows:

A. Reactive Power Capability

i. *Inverters are having reactive capability of 33%, 66% and 88%, or in some case up to 100% of active power depending upon the manufacturer and model.*

ii. *986MVAr dynamic reactive capability is available in the PV inverters at Pavagada Ultra Mega Solar Park.*

iii. *Night Mode facility is available in 1575MW out of 2050MW installed capacity.*

……

Certain developers have implemented PPC post trial operation. The developer wise capability and control is shown in the below table.

Developer	IC (MW)	Reactive Power Capability	Possibility of enabling night mode in non-generation hours	Level of control	Method of control for night mode
Adyah	275	183	No	25 MW Feeder	SCADA
Avaada Solar	150	144	Yes	Inverter	HMI
Avaada Solarise	150	96	Yes	25 MW Feeder	PPC
Azure Power	100	43	No	25 MW Feeder	SCADA
Fortum Solar	250	125	No	Inverter	HMI
KREDL	50	35	Yes	25 MW Feeder	SCADA
Parampujya	150	90	No	25 MW Feeder	SCADA
SBG Energy	200	120	Yes	25 MW Feeder	PPC
Tata Renewable	250	150	Yes	Inverter	HMI
Total	**1575**	**986**			

Table 12 Developer wise capability and control"

As per the above, a huge reactive power capability is available with the renewable generators which can support the grid.

(g) POSOCO, in its comments on the CERC (Ancillary Services) Regulations 2022 has suggested the following methodology for fixing the rate for reactive power:

> *"The capital cost of a bus reactor at 765 kV level based on various CERC tariff orders comes to approximately Rs 8 lakhs/MVAr. The annual tariff for such a bus reactor would be of the order of Rs 1.6 lakhs/MVAr. If the reactor is kept switched on for twelve (12) hours a day for nine months in a year, the MVArh generated would be 3240 MVArh and if the fixed costs are spread over this reactive energy, it works out to approximately 5 paise/kVARh. "*

As per above a flat rate of 5 paise per kVArh have been suggested by POSOCO to compensate the generators for their reactive power support.

(h) After considering international experience and suggestion of POSOCO, we find that cost based methodology may not be feasible since the generation mix over the years is expected to change. Since the cost components of a synchronous generating unit is different from non-synchronous generating units, such as usage of inverter for production of reactive power instead of excitation system, common norms for reactive power compensation for different types of generating units is difficult to establish. Further, the cost based methodology may not take into account the degradation of resource's reactive power capability over the years. Accordingly, a flat rate methodology for compensating reactive power has been proposed, wherein reactive power, irrespective of the source shall be compensated at 5 paise per kVarh. Further, any action against the grid requirement shall be payable by the regional entities i.e. suppose a generating unit draws VAR from grid when voltage is below 97%, it shall be liable to pay the charges as provided. Following has been proposed in Annexure-4 of the draft Grid Code:

(1) Reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The regional entities are therefore expected to provide local VAr compensation or generation such that they do not draw VARs from the EHV grid, particularly under low-voltage condition. To discourage VAr drawals by regional entities, VAr exchanges with ISTS shall be priced as follows:

(a) The regional entity pays for VAr drawal when voltage is below 97%
(b) The regional entity gets paid for VAr return when voltage is below 97%.
(c) The regional entity gets paid for VAr drawal when voltage is above103%.
(d) The regional entity pays for VAr return when voltage is above 103%.

Where all voltage measurements are at the interface point with ISTS.

(2) The charge for VArh shall be at the rate of 5 paise/kVArh w.e.f. the date of effect of these regulations. This rate shall be escalated at 0.5paise/kVArh per year thereafter, unless otherwise revised.

(i) Further all payments towards reactive charges shall be from and to the regional deviation and Ancillary Service Pool Account.

(j) POSOCO vide its comments to the CERC (Ancillary Services) Regulations 2022 suggested to include following in the Grid Code:

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

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

(k) Further the SRLDC Report on night mode operation also points out the requirement of active power consumption during night mode operation, to support the grid for reactive power. The Report provides as follows:

“Auxiliary Consumption

i. *Normally, the inverters enter into sleep mode after generation ours; however, they would be functioning if the night mode is enabled. There is a marginal increase in active power consumption after enabling night mode. Further as reactive power absorption Q increases, active power consumption also would increase. It is pertinent to mention that the marginal increase could not be measured because of measurement limitation at inverter level.*

ii. *It is understood that normally OEM indicates the normal auxiliary consumption without the night mode feature enabled. There is no mention of auxiliary consumption with the night mode feature in technical manuals*

iii. *A total of 4.16MUs of energy has been consumed for this exercise which was included in regional loss during the two months trial period.”*

(l) Accordingly following has been proposed in the draft Grid Code:

“(3) All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices for purpose of providing reactive power support, when operating under synchronous condenser/night-mode, shall not be charged under deviations and shall be treated as transmission losses in the ISTS.

(4)For IBRs of capacity 50 MW and below not coming directly to the point of interconnection but through the pooling at the Power Park Developer end, the Power Park Developer shall act as aggregator for the Reactive Energy Charges for payments to and from the Pool Account at RLDC level. The de-pooling of Reactive Energy charges amongst the individual wind and solar shall be done by the Power Park Developer."

(m)There would be a need to segregate the active power consumption due to its auxiliaries and due to night mode operation of invertors to provide reactive power support. SRLDC Report observes as follows:

"The inverters enter into sleep mode after generation hours normally however the inverter would be functioning if the night mode is enabled. It is understood that there is a marginal increase in active power consumption after enabling night mode. Further as Q increases active power consumption also increases. It is pertinent to mention that the marginal increase could not be measured because of measurement limitation. The extra consumption was considered as regional loss from 18:00 hrs to 06:30 hrs.

			Total	
Developer	IC	Active power consumption in MWh (at 220kV)		
		Actual during night mode trial period	Adjusted average consumption of SPD	Incremental
Adyah	275	940	240	701
Avaada Solarise	150	546	229	317
Avaada Solar	150	550	147	403
Azure Power	100	158	43	116
FortumSolar	250	1181	242	939
KREDL	50	30	24	5
Parampujya	150	831	127	705
SBG Energy	200	654	221	432
Tata Renewable	250	1095	556	540
01.08.2021 to 30.09.2021	1575	5986	1828	4157

2. *Table 24: Active power consumption consumed during trial operation*

3. *Total of **4.16 MUs** of energy is spent for this exercise as regional loss for the two months trial period."*

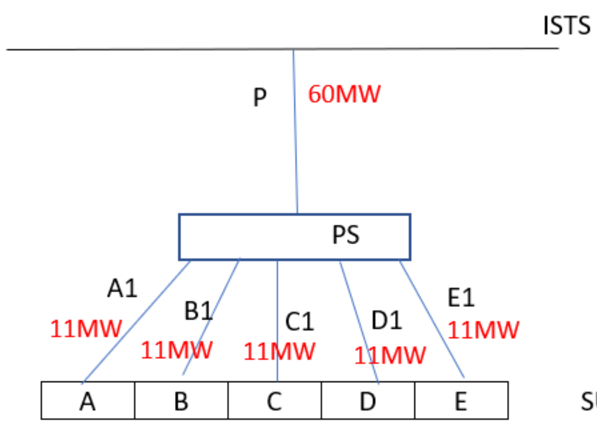
The active power consumption for reactive support during night mode operation has been taken out as the difference between active power consumption after night mode operation for reactive power is made operational and before the same is made operational. A total of 4.16. MU was considered as regional loss during the two month period of trial.

o) Considering the above report, an illustration to segregate night mode active power consumption from normal auxiliary consumption is included below for clarity, where a few generators connected at a pooling station are operating in night mode and few are not operating in night mode. However, NLDC may include the same or modified methodology in Detailed Procedure to be finalized in consultation with the stakeholders.

Illustration

Five Generators A, B, C, D, E Connected at common pooling station PS & connected to ISTS at point P

A. Night drawl without night mode



$A_1^1 = \frac{11}{55} \times 60 = 12MW$

$B_1^1 = \frac{11}{55} \times 60 = 12MW$

$C_1^1 = \frac{11}{55} \times 60 = 12MW$

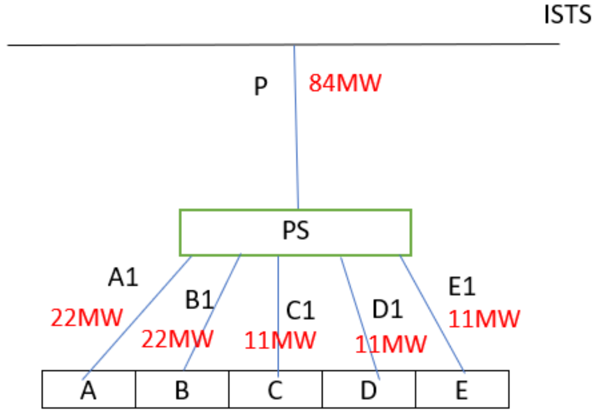
$D_1^1 = \frac{11}{55} \times 60 = 12MW$

$E_1^1 = \frac{11}{55} \times 60 = 12MW$

SUM = 55MW

Figure 10: Night Drawl without night Mode

B. Night drawl **with** night mode



$A_1^1 = \frac{22}{77} \times 84 = 24MW$

$B_1^1 = \frac{22}{77} \times 84 = 24MW$

$C_1^1 = \frac{11}{77} \times 84 = 12MW$

$D_1^1 = \frac{11}{77} \times 84 = 12MW$

$E_1^1 = \frac{11}{77} \times 84 = 12MW$

SUM = 77MW

Note A& B are in Night Modes

Figure 11: Night Drawl with night Mode

Incremental Consumption

Generator	SEM Value corresponding to ISTS End (MW)	Reference without Night Mode (MW)	Increment due to Night mode (MW)
	(A)	(B)	(C)=(A)-(B)
A	24	12	12
B	24	12	12
C	12	12	0
D	12	12	0
E	12	12	0

To be paid by generator for his Night Drawl

Extra Consumption for providing reactive Support

Note: A&B only participated in Night Mode
Note:Reference can be average of last 3 months or 1 month

The above is based on methodology followed by SRLDC in its report on night mode, however the methodology to be followed shall be included in the Detailed Procedure.

7.14 Field Testing for Model Validation

(a) The Expert Group has recommended that certain tests must be carried out periodically on the field since power system parameters may change overtime. Accordingly, field tests are proposed to be carried out on power system elements for ascertaining correctness of mathematical models used for simulation studies as well as ensuring desired performance during an event in the system. The mathematical models required for simulation need to be accurate in order to have desired performance during an event. This can only be assessed if the tests in the power system are carried out from time to time. Internationally, models are frequently validated in order to ensure desired performance during events. The Expert Group has shared some codes which are as follows:

"*NERC in USA through MOD -025-2, MOD-026-1, MOD-027-1 and MOD-033-1 standards have mandated the verified and validated data submission by generation owner, transmission owner and other power system instrument owner which are provided to Planners and System operators for simulation activity for planning as well as operation on the regular basis.*

a. ENTSOE Network Code provides that the relevant Network Operator in coordination with the Relevant TSO shall have the right to obtain the simulation models, that shall properly reflect the behavior of the Power Generating Module in both steady-state and dynamic simulations (50 Hz component) and, where appropriate and justified, in electromagnetic transient simulations. The models shall be verified against the results of compliance tests as given in the code. They shall then be used for the purpose of verifying the requirements of Network Code and for use in studies for continuous evaluation in system planning and operation.

b. EIRGRID provides for Dynamic Model Specifications for Users in their Code. It states that users applying for connection to the Transmission System must provide the TSO with relevant dynamic models and supporting documentation. The model documentation should clarify the range of short circuit levels for which the model is expected to perform to expected equipment behavior."

Based on the recommendation of the Expert Group, the tests to be conducted on power system elements have been proposed with a periodicity of 5 years or earlier, if required. The equipment owners shall submit a testing plan for the next year to the concerned RPC by 31st October.

8. Scheduling and Despatch Code

8.1. The scheduling and despatch code is proposed to have the following Sections:

Section Name	Description
Control Area Jurisdiction of Load Despatch Centre	This section defines the principles to be followed while determining the control area of an entity viz SLDC or RLDC
Responsibilities of Load Despatch Centre	This section enlists the responsibilities of NLDC, RLDCs and SLDCs
General Provisions	This section describes the general principles to be adhered while carrying out scheduling on day ahead basis
Security Constrained Unit Commitment (SCUC)	This section describes the principles of SCUC for ensuring resource adequacy and the principles of Unit Shutdown
Procedure for scheduling and despatch of inter-State Transaction	This section describes the scheduling and despatch methodology to be followed on day ahead basis and real-time basis
Security Constrained Economic Despatch (SCED)	This section describes the principles of SCED for optimizing the dispatch.

8.2. Control Area Jurisdiction of Load Despatch Center

(a) The 2010 Grid Code provides the control area jurisdiction as follows:

> ***“ 6.4 Demarcation of responsibilities:***
> *……………………*

2. *The following generating stations shall come under the respective Regional ISTS control area and hence the respective RLDC shall coordinate the scheduling of the following generating stations:*

a) *Central Generating Stations (excluding stations where full Share is allocated to host state),*

b) *Ultra Mega Power Projects including projects based on wind and solar resources and having capacity of 500 MW and above*

c) *In other cases, the control area shall be decided on the following criteria:*

   (i) *If a generating station is connected only to the ISTS, RLDC shall coordinate the scheduling, except for Central Generating Stations where full Share is allocated to one State.*

   (ii) *If a generating station is connected only to the State transmission network, the SLDC shall coordinate scheduling, except for the case as at (a) above.*

   (iii) *If a generating station is connected both to ISTS and the State network, scheduling and other functions performed by the system operator of a control area will be done by SLDC, only if state has more than 50% Share of power, The role of concerned RLDC, in such a case, shall be limited to consideration of the schedule for inter state exchange of power on account of this ISGS while determining the net drawal schedules of the respective states. If the State has a Share of 50% or less, the scheduling and other functions shall be performed by RLDC.*

   (iv) *In case commissioning of a plant is done in stages the decision regarding scheduling and other functions performed by the system operator of a control area would be taken on the basis of above criteria depending on generating capacity put into commercial operation at that point of time. Therefore it could happen that the plant may be in one control area (i.e. SLDC) at one point of time and another control area (i.e. RLDC) at another point of time. The switch over of control area would be done expeditiously after the change, w.e.f. the next billing period.*

3. *There may be exceptions with respect to above provisions, for reasons of operational expediency, subject to approval of CERC. Irrespective of the control area the jurisdiction, if a generating station is connected both to the ISTS and the STU, the load dispatch centre of the control area under whose jurisdiction the generating station falls, shall take into account grid security implication in the control area of the other load dispatch centre.*

4. *For those generating station supplying power to any state other than host state and whose scheduling is not coordinated by RLDC, the role of the concerned RLDC shall be limited to consideration of the schedule for inter-State exchange of power on account of this generating station while determining the net drawal schedules of the respective control area."*

(b) As per the above, the criteria while deciding the scheduling jurisdiction comprises of multiple parameters such as % share of power under ISTS or within State, connectivity to State system or ISTS and status of project viz Central Generating station or UMPP, in order to determine the jurisdiction of appropriate load despatch centre. The GNA regulations provide the scheduling flexibility within the quantum of GNA for injection/drawal of power for all kinds of contracts. This may result in varying % share of power within state or outside the state at different points of time. As a result of such flexibility, the methodology for determining the jurisdiction needs to be simplified in order to avoid transition of scheduling responsibilities between the load despatch centres from time to time.

(c) It is proposed that the quantum of connectivity with the intra-State transmission system (InSTS) or inter-State transmission system (ISTS) shall be the primary parameter in determining the control area jurisdiction for an entity. Thus, the entities connected only to ISTS shall be under the control area jurisdiction of respective RLDCs, while an entity that is connected only to InSTS shall be scheduled by SLDC. However, in case an entity is connected to both ISTS and InSTS, the percentage quantum of connectivity with ISTS shall be used as a criterion for determining the control area of that entity.

(d) The entities may include an injecting entity or a drawee entity such as a generating station or any other entity which seeks connectivity to ISTS/InSTS such as Renewable Power Park developer or Bulk consumer or distribution licensee covered under Regulation 17.1(iii) of GNA Regulations. All entities which have physical connection to the grid shall be covered under the jurisdiction of one of the load dispatch centres or the other as per the proposed principles.

(e) Further if an entity is connected to both intra-state transmission system and inter-state transmission system, the power may flow through either of the systems based on load generation balance and the same may vary at different points in time. Although the control area jurisdiction for such an entity connected to both ISTS and intra-state transmission system shall be fixed upfront as SLDC or RLDC based on quantum of Connectivity,there is a need for close coordination between both the load despatch centers keeping the dynamics of power flow expected in such cases.

(f) Accordingly, the following has been proposed as Regulation 43 of the draft Grid Code:

"

(4) The entities connected only to inter-State transmission system shall be under control area jurisdiction of RLDCs for scheduling and despatch of electricity for such entities.

(5) Entities connected to both inter-State transmission system and intra-State transmission system shall be under control area jurisdiction of RLDC, if more than 50% of quantum of connectivity is with ISTS, and if more than 50% of the quantum of connectivity is with intra-State transmission system, then it shall be under control area jurisdiction of SLDC.

(6) In case an entity is connected to both inter-State transmission system and intra-State transmission system, the load despatch centre responsible for scheduling such entity shall coordinate with the concerned RLDC or SLDC, as the case may be, with a view to ensuring grid security. "

8.3. Responsibilities of Load Despatch Centres

(a) As per the Electricity Act, the RLDC and SLDC are responsible for integrated operation of power system in the concerned region and in a state respectively. Sub-section (1) of Section 26 of the Act provides that NLDC shall be established at the national level for optimum scheduling and despatch of electricity among the RLDCs. Responsibilities of the load despatch centres have been detailed in the Draft Grid Code in line with the provisions of the Act.

(b) RLDC shall forecast the regional demand based on demand estimates provided by SLDCs. In addition to SLDCs, the entities such as bulk consumers of distribution licensee or entities such as ESS with demand and entities such as DVC would also submit their forecasted demand to enable RLDC prepare a regional demand as proposed at Regulation 31(f) of the Draft Grid Code.

(c) RLDC shall also forecast the generation from wind and solar generating stations for the purpose of operation and management of the grid and to make themselves ready to meet any eventuality due to intermittent nature of RE projects. The generating station may use this for the purpose of scheduling or may make their own forecast as deemed fit by the generating station. The commercial liability of deviation from schedule under either case shall, however, lie with the generating station.

(d) SLDC has been mandated to declare ATC/TTC for its State. ATC/TTC is also determined by States currently, which is displayed at NLDC website. A screenshot of same of NLDC website for intra-regional WR states for Aug 2022 is as follows:

									Rev-1	31.07.2022
State	**Date**	**Time Period (hrs)**	**TTC (MW)**	**TRM (MW)**	**ATC (MW)**	**Share allocation/ LTA/MTOA (MW)**	**Margin (ATC-share allocation/LTA/MTOA) (MW)**	**Limiting Constraint**	**Remarks**	
Maharashtra	01st Aug-31st Aug' 22	00-24	10060	300	9760	9890	-130	N-1 of 400 kV Parli-PG-Parli-MH-DC		
#Gujarat	01st Aug-31st Aug' 22	00-09	12820	370	12450	11207	1243	1. Contingency of 400 kV Kankroli-Zerda-S/c and high loading on 400 kV Bhinmal-Zerda-S/c 2. N-1 contingency of 400 kV Kudus-Kala-DC	If SSP Generation : **450 MW**	
		09-17	12420	370	12050	11207	843			
		17-24	12820	370	12450	11207	1243			
		00-09	12620	370	12250	11207	1043		If SSP Generation : **50 MW**	
		09-17	12220	370	11850	11207	643			
		17-24	12620	370	12250	11207	1043			
^DNH	01st Aug-31st Aug' 22	00-24	840	15	825	1200.63	-375.63	N-1 contingency of 220 kV Kala-Khadoli D/C		
# https://www.sldcguj.com/Operation/TTC-ATC-Gujarat_State_Revised_9500-9900_Web.pdf										
* https://www.sldcmpindia.com/page.php?id=20 (Updated as per SLDC MP declaration)										
^ For monitoring of DNH and DD ATC in real time system operation										
Rev.1- Due to change in Gujarat import capability, MTOAs and available margins										

(e) Some states are also uploading ATC/TTC on their websites . A sample is quoted below:

Ex-1: SLDC - Gujarat

Import Transfer Capability of Gujarat control area w.e.f. 29.10.2021

Time Period	Solar Hours (09:00 Hrs. to 17:00 Hrs.)	Non Solar Hours (17:00 Hrs. to 24:00 Hrs.) & (00:00 Hrs.to 09:00 Hrs.)
With SSP generation		
Import Total transfer capability of the State	**9830 MW**	**10230 MW**
Transmission Reliability Margin (2% of demand of the State)	**330 MW**	**330 MW**
Available Transfer Capability	**9500 MW**	**9900 MW**
Without SSP generation		
Import Total transfer capability of the State	**9630 MW**	**10030 MW**
Transmission Reliability Margin (2% of demand of the State)	**330 MW**	**330 MW**
Available Transfer Capability	**9300 MW**	**9700 MW**

Remark:

Limiting constraints observed for N – 1 contingency are as under:

(1) Tripping of one ckt of 400 kV D/C Banaskantha – Veloda line.

(2) Tripping of one 765/400KV, 1500 MVA ICT at Vadodara.

(3) Tripping of one ckt of 400 kV D/C Kala – Kudus line.

Some 220 / 132 KV Intra-State transmission elements are already observed critically loaded even under base case studies. Therefore, these elements are not considered as limiting condition for deriving Import Transfer Capability of the State.

Ex-2: SLDC – Delhi

TTC / ATC FOR DELHI CONTROL AREA FOR JULY -2022 ONWARDS

Duration	TTC(MW)	RM(MW)	ATC(MW)
JULY-2022 Onwards	7100	300	6800

(f) National Load Despatch Centre (NLDC) has been responsible for furnishing the availability of transmission corridors to the Power Exchanges in the collective transactions as per the 2010 Grid Code. Further, vide order dated 30.04.2015 in Petition No 158/MP/2013, in case of congestion, priority allocation of 10% in the constrained corridor was allowed in favour of small Power Exchange in DAM. However, subsequently in view of the entry of the third power exchange and the feedback received form the POSOCO, vide suo motu order in Petition No 6/SM/2022 dated 9th May 2022, the principles of allocation of transmission corridor among the power exchanges were reviewed and it was directed that in case of congestion, the available corridor margin among the Power Exchanges shall be allocated in the ratio of the initial unconstrained market clearing volume of DAM in the respective Power Exchanges. This is also in line with the principle of transmission corridor allocation approved by the Commission in 2020 for RTM. Accordingly, the same principle has been proposed in the draft Grid Code.

(g) SLDC is responsible for optimum scheduling and despatch of electricity, and to monitor grid operations within a State as per the Act. With increase in the intermittent sources of energy into the grid, the need for balancing the demand and supply in each control area would be paramount to ensure secured grid operation. In this regard the Commission has taken a number of steps and has also introduced the framework for Resource Adequacy in the draft Grid Code under which the SLDCs have been made responsible to forecast demand and generation including for solar and wind generating stations in its control area. The Commission would also like to emphasise that coordination among load despatch centres is paramount for ensuring the grid security. The Commission is of the opinion that adequate reserves need to be maintained at both regional and state control areas to make sure that responsibility of providing reserves is shared by all control areas. However, with due regard to its jurisdiction under the Act, the Commission has framed the Regulations for Ancillary Service for inter-State level and the complementary framework may be implemented by the State Electricity Regulatory Commissions for respective State Control Areas. Accordingly, while RLDCs have been made responsible for balancing demand and supply at regional level along with responsibility of maintaining and dispatching reserves at inter-state level. Similar enabling framework has been proposed for the SLDCs for their State control area.

8.4. General Provisions

(a) Requirement for Commencement of Scheduling

(i) Under the 2010 Grid Code, an entity is required to have Long Term Access, Medium Term Open Access or Short Term Open Access before RLDC can schedule its dispatch or drawl. Such types of access are being converted into GNA / T-GNA under the GNA Regulations.

(ii) The drawee entities must have GNA or T-GNA before they can schedule power under any contract. Further injecting entities should have GNA for getting their power scheduled. Suppose a generating station has Installed capacity of 1000 MW , however it has effective GNA for only 500 MW, the maximum power which can be scheduled from such generating station shall be 500 MW. This is, however, subject to provisions under the GNA Regulations where a generating station covered under Regulation 37 of the GNA Regulations (transition) applies for GNA, but the GNA is yet to become effective for want of transmission system. In such a case the generating station shall be allowed to schedule its power and the quantum scheduled shall be treated as T-GNA.

(iii) Grant letter of GNA or T-GNA, declaration of valid contracts and a copy of the valid contract, for transactions other than collective transactions shall be pre-requisites before commencement of any scheduling.

(iv) Accordingly, the draft Grid Code proposes as follows:

"(5) Requirement for Commencement of Scheduling:

(a) The following documents shall be submitted to the respective RLDC before commencement of scheduling of transactions under GNA or T-GNA, as the case may be:

(i) Grant of GNA with effective date, by the sellers and the buyers;
(ii) Grant of T-GNA with effective date, by the buyers;
(iii) Declaration by the sellers and the buyers about existence of valid contracts for the transactions. (iv) Copies of the valid contracts by the sellers and the buyers, for transactions other than collective transactions

(b) In case of allocation of power from the central generating stations by the Central Government, the concerned RLDC shall obtain the share allocation of each beneficiary issued by RPC."

(b) Adherence to Schedule

Users of the grid are required to adhere to their schedule of drawal or injection of electricity in the interest of security and stability of the grid.

(c) Area Control Error

(i) Area Control Error (ACE) measures imbalance of a control area by taking into consideration area interchange schedule and target frequency. ACE value is used as an indicator about system balance and ideally needs to be zero to ensure secure grid operations. Zero ACE is an indicator that the actual tie-line flow is equal to the scheduled tie line flow and that frequency of the system is equal to reference frequency and the system is operating at normal state. However, any deviation from zero has consequential impact on the frequency which can potentially threaten grid security.

(ii) Worldwide, Secondary Reserve deployment is being done to maintain the ACE close to zero. For a country like India with multiple regions/ control areas, it is important to ensure that frequency deviations and tie-line power flow deviations are managed within tolerable limits for grid security. The Ancillary Service Regulations, 2022 provide for deployment of secondary reserve at inter-state level to manage regional ACE. As envisaged in the Ancillary Regulations, 2022 complementary framework would be developed by the State to manage ACE for respective control area. Accordingly, the Commission, in the draft regulations, has proposed real time monitoring of ACE and intervention through deployment of reserves or demand management schemes in case any deviation is observed. Accordingly, the following has been proposed at regulation 45(7) of the draft Grid Code :

“(7) Area Control Error: The concerned Load Despatch Centre and other drawee regional entities shall keep their Area Control Error close to zero (0) by deploying reserves and automatic demand management scheme”

(d) Declaration of Declared Capacity by Regional entity generating stations

(i) The declaration of DC has been proposed to be capped at 100% MCR considering that maximum schedule that can be given to such a generating station has been limited to 100%, considering mandatory margin to be kept for primary response under Regulation 47(2)(b) of draft Grid Code. It has been brought to the notice of the Commission that in some cases thermal generating stations have been declaring DC beyond 100% i.e. even for the capacity which cannot be scheduled under the 2010 Grid Code. The DC is an offer by generating stations to its buyers to schedule power. The DC against which schedule cannot be given is not appropriate. Accordingly, it has been stipulated that the DC shall be capped at 100%.

(ii) DC revision was allowed for generating stations under the 2010 Grid Code. However, issues have been raised by stakeholders stating that once they punch the schedules against the DC, generating stations revise their DC leaving the beneficiary with no option but to procure power from elsewhere. We observe that DC is declared only on day ahead basis. A generating station has visibility on day ahead basis about its unit availability. Further, frequent revision of DC leads to uncertainty and additional costs for the distribution licensees. Accordingly, provision of DC revision has not been included as was prevailing in 2010 Grid Code,except for specified cases of Forced outage.

(e) Ramping Capability of Generators

(i) All generating stations shall be required to declare their ramping rates. It is observed that in view of the large scale renewable integration and dynamic shape of load curve, higher ramping support is required from thermal generating entities and accordingly, the entities demonstrating ramp rates above 1% are incentivized under the 2019 Tariff Regulations.

(ii) The CEA Technical Standards for Construction prescribe a ramp rate of 3% per minute above the control load (i.e. 50% of MCR) for thermal generating stations. However it has been observed that even 1% ramp rate has not been achieved for older power plants, and the generating stations have expressed their difficulty in achieving even 1% ramp rate at all times. The 2010 Grid Code also prescribed minimum ramp rate for such generating stations as 1%. Accordingly, 1% ramp rate is mandated for coal or lignite fired plants under the draft Grid Code.

(iii) The ramp rates for gas and hydro stations have not been specified in the CEA standards. It is proposed that the minimum ramp rate for such stations shall be 3% and 10% respectively. Following is proposed at Regulation 45(9) of draft Grid Code:

"(9) Ramping Rate to be Declared for Scheduling:

(a) The regional entity generating station shall declare the ramping rate along with the declaration of day-ahead declared capacity in the following manner, which shall be accounted for in the preparation of generation schedules:

(i) Coal or lignite fired plants shall declare a ramp up or ramp down rate of not less than 1% of ex-bus capacity corresponding to MCR on bar per minute;

(ii) Gas power plants shall declare a ramp up or ramp down rate of not less than 3% of ex-bus capacity corresponding to MCR on bar per minute;

(iii) Hydro power plants shall declare a ramp up or ramp down rate of not less than 10% of ex-bus capacity corresponding to MCR on bar per minute;

(iv) Renewable Energy generating station shall declare a ramp up or ramp down rate as per CEA Connectivity Standards"

(f) Optimum Utilization of Hydro Energy

(i) The importance of utilization of hydro energy has been emphasized by the Commission from time to time.

(ii) Vide Statement of Reasons dated 13th April, 2018 issued for the CERC (Indian Electricity Grid Code) Regulations (5th Amendment), 2017, it was observed that there should be no restriction in schedule during high inflow season to avoid spillage. The necessary extract is reproduced for reference:

"13.2.5 Number of stakeholders have submitted that restriction of schedule for keeping primary response margins should not be resorted to for hydro stations during high inflow season to avoid spillage. This suggestion has merit and therefore, has been accepted that during high inflow season to avoid spillage there shall be no restriction of schedule."

(iii) Further, vide order dated 30th March 2017 in Petition No. 434/GT/2014, it was observed that NLDC/RLDC shall ensure scheduling of the hydro stations including their overload capability. The relevant text is reproduced as follows:

"32…..
(b) Overload Capacity of generating station shall be 10% as per provisions of CEA Regulations and IEGC. NLDC/NRLDC shall ensure that the scheduling of the station shall be based on the installed capacity of 1000 MW with overload capacity of 10%"

(iv) Vide order dated 12th February 2019 in Petition No. 205/MP/2018, it was directed that no additional LTA shall be required on account of the overload capability, the relevant extract is reproduced as follows:

"Issue No. 1: Whether the power corresponding to overload capacity of a hydro generating station (up to 10%) during peak season shall be scheduled without taking LTA corresponding to the overload capacity?

…………………..

23. In the light of the express provisions in the Grid Code; dispensation provided to the Central Generating Stations for scheduling the generation corresponding to overload capacity during peak season; LTA being in place in the instant case for 880 MW; and availability of margins in transmission system commissioned at the behest of LTA customers, we are of the considered view that the hydro generating stations irrespective of ownership (private or government) are not required to obtain LTA corresponding to overload capacity (upto 10%) and the injection of the same should be allowed by concerned RLDC. In our view, even in case of a hydro generating station in the private sector, the RLDCs cannot compel them to obtain LTA/ MTOA/STOA for overload capacity up to 10% of existing LTA during high inflow period. Accordingly, RLDCs are directed to allow injection of power corresponding to overload capacity upto 10% of LTA without obtaining additional LTA/ MTOA/ STOA for the overload capacity."

(v) Accordingly, it is proposed that no additional GNA would be required to schedule power for such overload capacity, during high inflow season to avoid spillage, subject to availability of margins in the transmission system. The following has been proposed at Regulation 45(10) of the draft Grid Code:

"(10) Optimum Utilization of Hydro Energy

(a) During high inflow and water spillage conditions, for Storage type generating station and Run–of-River Generating Station with Pondage, the declared capacity for the day may be upto the installed capacity plus overload capability (upto 10%) minus auxiliary consumption, corrected for the reservoir level.

(b) During high inflow and water spillage conditions, the concerned RLDC shall allow scheduling of power from hydro generating stations for the overload capability upto 10% of Installed capacity without the requirement of additional GNA for such overload capacity, subject to availability of margins in the transmission system."

(g) Scheduling of renewable energy generating station by QCA

(i) Due to increase in number of renewable energy generating stations, many of which may be smaller in size (installed capacity), such generating stations may prefer to have an intermediate entity to manage day to day forecasting and resultant scheduling on their behalf. Further, individual forecasting efforts may lead to higher errors which may get reduced when forecasting is carried out over a larger area.

(ii) Accordingly, it is proposed to introduce the QCA for regional entity renewable generating stations or projects based on energy storage system connected at ISTS substation. The QCA shall coordinate and facilitate scheduling for such generating stations or energy storage system and undertake commercial settlement of deviations with the concerned RLDC. The concept of QCA was introduced through the FOR Model Regulations for Forecasting and Scheduling (F & S) for States. The Forum of Regulators (FOR) prepared the Model Regulations on F&S of Wind and Solar Generating Stations at the State level in 2015. The role of Qualified Coordinating Agency (QCA) has been defined as an Aggregator for Renewable Energy (RE) with Pooling Sub-station as the basic building block in the model regulations. The majority of States including RE rich States have notified F&S Regulations for their States in line with FOR Model Regulations. States such as Karnataka and Andhra Pradesh have permitted aggregation by QCA at the state level, whereas States such as Rajasthan, Maharashtra, Madhya Pradesh & Telangana have permitted aggregation at Pooling Sub-Station level. The functions of the proposed QCA have been listed in the draft Grid Code.

(iii) It has also been proposed that NLDC shall notify a procedure for aggregation of pooling stations for the purpose of combined scheduling and deviation settlement for wind or solar or renewable hybrid generating stations. NLDC may specify principles to be followed while allowing such aggregation across pooling stations in the Detailed Procedure.

(iv) While QCA is meant to facilitate aggregation of forecasting/scheduling of wind/solar generating stations, the ultimate responsibility of scheduling and choice of whether to go through QCA or not rests with the generators. QCA may be identified for a single or multiple pooling stations, in accordance with NLDC procedure of aggregation. Accordingly, the following possibilities are foreseen for QCA for a single or multiple pooling stations (not exhaustive):

a. QCA has been identified for all generating stations connected at a pooling station. In such a scenario, the QCA shall be responsible for overall forecasting, scheduling and commercial settlement functions of all the generators connected at the pooling station

b. QCA at a pooling station is identified for some of the generating stations but not all of generating stations at such pooling station. In such a scenario, QCA shall be responsible for overall forecasting, scheduling and commercial settlement functions of only those generators connected at the pooling station which have opted to be part of the aggregating/pooling mechanism through such QCA. Balance generating stations shall coordinate with RLDC/SLDC as per provisions of regulations.

c. In case QCA is not appointed at a pooling station, RLDC shall be responsible for the scheduling, communication, coordination with REGS of 50 MW and above and connected to Inter State Transmission System (ISTS). However, for plants having capacity less than 50 MW, Lead generator shall be responsible for the coordination and communication with RLDC, SLDC, RPC and other agencies for scheduling related activities

(h) Minimum Turndown Level for thermal generating stations

(i) The technical minimum was notified vide the fourth amendment of the 2010 Grid Code in respect of the Central Generating Station or inter-State generating station as 55% of MCR loading or installed capacity of the unit.

(ii) The technical minimum operating level has been suggested to be renamed as minimum turndown level by the Expert Group stating as follows:

> *"(2) Minimum turndown level:*
> *The technical minimum operating level has been reworded as minimum turn down level. Minimum turndown level has been defined as minimum station loading corresponding to the units on bar upto which a regional entity generating stations is required to be on bar on account of less schedule by its buyers or as per the direction of RLDC. The thermal generating stations shall be compensated for generation below the normative level as per the mechanism given in Annexure – 5 of the Grid Code."*

(iii) Further, it is observed that a thermal generating station may operate below specified 55% technical minimum level depending on its unit type and vintage, with or without use of oil. A generating station should not be debarred from operating at such a level possible for its unit, which may be less than 55% of MCR. We have also considered following developments:

a. Vide order dated 2.9.2015 in Petition No. 142/MP/2012 with I.A. 7/2013 the following was observed:

> *"13. CEA vide letter dated 12.9.2013 has submitted its views on technical minimum of thermal units as under:*
>
> *"The control range for coal fired Units is generally taken as 50% to 100% MCR and the rated steam temperature can be maintained in this range. However, the Units can operate at any lower load without any limits; and minimum load without oil support is taken as about 30% MCR and operation below this limit needs oil support. The CEA Technical Standards for Construction of Electric Plants and Electric Lines Regulations – 2010 prescribe a control load of 50% MCR. The operating capability generally specified in the technical specifications also stipulate continuous operation without oil support above 30% MCR load and control load range of 50% to 100% TMCR.*

2. _Thus Unit operation may be envisaged as indicated above, barring any specific operating constraints brought out or recommended by OEMs with proper technical justification."_

b. CEA, vide letter dated 10th December 2018 suggested norms for degradation to be considered in Station Heat Rate and Auxiliary Energy Consumption upto 40% loading (Source: https://cercind.gov.in/2018/draft_reg/CEA%20Recommendations%20for%20thermal%20generating%20stations%20for%20tariff%20period%202109-24.pdf).

c. CEA in its report dated January 2019 on "Flexible Operation Of Thermal Power Plant For Integration Of Renewable Generation", noted as follows:

"14. Costs Involved in Flexing Coal-Fired

Generation 14.1 Capital Expenditure

Capital expenditure is required to meet the requirement of flexible operation mainly for the capital interventions at unit level. The number and type of interventions required would vary from plant to plant depending on the age of unit and scope of works.
NTPC has demonstrated 40% minimum load operation at unit 6 (490 MW) of Dadri TPS. As per Preliminary estimates, considering the scope of works, the implementing company (Siemens) has estimated a capital expenditure of around Rs.20 crores for implementation of measures enabling stable operation at 40% minimum load. Similarly, an estimate of Rs. 50 crore has been provided by GE for unit 2 of Talcher TPS of NTPC to enable stable operation at 40% minimum load. Major retrofit is not required to operate a thermal unit at 55% load. Only modification of Operational procedures along with control system tuning are required."

d. As per above, it is observed that NTPC has demonstrated 40% minimum load operation at unit 6 (490 MW) of Dadri TPS.

Accordingly, "technical minimum" has been proposed to be renamed as "minimum turndown level" to give operational flexibility to the generating station and to ensure that it carries out its obligations under the PPA.

(iv) The compensation mechanism for the regional entity thermal generating stations operating on loads below normative level upto technical minimum, was included as part of the 2010 Grid Code in 2017. The compensation was introduced mainly because the norms for Section 62 projects under the Tariff Regulations have been specified considering specific past data and if loading is below the data based on which norms were specified, the variable charge based on norms may not correspond to the actual parameters of Station Heat rate, Auxiliary power consumption etc. Further since norms for generating stations under Section 62 are determined under the Tariff Regulations, the appropriate placement of compensation for such projects should be through Tariff Regulations. Accordingly, it has been proposed that compensation shall be included under Tariff Regulations for projects under Section 62. Further, generating stations under Section 63 or other generating stations are proposed to be compensated as per their contracts.

Accordingly, the following has been proposed in Regulation 45(12) of the draft Grid Code:

"(12) Minimum turndown level for thermal generating stations

The minimum turndown level for operation in respect of a unit of a regional entity thermal generating station shall be 55% of MCR of the said unit:

Provided that the Commission may fix through an order a different minimum turndown level of operation in respect of specific unit(s) of a regional entity thermal generating station:

Provided further that such generating station on its own option may declare a minimum turndown level below 55% of MCR:

Provided also that the regional entity thermal generating stations shall be compensated for generation below the normative level either as per the mechanism in the Tariff Regulations or in terms of the contract entered into by such generating station with the beneficiaries or buyers, as the case may be."

(i) Scheduling of Inter-Regional and Cross-Border Transactions

a. As per Ministry of Power (MOP) notification vide dated 2nd March 2005, the NLDC is responsible for Monitoring of operations and grid security of the National Grid as well as coordination for trans-national exchange of power. Accordingly, the following has been proposed at Regulation 45(13) of the draft Grid Code:

“(13) Scheduling of Inter-Regional and Cross-Border Transactions

(a) NLDC shall prepare schedule for cross-border exchange of power which shall be on net of the country basis;

(b) NLDC shall coordinate scheduling and despatch of electricity over interregional links with concerned RLDCs”.

b. RE generating stations generally draw power at night time or during non-generation hours to run their auxiliaries. Vide Order dated 25.4.2022 in Petition No. 345/MP/2018, in the matter of “Treatment of power drawn by CTU-connected 750 MW Rewa Solar Project during non-generation night hours and during shutdown periods and determination of tariff thereof” following was observed:

“37. We observe that the relevant Clauses in PPA are as under:

> *“6.1.4 Auxiliary power consumption will be treated as per the concerned State regulations. …..*
>
> *ii. The SPD shall be required to make arrangements and payments for import of energy (if any) as per applicable regulations. ……*
>
> *10.2.1 The SPD shall issue to SECI hard copy of a signed Monthly Bill/Supplementary Bill for the immediately preceding Month/relevant period based on the issuance of Energy Accounts along with all relevant documents (payments made by SPD for drawal of power, payment of reactive energy charges, Metering charges or any other charges as per guidelines of SERC/CERC, if applicable. Each Monthly Bill shall include all charges as per this Agreement for the energy supplied for the relevant Month based on Energy Accounts issued by RPC or any other competent authority which shall be binding on both the Parties. The Monthly Bill amount shall be the product of the energy as per Energy Accounts and the Applicable Tariff. Energy drawn from the grid will be regulated as per the regulations of the respective State the Project is located in.”*

38. At the outset, the Commission would like to state that the provisions any PPA cannot be in derogation of or in conflict with any provision of the Act or the Regulations. In case of conflict, the provisions of the Act and the Regulations will prevail over the provisions of the PPA. In the instant case, however, the Commission does not find any conflict. Rather, the PPA provides in clear terms that "the SPD shall be required to make arrangements and payments for import of energy (if any) as per applicable regulations". This is exactly in line with the interpretation of the Commission in the context of Issue (a) and Issue (b). The DSM Regulations, 2014 do not make a provision for solar generators drawing power during night hours and/or for maintenance and shut down. This should be interpreted to mean that such solar generators cannot meet their drawl requirement through DSM but need to enter into power purchase arrangement for such drawl. Such power purchase arrangement can be with the distribution licensee of the State in which the generator is located or with any other entity through open access. It is only when the arrangement is made with the State in which the generator is located that the „energy drawn from the grid will be regulated as per the regulation of the respective State the Project is located in‟. In the instant case, there is no such arrangement between the SPDs and the distribution licensee(s) of MP. As such, the energy drawn by the SPDs during night hours and/or for maintenance and shut down cannot be accounted for as import from the distribution licensee of MP. For such energy accounting, power purchase arrangement and drawl schedule of SPDs and the corresponding injection schedule of the distribution licensee(s) are a pre-condition. In the absence of any such arrangement, the prayer of the Petitioner that it be allowed to bill the SPDs towards power drawn during non-generation night hours and during shutdown periods or during any emergencies including their repair and maintenance, etc. is rejected.

39. However, a consequential question remains. The question is as to whether the WRLDC should continue to bill the SPDs as per the DSM Regulations. We have already interpreted the provisions of the DSM Regulations in detail in the context of Issue (a) and Issue (b). We reiterate that as the DSM Regulations do not have any provision dealing with drawl of power by the SPDs during night hours and/or for maintenance and shut down, it should be interpreted to mean that such SPDs cannot be allowed to inter-change such drawl through DSM Regulations.

40. Therefore, the Respondent-SPDs should immediately and not later than one month from the date of this Order, enter into power purchase arrangement for such drawl of power either with the distribution licensee of the State in which they are located or with any other entity through open access. Once such an arrangement has been made, the energy drawn should be scheduled and accounted as per the provisions of the Grid Code and deviation settled as per the provisions of the DSM Regulations, 2014 or the DSM Regulations, 2022 once the same is brought to force."

As per the above, it was directed that solar power developers should enter into power purchase agreement for drawl of power either with the distribution licensee of the State in which they are located or with any other entity through open access. We observe that without proper arrangement, drawal of power under DSM may pose a threat to grid security. Accordingly, the following has been proposed as Regulation 45(15) of the draft Grid Code:

"(15) A generating station including renewable energy generating station shall be allowed to draw power from ISTS during non-generation hours, whether before COD or after COD, only after obtaining schedule for such drawal of power in accordance with a valid contract entered into by it with a seller or distribution licensee or through power exchange."

8.5. Security Constrained Unit Commitment (SCUC)

(a) Expert Group had suggested the mechanism of SCUC as follows:

"(4) Security Constrained Unit Commitment (SCUC)

(1) The SCUC exercise shall be carried out to facilitate reliability of supply to the regional entities/beneficiaries taking into account optimal cost, adequate reserves, ramping requirements factoring security constraints:

Provided that, the payment of carrying cost for the generation reserves committed through SCUC shall be as specified by the commission.

(2) In order to ensure availability of adequate secondary and tertiary reserves with sufficient ramping capability, NLDC shall identify the generating unit for purpose of unit commitment at the national level three (3) days in advance of actual day of scheduling for regional entity generating stations on a rolling basis. NLDC, through RLDC shall advise the regional entity generators to commit or de-commit the unit. (Refer ANNEXURE – 7:Detailed Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Stations and for taking such units under Reserve Shut Down on scheduling below Minimum Turndown Schedule.)

Provided that as and when enabling framework is in place, reserves may be procured through the market.

(3) Based on the SCUC instructions from RLDC, the generating station shall revise the on-bar DC (with due consideration to ramp up/down capability), off-bar DC and ramp up/down rate.

(4) SLDC shall perform similar SCUC exercise at the intra-state level."

Further vide Annexure-7 to the suggested Grid Code by Expert Group, the following was suggested:

"

1. Methodology for committing and de-committing generating station or unit(s)

1) The generating station shall submit the time block wise capability of generating station (DC) and other information, by 0600 hours of the day for next three (3) days on rolling basis in line with this Grid Code.

2) RLDCs shall compile the above information along with the entitlement for each regional entity beneficiary and advise the same to all SLDC/beneficiaries by 0800 hours for next three (3) days as per Grid Code and amendments thereafter. Entitlements shall be calculated based on the DC.

3) The beneficiaries shall furnish their requisition for the next three (3) day to respective RLDC by 1100 hours of the day based on the entitlements given by the concerned RLDC in accordance with the Grid Code, as amended from time to time.
"

As per the above, it was suggested that beneficiaries were to give requisition 3 days in advance to ensure availability of adequate secondary and tertiary reserves and that once enabling framework is there, reserves may be procured through market. .

The Commission has already notified the CERC (Ancillary Services) Regulations, 2022 vide notification dated 12.2.2022 where an elaborate mechanism for procurement of secondary and tertiary reserves have been put in place. Further, we observe that demand forecasting by a buyer 3 days in advance which shall be used for scheduling power and have commercial liabilities may be difficult to implement under the current situation of demand forecasting. Accordingly, a modified approach to SCUC has been proposed under the draft Grid Code, keeping in view above aspects.

(b) Under draft Grid Code, SCUC is proposed as a mechanism to commit a resource for system security purpose.

(c) Under the 2010 Grid Code, "*Detailed Operating Procedure for Backing Down of Coal/Lignite/Gas unit(s) of the Central Generating Stations, Inter-State Generating Stations and other Generating Station and for taking such units under Reserve Shut Down on scheduling below Technical Minimum Schedule' (DOP)",* provided that if the net injection schedule for a particular generating station falls below technical minimum, RLDC may provide technical minimum schedule considering the system conditions in accordance with Regulations 6.5.14 and 6.5.20 of the Grid Code.

(d) Under the Ancillary Service Regulations, 2015, the system operator provided ancillary service through un-requisitioned surplus which may fluctuate on a day to day basis. A situation may arise where the reserves are required, but Unrequisitoned surplus is not available. Hence, an elaborate process of reserve procurement has been put in place under the Ancillary Service regulations, 2022. However, in case of likely shortage of reserves despite efforts made to procure such reserves in accordance with the Ancillary Services Regulations,2022, SCUC may need to be run. SCUC shall run only in such a case and not otherwise.

(e) Accordingly, it is proposed that SCUC would be run centrally by NLDC after the Day Ahead Market closes. The process has been proposed to start at 1330 hrs of D-1 day with preparation of list of generating stations that are likely to be below their minimum turndown level.

(f) The process and the associated rationale is described as follows:

Step	Time	Activity to be carried out	Rationale
Step-1	13:30 hours of	NLDC to publish a tentative list of generating stations that	The preliminary listing will help the system operator

Step	Time	Activity to be carried out	Rationale
	D-1 day	are likely to be below their minimum turndown level	identify the generating stations which can be utilized for the purpose of reserves.
Step-2	16:30 hours of D-1 day	Beneficiaries shall be allowed to revise their requisitions for the generating stations identified in Step 1 to enable such units to be on bar. The downward revision shall not be allowed for such stations brought to minimum turndown level by beneficiaries.	The Beneficiaries shall be allowed another chance to revise their requisitions so that they can commit the units as per their requirement. Such a step would reduce requirement of committing unit by NLDC. The beneficiary can choose not to requisition but once it has exercised this choice, downward revision is not allowed, because such an action (downward revision) will render the whole exercise of keeping the generating station on bar infructuous. NLDC shall consider such units under the list brought to minimum turndown level as on bar while finalizing further need to commit another unit under next step.
Step-3	From 16:30 to 18:00 hours of D-1	NLDC shall prepare the final list of generating stations and stacked as per the merit order. For any shortfall of reserves procurement under AS Regulations may be met with incremental energy to be scheduled from such identified stations so as to bring such units to their minimum turndown level.	NLDC shall be required to provide schedule upto minimum turndown level to ensure that generating stations remain on bar to provide reserves.
Step-4	18:00 hours of D-1	NLDC to update the list on the respective RLDC website	It shall give the generator time to be continued on bar for providing reserves.
Step-5		NLDC to schedule incremental energy to meet minimum turn down level of concerned generator by commensurate reduction in the SCED generating station with highest variable charge.	This is to maintain the load generation balance consequent to the incremental generation for adequate reserve requirement in the system. Linking it with the SCED optimization is to keep

Step	Time	Activity to be carried out	Rationale
			the minimum commercial implication without changing the schedule of beneficiaries.
Step-6		Any URS power available with a concerned generating station above its minimum turn down level would be deemed to be available for secondary and tertiary reserve procurement under AS Regulations.	This will ensure that adequate reserve capacity is available in the system on bar for grid security purpose.

(g) It is believed that going forward with increasing penetration of intermittent sources like wind and solar, it will be challenging to keep required reserves capacity on bar in the system. This mechanism would complement the procurement of SRAS and TRAS under the Ancillary Service Regulations, 2022 to provide some generating stations on bar for reserve requirement .

(h) It is further highlighted that the availability of reserves is an essential requirement for reliable operation of the integrated grid and therefore any such additional cost on account of SCUC mechanism above shall be paid from the Deviation and Ancillary Service Pool Account.

(i) **Unit Shut Down (USD)**

As per the provisions under the 2010 Grid Code, a generating station can opt for reserve shutdown if it doesn’t get sufficient requisition upto its technical minimum level. However, this may deprive those beneficiaries who have requisitioned power from such generating station.

We observe that once a generating station has declared DC for which it is entitled for fixed cost, it cannot deprive beneficiary from availing such power.

Hence, in order to honor the rights of the original beneficiaries of such generating station, it has been proposed that such generator may decide not to go under USD and generate power , may sell surplus power under power market as per provisions of PPA and Grid Code or if it decides to go under USD it may supply power to beneficiaries who have requisitioned schedule, from other generating stations through any contracts allowed under the PMR Regulations to meet its supply obligation towards its original beneficiaries. Accordingly the term “Reserve shutdown” has been done away with and have been replaced as proposed “unit shutdown” mechanism.

8.6. Procedure for Scheduling and Despatch for Inter-State Transactions

(a) The allocation of corridor on day ahead basis has been finalized under regulation 36 of the GNA Regulations which provides the principles to be followed while allocating the corridors. The allocation of corridors is done by way of scheduling of power, which is a subject matter of the Grid Code. Hence, as per the principles provided in the GNA Regulations, the scheduling timeline under the draft Grid Code has been proposed as follows:

S.No.	Activity	Time (By hours in D-1 day)
1.	Generating stations to declare DC for “D day”	0600 hrs
2.	RLDC shall declare entitled share for each beneficiary	0700 hrs
3.	SLDC on behalf of GNA grantee to give scheduling request within GNA	0800 hrs
4.	RLDC to check for constraints in transmission corridor and intimate the same to the user	0815 hrs

S.No.	Activity	Time (By hours in D-1 day)
5.	Submission of revised schedules	0830 hrs
6.	Issuance of final drawal schedules for GNA grantees	0900 hrs
7.	SLDC on behalf of GNA grantee to give scheduling request within T-GNA	
8.	Issuance of final drawal schedules by RLDC for T-GNA grantees	0930 hrs
9.	Commencement of Day Ahead Market	1000 hrs – 1130 hrs
10.	Power exchange to submit day ahead provisional schedules	1200 hrs
11.	NLDC to validate the trade schedules and intimate the same to power exchange	1230 hrs
12.	Submission of final trade schedules by power exchange	1300 hrs
13.	RLDC shall release balance corridors after finalisation of schedules under day ahead collective transactions.	1300 hrs
14.	RLDC to process exigency applications and update about balance transmission corridor	1400 hrs
15.	The balance transmission corridor may be utilised by GNA grantees by way of revision of schedule, as per clause (4) of Regulation 47 of these regulations, under any contract within its GNA or for exigency applications or in real time market on first cum first serve basis.	

(b) The draft Grid Code proposes following at Regulation 47(1)(f)

"(f) Allocation of corridors by RLDC for GNA grantees

(i) RLDC shall check if drawl schedules as requisitioned by drawee GNA grantees can be allowed based on available transmission capability: Provided that in case of constraint in transmission system, the available transmission corridor shall be allocated to the drawee GNA grantees in proportion to their GNA within the region or from outside region, depending upon the transmission constraint, whether it is within the region or from outside the region, as the case may be. The same shall be intimated to drawee GNA grantees by 8.15 AM on 'D-1' day.
(ii) GNA grantees shall revise their requisition for drawl schedule based on availability of transmission corridors for such grantee by 8.30 AM on 'D-1' day."

An Illustrative example to explain the proposed Regulations above is given below for ease of understanding.

Example based on assumptions:

a. Let us assume that there are two drawee GNA Grantees (State A and State B) located in a particular region say Northern Region (NR). The details of GNA granted to State A and State B are as follows:

State	GNA within Region (in MW)	GNA from outside the Region (in MW)	Total GNA (MW)
State A	7000	2000	9000
State B	8000	3000	11000

b. State A and State B have contracts with the Generators E, F and G located in a Bid Area W3 of Western Region (WR). The drawl schedule (MW) requested by State A and State B from such generators are as follows:

	From Generator E	From Generator F	From Generator G
Drawl Schedule requested by State A (MW)	1000	500	500
Drawl Schedule requested by State B (MW)	500	1000	1500

c. State A & State B have requested for a drawl schedule from Generators E, F and G of a total quantum of 5000 MW.

d. Suppose due to constraint in the transmission system, the maximum evacuation possible from the Bid Area W3 is say 4000 MW. For the purpose of allocation of transmission corridor, it shall be treated as follows:

(ii) Available transmission corridor between NR & WR allocated to State A in raio of its GNA from outside the region = [(GNA from outside the region)/ (Total GNA from outside the region for both States)] X Available corridor.

= (2000/5000)*4000 MW
= 1600 MW

(iii) Similarly Available transmission corridor between NR & WR allocated to State B=2400 MW((3000/5000)*4000MW)

(iv) The concerned RLDC shall intimate by 8:15 hrs to the State A and State B to revise their requisition for drawal schedule from W3 area utpo 1600 MW and 2400 MW respectively. State A and State B may revise their schedule from generators in W3 area as per their requirement limited to 1600 MW and 2400 MW respectively.

(c) Vide sixth amendment to the 2008 Open access Regulations dated 27th Dec 2019, the framework for real time market was notified. The said regulations provide as follows:

*"**Procedure for scheduling of transaction in Real-time market(RTM)***

13(B) All the entities participating in the real-time market for a specified duration may place their bids and offers on the Power Exchanges for purchase and sale of power. The window for trade in real-time market for day (T) shall open from 22.45hrs to 23.00hrs of (T-1) for the delivery of power for the first two timeblocks of 1st hour of day (T) i.e., 00.00 hrs to 00.30 hrs, and will be repeated every half an hour ther

eafter. The bidding mechanism for the real-time market shall be double-side closed bid auction for each time block of the delivery period. The Nodal Agency shall indicate to the Power Exchange(s) the available margin on each of the transmission corridors before the gate closure, i.e. before the window for trade closes for specified duration. The power exchanges shall clear the real-time market from 23.00hrs till 23.15hrs based on the available transmission corridor and the buy and sell bids for the real time market (RTM) for the specified duration. Then the cleared bids shall be submitted by the Power Exchanges to *the Nodal Agency for scheduling. The Nodal agency in accordance with the detailed procedure shall announce the final schedule by 23.45 hrs of (T-1) and communicate to the RLDCs to prepare the schedule for dispatch."*

It has been proposed that the 2008 Open access Regulations shall be repealed in accordance with provisions of GNA regulations and the process of scheduling for real time market have been included as a part of the draft Grid Code.

8.7. Additional factors to be considered while finalising schedule

(a) Security Constrained Economic Despatch

(i) The Commission vide its suo motu Order dated 31st January 2019 in Petition No. 02/SM/2019, directed Power System Operation Corporation (POSOCO) to implement a pilot on Security Constrained Economic Despatch (SCED) w.e.f. 01.04.2019, for thermal Inter-State Generating Stations. Subsequently, the Commission extended the pilot on SCED through various Orders.

(ii) The objective of Security Constrained Economic Despatch (SCED) is to optimise generation despatch after gate closure in the real time market, by incrementing generation from the generating stations with cheaper variable charge and decrementing commensurate generation from the generating station with higher variable charge, after considering the operational and technical constraints of generation and transmission facilities.

(iii) The Commission has observed that the SCED optimization process has resulted in savings for the beneficiaries. The concept of SCED has been proposed to be formalized by including it in the draft Grid Code.

(iv) At present, the SCED algorithm is run after the results of the real time market are finalized, in order to optimize the despatch. The process is as follows:

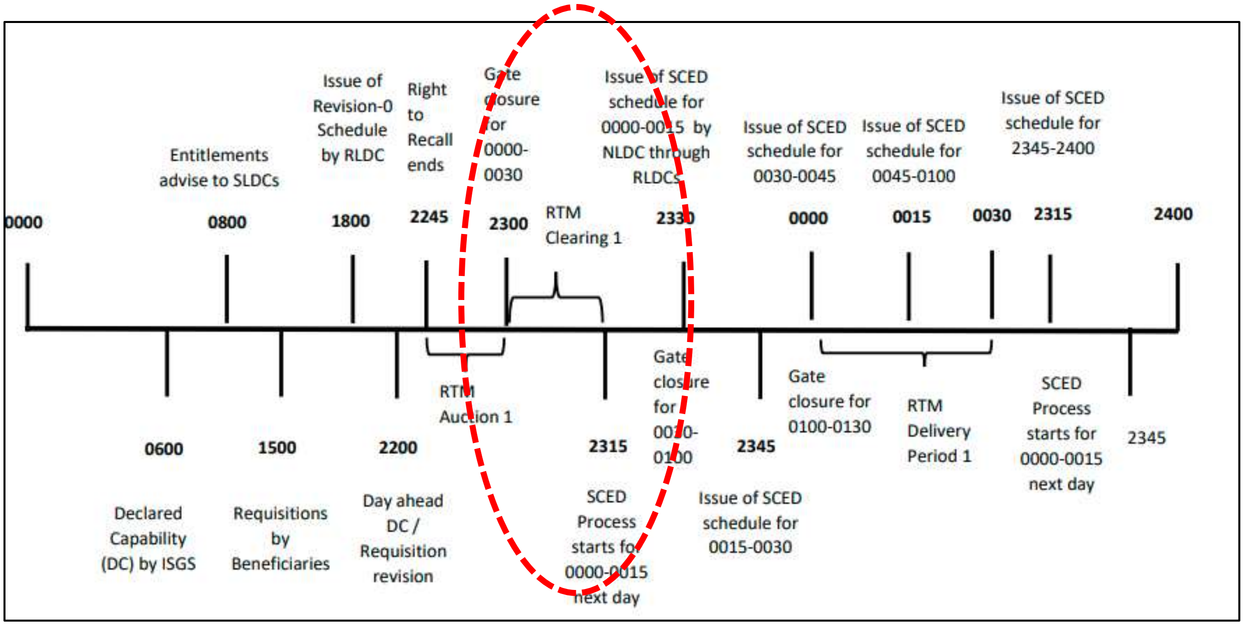


Figure 12: Timeline of SCED

(v) The salient features of SCED proposed under the draft Grid Code are summarized as follows:

a. NLDC shall be the nodal agency for implementing Security Constrained Economic Despatch (SCED) through RLDCs for the generating stations connected to inter-State transmission system that are willing to participate under SCED.

b. The schedules of the States/ beneficiaries would not be changed on account of SCED and the discoms/beneficiaries shall continue to pay the charges for the scheduled energy to the generator as per the existing practice. For any increment in the injection schedule of a generator due to SCED, the generator shall be paid from the National Pool Account (SCED) for the incremental generation at the rate of its variable charge. For any decrement in the schedule of a generator due to SCED, the generator shall pay to the aforesaid National Pool Account (SCED) for the decremental generation at the rate of its variable charge.

c. The deviation in respect of such generators shall be settled with reference to their revised schedule, and any increment or decrement of generation under the SCED shall not form part of schedule considered under the ancillary services.

(vi) An issue arose under prevailing mechanism when few thermal stations and gas stations raised the issue of compensating the difference of variable charge as considered while running SCED and as finalized at a later point in time, since their variable charge changed even after 2-3 months of such despatch. We observe that SCED runs on economic principles as last leg optimization. Any retrospective increase or decrease may defeat the entire stack made while dispatching under SCED. Hence, it has been proposed that the generators should declare their variable charge upfront after considering likely changes in fuel cost and part load compensation, if any. This upfront declaration is to avoid any retrospective adjustment of charges and also to avoid any compensation on account of SCED. No part load compensation shall be payable separately due to SCED.

(vii) The sharing of benefits for generating stations under Section 62 shall be in line with the Tariff Regulations and for others shall be in terms of their contracts.

8.8. Curtailment

(a) The curtailment has been dealt under the GNA Regulations as quoted below:

"38. Curtailment

38.1. When for the reason of transmission constraints or in the interest of grid security, as per the provisions in the Grid Code, it becomes inevitable to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed by the Regional Load Despatch Centre as per the following provisions:

(a) Transactions under T-GNA shall be curtailed first followed by transactions under GNA.

(b) Within transactions under T-GNA, bilateral transactions shall be curtailed first followed by collective transactions under day ahead market followed by collective transactions under real time market.

(c) Within bilateral transactions under T-GNA, curtailment shall be on pro rata basis based on T-GNA.

(d) Within transactions under GNA, curtailment shall be on pro rata basis based on GNA."

(b) Accordingly, the provision of curtailment in the draft Grid Code is on the same lines.

(c) It has also been proposed that within bilateral transactions, renewable energy generators shall be curtailed after curtailment of other conventional generation sources. Similarly, if transactions under GNA are curtailed, renewable energy generators shall be curtailed after curtailment of other conventional generation sources. The whole curtailment sequence is depicted as follows:

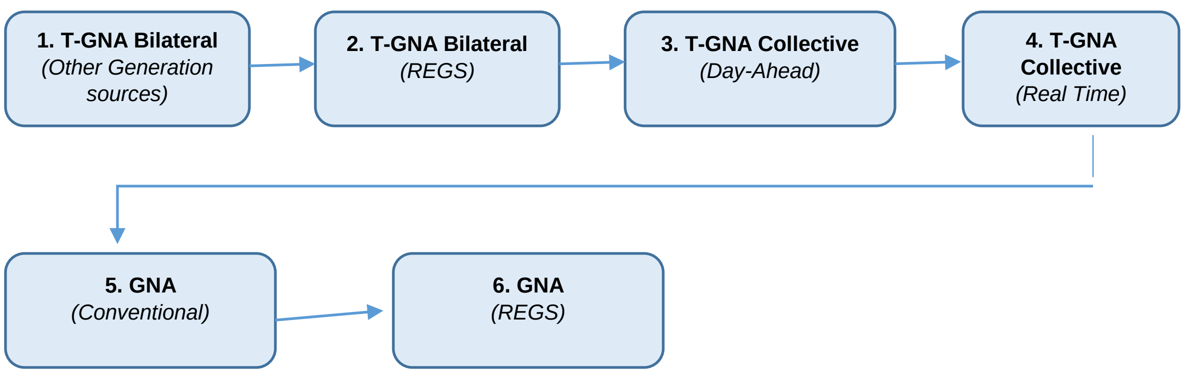


Figure 13: Sequence of curtailment

Accordingly, the draft Grid Code proposes at regulation 47(3) as follows:

*"**(3) Power to revise schedules:***

(a) Curtailment of Scheduled transactions for grid security When for the reason of transmission constraints or in the interest of grid security, it becomes inevitable to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed by the Regional Load Despatch Centre (keeping in view the transaction which is likely to relieve the threat to grid security) as follows:

(i) Transactions under T-GNA shall be curtailed first followed by transactions under GNA.

(ii) Transactions under T- GNA shall be curtailed in the following order:

(a) Within transactions under T-GNA, bilateral transactions shall be curtailed first followed by collective transactions under day ahead market followed by collective transactions under real time market;

(b) Within bilateral transactions under T-GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage), pro rata based on their T-GNA quantum;

(c) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on T-GNA, after curtailment of generation from other sources, within T-GNA.

(d) Collective transactions under day ahead market shall be curtailed after curtailment of bilateral transactions under T-GNA.

(e) Collective transactions under real time market shall be curtailed after curtailment of collective transactions under day ahead market.

(iii) Transactions under GNA shall be curtailed in the following order:

(a) Within transactions under GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage), on pro rata basis based on their GNA quantum.

(b) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with upto three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on their GNA quantum, after curtailment of generation from other sources, within GNA

(iv) RLDC or SLDC, as the case may be, shall publish a report of such incidents on its website."

8.9. Revision of Schedules

(a) It has been proposed under Regulation 47(i) of the draft Grid Code that the generating station whose tariff is determined under Section 62 of the Act, may sell its unrequisitioned surplus as available at 10 AM in the day ahead market. Once such URS power has been sold under Day ahead market, the same cannot be called back by the original beneficiaries of such generating stations.

Accordingly, it has been proposed that upward revision of schedule shall be possible only for remaining available quantum of power after finalization of sales under Day ahead market.

(b) Subject to the above, revision of already finalized schedule is allowed to be made by SLDCs, regional entity generating stations, regional entity ESSs, beneficiaries, buyers or cross-border entities from 7th/ 8th time block for transactions under GNA.

(c) A buyer can do downward revision of schedule from 7th/8th time block subject to provision of SCUC identified units. We also observe that the generating stations not under Section 62 may have specific provisions under their contracts for revision of schedule, and the same must be honored. Accordingly, it has been proposed at Regulation 47(4)(b) of draft Grid Code as follows:

"The request for revision of scheduled transaction for 'D' day, shall be allowed to be made in any time block starting 2 PM on 'D-1' day subject to the following:

(i) In respect of a generating stations whose tariff is determined under Section 62 of the Act, upward revision of schedule shall be allowed starting 2 PM on 'D-1' day, only in respect of the remaining available quantum of un-requisitioned surplus after finalization of schedules under day ahead market.

(ii) In respect of a generating stations whose tariff is not determined under Section 62 of the Act, revision of schedule shall be in terms of provisions of the respective contracts between the generating stations and beneficiaries or buyers. "

8.10. Grid disturbance of category GD-5

(a) The 2010 Grid Code provides for treatment of schedules in case of any grid disturbance. Such grid disturbance may lead to outage of a generator or a buyer thereby leading such entity not to adhere to its schedules.

(b) However, NPC submitted the draft for "Methodology of settlement of accounts for bilateral short term and collective transactions, for the period of Grid Disturbance" vide its letter dated 27th January 2017 under the 2010 Grid Code, wherein it was suggested to consider such treatment only for grid disturbance of category GD-5.

(c) The Expert group has also suggested to consider cases of Grid Disturbance of category GD-5 only. Accordingly, the draft Grid Code has proposed to consider only cases under GD-5 category.

(d) It is observed that if grid disturbance affects generating station but does not affect buyers, retrospective schedule revision for the generator and accordingly for the buyer may be detrimental to the interest of the buyer since it did not know about the disturbance that happened at generator end in real time and it drew power as per its schedule, but retrospective revision reduces its drawl schedule leading it to bear the DSM charges on account of overdrawal for no fault of theirs.

(e) Accordingly, it is proposed that retrospective revision of schedule shall only take place if the beneficiaries have also been impacted by such grid disturbance. However, no retrospective revision in the schedule drawal of beneficiaries or buyers shall be carried out if the beneficiaries or buyers have not been impacted by such grid disturbance and they continue to draw power. Accordingly, following has been proposed at Regulation 47(5)(c) of the draft Grid Code :

> *"(c) Scheduled generation of all the affected regional entity generating stations supplying power under bilateral transactions shall be deemed to have been revised to be equal to their actual generation for all the time blocks affected by the grid disturbance. Such regional entity generating station shall pay back the energy charges received by it for the scheduled generation revised as actual generation to the pool account.:*
>
> *Provided that, in case the beneficiaries or buyers of such regional entity generating station are also affected by such grid disturbance, the scheduled drawals of such beneficiaries or buyers shall be deemed to have been revised to corresponding actual generation schedule of regional entity generating stations.*
>
> *Provided further that in case the beneficiaries or buyers of such regional entity generating station are not affected by such grid disturbance and they continue to draw power, the scheduled drawals of such beneficiaries or buyers shall not be revised.*
>
> *d) The scheduled generation of all the affected regional entity generating stations supplying power under collective transactions shall be deemed to have been revised to be equal to their actual generation. Such regional entity generating stations shall refund the charges received towards such scheduled energy to the DSM pool account."*

(f) It is observed that the system operator is required to inform all users of the power system at the earliest and accordingly it has been proposed that declaration of grid disturbance shall be done at the earliest and the same shall be posted on the website of RLDC.

9. Cyber Security Code

9.1. Power sector is widely considered to be among the most critical infrastructure across the world and cyber security in power sector is paramount for protecting national critical infrastructure. Cyber-attacks in power sector, carried out with a malicious intent for disrupting the power system operations may lead to mal operation of equipment, equipment damages or even in cascading grid brownout/blackout. This chapter deals with measures to be taken to safeguard the national grid from spyware, malwa re, cyber-attacks, network hacking, keeping abreast of latest developments in the area of cyber-attacks and cyber security requirements in line with the guidelines developed by the competent authority.

9.2. The 2010 grid Code provides that all utilities shall have in place, a cyber security framework to identify the critical cyber assets and protect them so as to support reliable operation of the grid. The expert group, in its report had recommended a new chapter for Cyber Security with proposed regulations on identification of critical information infrastructure, appointment and responsibilities of information security committee and measures to be undertaken for ensuring cyber security. However, after the expert group submitted its report in January 2020, CEA has issued Cyber Security in Power Sector Guidelines, 2021 in October 2021 under the provision of Section 3(10) on Cyber Security in the "Central Electricity Authority (Technical Standards for Connectivity to the Grid) (Amendment) Regulations, 2019". The said guidelines lay down required actions for cyber security preparedness across various utilities in power sector so as to raise the level of cyber security preparedness for power sector. The aspects of cyber security proposed by the Expert Group as well as other aspects of cyber security have been extensively covered by the said CEA Guidelines. Accordingly, the Commission has proposed that all users, NLDC, RLDCs, SLDC, CTU and STUs shall have the framework of cyber security in place in accordance with Information Technology Act 2000; the CEA (Technical Standards for Connectivity) Regulations, 2007; the CEA (Cyber Security in Power sector) Guidelines, 2021 and any such regulations issued from time to time by an appropriate authority.

9.3. Cyber Security Audit

Article 14 of the CEA (Cyber Security in Power Sector) Guidelines, 2021 and subsequent amendments thereby, details out measures to carry out Cyber security Audit of IT and OT system by responsible entities. The Commission is of the opinion that the said provisions are comprehensive and have been developed after inputs from expert agencies in the field of cyber security. The Commission, has therefore proposed that all users shall strictly follow these guidelines to conduct cyber security audit as per the CEA (Cyber Security in Power sector) Guidelines, 2021 and other guidelines issued by the appropriate authority.

9.4. Further, Guidelines also provide for Cyber security incident report and response plan, Cyber crises management plan and other related provisions regarding the mechanism of reporting through Chief Information Security Officer (CISO). The Commission believes that the said guidelines and mechanism of reporting should be strictly followed by all responsible entities prone to cyber-attack, in accordance with the CEA (Cyber Security in Power Sector) Guidelines, 2021 and Information Technology Act, 2000.

9.5. The Commission observes that in case of a cyber-attack, the system operator must be informed immediately so that necessary steps can be taken to secure the overall operations of the power system. Further, it has been proposed that in such a case RPCs and the Commission shall also be informed.

10. Monitoring and Compliance Code

10.1. The existing Grid Code specifies that RLDCs and RPCs shall report instances of serious or repeated violation of provisions of IEGC to the Commission. The relevant provisions are as follows:

"1.5 Compliance Oversight

(i) RLDCs shall report to the Commission instances of serious or repeated violation of any of the provisions of the IEGC and incidences of persistent non-compliance of the directions of the RLDCs issued in order to exercise supervision and control required for ensuring stability of grid operations and for achieving the maximum economy and efficiency in the operation of the power system in the region under its control.

(ii) The Regional Power Committee (RPC) in the region shall also continuously monitor the instances of non-compliance of the provisions of IEGC and try to sort out all operational issues and deliberate on the ways in which such cases of non-compliance are prevented in future by building consensus. The Member Secretary RPC may also report any issue that cannot be sorted out at the RPC forum to the Commission. The RPC shall also file monthly reports on status of UI payment and installation of capacitors by states vis-à-vis the requirement/targets, as decided in the RPC.

(iii) The Commission may initiate appropriate proceedings upon receipt of report of RPCs or RLDCs referred to in (i) and (ii) above respectively.

(iv) In case of non-compliance of any provisions of the IEGC by NLDC, RLDC, SLDC, RPC and any other person the matter may be reported by any person to the CERC through petition.

(v) Notwithstanding anything contained in these regulations, the Commission, may also take suo-motu action against any person, in case of non-compliance of any of the provisions of the IEGC."

10.2. The expert group, in its report had recommended a separate chapter for monitoring and compliance which provides for self-audit as well as third party audit for the performance of all users. It has been proposed that the first level of checking is the self audit which should be conducted every year and reports to be submitted by 31st July of every year.

10.3. The Commission has also proposed the main contents of the self-audit report viz the details so as to understand how and why the non-compliance occurred, extent of damage caused by such non-compliance, steps and timeline planned to rectify the same and steps taken to mitigate any future recurrence in order to develop consistency across the self-audit reports.

10.4. The Reports of self audit for users shall be submitted to the concerned RLDC or SLDC on the basis of their respective control area since they manage the operation of such entities on a day to day basis. The non compliances should be discussed and resolved at RPC. However the exceptions shall be brought to the notice of the Commission for appropriate action as required.

10.5. Further the report for RLDC, NLDC, CTU and RPC shall be submitted to the Commission, and for STUs and SLDCs, shall be submitted to concerned SERC.

10.6. It has been proposed that independent third-party compliance audit may be directed by the Commission, for any user, CTU, NLDC, RLDC or RPC based on the facts brought to the knowledge of the Commission.

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