CENTRAL ELECTRICITY REGULATORY COMMISSION

NEW DELHI

No. L-1/265/2022/CERC Dated: 7th June 2022

PREAMBLE

The term “Grid” has been defined in sub-section 32 of Section 2 of the Electricity Act, 2003 (the Act) to mean the high voltage backbone system of inter-connected transmission lines, sub-stations and generating plants. The Central Commission has been vested with the functions under clauses (h) of sub-section (1) of Section 79 of the Act to specify the Grid Code having regard to the Grid Standards. Clause (d) of Section 73 of the Act mandates the Central Electricity Authority to specify the Grid Standards for operation and maintenance of the transmission lines. Further, clause (i) of sub-section (1) of Section 79 of the Act enjoins upon the Central Commission to specify and enforce the standards with respect to the quality, continuity and reliability of services by the licensees. Sub-Section 2 of Section 28 of the Act provides that the Regional Load Despatch Centre shall comply with such principles, guidelines and methodologies in respect of wheeling and optimum scheduling and despatch of electricity as the Central Commission may specify in the Grid Code. Clause (e) of sub-section (3) of Section 28 of the Act provides that the Regional Load Despatch Centre shall be responsible for carrying out real time operations for grid control and despatch of electricity within the region through secure and economic operation of the regional grid in accordance with the Grid Standards and the Grid Code. Sub-Section (1) of Section 26 of the Act provides that National Load Despatch Centre shall be established at the national level for optimum scheduling and despatch of electricity among the Regional Load Despatch Centres. Sub-Section (1) of Section

29 of the Act provides that the Regional Load Despatch Centre shall give such directions and exercise such supervision and control as may be required for ensuring stability of the grid operation and for achieving the maximum economy and efficiency in the operation of the power system in the region under its control. Sub-section (2) of Section 29 of the Act mandates every licensee, generating company, generating station, sub-station and any other person connected with the operation of the power system shall comply with the directions issued by the Regional Load Despatch Centre under sub-section (1). Sub-Section (3) of Section 29 provides that all directions issued by the Regional Load Despatch Centres to the transmission licensee of State transmission lines or any other licensee of the State or generating company (other than those connected with inter-State transmission System) or sub-station in the State shall be issued through the State Load Despatch Centre who shall ensure compliance to such directions by the concerned generating company or the licensee or sub-station. Sub-Section (3) of Section 33 of the Act provides that the State Load Despatch Centre shall comply with the directions of the Regional Load Despatch Centre. Sub-section (4) of Section 29 of the Act provides that the Regional Power Committee in the region may, from time to time, agree on matters concerning the stability and smooth operation of the integrated grid and economy and efficiency of the power system within the region. While Section 38 and Section 39 deal with the functions of the Central Transmission Utility and State Transmission Utility respectively, Section 40 and Section 42 deal with the duties of the transmission licensees and distribution licensees respectively. Therefore, the Act envisages and assigns specific roles and functions to Central Electricity Authority, Regional Power Committees, Central Transmission Utility, National Load Despatch Centre, Regional Load Despatch Centres, State Transmission Utilities, State Load Despatch Centres, generating companies and licensees and any other person connected with the operation of the power system in order to achieve real time operation and control of the grid within the regions and amongst the regions and also within the States for not only ensuring

secure, economic and stable operation of the grid but also for achieving maximum economy and efficiency of the power system.

Accordingly, the Grid Code hereinafter specified by the Central Commission 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 Act and the Rules and Notifications issued by the Central Government.

Under Clause (h) of sub-section (1) of Section 86 of the Act, the State Commissions are mandated to specify the State Grid Codes consistent with the Grid Code specified by the Central Commission under clause (h) of sub-section (1) of Section 86 of the Act. This has been duly recognized by the Hon'ble Supreme Court in its judgement dated 17.8.2007 in Civil Appeal No. 2104 of 2006 in the matter of Central Power Distribution Company & Others Vs Central Electricity Regulatory Commission.

Keeping in view the mandate and statutory framework as envisaged in the Act for stable, reliable and secure grid operation in order to achieve maximum economy and efficiency of the power system, the Grid Code apart from the provisions relating to the role of various statutory bodies and organisations and their linkages, contain extensive provisions pertaining to (a) reliability and adequacy of resources; (b) technical and design criteria for connectivity to the grid including integration of new elements, trial operation and declaration of commercial operation of generating stations and inter-State transmission systems; (c) protection setting and performance monitoring of the protection systems including protection audit; (d) operational requirements and technical capabilities for secure and reliable grid operation including load generation balance, outage planning and system operation; (e) unit commitment, scheduling and despatch criteria for physical delivery of electricity; (f) integration of renewables; (g) ancillary services and reserves; and (g) cyber security etc.

NOTIFICATION (DRAFT)

In exercise of powers conferred under clause (h) of sub-section (1) of Section 79 read with clause (g) of sub-section (2) of Section 178 of the Electricity Act, 2003 (36 of 2003), and all other powers enabling it in this behalf, the Central Electricity Regulatory Commission hereby specifies the Grid Code as under:

CHAPTER1

PRELIMINARY

1. SHORT TITLE, EXTENT AND COMMENCEMENT

(1) These regulations may be called the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2022.

(2) These regulations shall come into force from the date notified by the Commission.

2. SCOPE AND EXTENT OF APPLICATION

(1) These regulations shall apply to: all users, State Load Despatch Centres, Regional Load Despatch Centres, National Load Despatch Centre, Central Transmission Utility, State Transmission Utilities, licensees, Regional Power Committees and Power Exchanges to the extent applicable.

(2) For the purpose of these regulations, the Damodar Valley Corporation (DVC) shall be treated as a regional entity and a separate control area. The DVC Load Despatch Centre shall perform functions of a SLDC for the control area of DVC.

(3) The generating stations of the Bhakra Beas Management Board (BBMB) and Sardar Sarovar Project (SSP) shall be treated as regional entities and their generating units shall be scheduled and despatched in coordination with BBMB or Narmada Control Authority, as the case may be, having due regard to the irrigation requirements of the participating States.

(4) Any country inter-connected with the National Grid or Regional Grid shall be treated as a separate control area.

3. DEFINITIONS

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

Sr.No.	Particulars	Definition
1.	'Act'	means the Electricity Act, 2003;
2.	'Alert State'	means the state in which the system is within the operational parameters as defined in this Code but a contingency has occurred;
3.	'Ancillary Services'	in relation to power system operation, means the service necessary to support the grid operation in maintaining power quality, reliability and security of the grid and includes Primary Reserve Ancillary Service, Secondary Reserve Ancillary Service, Tertiary Reserve Ancillary Service, active power support for load following, reactive power support, black start and such other services as defined in this

Sr.No.	Particulars	Definition
		Code;
4.	'Ancillary Services Regulations' or 'AS Regulations'	means Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022;
5.	'Area Control Error' or 'ACE'	shall be as specified in Regulation 30(11) of these regulations;
6.	'Automatic Generation Control' or 'AGC'	means a mechanism that automatically adjusts the generation of a control area to maintain its interchange schedule plus its share of frequency response;
7.	'Automatic Voltage Regulator' or'AVR'	means a continuously acting automatic excitation control system to control the voltage of a generating unit measured at the generator terminals;
8.	'Available Transfer Capability' or 'ATC'	means power transfer capability of the inter-control area transmission system or across electrical regions or between ISTS and state network or between cross-border interconnections available for scheduling transactions in a specific direction, taking into account the network security declared by the concerned load despatch centre. Mathematically, ATC is the Total Transfer Capability less Transmission Reliability Margin;
9.	'Beneficiary'	means a person who has a share (as defined in clause 110 of this Regulation) in an ISGS;
10.	'Bilateral Transaction'	means a transaction for exchange of energy or

Sr.No.	Particulars	Definition
		power (MW or MWh) between a specified buyer and a specified seller, directly or through a trading licensee or discovered in the Term Ahead Market at power exchange through anonymous bidding, and scheduled from a specified point of injection to a specified point of drawal for a fixed or varying quantum of power (MW) for any time period;
11.	'Blackout State'	means a condition at a specific time where a part or all the operations of the power system have got suspended;
12.	'Black Start Procedure'	means the procedure necessary to recover from a partial or a total blackout in the region;
13.	'Bulk Consumer'	shall have the same meaning as defined in CEA Technical Standards for Connectivity;
14.	'Buyer'	means a person purchasing electricity through a transaction scheduled through inter-State transmission system in accordance with these regulations.
15.	'Captive Generating Plant'	means a power plant set up by any person to generate electricity primarily for his own use and includes a power plant set up by any co-operative society or association of persons for generating electricity primarily for use of members of such cooperative society or association;
16.	'CEA Grid Standards'	means the Central Electricity Authority (Grid Standards) Regulations, 2010

Sr.No.	Particulars	Definition
17.	'CEA Technical Standards for Communication'	means the Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020
18.	'CEA Technical Standards for Connectivity'	means the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007;
19.	'CEA Technical Standards for Construction'	means the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010
20.	'Central Generating Station'	means the generating station owned by a company owned or controlled by the Central Government;
21.	'Central Transmission Utility' or 'CTU'	means any government company, which the Central Government may notify under sub-section (1) of Section 38 of the Act;
22.	'Cold Start'	in relation to steam turbine means start up after a shutdown period exceeding 72 hours (turbine metal temperatures below approximately 40% of their full load values);
23.	'Collective Transaction'	shall have the same meaning as defined in Central Electricity Regulatory Commission (Power Market) Regulations, 2021;
24.	'Communication System'	shall have the same meaning as defined in Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017.;
25.	'Congestion'	means a situation where the demand for transmission capacity or power flow on any

Sr.No.	Particulars	Definition
		transmission corridor exceeds its Available Transfer Capability;
26.	‘Connectivity Agreement’	means an agreement between CTU and any other person setting out the terms relating to a connection to and/or use of the Inter-State Transmission System in terms of GNA Regulations;
27.	‘Connectivity’	means the state of getting connected to the inter-State transmission system by a generating station including a captive generating plant, a bulk consumer or an Inter-State Transmission licensee;
28.	‘Control Area’	means an electrical system bounded by interconnections (tie lines), metering and telemetry which controls its generation and/or load to maintain its interchange schedule with other control areas and contributes to regulation of frequency as specified in these regulations;
29.	‘Control Centre’	includes NLDC or RLDC or REMC or SLDC or Area LDC or Sub-LDC or DISCOM LDC including main and backup Centre, as applicable;
30.	‘Date of Commercial Operation’ or ‘COD’	shall have the same meaning as specified in Regulation 27 of these regulations;
31.	‘Declared Capacity’ or ‘DC’	in relation to a generating station means, the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day as defined in the Grid Code or whole of the day, duly taking into account the availability of fuel or water, and

Sr.No.	Particulars	Definition
		subject to further qualification in the relevant regulations;
32.	‘Demand’	means the demand of active power in MW;
33.	‘Demand Response’	means variation in electricity usage by end customers/control area manually or automatically, as per system requirement identified by concerned load despatch centre;
34.	‘Despatch Schedule’	means the ex-power plant net MW and MWh output of a generating station, scheduled to be exported to the Grid from time to time;
35.	‘DSM Regulations’	means Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) Regulations, 2022;
36.	‘Disturbance Recorder’ or ‘DR’	means a device for recording the behavior of the pre-selected digital and analog values of the system parameters during an event;
37.	‘Data Acquisition System’ or ‘DAS’	means a system for recording the sequence of operation in time, of the relays/equipment as well as the measurement of pre-selected system parameters;
38.	‘Drawal Schedule’	means the summation of the station-wise ex-power plant drawal schedules from all ISGS and drawal from/injection to regional grid under GNA and T-GNA;
39.	‘DVC’	means the Damodar Valley Corporation established under sub-section (1) of Section 3 of the Damodar Valley Corporation Act, 1948;

Sr.No.	Particulars	Definition
40.	'Emergency State'	means the state in which one or more variables are outside their operating limit or many of the equipment are operating above their respective loading limit;
41.	'Energy Storage System' or 'ESS'	means any system or device capable of storing electrical energy in any form using any technology and delivering it back in the form of electrical energy;
42.	'Event'	means an unscheduled or unplanned occurrence in the grid including faults, incidents and breakdowns;
43.	'Event Logging Facilities'	means a device for recording the chronological sequence of operations, of the relays and other equipment;
44.	'Ex-Power Plant'	means net MW or MWh output of a generating station, after deducting auxiliary consumption and transformation losses;
45.	'Fault Locator' or 'FL'	means a device installed at the end of a transmission line to measure/ indicate the distance at which a line fault may have occurred;
46.	'Flat frequency control'	means a mechanism for correcting ACE by factoring in only the frequency deviation and ignoring the deviation of net actual interchange from net scheduled interchange;
47.	'Flat tie-line control'	means a mechanism for correcting ACE by factoring in only the deviation of net actual interchange from net scheduled interchange ignoring frequency deviation;

Sr.No.	Particulars	Definition
48.	‘Flexible Alternating Current Transmission System’ or ‘FACTS’	means a power electronics based system and other static equipment that provide control of one or more AC transmission system parameters to enhance controllability and increase power transfer capability;
49.	‘Flow-gate’	means a group of parallel transmission line (s), outage of which may lead to cascade tripping or separation of systems or loss of generation complex or loss of load centre;
50.	‘Forced Outage’	means an outage of a generating unit or a transmission facility due to a fault or other reasons which has not been planned;
51.	‘Frequency Response Characteristics’ or ‘FRC’	means automatic, sustained change in the power consumption by load or output of the generators that occurs immediately after a change in the load-generation balance of a control area and which is in a direction to oppose a change in frequency. Mathematically it is equivalent to FRC = Change in Power (ΔP) / Change in Frequency (Δf);
52.	‘Frequency Response Obligation’ or ‘FRO’	means the minimum frequency response a control area has to provide in the event of any frequency deviation;
53.	‘Frequency Response Performance’ or ‘FRP’	means the ratio of actual frequency response with frequency response obligation;
54.	‘Frequency Stability’	means the ability of the transmission system to maintain stable frequency in the normal state

Sr.No.	Particulars	Definition
		and after being subjected to a disturbance;
55.	'Gate Closure'	"means the time at which the bidding for a specific delivery period closes at the power exchange and no further bidding or modification of already placed bids can take place for the said delivery period.
56.	'Generating Unit'	means a) for all generating stations except solar photo voltaic, wind and hybrid stations, an electrical generator coupled to a prime mover within a power station together with all plant and apparatus at the power station which relate exclusively to operation of that turbo-generator; b) for solar photo voltaic generating stations including hybrid, each inverter along with associated modules shall be reckoned as a separate generating unit; c) for wind generating stations including hybrid: each wind turbine generator with associated equipment shall be reckoned as a separate generating unit;
57.	'GNA Regulations'	means the Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022;
58.	'GNA Grantee'	means a person who has been granted GNA or is deemed to have been granted GNA under GNA Regulations;

Sr.No.	Particulars	Definition
59.	'Governor Droop'	in relation to the operation of the governor of a generating unit means the percentage drop in system frequency which would cause the generating unit under governor action to change its output from no load to full load;
60.	Grid-forming capability	means the capability of a Power Generating Module to generate its own voltage waveform without relying on the grid voltage to synchronize and run as a black-start resource.
61.	'Grid Security'	means the power system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterized by operational security limits;
62.	'Grid Standards'	means the standards specified by the Authority under clause (d) of the Section 73 of the Act;
63.	'Hot Start'	in relation to steam turbine, means the start up after a shutdown period of less than 10 hours (turbine metal temperatures below approximately 80% of their full load values);
64.	'Inertia'	means the contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is coupled with the power system and synchronized to the frequency of the power system;
65.	'Infirm Power'	means the electricity injected into the grid prior to the date of commercial operation of a unit of the generating station;

Sr.No.	Particulars	Definition
66.	‘Inter-State Generating Station’ or ‘ISGS’	means a central generating station or any other generating station having a scheme for generation and sale of electricity in more than one state;
67.	‘Inter-State Transmission System’ or ‘ISTS’	shall have the same meaning as defined in sub-section (36) of Section 2 of the Act;
68.	‘Licensee’	means a person who has been granted a license under Section 14 of the Act;
69.	‘Load’	means the active, reactive or apparent power consumed by a utility/installation of consumer;
70.	‘Maximum Continuous Rating’ or ‘MCR’	means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters;
71.	‘Merit Order’	means the order of ranking of available electricity generation in ascending order from least energy charge to highest energy charge to be used for deciding despatch instructions to minimize the overall cost of generation;
72.	‘Minimum Turndown Level’	means 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 as detailed in Chapter 7 of this Code;
73.	‘Nadir Frequency’	means minimum frequency after a contingency in case of generation loss and maximum frequency after a contingency in case of load loss;

Sr.No.	Particulars	Definition
74.	'National Grid'	means the entire inter-connected electric power network of the country;
75.	'National Load Despatch Centre' or 'NLDC'	means the centre established under sub-section (1) of Section 26 of the Act;
76.	'Net Drawal Schedule'	means the drawal schedule of a regional entity which is the algebraic sum of all its transactions through the inter-State transmission system at ISTS periphery after deducting the transmission losses;
77.	'Net Injection Schedule'	means the injection schedule of a regional entity which is the algebraic sum of all its transactions through the inter-State transmission system at ISTS periphery;
78.	'Normal State'	means the state in which the system is within the operational parameters as defined in these regulations
79.	'On-Bar Declared Capacity'	in relation to a generating station means the capability to deliver ex-bus electricity in MW from the units on-bar declared by such generating station in relation to any time block of the day or whole of the day, duly taking into account the availability of fuel and water and subject to further qualification in the relevant regulations;
80.	'On-Bar Installed Capacity'	means the summation of name plate capacities or the capacities as approved by the Commission from time to time, of all units of the generating station in MW which are on- bar. In case of a

Sr.No.	Particulars	Definition
		combined cycle module of a gas or liquid fuel-based stations, the installed capacity of steam turbine shall be in proportion to the on-bar capacity of gas turbines of the module;
81.	‘Off-Bar Declared Capability’	means the difference between Declared Capacity and On-Bar Declared Capacity in MW;
82.	‘Operation Co-ordination Sub-Committee’ or ‘OCC’	means a sub-committee of RPC which deliberates and decides the operational aspects of the regional grid;
83.	‘Primary Reserve’	means the maximum quantum of power which will immediately come into service through governor action of the generator in the event of sudden change in frequency. This reserve response shall start instantaneously and attain its peak in less than 30 seconds, and shall sustain upto 5 minutes;
84.	‘Pool Account’	means Deviation and Ancillary Service Pool Account as defined in DSM Regulations, where following transactions shall be accounted: i. deviations and ancillary services ii. reactive energy exchanges iii. congestion charge;
85.	‘Pooling Station’	means the ISTS grid sub-station where pooling of generation of connected individual generating stations is done for interfacing with the next higher voltage level;
86.	‘Power Exchange’	means an exchange registered under Central Electricity Regulatory Commission (Power

Sr.No.	Particulars	Definition
		Market), Regulations 2021;
87.	'Power System'	shall have the same meaning as defined in sub-section (50) of Section 2 of the Act
88.	'Protection Co-ordination Sub-Committee'	means a sub-committee of RPC with members from all the regional entities which decides on the protection aspects of the regional grid;
89.	'Qualified Coordinating Agency' or 'QCA'	means the lead generator or any authorized agency on behalf of REGS or RHGS (as per GNA Regulations) including Energy Storage Systems connected to one or more pooling station(s) for coordinating with concerned load despatch centre for scheduling, operational coordination and deviation settlement;
90.	'Ramp Rate'	means rate of change of a generating station output expressed in %MW per minute;
91.	'Rate of Change of Frequency' or '*df/dt*'	means the time derivative of the power system frequency which negates short term transients and therefore reflects the actual change in synchronous network frequency;
92.	'Reference contingency'	means the maximum positive power deviation occurring instantaneously between generation and demand and considered for estimation of reserves;
93.	'Regional Entity'	means such entities which are in the RLDC control area and whose metering and energy accounting is done at the regional level;
94.	'Regional Power	shall have the same meaning as defined in sub-

Sr.No.	Particulars	Definition
	Committee' or 'RPC'	section (55) of Section 2 of the Act.
95.	'Restorative State'	means a condition in which control action is being taken to reconnect the system elements and to restore system load;
96.	'Regional Energy Account' or 'REA'	means accounts of energy and other parameters issued by the respective RPC for the purpose of billing and settlement of charges of ISGS and other users of the concerned region;
97.	'Regional Transmission Account' or 'RTA'	means accounts of transmission issued by the RPC Secretariat for the purpose of billing and settlement of transmission charges of ISTS in the concerned region;
98.	'Regional Grid'	means the high voltage backbone system of inter-connected transmission lines, sub-stations and generating plants in a region;
99.	'Regional Load Despatch Centre' or 'RLDC'	means the Centre established under sub-section (1) of Section 27 of the Act;
100.	'Renewable Energy Generating Station' or REGS'	means a generating station based on a renewable source of energy with or without Energy Storage System and shall include Renewable Hybrid Generating Station.
101.	"Renewable Hybrid Generating Station" or "RHGS"	means a generating station based on hybrid of two or more renewable source(s) of energy with or without Energy Storage System, connected at the same inter-connection point.
102.	'Secondary Reserve'	means the maximum quantum of power which can be activated through Automatic Generation

Sr.No.	Particulars	Definition
		Control (AGC) to free the capacity engaged by the primary control. This reserve response shall come into service starting from 30 seconds and shall sustain up to 15 minutes;
103.	'Secondary Reserve Ancillary Service' or 'SRAS'	means the Ancillary Service comprising SRAS-Up and SRAS-Down, which is activated and deployed through secondary control signals.
104.	'Secondary Reserve Ancillary Service Provider' or 'SRAS Provider'	means an entity which provides SRAS-Up or SRAS-Down service in accordance with Ancillary Service Regulations;
105.	'Security Constrained Economic Despatch' or 'SCED'	means despatch of generating units as per merit order subject to operational and technical limits of generation and transmission facilities and shall be in terms of Regulation 47(2)(a) of these regulations;
106.	'Security Constrained Unit Commitment' or 'SCUC'	means committing or de-committing generating units while respecting limitations of the transmission system and unit operating characteristics and shall be in terms of Regulation 46 of these regulations;
107.	''Seller'	means a person, including a generating station, supplying electricity through a transaction scheduled in accordance with these regulations;
108.	'SERC' or State Commission	means State Electricity Regulatory Commission as defined in sub-section (64) of Section 2 of the Act.;
109.	'Settlement Nodal	means the nodal agency as notified by Ministry of

Sr.No.	Particulars	Definition
	Agency’ or ‘SNA’	Power, Government of India for each neighboring country for settlement of grid operation related charges in terms of Central Electricity Regulatory Commission (Cross Border Trade of Electricity) Regulations, 2019;
110.	‘Share’	means percentage or MW entitlement of a beneficiary in an ISGS either notified by Government of India or agreed between the generating company and beneficiary through contracts and implemented through GNA or TGNA, as the case may be;
111.	‘State Load Despatch Centre’ or ‘SLDC’	means the Centre established under sub-section (1) of Section 31 of the Act;
112.	‘State Transmission Utility’ or ‘STU’	means the board or the government company specified as such by the concerned State Government under sub-section (1) of section 39 of the Act;
113.	‘System Constraint’	means a situation in which there is a need to prepare and activate a remedial action in order to respect operational security limits;
114.	‘System State’	means the operational state of the power system in relation to the operational security limits which can be normal state, alert state, emergency state, extreme emergency state and restoration state;
115.	‘Technical Co-ordination Committee’ or ‘TCC’	means the sub-committee set up by the respective RPC to coordinate the technical and commercial aspects of the operation of the regional grid;

Sr.No.	Particulars	Definition
116.	'Tertiary Reserve'	means the quantum of power which can be activated in order to take care of contingencies and to cater to the need for replacing secondary reserves.;
117.	'Tie-line bias control'	means a mechanism of correcting ACE by factoring in deviation of net actual interchange from net scheduled interchange as well as frequency deviation
118.	'Time Block'	means block of duration as specified by the Commission for which energy meters record values of specified electrical parameters with first time block starting at 00.00 Hours, presently of fifteen (15) minutes duration;
119.	'Total Transfer Capability' or 'TTC'	means the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency;
120.	'Transmission Planning Criteria'	means the criteria issued by CEA for transmission system planning;
121.	'Transmission Reliability Margin' or 'TRM'	means the amount of margin earmarked in the total transfer capability to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions;
122.	'Trial Operation' or 'Trial Run'	shall have the same meaning as specified in Regulation 22 or Regulation 23 of these regulations, as applicable;

Sr.No.	Particulars	Definition
123.	'User'	means and includes generating company, captive generating plant, energy storage system, transmission licensee including deemed transmission licensee, distribution licensee, solar park developer, wind park developer, wind-solar photo voltaic hybrid system, or bulk consumer whose electrical plant is connected to the grid at voltage level 33 kV and above;
124.	'Voltage Stability'	means the ability of a transmission system to maintain steady acceptable voltages at all nodes in the transmission system in the normal situation and after being subjected to a disturbance;
125.	'Warm Start'	means the start up after a shutdown period between 10 hours and 72 hours (turbine metal temperatures between approximately 40% to 80% of their full load values) in relation to steam turbine;

(2) Words and expressions used in these regulations and not defined herein but defined in the Act or other relevant regulations of the Commission shall have the meaning as assigned to them under the Act or relevant regulations of the Commission.

(3) Reference to any Acts, Rules and Regulations shall include amendments or consolidation or re-enactment thereof.

CHAPTER 2

RESOURCE PLANNING CODE

4. GENERAL

(1) This chapter covers the integrated resource planning including demand forecasting, generation resource adequacy planning and transmission resource adequacy assessment, required for secure grid operation.

(2) The planning of generation and transmission resources shall be for reliably meeting the projected demand in compliance with specified reliability standards for serving the load with optimum generation mix with a focus on integration of environmentally benign technologies after taking into account the need, inter alia, for flexible resources, storage systems for energy shift and demand response measures for managing the intermittency and variability of renewable energy sources.

5. INTEGRATED RESOURCE PLANNING

(1) The integrated resource planning shall include:

(a) Demand forecasting as detailed in sub-Regulation (2) of this Regulation;

(b) Generation resource adequacy planning to meet the projected demand as detailed in sub-Regulation (3) of this Regulation; and

(c) Transmission resource planning as detailed in sub-Regulation (4) of this Regulation

(2) Demand Forecasting:

(i) Each distribution licensee within a State shall estimate the demand in its control area including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation, demand response, 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. The demand estimation shall be done using 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.

(ii) STU, based on the demand estimates furnished by the distribution licensees of the concerned State as per clause (i) of this sub-Regulation and in co-ordination with all the distribution licensees, shall estimate by 30th 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.

(iii) Forum of Regulators may develop guidelines for demand estimation by the distribution licensees for achieving consistency and statistical accuracy by taking into consideration the factors such as economic parameters, historical data and sensitivity and probability analysis.

(3) Generation Resource Adequacy Planning:

(a) After the demand estimation as per sub-Regulation (2) of this Regulation, each distribution licensee shall

(i) assess the existing generation resources and identify the additional generation resource requirement to meet the estimated demand in different time horizons, and

(ii) prepare generation resource procurement plan.

(b) Assessment of the existing generation resources shall be done with due regard to their capacity contribution to meet the peak demand.

(c) Generation resource procurement planning (specifying procurement from resources under State control area and regional control area) shall be undertaken in different time horizons, namely long-term, medium term and short-term to ensure

(i) adequacy of generation resources and

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

(d) In order to ensure optimum and least cost generation resource procurement planning, each distribution licensee shall give due consideration to the factors such as its share in the national coincident peak, seasonal requirement and possibility of sharing generation capacity seasonally with other States. For this purpose, each STU on behalf of the 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.

(e) Based on the information received under clause (iv) of this sub-Regulation and after considering inter alia the national level planning reserve margin, share of each State in the national coincident peak, seasonal requirements of States and possibility of sharing generation capacity seasonally among States, NLDC shall carry out a simulation by 31st October every year, to assist the States in drawing their optimal generation resource adequacy plan. While carrying out the simulation, NLDC shall also take into consideration the information related to demand estimation, generation planning and related matters as available with CEA. The simulation carried out by NLDC for this purpose shall be considered merely an aid to the distribution licensees in the respective States in their exercise of generation resource adequacy planning and the distribution licensees shall be responsible for all commercial decisions on generation resource procurement.

(f) After considering the demand forecasting and the generation resource procurement planning carried out based on the principles specified under this Regulation, each distribution licensee shall ensure demonstrable generation resource adequacy as specified by the respective SERC for the next five (5) years starting 1st April of the next year. Failure of a distribution licensee to meet the generation resource adequacy target approved by the SERC shall render the concerned distribution licensee liable for payment of resource adequacy non-compliance charge as may be specified by the respective SERC.

(g) For the sake of uniformity in approach and in the interest of optimality in generation resource adequacy in the States, 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.

(4) Transmission resource adequacy assessment

(a) CTU shall undertake assessment and planning of the inter-State transmission system as per the provisions of the Act and shall inter alia take into account:

(i) adequate power transfer capability across each flow-gate;

(ii) import and export capability for each control area;

(iii) import and export capability between regions; and

(iv) cross-border import and export capability.

(b) STU shall undertake assessment and planning of the intra-State transmission system as per the provisions of the Act and shall inter alia take into account:

(i) import and export capability across ISTS and STU interface; and

(ii) adequate power transfer capability across each flow-gate.

CHAPTER 3

CONNECTION CODE

6. GENERAL

(1) This chapter covers the technical and design criteria for connectivity, procedure and requirements for physical connection and integration of grid elements.

(2) The connectivity to the ISTS shall be granted by CTU in accordance with the GNA Regulations.

(3) Users seeking to get connected to the ISTS for the first time through new or modified power system element shall fulfill the requirements and follow the procedures specified under this Code prior to obtaining the permission of the NLDC or RLDC or SLDC, as the case may be.. Transmission licensees including deemed transmission licensees or cross-border entities shall comply with the technical requirements specified under this Connection Code prior to being allowed by NLDC or RLDC or SLDC to energize a new or modified power system element.

(4) After grant of connectivity and prior to the trial run for declaration of commercial operation, the tests as specified under this Code shall be performed.

7. COMPLIANCE WITH EXISTING RULES AND REGULATIONS

(1) All Users connected to or seeking connection to the grid shall comply with all the applicable regulations as enacted or amended from time to time, such as:

(a) Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007;

(b) Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010;

(c) Central Electricity Authority (Measures Relating to Safety & Electric Supply) Regulations, 2010;

(d) Central Electricity Regulatory Commission (Communication System for Inter-State Transmission of Electricity) Regulations,2017;

(e) Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006;

(f) Central Electricity Regulatory Commission (Connectivity and General Network Access to the inter-State Transmission System) Regulations, 2022;

(g) Central Electricity Regulatory Commission (Fees and Charges for Regional Load Despatch Centres) Regulations, 2019;

(h) Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020;

(i) Central Electricity Regulatory Commission (Furnishing of Technical Details by the Generating Companies) Regulations, 2009.

(j) Any other regulations and standards as specified from time to time.

8. PROCEDURE FOR CONNECTION

(1) The grant of connectivity to the ISTS by the CTU shall be governed by the GNA Regulations.

(2) NLDC, in coordination with RPCs and RLDCs after due consultation of stakeholders, shall publish a detailed procedure covering modalities for first time energization and integration of new or modified power system element. The procedure shall specify requirements for integration with the grid such as protection, telemetry and communication systems, metering, statutory clearances and modelling data requirements for system studies.

(3) Post completion of all physical arrangements of connectivity and necessary site tests, the concerned user shall request the RLDC for permission of first energization in the specified format as per the procedure published by NLDC.

(4) SLDC shall prepare procedure for first time energization of new or modified power system elements to intra-State transmission system. In the absence of such procedure of SLDC, the NLDC procedure shall apply for the elements of 220 kV and above (132 kV and above in case of North Eastern region).

9. CONNECTIVITY AGREEMENT

(1) In case of users seeking connectivity to the ISTS under GNA Regulations, Connectivity Agreement shall be signed between such users and the CTU.

(2) In case of an inter-State transmission licensee, Connectivity Agreement shall be signed between such licensee and CTU after the award of the project and before physical connection to ISTS.

10. TECHNICAL REQUIREMENTS

(1) NLDC or RLDC, as the case may be, 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, if any. The connectivity grantee, transmission licensee and SLDC/STU shall furnish all technical data including that of its embedded generators and other elements to the CTU and NLDC or RLDC, as the case may be, for necessary technical studies.

(2) Similar exercise shall be done by SLDC 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).

11. DATA AND COMMUNICATION FACILITIES

(1) Reliable speech and data communication systems shall be provided to facilitate necessary communication, data exchange, supervision and control of the grid by the NLDC, RLDC and SLDC in accordance with the CERC (Communication System for Inter-State Transmission of Electricity) Regulations, 2017 and the CEA Technical Standards on Communication.

(2) The associated communication system to facilitate data flow up to appropriate data collection point on CTU system including inter-operability requirements shall also be established by the concerned user as specified by CTU in the Connectivity Agreement.

(3) All users, STU and participating entities in case of cross-border trade shall provide, in coordination with CTU, the required facilities at their respective ends as specified in the connectivity agreement. The communication system along with data links provided for speech and real time data communication shall be monitored in real time by all users, CTU, STU, SLDC and RLDC to ensure high reliability of the communication links.

CHAPTER 4

PROTECTION CODE

12. GENERAL

(1) This chapter covers the protection protocol, protection settings and protection audit plan of electrical systems.

(2) There shall be a uniform protection protocol for the users of the grid:

(a) for proper co-ordination of protection system in order to isolate the faulty equipment and avoid unintended operation of protection system;

(b) to have a repository of protection system, settings and events at regional level;

(c) specifying timelines for submission of data;

(d) to ensure healthiness of recording equipment including time synchronization; and

(e) to provide for periodic audit of protection system.

13. PROTECTION PROTOCOL

(1) All users connected to the integrated grid shall provide and maintain effective protection system having reliability, selectivity, speed and sensitivity to isolate faulty section and protect element(s) as per the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity, the CEA (Grid Standards) Regulations, 2010 and the CEA Technical Standards for Communication.

(2) Back-up protection system shall be provided to protect an element in the event of failure of the primary protection system.

(3) RPC shall develop the protection protocol and revise the same, after review from time to time, in consultation with the stakeholders in the concerned region, and in doing so

shall be guided by the principle that minimum electrical protection functions for equipment connected with the grid shall be provided as per the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity, the CEA Technical Standards for Communication, the CEA (Grid Standards) Regulations, 2010, the CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, and any other CEA standards specified from time to time.

(4) The protection protocol in a particular system may vary depending upon operational experience. Changes in protection protocol, as and when required, shall be carried out after deliberation and approval of the concerned RPC.

14. PROTECTION SETTINGS

(1) RPCs shall undertake review of the protection settings, assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders of the respective region, from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the respective RPC.

(2) All users connected to the grid shall:

(a) furnish the protection settings implemented for each element to respective RPC in a format as prescribed by the concerned RPC;

(b) obtain approval of the concerned RPC for (i) any revision in settings, and (ii) implementation of new protection system;

(c) intimate to the concerned RPC about the changes implemented in protection system or protection settings within a fortnight of such changes;

(d) ensure correct and appropriate settings of protection as specified by the concerned RPC.

(e) ensure proper coordinated protection settings.

(3) RPCs shall:

(a) maintain a centralized database in respect of their respective region containing details of relay settings for grid elements connected to 220 kV and above (132 kV and above in NER).

(b) carry out detailed system studies, twice a year, for protection settings and advise modifications / changes, if any, to the CTU and to all users and STUs of their respective regions.

(c) provide the database access to CTU and NLDC and to all users, RLDC, SLDCs, and STUs of the respective regions. The database shall have different access rights for different users.

15. PROTECTION AUDIT PLAN

(1) All users shall conduct internal audit of their protection systems annually, and any shortcomings identified shall be rectified and informed to their respective RPC.

(2) All users shall also conduct third party protection audit of each sub-station at 220 kV and above (132 kV and above in NER) once in five years or earlier as advised by the respective RPC.

(3) After analysis of any event, each RPC shall identify a list of substations / and generating stations where third-party protection audit is required to be carried out and accordingly advise the respective users to complete third party audit within three months.

(4) The third-party protection audit report shall contain information sought in format enclosed as Annexure–1. The protection audit reports, along with action plan for rectification of deficiencies detected, if any, shall be submitted to the respective RPC and RLDC within a month of submission of third party audit report.

(5) Annual audit plan for the next financial year shall be submitted by the users to their respective RPC by 31st October. The users shall adhere to the annual audit plan and report compliance of the same to their respective RPC.

(6) Users shall submit the following protection performance indices of previous month to their respective RPC on monthly basis, which shall be reviewed by the RPC:

(a) The Dependability Index defined as $D = \frac{Nc}{Nc+Nf}$

where,

N_c is the number of correct operations at internal power system faults and

N_f is the number of failures to operate at internal power system faults.

(b) The Security Index defined as $S = \frac{Nc}{Nc+Nu}$

Where,

N_c is the number of correct operations at internal power system faults

N_u is the number of unwanted operations.

(c) The Reliability Index defined as $R = \frac{Nc}{Nc+Ni}$

Where,

N_c is the number of correct operations at internal power system faults

N_i is the number of incorrect operations and is the sum of N_f and N_u

(7) Each user shall also submit the reasons for performance indices less than unity of individual element wise protection system to the respective RPC and action plan for corrective measures. The action plan will be followed up regularly in the respective RPC.

(8) In case any user fails to comply with the protection protocol specified by the RPC or fails to undertake remedial action identified by the RPC within the specified timelines,

the concerned RPC may approach the Commission with all relevant details for suitable directions.

16. SYSTEM PROTECTION SCHEME (SPS)

(1) SPS for identified system shall have redundancies in measurement of input signals and communication paths involved upto the last mile to ensure security and dependability.

(2) For the operational SPS, RPCs shall perform regular dynamic studies and mock testing for reviewing SPS parameters & functions, at least once in a year.

(3) The users and SLDCs shall report about the operation of SPS within three days of operation to the concerned RPC and RLDC in the format specified by the respective RPCs.

17. RECORDING INSTRUMENTS

(1) All users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.

(2) The disturbance recorders shall have time synchronization and a standard format for recording analogue and digital signals which shall be included in the guidelines issued by the respective RPCs.

CHAPTER 5

COMMISSIONING AND COMMERCIAL OPERATION CODE

18. General

This chapter covers aspects related to (i) drawl of startup power from and injection of infirm power into the grid, (ii) trial run operation (iii) documents and tests required to be furnished before declaration of COD, (iv) requirements for declaration of COD.

19. Drawal of Start up Power And Injection Of Infirm Power

(1) A unit of a generating station including that of a captive generating plant which has been granted connectivity to the inter-State Transmission System in accordance with GNA Regulations shall be allowed to inter-change infirm power with the grid during the commissioning period, including testing and full load testing before the COD, after obtaining prior permission of the concerned Regional Load Despatch Centre:

Provided that concerned Regional Load Despatch Centre while granting such permission shall keep the grid security in view.

(2) The period for which such interchange shall be allowed-shall be as follows :-

(a) Drawal of start-up power shall not exceed 15 months prior to the expected date of first synchronization and 6 months after the date of first synchronization; and

(b) Injection of infirm power shall not exceed six months from the date of first synchronization.

(3) Notwithstanding the provisions of clause (2) of this Regulation, the Commission may in exceptional circumstances, allow extension of the period for inter-change of power

beyond the stipulated period on an application made by the generating station at least two months in advance of completion of the stipulated period:

(4) Drawal of start-up power shall be subject to payment of transmission charges as per Sharing Regulations;

(5) Start-up power shall not be used by the generating station for the construction activities;

(6) The onus of proving that the interchange of infirm power from the unit(s) of the generating station is for the purpose of pre-commissioning activities, testing and commissioning, shall rest with the generating station and the concerned RLDC shall seek such information on each occasion of interchange of power before COD. For this, the generating station shall furnish to the concerned RLDC relevant details of the specific commissioning activity, testing and full load testing, its duration and intended period of interchange, etc.

(7) RLDC shall stop the drawl of the start-up Power in the following events:

(a) In case, it is established that the start-up power has been used by the generating station for construction activity;

(b) In case of default in payment of monthly transmission charges.

20. DATA TO BE FURNISHED PRIOR TO NOTICE OF TRIAL RUN

(1) The following details, as applicable, shall be furnished by each regional entity generating station 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

Description	Units
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
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

21. NOTICE OF TRIAL RUN

(1) The generating company proposing its generating station or a unit thereof for trial run or repeat of trial run shall give a notice of not less than seven (7) days to the concerned RLDC and the beneficiaries of the generating stations wherever identified. The concerned RLDC shall commence the trial run from the requested date or in case of any system constraints not later than seven (7) days from the proposed date of trial run. The trial run shall commence from the time and date as decided and informed by the concerned RLDC.

(2) In case the repeat trial run is to take place within twenty-four (24) hours of the failed trial run, fresh notice shall not be required.

(3) The transmission licensee proposing its transmission system or an element thereof for trial run shall give a notice of not less than seven days to the concerned RLDC and CTU.

22. TRIAL RUN OF GENERATING UNIT

(1) Trial Run of Thermal Generating Unit shall be carried out in accordance with following provisions:

(a) A thermal generating unit shall be in continuous operation at MCR for seventy-two (72) hours on designated fuel:

Provided that:

(i) short interruption or load reduction shall be permissible with corresponding increase in duration of the test;

(ii) interruption or partial loading may be allowed with the condition that the average load during the duration of trial run shall not be less than MCR excluding period of interruption but including the corresponding extended period;

(iii) cumulative interruption of more than four (4) hours shall call for a repeat of trial run.

(b) Where on the basis of the trial run, a thermal generating unit fails to demonstrate the unit capacity corresponding to MCR, the generating company has the option to de-rate the capacity of the generating unit or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall be not more than 95% of the demonstrated capacity, to cater for primary response.

(2) Trial Run of Hydro Generating Unit shall be carried out in accordance with following provisions:

(a) A hydro generating unit shall be in continuous operation at MCR for twelve (12) hours:

Provided that-

(i) any interruption shall call for a repeat of trial run;

(ii) partial loading may be allowed with the condition that the average load during the duration of trial run shall not be less than MCR;

(iii) if it is not possible to demonstrate the MCR due to insufficient reservoir or pond level or insufficient inflow, COD may be declared, subject to the condition that the same shall be demonstrated immediately when sufficient water is available after COD.

(b) Where on the basis of the trial run, a hydro generating unit fails to demonstrate the unit capacity corresponding to MCR, the generating company shall have the option to either de-rate the capacity or to go for repeat trial run. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall be not more than 90% of the demonstrated capacity to cater for primary response

(3) Trial Run of Wind / Solar / Storage / Hybrid Generating Station

(a) Successful trial run of a solar inverter unit(s) aggregating to 50 MW and above shall mean flow of power and communication signal for not less than the period between sunrise to sunset in a single day with the requisite metering system, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and its performance shall be corroborated with the solar irradiation recorded at site during the day and plant design parameters. For the trial run, a declaration shall be given by the generating company that no panel has been replaced or added or taken out or design of the plant has been altered:

Provided that:

(i) the output below the corroborated performance level with the solar irradiation of the day shall call for repeat of the trial run;

(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient solar irradiation, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient solar irradiation is available after COD.

(b) Successful trial run of a wind turbine(s) aggregating to 50 MW and above shall mean flow of power and communication signal for a period of not less than four (4) hours during periods of wind availability with the requisite metering system, telemetry and protection system in service. The generating company shall record the output of the unit(s) during the trial run and corroborate its performance with the wind speed recorded at site(s) during the day and plant design parameters:

Provided that-

(i) the output below the corroborated performance level with the wind speed of the day shall call for repeat of the trial run;

(ii) if it is not possible to demonstrate the rated capacity of the plant due to insufficient wind velocity, COD may be declared subject to the condition that the same shall be demonstrated immediately when sufficient wind velocity is available after COD.

(c) Successful trial run of a standalone Energy Storage System (ESS) shall mean one (1) cycle of charging and discharging of energy as per the design capabilities with the requisite metering, telemetry and protection system being in service.

(d) Successful trial run of a pumped storage plant shall mean one (1) cycle of turbo-generator and pumping motor mode as per the design capabilities upto the rated water drawing levels with the requisite metering, telemetry and protection system being in service.

(e) Successful trial run of a hybrid system shall mean successful trial run of individual source of hybrid system in accordance with the applicable provisions of these regulations.

(f) Where on the basis of the trial run, solar / wind / storage / hybrid generating station fails to demonstrate its rated capacity, the generating company shall have the option to either to go for repeat trial run or de-rate the capacity subject to a minimum aggregated de-rated capacity of 50 MW. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall be not more than 90% of the demonstrated capacity to cater for primary response.

23. TRIAL RUN OF INTER-STATE TRANSMISSION SYSTEM

(1) Trial run of a transmission system or an element thereof shall mean successful energisation of the transmission system or the element thereof at its nominal system voltage through interconnection with the grid for continuous twenty-four (24) hours flow of power and communication signal from the sending end to the receiving end and with requisite metering system, telemetry and protection system:

Provided that under exceptional circumstances and with the prior approval of CEA, a transmission element can be energized at lower nominal system voltage level.

24. DOCUMENTS AND TEST REPORTS PRIOR TO DECLARATION OF COMMERCIAL OPERATION

(1) Notwithstanding the requirements in other standards, codes and contracts, for ensuring grid security, the tests as specified in the following clauses shall be scheduled and carried out in coordination with NLDC and the concerned RLDC by the generating company or the transmission licensee, as the case may be, and relevant reports and other documents as specified shall be submitted to NLDC and the concerned RLDC before a certificate of successful trial run is issued to such generating company or the transmission licensee, as the case may be.

(2) Documents and Tests Required for Thermal (coal/lignite) Generating Stations:

(a) The generating company shall submit OEM documents for (i) performance characteristic curve for boiler, turbine and generator, (ii) starting time of unit in cold, warm and hot conditions, (iii) design ramp rate;

(b) The following tests shall be performed:

(i) Operation at a control load of fifty (50) percent of MCR as per the CEA Technical Standards for Construction for a sustained period of four (4) hours.

(ii) Ramp-up from fifty (50) percent of MCR to MCR at a ramp rate of at least one (1) percent of MCR per minute and sustained operation at MCR for one (1) hour.

(iii) Demonstrate overload capability with valve wide open as per the CEA Technical Standards for Construction and sustained operation at that level for at least five (5) minutes.

(iv) Ramp-down from MCR to fifty (50) percent of MCR at a ramp rate of at least one (1) percent of MCR per minute.

(v) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 60%, 75% and 100% load.

(vi) Reactive power capability as per the generator capability curve as provided by OEM considering over-excitation and under-excitation limiter settings.

(3) Documents and Tests Required for Hydro Generating Stations:

(a) The generating company shall submit OEM documents for turbine characteristics curve indicating the operating zone(s) and forbidden zone(s). In order to demonstrate operating flexibility of the generating unit, it shall be operated below and above the forbidden zone(s).

(b) The following tests shall be performed considering the water availability and head:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability.

(iv) Operation in synchronous condenser mode wherever designed.

(4) Documents and Test Required for Gas Turbine based Generating Stations:

(a) The generating company shall submit OEM documents for (i) starting time of unit in cold, warm and hot conditions (ii) design ramp rate.

(b) The following tests shall be performed:

(i) Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

(ii) Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

(iii) Black start capability up to 100 MW capacity wherever designed.

(iv) Operation in synchronous condenser mode wherever designed.

(5) Documents and Tests Required for the Generating Stations based on wind and solar resources:

(a) The generating company shall submit certificate confirming compliance to CEA Technical Standards for Connectivity.

(b) The following tests shall be performed:

(i) Frequency response of machines as per the CEA Technical Standards for Connectivity.

(ii) Reactive power capability as per OEM rating at the available irradiance or the wind energy, as the case may be.

(iii) Grid-forming capability, wherever provided, in inverter based units that may be used as black start resource.

(6) Documents and Tests Required for Energy Storage Systems:

(a) The ESS shall submit certificate confirming compliance to the CEA Technical Standards for Connectivity.

(b) The following tests shall be performed:

(i) Power output capability in MW and energy output capacity in MWh.

(ii) Frequency response of ESS.

(iii) Ramping capability as per design.

(7) Documents and Tests Required for HVDC Transmission System:

(a) The transmission licensee shall submit technical details including operating guidelines such as filter bank requirements at various operating loads and monopolar/ or bipolar configuration, reactive power controller, power demand overrides, run-back features, frequency controller, reduced voltage mode of operation and power oscillation damping.

(b) The following tests shall be performed:

(i) Minimum load operation.

(ii) Ramp rate.

(iii) Overload capability.

(iv) Black start capability in case of Voltage source convertor (VSC) HVDC.

(8) Documents and Tests Required for SVC/STATCOM

(a) The transmission licensee shall submit technical particulars including operating guidelines such as number of blocks and rating of each block, single line diagram, V/I characteristics, rating of coupling transformer, MSR/MSC design parameters, different operating modes, IEEE standard Model, Power Oscillation Damping (POD) enabled and tuned (if not then reasons for same) and the results of Offline simulation-based study to validate the performance of POD.

(b) The following tests shall be performed to validate full reactive power capability of SVC and STATCOM in both the directions i.e. absorption as well as injection mode:

(i) POD performance test.

(ii) dynamic performance testing.

25. CERTIFICATE OF SUCCESSFUL TRIAL RUN

(1) In case any objection is raised by a beneficiary in writing to the concerned RLDC with copy to all concerned regarding the trial run within two (2) days of completion of such trial run, the concerned RLDC shall, within five (5) days of receipt of such objection, in

coordination with the concerned entity and the beneficiaries, decide if the trial run was successful or there is a need for repeat trial run.

(2) After completion of successful trial run and receipt of documents and test reports as per Regulation 24 of these regulations, the concerned RLDC shall issue a certificate to that effect to the concerned generating station, ESS or transmission licensee, as the case may be, with a copy to their respective beneficiary(ies).

26. Declaration by Generating Company and Transmission Licensee

(1) Thermal Generating Station

(a) The generating company shall certify that:

(i) The generating station or unit thereof meets the relevant requirements and provisions of the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations, as applicable.

(ii) The main plant equipment and auxiliary systems including balance of plant such as fuel oil system, coal handling plant, DM plant, pre-treatment plant, fire-fighting system, ash disposal system and any other site specific system have been commissioned and are capable of full load operation of the units of the generating station on sustained basis.

(iii) Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of unit have been put in service.

(b) The certificates as required under clause (a) of this Regulation shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the generating company and shall be submitted to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD.

(2) Hydro Generating Station

(a) The generating company shall certify that:

(i) The generating station or unit thereof meets the requirement and relevant provisions of the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations, as applicable.

(ii) The main plant equipment and auxiliary systems including drainage de-watering system, primary and secondary cooling system, LP and HP air compressor and firefighting system have been commissioned and are capable for full load operation of units on sustained basis.

(iii) Permanent electric supply systems including emergency supplies and all necessary Instrumentations Control and Protection Systems and auto loops for full load operation of the unit are put into service.

(b) The certificates as required under clause (a) of this Regulation shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the generating company and shall be submitted to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD.

(3) Transmission system

(a) The transmission licensee shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD of the company to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD that the transmission line, sub-station and communication system conform to the CEA Technical Standards for Construction, CEA Technical

Standards for Connectivity, CEA Technical Standards for Communication and these regulations and are capable of operation to their full capacity.

(4) Wind, Solar, Storage, and Hybrid Generating Station

(a) The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the concerned RLDC and to the Member Secretary of the concerned RPC before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity, CEA Technical Standards for Communication and these regulations.

27. DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD)

(1) A generating station or unit thereof or a transmission system or an element thereof or ESS may declare commercial operation as follows and inform CEA, the concerned RLDC, the concerned RPC and its beneficiaries:

(a) Thermal Generating Station or a unit thereof

(i) The commercial operation date in case of a unit of the thermal generation station shall be the date declared by the generating company after successful trial run at MCR or de-rated capacity as per Regulation 22 (1)(b), as the case may be, and submission of declaration as per Regulation 26(1) of these regulations.

(ii) In case of the generating station, the COD of the last unit of the generating station shall be considered as the COD of the generating station.

(b) Hydro Generating Station

(i) The commercial operation date in case of a unit of the hydro generating station including pumped storage hydro generating station shall be the date declared by the generating station after after successful trial run at MCR or de-rated capacity as per Regulation 22(2)(b), as the case may be, and submission of declaration as per Regulation 26(2) of these regulations.

(ii) In case of the generating station, the COD of the last unit of the generating station shall be considered as the COD of the generating station.

(c) Transmission System

(i) The commercial operation date in case of an Inter-State Transmission System or an element thereof shall be the date declared by the transmission licensee on which the Transmission System or an element thereof is in regular service at 0000 hours after successful trial operation for transmitting electricity and communication signal from the sending end to the receiving end as per Regulation 23 and submission of declaration as per Regulation 26(3) of these regulations :

Provided that the commercial operation date of a 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:

Provided further that where only some of the transmission elements of the ATS have achieved successful trial run and the Connectivity grantee under GNA Regulations seeks commercial operation of such element for utilization by such grantee and is agreed by the Central Transmission Utility,—the commercial operation date of such transmission elements of the ATS may be declared by the transmission licensee as per this Regulation:

Provided also that where only some of the transmission element(s) of the ATS have achieved successful trial run and if the operation of such transmission elements are certified by the concerned Regional Power Committee(s) for improving the performance, safety and security of the grid, the commercial operation date of such transmission element(s) of the ATS may be declared by the transmission licensee as per this Regulation:

Provided also that in case a transmission system or an element thereof executed under regulated tariff mechanism is prevented from regular service on or after the scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate petition along with a certificate from the CTU to the effect that the transmission system is complete as per the applicable CEA Standards, for approval of the commercial operation date of such transmission system or an element thereof:

Provided also that in case of inter-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee may declare deemed COD of the ISTS in accordance with the provisions of the Transmission Service Agreement after obtaining a certificate from the CTU to the effect that the transmission system is complete as per the specifications of the bidding guidelines and applicable CEA Standards.

(ii) The COD of a transmission element of the transmission system under Tariff Based Competitive Bidding shall be declared only after declaration of COD of all the pre-required transmission elements as per the Transmission Services Agreement :

Provided that in case any transmission element is required in the interest of the power system as certified by concerned RPC(s), the COD of the said transmission element may be declared prior to the declaration of COD of its pre-required transmission elements.

(d) Communication System

Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the transmission licensee from 0000 hour of which a communication system or element thereof shall be put into service after completion of site acceptance test including transfer of voice and data to the respective control centres as certified by the respective Regional Load Despatch Centre.

(e) Generating Stations based on Wind and Solar resources; ESS and Hybrid Generating Station

(i) The commercial operation date in case of units of a renewable generating station aggregating to 50 MW and above shall mean the date declared by the generating station after undergoing successful trial run as per clause (3) of Regulation 22 of these regulations,submission of declaration as per clause (4) of Regulation 26 of these regulations, and subject to fulfilment of other conditions, if any as per PPA.

(ii) In case of a generating station as a whole, the commercial operation date of the last unit of the generating station shall be considered as the COD of the generating station.

(2) Scheduling of generating station or unit thereof shall start from 0000 hours of the Commercial Operation Date of the said generating station or unit thereof.

CHAPTER 6

OPERATING CODE

28. OPERATING PHILOSOPHY

(1) All entities such as NLDC, RLDCs, SLDCs, CTU, STUs, RPCs, power exchanges, QCAs, SNAs, licensees, generating stations and other grid connected entities shall at all times function in coordination to ensure stability and resilience of the grid and achieve maximum economy and efficiency in operation of power system.

(2) Operation of the State grid shall be monitored by the respective SLDC. Operation of the regional grid shall be monitored by the respective RLDC. Operation of the National grid shall be monitored by NLDC.

(3) Detailed Operating Procedures for the National grid shall be developed, maintained and updated by NLDC in consultation with RLDCs and relevant stakeholders and shall be kept posted on NLDC's website.

(4) Detailed Operating Procedures for each regional grid shall be developed, maintained and updated by respective RLDCs in consultation with NLDC, concerned RPC and regional entities and shall be kept posted on the respective RLDC's website.

(5) Detailed Operating Procedures for each State grid shall be developed, maintained and updated by the SLDCs, consistent with the Detailed Operating Procedures of respective RLDC.

(6) NLDC, RLDCs and SLDCs shall have qualified operating personnel manning the control room round the clock.

(7) Every generating station and transmission substation of 132 kV and above shall have a control room manned by qualified operating personnel round the clock. Alternatively, the same may be operated round the clock from a remotely located control room, subject to the condition that such remote operation does not result in delay in execution of any switching instructions and information flow:

Provided that a transmission licensee owning a transmission line but not owning the connected substation, shall have a round the clock coordination centre.

(8) SNA and QCA shall have round the clock coordination centres manned by qualified personnel for operational coordination with the concerned load despatch centres and generating stations.

29. SYSTEM SECURITY

(1) All users shall operate their respective power systems in an integrated manner at all times in coordination with the concerned load despatch centres.

(2) Isolation, Taking out of service and Switching off of an element of the grid:

(a) No element(s) of the grid shall be isolated from the grid, except (i) during emergency as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be, where such isolation would prevent a total grid collapse or would enable early restoration of power supply; (ii) for safety of human life; (iii) when serious damage to a costly equipment is imminent and such isolation would prevent it; and (iv) when such isolation is specifically instructed by NLDC or RLDC or SLDC, as the case may be.

(b) Each RLDC, in consultation with CTU, the concerned users, SLDCs, STUs, shall prepare a list of important elements in the regional grid, including those in the State grids which are critical for regional grid operation and shall make available the said list to all concerned.

(c) An important element of the grid as listed at Clause (b) of this Regulation can be taken out of service only after prior clearance of the concerned RLDC, except under emergency as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be. RLDC shall inform opening or removal of any such important element (s) of the regional grid to NLDC and to the concerned regional entities who are likely to be affected, as specified in the Detailed Operating Procedure of NLDC.

(d) In case of switching off or tripping of any of the important elements of the regional grid under emergency conditions or otherwise, it shall be intimated immediately by the users with available details (i) to SLDC if the element is within the control area of SLDC, who in turn shall intimate the concerned RLDC and (ii) to RLDC if the element is within the control area of RLDC. The reasons for such switching off or tripping to the extent determined and the likely time of restoration shall also be intimated within half an hour. The concerned RLDC or SLDC and the users shall ensure restoration of such elements within the estimated time of restoration as intimated.

(e) The isolated, taken out or switched off elements shall be restored as soon as the system conditions permit. The restoration process shall be supervised by RLDC, in co-ordination with NLDC and concerned SLDC(s) in accordance with system restoration procedures of NLDC and RLDC(s).

(3) Maintenance of grid elements shall be carried out by the respective users, transmission licensees, STUs and CTU in accordance with the provisions of the Central Electricity Authority (Grid Standards) Regulations, 2010. Outage of any element which is causing or likely to cause danger to the grid or sub-optimal operation of the grid shall be monitored by the concerned RLDC. RLDC shall report such outages to RPC and RPC shall issue suitable instructions to restore such elements in a specified time period.

(4) Except under an emergency, or when it becomes necessary to prevent an imminent damage to a costly equipment, no user shall suddenly reduce its generating unit output by more than 100 (one hundred) MW [20 (twenty) MW in case of NER] without prior permission of the respective RLDC.

(5) Except under an emergency, or when it becomes necessary to prevent an imminent damage to a costly equipment, no user shall cause a sudden variation in its load by more than 100 (one hundred) MW without prior permission of the respective RLDC.

(6) All generating units shall have their automatic voltage regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers and any other requirement in operation, as per CEA Technical Standards for Connectivity. If a generating unit with capacity higher than 50 (fifty) MW is required to be operated without its AVR in service, the generating station shall immediately intimate to the concerned RLDC along with the reasons thereof and the likely duration of such operation and obtain its permission.

(7) The tuning, including for low and high voltage ride through capability of wind and solar generators or any other requirement as per CEA Technical Standards for Connectivity 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 or fault level changes near the generating plant as reported by NLDC or RLDC(s), as the case may be.

(8) 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.

(9) Provisions of protection and relay settings shall be coordinated periodically throughout the regional grid, as per plan finalized by the respective RPC in accordance with the Protection, Testing and Commissioning Code of these regulations.

(10) RPCs shall prepare the islanding schemes in accordance with Central Electricity Authority (Grid Standards) Regulations, 2010 for identified generating stations, cities and locations and ensure its implementation. The islanding schemes shall be reviewed and augmented depending on assessment of critical loads at least once in 3 (three) years.

(11) Mock drill of the islanding schemes shall be carried out annually by the respective RLDCs in coordination with the concerned SLDCs and other users involved in the islanding scheme.

(12) All distribution licensees, STUs and bulk consumers shall provide automatic under-frequency relays (UFR) and df/dt relays for load shedding in their respective systems to arrest frequency decline that could result in grid failure as per the plan given by the RPCs from time to time. The default UFR settings shall be as specified in Table-2 below:

Table 2: Default UFR Settings

Sr. No.	Stage of UFR Operation	Frequency (Hz)
1	Stage-1	49.40
2	Stage-2	49.20
3	Stage-3	49.00
4	Stage-4	48.80
Note 1: All states (or STUs) shall plan UFR settings and *df/dt* load shedding schemes depending on their local load generation balance in coordination with and approval of the concerned RPC. Note 2: Pumped storage hydro plants operating in pumping mode or ESS operating in charging mode shall be automatically disconnected before the first stage of UFR.		

The load shedding for each Stage of UFR operation, in percentage of demand or MW shall be as finalised by the respective RPCs.

(13) The following shall be factored in while designing and implementing the UFR and *df/dt* relay schemes:

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(a) The under-frequency and *df/dt* load shedding relays are always functional.

(b) Demand disconnection shall not be set with any time delay in addition to the operating time of the relays and circuit breakers.

(c) There shall be uniform spatial spread of feeders selected for UFR and *df/dt* disconnection.

(d) SLDC shall ensure that telemetered data of feeders (MW power flow in real time and circuit breaker status) on which UFR and *df/dt* relay are installed is available at its control centre. SLDC shall monitor the combined load in MW of these feeders at all the time. SLDC shall share the above data with the respective RLDC in real time and submit monthly exception report to the respective RPC. RLDC shall inform SLDCs as well as the concerned RPC on quarterly basis, durations during the quarter when combined load in MW of these feeders was below the level considered while designing UFR scheme by the RPC. SLDC shall take corrective measures within a reasonable period and inform the respective RLDC and RPC.

(e) RPC shall undertake monthly review of UFR and df/dt scheme and also carry out random inspection of the under-frequency relays. RPC shall publish such monthly review along with exception report on its website.

(14) NLDC, RLDCs, SLDCs, CTU, STUs or users may identify the requirement of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system to operate the transmission system within operating limits and to protect against situations such as voltage collapse, cascade tripping and tripping of important corridors/flow-gates. Any such SPS at the intra-regional level shall be finalized by the concerned RPC. SPS at inter-regional level and cross-border level

shall be finalized by NLDC in coordination with the concerned RPCs. SPS shall be installed and commissioned by the concerned users. SPS shall always be kept in service. If any SPS at intra-regional level is to be taken out of service, permission of the concerned RLDC shall be required. If any SPS at inter-regional level and cross-border level is to be taken out of service, permission of NLDC shall be required.

(15) NLDC, RLDCs, SLDCs, CTU, STUs and users shall operate in a manner to ensure that the steady state grid voltage as per the Central Electricity Authority (Grid Standards) Regulations, 2010 remains within the following operating range:

TABLE 3: VOLTAGE RANGE

Voltage (kV rms)		
Nominal	**Maximum**	**Minimum**
765	800	728
400	420	380
220	245	198
132	145	122
110	121	99
66	72	60
33	36	30

(16) NLDC, RLDCs and SLDCs, as the case may be, shall take appropriate measures to control the voltage as per their operating procedure.

(17) Transmission licensees and distribution licensees shall implement defense mechanisms as finalized by the respective RPCs to prevent voltage collapse and cascade tripping.

30. FREQUENCY CONTROL AND RESERVES

(1) The National Reference Frequency shall be 50.000 Hz and shall be measured with a resolution of +/-0.001 Hz. The frequency data measured at every second shall be archived by RLDCs.

(2) The NLDC, RLDC and SLDC shall ensure that the grid frequency remains close to 50 Hz. and ensure that the frequency is restored within the allowable band of 49.95-50.05 Hz at the earliest.

(3) All users shall adhere to their schedule of injection or drawl, as the case may be, and take such action as required under these regulations and as directed by NLDC or respective RLDCs or respective SLDCs so that the grid frequency is maintained and remains within the allowable band.

Reserves

(4) There shall be reserves as under:

(a) Primary, Secondary and Tertiary reserves:

(i) Primary, Secondary and Tertiary reserves shall be deployed for the purpose of frequency control, reducing area control error and relieving congestion.

(ii) The response under Primary reserve shall be provided as per these regulations.

(iii) Secondary reserves including automatic generation control and demand response shall be deployed by a control area as per these regulations or the Ancillary Services Regulations, as the case may be.

(iv) Tertiary reserves shall be deployed by a control area as per these regulations or the Ancillary Services Regulations, as the case may be.

(b) Black Start reserves:

Generating stations having black start capability shall be identified by NLDC and RLDCs to act as black start reserves.

(c) Voltage Control reserves:

Voltage Control reserves shall be deployed for controlling the voltage at a bus through reactive power injection or drawl.

(5) The reserves shall be operated as Ancillary Services, namely (a) Primary Reserve Ancillary Service (PRAS); (b) Secondary Reserve Ancillary Service (SRAS); (c) Tertiary Reserve Ancillary Service (TRAS); (d) Black Start Ancillary Services; and (e) Voltage Control Ancillary Services.

(6) The mechanism of procurement and deployment of PRAS shall be as specified in these regulations or in the Ancillary Services Regulations, as the case may be.

(7) The mechanism of procurement, deployment and payment of SRAS and TRAS shall be as specified in the Ancillary Services Regulations.

(8) The primary response of the generating units shall be verified by the LDCs during grid events.

Control Hierarchy

(9) Inertia:

The power system shall be operated at all the times with a minimum inertia to be stipulated by NLDC so that minimum nadir frequency post reference contingency stays above the threshold set for under frequency load shedding (UFLS). NLDC shall reschedule generation including curtailment of wind, solar and wind-solar hybrid generation, if required, in coordination with the respective RLDCs and SLDCs to maintain the minimum inertia.

(10) Primary Control:

(a) Primary control is 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. Primary control is the immediate automatic control implemented through turbine speed governors or frequency controllers.

(b) Primary control shall be provided by Primary Reserves Ancillary Service (PRAS).

(c) The minimum quantum of PRAS required for reference contingency shall be declared by NLDC at the start of each financial year.

(d) The generating stations and units thereof shall have the electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity and are mandated to provide PRAS.

(e) NLDC may also identify other resources such as ESS and demand resource to provide PRAS for which PRAS Providers shall be compensated in accordance with the Ancillary Services Regulations.

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

(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.

(k) The PRAS shall start immediately (within two seconds) when the frequency deviates beyond the dead band as specified in clause (i) of this Regulation and provide its full PRAS capacity obligation within 30 seconds and shall sustain up to five (5) minutes.

(l) Each control area shall assess its frequency response characteristics and share assessment with the concerned RLDC along with high resolution data of at least 1 (one) second for regional entity generating stations and energy storage systems and 10 (ten) seconds for state control area.

(m) The concerned RLDC shall calculate actual frequency response characteristic of all the control areas within its region. The performance of each control area in providing frequency response characteristic shall be calculated for each reportable event as per Annexure-2.

(n) The NLDC in consultation with RLDCs shall calculate actual frequency response characteristic at national level by factoring in FRC of all regions and shall also calculate FRC for cross border control areas.

(o) NLDC, RLDCs and SLDCs shall grade the median Frequency Response Performance annually, considering at least 10 reportable events. In case the median Frequency Response Performance is less than 0.75 as calculated as per Annexure-2, NLDC, RLDCs, SLDCs, as the case may be, after analyzing the FRP shall direct the concerned entities to take corrective action.

(11) Secondary Control:

(a) Secondary control is a centralized automatic function to regulate the generation or load in a control area to restore the frequency within the allowable band or replenish deployed primary reserves.

(b) Secondary Control shall be provided by a generating station or an entity having energy storage resource or an entity capable of providing demand response, on standalone or aggregated basis, connected to inter-State transmission system or intra-State transmission system, as Secondary Reserve Ancillary Service (SRAS) Provider, as specified in the Ancillary Services Regulations.

(c) Secondary control signals shall be automatically generated from NLDC and shall be transmitted to SRAS Providers through the concerned RLDC exercising the control area jurisdictions for desired automated response when the Area Control Error (ACE) goes beyond the minimum threshold limit of ±10 MW, which may be reviewed from time to time based on review of performance of SRAS.

Provided that as and when bi-directional communication system of SRAS providers with RLDCs is fully established, secondary control signals shall be automatically generated from the respective RLDC.

(d) ACE of each State or Regional control, shall be auto calculated at the control centre of NLDC or RLDC or SLDC, as the case may be, based on telemetered values, and external inputs, namely, the Frequency Bias Coefficient and Offset referred to in clauses (e) and (f) respectively of this Regulation as per the following formula:

$$ACE = (I_a - I_s) - 10 * B_f * (F_a - F_s) + Offset$$

Where,

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

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

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

F_a = Actual system frequency in Hz

F_s = Schedule system frequency in Hz

Offset = Provision for compensating measurement error

(e) Frequency Bias Coefficient (B_f) shall be assessed and declared by NLDC in coordination with RLDC for each region. Frequency Bias Coefficient (B_f) shall be assessed and declared by SLDC for each State. Frequency Bias Coefficient shall normally be based on median Frequency Response Characteristics (FRC) during previous financial year of each control area and refined from time to time.

(f) Offset shall be used to account for measurement errors and shall be decided by NLDC or RLDC or SLDC, as the case may be, for its respective control area.

(g) Secondary control may be operated under tie-line bias control, flat frequency control or flat tie-line control mode depending on grid requirements:

Provided that NLDC in coordination with RLDC and SLDC shall lay down in its Detailed operating procedure after stakeholder consultation, the conditions during which a particular mode shall be chosen and shall document the reasons for operating in a particular mode:

Provided further that the coordinated operation of AGC by the nested control areas shall be adopted based on mutually agreed protocols.

(h) Schedule system frequency (Fs) shall be reference frequency of 50 Hz unless otherwise specified by NLDC under certain conditions to be recorded in writing.

(i) RLDCs and SLDCs shall compute the ACE of the respective regional or state control area in real time based on telemetered data. ACE data shall be archived at the interval of 10 seconds or lower. RLDCs shall share the data with NLDC.

(j) The SRAS Providers shall start responding to SRAS signals within thirty (30) seconds and shall be capable of providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining at least for the next thirty (30) minutes.

The secondary reserves shall be gradually replaced by tertiary reserves within 30 minutes.

(k) With due regard to the requirement of planning reserve margin and resource adequacy referred to in clause (3) 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.

(l) Unless otherwise specified by the concerned SERC, the methodology specified in clause (k) of this Regulation shall be adopted by the SLDCs to estimate the secondary reserve capacity in their respective control areas.

(m) The reserve capacity as per the methodology mentioned in clause (k) of this Regulation shall be estimated by 15th February every year for next financial year and submitted to NLDC.

(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.

(p) Each State control area shall ensure availability of the quantum of secondary reserve at the State control area on day ahead basis with due regard to the secondary reserves estimated and allocated for that State by NLDC in terms of clause (o) of this Regulation, and inform the same to the concerned RLDC and NLDC.

(q) NLDC through RLDCs shall re-assess the quantum of requirement of secondary reserve at the state control area and regional level on day ahead basis and also on real time basis, with due regard inter alia to the secondary reserve maintained at State control area and the need to replenish primary reserves, as specified in the Ancillary Services Regulations.

(r) If a State falls short of maintaining secondary reserve capacity as allocated to it in terms of clause (o) of this Regulation, the NLDC through RLDC shall procure such Secondary reserve capacity on behalf of the State and allocate the cost of procurement of such capacity on that State based on the methodology specified in the Ancillary Service Regulations.

(s) Secondary reserves shall be procured by the NLDC from a generating station or an entity having energy storage resource or an entity capable of providing demand response, on standalone or aggregated basis, connected to inter-State transmission system or intra-State transmission system in accordance with the Ancillary Services regulations.

(t) All thermal and hydro generating stations shall make arrangements to enable automatic operation of plant from the appropriate load despatch centre by integrating the controls and tele-metering features of their system into the automatic generation control in accordance with the CEA Technical Standards for Construction and the CEA Technical Standards for Connectivity. The communication system shall be established in accordance with the CEA Communication Regulations.

(u) All renewable energy generating stations and ESS shall be enabled with frequency controller to provide secondary control in accordance with the CEA Connectivity Standards and the communication system shall be established in accordance with the CEA Technical Standards for Communication.

(v) SRAS shall have bi-directional communication system along with metering and SCADA telemetry in place as per the requirement stipulated in the Detailed Procedure issued under Ancillary Service Regulations.

(12) Tertiary Control:

(a) Tertiary reserves requirement for the regional control area and the State control area, shall be estimated by NLDC with due regard inter alia to the requirement of planning reserve margin and resource adequacy as referred to in Clause (3) of Regulation 5 of these regulations, so as to take care of contingencies and to cater to the need for replacing secondary reserves estimated at sub-clause (n) of clause (11) of this Regulation by 1st March every year, which will be implemented for the next financial year from 1st April onwards by the respective control areas.

(b) NLDC shall allocate such tertiary reserves capacity, to be maintained at regional control area and state control area, based on the estimated reserves as per these regulations and publish the information on its website by 1st March every year.

(c) Each State control area shall ensure availability of the quantum of tertiary reserve at the State control area on day ahead basis with due regard to the tertiary reserves estimated and allocated for that State by NLDC in terms of sub-clause (b) of clause (12) of this Regulation, and inform the same to concerned RLDC and NLDC.

(d) NLDC through RLDCs shall re-assess the quantum of requirement of tertiary reserve at the state control area and regional level on day ahead basis and also on real time basis, with due regard to estimation inter alia to tertiary reserve maintained at State control area and the need of replacing secondary reserves, as specified in the Ancillary Services Regulations.

(e) If a State falls short of maintaining tertiary reserve capacity as allocated to it in terms of sub-clause (d) of clause (12) of this Regulation, the NLDC through RLDCs shall procure such tertiary reserve capacity on behalf of this State and allocate the cost of procurement of such capacity to that State based on the methodology specified in the Ancillary Services Regulations.

(f) Tertiary reserves shall be procured by the NLDC from a generating station or an entity having energy storage resource or an entity capable of providing demand response, on standalone or aggregated basis, connected to inter-State transmission system or intra-State transmission system in accordance with the Ancillary Services regulations.

(g) Tertiary reserves to be provided by TRAS provider shall be capable of providing TRAS within fifteen (15) minutes of despatch 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 despatch 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.

(h) The quantum of reserves procured by each State control area shall be informed to the concerned RLDC.

(13) The control area wise performance of SRAS and TRAS shall be evaluated in accordance with the Detailed Procedure prepared by NLDC.

31. OPERATIONAL PLANNING

(1) Time Horizon

(a) Operational planning shall be carried out in advance by NLDC, RLDCs and SLDCs within their respective control areas with Monthly and Yearly time horizons in co-ordination with CTU, RPCs or STUs, as applicable.

(b) Operational planning shall be carried out in advance by NLDC, RLDCs and SLDCs within their respective control areas on Intra-day, Day Ahead, Weekly time horizons.

(c) RLDCs in consultation with NLDC shall issue procedure and formats for data collection to carry out :

(i) Operational planning analysis,

(ii) Real-time monitoring,

(iii) Real-time assessments.

(d) SLDC may also issue procedure and format for data collection for above purposes.

(2) Demand Estimation

(a) Each SLDC shall carry out demand estimation as part of operational planning after duly factoring in the demand estimation done by STU as part of resource adequacy planning referred to in clause (2) of Regulation (5) of these regulations. Demand estimation by SLDC shall be for both active power and reactive power incident on the transmission system based on the details collected from distribution licensees, grid-connected distributed generation resources, captive power plants and other bulk consumers embedded within the State.

(b) Each SLDC shall develop methodology for daily, weekly, monthly, yearly demand estimation in MW and MWh for operational analysis as well as resource adequacy purposes. Each SLDC, while estimating demand may utilize state of the art tools, weather data, historical data and any other data. For this purpose, all distribution licensees shall maintain historical database of demand.

(c) The demand estimation by each SLDC shall be done on day ahead basis with time block wise granularity for the daily operation and scheduling. In case, SLDC observes major change in demand in real time for the day, it shall immediately submit the revised demand estimate to concerned RLDC for demand estimate correction.

(d) Each SLDC shall submit node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand in MW and MVAr on monthly and quarterly basis for the nodes 132 kV and above for preparation of scenarios for computation of TTC and ATC by the concerned RLDC and NLDC.

(e) SLDC shall also estimate peak and off-peak demand (active as well as reactive power) on weekly and monthly basis for load - generation balance planning as well as for operational planning analysis, which shall be a part of the operational planning data. The demand estimates mentioned above shall have granularity of a time block. The estimate shall cover the load incident on the grid as well as net load incident taking into account embedded generation in the form of roof-top solar and other distributed generation.

(f) Based on the demand estimate furnished by the SLDCs, each RLDC shall prepare the regional demand estimate and submit to NLDC. NLDC, based on regional demand estimate furnished by RLDCs, shall prepare national demand estimate.

(g) Timeline for submission of demand estimate data by SLDCs to respective RLDC and RPC shall be as follows:

TABLE 5: TIMELINE FOR DEMAND ESTIMATION

Daily demand estimation	10:00 hours of previous day
Weekly demand estimation	First working day of previous week
Monthly demand estimation	Fifth day of previous month
Yearly demand estimation	31^{st} August of the previous year

(h) SLDCs, RLDCs and NLDC shall compute forecasting error for daily, day-ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce forecasting error in future. The computed forecasting errors shall be made available by SLDCs, RLDCs and NLDC on their respective websites.

(3) Generation Estimation

(a) The modalities of generation estimation by entities shall be as per the Procedure referred to in sub-clause (c) of clause (1) of Regulation 31 of these regulations.

(b) RLDC shall forecast generation from wind and solar generating stations which are regional entities for different time horizons as referred to in clause (1) of Regulation 31 of these regulations for the purpose of operational planning.

(4) Adequacy of Resources

(a) SLDCs shall estimate and ensure adequacy of resources, identify generation reserves, demand response capacity and generation flexibility requirement with due regard to the long term resource adequacy framework as specified in Regulation 5 of these regulations.

(b) SLDCs shall furnish time block-wise information for the following day in respect of all intra-state entities to the concerned RLDC who shall validate adequacy of resources with due regard to the following:

(i) Demand forecast aggregated for the control area;

(ii) Renewable energy generation forecast for the control area;

(iii) Injection schedule for intra-State entity generating station;

(iv) Requisition from regional entity generating stations.

32. OUTAGE PLANNING

(1) Outage planning shall be prepared for the grid elements in a coordinated and optimal manner keeping in view the system operating conditions and grid security. The coordinated generation and transmission outage plan for the national and regional grid shall take into consideration all the available generation resources, demand estimates, transmission constraints, factoring in water for irrigation requirements, if any. To optimize the transmission outages of the national and regional grids, to avoid grid operation getting adversely affected and to maintain system security standards, the outage plan shall also take into account the generation outage schedule and transmission outage schedule.

(2) Annual outage plan shall be prepared as follows:

(a) Annual outage plan of grid elements shall be prepared in advance for the financial year by the RPCs in consultation with the users, respective RLDCs and NLDC and reviewed before every quarter and every month.

(b) Annual outage plan shall be prepared in such a manner as to minimize the overall downtime, particularly where multiple entities are involved in outage of any grid element(s).

(c) The outage plan of hydro generation plant, wind and solar generation plant and its associated evacuation network shall be prepared with a view to extract maximum generation from these sources.

Example: Outage of wind generator shall be planned during lean wind season. Outage of solar generator, if required, shall be planned during the rainy season. Outage of hydro generator could be planned during the lean water season.

(d) Protection relay related outages, auto–re-closure outages and SPS testing outages shall be planned on monthly basis with prior permission of the concerned RPC, which shall consult the concerned RLDC & NLDC.

(3) Outage Planning Process shall be as follows:

(a) RPCs shall prepare and finalize the annual outage plan for the next financial year in respect of grid elements of their respective regional grid.

(b) RPCs shall prepare LGBR based on the LGBR submitted by SLDCs for their respective states and shall prepare annual outage plan for generating units and transmission elements in their respective region after carrying out necessary system studies in order to ensure system security and resource adequacy.

(c) RPCs shall finalize the outage plans in consultation with NLDC and respective RLDCs. The final outage plan and the final LGBR shall be intimated to NLDC, concerned RLDC, Users, STUs, CTU, the generating stations connected to the ISTS.

The final outage plan and the final LGBR shall be made available on the websites of the respective users, RPCs, RLDCs and NLDC.

(d) The timeline for Outage Planning Process shall be as follows:

TABLE 6: TIMELINE FOR OUTAGE PLANNING PROCESS

Activity	**Agency**	**Cut-off date**
Submission of proposed outage plan for the next financial year to RPC with the earliest start date and latest finishing date	CTU, STUs, transmission licensees and generating stations	31st October
Submission of LGBR of the control area to RPC for both peak and off-peak scenarios	SLDC	31st October
Publishing draft LGBR and draft outage plan of regional grid for next financial year on the concerned RPC's website for inviting suggestions, comments, objections etc of stakeholders.	RPC	30th November
Publishing final LGBR and final outage plan of regional grid for next financial year on the concerned RPC's website	RPC	31st December

(e) The annual outage plan shall be reviewed by RPC on monthly and quarterly basis in coordination with all the parties concerned, and adjustments shall be made wherever necessary.

(f) All users, CTU, STUs, licensees shall follow the annual outage plan. If any deviation is required, the same shall be allowed only with prior permission of the concerned RPC, which shall consult the concerned RLDC and NLDC.

(g) Each user shall obtain the final clearance from NLDC or the concerned RLDC, prior to the planned outage of any grid element. All deviations from the outage plan shall be uploaded on the RPC website.

(h) In case of grid disturbances, system isolation, partial black-out in a State or any other event in the system that may have an adverse impact on the system security due to proposed outage,

(i) NLDC or RLDC, as the case may be, shall have the authority to defer the planned outage;

(ii) SLDC, RLDC or NLDC, as the case may be, before giving clearance of the planned outage may conduct studies again.

(4) To facilitate coordinated planned outages of grid elements, a common outage planning procedure shall be formulated by each RPC in consultation with NLDC and concerned RLDC.

33. OPERATIONAL PLANNING STUDY

(1) Based on the operational planning analysis data, operational planning study shall be carried out by various agencies for time horizons as under:

TABLE 7: TIME HORIZON FOR OPERATIONAL PLANNING STUDY

Time horizon of operational planning study	Agency	Means for carrying out study
Real time and Intra-day	NLDC, RLDC, and SLDC	At least fifteen (15) minutes interval using online/offline SCADA/EMS system
Day-ahead	NLDC, RLDC, and SLDC	For various operating conditions using offline tools
Weekly	NLDC, RLDC, and SLDC	For various operating conditions using offline tools
Monthly/Yearly	RPC	For various operating conditions using offline tools

(2) SLDCs, RLDCs and NLDC shall utilize network estimation tool integrated in their EMS, and SCADA system for the real time operational planning study. All users shall

make available at all times real time error free operational data for successful execution of network analysis using EMS/SCADA. Failure to make available such data shall be immediately reported to the concerned SLDC, the concerned RLDC and NLDC along with firm timeline for restoration. The performance of online network estimation tools at SLDC and RLDC shall be reviewed in the monthly operational meeting of RPC. Any telemetry related issues impacting the online network estimation tool shall be monitored by RPC for its early resolution.

(3) SLDCs shall perform day-ahead, weekly, monthly and yearly operational study for the concerned State for:

(a) assessment and declaration of total transfer capability (TTC) and available transfer capability (ATC) for import or export of electricity by the State. TTC and ATC shall be revised from time to time based on commissioning of new elements and other grid conditions and shall be published on SLDC website with all the assumptions and limiting constraints;

(b) planned outage assessment;

(c) special scenario assessment;

(d) system protection scheme assessment;

(e) natural disaster assessment; and

(f) any other study relevant in operational scenario.

(4) RLDCs and NLDC shall perform day-ahead, weekly, monthly and yearly operational study for:

(a) assessment of TTC and ATC at inter-regional, intra-regional and inter-state level;

(b) planned outage assessment;

(c) special scenario assessment;

(d) system protection scheme assessment;

(e) natural disaster assessment; and

(f) any other study relevant in operational scenario

(5) RLDC shall assess intra-regional and inter-state level TTC and ATC and submit to NLDC. NLDC shall declare TTC and ATC for import or export of electricity between regions including simultaneous import or export capability for a region and cross-border interconnections 11 (Eleven) months in advance for each of the month on a rolling basis. TTC and ATC shall be revised from time to time based on commissioning of new elements and other grid conditions and shall be published on the websites of NLDC and respective RLDCs with all the assumptions and limiting constraints.

(6) Operational planning study shall be done to assess whether the planned operations shall result in deviations from any of the system operational limits defined under these regulations and applicable CEA Standards.

(7) NLDC, RLDCs, RPCs and SLDCs shall maintain records of the completed operational planning study, including dated power flow study results, operational plan and minutes of meetings on operational study.

(8) NLDC, RLDCs, RPCs and SLDCs shall have operating plans to address potential deviations of system operational limit identified as a result of the operational planning study. These operating plans shall be intimated to users in advance to take corrective measures. In case any user is unable to adhere to such operating plan, it

shall intimate the respective SLDC, RLDC and NLDC in advance with detailed reasons and explanation for the non-adherence. These detailed reasons and explanation shall be discussed in the monthly operation sub-committee of the respective region and a quarterly report shall be submitted to the Commission and CEA.

(9) Each SLDC shall undertake study on the impact of new elements to be commissioned in intra-state system in the next six (6) months on the TTC and ATC for the State.

(10) Each RLDC shall undertake study on the impact of new elements to be commissioned in the next six (6) months in (a) the ISTS of the region and (b) the intra-state system on the inter-state system.

(11) NLDC shall undertake study on the impact of new elements to be commissioned in the next six (6) months in (a) inter-regional system, (b) cross-border link and (c) intra-regional system on the inter-regional system.

(12) NLDC, RLDCs and SLDCs shall compare the results of the studies of impact of new elements on the system and transfer capability addition with those of the interconnection and planning studies by CTU and STUs, and any significant variations observed shall be communicated to CTU and STUs for immediate and long-term mitigation measures.

(13) Defense mechanisms like system protection scheme, load-rejection scheme, generation run-back, islanding scheme or any other scheme for system security shall be proposed by concerned user or SLDC or RLDC or NLDC and shall be deployed as finalized by the respective RPC.

34. SYSTEM RESTORATION

(1) Based on the template issued by NLDC, SLDC of each State and RLDC of each region shall prepare restoration procedure for the grid for their respective control areas, which shall be updated every year by the concerned SLDC and RLDC taking into account changes in the configuration of their respective power systems.

(2) Each RLDC, in consultation with NLDC, CTU, and the concerned STUs, SLDCs, users and RPC, shall prepare detailed procedures for restoration of the regional grid under partial and total blackout which shall be reviewed and updated annually by the concerned RLDC.

(3) Detailed procedures for restoration post partial and total blackout of each user system within a region shall be prepared by the concerned user in coordination with the concerned SLDC, RLDC or NLDC, as the case may be. The concerned user shall review the procedure every year and update the same. The user shall carry out mock trial run of the procedure for different sub-systems including black-start of generating units along with grid forming capability of inverter based generating station, VSC based HVDC black-start support at least once in a year under intimation to the concerned SLDC and RLDC. Diesel generator sets and other standalone auxiliary supply source to be used for black start shall be tested on weekly basis and the user shall send the test reports to concerned SLDC, RLDC and NLDC on a quarterly basis.

(4) Simulation studies shall be carried out by each user in coordination with RLDC for preparing, reviewing and updating the restoration procedures considering the following:

(a) Black start capability of generator;

(b) Ability of black start generator to build cranking path and sustain island;

(c) Impact of block load switching in or out;

(d) Line/transformer charging;

(e) Reduced fault levels;

(f) Protection settings under restoration condition.

(5) The thermal and nuclear generating stations shall be prepared for house load operation as per design. Concerned user and SLDC shall report the performance of house load operation of a generating station in the event where such operation was required.

(6) NLDC, RLDC and SLDC shall identify the generating stations with black start, grid forming capability, house load facility, inter-State or inter-regional ties, synchronizing points and essential loads to be restored on priority.

(7) During restoration process following a black out, SLDC, RLDC and NLDC are authorized to operate with reduced security standards for voltage and frequency and may direct for implementation of such operational measures, namely, suspension of secondary or tertiary frequency control, power market activities, defense schemes, reduced governor droop setting as necessary, in order to achieve the fastest possible recovery of the grid.

(8) All communication channels required for restoration process shall be used for operational communication only till the grid normalcy is restored.

(9) Any entity extending black start support by way of injection of power as identified in clause (6) of this Regulation shall be paid for actual injection @ 110 % of normal rate

of charges for deviation in accordance with DSM Regulations for the last block in which the grid was available.

35. REAL TIME OPERATION

(1) System state

Power system shall be categorized under normal, alert, emergency, extreme emergency and restoration state depending on the type of contingencies and value of operational parameters of the power system by RLDC, NLDC or SLDC, as the case may be.

(a) Normal state

Power system shall be categorized under normal state when the power system is operating with operational parameters within their respective operational limits and equipment are within their respective loading limits. Under normal sate, the power system is secure and capable of maintaining stability under contingencies defined in the CEA Transmission Planning Criteria.

(b) Alert state

Power system shall be categorized under alert sate when the power system is operating with operational parameters within their respective operational limits, but a single contingency leads to violation of security criteria. The power system remains intact under such alert state. However, whenever the power system is under alert sate, the system operator shall take corrective measures to bring back the power system to normal state.

(c) Emergency state

Power system shall be categorized under emergency sate when the power system is operating with operational parameters outside their respective operational limits or equipment are above their respective loading limits. Emergency state can arise out of multiple contingencies or any major grid disturbance in the system. The power system remains intact under such emergency state. However, whenever the power system is under emergency sate, the system operator, to bring back the power system to alert/normal state shall take corrective measures such as:

- extreme measures such as load shedding, generation unit tripping, line tripping or closing,
- emergency control action such as HVDC Control, Excitation Control, HP-LP Bypass, tie line flow rescheduling on critical lines, and
- automated action such as system protection scheme, load curtailment scheme and generation run-back scheme.

(d) Extreme Emergency state

Power system shall be categorized under extreme emergency state if the control actions taken during emergency state are not able to bring the system either to alert state or normal state and operational parameters are outside their respective operational limits or equipment are critically loaded. Extreme emergency state may arise due to high impact low frequency events like natural disasters. The power system may or may not remain intact (splitting may occur) and extreme events like generation plant tripping, bulk load shedding, under frequency load shedding (UFLS) and under voltage load shedding (UVLS) operation may occur.

(e) Restorative State

Power system shall be categorized under restorative state when control action is being taken to reconnect the system elements and to restore system load. The power system transits from restorative state to either the alert state or the normal state, depending on the system conditions.

(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.

(3) NLDC, RLDCs or SLDCs, as the case may be, shall maintain the grid in the normal state by taking suitable measures. In case the power system moves away from the normal state, appropriate measures shall be taken to bring the system back to the normal state. In case the power system has moved to extreme emergency state, appropriate LDCs shall take emergency action and initiate restorative measures immediately.

(4) Procedure to be followed during an event

(a) in case of an event on intra-State transmission system which may significantly impact the inter-State transmission system, the concerned SLDC shall immediately inform the RLDC;

(b) in case of an event on the inter-State transmission system or relating to a regional entity, the concerned entity shall immediately inform RLDC.

(c) immediately following an event on regional grid, the RLDC shall inform the concerned users and the concerned SLDC for necessary action.

(d) any warning in respect of system security issued by NLDC or RLDC or SLDC shall be taken note of immediately by the concerned users who shall take necessary action to withstand the said event or to minimize its effect.

(5) Operational coordination

(a) For operational coordination, each inter-State transmission licensee, generating station, QCA and SNA shall have a control center or coordination centre for round the clock coordination as specified in Clauses (7) and Clause (8) of Regulation 28 of these regulations.

(b) Any planned operation activity in ISTS system [such as transmission element opening or closing (including breakers), protection system outage, SPS outage and testing etc.] shall be done by taking operational code from RLDC or NLDC, as the case may be. The operational code shall have validity period of thirty (30) minutes from the time of issue. In case such operation activity does not take place within the validity period of the code, the entity shall obtain a fresh operational code from RLDC or NLDC, as the case may be.

36. DEMAND AND LOAD MANAGEMENT

(1) The demand and load shall be managed for ensuring grid security.

(2) Whenever the power system is in alert state or emergency state as assessed by SLDC or advised by RLDC,

(a) the respective distribution licensee shall abide by directions of SLDC to secure the system, and extreme measures like load shedding may be carried out as a last resort.

(b) SLDC or RLDC through SLDC may direct distribution licensee to restrict drawal from the grid or curtail load for ensuring the stability of the grid:

Provided that load shedding shall be resorted to after the demand response option has been exhausted.

(c) The load disconnected, if any, shall be restored as soon as possible on clearance from SLDC, in coordination with RLDC if required, after the system has been normalized.

37. POST DESPATCH ANALYSIS

(1) Operational analysis

(a) NLDC, RLDCs and SLDCs shall analyse the following:

(i) Pattern of demand met, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, ancillary services despatched, transmission congestion and (n-1) violations;

(ii) Generation mix in terms of source and station wise generation;

(iii) Irregular pattern in any of the system parameters mentioned in Clause 1(a) (i) and Clause 1(a) (ii) of Regulation 37of these Regulations and reasons thereof; and

(iv) Extreme weather events or any other event affecting the grid security.

(b) Such analysis shall be disclosed on their respective website in formats issued by NLDC.

(c) RLDCs shall prepare a quarterly report which shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of actions taken, including by those responsible for causing disturbances in the system parameters.

(d) RLDCs shall also provide such report to the concerned RPC.

(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.

(2) Event reporting

Event reporting shall make available adequate data to facilitate event analysis.

(a) Immediately following an event (grid disturbance or grid incidence as defined in CEA (Grid Standards) Regulations, 2010) in the system, the concerned user or SLDC shall inform the RLDC through voice message.

(b) Written flash report shall be submitted to RLDC and SLDC by the concerned user within the time line specified in the Table 8 below.

(c) Disturbance Recorder (DR), station Event Logger (EL), Data Acquisition System (DAS) shall be submitted within time line specified in the Table 8 below.

(d) RLDC shall report the event (grid disturbance or grid incidence) to CEA, RPC and all regional entities within twenty-four (24) hours of receipt of the flash report.

(e) After complete analysis of the event, user shall submit a detailed report in case of grid disturbance or grid incidence within one (1) week of occurrence of event to RLDC and RPC.

(f) RLDCs and NLDC (for events involving more than one region) shall prepare a draft report of each grid disturbance or grid incidence including simulation results and analysis which shall be discussed and finalized at Protection sub-committee of RPC as per timeline specified in the table below.

TABLE 8: REPORT SUBMISSION TIMELINE

Sr. No.	Grid Event^ (Classification)	Flash report submission deadline (users/ SLDC)	Disturbance record and station event log submission deadline (users/ SLDC)	Detailed report and data submission deadline (users/ SLDC)	Draft report submission deadline (RLDC/ NLDC)	Discussion in protection committee meeting and final report submission deadline (RPC)
1	GI-1/GI-2	8 hours	24 hours	+7 days	+14 days	+30 days
2	Near miss*	8 hours	24 hours	+7 days	+30 days	+30 days
3	GD-1	8 hours	24 hours	+7 days	+14 days	+30 days
4	GD-2/GD-3	8 hours	24 hours	+7 days	+21 days	+30 days
5	GD-4/GD-5	8 hours	24 hours	+7 days	+30 days	+30 days

^*The classification of Grid Disturbance (GD)/Grid Incident (GI) shall be as per the CEA (Grid Standards) Regulations, 2010.*

*****Near miss event means 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.*

(g) The implementation of the recommendations of final report shall be monitored in the protection sub-committee of the RPC. NLDC shall disseminate the lessons learnt from each event to all the RPCs for necessary action in the respective regions.

(h) Any additional data such as single line diagram (SLD) of station, protection relay settings, HVDC transient fault record, switchyard equipment and any other relevant station data required for carrying out analysis of an event by

RPC, NLDC, RLDC and SLDC shall be furnished by the users including RLDC and SLDC, as the case may be, within forty- eight (48) hours of the request. All users shall also furnish high-resolution analog data from various instruments including power electronic devices like HVDC, FACTS, renewable generation on the request of RPCs, NLDC, RLDCs or SLDCs.

(i) Triggering of STATCOM, TCSC, HVDC run-back, HVDC power oscillation damping, generating station power system stabilizer and any other controller system during any event in the grid shall be reported to the concerned RLDC and RPC if connected to ISTS and to the concerned SLDC if connected to intra-state system. The transient fault records and event logger data shall be submitted to the concerned RLDC or SLDC within 24 hours of occurrence of the incident.

(j) A monthly report on events of unintended operation or non-operation of protection system shall be prepared and submitted by each user to concerned RPC and RLDC within the first week of the subsequent month.

38. PERIODIC REPORTS

(1) Daily and monthly reports covering performance of the integrated grid shall be prepared by NLDC.

(2) Daily and monthly reports covering the performance of the regional grid shall be prepared by each RLDC based on the inputs received from SLDCs and users.

(3) The reports shall inter-alia contain the following:

(i) Frequency profile;

(ii) Source wise generation for each control area;

(iii) Drawal from the grid and area control error;

(iv) Demand met (peak, off-peak and average);

(v) Demand/Energy unserved in MW and MWh;

(vi) Instances and quantum of curtailment of renewable energy;

(vii) Voltage profile of important substations and sub-stations normally having low or high voltage;

(viii) Major generation and transmission outages;

(ix) Constraints and instances of congestion in transmission system;

(x) Instances of persistent/significant non-compliance of Grid Code;

(xi) Status of reservoirs.

(4) The NLDC shall prepare a quarterly report providing operational feedback for grid planning and re-optimization and submit to CTU and CEA and upload on its website.

39. Reactive Power Management

(1) All users shall endeavour to maintain the voltage at interconnection point in the range specified in the Grid Code.

(2) 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 Standard Regulations

(3) All generating stations connected to the grid shall generate or absorb reactive power as per instructions of the concerned RLDC or SLDC, as the case may be. within capability limits of the respective generating units.

Explanation: Capability limit of a generating unit shall be as specified by the OEM.

(4) NLDC, RLDCs or SLDCs may direct the users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at interconnection points.

(5) NLDC, RLDCs and SLDCs shall assess the dynamic reactive power reserve available at various substations or generating stations under any credible contingency on a regular basis based on technical details and data provided by the users.

(6) NLDC, RLDCs and SLDCs shall take appropriate measures to maintain the voltage within limits inter-alia using following facilities and facility owner shall abide by the instructions of NLDC, RLDCs and SLDCs:

(i) shunt reactors,

(ii) shunt capacitors,

(iii) TCSC,

(iv) VSC based HVDC,

(v) synchronous/non-synchronous generator voltage control ,

(vi) synchronous condenser,

(vii) static VAR compensators (SVC), STATCOM and other FACTS devices,

(viii) transformer tap change: generator transformer and inter-connecting transformer,

(ix) HVDC power order or HVDC controller selection to optimise filter bank.

(7) Reactive power facility shall be in operation at all times and shall not be taken out without the permission of the concerned RLDC or SLDC.

(8) Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages and if required, other options such as tap staggering may be carried out in the network.

(9) Hydro and gas generating units having capability shall operate in synchronous condenser mode operation as per instructions of RLDC or SLDC of the respective control area. Standalone synchronous condenser units shall operate as per instructions of RLDC or SLDC, as per respective control area.

(10) Any commercial settlement for reactive power shall be governed as per regulatory framework specified in Annexure–4 until the same is separately notified as part of the CERC Ancillary Services Regulations.

(11) If voltages are outside the limit as specified in clause (15) of Regulation 29 of these regulations and the means of voltage control set out in Clause (6) of this Regulation are exhausted, in that event SLDCs, RLDCs or NLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits including opening of lines considering security of system.

40. FIELD TESTING FOR MODEL VALIDATION

(1) There shall be periodic tests as required under Clause (3) of this Regulation 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.

(2) General provisions

(a) The owner of the power system element shall be responsible to carry out tests as specified in these regulations and for submission of reports to NLDC, RLDCs, CEA and CTU for all elements and to STUs and SLDCs for intra-State elements.

(b) All equipment owners shall submit a testing plan for the next year to the concerned RPC by 31st October for ensuring proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform the concerned RPC in advance.

(c) The tests shall be performed once in every five (5) years or whenever major retrofitting is done or if necessitated earlier due to any adverse performance observed during any grid event.

(d) The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports by the concerned RPC in consultation with NLDC, RLDC, CEA and CTU.

(3) Testing requirements

The following tests shall be carried out on respective power system elements:

TABLE 9: TESTS REQUIRED FOR POWER SYSTEM ELEMENTS

Power System Elements	Tests	Applicability
Synchronous Generator	(1) Real and Reactive Power Capability assessment. (2) Reactive Power Control Capability (As per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007) assessment. (3) Model Validation and verification test for the complete Generator and Excitation System model including PSS. (4) Model Validation and verification of	Individual Unit of rating 100MW and above for Coal/lignite, 50MW and above gas turbine and 25 MW and above

Power System Elements	Tests	Applicability
	Turbine/Governor and Load Control or Active Power/ Frequency Control Functions. (5) Testing of Governor performance and Automatic Generation Control.	for Hydro.
Non synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability for Generator (2) Power Plant Controller Function Test (3) Frequency Response Test (4) Fault Ride through Test (sample testing of a unit in the generating stations).	Applicable as per CEA (Technical Standards for Connectivity) Regulations, 2007
HVDC/FACTS Devices	(1) Damping capability of HVDC/FACTS Controller (2) Frequency Controller Capability of HVDC Controller (3) Reactive Power Controller (RPC) Capability for HVDC/FACTS (4) Validation of voltage dependent current order limiter (VDCOL) characteristic for ensuring proper validation of HVDC performance (5) Filter bank adequacy assessment based on present grid condition. (6) Validation of response by FACTS devices as per settings.	To all ISTS HVDC as well as Intra-State HVDC/FACTS

41. CAPACITY BUILDING AND CERTIFICATION

Capacity building, skill upgradation and certification of the personnel deployed in load despatch centres shall be done periodically under an institutional framework through accredited certifying agency (ies).

CHAPTER 7

SCHEDULING AND DESPATCH CODE

42. INTRODUCTION

This chapter deals with the procedure for scheduling injection and drawal of power by the regional entities and the modalities for exchange of information including scheduling for intra-state and cross-border entities transacting power through Inter-State Transmission System. This chapter also covers provisions in respect of control area jurisdiction.

43. CONTROL AREA JURISDICTION OF LOAD DESPATCH CENTER

(1) The national grid shall be demarcated into Regional and State control areas and each control area shall be under the jurisdiction of RLDC or SLDC, as the case may be.

(2) The RLDCs shall be responsible for scheduling and despatch of electricity, monitoring of real time grid operations and management of the reserves including energy storage system and demand response within its control area, supervision and control over the inter-state transmission system, processing of interface energy meter data and coordinating the accounting and settlement of regional pool account.

(3) The SLDCs shall be responsible for scheduling and despatch of electricity, monitoring of real time grid operations and management of the reserves including energy storage system and demand response within its State control area, supervision and control over the intra-State transmission system, processing of interface energy meter data and coordinating the accounting and settlement of State pool account, as may be specified by the appropriate State Commission.

(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.

44. RESPONSIBILITIES OF LOAD DESPATCH CENTRES

(1) The Regional Load Despatch Centre, in discharge of its functions under the Act, shall be responsible for the following, within its regional control area:

(a) Forecasting of demand based on the inputs from SLDCs (under clause (2) of Regulation 31 of these regulations) and other regional entities for each time block on day-ahead and intraday basis.

(b) Forecasting of generation from wind and solar generating stations, which are regional entities, for each time block on day-ahead and intraday basis:

Provided that such forecasts may be used by the wind and solar generating stations at their own risk and discretion along with all commercial liabilities arising out of it.

(c) Scheduling of electricity within the region which includes:

(i) Injection and drawal schedule for regional entities, cross-border entities, in accordance with the contracts;

(ii) Incorporation of schedules under collective transactions for regional entities;

(iii) optimisation of scheduling inter alia through Security Constrained Economic Despatch (SCED);

(d) Secure operation of grid by:

(i) Balancing demand and supply to minimize Area Control Error (ACE);

(ii) Maintaining and despatching reserves in accordance with these regulations and Ancillary Services Regulations.

(e) Assessment of transmission capacity for inter-State transmission system for secure operation of the grid including but not limited to:

(i) Assessment of TTC and ATC for inter-regional, intra-regional and inter-State levels for its region and submit to NLDC.

(ii) Assessment of TTC and ATC for import or export of electricity for a State in coordination with concerned SLDC and submit to NLDC.

(f) Publication of TTC and ATC, as finalised by NLDC, with all the assumptions and constraints on its website.

(g) Running of a Security Constraint Unit Commitment (SCUC) for regional entity generating stations.

(2) The National Load Despatch Centre, in discharge of its functions under the Act, shall be responsible for the following:

(a) Optimum scheduling and despatch of electricity over inter-regional links amongst Regional Load Despatch Centers;

(b) Coordination with Regional Load Despatch Centers for the energy accounting of inter-regional exchange of power;

(c) Coordination and scheduling of trans-national exchange of power;

(d) Coordination of the set-points of all HVDCs within the country and cross-border HVDC interconnections;

(e) Finalising the TTC and ATC with all assumptions and limitations based on inputs received from RLDCs and publishing the same on its website;

(f) Finalising SCED and SCUC through RLDCs and publishing the same on its website;

(g) Furnishing availability of transmission corridors to the Power Exchange(s) for day ahead and real time collective transactions and in case of congestion, allocating available transmission corridors among Power Exchange(s) in the ratio of initial unconstrained market clearing volume in the respective Power Exchange(s).

(3) The State Load Despatch Centre in discharge of its functions under the Act and for stable, smooth and secure operation of the integrated grid, shall be responsible for the following in its control area:

(a) Forecasting demand for its control area under Regulation 31(2) for each time block on day-ahead and intra-day basis;

(b) Forecasting of generation from wind and solar generating stations under its jurisdiction for each time block on day-ahead and intra-day basis;

Provided that such forecasts may be used by the wind and solar generating stations at their own risk and discretion along with all commercial liabilities arising out of it;

(c) Scheduling and despatch for the entities in the State control area in accordance with contracts.;

(d) Balancing demand and supply to minimize Area Control Error (ACE) for the State;

(e) Maintaining and despatching reserves;

(f) Declaring Total Transfer Capacity and Available Transfer Capacity in respect of import and export of electricity of its control area with inter-State transmission system in coordination with the Central Transmission Utility and revising the same from time to time based on grid conditions'

(4) Damodar Valley Corporation and Settlement Nodal Agency shall carry out the responsibilities in their respective control area, in accordance with clause (2) of this Regulation, for stable, smooth and secure operation of the integrated grid.

45. GENERAL PROVISIONS

(1) Details of regional entity generating stations to be published by RLDC

(a) RLDCs shall publish list of all regional entity generating stations within their control area, which shall be updated quarterly on its website along with details such as station capacity, allocated share of beneficiaries, contracted quantum by buyers and balance available capacity.

(b) RLDCs shall also publish details, as applicable, for regional entity generating stations other than renewable generating stations, as submitted by such generating stations in accordance with Regulation 20 of these regulations.

(c) RLDC shall publish the details, as applicable, for all regional entity renewable generating stations as submitted by such generating stations in accordance with Annexure-5.

(2) The regional entity generating stations must be capable of receiving the load setpoint signals from the RLDCs/NLDC as per CEA Technical Standards for Connectivity.

(3) List of Drawee Regional Entities:

RLDCs shall update on quarterly basis the list of all drawee regional entities within their respective control area and post the same on their websites along with allocated or contracted quantum from all entities excluding the intra-State entities within their control area.

(4) Entitlement of a buyer and beneficiary:

(a) In cases of allocation of power from central generating station by the Central Government, each beneficiary shall be entitled for MW despatch out of declared capacity of such generating station, in proportion to its share allocation.

(b) For all other cases not covered under Clause (a), the buyer shall be entitled for MW despatch out of declared capacity of regional entity generating station as per its contracts.

(c) The entitlement from regional entity generating station shall be rounded off up to two (2) decimal points for the purposes of scheduling and accounting.

(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.

(6) Adherence to Schedule:

Each regional entity shall regulate its generation or demand or both, as the case may be, so as to adhere to schedule of net injection into or net drawal from the inter-State transmission system.

(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.

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

(a) The regional entity generating station shall declare ex-bus Declared Capacity, limited to 100% MCR, on day ahead basis as per provisions of Regulation 47 of these regulations.

Provided that in case of REGS or ESS the available capacity shall be declared by such regional entity generating station .

(b) The regional entity generating stations may be required to demonstrate the declared capacity of their generating stations as and when directed by the concerned RLDC. For this purpose, RLDC, in coordination with SLDC and the beneficiaries, shall schedule the regional entity generating station upto its declared capacity as declared on day ahead basis at time of first declaration. RLDC shall ask each generating station, at least once in a year, to demonstrate the declared capacity.

(c) The schedule issued by the RLDC shall be binding on the beneficiaries for such testing of declared capacity of the regional entity generating station. In case the generating station fails to demonstrate the declared capacity, it shall be treated as mis-declaration for which charges shall be levied on the generating station by RPC as follows:

The charges for the first mis-declaration for a block or multiple blocks in a day shall be the charges corresponding to two days fixed charges at normative availability. For the second mis-declaration, the charges shall be corresponding to four days fixed charges at normative availability and for subsequent mis-declarations, the charges shall increase in a geometric progression over a period of a month.

(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.

(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.

(11) Scheduling of renewable energy generating station by QCA

(a) The regional entity renewable energy generating station(s) or Projects based on energy storage system(s) connected at a particular ISTS substation or at multiple ISTS substations may appoint a QCA on their behalf to coordinate and facilitate scheduling for such generating stations or energy storage system(s).

(b) 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 within six (6) months of notification of these regulations.

(c) The QCA shall be registered with concerned RLDC.

(d) QCA registered with the concerned RLDC shall, on behalf of wind, solar or renewable hybrid generating stations:

(i) Coordinate and facilitate scheduling of power with the concerned RLDC; and ;

(ii) Undertake commercial settlement of deviations with the concerned RLDC in accordance with the DSM Regulations.

(e) The concerned wind, solar or renewable hybrid generating stations including energy storage systems shall indemnify the RLDC for any act of commission or omission on the part of QCA including compliance with the Grid Code and settlement of its financial liability in the pooled account.

(f) Any dispute arising between the generating stations and QCA shall be resolved in accordance with the mechanism in the contracts entered into between them.

(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**.**

(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 inter-regional links with concerned RLDCs.

(14) A generating station or ESS or a drawee entity shall be allowed to schedule injection or drawal only upto its effective GNA quantum or T-GNA quantum, as applicable, in accordance with the GNA Regulations.

(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.

46. SECURITY CONSTRAINED UNIT COMMITMENT (SCUC)

(1) The objective of Security Constrained Unit Commitment (SCUC) is to commit a generating station or unit thereof, for maximisation of reserves in the interest of grid security, without altering the entitlements and schedule of the buyers of the said generating station in the day ahead time horizon.

(2) Reserves shall be procured and deployed in accordance with the Ancillary Services Regulations, and SCUC shall supplement such procurement of reserves under certain conditions, as specified in this Regulation.

(3) SCUC shall be undertaken if the NLDC, in coordination with RLDCs and based on assessment of the power system condition, anticipates that there is likely to be a shortage of reserves despite efforts made to procure such reserves in accordance with Ancillary Services Regulations.

(4) The SCUC may be undertaken on day ahead basis, in respect of the generating stations or units thereof, for which tariffs are determined by the Commission under section 62 of the Act, as per the following process:

(a) By 1330 Hrs of D-1 day, 'D' being the day of delivery, NLDC in coordination with RLDCs shall publish a tentative list of generating stations or units thereof, which are likely to be scheduled below the minimum turn down level of the respective stations for some or all the time blocks of the D day, based on beneficiary requisitions and initial unconstrained bid results of DAM in power exchanges, received till 1300 Hrs of the D-1 day.

(b) Beneficiaries of such stations, whose units are likely to be scheduled below minimum turndown level for some or all time blocks of the D day, shall be permitted to revise their requisitions from such stations by 1630 Hrs of D-1 day, in order to enable such units to be on bar. The revised requisition from the said generating stations, once confirmed by the beneficiaries by 1630 Hrs of D-1 day, shall be final and binding after 1630 Hrs of D-1 day and further reduction in drawal schedule shall not be allowed from such stations for such time blocks.

(c) After 1630 Hrs, the NLDC in coordination with RLDCs shall prepare the final list of such generating units that are likely to go below their minimum turndown level and such generating units shall be stacked as per merit order, that is, in the order of the lowest variable charge to the highest variable charge. The generating units so identified shall be considered for undertaking SCUC.

(d) If the NLDC in coordination with RLDCs, after considering the bid results as finalized and available from DAM-AS, anticipates shortfall of reserves in D day due to (i) extreme variation in weather conditions; (ii) high load forecast; (iii) the requirement of maintaining reserves on regional or all India basis for grid security;

(iv) network congestion, NLDC may schedule incremental energy from the generating units in the list referred to in sub-clause (c) of clause 4 of this Regulation, so as to bring such units to their minimum turndown level, in order to maximize availability of on-bar units, by 1800 Hrs. of D-1 day and update the list on the respective RLDC website.

(e) In order to maintain load generation balance consequent to scheduling of incremental generation as per sub-clause (d) of clause 4 of this Regulation, the NLDC in coordination with RLDCs, shall make commensurate reduction in generation from the on-bar generating station(s), subject to technical constraints, starting with the highest variable charge in the stack of generating stations maintained for the purpose of SCED in accordance with these regulations..

(f) The generating station from which incremental energy has been scheduled as per sub-clause (d) of clause 4 of this Regulation shall be paid from the Deviation and Ancillary Services Pool Account, for the energy charge equivalent to the incremental energy scheduled, and the generating station from which reduction in generation has been directed as per sub-clause (e) of clause (4) of this Regulation shall pay back to the Deviation and Ancillary Services Pool Account, the energy charge equivalent to the decremental energy.

(g) The URS power over and above the minimum turn down level, available in the generating station or unit thereof, brought on-bar under clause 4(d) of this Regulation shall be deemed to be available for use as SRAS or TRAS or both in terms of the Ancillary Services Regulations.

(h) UNIT SHUT DOWN (USD)

(i) The generating stations or units thereof, identified by NLDC in co-ordination with RLDCs, as per Clause (4) (c) of Regulation 46 of these regulations, but not brought on bar under SCUC, shall have the option to operate at a level below the minimum turn down level or to go under Unit Shut Down (USD).

(ii) In case a generating station, or unit thereof, opts to go under unit shut down (USD), the generating company owning such generating station or unit thereof shall fulfil its obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD, by entering into a contract(s) covered under the Power Market Regulation or by arranging supply from any other generating station or unit thereof owned by such generating company subject to honouring of rights of the original beneficiaries of the said generating station or unit thereof from which supply is arranged.

47. PROCEDURE FOR SCHEDULING AND DESPATCH FOR INTER-STATE TRANSACTIONS

(1) The following scheduling related activities shall be carried out on daily basis for regional entities, on day ahead basis, 'D-1' day, for supply of power on 'D' day, as follows:

(a) Declaration of Declared Capacity by generating stations:

(i) The generating station based on coal and lignite shall submit the following information for 0000 hours to 2400 hours of the 'D' day, by 6 AM on 'D-1' day,:

(a) Time block-wise On-bar Declared Capacity (MW) for on-bar units;

(b) Time block-wise Off-bar Declared Capacity (MW) for off-bar units;

(c) Time block-wise Ramp up rate (MW/min) for on-bar capacity;

(d) Time block-wise Ramp down rate (MW/min) for on-bar capacity;

(e) MWh capability for the day;

(f) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar;.

(ii) The generating station based on hydro energy shall submit the following information for 0000 hours to 2400 hours of the ‘D’ day, by 6 AM on ‘D-1’ day::

(a) Time block-wise ex-bus declared capacity;

(b) MWh capability for the day;

(c) Ex-bus peaking capability in MW and MWh;

(d) Time block-wise Ramp up rate (MW/min) for on-bar capacity;

(e) Time block-wise Ramp down rate (MW/min) for on-bar capacity;

(f) Unit-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity;

(g) Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations.

(iii) The generating station based on gas or combined cycle generating station shall submit the following for 0000 hours to 2400 hours of the ‘D’ day, by 6 AM on ‘D-1’ day:

(a) Time block-wise On-bar Declared Capacity (DC) for the station in MW separately for each fuel such as domestic gas, RLNG or liquid fuel and On-bar units;

(b) Time block wise Off-bar Declared Capacity(MW) and off-bar units;

(c) MWh capability for the next day;

(d) Time block wise Ramp up rate (MW/min) for on-bar capacity;

(e) Time block wise Ramp down rate (MW/min) for on-bar capacity;

(f) Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar.

(iv) The renewable energy generating station, individually or represented by a lead generator or QCA, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract-wise breakup for each time block for 0000 hours to 2400 hours of the ‘D’ day, by 6 AM on ‘D-1’ day.

(v) ESS including pumped storage plant, individually or represented by lead ESS or QCA on their behalf, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract-wise breakup for each time-block for 0000 hours to 2400 hours of the ‘D’ day, by 6 AM on ‘D-1’ day.

(vi) The availability declaration by regional entity generating station shall have a resolution of two decimal (0.01) MW and three decimal (0.001) MWh.

(b) Entitlement of each beneficiary or buyer:

(i) For generating station, where Central Government has allocated power, each State shall be entitled to a MW despatch up to the State’s Share in the station’s declared capacity for the day. Accordingly, based on declared capacity of such generating station, RLDC shall declare entitled share of each beneficiary or buyer for 0000 hours to 2400 hours of the ‘D’ day, by 7 AM on ‘D-1’ day

(ii) The generating station other than those having allocation of power by the Central Government shall indicate the declared capacity along with respective share of the beneficiary(ies) or buyers in accordance with the contracts entered with them. Based on declared capacity of such generating station and share of the beneficiaries or buyers as indicated by such generating station, RLDC shall declare share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day.

(c) The requisition for scheduling of intra-State entities shall be as submitted by the regional entity buyers and regional entity sellers in accordance with the contracts entered between them.

(d) The requisition for cross-border schedule along with its breakup from various sources shall be submitted by Settlement Nodal Agency (SNA) for 0000 hours to 2400 hours of the 'D' day, by 7 AM on 'D-1' day;

(e) Requisition of schedule by buyers who are GNA grantees:

(i) Based on the entitlement declared in accordance with sub-clause (b) of clause (1) of Regulation 47 of these regulations, SLDC on behalf of intra-State entities which are drawee GNA grantees, shall furnish time block-wise requisition for drawal to concerned RLDC in accordance with the contracts, by 8 AM of 'D-1' day.

(ii) Other drawee GNA grantees who are regional entities shall furnish time block-wise requisition for drawal to the concerned RLDC in accordance with contracts, by 8 AM of 'D-1' day.

(iii) The SLDC on behalf of the intra-State entities which are drawee GNA grantees, as well as other drawee GNA grantees while furnishing time block-wise requisition under this Regulation shall duly factor in merit order of the generating stations with which it has entered into contract(s):

Provided that the renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order.

(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.

(iii) RLDC shall issue final drawl schedules for GNA grantees by 9 AM on 'D-1' day.

(iv) For the purpose of "Use of GNA by other GNA grantees" as specified in GNA Regulations, the GNA shared with other entity shall considered as GNA of the new entity.

(g) Requisition of schedule by T-GNA grantees

(i) Based on the entitlement or otherwise, SLDC on behalf of intra-State entities which are T-GNA grantees, shall furnish time block-wise requisition for drawl to the concerned RLDC in accordance with contracts by 9 AM of 'D-1' day.

(ii) Other drawee T-GNA grantees who are regional entities, shall furnish time block-wise requisition for drawl to concerned RLDC in accordance with contracts by 9 AM of ‘D-1’ day.

(iii) Allocation of corridors by RLDC for T-GNA grantees RLDC shall check if drawl schedules as requisitioned by T-GNA grantees can be granted based on available transmission capability after allocating corridors to GNA grantees.

Provided that in case of constraint in transmission system, the available transmission corridor shall be allocated to the T-GNA grantees in proportion to their T-GNA.

(iv) RLDC shall issue final drawl schedules for T-GNA grantees by 9.30 AM of ‘D-1’ day.

(h) RLDC shall release the balance corridors after finalisation of schedules for GNA and T-GNA grantees for day ahead collective transactions.

(i) 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.

(j) Scheduling of collective transactions:

(i) Power Exchange(s) shall open bidding window for day ahead collective transactions from 10 AM to 11.30 AM of ‘D-1’ day.

(ii) The power exchange shall submit the day-ahead provisional trade schedules along with net power interchange of each bid area and region to NLDC by 12.00 Noon of ‘D-1’ day.

(iii) NLDC shall validate the same from system security angle and inform the power exchange with revisions required, if any, due to transmission congestion or any other system constraint by 12.30 PM of ‘D-1’ day.

(iv) The power exchange shall submit the final trade schedules to NLDC for regional entities and to SLDC for intra-State entities by 1.00 PM of ‘D-1’ day.

(k) RLDC shall release balance corridors after finalisation of schedules under day ahead collective transactions by 1.00 PM of ‘D-1’ day.

(l) RLDC shall process exigency applications received till 1 PM of ‘D-1’ day for the ‘D’ day by 2 PM of ‘D-1’ day.

(m) RLDC shall update the availability of balance transmission corridors, if any, after finalisation of schedules for exigency applications under clause (l) by 2.00 PM of ‘D-1’ day on its website. 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.

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

(i) All the entities participating in the real-time market may place their bids and offers on the Power Exchange(s) for purchase and sale of power.

(ii) The window for trade in real-time market for day (D) shall open from 22.45 hrs to 23.00 hrs of (D-1) for the delivery of power for the first two time-blocks of 1st hour of day (D) i.e., 00.00 hrs to 00.30 hrs, and will be repeated every half an hour thereafter.

(iii) NLDC shall indicate to the Power Exchange(s) the available margin on each of the transmission corridors before the gate closure.

(iv) The power exchanges shall clear the real-time bids from 23.00 hrs till 23.15 hrs of 'D-1' day based on the available transmission corridor and the buy and sell bids for the real time market (RTM) for the specified duration.

(v) The cleared bids shall be submitted by the Power Exchanges to the NLDC for scheduling. The NLDC shall announce the final schedule by 23.45 hrs of 'D-1' day and communicate to the RLDCs to prepare the schedule for despatch.

(o) Issuance of day-ahead schedule:

RLDC shall convey the following for the next day to all regional and other entities involved in inter-state transactions after each step of finalisation of schedules for GNA grantees and T-GNA grantees:

(i) The ex-power plant schedule to each of the regional entity generating station, in MW for different time blocks along with breakup of schedule for each beneficiary or buyer.

(ii) The "net drawal schedule" for each regional entity in MW for each time block.

(iii) All requisitions and schedules shall be rounded off to the nearest two decimals at each control area boundary for each of the transaction and shall have a resolution of 0.01 MW.

(p) Issue of schedules by SLDC:

(i) SLDCs shall take into account the schedule released by the concerned RLDC for their intra-State entities and finalise the intra-State schedule.

(ii) Power Exchange(s) shall furnish the detailed break up of each point of injection and each point of drawal within each State to respective SLDCs after receipt of acceptance from NLDC. Power Exchange(s) shall ensure necessary coordination with SLDCs for scheduling of the transactions.

(2) Additional factors to be considered while finalising schedule

(a) Security Constrained Economic Despatch (SCED)

(i) 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 taking into account the operational and technical constraints of generation and transmission facilities.

(ii) 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.

(iii) The generating stations, including those for which the tariff is determined by the Commission under Section 62 of the Act, willing to participate in SCED shall declare at their discretion, the variable charges upfront to NLDC on weekly basis after factoring in likely changes in fuel cost and part load compensation, if any.

(iv) NLDC shall prepare stack of URS available in such generating stations from the lowest variable charge to the highest variable charge in each time block. After gate closure in the real time market, the generating stations so identified shall be instructed and despatched for SCED Up in the order of the lowest variable charge to the highest variable charge, after taking into account ramp up or ramp down rate, response time, transmission congestion and such other parameters as stipulated in the Detailed Procedure. Corresponding to the incremental generation under SCED Up, instruction and despatch for SCED Down shall be given to the generating stations in the order of the highest variable charge to the lowest variable charge subject to ramp up or ramp down rate, response time, transmission congestion and such other parameters as stipulated in the Detailed Procedure.

(v) The deviation in respect of such generating stations shall be settled with reference to their revised schedule. The increment or decrement of generation under SCED shall not form part of schedule considered under ancillary services for such generating stations.

(vi) The schedule of beneficiaries shall not be changed on account of SCED. Buyers or beneficiaries shall continue to pay the charges for the scheduled energy directly to the generating station(s) participating in the SCED.

(vii) NLDC shall open a separate bank account called 'National Pool Account (SCED)'. All payments to and from the generating station(s) on account of SCED schedules shall flow from and to the said 'National Pool Account (SCED)'.

(viii) For any increment in the generation schedule on account of SCED, the participating generator shall be paid from the 'National Pool Account (SCED)' at the rate of its variable charge declared upfront by the generator. For any decrement in the generation schedule on account of SCED, the participating generator shall pay to the 'National Pool Account (SCED)' at the rate of variable charge.

(ix) The net saving to the generating stations shall be shared between the beneficiaries or buyers and the generating stations as per the prevailing Tariff Regulations in respect of the generating stations whose tariff is determined by the Commission under Section 62 of the Act and in respect of other generating stations as per the terms of the contracts with their respective buyers or beneficiaries.

(x) NLDC shall publish the Detailed Procedure for SCED within two months of the notification of these regulations after stakeholder consultation and intimate the Commission.

(b) Margins for primary response:

For the purpose of ensuring primary response, RLDCs and SLDCs, as the case may be, shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units, whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response.

In case of gas or liquid fuel-based units, suitable adjustment in Installed Capacity should be made by RLDCs and SLDCs, as the case may be, for scheduling in due consideration the prevailing ambient conditions of temperature and pressure vis-à-vis site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:

Provided that the hydro generating stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow periods to avoid spillage:

(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.

(b) In the event of bottleneck in evacuation of power due to outage, failure or limitation in the transmission system or any other constraint necessitating reduction in generation, the RLDC shall revise the schedules.

Provided that generation and drawal schedules revised by the Regional Load Despatch Centre shall become effective from 7th block or 8th block depending on time block in which schedule has been revised as first time block.

(c) In case of contingencies such as critical loading of lines, transformers, abnormal voltages or threat to system security, the following steps as considered necessary, may be taken by RLDC:

(i) Issue directions to concerned entities to adhere to the schedules;

(ii) Deployment of ancillary services;

(iii) Switching off pump storage plants operating in pumping mode;

(iv) Despatching emergency demand response measures;

(v) Direct the SLDCs or other regional entities to increase or decrease their drawal or injection by revising their schedules and such directions shall be immediately acted upon.

(d) Whenever RLDC revises final schedules due to reasons of grid security or contingency, brief reasons shall be informed immediately to the concerned entity followed by a detailed explanation to be posted on RLDC website within 24 hours.

(e) Any verbal directions by RLDC shall be confirmed in writing as soon as possible latest within twenty four hours.

(4) Revision of schedules on request of regional entities:

(a) SLDCs, regional entity generating stations, regional entity ESSs, beneficiaries, buyers or cross-border entities may revise their schedules under GNA as per clause (b) and clause (c) of this Regulation in accordance with their respective contracts.

Provided that scheduled transactions under T-GNA once scheduled cannot be revised other than in case of forced outage as per clause (7) of Regulation 47 of these regulations.

(b) 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.

(c) Based on the request for revision in schedule made as per sub-clauses (a) and (b) of Clause 4 of this Regulation, any revision in schedule made in odd time blocks shall become effective from 7th time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the RLDCs to be the first one.

(d) While finalizing the drawal and despatch schedules, in case any congestion is foreseen in the inter-State transmission system or technical constraints of a generating station, the concerned RLDC shall moderate the schedules as required, under intimation to the concerned regional entities.

(5) Grid disturbance of category GD-5:

(a) GD-5 is defined under Regulation 11(2) of CEA Grid Standards as "When forty per cent or more of the antecedent generation or load in a regional grid is lost".

(b) Certification of such grid disturbance and its duration shall be done by the RLDC.

(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.

(e) The declaration of grid disturbance shall be done by the concerned RLDC at the earliest. A notice to this effect shall be posted at its website by the RLDC of the region in which the grid disturbance has occurred which shall be considered as declaration of the grid disturbance by RLDC. All regional entities shall take note of the grid disturbance and take appropriate action at their end.

(f) Energy and deviation settlement for the period of any grid disturbance causing disruption in injection or drawal of power shall be done by the concerned RPC(s) in consultation with the concerned RLDC(s).

Provided that generation and drawal schedules revised by the Regional Load Despatch Centre shall become effective from 7th block or 8thblock depending on block in which schedule has been revised as first block.

(6) The generation schedules and drawl schedules shall be accessible to the regional entities though user credentials controlled access. After the operating day is over at 2400 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in despatch schedule of regional entity generating stations and drawal schedule of the States) shall be issued by the concerned RLDC. These schedules shall be the basis for commercial accounting.

(7) In case of forced outage of a unit of a generating station (having generating capacity of 100 MW or more) and selling power under bilateral transaction (excluding collective transactions in day ahead market and real time market through power exchange), the generating station or electricity trader or any other agency selling power from the unit of the generating station shall immediately intimate the outage of

the unit along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC or RLDC, as the case may be. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised accordingly. The revised schedules shall become effective from the time block and in the manner as specified in Clause (4) of this Regulation:

Provided that the generating station or trading licensee or any other agency selling power from a generating station or unit(s) thereof may revise its estimated restoration time once in a day and the revised schedule shall become effective from the 7^{th} time block or 8^{th} time block as per Clause (4) of this Regulation, counting the time block in which the revision is informed by the generator to be the first one.

Provided further that SLDC or RLDC as the case may be, shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit.

(8) Discrepancy in schedule

(a) All regional entities, open access customers, injecting entities and drawee consumers may closely check their transaction Schedule and point out errors, if any, to the concerned LDC.

(b) The final schedules issued by RLDC shall be open to all regional entities and other regional open access entities for any checking and verification, for a period of 5 days. In case any mistake or omission is detected, the RLDC shall make a complete check and rectify the same.

(9) Energy Metering and Accounting:

(a) The CTU shall be responsible for installation, operation and periodic calibration of Interface Energy Meters (IEMs) covering all the ISTS interface points, points of connections between the regional entities, cross border entities and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points.

(b) The installation, operation, calibration and maintenance of Interface Energy Meters (IEMs) with automatic remote meter reading (AMR) facility shall be in accordance with CEA (Installation and Operation of Meters) Regulations, 2006, as amended from time to time.

(c) The installation, operation, and maintenance of additional communication links, if any, required for the purpose of AMR facility shall be in accordance with CEA Communications Regulations.

(d) CTU shall provide access to such metering data to concerned RLDC and SLDCs.

(e) CTU shall be responsible for installation of Automatic Meter Reading and shall ensure that all IEMs not capable of having the facility of AMR are phased out within two (2) years on effectiveness of these regulations.

(f) Entities in whose premises the IEMs are installed shall be responsible for (i) monitoring the healthiness of the CT and PT inputs to the meters, (ii) taking weekly meter readings for the seven day period ending on the preceding Sunday 2400 hrs and transmitting them to the RLDC by Tuesday noon, in case such readings have not been transmitted through automatic remote meter reading (AMR) facility (iii) monitoring and ensuring that the time drift of IEM is within the limits as specified in CEA Metering Regulations 2006 and (iv) promptly intimating the changes in CT and PT ratio to RLDC.

(g) SLDC shall transmit the meter data from all installations within their control area to the concerned RLDC within the specified time schedule.

(h) RLDC shall, based on the IEM readings, compute time block wise actual net injection and drawal of regional entities and cross border entities within their control area.

Provided that the computations done by RLDCs shall be open to all regional entities and cross border entities for a period of fifteen (15) days for checking and verification.

(i) In case any error or omission is detected by self analysis or brought to notice by an entity, the RLDC or RPC or NLDC, as the case may be, shall make a complete check and rectify the error within a period of a month from date of such detection.

(j) RLDC shall forward the IEM readings and the implemented schedule to the concerned RPC on a weekly basis by each Friday for the preceding seven days period ending on the preceding Sunday mid-night, to enable the latter to prepare and issue the various accounts such as Deviation Settlement Mechanism (DSM), reactive charges, congestion charges, ancillary services, SCED, heat rate compensation charges and regional transmission deviation in accordance with relevant regulations.

(10) Inspection of Records:

The operational logs and records of the regional entity generating stations and inter-State transmission licensees shall be available for inspection and review by the RLDCs and RPCs.

(11) Oversight of Injection an Drawal:

NLDC or RLDC, as the case may be, shall periodically review the over drawal from or under injection into the grid. In case of persistent over drawal or under injection, the matter shall be reported to the RPC and the Commission for necessary action.

CHAPTER 8

CYBER SECURITY

48. GENERAL

(1) This chapter deals with measures to be taken to safeguard the national grid from spyware, malware, cyber-attacks, network hacking, procedure for security audit from time to time, upgradation of system requirements and keeping abreast of latest developments in the area of cyber-attacks and cyber security requirements.

(2) All users, NLDC, RLDCs, SLDCs, CTU and STUs shall have in place, a cyber security framework in accordance with Information Technology Act, 2000; CEA (Technical Standards for Connectivity) Regulations, 2007; CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such regulations issued from time to time, by an appropriate authority, so as to support reliable operation of the grid.

49. CYBER SECURITY AUDIT

All users shall conduct Cyber Security Audit as per the guidelines mentioned in the CEA (Cyber Security in Power Sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority.

50. MECHANISM OF REPORTING

(1) All entities shall immediately report to the appropriate government agencies in accordance with the Information Technology Act, 2000 in case of any cyber-attack.

(2) NLDC, RLDCs, SLDCs, RPCs and the Commission shall also be informed by such entities in case of any instance of cyber-attack.

CHAPTER 9

MONITORING AND COMPLIANCE CODE

51. GENERAL

This chapter deals with (a) monitoring of compliance of these regulations by various entities in the grid by RLDCs, RPCs or any other person, (b) manner of reporting the instances of violations of these regulations and (c) taking remedial steps or initiating appropriate action.

52. ASSESSMENT OF COMPLIANCES

The performance of all users, CTU, STUs, NLDC, RLDCs, SLDCs and RPCs with respect to compliance of these regulations shall be assessed periodically.

53. MONITORING OF COMPLIANCE

(1) In order to ensure compliance, two methodologies shall be followed:

(a) Self-Audit

(b) Compliance Audit

(2) Self –Audit:

(a) All users, CTU, STUs, NLDC, RLDCs, RPCs and SLDCs shall conduct annual self-audits to review compliance of these regulations and submit the reports by 31st July of every year.

(b) The self-audit report shall inter alia contain the following information with respect to non-compliance:

(i) Sufficient information to understand how and why the non-compliance occurred;

(ii) Extent of damage caused by such non-compliance;

(iii) Steps and timeline planned to rectify the same;

(iv) Steps taken to mitigate any future recurrence;

(c) The self-audit reports by users shall be submitted to the concerned RLDC or SLDC, as the case may be.

(d) The self-audit reports of NLDC, RLDCs, CTU, and RPCs shall be submitted to the Commission. The self-audit report of SLDC and STUs shall be submitted to the concerned SERC.

(e) The deficiencies shall be rectified in a time bound manner within a reasonable time.

(f) The monitoring agency for users shall be the concerned RLDC or SLDC on the basis of their respective control area. The monitoring agency shall track the progress of compliances of users, and exceptional reporting for non-compliance shall be submitted to the appropriate Commission.

(g) The monitoring agency for RLDC, NLDC, CTU and RPC shall be the Commission, and for STUs and SLDCs, shall be the concerned SERC.

(h) The Regional Power Committee (RPC) in the region shall also continuously monitor the instances of non-compliance of the provisions of these regulations and endeavor to sort out all operational issues and deliberate on the ways in which such cases of non-compliance shall be prevented in future by building consensus. The Member Secretary of respective RPCs may also report any unresolved issues to the Commission.

(i) The Commission may initiate appropriate proceedings upon receipt of report under sub-clauses (f) and (h) above.

(j) In case of non-compliance of any provisions of these regulations by NLDC, RLDCs, SLDCs, RPCs and any other person, the matter may be reported by any person to the Commission through filing of a petition.

(3) Independent Third-Party Compliance Audit:

The Commission may order independent third-party compliance audit for any user, CTU, NLDC, RLDC and RPC as deemed necessary based on the facts brought to the knowledge of the Commission.

CHAPTER 10
MISCELLANEOUS

54. POWER TO RELAX

The Commission, for reasons to be recorded in writing, may relax any of the provisions of these regulations on its own motion or on an application made before it by an affected person to remove the hardship arising out of the operation of any of these regulations, applicable to a class of persons.

55. POWER TO REMOVE DIFFICULTY

If any difficulty arises in giving effect to the provisions of these regulations, the Commission may, on its own motion or on an application made before it by the nodal agency, by order, make such provisions not inconsistent with the provisions of the Act or provisions of other regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of these regulations.

56. REPEAL AND SAVINGS

(1) Save as otherwise provided in these regulations, Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 and all subsequent amendments thereof shall stand repealed from the date of commencement of these Regulations.

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

57. ISSUE OF SUO MOTO ORDERS AND DIRECTIONS

The Commission may from time to time issue suo moto orders and practice directions with regards to implementation of these regulations and matters incidental or ancillary thereto, as the case may be.

(Harpreet Singh Pruthi)

Secretary

ANNEXURE - 1

THIRD PARTY PROTECTION SYSTEM CHECKING & VALIDATION TEMPLATE FOR A SUBSTATION

(1) Introduction

(1) The audit reports, along with action plan for rectification of deficiencies found, if any, shall be submitted to RPC or RLDC within a month of submission of report by auditor.

(2) The third-party protection system checking shall be carried at site by the designated agency. The agency shall furnish two reports:

I. Preliminary Report: This report shall be prepared on the site and shall be signed by all the parties present.

II. Detailed Report: This report shall be furnished by agency within one month after carrying out detailed analysis.

(2) Checklist

(1) The protection system checklist shall contain information as per this Regulation.

1) General Information (to be provided prior to the checking as well as to be included in final report):

a) Substation name

b) Name of Owner Utility

c) Voltage Level (s) or highest voltage level?

d) Short circuit current rating of all equipment (for all voltage level)

e) Date of commissioning of the substation

f) Checking and validation date

g) Record of previous tripping's (in last one year) and details of protection operation

h) Previous Relay Test Reports

i) Overall single line diagram (SLD)

j) AC aux SLD

k) DC aux SLD

l) SAS architecture diagram

m) SPS scheme implemented (if any)

2) The preliminary report shall inter-alia contain the following:

TABLE J: FORMAT OF PRELIMINARY REPORT

S. No.	Issues	Remarks
1	Recommendation of last protection checking and validation	Status of works and pending issues if any
2	Review of existing settings at substation	Recommended Action
3	Disturbance Recorder out available for last 6 tripping's (Y/N)	Recommended Action
4	Chronic reason of tripping, if any	Recommended Action
5	Major non-conformity/deficiency observed	Recommended Action

3) The relay configuration checklist for available power system elements at station:

a) Transmission Line

b) Bus Reactor/Line Reactor

c) Inter-connecting Transformer

d) Busbar Protection Relay

e) AC auxiliary system

f) DC auxiliary system

g) Communication system

h) Circuit Breaker Details

i) Current Transformer Details

j) Capacitive Voltage Transformers Details

k) Any other equipment/system relevant for protection system operation

4) The minimum set of points on which checking and validation shall be carried out is covered in this clause. The detailed list shall be prepared by checking and validation team in consultation with concerned entity, RLDC and RPC.

a) Transmission Line Distance Protection/Differential Protection

(a) Name and Length of Line

(b) Whether series compensated or not

(c) Mode of communication used (PLCC/OPGW)

(d) Relay Make and Model for Main-I and Main-II

(e) List of all active protections & settings

(f) Carrier aided scheme if any

(g) Status of Power Swing/Out of Step/SOTF/Breaker Failure/Broken Conductor/STUB/Fault Locator/DR/VT fuse fail/Overvoltage Protection/Trip Circuit supervision/Auto-reclose/Load encroachment etc.

(h) Relay connected to Trip Coil-1 or 2 or both

(i) CT ratio and PT ratio

(j) Feed from DC supply-1 or 2

(k) Connected to dedicated CT core (mention name)

(l) Other requirements for protection checking and validation

b) Shunt Reactor & Inter-connecting Transformer Protection

(a) Whether two groups of protections used (Group A and Group B)

(b) Do the groups have separate DC sources

(c) Relay Make and Model

(d) List of all active protections along with settings

(e) Status of Differential Protection/Restricted Earth Fault Protection/Back-up Directional Overcurrent/Backup Earth fault/ Breaker Failure

(f) Status of Oil Temperature Indicator/Winding Temperature Indicator/Bucholz/Pressure Release Device etc.

(g) Relay connected to Trip Coil-1 or 2 or both

(h) CT ratio and PT ratio

(i) Feed from DC supply-1 or 2

(j) Connected to dedicated CT core (mention name)

(k) Other requirements for protection checking and validation

c) Busbar Protection Relay

(a) Busbar and redundant relay makes and models

(b) Type of Busbar arrangement

(c) Zones

(d) Dedicated CT core for each busbar protection (Yes/No)

(e) Breaker Failure relay included (Yes/No), if additional then furnish make and model

(f) Trip issued to both Busbar protection in case of enabling

(g) Isolator indication and check relays

(h) Other requirements for protection checking and validation

d) AC auxiliary system

(a) Source of AC auxiliary system

(b) Supply changeover between sources (Auto/Manual)

(c) Diesel generator (DG) details

(d) Maintenance plan and supply changeover periodicity in DG

(e) Single Line Diagram

(f) Other requirements for protection checking and validation

e) DC auxiliary system

(a) Type of Batteries (Make, vintage, model)

(b) Status of battery Charger

(c) Measured voltage (positive to earth and negative to earth)

(d) Availability of ground fault detectors

(e) Protection relays and trip circuits with independent DC sources

(f) Other requirements for protection checking and validation

(g) Communication system

(i) Mode of communication for Main-1 and Main-2 protection

(ii) Mode of communication for data and speech communication

(iii) Status of PLCC channels

(iv) Time synchronization equipment details

(v) OPGW on geographically diversified paths for Main-1 and main-2 relay

(vi) Other requirements for protection checking and validation

f) Circuit Breaker Details

(a) Details and Status

(b) Healthiness of Tripping Coil and Trip circuit supervision relay

(c) Single Pole/Multi pole operation

(d) Pole Discrepancy Relay available(Y/N)

(e) Monitoring Devices for checking the dielectric medium

(f) Other requirements for protection checking and validation

g) Current Transformer (CT)/Capacitive Voltage Transformer (CVT) Details

(a) CT/CVT ID name and voltage level

(b) CT/CVT core connection details

(c) Accuracy Class

(d) Whether Protection/Metering

(e) CT/CVT ratio available and ratio adopted

(f) Details of last checking and validation of CT/CVT healthiness

(g) Other requirements for protection checking and validation

(h) Other protections: Direction earth fault, negative sequence, over current, over voltage, over frequency, under voltage, under frequency, forward power, reverse power, out of step/power swing, HVDC protection etc.

5) Summary of Checking: The summary shall specifically mention minimum following points:

(i) The settings and scheme adopted are in line with agreed protection philosophy or any accepted guidelines (e.g. Ramakrishna guidelines or CBIP manual based).

(ii) The deviations from the RPC protection philosophy, if any and reasons for taking the deviations shall be recorded.

(iii) All the major general deficiency shall be listed in detail along with remedial recommendations.

(iv) The relay settings to be adopted shall be validated with simulation based or EMTP studies and details shall be enclosed in report.

(v) The cases of protection maloperation shall be analysed from protection indices report furnished by concerned utility, the causes of failure along with corrective actions and recommendations based on the findings shall be noted in the report.

ANNEXURE - 2
GENERATION RESERVE ESTIMATION AND FREQUENCY CONTROL

1. Introduction

   This procedure is in line with the clause 30(10)(f) of IEGC which requires methodology for the following:

(1) Assessment of reference contingency,

(2) All India minimum target frequency response characteristics,

(3) Calculation of frequency response obligation of each control area,

(4) Criteria for reportable event,

(5) Calculation of actual frequency response characteristics of control area and

(6) Calculation of frequency response performance

2. The requirements are detailed in the points given below:

(1) Assessment of Reference Contingency

The reference contingency is the quantum of sudden generation or demand outage in an event. The reference contingency shall consider quantum of generation outage based on outage of largest power plant, group of power plants, a generation complex, or a generation pooling station, or the actual generation outage occurred in an event during last two years, or a credible outage scenario. Similarly reference contingency shall also consider outage of single largest load center or actual outage of load occurred in an event during last two years. To start with reference contingency shall be considered as outage of 4500 MW which shall be revised by NLDC from time to time. The primary reserve at All India level shall be more than the reference contingency quantum. Therefore, minimum quantum of primary reserve shall be currently 4500 MW.

(2) All India minimum target frequency response characteristics

(a) The all India minimum target frequency response characteristic (MW/Hz) shall be reference contingency quantum (MW) divided by maximum steady frequency deviation (Hz) allowable for the reference contingency event.

(b) The primary reserves shall be activated immediately (within few seconds) when the frequency deviates from 50 Hz. 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 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.

(c) Therefore, the minimum All India target Frequency Response Characteristic currently shall be quantum of load or generation loss in reference contingency (as defined in Section (1) above divided by frequency deviation value of 0.3 Hz i.e. 15000 MW/Hz (4500 MW/0.3 Hz).

(3) Calculation of Frequency Response Obligation (FRO) of each control area:

The minimum Frequency Response Obligation (FRO) of each control area in MW/Hz 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)

Provided FRO shall be nil in case of a control area not having any generation resources, such as Goa, DD, DNH etc.

(4) Criteria for reportable event:

The frequency response characteristic (FRC) calculation shall be carried out by each control area for any load or generation loss incident involving net change of more than 1000 MW of load or generation or a frequency change involving 0.1 Hz or more. The event shall be notified by the NLDC.

(5) Calculation of actual frequency response characteristics of control area

(a) Frequency Response Characteristics (FRC) computations:

Frequency Response Characteristics (FRC) will be computed for all events involving a sudden 1000 MW or more load or generation loss or a step change in frequency by 0.10 Hz i.e. for all reportable events as notified by NLDC. The FRC shall be worked out by NLDC, RLDCs and SLDCs to for each interconnection/region/control area (including for each generating station). Each generating station shall also compute it's FRC. The following steps shall be followed for computation of FRC

(i) After every event involving a sudden 1000 MW or more load or generation loss or a step change in frequency by 0.1 Hz, NLDC would get the PMUs frequency data. NLDC would also get the exact quantum of load/generation lost from the RLDC of the affected region.

(ii) NLDC shall plot the frequency graph and determine the initial frequency, minimum/maximum frequency, settling frequency and time points (points A, C and B of the Figure-a). Accordingly, frequency difference points & corresponding time to be used for FRC calculations would be informed to all RLDCs.

(iii) NLDC shall also work out region wise and neighboring countries (Bhutan and Nepal) FRC (Format as per Table - B) based on 10 second Historical Data Recording (HDR) data available at NLDC and inform all RLDCs within three (3) working days. RLDCs shall inform the SLDCs/regional entities in their region.

(iv) RLDCs shall also work out each control area wise FRC (Format as per Table -B) based on HDR data available at RLDCs within six (6) working days after the event.

(v) All the SLDCs shall work out FRC for all the intrastate entities (for events indicated by the Regional Load Despatch Centres) based on the HDR available at their respective SLDCs and submit the same to respective RLDC within six (6) working days after the event. (Format as per Table-B).

(vi) All regional entity generating stations shall also assess the FRC for their respective stations and submit the same to respective RLDC within six (6) working days. (Format as per Table-B). The high resolution data (1 second or better resolution) of active power generation and frequency shall also be shared with RLDC.

(b) Input data for FRC:

(i) The data for frequency response characteristic Calculations may be taken from the real time telemetered data recorded by the SCADA systems installed at Control Areas / Regional Load Despatch Centres / National Load Despatch Centre.

(ii) Bad quality of data could be flagged / mentioned by the control centre (s) and reasonable assumptions made for FRC computation. Details of these may be mentioned.

(c) Instructions for computation of FRC:

A sample frequency chart given at Figure-a with points A, B, and C labeled, depicts a typical frequency excursion caused by a loss of a large generator in Indian power system. Point A denotes the interconnection frequency immediately before the disturbance. Point B represents the Interconnection frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent area takes any corrective actions, automatic or manual. Point C represents the interconnection frequency at its maximum deviation due to the loss of generation.

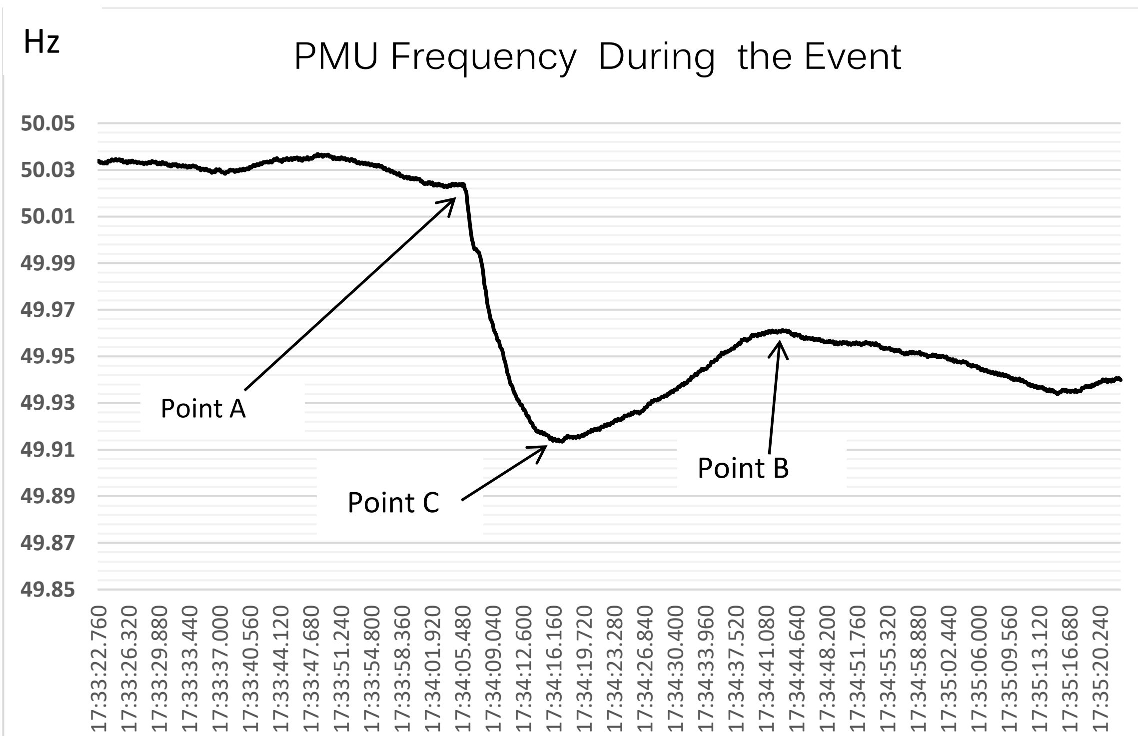


FIGURE A: SAMPLE PMU FREQUENCY PLOT SHOWING RELEVANT POINTS FOR FRC CALCULATION

(d) Steps to work out frequency response characteristics of control area are as follows: -

Step-1: Actual net interchange of the control area immediately before the disturbance (Point – A in the figure-a), say P_A. Sign convention for net power imported into a Control Area is positive (+) and net power exported out of a control area is negative (-).

Step-2: Actual net interchange of the control area immediately after the disturbance (Point – B in the figure-a), say P_B. Use the same sign convention as Step-1.

Step-3: The change in net interchange of the Control Area = (P_B -P_A). [For a disturbance that causes the frequency to decrease, this value should ideally be negative. The net interchange of a control area may be positive, if the drop in generation has occurred in that control area. Similarly, for load throw off or frequency rise cases in a control area, the net interchange shall normally be positive except for the Control Area, where the load throw off has taken place.]

Step-4: If the control area has suffered the loss, then Load or generation lost by the control area = PL. Otherwise, the loss (PL) is zero. Sign convention for Load Loss is negative (-) and Generation Loss positive (+).

Step-5: The Control Area Response Δ P = (PB-PA) - PL

Step-6: The Frequency immediately before the disturbance = fA.

Step-7: The Frequency immediately after the disturbance = fB.

Step-8: Change in Interconnection Frequency from Point A to Point B = Δf = (fB - fA)

Step-9: Frequency Response Characteristic (FRC) of the Control Area = Δ P/ Δf

Step-10: Frequency Response Obligation (FRO) of each control area calculated in advance as per Clause 3 of this Annexure

Step 11: Frequency Response Performance (FRP) = Actual Frequency Response Characteristic (AFRC)/ Frequency Response Obligation (FRO)

TABLE K: FRC CALCULATION SHEET TO BE USED BY ALL SLDC/RLDC/NLDC/CONTROL AREA

S. No	**Particulars**	**Dimension**	**Control Area-1 /Region**
1	Actual Net Interchange before the Event (Time= hh:mm:ss)	MW	
2	Actual Net Interchange after the Event (Time= hh:mm:ss)	MW	
3	Change in Net Interchange (2 - 1)	MW	
4	Generation Loss (+) / Load Throw off (-) during the Event	MW	
5	Control Area Response (3-4)	MW	
6	Frequency before the Event	Hz	
7	Frequency after the Event	Hz	
8	Change in Frequency (7-6)	Hz	
9	Frequency Response Characteristic (5 / 8)	MW/Hz	
10	Frequency Response Obligation (FRO) of control area	MW/Hz	
11	Frequency Response Performance (FRP)(9/10)	Numeric value (upto two decimal places)	

(6) Calculation of frequency response performance

(a) The performance of each control area in providing frequency response characteristic shall be calculated for each reportable event. Each control area shall separately assess their frequency response characteristic and share with RLDC along with high resolution data of at least one (1) second for regional entity generating stations and ten (10) second for state control area.

Frequency Response Performance (FRP) = Actual Frequency Response Characteristic (AFRC)/ Frequency Response Obligation (FRO)

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

TABLE L: 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

**Provided that for wind/solar generating stations and state control areas with internal generation less than 100 MW or annual peak demand less than 1000 MW, the FRP grading shall be indicative only.*

ANNEXURE-3

ASSESSMENT OF SECONDARY AND TERTIARY GENERATION RESERVES AT REGIONAL/STATE LEVEL

1. Area control error (ACE) for each Control Area shall be calculated using Regulation 30(11)(d), time blockwise for the last financial year.
2. The positive ACE and negative ACE shall be separately tabulated.
3. The positive ACE shall be arranged in ascending order and 99 percentile of such ACE shall be captured. Similarly, negative ACE shall be arranged in ascending order and 99 percentile of such ACE shall be captured.
4. Such 99 percentile of positive and negative ACE respectively of a control area for previous financial year, is the desired positive and negative secondary reserve capacity for such control area for next financial year. Desired quantum of tertiary reserve of the control area shall also be equal to such estimated secondary reserve.
5. The total reserves in a region shall be algebraic sum of reserves in each state control area. However, due to diversity within the region, the Region as a whole might need lesser reserves of secondary and tertiary reserves. As such, All India reserve capacity is taken as equal to reference contingency i.e 4500 MW and this reserve requirement shall be distributed pro-rata amongst the regions based on regional ACE which shall further be divided to identify the share of each state based on 99 percentile ACE of such State control area.
6. The amount of reserve to be kept with each State control area at Step 5 shall be validated against the maximum unit size of the intra-state generator of that control area such that reserve requirement is not more than unit size of maximum intra-state generator.

7. The secondary reserves for each control area obtained at Step 5 shall be further apportioned among the reserve to be kept at intra-state generation and at inter-state generation as per the following formulation:

   (1) The maximum demand and maximum internal generation are listed for each control area.

   (2) The ratio of demand met through internal generation and inter-state generation (drawl from the grid) is calculated.

   (3) The above ratio is used to apportion the secondary reserve obtained in Sl. No. 5 among the reserves to be maintained by each control area at intra-state generators and inter-state generators.

   Illustration: The maximum demand met of Punjab is 13602 MW and internal generation is 6932 MW. The drawl from the grid is therefore 13602-6932= 6670 MW. Suppose the reserve capacity calculated for Punjab in step-5 is 91 MW. The ratio of demand met by internal generation is 0.51(6932/13602) and by ISGS generation is 0.49 (6670/13602). Thus reserve to be kept by Punjab in intra-state generation is 46 MW(0.51*91) and in ISGS generation is 44 MW (0.49*91).

8. For control areas having no generation or very small generation, the entire reserves capacity calculated at step-5 for the state, shall be kept at inter-state generation.

ANNEXURE - 4

1. Reactive Power Compensation

(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.

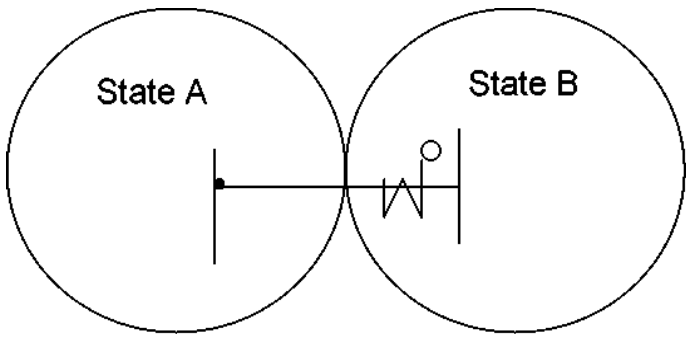
(3) All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per CEA Connectivity Standards, all the time including non-operating hours and night hours for solar. The active power consumed by these devices for purpose of 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

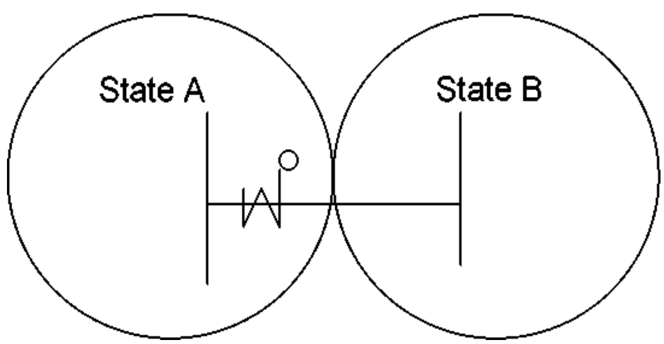
act as aggregator for the Reactive Energy Charges for payments to andfrom the Pool Account at RLDC level. The de-pooling of Reactive Energy charges amongst the individual wind and solar shall be done by the Power Park Developer.

2. Payment for Reactive Energy Exchanges On State-Owned Lines

<u>Case – 1</u>: Interconnecting line owned by State-A Metering Point: Substation of State-B

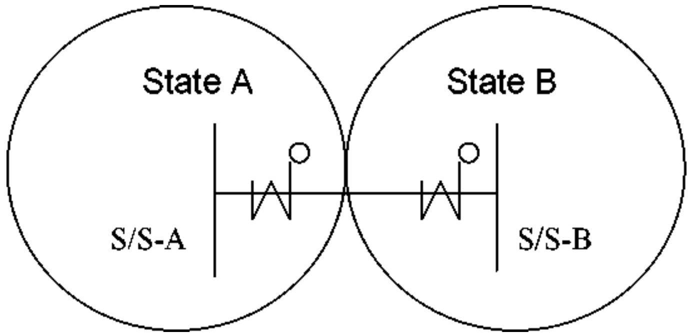


<u>Case - 2</u>: Interconnecting line owned by State-B Metering point: Substation of State-A



Note: Net VArh and net payment may be positive or negative

<u>Case – 3</u>: Interconnecting line is jointly owned by States-A and –B. Metering points: Substations of State-A and State-B



Net VArh exported from S/S-A, while voltage < 97% = X_1 Net VArh exported from S/S-A, while voltage > 103% = X_2 Net VArh imported at S/S-B, while voltage < 97% = X_3 Net VArh imported at S/S-B, while voltage > 103% = X_4

(i) State-B pays to State-A for X_1 or X_3, whichever is smaller in magnitude, and

(ii) State-A pays to State-B for X_2 or X_4, whichever is smaller in magnitude.

Note:

I. *Net VArh and net payment may be positive or negative.*

II. *In case X_1 is positive and X_3 is negative, or vice-versa, there shall be no payment under (i) above.*

III. *In case X_2 is positive and X_4 is negative, or vice-versa, there shall be no payment under (ii) above.*

3. Accounting And Payment For Reactive Energy Exchanges

(a) RPC Secretariat shall also issue the weekly statement for VAR charges, to all regional entities.

(b) The concerned regional entities shall pay the amounts into regional reactive pool account operated by the RLDC within 10 (ten) days of issue of statement.

(c) The regional entities who have to receive the money on account of VAR charges would then be paid out from the regional Deviation and Ancillary Service Pool Account, within two(2) working days from the receipt of payment in the Deviation and Ancillary Service Pool Account.

(d) If payments against the above VAr charges are delayed by more than two days, i.e., beyond twelve (12) days from issue of the statement by RPC Secretariat, the defaulting regional entity shall pay simple interest @ 0.04% for each day of delay. The interest so collected shall be paid to the regional entities who had to receive the amount, payment of which got delayed.

(e) Persistent payment defaults, if any, shall be reported by the RLDC to the Member Secretary, RPC, for initiating remedial action.

ANNEXURE-5

PROCEDURE SPECIFYING DATA, FORECASTING AND SCHEDULING FOR RENEWABLE ENERGY GENERATING STATIONS (REGS) AT INTER-STATE LEVEL

1. Introduction

(1) This procedure contains requirements of data submission by Renewable Energy Generating Station or the Qualifying Coordinating Agency (QCA) on behalf of Renewable Energy Generating Station(s), prior to COD and real time and scheduling methodology to be followed for multiple renewable energy generating station(s) connected at a pooling station.

(2) The responsibility to provide forecast and other data and to coordinate with RLDC under this Procedure shall be that of QCA on behalf of all generating stations it is representing.

Provided that where the QCA is not identified, individual renewable energy generating station or lead generator, as the case may be, shall be responsible for the same.

2. Role of Entities

(1) QCA or Renewable Energy Generating Station or Lead Generator

(a) The individual generating station or Lead Generator shall submit one time details to conc0erned RLDC as per Appendix-I to this Procedure. Further, if there is any change in the information furnished, then the updated information shall be shared with the concerned RLDC not later than 7 working days of such change.

(b) QCA (for the REGSs it is representing) or REGS (who are not represented through QCA) or Lead Generator, as the case may be, shall undertake the following activities:

(i) Shall undertake technical coordination amongst the generating stations it is representing, connected at a pooling station.

(ii) Provide to concerned RLDC, Available Capacity, Day ahead forecast (based on their own forecast or on the forecast done by RLDC) and Schedule as per Appendix-II through web-based application maintained by RLDCs.

(iii) Provide to concerned RLDC, real time data at turbine/inverter level and generation data at pooling station level as per Appendix-III.

(iv) Provide to concerned RLDC, monthly data:

a. For wind plants- average wind speed, average power generation for 15-min time block for each turbine

b. For solar plants - average solar irradiation, average power generation at 15-min time block level for all inverters* >=1 MW

* if a solar plant uses only smaller string inverters, then data may be provided at the plant level

(v) Be responsible for metering and data collection and co-ordination with RLDC, SLDC, RPC, CTU and other agencies as per IEGC and extant CERC Regulations issued by the Commission as amended from time to time.

(vi) Undertake commercial settlement for deviation as per applicable Regulations issued by the Commission.

(vii) Submit a copy of the agreement entered between QCA and generating stations authorizing QCA specific responsibilities on behalf of generating stations, to the concerned RLDC.

(viii) Use Automatic meter reading technologies for transfer, analysis and processing of interface meter data.

(ix) Shall furnish the contract rate(s) along with a copy of the contract(s), for the purpose of Deviation charge account preparation, to respective RPC.

(x) Shall comply the instruction of respective RLDCs in normal operation as well as emergency condition.

(xi) Shall establish protocol for communication with individual generators to implement the instructions of RLDCs effectively.

(xii) Shall maintain records and accounts of the time-block wise Schedules, the Actual generation injected and the deviation, for the pooling station and individual generator(s) separately.

(xiii) Shall ensure availability of data telemetry at the turbine/inverter level to the concerned RLDC and shall ensure the correctness of the real-time data and undertake the corrective actions, if required. The suggested data telemetry requirement is enclosed at Appendix-III.

(xiv) Keep each of the RLDCs indemnified at all times and shall undertake to indemnify, defend and save the SLDCs/RLDCs harmless from any and all damages, losses including commercial losses due to forecasting error, claims and actions including those relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the transactions undertaken by the Generators.

(2) RLDC

(a) The concerned RLDC shall be responsible for scheduling, communication, coordination with QCA or generating station or Lead Generator.

(b) The concerned RLDC will be responsible for processing the interface meter data and computing the net injections at pooling station represented by each QCA or REGS or Lead Generator, as the case may be, as specified in Annexure- V.

3. Forecasting

(1) QCA or generating station or Lead Generator shall provide the forecast to the concerned RLDC which may be based on their own forecast or RLDC's forecast as per Appendix-II.

(2) A generating station, or a Lead Generator or QCA on behalf of generating stations, may prepare schedule based RLDC's or their own forecast. Any commercial impact on account of deviation from schedule based on the forecast chosen by the generating station, or a Lead Generator or QCA shall be borne by the respective generating station, or a Lead Generator or QCA.

4. Scheduling and Despatch

(1) Following alternatives exist for Scheduling and Despatch for Generators within Solar / Wind /Hybrid Power parks due to multiple generation developers within the Park injecting at various points within the park and ultimately injecting at interface with ISTS:

Case-1 QCA has been identified for all generating stations connected at a pooling station.

Case-2 Where QCA at a pooling station is identified for some of the generating stations but not all of generating stations at such pooling station

Case-3 Where QCA at a pooling station is not identified following situations may arise

Case-A: The concerned RLDC shall be responsible for the scheduling, communication, coordination with REGS of 50 MW and above and connected to Inter State Transmission System (ISTS).

Case-B: Lead generator shall be responsible for the coordination and communication with RLDC, SLDC, RPC and other agencies for scheduling of REGSs individually having less than 50 MW, but collectively having an aggregate installed capacity of 50 MW and above and connected within the solar park.

Block diagram for Case-1, Case-2, Case-3 shall be as per Appendix-IV.

(2) For Case-1, QCA shall be responsible for doing de-pooling of DSM charges as per the mutual agreement between generating stations and QCA.

(3) For Case- 2 and Case- 3, where scheduling and accounting is to be coordinated by RLDC, a representative sketch showing the scheduling is at Annexure-IV.

(4) The change of QCA would need a notice period of fifteen (15) days and the changeover shall take place with effect from 0000 hours of a Monday, the first day of weekly settlement cycle.

(5) In case of any payment default by the QCA, the generating stations shall be liable to pay the DSM charges in proportion to their MW capacity.

Appendix-I

Details to be submitted by the Wind/Solar generating stations which are regional entities/ lead generator	
Type: Wind/Solar Generator	
Individual / on Behalf of Group of generating stations	
If on Behalf of Group of generating stations group of then details of agreement to be attached	
Total Installed Capacity of Generating Station	
Total Number of Units with details	
Physical Address of the RE Generating Station	
Whether any PPA has been signed: (Y/N)	If yes ,then attach details
Connectivity Details	Location/Voltage Level
Metering Details	Meter No. 1. Main 2. Check
Connectivity Diagram	(Please Enclose)
Static data	As per attached sheet
Contact Details of the Nodal Person	Name : Designation : Number: Landline Number, Mobile Number, Fax Number
Contact Details of the Alternate Nodal Person	Name : Designation : Number: Landline Number, Mobile Number, Fax Number

Data to be submitted by the REGS / lead generator for Wind turbine generating plants

S No	Particulars
1	**Type**
2	Manufacturer
3	Make /Model
4	Capacity
5	COD
6	Hub height
7	Total height
8	RPM range
9	Rated wind speed
Performance Parameters	
10	Rated electrical power at rated wind speed
11	Cut in speed
12	Cut out speed
13	Survival speed (Max wind speed)
14	Ambient temperature for out of operation
15	Ambient temperature for in operation
16	Survival temperature
17	Low Voltage Ride Through (LVRT) setting
18	High Voltage Ride Through (HVRT) setting
19	Lightning strength (KA & in coulombs)
20	Noise power level (db)
21	Rotor

22	Hub type
23	Rotor diameter
24	Number of blades
25	Area swept by blades
26	Rated rotational speed
27	Rotational Direction
28	Coning angle
29	Tilting angle
30	Design tip speed ratio
Blade	
31	Length
32	Diameter
33	Material
34	Twist angle
Generating station	
35	Generator Type
36	Generator no of poles
37	Generator speed
38	Winding type
39	Rated Gen.Voltage
40	Rated Gen. frequency
41	Generator current
42	Rated Temperature of generator
43	Generator cooling
44	Generator power factor
45	KW/MW @ Rated Wind speed
46	KW/MW @ peak continuous

47	Frequency Converter

48	Filter generator side
49	Filter grid side
Transformer	
50	Transformer capacity
51	Transformer cooling type
52	Voltage
53	Winding configuration
Weight	
54	Rotor weight
55	Nacelle weight
56	Tower weight
57	**Over speed Protection**
58	**Design Life**
59	**Design Standard**
60	Latitude
61	Longitude
62	COD Details
63	Past Generation History from the COD to the date on which DAS facility provided at RLDC, if applicable
64	Distance above mean sea level

For Solar generating stations: Static data points:

1. Latitude
2. Longitude
3. Turbine Power Curve
4. Elevation and orientation angles of arrays or concentrators
5. The generation capacity of the Generating Facility
6. Distance above mean sea level etc.
7. COD details
8. Rated voltage
9. Details of Type of Mounting: (Tracking Technology If used, single axis or dual axis, auto or manual)
10. Manufacturer and Model (of Important Components, Such as Turbine, Concentrators, Inverter, Cable, PV Module, Transformer, Cables)
11. DC installed Capacity
12. Module Cell Technology
13. I-V Characteristic of the Module
14. Inverter Rating at different temperature
15. Inverter Efficiency Curve
16. Transformer Capacity & Rating, evacuation voltage, distance form injection point

Appendix-II

Forecast and Schedule Data to be submitted by QCA, generating station-wise

<u>FORMAT: A (to be submitted a day in advance)</u>

15 Min time block (96 Block in a day)	TIME	Available Capacity (MW) - Day Ahead	Day Ahead Forecast (MW)	Day Ahead Schedule (MW)
1	00:00-00:15			
2	00:15-00:30			
3	00:30-00:45			
4	00:45-01:00			
.				
94				
95				
96				

Note: The forecast should ideally factor forecasting errors.

FORMAT: B (to be submitted on the day of actual generation, revision of availability and schedule, if any, shall be done as per these regulations.

15 Min time block (96 Block in a day)	TIME	Day ahead schedule (MW)	Current Available Capacity (MW)	Revised Schedule (MW)
1	00:00-00:15			
2	00:15-00:30			
3	00:30-00:45			
4	00:45-01:00			
.				
94				
95				
96				

Appendix-III

Real-time Data Telemetry requirement (Suggested List)

Wind turbine generating plants

1. Turbine Generation (MW/MVAR)
2. Wind Speed(meter/second)
3. Generator Status (on/off-line)- this is required for calculation of availability of the WTG
4. Wind Direction (degrees from true north)
5. Voltage(Volt)
6. Ambient air temperature (^{o} C)
7. Barometric pressure (Pascal)
8. Relative humidity(in percent)
9. Air Density (kg/m^3)

For Solar generating Plant s

1. Solar Generation unit/ Inverter-wise (MW and MVAR)
2. Voltage at interconnection point (Volt)
3. Generator/Inverter Status (on/off-line)
4. Global horizontal irradiance (GHI)- Watt per meter square
5. Ambient temperature (^{o}C)
6. Diffuse Irradiance- Watt per meter square
7. Direct Irradiance- Watt per meter square
8. Sun-rise and sunset timings
9. Cloud cover-(Okta)
10. Rainfall (mm)
11. Relative humidity (%)
12. Performance Ratio-

Appendix-IV

Block Diagram showing the case wise Scheduling and Forecasting considering a sample case

Case-I (QCA responsible for all generating stations) :

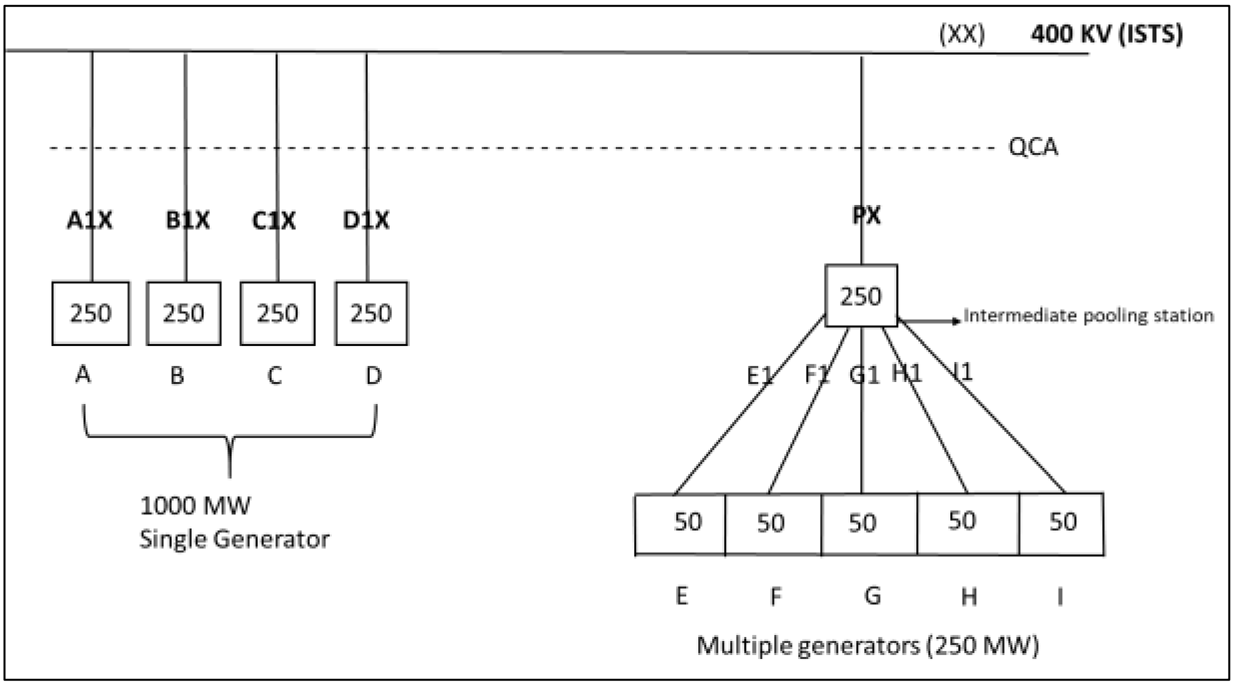


FIGURE B: QCA RESPONSIBLE FOR ALL GENERATING STATIONS

(a) Suppose an REGS of 1000 MW capacity is developed in four blocks namely A,B,C & D of 250 MW capacity each and is directly connected to point A1,B1,C1& D1 respectively at ISTS. Let REGSs of 50 MW each aggregating to 250 MW (5 Nos. namely E, F, G, H & I) be connected to intermediate pooling station. REGSs are connected to interface point E1, F1, G1, H1& I1 and thereby connected to ISTS at XX point.

(b) Suppose all the REGSs have mutually agreed to appoint a QCA for all scheduling and forecasting activities, such QCA, shall be responsible for carrying out activities as assigned under this Code.

Case-2 (QCA responsible for some of the generating stations):

A. QCA is responsible for all REGS connected at Intermediate pooling station

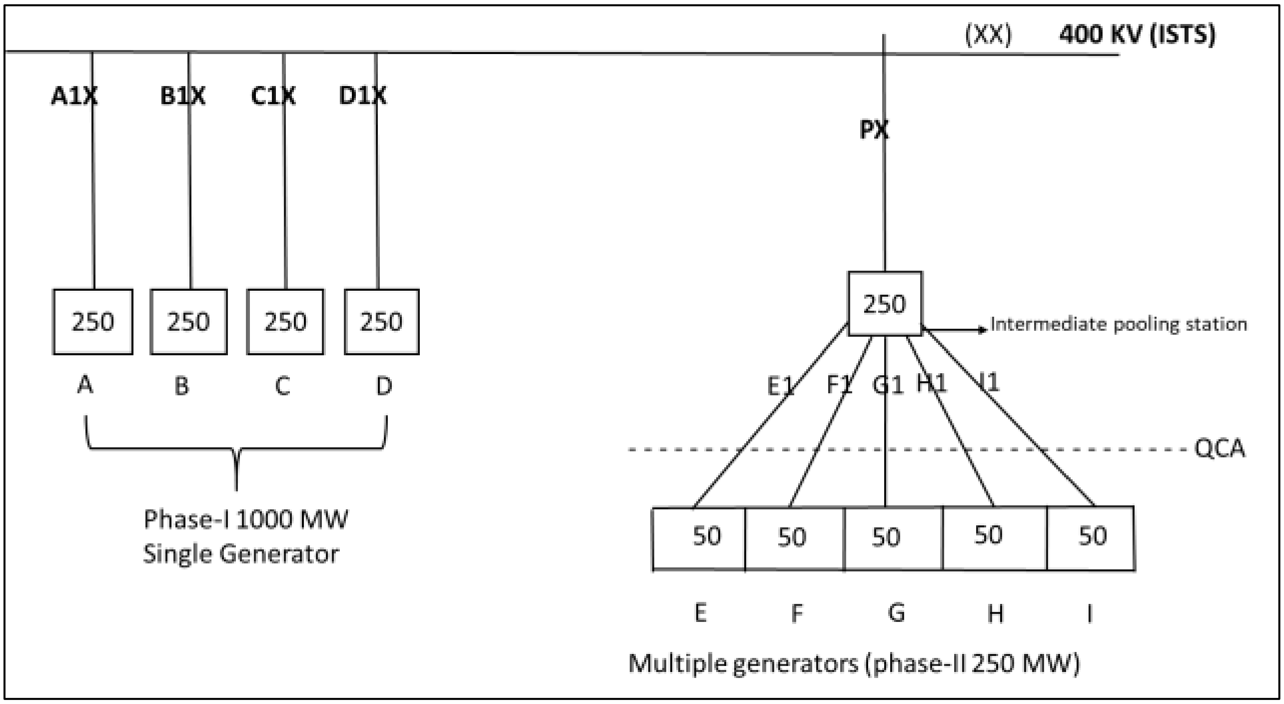


FIGURE C: QCA RESPONSIBLE FOR ALL REGS CONNECTED AT INTERMEDIATE POOLING STATION

B. QCA responsible for some REGS connected at Intermediate pooling station

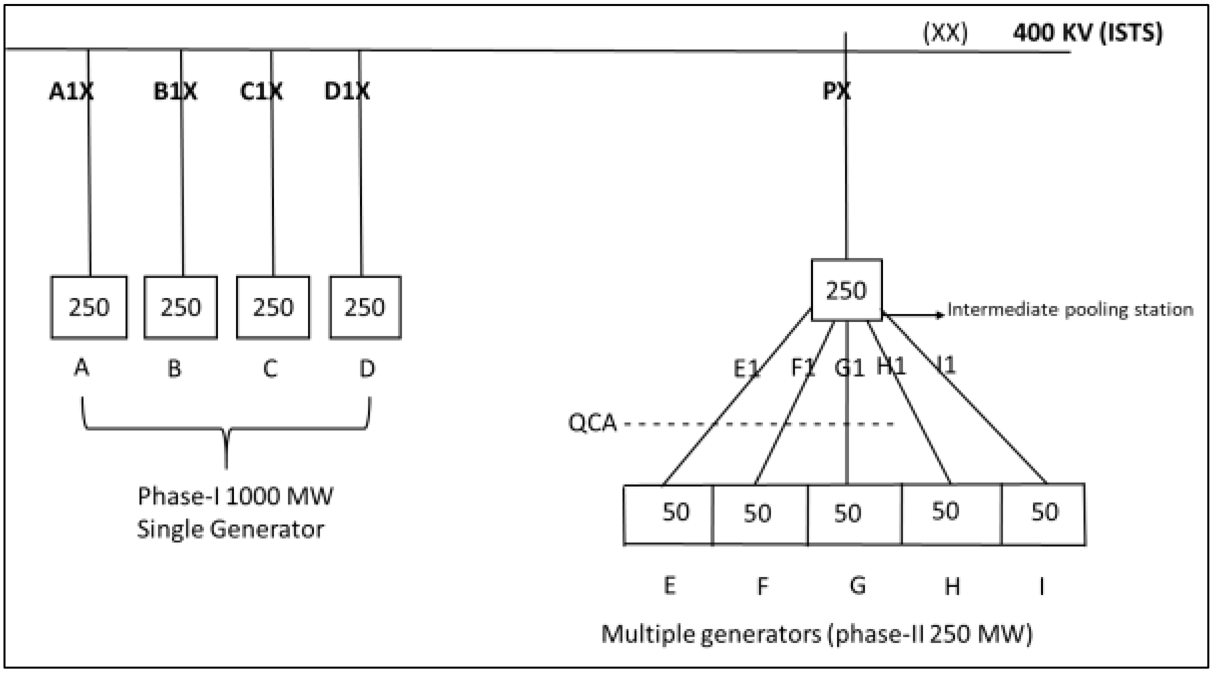


FIGURE D: QCA RESPONSIBLE FOR SOME OF THE REGS AT INTERMEDIATE POOLING STATION

In each of the above scenarios, the QCA shall be responsible for coordination of scheduling and de-pooling of DSM charges for all those REGS that mutually agreed to appoint a QCA. The other REGS shall be required to submit their schedule as well as be liable to pay their DSM charges.

Case-3: 50 MW and above (Phase-I &II)

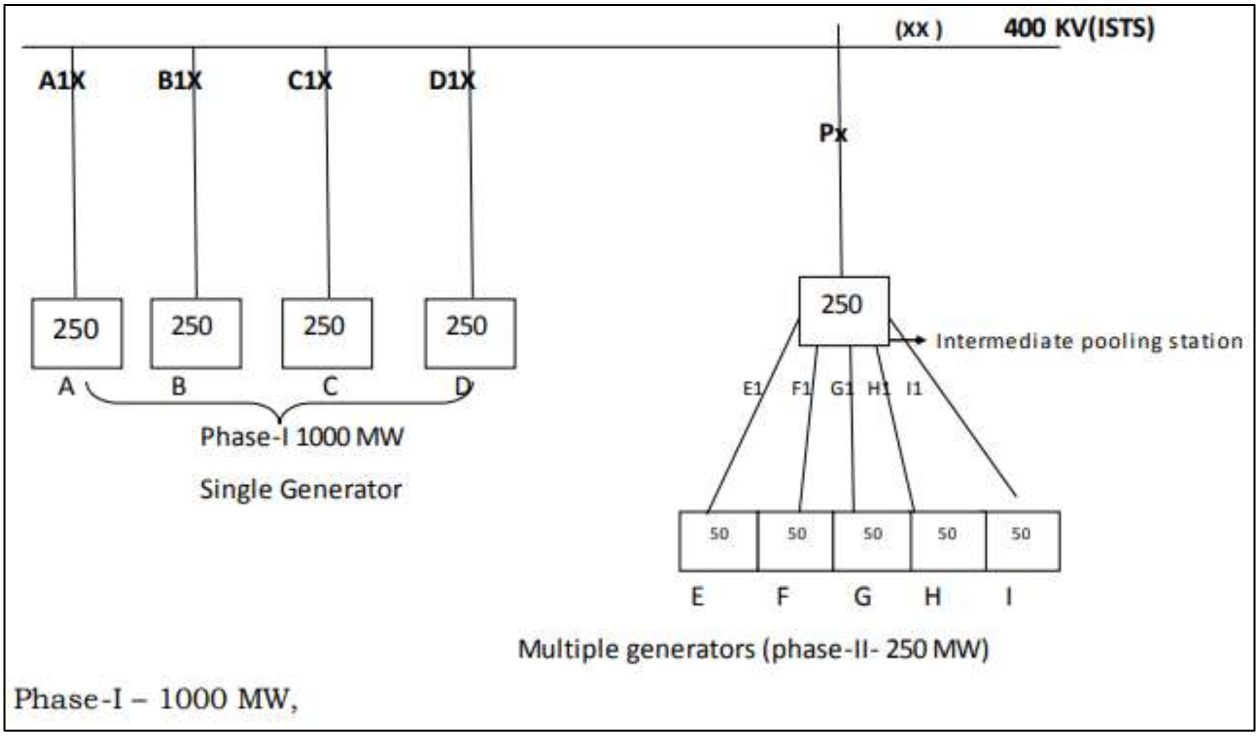


FIGURE E: 50 MW AND ABOVE(PHASE 1 &II)

A single generating station of 1000 MW capacity is developing the generating station in phase-1 in four blocks namely A,B,C & D of 250 MW capacity each and is directly connected to point A1,B1,C1& D1 respectively at ISTS. At the interface point scheduling and forecasting shall be done by RLDC.

Phase-II- 500 MW (Separate Generating station /Entities)

(a) Let multiple REGS of 50 MW each aggregating to 250 MW (5 Nos. Multiple Generating Stations of 50 Mw each (as separate entities), be connected to inter mediate pooling stations.

(b) REGS namely E, F, G, H & I each having the capacity of 50 MW each are connected to interface point E1, F1, G1, H1& I1 and thereby connected to ISTS at XX point.

(c) In such a case, scheduling, accounting, forecasting for these generating stations needs to be segregated at point E1, F1,G1, H1, I1. Scheduling shall be done at point P and shall be segregated at E1,F1,G1,H1,I1 by RLDC.

(d) Further there may be case where multiple generating stations less than 50MW (<50MW) capacity are connected to the intermediate pooling station are stated as under:-

Case-II Below 50 MW

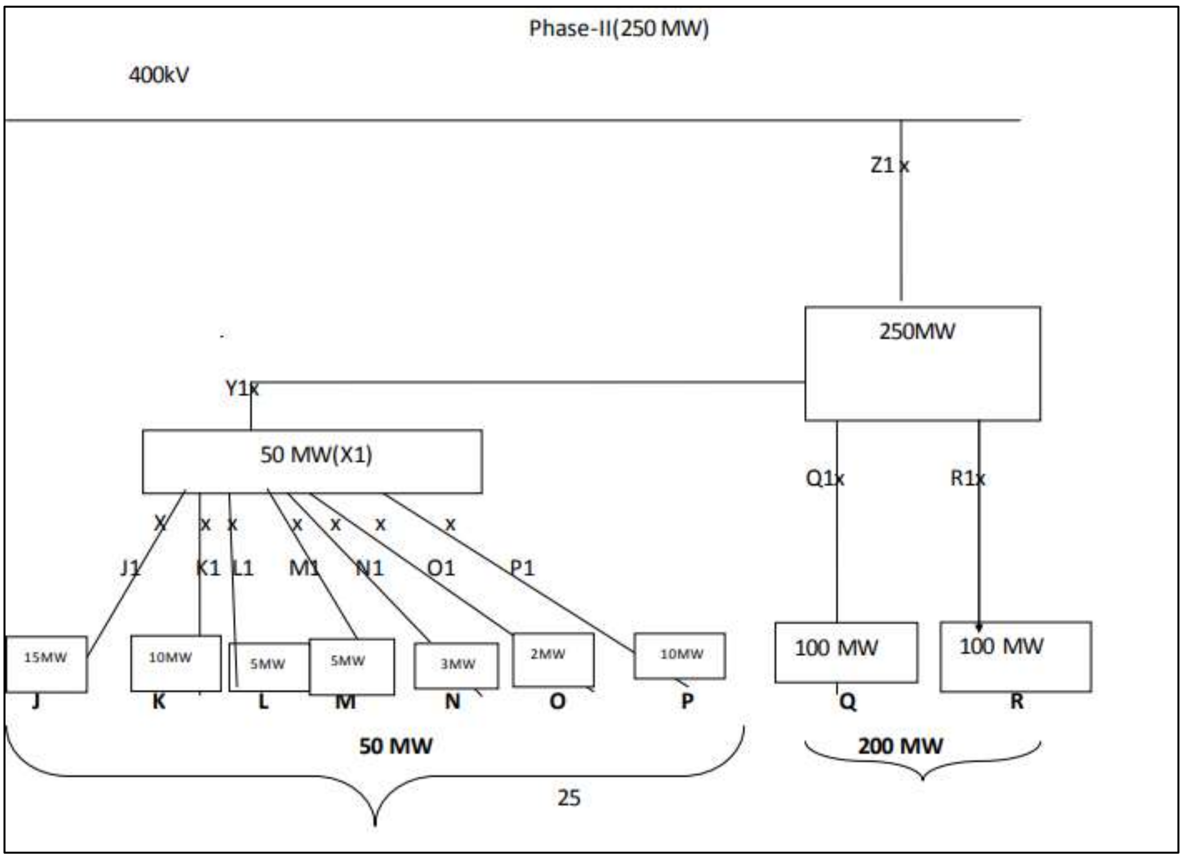


FIGURE F: CASE II BELOW 50 MW

(e) Let us consider, multiple REGS (namely J,K,L,M,N,O&P) collectively having an aggregate installed capacity of 50 MW or more and are represented through a Lead Generator. Further REGS Q & R each of 100 MW are connected at Q1 & R1. All these REGS are connected to ISTS at point Z1.

(f) Scheduling and forecasting for the REGSs J,K,L,M,N,O& P shall be done at Point Z1, but need to segregated at Point J1, K1,L1, M1, N1,O1& P1 and for REGSs Q & R needs to be segregated at Q1 and R1. In this case, RLDC shall schedule at point Z1 and segregate at Y1,Q1& R1 . The lead generator shall provide aggregated schedule to RLDC at Y1. Further the lead generator shall do segregation of schedules and other operational & commercial activities for generators J,K,L,M,N,O,P at points J1, K1,L1, M1, N1,O1& P1.

ANNEXURE- 6
ACCOUNTING AND POOL SETTLEMENT SYSTEM

(1) METERING, ACCOUNTING AND SETTLEMENT SYSTEM:

(a) At the Inter State Transmission System (ISTS) level, the basic principle followed is that all settlements for the energy scheduled are done directly between the sellers and the buyers, with the Regional Power Committee issuing the accounts specifying the quantum of energy scheduled. All deviations from the schedule are settled through a regulatory pool account maintained by RLDCs; a net settlement where only the deviation payments are handled.

(b) The settlement system shall be transparent, robust, scale-able (multi buyer/seller, inter connection with lower and upper pool systems) and dispute-free with integrity & probity possible and usage of state of the art techniques. The settlement computation details, applicable charges and operation of different regulatory pool accounts shall be in accordance with various regulations of the Commission.

(c) The Implemented Schedule incorporating all before-the-fact changes in schedule shall be used as a reference for energy accounting.

(d) Energy Accounts inter-alia shall indicate Declared Capability of generating stations, Entitlements, Requisitions, Scheduled loss, Scheduled transactions GNA and T-GNA and actual Interchange.

(e) Assumptions, if any, in the accounts shall be clearly stated in Notes to the Accounts.

(f) Each regional entity (whether a generating station, REGS, captive Power Plant, OA customer connected to ISTS, any other entity) in a region shall be a member of the regional pool and separately accountable for deviations. For cross border transactions, the Settlement Nodal Agency (SNA) as appointed by the Government of India would be a member of the regional pool.

ANNEXURE - 7

A. REPORTING REQUIREMENTS

S. No.	Entity Responsible	Reporting Requirement and Frequency	Relevant Regulation No.
1.	RPC	Exception report of UFR *(monthly)*	Operating Code: Regulation No. 29(13)(e)
		Annual Outage Plan*(annual)*	Operating Code: Regulation No. 32(2)(a)
		Feedback Report to address potential violation of system operational limit *(quarterly)*	Operating Code Regulation No. 33(8)
		Final report on grid disturbance *(post grid disturbance)*	Operating Code Regulation No. 37(2)(f)
2.	CTU	• All India transmission review*(yearly)* • Planned inter-regional and ISTS-STU power transfer capability for the next 3-5 years*(yearly)*	Resource Planning Code Regulation No. 5(4)(a)
3.	NLDC	Forecast error *(daily/day-ahead / weekly / monthly and yearly)*	Operating Code Regulation 31(2)(h)
		Operational study (*intra-day, Day-ahead/ weekly/ monthly/ yearly*)	Operating Code Regulation 31(1)(a), 31(1)(b)
		Operational analysis *(post despatch)*	Operating Code: Regulation No. 37(1)
		Draft report of each grid disturbance / grid *(post grid disturbance)*	Operating Code: Regulation No. 37(2)(f)
		Daily and monthly report of integrated grid performance *(daily and monthly)*	Operating Code Regulation 38(1)
4.	RLDC	Forecast error *(daily/day-ahead / weekly / monthly and yearly)*	Operating Code Regulation 31(2)(h)
		Operational study (*Day-ahead/ weekly/ monthly/ yearly*)	Operating Code Regulation 31(1)(a), 31(1)(b)
		Operational analysis *(post despatch)*	Operating Code: Regulation No. 37(1)

S. No.	Entity Responsible	Reporting Requirement and Frequency	Relevant Regulation No.
		Draft report of each grid disturbance *(post grid disturbance)*	Operating Code: Regulation No. 37(2)(f)
		Integrated grid performance *(daily and monthly)*	Operating Code Regulation 38(2)
		Details of regional entity generating stations *(quarterly)*	Scheduling and Despatch Code Regulation No. 45(1)
5.	SLDC	Exception report of UFR *(monthly)*	Operating Code: Regulation No. 29(13)(d)
		Forecast error *(daily/day-ahead/weekly/monthly and yearly)*	Operating Code Regulation 31(2)(h)
		Operational study *(intra-day/ Day-ahead/ weekly/ monthly/ yearly)*	Operating Code Regulation 31(1)(a), 31(1)(b)
		Operational analysis *(post despatch)*	Operating Code: Regulation No. 37(1)
		Flash report and detailed report on any grid disturbance *(post grid disturbance)*	Operating Code: Regulation No. 37(2)(f)
6.	User	Flash report and detailed report on any grid disturbance *(post grid disturbance)*	Operating Code: Regulation No. 37(2)(b)
		PSS tuning report by generators *(based on tuning requirements)*	Operating Code: Regulation No. 29(8)

B. PROCEDURE DRAFTING REQUIREMENTS

S. No.	Entity Responsible	Drafting Responsibilities	Regulation No.
1.	RPC	Common outage planning procedure	Operating Code: Regulation No. 32(4)
		PSS tuning procedure	Operating Code: Regulation No. 29(8)
2.	CTU	All India transmission review	Resource Planning Code Regulation No. 5(4)(a)
		Planned inter-regional and ISTS-STU power transfer capability for the next 3-5 years	

S. No.	Entity Responsible	Drafting Responsibilities	Regulation No.
3.	NLDC	Detailed procedure covering modalities for first time energization and integration of new or modified power system elements	Connection Code Regulation No. 8(2)
		Operating procedure	Operating Code: Regulation No. 28(3)
		Quantum of secondary / tertiary reserves	Operating Code: Regulation No. 30 (11) (n), 30(12)(a)
		Assessment of secondary / tertiary reserves	Operating Code Regulation No. 30 (11)(p) , 30(12)(d)
		Procedure for operational planning analysis, real-time monitoring, real-time assessments and format for data submission and updating	Operating Code: Regulation No. 31 (1)(c)
		Template for Restoration Procedure	Operating Code: Regulation No. 34 (1)
4.	RLDC	Operating procedure	Operating Code: Regulation No. 28(4)
		Procedure for operational planning analysis, real-time monitoring, real-time assessments and format for data submission and updating	Operating Code: Regulation No. 31 (1)(c)
		Restoration Procedure	Operating Code: Regulation No. 34 (1)
5.	SLDC	Detailed procedure covering modalities for first time energization and integration of new or modified power system elements	Connection Code Regulation No. 8(4)
		Operating procedure	Operating Code: Regulation No. 28(5)
		Restoration Procedure	Operating Code: Regulation No. 34 (1)
6.	Governing board of certifying	Periodic capacity building, certification and recertification for system operators at NLDC, RLDC, SLDC and	Operating Code: Regulation No. 41

S. No.	Entity Responsible	Drafting Responsibilities	Regulation No.
	agency	sub-LDC	