Indian Electricity Grid Code(IEGC)-2023

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Relevant Provisions in EA 2003

- **Section 79 (Functions of Central Commission):**

  “(1) The Central Commission shall discharge the following functions, namely:

  …………

  (h) to specify Grid Code having regard to Grid Standards;

  ………..”

- **Section 2(34):**

"Grid Standards" means the Grid Standards specified under clause (d) of section 73 by the Authority;

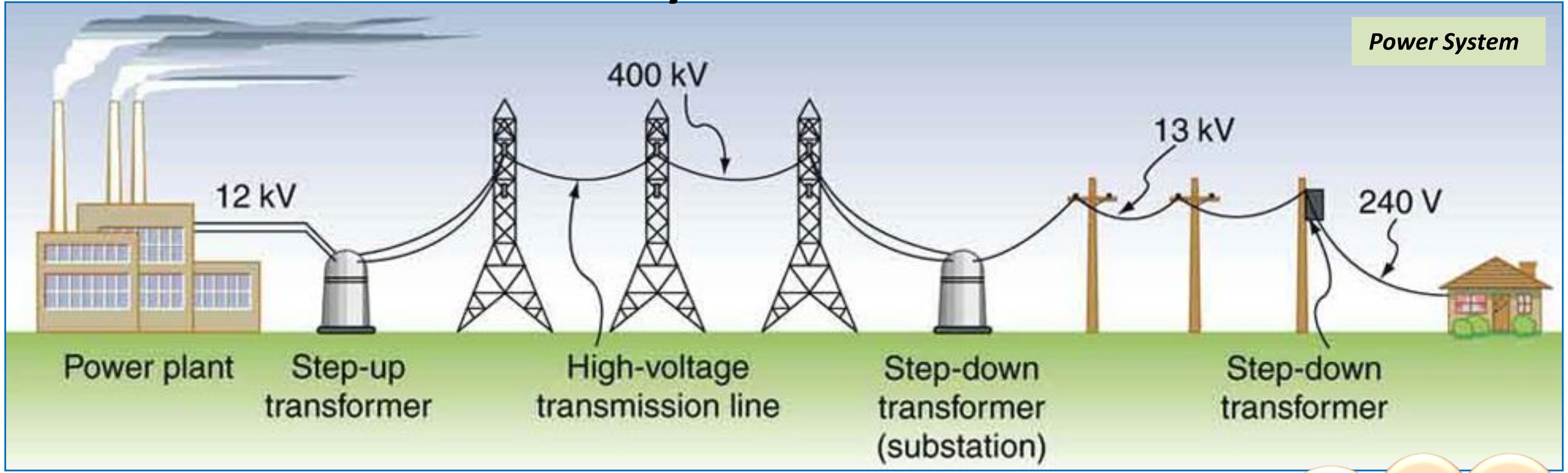
- **Section 73(d)**

  specify the Grid Standards for operation and maintenance of transmission lines

- **Section 2(32)**

Grid : the high voltage backbone system of interconnected transmission lines, sub-station and generating plants

Indian Electricity Grid Code – *Stakeholders*



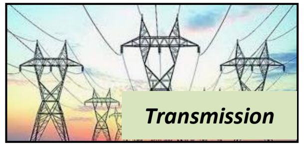
Generation

Transmission

Distribution and Supply of Electricity

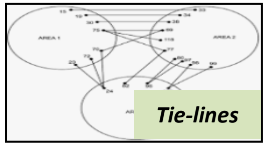
Conglomeration of number of agencies executing various tasks

Generation

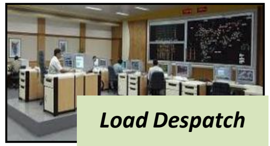


Transmission

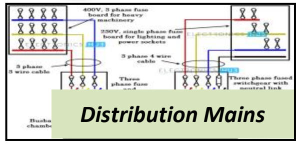
Substations



Tie-lines



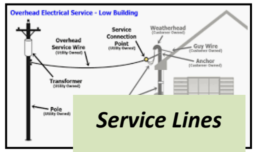
Load Despatch



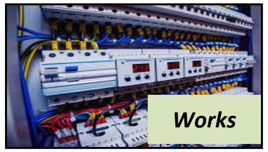
Distribution Mains

Supply Lines

Overhead Lines

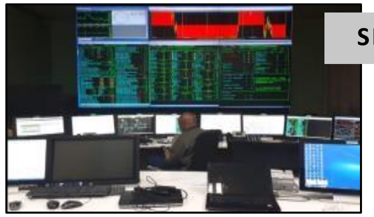


Service Lines



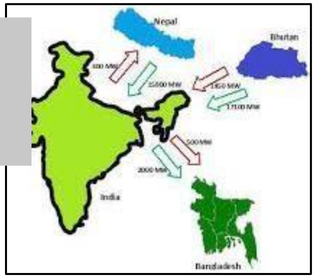
Works

Indian Electricity Grid Code – Scope



SLDCs

Interconnection with Neighbouring Countries (treated as separate control area)

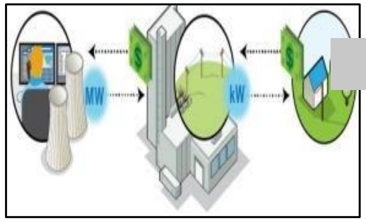


NLDC/ RLDCs

Sardar Sarovar Project

Utilities need to abide by IEGC –

- *Principles*
- *Procedures*



Licensees

Bhakra Beas Management Board

CEA/ Regional Power Committees

Power Exchanges

Damodar Valley Corporation

IEGC-2023 : Structure

Old - IEGC 2010	New - IEGC 2023
1. General 2. Role of various organizations and their linkages 3. Planning code for inter-state transmission 4. Connection code 5. Operating code 6. Scheduling and despatch code 7. Miscellaneous	1. Preliminary 2. Resource planning code 3. Connection code 4. Protection code 5. Commissioning and commercial operation code 6. Operating code 7. Scheduling and Despatch code 8. Cyber security 9. Monitoring and compliance code 10. Miscellaneous

Chapter-2

Resource Planning Code

Resource Planning Code : Key Features

- New Chapter added
- Covers the integrated resource planning including
  - Demand forecasting,
  - Generation resource adequacy planning and
  - Transmission resource adequacy assessment, required for secure grid operation.

Resource Planning Code

“Resource Adequacy means tying up sufficient capacity to reliably serve expected demand of the consumers in the DISCOMs license area in a cost-effective manner.”- Guidelines For Resource Adequacy Planning Framework For India, CEA

Roles and Responsibility of different utilities in Short term resource adequacy :

DISCOM
1. Demand forecast **Cl.5.2.(i)**
2. Generation Adequacy assessment **Cl.5.3**
3. Resource procurement plan **Cl.5.3**

STU
1. Demand forecast for overall state **Cl.5.2.(ii)**
2. Generation Adequacy assessment **Cl.5.3.(d)**

NLDC
1. Simulation study **Cl.5.3.(e)**

1. Shortage scenario
2. Optimal planned outage schedule

Commercial decision to be taken by DISCOM for additional resource procurement to meet SERC target **Cl.5.3.(e & f)**

Non compliance penalty as per SERC

Demand Forecasting…

Sl. no	Entity	Assignment	Timeline
5.2(i)	Each distribution licensee within a State	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. 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.	Submit the same to the STU by 31st July every year
5.2(ii)	STU	Estimate the demand for the entire State duly considering the diversity for the next five (5) years starting from 1st April of the next year. Based on input received from distribution licensee	30th August every year
5.2(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	No timeline given

Generation Resource Adequacy Planning…

Sl no	Entity	Assignment	Timeline
5.3(a)	Each distribution licensee	(i) assess the existing generation resources and identify the additional generation resource requirement to meet the estimated demand in different time horizons, (ii) prepare generation resource procurement plan.	After the demand estimation
5.3(d)	STU	on behalf of the distribution licensees in the State shall provide to NLDC, • the details regarding demand forecasting, • Assessment of existing generation resources • Such other details as may be required for carrying out a national level simulation for generation resource adequacy for States.	By 30th September every year
5.3(e)	NLDC	• Based on the information received NLDC shall carry out a simulation to assist the States in drawing their optimal generation resource adequacy plan. • The simulation carried out by NLDC for this purpose shall be considered merely an aid to the distribution licensees. distribution licensees shall be responsible for all commercial decisions on generation resource procurement	By 31st October every year
5.3(f)	Each distribution licensee	• Each distribution licensee shall ensure demonstrable generation resource adequacy as specified by the respective SERC for the next five (5) years • 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 noncompliance charge as may be specified by the respective SERC	
5.3(g)	Forum of Regulators	For the sake of uniformity in approach, 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.	No timeline given

Transmission resource adequacy assessment…

Sl. no	Entity	Assignment	Timeline
5.4(a)	CTU	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 : 1. adequate power transfer capability across each flow-gate 2. import and export capability for each control area; 3. import and export capability between regions; and 4. cross-border import and export capability.	Continuous process
5.4(b)	STU	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: 1. import and export capability across ISTS and STU interface; and 2. adequate power transfer capability across each flow-gate.	Continuou s process

Chapter 3

Connection Code

GENERAL

- Connectivity, procedure and requirements for physical connection and integration of grid element.
- Connectivity to the ISTS shall be granted by CTU.
- All the Transmission licensees shall comply with the technical requirements specified under this Connection Code.
- 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.

1. Procedure For Connection

- The grant of connectivity to the ISTS by the CTU
- Detailed NLDC first time charging procedure for energization and integration of new or modified power system element.
- Requisite format submission as per the FTC Procedure.
- SLDC first time charging procedure for intra-state elements.

2. Connectivity Agreement

- In **case of users** seeking connectivity to the ISTS under GNA Regulations, Connectivity Agreement shall be signed between such users and the CTU.
- In case of multiple Tx licensees at same substation , site responsibility schedule to specified i

- In **case of an inter-State transmission licensee**, Connectivity Agreement shall be signed between such licensee and CTU before physical connection
- In case of intra-state Tx system getting connected to ISTS CA between InSTS, CTU and ISTS licensee before physical connection..

3. Technical Requirements

- Joint study by CTU/NLDC or RLDC shall carry out a joint system study six (6) months before the expected date of first energization.

- Similar exercise shall be done by SLDC in consultation with STU for the intra-state system.

CONNECTION CODE

Interconnection studies for new power system elements six months in advance CL.10.(1):

Purpose

Why

- Impact of TTC/ATC
- Identify Constraint
- Design SPS if required for grid security

Data submission

USERS & CONNECTIVITY GRANTEE

- Generation Entity
- Load Serving Entity
- Transmission Licensee
- Settlement Nodal Agency

Data to be submitted to SLDC, RLDC or NLDC

Study

SLDC/RLDC/NLDC

For new elements in respective Jurisdiction Cl.33.(9) to (12)

Consultation with RLDCs/SLDCs/NLDC/STU & CTU

4. Data & Communication Facilities

- Reliable speech and data communication systems shall be with NLDC, RLDC and SLDC.

- 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.

- Real time data communication shall be established with all the concerned.

Chapter 4

Protection Code

Protection Code…

- ❑ General
- ❑ Protection Protocol
- ❑ Protection Settings
- ❑ Protection Audit Plan
- ❑ System Protection Scheme (SPS)
- ❑ Recording Instruments

Protection Code : General

Uniform protection protocol for the users of the grid

- For **proper co-ordination of protection system** in order to isolate the faulty equipment and avoid unintended operation of protection system;
- To have a **repository of protection system**, settings and events at regional level;
- Specifying **timelines** for submission of data;
- To ensure **healthiness of recording equipment** including time synchronization; and
- To provide for **periodic audit** of protection system.

Protection Code : Protection Protocol

All Users

- Provide and maintain effective protection system
- Back-up protection system to protect an element in the event of failure of the primary protection system.

RPC

- To develop/review/revise the protection protocol in consultation with the stakeholders in the concerned region

Guided by

- CEA Technical Standards for Construction,
- The CEA Technical Standards for Connectivity,
- CEA (Grid Standards) Regulations, 2010
- CEA (Measures relating to Safety and Electric Supply) Regulations, 2010
- CEA Technical Standards for Communication.
- Any other standards by CEA specified from time to time

Any protocol change depending on operational scenario

- Deliberation and approval of the concerned RPC.

Necessary protection | Protection Protocol | Intimation and Approval for Any change

Protection Code : Protection Settings

All Users

- Ensure correct and appropriate settings of protection as specified by RPC.
- Ensure proper coordinated protection settings.
- Furnish the protection settings to RPC.
- Obtain approval of the concerned RPC for (i) any revision in settings, and (ii) implementation of new protection system
- Intimate to the concerned RPC about the changes implemented: **within Fortnight**

RPC

- Maintain a centralized database for grid elements connected to 220 kV and above
- Provide database access with different access rights
- Review of the protection settings
- Assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders: **At least once in a year**.

Protection Code : Protection Audit Plan

Types of protection audit : Internal and Third Party

Users

- Conduct annual internal protection audit: Rectification of findings and information to RPC.
- Conduct third-party protection audit for substations above 220 kV
  - Once in Five years or earlier as advised by RPC
  - Submit third-party audit report to RPC
  - Action plan within one month after report submission to RPC/RLDC
- **Submission of Annual audit plan for next financial year to RPC: 31st October**
- Adhere to the annual audit plan and report compliance to RPC

Protection Code : Protection Audit Plan…

Users

- Submit protection performance indices to RPC (Monthly Basis for last month)
  - Dependability Index (*Nc/Nc+Nf*)
  - Security Index (*Nc/Nc+Nu*)
  - Reliability Index (*Nc/Nc+Ni*)
  - Reasons for performance indices <1 for individual element-wise protection system
  - Action plan for corrective measures.

RPC

- Regular follow up on action plan
- RPC to approach commission for non-Compliance of protection protocol or failure to undertake identified remedial action within the specified timelines,

Protection Code : System Protection Scheme (SPS) & Recording Instruments

- SPS to have redundancies in measurement of input signals and communication paths involved up to the last mile
- Users/SLDCs to report **SPS operation within three days of operation** to RPC/RLDC in format
- RPCs to perform **regular dynamic studies and mock testing (at least once in a year) of operational SPSs**
- Users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.
- Disturbance recorders to 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.

Protection Code

User

- ❖ Third party audit every 5 year or after event based on RPC recommendation **CL.15.(4)**
- ❖ Sharing of protection performance index on monthly basis: **CL.15.(6)**
  - ✓ The Dependability Index defined as D= $\frac{Nc}{Nc+Nf}$
  - ✓ The Security Index defined as S= $\frac{Nc}{Nc+N}$
  - ✓ The Reliability Index defined as R= $\frac{Nc}{Nc+N}$

Protection system performance of all users to be monitored at Regional level

Nc -**correct operations** at internal power system faults

Ni -**incorrect operations** and is the sum of Nf and Nu

Nf -**failures to operate** at internal power system faults

Nu -**unwanted operations**

Chapter 5

Commissioning and Commercial Operation Code

COMMISSIONING AND COMMERCIAL OPERATION CODE

Generating plant

1. Infirm injection period increased to one year from six-month **C L .19.(2)**
2. AGC connectivity mandatory **CL.24.2**
   - Thermal-200 MW and above
   - Hydro-25 MW and above

3.primary response test, reactive capability, black start, ramping, Technical minimum etc testing based on technology. **CL.24**

4.Scheduling of the generating station From **00:00 hrs. of D+2 ,where D is COD date CL.27.(1)**

Transmission

1. **Notice period of 7 days for trail operation CL.21.(2)**
2. List of all test to be performed during trail run for HVDC,FACTS

Storage

1.Successful trail means one cycle of charging(Pumping) and discharging(Generation) as per capability **CL.22.3.(e)**

2. Frequency response **CL.22.3.(f)**

General

Chapter covers aspects related to –

- Drawal of startup power from and injection of infirm power into the grid
- Trial Run Operation
- Documents and tests required to be furnished before declaration of COD
- Requirements for declaration of COD.

Drawal of start up power and injection of infirm power

- Before COD, Generator can draw start up power for various testing activities.
- The period for which such interchange shall be allowed shall be as follows :-
    - 15 months prior to first synchronization and 12 months after the date of first synchronization.
    - Injection of infirm power shall not exceed 12 months from the date of first synchronization.
- Commission can extend the timeline if necessary.
- Start-up power shall not be used by the generating station for the construction activities.
- The onus of proving drawal of start up power for testing activity and not for construction, lies with the generator.

Notice of trial run

- Generating station -Trial run notice shall be given of not less than 7 days to the concerned RLDC and the beneficiaries.

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

- For trial operation of transmission system, the licensee shall give a notice of not less than 7 days to the concerned RLDC and CTU, Dx licensee, owner of the inter-connecting system.
- RLDC to allow trial from the requested date and not later than 7 days in case of constraints

Trial run of thermal generating unit

- A thermal generating unit shall be in continuous operation at MCR for 72 hours on designated fuel.

With condition:

  - Short interruption shall be permissible with corresponding increase in duration of the test.
  - Average load should be above MCR.
  - Cumulative interruption is allowed up to 4 hours. Beyond this repeat of trial run

- In case generator fails to demonstrate MCR, Generator can de-rate the capacity of the generating unit or to go for repeat trial run. De-rated capacity not to be more than 95% of the demonstrated capacity

Trial run of hydro generating unit

- A hydro generating unit shall be in continuous operation at MCR for 12 hours:

With condition:

  - Any interruption shall call for a repeat of trial run;
  - Average load should be above MCR.
  - Cumulative interruption is allowed up to 4 hours. Beyond this repeat of trial run

  - If MCR can not be demonstrated for 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.

- In case generator fails to demonstrate MCR, Generator can de-rate the capacity of the generating unit. De-rated capacity not to be more than 90% of the demonstrated capacity

Trial run of solar generating station

- 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 4 hours on cumulative basis between sunrise to sunset in a single day.

With condition:

- The output below the corroborated performance level with the solar irradiation of the day shall call for repeat of the trial run
- 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.

Trial run of wind generating station

- 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 continuous 4 hours during periods of wind availability.

With condition:

  - The output below the corroborated performance level with the wind speed of the day shall call for repeat of the trial run.
  - 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.

Trial Run (Tr) Of Storage/Hybrid Generating Station & Transmission System

- TR of ESS duration is 1 cycle of charging and discharging of energy as per the design capabilities with metering , telemetry and protection in service.

- TR of PSP duration is 1 cycle of turbogenerator and pumping motor mode as per the design capabilities up to the rated water drawing levels.

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

- Trial run of a transmission system or an element shall mean continuous 24 hours MW/MVAr flow

Certificate of successful trial run (TRC)

- Objection regarding Trial run to be raised within 2 days of completion of trial run . RLDC to decide in 5 days of receipt of objection – successful or retrial.

- After completion of successful trial run and compliance with all the requisite documents/test reports, RLDC shall issue a Trial Run Certificate within three days

Declaration by generating company and transmission licensee

- Generating company/Transmission licensee should comply with all the CEA/CERC regulations.

- All the associated system must be commissioned and are capable of full load operation on sustained basis.

- A certificate shall be signed by the authorized signatory not below the rank of CMD or CEO or MD.

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

- The last unit of the generating station shall be considered as the COD of the generating station.

- For DOCO of Idle Charged Transmission element, CTU certificate is required.

- For TBCB project, COD must be in compliance with TSA.

Chapter-6

Operation Code

- **Operating Philosophy**

  All entities to function in coordination

  SLDC, RLDC, NLDC to monitor operation of state, regional and National grid

  Operating procedures to be developed , maintained and updated by SLDC, RLDC, NLDC

  SLDC, RLDC, NLDC, Gx and Tx substation above 110 kV level to have qualified man power manning control room round the clock

  Tx licensee not having substation, SNA, QCA to have coordination centre manned by qualified personnel functioning round the clock.

Operating code : General

No.	Clause	Changes with respect to old IEGC and Discussion
28.1	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.	a. "Resilience" aspect is introduced for the 1st time. ***"means the ability to withstand and reduce the magnitude or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, or rapidly recover from such an event;"*** b. Economy and efficiency is explicitly mentioned .
28.3 to 28.5	Operating procedure of NLDC,RLDC and SLDC	To be uploaded in website by NLDC and RLDC
28.6 to 28.8	24X7 manning of all control room	a. A transmission line owner who don't have any substation shall also have a 24X7 control room with proper manpower. b.Remote operation is allowed, provided that there will be no delay in execution of switching instruction from appropriate LDC c.SNA and QCA shall have round the clock coordination centres manned by qualified personnel

- **System Security**

(i) Isolation , taking out of service and switching off an grid element only during emergency as per DOP , safety of human life, damage to critical equipment , instruction by LDC.

(ii) taking out Important elements only with prior approval from RLDC

(iii) Isolated elements to to be restored as soon as possible.

(iv) AVR, PSS, Voltage controllers to be in service and tuning once in 5 years

(v) Protection Coordination by RPC

(vi) Islanding schemes by RPC and its mock drill.

(vii) UFR and df/dt relays, Identification of SPS

(viii) Ensure steady state voltage as per CEA Grid Standards.

Clause 29.10 & 1: Islanding

1. RPC to design islanding scheme for identified generating stations, cities and locations and ensure its implementation as per Grid standard regulation.

2. Review of scheme at least once in every **3 year**.

3. RLDC shall carry out mock drill of Islanding scheme in consultation with SLDC and other users involved once in every year.

Clause 29.12 & 13: Under frequency and df/dt defense mechanism

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.

Clause 29.12 & 13: Under frequency and df/dt defense mechanism….

Salient features of UFR designing and implementation:

- **No time delay**.
- **uniform spatial spread** of feeders selected for UFR and df/dt disconnection
- **Telemetering** of feeder where UFR and df/dt is installed and real time monitoring by SLDC as well as **RLDC**.
- Reporting of duration when the load in the selected feeders fall below desired load relief by **RLDC.**

Clause 29.14 : SPS….

- ❑ Demarcation between intra-regional, inter-regional and cross border SPS.

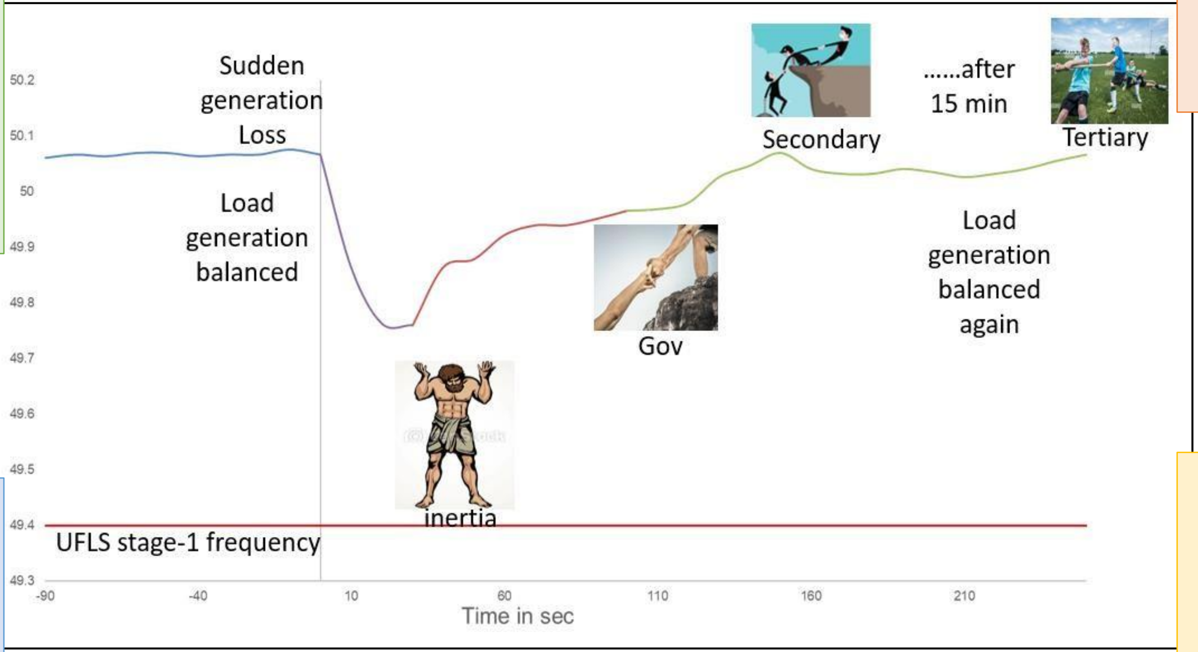
- ❑ NLDC permission for inter-regional and cross border SPS

Frequency Control:
Role of Inertia and Reserve

OPERATING CODE

- ❑ Start Immediately after frequency is changed → reach full response by 45 Sec → sustain 5 min CL.30.10.(m)
- ❑ RGMO replaced with FGMO
- ❑ Frequency response ObligationCL.30.10.(f)
- ❑ Data submission CL.30.10.(n)

Defence Mechanism



- ❑ Start Within 15 min of command received →reach fully obligation in 30 min→ sustain up to 60 min CL.30.12.(j)

- ❑ Despatch of Synchronous generator and curtailment of Solar and wind for ensuring minimum inertia CL.30.9

- ❑ Start Within 30 sec of command received →reach fully obligation in 15 min→ sustain up to 30 min CL.30.11.(j)

Stage of UFR Operation Frequency (Hz)	Frequency (Hz)
Stage-1	49.40
Stage-2	49.20
Stage-3	49.00
Stage-4	48.80

❖ Pumped storage hydro plants operating in pumping mode or ESS operating in charging mode shall be automatically disconnected before the first stage of UFR CL.29.12 Note-2

Clause 30 : FREQUENCY CONTROL AND RESERVES

- General:
  - Specification of frequency measurement resolution of **+/- 0.001** Hz.
  - Reference frequency 50 Htz and allowable band of frequency shall be **49.90-50.05** Hz
  - **Different reserve:**
    1. Primary Reserve
    2. Secondary Reserve
    3. Tertiary Reserve
    4. Black Start reserves
    5. Voltage Control reserves:
  - Reserve will be operated as ancillary services.

Clause 30 : FREQUENCY CONTROL AND RESERVES

- 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.
- The mechanism of procurement, deployment and payment of SRAS and TRAS shall be as specified in the **Ancillary Services Regulations.**
- LDC to evaluate FRC after each grid event.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Inertia and Primary reserve

- NLDC to decide minimum inertia requirement. For satisfying the minimum inertia requirement NLDC may if required, bring quick start synchronous generation on bar, **curtail wind, solar and wind-solar hybrid generation.**
- **Storage system and demand side response** are considered for primary response
- NLDC to declare Primary reserve requirement for reference contingency at the start of the financial year.
- **Electronically controlled** governing systems or frequency controllers mandated for generating units.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Inertia and Primary reserve

- Frequency response obligation for each control area will be assessed and communicated to each control area by NLDC by 15th March for the next financial year.

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	±10% of MCR
Gas based	Gas Turbine above 50 MW	±5% of MCR (corrected for ambience temperature)
WS Seller (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	As per CEA Technical Standards for Connectivity

Provided that:

1. WS Seller commissioned after the date as specified in CEA Technical Standards for Connectivity shall have the option to provide primary response individually through ESS or through a common ESS installed at its pooling station.
2. Nuclear generating station and hydro generating station (with pondage upto 3 hours or Run of the river projects) shall be exempted from mandatory primary response. They may provide primary response to the extent possible considering safety and security of machines and humans.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy : Inertia and Primary reserve

- Ripple factor and RGMO is removed and Dead band and FGMO introduced. Dead band up to 0.03 Hz allowed.
- Response time for primary reserve mentioned as follows:
  - Start immediately when frequency deviation beyond dead band
  - Reaching up to desired level by 45 sec
  - Sustain up to 5 min
- Each area to assess FRC
- RLDC shall assess FRC for region and NLDC for whole country considering cross border response as well. FRC-FRO-FRP
- **Grading** of performance and direction of corrective action in case median response is below 75 % of desired response.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

- Secondary reserve will replenish the primary reserve.
- Eligibility, procurement, deployment and sharing of cost of reserve will be as **Ancillary Services Regulations.**
- Minimum dead band is **+-10 MW in ACE.**
- Initially the SRAS control signal will be sent from NLDC , however once communication channel between RLDC and SRAS provider established.

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

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

- ACE archival at resolution of **10 sec or less and** sharing of Data from SLDC to RLDC and from RLDC to NLDC for reserve estimation.
- Response time of SRAS:
  - Starting within 30 sec
  - Delivering obligated capacity by 15 min
  - Sustain up to 30 min
- Reserve estimation methodology to be followed by RLDC
  - 99 percentile of positive and negative ACE during last financial year
  - 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.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

- Secondary reserve requirement on regional basis for reference contingency or capacity based on regional ACE which ever is higher
- Regional secondary reserve requirement to be divided into state control area prorate to 99 % ACE
- Reserve of each control area to be apportioned among intra-state generators and inter-state generators .

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Tertiary Reserve

- Response time of TRAS:
  - Starting within 15 min
  - Sustain up to 60 min
- TRAS shall be activated and deployed by the appropriate load despatch center on account of following events:
  - 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;
  - Generation unit or transmission line outages;
  - Any such other event affecting the grid security.
- The control area wise performance of SRAS and TRAS shall be evaluated in accordance with the Detailed Procedure prepared by NLDC.

Chapter-7

Scheduling And Despatch Code

43. Control Area Jurisdiction of LDCs

If Generator COD on or before 01.10.2023

as existing before the date of coming into force of these regulations (some special case)

If Generator COD after 01.10.2023

SLDC jurisdiction:

connected to intra-State

RLDCs jurisdiction:

entities connected to the inter-State only

Entities connected to both and intra-State :

Connectivity =>50% inter-state : RLDC

else SLDC

43. Control Area Jurisdiction for DVC system

Gen connected to ISTS lines :
RLDC jurisdiction

Gen connected to DVC system :
DVC jurisdiction

Entities connected to both ISTS and DVC system :
Connectivity =>50% inter-state : RLDC else DVC

45.5.Prerequisite for Commencement of Scheduling

Documents	Responsible entity to provide	Frequency of submission	Last date submit (D= day of scheduling)
Grant of Connectivity/ GNA/ T-GNA with Effective Date	Entitles who has taken Connectivity/GNA to their concerned RLDC	In case of any change	D-2 23:59 Hrs
Signed copies of valid contracts other than collective transactions	shall be submitted to concerned RLDCs where buyer and seller is located through WBES	one time activity for new contract or termination or modification of contract.	D-3 23:59 Hrs
The copy of contracts submitted can be linked with a **unique ID** by RLDC as a reference before scheduling.	RLDCs	For new contract	D-3 23:59 Hrs
Assessment of ATC	NLDC/RLDC/SLDC	11 month ahead and its revision from time to time.	Gate closure time line for ATC revision: 2 Hrs before the implementation time.

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

- All The regional entity generating station other than the WS seller shall declare Exbus Declared Capacity

DC

- **Thermal**
  - 100% MCR less auxiliary power consumption
  - Ramp rate:
    Coal & Lignite:>=1%
    Gas:>=3%
- **Hydro**
  - 100% MCR less auxiliary power consumption
  - high inflow and water spillage conditions: DC overload capacity
  - high inflow period :Notified by RPCs
  - Ramp rate: >=10%
- **WS seller**
  - Available capacity
  - as per CEA Connectivity Standards

46.SCUC : Security Constrained Unit Commitment

- Objective is to commit a generating station /unit to supplement the procurement of reserves in anticipation of shortage of reserves on day ahead basis. Also on three days ahead basis under certain circumstances.
- Reserves to be procured in accordance with AS regulations.
- SCUC for section 62 projects

- LGBR consequent to SCUC is maintained by reduction of generation from on-bar generators with highest energy charge.
- SCUC to be paid from Pool account . Corresponding units to pay back to the pool whose schedule has been reduced. Compensation for part load operations to the unit under SCUC to be paid from the pool.
- **Generating stations other than section can also opt to participate in SCUC**

- SCUC – 3 days in advance of the actual day of scheduling in case of non- availability of reserves on D-1, D day ahead or AS
- Requirement of SCUC declared by NLDC. Regional entities to declared DC for D day within 2 hours
- NLDC through RLDC advises regional entity to Commits unit by 1000 hrs on D-2 day under cold start

46.SCUC Timeline

14:00 hrs

- NLDC to publish **tentative list of generating stations** likely to be scheduled below min. turndown level. These units to be considered for SCUC

14:30 hrs

- Beneficiaries of these stations shall be **permitted to revise requisition** till this time
- **No further reduction of drawal schedule** after this time except when sch. of this gen. is above min. turndown level. Final list is prepared on which SCUC is run.

15:00 hrs

- **SCUC results declared**. Selected gen. provided min. turndown level schedule
- **Downward revision shall be blocked** for SCUC generators
- ➢ Reserves earmarked and blocked from sale/requisition

Beneficiaries cannot recall

URS power beyond the reserve quantum can be rescheduled

49.1.DC Declaration: Information submission

Coal/lignite/Gas based

- Blockwise On-bar DC
- Blockwise On-bar DC for all fuel types separately (Gas)
- Blockwise Off-bar DC
- Blockwise Ramp Up rate
- Blockwise Ramp Down rate
- Ramp rate :not less than Coal: 1%, Gas: 3%
- MWh Capability of Day
- MWh Capability(fuel-wise) of Day (Gas)
- Min. turndown level (MW & %)

Hydro

- Blockwise Ex-bus capacity
- MWh Capability of Day
- Ex-bus peaking capability in MW & MWh
- Blockwise Ramp Up rate
- Blockwise Ramp Up rate
- Ramp rate :not less than 10%
- Unit-wise forbidden zone (MW & %)
- Min MW & duration for water release for irrigation, drinking, etc.
- Unit-wise Max along with probable combination of unit max for inadequate water

Renewable energy generating station individually or represented by a lead generator or QCA

- aggregate available capacity of the pooled generation
- Aggregate schedule along with contract wise breakup for each time block.
- The source wise breakup of aggregate available capacity of the pooled generation

Generator DC limited to 100 % MCR less Aux. consumption

Hydro DC declaration up to 110 % during high inflow period.
high inflow period: notified by RPC.
No additional GNA required

49.B.Entitlement of beneficiary/buyer

For Gen. having Govt. allocated share	• Based on total DC (On-bar + Off-bar)
Other Gen.	• Shall indicate entitlement of Beneficaires in accordance with contracts along with DC
Resolution	• 2 decimal places

49.SCHEDULING TIMELINE

ग्रिड-इंडिया GRID-INDIA

By 06:00
DC

By 07:00
Entitlement
Mutually agreed req. against contracts btw reg. entity buyer/seller and intra state entity

By 08:00
Requisition by buyers with GNA, SNA cbte & Reserve intimation by SLDC

By 08:15 intimation to GNA grantee in case of Tx. constraint
By 08:30 GNA Grantee to revise Requisition

By 09:00

Issuance of final drawl / injection sch
Req. by regional T-GNA grantee

By 09:15 Requisition by buyers with T-GNA
By 09:15 Intimation of Replacement of power with REGS

By 09:45 Incorporation of REGS and Corridor allocation by RLDC for T-GNA, pro-rata in case of constraints
Sec-62 URS in DAM

DAM Window
10:00-11:00

11:45
Px→ NLDC
Prov. Trade sch.

By 12:15 NLDC Corridor check

By 13:00 Px→ NLDC
Fin DAM sch. incorporated and balance corridor released
Start Processing exigency appl. Received till 1.00 pm

SCUC

- Processing of exigency applications received till 13:00 PM.
- Update Available transmission corridors
- Utilised by GNA grantee for revision, by exigency appl., RTM

By 23:35
RLDC issues Fin sch.

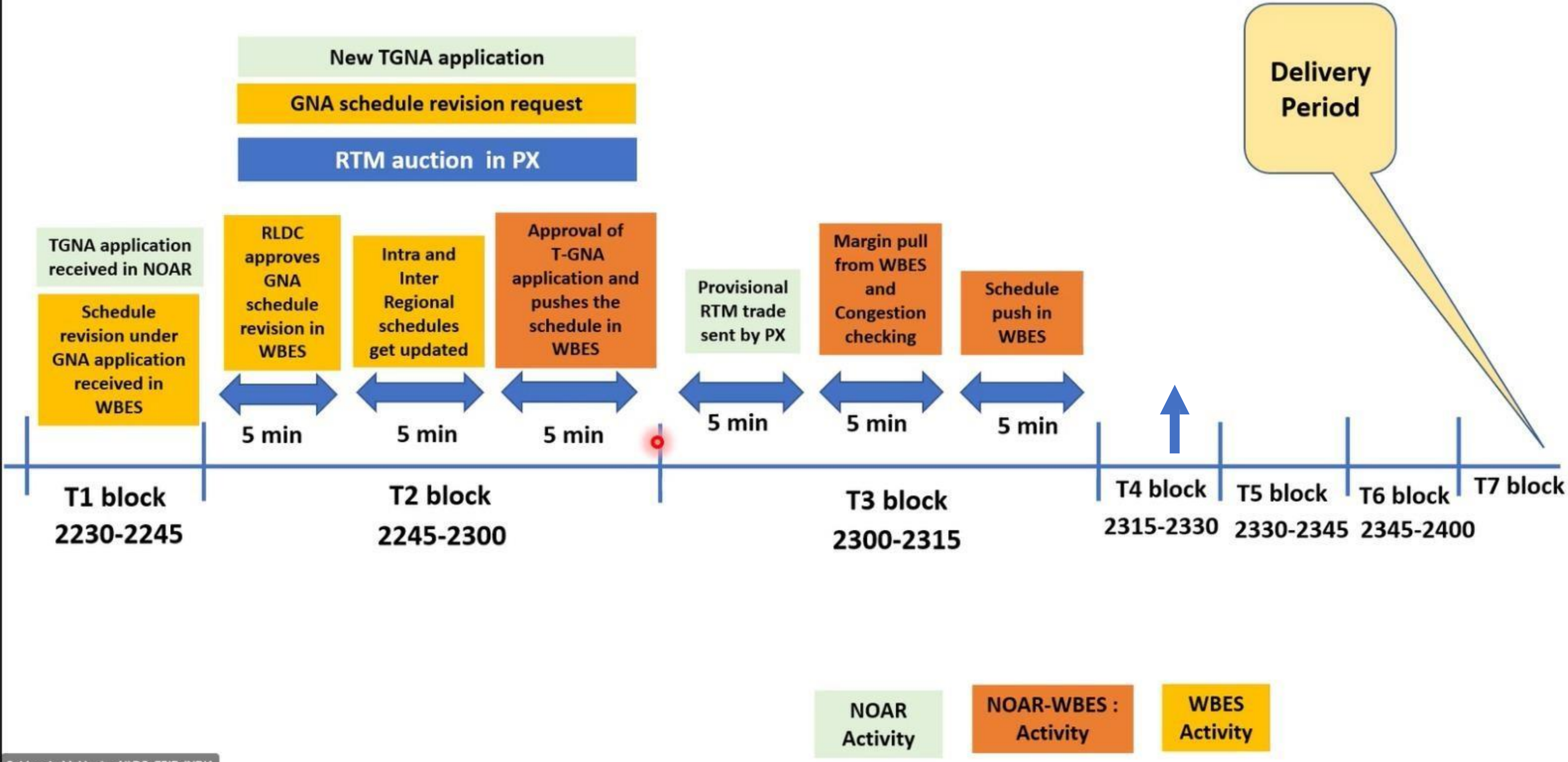
RTM, SCED, Ancillary services

By 00:00
Delivery day started

Requisitions under GNA - WBES

Requisitions under TGNA - NOAR

Day Ahead Scheduling after 1400 hrs. and Same Day scheduling

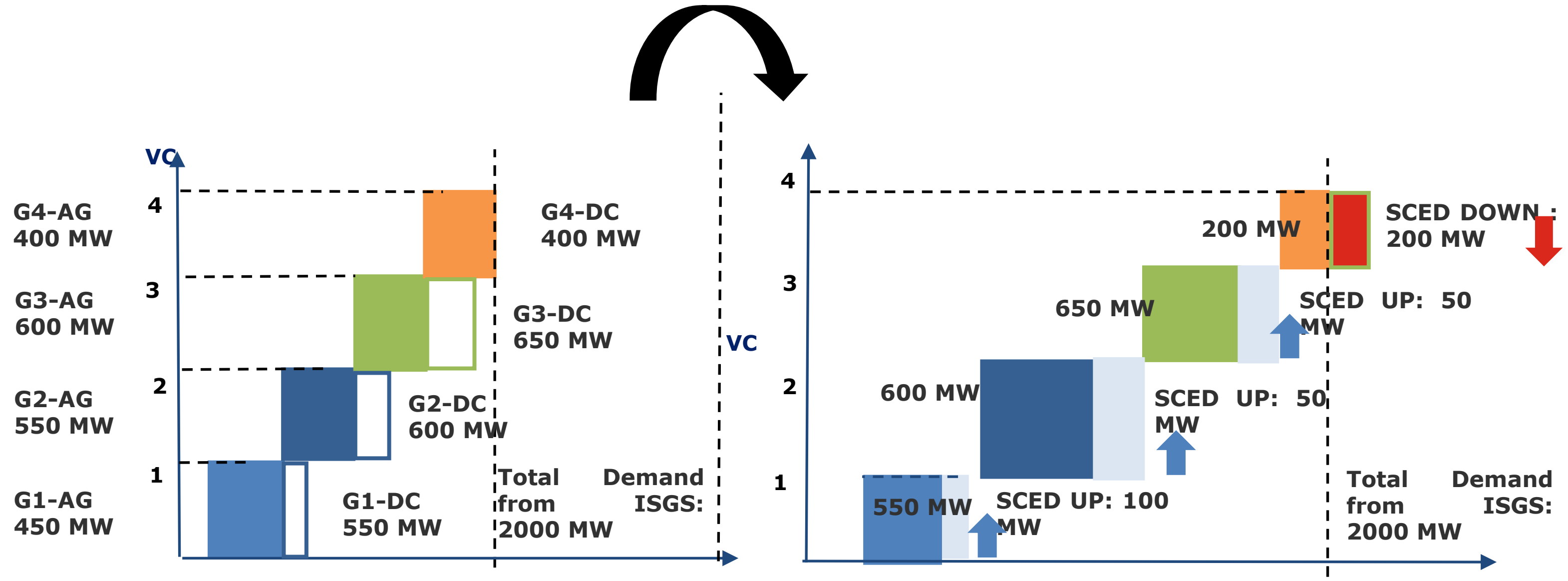


Subhendu Mukherjee NLDC, GRID-INDIA

Mechanism of SCED:

- Optimise generation dispatch after gate closure and finalization of RTM schedule
- NLDC nodal agency for implementation
- Willing generators to declare energy charge or SCED compensation charge
- Part load compensation on account of SCED for 62 to be paid from SCED account and for others to be factored in SCED compensation charge
- USD plants wishing to arrange power scheduled by beneficiaries through SCED to submit standing consent to NLDC before gate closure for arranging supply
  - Pmax = Schedule.
  - Pmin=0
- NLDC shall accommodate USD under SCED subject to
  - Only If the energy charge or SCED Compensation Charge, is higher than that of the marginal generating station of SCED
  - Entire drawal schedule can be accommodated (being amended)
  - No guarantee that SCED can provide the incremental schedule
- Gen deviations to be settled wrt revised schedules , no change in beneficiaries schedules
- Separate SCED bank account. Net savings to be shared
- Reduction in gen. , gen to pay back to pool account for the decremented energy due to SCUC.

Mechanism of SCED: Run after RTM Block by block every 15 minutes , 30 minutes before the actual dispatch period



Benefits to the pool:

a) Refund of VC of costly generator: 200 *4* 250 = Rs 2 lakhs (~USD 2500)

b) Part loading compensation to costly generator: = 200*0.5*250 = Rs 0.25 lakhs (say)(~USD 300)

c) Additional payment to cheaper generators =[100*1+50*2 +50*3]*250= Rs 0.875 lakhs (~USD 1100)

***Net profits remaining with the pool: a-b-c = Rs 0.875 lakhs (*(~USD 1100) per time block (15 minutes)**

Unit Shut Down (USD)

- T-GNA exigency buy-sell
- RTM buy-sell

- Units not brought on bar under SCUC
  - Operate at a level below the minimum turn down level or
  - Go under Unit Shut Down (USD)
- In case a generating station opts to go under unit shut down (USD) --- "arrange supply"
  - Obligation to supply its beneficiaries who had made requisition prior to it going under shutdown
  - by entering into a contract(s); or by arranging supply from any other generating station or unit thereof owned by such generating company; or
  - **Through SCED**
- In case of emergency conditions, for reasons of grid security, units under USD may be directed by NLDC/RLDCs to come on bar. Once on bar to be treated as SCUC

48.Generating station scheduling from Alternate Sources of Power

Gen. Station replacing schedule with REGS

- Shall enter into **contract** with REGS.
- Sec 62 generators: Net **savings** shall be **shared** as specified in Tariff Regulations/NLDC procedure

USD or Forced Outage of Generating units

- Generating station to **contract** with an alternate supplier under **bilateral** or **collective** transactions

- Scheduled quantum from alternate sources shall be **reduced** from schedule of generating station :Bilateral

- Effective from **7^{th}/8^{th} TB**
- Alternate supply through collective transaction , transacted quantum to be reduced from schedule of Gx
- Generating station **exempt** from **transmission charges and losses** for power purchased from alternate sources

Revision of schedules on day of operation

By RLDC

- For grid security(ISTS)
- Bottleneck in evacuation (ISTS)
- GD-5

Buyers

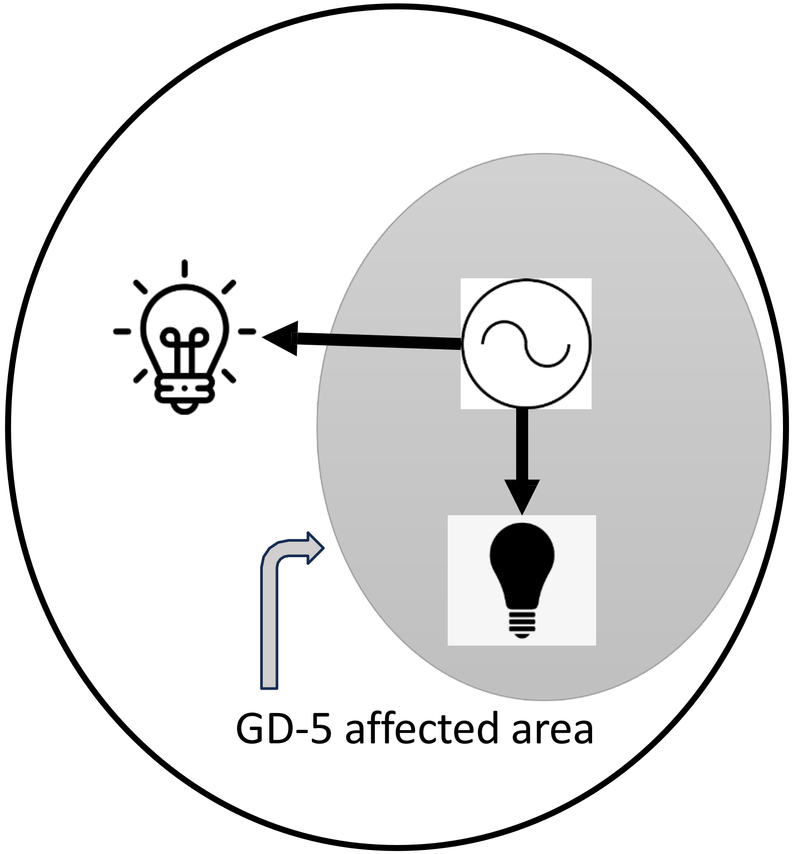
- Schedules under GNA (ISGS & Contract)
- 07th & 08th time block

Generators

- DC rev. due to Forced Outage
  - ✓ GNA/T-GNA revision
  - × Collective transaction: No revision
- In case of forecasting error WS seller may revise sch. and RoR hydro may revise its DC
- 07th & 08th time block from the time block intimation received

49.5. SCHEDULE REV. DUE TO GD-5

- **GD-5:** When 40% of antecedent load/generation is lost as per CEA grid standards
- RLDC to notify GD by posting in website incl. its duration



Sch. of affected Gen. under Bilateral/collective transaction to be revised as per actual for all affected TB

Corresponding schedule of beneficiaries of such gen to be changed who are also affected by GD

Sch. of unaffected beneficiaries should not be revised

Pay back energy charges received for the sch. made equal to actual

Deviation & AS pool Account

Chapter-8

Cyber Security

48. GENERAL

- 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.
- 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

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

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

- Cyber Security Coordination Forum to be formed by sectoral CERT . Sub- Committee at the regional level. Sectoral CERT to lay down rules of procedures for carrying out their activities.

Chapter 9

Monitoring and Compliance Code

Ch.9 MONITORING AND COMPLIANCE code

SELF AUDIT REPORT

Cl.56.2.b

How and why the non-compliance occurred

Extent of damage caused by such non-compliance

Steps and timeline planned to rectify

Steps taken to mitigate any future recurrence

User, QCA,SNA	PX	NLDC, CTU, RPCs, RLDCs	STU,SLDC
RLDC/SLDC	NLDC	CERC	SERC
Cl.56.2.c	Cl.56.2.d	Cl.56.2.e	Cl.56.2.e

MS RPC → Report any unresolved issues to the Commission.

Cl.56.2.i

- Self audit to be done on Annual basis and report submission by 31st July. (Cl.56.2.a)
- **Monitoring agency –** tracks user compliance, reports non-compliance to appropriate Commission. (Cl.56.2.g)

Self Audit

Conduct annual self-audits and submit the reports : 31st July of every year.

- **Should Contain information with respect to non-compliance:**
  - Sufficient information to understand how and why the non-compliance occurred
  - Extent of damage caused by such non-compliance
  - Steps and timeline planned to rectify the same
  - Steps taken to mitigate any future recurrence
- **Self-audit reports by users:** RLDCS or SLDCs (Monitoring agency)
- **Self-audit reports of NLDC, RLDCs, CTU, and RPCs :** Respective Commission (Monitoring agency)
- **Time-bound rectification plan with reasonable time**
  - Track the progress of compliances of users
  - Exceptional reporting for non-compliance to the appropriate Commission.

Regional Power Committee (RPC)

- Monitor the instances of non-compliance
- Endeavor to sort out all operational issues and
- Deliberate to reduce non-compliance by building consensus.
- Member Secretary to report any unresolved issues to the Commission.

Third Party Audit

Independent Third-Party Compliance Audit

- 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.

Thank You

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