OPERATING PROCEDURE FOR

ASSAM STATE GRID

Prepared in Compliance to

Clause 28 (5) of CERC (Indian Electricity Grid Code) Regulations, 2023 and

Clause 7.1.3 & 19.1 of AERC (Electricity Grid Code) Regulations, 2024.

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PREFACE

This document Operating Procedure for Assam state grid has been prepared as per Section 28 (5) of Central Electricity Regulatory Commission, Indian Electricity Grid Code Regulations 2023 and Clause 7.1.3 & 19.1 of Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2024.

It is a document for the stakeholders of the Assam Grid to understand & implement the relevant regulations, orders & procedures of AERC, the regulation of CEA and technical matters related to power system. Procedures under this document are to be followed by all entities operating in the state grid.

It is subject to change as per procedures laid down by competent authority from time to time. The intent of this document is to serve as a guide for the necessary formalities and procedures to be followed while running the power system. The procedure incorporated in this document is to be followed by the stakeholders for bringing uniformity throughout the State for smooth operation of power system and in the interest of grid security.

Words and expressions used in these procedures and not defined herein but defined in various regulations of AERC/CERC/CEA orders and procedures of CERC, judgments of ATE, rules and policies of MOP and Electricity Act, 2003 shall have the meaning assigned to them under these regulations, orders, procedures, rules, policies & the act.

This detailed procedure has been prepared in line with the prevalent regulations and central procedures. If any modification is required for removing difficulties, the same shall be done with prior approval of the Commission.

Disclaimer: Any typographical error which may have crept up inadvertently may please be ignored.

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CHAPTER 1: GENERAL

1.1 INTRODUCTION

In compliance to Clause 28 (5) of Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023 and Clause 7.1.3 & 19.1 of Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2024 Operating Procedure for Assam state grid has been prepared.

The operating procedure is to clearly specify the roles of each stakeholder in the state grid i.e., State Utilities such as Assam Electricity Grid Corporation Ltd (AEGCL), Assam Power Distribution Company Ltd (APDCL), Assam Power Generation Corporation Ltd. (APGCL), Independent Power Producers, Traders, System Operator i.e SLDC and other agencies operating in the power market to facilitate grid operation in efficient, secure, reliable and economic manner.

1.2 SCOPE

This document describes the role of all entities connected to the state grid in order to operate the grid in an integrated manner promoting efficiency, reliability and economy in conformation to the desired security standards and to meet the common interests of all the agencies.

These procedures are to be read in conjunction with the Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023 and Assam Electricity Regulatory Commission (Electricity Grid Code) Regulations, 2024 and other relevant regulations of AERC/CERC.

1.3 OBJECTIVE

Objective of this document is to:

a) Compile various provisions in the statute and regulations for guidance of state grid connected entities within Assam periphery.
b) Spell out the procedures in maintaining consistency and compliance of IEGC/ AEGC adopted for integrated system operation and facilitating operation, maintenance and development of regional power system in the most efficient, economic, secure and reliable manner.

1.4 ROLES and RESPONSIBILITY OF SLDC

1. The State Load Despatch Centre shall be the apex body to ensure integrated operation of the power system in a State.

2. The State Load Despatch Centre shall -

a. be responsible for optimum scheduling and despatch of electricity within a State, in accordance with the contracts entered into with the licensees or the generating companies operating in that State;

b. monitor grid operations;
c. keep accounts of the quantity of electricity transmitted through the State grid;
d. exercise supervision and control over the intra-State transmission system; and be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the Grid Standards and the State Grid Code.

3. The State Load Despatch Centre may levy and collect such fee and charges from the generating companies and licensees engaged in intra-State transmission of electricity or any other grid connected entity as may be specified by the Commission.

4. In accordance with section 33 of the Electricity Act,2003, the SLDC in a State may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in that State.

5. Every licensee, generating company, generating station, sub-station and any other entity connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre under sub- section (1) of Section 33 of the Electricity Act,2003.

6. The State Load Despatch Centre shall comply with the directions of the Regional Load Despatch Centre.

7. In case of inter-state bilateral and collective short-term open access transactions having a state utility or an intra-state entity as a buyer or a seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with relevant regulations of AERC/CERC.

8. SLDC shall be manned by qualified and experienced engineers and professionals who are well acquainted with the State Transmission System and grid operations.

9. Periodical Training shall be imparted to the personnel of the SLDC to update their skills in order to enable them to discharge their functions stipulated under the Indian Electricity Act.

10. If any licensee, generating company or any other entity fails to comply with the directions issued by SLDC, it shall be liable to penalty as stipulated under The Electricity Act'2003.

11. Operation of State Deviation and Ancillary Services pool account, State Reactive Energy account, State Congestion Charge Account and other functions as directed by the Commission.

12. In addition to above responsibilities SLDC shall undertake all the responsibilities

specified by the Commission under various Regulations of the Commission from time to time.

1.5 MAINTENANCE OF OPERATING PROCEDURES

The Operating Procedure shall be maintained by SLDC and reviewed periodically or earlier in case any significant changes take place in the system.

CHAPTER 2: OVERVIEW OF THE STATE GRID

The State Grid presently comprises of a Discom Utility i.e Assam Power Distribution Company Ltd. (APDCL), a state generator Assam Power Generation Corporation Ltd. (APGCL), Independent Power Producers (IPP), Captive Power Producers (CPP), Open Access consumers, Bulk Consumers etc. at various voltage levels.

The Assam transmission system is the largest in the North Eastern Region and accounts for more than 60% of the total energy requirement of the NER. It has interconnections with neighbouring states of Meghalaya, Tripura, Nagaland, Manipur and Arunachal Pradesh and is also connected with the rest of the national grid by various Inter State Transmission lines (ISTS) at 132kV, 220 kV and 400 kV levels. There is also a connectivity with Bhutan at 132kV level from Rangia Grid substation.

As on date of preparation of this document, the State Grid has handled a maximum of 2801.86 MW during the summer of 2025.

The Assam Grid comprises of around Eighty Two (82) EHV grid substations of AEGCL, seven (07) Generating stations of APGCL and twelve (12) Independent Power Producers.

2.1 The statistics of the transmission system of AEGCL on the date of preparation of this procedure are as follows:

GRID SUBSTATIONS OF AEGCL		
SL NO	**VOLTAGE LEVEL**	**COUNT OF SUBSTATIONS**
1	400/220/132/33	1
2	220/132/33	9
3	220/132	3
4	220/132/66/33	1
5	220/33	1
6	132/33	66
7	132/11	1
	TOTAL	**82**

TRANSFORMER DETAILS IN AEGCL			
SL NO	**VOLTAGE LEVEL**	**COUNT OF TRAFOS**	**MVA RATING**
1	400/220	2	630
2	220/132	29	3780
3	220/33	2	100
4	132/66	2	40
5	132/33	162	5448
6	132/11	2	32

TRANSMISSION LINE DETAILS		
SL NO	*VOLTAGE LEVEL*	*CKT KMS*
1	400kV	6.5
2	220kV	1940.5
3	132kV	3470.2
4	66kV	9
Total CKT KMS		**5426.2**

2.2 The Generation scenario of APGCL is as follows:

SL NO	GENERATING PLANT	FUEL	NO. OF UNITS	UNIT SIZE (MW)	CAPACITY (MW)
1	LAKWA THERMAL POWER PLANT	GAS	4	20+20+20 +37.2	97.2
2	LAKWA REPLACEMENT POWER PROJECT	GAS	7	9.975	67.825
3	NAMRUP THERMAL POWER PLANT	GAS	3	17+15+9	41
4	NAMRUP REPLACEMENT POWER PROJECT	GAS	2	62.25+ 36.15	98.4
5	KARBI LANGPI HYDRO ELECTRIC PROJECT	HYDRO	2	50	100
6	MYNTRENG STAGE 1	HYDRO	3	3	9
7	MYNTRENG STAGE 2	HYDRO	3	1.5	4.5
	TOTAL				**419.855**

2.3 The IPP's currently operating in the state are:

SL NO	UTILITY NAME	TYPE	CAPACITY (MW)
1	HAYEN HYDEL PRIVATE LIMITED, CHAMPAVATI	HYDRO	4.05
2	SURYATAAP SOLAR, GHORAMARI	SOLAR	5
3	AZURE SOLAR, ROWTA	SOLAR	25
4	AZURE SOLAR, BOKO	SOLAR	25
5	AZURE SOLAR, NAGAON	SOLAR	15
6	AZURE SOLAR, PAILAPOOL	SOLAR	25
7	MAHESHWARI MINING SOLAR, SAMAGURI	SOLAR	10
8	PATANJALI AYURVED SOLAR	SOLAR	4
9	JAKSON POWER SOLAR	SOLAR	70
10	CALCOM SOLAR	SOLAR	24
11	CALCOM WHRS	WHRS	8
12	BHAGWATI UDYOG CEMENT LTD	SOLAR	3
	TOTAL		**218.05**

CHAPTER 3: ESTIMATION AND RESOURCE ADEQUACY

3.1 INTRODUCTION

Forecasting of demand and estimation of resources is an important step for Resource adequacy assessment and plays a vital role in grid operation.

Integrated resource planning including demand forecasting, generation resource adequacy planning and transmission resource adequacy assessment is required for secure grid operation.

This chapter describes the procedures / responsibilities of the users of the grid for demand assessment as well as generation and transmission resource adequacy planning. The planning of generation and transmission resources shall be done for reliably meeting the projected demand in compliance with specified reliability and resilience standards for serving the load with optimum generation mix.

The provisions related to demand assessment and forecasting and Generation Resource Adequacy Planning shall be governed by AERC (Framework for Resource Adequacy) Regulations' 2024, AEGC 2024 and other relevant regulation.

3.2 DEMAND ESTIMATION AND FORECASTING

1) Clause 4.3 of the AEGC directs each distribution licensee to 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, in different time horizons, namely long-term, medium term and short-term. AEGCL, based on the demand estimates of APDCL shall estimate, in different time horizons, namely long-term, medium term and short-term, the demand for the entire State duly considering the diversity of the State.

2) The distribution licensees shall be responsible for assessing and forecasting of demand (MW) and energy (MWhr) for its own control area including embedded open access consumers as per Clauses 6 of the AERC (Framework for Resource Adequacy) Regulations, 2024. The category wise data shall be provided to AEGCL for state level demand estimation. The methodologies for demand estimation will be as per clauses 6 of the referred regulation.

3) Further, clause 31 (2) of the IEGC 2023 and Clause 7.3.2 of the AEGC directs SLDC to carry out demand estimation based on details collected from APDCL, AEGCL, grid-connected distributed generation resources, captive power plants and other bulk consumers embedded within the State in various timelines viz. an annual, monthly, weekly, and daily. The same shall be submitted to AERC, NERLDC and other authority as per clause 7.6 of AERC (Framework for Resource Adequacy) Regulations, 2024.

4) The Timeline for submission of demand estimate data by SLDC, as applicable, to the respective RLDC and RPC, in line with IEGC, is as follows:

TABLE: TIMELINE FOR DEMAND ESTIMATION (submission by SLDC)

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	30th September of the previous year

5) For preparation of the same, all state entities i.e generators, APDCL, Bulk Consumers are to provide the data as per the following timeline to SLDC in accordance with clause 7.3.2.h of AEGC 2024:

TABLE: TIMELINE FOR DEMAND ESTIMATION (submission to SLDC)

Daily demand estimation	09:00 hours of previous day
Weekly demand estimation	9:00 hrs of First working day of previous week
Monthly demand estimation	Fourth Day of Previous month
Yearly demand estimation	15th September of the previous year

The above information shall be shared by SLDC to the STU for estimation of demand of the entire state as per clause 7.5 of the *AERC* (Framework for Resource Adequacy) Regulations, 2024.

6) SLDCs shall compute forecasting error for intra-day, day-ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce error in the future. The error shall be made available in the SLDC's website.

3.3 GENERATION ESTIMATION AND FORECASTING

1) The generation estimation will have to be carried out in compliance to clauses 7.3.3 of the AEGC and 31.3 of the IEGC.

2) All the Intra-State generators of the state are to submit the generation forecast as per below timeline to SLDC/ NERLDC to enable preparation of adequacy of resources.

TABLE: TIMELINE FOR GENERATION ESTIMATION (submission to SLDC)

Daily generation estimation	09:00 hours of previous day
Weekly generation estimation	9:00 hrs of First working day of previous week
Monthly generation estimation	Fourth Day of Previous month

Yearly generation estimation	15th September of the previous year

3) SLDC shall furnish time block-wise information for the following day in respect of all intra-state entities to the concerned RLDC who shall validate the adequacy of resources, as per IEGC, 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;
   (v) Secondary and planned procurement through Tertiary reserve requirement;
   (vi) Planned procurement of power through other bilateral or collective transactions, if any.

   For the above, the generation forecast from the generators viz. APGCL, IPP's etc are accumulated by SLDC. The Demand Forecast is gathered from the state DISCOM. A balance sheet regarding Estimated Demand and Available sources is prepared in consultation with RLDC.

3.4 GENERATION RESOURCE ADEQUACY (YEAR AHEAD)

1) As per clause 5(3) of the IEGC and 4.3.1.2 of the AEGC, APDCL is to take-up assessment of generation adequacy to meetup the projected demand and prepare generation procurement plan.

2) This generation adequacy planning is to be done by APDCL following the AERC (Framework for Resource Adequacy) Regulations, 2024.

3) Assessment of the existing generation resources shall be done with due regard to their capacity contribution to meet the peak demand of the distribution licensee and the state.

4) 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.

5) SLDC shall on the basis of above assessment of existing generation and generation resource procurement planning furnished by the Distribution licensee shall estimate and ensure the adequacy of resources.

3.5 TRANSMISSION RESOURCE ADEQUACY

1) STU shall undertake assessment and planning of the Intra-State transmission system in compliance to clause 5.4.b of IEGC and 4.4 of the AEGC.

2) The following shall be taken into account while planning transmission resources:

a) Import and export capability across ISTS and AEGCL interface; and
b) Adequate power transfer capability across the Intra-State Transmission System.

While planning the transmission system due consideration shall be given to the demand and generation adequacy.

3.6 GENERATION RESOURCE ADEQUACY (DAY AHEAD/WEEK AHEAD/ MONTH AHEAD)

1) The generation and transmission line on bar and outage status including various constraints has to be reviewed before assessing resource adequacy of day ahead/week ahead/month ahead domain.

2) During the peak demand season, planned outages of generators units and major transmission lines to be avoided. In case of unavoidable in nature the required outage may be availed during the power surplus hours.

3) State DISCOM i.e APDCL shall plan adequate resources in a week ahead advance (from Monday) on rolling basis for meeting full demand. Further, it should also be reviewed in D-1 so that dependency on Real Time Market (RTM) can be minimized.

4) The renewable generators are to regularly monitor the weather condition in the located area. Any impact of weather such as cloud in solar should be informed to the load despatchers immediately. Schedule of the generation should also be revised with probable impact on generation. It will help in managing load generation balance at regional/national level by activating reserve, if any during the impacted period.

5) Emergency Preparedness: maintaining a reserve margin to handle unexpected contingencies, such as generator outages or extreme weather events. This includes having contingency plans for severe weather events, natural disasters, or other disruptions to ensure the continuity of power supply.

6) Hydro power stations would be scheduled maximum during non-solar peak hours. It would also be ensured that hydro stations would not operate as base load (barring canal-based stations, Run-Off-the River (ROR), ROR with pondage where overflowing conditions exist).

7) APDCL should intend to sell their surplus power into the market proactively (after factoring their own internal reserve requirement) so that enough resources are available into the various segments of market.

8) Unrequisition surplus should also be offered into the real time market by all generators.

9) DISCOM should also explore the possibility to tie up power with other states during lean demand period via various market instruments (PushP etc). In case shortfall is anticipated, the state DISCOM shall bridge the anticipated shortfall by day- ahead TGNA Transactions/collective transactions (PX trades).

10) The day ahead power balance can be maintained by procuring power from various segment of markets viz, DAM, HPDAM and additional power tie-up through other market instruments.

CHAPTER 4: SCHEDULING AND DESPATCH PROCEDURE

4.0 OBJECTIVE

This chapter deals with the procedures to be adopted for scheduling of ISGS, SSGS, IPPs, Joint Ventures, CGPs, Open Access Customers and REGS in detail and responsibility of SLDC in preparing and issuing daily schedule of dispatch/ drawal of generators and DISCOMs/Users respectively.

All the Intra state entities of the state shall get registered with SLDC for usage of the intra state scheduling platform. Intra-State entities will be scheduled through the intra state scheduling platform. This platform shall be linked with the (Web Based Energy Scheduling) WBES software of GRID-INDIA via API.

4.1 SCHEDULING PROCESS

1) By 6 AM on 'D-1' day, each Intra-State SSGS/IPPs/REGS will intimate SLDC, station-wise ex-power plant MW and MWH capabilities foreseen for the next day 'D', i.e., between 0000 hours to 2400 hours, at 15-minute intervals.
The Generating Stations shall submit the following information:

Generating Station based on coal and lignite:

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.

Generating Station based on hydro energy:

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.

h) Unit-wise maximum MW along with probable combination of unit maximum in case adequate water is not available.

Generating station based on gas or combined cycle generating station:

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 (fuel-wise) 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.

The renewable energy generating station based on wind/ solar, hybrid of wind and solar, 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. The source-wise breakup of aggregate available capacity of the pooled generation shall also be furnished.

ESS including pumped storage plant, individually or represented by the 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. The source-wise breakup of aggregate available capacity of the pooled generation shall also be furnished.

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

The entitlement of each Beneficiary or Buyer, from generating stations, shall be in accordance with Regulation 49.1.(b) of Indian Electricity Grid Code and amendments thereof.

3) NERLDC shall declare share of each Beneficiary or Buyer for 0000 hours to 2400 hours of 'D' day, by 7 AM on 'D-1' day.

4) SLDC will compile the generator-wise availability for ISGS/ other agreements /SSGS/ IPPs/ REGS entitlement of each Beneficiary or Buyer for 'D' day at 15-minute interval and intimate the same by 07:15 AM on 'D-1' day.

5) By 07:30 AM of 'D-1' day, each beneficiary or buyer will furnish requisition to SLDC in each ISGS, other agreements, Intra-State, SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of 'D' day.

6) The embedded open access consumer(s) shall have to declare the drawal from the DISCOM and through open access, separately, to the SLDC and DISCOM. Other provisions related to scheduling of OA consumers will be as per AERC (TCT for OA reg.) 2024.

7) By 8 AM of 'D-1' day, SLDC shall convey the requisition of the State to NERLDC from ISGS/ other agreements/ SSGS/ IPPs/ REGS for 0000 hours to 2400 hours of 'D' day.

8) 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 Grid Code, shall subject to technical constraints, duly factor in merit order of the generating stations with which intra-State entities has entered into contract(s) for drawal of power:

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.

9) NERLDC will check if drawal schedules as requisitioned can be allowed based on available transmission capability:

Provided that in case of constraint in transmission system, the available transmission corridor shall be allocated in proportion 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 the drawee entities by 8:15 AM on 'D-1' day.

10) The Intra-State Entities shall revise their requisition for drawal schedule based on availability of transmission corridors by 8:30 AM on 'D-1' day.

11) NERLDC will issue final drawal schedules and injection schedules for the State by 9 AM on 'D-1' day.

12) In case a generating station other than REGS intends to replace its schedule by power supplied from REGS, it shall intimate the quantum and source of power by which it intends to replace the power already scheduled by 9:15 AM on 'D-1' day.

13) 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 NERLDC in accordance with contracts by 9.15 AM of 'D-1' day.

14) RLDC and subsequently SLDC, shall incorporate the request from the above said generating station and finalize the injection and drawal schedules by 9:45 AM on 'D-1' day.

15) RLDC will release the balance corridors after finalisation of schedules for day ahead collective transactions.

16) Scheduling of Collective Transactions as per IEGC:

a) Power Exchange(s) shall open bidding window for day ahead collective transactions and TRAS from 10:00 AM to 11:00 AM of 'D-1' day.

b) 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 11.45 AM of 'D-1' day.

c) NLDC shall validate the same from system security point and inform the Power Exchange(s) with revisions required, if any, due to transmission congestion or any other system constraint by 12:15 PM of 'D-1' day.

d) The Power Exchange(s) 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.

17) RLDC will release balance corridors after finalisation of schedules under day ahead collective transactions by 1:00 PM of 'D-1' day.

18) RLDC/ SLDC shall process exigency applications received till 1:00 PM of 'D-1' day for 'D' day by 2:00 PM of 'D-1' day.

19) RLDC, and subsequently SLDC, shall update the availability of balance transmission corridors, if any, after finalisation of schedules for exigency applications by 2:00 PM of 'D-1' day on its website. The balance transmission corridor may be utilised by way of revision of schedule, under any contract within its GNA or for exigency applications or in real time market on first-come-first-served basis.

Scheduling of transactions in Real-Time Market (RTM), as per IEGC:

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

B. The window for trade in real-time market for 'D' day shall open from 22:45 hours to 23:00 hours of 'D-1' for the delivery of power for the first two time-blocks of 1st hour of 'D' day, i.e., 0000 hours to 0030 hours, and will be repeated every half an hour thereafter.

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

D. The Power Exchange(s) shall clear the real-time bids from 23:00 hours till 23:15 hours 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 and intimate the cleared bids to NLDC by 23:15 hours, for scheduling.

20) NLDC will finalise schedules under real time market (RTM) by 23:30 hours of 'D-1' day and RLDC, subsequently SLDC, shall publish the final schedules for dispatch by 23:35 hours of 'D-1'day. The scheduled finalized by SLDC shall have the following:

a) Ex-power plant generation schedule of SSGS/IPPs and other State generators including wind/ solar generators, Hybrid of wind and solar Generating Stations and Energy Storage System (ESS).

b) Drawal schedule of each entity in MW for each time block, along with break-up of (a) schedule from each of the sellers, (b) schedule of injection to InSTS and (c) injection or drawal schedule under collective transaction, on the basis of information received from the Power Exchange (s) or NERLDC, as applicable and as specified in the IEGC.

4.2 RULES FOR REVISION IN SCHEDULE

4.2.1 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 with immediate effect by the SLDC (in co-ordination with

Regional Load Despatch Centre, as applicable) keeping in view the transaction which is likely to relieve the threat to grid security, in conformity with the IEGC, as follows:

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

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

i. 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;
ii. 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 up to three hours pondage (in case of excess water leading to spillage), pro rata based on their T-GNA quantum;
iii. The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with up to 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.
iv. Collective transactions under day ahead market shall be curtailed after curtailment of bilateral transactions under T-GNA.
v. Collective transactions under real time market shall be curtailed after curtailment of collective transactions under day ahead market.

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

i. 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 up to three hours pondage (in case of excess water leading to spillage), on pro rata basis based on their GNA quantum.
ii. The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with up to 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.

d) SLDC shall publish a report of such incidents on its website.

4.2.2 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 SLDC shall revise the schedules:

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

4.2.3 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 SLDC:

a) Issue directions to concerned entities to adhere to the schedules;

b) Switching on/off pump storage plants operating in pumping mode;
c) Despatching emergency demand response measures;
d) Direct the state entities to increase or decrease their drawal or injection by revising their schedules and such directions shall be immediately acted upon;
e) Deployment of ancillary services, in co-ordination with NERLDC/NLDC as applicable.

4.2.4 Whenever SLDC 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 SLDC website within 24 hours.

4.2.5 Any verbal directions by SLDC shall be confirmed in writing as soon as possible latest within twenty-four hours.

4.2.6 Revision of schedules on request of buyers which are GNA grantees, in line with IEGC:

a) SLDC on behalf of intra-state entities, regional entity ESSs as drawee entities, beneficiaries, regional entity buyers or cross-border buying entities may revise their schedules under GNA as per sub-clauses (b) and (c) of this clause 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 or partial outage.

b) The request for revision of scheduled transaction for 'D' day, shall be allowed subject to the following:

i. Request of buyers for upward revision of schedule from the generating station whose tariff is determined under Section 62 of the Act shall be allowed starting 2 PM on 'D-1' day, only in respect of the remaining available quantum of un-requisitioned surplus in such generating stations, after finalization of schedules under day ahead market.
ii. Request of buyers for downward revision of schedule from the generating stations, whose tariff is determined under Section 62 of the Act shall be allowed in any time block subject to the provision relating to SCUC under Regulation 46 of the IEGC and amendments thereof.

Provided that downward revision of schedules by the buyers for 'D' day, after 1430 hrs on 'D-1' day in the generating station is permissible only for beneficiaries which have scheduled above their respective share of minimum turndown level in the generating station:

Provided also that downward revision by such beneficiaries, which have scheduled above their respective share of minimum turndown level in the generating station, shall be permissible limited to a quantum such that overall schedule of the generating station is at least at Minimum turndown level. The downward revision of schedules by such beneficiaries for 'D' day, after 1430 hrs on 'D-1' day shall be permissible on a pro-rata basis of the power scheduled above the minimum turndown level of their share at 1430 hrs of 'D-1' day.

iii. Request of buyers for upward or downward revision of schedule in respect of the generating stations other than those whose tariff is determined under Section 62 of the Act, shall be allowed 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 this clause, 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 SLDC (or RLDC, when RLDC approval is required) to be the first one.

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

4.3 ADDITIONAL FACTORS TO BE CONSIDERED WHILE FINALIZING SCHEDULE

4.3.1 Grid disturbance of category GD-5:

(a) GD-5 occurs when forty per cent or more of the antecedent generation or load in a regional grid is lost as defined in the CEA Grid Standards.

(b) Certification of such grid disturbance and its duration shall be done by the NERLDC and the notice posted by the NERLDC at its website, to this effect, shall be considered as declaration of the grid disturbance by RLDC. SLDCs shall take action for restoration of grid to normalcy, in coordination with NERLDC, if required. All state entities shall take note of the grid disturbance and take appropriate action at their end.

(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 state entity generating station shall pay back the energy charges received by it for the scheduled generation revised as actual generation to the Deviation and Ancillary Service 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 Deviation and Ancillary Service Pool Account.

(e) Energy and deviation settlement for the period of such grid disturbance causing disruption in injection or drawal of power shall be done by the SLDC:

Provided that generation and drawal schedules revised by the RLDC, subsequently by SLDC, shall become effective from 7th block or 8th block depending on block in which schedule has been revised as first block.

4.3.2 The generation schedules and drawl schedules shall be accessible to the state 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 state entity generating stations and drawal schedule of the buyers/beneficiaries shall be issued by the concerned RLDC. These schedules shall be the basis for commercial accounting.

4.3.3 Revision of Declared Capacity and schedule, shall be allowed on account of forced outage of a unit of a generating station or ESS (as an injecting entity) only in case of bilateral transactions and not in case of collective transaction. Such generating station or ESS (as injecting entity) or the electricity trader or any other agency selling power from the unit of the generating station or ESS shall immediately intimate the outage of the unit along with the requisition for revision of Declared Capacity and schedule and estimated time of restoration of the unit to SLDC. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised on pro-rata basis for all bilateral transactions. The revised Declared Capacity and schedules shall become effective from the time block and in the manner as specified in clause 8.6 of AERC (Electricity Grid Code) Regulations, 2024:

Provided that the generating station or ESS (as injecting entity) or trading licensee or any other agency selling power from a generating station or unit(s) thereof or ESS may revise its estimated restoration time once in a day and the revised schedule shall become effective from the 7th time block or 8th time block as per clause 8.6 of AERC (Electricity Grid Code) Regulations, 2024, counting the time block in which the revision is informed by the generator or ESS to be the first one:

Provided further that the SLDC 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.

4.3.4 Revision of Declared Capacity and schedule of a generating station or ESS (as an injecting entity) shall be allowed only in case of bilateral transactions and not in case of collective transaction as per following details:

(a) The generating station (other than lignite, gas based thermal generating station, and hydro generating station) or ESS (as an injecting entity) shall be allowed a maximum of 4 (four) revisions of Declared Capacity and schedule in a day subject to a maximum of

60 (sixty) revisions during a month, due to reasons such as a partial outage of the unit or variation of fuel quality or any other technical reason to be recorded in writing:

Provided that SLDC/NERLDC (as applicable) may allow upward revision of DC beyond the above limit keeping in view grid requirements.

(b) The generating station based on lignite, gas, or hydro generating station shall be allowed 6(six) revisions of Declared Capacity and schedule in a day subject to a maximum of 120 (One hundred twenty) revisions during a month, due to reasons such as a partial outage of the unit or water availability for hydro generating stations or fuel quality or variations in the supply of gas for gas generating stations or any other technical reason to be recorded in writing:

Provided that SLDC/NERLDC (as applicable) may allow upward revision of DC beyond the above limit keeping in view grid requirements

4.3.5 In case of requirement of revision of schedule due to forecasting error, a WS seller may revise its schedule only in case of bilateral transactions and not in case of collective transaction. Such revision of schedule shall become effective from the time block and in the manner as specified in 4.2.6.c.

4.3.6 In case of requirement of revision of Declared Capacity due to forecasting error, a RoR generating station may request for revision of its Declared Capacity and schedule only in case of bilateral transactions and not in case of collective transaction. Such revision shall become effective from the time block and in the manner as specified in 4.2.6.c

4.3.7 In the event of forced outage of a generating station or unit thereof, the generating company owning the generating station or unit thereof shall fulfil its supply obligation to the beneficiaries which made requisition from such generating station or unit thereof,

a) by entering into contract(s) covered under Power Market Regulations or

b) 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 the supply is arranged or

c) through SCED, as applicable.

4.3.8 Discrepancy in schedule

a) All state entities, open access customers, injecting entities and drawee consumers shall closely check their transaction Schedule and point out errors, if any, to the SLDC.

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

4.3.9 Margins for primary response:

For the purpose of ensuring primary response, SLDC (in co-ordination with NERLDC, wherever required), 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 shall be made by SLDC (in co-ordination with NERLDC, wherever required), 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 or any other overload capability as allowed in AEGC, during high inflow periods to avoid spillage.

4.3.10 Oversight of Injection and Drawal:

SLDC 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 GCMC for necessary action. If this still persists after being taken up at the GCMC, it shall be reported to the Commission the matter with recommendation.

4.3.11 UNIT SHUT DOWN (USD)

i. The generating stations or units thereof, identified by NLDC in co-ordination with RLDC/SLDC, as the case may be, as per subclause (c) of clause (4) of Regulation 46 of the IEGC 2023 and amendments thereof, 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 arranging supply either (a) by entering into a contract(s) covered under the Power Market Regulation; or (b) 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; or (c) through SCED as per the Detailed Procedure specified by NLDC in this regard.

iii. In case of emergency conditions, for reasons of grid security, a generating station or unit thereof, which is under USD, as may be directed by NLDC to come on bar, and in such event the generating station or unit thereof shall come on bar under hot, warm and cold conditions as per the time period to be specified in the detailed procedure as per the Detailed Procedure specified by NLDC in this regard.

iv. Once a generating station is brought on bar as per clause (iii) of this Regulation, it shall be treated as a unit under SCUC and scheduled and compensated as per the relevant regulations of the IEGC.

4.4 SCHEDULING FROM ALTERNATE SOURCE OF POWER BY A GENERATING STATION

1) A generating station may supply power from alternate source in case of Unit Shut Down (USD) or forced outage of unit(s). This facility shall also be available to a generating station other than REGS replacing its scheduled generation by REGS, irrespective of whether such identified sources are located within or outside the premises of the generating station or at a different location.

2) The methodology for scheduling of power from alternate sources covered under Unit Shut Down (USD) or forced outage of unit(s) shall be as per the following steps:
   i. The generating station may enter into contract with alternate supplier under bilateral transaction or collective transaction.
   ii. In case of bilateral transaction, the generating station shall request SLDC to schedule power from such alternate supplier to its beneficiaries, which shall become effective from 7th or 8th time block, as the case may be, in line with Clause 8.6 of AERC (Electricity Grid Code) Regulations, 2024.
   iii. The power scheduled from alternate supplier shall be reduced from the schedule of the generating station.
   iv. In case of alternate supply is arranged through collective transactions, the transacted quantum shall be reduced from the scheduled generation of the generating station.
   v. The generating station shall not be required to pay the transmission charges and losses for such purchase of power to supply to the buyer from alternate sources.
   vi. The generating station may also request the concerned RLDC to arrange alternate supply through SCED in accordance with the relevant provisions of the IEGC.

3) The methodology for scheduling of power from alternate sources for a generating station other than REGS replacing its scheduled generation by power supplied from REGS shall be as per the following steps:
   i. The generating station shall enter into contract with REGS for supply of power from alternate sources.
   ii. The generating station shall request SLDC to schedule power from such alternate source to its beneficiaries, which shall become effective from 7th or 8th time block, as the case may be.
   iii. The power scheduled from alternate source shall be reduced from the schedule of the generating station.
   iv. The generating station shall not be required to pay the transmission charges and losses for such purchase and supply from alternate sources to the buyer.
   v. In case of a generating station whose tariff is determined by the Commission under Section 62 of the Act, supply of power by such generating station to its buyer from

an alternate source, shall be subject to sharing of net savings as specified in the Assam Electricity Regulatory Commission (Terms and Conditions for Multi Year Tariff) Regulations, 2024 and amendments thereof.

vi. In case of a generating station other than whose tariff is determined by the Commission under Section 62 of the Act, supply of power by such generating station to its buyer from an alternate source shall be in accordance with the contract with the buyer and in the absence of a specific provision in the contract, in terms of mutual consent including on sharing of net savings between the generating station and the buyer.

4.5 MINIMUM TURNDOWN LEVEL FOR OPERATION OF THERMAL GENERATING STATIONS

The minimum turndown level for operation in respect of thermal generating units connected to STU network and which is in control area of SLDC shall be 55% of the MCR of the said unit or such other minimum power level as specified in the CEA Flexible Operation Regulations as amended from time to time, whichever is lower:

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

Provided further that such generating station on its own option may declare a minimum turndown level below the minimum turndown level specified in this Regulation:

Provided also that the thermal generating stations whose tariffs are adopted under Section 63 of the Act, shall be compensated for part load operation, i.e., for generation below the normative level of operation, in terms of the provisions of the contract entered into by such generating stations with the beneficiaries or buyers, or in the absence of such provision in the contract, as per the mechanism to be specified by the Commission separately.

Provided further that the thermal generating stations whose tariffs are determined under Section 62 of the Act by the Commission, shall be compensated for part load operation, as per provisions of applicable Regulations of AERC, unless separate notification is issued by the Commission.

CHAPTER 5: FREQUENCY CONTROL AND ANCILLARY SERVICES

5.1 INTRODUCTION

The National reference frequency of operation in Indian grid is 50.000 Hz. All the Users of the grid shall make all possible efforts and take necessary actions as directed by SLDC to maintain grid frequency within the normal IEGC band that is 49.900 Hz to 50.050 Hz.

SLDC shall endeavour to maintain the drawal or injection of the intra state entities at par with the schedule so that the grid frequency remains close to 50.000 Hz. In case frequency goes outside the allowable band all possible efforts to restore the frequency within the allowable band of 49.900-50.050 Hz shall be done.

All users shall comply to the directions of SLDC and take necessary action so that the grid frequency is maintained and remains within the allowable band. They are required to follow the instructions of SLDC for backing down generation, regulating loads, MVAr drawal, etc., to maintain the system frequency and grid voltage.

5.2 RESERVES

SSGS shall hold reserves of active/reactive power and regulate generation of their plant within respective declared parameters as per instruction of SLDC.

There shall be reserves as under:

1) 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 AEGC 2024.
iii. Secondary reserves including automatic generation control and demand response shall bedeployed by the control area as per these regulations or relevant regulations of CERC or AERC.
iv. Tertiary reserves shall be deployed by the control area as per these regulations or the Ancillary Services Regulations or the respective regulations on Ancillary Services of the State, as the casemay be.

2) Black Start reserves

Generating stations having black start capability, ESS and HVDC Station basedon VSC shall be identified by SLDC at the State level, to act as black start reserves.

3) Voltage Control reserves:

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

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.

5.3 PRIMARY FREQUENCY CONTROL:

1) 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.

2) The generating stations and units thereof shall have electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity Regulations and are mandated to provide PRAS. The generating stations and units thereof with governors shall be under Free Governor Mode of Operation.

3) As per IEGC, NLDC may also identify other resources such as ESS and demand resource to provide PRAS, in consultation with SLDC, for which PRAS providers shall be compensated in accordance with the Ancillary Services Regulations.

4) All the generating units shall have their governors or frequency controllers in operation all the time with droop settings of 3 to 6 % (for thermal generating units and WS Seller) or 0-10% (for hydro generating units) as specified in the CEA Technical Standards for Connectivity Regulations.

5) The primary response requirement of various types of generating units shall be as mentioned below

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 Regulations.

6) The provisions related to Primary Response Ancillary services will be governed by relevant clauses of AEGC 2024 and AERC Ancillary Services Reg. 2024.

5.4 FREQUENCY RESPONSE CHARACTERISTICS (FRC) AND FREQUENCY RESPONSE OBLIGATIONS (FRO):

1) Frequency response characteristics (FRC) and frequency response obligations (FRO) calculations shall be as per relevant clauses under AEGC 2024.

2) SLDC shall assess its frequency response characteristics and share the assessment with NERLDC along with high resolution data of at least 10 (ten) seconds for the state control area as per IEGC 30(10) (n) after receipt of information of Reportable event from NERLDC.

3) SLDC shall grade the median Frequency Response Performance annually, considering at least ten (10) reportable events, in coordination or as directed by NLDC/NERLDC. In case the median Frequency Response Performance is less than 0.75 as calculated, NLDC/RLDC/SLDC, as the case may be, after analysing the FRP, shall direct the concerned entities to take corrective action. All such cases shall be reported to the NERPC for its review.

5.5 SECONDARY FREQUENCY CONTROL

1) Secondary response is a reliability service and acts as a replacement to the exhausted primary frequency reserves and for correction of Area Control Error (ACE).

2) National Load Despatch Centre i.e. the Nodal Agency, in coordination with RLDCs and SLDCs, would estimate the quantum of requirement of SRAS at the regional level after factoring in the reserves for each state control area.

3) The Area Control Error (ACE) would be auto-calculated at SLDC based on telemetered values and the external inputs, as per the following formula:

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

Where,
Ia = Actual net interchange in MW (positive value for export)
Is = Scheduled net interchange in MW (positive value for export)
Bf = Frequency Bias Coefficient in MW/0.1 Hz (negative value)
Fa = Actual system frequency in Hz
Fs = Schedule system frequency in Hz
Offset = Provision for compensating for measurement error.

This ACE data shall be archived at an interval of 10 seconds or less. SLDC shall share the data with the NERLDC and NLDC.

4) SRAS will be activated and deployed by the Nodal Agency as and when required on account of the following events to maintain or restore grid frequency within the allowable band as specified in the Grid Code.

(a) Considering the state network as control area, Area Control Error (ACE) of the State going beyond the minimum threshold limit of ±10 MW or such other limit as may be notified by the Commission based on review of performance of SRAS;

(b) Such other events as specified in the Grid Code.

SLDC may operate SRAS in any of the three control modes namely, tie-line bias control mode, flat frequency control mode or flat tie-line control mode depending on grid requirements.

5) SRAS will be procured through the mechanism as specified in AERC Ancillary Services Reg. 2024, provided that the Commission based on review of the operation of SRAS, may direct procurement of SRAS through market-based bidding mechanism, if specified by the Commission.

6) A SRAS Provider willing to participate in SRAS will be required to provide standing consent to the Nodal Agency for participation, which shall remain valid till it is modified or withdrawn.

7) SLDC based on the estimate of the SRAS requirement as per relevant regulation shall ascertain availability of adequate SRAS capacity by factoring in the declarations made by the SRAS Providers on day-ahead basis and on real- time basis before the gate closure of the Real Time Market. SRAS Provider shall be selected for the state by SLDC as the case may be for providing SRAS-Up or SRAS- Down based on the Custom Participation Factor.

8) Secondary control signal for SRAS-Up and SRAS-Down shall be sent to the control centre of the SRAS Provider every 4 seconds by the Nodal agency. SRAS Provider shall allow its control centre to follow the secondary control signal for SRAS-Up or SRAS-Down automatically without manual intervention.

9) SRAS shall have a bi-directional communication system along with metering and SCADA telemetry in place as per the requirements stipulated under the Ancillary Service Regulations.

Other provisions related to Secondary Response Ancillary services will be governed by relevant clauses of AEGC 2024 and AERC Ancillary Services Reg. 2024.

5.6 TERTIARY FREQUENCY CONTROL

1) Tertiary reserves requirement for the State control area, shall be estimated by NLDC so as to take care of contingencies and to cater to the need for replacing secondary reserves. SLDC shall ensure the availability of the quantum of tertiary reserve as estimated in different time horizons.

2) TRAS provider shall be capable of providing TRAS within 15 (fifteen) minutes of despatch instructions from NLDC/ NERLDC/ SLDC, as the case may be, and shall be capable of sustaining the service for at least the next 60 minutes.

3) TRAS shall be activated and deployed on account of the 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 20 MW
   ii. Generation unit or transmission line outages;
   iii. Any such other event affecting the grid security.

4) If a State falls short of maintaining tertiary reserve capacity as allocated to it, whichever is lower, the NLDC through RLDCs shall procure such tertiary reserve capacity on behalf of the said State under advance intimation to the concerned State and allocate the cost of procurement of such capacity to that State.

Other provisions related to Tertiary Response Ancillary services will be governed by relevant clauses of AEGC 2024 and AERC Ancillary Services Reg. 2024.

5.7 PREVENTIVE MEASURES DURING HIGH FREQUENCY CONDITIONS

1) When the frequency is on a rising trend (above 50.05 Hz), actions for controlling high frequency operation shall be initiated.

2) In case the frequency is high (above 50.05 Hz) and is in increasing trend then the following actions may be taken in order of priority provided that actual generations/drawls are maintained close to the schedule:

   i. Lifting of planned load shedding, curtailments, if any
   ii. Generation backing down in coal fired thermal stations & Gas station (within state control area incase it is under drawing) as per merit order based on variable charges as per provisions of relevant regulations.
   iii. Downward revision of requisitions from ISGS as per merit order on request of beneficiaries

3) No generating unit shall be synchronized with the grid while the grid frequency is above 50.05 Hz. or higher.

4) SLDC may instruct the solar generator to back down generation on consideration of grid security or if safety of anyequipment or personnel is endangered and solar generator shall comply with the same.

5.8 PREVENTIVE MEASURES DURING LOW FREQUENCY CONDITIONS

In case the frequency is low (below 49.9 Hz) and is in decreasing trend then the following

actions may be taken in order of priority provided that actual generations/drawls are maintained close to the schedule:

i. Upward revision in requisition in ISGS (to the extent un-dispatched) on request of beneficiaries.

ii. Increase in generation wherever margins are available keeping margin for Primary response.

iii. Increase in generation by coal/gas fired stations within State control area (if it is over drawing) asper merit order based on variable charges.

iv. Other defence mechanism such as automatic Demand Management Scheme (ADMS), Automatic Under Frequency Load Shedding (AUFLS) etc may be brought into service.

CHAPTER 6: VOLTAGE AND REACTIVE POWER CONTROL

6.1 INTRODUCTION

1) Users of the State Transmission System shall make all possible efforts to ensure that the grid voltage always remains within the limits specified in the AEGC**.** The specified limit of voltage are given below:

Nominal Voltage (KV – rms)	Maximum Voltage (KV- rms)	Minimum Voltage (KV – rms)
765	800	728
400	420	380
230	245	207
220	245	198
132	145	122
110	121	99
66	72	60
33	36	30

2) All Users shall ensure that the temporary over voltage due to sudden load rejection remains within the limits specified as below :

Nominal Voltage (KV- Rms)	Phase to Neutral Voltage (kVpeak)
765	914
400	514
220	283
132	170
< 132 kV	As decided by the commission or as notified by CEA

3) The CEA Grid Standards 2010 clause 3.d also mandates the maximum voltage unbalance allowableas per the values provided in the below mentioned table.

Nominal (KV – Rms)	Voltage Unbalance (%)
765 & 400	1.5 %
220	2 %
33 to 132	3 %

Further the CEA Grid Standards Reg. 2010 and IEGC also mandates that bulk consumers

shall avoid unbalanced load during operation and distribution licensees i.e APDCL shall ensure that their loads are not unbalanced. CEA grid standard 2010 clause 3.1.h also mandates all entities to comply with permissible limit of voltage fluctuations.

4) Also, in compliance to clause 3.2 of the CEA Grid Standards Reg. 2010, the transmission licensees shall ensure that the voltage wave-form quality is maintained as per the limits provided below:

SL NO	SYSTEM VOLTAGE (kV rms)	TOTAL HARMONIC DISTORTION (%)	INDIVIDUAL HARMONIC OF ANY PARTICULAR FREQUENCY (%)
1	765	1.5	1
2	400	2	1.5
3	220	2.5	2
4	33 TO 132	5	3

5) To ensure the voltage profile is within operational limits, various reactive power devices and controlmechanisms shall be implemented.

6) STU and SLDC shall carry out load flow studies based on operational data available from time to time, to predict where voltage problems may be encountered and to identify appropriate measures to ensure that voltages remain within the defined limits. On the basis of these studies, SLDC shall instruct the generators within its control area to maintain specified voltage level at interconnecting points. SLDC and STU shall co-ordinate with the DISCOMs to determine voltage level at the inter-connection points. SLDC shall continuously monitor 400/220/132kV voltage levels at strategic sub-stations.

7) SLDC, in close coordination with NERLDC shall take appropriate measures to control State Transmission System voltages, which may include but not be limited to transformer tap changing, capacitor/ reactor switching including capacitor switching by DISCOMs at 33 kV sub-stations, operation of Hydro unit as synchronous condenser and use of MVAr reserves with the generators within its control area within technical limits agreed to between STU and Generators. Generators shall inform SLDC of their reactive reserve capability promptly on request.

8) SSGS and IPPs shall make available to SLDC, the up-to-date capability curves for all Generating Units, indicating any restrictions, to allow accurate system studies and effective operation of the State Transmission System. CPPs shall similarly furnish the net reactive capability that will be available for Export to/ Import from State Transmission System.

9) DISCOMs and Open Access Users shall participate in voltage management by providing local VAR compensation (as far as possible in low voltage system close to load points) such that they do not depend upon EHV grid for reactive support.

10) Close Co-ordination between Users and SLDC, STU and NERLDC shall exist at all times for the purposes of effective frequency and voltage management.

11) If voltage is outside the limit as specified under 6.1 1) and the means of voltage control is exhausted, SLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits including switching ON or OFF of lines considering the security of the system.

12) All generating stations shall be capable of supplying reactive power support so as to maintain power factor at the point of inter-connection within the limits of 0.95 lagging to 0.95 leading as per the CEA Technical Standards for Connectivity Regulations and amendments thereof.

13) All generating stations connected to the grid shall generate or absorb reactive power as per instructions of SLDC, within the capability limits of the respective generating units, where capability limits shall be as specified by the OEM.

14) The reactive interchange of Users shall be measured and monitored by SLDC.

15) SLDC may direct the Users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at inter-connection points.

16) SLDC shall assess the dynamic reactive power reserve available at various sub-stations or generating stations under any credible contingency on a regular basis based on technical details and data provided by Users.

6.2 AVRs/ PSSs OF GENERATORS & ITS TUNING

1) As per clause 7.2.12 of the AEGC, all generating units shall have their Automatic Voltage Regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers (Power Plant Controller) and any other requirements in operation, as per CEA Technical Standards for Connectivity Regulations and amendments thereof.

2) If a generating unit with a capacity higher than 100 (hundred) MW is required to be operated without its AVR or voltage controller in service, the generating station shall immediately inform the SLDC of the reasons thereof and the likely duration of such operation and obtain its permission.

3) As per clauses 7.2.13 of the AEGC, **t**he tuning of AVR, PSS, Voltage Controllers (PPC) 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 by the respective generating station:

a) at least once every five (5) years;
b) based on operational feedback provided by SLDC, after analysis of a grid event or disturbance;
c) in case of major network changes or fault level changes near the generating station as reported by SLDC; and
d) in case of a major change in the excitation system of the generating station.

4) 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 NERPC/SLDC. In case the tuning is not complied with as per the plan and procedure, the SLDC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the SLDC may approach AERC under Section 33(4) of the Act.

6.3 VAR GENERATION/ ABSORPTION BY GENERATING UNITS

1) To improve the overall voltage profile, all generators shall generate reactive power during low voltage condition and absorb reactive power during high voltage condition as per instructions from SLDC within the capability limit of the respective generating units.

2) Further clause 39.2 of IEGC and CEA Connectivity Standard Regulations, mandates all generating stations to provide reactive power support to maintain power factor at the point of interconnection within the limits of 0.95 lagging to 0.95 leading.

3) Standalone synchronous condenser units, Hydro and gas generating units capable of synchronous condenser operation shall operate in synchronous condenser mode operation as per instructions of SLDC. Compensation for such synchronous condenser mode of operationshall be done as per the procedure approved by the Commission.

4) All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that theyhave 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 providingreactive 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.

5) SLDCs may direct the users about reactive power set-points, voltage set-points and power factor control to maintain the voltage at interconnection points. So AVR set points, STATCOM voltage settings other voltage controller settings may be revised as per the directions of NERLDC to maximize the reactive reserve and reactive support.

6) 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, as per the procedure specified by NLDC.

6.4 DYNAMIC REACTIVE RESERVE

1) Dynamic reactive resources are the reactive resources that adjust reactive power output automaticallyin real-time over a continuous range within a specified voltage band in response to changes in grid voltages.

   Examples of Dynamic reactive resources include Synchronous generators, Synchronous condensers, static VAR compensators (SVC), STATCOM, VSC-based HVDC, non-synchronous inverter-based resources enabled to provide reactive power support.

2) Further, reactive power capability tests shall be performed once every five (5) years or whenever major retrofitting is done. If any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, as advised by SLDC or RLDC or NLDC or RPC. Further, the Reactive Power Capability tests may also be advised by SLDC or RLDC or NLDC or RPC, if it is observed that the generator /IBR/ condenser /FACTS /HVDC (VCC) is not able to provide sufficient reactive power support as per the capability curve submitted by the respective user.

6.5 TRANSFORMER TAPS

1) Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages, subject to technical feasibility, and wherever necessary, other options such as tap staggering may be carried out in the network.

2) The tap settings shall be reviewed and changed with change of season and based on system requirement. Frequent on-line tap changing may be avoided to the extent possible. Tap changing of substation shall be done after due consultation with SLDC.

6.6 CONTROL OF VOLTAGE AT GRID SUBSTATIONS/GENERATING STATIONS

Following corrective measures in order of priority shall be taken by SLDC for state entities in the event of voltage going outside the limits as stipulated in IEGC.

1) **HIGH VOLTAGE: OPERATORS ACTION**

   In the event of high voltage following specific steps would be taken by the respective grid substation/generating station at their own, with intimation to SLDC, unless specifically mentioned by SLDCs.

   Before taking any voltage control action the reason for high voltage as observed /reported be carefully studied. The network adjoining to the substation/s experiencing high voltage be also carefully studied and areas/substations /generating stations be identified where voltage control measures need to be taken:

i. The bus reactor be switched in.
ii. The switchable line/tertiary reactor are to be taken in
iii. The Generating units on bar at the stations in proximity to high voltage areas, absorb reactive power within the limits of their capability curves. Provided that these, absorption will be instructed only when local generator bus voltage is more than 0.97 PU.
iv. Check the possibility of changing the transformer Tap position.
v. Operate synchronous condensers wherever available for VAR absorption.
vi. Operate hydro generator / gas turbine as synchronous condenser for VAR absorption wherever such facilities are available.
vii. Opening one circuit of lightly loaded multi circuit lines around the area /substation where high voltage is reported, ensuring security of the balance network. In case it becomes essential to switch out one of the circuits of inter- regional lines to mitigate high voltage at one or more inter-regional sub-stations, due consent would be obtained from NERLDC.

2) **LOW VOLTAGE: OPERATORS ACTION**

In the event of low voltage, following specific steps would be taken by the respective grid substation/generating station at their own, with intimation to SLDC, unless specifically mentioned by SLDCs.

Before taking any voltage control action the reason for high voltage as observed /reported be carefully studied. The network adjoining to the substation/s experiencing low voltage be also carefully studied and areas/substations/generating stations be identified where voltage control measures need to be taken:

i. Close the lines which were opened to control high voltage after obtaining due permission.
ii. The bus reactors to be switched out.
iii. The switchable line/tertiary reactor be taken out.
iv. Concerned substations are to be instructed to ensure that all capacitors bank in the system are in put into service.
v. All generating units on bar shall generate reactive power up to the limits of their respective capability curves. Provided that these generation will be instructed only when local generator bus voltage is less than 1.03 PU.
vi. Operate hydro generator / gas turbine as synchronous condenser for VAR generation wherever such facilities are available for VAR generation i.e., at lagging p.f.
viii. Check the possibility of changing the transformer Tap position.

6.7 COMPUTATION OF VOLTAGE DEVIATION INDEX (VDI) AND VOLTAGE EXCURSION REPORT

1) Voltage Deviation Index (VDI) at important 220kV nodes of AEGCL grid is being calculated on Daily Basis by SLDC for identification of the nodes of under voltage & over voltage. The formula for calculating Voltage Deviation Index as given below:

   Daily VDI = (Duration of Voltage outside IEGC band in hours)/24

2) Voltage Excursion Reports are calculated for all the GSS of AEGCL on yearly basis. The formula for calculation of the Voltage variation index is:

   Voltage variation Index = (Maximum Voltage - Minimum Voltage) / Base voltage

CHAPTER 7: NETWORK SECURITY AND REAL TIME MONITORING

7.1 INTRODUCTION

This chapter outlines the necessary measures to ensure the continuous security of the network, both in response to potential issues originating within or external factors such as the failure of crucial lines, buses, generating units, or other essential grid components.

Additionally, it provides an overview of the steps needed to uphold system parameters at or near their nominal values during regular daily operations.

It is a critical aspect of maintaining the dependable and secure operation of electrical power networks. It encompasses a range of strategies and practices to safeguard the electricity supply and ensure grid stability.

This section highlights the measures to be adopted by the System Operators at State Load Despatch Centres (SLDCs), DCC, State Generating Stations, substations for safe and secure operation of the grid.

7.2 SYSTEM STATES

In accordance with Clause 35(1) of the IEGC 2023, the power system's operational state shall be classified into normal, alert, emergency, extreme emergency, and restoration states. This classification depends on the nature of contingencies and the operational parameter values assessed by NERLDC or SLDC's, as applicable.

The criteria for determining these states are as follows:

1) **NORMAL STATE**
   a) Voltage and power flows of the designated element are within the operational security limits as defined in the Grid code.
   b) Frequency is within the IEGC band.
   c) Sufficient reserves are available as per grid code
   d) Control area will remain within operational security limits after the activation of remedial actions such as SPS, rescheduling, etc. following the occurrence of a credible contingency.

2) **ALERT STATE**
   a) the power system is operating with operational parameters within their respective operational limits
   b) Any single contingency ('N-1) may result in violation of limits specified for voltage or active power for the designated elements i.e violation of security criteria.
   c) Sufficient reserves not available as per grid code for four consecutive time blocks.

3) **EMERGENCY STATE**
   i. The power system is functioning with operational parameters exceeding their designated limits, or equipment is operating beyond its specified loading

capacity arising out of multiple contingencies or major grid disturbance in the system.

ii. When following measures are required for bringing the system to normal state 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.

Automated action such as system protection scheme, load curtailment scheme and generation run-back scheme.

4) EXTREME EMERGENCY STATE

a) Frequency, voltage, active power flow, reactive power availability does not meet the criteria for the normal state, alert state and emergency defined above.
b) Even if the control actions taken during the emergency state are not able to bring the system either to an alert state or a normal state and operational parameters are outside their respective operational limits or equipment's are critically loaded.
c) The stability of the power system is uncertain, and it may or may not remain intact (splitting may occur), including events such as generation plant tripping, bulk load shedding (such as Loss of more than 20% of demand or generation whichever is higher in the respective control area Power system), under frequency load shedding (UFLS), and under voltage load shedding (UVLS) operations in the event of extreme conditions.

5) RESTORATIVE STATE

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

The system parameters like voltage, frequency and line or ICT loading shall be kept within safe limits in real time as per CEA grid standards and IEGC grid code regulations.

7.3 SWITCHING OF InSTS ELEMENTS:

1) In accordance with Clause 29(2)(a) of the IEGC & 7.2.3 of the AEGC, no component of the InSTS shall be disconnected from the grid unless:

i. It is necessary during an emergency situation.
ii. It is required for the protection of human life.

iii. There is an imminent risk of severe damage to critical equipment, and isolating it would prevent such damage.
iv. There is a specific SLDC directive. Any such disconnection must be promptly reported to SLDC within 15 minutes.

In addition, switching of elements incorporated in "List of Important Grid Elements of NER" will be coordinated by NERLDC via SLDC.

One copy of the latest updated switching diagram of all generating stations & all sub-stations/switching stations (66 kV and above) along with the details of line/unit/FSCs/Reactors/Capacitors/Transformers' Tap position etc. and position of CT, CVT, LA, WT, Isolator, CB & Earth Switch shall be kept at SLDC CR.

2) In case of switching off or tripping of any of the important elements of the InSTS under emergency conditions or otherwise, it shall be intimated immediately by the users with available details to SLDC who in turn shall inform the same to NERLDC in case the elements are incorporated in the "List of Important Grid Elements of NER".

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. Users shall ensure restoration of such elements within the estimated time of restoration as intimated.

3) The isolated, taken out or switched off elements shall be restored as soon as the system conditions permit. Before charging, all necessary precaution shall be taken care by substation and in coordination with other end substation.

4) With reference to important elements under NLDC perspective such as 132kV Rangia-Deothang TL. NERLDC shall obtain 'operation code' from NLDC before carrying out any switching operation of such element.

5) With reference to important elements under NERLDCs perspective. Users shall obtain 'operation code' from NERLDC via SLDC before carrying out any switching operation on any of the important elements under NERLDC perspective.

6) Users would ensure that the outage availed should come into service as per the scheduled time. Delays with reasons thereof if any should be reported to SLDC in advance.

7) After receiving the Outage/ Synchronisation Code, the switching operation shall be executed within 60 (sixty) minutes as to not lose the favourable grid conditions to avail the outage. In case of any delays / constraints in executing the switching code, SLDC shall be informed forthwith.

8) In case of unreasonable delays, SLDC or NERLDC as the case may be may cancel the code. In such cases, the intending entity shall seek for a fresh code for availing the outage.

9) During planned Shutdown of grid elements when both ends owned by different licensees, opportunity shutdown code will be issued from SLDC. Opportunity Shutdown availing entity shall be required to intimate the nature of work and time period for the work to be done.

10) Switching of elements such as generating unit synchronization or de-synchronization, transmission element opening or closing (including breakers), protection system outage such as Bus Bar protection, LBB protection, Auto reclose, System Protection Schemes (SPS) outage and testing, etc. shall be done by taking operational code from SLDC.

7.4 OTHER PRECAUTIONS TO BE TAKEN DURING SWITCHING:

In addition to the above, it is necessary that special attention to be paid to maintaining the reliability of the system.

The following areas need careful implementation by the concerned users:

1) In case of a two-bus/multi bus system at any substation it must be ensured that the segregation of feeders on the different buses is uniform. This would help in minimizing the number of elements lost in case of a bus fault. This is assuming the availability of bus-bar protection at such substation(s).

2) In 400 kV substations having a breaker and a half scheme, it must be ensured that the two buses at such substation remain connected at least by two parallel paths so that any line / bus fault does not result in inadvertent multiple outages.

3) In case any element, say a line or an ICT or a bus reactor, is expected to remain out for a period say beyond two hours at such substation, the main & tie breakers of such elements should be closed after opening the line side isolator. This is to be done after taking all suitable precautions to avert inadvertent tripping. This of course assumes that no maintenance is planned on such breakers / isolators.

4) Single pole auto-reclose facility on 400 kV / 220 kV/ 132 kV lines should always be in service. SLDC/ NERLDC's approval would be required for taking this facility out of service.

5) All precautions should be taken to avoid switching on to fault particularly in case of Interconnecting Transformers. In order to avoid fault current through costly equipment generally the line shall be charged from the far end, wherever possible.

6) A transmission line side shall preferably be charged from the grid substation. Dead line charging by a generator shall normally be avoided except during system restoration, black start, or in case where both ends of the transmission line are terminating at a generating station.

7) During test charging of transmission line for the first time, all safety precautions shall be taken and the transmission utility owning/operating the line shall satisfy the substation utility at either ends with regards to statutory/safety clearances. During test charging if the line does not hold even after two attempts, thorough checking of protection settings and line patrolling shall be carried out.

7.5 Demand Control and Management:

1) The need for demand control and management arises on account of following conditions:
   a) Variation in demand from the estimated value which cannot be absorbed by the grid.
   b) Unforeseen generation/ transmission outages resulting in reduced power availability.
   c) High reactive power demand.
   d) Over loading of critical corridors/flow gates.
   e) Over drawl of power beyond the limits as envisaged under Deviation Settlement Mechanism and related matters.
   f) Commercial reasons such as payment default leading to regulation of power supply by generating companies.

2) As per clauses 36.3 of the IEGC, whenever the power system is not in normal state as assessed by SLDC or RLDC:
   a) The respective distribution licensee i.e APDCL or bulk consumer shall abide by the directions of the 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 licensees or bulk consumers directly connected to STU, to restrict drawl from the grid or curtail load to ensure 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/ NERLDC after the system has been normalised.

3) SLDC shall match the consolidated demands of the DISCOMs with consolidated generation availability from SSGS, ISGS, IPP/CGP and other sources and exercise Demand Control to ensure that there is a balance between the energy availability and the demand.

4) DISTRIBUTION LICENSEE and other drawee entities shall restrict their drawal from the grid, within the net drawal schedule for ensuring grid security as per clause 7.6 of the AEGC.

5) Distribution Licensee shall ensure that requisite load shedding is carried out in its control area, so that there is no over drawal. APDCL via the Distribution Control Centre (DCC) shall also provide to SLDC, time-block wise details of such load shedding.

6) On exhaustion of all methods of demand management, SLDC may exercise load curtailment directly through tripping of circuit breaker using RTUs or through telephonic instructions.

7) In order to maintain the frequency within the stipulated band and maintain the network security, the interruptible loads shall be arranged in four groups, viz., load for scheduled power cuts/ load shedding, load for unscheduled load shedding, load to be shed through under frequency relays/df/dt relays and load to be shed under any System Protection Scheme identified at RPC/ state level. These loads shall be grouped in such a manner, that there is no overlapping between different groups of loads. In case of certain contingencies and/or threat to system security, the NERLDC may direct SLDC to decrease drawal of its control area by a certain quantum. Such directions shall immediately be acted upon by APDCL and other drawee entities.

8) SLDC, in coordination with STU and Distribution Licensee(s), shall develop Automatic Demand Management scheme with emergency controls at SLDC.

   The Distribution Licensees, in consultation with SLDC, shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response (as per the AERC Demand Response Regulations, 2024) etc., to reduce over drawal in order to comply with AEGC 2024.

9) SLDC shall devise standard, instantaneous, message formats in order to give directions in case of contingencies and /or threat to the system security to reduce deviation from the schedule by the Users/ Distribution Licensees/ Injecting Utility at different overdrawal/ Under Drawal/ Over-Injection/Under Injection conditions depending upon the severity. SLDC shall also ensure immediate compliance of these directions and any violation of SLDC's directions shall be intimated to the AERC through monthly report.

10) All Users /distribution licensee shall comply with direction of SLDC and carry out requisite load shedding or backing down of generation in case of congestion in transmission system to ensure safety and reliability of the system. In case of shortage of power availability with respect to demand, the DCC of the distribution licensees shall resort to shedding the load on economic principle.

11) The measures taken by Users/ Distribution Licensee shall not be withdrawn as long as the frequency remains at outside the limits or congestion continues, unless specifically permitted by the SLDC.

7.6 LOAD CRASH:

In the event of load crash in the system due to weather disturbance or any other reasons, following measure could be taken by SLDCs by the following methods in descending priority:-

(i) Backing down of hydel stations for short period immediately;
(ii) Lifting of the load restrictions, if any;
(iii) Exporting the power to neighbouring regions;
(iv) Backing down of thermal stations with a time lag of 5-10 minutes for short period;
(v) Closing down of hydel units (subject to non-spilling of water and effect on irrigation); and
(vi) Backing down of Renewable Energy Power Plants.

The above methodology shall be reviewed by Operation and Co-ordination Committee from time to time.

As and when such events occur, SLDCs shall inform about the event to NERLDC within 24 Hours of the incident and prepare a report and mail it to NERLDC.

7.7 LINE / ICT LOADING:

1) The loading for a transmission line shall be its thermal loading limit and the loading limit for an inter-connecting transformer (ICT) shall be its name plate rating.

2) SLDC and all other Users of the state grid shall endeavour to keep the transmission elements loadings within limits. For identifying credible system contingencies, loading of important flow gate and the interregional corridor shall be monitored. SLDC's shall coordinate with NERLDC to maintain the power flow within the transfer capability limits.

7.8 TRANSFER CAPABILITY

1) Total Transfer Capability (TTC) means the amount of electric power that can be transferred reliably over the transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency.

2) Transmission Reliability Margin (TRM) means the amount of margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. The TRM may be considered as minimum of 2% of demand of area/region or size of largest generating unit in that area/region.

3) Available Transfer Capability (ATC) means the transfer capability of the inter-control area transmission system available for scheduling commercial transaction (through GNA and TGNA) in a specific direction, considering the network security. Mathematically ATC is the Total Transfer Capability Minus Transmission Reliability Margin.

The updated ATC, TRM & ATC of all inter regional corridors and Intra Regional corridors shall be referred for facilitating optimum utilization.

4) ATC/TTC for 3 nos of timeframe viz. M+1, M+6, M+11 shall be calculated by SLDC as per the set timeline of IEGC. For carrying out calculation in timelines M+6, M+11, full details of any new Generator (Conventional/Solar/Others) and other grid elements which are to be integrated in the next six months is to be submitted to SLDC by 2nd of every month by APDCL/AEGCL & APGCL/ other generators as applicable.

5) The same is to be provided to NERLDC alongwith Node Wise Drawal/Injection for the three time frame as per timelines laid down in IEGC.

7.9 RECORDING INSTRUMENTS

1) The recording instruments such data acquisition system, disturbance recorder, event logger, fault locator, time synchronization equipment voice recorder and any other such equipment in each generating station / sub-station / control centre / SLDCs are to be kept in good working condition in order to record the events and sequence. All such places shall have a common time reference whose authenticity shall be ensured by periodic verification and validation procedure which will be developed and monitored by NERPC Secretariat.

2) As specified in Clause 15.3 of CEA (Grid Standards) regulations 2010 & Clause 37.2.c of IEGC 2023, all operational data, including disturbance recorder and event logger reports, for analysing the grid incidents and grid disturbance and any other data which in its view can be of help for analysing grid incident or grid disturbance shall be furnished by all the Entities within 24 (twenty four)hours to the Regional Load Despatch Centre and concerned Regional Power Committee.

3) As per Section 11.2.(h.ii) of CEA's Technical Standards for Construction, all generating stations must store important analog data in 1 second interval and binary input data in 1milli-second resolution. For calculation of Frequency Response Characteristics, every generator shall provide unit-wise data of DAS to SLDC.

4) As per 48.4.D of CEA Technical Standard for Construction of Electrical Plants and Electric Lines, 2010, disturbance recording shall be provided along with time synchronization equipment (TSE). TSE complete with antenna, all cables, processing equipment's etc., shall be provided to receive synchronizing pulse through Global Positioning System (GPS) compatible for synchronizing of Event Logger, Disturbance Recorder, Phasor Measuring Units, and SCADA/Automation system of the Sub-Station or Switchyard.

7.10 STANDARDIZATION OF RECORDING INSTRUMENTS

DR output plays a vital role in the analysis of an event. It is very much important to have a standard for allotment of DR channels for all transmission lines, Auto Transformers or Phase Shifters connected to buses, Shunt Capacitors, HVDC Terminals, Shunt Reactors and Dynamic VAR Devices so as to aid in analysis.

CHAPTER 8: OUTAGE COORDINATION

8.1 OBJECTIVE

Outage coordination is essential for optimizing the outage duration time, proper mobilization of resources at site, ensuring reliability of the grid and providing certainty to the electricity market. Outage of power system elements may be required for routine or emergency maintenance to prevent damage/failure or to facilitate network augmentation related activities. Since outages in the Power System influence the network reliability and security, they need to be planned and coordinated carefully.

8.2 OVERVIEW

1) Outage planning shall be done in line with chapter 11 of the AEGC 2024.

2) This outage procedure shall apply to all the InSTS elements and ISTS transmission lines which partly belongs to the state.

3) Outage planning shall be done by SLDC for the elements in a coordinated and optimal manner, keeping in view the system operating conditions and grid security as per clause 11 of the AEGC.

4) As per clause 11.3.1 of the AEGC, each User shall provide their operational planning data including outage programme for ensuing financial year to SLDC for preparing an overall outage plan for State Transmission System, as a whole.

5) Annual outage plan shall be prepared in advance for the financial year by SLDC in consultation with STU, DISCOMs and GENERATORs, as per their inputs and reviewed during the year on Bi-Monthly basis. SLDC will submit the same to NERLDC and NERPC in compliance to clause 11.3.7 of the AEGC and for finalisation of the LGBR for next financial year.

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

6) The outage plan of hydro generation plants, REGS and ESS and its associated evacuation network shall be prepared with a view to extracting maximum generation from these sources. Example: Outage of wind generator may be planned during lean wind season. Outage of solar generator, if required, may be planned during the rainy season. Outage of hydro generator may be planned during the lean water season.

7) Outages in the transmission network could either be on account of planned maintenance activities or construction related activities or any emergency conditions arising in the field.

8) SLDC is authorised to defer the planned outage in case of any of the following events:
   a) Major grid disturbance;
   b) System Isolation;
   c) Black out in the State;
   d) Any other event in the system that may have an adverse impact on system security by the proposed outage.

8.3 PROCEDURE FOR PLANNING OUTAGES

This section outlines the procedure to be followed while coordinating shutdowns of various elements such as transmission lines, transformers, reactors, auto-reclosers, generating units, Bus Bar protection, LBB protection, Auto reclose, System Protection Schemes (SPS) etc.

There are two categories of shutdowns:

Category 1: Elements which require approval of **NERLDC/NERPC.**
Category 2: Elements which require approval of **SLDC.**

The elements which are present in the LIST of Important Grid Element published by NERLDC fall under Category 1.

8.3.1 ANNUAL OUTAGE PLAN:

The Annual outage plan report for generating units and transmission elements in the region shall be prepared by NERPC in consultation of NLDC and RLDC & SLDCs as per clause 32.2 of IEGC 2023.The annual outage plan shall be followed by all users of the grid.

AEGCL shall submit proposed outage plan for the InSTS elements in theformat pescribed by SLDC, from time to time for the next financial year to SLDC by 15th September each year which would be submitted to NERPC for preparation of yearly LGBR. The data shall include the dates, nature of maintenance work planned whether mandatory or otherwise, duration of outage and related information.

8.3.2 OUTAGE PLAN

1) PROCEDURE FOR ELEMENTS UNDER CATEGORY 1: WHICH REQUIRE APPROVAL OF NERLDC /NERPC.

   a) Process of applying the shutdowns for approval in NERPC OCC meetings - MONTH AHEAD

      STEP 1: By 17:00 hrs of 1st date of the month, intending entity (AEGCL/ APGCL/ APDCL) is to apply to SLDC the list of all shutdowns for the succeeding month.

STEP 2: Once received, by 17:00 hrs of 3rd day of the month, SLDC shall send the proposed shutdown list to NERPC with a copy to NERLDC and upload the same in NERLDC Outage Portal.

STEP 3: For deliberation on the shutdowns proposed by all entities, a monthly shutdown meeting is held. The meeting is to be attended by APDCL Commercial (for shutdown of CSGS generators) & APGCL (for consent related to shutdowns which lead to backing down of APGCL generators) alongwith SLDC.

If power interruption is anticipated due to shutdown proposed by any other entity, the same is to be informed to the effected entities for consent.

STEP 4: During the shutdown meeting conducted by NERPC, consent for shutdowns requested by other entities is to be given by affected entity..

STEP 5: By the last week of the month, list of approved shutdowns for next month is shared by NERPC. The same is to informed to all intending entities.

STEP 6: D-3 of the shutdown, the same will reflect in the Outage Portal of NERLDC. The availing status of the element has to be punched in the portal after confirming from intending entity.

Where D is the proposed date of the shutdown.

STEP 7: If the availing status is Yes, the shutdown will reflect in the D-1 list circulated by NERLDC by 12:00 hrs every day.

b) Process of applying the shutdowns in POST- NERPC OCC meeting – WITHIN THE MONTH

Those shutdowns which cannot be applied or planned on month ahead basis falls under this category. Careful analysis of the requested shutdown is to be done and is forwarded to RPC.

STEP 1: The intending entity (AEGCL/ APGCL/ APDCL) shall apply the Post-OCC shutdowns to SLDC latestby 17:00 hrs of D-5.

STEP 2: If the reason for applying the shutdown in Post- OCC basis is justifiable, SLDC will forward the shutdown request to NERPC with a copy to NERLDC.

STEP 3: NERPC will forward the shutdowns to NERLDC for study. If any POST-OCC shutdown request effects pre approved OCC shutdowns, the same has to be intimated to the entities applying the OCC shutdowns.

STEP 4: NERLDC will revert the study report to NERPC, after which NERPC will approve the shutdown. If approved, the shutdown will reflect in D-1 list published by NERLDC.

c) Process of applying the shutdowns on EMERGENCY BASIS

For attending emergency nature of works, asset owner(s) shall send the proposal(s) directly to SLDC control room and SLDC will in-turn apply the same to NERLDC. The shutdown will be facilitated based on the actual grid conditions.

i. All outages which are not approved earlier but having impact on human and equipment safety and/or to meet any other emergency requirement or special conditions shall be considered under Emergency Category.

ii. The request for emergency outage shall have to be submitted along with the details like nature of emergency, proof of emergency, relevant photograph, impacts due to emergency situation, reasons and associated facts for not considering in the outage planning process in the format specified.

iii. Shutdown of elements that are applied under emergency clause of IEGC / AEGC shall be allowed immediately or within the shortest possible time subject to system conditions and its severity.In this case, if required, planned outage may be deferred. The intending utility shall coordinate with SLDC to get the planned shutdown re-scheduled on another date. Thereafter NERLDC shall try to give a mutually convenient date for the shutdown.

FORMAT: REQUEST FOR EMERGENCY TRANSMISSION ELEMENT OUTAGE BY INTENDING AGENCY TO NERLDC VIA SLDC

REQUEST FOR EMERGENCY TRANSMISSION ELEMENT OUTAGE BY INTENDING AGENCY TO NERLDC VIA SLDC		
1	Element Name	
2	Reason	
3	Proposed Shutdown start Date and time	
4	Proposed Shutdown end Date and time	
5	Daily basis or continuous basis	
6	Proof of emergency (Attachment to be added along with outage proposal)	
7	Any other element/bay is under outage in proposed stations	
8	Quantum of load or area affected during the outage	
9	Previous maintenance work carried out date	
10	Name and Designation of the officer responsible for Sitework	
11	Site contact number/responsible officer contact number	
12	Utility Remarks	
13	SLDC Remarks/Consent	

2) OUTAGE PROCEDURE FOR ELEMENTS UNDER CATEGORY 2: WHICH REQUIRE APPROVAL OF SLDC

a) Process of allowing PLANNED SHUTDOWNS

STEP 1: The shutdown of elements has to be applied by the intending entity (AEGCL/APGCL/APDCL/ other entities) on D-5 basis, where D is the proposed date of the shutdown.

STEP 2: After factoring the already approved shutdowns in OCC forum scheduled for the same date, SLDC will carry out necessary system studies. SLDC will review if any supply interruption to DISCOM/ HT consumers, re-dispatch of generation or non-compliance of N-1 contingency is expected due to the shutdown and will convey the same to the intending entity.

If no such situation is anticipated, shutdown will be approved from SLDC.

STEP 3: In case of any power interruption/generation re-dispatch is anticipated, the intending entity shall obtain necessary consent from Competent Authorities of respective DISCOM/HT consumers, Generator or any other affected entity.
Upon submission of the consent to SLDC, the shutdown shall be approved.

b) Process of allowing EMERGENCY SHUTDOWNS.

i. For attending emergency nature of works, intending entity shall send the proposal directly to SLDC control room in the format along-with details like nature of emergency, proof of emergency, relevant photograph, impacts due to emergency situation, reasons and associated facts for not considering in the outage under planned category.

ii. The outages which have impact on safety of human life and equipment safety and/or to meet any other emergency requirement or special conditions shall be considered under Emergency Category.

iii. If any planned shutdown needs to be cancelled/ deferred due to any emergency shutdown, the same may be done. The intending utility shall coordinate with SLDC to get the planned shutdown re-scheduled on another date.

iv. In case of emergency shutdowns, approval of competent authority may be taken by the intending entity. If time does not permit, the intending entity will intimate the same to competent authority in the shortest time possible.

v. In case the generators apply for emergency shutdown, the approval for emergency shutdown may be given only after careful analyzation of the cause. The approval of emergency is to be informed to the respective beneficiary.

FORMAT: REQUEST FOR EMERGENCY TRANSMISSION ELEMENT OUTAGE BY INTENDING AGENCY TO SLDC

REQUEST FOR EMERGENCY TRANSMISSION ELEMENT OUTAGE BY INTENDING AGENCY TO SLDC		
1	Element Name	
2	Reason	
3	Proposed Shutdown start Date and time	
4	Proposed Shutdown end Date and time	
5	Daily basis or continuous basis	
6	Proof of emergency (Attachment to be added along with outage proposal)	
7	Any other element/bay is under outage in proposed stations	
8	Quantum of load or area affected during the outage	
9	Previous maintenance work carried out date	
10	Name and Designation of the officer responsible for Sitework	
11	Site contact number/responsible officer contact number	
12	Utility Remarks	

7) OTHER POINTS

1) The code issued by SLDC for opening/ restoration of the element signifies approval only from the system point of view. The related line/sub-station personnel would be responsible for ensuring all safety precautions. All safety measures at site shall be the responsibility of the personnel authorized to execute the work.

2) During the approved shutdown of any element, any opportunity/ overlapping work by the concerned agencies is to be carried out only after getting the consent of SLDC or RLDC as the case may be.

3) Any deviation in the outage from the schedule can affect other planned outages as well as affect reliability and also the electricity markets. The agencies intending to avail an outage strictly adhere to the approval shutdown timings.

4) In case shutdown is extended beyond one day, then the applying authority will have to apply the same to SLDC with proper reason and justification of delay which has to be taken up with NERPC, if applicable.

5) A record of shutdowns being availed beyond approved time will be kept of outage

overshooting the approved time of return to bring in seriousness and to avoid market distortion. In case of repeated delay in normalization of outages by any entity, the same shall be reported by SLDCs/RLDCs to RPC & Competent Authorities of affected entities as applicable.

6) Operational studies shall be carried out in order to assess the grid security and network stability while finalizing the annual outage plan of these important elements.

7) All testing related to SPS / Mock drill for black start operation (including toggling of SPS) shall be approved/deliberated in all concerned RPC's and shall be requested as per outage planning procedure of RPC/ SLDC as applicable.

8) Shutdown of all line reactors should be planned along with line to optimize the overall outage of the element.

9) Re-scheduling of OCC/ pre-approved shutdown shall be avoided as much as possible as itmay require rescheduling Dispatch/Drawl or other shutdowns. In case any deviation from the approved shutdown, the period for which the element remain out of service, will not be treated as deemed available. The Re-scheduling of shutdown will have to follow D-5 procedure.

10) Any transmission element will be considered under long outage if restoration of the element is not done within 12 days from the date of outage.

11) All users shall operate their respective power systems in an integrated manner in coordination with SLDC at all times.

12) Generators reducing its generation by more than 20MW and shall take prior permission of SLDC as per clause 29.4 of the IEGC and 7.2.9 of the AEGC.

13) No user shall cause a sudden variation in its load by more than 100 (one hundred) MW without the prior permission of the SLDC, except in an emergency, or when it becomes necessary to prevent imminent damage to critical equipment as per clause 29.5 of the IEGC and 7.2.10 of the AEGC.

14) In case of alteration including modification/ replacement/ upgradation of an EHV element, applicable procedures for First Time Energisation and Interconnection for altered elements will have to be followed before charging of the element.

9.1 INTRODUCTION

A grid disturbance is a power system state under which a set of generating unit/ transmission elements trip in an abrupt and unplanned manner affecting the power supply in a large area and / or causing the system parameters to deviate from the normal values in a wide range. In the event of a grid disturbance, highest priority is to be accorded to early restoration / revival of the system.

The definition of **Grid Disturbance** and **Grid Incident** as per CEA (Grid standards) Regulation 2010 is as follows:

1) "Grid disturbance" means tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, resulting in total failure of supply at a sub-station or loss of integrity of the grid, at the level of transmission system at 220 kV and above (132 kV and above in the case of North-Eastern Region).

The classifications of grid disturbances in increasing order of severity as per CEA Grid Standards is given below: -

i. **Category-GD-1:** When less than ten percent of the antecedent generation or load in a regional grid is lost;

ii. **Category-GD-2:** When ten percent to less than twenty percent of the antecedent generation or load in a regional grid is lost.

iii. **Category-GD-3:** When twenty percent to less than thirty percent of the antecedent generation or load in a regional grid is lost

iv. **Category-GD-4:** When thirty percent to less than forty percent of the antecedent generation or load in a regional grid is lost

v. **Category-GD-5:** When forty percent or more of the antecedent generation or load in a regional grid is lost.

vi. **Category-Near Miss:** 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.

2) "Grid incident" means tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, which requires re-scheduling of generation or load, without total loss of supply at a sub-station or loss of integrity of the grid at 220 kV and above (132 kV and above in the case of North-Eastern Region).

The classifications of grid incidents in increasing order of severity as per CEA Grid Standards is given below: -

i. **Category-GI-1:** Tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, which requires re-scheduling of generation or load, without total loss of supply at a sub-station or loss of integrity of the grid at 220 kV (132 kV in the case of North-Eastern Region).

ii. **Category-GI-2:** Tripping of one or more power system elements of the grid like a generator, transmission line, transformer, shunt reactor, series capacitor and Static VAR Compensator, which requires re-scheduling of generation or load, without total loss of supply at a sub-station or loss of integrity of the grid at 400 kV and above (220 kV and above in the case of North-Eastern Region).

9.2 SYSTEM RESTORATION PROCEDURE

SLDC shall prepare detailed procedure for restoration of the InSTS as per Clause 12.4 of the AEGC. The restoration process shall take into account the generator capabilities and the operational constraints of InSTS with the object of achieving normalcy in the shortest possible time during an event. All Users must be aware of the steps to be taken during major grid disturbance(s) and system restoration procedure. These steps shall be followed by all the Users to ensure consistent, reliable and quick restoration.

This document is prepared by SLDC and is available as a separate document.

10.1 INTRODUCTION

The section specifies the events and incidents that are to be reported, the reporting route to be followed and information to be supplied in order to ensure consistent approach in reporting of the events/incidents.

Timely and accurate reporting and exchange of information plays an important role in grid operation. This assumes more importance during a disturbance or crisis. Timely and accurate information flow under such conditions would help people in making an informed decision and reduces uncertainty. All Users of the grid shall be responsible for collection and reporting of all necessary data to SLDC.

10.2 EVENT REPORTING

1) Immediately following an event (grid disturbance or grid incidence as defined in the CEA Grid Standards Regulation and amendments thereof) in the system, the concerned User shall inform SLDC which in turn shall inform NERLDC, if applicable through voice message.

2) Written flash report in format specified by SLDC shall be submitted to SLDC by the concerned User within the time line specified in Table below.

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

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

5) After a complete analysis of the event, the User shall submit a detailed report in the case of grid disturbance or grid incidence within one (1) week of the occurrence of event.

6) SLDC shall prepare a draft report of each grid disturbance or grid incidence, based on

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	+7 days	+60 days
2	Near miss **event**	8 hours	24 hours	+7 days	+7 days	+60 days
3	GD-1	8 hours	24 hours	+7 days	+7 days	+60 days
4	GD-2/GD-3	8 hours	24 hours	+7 days	+21 days	+60 days
5	GD-4/GD-5	8 hours	24 hours	+7 days	+30 days	+60 days

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

inputs including simulation results and analysis received from users, which shall be discussed and finalised at the SPCC, as per the timeline specified in Table below.

7) Any tripping/ switching of an element falling under the list of 'Important Elements of North Eastern Regional Grid', and all element of the InSTS, whether manual or automatic, shall be intimated to SLDC a reasonable time, say within ten (10) minutes of the occurrence of the event. Along with the tripping intimation, the reason for tripping (to the extent determined) and the likely time of restoration if assessable shall also be intimated. In case, likely time of restoration cannot be assessed at the time of FIR, same shall be submitted within one hour.

8) SLDC shall report multiple tripping occurring in control area due to inclement weather conditions resulting in load crash to NERLDC. Report shall contain the details of tripping and restoration of grid elements, load / generation loss if any, energy unserved in MW and MU contain the details of tripping and restoration of grid elements, load / generation.

9) Any additional data such as single line diagram (SLD) of the station, protection relay setting, HVDC transient fault record switchyard equipment and any other relevant station data required for carrying out analysis of an event by RPC, NLDC, NERLDC 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.

10) Monthly Submission of Performance Indices: As per Clause 15.7.6 of the AEGC, Users shall submit the protection performance indices i.e Dependability Index, Security Index & Reliability index of previous month to NERPC (for 132 kV and above system), SPCC and SLDC on monthly basis, which shall be reviewed by the SPCC.

10.3 PERIODIC REPORT:

A monthly report shall be prepared by SLDC as per clause 14.1.1 of the AEGC, which shall contain the following information:

1) Frequency profile.
2) Source wise generation for the control area
3) Drawal from the grid and area control error
4) Demand met (peak, off-peak and average)
5) Demand and energy unserved in MW and MWh
6) Instances and quantum of curtailment of renewable energy
7) Maximum and minimum frequency recorded daily and daily frequency variation index (FVI).
8) Voltage profile.
9) Voltage profile of selected sub-stations.
10) Major Generation and Transmission Outages.
11) Transmission Constraints and instances of congestion in the transmission system.

12) Instances of persistent/ significant non-compliance of Grid Code.
13) Grid Security events, leading to curtailment along with reasons.

SLDC provides similar information to NERLDC for preparation of reports at their end as per clause 38 (2) of the IEGC.

SLDC shall also upload a quarterly report on its website, 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 various actions taken by different Users and the Users responsible for causing the constraints.

10.4 ACCIDENT/ EVENT REPORTING

Clause 14.2 of the AEGC directs reporting of certain events that can potentially effect the state transmission system such as:

1. Exceptionally high / low system voltage or frequency.
2. Serious equipment problem, i.e., major circuit breaker, transformer or bus-bar etc.
3. Loss of Generating Unit.
4. Instance of Black Start.
5. Tripping of Transmission Line, Interconnecting transformer (ICT) and capacitor banks
6. Major fire incidents.
7. Major failure of protection.
8. Equipment and transmission line overload.
9. Accidents - Fatal and Non-Fatal.
10. Load Crash / Loss of Load.
11. Violation of Security Standards.
12. Grid indiscipline.
13. Non-compliance of SLDC instructions.
14. Excessive drawal deviations.
15. Minor equipment alarms.

The reporting user would promptly communicate the incident occurring in the lines and equipment affecting the State Transmission System to other affected user and the SLDC. SLDC may ask for a detailed report of the incident within one hour of the information.

In case of minor incident/ accident, the Reporting User shall submit an initial written report within two (2) hours and comprehensive report within twenty-four (24) hours of the submission of the initial written report, whereas, in other cases, the Reporting User shall submit a report within five (5) working days to SLDC. The format of the same shall be as decided by Grid Code Management committee of the state as constituted vide clause 3.4 of the AEGC which shall be available in SLDC website.

CHAPTER 11: DEFENCE MECHANISM

11.0 INTRODUCTION

Well-designed and healthy defence mechanism is a pre requisite for secure operation of the interconnected system. The following defense mechanism is operational in Assam and North- Eastern Region as a whole to take care of different credible contingencies, to ensure safe and secure grid operation.

11.1 PROTECTION SYSTEM

In line with the regulation 3 (e) of the CEA (Grid Standards) regulation 2010 all entities shall provide standard protection systems having reliability, selectivity, speed and sensitivity to isolate the faulty equipment and protect all components from any type of faults, within the specified fault clearance time and shall provide protection coordination as specified by North Eastern Regional Power Committee (NERPC).

Protection audit Plans of the protection systems are to be undertaken as per regulation 15.7 of the AEGC and clause No 12.2.e and clause No 15 of IEGC.

All substations of 220 kV and above shall be equipped with breaker fail protection and bus bar protection schemes. Non-clearance of the fault by a circuit breaker within the time limit mentioned above, the breaker fail protection shall initiate tripping of all otherbreakers in the concerned bus-section to clear the fault in next 200 milliseconds.

11.2 PROTECTION AUDIT PLAN

(1) All users of the state grid i.e distribution licensee, State Transmission Utility, generating company (s), etc. shall conduct internal audit of their protection systems annually, and any shortcomings identified shall be rectified and informed to SLDC, NERPC and the State Protection Coordination Committee (SPCC). The audit report along with action plan for rectification of deficiencies detected, if any, shall be shared with to SLDC, NERPC and the SPCC.

(2) All users shall also conduct third party protection audit of each sub-station at 132 kV and above once in five years or earlier as advised by the NERPC and SPCC shall supervise the same. For substations below 132kV connected to the State Grid, the third party audit shall be as per the methodology devised by the SPCC.

(3) The list of sub-stations/ generating stations identified by NERPC where third-party protection audit is required to be carried out, SPCC shall ensure completion of the third-party audit within three months. Further, for all elements of the State Grid SPCC shall identify a list of sub-stations/ 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 the format enclosed as Appendix–J of the AEGC. The protection audit reports along with action plan for rectification of deficiencies detected, if any, shall be submitted to NERLDC/NERPC (wherever applicable), SPCC and SLDC within a month of submission of third-party audit report. The necessary compliance to such protection audit report and NERLDC/NERPC directions shall be followed up regularly in SPCC meetings.

(5) Annual audit plan for the next financial year shall be submitted by the Users to NERLDC/NERPC (wherever applicable), SPCC and SLDC by 31st October. The Users shall adhere to the annual audit plan and report compliance of the same to SPCC and to SLDC for record purposes.

(6) Users shall submit the following protection performance indices of previous month to NERPC (for 132 kV and above system), SPCC and SLDC on monthly basis, which shall be reviewed by the SPCC:

The Dependability Index defined as $D = N_c / (N_c + N_f)$;
The Security Index defined as $S = N_c / (N_c + N_u)$; and
The Reliability Index defined as $R = N_c / (N_c + N_i)$;

where,
N_c is the number of correct operations at internal power system faults;
N_f is the number of failures to operate at internal power system faults;
N_u is the number of unwanted operations; and
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 NERPC (for 132 kV and above system), SPCC, SLDC and action plan for corrective measures. The action plan will be followed up regularly by the SPCC.

(8) In case any User fails to comply with the protection protocol specified by SPCC or fails to undertake remedial action identified by the NERPC/SPCC within the specified timelines, SPCC / SLDC/ STU may approach the Commission with all relevant details for suitable directions.

(9) Any changes in the network and protection settings of grid elements connected to the State Grid shall be informed to State Protection Coordination Committee (SPCC), SLDC and NERPC (in case of elements of 132kV and above voltage level) by the STU and DCC, as the case may be.

11.3 UFR AND RATE OF CHANGE OF FREQUENCY(DF/DT) RELAY:

1) In line with clause 29(12) of IEGC and 7.2.17 of the AEGC, distribution licensee, STU 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 below:

SL No	STAGE OF UFR OPERATION	FREQUECY (Hz)
1	STAGE -1	49.40
2	STAGE-2	49.20
3	STAGE-3	49.00
4	STAGE-4	48.80

Note-1: STU shall plan UFR settings and df/dt load shedding schemes depending on load generation balance in coordination with SLDC and approval of the NERPC.

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.

2) All Entities shall set their under frequency (UF) Relays and rate of change of frequency with time Relays in their respective systems, in accordance with the plan made by the North Eastern Regional Power Committee, to provide adequate load relief for grid security and ensurethe operation of these relays at the set frequencies.

3) The under-frequency and df/dt load-shedding relays should always be functional. Demand disconnection shall not be set with any time delay in addition to the inherent operating time of the relays and circuit breakers. There shall be a uniform spatial spread of feeders selected for UFR and df/dt disconnection.

4) 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 NERLDC in real time and submitmonthly exception report to NERRPC. NERLDC shall inform SLDCs as well as the NERPC on quarterly basis, durations during the quarter when combined loading 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.

5) Under-frequency and rate of change of frequency (UFR & df/dt) are envisaged to take care of sudden contingencies arising out of outage of generation stations or separation of inter-regional lines. UFRs setting are for steady state operation of the grid at considerably low frequency and df/dt settings are for fast change in frequency due to large generation outage.

6) SLDCs shall submit a detailed report of operation of these Relays at different frequencies to Regional Load Despatch Centre and Regional Power Committee on monthly basis and the Regional Power Committees shall carry out inspection of these Relays as and when required.

7) The UFRs installed in the Assam System at various stages as on March 2025 are attached as annexure. The UFR's are reviewed from time to time in consultation with NERLDC and NERPC which shall be available in SLDC website

11.4 SYSTEM PROTECTION SCHEME

1) Outage of a large capacity link carrying high power between two distant nodes in a synchronously interconnected system may result into excessive loading on parallel AC lines, severe drop in voltage profile, power oscillations and finally leading to a major blackout or brown out in the system, unless instantaneous corrective actions are in place. On the other hand, similar outage in an asynchronously connected system may result into load – generation imbalance on either side of the link.

2) In view of the above risks, few System Protection Schemes have been designed and implemented in Assam and North-Eastern region. As per clause 16(2) of IEGC, for the operational SPS, RLDC or NLDC, as the case maybe, in consultation with the concerned RPC(s) shall perform regular load flow and 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 immediately and detailed report shall be submitted within three days of operation to the concerned RPC and RLDC in the format specified by the respective RPCs.

4) A number of Special Protection Schemes (SPS) are currently active in Assam. A comprehensive document detailing the SPS in Assam System is available in Annexure 2.

11.5 AUTOMATIC DEMAND MANAGEMENT SYSTEM (ADMS):

1) Clause 36.2 of the IEGC and 7.6.c of the AEGC mandates the SLDC to develop Automatic Demand Management scheme with emergency controls at SLDC in consultation with APDCL and AEGCL.

2) The Distribution Licensees, in consultation with SLDC, shall also formulate and implement state-of-the-art demand management schemes for automatic demand management like rotational load shedding, demand response (as per the AERC Demand Response Regulations, 2024) etc., to reduce over drawal in order to comply with Regulation 7.6 (a) and Regulation 7.6 (b) of AEGC.
3) Manual as well as automatic demand disconnection is suggested from the distribution network under overdrawal conditions and on crossing the defined frequency limits. As the manual control at times become ineffective to decrease drawal by a certain quantum

within the time limit and hence the automatic demand disconnection scheme assumes significant importance. Automatic Demand Management System (ADMS) acts as a tool for ensuring security and reliability of the interconnected system.

4) To facilitate safe and secure Grid operation, it is proposed to trip the loads at lower voltage level (11kV) automatically corresponding to the signals originated from a dedicated ADMS server at SLDC.

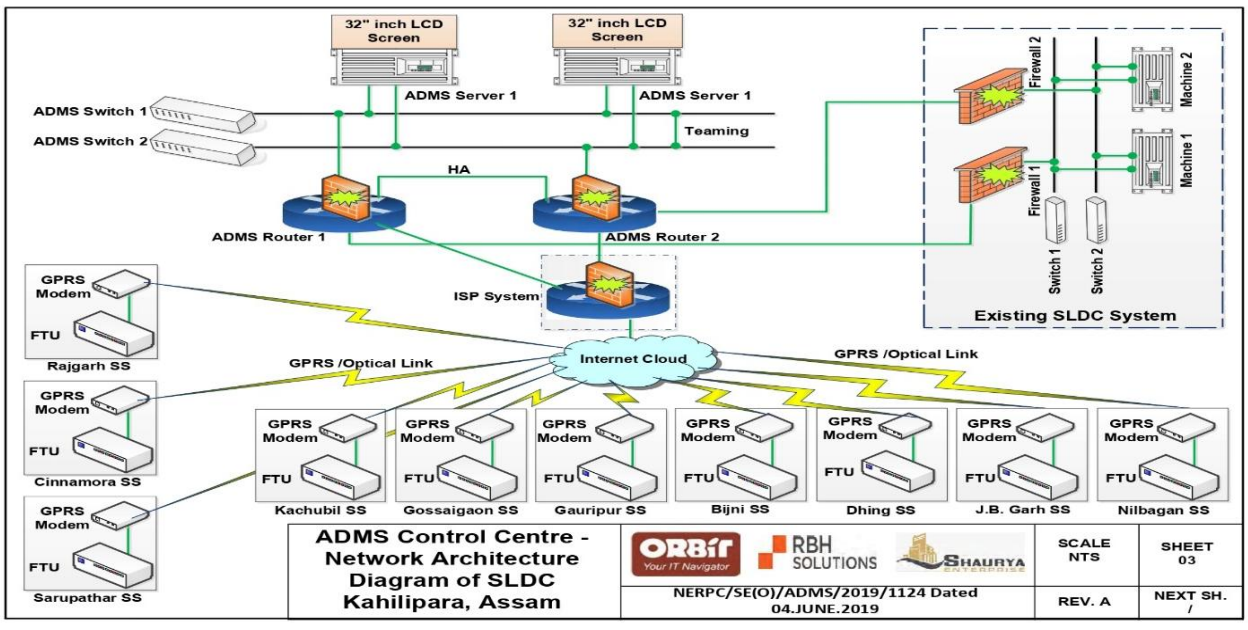
5) Automatic disconnection of load occurs when the operating conditions go beyond the permitted variations from the schedule or on any contingency noticed by SLDC, NERLDC or NLDC, such as drawal crossing the permitted limit, over-drawal when frequency is less than the set value as per IEGC, operation of regional/local SPS schemes for which signal will be originated from SLDC SCADA and any condition requiring manual intervention of load as decided by SLDC etc.

6) The ADMS scheme envisages a server at SLDC which accepts the operational parameters from the existing SCADA at SLDC – ASSAM and holds the intelligence to order non arbitrary load shedding at chosen 11 kV feeders throughout the state of ASSAM. The ADMS server shall communicate with the SLDC SCADA server on secure OPC standards.

7) For the functioning of ADMS, received data from distribution substation and SCADA servers of ASSAM, ADMS gets the schedule and drawl and other required information from SCADA server. Based on the information thus received, it sends trip command to distribution substations based on a logic/priority to bring the system back to safe limits.

8) ADMS server shall communicate with field terminal units at the 11kV substation and issue the trip command automatically for disconnection of load when the operating conditions go beyond the permitted variations from the schedule.

NETWORK ARCHITECTURE AT CONTROL CENTER-SLDC ASSAM



11.6 ISLANDING SCHEMES

To avoid total black out of the grid during system disturbances and for early normalization, the procedure for islanding of systems and major generating stations with associated loads needs to be developed constituent-wise/system wise. The islanding schemes shall be developed/reviewed in OCC/PCC of NERPC. The details of such schemes shall be available with NERLDC, concerned SLDCs and NERPC. The scheme would be reviewed at least once in a year by NERPC forum.

The following islanding Schemes in Assam are presently being devised and under implementation:

1. Guwahati Islanding Scheme
2. Upper Assam Islanding Scheme

CHAPTER 12: PERIODIC TESTING

12.1 OVERVIEW

Clause 40 of IEGC and Clause 15 of the AEGC requires testing of power system elements for ascertaining the correctness of mathematical models used for simulation studies as well as ensuring desired performance during an event in the system.

12.2 GENERAL PROVISIONS

1) The owner of the power system element shall be responsible for carrying out tests as specified in IEGC & AEGC regulations and for submitting reports to NLDC, RLDCs, CEA and CTU for all elements and to STUs and SLDCs for intra-State elements.

2) All equipment owners shall submit a testing plan for the next year to SLDC by 15th October to enable submission of the same to NERPC by 31st October to ensure proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform SLDC/NERPC in advance.

3) The tests shall be performed once every five (5) years or whenever major retrofitting is done. If any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, if so advised by SLDC or NERLDC or NLDC or RPC, as the case may be.

4) The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports in consultation with NLDC, NERLDC, CEA, RPC and CTU.

12.3 The testing of generators will be as per the guidelines of AERC AEGC and IEGC.

CHAPTER 13: FIRST TIME ENERGISATION AND INTERCONNECTION (FTEI) OF POWER SYSTEM ELEMENTS

13.1 INTRODUCTION

1) Clause 8.3 of IEGC and 5.3.4 of the AEGC requires SLDC to prepare procedure for first time energization of new or modified power system elements to intra-State transmission system.

2) Users seeking to get connected to the InSTS for the first time through a new or modified power system element shall fulfill the requirements and follow the procedures specified under AEGC prior to obtaining the permission of energization from the SLDC.

3) Transmission licensees including deemed transmission licensees or other intra-state entities shall comply with the technical requirements specified under the connection code of AEGC prior to being allowed by SLDC to energize a new or modified power system element.

4) Any existing InSTS user seeking to charge an element, new/ modified shall be required to fulfil the procedure for FTEI.

5) In accordance with the provisions of IEGC and AEGC, procedure for first time energization and integration of a new or modified power system element(s) shall be formulated by SLDC and the same is available as a separate document.

6) FTEI procedure shall be applicable to the following entities:
   a) Intra state Transmission lines/ Transformers/ Reactors / flexible alternating current transmission system (FACTS) Devices/ Buses/ Bays/ any other element of 66kV, 132kV voltage level irrespective of ownership.
   b) Intra State Generating Units within the state periphery irrespective of ownership including CPPs; connected to and injecting into state grid.
   c) Generating Transformers (GTs) /Station Transformers (STs) at Intra State generating stations.
   d) Bulk Consumers or Load Serving Entities and Combined (Load & Captive)

7) FTEI procedure shall be applicable in the following cases:

   a) Commissioning of a new power system element.
   b) Charging/Energization of power system elements after continuous outage/shutdown exceeding six months.
   c) Charging/Energization of transmission line/bay after alteration (including modification/ replacement/ upgradation) under Planned/Emergency/Forced outage:
      i. Replacement and/or upgradation of substation equipment: CT/PT/CVT/CB

/Isolator/LA/ Bushing/Wave trap

ii. Replacement of one phase of a failed Transformer/Reactor with a cold spare unit

iii. Replacement of one phase of a failed Transformer/Reactor with a hot spare unit

iv. Replacement of failed 3-ph Transformer/Reactor with new 3-ph Transformer/Reactor

d) Charging/Energization of transmission line after restoration of damaged/collapsed towers at the same location.

e) Restoration and charging /energization of transmission line through Emergency Restoration System towers, Interim bypass arrangement or Restoration and modification of transmission tower.

f) Charging/Energization after re-conductoring, re-bundling or similar other alterations involving change in nature of power flow in the line.

g) Charging/Energization of transmission line after upgradation/increase in voltage level or line rearrangements including Loop-In-Loop-Out.

h) Charging/Energization of transmission line after alterations involving change in course of transmission line i.e. in case of railway line/road/river crossing (with or without the use of ERS) and diversions or interim bypass arrangement or restoration and modification of transmission line/tower involving crossing of another line.

i) Anti-theft charging of already commissioned /new transmission line

i. Idle charging (for anti-theft) of a section or complete line length of new transmission line which is not terminated at both ends.

ii. Charging/Energization of already commissioned transmission line (complete line length or a section) which is under breakdown/outage.

13.2 JURISDICTION FOR ISSUANCE OF APPROVAL FOR FIRST TIME ENERGIZATION, TRIAL RUN, ISSUANCE OF CERTIFICATE OF SUCCESSFUL TRIAL RUN:

1) **NERLDC-** All regional ISTS elements including ISGS generators, Intra State elements of voltage level of 220kV and above irrespective of ownership.

2) **SLDC-** All Intra State elements irrespective of ownership of voltage level upto 132kV.

The detailed procedure for first time energisation and interconnection (FTEI) of power system elements of the Intra State elements including trial run, issuance of certificate etc. is published as a separate document.

CHAPTER 14: METERING AND ENERGY ACCOUNTING

14.1 INTRODUCTION

Section 32(2) of the Electricity Act 2003 mandates that the State Load Dispatch Centre (SLDC) shall, inter alia keep accounts of the quantity of electricity transmitted through the State grid. Energy Accounting involves book keeping of Long-term, Medium Term and Short-term transactions that were scheduled and dispatched, computation of energy actually delivered into the grid and energy actually withdrawn from the grid by the entities along with computation of total transmission losses in the grid.

14.2 METERING AND DATA COLLECTION

1) The STU or Discom, as the case may be, shall be responsible for procurement and installation of Interface Energy Meters (IEMs), at the cost of respective entity, at all the interface points and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points, and its operation and periodic calibration shall be done by the respective entity.

2) STU or Discom, as the case may be, shall be responsible for replacement of faulty meters at the cost of the respective entity.

3) The installation, operation, calibration and maintenance of Interface Energy Meters (IEMs) with automatic remote meter reading (AMR) facility shall be in accordance with the CEA Metering Regulations 2006 & its amendments thereof. Furthermore, the System architecture of telemetry and Revenue data collection for Long Term and Medium-Term open access customer as well as Short Term open access customer has to be followed by the respective entity as mentioned in Appendix-N of AERC (Electricity Grid Code Regulations' 2024)

4) For establishment of AMR system with SLDC, the necessary architecture and specifications should be as per SLDC. Appendix N may be taken as reference, however, it may vary as per site requirement.

14.3 INTRA STATE ENERGY ACCOUNTING

1) Energy accounting shall be the system employed to monitor and evaluate the performance of the AEGCL grid, specifically through the computation of Transmission and Transformation Losses on a monthly basis.

2) Transmission losses shall be calculated as the difference between the sum of all energy initially injected into the intra state transmission system from different interface points and the sum of energy transmitted to distribution licensees and consumers connected to the intra-state transmission system.

3) All points where the electricity is injected must be pre-identified and metered by Special energy Meters (main and check meters) prescribed for ABT metering by State Transmission Utility (STU).

4) Energy injected into the AEGCL Grid from the Central Sector Generating Stations (North-Eastern Region & Eastern Region), Bilateral Agreements, Power Exchanges, DSM statements or similar sources shall be considered when calculating import to the AEGCL Grid, in addition to generation within the state by State Sector Generating Stations, IPPs and CPPs.

5) All points where the electricity is drawn must be pre-identified and metered by Special energy Meters (main and check meters) prescribed for ABT metering by State Transmission Utility (STU).

6) AEGCL grid substations shall have to submit Energy Handling Data and Joint Meter Reading statements on or before 5th of every month for the previous month to SLDC. These statements shall be duly signed by the concerned officials of both STU and Discom.

7) The auxiliary energy consumption in the GSSs shall be considered as part of transmission losses.

8) Energy accounting for all open access customers shall be carried out by SLDC as per AERC (Terms and Conditions for Open Access) Regulations'2024 and its amendments thereof.

9) In case any error or omission is detected by self-analysis or brought to notice by an entity, the SLDC shall make a complete check and rectify the error within a period of a month from date of such detection.

10) The Intra State Energy Accounting statement is submitted State Transmission Utility by the SLDC; on quarterly or half-yearly or yearly basis, as the case may be, for onward submission to the Hon'ble Commission.

CHAPTER 15: OPEN ACCESS

All matters related to Open Access shall be governed by AERC (Terms and Conditions for Open Access) Regulations' 2024 and its detailed procedures, as amended from time to time.

CHAPTER 16: NATIONAL OPEN ACCESS REGISTRY

16.0 INTRODUCTION

NOAR shall be a common electronic platform for facilitating the T-GNA applications in inter-State transmission system (ISTS) and shall provide a single point electronic interface for all the stakeholders, availing TGNA in inter-State transmission system including T-GNA customers, state distribution utilities, state/central/IPP generators, trading licensees, Power Exchanges, National Load Despatch Centre (NLDC), Regional Load Despatch Centres(RLDCs), State Load Despatch Centres(SLDCs) and Regional Power Committees (RPCs);

NOAR Link: https://noar.in

The various procedures applicable for National Open Access Registry is available in the following link: https://noar.in/procedures

16.1 FUNCTIONS OF NLDC, NERLDC AND SLDC relating to NOAR

1) NLDC shall be the nodal agency for implementation and operation of NOAR and facilitate smooth functioning of NOAR.

2) Functions of NERLDC shall be as follows:

   a) NERLDC shall register T-GNA customers which are north eastern regional entities, and intra-State entities of north eastern region
   b) The RLDC of the region where point of drawl of electricity is situated shall be the nodal agency for approval of bilateral transactions. The nodal RLDC shall:
      i. Process all T-GNA advance and Exigency (except cross border transactions) through NOAR;
      ii. Incorporate the Transactions (as per the acceptance accorded) in the Daily Schedules of the Regional Entities;
      iii. Collect, account and disburse TGNA charges through NOAR.
      iv. Update the List of RBI Holidays in north eastern region in the NOAR.
      v. NERLDC shall be responsible for implementation of curtailment due to tripping of any NER ISGS.
      vi. NERLDC shall be responsible for implementation of curtailment due to any inter regional transmission constraint.

3) Functions of SLDC shall be as follows:

   a) Process registrations of all T-GNA customers which are intra-State entities through NOAR.
   b) Give standing clearance through NOAR for the T-GNA customers under its control area jurisdiction.

c) SLDCs shall be responsible for updating the list of weekly off and published holidays in the respective state in the NOAR.
d) Update the status of waiver of charges for intra-State transmission system and SLDC scheduling charges for T-GNA customers which are intra-State entities in NOAR.
e) Incorporate T-GNA transactions for the T-GNA customers which are intra-State entities in the daily schedules issued by them;
f) Make available export and import TTC, RM and ATC of the respective state in NOAR, if determined by SLDC.
g) Procedure for Grant of Temporary General Network Access (T-GNA) to the inter-State Transmission system through National Open Access Registry (NOAR).
h) A T-GNA customer shall be able to make an application for seeking standing clearance or applying for T-GNA transaction, both bilateral and Collective, only after successful registration on the NOAR platform.

16.2 REGISTRATION

The process of registration shall be as under.

1) Any Open access customer intending to avail T-GNA for the use of the Intra-State Transmission System(s) and/or Distribution System(s) of the licensees in the State including when such systems are used in conjunction with the Inter State Transmission System(s) through Bilateral or Collective Transaction or both shall get registered in the NOAR portal prior to fulfilment of requirements in all aspects as mandated under AERC (Terms and Conditions for Open Access) Regulations'2024 and its amendments thereof.

2) The applicant shall e-verify the filled-in application on the NOAR platform.

3) The applicant shall set a username and password after completion of the above process. These credentials shall be used by the applicant for accessing NOAR platform for applying for standing clearance or TGNA transaction.

4) Applicant should furnish all the details requested in the online registration process at NOAR as per **Format-A of Annexure-3**

5) In case of a T-GNA customer which is a regional entity, the application shall be processed by the NERLDC and for a T-GNA customer which is an intra-State entity the application shall be processed by the host SLDC. In case of inter-State trading licensees and Power Exchanges, the application shall be processed by NLDC.

6) After the receipt of application for registration, NLDC, NERLDC, SLDC as the case may be, shall conduct a preliminary scrutiny to ensure application form is complete in all respect along with the necessary documents In case of any discrepancy or requirement of any further information, the NLDC or NERLDC or SLDC, as the case may be, shall communicate the applicant through NOAR for rectification of the same within 2 (two) working day of receipt of the application. In case the applicant does not respond to the requirements of rectification within 2 (two) working days to the NLDC

or NERLDC or SLDC, the registration request shall be rejected and reasons for such rejection shall be communicated to the applicant through NOAR.

7) NERLDC shall register a T-GNA customer which is regional entity within 7 (seven) working days of receipt of complete application for new applications and within 3 (three) working days for renewal of registration through NOAR, the application is complete in all respect and grant registration or otherwise.

8) Host SLDC shall process the application for registration of a T-GNA customer which is intra-State entity within 5 (Five) working days of receipt of complete application for new applications and within 2 (two) working days for renewal of registration through NOAR, for completion of registration by NERLDC, provided that the application is complete in all respect and grant registration or otherwise.

9) NLDC shall process the registration application of the interstate electricity traders, and trading licensees engaged in cross border trade of electricity in terms of the Cross Border Regulations for injection into or drawl from the Indian grid and power exchanges within 7 working days through NOAR, after the complete application in all respect is received at NLDC.

10) In case where the host SLDC/NERLDC or NLDC, as the case may be, has communicated any deficiency or defect in the application, the date of receipt of application shall be considered as the date on which the application has been received duly completed after removing the deficiency or rectifying the defects, as the case may be and the period of 7 (seven) working days for NERLDC or NLDC, as the case may be, and 5 (five) working days for SLDC shall be reckoned from such date.

11) NERLDC shall register the TGNA customer which is intra-State entity within two (2) working days for new applications and within one (1) working day for renewal of registration through NOAR, after the receipt of inputs from the host SLDC.

12) In case of any change in the information provided by the T-GNA customer, it shall be incumbent upon the applicant to update the information in the NOAR.

13) In case of a change of a name of the T-GNA customer already registered in NOAR, such entity shall inform, along with relevant documents from the appropriate authority such as Registrar of Companies or National Company Law Tribunal or any other Court, to the NLDC or NERLDC, which shall upon verification of documents, update such change in its records and update the NOAR within 5 (five) working days. The concerned T-GNA customer shall settle all outstanding financial liabilities, as the case may be.

14) The T-GNA customer shall ensure that all details are correct and accurate, failing which, the registration may be cancelled or renewal may be denied by NERLDC or SLDC, as the case may be, with reasons communicated through NOAR.

15) The Nodal Agency shall maintain a centralised database of registered T-GNA customers based on registrations carried out by RLDCs and NLDC.

16) The grid connected entities shall be able to make an application for seeking standing clearance or applying for T-GNA transaction for both bilateral and collective, only after the registration process is complete in all respects

16.3 STANDING CLEARANCE PROCEDURE OF TGNA:

1) Any Open Access customer who has been successfully registered on NOAR shall apply through NOAR along with the requisite declaration as per **Format-B1** or **Format-B2**, for the issuance of a 'standing clearance' for availing T-GNA in Intra State Transmission System and/or Distribution System(s) of the licensees in the state in conjunction with the Interstate transmission System for a prespecified quantum (MW), specified period, at a prespecified interconnection point prior to fulfilment of all regulatory procedures as per AERC (Terms and Conditions for Open Access) Regulation'2024 and its amendments thereof.

2) NERLDC shall provide the standing clearance for the regional entity buyers up to the quantum of interstate T-GNA. For regional entity generating stations as sellers, NERLDC shall provide the standing clearance up to the approved GNA quantum as provided by Central Transmission Utility of India Limited (CTUIL).

3) T-GNA applicants shall check if there is any change in the details as entered during the time of registration prior to submitting the request for standing clearance. Changes, if any shall be submitted by the T-GNA applicant prior to submitting the application for standing clearance.

4) For intra-State entities, the consent of DISCOM, if any, shall be uploaded in the NOAR by SLDC or T-GNA customers.

5) For T-GNA customer which is an intra State entity, the application for standing clearance shall be forwarded to the host SLDC for verification and approval who shall process the application for grant of standing clearance or refusal within 3 (three) working days from the date of receipt of consent from the concerned distribution licensee and State Transmission Utility.

6) In case the SLDC finds that the application for standing clearance is incomplete or defective in any respect, it shall communicate the same to the entity within 2 (two) working days from the date of receipt of such application.

7) In cases where the host SLDC has communicated any deficiency or defect in the application, the date of receipt of application shall be considered as the date on which the application has been received duly completed after removing the deficiency or rectifying the defects, as the case may be and the period of 7 (seven) working days for the new grid connected entity and 3 (three) working days for an existing gird connected entity under Clause 5.j of NLDC Procedure for grant of GEOA shall be reckoned from such date.

8) The issuance of standing clearance shall be communicated to the T-GNA customer once the SLDC approves the application.

9) In case the SLDC fails to communicate issuance or refusal of standing clearance within the specified period of 3 (three) working days the standing clearance shall be deemed to have been granted.

10) In case the application has been found to be in order but the SLDC refuses to issue the standing clearance on the grounds in accordance with AERC (Terms and Conditions for Open Access) Regulations' 2024 then such refusal shall be communicated to the T-GNA applicant through NOAR within the period of three (3) working days from the date of receipt of the application along with reasons for such refusal.

11) The SLDC may withdraw the standing clearance or revise the quantum(MW)or period of the standing clearance issued in respect of any TGNA customer in case of transmission constraint or in the interest of grid security.

12) In case SLDC has not communicated the approval or refusal of the application for standing clearance within the period of three working days or seven working days, as the case may be, the standing clearance shall be deemed to have been granted by 00:00 hours of the next day, after the expiry of such period of three working days for a period for which such standing clearance was applied for or a period of 7 days, whichever is lower.

13) The standing clearance may be issued by the SLDC in the format as specified in **Format-C of Annexure-3** for a maximum period of one month at a time as per AERC (Terms and Conditions for Open Access) 2024 and its approved detailed procedure.

14) The approved standing clearance shall be terminated in NOAR automatically after 2 clear days in case any major changes in the registration details. The applicant has to apply for fresh standing clearance with the revised registration details to the SLDC/NERLDC/NLDC as the case may be. The major parameters are Name, Parent Company Name, Utility Type, Connectivity Details etc. Intimation shall be provided through NOAR to SLDC/RLDC as the case may be.

15) For renewal of the standing clearance, the grid connected entity shall apply as per the timeline provided in the AERC (Terms and Conditions for Open Access)2024 before expiry of the standing clearance through NOAR, with a request for renewal along with the declaration

16) The standing clearance issued by the NLDC/SLDC/NERLDC shall be used in all bilateral and collective category transactions.

17) The T-GNA customers to whom the standing clearance has been issued or deemed to have been issued, shall ensure that aggregate quantum in each time block of 15 minutes for all the bid(s) under any of the categories of bilateral and collective transactions in OTC market and/or Power Exchange(s) market shall not exceed the quantum of standing clearance or deemed standing clearance, as the case may be.

18) If the aggregate bid quantum of grid connected entity under bilateral transactions and collective transactions, including the approved T-GNA quantum exceeds the quantum of the standing clearance in any time block, by a T-GNA grantee, NLDC shall debar such grid connected entity from participating in bilateral and collective transactions for a period of seven (7) days under intimation to the concerned SLDC/NERLDC.

19) In case of regional entity generating station as a seller, if the aggregate bid quantum under bilateral transactions and collective transactions, exceeds the quantum of the approved standing clearance in any time block, NLDC shall debar such regional entity generating station from participating in bilateral and collective transactions for a period of seven (7) days under intimation to the Host RLDC.

20) The list of debarred T-GNA customer shall be displayed on the NOAR platform.

16.4 REVISION OF T-GNA

T-GNA granted under Exigency application category or under Advance application category for a period not exceeding one month cannot be revised.

16.5 SCHEDULING

1) An application for scheduling of bilateral transaction through T-GNA in the Intra State Transmission System(s) and/or Distribution System(s) in conjunction with the inter-State transmission system shall be made through NOAR only by the T-GNA customer registered in NOAR and having a valid standing clearance at least for the period of which an application is being made.

2) For each application the sum of total quantum under GNA, already approved T-GNA transactions and the T-GNA quantum applied shall be within the limit of the approved quantum as per standing clearance for the applied period, which shall be checked through NOAR.

3) In case of any violation of the approved quantum as per standing clearance for the applied period, the same shall be electronically intimated to the concerned TGNA customer.

4) Scheduling of cross border transactions shall be done through NOAR in accordance with CERC (Connectivity and General Network Access to the inter-state Transmission System) Regulations, 2022 and CERC (Cross Border Trade of Electricity) Regulations, 2019 as amended from time to time.

5) The transmission charges and losses in the ISTS for both bilateral and collective transactions shall be facilitated through NOAR in accordance with CERC (Sharing of Inter State Transmission Charges and Losses) Regulations, 2020 as amended from time to time. For use of Intra State transmission system and/or distribution system, applicable charges and losses shall be in accordance with AERC(Terms and Conditions for Open Access) Regulation'2024 and its amendments thereof.

6) Advance category:

a) Scheduling request by T-GNA grantees under Advance application category shall be made on day ahead basis before the opening of bidding window for collective transactions under day ahead market, as per provisions of the Grid Code. T-GNA grantee under Advance application category may request to schedule power upto its T-GNA quantum at the time of making scheduling request

b) T-GNA granted under Exigency application category shall be considered as scheduled, which cannot be revised.

16.6 GRANT OF TGNA:

1) An application for availing T-GNA for bilateral transaction in the interstate transmission system shall be made through NOAR only by the registered applicants.

2) The application for grant of T-GNA for a bilateral transaction shall contain the details as per **Format D of Annexure-3.**

3) The advance T-GNA bilateral application may have valid standing clearance from SLDC, under whose jurisdiction the point of drawl is located, in case the buyer is an intra-State entity. If at the time of making of the advance application for T-GNA, the point of injection has not been identified, the target injection region shall be provided by the applicant. The point of injection shall be submitted along with the scheduling request.

4) The T-GNA exigency application shall have valid standing clearance from the SLDC, under whose jurisdiction the point of injection and drawl are located.

5) The applications for grant of T-GNA shall be processed by SLDC in accordance with the AERC (Terms and Conditions for Open Access) Regulations' 2024 and its amendments thereof, in case of Intra state entity.

6) In case of Intra state entity, T-GNA may be applied for a period of one month as per AERC (Terms and Conditions for Open Access) Regulations' 2024 and its amendments thereof.

7) All the advance applications received for grant of T-GNA shall be considered on first-come-first served basis and shall be processed latest by 23:59 hours of the (D+1) day, 'D' being the date of successful submission of the application though NOAR.

8) Exigency applications for T-GNA with the schedule for (S) day shall be processed as under:

i. Applications received till 1300 hrs of (S-1) day shall be processed after 1300 hrs on (S-1) day on first-come-first-served basis, and shall be finalised by 1400 hrs of (S-1) day.

ii. Applications received after 1300 hrs of (S-1) day or in the (S) day shall be processed within 4 time blocks, on first-come-first-served basis

9) Payment schedules shall be generated for approved transactions and shall be notified to the T-GNA grantee through NOAR as per **Format-E of Annexure-3..**

16.7 PAYMENT

1) Terms of Payment:

   a) All payments associated with bilateral and collective transactions shall be made by the applicant electronically through the payment gateway of NOAR.

   b) No retrospective adjustments for TGNA rates shall be made for the already approved TGNA bilateral and collective transactions.

   c) Transmission charges for T-GNA under Advance application category shall be deposited by the T-GNA grantee with the Nodal Agency as under:

      i. For T-GNA up to one (1) month - within three (3) working days of grant of T-GNA.
      ii. For T-GNA for more than 1 month - charges for the first month, within three (3) working days of grant of T-GNA but before the start date of T-GNA and charges for each subsequent month including part thereof, if any, on rolling basis, one month in advance.

   d) Transmission charges for T-GNA under Exigency application category shall be deposited along with the application.

   e) All the applicable charges for T-GNA customer connected to Intra state Transmission System shall be levied as per AERC (Terms and Conditions for Open Access) Regulations' 2024 and its amendments thereof.

2) Default in Payment:

   a) In case of default in payment of application fee, transmission charges, interest or any other charges or fees specified under the CERC regulations, NERLDC, at its discretion may not schedule the transaction and the defaulting entity shall not be able to apply for new applications through NOAR in future until such time the default is cured.

   b) In case of Intra State entity, any default in payment of application fee, transmission charges, interest or any other charges or fees specified under the AERC (Terms and Conditions for Open Access) regulations 2024 and its amendments thereof, SLDC, at its discretion may not schedule the transaction and the defaulting entity shall not be able to apply for new applications through NOAR in future until such time the default is cured.

16.8 MISCELLANEOUS

1) All costs, expenses, charges associated with the application, such as transaction cost associated with payment gateway etc. shall be borne by the T-GNA customer.

2) The list of T-GNA customers which are regional entities and the intra-State entities shall be displayed through NOAR.

3) It shall be the responsibility of all the T-GNA customers which are registered in NOAR to maintain the confidentiality of the login credentials issued to them to prevent any possible misuse.

The Ministry of Power has notified the Electricity (Promoting Renewable Energy Through Green Energy Open Access) Rules, 2022 on 06th June 2022 and amendments thereof with the aim of accelerating India's ambitious renewable energy programmes. Ministry of Power vide notification dated 08th July, 2022 notified Power System Operation Corporation (POSOCO) now Grid-India as Central Nodal Agency to set up and operate a single window green energy open access system for renewable energy under these Rules. National Portal will serve the consumers from all over the country.

To participate in the Green Energy open access (for both Inter-state and Intra-state), the entity should register in the GOAR portal.

GOAR Link: https://greenopenaccess.in/landing

The entity can apply for only bilateral application for T-GNA and intra-state open access through the GOAR portal.

CHAPTER 17: DEVIATION SETTLEMENT MECHANISM

All matters related to Deviation Settlement shall be governed by AERC (Deviation Settlement Mechanism and Related Matters) Regulations, 2024 and its Detailed Procedure, as amended from time to time.

CHAPTER 18: REACTIVE POWER COMPENSATION

18.1. INTRODUCTION

1) Reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The State 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 State entities, VAr exchanges with Intra State Transmission System shall be priced as follows:

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

   Where all voltage measurements are at the interface point with Intra State Transmission System.

2) The charge for VArh shall as be as per provisions of relevant regulations.

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 Intra State Transmission System.

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

5) For any interconnecting line between two states, owned by the States, the interface points shall be treated in terms of this Regulation for the purpose of reactive power charges.

18.2 ACCOUNTING AND PAYMENT FOR REACTIVE ENERGY EXCHANGES

1) SLDC shall be responsible to issue the weekly statement for VAR charges, to all State entities including Open Access Customers.

2) The concerned State entities shall pay the amounts into state Pool Account operated by the SLDC within 10 (ten) days of issue of statement.

3) The State entities who have to receive the money on account of VAR charges would then be paid out from the aforesaid Pool Account, within two (2) working days from the receipt of payment in the Pool Account.

4) 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 SLDC, the defaulting entity shall pay simple interest @ 0.04% for each day of delay. The interest so collected shall be paid to the state entities who had to receive the amount, payment of which got delayed.

5) Persistent payment defaults, if any, shall be reported by the SLDC to the Grid Code Management committee (GCMC), for initiating remedial action.

CHAPTER 19: RENEWABLE PURCHASE OBLIGATION (RPO)

All matters related Renewable Purchase Obligation shall be governed by AERC (Renewable Purchase Obligation and its compliance) Regulations, 2010 as amended from time to time.

CHAPTER 20: EMS/SCADA - MONITORING AND CONTROL

20.1 INTRODUCTION

A Supervisory Control and Data Acquisition (SCADA) system is an integrated software system which provides real-time monitoring and telemetry of status information for power system equipment and control capabilities for electrical power transmission and generation. It allows to store real-time and static system data, monitor system data, issue controls to devices, configure and handle alarms.

Energy Management System (EMS) is a computer-based tool to help manage power system operations. The system collects, coordinates, analyses and disseminates operational power system information to serve as a decision support tool for power system operation personnel.

The SCADA/EMS subsystem is the heart of the system. It hosts all the SCADA and EMS databases, carries out the SCADA processing and the EMS calculation, feeds the historical information server, sends the data to the operator consoles, etc. The SCADA/EMS functions viz. Data Acquisition, Data processing, Networks Status Processor, Alarm, Tagging, Power Flow, Contingency Analysis are implemented in SCADA/EMS servers.

20.2 FACILITIES AVAILABLE IN CONTROL ROOM

SCADA/EMS System and Wide Area Monitoring System (WAMS) has been set up at SLDC for real time monitoring and controlling of power system.

SCADA allows real time monitoring of power system with the help of analog and status data at an interval of 5-10 seconds whereas WAMS system allow visualization of 40 ms interval power system data.

20.3 SUPERVISORY CONTROL AND DATA ACQUISITION / ENERGY MANAGEMENT SYSTEM

1) SYSTEM ARCHITECTURE

A SCADA domain is an autonomous instance that fulfils an operational role, such as Main Control Centre (MCC) or Backup Control Centre (BCC). It is a collection of (optionally redundant) servers. Each server provides a specific role defined by the databases and services it hosts. For instance, a server hosting SCADA and Historian services (functions) will run SCADA and Historian applications.

Replication and automatic failover between redundant servers are provided by standard services. User authentication and permissions have been defined independently for each domain. From a user perspective, each domain requires independent authentication and authorization.

All the servers and network equipment are rack- mounted in standard computer cabinets. Critical functions have redundant configuration at each level including

redundant power supply units. Failure of one single server does not affect the system. Both Main and Backup control centres are always in operation and in case of any disaster at the main control room, system can be managed from the back up location.

North-Eastern Regional Load dispatch Centre SCADA/EMS system have been separated into several different segments, each with a specific purpose based on type and location. Each segment covers redundancy and functionality including production, network management, development, corporate and dispatcher training.

At the Main Site, these segments are:

a. MCC (Main Control Centre)
b. PDS (Program Development System)
c. DTS (Dispatcher Training Simulator)

At the Backup Control Center, these segments are:

a. BCC (Backup Control Centre)
b. PDS (Backup Program Development System)
c. DTS (Dispatcher Training Simulator)

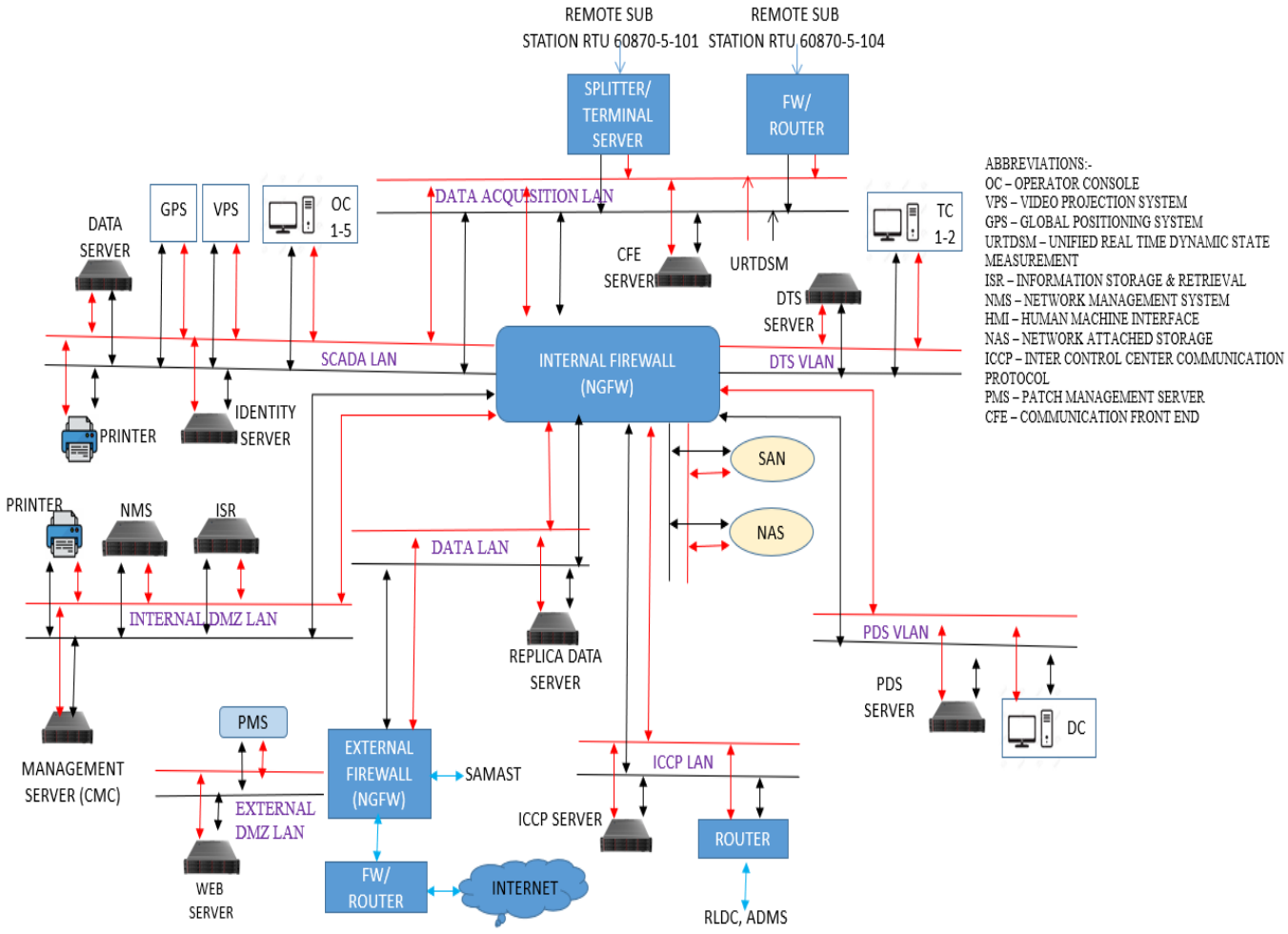


Fig. 1 Typical Architecture of SCADA/EMS system

2) OPERATION PHILOSOPHY

MCC and BCC have a set of historical server's cluster for archival and data retrieval. Two data stores have been configured independently namely:

The historical data between MCC and BCC is not synchronized and it is configured as two independent historical clusters.

The operator of either control centre can access historical data of both control centres

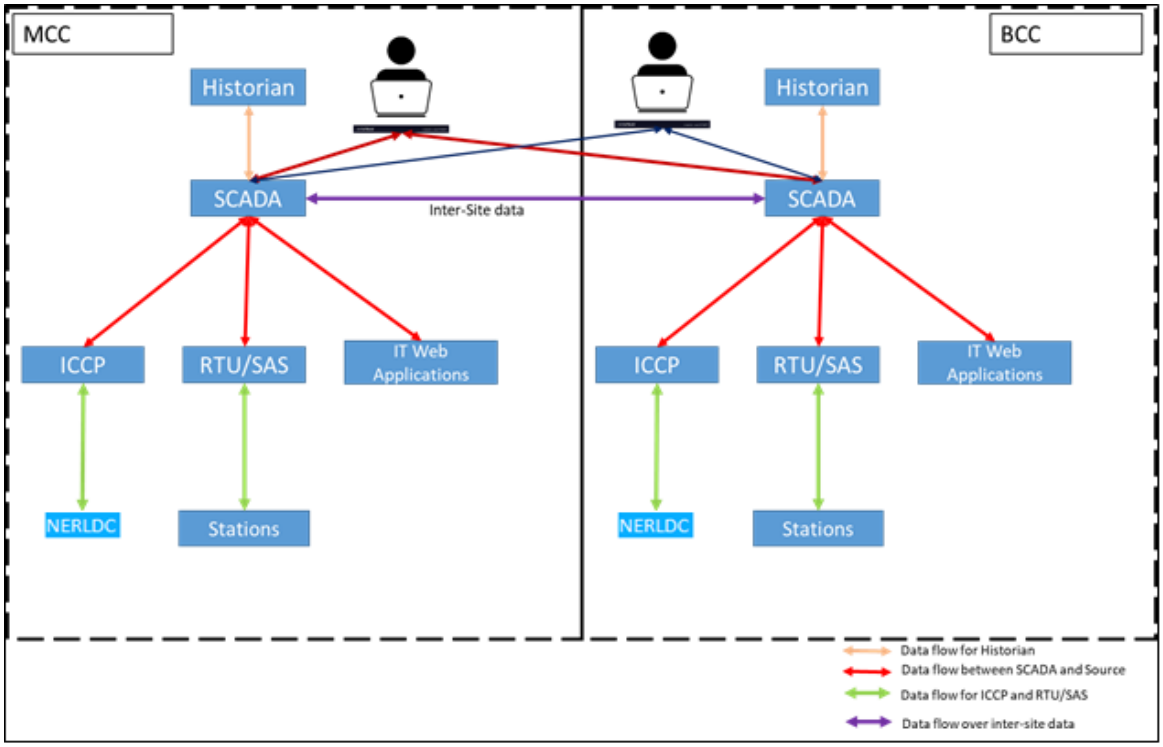


Fig. 2 Historical Data Archiving & Retrieval Data Flow

3) SCADA SUB SYSTEM

The SCADA subsystem for SLDC collects real-time data from RTUs/SAS systems of remote stations and NERLDC via ICCP. SCADA subsystem is implemented via SCADA Application which is an open, scalable and feature-rich Supervisory Control and Data Acquisition (SCADA) software product.

SCADA Application provides very efficient real-time information management and control for demanding operations centres. SCADA is based upon a very effective and high- performance real-time database and Graphical User Interface (GUI) system for support of various SCADA applications.

It comprises of the physical infrastructure i.e. Servers, workstations, Network Devices (Routers, switches, firewalls) etc. SCADA architecture is based on Open and

Distributed computer System architecture with hardware and software level redundancy.

The SCADA user interface is based upon the user interface product and enables users to:

a. Provides Graphical User Interface
b. Provides Limit Checking
c. Apply tags that control point behaviour to individual points and groups of points in the SCADA database
d. Temporarily override limits and/or to modify limits using the Analog limit modes
e. View processed data, such as minimum value, maximum value, integrated value and average value
f. View extended calculations for Analog points and the results
g. Provides Tabular Displays

4) ENERGY MANAGEMENT SYSTEM

The EMS functions help grid operators in decision making. It gives scientific logic for any actions and warning for any emergency situation. Power system can be analysed for different operating conditions and further analysis can be done through its base case.

The EMS subsystem at SLDC is implemented which is a high-performance, open-systems- based network security analysis package that is ideal for online security analysis, operations planning and offline engineering studies.

EMS application uses state-of-the-art, field-proven algorithms and can be linked to SCADA system to provide online security monitoring and analysis functions. Using open data-interface protocols, EMS application allows for the efficient exchange of input and output data with SCADA systems. It also provides powerful data query capabilities for analyzing solution results. Input and output data can be exchanged using relational databases through an SQL interface.

It uses SCADA graphical user interface (GUI) that comprises a range of detailed tabular and graphic displays which serve as the operator view, allowing for optimum control and maintenance of network security analysis software. EMS application is an advanced tool for performing security analysis and creating studies that are useful for the operation, planning and engineering of electric power systems.

The EMS applications requirements for SLDC are grouped into the following subsystem:

a) Network Analysis suite including all the Power System Analysis functions required for State Estimation, Optimal Power Flow, Real Time contingency analysis, Transmission loss sensitivity factors, Post disturbance analysis.

b) Dispatcher Training Simulator which is an operator training simulator package for training and enhancing the skills of the dispatchers by providing a realistic response platform to simulate power system operation

5) Remote station data flow and Inter Control Centre Protocol (ICCP Subsystem)

a) Data Flow in ICCP

The inter-site communication subsystem handles the communication with NERLDC using the ICCP communication protocols.

b) Data Flow in IEC-60870-5-101 and IEC 60870-5-104

IEC 60870-5-101 and IEC 60870-5-104 is an international standard that defines a communication protocol for tele control (telemetry and control) systems. It is being used for data flow from substation (slave) to respective control centres (master).

IEC 60870-5-101 and IEC 60870-5-104 are both communication protocols used in the field of industrial automation and control systems (IACS) for remote monitoring and control. IEC 101 relies on polling and explicit requests for data exchange and control commands, while IEC 104 uses unsolicited reporting of data updates and supports selective retrieval of information.

SLDC SCADA acquire data from the substation over IEC 101 and IEC 104 protocol using various communication technology such as Fiber Optics, VSAT, PLCC and GPRS. Terminal servers and routers are installed in SLDC for communication with IEC 101 and IEC 104 based stations respectively.

All CFE processes run on both servers at all times. One server is considered online and handles all of the processing; the other server (the backup) constantly checks the status of the online server to determine whether it needs to take over in the event of a failure.

CFE Server process acts as the interface for the CFE component of the communication. It accepts incoming connection attempts and initiates outbound connections. It handles all CFE communications between substations and control centres and updates local data and statistics. Reporting interval of telemetry data from substation to control centre range from 2-10 second

In brief, Gateways/RTUs are installed at substations and generating stations. Data is received by Front End Processing Servers at the reporting control centre. Following types of data is being acquired in the scan rate of 4-10 seconds in the SCADA systems:

a. Analog Data e.g. MW-Mega Watts, MVAR-Mega Watts (Reactive), KV (Voltage), Hz (Frequency), Tap (Transformer Tap Position) etc.

b. Digital Data e.g. CB (Circuit Breaker Status), IS (Isolator position) etc.

6) INFORMATION STORAGE AND RETRIEVAL (ISR SUBSYSTEM):

The Information Storage and Retrieval (ISR) subsystem is based on historian application. It stores user-defined data and events into historical databases. In particular, the ISR system will store:

a. Status and Analog Values for storage and playback
b. Alarms
c. Events

The ISR system is implemented on redundant set of historical server cluster.

7) MANAGEMENT OF HISTORICAL DATA

The Management of Historical data is handled by a specific set of applications running on a dedicated server cluster configuration.

Some of the main functionality of application is mentioned below:

a. It is based on Big Data Technology.
b. It records data from SCADA databases
c. Integrated user interface with SCADA application provides the ability to view and query the data collected.

8) REPORTING SOFTWARE

eDNA Wonderware is tool for Tabular Reports, Historical Data Analysis for Complex Reporting and Third-Party Excel for ad-hoc reporting have been provided to SLDC allowing building user friendly, flexible and easy to build and modify reports accessing the historian database.

20.4 VISUALIZATION IN CONTROL ROOM

1) Real time monitoring of power system is being provided by SCADA system. At SLDC power map and Single line Diagram has been prepared for better visualization of power system data. All 132 kV and above substations and it's inter connecting lines have been shown in power map in different colour. Real time data of frequency, voltage, active and reactive power flow has been shown on geo map in different colours.

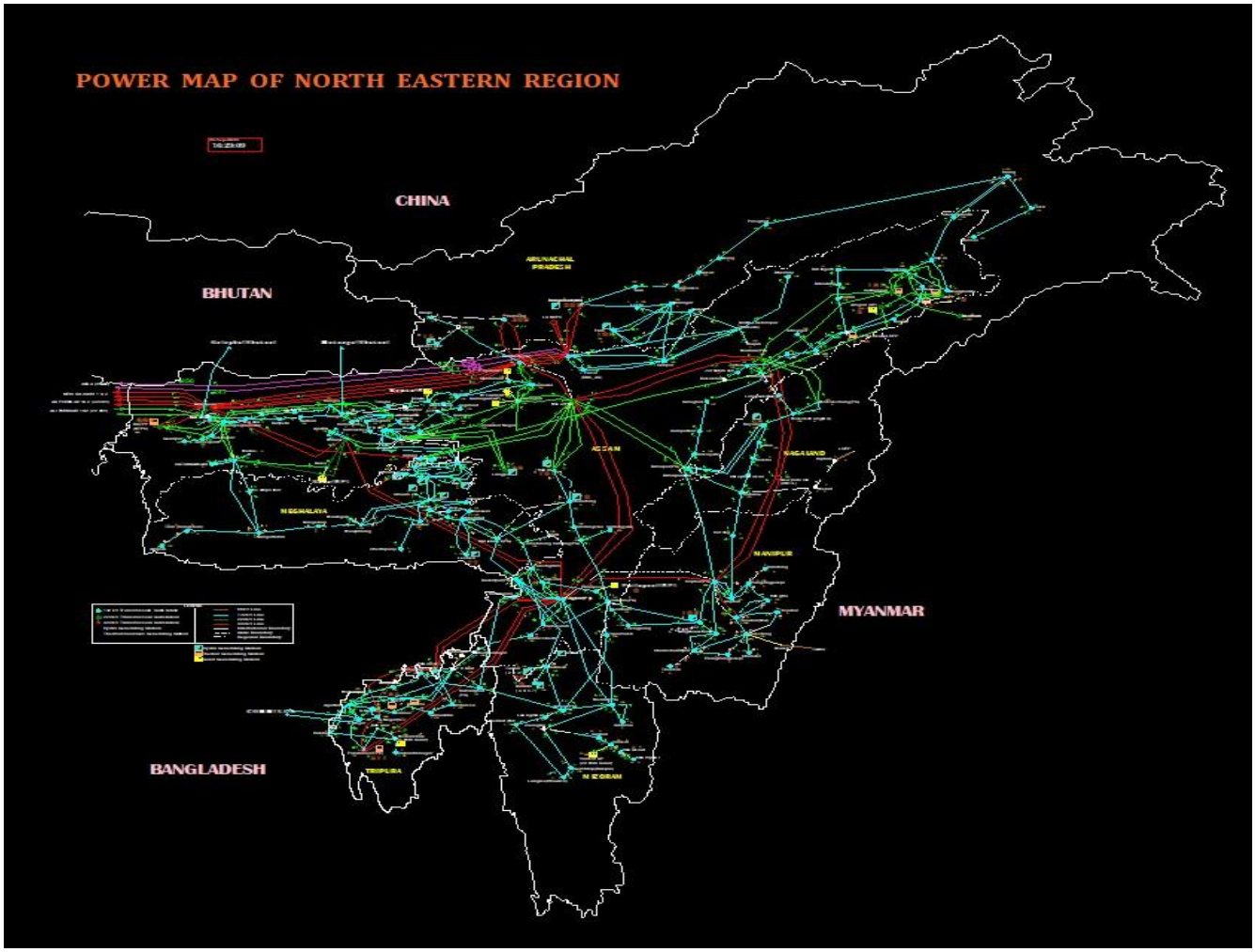


Fig. Geographical Display

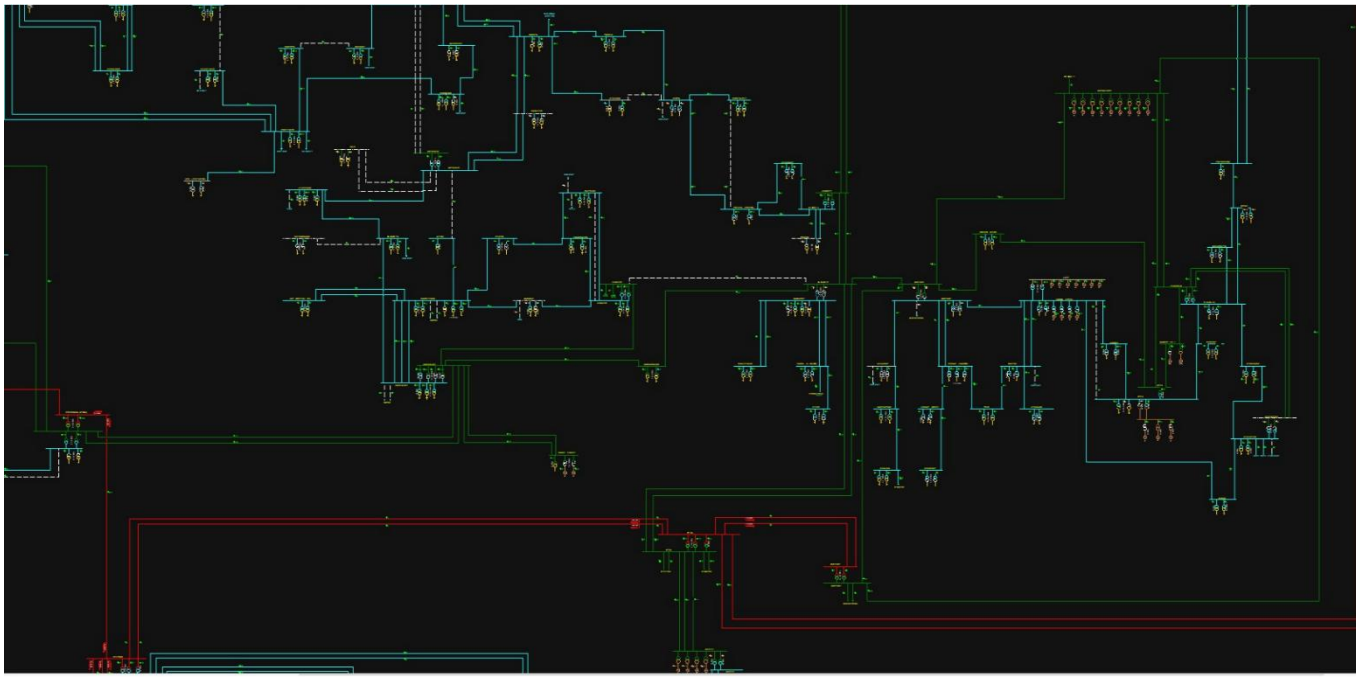
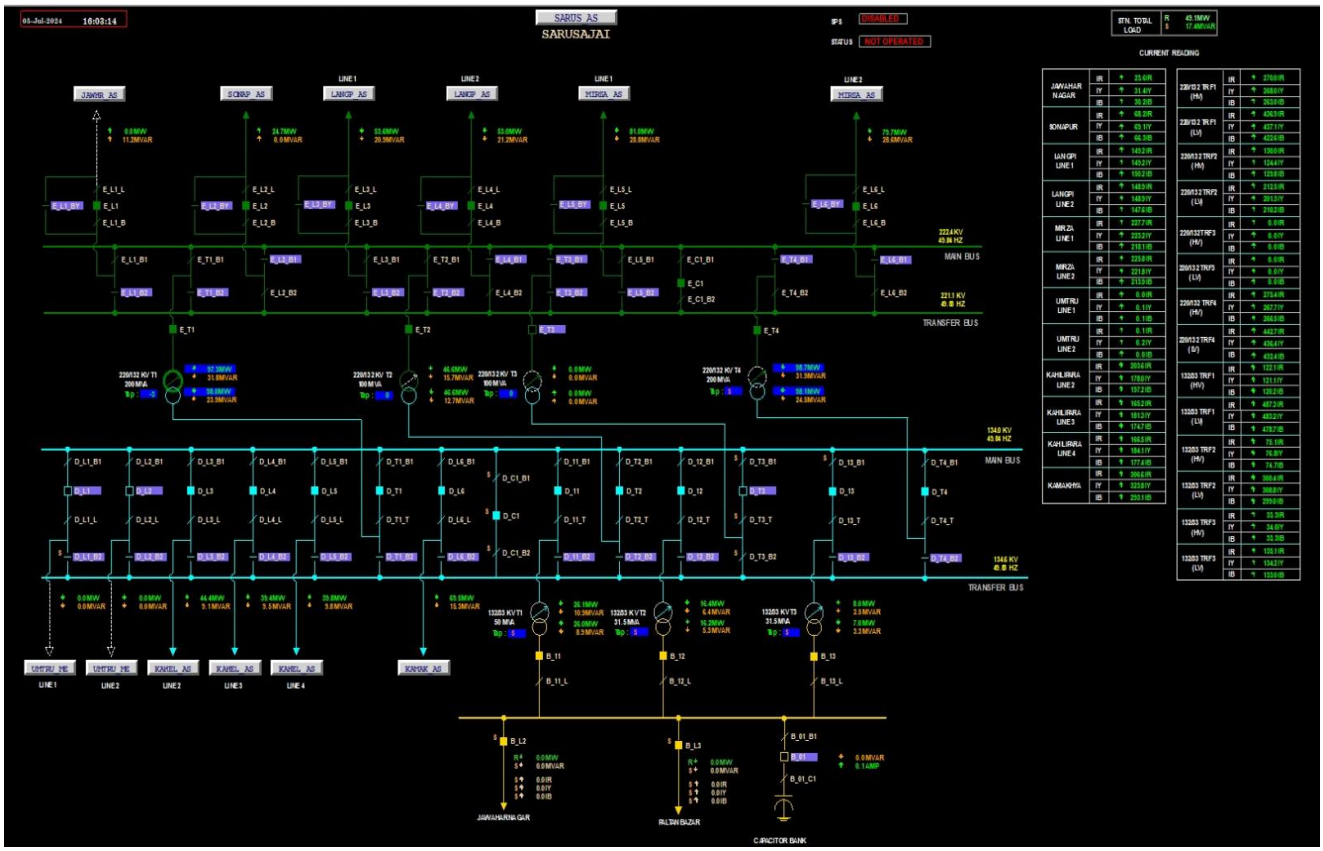


Fig. Power Map

2) For each substation, single line diagram has been prepared which depicts interconnecting nodes (buses), interconnecting lines, bus arrangement, status of circuit breaker and isolators, flow at both ends of lines with indication for direction of flow, colour coding based on voltage and type of data, firm / dotted lines for in-service / out-of-service lines, weather data (Temperature, RH), reactor data, physical layout of the equipment in the substation – Buses, transmission lines, transformers, generators, reactors, CBs, ISO, power flows into and out of the station bus (magnitude & direction).



3) Tabular presentation has been prepared which depicts overall state demand and generation, each power plant real time generation data, source wise (solar, non-solar) generation data etc.

4) Visualization of data is being done with quality tags. Different quality tags viz un-initialized data/garbage, limit violation, unreasonable, manually replaced, calculated, alarm inhibited, remote suspect, state estimator output etc. displayed along with data, so that operator can have better reliable information about the system.

5) Animation: MW and MVAR flow animations are associated with transmission lines on both System Overview and Regional Schematic displays. Arrows are used to animate flows. The size of the arrows represents the magnitude of the flow and the direction of the arrow represents the direction or sign of the flow. Different coloured arrows

represent MW and MVAR flows. Varying thickness of transmission line depending on line loading is being used.

6) One-size fits all does not hold true for operators. Operator preferences are given priority. Operator are allowed to set their own room which is a collection of view ports for better visualization and understanding of power system. It brings out creativity of the operators and instils a feeling of ownership / personalization.

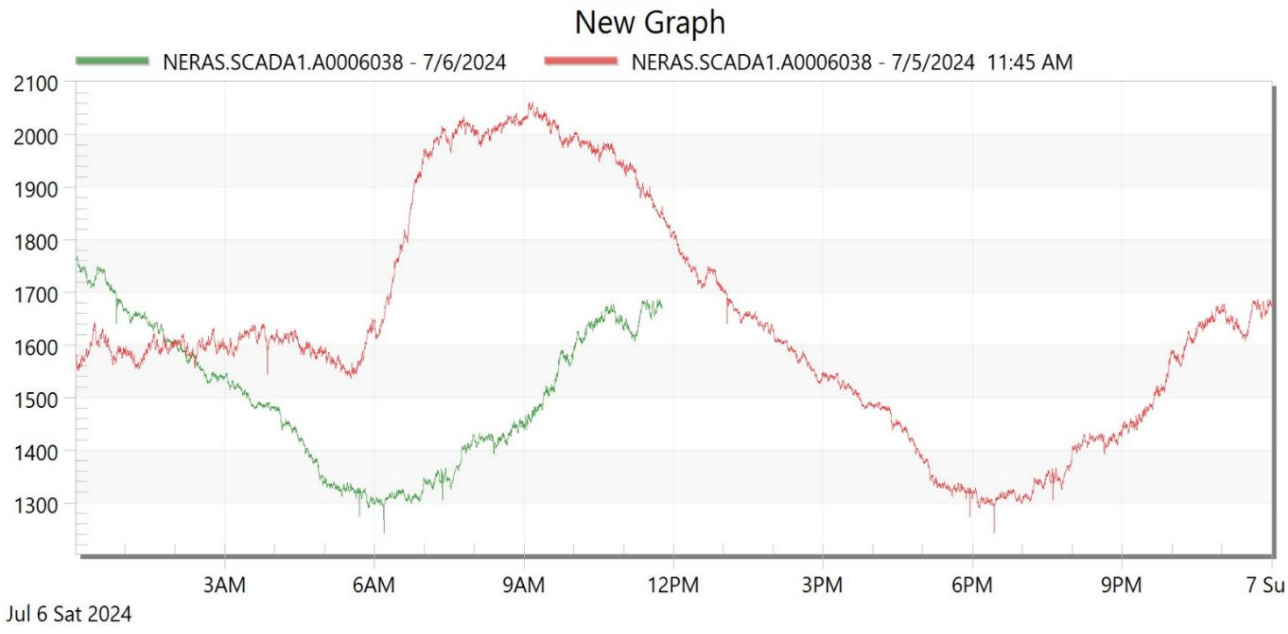
7) Identification of anomalous condition in Indian Grid is being highlighted to operators through alarms and SoE. Its annunciation is configurable and based on configuration an email and sound are generated to draw the attention of operator. Viewpoint application is being used to monitor alarms and SoE.

8) Reconstruction of past events is being done through playback feature of SCADA. It improves operator's understanding of power system behaviour and in turn skills them how to react for similar incidents in future.

9) For fastest acknowledgment of any change in pattern of data, trending application is being used. It is quite useful tool. It allows operator to trend real time data, compare real time data with previous data in same trend window, colour shading if data is violating any limit.

10) Trending is a tool for monitoring and viewing any non-text value in electrical system. Trending enables to plot historical and real-time data as a graphical trend.

Fig. Trending



Although Trending is typically used to trend SCADA values (analog, status or accumulator) It is easy to add and remove trend pens, quickly monitor and compare points.

Trending enables operators to:

a. Graph historical and real-time data.
b. Compare minimum/maximum values.
c. Print data graphs.
d. Export data in a CSV format.

The Trending product enables operator to view pens in an individual trend or in boards which can contain multiple trends. Trending provides a feature-rich user interface for displaying data points as a graph and includes a wide variety of configuration options with the capability of presenting data as either trend lines.

20.5 OPERATION & MAINTENANCE OF SCADA/ EMS SYSTEM

The responsibility of maintaining various components of the SCADA/EMS system is as follows:

1) User shall provide Systems to telemeter power system parameters as per IEGC 2023, Regulation 6(3) of CERC Technical Standards for Grid Connectivity 2007, Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017, AERC (Terms and conditions for Open Access) Regulations, 2018, AERC (Co-generation and Generation of Electricity from Renewable Sources of Energy) Regulations, 2015 and any other regulation which deemed applicable.

   The list of data to be provided by a user is tabulated below:

Sl. No.	Element	Telemetered data
1	Bus	Voltage and Frequency
2	Line	MW and MVAr
3	Transformers	**HV Side:** MW, MVAr and Tap Position **LV Side:** MW and MVAr
4	Unit	MW and MVAr
5	Bay	Circuit Breakers and Isolators
6	Reactors/ Capacitor Banks	MVAr

	Note: • The points listed above are in compliance with the existing regulations by CERC and CEA. • The above list is for reference purpose only. For the detailed list of data points that would be made available to SLDC/RLDC in real time, Guidelines on "Interface Requirements" under the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017 shall be followed. However, some other parameters might need to be provided as per Control Centre requirement based on the SLD and site condition.

2) The Charging Code (First-time Charging as well as subsequent shut-down/charging) cannot be given for any element in case the corresponding real-time data as mentioned in point (a) above is not available at SCADA system of SLDC. The mandatory condition of first-time charging code also includes the availability of dedicated-voice communication and redundant communication path between the station and Main/Backup SLDC.

3) The details for database and configuration related activities such as Single-Line-Diagram, Network Parameters (line length, conductor type, MVA ratings of devices, Tap-Changer details, etc.), Generation Parameters (MVA rating of Units, Capability curves, Min and Max MW Capacity, etc.), RTU/SAS details, etc. shall be made available with SLDC by the user so as to facilitate timely completion of database-modeling, display building, onlining, preparation of signal lists, including the analog points in drawl/bus summation/corridor flow calculations, sharing of information with RLDC, etc. The real time data shall be made available at SLDC/RLDC and validated prior to charging. The following timeline shall be followed:

   a) SLDC shall be intimated at least 7 working days prior to configuration in local RTU/SAS gateway informing about the change and seeking I/O address.

   b) SLDC shall be intimated at least 3 working days prior to the proposed date of data validation for conformation on the date of data validation from SLDC.

4) The responsibility of maintaining the Control Centre at SLDC is with SLDC

5) The new SCADA/EMS project under ULDC-Scheme for SLDC is fully operational. In the event of non-reporting of RTU, the matter is being taken up with the concerned user. The integration of new RTUs with the SCADA is an ongoing process and the same is being taken-up as and when required.

20.6 DAY-TO-DAY OPERATIONAL & DEVELOPMENT ACTIVITIES

1) Visualization/ Monitoring of Assam power system
2) Analysis of past events using Sequence of Event (SOE) records & through Historical Data Recorder (HDR) reconstruction.
3) Data storage through HIS (Historical Information System) & storing of HDR files in separate system for future use.
4) Monitoring of SCADA/EMS system, rectification/ follow-up action in case of outage of any components of SCADA/EMS system
5) Creation/ Modification of Displays
6) Database modification, Integration of new elements, substations & generating stations etc.
7) Data validation.

CHAPTER 21: CYBER SECURITY COORDINATION

21.1 INTRODUCTION

Cyber security posture of Information Communication Technologies (ICT) such as hardware, software used in Control Centers need to be strong against malicious attackers designed to access, alter, delete, destroy the IT/OT systems and associated sensitive data. This section describes the measures to be adopted by the System Operators at SLDC and other state -entities for ensuring secure Grid Operation

21.2 RELEVANT REGULATORY PROVISIONS

As per clause 50 (2) of IEGC, all utilities shall have in place, a cyber- security framework to identify the critical cyber assets and protect them so as to support reliable operation of the grid. Further, in line with CERC Communication System for inter-State transmission of electricity) Regulations, 2017, NLDC shall monitor case of cyber security incidences and discuss them at RPC level and take necessary action as deemed fit.

CEA has notified Technical Standards for Communication System in Power System Operations Regulations, 2020 wherein Cyber Security related standard stipulates that all users and control centres connected to the communication system shall have robust programs in place to adequately and continuously manage cyber security risks that could adversely impact power system communications infrastructure.

Cyber Security program shall address the following namely –

1) Compliance with provisions of the Information Technology Act, 2000 (21 of 2000) and National Cyber Security Policy, 2013 as amended from time to time.
2) Implementation of the National Critical Information Infrastructure Protection Centre (NCIIPC) Guidelines.
3) Implementation of guidelines and advisories issued by Computer Emergency Response Team (CERT-In) and applicable Sectoral Computer Emergency Response Team.
4) Compliance to the Central Electricity Authority (Cyber Security) Regulations, as and when they come into force.

21.3 SECTORAL CERT FOR THE GRID OPERATION:

CERT-GO housed at GRID-INDIA is responsible for necessary coordination and collaboration to ensure cyber security implementation in National, Regional and State Grid Operation functions and associated infrastructure. Whereas, at regional level, regional load dispatch centers are the nodal agencies for coordination and collaboration to ensure cyber security implementation in SLDCs of the region.

21.4 CYBER SECURITY PROGRAM:

It comprises technologies, processes, and methods designed to protect computer systems, data, and networks from unauthorized access. A cyber security program's objective is to protect critical systems and sensitive data from phishing scams, ransomware attacks, data breaches, and identity theft. The best cyber security programme needs to include:

1) Application security
2) Cloud security
3) Data security
4) Endpoint security
5) Identity management
6) Infrastructure and database security
7) Mobile security
8) Network security
9) Operational security

21.5 CYBER HYGIENE

While technology plays a vital role at multiple levels, another important layer of prevention is the creation of a security awareness culture across the organization. Most potential harmful acts are usually based on routine behaviours such as clicking on an unknown link or email attachment. GRID-INDIA has adopted cyber hygiene practices to help in elimination of vulnerabilities as part of a collective effort. Cyber hygiene practices to be followed by all the entities for ensuring cyber security are listed below:

1) Desktops should be locked when not in use to prevent unauthorised access.

2) Physical access to all critical areas like Control Room, Server room, UPS Room etc. should be controlled through RFID/Bio-metric based Access control mechanism.

3) Clear Desk policies should be followed. The hard copies of Sensitive data should not be left unattended on the desk and should be kept safely and securely by restricting access.

4) USB / any other removable media shall not be used in office premises / within office network. Mobile phones/tablets are not allowed to be connected to office desktops for charging the devices and/or for data transfer.

5) Policy level control through Active Directory (AD) should be implemented for enforcing the usage of strong passwords containing minimum 12 characters and having alphanumeric and special symbols.

6) Passwords should be changed mandatorily on regular periodicity of 45 days.

7) Confidentiality of sensitive aata shall be maintained through various controls as per ISMS Standard requirement such as Password protection, Encryption etc.

8) Secured and encrypted protocols like HTTPs, SFTP shall be used to publish and transfer data over web.

9) Administrative rights of desktop shall be restricted through AD.

10) Open-source browser-based VPN extension services shall not be in use in office network. VPN access shall be restricted through VPN usage policy.

21.6 DATA BACKUP AND RESTORATION

1) Periodic backup of critical data shall be taken by individual concerned employee. Periodicity of backup shall be decided and periodically reviewed based on the criticality of the data.

2) Backup data from backup media shall be tested on regular basis to ensure data restoration in case of emergency.

3) Back Up control centre readiness- Mock drills to run the grid operation from backup control centre shall be conducted and attended on a frequent basis to ensure the readiness of the backup system in case of emergency Training & Awareness.

4) Manpower shall be trained to build competency of the Operator to handle any cyber emergency situation without much impact on the grid.

21.7 EMERGENCY PREPAREDNESS

At any point of time, a critical scenario may arise wherein systems are compromised as a result of failure of an ICT system or network of ICT systems, due to technical reasons, intentional acts or negligence leading to consequences that endanger the Grid Operation.

Following are some of the crisis situations which may occur in real time and needs operator's attention:

1) System is showing a different display
2) Data is not getting updated in the database
3) Invalid data being shown in database
4) Distorted dashboard display
5) Login credentials showing as invalid
6) Reports not getting generated
7) Loss of functionality of one critical server like FEP/ SCADA/ICCP etc. in OT or WBES/Shutdown Management/Reporting System etc. in IT
8) Server taking too long to respond
9) New and unknown applications loading on start-up
10) Delayed response from database
11) Ransomware message display.
12) New files with different extensions.
13) VPS display turned off suddenly.
14) Unwanted mail generated from / using GRID-INDIA Mail domain.
15) Or any other anamaly in IT or OT Systems which is beyond understanding / control of the Operator.

In the scenarios mentioned above the following are the steps to be followed:

i) Step 1: Contact CISO/ Crisis Management Team of the NERLDC/ NLDC immediately.
ii) Step 2: Contact the concerned departmental coordinator and Vendor's representative as per escalation matrix provided for any maintenance call.
iii) Step 3: Immediately switch off the system which is behaving abnormally.
iv) Step 4: If possible, remove the infected system from the network by disconnecting physical connections.
v) Step 5: Change local AD and AEGCL Mail Log-In Password.
vi) Step 6: If anomalous data is observed in Web-applications like WBES / Reporting software, switch application in Manual Mode and stop Auto-Schedule / Auto-fetching of data till further resolution from IT/OT Team.
vii) Also, intimate any such happening to the SLDC shift operators through message / mail and communicate on restoration.

As per the Cyber Crisis Management Plan (CCMP), all control centers have nominated CISO and Crisis Management Team (CMT). CISO shall head the CMT at each location. In case of any cyber crisis situations, grid operator is directed to contact0 CISO/ CMT.

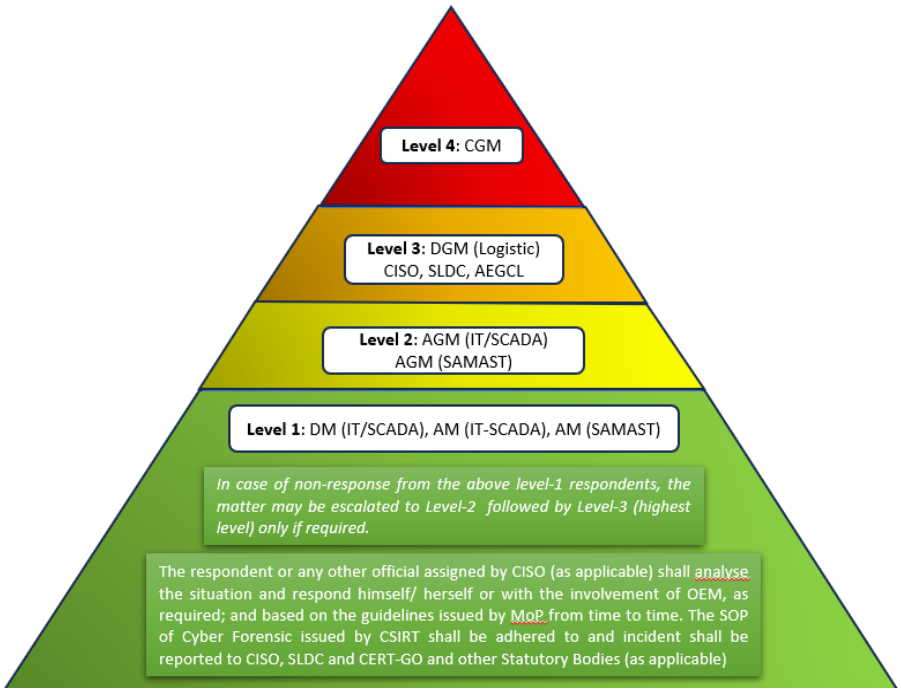


Table Structure of Service Escalation Matrix for Operator to communicate in case of any possible Cyber Security breach observed in IT & OT Systems:

21.8 COMPLIANCE TO CEA CYBER SECURITY GUIDELINES

CEA has published "CEA(Cyber Security in Power Sector) Guidelines, 2021" dated 07.10.2021 under the provision of regulation (10) of the CEA (Technical Standard for connectivity to the Grid) (Amendment) Regulation 2019. Further CERT-In vide publication ref. No. 20(3)/2022- CERT-In dated 28.04.2022 issued "Directions under sub-section (6) of section 70B of the Information Technology Act, 2000 relating to information security practices, procedure, prevention, response and reporting of cyber incidents for Safe & Trusted Internet" for all concerned utilities and GoI agencies.

Necessary extracts of the relevant provisions of the aforesaid Guideline/Direction have been included herein for adherence by the concerned Operators.

Government of India has set up the Indian Computer Emergency Response Team (CERT-In) for Early Warning and Response to cyber security incidents and to have collaboration at National and International level for information sharing on mitigation of cyber threats. CERT- In regularly issues advisories on safeguarding computer systems and publishes Security Guidelines which are widely circulated for compliances.

The Guidelines on Cyber Security, as given below, requires mandatory Compliance by all Responsible Entities.

The Responsible entity will strictly adhere to following cardinal principles while framing cyber security policy:

1) There is hard isolation of their OT Systems from any internet facing IT system.

2) May keep only one of their IT systems with internet facing at any of their site/location if required which is isolated from all OT zones and kept in a separate room under the security and control of CISO.

3) Downloading/Uploading of any data/information from their internet facing IT system is done only through an identifiable whitelisted device followed by scanning of both for any vulnerability/malware as per the SOP laid down and for all such activities digital logs are maintained and retained under the custody of CISO for at least 6 months. The log shall be readily to carry out the forensic analysis if asked by investigation agency.

4) List of whitelisted IP addresses for each firewall is maintained by CISO and each firewall is configured for allowing communication with the whitelisted IP addresses only.

5) Communication between OT equipment/systems is done through secure channel preferably of POWERTEL through fibre optic cable. Security configuration of the communication channel is also to be ensured.

6) All ICT based equipment/system deployed in infrastructure/system mandatorily CII are sourced from the list of the "Trusted Sources" as and when drawn by MoP/CEA.

7) The Responsible Entity shall ensure annual review of their Cyber Security Policy by subject matter expert and changes shall be made therein only after obtaining the due approval from Board of Directors.

8) The Responsible Entity shall have an Information Security Division (ISD), headed by CISO. The Responsible Entity shall ensure that the ISD must be functional on 24x7x365 basis and is manned by sufficient numbers of Engineers having valid certificate of successful completion of course on cyber security of Power Sector from the Training Institutes designated by CEA.

9) The Responsible Entity shall ensure that ISD

   a) Has on-boarded Cyber Swachhta Kendra(CSK) of CERT-In, if they have public IPs.
   b) Has timely acted upon the advisories, guidelines and directive of NCIIPC, CSK, CERT-In and Sectoral CERTs
   c) Has deployed an Intrusion Detection System and Intrusion Prevention System capable of identifying behavioural anomaly in both IT as well as OT Systems.
   d) Shares reports on incident response and targeted malware samples with CERT-In.
   e) Updates the firmware/software with the digitally signed OEM validated patches only.
   f) Enables only those ports and services that are required for normal operations. In case of any emergency the procedure as laid in access management be followed.
   g) Maintains firewall logs for the last 6 months duration. Firewall logs shall be analysed and all critical and high severity comments shall be addressed for effective closure.

10) The Responsible Entity shall routinely audit and test security properties of the Critical System and must act upon, in case if any new vulnerabilities is identified through testing or by the equipment manufacturer.

11) The CISO of the Responsible Entity shall report in the formats prescribed by CERT-In, all Cyber Security Incidents, classified as reportable events.

12) Root cause analysis for all reportable events shall be carried out and corrective action taken, so as to ensure that any re-occurrence of such event can be managed with ease.

13) The Responsible Entity shall incorporate procedure for identifying and reporting of sabotage in their Cyber Security Policy within 30 days from issue of the Guidelines, or grant of licence under the appropriate legal provisions to the Responsible Entity.

14) The CISO shall be held liable for non-reporting of identified sabotage(s) as per procedure laid for identifying and reporting of sabotage in the Cyber Security Policy of the Responsible Entity.

15) The Responsible Entity shall through a CERT-In Empanelled Cyber Security OT Auditor get their IT System audited at least once every 6 (six) months, OT System at least once every 12 (twelve) months and shall close all critical and high vulnerabilities

within a period of one month and medium as well as low non- conformity before the next audit. Effective closure of all non-conformities shall be verified during the next audit.

21.9 CYBER SECURITY CO-ORDINATION FORUM

In compliance to regulation 53(2) of the IEGC, NLDC has prepared a procedure for Cyber Security Coordination Forum to deliberate and coordinate the cyber security Challenges and gap analysis under grid operation which is available at following location.

https://posoco.in/nldc-procedures/

At the regional level, Regional Cyber Security Coordination Forum has been formed to carry out the same works at Regional level with the coordination with the state.

21.10 SUMMARY

Grid Operator need to access real time data without any interruption to ensure the safe and secure grid operation. Any data/software/hardware crisis will result in huge regional as well as national asset loss. So, in this era of cyber physical systems, cyber security of critical infrastructure plays a major role. Adhering to cyber security policies and procedures shall help to keep the systems safe and secure.

22. LIST OF ANNEXURES

ANNEXURE NO	CONTENT
1	LIST OF UFRs in ASSAM SYSTEM AS ON MARCH 2025
2	SPECIAL PROTECTION SCHEME (SPS) IN AEGCL SYSTEM
3	DOCUMENTS RELATED TO NOAR REGISTRY