

UNIFORM PROTECTION PROTOCOL

(Approved in 15th meeting of National Power Committee held on 14.11.2024)

NATIONAL POWER COMMITTEE CENTRAL ELECTRICITY AUTHORITY

Prepared in Compliance to

Clause 12(2) and Clause 13 of Central Electricity Regulatory
Commission Indian Electricity Grid Code Regulations, 2023

July 2024

Chapters

- 1. Background**
- 2. Applicability**
- 3. Definitions**
- 4. General Philosophy of Protection System**
- 5. Protection Schemes**
- 6. Protection Settings & Coordination**
- 7. Disturbance Monitoring, Analysis and Reporting**
- 8. Protection Audit Plan**
- 9. Performance Monitoring of the Protection Systems**
- 10.Compliance Monitoring**

UNIFORM PROTECTION PROTOCOL

1. Background

National Power Committee in its 14th meeting held at Bangalore under the chairmanship of Chairperson, CEA has decided that the protection subgroup of NPC may finalise a Uniform Protection Protocol and Uniform Protection Setting Procedure for all regions in consultation with RLDCs/GRID-India.

1.1. The Uniform Protection Protocol has been prepared in accordance with Clauses 12(2) & 13 of the Indian Electricity Grid Code, 2023 (IEGC 2023) notified by the Central Electricity Regulatory Commission.

1.1.1. The clause 12(2) of the IEGC 2023:

“There shall be a uniform protection protocol for the users of the grid:

- a) for proper co-ordination of protection system in order to protect the equipment/system from abnormal operating conditions, isolate the faulty equipment and avoid unintended operation of protection system;*
- b) to have a repository of protection system, settings and events at regional level;*
- c) specifying timelines for submission of data;*
- d) to ensure healthiness of recording equipment including triggering criteria and time synchronization; and*
- e) to provide for periodic audit of protection system.”*

1.1.2. The clause 13 of the IEGC 2023:

“13. Protection protocol

- (1) All users connected to the integrated grid shall provide and maintain effective protection system having reliability, selectivity, speed and sensitivity to isolate faulty section and protect element(s) as per the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity, the CEA (Grid Standards) Regulations, 2010, the CEA Technical Standards for Communication and any other applicable CEA Standards specified from time to time.*
- (2) Back-up protection system shall be provided to protect an element in the event of failure of the primary protection system.*
- (3) RPC shall develop the protection protocol and revise the same, after review from time to time, in consultation with the stakeholders in the concerned region, and in doing so shall be guided by the principle that minimum electrical protection functions for equipment connected with the grid shall be provided as per the CEA Technical Standards for Construction, the CEA Technical*

Standards for Connectivity, the CEA Technical Standards for Communication, the CEA (Grid Standards) Regulations, 2010, the CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, and any other CEA standards specified from time to time.

- (4) The protection protocol in a particular system may vary depending upon operational experience. Changes in protection protocol, as and when required, shall be carried out after deliberation and approval of the concerned RPC.*
- (5) Violation of the protection protocol of the region shall be brought to the notice of concerned RPC by the concerned RLDC or SLDC, as the case may be."*

1.2. The Uniform Protection Protocol stipulates General Protection Philosophy of Protection System, Protection Schemes for Generators & various Transmission Elements in Power System, Protection Settings & their Coordination among entities, Disturbance Monitoring, Analysis and Reporting, Time Synchronization of Protection Systems, Protection Audit Plan, Performance of Protection Systems & Compliance Monitoring.

2. Applicability

The Uniform Protection Protocol shall be applicable to all Regional entities, State/Central/Private Generating Companies/ Generating Stations, SLDCs, RLDCs, CTU, STUs, Transmission Licensees and RPCs, connected at 220 kV (132 kV for NER) and above.

3. Definitions

Words and expressions used in this Uniform Protection Protocol are defined in the Act or any other regulations specified by the Central Commission or Central Electricity Authority shall, unless the context otherwise requires, have the meanings assigned to them under the Act or other regulations specified by the Central Commission, as the case may be.

4. General Philosophy of Protection System

4.1. Protection philosophy shall be in accordance with below mentioned objectives, design criteria and other details. However, protection design in a particular system may vary depending upon judgment and operational experience in the broad contours of the protection philosophy. Consideration must also be given to the type of equipment to be protected as well as the importance of this equipment to the system. Further, protection must not be defeated by the failure of a single component.

4.1.1. Objectives:

The basic objectives of any protection schemes should be to:

- (i) Protect equipments from abnormal operating conditions.
- (ii) Automatically isolate the faulty element.
- (iii) Avoid unintended or misoperation of protection system.

- (iv) Mitigate the effect of short circuit and other abnormal conditions in minimum possible time and area.
- (v) Indicate the location and type of fault and
- (vi) Provide effective tools to analyze the fault and decide remedial measures.

4.1.2. Design Criteria:

To accomplish the above objectives, the four design criteria for protection that should be considered are:

- (i) fault clearance time/speed;
- (ii) selectivity;
- (iii) sensitivity and
- (iv) reliability (dependability and security)

4.1.2.1. **Fault clearance time/speed:** It is defined as the time required to interrupt all sources supplying a faulted piece of equipment. In order to minimize the effect on customers and maintain system stability, Fault clearance time shall be as per CEA Grid Standard Regulations 2010, as amended to date.

4.1.2.2. **Selectivity:** Selectivity is the ability of the protective relaying to trip the minimum circuits or equipment to isolate the fault .To ensure Selectivity, coordination shall be ensured with the adjacent protection schemes including breaker failure, transformer downstream relays, generator protection and station auxiliary protection.

4.1.2.3. **Sensitivity:** Sensitivity demands that the relays be capable of sensing minimum fault conditions without imposing limitations on circuit or equipment capabilities. To ensure Sensitivity, the settings must be investigated to determine that they will perform correctly for the minimum fault current envisaged in the system, yet remain stable during transients and power swings from which the system can recover.

4.1.2.4. **Reliability:** Reliability is a measure of protective relaying systems certainly to trip when required (dependability) and not to trip falsely (Security). To ensure Reliability, two independent auxiliary direct current supplies shall be provided for Main-I and Main-II relays. The Main-I and Main-II relays should be from two different makes or operating with different algorithm. The CB's shall have two independent trip coils and two independent trip circuits. Each protection device should trip at least one of them by independent auxiliary DC- supplies.

4.1.2.5. **Security:** To ensure Security, the protection shouldn't limit the maximum transmission capacity of the element. Distance protection in particular could cause spurious tripping due to specific grid conditions, in case of high load operation. Therefore, any special topologies must be known and considered for protection parameterization. For parallel Over Head Lines it is necessary to consider the rapid increase of load current in the healthy line when the faulty line trips and the protection operation must allow such conditions The

load encroachment detection function of the relays must be used, when the highest distance zone resistance reach conflicts with the maximum transmitted load on the protected element.

- 4.2. All generating units shall have standard protection system to protect the units not only from faults within the units and within the Station but also from faults in sub-stations and transmission lines.
- 4.3. The generator, generator transformer, unit auxiliary transformer shall be provided with protection systems connected to two independent channels or groups, such that one channel or group shall always be available for any type of fault in the generator and these transformers;
- 4.4. Protection relays shall be configured in such a way that analog, digital and milli ampere input points shall not pick up due to stray voltages. All protection relays should enough spare input and output contacts for taking care of future expansions.
- 4.5. Protective relays shall be used to detect electrical faults, to activate the alarms and disconnect or shut down the faulted apparatus to provide for safety of personnel, equipment and system within shortest possible time.
- 4.6. Electrical faults shall be detected by the protective relays arranged in overlapping zones of protection.
- 4.7. The protection relays for the generators, motors, transformers and the transmission lines shall generally be of numerical type.
- 4.8. All relays used shall be suitable for operation with CTs secondary rated for one ampere or five amperes as per relevant Indian Standards or International Electrotechnical Commission or Institute of Electrical and Electronics Engineers standards.
- 4.9. Relevant Indian Standards or International Electrotechnical Commission or Institute of Electrical and Electronics Engineers standards shall be applied for protection of generators, transformers and motors.

5. Protection Schemes

The electrical protection functions for equipment connected with the grid shall be provided as per the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date, the CEA (Technical Standards for connectivity to the Grid) Regulations 2007 amended to date, the CEA (Technical Standards for Communication System in Power System Operation) Regulations 2020 amended to date, the CEA (Grid Standards) Regulations 2010 amended to date, the CEA (Measures relating to Safety and Electric Supply) Regulations 2023 amended to date, and any other CEA standards specified from time to time.

5.1. Protection Scheme for Thermal Generating Units

The electrical protection functions for generator, generator transformer, unit auxiliary transformer and station transformer of **coal or lignite based thermal generating stations, gas turbine based thermal generating stations, internal combustion (IC) engine based**

thermal generating stations shall be provided in accordance with but not limited to the list given in **SCHEDULE-I** of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date.

5.2. Protection Scheme for Hydro Generating Units

- 5.2.1. For the generating units with a rating of more than one hundred megawatt (100 MW), protection system shall be configured into two independent sets of protection (Group A and B) acting on two independent sets of trip coil fed from independent DC supplies, using separate sets of instrument transformers, and segregated cables of current transformers and voltage transformers.
- 5.2.2. The protection functions for Generator, Excitation Transformer, Generator, Transformer, Unit Auxiliary Transformer, and Station Auxiliary Transformer shall be provided in accordance with but not limited to the list given in SCHEDULE-IV of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date except for variable speed units which will have specialized protection functions.

5.3. Protection Scheme for REGs/RHGS/BESS

Protection Schemes for Renewable Energy (RE) Power Plants of Solar power generation, Wind power generation, Battery Energy Storage System (BESS) and Hybrid of these connected with grid at voltage level above 650 volts shall be in accordance with the Central Electricity Authority (Technical Standards for Construction of Renewable Energy Power Plants) Regulations, 2024 from the date as & when these regulations are notified).). As per Central Electricity Authority (technical Standards for Connectivity of the Distributed Generation Resources) amendment Regulations, 2019 regulation 11A-**Standards for charging station, prosumer, or a person connected or seeking connectivity to the electricity system;-**

- (1) The applicant shall provide a reliable protection system to detect various faults and abnormal conditions and provide an appropriate means to isolate the faulty equipment or system automatically.
- (2) The applicant shall ensure that fault of his equipment or system does not affect the grid adversely.
- (3) The protective relays deployed for inverter protections in RE plants shall possess protections from AC/DC over current, over and under frequency and shall comply features like LVRT/HVRT (**as per CEA Technical Standards for Connectivity**).
- (4) The protective relays deployed in RE plants shall be immune from conditions like phase jumps and sharp change in frequency during fault scenarios.
- (5) The inverters and BESS in RE plants shall responds to abnormal conditions arises due to system faults within its operating margin in holistic manner.
- (6) Protection settings of inverters/WTG shall be coordinated in such a way that it accounts for the voltage rise/drop between inverter/WTG terminal & Point of interconnection (POI). Overvoltage /under voltage trip settings should be configured accordingly.

- (7) The protection settings of elements in collector system viz. transformers, cables etc. shall such that it allows RE plants to ensure the compliance of CEA standards at POI.
- (8) Sub-cycle transients or measurement inaccuracy shall be factored while configuring the protection settings.

5.4. Substations & Transmission Line

5.4.1. All major protection relays for the Voltage levels 66 kV and above shall be of numerical type and communication protocol shall be as per IEC-61850.

5.4.2. Grouping of Protection systems for the voltage level 66 kV and above:

- i. The protection circuits and relays shall be electrically and physically segregated into two groups each being independent and capable of providing uninterrupted protection even in the event of one of the protection group fails or taken out for maintenance.
- ii. Interconnection between these two groups shall not generally be attempted. However, such interconnection shall be kept to the bare minimum, if found absolutely necessary.

5.4.3. The protections required in respect of transmission lines, transformers, reactors and bus bar protection and local breaker backup protection (breaker failure protection) but not limited to shall be in accordance with **SCHEDULE-V** of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date.

5.5. HVDC Terminals/ Stations

5.5.1. Classical HVDC Terminals/ Stations

- i) HVDC system protection shall consist of two parts:

(A) AC side protection:

AC side protection function shall cover the zone for converter transformer, AC filters, shunt capacitors, shunt reactors, and bus bars. These protections shall generally follow the same philosophy as in a typical substation i.e. detection of fault by relay and tripping of circuit breaker.

(B) DC side protection:

DC side protection shall cover the zones consisting of the valve hall, DC switchyard including smoothing reactor and DC filters, DC line, DMR line / electrode line and ground electrode. The protection equipment shall be designed to be fail safe and shall ensure high security to avoid maloperation/ unwanted shutdown due to protection equipment failures. ii) Following a DC Line fault, the HVDC System shall have the facility to restart, one or more times, the faulted pole at a variable pre-selected DC voltage level(s), not below 80% of the nominal voltage rating. The DC transmission system shall be capable of recovery in a controlled and stable

manner without commutation failures during recovery following ac and dc system faults. The post fault power order shall be equal to the pre-fault power order unless AC/ DC systems dictate otherwise.

- ii) Protection system required in respect of Classical HVDC Terminals/ Stations but not limited to shall be in accordance with 13 (b) of Part A of SCHEDULE-VI of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date.
- iii) HVDC Stations shall have ensure the open line test (OLT) before charging of lines after DC faults.
- iv) All HVDC stations should prioritize the protections with back up for DC line faults, Differential protections for DC yard equipment including converter valves, Filter protections, External block protections for problems like smoke detections, valve cooling etc. AC side protections and protection block for various controller maloperation issues.

5.5.2. Voltage Source Converter (VSC) based HVDC Terminals/Stations

- i) The protection equipment shall be designed to be fail-safe and shall ensure high security to avoid mal-operation/ unwanted shutdown due to protection equipment failures.
- ii) Protection system required in respect of Voltage Source Converter (VSC) based HVDC Terminals/ Stations but not limited to shall be in accordance with 8 (b) of Part B of **SCHEDULE-VI** of CEA (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date.

5.5.3 STATCOM: All STATCOM shall be having sensitive and fast acting protection system for coupling transformer, MSC, MSR, MV bus, VSC branches and valve hall.

- i) The utility should redundancy for the protections like capacitor unbalance, Neutral displacement, cooling and temperature dependent protections all the time.

5.6. Philosophy of Transmission Line Protection

5.6.1. Transmission circuit construction can be considered in three main categories viz.: Overhead construction, Underground cable construction and Composite (overhead plus underground) construction. The requirements of overhead line and cable protection systems vary greatly, due to the exposure of transmission circuits to a wide variety of environmental hazards and are subjected to the wide variations in the format, usage and construction methodologies of transmission circuits. The type of protection signaling (tele- protection) or data communication systems required to work with the protection systems will also influence protection scheme requirements.

5.6.2. Transmission circuit Main protection is required to provide primary protection for the line and clear all type of faults on it within shortest possible time with reliability, selectivity and sensitivity. Transmission circuit back-up protection shall cater for failure of any main protection system to clear any fault that it is expected to clear. A protection function that offers back-up for most faults may also provide main protection for some fault conditions. Combinations of main and back-up protection systems should be used to address the main and application specific requirements for transmission circuits.

5.6.3. **Design Criteria:** While designing the scheme for protection of transmission lines following criteria shall be considered:

- i) The systems applied must be capable of detecting all types of faults, including maximum expected arc resistance that may occur at any location on the protected line.
- ii) The protection should be set not to trip under system transient conditions, which are not short circuits. Conversely where the short circuit current is low due to local grid conditions (weak network) or due to high resistance of the arc, this must be taken into consideration to trip the relay by using the most appropriate criterion, without jeopardizing the unwanted tripping during heavy load conditions.
- iii) The design and settings of the transmission line protection systems must be such that, with high probability, operation will not occur for faults external to the line or under non-fault conditions.
- iv) The over current protection for the transmission lines 220 kV and above voltage levels shall generally be in disabled condition.

5.6.4. **Reliability Criteria:**

- i) **For transmission line having voltages at 220kV and above:** High speed Duplicated Main Protection (Main-I and Main-II) shall be provided. Main-I protection shall be carrier aided non-switched distance protection. Main-II protection shall be carrier aided non-switched distance protection, or phase segregated line differential protection. For very short line (less than 10 km), cable or combination of overhead line and cable, line differential protection with distance protection as backup (built-in Main relay or standalone) shall be provided mandatorily as Main-I and Main-II.

In addition to above, following shall also be provided:

- a) Auto reclose relay (Standalone or as built-in function of Main-I & Main-II relay) suitable for 1 ph or 3 ph (with deadline charging and synchro- check facility) reclosure.
- b) Inverse Definite Minimum Time (IDMT) directional E/F relay (Standalone or as built-in function of Main-I & Main-II relay).

- c) Inverse Definite Minimum Time (IDMT) Directional over current for 220 kV lines if Main-II is not provided.

Main Protection shall have following features:

- a) The Main-I and Main-II protection shall be numerical relays of different makes or employ different fault detection algorithm.
- b) Each distance relay shall protect four/five independent zones (three/four forward zones and one reverse zone). It shall be provided with carrier aided tripping through PLCC or OPGW/FOTE communication.
- c) The relays should have sufficient speed so that they will provide the clearing times as defined in the CEA Grid Standards Regulations amended time to time.
- d) The Main-I and Main-II relays shall be powered by two separate DC sources.
- e) Both, Main-I and Main-II shall send initiation signal to Breaker Failure Relay / LBB Protection system.
- f) Internal Directional Earth Fault function shall be set to trip the line in case of high resistance earth faults.
- g) The Broken Conductor detection shall be used for alarm purpose only.
- h) The internal overvoltage function shall be used to protect the line against over voltages. Two stage over voltage protection for the transmission lines (Stage-I as Voltage and Time graded & Stage-II @ 140% of Nominal Voltage with time delay 100ms) shall be implemented for the transmission lines of voltage levels 400kV and above. The OVR grading, Voltage and Time graded, for the Stage-I over voltage protection shall be as recommended by RPC/RLDC. The lines emanating from same substation shall be provided with pickup as well as time grading to avoid concurrent trippings. The overvoltage relay shall have better than 98% drop-off to pick-up ratio (the ratio of the limiting values of the characteristic quantity at which the relay resets and operates). For over voltage detection, though Ph-N voltage is preferable to Ph-to-Ph voltage, to achieve required discrimination for OVR grading on account of limitation imposed by voltage resolution of the relay, Ph-to-Ph voltage to be used for Over Voltage detection.
- ii) **For transmission lines having voltages at 132kV/110kV:** There should be at least one carrier aided non-switched four/five zone distance protection scheme. Carrier aided zone protection may be optional for the radial feeders and feeders having intermittent loads. In addition to this, another non switched/switched distance scheme or Inverse definite Minimum time(IDMT) directional over current and earth fault relays should be provided as back up. Main protection should be suitable for single or three phase tripping. Additionally, auto-reclose relay suitable for 1 ph or 3 ph (with dead line charging and synchro-check facility) reclosure shall be provided. In case of both line protections being Distance Protections, IDMT type Directional E/F relay (standalone or as built-in function of Main-I & Main-II relay) shall also be provided additionally.

5.6.5. Following types of protection scheme to be adopted to deal with faults on the lines:

- i) **Distance Protection Scheme:** The scheme shall be based on the measuring the impedance parameters of the lines with basic requirements as below:
 - a) Each distance relay shall protect four/five independent zones (three/four forward zones and one reverse zone). It shall be provided with carrier aided tripping through PLCC or OPGW/FOTE) communication.
 - b) Each Distance Relay:
 - i. Shall include power swing detection feature for selectively blocking, as required.
 - ii. Shall include suitable fuse-failure protection to monitor all types of fuse failure and block the protection.
 - iii. Shall include load encroachment prevention feature like Load blinder.
 - iv. Shall include Out of Step trip function.
 - v. Distance relay as Main protection should always be complemented by Directional ground protection to provide protection for high resistive line faults.
 - vi. Shall be capable to protect the series compensated lines from voltage inversion, Week end infeed and current inversion phenomenon. Special measures must be taken to guard against these phenomenon.
 - ii) **Line Differential Protection:** The scheme shall be based on the comparing the electrical quantities between input and output of the protected system. Provided that:
 - a) Due to the fact that short lines (less than 10kM) and/or cables do not have enough electrical length, the current differential relay should always be used.
 - b) For Cables, at least a differential line protection shall be used in order to guarantee fast fault clearing while maintaining security. The reason being that there are many sources of errors associated to other protection principles, especially for ground faults in cables.
 - c) The differential protection shall have following requirements:
 - i. Line differential as Main-I with inbuilt backup Distance Protection shall be installed for all the lines irrespective of length (subject to technical limitations).
 - ii. Zone-I protection feature shall get automatically enabled in case of communication failure observed by the differential relay.

- iii. The differential relays provided in 220 kV and above system must operate in less than 30 ms. RPC/RLDC may decide on differential protection on voltage level below 220 kV.
- iv. The current differential protection should be a reliable type (preferably digital). The protection should be of the segregate phase type, i.e. it should be able to detect the phase in fault and therefore for the case of single line-ground (SLG) faults to trip only the phase in fault (also to establish single phase A/R). The synchronization of the measured values is done via a communication system. The communication system for differential line protection should be based on fibre optic and any equipment should comply with the IEC 60834.

5.6.6. Auto Reclosing:

The single phase high speed auto-reclosure (HSAR) at 220 kV level and above (except for the composite feeders: overhead plus underground) shall be implemented, including on lines emanating from generating stations. If 3-phase auto reclosure is adopted in the application of the same on lines emanating from generating stations should be studied and decision taken on case to case basis. For 132 kV system, three phase auto-reclosure (TPAR) is optional. As per CEA construction standards for construction of electrical plants and lines regulation) 2022, 3 Phase A/R is optional for 132 KV system.

i) AR Function Requirements:

It shall have the following attributes:

- a) Have single phase or three phase reclosing facilities.
- b) Incorporate a facility of selecting single phase/three phase/single and three phase auto-reclose and non-auto reclosure modes.
- c) Have facilities for selecting check synchronizing or dead line charging features.
- d) Be of high speed single shot type
- e) Suitable relays for SC and DLC should be included in the overall auto reclose scheme if three phase reclosing is provided.
- f) Should allow sequential reclosing of breakers in one and half breaker or double breaker arrangement.

It may have the following attributes as well:

- (1) Have a continuously variable single phase dead time.
- (2) Have continuously variable three phase dead time for three phase reclosing.
- (3) Have continuously variable reclaim time.

ii) Scheme Special Requirements:

- a) Modern numerical relays (IEDs) have AR function as built-in feature. However, standalone AR relay or AR function of Bay control unit (BCU) for 220kV and above voltage lines may be used. For 132kV/110kV lines, AR functions built-in Main distance relay IED can be used.
- b) Fast simultaneous tripping of the breakers at both ends of a faulty line is essential for successful auto-reclosing. Therefore, availability of protection signaling equipment is a pre-requisite.
- c) Starting and Blocking of Auto-reclose Relays:

Some protections start auto-reclosing and others block. Protections which start A/R are Main-I and Main-II line protections. Protections which block A/R are:

- i. Breaker Fail Relay
- ii. Line Reactor Protections
- iii. O/V Protection
- iv. Received Direct Transfer trip signals
- v. Busbar Protection
- vi. Zone 2/3 of Distance Protection
- vii. Carrier Fail Conditions
- viii. Circuit Breaker Problems.
- ix. Phase to Phase Distance Trip
 - x. AR selection switch in OFF / Non-auto position
 - xi. Logic AR OFF in SAS
- xii. Phase Distance Start (when Auto reclosure is in progress)

When a reclosing relay receives start and block A/R impulse simultaneously, block signal dominates. Similarly, if it receives 'start' for 1-phase fault immediately followed by multi- phase fault the later one dominates over the previous one.
- xiii. Fault on reclaim time
- xiv. Fault on line charging
- xv. Pole discrepancy

iii) Requirement for Multi breaker Arrangement:

Following schemes shall be adhered to multi-breaker arrangements of one and half breaker or double breaker arrangement:

- a) In a multi-Circuit Breaker (C.B.) arrangement one C.B. can be taken out of operation and the line still be kept in service. After a line fault only those C.Bs which were closed before the fault shall be reclosed.
- b) In multi-C.B. arrangement it is desirable to have a priority arrangement so as to avoid closing of both the breakers in case of a permanent fault.
- c) A natural priority is that the C.B. near the busbar is reclosed first. In case of faults on two lines on both sides of a tie C.B. the tie C.B. is reclosed after the outer C.Bs. The outer C.Bs. do not need a prioritizing with respect to each other.

iv) Setting Criteria:

Auto reclosing requires a dead time which exceeds the de-ionizing time. The circuit voltage is the factor having the predominating influence on the de-ionizing time. Single phase dead time of 1.0 sec. is recommended for 765 kV, 400 kV, 220 kV and 132 kV system. As per CEA construction standards for construction of electrical plants and lines regulation) 2022, 3 Phase A/R is optional for 132 KV system. Therefore, 132kV system may be included based on RPC/RLDC input. For the lines emanating from generating stations single-phase dead time upto 1.5 sec may be adopted.

- a) According to IEC 62271-101, a breaker must be capable of withstanding the following operating cycle with full rated breaking current:

O - 0.3 s - CO - 3 min - CO

O- stands for Open

CO- stands for Close-Open

The rated operating cycle of the circuit breaker consisting of an opening, a holding time of 0.3 seconds, a CO cycle, a 3-minute wait, and another CO cycle.

The recommended operating cycle at 765 kV, 400 kV, 220 kV and 132 kV is as per the IEC standard. As per CEA construction standards for construction of electrical plants and lines regulation) 2022, 3 Phase A/R is optional for 132 KV system. Therefore, 132kV system may be included based on RPC/RLDC input. Therefore, reclaim time of 25 Sec. is recommended.

5.6.7. Power Swing Blocking and Out of Step (OOS) Function

Large interconnected systems are more susceptible to Power Swings in comparison to the erstwhile smaller standalone systems. Inter-area Power

Swings can be set up even due to some event in far flung locations in the system. During the tenure of such swings, outage of any system element may aggravate the situation and can lead to instability (loss of synchronism). It is hence extremely important that unwanted tripping of transmission elements need to be prevented, under these conditions. Distance protection relays demand special consideration under such a situation, being susceptible to undesirable misoperation during Power swings which may be recoverable or irrecoverable power swings. Following steps may be adopted to achieve above objective:

i) Block all Zones except Zone-I

This application applies a blocking signal to the higher impedance zones of distance relay and allows Zone 1 to trip if the swing enters its operating characteristic. Breaker application is also a consideration when tripping during a power swing. A subset of this application is to block the Zone 2 and higher impedance zones for a preset time (Unblock time delay) and allow a trip if the detection relays do not reset.

In this application, if the swing enters Zone 1, a trip is issued, assuming that the swing impedance entering the Zone-1 characteristic is indicative of loss of synchronism. However, a major disadvantage associated with this philosophy is that indiscriminate line tripping can take place, even for recoverable power swings and risk of damage to breaker.

ii) Block All Zones and Trip with Out of Step (OOS) Function

This application applies a blocking signal to all distance relay zones and order tripping if the power swing is unstable using the OOS function (function built in modern distance relays or as a standalone relay). This application is the recommended approach since a controlled separation of the power system can be achieved at preselected network locations. Tripping after the swing is well past the 180-degree position is the recommended option from CB operation point of view.

Normally relay is having Power Swing Un-block timer which unblocks on very slow power swing condition (when impedance locus stays within a zone for a long duration). Typically, the Power swing un-blocking time setting is 2sec.

However, on detection of a line fault, the relay has to be de-blocked.

Placement of OOS trip Systems

Out of step tripping protection (Standalone relay or built-in function of Main relay) shall be provided on all the selected lines. The locations where it is desired to split the system on out of step condition shall be decided based on system studies.

The selection of network locations for placement of OOS systems can best be obtained through transient stability studies covering many possible

operating conditions. Based on these system studies, either of the option above may be adopted after the approval of PCSC of RPC.

While applying Power Swing Blocking (PSB) in the distance protection relay a few other important aspects also need to be considered:

- PSB function should not block if negative sequence or zero sequence currents are present. Once blocked, the PSB should unblock if negative sequence or zero sequence currents are detected. Power Swing is a balanced three phase phenomenon and unbalance can only occur in the case of an asymmetrical fault.
- It will be desirable that during tenure of PSB, the distance protection is capable of detecting a fault and tripping. If such a feature is not available in the relay, PSB should be unblocked after a time delay, corresponding to the half cycle period of the slowest expected Swing Frequency (usually 2s corresponding to the slowest swing frequency of 0.25Hz is considered as default), to avoid the protection remaining perpetually blocked.

5.7. Transmission Relay Loadability

Transmission Relay Loadability means the loading permitted in the transmission line by the relay including a security margin. The relay Loadability is to be arrived in such a way as far as possible not to interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers. Transmission relay do not prematurely trip the transmission elements out-of-service and allow the system operators from taking controlled actions consciously to alleviate the overload.

5.7.1. Protective relay settings shall

- i) Not limit transmission Loadability;
- ii) Not interfere with system operators' ability to take remedial action to protect system reliability and;
- iii) Be set to reliably detect all fault conditions and protect the electrical network from the faults.

5.7.2. The protective functions which could trip with or without time delay, on load current i.e. load responsive phase protection systems including but not limited to:

- i) Phase distance.
- ii) Out-of-step tripping.
- iii) Switch-on-to-fault.
- iv) Overcurrent relays.

- v) Communications aided protection schemes including but not limited to:
 - Permissive overreach transfer trip (POTT).
 - Permissive under-reach transfer trip (PUTT).
 - Directional comparison blocking (DCB).
 - Directional comparison unblocking (DCUB).
- vi) Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

5.7.3. Each Transmission Licensee and Generating Company, shall use any one of the following criteria for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Grid for all fault conditions. Relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees shall be evaluated.

- i) For Distance protection relays of transmission lines, the Zone-3 shall prevent load encroachment, considering the following criteria:

- a) Maximum load current (I_{max}) may be considered as 1.5 times the thermal rating of the line or 1.5 times the associated bay equipment current rating (the Minimum of the bay equipment individual rating) whichever is lower.

(The rating considered is approximately 15 minutes rating of the Transmission facility).

- b) For setting angle for load blinder, a value of 30 degree may be adequate in most cases.

- c) The Distance protection relays shall have provision for load blinder characteristic or load encroachment detection. ii) For Directional Overcurrent relays, wherever used in a transmission line (132/110 kV level), the following shall be adopted:

- a) An overload alarm shall be set at 110% of the thermal rating of the line with sufficient delay. This alarm shall allow the operator to take corrective action.
- b) The Directional Overcurrent relay shall allow the line to carry 1.2 times of the thermal rating of the associated line or bay equipment (whichever is lower) at least 10 minutes.

- iii) For transformer protection relays the following shall be adopted:

- Set the definite time transformer overload relay atleast 105% of the transformer ratings with sufficient delay. It shall be wired for alarm purpose only to allow the operator to take corrective action. No tripping shall be issued from this relay.

- The back-up overcurrent relays shall use IDMT characteristics and be suitably coordinated with the upstream transmission network.
- Install supervision for the transformer using either a top oil or simulated winding hot spot temperature element. The alarm and trip settings for these relays shall be set by individual entities based on the manufacturer's recommendation.

Thermal ratings as specified in the prevailing CEA's Manual on Transmission Planning Criterion shall be used for above requirement.

6. Protection Settings & Coordination

The purpose is to ensure system protection is coordinated among the grid connected entities. The Protection systems coordination comprises the following:

- i) *Each Transmission Licensee, Load Dispatch Centre (LDC) and Generating Company shall keep themselves familiarized with the purpose and limitations of Protection System schemes applied in its area of control.*
- ii) *Each Transmission licensee shall coordinate its Protection System schemes with concerned transmission system, sub-transmission system and generators.*
- iii) *Each Generating Company shall coordinate its Protection System schemes with concerned transmission system and station auxiliaries.*
- iv) *Each Transmission Licensee and Generation Company shall be responsible for settings calculations for protection of elements under its ownership. It shall be the responsibility of the respective asset owner to obtain the inputs (adjacent line settings, infeed values etc.) from STU/Generating Company/ Transmission Licensee necessary for calculation of the settings.*
- v) *STU/Generating Company/Transmission Licensee shall provide the infeed values/latest network model to the requesting entity, within 15 days of receipt of such a request from the entity.*
- vi) *Each Generating Company and Transmission Licensee, for voltage levels 400kV and above and interstate lines, shall submit the protection settings as per the format prescribed, along with the calculation sheets, co-ordination study reports and input data, in advance, to RPC/RLDC for every new element to be commissioned. The mentioned information shall be submitted to the RPC/RLDC two months in advance for all the elements proposed to be commissioned. RPC shall furnish the approved settings within forty days from the date of submission of the settings by the entity.*
- vii) *If required Protection Setting Sub Group (PSSG) may be constituted under PCSC in the RPCs with the expert members from all States & UTs, Major Transmission Licensee in the Region, Major Generating Company in the Region, Grid-India/RLDC & RPC Secretariat for analysing/reviewing the proposed protection settings of the new elements as well as changes in the existing protection settings, as arrived by the*

proposer as per the Chapter 6 of Uniform Protection Protocol. The PSSG recommended protection settings shall be ratified by PCSC of respective RPC.

Or

Any procedure that is finalized and approved by the Protection Sub-Committee of respective RPC.

- viii) The PCSC shall review the settings to ensure that they are properly coordinated with adjacent system and comply with the existing guidelines. The onus to prove the correctness of the calculated settings shall lie with the respective Transmission licensee/Generation Company. In case, the PCSC feels that the adjacent transmission system settings need to be changed, in view of the new element, it shall inform the concerned entity for revision of the existing settings.*
- ix) The PCSC of RPC shall review and approve the settings based on the inputs /report submitted by the entities.*
- x) The approved settings shall be implemented by the entity and proper record of the implemented settings shall be kept. The modern numerical relays have several settings for various features available in the relay. It shall be ensured that only the approved features and settings are enabled in the relay. No additional protection/setting shall be enabled without the prior approval of RPC.*
- xi) Each Transmission licensee and Generating Company shall co-ordinate the protection of its station auxiliaries to ensure that the auxiliaries are not interrupted during transient voltage decay.*
- xii) Any change in the existing protection settings, for voltage levels 400kV and above & interstate lines, shall be carried out only after prior approval from the RPC. The owner entity shall inform all the adjacent entities about the change being carried out.*
- xiii) In case of failure of a protective relay or equipment failure, the Generating Company and Transmission Licensee shall inform appropriate LDC/RLDC/RPC. The Generating Company and Transmission Licensee shall take corrective action as soon as possible.*
- xiv) Each Transmission Licensee shall coordinate Protection Systems on major transmission lines and interconnections with neighbouring Generating Company, Transmission Licensee and appropriate LDC.*
- xv) RPC in consultation with the RLDC & Regional entities shall undertake review of the protection settings, assess the requirement of revisions in protection settings and revise protection settings, from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the RPC & RLDC. The modifications/changes, if any, in protection settings shall be advised to the respective users and STUs.*

- xvi) *RPC shall maintain a centralized database and update the same on periodic basis in respect of their respective region containing details of relay settings for grid elements connected to 220 kV and above. RLDC also shall maintain such database. Respective Transmission licensee/Generating Company/Entities are responsible for ensuring to make available the implemented protection settings in the centralized database within fifteen days from the date of commissioning.*
- xvii) *If System Protection Schemes (SPS) is recommended to be implemented by the appropriate forum/Sub-Committee of RPC on account of operational & system constraints, the same shall be implemented by the concerned Transmission licensee/Generating Company/Entities within the specified timelines.*
- xviii) *IBR settings like phase jump, df/dt settings, over currents settings, over/under frequency, over/under voltage, LVRT/HVRT etc. for Solar, Wind & Battery Energy Storage System (BESS) etc. to be reviewed in protection subcommittee meetings.*

Note: - It was agreed in the meeting held on 28.06.2024 with members of protection Sub group of NPC that there is no need for preparation of separate uniform protection setting procedure. RPCs may develop an internal mechanism to ensure effective coordination among all grid-connected entities to achieve the required procedure. However, RPCs may refer the above Chapter 6 for the purpose of development of such internal mechanisms to review of the protection settings in consultation with the stakeholders of the respective region.

7. Disturbance Monitoring, Analysis and Reporting

The Purpose is to ensure that adequate disturbance data is available to facilitate Grid event analysis. The analysis of power system disturbances is an important function that monitors the performance of protection system, which can provide information related to correct behavior of the system, adoption of safe operating limits, isolation of incipient faults.

7.1. The Disturbance Monitoring Requirements include the following:

- i) Each Transmission Licensee and Generating Company shall provide Sequence of Event (SOE) recording capability by installing Sequence of Event recorders or as part of another device, such as a Supervisory Control and Data Acquisition (SCADA) Remote Terminal Unit (RTU), Phasor Measurement Unit (PMU), a generator plants Digital (or Distributed) Control System (DCS) or part of Fault recording equipment.

This capability shall be provided at all substations and at locations to record all the events in accordance with CEA Grid Standard Regulations, 2010 amended to date. The following shall also be monitored at each location:

- a) Transmission and Generator circuit breaker positions
- b) Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in (a) above.

- c) Tele protection keying and receive
- ii) In either case, a separate work station PC shall be identified to function as the event logger front end. The event logger work-station PC should be connected to UPS (Uninterrupted Power Supply).

The event logger signals shall include but not limited to

- All Circuit Breaker and isolator switching Operations
 - Auxiliary supply (AC, DC and DG) supervision alarms
 - Auxiliary supply switching signals
 - Fire-fighting system operation alarms
 - Operation signals (Alarm/Trip from all the protection relays.)
 - Communication Channel Supervision Signals.
 - Intertrip signals receipt and send.
 - Global Positioning System (GPS) Clock healthiness.
 - Control Switching Device healthiness (if applicable).
 - RTU/Gateway PC healthiness
 - PMU Healthiness
 - All Circuit Breaker Supervision Signals.
 - Trip Circuit Supervision Signals.
- iii) Each Transmission Licensee/Generating Company/Users shall provide Disturbance recording capability for the following Elements at facilities:
- All transmission lines (Each line shall be provided with facility for distance to fault locator)
 - Autotransformers or phase-shifters connected to busses.
 - Shunt capacitors, shunt reactors.
 - Individual generator line interconnections.
 - Dynamic VAR Devices.
 - HVDC terminals.
 - Bus Bars
 - Inverter and PPC
 - Generators
 - Statcom
- iv) The Disturbance recording feature shall be enabled and configured in all the numerical relays installed. Disturbance recording system shall have minimum

recording time of 3 seconds (0.5 seconds for pre-fault and 2.5 seconds for post fault).

- v) Each Generating Company shall provide Disturbance recording capability for Generating Plants in accordance with Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations 2022 amended to date, the CEA (Technical Standards for connectivity to the Grid) Regulations 2007 amended to date.
- vi) Each Transmission Licensee and Generating Company shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following:
 - Three phase-to-neutral voltages. (Common bus-side/line side voltages may be used for lines.)
 - Three phase currents and neutral currents.
 - Polarizing currents and voltages, if used (As applicable).
 - Frequency (As applicable).
 - Real and reactive power (As applicable).
 - V sync(Synchronizing voltage) (For TPAR)
 - Mutual compensation current(In case of parallel line)

The Minimum parameters to be monitored in the Fault record shall be specified by the PCSC of RPCs.

- vii) Each Transmission Licensee and Generating Company shall provide Disturbance recording with the following capabilities:
 - The Disturbance recorders shall have time synchronization and a standard format for recording analogue and digital signals (DR labels to be standardized as per the Report of FOLD Working Group - 3 on DR Parameter Standardization). The data files shall be capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool as per the latest revision of IEEE Standard C37.111.
 - Each Fault record duration and the trigger timing shall be settable and set for a minimum 3 second duration including 0.5 seconds for pre-fault and 2.5 seconds for post fault
 - Each Fault recorder shall have sampling frequency of 1 kHz or better.
 - Each Fault recorder shall be set to trigger for at least the following:
Internal protection trip signals, external trigger input and additional triggers may be assigned as necessary.

- viii) Each Transmission Licensee and Generating Company shall keep the recording instruments (disturbance recorder and event logger) in proper working condition

and shall establish a maintenance and testing program for Disturbance Recorder (DR) that includes

- Maintenance and testing intervals and their basis.
 - Summary of maintenance and testing procedures.
 - Monthly verification of communication channels used for accessing records remotely (if the entity relies on remote access and the channel is not monitored to a control centre staffed around the clock, 24 hours a day, 7 days a week (24/7)).
 - Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control centre).
 - Monthly verification of active analog quantities.
 - A requirement to return failed units to service within 90 days. If a Disturbance Recorder (DR) will be out of service for greater than 90 days, the Transmission Licensee and Generating Company shall keep a record of efforts aimed at restoring the DR to service.
- ix) The time synchronization of the disturbance recorders shall be corroborated with the PMU data or SCADA event loggers by RLDCs. RLDCs shall list out for Disturbance recorders which are non-compliant for discussion in PCSC meetings of RPCs.
- x) Each Transmission Licensee and Generating Company shall submit the data files to the RLDCs conforming to the following format requirements:
- The data files shall be submitted in COMTRADE and PDF format.
 - File shall have contained the name of the Relay, name of the Bay, station name, date, time resolved to milliseconds, event point name, status.

The DR archives shall be retained for a period of three years.

- xi) A separate work-station PC, powered through UPS (Uninterrupted Power Supply) shall be identified with access to all the relays for extraction of DR. Auto Download facility shall be established for automatic extraction of the DR files to a location on the work-station PC.
- xii) **Time Synchronization Equipment**
- a) Time Synchronizing Equipment complete with antenna, all cables and processing equipment shall be provided to receive synchronizing pulse through Global Positioning System or Indian Regional Navigation Satellite System Navic compatible for synchronization of event logger, disturbance recorder, Phasor Measurement Units, and Supervisory Control and Data Acquisition System or Substation Automation System.
 - b) Each substation shall have time synch equipment to synchronize all the numerical relays installed. Before any extension work, the capability of the

existing Time-sync equipment shall be reviewed to ensure the synchronization of upcoming numerical relays.

- c) The status of healthiness of the time-sync device shall be wired as “Alarm” to SCADA and as an “Event” to Event Logger.
- d) The time synch status of all the installed numerical relays and event logger shall be monitored monthly and recorded. The Monthly records for relays not in time-sync shall be reported to RLDCs and RPCs. This record shall be archived for a period of three years by each concerned agency.
- e) Remedial action shall be taken by the concerned substation/ Protection department immediately to make the relays in time synchronization with reference to external time source.
- f) All the new Grid elements/Bay extension shall have accurate and precise Time synchronization equipment.

7.2. Disturbance Analysis and Reporting

The Disturbance Analysis and Reporting shall be carried out in line with Central Electricity Authority (Grid Standards) Regulations, 2010, IEGC Grid Code Regulations 2023 and as per the revised SOP to address the Grid Disturbances (GDs)/Grid Incidents (GIs)/any other Protection Tripping’s approved in the Protection sub group of NPC which is being adopted in all region. (at **Annexure-I**)

8. Protection Audit Plan

The Protection Audit of the substations connected with ISTS system shall be carried out in line with the Central Electricity Authority (Grid Standards) Regulations, 2010, IEGC Grid Code Regulations 2023 and as per the approved SOP for Protection System Audit of the sub group of RPCs/NPC which is being adopted in all region. (at **Annexure-II**)

9. System Protection Schemes (SPS)

If System Protection Schemes (SPS) is recommended to be implemented by the appropriate forum/Sub-Committee of RPCs on account of operational & system constraints, the same shall be implemented by the concerned Transmission licensee/Generating Company/Entities within the specified timelines. The provisions related to SPS as mentioned in CEA regulations and CERC (IEGC) 2023 regulations and their amendments from time to time shall be followed.

10. Performance Monitoring of the Protection Systems

- 10.1. Users/Entities shall submit the following protection performance indices of previous month to RPCs and RLDCs on monthly basis for 220 kV (132 kV in case of NER) and above by 15th of the subsequent month and the same shall be reviewed in the ensuing PCSC meeting of RPCs.

- a) The Dependability Index defined as

$$D = \frac{N_C}{(N_C + N_F)}$$

Where, N_C is the number of correct operations at internal power system faults and N_F is the number of failures to operate at internal power system faults.

b) The Security Index defined as

$$S = \frac{N_C}{(N_C + N_U)}$$

Where, N_C is the number of correct operations at internal power system faults and N_U is the number of unwanted operations.

c) The Reliability Index defined as

$$R = \frac{N_C}{(N_C + N_I)}$$

Where, N_C is the number of correct operations at internal power system faults and N_I is the number of incorrect operations and is the sum of N_F and N_U

10.2. Users/Entities shall furnish the reasons for performance indices less than unity of individual element wise protection system to the RPC and action plan for corrective measures. The action plan will be followed up regularly in the PCSC Meetings.

11. Compliance Monitoring

11.1. The Uniform Protection Protocol shall be reviewed as and when required, in consultation with the stakeholders by Protection Sub Group of NPC after discussion in respective RPC.

11.2. Violation of the Uniform Protection Protocol shall be brought to the notice of RPCs by the RLDCs or concerned SLDC, as the case may be.

11.3. In case any User/Entity fails to comply with the Uniform Protection Protocol or fails to undertake remedial action identified by the PCSC of RPCs within the specified timelines, the RPCs would approach the Commission with all relevant details for suitable directions.

2.

Revised Final Standard Operating Procedure (SOP) to address the Grid Disturbances (GDs)/Grid Incidents (GIs)/any other Protection Trippings

1. Immediately following an event (grid disturbance/incidence as defined in the CEA (Grid Standards) Regulations 2010 and subsequent amendment in the system, the concerned user/entity or SLDC shall inform to the RLDC through voice message.
2. Written flash report shall be submitted to RLDC and SLDC by the concerned user/entity within the time line specified in **Table 8** below, as per the IEGC, 2023.
3. In compliance of IEGC, 2023, All the Users, STU/SLDC are required to furnish the following information in respect of Grid Occurrences(GD/GI) within the time line specified in **Table 8** below, to RLDC/ RPC:
 - (i) First Information Report (FIR)
 - (ii) Event Logger (EL) output
 - (iii)Disturbance Recorder (DR) output
 - (iv) Trip event analysis report-TR (with pre and post fault system conditions)
 - (v) Data Acquisition System (DAS)
4. RLDC shall report the event (grid disturbance or grid incidence) to CEA, RPC and all regional entities within twenty-four (24) hours of receipt of the flash report.
5. After a complete analysis of the event, the user/entity shall submit a detailed report in the case of grid disturbance or grid incidence within one (1) week of the occurrence of event to RLDC and RPC.
6. Based on the above detailed report submitted to RLDC by the entities, RLDC shall Categorize Grid Occurrences into grid incidents (GIs) and grid disturbance (GDs) based on criteria as per the CEA (Grid Standards) Regulations 2010 and subsequent amendment. RLDC shall also submit the Auto Reclosure (A/R) failure events, PLCC related events, any other protection related events to RPCs on monthly basis.
7. RLDCs and NLDC (for events involving more than one region) shall prepare a draft report of each grid disturbance or grid incidence including simulation results and analysis along with associated PMU plots of appropriate resolution, which shall be discussed and finalized at the Protection sub-committee/sub-group of RPC as per the timeline specified in **Table-8** below.

TABLE 8 : REPORT SUBMISSION TIMELINE

Sr. No.	Grid Event [^] (Classification)	Flash report submission deadline (users/ SLDC)	Disturbance record and station event log submission deadline (users/ SLDC)	Detailed report and data submission deadline (users/ SLDC)	Draft report submission deadline (RLDC/ NLDC)	Discussion in protection committee meeting and final report submission deadline (RPC)
1	GI-1/GI-2	8 hours	24 hours	+7 days	+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.

(The above table is as per the IEGC 2023)

8. RPCs shall circulate all the GDs, GIs, near miss events, A/R events, PLCC mal-operation events, any other protection related event etc. along with the Agenda for Protection Co-Ordination Sub-Committee (PCSC) of RPCs. PCSC meetings are to be held in every month.
9. The implementation of the recommendations of the final report shall be monitored by the protection sub-committee of the RPC. Tripping portals deployed for reporting of the GDs & GIs on RLDCs portal, shall also have compliances reporting of PCSC recommendations on this portal. NLDC shall disseminate the lessons learnt from each event to all the RPCs for necessary action in the respective regions.
10. Constituents/entities shall furnish the following details to RPCs/RLDCs in respect of all the grid occurrences for analysis:
 - a) Detailed analysis of the events
 - b) SLD or equivalent pictorial representation clearly showing:
 - i. Location of fault with distance
 - ii. Fault details with type & relay indications
 - iii. CT/PT/CVT rating details with location
 - iv. Bus-bar arrangement/ Configuration of feeders and other information related to the ratings of the information required for analysis of the disturbance.
 - v. CB positions (OPEN/ CLOSE) before and after fault
 - vi. Isolator & Earth-switch positions (OPEN/CLOSE)
 - vii. Voltage, frequency & power flows with direction at the time of fault
 - c) Output of Event logger & Disturbance recorder
 - d) Remedial Action(s) taken
 - e) Relay setting details

HVDC Station Disturbance : Any additional data such as HVDC transient fault

record, switchyard equipment and any other relevant station data required for carrying out analysis of an event by RPC, NLDC, RLDC and SLDC shall be furnished by the users including RLDC and SLDC, as the case may be, within forty- eight (48) hours of the request. All users shall also furnish high-resolution analog data from various instruments including power electronic devices like HVDC, FACTS, renewable generation (inverter level or WTG level) on the request of RPCs, NLDC, RLDCs or SLDCs.

Generating Station Disturbance: Generating Station shall furnish high-resolution analog data from various instruments including AVR response, PSS response required for analysis of disturbance.

11. The respective entities (for which the Grid occurrence is placed in the PCSC agenda) shall present the Grid Occurrence which shall cover all related aspects such as:
 - a) Antecedent conditions,
 - b) Bus-configuration,
 - c) Reasons of GD/ GI occurrence,
 - d) Relevant Diagrams showing location of the fault,
 - e) Bus bar arrangement/configuration of feeders and other connected equipment with proper CB positions (OPEN/ CLOSE) at the time of occurrence of the fault,
 - f) Type of protections operated,
 - g) Substantiation of the protections operated by relevant DRs & ELs,
 - h) Reasons for protection systems mal-operation/non-operation,
 - i) Remedial measures taken/ proposed, etc.
12. In respect of failure or Non-operation of A/R events, PLCC mal-operation events, any other protection related event as given in the PCSC agenda the concerned entities, shall furnish the reasons along with remedial action taken to RPCs/RLDCs. The same would be analyzed by the PCSC.
13. In the PCSC meetings, all the GDs, GIs, near miss events, A/R non-operation/mal-operation, PLCC mal-operations, other protection related trippings/events as circulated in the agenda shall be analyzed in detail by the PCSC forum and conclude the suitable recommendations to avoid the recurrence of such incidents in the future.
14. The action plan by the entities shall be furnished to RPC for implementation of the PCSC recommendations along with the timelines.
15. The implementation of the PCSC recommendations shall be followed up in the monthly PCSC meetings of RPC.
16. When grid disturbances or grid incidents occurred at major/critical substations and at substations that affected critical/essential/strategic loads, a Protection System Analysis Group (PSAG) shall be constituted consisting of the members from RPC, NLDC, RLDC, PGCIL, a Protection Expert from the region along with the Entity under whose jurisdiction GD/GI occurred to analyze the GD/GI in detail by visiting the respective substation/substations physically and conducting the meetings. PSAG would finalize the remedial actions and recommendations after deliberations and detailed analysis. The progress of implementation of the PSAG shall be followed up in the monthly PCSC Meetings.
17. If grid disturbance or grid incident is due to operational issue or transmission constraint/inadequacy, Grid-India shall share feedback to CTU or respective STU.

18. In case any user/entity fails to undertake remedial action identified by the RPC within the specified timelines as decided by PCSC of RPC, the concerned RPC may approach the Commission with all relevant details for suitable directions.
19. A date depository of the event as maintained by the RLDC shall be accessible to every entity and the entity shall upload all the relevant documents on the RLDC portal of trippings.

Revised Standard Operating procedure for Third Party Protection System Audit

A protection system audit is a review and evaluation of the protection systems of a substation with an objective to verify whether required protection systems have been put in place at station by the concerned utility, and to recommend suitable measures to provide for the same.

Ministry of Power, had constituted a Committee under the Chairmanship of Chairperson CEA to examine the grid disturbances on the 30th and the 31st July 2012. One of important recommendation of the committee was conducting of extensive audit of protection system. List of sub-stations where protection audit is to be undertaken on priority basis was prepared and audited across the country. This was the beginning of protection audit across the country and large number of important 400 and 220kV substations were audited.

Keeping in view the importance of Protection System Audit, Standard Operating Procedure has been prepared for the reference purpose. It will provides a step-by-step guide for RPCs to follow during the audit process.

1. All users shall conduct third party protection audit of each sub-station at 220 kV and above (132 kV and above in NER) once in five years or earlier as advised by the respective RPC.
2. After analysis of any event, each RPC shall identify a list of substations / and generating stations where third-party protection audit is required to be carried out and accordingly advise the respective users to complete third party audit within three months.
3. Third Party Protection Audit shall be carried out by the third party designated agencies in line with the IEGC Regulations 2023 or by the audit teams constituted by RPCs with the members from other states (at least two) who opt for the RPC coordinated third party protection audit.
4. The third-party protection audit report shall contain information sought in the format as per IEGC 2023 and its further amendments.
5. Annual audit plan for the next financial year shall be submitted by the users to their respective RPC by 31st October. The users shall adhere to the annual audit plan and report compliance of the same to their respective RPC.

6. Criteria for choosing substations for third party protection audit:

The following criteria are generally applied during choosing a substation for protection audit.

- i. Substations/ Generating (SS/ GS) stations with frequent grid incidences or frequent maloperations or any grid occurrence in any substation which affected supply to large number of substations and caused significant load loss. In this case, third-party protection audit may be carried out within three months or as decided in the Protection sub-Committee Meeting of the RPC.
- ii. Important 400kV and 765kV substations (SS) / Generating stations (GS) including newly commissioned SS/ GS. In this case, third-party protection audit may be carried out at a frequency decided in the Protection sub-Committee Meetings of respective RPCs.

7. Protection audit Procedure:

- i. After identification of stations for protection audit, the same is communicated to the owner utility seeking nomination of one nodal officer for each Station.
- ii. The nodal officer shall provide the details of substation for preparation of protection audit format (in line with IEGC and subsequent amendments).
- iii. Meanwhile nominations shall be sought from all utilities to form regional teams for audit. Regional teams comprising of engineers from various utilities /utility (other than the team of host State) of the region shall be formed based on the no. of SS to be audited. (Each team may consists of 3 or 4 engineers from utilities other than the host utility and at the maximum a team will be able to audit 3 to 4 stations in 7-9 days or so)
- iv. Once the team details and list of stations to be audited is finalised the details of nodal officers, team members , list of stations to be audited by each team is shared to all for further coordination regarding planning and conduction of audit.
- v. Based on the inputs received from nodal officer regarding the list of elements in the substation to be audited, protection audit formats shall be prepared by RPC (in line with IEGC) and circulated to nodal officer. The nodal officer along-with the substation engineers shall fill the audit format and furnish the same along-with various attachments sought as part of the audit format within a week or so. List of attachments shall be given in the covering page of audit format.
- vi. In case, other entity's bays /equipment are existing in the substation to be audited, the entity shall furnish all the details of its equipment to the Audit Team/Agency and the other entity shall be available during the Protection Audit.
- vii. The filled in audit format along-with the received annexures shall then forwarded to the audit team by the nodal officer and any further clarification regarding the format or attachments shall be taken up by the audit team with the nodal officer under intimation to RPC.
- viii. The SS/ GS shall be audited based on the data filled in audit format checking for compliance of Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022, Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 & CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, CERC regulations and amendments to the same, approved guidelines of RPC, best practices in industry, report of the Task Force on Power System Analysis Under Contingencies and as per the "Model Setting Calculations For Typical IEDs Line Protection Setting Guide Lines Protection System Audit Check List Recommendations For Protection Management Sub-Committee on Relay/Protection Under Task Force For Power System Analysis Under Contingencies" etc.
- ix. After conduct of audit, the shortcomings observed in the audit shall be discussed in detail with the nodal officer and substation engineers and recommendations are finalised.
- x. The filled in audit format along-with the recommendations and attachments shall be finalised and final protection audit report RPC (in line with IEGC) shall be compiled.
- xi. The audit team shall check the criteria for activation/archival of DR, as decided in the respective Protection sub-Committees of RPC.

- xii. Final protection audit report shall be discussed in Protection Coordination Committee and recommendations may be accepted/deleted/modified as per the scope of audit and compliance of various regulations/guidelines etc.
- xiii. The recommendations of all SS audited shall be inserted into audit recommendations database and update regarding recommendations shall be sought from respective utilities.
- xiv. Action plan for rectification of deficiencies detected, if any, shall be submitted to the respective RPC and RLDC and monthly progress will be submitted.
- xv. The travel expense from place of duty to Substation/Generating Station to be audited shall be borne by respective Auditor (Parent Organisation). The expense for boarding, lodging any travel of the team during the audit period shall be borne by the organisation owning the Substation/Generating Station.
