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केंद्रीय विद्युत प्राधिकरण/Central Electricity Authority
राष्ट्रीय विद्युत समिति/National Power Committee [ISO 9001:2008]
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No. 3/NRCE/NPC/CEA/2016/ 743–749 Date: 01st November 2016

विषय: **2nd Meeting of Subgroup in respect of "Preparation of reliability Standards for Protection System and Communication System" – Reg.**

महोदय/Sir,

In continuation to the letter dated 20th October 2016, enclosed, please find a copy of the Agenda Notes for the 2nd meeting of the Subgroup scheduled on **04th November 2016 at 1100 Hrs** in NRPC Conference Hall, 2nd Floor, NRPC Building, Katwaria Sarai, New Delhi.

All the Members of the Subgroup are requested to kindly make it convenient to attend the meeting.

भवदीय / Yours faithfully,

Sd/-

संलग्नक: यथोपरि।/ Encl: as above

(धी.कु.श्रीवास्तव / D.K.Srivastava)
निदेशक / Director

To:

1. Shri Ajay Talegaonkar, Superintending Engineer (O), NRPC, New Delhi.
2. Shri Vijay Menghani, Director, GM Div., CEA, New Delhi.
3. Shri Y.K. Swarnkar Director, PSETD Div., CEA, New Delhi.
4. Shri Mukesh Khanna, AGM (CTU-Plg.), POWERGRID, Gurgaon.
5. Shri N.Gunasekaran, EE/P&C, TANTRANSCO, Guindy, Chennai.
6. Shri N.L Jain, DGM, POSOCO, New Delhi.
7. Shri A.K.Haldar,GM (OS-Elect.), NTPC,COS,EOC,Noida

AGENDA NOTES FOR THE SECOND MEETING OF NRCE SUB-GROUP IN RESPECT OF PREPARATION OF STANDARDS OF PROTECTION SYSTEM

Meeting Date:04.11.2016 **Venue: NRPC Conference Hall**

Background:

The first meeting of the Sub-group held on 3rd June 2016 and several issues related to protection system were deliberated. It was agreed that a part report on few issues out the issues deliberated and identified from NERC reference document, at a time may be prepared and submitted.

Accordingly, a draft proposal on the following items is put up for deliberation in the second meeting of the Sub-group:

1. Definition of Protection System its Philosophy and aspects related to Protection Coordination
2. Regional Disturbance Monitoring and Reporting

The definitions are not included in CEA standards and therefore indicated for clarity. Protection philosophy of only line protection has been considered for the time being.

No comments were received so Minutes of previous meeting issued vide letter dated 09-06-2016 may be considered approved

AGENDA 1.1: DEFINITIONS RELATED TO PROTECTION SYSTEM

a) "**Auto Reclosing**" means automatic closing of a circuit breaker by a relay system without operator initiation.

b) "**Dependability**" is ability of relay to trip when it is expected to trip.

c) "**Fault clearance time**" is defined as the time required to interrupt all sources supplying a faulted piece of equipment.

d) "**Protection limiting current**" is defined as the value of the current which can be transferred safely – i.e. without picking-up of starter elements and/or tripping of the protection system. Thereby the settings of starter elements, reset ratios, measuring tolerances and additional safety factors have to be considered by protection engineers.

e) "**Protection System**" is defined as those components used collectively to detect defective power system elements or conditions of an abnormal or dangerous nature, to initiate the appropriate control circuit action, and to isolate the appropriate system components.

f) "**Reliability**" is a measure of the protective relaying system's certainty to trip

(more definitions would be added as and when required while developing the remaining identified issues)

AGENDA 1.2 PHILOSOPHY OF PROTECTION SYSTEM:

There shall be protection philosophy, which shall be prepared and adopted by each RPC in coordination with stakeholders in the concerned region. Protection design in a particular system may vary based upon judgment and experience in the broad contours of protection philosophy. Consideration must be given to the type of equipment to be protected as well as the importance of this equipment to the system. While protection must not be defeated by the failure of a single component, several considerations should be weighed when judging the sophistication of the protection design: Objectives, design criteria and other details are as below:

1.2.1 **Objectives**: *the basic design objectives of any protective scheme are to:*

i. Maintain dynamic stability.
ii. Prevent or minimize equipment damage.
iii. Minimize the equipment outage time.
iv. Minimize the system outage area.
v. Minimize system voltage disturbances.
vi. Allow the continuous flow of power within the emergency ratings of equipment on the system.

1.2.2 **Design Criteria**: To accomplish the design objectives, the four criteria for protection that should be considered are *fault clearing time; selectivity; sensitivity and reliability (dependability and security).*

1.2.3 **Fault clearing time**: In order to minimize the effect on customers and maintain system stability, fault clearing time should be kept to a minimum and shall be as per CEA Grid Standard Regulations 2010.

1.2.4 **Selectivity**: Coordination is required with the adjacent protection schemes including breaker failure, generator potential transformer fuses and station auxiliary protection.

1.2.5 **Sensitivity**: the settings must be investigated to determine that they will perform correctly during transient power swings from which the system can recover.

1.2.6 **Reliability**: For reliability, two independent auxiliary direct current-supplies with separate circuit breaker's coils or main circuit breakers. The main and backup protective functions should be separated with at least two independent devices, supplied from two different manufacturers or operating with different protection principles as far as possible. Relays from the same manufacturer are acceptable for both the primary and backup systems, however, use of different models is preferred. The relays may be connected at two different correctly rated current transformer cores, according to reliability assessment or imposed by operating condition of protection systems. The CB's 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.

In solidly earthed EHV networks single phase A/R should be generally implemented. After execution of necessary stability studies three phase fault A/R is also allowed, without endangering the system stability and security.

1.2.7 **Security**: the line protection shouldn't limit the maximum transmission capacity of the line. 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 Line's 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 re-dispatching (load transfer etc.). In some cases, it may be necessary to apply power swing blocking functions and then also out-of-step operations. Nevertheless, for dependable fault detection the distance protection setting needs a minimum of resistance reserve. This sets a limit of the maximum load by using the distance protection. The load encroachment function must be used, whenever possible and it is strongly recommended for the cases when the highest distance zone resistance reach conflicts with the maximum transmitted load on the protected element.

1.2.8 **Philosophy of Line Protection:**

Fault incidents on transmission lines are high due to their relatively long lengths and exposure to the elements. Highly reliable transmission line protective systems are critical to system reliability. As such, independent primary and backup line protection systems are a requirement for all lines covered by this guideline. 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.
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.
Protection relays must allow the maximum possible loadability of the protected equipment, without diminishing the clearing of anticipated faults according the simulation studies. Special care must be taken to avoid unwanted tripping of certain distance relays or avoidance of decreasing the loadability due to the transient enlargement of the dynamic mho characteristic, in case this type of characteristic is applied. This must be checked by the protection engineers from the relay application manual and the algorithm of operation. Load encroachment feature of distance relays and –if possible- the setting of torque angle and trip angle of directional overcurrent relays must be applied.

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.

Relevant lists for all CB must be issued, updated and available to the dispatching personnel, indicating the normal and emergency operating limits of the transmission circuits and allows them to be included in the EMS on line operating data
Normally the settings related to the maximum possible load ability of the protected equipment are specified after a dedicated load flow study and contingency analysis

1.2.9 **Primary Protection**:

(a) The primary line protection should provide high-speed simultaneous tripping of all line terminals. On network lines, this may typically require the use of a pilot relay system.

(b) The relays should have sufficient speed so that they will provide the clearing times for system reliability as defined in the CEA Standards Regulation, 2010.

1.2.10 **Back-up Protection**:

The back-up protection should be independent of the primary relays with both primary and back-up relays should be connected to independent CTs located on the "bus" side of the breaker so that breaker faults will be detected by the primary and backup relays of both zones adjacent to the breaker. Back-up protection must always include a non-pilot tripping scheme for phase and ground faults.

Distance protection Zone settings shall be as per the guidelines of SubGroup **under Ramakrishna Task Force and CBIP Guidelines**. All System Operators will do the settings of the protection system in such way that short circuits in the grid will be detected and cleared selectively. Therefore, the settings depend directly from the technical conditions in the grid.

1.2.11 **Backup pilot** – The backup protection may require the inclusion of a pilot tripping system in order to meet clearing time requirements.

The current line differential protection, associated with distance protection is considered a preferable protection technique for HV and EHV lines. A precondition is the reliable availability of reliable telecommunication links. This principle of protection should always be used for multi terminal lines, where other protection principles, e.g. distance, cannot guarantee selectivity with protection of other elements of the system, or when and where instantaneous clearing time need to be guaranteed. Additionally, it can be used for lines with tapped transformers. Due to the fact that short lines and/or cables do not have enough electrical length, the current differential relay should always be used.

For Cables, use at least a differential line protection 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. For short cables, as for short lines, where redundancy is required double current differential protection could be used. Where double current differential protection is decided to be used, for very specific and sound reasons, it must have as back-up at least overcurrent protections, especially for radial feeders.

Differential protection requirements: the current differential protection should 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 fiber optic and any equipment should comply with the **IEC 60834**. When redundancy is a requirement and double differential scheme is needed the communication channels will be fully and physically redundant, and therefore will not share the same physical path/cable.

For differential protection (current or others), in order to synchronize the analogue measurement, the maximum delay of the transmission system should be less than 10ms and the asymmetry in the pick-up times should be less than 1 ms.

Restricted Ground Fault Protection: A scheme must be provided to detect ground faults with high fault resistance.

Close-In Multi-Phase Fault Protection (Switch onto Fault Protection): Relays requiring polarizing voltage may not operate for close-in multi-phase faults when a line is energized if the relays are supplied from line-side voltage transformers. Such faults typically occur when grounds are left connected to the line following line maintenance. *these faults must be detected by the primary or back-up line protection relays. If this cannot be achieved, a specially designed scheme must be provided to detect and clear such faults.*

Single-Phase Tripping: Single-phase tripping of transmission lines may be applied as a means to enhance transient stability. In such schemes, only the faulted phase of the transmission line is opened for a phase-to-ground fault. Power can therefore still be transferred across the line after it trips over the two phases that remain in service.

Number of details need to be considered when applying single-phase tripping schemes compared to three phase tripping schemes. These issues include: faulted phase selection, arc deionization, automatic reclosing considerations, pole disagreement, and the effects of unbalanced currents. Due to the complex nature of the protective systems involved with single-phase tripping schemes, any planned application of such a scheme are subject to review and approval by the Protection Subcommittee of RPC.

Auto Reclosing: For fault interrupting devices at system voltages *above 220 kV* automatic reclosing schemes shall be deployed with following details:

Philosophy: Experience indicates that the majority of overhead line faults are transient and can be cleared by momentarily de-energizing the line. It is therefore feasible to improve service continuity and stability of power systems by automatically reclosing those breakers required to restore the line after a relay operation. Also, reclosing can restore the line quickly in case of a relay misoperation.

The following types of Auto Reclosing may be adopted:

(i) High-Speed Auto reclosing- Refers to the auto reclosing of a circuit breaker after a necessary time delay (less than one second) to permit fault arc deionization with due regard to coordination with all relay protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

(ii) High-Speed Line Reclosing- The practice of using high-speed autoreclosing on both terminals of a line to allow the fastest restoration of the transmission path.

(iii) Delayed Reclosing- Reclosing after a time delay of more than 60 cycles

(iv) Reclosing Through Synchronism Check- A reclosing operation supervised by a synchronism check relay which permits reclosing only when it has determined that proper voltages exist on both sides of the open breaker and the phase angle between them is within a specified limit for a specified time.

(v) Single-Shot Reclosing-A reclose sequence consisting of only one reclose operation. If the reclose is unsuccessful, no further attempts to reclose can be made until a successful manual closure has been completed.

(vi) Multiple-Shot Reclosing -A reclose sequence consisting of two or more reclose operations initiated at preset time intervals. If unsuccessful on the last operation, no further attempts to reclose can be made until a successful manual closure has been completed.

Reclosing Requirements: Following requirements must be met when applying automatic reclosing on transmission lines:

(i) The impact on generator shaft torque of system connected generators due line reclosing must be considered. Turbine generator shaft damage could occur due to oscillations created by reclosing operations on nearby transmission lines. An appropriate time delay must be used to maintain the generator shaft torque within acceptable values. Turbine generator shaft damage could occur due to oscillations created by reclosing operations on nearby transmission lines.

(ii) Reclosing times and sequences must take into account the capability of the fault interrupting device, i.e. circuit breaker.

(iii)Reclosing for line faults should not be used on transmission lines consisting entirely of cable, since cable faults are permanent. Where combinations of open wire and cable are used, an evaluation should be made to determine if reclosing should be used for faults in the aerial portion of the circuit and blocked for cable faults.

(iv)Automatic reclosing should be configured to prevent reclosing on a failed transformer or reactor, or failed breaker.

(v) Automatic reclosing of transmission line circuit breakers should be blocked while a direct transfer trip (DTT) signal is being received.

(vi)The operation of the breaker failure relay scheme on a breaker should block reclosing on adjacent breakers. If the failed breaker can be automatically isolated, the reclose function may be restored to the adjacent breakers.

(vii) The operation of a transformer or bus protective relay scheme may also be a reason for blocking reclosing.

(viii) Automatic reclosing should not be used where transient voltage analysis studies indicate that reclosing may produce switching surges exceeding equipment design levels.

(ix)Automatic reclosing following out-of-step conditions must be reviewed and approved by PJM, with input from the PJM Relay Subcommittee as necessary.

(x) Auto Reclosing for three phase faults is applied only after assuring that due to system configuration and S/S arrangement, there is not the possibility of jeopardizing system security and stability

High Speed Auto Reclosing Requirements: Following requirements must be met when applying high-speed automatic reclosing (HSR) on transmission lines:

(i) The reclose interval must be selected to allow for proper de-ionization of the fault arc. Based on voltage level, the minimum dead time (in cycles) required can be determined from the following equation:

$$T = 10.5 + (kV/34.5) \text{ cycles}$$

Where kV is the rated line-to-line voltage.
Note: the equation above is valid for voltages as high as 230 kV but may be overly conservative at higher voltages. For example, industry experience indicates that 30 cycle dead time is adequate at 765 kV.

(ii) Most applications of HSR do not require study for stability, unless the HSR is on a line electrically close to a line originating at a generating station. If the results from such stability studies indicate that reclosing following a specific type of fault or system condition would result in an unacceptable situation, adaptive reclosing as defined in ANSI/IEEE Std.

(iii)Most adaptive reclosing auto reclosing schemes or selective reclosing schemes use the operation of specific relays or relay elements to initiate the scheme. Some schemes only permit reclosing for pilot relay operations, while others permit reclosing for all instantaneous relay operations. Others only block (or fail to initiate) reclosing for conditions such as multi-phase faults where system stability is of concern or where sensitive or critical loads may be affected.

(iv)High-speed reclosing must only be initiated by a communications assisted relaying scheme.

Tapping of Bulk Power Transmission Circuits for Distribution Loads: For economic reasons, it has become increasingly popular to tap existing bulk power transmission circuits as a convenient supply for distribution type loads. The following discussion is presented in recognition of the need to protect the integrity of the bulk transmission system.

(a) The tapping of 400 kV lines (and other lower voltage but still critical lines) for distribution load increases the likelihood of interruptions (natural or by human error) to the bulk power path. Distribution station transformer low voltage leads and bus work is more susceptible to faults than higher voltage equipment.
(b) The bulk power path should be protected from interruption due to any such faults by the use of local fault-interrupting devices applied on the transformer high side. (The source terminal relays should not initiate the interruption of the bulk power path for low side faults.) The local interrupting device may be either a breaker or a circuit switcher. In either case, provisions must be made for a failure of the device to clear a fault.

Three Terminal Line Applications: *Three terminal line applications shall only be permitted at voltages less than 220 kV when the requirements listed below are met. No three terminal line applications are permitted on systems at 220 kV and above.*

AGENDA 1.3: PROTECTION COORDINATION (AS PER NERC PRC-001-1.1)

Part 1 (Requirements)

The purpose is to ensure system protection is coordinated among operating entities. The Protection coordination requirement shall include the following:

(1) Each Transmission Operator, LDC, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area of control.

(2) Each Generator Operator and Transmission Operator shall notify reliability of relay or equipment failures as follows:

2.1 If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and concerned LDC. The Generator Operator shall take corrective action as soon as possible.

2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its LDC and affected Transmission Operators. The Transmission Operator shall take corrective action as soon as possible.

(3) A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and respective LDC.
3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and LDC.

(4) Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and LDC.

(5) A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:

5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.
5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.

(6) Each Transmission Operator and concerned LDC shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Licencies of each change in status.

(7) Each Transmission Operator, concerned LDC, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area.

(8) A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

8.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.
8.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

(9) Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities

Part 2 (Measures)

The measures to be done for Protection coordination are as follows:

(1) Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, protection relay settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 3, 3.1, and 3.2.

(2) Each Transmission Operator and LDC shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)

(3) Each Transmission Operator and concerned LDC shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems.

(4) Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, revised fault analysis study, protection settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 8, 8.1, and 8.2.

AGENDA 2.0 DISTURBANCE MONITORING AND REPORTING

The Purpose is to ensure that adequate disturbance data is available to facilitate Bulk Electric System event analyses. 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, The Disturbance Monitoring Requirements Shall include the following:

(1) Each Transmission Owner and Generator Owner 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), a generator plants Digital (or Distributed) Control System (DCS) or part of Fault recording equipment.

This capability shall

1.1 Be provided at all substations and at locations to record Grid Disturbances (GI 1 or 2) and Grid Disturbances (GD1, GD2, GD3, GD4, GD5) in accordance with CEA Grid Standard Regulation, 2010. Circuit breaker operation affects continuity of service to radial Loads greater than 300MW, or the operation of which drops 50MVA Nameplate Rating or greater of Generation, or the operation of which creates a Generation/Load island. Be provided at generating units above 50MVA Nameplate Rating or series of generating units utilizing a control scheme such that the loss of 1 unit results in a loss of greater than 50MVA Nameplate Capacity, and at Generating Plants above 300MVA Name Plate Capacity.
The following will be monitored at each location listed in 1.1:

1.1.1 Transmission and Generator circuit breaker positions
1.1.2 Protective Relay tripping for all Protection Groups that operate to trip circuit breakers identified in 1.1.1.
1.1.3 Tele protection keying and receive

(2) Each Transmission Owner shall provide Fault recording capability for the following Elements at facilities:

2.1 All transmission lines.

2.2 Autotransformers or phase-shifters connected to busses.

2.3 Shunt capacitors, shunt reactors.

2.4 Individual generator line interconnections.

2.5 Dynamic VAR Devices.

2.6 HVDC terminals.

Provided that each Transmission Owner shall have Fault recording capability that determines the Current Zero Time for loss of Bulk Electric System (BES) transmission Elements.

(3) Each Generator Owner shall provide Fault recording capability for Generating Plants at and above 500 MVA Capacity for Hydro and 100 MVA Capacity for Thermal and connected through a Generator Step Up (GSU) transformer to the Grid.

(4) Each Transmission Owner and Generator Owner shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following:

4.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)

4.2 Three phase currents and neutral currents.

4.3 Polarizing currents and voltages, if used.

4.4 Frequency.

4.5 Real and reactive power.

(5) Each Transmission Owner and Generator Owner shall provide Fault recording with the following capabilities:

5.1 Each Fault recorder record duration shall be a minimum of one (1) second.
5.2 Each Fault recorder shall have a minimum recording rate of 16 samples per cycle
5.3 Each Fault recorder shall be set to trigger for at least the following:
5.3.1 Monitored phase overcurrents set at 1.5 pu or less of rated CT secondary current or Protective Relay tripping for all Protection Groups.
5.3.2 Neutral (residual) overcurrent set at 0.2 pu or less of rated CT secondary current.
5.3.3 Monitored phase undervoltage set at 0.85 pu or greater.
5.4 Document additional triggers and deviations from the settings in 6.3.2 and 6.3.3 when local conditions dictate.

(6) Each Transmission Owner and Generator Owner shall establish a maintenance and testing program for standalone DME (equipment whose only purpose is disturbance monitoring) that includes

6.1 Maintenance and testing intervals and their basis.
6.2 Summary of maintenance and testing procedures.
6.3 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 center staffed around the clock, 24 hours a day, 7 days a week (24/7)).
6.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).
6.5 Monthly verification of active analog quantities.
6.6 A requirement to return failed units to service within 90 days. If a DME device will be out of service for greater than 90 days, the owner shall keep a record of efforts aimed at restoring the DME to service.

(7) Each LDC, Transmission Owner and Generator Owner shall share data within 30 days upon request. Each LDC, Transmission Owner, and Generator Owner shall provide recorded disturbance data from DMEs within 30 days of receipt of the request in each of the following cases:

7.1 CEA, RPCs/State, other LDC.
7.2 Request from other Transmission Owners, Generator Owners connected with ISTS.

(8) Each LDC, Transmission Owner and Generator Owner shall submit the data files conforming to the following format requirements:

8.1 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.
8.2 Disturbance Data files shall be named in conformance with the latest revision of IEEE Standard C37.232.
8.3 Fault Recorder shall contain all monitored channels. SOE records shall contain station name, date, time resolved to milliseconds, SOE point name, status.

(9) Each LDC, Transmission Owner and Generator Owner shall maintain, record and provide to the RPC / CEA, upon request, the following data on the DMEs installed to meet this standard:

9.1 Type of DME.

9.2 Make and model of equipment.

9.3 Installation location.

9.4 Operational Status.

9.5 Date last tested.

9.6 Monitored Elements.

9.7 All identified channels.

9.8 Monitored electrical quantities.

***

Some provisions relating to protection system in CEA's various technical Standards

A. Grid Connectivity Standards

Regulation 2 : Definitions

(9) "Earth Fault Factor" at a location in a three-phase system means the ratio of 'the highest root mean square (r.m.s.) phase-to-earth power frequency voltage on a sound phase during a fault to earth (affecting one or more phases)' to 'the r.m.s. phase-to-earth power frequency voltage which would be obtained at the selected location without the fault';

(12) "Event Logging Facilities" means a device provided to record the chronological sequence of operations of the relays and other equipment;

(18) "Isolator" means a device for achieving isolation of one part of an electrical system from the rest of the system;

(23) "Protection System" means the equipment by which abnormal conditions in the grid are detected and fault clearance, actuating signals or indications are initiated without the intervention by the operator;

"(28A) "Standard Protection" means electrical protection functions specified in Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010".

(29) "System Protection Scheme" means a scheme designed to detect abnormal system conditions and take predetermined, corrective action to preserve system integrity and provide acceptable system performance;

(33) "Under Frequency Relay" means a relay which operates when the system frequency falls below a pre-set value;

Regulation 6:

6. Protection System and Co-ordination

(1) Protection system shall be designed to reliably detect faults on various abnormal conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protection zone. The protection system should also detect abnormal operating conditions such as equipment failures or open phase conditions.

(2) Every element of the power system shall be protected by a standard protection system having the required reliability, selectivity, speed, discrimination and sensitivity. Where failure of a protective relay in the requester's system has substantial impact on the grid, it shall connect an additional protection as back up protection besides the main protection.

(3) Notwithstanding the protection systems provided in the grid, the requester and user shall provide requisite protections for safeguarding his system from the faults originating in the Grid.

(4) Bus Bar Protection and Breaker Fail Protection or Local Breaker Back Up Protection shall be provided wherever stipulated in the regulations.

(5) Special Protection Scheme such as under frequency relay for load shedding, voltage instability, angular instability, generation backing down or Islanding Schemes may also be required to be provided to avert system disturbances.

(6) Protection co-ordination issues shall be finalized by the Regional Power Committee.

(7) The requester and user shall develop protection manuals conforming to various standards for the reference and use of its personnel.

Regulation 7:

7. Disturbance Recording and Event Logging Facilities

Every generating station and sub-station connected to the grid at 220 kV or above shall be provided with disturbance recording and event logging facilities. All such equipment shall be provided with time synchronization facility for global common time reference.

Part-II (1)

(8) Every generating unit shall have standard protections to protect the units not only from faults within the units and within the station but also from faults in transmission lines. For generating units having rated capacity greater than 100 MW, two independent sets of protections acting on two independent sets of trip coils fed from independent Direct Current (DC) supplies shall be provided. The protections shall include but not be limited to the Local Breaker Back-up (LBB) protection.

(10) Bus bar protection shall be provided at the switchyard of all generating station.

(14) The standards in respect of the switchyard associated with the generating stations shall be in accordance with the provisions specified in respect of 'Sub-stations' under Part III of these Standards.

Part-III

The transmission lines and sub-stations connected to the grid shall comply with the following additional requirements besides the general connectivity conditions under these regulations and General Standards for Connectivity to the Grid as specified in Part I of the Schedule.

(1) Bus bar protection shall be provided on all sub-stations at and above 220 kV levels for all new sub-stations. For existing sub-stations, this shall be implemented in a reasonable time frame.
(2) Local Breaker Back-up (LBB) protection shall be provided for all sub-stations of 220kV and above.
(3) Two main numerical Distance Protection Schemes shall be provided on all the transmission lines of 220 kV and above for all new sub-stations. For existing sub-stations, this shall be implemented in a reasonable time frame.

(4) Circuit breakers, isolators and all other current carrying equipment shall be capable of carrying normal and emergency load currents without damage. The equipment shall not become a limiting factor on the ability of transfer of power on the inter-state and intra-state transmission system.

(5) All circuit breakers and other fault interrupting devices shall be capable of safely interrupting fault currents for any fault that they are required to interrupt. The Circuit Breaker shall have this capability without the use of intentional time delay in clearing the fault. Minimum fault interrupting requirement need be specified by the Appropriate Transmission Utility. The Circuit Breaker shall be capable of performing all other required switching duties such as, but not limited to, capacitive current switching, load current switching and out-of-step switching. The Circuit Breaker shall perform all required duties without creating transient over-voltages that could damage the equipment provided elsewhere in the grid. The short circuit capacity of the circuit breaker shall be based on short-term and perspective transmission plans as finalized by the Authority.

B. Grid Standards

Regulation 3:

(e) provide standard protection systems having the 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 the Regional Power Committee.

Explanation.- For the purpose of this regulation "fault clearance time" means the maximum fault clearance times are as specified in the Table 4 below,-

Table 4

S.No.	**Nominal System Voltage (kV rms)**	**Maximum Time (in milliseconds)**
1	765 and 400	100
2	220 and 132	160

Provided that in the event of non clearance of the fault by a circuit breaker within the time limit specified in Table 4, the breaker fail protection shall initiate tripping of all other breakers in the concerned bus-section to clear the fault in the next 200 milliseconds.

Regulation 9:

9. Automatic under frequency Relay.- (1) 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 Regional Power Committee, to provide adequate load relief for grid security and ensure the operation of these relays at the set frequencies.

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

Regulation 10:

10. Islanding Schemes.- (1) The Regional Power Committees shall prepare Islanding schemes for separation of systems with a view to save healthy system from total collapse in case of grid disturbance.

(2) The Entities shall ensure proper implementation of the Schemes referred to in sub-regulation (1).

Explanation.- For the purposes of this regulation 'Islanding Scheme' means a scheme for the separation of the Grid into two or more independent systems as a last resort, with a view to save healthy portion of the Grid at the time of grid disturbance.

Regulation 12:

12. Reporting of events affecting grid operation.- (1) Any tripping of generating unit or transmission element, along with relay indications, shall be promptly reported by the respective Entity to the Appropriate Load Despatch Centre in the reporting formats as devised by the Appropriate Load Despatch Centre.

(2) The Appropriate Load Despatch Centre shall promptly intimate the event to the Regional Load Despatch Centres and State Load Despatch Centres of the affected regions and States respectively which shall, in turn, take steps to disseminate this information further to all concerned.

Regulation 15:

(3) 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 twenty four hours to the Regional Load Despatch Centre and concerned Regional Power Committee.

(4) All equipment such as disturbance recorders and event loggers shall be kept in healthy condition, so that under no condition such important data is lost.

C. Construction Standards

For Thermal Generating Stations

(10) **Protection system-** (a) Fully graded protection system with requisite speed, sensitivity and selectivity shall be provided for the entire station. Protection system shall be designed so as to avoid mal-operation due to stray voltages. Generator, generator transformer, unit auxiliary transformer(s) shall be provided with protection systems connected to two independent channels/ groups, such that one protection system shall always be available for any type of fault in the generator/ generator transformer/ unit auxiliary transformer(s).

(b) The electrical protection functions for generator, generator transformer, unit auxiliary transformer(s) and station transformer(s) shall be provided in accordance with but not limited to the list given in Schedule- I.

For Hydro Stations

(12) **Electrical protection system**

(a) Fully graded protection system with requisite speed, sensitivity and selectivity shall be provided for the entire Station. Protection relays shall be configured in such a way that digital input points shall not pick up due to stray voltages.

(b) 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.

(c) Electrical faults shall be detected by the protective relays arranged in overlapping zones of protection.

(d) 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. For the generating units with a rating of more than 100MW, 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 (CTs)/ voltage transformers (VTs). The main protection relays for the generators, motors, transformers and the transmission lines shall generally be of numerical type.

(e) All relays used shall be suitable for operation with CTs secondary rated for 1 Amp or 5 Amps as per relevant IS/ IEC/ IEEE standards.

(f) The protections to be provided for the generating units as a minimum shall be as per Schedule- IV.

(g) Relevant IS/ IEC/ IEEE standards shall be applied for protection of generators, transformers and motors.