Email: cenpccea@gmail.com

भारत सरकार/Government of India
विद्युत मंत्रालय/Ministry of Power
केंद्रीय विद्युत प्राधिकरण/Central Electricity Authority
राष्ट्रीय विद्युत समिति/National Power Committee [ISO 9001:2008]
कटवारिया सराय/Katwaria Sarai, नई दिल्ली / New Delhi – 110016
वैबसाइट / Website: www.cea.nic.in

No. 3/NRCE/NPC/CEA/2016/ 867–873 Date: 13th December 2016

विषय: **Record Notes of Discussions in the 2nd Meeting of Subgroup in respect of "Preparation of reliability Standards for Protection System and Communication System" – reg.**

महोदय/Sir,

The record notes of discussions in the 2nd meeting of the Subgroup for preparation of reliability standards for Protection System and Communication System held on 04th November 2016 at New Delhi is enclosed for kind information please.

भवदीय / Yours faithfully

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

To:
1. Superintending Engineer (O), NRPC, New Delhi.
2. Shri Vijay Menghani, Director (GM), 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

CENTRAL ELECTRICITY AUTHORITY
NATIONAL POWER COMMITTEE

Summary Record of Discussions in the Second Meeting of Subgroup for Preparation of Reliability Standards for Protection System and Communication System held on 04th November 2016 at NRPC, Katwaria Sarai, New Delhi

1. Introduction:

The second Meeting of the Subgroup for preparation of "Reliability Standards for Protection System and Communication System" for Indian Power System was held on 4th November, 2016 in NRPC Conference Hall, Katwaria Sarai, New Delhi. The list of the participants is at **Annexure-I.**

Welcoming the participants, Member Convener informed that as decided in the first meeting of the Sub-group the following items were proposed for deliberation in this meeting:

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

A draft proposal on the above items were prepared and circulated based on the documents of NRCE, PJM, ENTSOE, CBIP Manual 2016 etc. He sought views/inputs of Members on the items in order to prepare the report.

2. CONFIRMATION OF THE RECORD NOTES OF DISCUSSIONS IN THE FIRST MEETING OF SUBGROUP

The Record Notes of the first meeting held on 03rd June 2016 was issued on 09th June 2016. No comments were received.

SE (O), NRPC sought clarification on Special Protection Scheme (SPS) and Remedial Action Scheme (RAS). Member Convener stated that both are same, it could be termed SPS instead of RAS.

After deliberation, the subgroup agreed to modify item No.4 Reporting of Remedial Action Scheme Misoperation as **Reporting of Special Protection System Misoperation** in the list of broad areas of protection system finalized in the first meeting.

The Subgroup confirmed the Record Notes of first meeting with the above modification.

3. **Summary of Deliberations in the Meeting:**

3.1 It was decided that "Definitions" part of the document would be prepared after finalization of the document on the items proposed for inclusion in the report.

3.2 Philosophy of Protection System framed by the Subgroup shall be adopted at National level.

3.3 Suitable provision shall me made in the document for providing prior information by Generator Companies and Transmission Licensee in case of any addition of new elements or changes in settings to the concerned RPCs in a standard format.

3.4 The modified proposal in respect of "Definition of Protection System its Philosophy and aspects related to Protection Coordination" prepared based on the views/suggestions of the subgroup is at **Annexure-II.**

3.5 The prevailing provisions related to Protection System in various Technical Standard / Regulations of CEA is at Annexure **III.**

The date and venue of the 3rd meeting of the subgroup will be intimated in due course.

******

ANNEXURE - I

National Power Committee

Second Meeting of NRCE-Subgroup in respect of "Preparation of reliability Standards for Protection System and Communication System" held on 04th November 2016 at NRPC Conference Hall, New Delhi.

LIST OF PARTICIPANTS

S No.	Name (IN CAPITAL LETTERS)	Designation	Organisation	E mail Id	Mobile No.	Signature
1	VIKRAM SINGH	DIRECTOR, RA	CEA	VIKRAMSINGHFMS@GMAIL.com	9868893051	
2.	Y. K. SWARNKAR	DIRECTOR PSETD	CEA	ykswarnkar@gmail.com	9810327346	
3.	VIJAY MENGHANI	Director	CEA	menghaniv@gmail.com	9899035454	4.11.16
4.	Rajil Srivastava	AGM-Engg SU	Powergrid, gurgaon	rajil@powergridindia.com	9910370115	04/11/16
5.	N. GUNASEKARAN	EE/P&C/Guindy.	TANTRANSCO.	eepcgndy@tnebnet.org	9445892693	4/11/16
6.	N.L. Jain	DGM-NLDC	NLDC, POSOCO	nl.jain@posoco.in	9999143112	
7	BRIJENDRA B. SINGH	Dy Mgr	NLDC, POSOCO	brijendra@posoco.in	7042954333	
8	Naresh Kumar	E.E.	NRPC	seo-nrpc@nic.in	8860310624	
9.	AJAY TALEGAONKAR	S.E	NRPC	seo-nrpc@nic.in	9910728144	
10	D.K. SRIVASTAVA	Director	NPC, CEA	dhirajsrivastava@gmail.com	9560763305	
11	K.P. MADHU	DD	NPC, CEA	kp.madhu@gov.in	8447483698	
12	DEEPANSHU RASTOGI	AD-I	NPC, CEA	deepanshurastogi.cea@gov.in	9789957461	4/11/16
13.	Himanshu Lal	AD-I	NPC, CEA	himanshulal33@gmail.com	8527029905	

ANNEXURE-II

(1) DEFINITIONS RELATED TO PROTECTION SYSTEM

1.1 DEFINITIONS:

This part of the standard will be formed after the completion of the whole document.

1.2 GENERAL PHILOSOPHY OF PROTECTION SYSTEM:

There shall be protection philosophy shall be prepared and adopted by each RPC in coordination with stakeholders in the concerned region in accordance with below mentioned objectives, design criteria and other details. However, protection design in a particular system may vary depending upon judgment and experience in the broad contours of above 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:

1.2.1 Objectives:

The basic objectives of any protection schemes should be to:

(i) Mitigate the effect of short circuit and other abnormal conditions in minimum possible time and area.

(ii) Indicate the location and type of fault and

(iii)Provide effective tools to analyze the fault and decide remedial measures.

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

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

1.2.2.2 Selectivity: To ensure Selectivity, coordination shall be ensured with the adjacent protection schemes including breaker failure, transformer downstream relays, generator protection and station auxiliary protection.

1.2.2.3 Sensitivity: 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.

1.2.2.4 Reliability: 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.

1.2.2.5 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.

1.3 PHILOSOPHY OF LINE PROTECTION:

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.

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.

1.3.1 Design Criterions: While designing the scheme for protection of transmission lines following criteria shall be included:

(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) Protection relays must allow the maximum possible loadability of the protected equipment, while ensuring the clearing of anticipated faults according to the simulation studies.

(iv) 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.

(v) Settings related to the maximum possible loadability of the protected equipment shall be specified after a suitable load flow study and contingency analysis.

1.3.2 Reliability Criterions:

A. **For transmission line having voltages at 220kV and above:** High speed Duplicated Main Protection (Main-I and Main-II) with two independent auxiliary direct current-supplies shall be provided for each of the relays and at least one of them being carrier aided non-switched three zone distance protection. The other protection may be a phase segregated current differential (this may require digital communication) phase comparison, directional comparison type or a carrier aided non-switched distance protection.

In addition to above following shall also be provided:

(i) Two stage over-voltage protection. However, in such cases where system has grown sufficiently or in case of short lines, utilities on their discretion may decide not to provide this protection.

(ii) Auto reclose relay suitable for 1 ph/3 ph (with deadline charging and synchro-check facility) reclosure.

(iii) Sensitive IDMT directional E/F relay (standalone or as built-in function of Main-I & Main-II relay).

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 independent zones (three forward zones and one reverse zone). It shall be provided with carrier aided tripping.
c. The relays should have sufficient speed so that they will provide the clearing times as defined in the latest revision of CEA Grid Standards Regulations.
d. The Main-I and Main-II relays shall be powered by two separate DC source.
e. Both, Main-I and Main-II shall send separate initiation signal to Breaker Failure Relay.
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. The protection shall be set in two stages. The lines emanating from same substation shall be provided with pick-up as well as time grading to avoid concurrent trippings. The overvoltage relay shall have at least 98% drop-off to pick-up ratio. The detection shall be made on phase to phase voltage.

B. **For transmission line having voltages at 132kV:** There should be at least one carrier aided non-switched three zone distance protection scheme. In addition to this, another non-switched/switched distance scheme or directional over current and earth fault relays should be provided as back up. Main protection should be suitable for single and three phase tripping. Additionally, auto-reclose relay suitable for 1 ph/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.

1.3.3 Following types of protection scheme may be adopted to deal with faults on the lines:

1.3.3.1. 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 independent zones (three forward zones and one reverse zone). It shall be provided with carrier aided tripping.
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.

1.3.3.2 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 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.

The differential protection shall have following requirements:

(i) Line differential as Main-I with inbuilt Distance Protection shall be installed for all the lines (irrespective of length), if OPGW communication is available. The inbuilt distance protection feature shall get automatically enabled in case of communication failure observed by the differential relay.
(ii) The differential relays provided in 220kV and above system must operate in less than 20ms.
(iii) 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.
(iv) 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.

1.3.4. Auto Reclosing:

The single phase high speed auto-reclosure (HSAR) at 220 kV level and above 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 by respective RPC.

1.3.4.1 AR Function Requirements:

It shall have the following attributes:

(i) Have single phase and/or three phase reclosing facilities.
(ii) Have a continuously variable single phase dead time.
(iii) Have continuously variable three phase dead time for three phase reclosing.
(iv) Have continuously variable reclaim time.
(v) Incorporate a facility of selecting single phase/three phase/single and three phase auto-reclose and non-auto reclosure modes.
(vi) Have facilities for selecting check synchronizing or dead line charging features.
(vii) Be of high speed single shot type
(viii) Suitable relays for SC and DLC should be included in the overall auto-reclose scheme if three phase reclosing is provided.
(ix) Should allow sequential reclosing of breakers in one and half breaker or double breaker arrangement.

1.3.4.2. Scheme Special Requirements:

(i) Modern numerical relays (IEDs) have AR function as built-in feature. However, it is recommended to use standalone AR relay or AR function of Bay control unit (BCU) for 220kV and above voltage lines. For 132kV lines, AR functions built-in Main distance relay IED can be used.
(ii) 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.
(iii) 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:
a. Breaker Fail Relay
b. Line Reactor Protections
c. O/V Protection
d. Received Direct Transfer trip signals
e. Busbar Protection
f. Zone 2/3 of Distance Protection
g. Carrier Fail Conditions
h. Circuit Breaker Problems.
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.

1.3.4.3 Requirement for Multibreaker Arrangement:

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

(i) In a multi-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.

(ii) 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.

(iii) 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 prioriting with respect to each other.

(iv) In case of bus bar configuration arrangement having a transfer breaker, a separate auto-reclosure relay for transfer breaker is recommended.

1.3.4.4 Setting Criteria:

(i) Auto-reclosing requires a dead time which exceeds the de-ionising time. The circuit voltage is the factor having the predominating influence on the de-ionising time. Single phase dead time of 1.0 sec. is recommended for 765 kV, 400 kV and 220 kV system.

(ii) According to IEC Publication 56.2, a breaker must be capable of withstanding the following operating cycle with full rated breaking current:

$$0 \quad + 0.3\text{ s} + \text{CO} + 3\text{ min} + \text{CO}$$

The recommended operating cycle at 765kV, 400 kV and 220 kV is as per the IEC standard. Therefore, reclaim time of 25 Sec. is recommended.

1.3.5. Power Swing Blocking and 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 mis-operation during Power swings which may be recoverable or irrecoverable power swings. Following steps may be adopted to achieve above objective:

A. 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.

B. 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.

C. 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.

1.3.6. VOLTAGE AND CURRENT INVERSION

<u>Voltage inversion on Series Compensated line:</u> The phenomenon where the voltage at the relay point reverses its direction is commonly called as voltage inversion. Voltage inversion causes false decision in conventional directional relays. Special measures must be taken in the distance relays to guard against this phenomenon.

<u>Current inversion on Series Compensated line:</u> In certain cases, the fault current will lead source voltage by 90 degrees called as Current inversion which causes a false directional decision of distance relays

1.4 PROTECTION COORDINATION:

A protection-coordination study shall be done to determine the trip settings of each protective device in the power system so that maximum protection with minimum interruption is provided for all faults that may happen in the system. System studies shall be conducted using computer-aided tools to assess the security of protection by finding out trajectory of impedance in various zones of distance relay under abnormal or emergency system condition on case-to-case basis particularly for critical lines / corridors.

Relay coordination calculation module must consider the operating characteristics of the relays, normal operating and thermal or mechanical *withstand characteristics* of the equipment and must determine the optimum relay settings to achieve the protection objectives stated under Para 1.2.1.

In addition, the settings must be fine-tuned, simulating faults using Real Time Digital Simulator on case-to-case basis particularly for critical lines / corridors.

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 Licensee, LDC and Generator Company shall keep themselves familiarized with the purpose and limitations of Protection System schemes applied in its area of control.

(2) Each Transmission licensee shall coordinate its Protection System schemes with concerned transmission system, sub-transmission system and generators.

(3) Each Generating Company shall coordinate its Protection System schemes with concerned transmission system and station auxiliaries.

(4) 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 CTU/STU/RPC necessary for calculation of the settings.

(5) CTU/STU shall provide the infeed values/latest network model to the requesting entity, within 15 days of receipt of such a request from the entity. The RLDC shall provide the existing settings of the adjacent substations within 15 days of such a request from the requesting entity.

(6) Each Generating Company and Transmission Licensee shall submit the protection settings along with the calculation sheets, co-ordination study reports and input data, in advance, to respective RPC for every new element to be commissioned. The mentioned information shall be submitted to the RPC by first week of each month for all the elements proposed to be commissioned in the following month.

(7) The appropriate sub-committee of RPC 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 sub-committee 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.

(8) If the RPC feels the need, it may recommend carrying out the dynamic study for the concerned system to ensure that the present settings are sufficient for maintaining the dynamic stability of the system. In such a case, on being directed by RPC, the respective CTU/STU shall carry out the necessary dynamic studies and submit the report to the RPC.

(9) 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 by respective Regional Power Committee.

(10) Each Transmission licensee and Generation Company shall co-ordinate the protection of its station auxiliaries to ensure that the auxiliaries are not interrupted during transient voltage decay.

(11) Any change in the existing protection settings 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.

(12) In case of failure of a protective relay or equipment failure, the Generator Company and Transmission Licensee shall inform appropriate LDC. The Generator Company and Transmission Licensee shall take corrective action as soon as possible.

(13) Each Transmission Licensee shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Company, Transmission Licensee, and appropriate LDC.

(14) Each Transmission Licensee, Generator Company and Distribution Licensee shall monitor the status of each Special Protection System in their area, and shall inform to concerned RLDC about each change in status.

Part 2 (Measures)

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

(1) Each Generator Company and Transmission Licensee 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 their Protection System, new Protection System or changes in it.

(2) Each Transmission Licensee, Generator Company and Distributor 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 confirm and that it informed to concerned RLDC about changes in status of one of its Special Protection Systems.

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 Licensee and Generator 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), 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 all the events in accordance with CEA Grid Standard Regulation, 2010 and at locations where 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.

1.2 Be provided at generating units above 50MVA Nameplate Rating and at Generating Plants above 300MVA Name Plate Capacity.

The following shall also be monitored at each location listed in 1.1 and 1.2:

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) 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.
- GPS Clock healthiness.
- Control Switching Device healthiness (if applicable).
- RTU/Gateway PC healthiness
- All Circuit Breaker Supervision Signals.
- Trip Circuit Supervision Signals.

(3) Each Transmission Licensee shall provide Disturbance recording capability for the following Elements at facilities:

3.1 All transmission lines.

3.2 Autotransformers or phase-shifters connected to busses.

3.3 Shunt capacitors, shunt reactors.

3.4 Individual generator line interconnections.

3.5 Dynamic VAR Devices.

3.6 HVDC terminals.

(4) The Disturbance recording feature shall be enabled and configured in all the numerical relays installed.

(5) Each Generator Company shall provide Disturbance recording capability for Generating Plants in accordance with the CEA Technical Standards for Connectivity and CEA Technical Standards for Construction of Plants.

(6) Each Transmission Licensee and Generator Company shall record for Faults, sufficient electrical quantities for each monitored Element to determine the following:
6.1 Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)
6.2 Three phase currents and neutral currents.
6.3 Polarizing currents and voltages, if used.
6.4 Frequency.
6.5 Real and reactive power.
The Minimum parameters to be monitored in the Fault record shall be specified by the respective RPC.

(7) Each Transmission Licensee and Generator Company shall provide Disturbance recording with the following capabilities:
7.1 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.
7.2 Each Fault record duration and the trigger timing shall be settable and set for a minimum 2 second duration including 300ms pre-fault time.
7.3 Each Fault recorder shall have a minimum recording rate of 64 samples per cycle.
7.3 Each Fault recorder shall be set to trigger for at least the following:
Internal protection trip signals, external trigger input, analog triggering (any phase current exceeding 1.5 pu of CT secondary current or any phase voltage below 0.8pu, neutral/residual overcurrent greater than 0.25pu of CT secondary current). Additional triggers may be assigned as necessary.

(8) Each Transmission Licensee and Generator Company shall establish a maintenance and testing program for Disturbance Recorder (DR) that includes

8.1 Maintenance and testing intervals and their basis.
8.2 Summary of maintenance and testing procedures.
8.3 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)).

8.4 Monthly verification of time synchronization (if the loss of time synchronization is not monitored to a 24/7 control center).
8.5 Monthly verification of active analog quantities.
8.6 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 Generator Company shall keep a record of efforts aimed at restoring the DR to service.

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

9.1 CEA, RPCs/State, other LDC.
9.2 Request from other Transmission Licensee and Generator Company connected with ISTS.

(10) Each Transmission Licensee and Generator Company shall submit the data files to the appropriate RLDC conforming to the following format requirements:

10.1 The data files shall be submitted in COMTRADE Format
10.2 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.

(11) 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.

(12) Time Sync Equipment

12.1 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.

12.2 The status of healthiness of the time-sync device shall be wired as “Alarm” to SCADA and as an “Event” to Event Logger.

12.3 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 appropriate RLDC and RPC. This record shall be archived for a period of three years by each concerned agency.

(13) Disturbance Analysis and Reporting

13.1 Subsequent to every tripping event, the concerned utility shall submit all the relevant DR files in COMTRADE format along with SOE, to the appropriate Load Dispatch Centre, regional power committee, Remote End Entity and the entity connected to the downstream of transformers (in case of transformer tripping).

13.2 Each utility shall develop internal procedure of disturbance analysis. Necessary software shall be available with the entities to view and analyse the fault record files in COMTRADE format. The detailed analysis report shall identify the reason of fault, detailed sequence of events, mis-operations identified (if any), reason of protection mis-operation and corrective actions taken. Every entity shall submit the detailed analysis report within one week of the date of event occurrence, to the appropriate load dispatch center.

13.3 A monthly report shall be prepared by each utility, mentioning the events of protection mis-operations whose reasons could not be identified and require further follow-up. This report for each month shall be submitted to RPC and RLDC within the first week of the subsequent month.

13.4 The detailed analysis reports shall be archived periodically. The archive shall be retained for a period of three years by each concerned agency.

13.5 The analysis reports shall be discussed in the Protection Sub-Committee meetings of the RPC to be held periodically. The sub-committee shall identify the lessons learnt during the events being discussed. The lessons learnt shall contain the incidence and learning details without any reference to the particular entity or location.

13.6 Each RPC shall develop and maintain a web based portal to act as a data repository with the facility for utilities to upload the fault records, analysis reports and protection relay settings.

***

ANNEXURE-III

Some of the Provisions Relating to Protection System in Various Technical Standards / Regulations of CEA

A. Technical Standards for Connectivity to the Grid, Regulations:

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" mans 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 shalt 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 he 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 toad 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 – Grid Connectivity Standards Applicable to the Generating Units

1. New Generating Units.

(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 Pan Ill of these Standards.

Part-III - Grid Connectivity Standards Applicable to the Transmission Line and Sub-Station.

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 bat 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-nations 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 Regulations:

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 analyzing the grid incidents and grid disturbance and any other data which in its view can be of help for analyzing 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. Technical Standards for Construction of Electrical Plants and Electrical Lines Regulations:

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:

(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 he 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.

(12) **Electrical protection system**

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.