



NORTHEAST POWER COORDINATING COUNCIL, INC.
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October 3rd, 2016

Subject: Approval Ballot for NPCC Regional Reliability Directory#11 *Disturbance Monitoring Equipment Criteria* and retirement of A-15 *Disturbance Monitoring Equipment Criteria*

NPCC Full Member Representatives and Alternates:

Attached for your approval is new NPCC Directory #11 *Disturbance Monitoring Equipment Criteria* which was developed in accordance with the process outlined in the NPCC Directory Development and Revision Manual.

Directory #11 was created by the NPCC Task Force on System Protection (TFSP) with due consideration of the FERC approved NERC continent-wide standard PRC-002-2 *Disturbance Monitoring and Reporting Requirements*, the recently retired NPCC Regional Standard PRC-002-NPCC-01 *Disturbance Monitoring* and the existing NPCC A-15 *Disturbance Monitoring Equipment Criteria*.

In order to augment PRC-002-2 and in accordance with Section 313 of the NERC Rules of Procedure, the draft of Directory #11 retains portions of the existing A-15 Criteria that provide guidance for the effective application of equipment necessary to capture the data required by the NERC standard. Specifically, Directory #11 establishes disturbance monitoring functional capability requirements that apply to all NPCC BPS elements as identified through the performance based methodology of NPCC Document A-10, "*Classification of Bulk Power System Elements*".

In the development of the draft of Directory #11 the TFSP conducted a comprehensive review to ensure that there were no duplication or conflicts with the requirements of PRC-002-2. The TFSP also, as appropriate, incorporated functionally related 'B' documents as Appendices into the Directory.

Concurrent with Directory #11 approval the following NPCC documents will be retired:

- A-15 *Disturbance Monitoring Criteria*
- B-25 *Guide to Time Synchronization of Substation Equipment---* (Appendix A)
- B-26 *Guide for Application Disturbance Monitoring Equipment--*(Appendix B)
- B-28 *Guide for Generator Sequence of Events Monitoring---* (Appendix C)

The draft of Directory #11 was posted to the NPCC Open Process review for a 45-day comment period and the TFSP has considered and responded to all comments.

The NPCC Reliability Coordinating Committee (RCC) approved Directory#11 on September 7th, 2016.

In accordance with Section VIII of the Amended and Restated By-laws dated April 15th, 2011 this document will be considered approved upon receipt of a two-thirds weighted affirmative vote of the Full Members:

Your vote to approve signifies acceptance of:

- The NPCC Regional Reliability Directory #11 “*Disturbance Monitoring Equipment Criteria*”
- Retirements of the following documents:
 - A-15 “*Disturbance Monitoring Equipment Criteria*”
 - B-25 “*Guide to Time Synchronization of Substation Equipment*”
 - B-26 “*Guide for Application Disturbance Monitoring Equipment*”
 - B-28 “*Guide for Generator Sequence of Events Monitoring*”

Please log in to the NPCC Website with your user identification and password and cast your vote electronically by October 24th, 2016.

<https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=130>

Please contact me with any questions regarding Directory content or voting instructions.

Thank you.

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Regional Reliability Reference Directory # 11
Disturbance Monitoring Equipment Criteria

Full Member Ballot
October 3rd, 2016

Adopted by the Members of the Northeast Power Coordinating Council Inc., on XXXX, XX 201X,
based on recommendation by the Reliability Coordinating Committee, in accordance with Section
VIII of the NPCC Amended and Restated Bylaws dated January 1, 2012 as amended to date.

Version History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0			New

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1.0 Introduction

1.1 Title: **Disturbance Monitoring Equipment**

1.2 Directory #11

1.3 Objective:

Provide the application and functional requirements for the **disturbance monitoring equipment (DME)** employed in NPCC such that adequate **disturbance** data is available to facilitate analysis of **bulk power system (BPS) disturbances**. All references to equipment and facilities herein, unless otherwise noted, will be to **BPS elements**.

1.4 Effective Date:

Immediately upon approval of the NPCC Full Members.

1.5 Background:

This Directory was developed from the NPCC A-15 - **Disturbance Monitoring Equipment** Criteria document approved on August 23, 2007.

In this document the terms **DME**, Sequence of Events Recording (SER), and **fault Recorders (FRs)** all refer to functional capability and not to discrete devices. Dynamic Disturbance Recorders (DDRs) are also considered **DME**. However, this document does not contain requirements for DDRs because sufficient requirements exist in NERC PRC-002-2 Disturbance Monitoring and Reporting Requirements.

Appendices for consideration in the implementation of this Directory have been developed from the approved B-25, B-26, and B-28. The Appendices include guidance for DDR applications.

All of the criteria and requirements stipulated in this Directory apply to all new installations and modifications to existing installations.

1.6 Applicability:

1.6.1 Functional Entities (Responsible Entities)

Transmission Owners
Generator Owners

1.6.2 Facilities

These requirements shall apply to all **BPS** facilities. **BPS** facilities that are also classified as NERC **Bulk Electric System (BES)** shall adhere to the more stringent of the requirements of this Directory and the requirements in the applicable version of PRC-002.

1.6.3 Applicability of NPCC Criteria:

The requirements of an NPCC Directory apply to those facilities defined as NPCC **BPS elements** as identified through the performance based methodology of NPCC Document A-10, "*Classification of Bulk Power System Elements*," the list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by a NPCC Directory may also reside in external tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinators, Planning Coordinators, Transmission Operators, Balancing Authorities and/or Transmission Owners as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements. NPCC will not enforce compliance to the NPCC Directory requirements in this document on any entity that is not a NPCC Full Member.

2.0 Defined Terms

Unless specifically noted in this document terms in bold typeface are defined in the NPCC Glossary of Terms.

2.1 **Current Zero Time** - the time of the final current zero on the last phase to interrupt

3.0 NPCC Full Member Criteria

Sequence of Events

- R1.** Each Transmission Owner and Generator Owner shall provide SER capability. This capability shall:
- 1.1 Be provided at all **BPS** facilities.
 - 1.2 Be provided at generating facilities where the generator step up transformer is a **BPS element**.
 - 1.3 Monitor and record status change for the following:

- 1.3.1 Transmission and generator circuit breaker positions
- 1.3.2 **Protective relay** tripping for all **protection groups** that operate to trip circuit breakers
- 1.3.3 **Teleprotection** keying and receive

Fault Recording

- R2.** Each Transmission Owner shall have **fault** recording capability that determines the **current zero time** for loss of **BPS elements**.
- R3.** Each Transmission Owner shall be able to determine **fault** recording data for the following **elements** at facilities, where FR is required as per R2 above:
 - 3.1 All transmission lines.
 - 3.2 Transformers with the primary terminal and at least one secondary terminal operated at 100 kV or higher and phase shifters (phase angle regulators).
 - 3.3 Shunt capacitors, shunt reactors.
 - 3.4 Generator interconnection where the generator step up transformer is a **BPS element**. This includes monitoring the high voltage or low voltage terminal of the generator step up transformer.
 - 3.5 Dynamic VAR Devices.
 - 3.6 HVDC terminals.
- R4.** Each Transmission Owner shall record for **faults**, sufficient electrical quantities for each **element** in R3 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.
- R5.** Each Transmission Owner shall provide **fault** recording with the following capabilities:
 - 5.1 Each **FR** record duration shall be a minimum of one (1) second with at least 2 cycles of pre-trigger data.

- 5.2 Each FR shall have a minimum recording rate of 16 samples per cycle.
- 5.3 Each FR 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 5.3.2 and 5.3.3 when local conditions dictate.

Time Synchronization

- R6. Each Transmission Owner and Generator Owner shall time synchronize all SER and FR data for **BPS elements** to meet the following:
 - 6.1 Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.
 - 6.2 Synchronized device clock accuracy within ± 2 milliseconds of UTC.
 - 6.3 Monthly verification of time synchronization shall be provided or the loss of time synchronization shall be monitored and alarmed to a control center staffed 24 hours a day, 7 days a week (24/7).

Device Software Configuration

- R7. FR settings in the software shall be verified every six (6) years.

Equipment Failure

- R8. Each Transmission Owner and Generator Owner shall, within 90-calendar days of the discovery of a failure of the recording capability including time synchronization for the SER or FR data, either:
 - Restore the recording capability, or
 - Develop and implement a documented corrective action plan.

Data

- R9. Each Transmission Owner and Generator Owner shall provide, upon request, all SER and FR data for **BPS elements** to the Responsible Entity, Regional Entity, or NERC in accordance with the following:

- 9.1 FR data shall contain all monitored channels. SER records shall contain station name, date, time resolved to milliseconds, SER point name, status.
- 9.2 Data will be retrievable for the period of 10-calendar days, inclusive of the day the data was recorded.
- 9.3 Data will be provided within 30-calendar days of a request unless an extension is granted by the requestor.
- 9.4 SER data will be provided in ASCII Comma Separated Value (CSV) format following Attachment 2 of NERC PRC-002-2.
- 9.5 FR data will be provided in electronic files that are formatted in conformance with C37.111, (IEEE Standard for Common Format for Transient Data Exchange (COMTRADE), revision C37.111-1999 or later.
- 9.6 Data files will be named in conformance with C37.232, IEEE Standard for Common Format for Naming Time Sequence Data Files (COMNAME), revision C37.232-2011 or later.

4.0 Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

NPCC will not enforce a duplicate sanction for the violation of any Directory#11 requirement that is also required for compliance with a NERC Reliability Standard.

Prepared by: Task Force on System Protection

Review and Approval: Revision to any portion of this Directory will be posted by the Task Force on System Protection in the NPCC Open Process for a 45-day review and comment period. Upon addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections

pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or other portions of the document such as links, etc., only require RCC approval. Errata may be corrected by the Task Force on System Protection at any time.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References:

NPCC Glossary of Terms
Classification of Bulk Power System Elements (A-10)
NERC Standard PRC-002-2 **Disturbance** Monitoring and Reporting
Requirements
SP6 Report Synchronized Event Data Reporting

Appendix A

Guide to Time Synchronization of Substation Equipment (Formerly NPCC Guideline B-25)

1.0 Introduction and Scope

Background information on the need for time synchronization of substation equipment is contained in the report of SP6 originally issued on February 9, 2005. The report is available on the public portion of NPCC website.

This Appendix covers time synchronization of substation equipment such as FRs, SER recorders, **protective relay** intelligent electronic devices (IEDs), RTUs, and generally any substation equipment capable of accepting external synchronization, but with specific exceptions noted in this introduction.

Phasor Measurement Units (PMUs) have more stringent accuracy requirements than other substation equipment. PMUs often include a GPS clock as an integral part. When not included, purchasers of PMUs are advised to consider making dedicated GPS receiver and interconnection wiring a part of the purchase of a PMU. Purchasers are also advised to consider IEEE Standard C37.118, *IEEE Standard for Synchrophasors for Power System*. PMUs are not covered by the remainder of this Appendix.

All Remote Terminal Units (RTUs) used for SER should be capable of accepting an external synchronizing signal and shall be capable of time-stamping events at the substation and transmitting time-stamped SER data to the SER master.

Existing legacy RTUs are either synchronized by network means (such as SNTP or NTP), or are not synchronized at all. Some legacy RTUs have neither the internal clocks, nor the means to accept GPS. The events from these RTUs are stamped by the SCADA system at the time of the arrival of the event to SCADA host. Such systems are not capable of providing the accuracy called for in this Appendix, and should be replaced as they reach end-of-life.

The coming generation of SCADA/EMS/RTU equipment will be capable of accepting and utilizing event time-stamps applied at the substation.

As an alternative to stand alone GPS receiver and the IRIG-B protocol, some network time protocols may also provide the accuracy required.

2.0 Accuracy Requirements

Accuracy for purposes of this guide means accuracy of synchronization to the worldwide standard Time Scale which is Coordinated Universal Time (UTC). UTC is most commonly available from GPS clocks, although there are other means. Note that selection of Time Zone is a separate matter from Time Scale and is dealt with later in this Appendix.

The design accuracy requirements of the substation synchronizing system, including GPS clock and the synchronizing interconnection system up to the synchronizing input port on the utilization IED, should be a total uncertainty of -1 to +2 milliseconds as stated in the SP6 report. That is, the signal at the input port could be up to 1 millisecond early or 2 milliseconds late. There is every likelihood that users following this guide will achieve uncertainties lower than this.

The SP6 working group was unable to quantify the internal delays in instrument transformers, associated wiring, and recording devices. However, we can infer from test results that these internal delays are variable, and in the case of some older equipment, can be over 4 milliseconds. Thus, the uncertainty in a synchronizing system designed according to this Appendix will be a smaller contributor to total uncertainty than the internal delays in recording devices.

The use of multiple GPS receivers may help in decreasing overall length of interconnecting cabling and thus decreasing error.

3.0 GPS Receivers

GPS receivers are the most common way of obtaining synchronization to UTC Time Scale. GPS receivers with 1 microsecond uncertainty should be employed in all new installations.

GPS receivers installed in electric utility substations should be qualified for the substation environment. The power supply for the receiver should be connected to the station battery, and should comply with IEEE Std. C37.90.1.

GPS clocks are capable of applying offsets to UTC, programmable by the user. This is dealt with in the next section.

4.0 Time Zones

Part 6.1 of this Directory includes the statement “Synchronization to Coordinated Universal Time (UTC) with or without a local time offset.” This statement implies that various practices of NPCC Members regarding time zone are acceptable, as long as the records are clearly labeled with the hours of offset.

5.0 IRIG-B Interconnection Methods

The de facto industry standard for time synchronization of electric utility equipment has been IRIG-B, in both the 1-kHz amplitude modulated and the DC shift formats. Amplitude modulated IRIG-B is more secure against most types of interference and is more suitable for larger interconnection networks. DC shift IRIG-B is more accurate and is more suitable for networks which are very limited in size and in complexity. Either of these forms of IRIG-B may be used.

It is essential that the interconnections between the receiver and substation IEDs be designed to minimize signal losses. Users should familiarize themselves with the manufacturer's recommendations for IRIG-B interconnections, and refer to the SP6 report for more detailed guidance. Assuming the interconnections are made in accordance with these recommended practices, cables may be routed within the substation in a conventional manner for electric power facilities, whereby instrument cabling is isolated from power cabling.

Large facilities may require additional GPS receivers, distribution amplifiers, or fiber optic links. Refer to the section following on Isolation/Separation.

IRIG-B signal distribution equipment installed in electric utility substations must be qualified for the substation environment. This may require the use of a substation qualified DC/DC power supply. Such equipment is commercially available.

6.0 Monitoring and Alarming

Time synchronization equipment (GPS clocks, IRIG-B distribution and IEDs) should be monitored and alarmed. Most devices are designed and equipped with varying degrees of hardware failure and loss-of-signal detection and alarming functions. These are typically:

- GPS Clock
 - Clock hardware failure (including loss of input power)
 - Loss of satellite lock
- IRIG-B Fiber Transmitters/Receivers
 - Loss of Signal/Hardware Failure

These alarms should be monitored in a manner consistent with established practice, which could include:

- Station Annunciator
- SCADA System
- Sequence of events Recorder

Certain end-use devices, such as numerical relays, may additionally provide alarm indication for loss of synchronizing signal, as well as possibly a time-tagged event

recording of the failure.

7.0 Maintenance/Testing

It is expected that installed time synchronizing systems will be maintained in proper, fully operational condition. In order to meet that objective, provisions must be in place to ensure that any necessary repairs are made in a timely manner, and to have the required spare equipment available. The term “timely” is subjective, however, it is recommended that any reported failures would be repaired in a matter of days.

GPS receivers, as well as synchronizing accessories, are typically not considered field-serviceable units. Spare units of every type sufficient to cover the installed equipment base should be provided.

To the extent that time synchronizing equipment is self-monitoring and checking, specific maintenance recommendations other than the manufacturers’ are not necessary. Inspections of the status of the time synchronizing systems should be made whenever maintenance/inspection of any of the equipment being synchronized is being performed. The testing of the alarm/monitoring functions should be undertaken at the time of installation and following any associated modifications.

8.0 Isolation/Separation Issues

It is not necessary to provide separate GPS receivers for each **protection group** since time synchronization is a monitoring function rather than a **protection** function. However, the designer should keep in mind that both **protection groups** when linked through metallic IRIG-B network wiring have the possibility that a surge voltage propagating through the IRIG-B network could affect both **protection groups**. One option to avoid this contingency is the use of fiber optic links as isolation, or the use of separate GPS receivers for the two **protection groups**.

Appendix B

Guide for Application of Disturbance Monitoring Equipment (Formerly NPCC Guideline B-26)

1.0 Introduction

The power system is routinely subjected to **faults** or **disturbances** which can range from transient **faults** on transmission lines to system-wide **disturbances** involving many states, provinces or countries. Investigation of each incident is critical in optimizing the performance of **protection systems** with the goal of preventing future incidents from becoming wide-area **disturbances**. The tools required to perform post-incident analyses include **DME** which can capture pre-event, event, and post-event conditions with a high degree of accuracy.

As technology has advanced, the capabilities and options available in modern recording equipment have improved dramatically. With these advancements comes the challenge of understanding how to configure them to maximize the benefits of recorded data. This guide provides the users of recording equipment within NPCC with many of the recommendations which should be considered in application of various **DME**.

There are many names given to these devices in the industry, but for the purposes of Directory #11 the recorders can be classified into two categories:

- **FR (Fault Recorder)**
- Sequence of events Recorder

A **FR** is generally used to record **faults** on the power system. The sampling rate is high (many samples per cycle) to provide the resolution required, but the length of the record is short (a few seconds at most), limited to immediate pre-**fault**, **fault**, and post-**fault** conditions.

A **DDR** is used to record power swings on the system. The sampling rate is lower (one sample every 1-10 cycles) but the length of the record is longer to capture a long, low frequency power swing. Modern **DDRs** are capable of continuous recording.

A sequence of events recorder captures the sequence of events for monitored changes of state occurring in substations or power plants. It is used in conjunction with records from **FRs** or **DDRs** to complete post-event analyses. For non-**fault** conditions, the **SER** capability record may be the only recorded data available.

Modern DME often has the capability to perform more than one of the three functional categories discussed above.

This Appendix also provides the user with general guidance regarding the application of DME.

2.0 FRs

2.1 Deployment

The goal of the deployment requirement is to ensure the entity can determine the current zero time of all faulted transmission elements and not necessarily requiring **FR** coverage at each and every transmission station. Overlapping coverage of **FRs** increases the probability that during a system **disturbance** one or more **FRs** in a given area will trigger.

2.3 Record Length

The record should contain enough pre-trigger, trigger (**fault**), and post-**fault** information to evaluate **protection system** performance. The number of cycles of pre-trigger information should be sufficient to allow for the replication of pre-**fault** values if a dynamic simulation of a **protection system** operation is warranted (e.g., 10-cycles of pre-trigger). The user should consider the following when setting up a **FR**:

- **FR** characteristics (sampling rate, memory, number of channels, etc.)
- Minimum record required to capture a time-stamp
- Requirements of local relays for reproducing events in the relays
- Expected local clearing time for most **faults**

2.4 Triggers

Analog and digital triggers should be used to optimize the recording of system **faults**, **protective relaying** performance, and abnormal system conditions. Settings of trigger values in a **FR** may vary by location, and evaluation of triggers should be done periodically after the initial commissioning of a recorder with adjustments made as necessary to reflect operating experience and changes in system conditions.

It is important to understand the operating characteristic of each manufacturer's **FR** to ensure that it is configured to capture all desired system events. In some **FRs** the operation limit of a trigger is settable. Incorrect application of these limiters could prevent the **FR** from recording critical information.

There are a variety of other trigger settings available that may be considered for use in a **FR** depending on need. Some of the triggers available are:

- Overcurrent (required)
- Undervoltage (required)
- Zero sequence overcurrent (required)
- Overvoltage
- Zero sequence voltage (requires 3-phases of voltage)
- Positive rate-of-change of current, voltage, or frequency
- Negative rate-of-change of current, voltage, or frequency
- Total harmonic distortion trigger (current or voltage)
- Positive sequence (requires 3-phases of current or voltage)
- Negative sequence (requires 3-phases of current or voltage)
- Impedance
- Frequency deviation (over/under from nominal)
- Delta frequency (step change in frequency)
- Frequency rate-of-change (relative to a setpoint for rate-of-change)
- Tripping relay operation or breaker operation

When selecting a frequency deviation trigger for transient recording, the trigger should be set higher than normal deviations for **load** changes in an area.

2.5 Sampling Rates

The **FR** sampling frequency can optionally be set high enough to enable the use of records to verify system models and also be sufficient to allow capture of harmonics related to transient conditions such as breaker re-strikes. A sampling frequency of 3840 Hz (64 samples/cycle) is suggested in order to capture such transient phenomena.

3.0 Sequence of Events Recorders

3.1 SER Capability

Sequence of events recorders can be installed as stand-alone devices or as part of another device, such as a Supervisory Control and Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control Systems (DCS) or as part of **fault** recording equipment.

3.2 Point Assignments

SOE recorders are intended to monitor the change-of-state of devices and control signals in a station. Essential to this application is the monitoring of circuit breaker and circuit switcher positions (as required to interrupt **fault**

current). Additional information in analyzing an event can be gained from monitoring other significant data points in the station, including:

- Breaker trip coil energization
- Output contacts of **protective relays** or auxiliary relays used for tripping (required)
- **Teleprotection** key and receive functions (required)
- Selected control relays (voltage, reclosing, etc.)
- Disconnect switch positions
- Significant alarm points
- Security systems events

3.2 Interposing Relays

The intent of a SER recorder is to capture an accurate sequence of the high speed operations of various devices in a station. This enables the user of the data to identify the conditions that existed prior to each step in the sequence and to understand the nature of the subsequent operations. The objective is to determine if the operations were correct and to correlate the system data at each step with that which would be expected based on system design and modeling. In order to satisfy this objective, it is critical to be able to establish the time of an event as precisely as possible. In so doing, the user must be aware of any time delay inherent in the contact inputs being recorded. Even circuit breaker auxiliary switches or other direct contacts may introduce a time delay—in fact, the opening of a breaker’s auxiliary contacts would not likely correspond to the true current-zero arc interruption of the breaker’s primary contacts.

Interposing relays are often used to facilitate connection of control points to SER recorders. This practice is sometimes necessary due to the unavailability of contacts on monitored devices. However, conventional interposing relays would add delay to the recording of events at the SER recorder. For this reason, conventional interposing relays should not be used where the device being monitored may be critical to establishing the time of an event. Special utility-grade event recorder relays are available which provide a deterministic high speed interface (typically under 2 ms with 0.5 ms repeatability) as well as the diode blocking components required for direct insertion of the package into relay trip schemes and circuits. If an interposing relay is required, care should be taken to assure the fastest and most repeatable possible operating time of the relay (pickup and dropout). Any data provided for analysis should identify which points are monitored using interposing relays as well as an estimate of the operating times of the interposing relays.

3.3 Use of RTUs for SER

Many new SCADA RTUs have the ability to provide SER functionality. These RTUs can accept GPS time synchronization signals and can time-stamp inputs to the nearest millisecond. In order to take advantage of this feature, it is necessary to have a means to bring the data back from the RTU to the individuals performing the data analysis. Protocols are now available that support transfer of the data, complete with time-stamp, to the SCADA Master. At that point, the data can be accessed for analysis. In providing this feature via the RTU, it is important that the communication bandwidth be sufficient to simultaneously support all normal SCADA functions without compromise.

4.0 Common Issues

4.1 Data format

Disturbance records should be stored in the native file format in order to preserve the integrity of the data. However, in sharing files, it must be noted that not all COMTRADE conversion utilities function in the same way and information contained in the native file format may not be carried into the new file.

4.2 Power Supply

The power supplies of all substation equipment covered by this document should be supplied from a station battery and qualified for utility grade substation service. This includes the GPS receiver/clock, the SCADA/EMS RTU, the **DME**, modems, and any equipment supplying signals to the **DME**. Modems may be powered from AC station service provided sufficient storage capacity exists within the recorder to cover the time required to re-establish station service if interrupted. Consideration should be given to powering master station computers and support equipment from a UPS and/or emergency generator at the control center or engineering offices such that automatic record retrieval is not interrupted and event analysis can proceed before normal power is restored. Consideration should also be given to the end-to-end communications channels, which may involve computer networking equipment and switches, etc.

4.3 Monitoring

DME should be monitored by SCADA or some other alarming method for equipment failure, loss of power, or shortage of storage capacity. GPS receivers/clocks and any associated IRIG-B distribution equipment should be similarly monitored for equipment failure, loss of power, or loss of synchronization. Loss of synchronization may also be recorded within the

DME record.

4.4 Communication

Communication between the master station and **DME** should be reliable, even during system **disturbances**, and should meet cyber security standards where warranted. Communication should be sufficiently fast and over a sufficient number of channels to permit retrieval of records in a timely manner to support system operations and restoration. Consideration should be given to a prioritization scheme to allow records with the most important information on a **disturbance** to be retrieved first. This may be based upon proximity to the **disturbance** and capability of the **DME**.

Appendix C

Guide for Generator Sequence of Events Monitoring (Formerly NPCC Guideline B-28)

1.0 Introduction

Advances in the application of integrated computer system technology to power system **DME** has proven to be an invaluable tool in the analysis of the performance of substation and power plant **protection** and control systems during **fault** or transient **disturbance** events. Of these computerized monitoring equipment devices, SER capability systems are capable of providing traceable, time-stamped, data records indicating the operating sequence for each of the monitored **elements** of the power system. Each one of these **element** records is termed a SER record. The purpose of this Appendix is to provide fundamental guidance in the application of SER recorder monitoring systems deployed at generating units or generating plants in accordance with this NPCC Directory #11, *Disturbance Monitoring Equipment Criteria*. It is intended to identify key areas for monitoring the generator mechanical and electrical **protection** and control system trips. This Appendix document will supplement the Appendix B, *Guide for Application of Disturbance Monitoring Equipment* in its recommendations relative to generator units.

2.0 Generator Sequence of Event Recorder - General Design Considerations

- 2.1 This Appendix applies to conventional stand-alone generator SER systems or plant computer control systems with SOE recording capability, whether the event data is accessed via local or remote communications.
- 2.2 For multi-generator power plant installations, each generator unit should have its own SER capability whether used in a single plant SER system or a combined remote and master station arrangement. The functionality of each unit's SER data collection should be independent of the status of other units.
- 2.3 A stand-alone SER recorder is configured and wired to accommodate a number of active inputs. Input circuits should be provided with optical couplers and a high noise rejection interface to isolate the recorder logic from transients on the field wiring ground plane. Input buffering may be used to provide an adjustable time delay range of at least 1 to 50 milliseconds to eliminate nuisance event recording due to contact bounce. The real-time indication for off-normal conditions of a point should not be affected by this delay.
- 2.4 The scan rate of the SER recorder should be capable of detecting the change of state between any two of its inputs in one (1) millisecond or less.

- 2.5 Ground detection circuitry should be provided to detect a ground on either side of any field contact input leads.

3.0 SER Record Selection Criteria

- 3.1 The SER record requirements for the type of generating facility will vary for hydroelectric, fossil, combined cycle gas and steam turbines, wind turbines, and nuclear power plants. This document provides the user with some recommended SER record selections for monitoring generator facilities. Specific requirements relative to the actual installations should be assessed by the user in conjunction with the generator manufacturer's recommendations.
- 3.2 Each generator SER unit should continuously scan its monitored device contacts or control signal to detect any change of state subsequent to the previous scan. An event record is defined as any change in state of these contacts or signals. The SER recorder channels are assigned attributes to designate the events as critical, non-critical (alarm) or test. Upon detecting an event, the SOE recorder time-tags and stores the SER record event in sequential non-volatile memory.
- 3.3 Each generator SER record should include the description of the activated function initiated by the pickup, operation, reset, failure, change in state of inputs or outputs, and timing of **protection** and control parameters and internal variables.
- 3.4 The user should set the generator SER recorder to record the digital data points as well as establish the criteria for triggering an event record according to basic requirements as illustrated in Section 4.0. The records are time-stamped with a reference to the internal clock having a resolution of one millisecond. It also should be possible to view or retrieve many event recorded reports from the SER recorder via communication ports.
- 3.5 SER Point Selection:
- a.) SER points for all discrete generator electrical **protections** that do not possess internal SER recording and time synchronized capability, including all detection **elements** that initiate tripping. (i.e.: relay function designations 87, 50, 40, 51V, 64, 21, etc.)
 - b.) SER points for all generator mechanical **protection** including all detection **elements** that initiate tripping. (i.e.: relay function designations 71, 38, 12, 14, 63 etc.)
 - c.) SER recording points for all trip **relays**. (i.e.: relay function designations 94, 86 etc.)

- d.) SER points for all delay timers (62) associated to blocking or tripping relays (i.e.: Voltage supervision, position switch devices, 64 etc.)
- e.) SER points to monitor the position of all interrupt devices initiated by **protection**. (i.e.: relay function designations 41, 87, 52, 89 etc.)
- f.) SER points to monitor the start-up of each turbine unit and its synchronization to the system.
- g.) SER points to monitor the presence of voltage including the position of breakers on the primary voltage side of the auxiliary supplies.
- h.) SER points to detect loss of dc supply necessary to operate synchronizers and vibration devices.

4.0 SER Record Basic Requirements

The following tables contain some of the recommended **protection** and control functions to meet the basic requirements for SER. The responsible GO may combine select functions to aggregate an overall **protection** and control operation. It is the responsibility of the GO to determine each function's priority for monitoring their specific generator and plant auxiliary support system.

SYSTEM SUPERVISION

FUNCTION	CODE
LOSS OF DC	30P/DC
LOSS OF TIME SYNCHRONIZATION	LOSS SYNC
DC SYSTEM GROUND DETECTION	DC GROUND

ELECTRICAL PROTECTION « A and B »

FUNCTION	CODE
OVEREXCITATION	24
MOTORIZATION (REVERSE POWER)	32
NEGATIVE SEQUENCE	46
LOSS OF FIELD (ALL TIME DELAYED AND INSTANTANEOUS ELEMENTS)	40
VOLTAGE TRANSFORMER SUPERVISION	60/VTS
VOLTAGE RESTRAINED OVERCURRENT	51V
BACKUP TIME-DELAY DISTANCE	21
ACCIDENTAL ENERGIZATION	50/27
OVERVOLTAGE (ALARM AND TRIP LEVELS)	59A-59T
STATOR GROUND 95 %- 100% DETECTORS(ALL LEVELS)	64

GENERATOR UNIT DIFFERENTIAL	87G
GLOBAL GENERATOR AND TRANSFORMER UNIT DIFFERENTIAL PROTECTION (PHASE AND GROUND)	87U
SPLIT DIFFERENTIAL PROTECTION	87S
ALARM NUMERICAL PROTECTION FAILURE	74
GENERATOR OVERFREQUENCY PROTECTION	81O
GENERATOR UNDERFREQUENCY PROTECTION	81U
GENERATOR UNDERVOLTAGE PROTECTION -TRIP	27T
GENERATOR UNDERVOLTAGE PROTECTION -ALARM	27A
ALL TRIP OR AUXILIARY TRIP OR PARTIAL TRIP RELAYS	94

MECHANICAL PROTECTION

FUNCTION	CODE
ALL LOW OIL LEVEL DETECTORS	71
ALL LOW AIR AND OIL PRESSURE LEVEL DETECTORS	63
ALL TYPES OF HIGH BEARING TEMPERATURE LEVELS	38
ALL LEVELS OF EXCESSIVE VIBRATION DETECTORS	39
ALL TYPE OF SHUT DOWN DEVICES(SPEED GOVERNORS, LOCAL OR REMOTE EMERGENCY SHUTDOWN FUNCTIONS)	5
ALL TIME- DELAY RELAYS ASSOCIATED WITH MANUAL OR AUTOMATIC SHUT DOWN MECHANICAL SEQUENCE OF THE TURBINE UNIT	62/MECH
ALL LEVELS OF PROTECTION TIME DELAYS	62-X
ALL LEVELS OF MECHANICAL OR ELECTRICAL OVERSPEED DETECTORS (140%, 110%)	12E-12M
ALL LOCK-OUT RELAYS	86L-X/A
TORSIONAL STRESS PROTECTION-TRIP	
TORSIONAL STRESS PROTECTION-ALARM	

BACKUP PROTECTION

FUNCTION	CODE
ALL TIME- DELAY RELAYS ASSOCIATED WITH ELECTRICAL OR MECHANICAL BACKUP PROTECTIONS	62B-E 62B-M
BREAKER FAILURE PROTECTION	50BF
ALL BACK-UP TRIP RELAYS (MECHANICAL OR ELECTRICAL)	94BF-M/E

VOLTAGE REGULATORS

FUNCTION	CODE
ROTOR GROUND AND VIBRATION	64F*39VB
HIGH OIL TEMPERATURE (EXCITATION TRANSFORMER)	26
FIELD CIRCUIT BREAKER SUPERVISION	41
ABNORMAL FIRING (FIRING FAULTS)	48

REGULATOR DEVICE FAULTS	90
HIGH WINDING TEMPERATURE OF EXCITATION TRANSFORMERS	49
ALL INSTANTANEOUS AND TIME DELAYED EXCITATION OVERCURRENT	50/51EXC
OVERCURRENT	50/51
ROTOR OVERVOLTAGE (INSTANTANEOUS OR TIME DELAYED)	59F/59F-62
LOW COOLING AIR PRESSURE	63 AP
VENTILATION FAILURE	74/VENT
LOSS OF REGULATOR VOLTAGE	27/90
TIME DELAYED ROTOR GROUND	64F/62
STABILIZER CIRCUIT FAULTS	74/STAB
EXCITATION PULSE CIRCUIT FAULTS	90PULSE
THYRISTOR FAULTS	74 THY
STABILIZER MONITORING FUNCTION (IN/OUT OF SERVICE)	83 STAB

TRANSFORMER PROTECTION

FUNCTION	CODE
OVERCURRENT	50/51/T
DIFFERENTIAL	87T
GROUND OVERCURRENT	50/51G/T
HIGH WINDING TEMPERATURE	49D
HIGH PRESSURE GAS	63D
EXTINCTION DEVICE DETECTORS	45
GLOBAL DIFFERENTIAL(GENERATOR AND TRANSFORMER)	87U
CABLE GROUND DETECTION DEVICES AND TIME DELAYS	64T-62
ALL TRIP RELAYS	94-X/T
ALL TIME DELAYED DEVICES	62
TRANSFORMER VENTILATION MONITORING SYSTEMS	5V/T
TRANSFORMER OVEREXCITATION OR VOLT/HERTZ	24
TRANSFORMER HIGH SIDE DISCONNECT SWITCH	89
TRANSFORMER OVERVOLTAGE PROTECTION	59T/62

START-UP AND SHUT-DOWN SUPERVISION

FUNCTION	CODE
LOCAL/REMOTE AUTOMATIC/MANUAL TURBINE STATUS - AUTO/MANUAL	43/XX
MANUAL POSITION OF TURBINE VOLTAGE REGULATOR	90/MAN
SPEED GOVERNOR AUTOMATIC POSITION	65/AUTO
SYNCHRONIZER AUTOMATIC POSITION	43SY
SERVO-MOTORS UNLOCK POSITIONS	20 V
UNIT TURBINE SHUT DOWN OR START-UP	43 XXX
GRADUAL VOLTAGE START-UP	4/GRAD V

WATER FLOW MONITORING LEVELS	80W/XX
BREAK MONITORING AT START-UP	39X/BREAK
FIELD BREAKER IN CLOSE POSITION	41MA
ALARM FOR LOW TURBINE VOLTAGE LEVEL	27XX
MAIN BREAKER IN CLOSE POSITION	Ma/52A
EXCESSIVE START-UP TIME	48 START

SPEED GOVERNORS

SPEED GOVERNOR MAJOR FAULTS	65/MAJ
UNDERSPEED FUNCTIONS (80%)	14E/80%
110% LONG OVERSPEED DELAY DEVICE	62/110%
SLOW MECHANICAL OVERSPEED DELAY DEVICE	62SM
BLADE POSITION DETECTORS	33
SPEED GOVERNOR EMERGENCY SHUT-DOWN	BP-RV/5
ALL UNDERSPEED LEVEL DETECTORS AND MAJOR FAULTS	14E XX /74

SYNCHRONIZATION

FUNCTION	CODE
PERMISSIVE SYNCHRONIZATION	25P
FAULTED SYNCHRONIZER	25FS
PERMISSIVE SIGNAL TO CLOSE BREAKERS	25Z
LONG SYNCHRONIZATION TIME	48/25

AUXILIARY SUPPLY

FUNCTION	CODE
LOW AC VOLTAGE	27AC
AUXILIARY RELAY FOR SOURCE TRANSFERS	83
OVERCURRENT(PHASE AND GROUND)	50/51
DIFFERENTIAL	87
ALL 62, 86 AND 94	62, 86, 94
CIRCUIT BREAKER POSITION MONITORING	MA/52XX
FIRE TRANSFORMER PROTECTION	94/FIREXX
TRANSFORMER AND TAP CHANGER HIGH TEMPERATURE	49XX
GAS PRESSURE TRANSFORMER TAP CHANGER DEVICES	63/XX
BACK-UP TIME DELAYED DEVICES	62XX/XX

SF6

AUXILIARY LOW PRESSURE SF6	63x/SF6
TIME DELAY LOW PRESSURE SF6	62-x/SF6
TRIP DEVICE SF6	94-x/SF6

OTHER MONITORING FUNCTIONS	CODE
POSITION TURBINE SWITCH CLOSE STATUS	Ma/89A
GENERATOR UNIT CIRCUIT BREAKER POSITION	52
GENERATOR HIGH SIDE CIRCUIT BREAKER POSITION	52
WATER FLOW VALVE OPEN STATUS	Ma/105 VP
BREAKS LOW AIR PRESSURE	63/XX
BREAKS TIME DELAYS	2/BK
TIME DELAY SLIPPING DETECTORS	2/SL
SLIP DETECTORS	39X/SL

FIRE PROTECTION

FUNCTION	CODE
SMOKE AND HEAT DETECTORS	45X