1515 BROADWAY, NEW YORK, NY 10036-8901 TELEPHONE: (212) 840-1070 FAX: (212) 302-2782

SP6 Report

Synchronized Event Data Reporting

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SP-6 Contributing Members:
John Ferraro (Chairman – Northeast Utilities), James Allcorn (NYISO), Hung Huynh (Nova Scotia Power), Jim Ingleson (NYISO), Quoc Le (NPCC), Xiaochuan Luo (ISO-New England), Laurie Martuscello (National Grid), Anthony Napikoski (United Illuminating), Jeff Pond (National Grid), Vasilios Tsolias (National Grid), Gary Young (BC Hydro – Liaison with WECC)

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NOMENCLATURE

BPS	Bulk Power System
DFR	Digital Fault Recorder
DME	Disturbance Monitoring Equipment (DRE is preferred)
DRE	Disturbance Recording Equipment – includes digital fault recorder, dynamic swing recorder, sequence of events recorder, power quality recorder, and/or combination devices
DSR	Dynamic Swing Recorder
EMS	Energy Management Systems
GOES	Geostationary Operational Satellite Program
GPS	Global Positioning System
ICCP	Inter-control Center Communication Protocol
IED	Intelligent Electronic Device
ISO	Independent System Operator
NERC	North American Electric Reliability Council
NIST	National Institute of Standards and Technology
NTP	Network Time Protocol
PLC	Programmable Logic Controller
PMU	Phasor Measurement Unit
RTO	Regional Transmission Organization
RTU	Remote Terminal Units
SCADA	Supervisory Control and Data Acquisition
SER	Sequence of Event Recorder
SOE	Sequence of Events

I. INTRODUCTION

A prompt and accurate sequence of events should be established following a widespread disturbance to provide timely analysis and reporting of the disturbance. The time and effort to reconstruct the events of the August 14, 2003 Blackout demonstrated the need to coordinate the time clocks of all disturbance monitoring devices installed at critical locations on the bulk power system to a precise time reference. It also reinforced the need for accurately time stamped operational data such as that from EMS/SCADA/SER, and non-operational data from digital swing or fault recorders.

As a result of the Blackout, NERC has directed each region to strengthen their requirements for Disturbance Recording Equipment. This document will provide recommendations for deployment of DRE, and for use of the fault and event monitoring capabilities of protective relays at BPS facilities. The accuracy of time stamping of data from DRE as well as from EMS/SCADA systems will also be addressed. Today, precise time receiving devices are inexpensive, easy to configure and require little maintenance. They can be used to synchronize the time clocks of DRE and EMS/SCADA systems.

We should note that this report doesn't address requirements for stand-alone SER equipment since there are no companies using new SERs in NPCC (that we're aware of) that aren't associated with another system.

II. TIME SYNCHRONIZATION for DRE and SCADA/EMS SYSTEMS

A. UTC Time Scale

GPS receivers provide UTC time scale, the world wide standard time scale, which is maintained by approximately 50 standards laboratories throughout the world which "coordinate" UTC with each other. The participating laboratories include the Canadian National Research Council and the US NIST (formerly the National Bureau of Standards). Each maintains and distributes UTC in its own country. In the US, the United States Naval Observatory receives UTC from NIST and passes it on to the GPS system. Some necessary corrections are made within the GPS receivers, and the receiver time code output can be considered to be essentially UTC time scale.

B. The GPS Service

The GPS service is based on a constellation of 24 orbiting satellites that provide worldwide navigation signals. Since the navigation capability is based on precise timing measurements, GPS also provides precise time signals as a by-product, and is a convenient, reliable, and economical source of UTC time scale, available not only everywhere in the NPCC Region, but throughout the world. In times of crisis, the Department of Defense has the capability to degrade GPS service in specific world areas. It is very unlikely that this would ever be done in any area of Canada or the United States.

C. The GOES Service

GOES (Geostationary Operational Satellite Program) receivers were used for some early synchronized installations. Experience indicates that GOES synchronization is not as reliable as GPS. There are only 2 GOES satellites, only one of which is normally available in the NPCC Region. GOES time service was discontinued on January 1, 2005, at which time US NIST ceased monitoring the timing accuracy of the GOES program. GOES time service has since been re-instated, but the accuracy of the GOES receivers can no longer be assured. Therefore, the working group recommends that GOES receivers be replaced by GPS receivers.

D. Time Zone Selection

GPS receivers are capable of providing a time code output with no offset from the time zone centered on the Prime Meridian, passing through Greenwich England. This zero offset time zone has been designated as Zulu or GMT, and is also often designated "UTC". The use of UTC as a time zone designation results in the potential for confusion with the UTC time scale. Because of this potential for confusion, the time zone designations Zulu, GMT, or UTZ are preferred over the use of “UTC” as a time zone designation. Use of the "zero offset" time zone is very helpful in those cases when records are of interest across more than one time zone, such as with dynamic swing recorders and wide area monitoring systems.

GPS receivers are also capable of providing time code output with offsets for local time. Examples of local time zones are Atlantic Standard Time (AST), Eastern Standard Time, (EST), and Central Standard Time (CST). GPS receivers are also capable of providing a time code output which automatically changes to Daylight Saving Time (and back) at the proper times. Examples of local daylight time zone designations for the same example time zones are ADT, EDT, and CDT. Conventionally, changeover occurs when local time reaches 02:00 on the first Sunday in April and on the last Sunday in October.

Use of such local time zones, and the application of daylight savings time adjustment, are left to the discretion of the individual utility. Local time zones are often preferred when the recorded information is of local interest only, such as is the case with power quality recordings.

A time zone conversion has been provided as an appendix to this report. A combination of letters following a time should always be understood to be a time zone designation. No inference should be made from these letters as to the time scale, or to the method or quality of synchronization.

E. GPS Receiver Accuracy

NIST suggests that the term “accuracy” be used to describe the subject qualitatively, and the term “uncertainty” be used when referring to a quantitative statement. Investigation by the working group suggests that existing GPS receivers can be expected to provide a time code output which has an uncertainty on the order of 1 millisecond.

One manufacturer of very widely used GPS receivers formerly offered higher accuracy as an option on their most popular model. During 2003, this option became part of the standard offering. If the GPS receiver is new, or had the high accuracy option, and if other details listed below are taken care of properly, the expected uncertainty in the receiver time code output can be reduced to approximately 1 microsecond. Details that should be taken care of properly for an optimum receiver installation include the following:

1. Make sure that the actual antenna cable delay is programmed into the receiver. GPS receivers are typically programmed for the delay of the standard furnished antenna cable.

2. The receiver should auto-survey for satellites to establish synchronization. It should also have the capability to lock on and hold position.

3. The antenna should be mounted with the clearest possible view of the sky in all directions.

In addition, the clock power supply should be from station battery.

The working group recommends that future GPS receivers be installed and configured so that their time code uncertainty will be on the order of 1 microsecond. Existing receivers should be assumed to have a time code uncertainty of 1 millisecond.

The total uncertainty, however, also includes the delay introduced in the time code distribution system. This delay can be on the order of 100 microseconds in a well designed copper distribution system, but can range from 10 microseconds to 1 millisecond (Reference 9). Clearly the distribution system is a very significant source of variable delay, contributing to uncertainty. See section II.G below.

F. <u>IRIG-B Time Code Format</u>

IRIG-B serial time code always contains encoded time information and can also include control functions. Actually there are many variants of IRIG-B time code, and the specific format variant generally used in the power industry is B123. For a complete explanation of the variants please see Reference 10. IRIG stands for InterRange Instrumentation Group.

Both formats B123 and B120 include a time-of-year word, and this word is transmitted at the beginning of each frame, i.e. once every second. This time-of-year word does not include the year. B120 is different from B123 in that it also includes a 27 bit control function word. A definition for the control function word is contained in IEEE 1344, *Standard for Synchrophasor Measurement,* and this format definition includes the year, local offset, time quality, and event notifications. Many clocks are capable of shifting from B123 to B120. The group has found few recording devices that can take advantage of the control function word in their disturbance recording equipment. We recommend that this option should be generally made available in the future.

Thus the IRIG-B signal may be either B123 or B120 but we will refer to it in this report as "IRIG-B." One or more IRIG-B output drivers are commonly available on GPS receivers.

G. <u>Distribution of Timing Signals</u>

The IRIG-B distribution network is a potential source of significant time delay. As stated previously this delay is believed to range from 10 microseconds to 1 millisecond. The group investigated recommendations from various manufacturers, and common practices among utilities.

IRIG-B output drivers are commonly available in two types, unmodulated and modulated. GPS receivers may be ordered with one or the other or both types of drivers. It is also possible to purchase a GPS receiver with more than one driver of each type. An unmodulated driver applies a direct IRIG-B signal voltage to the output terminals, while the modulated driver uses IRIG-B to modulate a 1000 Hz audio signal, and applies the resultant to the output terminals. Both unmodulated and modulated output drivers are in wide use in NPCC, and the group takes no position at this time as to which is superior,

There are significant variations in the methods of interconnecting GPS receivers with DREs. The group feels that more work needs to be done in this area. Work accomplished so far is contained in Appendix B, "Distribution of IRIG-B Time Signal."

H. RTU Time Synchronization

RTUs have internal clocks that drift like the clocks of any other computer device. RTUs along with other substation devices are often required to time tag events, automatically freeze accumulators or perform specific events at timed intervals. In order to support these time-related activities a dependable and accurate time source is required. There are a number of methods that can be used to synchronize the clocks of substation equipment, (RTUs, IEDs, PLCs, relays, etc). Listed in the order of preference when performance and accuracy are the objectives:

1. Install individual GPS receivers at each substation and propagate the time signal over an IRIG-B network, either over fiber or copper.
2. Use a centrally located GPS receiver and propagate the time signal over an IRIG-B network either over fiber or copper (see Appendix B).
3. Use the centrally located time from the master station, SCADA/EMS, and disseminate the time over the RTU communication channel. (The DNP protocol supports this type of synchronization.)

The third method is very cost effective but requires that the SCADA/EMS support time synchronization through the RTU communication protocol. To synchronize the RTU clock the master station must be able to anticipate (i.e. measure) the propagation delay from the master station to the substation and apply the correct time to synchronize the RTU. The channel propagation delays vary according to the type of communication (point-to-point, multipoint or frame relay) circuit used. Depending on the type of communication used the performance will be inconsistent. Using this method for synchronization, anecdotal evidence suggests that the client time accuracy (RTU, IED) can vary from 20-75 milliseconds. This method should only be considered as a last resort.

The first method, using a GPS receiver connected directly (via IRIG-B), will provide the best accuracy and is the preferred method in that the delays are known.

The second method can be used if the wide area infrastructure is in place to be able to support the IRIG-B distribution. Evidence from implemented systems using this method has shown that 8-millisecond delay can be achieved.

I. Overall Accuracy of Time Signal to DRE and/or EMS/SCADA Systems

After consideration of the above factors, the working group will assume that, for an installation of a local time source (which includes the GPS receiver and coax cable up to 500 meters in length) at a substation, the time source system will provide time code to disturbance recording devices with up to a 1 millisecond delay and a 1 millisecond uncertainty. If all the listed recommendations are followed, including high receiver accuracy, such installations will be assumed to have a total uncertainty of -1 to +2 milliseconds.

For an installation of a central time source system, such as a GPS receiver at the control center, which distributes the time to remote disturbance recording devices in the substations, the uncertainty will also depend on the timing signal protocol and the communication channel.

For a distribution using IRIG-B time signal over fiber (SONET) communication network, a delay of up to 8 milliseconds (for a SONET system of approximately 1000km in length) with an uncertainty of -1 to +2 milliseconds can be achieved.

For a distribution using NTP over fiber communication network, the delay could be in the range of 50 milliseconds.

For a distribution using PTP, the delay should be much less than NTP. However, this is an emerging standard and is not presently supported by hardware in the industry.

J. Redundancy

It is a general position of the NPCC that if a function is of sufficient importance, it should be done redundantly. Applied to synchronized event data reporting, we interpret this to mean that if an event time is important, there should be at least two means of recording it.

The working group is recommending that DFR capability be provided at all Bulk Power System stations. It is well known that local fault analysis can be done without DFR capability at all stations. It is felt that the installation of such capability at all Bulk Power System stations will result in enhanced capability to provide synchronized event reporting times, and will result in an appropriate level of redundancy. Any individual DFR may at any time be out of service for a variety of reasons.

EMS event times are available more quickly than times obtained from DFR analysis following a disturbance, and thus provide another level of redundancy. However, as discussed in detail in another section of this report, there are significant latency times involved at the present stage of development.

Another aspect of redundancy is the possibility of providing 2 GPS clocks at a location, and interconnecting them to the synchronized equipment through a device known as an interconnection arbiter. As far as the working group has found, this has not been done in the power industry, and the group does not find sufficient reason to recommend it. However it is definitely important to make sure that we always know when a GPS has failed. This is covered elsewhere in this report. It is also highly desirable that each transmission owner keep a GPS receiver in stock as a spare. The cost of the spare receiver would be on the order of $2000 or less.

K. Monitoring

At least one form of GPS receiver loss of synchronization monitoring should be employed at all locations. Following are some recommendations for synchronization monitoring.

Receiver loss of synchronism, also called "loss of lock" contacts should be provided on all GPS receivers. These contacts should be connected to the SCADA/EMS system to provide indication of antenna, feed line, or receiver problems. Another approach would be to connect these contacts to a digital input of a disturbance recorder. Users would then need to make sure that this digital input is displayed and checked during routine use of the record display software. Ideally, both of the above should be done, but there is normally only one loss of synchronism contact, and in such cases the first option is preferable.

Receiver time code output can include a loss of lock indication. (See discussion of IRIG-B time code below.) Some manufacturers offer a method of determining if synchronization was available when a particular transient record was generated. This indication is typically displayed in a comment field contained within the record and can only be viewed using the manufacturers access and display software. Most DFR manufacturers offer a method of inserting the IRIG-B code in an analog or digital input which can be viewed in each record.

In the event an IED fails to receive an adequate external time signal, the IED will revert to an internal clock. Unfortunately most IEDs do not report that this has occurred. We urge manufacturers to develop the ability to alarm when the device has reverted to its internal clock. Most of the problems experienced with GPS receivers have been problems with antenna obstruction, antenna position, and antenna feed line, and the receiver loss of synchronism contact discussed above would provide indication for these common problems.

Naturally occurring power system events can be used to monitor the quality of synchronization to the UTC time scale at all locations which trigger for the events. We should take advantage of such events and confirm synchronization regularly.

III. ISSUES AFFECTING ACCURACY OF TIME STAMPING

It's anticipated that reporting of event times will be presented with a resolution in milliseconds, understanding that the uncertainty of the reported time may be several milliseconds. The Working Group suggests that event reporting by member companies have a total uncertainty of 2 milliseconds (-2 to +2). Sample event data presented in Appendix F illustrates that these results are achievable.

The accuracy of the time stamp will vary by manufacturer, and between the various models of protective relays and DFRs. Time stamping of events is affected by the sampling and scan rates of the IED. The method in which a change is detected within the device may also affect the time stamp. The time stamp will be recorded at the time the change is detected during the scan cycle of the IED.

The uncertainty of the time stamp assigned by a microprocessor relay for an oscillography record will typically range from one to four milliseconds. However, the time stamp for digital I/O can vary as much as 30 ms or more depending on the number of algorithms being processed in an IED at the time a change is detected.

The uncertainty of time stamping by DFRs (typically better than 500 microseconds) is generally better than that of a relay. Time stamping accuracy of a DFR is determined by the reciprocal of the sampling frequency. As an example a DFR with a sampling frequency of 3840Hz will have an expected uncertainty of 260 microseconds.

With advances in technology incorporated into relay and recorder products it is expected that the time stamping accuracy will improve. One manufacturer reports a time stamping uncertainty of 500 microseconds in their new relay product line.

The accuracy of the time stamp is also affected if an intermediate device such as a communications processor issues the time stamp. In these cases, the time stamp recorded in the communication processor for an event in a relay or a digital input/output change of state could be significantly delayed due to the scan rate of the communication processor.

IV. RECOMMENDATIONS FOR ACCURATE TIME STAMP DATA

The importance of providing correct time information on data that could be used to analyze system disturbances was recognized in the recent blackout report, and this report recommends substantial improvements to the current practice with the deployment of available technology to improve the quality of this data.

The following are the working group's recommendations in order to provide highly accurate time stamped data:

a. Use an accurate and reliable time source that is traceable to a recognized standard. GPS receivers provide the traceability required and are recommended for obtaining a time reference and should be used for all DREs installed in BPS substations. (There should be a "grace period" during which GPS receivers should be installed in locations which do not presently have them).
b. As systems are upgraded or replaced, order RTUs and other station devices with the ability to accept external time sources.
c. As systems are upgraded or replaced, specify robust SCADA/EMS software and communication protocols to handle time stamps from the remote stations.
d. GPS synchronization should also be provided for all protective relays which have fault recording capability in BPS stations. The working group suggests that the priority for this should be less than the priority assigned for disturbance recorder synchronization.
e. It is also recommended that GPS synchronization be provided for DREs and protective relays located at non-BPS stations where the relays may provide useful information following a wide area disturbance.
f. Monitor for loss of synchronization signals
g. Use current-zero for reporting time of line opening.
h. Use attached spreadsheets for format of event reports.

V. TIME TAGGING AN EVENT

There are a number of different times that may be associated with a power system event or disturbance. It is important when sharing information with others that the times reported be clearly identified. It is recommended that the current-zero time be recorded as the event time tag for wide-area disturbance reporting. A summary of the available times follows:

A. Trigger Time

Any triggered event record will have a trigger time associated with it. Usually this time will be part of the file name or linked to the file record. This trigger time is useful in identifying the records related to an event as it is the approximate time of the event.

B. Fault Inception Time

When analyzing a fault record there are several significant times. The first is the fault inception, or the time at the beginning of the fault. When there is a breakdown of insulation or a sudden phase to phase or phase to ground contact the current level will usually increase abruptly and there will be a phase angle shift from primarily resistive current to inductive current. To capture this, of course the recorder should be set to record several cycles of pre-trigger waveform. Occasionally the current will build up gradually to a point where it activates the overcurrent trigger. In this case there probably will not be sufficient pre-trigger record available to identify the fault inception.

C. Current-Zero Time

The end of the fault or opening of a line terminal where the current goes to zero is considered the current-zero, and each terminal that operates should be reported. Zero current is when the last monitored phase current equals zero. In the event only one phase current of a circuit is monitored this will be considered the reportable current-zero time.

The difference between phases is approximately 2.8 milliseconds, therefore when comparing current zero times of different phases the uncertainty could be plus or minus 5.6 milliseconds. Additionally, when comparing current zero times across a wide area the phase shift across the system will introduce a time difference. A one millisecond time difference represents a phase shift of 21.6 degrees.

D. Clearing Time

The clearing time (fault duration) is the time span from fault inception to fault current-zero. Transmission protection schemes are typically designed to have a maximum clearing time of six cycles. A typical clearing time for back-up protection is 30 cycles. When analyzing a fault, one measure of correct performance is verifying the fault duration was within the desired clearing time. Clearing time is comprised of two times, the relay operating time and the circuit breaker interrupting time.

E. Non-Fault Events and Wide Area Disturbances

In reporting circuit outages for wide area disturbances such as a blackout, the most precise time to use for the circuit interruption is the current-zero. This assumes that a record is triggered which captures the current-zero. A circuit breaker 52a contact input would accomplish this. This method also requires a recorder to be located at least at one end of each line, and in order for the 52a contact to trigger it the end with the recorder must trip. It further assumes that if a disturbance recorder is used, it’s recording the current waveform and not just an RMS signal; though the current-zero on the RMS record will be fairly accurate. This also assumes that sampling and recording rates are sufficient to provide the desired accuracy. A recording rate on the order of 720 HZ (12 samples per cycle) would be required to provide reasonable accuracy. If all three phases are available then the last phase to go to zero should be reported. If only one phase is recorded and it’s the first phase interrupted then the time reported would be for the phase recorded. In either event the report should include indication of whether it is the last phase or the only phase available.

Using the current zero method also requires analysis of each record and assembly of a sequence of events from these records. It may be possible with many EMS/SCADA systems to record SOE times at a central location. However, these times will be based upon breaker auxiliary contacts or auxiliary relays which introduce additional delays.

VI. THE DRD REPORT

The SS38-6 report "Review of Dynamic Recording Devices, Edition 2, 1999" (Reference 12, also known as the DRD Report) has been a valuable reference to this work and is available on the NPCC Member website along with other references. To some extent, this present report of SP-6 updates or takes the place of the DRD Report, and some quotations and content from the DRD Report have been incorporated into this work. However, the DRD Report has lasting value and should continue to be available to the membership.

Since the DRD Report was last published, there's been a terminology change, and references in the report to "Dynamic Recording Devices" or "DRDs" should be understood to be the same as what we are now calling "Dynamic Swing Recorders" or "DSRs."

A complete survey of Disturbance Recording Equipment within NPCC has been completed by SP-6, and this work completely replaces Appendix A and Appendix B of the DRD Report.

The listings of DSRs outside NPCC (Section 4.0 of the DRD Report) is a useful reference, however we have not updated it. Similarly, the listing of commercially available DSRs (Section 6.0 of the DRD Report) is a useful reference, but this is a maturing field with DSRs available from many more manufacturers, and we have not attempted to update this list.

VII. DYNAMIC SWING RECORDERS

A. Deployment

DSRs, which are capable of sufficiently long term recording to analyze power system oscillations and damping, should be installed at critical transmission stations and large generating plants (identified by NPCC) to provide recordings of electrical and mechanical behavior of the power system before, during and after major system disturbances. This information is necessary to ensure that data is available to evaluate power system performance and determine the cause of system disturbances related to power system oscillations. Recorded data is also important to validate power system simulation models and to improve the accuracy of simulations.

The following is a quotation from Section 1.2 of the DRD Report:

"The NPCC Working Group on Review of Reliability of Inter-Area Operations (COSS-2) conducted a number of studies intended to replicate system response to a number of planned and unplanned events. The Inter-Area Dynamic Analysis Working Group (SS-38) has continued this work. The information obtained from Dynamic Recording Devices (SP-6 is using the term DSRs) proved to be extremely useful during event reconstruction. ….COSS-2 concluded that additional suitable recorders were required over a wide geographic area, not only to assist in event reconstruction, but also to provide insight into the physical nature of the oscillations observed."

The DRD Report presented minimum technical requirements which include the ability to record system frequency variations, a 20-30 second recording window, the ability to capture system oscillations of 0.2 to 2 Hz, the ability to trigger for significant system events (including low frequency oscillations), and time synchronization to at least 10 ms. These minimum technical requirements were written several years ago and are exceeded by the recommendations in this report.

The locations of DSRs can be selected with the help of time-domain simulation or small signal analysis to help identify the most critical substations where local and inter-area power system dynamics can be monitored. With time-domain dynamic simulation (non-linear transient/dynamic stability analysis), we should be able to tell which stations exhibit the largest swing during disturbance. With small signal analysis (linear eigen-value analysis to identify the oscillation modes and mode shapes), we should be able to determine for a certain oscillation frequency, i.e. 0.5 Hz, which stations and what analog quantities can be used to observe the oscillation. Combining time-domain dynamic simulation and linear based small signal analysis, we can identify the critical stations to site the DSR.

Lacking such analysis, the working group suggests that DSRs should be well distributed across the NPCC Region. The Area security coordinator should be a part of such decisions. (SP-6 intends to produce a map showing present locations of DSRs which will be used to seek guidance from other task forces as to locations where DSRs should be added in the future.)

It is important to note that, at the present stage of development, it is possible to include DSR functions in the same chassis with DFR functions. Thus, whenever a DFR is to be upgraded, it is possible to add DSR functionality without greatly increasing the total cost of the upgrade. The working group recommends that the addition of DSR functionality should be considered whenever a DFR is to be upgraded.

B. <u>Channels</u>

When feasible, all BPS circuits within the selected stations should be monitored, including BPS transformers. The monitoring of transformers at some stations could provide information regarding load characteristics during system disturbances. The DRD report (Reference 12) points out that there are a significant number of voltage-only installations which have evolved from an old NPCC project on frequency monitoring, the "MDFR" project. Much valuable experience has been gained from these installations, and they should be maintained and updated to include both frequency and voltage magnitude channels.

When feasible, at least a single phase of analog current per line and a voltage from the same phase should be monitored. Stability simulations assume that the post-fault response of the power system is balanced in the three phases, therefore monitoring the single phase should provide satisfactory results and reduce by two-thirds the amount of data needed to process and store. The basic design of a DSR shall not preclude the use of all three phases.

Digital inputs, such as circuit breaker status and protective relay output contacts, may also be monitored in DSRs.

C. <u>Maintenance</u>

Periodic maintenance should be performed on DSRs to assure their accuracy and availability. The communication channels used for accessing records remotely should be verified monthly. Proper recording of analog channels should be verified and compared to the records captured when the DSR was commissioned to confirm all channels are recording accurately. Time synchronization should be checked by observing the coincident operation of DREs for a power system event where analog waveforms at distant stations establish a common reference. If a DSR is found defective, repairs should be performed on a priority basis to identify the problem and recommend parts replacement or field repair.

A final documentation package, including equipment arrangement drawings, cabinet and equipment wiring and interconnection drawings, maintenance manuals and test reports should be kept at the station.

D. <u>Monitoring</u>

Alarm outputs should be connected to the SCADA system to provide indication of recorder problems. Alarms that should be included at a minimum are: Power Supply Failure, Storage Device Failure (Hard Drive, Non-Volatile RAM), and Storage Device Full. If the recorder has the capability, loss of IRIG-B input should also be alarmed. (The capability to alarm for loss of IRIG-B time synchronization is currently not available in DSRs. However, some manufacturers offer a method of verifying the presence of the IRIG-B source in an event record. There are also methods available to convert the IRIG-B source to an analog or digital input to visually verify the presence of the IRIG-B source when viewing a record.) The industry should lobby the DSR manufacturers to develop this capability.

E. <u>Triggering</u>

Both analog and digital triggers should be used to capture system disturbances. Past experience has shown that system frequency is the best indicator of system abnormality. Therefore delta frequency and frequency rate-of-change are the most important triggers for wide area monitoring. Significant experience has been accumulated in NPCC on setting these frequency triggers. In addition, over/under current and voltage, rate of change of voltage and power, etc., can provide additional trigger opportunities. An area of current research involves triggering on oscillations. At the present time there are two installations in NPCC which trigger on oscillatory behavior of frequency. These locations are Northfield, MA and Edic, NY. Although these triggers had been in service for only a short time at the time of this report, they have been quite successful.

Power Swing Blocking or Out-of-Step Tripping elements of transmission line protection or generator protection systems are two examples of useful digital inputs that may be used as triggers if they are available at the swing recorder location. Additionally the operation of any protective relay in a station could be used to trigger the operation of a DSR.

F. <u>Record Duration, Data Rate, and File Size</u>

The pre-trigger and post-trigger recording time must be sufficient to capture the beginning and the end of a disturbance. If the trigger condition is detected again while recording is in progress, recording should continue until the magnitude of the triggering quantities stabilizes at a level that no longer meets the trigger condition. A typical dynamic event could be anywhere from 1 second to 60 seconds.

Obviously a tradeoff exists among the parameters of record duration, data storage rate, and record file size. With the local storage capacities that were available in the past, and with transfer of files over dial-up telephone lines, it was necessary to keep the record file size fairly small. The following are examples of some existing systems.

72 second record duration, 6 Hz data storage rate (1990)
90 second record duration, 10 Hz data storage rate (1999)

Such systems continue to provide very useful information and are adequate to observe the important system oscillation modes, which are generally in the area of .25 to 1.0 Hz. A minimum 30 seconds pre-trigger and 60 seconds post-trigger recording window, with data rate of at least 10 Hz, is recommended for future installations. We recommend that future DSR installations be able to accurately observe system oscillation in a range exceeding 0.2 to 2.0 Hz. DSR installations should always retrigger when a trigger parameter is exceeded during the post-trigger period. The maximum record length should not be limited, unless storage restrictions make such limitation necessary.

In the future, with continuing advances in local storage capacities and communication technology, it should be possible to take advantage of greater record lengths, and faster data storage rates (such as 60 Hz., i.e., one sample per cycle, or higher). Continuous recording capability is now technically feasible, and should be considered for future installations.

G. Data Format

DSR records should be stored in the native file format on a shared server which is backed up periodically.

When sharing files, the records shall be converted to COMTRADE. However, it must be noted not all COMTRADE conversion utilities function in the same way and information contained in the native file format of a DSR may not be carried into the new file, so it is important to retain the native file. The COMTRADE standard is listed as Reference 13.

When naming a file for sharing or archiving, the date and time should be contained in the file name. Please consult the IEEE document *"File Naming Convention for Time Sequence Data - Final Report of IEEE Power System Relaying Committee Working Group H8"* (COMNAMES) (Reference 14). This document is an IEEE Committee report, however work is presently underway to make it a standard. The group assigned to prepare the standard is working group H8 of the Power System Relaying Committee.

H. Other Recorders

There were several additional categories or variants of DSRs which were explained in DRD report. These are as follows:

1. Phasor Measurement Units (PMUs)
   PMUs are included in the survey, and those PMUs which are installed at present within the NPCC Region are functioning as dial-up DSRs. PMUs have an important advantage in that they sample synchronously at all locations. This simplifies some kinds of dynamic analyses. Those PMU's presently installed in NPCC also have the capability to continuously output their data to a central collection point. Many benefits are claimed for

collecting and analyzing such data over a wide area. One of the benefits expected to result in an early return is visibility into neighboring regions. Information on the Eastern Interconnection Phasor Project is available at: http://phasors.pnl.gov/EIPP_About.html.

2. Power System Stabilizer (PSS) Recorders.
   Such recorders are primarily intended to aid in setting up stabilizers and to assess stabilizer performance during disturbances. Although essentially the same as DSRs, they are viewed as a possible source of supplementary information, not as a primary source. These recorders were included in the DRD Report, but are not included in the present survey.

Area control center high speed sampling systems are in operation at some NPCC control centers. Such recordings have been very useful in investigating disturbances in the past. Control centers normally have particularly good and compete telemetry on their control area tie lines. Sampling frequencies of such systems are in the range of 4 Hz to 10 Hz. Such control center recorders were included in the DRD Report but are not included in the present survey.

VIII. DIGITAL FAULT RECORDERS

A. Deployment

DFRs should be installed in all Bulk Power System transmission substations. DFRs should also be installed in stations that are transmission inter-ties or interconnections for large generation facilities. It is well known that local fault analysis can be done without DFR capability at all stations. However, the installation of such capability at all Bulk Power System stations will result in enhanced capability to provide synchronized event reporting times, and will result in an appropriate level of redundancy since any individual DFR may at any time be out of service for a variety of reasons.

B. Recorder Performance

A DFR record must be of sufficient length to accurately analyze a system disturbance. A record duration of one-second is considered sufficient to capture a transient. However, it's important for the configuration of the DFR to be tailored to the application based upon the characteristics of the DFR and the protection elements in service on the system. Consideration must also be given to the time stamp method in a record as some DFRs require a minimum record length of 1.25s to mark the second of the IRIG-B pulse for accurate time-stamping.

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). Most manufacturers of microprocessor based relays require up to 60-cycles of pre-fault to fully initialize voltage memory circuits to function accurately. Relay testing software allows replication of waveforms, where the 10-cycles of pre-trigger can be replicated six times to create the necessary pre-fault values to test a relay.

The DFR sampling frequency must be high enough to use the records to verify system models. The sampling frequency also must be sufficient to allow capture of harmonics related to transient conditions such as breaker re-strikes. It's recommended that a DFR have a minimum sampling frequency of 3840 Hz (64 Samples/Cycle).

C. Channels

To facilitate fault analysis and review of protection system operations, and to enable the performance of dynamic simulation tests, all BPS circuits within a station should be monitored. At minimum, two-phases of a delta connection and three-phases of a wye connection need to be monitored for analog current and voltage (voltages may be common to other switchyard elements). This allows for calculation of the channel not being monitored using symmetrical component calculations. However, it is advisable that all current and voltage phases be monitored. Monitoring of all three-phases also provides a method for checking the health of the current and voltage transformers (or CCVTs) which may also be monitored by relays. Where DFRs are installed at substations with a majority of digital relays, some compromise of channel assignments may be considered.

Digital inputs to a DFR should not be limited to circuit breaker open or relay output contacts. Additional digital inputs should be used to allow for the evaluation of protection system performance (i.e. Carrier Start, Carrier Stop, Carrier Receive, and other pilot channel functions).

D. Maintenance

Periodic maintenance should be performed on DFRs to assure their accuracy and availability. The communication channels used for accessing records remotely should be verified monthly. Proper recording of analog channels should be verified and compared to the records captured when the DFR was commissioned to confirm all channels are recording accurately. Time synchronization should be checked by observing the coincident operation of DREs for a power system event where analog waveforms at distant stations establish a common reference. If a DFR is found defective, repairs should be completed with the same priority given to protective relays.

E. Monitoring

Alarm outputs should be connected to the SCADA/EMS system to provide indication of recorder problems. Alarms that should be included at a minimum are: Power Supply Failure, Storage Device Failure (Hard Drive, Non-Volatile RAM), and Storage Device Full. If the recorder has the capability, loss of IRIG-B input should also be alarmed. (The capability to alarm for loss of IRIG-B time synchronization is currently not available in DFRs. However, some manufacturers offer a method of verifying the presence of the IRIG-B source in an event record. There are also methods available to convert the IRIG-B source to an analog or digital input to visually verify the presence of the IRIG-B source when viewing a record.) The industry should lobby the DFR manufacturers to develop this capability.

F. Triggering

Analog and digital triggers should be used to optimize the recording of system faults, protective relaying performance, and abnormal system conditions. Typical analog triggers are over-current, over and under-voltage. Typical digital triggers include circuit breaker change of state and protection system operations.

Settings of trigger values in a DFR may vary by location. Evaluation of triggers should be done periodically after the initial commissioning of a recorder and adjustments made as necessary. This process will help to eliminate spurious triggers, whereby unnecessary records are generated.

It is important to understand the operating characteristic of each manufacturers digital fault recorder to ensure that it is configured to capture all desired system events. In some DFRs the operation limit of a trigger is settable. Incorrect application of these limiters could prevent the DFR from recording critical information.

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

- Positive Rate of Change
- Negative Rate of Change
- Total Harmonic Distortion Trigger
- Positive Sequence
- Negative Sequence
- Zero Sequence
- Impedance
- Frequency Deviation
- Delta Frequency
- Frequency Rate-of-Change

The Positive and Negative Rate-of-Change triggers can typically be applied to current, voltage or frequency channels. The rates of change are specified by the user.

The Total Harmonic Distortion trigger can be applied to current or voltage channels and will trigger for a value over a preset threshold. Voltage is a better indication of harmonics present on the system however current transformers have a better frequency response over a wide range of frequency. Voltage transformers and especially CVT's have poor frequency response at other than the fundamental frequency.

Positive, Negative and Zero Sequence triggers can be applied to voltage or current channels and will trigger for a value over a preset threshold. These channels must consist of three phase groups. The current channels must be from the same line. The zero sequence trigger can be very useful for detecting ground faults because it can be set more sensitive than load current. When applied to a three phase voltage or current group it can take the place of an "over" trigger on a neutral voltage or current channel.

Frequency triggers are applied to a frequency channel usually derived from a voltage channel. Frequency Deviation is an under and/or over frequency trigger from a fixed normal frequency, typically 60 Hertz. Delta Frequency is also a form of an over and under trigger but is based upon the sudden or step-change deviation from a slowly varying or rolling average frequency. This allows the Delta Frequency trigger to be set more sensitive than the Frequency Deviation trigger.

Rate-of-change of frequency triggers (df/dt) compare the rate-of-change of frequency to a setpoint, which if exceeded for a set time delay, will trigger the DFR.

A company should consider using these triggers to capture system events that could cause power swings or a wide-area outage. Records captured with these trigger settings would serve as a back-up to DSRs. Setting of frequency triggers should not be treated the same as a DSR, where triggers are set to capture the effects of load changes on the system. When selecting a frequency deviation trigger for transient recording, the trigger should be set higher than normal deviations for load changes in an area. Frequency deviation is affected in part by the inertia constant of the prime movers in a load area, and a prime mover with a high constant of inertia can ride through a shift in load with little or no change in frequency, where the opposite is true for a prime mover with a low inertia constant.

Any tripping relay operation or automatic breaker operation in a station should be used to trigger the DFR.

G. Data Format

Digital fault records should be stored in the native file format on a shared server which is backed up periodically.

When sharing files the records shall be converted to COMTRADE. However, it must be noted not all COMTRADE conversion utilities function in the same way and information contained in the native file format of a DFR may not be carried into the new file. The COMTRADE standard is listed as Reference 13.

When naming a file for sharing or archiving, the date and time should be contained in the file name. Please consult the IEEE document *"File Naming Convention for Time Sequence Data - Final Report of IEEE Power System Relaying Committee Working Group H8"* (COMNAMES) (Reference 14). This document is an IEEE Committee report; however work is presently underway to make it a standard. The group assigned to prepare the standard is working group H8 of the Power System Relaying Committee.

H. Dynamic Swing and Trend Recording

New disturbance recorders are multifunction devices providing many features. Some DFRs may also be used for:

- Dynamic Swing Recording
- Trending
- Sequence-of-Events
- Metering

Features such as dynamic swing recording and trending could offer insight into large wide area events and provide back up to other recording devices. Use of these features should be considered when installing a disturbance recorder with these capabilities.

IX. PROTECTIVE RELAYS as FAULT and EVENT RECORDERS

A. Deployment

Most microprocessor protective relays have recording capability for both fault waveform (oscillographic) records and SOE records. They generally do not have longer term recording capability characteristic of DSRs. Occasionally, a protective relay may be deployed not as a protective device but merely for its recording and fault locating capability. When used in this way the same considerations should apply as those for fault recorders (see section VIII.B). However, because fault recorders are better suited than protective relays to the job of fault recording for many lines within a station, this practice is not recommended. One of the main functions of disturbance analysis is to verify proper relay performance; therefore it is desirable to have an independent device for fault recording rather than using the same device for both protection and fault recording. A single problem or failure will not cause both the protection device to fail to operate or to operate improperly and the recording device to fail to operate or to record invalid signals (this is not to be confused with the application of 'dual high speed' protection commonly used today). Another main advantage of DFRs is the recording of multiple transmission line voltages and currents during the clearing of a specific line fault along with the additional event recording throughout a station for teleprotection and circuit breaker operations.

Relays that are deployed as protective devices must be deployed to meet the needs of the protection application, first and foremost; nothing related to the fault recording function of the relay shall be allowed to compromise the protection function. When relays are deployed in transmission substations, especially those which do not have separate fault recorders, then the fault recorder capability of the relays should be used to the optimum extent possible without compromising the protection function. At least one relay on each line or protective zone should be capable of fault recording.

B. <u>Channels</u>

Analog channels used on a protective relay must be chosen to meet the needs of the protection. Generally this will mean three or four (neutral) phases of current and possibly three voltage phases (depending upon the relay type). The relay could have voltage channels for monitoring a $3V_0$ (broken delta) voltage or this may be done internal to the relay. The relay may also have a channel for monitoring a separate phase voltage on the other side of a circuit breaker for synchronizing or synch-check functions. Care must be taken to connect an analog quantity to the intended analog input, even if that function is not used, as it may cause the relay's protective functions to operate incorrectly. For instance, connecting something other than $3V_0$ to that channel, even if those functions using $3V_0$ are not used, may affect the relays performance. Also the selection of ct and vt ratings and ratios must be done to optimize the protection function, not the recording function.

Most relays also have inputs for monitoring status of external contacts, usually referred to as digital or binary inputs. These inputs may require a particular type of contact or they may accept a variety of configurations; either dry (isolated) or wet (with a d.c. voltage on one side) contacts and either normally open ("a") or normally closed ("b") contacts. These external contacts can provide circuit breaker and disconnect position (open or closed) as well as provide information from other relays or devices, such as electromechanical relays or pilot channel receivers and transmitters. These external inputs can be valuable in verifying proper operation and timing of devices. However, as with binary inputs to fault recorders or Sequence of Events Recorders (SER) the user must take into consideration the timing and characteristics of the input contacts and the devices driving them. For instance, if an interposing relay is used to provide contact multiplication, the additional time of that interposing relay must be considered in the analysis. Some contacts will experience contact bounce which will give an intermittent indication of the change of state. Others will have fixed or programmable de-bounce timers designed to override the intermittent signal and provide a solid signal. While this may have some benefits, it can also mask the real contact times. Also the sampling rates of the relay binary inputs must be considered. A 52a contact is preferred for circuit breaker status monitoring because the 52a contact changes state closer to the parting of the main circuit breaker contacts than does the 52b contact which may be as much as a few cycles slower. As with other considerations, the contact inputs to the relay must first meet the needs of the protective function and those used for SOE recording should not compromise the protective functions.

In addition to external inputs, the relay fault record and or SOE record will usually include indication of status changes for internal functions within the relay. For instance, the record may show when a particular zone or overcurrent element operated and then when the timer associated with that element timed out and the trip output was initiated. These are particularly useful in analyzing the operation of a relay.

C. Maintenance

Maintenance of the protective relay should be done on a schedule to meet the needs of the protective functions as required by the manufacturer, NPCC, or the individual utility standards, whichever is most stringent. Maintenance for the recording function should include verifying the recording function triggers as programmed, verifying the calibration of the relay vs. the test quantities injected. Remote communications should be tested monthly for those relays that record in lieu of a DFR. Records, especially those from multiple stations for a single power system fault, should be checked regularly to verify time synchronization between recording devices locally and at remote stations.

D. Monitoring

In addition to monitoring the operation of the protective functions of the relay, there should be a contact output to the SCADA/EMS system indicating that a record has been created. Alternatively, the records may be uploaded to a central server for access at a later time. Relays have limited record storage capacity and therefore need to be interrogated and the records downloaded shortly after an event to prevent them from being overwritten. At the present, most relays don’t have the capability to close a contact to send an alarm on loss of synchronization with the referenced IRIG-B time. The industry should lobby the relay manufacturers to develop this capability.

E. Triggering

The triggers that can be used to initiate a record on a relay are generally the various protective functions. The default trigger is usually the trip signal.

However overcurrent (50, 51, 67) and over (59) and under (27) voltage functions can also be used as can over and underfrequency (81) and other relay functions such as distance elements (Zone 1, 2, 3, etc.) and timer outputs. Elements that initiate timers such as Zone 2 distance can be used to initiate a record at the beginning of a fault while the trip output can be used to trigger a record at the end of a fault thereby recording both regardless of the record duration. In many relays, elements may be set to trigger regardless of whether they are used as a protective function. In fact, using elements that are not part of the protective function allows them to be set more sensitively in some cases. However, care must be taken to make sure these elements are not set to trip or work in the trip logic. Setting triggers using elements other than the protective functions allows records to be triggered for faults outside the protective zone for that relay. Another useful trigger is upon reclosing to verify reclosing times and to capture the beginning of the second fault if it is permanent. While this can create a large volume of records, these additional records can often provide valuable information about the event. As mentioned above, external contacts can also be connected to trigger records (cross-trigger from other protection group). This allows records to be triggered by electromechanical relay schemes and schemes for other zones of protection. Since relays generally have limited storage capability, triggers settings should balance the need to retain data for analysis of initiating conditions, and attempt to prevent loss of data due to having records overwritten.

F. <u>Record Duration</u>

Recording duration capability of relays tends to be very limiting. This is one of the major disadvantages of relays over fault recorders. The total recording capability is fixed by the memory size, the sampling or recording rates, the record length and the number of records. The relay usually allows the user to program a record duration or the number of records. One value determines the other. For instance, a relay may allow the user to program 16 records of 8 cycles duration or 8 records of 16 cycles duration or 4 records of 32 cycles. Newer relays allow the user to also program the sampling or recording rate and tend to have larger memory sizes. Relays usually do not have as many options for specifying record length as do fault recorders. While some fault recorders allow specifying pre-fault (or pre-trigger), post trigger, and a maximum record length or a post fault length (after the trigger resets), most relays only allow the user to set a pre-trigger and record length or number of records. A record length should allow recording of the entire fault including several cycles post fault. That could be 30 or 60 cycles or more for step-distance or time overcurrent functions. This is not practical for most relays, though it can be done with fault recorders. As mentioned above, judicious use of triggers can ensure recording the beginning and end of a fault, but changes in between may be lost. In some cases, during a longer duration evolving fault, a third record may be triggered by a different relay element between the initial record and the final record. For instance a single phase to ground fault which triggers on the pickup of a 67N element may evolve into a phase to phase fault and trigger a second recording on a phase distance or overcurrent element, then trigger a final record from the trip signal. When determining the maximum number of records, the user must consider reclosing sequences and restoration that might occur before the records can be retrieved. A single fault could generate 2 to 6 records or more including intermediate records, reclosing and restoration. Under severe weather conditions this could occur more than once in a 24 hour period. Prompt retrieval of records is important to prevent the loss of records. Unfortunately, unlike most fault recorders, the relay is not capable of initiating the sending of a record to the master station upon occurrence of a fault, a function called auto-calling. Nor is most relay master station communication software capable of time based auto-polling; the polling must be initiated manually.

G. Data Format

Protective relay fault records should be stored in the native file format on a shared server which is backed up periodically. When sharing files the records shall be converted to COMTRADE. However, it must be noted 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.

When naming a file for sharing or archiving, the date and time of the event trigger should be contained in the file name. Other information that should be included in the file name is listed in the IEEE document *"File Naming Convention for Time Sequence Data - Final Report of IEEE Power System Relaying Committee Working Group H8"* (COMNAMES).

H. Dynamic Swing and Trend Recording

With the possible exception of out-of-step relays the memory size and triggering capability of relays do not lend themselves to dynamic swing recording. Many relays have the ability to record instantaneous and or demand values at very course intervals ranging from one minute to one hour for as much as a month or more. This data is valuable for planning purposes but is of little value for monitoring abnormal conditions or disturbances. Out-of-step relays should be considered as a possible external trigger to a dynamic swing recorder.

I. Other Considerations

1. Time Synchronization
   Time synchronization of microprocessor relays is as important as time synchronization of fault recorders. A system disturbance may cause multiple protective relays within more than one substation to produce records. While they may not contain essential information, often more than one relay will. The issues noted in Section III "Issues Affecting Accuracy of Time Stamping" limit the relative accuracy of time stamps in protective relays.

2. Redundancy

Redundancy in fault recording can be achieved in many ways. It is not required to have redundant devices recording each phase of current and voltage on every line or protective zone. If fault recording relays are deployed along with fault recorders or if multiple fault recording relays are deployed then the redundancy should be taken advantage off. In some cases one device may trigger a record while a second device may not. In other cases both may trigger a record. In these cases the records should be compared as a check on the accuracy and calibration of the two devices as well as how they may differ due to different filtering, sampling rates, or other characteristics of the recording devices. When deployed on different instrument transformers, this redundancy can be useful in comparing the performance of the instrument transformers under fault conditions as well as verifying proper ratios and polarity.

3. <u>Filtering</u>
   Many relays employ filtering to filter out all but the fundamental frequency (60 Hz). In some relays the filtering is only done on the signal used for protection and the raw signal is recorded. In other relays the recorded data is filtered. The user must be aware of the techniques employed by a particular relay when analyzing an event as the filtering may provide a distorted representation.

X. SCADA/EMS TELEMETRY

A. Introduction

This section will focus on: describing the current practice of RTU to SCADA/EMS data collection; describing the issues and difficulties that telemetry time skew causes in recreating sequence of events; proposing the options and advocating a best practice approach to improve on the current practice. Although station based DSRs, DFRs, SOEs and digital protective relays are typically the most accurate recorders of power system disturbances, the historical data record for multiple stations are available from SCADA, and can add to disturbance investigation information.

One of the problems during the recreation of the blackout sequence of events was that the data provided was recorded and time stamped by SCADA and EMS systems when the data was received at each location. The data received at each SCADA/EMS location were anywhere from a few seconds to tens of seconds away from actual event time. This “telemetry skew” is also an issue for data within a SCADA/EMS due to the multiple RTUs that the data is collected from and also due to the asynchronous scanning of the RTUs.

Traditionally this inherent telemetry skew has not been an issue because the primary purpose of SCADA systems has been for monitoring and control and not for precise post-event analysis of power system disturbances. For localized disturbances, SCADA/EMS systems provide operators a record of the sequence of events which they can use to take appropriate actions.

B. SCADA/EMS Data Collection Process

The NERC Guideline on *Time Stamping of Operational Data Logs*, *version 0.9.1 draft* captures the essence of the current SCADA/EMS data collection process:

"Telemetry skew happens when communication delays or scan rates cause the receipt of information to not occur strictly in "real time". For example, when a breaker in a substation opens, monitoring equipment in the substation should capture the time associated with the operation. At some point later, perhaps several hundred milliseconds, the RTU may detect the breaker operation, and capture the time. Later, the SCADA central server will poll the RTU, and detect that the status point associated with the breaker has changed, and store an updated point value in the database, optionally with a time stamp. Then, the SCADA alarm subsystem will generate an uncommanded operation alarm, with an alarm time associated, and present it to the SCADA system operator. Even later, the breaker status may be communicated to an ISO or RTO, and upon receipt of the status point, the updated value will be stored, timestamped, and perhaps alarmed at the ISO or RTO.

Each of these timestamps will be different due to scanning rates, communication delays, and system processor loads and message queue lengths. It is conceivable that the total time skew resulting from a telemetry sequence may exceed a minute. Of prime importance to the analysis of an event is the initial time stamp, which should be preserved for later analysis. Other time stamps may be used to determine when the succeeding systems found out that the point value was changed, but they will not be of primary use in developing an accurate electric system event timeline."

Referring to Fig. 1 below it is evident that an event is perceived as occurring at different times to different centers. The working group recommends that the following three fundamental changes be implemented to the SCADA/EMS data collection from Bulk Power System substations as systems are upgraded or replaced:

1. Implement devices and systems (RTUs, IEDs, PLCs, relays, etc) at the Bulk Power System substation that can time stamp data.
2. Implement the upstream systems and protocols to be able to propagate the time stamp information.
3. Provide an accurate and reliable time source at the substation that is traceable to a recognized standard. GPS receivers provide this capability.

The end result of the working group's recommendation will be that the device or system that senses the actual event (relay, PLC, RTU, IED, etc.) will have the capability to time stamp the event and the time stamp will be able to be propagated along to the upstream system. The upstream system will be able to accept and report the time stamp. Additionally the SCADA/EMS will be able to transmit the event along with its time stamp to ISO and RTO organizations via ICCP. Unfortunately, only the most modern substation devices, SCADA/EMS systems and protocols are able to fully process the source data time stamp. This includes many existing SCADA/EMS systems. It is not being advocated to replace existing operational systems. However, when systems are added, upgraded or replaced, this capability should be implemented.

It is recognized that it will take time before existing systems are replaced. In the interim, in order to substantially provide the capability requested without requiring whole change outs of systems, new Bulk Power System substation RTUs, IEDs, and relays should be implemented with the capability to accept a local GPS time source, be able to time stamp the data and buffer and locally store this data for retrieval via offline means, i.e. other than through the SCADA/EMS. The locally buffered data can be retrieved by a dial-up download process or by local plug-in and download.

The ability to process the time stamp and pass it along should be a requirement for any intelligent device considered for use at a substation. The industry should move to upgrade the communications protocols which accommodate time stamping at the originating device. As devices and systems at the substation become more integrated, there may be a need for a substation computer that can also act as a protocol converter to communicate with the EMS, thereby precluding the need for a standalone RTU.

C. SCADA/EMS Time Reference

The servers and workstations that are part of SCADA/ EMS systems have internal clocks that will drift even if set to an absolutely accurate time reference, some by as much as several seconds a day. It's possible for the servers and workstation clocks to maintain millisecond accuracy, but only if their clocks are repeatedly reset over the course of a day. The challenge is to reset the clock before it drifts too far, and to do so using a time source that is accurate.

An accurate time must come from somewhere. How accurate that time needs to be depends on the application and operations to be performed. GPS receivers can provide an accurate and traceable time signal with accuracy to about 1 microsecond to UTC. With the implementation of a GPS receiver there are a couple of methods for synchronizing the SCADA/EMS server and workstation clocks to UTC time: 1) provide an IRIG-B distribution network and 2) provide the time signal to an NTP server in the SCADA/EMS network which can then be used to distribute UTC time locally to all the computers on the network. (NTP is an internationally recognized protocol for synchronizing the clocks on client machines with clocks on network time servers. NTP is available on virtually all computing platforms — either as a built-in service of the operating system or as widely available client software.) The working group recommends as a minimum, time synchronization of the SCADA servers from a GPS receiver with an IRIG-B network.

SCADA/EMS Data Collection Process

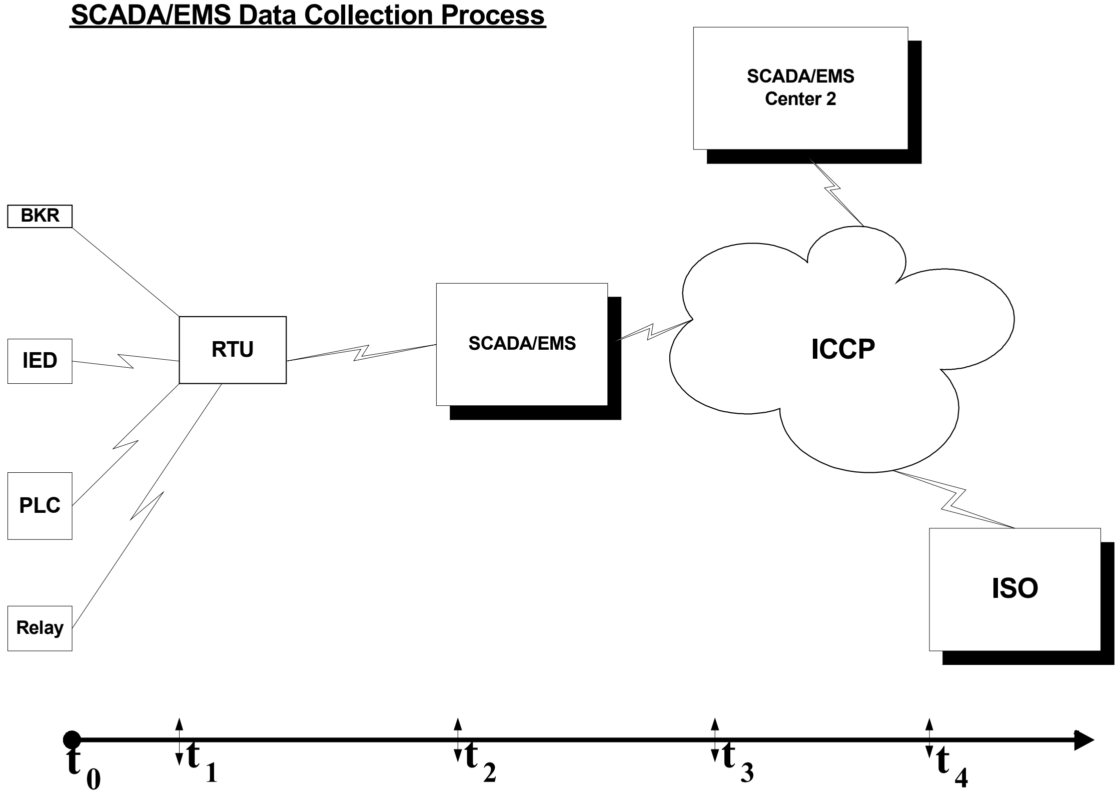

Fig. 1 Telemetry Timeline

When considering the time synchronization architecture to be applied, one must also take into account the path delays between the server and the clients (as well as the security of the time source). When devices communicate over an ethernet LAN, the propagation delay across the local network is assumed to be not better than a direct IRIG-B connection. When there are intervening WAN infrastructures, inconsistent delays between the client requests and server responses can produce inconsistent results due to network loading and the nondeterministic response of Ethernet networks. On a WAN, NTP client time accuracy can vary between 10 to 50 milliseconds, and individual time corrections can frequently vary by quite a bit more.

In the future as support for the recently approved IEEE 1588 increases, it should be explored for possible implementation (IEEE 1588 defines a protocol that enables the precise synchronization of clocks in the systems of a networked environment; IEEE 1588 was approved by the IEEE Standards Board Review Committee at its September 12, 2002, meeting).

XI. DATA RETENTION

Data should be retrieved from the recording devices on a regular basis to prevent records from being overwritten. Retrieved records should be maintained for two years (trigger events not related to actual system disturbances need not be retained). However, if records of a particular system disturbance may be used for other purposes, a company should maintain a separate archive of these events for future reference. Transients in these files may be used for dynamic simulations and/or the performance evaluation of protective relays.

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Appendix A

Northeast Power Coordinating Council
Task Force on System Protection

Synchronized Event Data Reporting Working Group (SEDR WG)

Scope

Overall Objective

Collecting event data after the Aug 14 blackout demonstrated the critical importance of time synchronization in establishing the sequence of events. The Working Group on Synchronized Event Data Reporting Working Group (SEDR WG) will take advantage of the lessons learned, and investigate the area of synchronized event reporting, and make recommendations for improvements to NPCC Criteria and other NPCC documents so that NPCC might better be able to quickly establish the event sequence after any future wide area disturbance. The SEDR WG will prepare a report, with appropriate background material clearly listing recommended changes to NPCC documents, to realize this objective. The SEDR WG will present this report at the NPCC General Meeting September 29-30, 2004.

The group, working in conjunction with appropriate Task Forces, will identify costs and benefits of recommended changes to NPCC documents.

The SEDR WG will take into consideration the following in the investigation:

Guiding Principle

To successfully reconstruct power system disturbances, all significant event times must be reported and analyzed relative to a common time reference.

Specific TFSP Areas of Concern: Digital Fault Recorders (DFRs) and Sequence of Event Recorders (SERs)

Document A-5, 2.7.2 states: "Event and fault recording capability should be provided to the maximum practical extent to permit analysis of system disturbances and protection system performance. It is recommended that these devices be time synchronized."

The SEDR WG will consider strengthening the above criteria statement to support the overall objectives, also addressing criteria on where such devices should be installed.

The problems briefly described below are known to have interfered with the August 14 investigation and should be addressed by the group:

Synchronization was, in some cases, not provided.
Synchronization was provided but not to the GPS System.
Synchronization was provided but was inoperative.

The inoperative synchronization condition was in some cases not apparent through alarms, and/or not obvious to the user. Some DFRs did not trigger under Aug 14 conditions due to those DFRs being configured to record on the occurrence of faults.

Specific TFCP Area of Concern – Dynamic Swing Recorders

Draft A-2, 2.3 - "AREAS shall install dynamic recording devices and provide recorded data necessary to enhance analysis of wide area system disturbances and validate system simulation models. These devices should be time synchronized and should have sufficient data storage to permit a few minutes of data to be collected. Information from these devices should be used in tandem, when appropriate, with shorter timescale readings from faults recorders and sequence of events recorders (SER), as described in the Bulk Power System Protection Criteria (Document A-5), paragraph 2.7.2."

The SEDR WG will consider strengthening the above criteria statement to support the overall objectives, also addressing criteria on where such devices should be installed.

Some of the above synchronization problems may also apply to DFRs.

General Synchronization Concerns

The device synchronization system of choice is clearly the Global Positioning System (GPS). The SEDR WG will investigate and provide background information on the GPS system. Millisecond resolution is expected of GPS times. What is the expected accuracy? What accuracy is required for this application?

Where Geostationary Operations Environmental Satellite (GOES) receivers still exist, are they acceptable? GOES is a satellite network that pre-dates GPS. Many GOES receivers are still in service. Will these need to be replaced with GPS receivers, and if so, how soon?

The result of these changes should be that times for the more important system events are fixed by more than one device.

The SEDR WG's recommendations will address maintenance of the various clocks, recorders and EMS equipment.

Dynamic Recording Devices (DRD) Report (presently assigned to SS-38)

The SEDR WG will make appropriate additions and revisions to the DRD Report in support of the criteria changes.

The survey work that needs to be done to support updating the DRD Report could be combined with survey work arising from this investigation. For example, the survey and tabulation could be expanded to include information on synchronization.

EMS Areas of Concern

Times were "stamped" at the receiving systems and were delayed by many seconds because of the volume of messages being received. The event times clearly should be established at the source.

Apparently many present communication protocols do not at present allow for time "stamping" at the source Remote Terminal Unit (RTU). The SEDR WG shall address this problem, and make changes needed that will result in source time stamping, recognizing that present EMS systems may not have this capability.

The SEDR WG will consider the adoption of criteria that will lead to source time stamping with GPS synchronization.

Related Items

The SEDR WG will address areas of reporting and presenting sequence of events data, for example what data is most important? For example, the time when the most important transmission lines ceased to be a conducting path, i.e. the time of current zero, are such significant events. The corresponding time for the most important generating units are likewise significant events. Make clarifications that would facilitate the reporting process.

The collection of records for analysis is not part of synchronization, but is related, and is definitely part of C-25 and the "DRD Report" which will certainly be impacted by this work. Both the DRD Report and C-25 are due for overall revision at this time.

NPCC Documents Affected Include the Following

Criteria Documents A-2 and A-5
C-25 "Procedure to Collect Power System Event Data" TFSP May 21, 2001
Report SS38-6 “Review of Dynamic Recording Devices” Edition 2, 1999, including Survey of Fault Recording and Sequence of Event Recording Capabilities

Outside Source Documents Include the Following

NERC Blackout Recommendations, February 10, 2004: Recommendation 12, "Install Additional Time-Synchronized Recording Devices as Needed."

NERC I.F.S1.M1 on disturbance monitoring.

Approved by RCC on March 18, 2004

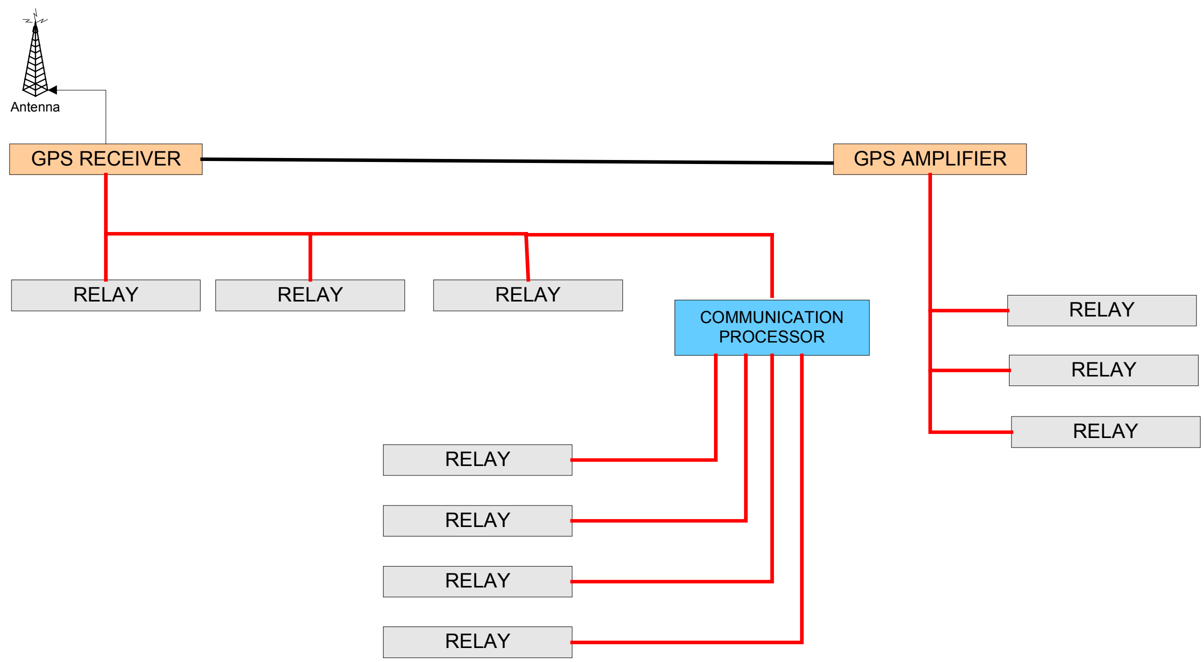
Appendix B

Distribution of IRIG-B Time Signal

There are several options for the distribution of the IRIG-B signal. The IRIG-B signal originates in an output driver of a GPS clock, and as explained previously in II.G. of this report, output drivers are of two types, which are unmodulated and modulated. Various output driver options are available. It is possible to purchase multiple output drivers in a GPS clock. It is also possible to purchase multiple output connectors that are all connected to the same output driver, which is much less desirable than multiple drivers.

The following general discussion of IRIG-B distribution applies to both unmodulated and modulated networks, unless otherwise stated.

The most common distribution methods are via coaxial cables using BNC connectors (with T-connectors to daisy chain multiple devices), shielded twisted pair copper, non-shielded twisted pair copper, and fiber optic. Yet another method for distributing the IRIG-B signal is using an intermediary device such as a communication processor. The signal may also be distributed through amplifiers that are designed for connection to the GPS receiver. Refer to diagram below.



IRIG-B Signal Distribution Diagram

The most common equipment connection methods are screw terminals, BNC, and DB9 serial connectors. Manufacturers may offer options in connectors. The group has considerable experience with using coaxial cable for both unmodulated and modulated networks, and offers the following recommendations for coaxial cable networks.

1. Use a good grade of nominal 50 ohm coaxial cable such as one of the variations of RG-58 (for example RG-58C/U).

2. Use 50 ohm “BNC” connectors for network connections, rather than open terminals, whenever possible. BNC connectors are mechanically reliable and maintain a constant impedance through the connection. Most sources indicate that “BNC” is derived from “Bayonet Neill-Concelman”, named for engineers responsible for the development of the connector. Both nominal 50 and 75 ohm versions are available, and only 50 ohm versions should be used. It is also suggested that good quality brands be used.

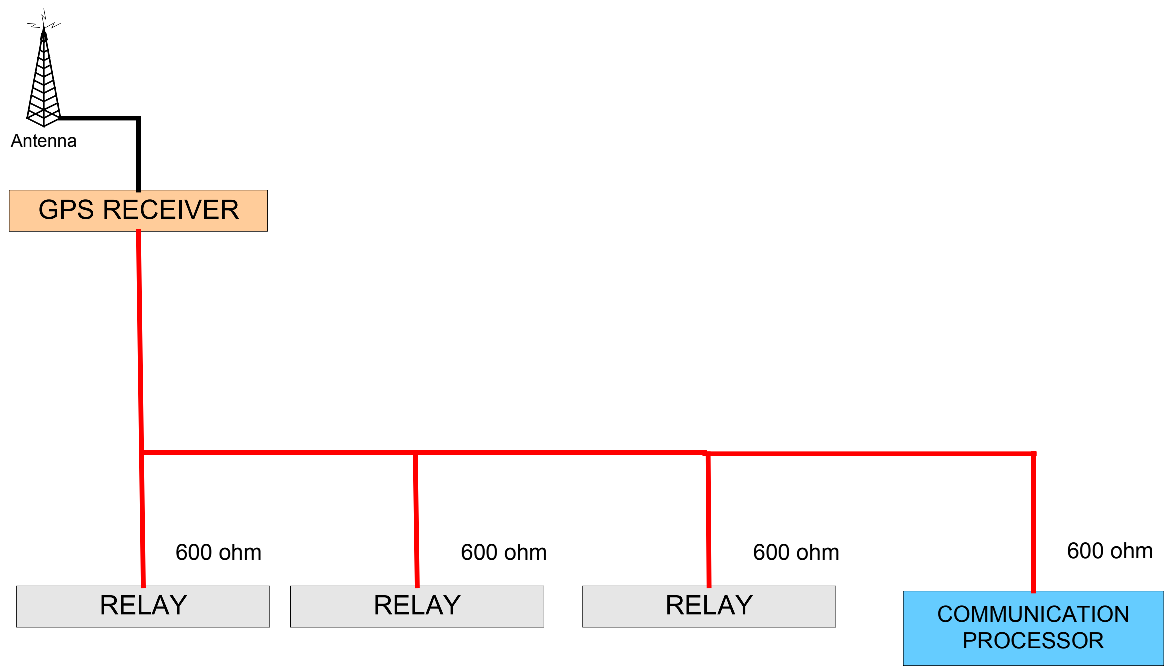
3. Limit the number of devices to the capacity of the output driver. An example calculation follows.

4. Limit the extent of the network to 500 meters total.

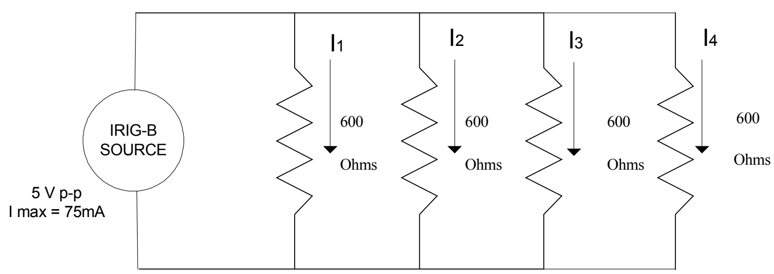
Multiple devices may be connected to a single output driver from the GPS receiver clock. However, it is important to not exceed the maximum output current of the output driver.

The following discussion and example apply to an unmodulated network. Typical output of a GPS receiver clock is 75 mA. A practical approach would be to limit the load of each receiver output to 80% of the output rating to maintain a good performance margin. Exceeding the output of the GPS receiver will affect the accuracy of the IRIG-B pulse, effectively rounding off the leading edge making it difficult for the receiving device to read the pulse. If a choice is made to load the output of the receiver near the maximum output, it is important to verify the integrity of the IRIG-B timing pulse. This may be accomplished by connecting an oscilloscope at the end of the distribution circuit.

The following example demonstrates the calculation of the current load presented to the IRIG B source generator. Each IED load on the IRIG B link presents parallel impedance to the source. For demonstration purposes the load impedance is the same for all devices. This is not typical and manufacturer specifications must be used to determine the actual impedance.



The equivalent circuit can be drawn as follows:



The general equation for parallel impedance is:

$$\frac{1}{Z_{Total}} = \frac{1}{Z_1} + \frac{1}{Z_2} + \frac{1}{Z_3} + \ldots$$

$$I_{Total} = I_1 + I_2 + I_3 + \ldots$$

Since the impedance is equal for each node in this example the current required for each load on the IRIG-B source (the current for one node) can be calculated and then multiplied by the number of nodes.

Therefore:

$I_1 = E_s / R_1$

$I_1 = 5 \text{ v} / 600\ \Omega$

$I_1 = 0.0083$ A or 8.3 mA

Total Load will then be:

$I_T = I_1 * 4$

$I_T = 8.3 \text{ mA} * 4$

$I_T = 33.2$ mA

NOTE: The above calculation does not take the cable losses into account. If done in this manner it is recommended that the IRIG-B output not be loaded more than eighty-percent of the maximum output to ensure the quality of the IRIG-B signal.

Appendix C
Survey Form for Disturbance Recording Equipment

Existing

Date Reporting: ______________________________

Person Reporting (Name): ______________________________

Email Address: ______________________________

Phone Number: ______________________________

	NERC 5A								NERC 5C		NERC 5D
			Disturbance Monitoring Equipment (DME)								
Area	**Location (Substation name)**	**kV**	**OSC**	**DFR**	**DSR**	**SER**	**PMU**	**Relay as DME**	**Equipment Owner**	**Data Owner (if applicable)**	**Equip. Type (Triggered or Continuous)**
New York	Example	345		X					XYZ	ABC	Triggered

NERC 5E	NERC 5G	NERC 5F	NERC 5F		NERC 5H		NERC 5H	NERC 5H		
Year of Installation	**Primary Purpose of Installation**	**Equip. Make**	**Equip. Model**	**Rem Acc.**	**H. Time-Synch Capability? (Yes - to what source? or No)**	**If "yes to H,is Sync Monitor?**	**I. If "no" to H, Plan to Add Capability?**	**J. If "yes" to I, When?**	**Status**	**Entry Date**
2000	Fault recording	DEF	555	Yes	Yes - to GPS	No			Active	8/4/2004

Appendix C (Cont'd)
Survey Form for Disturbance Recording Equipment

Planned

Date Reporting: ______________________
Person Reporting (Name): ______________________
Email Address: ______________________
Phone Number: ______________________

	NERC 6A								NERC 6C
Area	**Location (Substation Name)**	**kV**	**Planned Disturbance Monitoring Equipment (DME)**						**Equipment Owner**
			OSC	**DFR**	**DSR**	**SER**	**PMU**	**Relay as DME**	
New York	Example	kV			X				XYZ

	NERC 6D	NERC 6E	NERC 6F	NERC 6G
Data Owner	**Equip. Type (Triggered or Continuous)**	**Year of Planned Installation**	**Primary Purpose of Installation**	**Time-Synch Capability? (Yes or No)**
ABC	Continuous	2005	Monitor/analysis of dynamic performance	Yes

Appendix D
Event Data Collection Form
Transmission

This data file is intended to simplify the data collection and compilation process following major system disturbance.
Please fill the appropriate worksheet and return the file to NPCC.

TRANSMISSION WORKSHEET INSTRUCTIONS

TIME OPENED (CURRENT ZERO TIME) is the column in which you enter the time of each event to the nearest millisecond in the format of hh:mm:ss.sss using the 24 hour clock. If possible please enter the time when current is zero and not the time of the relay action or time of the record.

TIME ZONE is the column in which you enter the time zone in which you are reporting the events such as EDT, EST, etc..

TIME SOURCE is where the data for the event entry comes from, such as DFR, SER, SCADA, etc…

SYNCHRONIZATION METHOD is if the data is GPS/GOES synchronized or not synchronized.

TERMINAL/LINE NAME Please enter all transmission related events including lines, transformers, capacitors, etc. Enter the line name in the form of "to bus-from bus/line name" then what the event is(tripped, switched out, reclosed, autoreclosed, etc…). For example Acme South-Acme North/1 line tripped. If the event is equipment enter the event in the form of "bus type of equipment". For example Acme North Capacitor Bank #2 tripped.

PRE-DISTURBANCE LINE LOADING (MW) enter the line MW flow before the event.

PRE-DISTURBANCE LINE LOADING (MVAR) enter the line MVar flow before the event.

LINE NORMAL RATING (MW) enter the line normal MW rating during the event.

LINE 15 MINUTE EMERGENCY RATING (MW) enter the line 15 emergency MW rating during the event.

CAUSE OF TRIP enter the type of relay that cause the line to trip such as zone 1 distance. If the line was manually opened just enter operator as cause of trip.

NOTES/COMMENTS please enter any other relevant information about the event.

Date Reporting: ______________________________

Member System: ______________________________

Person Reporting (Name): ______________________________

Email Address: ______________________________

Phone Number: ______________________________

TIME OPENED (CURRENT-ZERO TIME) hh:mm:ss.sss	TIME ZONE	TIME SOURCE	SYNCHRONIZATION METHOD	TERMINAL/ LINE NAME	PRE-DISTURBANCE LINE LOADING (MW)	PRE-DISTURBANCE LINE LOADING (MVAR)	LINE NORMAL RATING (MW)	LINE 15 MINUTE EMERGENCY RATING (MW)	CAUSE OF TRIP	NOTES/COMMENTS

Event Data Collection Form
Generation

GENERATION WORKSHEET INSTRUCTIONS

TIME OPENED (CURRENT ZERO TIME) is the column in which you enter the time of each event to the nearest millisecond in the format of hh:mm:ss.sss using the 24 hour clock. If possible please enter the time when current or power flow is zero and not the time of the relay action or time of the record.

TIME ZONE is the column in which you enter the time zone in which you are reporting the events such as EDT, EST, etc..

TIME SOURCE is where the data for the event entry comes from, such as DFR, SER, SCADA, etc…

SYNCHRONIZATION METHOD is if the data is GPS/GOES synchronized or not synchronized.

UNIT NAME Please enter all generation related events. Report all machines in a plant as different entries.

PRE-DISTURBANCE NET REAL OUTPUT FROM ONLINE GENERATION (MW) enter the machine MW output before the event for each machine in the plant.

PRE-DISTURBANCE REACTIVE OUTPUT FROM ONLINE GENERATION (MVAR) enter the machine MVar output before the event for each machine in the plant.

UNIT CAPACITY DURING THIS TIME PERIOD (MW) enter each machine MW capacity during the time of the event.

CAUSE OF TRIP enter the type of relay that cause the machine to trip such as under/over voltage relay, under/over frequency, reverse power, etc... If the machine was manually taken off line just enter operator as cause of trip.

NOTES/COMMENTS please enter any other relevant information about the event.

Date Reporting: ______________________________

Member System: ______________________________

Person Reporting (Name): ______________________________

Email Address: ______________________________

Phone Number: ______________________________

TIME OPENED (CURRENT-ZERO TIME) hh:mm:ss.sss	TIME ZONE	TIME SOURCE	SYNCHRONIZATION METHOD	UNIT NAME	PRE-DISTURBANCE NET REAL OUTPUT FROM ON LINE GENERATION (MW)	PRE-DISTURBANCE REACTIVE OUTPUT FROM ON LINE GENERATION (MVAR)	UNIT CAPACITY DURING THIS TIME PERIOD (MW)	CAUSE OF TRIP	NOTES/COMMENTS

Appendix D (Cont'd)
Event Data Collection Form
Customers

CUSTOMERS WORKSHEET INSTRUCTIONS

TIME OPENED (CURRENT ZERO TIME) is the column in which you enter the time of each event to the nearest millisecond in the format of hh:mm:ss.sss using the 24 hour clock. If possible please enter the time when current or power flow is zero and not the time of the relay action or time of the record.

TIME ZONE is the column in which you enter the time zone in which you are reporting the events such as EDT, EST, etc..

TIME SOURCE is where the data for the event entry comes from, such as DFR, SER, SCADA, etc…

SYNCHRONIZATION METHOD is if the data is GPS/GOES synchronized or not synchronized.

TYPE OF LOAD SHED enter the type of load shed.

LOAD INTERUPTED (MW) enter the MW for each load shed event.

NOTES/COMMENTS please enter any other relevant information about the event.

Date Reporting: ______________________________

Member System: ______________________________

Person Reporting (Name): ______________________________

Email Address: ______________________________

Phone Number: ______________________________

TIME OPENED (CURRENT-ZERO TIME) hh:mm:ss.sss	TIME ZONE	TIME SOURCE	SYNCHRONIZATION METHOD	UF=Underfrequency, UVLS=Undervoltage Load Shedding, LV=Low Voltage MS=Manually Shed, OOS=Out-of-step, LT=Line trip, RAS=Remedial Action	LOAD INTERRUPTED (MW)	NOTES/COMMENTS

Appendix E

Major Time Zones of Canada & US

Offset	Code	Name	Abbreviation
0	Z	Universal Time Zone	UTZ
-1			
-2			
-3	-3s -3d	 Atlantic Daylight Time	 ADT
-4	-4s -4d	Atlantic Standard Time Eastern Daylight Time	AST EDT
-5	-5s -5d	Eastern Standard Time Central Daylight Time	EST CDT
-6	-6s -6d	Central Standard time Mountain Daylight Time	CST MDT
-7	-7s -7d	Mountain Standard time Pacific Daylight Time	MST PDT
-8	-8s -8d	Pacific Standard Time	PST

Daylight Saving Time Changeover Dates

Year	To Daylight Time @ 02:00 on:	To Standard Time @ 02:00 on:
2000	Apr 2	Oct 29
2001	Apr 1	Oct 28
2002	Apr 7	Oct 27
2003	Apr 6	Oct 26
2004	Apr 4	Oct 31
2005	Apr 3	Oct 30
2006	Apr 2	Oct 29
2007	Apr 1	Oct 28
2008	Apr 6	Oct 26

Time Zone Conversions

To Convert From		To UTZ Add	To ADT Add	To AST EDT Add	To EST CDT Add	To CST MDT Add	To MST PDT Add	To PST Add
UTZ		0	-3	-4	-5	-6	-7	-8
		1	-2	-3	-4	-5	-6	-7
		2	-1	-2	-3	-4	-5	-6
	ADT	3	0	-1	-2	-3	-4	-5
AST	EDT	4	1	0	-1	-2	-3	-4
EST	CDT	5	2	1	0	-1	-2	-3
CST	MDT	6	3	2	1	0	-1	-2
MST	PDT	7	4	3	2	1	0	-1
PST		8	5	4	3	2	1	0
		9	6	5	4	3	2	1

Conversions: ms, cycles, degrees

(60 Hz)

ms	cycles	degrees
1000	60	
500	30	
100	6	
50	3	
33.3	2	
16.7	1	360
15.3	11/12	330
13.9	5/8	300
12.5	3/4	270
11.1	2/3	240
9.7	7/12	210
8.3	1/2	180
6.9	5/12	150
5.6	1/3	120
4.2	1/4	90
2.8	1/6	60
1.4	1/12	30
0	0	0

Appendix F

Sample Event Data

On October 24, 2004, there was a single line to ground fault in a 345 kV capacitor bank at East Fishkill, NY. This fault was cleared normally, in about 3 cycles. The working group asked several engineers to use their available DFRs to observe the time that the fault current interruption was completed. We asked that these times be provided to the nearest millisecond. In this particular case, all of these DFRs were synchronized to GPS, so this information is not included in the table. The "Busses" column indicates how many busses exist between each recorder and the fault. The results of this inquiry were as follows:

Busses	Owner & Station	EDT	DFR
1	CH Roseton Swyd	10:29:54.922	LEM Ben
0	CH East Fishkill	10:29:54.920	LEM Ben
2	CH Rock Tavern	10:29:54.920	LEM Ben
3	CH Hurley Avenue	10:29:54.920	LEM Ben
2	NM Athens Swyd	10:29:54.919	Mehta Tech
2	NM Leeds	10:29:54.919	Mehta Tech
0	CE East Fishkill	10:29:54.921	LEM Ben
1	CE Pleasant Valley	10:29:54.920	USI
1	CE Dunwoodie	10:29:54.920	USI
2	NU Plumtree	10:29:54.921	E-Max
3	NU Norwalk	10:29:54.921	Hathaway
2	NU Frost Bridge	10:29:54.920 *	Hathaway

* Two cross-triggered DFRs at this location produced different results, 10:29:54.912 and 10:29:54.920. This situation resulted from a loss of IRIG-B input to one of the DFRs.

Appendix G

Disturbance Recording Equipment Survey Summary

SP-6 conducted a survey of DREs within NPCC, and has collected data for 298 stations (not all are BPS) in the region. The results of the survey are summarized here.

- DFRs are utilized at 239 substations in the region (some of these locations have multiple recorders). There also exists five oscillographs at three additional locations, but those three locations have no working recorders.
  - 184 of these stations use GPS synchronization for the DFRs.
  - 47 stations use other means for synchronization (at the time of the survey).
  - 98 stations have monitoring of the synchronizing signal.
  - 34 additional DFRs are planned for installation in the Region (some may be replacements)

- DSRs are installed at 39 substations in the region, although one of these is now out of service.
  - 36 of these stations use GPS synchronization for the DSRs.
  - 1 station is synchronized by a GOES clock (planned for replacement).
  - 14 stations have monitoring of the synchronizing signal.
  - 21 additional DSRs are planned for installation in the region – Many of these take advantage of the dual capabilities of newer DFRs.

- SERs and/or SER capabilities are reported to be installed at 178 substations in the region. Many stations get this capability through the SOE features of SCADA RTUs. The Working Group believes this capability may exist in several locations that weren't reported, since many respondents may have reported on stand-alone SER installations only.
  - 131 of the reported SERs use GPS for synchronization
  - 43 stations use other means to synchronize their SERs
  - 36 stations have monitoring of the synchronizing signal.
  - New stand-alone SERs are generally not installed in the region since SOE capability is available on other platforms (RTUs, DFRs, etc.).

- The Working Group attempted to survey locations where relays are used as DRE in lieu of DFRs. Many respondents identified facilities where microprocessor based relays were installed, but the concept of these being used "in lieu" of DREs was lost in the responses.
  - Many facilities throughout NPCC have digital relays installed.
  - Many of those reported are not synchronized.
  - Time stamps in some relays are less accurate than other DRE (even with GPS synchronization), and consideration should be given to this when evaluating locations for deployment of DREs.
  - Limited sampling rate, memory, record length

- PMUs are installed at 13 locations in the region, but all are presently in New York or Quebec. Four additional units are planned for installation in Ontario.