MEMORANDUM

To: Transmission Owners (TOs), Distribution Providers (DPs) that own transmission Protection System(s), and Generator Owners (GOs)

From: Texas Reliability Entity (Texas RE)

Date: March 23, 2012

Re: PRC-004-2a Protection System Misoperation Reporting Procedures Revision 0

This memorandum is being sent to all registered Transmission Owners (TOs), Distribution Providers (DPs) that own transmission Protection System(s), and Generator Owners (GOs) in the ERCOT Region. Attached is the Texas RE Procedure referenced in PRC-004-2a, Requirements R1, R2 and R3. This procedure becomes effective on April 1, 2012.

Quarterly misoperation reports will be due on the last day of the second month after each calendar quarter per the table below. All protection system misoperations shall be reported via the reporting procedure.

Reporting Period	Due Date
January 1 through March 31	May 31
April 1 through June 30	August 31
July 1 through September 30	November 30
October 1 through December 31	February 28

Please see attached procedural document and refer to the periodic data submittal form on the Texas RE website (http://www.texasre.org).

NOTE: The technical requirements, definitions, periodic data submission requirements and submission frequency are similar to those currently in the ERCOT Nodal Operating Guide, Section 6 and Section 8b, as developed with the ERCOT System Protection Working Group. New components in this procedure include the timeline for analysis and implementation of corrective action plans.

Texas Reliability Entity

Regional Criteria

Procedure For

Analysis, Mitigation and Reporting of Transmission and Generation Protection System Misoperations

NERC Reliability Standards PRC-004-2a, PRC-016-0.1, and PRC-022-1

Procedure for Analysis, Mitigation and Reporting of Transmission and Generation Protection System Misoperations

I. Introduction/Purpose

This document sets forth the Texas Reliability Entity (Texas RE) procedures for the identification, analysis and reporting of Misoperations of transmission and generation Protection Systems, Special Protection Systems (SPS) Undervoltage Load Shed (UVLS) and Underfrequency Load Shed (UFLS), as well as the development and implementation of corrective actions taken to mitigate future Misoperations per NERC Reliability Standards PRC-004, PRC-016 and PRC-022.

While protective relaying systems operate with a high degree of reliability and security, on occasion, relays and relaying schemes misoperate. Such misoperations can result in widespread disturbances and can have adverse effects on neighboring entities and systems. It is therefore imperative that all protective relaying operations be monitored for correctness, and if a misoperation occurs, that appropriate analysis is performed and corrective actions are taken to prevent re-occurrence.

Information submitted on Protection System Misoperations as part of this process will be treated as confidential. Such information will be maintained, distributed, and communicated in a manner consistent with Section 1500 of the NERC Rules of Procedure.

II. References

a. NERC Standard PRC-004-2a, 'Analysis and Mitigation of Transmission and Generation Protection System Misoperations'
b. NERC Standard PRC-016-0.1, 'Special Protection System Misoperations'
c. NERC Standard PRC-022-1, 'Undervoltage Load Shedding Program Performance'
d. Texas RE Misoperation Reporting Template
e. Texas RE Misoperation Reporting Attestation Form

III. Applicability

This procedure applies to the following Registered Entities:
a. Transmission Owners (TOs)
b. Distribution Providers (DPs) that own transmission Protection System(s)
c. Generator Owners (GOs)

IV. Protection System Misoperation Requirements

In the ERCOT Region, all possible Protection System Misoperations (unwanted trips, failures to trip when intended, failures to automatically reclose when intended, etc.) shall be analyzed by the facility owner(s) promptly and any deficiencies shall be investigated and corrected per the following NERC requirements:

a. PRC-004-2a R1: The Transmission Owner and any Distribution Provider that owns a transmission Protection System shall each analyze its transmission Protection System Misoperations and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

b. PRC-004-2a R2: The Generator Owner shall analyze its generator Protection System Misoperations, and shall develop and implement a Corrective Action Plan to avoid future Misoperations of a similar nature according to the Regional Entity's procedures.

c. PRC-004-2a R3: The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide to its Regional Entity, documentation of its Misoperations analyses and Corrective Action Plans according to the Regional Entity's procedures.

d. PRC-016-0.1 R3: The Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of the misoperation analyses and the corrective action plans to its Regional Reliability Organization and NERC on request.

e. PRC-022-1 R1.5: Each Transmission Operator, Load-Serving Entity, and Distribution Provider that operates a UVLS program to mitigate the risk of voltage collapse or voltage instability in the BES shall analyze and document all UVLS operations and Misoperations. The analysis shall include: (R1.5) For any Misoperation, a Corrective Action Plan to avoid future Misoperations of a similar nature.

V. Definitions

Protection System: Per the current NERC Glossary of Terms definition as modified by the bold-face text below.

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices. **For the purposes of this procedure, this includes transformer sudden pressure relays and fault pressure relays.**
- **Control circuitry and relays associated with automatic reclosing of transmission circuits (not including the circuit breaker mechanism or close coil)**

Special Protection System: Per the current NERC Glossary of Terms definition.

Corrective Action Plan: Per the current NERC Glossary of Terms definition.

Applicable Elements: Protection System Misoperations shall be analyzed, mitigated and reported according to this procedure for the following applicable elements:

a. Transmission lines operated at 100kV or higher;
b. Circuit breakers operated at 100kV or higher;
c. Transformers with one primary terminal and at least one secondary terminal operated at 100kV or higher;
d. Generation resources with individual generating unit > 20 MVA (gross nameplate rating) and is directly connected to the bulk power system, or; generating plant/facility > 75 MVA (gross aggregate nameplate rating) or when the entity has responsibility for any facility consisting of one or more units that are connected to the bulk power system at a common bus with total generation above 75 MVA gross nameplate rating;
e. Any generation resource that is a Blackstart resource;
f. Buses operated at 100kV or higher;
g. Series/Shunt capacitors operated at 100kV or higher;
h. Series/Shunt reactors operated at 100kV or higher;
i. HV DC systems operated at 100kV or higher;
j. Dynamic reactive systems operated at 100kV or higher;
k. Special Protection Systems/Remedial action schemes;
l. Undervoltage load shed systems (UVLS) (* See Note); and
m. Underfrequency load shed systems (UFLS) (* See Note).

*** NOTE**: For the purposes of this procedure, for multi-function relays applied at less than 100kV, only a misoperation of the UVLS or UFLS function shall be reported.

Protection System Misoperation:
NERC Glossary Definition of Misoperation:

- Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection.
- Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone).
- Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

For the purposes of this procedure procedure, Protection System Misoperations include the following items.

a. <u>**Failure to Trip**</u> – Any failure of a protective relay system to initiate a trip to the appropriate terminal when a fault is within the intended zone of protection of the device (zone of protection includes both the reach and time characteristics);
b. <u>**Slow Trip**</u> – An operation of a protective relay system for a fault in the intended zone of protection where the relay system initiates tripping slower than the system design intent;
c. <u>**Unnecessary Trip During a Fault**</u> – Any unnecessary protective relay system operation for a fault not within the zone of protection;
d. <u>**Unnecessary Trip Other Than Fault**</u> – Any unnecessary protective relay system operation for non-fault conditions such as power swings, under-voltage, over-excitation, etc. for which the Protection System is not intended to operate; and
e. <u>**Failure to Reclose**</u> – Any failure of a protective relay system automatic reclosing control scheme to automatically reclose following a fault, within its design intent.

The following events ARE NOT reportable Protection System Misoperations subject to these requirements:

a. Trip Initiated by a Control System – Operations which are initiated by control systems (not by protective relay system), such as those associated with generator controls, or turbine/boiler controls, Static VAr Compensators, Flexible AC Transmission devices, HVDC terminal equipment, circuit breaker mechanism, or other facility control systems, are not considered protective relay system misoperations;

b. Facility owner authorized personnel action that directly initiates a trip is not considered a misoperation. It is the intent of this reporting process to identify misoperations of the protective relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the protective relay system. If an individual directly initiates an operation, it is not counted as a misoperation (e.g. unintentional operation during tests); however, if a technician leaves trip test switches or cut-off switches in an inappropriate position and a system fault or condition causes a misoperation, this would be counted as a protective relay system misoperation;

c. Failure of Relay Communications – A communication failure in and of itself is not a misoperation if it does not result in misoperation of the associated protective relay system.

d. Lack of targeting, such as when a high-speed pilot system is beat out by high-speed zone is not a reportable misoperation;

e. Fault clearing consistent with the time normally expected with proper functioning of at least one protection system, then a primary or backup protection system failure to operate is not required to be reported;

f. Operation of properly coordinated backup Protection System relays to clear the fault in an adjacent zone is not a misoperation if the primary protection fails to clear the fault within the specified time;

g. Correct breaker failure relay operation in association with a failed breaker, unless the breaker failed to operate due to a defective trip coil;

h. Human and operational errors or equipment failures occurring while work is being performed (e.g. maintenance, construction and/or commissioning activities) in the substation (e.g., a cover being replaced in an incorrect manner, secondary leads replaced in the wrong position, an incorrect test switch being used to isolate equipment resulting in a trip);

i. Generator mechanical trips, such as turbine or fuel system trips;

j. Generator trips caused by automatic voltage regulator, exciter control, or power system stabilizer (however, misoperation of protection functions within the excitation system shall be reported per examples of reportable misoperations); and

k. An operation of a generator Protection System that does not result in the loss of generation, while a unit is being brought on or off line and is not synchronized with the system.

SPS Misoperation: SPS misoperations are defined as follows:

a. **Failure to Operate** – Any failure of a SPS to perform its intended function within the designed time when system conditions intended to trigger the SPS occurs;

b. **Failure to Arm** – Any failure of a SPS to automatically arm itself for system conditions that are intended to result in the SPS being automatically armed;

c. **Unnecessary Operation** – Any operation of a SPS that occurs without the occurrence of the intended system trigger condition(s);

d. **Unnecessary Arming** – Any automatic arming of a SPS that occurs without the occurrence of the intended arming system condition(s); and

e. Failure to Reset – Any failure of a SPS to automatically reset following a return of normal system conditions if that is the system design intent.

Protection System Misoperation Causes: Causes of Protection System misoperations, including SPS misoperations, shall be classified as follows in reports provided to the Regional Entity:

a. AC system – This category includes misoperations due to problems in the AC inputs to the Protection System. Examples would include misoperations associated with CT saturation, loss of potential, or rodent damaged wiring in voltage or current circuit;

b. As-left personnel error – This category includes misoperations due to the as-left condition of the protection system following maintenance or construction procedures. These include test switches left open, wiring errors not associated with incorrect drawings, carrier grounds left in place, or settings placed in the wrong relay, or incorrect field settings left in the relay that do not match engineering approved settings;

c. Communication failure – This category includes misoperations due to failures in the communication systems associated with Protection System schemes inclusive of transmitters and receivers. Examples would include misoperations caused by loss of carrier, spurious transfer trips associated with noise, telecommunication errors resulting in malperformance of communications over leased lines, loss of fiber optic communication equipment, or microwave problems associated with weather conditions;

d. DC system – This category includes misoperations due to problems in the DC control circuits. These include problems in the battery or charging systems, trip wiring to breakers, or loss of DC power to a relay or communication device;

e. Incorrect setting/logic/design error – This category includes misoperations due to "engineering" errors by the Protection System owner. These include setting errors, errors in documentation, and errors in application. Examples would include uncoordinated settings, incorrect schematics, or multiple CT grounds in the design;

f. Relay failure/malfunction – This category includes misoperations due to improper operation of the relays themselves. These may be due to component failures, physical damage to a device, firmware problems, or manufacturer errors. Examples would include misoperations caused by changes in relay characteristic due to capacitor aging, misfiring thyristors, damage due to water from a leaking roof, relay power supply failure, or internal wiring/logic error. Failures of auxiliary tripping relays fall under this category; and

g. Unknown – This category includes misoperations where no clear cause can be determined. Requires extensive documentation of investigative actions if this cause code is utilized.

VI. Analysis and Corrective Action Plan Requirements

Timely analysis of Misoperations and development and implementation of Corrective Action Plans is of critical importance to bulk electric system reliability in the ERCOT Region.

When it analyzes a Protection System or SPS Misoperation, the responsible entity shall, to the best of their ability, accurately identify the underlying or "root" cause in sufficient detail to develop a Corrective Action Plan that remedies the problem to prevent Misoperation recurrence. Where a cause cannot be identified, a thorough documentation of the investigation is required to aid future investigation of the Misoperation, particularly if it recurs. It is expected that the responsible entity will perform due diligence to identify the Misoperation cause. Evidence which may assist in analysis of Misoperations includes sequence of events data, relay targets, Disturbance Monitoring Equipment (DME) records, relay calibration and simulation tests, communication noise and attenuation tests, CT/VT ratio tests, DC continuity checks and functional tests, and studies (e.g. short circuit and coordination studies) performed in the attempt to determine the root cause.

The owner of the protective system that is found to have misoperated is responsible for reporting the Misoperation. If a Misoperation occurs on a tie line between two entities responsible for reporting Misoperation data per this procedure, the Misoperation shall be reported by one or the other entity, but not both. The entities shall reach agreement on which party submits the Misoperation. Texas RE may be consulted for input on this decision.

When a root cause of a Misoperation is identified, a Corrective Action Plan must be developed to address the cause(s), and which will improve the performance and reliability of the BES. Registered Entities must have a process in place for developing Corrective Action Plans. A Corrective Action Plan should include interim corrective actions (if necessary), final corrective actions, and a timeline for completion delivery dates. Interim corrective actions may be useful to quickly address some of the aspects of the Misoperation prior to implementation of a final solution.

Registered Entities shall complete Misoperation analyses and Corrective Action Plans per the following timelines:

Corrective Action Item	Due Date
Analyze Misoperation to determine root cause	Within 90 calendar days of event
Develop Corrective Action Plan and timetable for implementation (if root cause identified)	Within 120 calendar days of event
Develop additional investigation steps and work timetable (if root cause not identified)	Within 120 calendar days of event
Complete implementation of Corrective Action Plan	Within 180 calendar days after development of Corrective Action Plan or per Corrective Action Plan timetable, whichever is longer

VII. Periodic Data Submittal Requirements

The Transmission Owner, any Distribution Provider that owns a transmission Protection System, and the Generator Owner shall each provide documentation to Texas RE of its Protection System and SPS Misoperation analyses and Corrective Action Plans according to the these procedures.

Transmission Owners shall document the performance of their protective relay systems utilizing the method described in the paper "Transmission Protective Relay System Performance Measuring Methodology," IEEE/PSRC Working Group I3 September 16, 1999 (Reference Attachment 3). The performance data reported shall include the total number of protective relay system and automatic reclosing misoperations, the total number of events, and the factor "k."

Periodic Data Submittals consist of two forms:

a. Attestation form. Total number of events and “k” factor will be submitted on the attestation form. Reference Attachment 2 for a sample attestation form.
b. Protection System Misoperation Report Template. Protection System Misoperation reports shall be submitted on the most recent version of the Misoperation Report Template posted on Texas RE website (http://www.texasre.org). Reference Attachment 1 for a description of the Misoperation Report Template fields and the information that is to be provided.

All forms and reports are to be submitted via webCDMS.

Changes, updates or corrections to the analysis of a specific Misoperation or Corrective Action Plan will be submitted in a subsequent quarterly report following the update. Resubmittal(s) of Misoperation information will be identified on the Misoperation Report Template by selecting “Yes” in the “Resubmittal Check” column. Each responsible entity will report the status of each of its Misoperation Corrective Action Plan or interim action plans in the periodic data submittal until the Corrective Action Plan is reported complete.

Each responsible entity should retain its complete documentation concerning Misoperations, analyses, Corrective Action Plans, etc. in accordance with NERC requirements for data retention. Additional information should not be submitted to Texas RE unless requested.

VIII. Submission Frequency

Quarterly, per the following schedule:

Reporting Period	Due Date
January 1 through March 31	May 31
April 1 through June 30	August 31
July 1 through September 30	November 30
October 1 through December 31	February 28

If the due date falls on a non-working day (i.e. weekend or state/federal holiday), the data submittal will be due on the next business day.

IX. Texas RE Review and Oversight

The Texas RE Reliability Services group will review the required data submittals within 30 calendar days after the end of each reporting period. Each Protection System Misoperation submittal will be reviewed for completeness of 1) Misoperation description; 2) Cause; 3) Corrective actions taken or planned; and 4) Submittal completeness. Appropriate follow-up actions will be taken to ensure all Misoperations are resolved and that corrective actions are implemented for all outstanding Misoperation investigations. Additional follow-up actions, if any, will be completed no later than 45 calendar days after the end of each reporting period. Any submitted Misoperations related to a failure of automatic reclosing as well as “k” factor event data are removed by Texas RE from the Misoperation data prior to submitting to NERC for the ERCOT Region.

On an annual basis, Texas RE will assess the Misoperation data and develop a regional Misoperation summary report. This regional Misoperation summary report will be shared with the ERCOT System Protection Working Group. The report may include overall regional Misoperation performance, summary data of Misoperation causes, observed Misoperation trends, and recommendations for follow-up from a regional perspective. Individual Registered Entity identities will be redacted.

X. Revision History

This procedure is considered to be the effective on the first day of the next calendar quarter after approval by Texas RE management. Texas RE will continue to work with the Registered Entities on changes to this procedure and the related Misoperation Report Template.

Revision	Date	Approved By	Comments
0	March 23, 2012	Mark Henry	Initial

XI. Review and Retention Requirements

The Texas RE Reliability Services group will review this document every three years or as appropriate for possible revision. The existing or revised document will be publicly posted and distributed to all affected Transmission Owners, Generator Owners, and Distribution Providers within 30 calendar days of approval of these procedures. Texas RE will retain documentation of any changes to this procedure for a period of six years.

Additionally, Texas RE will keep the required Misoperation data submittals for each Registered Entity for a minimum of six years.

ATTACHMENT 1 – Quarterly Misoperation Report Form Fields

Field Name	Description
Resubmittal Check	Select 'Yes' or 'No' from drop-down list
Regional Entity	Select 'TRE' from drop-down list
Entity Name	Enter Registered Entity name
Misoperation Date	Enter Date of misoperation in MM/DD/YYYY format
Misoperation Time	Enter Time of misoperation in HH:MM:SS format
Time Zone	Select the standard time zone from drop-down list
Facility Name	Substation or generation station where the misoperation occurred)
Equipment Name	Identify by name the generator, transmission line, transformer, bus or equipment protected by the Protection System that Misoperated.
Equipment Type	Select equipment type (i.e. line, bus, transformer, generator, etc.) from dropdown list
Facility Voltage	Select facility voltage, in kV, from drop-down list
Equipment Unavailable	Enter names of the equipment becoming unavailable due to the Misoperation (equipment only refers to circuits, transformers, busses, but not breakers UNLESS the breaker is the only element).
Event Description	Provide a brief description of the event and detailed description of Misoperation root causes
Misoperation Category	Select Misoperation Category from drop-down list.
Cause(s) of Misoperation	Select root cause(s) of the Misoperation from drop-down list.
Protection Systems/Components that Misoperated	Provide information on the components/protection systems that misoperated including relay models (types) and protection schemes.
Relay Technology	Select 'Electromechanical', 'Solid State', or 'Microprocessor' from drop-down list
TADS Reportable?	Automatically populated based on voltage selection and equipment type
TADS Cause Code	Automatically populated based on TADS Reportable column
TADS Event ID	Enter TADS Event ID, if applicable
Corrective Action Status	Select Corrective Action status ('Analysis in Progress', 'Analysis Complete', Corrective Action in Progress', or 'Corrective Action Complete') from drop-down list
Corrective Action Plan	Provide a brief description of the corrective action plan
Actual Analysis Completion Date	If analysis of misoperation is complete, enter actual completion date in MM/DD/YYYY format
Actual Corrective Action Completion Date	If corrective actions are complete, enter Corrective action actual completion date in MM/DD/YYYY format
Name of Person Filing Report	Name of person filing the misoperation report
Phone Number	Phone number of person filing the misoperation report
Email Address	Email address of person filing the misoperation report
Date of Report	Enter date of the misoperation report in MM/DD/YYYY format

TEXAS RELIABILITY ENTITY

ATTACHMENT 2 – Periodic Data Submittal Attestation Form

Protection System Misoperation Data Submittal
PRC-004 and PRC-016

Reporting Period: (FILL IN REPORTING PERIOD QUARTER)
Submission Period: (ENTER DATES FOR REPORTING PERIOD)

Responding Entity is a:

☐ Transmission Owner ☐ Generator Owner ☐ Distribution Provider

Please mark all the following that are applicable:

☐ Entity has experienced a misoperation during this quarter. (Entities experiencing a Misoperation are required to upload a Misoperation Report Template. The Misoperation Report Template is available in the document download section in webCDMS)
☐ Entity has **NOT** experienced a misoperation during this quarter
☐ Entity does not own a Transmission or Generation Protection System (PRC-004)
☐ Entity does not own a Special Protection System (PRC-016)

Please provide total system events by quarter and by voltage level for transmission events.

Quarter	138 kV	138 kV 'k' Factor	345 kV	345 kV 'k' Factor
1st				
2nd				
3rd				
4th				

As a member of senior management (Vice President, Director, or other senior management), I am the responsible person for the oversight of the entity's implementation of, and compliance with the applicable NERC-approved reliability standard requirements. I certify that the answers provided above are true to the best of my knowledge for the Reporting Period and Submission Period noted above.

Signature: ______________________________

Name (print): ______________________________

Title: ______________________________

Registered Entity: ______________________________

NCR: ______________________________

Signature Date: ______________________________

The completed and signed form should be uploaded via webCDMS.

ATTACHMENT 3 – IEEE/PSRC Working Group Paper, "Transmission Protective Relay System Performance Measuring Methodology", September 16, 1999

Transmission Protective Relay System Performance Measuring Methodology
IEEE/PSRC Working Group I3
9/16/1999

W. M. Carpenter, Chairman
P. Carroll
A. J. Dubois
J. Ferraro
D. Fredrickson
M. Ibrahim
H. Jacobi
D. A. Jamison
E. Krizauskas
P. Kotos
B. Lowe
W. J. Marsh, Jr.
D. Miller
G. Moskos
D. R. Sevcik
F. Marquez, Vice-Chairman
H. M. Shuh
L. E. Smith
P. Solanics
D. Viers
J. E. Waldron
J. D.Wardlow
J. A.Zipp

1.0 Introduction

To varying degrees, different transmission system operators have measured the performance of their protective relay systems; however, general comparisons cannot be made between different transmission systems because no consistent performance measuring criterion has been utilized. This paper presents a simplistic approach to analyzing the performance of a protective relay system that is associated with any transmission system. This simplistic approach asks " When a system event occurs, did everything work correctly, or did something in the protective system misoperate?" If everything operates as designed, it is counted as one correct operation (even though multiple breakers might have operated). If one or more terminals of the protective relay system misoperate, they are categorized as to the type of misoperation. The total number of misoperations can be compared to the total number of events to determine the relative success of the protective relay system. This simplistic approach is broad enough to allow for comparisons between different transmission systems with different design parameters. However, in using this information in a comparative fashion between different transmission systems, it is necessary to consider the differences in design parameters and in the expected performance of the protective relay system.

2.0 Measuring Methodology

The measuring methodology involves identifying all system misoperations, comparing them to the number of events (i.e. opportunities to misoperate), and calculating a percentage of misoperation.

2.1 Definition of Protective System Misoperation

Fundamental to this relay performance measuring methodology is defining a misoperation and grouping them into logical categories. Table 1 is the foundation for defining a misoperation. The misoperation table is structured such that:

a) Dependability, security, and system restoration statistics can be recorded and trended separately or summed into a total misoperation category;
b) Companies can look at only the performance of the relay system, the performance of the circuit breakers, or the performance of the entire protective system;
c) The criterion can be applied for different voltage levels, or as a composite of several voltage levels.

Additionally, this table structure allows for easy comparison between companies.

It should be noted that this definition is intended to measure the protective system as a whole and not the individual relaying components. For instance, if a fault occurs and is isolated from a backup (or redundant) protective system that operates with no intentional time delay, the fact that the primary system did not operate does not constitute a misoperation.

Table 1 MISOPERATION TABLE

	Dependability			Security		System Restoration	Total Misoperations
	Failure to Trip	Failure to Interrupt	Slow Trip	Unnecessary Trip During Fault	Unnecessary Trip for Non-Fault Event	Failure to Reclose	
Relay (A) System [I]	1	---	2	3	4	5	Total for Relay System
Circuit (B) Breaker [II]	6	7	8	---	9	10	Total for Circuit Breakers
Protective System [III] (A+B)	1+6	7	2+8	3	4+9	5+10	Total for Protective System

I - Relay System defined as the protective relays, communication system, voltage/current sensing devices, and dc system up to the terminals in the circuit breaker.

II - Circuit Breaker is a generic term for any fault interrupting device.

III - Protective System includes both relay system and circuit breakers (A+B).

The numbers in the table refer to the legend where a definition of the category is given.

LEGEND:

(1) Failure To Trip (Relay System)
Any failure of a relay system to initiate a trip to the appropriate terminal when the fault is within the intended zone of protection of the protective device.

(2) Slow Trip (Relay System)
A correct operation of a relay scheme for a fault in the intended zone of protection where the relay scheme initiates the trip slower than the system design intends.

(3) Unnecessary Trip During a Fault (Relay System)
Any undesired relay-initiated operation of a circuit breaker during a fault when the fault is outside the intended zone of protection.

(4) Unnecessary Trip Other Than Fault (Relay System)
The unintentional operation of a protective relay which causes a circuit breaker to trip when no system fault is present; may be due to environmental conditions, vibration, improper settings, heavy load, stable load swings, defective relays, or SCADA system malfunction. Employee action that directly initiates a trip **is not** included in this category. See Clause 3.1 Human Performance.

(5) Failure to Reclose (Relay System)
Any failure of a relay system to automatically reclose following an event if that is the system design intent.

(6) Failure to Trip (Circuit Breaker)
The failure of a circuit breaker to trip during a fault even though the relay system initiated the trip command.

(7) Failure to Interrupt (Circuit Breaker)
The failure of a circuit breaker to successfully interrupt a fault even though the circuit breaker mechanically attempts to open.

(8) Slow Trip (Circuit Breaker)
A circuit breaker which operates slower than the design time during a fault following the trip initiation from the relay system.

(9) Unnecessary Trip Other Than Fault (Circuit Breaker)
The tripping of a circuit breaker due to breaker problems such as low gas, low air pressure, etc.

(10) Failure to Reclose (Circuit Breaker)
Any failure of a circuit breaker to successfully reclose following the reclose initiate signal from the relay system.

2.2 Definition of Event

An event is defined as "**the operation of all necessary breakers to isolate an electrical fault including all subsequent automatic or manual recloses (and trips if appropriate) or any set of conditions resulting in an unintentional operation of the protective system**". For example, if three breakers trip and successfully reclose following a temporary electrical fault, this counts as one event. If the same three breakers trip multiple times for a planned reclose-trip sequence during a permanent fault, this counts as one event.

2.3 Percent Misoperation

For any selected time period, percent misoperation of a relay scheme for a system is defined in Equation 1.

Where:

$$\%\,\text{Misoperation} = \frac{\text{All Misoperations}}{\text{Total \# of Events} + K} \times 100 \qquad (1)$$

"All Misoperations" is the sum of the misoperations (as defined in Table 1) that have occurred over a time period.

"Total # of Events" is the sum of events (as defined in Clause 2.2) that have occurred over the same time period.

"K" is equal to the number of misoperations for any event minus one.

"K" is an add-on term to account for those situations where more than one misoperation occurs during an event. "K" is a cumulative number that will increase as multiple misoperations occur during events within the period under review. For instance, during an event, if two misoperations occur, the value of K would be increased by 1. If three misoperations occurred during an event, the value of K would be increased by 2. Therefore, if during the time period under study, there were no events where more than 1 misoperation occurred, K would equal zero. However, if during this period, three misoperations occurred during one event, K would equal 2.

Using this equation, percent misoperation can be determined for any voltage class, or for a combination of voltage classes. Furthermore, the misoperation of the protective system can be monitored with or without the circuit breakers.

3.0 Application of Measuring Criterion

When this measuring criterion is first applied, several questions will probably arise. This section should address many of them.

3.1 Human Performance

It is the intent of the measuring criterion to measure the performance of the relay system as it interrelates with the electrical system, not as it interrelates to personnel involved with the relay system. With this in mind, if an individual directly initiates an operation, it is not counted as a misoperation (i.e., unintentional operation during tests). On the other hand, if a technician leaves trip test switches or cut-off switches in an inappropriate position and a system fault or condition causes a misoperation, this would be counted as a relay system misoperation.

3.2 Abnormal Electrical System Conditions

In order to keep the measuring criterion simple, it is desirable to virtually eliminate exceptions to what constitutes a misoperation. For that reason, if a system configuration is abnormal and the relay system misoperates, or if simultaneous faults occur on the system and the relay system misoperates, these conditions would count as a misoperation of the relay system.

3.3 Application at Multiple Voltage Levels

In many cases, the application of this measuring criterion will be segregated by various system voltage levels. This is often necessary to effectively measure the performance of the high speed communication-assisted line relay systems used at the higher voltages from the more basic relay systems often used at lower voltages. When this is done, a fault that occurs at one voltage level on a system may cause a misoperation of the relay system associated with a different voltage level. In this case, the misoperation should be classified as a misoperation of the voltage level where the misoperation occurs. This may or may not be the voltage level where the fault (event) occurred. It is recognized that this could lead to a small statistical error in looking at the percent correct operation of a particular voltage class; however, it is generally insignificant and it will correct itself as the data is rolled up into groups of voltage classes.

3.4 Multiple Misoperations During an Event

Occasionally, during a system event, more than one terminal or one relay system on a system misoperates. When this occurs, **each terminal that misoperates** should be counted as a misoperation. For instance, if a fault occurs and is properly cleared from the system, but a remote terminal to the fault line also trips in error, and the system fails to properly reclose, this would be counted as two misoperations. One misoperation would be classified as an "Unnecessary Trip During Fault" and one would be classified as a "Failure to Reclose". This would be a situation where the K factor shown in equation 1 would be increased by one.

However, if a fault occurs, the system recloses multiple times into the fault, and a remote terminal to the line section trips during the various reclosures, this would only count as one misoperation. This is because the original fault and all subsequent closures into the fault are counted as the same event.

4.0 How to use the Information

This information can be used in a variety of ways, either for a transmission system to compare itself to itself over various time periods, or to compare itself to other transmission systems. When making comparisons between different systems, care must be taken to consider differences in the design expectations, design type, and maintenance practices. For instance, some systems do not require communication-assisted tripping schemes for quick clearing of transmission line faults. The protective relay performance of these particular relay systems is typically better than that of the high-speed communication-assisted relay systems.

4.1 Use of Misoperation Table

The misoperation table can be used as a stand-alone reporting format. This allows for logical grouping of various failures of the protective relay system and the associated circuit breakers. Used in this fashion, a transmission system operator can track trends in the system performance over time or compare among different transmission systems.

4.2 Calculating Percent Misoperation

By calculating a percent misoperation, the measuring criterion normalizes itself to the opportunity for misoperation. This is important for internal comparisons over time where the number of faults may be substantially different from one period to the next. It is also important for any comparisons among companies because by normalizing to the number of events, it allows for comparison of transmission systems, regardless of size of the system or number of fault events on the system.

5.0 Example Use of Measuring Criterion

For purpose of example, this measuring criterion is applied to a utility's 345 kV and 138 kV protective system performance for the year 1997. For that particular year, there were 43 relay system misoperations, 5 circuit breaker misoperations, and 553 events.

5.1 Use of the Misoperation Table

Table 2 is a summary of the results of the utility's annual protective system performance. In that particular year, there were 7 slow trips due to the relay system and one due to problems with a circuit breaker operating mechanism. For this utility, a slow trip is any transmission system fault where the total clearing time for the fault is in excess of 8 cycles. These slow trips ranged from 9.5 cycles to 38 cycles.

There were a total of 31 occurrences of unnecessary trips during a fault. Most were the result of problems with powerline carrier systems and with the relaying associated with the communication-assisted relay schemes. There were 2 cases of circuit breakers tripping due to problems with the circuit breaker. In both of these cases, there were problems with gas compressors causing the breaker to be automatically removed from service.

There were 7 cases where automatic reclosing did not occur as designed. Five cases were the result of problems in the relay scheme. Two cases were due to problems with the circuit breakers.

5.2 Use of Percent Misoperation Formula

There were 553 events during the year. The majority of these events were due to transmission line faults. Following most of these faults, the system was successfully restored through automatic reclosing. About 5% of these events resulted in facilities automatically reclosing into the faults and eventually "locking out" the faulted circuit.

Out of the 553 events, there were three events where relay systems misoperated on more than one terminal. On one event, three separate terminals tripped unnecessarily. This adds 2 to the K factor in equation 2. On another event, both a slow trip and a failure to reclose occurred. This adds 1 to the K factor. On a third event, both a slow trip and an extra trip occurred. This also adds 1 to the K factor.

$$\%\,\text{Misoperation} = \frac{43}{\{553 + (2 + 1 + 1)\}} \times 100 = 7.7\% \qquad (2)$$

Solving for equation 2, the total percent misoperation for this example, is 7.7%.

The bottom three rows of Table 2 indicate the percent misoperation by the various categories. These percentages could also be applied for each category in the table and segregated by voltage class if the user desired.

Table 2
MISOPERATION TABLE
For Example Utility

	Dependability			Security		System Restoration	Total Misoperations
	Failure to Trip	Failure to Interrupt	Slow Trip	Unnecessary Trip During Fault	Unnecessary Trip Other Than Fault	Failure to Reclose	
Relay System	0	---	7	31	0	5	43
Circuit Breaker	0	0	1	---	2	2	5
Total Protective System	0	0	8	31	2	7	48
Percent Incorrect Operation Relay System	0%	0%	1.3%	5.6%	0%	0.9%	7.7%
Percent Incorrect Operation Circuit Breaker	0%	0%	0.2%	0%	0.4%	0.4%	0.9%
Percent Incorrect Operation Protective System	0%	0%	1.4%	5.6%	0.4%	1.3%	8.6%