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**ANATOMY OF POWER SYSTEM BLACKOUTS
AND PREVENTIVE STRATEGIES BY
RATIONAL SUPERVISION AND CONTROL
OF PROTECTION SYSTEMS**

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for the

Power Systems Technology Program

Energy Division

Oak Ridge National Laboratory

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ABSTRACT

This report establishes the concept of hidden failures in relays and associated devices used for the protection of electric power systems. A hidden failure is a defect such as a component failure, inappropriate setting or incorrect external connection that remains undetected until some other system event causes the hidden failure to initiate a cascading outage. Associated with the study of hidden failures, this report examines the impact such defects might have by defining regions of vulnerability. A region of vulnerability is the area of the system in which a hidden failure will be activated. To determine such areas we have established criteria associated with load flows and steady-state stability, such as lack of convergence, and employed a technique known as importance sampling in which the simulation is done with the probabilities altered so that the rare event happens more frequently. Our purpose is to provide a framework for further research into relay vulnerability, possibly using adaptive techniques to eliminate hidden defects. We believe control strategies can be developed to prevent cascading normal operations from developing into severe outages by extending the present criteria using steady-state stability and load flow studies into the area of transient stability, and further research into importance sampling would provide significant benefits in evaluating corrective actions.

EXECUTIVE SUMMARY

Studies of power system disturbance reports have revealed an important issue regarding the role played by relays or protection systems when power systems are under stress (i.e. a line and generator outage resulting in overloaded lines). It has been found that relay or protection systems play a very important role in the sequence of events that lead to power system blackouts. Failures in the protection systems turn out to be one of the most important factors in the overall process of power system failures. Insecure or failed protection systems, which remain undetected, can make a bad situation worse. Every type of relay failure, however, does not fall into this category. Failures that lead to a misoperation immediately, and can be detected and corrected right away, are not significant factors in cascading outages. Failures that have the potential to remain hidden until some abnormal states of the power systems are reached, are the most significant and are the primary subject of this investigation.

The abnormal power system states are, in general, faults, overloads, reverse power flows, etc. During these states, the hidden failure may be activated to cause a relay misoperation. To prevent the power system blackouts, or at least reduce their likelihood, we need a better understanding of the hidden failures in the protection systems and of the mechanism of the power system blackouts. Previous to this study, a study on "Adaptive Protection of Transmission Systems" was conducted. That research identified several key protection functions which could benefit from adaptive techniques. Continued research using adaptive techniques on relays with hidden failures presents opportunities to eliminate or minimize the effect of incorrect relay operations on major outages. Self-monitoring and self-checking techniques can uncover and define the potential failure. Supervising existing relays, replacing components or substituting other relays, adjusting CT or PT inputs, changing settings or revising control or tripping logic can correct the problem.

The concept of hidden failures assumes that relay or relay system defects can exist and not be immediately apparent. Hidden failures are therefore defects that will cause protective misoperations in the presence of other system abnormalities. All of the commonly used protection schemes have been studied to identify possible hidden failures.

The area of the power system in which the hidden failures can influence relay performance has been defined as a region of vulnerability. If an abnormal power system state occurs inside a given region of vulnerability, the hidden failure could cause the relay to incorrectly trip its associated circuit breaker. In order to quantify the effect of hidden failures within a region of vulnerability, the vulnerability index is calculated. This parameter, in addition to an analysis of hidden failures, will allow the evaluation of the

relative importance of each relay system and region of vulnerability.

In spite of the obvious importance to the industry, there has been little analytic or simulation work in the area of cascading outages of the bulk power system. The reasons are based in the enormous complexity of the problem. The difficulty of simulating rare events coupled with the lack of data on which to base models, have precluded work in the area. The North American Electric Reliability Council (NERC) reports make it obvious that major outages typically involve a number of unlikely or "shouldn't have happened" events. Since simulation studies which capture a number of low probability events are difficult to perform and since the exact probabilities of the various unlikely events are not known, almost no attempt has been made to simulate the temporal spreading of the outage. We have concluded, however, that using analysis and simulation, there is a substantial return from self-checking and monitoring of microprocessor relays. The probability of a simple event leading to a widespread outage is greatly reduced by self-checking and monitoring of individual relays. A technique has been established for determining the probability of a cascading outage in terms of the individual probabilities of a hidden failure in a relay that could lead to an incorrect trip.

A discussion of cascading outages should be approached from two aspects; the power system itself and the protective systems. In general, the considerations involved are very different. The power system is designed, and should be operated, so that the loss of one or two elements will not jeopardize the integrity of the system. The various reliability councils in the U.S. have established planning criteria that allows the loss of a corridor or a generating plant without reducing the voltages at the customer or overloading lines or transformers so that they are in danger of tripping out. This is done to minimize the possibility of cascading outages. It is recognized that multiple elements can be lost due to a fault and subsequent incorrect trip or a line out for maintenance followed by a fault on another line section. Protective systems, however, which are primarily designed to remove system elements, may unduly undermine the planning criteria. Relaying philosophy often allows incorrect or unnecessary trips to avoid the less desirable alternative of failing to trip. This relay philosophy is based on the fact that the power system is redundant. If, therefore, the system has degraded past the point where it can withstand the loss of another element, the hidden failures will exacerbate the situation. The compelling result of the present study is that the concept of hidden failures, coupled with adaptive relaying, and a rational supervision strategy can be significant in minimizing the possibility of cascading outages. Indeed, by implementing computer based supervisory systems at vulnerable sites, the possibility of blackouts can be significantly reduced.

1. INTRODUCTION

Relay or protection systems play a very important role in the sequence of events that lead to power system blackouts. Insecure or failed protection systems, which remain undetected, can make a bad situation worse. It should be clear that every type of relay failure does not fall into this category. Failures that lead to a misoperation immediately, and can be detected and corrected right away, are not of interest for our present discussion. We are interested in failures that are not activated until some abnormal states of the power system are reached. These abnormal states are, typically, faults, overloads, reverse power flows, etc. It is known that undetected (or hidden) failures in protection systems commonly lead to multiple contingencies, which, in turn, can lead to power system blackouts [1,2,10]. Therefore, a better understanding of the hidden failures of the protection system can lead to control strategies, which will reduce the likelihood of the occurrence of major power system outages.

The present team of researchers has successfully completed a previously funded research project on adaptive transmission system protection [8]. During that research, we identified several key protection functions which could benefit from adaptive techniques. A very fruitful avenue for continued research appears to be the use of adaptive techniques on relays with hidden failures so as to eliminate or minimize the effect of incorrect relay operations on major outages.

1.1 Vulnerability of relay systems

The questionnaire included in Appendix H was distributed to approximately 500 relay and power system engineers to evaluate the experience of the industry relative to wide-scale disturbances. Twenty-three responses were received. The results have been analyzed for the broad categories covering the correctness of the relay performance in these events and for the specific component failures involved. In addition to the questionnaire, North American Reliability Council (NERC) [1] and other U.S. [2,10] reports were studied.

The operation of all commonly applied protective relay schemes on HV and EHV systems have been analyzed from the point of view of failure and have been determined to perform correctly [3,4,5]. These failures have been further examined to determine if hidden failures, that is, failures that do not make themselves immediately known, play an important role in extending the disturbance.

1.2 Regions of Vulnerability

The Hidden Failures (HF) that were analyzed were exposed by one or several

abnormal power system states. If the fault occurs in an area that is relatively close to the location of the relay with the HF, its effects may reach the relay. In other words, each HF has a region of vulnerability (RV) associated with it. The New England 39-bus system was used to examine all of the possible RVs that are associated with either relays using distance (impedance or reactance) or current magnitude.

1.2.1 Vulnerability Index.

It is necessary to compute the vulnerability index associated with the relays when they are subjected to some contingencies. The contingency used was to have two lines removed from service; one line due to a fault and the other due to a HF. The resulting system is considered stable if there is a load flow solution. Five factors were examined to determine the existence of a load flow.

- (1) Normalized change in the determinant of $[B']$ from the base case.
- (2) Normalized change in the determinant of $[B'']$ from the base case.
- (3) The largest deviation of the phase angle in the first iteration.
- (4) The norm of the deviations of all phase angles in the first iteration.
- (5) Line flows of the dropped lines.

where $[B']$ and $[B'']$ are the two matrices used in fast-decoupled power flow equations.

1.2.2 Cascading power system outages.

Little analytic or simulation work has been done in the area of cascading outages due to the enormous complexity of the problem. Simulation studies which capture a number of low probability events are difficult to perform and the exact probabilities of various unlikely events are not known. Therefore, no attempt has been made to simulate the temporal spreading of an outage. The probabilities are treated parametrically and we demonstrate in section 3.2 that a substantial reduction in overall system failure probability does occur if self-checking and self-monitoring can eliminate the HF. The study of rare events in a large system presents a formidable amount of calculations with increasing doubt as to the reliability of the overall, long-term behavior. The technique of "importance sampling" is used to make this problem more manageable. In this technique, the probabilities are altered so that the rare event happens more frequently and the effect of reducing the probabilities can be analyzed.

It is possible to study the consequence of relay self-checking and self-monitoring. The exact probability models and numbers were not the intended thrust of this work. The probability of an HF causing an incorrect trip is small. However small, that probability is increased when other events occur within the relay RV. Reducing the line outage probability with improved self-checking and self-monitoring has a significant influence on overall system reliability.

2. VULNERABILITY OF RELAY SYSTEMS

2.1 Industry Survey

In July, 1989 the questionnaire shown in Appendix VIII was sent to approximately 500 relay and power system engineers requesting their assistance in analyzing incidents that, in their opinion, were initiated or exacerbated by improper relay operation. This questionnaire was designed to evaluate the experience of the utility industry relative to wide-scale disturbances. We received twenty-three specific responses to the questionnaire, several letters addressing the subject but without answering the questionnaire itself and related reports on outages from Holland, Sweden, Belgium, France and Ireland. The questionnaire requested the respondents to broadly categorize the relay performance as follows:

- Incorrect but Appropriate — the relay did not respond as it was intended but the action was appropriate to minimize the consequences of the event.
- Incorrect and Inappropriate — The relay misoperated and the action was harmful to the system.
- Correct but Inappropriate — the relay responded properly according to the information it received and its setting was correct but the action was harmful to the system.

A breakdown of the causes of the outages as reported in the questionnaire is as follows:

Incorrect and Appropriate	—	2
Incorrect and Inappropriate	—	18
Correct and Inappropriate	—	4

These results are, in themselves, not very meaningful since each of the incidents involved many circuit breaker operations and the respondents did not attempt to categorize each of them. For instance, in almost every case there were many "Correct and Appropriate" operations and several operations that could fall in more than one category. Nevertheless, the tabulation above, although totaling more than the number of responses, is a summary of what appeared to be the most significant of the operations for the purpose of analyzing any trends. The numbers emphasize the fact that most wide-scale disturbances are due to relays that misoperate and that such misoperations are an important factor in cascading the outage.

The questionnaire also asked the respondent to assess the underlying basis for any misoperations based upon their investigation of the event. The results are as follows:

Application	—	8
Maintenance	—	8

Setting	—	10
Calibration	—	3
Transient	—	3
Other	—	2

Here, too, the numerical results do not provide a great deal of insight into the problem of studying the anatomy of a cascading outage. Of the 24 responses, we have identified 34 categories of underlying problems since several responses cited more than one cause. It is interesting to note, however that the majority of problems are associated with conditions that may have been correct when the relay was first applied or installed but, in time, became inadequate for the system at the time of the event. An interesting tabulation for our purposes is a catalog of the causes, and a comment on how they could be corrected or mitigated. Analysis of each of the 23 responses, plus the reports from Europe and the reports of several well-known blackouts such as the Northeast Blackout in 1965 [1], the Con Ed blackout in 1977 [10] and several unpublished American Electric Power events described in Appendix J provide such a tabulation in Table 2.1.

Table 2.1 indicates that all of the potential failures or errors can be corrected if the studies and simulations are sufficiently comprehensive, the setting calculations recognize all of the anticipated possible system configurations and testing and calibration is performed often enough and without their own errors. It is clear that, since no corrective program can be so all-encompassing, problems will continue to exist.

2.2 Outage Reports

The North American Electric Reliability Council (NERC) prepares an annual report of major disruptions in North America reporting approximately ten major events a year. The U.S. Department of Energy (DOE) has established requirements for reporting electric system emergencies. The criteria for reporting include loss of load of over 300 MW for more than 15 minutes for utilities with a previous year's peak load greater than 3000 MW, 200 MW or 50% of system load for more than 15 minutes for utilities with less than 3000 MW peak load, load shedding of over 100 MW, continuous interruption for 3 hours or longer to 50,000 customers or more than 50% of the total customers being served, voltage reductions of 3% or greater, public appeals to reduce consumption and incidents of sabotage or vandalism. When a utility makes such a report, a copy is sent to NERC. In 1987, for example, 37 such incidents were reported to DOE and NERC. Disturbances that were beyond the control of the utilities, such as natural disasters, are eliminated, allowing the NERC report to concentrate on disturbances caused by unexpected system operating problems or conditions. Reports are then reviewed for general interest and applicability,

Table 2.1 Relay problems and corrective actions

Relay Problems	Corrective action
<p><u>Setting</u> Typical instance of incorrect setting could occur when load exceeds setting, fault current is too low, miscoordination with back up relays and miscoordination with pilot wire relays.</p>	<p>More accurate or more comprehensive calculations. New Settings.</p>
<p><u>Maintenance and Calibration</u> Common component failures that could occur are open trip coil, defective component, broken wire, loss-of-carrier, incorrect polarizing, slow mechanical interlock, complex testing procedures and "sneak" circuits (a tripping path obscured by the complexity of the circuit.</p>	<p>More complete testing and training.</p>
<p><u>Application and design</u> Failures can result from fundamental errors in the design or application such as incorrect timing window, slow relay dropout, evolving fault, relay out of service, transient performance, abnormal system configuration, primary equipment failure, undervoltage supervision and breaker contacts vs current detector.</p>	<p>Better simulation and on-site testing.</p>

specifically relating to planning, operation and relaying. These reports are then examined further to establish the exact sequence of events and determine if any failures or errors were involved. In 1987, five such events out of the original 37 were reported in detail in the NERC report.

This section presents a summary of 49 NERC events for the five-year period from 1984 to 1988, presented in the format developed for the questionnaire responses as shown in Appendix H. There were 14 events reported in 1984, 12 in 1985, seven in 1986, five in 1987, and 11 in 1988. The first significant observation is that of the 49 major events reported in the five year period, 36 or 73.5% involved relaying systems or "special

protection systems". "Special protection systems" refers to a particular protection system used by the western utilities to monitor a wide area and drop generation through transferred tripping. This category was used by NERC in the early part of the five-year period but was dropped in the later years. Three of the cases in 1984 involved these "special protection systems. A portion of the Commentary of the 1989 report is typical of the findings.

"Protection system misoperation was a contributing factor in two of the disturbances reviewed. Three of the incidents reviewed were caused or aggravated by other protection system problems. These problems include defective relay components, relays improperly applied, and power line carrier circuits that had not been tuned properly.

As noted in previous Reports, protection system design, application, operation, and maintenance are important factors that play a major role in transmission reliability and control. These are especially critical in heavily-loaded transmission lines. As utilities rely more on remote generation and interchange, transmission system relay coordination within and among control areas and Reliability Councils is crucial."

Involvement of the relaying system does not necessarily imply that the relaying system initiated the event. In most cases, the initiating event was some natural event or device failure. The subsequent relay system misoperation then contributed to the disturbance becoming major. In other words, a "hidden defect" in the relay which was not seen prior to the disturbance, caused the relay to misoperate or fail to operate because of the stress of the disturbance. In order to examine these "hidden defects" in the relays which caused the misoperations, we classified the 36 cases involving relays using the categories developed in the questionnaire evaluation. For the 36 relaying cases the number in each of the categories is given in Table 2.2.

Table 2.2 The number of relay defects in each category

Category	Number
Application	11
Maintenance	16
Setting	4
Calibration	0
Transient	0
Other	7
Total	38*

*Two of the 36 events had two causes.

Of the seven "other", six were unknown and one involved the physical mounting of the relay. It seems likely that some of the six were actually undetected maintenance

problems or hidden defects that went back into hiding. The total is 38 because two of the 36 events had two causes. The 16 cases involving maintenance constitute 44.4% of the 36 relay cases and 32.6% of the five-year total of the major system disturbances. If the six unknown were added to the 16, the percentages would be 61.1% and 44.9% respectively. The 16 cases are examined in more detail to learn the nature of the hidden defects in the relay system that contribute to major system disturbances. The 16 cases are listed below. The term LOC is used for loss-of-carrier or, more generally, loss-of-communication. When used, the term is explained in the list.

- (1) defective or failed edge connector
- (2) LOC (phase comparison)
- (3) accidental ground
- (4) defective sudden pressure relay
- (5) incorrect polarizing
- (6) faulty pin contact
- (7) defective or failed switch
- (8) bent contact
- (9) open resistor
- (10) broken wire
- (11) iron filing in micro switch
- (12) LOC(carrier)
- (13) communication circuit noise
- (14) auxiliary contacts misaligned
- (15) faulty contact
- (16) LOC(tone equipment for load shedding)

It is worth noting that four of the failures (2, 12, 13 and 16) (25%) are communication related, while most of the rest were defective components. The consistency of the relay system involvement in these major system disturbances over the five-year period shown in Table 2.3 is striking. The NERC reports make it clear that there would be much to be gained by identifying hidden relay failures before the disturbance. If even half of the hidden defects were eliminated, a substantial number of major disturbances could possibly be avoided.

Table 2.3 Outages involving relays from 1984 to 1988 in NERC reports

Year	Cases with Relay system involvement /Total Cases
1984	10/14 = 71.4%
1985	11/12 = 91.7%
1986	5/7 = 71.4%
1987	3/5 = 60.0%
1988	7/11 = 63.6%
Total	36/49 = 73.5%

During this study it became apparent that the concept of hidden failures had to be more rigorously defined and applied. It was the purpose of this research activity to examine defects in a relay or relay system that go undetected and can result in a worsening of a system disturbance, i.e. can significantly degrade system integrity resulting in loss of stability or load. In this context, *a hidden failure is defined to be a permanent defect that will cause a relay or a relay system to incorrectly and inappropriately remove a circuit element(s) as a direct consequence of another switching event.*

A failure that results in an immediate trip without any prior event is not considered a hidden failure. The power system must be planned and operated to withstand the loss of any element without exceeding the NERC criteria for reporting a disturbance.

A hardware failure that results in the relays failing to operate a breaker and trip out a faulted line or device is also not considered a hidden failure since redundant or backup protection or breaker failure systems must normally be provided for such a contingency.

A defect or malfunction that occurs at the instant of a fault or switching event, e.g. a "hole" in the blocking signal or an insulation failure caused by a switching surge, was similarly not considered a hidden failure since such a failure is not a permanent condition and cannot be monitored or detected before hand.

Before addressing the specific problem of hidden failures as defined above, let us examine the general performance characteristics of each element of the protection chain, and more particularly, how it fails and how such a failure can be detected.

2.3 Performance of protective system elements

This section describes possible failures that may occur in protective system elements.

2.3.1 Transducers

Current Transformer Failures – The current input to a relay can be shorted or open. Open CT leads will cause excessive secondary voltages and insulation failures resulting in arcing, damage and short circuits in some part of the secondary winding and connected devices and, as a result, do not usually remain undetected. Short circuited CTs, on the other hand, will result in no current to the relay and, by itself, will not be detected.

In a differential circuit, the relay operating current is much less than the normal secondary load current and loss of one CT input will result in the relay operating. Unless there is very little load this will usually occur simultaneously when the CT is shorted.

Overcurrent, distance and directional relays for line or equipment protection require current to operate for a fault within its zone of protection. In a single breaker configuration a shorted CT does not have any secondary current flow and the relay will not operate. In a double breaker configuration, such as breaker-and-a-half or ring bus, loss of one CT input

does not reduce the current input to the relay to zero, but it results in the relay current not representing the actual line current. The relay will not operate unless the fault current is greater than the relay pickup current. Although the relay may eventually operate to trip the associated breakers for an internal fault, there will be loss of coordination and other system elements may trip incorrectly.

If the relay is provided to perform an interlock or supervisory function such as an independent directional relay or a fault detector, and is fed from a separate CT, loss of that CT's current will result in failure to operate in the single breaker case or erratic operation due to the secondary current not representing the desired monitored current in a double breaker arrangement. In either case, the defect will result in additional system element outages due to the operation of backup relays or loss of coordination when a system fault occurs. There are some situations in which a relay is used to monitor the current in a line, transformer or other equipment to supervise an energizing or reclosing scheme. In such situations the failure of the supervising relay will result in incorrect, even unsafe, operation during normal energizing restoration or load switching.

CTs are not usually monitored to detect open or short circuits. To do so requires the addition of equipment that adversely affects reliability. It is more likely that the condition of the CT can be determined by monitoring the connected devices themselves.

Potential Transformer Failures —The voltage input can also be either open or short circuited. In either case, there would be no voltage delivered to the relay. However, a short circuited PT would develop very high secondary currents and cause the PT's fuses to blow, resulting in an open circuit condition for the relay. Let us consider this open circuit condition for, as an example, an admittance relay. Theoretically, without voltage there would be no developed torque within the relay and the relay should not operate. In practice, the voltage does not instantly go to zero. There is arcing and some finite decay. If the current is sufficiently high during this period of decay, a torque will be developed, and the relay will operate, but at some unintended voltage and current. We are not considering this a hidden failure. If the load current is not high enough the voltage will go to zero without a relay operation. This also should not be considered a hidden failure since the relay will not have enough voltage to develop a contact-closing torque even when the current does reach an operating level during a subsequent system event. This applies, however, only to a relay fed from a single phase voltage source. The usual phase distance relays are fed from two phases in which case the healthy phase does provide contact-closing torque when the current increases. This would be an example of a hidden failure.

It is usual to monitor the PT with indicating lights and perhaps a local alarm more as

an aid to the switchmen and wiremen. It is of course feasible to also remotely monitor the PT without the same degree of unreliability that exists with the CT.

2.3.2 Electromechanical relay failures

Within the electromechanical relays the resistors, capacitors and coils are responsible for the settings and the characteristics of the relay. When any of these components fail, either open or short circuited, the relays will either operate immediately, fail to operate under any circumstances, or have their settings or characteristics altered so the relay might operate incorrectly during a system event. Such relays must therefore be considered potential hidden failure candidates. The mechanical parts of these relays consists of discs, cups, plungers or armatures which can warp and bind or attract dust or magnetic particles which will affect their action; bearings which can crack or bind; springs and contacts which can fail. Contacts can be bent in the operating position, bent so operation is not possible or oxidized so that electrical contact cannot be made. Depending on the application of the relay, i.e., a tripping relay or a permissive supervising relay, the relay may contain a potential hidden failure.

Electromechanical relays are not easily monitored and cannot incorporate means for self-checking. Periodic testing is the most common preventive maintenance procedure.

2.3.3 Solid state relay failures

The vulnerable elements of solid state relays are the input electronics which can be level detectors for fault identification or settings; supervising cards for sequence measurements or interlocks; output circuits such as telephone-type relays or silicon-controlled rectifiers and a variety of timing cards which determine the characteristics of the relay, the coordination of tripping zones and other coordinating requirements such as communication and logic functions. Since these elements can fail in any number of ways it must be assumed that solid state relays have the potential for hidden failures.

Solid state relays are more easily monitored than electromechanical relays but at a significant cost in money and reliability.

2.3.4 Communication failures

All HV and EHV primary protection depend upon a pilot scheme using a communication link. The applications can be classified as a blocking scheme or a tripping scheme using either a continuous signal or an on-off signal. The media for communication can be power line carrier (PLC), microwave, fiber optics or metallic cable. Continuous transmission such as a transfer tripping scheme or an unblocking scheme sends a continuous guard signal and shifts to a tripping frequency when a trip is required. This method is less prone to hidden failures since it provides an automatic monitor of the transmitted signal and much of the equipment. The on-off signal is more difficult to

monitor and usually relies on periodic transmission tests. In addition, on-off schemes can misoperate when transients occur during a fault or a "hole" appears in the carrier at such a time. These possibilities are not considered hidden failures since they are not present during steady-state conditions. The media such as microwave and fiber optics are multi-function and also can be more easily monitored than PLC. Similarly, the metallic cable can be equipped with low-level monitoring signals.

2.3.5 Pilot relay failures

A Pilot relay can be classified by either its signal usage or type of fault detection. The relay uses a channel signal for either blocking or tripping a circuit breaker. Moreover, it uses either a directional comparison or a phase comparison for its fault detection.

Blocking Schemes— The logic of a blocking scheme requires that a fault detector be activated, a directional relay be activated and no blocking signal be received. Figures A.1 and A.2 of Appendix A show the possible HF modes.

Tripping schemes— The logic associated with tripping schemes is similar to that of a blocking scheme with the important exception that a signal is required to trip. There are directional underreaching and/or overreaching relays to initiate transmission and to supervise the trips. The HF modes are described below.

Phase Comparison— A phase comparison scheme requires synchronized signals to indicate an internal fault by a coincidence of the positive and/or negative halves of the current sine wave; or an external fault by opposition of the appropriate halves. In addition, low-level fault detectors indicate the presence of a fault and high-level fault detectors supervise the tripping. Phase comparison schemes can be either single phase or dual phase comparison. The single-phase comparison scheme monitors either the positive or the negative half-cycle. There is no protection during the unmonitored half-cycle. The dual phase comparison scheme monitors both the positive and the negative half cycle and a trip can occur on either. If the transmitted signal is missing, the relay acts as a sensitive overcurrent relay and will trip for internal or external faults at current levels above the high fault detector setting, which may be equal to some load conditions. If the low level fault detectors is continuously picked up, the signal is continuously transmitted and a false trip will not occur. If the low-level fault detector cannot pick up the situation, this is the same as loss of signal and the relay will initiate a trip at the high level fault detector setting. If the high level fault detector is continuously activated, a false trip will occur for internal faults at the level of the low fault detector pickup. External faults will not result in incorrect trips if the signals maintain their synchronism.

The pilot wire system is essentially the simplest, and with channel monitoring and fault detectors, may be the most secure and dependable. It can be used in either a tripping

or a blocking mode. The scheme is essentially a current differential that depends on the comparison of currents in or out of the protected zone. It's application is limited however, since it requires a metallic pair of wire between the two protective relay terminals.

2.4 Hidden Failures

This section describes the operation of the commonly used relay schemes, and identifies the inherent hidden failures of each scheme. Appendix A gives further details of these schemes and their influence on the region of vulnerability. The acronyms are explained in Appendix A, and listed in the list of acronyms.

2.4.1 Directional comparison blocking (DCB)

This scheme is shown in Figure 2.1 and the logic for correct operations is shown in table 2.4. During an external fault, a fault detector must pickup to start transmitting a blocking signal and the directional relay at one or the other end will not be activated to stop transmission. The blocking signal is received at both ends to prevent a trip [3].

Figure 2.1 - Directional Comparison Blocking

A hidden failure can exist if:

- the appropriate fault detector cannot be activated to start transmitting a blocking signal;
- a directional relay is continuously activated which will immediately stop transmitting a blocking signal once it starts;
- the receiver relay cannot be activated which allows a false trip when the associated directional relay operates;
- the transmitter cannot transmit which allows a false trip for all external faults.

Table 2.4 Operations of directional comparison blocking scheme

INTERNAL FAULT				EXTERNAL FAULT			
FD_A	YES	FD_B	YES	FD_A	YES	FD_B	NO
D_A	YES	D_B	YES	D_A	YES	D_B	NO
T_A	NO	T_B	NO	T_A	NO	T_B	YES
R_A	NO	R_B	NO	R_A	YES	R_B	YES
$TRIP_A$	YES	$TRIP_B$	YES	$TRIP_A$	NO	$TRIP_B$	NO

Note : T and R refer to the transmission and reception of the signal, respectively.
Subscripts A and B refer to opposite ends of transmission line.

2.4.2 Directional comparison unblocking (DCU)

Figure 2.2 shows the logic diagram and schematic for this scheme. The correct operations are shown in Table 2.5 where BLK and UNBLK stand for blocking and

Figure 2.2 - Directional comparison unblocking scheme

unblocking signals respectively. A continuous blocking signal is transmitted from each end to the other over separate communication channels. An overreaching directional phase and ground relay (D) detects a fault from the bus into the line and beyond. When this relay picks up it shifts the transmitted signal from a blocking frequency to an unblocking frequency. A trip occurs if the directional overreaching relay picks up and an unblocking signal is received.

Table 2.5 Operations of directional comparison unblocking scheme

INTERNAL FAULT				EXTERNAL FAULT			
D_A	YES	D_B	YES	D_A	YES	D_B	NO
T_A	UNBLK	T_B	UNBLK	T_A	UNBLK	T_B	BLK
R_A	UNBLK	R_B	UNBLK	R_A	BLK	R_B	UNBLK
$TRIP_A$	YES	$TRIP_B$	YES	$TRIP_A$	NO	$TRIP_B$	NO

Note : BLK and UNBLK stand for blocked and unblocked.
Subscripts A and B refer to opposite ends of transmission line.

A hidden failure can exist if:

- the unblocking contact is continuously picked up and the directional relay picks up on an external fault or heavy load.
- a directional overcurrent relay is continuously picked up and the transmitter shifts to the unblock mode for an external fault.

2.4.3 Transfer trip

There are a variety of transfer trip schemes depending upon the particular application. Fundamentally, however, all schemes use a frequency shift communication link. A trip occurs if the received signal shifts from a low frequency to a high frequency.

In the Direct Transfer Trip (DTT) scheme, there is no supervision and no hidden failures. If the transmitter misoperates in the trip frequency, there is an immediate trip; hence no hidden failure. If the transmitter cannot operate, there is no trip possible.

In a Permissive Underreaching Transfer Trip scheme (PUTT), for an internal fault, supervision is provided by the underreaching relay at one end while the underreaching relay at the other end shifts the frequency from low to high. The underreaching relays must overlap each other and must not overreach the protected line section. They key their local transmitter to the trip frequency. At the remote terminal the combination of trip signal

received and underreaching relay activated will trip the remote circuit breaker. For an external fault, neither relay is activated.

A hidden failure can exist if:

- a) an underreaching relay is continuously energized or
- b) a transmitter is stuck in the trip mode, sending a tripping signal to the remote end.

The trip occurs when an external fault occurs, activating one of the overreaching relays.

In the Permissive Overreaching Transfer Trip scheme (POTT), an overreaching relay provides the supervision while the underreaching relay shifts the frequency. Figure 2.3 and the logic Table 2.6 show the situation for the POTT. The other schemes are similar.

A hidden failure can exist if:

- a) an overreaching relay is continuously energized and the transmitter shifts to the high frequency for an external fault beyond the other terminal
- b) if the transmitter is stuck in the trip mode and a fault occurs within the reach of the opposite directional overreaching relay.

Figure 2.3 - Permissive Overreaching Transfer Trip

Table 2.6 Operations of transfer trip scheme

INTERNAL FAULT				EXTERNAL FAULT			
R_{UA}	YES	R_{UB}	YES	R_{UA}	NO	R_{UB}	NO
R_{OA}	YES	R_{OB}	YES	R_{OA}	YES	R_{OB}	NO
T_A	YES	T_B	YES	T_A	NO	T_B	NO
G_A	NO	G_B	NO	G_A	YES	G_B	NO
TRIP _A	YES	TRIP _B	YES	TRIP _A	NO	TRIP _B	NO

Note : Subscripts A and B refer to opposite ends of transmission line.

2.4.4 Single phase comparison

A single phase comparison scheme requires synchronized signals to indicate an internal fault by a coincidence of positive and/or negative half-waves or an external fault by opposition of the appropriate half-wave. In addition, low level fault detectors indicate the presence of a fault and high level fault detectors supervise the tripping.

Figure 2.4 shows the one-line and schematic for the single phase comparison scheme. Table 2.7 shows the correct operations of the relay (COIN stands for coincidence).

Figure 2.4 - Phase comparison schematic diagram.

A hidden failure can exist if:

- a) The transmitted signal is missing. The relay then acts as a sensitive overcurrent relay and will trip for external faults at current levels above the high fault detector setting, which may be equal to some load conditions.
- b) Similarly, if the low level fault detector cannot operate, the result is the same as a loss of signal.
- c) If the high level fault detector is continuously picked up, a false trip will occur at the level of the low fault detector pickup which could be at load levels.

External faults will not result in incorrect trips if the signals maintain their synchronism.

Table 2.7 Operations of single phase comparison

INTERNAL FAULT				EXTERNAL FAULT			
FD _{1A}	YES	FD _{1B}	YES	FD _{1A}	YES	FD _{1B}	YES
FD _{2A}	YES	FD _{2B}	YES	FD _{2A}	YES	FD _{2B}	YES
T _A	YES	T _B	YES	T _A	YES	T _B	YES
R _A	YES	R _B	YES	R _A	YES	R _B	YES
COIN	YES	COIN	YES	COIN	NO	COIN	NO
TRIP _A	YES	TRIP _B	YES	TRIP _A	NO	TRIP _B	NO

2.4.5 Dual phase comparison

Unlike the single phase comparison scheme, this system uses both the positive and the negative half-cycles of the 60 Hz sine wave. The sensing network produces a single-phase voltage proportional to the three-phase line currents. This single-phase voltage provides both a fault detector and transmitting keying function. The keying circuit shifts the transmitter back and forth between a high frequency and a low-frequency during each half cycle. These frequencies are then transmitted to the other terminal where the receiver produces two output voltages corresponding to the two frequencies where they are compared to the local voltages. A trip occurs when the received and local frequencies coincide and the fault detector has operated.

A hidden failure can exist if:

- a) The high-set fault detector is continuously energized. A false trip occurs at the level of the low-set fault detector.
- b) If it is continuously activated, a false trip would occur at the level of the

low-set FD.

If the high-set FD cannot operate, tripping is disabled which is not a hidden failure.

2.4.6 Pilot wire relay

The pilot wire (P/W) system is essentially the simplest, and with channel monitoring and fault detectors may be the most secure and dependable. Its application is limited however since it requires a metallic pair of wire between the terminals. There are two elements involved in the trip or block logic at either end of a terminal protected by pilot-wire; the relay itself and the metallic wire. The P/W circuit can be used to send a tripping or a blocking signal. The wire can fail opened or shorted and in either case no signal will be transmitted or received. The circuits are usually monitored and an alarm is sent should a short or open occur but the usual practice is to keep the relays in service until the circuit can be serviced. The relay can fail in either the trip or no-trip mode.

Figure 2.5 shows the blocking scheme.

Figure 2.5 - Schematic for blocking pilot system.

A hidden failure can exist if:

The relay fails in the trip mode and there are fault detectors used to help in the setting or some other reason. The trip will occur when an external fault occurs. This would then be a hidden failure since no immediate trip occurs but the relay will operate on an external fault.

2.4.7 Breaker failure relay

The input to breaker failure relaying consists of breaker auxiliary switches and/or

overcurrent relays, a timer and the initiating protective relay initiating a trip signal to a given breaker as shown in Figure 2.6. If the auxiliary switch and/or overcurrent relay is continuously picked up the timer may stay picked up through the seal-in circuit when a fault is cleared. This will result in immediate trip of the breaker failure lockout relay and is, therefore, not a hidden failure. A hidden failure exists if the timer fails in the picked up position. Coordination is lost and the breaker failure relay operates even if the fault is cleared.

2.4.8 Bus differential relay

Normally, there are no hidden failures associated with the bus differential relays. All of the analyzed defects result in either an immediate trip or a failure to trip. A possible exception is the double contingency of a shorted CT on an open feeder. When the feeder is energized and picks up sufficient load, the differential will misoperate.

Figure 2.6 - Breaker Failure

2.4.9 Transformer differential relay

A transformer differential can consist of an overcurrent relay, a percentage differential relay, or a harmonic restraint differential relay. Figure 2.7 shows the operating and restraint windings of a percentage differential relay. The harmonic restraint is obtained through internal filters. The input to any transformer differential relay is derived from current transformers measuring all sources of fault current and connected so the relay operating coil sees their algebraic sum. An overcurrent, percentage or harmonic-restraint

relay can have its operating coil open or shorted. In either event, the relay will fail to operate for an internal fault. This is not a hidden failure for our purposes.

A percentage or harmonic-restraint differential relay can have its restraint coils open or shorted. If any of the restraint coils are open this will result in an open circuit for the associated current transformer which will probably result in arcing and eventually a fault that will have to be cleared by other relays. This is not a hidden failure. If any of the restraint coils are shorted, there will be no restraining torque and the relay will misoperate for load conditions. This is a hidden failure.

A harmonic-restraint has filter circuits. If they are open or shorted there will be no restraint during energization of the transformer. This will probably not be a serious condition for the system since the transformer is being returned to service and there is no major change at the time of energization.

Figure 2.7 - Transformer differential relay scheme

2.4.10 Instantaneous, phase distance relays

There are no hidden failures associated with this relay.

2.4.11 Second and third zone distance relays

Protective relay contacts Z_2 and Z_3 start separate timers and each relay contact and timer contact, in series, will initiate a trip as shown in Figure 2.8. A continuously closed

Figure 2.8 - Zone 2 and Zone 3 Protection

relay contact will start the timer and allow it to time out, resulting in an immediate false trip. This is not a hidden failure. A relay contact that cannot close will result in a failure to trip, which is also not a hidden failure. If the timer fails open, there is again a failure to trip. If it fails closed then there would be a false trip when the relay contact closes, resulting in loss of coordination. This is a hidden failure.

2.4.12 Directional overcurrent ground relay

The schematic diagram of this relay is shown in Figure 2.9. This relay uses the current magnitude for both pickup and time. The relay contact can fail closed or open. A

Figure 2.9 - Polarizing circuit

closed contact trips immediately; no hidden failure. An open contact would result in a failure to trip when a fault occurs, requiring backup relays to trip. This is also not a hidden failure. The directionality feature is derived from a current and/or potential polarizing source as shown in the figure.

Should either of these fail then the relay would trip incorrectly for backward faults or fail to trip at all. Both of these are hidden failures.

3. REGIONS OF VULNERABILITY AND SIMULATION OF CASCADING POWER SYSTEM OUTAGES

3.1 Introduction

As previously mentioned, the industry responses to the questionnaire given in Appendix H and the NERC disturbance outage reports [1] were studied to identify failure modes and their consequences on power systems. In addition, the following relaying schemes commonly used in transmission system were analyzed:

- (1) Directional comparison blocking (DCB)
- (2) Directional comparison unblocking (DCU)
- (3) Direct transfer trip (DTT)
- (4) Permissive overreaching transfer trip (POTT)
- (5) Permissive underreaching transfer trip (PUTT)
- (6) Single phase comparison
- (7) Dual phase comparison
- (8) Pilot wire (P/W)
- (9) Bus differential relay
- (10) Breaker failure relay
- (11) Transformer differential relay
- (12) Instantaneous phase distance relay
- (13) Second and third zone distance relay
- (14) Directional overcurrent ground relay

All the failure modes of each relaying scheme leading to vulnerable states of the power system were cataloged. However, not all of the modes lead to a hidden failure (HF). The one leading to an immediate trip or causing backup relays to operate are not considered an HF. The HF can be exposed by one or several abnormal power system states. For instance, if a fault occurs not too far from the location of the relay with the HF, its effects may reach the relay. In other words, each HF has a region of vulnerability (RV) associated with it. If the abnormal power system state occurs inside the RV, the HF will cause the relay to incorrectly trip the circuit breaker.

3.1.1 Region of Vulnerability

There are two types of input signals taken by the relaying schemes that have been examined for regions of vulnerability.

1. Distance (impedance or reactance)
2. Current magnitude

For relays that operate for a fault within a certain distance of their locations, we assume that the reach settings of relay units are as follows :

1. Underreaching unit	0.7 of the line length
2. Overreaching unit	1.5 of the line length
3. Zone 2 relay	1.2 of the line length
4. Zone 3 relay	the entire line plus 1.2 of the length of the longest line behind the remote bus

The current magnitude relays operate for the input current magnitude whenever the current exceeds their pick-up settings. The idea of relays with an HF having an RV surrounding themselves may not be directly applicable to these relays. If, however, the input signal is a fault current, we can indirectly apply it. This is, in general, due to the fact that the farther the fault is from the relay, the smaller is the fault current. Consequently, we can find the locations beyond which the relay would not operate. Those locations will form a boundary of the RV for current magnitude relays.

Appendix A shows all the relays with hidden failures together with a brief explanation of relay operations, their simplified logic diagrams, and lists of the HF's followed by their effects and RV's. The list of acronyms defines the symbols used below.

From the examination of all the RV's, there are four types of RV's that are a direct measure of distance from the relay. They are different in either being behind the local or remote bus, and in the reach of the region.

Type 1. Reverse Local Bus Vulnerability Region: RV is behind the local bus (bus A) and has a reach of half of the line protected by the relay. Figure 3.1 shows an example of this type of RV.

Figure 3.1 – Region of Vulnerability Type 1

A fault inside the RV (shaded area) will cause line AB to be mistakenly disconnected if the protection system has a hidden failure. This type of RV belongs to the HF's shown in Table 3.1

Table 3.1 Hidden failure modes causing region of vulnerability type 1

Relay	Hidden failure modes
DCB	FD _A cannot pick up Transmitter fails to transmit
DCU	D _A continuously picks up
POTT	D _A continuously picks up
PUTT	Transmitter continuously transmits

Type 2. Reverse Remote Bus Vulnerability Region: RV is behind the remote bus (bus B) and has a reach of half of the line protected by the relay as shown in Figure 3.2.

Figure 3.2 – Region of Vulnerability Type 2

The following HF's have this type of RV :

Table 3.2 Hidden failure modes causing region of vulnerability type 2

Relay	Hidden failure modes
DCB	R _A cannot pick up
DCU	R _A continuously picks up
POTT	R _A continuously picks up
PUTT	R _A continuously picks up

Type 3. Zone 2 Vulnerability Region: RV is behind the remote bus and has a reach of 0.2 of the line protected by the relay. When the timer of Zone 2 distance relay fails closed, this RV exists.

Type 4. Zone 3 Vulnerability Region: RV is similar to type 3 except for the reach of the region is 1.2 of the longest line connected behind the remote bus. Zone 3 distance relay with the timer failed closed possesses this type of RV.

3.1.2 Region of Vulnerability Calculation

All the calculations are performed using the New England 39-bus test system, the one-line diagram of which is shown on page 40. The system load flow data is given in Appendix I.

The complete results of the calculation of all four RV's that are the direct measure of distance are included in Tables B.1 to B.4 in Appendix B. An example result of type 1 RV taken from Appendix B is shown below for relay 2,1.

TABLE 3.3 An example of region of vulnerability calculation

Relay	RV	Triggering lines
2,1	.0466	3 5 6 4 30

Figure 3.3 – An Example Result of RV Type 1

We assume that $R_{2,1}$ has an HF leading to an RV type 1. This region, shown by shaded area, has a reach of half of line L1 or $0.0411/2$ or 0.02055 pu in all directions behind bus 2. In the direction of L4, it covers all L4, which is 0.0086 pu, and goes beyond bus 25 to cover part of L30 by $0.02055 - 0.0086$ or 0.01195 pu. Similarly, in the direction of L3, it covers all L3, 0.0151 pu, and part of L5 and L6 each by $0.02055 - 0.0151$ or 0.00545 pu. Therefore, the RV type 1 of $R_{2,1}$ is $0.0086 + 0.01195 + 0.0151 + 2(0.00545)$ or 0.0466 pu.

A fault inside the shaded region which is not in the zone of protection of $R_{2,1}$ will trigger $R_{2,1}$ to incorrectly trip L1 causing the second contingency. For example, if there is a fault on L4, this fault will be cleared by disconnecting L4; in addition to this first contingency, L1 will also be disconnected due to the HF in $R_{2,1}$.

The rest of the HF's are not a direct measure of the distance from the relay. They are the failure modes of relays operated by current magnitude. As mentioned earlier, if the input to the relay is a fault current we can find the boundary of the RV. This is done by first, assuming that the boundary is on the buses. Then, a short-circuit calculation is performed when a fault is placed on the system buses one at a time. If the relay sees a current higher than its pick up setting, the bus having the fault is considered to be inside the RV. The last bus in each direction is considered to be the boundary of the RV. Relays with HF's that fall into this category are :

- Phase comparison blocking (PCB) relay acting as a nondirectional overcurrent relay with pick-up setting at FD_H level.
- Directional overcurrent ground relay tripping for backward faults, due to a loss of directionality.

A three-phase fault is used in the calculation for the phase comparison blocking relay. We assume that the setting of the FD_H unit is set at 200 % of the maximum load current. In the calculation for the ground relay, the short-circuit study is performed with a single-line-to-ground fault.

The results of the RV calculation for PCB relay are shown in Tables C.1 and C.2 in Appendix C, and those of the ground relays are in Tables D.1 and D.2 in Appendix D. Tables C.1 and C.2 show the setting of each relay and fault current seen by the relay when there is a bus fault. Bus faults leading to fault current smaller than the setting are excluded from the tables. The RV of each relay and lines that are covered by the region are shown in Tables C.2 and D.2.

In general, it can be seen from the results that relays with large settings tend to have small RV's while those with small settings have large RV's. In some cases, the RV's of small setting relays may cover almost the entire test system. The RV of PCB of $R_{27,17}$ in Table C.2, and that of directional ground overcurrent relay $R_{26,29}$ in Table D.2 reveal this situation.

3.1.3 Vulnerability Index Calculation

After the regions of vulnerability of a relay with an HF has been defined, the next step is to calculate the relative importance of each region, called vulnerability index. One of the measurements that can be used to determine this index is the stability or instability

of the system following some power system contingencies. The process starts with having a fault inside the region. The fault causes the relay protecting the line with the fault to trip; this is the first contingency. In addition to the first contingency, the relay with the HF is triggered to trip the line it is protecting. As a consequence, two lines are disconnected.

The steady-state stability limit or the lack of the load flow to converge to a solution are used as a criterion to indicate the vulnerability level. The following values are examined for a possibility of any of them being an index indicating a vulnerability level of the system following the outages:

1. Normalized changes in the determinant of [B']
2. Normalized changes in the determinant of [B'].
3. Line loading. (MVA)
4. The largest deviation of the phase angle, in the first iteration, from the base case solution, $\Delta\theta_1$.
5. The norm of the deviation of all the phase angles:

$$\Delta\theta_t = \sqrt{\Delta\theta_1^2 + \Delta\theta_2^2 + \dots + \Delta\theta_n^2}$$

where [B'] and [B'] are the two matrices used in the Fast Decoupled Load Flow. The determinants of the base case power system are used as the base values for the normalizations in 1. and 2.

The results of the calculation when two lines terminating on the same bus are dropped at a time are shown in Appendix E in Tables E.1 to E.5. Outages leading to islanding are not included in the tables. Each table is sorted in the descending order of one of the five values.

From the inspection, it can be concluded that the variation in the determinants alone cannot be the index in our consideration. This seems to be the case for the MVA flow also. On the other hand, $\Delta\theta_1$ and $\Delta\theta_t$ give a much stronger indication whether a load flow may have a solution or not. When these values are large, the load flow solution tends to diverge. These changes in angle alone, however, are not enough to indicate the divergence; this can be seen in some cases when $\Delta\theta_1$ and $\Delta\theta_t$ are large but the others are small the load flow solution can still be obtained. Consequently, the index should probably be a weighted combination of all the five values.

3.1.4 Steady State Instability Index

Let	x_1	=	change in det[B']
	x_2	=	change in det[B']

$$\begin{aligned}
x_3 &= \text{change in } \Delta \theta_1 \\
x_4 &= \text{change in } \Delta \theta_t \\
x_5 &= \text{line flows}
\end{aligned}$$

The steady state instability index (SII) of each contingency computed from the above five indices with uniform weighting factors is

$$SII_{k,l} = \|x_{k,l,1}\| + \|x_{k,l,2}\| + \|x_{k,l,3}\| + \|x_{k,l,4}\| + \|x_{k,l,5}\|$$

where $\|x_{k,l,i}\| = \frac{x_{k,l,i}}{\max\{x_i\}}$ (normalization), k and l are lines involved in the contingency. If SII is a good indication of the steady-state instability, we expect cases that do not have a load flow to cluster at the top part of the table sorted according to the values of SII. Table F.1 in the Appendix F shows the results of this study where cases with asterisks do not have load flow solutions. Obviously, SII in Table F.1 does not give any clear indication concerning steady-state stability. A number of cases without a load flow (dropping lines 5 and 7, 10 and 14, and 13 and 14) are located close to the bottom of the table. Further examination reveals that there are relatively large loads connected to the terminals of these lines. Consequently, total loads at the terminals of the dropped lines should be considered as another factor (X_6) in addition to the existing five. Again, the uniform weighting factors are used for all six indices and the results are shown in Table F.2 which is clearly better than the previous one.

However, there are still some contingencies that do not cause steady-state instability and their SIIs are greater than of those contingencies causing instability. This can be seen from $SII_{31,33}$ and $SII_{31,32}$ being greater than $SII_{13,14}$, $SII_{11,12}$ and $SII_{5,7}$ as well as $SII_{5,6}$, $SII_{9,10}$ and $SII_{12,16}$ being greater than $SII_{10,14}$. Other values of the weighting factors have been tried along with adding other factors; however, the results on the SII profile are not improved and sometimes are even inferior to the one shown in Table F.2. As a result, we still have to perform full load flow calculations in some situations. With the assistance of SII, the number of full load flow studies can be significantly reduced. In our example in Table F.2, the top part of the table does not have a load flow, while the bottom one does. Between them, there is a band of indecisiveness where we cannot make a decision concerning steady-state stability by inspecting the values of SIIs alone. Therefore, we have to perform the full load flow calculations for the contingencies, those SIIs of which fall inside this band.

There are $2C_{46}$ or 1035 possible second contingencies in the New England 39 bus test system. The 46 is the arrangement of 34 lines and 12 transformers with two elements out

of service. Three hundred eighty-eight of these contingencies result in a bus left disconnected from the rest of the system. If the steady-state issue of the entire system is the primary concern, there is clearly no load flow for these cases. This can easily be detected when $\det[B']$ is equal to zero, further reducing the number of load flow studies.

Moreover, a number of second contingencies cause a very large change in $\det[B']$ from the base case, for example, from the order of 10^{78} to 10^{70} . The system, obviously, cannot cope with these severe disturbances and it will lose the steady state stability. If the large changes are detected, we can also avoid performing the load flow for these contingencies. Table 3.4 shows the number of cases that clearly do not have load flow solutions due to the two reasons.

Table 3.4 The number of clearly unstable cases

$\det[B'] = 0$	Large change in $\det[B']$
388 cases	92 cases

Table F.3 in the appendix (555 cases) shows the outcomes of the SII computations excluding the two kinds of contingencies mentioned above.

The vulnerability index (VI) of each relay should be calculated from its RV taking into account the effects of contingencies that can occur inside the region. Since some lines are only partially covered by the region, only that part of the lines should be used in the VI calculation. An example of the VI calculation is shown below for relay 2,1.

Figure 3.4 – An Example Result of VI Calculation

In Figure 3.4, the boxed and shaded region is the Type I RV of the relay which covers entire lines 4 and 3, and parts of lines 5, 6 and 30 as in Figure 3.3. From the steady state load flow studies, there are two scenarios of the second contingencies causing the system to become unstable — the loss of lines 1 and 3, and the loss of lines 1 and 5. Therefore, only line 3 and part of line 5 that are in the shaded area are accounted for defining the VI of $R_{2,1}$. The others, which do not cause the instability, are not involved. Since the entire length of line 3 (reactance = .0151 pu) and part of line 5 (0.0054 out of 0.0213 pu) are covered by the RV, the VI is equal to $0.0151 + 0.0054$ or 0.0205 pu. Table G.1 in the Appendix G shows the results of the VI calculation of RV Type I. The VI of Type II can be extracted from Table G.1, since Type II is the opposite of Type I; for example, the VI of RV Type I of relay 2,1 is equal to the VI of RV Type II of relay 1,2. Tables G.2 and G.3 are the VI of Type III and IV respectively. The VI of the current magnitude relays are presented in Table G.4 for phase comparison blocking relays and in Table G.5 for overcurrent ground relays. The other criterion which can be useful in defining the vulnerability level is transient stability limit. As in general transient stability problem, time-domain solution is time consuming. At present, the application of extended equal area criterion to the calculation of the vulnerability index are being studied.

3.2 Simulation of Cascading Power System Outages

In spite of the obvious importance to the industry, there has been little analytic or simulation work in the area of cascading outages of the bulk power system. The reasons are based on the enormous complexity of the problem. The difficulty of simulating rare events coupled with the lack of data on which to base models, have precluded work in the area. The NERC reports make it obvious that major outages typically involve a number of unlikely or "shouldn't have happened" events. Since simulation studies which capture a number of low probability events are difficult to perform and since the exact probabilities of the various unlikely event are not known, almost no attempt has been made to simulate the temporal spreading of the outage. It is our intention to establish, using analysis and simulation, that there is a substantial return from self-checking and self-monitoring of microprocessor relays. We hope to show that the probability of a simple event leading to a widespread outage is greatly reduced by self-checking and monitoring of individual relays. We establish a technique for determining the probability of a cascading outage in terms of the individual probabilities of a hidden failure in a relay leading to an incorrect trip. The conclusion is not dependent on the exact numbers used for the probability that an exposed line will trip in that we treat the individual probabilities parametrically. That is, if self-checking and monitoring reduce the probability of hidden failure by 50%, how much

reduction in overall system failure probability results? The New England 39 bus system was the vehicle for the simulation. The protection system for the power system was designed previously in this study. We hypothesize a probability model for the existence of hidden failures in the overall line protection. The assumption is that if any line sharing a bus with given transmission line L trips, then the hidden failures in line L are exposed. That is, there is a probability p that line L will trip. In the first small example p is a constant, while for the 39 bus system p will be taken as a function of impedance seen by the relay with a lower probability if the impedance is large.

3.2.1 Example

If one line is tripped legitimately, all the lines connected to its ends are now exposed to incorrect tripping. The probability of such a trip is, of course, quite small. Consider the four bus, six line system shown in Figure 3.5a. If line 4 is tripped for legitimate reasons, the four lines 1, 2, 3, and 5 are exposed to incorrect tripping because of hidden failures in the relays protecting them. Line 6 is not exposed since it is not connected to a bus to which line 4 was connected. This situation is shown in Figure 3.5b with the four exposed lines dashed. The 16 possible outcomes are shown in Figure 3.5c. The networks of Figure 3.5c are possible combinations of line outages. 0 line out (${}_0C_4=1$), 1 line out (${}_1C_4=4$), 2 lines out together (${}_2C_4=6$), 3 lines out together (${}_3C_4=4$) and 4 lines out together (${}_4C_4=1$). For ease of illustration, the probability of an exposed line tripping is taken as p , with the probability of an exposed line not tripping is $q = (1 - p)$. Hence, with probability q^4 all four lines do not trip; with probability $p q^3$, there are four ways one line could trip while three did not trip (labeled e, f, g , and h); with probability $p^2 q^2$, there are six ways two lines could trip while two did not trip (four of which are labeled a, b, c , and d); with probability $p^3 q$ there are four ways three lines could trip while one did not trip; and, with probability p^4 there is only one way all four lines could trip. All of the networks resulting from three or four additional outages, and two resulting from two outages have at least one bus upon which no lines terminate. If we take that condition to be a "major power system disturbance" for our example, then the probability of such a disturbance in one step is

$$p^4 + 4 p^3 q + 2 p^2 q^2 = 2 p^2 - p^4 \text{ since } q = 1 - p \quad (1)$$

The networks $a-h$ must each be analyzed for further line losses. The model assumes that the process is repeated, for example, in network e , line 1 has tripped exposing lines 2, 5, and 6 to false tripping with probability p . Some lines such as line 6 in network a are exposed twice when two lines connected to a bus to which it is connected are tripped. These lines are shown with longer dashes in Figure 3.5c. Networks a and d can only survive if all the exposed lines fail to trip.

This gives a probability of failure of cases a and d

$$2 p^2 q^2 (1 - q^4) \quad (2)$$

where the q^4 indicates that all 4 lines fail to trip. The failure probability is 1 less the probability of not failing

Figure 3.5a The original network

Figure 3.5b The network after the loss of line 4

Figure 3.5c The 16 possible networks after one step

Networks b and c survive if the remaining lines do not trip or if line 6 trips in the next step and then no additional lines trip. The probability of failure of networks b and c is

$$2 p^2 q^2 (1 - q^6 - 2 q^4 p q^2 - q^4 p^2 q^2) \quad (3)$$

Again, as in cases a and d, the probability of failure is 1 less the probability of not failing. The three negative terms in (3) are: all three lines exposed from both ends holding, one end of line 6 tripping (the 2 since there are two ends) while the other two lines do not

trip and then in the next step the two remaining lines not tripping, and both ends of line 6 tripping while the other two lines do not trip and then in the next step the two remaining lines not tripping, respectively.

Networks *e*, *f*, *g*, and *h* are all identical and are decomposed in Figure 3.6. Five of the eight result in failure while networks *ea* and *eb* must be further analyzed. The five failure probabilities are

$$pq^3(p^3 + 3p^2q + pq^2) \quad (4)$$

Figure 3.6a Network *e*, *f*, *g*, *h*

Figure 3.6b The 8 possible resulting networks

Network *ea* will only survive if the remaining lines do not trip or if line 3 trips and then the remaining two lines hold. This gives a probability of failure of

$$p^2q^5(1 - q^3 - q^2p - q^2) \quad (5)$$

Again the last negative term in (5) represents the two stage event of lines 2 and 5 do not trip, line 3 trips exposing lines 2 and 5 again and then lines 2 and 5 do not trip. Finally network *eb* can only survive if all the remaining lines fail to trip yielding the last failure probability of

$$p^2 q^5 (1 - q^3). \quad (6)$$

The overall probability of a failure initiated by the loss of line 4 given this model is the weighed sum of (1) through (6) $((1) + (2) + (3) + 4[(4) + (5) + (6)])$ or

$$P = p^4 + 4 p^3 q + 2 p^2 q^2 + 2 p^2 q^2 [2 - q^4 - q^6(1 + 2 p + p^2)] \\ + 4 p^2 q^2 [p^2 q + 3 p q^2 + q^3(2 - 2 q^3 - p q^4)] \quad (7)$$

With $q = 1 - p$, equation (7) could be written as a 12th order polynomial in p . It is plotted versus p in Figure 3.7. A simulations study of 1000 of the cascading outage with $p = 0.5$ produced 882 failures, while $p = 0.1$ produces 69 failures. The corresponding values of P are $P(0.5) = 0.8813$ and $P(0.1) = 0.0724$. At each step the simulation program drew a random number uniformly distributed in $[0,1]$, such a uniform random variable is equally likely to be any number between zero and one, for each exposed line, compared that number with p , removed the lines for which the random number drawn was less than p , and determined the exposed lines for the next step. The program stopped if any bus had no lines connected to it or if there were no new lines tripped in a step.

Figure 3.7 Probability of System Failure versus Probability of exposed line tripping incorrectly (equation 7) for the Four-Bus System

3.2.2 Importance Sampling

For sufficiently small p , $P \approx 2 p^2$, a reflection of the fact that there are two ways that the failure of exactly two lines can lead to failure. This can be seen from equation 7 by letting $q=1$ and finding the lowest power of p . For such small values the simulation would require a large number of simulations. An estimate of the number of observations needed

to estimate a simple probability is given in [6]. If $\{x_i\}$ are identically distributed Bernoulli random variables with

$$P\{x_i = 1\} = \rho = 1 - P\{x_i = 0\}$$

where

$$P\{x_i = 1\} = \text{the probability of the event occurring}$$

$$P\{x_i = 0\} = \text{the probability of the event not occurring}$$

and we wish to estimate ρ with at most a 20% error with 95% confidence. That is, we want the estimate $\hat{\rho}$

$$\hat{\rho} = \frac{1}{N} \sum_{i=1}^N x_i \quad (8)$$

to be such that

$$P\{|\rho - \hat{\rho}| \leq 0.2 \rho\} \geq 0.95 \quad (9)$$

where N is the number of observations of the random variables x_i . For example, $x_i = 1$ could correspond to a line being in operation and $x_i = 0$ could correspond to the line being tripped. In [6] the estimate of N is found to be

$$N \cong 100/\rho \quad (10)$$

The complexity of such a small network indicates that analytic approaches to realistic systems is impossible. If the probability of cascading outages is as small as experience indicates, then the study of the mechanism of these failures through simulation would seem to require formidable amounts of computation. With a P of 10^{-6} , from equation (10) we would need close to 10^8 simulations of the cascading outage. Each simulation would require a number of random number draws, putting in question the long term behavior of the random number generator.

The above mentioned problems are typical of the study of rare events in large systems. The search for techniques to overcome these obstacles is an active research area in digital communications. For example, the Aloha communication network has been studied using these techniques [7]. Rare events such as the large scale outage of the telephone system are similar to power system outages in structure. One valuable technique is that of *importance sampling* in which the simulation is done with the probabilities altered so that the rare event happens more frequently. If we take the preceding 4 bus, 6 line example to illustrate the technique, the event: line 1 trips in the first step (2, 3 and 4 do not trip) exposing lines 2, 5, and 6 in the second step, lines 2 and 5 trip in the second step (6 does not) isolating bus 2 would be recorded as a 1 in a conventional simulation. The number of 1s in N simulations divided by N is the estimate of the probability of a cascading failure. In importance sampling, rather than using the actual probabilities, p and

q , the simulation is done with altered probabilities pp and $qq = (1 - pp)$ and rather than recording a 1 we record a number, t computed as we proceed in the simulation. The number, t is the ratio of the actual probability of the events divided by the probabilities used in the simulation. For the event described

$$t = \left[\frac{p}{pp} \right] \left[\frac{q}{qq} \right]^3 \left[\frac{p}{pp} \right]^2 \left[\frac{q}{qq} \right] \quad (11)$$

The first two terms in Equation (11) are from the first step while the next two terms are from the second step. The actual probability of the particular event is $p^3 q^4$ while the probability that the event occurs in the simulation is $(pp)^3 (qq)^4$. It can be seen that the estimate of the probability P formed as a sum of t 's divided by the number of trials

$$\hat{P} = \frac{1}{N} \sum_{i=1}^N t_i \quad (12)$$

will have the correct mean [6] even if N is smaller than the $100/P$ estimate. For example, if $p = 10^{-6}$ in Equation (7), $P \cong 2 \times 10^{-12}$, and from equation (10) $N \cong 5 \times 10^{13}$. If we let $pp = 0.5$, the failure will occur an average of 882 times in a 1000 as in the simulation described following equation (7). Small numbers such as $t = [(10^{-6})^3 (1-10^{-6})^4] / [(0.5)^3 (0.5)^4] = 1.28 \times 10^{-16}$ will be recorded for the failure described above. The one-step failure produced by lines 1 and 2 tripping at step one have a larger probability ($t = p^2 q^2$) and a larger t ($t \cong 10^{-12}$). The variance of the estimate $\hat{P}$ is a function of how the probability pp is chosen.

Figure 3.8 Probability of an exposed line tripping incorrectly

In a more general problem each line will have a different probability of tripping incorrectly (rather than the fixed value p used in the example). A simple model is shown in Figure 3.8 where the probability of an exposed line tripping incorrectly is modeled as a function of the

impedance seen by the line relay. The value of three times the zone three impedance setting is chosen to account for a fault detector value. Other models are possible with piece wise linear shapes or dependence on the line flow rather than impedance seen by the relay. The dependence of the probability on current system conditions means that the impedance or flow must be recomputed after each outage in the simulation. Since a true load flow after each outage would involve excessive amounts of computation, the DC load flow assumptions of unit voltage magnitudes and small angles are used with rank one corrections made for a tripped line. The approximation becomes rather crude as a large number of lines are lost. Since long chains of line outages have much smaller probabilities, the need for accuracy is not great. That is, failures which involve a small number of lines such as the loss of the two lines 1 and 2 in the example, have larger probabilities (p^2q^2) than the loss of all four lines which has probability p^4 . If probabilities that depended on flows were used, more accurate flows are needed when only a few lines are out than when a large number of lines are tripped. Nevertheless, there is substantial amount of computation involved in the direct application to importance sampling to the power system problem. To illustrate the computational burden, the simulation of 5000 events initiated by a single line outage in the 39 bus system using the model in Figure 3.8 and a DC load flow after each line outage takes about four hours on a SUN SPARC Station IPX using MATLAB. It is clear that a large number of iterations are needed to overcome the erratic behavior of the estimate. The number 5000 is selected only to illustrate the computation required. The difficulty is the choice of the probabilities (pp in Equation (11)) used in the simulation. Simply making the rare events more likely does not guarantee that the standard deviation of the estimate of the probability is acceptable. A persistent problem is the occurrence of a supposedly low probability event (a small pp in Equation (11)) which produces a large value for t which distorts the estimate.

3.2.3 A Variation on Importance Sampling

For the power system problem there is an alternate to importance sampling which seems to be even more computationally efficient. The numerator of Equation (11) is the actual probability of the sample path (the sequence of line outages). Rather than accumulating the weighted probabilities as in Equation (12), we can record the distinct sample paths exposed in the simulation (using the pp probabilities) along with the actual probabilities (the numerators of equation (11)) and sum the probabilities. If the number of simulations is large enough to produce the significant sample paths, then the sum is a tight lower bound to the actual probability of failure. Although the choice of the simulation probabilities, (the pp 's) is less critical than the direct importance sampling, some variation

in the typical sample paths are observed as the rule for generating the pp 's is changed. If all exposed lines are given the same probability (say $1/2$) then the resulting sample paths are somewhat different than those obtained when the exposed probabilities are simply scaled up so the largest is $1/2$. A solution which seems to have sufficient richness is to randomize the rule for generating the simulation probabilities as follows. If p_j represents the actual probability of the j^{th} exposed line tripping (from Figure 3.8) and $p_{\max}$ represents the maximum probability among all the exposed lines, then

$$pp_j = 0.5 \left[\frac{p_j}{p_{\max}} \right]^{\mu_j}$$

where the μ_j are uniform random variables in the interval $[0, 1]$ i.e. any number between 0 and 1 is equally likely. The value $\mu_j = 1$ corresponds to uniform scaling while a value of 0 corresponds to setting all the values to $1/2$. Since the μ_j are chosen at each step, all combinations are exposed. An example using the New England 39 bus system will show the obvious advantage of the technique.

3.2.4 The New England 39 Bus System

The 39 bus system is shown in Figure 3.9 on the next page. The simulation begins from a base load flow with previously designed relay settings. A line is selected as the location of the initiating event and the following iterations repeated N times.

- 1) Determine the lines that have been tripped in the last iteration. (initialized with the selected line out)
- 2) Determine all lines connected to buses of the lines in step 1) (the exposed lines)
- 3) Recompute the impedances seen by the relays for the exposed lines. (DC load flow)
- 4) Find the probability of tripping for each exposed line using Figure 3.8
- 5) For each exposed line draw a random number to determine whether the line tripped. The probabilities used are not those from step 4) but larger numbers selected to be sure all reasonable sample paths are observed at least once.
- 6) For the exposed lines record

$$t_i = \prod_{\text{all lines that tripped}} p_j \quad \prod_{\text{lines that didn't trip}} (1 - p_k)$$

where $\prod_{i=1}^N$ indicates a product of N terms

- 7) Record the lines that are tripped.
- 8) Return to 1) if any lines tripped and all buses still connected. Continue until no lines are lost or all lines connected to any bus are tripped.
- 9) If failure, determine if

$$t = \prod_{\text{all steps}} t_i$$

is a new number (a new sample path – a new sequence of line outages). If so record it.

With line 6 tripped, lines 3, 5, and 25 are exposed. Using $p = 0.05$ in Figure 3.8, the most likely terminal states are shown in Table 3.5 below.

Table 3.5 Probabilities and terminal states for the 39 bus system with the model in Figure 3.8 for individual line outages with $p = 0.05$ initiated with line 6 out.

Probability	Lines Out									
0.6451×10^{-3}	3	5	6							
0.3701×10^{-3}	6	25								
0.0202×10^{-3}	1	3	5	6						
0.0171×10^{-3}	3	6	25							
0.0092×10^{-3}	3	5	6							
0.0045×10^{-3}	5	6	7	8						
0.1283×10^{-6}	1	2	3	6						
0.0918×10^{-6}	5	6	25							
0.0775×10^{-6}	3	5	6	8						
0.0774×10^{-6}	3	5	6	7						
0.0059×10^{-6}	5	6	7	8						
.										
.										
.										
9.61×10^{-18}	3	4	6	26	30	31	32	33	34	

$$P = 0.0011$$

With $N = 500$, 31 distinct sample paths were found. The final state listed at the bottom of Table 3.5 is the 28th ranked in probability but involves the most lines. The sum of the probabilities rounded to 4 decimal places (the probability of losing at least one bus)

is

$$P = 0.0011$$

Repeated simulations of $N = 500$ gave different numbers of distinct sample paths (28 and 30) but continued to give exactly the same P . The reason is clear when one realizes that the first six entries in Table 3.5 add up to 0.0011. That is, the entries below the first six contribute almost nothing to the sum. The entries in the tables are the lines out when the simulation terminates and do not give the sequence of events which lead to the final state. For example, the final state 3 5 6 out appears in Table 3.5 in the first and fifth position with two different probabilities. One event corresponds to line 3 tripping first and then line 5 while the other is the tripping of both lines 3 and 5 at the first step. The order of line tripping is not given in the tables since it is only the intention here to show that monitoring (reduction of the probability of hidden failure) will reduce the probability of cascading outage.

The results are repeated in Table 3.6 for the probability of individual line outages reduced by one half. It is interesting to note that the order of occurrence of the sample paths are altered. Since the probability of line outages is based on flows, the probabilities of a line tripping do not scale exactly with a change in the base height in Figure 3.8. The overall outage probability is reduced by a factor of $0.011/3.6291 \times 10^{-4} = 3.03$. If the typical failure required the loss of only one line, P would change by a factor of two if p were increased by a factor of two. If two lines were required P would increase by a factor of four, etc. It is clear that line 6 is in a sensitive location and the typical failure requires an average of between one and two lines. Other lines as the initiating event give different results for P and for the effect of altering p . Line 20 gives the results in Table 3.7

Table 3.6 Probabilities and terminal states for the 39 bus system with the model in Figure 3.8 for individual line outages with $p = 0.025$ initiated with line 6 out.

Probability	Lines Out			
0.1185×10^{-3}	6	25		
0.1640×10^{-3}	3	5	6	
0.0043×10^{-3}	3	6	25	
0.0025×10^{-3}	1	3	5	6
0.0024×10^{-3}	3	5	6	
0.0012×10^{-3}	3	5	6	

$$P = 3.6291 \times 10^{-4}$$

If the probability from Figure 3.8 is changed to $p = 0.025$, with line 20 as the initiating event, P is reduced to .0081, the factor of $1/2$ ($\frac{.0081}{.0163}$) reflecting the fact that the most common sample path is a one line (line 19) failure. If we take the loss of two buses as a criteria for failure rather than one, and move the initiating event to line 8, more lines need to trip in order for a failure and the probability P is considerably smaller as seen in Table 3.8. A total of 78 distinct sample paths were found for this case. The longest sample

Table 3.7 Probabilities and terminal states for the 39 bus system with the model in Figure 3.8 for individual line outages with $p = 0.05$ initiated with line 20 out.

Probability	Lines Out			
0.015	19	20		
0.0005	19	20	21	
0.0004	19	20	22	
0.0002	19	20	21	22
0.013×10^{-3}	19	20	21	23
0.0082×10^{-3}	20	21	23	27
0.0074×10^{-3}	20	22	23	27

$$P = 0.0163$$

path involved the tripping of 13 lines (1,2,3,4,5,7,8,11,12,30,32,33) with a probability of 6.06×10^{-29} .

Table 3.8 Probabilities and terminal states for the 39 bus system with the model in Figure 3.8 for individual line outages with $p = 0.05$ initiated with line 8 out. Two buses disconnected required for termination

Probability	Lines Out				
0.2228×10^{-6}	5	7	8	9	10
0.1198×10^{-6}	3	5	6	7	8
0.0968×10^{-6}	5	7	8	9	10
0.0681×10^{-6}	5	7	8	10	13 14
0.0491×10^{-6}	3	5	6	7	8
0.0261×10^{-6}	5	7	8	9	10

$$P = 6.5743 \times 10^{-7}$$

With $p = 0.025$, the sample paths are unchanged but $P = 3.6715 \times 10^{-8}$, a reduction

by a factor of 17 because more than 4 lines are required to trip in order to lose two buses. In a real sense, the more reliable the system is, the more is gained by self checking and monitoring. If the system is on the verge of failure, i.e. one false trip and the system is down, then reducing the probability of a single line tripping by a factor of $1/2$ reduces the probability of system failure by the same factor of $1/2$. On the other hand, if four lines have to trip before the system fails, then reducing the probability of a single line tripping by a factor of $1/2$ reduces the probability of system failure by a factor of $1/16$.

4. RATIONAL MONITORING AND CONTROL STRATEGIES

4.1 Introduction

The analysis of the previous sections on regions of vulnerability and hidden failure modes as well as the survey results are for conventional analog relaying systems. Such systems will be the norm for the foreseeable future. If the protection system were essentially digital, it is reasonable to expect different failure modes and different probabilities of hidden failures from the protection system. It is anticipated that digital systems with their inherent ability (via software) to perform self monitoring will allow them to be more reliable than analog systems. Future studies are necessary to verify these beliefs and develop the appropriate self-checking, self-calibrating and control strategies for digital systems. Given the existing analog systems, however, it is possible to imagine intervention by a rational control scheme implemented in a microprocessor-based system to improve performance.

The studies of regions of vulnerability and to a lesser extent, the importance sampling work, have indicated which relays are the ones with potential hidden failures that can produce the most serious consequences. Thus, relays with a high-vulnerability index can be identified and their hidden failure modes examined. With the knowledge of which relays are the most vulnerable, counter measures can be taken to reduce or eliminate the likelihood of the hidden failure of key relays. The digital monitoring and control system will have to receive a number of power system quantities as inputs and will interface with existing analog systems at the contact level. The digital monitoring and control system could have contacts in series or parallel with the contacts of the key analog relays.

4.2 Structure of the Monitoring and Control System

It is proposed that a computer-based monitoring and control system be placed in the substation to control the critical relays which have a high-index of vulnerability. A possible system structure is shown in Figure 4.1 below. The relays with high vulnerability index, and their vulnerable functions have been identified. The Hidden Failure Monitoring and Control System (HFMCS) has as inputs the same signals which go to the high vulnerability relays. The outputs of the HFMCS are combined logically with the outputs of the traditional relays in an appropriate logical connection.

For example, consider the possibility that the hidden failure is the loss of directionality in an overcurrent relay. The HFMCS would receive the operating and polarizing signals used by the traditional relay. It would perform a directional calculation, and provide an output contact. The output of the HFMCS would be connected in series

Figure 4.1-Structure of Monitoring and Control System.

with the directional contact of the traditional relay. This corrective implementation is covered in more detail in Section 4.3.

One may be concerned with the reliability of the HFMCS, and the impact of its failure on the overall protection system. As the HFMCS are computer based, they will have a built in self-checking capability. As a result, the probability of occurrence of a hidden failure in the composite system, at the time that it is required to function, will be significantly reduced. It is conceivable that two HFMCS per station could be implemented, and their outputs paralleled, in order to improve overall system dependability. Other examples of controlling the hidden failures of traditional relays are discussed in the next section.

4.3 Control Strategies for Eliminating Hidden Failures

In this report we have established that the commonly-used analog protective systems have hidden failures associated with the following relay characteristics:

- Fault detectors
- Directionality
- Distance Measurement
- Timers
- CT and PT input

As discussed above, using the techniques developed in this study, we can identify those lines and terminals that present the greatest hazard to system reliability. We can therefore add to those lines appropriate digital equipment to provide the necessary supervision. The strategy to correct loss of directionality was discussed briefly above to explain the structure of the proposed monitoring and control system. In this section we will develop that idea in greater detail.

Fault Detectors

All of the protective schemes studied rely to some extent on a fault detection function. Directional comparison blocking schemes use an admittance (mho) or impedance (ohm) zone protection to start the carrier, and transfer tripping schemes use an overreaching relay to supervise the local trip. Similarly, phase-comparison and pilot wire schemes use a fault detector in their tripping logic. If a shunt is added to a critical line to provide line current to a digital relay, the digital relay would be set above maximum load current. It could then supervise the output of the related relay, so that it could not initiate an incorrect trip should its own fault detector fail. This digital relay output would be in series with the existing relay contact. Since the digital relay is self-checking, then if it should fail it would immediately remove itself from the circuit and return the protection to the original condition. It is highly unlikely that the digital relay would fail immediately prior to or during a fault, so the security is not significantly affected. Of course, as mentioned, two digital relays could be used, each output in parallel with each other, and both outputs in series with the existing relay to provide further security.

Directionality

Almost all protective schemes rely on a directional element, the failure of which would constitute a hidden failure. The mho tripping element in the directional comparison scheme and overreaching relay in the permissive transfer trip schemes are typical examples. In a manner similar to the fault detector, a microprocessor-based relay on a given critical line could establish the direction of a fault and supervise the existing relays.

Distance Measurement

The strategy for providing a distance supervision is the same as that for fault current magnitude and directionality. Conceivably the same microprocessor can be used to establish all three parameters. The main concern here would be the incorrect measurement of distance by an admittance-type relay used in a directional comparison or transfer tripping scheme. The digital relay performs an independent, and more precise calculation of the fault location and can be used, with appropriate logic, to supervise all zones of protection.

Timers

Timers present a more difficult problem since the specific settings will vary with the zones and, perhaps, an unusual coordination situation. However, using the same microprocessor-based relay that establishes a fault level and a directionality, it is possible to provide a minimum time, e.g. 10 cycles, before initiating a separate, independent output. This output would then operate several auxiliary relays, each of which would supervise the various timing requirements such as breaker failure, zone 2, and zone 3 of the protected line. The suggested 10 cycle setting is below each of these times and would assure that the timer is not shorted or totally inoperative. It does not, of course, correct for a miscalibrated time but it is long enough to guarantee that primary and first zone protection will have had an opportunity to operate.

CT and PT Input

The discussion in Section 2.3 indicated that a CT will fail either as an open circuit or a short circuit. The open circuit will result in insulation failure and some immediate action mentioned in that section. A short circuit will result in little or no current to the protective devices. The shunt described above would provide indication that there is a current output from the CT and the self-monitoring system by comparing the three-phase currents can determine if one phase has failed. The usual corrective action would be to remove the relay from service and send an alarm to the proper station personnel. Failure of the PT is also discussed in Section 2.3 and, as indicated, only the open circuit can result in a hidden failure. As discussed, although there is a tendency, with zero voltage, to result in no torque being developed, hence no relay operation, some connections will result in a hidden failure. The correction would be to provide a separate monitoring device to supervise the vulnerable relays.

4.4 Summary

Given the importance of hidden failure modes in traditional relaying systems, intervention by computer-based rational control schemes is proposed. Relays with high-vulnerability index can be identified, and their vulnerable functions and failure modes identified. Counter-measures to reduce or eliminate the likelihood of the hidden failure of key relays can be provided. A Hidden-Failure Monitoring and Control System (HFMCS) would have as its inputs the same signals which go to the high-vulnerability relays. The outputs of the HFMCS would then be combined with the outputs of the traditional relays in an appropriate logical connection. The reliability of the HFMCS, and the impact of its failure on the overall protection system can be addressed by supplying redundancy in the HFMCS itself.

5. CONCLUSIONS

This report establishes the concept of hidden failures in relays and associated devices used for the protection of electric power systems. Relay hidden failures are found to be one of the principal causes of major power system failures. An industry survey was conducted to establish causes of power system blackouts. Research was carried out on how to make their occurrence less likely. The results of the research and conclusions drawn from this study can be summarized as follows:

- (1) The analysis of the industry survey and various reports of outages from U.S., Canadian and European relay engineers indicates that hidden relay defects can be a major factor causing otherwise routine relay operations to develop into widespread outages. The majority of failures are associated with conditions that may have been correct when the relay or relay system was first installed but, in time, became inadequate for the electric power system at the time of a given event. Reasons for inappropriate relay operations include the fact that relay settings may not be reexamined as system operating conditions or loads change; interlocks and trip logic may not be consistent with transmission line or generation changes. Calibration and maintenance procedures only verify component reliability at the time of the periodic check. The important result of this analysis is that many failures do not become immediately apparent but manifest themselves during some other system failures or switching events. Primary and backup relay schemes and associated protection system equipment have been examined to determine the mechanism and effect of such hidden failures.
- (2) A new concept of regions of vulnerability of a protection system has been introduced and quantified. A region of vulnerability is an area within which a hidden failure may cause the loss of additional system elements. The technique of finding the region of vulnerability and its use has been demonstrated in the report for a representative power system. The relative importance of a region of vulnerability is indicated by a number called vulnerability index. A technique for computing the vulnerability index has been proposed. Protection systems having a large value of vulnerability index should be monitored and controlled to eliminate any possible hidden failures.
- (3) recognizing that probability is an important element of relay operations, and particularly of relay failures, the technique of "importance sampling" has been used to calculate the relative probability of having hidden failures in order to

take appropriate corrective action.

- (4) It is clear that adaptive relaying, particularly where digital relays are involved, offers an opportunity to detect hidden failures before a major disaster occurs. The ability to self-check and self-monitor, coupled with the adaptive features of changing settings or revising control and trip logic in response to existing conditions, offers a potential solution to mitigating and preventing hidden failures from disturbing the power system and causing cascading outages.
- (5) A new concept of a hidden failure monitoring and control system has been developed. This new supervisory hardware system can be installed in a substation to independently monitor the performance of important relays in the substation, and supervise their operation during critical power system states. The implementation of such a system offers an attractive possibility for secure operation of power systems.
- (6) Possible areas of further research include: an experimental installation of the hidden failure monitoring and control system in the field. It would also be useful to verify that the technique proposed in this report is effective by testing it on a larger power system.

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7. GLOSSARY OF COMMONLY USED ACRONYMS

AEP	American Electric Power
CB	Circuit Breaker
CT	Current Transformer
D	Directional Relay Contact
DOE	U.S. Department of Energy
DTT	Direct Transfer Trip
EHV	Extra High Voltage (above 230 KV)
FD _x	Fault Detector (_x stands for high, low, A or B)
HF	Hidden failure
HV	High voltage (up to 230 KV)
kV	Kilovolts
IEEE	Institute of Electrical and Electronics Engineers
LOC	Loss of communication (or carrier)
MW	Megawatts or 10 ⁶ watts
NERC	North American Electric Reliability Council
O/C	Overcurrent
PCB	Phase comparison blocking
PLC	Power line carrier
PSRC	IEEE Power system relaying committee
POTT	Permissive overreaching transfer trip
PT	Potential Transformer
PUTT	Permissive underreaching transfer trip
P/W	Pilot wire
R	Receiver relay contact
RV	Region of vulnerability
SCR	Silicon controlled rectifier
SII	Steady-state instability index
TT	Transfer Trip
VI	Vulnerability index
Z _x	Relay zone setting (_x stands for first, second, etc.)

APPENDIX A

Details of protective schemes

a) One-line diagram of protection zone

b) Logic schematic for relay system

c) Functions of relay system

<u>Element</u>	<u>Description</u>	<u>Function</u>
FD_X	Fault detector (block unit)	Detects fault and starts transmitter
D_X	Directional relay(trip unit)	Stops transmitter
R	Receiver	Receives remote transmission
T	Transmitter	Transmits channel signal
CB_X	Circuit breaker	Disconnects the line
52a	Circuit breaker contact	Trips circuit breaker
F_A	Fault at location A within the reach of D_B behind bus A	
F_B	Fault at location B within the reach of D_A behind bus B	
52a and CB_A trip when D_A operates and no signal is received		

d) Hidden failures of relay system at A

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
FD_A cannot pick up	CB_B trips for F_A	Half of the line behind bus A
T_A fails to transmit	CB_B trips for F_A	Half of the line behind bus A
R_A cannot pick up	CB_A trips for F_B	Half of the line behind bus B

Fig A.1 Hidden Failure Modes of Directional Comparison Blocking (DCB)

a) One-line diagram of protection zone

b) Logic schematic for relay system

c) Functions of relay system

<u>Element</u>	<u>Description</u>	<u>Function</u>
D_X	Directional relay(trip unit)	Shifts transmitter to unblocking
R	Receiver	Receives remote transmission
T	Transmitter	Transmits channel signal
CB_X	Circuit breaker	Disconnects the line
52a	Circuit breaker contact	Trips circuit breaker
F_A	Fault at location A within the reach of D_B behind bus A	
F_B	Fault at location B within the reach of D_A behind bus B	
52a and CB_A trip when D_A operates and a trip signal is received		

d) Hidden failures of relay system at A

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
D_A continuously pick up	Both CBs trip for F_A	Half of the line behind bus A
R_A continuously pick up	CB_A trips for F_B	Half of the line behind bus A

Fig A.2 Hidden Failure Modes of Directional Comparison Unblocking (DCU)

a) One-line diagram of protection zone

b) Logic schematic for relay system

c) Functions of relay system

<u>Element</u>	<u>Description</u>	<u>Function</u>
D _X	Directional relay(trip unit)	Shifts transmitter to unblocking
R	Receiver	Receives remote transmission
T	Transmitter	Transmits channel signal
CB _X	Circuit breaker	Disconnects the line
52a	Circuit breaker contact	Trips circuit breaker
F _A	Fault at location A within the reach of D _B behind bus A	
F _B	Fault at location B within the reach of D _A behind bus B	
52a and CB _A trip when D _A operates and a trip signal is received		

d) Hidden failures of relay system at A

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
D_A continuously pick up	Both CBs trip for F_A	Half of the line behind bus A
R_A continuously pick up	CB_A trips for F_B	Half of the line behind bus A

Fig A.3 Hidden Failure Modes of Permissive Overreaching Transfer Trip (POTT)

a) One-line diagram of protection zone

b) Logic schematic for relay system

c) Functions of relay system

<u>Element</u>	<u>Description</u>	<u>Function</u>
FD _X	Fault detector (block unit)	Detects faults
D _X	Directional relay (trip unit)	Keys transmitter
R	Receiver	Receives remote transmission
T	Transmitter	Transmits channel signal
CB _X	Circuit breaker	Disconnects the line
52a	Circuit breaker contact	Trips circuit breaker
F _A	Fault at location A within the reach of FD _B behind bus A	
F _B	Fault at location B within the reach of FD _A behind bus B	
52a and CB _A trip when D _A operates and/or FD _A operates and a signal is received		

d) Hidden failures of relay system at A

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
T_A continuously transmits	CB_B trips for F_A	Half of the line behind bus A
R_A continuously picks up	CB_A trips for F_B	Half of the line behind bus A

Fig A.4 Hidden Failure Modes of Permissive Underreaching Transfer Trip (PUTT)

a) One-line diagram of protection zone

b) Logic schematic for relay system

c) Functions of relay system

<u>Element</u>	<u>Description</u>	<u>Function</u>
FD _{HX}	High level fault detector	Arms the system for tripping
FD _{LX}	Low level fault detector	Keys on/off transmitter
R	Receiver	Receives remote transmission
T	Transmitter	Transmits channel signal
CB _X	Circuit breaker	Disconnects the line
52a	Circuit breaker contact	Trips circuit breaker
F _A	External fault behind bus A; I _A and I _B are in phase	
F _B	External fault behind bus B; I _A and I _B are in phase	
F _{AB}	Internal fault between buses A and B; I _A and I _B are out of phase	
52a and CB _A trip when FD _{HA} operates, and FD _{LA} and R _A are out of phase		

d) Hidden failures of relay system at A

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
Loss of signal	Both CBs act as nondirectional o/c relay with FD _H setting	Fault current dependent
FD _{LA} continuously picks up	CB _A acts as an o/c relay	Fault current dependent
FD _{LA} cannot pick up	CB _B acts as an o/c relay	Fault current dependent

Fig A.5 Hidden Failure Modes of Phase Comparison Blocking (PCB)

a) One-line diagram of protection zone

b) Logic schematic for relay system

c) Functions of relay system

<u>Element</u>	<u>Description</u>	<u>Function</u>
Z_2	Fault detector for zone 2	Detects faults
Z_3	Fault detector for zone 3	Detects faults
T_2	Timer 2 contact	Sets time-delay
T_3	Timer 3 contact	Sets time-delay
CB_X	Circuit breaker	Disconnects the line
52a	Circuit breaker contact	Trips circuit breaker
F_2	A Fault between bus B and the end of the reach of Z_2	
F_3	A Fault between bus B and the end of the reach of Z_3	
F_B	Fault at location A within the reach of D_A behind bus B	
52a and CB_A trip when Z_2 and T_2 or Z_3 and T_3 operate		

d) Hidden failures of relay system at A

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
T_2 fails closed	CB_A trips for F_2 without time-delay	0.2 of the line behind bus B
T_3 fails closed	CB_A trips for F_3 without time-delay	1.2 of the line behind bus B

Fig A.6 Hidden Failure Modes of Second- and Third-Zone Distance Relays

Table A.1 Directional Overcurrent Ground Relay

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
Polarizing source or coil shorted	Trips for backward fault	Fault current dependent

Table A.2 Transformer Differential Relay

<u>HF</u>	<u>Consequence</u>	<u>RV</u>
Restraint coil shorted	Trips on heavy load current	Load current dependent

The rest of the relaying schemes examined in Section 2 of the report do not have any HF.

APPENDIX B

**Regions of vulnerability as a measure of distance
For 39-bus New England power system model**

Table B.1 Region of Vulnerability Type 1
Reverse Local Bus Vulnerability Region

RELAY X Y	LINE	RV	#LTG	TRIGGER LINE(S)
1 2	1	0.0205	1	2
1 30	2	0.0125	1	1
2 1	1	0.0466	5	3 5 6 4 30
2 3	3	0.0151	2	1 4
2 25	4	0.0086	2	1 3
3 2	3	0.0151	2	5 6
3 4	5	0.0213	2	3 6
3 18	6	0.0133	2	3 5
4 3	5	0.0213	2	7 8
4 5	7	0.0128	2	5 8
4 14	8	0.0129	2	5 7
5 4	7	0.0166	4	9 11 12 10
5 6	9	0.0026	2	7 10
5 8	10	0.0142	4	7 9 11 12
6 5	9	0.0026	2	11 12
6 7	11	0.0112	4	9 7 10 12
6 11	12	0.0097	4	9 7 10 11
7 6	11	0.0046	1	13
7 8	13	0.0023	1	11
8 5	10	0.0112	3	13 11 14
8 7	13	0.0046	2	10 14
8 9	14	0.0389	6	10 7 9 11 12 13
9 8	14	0.0181	1	15
9 30	15	0.0125	1	14
10 11	16	0.0022	1	17
10 13	17	0.0022	1	16
11 6	12	0.0041	1	16
11 10	16	0.0022	1	12
13 10	17	0.0022	1	18
13 14	18	0.0050	2	17 16
14 4	8	0.0129	2	18 19
14 13	18	0.0101	2	8 19
14 15	19	0.0217	3	8 18 17
15 14	19	0.0152	5	20 21 22 23 24
15 16	20	0.0047	1	19
16 15	20	0.0188	4	21 22 23 24
16 17	21	0.0178	4	20 22 23 24
16 19	22	0.0399	8	20 19 21 25 26 23 24 29
16 21	23	0.0270	5	20 21 22 24 29
16 24	24	0.0118	4	20 21 22 23
17 16	21	0.0089	2	25 26

Note 1. Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

2. #LTG stands for the number of triggered lines.

Table B.1 (continued)

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)							
17 18	25	0.0082	2	21	26						
17 27	26	0.0173	3	21	25	6					
18 3	6	0.0066	1	25							
18 17	25	0.0041	1	6							
21 16	23	0.0068	1	27							
21 22	27	0.0070	1	23							
22 21	27	0.0070	1	28							
22 23	28	0.0048	1	27							
23 22	28	0.0048	1	29							
23 24	29	0.0175	2	28	27						
24 16	24	0.0030	1	29							
24 23	29	0.0550	8	24	20	19	21	25	26	22	23
25 2	4	0.0043	1	30							
25 26	30	0.0237	3	4	1	3					
26 25	30	0.0485	4	31	26	32	33				
26 27	31	0.0221	3	30	32	33					
26 28	32	0.0711	4	30	31	26	33				
26 29	33	0.0938	4	30	31	26	32				
27 17	26	0.0087	1	31							
27 26	31	0.0074	1	26							
28 26	32	0.0237	2	34	33						
28 29	34	0.0076	1	32							
29 26	33	0.0313	2	34	32						
29 28	34	0.0076	1	33							
30 1	2	0.0125	1	15							
30 9	15	0.0125	1	2							

Table B.2 Region of Vulnerability Type 2
Reverse Remote Bus Vulnerability Region

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)					
1 2	1	0.0466	5	3	5	6	4	30	
1 30	2	0.0125	1	15					
2 1	1	0.0205	1	2					
2 3	3	0.0151	2	5	6				
2 25	4	0.0043	1	30					
3 2	3	0.0151	2	1	4				
3 4	5	0.0213	2	7	8				
3 18	6	0.0066	1	25					
4 3	5	0.0213	2	3	6				
4 5	7	0.0166	4	9	11	12	10		
4 14	8	0.0129	2	18	19				
5 4	7	0.0128	2	5	8				
5 6	9	0.0026	2	11	12				
5 8	10	0.0112	3	13	11	14			
6 5	9	0.0026	2	7	10				
6 7	11	0.0046	1	13					
6 11	12	0.0041	1	16					
7 6	11	0.0112	4	9	7	10	12		
7 8	13	0.0046	2	10	14				
8 5	10	0.0142	4	7	9	11	12		
8 7	13	0.0023	1	11					
8 9	14	0.0181	1	15					
9 8	14	0.0389	6	10	7	9	11	12	13
9 30	15	0.0125	1	2					
10 11	16	0.0022	1	12					
10 13	17	0.0022	1	18					
11 6	12	0.0097	4	9	7	10	11		
11 10	16	0.0022	1	17					
13 10	17	0.0022	1	16					
13 14	18	0.0101	2	8	19				
14 4	8	0.0129	2	5	7				
14 13	18	0.0050	2	17	16				
14 15	19	0.0152	5	20	21	22	23	24	
15 14	19	0.0217	3	8	18	17			
15 16	20	0.0188	4	21	22	23	24		
16 15	20	0.0047	1	19					
16 17	21	0.0089	2	25	26				
16 21	23	0.0068	1	27					
16 24	24	0.0030	1	29					
17 16	21	0.0178	4	20	22	23	24		
17 18	25	0.0041	1	6					

Note 1. Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

2. #LTG stands for the number of triggered lines.

Table B.2 (continued)

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)
17 27	26	0.0087	1	31
18 3	6	0.0133	2	3 5
18 17	25	0.0082	2	21 26
19 16	22	0.0399	8	20 19 21 25 26 23 24 29
21 16	23	0.0270	5	20 21 22 24 29
21 22	27	0.0070	1	28
22 21	27	0.0070	1	23
22 23	28	0.0048	1	29
23 22	28	0.0048	1	27
23 24	29	0.0550	8	24 20 19 21 25 26 22 23
24 16	24	0.0118	4	20 21 22 23
24 23	29	0.0175	2	28 27
25 2	4	0.0086	2	1 3
25 26	30	0.0485	4	31 26 32 33
26 25	30	0.0237	3	4 1 3
26 27	31	0.0074	1	26
26 28	32	0.0237	2	34 33
26 29	33	0.0313	2	34 32
27 17	26	0.0173	3	21 25 6
27 26	31	0.0221	3	30 32 33
28 26	32	0.0711	4	30 31 26 33
28 29	34	0.0076	1	33
29 26	33	0.0938	4	30 31 26 32
29 28	34	0.0076	1	32
30 1	2	0.0125	1	1
30 9	15	0.0125	1	14

Table B.3 Region of Vulnerability Type 3
Zone 2 Vulnerability Region

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)			
1 2	1	0.0164	2	3	4		
1 30	2	0.0050	1	15			
2 1	1	0.0082	1	2			
2 3	3	0.0060	2	5	6		
2 25	4	0.0017	1	30			
3 2	3	0.0060	2	1	4		
3 4	5	0.0085	2	7	8		
3 18	6	0.0027	1	25			
4 3	5	0.0085	2	3	6		
4 5	7	0.0051	2	9	10		
4 14	8	0.0052	2	18	19		
5 4	7	0.0051	2	5	8		
5 6	9	0.0010	2	11	12		
5 8	10	0.0045	2	13	14		
6 5	9	0.0010	2	7	10		
6 7	11	0.0018	1	13			
6 11	12	0.0016	1	16			
7 6	11	0.0037	2	9	12		
7 8	13	0.0018	2	10	14		
8 5	10	0.0045	2	7	9		
8 7	13	0.0009	1	11			
8 9	14	0.0073	1	15			
9 8	14	0.0145	3	10	13	11	
9 30	15	0.0050	1	2			
10 11	16	0.0009	1	12			
10 13	17	0.0009	1	18			
11 6	12	0.0033	2	9	11		
11 10	16	0.0009	1	17			
13 10	17	0.0009	1	16			
13 14	18	0.0040	2	8	19		
14 4	8	0.0052	2	5	7		
14 13	18	0.0020	1	17			
14 15	19	0.0043	1	20			
15 14	19	0.0087	2	8	18		
15 16	20	0.0075	4	21	22	23	24
16 15	20	0.0019	1	19			
16 17	21	0.0036	2	25	26		
16 21	23	0.0027	1	27			
16 24	24	0.0012	1	29			
17 16	21	0.0071	4	20	22	23	24
17 18	25	0.0016	1	6			

- Note 1. Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.
2. #LTG stands for the number of triggered lines.

Table B.3 (continued)

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)
17 27	26	0.0035	1	31
18 3	6	0.0053	2	3 5
18 17	25	0.0033	2	21 26
19 16	22	0.0156	4	20 21 23 24
21 16	23	0.0108	4	20 21 22 24
21 22	27	0.0028	1	28
22 21	27	0.0028	1	23
22 23	28	0.0019	1	29
23 22	28	0.0019	1	27
23 24	29	0.0103	5	24 20 21 22 23
24 16	24	0.0047	4	20 21 22 23
24 23	29	0.0070	1	28
25 2	4	0.0034	2	1 3
25 26	30	0.0194	3	31 32 33
26 25	30	0.0065	1	4
26 27	31	0.0029	1	26
26 28	32	0.0095	1	34
26 29	33	0.0125	1	34
27 17	26	0.0069	2	21 25
27 26	31	0.0088	3	30 32 33
28 26	32	0.0284	3	30 31 33
28 29	34	0.0030	1	33
29 26	33	0.0375	3	30 31 32
29 28	34	0.0030	1	32
30 1	2	0.0050	1	1
30 9	15	0.0050	1	14

Table B.4 Region of Vulnerability Type 4
Zone 3 Vulnerability Region

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)															
1 2	1	0.0501	5	3	5	6	4	30											
1 30	2	0.0300	2	15	14														
2 1	1	0.0300	2	2	15														
2 3	3	0.0594	7	5	7	8	6	25	21	26									
2 25	4	0.0517	4	30	31	32	33												
3 2	3	0.1155	7	1	2	4	30	31	32	33									
3 4	5	0.0363	8	7	9	11	12	10	8	18	19								
3 18	6	0.0115	3	25	21	26													
4 3	5	0.0393	5	3	1	4	6	25											
4 5	7	0.0400	7	9	11	13	12	16	10	14									
4 14	8	0.0521	6	18	17	16	12	19	20										
5 4	7	0.0680	7	5	3	6	8	18	17	19									
5 6	9	0.0793	11	11	13	10	7	14	12	16	17	18	8	19					
5 8	10	0.1298	13	13	11	9	7	5	8	18	19	12	16	17					
				14	15														
6 5	9	0.0374	6	7	5	8	10	13	14										
6 7	11	0.0064	3	13	10	14													
6 11	12	0.1213	15	16	17	18	8	5	7	9	11	10	19	20					
				21	22	23	24												
7 6	11	0.1049	12	9	7	5	8	18	19	10	13	14	12	16					
				17															
7 8	13	0.1454	13	10	7	5	8	18	19	9	11	12	16	17					
				14	15														
8 5	10	0.0460	9	7	5	8	9	11	13	12	16	17							
8 7	13	0.0129	3	11	9	12													
8 9	14	0.0300	2	15	2														
9 8	14	0.0291	5	10	7	9	13	11											
9 30	15	0.0300	2	2	1														
10 11	16	0.1577	14	12	9	7	5	3	6	8	18	17	19	10					
				13	11	14													
10 13	17	0.1954	22	18	8	5	3	6	7	9	11	13	10	14					
				12	16	19	20	21	25	26	22	23	24	29					
11 6	12	0.0875	10	9	7	5	8	18	19	10	13	11	14						
11 10	16	0.0336	4	17	18	8	19												
13 10	17	0.0444	7	16	12	9	7	10	11	13									
13 14	18	0.0656	7	8	5	7	9	10	19	20									
14 4	8	0.0799	11	5	3	6	7	9	11	13	12	16	10	14					
14 13	18	0.1188	12	17	16	12	9	7	5	8	19	10	13	11					
				14															
14 15	19	0.0169	5	20	21	22	23	24											
15 14	19	0.0335	6	8	5	7	18	17	16										

- Note 1. Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.
2. #LTG stands for the number of triggered lines.

Table B.4 (continued)

RELAY	LINE	RV	#LTG	TRIGGER LINE(S)
15 16	20	0.1042	9	21 25 6 26 22 23 27 24 29
16 15	20	0.0304	3	19 8 18
16 17	21	0.0415	4	25 6 26 31
16 21	23	0.0168	2	27 28
16 24	24	0.0420	2	29 28
17 16	21	0.0897	7	20 19 22 23 27 24 29
17 18	25	0.0186	3	6 3 5
17 27	26	0.0235	4	31 30 32 33
18 3	6	0.0658	7	3 1 4 30 5 7 8
18 17	25	0.0771	9	21 20 19 22 23 24 29 26 31
19 16	22	0.0721	9	20 19 21 25 26 23 27 24 29
21 16	23	0.1042	9	20 19 21 25 6 26 22 24 29
21 22	27	0.0172	2	28 29
22 21	27	0.0243	5	23 20 21 22 24
22 23	28	0.0453	6	29 24 20 21 22 23
23 22	28	0.0172	2	27 23
23 24	29	0.0106	5	24 20 21 22 23
24 16	24	0.1042	9	20 19 21 25 6 26 22 23 27
24 23	29	0.0326	3	28 27 23
25 2	4	0.1701	18	1 2 3 5 7 9 10 8 18 19 6
25 26	30	0.3618	23	25 21 20 22 23 24 26
				31 26 21 20 19 8 18 22 23 27 28
				24 29 25 6 3 1 4 5 7 32 34
				33
26 25	30	0.0512	5	4 1 3 5 6
26 27	31	0.0242	3	26 21 25
26 28	32	0.0181	2	34 33
26 29	33	0.0187	2	34 32
27 17	26	0.0267	7	21 20 22 23 24 25 6
27 26	31	0.2531	10	30 4 1 3 5 6 25 32 34 33
28 26	32	0.3740	23	30 4 1 3 5 6 25 31 26 21 20
				19 8 18 22 23 27 28 24 29 7 33
				34
28 29	34	0.1000	4	33 30 31 32
29 26	33	0.2586	19	30 4 1 3 5 6 31 26 21 20 19
				22 23 27 24 29 25 32 34
29 28	34	0.0758	4	32 30 31 33
30 1	2	0.0575	3	1 3 4
30 9	15	0.0508	4	14 10 13 11

APPENDIX C

Regions of vulnerability as a measure of fault current

For 39—bus New England power system model

Table C.1 Results of fault current calculation for the calculation of RV of phase comparison blocking relay.

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
1 2	5.292	1	-17.13
		2	13.59
		30	-11.20
		25	9.34
		3	7.68
		39	6.89
		18	5.45
2 1	5.886	1	17.13
		2	-13.59
		30	11.20
		25	-9.34
		3	-7.68
		39	-6.89
1 30	5.292	1	-32.42
		2	-13.59
		30	11.20
		25	-9.34
		3	-7.68
		39	-6.89
		18	-5.45
30 1	4.890	1	32.42
		2	13.59
		30	-11.20
		25	9.34
		3	7.68
		39	6.89
		18	5.45
2 3	17.192	17	5.26
		3	27.28
		2	-21.21
		3	-27.28
		2	21.21
2 25	10.146	25	36.13
		2	-18.83
		37	17.02
		26	11.72

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
25 2	10.244	25	-36.13
		2	18.83
		37	-17.02
		26	-11.72
3 4	6.932	4	20.62
		3	-18.19
		5	14.66
		6	14.07
		14	13.13
		11	12.09
		10	11.87
		13	11.69
		2	-11.64
		8	11.44
		7	11.25
		18	-9.47
		25	-8.15
4 3	7.278	4	-20.62
		3	18.19
		5	-14.66
		6	-14.07
		14	-13.13
		11	-12.09
		10	-11.87
		13	-11.69
		2	11.64
		8	-11.44
		7	-11.25
		18	9.47
		25	8.15
3 18	2.332	18	25.48
		17	18.76
		3	-18.54
		16	12.85
		2	-9.57
		24	9.48
		27	8.29
		21	7.62
		22	6.41
		15	6.34
		19	6.16
		4	-6.13
		23	5.98

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
18 3	2.598	39	-4.86
		25	-4.60
		26	4.28
		33	4.20
		35	4.20
		5	-3.92
		20	3.83
		6	-3.64
		8	-3.08
		36	3.00
		7	-2.99
		1	-2.88
		30	-2.79
		11	-2.66
		34	2.57
		10	-2.36
		18	-25.48
		17	-18.76
		3	18.54
		16	-12.85
		2	9.57
		24	-9.48
		27	-8.29
		21	-7.62
		22	-6.41
		15	-6.34
		19	-6.16
		4	6.13
		23	-5.98
		39	4.86
		25	4.60
		26	-4.28
		33	-4.20
		35	-4.20
		5	3.92
		20	-3.83
		6	3.64
		8	3.08
		36	-3.00
		7	2.99
		1	2.88
		30	2.79
		11	2.66

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
4 5	8.334	5	20.24
		4	-19.92
		6	17.50
		8	15.15
		7	14.58
		3	-11.07
		11	8.56
5 4	8.302	5	-20.24
		4	19.92
		6	-17.50
		8	-15.15
		7	-14.58
		3	11.07
		11	-8.56
4 14	12.648	14	20.21
		4	-18.07
14 4	12.614	14	-20.21
		4	18.07
5 6	23.630	5	-27.99
6 5	23.616	5	27.99
5 8	15.332	8	19.68
8 5	15.368	8	-19.68
6 7	20.816	7	24.97
7 6	20.858	7	-24.97
6 11	15.982	11	26.94
		10	22.16
		6	-18.19
		13	17.56
11 6	15.950	11	-26.94
		10	-22.16
		6	18.19
		13	-17.56
7 8	9.222	7	-24.32
		8	16.83

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
8 7	9.212	7	24.32
		8	-16.83
8 9	7.712	9	15.51
		8	-14.70
		7	-13.03
		6	-12.97
		5	-12.95
		30	10.39
		11	-10.15
		4	-9.61
		10	-9.46
		13	-8.81
		14	-8.53
		9	-15.51
		8	14.70
		7	13.03
9 8	7.040	6	12.97
		5	12.95
		30	-10.39
		11	10.15
		4	9.61
		10	9.46
		13	8.81
		14	8.53
		9	-32.45
		8	-14.70
		7	-13.03
		6	-12.97
		5	-12.95
		30	10.39
9 30	7.040	11	-10.15
		4	-9.61
		10	-9.46
		13	-8.81
		14	-8.53
		9	32.45
		8	14.70
		7	13.03
		6	12.97
		5	12.95
		30	-10.39
		11	10.15
		9	32.45
		8	14.70
30 9	4.680	7	13.03
		6	12.97
		5	12.95
		30	-10.39
		11	10.15
		9	32.45

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
10 11	16.494	4	9.61
		10	9.46
		13	8.81
		14	8.53
		31	5.85
		3	5.67
		15	5.26
		16	5.19
		32	5.17
		11	25.37
11 10	16.534	10	-22.03
		6	17.03
		11	-25.37
10 13	14.860	10	22.03
		6	-17.03
		11	-25.37
13 10	14.902	13	27.50
		10	-19.38
		14	17.17
13 14	14.112	13	-27.50
		10	19.38
		14	-17.17
14 13	14.156	13	-23.37
		10	-19.25
		14	18.36
		11	-15.09
14 15	1.752	13	23.37
		10	19.25
		14	-18.36
		11	15.09
		15	18.78
		14	-17.92
		16	14.05
		13	-13.34
		10	-12.44
		4	-11.64
		11	-11.56
		6	-10.98
		5	-10.76
		24	10.37
		8	-8.67

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
15 14	1.644	7	-8.61
		21	8.33
		17	7.50
		22	7.01
		32	-6.80
		19	6.73
		23	6.54
		12	-6.00
		31	-4.95
		33	4.59
		35	4.59
		20	4.19
		9	-3.72
		27	3.69
		18	3.54
		36	3.28
		34	2.81
		30	-2.71
		26	2.42
		15	-18.78
		14	17.92
		16	-14.05
		13	13.34
		10	12.44
		4	11.64
		11	11.56
		6	10.98
		5	10.76
		24	-10.37
		8	8.67
		7	8.61
		21	-8.33
		17	-7.50
		22	-7.01
		32	6.80
		19	-6.73
		23	-6.54
		12	6.00
		31	4.95
		33	-4.59
		35	-4.59
		20	-4.19
		9	3.72
		27	-3.69
		18	-3.54
		36	-3.28

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
15 16	15.242	34	-2.81
		30	2.71
		26	-2.42
		3	1.69
		15	-36.00
16 15	15.094	14	-17.92
		15	36.00
16 17	10.472	14	17.92
		17	32.70
17 16	10.446	18	22.90
		16	-22.25
		27	17.68
		24	-16.42
		3	14.96
		26	13.49
		21	-13.19
		2	12.49
		15	-12.48
		22	-11.09
		25	11.04
		19	-10.66
		17	-32.70
		18	-22.90
		16	22.25
		27	-17.68
		24	16.42
		3	-14.96
		26	-13.49
		21	13.19
		2	-12.49
		15	12.48
		22	11.09
		25	-11.04
		19	10.66
16 19	22.518	19	26.72
19 16	22.336	19	-26.72
16 21	14.446	21	30.17
		22	18.23

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
21 16	14.450	21	-30.17
		22	-18.23
16 24	4.346	24	44.45
		23	13.07
		16	-7.96
		22	7.88
		36	6.57
		17	-5.64
		15	-5.26
		35	5.16
24 16	4.236	24	-44.45
		23	-13.07
		16	7.96
		22	-7.88
		36	-6.57
		17	5.64
		15	5.26
		35	-5.16
		18	4.33
17 18	8.912	18	30.69
		17	-18.76
		3	18.54
		16	-12.85
		2	9.57
		24	-9.48
18 17	8.900	18	-30.69
		17	18.76
		3	-18.54
		16	12.85
		2	-9.57
		24	9.48
17 27	1.686	27	25.97
		26	17.77
		17	-12.06
		16	-9.40
		29	8.48
		28	8.22
		18	-7.80
		24	-6.93
		38	6.73
		25	6.44

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
27 17	1.488	15	-6.13
		21	-5.57
		22	-4.68
		19	-4.50
		23	-4.37
		14	-3.88
		3	-3.58
		4	-3.39
		33	-3.07
		35	-3.07
		37	3.04
		13	-3.02
		2	2.92
		10	-2.88
		5	-2.80
		20	-2.80
		6	-2.79
		11	-2.75
		8	-2.22
		7	-2.20
		36	-2.20
		34	-1.88
		27	-25.97
		26	-17.77
		17	12.06
		16	9.40
		29	-8.48
		28	-8.22
		18	7.80
		24	6.93
		38	-6.73
		25	-6.44
		15	6.13
		21	5.57
		22	4.68
		19	4.50
		23	4.37
		14	3.88
		3	3.58
		4	3.39
		33	3.07
		35	3.07
		37	-3.04
		13	3.02
		2	-2.92
		10	2.88

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
		5	2.80
		20	2.80
		6	2.79
		11	2.75
		8	2.22
		7	2.20
		36	2.20
		34	1.88
		32	1.58
21 22	27.260		
22 21	27.122		
22 23	3.032		
		23	23.36
		22	-18.65
		35	-12.21
		36	11.73
		21	-9.13
		24	3.19
		23	-23.36
		22	18.65
		35	12.21
23 22	3.314	36	-11.73
		21	9.13
23 24	15.334		
24 23	15.408		
25 26	4.244		
		26	17.24
		25	-12.26
		27	11.20
		2	-8.38
		29	8.23
		28	7.98
		38	6.53
		17	6.15
		37	-5.78
		16	4.57
		39	-4.25
		26	-17.24
		25	12.26
		27	-11.20
		2	8.38
		29	-8.23
		28	-7.98
		38	-6.53
		17	-6.15
26 25	5.000		

Table C.1 (continued)

RELAY	FD _H SETTING	FAULT BUS	FAULT CURRENT
26 27	11.524	37	5.78
		27	18.25
		26	-17.77
		17	12.06
27 26	11.672	27	-18.25
		26	17.77
		17	-12.06
26 28	5.812	28	11.33
		29	8.36
		38	6.63
28 26	5.772	28	-11.33
		29	-8.36
		38	-6.63
26 29	7.892	29	8.36
29 26	7.768	29	-8.36
28 29	14.498	28	-15.43
29 28	14.444	28	15.43

Table C.2 RV of phase comparison blocking relay.

Relay	FD _H setting	RV	No. of buses in RV	No. of lines in RV	Bus(es) inside the RV	Line(s) inside the RV
1 2	5.292	.1212	7	6	1 2 30 25 3 39 18	1 2 3 4 6 44
2 1	5.886	.1079	6	5	1 2 30 25 3 39	1 2 3 4 44
1 30	5.292	.1212	7	6	1 2 30 25 3 39 18	1 2 3 4 6 44
2 3	17.192	.0151	2	1	3 2	3
3 2	17.430	.0151	2	1	3 2	3
2 25	10.146	.0641	4	3	25 2 37 26	4 30 43
25 2	10.244	.0641	4	3	25 2 37 26	4 30 43
3 4	6.932	.1385	13	14	4 3 5 6 14 11 10 13 2 8 7 18 25	3 4 5 6 7 8 9 10 11 12 13 16 17 18
4 3	7.278	.1385	13	14	4 3 5 6 14 11 10 13 2 8 7 18 25	3 4 5 6 7 8 9 10 11 12 13 16 17 18
3 18	2.332	.4712	29	31	18 17 3 16 2 24 27 21 22 15 19 4 23 39 25 26 33 35 5 20 6 8 36 7 1 30 11 34 10	1 2 3 4 5 6 7 9 10 11 12 13 16 20 21 22 23 24 25 26 27 28 29 30 31 39 40 41 42 44 46
18 3	2.598	.4489	27	29	18 17 3 16 2 24 27 21 22 15 19 4 23 39 25 26 33 35 5 20 6 8 36 7 1 30 11	1 2 3 4 5 6 7 9 10 11 12 13 20 21 22 23 24 25 26 27 28 29 30 31 39 41 42 44 46
4 5	8.334	.0699	7	7	5 4 6 8 7 3 11	5 7 9 10 11 12 13
5 4	8.302	.0699	7	7	5 4 6 8 7 3 11	5 7 9 10 11 12 13
4 14	12.648	.0129	2	1	14 4	8
14 4	12.614	.0129	2	1	14 4	8
6 11	15.982	.0168	4	3	11 10 6 13	12 16 17
11 6	15.950	.0168	4	3	11 10 6 13	12 16 17
7 8	9.222	.0046	2	1	7 8	13
8 7	9.212	.0046	2	1	7 8	13
8 9	7.712	.1415	11	12	9 8 7 6 5 30 11 4 10 13 14	7 8 9 10 11 12 13 14 15 16 17 18

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table C.2 (continued)

Relay	FD _H setting	RV	No. of buses in RV	No. of lines in RV	Bus(es) inside the RV	Line(s) inside the RV
9 8	7.040	.1415	11	12	9 8 7 6 5 30 11 4 10 13 14	7 8 9 10 11 12 13 14 15 16 17 18
9 30	7.040	.1415	11	12	9 8 7 6 5 30 11 4 10 13 14	7 8 9 10 11 12 13 14 15 16 17 18
30 9	4.680	.2389	16	17	9 8 7 6 5 30 11 4 10 13 14 31 3 15 16 32	5 7 8 9 10 11 12 13 14 15 16 17 18 19 20 37 38
10 11	16.494	.0125	3	2	11 10 6	12 16
11 10	16.534	.0125	3	2	11 10 6	12 16
10 13	14.860	.0144	3	2	13 10 14	17 18
13 10	14.902	.0144	3	2	13 10 14	17 18
13 14	14.112	.0187	4	3	13 10 14 11	16 17 18
14 13	14.156	.0187	4	3	13 10 14 11	16 17 18
14 15	1.752	.5387	30	33	15 14 16 13 10 4 11 6 5 24 8 7 21 17 22 32 19 23 12 31 33 35 20 9 27 18 36 34 30 26	7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 31 35 36 37 38 39 40 41 42 46
15 14	1.644	.5733	31	35	15 14 16 13 10 4 11 6 5 24 8 7 21 17 22 32 19 23 12 31 33 35 20 9 27 18 36 34 30 26 3	5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 31 35 36 37 38 39 40 41 42 46
15 16	15.242	.0217	2	1	15 14	19
16 15	15.094	.0217	2	1	15 14	19
16 17	10.470	.1807	13	13	17 18 16 27 24 3 26 21 2 15 22 25 19	2 2 2 2 2 2 3 3
17 16	10.446	.1807	13	13	17 18 16 27 24 3 26 21 2 15 22 25 19	3 4 6 20 21 22 23 24 25 26 27 30 31
16 21	14.446	.0140	2	1	21 22	27
21 16	14.450	.0140	2	1	21 22	27
16 24	4.346	.1103	8	7	24 23 16 22 36 17 15 35	20 21 24 28 29 41 42
24 16	4.236	.1185	9	8	24 23 16 22 36 17 15 35 18	20 21 24 25 28 29 41 42
17 18	8.912	.0514	6	5	18 17 3 16 2 24	3 6 21 24 25

Table C.2 (continued)

Relay	FD _H setting	RV	No. of buses in RV	No. of lines in RV	Bus(es) inside the RV	Line(s) inside the RV
18 17	8.900	.0514	6	5	18 17 3 16 2	3 6 21 24 25
17 27	1.686	.5998	32	37	24 27 26 17 16 29 28 18 24 38 25 15 21 22 19 23 14 3 4 33 35 37 13 2 10 5 20 6 11 8 7 36 34	3 4 5 6 7 8 9 10 11 12 13 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 39 40 41 42 43 45 46
27 17	1.488	.6198	33	38	27 26 17 16 29 28 18 24 38 25 15 21 22 19 23 14 3 4 33 35 37 13 2 10 5 20 6 11 8 7 36 34 32	3 4 5 6 7 8 9 10 11 12 13 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34 38 39 40 41 42 43 45 46
22 23	3.032	.1001	6	5	23 22 35 36 21	27 28 29 41 42
23 22	3.314	.0651	5	4	24 23 22 35 36 21	27 28 41 42
25 26	4.244	.2637	11	11	26 25 27 2 29 28 38 17 37 16 39	4 21 26 30 31 32 33 34 43 44 45
26 25	5.000	.2367	9	9	26 25 27 2 29 28 38 17 37	4 26 30 31 32 33 34 43 45
26 27	11.524	.0320	3	2	27 26 17	26 31
27 26	11.672	.0320	3	2	27 26 17	26 31
26 28	5.812	.0307	3	2	28 29 38	34 45
28 26	5.772	.0307	3	2	28 29 38	34 45

APPENDIX D

Regions of vulnerability of directional o/c ground relays

For 39-bus New England power system model

Table D.1 Results of fault current calculation for the calculation of RV of directional overcurrent ground relay.

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
1 2	0.198	1	-14.94
		30	-6.55
		9	-0.77
2 1	2.944	2	-5.72
1 30	0.289	1	-25.13
		2	-5.72
		25	-2.51
		3	-2.28
		18	-1.32
		17	-1.10
		26	-0.83
		4	-0.80
		27	-0.75
		16	-0.74
		14	-0.51
		15	-0.50
		24	-0.48
		21	-0.31
		13	-0.30
30 1	1.125	30	-6.55
2 3	4.046	2	-11.38
		25	-4.27
3 2	0.746	3	-27.52
		18	-14.51
		17	-10.66
		4	-10.54
		16	-7.44
		14	-6.64
		15	-5.43
		5	-5.33
		24	-4.82
		6	-4.57
		13	-4.19
		27	-4.14
		11	-3.56
		8	-3.55
		10	-3.52
		7	-3.42

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
2 25	0.896	21	-3.14
		26	-1.76
		22	-1.41
		23	-1.35
		9	-1.09
		19	-1.02
		2	-21.24
		3	-7.52
		1	-4.19
		18	-2.94
		4	-2.78
		30	-1.98
		14	-1.59
		5	-1.44
		6	-1.23
		13	-1.03
		8	-1.01
		17	-0.98
		7	-0.95
25 2	0.488	11	-0.92
		25	-25.93
		26	-5.41
		27	-2.43
		28	-1.41
		29	-0.99
3 4	1.961	3	-16.04
		18	-7.88
		2	-6.10
		17	-5.12
		25	-2.91
		27	-2.53
4 3	2.237	4	-15.09
		14	-7.61
		5	-7.47
		6	-6.32
		13	-5.01
		8	-4.97
		7	-4.78
		11	-4.61
		10	-4.36
3 18	4.609	3	-15.58
		2	-5.28

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
18 3	0.907	18	-22.38
		17	-15.78
		16	-9.06
		27	-6.67
		24	-5.87
		15	-4.12
		21	-3.83
		26	-3.69
		22	-1.72
		23	-1.65
		19	-1.25
		28	-0.96
4 5	2.762	4	-23.01
		14	-10.38
		3	-9.76
		18	-5.84
		15	-5.21
		17	-5.10
		16	-4.85
		2	-3.76
		13	-3.20
		24	-3.15
5 4	3.017	5	-13.72
		6	-10.46
		8	-8.80
		7	-8.27
		11	-3.15
4 14	1.664	4	-17.95
		3	-6.28
		5	-6.25
		6	-4.14
		8	-3.82
		7	-3.49
		2	-2.35
		18	-2.03
14 4	1.307	14	-17.98
		13	-8.21
		15	-6.53
		10	-4.46
		16	-3.23
		24	-2.09
		11	-1.46
		21	-1.36

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
5 6	0.823	5	-40.25
		4	-19.24
		8	-12.57
		14	-8.26
		3	-8.17
		7	-5.16
		18	-4.86
		9	-4.30
		17	-4.22
		15	-4.20
		16	-3.96
		2	-3.22
		24	-2.56
		30	-2.21
		27	-2.00
		13	-1.82
		21	-1.67
		25	-1.62
		26	-1.42
		1	-0.88
6 5	1.992	6	-12.18
		11	-4.41
5 8	2.332	5	-7.34
		4	-3.77
8 5	0.953	8	-21.37
		7	-13.43
		9	-7.25
		30	-3.24
6 7	7.016		
7 6	0.159		
6 11	3.818	7	-27.90
		8	-19.71
		9	-6.69
		30	-3.04
		5	-1.63
		4	-0.56
		1	-0.42
		3	-0.25
		2	-0.17
		6	-17.62
		5	-14.39
		7	-11.65
		8	-11.29

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
11 6	1.811	4	-3.87
		9	-3.84
		11	-24.33
		10	-15.83
		13	-10.98
7 8	2.980	14	-3.82
		7	-20.19
		6	-3.69
8 7	0.450	8	-19.71
		9	-6.69
		30	-3.04
		5	-1.63
		4	-0.56
8 9	2.847	8	-8.36
		7	-6.75
		5	-5.72
		6	-5.41
		4	-3.21
		11	-3.12
9 8	1.195	9	-13.95
		30	-6.28
9 30	0.291	9	-25.00
		8	-8.36
		7	-6.75
		5	-5.72
		6	-5.41
		4	-3.21
		11	-3.12
		10	-2.39
		14	-2.28
		13	-2.17
		3	-1.34
		15	-1.06
		16	-0.88
		18	-0.86
		17	-0.81
		24	-0.57
		21	-0.37
		27	-0.37
		2	-0.36

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
30 9	1.753	30	-6.28
10 11	2.759	10	-15.83
		13	-10.98
		14	-3.82
11 10	2.084	11	-33.94
		6	-17.62
		5	-14.39
		7	-11.65
		8	-11.29
		4	-3.87
		9	-3.84
10 13	6.493	10	-9.85
13 10	1.588	13	-39.72
		14	-23.51
		4	-11.20
		15	-10.04
		16	-7.33
		3	-5.72
		17	-5.30
		24	-4.75
		18	-4.64
		21	-3.10
		27	-2.43
		2	-2.30
		5	-1.96
		26	-1.62
13 14	2.344	13	-15.49
		10	-9.85
		11	-6.01
14 13	3.025	14	-23.51
		4	-11.20
		15	-10.04
		16	-7.33
		3	-5.72
		17	-5.30
		24	-4.75
		18	-4.64
		21	-3.10

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
14 15	3.738	14	-13.01
		13	-7.28
		4	-6.76
		10	-5.39
		11	-4.54
		5	-4.29
		6	-4.04
15 14	2.786	15	-16.57
		16	-10.56
		24	-6.84
		17	-5.28
		21	-4.46
15 16	0.533	15	-33.23
		14	-13.01
		13	-7.28
		4	-6.76
		10	-5.39
		11	-4.54
		5	-4.29
		6	-4.04
		8	-2.99
		7	-2.93
		9	-1.02
		3	-0.56
16 15	5.576	16	-10.56
		24	-6.84
16 17	5.870	16	-15.81
		24	-10.24
		15	-7.97
		21	-6.68
17 16	0.606	17	-31.93
		18	-20.67
		27	-14.27
		3	-11.79
		26	-8.97
		2	-5.42
		25	-4.14
		4	-2.49
		28	-2.33
		29	-1.63
		1	-1.08
		5	-1.01

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
16 19	2.771	6	-0.75
		8	-0.65
		7	-0.61
		16	-21.77
		24	-14.10
		17	-12.77
		15	-12.10
		21	-9.20
		18	-8.65
		3	-5.91
		27	-5.73
		14	-5.68
		4	-4.43
		22	-4.13
		23	-3.96
		26	-3.63
19 16	3.934	13	-3.28
		19	-6.89
16 21	2.870	16	-14.27
		24	-8.62
		17	-8.37
		15	-7.94
		18	-5.67
		3	-3.88
		27	-3.75
		14	-3.73
		4	-2.90
21 16	0.596	21	-22.97
		22	-7.40
		23	-2.05
16 24	2.773	16	-9.40
		17	-5.51
		15	-5.23
		18	-3.74
24 16	0.395	24	-39.82
		23	-6.70
		22	-1.72
17 18	3.593	17	-15.78
		16	-9.06
		27	-6.67
		24	-5.87

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
18 17	2.246	15	-4.12
		21	-3.83
		26	-3.69
		18	-27.63
		3	-15.58
		2	-5.28
17 27	3.889	4	-4.56
		17	-10.87
		18	-6.97
		16	-6.75
		24	-4.37
27 17	2.588	27	-20.94
		26	-12.66
		28	-3.29
		25	-2.77
21 22	0.430	21	-26.37
		16	-14.27
		24	-8.62
		17	-8.37
		15	-7.94
		18	-5.67
		3	-3.88
		27	-3.75
		14	-3.73
		4	-2.90
		26	-2.38
		13	-2.15
		19	-1.97
		2	-1.72
		5	-1.66
		10	-1.65
		6	-1.51
		11	-1.47
		25	-1.21
		8	-1.14
22 21	3.591	7	-1.11
		28	-0.62
		29	-0.43
		22	-7.40
22 23	1.787	22	-13.87
		21	-5.04

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
23 22	2.518	23	-22.68
		24	-3.57
23 24	3.407	23	-6.70
24 23	0.436	24	-12.51
		16	-9.40
		17	-5.51
		15	-5.23
		18	-3.74
		21	-2.63
		3	-2.55
		27	-2.47
		14	-2.45
		4	-1.91
		26	-1.57
		13	-1.42
		19	-1.29
		2	-1.13
		5	-1.10
		10	-1.09
		6	-0.99
		11	-0.97
		25	-0.80
		8	-0.75
		7	-0.73
25 26	1.111	25	-7.07
		2	-3.04
26 25	0.718	26	-14.38
		27	-8.78
		17	-4.98
		28	-3.74
		16	-3.05
		18	-2.87
		29	-2.62
		24	-1.98
		15	-1.69
		21	-1.29
		14	-0.78
		3	-0.74
26 27	3.796	26	-12.66

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
27 26	0.534	27	-17.93
		17	-10.87
		18	-6.97
		16	-6.75
		24	-4.37
		15	-3.85
		3	-3.80
		21	-2.85
		14	-2.12
		4	-2.07
		22	-1.28
		13	-1.25
		23	-1.23
		5	-1.13
		6	-1.00
		10	-0.98
		19	-0.93
		11	-0.91
		8	-0.77
		7	-0.74
26 28	0.773	26	-7.28
		27	-4.57
		17	-2.94
		25	-2.15
		18	-2.05
		16	-1.85
		3	-1.53
		2	-1.45
		24	-1.20
		15	-1.08
		21	-0.78
28 26	1.075	28	-6.84
26 29	0.020	29	-2.46
		26	-7.28
		27	-4.57
		17	-2.94
		25	-2.15
		18	-2.05
		16	-1.85
		3	-1.53
		2	-1.45
		24	-1.20
		15	-1.08
		21	-0.78

Table D.1 (continued)

RELAY	PICKUP SETTING	FAULT BUS	FAULT CURRENT
		4	-0.74
		14	-0.67
		13	-0.40
		5	-0.40
		6	-0.35
		22	-0.35
		23	-0.34
		10	-0.32
		11	-0.31
		1	-0.29
		8	-0.27
		7	-0.26
		19	-0.25
		30	-0.17
		9	-0.11
29 26	1.075	29	-2.46
28 29	0.773	28	-20.68
		26	-7.28
		27	-4.57
		17	-2.94
		25	-2.15
		18	-2.05
		16	-1.85
		3	-1.53
		2	-1.45
		24	-1.20
		15	-1.08
29 28	2.623	21	-0.78

Table D.2 RV of directional overcurrent ground relay

Relay	Pick up setting	RV	No. of buses in RV	No. of lines in RV	Bus(es) inside the RV	Line(s) inside the RV
1 2	0.198	.0500	3	2	9 30 1	2 15
1 30	0.289	.2543	15	16	13 21 24 15 14	1 3 4 5 6
					16 27 4 26 17	8 18 19 20 21
					18 3 25 2 1	23 24 25 26 30
						31
2 3	4.046	.0086	2	1	25 2	4
3 2	0.746	.3288	22	25	19 9 23 22 26	5 6 7 8 9
					21 7 10 8 11	10 11 12 13 14
					27 13 6 24 5	16 17 18 19 20
					15 14 16 4 17	21 22 23 24 25
					18 3	26 27 28 29 31
2 25	0.896	.1956	14	14	11 7 17 8 13	1 2 3 5 6
					6 5 14 30 4	7 8 9 10 11
					18 1 3 2	12 13 18 25
25 2	0.488	.1720	5	5	29 28 27 26 25	30 31 32 33 34
3 4	1.961	.0625	6	5	27 25 17 2 18	3 4 6 25 26
					3	
4 3	2.237	.0802	9	10	10 11 7 8 13	7 8 9 10 11
					6 5 14 4	12 13 16 17 18
3 18	4.609	.0151	2	1	2 3	3
18 3	0.907	.2034	12	12	28 19 23 22 26	20 21 22 23 24
					21 15 24 27 16	25 26 27 28 29
					17 18	31 32
4 5	2.762	.1268	10	10	24 13 2 16 17	3 5 6 8 18
					15 18 3 14 4	19 20 21 24 25
5 4	3.017	.0358	5	5	11 7 8 6 5	9 10 11 12 13
4 14	1.664	.0901	8	8	18 2 7 8 6	3 5 6 7 9
					5 3 4	10 11 13
14 4	1.307	.0692	8	7	21 11 24 16 10	16 17 18 19 20
					15 13 14	23 24
5 6	0.823	.3692	20	22	1 26 25 21 13	1 2 3 4 5
					27 30 24 2 16	6 7 8 10 13
					15 17 9 18 7	14 15 18 19 20
					3 14 8 4 5	21 23 24 25 26
						30 31
6 5	1.992	.0082	2	1	11 6	12
5 8	2.332	.0128	2	1	4 5	7
8 5	0.953	.0659	4	3	30 9 7 8	13 14 15
7 6	0.159	.1924	9	9	2 3 1 4 5	1 2 3 5 7
					30 9 8 7	10 13 14 15
6 11	3.818	.0767	6	6	9 4 8 7 5	7 9 10 11 13
					6	14
11 6	1.811	.0187	4	3	14 13 10 11	16 17 18

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table D.2 (continued)

Relay	Pick up setting	RV	No. of buses in RV	No. of lines in RV	Bus(es) inside the RV	Line(s) inside the RV
7 8	2.980	.0092	2	1	6 7	11
8 7	0.450	.0853	5	4	4 5 30 9 8	7 10 14 15
8 9	2.847	.0486	6	6	11 4 6 5 7	7 9 10 11 12
					8	13
9 8	1.195	.0250	2	1	30 9	15
9 30	0.291	.2511	19	21	2 27 21 24 17	3 5 6 7 8
					18 16 15 3 13	9 10 11 12 13
					14 10 11 4 6	14 16 17 18 19
					5 7 8 9	20 21 23 24 25
						26
10 11	2.759	.0144	3	2	14 13 10	17 18
11 10	2.084	.0849	7	7	9 4 8 7 5	7 9 10 11 12
					6 11	13 14
13 10	1.588	.1851	14	14	26 5 2 27 21	3 5 6 7 8
					18 24 17 3 16	18 19 20 21 23
					15 4 14 13	24 25 26 31
13 14	2.344	.0086	3	2	11 10 13	16 17
14 13	3.025	.1151	9	9	21 18 24 17 3	5 6 8 19 20
					16 15 4 14	21 23 24 25
14 15	3.738	.0552	7	7	6 5 11 10 4	7 8 9 12 16
					13 14	17 18
15 14	2.786	.0377	5	4	21 17 24 16 15	20 21 23 24
15 16	0.533	.1595	12	13	3 9 7 8 6	5 7 8 9 10
					5 11 10 4 13	11 12 13 14 16
					14 15	17 18 19
16 15	5.576	.0059	2	1	24 16	24
16 17	5.870	.0288	4	3	21 15 24 16	20 23 24
17 16	0.606	.3373	15	17	7 8 6 5 1	1 3 4 5 6
					29 28 4 25 2	7 9 10 11 13
					26 3 27 18 17	25 26 30 31 32
						33 34
16 19	2.771	.2158	14	15	13 26 23 22 4	5 6 8 18 19
					14 27 3 18 21	20 21 23 24 25
					15 17 24 16	26 27 28 29 31
16 21	2.870	.1189	9	9	4 14 27 3 18	5 6 8 19 20
					15 17 24 16	21 24 25 26
21 16	0.596	.0236	3	2	23 22 21	27 28
16 24	2.773	.0265	4	3	18 15 17 16	20 21 25
24 16	0.395	.0446	3	2	22 23 24	28 29
17 18	3.593	.0697	7	6	26 21 15 24 27	20 21 23 24 26
					16 17	31
18 17	2.246	.0497	4	3	4 2 3 18	3 5 6
17 27	3.889	.0230	4	3	24 16 18 17	21 24 25
27 17	2.588	.0944	4	3	25 28 26 27	30 31 32

Table D.2 (continued)

Relay	Pick up setting	RV	No. of buses in RV	No. of lines in RV	Bus(es) inside the RV	Line(s) inside the RV
21 22	0.430	.4149	23	27	29 28 7 8 25 11 6 10 5 2 19 13 26 4 14 27 3 18 15 17 24 16 21	3 4 5 6 7 8 9 10 11 12 13 16 17 18 19 20 21 22 23 24 25 26 30 31 32 33 34
22 23	1.787	.0140	2	1	21 22	27
23 22	2.518	.0350	2	1	24 23	29
24 23	0.436	.2899	21	24	7 8 25 11 6 10 5 2 19 13 26 4 14 27 3 21 18 15 17 16 24	3 4 5 6 7 8 9 10 11 12 13 16 17 18 19 20 21 22 23 24 25 26 30 31
25 26	1.111	.0086	2	1	2 25	4
26 25	0.718	.2379	12	12	3 14 21 15 24 29 18 16 28 17 27 26	6 19 20 21 23 24 25 26 31 32 33 34
27 26	0.534	.2778	20	23	7 8 11 19 10 6 5 23 13 22 4 14 21 3 15 24 16 18 17 27	1 1 1 1 1 1 1 1 2 2 2 2 2 2 2 2 2 2
26 28	0.773	.1472	11	11	21 15 24 2 3 16 18 25 17 27 26	3 4 6 20 21 23 24 25 26 30 31
28 26	1.075	.0151	2	1	29 28	34
26 29	0.020	.4759	26	31	9 30 19 7 8 1 11 10 23 22 6 5 13 14 4 21 15 24 2 3 16 18 25 17 27 26	1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31
28 29	0.773	.1946	12	12	21 15 24 2 3 16 18 25 17 27 26 28	3 4 6 20 21 23 24 25 26 30 31 32

APPENDIX E

Vulnerability index calculations

For 39-bus New England power system model

Table E.1 Vulnerability index
In the descending order of the change in det [B']

DROPPED LINES	CHANGE IN DET [B']	CHANGE IN DET [B*]	$\Delta\theta_1$ (deg)	$\Delta\theta_t$ (deg)	LINE FLOW (MVA)
* 3 4	0.993	0.894	25.6	66.6	1313.
12 16	0.993	0.989	19.5	74.9	1403.
* 20 24	0.992	0.983	20.9	80.9	851.
21 25	0.992	0.980	14.3	48.0	863.
17 18	0.991	0.988	8.4	26.6	1253.
* 10 13	0.989	0.976	87.7	137.2	1017.
9 12	0.984	0.968	16.3	48.8	1683.
25 26	0.984	0.961	17.3	51.0	467.
21 26	0.983	0.958	14.3	48.2	536.
* 9 11	0.982	0.971	49.6	190.4	1869.
* 20 23	0.981	0.950	39.8	103.2	1304.
1 4	0.980	0.815	27.6	66.5	779.
9 10	0.976	0.969	5.5	15.6	1637.
7 9	0.973	0.965	5.5	15.5	1347.
8 18	0.971	0.948	10.0	27.2	1135.
* 3 6	0.968	0.934	32.0	97.3	921.
* 1 3	0.965	0.817	53.6	127.3	1088.
* 13 14	0.964	0.922	9.3	31.5	706.
5 6	0.955	0.907	10.5	40.7	417.
* 7 8	0.954	0.930	25.8	63.5	878.
18 19	0.951	0.912	10.0	27.3	676.
* 3 5	0.949	0.894	23.3	58.7	1118.
* 11 12	0.945	0.911	19.8	64.3	1554.
31 32	0.945	0.888	32.6	67.3	902.
8 19	0.937	0.888	14.7	30.8	601.
31 33	0.928	0.852	33.3	69.6	902.
* 5 7	0.924	0.884	8.0	25.1	655.
* 5 8	0.924	0.883	15.5	69.5	837.
* 10 14	0.912	0.811	9.8	35.0	965.
7 10	0.883	0.850	7.5	16.9	986.
30 32	0.880	0.750	12.6	35.7	494.
30 33	0.842	0.670	13.3	37.3	594.

- Note 1. Cases with * and bold do not converge to a load flow solution.
2. Det stands for determinant.
3. Δ designates change in.

Table E.2 Vulnerability index
In the descending order of the change in det [B']

DROPPED LINES	CHANGE IN DET [B']	CHANGE IN DET [B']	$\Delta\theta_1$ (deg)	$\Delta\theta_t$ (deg)	LINE FLOW (MVA)
12 16	0.993	<i>0.989</i>	19.5	74.9	1403.
17 18	0.991	<i>0.988</i>	8.4	26.6	1253.
* 20 24	0.992	<i>0.983</i>	20.9	80.9	851.
21 25	0.992	<i>0.980</i>	14.3	48.0	863.
* 10 13	0.989	<i>0.976</i>	87.7	137.2	1017.
* 9 11	0.982	<i>0.971</i>	49.6	190.4	1869.
9 10	0.976	<i>0.969</i>	5.5	15.6	1637.
9 12	0.984	<i>0.968</i>	16.3	48.8	1683.
7 9	0.973	<i>0.965</i>	5.5	15.5	1347.
25 26	0.984	<i>0.961</i>	17.3	51.0	467.
21 26	0.983	<i>0.958</i>	14.3	48.2	536.
* 20 23	0.981	<i>0.950</i>	39.8	103.2	1304.
8 18	0.971	<i>0.948</i>	10.0	27.2	1135.
* 3 6	0.968	<i>0.934</i>	32.0	97.3	921.
* 7 8	0.954	<i>0.930</i>	25.8	63.5	878.
* 13 14	0.964	<i>0.922</i>	9.3	31.5	706.
18 19	0.951	<i>0.912</i>	10.0	27.3	676.
* 11 12	0.945	<i>0.911</i>	19.8	64.3	1554.
5 6	0.955	<i>0.907</i>	10.5	40.7	417.
* 3 4	0.993	<i>0.894</i>	25.6	66.6	1313.
* 3 5	0.949	<i>0.894</i>	23.3	58.7	1118.
31 32	0.945	<i>0.888</i>	32.6	67.3	902.
8 19	0.937	<i>0.888</i>	14.7	30.8	601.
* 5 7	0.924	<i>0.884</i>	8.0	25.1	655.
* 5 8	0.924	<i>0.883</i>	15.5	69.5	837.
31 33	0.928	<i>0.852</i>	33.3	69.6	902.
7 10	0.883	<i>0.850</i>	7.5	16.9	986.
* 1 3	0.965	<i>0.817</i>	53.6	127.3	1088.
1 4	0.980	<i>0.815</i>	27.6	66.5	779.
* 10 14	0.912	<i>0.811</i>	9.8	35.0	965.
30 32	0.880	<i>0.750</i>	12.6	35.7	494.
30 33	0.842	<i>0.670</i>	13.3	37.3	594.

Note 1. Cases with * and bold do not converge to a load flow solution.
2. Det stands for determinant.
3. Δ designates change in.

Table E.3 Vulnerability index calculation.
In the descending order of $\Delta\theta_1$

DROPPED LINES	CHANGE IN DET [B']	CHANGE IN DET [B']	$\Delta\theta_1$ (deg)	$\Delta\theta_t$ (deg)	LINE FLOW (MVA)
* 10 13	0.989	0.976	87.7	137.2	1017.
* 1 3	0.965	0.817	53.6	127.3	1088.
* 9 11	0.982	0.971	49.6	190.4	1869.
* 20 23	0.981	0.950	39.8	103.2	1304.
31 33	0.928	0.852	33.3	69.6	902.
31 32	0.945	0.888	32.6	67.3	902.
* 3 6	0.968	0.934	32.0	97.3	921.
1 4	0.980	0.815	27.6	66.5	779.
* 7 8	0.954	0.930	25.8	63.5	878.
* 3 4	0.993	0.894	25.6	66.6	1313.
* 3 5	0.949	0.894	23.3	58.7	1118.
* 20 24	0.992	0.983	20.9	80.9	851.
* 11 12	0.945	0.911	19.8	64.3	1554.
12 16	0.993	0.989	19.5	74.9	1403.
25 26	0.984	0.961	17.3	51.0	467.
9 12	0.984	0.968	16.3	48.8	1683.
* 5 8	0.924	0.883	15.5	69.5	837.
8 19	0.937	0.888	14.7	30.8	601.
21 25	0.992	0.980	14.3	48.0	863.
21 26	0.983	0.958	14.3	48.2	536.
30 33	0.842	0.670	13.3	37.3	594.
30 32	0.880	0.750	12.6	35.7	494.
5 6	0.955	0.907	10.5	40.7	417.
8 18	0.971	0.948	10.0	27.2	1135.
18 19	0.951	0.912	10.0	27.3	676.
* 10 14	0.912	0.811	9.8	35.0	965.
* 13 14	0.964	0.922	9.3	31.5	706.
17 18	0.991	0.988	8.4	26.6	1253.
* 5 7	0.924	0.884	8.0	25.1	655.
7 10	0.883	0.850	7.5	16.9	986.
7 9	0.973	0.965	5.5	15.5	1347.
9 10	0.976	0.969	5.5	15.6	1637.

- Note 1. Cases with * and bold do not converge to a load flow solution.
2. Det stands for determinant.
3. Δ designates change in.

Table E.4 Vulnerability index calculation.
In the descending order of $\Delta\theta_t$

DROPPED LINES	CHANGE IN DET [B']	CHANGE IN DET [B']	$\Delta\theta_1$ (deg)	$\Delta\theta_t$ (deg)	LINE FLOW (MVA)
* 9 11	0.982	0.971	49.6	190.4	1869.
* 10 13	0.989	0.976	87.7	197.2	1017.
* 1 3	0.965	0.817	53.6	127.3	1088.
* 20 23	0.981	0.950	39.8	103.2	1304.
* 3 6	0.968	0.934	32.0	97.3	921.
* 20 24	0.992	0.983	20.9	80.9	851.
12 16	0.993	0.989	19.5	74.9	1403.
31 33	0.928	0.852	33.3	69.6	902.
* 5 8	0.924	0.883	15.5	69.5	837.
31 32	0.945	0.888	32.6	67.3	902.
* 3 4	0.993	0.894	25.6	66.6	1313.
1 4	0.980	0.815	27.6	66.5	779.
* 11 12	0.945	0.911	19.8	64.3	1554.
* 7 8	0.954	0.930	25.8	63.5	878.
* 3 5	0.949	0.894	23.3	58.7	1118.
25 26	0.984	0.961	17.3	51.0	467.
9 12	0.984	0.968	16.3	48.8	1683.
21 26	0.983	0.958	14.3	48.2	536.
21 25	0.992	0.980	14.3	48.0	863.
5 6	0.955	0.907	10.5	40.7	417.
30 33	0.842	0.670	13.3	37.3	594.
30 32	0.880	0.750	12.6	35.7	494.
* 10 14	0.912	0.811	9.8	35.0	965.
* 13 14	0.964	0.922	9.3	31.5	706.
8 19	0.937	0.888	14.7	30.8	601.
18 19	0.951	0.912	10.0	27.3	676.
8 18	0.971	0.948	10.0	27.2	1135.
17 18	0.991	0.988	8.4	26.6	1253.
* 5 7	0.924	0.884	8.0	25.1	655.
7 10	0.883	0.850	7.5	16.9	986.
9 10	0.976	0.969	5.5	15.6	1637.
7 9	0.973	0.965	5.5	15.5	1347.

- Note 1. Cases with * and bold do not converge to a load flow solution.
2. Det stands for determinant.
3. Δ designates change in.

Table E.5 Vulnerability index calculation.
In the descending order of line flow

DROPPED LINES	CHANGE IN DET [B']	CHANGE IN DET [B']	$\Delta \theta_1$ (deg)	$\Delta \theta_t$ (deg)	LINE FLOW (MVA)
* 9 11	0.982	0.971	49.6	190.4	1869.
9 12	0.984	0.968	16.3	48.8	1683.
9 10	0.976	0.969	5.5	15.6	1637.
* 11 12	0.945	0.911	19.8	64.3	1554.
12 16	0.993	0.989	19.5	74.9	1403.
7 9	0.973	0.965	5.5	15.5	1347.
* 3 4	0.993	0.894	25.6	66.6	1313.
* 20 23	0.981	0.950	39.8	103.2	1304.
17 18	0.991	0.988	8.4	26.6	1253.
8 18	0.971	0.948	10.0	27.2	1135.
* 3 5	0.949	0.894	23.3	58.7	1118.
* 1 3	0.965	0.817	53.6	127.3	1088.
* 10 13	0.989	0.976	87.7	137.2	1017.
7 10	0.883	0.850	7.5	16.9	986.
* 10 14	0.912	0.811	9.8	35.0	965.
* 3 6	0.968	0.934	32.0	97.3	921.
31 33	0.928	0.852	33.3	69.6	902.
31 32	0.945	0.888	32.6	67.3	902.
* 7 8	0.954	0.930	25.8	63.5	878.
21 25	0.992	0.980	14.3	48.0	863.
* 20 24	0.992	0.983	20.9	80.9	851.
* 5 8	0.924	0.883	15.5	69.5	837.
1 4	0.980	0.815	27.6	66.5	779.
* 13 14	0.964	0.922	9.3	31.5	706.
18 19	0.951	0.912	10.0	27.3	676.
* 5 7	0.924	0.884	8.0	25.1	655.
8 19	0.937	0.888	14.7	30.8	601.
30 33	0.842	0.670	13.3	37.3	594.
21 26	0.983	0.958	14.3	48.2	536.
30 32	0.880	0.750	12.6	35.7	494.
25 26	0.984	0.961	17.3	51.0	467.
5 6	0.955	0.907	10.5	40.7	417.

- Note
1. Cases with * and bold do not converge to a load flow solution.
 2. Det stands for determinant.
 3. Δ designates change in.

APPENDIX F

Steady-state instability calculations

For 39-bus New England power system model

Table F.1 Steady-state instability index using five factors

L1	L2	$\Delta \det B'$	$\Delta \det B''$	$\Delta \theta_1$	$\Delta \theta_t$	FLOW	SII
*	9 11	0.982	0.971	49.6	190.4	1869	4.536
*	10 13	0.989	0.976	87.7	137.2	1017	4.248
*	1 3	0.965	0.817	53.6	127.3	1088	3.660
*	20 23	0.981	0.950	39.8	103.2	1304	3.642
	12 16	0.993	0.989	19.5	74.9	1403	3.366
	9 12	0.984	0.968	16.3	48.8	1683	3.312
*	3 6	0.968	0.934	32.0	97.3	921	3.288
*	11 12	0.945	0.911	19.8	64.3	1554	3.268
*	3 4	0.993	0.894	25.6	66.6	1313	3.248
*	20 24	0.992	0.983	20.9	80.9	851	3.111
	31 32	0.945	0.888	32.6	67.3	902	3.057
*	3 5	0.949	0.894	23.3	58.7	1118	3.032
	31 33	0.928	0.852	33.3	69.6	902	3.024
*	7 8	0.954	0.930	25.8	63.5	878	2.999
	9 10	0.976	0.969	5.5	15.6	1637	2.983
	17 18	0.991	0.988	8.4	26.6	1253	2.903
	1 4	0.980	0.815	27.6	66.5	779	2.892
	21 25	0.992	0.980	14.3	48.0	863	2.867
	7 9	0.973	0.965	5.5	15.5	1347	2.820
*	5 8	0.924	0.883	15.5	69.5	837	2.813
	8 18	0.971	0.948	10.0	27.2	1135	2.801
	25 26	0.984	0.961	17.3	51.0	467	2.678
	21 26	0.983	0.958	14.3	48.2	536	2.662
*	13 14	0.964	0.922	9.3	31.5	706	2.552
*	10 14	0.912	0.811	9.8	35.0	965	2.550
	18 19	0.951	0.912	10.0	27.3	676	2.499
	8 19	0.937	0.888	14.7	30.8	601	2.492
	7 10	0.883	0.850	7.5	16.9	986	2.451
	5 6	0.955	0.907	10.5	40.7	417	2.435
*	5 7	0.924	0.884	8.0	25.1	655	2.398
	30 32	0.880	0.750	12.6	35.7	494	2.240
	30 33	0.842	0.670	13.3	37.3	594	2.191

Note Cases with * do not converge to a load flow solution.

Table F.2 Steady-state instability index using six factors

L1	L2	$\Delta \text{det} B'$	$\Delta \text{det} B'$	$\Delta \theta_1$	$\Delta \theta_t$	FLOW	LOAD	SII
* 10	13	0.989	0.976	87.7	137.2	1017	1350	5.232
* 9	11	0.982	0.971	49.6	190.4	1869	249	4.717
* 20	23	0.981	0.950	39.8	103.2	1304	1295	4.586
* 20	24	0.992	0.983	20.9	80.9	851	1293	4.054
* 1	3	0.965	0.817	53.6	127.3	1088	322	3.894
* 3	5	0.949	0.894	23.3	58.7	1118	1159	3.876
* 3	6	0.968	0.934	32.0	97.3	921	803	3.873
* 5	8	0.924	0.883	15.5	69.5	837	1372	3.813
* 7	8	0.954	0.930	25.8	63.5	878	1066	3.775
* 3	4	0.993	0.894	25.6	66.6	1313	548	3.648
31	33	0.928	0.852	33.3	69.6	902	854	3.646
31	32	0.945	0.888	32.6	67.3	902	778	3.624
* 13	14	0.964	0.922	9.3	31.5	706	1350	3.536
* 11	12	0.945	0.911	19.8	64.3	1554	249	3.449
* 5	7	0.924	0.884	8.0	25.1	655	1372	3.398
5	6	0.955	0.907	10.5	40.7	417	1319	3.397
9	10	0.976	0.969	5.5	15.6	1637	551	3.385
12	16	0.993	0.989	19.5	74.9	1403	0	3.366
* 10	14	0.912	0.811	9.8	35.0	965	1102	3.353
9	12	0.984	0.968	16.3	48.8	1683	0	3.312
7	10	0.883	0.850	7.5	16.9	986	1084	3.240
21	25	0.992	0.980	14.3	48.0	863	491	3.225
7	9	0.973	0.965	5.5	15.5	1347	533	3.209
8	18	0.971	0.948	10.0	27.2	1135	533	3.189
8	19	0.937	0.888	14.7	30.8	601	887	3.138
21	26	0.983	0.958	14.3	48.2	536	620	3.113
1	4	0.980	0.815	27.6	66.5	779	229	3.059
25	26	0.984	0.961	17.3	51.0	467	452	3.007
17	18	0.991	0.988	8.4	26.6	1253	0	2.903
30	33	0.842	0.670	13.3	37.3	594	793	2.769
30	32	0.880	0.750	12.6	35.7	494	716	2.762
18	19	0.951	0.912	10.0	27.3	676	355	2.757

Note Cases with * do not converge to a load flow solution.

Table F.3 Steady-state instability index for the entire system using six factors ranked by highest SII to lowest

	L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	10	11	0.978	0.953	134.4	249.0	1507	1599	4.648
*	3	31	0.987	0.930	110.1	314.9	1336	1496	4.518
*	5	20	0.987	0.937	68.5	312.7	930	3034	4.418
*	7	18	0.985	0.934	84.0	397.1	952	1066	4.254
*	10	13	0.989	0.976	87.7	137.2	1016	2700	4.116
*	20	27	0.980	0.948	49.0	116.8	1907	1941	3.942
*	2	3	0.979	0.891	59.8	140.6	1063	2896	3.890
*	20	25	0.992	0.973	58.4	220.4	1030	1670	3.852
*	8	12	0.976	0.934	68.0	230.0	1213	1066	3.821
*	9	11	0.982	0.971	49.6	190.4	1869	497	3.775
*	2	27	0.973	0.896	36.7	80.2	1516	2851	3.756
*	2	20	0.984	0.944	27.0	111.3	912	3612	3.746
*	20	23	0.981	0.950	39.8	103.2	1267	2591	3.722
*	3	15	0.979	0.892	43.7	115.9	1014	2896	3.687
*	15	27	0.973	0.900	34.6	70.9	1405	2851	3.672
*	20	34	0.987	0.971	37.7	93.1	1325	2327	3.666
*	27	34	0.978	0.946	34.4	81.2	1943	1564	3.660
*	15	20	0.984	0.946	21.6	91.8	867	3612	3.639
*	6	20	0.986	0.956	43.2	168.9	767	2300	3.629
*	13	27	0.969	0.943	33.8	67.2	1629	2192	3.628
*	3	20	0.978	0.941	33.8	113.7	1470	1978	3.627
*	12	17	0.993	0.971	85.1	166.9	1325	0	3.623
*	2	34	0.982	0.944	31.6	62.5	950	3245	3.579
*	3	27	0.964	0.893	34.3	91.2	2057	1215	3.578
*	3	30	0.972	0.840	71.7	163.6	1022	1376	3.576
*	9	13	0.991	0.986	31.8	129.2	1376	1599	3.572
*	4	20	0.991	0.940	42.2	133.2	1157	1807	3.569
*	21	27	0.981	0.936	43.9	91.7	1717	1241	3.568
	7	12	0.988	0.940	46.8	208.0	1031	1066	3.545
	2	23	0.974	0.900	27.5	64.3	899	3505	3.544
*	20	29	0.950	0.898	29.8	92.8	1340	2436	3.532
*	5	27	0.946	0.868	36.2	77.0	1485	2273	3.528
*	8	27	0.942	0.893	36.4	75.5	1783	1659	3.523
*	27	31	0.974	0.933	31.3	78.4	1787	1449	3.514
*	12	27	0.971	0.922	42.1	107.1	1935	594	3.502
*	16	27	0.979	0.950	39.6	91.6	1977	594	3.500
*	10	27	0.923	0.859	34.3	68.4	1891	1695	3.494
*	13	20	0.981	0.969	18.7	75.5	1015	2947	3.493
*	31	34	0.983	0.966	44.5	75.1	1215	1843	3.492
*	3	34	0.976	0.941	36.6	81.6	1473	1627	3.478
*	23	34	0.979	0.948	28.1	66.5	1338	2222	3.477
*	3	26	0.985	0.918	56.3	173.8	880	1216	3.475
*	2	5	0.964	0.864	26.7	80.1	516	3950	3.474
*	15	34	0.982	0.946	28.4	52.9	815	3245	3.473

Note Cases with * do not converge to a load flow solution.

Table F.3 (continued)

L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}'$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	11 27	0.938	0.886	33.1	63.5	2126	1091	3.466
	2 31	0.979	0.928	28.2	73.8	788	3124	3.460
*	20 31	0.985	0.963	26.2	80.2	1184	2209	3.447
*	16 18	0.991	0.966	74.0	133.4	1320	0	3.447
*	9 27	0.976	0.953	28.8	53.4	2253	594	3.445
*	4 27	0.985	0.890	37.2	90.0	1759	1047	3.441
*	15 23	0.974	0.904	25.4	53.4	753	3505	3.440
	2 13	0.975	0.940	16.5	42.8	635	3857	3.422
*	13 34	0.979	0.969	27.3	49.1	1072	2569	3.419
*	10 20	0.952	0.923	19.1	76.6	1275	2451	3.414
	13 23	0.970	0.945	24.6	48.9	1024	2837	3.411
*	8 20	0.973	0.952	18.6	75.9	1169	2414	3.401
*	25 27	0.976	0.948	38.9	81.5	1645	911	3.396
*	20 24	0.992	0.983	20.9	80.9	822	2585	3.371
*	3 23	0.965	0.897	25.6	78.4	1415	1874	3.369
*	29 34	0.946	0.897	28.1	58.4	1401	2093	3.367
*	3 14	0.969	0.843	44.2	123.9	1039	1725	3.367
*	15 31	0.979	0.931	23.6	60.6	712	3124	3.362
*	11 20	0.962	0.938	17.6	68.8	1513	1846	3.360
*	21 23	0.982	0.939	34.7	75.6	1110	1898	3.359
*	5 34	0.964	0.929	30.6	58.9	896	2667	3.358
*	7 27	0.950	0.893	29.8	56.8	1602	1659	3.355
*	2 12	0.977	0.918	25.2	100.7	941	2264	3.344
*	3 13	0.965	0.938	24.5	62.8	1165	2219	3.339
*	5 15	0.964	0.871	13.5	49.5	589	3950	3.338
*	10 34	0.948	0.923	27.8	49.6	1331	2075	3.336
*	4 34	0.990	0.941	40.0	77.3	1187	1441	3.331
*	16 20	0.987	0.973	22.1	94.5	1371	1350	3.330
*	14 27	0.961	0.855	34.6	71.2	1422	1695	3.329
*	8 34	0.961	0.941	28.5	55.4	1223	2036	3.329
*	14 20	0.977	0.922	21.6	93.3	894	2451	3.329
*	6 27	0.961	0.915	35.1	71.6	1357	1537	3.325
*	12 20	0.983	0.958	23.3	104.5	1319	1350	3.321
*	2 16	0.983	0.948	22.4	77.8	977	2264	3.318
*	17 27	0.979	0.955	29.8	57.9	1905	594	3.315
	8 23	0.944	0.896	27.2	58.5	1173	2303	3.310
*	2 10	0.940	0.853	17.7	47.8	895	3362	3.309
*	8 16	0.975	0.954	34.3	112.9	1245	1066	3.308
	5 23	0.948	0.873	27.0	60.6	836	2927	3.302
*	23 31	0.975	0.935	22.1	64.4	1161	2101	3.301
*	12 23	0.972	0.925	32.9	94.1	1327	1241	3.299
*	12 34	0.980	0.958	34.6	88.8	1377	985	3.297
	2 4	0.988	0.890	27.6	67.5	760	2722	3.296
	2 8	0.952	0.888	16.5	49.7	787	3323	3.295
	2 29	0.934	0.801	17.5	54.4	964	3355	3.295
*	13 15	0.975	0.947	9.3	30.6	524	3857	3.294
*	3 25	0.980	0.959	36.3	119.1	1179	962	3.294

Table F.3 (continued)

	L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	11	34	0.958	0.938	26.4	45.1	1561	1473	3.289
*	16	23	0.980	0.952	30.4	77.0	1352	1241	3.284
	2	24	0.989	0.967	17.0	45.2	408	3504	3.282
	10	23	0.926	0.864	25.2	50.1	1281	2341	3.280
*	16	34	0.986	0.973	32.5	72.5	1406	985	3.274
*	9	20	0.985	0.974	13.5	49.8	1637	1350	3.271
*	2	11	0.950	0.881	16.1	40.6	1128	2758	3.269
*	24	34	0.991	0.983	28.1	52.1	807	2254	3.261
	13	31	0.975	0.961	20.8	50.9	901	2455	3.257
*	20	33	0.944	0.875	26.5	88.3	1007	2191	3.256
*	3	5	0.949	0.894	23.3	58.7	1078	2319	3.246
*	11	23	0.940	0.890	23.9	44.1	1509	1736	3.245
*	7	20	0.969	0.942	15.2	60.2	991	2414	3.245
*	3	24	0.985	0.966	25.6	66.8	972	1923	3.244
	5	31	0.957	0.909	26.3	68.4	779	2546	3.241
*	9	34	0.984	0.974	22.2	39.6	1690	985	3.240
*	8	21	0.974	0.930	26.9	95.8	995	1714	3.238
	2	21	0.985	0.930	14.9	51.3	722	2921	3.232
*	12	15	0.977	0.925	22.3	84.4	812	2264	3.230
	4	23	0.985	0.894	28.0	76.0	1133	1699	3.229
*	26	27	0.970	0.921	34.8	70.0	1327	1174	3.228
*	3	8	0.935	0.886	26.3	71.9	1318	1686	3.226
	4	15	0.988	0.889	25.4	58.1	687	2722	3.223
*	27	33	0.910	0.771	34.4	74.8	1622	1429	3.222
	15	24	0.989	0.968	8.6	33.2	477	3504	3.221
*	18	27	0.964	0.917	27.6	56.0	1858	594	3.219
*	5	21	0.987	0.922	23.5	87.6	680	2343	3.217
*	3	6	0.968	0.934	32.0	97.3	918	1606	3.216
*	9	23	0.977	0.954	19.6	31.7	1639	1241	3.216
*	27	32	0.932	0.826	34.4	73.8	1523	1278	3.215
*	7	17	0.982	0.960	29.2	130.3	991	1066	3.215
*	21	34	0.987	0.964	21.6	59.9	1159	1646	3.212
*	20	32	0.958	0.905	25.8	86.9	911	2040	3.211
*	2	9	0.980	0.950	10.8	20.1	1257	2264	3.210
*	27	30	0.943	0.847	33.5	68.2	1449	1323	3.206
*	4	25	0.992	0.944	44.9	129.1	889	779	3.204
*	3	16	0.977	0.946	28.6	84.8	1522	644	3.204
*	15	29	0.934	0.809	15.4	42.7	832	3355	3.198
*	3	29	0.909	0.794	25.6	71.7	1489	1756	3.195
*	15	16	0.983	0.952	15.5	63.1	884	2264	3.192
	13	29	0.923	0.891	14.6	37.7	1086	2672	3.191
	23	25	0.977	0.950	29.7	64.9	1042	1563	3.186
*	17	20	0.987	0.978	16.0	65.1	1302	1350	3.186
*	3	12	0.967	0.915	30.0	98.2	1468	644	3.183
*	7	34	0.966	0.942	23.4	42.4	1041	2036	3.183
*	7	8	0.954	0.930	25.8	63.5	877	2131	3.181
*	3	10	0.915	0.846	24.2	61.8	1425	1725	3.181

Table F.3 (continued)

	L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}'$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	8	15	0.952	0.892	10.8	37.9	671	3323	3.176
	4	13	0.985	0.937	25.1	56.5	873	2054	3.176
*	10	15	0.940	0.871	9.3	33.6	772	3362	3.174
*	29	31	0.935	0.870	21.7	57.9	1230	1960	3.170
*	19	27	0.954	0.879	32.2	64.3	1328	1303	3.170
*	15	21	0.985	0.932	14.1	48.1	605	2921	3.169
*	25	34	0.984	0.971	30.7	59.6	1090	1306	3.165
*	1	3	0.965	0.817	53.6	127.3	1088	644	3.162
*	3	9	0.973	0.949	19.7	46.7	1786	644	3.159
*	9	18	0.981	0.964	26.2	114.5	1603	0	3.157
	12	13	0.972	0.956	20.8	71.8	1062	1599	3.157
*	20	30	0.967	0.917	19.2	78.8	871	2085	3.156
*	21	29	0.953	0.875	24.7	63.5	1173	1771	3.156
*	3	11	0.931	0.876	22.7	55.6	1662	1125	3.154
	10	31	0.938	0.902	21.1	50.9	1162	1959	3.154
*	14	34	0.974	0.921	28.4	53.2	831	2075	3.152
	2	7	0.964	0.888	13.2	29.0	605	3323	3.149
	8	31	0.954	0.925	21.1	53.9	1054	1921	3.143
	5	13	0.948	0.924	9.3	35.1	596	3279	3.142
*	5	8	0.924	0.883	15.5	69.5	747	2746	3.140
*	20	26	0.982	0.957	22.0	82.1	729	1932	3.139
	8	13	0.944	0.938	10.5	32.8	908	2664	3.137
	2	25	0.980	0.945	15.6	53.0	652	2585	3.135
*	20	28	0.986	0.954	19.5	79.9	800	1872	3.133
	7	23	0.952	0.897	20.6	36.3	992	2303	3.133
*	11	15	0.950	0.894	7.8	26.4	1009	2758	3.131
*	6	34	0.973	0.953	28.5	52.9	784	1947	3.130
	13	21	0.982	0.961	13.9	46.9	845	2247	3.126
*	3	21	0.979	0.933	20.2	63.6	1252	1304	3.125
*	3	4	0.993	0.894	25.6	66.6	1308	1096	3.120
	24	31	0.989	0.978	21.7	54.2	676	2116	3.119
*	18	20	0.979	0.962	15.4	59.5	1243	1350	3.116
*	1	20	0.974	0.906	25.6	108.0	936	1350	3.116
*	11	31	0.950	0.921	19.7	45.8	1397	1354	3.113
*	17	34	0.986	0.976	24.2	44.4	1333	985	3.112
	12	31	0.977	0.946	26.8	86.1	1207	860	3.110
	2	6	0.968	0.910	16.9	45.4	359	3218	3.109
	16	31	0.983	0.965	25.2	71.8	1248	860	3.106
	6	23	0.962	0.918	25.9	54.1	731	2196	3.106
	16	29	0.948	0.904	20.4	67.5	1420	1112	3.103
*	9	15	0.980	0.953	5.5	15.0	1128	2264	3.102
*	1	27	0.956	0.827	36.7	78.5	1533	594	3.101
	13	16	0.980	0.972	14.5	53.2	1091	1599	3.101
	2	17	0.983	0.953	13.1	28.6	906	2264	3.098
*	14	23	0.963	0.860	25.4	53.7	768	2341	3.097
*	12	21	0.984	0.947	26.9	106.9	1149	661	3.095
	5	24	0.977	0.958	9.8	40.8	499	2930	3.092

Table F.3 (continued)

L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	17 23	0.980	0.957	20.6	38.0	1279	1241	3.085
	4 8	0.973	0.881	27.3	68.1	1026	1520	3.085
	4 5	0.975	0.857	26.8	63.6	754	2144	3.084
*	12 29	0.927	0.850	22.9	85.5	1391	1112	3.078
*	9 31	0.981	0.967	15.7	39.8	1524	860	3.076
*	3 7	0.946	0.890	20.6	53.8	1141	1686	3.075
*	5 12	0.952	0.897	21.9	89.4	892	1686	3.075
	4 12	0.986	0.913	33.6	105.5	1179	458	3.071
*	21 31	0.986	0.964	16.4	60.7	988	1519	3.065
*	3 17	0.977	0.951	22.5	56.6	1453	644	3.063
	13 24	0.987	0.982	9.3	27.9	499	2815	3.060
	4 16	0.990	0.945	31.0	86.9	1221	458	3.059
	4 10	0.964	0.843	25.7	58.4	1134	1557	3.059
	4 6	0.987	0.909	36.4	98.6	604	1417	3.059
*	5 16	0.965	0.934	15.4	69.7	957	1686	3.058
	4 29	0.962	0.789	25.8	67.6	1202	1562	3.057
*	18 34	0.976	0.954	22.4	46.2	1298	985	3.056
	2 33	0.926	0.760	20.4	54.4	628	3109	3.056
*	7 15	0.964	0.896	7.9	20.2	510	3323	3.054
*	10 12	0.931	0.889	21.7	74.9	1322	1102	3.051
	9 10	0.976	0.969	5.5	15.6	1636	1102	3.048
	31 33	0.928	0.852	33.3	69.6	893	1707	3.047
	4 24	0.994	0.965	25.8	60.1	650	1723	3.044
	6 31	0.979	0.946	25.1	69.2	632	1817	3.043
	2 32	0.944	0.818	19.7	52.7	528	2957	3.040
*	14 31	0.970	0.899	23.6	62.0	736	1959	3.040
*	10 21	0.955	0.904	14.6	48.1	1104	1752	3.038
*	16 21	0.988	0.966	22.5	82.2	1179	661	3.037
*	28 34	0.985	0.954	28.1	52.0	804	1500	3.033
	6 15	0.968	0.913	8.4	34.0	382	3218	3.030
*	10 16	0.951	0.929	15.3	55.4	1353	1102	3.029
*	30 34	0.962	0.923	24.4	49.2	868	1721	3.028
	2 30	0.954	0.840	19.2	44.3	459	3001	3.028
	2 28	0.982	0.911	17.0	44.8	389	2785	3.027
*	15 25	0.980	0.946	11.3	41.5	534	2585	3.024
*	9 29	0.939	0.909	9.6	19.5	1705	1112	3.024
*	8 9	0.964	0.956	9.7	26.6	1528	1066	3.024
*	4 11	0.971	0.874	24.4	52.4	1369	952	3.023
	23 33	0.913	0.779	25.2	58.6	1017	2086	3.022
	7 13	0.952	0.938	9.3	18.6	726	2664	3.020
*	9 17	0.987	0.980	17.2	70.6	1643	0	3.020
	7 31	0.960	0.926	17.0	44.3	873	1921	3.014
	12 24	0.988	0.975	21.4	76.7	801	1281	3.012
	23 32	0.934	0.833	25.2	57.3	917	1934	3.011
	2 18	0.971	0.912	11.3	28.2	862	2264	3.011
*	26 34	0.980	0.960	26.2	49.9	761	1563	3.011
	2 26	0.976	0.916	16.8	44.1	328	2845	3.010

Table F.3 (continued)

L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_l$	$\Delta \theta_t$	FLOW	LOAD	SII
23	26	0.971	0.924	25.6	52.1	712	1823	3.010
31	32	0.945	0.888	32.6	67.3	794	1554	3.008
7	16	0.982	0.957	17.5	70.9	1063	1066	3.007
*	15	0.983	0.955	7.5	22.3	822	2264	3.005
8	29	0.855	0.794	17.2	47.7	1237	2141	3.002
8	24	0.976	0.966	10.7	37.3	653	2289	3.001
*	19	0.969	0.932	26.7	48.4	764	1671	3.001
*	18	0.965	0.920	18.4	36.8	1248	1241	3.000
*	11	0.964	0.923	13.5	44.8	1334	1149	2.999
*	11	0.945	0.911	19.8	64.3	1552	497	2.996
10	24	0.968	0.955	7.4	28.4	759	2331	2.993
*	5	0.948	0.811	14.1	51.0	626	2784	2.991
5	29	0.865	0.748	17.0	50.3	912	2779	2.988
25	29	0.939	0.899	19.7	53.7	1103	1429	2.988
23	30	0.945	0.853	24.3	50.4	811	1978	2.982
21	24	0.992	0.979	15.7	49.5	586	1934	2.980
*	9	0.986	0.968	11.7	41.4	1463	661	2.979
2	19	0.964	0.869	16.8	43.5	329	2960	2.979
*	13	0.964	0.922	9.3	31.5	546	2700	2.978
*	4	0.989	0.947	19.9	37.7	1496	458	2.976
25	31	0.987	0.967	21.7	54.2	917	1182	2.975
3	28	0.975	0.907	25.6	66.7	951	1152	2.971
*	27	0.917	0.854	34.4	70.0	1298	694	2.971
*	11	0.960	0.943	13.8	46.3	1588	497	2.970
*	27	0.917	0.854	34.4	69.9	1291	694	2.968
*	17	0.983	0.969	18.2	48.4	1178	860	2.967
13	25	0.977	0.969	10.7	37.4	776	1917	2.967
*	3	0.960	0.910	21.0	56.2	1393	644	2.965
*	5	0.960	0.940	5.5	16.5	1209	1686	2.963
13	33	0.914	0.868	16.2	37.6	751	2434	2.962
15	33	0.926	0.769	17.3	42.6	515	3109	2.961
9	12	0.984	0.968	16.3	48.8	1681	0	2.960
16	24	0.991	0.984	15.0	58.1	859	1281	2.956
*	1	0.971	0.906	31.6	60.3	960	985	2.956
8	10	0.862	0.848	10.7	33.7	1167	2167	2.956
15	28	0.982	0.914	8.6	33.1	428	2785	2.956
8	25	0.961	0.945	16.0	60.3	925	1384	2.956
15	30	0.954	0.846	10.4	33.3	491	3001	2.954
*	15	0.971	0.915	10.0	29.0	742	2264	2.954
12	16	0.993	0.989	19.5	74.9	1397	0	2.953
13	17	0.980	0.974	9.3	21.5	1019	1599	2.952
15	32	0.944	0.825	16.6	40.7	434	2957	2.951
19	23	0.955	0.883	23.0	45.8	715	1941	2.951
*	8	0.889	0.877	10.2	27.3	1399	1562	2.942
*	11	0.974	0.964	5.9	21.2	996	1743	2.936
*	3	0.923	0.810	25.6	74.4	1061	1337	2.936
*	3	0.899	0.749	25.6	75.9	1157	1492	2.935

Table F.3 (continued)

	L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	5	10	0.873	0.814	8.6	34.0	851	2784	2.934
	14	24	0.984	0.954	9.2	33.7	514	2331	2.926
*	11	29	0.845	0.782	13.9	32.0	1576	1587	2.926
	12	25	0.978	0.958	23.3	94.3	1080	322	2.925
	13	18	0.966	0.952	10.0	29.6	983	1599	2.925
	4	21	0.992	0.925	18.3	57.3	960	1117	2.923
	13	32	0.935	0.900	15.5	35.6	651	2284	2.923
	6	13	0.962	0.950	9.3	28.9	469	2540	2.923
*	5	11	0.897	0.849	7.4	27.1	1088	2180	2.919
	15	26	0.976	0.919	8.0	31.1	328	2845	2.915
*	20	36	0.948	0.921	19.5	79.9	718	1422	2.911
	5	6	0.955	0.907	10.5	40.7	413	2641	2.911
	10	29	0.808	0.729	15.1	38.7	1345	2182	2.910
*	20	35	0.948	0.921	19.5	79.8	712	1422	2.908
*	6	21	0.987	0.968	17.0	59.9	557	1623	2.908
*	17	29	0.948	0.914	10.6	27.5	1348	1112	2.907
	7	9	0.973	0.965	5.5	15.5	1346	1066	2.902
*	12	14	0.966	0.891	22.3	85.7	829	1102	2.902
*	18	31	0.971	0.942	16.5	51.0	1129	860	2.901
*	3	19	0.948	0.863	25.0	64.2	878	1321	2.899
	4	7	0.977	0.881	21.2	42.7	845	1520	2.898
*	5	7	0.924	0.884	8.0	25.1	578	2746	2.898
	9	16	0.987	0.979	10.2	28.4	1715	0	2.891
	24	33	0.962	0.927	16.9	41.5	491	2120	2.891
	9	24	0.990	0.985	5.5	14.3	1120	1281	2.890
	7	21	0.971	0.927	10.4	40.4	813	1714	2.889
	1	23	0.958	0.833	27.5	62.2	907	1241	2.885
	28	31	0.982	0.941	21.7	54.4	661	1381	2.882
	10	25	0.942	0.924	11.2	38.7	1034	1421	2.882
*	4	14	0.982	0.838	25.4	57.8	712	1557	2.882
	5	25	0.972	0.943	10.4	36.7	609	2007	2.880
*	14	16	0.976	0.929	15.5	64.2	905	1102	2.880
*	15	19	0.964	0.876	7.7	27.6	318	2960	2.873
	6	12	0.965	0.932	22.0	82.0	775	962	2.872
*	5	17	0.965	0.941	7.5	25.2	893	1686	2.866
	8	17	0.975	0.965	7.8	23.5	1172	1066	2.866
	16	33	0.942	0.885	21.3	65.8	1084	850	2.863
	16	25	0.985	0.973	17.4	72.8	1108	322	2.861
	7	24	0.979	0.966	7.8	19.1	478	2289	2.859
	6	29	0.901	0.836	15.9	43.2	798	2073	2.859
	4	17	0.990	0.950	21.6	44.8	1150	458	2.858
*	10	17	0.951	0.936	7.5	19.1	1281	1102	2.855
	6	8	0.937	0.911	12.2	45.7	622	2007	2.855
	8	18	0.971	0.948	10.0	27.2	1134	1066	2.852
	13	30	0.945	0.912	9.3	27.2	557	2330	2.849
	21	25	0.992	0.980	14.3	48.0	862	982	2.849
*	14	21	0.978	0.901	14.1	47.7	626	1752	2.843

Table F.3 (continued)

L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta l$	$\Delta \theta t$	FLOW	LOAD	SII
13	28	0.979	0.951	9.3	27.8	492	2122	2.842
7	29	0.875	0.794	10.6	25.1	1055	2141	2.836
19	31	0.965	0.914	19.4	53.4	600	1559	2.836
7	10	0.883	0.850	7.5	16.9	986	2167	2.832
* 11	25	0.953	0.939	10.0	31.8	1263	816	2.830
* 11	17	0.960	0.948	7.4	20.1	1516	497	2.830
4	33	0.958	0.747	28.8	71.6	865	1306	2.828
24	32	0.971	0.944	16.2	39.7	398	1965	2.828
13	26	0.971	0.954	9.3	26.3	447	2179	2.827
6	16	0.975	0.957	15.4	61.7	819	962	2.826
1	31	0.966	0.880	28.2	70.1	806	860	2.824
* 8	14	0.931	0.843	10.8	38.3	692	2167	2.822
12	33	0.919	0.819	23.4	83.5	1055	850	2.821
* 7	11	0.904	0.877	5.7	16.0	1217	1562	2.815
16	32	0.956	0.913	20.6	64.3	985	696	2.814
6	24	0.983	0.973	7.7	33.2	297	2236	2.813
13	19	0.956	0.928	9.3	23.3	450	2305	2.812
24	25	0.990	0.983	11.3	42.0	513	1592	2.811
* 10	14	0.912	0.811	9.8	35.0	791	2203	2.809
4	32	0.968	0.808	28.1	69.7	766	1153	2.808
5	28	0.963	0.887	9.8	40.4	457	2207	2.803
* 34	36	0.944	0.921	28.1	51.9	720	1034	2.803
9	33	0.932	0.890	11.0	22.5	1368	850	2.800
* 34	35	0.944	0.921	28.1	51.8	713	1034	2.799
21	33	0.947	0.847	14.3	50.1	838	1511	2.797
12	32	0.939	0.863	22.7	82.2	955	696	2.794
* 14	29	0.904	0.721	15.4	43.1	848	2182	2.791
17	21	0.988	0.969	9.1	34.4	1107	661	2.788
* 11	18	0.932	0.904	10.0	31.3	1474	497	2.785
* 9	14	0.971	0.931	5.5	15.1	1143	1102	2.784
4	28	0.990	0.906	25.8	59.7	634	979	2.783
* 5	19	0.969	0.853	10.4	42.7	354	2383	2.783
17	24	0.991	0.986	7.5	22.1	792	1281	2.782
* 11	14	0.928	0.845	8.4	27.7	1026	1599	2.781
* 5	18	0.940	0.891	10.0	27.2	819	1686	2.781
* 10	18	0.915	0.880	10.0	25.7	1243	1102	2.781
* 18	29	0.911	0.840	10.0	28.5	1312	1112	2.776
26	29	0.924	0.847	15.6	40.9	775	1680	2.775
24	30	0.976	0.951	8.1	31.1	410	2001	2.771
6	10	0.906	0.877	7.4	29.5	731	2047	2.770
21	30	0.968	0.901	14.2	53.8	644	1397	2.767
12	28	0.980	0.933	21.4	76.1	797	523	2.767
18	24	0.985	0.973	10.0	27.3	726	1281	2.766
4	18	0.983	0.907	19.7	42.3	1101	458	2.765
4	19	0.980	0.861	26.7	63.5	572	1159	2.763
21	32	0.960	0.884	14.3	49.4	738	1357	2.762
5	26	0.950	0.893	9.6	38.5	361	2267	2.762

Table F.3 (continued)

	L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
*	9	25	0.982	0.975	6.1	16.9	1392	322	2.761
	2	36	0.932	0.848	17.0	44.8	305	2324	2.758
	12	26	0.973	0.937	21.6	75.1	752	582	2.757
	2	35	0.932	0.848	17.0	44.7	299	2324	2.755
	5	32	0.886	0.769	18.7	48.3	500	2379	2.755
	12	30	0.949	0.879	21.1	73.4	861	737	2.755
	9	32	0.949	0.917	10.3	20.5	1269	696	2.750
	6	9	0.970	0.959	5.5	13.3	1093	962	2.749
	5	30	0.906	0.796	10.9	40.3	525	2422	2.746
	8	28	0.960	0.908	10.7	36.8	645	1589	2.746
	1	13	0.959	0.900	10.3	40.3	646	1599	2.746
	16	30	0.964	0.923	14.8	55.0	914	737	2.744
	8	19	0.937	0.888	14.7	30.8	600	1773	2.743
*	1	5	0.941	0.772	20.5	75.6	552	1686	2.743
	23	36	0.920	0.860	25.2	52.3	666	1309	2.741
	18	21	0.980	0.943	10.0	33.5	1070	661	2.741
	23	35	0.920	0.860	25.2	52.2	659	1309	2.738
	6	11	0.924	0.901	6.1	22.5	966	1446	2.738
	8	32	0.878	0.811	16.6	43.9	801	1751	2.737
	21	26	0.983	0.958	14.3	48.2	534	1239	2.737
	25	33	0.932	0.877	19.5	50.9	769	1170	2.736
*	12	19	0.960	0.903	23.1	66.8	755	709	2.734
	5	33	0.850	0.695	19.4	50.1	588	2531	2.731
	21	28	0.987	0.942	14.3	48.4	579	1176	2.730
	8	26	0.946	0.913	11.0	35.8	598	1646	2.729
	8	33	0.839	0.751	17.3	45.6	901	1900	2.728
	16	28	0.986	0.957	15.0	57.5	847	523	2.725
	19	25	0.980	0.938	18.7	69.8	467	1024	2.717
	7	25	0.963	0.943	7.7	22.2	744	1384	2.716
	10	28	0.947	0.879	7.4	28.3	753	1625	2.715
	9	30	0.957	0.927	6.5	20.2	1180	737	2.710
	16	26	0.981	0.960	15.2	56.2	789	582	2.709
*	9	19	0.965	0.940	8.8	26.1	1069	709	2.708
*	14	25	0.971	0.922	11.3	41.6	556	1421	2.705
	15	36	0.932	0.853	8.7	32.9	380	2324	2.705
*	7	14	0.948	0.849	7.9	19.0	535	2167	2.705
	15	35	0.932	0.853	8.6	32.8	379	2324	2.704
	6	14	0.953	0.873	9.0	34.4	418	2047	2.700
	16	19	0.971	0.938	16.0	47.8	789	709	2.695
	17	33	0.942	0.896	13.0	30.5	1011	850	2.692
	10	26	0.927	0.885	7.4	26.7	706	1683	2.691
*	14	17	0.976	0.934	7.5	21.7	845	1102	2.691
	25	32	0.949	0.907	18.8	49.2	669	1017	2.690
*	1	12	0.962	0.863	24.3	97.6	952	0	2.690
	24	26	0.987	0.975	7.7	30.7	246	1837	2.688
	9	28	0.983	0.959	7.6	16.1	1115	523	2.684
	8	30	0.899	0.834	10.4	35.1	711	1796	2.684

Table F.3 (continued)

L1	L2	$\Delta \text{detB}'$	$\Delta \text{detB}''$	$\Delta \theta_1$	$\Delta \theta_2$	FLOW	LOAD	SII
	17 18	0.991	0.988	8.4	26.6	1248	0	2.680
*	3 36	0.907	0.841	25.6	66.6	868	683	2.679
	19 24	0.980	0.961	7.7	27.1	239	1924	2.677
*	3 35	0.907	0.841	25.6	66.5	862	683	2.676
*	11 32	0.869	0.801	14.5	29.8	1139	1186	2.674
	6 7	0.939	0.908	7.7	18.9	442	2007	2.673
	11 28	0.958	0.903	5.9	21.4	990	1020	2.672
	10 32	0.837	0.753	15.9	36.4	909	1789	2.671
*	11 33	0.827	0.737	15.2	32.0	1239	1337	2.660
	9 26	0.977	0.962	5.5	16.4	1068	582	2.659
*	1 16	0.973	0.913	17.0	74.6	995	0	2.658
	25 26	0.984	0.961	17.3	51.0	464	903	2.655
	1 24	0.982	0.945	10.8	42.1	441	1281	2.650
	11 26	0.941	0.908	5.9	20.0	939	1078	2.650
	1 4	0.980	0.815	27.6	66.5	778	458	2.645
	19 29	0.884	0.764	13.0	35.1	778	1776	2.643
	29 30	0.858	0.706	14.3	39.8	883	1842	2.643
	6 17	0.975	0.961	7.5	22.5	750	962	2.642
	29 32	0.830	0.667	16.2	47.6	979	1804	2.641
	17 32	0.956	0.921	12.3	28.7	913	696	2.639
	31 36	0.933	0.899	21.7	54.3	576	928	2.638
	17 25	0.985	0.976	7.6	24.7	1035	322	2.637
	14 28	0.974	0.876	9.2	33.6	465	1625	2.636
	31 35	0.933	0.899	21.7	54.2	570	928	2.635
	10 33	0.786	0.673	16.6	38.3	1009	1940	2.631
	16 36	0.961	0.941	19.8	71.3	762	177	2.629
	16 35	0.961	0.941	19.5	72.7	755	177	2.627
	25 30	0.971	0.921	11.8	42.8	572	1059	2.627
*	14 18	0.959	0.877	10.0	28.4	761	1102	2.614
	10 30	0.864	0.782	7.4	27.1	818	1834	2.611
	10 19	0.890	0.822	7.3	22.9	709	1808	2.611
	18 25	0.973	0.955	10.0	25.0	1000	322	2.608
	7 28	0.966	0.908	7.8	20.2	467	1589	2.608
*	11 30	0.891	0.824	5.9	20.9	1055	1230	2.606
	1 21	0.976	0.883	14.9	50.3	734	661	2.605
	6 33	0.890	0.800	17.3	42.5	462	1811	2.605
	6 18	0.957	0.927	10.0	28.5	698	962	2.600
	13 36	0.920	0.916	9.3	27.5	407	1678	2.597
	17 30	0.964	0.930	7.5	26.4	846	737	2.595
	13 35	0.920	0.916	9.3	27.4	400	1678	2.594
	14 26	0.964	0.882	8.6	31.5	364	1683	2.594
*	11 19	0.911	0.857	5.8	17.6	941	1205	2.593
	7 26	0.953	0.913	7.7	19.6	416	1646	2.591
	14 30	0.934	0.775	11.0	34.3	527	1834	2.590
	7 32	0.894	0.812	11.5	25.5	619	1751	2.589
	6 32	0.917	0.849	16.6	40.7	363	1657	2.588
	7 33	0.861	0.751	12.2	27.4	719	1900	2.586

Table F.3 (continued)

	L1	L2	$\Delta\text{detB}'$	$\Delta\text{detB}'$	$\Delta\theta_l$	$\Delta\theta_t$	FLOW	LOAD	SII
*	1	9	0.967	0.917	9.6	19.4	1270	0	2.585
	25	28	0.983	0.954	11.3	41.2	507	843	2.581
	1	8	0.922	0.812	11.8	47.1	799	1066	2.579
	29	33	0.776	0.560	16.9	49.2	1079	1959	2.572
	7	30	0.912	0.834	7.8	23.5	534	1796	2.570
	7	19	0.929	0.866	7.7	24.7	419	1773	2.565
	14	32	0.919	0.745	16.6	41.1	460	1789	2.562
	6	30	0.953	0.872	8.5	30.5	331	1697	2.558
	17	28	0.986	0.961	7.5	23.1	778	523	2.556
*	1	11	0.919	0.801	12.1	39.2	1142	497	2.556
	6	26	0.975	0.937	9.6	33.7	177	1537	2.553
*	1	10	0.901	0.753	11.5	45.7	907	1102	2.551
	17	19	0.971	0.950	7.5	22.7	718	709	2.550
	28	33	0.938	0.803	16.9	41.4	484	1364	2.547
	1	29	0.891	0.668	17.5	51.9	975	1112	2.547
	6	28	0.973	0.926	7.7	33.0	261	1474	2.545
	12	36	0.926	0.887	21.6	76.7	712	177	2.544
	12	35	0.926	0.887	21.7	75.9	706	177	2.540
	17	26	0.981	0.964	7.5	22.1	718	582	2.539
	4	36	0.961	0.838	25.8	59.7	549	536	2.537
	14	33	0.893	0.663	17.3	42.9	538	1940	2.536
	18	33	0.900	0.805	11.2	32.8	976	850	2.535
	4	35	0.961	0.838	25.8	59.7	543	536	2.534
*	14	19	0.947	0.819	8.0	27.9	354	1808	2.526
	24	36	0.965	0.953	7.7	31.9	281	1291	2.525
	24	35	0.965	0.953	7.7	31.8	278	1291	2.524
	26	33	0.915	0.826	15.0	38.5	440	1427	2.522
	28	32	0.953	0.851	16.2	39.5	387	1213	2.519
	18	28	0.975	0.928	10.0	28.5	720	523	2.519
	18	30	0.937	0.870	10.0	33.4	785	737	2.517
	18	32	0.924	0.853	10.5	31.4	876	696	2.515
	18	26	0.966	0.932	10.0	27.9	673	582	2.506
	18	19	0.951	0.912	10.0	27.3	676	709	2.502
	6	19	0.968	0.899	7.7	26.6	174	1642	2.501
	21	36	0.951	0.901	14.4	48.5	494	715	2.498
	1	25	0.967	0.908	13.4	50.9	662	322	2.495
	21	35	0.951	0.901	14.3	48.5	488	715	2.495
	26	32	0.936	0.869	14.3	36.7	340	1275	2.493
	5	36	0.861	0.807	9.9	40.4	395	1747	2.475
	5	35	0.861	0.807	9.8	40.3	392	1747	2.473
	28	30	0.961	0.869	8.1	31.1	373	1257	2.468
	9	36	0.938	0.930	5.5	15.4	1031	177	2.466
	9	35	0.938	0.930	5.5	15.3	1024	177	2.463
	1	17	0.973	0.921	7.6	25.8	925	0	2.443
	26	28	0.979	0.931	7.7	30.5	214	1104	2.436
	1	7	0.941	0.812	7.1	26.2	618	1066	2.431
	8	36	0.852	0.843	10.9	36.9	561	1152	2.424

Table F.3 (continued)

L1	L2	$\Delta\text{detB}'$	$\Delta\text{detB}'$	$\Delta\theta_l$	$\Delta\theta_t$	FLOW	LOAD	SII
8	35	0.852	0.843	10.8	37.1	554	1152	2.422
1	6	0.947	0.850	10.7	42.4	383	962	2.412
17	36	0.961	0.948	8.4	26.9	693	177	2.409
17	35	0.961	0.948	8.5	27.6	687	177	2.409
19	28	0.968	0.893	7.7	27.4	209	1230	2.408
19	32	0.902	0.781	14.8	34.7	343	1387	2.398
30	32	0.880	0.750	12.6	35.7	454	1433	2.392
19	33	0.871	0.710	15.5	36.6	443	1536	2.388
19	26	0.959	0.900	7.7	26.6	140	1286	2.387
30	33	0.842	0.670	13.3	37.3	549	1586	2.362
19	30	0.923	0.807	7.7	28.0	280	1433	2.360
29	36	0.793	0.721	15.2	41.4	735	1139	2.359
29	35	0.793	0.721	15.2	41.3	728	1139	2.355
25	36	0.937	0.922	11.3	41.2	422	407	2.354
1	18	0.953	0.853	10.0	26.3	874	0	2.351
25	35	0.937	0.922	11.3	41.2	416	407	2.351
1	28	0.970	0.852	10.8	41.7	417	523	2.340
14	36	0.901	0.786	9.2	33.4	419	1183	2.340
14	35	0.901	0.786	9.2	33.3	417	1183	2.339
11	36	0.841	0.833	5.9	20.9	905	593	2.337
11	35	0.841	0.833	5.9	20.8	898	593	2.333
10	36	0.802	0.793	7.4	28.0	668	1183	2.331
10	35	0.802	0.793	7.4	28.0	661	1183	2.328
1	26	0.960	0.859	10.6	41.0	347	582	2.318
1	32	0.908	0.696	19.7	50.1	539	696	2.306
7	36	0.873	0.843	7.7	19.6	381	1152	2.299
7	35	0.873	0.843	7.7	19.5	375	1152	2.296
18	36	0.909	0.878	10.3	27.7	635	177	2.277
18	35	0.909	0.878	10.3	28.6	629	177	2.275
1	30	0.925	0.733	13.0	40.2	488	737	2.273
1	33	0.878	0.599	20.4	51.9	638	850	2.271
6	36	0.899	0.873	7.7	32.8	190	1004	2.266
6	35	0.899	0.873	7.7	32.7	186	1004	2.264
1	19	0.940	0.781	10.6	40.4	346	709	2.250
28	36	0.943	0.875	7.7	31.7	235	616	2.232
28	35	0.943	0.875	7.7	31.6	232	616	2.231
26	36	0.922	0.882	7.7	30.2	138	663	2.182
26	35	0.922	0.882	7.7	30.2	134	663	2.180
32	36	0.825	0.745	16.2	39.4	302	753	2.128
32	35	0.825	0.745	16.2	39.3	295	753	2.125
30	36	0.854	0.775	8.1	30.8	302	801	2.118
30	35	0.854	0.775	8.1	30.7	298	801	2.116
19	36	0.881	0.816	7.7	27.0	131	813	2.102
19	35	0.881	0.816	7.7	27.0	127	813	2.100
33	36	0.769	0.663	16.9	41.2	399	900	2.079
33	35	0.769	0.663	16.9	41.2	392	900	2.076
1	36	0.888	0.745	10.8	41.7	335	177	2.026
1	35	0.888	0.745	10.8	41.6	329	177	2.023

APPENDIX G

Vulnerability indices for regions of vulnerability

For 39-bus New England power system model

Table G.1 VI for RV Type 1, Reverse Local Bus Vulnerability Region

RELAY		RV	VI
1	2	0.0205	0.0205
1	30	0.0125	0.0125
2	1	0.0466	0.0205
2	3	0.0151	0.0151
2	25	0.0086	0.0043
3	2	0.0151	0.0151
3	4	0.0213	0.0106
3	18	0.0133	0.0066
4	3	0.0213	0.0213
4	5	0.0128	0.0128
4	14	0.0129	0.0129
5	4	0.0166	0.0038
5	6	0.0026	0.0000
5	8	0.0142	0.0060
6	5	0.0026	0.0013
6	7	0.0112	0.0112
6	11	0.0097	0.0056
7	6	0.0046	0.0046
7	8	0.0023	0.0023
8	5	0.0112	0.0112
8	7	0.0046	0.0046
8	9	0.0389	0.0389
9	8	0.0181	0.0181
9	30	0.0125	0.0125
10	11	0.0022	0.0022
10	13	0.0022	0.0022
11	6	0.0041	0.0000
11	10	0.0022	0.0000
13	10	0.0022	0.0000
13	14	0.0050	0.0007
14	4	0.0129	0.0000
14	13	0.0101	0.0000
14	15	0.0217	0.0000
15	14	0.0152	0.0123
15	16	0.0047	0.0047
16	15	0.0188	0.0188
16	17	0.0178	0.0133
16	19	0.0399	0.0399
16	21	0.0270	0.0270
16	24	0.0118	0.0089
17	16	0.0089	0.0000
17	18	0.0082	0.0000
17	27	0.0173	0.0000
18	3	0.0066	0.0066
18	17	0.0041	0.0041

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table G.1 (continued)

RELAY		RV	VI
19	16	0.0000	0.0000
21	16	0.0068	0.0068
21	22	0.0070	0.0070
22	21	0.0070	0.0070
22	23	0.0048	0.0048
23	22	0.0048	0.0048
23	24	0.0175	0.0175
24	16	0.0030	0.0030
24	23	0.0550	0.0474
25	2	0.0043	0.0043
25	26	0.0237	0.0161
26	25	0.0485	0.0161
26	27	0.0221	0.0073
26	28	0.0711	0.0237
26	29	0.0938	0.0313
27	17	0.0087	0.0087
27	26	0.0074	0.0073
28	26	0.0237	0.0237
28	29	0.0076	0.0076
29	26	0.0313	0.0312
29	28	0.0076	0.0076
30	1	0.0125	0.0125
30	9	0.0125	0.0125

Table G.2 VI for RV Type 3, Zone 2 Vulnerability Region

RELAY		RV	VI
1	2	0.0164	0.0082
1	30	0.0050	0.0050
2	1	0.0082	0.0082
2	3	0.0060	0.0060
2	25	0.0017	0.0017
3	2	0.0060	0.0060
3	4	0.0085	0.0085
3	18	0.0027	0.0027
4	3	0.0085	0.0043
4	5	0.0051	0.0000
4	14	0.0052	0.0000
5	4	0.0051	0.0051
5	6	0.0010	0.0005
5	8	0.0045	0.0045
6	5	0.0010	0.0000
6	7	0.0018	0.0018
6	11	0.0016	0.0000
7	6	0.0037	0.0037
7	8	0.0018	0.0018
8	5	0.0045	0.0000
8	7	0.0009	0.0009
8	9	0.0073	0.0073
9	8	0.0145	0.0145
9	30	0.0050	0.0050
10	11	0.0009	0.0000
10	13	0.0009	0.0000
11	6	0.0033	0.0016
11	10	0.0009	0.0009
13	10	0.0009	0.0009
13	14	0.0040	0.0000
14	4	0.0052	0.0052
14	13	0.0020	0.0000
14	15	0.0043	0.0043
15	14	0.0087	0.0000
15	16	0.0075	0.0075
16	15	0.0019	0.0019
16	17	0.0036	0.0000
16	19	0.0000	0.0000
16	21	0.0027	0.0027
16	24	0.0012	0.0012
17	16	0.0071	0.0053
17	18	0.0016	0.0016
17	27	0.0035	0.0035
18	3	0.0053	0.0027

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table G.2 (continued)

RELAY		RV	VI
18	17	0.0033	0.0000
19	16	0.0156	0.0156
21	16	0.0108	0.0108
21	22	0.0028	0.0028
22	21	0.0028	0.0028
22	23	0.0019	0.0019
23	22	0.0019	0.0019
23	24	0.0103	0.0103
24	16	0.0047	0.0035
24	23	0.0070	0.0070
25	2	0.0034	0.0017
25	26	0.0194	0.0065
26	25	0.0065	0.0065
26	27	0.0029	0.0029
26	28	0.0095	0.0095
26	29	0.0125	0.0125
27	17	0.0069	0.0000
27	26	0.0088	0.0029
28	26	0.0284	0.0095
28	29	0.0030	0.0030
29	26	0.0375	0.0125
29	28	0.0030	0.0030
30	1	0.0050	0.0050
30	9	0.0050	0.0050

Table G.3 VI for RV Type 4, Zone 3 Vulnerability Region

RELAY		RV	VI
1	2	0.0501	0.0217
1	30	0.0300	0.0300
2	1	0.0300	0.0300
2	3	0.0594	0.0594
2	25	0.0517	0.0388
3	2	0.1155	0.1155
3	4	0.0363	0.0363
3	18	0.0115	0.0098
4	3	0.0393	0.0181
4	5	0.0400	0.0114
4	14	0.0521	0.0160
5	4	0.0680	0.0511
5	6	0.0793	0.0506
5	8	0.1298	0.0986
6	5	0.0374	0.0134
6	7	0.0064	0.0064
6	11	0.1213	0.0992
7	6	0.1049	0.1049
7	8	0.1454	0.0666
8	5	0.0460	0.0281
8	7	0.0129	0.0110
8	9	0.0300	0.0300
9	8	0.0291	0.0291
9	30	0.0300	0.0300
10	11	0.1577	0.1065
10	13	0.1954	0.1192
11	6	0.0875	0.0675
11	10	0.0336	0.0240
13	10	0.0444	0.0421
13	14	0.0656	0.0310
14	4	0.0799	0.0619
14	13	0.1188	0.0899
14	15	0.0169	0.0132
15	14	0.0335	0.0026
15	16	0.1042	0.1042
16	15	0.0304	0.0304
16	17	0.0415	0.0160
16	19	0.0000	0.0000
16	21	0.0168	0.0168
16	24	0.0420	0.0420
17	16	0.0897	0.0838
17	18	0.0186	0.0160
17	27	0.0235	0.0176
18	3	0.0658	0.0151

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table G.3 (continued)

RELAY		RV	VI
18	17	0.0771	0.0213
19	16	0.0721	0.0721
21	16	0.1042	0.0612
21	22	0.0172	0.0172
22	21	0.0243	0.0243
22	23	0.0453	0.0442
23	22	0.0172	0.0172
23	24	0.0106	0.0106
24	16	0.1042	0.0523
24	23	0.0326	0.0326
25	2	0.1701	0.0438
25	26	0.3618	0.1115
26	25	0.0512	0.0237
26	27	0.0242	0.0208
26	28	0.0181	0.0181
26	29	0.0187	0.0187
27	17	0.0267	0.0036
27	26	0.2531	0.0711
28	26	0.3740	0.1330
28	29	0.1000	0.1000
29	26	0.2586	0.0998
29	28	0.0758	0.0758
30	1	0.0575	0.0493
30	9	0.0508	0.0508

Table G.4 VI for RV of phase comparison blocking relay

RELAY		RV	VI
1	2	0.1212	0.0582
2	1	0.1079	0.0582
1	30	0.1212	0.0743
30	1	0.1294	0.0743
2	3	0.0151	0.0000
3	2	0.0151	0.0000
2	25	0.0641	0.0555
25	2	0.0641	0.0555
3	4	0.1385	0.0907
4	3	0.1385	0.0907
3	18	0.4712	0.1807
18	3	0.4489	0.1627
4	5	0.0699	0.0305
5	4	0.0699	0.0305
4	14	0.0129	0.0000
14	4	0.0129	0.0000
5	6	0.0000	0.0000
6	5	0.0000	0.0000
5	8	0.0000	0.0000
8	5	0.0000	0.0000
6	7	0.0000	0.0000
7	6	0.0000	0.0000
6	11	0.0168	0.0043
11	6	0.0168	0.0043
7	8	0.0046	0.0000
8	7	0.0046	0.0000
8	9	0.1415	0.1052
9	8	0.1415	0.1052
9	30	0.1415	0.1165
30	9	0.2389	0.2139
10	11	0.0125	0.0000
11	10	0.0125	0.0000
10	13	0.0144	0.0000
13	10	0.0144	0.0000
13	14	0.0187	0.0043
14	13	0.0187	0.0043
14	15	0.5387	0.2656
15	14	0.5733	0.2869
15	16	0.0217	0.0217
16	15	0.0217	0.0217
16	17	0.1807	0.0995
17	16	0.1807	0.0995
16	19	0.0000	0.0000

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table G.4 (continued)

RELAY		RV	VI
19	16	0.0000	0.0000
16	21	0.0140	0.0140
21	16	0.0140	0.0140
16	24	0.1103	0.0955
24	16	0.1185	0.0955
17	18	0.0514	0.0284
18	17	0.0514	0.0284
17	27	0.5998	0.2550
27	17	0.6198	0.2750
21	22	0.0000	0.0000
22	21	0.0000	0.0000
22	23	0.1001	0.0905
23	22	0.0651	0.0555
23	24	0.0000	0.0000
24	23	0.0000	0.0000
25	26	0.2637	0.1126
26	25	0.2367	0.0945
26	27	0.0320	0.0173
27	26	0.0320	0.0173
26	28	0.0307	0.0307
28	26	0.0307	0.0307
26	29	0.0000	0.0000
29	26	0.0000	0.0000
28	29	0.0000	0.0000
29	28	0.0000	0.0000

Table G.5 VI for RV of overcurrent ground relay

RELAY		RV	VI
1	2	0.0500	0.0500
2	1	0.0000	0.0000
1	30	0.2543	0.0869
30	1	0.0000	0.0000
2	3	0.0086	0.0086
3	2	0.3288	0.3192
2	25	0.1956	0.0351
25	2	0.1720	0.0621
3	4	0.0625	0.0151
4	3	0.0802	0.0756
3	18	0.0151	0.0151
18	3	0.2034	0.0600
4	5	0.1268	0.0688
5	4	0.0358	0.0092
4	14	0.0901	0.0610
14	4	0.0692	0.0137
5	6	0.3692	0.2764
6	5	0.0082	0.0000
5	8	0.0128	0.0000
8	5	0.0659	0.0659
6	7	0.0000	0.0000
7	6	0.1924	0.1924
6	11	0.0767	0.0567
11	6	0.0187	0.0144
7	8	0.0092	0.0092
8	7	0.0853	0.0725
8	9	0.0486	0.0486
9	8	0.0250	0.0250
9	30	0.2511	0.2146
30	9	0.0000	0.0000
10	11	0.0144	0.0144
11	10	0.0849	0.0567
10	13	0.0000	0.0000
13	10	0.1851	0.0868
13	14	0.0086	0.0043
14	13	0.1151	0.0442
14	15	0.0552	0.0108
15	14	0.0377	0.0183
15	16	0.1595	0.1595
16	15	0.0059	0.0059
16	17	0.0288	0.0229
17	16	0.3373	0.1025
16	19	0.2158	0.2158

Note Terminology indicates that relay is at bus X and protects the line that connects bus X to bus Y.

Table G.5 (continued)

RELAY		RV	VI
19	16	0.0000	0.0000
16	21	0.1189	0.0242
21	16	0.0236	0.0236
16	24	0.0265	0.0094
24	16	0.0446	0.0446
17	18	0.0697	0.0094
18	17	0.0497	0.0284
17	27	0.0230	0.0000
27	17	0.0944	0.0470
21	22	0.4149	0.4149
22	21	0.0000	0.0000
22	23	0.0140	0.0140
23	22	0.0350	0.0350
23	24	0.0000	0.0000
24	23	0.2899	0.1214
25	26	0.0086	0.0086
26	25	0.2379	0.0565
26	27	0.0000	0.0000
27	26	0.2778	0.1438
26	28	0.1472	0.0245
28	26	0.0151	0.0151
26	29	0.4759	0.0672
29	26	0.0000	0.0000
28	29	0.1946	0.1946
29	28	0.0000	0.0000

APPENDIX H

Industry survey questionnaire

- (1) System Load (MW) _____
- (2) Please give a short description of the incident. If you have a written description for other purposes a copy would be appreciated.
- (3) Describe the configuration of the system involved. (Attach a sketch if possible)
- (4) Describe the relay or relay system that operated incorrectly.
- (5) Check your evaluation of the relay performance as described below:
 - Correct and Appropriate
 - Correct but Inappropriate
 - Incorrect but Appropriate
 - Incorrect and Inappropriate

(6) The underlying basis for the relay misoperation was error in

Application

Maintenance

Setting

Calibration

Transient

Other

(7) Describe any corrective action you felt would have prevented this operation

(8) If needed, would you be willing to answer some follow-up clarifying question on the telephone ?

If yes, please give phone number, and preferred time of day when might be reached

NAME : _____

COMPANY AFFILIATION : _____

ADDRESS : _____

PHONE : (_____) _____

APPENDIX I
New England 39 bus system data

Table I.1 Bus data

BUS	TYPE	V (pu)	GEN (MW)	GEN (MVAR)	LOAD (MW)	LOAD (MVAR)
1	2	1.00	0.0	0.0	0.0	0.0
2	2	1.00	0.0	0.0	0.0	0.0
3	2	1.00	0.0	0.0	322.0	2.4
4	2	1.00	0.0	0.0	500.0	184.0
5	2	1.00	0.0	0.0	0.0	0.0
6	2	1.00	0.0	0.0	0.0	0.0
7	2	1.00	0.0	0.0	233.8	84.0
8	2	1.00	0.0	0.0	522.0	176.0
9	2	1.00	0.0	0.0	0.0	0.0
10	2	1.00	0.0	0.0	0.0	0.0
11	2	1.00	0.0	0.0	0.0	0.0
12	2	1.00	0.0	0.0	7.5	88.0
13	2	1.00	0.0	0.0	0.0	0.0
14	2	1.00	0.0	0.0	0.0	0.0
15	2	1.00	0.0	0.0	320.0	153.0
16	2	1.00	0.0	0.0	329.0	32.3
17	2	1.00	0.0	0.0	0.0	0.0
18	2	1.00	0.0	0.0	158.0	30.0
19	2	1.00	0.0	0.0	0.0	0.0
20	2	1.00	0.0	0.0	628.0	103.0
21	2	1.00	0.0	0.0	274.0	115.0
22	2	1.00	0.0	0.0	0.0	0.0
23	2	1.00	0.0	0.0	247.5	84.6
24	2	1.00	0.0	0.0	308.6	-92.2
25	2	1.00	0.0	0.0	224.0	47.2
26	2	1.00	0.0	0.0	139.0	17.0
27	2	1.00	0.0	0.0	281.0	75.5
28	2	1.00	0.0	0.0	206.0	27.6
29	2	1.00	0.0	0.0	283.5	26.9
30	3	1.03	1000.0	0.0	1104.0	250.0
31	1	0.982	0.0	0.0	9.2	4.6
32	3	0.983	650.0	0.0	0.0	0.0
33	3	0.997	632.0	0.0	0.0	0.0
34	3	1.012	508.0	0.0	0.0	0.0
35	3	1.049	650.0	0.0	0.0	0.0
36	3	1.063	560.0	0.0	0.0	0.0
37	3	1.028	540.0	0.0	0.0	0.0
38	3	1.026	830.0	0.0	0.0	0.0
39	3	1.048	250.0	0.0	0.0	0.0

Type 1 - Swing bus

Type 2 - Load bus

Type 3 - Generator bus

Table I.2 Line data

LINE	BUS	BUS	R (pu)	X (pu)	Y (pu)	TYPE	TAP
1	1	2	.0035	.0411	.34935	1	--
2	1	30	.0010	.0250	.3750	1	--
3	2	3	.0013	.0151	.1286	1	--
4	2	25	.0070	.0086	.0730	1	--
5	3	4	.0013	.0213	.1107	1	--
6	3	18	.0011	.0133	.1069	1	--
7	4	5	.0008	.0128	.0671	1	--
8	4	14	.0008	.0129	.0691	1	--
9	5	6	.0002	.0026	.0217	1	--
10	5	8	.0008	.0112	.0738	1	--
11	6	7	.0006	.0092	.0565	1	--
12	6	11	.0007	.0082	.06945	1	--
13	7	8	.0004	.0046	.0390	1	--
14	8	9	.0023	.0363	.1902	1	--
15	9	30	.0001	.0250	.6000	1	--
16	10	11	.0004	.0043	.03645	1	--
17	10	13	.0004	.0043	.03645	1	--
18	13	14	.0009	.0101	.08615	1	--
19	14	15	.0018	.0217	.1830	1	--
20	15	16	.0009	.0094	.0855	1	--
21	16	17	.0007	.0089	.0671	1	--
22	16	19	.0016	.0195	.152	1	--
23	16	21	.0008	.0135	.1274	1	--
24	16	24	.0003	.0059	.034	1	--
25	17	18	.0007	.0082	.06595	1	--
26	17	27	.0013	.0173	.1608	1	--
27	21	22	.0008	.0140	.12825	1	--
28	22	23	.0006	.0096	.0923	1	--
29	23	24	.0022	.0350	.1805	1	--
30	25	26	.0032	.0323	.2565	1	--
31	26	27	.0014	.0147	.1198	1	--
32	26	28	.0043	.0474	.3901	1	--
33	26	29	.0057	.0625	.5145	1	--
34	28	29	.0014	.0151	.1245	1	--
35	12	11	.0016	.0435	.0	2	1.006
36	12	13	.0016	.0435	.0	2	1.006
37	6	31	.0000	.0250	.0	2	1.070
38	10	32	.0000	.0200	.0	2	1.070
39	19	33	.0007	.0142	.0	2	1.070
40	20	34	.0009	.0180	.0	2	1.009
41	22	35	.0000	.0143	.0	2	1.025
42	23	36	.0005	.0272	.0	2	1.000
43	25	37	.0006	.0232	.0	2	1.025
44	2	39	.0000	.0181	.0	2	1.025
45	29	38	.0008	.0156	.0	2	1.025
46	19	20	.0007	.0138	.0	2	1.060

Type 1 - Transmission line

Type 2 - Tap-changing transformer on line

Table I.3 Generator data

GEN	BUS	X_d (pu)	H (sec)
1	30	.006	500.0
2	31	.0697	30.3
3	32	.0531	35.8
4	33	.0436	28.6
5	34	.132	26.0
6	35	.05	34.8
7	36	.049	26.4
8	37	.057	24.3
9	38	.057	34.5
10	39	.031	42.0

APPENDIX J
AEP outages

AEP outages

Several of the relay problems listed on Table 2.1 are based upon the authors' familiarity with events occurring in the AEP system, events that were reported in internal AEP memoranda and are not available to the general public.

On a Saturday morning in June 1980, a series of events occurred that could have led to a widespread outage but was prevented from doing so by the light load at the time. A permanent fault occurred within Gavin 765kV station on the Gavin-Marysville line. The line tripped out, reclosed with high speed, retripped, and reclosed with 10 seconds time delay. All of these operations were proper. However, during the first reclose, The Gavin-Mitchell 765kV line tripped incorrectly at Mitchell due to a momentary loss of the carrier signal. At Mitchell, a wiring error resulted in the operation of the breaker failure relay, locking out the Mitchell breakers and sending a trip signal to Gavin. During the second reclose on the Gavin-Marysville line a repeat of the loss of carrier resulted in the Gavin-Amos line tripping at Amos where the breaker did a high-speed reclose. Although this resulted in a out-of-step reclose on the Gavin unit, no damage was incurred and the system was restored.

In May 1973, a blackout occurred in an area of the Appalachian Power Company as a result of an incorrect setting. A backup distance relay had a wrong setting for several months but it was undetected due to the correct performance of the primary pilot-wire relays. At the time of this event, the pilot-wire relays on the adjacent line were removed from service for calibration. A fault occurred and the incorrectly set relay lost coordination, resulting in both the faulted line and the adjacent line tripping. This resulted in overloads on the other lines and subsequent tripping of all lines in the area.

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