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Emergency response system for electric power systems

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Action Logic: A set of *remedial actions*. This includes proper actions for each initiating event under each system operating condition.

Action / Remedial Action: A switching or a control on the network executed by the system operator or automatic device to prevent the *system failure* resulting from the *initiating event* and *post-initiating event*.

Emergency Bids: A price a *load serving entity* asks for having a certain amount of its load cut to meet power system emergency (system failure imminent) need.

Event: One or a series of large disturbances happens to the power system, including system element failure and network switching.

Initiating Event: An *event* consisting of one or more stage of large disturbance that happens to the normally operated power system (no element at fault or out of service), with an uncertainty. *Initiating event* is called *contingency* by power system engineers.

Post-initiating Event: An *event* that happens as a result of protective relay's action following the *Initiating Event*. In this research work, protective relays are assumed to work as designed at the *post-initiating event* stage without any failure.

Cascading Event: An event consisting of a sequence of large disturbances, among which disturbances that occur later in the sequence are the results of earlier ones in the sequence. Cascading event includes both the *initiating event* and the *post-initiating event*.

Load Serving Entity: An entity that buys electric power from the wholesale market (*power market*) and then sells to retail customers.

Operating Condition: A profile of how the energy is flowing in the electric power network. It includes the generation level of each generator, the load level at each load bus, the power flowing through each branch (line and transformer), and the voltage at each bus.

Power Market: The wholesale market where the power producers sell power and the *load serving entities* buy power.

Power System Protection system: The automatic system in electric power network that detects and thus isolates certain faulted (e.g., short circuit) element (e.g., a line, transformer, or generator) in order to keep the rest of the network intact.

Protective Relay: The device (*relay*) that implements the *protection* function. When triggered by certain electric measurements of the power network, it sends a single to a breaker to isolate the faulted element. The protection system for one element may contain multiple relay types.

System Protection Scheme: A System Protection Scheme or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take predetermined corrective action (other than the isolation of faulted elements) to preserve system integrity and provide acceptable system performance [1].

System Failure: Uncontrolled and unplanned losses of system integrity, which include uncontrolled system islanding, uncontrolled loss of major loads, uncontrolled loss of major system elements. *System failure* is identified by system topological change.

System Abnormal Condition: Abnormal system conditions that could lead to a *system failure*. This includes low voltages, line over-loads, transient dynamics, and other abnormal conditions. *System problem* is identified as the value change of analog variables of the power system.

1 INTRODUCTION

Transmission system reliability has been the major concern of the electric power supply, since transmission systems connect the generation sources with demand centers. The interconnected transmission system must be able to continuously and reliably operate within elements and system thermal, voltage, and stability limits, while supplying adequate power to customers. According to North American Electric Reliability Council (NERC) planning standard [1], electric systems must be planned to withstand the more probable forced and maintenance outage system contingency (initiating event) at projected customer demand and anticipated electricity transfer levels. Extreme but less probable contingency (initiating event) should also be evaluated and accounted for by risks and consequences analysis.

Different measurements are utilized to achieve adequate reliability level:

- More transmission lines are constructed to enhance the transmission capability.
- Faster and more sophisticated protection and control devices are armed and better coordinated to protect certain elements of power network.
- Coordinated wide area protections are equipped to prevent system-wide failures, which could not be accounted for by normal protection and control devices.

The modern power system is supposed to be very robust under these sophisticated and well-coordinated measures.

1.1 The need for a new emergency response system

Despite all the measures taken to enhance the overall system reliability, there are always some unpredictable rare events that will lead the system to catastrophic consequences – large area blackouts. And, as the society relies more and more on electricity supply, the interruption cost has increased dramatically [2]. Good examples of these events are listed below. The actual costs for these events are hard to determine due to very large but uncertain indirect economic impact.

On July 2, 1996, a short circuit on a 345-kV line in Wyoming started a chain of events leading to a breakup of the western North American power system. Five islands were formed with controlled and uncontrolled load shedding, uncontrolled generation tripping, and total blackout covering southern Idaho [3].

On July 3, 1996, a chain of events similar to what occurred on July 2, 1996 began to unfold. The IPC (Idaho Power Company) system operators, recognizing the potential for an incident similar to that of July 2, manually shed about 1,200 MW of demand in the Boise area. This action prevented a repeat of July 2's voltage collapse in the Boise area and contained the disturbance to the IPC system [4].

On August 10, 1996, a major failure occurred in the Western Systems Coordinating Council (WSCC) system, resulting in break-up into four islands, with loss of 30,390 MW of load affecting 7.49 million customers in western North America [5].

On March 11, 1999, a blackout caused the loss of 25 GW of load and was the most severe of the Brazilian electric system history. This disturbance affected as much as 74 million people, for as long as four hours [6].

On January 2, 2001, a major grid collapse occurred in northern India, in which over 13000 MW of generation was lost for many hours.

With current normal protection and wide area protection devices, these complicated events are typically too rare to plan for yet too severe to defend against once they happen. In the meantime, these catastrophic events produce such severe impacts that to ignore the probability of its occurrence and not to think of defense strategy is unacceptable. A new emergency response system being capable of preventing and mitigating these rare-but-severe events is of urgent necessity.

1.2 Characteristics of high consequence disturbances

To develop this emergency response system, it would be beneficial to identify common characteristics of these high consequence disturbances. According to [4] and [7], the following characteristics are identified.

Timeframe

These high consequence disturbances usually involve a relative long timeframe. We investigated cascading events in North America based on major blackout data of 1996-1999 from [4], and results indicate, of 14 cascading disturbances, 8 occurred in duration of 30 seconds or less, 1 occurred in duration of between 30 seconds and 5 minutes, and 5 occurred in duration of more than 5 minutes. For the latter 6 events, early effective remedial action could prevent the catastrophic consequence. This characteristic demands accurate long-term simulations during system planning and remedial action design procedure. This is neither required nor implemented in current practices.

Importance of operator knowledge on unfolding cascading events

Because of the long-term feature of these large disturbances, early operator action could have prevented the catastrophic consequence. Consider the disturbance that occurred on July 3, 1996 as an example. The initial event of this disturbance is quite similar as that of July 2. The operator, with the experience of the previous day, knew what would happen if no action were taken. He then took effective action to shed load in the Boise area, and the disturbance impact was mitigated with only a small number of customers affected.

Protective relay performance

Another characteristic is that protective relay undesirable operation is a major contributor to these 'unpredictable' rare events. For example, during both the 2 July and 10 August blackouts of WSCC system, undesirable generator tripping was the main contributing factor to the severity of the disturbances [8]. The undesirable tripping was the result of poor designs of generator over-excitation relay, generator over-excitation limiters, and phase unbalance relay for three-phase thyristor bridge rectifiers. In fact, according to the statistical result of large disturbances in North America from 1979 to 1995 [7], protection problems contribute to about 63% of large disturbances. This fact demands accurate relay modeling in simulations during remedial action design procedure.

Initiating events

Another characteristic is that, almost all these large system disturbances are initiated by some very unusual initiating events, which are too rare to be included in the normal initiating event set during system planning or remedial action design procedure, although

NERC do require considering some extreme initiating events. To make a new emergency response system work, a much larger initiating event set is to be investigated.

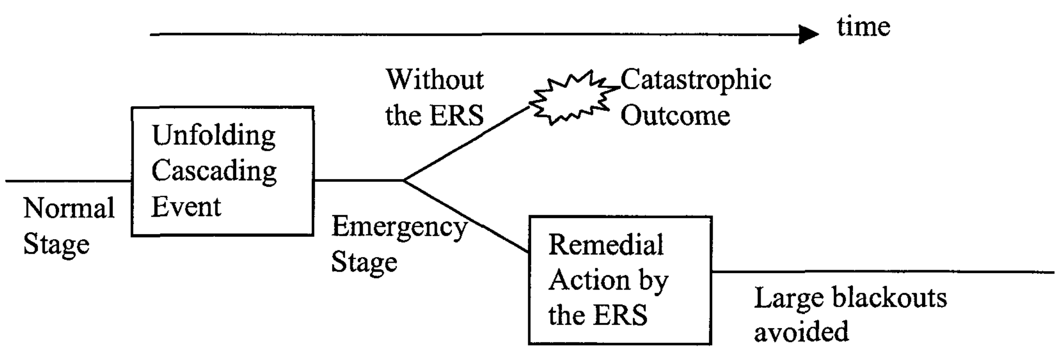
To draw a conclusion, low probability, high consequence events do happen to power systems. At the same time, the catastrophic consequences are not inevitable. Early appropriate action is able to prevent such outcomes. An emergency response system being able to predict the emerging problem and take early action to defend power systems is required and is feasible. The key to the success of this system is its ability of capturing most system failure types, which would require conducting long-term simulation with accurate relay modeling. A much larger initiating event set is also the success key. We refer to such a system as Emergency Response System (ERS).

1.3 An analogy of ERS and TCAS

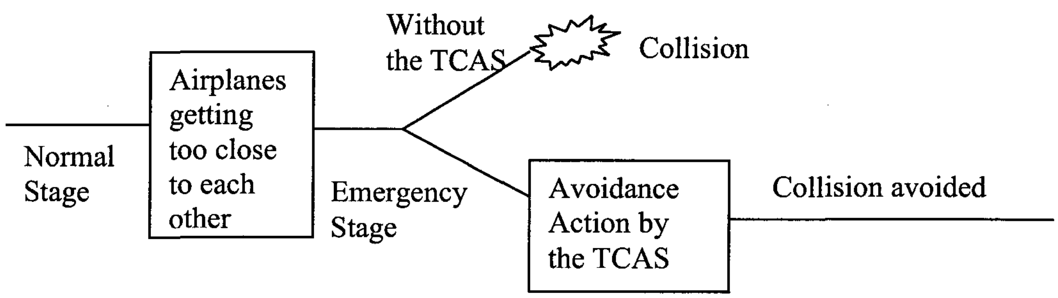
To better understand what ERS means to a power system, an analogy is provided in Figure 1.1. This figure shows the analogy of the ERS and the Traffic Alert and Collision Avoidance System (TCAS), which is used for air traffic control. When two or more aircrafts are going to pass too close to each other, TCAS can detect this emergency situation, sound alarm to each pilot, and provide corresponding action suggestion (to descend or climb) to each pilot to avoid the midair collision.

1.4 Adaptiveness of ERS to power market operations

While the main motivation for designing this new ERS system is to defend power systems against rare-but-severe events, the structure of this new system enables it to be more adaptive to the ongoing power market operations as well. The cost of remedial actions becomes more important with the presence of power markets because of the emphasis on financial competitiveness. Market participants have begun to bid for emergency measures [9]. For example, the bids shows for what cost how much of its load could be cut off from the system. This cost information continuously changes in real time and should be counted for when determining optimal remedial actions.



a. The ERS system in power system



b. The TCAS system in air traffic control system

Figure 1.1 Analogy of the ERS and the TCAS

Under this circumstance, fixed remedial action logics designed by offline calculation may no longer be regarded as appropriate. ERS implements real-time automatic action logic design, which is based on real-time system data, including market data. The remedial action identified by ERS is desirable for power market operations.

1.5 Contribution of this work

In this dissertation, an ERS system is designed, including its physical structure and the approaches to implement its key parts. The core of this system design, a generalized remedial action logic design process, is developed. A demonstrative automatic intelligent action logic design system is constructed to test the ERS system feasibility and its efficiency of predicting and preventing catastrophic outcomes. Corresponding test results are provided. Major improvements of this ERS system over traditional system protection plan are identified. In addition, some important issues regarding implementing the ERS system are addressed; some guidelines are provided for the key implementation steps; some algorithms are suggested and tested by numerical results.

1.6 Organization of the document

In Chapter 2, the basic concepts of System Protection Schemes (SPS) are introduced and most recent improvements on SPS design are reviewed, since the ERS system is evolved from SPS systems. Chapter 3 examines the evolution path of SPS design, derives the framework of the ERS from there, and shows how this new framework makes major breakthroughs over traditional SPS/defense plan. Chapter 4 develops a generalized remedial action logic design mechanism, which is the core of the success of this ERS system. A software-based automated intelligent action logic design system constructed by the author is presented in Chapter 5. The test results show the feasibility and effectiveness of this new ERS system. Chapter 6 describes how to implement some other key elements in the new system, addresses important implementation issues, and presents numerical test results of suggested algorithms. Chapter 7 closes this document by identifying the main contributions of this work and suggesting future works.

2 REVIEW OF SPS

The ERS proposed in this work is closely related to System Protection Schemes (SPS), because both systems need similar power network inputs and produce similar outputs – remedial actions for defending power systems against rare system disturbances and maintain system integrity. ERS can be regarded as an advanced SPS or advanced SPS-formed defense plan.

2.1 SPS and defense plan

A definition of SPS is given in [1]: A System Protection Scheme or Remedial Action Scheme (RAS) is designed to detect abnormal system conditions and take predetermined corrective action (other than the isolation of faulted elements) to preserve system integrity and provide acceptable system performance.

The purpose of installing SPS is to prevent the loss of network integrity characterized by a combination of the following power system performance problems:

- Transient angle instability;
- Small signal angle instability;
- Frequency instability;
- Short-term voltage instability;
- Long-term voltage instability;
- Cascaded tripping.

These problems are further described in [10].

The major control actions of SPS to contain the above problems include:

- Generation rejection;
- Turbine fast valving;
- Gas turbine / pumping storage start-up;
- Actions on the AGC such as setpoint changes;
- Under frequency load shedding (UFLS);
- Under voltage load shedding (UVLS);

- Remote load shedding;
- HVDC fast power change;
- Automatic shunt switching (shunt reactor/capacitor tripping or closing);
- Dynamic braking or braking resistor;
- Controlled opening of interconnection / area islanding;
- Tap changer blocking and setpoint adjustment;
- Quick increase of generator voltage setpoint.

Reference [11] describes all of these actions.

A basic classification of SPS is based on their control variables, by which the SPS is classified as response-based or event-based [11]. Response-based SPS are based on measured electric variables, and basically include UFLS and UVLS. Event-based SPS are designed to operate upon the recognition of a particular event.

Reference [12] discusses the benefits of using SPS from the point of view of utilities and customers respectively, while [11] has a more conclusive statement about the benefits:

- Improve power system operation;
- Operate power system closer to their limits;
- Increase power transfer limit while maintaining the same level of system security;
- Compensate for delays in the construction program;
- Increase the power system security particularly towards extreme initiating events leading to system collapse.

It is hard to identify a definite date of birth for SPS due to the close relationship between SPS and regular protection devices. Reference [13] reports on the first survey on SPS applications. In that survey, a total of 93 schemes were reported in operation in 18 utilities located throughout the world. A later survey was reported in [14], where a total of 111 schemes were reported.

SPS is also regarded as a part of a complete defense plan against different identified extreme initiating events. Defense plans could be defined as a set of coordinated defensive measures whose main purpose is to ensure the overall power system is protected against major disturbances and multiple contingency events [11]. One defense plan includes a group of related SPS devices. The ERS system developed in this work is one type of advanced defense plan. The main difference between the ERS and traditional defense plan is in the action logic design method of event-based SPS units, which is shown in the following chapters. For convenience, unless explicitly stated, "SPS" in this chapter refers to event-based SPS.

References [15], [16] and [17] introduce defense plans in Canada, France and Russia respectively. Reference [18] introduces multiple defense plans including one in Romania. Some SPS implementation and experiences in Canada and America can be found in [19]-[24]. SPS examples in South Africa, Ireland, Yugoslavia and United Arab Emirates are introduced in [25], [26], [27] and [28]. Two SPS from Australia are reported in [29] and [30]. Online calculation based SPS are implemented in Japan ([31], [32]) and China ([33]-[35]).

2.2 Typical traditional SPS mechanism and their performance

Most existing traditional SPS use the mechanism described in Figure 2.1. Numerous calculations are performed offline for many pairs of pre-specified initiating event and operating condition; corresponding optimal actions are determined for each pair to maintain the integrity of the system; an action table is established for all initiating event and operating condition pairs. This table is stored in the SPS before it is put online. Once a initiating event happens to the power system, the device looks up the initiating event and the pre-fault operating condition in the table, finds the pre-determined action for this pair, and then sends out a control signal to execute the action. Undesirable system impacts should be prevented as designed.

Traditional SPS performance could be extended in the following areas:

1) ***Adaptiveness to operating conditions.*** Since all calculation is done offline, traditional SPS must match real-time operating condition to what is stored in the table, which is pre-assumed. This involves a "mis-match" error.
2) ***Adaptiveness of initiating event set.*** Because of the large computational burden, the initiating events they can consider are limited.
3) ***Properness of action.*** Lacking flexibility on the first two areas, traditional SPS sacrifices its accuracy to gain its adaptiveness to various operating conditions. The remedial actions designed for traditional SPS are generally conservative.

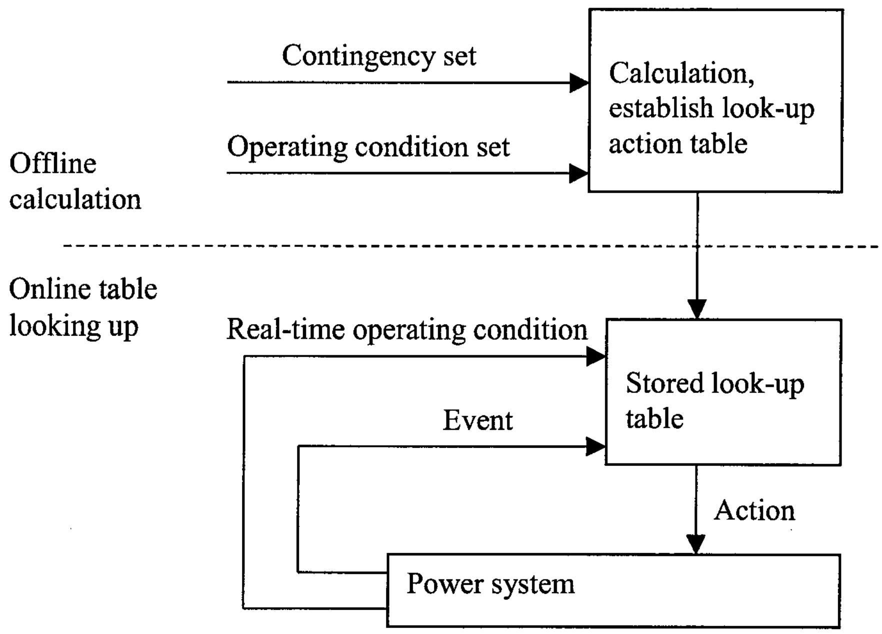


Figure 2.1 Typical SPS mechanism

2.3 New progress in SPS design

2.3.1 Adaptiveness to operating conditions

To address the traditional SPS' weakness in area 1 above, some engineers have developed new SPS that is adaptive to operating condition, utilizing online real-time system data for the decision-making procedure. Reference [32], [33] and [35] introduced implementation of adaptive remedial actions based on online security assessment. They all use direct method and distributed computation to speed up the calculation. Direct method is used in initiating event screening and/or action selection process. The uncertainty of the operating condition is reduced. The remedial action each for initiating events is determined online but before the disturbance.

2.3.2 Adaptiveness to initiating events

References [36]-[39] utilizes Phasor Measurements Unit (PMU) to achieve adaptive SPS. The main philosophy is that, with the help of PMU, we may detect and identify the initiating event and corresponding system dynamics, thus eliminate the dependence on models and enumeration of initiating events. Reference [36] uses energy function based method and reference [37] uses One Machine Infinite Bus (OMIB) based direct method to predict the system stability performance from the initial system trajectory. Reference [38] does the same thing but by using a pattern recognition technique. Reference [39] specially deals with voltage instability. It uses real-time data from PMU to calculate the real-time power transfer margin at different buses, considering voltage instability.

2.3.3 Closed-loop control

Reference [40] proposes an extension to methods described above – closed-loop control. This approach is similar to that of [36]-[38] and also relies on PMU, but its control action is not necessarily a one-time action. After each action, it keeps tracking the system trajectory using PMU to determine whether the action is sufficient and another layer of action is necessary.

2.3.4 Intelligent techniques

Intelligent system is a common way people seek to make SPS adaptive. Reference [41] uses neural network to train the SPS on its action selection. References [42]-[43] use fuzzy technique to provide the operator with decision support. References [38] and [44] use pattern recognition to recognize disturbance, predict the instability, and then find a remedial action. Data mining and temporal machine learning are used in [45] to cope with uncertainties in power systems.

Although these intelligence methods are to some extent adaptive to different pre-fault scenarios, modeling data, or fault location, the training process usually needs large amount of offline calculation results. And, while the validation of their implementation can be checked by simulation, it is not guaranteed that a special case will not be missed.

2.3.5 Dynamic Decision Event Tree (DDET) [46]

Dynamic Decision Event Trees (DDETs) [46] are storage mechanisms for events, system responses, and remedial actions that may occur with a power system. In DDET, scenarios are comprised of initiating events followed by a succession of sequential events and decisions through time. The DDET root node corresponds to the normal (no event) operating conditions as indicated by the current system state. Branches emanate from the root node to first tier of nodes. These first tier nodes represent initiating events, from which emanates a tree of additional nodes and branches that represent succeeding events that occur as a result of the initiating event.

The DDET is similar to the event tree, except for two fundamental differences. First, it includes decision nodes where it is effective and possible to take actions that avoid or mitigate the event consequences. Second, it is dynamic; it grows according to a set of branching rules, and the tree structure, branch probabilities, consequence values, and decisions are updated as necessary to reflect changes in the physical network.

The word 'dynamic' has three implications here. First, the tree for a system is different for different system configurations, so that it changes with time. Second, the system performance as events unfold is governed by differential as well as algebraic equations. Time domain simulation is necessary to construct the tree. The third implication, which is also an attractive feature of DDET, is that the growth and updating processes occur continuously with as much computing power as is available. In addition, trees can be stored. Therefore, when a cascading event begins to unfold, the amount of available information in the DDET can be very large, and the speed with which the action is taken is limited only by the efficiency of the search necessary to find the location in a tree corresponding to the particular situation at hand.

DDET is a basic tool used in implementing ERS. There are two essential questions related to DDET: (a) How to construct it? (b) How to use it? In regard to the first question, how to construct DDET, there are 4 essential features:

1) Simulation engine: Here the main issues are modeling (long-term dynamics and protective relay) and integration method.
2) Event selection: Initial events are selected.
3) Detection of impending system failures.

4) Identifying optimal remedial actions.

We provide only a brief summary of (2) in this work as other ISU researchers have well addressed this topic. We address the modeling issue in (1), and we focus our efforts on (3) and (4). In addition, we address the second question: how to use DDET?

In this dissertation, any single DDET is stored in the form of a table as shown in Table 2.1. This table is filled out during online action logic design process and stored in DDET database. When some disturbance happens, the ERS will search the DDET by looking up this table and find the optimal action to take. Alternative action is stored to make ERS adaptive to real-time action cost information, and its usage is introduced in Chapter 3.

Table 2.1 Example of DDET

Initiating event No.	System failure type	Optimal action	Alternative action
1	Failure 1	Action [1,1]	Action [1,2]
...	...	...	...
n	Failure *n*	Action [n,1]	Action[n,2]

3 EMERGENCY RESPONSE SYSTEM FRAMEWORK

This chapter describes the framework of the ERS. At first a comparison of different system protection paradigms is presented, and certain SPS attributes on which different paradigms perform differently are identified. An ERS conceptual design is then developed in order to achieve better performances on these attributes.

3.1 SPS, defense plan, and ERS

As introduced in Chapter 2, SPS can be classified into two categories: response-based SPS and event-based SPS. A defense plan is composed of a group of coordinated SPS, including both response-based SPS and event-based SPS. Generally, these SPS units are distributed and are set separately with offline calculation without a central control center.

Like a defense plan, ERS also includes a group of coordinated SPS units. However, these SPS units are different from the traditional SPS in three ways. First, these units are coordinated by a control center and receive updated settings and action logics from the control center constantly. Second, ERS uses a more advanced mechanism for the remedial action logic design for event-based SPS units, and this is the major contribution of ERS design. Third, the ERS makes action suggestions to the system operator for long-term system problem. This feature is not available in tradition SPS based defense plan.

In this dissertation, we focus on the development of the event-based remedial action logic design mechanism, because that is the main characterizing difference between the ERS and the traditional SPS/defense plan. The ERS is designed this way because it is always preferred that more disturbances could be mitigated by event-based remedial actions rather than response-based remedial actions. To understand this, let's review the purposes of installing response-based SPS:

- There may occur some unexpected initiating events not included in the initiating event set and/or some unexpected operating conditions. Should these initiating events and/or operating conditions occur, response-based SPS acts to mitigate the impacts.

- Due to inaccuracy of power system components modeling, the simulation used to design the remedial action does not always give the right solution. Under such a scenario, power systems also rely on response-based SPS to mitigate the impacts.

Ref [39] and [48] partially addressed these issues.

The drawbacks of response-based SPS are:

- The time for response-based SPS to take remedial action is usually much longer than event-based SPS, since it has to wait for specific power network measurement to reach a certain triggering level. For example, wait for the voltage at a bus to drop to a triggering value. This drop is the result of some initiating event and can happen much later than this initiating event. Generally, an earlier action can save the power system with less cost, and some system failure can only be prevented if an early stage action is taken.
- It is almost impossible to precisely evaluate the right amount of action to take for response-based SPS. The reasons are: (1) Only local measurements are used to determine the amount of action to take during real-time. Pre-assumed system data were used in determining the settings for action amounts. This determines that the action designed cannot be guaranteed to be appropriate. (2) The action is taken in a 'trial' manner. That is, no simulation is done before applying it to verify the effectiveness of this action under this scenario. As a result, the action taken by a response-based SPS is always conservative, and more than one layer of actions should be designed to establish a closed-loop control to make up this problem. However, this multi-layer action design further prolongs the process of taking remedial actions and reduces the effectiveness of these remedial actions.

As a result, for a defense plan, it is desirable that more system wide disturbances (more initiating events under more operating conditions) can be captured by fast and accurate event-based SPS, thus defense the power system at an early stage.

3.2 SPS evolution and SPS attributes

3.2.1 SPS evolution

No matter what kind of SPS it is, the general decision mechanism is shown in Figure 3.1. Note that the action logic design process can be done either offline or online. However, the mechanisms of obtaining system data, detecting and using disturbance information, and designing remedial action logic have always been improving.

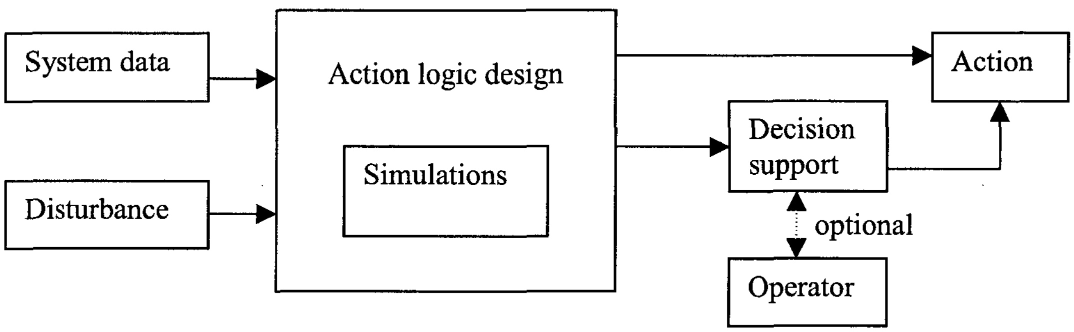


Figure 3.1 SPS decision-making mechanism

Table 3.1 shows major mechanism comparisons along the evolution path of SPS technologies:

- Most existing SPS belong to 'Traditional SPS' category. They are either response-based SPS or event-based SPS. The major characteristic of traditional SPS is that all the simulations and action logic designs are done offline. The system data used for logic design is offline assumed. A look-up table is then created for online use. Real-time operating condition may differ from those assumed data, and 'mis-match' errors may occur while matching real-time conditions to what is stored in the look-up table.
- Online calculation based SPS as presented in [32], [33] and [35] are referred to here as 'Advanced SPS'. They have been extended from the traditional SPS to use real-time system data for developing the action logic. The simulations

Table 3.1 Comparison of different protection paradigms

Increasing level of effectiveness →					
Comparison Aspects	Traditional SPS		Advanced SPS	Emergency Response System (ERS)	Advanced Emergency Response System (AERS)
	Response-based SPS	Event-based SPS			
System condition for logic design	Offline and assumed	Offline and assumed	Partial real-time data, partial assumed	Real-time data	Real-time data
Initiating event set	N/A	Fixed	Fixed, very small	Flexible, very large	Any initiating event
Logic design time frame	Offline	Offline	Online, periodic	Online, Flexibly scheduled	Online, after initiating event
Simulation work load	Heavy	Very heavy,	Relatively light	Medium	Light
Simulation speed requirement	Slow	Slow	Fast	Fast	Faster than real-time

and logic design process are done online. This avoids the operating condition 'mis-match' in Traditional SPS.

- ERS is the work to be introduced in this document. One major characteristic of the ERS is that its initiating event set is dynamic and can dramatically increase in size. The purpose is to defend the power system against a much larger set of system events. To accomplish this online, the logic design process is generalized and automated.

- Advanced Emergency Response System (AERS) is the ultimate goal of SPS/defense plan design. With the fast computation and communication that may be possible in the future, the simulations and remedial action design can be performed after the initiating event using real-time operating condition data, and the execution of the action would still be early enough to mitigate the catastrophic outcomes.

3.2.2 SPS attributes

Identifying the main attributes of SPS will help to provide a design basis for ERS. In this section, SPS attributes are identified. After the ERS conceptual design is presented in the next section, the ERS improvements over traditional defense plan on these attributes are identified.

There are four main attributes for SPS as listed below. Performances of different SPS on these four attributes are mainly determined by the first two aspects compared in Table 3.1.

1) Adaptiveness to network configurations and operating conditions

Whether the action logic is developed based on real-time configuration and operating conditions or on assumed configuration and operating conditions determines how adaptive the SPS is to network configurations and operating conditions.

2) Adaptiveness to initiating events

SPS are often designed to trigger for initiating events that involve multiple outages of power system components. The number of these initiating events that the SPS is prepared for and the sum total of their probabilities determine how adaptive the initiating event set is.

3) Effectiveness of system failure detection during simulation

The percentage of system failure types are detected by the simulation engine of the SPS design defines the effectiveness of its system failure detection function. For example, protection system operations and long-term system instability are not considered during traditional SPS logic design process. As a result, system failures caused by these problems cannot be captured by traditional SPS. As mentioned in Chapter 1, these system failure types comprise a large portion of power system large disturbances.

4) Adaptiveness to online changing criteria factor for action seletion

The criteria for choosing optimal action are according to the action's effectiveness, feasibility, and economic cost (see Section 4.4). One example of changing criteria factor is the economic information such as emergency load-cut bids from Load Serving Entities (see Section 1.4). Whether the remedial action design/selection process accounts for real-time economic information determines how adaptive the SPS is on power market information. Traditional SPS action design does not have this feature.

3.3 ERS conceptual design

3.3.1 The conceptual design

To make major breakthroughs on the four attributes of SPS design, we propose the following ERS conceptual design with new mechanisms that make all these possible. We also design a supplemental physical structure for implementing this ERS system, which integrates the advantages of centralized and decentralized layouts. The conceptual design of ERS is illustrated in Figure 3.2. We describe it in terms of its two basic modes of operation: Anticipatory computing and Response.

3.3.2 Tasks during anticipatory computing mode

During normal operating condition (when there is no disturbance), there are 7 main computation tasks running online:

Management

This task coordinates all the communication between other tasks. It also monitors key ERS features, including the available computation resources, which task is running on which

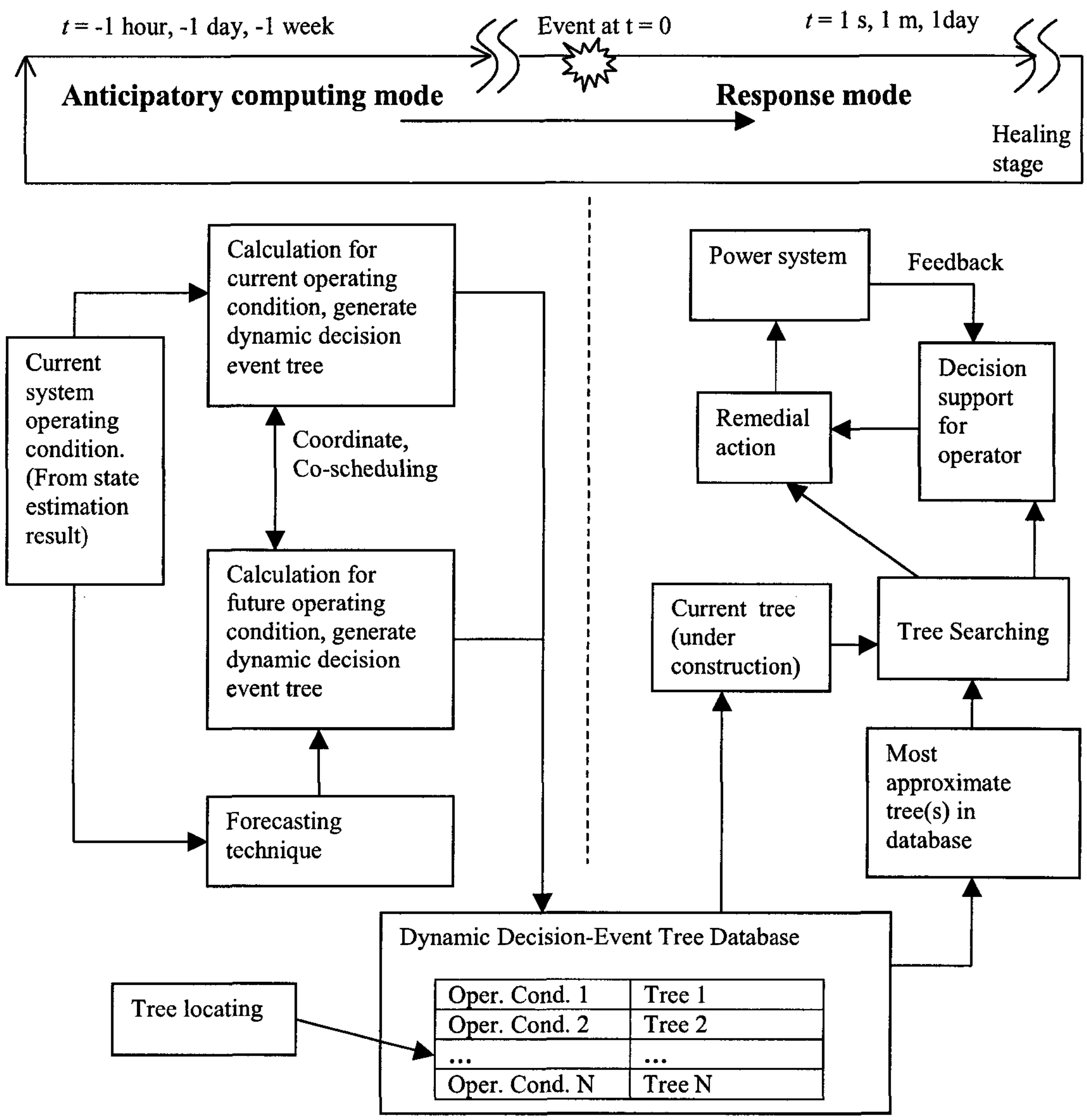


Figure 3.2 ERS conceptual design

CPU, and the information flow. It also provides a graphical user interface (GUI) to interact with the system analyst and operator. It is similar to the manager module in [47].

Forecasting

ERS forecasts the future operating conditions and predicts those of high-risk. The result provides indications for an early DDET tree (see Table 2.1) construction so that a more prepared tree will be ready when the high-risk period comes. This is a critical feature associated with DDET, which makes the ERS adaptive to network configurations, operating conditions, and initiating events. This computation, combined with DDET storage and retrieval mechanism, ensures that there is always a prepared tree that can provide corresponding remedial action/suggestion.

Initiating events selection

The initiating event selection task identifies initiating events of high and intermediate likelihood that may result in a catastrophic outcome. These events are then put into the initiating event set and passed to the 'tree construction' unit for processing. These events comprise the first tier of nodes (first column in Table 2.1) following the root node (original operating condition) in the DDET. The method to select these initiating events is introduced in Chapter 4. The initiating events selection method ensures that most likely catastrophic initiating events are included in the DDET so that ERS is much more adaptive to system initiating events than a traditional defense plan.

Scheduling

The scheduling problem requires identification of how to use available computational resources; at any point in time, the decision must be made: "what to compute next?" There are two types of scheduling tasks:

Scheduling within the same timeframe

After initiating event selection (either for the current condition or some future condition), a task-scheduling function ranks the chosen events. The events are studied by this rank and appropriately located in the DDET.

Scheduling between timeframes

This is a higher-level scheduling function that allocates computer resources between tasks for current operating condition and tasks for future operating conditions.

The overall objective of task scheduling is to maximize the 'readiness' of the system to catastrophic events, where 'readiness' is described in Section 3.6. A proposed scheduling method to achieve this objective is introduced in Chapter 6. By maximizing the 'readiness' of the system, ERS achieves high adaptiveness to system initiating events.

Tree construction

DDET is like an event tree, but with the capability of continuous growth, in the direction of both breadth and depth. Also, the DDET includes decision nodes. Implementation of these actions could be automated for transient problem and could be provided to the system operator as a suggestion for long-term system problems. So, the main computation burdens of DDET construction are system failure detection and remedial action identification.

System failure detection

A system failure refers to uncontrolled and unplanned losses of system integrity, which include uncontrolled system islanding, uncontrolled loss of major loads, uncontrolled loss of major system elements. System failure detection is supported by time domain simulation. During simulation, only system failure triggers the action identification function; minor impacts on power system are not targets for ERS actuation. The method of detecting system failures and the requirements of the time domain simulation are introduced in Chapter 4.

Remedial action identification

After a system failure is detected, the next step is to identify remedial actions to prevent it. This process includes three components: identify the right action type, identify action candidates, and determine the optimal action amount. The types of actions, introduced in Chapter 2, include load shedding, generator tripping, fast valving, dynamic braking, and controlled islanding. The techniques involved in this action logic design process are addressed in Chapter 4.

There are two possibilities for constructing the DDET. Before constructing the tree, ERS checks the DDET database to determine whether a tree constructed under the same or very similar operating condition exists. If it exists, the computation task is to expand the tree to embrace a broader class of initiating events. If a tree does not exist, a new tree is constructed. By this procedure, DDET continues to expand in order to include a large number of system initiating events, and it makes ERS much more adaptive to system initiating events, including those severe rare events.

Alternative actions

When there is a cost associated with the remedial action and some alternative actions are available, we should identify and store these alternative actions in DDET as well. This is for real-time action cost consideration. For example, load serving entities have started to bid for emergency measures [9]. That is, during emergency situation, for what price how much load could be shed to mitigate system emergency. Since this real-time cost information changes often, the optimal action is not necessarily fixed. Should the cost bids from market participants change, all the alternative actions should be reexamined to determine the current optimal action (with least cost). This reexamination process does not take much computation time since no time domain simulation is involved. These simple algebra calculations can be done almost instantly after new emergency bids become available. The real-time emergency cost information is stored in market database and published on ISO's public websites. This adaptive feature was not accomplished by traditional SPS design.

Tree locating

Tree locating is one task that keeps running during normal operation. It tracks the moving trajectory of system operating condition and locates a tree (or trees) in the database which is constructed under the closest operating condition. Thus, at any particular time, ERS knows the "best" tree(s) in the DDET database in terms of operating condition. This task saves time for response-mode operation and ensures that a tree is always available at any time. This feature also increases ERS' adaptiveness to system configurations and operating conditions.

Optimal action update

This task is triggered when any new emergency bids become effective in power market database. Since these emergency bids could change the cost of cost-sensitive remedial actions (mainly and load shedding), an update is necessary to determine the current optimal actions once cost factors change. Since alternative actions were also identified during tree construction process, this update could be done instantly. However, this is a significant improvement over tradition SPS design, and is highly desirable in current deregulated electric power system.

Following some period of online operation, a database of well-constructed DDET trees will be ready for use. At that time, the main computational task shifts from new tree construction to expansion and updating of existing trees.

3.3.3 Tasks during response mode

When an initiating event occurs, at first the ERS checks whether this event is included in the tree that was under construction right before the event and using the most recent normal operating condition. If that is the case, ERS locates the initiating event in the tree and follows the path to find the corresponding impact and suggested remedial action. The impact and suggestion are provided to the system operator for his decision support for long-term system problems. For transient system problem, the remedial action is carried out immediately to prevent the severe impacts.

If the initiating event is not in the most recent tree, the ERS uses the "best tree(s)" that the "tree locating" task provides. ERS provides the impact and suggested remedial actions to the operator in the same way as above, but it also provides the operator with the differences between the recent operating condition and the operating conditions that these trees are based on. The differences are measured by the differences of major values characterizing the operating condition, such as generator output, load level, and tie line flow.

3.4 ERS Improvements

Based on the ERS conceptual design above, we summarize the improvements that ERS makes over the traditional SPS/defense plan on the four SPS attributes.

Adaptiveness to network configuration and operating conditions

Traditional SPS action logic is developed offline using computer models with assumed network configurations and operating conditions. A partial description of the network configuration and operating condition is used as input to the SPS, and SPS action logic is developed accordingly. It is intended that this partial description be enough to fully capture the inputs necessary to maintain effective action logic, but there are always some less important features of the network configuration and operating conditions that are excluded from SPS input but still impact action logic effectiveness. Traditional SPS action logic is not adaptive to changes in these remaining features. As a result, its effect on system performance may differ from what was intended.

ERS overcomes this drawback and is adaptive to network configuration and operating conditions. Unlike traditional SPS, ERS obtains real-time system data and determines action logic based on it. As a result, the action taken is more effective.

As ERS, Advanced SPS also utilizes real-time data for action logic design, and is more adaptive than traditional SPS. However, there is a 'dead period' associated with Advanced SPS. That is, once the system has a big change in its topology because of switching, the action logic must be refreshed. Suppose that the time to refresh the action logic is 5 minutes. If an initiating event occurred during this 5-minute period, no up-to-date action logic would be available. Ironically, this beginning period of a new system configuration is more likely to have initiating events occur, considering that the switching may be undesirable. What is being done today is that a backup action logic table as in the traditional SPS will be activated during this period. Thus, Advanced SPS is not adaptive enough to operating conditions. ERS avoids this 'dead period' inherent to Advanced SPS because the ERS always has a prepared pre-constructed tree available for unexpected outage conditions.

Adaptiveness to initiating events

Both traditional SPS and Advanced SPS use a fixed initiating event set. It is not an adaptive initiating event set and can only capture a very limited number of events. In ERS, however, the DDET keeps growing as long as computation power permits. There are a large number of events that can be captured by the DDET. Furthermore, DDET can be stored and retrieved. So, as similar operating conditions occur, the DDET continues to grow over days, weeks, months, or even years and become quite full. This event tree is much more adaptive than the initiating event set in traditional SPS and Advanced SPS.

Effectiveness of system failure detection during simulation

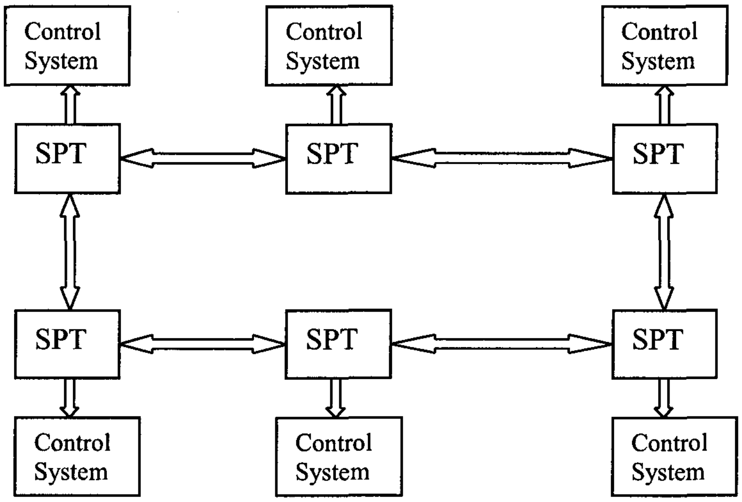
As introduced in Chapter 1, many power system large disturbances are long-term in nature, and protection system operation is a major contributor to cascading disturbances. ERS system makes improvement on incorporating long-term simulation and detailed protective relay modeling. As a result, it is able to provide a much more effective system failure detection mechanism, which is crucial to a successful SPS design. This simulation issue will be introduced in Chapter 4 and some test results can be found in Chapter 5.

Adaptiveness to real-time market information

With online real-time information interchange with power market database, and with alternative actions available in DDET, ERS is able to identify the optimal remedial action based on real-time costs in a very fast manner. It is not accomplished by traditional SPS design.

3.5 Architectural design for ERS

The architecture layout of defense plans can be basically classified into two types: decentralized and centralized architectures. Reference [49] proposes a decentralized system architecture, based on System Protection Terminals (SPT). The SPTs are installed in power system substations, where measurements are taken and actions performed. They are tied together with a high bandwidth communication system as shown in Figure 3.3.



SPT: System Protection Terminal [49]

Figure 3.3 Decentralized architecture based on SPT

SPT gets inputs of local power system measurements, as well as remote measurements and signals from other SPTs. It also receives GPS (Global Positioning system) time synchronizing signals and operator setting inputs. SPT sends output of its measurements and power system information to other SPTs and to the operator. It also sends control action command to substation control system when a remedial action is deemed as necessary.

Reference [50] lists several possible design architectures for defense plans. Emphasis was given to a 'Multi-layered architecture' (Figure 3.4). There are up to three layers in this architecture. The bottom layer is made up of PMUs (Phasor Measurement Unit), or PMUs with additional protection functionality. The next layer up consists of several local protection centers, each of which interfaces directly with a number of PMUs. The top layer, System Protection Center, acts as the coordinator for the local protection centers. This architecture is generally a centralized architecture and integrates protection devices and EMS (Energy Management System, which monitors the power system data in real-time). It is proposed because a comprehensive solution needs the whole system information from EMS [50]. Reference [39] uses this architecture to implement its defense plan.

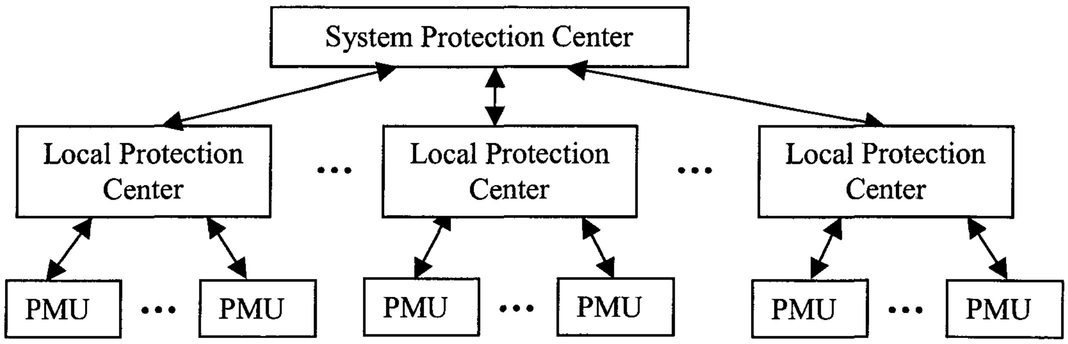


Figure 3.4 Multi-layered architecture for defense plan

ERS uses a centralized architecture design. However, it utilizes similar local units as SPTs in [49], for these local units are interconnected. These SPTs are located at substations. They can perform both event-based and response-based remedial actions. Figure 3.5 shows the architecture of an ERS system. Figure 3.6 shows the information exchanges associated with one SPT in the ERS system.

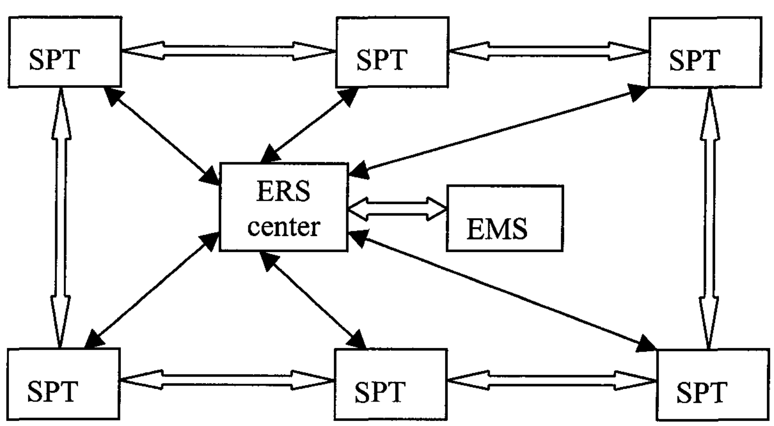


Figure 3.5 Centralized ERS architecture design

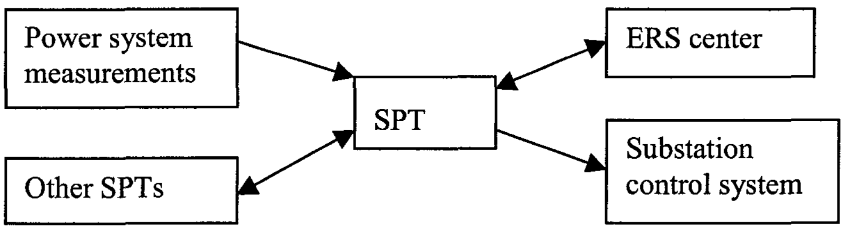


Figure 3.6 SPT information exchange in ERS system

Information flow within the ERS is as follows:

- ***EMS to ERS Center:*** Results of state estimation, weather information, market bids information, and other related information.
- ***ERS Center to EMS:*** Collected local measurements, initiating events occurred, actions taken, real-time phase information from PMUs.
- ***ERS Center to SPT:*** Updated remedial action logic design.
- ***SPT to ERS center:*** Initiating events occurred, actions taken, local real-time measurements, phase measurements.
- ***SPT to SPT:*** Local real-time measurements, initiating events occurred, actions taken.

This architecture design brings the following features to the ERS system:

- Centralized remedial action design use complete system data to guarantee the properness of the remedial action;
- ERS Center constantly updates the optimal actions at SPT according to the changes on system configuration, operating condition, and market bids.
- SPT takes action in a fast manner. With stored updated action table, usually it only needs locally detected initiating event as input to take the right action. When local information is not enough, additional information can be obtained from closest neighbor SPTs.
- Downward information contains action table, which is represented by very limited amount of data and can be transferred quickly.

- Local measurements provide EMS state estimator with reliable data, even with phase information. This largely improves the state estimator performance.

The hardware design and communication protocol should be standard. This is an essential requirement to establish an open system. An open system is able to easily communicate and interact with outside systems. It also has high scalability.

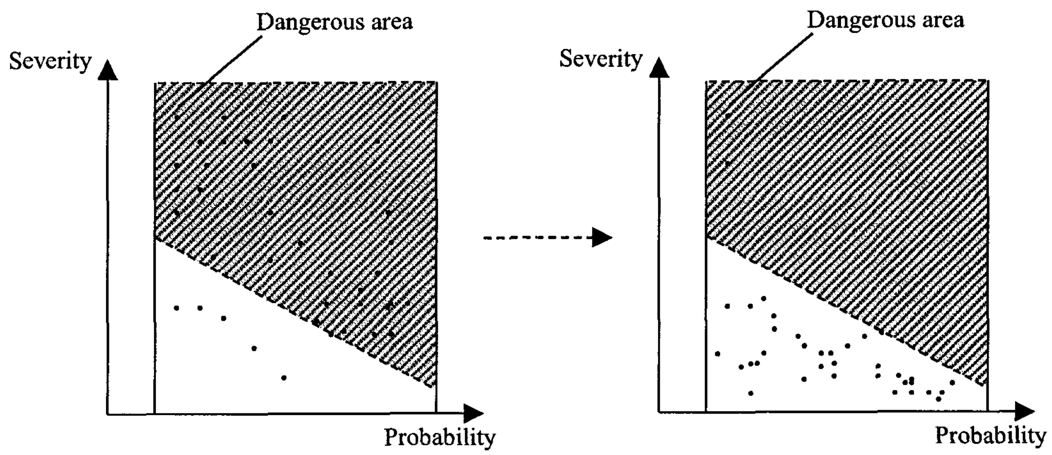
3.6 ERS system optimal operation objective

During the operation of ERS, our optimal performance goal is to maximize our 'readiness' to those high probability catastrophic events for both the current system condition and forecasted high-risk future conditions. That is, of what portion (*in probability*) of all the potential system-failure-causing initiating events the ERS has analyzed.

Advanced SPS presented by [47] has a similar objective. However, it didn't consider the different probabilities for different initiating events. The readiness index of that system is in terms of how many initiating events out of the total number in the initiating event set are analyzed.

One way to understand the ERS objective is per the graph shown in Figure 3.7. In this graph, we put all the initiating events in a two-dimension plane. One dimension represents the probability of the event and the other dimension, severity, represents the event's impact on power system. We put their original distribution in the graph at left and the distribution after some time's action logic design process in the graph at right. An initiating event will move down in the direction of less severity after been processed by ERS, because some action is available for containing this event and thus alleviate the impact. Then, our objective can be clearly described as to move the events out from the dangerous area in a shortest time, or, in a certain time, move as many events out from the dangerous area as possible. Priority should be given to events with high probabilities.

In Figure 3.7, events with extremely low probability are not pictured because they will not be in the initiating event set for analysis. It is clear that after some time, more events move from dangerous area to safe area, and the system becomes less vulnerable.



a. original events distribution

b. distribution after some time

Figure 3.7 Graphical illustration of maximizing readiness

4 GENERALIZED ACTION LOGIC DESIGN PROCESS

Our design of the ERS has all computation performed online though not in real-time. This requires a high computational speed, and as a result, the process must be automated, without human intervention. This chapter describes the design for automating online remedial action identification.

This automatic process is comprised of three stages: initiating events selection, system failure detection, and remedial identification, as illustrated in Figure 4.1. The output of this process is an optimized remedial action for each deserving event in the initiating event set. These actions include both current optimal actions and alternative actions, as discussed in Section 3.3.

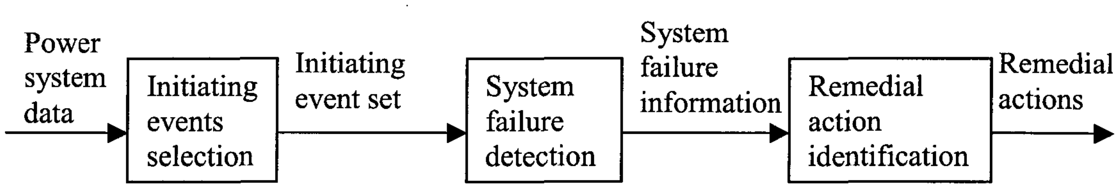


Figure 4.1 Three stages of automatic action logic design

In this chapter, we describe the approach used in selecting initiating events based on the work reported in [51][52][53]. For system failure detection, we specify the requirements for a simulation tool and propose a generalized system detection mechanism. A general formulation for action identification is described.

A list of mostly used terminology is presented at the beginning of this dissertation. The terms frequently used in this chapter are: initiating event, post-initiating event, system failure, and system abnormal condition. An alternative definition for *system failure* is in term of bus voltage magnitude and frequencies. For example, "System failure is when one or more bus voltages fall below 0.7 pu for more than 1 second (i.e., a non- recoverable voltage) or system frequency deviates by more than 0.5 Hz for more than 10 seconds (i.e., a non-recoverable frequency excursion). One feature of this alternative definition is that it is a pure subset of the system failures. It contains no conditions that are not failures; when it is satisfied, it is certain that the system is failed. We prefer our definition because it is a complete set of system failures. Thus, we need not be concerned that some highly undesirable conditions would receive no attention.

4.1 Initiating events selection

As introduced in [11], the current criterion used in industry for selecting initiating events in SPS design is to satisfy system planning rules or other design criteria. For example, NERC planning standard [1] defines 4 categories of system normal and initiating event conditions, for which planning is to be done. However, for categories C and D, which involve component multiple outages or/and cascading outages, it is not clear what is a complete set of such initiating events. Although a guideline is given in [1] to find such credible multi-outage initiating events, utilities and Independent System Operators (ISO) use their experiences to find a very limited set of extreme initiating events to study. This very limited initiating event set is used because offline studies require much human intervention and judgment, resulting in a high cost of human labor.

As will be addressed later in this chapter, ERS automatically performs the complete system study (initiating event selection, system failure detection, and remedial action identification) without human intervention, thus increases the speed of this action logic design process while reducing human labor. Another major improvement inherent to ERS is the expansion of the number of initiating events studied. As long as the computation power permits, more and more initiating events are studied and corresponding action are identified for each resulting in unacceptable performance.

In processing a large number of initiating events, ERS uses risk to prioritize them. High-risk initiating events are those with non-negligible probability and severe system impact. ERS identifies high-risk initiating events based on estimated probability and severity. Probability estimates are made in terms of order of magnitude (i.e., "probability order") based roughly on the number of independent failures necessary to initiate the event. Severity estimates are made in terms of number of components removed from service for the given initiating event. Evaluation of probability and severity in this way requires (a) selection of a single fault location and (b) topological assessment of adjoining substation configurations to determine the number of components to be removed for different levels of protection system reliability. Step (b) is performed using the breaker-switch data as normally available in an Energy Management System (EMS) topology processing applications, and processing that data using a network-search algorithm based on graph theory. This algorithm and associated implementation was developed by Chen in [51] and is not described further here.

This approach results in identifying two kinds of high-risk initiating events:

1) Initiating events resulting in two or more component outages without any protection failure. Such events are high risk because a single failure (e.g. a fault) results in outage of more than one component.
2) Initiating events resulting in outage of 3 or more components from a single fault plus a single protection/breaker failure. Such events have lower probability than those of category (1) but generally higher severity.

A third class of high-risk initiating events are called common mode and include, for example, loss of two lines on the same right-of-way. Such events are identified by inspection and are placed with high priority in the initiating event set.

Simultaneous independent events are not assessed as a result of their low probability and their extremely large number. An example would be two simultaneous unrelated faults. Such events have lower probability than that of category (2) above (fault plus breaker/protection failure). It is emphasized that the above constitute the initiating events only. Subsequent events, e.g., post-initiating event, are identified through simulation.

4.2 System failure detection

The basis for system failure detection is a time domain simulation engine. Without an accurate simulation result, failure detection criteria are meaningless. The first part of this section will specify the requirements for the ERS simulation engine. A sample simulation engine constructed by the author is presented in Chapter 5. The second part of this section introduces a generalized relay based system failure detection mechanism used by ERS. This failure detection mechanism is intelligently designed so that it runs automatically.

4.2.1 ERS simulation requirements

Implementation of the ERS simulator requires distributed computation to provide sufficient analysis speed. This is not a requirement for the simulator itself. However, it naturally increases the preparedness level enabled by the ERS.

There are three basic requirements for the simulator.

1) **Long-term simulation ability:** This requirement is consistent with the industry's perspective of SPS design [11]. However, it is noteworthy that the literature does not reinforce this, suggesting that practical SPS design deviates from this perspective. Reference [54]-[58] describe some simulation techniques of long-term dynamic response. Properly modeling Under Load Tap Changers, load dynamics, turbine-boiler dynamics, and AGC are essential to long-term simulation.
2) **Transmission system protective relay modeling:** Any transmission protective relay that could lead to tripping of components following an initiating event must be represented in the simulator. Some protective relays that must be modeled are:
   - ***Over-current relay.*** Improperly adjusted over-current relay could operate during a stressed but not faulted system operating condition. This is undesirable. For example, many utilities set the pickup of instantaneous over-current relays for a remote end fault at 115% to 125% of the maximum symmetric load current flow with all ties closed at the remote end, and this is not always a valid setting [59] because the relay could operate under extremely high loadings.
   - ***Impedance relay.*** An impedance relay could also operate during a stressed but not faulted system operating condition, which is undesirable. This is caused by the high current and low voltage that is typical of a stressed operating condition. Such an occurrence contributed in the WSCC August 1996 system failure [8]. An impedance relay could also operate undesirably during system dynamics, such as during a strong swing. Blocking impedance relay during the transient can be adopted as a remedial action. This practice is discussed in IEEE Standard for Transmission Line Protection [60]. Blocking out-of-step

relay as a remedial action is used in the WSCC system at Malin substation [61].

- ***Over-excitation relay.*** The over-excitation relay is identified as a major contributor to the 1996 WSCC blackouts [8]. Low system voltage forces generator to over-excite, activating these relays at several plants resulting in generation tripping. Tripping generation further weakened system reactive power support, further decreasing bus voltages. Generator controls should limit the excitation level instead of trip the generator during such scenarios.
- ***Over-excitation limiters.*** Unlike other relays listed here, over-excitation limiter doesn't contribute to the cascading events, yet it needs to be modeled because it plays an important role during simulation. It can be regarded as a control element during simulation instead of a relay.
- ***Out-of-step relay.*** Out-of-step relay could trip either a tie line or a generator [10]. It can be implemented by impedance relay. Out-of-step relay operates during a system unstable condition. It is used by ERS as one indication of system failure.
- ***Underfrequency load shedding.*** UFLS is modeled because it sheds load. Large amount of load shedding is regarded as system failure by ERS.
- ***Undervoltage load shedding.*** UVLS is modeled for the same reason as UFLS.
- ***Traditional event-based SPS.*** ERS treats existing SPS as a normal protective relay as it is activated by a measured network value. The action taken by SPS usually has a significant impact on the power system and must be modeled in simulation.

Other relays can also be modeled. The above relays are listed because they play major roles during system wide disturbances. When manpower is limited for relay modeling, priority should be given to these relays.

3) A "simulation backup" function is also required for ERS simulation. This feature provides that the simulator records some simulation scenarios as the simulation progresses. If afterwards we want to insert an action at some moment and examine its effect on the result, we need not repeat the simulation. Instead, we can 'backup' to the moment we want to insert the action by restoring the saved

snapshot, apply the action, and then resume the simulation from that moment. This feature does not consume tremendous amount of storage because only several snapshots are stored by simulation and they are discarded after a remedial action is identified for this initiating event.

4.2.2 Generalized system failure detection approach

In designing traditional SPS and advanced SPS as introduced in [15], [16], [32], and [33], the problems with the specific system (including angular instability, line overload, and low voltage profile) are known a priori. During online (Advanced SPS) or offline (traditional SPS) design the simulators specifically detect those predicted problems. If these problems occur, corresponding actions are identified to contain them. This approach does not generalize for the case when problems are not known a priori. In addition, since protective relays are not modeled in the simulation, some potential problems (for example, undesirable relay operations) are not detected by these simulators. Unlike Traditional SPS and Advanced SPS, ERS uses a general approach for system failure detection by properly modeling the protection system.

A system failure, no matter it is a large loss of load, loss of a major element, or an uncontrolled islanding, results from the actions of protection systems. Therefore, the ERS uses the relay actions as indications of upcoming system failure. According to their results, relay actions are classified as the following three categories, and corresponding system failure detection criteria are identified:

1) *Branch Trip*

Relays producing this result: Line or transformer protections and out-of-step relays.

System failure to detect: Uncontrolled/unacceptable system islanding.

Upon the detection of a branch trip by a protective relay, the simulator checks whether major islands are formed. If the system is islanded, the occurrence of either of the following two situations is regarded as a system failure:

- The generation-loading imbalance in any of the islands exceeds a specified threshold;

- The islanding formed is not allowed by system operation rules.

2) Load Shedding

Relays producing this result: UFLS, UVLS.

System failure to detect: Large amount of load loss.

Upon the detection of a load shedding by a protective relay, the simulator checks whether the total load loss exceeds a specified percentage of total system load. If the answer is yes, a system failure is detected.

3) Generator Tripping

Relays producing this result: Generator protections and out-of-step relays.

System failure to detect: Large amount of generation loss.

Upon the detection of a generator tripping by a protective relay, the simulator checks whether the total generation-load imbalance exceeds a specified percentage of total system capacity. A large imbalance will cause large load loss eventually.

Independent of whether the protective relay actions produce system failures directly, the scenarios of these relay actions should be saved during the simulation. Once it is identified (through failure detection within the simulator) that one of them is the cause of some system failure, corresponding remedial action will be identified to prevent it according to this stored cause of this protective relay action (Figure 4.2).

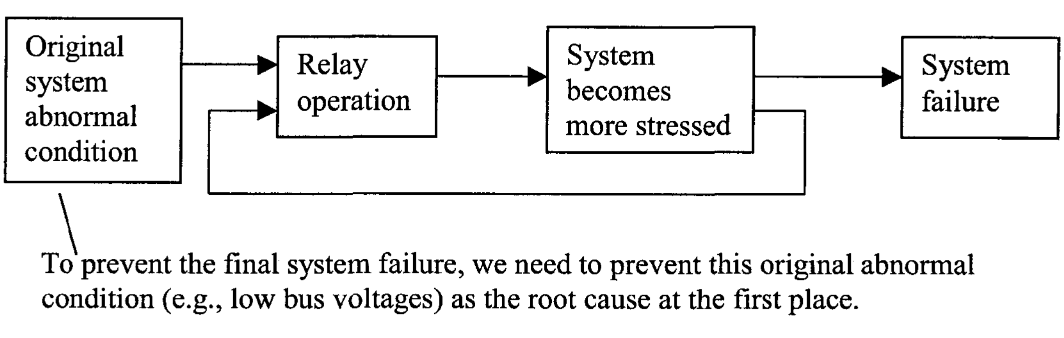


Figure 4.2 Save all the relay action scenarios for future trace-back

4.2.3 Conclusion

In conclusion, with this generalized new system failure detection approach, ERS is able to detect system failures without human intervention, thus making the whole process automatic, which is essential for online implementation. At the same time, with long-term simulation and detailed relay modeling, it is even better than traditional human processed system detection because a much larger number of system failure types, which used to be 'hidden' during traditional system failure detection, can be detected.

4.3 Remedial action identification

For a certain initiating event, with the ERS system failure detection function, system failure is identified automatically. The failure information is then provided to the 'remedial action identification' unit for generating appropriate remedial action.

4.3.1 System failure detection and remedial action identification

System failure detection is not only a pre-step of remedial action identification; it is also an integral part of this action identification, since it is the tool to verify the effectiveness of identified actions. The complete ERS system computation arrangements for processing one initiating event (constructing one branch of one DDET) can be described by Figure 4.3.

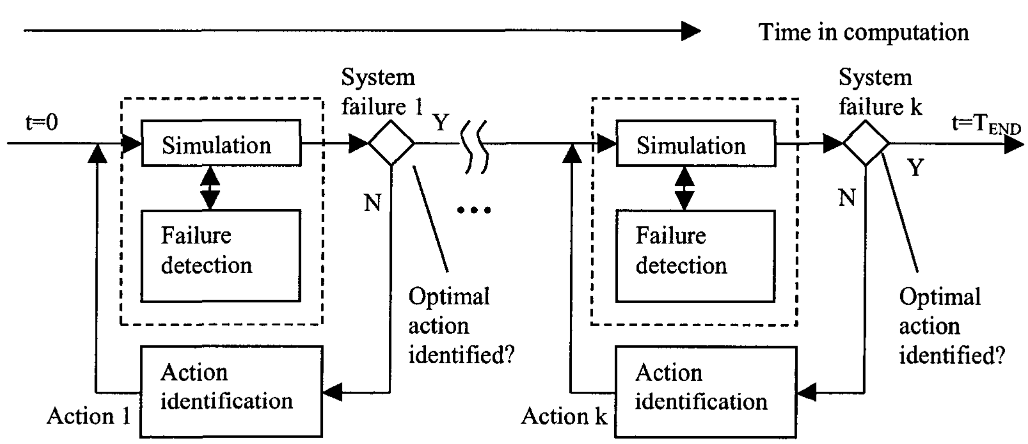


Figure 4.3 'System failure detection' is an integral part of the whole 'remedial actions identification' process

From this figure we see that it is possible to have multiple system failure types for one initiating event and thus require a group of remedial actions to contain them. The output of this process then could be a series of actions along a time span instead of a single one-time action. This nature complicates the action identification task.

In this figure it is clear that 'System failure detection' is an integral part of the 'remedial actions identification' process, because:

1) After a remedial action is designed for every single system failure, simulation based system failure detection is run to verify its effectiveness. The action should be effective (results in satisfactory system performance) and necessary (no less expensive action would have also been effective). This is an iterative procedure for every identified system failure in order to find the right action and its right amount.
2) Initial simulation stops once it encounters the first system failure. And, multiple iterative procedures as in (1) have to be completed until all the system failures are prevented and a final safe system condition is reached by simulation at time T_{END}, which is the pre-specified long-term simulation termination time point. The whole process of simulating for a single initiating event is done in a 'back-and-forward' manner, and involves 'system failure detection' and 'remedial action detection' alternatively.

The time scale in Figure 4.3, from left to right, represents the sequence of computation effort. It does not necessarily represent, although usually it represents, the sequence of events conditions that happen to the power system. We prevent system failures one by one, but failure $i+1$ is not necessary to occur at a time later than failure i in the power system. Instead, failure $i+1$ can be the result of the effect of the actions identified for failure i, and its occurrence can be earlier than failure i, because those actions are executed at a time before failure i occurs.

4.3.2 Source inputs for remedial action identification

The information basis for identifying remedial actions is provided by the simulation tool, which includes system failure type, relay actions that lead to this system failure, and the system abnormal condition triggering these relay actions (see Figure 4.2).

System failure and *System abnormal condition* (see the list of terminology) have different roles during remedial action identification. *System failure* is the trigger of the action identification procedure. Since the ERS is designed for system-wide disturbances, only system failure is of concern. System abnormal conditions, although can, do not always lead to a large system failure, and cannot be used as a trigger for this purpose. *System abnormal condition* is the main input and is the basis of how to identify appropriate actions because the reason for system failure is relay actions, and the reason for relay actions is system abnormal condition. To prevent a system failure is to prevent the original system abnormal condition that causes the final failure at the first place (see Figure 4.2).

All relay actions and their causing system abnormal conditions are stored by the simulation process. From these stored information we can trace back to find the original causing system abnormal condition, and provide it to the action identification unit as an input.

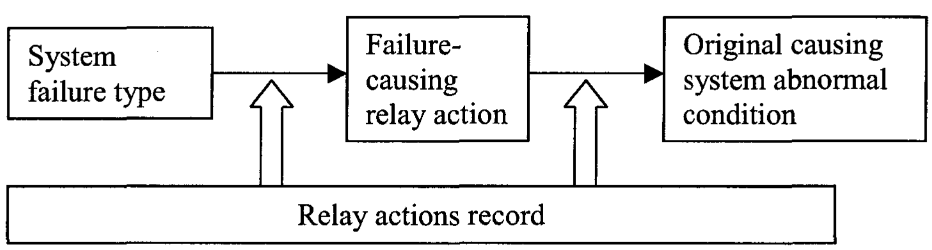


Figure 4.4 Trace back to find the original causing system abnormal condition

4.3.3 General action identification problem formulation

Upon the identification of the specific system abnormal condition by the 'trace-back' process, some action is to be identified to contain this abnormal condition, as shown in Figure 4.5. This process is like the task for a traditional SPS logic designer. In this section, an

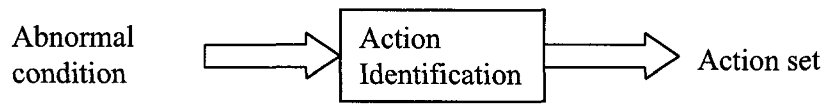


Figure 4.5 Input and output of action identification units

optimization formulation is established to represent this task. At this point, we assume only one system failure is in presence.

Ideally, the general design problem faced by every SPS action designer can be formulated by the following optimization problem:

Optimization problem formulation

$$\begin{aligned} &\textit{Objective:} && Min\ E(A) \qquad (4.1) \\ &\textit{Subject to:} && M(A) \geq \varepsilon \\ & && A \in \Phi_A \end{aligned}$$

Where, E represents the economic cost associated with the actions.

A is an $n \times 1$ vector representing the status/amount of each available action.

M is the safety margin value. When a system failure happens, $M < 0$.

ε is the lower limit for system safety margin.

Φ_A is the feasible value set for vector A.

n is the total number of available actions in the system.

$$A = [a_1, a_2, ..., a_n]^T.$$

Element a_i $(i = 1, 2, ..., n)$ is the value/state of the ith control action. The data type of a_i can be:

- *Real.* For example, threshold setting changes.
- *Discrete.* For example, remote load tripping.
- *Boolean.* For example, shunt switching.

And a value of 0 means 'action is not taken'.

Cost function expression

Function E can be expressed as:

$$E(A) = \sum_{i=1}^{n} E_i(a_i) + R\left(\sum_{i=1}^{n} I_{\{a_i \neq 0\}}\right)$$

where, E_i is the effort/cost factor associated with the ith action.

$E_i(a_i) \equiv 0$ if there is no economic cost associated with this action. For example, setting change.

$E_i(a_i) = k \bullet a_i$ if the economic impact is proportional to the action amount. For example, load shedding for loads with fix emergency bids (same price for different amount of load shedding).

$E_i(a_i)$ is of more complicated form (nonlinear and/or discrete) for actions other than the above two types. For example, load shedding for loads with multi-tier emergency bids.

Function I is a validation function, which is defined by:

$$I_{\{b \in B\}} = \begin{cases} 1 & \text{if } b \in B \\ 0 & \text{Otherwise} \end{cases}$$

R is a monotonically increasing function. It represents the unwillingness to take multiple actions.

The objective function

There are two criteria to achieve this minimization objective. The first criterion is to minimize the expected total economic cost, which is easy to understand. The second criterion is to minimize the number of actions chosen. The reason is that increased number of actions will increase the control complexity and corresponding uncertainties, thus causing security problems.

This formulation also forces the program to seek the most effective actions. Because ineffective action will make both term R and term ΣE_i very high since it cannot contain the system failure by its own, and it needs a large amount to produce working effect.

The constraints

There are two constraints in (4.1). The constraint with action A simply reflects system available actions:

$$\Phi_A = \{[a_1, a_2, ..., a_n] | a_i \in \phi_i, \ i = 1, ..., n\}$$

φ_i is the feasible set of value a_i. Depending on the type of the action and the type of this value, the set can be a region for real numbers (real a_i numbers), a set of discrete numbers (discrete a_i numbers), or an on-off status {0,1} for Boolean values.

In the other constraint, the safety margin M represents the system's security with regard to a potential system failure. This margin is defined as the distance to the corresponding relay triggering threshold. The 'Distance' is associated with relay characteristics. Different definitions are defined for different relay triggering modes. This can be associated with electric value (voltage, current, etc) and/or time value (the duration that a value is within the triggering zone).

4.3.4 Remedial action identification procedure

General analysis

Formal optimization solution methods are generally not easily applied to the previously defined problem because $M(A)$ has no analytic expression, and its evaluation is done by computationally intensive time domain simulations. We use heuristic procedures to solve this problem. There are three steps to the heuristic:

1) ***Action types screening.*** At this step, only certain types of actions are retained for consideration according to specific system abnormal condition. The basis for making this screening is a general knowledge base regarding remedial action functions, which is shown later in this chapter.

2) ***Action candidates' identification.*** This step checks the availability of the action types identified from step 1 in the actual power system. With system topology information and automated search process, limited effective action candidates can be identified.

3) ***Determining optimal action amounts and optimal action.*** This step computes the optimal action amount for each action candidate provided from Step 2. The optimal action is determined by comparing the costs of all action candidates. Other actions are stored in DDET as alternative actions.

Steps 1 and 2 reduce the control variables; Step 3 finds the optimal solution. The three steps are illustrated in Figure 4.6. In [32] and [33], only the last step is implemented. The reason is that their initiating event set is fixed and corresponding action types can be identified offline. The only task online is to determine the action amount. The action identification method introduced here for ERS is clearly more general. Implementation of each step is described in the remainder of this chapter.

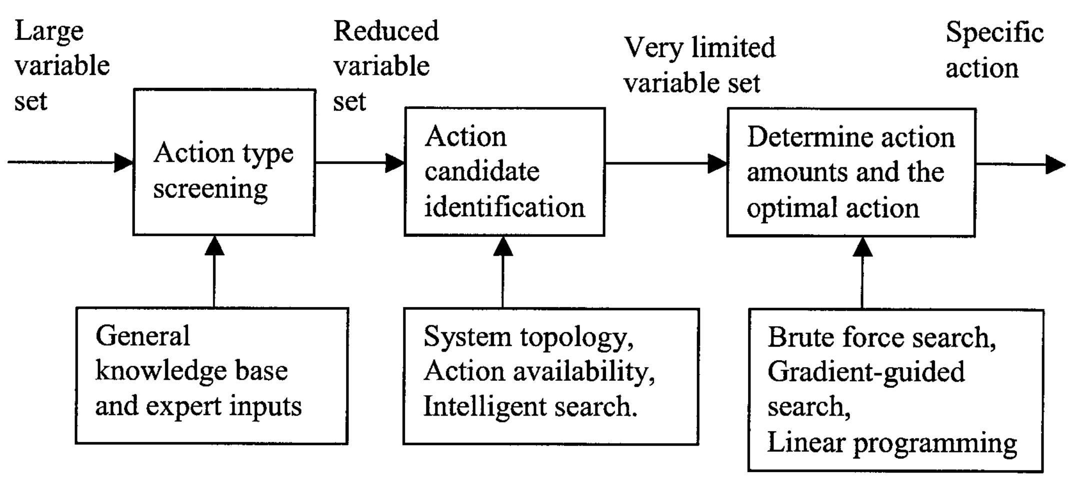


Figure 4.6 Three steps of optimal action identification

Step1: Action type screening

As stated above, with inputs of specific system abnormal condition, such as low bus voltages, the first step is to identify specific type of effective actions using general knowledge base. A table in [70] classifies system disturbances into four major classes – loss of generation, loss of demand, loss of transmission, and loss of transmission causing a system split. The possible impacts of each disturbance are enumerated. Also in the table are possible remedial actions, the time to implement them, and methods and system data required to determine remedial actions. While the structure of this table is good, the containment methods listed in the table are limited to only generation and load adjustment and network reconfiguration. In contrast, reference [11] provides a table with a broader array of remedial action types, as illustrated in

Table 4.1. While the action set listed in this table is relatively complete, the classification of abnormal conditions is too broad for action identification purpose. The events listed in this table are the final outcome of system failures, rather than the abnormal conditions leading to the system failure. For example, an undesirable line trip could cause transient instability, voltage instability, cascaded line tripping, and even frequency instability (when a line trip isolates an amount of load or generation). And the abnormal condition causing this trip can be a severe overloading (causing the operation of an over-current relay) or system dynamic swing (causing an impedance relay undesirable operation). When we design remedial action, what we really need is the identification of the original abnormal condition causing the trip of the line, not just the final system failure type.

Combined the advantages of these two tables from references and adding relay related terms, a new table is created, as shown in Table 4.2. The first row lists the relay actions, as well as the abnormal conditions leading to them, thus produce system failure. The first column lists the type of actions that we could use to mitigate the impact. By relating relay actions to system abnormal conditions, it is easier to identify effective action types from the relay actions records by the system detection software unit.

Table 4.1 Most used SPS actions to counteract power system instability phenomena

Action types / Abnormal condition	Generation Rejection	Turbine fast valving	Gas turbine start-up	Actions on the AGC	Underfrequency load shedding	Under voltage load shedding	Remote load shedding	HVDC fast power change	Automatic shunt switching	Braking resistor	Controlled opening of interconnection	Tap changers blocking
Transient instability	X	X					X		X	X	X	
Frequency instability Frequency diminution Frequency rise	X		X		X			X			X	X
Voltage instability	X		X	X		X		X	X		X	X
Cascade line tripping	X		X	X			X	X				

Step 2: Action candidates identification

With certain types of action identified, the task of this step is to identify existing control locations to serve as action candidates. This requires knowledge of specific power network information in terms of network topology and action location (see Figure 4.7).

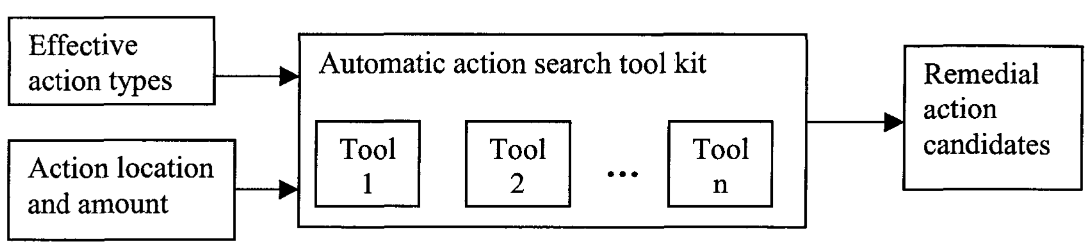


Figure 4.7 Action candidate identification process

Qualified action candidates should satisfy the following requirement:

1) Available for execution;
2) Sufficiently effective for available executable amount.

Table 4.2 Action type selection guide

Abnormal conditions & relay action / Actions	Frequency decrease/ Generation unit off-frequency relay/ UFLS	Frequency increase/ Generation unit off-frequency relay	Voltage deviation/ overexcitation relay action/ UVLS	Transient instability (swing)/ out-of-step relay/ impedance relay action	Overload/ overcurrent relay/ Impedance relay action
Generator tripping		X	X	X	X
Fast valving		X		X	
Gas turbine start-up	X		X		X
UFLS	X				
UVLS			X		
Remote load shedding				X	X
HVDC fast power change	X	X	X		X
Shunt switching			X	X	
Series switching			X	X	
Dynamic braking				X	
Tap changer blocking	X		X		
Controlled islanding	X		X	X	
Transient relay blocking				X	

The automatic network action search is a tool kit that contains different search algorithms for different system abnormal conditions and remedial actions. There are many such tools in the kit. A user can develop their own tool according to their specific requirement.

Examples of these tools follow:

- Load shedding is one effective remedial action for relieving circuit overload. The most effective load can be identified by power flow sensitivity analysis. Loads to which the overloaded line flow is most sensitive are candidates.
- For plant instability, we seek low cost measures, such as plant fast valving, dynamic braking, or series insertion. If these are not available, we consider generator-tripping. Some generator(s) at this plant must be dropped to maintain system synchronism.
- For system instability, as detected by out-of-step condition across ties, we can design controlled islanding schemes to minimize total load loss. The automatic optimal islanding algorithm under development by some other researchers at ISU [71] can be utilized to find the optimal islanding schemes.
- For under/over voltage problems, we first look for available shunt capacitor/reactor to switch in/off, because the cost is almost zero. If that is not available, we shed load for under-voltage problem in the low voltage area.

According to the topology searching methods, there are two search modes:

1) Breadth first search without direction guide

This is the search method for part of nodal problems, where the action has the same qualitative effect in any direction. For example, if we seek a shunt switching for a low/high voltage problem at a node, we search from this node with a breadth-first method considering electric distance, but not direction, as shown in Figure 4.8.

2) Directional search

This is the search method for nodal problems where the action can have a different qualitative effect depending on the direction. For example, we want to shed some load to prevent an undesirable line trip caused by overload, so we search for loads at the direction of the power receiving end, not just to find the closest load (see Figure 4.9). Otherwise, we may select an action that makes the situation worse.

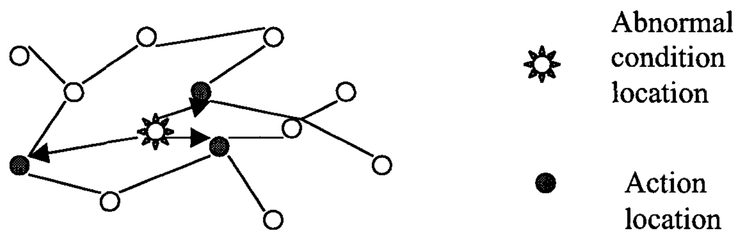


Figure 4.8 Non-directional breadth-first action search

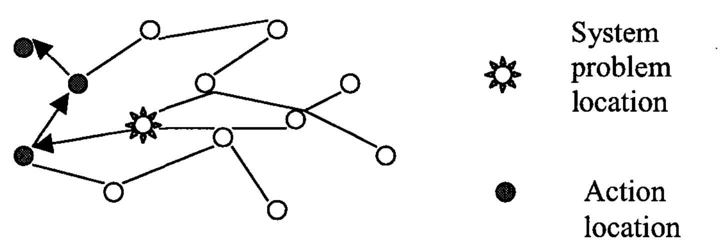


Figure 4.9 Directional action search

<u>Step 3: Determine the optimal action amount and optimal action</u>

Given a set of action candidates, the task of this step is to determine the optimal action amount for each action. After all the optimal amounts of actions are calculated, we can compare the costs associated with these actions and identify the action with least cost as the optimal solution for designated system abnormal condition.

As introduced in Chapter 3, for non-optimal actions, the calculations done are still of value, because there actions are stored in DDET as alternative actions. An alternative action can be an optimal action in a future time, as the cost factors from power market change. Cost comparison is straightforward after optimal action amounts are identified. The focus of this section is to describe the method to find the optimal action amount. The process of determining the optimal amount for a candidate action is illustrated in Figure 4.10.

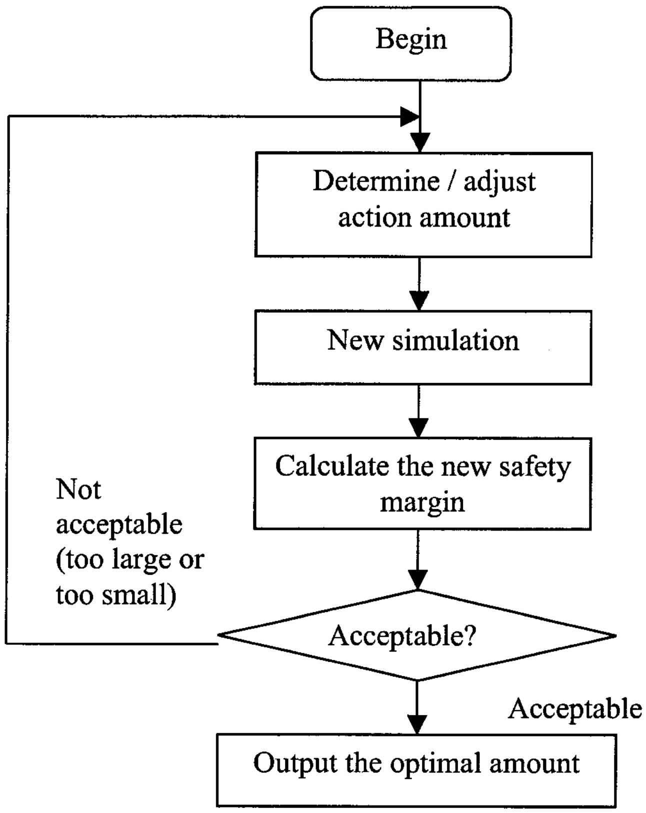


Figure 4.10 Decision process for determining optimal action amount

Every action candidate usually contains only one or two specific actions. At this time, as the number of specific action is fixed, we can ignore item *R* in function *E*. Then, the optimization problem becomes:

$$\textit{Minimize: } E(A') = \sum_{i=1}^{n'} E_i(a_i)$$

$$\text{Subject to: } M(A') \geq \varepsilon$$

$$A' \in \Phi_{A'}$$

Now, n' is a small number, for example, 1 or 2, and A' is an $n' \times 1$ vector.

This simplified optimization problem can be solved by following methods:

1) Binary search

This approach iteratively converges to a desired target margin by adjusting the action as a function of the difference between this target margin and the margin of the last simulation. When the feasible region is very limited (for example, with only one action or very limited discrete feasible options) and no good analytical form of function *M* is available, this is a good and convenient approach.

Here is an example. Assume that *E(A)* is a monotonically increasing function of *A*. Then, to minimize *E* is to minimize *A*. We can try some values of A by putting this action in the simulation program and then adjusting its value as a function of the resulting margin. If margin is too large, reduce costly action; otherwise, increase the costly action. This binary search process goes on until a certain accuracy of A is achieved, as shown in Figure 4.11.

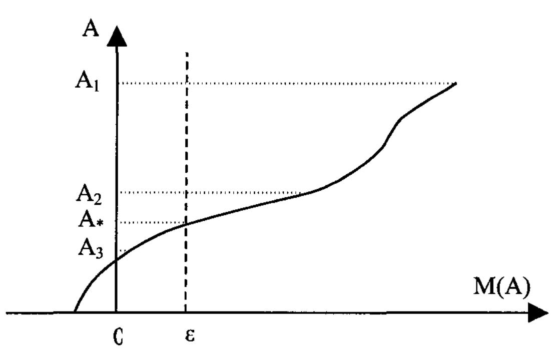


Figure 4.11 Binary search algorithm to find the optimum

2) Direct analytical solution

Sometimes function *M* is an explicit and known function of *A*. Suppose that *M(A)* is monotonically decreasing and Function *E(A)* is monotonically increasing with respect to *A*, we can find the optimal action amount at a specific point of *M*. We directly obtain the optimal action amount by solving equation: *M(A)* $=\varepsilon$. One example is: when we have an accurate and complete voltage-power nose curve for one load node, we can directly find the optimal load to shed in one step [39][48].

3) Gradient-based iterative method

If at each point, the gradient information (sensitivities of E and M to A) can be obtained, a Gradient-based direct climbing algorithm can be used to find the optimum. Although the form of function E is likely to be simple, the form of M is always implicit. So, unlike the problem of nonlinear objective with linear constraints, which has most of its difficulty in dealing with the objective function, the difficulty with this nonlinear programming problem lies with the one nonlinear constraint on margin $M(A)$. Correspondingly, while it should be easy to find the 'steepest' direction, it is hard to judge the boundary of the feasible region and to determine the step size to climb in order to keep every point within the feasible region. Under this circumstance, the gradient information of margin can be used, with some other heuristic rule, to judge good step sizes. In this optimum problem, the optimum will locate at the boundary of the feasible region. That is, the margin will be at its lower limit.

If function E and M can be approximated by a second-order polynomial, the Newton method based climbing algorithm can be used. A larger step size can be used and the optimal can be obtained with fewer iterations. We can obtain this approximate second order information once we have at least three simulation runs, as the algorithm used in [69].

4) Alternative methods

Some alternative methods can also be considered. These methods are provided here for completeness, and they are not tested in this work.

(a) Interior point algorithm

When function M is in analytical form, we can use interior point algorithm as used in the optimal power flow problem [72]. That is to represent the inequality constraints in the object function with logarithmic form, having barrier parameters as their weight. The original optimization problem becomes one without inequality constraint and can be solved by Lagrangian method. The barrier parameters need to be adjusted toward zero while solving this optimization problem iteratively by Newtown's method or Gradient method.

(b) Solution by linear programming

As we know, although function E is likely to be in a linear form, function M is usually not. However, if we have sufficient sensitivity information at sufficient points (this is not always easy to obtain), we can approximate M as a piecewise function of A. For example, assume that the optimization problem with two actions can be simply formed as below:

$$\begin{aligned}
&\textit{Minimize:}\ \ E(a_1, a_2) = f_1 * a_1 + f_2 * a_2 \\
&\textit{Subject to:}\ M(a_1, a_2) \geq \varepsilon \\
&\qquad\qquad\ 0 \leq a_1 \leq U_1 \\
&\qquad\qquad\ 0 \leq a_2 \leq U_2
\end{aligned}$$

where: U_1, U_2, are the upper bounds of control 1 and 2 respectively. E is linear and f_1 and f_2 are constant factors.

Now, divide a_1 and a_2 into pieces and represent M with piecewise function.

$$\begin{aligned}
a_1 &= a_{11} + a_{12} + \ldots + a_{1m} \\
a_2 &= a_{21} + a_{22} + \ldots + a_{2n} \\
M &= \sum_{j=1}^{m} k_{1j} \cdot a_{1j} + \sum_{j=1}^{n} k_{2j} \cdot a_{2j} + C
\end{aligned}$$

where C is a constant term. The new optimization problem is converted to a linear programming problem:

$$\begin{aligned}
&\textit{Minimize:}\ \ E(a_1, a_2) = f_1 \cdot a_{11} + \ldots + f_1 \cdot a_{1m} + f_2 \cdot a_{21} + \ldots + f_2 \cdot a_{2n} \\
&\textit{Subject to:}\ k_{11} \cdot a_{11} + \ldots + k_{1m} \cdot a_{1m} + k_{21} \cdot a_{21} + \ldots + k_{2n} \cdot a_{2n} \geq \varepsilon - C
\end{aligned}$$

$0 \le a_{11} \le U_{11}$

$\dots$

$0 \le a_{1m} \le U_{1m}$

$0 \le a_{21} \le U_{21}$

$\dots$

$0 \le a_{2n} \le U_{2n}$

However, some additional constraints are necessary for this problem. There is a certain sequence of these segments: $a_{1,i}$ can only be nonzero when $a_{1,i-1}$ is at its upper limit $U_{1,i-1}$. This is not easy to express by linear constraints. This can be automatically achieved if we add the following penalty term to the objective function:

$$P = B\left[\sum_{i=2}^{m} a_{1,i}\left[U_{1,i-1} - a_{1,i-1}\right] + \sum_{i=2}^{n} a_{2,i}\left[U_{2,i-1} - a_{2,i-1}\right]\right]$$

where B is a very big number so that if any term is nonzero in the summation term, P will be a very big number. The solution of the following linear programming problem should give the real optimum we need. The new complete new optimization problem is:

Minimize: $E(a_1, a_2) = f_1 \cdot a_{11} + \dots + f_1 \cdot a_{1m} + f_2 \cdot a_{21} + \dots + f_2 \cdot a_{2n} + P$

Subject to: $k_{11} \cdot a_{11} + \dots + k_{1m} \cdot a_{1m} + k_{21} \cdot a_{21} + \dots + k_{2n} \cdot a_{2n} \ge \varepsilon - C$

$0 \le a_{11} \le U_{11}$

$\dots$

$0 \le a_{1m} \le U_{1m}$

$0 \le a_{21} \le U_{21}$

$\dots$

$0 \le a_{2n} \le U_{2n}$

Once again, although this linear programming problem is easy to solve, to get this piecewise linear information we need the sensitivity information at many points, and this is not a trivial computation task for most cases.

4.4 Summary

This chapter introduced three major steps for a generalized intelligent action logic design process – initiating events selection, system failure detection, and remedial action identification. For remedial action identification, there are three steps involved – action type screening, action candidate identification, and optimal action amount determination. Corresponding algorithms are recommended for different steps.

5 AUTOMATIC ACTION LOGIC DESIGN DEMONSTRATION SYSTEM

To illustrate the feasibility and the effectiveness of the automatic intelligent action logic design process proposed in Chapter 4, a demonstration system is constructed. Corresponding results are examined on a simple test power system. This demonstration system is a software-based package that implements steps 2 and 3 in this automatic process – system failure detection and remedial action identification. Step 1, initiating events selection, will appear in the works of other ISU researchers. Their results, an initiating event set, can be passed to this software as its input. The two packages are constructed in one Visual C++ workspace and can easily exchange data. The execution file runs on Windows based PCs.

5.1 System specifications and features

This section provides the specifications and features of the software application designed to implement the ERS. The execution speed of this system is also reported.

5.1.1 System specifications:

Specifications are made in term of inputs, outputs, and margin setting.

System input

1) ***Power system data.*** This includes the following:

- Steady state analysis data (system topology, buses, generations, loads, branches);
- Dynamic data (generator parameters, exciter, governor, dynamic load);
- Relay data (type and settings);
- Available remedial actions data.

2) ***Initiating event set.*** This can be received from the initiating events selection program.

3) ***Different operating conditions***. This is provided to the program in terms of generation and load levels.

System output

1) Optimal remedial action (if applicable) for each initiating event in the initiating event set under the given operating condition.
2) Alternative actions for each initiating event, if available.
3) Simulation progress reports. This includes events sequences (relay actions, exciter limiter actions), action search trials, and system failure types.
4) Time domain trajectory of specified values.
5) CPU time consumed by each initiating event.

Margin setting

Safety margin lower limit is set to 5%. That is, after applying the remedial action, the failure triggering relay should not be triggered if we adjust its settings (e.g., triggering voltage for UVLS, triggering impedance for an impedance relay) by 5% towards the direction that is easier to trigger the relay.

5.1.2 System features

This demonstration system has the following features:

1) Given initial operating condition and initiating event set, the entire remedial action logic design process is done automatically without human intervention or additional human inputs.
2) A general relay action based system failure detection approach is used. This enables the automation of system failure detection process.
3) Action type screening and action candidate identification is done automatically according to general knowledge and actual power system data. Although only a limited number of action choosing methods are developed, other methods can be integrated in the structure easily because of the open structure of this software.
4) Optimal action amount search is done automatically by binary search (see Section 4.4).

5) Relays are modeled to accurately capture relay actions and their effects on power system performance.
6) Long-term simulation is implemented to detect long-term power system failures and thus provide action suggestions to the system operator that are appropriate for the long-term.
7) Optimal remedial action is determined by considering the associated costs. Alternative remedial actions are also identified and stored for future use.
8) System implements generator and control dynamic models, including exciter, governor, and dynamic load.
9) Selected simulation snapshots are stored along with simulation process. A simulation can be backed-up (see Section 4.3) to one such snapshots for the purpose of inserting an action. Further simulation starts from this snapshot instead of time 0.

5.1.3 Execution speed

The executable file is run on PCs with Intel® Pentium® III Processor (500 M Hz). The test power system has 6 buses and 4 generators. For an uninterrupted 600-second simulation run, the average computation time is around 45 seconds. When a system failure is detected and remedial action is necessary, the total processing time for one initiating event, including simulation and action design, varies from 48 seconds (for an early stage system failure) to more than 200 seconds (for cases requiring multiple actions and thus more action trials).

Sparse techniques ([73]-[76]) and network reduction ([77]) techniques are not used in this program due to labor constraint. The computation time would approximately increase proportionally with respect to the square of the size of the system. The simulator can be replaced by any faster commercial simulator once it is available.

5.2 Program flowcharts

The main program flowchart is outlined in Figure 5.1. The block 'remedial action identification process' in Figure 5.1 is expanded with great detail in Figure 5.2.

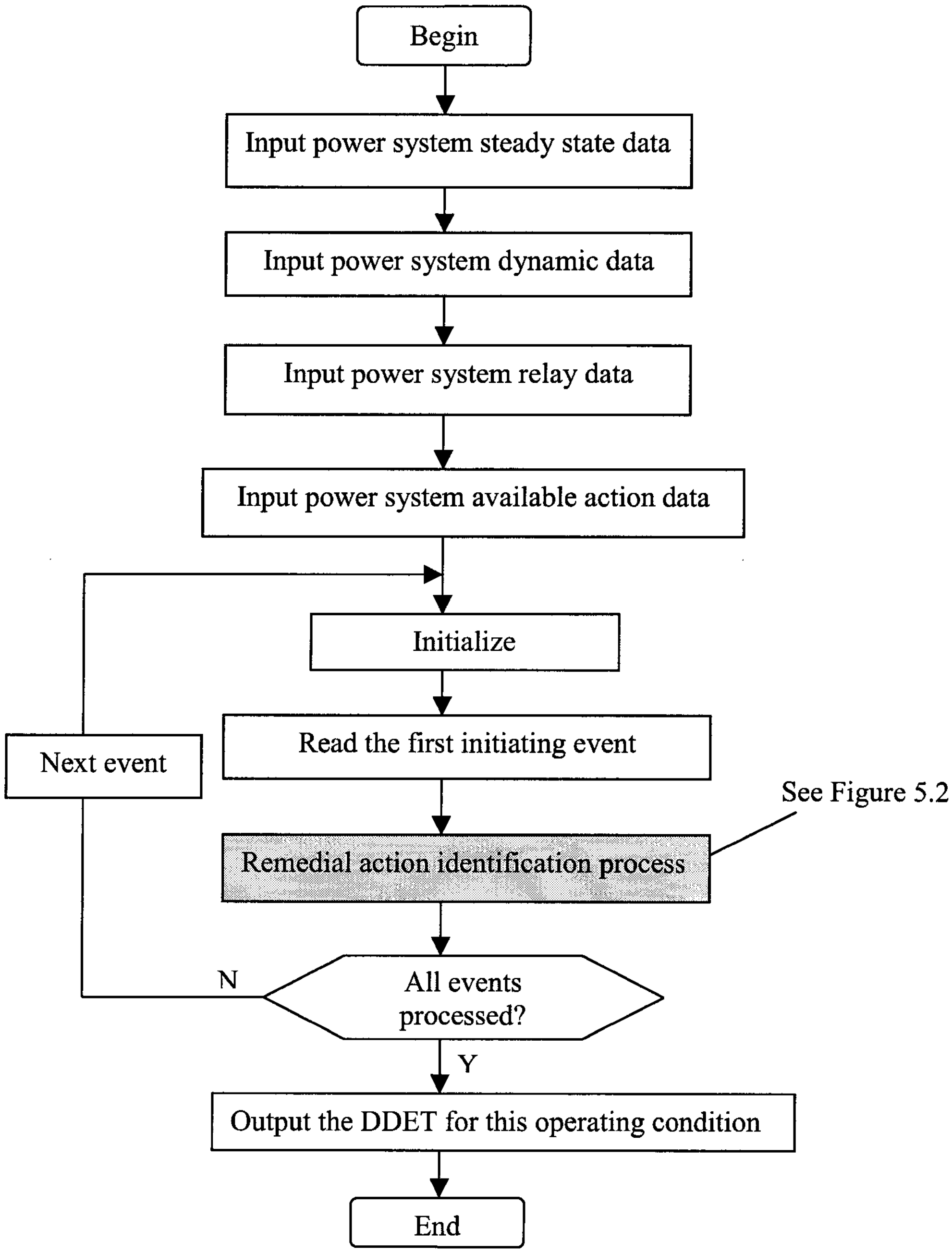


Figure 5.1 Demonstration system program flowchart

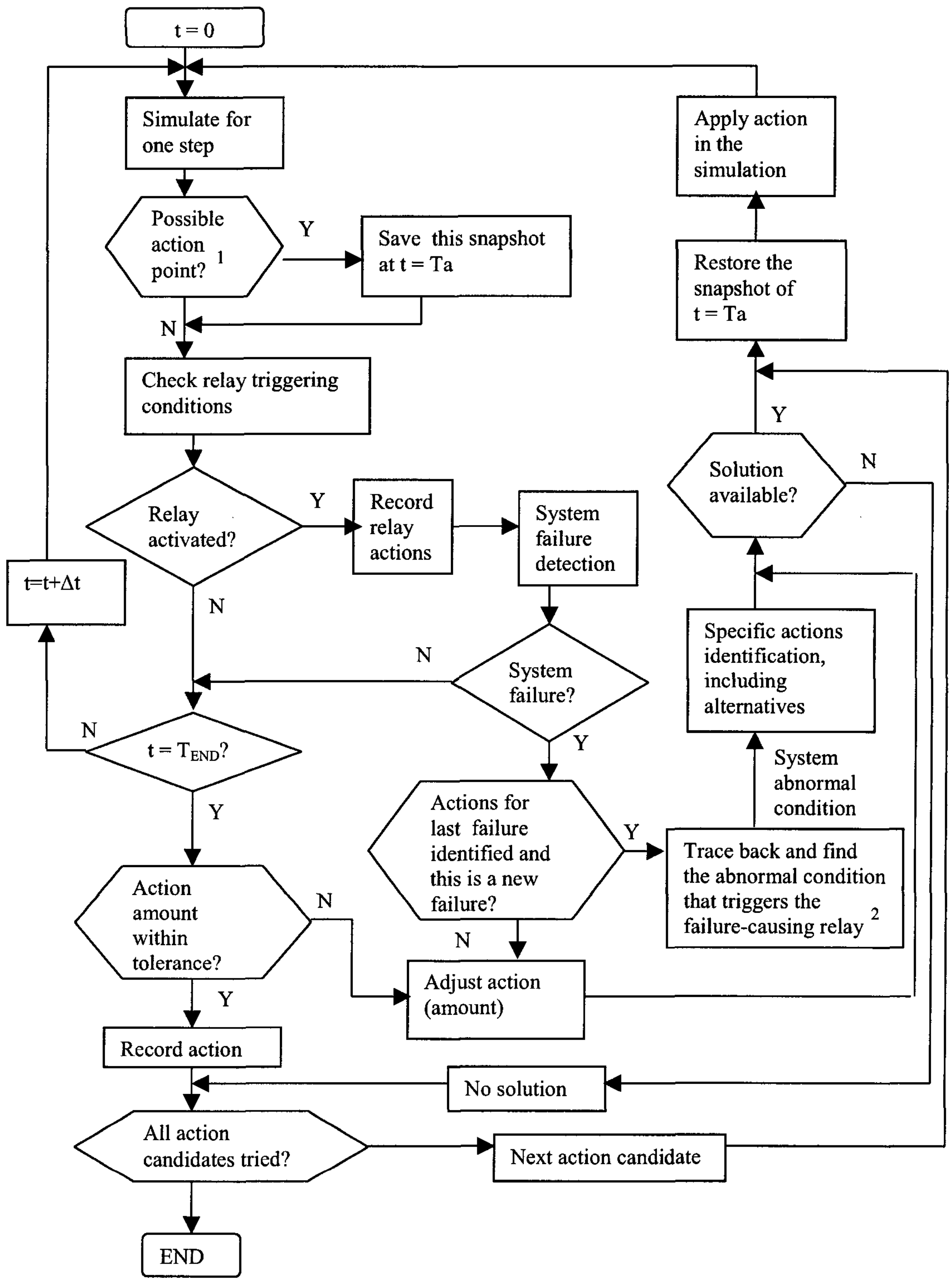


Figure 5.2 Remedial action identification process flowchart

5.3 Control models

To properly model the power system, some controls are represented in the simulator. We generally choose relatively simple models for these controls so as not to become overly occupied with this task, but there is no reason why a full array of such models could not be provided, given the necessary investment in labor.

Simplified governor model

A simplified governor model from [10] is used. The block diagram is shown in Figure 5.3.

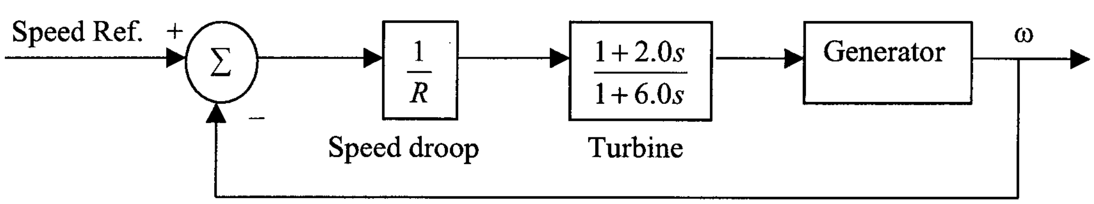


Figure 5.3 Simplified governor model

Simple exciter model

A simple exciter model for an alternator-fed SCR (silicon controlled rectifier) excitation system from [78] is used, as illustrated in Figure 5.4.

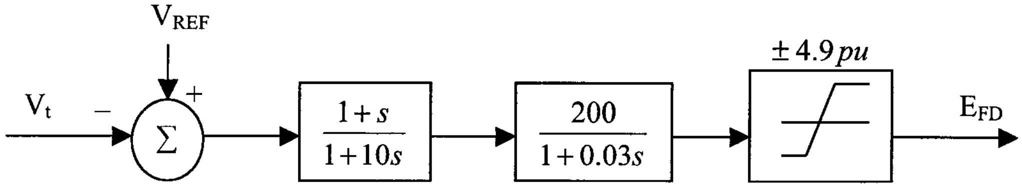


Figure 5.4 A simple exciter model

Thermostatically controlled dynamic load model

A simple model for thermostatically controlled loads from [10] is used, as shown in Figure 5.5. This type of load can exacerbate the system voltage problem during a long-term low voltage profile.

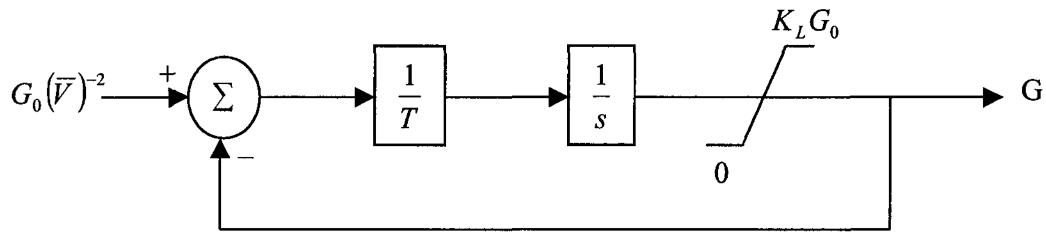


Figure 5.5 A simple model for thermostatically controlled loads

Relay models

Due to the limitation on labor, relays modeled in this demonstration system do not compose a complete set of power system protective relays. These relays are modeled because they are known as the most problem-causing relays during power system large disturbances. Examples of relays not modeled in this software are R-Rdot relay, bus differential relay, Under-frequency load shedding relay, and generator out-of-step relay. These relays can be added to the simulator in the same manner if addition labor investment is available.

Line impedance relay

Impedance relay is widely used for transmission lines. The common practice in the United States has been to use separate distance units for the several protection zones [79]. In this demonstration system, Zone 1 protection is not modeled. The reasons are: (1) Zone 1 protection trips a line instantaneously after the detection of a fault. Even if this is an undesired operation, there is no time for a remedial action to respond and prevent this trip. (2) Based on the initiating event selection criteria, we assume that there is no failure from Zone 1 protection in post-initiating events.

A typical setting for Zone 2 protection is about 120% of the impedance of the protected line, with a time delay of 0.3 to 0.5 seconds [10]. In this demonstration system, Zone 2 protection is modeled. The setting is set to 120% of the impedance of the protected line, with a time delay of 0.5 seconds. A directional impedance characteristic [79] is used, as shown in Figure 5.6.

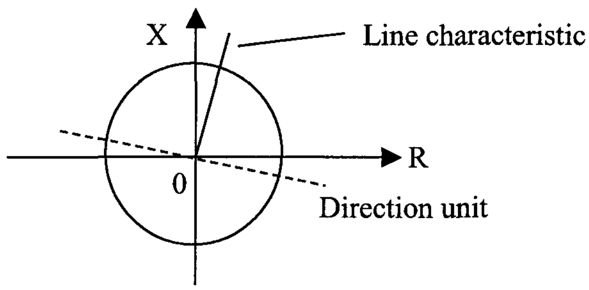


Figure 5.6 Directional impedance relay characteristic

Line over-current relay

Some utilities also use over-current relay in transmission line protection [59][79][80]. In this work, over-current relays are modeled at selected lines with a setting of about 1.5 times of the maximum load. This type of over-current relay usually has time-inverse characteristics [79]. To model it, multiple setting-time pairs can be used. In order to simplify the model, one time delay of 5 seconds is used for approximately 1.5 times the maximum load setting.

Generator over-excitation protection relay

Over-excitation of a generator will occur whenever the ratio of the voltage to frequency (volts/ hertz) applied to the terminals of the generator exceeds 1.05 pu [81]. The relay detects high volts/hertz ratio and can have one or dual fixed time delays. It can also perform according to time inverse characteristic. In this demonstration system, a fixed time over-excitation relay is used with a setting of 120% volts/hertz ratio and a time delay of 5 seconds.

Under-voltage load shedding

Normally, a UVLS will operate and trip a feeder circuit breaker when the input level decreases below a pre-set threshold for a time longer than a few seconds

[11]. According to [82], typical time delay is 3.5 to 8 seconds. Although load shedding is often initiated in steps, this demonstration system uses a one step load shedding to test the impact of this relay. Time delay is set to 5 seconds.

Automatic shunt switching

Like under-voltage load shedding, automatic shunt switching is a type of response-based remedial action [11]. One example can be found in [61]. An auto-closing of a capacitor bank is modeled in this test system, which automatically switch in a capacitor when the voltage drops below 0.9 pu for 5 seconds.

5.4 Test system description

A 6-bus 4-generator power system is designed to test the effectiveness of the developed action logic design software. It is designed somehow to represent some long distance power delivery problems that have been observed in the western North America interconnection. The one-line diagram of this test system is shown in Figure 5.7.

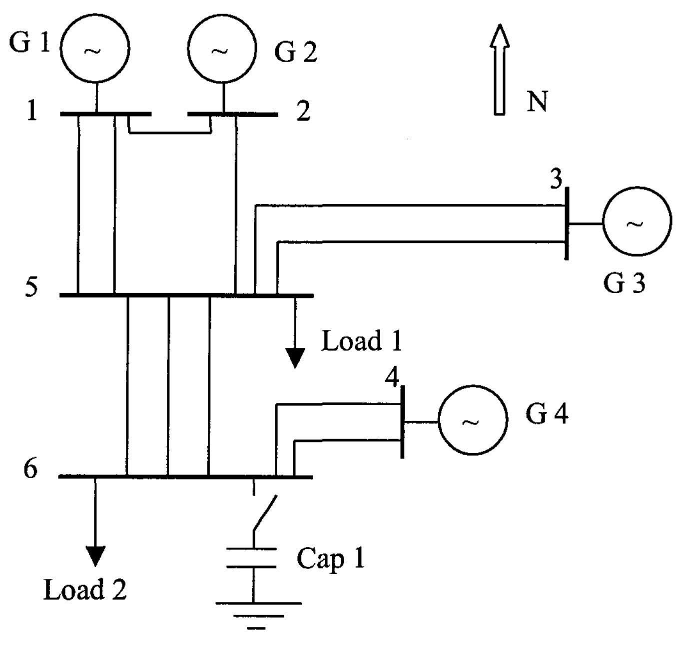


Figure 5.7 One-line diagram of the test power system

This is a simple test system. A large portion of the load is located at bus 6. Power flows from north to south. Lines 1-5, 2-5, 3-5, and 5-6 are long distance transmission lines. Loads at bus 5 and 6 are modeled with thermostatically controlled load model. When there is some line outage and the system is stressed, long-term voltage collapse is likely to occur. Under-voltage load shedding is equipped at bus 5 that sheds 20% of load at bus 5 when its voltage is lower than 0.9 pu for 5 seconds. At bus 6, a shunt capacitor will automatically switch in when the voltage is lower than 0.9 pu for 5 seconds. Because the voltage at bus 6 is always lower than that of bus 5, this auto-closing of shunt capacitor occurs earlier than the under-voltage load shedding.

System data can be found in Appendix B, including system branch data, generator dynamic data, and relay settings. The dynamic data is set according to typical machine data from the Appendix D in [77]. Zone 2 impedance relay is modeled on every line. Over-current relay is modeled on line 1-5 and 2-5. All generators are modeled with over-excitation relay. UVLS and automatic shunt switching are modeled as mentioned above. In addition, a temporary UVLS relay is modeled at bus 6 with a setting of 0.88 pu and a delay of 5 seconds. This is based on an assumption that the load at bus 6 would be shed if the voltage falls below 0.88 pu for 5 seconds. We made this assumption since most UVLS settings are about 0.9 to 0.92 pu [82], a sustained voltage lower than 0.88 indicates that no more UVLS is available to bring the voltage back. And, the long duration low voltage can cause tripping of voltage sensitive equipment, including electric motors and computers [83]. Long-term low voltage will also cause abnormally high current and heating in stator and rotor of a motor [84]. This UVLS is a simplification to avoid further detailed load modeling and can provide an early indication of voltage collapse. Should more detailed load models and its protection become available, they should replace this UVLS to detect system voltage collapse. The economic costs for shedding load at buses 5 and 6 are set to of ratio 1:1.

5.5 Simulation validation

To validate the accuracy of the simulator of this demonstration system, test simulations are run on two simple power systems. The results are compared with that generated by a commercial software package – PSS/E (Power System Simulator for Engineering) [85].

5.5.1 Validation on the Ontario Hydro 4-generator system

At first a validation is done on a simplified 4-generator system. It is derived from an Ontario Hydro 4-machine system designed for fundamental studies of inter-area oscillations in power systems [86][87].

System description

The one-line diagram of this test system is shown in Figure 5.8. System data can be found in Appendix A.

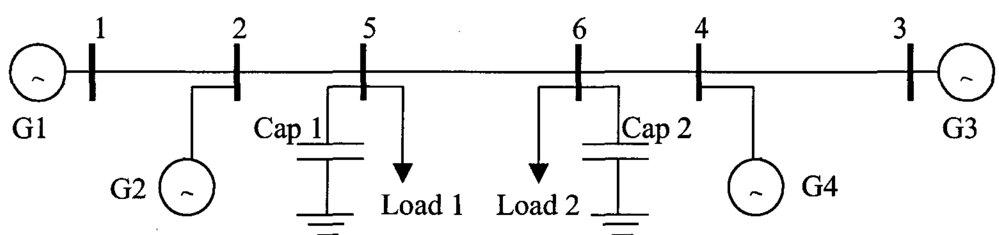


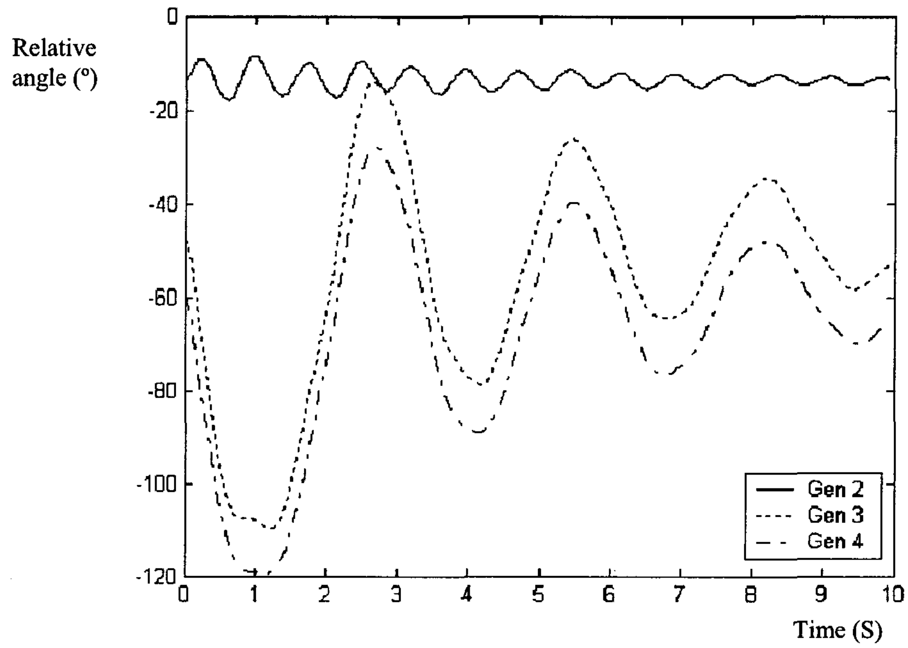
Figure 5.8 Ontario Hydro 4-generator test system

Simulation condition

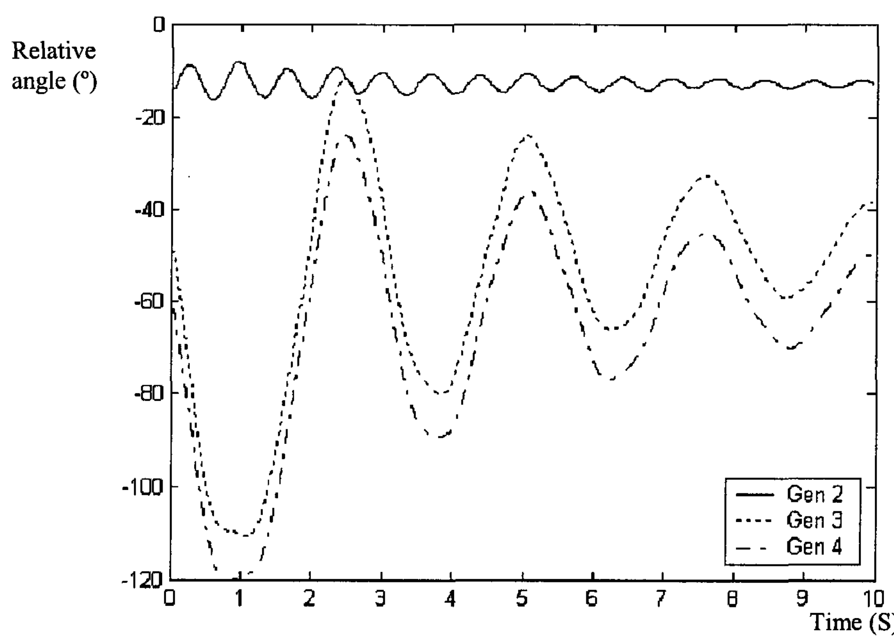
The original operating condition is shown in the power flow data in Appendix A. The initiating event is: at 0 second, a three-phase fault is applied to bus 5, and it is cleared at 0.1 second. Generators are modeled classically [77]. Loads are modeled as constant impedance. The simulation time is 10 seconds.

Test results

Generator relative angle is chosen as the test value. Generator 1 is set as the reference generator, i.e., with angle equal to 0. Test results are shown in Figure 5.9. From the results we see that the demonstration system simulator generates a result that is very similar to PSS/E.



a. Results from PSS/E



b. Results from demonstration system

Figure 5.9 Simulation results comparison on the Ontario Hydro 4-generator system

5.5.2 Validation on the 4-generator test system

A second validation is done on the test system shown in Figure 5.7, since this is the system we use to evaluation the demonstration software. The initiating event is: at 0 second, a three-phase fault is applied to bus 5, and it is cleared at 0.1 second. Generators are modeled classically and none of the controls listed in Section 5.3 are modeled, since they are inconsistent with the models in PSS/E. The simulation time is 10 minutes (600 seconds).

Again, generator relative angle is selected as the test value. Generator 1 is selected as the reference generator. Test results of transient stage and the long-term stage are compared in Figure 5.10 and Figure 5.11 respectively. From the result we see that the simulator generates similar results as PSS/E for this test system during both transient and extended time frames. In addition, the fact that the simulator is stable for 10 minutes indicates that the integration method is numerically stable.

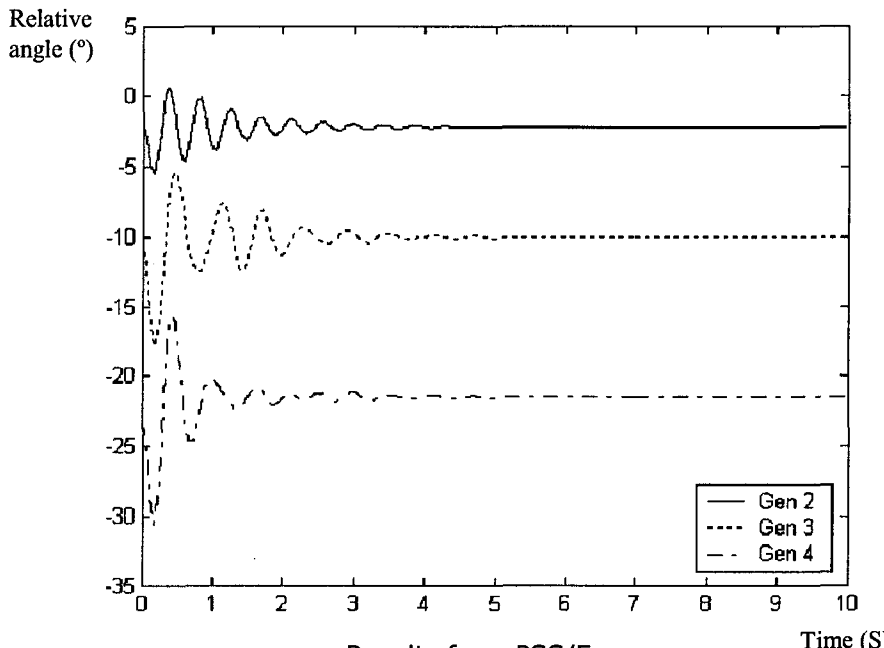
5.5.3 Notes on long-term simulation

PSS/E uses a Z form expression of the trapezoidal integration algorithm, an implicit algorithm [88], for long-term simulation [89]. The purpose is to increase simulation speed by larger time step while avoiding numerical instability problem [90].

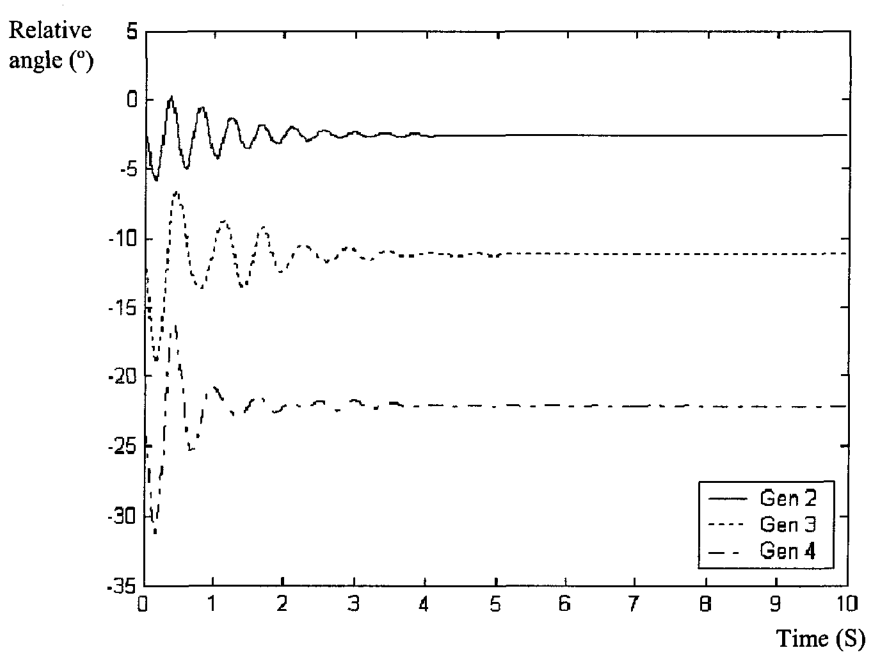
Although implicit algorithms are usually used with larger integration step for power system simulation software to increase simulation speed [91], Euler integration method is used with this demonstration system, because of its simplicity, and because simulation speed is not a concern at this stage of research. Euler method is an explicit method [88]. To avoid numerical instability, a short time step should be used. In this program, time step is set as 0.005 seconds, for this is much smaller than the smallest time constant of the simulated system. The numerical stability is verified by test results.

5.6 Demonstration system test results

For a given set of initiating events, and a set of different system configurations and operating conditions, the demonstration system generates the remedial actions for every

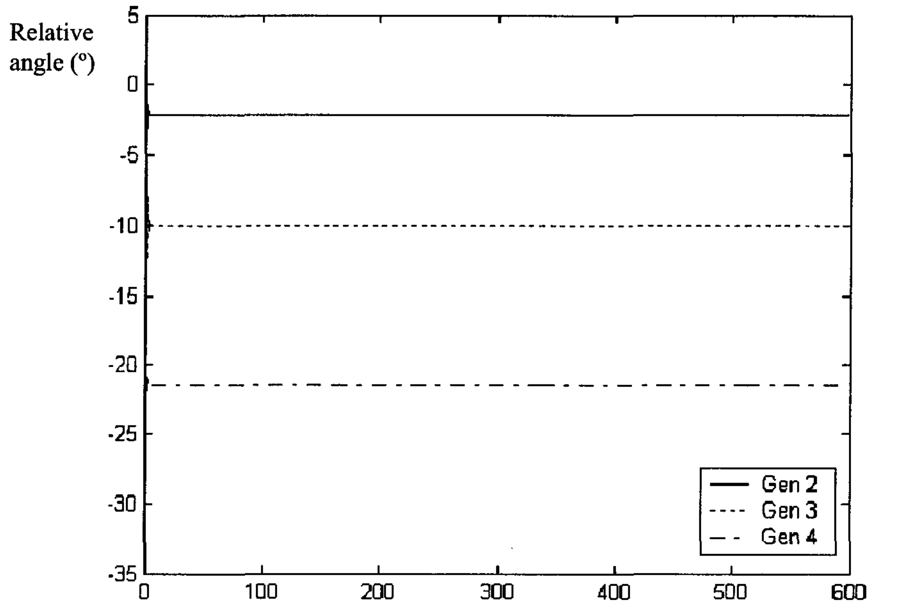


a. Results from PSS/E

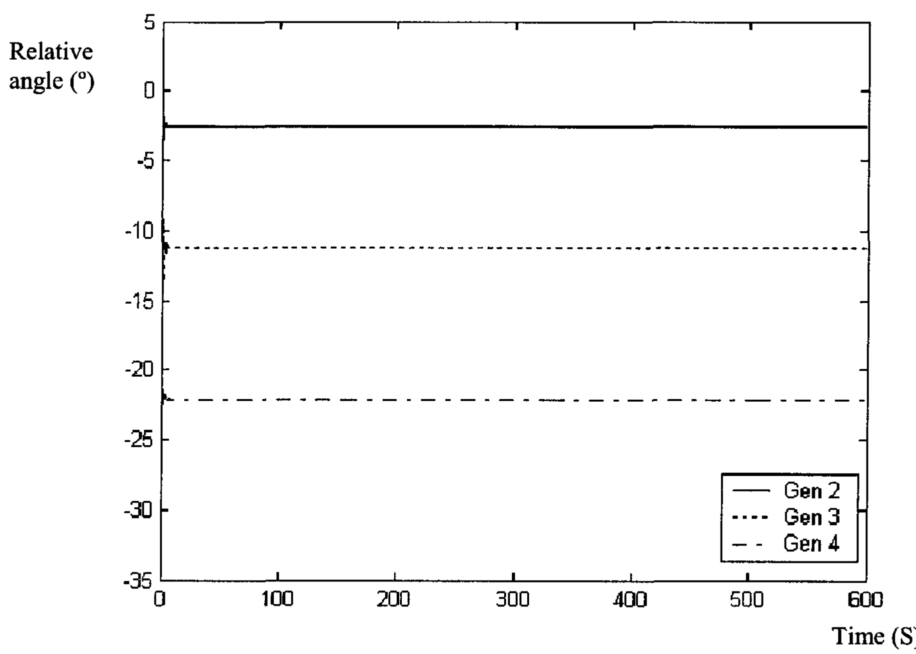


b. Results from demonstration system

Figure 5.10 Transient simulation result comparison for the test system



a. Results from PSS/E



b. Results from demonstration system

Figure 5.11 Long-term simulation result comparison for the test system initiating event under each system operating condition. A DDET tree is then constructed for each operating condition.

There are two types of remedial actions. When the system failure is of short-term nature (less than T seconds), the remedial action is an automatic instant action. Otherwise, the remedial action is provided to the operator within T seconds following the disturbance. We have selected T=40 seconds based on the response time of an experienced system operator, but this time could be chosen based on some other criteria if appropriate.

For a given system operating condition, the tree construction process is completely automated. The result of each tree is shown in this document in the format of a table, with each row representing a branch from the root node. All the control models listed in Section 5.3 are implemented during the tests. Generators are represented by E" model [77]. The code implementing this model is translated from a MATLAB code created for an ISU course project. The result of translated code exactly matches that of the original MATLAB code. The accuracy of the original MATLAB code was verified by the results generated by many individuals who worked independently on the same project.

5.6.1 Initiating events

In this test, a fixed set of initiating event is used. Automated selection of initiating events was designed as part of another ongoing dissertation that will interface with this work through an event list. The fixed initiating event set used in the test includes most N-1 initiating events and some multi-outage initiating events. A total of 17 initiating events are included, and are listed in the tables shown in following sections. Only symmetric 3-phase faults may be represented in the simulator at this point in time.

Faults are cleared at 0.1 seconds, which is within the normal clearing time range for transmission systems [79]. However, according to NERC Planning Standard [1], 3-phase faults with delayed clearing (due to stuck breaker or protection problem) should be included when considering category D disturbances, and as a result, delayed fault clearing is sometimes studied in normal transmission planning practices [92]. Therefore one contingency in the event list has a fault clearing time of 0.2 seconds.

5.6.2 Case 1: Normal operating condition

A computation is done for a normal system operating condition (normal loading and no line out of service), which is not a stressed condition. This condition is summarized in Table 5.1. The computation shows that, under this operating condition, all 17 initiating events result in acceptable system performance, i.e., no system failure is detected during the simulated period (10 minutes). The computation time for each initiating event varies from 42 to 51 seconds. The average computation time is 47 seconds.

Table 5.1 Normal operating condition (Case 1)

Bus No.	Generation (MW)	Load (MW)
1	1071.25	–
2	814.64	–
3	711.60	–
4	476.91	–
5	–	1200.0
6	–	1800.0

5.6.3 Case 2: A more stressed system operating condition

A more stressed operating condition is obtained by increasing the system loading according to Table 5.2. The resulting event tree is shown in Table 5.3, where it is observed that voltage collapse occurs for events 11-17. This is due to the additional power delivered across the transmission path. Table 5.3 also lists the actions identified by the ERS, which are different amounts of load shedding. It is illuminating to examine one of these cases, event 14, in more detail. This event models outage of two lines. When no action is taken, a voltage collapse occurs as shown in Figure 5.12 and Figure 5.13.

Table 5.2 System operating condition for Case 2

Bus No.	Generation (MW)	Load (MW)
1	1071.25	–
2	814.64	–
3	1020.80	–
4	889.99	–
5	–	1200.0
6	–	2500.0

Table 5.3 Remedial actions for Case 2

No.	Event at t=0 s	Event at t=0.1 s (t=0.2 s for Init. event No. 2)	System failure type	Remedial action	CPU time (s)
1	3 phase fault at one line between 3-5 near bus 5.	Trip the faulted line between 3-5.	No problem.	–	47
2	3 phase fault at one line between 3-5 near bus 3.	Trip the faulted line between 3-5.	No problem.	–	47
3	3 phase fault at one line between 2-5 near bus 5.	Trip line 2-5.	No problem.	–	45
4	3 phase fault at one line between 1-5 near bus 5.	Trip the faulted line between 1-5.	No problem.	–	44
5	3 phase fault at one line between 1-5 near bus 1.	Trip the faulted line between 1-5.	No problem.	–	44
6	3 phase fault at one line between 2-5 near bus 2.	Trip line 2-5.	No problem.	–	45
7	3 phase fault at one line between 1-2 near bus 1.	Trip line 1-2.	No problem.	–	46
8	3 phase fault at one line between 1-2 near bus 2.	Trip line 1-2.	No problem.	–	46
9	3 phase fault at one line between 4-6 near bus 6.	Trip the faulted line between 4-6.	No problem.	–	46
10	3 phase fault at one line between 4-6 near bus 4.	Trip the faulted line between 4-6.	No problem.	–	46
11	3 phase fault at one line between 5-6 near bus 6.	Trip the faulted line between 5-6.	Voltage collapse at about 575 s [a]	Shed 3.1% load at bus 6 at 40 s.	237
12	3 phase fault at one line between 5-6 near bus 5.	Trip the faulted line between 5-6.	Voltage collapse at about 572 s	Shed 3.1% load at bus 6 at 40 s.	237
13	Trip two of the three lines between 5-6	None.	Voltage collapse at about 5 s	Shed 15.6% load at bus 6 at 0.1 s. [b]	153
14	3 phase fault at one line between 5-6 near bus 5.	Trip the faulted line between 5-6 and one line between 3-5.	Voltage collapse at about 140 s	Shed 9.4% load at bus 6 at 40 s.	169
15	3 phase fault at one line between 1-5 near bus 5.	Trip line 1-5 and one line between 3-5	Voltage collapse at about 109 s	Shed 9.4% load at bus 6 at 40 s.	140
16	3 phase fault at one line between 2-5 near bus 5.	Trip line 2-5 and one line between 3-5	Voltage collapse at about 98 s	Shed 9.4% load at bus 6 at 40 s.	141
17	3 phase fault at one line between 5-6 near bus 6.	Trip the faulted line 5-6 and one line between 4-6.	Voltage collapse at about 229 s	Shed 3.1% load at bus 6 at 40 s.	193

a. This is the time that the simulator indicates the voltage collapse by a low voltage at bus 6. See Section 5.4 for detail. Real system oscillation will occur at a time later than this time.

b. In this test, event based remedial action is assumed to take place 0.1 seconds after detection of the initiating event for the short-term problem. For all the test cases in this work, a slightly different action speed gives similar test result.

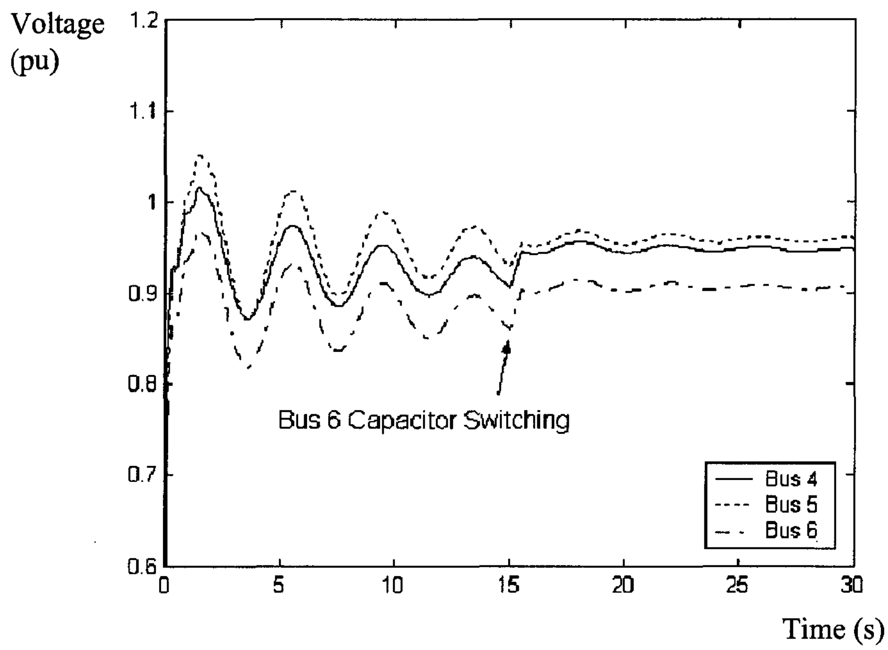


Figure 5.12 Short-term response for initiating event 14, Case 2 without action

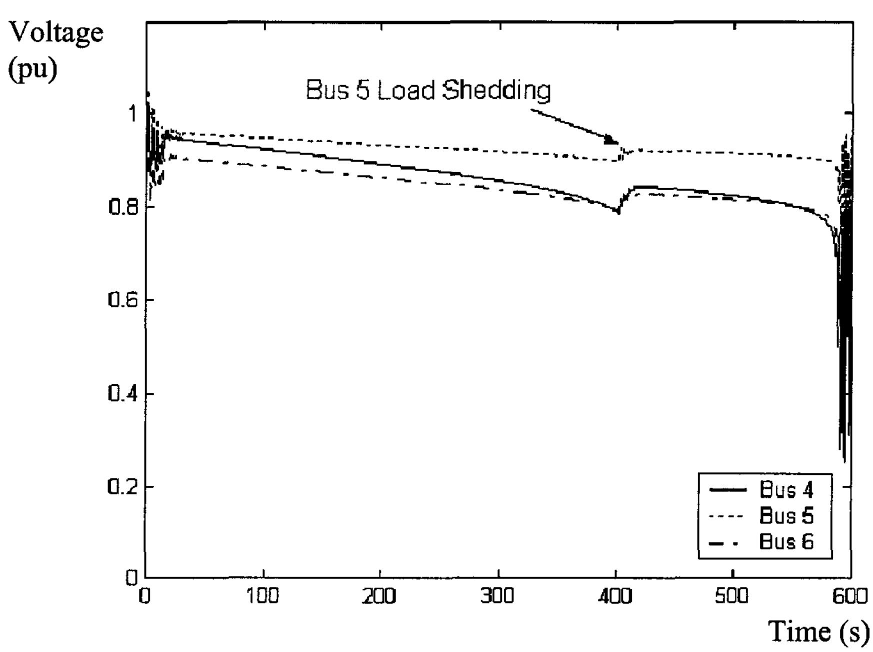


Figure 5.13 Long-term response for initiating event 14, Case 2 without action

Because of the severity of the initiating event (outage of two lines), power delivery capability is largely weakened and a low voltage profile appears on the southern buses (buses 4,5,6). Automatic capacitor switching takes place at bus 6 at about 15 seconds. However, system voltage continues to drop. Since no remedial action is taken, armed under-voltage load shedding at bus 5 shed 20% of its load at about 400 seconds. This is still not enough to save the system. A system-wide oscillation eventually occurs at about 580 seconds, as seen in Figure 5.13. After applying the identified action – shedding 9.4% load at bus 6 at 40 seconds, satisfactory system performance is achieved as shown in Figure 5.14.

Initiating event 13 is a more severe case, and a performance violation is indicated much earlier at about 5 seconds. As we see from Figure 5.15, the voltage collapses and unstable behavior occurs at about 200 seconds. After applying the identified remedial action – load shedding at bus 6 at 40 seconds, acceptable system performance is achieved for initiating event 13, as indicated in Figure 5.16. The difference of this action from that of initiating event 14 is that this action will be taken as an automatic remedial action instead of a suggestion to the operator because the early violation could not be mitigated otherwise.

5.6.4 Case 3: Maintenance configuration with normal load

In this case, one of the two lines between buses 1 and 5 is out of service for maintenance. The system load is of normal level as indicated in Table 5.4. However, unit 1 generation must be reduced due to the line outage in order to avoid a steady-state overload. Therefore, unit 3 generation must be increased to compensate and satisfy the demand.

Table 5.4 System operating condition for Case 3

Bus No.	Generation (MW)	Load (MW)
1	551.55	–
2	458.57	–
3	1229.60	–
4	723.05	–
5	–	1200.0
6	–	1700.0

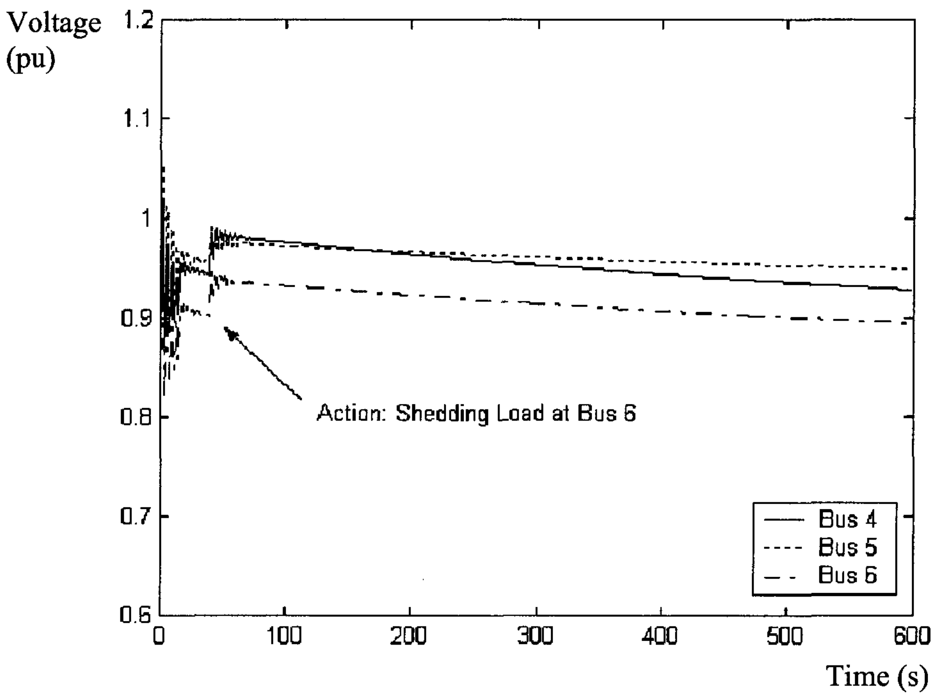


Figure 5.14 System response for initiating event 14, Case 2 with action

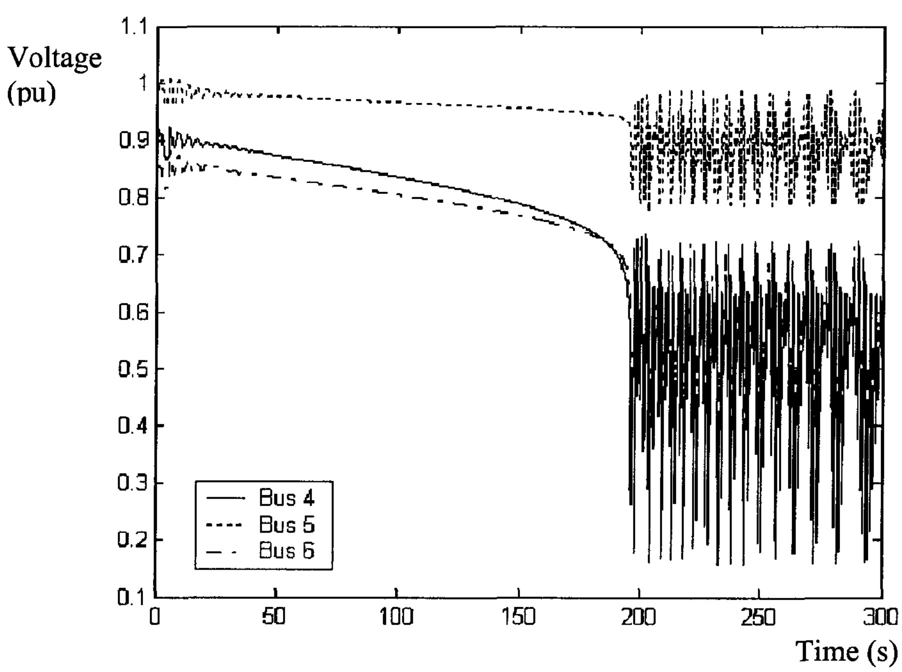


Figure 5.15 System response for initiating event 13, Case 2 without action

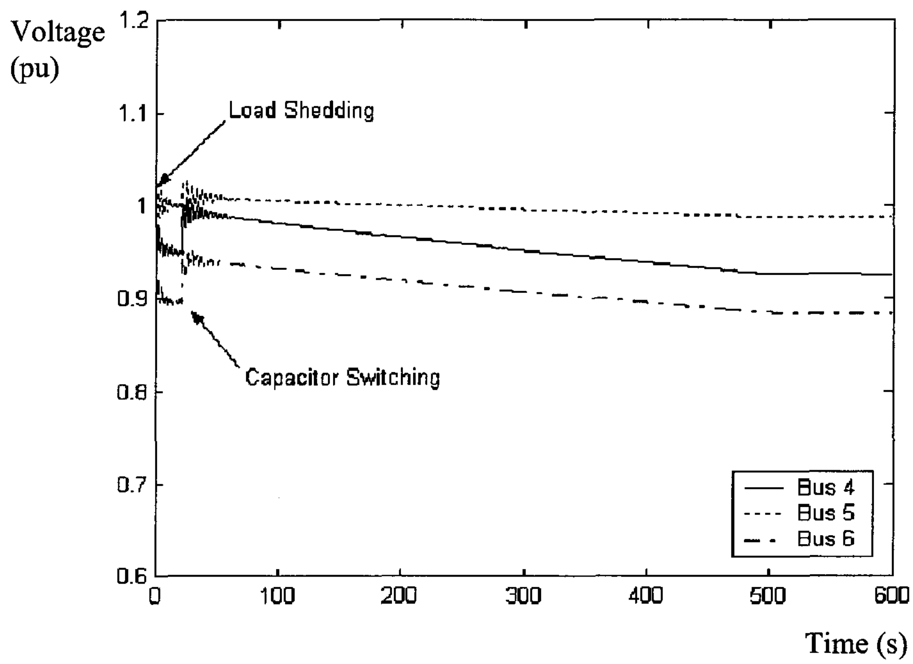


Figure 5.16 System response for initiating event 13, Case 2 with action

After the automatic action logic design, the result shows that only initiating event 2 is dangerous and needs remedial action, as shown in Table 5.5. This system failure was caused by a protection undesirable operation. Voltage problems do not occur in this case. Figure 5.17 and Figure 5.18 illustrate the impedance magnitude and angle, respectively, seen from either end looking into line 3-5 (the impedance relays on this line were disabled to create these curves). From these plots, we see that for a time duration longer than 0.5 seconds, the impedance observed by the Zone 2 relays at both ends of line 3-5 falls into the triggering zone. This would trip line 3-5 0.5 seconds thereafter and isolate a large amount of generation at generator 3. A system failure then occurs at a time about 0.5 seconds.

Table 5.5 Remedial action for Case 3

No.	Event at t=0 s	Event at t=0.2 s	System failure type	Remedial action
2	3 phase fault at one line between 3-5 near bus 3.	Trip the faulted line between 3-5.	System separated by false-trip of the other line between 3-5 by Zone 2 impedance relays at 0.51 s.	Block the otherwise-would-falsely-trip relays for 0.5 s starting at 0.3 s.

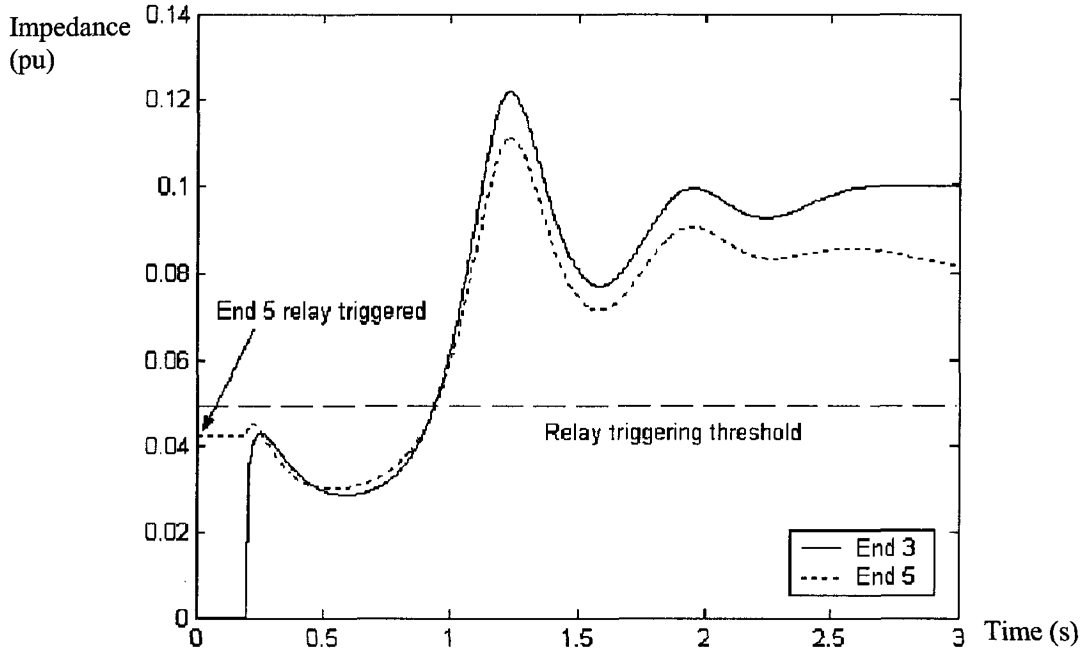


Figure 5.17 Observed impedance magnitudes by line 3-5 for initiating event 2, Case 3

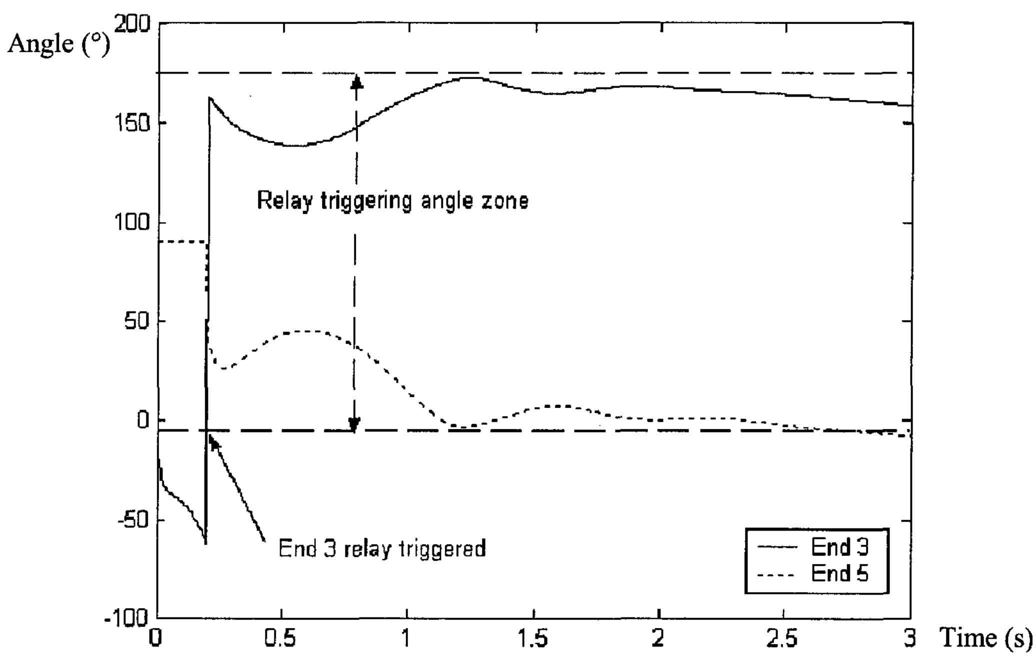


Figure 5.18 Observed impedance angle by line 3-5 for initiating event 2, Case 3

The identified remedial action is to block both relays for 0.5 seconds starting from the time of 0.3 seconds. Then the time duration from relay activation point (0.8 s) to the time of relay exiting the triggering zone (0.95 s) is 0.15 seconds, which is less than the delay of these two relays – 0.5 seconds. The system integrity is maintained. This action design is consistent with the 'transient blocking logic for parallel lines' discussed in IEEE transmission line protection standard [60]. Without relay modeling, this relay undesirable operation would remain "hidden" until this particular disturbance occurred.

5.6.5 Case 4: Maintenance configuration with decreased generation at unit 3

This case is similar to Case 3, with a slightly higher load level. However, output of unit 3 is decreased relative to Case3, as indicated in Table 5.6. The generated tree is shown in Table 5.7. The initiating events are the same as described in Table 5.3.

Table 5.6 System operating condition for Case 4

Bus No.	Generation (MW)	Load (MW)
1	708.45	–
2	615.35	–
3	916.65	–
4	825.73	–
5	–	1200.0
6	–	1800.0

In the tree shown in Table 5.7, for some initiating events, there are alternative actions available. The reason is that, these system failures are caused by overload on both line 1-5 and 2-5, and alleviation of these overloads can be achieved by shedding load at either bus 5 or bus 6. To determine the best action, corresponding costs are compared. Cost factors for bus 5 and bus 6 are set to of ratio 1:1 in this computation.

Of all the 7 problematic initiating events in this tree, initiating event 13 has a similar voltage collapse problem as it does in Case 2. The other 6 initiating events result in overload at either line 1-5 or 2-5. We take initiating event 3 as an example. As shown in Figure 5.19, when no action is taken, the over-current relay at line 1-5 will operate at about 21 seconds.

Table 5.7 Remedial actions for Case 4

No.	System failure type	Optimal action	Alternative action
1	No problem.	–	–
2	No problem.	–	–
3	System separated by tripping of the line 1-5 by over-current relay at 21.2 s.	Shed 28% load at bus 5 at 0.2 s	Shed 22% load at bus 6 at 0.2 s
4	System separated by tripping of the line 2-5 by over-current relay at 21.2 s.	Shed 28% load at bus 5 at 0.2 s	Shed 22% load at bus 6 at 0.2 s
5	System separated by tripping of the line 2-5 by over-current relay at 25 s.	Shed 28% load at bus 5 at 0.2 s	Shed 22% load at bus 6 at 0.2 s
6	System separated by tripping of the line 1-5 by over-current relay at 25 s.	Shed 28% load at bus 5 at 0.2 s	Shed 22% load at bus 6 at 0.2 s
7	No problem.	–	–
8	No problem.	–	–
9	No problem.	–	–
10	No problem.	–	–
11	No problem.	–	–
12	No problem.	–	–
13	Voltage collapse at time about 305 s.	Shed 3.1% load at bus 6 at 40 s	–
14	No problem.	–	–
15	System separated by tripping of the line 2-5 by over-current relay at 26 s.	Shed 22% load at bus 6 at 0.2 s	Shed 41% load at bus 5 at 0.2 s
16	System separated by tripping of the line 1-5 by over-current relay at 26 s.	Shed 22% load at bus 6 at 0.2 s	Shed 41% load at bus 5 at 0.2 s
17	No problem.	–	–

After applying the identified remedial action, the relay would not operate. The result is shown in Figure 5.20. This gives the operator time to re-dispatch system generation without islanding the system. The relay setting and system configuration for this example could be an undesired setting experienced by practice [59].

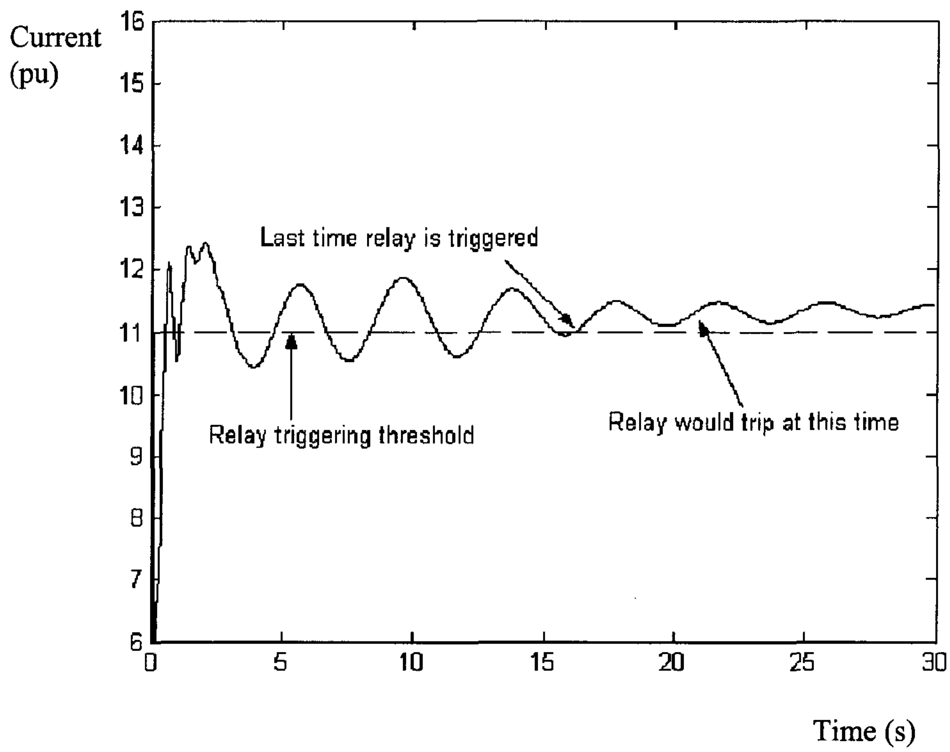


Figure 5.19 Current observed by line 1-5 for initiating event 3, Case 4 without action

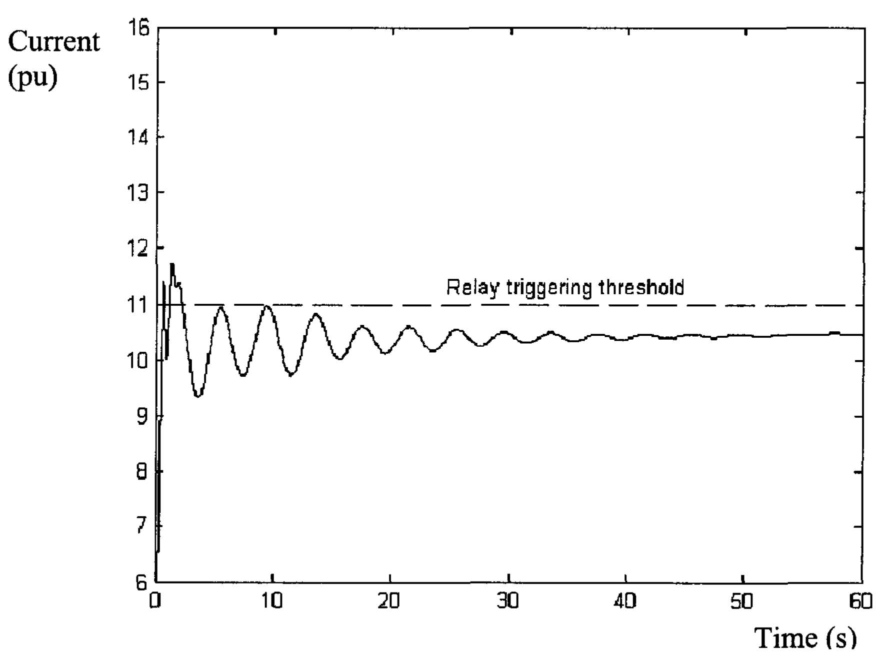


Figure 5.20 Current observed by line 1-5 for initiating event 3, Case 4 with action

5.6.6 Case 5: Maintenance configuration with stressed operating condition

Compared with Case 4, this case has a higher load level and the generation from unit 3 is increased, as shown in Table 5.8. The generated tree is shown in Table 5.9. The problems occurring under this case include all the problem types experienced by cases 2, 3, and 4. The impedance undesirable operation problem experienced with initiating event 2 here is similar to that of Case 3. The only difference is that, here, only the relay at the remote end (end 5) would operate. Problems with initiating event 13 to 16 are of the same nature as that in Case 2. Problems with initiating event 3 to 6 are similar as that in Case 4. However, under this scenario, the time frame of this over-current operation is much longer than that in Case 4, and thus more phenomena are involved.

Table 5.8 System operating condition for Case 5

Bus No.	Generation (MW)	Load (MW)
1	655.95	–
2	562.89	–
3	1229.60	–
4	829.7	–
5	–	1200.0
6	–	2000.0

We consider initiating event 3 as an example. As shown in Figure 5.21, when no action is taken, the over-current relay trips line 1-5 at about 93 seconds. The reason for the current jump at about 88 seconds is the automatic shunt switching occurs at bus 6. While this is necessary to increase the voltage at bus 6, it also increases the load current at bus 6. This effect is similar to that of the Under Load Tap Changer's (ULTC) behavior during a long-term voltage collapse where a voltage regulating action also increases current flow. After applying the identified action (shed 9.4% load at bus 6 at 40s), the operation of relay is prevented, as illustrated in Figure 5.22.

Table 5.9 Remedial actions for Case 5

No.	System failure type	Optimal action	Alternative action
1	No problem.	–	–
2	System separated by tripping of the other line between 3-5 by Zone 2 impedance relays at 0.51 s.	Block this Zone 2 relay for 0.5 s.	–
3	System separated by tripping of the line 1-5 by over-current relay at about 93 s.	Shed 9.4% load at bus 6 at 40 s.	Shed 22% load at bus 5 at 40 s.
4	System separated by tripping of the line 2-5 by over-current relay at about 91 s.	Shed 9.4% load at bus 6 at 40 s.	Shed 22% load at bus 5 at 40 s.
5	System separated by tripping of the line 2-5 by over-current relay at about 90 s.	Shed 9.4% load at bus 6 at 40 s.	Shed 22% load at bus 5 at 40 s.
6	System separated by tripping of the line 1-5 by over-current relay at about 92 s.	Shed 9.4% load at bus 6 at 40 s.	Shed 22% load at bus 5 at 40 s.
7	No problem.	–	–
8	No problem.	–	–
9	No problem.	–	–
10	No problem.	–	–
11	No problem.	–	–
12	No problem.	–	–
13	Voltage collapse at about 58 s.	Shed 9.4% load at bus 6 at 40 s.	–
14	Voltage collapse at about 176 s.	Shed 9.4% load at bus 6 at 40 s.	–
15	Voltage collapse at about 156 s.	Shed 9.4% load at bus 6 at 40 s.	–
16	Voltage collapse at about 159 s.	Shed 9.4% load at bus 6 at 40 s.	–
17	No problem.	–	–

5.6.7 Case 6: Maintenance configuration with over-stressed operating condition

Compared with Case 5, this case has a much higher load level, as shown in Table 5.10. This is not an acceptable operating condition as bus 6 voltage (0.96 pu) is well below its required minimum level, e.g. 0.98 pu. This case is shown here to test the performance of the demonstration system under an over-stressed operating condition. The generated tree is shown in Table 5.11. According to this table, all initiating events require remedial action. Some actions have extremely high cost. This situation is N-1 insecure and therefore would require preventive action by the operator.

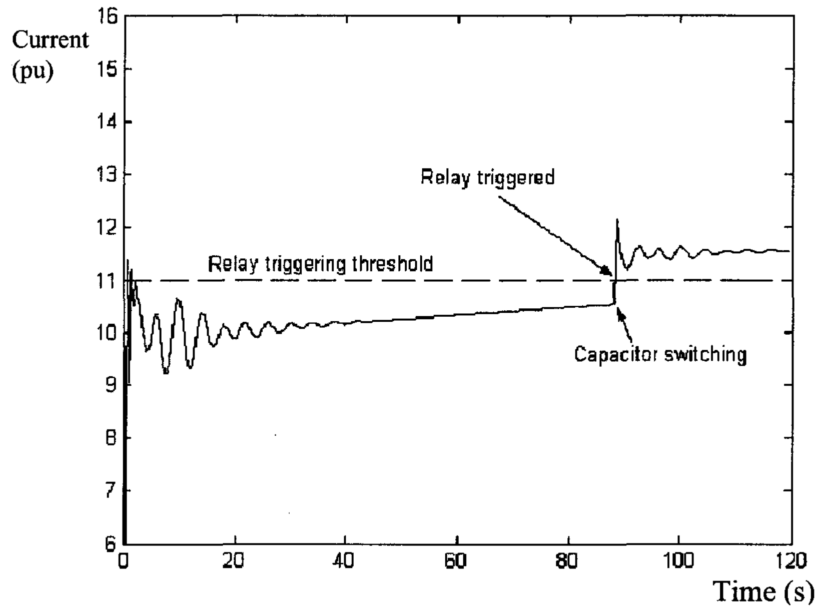


Figure 5.21 Current observed by line 1-5 for initiating event 3, Case 5 without action

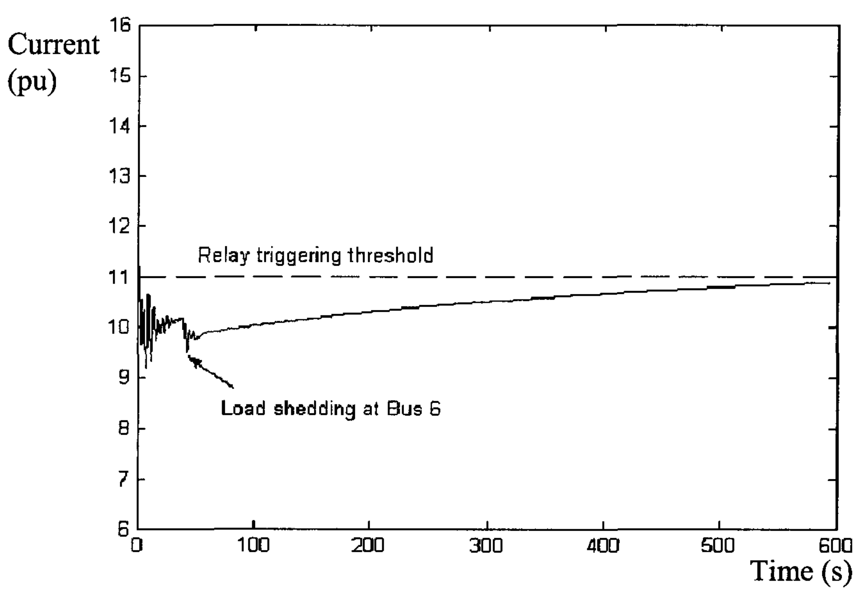


Figure 5.22 Current observed by line 1-5 for initiating event 3, Case 5 with action

Table 5.10 System operating condition for Case 6

Bus No.	Generation (MW)	Load (MW)
1	1072.31	–
2	504.26	–
3	1229.60	–
4	889.06	–
5	–	1200.0
6	–	2400.0

Table 5.11 Remedial actions for Case 6

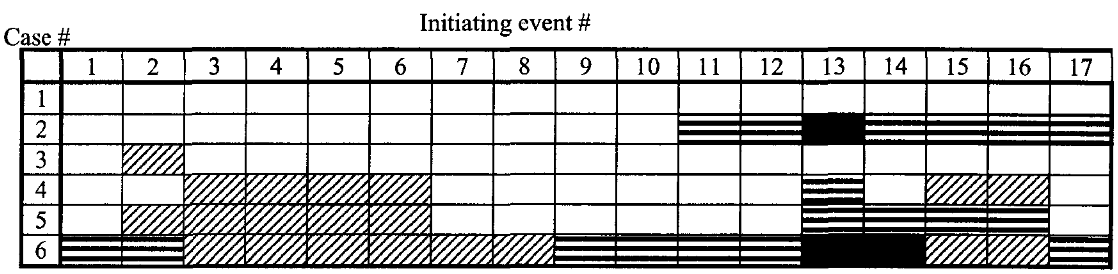
No.	System failure type	Optimal action	Alternative action
1	Voltage collapse at about 149 s	Shed 9.4% load at bus 6 at 40 s.	–
2	Voltage collapse at about 150 s	Shed 9.4% load at bus 6 at 40 s.	–
3	System separated by tripping of the line 1-5 by over-current relay at about 5.4 s.	Shed 41% load at bus 6 at 0.2 s.	Shed 91% load at bus 5 at 0.2 s.
4	System separated by tripping of the line 2-5 by over-current relay at about 5.4 s.	Shed 41% load at bus 6 at 0.2 s.	Shed 91% load at bus 5 at 0.2 s.
5	System separated by tripping of the line 2-5 by over-current relay at about 5.3 s.	Shed 41% load at bus 6 at 0.2 s.	Shed 91% load at bus 5 at 0.2 s.
6	System separated by tripping of the line 1-5 by over-current relay at about 5.3 s.	Shed 41% load at bus 6 at 0.2 s.	Shed 91% load at bus 5 at 0.2 s.
7	System separated by tripping of the line 1-5 by over-current relay at about 186 s.	Shed 16% load at bus 5 at 40 s.	Shed 10% load at bus 6 at 40 s.
8	System separated by tripping of the line 1-5 by over-current relay at about 185 s.	Shed 16% load at bus 5 at 40 s.	Shed 10% load at bus 6 at 40 s.
9	Voltage collapse at about 530 s	Shed 3.2% load at bus 6 at 40 s.	–
10	Voltage collapse at about 530 s	Shed 3.2% load at bus 6 at 40 s.	–
11	Voltage collapse at about 240 s	Shed 3.2% load at bus 6 at 40 s.	–
12	Voltage collapse at about 240 s	Shed 3.2% load at bus 6 at 40 s.	–
13	Voltage collapse at about 5 s	Shed 22% load at bus 6 at 0.1 s.	–
14	Voltage collapse at about 27 s	Shed 16% load at bus 6 at 0.2 s.	–
15	System separated by tripping of the line 2-5 by over-current relay at about 5.6 s.	Shed 38% load at bus 6 at 0.2 s.	Shed 90% load at bus 5 at 0.2 s.
16	System separated by tripping of the line 1-5 by over-current relay at about 5.6 s.	Shed 38% load at bus 6 at 0.2 s.	Shed 90% load at bus 5 at 0.2 s.
17	Voltage collapse at about 107 s	Shed 9.4% load at bus 6 at 40 s.	–

5.7 Result analysis

Specific cases and system problems have been analyzed in individual cases. In this section we take a global look at the entire set of results via Table 5.12. In the table, each row represents one operating condition case, and each column represents one initiating event.

Cells are classified into 4 categories as shown in the note just below the table. Types 1, 2, and 3 represent the occurrence of system failure requiring remedial action. Among these, only type 3 system failure can be captured by the traditional SPS logic design process and be prevented. For the cases tested in this work, only 3 out of 41 system failures are of type 3. This result shows how the ERS system could dramatically increase the system safety for certain cases.

Table 5.12 Overview of test results



1. System failure caused by relay operation during post-initiating event. (20 occurrences)
2. System long-term voltage collapse. (18 occurrences)
3. Transient voltage collapse. (3 occurrences)
4. System is safe under this initiating event.

5.8 Conclusion

This demonstration system is an automatic program. Given an operating condition and a list of initiating event, this program constructs a tree including necessary remedial actions automatically. The processes of system failure detection and remedial action identification are also done automatically. This automated process is the core feature that makes the ERS online application feasible.

Numerical results on the test system shows the importance of including relay models and long-term simulation in ERS simulator. Alternative actions are also provided for some cases, as it is necessary where the power market operation is in place. Results also show the effectiveness of the ERS action logic design process. For the tested system, the ERS system can capture and thus prevent over 10 times the system failures as traditional SPS logic design process.

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[1] Possible action points are the time points at which an identified action can be taken. For example, it can be a very short time after an initiating event is detected for transient problem, or a reasonable long time after the initiating event that the system operator could take suggested action.

[2] See Section 4.3.2.

6 KEY STEPS AND ISSUES IN ERS IMPLEMENTATION

There are some key steps involved in implementing ERS. In this chapter we provide guidelines for implementing these key steps, and we recommend applicable algorithms. Important implement issues are also addressed.

6.1 Computation for forecasted conditions

Advanced SPS in [31]-[35] perform security analysis based only on the system current operating condition. However, in a high-risk future period the system is more vulnerable and needs more time for DDET construction. To account for this problem, ERS constructs trees in advance when necessary. That is, the ERS begins the construction process according to forecasted high-risk operating conditions. This can give the ERS enough time to prepare a tree for future use when the high-risk period comes.

Risk assessment methods for power system are addressed in [93]. The high-risk period here refers to time of severe weather or over-stressed system configuration and operating condition. The risk is high during these periods because more initiating events could lead the system to failure with a higher impact value, and the probabilities of initiating events are higher. The increased values of both terms (probability and impact) in producing system risk cause a higher system risk.

As shown in Figure 6.1, after a high-risk period is identified, the first thing is to check with the database to see whether a tree based on this high-risk condition exists. If no satisfactory existing tree found, new computation should be conducted to prepare a tree of sufficient size for the identified high-risk future period. Before starting the computation, there are two tasks to be done to determine the time and CPU(s) to perform this computation.

<u>Lead-time for forecasted computation</u>

Determination of the lead-time for the forecasted computation is an important decision-making problem. If the computation starts too early, the information available is highly uncertain and so the forecasting is uncertain as well. On the other hand, if the computation starts too late, the time remaining may not be enough for a complete solution of

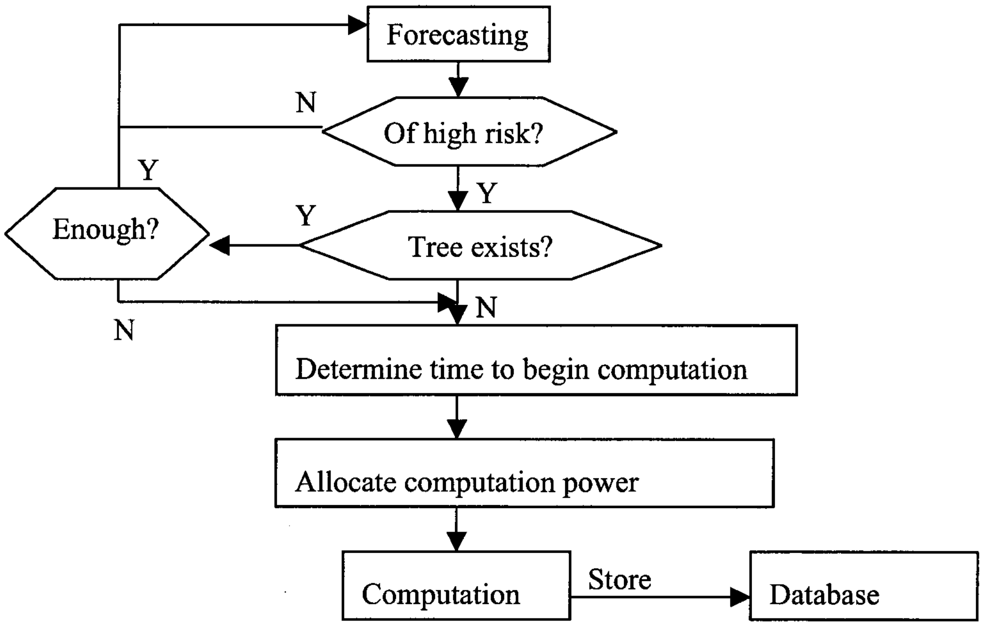


Figure 6.1 Computation based on forecasting

the targeted problem. Thus, we must optimize the selected lead-time in order to obtain a desired accuracy (via minimizing forecasting error) yet complete the computing task.

Allocation of computational resources

Given that available computation resources are limited, we need to allocate it between current and future tasks. How much computational power to dedicate to each of them depends on the readiness of the current tree in comparison to that of the future tree. Although this is an important problem, we will not further address it here. We point it out, however, by doing so we strengthen the ability of future researchers to extend this work.

6.2 Task scheduling in a distributed computation system

6.2.1 Objective

After the step of initiating events selection comes the step of event queuing, where we must answer the question: "with all these initiating events, what sequence should be followed to analyze them? Which one to analyze next?" The answer to this question is based on maximization of the ERS readiness. The readiness index is introduced in Section 3.6. In short, this index represents of what portion (in probability) of all the potential catastrophic events the ERS has analyzed.

6.2.2 Simple task scheduling algorithm

Tasks with time constrains are called real-time tasks and requires appropriate scheduling method. Typical real-time task has requirements on the earliest start time, completion deadline, pertaining resources, and synchronism with other tasks. Task scheduling can be either preemptive or non- preemptive [94]. In non-preemptive scheduling, one task is not interrupted by other tasks. Non-preemptive scheduling has a lower scheduling overhead compared with preemptive scheduling. Non-preemptive scheduling is solved by heuristics [94].

In this work, we use non-preemptive scheduling for simplification, and then further simplify the problem by not considering the above-mentioned hard time constrains and the resource requirements other than CPUs. The objective of this simplified scheduling problem is to maximize the number of processed tasks completed in a given amount of time and to maximize the number of processed tasks at any particular time.

For this scheduling problem, the known information includes:

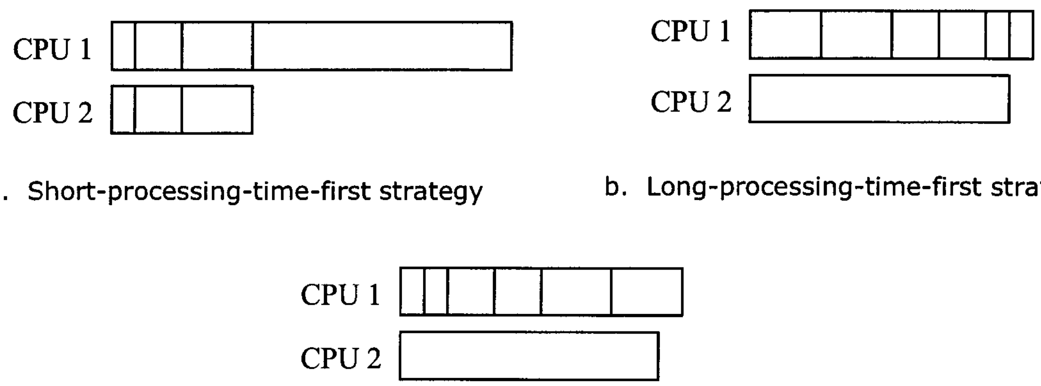
- Number of tasks.
- Number of processors (CPU).
- Processing time for each task.

The goal is to find a heuristic algorithm such that it completes as many tasks as possible in a given time. The output of the task-scheduling problem includes:

- The assigned processor for each task.
- For tasks assigned to the same processor, the sequence the tasks should be processed.

Short-processing-time-first strategy

This is a greedy algorithm [94]. This algorithm assigns an unprocessed task with the least processing time to a processor whenever a processor becomes available. This algorithm can assure that at the period before the end of the task-scheduling problem, the number of processed tasks approximately achieves the maximum. However, it is also possible that time to complete all the tasks is unnecessarily long as shown in Figure 6.2- a. The effect of this becomes more influential as the number of processors increases, and it becomes less influential as the number of tasks increases.



a. Short-processing-time-first strategy

b. Long-processing-time-first strategy

c. Hybrid strategy

Figure 6.2 Comparison of different task scheduling strategies - illustration

Long-processing-time-first strategy

This algorithm assigns an unprocessed task with the longest estimated processing time to a processor whenever a processor becomes available. This algorithm usually completes all tasks in a time shorter than the short-processing-time-first algorithm, but it tends to complete fewer tasks early on, as shown in Figure 6.2-b.

The advanced SPS introduced in [33] uses this strategy for task scheduling. It is effective there because the number of initiating events it considers is very limited and its objective is to complete all tasks in an assigned time of 5 minutes. The ERS, however, has a very large initiating event set, and its goal is not only to complete all of them in a given time, but also to complete as many as possible at any given time. Based on the observation of these two algorithms, a hybrid strategy that incorporates the advantages of these two algorithms can be developed.

Hybrid scheduling strategy

This strategy works in the following way. Before actually assigning tasks to processors, we initially schedule the tasks in a 'virtual' way using the long-processing-time-first algorithm, and record which task would be processed by which processor. Then, for each processor, we rank its tasks using the short-processing-time-first algorithm. Having this information, we assign the tasks to the dedicated processor in the re-ranked order. The result of this hybrid strategy is close to the result of 'Short-processing-time-first' strategy in the early part of the time period and is the same as the result of the 'Long-processing-time-first' strategy at the end of the time period, as shown in Figure 6.2– c. A numerical result of the comparison of these three strategies is shown in Figure 6.3. This test assumes that there are 30 tasks and 9 processors. Task length varies from 40 seconds to 300 seconds.

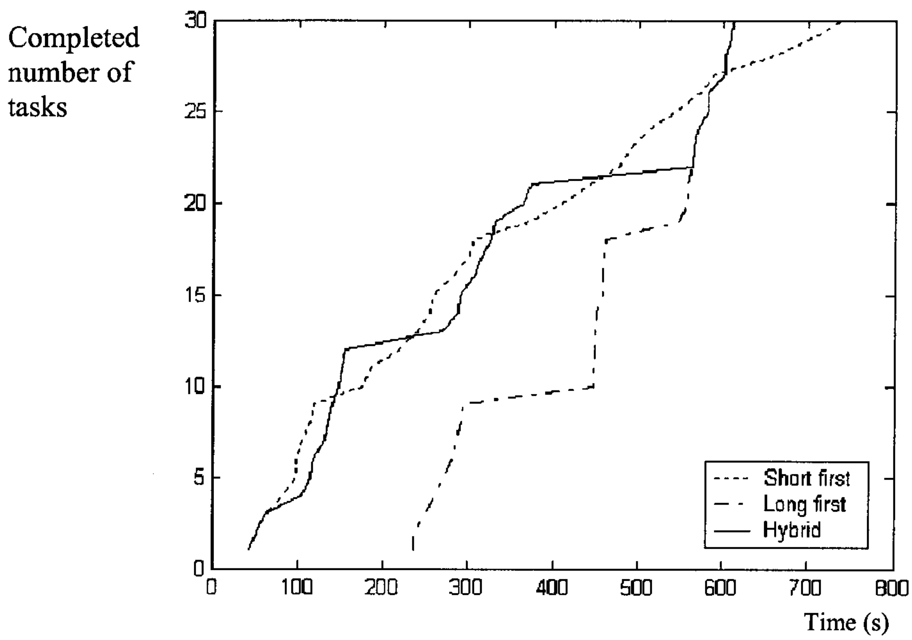


Figure 6.3 Comparison of different task scheduling strategies – test result

For ERS, the processing time for a task (one initiating event) is not unknown a priori. However, it is possible to obtain reasonably good estimates. Suppose that the system has run for some time, say, 6 months. Most events in the initiating event set should have appeared in some previous initiating event set and been processed under a different but similar operating condition. In general, the processing time for one event under different but similar operating conditions has some consistency, at least in a relative manner.

As an example, the initiating event processing times for test cases in Chapter 5 are listed in Table 6.1. Even for these 5 dramatically different cases we can observe a good deal of processing time consistency. For example, for a given condition, all processing times for initiating events 3 to 6 are similar; times for initiating event 1, 2, and 7 to 10 are similar; times for initiating events 11 and 12 are usually longer than initiating event 17; initiating events 13 to 16 are more likely to cause system failure and then need a long time for processing. When we actually seek this estimation, we use only similar operating condition, which would give much more consistency compared with this example.

Table 6.1 Initiating event processing time in seconds for Case 1 to 5

Case # \ Initiating event #	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
1	47	47	46	45	45	46	47	47	47	47	51	50	47	47	42	42	47
2	47	47	45	44	44	45	46	46	46	46	237	237	153	169	140	141	193
3	43	44	42	41	41	42	43	43	43	43	47	47	43	44	38	39	43
4	43	43	265	257	256	264	43	43	43	43	47	46	185	43	212	224	43
5	43	43	273	265	264	273	43	43	43	43	46	46	139	169	140	145	43

Additional simulations are performed to investigate the influence of error in processing time prediction on the result of different scheduling methods. Two examples are given in Figure 6.4 and Figure 6.5. As before, this test assumes that there are 30 tasks and 9 processors, and task processing time varies from 40 seconds to 300 seconds. In the figures, solid lines are expected number of tasks completed using estimated task processing time to schedule, and the dotted lines are actual number of tasks completed considering estimation errors. Long-processing-time-first scheduling is not included because its performance is poor. In this test, actual processing time for each task is selected from a normal distribution having mean equal to the estimated time and variance of 10 and 50 seconds, respectively, for the two cases. This provides a random imitation in the actual completion time for each task. From the result we conclude that, for this particular case, predicting the completion time works well when the variance is 10 seconds, as indicated by the close proximity of the curves representing the cases with and without uncertainty, respectively. The estimation becomes meaningless when the variance is 50 seconds – two dotted lines are very close to each other, which means that the actual result with this uncertainty would be very independent of the scheduling strategy used.

6.2.3 Task scheduling with probability consideration

Given the fact that there are an extremely large number of initiating events to assess, it is not enough to simply minimize the time because it is not practical to attempt to assess all of them. So we need a basis for scheduling the sequence in which the initiating events are assessed. The fundamental concept on which our scheduling scheme is based is that we attempt to be as prepared, or as ready, as possible within a given amount of time. This concept is the underlying thought behind our goal to maximize the readiness index, which is the ratio of total probability of assessed initiating events to the total probability of all events in the probability space.

Two observations simplify implementation of this goal:

- Precise probabilities of rare events are not available, but it is possible to assess the order in magnitude of rare event probabilities. For example, we may classify a rare event probability as of order10^{-2} or 10^{-3}.
- The ratio of the maximum processing time to the minimum processing time of a single event usually does not exceed 10.

From these facts we conclude: If we divide initiating events into groups according to their probability orders, for the events in one group, even the event with longest processing time should be processed before the event in the lower probability group having the least processing time.

Thus, we extend the simple task-scheduling problem to fit the need to maximize the 'probability readiness':

Step 1: Divide all the events in the initiating event set into groups by their probability orders. Events in higher probability groups are to be scheduled before events in lower probability groups.

Step 2: In each group, apply the algorithm for simple scheduling problem.

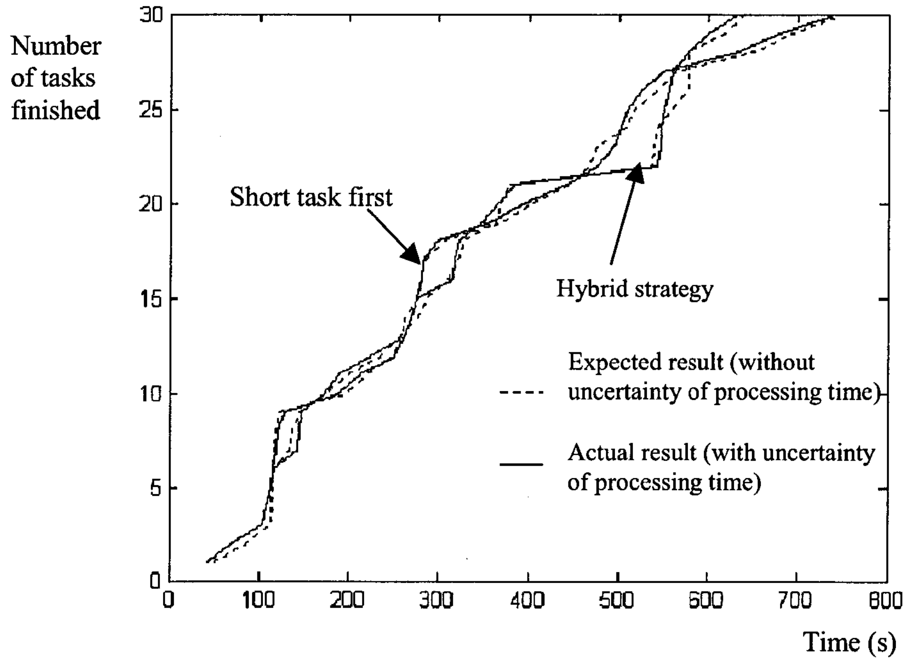


Figure 6.4 Task scheduling with time uncertainty, variance equal 10 s

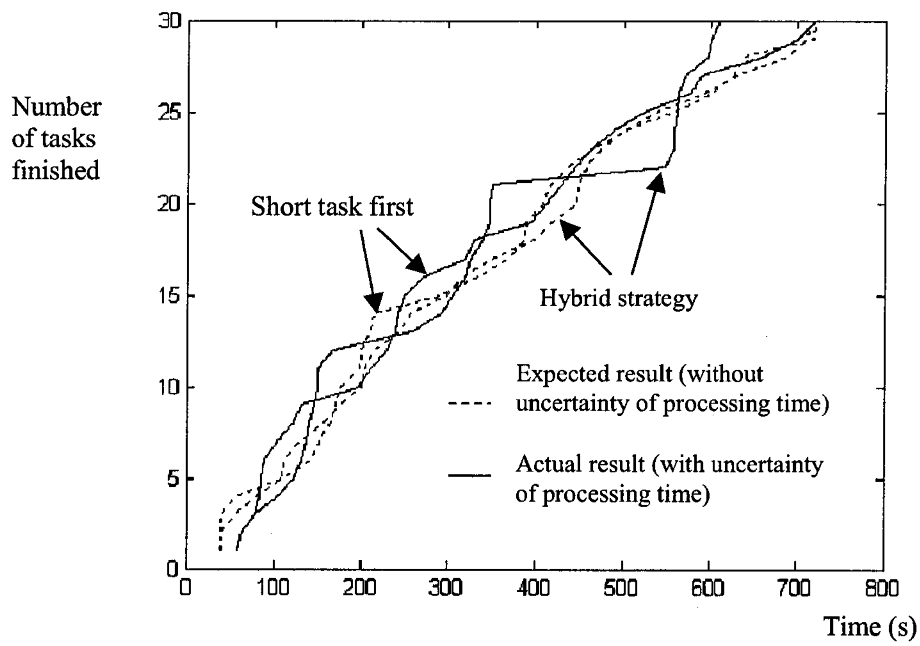


Figure 6.5 Task scheduling with time uncertainty, variance equal 50 s

For groups that we are sure we can finish, we use hybrid scheduling strategy to finish them with least time. For later groups that we may only finish part of them within the given time, we use either hybrid or short-processing-time-first strategy to finish as many tasks as possible for the time given.

6.3 Using trajectory sensitivity for determining optimal action amount

Trajectory sensitivity applications in power systems can be found in [69][95][96]. It is also a good tool to determine the optimal action amount for ERS system, since most problems are caused directly by a system trajectory passing through a relay-triggering zone. As discussed in Section 4.4, sensitivity information is useful for finding the optimal action amount quickly. Although the trajectory sensitivity technique is not implemented in the demonstration system, separate tests are performed to verify its feasibility. One example is to be presented below. Simulations in this section are obtained from PSS/E software.

System and initiating event description

A 179-bus WSCC system is used as the test power system. The system one-line diagram is shown in Figure 6.6. The initiating event examined is as follows: At time 0, a 3-phase fault occurs on line 99-81 close to bus 99; at time of 0.1 second, line 99-81 is tripped. At the same time, generator 36 is tripped to maintain the system stability, as the system would otherwise lose synchronism. Also occurring at this time is the tripping of a shunt capacitor at bus 85 to prevent the possible transient over-voltage. This capacitor tripping turns out to cause more problems – transient voltage dips at load bus 85. The bus 85 voltage is shown in Figure 6.7.

As required by NERC/WECC (Western Electricity Coordinating Council) planning standards [97], for category B and C initiating events [1], transient voltage dip should not exceed 20% for more than 20 to 40 cycles at load buses. Here we assume that this would require that the voltage dip should not fall below 0.8 pu at bus 85 for over 0.4 seconds. In

Figure 6.7 one can see that the voltage continuously falls below 0.8 pu. This causes a violation of the WECC reliability criteria. To prevent this voltage dip violation, load shedding at bus 85 during transient disturbance is taken as a remedial action.

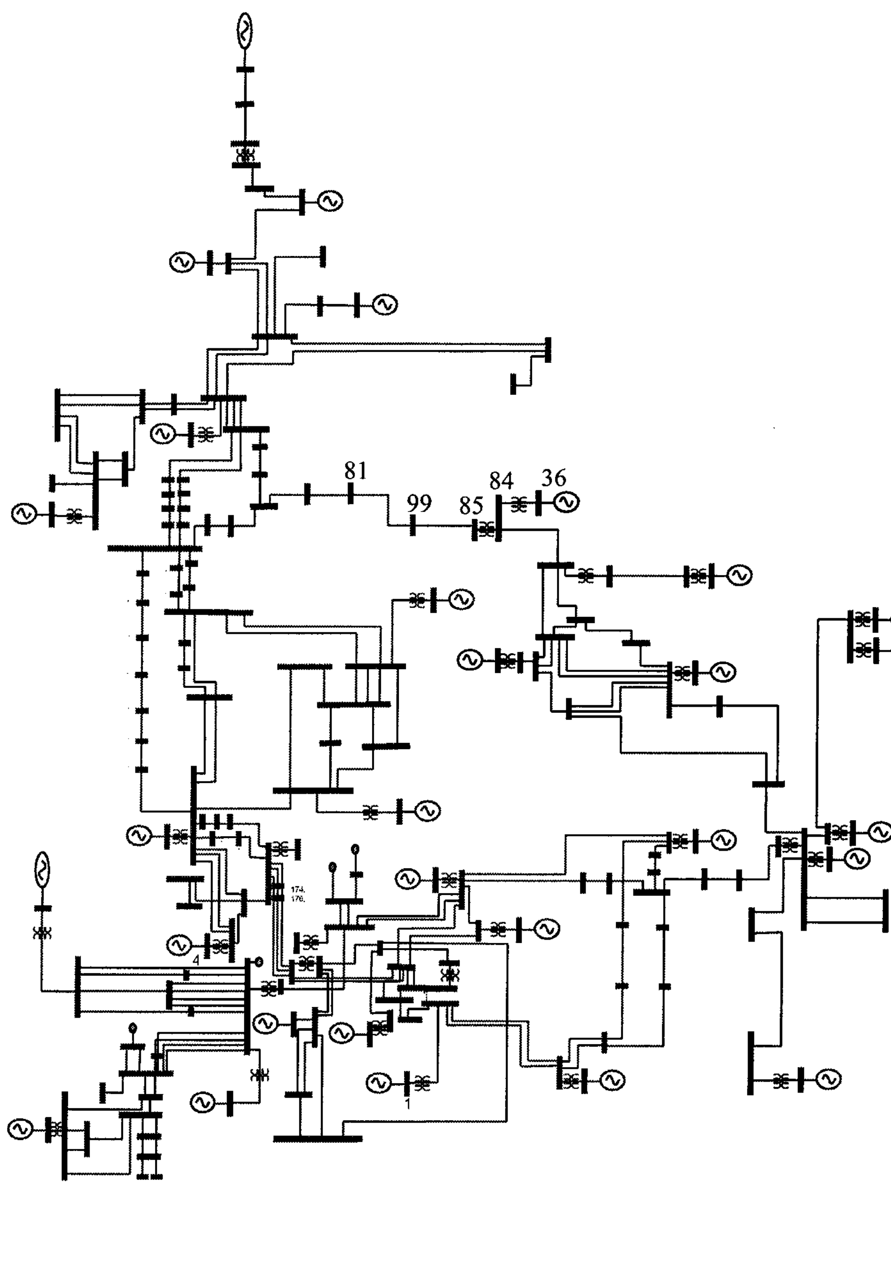


Figure 6.6 WSCC 179-Bus system

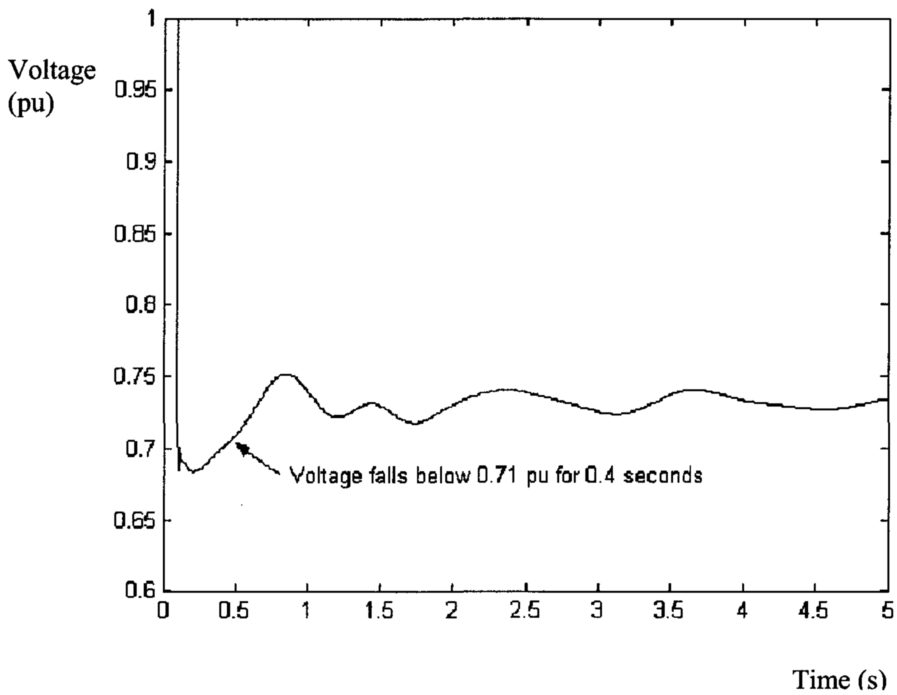


Figure 6.7 Transient voltage dip at bus 85 without load shedding

Determine optimal load shedding amount using trajectory sensitivity

Voltage trajectory sensitivity with respect to load shedding amount is needed to determine the optimal action amount. This sensitivity can be calculated from an analytical method (including numerical calculation if necessary) [98]. However, it is also possible to adopt the elementary approach of two computer runs, one for nominal and one for changed parameters [98].

For this test case, we already have one simulation result – 0% load shedding. The result of Figure 6.7 shows that the voltage level below which the voltage falls for exactly 0.4 seconds is 0.71 pu. In order to get the sensitivity value, we need a second simulation result. So we repeat the simulation but shed the whole load at bus 85 at 0.1 seconds in order to obtain the sensitivity information. The result is shown in Figure 6.8.

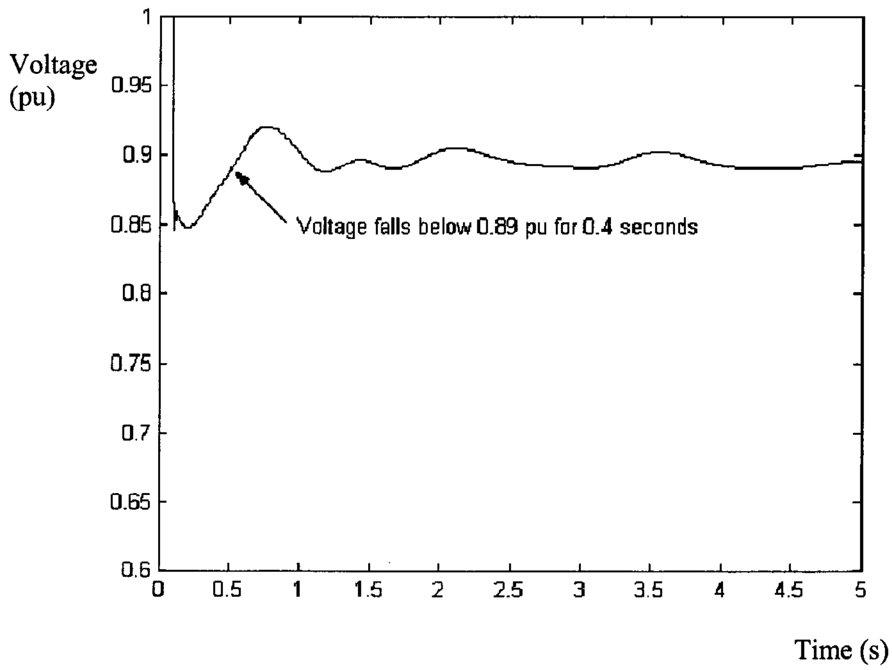


Figure 6.8 Transient voltage dip at bus 85 without 100% load shedding

Suppose that $V_a(t)$ is the voltage trajectory obtained by shedding L_a% load at bus 85, then $V_a(t)$ can be expressed by a trajectory sensitivity value:

$$V_a(t) = V_1(t) + S(t) \cdot L_a\% \qquad \text{Equation (6.1)}$$

where: $V_1(t)$ is the voltage in Figure 6.7;

$S(t)$ is the trajectory sensitivity factor that can be calculated from the two simulation runs according to:

$$S(t) = \frac{V_2(t) - V_1(t)}{100\% - 0\%} \qquad \text{Equation (6.2)}$$

where, $V_2(t)$ is the voltage in Figure 6.8.

By simple algebra calculations and low voltage duration detection, the critical point is found: The voltage would fall below 0.8 pu for 0.4 seconds when the load shedding level is 46.83%. The predicted corresponding voltage trajectory is shown in Figure 6.9. This sensitivity calculation time is negligible compared with time domain simulation, since only algebraic calculations are involved. And, unlike simulations, this sensitivity calculation does not increase as the system size increases.

To test the accuracy of this prediction, a simulation run is conducted with 46.83% load shedding. The result is shown in Figure 6.10. The result shows that the voltage falls below 0.806 pu for 0.4 seconds. Assuming our goal is to achieve 0.01 pu accuracy, the optimal action amount is found by the first trial. That is, only one additional simulation is run before the critical point is identified (another simulation is necessary for verification). For convenience, the sensitivity predicted curve is also shown in Figure 6.10.

<u>Determine optimal load shedding amount using binary trial</u>

As a comparison, we use the binary search (see Section 4.4) method to search this critical point again. The searching procedure is shown in Table 6.2. The result shows, for an error tolerance of 0.01 pu, 4 additional simulation runs are necessary to reach the solution. For this case, the sensitivity based method is at least 2 times as fast as the traditional binary search method.

Table 6.2 Determine optimal action amount by Binary Search Method

Trial No.	Load shedding amount (%)	Voltage that covers 0.4 seconds (pu)
1	50.0	0.812
2	25.0	0.767
3	37.5	0.789
4	43.8	0.799

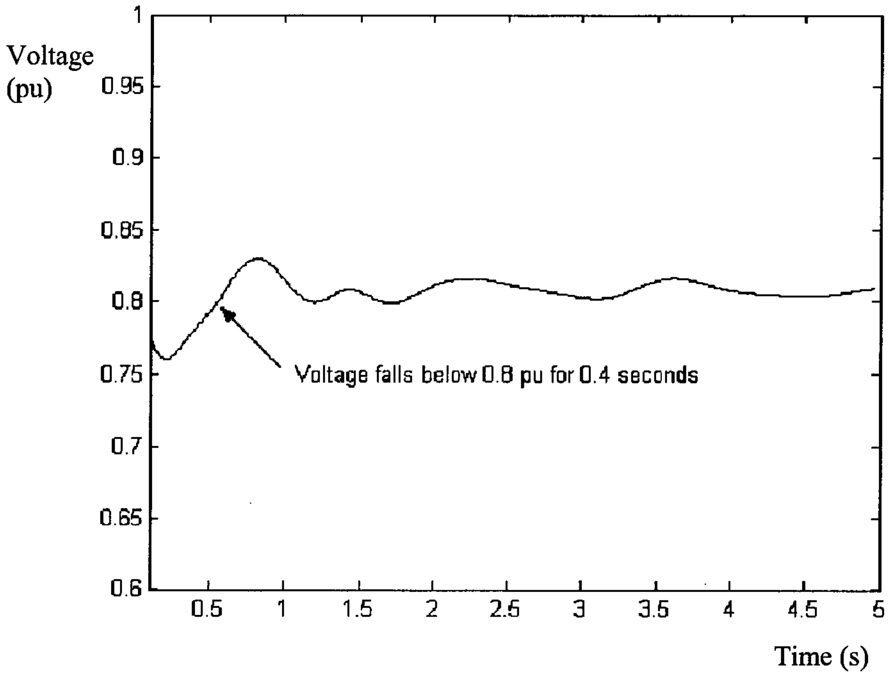


Figure 6.9 Voltage curve with 46.83% load shedding by sensitivity prediction

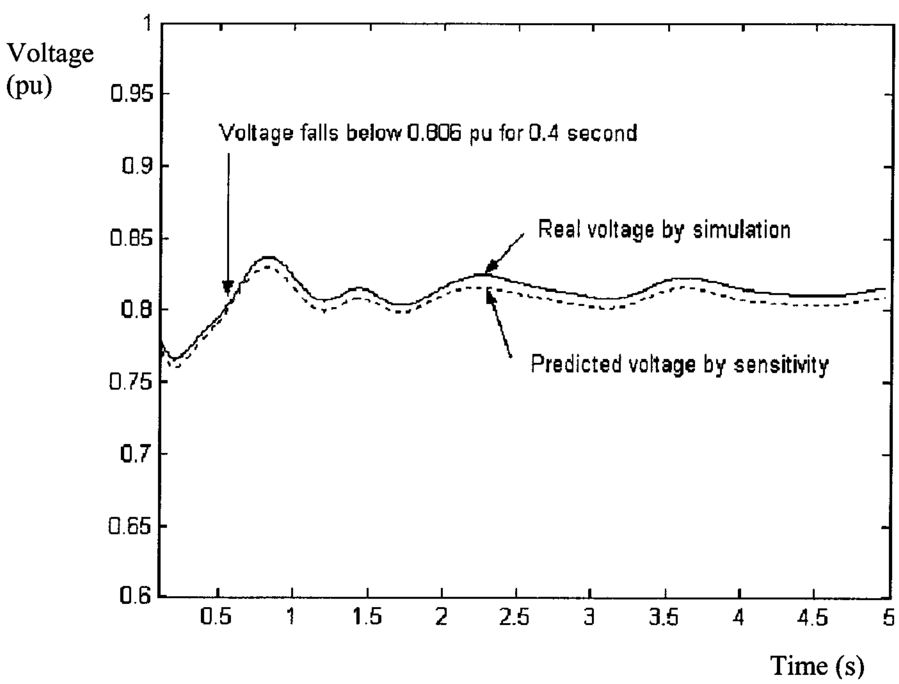


Figure 6.10 Voltage curve with 46.83% load shedding by simulation

Summary

Generally speaking, sensitivity information gives a very good direction and step size for adjusting the action amount, and thus usually reaches the solution with fewer simulations. This effect is not very significant when the options are discrete, but for continuous control, the efficiency improvement of sensitivity is dramatic.

When more than 2 simulation runs are available, the sensitivity technique can be extend to include a second order term as in Equation 6.3. This will increase the efficiency of this method when the relation between the trajectory and the sensitivity parameter is highly nonlinear [69].

$$V_a(t) = V_1(t) + S_1(t) \cdot L_a\% + S_2(t) \cdot (L_a\%)^2 \qquad \text{Equation (6.3)}$$

6.4 Coordination issues

6.4.1 Coordination between response-based action and event-based action

The most common response-based remedial actions are UFLS and UVLS. Response-based actions can act as either a last line of defense after an event-based action, or as an integrated part in a defense plan. The settings of these load-shedding relays are designed by offline calculation based on certain assumptions regarding operating conditions and once set, typically are not adjusted. However, after the execution of event-based actions, some assumptions on operating conditions may no longer be valid, making the UFLS or UVLS settings inappropriate. For example, UFLS that use rate of frequency change need information about the system inertia for calculating the settings, but the system inertia will change after generator tripping from event-based actions. As a consequence, some coordination should be carried out between the response-based action and the event-based actions.

Reference [99]-[101] report on an adaptive load-shedding scheme. They suggest acquisition of online information to adjust the settings of load-shedding scheme. Basically, system inertia (generator tripping), generation reserve, and system topology (islanding) can influence the settings. The ERS designed in this work should be able to send signals to those response-based SPS and change their settings continuously according to current system condition and designed event-based action logics.

6.4.2 Coordination between existing traditional SPS action and the ERS decision suggestion

During the ERS simulation, existing automated SPS action should also be modeled in the same manner as protective relays. Without considering the automated action by traditional SPS, suggestions to the operator may be ineffective or even problematic, further exacerbating poor system performance. As a lesson learned from the midair crash that occurred in Germany on July 2, 2002 [102], conflicting warnings/suggestions from an automatic device and from a human being can result in catastrophic consequences.

6.4.3 Coordination between different engineer groups

As a result of the increased scope of ERS compared with SPS, a larger group of engineers will be involved in ERS development and implementation tasks. ERS vendor, EMS vendor, protection engineers in utilities, and system operations engineers in utilities will all play important roles. Without good coordination from a higher management level, efforts from different groups would be weakened.

7 CONCLUSIONS AND FUTURE WORK

7.1 Contribution of this work

For modern power systems, catastrophic cascading events still cause huge losses to the economy and society. The ERS system proposed in this work is capable of capturing most of these cascading events and defending the power systems against them. The most significant contributions of this work are summarized in what follows.

A system design with significant advantages

An emergency response system is designed. This design defends the power system much more effectively than what is currently in place (traditional SPS):

1) It defends power systems under a wider range of system configurations and operating conditions;
2) It defends power systems against a larger number of initiating events, including catastrophic cascading system disturbances;
3) It defends power systems against more types of system failure, including protective relay operation caused system failure and long-term system instabilities, which are the main contributors of large system disturbances.

This system design also enable use of real-time power market information, which is a crucial feature providing that the selection of actions to mitigate poor post-initiating performance may be done based on a balance between the cost of the action and its effectiveness.

A generalized automated remedial action logic design process

This work generalized the basic remedial action design features in such a way so as to make what has heretofore been highly application-specific technology – the SPS action logic design – into an automated and intelligent decision process. This contribution is important, because it is the fundamental enabler for the ERS, making it effective in an emergency scenario where response must be very fast. This contribution is also important because it serves to encapsulate, in a formalized way, the SPS design process; as a result it will be useful to SPS designers in reflecting on and improving upon what they do.

Demonstration system construction

A demonstration software system is constructed to verify the effectiveness and feasibility of ERS. Large amount of labor was spent on building the basic simulation tool. The main feature of this system includes:

- Relay models and long-term simulation are implemented to detect protective relay operation cause system failure and system long-term instability;
- Remedial action logic design for multiple initiating events is processed automatically without human intervention;
- Alternative actions are also identified to make the system adaptive to power market practice.

Test results show that ERS is much more effective than traditional SPS and its implementation is feasible.

Other implementation issues

Key implementation issues are studied in this work and corresponding advance algorithms are suggested. In particular, event queuing by task scheduling algorithms and optimal action amount determination by trajectory sensitivity techniques are demonstrated with examples.

7.2 Future work

A complete ERS system is a comprehensive system, including both hardware and software, with cooperation between different human sources. There is still significant work remaining before an ERS is realized. This work is summarized in what follows.

1. Software design

There is significant work necessary to complete other function blocks illustrated in Figure 3.2, the core of which is identified below.

a) ***Forecasting:*** This is to predict the high-risk future period so that a computation for this period can be started in advance. A good method is needed to effectively predict these high-risk periods, and to determine a good lead-time for this early computation.

b) ***DDET database management:*** After the ERS operates online for some time, the available DDET data volume is large. A challenging work is to develop a good management system for using this large storage so that the search time for a certain action is not adversely impacted by the amount of DDET available.

c) ***State estimation:*** State estimation function in the energy management system provides ERS with real-time power system operating condition. The accuracy of the state estimation function is critical because it directly determines the output of ERS, the remedial actions. The current accuracy of state estimations is good enough for monitoring purpose. But improvement is necessary if it is for automatic remedial action design purpose.

2. Action candidate identification

Although this dissertation has significantly developed the action candidate identification procedures, there are still two aspects that need further development.

a) ***System control models:*** This includes all control devices on generators, lines, transformers, and loads, including relays. This dissertation only implemented limited controls due to labor constraint. Realization of ERS would require accurate modeling on all controls for accurate action identification.

b) ***Automatic action search tool kit:*** This work implements a limited set of action search tools, which include load shedding for overload and under-voltage problem, shunt switch for low voltage problem, and impedance relay blocking for impedance relay undesirable operation. Other items in Table 4.2 needs further efforts to implement.

3. Other issues

This work mainly develops software logic, which is the core of the ERS design. However, the following issues require significant work as well.

a) ***Hardware design:*** This dissertation proposed a centralized design for implementing the ERS (see Section 3.5). To build a reliable hardware system to implement this design requires the expertise from computer engineers.
b) ***Communication issues:*** The ERS will communicate with other devices to collect and report real-time information. A standard reliable communication (both hardware and software) needs to be developed to implement ERS.
c) ***Source information availability:*** The continuous good performance of the ERS depends on the constant inputs of accurate power system model from system model engineers. Certain standards and guidelines should be established to ensure a constant update of the system model used by the ERS.

It would also be beneficial to analyze the possibility of implementing the framework of the ERS to defend the power system at restoration stage. There, 'initiating event' for the system would be system restoration switching sequence instead of system faults. Besides relay modeling, automatic restoration of loads should also be modeled. Difficulties to be overcome are: estimation of cold load to pick up, predicting a longer series of system events, and suggesting optimal restoration switching sequence.

7.3 Conclusions

The motivation behind this work is that there is little or no decision-support tools for control room operators to use in identifying early and effective actions when facing fast developing system-wide disturbances, and as a result, initiation of such disturbances is very likely to result in high consequences. The goal of this work is to develop a power system emergency response system to provide effective decision support during the early stages of a large system disturbance in order to mitigate its impact.

The innovative design of the ERS system provided by this work defends power systems against system-wide disturbances. The key of the success is the ability of predicting a large set of system disturbances and automatically (and thus rapidly) identifying optimal remedial actions. Test results from a demonstration system verify the effectiveness and feasibility of the ERS system.

APPENDIX A. ONTARIO HYDRO 4-GENERATOR SYSTEM DATA

Following data are in PSS/E format.

Power flow data:

```
0   100.0 / FRI, MAR 08 2002  12:19
                               100.0

  1 'AAR1GEN1'    230.0 2  0.00  0.00   1   0 1.0300  45.96
  2 'AAR1GEN1'    230.0 2  0.00  0.00   1   0 1.0041  35.09
  3 'AAR1GEN1'    230.0 3  0.00  0.00   1   0 1.0300   0.00
  4 'AAR1GEN1'    230.0 2  0.00  0.00   1   0 1.0036   -9.89
  5 'LOADLOA1'    230.0 1  0.00  2.235  1   0 0.9555   25.98
  6 'LOADLOA2'    230.0 1  0.00  2.580  1   0 0.9522  -18.32
0
    5,'1 ',1,    1,    1,  1241.00, 100.0,  0.0,  0.0,   0.0,     0.0,   1
    6,'1 ',1,    1,    1,  1699.00, 100.0,  0.0,  0.0,   0.0,     0.0,   1
0
   1, 1,     790.00,     101.65, ,,,,,, 0.033
   2, 1,     790.00,     500.00, ,,,,,, 0.033
   3, 1,     719.94,      97.98, ,,,,,, 0.033
   4, 1,     740.00,     500.00, ,,,,,, 0.033
0
   1      2 1  0.002500  0.025000
   2      5 1  0.001000  0.010000
   5      6 1  0.022000  0.220000
   3      4 1  0.002500  0.025000
   4      6 1  0.001000  0.010000
0
0
 1     0     0.00     0.00 '        '
0
0
0
0
0
0
0
0
```

Dynamic data:

```
  1 'GENCLS'  1      58.50   45.0    /
  2 'GENCLS'  1      58.50   45.0    /
  3 'GENCLS'  1      58.50   45.0    /
  4 'GENCLS'  1      58.50   45.0    /
```

APPENDIX B. DEMONSTRATION SYSTEM TEST DATA

System branch data: (in pu, use system base MVA: 100 MVA)

No.	From Bus	To Bus	ID	R	X	B
1	1	5	1	0.004	0.04	2.5
2	1	5	2	0.004	0.04	2.5
3	2	5	1	0.004	0.04	2.5
4	1	2	1	0.000	0.01	0.0
5	3	5	1	0.004	0.04	2.5
6	3	5	2	0.004	0.04	2.5
7	5	6	1	0.002	0.02	2.0
8	5	6	2	0.002	0.02	2.0
9	5	6	3	0.002	0.02	2.0
10	4	6	1	0.002	0.02	1.0
11	4	6	2	0.002	0.02	1.0

Dynamic data for the 4 generators*:

ID	D	Xd	Xq	Xl	Xd'	Xq'	Xd"	Xq"	Td_0'	Tq_0'	Td_0"	Tq_0"	H	Tj	r
1	12.0	1.8	1.7	0.15	0.25	0.25	0.18	0.18	6.0	0.15	0.03	0.15	3.0	6.5	0.001
1	12.0	1.8	1.7	0.15	0.25	0.25	0.18	0.18	6.0	0.15	0.03	0.15	3.0	6.5	0.001
1	12.0	1.8	1.7	0.15	0.25	0.25	0.18	0.18	6.0	0.15	0.03	0.15	3.0	6.5	0.001
1	12.0	2.1	2.1	0.15	0.25	0.25	0.34	0.33	5.0	0.5	0.04	0.07	3.0	6.5	0.0016

* These values are pu values based on machine base MVA. Base MVA for Generator 1 to Generator 3 is 1300 MVA. Base MVA for Generator 4 is 850 MVA

System relay data:

No.	Type	Location	Settings
1	Impedance	Line 1-5, ID 1, End 1	Z=0.05pu, T=0.5 s
2	Impedance	Line 1-5, ID 1, End 5	Z=0.05pu, T=0.5 s
3	Impedance	Line 1-5, ID 2, End 1	Z=0.05pu, T=0.5 s
4	Impedance	Line 1-5, ID 2, End 5	Z=0.05pu, T=0.5 s
5	Impedance	Line 2-5, ID 1, End 2	Z=0.05pu, T=0.5 s
6	Impedance	Line 2-5, ID 1, End 1	Z=0.05pu, T=0.5 s
7	Impedance	Line 1-2, ID 1, End 1	Z=0.0125pu, T=0.5 s
8	Impedance	Line 1-2, ID 1, End 2	Z=0.0125pu, T=0.5 s
9	Impedance	Line 3-5, ID 1, End 3	Z=0.05pu, T=0.5 s
10	Impedance	Line 3-5, ID 1, End 5	Z=0.05pu, T=0.5 s
11	Impedance	Line 3-5, ID 2, End 3	Z=0.05pu, T=0.5 s
12	Impedance	Line 3-5, ID 2, End 5	Z=0.05pu, T=0.5 s
13	Impedance	Line 5-6, ID 1, End 5	Z=0.025pu, T=0.5 s
14	Impedance	Line 5-6, ID 1, End 6	Z=0.025pu, T=0.5 s
15	Impedance	Line 5-6, ID 2, End 5	Z=0.025pu, T=0.5 s
16	Impedance	Line 5-6, ID 2, End 6	Z=0.025pu, T=0.5 s
17	Impedance	Line 5-6, ID 3, End 5	Z=0.025pu, T=0.5 s
18	Impedance	Line 5-6, ID 3, End 6	Z=0.025pu, T=0.5 s
19	Impedance	Line 4-6, ID 1, End 4	Z=0.025pu, T=0.5 s
20	Impedance	Line 4-6, ID 1, End 6	Z=0.025pu, T=0.5 s
21	Impedance	Line 4-6, ID 2, End 4	Z=0.025pu, T=0.5 s
22	Impedance	Line 4-6, ID 2, End 6	Z=0.025pu, T=0.5 s
23	Over-current	Line 1-5, ID 1, End 1	I=11pu, T=5 s
24	Over-current	Line 1-5, ID 2, End 1	I=11pu, T=5 s
25	Over-current	Line 2-5, ID 1, End 2	I=11pu, T=5 s
26	Over-excitation	Generator 1	V/Hz=1.2, T=5 s
27	Over-excitation	Generator 2	V/Hz=1.2, T=5 s
28	Over-excitation	Generator 3	V/Hz=1.2, T=5 s
29	Over-excitation	Generator 4	V/Hz=1.2, T=5 s
30	UVLS	Load at Bus 5	V=0.9pu, 20% load, T=5 s
31	Auto capacitor bank switching	Bus 6	V=0.9pu, B=3.0, T=5 s

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