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IEEE PSRC Working Group C15

Design and Testing of Selected System Integrity Protection Schemes (SIPS)

Working Group Members

Jonathan Sykes (Chair)

Yi Hu (Vice-Chair)

Mark Adamiak, Alex Apostolov, Bui Dac-Phuoc, Jim Ebrecht, Alla Deronja, Gene Henneberg, Shinichi Imai, Vahid Madani, Dean Miller, Alfredo De La Quintana, Benton Vandiver, Roger Whittaker, Mohammad Zubair, Solveig Ward

Assignment:

To create a working group report and a summary IEEE paper that will describe the design and testing of a selected number of System Integrity Protection Schemes (SIPS). The work will not include System Integrity Protection Schemes that are already covered by works of previous and current PSRC working groups.

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1 INTRODUCTION

A joint IEEE PSRC/CIGRE report, “Global Industry Experiences with System Integrity Protection Schemes (SIPS)”, published in 2009 and a summary IEEE paper of the report [1.2] has found wide application of system integrity protection schemes (SIPS) in the global power industry. Unlike conventional protection systems that are applied to protect a specific power system element, SIPS are installed to protect the integrity of the power system or strategic portions of the system. SIPS encompass Special Protection Schemes (SPS), Remedial Action Schemes (RAS) and varieties of other safety nets. These schemes provide reasonable countermeasures to slow and/or stop cascading outages caused by several levels of contingencies. According to the report [1.2], SIPS in application today include

- Generator Rejection
- Load Rejection
- Under-Frequency Load Shedding
- Under-Voltage Load Shedding
- Adaptive Load Mitigation
- Out-of-Step Tripping
- Voltage Instability Advance Warning Scheme
- Angular Stability Advance Warning Scheme
- Overload Mitigation
- Congestion Mitigation
- System Separation
- Shunt Capacitor Switching
- Tap-Changer Control
- SVC/STATCOM Control
- Turbine Valve Control
- HVDC Controls
- Power System Stabilizer Control
- Discrete Excitation
- Dynamic Braking
- Generator Runback
- Bypassing Series Capacitor

- Black-Start or Gas-Turbine Start-Up
- AGC Actions
- Busbar Splitting

The design and testing of SIPS varies from scheme to scheme and is very different from design and testing of conventional protection systems. SIPS design even varies from application to application for the same type of scheme. The proper design, documentation, and testing of SIPS is the basis for reliable and accurate operation of such schemes, which often are the last line of defense for preventing the protected system from cascading outages. For some SIPS, their design and/or testing have been studied extensively over the years, such as the under-frequency load shedding scheme [1.3], out-of-step tripping, etc., but other SIPS are less studied, such as generator rejection, load rejection, etc., which are also in wide use in power systems according to the report [1.2].

In this report, the high level general considerations in SIPS design and testing will be summarized. The industry practice in design and testing of the following selected SIPS with example implemented schemes will be described:

- Generator rejection
- Load rejection
- Adaptive load mitigation
- Dynamic braking
- System separation

This report focuses on practical examples of SIPS rather than the theoretical SIPS concept. For each selected SIPS, the report includes:

- Design examples with descriptions of their measurement input, detection methods, processing and logics, mitigation actions, and communications used
- Specific design considerations for each design example, which include performance requirements, redundancy, dependability and security, flexibility and expandability, and/or coordination with other protection systems and controls.
- Testing of these design examples, including design for testing, functional performance testing, field commissioning testing, and regular maintenance testing

1.1 Acronyms and Abbreviations

Acronyms and abbreviations used in this report are listed below.

Acronym / Abbreviation	Definition / Description

Acronym / Abbreviation	Definition / Description
ACSR	Aluminum Conductor Steel-Reinforced
AGC	Automatic Generation Control
COMTRADE	COMmon format for TRAnsient Data Exchange
CPS	CrossPoint Switch
CPU	Central Processing Unit
CSU	Channel Service Unit
DC	Direct Current
DNP	Distributed Network Protocol
DS-0	Digital Signal level 0
DS-1	Digital Signal level 1
E1	Digitally multiplexed telecommunications carrier systems with a line data rate of 2048 Mbps
EMS	Energy Management System
EMTP	ElectroMagnetic Transient Program
ER	Event Report
FAT	Factory Acceptance Test
FSK	Frequency Shift Key
GOOSE	Generic Object Oriented Substation Event
GPS	Global Positioning System
HMI	Human-Machine Interface
HVDC	High-Voltage Direct Current
I/O	Input/Output
IEC	International Electrotechnical Commission
IED	Intelligent Electronic Device
LRC	Load Rejection Cell (for Load Rejection Scheme, chapter 4)
LRS	Load Rejection Schemes
mGrid	micro-grid
MPLS	MultiProtocol Label Switching
NERC	North american Electric Reliability Corporation
PC	Personal Computer
PCBD	Power Circuit Breaker trip Delay
PLC	Programmable Logic Controller
POTT	Permissive Overreaching Transfer Trip
PSS/E	Power System Simulation for Engineering software
RAS	Remedial Action Schemes
RMS	Root Mean Square
RTU	Remote Terminal Unit
SAT	Site Acceptance Test
SCADA	Supervisory Control And Data Acquisition
SCS	Substation Control System
SDH	Synchronous Digital Hierarchy
SER	Sequence of Events Recorder
SIPS	System Integrity Protection Schemes

Acronym / Abbreviation	Definition / Description
SOE	Sequence Of Events
SONET	Synchronous Optical NETwork
SPS	Special Protection Schemes
STATCOM	STATic synchronous COMpensator
SVC	Static Var Compensator
T1	Digitally multiplexed telecommunications carrier systems with a line data rate of 1544 Mbps
TBDA	Trip-Block Decision Angle
TLC	Transmission Line Cell (for Load Rejection Scheme, chapter 4)
TMR	Triple Modular Redundant
TSLP	Trip-block characteristic SLoPe
UPS	Uninterruptible Power Supply
VPS	Virtual Power Station

2 GENERAL CONSIDERATIONS IN SIPS DESIGN AND TESTING

Although SIPS are typically different from each other because their applications are specific to special requirements, there are some considerations in their design and testing that are generally common to them all.

2.1 Power System Hierarchy

The specific hierarchy of the electric power system needs to be considered in the design and implementation of SIPS.

Today's electric power system is very complex, consisting of a large number of generation power plants that generate electric power for delivery to the loads through highly interconnected transmission systems and distribution networks. The electric power system is operated with energy management systems to maintain generation-load balance of the system ensuring sufficient security margin to withstand certain system contingencies, such as loss of a transmission line and/or generating unit.

When the power system cannot be operated securely against such contingencies or when multiple contingencies occurring within a very short time period may result in system instability or overloaded elements, a SIPS should be considered. The action of the SIPS may decelerate the system, reestablish the balance between load and generation, isolate the unstable parts of the system, or unload the overloaded elements. These SIPS actions highly depend on the hierarchy of the part of the power system where they are applied and must be properly addressed in the SIPS design.

The following subsections discuss several areas that should be considered in future SIPS designs or in re-assessing the design of existing SIPS.

2.1.1 Transmission System Islands

System islands typically result from the tripping of multiple bulk transmission lines. Since this occurrence is generally an uncontrolled action, it is rare that a load – generation balance is achieved within the islanded part of the system at the time of islanding. After an island is formed, the operation of underfrequency load shedding schemes could achieve a post-islanding load-generation balance for the island if there is more load than generation. If at the moment of separation the generation is greater than the load, generator controls based on overfrequency elements could affect the load-generation balance. As a result of the system islanding, a large number of generating units and customers' load could be lost which could be prevented or minimized by the actions of a SIPS. It is therefore very important to design and apply proper SIPS in order to prevent the uncontrolled formation of transmission system islands.

2.1.2 The Sub-Grid

The Sub-Grid is a new concept that can be defined as a controlled transmission island. Based on continuous monitoring of the load and generation in different areas of the system, in case of an emergency the Grid can be split into Sub-Grids with a relative balance between the load and generation within most of Sub-Grids.

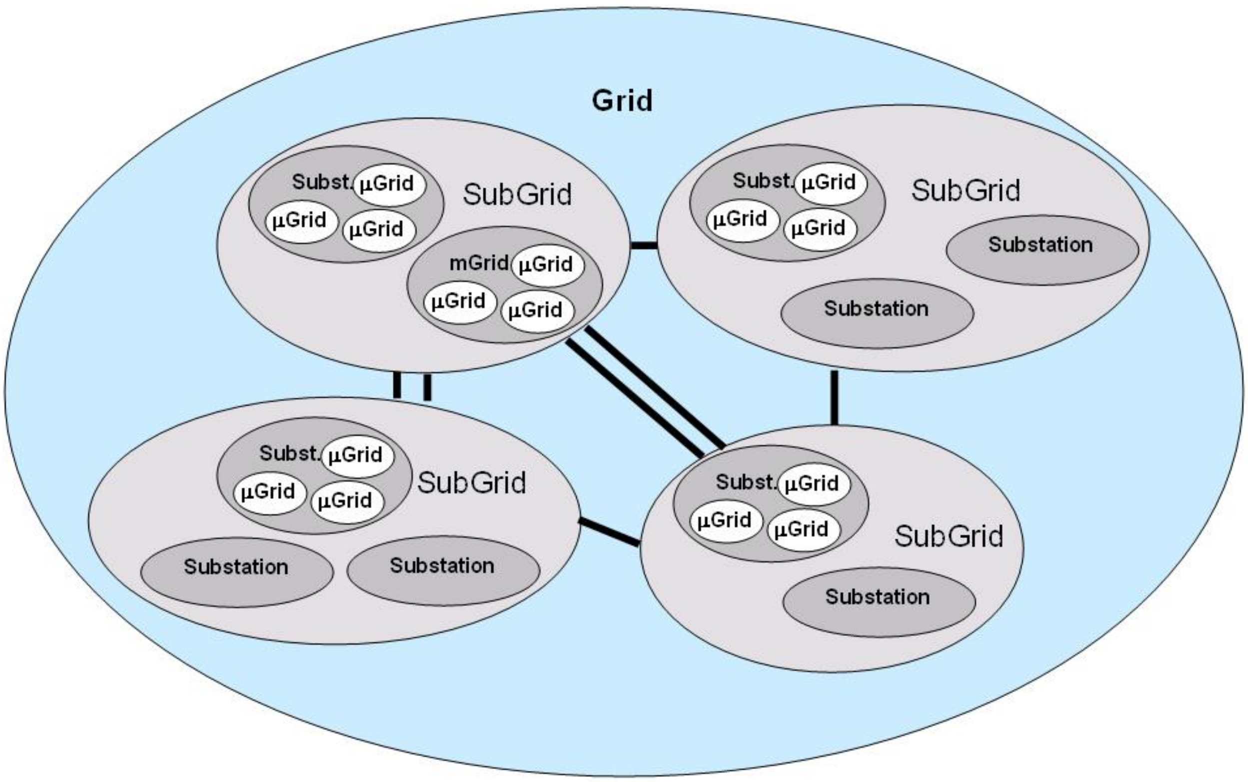

Figure 2-1 Grid Hierarchy

As shown in Figure 2-1, under normal conditions all Sub-Grids operate in parallel as part of the grid. They need to be continuously monitored in order for the grid control system to be able to determine the state of each Sub-Grid balance.

Each Sub-Grid contains one or more substations that can be considered as mini-grids that increasingly include different types of distributed energy resources.

Each substation may contain distribution feeders with one or more Micro-Grids (μGrid in Figure 2-1).

The Sub-Grid balance can be determined based on different sources of information:

- System configuration
- Generation
- Loads
- Power flow between the Sub-Grids

Based on this real-time data the control system can make a decision during an emergency to split and put one or more Sub-Grids in an Island Mode to prevent a disturbance in one or more Sub-Grids from spreading to the rest of the Sub-Grids. Load rejection or generation control can be used in the isolated Sub-Grids to ensure a successful execution of the controlled islanding process.

A Sub-Grid will typically include one or more utility or non-utility owned power stations. With the development of Smart Grid and the wide spread penetration of distributed energy resources it is necessary to include one or more Virtual Power Plant (VPP) in the design of load rejection systems. A VPP is a cluster of distributed generation installation (such as a wind turbines, solar panels, or micro-hydro, etc.), which are collectively operated by a central control entity.

Each substation connected to the Sub-Grid transmission system will be considered as a Mini-Grid if it has some form of distributed energy resources. The control systems of the Sub-Grid will track the level of balance of each substation based on the power flow through the power transformers.

Load rejection or generation control can be used at each level of the system based on signals from the upper levels of the system and local monitoring of the load – generation balance.

In reference [2.1] an application example of a SIPS used to form controlled transmission system islands supplying critical area loads is introduced. To detect system separation the scheme monitors the phase angle between the main grid and several possible Sub-Grids by sampling voltage values measured at local and remote substations and using a high speed communications network to speed up the comparison of the values. The amount of load shed and reactive power compensation action taken within the Sub-Grids is based on on-line network analysis. The system achieves mitigating action within one second.

2.1.3 The Mini-Grid

Traditionally, the distribution system of a substation is supplied through one or more power transformers and does not have any other active source. This distribution system configuration has changed with the connection of increasing numbers of distributed generators to distribution feeders. It might now be possible to balance the combined output of all the distributed generators with at least the critical loads on the distribution system.

A distribution system of a substation that has distributed generation is defined as a Mini-Grid. It can be isolated from the rest of the Grid when all power transformers are taken out of service due to fault, abnormal system conditions or intentionally in order to reduce the effect of a wide area disturbance on the distribution system.

Monitoring and controlling the balance in the substation distribution system will be one of the main tasks of the Substation Control System (SCS) with load rejection as one of the main tools available to maintain the balance.

2.2 Generic SIPS Description Model

A SIPS is designed to detect abnormal system conditions, to decide on a course of actions, and to take the appropriate corrective actions. This generalized concept is shown in Figure 2-22 below.

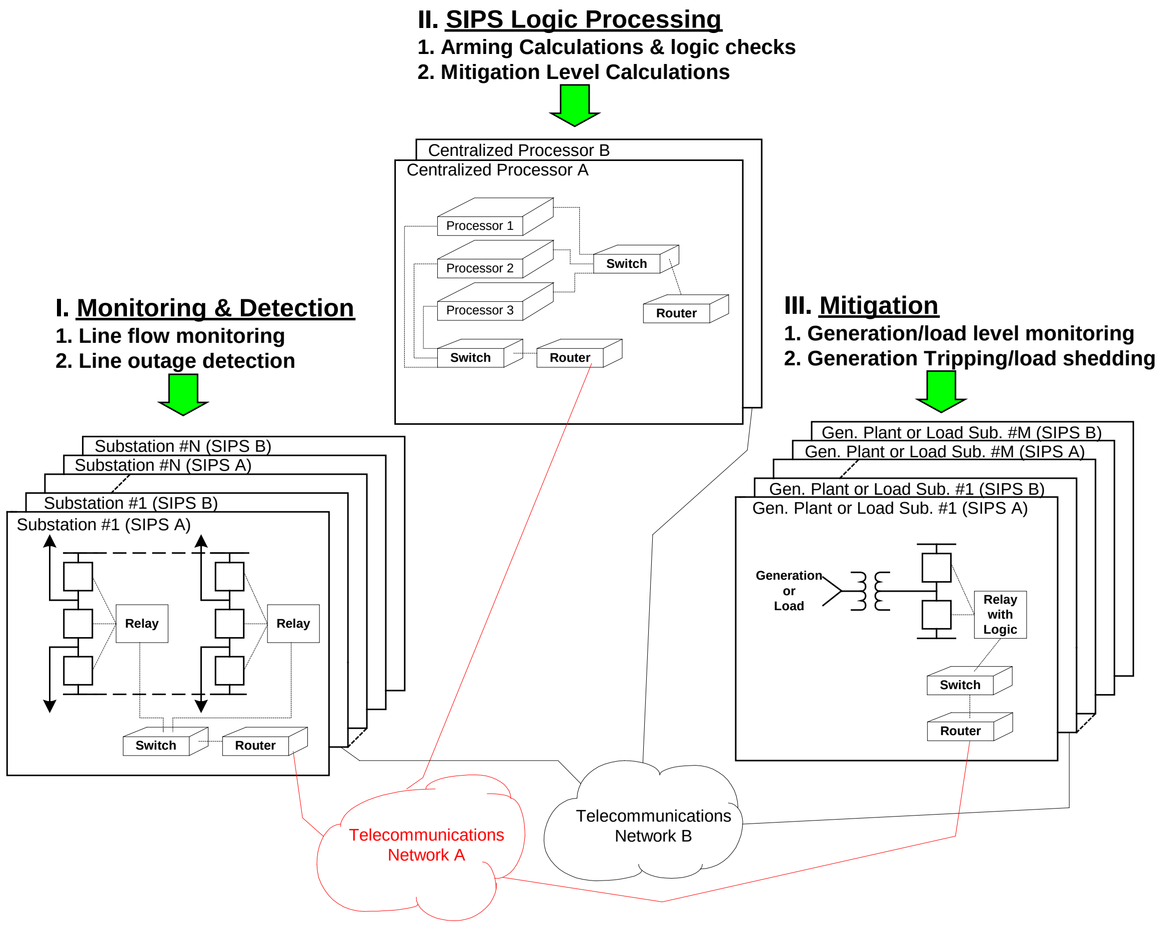

Figure 2-2 Generalized SIPS Architecture

2.2.1 Monitor and Detect

The Monitor function generally involves the measurement of power flows on lines, voltages, frequency, rate of change of frequency, and/or other factors pertinent to the specific system condition. Detection is the determination that a line, generator, transformer, or other power system component is out of service. Security of detection can be accomplished through the measurement of two quantities. For example, on a line, a line outage can be securely detected by requiring that the circuit breaker status is monitored to be “Open” and the current on the line is less than a minimum pickup value. Most SIPS are critical to system performance. As such, these schemes are generally designed (and often mandated) to be composed of fully redundant “A” and “B” sets of equipment.

2.2.2 Communicate

The information from the various monitoring and detection sites must be communicated to a decision function. In a physical implementation, the decision function can either be centralized in one location or distributed throughout multiple locations. The size of the scheme and the number of locations involved are usually factors in determining the physical architecture. The performance capabilities of available communications technology generally removes communication latency as a factor in the centralized vs. distributed decision. Measurements on actual implementations have demonstrated that device-to-device latencies in the order of 3 to 7 ms are readily achievable.

Similar to the implementation architecture of the monitor and detection function, the communications system for the SIPS must generally be designed for redundant operation such that no single communications system element failure can prevent the SIPS from performing its functions. Multiple point-to-point links or communications rings can be utilized to meet this criterion.

Although high-speed communications technology is available, economics may dictate that existing communications infrastructure with higher latency is used. In this scenario, communications latency must be factored into the overall system performance criteria.

2.2.3 Decide

Once all relevant data has been communicated to the decision function, the data is typically analyzed for conformance to pre-determined critical operating conditions. For example, the planning engineer will have a priori determined that if Lines 1 and 2 are overloaded and Line 3 is reported as having been outaged, 100 MW of load has to be shed. A SIPS will typically consist of multiple contingencies as described above. As most SIPS are required to operate “as fast as possible”, there is typically very little operator interaction with the real time decision. Operator interfaces are usually provided to monitor the status and health of the system, to facilitate in the testing of scenarios, and sometimes to “arm” the scheme when warranted by system conditions.

2.2.4 Mitigate

Once a decision to take action is made, the desired action must be communicated to actionable devices in the field. The actionable devices are typically known as mitigation devices. Depending on the required action, mitigation devices can span all the way from high-voltage substations down to distribution substations. In the cases where dynamic stability is being addressed, mitigation will most likely take place in high voltage substations. When overload conditions are being addressed, mitigation will usually take place at sub-transmission to distribution levels. Again, typical installations will include a redundant “A” and a “B” system.

2.3 Communications Requirements

This section explains the types of communications tools used to implement SIPS. Communications are used to acquire data from distant locations for the central controller where the decision for any action is made. Communications are also used to send commands to the field to execute the action. The communications paths may not be the same or of the same criticality. This section will examine the types of communications paths for data acquisition and transmitted operations.

Mitigation action signals are sent from the controller to the field. These signals typically cause tripping or closing of breakers. Status signals, representing the condition of the power system are sent from the field to the controller. Status signals communicate breaker or switch positions to the controller. Monitoring signals, also sent from the field to the controllers for evaluation, are analog value signals such as MW and MVar representing system loading. SIPS signals are carried over various communication systems including but not limited to: SONET, microwave, leased line, fiber, Ethernet, satellite, radio and power line carrier.

In order to assure system stability, SIPS signals transmission requires speed, security and dependability from the communications system that it uses. Security is for the communications system to not produce inappropriate action as a result of a component failure or a communications circuit media issue and dependability is to pass the control signal in spite of a single system component failure. SIPS event detection signals are sent to the controller to trigger SIPS decision makings and SIPS control action signals to the field for mitigation actions such as opening or closing breakers.

SIPS monitoring signals are measured and/or calculated signals representing analog values of power delivery. The signals may be in a digital format such as DNP, proprietary protocol, IEC 61850, or analog frequency shift key (FSK). SIPS monitoring signals from the field that are transmitted to the controller may not require the same speed of delivery as event detection and control action signals if these signals are not quantities that trigger the decision making and mitigation actions of the SIPS but are quantities that influence what action should be taken when certain events occur. These SIPS monitoring signals from the field may be dependent on existing low speed communications architecture at the utility.

Direct fiber, digital microwave, and SONET provide low latency for a given transmitted signal. Satellite signals have the greatest delay. Ethernet delays are variable based on the equipment, the number of nodes, and configuration used.

Communication delays vary depending on the communications system used. Direct fiber is different than digital multiplexing schemes, and packet based communications (e.g. Ethernet) differ from time division multiplexing (T1/E1 and SONET/SDH). “Through node delay” is the time it takes for a signal to travel through a node. “Re-frame delay” is the amount of time a multiplexer will require to resume communications after an interruption of service. A list of typical delays is presented below:

Media Used	**Typical Delay**
Contact Closure Audio over Analog Channel	10 – 15 ms
Audio over Digital Multiplexer	10 – 15 ms
Asynchronous back to back cross cable	18.07 ms @ 9.6 kbps
Asynchronous back to back cross cable	13.57 ms @ 19.2 kbps
Contact Closure via digital T1	5 ms
Point-to-Point Direct Fiber	8 us / mile
Digital Microwave Delay Pt to Pt	5 us /mile
Digital Microwave Channel Delay	500 to 600 us
Digital Microwave Re-frame delay	100 ms
DS-1 Multiplexer Re-frame Delay	<50 ms
Through Node SONET Delay	50 us
SONET reframe delay	>60 ms
SONET ring switch transfer time	<50 ms
SONET time to sense a failure	<10 ma
DS-1 Multiplexer Through Node Delay	125 to 250 us
DS-1 Multiplexer de-synchronization delay	<100 us
DS-1 Multiplexer synchronization delay	<100 us
DS-1 Multiplexer DS-0 Data Buffering	>1 ms
Channel Service Unit, CSU	>20 ms
Ethernet Packet Communications, MPLS	5.5 – 25.4 ms depending on configuration & number of nodes

The times shown are examples of typical delays. Manufacturers have different methodologies to lessen the impact of delays, reframing, and outage detection.

2.4 Centralized SIPS vs. Distributed SIPS

SIPS have traditionally been designed as centralized automated protection systems. These SIPS may rely on local inputs (e.g. breaker statuses) and initiate local control actions (e.g. trip generator). In addition to local data, SIPS may require additional inputs from remote stations or initiate additional control actions at other remote stations; these signals are transferred via the communications systems, but the decision-making may still be done by the centralized logic processor.

As transmission systems are operated closer to their stability margins and approach other operating limits, automated control actions may be required at various stations in an area, in response to various contingencies in the area. For instance, SIPS may be required to trip remote wind farms in addition to local conventional generators. The availability of high speed, reliable communications allows for the deployment of these wide area SIPS.

Most schemes deployed today are centralized SIPS. In centralized SIPS, all logic processing and arming is done at a central site, and only input/output (I/O) interface devices are deployed at the remote sites. These input interface devices typically have limited intelligence and are only required to monitor breaker statuses and other inputs at remote stations, and transfer all data to the central logic processor. Based on the arming signals, this central processor will then send trip commands to the output interface devices. In some cases where improved security is required, the I/O devices may employ polling and supervision schemes.

In distributed SIPS, the logic processing and arming functionality is distributed across the various stations. The logic processor at each station can independently initiate control actions. Once contingencies are detected, the interface I/O devices can transmit the signals to the local logic processor, which can initiate local control actions, as well as transmit remote trip signals over the communications systems. In such a distributed approach, all remote sites do not need to communicate with one central site, and local tripping for locally detected contingencies does not rely on the communications systems.

2.5 Redundancy Considerations

Failure of the SIPS to operate when required, or its undesired or unintentional operation may have adverse impact on the power system. Therefore, design of the SIPS often involves redundancy or some backup functions. Although simple redundancy or backup systems will improve the dependability of the system it will reduce the security of the overall system. To maintain the security level of a single system and achieve the dependability of a redundant system a two out of three voting system may be needed. Redundant systems also improve operations and maintenance efficiency by minimizing downtime, and the overall life cycle support. Redundancy applied to facilitate maintenance might be in addition to the redundancy that is applied to overcome failures.

One drawback of redundant systems is increased hardware. Depending on the application philosophy of primary and redundant applications being same or different hardware (component), additional training costs and need for more spare parts may also be considered as drawbacks. However, if product and type of hardware used are common to other (conventional) protection and control applications, then added hardware and training are addressed from a “Program” level at the power company.

Some of the operational benefits of redundant systems include:

- Safeguards against malfunctions in case an element in the chain fails to operate.
- Reducing impact of measurement source failure. For example if voltage and frequency are computed from a voltage source when the source information is not correct. Comparison with measurements from a redundant source can be used to detect such a failure.
- Minimizing inadequacy in the design of one of the devices if the principle of operation is not repeated in the redundant (alternate) system.
- Redundant systems increase dependability. They provide assurance to mitigate design flaws. For example:
  - Failure in a power supply design
  - Failure in the processor board
  - Bad digital signal processing

- Failure of a common operating element
- Failure or malfunction of software

Above are some of the examples of the benefits of redundant system. There are many benefits including maintenance, and safeguards against life cycle failures, such as aging of components (e.g. electrolytic capacitor drying, transistor age failure mechanism).

One additional complexity of applying redundant systems is the coordination of the responses of the two systems. If there are multiple actions that the SIPS can take for a single event depending on the condition of the power system and the outputs of the redundant control systems are simply combined using a logic OR function the combined system response may not produce the desired results for all conditions. The responses of the redundant systems as well as the health of the individual systems may need to be monitored. If the predicted responses of the two systems are different, then the output of the system with the most alarms may need to be inhibited.

An example of such a situation is a generator rejection SIPS that could disconnect multiple generating units for the loss of transmission lines through an automatic generator selection algorithm. Depending on the condition of the transmission network, different amounts of generation would need to be tripped for loss of a transmission line. When the power output of one of the generators is operating at or near the SIPS generator rejection power requirements, within the accuracies of the measuring circuits, the redundant SIPS systems could select and trip different generators for the loss of the same transmission line. Without a monitoring system, multiple generators could be tripped when the tripping of one generator would have been the correct response even when the SIPS system is operating within specifications. When the SIPS systems have some performance issues, the results of permitting both systems to trip generators without supervision will most likely produce unfavorable results.

2.6 Functional and System Testing of SIPS

Functional testing is the most widely accepted practice for protection and control systems and is required to ensure that the SIPS and each of its components will operate as designed under different system conditions.

Understanding what has or has not been tested in a complex system is still a major challenge for many organizations. The time commitment required for quality assurance functional testing needs to be one of the highest priorities for ensuring successful operation of the SIPS.

With functional testing the engineering, commissioning and maintenance teams translate functional requirements into executable test cases that confirm how well the SIPS satisfies the requirements at any given time or under any specific conditions. A test plan needs to be developed in order to build a suite of executable tests that define and verify the functionality requirements, providing a fast and objective way to assess the performance of the tested function. It is important to include in this test plan the simulation of common events and conditions for which the SIPS should not operate, particularly when the consequences of false operation are harmful to the system or costly. This process should start together with the design of the SIPS and follow through at each step until the detailed test plan for the SIPS and each of its components is defined. These tests can then be executed regularly to ensure that functional modifications or firmware upgrades do not unintentionally change previously verified functionality.

An effective functional testing practice involves the definition of guidelines for using functional testing technologies effectively (based on the user's protection testing philosophy), and then the implementation and integration of those guidelines into the asset management system.

To achieve effective system testing, the user or manufacturer must not only have a defined practice for its use, but that practice must be implemented and integrated into the engineering process so that it can be used consistently and regularly across the organization. The definition of the functional tests will be part of the design and testing documentation of the SIPS. At the time when the functionality of every single element of the SIPS is designed, it must be specified how it is going to be tested.

The following sections discuss different methods for functional testing of SIPS and their individual components as a function of the type of test being performed. They include some definitions of the types and methods to be used for functional and application testing. Since we are testing complex SIPS, it is clear that methods and tools for System Testing are needed.

System testing is a type of testing conducted on a complete, integrated system to evaluate the system's compliance with its specified requirements.

As a rule, system testing takes, as its input, all of the "integrated" components that have successfully passed integration testing and also the software system itself integrated with any applicable hardware system.

System testing is actually done to the entire system against the Functional or System Requirement Specification. Moreover, the system testing is an investigatory testing phase, where the focus is on trying to make the SIPS fail and test not only the design, but also the behavior and the expected performance of the SIPS. It is also intended to test up to and beyond the bounds defined in the requirements specification.

The specification of the functional testing and the development of the test plans are preferably performed by a different team than the team designing the SIPS. This team still needs to work with the SIPS design team in order to have good understanding of the SIPS functionality.

2.6.1 Functional Testing Methods

Functional testing methods can be divided into several categories. They are related to the complexity of the functionality of the individual devices being used in the different levels of the hierarchical system, as well as the types of distributed functions implemented in it.

The following are the more commonly used testing methods:

- Functional element testing
- Integration testing

- Function testing
- System testing

A function in this case can be considered as a sub-system with different level of complexity, for example a system monitoring function, while the system is the complete redundant SIPS.

Regardless of what is being tested, the test object needs to meet the requirement for testability. This is a design characteristic which allows the status (operable, inoperable, or degrade) of a system or any of its sub-systems to be confidently determined in a timely fashion. Testability attempts to qualify those attributes of system design which facilitate detection and isolation of faults that affect system performance. From the point of view of testability a functional element in SIPS is the unit that can be tested, because it is the smallest element that can exist by itself and exchange information with its peers in the SIPS.

Another consideration is the purpose of the test and it needs to be clarified if the tests are performed in relation to acceptance of a new product or function to be used as a system monitor or process controller (or both), the engineering and commissioning of a substation component or the complete SIPS or its maintenance. From that perspective different testing methods can be implemented even in the testing of the same functional element or function.

For example the testing of a system monitoring function during the user acceptance phase may focus on the testing of the measuring element characteristic using search test methods. During the commissioning the operating times for different system conditions may be the important ones to be achieved through transient simulation methods.

The knowledge of the internal behavior of the test object or more specifically the logic or algorithms implemented determines how the tests are being executed. The most commonly used test methods from this point of view are:

- Black box testing
- White box testing

An important aspect that needs to be considered during the testing is the availability of redundant devices performing the different SIPS functions.

The following sections discuss in more detail the different testing methods listed above.

2.6.1.1 Black Box Testing

Black Box Testing is a very commonly used test method where the tester views the test object as a black box. This means that we are not interested in the internal behavior and structure of the tested function.

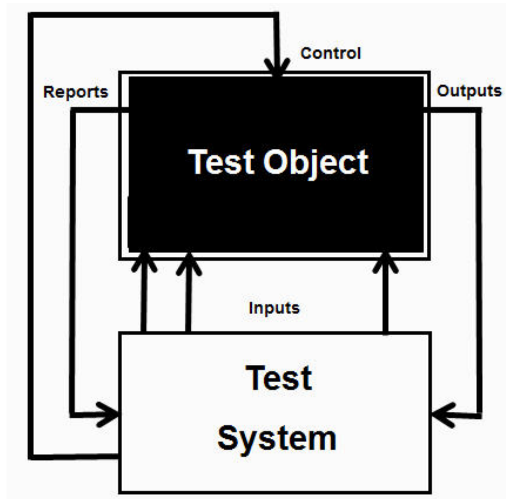

Figure 2-3 Black Box Testing

In the case of black box testing the test system is only interested in finding conditions under which the test object does not behave according to its specifications. Test data are derived solely from the specifications without taking advantage of knowledge of the internal structure of the function.

Black box testing is typically used for:

- functional elements testing
- SIPS factory testing
- SIPS site acceptance testing

Since functional elements are defined as units that are the smallest that can exist independently and are testable, it is clear that black box testing is the only method that can be used for their testing.

The response of the test object to the stimuli applied to the test object's inputs can be monitored by the test system using the operation of physical outputs, communications messages or reports.

2.6.1.2 White Box Testing

White box testing is a method where the test system is not only concerned with the operation of the test object under the test conditions, but also views its internal behavior and structure.

In the case of SIPS it means that it will not only monitor the operation of the system at its function boundary, but also monitor the exchange of signals between different components of the system.

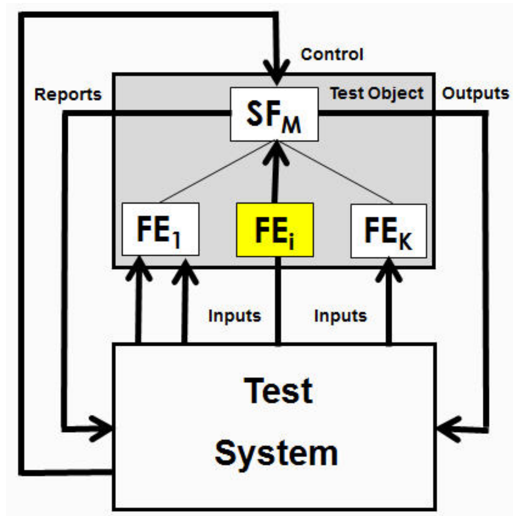

Figure 2-4 White Box Testing

The testing strategy allows us to examine the internal structure of the test object and is very useful in the case of analysis of the behavior of the test object, especially when the test failed.

In using this strategy, the test system derives test data from examination of the test object's logic without neglecting the requirements in the specification. The goal of this test method is to achieve high test coverage through examination of the operation of different components of a complex function and the exchange of signals or messages between them under the test conditions.

This method is especially useful when we are testing distributed functions based on different logical interfaces. The observation of the behavior of the sub-functions or functional elements is achieved by the test system through monitoring of the exchange of messages between the components of the test object.

The test scenarios however do not have to be different from the ones used under black box testing.

2.6.1.3 Top-down Testing

Top-down testing is a method that can be widely used for SIPS, especially during site acceptance testing, when we can assume that all the components of the system have already been configured and tested.

Top-down testing can be performed using both black box and white box testing methods.

The testing starts with the complete system, followed by function or sub-function testing and if necessary functional element testing.

In the case of factory acceptance testing, when not all components of a system or sub-system are available, it is necessary for the test system to be able to simulate their operation as expected under the test scenario conditions. In this case the test system creates the so called Stubs for functions or functional elements that are not yet available.

Top-down testing results in re-testing of higher level elements when new lower level elements of the system are added. The adding of new elements one by one should not be taken too literally. Sometimes a collection of elements will be included simultaneously, and the whole set of elements will serve as test harness for each functional element test.

Each functional element is tested according to a functional element test plan, with a top-down strategy.

A testing stub is a module which simulates the operations of a module which is invoked within a test. The testing stub can replace the real module (for example a line monitor) for testing purposes.

The testing of the individual components of a system function might be required in the case of failure of a specific test, which is shown in Figure 2-5. The function boundary for each of these tests will be different and will require a different set of stimuli from the test system, as well as the monitoring of the behavior of the functional elements using different signals or communications messages.

For example if Test 1 (see Figure 2-5) of the complete SIPS fails, the user needs to start testing subfunctions down the SIPS functional hierarchy. If any of these Test 2 level tests fails, then Test 3 level tests need to be performed, until eventually a failure of a function element at the bottom of the hierarchy is detected.

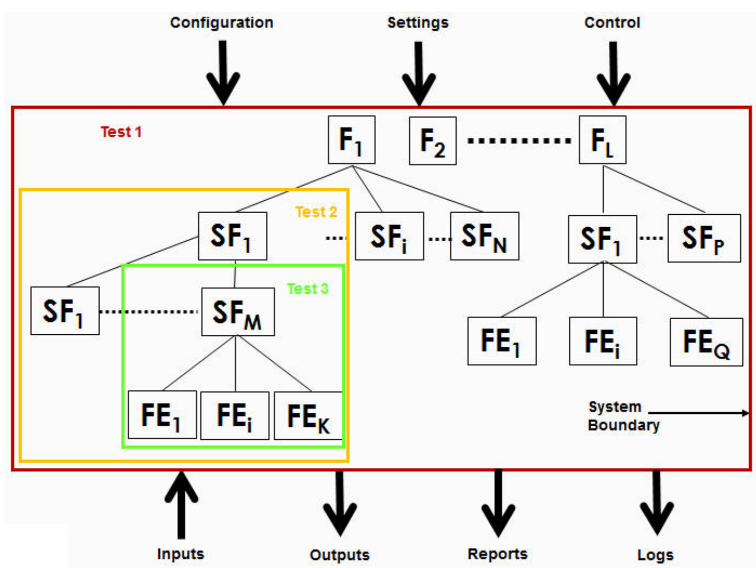

Figure 2-5 Top-down testing of a system monitoring function

2.6.1.4 Bottom-up Testing

Bottom-up testing is a method that starts with lower level functions – typically with the functional elements used in the system – for example FE1, FEi, etc..

This method is more suitable for type testing by a manufacturer or acceptance testing by the user.

When testing complex multilevel functions or systems, driver functional elements must be created for the ones not available. The test system must be able to simulate any missing component of the system when performing for example factory acceptance testing.

There are many similarities in the test scenarios used in the bottom-up, compared to the top-down method. The main difference between the two methods is the order that the tests are performed and the number of tests required.

2.6.2 Regression Testing

One of the characteristics of modern multifunctional substation protection, automation and control devices is the continuous improvement in their functionality due to user requests or for fixing different bugs. This raises an important question for the user – what should be tested, and how, in order to ensure that the modified firmware is going to operate as intended.

Testing which is performed after making a functional improvement or repair of the software is called regression testing. Its purpose is to determine if the change has regressed other aspects of the functionality. As a general principle, functional tests should be fully repeated if a function module is modified, and additional tests which expose the fixed bug are added to the test plan. The functional element will then be re-integrated and integration testing repeated.

2.6.3 Device Acceptance Test

The process of acceptance of any new product by a user is known as a device acceptance test. Its goal is the verification of the correct behavior of the individual device to be used in substation protection, automation and control system. The acceptance test is a precondition for making a product acceptable for use in the SIPS though acceptance tests are not unique to SIPS.

It is done by use of the system testing software tools under the substation, electric power system and environmental test conditions corresponding with the technical specification of the tested devices.

Acceptance tests are carried out with devices that are commercially available. Acceptance tests should be performed using a bottom-up approach and include every single component, functional element and function implemented in the device that is intended for current or future application in the user's facilities. Their goal is to ensure that the device really meets all technical specifications listed in the device documentation that are of interest to the user.

Acceptance testing also may require the use of some specific to the user real life fault or disturbance records.

Depending on the acceptance testing philosophy of the user and the available testing facilities, the test may also cover environmental conditions testing, including some functional tests under extreme environmental conditions specific to the user's territory.

The functional part of the acceptance testing should be based on a set of test scenarios that as realistically as possible simulate the user's substation or electric power system conditions that the tested function is design to operate for.

The acceptance testing should cover all intelligent electronic devices (IEDs) that are intended to be used in the SIPS. Different methods described earlier can be used.

2.6.4 Device Interoperability Test

A device interoperability test is required as part of the product testing before it is accepted for use in a SIPS. It is intended to check the correct behavior of any device when integrated as part of a system. This is to ensure that the device interoperates correctly with other devices approved by the user for application in the SIPS.

Such interoperability tests should be limited to simulation that will result in the sending and receiving of the different types of messages required for the distributed applications between individual devices such as an IEC 61850 GOOSE.

The interoperability test is performed in the lab at the beginning of the SIPS design process and is used to ensure that all devices will be able to exchange correctly the types of messages to be used in the SIPS.

The device interoperability test is an integral part of the approval process of devices.

2.6.5 Integration Test

Integration test is used to ensure that the individual components of the system not only interoperate correctly, but also meet the performance requirements according to the SIPS development specification.

In this case they will include testing of devices at two ends of a communications link. The methods and tools used are in the category of end-to-end and sub-system testing as described earlier.

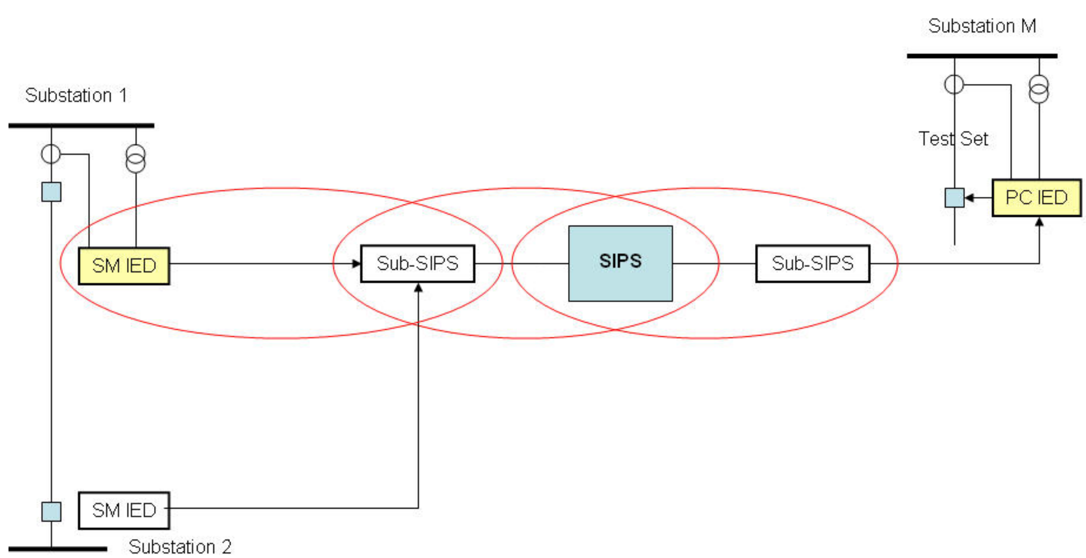

Figure 2-6 Integration test

Figure 2-6 illustrates the scope of some integration tests for an example SIPS. These include tests between SM IED (status monitoring IED) and sub-SIPS on the left side, sub-SIPS one the left side and SIPS at the center, and SIPS at the center and sub-SIPS on the right side.

Many SIPS are applied in applications where different control actions are taken depending on the condition of the power system. Whereas in the typical protective relay application the decision is to trip or not trip a given set of breakers and once the decision to trip is made no further action is required. With many SIPS once the initial action is taken the system must remain in service ready to take further action depending on future events on the power system. The action taken by the SIPS changes the status of the inputs to the SIPS. The power system is moved to a new state and the SIPS must be enabled for further action which may be required in a short time frame. For this type of SIPS a closed loop test system needs to be developed to implement a more realistic test than an open loop test system can provide.

The test system must emulate the power system so that the action of the SIPS will correctly change the value of the inputs to the SIPS. The better the test system emulates the response of the power system to the SIPS control actions the better the test which will result in fewer surprises once the SIPS is implemented in the field.

2.6.6 SIPS Factory Acceptance Test (FAT)

The factory acceptance test (FAT) is a customer agreed functional test of the specifically designed and implemented SIPS. It is a subject of agreement between the final user and the system integrator and is highly recommended since it allows the detection of potential problems in an earlier stage of the project, when it is less expensive and easier to fix them.

Factory acceptance testing may be performed using a top-down approach based on a test plan including test scenarios defined as part of the design of the system. Black box testing methods can be used until any failure of the system for a specific test occurs. White box testing will then be used to determine the reason for the test failure.

One of the main characteristics of factory acceptance testing is that not all components of the system are available. That requires from the test system the ability to simulate any device missing from the factory system, which is a part of the real SIPS.

Another factor for the FAT is that all existing components of the system are configured and set according to the requirements of the real system application.

The factory acceptance test may thus be based on configuration of all devices using the system configuration file for the project.

If a utility performs the role of the System Integrator, a FAT may be performed at the proper utility's facility according to test plans defined as a result of this report.

One of the responsibilities of the Test System during a FAT is not only to apply stimuli to the inputs of the tested SIPS, but also to simulate the missing function elements (FEi in yellow in Figure 2-4) of the SIPS.

2.6.7 SIPS Site Acceptance Test (SAT)

The SIPS Site Acceptance Test (SAT) of a substation protection, automation and control system includes complete testing of the SIPS which is distributed at multiple sites. It is the verification of each data and control point and the correct functionality not only of the individual components of the system, but also the communications between the different sites. The site acceptance test is a precondition for the SIPS being put into operation.

The SAT, similar to the FAT is a customer agreed functional test of the specifically manufactured substation protection, automation and control system, performed with the complete system as installed in the substation.

It is also a subject of agreement between the final user and the system integrator from the point of view of the content of the test plan and the responsibilities of the involved parties.

There are no specific guidelines on what should be included in a SIPS site acceptance test. Development of such guidelines will be of great help to the industry in order to ensure the completeness of the testing process and reduce the probability for failure of the system when put in service.

Site acceptance testing may be performed using a top-down approach based on a test plan including test scenarios defined as part of the design of the system.

Black box testing methods can be used until any failure of the system for a specific test occurs. White box testing will then be used to determine the reason for the test failure.

One of the main characteristics of site acceptance testing is that all components of the system are available. That requires from the test system the ability to simulate all required analog, binary or other signals required for the testing of any specific substation or electric power system condition that the real system is designed to handle.

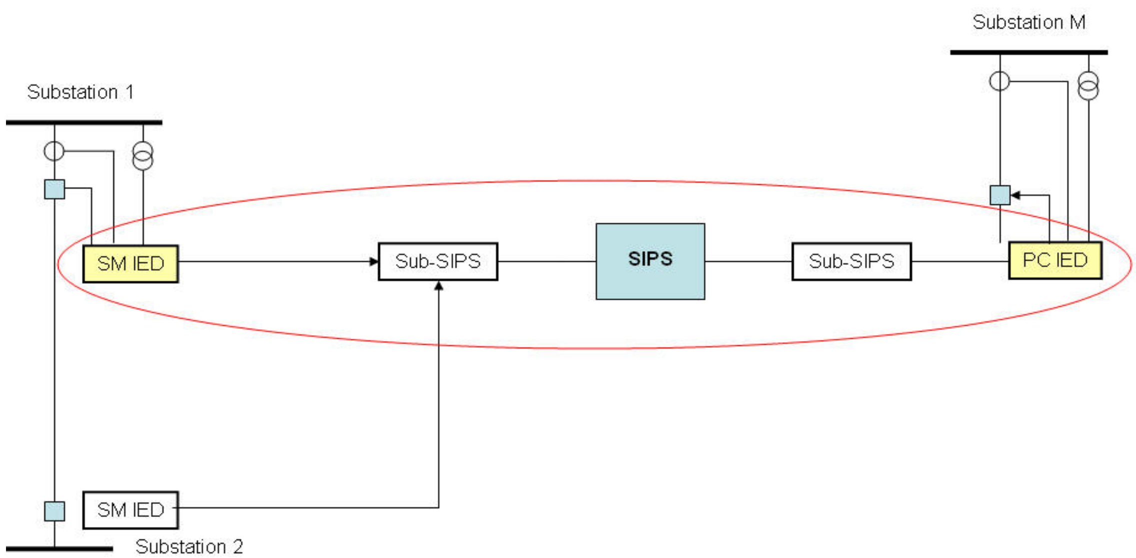

Figure 2-7 SIPS end-to-end site acceptance test

The final stage of the SIPS site acceptance test may be performed as end-to-end testing to ensure that all the wiring between the process and the devices included in the substation protection, automation and control system are properly done.

Figure 2-7 illustrates the scope of an end-to-end test for an example SIPS from SM IED to PC IED. The Sub-SIPS on the left collects the measurement data for the central SIPS for making decisions. The central SIPS sends control signals to the Sub-SIPS on the right for PC IED to take appropriate control actions.

2.7 Utility Documents

The design and testing of SIPS may need to follow the requirements of reliability coordination authorities in addition to utility's own guidelines. For example, the Western Electricity Coordinating Council has developed a document, "Guide for Remedial Action Scheme", with its member utilities. There are similar documents in other reliability coordination regions, such as the guideline document for SPS in the Northeast Power Coordinating Council region. These Regional Reliability Organizations documents usually are available on their respective web sites.

Individual utilities have also developed whitepapers about the SIPS for their own use.

All these documents may not be publicly available. However, if available, affected entities should consult and follow the requirements in their SIPS design, documentation, and testing guidelines to ensure compliance.

3 DESIGN AND TESTING OF GENERATOR REJECTION SCHEMES

This section covers the practical design and testing of generator rejection schemes.

Generation rejection schemes involve tripping of one or more generating units. The practice of generator tripping is used on all kinds of units but especially on hydro-generator units.

Generation rejection improves transient stability by reducing the accelerating torque on the machines that remain in service after a disturbance.

Generation rejection can also be used to reduce power transfers on certain parts of a transmission system and thus solve overload or voltage stability problems.

3.1 Generator Rejection Scheme Design Example

3.1.1 Power System

A four unit coal-fired electrical generating plant located in the western United States has the capacity of a net output of 2120 MW. The Plant is remote from the load and connected to a transmission network by three long 345 kV and two 230 kV transmission lines. When the transmission path is being operated at the path load transfer limit and a transmission line in the path is lost, the generation at the Plant must be reduced to maintain the transient stability of the power grid. To arrest the transient power swing following the clearing of the line fault from dropping the voltage below 0.3 per unit, a

SIPS that trips generating units at the Plant is deployed. When the transmission path is loaded at the transfer limit and a close in severe line fault occurs the SIPS must take action and disconnect generation from the system in five cycles on a 60 Hz basis. The five cycles are measured from the inception of the fault until the generator breaker disconnects the generator. For less severe faults additional time can be taken.

3.1.2 SIPS Requirements

The SIPS dynamically calculates the generation needed to be shed for each of the pre-identified events and then selects generators to shed, based on a generation selection algorithm. The main requirements of the SIPS are as follows:

- Fast (operation must be less than 20 milliseconds for the most severe events)
- Reliable (with a balance between dependability and security)
- Available
- Deterministic

Based on the stability studies for the most severe fault cases, which are multiphase faults on a 345kV line close to the Plant, the total time from event to resulting action must not exceed five cycles. A realistic timing for the most severe faults, faults well within the zone 1 reach of the line relays, is less than 16 ms for the line relays, no communication time required, a SIPS processing time of 20 ms, and a unit breaker clearing time of 25 ms. This would produce an overall reaction time of 61 ms or 3.7 cycles. When the typical fault detection, communications time, and unit breaker opening time are excluded from the total time budget, the SIPS controller is left with 20 milliseconds of operating time. The SIPS operating time is the total measured time from an input voltage asserting to 90 percent to an output fully conducting including breaker operating time.

For less severe fault cases, lower speed is acceptable. Although the SIPS controller has the capability to process the signals in the time needed for the most severe case, the process is deliberately delayed for single-line-to-ground faults. Since a single-line-to-ground fault can evolve to a multiphase fault in the time it takes to detect and clear the fault, delaying the SIPS's response is beneficial. If the processing for the initial indication of a single-line-to-ground fault is not delayed, excessive generator tripping could result. If, due to system conditions, a small amount of generation tripping was required for the single-line-to-ground fault and the power output of the selected generator for tripping was adequate for a single-line-to-ground fault but inadequate for a multiphase fault, multiple generators could be tripped when the fault evolved to a multiphase fault. By delaying the SIPS to see if the fault condition will worsen before the fault is cleared, the minimum amount of generation will be tripped. At any time if a multiphase fault is detected, the action of the SIPS is taken without any additional delays.

For the loss of a transmission line, in the transmission path, that is remote from the Plant the status of the line loss needs to be communicated to the SIPS controller. This communication adds additional delay but the studies have shown that the delayed response will not have adverse effect on the stability of the power system.

To provide reliability with a balance between dependability and security a triple modular redundant (TMR) system was required. With the correct and timely response of the SIPS being critical to the stability of the power grid, the dependability of the SIPS is important. For this reason, the SIPS must be a system containing redundant inputs, outputs, and processing units. Transmission line fault incidents are unusually high for this transmission system due to the following factors:

- The nearly 400 km length of the transmission lines
- The rugged terrain the lines cross
- The above 2500 m elevation of the lines
- Difficult grounding conditions
- Insulator contamination
- Other unknown factors

The average incidence of faults on this transmission system is 0.8 faults per week. The Plant is base loaded 24 hours a day. Between the Plant's loading and the transmission line fault incidents, the SIPS is often called on to react. Most of these events do not require generator unit tripping, because the Plant is operated at loading levels below the arming level for the most common transmission line faults, single-line-to-ground faults. The consequence of tripping a 530 MW coal-fired unit involves significant costs and reduces the reliability of the unit. For these reasons, balancing dependability with security against false operations is very important, and therefore the SIPS uses a TMR voting control system. Two out of three identical systems must agree on the status of the inputs and the resulting outputs for the system to cause the tripping of a generator unit.

This triple modular redundancy is extended to the power transducers feeding the SIPS data. Due to cost and complexity, the triple redundancy was not extended to two of the major subsystems of the SIPS: the communications systems which carry critical data from remote locations to the logic processors and the fault severity units. These subsystems are redundant but not triplicate. To accommodate the limitations of these subsystems and provide the availability needed for the SIPS, dual TMR systems were installed. The transmitters and receivers that use one communications network and one set of the fault severity units are connected to one TMR system. The communications equipment using the alternative communications network and the alternate fault severity units are connected to the second TMR system. Both TMR systems are normally in service, and either system can trip the generator units.

Due to the speed at which the SIPS must operate, the accuracy of the power transducers, and the scanning nature of a programmable logic controller (PLC), there are several predictable circumstances where the two TMR systems will not select the same generator unit to trip for the same event. The most likely circumstance would be when a unit's power output is near an analog threshold; in this case, one of the TMR systems could select one unit and the other select a different unit as the apparent level of the unit operating at the edge moves in and out of selection. This condition would result in tripping two generators rather than one. Since this is an unacceptable event, provisions were designed into the SIPS to prevent this type of event from happening. Two independent processors review what each of the TMR systems is planning to do if an event were to occur. This is possible because of the way the TMR systems predetermine their action for each of the possible line loss events based on current system conditions. In the case of discrepancies, the supervision systems will assess the overall quality indicators of the system and decide which SIPS will be allowed to operate. The quality indicators are the weighted average of the system communications and hardware alarms. Primary and backup supervision units are designed for redundancy and use different technology hardware, software, and communications protocols to further ensure reliability.

3.1.3 SIPS Architecture

Figure 3-1 is an overview of the major systems in the SIPS. SIPS Systems C and D are identical, triple redundant systems with full two-out-of-three voting.

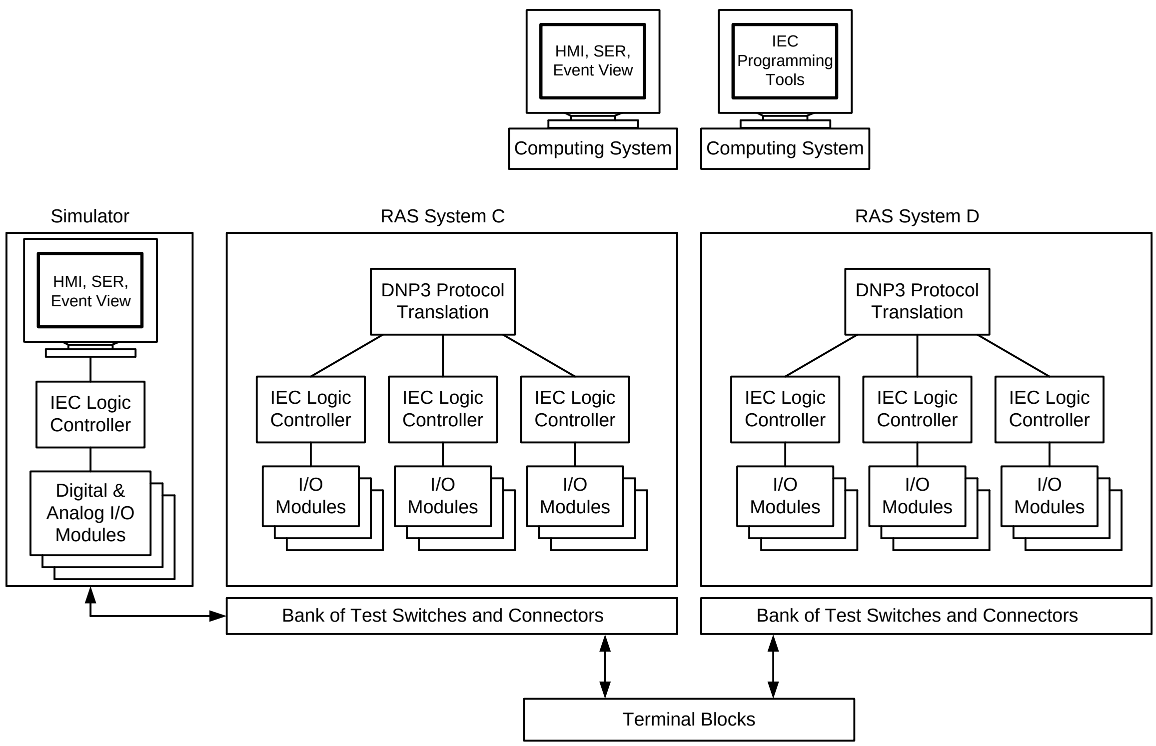

Figure 3-1 SIPS System Architecture Overview

Each input/output (I/O) point to the field is wired to three independent I/O points on both systems. Each half of the I/O is separately wired to terminal blocks, and all SIPS controllers and wetting voltages are powered by separate DC battery systems. This creates a system of two completely autonomous control systems; hence this system is considered “Dual Primary.”

Within each SIPS system (C and D), there are three autonomous IEC logic controllers with fully independent I/O modules. These three controllers perform two-out-of-three voting via high-speed communications links. A single substation-hardened computer provides a human-machine interface (HMI), sequence of events viewing, and event report viewing oscillography. Another hardened computer is used as an engineering workstation and contains the development environment for all hardware (IEC 61131-compliant programming).

Each SIPS system (C and D) has its own protocol gateways for communications to an energy management system (EMS). These gateways communicate the necessary status, metering, and controls to and from the SCADA masters via DNP 3.0. SIPS Systems C and D are completely isolated on separate networks, and all logic on each system runs without any knowledge of the other system. The router between the two systems is configured to prohibit all traffic between the two SIPS systems. The router limits communications from the SIPS systems only to the HMI, engineering workstation, and supervisory systems.

Although the SIPS HMI is designed to run continuously, it is not necessary for the SIPS to operate. The HMI is only necessary for changing the settings used for the SIPS computations. These settings are stored in nonvolatile memory in the individual SIPS controllers, making the SIPS operations independent of the HMI.

The HMI station serves as the user interface to all controllers and subsystems. The functionality includes:

- Status display of live power system data on a summarized one-line screen.
- Status display for every system input and output, including data shared through the EMS system.
- Ability to change and view adjustable settings loaded in the SIPS controllers.
- Real-time view of the CPS matrix that shows the action to be taken for every contingency.
- Communications and alarm screens that reflect current device and communications alarms.
- Sequence of events (SOE) gathering, archiving, and viewing.
- Historical alarm and event viewing. The event files can be played back to the SIPS through the test simulator.

The HMI collects data from all six controllers and the four EMS interfaces. Screens exist to view the data individually for verification that they agree and to view the one-line screen that reflects the system status as determined by the two-out-of-three voting logic. The data set for the one-line screen is picked by the same algorithm that is present in the supervision logic. The one-line and I/O screens are critical for testing, and commissioning purposes, because they provide visual verification of what occurs during each test.

Due to the immense amount of data required to fill the system adjustable gains, a database file was created to hold these large matrices. There are eight matrices that are of dimension 64 x 1000 x 4 (256,000 gains), and several other matrices of smaller sizes. When edits are made to any one of the 256,000 gains, the controllers detect that new settings are available and issue a signal that the loaded settings are old. At this point, the database files are compacted into several binary files; these files are then transferred to the controllers at the operator’s request. These binary files are stored in nonvolatile memory on the controllers and are viewable in tables through the HMI.

Each controller creates SOE logs, Event Report Logs, and alarm tags. There are two main ways to view alarms on the HMI: through the communications and alarm screens and through the SOE logs. The communications and alarm screens show the active state of major device, communications, and diagnostic alarms. The SIPS has complete diagnostic capability that automatically pinpoints any faults or errors within the system (hardware and software) to a failure location within a hardware device or a software module. If an alarm clears but was not acknowledged, there is still an indication that the alarm was not viewed by an operator. The SOE logs show all alarm points time-stamped as to when any changes occurred. All data in the SOE logs are time-stamped with 1-millisecond accurate resolution.

Event Reports (ER) are in flat file format, similar to COMTRADE format. The ER logs contain the status of every I/O point in the SIPS sampled at 2 millisecond intervals. The ER logs contain data for two seconds prior to each event, and four seconds after every event. This allows for easy diagnostic evaluation of what occurred during the event. Also, the event file can be replayed to the SIPS through the test simulator.

The SOE logger in the SIPS contains raw, digital I/O, internal digital values of great interest in the controller, and all system alarms (e.g., data disparities, equipment failures). The SOE logger is responsible for detecting, identifying, and making available to file the SOEs of selected, critical variables.

All hardware in the SIPS is protective relay-class, substation-hardened equipment with extended temperature range, physical shock resistance, electro-magnetic immunity, and static discharge capabilities. All outputs are trip-rated dry contacts; there are no interposing relays in the system.

The control algorithm is running on an embedded real-time controller engine. This engine is programmable in all IEC 61131 programming languages. There are no fans and no spinning hard drives in any equipment. All components run off of the substation battery. No ac power is used in the SIPS panels.

Additionally, every zone of the SIPS hardware, firmware, and software contains continuous self-diagnostics. This guarantees the detection of catastrophic failures of any component(s) in the system. Every device in the SIPS design has a normally closed, watchdog alarm contact that will assert if any device is powered down or has a hardware or firmware failure. These contacts are cross-wired to other devices for monitoring, which guarantees that a failure in one device will not propagate further.

The logic, settings, and configuration installed on each hardware system are developed and tested to be fault tolerant, meaning that bad computations are intentionally rejected. For example, if a line metered value is out of range or coming from a failed device, an alarm will be asserted, and the logic will declare that specific data as bad. All logic, settings, and configurations are set up to automatically reject bad data and reselect available (good) data. Bad data will not be used to make decisions.

The result of these design decisions is a SIPS that requires four carefully selected concurrent hardware failures to prevent SIPS operation.

3.1.4 Events and Actions

The availability of eleven individual transmission lines is monitored in a real time high speed manner by the SIPS. The single loss or combined loss of multiples of these lines is an event that could trigger an action by the SIPS. Any event in the power system that may require a SIPS action is identified as an N Event (contingency). The communication and input voting logic makes it possible for the processors to detect N Events in less than 8 milliseconds. The SIPS is designed to respond to closely timed or simultaneous events; this functionality is key to a successful SIPS control strategy.

Any information not provided to the SIPS requires the assumption of the worst case scenario. This would result in the tripping of generator units when it is not necessary for the stability of the power system. For this reason the cause for the transmission line loss is taken into consideration for the loss of the lines that radiate out from the Plant. The severity of the fault will impact the action to be taken. Relays are set up for fault detection and discrimination. The relays categorize each detected fault into one of the following:

- No fault or single-line-to-ground fault
- Phase-to-phase close-in fault
- Phase-to-phase remote fault
- Three-phase close-in fault
- Three-phase remote fault

The actions taken by the SIPS for a line loss event includes tripping the generating units, switching on shunt capacitor bank and/or bypassing a series capacitor bank. The SIPS evaluates the prefault conditions and determines which of the above actions needs to be executed for each contingency. The primary conditions that are used to determine whether generator units will need to be tripped for the different line loss events are the real power output of the Plant or the real power flow on the three 345kV transmission lines and the impedance of the remaining lines. The 345kV lines are series compensated with multi-segment series capacitor banks. The number of series capacitor segments that are bypassed in the remaining lines prior to the line loss reduces the stability limit of the system and lowers the arming levels in the SIPS. In addition to the power flows and compensation levels an extensive number of critical power network elements are also monitored. The status of those critical power network elements as well as the prior outage of transmission lines for which the loss of the lines have triggered an event are considered pre-existing state for the SIPS. The pre-event state of the power system establishes the arming levels for SIPS action.

Any event that changes the configuration of the power system that is critical to the transfer path is identified as a J State. Most of the N Events become J States in the SIPS after a fixed amount of time. For example a remote phase to phase fault on the one of the 345 kV line from the Plant is an N Event. This N Event becomes the J State that the line is out of service. But J States are not limited to just N Events. The outage of each power network element that is critical to the flow of power from the Plant to the load is a J State.

A change of a J State will not require a SIPS action but changes the reaction the SIPS will take for the next N Event. Other examples of J States are the outage of synchronous condensers, transformers, shunt capacitors, and transmission lines. J State data does not need to be processed in a high speed matter. Low-speed data can be processed every 200 milliseconds. This data is used in determining the power system state, determining the appropriate arming levels, and calculating the remedial actions for all the predefined contingencies. Data from the EMS system on the status of the surround network fall under this category.

The combination of J States is called a system state. For example, an instance when there are two lines open and a capacitor is out of service is identified as three concurrent J States. These three states converge to a unique system state, and this system state determines the limits of the system. The SIPS uses the system state to determine which gain constants need to be used in the action-determining calculation.

The redundant SCADA gateway systems function as the intermediary for receiving data from the EMS that is used in the SIPS system calculation algorithms. These gateways are also used for providing data to the EMS regarding the status and operating characteristics of the SIPS system.

Each IEC controller performs integrity comparisons of data set points coming from the two deferent EMS front-end processors. Based upon quality indicators, the controllers select which data source (gateway) to use. Because the code (library) running in each controller is identical, the decisions are identical.

3.1.5 Control System Decision Making

The SIPS uses the arming level equation and calculates up to 64 arming levels every 200 milliseconds. The arming level equation is basically a polynomial equation that uses measured real and reactive power generation (local inputs), compensation level of the 345 kV lines (remote inputs), several path flows (local and remote inputs), and eight gain factors that define system sensitivity. Data are gathered from local and remote systems, and all the J States that are active in the system are identified. The identified J States are mapped to a new system state. This system state identifies which gain factors need to be used in the arming level calculation equation. A total of eight gain factors can be loaded from a lookup table, and there are four lookup tables that represent each season (spring, summer, autumn, winter). These gain factors define the system sensitivity to each component in the arming equation and are developed from system studies.

The arming level calculation logic calculates an arming level for each contingency. This arming level will be used in the generation-to-shed calculation equation (1) for each contingency, which results in a generation-to-shed value for each contingency. The values will be zero if no generation needs to be shed. For all values greater than zero, the generator selection algorithm will determine which of the four generators need to be shed. Operators are given preference in selecting units to shed. If no unit is selected by the operators, the algorithm will select the optimum units. The following is the generation-to-shed calculation equation:

$$G = K_{nj} \bullet \left(F_{nj} - AL_{nj}\right) - X \quad (1)$$

where:

AL_{nj} = calculated arming levels from previous logic.

K_{nj} = coefficient that changes with facility outage and fault type. These are predetermined values that reside in a lookup table. In most cases, the value equals 1.

F_{nj} = either net Plant generation or net path flow, which depends on the preexisting outage combination *j* and fault type *n*. The selection of Plant generation or path flow is predetermined by system planning.

X = generation dropped by SIPS in last 5 seconds.

The crosspoint switch (CPS) is the final result of the SIPS algorithm. The CPS shows the N Event and the actions. The results from the generator selection algorithm are used to populate the CPS. The CPS is preloaded and will give operators information on how the SIPS is going to respond for each contingency. As soon as an N Event is detected, the SIPS knows which actions it needs to take and triggers the actions. Figure 3-2 shows a typical CPS.

Actions \ Ns		N_1	N_2	N_3	N_4	•	•	•	•	•	•	N_{64}
Trip Gen1	I_1	X			X					X		
Trip Gen2	I_2		X		X				X			
Trip Gen3	I_3						X		X			
Trip Gen4	I_4		X				X					
	•	X			X							
	•		X						X			
	I_{16}		X				X					

Figure 3-2   Crosspoint Switch

The logic processing can be done in single or multithread. The entire SIPS algorithm is tedious and time-consuming if done in a single thread. The controllers have multithread processing capabilities, which provide flexibility in dividing the tasks into groups based on how fast they need to be computed. This also makes the SIPS algorithm deterministic and prevents time-consuming tasks from delaying the SIPS actions. The SIPS algorithms are arranged into three schedulers: 1-millisecond, 8-millisecond, and 1-second tasks.

3.1.6 Critical Timing

There are two special logic timers used in the SIPS logic. Any contingency that happens in the power system creates a disturbance. For example, a line is tripped. Due to this line loss the power is redistributed across different paths and there are power swings causing the gathered analog data to fluctuate as the power system settles towards a steady state condition once more. During this time, if the gathered analog data are used in the arming level calculation, it may result in poor quality decisions. To prevent these disturbances from affecting SIPS decisions, all generation-to-shed values calculated prior to this event are frozen for a certain period of time, in this case, 5 seconds. It is at the end of the analog freeze that the N Events are transitioned to J States. If a second event happens during this time, the timer is reset, and the 5-second counter starts again.

The CPS is predetermined and the SIPS is ready to go for the first contingency that happens in the system. As soon as the contingency happens, the CPS is recalculated in the next scan that is in the next millisecond. If no generation is shed, the CPS remains the same; otherwise, the SIPS Systems A and B come up with their own new CPSs. If the CPSs are different, the supervisory system decides which system is allowed to operate for the next contingency. However, it takes around 12 milliseconds to send the CPS to the supervision unit and receive a decision from it. During the 12 milliseconds after the first contingency, the A and B Systems can have different CPSs, which may lead to different decisions if a second contingency happens in this 12-millisecond window. The closely timed event logic is used to prevent these cases. Once a first contingency (that sheds generation) happens, a 16-millisecond timer is started. During this timer duration, if additional events happen, all of these events are queued and evaluated at the expiration of the timer. This gives the supervision unit enough time to evaluate the CPSs, make a decision, and prevent the A and B Systems from making different decisions for closely timed events.

If an event happens and a line is tripped, the SIPS detects the contingency, verifies the generation-to-shed values, and trips a generator. The 5-second timer starts and the analog input values in the SIPS are frozen. If, after some time (e.g., 100 milliseconds), the SIPS detects another contingency, it will over-trip if it does not take into account the generator tripping that happened during the last scan. As soon as a contingency is detected, if the SIPS detects another contingency in the next 5 seconds, the fast recalculate code is run, which modifies the generation-to-shed values based on how much generation was shed for the previous contingency. X in *(1)* serves this purpose. It deletes the generation shed by the SIPS in the last 5 seconds and prevents over-tripping for multiple events in a short time frame.

3.2 Testing of Generator Rejection Schemes

The SIPS is equipped with a test simulator which simulates all SIPS external inputs, including digital status, control inputs, analog data, and DNP 3.0 data streams. The test simulator simulates the power system. Outputs from the SIPS generate changes in the inputs to the SIPS in the same time sequence as the power system. The test simulator was designed to play back power system events into one of the redundant SIPS (C or D). Through test plugs and software interlocks the SIPS systems, either C or D can be isolated from the field wiring and connected to the test simulator without disturbing any of the field wiring. When under test, the SIPS will not receive any inputs other than the conditions supplied by the test simulator. With the simulator any modifications to the SIPS can be fully functionally tested prior to going live with the modified system.

Playback simulator software is used to easily simulate system conditions and events. This allows the creation of text files that contain analog and digital data reflecting specific scenarios to be sent to the SIPS system. The files are sent through an algorithm that separates each value and creates a system-wide event that can last between 2 milliseconds and several seconds in length. In this fashion, engineers can observe the reaction of the SIPS algorithm to several different events very quickly. The test simulator uses hard-wired analog and digital signals that extend through the interconnect panels to the SIPS inputs.

The ER logs created by the SIPS for power system events can be played back to the SIPS under test through the test simulator. The file structure of the ER logs are exactly the same as those created by the engineers, as described above. The outputs from the SIPS during the event are blinded from the test simulator so that those responses will not affect the response of the SIPS under test. In this way, each event recorded on the power system can be played back into the SIPS and observed to quickly evaluate the control system's response with new settings for all known and recorded events.

Besides the two dynamic modes of operation the test simulator can be operated as a static simulator. This mode provides the operator the ability to drive each individual input to the SIPS to a desired value. For example, the system is used to set EMS set points, set breaker status conditions, and detect generator trips from the SIPS. This is extremely useful for testing all I/O points and creating any desired power system scenarios for presentation to the SIPS controls.

Additionally, the simulator has controls for biasing the analog values to test the voting logic. Discrepancies between the redundant analog inputs are the most likely source of differing inputs to the SIPS, due to the maintenance required on transducers to keep them calibrated. The controls to bias the inputs allow for skewing the analog inputs to each SIPS subsystem. Running tests this way verifies that two out of three systems agree before an action is taken.

Special arrangements were made for placing both SIPS systems under test at the same time to verify the supervision logic. In this test configuration the analog signals between System A and B are skewed for the verification of that logic. This test is usually only done if modifications are made to the supervision logic. Taking both SIPS systems out of service at the same time requires significant restriction on the operation of the Plant.

The process of testing a system like this involved many groups including: protection and control, and communications engineering; relay and communications technicians; system planning; and system operations. A checklist was created prior to testing that systematically checks each input and output (I/O) of the SIPS including all of the data shared with the EMS. This ensures that each individual component was operable. Once the check of the I/O was completed, the test simulator is used to run a set of system tests.

To ensure a safe installation that would not risk the integrity of the operation of the Plant each and every item within the checklist contained a specific method for testing and was described within the documentation for the commissioning. By doing this, everyone involved could gain an understanding of the reasoning behind the process. Again, communication across the various groups involved in the SIPS project is one of the most critical objectives to achieve.

4 DESIGN AND TESTING OF LOAD REJECTION SCHEMES

Load rejection is a protection system designed to trip load following an event that may lead to a local or wide area disturbance. The typical applications are designed to keep a system or sub-system in parallel with the remaining parts of the system in case of the loss of a major supply to the affected power system area. Such major supply deficiency may be caused by:

- loss of significant amount of generation
- loss of important transmission lines or interconnections
- overloading of transmission lines or power transformers

Load rejection is one of the actions taken by SIPS at the different levels of the electric power system hierarchy. Load rejection is not the automatic underfrequency load shedding program, since one of SIPS main goals is to prevent the separation of an area of the system before the change of frequency can result in the operation of the underfrequency relays.

4.1 Load Rejection Scheme Design Example

Load rejection schemes (LRS) are usually analyzed and initiated from a central location. A reliable communications network is required to collect the needed input information upon which to base the decision and then issue the required tripping commands. The arming of the Load Rejection systems may be based on power system conditions and recognized contingencies analyzed off-line and can be either automatic or manual via an operator. An alternative is to arm the scheme based upon system studies and take action in real-time if the contingency develops.

The load rejection scheme presented here includes disconnection of one or more mining industrial plants. The arrangement and range depend on the total load to be compensated in order to stabilize the electric power grid, and to bring back the power flow of the transmission lines to a safe level and within its specified operation range.

This System Integrity Protection Scheme - Load Rejection Scheme (SIPS-LRS) system was designed and implemented in 2008.

4.1.1 Associated Power Generation System and Basic Solution Description

The associated electrical system is located in northern Chile. The SIPS-LRS was implemented on the system shown in the following diagram Figure 4-1.

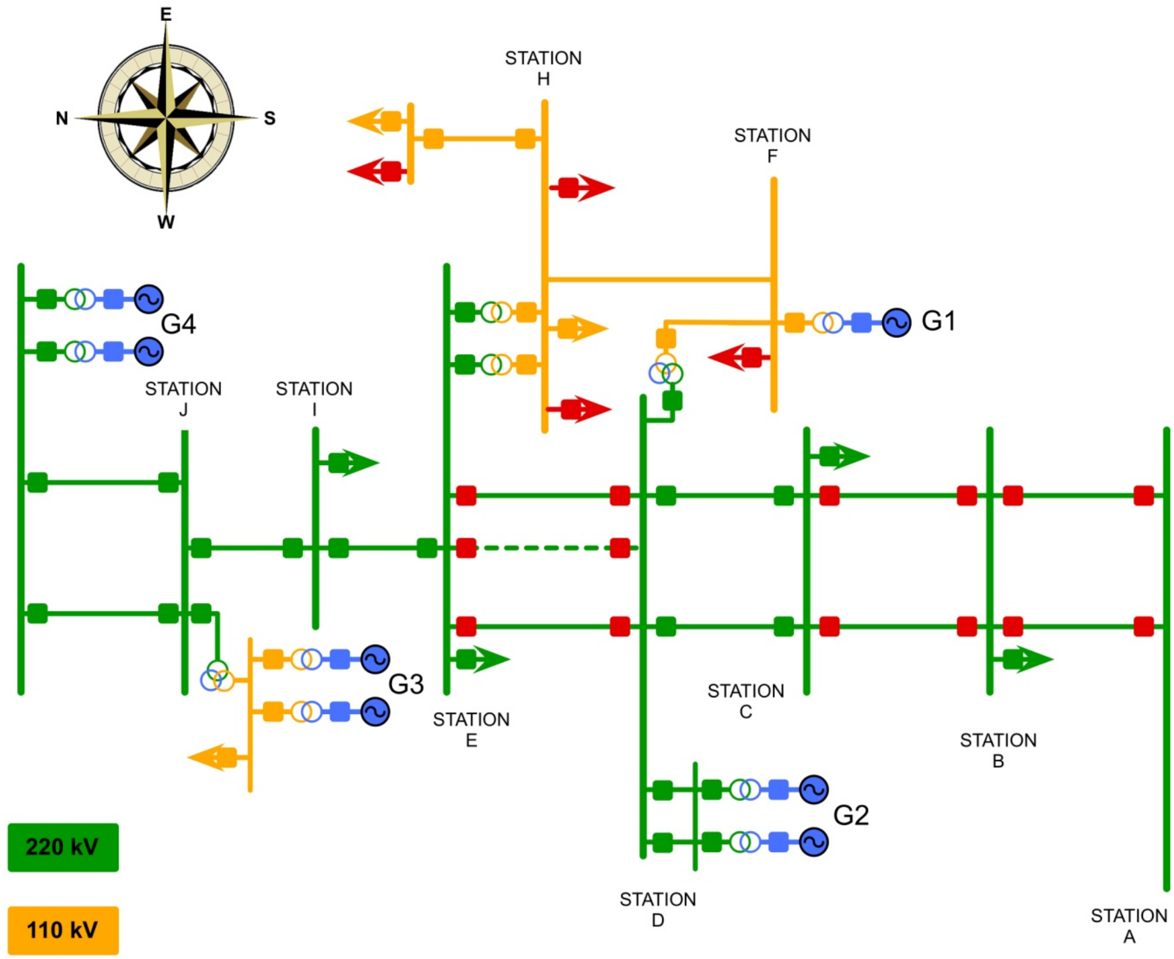

Figure 4-1 SIPS-LRS Specific electrical one-line diagram from northern area

During normal conditions the supply to the northern (left) side of the Station D (at the center of the drawing in Figure 4-1) depends essentially on the power transfer capacity of the transmission lines between Station D and Station E (220 kV) and between Station F and Station H (110 kV), as well as local low cost generation of the power plants G1, G2, G3 and G4.

The local power generation has been available with low cost natural gas supply at Power plant G4. Unfortunately, natural gas supply restrictions caused direct impact to this plant's availability. When this SIPS-LRS implementation decision took place, only one of the units of the plant could operate in fuel oil mode instead of gas (the second unit was still in process to modify its combustion mode).

Operation of G4 plant in fuel oil mode is much more complicated than in natural gas mode. This is because of the initial design of the plant was supposed to be supplied exclusively with natural gas. The operation of G4 plant in fuel oil mode for extended periods leads to increased outage risk on these units.

In the case of all units located at the northern area from Station D, (i.e.: G3, G1, G4 in fuel oil combustion mode), and if a partial or total blackout occurs in Chilean electric grid, the service recovery plan in the area would be delayed because of the excessive outage duration for these units. This statement is given without considering that these units may be out of service for a longer time than blackout time itself.

On the other hand, considering the expected growth about energy demand for the northern part of Station E, and the capacity of available transmission system, it is highlighted that these plants G2, G3 and G4 (operating in fuel oil mode), would be requested part of the time in order to supply energy needs north of Station A. In the case that one of the units at power plants G4 or G2 would be unavailable, (for whatever reason like a planned outage, unexpected trip, or lack of fuel supply), there would be a significant risk during the demand peak period of the day, that the northern area system would be operated beyond “n-1” criterion and that the operator of the system would have to perform load reductions north of the Station C to assure system integrity.

Taking into consideration all the criteria explained before, and in order to increase transmission capacity between Station A - B (2x220 kV) and Station B – C (2x220 kV), the decision was taken to implement a SIPS-LRS which acts on non critical loads located in the area.

In case of contingency in some of the 220 kV Station A – B or Station B – C lines, the scheme disconnects loads automatically in order to adjust to the remaining operating line capacity (using adjusted n-1 safety criterion).

This SIPS-LRS was implemented using a satellite communications system, due to commissioning time constraints and that conventional technology would have resulted in complex and long execution time, which did not match the goals of this project. Among these goals was to have this system SIPS-LRS in operation on urgent basis and simultaneously with the commissioning of the new third circuit between Station D and E 220 kV (segmented line).

The operational logic of this SIPS-LRS required an intelligent system to allow highly flexible programming based on information relating to power transfer through transmission lines located between Station A and B 220 kV, Station B and C 220 kV, and using the breaker position status of these lines. Therefore, the SIPS-LRS according to some predefined operational and load transfer conditions, would send load rejection commands to loads that are part of this scheme in order to optimize the load rejection scheme by only disconnecting the necessary loads to compensate the specific contingency using the most efficient conditions.

This SIPS-LRS was designed to remain in operation until the commissioning of the third and fourth units of the plant G2.

4.1.2 LRS Requirements

The SIPS-LRS monitors constantly the power flows of the twin circuit transmission lines of Stations A, B and C. During normal operating conditions, i.e. within the criterion n-1, the system is programmed to stay in standby without any action to the loads. During unusual conditions, i.e. when the power flow increases such that the defined power limits are exceeded n-1 criterion, the system computes how much load would be required to be shed, in case that a contingency would occur on the lines and leading to the loss of one of the two circuits.

The load armed to be shed is adjusted in order to maintain an equivalent or lower power flow than the nominal values in normal conditions.

The time to perform load rejection in that case is not critical. It depends on the thermal capability limit of the circuit, and it is targeted to get execution time between one and four seconds for scheme operation.

The requested system availability is designed to meet the electricity technical and quality specification in force in the country.

If the load supposed to be rejected (and previously declared in the system as such) fails to be disconnected for any reason, the system performs an alternative load block selection to match with the scheme target. If the available load to be rejected is not sufficient to maintain the line power flows within safe margins for operation, the LRS system will raise an alarm to the operation center.

The SIPS system operation, either in normal or in transient conditions does not cause unacceptable transient perturbations to the grid when used within its design conditions.

Probability of outage occurrence to the transmission line leading to circuit breaker opening is actually once every two years.

4.1.3 LRS Architecture

Figure 4-2 shows simplified architecture, and Figure 4-3 shows detailed structure for this LRS.

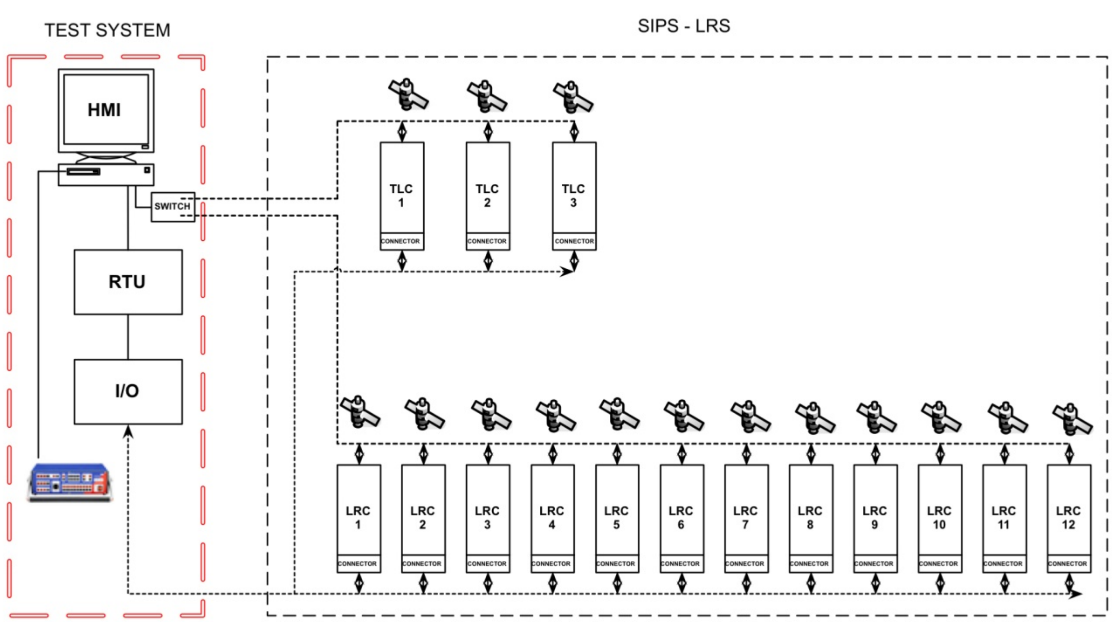

Figure 4-2 Architecture proposal for Chilean SIPS-LRS, using satellite communications

Because of the FAT restrictions, the satellite communication link is replaced by an optic fiber net during FAT tests. The inherent satellite time delay is modeled in the system during the tests.

The line power flow conditions, loads, and disconnection simulations are performed via a set of inputs and outputs controlled from a RTU. The tests are programmed and executed by a PC computer. Interaction with test operator is realized via the HMI implemented in the test PC.

This architecture shows the lines monitoring cells concept: Transmission Line Cells (TLC) and Load Rejection Cells (LRC). The following Figure 4-3 shows the TLC lines and LRC Load cells distribution in the grid.

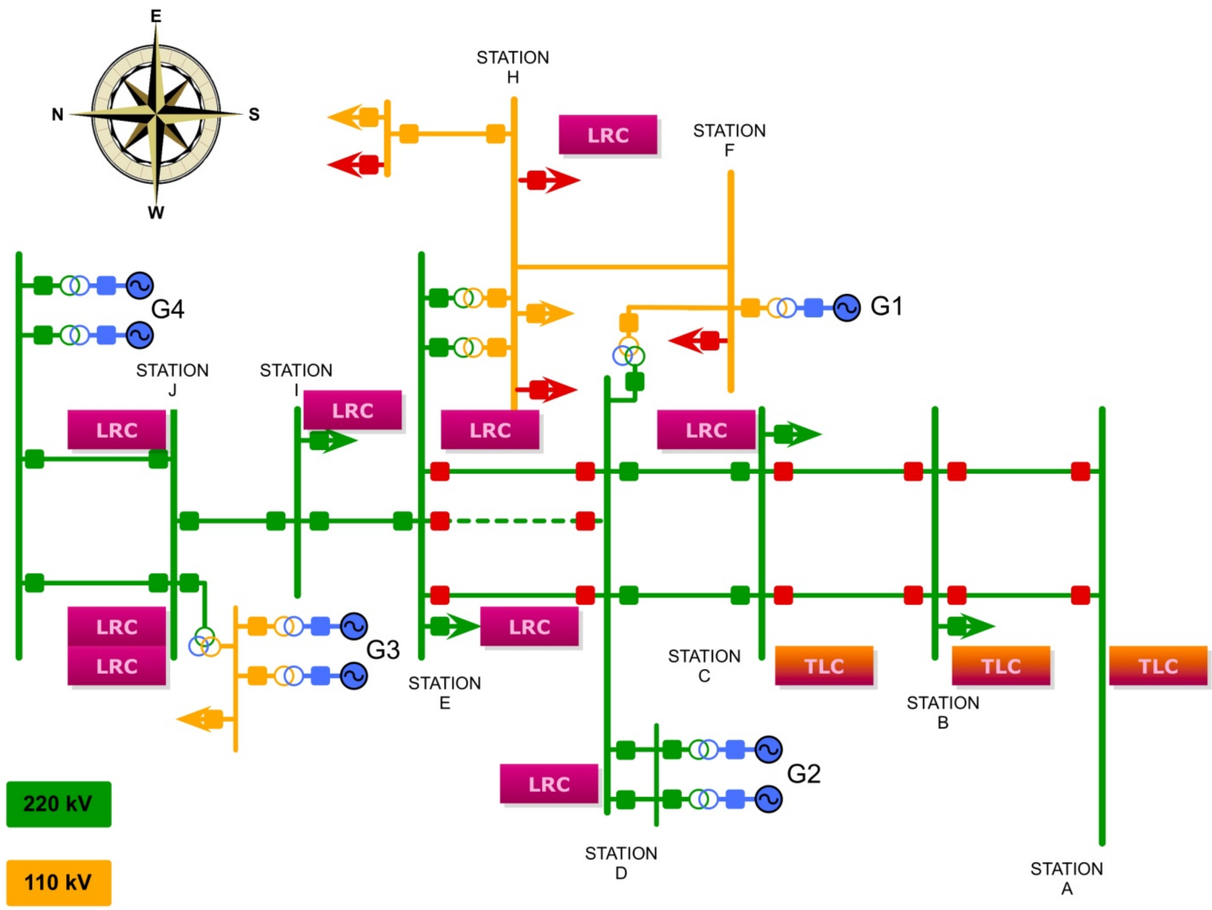

Figure 4-3 Detailed architecture SIPS-LRS with cells.

Each of these cells includes all LRS equipment and from each of the cells it is possible to access field signals from voltage and current transformers.

Each TLC cell type contains voltage, current and active/reactive power transducers, temperature probes, digital inputs for circuit breakers status, energy backup system with UPS and batteries set, satellite time synch and communications system, and dual redundant central processing unit/ power supply Remote Terminal Unit (RTU).

Each LRC cell type is made of the same type of measurement transducers and redundant equipment as the TLC cell type, plus digital outputs to send the commands to circuit breakers.

Figure 4-4 and Figure 4-5 show typical schematic structure of the transmission line cell (TLC) and of the load rejection cell (LRC) respectively.

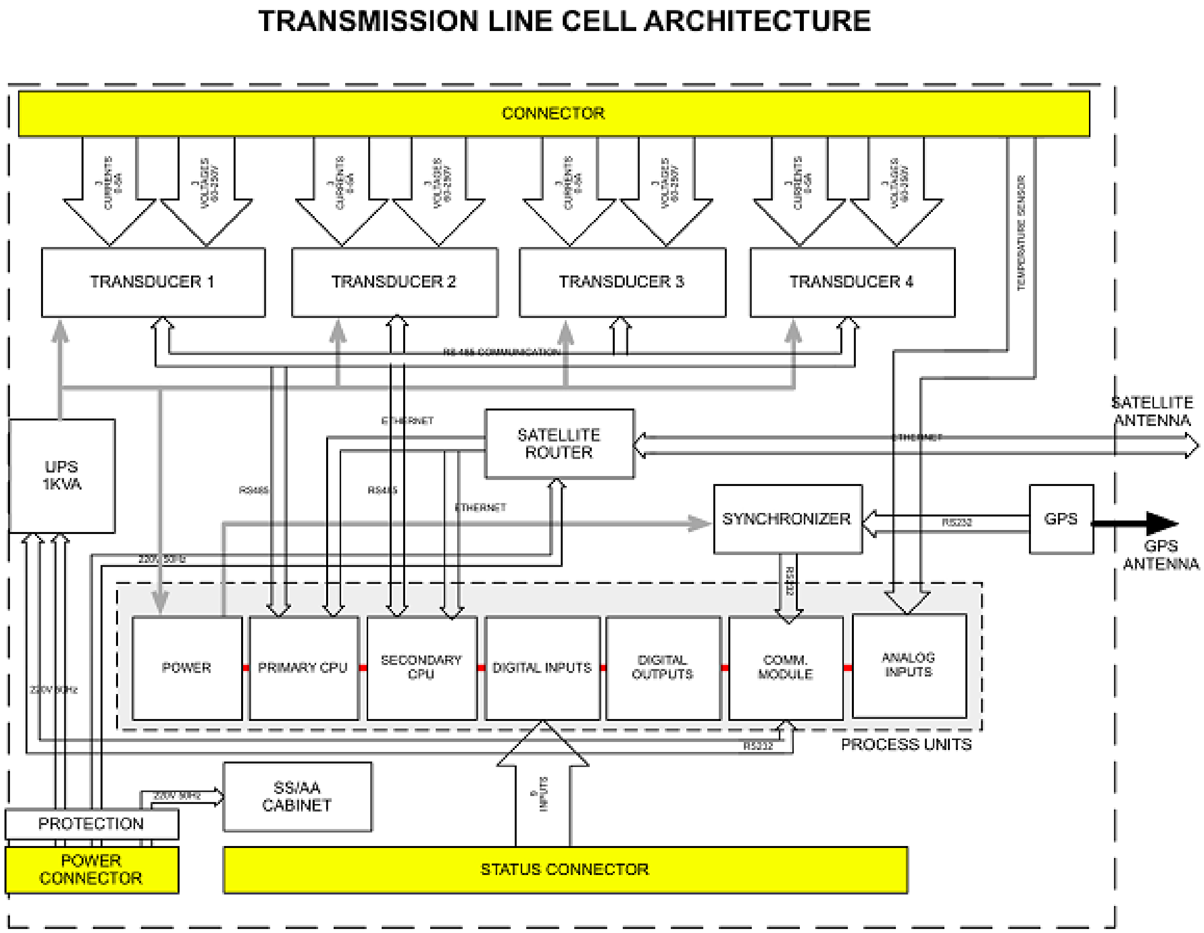

Figure 4-4 Transmission Line Cell structure

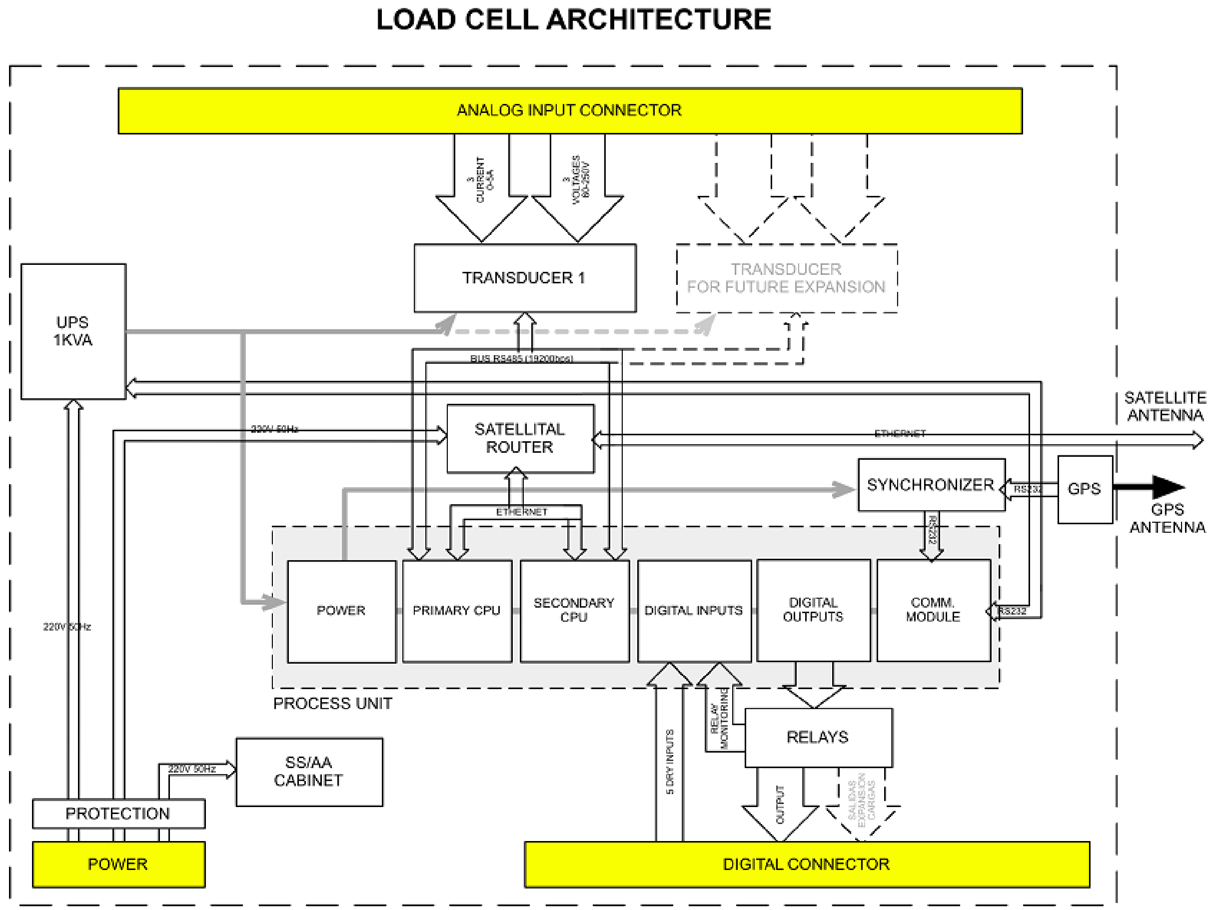

Figure 4-5 Load Rejection Cell structure

Prior to commissioning, cells are assembled and tested at the factory according to FAT test protocol executed by the subsystem shown in the left dashed box of the Figure 4-2.

Basically, the test protocol is RTU-based and simulates line transmission breakers opening with several load and flow conditions for such line simulation. A set of pre assigned signals allows the system to be tested in several plausible conditions reflecting real operation conditions.

Each of the LRC cells supervises the load status (availability and range of the available load rejection power). This information is transmitted to TLC cells whenever one of them is requesting this status. The sampling rate is approximately once a second.

The TLC cells use this information to arm the optimal load to be disconnected. The TLC cells are not synchronized to each other, but because of the same decision algorithm used for each of them, and the fact that they get the same input set of variables, these cells generate the same load rejection order. Therefore, each LRC may possibly receive up to three concurrent and identical commands to disconnect its assigned load.

Each TLC cell sends its messages in broadcast mode to the LRC cells. The message is universal and follows dedicated proprietary protocol designed by the RTU manufacturer. Each LRC cell compares its address with one or several addresses embedded into the message. If its own address matches with one of the addresses embedded in the message, the LRC cell decodes and reads this message and sends the requested information or a disconnecting order to the corresponding load.

In the reverse direction, each LRC cell sends its messages in broadcast mode to the three TLC cells. In this case there is no decoding process from TLC cell. Each time this message reaches the cells, the reading from the TLC cell is immediate. Each LRC cell is constantly sending its load availability status to TLC monitoring cells, which constantly process the information to select the disconnection scheme in case of circuit loss.

The implemented structure does not consider redundancy for the systems. The reliability of the scheme is reached mainly using up to three simultaneous trip orders sent from TLC. Therefore, the risk that the system would fail to disconnect appropriate load is very low. Only one level of redundancy is used at RTU's CPU level for each cell.

Each of the cells communicates via satellite link between interface ports via Ethernet.

The communications protocol is the dedicated proprietary protocol designed by the RTU manufacturer and used in all the cells. It allows faster and more efficient communication between all RTU's cells.

Each TLC and LRC cell runs an auto diagnostic program routines included in its respective master program. It allows monitoring health status of the equipment and communications links. This real time communications link health monitoring is complemented by historical trend about the link's behavior. This trend is recorded and analyzed in order to detect communication link slowly degrading status, and thus to generate earlier alarms and to anticipate and avoid any communications failures.

The system is equipped with monitoring station located at operator site of the company in charge of system operation. From this monitoring site it is possible to supervise the system status, to change configuration parameters, to validate or inhibit loads for preselecting process, and also to remotely change any cell program scheme. Each of these actions is assigned with different access level and requests different passwords and safety levels.

Any action performed from this monitoring station is recorded into a log which keeps all information to allow tracing the full detailed historic map relating to all system access through this station.

All monitoring and control programs are implemented in powerful processing and calculation dedicated RTU. This RTU is programmable with languages and environment IEC 61131 standard compliant. HMI incorporated in this monitoring station allows real time checking of variables. Examples include but are not limited to:

- Dynamic one-line diagram of the system status, displaying all necessary relevant electrical values.
- Communications network status
- Alarms and equipments auto diagnostic tests results

The station also allows extracting of the following stored data:

- System generated alarms log
- Events log
- Electrical values history log

Any information recorded into the cells has its own time stamp with 1 msec time resolution. The information extracted from LRC and TLC cells through the monitoring station's HMI, is stored to its hard disk with ".csv" extension able to be converted into Excel format.

For each event, each cell keeps the information about prior and post event status. The event is received and processed by the TLC cells but received and processed by the LRC only if joined to a trip order reception. Therefore, the LRC cell which doesn't receive a trip order doesn't generate an event log. The data recording sample time depends on the required speed of the monitoring station HMI. The common sampling time is 10 seconds.

Any equipment part of the cells for this system are fully compliant for application in electrical substations (temperature operating range extended, electromagnetic shielded, reinforced solid construction and electrostatic resistant).

4.1.4 Brief Description of the Operation HMI

The system is permanently monitored and supervised by the supervision and sequence of event logging station located at operator's premises. This special supervision and logging station is designed similarly as the other cells of the system and communicates via satellite link with the rest of the system network. In addition it has specific supervision and configuration rights which are not implemented in the rest of cells. It is possible from this station to administer full operation of the whole system. Figure 4-6 shows the type of visual interface which was developed for the operator:

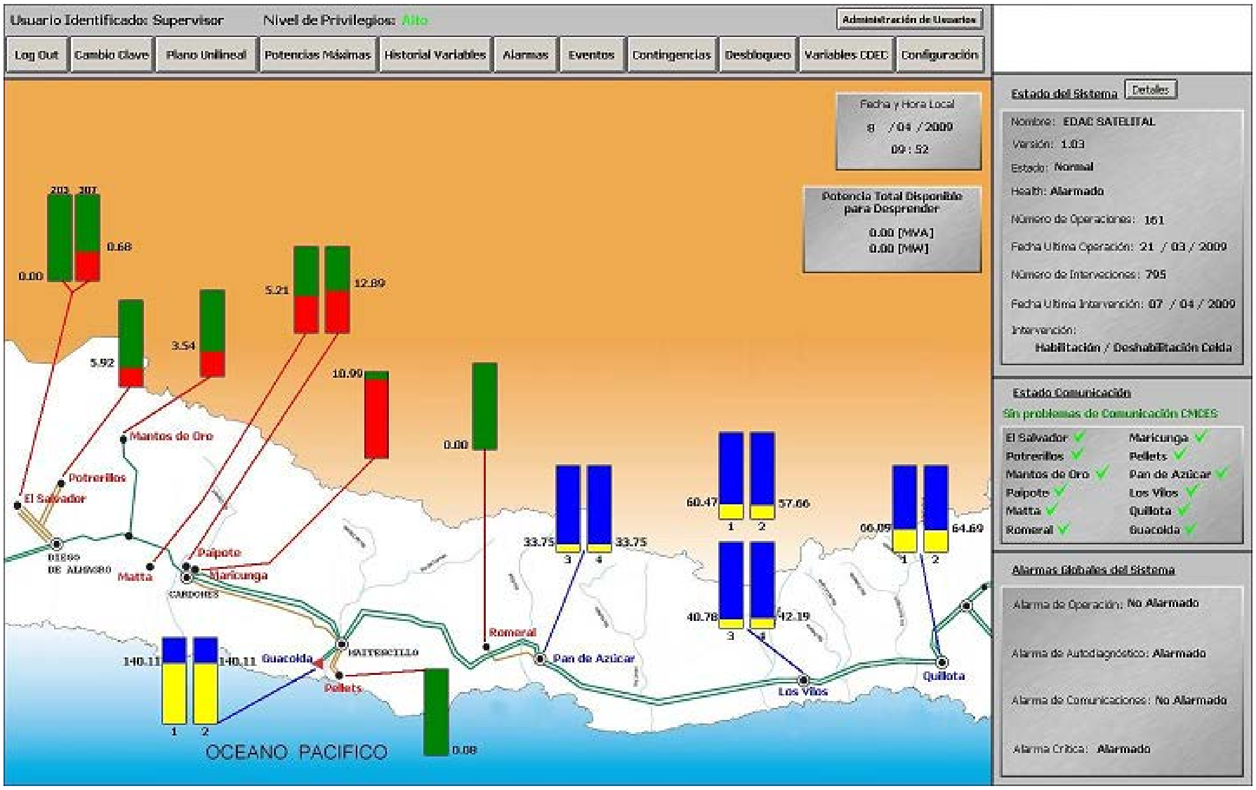

Figure 4-6 Operational SIPS-LRS[1] HMI

The blue bars represent transmission line cells (TLC)

The yellow area part of this blue bar represents the instant active power value transported in that line and at the monitoring point. In the case of the cell located in G2[2] (Guacolda), yellow color shows instant active power generated from G2 power plant. The black color figures beside bars show numeric value corresponding to bars quick view.

The green background shows load from load cells (LRC) corresponding bars.

The red color shows the active power level available for load rejection at this load monitoring point. The black color figures beside bars show numeric value corresponding to bars quick view.

The top right corner of the HMI display shows the total MVA and MW load able to be rejected by the system.

Some of the main characteristics of the HMI interface include:

- On line supervision for the available loads to be rejected
- On line supervision for the active and reactive power transmission
- Enabling and disabling the system

[1] The values shown in this HMI illustration are not reflecting specific operation real case.

[2] This HMI illustration also shows existing special Line rejection cell installed at G2 power plant (Guacolda). It corresponds to an older SIPS which interact with this scheme and is shown for information.

- Remote upload of new programs to the cells
- Remote diagnostic of the system
- Logging of the most relevant electrical variables
- Alarm and events sequences log and administration

4.1.5 Events and Actions

During normal operation, the system monitors the power flows and the breaker status for the whole set of lines located between Stations Q-LV-Paz. This monitoring detects overload type or breakers trip contingencies. More specifically, monitoring allows defining the value for an eventual overload contingency in either of the lines and also detects breaker opening in either of the two lines. The system doesn't consider information about the outage type (single phase, bi phase, etc.) but simply starts the control sequences regarding loss of any of the lines.

Prior to any event occurrence and at any time, each of the TLC cells is performing schemes and cases analysis, and defines a control and action matrix regarding the actual situation. On the basis of this analysis the system defines which load rejection arrangement will optimize the power demand in the remaining operating circuit, to avoid unnecessary load rejection. It also allows the loads to be rejected in the contingency situation in a fair manner. For this last case a special record is created to track how many times each load has been rejected. The highest priority for future load rejection is then assigned to the loads which have the lowest participation rank for this particular contingency.

When the SIPS scheme is in operation and in the case of breaker opening in one of the circuits belonging to lines between Stations A, B and C, each of the TLC cells of this line defines how much load is necessary to reject to restore the remaining circuit to its normal operation status within assigned operation margins. Since this analysis is performed constantly, the value of the total load rejection is also computed and defined. The remaining analysis determines the best rejection scheme configuration taking into account the value and the loads priority.

The system doesn't perform heavy calculation during the control phase. Therefore the reaction time is fairly short, allowing the total set of load rejection actions to only last between one and four seconds. Once the load rejection order is sent, the TLC cells perform a load rejection feedback request to the LRC in order to validate the process loop.

The system checks that remaining circuit's power flow has decreased, reaching the defined or lower value as specified setting by the operation scheme. If the load rejection was executed correctly and the remaining circuit is restored within operation margins, the system returns to monitoring status and sends corresponding system alarms to the HMI monitoring station. However, if the load rejection failed for any reason like unrecognized command or other type of fault, the system sends back immediately the initial load rejection order and again performs the power drop check and provides a specific alarm for the system operation failure. If the failure remains, the system defines a new set of loads to be rejected to satisfy the necessary power reduction in the circuit and sends a new rejection order.

If all control actions fail and the contingency cannot be reduced by automatic load reduction, a critical alarm is sent to the electrical main operation center. This allows the system operator to perform manual load rejection via direct voice communication with mining companies for example. The system defines the critical time for an overload line contingency. If this estimated time expires and the system has not detected load rejection, then a special protection unit is activated and a trip order is sent directly to the circuit breaker of the over loaded circuit.

The system may be disabled locally via manual order or through PC.

4.2 Testing of Load Rejection Scheme

The system SIPS-LRS has its own test sequence. The test system developed is shown in red color dashed box in Figure 4-7.

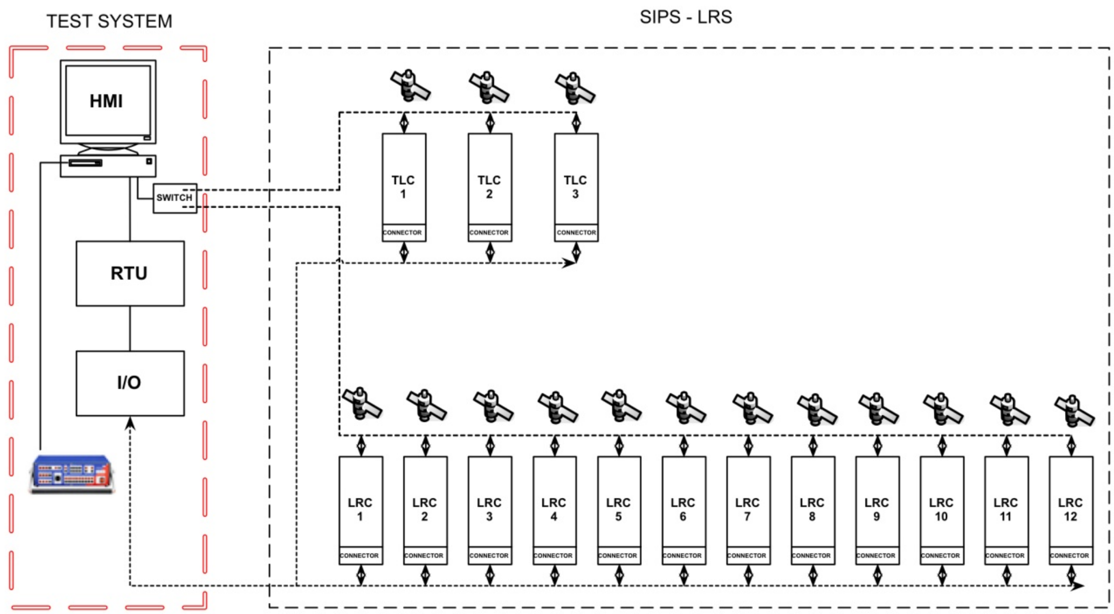

Figure 4-7 Test system connected to SIPS

Figure 4-7 shows the use of a testing cell, outlined in red, including:

- One RTU with digital I/O modules to simulate breakers status.
- One analog generator (Universal relay test set and commissioning tool) to simulate power values and feed at least two line transducers (the rest of the values are internally simulated). The test unit is connected to PC through an independent communications port.
- One communication interface to simulate Load Cell information

The sequence of events may be programmed into a computer PC type, and with time accuracy down to 100 ms, which allows flexible operation cases designed for the SIPS-

LRS. The same system is used either for the FAT tests and the SAT tests. Site Acceptance Tests use the real electrical values from the field. The test system is handled via dedicated HMI, generates individual step changes from the operator, or executes the sequence of programmed changes.

The system also may check the response time of the complete RTU, measuring with 1 ms time accuracy the total hardware and software processing time from the digital input request (contingency information) up to the digital output activation (load rejection order) via communications port.

Both the input request (stimulus) and the output orders (response) are logged into the test PC computer. This allows analyzing the system in flexible test modes regarding different sequences of operation.

5 DESIGN AND TESTING OF ADAPTIVE LOAD MITIGATION SCHEMES

Adaptive load mitigation schemes typically take an initial action then monitor the effect of that action before evaluating and executing further actions. For such adaptive schemes, additional corrective actions continue to be executed until the congestion is mitigated and system is relieved. The arming of such schemes determines the mode of operation and whether the system adjustments need to be immediate or the conditions support more gradual balancing of load and system capability, including generation. These schemes may rely on substation load, where monitoring elements of the scheme are located, or communications based systems.

5.1 Adaptive Load Mitigation Scheme Design Example

5.1.1 SIPS Testing for Adaptive Load Mitigation

SIPS typically monitor the power system so that the mitigation actually executed adapts to the minimum action required by the specific system conditions. The thermal overload mitigation described below is such a scheme.

5.1.2 SIPS Operating Requirements

The SIPS is applied to an area that is served by five 115 kV transmission lines. Three of these lines (A, B and C, see Figure 5-1) connect to power plant station N which is substantially less economic to operate than other available generation sources. Loss of any one of these three lines does not result in system performance outside acceptable limits. Despite its uneconomical characteristics, the plant is designated “must run” at a low load level to minimize the risks described below.

The other two “source” 115 kV lines (D and E) connect the area to more economical generation and stronger transmission sources. Loss of line E, by itself, does not result in system performance outside acceptable limits. However, during peak load conditions, loss of line D results in an overload of line E by as much as 60% above its thermal rating, depending on the actual load levels on the system. The 230 kV system that feeds into generation station N also can provide partial capability to reduce the load on line E, but not enough to completely mitigate the overload. Even at full rated output, the uneconomical generation at station N cannot supply enough load to avoid the overload conditions on line E. It is not acceptable to simply trip line E to relieve the overload because area voltage would fall below 0.8 per unit.

The most critical single outage is line D. However, if line D can be put back in service quickly enough, the line E overload is eliminated. Therefore single-shot automatic reclosing with a two-second open interval was installed on line D.

Outages on the 230 kV system may also result in overloads on line E, though not as critical as for line D outages. The 230 kV lines already include automatic reclosing, though outages of the 230/115 kV transformer or 115 kV phase shifter in series with the transformer would involve substantial delays before restoration. Any of these outages can be eventually offset by ramping up the thermal generation at station N, though the maximum ramp rate is much too slow to avoid a critical overload of line E.

Without additional transmission line capability the only solution is load shedding in the area. The amount of load that must be shed varies as a function of the actual load at the time of the critical outage. Due to the system configuration, it is more effective to relieve the overload by shedding loads closer to the terminals of the overloaded line E. The best case for load shedding effectiveness is about 0.8 MW of reduced line E load for each 1.0 MW of load shed, i.e. if line E is overloaded by 20 MW, at least 25 MW of load must be shed to mitigate that condition.

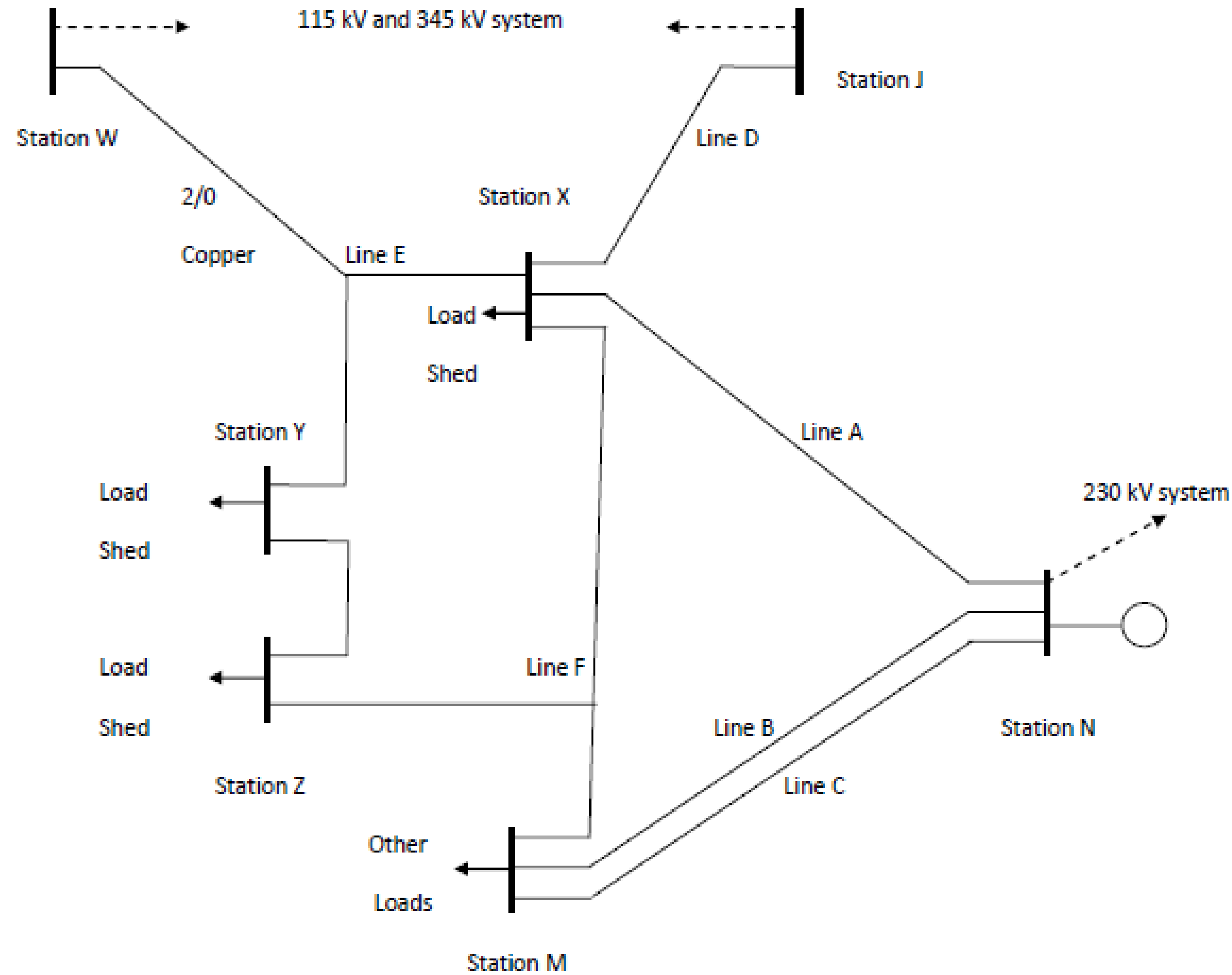

Figure 5-1 One-Line diagram of the 115 kV system that subjects the three-terminal Line E to thermal overload for several single contingencies

5.1.3 SIPS Description

This thermal overload mitigation SIPS continuously monitors line E current at the station W terminal and initiates load shedding at up to three substations. It is not necessary to monitor the line D or 230 kV system status. Loads are shed by individual feeders, with two seconds delay between tripping of each feeder breaker. Load is always shed first at station X, then station Y and finally station Z until the line E current falls below its rating. Since the problem is thermal overload, some delay is acceptable before shedding load.

Line E is a three terminal line protected by a POTT scheme using peer-to-peer relay communications. Load shedding stations X and Y are two of the three terminals, while the third terminal at station W experiences the heaviest loads. The station W line protection relay monitors line current and operates the SIPS initiation and test logic, plus several peer-to-peer bits not used by the POTT scheme to communicate line E overload and test scheme bits from station W to station X and Y. Station Y communicates via a separate channel to station Z for additional load shedding capability (see Figure 5-2). All communications channels are continuously monitored and initiate SCADA alarms for failures.

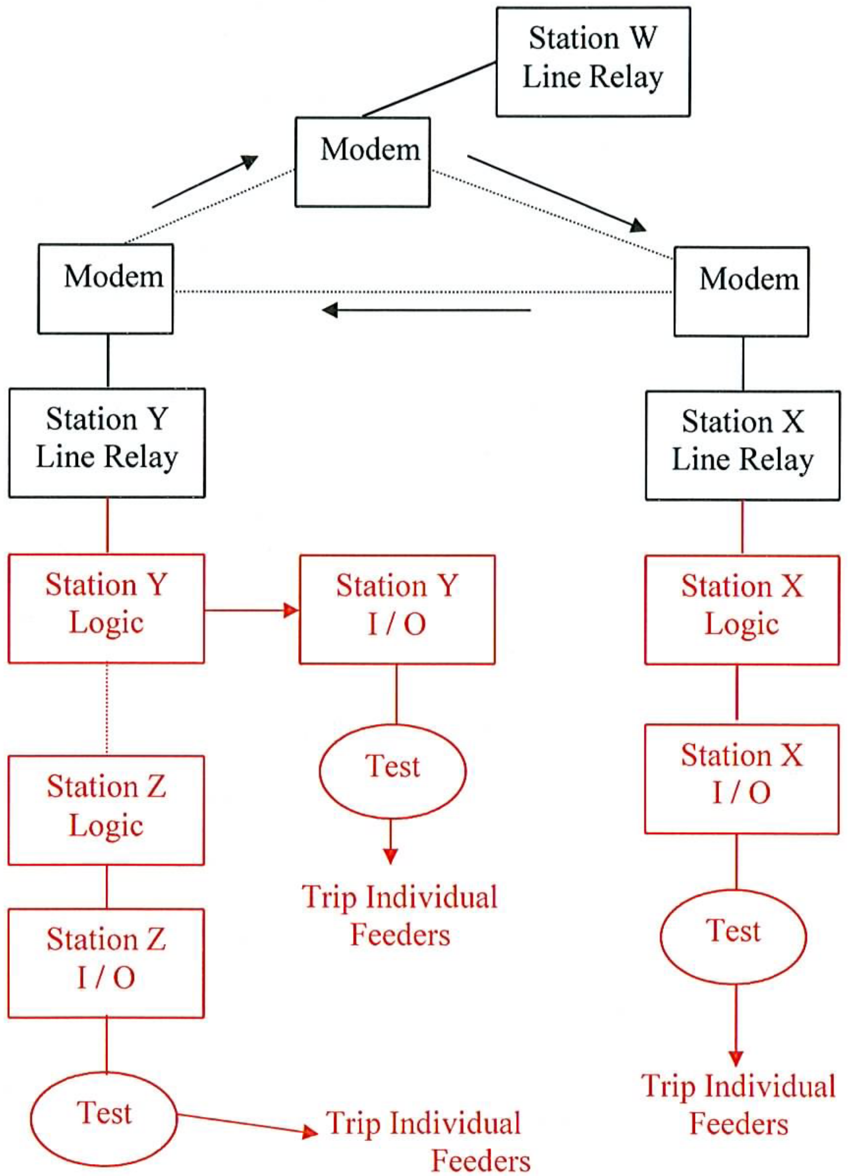

Figure 5-2 Line E Thermal Overload SIPS architecture showing original line protection communication channels, SIPS logic processing, scheme I/O, and Test facilities.

If the line E current at station W exceeds 80% of the line rating for 5 seconds, an alarm is provided through SCADA to the EMS and system operator. If the current exceeds 100% of the line rating for 5 seconds, a separate alarm is sent to the EMS and the SIPS asserts an “overload” status bit in the peer-to-peer communications. The 5 second delays avoid sending alarms during normal fault clearing and line reclosing.

Each site is designed to trip up to eight existing or future feeders. Each feeder has an associated local manual switch to enable or disable shedding that feeder (not shown on Figure 5-2). Existing feeders are available to be tripped by the SIPS unless they serve critical loads such as hospitals. “Future” feeder switches are operated in the “defeat” position. Stations X, Y and Z each have logic processors and two I/O modules which execute identical logic.

The SIPS has up to 18 feeders potentially available (six at X, four at Y and eight at Z). Total peak load normally available to the SIPS and enabled for tripping (>70 MW on 14 feeders) substantially exceeds the highest expected load shedding requirement (~50 MW).

The “overload” bit from station W starts a 5:00 minute timer at station X logic processor plus 5:20 and 5:40 timers at the stations Y and Z logic processors. The 5 minute delay is the longest duration that the line conductor can withstand under the estimated worst case overload conditions.

Each feeder tripped reduces the total load on line E. As long as the load on line E remains above the line rating, load shedding begins at 5 minutes and continues every two seconds (6-14 seconds between stations). When station X load shedding has been completed, but was not sufficient to relieve the overload, the 5:20 timer at station Y begins load shedding. When station Y completes its available load shedding, but more is required, the 5:40 timer at station Z begins its load shedding sequence. If any feeder breaker fails to trip, the scheme controls adequate load to continue tripping feeders until the line E load is reduced to a safe level. When the line E falls below the rating, the station W “overload” bit resets and the scheme logic stops further load shedding. Thus actual SIPS action is automatically scaled to the size of the line overload.

5.2 Testing of Adaptive Load Mitigation Schemes

Testing this SIPS is manually initiated, but automatic in execution. A manual push button at station W puts the SIPS in either the Normal or Test mode. The Test mode includes a local indication light and the Normal/Test status is provided to the EMS and system operator through the SCADA.

Each load shedding station X, Y and Z includes an electrically operated rotary test switch to put the scheme load shedding logic in either the Normal or Test mode (Figure 5-2 and Figure 5-3. The Normal mode allows the SIPS to trip the breakers. The Test mode blocks the SIPS from tripping the breakers but still monitors receipt of the trip signal.

Figure 5-3 shows the schematic for a load shedding breaker including the test switch contacts and monitoring functions. As at station W, the Test mode includes a local indication light and the Normal/Test status is provided to the EMS through the SCADA. The I/O module inputs IN1 and IN5 (for breaker 1, separate inputs for other breakers) confirm that the trip signal is received at the breaker and is time stamped by the logic processor.

The test philosophy uses the normal SIPS operating logic to prove that the I/O module contacts that trip each breaker actually operate, while the Test mode prevents actual breaker trips. Scheme testing is initiated locally from station W and automatically continues through three stages: (1) Test mode confirmation, (2) SIPS action simulation, and (3) Test mode reset.

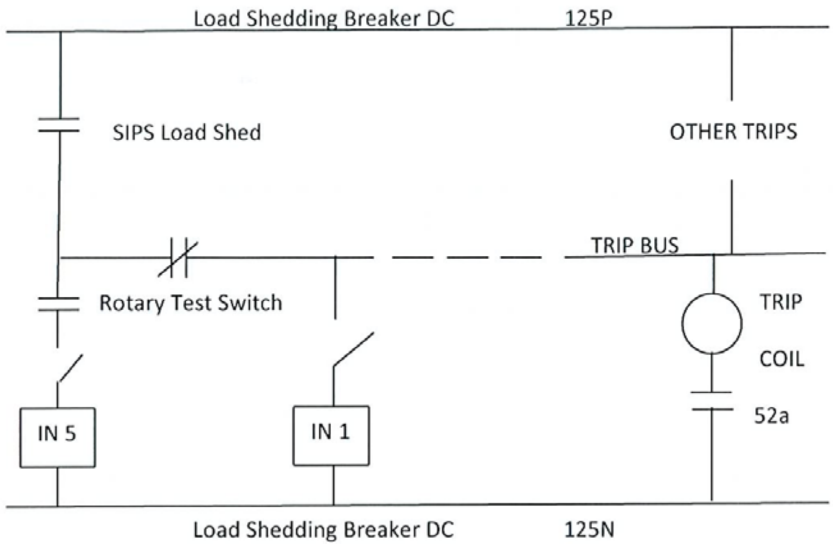

Figure 5-3 Schematic of SIPS load shedding breaker showing the test switch (in normal mode) and scheme monitoring arrangements.

5.2.1 Test Mode Confirmation

The station W push button sets a logic latch in the line protection relay which sends a peer-to-peer Test status bit to station X. Station X operates its rotary test switch and monitors that switch status. When station X test switch is in the Test mode, the station X line relay sends the Test Mode status on to station Y. When station Y test switch is in the Test mode, the station Y logic processor passes the Test Mode signal on to station Z's logic processor and its test switch. The station Z test switch then provides its test status back through station Y, which passes it on to station W, confirming that all test switches are in the Test mode. If any test switch fails to operate, the Test mode signal is not sent to the next station. If the Test mode status does not return to station W within 10 seconds, the test is stopped and relay technicians are alerted to diagnose the problem.

5.2.2 SIPS Action Simulation

Station W line relay recognizes the successfully returned Test mode status bit originating from station Z and asserts the peer-to-peer "overload" bit. Just as would occur during "live" operation, receipt of the "overload" bit at station X begins that 5:00 minute delay before load is shed. When the 5:00 timer expires, trip signals are sent to the feeder breakers at two-second intervals and the scheme monitors that the trip signal is actually received (e.g. IN5 for breaker 1 in Figure 5-3). This sequence is completed even for feeders that are excluded from tripping by their local "defeat" switches due to serving critical loads or future feeders. The trip signal is then passed on to station Y and subsequently to station Z, where breaker trips and monitoring operates in the same manner as at station X. When the station Z test tripping is successfully completed, the logic provides the status bit back through station Y to station W, confirming that the scheme trip testing is complete and station W resets the “overload” bit. Failure of any of the trip signals to be received at the breaker (i.e. INx doesn’t assert) blocks the test trip signal from being sent to the next breaker and station. If the test tripping status does not return to station W within six minutes, the test is stopped and relay technicians are alerted to diagnose the problem.

5.2.3 Test Mode Reset

When station W recognizes the returned trip status bit from station Z, the line relay logic resets the peer-to-peer “overload” bit, then asserts and sends a Test Reset bit to Station X. Station X resets its test switch and passes the signal to station Y. Station Y resets its test switch and passes the signal to station Z. Station Z resets its test switch and passes the signal back through station Y to station W, confirming that the Test mode is reset. Successful completion of the test sequence also resets the Test mode logical latch. Failure of any test switch to reset blocks the reset signal from being sent to the next station. If the Test mode reset status does not return to station W within 10 seconds, the test is stopped and relay technicians are alerted to diagnose the problem.

6 DESIGN AND TESTING OF DYNAMIC BRAKING SCHEMES

A dynamic brake is a resistive shunt type load that is switched onto the power system briefly to help maintain transient stability once a disturbance has occurred. When a fault occurs on the power system, the load is suddenly reduced and perfect balance between load and generation is disturbed. Excess kinetic energy, due to the difference of constant mechanical power input to the prime mover of a synchronous generator and the reduced electric power delivered from its terminals, begins to accelerate the rotor. This energy, converted into electrical power, interacts with remote machines producing a power swing. Equilibrium can be restored if the amount of excess energy is limited by fast fault clearing and if sufficient restoring forces are available. Stability depends upon system characteristics such as inertia and system impedance, and it involves action of governors, stabilizers, and voltage regulators. Damping may be enhanced by application of a brake to absorb the excess electrical energy. Success may depend upon the size of the brake load with respect to the amount of excess energy, the duration of brake load application, and the number of insertions.

Typically a three-phase power circuit breaker is used to insert a dynamic brake once, just after the fault is cleared but during the first system swing. Other possible methods include thyristor controlled insertion, single phase insertion, and multiple insertions during recurring swing periods [6.2].

6.1 Dynamic Braking Scheme Design

A dynamic braking scheme can be a local scheme existing at only a single power system station location or it can include equipment locations that cover a wider area. The design might require signal measurement, logical decision making, possibly telecommunications equipment, control outputs, and a switch device, not to mention the brake itself. Braking schemes are typically open loop, one-shot control systems, although more complex continuous loop type multi-shot brake schemes might be applied.

6.1.1 Example Designs / Schemes

In this example, application of a dynamic brake enhances transient angular stability between adjacent systems allowing one system to benefit from the other systems' remotely located renewable power sources. When first installed, availability of this three-phase 1400 MW braking scheme was thought to increase power transfer capability by 900 MW. [6.1] Today, total possible transfer between these systems is approximately 5 GW of AC and 3 GW of HVDC. Installed generating capacity of the sending system is near 50 GW.

This brake is applied to a system which also has several other SIPS schemes in operation at any time. Brake availability avoids the need for equivalent generation reduction amounts using a gen-drop scheme when the system is in export mode. The brake is applied at a single location adjacent to large hydroelectric generation units as part of a wide area protection scheme. The control is open loop type, with fixed duration of application. This eliminates the need to measure convergence of system speeds. A single insertion during the first power swing is applied using a power circuit breaker.

6.1.1.1 Brake Design

Each phase of this braking resistor is supported on a modified double-circuit 115 KV suspension tower body approximately 90 feet high. The towers serve as dead end support for the 795-MCM ACSR Drake conductor that energizes the resistor from the substation 230 KV bus. The grid resistor for each phase is formed by 14,700 feet of ½ inch, 19-strand, stainless steel wire zigzagged around the tower in 60 foot vertical loops. Loops consist of individual wire elements bonded together by compression jumper fittings and vertically supported through insulated sheaves and clevis insulators between an upper rack and a lower rack. The lower rack is held out from the tower legs by vertically hinged insulated struts and is weighted to maintain tension in the grid wires which can elongate during brake operation. Current flows thru individual series connected grid elements in such a way as to neutralize grid inductance.

6.1.1.2 Wide Area Protection Scheme Design

Insertion is caused by logical decisions based upon measurements at several locations. Locally, redundant power rate relays detect incremental response of generation to severe disturbances. Level, and rate of change of electrical power of the local hydro units outputs are measured. [6.3] Depending upon the current level of power, a sudden decrease of sufficient magnitude, measured over a 200 millisecond time interval, coupled with a 10% or greater drop in bus voltage, causes insertion. Either relay can initiate insertion. (This power measurement is a practical way to approximate local accelerating energy. The voltage measurement adds security, for example in the case of a unit breaker inadvertently opening.) Several different setting levels are used to determine severity of the disturbance/fault.

A second portion of logic inserts the brake when multiphase faults occur on nearby critical transmission lines. Protective relays detect in-zone faults and key an "insert" signal over a single analog radio teleprotection channel.

A third portion of logic inserts the brake from similar power rate relay logic located at a distant power transfer location via a single teleprotection channel.

A fourth portion of logic, enabled by SCADA dispatchers when the local power system/control area is exporting power above a threshold, inserts the brake if any of several different combinations of transmission lines are simultaneously out-of-service.

6.1.2 Specific Design Considerations

Redundant measurement of the status of each line terminal depends upon breaker 52b switches, line relay trip signals, and other logic used to detect if reclosing is imminent. Line loss status is keyed over individual protection channels to redundant controllers at different locations. Each controller makes three separate determinations with at least two of three being in agreement to initiate control action. Redundancy here is used to improve dependability of system measurements at some increased risk of insecure/inadvertent operation. Test switches are minimized and design is kept as separate as possible from other protection schemes to reduce opportunity for human error.

Redundant relays protect this brake from thermal overload, protect the system from brake faults, accept insertion signals from the different controllers, and control brake insertion timing. The brake is designed to be able to withstand up to three seconds of continuous operation between cooling periods. The intended duration of application is 0.5 seconds. It is connected to the system by a three phase circuit breaker which takes approximately 100 milliseconds to close. Insertion may be locally disabled. Occurrence of accidental insertion has not been harmful to system stability. Failure of the brake to insert when called upon might contribute to system separation. Prolonged insertion could be detrimental to stability. Breaker failure protection is provided to trip adjacent breakers upon detection of failure to interrupt current.

Although some components of this wide area scheme, such as line loss measurement, power rate relays, and controllers, are redundant; other components including the brake itself, the breaker close circuit, and certain teleprotection channels are not. Here, redundancy has been applied to increase dependability as either redundant component may initiate control action. Switches are also applied at a central location to allow operators to arm and disarm different implementations of the scheme, and hopefully thereby reduce opportunity for error.

6.2 Testing of Dynamic Braking Schemes

6.2.1 Functional Performance Validation and Timing Testing

Computer simulation was used to validate the theory and function of this proposed dynamic brake control system. Actual field test data for switches and typical values for expected control system throughput delay is accounted for. Once installed, Routine tests are performed to verify operation of components, integrity of logic, and continuity of wiring from input to output. Also, actual operations of the brake routinely occur which tend to support application as stable operation of the power system is observed.

6.2.1.2 Testing the Design Concept By Computer Simulation

Prior to installing the brake EMTP (ElectroMagnetic Transient Program) studies were conducted of particular system performance during swings caused by faults at different locations under varying conditions, with and without application of this brake.

Transient stability computer simulations are often used to observe maximum accelerating power, generator terminal voltage, and the change of voltage angle across the system reactance that occurs during a swing. The equal area criteria method is used to predetermine if stability is possible, and whether or not a critical angle is reached. This partially depends upon the level of power transfer that existed just before the fault.

A simple model describes dynamic braking during the first swing period. In the single machine infinite bus model, the aggregate generation of one system is represented by a single synchronous machine, the remote system is represented by an infinite bus (with infinite inertia), and the interconnecting transmission network is represented by reactance. The brake is assumed to be a fixed load independent of generator bus voltage or rotor angle. See Figure 6-1.

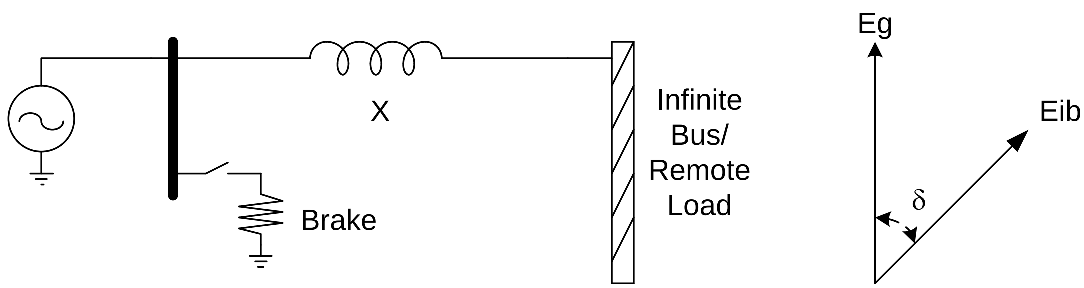

Figure 6-1 Single Machine Infinite Bus Model

Rotor acceleration (or deceleration) is proportional to the difference between the constant mechanical power input of the generator and the sum of electrical power transferred by the transmission network plus the electrical power dissipated by the brake:

$$\dot{\delta} = \omega$$

$$\dot{\omega} = \frac{\omega_0}{2H} * P_{mech} - \frac{\omega_0}{2H} * P_{brake} - \frac{\omega_0}{2H} * \frac{E_g * E_{ib}}{X} * \sin\delta$$

The relative velocity of a generator, which directly relates to the energy stored in its inertia, can be approximated by integrating the accelerating power:

$$\omega = \int \frac{\omega_0}{2H} * P_a$$

While inserted at the generator step-up bus, real power absorbed by the brake reduces the value of accelerating mechanical power, since a portion of the generator output power goes directly to the braking resistor, thus reducing the power that the transmission line must transfer.

For the example described by section 6.1.1, transient simulations including use of EMTP (ElectroMagnetic Transient Program) were applied to study a particular system performance during swings caused by faults at different locations under varying conditions, with and without application of a brake, and without consideration of damping effect of governors, stabilizers, or regulators [6.2]. Application of a dynamic brake resistor was found to enable greater power transfer while maintaining stability. See Figure 6-2 for an example of a phase plane plot of the system with and without a brake application. (A stable post fault trajectory remains inside the separatrix.)

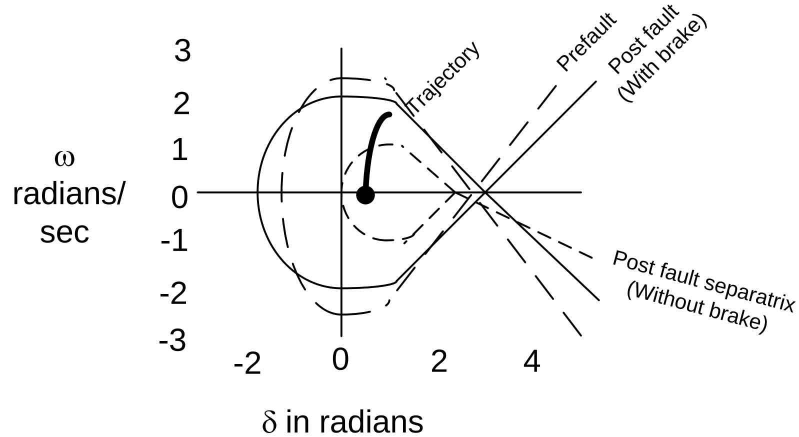

Figure 6-2 Phase Plane plot of Stability Regions

Notation to Figure 6-2

The darkest line in the figure represents the trajectory of a given power swing in values of delta (δ) and omega (ω). The other three lines in the figure (dotted or solid) which form loops, are each called a separatrix. The separatrix represents maximum values (or deviations) of delta (position) and omega(speed) which can occur for a stable power system. Once these values are exceeded then the system becomes unstable. These values are determined by the computer modeling of the system being studied here as described. See reference 6.8.

The outermost dotted line separatrix represents the stability boundary for the system at a given transfer level with no fault. The inner dotted line separatrix represents a stability boundary for the same system condition after a fault but without a brake being applied. The solid line separatrix represents a stability boundary for the same system condition with a fault and with a brake being applied.

Figure 6-2 illustrates that application of the brake enhances the stability of this power system under these conditions. If a given swing trajectory remains inside the region bounded by the separatrix, then this is a stable swing. The region bounded by the separatrix with a brake applied is much larger than the region bounded by the separatrix that does not include a brake application.

6.2.1.2 Routine Function Testing

Portions of this braking scheme are local and unique to itself whereas other components are shared by other SIPS. Routine tests are performed to verify operation of components, integrity of logic, and continuity of wiring from input to output. Experience has shown that occasional changes in local non-SIPS schemes have inadvertently impacted SIPS schemes. Components such as line loss status and unit breaker controls are often owned and operated by different utilities each with different practices.

Test switches are available to isolate components. Alarms alert operators when test switches are out of normal position. Separate DC air circuit breaker switches allow for isolation of line loss sensing, teleprotection equipment, and controllers or relays. A loop back test of channel integrity while in service is available. Relays may be isolated by test switches. Teleprotection channels may be isolated from controllers.

6.2.2 Field Commissioning Testing

During commissioning, several on site 0.5 second insertions of this brake were performed to verify brake design and system response. System behavior was as predicted by system studies with the bus voltage dipping by only 2%. [see reference 6.1]

6.2.3 Regular Testing Plan

Components of the local portion of this braking scheme are tested at least once every five years unless brake operation has occurred within the previous six months. Components shared by other SIPS are tested as often as once a year unless operation of the component has occurred with the previous 30 days. The annual test includes verification of continuity of interconnected components as an overall scheme where inputs such as line loss measurement are exercised and outputs such as breaker operations are verified.

Components are isolated and exercised to verify that proper alarms, event reporting, and SCADA control is operational. In addition, controllers are tested whenever changes are made to hardware, firmware, settings or logic, or wiring.

7 DESIGN AND TESTING OF SYSTEM SEPARATION SCHEMES

Transient or angular stability is the ability of the power system to maintain synchronism when it is subjected to a severe transient disturbance. The resulting system response involves large excursions of generator rotor angles and is influenced by the nonlinear power-angle relationship. Stability depends on both the initial operating state and the severity of the disturbance.

Disturbances of widely varying degrees of severity and probability of happening can occur in the system. However, the system is designed and operated to be stable for a selected set of contingencies. The contingencies usually considered are short-circuit currents on transmission lines, which can be of different types, including phase-to-ground, phase-to-phase, phase-to-phase-to-ground, or three-phase. Additionally, bus or transformer faults may be considered.

7.1 System Separation Scheme Design Example

To determine a need for system separation, extensive transient system stability studies are required. In transient stability studies, the study period of interest is usually limited to 3 to 5 seconds following a disturbance although it may extend to about 10 seconds for very large systems with dominant inter-area modes of oscillation.

Dynamic studies are performed for faults in the transmission system for various types of faults, fault locations, prior outages, and transfer levels. These studies, therefore, cover a wide variety of both stable and unstable scenarios. The modeling includes the swings (both speed and acceleration) that the potential SIPS relaying would see for both stable and unstable responses. The study results are utilized to confirm that the SIPS relaying would only operate when the system would lose synchronism.

The need for a system separation SIPS may arise if a transmission system has limited power transfer capabilities due to limited transmission and generation infrastructure, thus increasing a chance for severe transient disturbance occurrences.

Power swings in this transmission system can enter the characteristics of the main protective line relaying and cause them to trip for no-fault conditions, contributing to a widespread system outage. To prevent this, out-of-step blocking relays are employed to block the operation of the line relays for power swings, and the system separation SIPS is employed to respond to the power swings.

The system separation SIPS serves as the primary means for maintaining system angular stability and maintain reliability within regulator planning requirements such as NERC TPL-003 (or category C – double contingency events). It will trip for unstable power swings separating the system in two islands and block system separation for stable power swings.

The SIPS for system separation is designed to detect and isolate unstable power swings that can arise between the two distinctive areas of the power system under certain fault conditions. A one-line diagram of an example system is presented in Figure 7-1. If an unstable swing is detected, this SIPS initiates tripping the high voltage transmission lines between the two areas at the substation where it is installed because its location is suitable for monitoring the power transfer and power swings and it is the only location where a single tripping function can be used to separate the two systems. This action is intended to island the unstable system and ensure continued reliable operation of the remainder of the transmission network.

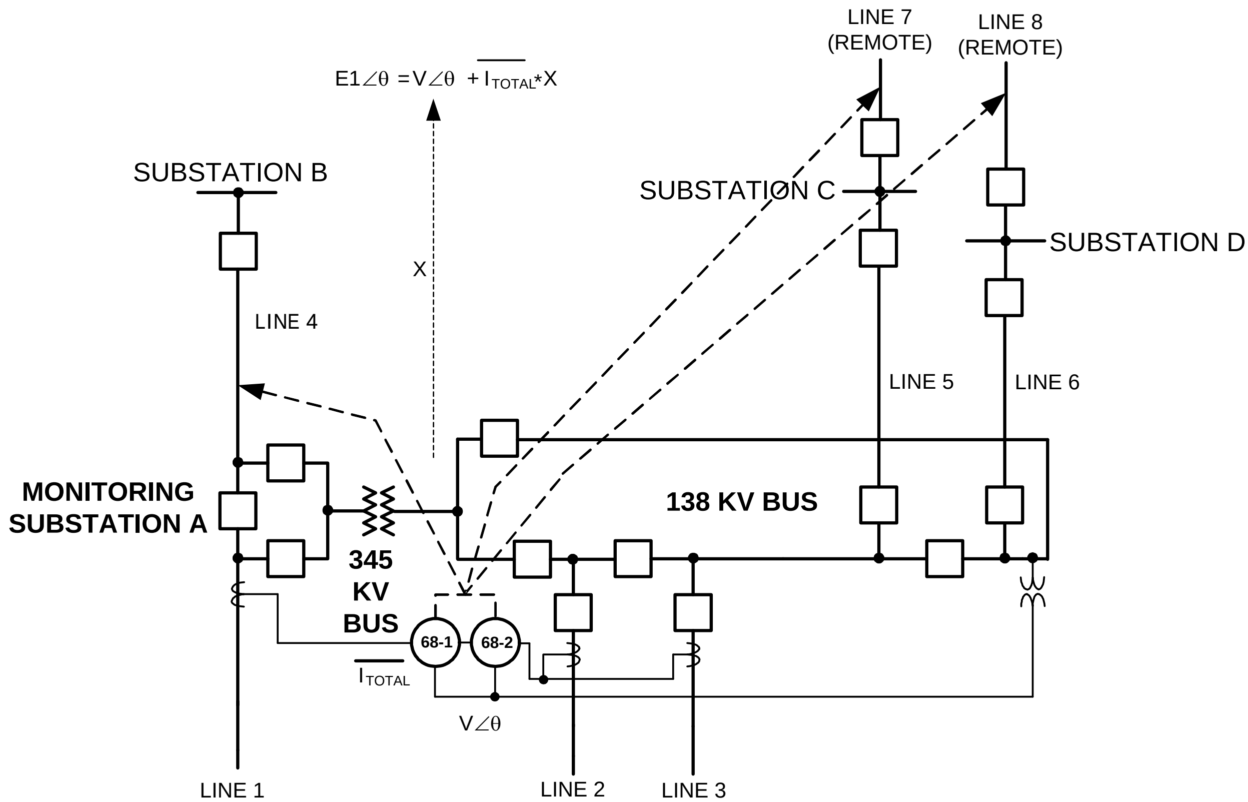

Figure 7-1 Example System One-Line Diagram

This particular system separation SIPS is comprised of two (for the purpose of reliability) identical microprocessor relays at the monitoring substation functioning as power swing relays. Both relays – identified as 68-1 (main) and 68-2 (redundant) - receive measurements of the respective bus voltage and line currents for the lines terminating at the substation as shown in Figure 7-1.

The total current in the power swing relays (designated as I_{TOTAL} in Figure 7-1) is the sum of the currents of lines 1, 2, and 3 measured at the monitoring substation A. To reference to the same base current seen by the relays as a result of the different line voltages an auxiliary transformer is installed in the CT circuit of the 345 kV line 1. The dashed lines with arrows indicate the line breakers tripped by the power swing relays.

These line currents and voltage measurements are used by the relays to calculate the source voltage vectors for the two equivalent systems, emanating from the monitoring substation. The phase angle difference between these two voltage vectors, along with the rate of change and acceleration of this difference, are then used to determine if the systems are moving out of step. Internal logic in the power swing relays prevents operation of the relays during a fault condition by employing a time delay to allow other protective relays to operate to isolate the primary fault before determining if an unstable swing is present.

Four setting groups are used in the relays to change settings to account for changes in system configuration to appropriately reflect the change in equivalent system impedance needed for the power swing calculation. This logic is shown in Figure 7-3. Local breaker auxiliary contacts at the monitoring substation and remote breaker status points transmitted from the remote ends of the affected lines are connected to automatically select the proper setting group based on whether the system is intact or various combinations of lines are out of service (Figure 7-2).

When the SIPS determines a power swing that will result in a loss of synchronism at the affected power plant, an island will be created that keeps as much of the system intact as possible while isolating the angular instability.

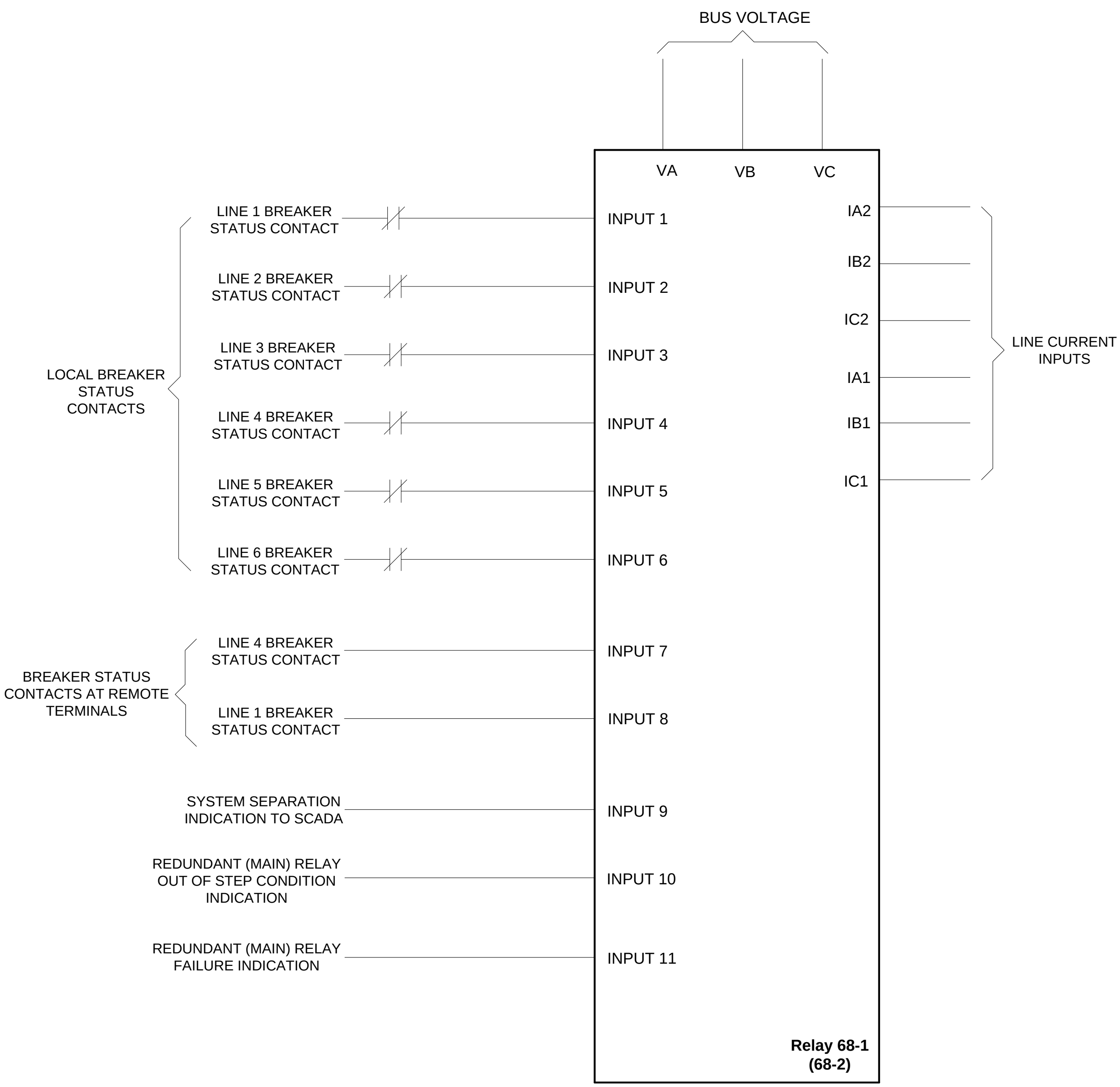

Figure 7-2 SIPS Relaying Inputs (Main and Redundant)

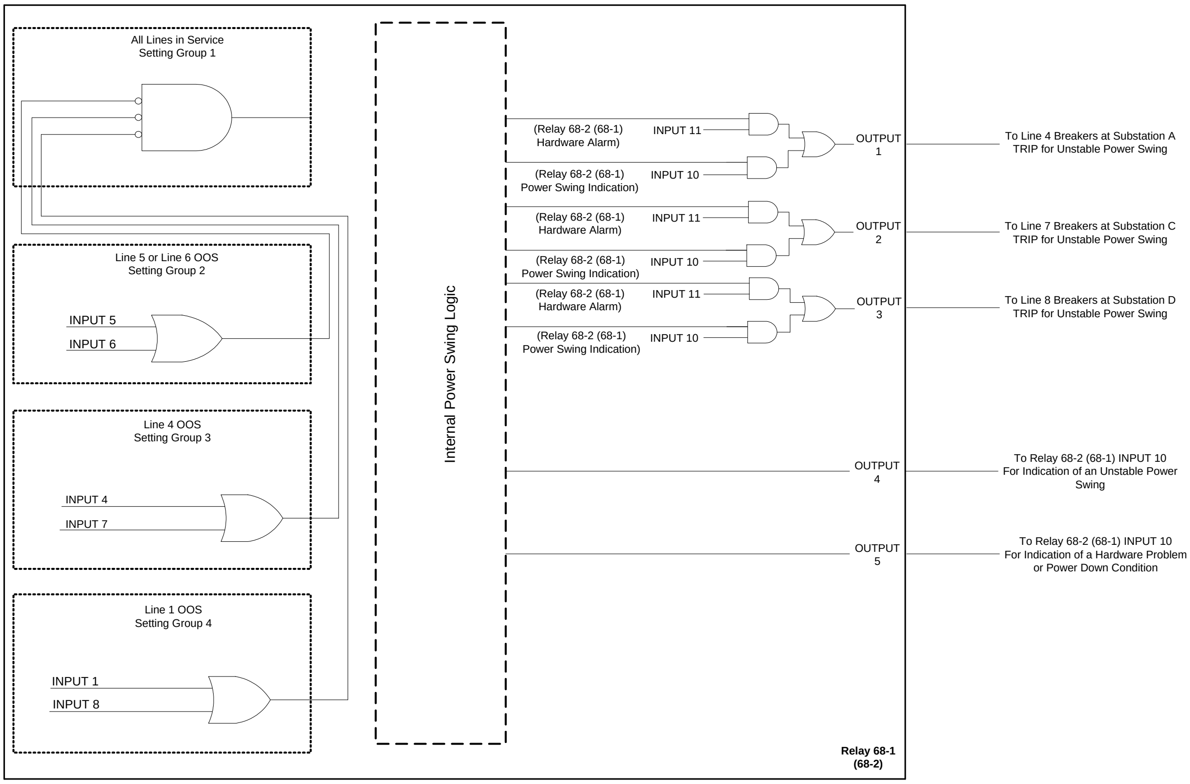

Figure 7-3 SIPS Relaying Logic (Simplified)

The SIPS relays 68-1 and 68-2 operate to achieve both dependability and security. The output of both relays is normally required to trip the breakers. But if one of the relays fails, its failure will be detected by the relay's self monitoring system which will bypass the requirement for that relay's trip output. Consequently a failure of a single component will not result in the SIPS not operating when required and ensuring that the instability is isolated from the rest of the system. This ensures the scheme's security.

Correct operation of the relays results in splitting the system in two allowing the system's weaker area to island or collapse but preserving the rest of the system from imminent loss of synchronism. Correct operation also includes no SIPS operation for stable events.

Failure of the relays to operate for unstable system events will result in the loss of the weaker part of the system which could cascade into the rest of the system. If the power swing relays cause the separation of the systems the island containing the weaker part of the system will mostly go unstable.

The SIPS is not expected to operate in an unintended manner due to the logic of the tripping scheme. However, if the SIPS relaying were to operate in an unintended manner, the weaker part of the system would be islanded, and simulations show that there would be no performance issues on the remaining transmission network.

7.1.1 Power Swing Relaying Operating Principle

The power swing function's principle of operation is based on comparing in the central location the voltage phasor angles on two buses that present two different systems which, if not synchronized, will have to be split by the out-of-step relaying.

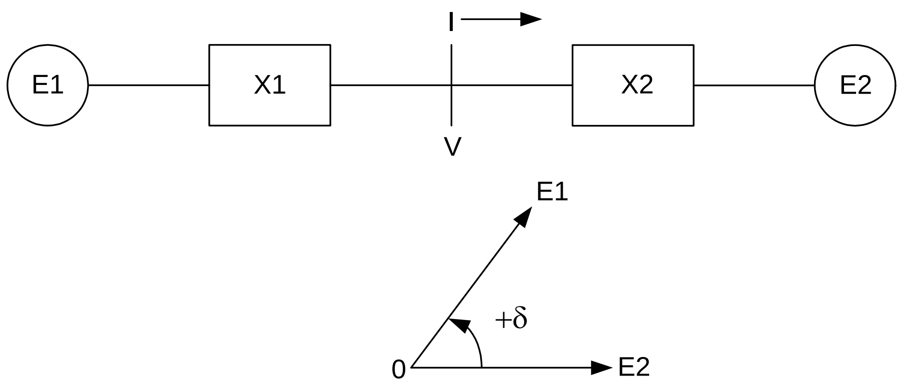

Figure 7-4 Power System Model

δ is the angle between source E1 and source E2, and V and I are the relay's voltage and current, respectively.

E1=V+jX1•I

E2=V+jX2•I

The angle δ between these phasors is found as follows:

A+jB=E1•(E2)*

Where A is the real part of the complex product of E1 and the complex conjugate of E2;

B is the imaginary part.

Then, δ = cot-1 (A/B)

δ', the rate of change of angle δ, is found as:

$$\delta' = \frac{A \bullet B}{A^2 + B^2}$$

The angle acceleration, δ'', is found by filtering first derivatives and taken over three cycles for smoothing.

$\delta'' = \delta'k - \delta'k\text{-}3$

Where k is δ' value at a given cycle

δ, δ', and δ'' are used by the power swing relay to assess system stability by examining their loci in two planes (Figure 7-5 and Figure 7-6).

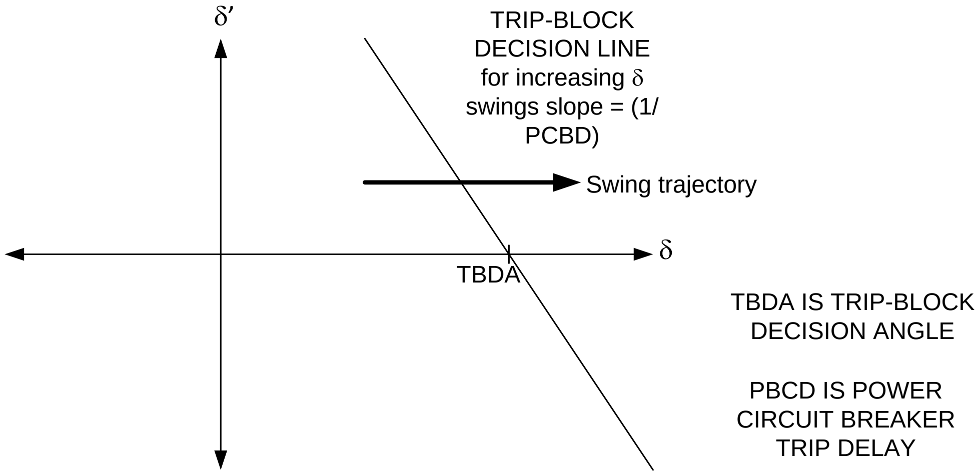

Figure 7-5 δ vs. δ′ Plane

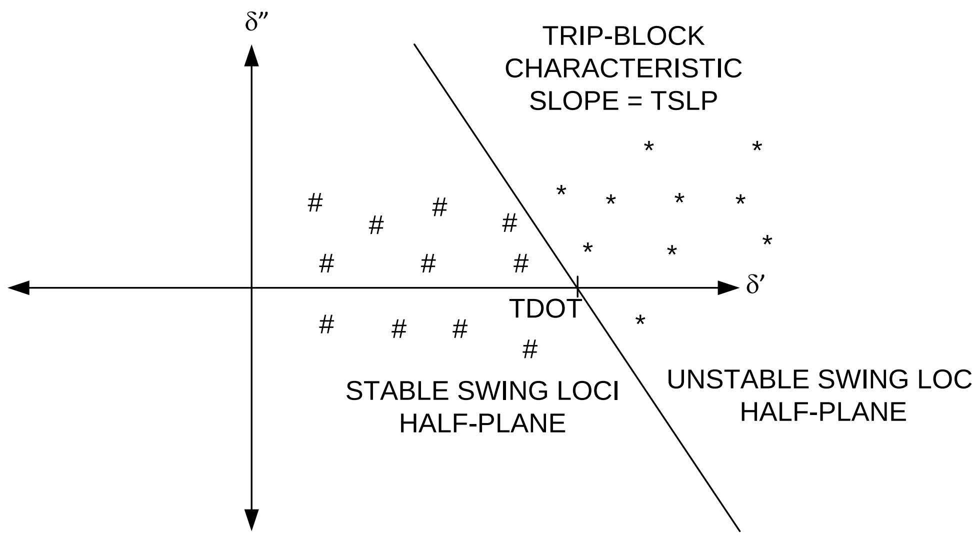

Figure 7-6 δ′vs. δ″ Plane

If tripping (or blocking) is initiated when the swing trajectory crosses the TRIP-BLOCK DECISION LINE in the δ vs. δ′ plane (Figure 7-5), then the power circuit breaker has just the necessary time to complete its operation before the TRIP-BLOCK DECISION ANGLE (TBDA) is actually reached.

In Figure 7-6, the loci for several different stable (#) and unstable (*) swings are plotted at the moment that the power angle crosses the TRIP-BLOCK DECISION LINE.

This explains how the information from the two planes (Figure 7-5 and Figure 7-6) is utilized by the power swing relay to arrive at a TRIP-BLOCK (or, equivalently, UNSTABLE-STABLE) decision. Examining the swing loci in the δ vs. δ′ plane (Figure 7-5) permits the relay to determine when the power angle has reached a pre-determined value (TBDA), and plotting the loci in the δ' vs. δ'' Plane (Figure 7-6) at that instant permits the stable/unstable decision.

7.2 Testing of System Separation Scheme

The System Separation scheme testing used COMTRADE files, which were run through the relay vendor's test system. Initially, tests were run using both stable and unstable swings. This test data was written by the relay vendor's application engineer and generated utilizing Mathcad. Testing was done to eliminate any problems found in the custom logic of the SIPS relays and to prove that the logic actually did what it was supposed to do.

After that was accomplished, the COMTRADE files were developed by starting with the PSS/E (commercial Power System Simulation for Engineering software) simulations of stable and unstable power swings. The data from the results of the PSS/E study was converted into the COMTRADE format. While the PSS/E dynamic studies produce single-phase, RMS values at 4 samples per cycle, the COMTRADE files are three-phase, instantaneous values at 16 samples per cycle. The current vectors were derived from the real/reactive power and voltage since the PSS/E does not directly provide the current values.

Linear interpolation was used to increase the number of samples from 4 per cycle to 16 per cycle. After superimposing a 60 Hz sine wave on the RMS voltage to create single-phase instantaneous data, the other two phases were developed by phase shifting the sine wave forward and backward 120°. The power swing occurs after any faults have cleared, and this assumption was deemed acceptable.

Having previously calculated the current vector in RMS, the instantaneous currents were calculated by applying the angle to the calculation to phase shift the calculated instantaneous current. All of these calculations were performed utilizing an Excel spreadsheet.

The primary currents and voltages were reduced to secondary currents and voltages, and these were moved to the format required by COMTRADE. COMTRADE requires all the values be positive integers, and shift and scaling factors are provided in the configuration files that correspond to the data files. The shift and scaling factors were selected to provide maximum data resolution while staying within the format requirements of COMTRADE.

The end result was a COMTRADE file with nine analog channels: A, B and C phases of the 138 kV bus voltage, the combined 138 kV line flow, and the 345 kV line flow.

The COMTRADE files were run through the SIPS relay by the application engineer, and the results were provided to the transmission planning engineer. After running a number of different cases through the relay, the transmission planning and protection engineers were satisfied and the SIPS relays were placed in service with the custom logic.

8 CONCLUSIONS

SIPS are often the last line of defense of an electric power grid to limit the extent large scale system disturbances, cascading failure and even blackouts. They require careful design and proper testing to ensure their reliable operation. The objective of this report is to present the design considerations, and the specific design and testing of actual schemes and to serve as reference to those interested in these SIPS. All example schemes were installed SIPS used to enhance system operation and reliability.

The SIPS included in this paper demonstrated that design and testing of SIPS are highly system dependent. Specific system and grid conditions, such as grid topology, generation levels, load levels, load flow patterns, etc., greatly influence the types of SIPS being selected. However, the design and testing of a specific scheme of the same type of SIPS should still take specific power system and grid conditions into account.

Often owners and reliability regions will deploy a combination of several types of SIPS to achieve the desired system integrity and reliability objectives, e.g. a centralized SIPS that includes the use of load rejection schemes in one area and generation rejection schemes in another other area. These schemes can be very diverse in design. This requires owners and the region to perform detailed and sometimes extensive studies and apply the appropriate standards and oversight to ensure the design meets acceptable performance requirements. The examples in this report are intended to provide owners a reference of design and testing techniques used to meet a specific application and are not intended to apply to every SIPS. The owner will need to also ensure all SIPS are properly coordinated, but SIPS coordination is beyond the scope of this report.

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