WAMS-based Intelligent Load Shedding Scheme for Preventing Cascading Blackouts

Santosh Sambamoorthy Veda

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Arun G. Phadke, Co-Chairman

James S. Thorp, Co-Chairman

Virgilio A. Centeno

Jaime De La Ree-Lopez

Sandeep K. Shukla

Mark A. Pierson

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(ABSTRACT)

Severe disturbances in a large electrical interconnection cause a large mismatch in generation and load in the network, leading to frequency instability. If the mismatch is not rectified quickly, the system may disintegrate into multiple islands. Though the Automatic Generation Controls (AGC) perform well in correcting frequency deviation over a period of minutes, they are ineffective during a rolling blackout. While traditional Under Frequency Load Shedding Schemes (UFLS) perform quick control actions to arrest frequency decline in an islanded network, they are not designed to prevent unplanned islanding.

The proposed Intelligent Load Shedding algorithm combines the effectiveness of AGC Scheme by observing tie line flows and the speed of operation of the UFLS Scheme by shedding loads intelligently, to preserve system integrity in the event of an evolving cascading failure. The proposed scheme detects and estimates the size of an event by monitoring the tie lines of a control area using Wide Area Measurement Systems (WAMS) and initiates load shedding by removing loads whose locations are optimally determined by a sensitivity analysis. The amount and location of the load shedding depends on the location and size of the initiating event, making the proposed algorithm adaptive and selective. Case Studies have been presented to show that control actions of the proposed scheme can directly mitigate a cascading blackout.

Dedicated to

My Parents,

Late Aunt Indrani,

Aunt Usha

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List of Acronyms

Acronym	Description
WAMS	Wide Area Measurement System
WAMPACS	Wide Area Measurement, Protection And Control System
PMU	Phasor Measurement Unit
ILS	Intelligent Load Shedding
UFLS	Under Frequency Load Shedding
AGC	Automatic Generation Control
LFC	Load Frequency Control
WECC	Western Electricity Coordinating Council
SONGS	San Onofre Nuclear Generation Station
COI	California - Oregon Inter-tie
FACTS	Flexible AC Transmission System
HVDC	High Voltage Direct Current
PDCI	Pacific DC Inter-tie
LSF	Load Shift Factor
PSLF	Positive Sequence Load Flow (Software)
EPCL	Engineer Program Control Language

Chapter 1

Introduction

The earliest of electrical grids consisted of Direct Current (DC) generators that were located in the vicinity of Direct Current (DC) loads which were typically a few incandescent bulbs. With the invention of Alternating Current (AC) generators, motors and transformers, transmission over long distances became a feasible option. Taking advantage of the economies of scale, the electric grids began to spread across whole cities and towns. Today, the interconnection of the electrical networks span whole continents. While the system loading has unmistakably increased manifold, the nature of the electric grid, in terms of generation and load characteristics has also changed over time. The deregulation of the electric grid has brought about its own opportunities and challenges as well. These changes have invariably altered the way power systems engineers handle the stability of operation and control of the network.

1.1 Power System Stability

Power System Stability is defined as "the property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after a disturbance." [1] Power System Stability can be classified into three types, angular, voltage and frequency stability.

1.1.1 Angular Stability

Angular Stability is the ability of the synchronous machines that are connected to the network to remain in synchronism. Depending on whether the system is tested against a small or a large disturbance, angular stability can be further classified into two types, namely small signal stability and transient stability. Small signal stability indicates that the machines can remain in synchronism after a small disturbance, while small signal instability results in increasing amplitudes of electromechanical oscillations that eventually take the machines out of synchronism. Transient stability indicates that the machines can get back to a normal operating state after a large transient disturbance like a fault. Such a disturbance causes wide variations in the rotor angles. If a system is transiently unstable, the machines in the system will not be able to get back to synchronism and hence the system collapses.

1.1.2 Voltage Stability

Voltage Stability is the property by which the power system can keep the voltage magnitudes at all the buses at an acceptable level. Voltage instability is caused by lack of sufficient reactive power, which in turn is affected by the loading level on transmission lines. If the transmission lines are heavily loaded, the reactive power consumed by the line reactances is much higher and hence the voltage magnitude decreases. The relation between line loading and the voltage drop is highly non-linear. After reaching a certain point on the power-voltage curve (nose curves) called the critical voltage point at a small part of the network, the voltage suddenly drops very steeply leading to local network blackout. This phenomenon is called voltage collapse.

1.1.3 Frequency Stability

Frequency Stability is the property by which the power system can keep the operating frequency of the system at the nominal value. Unlike voltage stability, frequency stability is a global problem. Frequency stability is determined by the ability of the power system to match the total generation in the system with total loading at any point of time. When there is a mismatch, the operating frequency deviates from the nominal value. If there is excessive load, the frequency drops to a lower value and if there is excessive generation, the frequency increases to a higher value. Due to the continuously changing nature of the load, the frequency does deviate by a very small amount, but this is corrected immediately by adjusting the generation. The focus of the dissertation is frequency stability over the "medium term (10 seconds to a few minutes)" [1] of large interconnected networks when subjected to a large disturbance.

1.2 Load Frequency Control

Load Frequency Control (LFC) is the process of maintaining the frequency across an interconnected network by controlling the generation. The LFC is a multi-tiered control scheme that consists of primary or governor controls, secondary control or the Automatic Generation

Control (AGC) and tertiary control or economic dispatch.

When the load is exactly matched by generation, the system is said to be at equilibrium at a constant frequency. At every machine in the system, the input mechanical torque and the output electrical load are constant. When there is a small increase in load, the machines to start to decelerate due to the difference between constant input mechanical torque and elevated electrical load, causing a decline in the system frequency. This behavior is dependent on the machine's speed-droop characteristics. If the machines are equipped with speed governors, the governors act to increase the input mechanical torque supplied by the turbine connected to the machine's input. This control action is called the primary frequency control and it helps in matching the system generation to the load increase. Thus the primary control only balances the system load and generation, thereby stabilizing the system frequency and does not help in restoring the frequency to the nominal value. The governor system usually kicks in, in about 3 to 4 seconds.

The Secondary Control or the Automation Generation Control adjusts the load reference points on the turbines so as to restore the frequency back to the nominal value. In an interconnected network consisting of several areas, any increase in load is reflected on the frequency of the area as well as the tie line flows that connect any two areas. The AGC monitors these two factors to calculate the Area Control Error (ACE) which is a sum of the deviation in tie line flows from the scheduled values and change in load due to the frequency deviation. The AGC uses the ACE to compute the value of generation that has to be increased within that area to counteract the frequency deviation and restore tie flows. The time frame for AGC control functions is in the order of a few minutes. The Tertiary Control usually spans over several minutes to hours. It involves planning generation planning and reserve deployment based on economic and network constraints. It usually takes into account planned outages of generators and ensures that adequate spinning reserves are available in the system.

1.3 Under Frequency Load Shedding (UFLS)

Under Frequency Load Shedding is used as the last resort to stem a decline in frequency when there is a large mismatch in load and generation. Such a mismatch occurs usually due to a forced outage of a generator or sudden increase in load. The Under Frequency Load Shedding is usually used after a severe network disturbance which leads to the disintegration of the interconnection into several islands. Since these islands are unplanned, there will be a wide mismatch between load and generation in each of these islands. If there is excessive load, the frequency continues to decline rapidly and in case of excessive generation, the frequency continues to increase. If adequate control action is not taken, the wide frequency excursions would lead to subsequent tripping of all available generation within the system leading to a system blackout. Such a scenario makes it difficult to reconnect and restore the network after the outage. In order to limit the frequency deviations within the islands, loads are shed if the frequency drops below a certain value. Similarly, in over generated areas, generators are tripped on over frequency.

UFLS Schemes operate by shedding a preset fraction of the total load, at a certain frequency threshold. A typical load shedding system in the California network operates in multiple stages as follows:

Stage 1 - Drop 5.8% of load at a bus at 59.5 Hz

Stage 2 - Drop 5.7% more load at a bus at 58.9 Hz

Stage 3 - Drop 5.6% more load at a bus at 58.7 Hz

Stage 4 - Drop 7.1% more load at a bus at 58.5 Hz

Stage 5 - Drop 6.0% more load at a bus at 58.3 Hz

1.4 Wide Area Measurement Systems (WAMS)

The Wide Area Measurement System had its genesis at the Center of Energy Engineering Lab (formerly, Power Systems Lab) of Virginia Tech, with the invention of the first Phasor Measurement Unit (PMU). Until then, power systems operation and control was limited only to local measurements; use of limited remote measurements was restricted to specialized protection schemes designed to be used for a specific situation. Since the electric grids span vast geographical areas, it was difficult even to monitor the system in a reasonable time frame. In the event of a system outage, it would take several months before the causes and propagation paths of the blackout can be concluded.

The PMUs brought two important improvements to power systems measurement and relaying. The first is that all the measurement data were time tagged with GPS synchronization. This ensures that the data samples collected from the vast network can be arranged by the time tags and an accurate snapshot of the entire system can be visualized at every sampling time. The second improvement is the availability of data at a very high rate with a very small communication delay. This ensures that the network can be monitored on near-real time scales using the PMU data.

The advent of the PMUs has brought about a renewed interest among the power systems engineers to develop a plethora of applications that seek to improve the control and operation of power systems. The dissertation presented herein is one such application. The objective of the project is to enhance the load frequency control of the system using WAMS, with a special focus on mitigating cascading blackouts.

Chapter 2

Need for Intelligent Load Shedding Scheme

One of the basic principles of power system operations is to balance the amount of load with the amount of generation. Load shedding is the process of removal of excess load when there is deficiency in generation, so that the mismatch is rectified. Some of the load shedding techniques like the Under Frequency and Under Voltage load shedding schemes are well established and continue to be used widely for correcting frequency and voltage changes respectively. Since voltage magnitude is a local phenomenon, it may not benefit much from the WAMS perspective. This research work is limited to frequency problems alone. This chapter discusses the need for a new Intelligent Load Shedding scheme especially, given the simplicity of current load shedding systems and their proven track record and how such a scheme can supplement the actions of Load Frequency Control.

2.1 Need for Smarter Load Relief

Traditional load shedding systems have been designed to shed loads based on parameters like frequency and voltage magnitudes that are measured locally. When the generation and supply within an area is not balanced, the frequency deviates from the nominal value. If the area is under-generated, the frequency declines, and it increases if the area is over-generated. Thus, load shedding relays measure frequency at the local bus and if the frequency drops below a certain value, a certain fraction of load connected to the bus is dropped. If the frequency keeps dropping, greater amounts of load are dropped. Reference [2] describes the procedure for setting up the Under Frequency Load Shedding (UFLS) scheme. Frequency Trend Relays are also used, if greater generation deficiencies are encountered. [1] This value of frequency threshold and the amount of load to be shed is predetermined based on system studies.

The UFLS scheme is the last resort that is employed during an emergency and its main objective is to prevent total system collapse within an area. One of the drawbacks of the UFLS scheme is that, by the time these relays operate, the area under consideration would have already been disconnected from the rest of the network. Thus the scheme does not proactively shed loads to prevent an island; it only tries to prevent further frequency decline after the area has been islanded from the rest of the network. The other drawback of the scheme is that the settings for the relays are preset based on exhaustive studies. With rapid expansion of electrical networks and the continually changing nature of the grid, these settings may become less effective or even obsolete over different operating conditions. Under such situations, the quantity and location of the load being shed is not optimal, resulting in shedding more loads than actually necessary and a sub-par performance. While it may sound innocuous, such below-optimal performance has been cited as major reasons why major blackouts could not be contained. [3]

A wide range of existing schemes as well as newly proposed schemes depend on frequency or rate of change of frequency (df/dt) as a measure for determining the amount of load to be shed. Reference [4] finds that there is very little correlation between observed frequency and the actual size of the event. The oscillatory nature of df/dt and load sensitivity to frequency make such measurements unreliable.

The proposed scheme uses Wide Area Measurement Systems (WAMS) to detect a major disturbance and proactively reduces loads so that system islanding is prevented. In addition, the load shedding is optimized for location and amount, so that effective results are achieved with minimum loss of load.

2.2 Need for Faster Load Frequency Control

During the normal operation of the electrical grid, the power generated by each generator is kept at a set value, determined by a variety of factors including cost of fuel, losses in the transmission lines and congestion on the transmission corridors. In addition to meeting the actual load, some amount of generation is kept on standby as a back-up in case of a forced outage of a generator. This slack generation is called the spinning reserves. When there is a mismatch in the system with excessive load, this spinning reserves can be tapped into, for temporarily overcoming the deficit. This is achieved by a control mechanism called the Automatic Generation Control (AGC). The AGC is a widely implemented supplementary control that modifies the turbine reference point (and hence, the power output) of select generators within an area based on a change in frequency and a change in tie line values, thus rectifying the deficit and restoring area frequency.

Although well proven, the AGC scheme has its own drawbacks. One of the disadvantages of the system is that it is slow acting, when compared to the rapidness of propagation of blackouts in an interconnected network. For instance, the maximum speed of secondary control is 15 minutes for the European UCTE system. [5] In addition, frequency excursion as a measure of the size of disturbance has been proven to be not reliable. [4] During heavy loading conditions, the AGCs maneuverability is very much restricted due to the limited availability of spinning reserves. This is especially true for electrical grids in developing countries, where sufficient spinning reserves may not be available. Also, the AGC operation is suspended for major system events that cause a splitting of the interconnected systems, based on very large changes in frequency. [1] In addition, the effectiveness of the AGC is restricted by the limitations on the prime movers. [1]

The proposed Intelligent Load Shedding (ILS) scheme has been designed to complement the performance of the AGC system under stressed system situations. The ILS scheme is faster acting and could provide a fillip to ensure an effective AGC operation to restore the system frequency to its nominal value.

2.3 Effective Use of Upcoming WAMPAC Infrastructure

The invention of Phasor Measurement Units (PMUs) at Virginia Tech has ushered in a new phase of development of systems based on wide area measurements for improving the reliability of operation of the geographically vast electrical grids. The Wide Area Measurement, Protection And Control (WAMPAC) systems are expected to be an integral part of grid modernization in the United States [6] and around the world. The advent of these technologies has provided the power systems engineers with a rare opportunity to improve upon the existing system, to make it more adaptive and effective, while at the same time minimize load shedding by optimization. The proposed algorithm has been developed after analyzing the drawbacks of current systems through the perspective of the potential capabilities of these upcoming technologies.

2.4 Other Requirements

The load shedding scheme should have a sense of the amount of load that is currently connected to the network within a given area. This knowledge is necessary to ensure that the control actions that are initiated by load shedding are effective and optimum. It should be adaptive so that the scheme can adjust itself to a wide range of operating situations. The load shedding scheme should also be able to readily incorporate the vast experience in operating the system as well as the current status of operation, for taking the best decisions for maintaining stability of the grid.

2.5 Literature Review

The idea of an "Intelligent Load Shedding" itself is not new; general aspects of an "intelligent" load shedding system have been outlined in references [7], [8] and [9]. Reference [10] describes the disadvantages of under frequency load shedding and the need for an intelligent load shedding scheme based on frequency measurements. The proposed relay dynamically adjusts its frequency threshold and time delay settings based on "normal operating frequency of the system, number of load shedding steps and system configuration." The Fast Acting Load Shedding (FALS) [11] is a wide-area measurements based system that is in operation at Florida Power & Light (FPL). The FALS scheme is designed with a very specific scenario, where a certain disturbance leads to an uncontrolled islanding.

Reference [12] describes a WAMS-assisted adaptive load shedding scheme that takes into account frequency and voltage stability criteria to shed loads, based on disturbance calculations. Given the dynamic model of all the generators connected to the network and the initial rate of change of frequency, the disturbance power is calculated. The difference between the disturbance power and threshold of power mismatch is taken as the amount of load to be shed. The actual load shedding is performed when the frequency hits a certain threshold value (which is taken as 59.5 Hz in Reference [12].

Reference [3] discusses the deficiency of operation of UFLS schemes during all the major blackouts in the US and the need for load shedding to be based on real time information. The load shedding is performed by calculating the frequency trajectories at the Center of Inertia (COI) of the network.

Chapter 3

Developing Reduced-WECC Model

The Intelligent Load Shedding algorithm is being proposed as a scheme that takes advantage of system-wide awareness being brought about by the advent of extensive Wide Area Measurements System (WAMS). Therefore, the use of a large network for developing and testing the algorithm is necessary to validate its results. During the research project, two large models, Full WECC and Reduced WECC were used. Both these models represent the same network at the same loading conditions, but in different network sizes. The Full Loop model is the most detailed of the two models; it represents all the utilities within the whole WECC network in great detail, including most of the dynamic components of the system. The Full Loop model works best for testing the algorithm, since a system-wide knowledge is required to fully assess the impacts of the algorithm.

The Reduced WECC model, on the other hand, is a smaller model of the WECC system, with California represented in great detail, while the rest of the WECC network outside California is represented by an equivalent network. The project funded by the California Institute of Energy & Environment as part of the Public Interest Energy Research (PIER) program, has a special focus on the California network. The Reduced WECC model was developed by the candidate under the aegis of the same project. The Reduced Model is a compound model that combines two different models of varying detail, into a single model. This Chapter describes the development of the Reduced WECC and its validation against the Full WECC case. The figures and tables used here, have been taken from a report [13], co-authored by the candidate as part of the same project.

3.1 Development of California Network

California, being the area of focus, has to be represented in as much detail as possible. In order to achieve this, the California network was extracted from the Heavy Winter case of the Full WECC model. The Full WECC Heavy Winter Model contains over 15,000 buses and over 2000 machines representing a total loading of 128 GW between 21 utility areas spread across the western half of the North American continent. It also has two major HVDC systems that bring in power into California from the North and the East.

In the Full model, California is represented by five utility areas, Pacific Gas & Electric PGE (Area 30), Los Angeles Department of Water and Power LADWP (Area 26), Southern California Edison SCE (Area 24), San Diego Gas & Electric SDGE (Area 22) and Imperial Irrigation District IID (Area 21). The substations (buses) that belong to these five utilities were retained, while the rest were removed from the network. A list of twenty-eight tie lines that connect these five areas to the rest of the WECC network was compiled. The tie lines that carry a total power of about 1GW were retained, whereas the rest of the tie lines were replaced by equivalent generators. To avoid the effect of these introduced generators in the dynamic response of the network, these generators are converted to Constant PQ loads with negative values, during dynamic simulations. The tie flows along these seven major tie lines is listed below.

Major inter-ties	From	To	MW	MVAR
Malin to Round Mt1	BPA	PGE	967	-17
Malin to Round Mt2	BPA	PGE	978	-148
Capt. Jack to Olinda	BPA	PGE	1194	-295
Moenkopi to El Dorado	Arizona	SCE	1098	-29
Palo Verde to Devers	Arizona	SCE	1162	18
Navajo to Crystal	Arizona	LADWP	1165	-32
Hassyamp to N. Gila	Arizona	SDGE	985	166
		Net Inflow	7549	

Table 3.1: Major Tie Lines Carrying About 1 GW of Power in Full WECC Model

3.2 Development of Outside-California Network

The "Outside-California" part of the network is extracted from the DC Multi-Infeed Study model of the WECC comprising of 128 buses, described in [14]. The total loading in the network is about 61GW with 37 generators. The last 65 buses comprise the California network while the rest of the buses comprise the entire WECC network outside California. Each of the two HVDC systems is represented as a positive Constant PQ-load at the source end and a negative Constant-PQ load at the termination end. A schematic of this network is presented in the figure below.

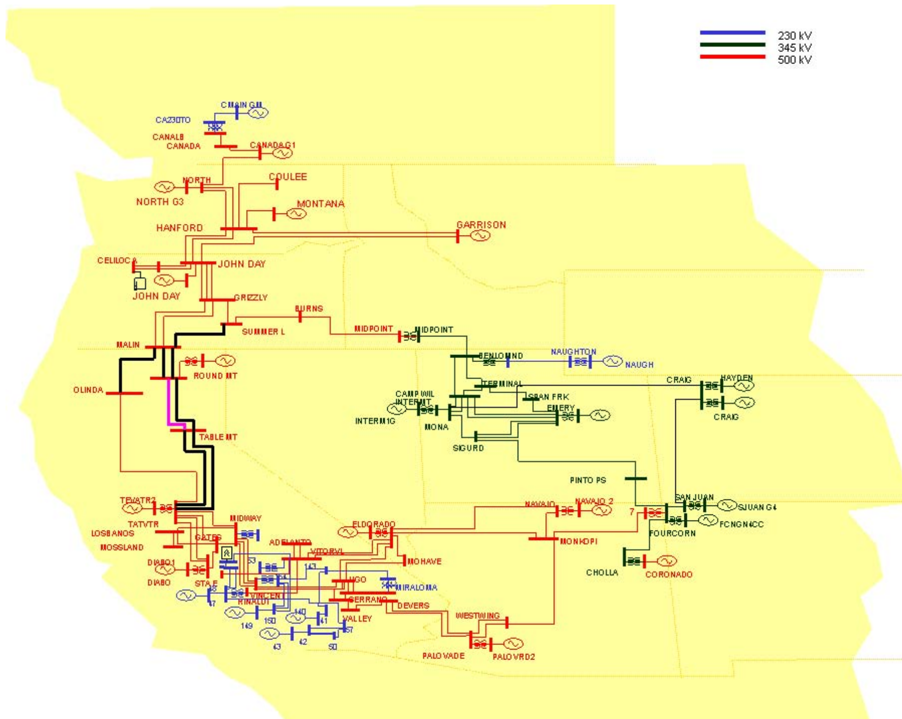

Figure 3.1: Schematic of the 128-Bus WECC System [Source Unknown]

The 128-bus model was developed in 1994 or earlier, while the Full WECC model was developed in 2004. The two models are significantly different in terms of loading level and bus configurations, even though they both represent the same network. In addition, the 128-bus model represents an equivalent model, while the Full WECC model is a representation of the actual network. This implies that the generators used in the 128-bus model are much larger in size and the transmission lines appear much stiffer (lower impedances) than the Full WECC case.

In order to create a single model from the two different models, we have to ensure that the boundary conditions at the interface where the two models are to be merged, are the same. Since the California network is to be preserved as it is modeled in the Full WECC case, the rest of WECC network from the 128-bus model has to be modified to achieve the same boundary conditions. In these models, the term "boundary conditions" refers to the voltage angles and magnitudes of peripheral buses at the merging interface and net power injection at these buses. Ensuring that the tie flows are the same is the first step to integrating the two models. The inter-ties connecting California and rest of WECC in the equivalent model were identified and are listed in the table below.

inter-ties	**Real Power (MW)**	**Reactive Power (MVAR)**
Malin-RoundMt 1	982	66.7
Malin-RoundMt 2	971	78.4
Malin-Olinda	1150	-35.4
MoenkopiEl Dorado	993	-57.4
NavajoEl Dorado	843	98.4
Palo Verde Devers 1	903	45.6
Palo Verde Devers 2	903	45.6
Net Inflow	6745	

Table 3.2: List of Tie Lines in 128-Bus WECC Model

There are two issues that need to be addressed, when the information on Table 3-1 and Table 3-2 are compared. The first is that a few important boundary buses to the East of California are missing in the 128-bus model. The second issue is that the net inflow into California is considerably lower in the 128-bus model than in the Full WECC case. The following sections describe how these issues are addressed.

3.2.1 Introducing Missing Boundary Buses

The boundary buses, North Gila, Hassyampa and Crystal located in Arizona, are absent in the older 128-bus model. Without these buses, the tie lines cannot be adjusted to provide equivalence with the Full WECC model. Also, since the inflow at these buses from Arizona is very significant (about 1 GW at each bus), introducing these buses and transmission lines that connect them to the rest of the network in the 128-bus model is very important. The parameters of the corresponding lines from the Full WECC were used as a starting value for these new transmission lines in the 128-bus system. The line parameters of the newly introduced lines have to be tweaked so as to maintain the same power flows across the network. This was achieved by using Short Circuit Studies.

A three phase fault was placed on each of these buses in the full loop model and the fault currents on the transmission lines connecting the buses were measured. The same procedure was repeated on the 128-bus model also. The line parameters of the new transmission line in the 128-bus model was adjusted until the proportion of fault currents obtained from both the equivalent model matched that of the Full WECC model. This ensures that the network modifications introduced in the 128-bus model are equivalent to the Full WECC model. The changes made to the network in the Eastern region of the 128-bus model are shown below.

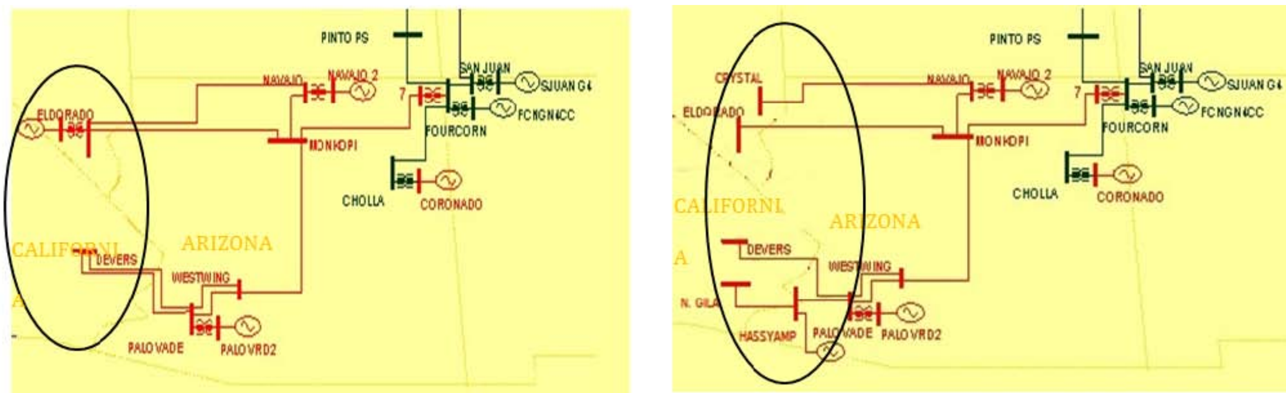

Figure 3.2: East of California in the 128-Bus System Before & After Network Modification

3.2.2 Adjusting Inflows into California

The second problem that has to be addressed with the 128-bus model is to increase the power flows on the tie lines, so as to match the inflows observed in the Full WECC model. This can be achieved only by re-dispatching the generators outside California. Usually a simple load flow using well-proven techniques like Gauss-Siedel or Newton-Raphson iterations would solve this problem; but in this case, we also have additional constraints, namely the voltage magnitudes and voltage angles on the boundary buses. Since we are using a large network, the initial values of voltage angles and magnitudes of all the buses have to be closer to the final solution, failing which the load flow may not converge. Hence, the voltages on the boundary buses in the 128-bus model have to be matched with that of the Full WECC model.

The above issue was solved by formulating it as a multiple swing bus load flow problem. The load flow was performed by using PSLFs Inter-area Exchange Control. First all the buses that belong to California in the equivalent model were removed. A generator is connected to each of the boundary buses and each bus is set as a swing bus with a specified voltage angle and magnitude, taken from the Full model. Since the boundary buses are declared as a swing bus, their voltage magnitudes and angles will not be changed during load flow iterations. Then, each boundary bus-generator pair is declared as a separate "area", while all the other buses in the modified equivalent network are taken as a single area (Area 0). The inter-area flows between the areas are set to be equal to the required tie flow values. Thus, the California network has been replaced equivalently by the six swing generators and the problem of matching inflows has been reformulated as an inter-area exchange problem. Now the load flow is solved using PSLFs Inter-area Exchange option. A schematic of the above network modifications is shown below.

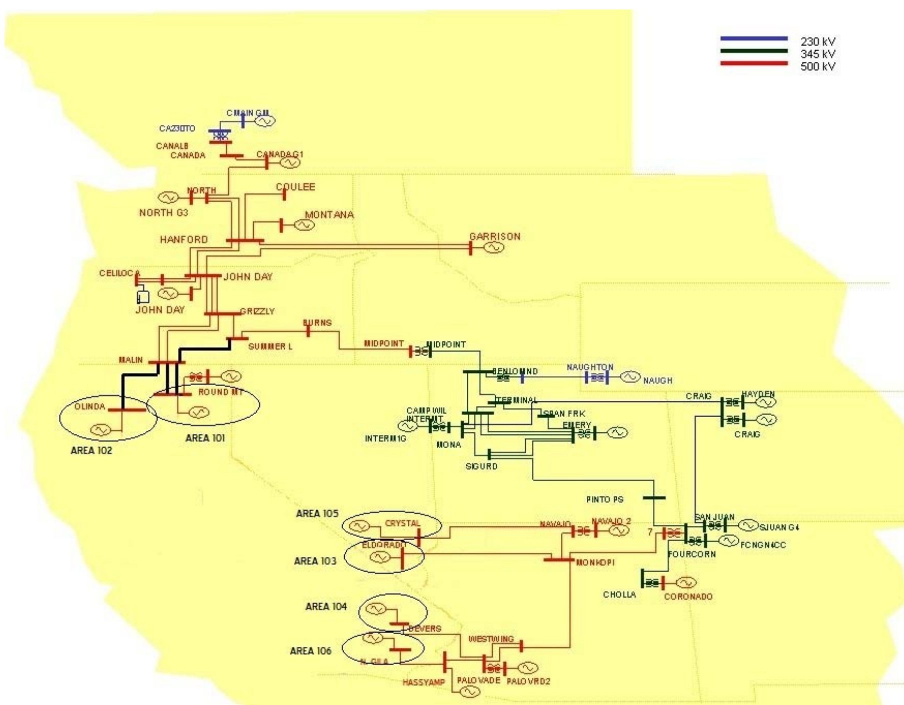

Figure 3.3: Multiple Swing Bus Load Flow Schematic

Since the inter-area exchange control is only one of the several options for solving the load flow in PSLF, the outcome of the first run was close, but not satisfactory. In order to achieve the desired results, the generator outputs of the machines and the loads inside "Area 0" have to be adjusted and the load flow solved again. Additional loads were added to adjust for reactive power flows and the load flow was solved several times, until the actual inter-area exchanges were close to the required tie flow values. After achieving the final solution, the 6 equivalent generators that represented California were removed.

3.3 Integration of the Two Constituent Networks

With the above two issues being addressed, the equivalent network has all the required boundary buses at the same bus voltages as the boundary buses in the Full loop model. The inter-tie flows have also been adjusted to match the required inflows. With seven of the twenty-eight tie lines being accounted for, the two networks were merged together. While the tie flows from the other twenty-one smaller tie lines were insignificant compared to the total system imports, these flows cannot be simply dispensed with, due to local stability problems. In order to solve this problem, 11 equivalent generators were introduced to replace the flows from these smaller tie lines. These generators were then netted, so that they do not participate in the dynamic response of the network. When generators are netted, they are automatically converted by the PSLF program into Constant-PQ loads with negative values, curtailing all of their dynamic response. Thus the Reduced WECC model now consists of a 4000+ bus network representing California in detail and a 67-bus 30-machine equivalent network representing the rest of the WECC network, inter-connected by 7 major tie lines and 11 equivalent generators representing smaller inter-ties.

In addition, there are two High Voltage DC (HVDC) systems in the WECC network that are very crucial for the stability of the entire grid, that have to be created in the new model. The Inter Mountain HVDC System transfers about 1.7GW of power from the coal-fired plants in Utah to California, while the Pacific DC inter-tie brings in over 2.5 GW from hydro plants in the North. The HVDC systems are modeled as Constant PQ loads in the equivalent model. These HVDC systems were re-modeled as dynamic systems in PSLF using the parameters obtained from the full loop model.

The Inter Mountain HVDC System is modeled as a two-terminal DC network, represented by "epcdc" model in the PSLF using existing buses. The Pacific DC System is represented as a Multi-terminal DC System, modeled as "dcmt" system. The operation of the Pacific DC inter-ties (PDCI) is programmed by a special user-written program, "pdci_ns3.p" developed by the WECC. In order to introduce the PDCI, four new buses were created by extending two existing buses in the Celilo region. A schematic of the Pacific DC system is shown below.

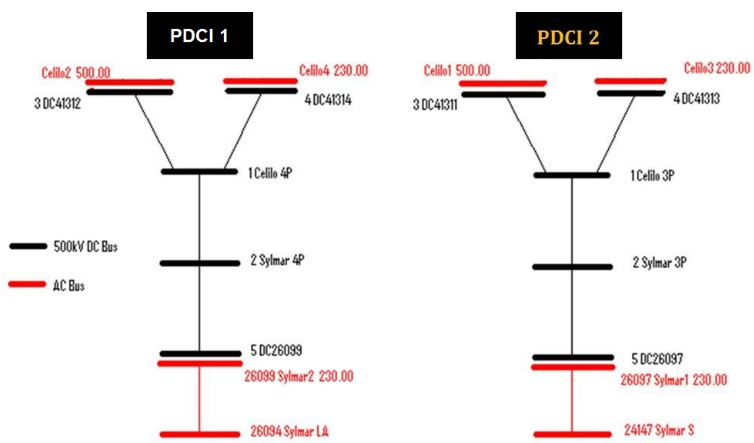

Figure 3.4: Modeling of Pacific DC inter-tie in PSLF [Source Unknown]

Once the required components are added, the dynamic file for the model was created by modifying the merging of the dynamic data from the full model and the reduced model. The generators inside California are represented as a detailed two-axis model, while the generators outside California are modeled as classical machines.

3.4 Model Validation

In order to validate the newly created model and ensure that it represents the Full WECC network, the model was tested on criteria like comparison of tie flows, flows along important paths, HVDC System performance, dynamic response and small signal analysis. The results from the above tests are presented below.

3.4.1 Load Flow Results

Load flow for the new model was computed using PSLF suite. The values of inter-tie flows, flows along important paths and HVDC Converters were recorded and compared with the Full WECC Model. The results are presented below.

	Full WECC	**Reduced WECC**	**Difference**
	P (MW)	**P (MW)**	**P (MW)**
Malin-RoundMt 1	967	1016	+52
Malin-RoundMt 1	978	1024	+49
Malin-Olinda	1194	1246	+46
MoenkopiEl Dorado	1098	1121	-41
PaloVerde-Devers	1162	1024	-74
Navajo-Crystal	1165	1184	+19
HassyampN.Gila	985.4	1010	+24.5
Total	7549.5	7625	+75.5

Table 3.3: Comparison of inter-tie Flows Between the Full Model and the Reduced Model

Another measure of comparing the two models is to study the flows along certain paths in the grid. Since California is our area of focus, three important paths within California were chosen for comparison namely, Path 66 (California-Oregon inter-tie - COI), Path 15 (Los Banos, Gates, Diablo to Midway) and Path 26 (Midway to Vincent). In all these comparisons, the reduced model had an excess of about 200MW. This can be attributed to the slightly increased inter-tie flows observed on the COI lines. These three corridors are in series, starting with the COI lines in the North heading down to the load centers closer to the Vincent bus.

Path	**Full Model (MW)**	**Reduced Model (MW)**	**Difference (MW)**
Path 66	3140	3286	+146
Path 15	2286	2479	+193
Path 26	2035	2241	+206

Table 3.4: Real Power Flows Along Three Important Paths in California

Similarly, the net real power transferred at the DC Converters for the two HVDC systems is tabulated below.

DC Converter	**Full WECC**	**Reduced WECC**	**Difference**
	P (MW)	**P (MW)**	**P (MW)**
Inter Mountain	1744.2	1744.4	-0.2
Adelanto	-1688.7	-1682.7	-6
Celilo 1	498.7	498.7	0
Celilo 3	748	748	0
Sylmar 1	-1129.3	-1129.3	0
Celilo 2	501.3	501.3	0
Celilo 4	752.1	752.1	0
Sylmar 2	-1136	-1136	0

Table 3.5: Comparison of HVDC Injections Between the Full Model and the Reduced Model

In the above tables, we can see that the real power values recorded in the reduced model matches very closely with that of the Full WECC system. The reactive power flows are slightly higher in the reduced model. This does not pose any problems since the observed reactive power differences affect voltage magnitudes only very slightly. Also, the effect of excessive reactive power flows is limited to a local area.

3.4.2 Dynamic Simulation Results

One of the basic tests for correct dynamic modeling of a network is stable initial conditions for all the models. These initial conditions for the various dynamic models are calculated based on the output of the load flow; the load flow has to be vetted for all possible errors before dynamic testing of the model. Since the dynamic states for all the models are computed iteratively, the simulation will show instability based on unsteady initial conditions alone.

Thus the dynamic test can expose underlying problems with the load flow solutions. The dynamic test for the reduced model without any disturbance is shown below. In this test, dynamic simulation was run for 20 seconds without any disturbance and the value of voltage angles for all the 500kV buses were measured. A flat profile indicates an error-free model.

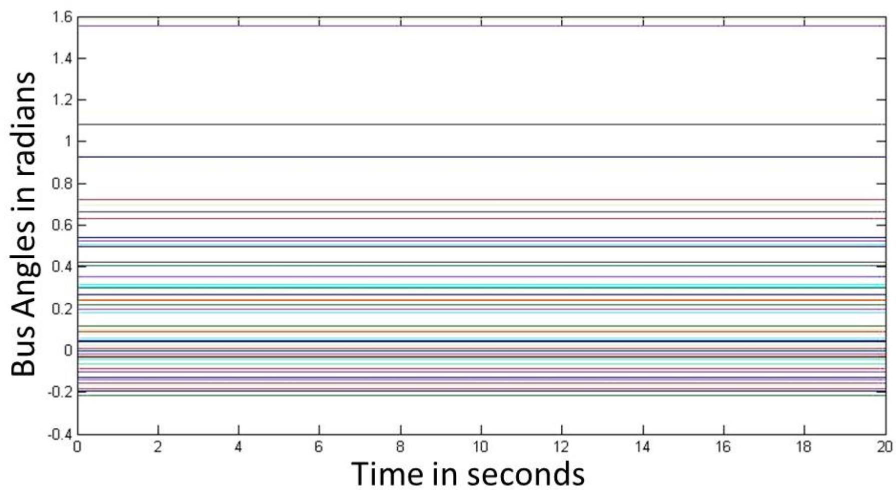

Figure 3.5: Voltage Angles at all 500kV Buses in the Reduced WECC Model

3.4.3 Small Signal Analysis

Small Signal Stability helps us to evaluate the stability of a system operating at a stable operating point, when it is subjected to a small disturbance. The small signal response of the system is basically the response of the generators that are connected to that system, when a small disturbance is placed on it. In interconnected networks, groups of large generators are typically connected to other such groups by long transmission lines. Given the right conditions like high load conditions, these groups of generators may oscillate against each other. The frequency of these oscillations is inversely proportional to the total inertia of the group; the lower the frequency, the larger the size of the generators oscillating. If the transmission lines connecting these groups of generators are less stiff (high impedance or longer lines), the damping of these oscillations are low, it leads to sustained oscillations that are detrimental to network operation. This behavior is called Inter-area oscillations. When a single machine or a much smaller group of machines oscillate against the system, it is called Intra-area oscillations. Intra-area oscillations are higher in frequency and have localized effect; they can be damped easily by local controls on the machine(s) that oscillate.

Inter-area oscillations have system-wide effect, causing oscillations of machine speeds, output power, power transmitted on transmission lines, etc. Being a system-wide phenomenon, the nature of the oscillations depend on both the static parameters of the network defined by algebraic equations and the dynamic properties of the power system components, defined by differential equations. Thus, a small signal analysis is an important criterion for comparison of the two models.

A straightforward method to study small signal stability would be to construct the differential-algebraic model of the system and then, compute the plant or the system state matrix and perform an eigenvalue analysis on it. The eigenvalues of the System Matrix yield the frequency and damping ratio for every mode of oscillation present in the system, while the right eigenvector contains information on mode shapes and participation factors for each generator in a particular mode of oscillation. While this method can be applied to smaller networks, it can be very cumbersome when applied to large networks. Since the electric grids are typically made up of a large number of buses, the sheer size of the plant matrix for such a network is a major impediment in applying this technique.

An alternate means of performing the small signal analysis is by the use of measurement-based methods. Measurement-based methods estimate the modes of oscillation by measuring parameters like voltage angles, tie line flows, generator rotor angles, etc. and decomposing the signal into a set of sinusoids. The number of modes of oscillations (number of sinusoids) depends on the order number of the model that is specified during decomposition. There are several techniques under this category that have been demonstrated successfully to be viable online estimation tools.

The Matrix Pencil method is one of the polynomial methods, used to estimate eigenvalues from a measured signal. [15] Let the dynamic response of the system be given by,

$$y(t) = x(t) + n(t)$$

where $y(t)$ is observed signal, $x(t)$ is the actual signal and $n(t)$ is the noise.

The actual signal is approximated to a function given by $\sum_i R_i e^{\lambda_i t}$, where R_i is the residual and λ_i is the eigenvalue of the i^{th} mode. The above equation is discretized by replacing t by kTs, where Ts is the sampling period.

$$y(kTs) = \sum_{i=1}^{M} R_i z_i^k + n(kTs) \tag{3.1}$$

where M is the reduced order of the model.

The values of M, R_i and z_i are estimated from the measured dynamic response of the system. Z_i contains information about the eigenvalues of the system.

In order to use the measurement methods, the oscillations have to be excited by a suitable disturbance. This was achieved in the reduced model by stepping up the power transferred across the Pacific DC inter-tie by 40MW. The voltage angles at all the Extra High Voltage (345 kV and above) were measured. These signals were processed by the Matrix Pencil program developed in [16]. The modes of oscillations present in the reduced model that were determined is listed in the table below.

<table>
<tr><th>Mode</th><th>Frequency (Hz)</th><th>Damping Ratio</th></tr>
<tr><td rowspan="4">North-South</td><td rowspan="2">0.26/0.27/0.28</td><td>0.2</td></tr>
<tr><td>0.08</td></tr>
<tr><td>0.29</td><td>0.1</td></tr>
<tr><td>0.3/031</td><td>0.02</td></tr>
<tr><td rowspan="2">Alberta</td><td rowspan="2">0.42</td><td>0.004</td></tr>
<tr><td>0.06</td></tr>
<tr><td rowspan="3">Kemano</td><td>0.51</td><td>0.02</td></tr>
<tr><td rowspan="2">0.55</td><td>0.04</td></tr>
<tr><td><0.01</td></tr>
<tr><td>Colstrip</td><td>0.8</td><td>0.02</td></tr>
</table>

Table 3.6: Real Power Flows Along Three Important Paths in California

The modes of oscillations present in the WECC system have been determined by Prony analysis, another measurement-based method in [17]. The results are presented below.

Mode	**Frequency (Hz)**	**Damping Ratio**
North-South	0.318	0.083
	0.244	0.091
		0.096
Alberta	Absent	Nil
	0.376	0.091
	0.373	0.081
Kemano	0.626	0.154
	0.62	0.088
	0.642	0.099
Colstrip	0.889	0.107
	0.776	0.102
	0.83	0.109

Table 3.7: Real Power Flows Along Three Important Paths in California

Chapter 4

Intelligent Load Shedding Scheme

This Chapter presents a description of the various functional modules of the proposed Intelligent Load Shedding (ILS) scheme and their functions.

4.1 Objective

The main objective of the Intelligent Load Shedding (ILS) Scheme is to limit, if not prevent a rolling black-out. This is achieved by containing the effects of a loss of generation or a sudden increase in load within an area by shedding sufficient loads within that area. Thus, any generation-demand mismatch is set right, as soon as such a mismatch is detected by the algorithm. The scheme uses Wide Area Measurements System (WAMS) to ascertain a potentially destabilizing disturbance and initiates control actions to prevent a system collapse.

4.2 Scheme Requirements

As a Wide-Area Measurement System-based control scheme, the ILS algorithm shares some common requirements with other such schemes, like robust communication network, high resolution measurements, etc. Some of the considerations that are specific to the proposed scheme are,

Selection of Control Area - The ILS scheme monitors the boundaries of a chosen control area. Such an area can be a major load center, the network area of a utility or a strongly inter-connected group of utilities. The Control Area can also be an event-prone part of the grid. Since the ILS Scheme uses only the tie lines that connect the area to the rest of the network, a tightly connected Control Area yields a quicker and surer diagnosis of a disturbance.

Availability of Sufficient Loads for Shedding - Since the ILS Scheme uses the loads as an asset for maintaining the systems operational integrity it requires some maneuverability with load shedding for effective operation. While it can be safely assumed that there will be sufficient loads, the amount and number of loads that can be shed by a control center can be limited by a number of factors.

Availability of Real Time Monitoring - The ILS Scheme bridges the need for quick and decisive action during the time of an incipient crisis and delayed response of existing controls. For the ILS Scheme to handle crisis situations quickly and effectively, it is very important that the ILS scheme has real time situational awareness. The number of parameters that actually need to be monitored real time by the ILS is much less, especially for a scheme that spans a wide geographical area. Real Power flows on major tie lines and the operational status of major equipment require real time monitoring, while computations for load shift factors and small signal analysis do not necessarily require real time awareness.

4.3 Operation

The proposed algorithm uses a combination of real time operating data and non-real time offline computations to diagnose and tackle a disturbance. The operation of the proposed algorithm is presented in the flowchart below.

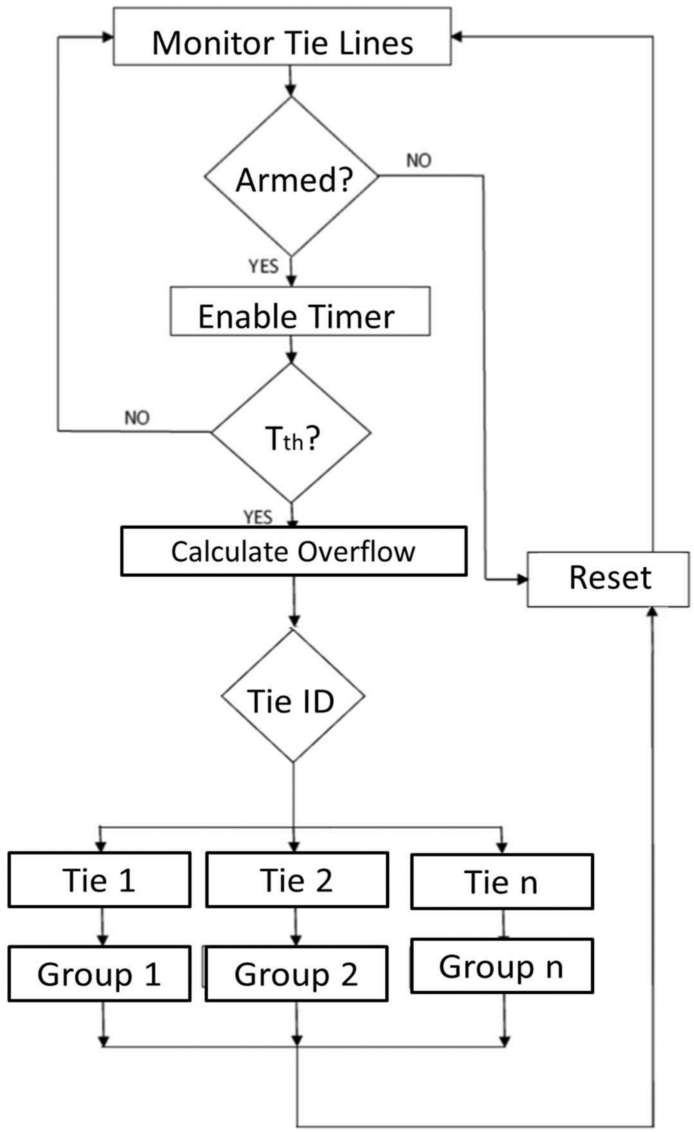

Figure 4.1: Flowchart of the ILS Algorithm

There are two inputs for the ILS scheme: real time flows observed on the interface between the control area and the rest of the network and operating status of major power systems equipment including large generators and HVDC converters. The power flows on the tie line are monitored and recorded by the "Monitor Tie Line" block, while the operating status of major equipment is used by the Arming Signal block to enable or disable load shedding.

The ILS Scheme observes major tie lines that connect the Control Area to the rest of the network to determine if a contingency has occurred within the area. The magnitude of the deviation of the tie flows from their schedule values indicates the size of the generation that has been lost. A fraction of this total overflow is taken as the amount of load that needs to be shed inside the Control Area. The ILS Scheme then identifies the tie line that has the most deviation. Depending on its own load-line flow sensitivity analysis, the ILS Scheme selects the group of loads that is most suitable for relieving the excess flows on the identified tie line and the load shedding is initiated. It then resets the overflow values, timers and re-initiates the Load Shift Factor Computations and continues to monitor the system.

4.4 Functional Modules

The Intelligent Load Shedding scheme consists of multiple modules. The Load Sensitivities Module computes the load shift factors continuously for all the major loads with respect to the major tie lines. It is sufficient that this module be run only when there is a significant change in the loading conditions of the grid. The System Monitoring Module monitors real power flows on major tie lines and updates the operating status of large generators on a real time basis. The output of this module is used to determine if the Intelligent Load Shedding scheme has to be activated. The Load Shed Computation Module decides the location and the amount of load to be shed, if the Intelligent Load Shedding scheme, indeed, has to be employed. It uses the output of the Sensitivity Factor Module to determine the location of the loads to be shed and the output of the System Monitoring Module to determine how much load needs to be shed. Execution & Reconfiguration Module executes the load shedding actions determined by the Load Shed Computation Module. The Execution & Reconfiguration Module also resets the other modules of the ILS Scheme after the desired control actions have been taken.

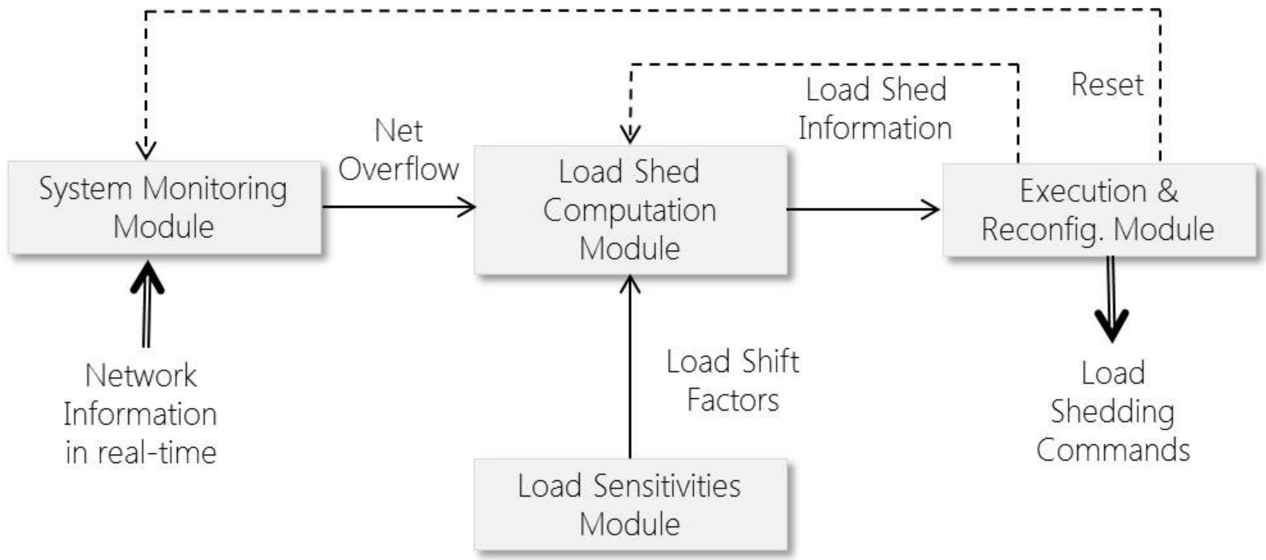

Figure 4.2: Functional Modules of ILS Scheme

4.4.1 Load Sensitivities Module

The Load Sensitivities Module computes the Load Shift Factors (LSF) for the loads at the current operation condition. The Load Shift Factor is a measure of the sensitivity of a certain load with respect to the flows across a particular transmission line. In other words, the Load Shift Factor of a load to a line is an indication of how much the flow across the line would change, when there is a change in the load.

The Load Shift Factors can be calculated either using the Admittance Matrix or by the perturbation method. [1, pp. 52 - 63] The Admittance matrix can be used effectively for smaller, meshed systems, while for larger interconnected networks sparsity of the Admittance

Matrix can pose a considerable challenge with the calculations. When using the admittance matrix, the load shift factors are calculated as,

$$LSF_{il} = \frac{(X_{pi} - X_{qi})}{X_l} \tag{4.1}$$

where LSF_{il} is the Load Shift Factor of load i with respect to line l, x_l is the inductive reactance of line l, and p and q are the two ends of line l.

Due to the drawbacks of the Admittance matrix method, the LSF values were calculated using the Perturbation method through dynamic simulations in PSLF. For each of the model cases, the loads within the monitored area and the major tie lines were identified. The load at each bus was incremented by 100 MW and the change in the inflows on these major tie lines was calculated and the total change in inflow was also calculated. The linearity of these factors was assessed using simulations that were run with different increments of load values. In each of these simulations, the LSF values remained about the same. The LSF is computed as follows,

$$LSF_{il} = \frac{\Delta T_l}{\Delta P_i} \tag{4.2}$$

where LSF_{il} is the Load Shift Factor of load i with respect to line l, ΔT_l is the change in flow in the transmission line l in MW, and ΔP_i is the change in real power at the load i in MW.

During the development of the ILS algorithm, only two operating conditions, heavy winter and heavy summer, were considered since they represent the heaviest loading conditions in a certain system model. Hence, the Load Shift Factors had to be calculated only once for each of the two operating conditions. But in a practical power system, the loading conditions change at almost every instance, with identifiable peak loading conditions and off-peak conditions witnessed on daily, weekly and seasonal cycles. While smaller changes do not warrant a reassessment of the LSF, significant changes in loading conditions necessitate a fresh round of computations to calculate these sensitivity factors. Since the load variations over a period of any duration are gradual and cyclic, the LSF computations can be supplemented by load forecasting methods, in the absence of real-time capabilities.

The ILS Scheme monitors the major tie lines that connect the monitored network to the rest of the network; thus the LSF were calculated for all the loads within the area with respect to these major tie lines. Based on these calculations, the loads within a single utility or a large group of contiguous loads were grouped together and their combined sensitivity was analyzed with respect to each of the tie lines. Thus, in the event of a need to shed load, the ILS algorithm would select and shed the load grouping that is most suitable to relieve excess flows on the tie lines.

4.4.2 System Monitoring Module

The System Monitoring Module checks the entire grid for signs of contingency in real time. The two functions of this module are to provide an arming signal that activates the ILS scheme and to provide the amount of total overflow into the monitored network. Accordingly, the inputs to the System Monitoring Module are the operating status of large generators, HVDC Converters and critical lines in the system and the power flows on major tie lines on a real time basis. Based on the above inputs, the System Monitoring Module decides if there is indeed a disturbance within the Control Area.

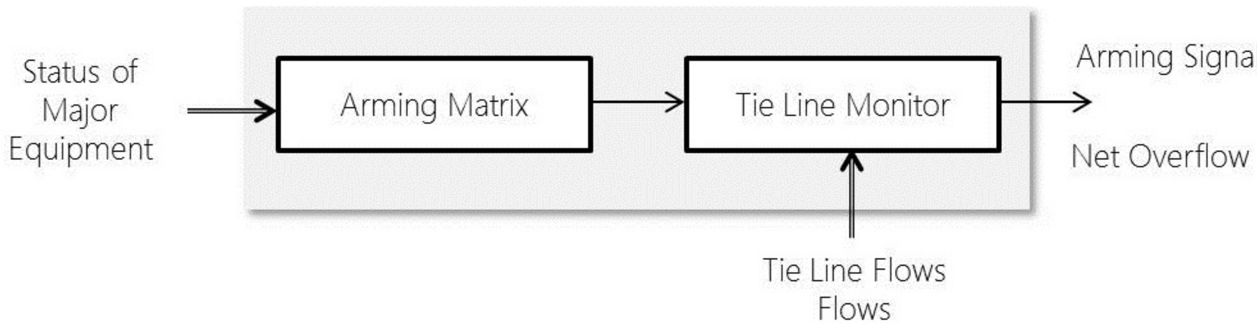

Figure 4.3: System Monitoring Module

(i) Arming Matrix

This module enables the ILS Scheme whenever there is a possibility of a rolling black out. While the exact path of a cascading blackout is difficult to predict, the blackouts are always triggered or exacerbated by a single major event. This results in series of contingencies that follow the main triggering event. By monitoring the status of major equipment across the power network, the System Monitoring Module looks for possible signs of an impending blackout. Several contingency studies are undertaken by utilities on a day-to-day operating basis which help the operators understand the effect of loss of certain equipment. The ILS Scheme can readily incorporate this valuable knowledge, by the use of an Arming Matrix.

The nature and type of a contingency alone would not help us make an informed decision about the need for arming the ILS scheme. Other factors like the current loading conditions and availability or non-availability of spinning reserves, etc. should also be taken into account while determining the output of the decision making. For instance, loss of two units at the San Onofre Nuclear Generation Station(SONGS) in Southern California has a greater impact on the system in the Heavy Summer loading case than at Heavy Winter loading, due to the differing loading conditions. Similarly, when the loss of SONGS units is accompanied with even a smaller contingency in the vicinity, it triggers a major system crisis, as was the case with the San Diego Blackout on September 8, 2011.

The Arming Matrix is a simple table that helps determine whether the ILS scheme needs to be armed or if the ILS scheme can remain disarmed. The System Monitoring module populates the matrix with the operating status of the major equipment, as also with the loading levels on important tie lines. Once the Arming Matrix is populated, the actual decision making is based on contingency studies for various loading conditions and any prior operating experience that may be available. Thus the arming matrix initiates load shedding through the ILS Scheme only when it is absolutely necessary, to protect the integrity of the system.

The Arming Matrix enhances the adaptability of the ILS scheme by ensuring that the algorithm can base its actions on the current operating conditions. It also allows the operator the choice of biasing the ILS algorithm towards a more aggressive or a more passive operation. This flexibility is important since the proposed algorithm has to fit into the gamut of already existing control schemes. When the algorithm is biased towards passivity, it ensures that load shedding is the last resort and that other possible control actions have been undertaken already. When biased towards aggressiveness, the algorithm takes whatever actions that may be necessary to ensure that the current disturbance is brought under control.

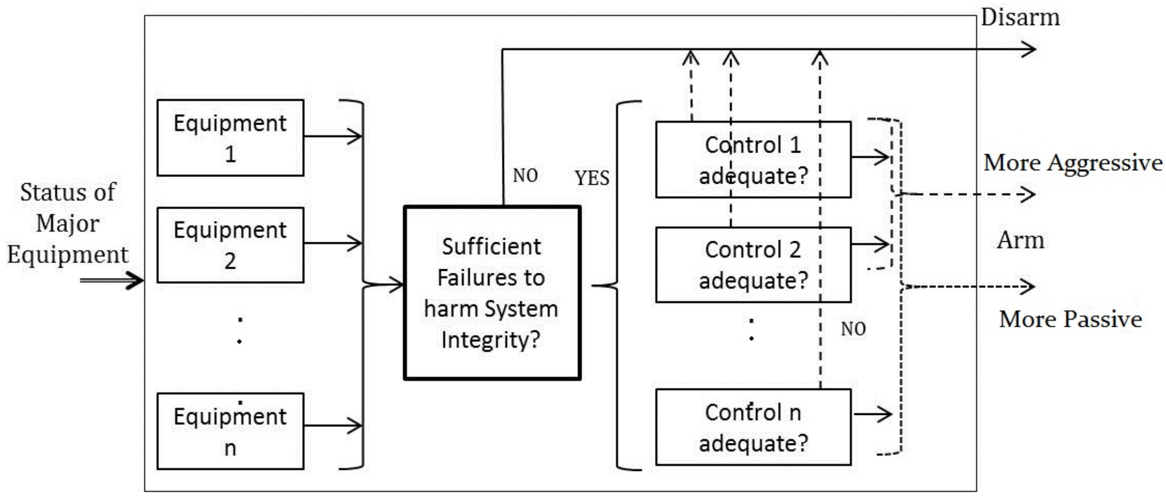

Figure 4.4: Arming Matrix Logic

As shown in the functional diagram of the Arming Matrix below, the decision to arm is taken only when a combination of sufficient failures that could seriously harm system integrity has occurred. Once this condition is met, the decision making ascertains if the existing controls can adequately manage the disturbance. If it is determined, based on contingency studies and prior operating experience, that existing controls are inadequate or too slow to effectively tackle the contingency, the arming signal is enabled and the ILS Scheme is put to action.

Tie Line Monitor

The ILS Scheme determines the actual amount of load to be shed, based on the total overflow into the monitored area as observed at the boundary of the monitored network. When there is more demand than generation within an area, the tie lines carry the power difference between load and generation into the area. Most of this imported power is transferred by major High Voltage and Extra High Voltage tie lines. The flows on these tie lines, called the inter-area exchanges, are limited to the scheduled values, during normal operating conditions. In case of a loss of generation within an area, there will be an increase in the power imported to make up for the lost generation. Thus, when there is a loss of a large generator as a result of a stand-alone event or as one of the events of a cascading failure, the tie flows deviate from the scheduled values by a large amount. The actual deviation depends on the size and location of the machine that was lost and also the availability of spinning reserve at that point of time.

The System Monitoring Module records the inter-tie flows on a real time basis. Net Overflow is calculated as a moving average of the sum of the differences between the current flows in MW and scheduled flows in MW for each monitored tie line. In order for this module to initiate further action, the overflow has to persist for a certain finite duration of time, called the Timer Threshold. The Timer Threshold is the period for which the net overflow value has to be persistent, i.e., be steady or keep increasing, but not decrease drastically. The Timer Threshold is included to ensure that power swings due to small signal oscillations are discounted when calculating the value of net overflow. The Timer Threshold is determined by the time period of the inter-area oscillations.

Inter-area oscillations are observed when groups of generators in one area of a large interconnected system oscillate against other groups of generators in other areas due to small-signal instability. When large groups of generators are involved, the frequency of oscillation is very low, in the order of 0.2 to 0.3Hz, while smaller groups produce oscillations of 0.4 to 0.8Hz. [2, pp. 817 - 818] Under-damped Inter-area Oscillations are a global problem that can be observed as power swings on long High Voltage and Extra High Voltage lines that act as an interface between the two oscillating groups of generators. Such oscillations require a different set of control actions that include Power System Stabilizers, Exciters, etc.

There are quite a few proven techniques to compute the frequencies and damping ratios of the small signal oscillations. These methods are broadly classified into two categories, model-based and measurement-based. Although the model-based methods are more accurate, the need to compute the plant matrix of the system makes these methods unsuitable for very large systems. Measurements-based methods are further classified into Transient and Ambient methods, based on the nature of their preferred input data. For the development of the algorithm, widely used measurement-based algorithms like the Prony Analysis and Matrix Pencil were used.

In the absence of a Timer Threshold, it is quite possible that the power oscillations could be misconstrued as a deviation from the scheduled values of tie flow. Hence it is important to ensure that the overflow observed is characteristic of loss of generation or a sudden increase in load scenario. It can however be improved upon by performing an online small signal analysis and determine the dominant mode of oscillation at the given load conditions. If these oscillations are well damped, then the Timer Threshold can be ignored and the value of Net Overflow can be computed instantaneously, if and when the output of the Arming Matrix requires initiation of load shedding.

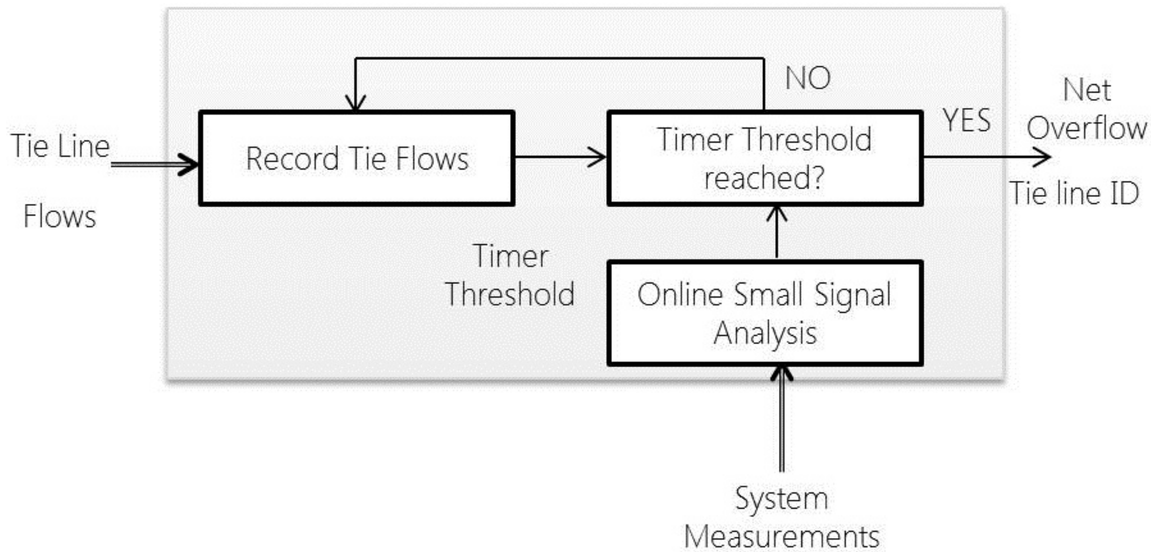

Figure 4.5: Tie Line Monitor

4.4.3 Load Shed Computation Module

The Load Shed Computation module, by default is in a disarmed state; it is activated only when the System Monitoring Module issues an arming signal based on the output of the Arming Matrix. This module uses the inputs received from the Load Sensitivities and the System Monitoring Module to compute the location and the amount of load shedding respectively. As discussed in the earlier sections, the output from the Load Sensitivities module changes only when there is a significant change in the loading conditions of the system, while the output from the System Monitoring Module is based on continuous real time assessment of the system.

The System Monitoring Module calculates the net overflow from all tie lines that deviate from their scheduled values. It sends the value of the net overflow along with the identity of the tie line that shows the highest overflow, to the Load Shed Computation module. Depending on the computations performed by the Load Sensitivities module and the identity of the tie line that has the highest deviation from its scheduled value, the Load Shed Computation module selects the group (location) of loads that need to be shed.

When there is a loss of generation or a sudden increase in load, a supply-demand mismatch is created within the control area causing the primary generation control to act. The primary control is the droop response of the generators causing a local drop in frequency and slowing of generators. Since the generation within the area cannot make up for all of the mismatch, the remainder of the lost generation appears on the tie lines as increased flows or as Area Control Error (ACE). Thus the total overflow into an area gives an indication of the generation-load mismatch. This net overflow value is used to calculate the amount of load to be shed at the selected location.

Only a fraction of the total overflows is taken as the amount of load to be shed. This fraction is determined by performing contingency studies on the system under consideration. The contingency studies comprising the loss of generation scenario give a general idea of the correlation between the size of generation lost and the amount of tie line deviations that can be expected. The reason why only a fraction and not the entire value of overflows is used, is because the secondary generation control, called the Automatic Generation Control (AGC) uses the ACE to further increase generation, but on a much longer time scale than the proposed algorithm.

After selecting the location of the load and the total amount of load to be shed, low priority loads and loads that can readily be disconnected from the network are shed first, until sufficient load has been shed. The remainder of the load to be shed is distributed equally among the other available loads in the selected area. The Load Shed Computation module passes on these values to the Execution & Reconfiguration Module.

4.4.4 Execution & Reconfiguration Module

The Execution & Reconfiguration module executes the actual load shedding commands issued by the ILS Scheme and reconfigures the other ILS modules after the load shed actions have been taken. This module acts as the interface between the algorithm and controls on the existing system, when the ILS is implemented. The interface could be the feeder breakers that are connected to the Under Frequency Load Shedding scheme. The author hopes that with the proliferation of the IEC 61850-compliant substations, there will be more available options through which a seamless interface can be made possible. This module also resets the other ILS modules after the control actions have been taken. After the control actions taken by the ILS scheme and the primary and secondary generation controls, the scheduled tie flow values would warrant some correction. In addition, the Arming Matrix and the overflows have to be re-computed calling for an effective reset of the other ILS modules.

Chapter 5

Implementation of the ILS Scheme

The first step towards implementing the ILS scheme is to identify a control area that satisfies the requirements mentioned in section 4.2. The control area is a contiguous group of buses among a larger network of buses. These buses are interconnected as a combination of both radial and mesh networks. The Control Area has a certain amount of loading at a given time and may or may not have generation. The mismatch between the load and the generation is imported through the tie lines that connect the control area to the rest of the network. The Control Area may also have other power systems components like HVDC Converters, Capacitor banks and Flexible AC Transmission System (FACTS) devices.

After the Control Area is selected, the major tie lines are identified. The definition of what constitutes a major tie line is determined by the total power imported and transmission voltage of the tie line. The tie lines are chosen in such a way that they account for most of the flows into the area. All the major sources of power like large generators and HVDC sources within and outside the Control Area are also identified. Then, contingency studies are performed with specific focus on power sources in the control area, when the network is at one of its peak loading conditions. The peak loading conditions serve as a worst-case scenario for designing the scheme. Based on these results, various combinations of contingencies that cause frequency instability within the Control Area and its vicinity are drawn. These studies also provide a general idea of how much power is imported when there is a loss of generation within the control area. Conversely, given the general fraction of power that gets imported and the value of overflows observed on the ties, we could arrive at an approximate value for the size of the generation lost or sudden load increase.

All the loads within the control area are also identified. The Load Shift Factors are calculated for each of the loads with respect to all the major tie lines, by the perturbation method described in section 4.4.3. For each tie line, the loads that have the highest Load Shift Factor values are grouped together. Thus, each tie line has a specific group of loads that are most sensitive to the flows on its ties. It is quite possible that the flows on several tie lines may be most sensitive to the same load groups or that, certain tie lines do not exhibit strong sensitivity to any specific load group. A small signal stability analysis is performed to ascertain the presence of under-damped or undamped oscillations in the system and thereby deduce a value for the Timer threshold. Then, all the critical components in the grid are identified. The status of these components are used to populate the Arming matrix, which in turn, is used to initiate the Arming signal. Now the ILS Scheme continuously monitors the tie lines for any change in inter-area exchange.

When a sudden change in scheduled flows is detected, based on the output of the Arming matrix, the need for load shedding is assessed. When there is a need for shedding loads, the tie line with the maximum overflow is identified. The total overflow on all the tie lines is computed. The group(s) of loads that is associated with the tie line is selected. If there are multiple groups of loads, then they can be prioritized based on other factors like voltage stability, load criticality, etc. The amount of load to be shed at each bus within the selected area is determined from the total overflow value computed. Accordingly, the loads are shed and the tie flows are monitored. The load shedding is repeated until a significant drop in overflows is detected. Once adequate load is shed, the loading on critical transmission lines would also return to normal values. After this, the intelligent load shedding scheme is reset. New scheduled values for the tie lines are calculated. Load shift factors are also computed, after a fresh assessment of current loading conditions.

5.1 Model Description

The ILS scheme was developed and tested using GE's Positive Sequence Load Flow (PSLF) software. The PSLF is a power system analysis software suite developed by the GE Energy. The algorithms in the PSLF suite have been developed to handle large utility-scale systems of up to 80,000 buses [18]. The Load flow modules and dynamic simulation modules of the suite were employed, along with PSLFs automation and scripting tool, Engineer Program Control Language (EPCL). The ILS scheme uses the Reduced WECC and Full WECC models at Heavy Winter loading conditions for developing and testing respectively. As described in Chapter 3, the Reduced WECC model resembles the Full WECC model as far as the network inside California is concerned. Hence, the algorithm developed by using the results obtained from the Reduced WECC Model can be transplanted to the Full WECC system with minor modifications. The Full WECC system is used for testing since we would like to observe the effect of using ILS on the entire WECC system.

The Full WECC Heavy Winter Model contains over 15,000 buses and over 2000 machines representing a total loading of 128 GW between 21 utility areas spread across the western half of the North American continent. Dynamically, all the generators are represented by a two-axis model. All the generators are equipped with Exciters to control the exciting current and turbines to control the prime mover output. About 1000 generators are equipped with

Power System Stabilizers to improve the dynamic stability of the system. On average, the total system loading is dominated by constant current loads (about 70%) and frequency-dependent loads (20%), while the rest is made up of constant impedance and constant power. The dynamic representation also contains other devices like the High Voltage DC (HVDC) systems and Static VAR Compensators (SVC). The model also has about 1400 relays, with a majority of them being Under-Frequency Load Shedding relays while there are a few Out-of-Step and distance protection relays.

As explained in the following section, the ILS algorithm's main focus was the California network and hence, a power system model smaller than the 15000-bus model but without a compromise on the detailed representation of the California network was required. The Reduced WECC model is a compound model developed by the researcher to address this need for an adequately-sized model. The Reduced-WECC model was developed by combining the detailed California network (about 4000 buses) extracted from the Full WECC network and Outside California network (67 buses) extracted from the 128-bus Equivalent WECC System used in [14]. Before the two networks could be combined, their boundaries had to be matched. This was achieved by introducing new buses and transmission lines at the interface of the two networks through short circuit studies and by increasing the power output of the generators inside the network representing the WECC outside California through a multi-swing bus load flow study. In addition, the two crucial HVDC systems described above were also added to the model.

While the generators within California are represented by a detailed two-axis model and the loads by dynamic load types, the generators outside California are represented by classical machines and the loads are represented as Constant-PQ type. The new Reduced-WECC model was validated against the Full WECC model using several criteria including major path flows, tie line flows, voltage magnitudes at all the Extra High Voltage buses, performance of the HVDC systems, dynamic response to contingencies and small signal response. It was found that the new models response matched very well the response of the Full WECC model in all the above aspects. Thus, the Reduced-WECC model is a smaller sized model while still preserving the detailed representation of the California network.

5.2 Selecting a Control Area

The Control Area or the Area of Supervision is a contiguous network of buses that forms a subset of the entire network. The Control Area is selected based on the requirements outlined in Section 4.2.1. For the actual development of the algorithm, the control area is taken as the network that represents California in the Reduced-WECC model. In the Full Loop model, California is represented by five utility areas namely, Pacific Gas & Electric (PGE), Los Angeles Department of Water and Power (LADWP), San Diego Gas & Electric (SDGE), Imperial Irrigation District (IID) and Southern California Edison (SCE). The selected Control Area forms a major bulk of the WECC network, in terms of buses and loading. The California network comprises of about 4000 buses and 640 machines with a generation of 29GW and a total load of 39GW. Some of the major generators are listed in the table below.

Machine	kV	Area	Real Power (MW)	Reactive Power (MVAR)
Diablo 1	25	PGE	1150	-164
Diablo 2	25	PGE	1150	-147
San Onofre 1	22	SCE	1080	83
San Onofre 2	22	SCE	1070	83
Inter Mountain 1	26	LADWP	950	210
Inter Mountain 2	26	LADWP	950	210
Pittsburg	20	PGE	580	57

Table 5.1: List of Major Generators Within the Control Area

In the Full WECC model, the difference between the total load and generation within the area is met by importing power from the rest of WECC network through 28 tie lines with base voltages ranging from 65kV to 500kV. Of these 28 tie lines, 7 of them have a base voltage of 500kV and import about 1GW each, accounting for over 80% of the total inflows, and hence are ideal candidates for providing real time input for the ILS Scheme. These tie lines are listed in the table below. In the Reduced WECC model, these 7 major tie lines are preserved while the other smaller tie lines were replaced by equivalent generators. The first three tie lines listed are collectively called the California-Oregon Inter-tie (COI) and they account for about 3GW of all imports, from the hydro-power rich northern-most regions of the WECC system.

Tie Line	**From Area**	**To Area**	**Real Power (MW)**
Capt. JackOlinda	BPA	PGE	1208.5
MalinRound Mountain Circuit 1	BPA	PGE	985.4
MalinRound Mountain Circuit 2	BPA	PGE	997.9
Palo VerdeDevers	Arizona	SCE	1176.3
MoenkopiEl Dorado	Arizona	SCE	1097.5
NavajoCrystal	Arizona	SCE	1165.2
HassyampaNorth Gila	Arizona	SCE	985.5

Table 5.2: List of Major Tie Lines

The Control Area also contains a few critical power system components like the High Voltage DC Systems (HVDC) and the Static VAR Compensators. There are two HVDC Systems inside the Control Area. The Inter Mountain HVDC system is operated by the LADWP and it helps in transferring about 1700MW of power from its coal fired generating station in Utah to Adelanto near the Los Angeles area. [19] The DC network operates at 200kV and is represented by a two terminal DC system in the PSLF model. The other HVDC system is the 1360km-long Pacific HVDC Inter-tie that transfers hydro power from Northern WECC to the California. [20] The Pacific Inter-tie is a multi-terminal DC system rated at 3100 MW operated at 500kV, but carries about 2500MW at Heavy Winter loading. It starts at Celilo in Oregon as a four terminal network and ends in Sylmar in California as a two terminal network. These HVDC systems play a crucial role in maintaining the stability of the selected area, due to the large amount of power transferred by them and their proximity to the major load centers.

5.3 Loss of Generation Simulation Studies

After the control area is selected, the next step is to study the response of the network, when there is a loss of generation within the control area. A generator tripping can occur due to a local fault or due to action of special schemes in response to an evolving wide area disturbance. The objective of loss of generation studies is to gain an insight into the amount and modes of power transfer that occurs when there is a mismatch within the control area. The results of these studies can be used to estimate the amount of generation lost by measuring the total increase in tie line flows. It also helps to estimate the location of the generator that was lost by studying the combination of ties that respond strongly to the event. We could also estimate the consequences of the disturbance, if additional information like congestion on important transmission corridors, system loading, availability or non-availability of back up generation, etc. is known.

These studies were performed by using dynamic simulations in PSLF. The simulation is run for 1 second without any disturbance to ensure that the model is in a steady state. At the first second of the simulation, one of the major generators is removed from service and the tie line flows are recorded over a period of 20 seconds. The simulation result for tripping Diablo Unit 1 is shown in Figure 5.1. The tripping of Diablo 1 causes a mismatch of 1150MW inside the Control Area resulting in a sustained increase of tie line imports. The initial oscillations on the tie line correspond to the droop response of the generators, inside and outside the Control Area.

As shown, the three tie lines that constitute the California Oregon Inter-tie (COI) have picked up most of the overflows on the tie lines. This can be attributed to the overwhelming presence of hydro power units in the northern-most regions of WECC, from which the COI lines originate. The other major tie lines that connect California to the rest of WECC system originate in the eastern regions of the WECC that are predominantly thermal power stations and thus have limited maneuverability. It can be seen that for a loss of 1150MW within the control area, about 60% of the mismatch is met by tie line imports, while the internal generators make up for the rest. Nearly 75% of these imports happen across the COI lines.

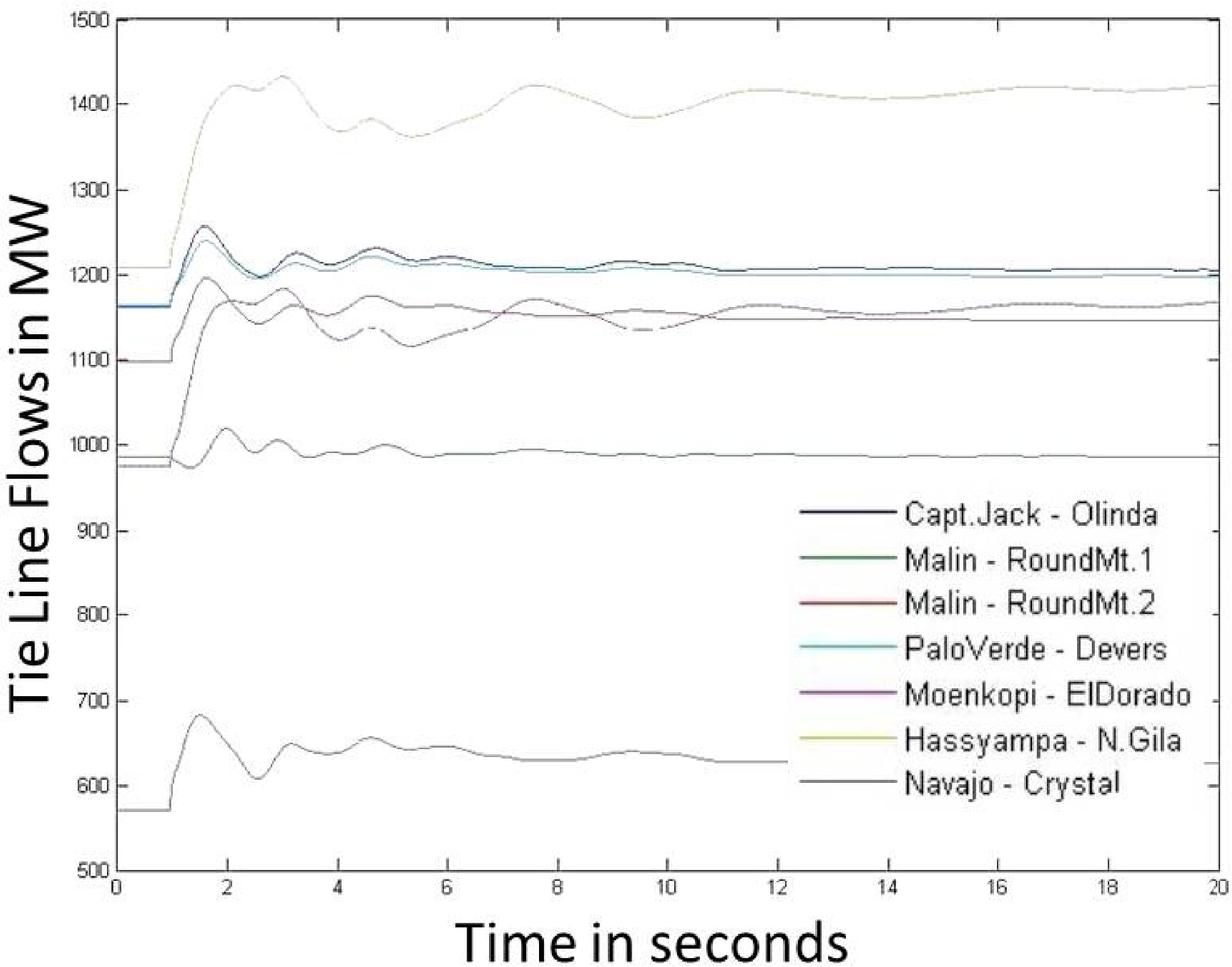

Figure 5.1: Tie Line Response to Loss of Diablo Unit 1

Similarly, the network response on the tie line was studied for loss of generators above

300MW. From the results, it was seen that tie line imports, especially the COI lines, make up a good portion of the network response to a generation-supply mismatch within California. Hence, monitoring the change in tie line flows helps us to not only determine a disturbance but also estimate the size of such a disturbance.

5.4 Load Shift Factors (LSF) Calculation

The Load Shift Factors are calculated using the perturbation method, wherein the load at each bus within the Control Area is changed by a certain fixed amount (100MW) and the changes in flow across the major tie lines are studied. The load at all the buses within the Control Area is increased, one at a time. This increase in load results in a change in the operating points of all the generators inside and outside California. The change in generator outputs is the inertial response of the generators owing to a change in the system load. The change in generator outputs outside the control area appears on the tie lines as a change in the power flow. The LSF for each line and bus combination is calculated using these changes in real power flows. The dynamic simulation module of the PSLF suite was used for running these simulations.

The results from one of the simulations on the WECC Heavy Winter model are presented below. The load at bus 36416 ST MARIA 9.11kV located within the PGE area is increased from 2 MW to 102 MW (a load increase of 100MW) and the change in generator outputs and change in tie flows are determined. The ratio of the change in tie line flow to the change in load (100MW) gives the Load Shift Factor for that particular load with respect to the tie line.

Tie Line	Real Power Before Load Increase (MW)	Real Power After Load Increase (MW)	Change in Tie Flows (MW)	Load Shift Factor
Capt.Jack Olinda	1208.5	1221.8	13.3	0.133
Malin RndMt.1	985.4	987.8	2.4	0.024
Malin RndMt.2	997.9	1000.3	2.4	0.024
PaloVerde Devers	1176.3	1167.6	-8.7	-0.087
Moenkopi El Dorado	1097.5	1103.6	6.1	0.061
Hassyampa N.Gila	985.5	986.5	1	0.01
Crystal Navajo	1165.2	1169.6	4.4	0.044

Table 5.3: Calculation of Load Shift Factors for a Sample Load

The Load Shift Factors (in %) for loads within California with respect to the 7 major tie lines were calculated for each of the load buses in California with respect to the seven major tie lines. These LSF calculations have been done at the Heavy Winter loading condition and hence need not be calculated for every contingency. However, if there is a significant change in the system loading or when implemented in real time, the LSF has to be computed periodically for effective load shedding. From the Load Shift Factors computed above, there are some observations that can be made about the Load-Tie sensitivity. These observations will be used to decide on the location of the load to be shed, based on tie line measurements.

- California Oregon Inter-tie(COI) comprised of three northern tie lines record an increase in power flow for an increase in load within any utility area except in SDGE
- The power flow along COI lines is most sensitive to loads located within PGE (based on comparatively larger LSF values for loads located inside PGE)

- Loads in SDG&E are best suited to relieve an increase in flows along Hassyampa North Gila tie line.
- Although PaloVerdeDevers and MoenkopiElDorado tie lines contribute about 1GW power each to the California network, they contribute significantly lesser than COI lines, when there is a mismatch in power flow inside California.

Based on the above inferences, the load shedding algorithm identifies the tie lines which carry the highest overflow and sheds the loads in the area associated with that tie line.

5.5 Small Signal Analysis

As discussed in previous sections, power flows along the inter-ties are a very important measure for the Intelligent Load Shedding Scheme. The presence of oscillations as can be observed in Figure 5-1, may reduce the accuracy of the estimate of tie line overflows. Hence it is necessary that the frequency of these oscillations can be ascertained, before we can arrive at a final estimation of the tie line overflows.

Whenever a large event occurs, it causes a shift in the operating point of the dynamic elements in its vicinity; the larger the event, the wider is its effect on the system. The transient response of the tie line flows observed during the tripping of Diablo Unit 1 is characteristic of power flows on long transmission lines that connect two interlinked areas in a very large network. The oscillations that are observed on the ties is indeed the small signal oscillations that occur between large groups of generators located in different parts of a network, when there is a disturbance. These oscillations when well damped, do not pose any significant risk to the system operation; but if the damping is not sufficient, these oscillations increase in magnitude progressively, leading to power swings that could cause mis-operation of a wide variety of power system protection schemes. In this research work, the author is only concerned about the effect of these oscillations on calculating the tie line overflows. If the frequency of these oscillations can be deduced, the total overflows into the control area can be computed more accurately.

The oscillations can be computed by performing a small signal analysis on the network. Since the scheme uses test cases based on the heavy winter loading, the Small Signal studies performed for validating the Reduced-WECC model, described in Chapter 3, is sufficient to estimate the frequency of oscillations that can be expected to be seen on the tie lines. Among these frequencies, the lowest frequency that is most prevalent in the network is taken as the base oscillatory frequency. The multiplicative inverse of this frequency gives the time period for the slowest oscillation. This Time period is taken as the value of Timer Threshold for the algorithm. Thus, the algorithm has to record the tie lines flows as a moving average over the Timer Threshold, after detecting a loss of generation. This moving average value provides a very accurate measure of the actual overflow values observed. Though the small signal analysis results are a good indicator for deciding the Timer Threshold, the dominant mode of oscillation in the network is actually dependent on the contingency that causes these oscillations. It is here that real-time oscillation deduction helps in improving the guess for Timer threshold.

If the network conditions change significantly, or when implemented in real time, the small signal analysis can be performed online to estimate the value of Timer Threshold. A variety of algorithms for quick and accurate online analysis of small signal stability have been described in [21], [22].

5.6 Algorithm Coding

Using the results from the above analyses, the algorithm was developed in EPCL, a scripting tool which is part of the PSLF suite. The operation of the scheme is described in Chapter 4. The EPCL allows us to create two kinds of programs for automating simulations, namely, the Main and Inrun Programs. The Main Program specifies the actual models that are loaded and other macro controls like initiating and clearing contingencies and their timing in the simulation. The Inrun Program is equivalent to a sub-routine or a function that is automatically called by the main program at every time step of the simulation. The Inrun Program performs micro controls like data recording, data mining, creating output files, etc. at every time step. The algorithm is coded in such a way that the main program contains the timed contingencies (for testing purposes) while the inrun program contains the actual algorithm. The Inrun program also records important variables like tie lines flows and bus frequencies at various locations of the network.

The algorithm in this form can be applied to any network with minor modifications. The modifications include the identification numbers for the tie lines, load areas that are to be shed corresponding to those tie lines based on LSF calculations, expected tie line increases when there is loss of generation based on contingency studies and expected time period of oscillations based on small signal analysis.

Chapter 6

Discussion of Results

The proposed algorithm is tested on the Full WECC model for different contingencies inside the California network. The contingencies involve loss of major generators and HVDC systems and a combination of these contingencies. The contingencies were drawn from previous research experience on working with the WECC network at the Center for Energy Engineering lab at Virginia Tech, in addition to the work done by the candidate. The contingencies were then selected based on their effect on the system frequency. The results from the ILS Scheme are presented below. While the first section explains the operation of the ILS Scheme with a simulated test case, the following sections describe the other aspects of the ILS Scheme with more test cases. In all the test cases, the simulation is run without any disturbance until 1 second, and then the contingency is initiated. The simulation is then continued for 30 seconds.

6.1 Operation of the ILS Scheme

The ILS Scheme monitors the tie flows watching for signs of a disturbance. Whenever a disturbance occurs, a sudden spurt in inflows is detected. In the developed algorithm, after a significant rise in tie flows (10% above nominal value) is observed, the tie line with the highest flow is identified. Then, the amount of load that needs to be shed is calculated as a fraction (10% for overflows of 3000MW and less and 50% for overflows greater than 3000MW) of the total overflow. The location of the load shedding is decided by LSF calculations, based on the tie line that has the highest overflow. Then the fraction of load to be shed at each bus is calculated as a ratio of the amount of load that needs to be shed to the total load in the selected area. Then, the load at each bus within the selected area is reduced by the load fraction percentage calculated earlier, on reaching the Timer Threshold. The Timer Threshold is taken as 2 seconds for contingencies within California, based on oscillations observed after the contingency.

The operation can be elucidated with the example of a test case involving the San Onofre Nuclear Generation Station (SONGS). SONGS units are some of the largest generators in the WECC system. The SONGS has two machines that produce 1080 MW each. The San Diego Blackout in 2011 has indeed proven that tripping of SONGS is a very real possibility. The change in power flows on the seven major tie lines for tripping SONGS is presented below. The first plot shows the change in tie line flows without the ILS Scheme, while the second plot has the ILS Scheme enabled.

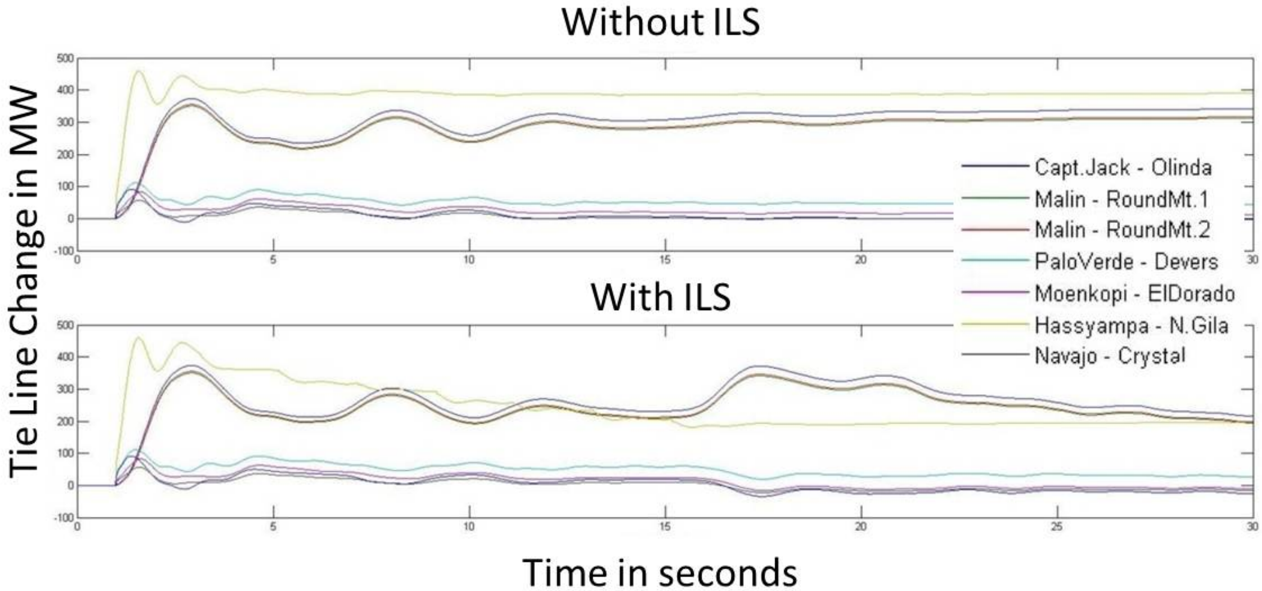

Figure 6.1: Change in Tie Flows Without and With ILS for SONGS Trip

As seen in the first plot, the tie line flows in the COI lines and Hassyampa-North Gila line increased to a very high value. A combination of generation inertial responses, generation controls, Under-frequency load shedding relays and load dynamics cause fluctuations in the tie lines flows. At the end of 30 seconds, the combined increase in tie line flows remains over 1300 MW. In the second plot, when the ILS scheme is deployed, the tie line flows keep decreasing as loads are shed in multiple blocks. The load shedding information is presented in the table below.

Time(sec)	Area	Overflow(MW)	Area Load	Load Fraction
3.146	SDGE	1577.22	3468.86	0.0455
5.15	SDGE	1218.03	3317.46	0.0367
7.154	SDGE	1204.2	3232.36	0.0373
9.158	SDGE	1132.99	3152.12	0.0359
11.162	SDGE	1061.3	3057.76	0.0347
13.166	SDGE	1033.97	2977.92	0.0347
15.171	SDGE	972.32	2895.14	0.0336
17.174	PGE	1206.68	14310.19	0.0084
19.178	PGE	1129.06	14271.01	0.0079
21.182	PGE	1117.14	14161.73	0.0079
23.186	PGE	991.1	14067.72	0.007
25.189	PGE	924.62	14000.88	0.0066
27.193	PGE	889.19	13925.35	0.0064
29.197	PGE	825.99	13860.9	0.006

Table 6.1: Load Shedding by ILS for SONGS Trip

As shown in the table, the ILS scheme identifies SDGE area as the location for load shedding. This was determined since the Hassyampa North Gila line to be highly overloaded(from Figure 6.1). The ILS algorithm calculated the total overflow and sheds 10% of that total overflow, by distributing load shedding among all the load buses in SDGE. It can be further seen from the table that at about 17 seconds, the ILS algorithm selects PGE for load shedding. This decision was made since the COI lines are more loaded than the Hassyampa - N. Gila line (from Figure 6.1). Thus the ILS tries to relieve the excess flows on COI by shedding loads in Pacific Gas & Electric (PGE) utility area. As the last column, Load Fraction shows, the ILS algorithm does not have a pre-set value of load to be shed; that value is determined rather dynamically based on the requirement. Also, distributing load shedding into multiple rounds helps to minimize the loads to be shed. In the 30 second simulation about 1500MW of load has been shed. The amount of load shed will be much smaller in the presence of fast-acting AGC systems due to increased generation.

The frequency response for all the areas within WECC is shown below, without and with the ILS Scheme. The frequency for an area is taken as the frequency at the swing bus for that area. It can be seen that with ILS, the frequency of the entire network recovers to 60Hz by the end of the simulation, while without ILS the frequency does not recover back to nominal value, although it is still within acceptable limits.

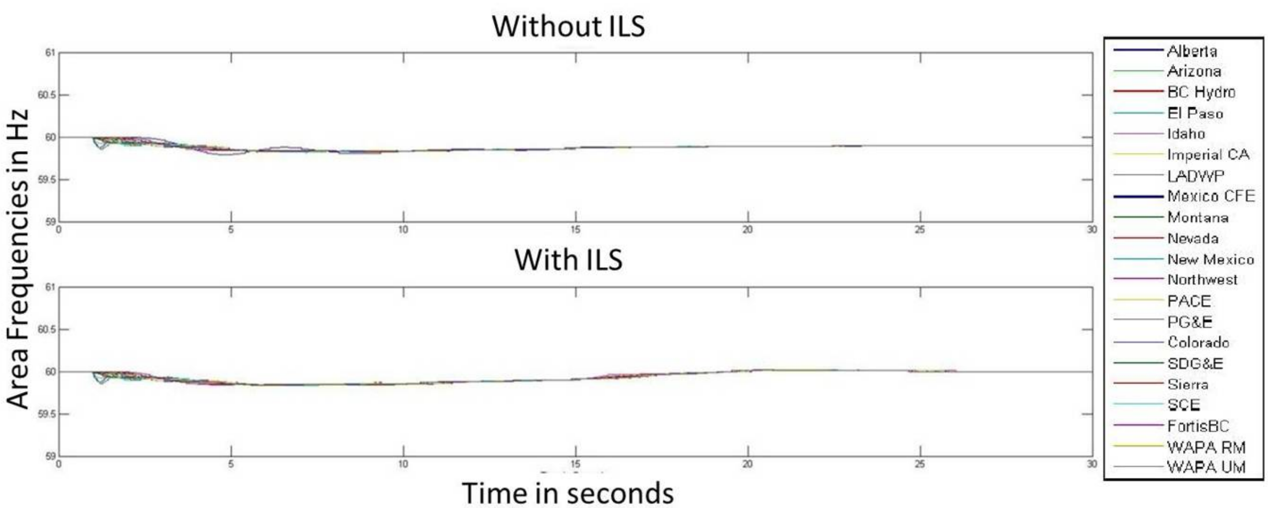

Figure 6.2: Area Frequencies Without and With ILS for SONGS Trip

6.2 Loss of Diablo Canyon Power Plant

The Diablo Canyon Power Plant is the largest nuclear generation station in California. It has two units, each generating 1150MW. The plant is operated by Pacific Gas & Electric (PGE). The power flows along the tie lines without and with the ILS Scheme is plotted below.It can be seen that the tie line flows show a marked decrease due to load shedding with the ILS Scheme enabled.

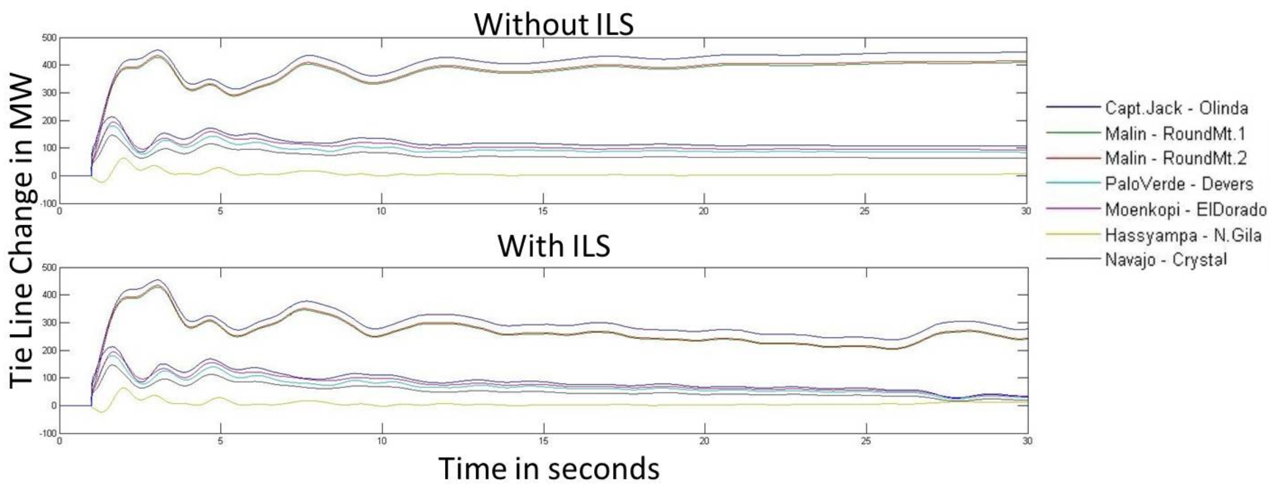

Figure 6.3: Tie Flows Without and With ILS for Tripping Diablo

Similarly, Area frequencies without and with the ILS Scheme are recorded and plotted below. As shown, the frequency recovers to nominal 60Hz by the end of the simulation.

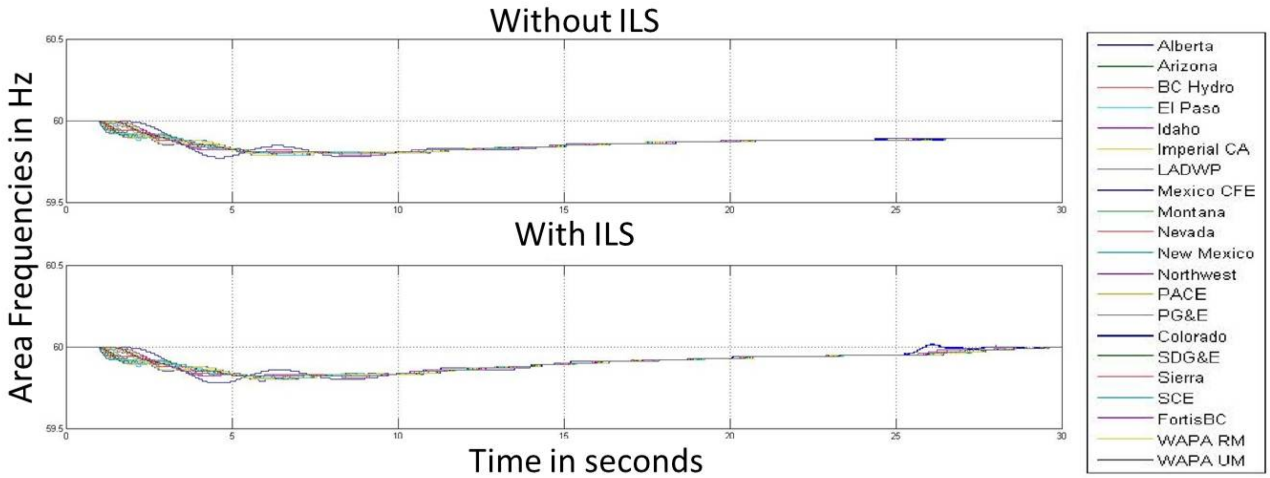

Figure 6.4: Area Frequencies Without and With ILS for Tripping Diablo

The details of load shedding action initiated by the ILS algorithm are tabulated below. The ILS scheme shed a total of 1610 MW inside the Pacific Gas & Electric (PGE) area.

Time(Sec)	Area	Overflow(MW)	Area Load	Load Fraction
3.137	PGE	1837.31	14300.52	0.0128
5.142	PGE	1362.88	14228.82	0.0096
7.146	PGE	1398.23	14066.33	0.0099
9.15	PGE	1264.12	14045.13	0.009
11.154	PGE	1209.23	13893.28	0.0087
13.158	PGE	1168.12	13836.52	0.0084
15.162	PGE	1094.24	13729.15	0.008
17.166	PGE	1078.5	13643.94	0.0079
19.17	PGE	1002.21	13559.51	0.0074
21.173	PGE	979.01	13480.96	0.0073
23.177	PGE	921.7	13403.73	0.0069
25.181	PGE	883.93	13331.12	0.0066
27.185	PGE	962.14	13233.26	0.0073
29.188	PGE	936.67	13192.02	0.0071

Table 6.2: Load Shedding by ILS for Diablo Trip

6.3 Loss of Inter Mountain HVDC System

The Inter Mountain HVDC System operated by the Los Angeles Department of Water and Power (LADWP), evacuates power from Utah, located in the Eastern side of the network, supplying California about 1.7 GW of power. It is located close to the major load center of Los Angeles, making the HVDC system very crucial to system operation in California. The tie flows and frequency plots for tripping the Inter Mountain system is shown below.

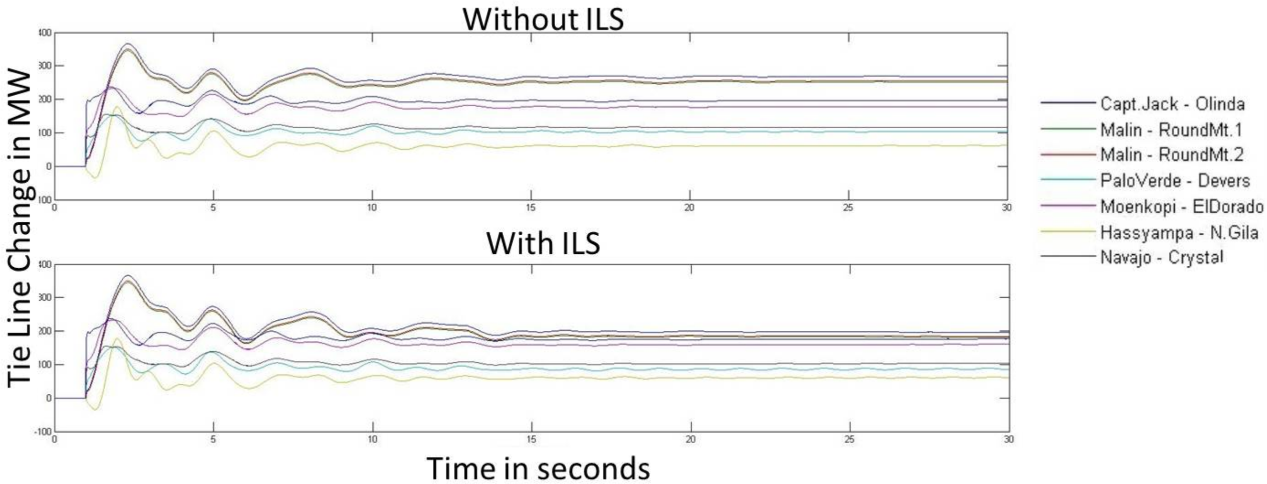

Figure 6.5: Tie Flows Without and With ILS for Tripping Inter Mountain HVDC System

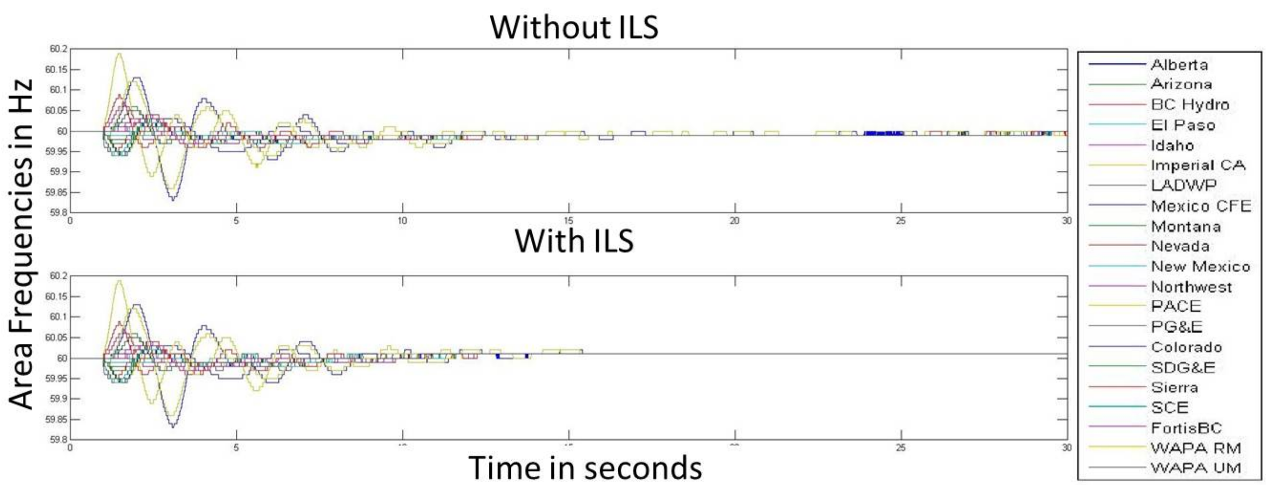

Figure 6.6: Area Frequencies Without and With ILS Scheme for Tripping Inter Mountain HVDC System

Like the previous case, the frequencies settle down slightly much quicker and closer to the nominal value when the ILS Scheme is employed. The final frequency is a notch higher than the nominal frequency of 60Hz, which can be attributed to load shedding initiated by the Under Frequency Load Shedding Scheme in areas like Alberta which experience heavy frequency swings. The total amount of load that is shed in this case is 515 MW and the load shedding details are listed below.

Time(sec)	**Area**	**Overflow(MW)**	**Area Load**	**Load Fraction**
3.575	PGE	1357.49	14383.29	0.0094
5.579	PGE	1257.17	14313.23	0.0088
8.567	PGE	1294.32	14180.87	0.0091
13.037	PGE	1237.29	14069.14	0.0088

Table 6.3: Load Shedding by ILS for Tripping Inter Mountain HVDC

6.4 Loss of Inter Mountain HVDC System & Diablo Unit 1

The next case that was simulated is a double contingency of loss of both Inter Mountain HVDC System and one unit of Diablo. The simulation results without and with the ILS Scheme are presented below.

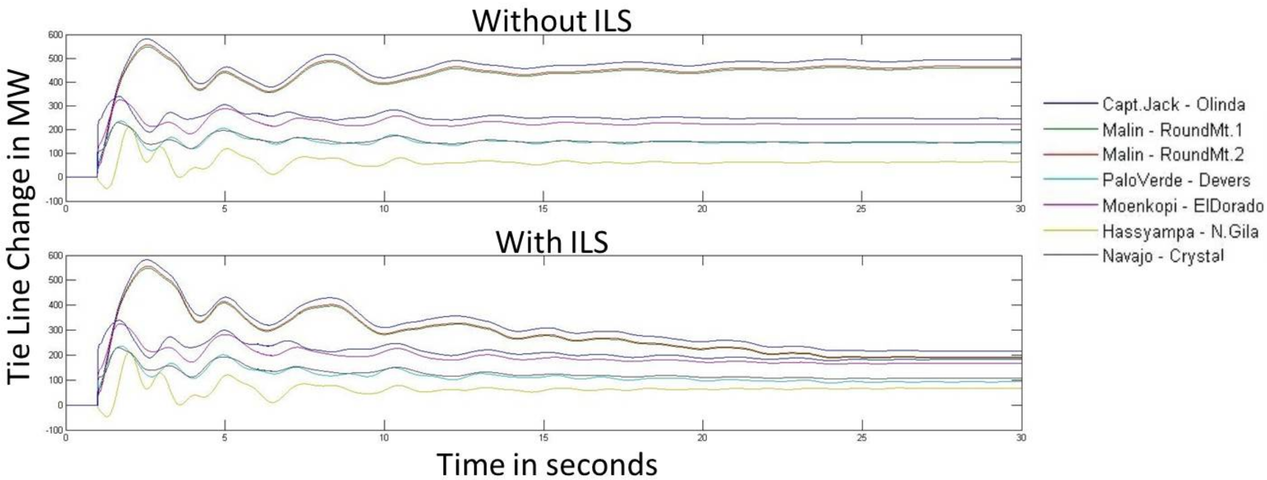

Figure 6.7: Area Frequencies Without and With ILS for Tripping Inter Mountain & Diablo

Like the previous cases, the ILS algorithm works to minimize the tie line flows by shedding loads inside PGE. This ensures a faster stabilization of frequencies across the WECC network.

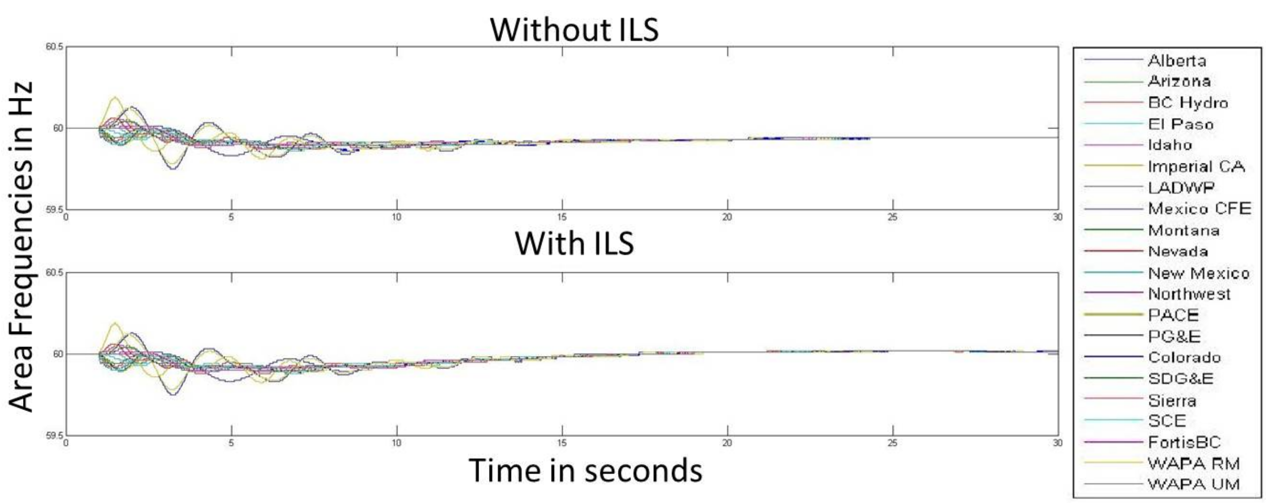

Figure 6.8: Area Frequencies Without and With ILS for Tripping Inter Mountain & Diablo

The total load that is shed in this case is 1870 MW spread over 11 rounds within a period of 20 seconds after the initiation of the contingency. In terms of normalizing tie flows and frequency recovery, the network performs better with the ILS Scheme than without. The details of the ILS actions are tabulated below.

Time(sec)	Area	Overflow(MW)	Area Load	Load Fraction
3.337	PGE	2364.1	236.41	14356.99
5.342	PGE	2191.17	219.12	14128.11
7.346	PGE	1995.53	199.55	13901.02
9.35	PGE	1716.4	171.64	13852.55
11.354	PGE	1673.22	167.32	13675.57
13.358	PGE	1687.24	168.72	13572.5
15.362	PGE	1576.23	157.62	13418.01
17.366	PGE	1480.86	148.09	13296.79
19.37	PGE	1392.59	139.26	13191.53
21.373	PGE	1347.85	134.78	13077.82
23.377	PGE	1276.95	127.69	12970.43

Table 6.4: Load Shedding by the ILS for Tripping Inter Mountain & Diablo

6.5 Loss of Inter Mountain HVDC System and One Pole of PDCI

The two HVDC systems that transfer power to California are very crucial for the integrity of the entire WECC system. The Inter Mountain HVDC System evacuates power from coal-fired plants in Utah, located in the Eastern side of the network, while the Pacific DC inter-tie (PDCI) transfers power from the hydro plants of Northern WECC. When either of these systems is lost, there is excessive generation in the areas near the source while there is excessive load in California, the terminal end. When such a tripping happens, the AC inter-ties that run in parallel to these DC systems get overloaded, causing further stress along crucial transfer corridors in the system. Thus when HVDC systems get tripped, it is the transmission capacity that is lost. The sudden loss of such large transmission capacities result in wide swings of frequencies between multiple areas.

The HVDC model in PSLF for the PDCI, allows it to be operated on one pole. HVDC systems with two poles (positive and negative circuits) can be operated on just one pole for a short duration of time at half the rated capacity. This ability allows the HVDC system to continue functioning even if one of is poles is removed from service due to a planned or forced outage. In this case study, the Inter Mountain system and one pole of the PDCI is removed from service at 1 second and the simulation is run for 30 seconds. In this test case, 1.7GW of power transferred by the Inter Mountain system and 1.2GW of power transferred by the PDCI is lost, resulting in a total loss of 2.9 GW. Since these systems feed one of the largest load centers, their loss results in a catastrophic system collapse. The area frequencies for this test case without and with the ILS Scheme are presented below.

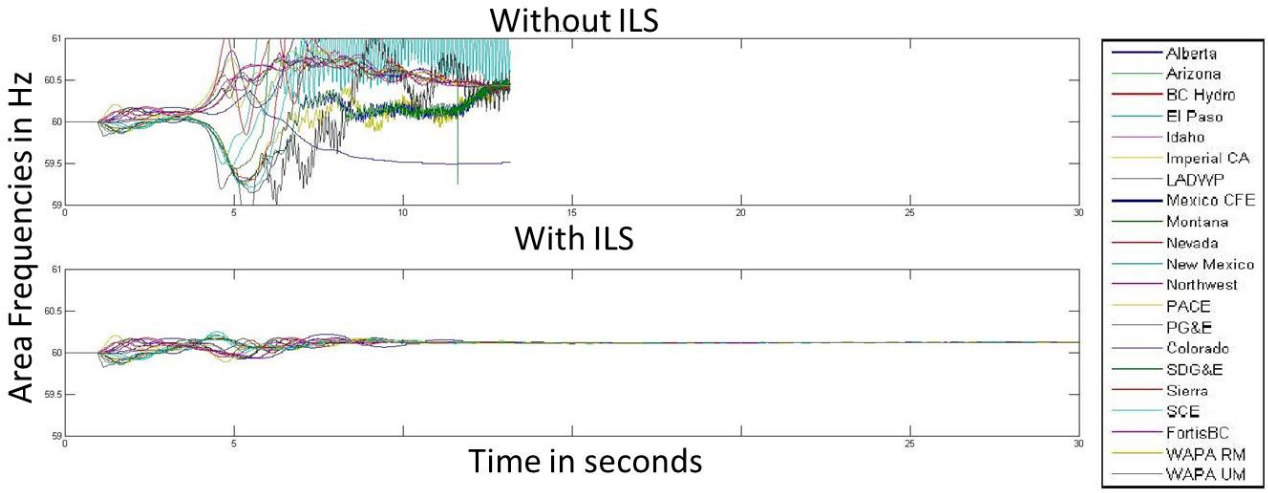

Figure 6.9: Area Frequencies Without and With ILS for Tripping Inter Mountain & PDCI

As shown above, the dynamic simulations fail to converge due to wide swings in area frequencies. This triggers a wide range of protection systems like the distance protection relays, out-of-step protection relays and the generators protection controls, in addition to under frequency and under voltage load shedding. The frequency plot shows how the different areas start to separate just after 4 seconds into the simulation. The machines in areas with excessive generation like the Northern and the Eastern WECC start to accelerate. This is indicated by the rapidly increasing frequencies of a group of areas. The machines in generation-deficient areas like California start to decelerate due to excessive load. This is indicated by declining frequencies.

The apparent splitting of the WECC observed in the frequency plot just after 5 seconds into the simulation, fails to maintain the integrity of the separating areas, leading to large frequency swings. These swings in turn trigger more generation outages and load shedding, resulting in a complete system outage. The tie line flows are presented below.

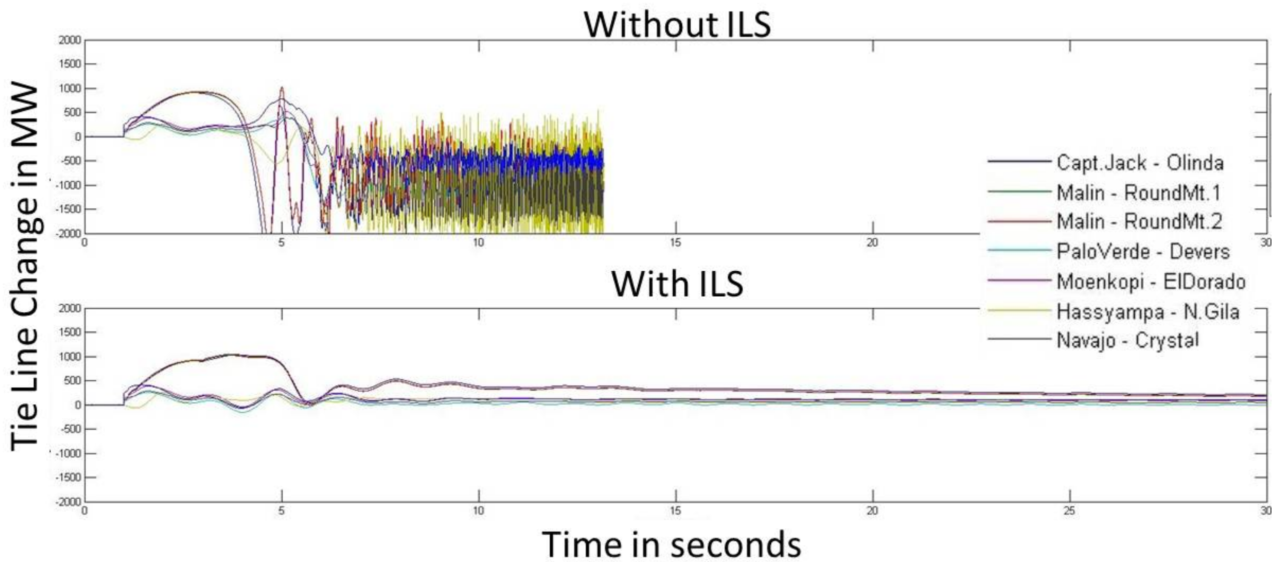

Figure 6.10: Tie Flows Without and With ILS for Tripping Inter Mountain & PDCI

As shown above, the ILS Scheme rapidly sheds loads within the California network so as to reduce the mismatch between the load and generation. This greatly reduces the loading on AC inter-ties, thereby allowing the system more leeway in handing the crisis. It can be seen that the ILS action within California greatly benefited the entire network by keeping the areas interconnected. This can be observed in the frequency plots. The frequency response in the first few seconds after the contingency is very similar to that of the case without the ILS. It is after the first load shedding action of the ILS that power flows on the tie lines get subdued.

The tie lines show a spurt in inflows right after the first action. This can be attributed to continued tripping of generators within California, due to voltage problems and power swings due to the original contingency. At this point in the frequency plot we can also observe that the machines in different areas are starting to oscillate against each other.

Subsequent actions by the ILS Scheme, indicated by the sustained decrease in the tie line flows, dampens these oscillations further, keeping the entire network together. The final frequency of the network is higher than the nominal frequency, indicating more generation than demand in the network. This can be explained by additional load tripping caused by the Under Frequency and Under Voltage load shedding schemes. This case study shows how the ILS Scheme can prevent a potential blackout by preventing system disintegration.

In this scenario, the ILS sheds a total load of 5GW, which is much higher than the initial loss of 2.9GW. This is due to the fact that more generators are forced to go offline due to frequency swings and sudden voltage dips associated with sudden loss of generation. Also, with the initial total overflows calculated being above 3000MW, the ILS scheme sheds 50% of the total overflow. This ensures that the ILS system takes more effective load curtailing for a larger contingency than for a smaller one. The ILS load shedding information is presented in the next table.

Time(sec)	Area	Overflow(MW)	Area Load	Load Fraction
3.037	PGE	3519.02	13024.53	0.1351
5.042	PGE	3581.65	13131.72	0.1364
7.975	PGE	1960.29	11221.53	0.0175
9.979	SDGE	1529.14	3487.86	0.0438
11.983	PGE	1497.08	11106.07	0.0135
13.987	PGE	1402.44	11044.74	0.0127
15.991	PGE	1295.59	10913.74	0.0119
17.995	PGE	1255.65	10829.12	0.0116
19.999	PGE	1188.59	10741.67	0.0111
22.002	PGE	1099.58	10644.81	0.0103
24.006	PGE	1073.97	10568.12	0.0102
26.01	PGE	977.78	10487.63	0.0093
28.013	PGE	964.27	10413.23	0.0093

Table 6.5: Load Shedding by the ILS for Tripping Inter Mountain & PDCI

6.6 Summary of Test Results

From the test cases presented above, it can be seen that the ILS Scheme is effective in detecting the occurrence and estimating the size of an event, based on real time tie flows. The ILS Scheme also initiates control actions based on the estimations and offline sensitivity studies to limit the effect of the event. All these case studies also show that the ILS was effective in bringing the frequency of the entire interconnection back to the nominal value in a much shorter time frame (by the end of the 30-second simulation). While this aspect may not warrant much attention in the event of a standalone contingency, this is a very important consideration when seen in the context of a rolling blackout. When the system is stressed, it is necessary that the frequency be brought back to the nominal value as soon as possible to prevent the network from deteriorating further. If the frequency decline is left unchecked, it could cause formation of islands, that could subsequently lead to a black out in these islands.

In a few of the cases, the frequency settles at a notch higher than the nominal frequency; this can be attributed to the Under Frequency and Under Voltage load shedding schemes that get triggered when a large event occurs. While the ILS Scheme has been shown that it responds to all the case studies presented above, use of the Arming Matrix can limit its control actions to the most severe of cases. This is necessary since the loads have to be preserved as much as possible and with least disruption to the customers.

The last case study presented provides us ample proof to show how the ILS Scheme can directly prevent a blackout by proactively shedding loads, when a large contingency is detected. While the system collapses within 10 seconds of the occurrence of the event without intervention, the ILS Scheme not only retards the process of system separation, but also prevents the system from islanding by rectifying the load-generation mismatch.

Chapter 7

Future Work & Conclusion

This chapter presents some ideas on further developing different aspects of the proposed algorithm. It also presents some conclusions drawn by the author based on the development and simulation results presented in the preceding chapters.

7.1 Improvements to Scope

This section discusses ideas that could be used to expand the scope of the proposed ILS Scheme. With this research work, the algorithm is limited to shedding loads in a net importing area, by monitoring of inter-ties that connect this area to the rest of the network.

7.1.1 Generator Rejection

Within a control area, when there is a mismatch between load and generation with excessive generation, there is an increase in the tie line flows to compensate for the mismatch in generation. Similarly, if the control area is a net exporter of power, the tie line flows increase when there is a loss of load within the area. If this mismatch is not corrected quickly, the frequency for the area may increase, leading to tripping of generators due to overfrequency. Thus, the tie lines can be monitored for any change in power flows and depending on magnitude of change in tie flows, generators can be rejected to ensure that a balance is achieved within the control area at the earliest time. In addition to generation-load mismatch, generator tripping has been used as a means for maintaining stability in the network. Generator tripping, through special schemes, helps decongest certain critical transmission corridors in an unstable situation. [1] The algorithm can include these existing schemes also, when performing generation rejection.

One of the main considerations for such a scheme is the allowed operating times. Presence of oscillations in the tie line measurements may significantly delay the tripping decisions. This time delay should not exceed the allowed delay on tripping a generator after an overfrequency situation has been detected.

7.1.2 Voltage Stability Consideration at Load Buses

The voltage magnitudes at individual buses do not pose a concern to the overall system operation, since voltage magnitudes are affected by reactive power flows that are restricted to a local area. Thus voltage regulation at a bus is a local problem that is dealt with components like Under Load Tap Changing (ULTC) transformers, shunt reactors and compensators located at the same bus or a bus in its vicinity. When the system is under stressed operating conditions, voltage stability becomes an issue in parts of the network that are operated at lower voltages. Load shedding is performed to alleviate such voltage collapse problems by shedding loads when the voltage drops below a certain threshold.

Although the proposed ILS Scheme does not take into account the voltage stability considerations, it is fairly straightforward to include these constraints when loads are selected for shedding. While there are a few static methods for predicting voltage collapse problems, the ILS algorithm would best benefit from an online dynamic security assessment technique. Reference [23] proposes a new voltage stability indicator, called the L-index that assesses the voltage stability of the network at various buses. Reference [12] uses the L-index to perform voltage stability analysis using Wide Area Measurement Systems. Such an approach can expand the scope of the ILS Scheme to include voltage stability constraints.

7.2 Improvements to Effectiveness

The following section puts forth some ideas for enhancing the effectiveness of the proposed algorithm.

7.2.1 Tie Line Outage

The ILS algorithm assumes that the tie lines that are being monitored are in service throughout the disturbance. While the tie lines do have some additional protection and control measures to keep them in service even during large disturbances, there is always the possibility that they could also be lost. In the current configuration, the ILS scheme has no means of coping up with monitoring the control area, once the tie lines are out of service. This can be rectified by a sensitivity analysis involving the Line Outage Distribution Factors (LODF). Line Outage Distribution Factors indicate how the flows along a certain line get distributed among other lines, when that line is taken out of service. [24] It is given by,

$$LODF^{l,k} = \frac{\Delta P^{l}}{P_{o}^{k}} \tag{7.1}$$

Where, $LODF(l,k)$ is the line outage distribution factor when monitoring line l after an outage on line k, ΔP_l is the change in MW flow on line l P_o^k is the original flow on the line k before the outage.

Once the LODF is computed and given the values of flow on lines l and k, the value of line flow on line l, after k is outaged is given by $P_o^l + LODF^{l,k} * P_o^k$. Being a linear factor, the LODF values can be pre-calculated and used for different line outage scenarios. The ILS algorithm can now be informed of expected tie line increases due to line outages and also be programmed to monitor additional lines, if the original tie line is lost.

7.2.2 Concerted ILS Scheme

The choice of how vast of an area is optimal for the proposed ILS Scheme is a tricky question. While the answer to the question depends on practical limitations like maximum allowable communication delays, regulatory framework, etc., we can briefly discuss the possibilities without considering these constraints. The author hypothesizes that if the area being monitored is a smaller and more tightly connected, the tie line measurements are more reliable as an indication of the mismatch within that area. Also it helps us to localize the effect of a mismatch better, by shedding loads in the vicinity of the event. This can be illustrated with example of California network. In the simulations, it was seen that any generation lost anywhere in the network is reflected heavily on the California-Oregon inter-tie, whose flows are best normalized by shedding loads within PGE. Thus, any loss in generation in any area with California would ostensibly lead to load shedding in PGE area. Although maintaining system integrity takes precedence over these considerations, the above result is not favorable. Also, if load shedding can be performed closer to the original location where the loss of generation occurred, it is possible that the amount of load required to be shed may be smaller.

In spite of all the advantages of selecting a smaller control area, a major drawback of such an approach is that the amount of load to be shed would be very limited. This could adversely affect the effectiveness of the scheme itself. In addition, the actual effect of loss of generation on a smaller area is more significant than the effect of loss of same amount of generation on a larger area, due to averaging effect. Thus, larger areas may require less frequency control actions by the ILS Scheme than smaller areas.

The above paradox can be solved using a two-level Concerted ILS Scheme where in each area in a group is monitored by a primary ILS Scheme through inter-area tie lines while the entire group is monitored by secondary ILS through tie lines that connect the group to the rest of the network. When there is a loss of generation, the primary ILS Scheme will be allowed to shed loads only if the secondary ILS algorithm considers the event to be a major disturbance. In addition, primary ILS schemes can be designed for major load centers or grid locations that are prone to disturbances in an effort to contain the propagation of the disturbance.

7.3 Improvements to Simulation & Testing

The proposed algorithm has been developed to make effective use of communications infrastructure that is expected to be in place with the advent of WAMPAC systems. During the development, it is implicitly assumed that the communication network does not pose any hindrance to measurements and actions of the ILS Scheme. While this assumption is acceptable at developing the concept of a WAMS-based ILS, it is necessary that the ILS scheme is tested on a co-simulation platform, where the power and communication network simulations are performed simultaneously.

Reference [25] proposes a new event-driven co-simulation platform that combines a power system simulator, PSLF and a network simulator, NS2, to perform co-simulations. The article also discusses the various features of other co-simulation suites that are currently used. Such co-simulations help us study the interaction between the two networks. Co-simulation tools help us understand two important aspects of these interactions.

The first aspect is that the constraints imposed by the communication network have to be taken into account while developing a new scheme. This would impose some limitations on the design of the scheme and also affect the effectiveness of the outcome. One such example is the discussion on a Concerted ILS Scheme in section 7.2.2. The geographical expanse for the primary ILS scheme will be limited by the maximum allowed communication delays and the available bandwidth. Similarly, the location and number of real time inputs and load shedding points available for the ILS Scheme will be dependent on the communication network also. Since the ILS Scheme is a real-time algorithm that acts on the time scale of a few tens of seconds, the communication delays will be a major factor in determining the effectiveness of the scheme. Reference [26] provides a general estimate of the maximum time delays that can be allowed for such a scheme.

The second aspect is the reliability and robustness of the whole scheme. Since a system is only as strong as the weakest link, it is necessary that the ILS scheme incorporate measures for ensuring a robust performance. This is possible only if the underlying inter-dependencies between the two networks are understood. Thus ILS Scheme would further benefit from being tested on a co-simulation platform and including the identified constraints into the design and implementation of the scheme.

7.4 Summary

The main objective of the project is to use the WAMS to overcome some of the drawbacks of the existing control schemes, especially in the event of a large disturbance. The need for such a scheme has been discusses in Chapter 2. Chapter 3 discusses the development and validation of a new large-scale model of the WECC system that was used to develop the proposed scheme. Chapter 4 discusses the various functional modules of the scheme with detailed flowcharts to explain the operation of each module. Chapter 5 discusses the system studies that were performed on the newly developed model. The ILS algorithm was developed and implemented based on the results obtained from the various studies. Chapter 6 discusses testing of the ILS Scheme with various case studies. A summary of the test results have been presented at the end. Chapter 7 discusses some ideas that can be worked upon to improve the proposed scheme.

7.5 Conclusion

The main objective of the proposed algorithm is to revisit the existing load frequency control schemes and adapt these schemes to make the best use of the WAMPAC systems. From the simulation case studies, it has been shown that the proposed algorithm is capable of using wide area measurements to detect and estimate the presence of a disturbance. Its control actions have been effective in stemming a decline in frequency. In the case study involving largest event, it has been shown that the ILS Scheme is capable of directly preventing a cascading outage.

By virtue of its design, the ILS Scheme has some very desirable load shedding characteristics that are inherent. The ILS Scheme is adaptive, since the load shedding calculations are performed only after the detection of an event. The ILS Scheme decides on the amount of load that is to be shed only after determining the size of the event from the surge in tie flows. The location of the load is also dependent on the location of the actual event. Thus, the location and amount of load to be shed, along with the fraction of load to be shed in each bus within an area, are all computed dynamically. In addition to determining location of the load, other criteria like voltage stability, load priority, etc. can be used to make the shedding very selective.

The centerpiece of the ILS design is that it is a preventative scheme that anticipates an imminent network collapse through reliable system measurements. Though the classic protection dilemma of dependability versus security still exists, the ILS Scheme through the Arming Matrix provides some flexibility with biasing the algorithm towards either setting. Without taking into account any communication network constraints, the ILS Scheme has been proven that it is scalable. The simulation results presented herein were obtained from testing the algorithm on a large-scale practical network. In the present configuration, the ILS Scheme has been programmed to monitor a little over one-fourth of the entire WECC network. The algorithm can be scaled up and down to fit any network, so long as the control area requirements are satisfied. The proposed algorithm is also independent of the actual network in that it monitors only the power flows on major tie lines and operating statuses of critical components for initiating the control actions. This is especially important since a large disturbance causes significant changes to the nature of the network and any intelligent load shedding scheme should be robust enough to perform effectively through these events.

The nature of the grid has been continuously evolving ever since the first electrical network was established. This is quite visible not only from the type and characteristics of loads and generation systems that are connected, but also from the complexity of network problems that power systems engineers have been trying to battle. WAMPAC systems have gained the attention of our community as one of the most potent tools at our disposal to carry forward the vision of a smarter grid. The author, through this research work hopes to reiterate the possibility of WAMPAC systems as a viable tool for redesigning the existing schemes and to help us tackle the current problems and also prepare us to face future challenges.

7.6 Main Contribution

The main contribution of the research work is to propose an effective tool for maintaining system integrity in the event of large disturbances, by combining features of slower-acting generation controls and faster-acting load curtailment procedures. The objective of frequency stability is achieved by using reliable measurements like real-time tie line flows and operating status of equipment, instead of frequency measurements which have been shown to be unreliable.

In addition, the procedure for creating and validating the load flow and dynamics of a compound model has been presented. Depending on the objective, this can greatly simplify power system analysis on large networks, by eliminating large parts of the network without compromising network functionality. For instance, the 15000-bus WECC network was reduced to 4100-bus system without losing the system dynamics of the removed network.

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