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ISLANDING TECHNIQUE IN ELECTRICAL POWER SYSTEMS TO AVOID CASCADING FAILURE

by

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ABSTRACT

In order to increase the reliability of the power system and to make use of trapped generation potential from renewable sources due to lack of transmission availability, the interconnection of modern day power systems is increasing day by day. Lack of timely response to the ramping load and high degree of interconnection can lead to cascading failures. Upon inception, these can spread through the system within seconds and may result in a total system blackout.

Natural calamities and erroneous operations of components are often the causes of system disturbances. The type and the location of these disturbances determine it's impact on the system. Cascading failures spread through the system rapidly and pose a serious threat to system stability. Recent examples of such disturbances are the major blackouts that occurred in India on 30th and 31st July 2012. A loss of load of several thousands of megawatts was observed.

Blackouts not only result in inconvenience to the residential customers but also cause a heavy monetary loss to the industry and to the nation as a whole. Depending upon the current system conditions, generation rescheduling or load shedding can be employed to combat system disturbances. System islanding is usually the last resort if none of the above produces desired results.

The aim of this thesis to develop a program for identification of line outages that can initiate a cascading failure in the system. Development of generation rescheduling and load shedding algorithms to curb overloads in these lines. It also includes development and implementation of islanding procedure on a IEEE 118 Bus system, if the generation rescheduling and load shedding does not work. The system will be split into 3 independent stable islands as a preventive measure to avert the cascading failures.

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I take pleasure in thanking my parents for always being my support. This work is a result of the constant inspiration I have received from them. I will strive hard to follow their teachings in my future life. God almighty has always been there to guide me in taking the correct decisions in life from time to time.

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1 INTRODUCTION

1.1 POWER SYSTEM OPERATION AND BLACKOUTS

Starting from the load forecasting, the process of power system operation, goes through a lot of technical, economical and security related analyses before the power is ready to be delivered it's consumers. In essence, a successful operation of a power system means meeting many more constraints than just the generation and load balance. This requires tremendous data to be monitored by the Load Balancing Authorities(LBAs) and the power system operators. All the generated data is then checked for its correctness and this process is called as the state estimation. The collected reliable data is then fed to heavy computer programs for analyses. These programs run the security constrained unit commitment and unit dispatch algorithms to obtain generation schedules of the generating units and other settings.

Owing to enormous size of the system and its vulnerability to the disturbances due to component outages, the above said process may have to be repeated after every five minutes to take into consideration the changes in the system, round the year. The equipment in power systems are protected by protection devices. In the event of deviation from normalcy in operating conditions, these devices trip open the transmission lines/transformers/generators to avoid permanent damage to the costly equipment. It is essential to know the state of the system for; there can be certain instances where outage of one line can lead another outage and the chain so continues. This is called as *cascading failure* and is the nightmare of every power system operator as this propagates through the system in a matter of seconds and can cause a complete system blackout.

A power system blackout can be thought of as a situation when loads of thousands of megawatts is disconnected from the generators supplying power in a specific wide spread area. The blackout situation does not arise all of a sudden but is a result of series of events. The power system transits from normal operating condition to critical condition and then to emergency condition before entering into a state of total blackout.

If corrective actions are not taken well within time, then undesirable results are inevitable. The one major problem encountered while dealing with today's highly interconnected power systems is it's size. Thousands of kilometers of transmission lines, several thousand buses and the protecting devices associated with it generate a lot of data to be analyzed every second in order to ensure proper functioning of the power system. The power system operation also has critical economic aspects related to it. After initiation, if not arrested soon, cascading failures can lead to a total blackout situation. A total blackout of the system results in distress to the residential customers and a hefty monetary loss to the industry. Thus, it becomes extremely essential to identify such events which can initiate a cascade failure and try avoid landing up in such a situation or have some procedure ready to avoid total system blackout.

1.2 PROBLEM STATEMENT

The problem statement for this thesis can be stated as follows -
Given the system with its topological, technical and operating details, if there is a disturbance event that can result into a cascading failure in the system, what preventive measures can be taken to prevent the system from a complete blackout?

This problem can be addressed by a couple of methods or a combination of them. It should be noted that the method employed in a given situation, depends upon the current state of the system, system topology and the location of disturbance. Different lines are connected to different types of buses, for example generation bus or a load bus. Moreover, changing system operating parameters for mitigation of one problem can result into another problem because of the interconnections. Thus, all the solutions should be checked for complete accuracy before employed. Usually this is done using computer simulations.

1.3 MOTIVATION

The motivation for working on this problem were the recent major blackouts that happened in India in the month of July 2012. The country is mainly divided into four grids by virtue of its geography. In two blackouts that occurred on two consecutive days left one or more grids in the dark state for hours.

This happened on a hot day of summer and looked like a result of lack of planning and action from the utility side. However, there are more aspects to it and if any of such disasters are to be avoided in the future, a detailed analysis of the sequence of events and the causes of failure have to be carefully analyzed. This will not only increase our understanding about the large system behavior in the event of such disturbances but will also help us in development of procedures to be followed to avoid them.

1.4 TOOLS USED

The main tool for this thesis is MATLAB. The function codes for contingency analyses, finding out the Bus-Branch Incidence Matrix, Overloaded Lines were all developed using MATLAB. The code for running a power flow and optimal power flow solution was taken from MATPOWER. This code was altered to suppress some of the results it printed to make the results concise.

1.5 THESIS LAYOUT

This thesis report is divided into 8 Sections. First Section explains the basics of the power system operation and the problem statement. Second Section is dedicated to a report on the blackouts in India. The third Section introduces cascading failures and related aspects.

Fourth Section talks about the system security analysis and different methods of analysis including contingency analysis. Fifth Section explains the approach proposed to attack the problem statement. Sixth Section is about the concept of intentional islanding in power systems. The seventh Section enumerates the results and the analysis done. The last Section discusses the conclusions that are drawn from the thesis work.

2 REPORT ON BLACKOUTS IN INDIA

This report is based on report generated by the *Inquiry Committee formed for the Grid Disturbance in the Northern, Eastern and North-Eastern Grids in India* [1]. The complete transmission system in India is divided into four regional grids by virtue of geography. The four grids and their respective acronyms are shown in Table 2.1.

Table 2.1. Regional Grids and their acronyms

Grid Name	Acronym
Northern Regional Grid	NR
Western Regional Grid	WR
North-Eastern Regional Grid	NER
Southern Regional Grid	SR

2.1 BLACKOUT ON 30^{th} AUGUST 2012

The NR is connected to WR through a number of interconnections but it was observed that many of the interconnections were out of service due scheduled and forced outages at the time of disturbance. The 400(kV) Bina-Gwalior-Agra was the only main AC circuit remaining which connected NR to WR. The power withdrawal by the utilities in the NR was observed to be much more than scheduled, prior to the disturbance. Thus the flow of power from WR to NR region via Bina-Gwalior-Agra link increased which led to overloading of the tie-line (the line carried around 1450(MW) against the nominal capacity of 691(MW).

The regional load dispatch centers initiated load shedding to reduce the load on this line but the measures taken were inadequate. WR was also informed to reduce the generation to curb the power flow through this line but the response was not quick enough. The line soon tripped zone 3 protection. This happened due to load encroachment. Load encroachment is defined as the measured impedance, due to load, current and voltage, exceeding the impedance determined by the loadability of an impedance relay at a specific power factor [2]. With the increasing load, the current flow through the line increased and due to lack of reactive power compensation, the voltage profile of the line dropped. This condition was sensed by the distance relay as fault and it tripped the line. It should be noted that the real power flow on the line was not very high but high amount of reactive power flow resulted into high currents and low voltage at Bina end. The tripping of the line was confirmed to be due to load encroachment as no records of faults on the line were found. Figure 2.1 shows the four regional grids on the map of India along with the all major transmission lines and interconnections between various grids. Different colors are used to indicate different voltage levels.

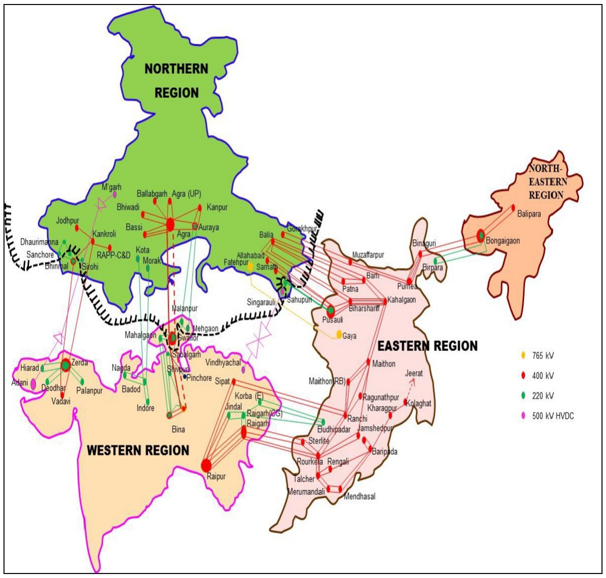

Figure 2.1. Indian grid and interconnections [1]

Before the disturbance, the NR was already 5686(MW) deficit of generation. Most of this power was supplied by the WR via tie lines. When the Bina-Gwalior-Agra line tripped due to load encroachment, the power was re-routed to NR through

ER. This path WR-ER-NR is much longer than the previous one. Re-routing resulted in large angular separation between group of machines in WR and NR.

This can be verified from a simple Power-Angle equation as follows.

$$P_{1,2} = \frac{|E_1| \times |E_2|}{X_{1,2}} \times \sin(\delta)$$

Where -

$P_{1,2}$ = Real power transferred from node 1 to node 2 in the circuit

$|E_1|$ = Voltage at node 1

$|E_2|$ = Voltage at node 2

$X_{1,2}$ = Transfer reactance between nodes 1 and 2

δ = Angular separation between node 1 and 2

The two nodes here, can be thought of as the point of exit in WR and the point of entry in NR for the power flow. Re-routing increased the transfer reactance between these two points due to additional reactance from the lines in the ER. The bus voltages are usually maintained within a range of +/- 5% of the nominal value. Also, 'sin' in an increasing function. So, if we are to transfer the same amount of power between two points with increased transfer reactance (or impedance) between the two, the value of δ has to go up. Which means that the rotors of the NR machines further fall behind the rotors in the WR machines. This can result into another phenomenon called as power swings.

Most of the installed relays were distance relays (ex. Impedance relays) and thus could not differentiate between a power swing and a fault condition and so tripped on power swings. At this stage the NR was totally isolated from other grids. As previously stated, NR was generating around 5686(MW) less than it's demand. So the frequency dropped and the system went into blackout due to operation of under frequency relays.

It is obvious that this loss of load rendered ER and WR regions with a surplus generation and the frequency in these regions shot up. This also caused a few of the WR generating units to shut down. Thus the connections between the WR and ER were saved from being overloaded all the regions but NR survived from the blackout condition.

2.2 BLACKOUT ON 31^{st} AUGUST 2012

This was a more severe incident and the grid disturbance disconnected the WR from ER, NER and the NR. The three regions finally collapsed and went into state of black out. Before the disturbance, the ER and WR had surplus generation whereas the NER and NR were importing powers from other regions. Many interconnecting lines were out of service for different reasons and the system was operating in an insecure condition at the frequency 49.84 Hz prior to disturbance. With the ramping load in the NR, the system was pushed further into insecure condition and the load dispatch centers were told to start shedding load. In addition to this, the WR was also asked to reduce the generation to reduce the power injection into the interconnecting lines.

The NR was connected to the WR via majorly 3 AC tie-lines but soon all of them tripped one by one. It can be predicted that the first line tripped due to load encroachment, same as on the previous day. The others tripped due to overloading, which was a cascading effect. As done on the previous day, the power to the NR from WR was rerouted via ER. But again this caused power swings. This time, the electrical center of the power swing was inside the ER and nearer to the WR-ER interface. So the situation was slightly different from that on 30th Aug.

As a consequence of the power swing, the tie-lines between WR and the ER tripped. This resulted into separation of NR+NER+ER from the WR at about 13:00 hrs. Thus the supply of about 3000(MW) from the WR was cut off and the frequency in the NR+NER+ER (new grid) started dropping. The grid has Automatic Under Frequency Load Shedding Schemes and df/dt relays. These two could together shed a total load of around 5620(MW). But the load relief was not enough and the frequency continued to drop. Eventually due to tripping of some generating unit because of under frequency relay, large angular oscillations were generated in the rest of the system and a large number of lines tripped within the new grid. At first the NR separated from ER+NER and then collapsed due to under frequency. Later the NER+ER system also collapsed leaving a few islands empowered.

2.3 CAUSES AND REMEDIES

There are a number of factors that initiated the disturbance and eventually led to a major black out. Below are the causes and remedies, which, if would have been observed earlier, could have saved this incident.

- Overloading and lack of reactive power compensation resulted in tripping of transmission lines. Adequate reactive power compensation may have avoided the load encroachment and the subsequent line tripping.
- The generating units were not on governor control due to other practical reasons. If the generating units would have been on the governor control, their generation would have increased with the dropping frequency and the chances of survival of individual regions would have been better. Lack of governor response also barred the formation of electrical islands, which could have been the ultimate resort and could have accelerated the restoring action.
- All the generating units are equipped with Power System Stabilizers which pro-

tect the power system from various destabilizing conditions. But they were not tuned or calibrated properly and hence could not function well. These need to be tuned and calibrated to account for the changes in the grid interconnections.

- It was observed that the load relief that should have been achieved due to operation of under frequency relays and df/dt relays, was not achieved. The NR has (Under Frequency Relays) UFR based load shedding of around 3000(MW) and df/ft based shedding of around 6000(MW). If these schemes had operated at the desired point of time, the collapse of NR could have been avoided. So there is a need to give this aspect a bit more of attention and make sure that these schemes operate in the correct manner henceforth. There is a strong need to strengthen the inter-state transmission network.
- Lack of ample inter-state connections limits the power transfer capacity between the states and also leads to voltage profile drops at the tail ends of the line. The same this happened on both the days and this condition was sensed as a fault by the distance relays.
- There is a need to provide better tools for the state estimation of the system periodically. Currently the system administrators use the static state estimation results to carry out the dispatch.
- There is a need of tools that can estimate the state of the system dynamically and at a faster rate. This will enable the operators to know the actual power flows on different lines. This data can be used to determine whether a particular relay on a particular line will trip or not.

  If at all the operators are provided with the data closest to the real data, they can either

  1. Initiate load shedding to obtain load relief

2. Reschedule the generating units in order to decrease the loading on specific overloaded lines
3. Can make efficient use of the HVDC links within the network Thyristor Controlled Compensation Schemes to provide more reactive power compensation
4. If none of that helps, breakdown the system into small independent subsystems, called as *islands*.

3 CASCADING FAILURES

3.1 THE CONCEPT

A cascading failure is a condition of interconnected systems when the failure of one part or component can lead to a failure in related areas of the system that propagates itself to the point of an overall systems failure [3]. On a hot summer day, the load profile is usually high due to excessive power used by the air-conditioning units. Ramping up the load beyond certain limit can cause overloading of lines in the transmission network. The lines and transformers are protected by protective devices such as relays and circuit breakers. Various devices monitor the current or power flows through the lines and voltages at the sending and receiving ends of the transmission lines. The transmission lines can be tripped open if the flows through the lines exceed their permissible limits or if the relays detect a fault in the line or if the voltage at the receiving or sending end violates its limits. In any of these cases the lines are tripped open in order to avoid damage to the equipment and to maintain the stability of the power system.

Usually the system is designed to be $(N-1)$ secured. Meaning that, loss of any one of the lines/transformer/generator in the system will not result into instability of the system. However, there can exist certain critical lines in the system, which when tripped open, can overload other lines sharing a common bus. The other overloaded lines are then tripped open by their respective protective equipment and this cycle goes on. This is called a cascading failure. A cascading failure, once initiated, usually spreads though the system within seconds and can result into severe load and generation imbalance. This in turn results in a total system failure.

Thus, closely monitoring such critical lines and taking safety measures before any constraint violation becomes essential to avoid cascading failure. Taking the corrective action well within the time is another critical issue. All the power carrying components have steady state and emergency ratings. The emergency rating has two components. First one is the maximum amount of power that it can carry and the second component it the time for which it can carry this amount of power before sustaining a failure. Hence, taking the corrective actions well within the stipulated time frame is of prime importance.

3.2 CAUSES

Invariably, the result of an uncontrolled cascading failure is either a total blackout condition or formation of an island which is cut off from the rest of the system. This process, is usually complex and a result of a series of events. Some of these individual events may have the same cause while the other might have a different one. For example, one transmission line may get tripped because of overloading. When this line is taken out of service, the power flowing through it is taken up by the adjacent lines. The increase in their flows may result in a lower voltage at the end of the line and then it will trip on operation of the undervoltage relay.

The relays in the system may not be able to differentiate between a power swing and a fault and trip open the line. Thus there can be numerous causes which result into a cascading failure of the transmission lines in the power systems. Load-Generation mismatch and its result being either sag or swell in the system frequency, faults, load encroachment large power swings, forced outages because of natural calamities,reactive power problems are some of the reasons which can be attributed to the initiation of a cascading failure in the power system.

3.3 EFFECTS

The consumers of the power can be broadly divided into two categories - residential and industrial. Households and big apartment complexes constitute to the residential loads while everything from manufacturing factories to hospitals and airports make up for industrial customers. With no power supply, the manufacturing in the industries come to a standstill resulting in wastage of man hours and loss to the industry. The other services that rely on power supply from utilities such as communication towers, water pumping stations are also affected by long lasting power cuts.

In a country like India, where in most parts, weather does not take life threatening form, 12 hour long power cuts will not cause lives. But countries facing severe weather conditions, a loss of power for 12 hours, especially in the months of chilling winters, can pose a serious threat to human lives.

3.4 NERC DIRECTIVES

The North American Reliability Council has laid out directives and standard procedures that may be followed should an operator observe an event of cascading failure in the system. The operators are also given certain rights which they should exercise in order to put the system back into secured condition. The directives have been in place for a long but were not mandatory until the year 2005. Energy Policy Act of 2005 made these practices and standards mandatory for the system operators. This decision was mainly influenced by the blackouts experienced by United States in 2003[3].

The operating standards for the system operators and load balancing authorities, are given in the *Transmission Operations* while the emergency procedures to be followed are stated in *Emergency Preparedness and Operations.* The operators or the load balancing authorities are expected to take steps according to the current operating procedure of the power system. The Transmission Planning (TPL) directives have categorized the operating range of the system into four categories A,B, C and D. Table 3.1 gives a brief description of the operating system categories as laid out by NERC.

Table 3.1. Description of NERC defined system operating categories

CATEGORY	**DESCRIPTION**
A	Normal system operation with non contingencies
B	Single contingency
C	Two or more contingencies
D	Two or more contingencies or cascading out of service

The power systems should be operated (or modeled) in such a way that the most severe single contingency should not induce sustained instability or cascading outages or uncontrolled separation into the power system. The other directive says that, if the system operator or the load balancing authority is generation deficient, and in spite of taking all other possible measures, is not able overcome the load-generation mismatch, then it (Operator / LBA) has the right to shed customer load rather than putting the system into a risk of uncontrolled failures.

The most common contingencies observed in the power systems are loss of a transmission line/transformer or loss of a generator. The system may lose a line or a generator on account of the operation of protective devices installed for equipment protection from damage. The protective relays may or may not operate due to actual occurrence of fault on the line/machine. For example, high load levels (and lack of reactive power compensation) may result in dip in the end voltages of the transmission line and a distance relay may see it as a fault on the line. This is what happened as one of the events in India and is called as load encroachment.

The most severe contingency case can be the most heavily loaded line in the system or the generating unit with highest generation levels. The directives then say that, even if we lose any one of these, the system should have adequate resources to make up for the loss of transmission/generation capability. In case of loss of most heavily loaded transmission line, the other lines, when take up the power from the lost line, should not get overloaded themselves otherwise it will lead to cascade failure. While, in case of loss of the generator with highest generation levels, the other generators, taking up the lost generation should have adequate spinning reserves.

They ratio in which different 'in-service' lines take up the lost power from outaged line depends upon the Line Outage Distribution Factors (LODF). Similar happens in the case of a generator contingency and the ratio in which other generators take up the lost generation depends upon the Generation Shift Factor(GSF), provided their generation levels are not pegged.

There are many constraints under which the power systems operate. It's operation should make sure that all the electrical as well as the economic constraints are met. The 'must-run' status generators are always committed preferentially to the load, after that come the most economical ones. So, the generation levels of the generators in the system are set in a way that ensures lowest value of the cost function. If, due to occurrence of some failure the system security is at stake, then the generation levels may be rescheduled so that any possibility of a cascade failure is avoided. Even after this, if the LBA is not in a position to get the system back in the secured condition, then the LBAs can shed load so as to avoid the mismatch between the generation and load levels. Thus, it is clear that the system security is given the utmost importance. The simple reason behind this is, if it enters in a blackout state, then anyways the customers will face discontinuity in the power. Also, starting the system back up from a blackout state is a very difficult task. The massive nuclear plants and thermal plants have their minimum-up time and minimum-down time constraints. The thermal power plants also have their Boiler Light Up times (BLUs). All these need to be taken into consideration while restoring the system back in service and is a tedious and time taking task.

4 SYSTEM SECURITY ANALYSIS

All the large scale power systems are employ Energy Management System(EMS) to monitor and control the operations of the power system. The power system operator, with the help of EMS, then takes corrective actions to drive the system into a safer zone, if needed. IN order, to ensure economic, safe and reliable operation of the power system, it has to go through a lot of processes. The different steps in system security analysis are described as follows.

4.1 STATE ESTIMATION

The process of system security analysis starts with collection of different data from all the substations within the system. Due to a large amount of data being transmitted over long distances, it invariably has errors to certain extent. Since so many parameters are measured at numerous substations, it may result in over estimation of the parameters. Thus usually all the readings are assigned a weightage based upon the correctness and accuracy of the monitoring devices measuring them. All this data is then collected and transmitted to the control room where it is displayed on the operator's screen for monitoring. The different values that are usually monitored are voltages, power flows, currents, status of the circuit breakers at the substation level. In addition to this, other critical values like system frequency, generation unit output levels can also be monitored.

With the help of the SCADA system, the system operator can give commands to change the taps of the transformers installed at remote locations to maintain voltage profile in a certain region. It is difficult for humans to analyze such huge amount of data, so computers are employed which can generate an alarm should it see a system constraint violation. The collected data can then also be fed to advanced computer programs which can analyze it to determine the probable threats to the system security.

4.2 ANALYSES METHODS

There are a number of different analysis tools used to analyze the security of the power system. The methods differ in the time-frame they take into consideration for analysis or analyze different aspects of the system. For example some methods just monitor the transient phenomenon of the system compared to other methods which do a steady state system analysis. All these methods generate different reports which can be used by the operators to take appropriate actions. Some of the security analyses techniques are discussed in this thesis report.

4.2.1 Transient Security Assessment. The transient security assessment is done to observe the transient behavior of the system. Thus the time frame of this study is usually of the order of few milliseconds upto a second. They usually monitor the power swings taking place in the systems or the transient oscillations (hunting) phenomenon exhibited by the generator rotors in case of a sudden change (usually loss) in the load.

4.2.2 Voltage Security Assessment. This method usually employs regular power flow programs to solve for steady state voltage levels in the system. Typically it may use Newton-Raphson power flow solution method. It should be noted the aim of this study is to calculate the P-Q and P-V curves and thus they can not employ a simpler and faster DC power flow method.

4.2.3 Available Transfer Capacity Analysis. This analysis is primarily performed to calculate the total power transfer capacity of the system between two given points. This system takes into consideration all the limits and constraints developed as a result of previous analysis methods.

4.2.4 Contingency Analysis.

Owing to the enormous size of the systems and the complex interconnection, everything from detection, analysis to preventive action initiation becomes a complex and lengthy process. After studying the blackouts in India, we now know that after initiation, the cascading failures spread through the system within a fraction of a second before any human can take action. This makes it extremely essential to study the probable cases which can initiate a cascading outage in the system and operate the system in a preventive manner so that the initiation can be avoided.

Contingency Analysis is a process that is used to imitate these problems on a computer model of the power system and then study its effects so that we can operate better and avoid landing into the trouble of cascading failure. For example, the system model can be used to study the outage of a line between buses A and B. The program pulls the line between buses A and B out of service deliberately so that the after effects can be studied. If it is observed that outage of this line can initiate a cascading failure, then preventive measures can be taken in advance to avoid its outage.

The core idea of contingency analysis has been explained above and also it's purpose. If the operator intends to consider the bus voltages and the reactive power flows, he may opt for a full Newton-Raphson solution otherwise a simple DC power flow solution can be attempted. It should be understood that a typical large scale power system may have tens of thousands of buses and tens of thousands of transmission lines. Solving a full AC power flow solution can demand for extended time and higher computational power than a DC decoupled power flow solution.

Before a list of all possible contingencies that can initiate a cascading failure in the system can be obtained, it becomes mandatory to remove each component in the system one at a time, run a power flow solution and then analyze the results for constraint violations. If a single component is taken out of service from and the system is solved for a power flow solution then it is called as $(N-1)$ contingency solution. Similarly taking out two components will mean it is a $(N-2)$ contingency. The size of the problem explodes with every additional component taken out of the system because of the combinations. Comprehensive computer programs can be written to do this work.

4.3 SECURITY CONSTRAINED OPTIMAL POWER FLOW

The purpose of performing optimal power flow on a system is to meet the load demand at the lowest possible cost. While the minimization constraint can also be something else than the cost, mostly the optimal power flow solution is solved for cost function minimization. The security constrained optimal power flow can be thought of a combination of optimal power flow and contingency analysis. The incorporation of the security constraint can result in different generation schedules, transformer tap settings, than a normal optimal power flow without security constraints. This all is done with an aim that whenever a contingency occurs, it should not result into violations of the system constraints.

Allen J. Wood, in this book,'Power Generation Operation and Control' divides the process of security constrained power flow into four parts. The power system under consideration is first modeled in a computer program. These steps are executed one by one to reach to the ultimate solution of security constrained optimal power flow.

4.3.1 Optimal Dispatch. This corresponds to a state of the power system where an optimum solution for the system has been obtained and the system is working as per it. However, this does not mean that the system is in the most secured state.

4.3.2 Post Contingency. This is considered to be the state of the power system where a contingency has occurred (say forced outage of a transmission line/transformer due to overload) and this results in violation of one or many of the system constraints (say overloading of another line in service).

4.3.3 Secure Dispatch.A state of the system no contingency has taken place but the system is operating with corrected state so that, even if the same contingency does happen, no constraints will be violated

4.3.4 Secure Post-Contingency Dispatch. After getting the system to work with the corrections applied, again the same contingency is applied on the system. But this time the system is observed to work within the limits and no violations are observed.

5 PROPOSED APPROACH

The initial problem statement said that, we are given model of a large scale power system with all it's technical and working conditions details. Now, the system operating condition changes in such a way that a disturbance that can initiate cascading failures is likely to occur. What should be the system operator's response in such a case? Starting with the identification of the possible contingencies that can induce cascading failures in the system, we will work our way through the problem in this Section to obtain a final solution.

5.1 SELECTION OF CRITICAL CONTINGENCIES

Before proceeding any further with the problem, it is made clear at this point that, in order to avoid extreme complexity in the problem, we will only be considering disturbances that either involve a transmission line or a transformer outage. This means that generator contingencies are not considered in this problem.

In order to study the effect of the cascading failures on the system, firstly, it is very important to identify the cases which can initiate such kind of disturbances. With a system composed of thousands of transmission lines, transformers and generators. analyzing the system in real time for critical contingencies can take too much of time and before we identify a potential threat and try to apply the remedial measures, the system may have already got under uncontrolled failures.

A power system can be modeled using a computer program. Any changes happening in the system, for example addition of a new transmission line, can be included in the program later as well. $(N-1)$ contingency algorithm is used in this thesis work to identify the lines which can initiate a cascading failure in the system. Figure 5.1 shows the process that has been used to identify the the lines which can initiate a cascading failure in the power system. For the purpose of discussion through this thesis work, these lines are referred to as 'critical contingencies'.

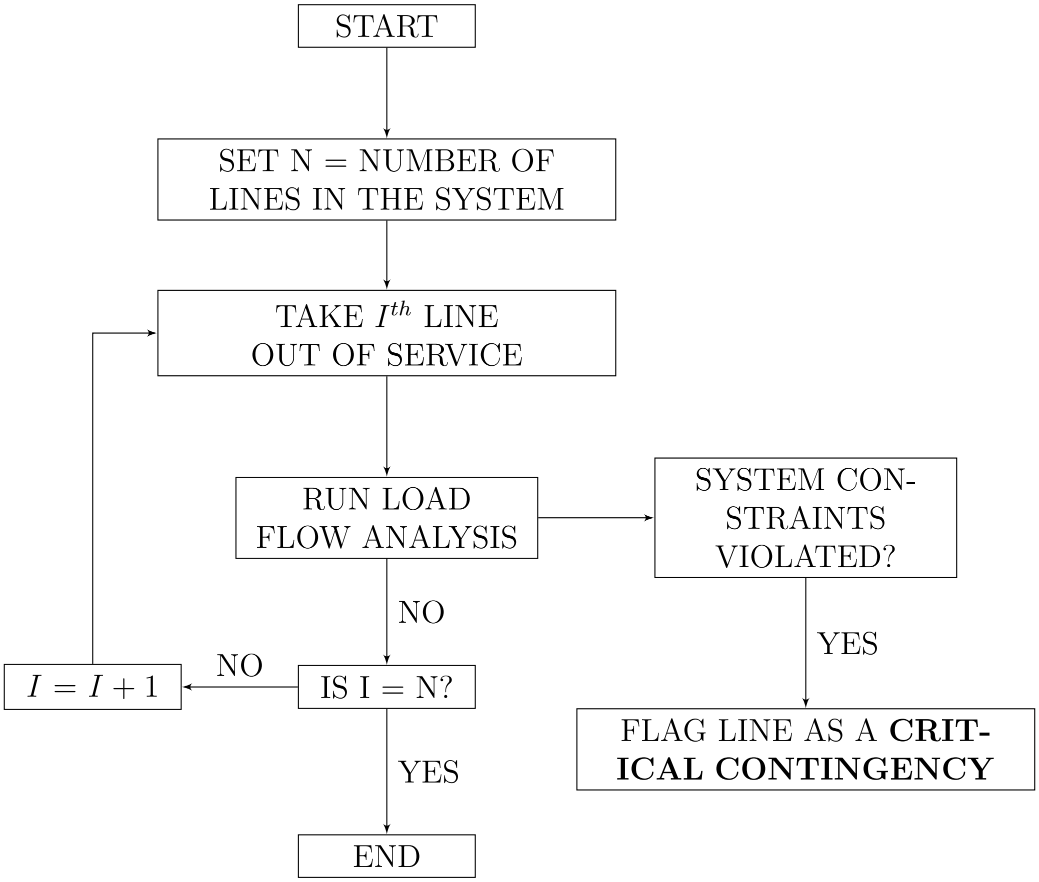

Figure 5.1. Contingency Analysis Flow-chart

5.2 REDUCING SIZE OF THE PROBLEM

All the analysis work has been done on a IEEE 118 BUS system which has 186 transmission lines in total. A real world power system may have thousands of buses and tens of thousands of transmission lines. Since we are not concerned about the generator contingencies, all those lines, which when switched opened for a $(N-1)$ contingency analysis, leave one or more generators isolated, should not be removed. Removing these lines will essentially result in two contingencies - one being the line itself and another being the generator isolated.

In order to reduce the time required to perform the $(N-1)$ contingency analysis, such lines are flagged ahead of time and are then excluded from being taken out of service during the contingency analysis. The program that identifies such lines takes just a few seconds to identify such lines. For the sake of discussion through this thesis, we will refer the set of such lines as 'critical lines'. The program analyzes the topology of the system and then flags the critical lines in the system. Table 5.1 gives the number of critical lines identified in a system against the total number of lines in the system and also the time required to run the code.

Table 5.1. Time taken to flag critical lines

Test Case	No. of lines	No. of critical lines found	Time Elapsed(s)	Time per PF solution(s)
ieee_30	41	3	0.03	0.05
case39	46	10	0.01	0.02
case57	80	2	0	0.01
case118	186	9	0.01	0.02
case2383qp	2896	574	3.78	0.22
case2737sop	3506	336	5.37	0.24

If, in the process of taking out lines one by one, such a 'critical branch' is taken out of service, then the power flow solution does not converge but still it takes its time. So, flagging these lines ahead of time saves a lot of time and computational effort. It can be easily pointed out from the figures in the table that as the system size increases, it becomes more and more advantageous to flag the critical lines before running the contingency analysis to save time.

5.3 PERFORMANCE INDEX

As said earlier, a large scale power system may have tens of thousands of transmission lines. So, even if the generator contingencies are neglected, there are several thousand power flow solutions to solve for each out of service line. However, mostly, the systems are so designed that only a few outages in the system can be a serious threat to the system security.

The load demand on the system changes with time and also with the days of week and seasons of the year. Thus the generation levels of of generating units in the system keep on changing so as to maintain the most economical operating conditions possible. In addition to this, some lines might be kept out of service for scheduled maintenance. This makes it mandatory to run a power flow every time for every contingency keeping incorporating the current generation schedules and the current system constraints. But this task is greatly simplified if we have a list of the 'critical contingencies' based upon their effect on the system if they are tripped open. In order to reduce the amount of data to be analyzed to make the computation process faster, a Performance Index(PI) is defined for all the transmission lines in the system as follows -

$$PI = \Sigma(\frac{S_{normalflow}}{S_{maxlimit}})^{2n}$$

The meaning of the performance index can be explained in the following manner. While running a contingency analysis, we take a line out of service and run the power flow solutions to obtain the apparent power flows through all the lines in the system. Now, for the every line in service we take the ratio of the actual apparent power flowing through it to the apparent power limit of the line, raise it's power to an even number (say 2) and add the ratios calculated for all the lines in service. Then this PI is defined for the line we initially took out of service. Moving ahead with our contingency analysis, take out another line from service. Again calculate the performance index for the line put out of service.

The reason for raising the power of the ratio to an even number is to give a higher weightage to the overloaded lines while calculating the PI. If the power is a number more than or equal to 2, then the overloaded lines will contribute towards the performance index more heavily than the lines with its flows under their limits.

5.3.1 Ordering PIs.

At the end of PI calculation process, what we have is a table with all the transmission lines listed and their respective performance indices marked against them. Upon arranging this table in the descending order of the performance indices, we essentially get a table that shows the effect of an outaged line on the system in the descending order. Meaning, the top line in the system,if outaged, will have maximum effect effect on the system, in terms of overloading of other lines in service.

Now, we have the freedom to select a specific number of lines from the top of the list of all the transmission lines in the power system. We will of course choose a desired number of lines from the top of the table because these lines are the ones which will leave a greater impact on the system if outaged. Note that the system operator can decide how many lines to select. The lower a line is in the table, the lesser impact it will leave on the system if outaged.

5.4 RELIEVING OVERLOAD

The system parameters of the IEEE 118 BUS system are then changed in such a manner that running a load flow analysis indicates that the flow in one of the critical contingency lines exceeds it's limit by 10%. MATPOWER loadflow program is used for this purpose. The program then uses three basic solution techniques in order to relieve the overload on the line. The three solutions are listed below in the order of their priority.

1. Generation Increase
2. Load Shedding
3. System Islanding

5.4.1 Generation Increase.

This is the first method that is used to relieve the overload on the overloaded line. This approach basically takes advantage of the spinning reserves that the system has at it's disposal. Spinning Reserve is the on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction by the ISO. Spinning Reserves are usually expressed as a percentage of the Operating Reserves. The ISO norms determine this percentage and it is 50% for CAISO and MISO [4][5]. The spinning reserves are made use of before resorting to load shedding.

However, employing this solution depends upon the system topography as well as the current system conditions. The direction of power flow in the overloaded line is determined before moving ahead with the procedure. Let us consider the a situation shown in Figure 5.2.

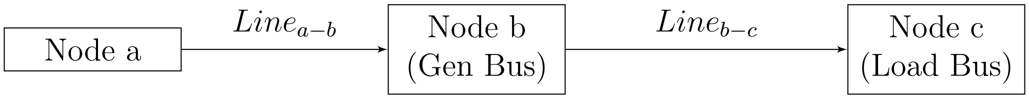

Figure 5.2. Example 1

Let us assume that $Line_{a-b}$ is a critical contingency which has power flow of 10% above its limit. The power flows from bus a to bus b. $Line_{b-c}$ is another line with its power flow well under its limits and carries power from bus b to bus c. Bus b is a generator bus and bus c is a load bus. The load at bus c is being fed partially by the generator at bus b and the rest power comes via bus a, flowing through $Line_{a-b}$.

If the generation at bus b is increased,it will result in lesser power flow through $Line_{a-b}$ and it's overload might be reduced. However, this is subject to the condition that generator at bus b is not already operating at its peak and has some spinning reserves available. Also, increasing generation at bus b will also result in more power flowing through $Line_{b-c}$. Thus care should be taken that we do not overload $Line_{b-c}$ in the process of relieving overload on line $Line_{a-b}$. The system may not then operate in the most economical condition possible, but initiation of cascading failure can be avoided.

5.4.2 Load Shedding.NERC directives say that in spite of taking all the possible remedial measures, if the system operator still sees a generation deficit, then he can shed consumer load instead of putting the system security at risk. However, there are more aspects to be considered before actually shedding any consumer load. The location and the amount of load that should be shed has to be determined. The obvious location can be the nearest load to the overloaded line.

The amount of load shed should just be enough to avoid the overloading of the line in consideration. To achieve this, we use an iterative process. If the line is overloaded by $X(MW)$, then $X(MW)$ of load is shed at first. The load flow is run again to check whether the overload still persists. If it does, then again load equal to the new overloading level is shed. This process is continued until the overload on the system vanishes.

5.4.3 Exceptions. The process of increasing the generation and shedding the load does not always work. Sometimes, the generation level at a particular bus may reach its limit before the overload is relieved. In another case, the load might have been fed partially through two lines with different impedances. Shedding the load in such a case results in reduction in power flow through the line which has lower impedance of the two. Thus the load shedding may not be enough to get rid of the overload. In such cases, the iterations may just go on and on and may never succeed.

The other exception can be that no such generation bus might be available for the generation to be increased or it might be operating at its limit. We may as well not have a load available to shed in the exact position explained above. In all such situations, we are left with no other alternative but to resort to islanding of the system. If such scenarios are detected, the program automatically moves over to the islanding procedure. The overloaded line is then opened along with several other lines in order to split the system into 3 independent islands.

6 ISLANDING

The state of islanding in a power system can be defined as A condition in which a part of the power system that have both load and generation resources remains energized while isolated of the rest of the power system [5].

Islanding or breaking up of a large power system into smaller mutually disjoint systems can either be intentional or unintentional. Many times, system disturbances cause lines in the power system to open this disconnecting a certain portion of the system from the rest. Such islands are called as natural islands and they are usually a result of system disturbances. The system then breaks up into two or many disconnected parts which may have generation as well as loads. If they are to sustain as small independent systems, the load-generation levels in all the islands should match. The islands will otherwise collapse. A good example of this can be the NR grid in India. During disturbances on both the days, the NR was disconnected from all the other grids. Since the NR was significantly generation deficit, the frequency in the NR went down and finally resulted in collapse of whole NR.

In such cases, splitting the system intentionally into islands which will be more stable seems to be a better option. Since this splitting is intentional, the probability of generation-load match is much better. If needed, the load in the individual islands can also be adjusted to match the generation levels thus ensuring the sustainability of the island. The process of intentional islanding can, thus, include opening up few lines in the power system and breaking it up into smaller disconnected parts.

6.1 ANT SEARCH MECHANISM

Different algorithms such as min-cut algorithm (which ensures system split up with minimum number of lines opened) or swarm algorithm have been used in the past for intentional islanding of the system.

In this thesis work, another approach known as the ant search mechanism is used[6]. Based upon the ends of the overloaded line, the system is split up intentionally into 3 independent islands. The ant search mechanism basically involves creation of one ant for each island to be formed. So, each of these ants start from a bus and move towards the other unoccupied buses in the system. On reaching another bus, the ants mark that bus as 'occupied' and move towards a different bus.

All the possible buses are connected together in such a manner. However, it is not possible to exhaust all the buses in the system using this procedure. So, the remaining buses are connected to the nearest 'occupied' buses. Since we intend to split the system into 3 islands, we start with three ants.

6.2 SELECTION OF ANTS

Let us say that the overloaded line is carrying power from bus a to bus b. The two ants are then selected in the following manner -

1. Ant 1 is bus a
2. Ant 2 is bus b

In a system with 118 buses, now we have a choice of choosing ant 3 from rest 116 buses. We start with setting bus 1 to be ant 3. The system is then split according to the algorithm discussed above. After all the three islands have been formed, a slack bus is assigned in each island. An optimal power flow analysis is then run for each of the islands and the results are scanned for any system constraint violations. If all the three islands are found to be stable after shedding some load, then the amount of load that had to be shed and the number of lines that had to be opened are recorded.

Then the ant 3 is changed to bus 2 of the system and the same procedure is repeated again. This cycle continues until all the 116 buses in the system are exhausted. Figure 6.1 shows the flow chart of this procedure.

6.3 POST ISLANDING PROCEDURES

Section 6.2 explained the algorithm for formation of the islands. After each island is created, the total generation and total loads in each island is calculated. If the island is generation deficit, then just enough load is shed to obtain generation - load balance. The total amount of load shed in all three buses is recorded. After balancing generation and load, an optimal power flow solution is run using MATPOWER. Results of the optimal power flow solution are checked for any constraint violation. Constraint violation may mean lower or higher bus voltage or higher power flows in the transmission lines.

6.3.1 Power Flow and Voltage Constraints. Since we are operating the system in an emergency situation, emergency power flow ratings of the transmission lines are followed. Several factors govern the power flow ratings of the transmission line but mostly the power flow capacity of a transmission line is determined by thermal constraints. Thus, transmission lines can have different emergency ratings for different times of year, summer or winter[7].

For the sake of simplicity, we assume that the emergency rating of all transmission lines in the system is 116% of the normal continuous rating, which is the average of summer and winter ratings. The bus voltages are maintained within 0.94(pu) to 1.06(pu).

If any of these constraints are violated, then the solution is discarded. If all the system parameters stay within the limits, then for that Ant3, the total load shed

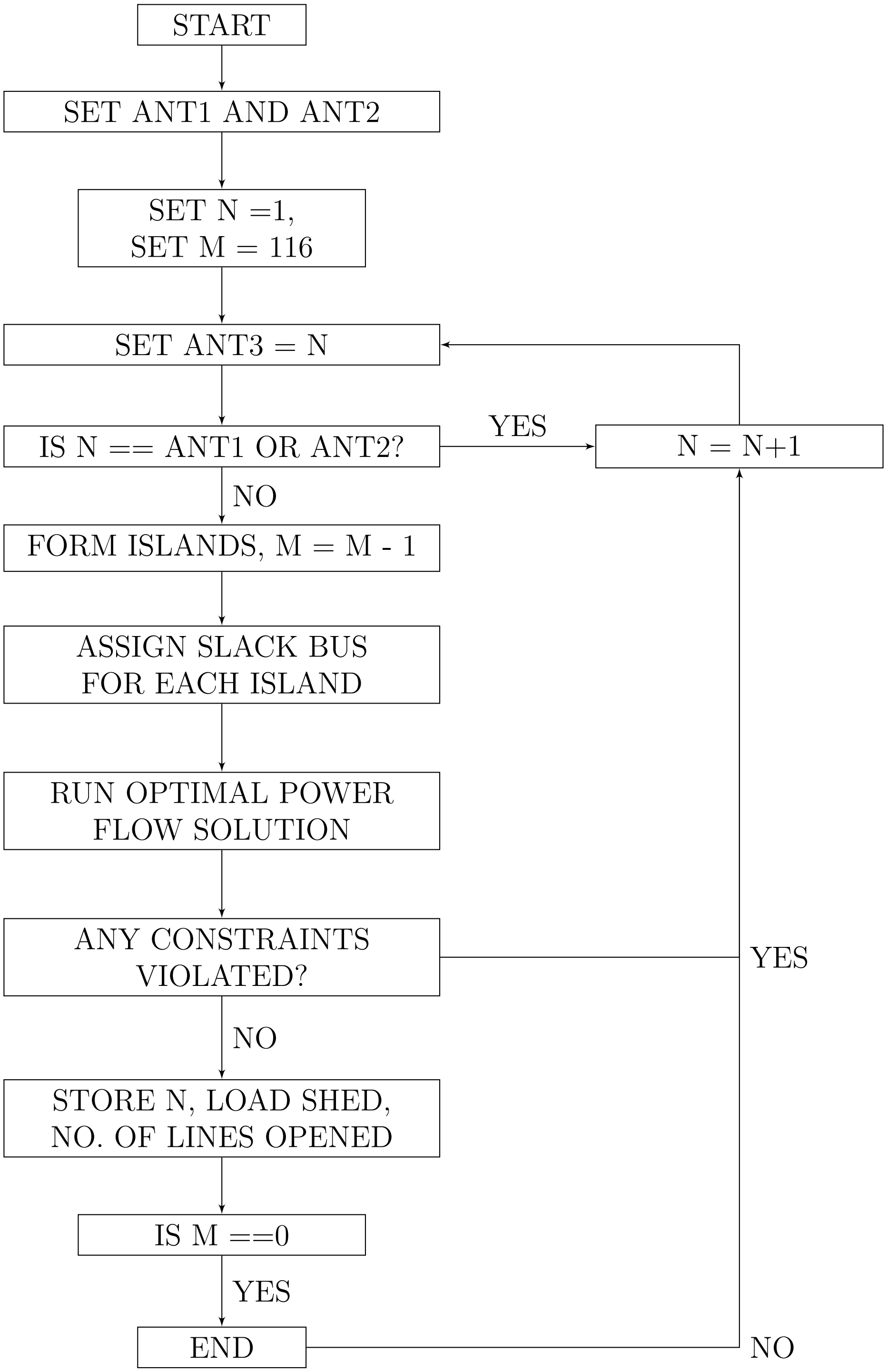

Figure 6.1. Island formation flow chart

and the total number of lines opened for the islands formation is recorded. After successful testing for stability of all the three island, if two of them are found to be considerably smaller in size then the third one, then depending upon the topology of the system, the two smaller islands can also be joined together. This will essentially split the system into two islands. This decision is taken if it results in still lower amount of load shed.

6.4 OPTIMAL SOLUTION

An optimal solution would be when the total load shed and the number of lines opened will be minimum. For this purpose, we define another index which will be called as 'Islanding Index' for the sake of discussion in this thesis work. The Islanding Index is defined as follows -

$$\text{Islading Index} = 0.15 \times \text{No. of lines opened} + 0.85 \times \text{Total load Shed}$$

Thus we weigh both the parameters differently to come up with a single Index. A graph is plotted using all such indices for each successful selection of Ant3. The scheme which gives the lowest value of Islanding Index is considered as the optimal solution. This step concludes the islanding procedure for a particular overloaded line.

7 ANALYSIS AND RESULTS

The system used for testing the program is IEEE 118 BUS system. The system has 186 transmission lines in total. Out of these, 10 lines are considered as critical contingencies in this thesis and a mitigation technique for overloading of all of them, one at a time, is attempted.

7.1 CRITICAL LINES

Firstly, the system topology is analyzed in order to identify the critical lines in the system. Since we are not considering any generator contingencies and only $(N - 1)$ contingency situations, identification of critical lines beforehand becomes advantageous. Critical lines are those line, which if opened, result in isolation of one or more generators from the rest of the system. Table 7.1 gives the list of critical lines in the IEEE 118 bus system.

Table 7.1. List of Critical Lines

Serial No.	From Bus	To Bus
1	10	9
2	73	71
3	87	86
4	111	110
5	112	110
6	116	68
7	117	12
8	9	8
9	86	85

7.2 CRITICAL CONTINGENCIES

Later, a $(N - 1)$ contingency analysis is performed on the system for each transmission line and transformer in the system. The results for each of them are analyzed. The contingencies which result in overloading of other transmission lines, thereby posing a risk of cascading failure, are identified. These lines are then arranged in decreasing order of their impact on the system. The impact is measured in terms of the overloading of other lines in service, then this line goes out of service. The impact is measured by Performance Index (PI). It should be noted that the program calculated Performance Indices for all the lines in the system. The operator has a choice to select a definite number of lines to be monitored out of all. Table 7.2 lists the top 10 critical contingencies.

Table 7.2. List of Critical Contingencies

Serial No.	From Bus	To Bus	PI	Direction
1	8	5	104.97	1
2	38	65	60.84	-1
3	26	30	60.43	1
4	38	37	58.18	1
5	30	17	54.85	1
6	64	65	54.48	-1
7	103	110	54.26	1
8	25	27	52.00	1
9	34	637	49.70	-1
10	100	103	48.24	1

In the table, PI stands for Performance Index and Direction shows the direction of power flow in the line. 1 means power flowing from 'From Bus' to 'To Bus' and -1 means opposite.

7.3 LINE OVERLOADS AND MITIGATION TECHNIQUES

Unanticipated increase in power demand or inaccurate load forecasting can lead to overloading of transmission lines in the system. Generation increase or load shedding are the two simple options before the system operators, in such a scenario. Out of the two, load shedding is always given the least preference. If, none of above two techniques are feasible, then, in order to keep the maintain system security, the operators may resort to system islanding.

After the initial analysis, we now try to imitate a situation of overloading one of the critical contingencies. For this purpose, first, the normal power flow in the line is determined. Then the line limit is set to 10% below the normal flow limit. This results in overloading the line by 10%. The data is then fed to the program and the results are discussed below.

7.3.1 Line 8-5.

Details of $Line_{8-5}$ and the mitigation solution are given below -

Normal Power Flow = 360.74(MVA)

Line Limit = 541(MVA)

New Limit Set = 327.94(MVA)

Overload = 32.8(MVA)

The power in $Line_{8-5}$ flows from bus 8 to bus 5. Bus 5 is connected to buses 3, 4, 6 and 11. Generators 4 and 6 are not generating upto their limits. Generation at bus 4 is 0(MW). Thus the generation at bus 4 is increased until the overload is relieved. This results in generation at bus 4 to go up to 55.01(MW).

Thus the overload on $Line_{8-5}$ is relieved by ramping up the generation at bus 4 from 0(MW) to 55.01(MW).

7.3.2 Line 26-30. Details of $Line_{26-30}$ and the mitigation solution are given below -

Normal Power Flow = 224.00(MVA)

Line Limit = 336.00(MVA)

New Limit Set = 203.6(MVA)

Overload = 20.40(MVA)

$Line_{26-30}$ carries power from bus 26 to bus 30. Bus 30 is also connected to bus 8 which is a generator bus. But if the generation level at bus 8 is increased, this does help in reducing the overload on $Line_{26-30}$ but at the same time, it starts overloading another lines. If the generation at bus 8 is increased, $Line_{8-30}$ and $Line_{65-68}$ have their flows exceeding their limits and thus this can not be a possible solution.

Bus 30 is also connected to buses 17 and 38. Bus 17 has a load which is less than the 'overload' value. Thus shedding that load will not relieve the overload. Bus 38 does not have any load at all. Thus in order to save initiation of cascading failures in the system, the system is broken into 3 islands. Islanding Factor for every choice of Ant3 is calculated. Figure 7.1 is a plot of Islanding Index against the choice of Ant3.

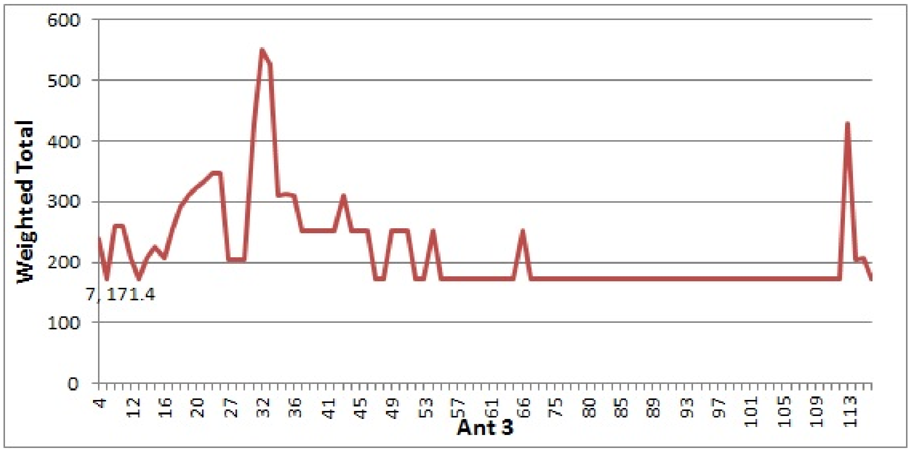

Figure 7.1. slanding Indices for $Line_{26-30}$

Another approach, in this case is tried, where the system is split up in just two lines. The results for both the split ups are given in Table 7.3.

Table 7.3. Islands comparison for $Line_{26-30}$

Item	3 Islands	2 Islands
Buses in Island1	108	110
Buses in Island2	8	8
Buses in Island3	2	–
No. of lines opened	9	8
Total Load Shed	212(MW)	212(MW)

It can be seen that the Total Load Shed does not change with the number of islands formed, in this case. However, one less line has to be opened in order to split the system into 2 islands rather than 3.

7.3.3 Line 38-65.

Details of $Line_{38-65}$ and the results of mitigation solution are given below -

Normal Power Flow = 189.76(MVA)

Line Limit = 285.23(MVA)

New Limit Set = 172.51(MVA)

Overload = 17.25(MVA)

$Line_{38-65}$ carries power from bus 65 to bus 38. Bus 38 is connected to buses 30 and 37. Both buses, 30 and 37, neither have any load or any generation. So, system islanding is initiated. Figure 7.2 shows the Islanding Indices for different Ant3 choices.

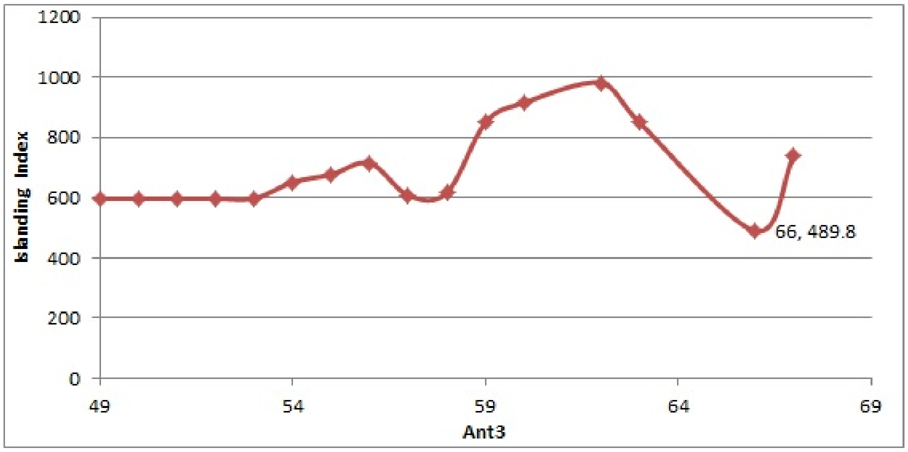

Figure 7.2. Islanding Indices for $Line_{38-65}$

It can be seen that if Ant3 is chosen to be bus 66, lowest value of the Islanding Index can be obtained. The details of the islanding scheme with Ant3 being bus 24 are given below -

No. of buses in Island 1 = 25

No. of buses in Island 2 = 59

No. of buses in Island 3 = 34

Total Load Shed = 572(MW)

No. of Lines Opened = 24

In this case, when the system is split up into two islands, both the islands formed are not stable. Meaning that, after running a optimal power flow solution, one or more system constraints are found violated. If such a split up is done, the lines in the individual buses soon trip open one by one and the islands will eventually collapse. Thus, splitting the system in 2 buses is not a feasible solution.

7.3.4 Line 38-37.

Details of $Line_{38-37}$ and the results of mitigation solution are given below -

Normal Power Flow = 268.98(MVA)

Line Limit = 402.32(MVA)

New Limit Set = 244.52(MVA)

Overload = 24.26(MVA)

In $Line_{38-37}$, power flows from bus 38 to bus 37. Bus 37 is also connected to bus 34, which is a generator bus. If the generation at bus 34 is increased, it may relieve overload on line $Line_{38-37}$. When the generation level at bus 34 is increased from 0(MW) to 53.67(MW), the overload on $Line_{38-37}$ is relieved.

7.3.5 Line 30-17.

Details of $Line_{30-17}$ and the results of mitigation solution are given below -

Normal Power Flow = 249.09(MVA)

Line Limit = 373.80(MVA)

New Limit Set = 226.44(MVA)

Overload = 22.65(MVA)

$Line_{30-17}$ carries power from bus 30 to bus 17. Bus 17 is in turn connected to buses 15 and 18. Bus 15 is a generator bus. So, an attempt is made to relieve the overload on $Line_{30-17}$ by increasing the generation level at bus 15. However, to self arrest the program, a limit is set on the maximum number of iterations. The system is not able to get rid of the overload on line $Line_{30-17}$ even after 20 iterations of increasing the generation at bus 15. As bus 18 is also a generator bus, the program them jumps to bus 18. When the generation level at bus 18 is increased to 68.54(MW) from 0(MW), the overload on $Line_{30-17}$ is relieved.

7.3.6 Line 64-65.

Details of $Line_{64-65}$ and the results of mitigation solution are given below -

Normal Power Flow = 194.55(MVA)

Line Limit = 291.71(MVA)

New Limit Set = 176.86(MVA)

Overload = 17.89(MVA)

The power in $Line_{64-65}$ flows from bus 65 to bus 64. Bus 64 is also connected to buses 61 and 63. Since bus 61 is a generator bus, its generation is increased from 160(MW) to 191(MW) in order to relieve the overload on $Line_{64-65}$. So an increase in generation of 30(MW) is needed.

7.3.7 Line 103-110.

Details of $Line_{103-110}$ and the results of mitigation solution are given below -

Normal Power Flow = 61.19(MVA)

Line Limit = 91.01(MVA)

New Limit Set = 56.08(MVA)

Overload = 5.11(MVA)

$Line_{103-110}$ carries power from bus 103 to bus 110. Bus 110 itself is a generator bus. Taking the direction of pwoer flow into consideration, it is obvious that if the generation level at bus 110 is increased, it may result in lower loading of $Line_{103-110}$. After increasing the generation at bus 110 from 0(MW) to 9.31(MW), it is observed that the overload on $Line_{103-110}$ is relieved. It should be noted that since the generator is on the end bus of the line itself, the generation increase at bus 110 and the initial overloading level of the line match more closely.

7.3.8 Line 25-27.

Details of $Line_{25-27}$ and the results of mitigation solution are given below -

Normal Power Flow = 146.65(MVA)

Line Limit = 329.82(MVA)

New Limit Set = 133.31(MVA)

Overload = 13.34(MVA)

Power in $Line_{25-27}$ flows from bus 25 to bus 27. In this case, bus 27 is a generator. So the generation level at bus 27 is boosted to 39.85(MW) from 0(MW), in order to relieve the overload on the line.

7.3.9 Line 34-37.

Details of $Line_{34-37}$ and the results of mitigation solution are given below -

Normal Power Flow = 97.90(MVA)

Line Limit = 153.41(MVA)

New Limit Set = 88.88(MVA)

Overload = 9.02(MVA)

$Line_{34-37}$ carries power from bus 37 to bus 34. Just like the previous few cases, bus 34 is a generator bus. Also, the generation level of bus 34 is below the maximum limit. Thus the program attempts to boost up the generation level at bus 34 to relieve overload on line. It is found that when the generation at bus 34 reaches 29.86(MW), the overload on $Line_{34-37}$ is gone.

7.3.10 Line 100-103.

Details of $Line_{100-103}$ and the results of mitigation solution are given below -

Normal Power Flow = 123.74(MVA)

Line Limit = 181.85(MVA)

New Limit Set = 112.49(MVA)

Overload = 11.25(MVA)

$Line_{100-103}$ has a power flow from bus 100 to bus 103. Bus 103 itself is a generator bus. Thus incraesing its generation level may relieve the overload on the line. Previous generation level of bus 103 is 40(MW). It is seen that when this level reaches 55.7(MW), the overload on the line vanishes. Thus an increase in the generation level of bus 103 by 15.7(MW) avoided $Line_{100-103}$ from being tripped open due to overload.

This section summarizes the mitigation techniques that can be adopted to avoid overloading of 10 lines. Once the methodology is developed, it can be extended for more lines as well. The next section will discuss the accomplished work.

8 CONCLUSION

For a defensive mechanism to be developed against cascading failures in the power systems, it is very essential to analyze any of such previous events. Mainly because, such disturbances occupy a vast area and can result into a total blackout. Blackouts are usually a result of series of event rather than one single. However, it becomes extremely essential to find out that one single incident that initiated the process. Although less frequent, the blackouts cause inconvenience on a massive scale. This Section is dedicated to discussion of conclusions that can be drawn from this thesis work.

The different remedial measures that could have been taken in order to prevent the system from blackout have already been discussed in section 2.3. From the study of blackouts in India, it can be inferred that unanticipated load ramping or in other words, inaccurate load forecasting put the power system components under a lot of stress. From the blackouts in India, it inferred that had there been a better forecast of the load in the NR, they Load Balancing Authorities would have been better prepared. They might even have initiated the load shedding well in advance to avoid overloading few inter-regional lines in service. The blackouts in India also bring out the importance of SCADA system and the concept of real time monitoring of the system. Real time voltage profiles of the buses and power flows in the line help the system operators to operate better and take timely decisions based on the changing parameters of the system.

In a power system system of real world size, there can be thousands of transmission lines, transformers and generators. Not all of them, if outaged, will initiate a cascading failure in the system. Finding out the critical lines in the system, hugely reduces the size of the problem. Even if the data is collected by a SCADA system and displayed on the monitors for the system operators in a concise way, it still is a lot of data to analyze. Just monitoring the most significant transmission lines (or components in general) increases the effectiveness of the monitoring process.

The process of mitigating overloads on lines can be different for different lines. It totally depends upon the location of line, how much power was the line carrying, the direction of power flow in the line as well as the surroundings of the line. This conclusion can be bolstered by the fact that we had many more options for Ant3 in case of $Line_{26-30}$ than for $Line_{38-65}$. Surroundings here may mean availability of a generator or a load center near the overloaded line. It is usually observed that a change in load or generation at a bus which is 3 buses away from the concerned line, does not affect the loading of the line much. So different lines need to be treated differently.

System security is always given a priority over the economic operation of the system in case of emergency situations. Also, shedding load bears the least priority and is done if the operator is generation deficit even after trying all the other possible options. Increasing generation at a generator bus to avoid overloading of a particular line, may result in overloading of other adjacent lines. Such a solution only makes the situation worse and hence should be avoided.

Intentional islanding is always the last option for the system operators. Splitting up the system into different islands needs opening up transmission lines. In our case, we came across a situation where we had to open 11 or 13 transmission lines. Opening transmission lines can be significantly difficult tasks as it can also induce transient disturbances in the power system risking its stability. Just splitting up the system into islands is not enough. The stability of the islands should be checked first. Since intentional system islading may include decommissioning fewer generators from the loads or fewer load shedding, it ensures a faster recovery from the emergency situation to a normal working condition. Thus, intentional islanding is always a better option than system blackout.

It can be concluded that the system can be split up into varying number of islands, grouping different buses together. An active method of islanding which takes into consideration of current generation levels of different generators, geographical aspects of the system and ensuring minimum generation - load imbalance, can be the best possible method. Sometimes the generators in a particular geographic area are coherent. This property can be beneficially exploited while performing intentional power system islanding in order to minimize the risks of pwoer swings and the disturbances happening on account of it.

APPENDIX

IEEE 118 BUS SYSTEM DATA

The bus data for IEEE 118 bus system is given in the following table on a 100(MVA) base [8].

Where -

Bus No. = Bus Number

Type = Bus type

1 = Load Bus

2 = Generator BUs

3 = Slack Bus

4 = Isolated Bus

Pd = Real Power Demand

Qd = Reactive Power Demand

Gs = Shunt Admittance

Bs = Shunt Suseptance

baseKv = Base Voltage (kV)

Vmax = Maximum Voltage

Vmin = Minimum Voltage

Bus No.	Type	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
1	2	51	27	0	0	138	1.06	0.94
2	1	20	9	0	0	138	1.06	0.94
3	1	39	10	0	0	138	1.06	0.94
4	2	39	12	0	0	138	1.06	0.94
5	1	0	0	0	-40	138	1.06	0.94
6	2	52	22	0	0	138	1.06	0.94
7	1	19	2	0	0	138	1.06	0.94
8	2	28	0	0	0	345	1.06	0.94
9	1	0	0	0	0	345	1.06	0.94
10	2	0	0	0	0	345	1.06	0.94
11	1	70	23	0	0	138	1.06	0.94
12	2	47	10	0	0	138	1.06	0.94
13	1	34	16	0	0	138	1.06	0.94
14	1	14	1	0	0	138	1.06	0.94
15	2	90	30	0	0	138	1.06	0.94
16	1	25	10	0	0	138	1.06	0.94
17	1	11	3	0	0	138	1.06	0.94
18	2	60	34	0	0	138	1.06	0.94
19	2	45	25	0	0	138	1.06	0.94
20	1	18	3	0	0	138	1.06	0.94
21	1	14	8	0	0	138	1.06	0.94
22	1	10	5	0	0	138	1.06	0.94
23	1	7	3	0	0	138	1.06	0.94
24	2	13	0	0	0	138	1.06	0.94
25	2	0	0	0	0	138	1.06	0.94
26	2	0	0	0	0	345	1.06	0.94
27	2	71	13	0	0	138	1.06	0.94

Bus No.	Type	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
28	1	17	7	0	0	138	1.06	0.94
29	1	24	4	0	0	138	1.06	0.94
30	1	0	0	0	0	345	1.06	0.94
31	2	43	27	0	0	138	1.06	0.94
32	2	59	23	0	0	138	1.06	0.94
33	1	23	9	0	0	138	1.06	0.94
34	2	59	26	0	14	138	1.06	0.94
35	1	33	9	0	0	138	1.06	0.94
36	2	31	17	0	0	138	1.06	0.94
37	1	0	0	0	-25	138	1.06	0.94
38	1	0	0	0	0	345	1.06	0.94
39	1	27	11	0	0	138	1.06	0.94
40	2	66	23	0	0	138	1.06	0.94
41	1	37	10	0	0	138	1.06	0.94
42	2	96	23	0	0	138	1.06	0.94
43	1	18	7	0	0	138	1.06	0.94
44	1	16	8	0	10	138	1.06	0.94
45	1	53	22	0	10	138	1.06	0.94
46	2	28	10	0	10	138	1.06	0.94
47	1	34	0	0	0	138	1.06	0.94
48	1	20	11	0	15	138	1.06	0.94
49	2	87	30	0	0	138	1.06	0.94
50	1	17	4	0	0	138	1.06	0.94
51	1	17	8	0	0	138	1.06	0.94
52	1	18	5	0	0	138	1.06	0.94
53	1	23	11	0	0	138	1.06	0.94
54	2	113	32	0	0	138	1.06	0.94

Bus No.	Type	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
55	2	63	22	0	0	138	1.06	0.94
56	2	84	18	0	0	138	1.06	0.94
57	1	12	3	0	0	138	1.06	0.94
58	1	12	3	0	0	138	1.06	0.94
59	2	277	113	0	0	138	1.06	0.94
60	1	78	3	0	0	138	1.06	0.94
61	2	0	0	0	0	138	1.06	0.94
62	2	77	14	0	0	138	1.06	0.94
63	1	0	0	0	0	345	1.06	0.94
64	1	0	0	0	0	345	1.06	0.94
65	2	0	0	0	0	345	1.06	0.94
66	2	39	18	0	0	138	1.06	0.94
67	1	28	7	0	0	138	1.06	0.94
68	1	0	0	0	0	345	1.06	0.94
69	3	0	0	0	0	138	1.06	0.94
70	2	66	20	0	0	138	1.06	0.94
71	1	0	0	0	0	138	1.06	0.94
72	2	12	0	0	0	138	1.06	0.94
73	2	6	0	0	0	138	1.06	0.94
74	2	68	27	0	12	138	1.06	0.94
75	1	47	11	0	0	138	1.06	0.94
76	2	68	36	0	0	138	1.06	0.94
77	2	61	28	0	0	138	1.06	0.94
78	1	71	26	0	0	138	1.06	0.94
79	1	39	32	0	20	138	1.06	0.94
80	2	130	26	0	0	138	1.06	0.94
81	1	0	0	0	0	345	1.06	0.94

Bus No.	Type	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
82	1	54	27	0	20	138	1.06	0.94
83	1	20	10	0	10	138	1.06	0.94
84	1	11	7	0	0	138	1.06	0.94
85	2	24	15	0	0	138	1.06	0.94
86	1	21	10	0	0	138	1.06	0.94
87	2	0	0	0	0	161	1.06	0.94
88	1	48	10	0	0	138	1.06	0.94
89	2	0	0	0	0	138	1.06	0.94
90	2	163	42	0	0	138	1.06	0.94
91	2	10	0	0	0	138	1.06	0.94
92	2	65	10	0	0	138	1.06	0.94
93	1	12	7	0	0	138	1.06	0.94
94	1	30	16	0	0	138	1.06	0.94
95	1	42	31	0	0	138	1.06	0.94
96	1	38	15	0	0	138	1.06	0.94
97	1	15	9	0	0	138	1.06	0.94
98	1	34	8	0	0	138	1.06	0.94
99	2	42	0	0	0	138	1.06	0.94
100	2	37	18	0	0	138	1.06	0.94
101	1	22	15	0	0	138	1.06	0.94
102	1	5	3	0	0	138	1.06	0.94
103	2	23	16	0	0	138	1.06	0.94
104	2	38	25	0	0	138	1.06	0.94
105	2	31	26	0	20	138	1.06	0.94
106	1	43	16	0	0	138	1.06	0.94
107	2	50	12	0	6	138	1.06	0.94
108	1	2	1	0	0	138	1.06	0.94

Bus No.	Type	Pd	Qd	Gs	Bs	baseKV	Vmax	Vmin
109	1	8	3	0	0	138	1.06	0.94
110	2	39	30	0	6	138	1.06	0.94
111	2	0	0	0	0	138	1.06	0.94
112	2	68	13	0	0	138	1.06	0.94
113	2	6	0	0	0	138	1.06	0.94
114	1	8	3	0	0	138	1.06	0.94
115	1	22	7	0	0	138	1.06	0.94
116	2	184	0	0	0	138	1.06	0.94
117	1	20	8	0	0	138	1.06	0.94
118	1	33	15	0	0	138	1.06	0.94

The line data for IEEE 118 bus system is given in the following table on a 100(MVA) base [8].

Where -

Fbus = ’from’ bus of line

Tbus = ’to’ bus of line

R = Resistance of line

X = Reactance of line

B = Suseptance of line

Rate A = Continuous rating of line

Ratio = Tap Ratio of transformer

Fbus	Tbus	R	X	B	Rate A	Ratio
1	2	0.0303	0.0999	0.0254	60.63	0
1	3	0.0129	0.0424	0.01082	63.6	0
4	5	0.00176	0.00798	0.0021	160.5	0
3	5	0.0241	0.108	0.0284	107.19	0
5	6	0.0119	0.054	0.01426	132.82	0
6	7	0.00459	0.0208	0.0055	80.64	0
8	9	0.00244	0.0305	0.581	674.5	0
8	5	0	0.0267	0	541	0.985
9	10	0.00258	0.0322	0.615	679.32	0
4	11	0.0209	0.0688	0.00874	96.319	0
5	11	0.0203	0.0682	0.00869	115.89	0
11	12	0.00595	0.0196	0.00502	110.44	0
2	12	0.0187	0.0616	0.01572	85.78	0
3	12	0.0484	0.16	0.0406	53.31	0
7	12	0.00862	0.034	0.00874	59.74	0

Fbus	Tbus	R	X	B	Rate A	Ratio
11	13	0.02225	0.0731	0.01876	82.96	0
12	14	0.0215	0.0707	0.01816	63.06	0
13	15	0.0744	0.2444	0.06268	29.31	0
14	15	0.0595	0.195	0.0502	29.98	0
12	16	0.0212	0.0834	0.0214	49.51	0
15	17	0.0132	0.0437	0.0444	243.73	0
16	17	0.0454	0.1801	0.0466	40.28	0
17	18	0.0123	0.0505	0.01298	189.035	0
18	19	0.01119	0.0493	0.01142	83.79	0
19	20	0.0252	0.117	0.0298	39.78	0
15	19	0.012	0.0394	0.0101	91.76	0
20	21	0.0183	0.0849	0.0216	66.32	0
21	22	0.0209	0.097	0.0246	64.94	0
22	23	0.0342	0.159	0.0404	82.23	0
23	24	0.0135	0.0492	0.0498	39.98	0
23	25	0.0156	0.08	0.0864	256.75	0
26	25	0	0.0382	0	208.9	0.96
25	27	0.0318	0.163	0.1764	329.82	0
27	28	0.01913	0.0855	0.0216	49.28	0
28	29	0.0237	0.0943	0.0238	38.14	0
30	17	0	0.0388	0	373.8	0.96
8	30	0.00431	0.0504	0.514	157.95	0
26	30	0.00799	0.086	0.908	336	0
17	31	0.0474	0.1563	0.0399	69.99	0
29	31	0.0108	0.0331	0.0083	27.16	0
23	32	0.0317	0.1153	0.1173	209.53	0

Fbus	Tbus	R	X	B	Rate A	Ratio
31	32	0.0298	0.0985	0.0251	73.71	0
27	32	0.0229	0.0755	0.01926	63.95	0
15	33	0.038	0.1244	0.03194	44.23	0
19	34	0.0752	0.247	0.0632	57.64	0
35	36	0.00224	0.0102	0.00268	33.9	0
35	37	0.011	0.0497	0.01318	83.29	0
33	37	0.0415	0.142	0.0366	64.96	0
34	36	0.00871	0.0268	0.00568	49.08	0
34	37	0.00256	0.0094	0.00984	153.41	0
38	37	0	0.0375	0	402.32	0.935
37	39	0.0321	0.106	0.027	82.64	0
37	40	0.0593	0.168	0.042	66.29	0
30	38	0.00464	0.054	0.422	187.03	0
39	40	0.0184	0.0605	0.01552	63.22	0
40	41	0.0145	0.0487	0.01222	35.17	0
40	42	0.0555	0.183	0.0466	45.31	0
41	42	0.041	0.135	0.0344	77.26	0
43	44	0.0608	0.2454	0.06068	38.8	0
34	43	0.0413	0.1681	0.04226	41.57	0
44	45	0.0224	0.0901	0.0224	75.89	0
45	46	0.04	0.1356	0.0332	83.04	0
46	47	0.038	0.127	0.0316	47.21	0
46	48	0.0601	0.189	0.0472	35.7	0
47	49	0.0191	0.0625	0.01604	32.49	0
42	49	0.0715	0.323	0.086	135.92	0
42	49	0.0715	0.323	0.086	135.92	0

Fbus	Tbus	R	X	B	Rate A	Ratio
45	49	0.0684	0.186	0.0444	77.2	0
48	49	0.0179	0.0505	0.01258	52.99	0
49	50	0.0267	0.0752	0.01874	82.9	0
49	51	0.0486	0.137	0.0342	104.55	0
51	52	0.0203	0.0588	0.01396	43.85	0
52	53	0.0405	0.1635	0.04058	26.25	0
53	54	0.0263	0.122	0.031	46.71	0
49	54	0.073	0.289	0.0738	79.94	0
49	54	0.0869	0.291	0.073	79.94	0
54	55	0.0169	0.0707	0.0202	26.24	0
54	56	0.00275	0.00955	0.00732	43.15	0
55	56	0.00488	0.0151	0.00374	49.95	0
56	57	0.0343	0.0966	0.0242	37.09	0
50	57	0.0474	0.134	0.0332	55.54	0
56	58	0.0343	0.0966	0.0242	22.87	0
51	58	0.0255	0.0719	0.01788	43.27	0
54	59	0.0503	0.2293	0.0598	46.93	0
56	59	0.0825	0.251	0.0569	72.1	0
56	59	0.0803	0.239	0.0536	72.1	0
55	59	0.04739	0.2158	0.05646	53.34	0
59	60	0.0317	0.145	0.0376	99.34	0
59	61	0.0328	0.15	0.0388	118.88	0
60	61	0.00264	0.0135	0.01456	169.04	0
60	62	0.0123	0.0561	0.01468	61.61	0
61	62	0.00824	0.0376	0.0098	65.27	0
63	59	0	0.0386	0	249.1	0.96

Fbus	Tbus	R	X	B	Rate A	Ratio
63	64	0.00172	0.02	0.216	249.1	0
64	61	0	0.0268	0	169.96	0.985
38	65	0.00901	0.0986	1.046	285.23	0
64	65	0.00269	0.0302	0.38	291.71	0
49	66	0.018	0.0919	0.0248	270.86	0
49	66	0.018	0.0919	0.0248	270.86	0
62	66	0.0482	0.218	0.0578	61.47	0
62	67	0.0258	0.117	0.031	42.38	0
65	66	0	0.037	0	163.67	0.935
66	67	0.0224	0.1015	0.02682	84.82	0
65	68	0.00138	0.016	0.638	99.4	0
47	69	0.0844	0.2778	0.07092	89.25	0
49	69	0.0985	0.324	0.0828	75.32	0
68	69	0	0.037	0	253.3	0.935
69	70	0.03	0.127	0.122	167.3	0
24	70	0.00221	0.4115	0.10198	31.08	0
70	71	0.00882	0.0355	0.00878	46.67	0
24	72	0.0488	0.196	0.0488	27.38	0
71	72	0.0446	0.18	0.04444	37.13	0
71	73	0.00866	0.0454	0.01178	18.46	0
70	74	0.0401	0.1323	0.03368	50	0
70	75	0.0428	0.141	0.036	44.45	0
69	75	0.0405	0.122	0.124	167.79	0
74	75	0.0123	0.0406	0.01034	79.13	0
76	77	0.0444	0.148	0.0368	101.65	0
69	77	0.0309	0.101	0.1038	93.75	0

Fbus	Tbus	R	X	B	Rate A	Ratio
75	77	0.0601	0.1999	0.04978	81.44	0
77	78	0.00376	0.0124	0.01264	103.48	0
78	79	0.00546	0.0244	0.00648	71.08	0
77	80	0.017	0.0485	0.0472	210.6	0
77	80	0.0294	0.105	0.0228	210.6	0
79	80	0.0156	0.0704	0.0187	108.78	0
68	81	0.00175	0.0202	0.808	131.41	0
81	80	0	0.037	0	131.41	0.935
77	82	0.0298	0.0853	0.08174	378.17	0
82	83	0.0112	0.03665	0.03796	81.92	0
83	84	0.0625	0.132	0.0258	67.36	0
83	85	0.043	0.148	0.0348	101.93	0
84	85	0.0302	0.0641	0.01234	56.81	0
85	86	0.035	0.123	0.0276	28.02	0
86	87	0.02828	0.2074	0.0445	23.39	0
85	88	0.02	0.102	0.0276	77.01	0
85	89	0.0239	0.173	0.047	108.74	0
88	89	0.0139	0.0712	0.01934	150.8	0
89	90	0.0518	0.188	0.0528	221.69	0
89	90	0.0238	0.0997	0.106	221.69	0
90	91	0.0254	0.0836	0.0214	75.5	0
89	92	0.0099	0.0505	0.0548	404.06	0
89	92	0.0393	0.1581	0.0414	404.06	0
91	92	0.0387	0.1272	0.03268	42.12	0
92	93	0.0258	0.0848	0.0218	88.02	0
92	94	0.0481	0.158	0.0406	81.19	0

Fbus	Tbus	R	X	B	Rate A	Ratio
93	94	0.0223	0.0732	0.01876	72.63	0
94	95	0.0132	0.0434	0.0111	63.13	0
80	96	0.0356	0.182	0.0494	46	0
82	96	0.0162	0.053	0.0544	41.59	0
94	96	0.0269	0.0869	0.023	49.53	0
80	97	0.0183	0.0934	0.0254	56.28	0
80	98	0.0238	0.108	0.0286	45.75	0
80	99	0.0454	0.206	0.0546	34.83	0
92	100	0.0648	0.295	0.0472	52.63	0
94	100	0.0178	0.058	0.0604	73.65	0
95	96	0.0171	0.0547	0.01474	31.95	0
96	97	0.0173	0.0885	0.024	34.15	0
98	100	0.0397	0.179	0.0476	20.4	0
99	100	0.018	0.0813	0.0216	34.78	0
100	101	0.0277	0.1262	0.0328	44.21	0
92	102	0.0123	0.0559	0.01464	67.85	0
101	102	0.0246	0.112	0.0294	60.98	0
100	103	0.016	0.0525	0.0536	112.49	0
100	104	0.0451	0.204	0.0541	86.11	0
103	104	0.0466	0.1584	0.0407	75.12	0
103	105	0.0535	0.1625	0.0408	98.05	0
100	106	0.0605	0.229	0.062	91.92	0
104	105	0.00994	0.0378	0.00986	109.78	0
105	106	0.014	0.0547	0.01434	34.21	0
105	107	0.053	0.183	0.0472	40.25	0
105	108	0.0261	0.0703	0.01844	59.73	0

Fbus	Tbus	R	X	B	Rate A	Ratio
106	107	0.053	0.183	0.0472	36.44	0
108	109	0.0105	0.0288	0.0076	54.79	0
103	110	0.03906	0.1813	0.0461	91.04	0
109	110	0.0278	0.0762	0.0202	28.73	0
110	111	0.022	0.0755	0.02	54.07	0
110	112	0.0247	0.064	0.062	113.85	0
17	113	0.00913	0.0301	0.00768	31.95	0
32	113	0.0615	0.203	0.0518	60.16	0
32	114	0.0135	0.0612	0.01628	34.12	0
27	115	0.0164	0.0741	0.01972	48.32	0
114	115	0.0023	0.0104	0.00276	26.66	0
68	116	0.00034	0.00405	0.164	293.57	0
12	117	0.0329	0.14	0.0358	32.31	0
75	118	0.0145	0.0481	0.01198	69.91	0
76	118	0.0164	0.0544	0.01356	40.03	0

The generator data for IEEE 118 bus system is given in the following table on a 100(MVA) base [8].

Where -

Bus = Generator Bus Number

Pg = Generation Level

Qmax = Maximum reactive Power at bus

Qmin = Minimum Reactive Power at bus

Pmax = Maximum Real Power at Bus

bus	Pg	Qmax	Qmin	Pmax
1	0	15	-5	100
4	0	300	-300	100
6	0	50	-13	100
8	0	300	-300	100
10	450	200	-147	550
12	85	120	-35	185
15	0	30	-10	100
18	0	50	-16	100
19	0	24	-8	100
24	0	300	-300	100
25	220	140	-47	320
26	314	1000	-1000	414
27	0	300	-300	100
31	7	300	-300	107
32	0	42	-14	100
34	0	24	-8	100

bus	Pg	Qmax	Qmin	Pmax
36	0	24	-8	100
40	0	300	-300	100
42	0	300	-300	100
46	19	100	-100	119
49	204	210	-85	304
54	48	300	-300	148
55	0	23	-8	100
56	0	15	-8	100
59	155	180	-60	255
61	160	300	-100	260
62	0	20	-20	100
65	391	200	-67	491
66	392	200	-67	492
69	516.4	300	-300	805.2
70	0	32	-10	100
72	0	100	-100	100
73	0	100	-100	100
74	0	9	-6	100
76	0	23	-8	100
77	0	70	-20	100
80	477	280	-165	577
85	0	23	-8	100
87	4	1000	-100	104
89	607	300	-210	707
90	0	300	-300	100

bus	Pg	Qmax	Qmin	Pmax
91	0	100	-100	100
92	0	9	-3	100
99	0	100	-100	100
100	252	155	-50	352
103	40	40	-15	140
104	0	23	-8	100
105	0	23	-8	100
107	0	200	-200	100
110	0	23	-8	100
111	36	1000	-100	136
112	0	1000	-100	100
113	0	200	-100	100
116	0	1000	-1000	100

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VITA

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