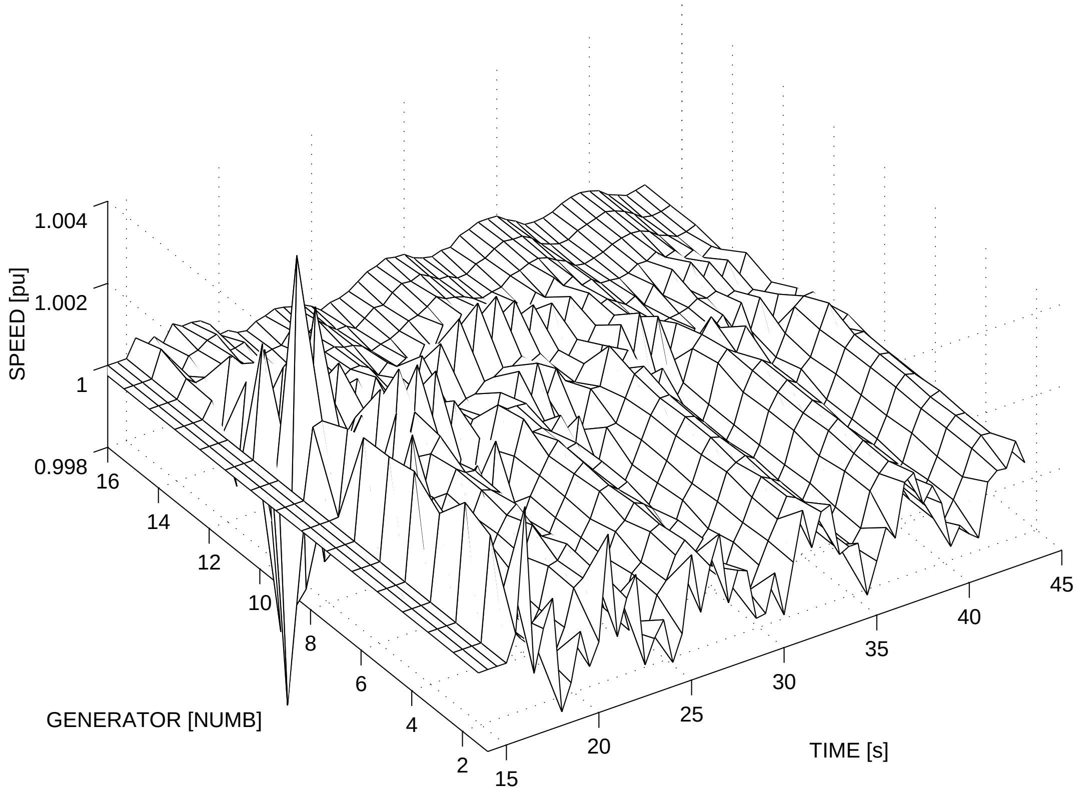


Protection Strategies to Mitigate Major Power System Breakdowns

Mattias Jonsson

Department of Electric Power Engineering
CHALMERS UNIVERSITY OF TECHNOLOGY
Göteborg, Sweden 2003

THESIS FOR THE DEGREE OF DOCTOR OF PHILOSOPHY

Protection Strategies to Mitigate Major Power System Breakdowns

by

MATTIAS JONSSON

Department of Electric Power Engineering
Chalmers University of Technology
Göteborg, Sweden 2003

Protection Strategies to Mitigate Major Power System Breakdowns
MATTIAS JONSSON
ISBN 91-7291-293-6

Doktorsavhandlingar vid Chalmers tekniska högskola
Ny serie nr 1975
ISSN 0346-718X

School of Electrical Engineering
Chalmers University of Technology
Technical Report No. 447
ISSN 1651-498X

Department of Electric Power Engineering
Chalmers University of Technology
SE-412 96 Göteborg
Sweden
Telephone: +46 (0)31 - 772 1660
Fax: +46 (0)31 - 772 1633

Cover: Inter-area modes in the 68 bus NPCC system.

Chalmers bibliotek, Reproservice
Göteborg, Sweden 2003

Abstract

This thesis deals with new methods to improve the performance of power system protection in the case of voltage- and transient instability. These methods are designed primarily to mitigate power system breakdown. Relay algorithms are proposed where conventional distance protection is combined with additional relay criteria. In case of voltage instability the criteria are based on the derivative of the voltage whereas the rate of change of the phase angle of the current is used for transient instability. For generator coherency determination a method based on wide area generator speed measurements and Fourier analysis is proposed. Using this method a concept for a System Protection Scheme addressing inter-area events is introduced. Finally, an emergency scheme based on conventional distance relays is proposed to avoid a complete system collapse in the case of severe voltage instability.

The performance of these new methods has been compared with conventional methods based on simulations using different test systems.

The proposed relay algorithms improve the relay security with respect to voltage instability whereas the reach of the distance protection is not restricted. Neither the line length, different swing frequencies or faults having a slowly decreasing impedance will affect the performance of the proposed schemes as may be the case when using conventional Power Swing Detectors. The fault clearing will also not be blocked as with conventional PSD applications. The proposed method for establishing generator coherency leads to almost identical results if compared with off-line methods as modal analysis or generator speed. Results obtained from phasor measurements however showed deviations. This work also demonstrates that, taking initial transient distortion after a contingency into account, a reliable coherency is faster obtained by the proposed technique than by methods using pure speed or generator voltage angle measurements. It has been demonstrated that the proposed emergency scheme can save part of the system from a voltage collapse. Black-start can then be avoided and the restoration time can be reduced.

Keywords: Distance protection, Generator coherency, Out-of-Step Protection, Power Swing Detectors, Voltage instability, System Protection Schemes, Transient instability, Wide Area Protection.

Acknowledgements

I owe my deepest gratitude to my advisor Professor Jaap Daalder. First for accepting me as a student, then for the support and help he has given me throughout the project. Finally for what I appreciate the most, that he has given me the feeling that his ”door is always open” when I had any kind of problem.

Dag Holmberg at Svenska Kraftnät is acknowledged for his efforts in arranging the financial support for this project. The members of my steering group Magnus Danielsson, Leif Koppari, Lars Wallin and Kenneth Walve are acknowledged for their valuable contributions. All group members are with Svenska Kraftnät. Additional staff at Svenska Kraftnät that I would like to thank for their help and support are Anders Edström, Anders Fransson (nowadays with Svenska Energihuset), Dag Ingemansson, Bertil Kielén, Allan Lundberg, Thomas Thor and Karl-Olof Jonsson. I also would like to thank the management of Svenska Kraftnät for funding the ARISTO computer.

ABB Power Systems are acknowledged for providing SIMPOW free of charge. Special thanks go to Sune Sarri, Lars Lindkvist and Jonas Persson for their valuable help with SIMPOW. In addition I would like to thank Stefan Arnborg, Svenska Kraftnät for being so generous with his ”dsl models” when I started to work with SIMPOW.

I am deeply grateful to Magnus Akke, Lars Messing and Daniel Karlsson, all with ABB Automation Technology Products AB, for their unrestrained way of sharing their great expertise in the area.

I would like to sincerely thank Associate Professor Miroslav Begovic at Georgia Institute of Technology, Atlanta, USA for accepting me as a visiting scholar in his research group during the spring and summer, 2002.

Annika, Arne, Jan-Olov and Valborg thank you for all help with various practical things, I really appreciate it.

Many thanks to all the staff and former colleagues at the Department of Electric Power Engineering for the pleasant working atmosphere and your friendship.

Finally, I owe my deepest gratitude to Jenny-Ann and my parents, for understanding, encouragement and love throughout this project.

LIST OF PUBLICATIONS

This thesis is based on the work reported in the following papers.

A Jonsson M, Daalder J, “An adaptive scheme to prevent undesirable distance protection operation during voltage instability”, Accepted for IEEE Transactions on Power Delivery.

B Jonsson M, Daalder J, “A new protection scheme to prevent mal-trips due to power swings”, IEEE/PES Transmission and Distribution Conference and Exposition, October 28 - November 2, 2001, Atlanta, USA. Proceedings Vol. 2, pp. 724 - 729.

C Jonsson M, Daalder J, ”A distance protection scheme to prevent mal-trips during abnormal power system conditions”, Cigré Study Committee 34 Colloquium and Meeting, September 10 - 14, 2001, Sibiu, Romania. Proceedings paper 113.

D Jonsson M, Begovic M, Daalder J, “A new method suitable for real time generator coherency determination”, Submitted to IEEE Transactions on Power Systems.

E Jonsson M, Daalder J, Begovic M, “A system protection scheme concept to counter inter-area oscillations”, Submitted to IEEE Transactions on Power Delivery.

F Jonsson M, Daalder J, Walve K, “An emergency strategy scheme based on conventional distance protection to avoid complete system collapse”, Accepted for IEEE/PES Transmission and Distribution Conference and Exposition, September 7 - 12, 2003, Dallas, USA.

Contents

Chapter 1 Introduction

1.1 Background and Motivation

At about 13.00 hrs. on Tuesday December 27, 1983, the Swedish electrical power system experienced the most severe disturbance of the last 30 years. The blackout resulted in a number of projects by the utilities and universities where different aspects of the collapse were investigated. Several projects analysed the behaviour of different power system elements such as generators, transformers and loads while other projects were addressing numerical methods intended to analyse events similar to the collapse.

These investigations of the 1983 blackout indicated that the performance of the relay protection system might had been deficient. At the same time developments in computer and communication technologies have significantly enhanced the potential for improved protection systems. As a result the project *Protection Strategies to Mitigate Major Power system Breakdowns* was initiated by Svenska Kraftnät[1] in co-operation with Chalmers University of Technology. The aim of the project has been to investigate the performance of the existing relay protection during abnormal operating conditions and to improve protection methods in order to avoid extensive system breakdowns.

The NORDEL system in Fig. 1.1 is a synchronous system involving Finland, Norway, Sweden and the part of Denmark east of the Great Belt. This system is connected to surrounding synchronized systems by HVDC interconnections. There are also two HVDC interconnections within the Nordel system; one from the middle part of Sweden to the south part of Finland and one from the Swedish mainland to the island of Gotland. The installed generation capacity for the NORDEL system amounts to about 80 000 MW. Approximately 50 % is hydro generation and 50 % thermal generation (oil, coal and nuclear).

In the Swedish electrical power system the main load centres are located in the central and south regions while a significant part of the generation is located in the north. The regions are separated by hundreds of km and thus the Swedish bulk power system involves

1. Regulator of the Swedish bulk power system.

large power transfers over long distances. Deregulation resulting in the decommission of (small) power plants in the south part of Sweden has further enhanced the radial characteristic of the system. The possibilities for local generator support in the case of abnormal operating conditions have obviously been reduced. In addition an increased variation of power flow directions has been experienced during recent years. As a result the main constraints for the NORDEL system are represented by power system stability issues.

The main ambition in this project has been to improve the protection performance during power system instability without jeopardizing fault clearance. During the first part of the project which was concluded by the licentiate degree, focus was given to local area protection schemes. Furthermore, in the second part concluded by the Ph.D degree focus was given to extensive protection systems involving large areas.

1.2 Outline of the Thesis

This dissertation is organized into two parts. The first part gives a background to the relevant topics while the second part includes six papers in which the main technical contributions from this project are presented.

The background and motivation for the thesis are given in Chapter 1 while Chapter 2 summarizes power system instability phenomena. Chapter 3 and Chapter 4 discuss the relevant relations between power system instability and power system protection. Chapter 3 treats local area protection while Chapter 4 discusses System Protection Schemes. Chapter 5 briefly introduces the papers enclosed in the second part of this dissertation. Finally, the conclusions and suggestions for future work are presented in Chapter 6.

At the end of part 1 an appendix and the references of the six first chapters are included.

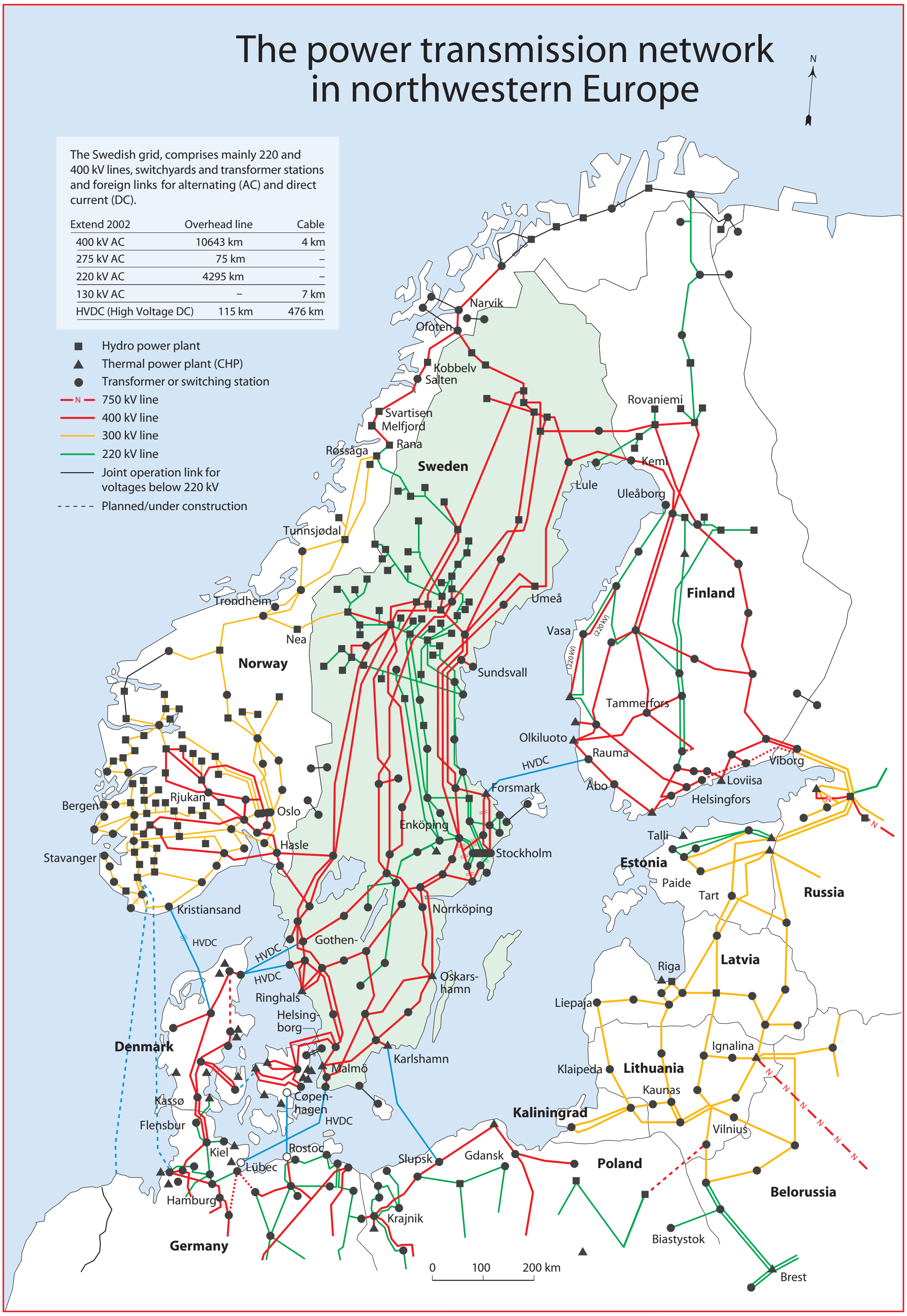


Figure 1.1 The NORDEL system.

Chapter 2 Power System Instability

In this section a brief summery of power system instability is given. The different types of power system instability are further described by Kundur [1] while attention here is given to instability aspects relevant to power system protection. In particular the focus is on the relation between grid configuration and system instability due to its importance in the case of protection applications. For simplicity the different types of power system instability are discussed separately. During a severe disturbance some of these phenomena may occur simultaneously though.

2.1 Angle Instability - Power Oscillations

The fundamental phenomena appearing in a power system in case of angle instability are power oscillations. Depending on their severity and origin they are categorised as transient angle instability or small-signal angle instability.

Generally power oscillations can be divided into three different categories; **1)** *local plant mode oscillations or inter machine oscillations with a frequency range of 0.7 - 2 Hz (6 Hz),* **2)** *inter-area oscillations, where groups of generators are swinging against each other in the frequency range of 0.4 - 0.7 Hz* and **3)** *large sub-systems oscillating against each other where the swinging frequency usually is in the order of 0.1 - 0.3 Hz.*

2.1.1 Transient Angle Instability

According to Kundur transient stability is the ability of the power system to maintain synchronism when subjected to a severe disturbance such as a fault on transmission facilities, loss of generation, or loss of a large load [1]. Usually this type of disturbances leads to large excursions of generators angles and significant changes in active and reactive power flows, bus voltages, system frequency and other system variables. Accordingly both the customers and the power system are confronted to these features where they have a more or less developed transient characteristic. In case appropriate counteractions are not taken transient instability may result in extensive power system blackouts.

Loss of synchronism may include one single generating unit, a power plant represented by multiple generators, a region of the network or several interconnected regions. The loss of synchronism may occur during the first swing after the disturbance or after a number of divergent oscillations. In the first case the mismatch between the electrical and mechanical torque is considered to be the main issue while insufficient damping is associated to loss of synchronism after a few swings.

Lightly meshed networks, large power flows and long distance power transport are features which contribute to transient angle instability. Accordingly tie-lines, bottlenecks and weak interconnections (between different countries) are typical sources of transient instability. As transient instability includes large voltage and power variations, fast tripping of power system devices may be initiated due to undesirable protection operation. This is especially true for some generator and line protection [2].

2.1.2 Small-Signal Angle Instability

Small-signal stability is the ability of the power system to maintain synchronism when subjected to small disturbances. In this context, a disturbance is considered to be small if the equations that describe the resulting response of the system may be linearized for the purpose of analysis [1]. Such disturbances happen all the time due to small variations in loads and generation. The physical response of the system may be a steady increase in rotor angle due to lack of synchronizing torque or rotor oscillations of increasing amplitude due to lack of sufficient damping torque. Important to observe is that although the initial phase can be described by linear behaviour the consequences of these oscillations could be non-linear.

Measures to counteract small-signal instability are usually based on closed-loop controls. These devices provide dynamic control of electric quantities of the power system. Typical examples of closed-loop control devices include generator excitation control, power system stabilizers (PSS), Static Var Compensators (SVCs) and series capacitors with a closed-loop controlled varying capacitance. Closed-loop control devices are not included here as they fall outside the scope of the project.

Normally, power oscillations associated with small-signal stability have amplitudes which are non-relevant to protection applications. Consequently, in this report we will exclusively discuss the interaction between transient instability and protection applications. However, in case small-signal instability results in power oscillations relevant to protection applications the fundamental principles and relevant issues applicable to transient instability are also true for small-signal instability.

2.2 Voltage Instability

Voltage stability is concerned with the ability of a power system to maintain acceptable voltages at all buses in the system under normal conditions and after being subjected to a disturbance. A system enters a state of voltage instability when a disturbance such as an increase in load demand or a change in system conditions causes a progressive and uncontrollable decline in voltage. The main factor causing instability is the inability of the power system to meet the demand for reactive power [1]. According to the time duration of load response, voltage instability can roughly be divided into two different categories; short-term and long-term voltage instability. Induction motors restore their active power consumption within one second (short-term) while Load Tap Changers (LTCs) will restore voltage dependent loads within one to several minutes (long-term). Also thermostatically controlled loads have a recovery time in the range of minutes. In case of long-term voltage instability generator current limiters may be activated to protect the generators from thermal stresses. When current limiters are activated the operating condition of the power system is often seriously aggravated. Particularly armature current limiter activation often leads to blackouts. In many situations the distinction between voltage and transient instability is diffuse as aspects of both phenomena may exist for a single disturbance.

Voltage instability may be caused by a variety of single and/or multiple contingencies. Typical initiating events are heavy load pick-up and grid weakening. Obviously generator tripping also contributes to voltage instability; especially tripping of generators located close to the loads supporting the voltage control in that area. Generator tripping can be the event which initiates voltage instability, but it may also be an accelerating element when it occurs some time into a voltage instability event.

In case of short-term voltage instability the system may collapse within a few seconds after the disturbance if no curative measures are taken.

For short-term voltage instability the fault clearing time may be essential as an induction motor dominated load, e.g air conditioning, may become unstable if the fault is present for a longer period.

During long-term voltage instability the power system normally reaches a quasi-stable low voltage operating point after the initial disturbance. Because of the voltage drop LTCs will start to restore the voltage on regional transmission and distribution levels. In turn the loads recover which leads to increased system loading. Consequently the voltage will further decline and the LTCs will operate again to restore the loads. This interaction between LTCs and increased system loading continues while the voltage on the transmission level declines continuously. The reactive power demand of the system is continuously increasing as the voltage is decreasing. Eventually the reactive power demand cannot be supplied by the generators and their current limiters operate. At this moment the voltage decay accelerates significantly, which in turn leads to generator tripping due to low voltage and cascading line outages due to overload. The voltage decay due to LTCs is obviously restricted to the operating range of the tap-changers.

In case of a heavy load pick-up in a highly meshed network the crucial aspect with respect to voltage stability will initially be related to whether local generators manage to meet the increased load demand without hitting their limits. As when the local units hit their limits, stability will depend on the capability of the surrounding system to provide active and reactive power. If the surrounding system is strong it will be able to support the highly loaded area successfully. However, if the surrounding system is weak a sufficient support will most likely not be given and the situation may aggravate to a voltage collapse. Generally speaking the more circuits and the shorter the lengths of the circuits in the grid, the stronger the network.

When a long distance separates a load centre from a significant amount of supply, a grid weakening between the two areas may lead to voltage instability. The remaining grid may not have the capability to transport the required power at a sufficient voltage level, which in turn increases the reactive power demand from the system and the tap-changer interaction as discussed above. Moreover this may lead to generators hitting their limits, cascading lines outages because of (distance) relays operating on overload and eventually to a collapse.

The case where generators located close to loads are tripped is similar to the case of a heavy load increase. Also in this case the stability will be decided by the capability of the surrounding system to provide active and reactive power to the area lacking generation.

To summarize, voltage instability is especially likely for system configurations where large amounts of power have to be transported long distances in a lightly meshed network as in the case for weak interconnections between remote generation areas and load centres.

In addition to the network configuration also the following aspects are important as far as voltage stability is concerned:

- Active and reactive power reserves. For example, generators, synchronous condensers and SVCs. Both the amount of available reactive power and the location are important.
- Passive reactive power reserves such as capacitors.
- System loading levels. High loading levels are critical.
- Low power factor.
- Load characteristics. Especially the load recovery due to LTC operation as discussed above (or thermostatic heating).

2.3 Frequency Instability

Frequency stability describes the ability of a power system to maintain the system frequency within an acceptable range during normal operating conditions or after a severe disturbance. Thus frequency instability occurs when there is a mismatch between load and supply and the system cannot compensate for this mismatch before the frequency reaches an unacceptable value. Typical events which may lead to frequency instability are major outages of generating units and splitting of the system into isolated areas.

In case normal frequency control measures fail to maintain the frequency within an acceptable range, it is still important to limit frequency excursions. Especially generators are sensitive to fairly small frequency deviations. Normally generators can operate within a band of ±0.5 Hz related to nominal frequency (50 and 60 Hz systems) without any restrictions. Additionally generators can operate outside these values for a limited time period given by manufacturing constraints.

Publication [3] refers to an example of typical steam turbine limitations during abnormal frequency conditions where the worst case limitations have been specified by five turbine manufactures with respect to 60 Hz operation [4]. The example indicates that operation between 58.5 and 57.9 Hz is permitted for ten minutes during the generator life time before turbine blade damage is probable. Note that steam turbines may be considered to be the weakest link with respect to low frequency operation. In Sweden thermal power units are tripped around 47.5 Hz to protect the steam turbines against detrimental vibrations. The hydro units in operation are more robust and can handle operating frequencies down to 45 Hz [5].

Due to its nature protection applications responding to frequency instability are normally rather straightforward. For example, unit devices protecting equipment from damage in the case of frequency excursions should respond to a certain frequency deviation present for a specified duration. Accordingly, simple frequency relays with settings relevant to the current application can be used. Similarly the process for System Protection Schemes responding to frequency instability is also straightforward, although extensive setting procedures in order to obtain the optimal curative measures may be required. Hence, no further attention is explicitly given to frequency instability in this dissertation. Still there is a close relationship between frequency- and transient instability and as far as undesirable distance protection performance is concerned, the discussion in section 3.2 is also relevant to events involving frequency instability.

2.4 The Relation Between Network Configuration and System Instability Phenomena

As indicated above the network configuration where large amounts of power have to be transported long distances over weak interconnections is vulnerable with respect to power system instability. In Table 2.1[1] a rough classification has been made with respect to the relation between network configuration and the different power system instability phenomena. The different system structures can roughly be

1. The table was originally introduced in [3].

divided into densely meshed transmission systems with dispersed generation and demand or lightly meshed transmission systems with localised centres of generation and demand. Furthermore the coupling of the local sub-system to the surrounding system can also be given a classification. The first characteristic includes transmission systems which are parts of larger power networks. The second characteristic includes transmission systems that are not synchronously interconnected with neighbouring systems or the largest partner in the current power network.

Table 2.1: The relation between network configuration and power system instability phenomena.

	Densely meshed system with dispersed generation and demand	**Lightly meshed system with localised centres of generation and/or demand**
Sub-system being a part of a large power network	Small-signal instability Thermal overload No large frequency variations	Transient instability Small-signal instability Voltage instability
Separate systems not synchronously interconnected to other systems. Systems by far the largest sub-system in a power network	Thermal overload Large frequency variation	Transient instability Voltage instability Large frequency variation

Chapter 3 Power System Instability and Local Area Protection

During a power system instability the presence of negative or zero sequence currents is usually limited. Therefore, protection schemes responding to unbalanced operation should be unaffected by instability events. Most relays respond to a quantity directly linked to the safe operation of the particular system component protected by the relay unit. Irrespective of the surrounding system status, the relay should operate when the relay criteria reach the tripping level(s) in order to avoid equipment damage. Also this type of protection devices is of less importance as far as power system instability is concerned. Finally, there is a class of relays responding to the impedance calculated from measured voltages and currents. Distance protection belongs to this class and is mainly used as line protection, but can also be utilized for generators. For generators the impedance protection is used against internal short circuit- and/or loss of excitation. Generator impedance protection is of less concern with respect to power system instability due to limited reach and its reverse characteristic. However, in the case of strong transmission networks the concerns associated to transient instability and line distance protection may be more relevant to the generator protection. In this chapter the focus is on line distance protection as all relevant phenomena are then included. At the same time identical fundamental concepts can be applied on any relevant issue involving generator impedance protection.

3.1 Distance Protection and Voltage Instability

Here the performance of distance protection during *long term* voltage instability is discussed. The behaviour of distance protection during short term voltage instability is similar to the performance during transient instability. For the relation between short term voltage instability and distance protection the reader is referred to section 3.2.

3.1.1 Distance Protection may Contribute to Voltage Instability

One can define 10 distinct types of possible short circuit faults in a three phase power system [6]. In order to calculate the correct fault distance for all types of faults, different voltage and current signals are used by the distance relay. Basically two types of equations are applied. For three phase faults and phase to phase faults (3.1) is used where L1 and L2 are the faulted phases. Equation (3.2) is valid for phase to ground fault involving phase L1.

$$\bar{Z}_r = \frac{\bar{U}_{L1} - \bar{U}_{L2}}{\bar{I}_{L1} - \bar{I}_{L2}} \tag{3.1}$$

$$\bar{Z}_r = \frac{\bar{U}_{L1}}{\bar{I}_{L1} + \dfrac{\bar{Z}_0 - \bar{Z}_1}{\bar{Z}_1} \cdot \bar{I}_0} \tag{3.2}$$

$\bar{U}_{L1}$, $\bar{U}_{L2}$: Phase voltages at the relay location.

$\bar{I}_{L1}$, $\bar{I}_{L2}$: Phase currents at the relay location.

$\bar{I}_0$: Residual (zero sequence-) current at the relay location.

$\bar{Z}_1$: Positive sequence impedance for the primary protected circuit.

$\bar{Z}_0$: Zero sequence impedance for the primary protected circuit.

$\bar{Z}_r$: the apparent impedance as seen by the distance relay.

Voltage instability is a phase symmetrical phenomenon. Hence no zero sequence component is present and the phase voltages and currents are symmetrical. Thus the apparent impedance $\bar{Z}_r$ as seen by a distance relay during voltage instability is given in (3.3). Here $\bar{U}$ is the line to line voltage and P and Q are the injected active and reactive power at the location of the relay.

$$\bar{Z}_r = \frac{\bar{U}_{L1}}{\bar{I}_{L1}} = \frac{|\bar{U}|^2 \cdot (P + jQ)}{P^2 + Q^2} \tag{3.3}$$

In case $\overline{Z}_r$ remains within the area of one of the pre-defined tripping zones during a time exceeding the setting of the timer associated to the zone, the relay will operate. Low system voltages and high (reactive) power flows are typical for voltage instability events. It follows from (3.3) that these events will lead to a reduced apparent impedance which in turn may result in undesirable relay operation. This behaviour is normally devastating as the system already is in a critical operating condition.

Case **a** in Fig. 3.1 corresponds to a short circuit fault while case **b** corresponds to a scenario where the zones of operation are slowly (seconds to minutes) approached from outside as the voltage decreases and/or the reactive power increase. Undesirable relay operations due to voltage instability will then mainly be initiated by the zone with the longest reach. Normally this is the zone used for remote back-up protection; i.e zone 3. In some applications start elements are applied which have a longer reach than the zone 3. However, they can usually not trip the line but only activate the tripping elements.

The sensitivity for mal-trips due to voltage instability is depending on the length of protected lines, the relay characteristic, the devices used to prevent load encroachment, the safety margins concerning overload and the robustness of the system. Also the *protection philosophy* in the setting process of the distance relay with the longest reach is important; is dependability or security emphasized?

Paper A proposes a method to avoid incorrect distance relay tripping in the case of voltage instability.

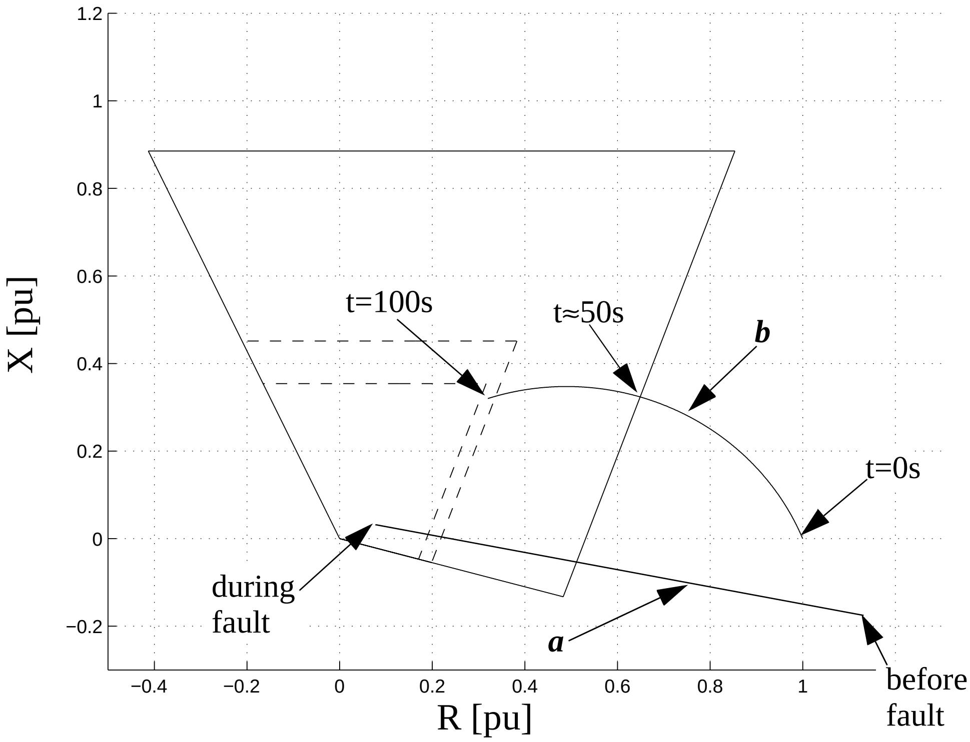


Figure 3.1 Apparent impedance as seen by a distance relay during different power system events. ***a***: Short circuit fault involving the primary protected circuit. ***b***: A case where the voltage linearly decreases from U=1 pu to U=0.8 pu and the reactive power linearly increases from Q=0 pu to Q=1 pu during a time interval of 100 s. The injected active power is held constant at P=1 pu.

3.1.2 Worldwide Experience on Voltage Collapse Related to Distance Protection

Undesirable distance protection operations during long term voltage instability have contributed to blackouts worldwide. About 52 seconds after the initiating event in the Swedish blackout in 1983 [7-11], at a voltage level of approximately 300 kV, a distance relay located in the receiving end of the long distance transmission line between Kilforsen and Hallsberg operated. Roughly 1 second later cascading outages followed and almost instantaneously south Sweden experienced a blackout. About 65% of the pre-fault load was lost. As distance protection usually is directional it may seem a bit remarkable that the relay in the receiving end of the line between Kilforsen and Hallsberg operated. However the relay was operated in such a way that when the apparent impedance remained within the start zone for a time longer than 3.2 seconds without relay operation, the start element alone initiated tripping. In such a case the relay behaved as a non-directional unit with a long reach having a circular impedance characteristic, where operation due to load encroachment was not obstructed.

On July 2, 1996 the WSCC system was operated within its transfer limits and only a few facilities were out of service [12-14]. Due to a single phase to ground fault resulting in remedial actions, and incorrect relay operation as a result of mechanical failure the system was significantly weakened. About 24 seconds after the initial fault an important 230 kV line tripped through its zone 3 relay due to moderate overload and moderate voltage depression. Cascading outages resulted and approximately 10 seconds later the system had separated into five electrical islands. About 2 million customers were affected by the disturbance. Furthermore, a zone 3 distance relay operated incorrectly during the restorative process due to load encroachment and delayed the restoration of the system.

On March 11, 1999, Brazil [15] faced the most severe power interruption in its history. About 72 % of the pre-disturbance load amounting to 34 200 MW was affected. The initiating event of the blackout was a phase to ground fault in a substation which led to the loss of five incoming 440 kV lines. The system survived this contingency and recovered to a quasi stable operating point. About 12 seconds after the phase to ground fault another line tripped. Cascading outages followed and approximately 18 seconds later the entire network collapsed. The tripping of the line after 12 seconds was initiated by the start unit of the distance protection. The start unit had the longest reach of all zones of operation to provide remote back-up for all adjacent lines which are much longer than the given line. The start unit had been given a setting corresponding to a very long reach with an associated time delay of 1.5 seconds. Hence, when the line loading increased after the initial fault and likely in combination with an increasing reactive power demand throughout the entire system, the apparent impedance entered the start zone and the relay operated.

Further examples where undesirable (zone 3) distance protection operations have contributed to blackouts include the ¨November 9, 1965 Northeastern U.S/Canada disturbance and the August 22, 1987 Western Tennessee U.S blackouts [16].

3.2 Distance Protection and Transient Instability

Power oscillations are inherent to power systems. They may result from any power system event such as line switching, short circuit faults, generator tripping or load shedding. During normal operation the magnitude of the oscillations are usually small and quickly attenuated. However, during abnormal operation the oscillations can be severe and are in some cases of an increasing nature. In this section the relation between power oscillations and distance protection is examined.

3.2.1 Distance Protection During Transient Instability

Referring to the frequency range of power oscillations given in 2.1 power oscillations may be the source of incorrect relay behaviour as the cycle times of the oscillations are in the same time range as the timer settings of the protection devices.

The two machine system in Fig. 3.2 can be used to analyse the performance of distance protection during power oscillations. The machines are interconnected through a 200 km long transmission line and they are represented by voltage sources with constant magnitude behind their transient reactance. By studying the apparent impedance as seen by a relay located at C for different transfer angles the effect of power oscillations can be examined. The analysis made in this section is similar to the one given by Kundur in [1].

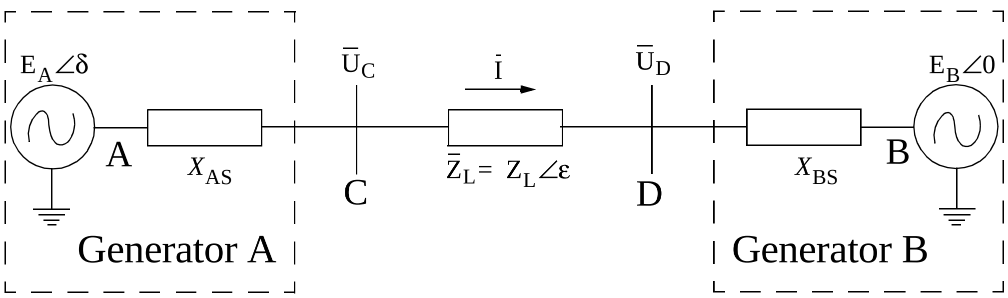


Figure 3.2 Two machine system.

In Fig. 3.2, $\overline{E}_A$ and $\overline{E}_B$ are the internal voltages of the machines and X_{AS} and X_{BS} are the transient reactances. $\overline{E}_B$ is assumed to be the reference phasor and δ represents the angle by which $\overline{E}_A$ leads $\overline{E}_B$. Hence the current $\overline{I}$ is given in (3.4) and the voltage $\overline{U}_C$ in (3.5).

$$\bar{I} = \frac{E_A\angle\delta - E_B\angle 0}{jX_{AS} + \overline{Z}_L + jX_{BS}} \tag{3.4}$$

$$\overline{U}_C = E_A\angle\delta - jX_{AS}\bar{I} \tag{3.5}$$

The apparent impedance as seen by the relay at C during phase symmetrical operation can be determined when (3.4) and (3.5) are inserted into (3.6).

$$\overline{Z}_C = \frac{\overline{U}_C}{\bar{I}} = \frac{E_A\angle\delta}{\bar{I}} - jX_{AS} \tag{3.6}$$

$$\overline{Z}_C = -jX_{AS} + (jX_{AS} + \overline{Z}_L + jX_{BS}) \cdot \frac{E_A\angle\delta}{E_A\angle\delta - E_B\angle 0} \tag{3.7}$$

Fig. 3.3 shows the locus of $\overline{Z}_C$ as a function of the transfer angle δ in the RX-diagram when different ratios of the magnitude of the internal voltages of the generators are applied in (3.7). The zones of operation of the relay are set to cover 80%, 120% and 200% of the line length, respectively.

During a power swing the transfer angle δ will vary. For a stable swing, δ gradually increases until the maximum value is reached where the trajectory shifts direction and δ decreases until the minimum value is reached where the trajectory ones again shifts direction. This sequence of events is repeated until the oscillations are damped out. If the trajectory of δ reaches beyond 180 degrees the swing can be considered to be unstable.

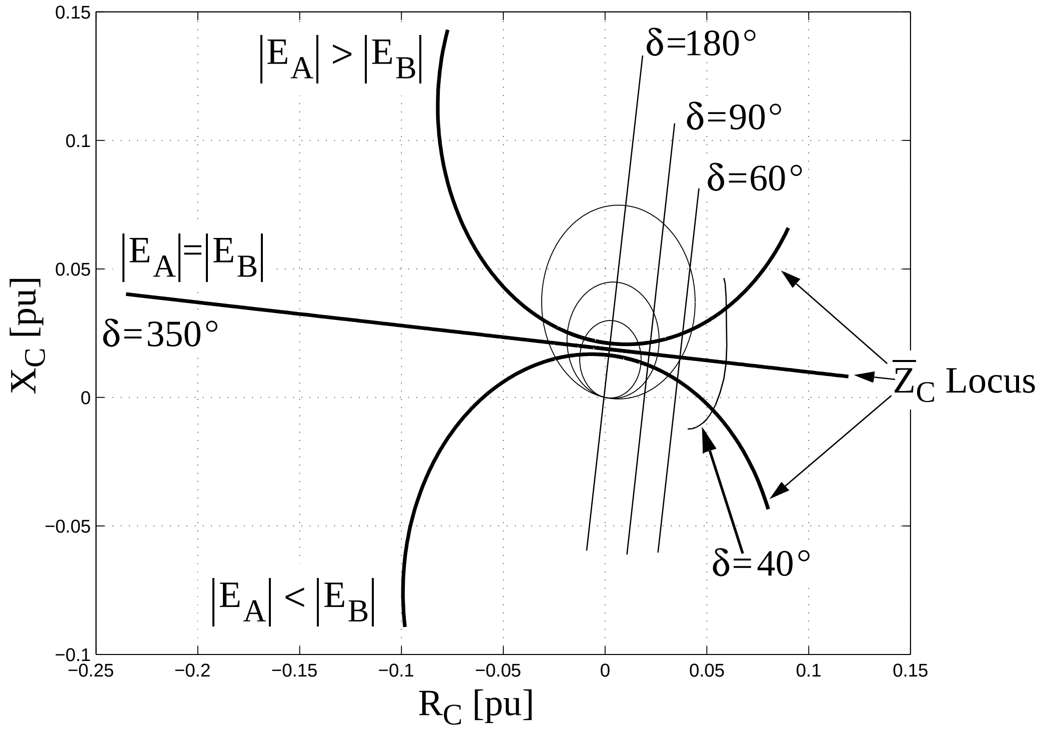


Figure 3.3 The locus of $\overline{Z}_C$ (bold curves) for different values of the ratio $|E_A|/|E_B|$ when δ is increased from 20° to 350°. Specific values of $\overline{Z}_C$ at a given transfer angle δ are given by the intersection of the locus of $\overline{Z}_C$ and the characteristic for constant δ. In addition the three zones of operation of the relay are indicated.

For the transfer angle δ=0, the current $\bar{I}$ in (3.4) is zero and thus the apparent impedance $\overline{Z}_C$ is infinite. As the transfer angle increases the apparent impedance $\overline{Z}_C$ moves towards, and enters the zones of operation eventually. Fig. 3.4 shows that the point where the locus crosses the total system impedance corresponds to a transfer angle of 180 degrees. If the angle reaches 180 degrees loss of synchronism occurs (a pole is slipped for generator A). Unless the system is separated by protective devices the initial pole slipping will be followed by repeated pole slips in rapid succession. During pole slipping the voltages and apparent impedances at points near the *electrical centre*, i.e the intersection point between the system impedance and the δ trajectory, oscillates rapidly. Furthermore, the voltage at the electrical centre is zero for a transfer angle of 180 degrees. Consequently the relay at C will actually see a three phase fault at the electrical centre. In case of identical internal voltage magnitude the locus of $\overline{Z}_C$ is a straight line. The impedance loci are circles with their centres on the extensions of the impedance line AB in case the internal voltage magnitude differ. For $|E_A| > |E_B|$ the electrical centre will be above the impedance centre while it will be below when $|E_A| < |E_B|$.

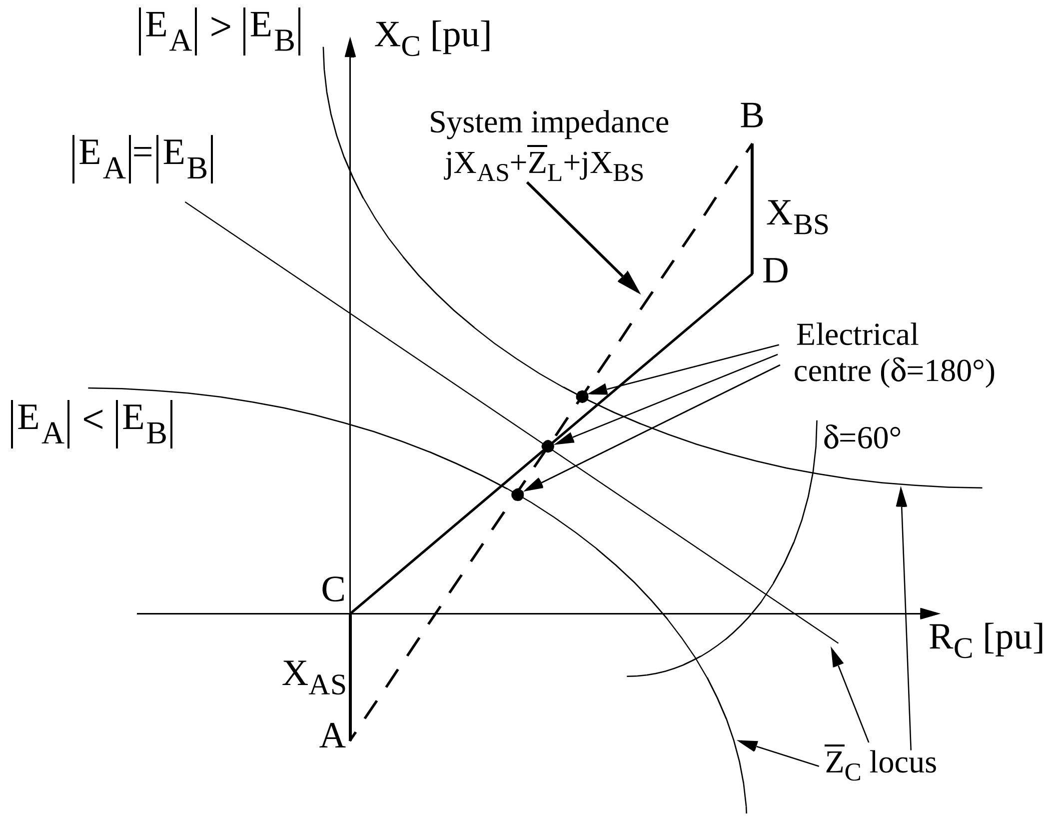


Figure 3.4 The electrical centre for the two machine system in Fig. 3.2.

Fig. 3.3 indicates that when a power swing with a given cycle time reaches a certain angle the apparent impedance will remain within a tripping zone during a certain time period. The timer of the zone may expire and consequently the relay operates. In this way the distance relay may operate undesirably for a stable power swing. The relay type strongly influences the sensitivity for this type of mal-trips. Numerical relays usually reset the associated timer when the apparent impedance leaves the tripping zone. This means that the impedance must remain within the area of the tripping zone during the entire timer setting period to initiate a tripping signal. For relays supervised by a start element, the apparent impedance must not always remain within the tripping zone during the entire timer setting period to initiate tripping. As the timers usually are not reset until the impedance leaves the start zone. Hence, as long as the impedance remains within the area associated to the start element the impedance can enter, leave and re-enter the zones of operation unlimited times and the timer will in any case continue to count. This means that a tripping signal is generated immediately when the zone of operation is entered after the timer has expired. If the start element has a shape which surrounds all the tripping zones the area which decides the likelihood for mal-trips due to power swings has increased. Therefore it is very important to take this effect into account when power oscillations are considered with respect to undesirable distance protection operations.

Fig. 3.3 and Fig. 3.4 illustrate the impedance trajectories for a relay located in the sending end of a line. The trajectories for the receiving end are identical but reversed.

Observe that the assumption made above where the internal machine reactance and voltages are given fixed values is a rough reflection of the system behaviour suitable for illustration. In real operation the electrical centres are non-fixed points as the internal machine impedances and voltages will vary during dynamic conditions.

Distance protection should not operate for stable swings. However, in the case of unstable power swings the protection system should operate to divide the system into stable sub-systems or to separate the ”sick” part of the system from the ”healthy” parts. The issue is further discussed in the next section.

3.2.2 Power Swing Detectors - Out-of-Step Protection

Different approaches for Power Swing Detectors and Out-of-Step Protection have been suggested throughout the years. In [17] a method to avoid mal-trips due to high frequency (above 6 Hz) power swings is proposed based on the phase angle of the voltages at the line terminals and at the fault location. The method is restricted to avoid zone 1 mal-operations due to power swings. Another indicator is proposed in [18-20] where tripping is prevented if the rate of change of an electric quantity exceeds a threshold value. In [21] decision trees are used to classify a transient swing on the basis of real-time phasor measurement. Furthermore, neural networks are used in [22] to detect power swings. An adaptive out-of-step relay is proposed in [23,24] which uses the equal area criterion and GPS technology. Also the algorithm introduced in [25] applies the equal area criterion to assess the stability of the generators and determine when pole-slipping will occur. In [26] circle fitting and parameter estimation are applied to discriminate power swings from faults. However, the most common method used for Power Swing Detectors and Out-of-Step Protection is based on the transition time through a blocking impedance area in the RX-diagram.

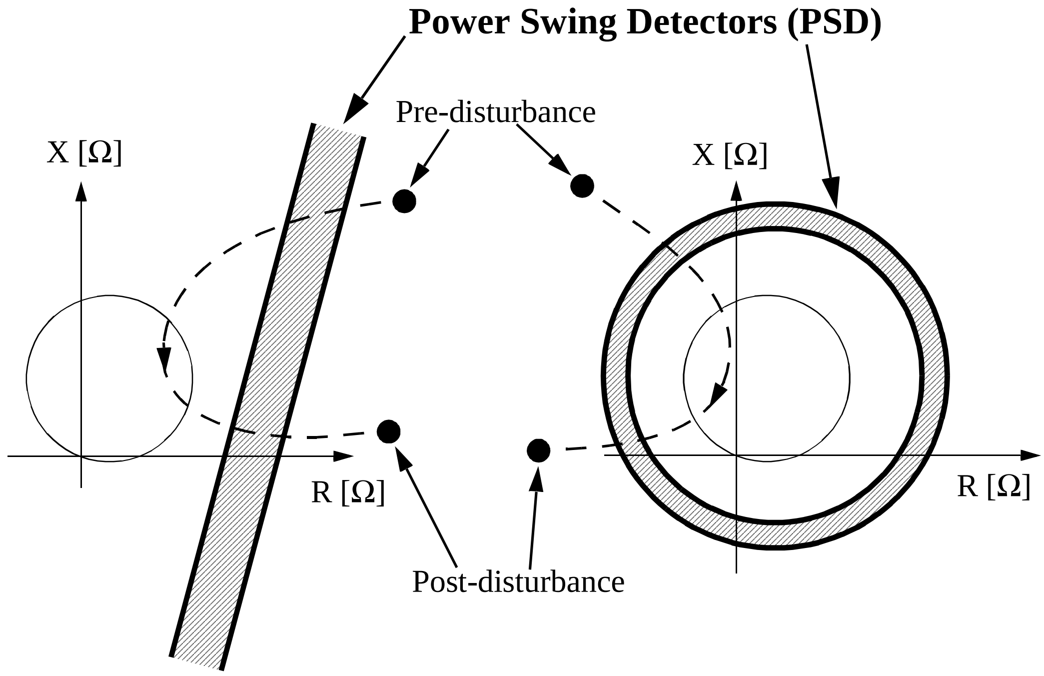


Figure 3.5 Vertical and circular characteristics for Power Swing Detector schemes. The dashed lines indicate trajectories for the apparent impedance during a power swing. The left scheme is operated at the sending end of a line and the right scheme is located at the receiving end of a line.

Basically the method uses the feature that the movement of the apparent impedance during power swings is slow as compared to its movement for short circuit faults. Fig. 3.5 shows two different characteristics of Power Swing Detector (PSD) schemes. When the apparent impedance penetrates the outer circle or line of the PSD schemes a timer is started. If the impedance crosses the grey area very rapidly the PSD determines a short circuit fault and tripping is permitted. If the transition time for the apparent impedance through the grey area exceeds the pre-set timer value, the tripping function is blocked during a certain time. Usually the pre-set value for the timer amounts to about 80 ms and tripping is blocked during a couple of seconds.

A circular PSD device is discussed in [27] where the inner circle is composed by the outermost zone of operation i.e zone 3. In order to cater for the fastest possible swings the outer circle is normally set with a reach as large as possible and consistent with load discrimination. However, to achieve satisfactory performance the reference asserts that the outer circle should have a diameter of at least 1.3 times the diameter of the outermost zone of operation.

In some protection schemes the PSD is used alone. This means that the distance relays will not operate due to stable power swings but neither the unstable power swings will be controlled. Thus some device is needed as a supplement to the PSD to distinguish stable power swings from unstable ones so that adequate relay action can be obtained. This can be achieved by adding an additional circle (mho relay) or line (blinder) to the characteristics in Fig. 3.5. If the PSD has detected a power swing, the Out-of-Step Characteristic (OSC) is activated to decide if the swing is stable or unstable. The location of the line and circle related to the OSC in Fig. 3.6 is usually determined by simulating numerous power swing cases [6]. The impedance trajectory as seen by the distance relay for each of the stable cases is analysed. It will be found that all stable swings come no closer than a certain minimum distance from the origin in the RX-diagram. In order to detect unstable swings the OSC is usually given a position at a shorter distance from the origin than the minimum distance obtained from the simulations. When the PSD in Fig. 3.6 detects a power swing the distance relay waits for the apparent impedance to pass the OSC. If the swing is stable the OSC is not passed and the relay is inactivated while if the swing is unstable the OSC will be penetrated and the relay initiates tripping.

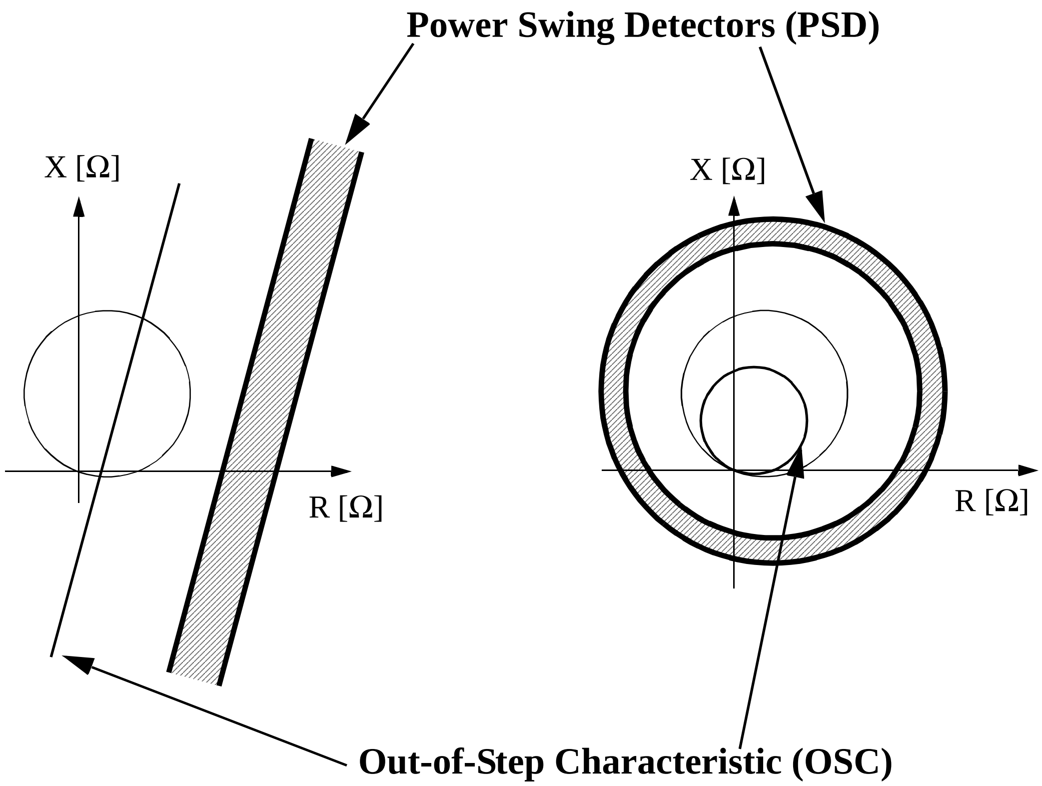


Figure 3.6 Power Swing Detectors and Out-of-Step scheme for relays located at the sending end.

Sometimes the inner circle or the inner line of the PSDs in Fig. 3.5 is applied as the boundary for stable swings. When the apparent impedance passes the outer circle or line the timer is started. If the inner circle or line is penetrated shortly after the timer is started the device declares a short circuit fault. Alternatively, if the inner circle or line is not passed the device declares a stable swing while in case the inner line or circle is penetrated after the timer has expired the device signals an unstable swing. However, depending on the system configuration nearby the relay this solution may not be acceptable with respect to line length, fault clearing, load discrimination and the nature of possible power swings.

If the line flow may occur in both directions the PSD and the OSC must be duplicated; one application for sending and one for receiving operating conditions. The application for the receiving operating condition looks similar as for the devices in Fig. 3.6 but is located on the opposite side of the tripping characteristic.

The system in Fig. 3.7 can be used to study the influence of the source impedance on the apparent impedance as seen by a relay located at bus T during power swings. In the system one generator is connected to an infinite system through a single transmission line. In Fig. 3.8 two different swing loci as seen by the relay are illustrated where the ratio between the impedance of the transmission line and the source impedance is varied.

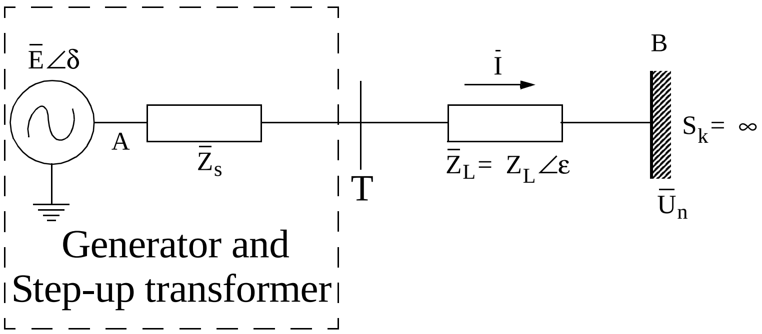


Figure 3.7 A generator connected to an infinite system through a transmission line.

Fig. 3.8 indicates that for generators connected to the main grid through a weak interconnection (large line impedance) the electrical centre may appear on the transmission line. However, for generators connected via a strong grid the electrical centre will be in the step-up transformer or in the generator itself. Although power oscillations are mainly relevant in the case of weak connections, they may also be present in strong line configurations. Consequently, the Power Swing Detector and the Out-of-Step Characteristic included in the line protection may be incapable to detect swings in the case of this type of line configurations. To cope with the phenomenon the Generator Out-of-Step Protection is introduced. The Generator Out-of-Step Protection [28] operates similar to Out-of-Step Protection for transmission lines and is used to clear unstable swings when the electrical centre is within the generator or step-up transformer. Note that line protection schemes may be unaffected by the phenomenon as certain (mho) distance relays inherently adjust their tripping zones with respect to the source impedance [29].

In addition to the source impedance also a low excitation level tends to contribute to an impedance trajectory through the step-up transformer or the generator. See the case $|E_A|<|E_B|$ in Fig. 3.3.

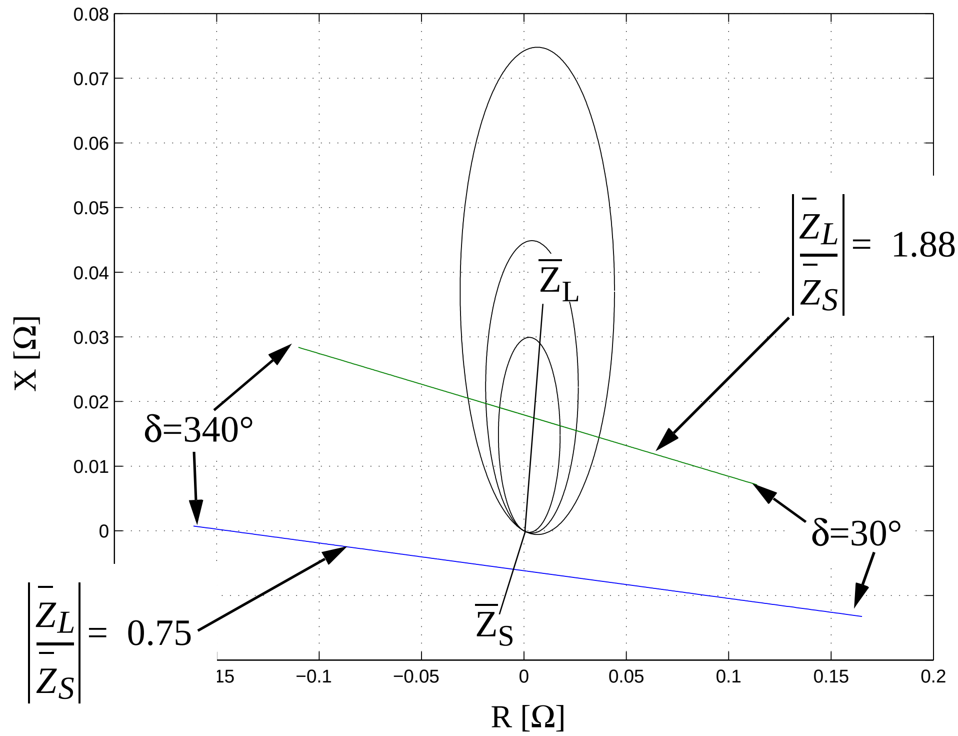


Figure 3.8 The apparent impedance trajectories as functions of the transfer angle δ for two different ratios of the relation between the line impedance and the source impedance as seen by the relay located at T in Fig. 3.7.

As intimated in the beginning of this section many approaches of Power Swing Detectors and Out-of-Step schemes have been proposed throughout the years. One reason is that the conventional schemes described in this section have their limitations and thus sometimes operate unsatisfactory. The limitations involve reduced availability in the case of long lines, setting conflicts with respect to different oscillation-frequencies, blocked fault clearing and incorrect operation in case of slowly decreasing fault resistances. In ***Paper B*** a proposal for a PSD is discussed which avoids most of those setbacks.

3.2.3 Worldwide Experience on Distance Protection and Transient Instability

In this paragraph a few relevant events are briefly discussed. The data presented were obtained from a survey carried out by CIGRÉ WG 34.09. On July 27, 1989 in Portugal a Power Swing Detector failed to operate and on August 24, 1993, in Spain three distance relays operated due to power swings as the swings had a higher frequency than the effective range of the blocking unit. Furthermore, on July 18, 1995 the WSCC system was subjected to incorrect out-of-step blocking during non-three phase faults. The location of the out-of-step protection was the main reason for inadequate performance during a disturbance in South Africa on June 7, 1996.

In Florida [30] and in South Africa [31] incorrect relay behaviour during power swings has been (and still is) a major concern.

An unwarranted distance relay operation due to a power swing was the immediate reason for the system breakdown in the south-western part of Sweden and Denmark in 1956 [32]. As a result power oscillations and associated protection measures were given significant attention. However, apart from a limited number serving interconnections between Sweden and the other Nordic countries, all Power Swing Detectors were taken out of service in the middle of the seventies. To the author’s knowledge no formal investigation was carried out and the decision was most likely based on the following arguments. As the transmission system recently had been reinforced power oscillations were not expected to cause any trouble and PSDs were therefore considered unnecessary. In addition some doubts were addressed towards their operational reliability. The general opinion is that power oscillations were rare in the Swedish transmission system during this period and the removal of the PSDs was never questioned. However, in the late evening of the New Years day, 1997, the Nordic power system was subjected to serious inter-area oscillations. The oscillations resulted from a busbar fault coincident with large power flows in an unusual direction. A few generator units and lines were lost but no load was affected. However, a couple of distance relays were very close to trip due to the impedance swings. In case these relays had ordered tripping a disturbance similar to the 1983 [11] had most likely occurred. In case PSDs had been in service, the risk of incorrect relay operation due to the swings had been eliminated. The number of recorded oscillation events has increased significantly during recent years in the Swedish power system. In 1996 the annual number of recorded inter-area oscillation events amounted to about 15 while in the year 2000 this number had increased to more than 300 [33]! In fact, in a few cases, operating conditions have occurred where the system was close to its limits and on the brink of a severe disturbance. Note that about 30 % of the events recorded in 2000 were related to one specific maintenance job lasting a period of three weeks.

Chapter 4 Power System Instability and System Protection Schemes

The protection schemes discussed here are intended to counter extreme contingencies and normally involve dispersed system devices for detection, data acquisition and curative measures. These schemes are referred to by different names e.g ”System Protection Scheme”, ”Wide Area Protection Scheme”, ”Special Protection Scheme”, ”Contingency Arming Scheme”, ”Discrete Supplementary Controls” and ”Remedial Action Scheme”. Normally the expression ”Wide Area Protection Scheme” is exclusively used for schemes introduced to counter complex and large phenomena which may jeopardise the integrity of the whole system. Other expressions may range from very local schemes to extensive wide area schemes. In a recent report [3] published by CIGRÉ, TF 38.02.19 the term ”System Protection Scheme” has been selected and will also be used throughout this thesis.

System Protection Schemes are an attractive alternative for increasing the utilisation of electrical power systems. First of all the economical aspects are in favour of System Protection Schemes as control and protection equipment are less expensive than EHV hardware equipment. Furthermore, System Protection Schemes can mitigate wide area disturbances effectively. Finally, the environmental aspects of System Protection Schemes are appealing as no new line corridors are required. The fast progress during recent years within the area of numerical and communication technologies has increased the potential of technically complex and cost-effective System Protection Schemes. The ability to acquire and process wide area data has also improved significantly. The Phasor Measurement Unit [34-36] and inexpensive fibre optics are two attributes which have simplified the realization of these features. Particularly the reliability can be improved if compared to older solutions. Moreover there is a trend today that protection and control functions are merged together in sophisticated substation and control units. This process also facilitates System Protection Schemes.

Extensive surveys over System Protection Schemes have been made by both Cigré and IEEE [3,37-39]. In addition a number of detailed publications over specific System Protection Schemes [40-44] and related subjects [45-56] have been published. The material in this chapter is to a large extent based on these publications. Appendix 1 gives a general overview with respect to the relations between different power system events, type of system, network configurations, curative measures and the indicators to be used to detect abnormal operating conditions and initiate the curative measures. The appendix can be considered as a summary of the material published in this chapter.

4.1 System Protection Schemes

Conventional power system protection is mainly used to protect power system equipment from damage while the fundamental aim of System Protection Schemes is to protect the power system against partial or total breakdown. To obtain this objective protective measures are taken when abnormal operating conditions are identified. For these occasions no ”traditional fault situation” is present but the system itself may be in transition to a dangerous situation such as a wide area disturbance or a complete system blackout. Accordingly the protective measures are used to counteract this transition and bring the system back to a safe operating condition.

In [3] the following definition is given, ”*A System Protection Scheme is designed to detect abnormal system conditions and take predetermined, corrective action (other than the isolation of faulted elements) to preserve system integrity and provide acceptable system performance*” and in [37] ”*A System Protection Scheme is a protection scheme that is designed to detect a particular system condition that is known to cause unusual stress to the power system, and to take some type of predetermined action to counteract the observed condition in a controlled manner*”. Note that in [37] System Protection Schemes are referred to as Special Protection Schemes.

System Protection Schemes (SPS) are used for different purposes. Below their main objectives are listed:

1. **Operate power systems closer to their limits.**
   Due to deregulation and environmental constraints the operating margins have been reduced in many power systems worldwide. SPS are used to operate power systems closer to their limits without reducing the operating security of the system or impairing overall economic objectives. A typical application may be the reduction of congestion limitations between supply and load areas. Similarly, in the case of limited financial resources SPS may be used to avoid or postpone reinforcements of the transmission system without reducing its operating security.

2. **Increase power system security (particularly for extreme contingencies leading to system collapse).**
   By including SPS and maintaining the original operating limits the power system security can be increased. This type of SPS are often designed to counteract serious disturbances.

3. **Improve power system operation.**
   SPS may be designed to cope with operational difficulties imposed by certain power system characteristics. Examples are operating conditions characterised by a higher rate of exposure to multiple faults than tolerated by the design criteria or large frequency and voltage variations in adjacent sub-systems. Actions are typically taken when a certain ”key element” is lost or a particular operating condition is present.

4. **Compensate for delays in a construction program.**
   SPS may be used as a temporary solution such as before and during the time a new transmission line is constructed.

Normally, SPS are dormant integrated protection systems which operate infrequently. The control actions taken by SPS are usually pre-determined and the SPS can be armed or disarmed depending on the power system conditions. Fig. 4.1[1] shows the general structure of SPS. Generally all SPS include three main functions. First the scheme collects input data from the power system. These input data may be quantities like voltage or frequency. Alternatively, the input data are

1. Originally published in [3].

related to some specific power system event, for example the tripping of a specific transmission line. Next the scheme evaluates the input data and makes decisions for the actions to be taken. This task is performed in the ”DECISION PROCESS” block where the input data are used to represent some kind of *indicator(s)*. Normally the decision process is based on discrete feed forward laws. Finally the actions to be taken by the SPS are launched by the ”ACTION” block. Typical actions may be load- or generator shedding.

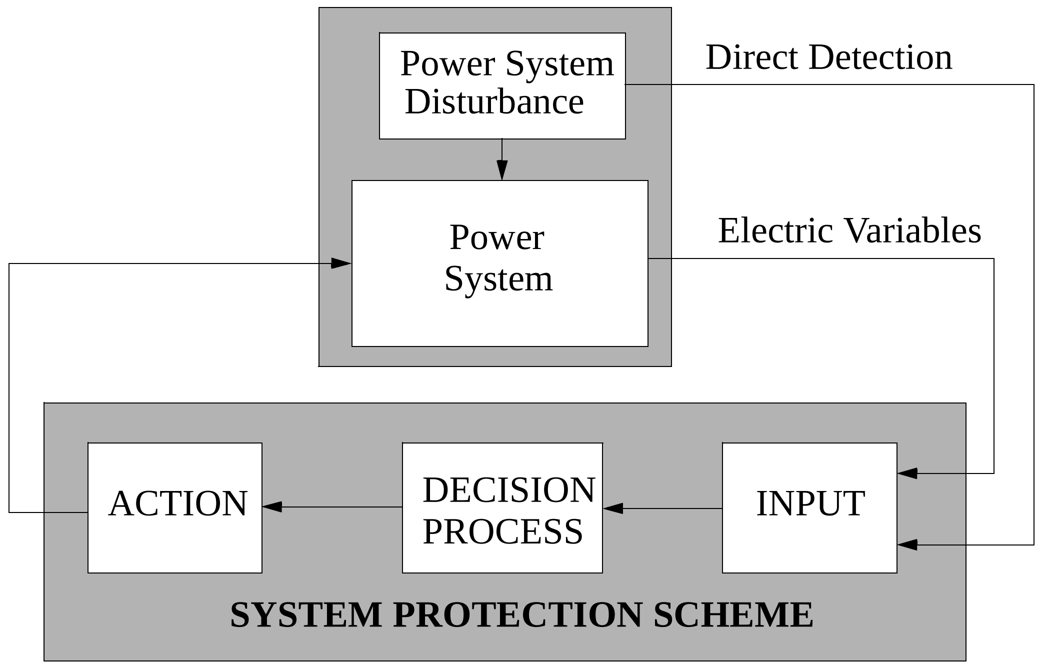


Figure 4.1 General structure of a System Protection Scheme.

4.1.1 Event- and Response based SPS

Dependent on the input variables, SPS are classified as response based or event based. SPS using input signals like voltage and frequency are referred to as ”*response based*”. SPS which use input signals that are based on specific events (or a particular combination of events) like the tripping of a certain line are called ”*event based*”. Event based SPS are of the open loop type whereas response based schemes are of the closed loop type.

Event based SPS are used in the case of critical events which are easy to identify and may lead to consequences which are particularly critical for the system stability and therefore require fast counteraction. The main benefit of event based SPS are their fast response. The fundamental idea of event based schemes is to initiate curative actions quickly and before overall system behaviour becomes degraded. This type of schemes may be very effective as rapid control actions to limit electromechanical dynamics before system stability is threatened. Event based schemes are based on rules obtained from off-line simulations. Typical examples of applications are generation rejection or remote load shedding initiated by the tripping of a specific transmission line. The major drawback of event based SPS is their reliability, as the performance of the schemes normally relies on a limited number of critical variables.

Response based SPS are inherently slower than event based SPS as they must wait for the system response; e.g the frequency or voltage to drop below a certain threshold. On the other hand response based SPS are more general than event based SPS as they react with respect to critical system quantities whatever the cause of the disturbance. Event based SPS will only take action in the case of specific events. Accordingly, response based SPS are also efficient for events that are not explicitly identified or foreseen. Response based SPS are usually simple and secure schemes and their reliability depend mainly on the variables chosen and their behaviour. Moreover, these schemes are usually insensitive to the failure of a single component as they are often decentralised. Two common examples of response based SPS are underfrequency- and undervoltage load shedding.

4.1.2 Local-, Central-, Remote-, Limited Area and Wide Area Applications

System Protection Schemes can be based on local, central-, remote-, limited area or wide area arrangements.

Local SPS acquire all the information necessary for the decision process at the same location as where the curative actions are performed. Generally local SPS are considered to be very reliable and secure as they are not dependent on long distance communication and their actions are limited. Often such schemes are distributed throughout a region of the network and together they fulfil the requirements. An example is UnderFrequency Load Shedding (UFLS), likely the most common local system protection scheme application. Normally a complete UFLS strategy is based on a number of load blocks at different locations (local UFLS SPS) which all are tripped with respect to local frequency criteria. In case of failure of a single local scheme the other devices will still be able to counteract the disturbance. *Limited area Remote* SPS are here considered to represent applications which affect a limited area but include more than one location, e.g remote load shedding. A typical example of limited area remote load shedding is that in case a unit is lost in a generator station a signal is sent from that station to initiate load shedding in another substation.

Central SPS collect data from remote locations and process these data at a central location. This central location may for example be the utility’s main building complex where the control room is located. When the decision process is completed, signals are sent to the remote locations to launch the curative measures. Obviously the central schemes are highly dependent on telecommunication facilities which influence their reliability. Central SPS may have the *Limited area* feature. However, more common is the *Wide area* approach. The difference between a Limited area remote scheme and a Limited area central scheme can be explained as follows. When the contingency has been detected locally the remote scheme directly issues orders to the remote station where the corrective actions should be taken. In the case of a Limited area central scheme, signals are first sent from the station where the contingency is detected to the central location, and after processing, from the central location to the remote station where the corrective actions are carried out.

The decision process of *Wide area* SPS uses input data from a large number of locations throughout a wide area. They can have the central approach but can also be represented by a number of remote stations interacting with each other. SPS based on a network of remote stations together with central schemes are obviously more complex than local SPS and are strongly dependent on communication tools. For these schemes the security is the main concern as in case of undesirable operation (during normal operation) the consequences will be significant. The different types of SPS arrangements are illustrated in Fig. 4.2.

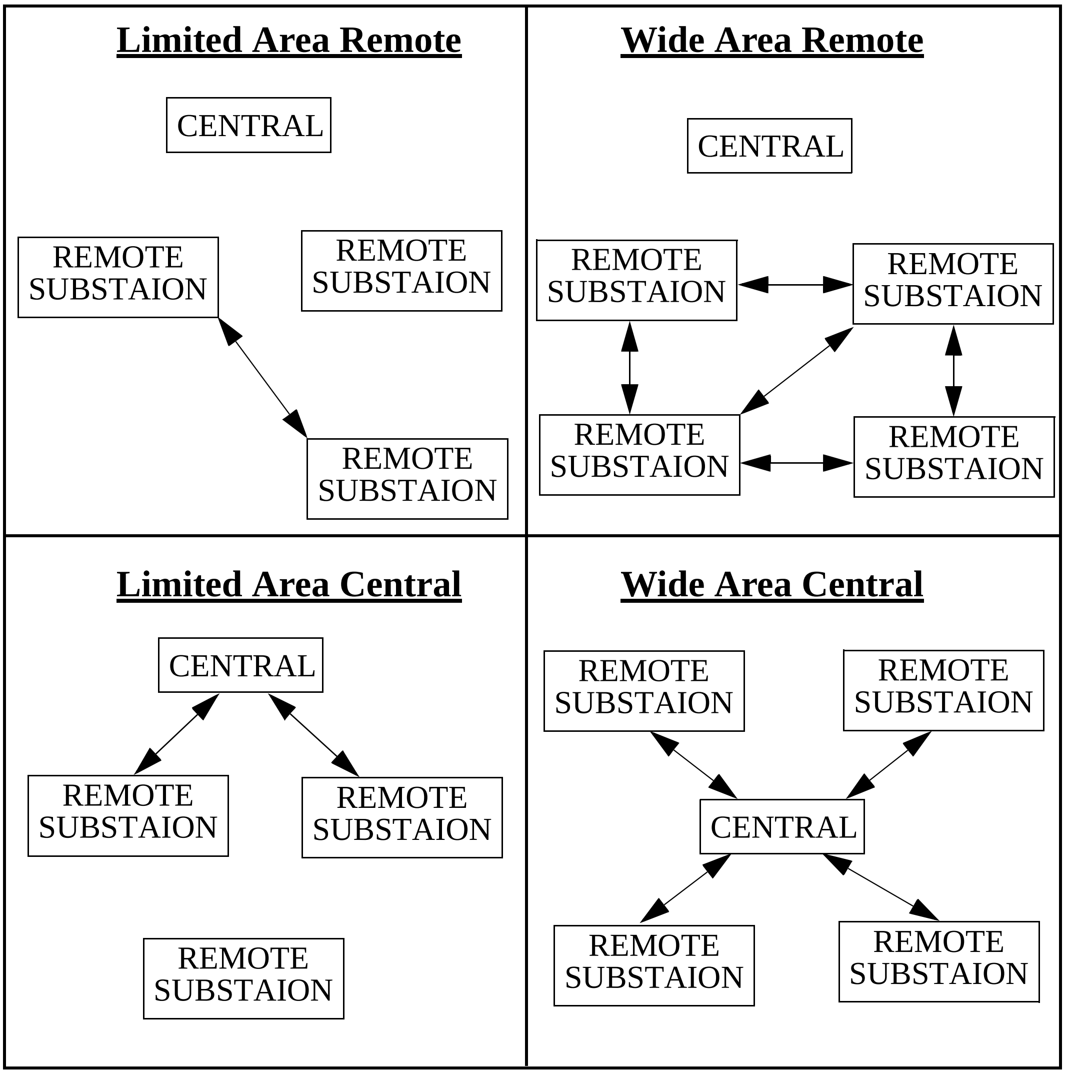


Figure 4.2 Illustration of Limited-/Wide area Central and Remote applications.

4.2 Detection and Control Indicators for System Protection Schemes

In order to obtain appropriate SPS operation, detection and control indicators are required. A large number of indicators based on sophisticated mathematical methods have been proposed for off-line studies applicable during the planning phase. However, real-time applications require indicators which are obtained very fast and thus there are few indicators, apart from measured electrical quantities and direct events, which are applicable. Dimension-less indices are also sometimes useful, for example in case of long term voltage stability events. However, they are more applicable as guidance for operators. Often the main concerns in case of SPS design may not only be the choice of indicators but the way of obtaining appropriate setting values for the indicators. The next sections briefly describe indicators applicable for the determination of power system instability.

4.2.1 Indicators to Determine Voltage Instability

Indicators for voltage instability are often related to the maximum loadability of the system. For event based SPS loss of generation, reactive resources and transmission facilities are typically used as indicators as they represent phenomena which may contribute to voltage instability. In the case of response based SPS the following indicators based on direct measurement represent the most common inputs:

- Bus voltage magnitude. In many systems the bus voltage magnitude is the main indicator available to detect voltage instability. However depending on the location in the system its reliability as an indicator varies significantly. For example, close to generators and at buses with a high level of shunt capacitor compensation the voltage may indicate a too positive system status. For buses located away from generation and with no shunt capacitor compensation the voltage may well be a valuable indicator.
- Reactive and active power output from generators.
- Reactive power reserves within regions.
- Active and reactive power flows on lines (tie-lines).
- Generator (field/armature) current limiter status.
- Active and reactive load demand.

Additional straightforward indicators which can be determined from loadflow solutions or measurements are the active/reactive line losses and sensitivities with respect to changes in active and reactive bus power [57]. A number of Voltage Collapse Indicators have been developed where the distance to voltage collapse can be obtained from a dimension-less index. Mainly two categories exist. First the straightforward type where the index is based on the fraction of the present value and the collapse value of any quantity; e.g the voltage or power flow. The second type is more extensive where the indices typically are given in a general form [58,59] as in (4.1).

$$VCI(z, z^c) = \sum_i w_i \cdot f_i(z, z^c) \tag{4.1}$$

Here $f_i(z,z^c)$ is a real-valued function of z and z^c; z is a vector consisting of measurable variables e.g the load bus voltages, load bus real and reactive power, generator reactive power etc.; z^c is a reference value of z and w_i are positive weighing functions. In order to detect voltage instability the VCI is compared to a threshold (TH) value. Thus system stability is decided with respect to the relations given in (4.2).

$$\begin{aligned} &VCI(z, z^c) \le TH \quad \Rightarrow \text{System is voltage stable} \\ &VCI(z, z^c) > TH \quad \Rightarrow \text{System experience voltage collapse} \end{aligned} \tag{4.2}$$

The indicators given so far are fairly simple (but fast) and are based on the threshold principle i.e when the indicator exceeds or drops below a pre-defined threshold value the corrective measures are carried out. Although the principle is simple the main challenge related to this approach is obviously the choice of appropriate threshold values. Today the setting values are often based on operator experience or numerous simulations. No explicit methods are available to optimize the corrective measures with respect to location, time for activation and extent. However, there are methods to predict voltage instability and thus the normal proceeding is to perform simulations where the point of instability is identified for different contingencies without corrective measures. The next step is to perform further simulations where corrective actions are included and based on these repeated simulations the setting values for the corrective measures can be decided. A number of methods applicable for the setting process of System Protection Schemes are briefly mentioned below. Most methods are only applicable for the planning phase while a few also can be used as on-line indicators.

Many static methods have been proposed to predict voltage instability. These methods exclude time dependent phenomena but are still considered valuable in the analysis of voltage instability as they are less computational expensive than detailed time-domain simulations. Although time-domain simulations are considered to reflect the most appropriate system behaviour, static and dynamic methods can be used jointly to obtain the most favourable settings of SPS equipment. Methods to identify voltage instability include *PV- and QV curves* [16]. Development of these curves is a fairly extensive work as every network configuration corresponds to a unique curve. In order to reduce the amount of work different curve-fittings methods may be used [60]. There are also methods based on PV curves with some extensions involving load margins, bifurcation points, sensitivity and energy methods [61-66]. Another extension of PV- and QV curves are the *PQV surfaces* [67] which can be developed for the entire system or for individual buses. Generally these curves and surfaces are used for planning, monitoring or post-disturbance investigations but they can also be used to control SPS measures. Different approaches based on the *Jacobian matrix* [68-74] are common tools for voltage instability identification. Generally the Jacobian is too computational demanding to be used as an on-line predictor and thus more suitable for the planning process. However, in [69] areas are merged together and treated as one bus in order to reduce computation data. Another but dubious method, due to its sensitivity to numerical inadequacies, is the *Convergence of the loadflow* [75,76]. There are also numerous *Impedance* based methods proposed for voltage instability identification. The Voltage Instability Predictor (VIP) based on a pair of impedances that coalesce when reaching the critical point [77-80] is the most encouraging as an on-line tool. Other proposals involve a *voltage stability Index for single lines* [81-85]. In [86] a method is proposed where the entire system is reduced to a single line which then is investigated by a single line index. Other methods use *Fourier transforms* [87,88], *Energy functions* [89,90], *Phasors* [91,92], numerical *Optimization techniques* [93-95] and methods based on *Neural network* [96-100].

Under Voltage Load Shedding represents an important curative measure in the case of voltage instability. Accordingly extensive effort has been given to indicators in order to assure optimal shedding [101,102]. In [103] a method is given to optimize the load shedding for load having a large share of induction motors. Other techniques which have been used to obtain an optimal UVLS scheme are numerical optimization based on an objective function and Fuzzy logic [104-106].

4.2.2 Indicators to Determine Transient Angle Instability

Due to the high speed requirements event based SPS are preferable to prevent transient instability. Typical events used as indicators are related to loss of generation-, transmission- and load facilities. For response based SPS, indicators obtained by direct measurements are normally used, but also indicators based on complex mathematical concepts. Typical quantities that can be monitored (and used as indicators) from both lines and generators include:

- Voltage threshold values exceeded by the voltage within a pre-defined time period.
- Power threshold values exceeded by the active power within a pre-defined time period.
- Apparent power outside pre-defined threshold limits.
- (Frequency).

More extensive methods to investigate, detect and predict transient instability include the *Equal area criterion* [107-112] which probably is the most well known transient stability criterion. This criterion performs best for two machine systems and therefore requires system reduction in the case of large systems. Dependent on the system configuration the reduction may vary in its degree of complexity and accuracy. For practical applications the equal area criterion is most suitable for individual generators feeding large systems through weak interconnections or for weak interconnections connecting large systems. Inherently the *Swing equation* addresses transient instability. However, solving the swing equations for a large system is fairly time consuming and therefore suitable for the planning stage. In order to obtain on-line tools based on the swing equation decision trees [113], neural networks and pattern recognition have been proposed [114]. *Voltage phasors* are a common tool for transient instability identification where the angle difference between different buses normally is used as a stability measure [115,116]. The voltage phasors to monitor are normally easy to identify in the case of radial system configurations. However, many systems are strongly meshed and have dispersed generation. In order to solve this problem the system is divided into coherent generator groups where one “pilot“ generator is selected for each group. The angle differences between the system regions are obtained by comparing the angles of the “pilot“ generators. A method to merge generators into coherent groups is proposed in [117]. Furthermore, a commissioned scheme based on phase angle validation is described in [118-123]. In [124,125] extra criteria are used in addition to the angle difference criterion to increase the reliability of the protection. These additional criteria must also remain within pre-determined ranges in order to dispense corrective actions. The additional criteria are frequency deviation, load bus voltage magnitude and load bus voltage angle. Another but less common approach to distinguish coherent groups is to study the angle deviation in each bus with respect to the steady state condition [126]. Furthermore, in [127] a method is proposed where the voltage angle is predicted by applying the least square method, and dependent on that prediction the control actions may be carried out. In case of transient instability the different swing modes can be determined from the *Frequency spectrum*. Possible input signals are voltage, frequency, real-/reactive power, rotor angle or rotor speed [128-132]. Other methods proposed for the analysis of transient instability involve *Modal analysis* [133], *Energy functions* [134-139], *Rotor angle* and *Rotor speed deviation* [140], *Time domain* simulations [141], *Taylor/Maclaurin* expansions and *trigonometrical* functions [142-145], *Out-of-Step Relays* [2], *Lyponov stability analysis* [146,147], *Trajectory technique* [148-150] and *Mapping/Pattern recognition* [151,152].

Today the extensive methods mentioned above are often inapplicable as accurate real-time tools for large power systems. In the case of detailed system modelling they often result in mathematical tasks, which the computers are incapable to solve within the required time frame. If simplifications are introduced to facilitate the computational requirements the results may be unreliable. To assure effective curative actions in the case of transient instability on-line generator coherency determination is often required. Normally reliable generator coherency methods are computational expensive and therefore limited to off-line studies. In ***Paper D*** a simple coherency method is introduced that suits applications based on communication and GPS technology. This new concept results in a more accurate generator coherency than phasor measurements. This is of particular interest as phasor measurements are the most common on-line tool for generator coherency determination. In ***Paper E*** the method is applied on a SPS addressing inter-area oscillations. ***Paper D*** and ***Paper E*** are based on a method briefly introduced in [131].

The extensive methods mentioned above are continuously developed and may become applicable as real-time tools in the future. Present research deals with conventional computer calculation methods but also more modern approaches such as neural networks [113,129,153], decision trees [154], chaos [155], fuzzy logic [156-158] are investigated. Typically neural networks can be used to increase the speed of prediction. Neural networks are trained during off-line simulations; during on-line operation only limited and simple calculations are required.

4.2.3 Indicators to Determine Frequency Instability

Due to the nature of the frequency instability phenomena the following quantities are used as indicators for response based SPS:

- Frequency.
- Rate of change of frequency.

Indicators for event based SPS may be:

- Loss of a power station, a HVDC interconnection or tie-lines.
- Loss of a load centre.
- Pre- and post contingency power flows.

4.3 Curative Measures for System Protection Schemes

Table 4.1 gives an overview of the most common SPS in operation. The table was originally published in [37,38] and is based on a joint survey over SPS performed by IEEE and CIGRÉ. In total 49 utilities from 17 countries responded to a survey describing 111 schemes. Furthermore, Table 4.2 gives a general overview for which categories of power system instability the different types of curative measures are suitable. The table was originally published in [3].

Table 4.1: Mixture of most common SPS types.

Type of SPS	[%]
Generation Rejection	21.6
Load Rejection	10.8
Underfrequency load shedding	8.2
Controlled system separation	6.3
Turbine fast valving	6.3
Load & Generator rejection	4.5
Stabilizers	4.5
HVDC fast power change	3.6
Out-of-step relaying	2.7
Discrete excitation control	1.8
Braking resistor	1.8
Generator run-back	1.8
Var compensation	1.8
Combination of schemes	11.7
Others	12.6
All SPS	100

Table 4.2: Curative measures and their fields of application.

	Generation Rejection	Turbine fast valving	Gas turbine start-up	Actions on the AGC	Underfrequency load shedding	Undervoltage load shedding	Load rejection	HVDC fast power change	Automatic shunt switching	Braking resistor	Controlled system separation	Tap changer blocking
Transient instability	X	X					X	X	X	X	X	
Frequency instability (freq. decay)			X		X			X			X	X
Frequency instability (freq. rise)	X							X				
Voltage instability	X		X	X		X		X	X		X	X
Cascade line outages	X		X	X			X	X				

Fig. 4.3[1] shows the relationship between the duration of major power system phenomena and the approximate time frame of SPS actions used to limit their consequences. The time frames for different control and protection categories are indicated. The time scale is logarithmic and solid lines represent the typical operating range for the curative measures while dotted lines indicate potential operating ranges.

1. Originally published in [3].

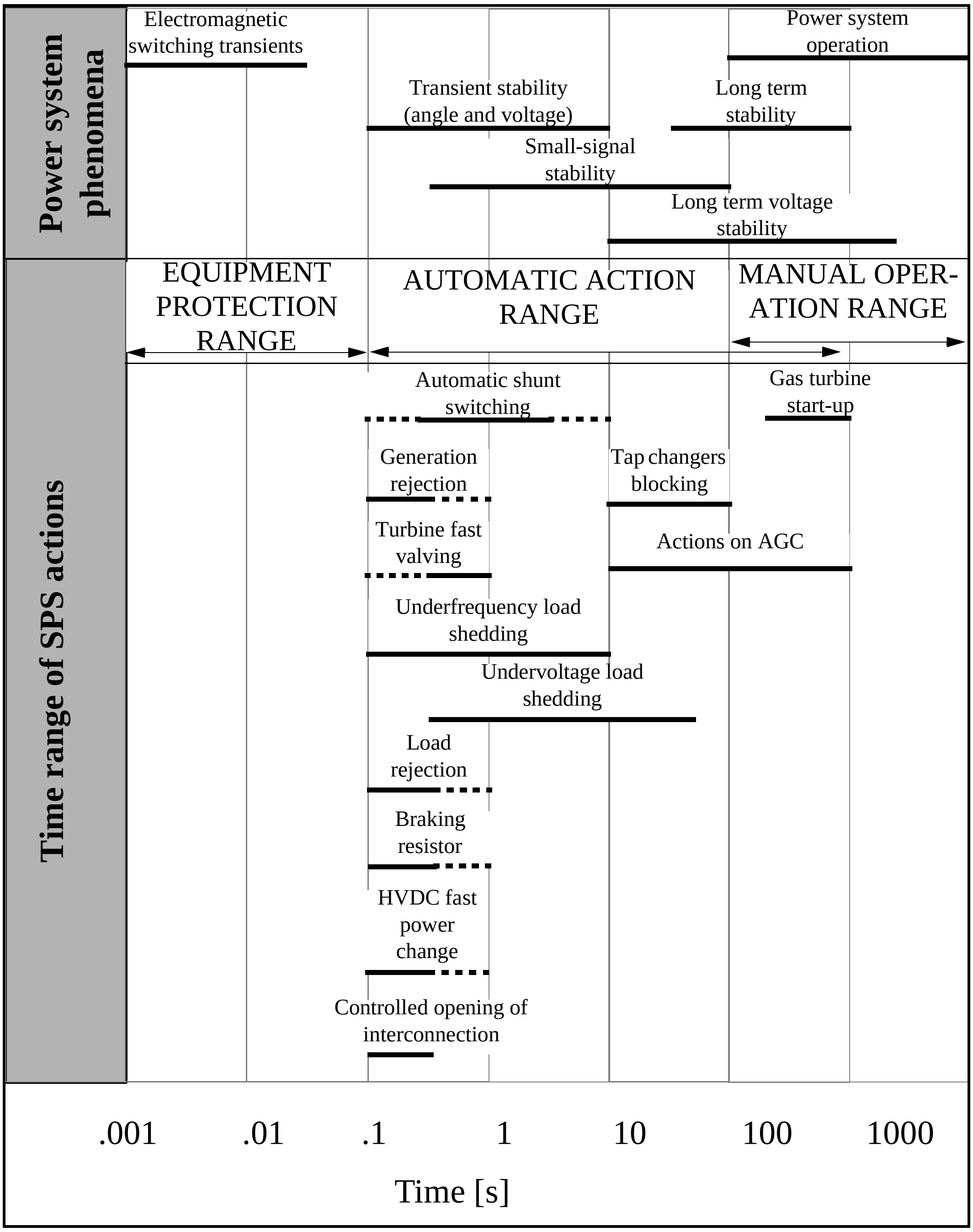


Figure 4.3 Time frame relation between curative measures and power system phenomena.

System separation schemes are normally used as a curative measure for transient instability. However, sometimes separation schemes can also be designed to prevent the penetration of voltage instability from neighbouring systems. These schemes are normally applied on the borderline between different countries or large utilities. ***Paper F*** is introducing a similar scheme but instead of invoking large system regions the aim of this scheme is to secure voltage stability in at least one part of the system in order to avoid a black start. The scheme is using conventional distance protection and should operate when a complete breakdown cannot be obstructed by any other means.

4.4 System Protection Schemes in the Nordel System

SPS in the Nordel system will be treated here. An extensive survey on SPS and field experience worldwide is given in [159].

The instantaneous emergency reserve in the Nordel system is equivalent to the loss of the largest unit in service; normally about 1200 MW. In addition SPS are used for extreme contingencies such as severe grid weakening or a loss of generation exceeding the largest unit. There are a number of SPS operating in the Nordel system today, addressing all different types of power system instability, involving large and small areas. Examples are active power support from neighbouring regions via HVDC links, automatic conversion from pure reactive generation to active generation for some hydro units, automatic start of gas turbines, load shedding or system separation. To avoid overload or instability in case of reduced transfer capacity in critical intersections generator shedding is applied. The HVDC support is activated in case of low frequency and/or low voltage in the HVDC station or low voltage in a remote station. A number of Emergency Power Control steps are implemented in the control systems of the links. There are different setting possibilities but the most common way to control the power flow is to apply a number of time-delayed step-changes e.g ΔP=50 MW with a 2 s time delay. Automatic frequency controlled start of gas-turbines is used to some extent within the Nordel system. In Sweden these units are started at 49.5 Hz. Non-discriminative UFLS is used as a final curative measure in case of extreme loss of generation. The UFLS is divided into five steps where each step has two different time delays.

Fig. 4.4 gives an overview of the main corrective measures used to counteract the different types of power system instability in the Nordel system. The grey window represents the emergency reserve together with on-line hydro units. The emergency reserve is divided into instantaneous-, fast- and slow reserves. The emergency reserve is intended to counter frequency decays down to 49.5 Hz. In case the frequency drops below 49.5 Hz a severe contingency has occurred according to the design criteria. Thus additional SPS (e.g UFLS) is used to arrest further frequency decay.

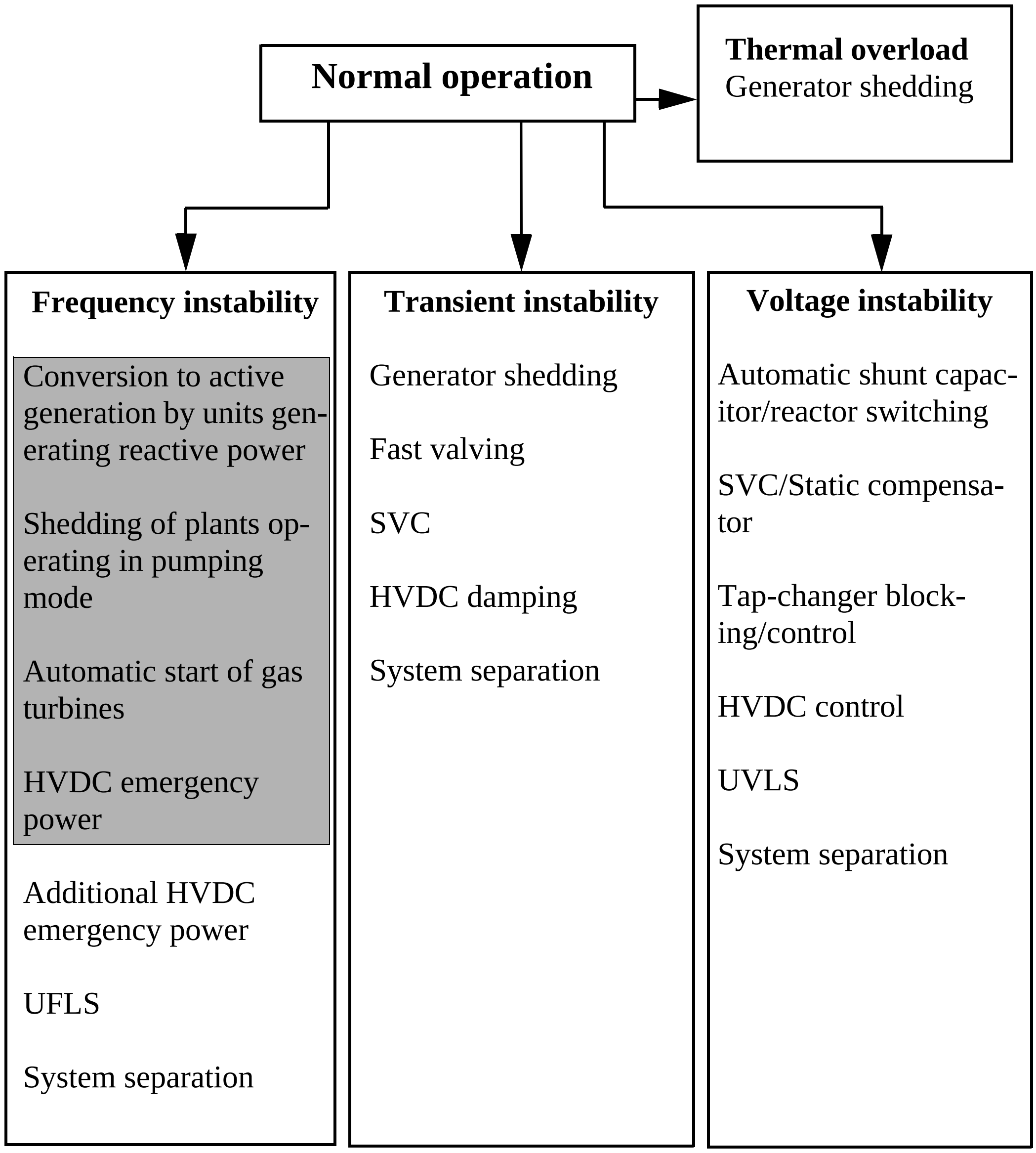


Figure 4.4 Main System Protection Schemes in the Nordel system. The grey window represents corrective measures which are a part of the emergency reserve.

Table 4.1 gives an overview of the extent of installations of corrective measures used for SPS in the Nordel system. Some schemes involve only one type of corrective action while other schemes comprise numerous actions. The extent of installations in 2001 is compared to the situation in 1992 [160,161].

Table 4.1: Overview of SPS in the Nordel system 1992 and 2001.

SPS	Available 1992	Available 2001
Generator shedding	approx. 7000 MW	approx. 7000 MW
Fast valving	max. 350 MW	approx. 480 MW
Conversion to active power generation by hydro units generating reactive power	approx. 1795 MW	approx. 438 MW
Shedding of plant operating in pumping mode	950 MW	550 MW
Automatic start of gas turbines (and a diesel unit)	695 MW (20 MW)	485 MW (20 MW)
Automatic shunt capacitor switching[a]	about 1500 MVAr + 23 capacitors in Finland	about 1750 MVAr + 26 capacitors in Finland
Automatic shunt reactor switching	3700 MVAr + the reactors in Sweden minus the reactors in the Sydkraft area	8500 MVAr
SVC	±930 MVAr +360 MVAr inductive	±1250 MVAr +360 MVAr inductive
Static compensators	-	140 MVAr
Tap-changer blocking	-	In operation in Finland and Norway

SPS	Available 1992	Available 2001
HVDC, Control of Norway - Denmark power flow in case of low voltage in Norway	max. 240 MW	max. 240 MW Similar scheme for Baltic cable (max. 200 MW), SwePol Link (max. 300 MW) and Kontek (max. 250 MW) in case of low voltage in local station or in Sege
HVDC emergency power	max. 560 MW to counter frequency decay	max. 890 MW to counter frequency decay
HVDC damping	?	±100 MW
UVLS	max. 200	max. 200
Automatic UFLS[b]	Sweden: 34 % of tot. load Norway: 32 % of tot. load Finland: 20 % of tot. load Denmark: 45 % of tot. load	Sweden: 34 % of tot. load Norway: 32 % of tot. load Finland: 20 % of tot. load Denmark: 45 % of tot. load
System separation	Similar to the 2001 situation	HVDC interconnections are severed in case of severe underfrequency or overvoltage. Finland: Isolated island operation in case of underfrequency. The south part of Norway is separated from the remaining system in case of strained operation of the Hassle bottleneck. Splitting schemes based on power-, voltage levels and loss of circuit also exist.

SPS	Available 1992	Available 2001
Power swing detectors	Similar to the 2001 situation	Generally used to detect power swings but not to avoid undesirable relay operation or control system separation. However, in Norway there is a limited number of detectors which also control corrective actions (generator rejection).

a. Although the numbers are according to [160] and [161] information is missing or presented differently for certain countries which may affect the presented data.
b. The values presented here were slightly updated when the new load shedding policy was introduced on January 1, 2002.

Chapter 5 Summary of Publications

As a part of this Ph.D dissertation the papers presented below are published in their full length. ***Paper A* - *Paper C*** address local area protection while ***Paper D* - *Paper F*** analyse applications associated with System Protection Schemes.

5.1 *Paper A*: An Adaptive Scheme to Prevent Undesirable Distance Protection Operation During Voltage Instability

The paper introduces an adaptive algorithm to prevent undesirable distance protection operation during voltage instability. The rate of change of voltage is used as an additional relay criterion to improve the distance relay security with respect to voltage instability. The performance of the new algorithm is analysed using two different test systems; a 15 bus system developed by the authors and the NORDIC32 system [162].

This paper has been published in condensed form as [163].

5.2 *Paper B*: A New Protection Scheme to Prevent Mal-trips due to Power Swings

In this paper distance protection algorithms based on mathematical logic blocks are proposed. The algorithms prevent mal-trips due to power oscillations using additional criteria in combination with traditional distance relaying. These additional criteria are based on symmetrical components and the rate of change of the phase angle associated with the current as seen by the relay. Finally, the performance of the algorithms is analysed in a simulation performed in a eighteen bus system developed by the authors.

5.3 *Paper C*: A Distance Protection Scheme to Prevent Mal-trips During Abnormal Power System Conditions

In this paper distance relay algorithms are further developed based on ***Paper A*** and ***Paper B***. The eighteen bus system introduced in ***Paper B*** is used to investigate the performance of the algorithms.

5.4 *Paper D*: A New Method Suitable for Real Time Generator Coherency Determination

Based on three test cases in a 68 bus system the paper illustrates that wide area generator speed measurements combined with Fourier analysis can be used to determine coherent generator groups. To verify its performance the new method is compared to conventional methods based on the generator speed, modal analysis and phasor angle measurements.

5.5 *Paper E*: A System Protection Scheme Concept to Counter Inter-Area Oscillations

This paper introduces a concept of a generator coherency based System Protection Scheme, addressing inter-area oscillation events. The scheme is based on the coherency method introduced in ***Paper D***. A simulated test case in a 68 bus system is used to introduce the operating principle of the scheme. The test case is also used to evaluate the scheme's suitability for different well established DSP methods. Aspects such as evolving-/sliding window functions, window size and frequency resolution are examined.

5.6 *Paper F*: An Emergency Strategy Scheme Based on Conventional Distance Protection to Avoid Complete System Collapse

In order to reduce the restoration time after a voltage collapse affecting a large system an emergency protection scheme based on conventional distance protection is proposed. The performance of the scheme is investigated using the NORDIC32 test system [162].

5.7 Other Publications Reported within the Scope of the Project

In addition to this Ph.D thesis a licentiate thesis [2] and a technical report [159] have been published.

5.7.1 Licentiate thesis - Line Protection and Power System Collapse

In the licentiate thesis the influence of line protection on transient- and voltage instability is investigated. Different types of line protection applications are discussed and their likelihood of contributing to power system instability is analysed. The different types of relay characteristics used in distance protection are analysed and their relative numbers in the Swedish transmission system are given. Statistics of zone 3 distance protection operation in the Swedish transmission system are shown for the period 1985 - 2000. Additionally, a number of disturbances related to distance protection and power system instability is investigated.

Also the significance of co-ordination between distance protection and generator current limiters in case of voltage instability is investigated. Subsequently the interaction between distance protection and other protection devices during power system instability is discussed. Conventional Power Swing Detectors and Out-of-Step Protection have also been examined.

Papers A-C introduced above are all incorporated into the thesis.

5.7.2 Technical Report - Present Status of System Protection Schemes

The report gives an overview of publications and projects within the area of System Protection Schemes. Different theoretical aspects involving power system instability, indicators, system configuration, curative measures and their internal relations are examined. Furthermore, an extensive survey of commissioned System Protection Schemes worldwide is presented.

Chapter 6 Conclusions and Future Work

6.1 Conclusions

This thesis introduces new methods to improve the performance of power system protection in case of system instability. The methods are primarily designed to mitigate power system breakdown.

Distance protection may contribute to power system instability. Measures to improve its performance have been proposed using new relay criteria combined with conventional impedance characteristics. In case of voltage instability the criteria are based on the derivative of the voltage whereas the rate of change of the phase angle of the current is used for transient instability. The measures improve the relay security with respect to voltage instability whereas the reach of the distance protection is unrestricted. Line length, different swing frequencies or faults having a slowly decreasing impedance will not affect the performance and availability of the proposed schemes, which may be the case for conventional Power Swing Detectors. Furthermore, fault clearing will not be blocked as in the case of conventional PSD applications.

A high degree of security is relevant today as the trend implies that utilities are subjected to penalty fees in the case of undelivered energy. Companies therefore want to avoid undesirable relay tripping indeed. The methods proposed here are based on mathematical logic blocks which are easily adapted to numerical relays.

In the Swedish bulk power system the number of power oscillations has increased significantly during recent years. To dampen oscillations a well established generator coherency is often required. In this thesis a method based on wide area generator speed measurements and Fourier analysis is proposed for the purpose of on-line coherency tracking. The performance of the new method has been evaluated by comparing the generator coherency obtained from the new method with coherencies obtained from conventional methods based on generator speed, modal analysis and phasor angle measurements. The new method and the off-line methods based on generator speed and modal analysis give almost identical results, however the results obtained from phasor measurements show deviations. This is particularly interesting as the generator angle probably is the most common on-line indicator for generator coherency determination. Furthermore, taking the transient distortion immediately after a disturbance into account, this work indicates that the method introduced here generates a reliable coherency considerably quicker than the methods based on pure speed or generator voltage angle measurements.

Using a method based on speed measurement combined with Fourier analysis a concept for a System Protection Scheme addressing inter-area events is proposed. Different Digital Signal Processing issues such as window functions, time-frequency resolution and signal analysis methods have been investigated. Based on these investigations a scheme was designed. For the detection of inter-area modes, parametric methods are the most feasible. Evolving window functions generally detect the main mode somewhat faster than sliding windows. However, evolving windows require a trigger activated by the presence of an inter-area mode. This trigger may complicate the design of the scheme and therefore the design proposed here is based on a sliding window. To shorten the detection time of the main mode, a reduced frequency resolution can be applied. However, a lower frequency resolution contributes to spectral mode shifts and reduces the quality of the estimate of the instantaneous speed deviation. As a result the discrimination of the unstable/stable nature of the modes is of a lower quality. Also the phase estimation deteriorates which in turn leads to a less reliable generator coherency determination. The design proposed here is therefore based on a high frequency resolution, accepting a somewhat slower response.

Finally, an emergency scheme is proposed utilising conventional distance relays to avoid a complete system collapse in case of severe voltage instability. The purpose of the scheme is to co-ordinate all distance relays belonging to a transfer section so they will simultaneously operate due to the voltage instability. As a result a part of the system can be saved from the collapse, black-start can be avoided and the restoration time can be reduced. Furthermore, in case long distance communication is introduced the scheme can be utilized for the supervision of corrective measures such as generator or load shedding.

6.2 Future Work

Future work directly linked to the work in this thesis includes various practical issues related to the realization of the proposed applications. For the distance relay algorithms emphasising security, issues such as data memory, window size and data filtering must be further investigated. To obtain reliable operation well defined setting procedures for the new relay criteria should also be developed.

The System Protection Scheme based on speed measurements and Fourier Analysis is still at an early stage of development. An adaptive frequency resolution for the detection process could be used to further improve the performance of the scheme. Also the main mode tracking systems could be based on a combination of evolving and sliding window functions.

A future approach could be the use of extensive protection systems where equipment protection and System Protection Schemes are closely related to each other. As communicative relays become more widely used a large amount of data is available and the number of possible remedial actions increases significantly. These features are attractive for SPS. At the same time the wide area data acquisition used to control the actions associated with the SPS, can also be used to prevent incorrect equipment protection performance, as their algorithms can be based on wide area data. Possible research topics are the optimal utilization of the extensive data with respect to relay algorithms and the detection and counteraction of different power system phenomena. Also the optimal co-ordination between local and system wide protection applications with respect to dependability and security should be investigated.

Traditionally measures taken by System Protection Schemes have been extensive. The schemes have not been adjusted to each specific disturbance and sometimes the overstated curative measures have resulted in needless social inconvenience and unnecessary large disturbance cost. Another aspect is the relation between operating safety limits and the (real-time) prevailing operating conditions where the remedial measures represent one feature. To utilize the system (at every single moment) to its maximum capacity a continuous optimization must be performed with respect to all parameters where also the remedial actions should be adjusted based on the actual system condition. There are therefore major incentives for more accurate and intelligent (adaptive) applications controlling the corrective measures.

One interesting tool for this purpose is GPS synchronized wide area measurements where the system status is provided in real-time. This feature combined with for example Artificial Intelligence could be a fruitful area.

As computers become faster more sophisticated DSP methods can be used for protection applications. Traditionally the measured relay signals have been processed based on DSP techniques, and then the electrical quantities associated with the signals have been used as relay criteria. However, the present situation makes it interesting to search for new relay criteria based on inherent DSP parameters. Typically the criteria could be an intermediate quantity obtained from the DSP process during the evaluation of the electrical signal.

An observation made during the project is the importance of accurate protection modelling during simulation based studies. Another observation is the influence of numerical defects during simulations close to instability. An ever lasting important task is to further develop simulations tools, both with respect to numerical and modelling aspects.

A result of the more extensive use of communication in power system protection are the increased requirements of data security. Overall this is a very relevant topic involving numerous aspects of power system operation. The topic offers many challenges within a broad range of different research areas.

References

[1] Kundur P, ”Power System Stability and Control”, ISBN 0-07-035958-X, McGraw - Hill, 1994.

[2] Jonsson M, ”Line Protection and Power System Collapse”, Technical Report No. 393L, Chalmers University of Technology, Sweden, 2001.

[3] CIGRÉ, TF 38.02.19, ”System protection schemes in power networks”, June, 2001.

[4] ANSI/IEEE C37.106-1987, ”Guide for abnormal frequency protection for power generating plants”.

[5] Lindahl S, ”Frekvenshållning inom Nordel-systemet”, Nordel 1983, Särtryck ur årsberättelsen, Sydkraft AB, 1983 (In Swedish).

[6] Horowitz S.H, Phadke A.G, ”Power System Relaying”, ISBN 0-86380-185-4, Research Studies Press Ltd, 1995.

[7] ”The blackout in Sweden 27-12-1983”, Vattenfall publication, February 1984.

[8] Larsson S, Kearsly R, ”The blackout in the Swedish Power Supply System, December 1983”, CEPSI Conference, Manilla, Philippines, November 1984.

[9] Kearsly R, ”Restoration in Sweden and Experience Gained from the Blackout of 1983”, IEEE Transactions on Power Systems, Vol. PWRS-2, No. 2, May 1987, pp. 422-428.

[10] Otterberg R, ”Restoration After Disturbances in the Swedish Bulk-Power Network - Instruction System and Automatic Equipment”, CIGRÉ Study Committee 39 Colloquim, Toronto, Canada, September 1985.

[11] ”DRIFTSTÖRNING 83-12-27”, RAPPORT FRÅN ARBETSGRUPP, MARS 1984 (In Swedish).

[12] Western Systems Coordinating Council Disturbance Report For the Power System Outages that Occurred on the Western Interconnection on July 2, 1996, 1424 MAST and July 3, 1996, 1403 MAST, Approved September 19, 1996.

[13] Taylor C.W, Erickson D.C, ”Recording and Analyzing the July 2 Cascading Outage”, IEEE Computer Applications in Power, Vol. 10, No. 1, January 1997, pp. 26 - 30.

[14] Samuelsson O, ”Wide Area Measurements of Power System Dynamics - The North American WAMS Project and its Applicability to the Nordic Countries”, Elfork report 99:50, January 2000.

[15] X. Vieira *et. al*, ”The March 11:th 1999 Blackout: Short-Term Measures to Improve System Security and Overview of the Reports Prepared by the International Experts”, CIGRÉ Session, SC 39 Workshop on Large Disturbances, Paris, August 29, 2000.

[16] Taylor C.W, ”Power System Voltage Stability”, ISBN 0-07-113708-4, McGraw-Hill, 1994, pp. 263.

[17] Mechraoui A, Thomas D.W.P, ”A new distance protection scheme which can operate during fast power swings”, IEE Conference Publication No. 434, Developments in Power System Protection, March 25-27, 1997, pp 206 - 209.

[18] Ilar F, ”Innovations in the Detection of Power Swings in Electrical Networks”, Brown Boveri Review No. 68, 1981.

[19] Machowski J, Nelles D, ”Licentia Patent-Verwaltungs-GmbH AEG-Franfurt, P4100646.1”.

[20] Machowski J, Nelles D, ”New Power Swing Blocking Method”, IEE Developments in Power System Protection, Conference Publication No. 434, March 25-27, 1997, pp 218 - 221.

[21] Rovnyak S *et.al*, ”Decision trees for real-time transient stability prediction”, IEEE Transaction on Power Systems, Vol. 9, No. 3, August 1994, pp. 1417-1426.

[22] Jiali H, Yuqian D, Yongli L, Gang W, Shanshan L, ”Distance Relay Protection Based on Artificial Neural Network”, Proceedings of the 4th International Conference on Advances in Power System Control, Operation and Management, APSCOM-97, Hong Kong, November 1997, pp. 515 - 520.

[23] Centeno V *et. al*, ”An adaptive out-of-step relay”, IEEE Transaction on Power Delivery, Vol. 12, No. 1, January 1997, pp. 61-71.

[24] Centeno V, Phadke A.G, Edris A, ”Adaptive out-of-step relay with phasor measurement”, IEE Conference Publication No. 434, Developments in Power System Protection, March 25-27, 1997, pp 210 - 213.

[25] Redfern M.A, Checksfield M.J, ”A new pole slipping protection algorithm for dispersed storage and generation using the equal area criterion”, IEEE Transaction on Power Delivery, Vol. 10, No. 1, January 1995, pp. 194-202.

[26] Hemmingsson M, “Power System Oscillations - Detection, Estimation & Control“, Ph.D thesis, ISBN 91-88934-27-6, Lund University, 2003.

[27] ”Protective Relays Application Guide”, GEC ALSTHOM, ed. 3, 1987.

[28] IEEE Working Group Report, ”Out of Step Relaying for Generators”, IEEE Transaction, Vol. PAS-96, September /October 1977, pp. 1556-1564.

[29] Elmore W.A, ”Pilot Protective Relaying”, ISBN 0-8247-8195-3, Marcel Dekker Inc, 2000.

[30] Fouad A.A *et.al*, ” Investigation of Loss of Generation Disturbances in the Florida Power and Light Company Network by the Transient Energy Function Method”, IEEE Transaction on Power Systems, PWRS-1, No. 3, 1986, pp. 60-66.

[31] van Eyssen J, ”Introducing a new application philosophy for out-of-step protection”, IEE Conference Publication No. 434, Developments in Power System Protection, March 25-27, 1997, pp 214 - 217.

[32] ”The Swedish 380 kV System”, Kungl. Vattenfallsstyrelsen, Kungl. Boktryckeriet P.A Norstedt & Söner, 1960.

[33] Wide Area Protection seminar, “Real-Time Monitoring of Fast Dynamic in the Swedish National Grid (Fast RTMS)”, Presentation by Svenska Kraftnät, Västerås, Sweden, April 2, 2001.

[34] Phadke A.G, ”Synchronized Phasor Measurements in Power Systems”, IEEE Computer Applications in Power, Vol. 6, No. 2, April 1993, pp. 10 - 15.

[35] Martin K.E *et.al*, ”IEEE Standards for Synchrophasors for Power Systems”, IEEE Transactions on Power Delivery, Vol. 13, No. 1, January 1998, pp. 73 - 77.

[36] Hauer J.F, ”Validation Of Phasor Calculations In The Macrodyne PMU For California-Oregon Transmission Project Tests Of March 1993”, IEEE Transactions on Power Delivery, Vol. 11, No. 3, July 1996, pp. 1224-1231.

[37] Anderson P.M, LeReverend B.K, ”Industry Experience with Special Protection Schemes”, IEEE Transactions on Power Systems, Vol. 11, No. 3, August 1996, pp. 1166- 1179.

[38] CIGRÉ WG 39.05, LeReverend B.K, Anderson P.M, ”Industry Experience with Special Protection Schemes”, Electra, No. 155, August, 1994.

[39] IEEE Power System Relaying Committee C6, ”Wide Area Protection and Emergency Control”, working.

[40] Trudel G *et.al*, ”Hydro-Québec’s defence plan against extreme contingencies”, IEEE Transactions on Power Systems, Vol. 14, No. 3, August 1999, pp. 958 - 966.

[41] Faucon O, Dousset L, ”Coordinated Defence Plan Protects Against Transient Instabilities”, IEEE Computer Applications in Power, Vol. 10, Issue. 3, July 1997, pp. 22 - 26.

[42] Harker K, ”The North Wales supergrid special protection schemes”, Electronics & Power, no. 9, September, 1984, pp. 719 - 724.

[43] Coetzee G.J, Wittwer F, ”Development of a transient stability protection system for Eskom’s Matimba power station”, IEE Conference Publication No. 434, Developments in Power System Protection, March 25 - 27, 1997, pp. 36 - 39.

[44] Ingelsson B, Lindström P-O, Karlsson D, Runvik G, Sjödin J-O, ”Wide-area protection against voltage collapse”, IEEE Computer Applications in Power, Vol. 10, Issue. 4, October 1997, pp. 30 - 35.

[45] CIGRÉ TF 38.01.03, ”Planning against voltage collapse”, 1987.

[46] CIGRÉ TF 38.02.08, ”Long Term Dynamic Simulation Methods”, 1995.

[47] CIGRÉ TF 38.02.10, ”Modelling of Voltage Collapse Including Dynamic Phenomena”, 1993.

[48] CIGRÉ TF 38.02.11, ”Indices Predicting Voltage Collapse Including Dynamic Phenomena”, 1994.

[49] CIGRÉ TF 38.02.12, ”Criteria and Countermeasures for Voltage Collapse”, 1995.

[50] CIGRÉ TF 38.01.07, ”Control of Power System Oscillations”, 1996.

[51] CIGRÉ WG 34.08, ”Protection against Voltage Collapse”, No. 128, August, 1998.

[52] CIGRÉ TF 38.02.14, ”Analysis and Modelling Needs of Power Systems under Major Frequency Disturbances”, 1999.

[53] CIGRÉ TF 38.02.17, ”Advanced Angle Stability Controls”, 1999.

[54] IEEE Power System Relaying Committee K12, ”System Protection and Voltage Stability”, 1993.

[55] IEEE Power System Relaying Committee K12, ”Voltage Collapse Mitigation”, 1997.

[56] IEEE Power System Relaying Committee C6, ”Performance of Generator Protection During Major System Disturbances”, working.

[57] Ajjarapu V, Feng Z, ”A novel approach for voltage collapse analysis and control”, Proceedings of PowerCon, 1998, pp. 1499 - 1503.

[58] Fischl R, Mercede F, ”Can Voltage Security Indices Predict Voltage Collapse Problems in Large-Scale Power Networks”, Proceedings of IEEE International Symposium on Circuit and Systems, 1988, pp.665 - 668.

[59] Fischl R *et.al*, ”A comparison of indices for predicting voltage collapse in power systems”, Proceedings of the 27th Conference on Decision and Control, Austin, Texas, USA, December, 1988.

[60] Ejebe G.C *et.al*, ”On-Line Voltage Stability Assessment: Framework and Implementation”, Proceedings of IEEE PES Winter meeting, Tampa, Florida, USA, 1998.

[61] Dobson I *et.al*, “Voltage Collapse in Power Systems”, IEEE Circuit and Devices Magazine, Vol. 8, Issue. 3, May 1992, pp. 40 - 45.

[62] Evers T.A *et.al*, “Prediction of Voltage Collapse in Power Systems”, Proceedings of the Thirtieth Southeastern Symposium on System Theory, 1998, pp. 354 - 358.

[63] Greene S *et.al*, ”Sensitivity of the load margin to voltage collapse with respect to arbitrary parameters”, IEEE Transactions on Power Systems, Vol. 12, No. 1, February 1997, pp. 262 - 272.

[64] Sam D *et.al*, “Local Severity Indices and Alarm Processing for Small Scale Power Systems”, Proceedings of the American Control Conference, Arlington, USA, June 25 - 27, 2001.

[65] Crow M.L, Lesieutre B.C, “Voltage collapse”, IEEE Potentials, Vol. 13, No.2, April 1994, pp. 18 - 21.

[66] Kulkarni S.S *et.al*, ”New perceptions in integrated power system operation and control”, Proceedings of IEEE Region 10 International Conference on Global Connectivity in Energy, Computer, Communication and Control, 1998, pp. 489 - 496.

[67] Yabe K *et.al*, ”Conceptual Designs of AI-based Systems for Local Prediction of Voltage Collapse”, IEEE Transactions on Power Systems, Vol. 11, No. 1, February 1996, pp. 137 - 145.

[68] Momoh J.A, Zhang Y, ”Voltage Stability Estimation”, Proceedings of IEEE International Conference on Systems, Man and Cybernetics, 1990, pp. 94 - 97.

[69] Begovic M.M, Phadke A.G, ”Voltage stability assessment through measurement of a reduced state vector”, IEEE Transactions on Power Systems, Vol. 5, No. 1, February 1990, pp. 198 - 203.

[70] Chiang H-D, René J-J, ”Toward a Practical Performance Index for Predicting Voltage Collapse in Electric Power Systems”, IEEE Transactions on Power Systems, Vol. 10, No. 2, May 1995, pp. 584- 592.

[71] Canizares C.A *et.al*, ”Comparison of Performance Indices for Detection of Proximity to Voltage Collapse”, IEEE Transactions on Power Systems, Vol. 11, No. 3, August 1996, pp. 1441 - 1450.

[72] Madan S, Bollinger K.E, ”Artificial Intelligence Assisted Voltage Stability Enhancement”, Proceedings of Canadian Conference on Electrical and Computer Engineering, 1996, pp. 392 - 395.

[73] De Angelis G *et.al*, ”Transient voltage stability signature in time domain simulations”, Proceedings of MELECON 8th Mediterranean Electrotechnical Conference, 1996, pp. 859 - 862.

[74] Löf P.A *et.al*, ”Fast calculation of a voltage stability index”, IEEE Transactions on Power Systems, Vol. 7, No. 1, February 1992, pp. 54 - 64.

[75] Tamura Y *et.al*, ”Voltage Instability Proximity Index (VIPI) Based on Multiple Load Flow Solutions in Ill-conditioned Power Systems”, Proceedings of the 27th Conference on Decision and Control, Austin, Texas, USA, December, 1988.

[76] Tamura Y *et.al*, ”Relationship between voltage instability and multiple load flow solutions in electric power systems”, IEEE Transactions on Power Apparatus and Systems, Vol. 102, No. 5, May 1983, pp. 1115 - 1125.

[77] Vu K *et.al*, ”Use of Local Measurement to Estimate Voltage-Stability Margin”, IEEE Transactions on Power Systems, Vol. 14, No. 3, August 1999, pp. 1029- 1035.

[78] Vu K *et.al*, ”Voltage Instability Predictor (VIP) and Its Applications”, Proceedings of PSCC 99 Conference, June, 1999.

[79] Vu K *et.al*, ”Grids Get Smart Protection and Control”, IEEE Computer Applications in Power, October, 1997.

[80] Julian D.E *et.al*, ”Quantifying Proximity To Voltage Collapse Using The Voltage Instability Predictor (VIP)”, Proceedings of IEEE Power Engineering Society Summer Meeting, 2000, pp. 931 - 936.

[81] Moghavvemi M, Omar F.M, ”Technique for contingency monitoring and voltage collapse prediction”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 145, No. 6, November 1998, pp. 634 - 640.

[82] Moghavvemi M, Omar F.M, ”A Line Outage Study for Prediction of Static Voltage Collapse”, IEEE Power Engineering Review, Vol. 18, No. 7, July 1998, pp. 52- 54.

[83] Moghavvemi M, Faruque M.O, ”Estimation of Voltage Collapse from Local Measurement of Line Power Flow and Bus Voltages”, Proceedings of International Conference on Electric Power Engineering (PowerTech). Budapest, 1999, pp. 77.

[84] Chiang H-D *et.al*, ”On voltage collapse in electric power systems”, Proceedings of Power Industry Computer Application Conference (PICA), 1989, pp. 342 - 349.

[85] Chiang H-D *et.al*, ”On voltage collapse in electric power systems”, IEEE Transactions on Power Systems, Vol. 5, No. 2, May 1990, pp. 601 - 611.

[86] Jasmon G.B *et.al*, ”Prediction of voltage collapse in power systems using a reduced system model”, International Conference on Control, 1991, pp. 32 - 36.

[87] Marceau R.J *et.al*, ”Fourier methods for estimating power system stability limits”, Proceedings of the Power Industry Computer Application Conference, 1993, pp. 418 - 425.

[88] Marceau R.J *et.al*, ”Fourier methods for estimating power system stability limits”, IEEE Transactions on Power Systems, Vol. 9, No. 2, May 1994, pp. 764 - 771.

[89] DeMarco C.L, Overbye T.J, ”An energy based security measure for assessing vulnerability to voltage collapse”, IEEE Transactions on Power Systems, Vol. 5, No. 2, May 1990, pp. 419 - 427.

[90] Overbye T.J *et.al*, ”A composite framework for synchronous and voltage stability in power systems”, Proceedings of IEEE International Symposium on Circuit and Systems, 1992, pp. 2541 - 2544.

[91] Gubina F, Strmcnik B, ”Voltage Collapse Proximity Index Determination Using Voltage Phasors Approach”, IEEE Transactions on Power Systems, Vol. 10, No. 2, May 1995, pp. 788 - 794.

[92] Verbic G, Gubina F, ”A new concept of Protection against Voltage Collapse Based on Local Phasors”, Proceedings of PowerCon 2000, 2000, pp. 965 - 970.

[93] Guo R *et.al*, ”Preventive/Corrective Control for Voltage Stability Using Predictor-Corrector Interior Method”, Proceedings of PowerCon 1998, 1998, pp. 1513 - 1517.

[94] Tuglie E.D *et.al*, ”Real-time preventive actions for the enhancement of voltage-degraded trajectories”, IEEE Transactions on Power Systems, Vol. 14, No. 2, May 1999, pp. 561 - 568.

[95] Tuglie E.D *et.al*, ”A Corrective Control for Angle and Voltage Stability Enhancement on the Transient Time-Scale”, IEEE Transactions on Power Systems, Vol. 15, No. 4, November 2000, pp. 1345- 1353.

[96] Hui K.C, Short N.J, ”Voltage security monitoring, prediction and control by neural networks”, Proceedings of IEE International Conference on Advances in Power System Control, Operation and Management, November 1991, Hong Kong.

[97] Momoh J.A *et.al*, ”Investigation of Artificial Neural Networks for Voltage Stability Assessment”, Proceedings of IEEE International Conference on Systems, Man and Cybernetics, 1995, pp. 2188 - 2192.

[98] Chen D, Mohler R, “Load modelling and voltage stability analysis by neural networks”, Proceedings of the American Control Conference, June 1997, Albuquerque, New Mexico, USA.

[99] Belhadj C.A *et.al*, “Voltage stability estimation and prediction using neural network”, Proceedings of PowerCon 1998, 1998, pp. 1464 - 1467.

[100] Dinavahi V.R, Srivastava S.C, “ANN Based Voltage Stability Margin Prediction”, Proceedings of IEEE Power Engineering Society Summer Meeting, 2001, pp.1275 - 1280.

[101] Moors C *et.al*, ”Load Shedding Controllers against Voltage Instability: a comparison of designs”, Proceedings of IEEE Porto Power Tech. Conference, Porto, Portugal, September 10 - 13, 2001.

[102] Arnborg S, ”Emergency Control of Power Systems in Voltage Unstable conditions”, Ph.D thesis, ISSN 1100-1607, Stockholm, Sweden, 1997.

[103] Balanathan R *et.al*, ”Undervoltage load shedding for induction motor dominant loads considering P,Q coupling”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 146, No. 4, July 1999, pp. 337- 342.

[104] Tso S.K *et.al*, ”Evaluation of load shedding to prevent dynamic voltage instability based on extended fuzzy reasoning”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 144, No. 2, March 1997, pp. 81 - 86.

[105] Balanathan R *et.al*, ”Undervoltage load shedding to avoid voltage instability”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 145, No. 2, March 1998, pp. 175 - 181.

[106] Tuan T.Q *et.al*, ”Emergency load shedding to avoid risks of voltage instability using indicators”, IEEE Transactions on Power Systems, Vol. 9, No. 1, February 1994, pp. 341 - 351.

[107] Lemmon W.W *et.al*, ”Transient stability prediction and control in real-time by QUEP”, IEEE Transactions on Power Systems, Vol. 4, No. 2, May 1989, pp. 627 - 642.

[108] Dong Y, Pota H.R, ”Transient stability margin prediction using equal-area criterion”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 140, No. 2, March 1993, pp. 96 - 104.

[109] Redfern M.A, Checksfield M.J, ”A new pole slipping protection algorithm for dispersed storage and generation using the equal area criterion”, IEEE Transactions on Power Systems, Vol. 10, No. 1, January 1995, pp. 194 - 202.

[110] Tso S.K, Cheung S.P, “Fast prediction of transient stability margin in systems with SVC control and HVDC link”, Proceedings of EMPD 95 International Conference on Energy Management and Power Delivery, 1995, pp. 456 - 461.

[111] Wang L *et.al*, “Quantitative search of transient stability limits using EEAC”, Proceedings of IEEE Power Engineering Society Summer Meeting, 1997.

[112] Pavella M *et.al*, “An approach to real-time transient stability assessment and control”, Proceedings of IEEE Power Engineering Society Summer Meeting, 1997.

[113] Ah King R.T.F, Rughooputh H.C.S, “Real-time transient stability prediction using neural tree networks”, Proceedings of the IEEE International Conference on Intelligent Systems for the 21st Century, June 1995, pp. 2182 - 2187.

[114] Yan P, “Pattern recognition techniques applied to the classification of swing curves generated in a power system transient stability study”, Proceedings of the IEEE Southeastcon 2000, 2000, pp. 493 - 496.

[115] Bretas N.G, Phadke A.G, “Real time instability prediction through adaptive time series coefficients”, Proceedings of IEEE Power Engineering Society Winter Meeting, 1999, pp. 731 - 736.

[116] Su M-C *et.al*, ”Neural-network based fuzzy model and its application to transient stability prediction in power systems”, IEEE Transactions on Systems, Man and Cybernetics - Part C: Application and Reviews, Vol. 29, No. 1, February 1999, pp. 149 - 157.

[117] Ota Y *et.al*, “Evaluation of stability and electric power quality in power system by using phasor measurements”, Proceedings of PowerCon 2000, 2000, pp. 1335 - 1340.

[118] Trotignon M *et.al*, ”Plan de défence du réseau THT Francais contre les incidents généralisés: dispositions actuelles et perspectives d´évolution”, CIGRÉ Report 39-306, September, 1992, Paris, France.

[119] Counan C *et.al*, ”Major incidents on the French electric system: potentiality and curative measures studies”, IEEE/PES Summer meeting, Paper 92 SM 432-5 PWRS, July, 1992, Seattle, USA.

[120] Bidet M, ”Contingencies: system against losses of synchronism based on phase angle measurements”, IEEE/PES Winter meeting, Panel session on application and experiences in power system monitoring with phasor measurement, 1993.

[121] Faucon O, Dousset L, Boisseau, Harmand Y, ”Coordinated Defence Plan - an integrated protection system”, CIGRÉ Report 200-07, Symposium, 1995, Helsinki, Finland.

[122] Denys P *et.al*, ”Measurement of voltage phase for the French future defence plan against losses of synchronism”, IEEE Transactions on Power Delivery, Vol. 7, No. 1, January 1992, pp. 62 - 69.

[123] Lemoing H. *et.al*, ”Experiment of a satellite-type transmission network for the defence plan”, SEE meeting, August 10, 1991, Paris.

[124] Liu C-W, Thorp J, ”Application of synchronised phasor measurements to real-time transient stability prediction”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 142, No. 4, July 1995, pp. 355 - 360.

[125] Liu C-W *et.al*, ”New Methods for computing power system dynamic response for real-time transient stability prediction”, IEEE Transactions on Circuit and Systems-I: Fundamental Theory and Applications, Vol. 47, No. 3, March 2000, pp. 324 - 337.

[126] Minakawa T, “The required technological breakthrough in developing universal emergency control systems in terms with transient and dynamic stability”, Proceedings of IEEE Power Engineering Society Winter Meeting, 2000, pp. 66 - 71.

[127] Wang Y-J *et.al*, “A remedial control scheme protects against transient instabilities based on Phasor Measurement Units (PMUs) - A case study” Proceedings of IEEE Power Engineering Society Summer Meeting, 2000, pp. 1191 - 1195.

[128] Chang C-L *et.al*, ”Oscillatory stability analysis using real-time measured data”, IEEE Transactions on Power Systems, Vol. 8, No. 3, August 1993, pp. 823 - 829.

[129] Sharaf A.M *et.al*, ”Transient stability and critical clearing time classification using neural networks”, Proceedings of IEE 2nd International Conference on Advances in Power System Control, Operation and Management, December 1993, Hong Kong, pp. 365 - 372.

[130] Sharaf A.M *et.al*, ”Neural network pattern classification of transient stability and loss of excitation for synchronous generators”, Proceedings of IEEE International Conference on Neural Networks, 1994, pp. 2916 -2921.

[131] Begovic M.M, Milisavljevic M, ”Monitoring and Control of Interarea Oscillations Via Real-Time Measurements and TCSC Control”, Proceedings of the Bulk Power System Dynamics and Control IV - Restructuring, Santorini, Greece, August 24 - 28, 1997.

[132] Hemmingsson M *et.al*, “Estimation of electro-mechanical mode parameters using frequency measurements”, Proceedings of IEEE Power Engineering Society Winter Meeting, 2001.

[133] Demarco C.L, “Identifying swing mode bifurcations and associated limits on available transfer capability”, Proceedings of the American Control Conference, Philadelphia, Pennsylvania, USA, June 1998.

[134] Vittal V *et.al*, ”Transient stability analysis of stressed power systems using the energy function method”, IEEE Transactions on Power Systems, Vol. 3, No. 1, February 1988, pp. 239 - 244.

[135] Chiang H-D *et.al*, “Direct stability analysis of electric power systems using energy functions: theory, applications, and perspectives”, Proceedings of the IEEE, Vol. 83, No. 11, November 1995 pp. 1497 - 1529.

[136] Lo K.L *et.al*, “Power system transient stability analysis by using modified Kohonen network”, Proceedings of IEEE International Conference on Neural Networks, 1995, pp. 893 - 898.

[137] Marceau R.J *et.al*, “Signal energy search strategies for transient stability transfer limit determination”, Proceedings of IEEE Power Engineering Society Summer Meeting, 1997.

[138] Marceau R.J, Soumare S, ”A unified approach for estimating transient and long-term stability transfer limits”, IEEE Transactions on Power Systems, Vol. 14, No. 2, May 1999, pp. 693 - 701.

[139] Tao W, Liu S, “Stability limits prediction by second order sensitivity based BCU method with structure preserving model”, Proceedings of PowerCon 1998, 1998, pp. 1325 - 1330.

[140] Morioka Y *et.al*, ”System separation equipment to minimize power system instability using generator’s angular-velocity measurement”, IEEE Transactions on Power Delivery, Vol. 8, No. 3, July 1993, pp. 941 - 947.

[141] Tang C.K *et.al*, ”Transient stability index from conventional time domain simulation”, IEEE Transactions on Power Systems, Vol. 9, No. 3, August 1994, pp. 1524 - 1530.

[142] Sun J.H, Lo K.L, “Transient stability real-time prediction for multi-machine power systems by using observation”, Proceedings of TENCON '93, IEEE Region 10 Conference on Computer, Communication, Control and Power Engineering, 1993, pp. 217 -221.

[143] Auckland D.W *et.al*, ”Artificial neural network-based method for transient response prediction”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 142, No. 3, November 1995, pp. 323 - 329.

[144] Qingsheng L *et.al*, “Real-time prediction and control for transient stability of multi-machine power system”, Proceedings of PowerCon 1998, 1998, pp. 1361 - 1363.

[145] Daoud A.A *et.al*, “A new fast-learning algorithm for predicting power system stability”, Proceedings of IEEE Power Engineering Society Winter Meeting, 2001, pp. 594 - 598.

[146] Lyapunov A.M, ”General problem of stability of motion”, (English translation) Academic Press, Inc., 1967.

[147] Machowski J *et.al*, “Power system dynamics and stability”, ISBN 0-471-95643-0, John Wiley & Sons, 1998.

[148] Ejebe G.C *et.al*, “Transient energy based screening and monitoring for stability limits”, Proceedings of IEEE Power Engineering Society Summer Meeting, 2001.

[149] Wang L, Girgis A.A, ”A new method for power system transient instability detection”, IEEE Transactions on Power Delivery, Vol. 12, No. 3, July 1997, pp. 1082 - 1089.

[150] Hiskens I.A, Akke M, ”Analysis of the Nordel power grid disturbance of January 1, 1997 using trajectory sensitivities”, IEEE Transactions on Power Systems, Vol. 14, No. 3, August 1999, pp. 987- 994.

[151] Mannerback K-J, Rydberg J, ”On line fault identification algorithms on severe fault conditions in weak network supported by HVDC light”, Master-thesis, Department of Electrical Power Engineering, CHALMERS, 2001.

[152] Chang C.S, ”A hybrid model for transient stability evaluation of interconnected longitudinal power systems using neural network/pattern recognition approach”, IEEE Transactions on Power Systems, Vol. 9, No. 1, February 1994, pp. 85- 92.

[153] Huang K *et.al*, ”Neural-net based critical clearing time prediction in power system transient stability analysis”, Proceedings of IEE 2nd International Conference on Advances in Power System Control, Operation and Management, December 1993, Hong Kong, pp. 679 - 683.

[154] Rovnyak S *et.al*, ”Decision trees for real-time transient stability prediction”, IEEE Transactions on Power Systems, Vol. 9, No. 3, August 1994, pp. 1417 - 1426.

[155] Liu C-W *et.al*, ”Detection of transiently chaotic swings in power systems using real-time phasor measurement”, IEEE Transactions on Power Systems, Vol. 9, No. 3, August 1994, pp. 1285 - 1292.

[156] Tso S.K *et.al*, ”Fuzzy assessment of power system transient stability level based on steady-state data”, IEE Proceedings on Generation, Transmission and Distribution, Vol. 144, No. 6, November 1997, pp. 525 - 531.

[157] Xinli S *et.al*, “A fuzzy theory based principle to distinguish stable swings and unstable swings in complicated power systems”, Proceedings of PowerCon 1998, 1998, pp. 1091 - 1095.

[158] Liu C-W *et.al*, ”Application of a novel fuzzy neural network to real-time transient stability swings prediction based on synchronized phasor measurement”, IEEE Transactions on Power Systems, Vol. 14, No. 2, May 1999, pp. 685 - 692.

[159] Jonsson M, “Present Status of System Protection Schemes“, Tech.Report 23R, ISSN 1401-6167, Chalmers University of Technology, Gothenburg, Sweden, 2002.

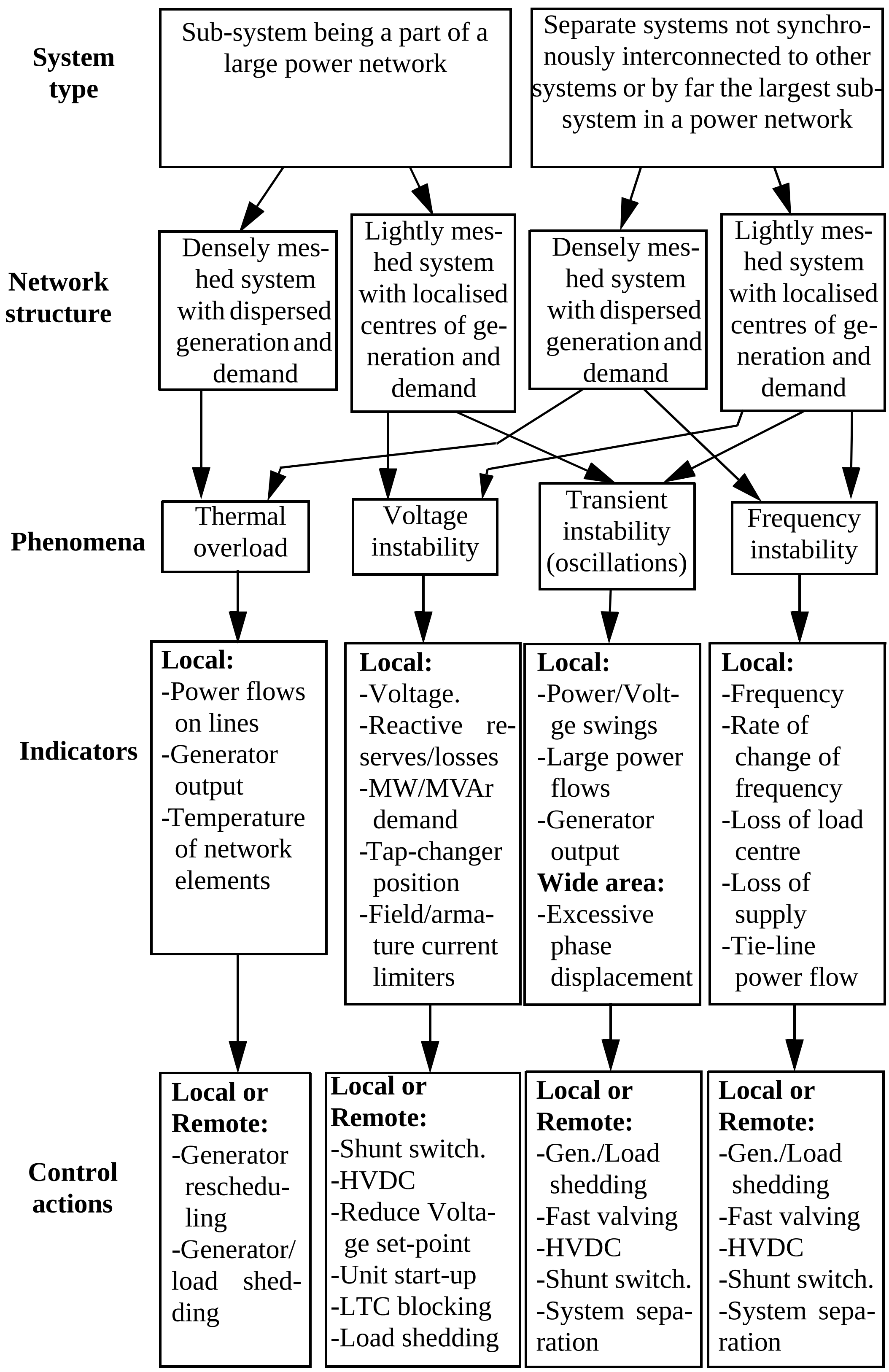
[160] Fismen S.A, ”Nettvern i Nordel-området”, NOSY-rapport, June 29, 1992, Oslo, Norway, (in Norwegian).

[161] Janset O.P, ”Nettvern i Nordel-området”, NOSY-rapport, status 2000, Oslo, Norway, (in Norwegian).

[162] CIGRÉ TF 38-02-08, ”Long Term Dynamics Phase II”, 1995.

[163] Jonsson M, Daalder J, “Distance Protection and Voltage Stability“, PowerCon 2000, December 4-7, Perth, Australia, Proceedings Vol.2, pp. 971-976.

Appendix I Summary of Important SPS Features



Paper A

An adaptive scheme to prevent undesirable distance protection operation during voltage instability

M. Jonsson, J. Daalder

Accepted for IEEE Transactions on Power Delivery

Paper B

A new protection scheme to prevent mal-trips due to power swings

M. Jonsson, J. Daalder

Presented at
IEEE/PES Transmission and Distribution Conference and Exposition,
October 28 - November 2, 2001, Atlanta, USA.

Paper C

A distance protection scheme to prevent mal-trips during abnormal power system conditions

M. Jonsson, J. Daalder

Presented at
Cigré Study Committee 34 Colloquium and Meeting,
September 10 - 14, 2001, Sibiu, Romania.

Paper D

A new method suitable for real time generator coherency determination

M. Jonsson, M. Begovic, J. Daalder

Submitted to IEEE Transactions on Power Systems

Paper E

A system protection scheme concept to counter inter-area oscillations

M. Jonsson, J. Daalder, M. Begovic

Submitted to IEEE Transactions on Power Delivery

Paper F

An emergency strategy scheme based on conventional distance protection to avoid complete system collapse

M. Jonsson, J. Daalder, K. Walve

Accepted for
IEEE/PES Transmission and Distribution Conference and Exposition,
September 7 - 12, 2003, Dallas, USA.