Distributed Intelligence in Critical Infrastructures for Sustainable Power

ENK5-CT-2002-00673

Deliverable 1.5: Intelligent Load Shedding

Zoran Gajic & Daniel Karlsson, ABB

Ch Andrieu, IDEA

Per Carlsson, EnerSearch

Nayeem Rahmat Ullah, Sumbo Okuboye, ABB

Identifier:	**IDEA_ABB_ILS_WP15_002_09**
Date:	**August 24, 2005**
Class:	**document**
Responsible Partner:	**ABB, EnerSearch**
Annexes:	
Distribution:	**Public**
Overview:	**Intelligent Load Shedding**

The CRISP consortium consists of:

ECN	Principal Contractor & Coordinator	The Netherlands
IDEA	Principal Contractor	France
EnerSearch AB	Principal Contractor	Sweden
Sydkraft AB	Principal Contractor	Sweden
Blekinge University of Technology	Principal Contractor	Sweden
ABB AB	Principal Contractor	Sweden
Eneco	Assistant Contractor	The Netherlands

<u>Control Versions</u>:

Version	Date	Author	Description of Changes
01	2003-12-31	Per Carlsson, Zoran Gajic, Daniel Karlsson	Draft - for comments
…			
04	2005-04-18	Ch Andrieu	Global review of the document Deep changes in the structure keeping main existing contents and results Addition of new view and contents
05	2005-04-27	Daniel Karlsson	Addition of Chapter 5 & 6 + a few abbreviations + a few references
06	2005-07-01	Ch Andrieu	Changes in the structure chapters 5&6 > 4&5 contents added
07	2005-08-18	Ch Andrieu	Contents added Review & Finalization
08	2005-08-22	Ch Andrieu	Finalization
09	2005-08-24	G.J. Schaeffer	Final

Table of Contents

List of Figures

References

[D1.3] M.Fontela & co, “Distributed generation as a means to increase system robustness", deliverable D1.3 of ENK5-CT-2002-00673 CRISP-project.

[D1.4] C. Andrieu & co, “Fault detection, analysis and diagnostics in high-DG distribution systems ", deliverable D1.4 of ENK5-CT-2002-00673 CRISP-project.

[D1.7] C. Andrieu & co, “Distributed Network Architectures", deliverable D1.7 of ENK5-CT-2002-00673 CRISP-project.

[1] Johansson, S.: *Long-term Voltage Stability in Power Systems – Alleviating the Impact of Generator Current Limiters*, Technical Report No. 335, Dept. of Electric Power Engineering, Chalmers University of Technology, Sweden, ISBN 91-7179-624-8, 1998.

[2] Taylor, C.W., Van Leuven, A.L.: *CAPS: improving power system stability using the time-overvoltage capability of large shunt capacitor banks,* Power Delivery, IEEE Transactions on Volume 11, Issue 2, April 1996 Page(s):783 - 792

[3] Larsson, M., Karlsson, D.: *Coordinated Control of Cascaded Tap Changers in a Radial Distribution Network*, Paper SPT PS 22-06-0405, Stockholm Power Tech Conference, Stockholm, Sweden, June 18-22, 1995.

[4] Karlsson, D., Hill, D.J.; *Modelling and identification of nonlinear dynamic loads in power systems,* Power Systems, IEEE Transactions on Volume 9, Issue 1, Feb. 1994 Page(s):157 - 166

[5] Arnborg, S.: Emergency Control of Power Systems in Voltage Unstable Conditions, Electric Power Systems, Royal Institute of Technology, Sweden, ISSN 1100-1607, 1997.

[6] "Causes of the August 14th Blackout", Interim Report from the U.S.-Canada Power System Outage Task Force.

[7] "Elavbrottet 23 september, 2003 (Blackout 23 September, 2003)", Report Nr 1:2003, Svenska Kraftnät, 2003-11-03, available on www.svk.se.

[8] "Interim Report of the Investigation Committee on the 28 September 2003 Blackout in Italy", UCTE, 2003-10-23.

[9] Cigré TF 38.02.19 (Convenor: D. Karlsson), System Protection Schemes in Power Networks, to appear 2001.

[10] Gustafsson, M.; Krantz, N.: *Voltage Collapse in Power systems – Analysis of Component Related Phenomena using a Power System Model*, Technical Report No. 215L, 1995, Dept. of Electrical Power Engineering, Chalmers University of Technology, ISBN 91-7197-221-8.

[11] Ingelsson, B.; Lindstrom, P.-O.; Karlsson, D.; Runvik, G.; Sjodin, J.-O.: *Wide-area protection against voltage collapse*, Computer Applications in Power, IEEE, Volume 10, Issue 4, Oct. 1997 Page(s):30 - 35

[12] Swedish Patent Application No. 0303619-1.

[13] Swedish Patent No. 0300243-3.

[14] M. Gustafsson, N. Krantz, “Voltage Collapse in Power systems”, Tech. Report No.215L, Chalmers University of Technology, Gothenburg, Sweden, 1995. ISBN 91-7197-221-8.

[15] William D. Stevenson, JR., “Elements of Power System Analysis”, 1982. ISBN 0-07-066584-2.

[16] Arthur R. Bergen, Vijay Vittal, “Power System Analysis”, 2000.

[17] John G. Proakis, Dimitris G. Manolakis, “ Digital Signal Processing Principles, Algorithms and applications”, ISBN 0-02-396815-X

[18] Narain G. Hingorani, LaszloGyugyi, “Understanding Facts: Concepts and Technology of Flexible AC Transmission Systems,” IEEE Press, ISBN 0-7803-3455-8.

[19] Magnus Akke, “ Some Control Applications in Electric Power Systems,” PhD Thesis, Department of Industrial Electrical Engineering and Automation (IEA), Lund Institute of Technology (LTH), Sweden.

[20] Brian D. Hahn, ”Essential MATLAB for Scientists and Engineers”, ISBN 0 340 691441

additional reference:

[a0] M. Jonsson, “Present Status of System Protection Schemes,” Chalmers University of Technology, Gothenburg, Sweden, 2002.

[a1] Andersson, Arne and Ygge, Fredrik: Managing large scale computational markets. In H. El-Rewini, ed. *Proceedings of the Software Technology track of the 31th Hawaiian International Conference on System Sciences (HICSS31),* volume VII, pp 4 – 14. IEEE Computer Society, Los Alamos, January 1998. ISBN 0-8186-8251-5, ISSN 1060-3425, IEEE Catalogue Number 98TB100216.

[a2] Bidding on the spot market. An overview of the bidding capabilities on the NordPool day-ahead market. Downloadable from http://www.nordpool.no

[a3] Carlsson, Per, and Andersson, Arne, and Ygge, Fredrik: A Tractable Mechanism for Time Dependent Markets. Accepted for IEEE CEC’03, Newport Beach, USA, June 2003. An extended version is downloadable as a technical report from http://www.it.uu.se/research/reports, report no. 2003-027.

[a4] Carlsson, Per, and Andersson, Arne, and Ygge, Fredrik: Extending Equilibrium Markets. *IEEE Intelligent Systems,* 16(4), pp 18 – 26, July/August 2001

[a5] Carlsson, Per, and Ygge, Fredrik, and Andersson, Arne: Extending Equilibrium Markets. IEEE Intelligent Systems, July/August 2001, volume 16, number 4, pp. 18 – 26.

[a6] Carlsson, Per, and Ygge, Fredrik, and Ottosson, Hans: Communication Tests of Electronic Power Markets through Power Line Communication. Proceedings of Power Systems and Communications Infrastructures for the Future. CRIS conference in Beijing, September 2002. (Available from http//:www.cris-inst.com)

[a7] http://www.elbas.net

[a8] http://www.nordpool.no

[a9] Jelsma, J., and Kets, A., and Kamphuis, I.G., and Wortel, W.: SMART work package 4.2, Smart field test: experience of users and technical aspects.

[a10] Ottosson, Hans, and Ygge, Fredrik, and Carlsson, Per, and Lehmann, Josef: Trial Report – Lugano. Deliverable D11:1 of the PALAS (Power line as an Alternative Local AccesS) project, IST-1999-11379.

[a11] Projekt MINTOP, Project report on a Sydkraft project on peak load reduction. Malmö, 1998 (in Swedish).

[a12] Rasmusson, Lars: Agent Negotiation over Compound Network Resources. In *Proceedings of the IAT99 Workshop on Agents in Electronic Commerce.* Hong Kong 1999.

[a13] Rasmusson, Lars: Pricing Virtual Paths with Quality-of-Service Guarantees as Bundle Derivatives. *Submitted.*

[a14] Sutherland, I. E.: A Futures Market in Computer Time. *Communications of the ACM,* 11(6), pp 449 – 451

[a15] Svenska Elverksföreningen: Belastningsberäkning med typkurvor. Technical report on load calculations based on customer profiles. 1991.

[a16] Teknikstyrning av elanvändning, Rapport 1, Project report on a Sydkraft and Svensk Energiutveckling project on load side control. This part is the technical report. Kristianstad, 1989 (in Swedish).

[a17] Teknikstyrning av elanvändning, Rapport 2, Project report on a Sydkraft and Svensk Energiutveckling project on load side control. This part covers results and conclusions. Kristianstad, 1990 (in Swedish).

[a18] Walsh, W. E., and Wellman, M. P., and Ygge, F: Combinatorial Auctions for Supply Chain Formation. *Second ACM Conference on Electronic Commerce (ACM EC'02),* pp 260 – 269, Minneapolis 2000.

[a19] Wurman, Peter R.: Market Structure and Multidimensional Auction Design for Computational Economies. Ph.D. Thesis, University of Michigan, 1999.

[a20] Ygge, Fredrik, and Akkermans, Hans: Decentralized Markets versus Central Control: A Comparative Study. *Journal of Artificial Intelligence Research,* 11, pp 301 – 303, 1999.

[a21] Ygge, Fredrik, and Akkermans, Hans: Resource-Oriented Multicommodity Market Algorithms. *Autonomous Agents and Multi-Agent Systems,* 3, pp 53 – 71, Kluwer Academic Publishers, 2000.

[a22] Ygge, F., and Akkermans, H., and Andersson, A., and Krejic, M., and Boertjes, E.: The HomeBots System and Field Tests: A Multi Commodity Market for Predictive Load Management. *Proceedings of the Fourth International Conference and Exhibition on The Practical Applications of Intelligent Agents and Multi-Agents (PAAM99),* pp 363 – 382, 1999.

[a23] Ygge, Fredrik: Market-Oriented Programming and its Application to Power Load Management. Ph.D. Thesis, Lund University, ISBN 91-628-3055-4, Lund 1998.

Abbreviations

Acronym	Means
AC	Alternating Current
ANN	Artificial Neural Network
AVR	Automatic Voltage Regulator
CB	Circuit Breaker
CPU	Central Processing Unit
CRISP	Distributed Intelligence in CRitical Infrastructures for Sustainable Power
CT	Current Transformer
DG	Distributed Generation
DG	Dispersed Generation
DG-RES	Distributed generation based on renewable energy systems
DLS	Distributed Load Shedding
DNO	Distribution Network Operator
DoS	Denial of Service (security study)
DR	Distributed Resources
EPC	Emergency Power Control
EPS	Electric Power System
HV	High Voltage
HVDC	High Voltage Direct Current
HVDC-light	HVDC system based on transistor technology
ICT	Information and Communication Technology
IEC	International engineering consortium
ILS	Intelligent load shedding
IP	Internet Protocol
LAN	Local Area Networks

LS	Load shedding
LV	Low Voltage
MV	Medium Voltage
PC	Personal Computer
PCC	Point of Common Coupling
PLC	Power Line Carrier
PS	Power System
QoS	Quality of Service
RES	Renewable Energy Systems
RTU	Remote Terminal Unit
SCADA	Supervisor Control and Data Acquisition
SLR	Smooth Load Relief
SPS	System Protection Scheme
SVC	Static Var Compensator
TSO	Transmission System Operator
UML	Unified Model Langage
VT	Voltage Transformer
WAN	Wide Area Networks

Summary

Load shedding has been used to mitigate the consequences of large disturbances in electric power systems, since the beginning of the electrification era. The way to execute the load shedding, i.e. open a circuit breaker, has hardly developed at all for a 100-year period. The modern society dependence on reliable electricity supply is continuously increasing. This means that the consequences of traditional load shedding are not acceptable. In the meantime computer and communication technology has developed tremendously. There is also a trend to use more and more intelligent control and less hardware, such as lines and generators, to provide the required level of reliability for the electric supply. Especially in power systems, and parts of power systems, comprising distributed generation, there seems to be a great potential to improve the overall cost/benefit-ratio for the desired level of reliability, by the use of intelligent “load shedding”.

“Intelligent load shedding" is a means to improve power system stability, by providing an adapted load control along the distribution network, in situations where the power system otherwise would go unstable. The work with intelligent load shedding in this work package results in various technical principles of dedicated algorithms. These algorithms intend to bring a support tool for the operating system during critical situations. The main aspects are evaluating the right amount and location of power response for a given disturbance, and evaluating the right time response expected in order to comply with an acceptable stability recover. This time response is a main object in order to define appropriate ICT network enabling such a reliable implementation.

A main problem of the intelligent load shedding is how to choose load to shed conveniently and quickly. There is a technical problem of finding the right level and location of the load to shed, and also an economical problem of giving incentives in order to have enough remote controlled loads. Some aspects on a dedicated market system are reported in the document in order to start to express some ICT system expectations and requirements.

Another aspect is the required coordination of the responses of local production and local controlled loads, in order to combine adequately the efforts to support the system.

1 Introduction

The "intelligent load shedding" is a means enabling to improve power system stability, by providing a real time adapted load control and load shedding, in situations where the power system otherwise would go unstable. The work with intelligent load shedding in this work package results in various technical principles of dedicated algorithms. These algorithms intend to bring a support tool for the operating system during critical situations. The main aspects are evaluating the right amount and location of power response for a given disturbance, and evaluating the right time response expected in order to comply with an acceptable stability recover. This time response is a main object in order to define appropriate ICT network enabling such a reliable implementation.

Task 1.5 covers the study of the steady-state and the dynamical characteristics of the loads, their modelling and simulation in critical network situations in order to evaluate appropriate ILS strategies. When the technical assessment is performed, the real implementation needs associated market and ICT system. The ICT system requirement has to deal with the time responses expected for the technical solution proposed and the chosen market proposed.

The last blackouts show that the existing load shedding is not sufficient enough for some critical EPS situations. A main aspect is the need of an appropriate response in power and in time with fast remote supervision and control.

The aim of the load shedding is keeping the power system stability, i.e. keep the bulk power or transmission system energised together with as much of the load as possible. In our case of intelligent load shedding, the loads shed are assumed to be distributed among the feeders: chosen loads among the network are disconnected. Before removing loads or just after this kind of action, a way to contribute to the stability during critical situations on the EPS is maintaining a smooth load relief: the variations of power exchanges are limited in magnitude and in time (except for means dedicated for fast power balance) in order to avoid too much stresses on the voltage control (frequency and magnitude).Additionally various critical preventing actions may be taken in order to contribute to support the system facing a temporary disturbance: for instance maintaining a low voltage level (but still normal) on the distribution network helps to limit the injected current by the transmission network. These three kinds of approach need to be coordinated between them in order to be enough efficient and coherent. It involves specific market incentives and associated ICT requirements.

The existing load shedding system is based on frequency or magnitude voltage thresholds and involves opening of complete and distributed MV feeders (the sending-end circuit-breaker on 10kV or 20kV is ordered to open). The magnitude of power disconnection is not really known, leading to possible instability increase. The priority of load shedding is done feeder by feeder, what is not convenient with safety and security purposes. A best way is to define priority between the loads (for instance elevators may involve safety aspects) and warn the remaining supplied loads of the critical situation being faced (for instance the elevators may be stopped at the next floor with doors blocked open if critical warning is maintained).

The traditional view on shedding system is for large stability purpose at transmission level. In the future and in addition another kind of problem may be solved also by local shedding distributed in the feeders: voltage and current constraints occurring inside the distribution feeders. This need will appear when the dispersed local production (DR) will be taken into account in the reduced design or reduced reinforcement of the lines and the cables. So the

ILS functions and goals are larger than stability on transmission, they will deal also with the energy management and security assessment of the whole system on distribution and transmission. What is needed is to proceed step by step recovering the previous action on transmission security, and then to integrate the other valuable functions (enough profitable for the different actors of the local market) gradually.

The traditional LS for transmission includes two main protection systems based on relays for detecting underfrequency and relays for detecting undervoltage situations. A first part of the document presents the existing LS with these two ways of detection and action.

A second part deals with the concept of intelligent load shedding and of smooth load relief, and with the associated needed market and ICT system. The main kinds of investigated actions are presented.

A third part deals with the general problem of EPS large oscillation mitigation. At the same time ILS may contribute to the mitigation by appropriate fast loads oscillations but also take benefit of the existing damping system (the efficiency and the accuracy of the required distributed LS depends on the capacity of the system to face a given magnitude of oscillation, magnitude linked to transient global power imbalance). Moreover the right identification of the large disturbance occurring on the transmission network is of prime interest: the best action on DR or on controlled loads facing power oscillations or global power unbalance are different.

2 Description of existing load-shedding system

Automatic load shedding is basically a last resort backup measure. As such, it will be called on to operate only when a highly improbable, potentially catastrophic disturbance occurs. Therefore, if the possibility of complete system collapse is to be avoided during such a disturbance, load shedding should be simple and drastic, rather than elaborate and complex.

Implementing an effective load shedding program is not difficult. Calculations are not complex and extensive system studies are unnecessary. Moreover, new static relays with their greater precision and stability can achieve secure, coordinated, system-wide automatic load shedding and load restoration.

2.1 Under-frequency Controlled Load Shedding

Any part of a power system will begin to deteriorate if there is an excess of load over available generation. The prime movers and their associated generators begin to slow down as they attempt to carry the excess load. Tie lines to other parts of the system, or to other power systems across a power pool, attempt to supply the excess load. This combination of events can cause the tie lines to open from overload or the various parts of the systems to separate due to power swings and resulting instability. The result may be one or more electrically isolated islands in which load may exceed the available generation.

Further, the drop in frequency may endanger generation itself. While a hydroelectric plant is relatively unaffected by even a ten percent reduction in frequency, a thermal generating plant is quite sensitive to even a five percent reduction. Power output of a thermal plant depends to a great extent on its motor-driven auxiliaries such as boiler feed-water pumps, coal pulverizing and feeding equipment, and draft fans. As system frequency decreases, the power output to the auxiliaries begins to fall off rapidly which in turn further reduces the energy input to the turbine and consequently to the generator. The situation thus has a cascading effect with a loss of frequency leading to a loss of power which can cause the frequency to deteriorate further and the entire plant is soon in serious trouble. An additional major concern is the possible damage to the steam turbines due to prolonged operation at reduced frequency during this severe overload condition.

To prevent the complete collapse of the island, underfrequency relays are used to automatically drop load in accordance with a predetermined schedule to balance the load to the available generation in the affected area. Such action must be taken promptly and must be of sufficient magnitude to conserve essential load and enable the remainder of the system to recover from the underfrequency condition. Also, by preventing a major shutdown, restoration of the entire system to normal operation is greatly facilitated and expedited.

It is generally recognized that the sudden loss of generating capacity on a system will be accompanied by a decrease in system frequency. The frequency will not suddenly deviate a fixed amount from normal but rather will decay at some rate. The initial rate of frequency decay will depend solely on the amount of overload and on the inertia of the system. However, as the system frequency decreases, the torque of the remaining system generation will tend to increase, the load torque will tend to decrease and the overall effect will be a reduction in the rate of frequency decay. Assuming no governor action, the damping effect produced by changes in generator and load torques will eventually cause the system frequency to settle-out at some value below normal. If governor action is considered, and if the remaining generators have some pick-up capability, the rate of the frequency decay will be reduced further and the frequency will settle out at some higher value. In either case the system would be left at some reduced frequency that may cause a further decrease in generating capacity before any remedial action could be taken. The variation of system frequency during such a disturbance is not a smooth rate of decay but rather is oscillatory in nature because of the interaction of the interconnected generators. Moreover, the rate of decay and the period of oscillation may differ appreciably across the system.

In general, it is not possible to analytically determine the frequency oscillations that can occur on a system of appreciable size during such a disturbance. The nature of these oscillations can only be determined from detailed computer studies of the system. However, it is possible to determine, and predict with reasonable accuracy, the average rate of frequency decay that can occur for different magnitudes of generation deficiencies. Voltage level can also affect the system active power loading. It is usually assumed that a one percent change in voltage will produce a corresponding one percent change in active load power.

During severe system emergencies, which result in insufficient generation to meet load, an automatic load shedding program throughout the affected area can prevent a total system collapse. It also helps to achieve fast restoration of all affected loads. The application of underfrequency relays in substations throughout the load area, preset to drop specific percent magnitudes of load at predetermined low system frequency values, provides the simplest automatic load shedding program. Relay settings can be developed to drop the minimum load to arrest system frequency decay at a safe operating level. Additional underfrequency relays can also be applied to initiate a safe and orderly separation or shutdown if the emergency is beyond the capabilities of the load shedding program.

2.1.1 Basic Principles for Underfrequency Controlled Actions

The maintenance of maximum service reliability has always been the primary concern of the electric utility industry. To attain this end, power systems are designed and operated so that for any predicted system condition, there will always be adequate generating and transmission capacities to meet load requirements in any system area. For the most part, this design and operating procedure has been successful in producing a high degree of service continuity, even under emergency conditions. However, regardless of how great the planned margins are in system design and operation, there have been, and probably always will be, some unpredictable combination of operating conditions, faults, forced outages, or other disturbances which cause system split-ups and/or a deficiency in generating capacity for existing area loading. When this occurs on a modern power system, it generally indicates that a highly improbable and potentially catastrophic event has occurred. Therefore, it is essential that the generation deficiency be quickly recognized and the necessary steps taken to prevent the disturbance from cascading into a major system outage. The immediate problem is to attain a balance between generation and load before the decaying system frequency caused by the overload affects the performance of the remaining generation and power plant auxiliaries. This balance can be achieved by increasing generation or by automatic load shedding on low frequency.

In general, the first alternative, increasing generation, can not be accomplished quickly enough to prevent a major decrease in system frequency, or in the extreme, there may not be sufficient available generating capacity to pick up the additional load.

On the other hand, the second alternative, automatic load shedding on low frequency, provides a quick and effective means for attaining a generation-load balance and for restoring system frequency to normal. The application of underfrequency relays throughout the load area, preset to drop increments of load at specific levels of low frequency, provides a simple and direct method for alleviating system overloads and for minimizing the magnitude and duration of any service interruption. Since system overloads are generally caused by a major disturbance of unknown cause and system collapse may be imminent, load shedding should be performed quickly and automatically.

2.1.2 Load Shedding Programs

Ideally, a load shedding program should quickly recognize a generation deficiency, determine accurately the degree of overload, and then precisely shed only the amount of load required to restore system frequency to normal. While it may be possible to closely realize this ideal on a small system for predicted events, it will be difficult, if not impossible, to achieve on a system of appreciable size. Considering the oscillatory nature of the frequency decay, it should be apparent that it would be difficult to establish a load shedding program which will precisely drop equal increments of load at the same instant all over the system. These frequency oscillations will tend to introduce a certain degree of randomness in underfrequency relay operation and, hence, in the amount of load shed. Moreover, because of these oscillations, it may be inevitable that more load will be shed than necessary at some system locations.

In general, it will not be possible to accurately predict the degree of randomness or the amount of overshedding that will occur under all system conditions. Computer studies of the system can provide a good indication of the frequency oscillations which will occur at various load buses for some emergency conditions, but this data will not necessarily be pertinent during an actual disturbance. In spite of these unpredictable parameters, it is possible to establish an effective load shedding program. The following paragraphs discuss the factors which must be considered in developing a load shedding program and describe the procedure involved in achieving relay settings.

2.1.3 Power System Characteristics

To apply underfrequency relays for load shedding, it is necessary to have some knowledge of how the frequency will vary when load exceeds the generating capacity of a system, and when the system is recovering from such an overload. Because of the numerous variables involved, it is usually difficult, if not impossible, to obtain a precise frequency characteristic for a system of appreciable size. However, it is not essential that a precise characteristic be known in order to apply underfrequency relays. It is only necessary to obtain a basic knowledge of the phenomena involved and the effect of the various parameters on the overall characteristic.

An underfrequency disturbance event will typically have all loads shed within 0.3 and 10 seconds after the inception of the disturbance. Governors will not operate to adjust MW output levels by any appreciable amount in this time frame, which means the frequency will change in accordance with the system inertial response characteristic. Looking at frequency alone, a simple model can be constructed using one equivalent generator supplying total system load (generator auxiliary power, losses, and customer load). The frequency response characteristics of load and generation are properly accounted for in this simple model. The simple model cannot account for transient variations in load resulting from transient variations in voltage.

Whatever the voltage effect is, only the net generation and load imbalance affects the frequency. A full network model using the transient stability program can include the effects of voltage on the load as well as losses during the dynamic time frame. The detailed program calculates the voltage profile resulting from a specific disturbance scenario, and presuming that the relationship between transient load and transient voltage is known, the net effect on the transient frequency can be determined. The detailed program can also show transient flows on the transmission system, and simulate islanding patterns.

The rationale for evaluating various values of equivalent generator inertia is that the mix of generation that trips during a disturbance is random, meaning that the mix of generation remaining after a disturbance is also random. This is especially true when the initiating disturbance can occur anywhere within the interconnected power system. The rationale for evaluating various load sensitivities is that the characteristics of load can change radically between seasons and geographic areas. The current industry trend is to have a static off-nominal frequency program that does not change seasonally but gives acceptable performance for a wide range of initiating disturbances. Typically the under frequency load shedding plan is to be designed to meet the criteria specified above for losses of generation of 1%, 2%, 3%, 4%, 5%, 10%, 15%, 20%, 25%, and 30%.

Where individual operating utility companies are interconnected, resulting in a power pool, it is essential that system planning and operating procedures are coordinated to provide a uniform automatic load shedding program. The number of steps, the frequency levels and the amount of load to be shed at each step shall be established by agreement between the power pool members. All involved utilities then should strictly implement this agreed under frequency load shedding program.

2.1.4 Maximum System Overload

Load shedding programs are usually designed to protect for some maximum overload condition. In many instances, it is difficult, if not impossible, to determine what this maximum overload will be. For example, on large interconnected systems, it may be difficult to define where and how an area is going to separate from the system and therefore what the generation-load balance will be. In some cases, system stability studies will indicate the likely points of separation and the probable overload can be estimated for the separated area.

The uniform under frequency load shedding plan should provide coverage during a substantial loss of generation or resources (e.g. 25-33%). A under frequency load shedding plan can be designed for a 50% range of generation overload. For example, a 33% loss of generation represents a 50% overload on remaining generation. A 50% loss of generation represents a 100% overload on remaining generation. A good off-nominal underfrequency program can be designed for a 0%-50% generation overload, a 25%-75% overload, or a 50%- 100% overload. A program designed for a 50%-100% overload will most probably not work at all for a contingency that involves only a 0%-50% overload. The loss of 33% of total generation is, by any present standard, a severe contingency. As a practical matter, a well behaved under frequency load shedding program cannot be designed for loss of generation beyond 33% unless load is massively over shed at higher frequencies to prevent the dynamic frequency from falling below the point at which the thermal generating units trip instantaneously (i.e. 46.5 Hz in 50Hz power system). This massive over shedding of load must then be accompanied by massive automatic and high speed load restoration to prevent the units from tripping due to overfrequency. The program designed for loss of generation beyond 33% will typically not work at all for loss of generation less than 33%. In view of these problems, the uniform off-nominal program shall be designed up to a maximum generation and load imbalance of 33%.

Obviously, it will be less difficult to determine the possible overloads on industrial or small municipal systems, which receive a major portion of their required power from a transmission utility over one or two tie-lines.

2.1.5 Maximum Load to be Shed

The amount of load to be shed should be sufficient to restore system frequency to normal or close to the rated value (within 1Hz band from the rated frequency). To accomplish this, it would mean the load that is shed should nearly equal the amount of overload. However, it is not essential that the frequency be restored exactly to the nominal value.

If there is any discretion allowed, the preferred option is to have the postdisturbance frequency settle out above the rated frequency, as opposed to below the rated power system frequency (i.e. 50Hz or 60Hz). If the frequency settles out above rated frequency within 0.5Hz band, then in the short order the governors will automatically act to restore the system to the rated frequency value. This will facilitate the restoration of ties (in the case of islanding) and in any event it is the preferred operating mode of the generators (to prevent spurious trips within the generating plant).

If the frequency levels settle out below rated frequency within 0.5Hz band, then governors will act to raise generation, however longer time delays are potentially possible because additional fuel must be added to boilers before the increased generation can be supported. There is also the possibility that increased generation may not be available, and load must be manually shed to achieve nominal frequency. Because of the possibility of damage to steam turbines, it is not recommended that less load be shed and thereby permit system frequency to settle-out at some level which is lower than 1 Hz from the rated frequency value.

Therefore as a conclusion it can be said that a post disturbance frequency equal to the rated frequency or slightly above is judged to be the best because it maximize the dispatcher's ability to initiate system restoration activities.

2.1.6 Initiation of Load Shedding - Frequency Level

The frequency level at which load shedding is initiated depends on several factors. For one, the level should be below any frequency drop from which the system could recover or below any frequency at which the system could continue to operate. On isolated systems, systems without interconnections, it may be reasonable to operate at some reduced frequency during emergency conditions. On large interconnected systems, frequency deviations of more than 0.2-0.3 Hz usually indicate a severe disturbance and therefore load shedding could be initiated at a higher level, say 49.5 Hz for 50 Hz system.

Another factor, which must be considered, is the frequency deviations that occur during system swings. When the local generation swings with respect to the large system, there can be a large frequency variation in the vicinity of the power generation plant. If the electrical center of this system is somewhere in the transmission system, the nearby frequency will vary around the generator frequency. In the more common case, the electrical center will be somewhere in the generator step-up transformer, and the nearby power system frequency will vary around the rated value. If the generator swings are large, the frequency deviations in the surrounding power system can be appreciable.

The load shedding programs must be coordinated with equipment operating limitations during low frequency operation. These limitations are usually associated with operation of power plant auxiliaries. According to some tests performed by different utilities, the performance of power plant auxiliaries begins to fall off and power plant output begins to decrease at frequencies 1 Hz below from the nominal value and reach a limiting condition between 5-8 Hz below the rated frequency value. To provide some margin, the maximum frequency decay is usually limited to 4 Hz from the rated frequency value, although in most power systems it will be limited to 3 Hz from the rated frequency value. Therefore load shedding must occur at some higher frequency level. Because of relay and breaker operating times, the frequency will continue to drop below the relay setting before the load is actually shed.

The figure 18 of the document [D1.3] illustrates clearly the dynamical variation of the frequency at a large scale view (Europe) for a large disturbance occurring in Spain. The large power swings observed during a few seconds are mainly caused by the distributed power controls (in the large power plants) and the other dynamical characteristics of the EPS. When the load shedding occurs some new dynamical characteristics are added in the system. The oscillations may be increased or decreased locally depending on the installed control for the load shedding. As observed in this figure 18, the instantaneous frequency is no more the same in the various locations during the large power oscillations. The action of the ILS should be local and should target the average value of these large oscillations. In the same example and in the case of a larger disturbance occurring in Spain, the frequency drop in Spain should be reduced by adequate local load shedding. If this action is not sufficient, the load shedding is induced in the surrounding countries and so on. The role of the ILS is not to replace the control of the large power plants but to support the system during critical situations (frequency drop exceeding 0.5 Hz).

2.1.7 Number and Size of Load Shedding Steps

The initial step in the procedure is the selection of the number of load shedding steps and the load to be shed per step. The number of load shedding steps selected is usually related to the maximum load to be shed. The larger the total load to be shed, the larger the number of load shedding steps used. In general, the number of implemented load shedding steps should be limited to three to five steps. Experience has shown that relay coordination is easier to achieve and the minimum amount of load will be shed when the number of load shedding steps fall in this range. The underfrequency relay manufacturers provide set points in increments of 0.01 Hz. However, practical considerations suggest that the minimum separation between steps should be at least around 0.1 Hz.

The load shed per step is not particularly critical. The amount of load shed on the initial step is usually related to the size of the largest generator or the pick-up capacity of the interconnecting tie-lines. A number commonly used for this first step is ten percent of system load. The amount of load shed in each succeeding step is usually determined by arbitrarily allocating some portion of the remaining load to be shed to each step.

It should be apparent that the selection of the number and size of load shedding steps is more or less arbitrary. In some instances, it will be possible to obtain coordinated load shedding within the specified frequency range with the initial selection. In others, it will be necessary to adjust both the number and size of steps in order to shed the entire load within the prescribed limits.

In applying the underfrequency relay in a load shedding program it must be recognized that a low frequency condition does not begin to be corrected until a circuit breaker operation occurs to disconnect some load.

Underfrequency relays typically have an operating time of 5-15 cycles depending on a particular type. As a system average, a 6 cycle operating time of breakers is used to trip load. Many systems will use distribution breakers to trip load. These distribution breakers are typically slower than transmission breakers. Although some systems will use transmission breakers to trip load, a system wide and conservative figure of 6 cycles can be typically used. However, with this assumption it implies that load will be shed between 11 and 21 cycles after the frequency reaches the set threshold level.

2.1.8 Relay Settings

The load shedding relays may be electromechanical, solid-state or numerical. The measuring element senses a frequency equal to its setting and will operate after a certain amount of time has elapsed after the frequency passes through its setting on its way down. The load shedding relays are typically installed in distribution or subtransmission stations, where feeder loads can be directly controlled. Loads throughout the system are classified as being critical, or non-critical. The order of priority of shedding is determined by the relative criticality of the load.

The determination of practical relay settings for a load-shedding program is essentially a trial and error procedure. The purpose of this procedure is to determine the best combination of number and size of load shedding steps and corresponding relay settings which will shed the required load within the frequency limits specified for a maximum overload condition, and yet which will shed a minimum amount of load for less severe conditions. In general, this is not a complicated procedure and requires only a few trials to arrive at optimum settings.

The load-shedding program must be coordinated with equipment operating limitations under low-frequency operation. These limitations or restrictions are primarily associated with operation of steam turbines or powerhouse auxiliaries. In general, continuous steam turbine operation should be restricted to frequencies above 48.5 Hz (50 Hz system base), and operation below 48.5 Hz should be for a limited time only, e.g. 10 minutes or less. The controlling parameter is the fatigue of turbine blades at low frequencies, which is a limitation determined by the specific turbine manufacturer. Tests on power plant auxiliary performance indicate that a limit of approximately 45 Hz, below which plant output begins to reduce and motors, driving constant active power load, will see an increase in current, increasing heating and approaching overcurrent relay settings.

The procedure for determining underfrequency relay settings is similar in many respects to the methods used in coordinating any group of protective relays. Selectivity is achieved through the adjustment of pick-up settings and through time coordination. Before considering the procedure for obtaining a selective load shedding program, it is necessary to comment briefly on a few factors that affect time coordination.

There is a minimum time delay required for each load shedding step. This time delay is necessary to prevent unnecessary shedding of load during the frequency oscillations which can occur on the load bus. For example, if the frequency drops below 47.75 Hz after sufficient load has been shed to start recovery of system frequency. If there was a load shedding step at 47.8 Hz, this load might be shed unnecessarily. In this instance, a time delay of 0.3 second would prevent such operation. While it is not possible to generalize on the amount of time delay to use on all systems, it appears that a 0.3 to 0.4 second time delay will be sufficient in most instances.

Some types of load will require additional time delay in order to prevent unnecessary shedding of load. For example, a load, which is tapped on a transmission circuit, can experience a gradual decay in voltage and frequency when the transmission line is tripped because of a fault, or for any other reason. The decay may be caused by the characteristic of the line or by the slowing down of motors associated with load. This decay will be sustained long enough to cause operation of high-speed underfrequency relays. A time delay of 0.35 to 0.5 second will usually be sufficient to ride over this condition. If there are only a few loads of this type, it is not necessary to consider this additional time delay in the general load shedding program. These loads would be taken care of on an individual basis. For more information please refer to the next chapter.

2.1.9 Practical Examples of Relay Settings

Svenska Kraftnät, transmission utility in Sweden (see next figure) has adopted the following under frequency load shedding plan:

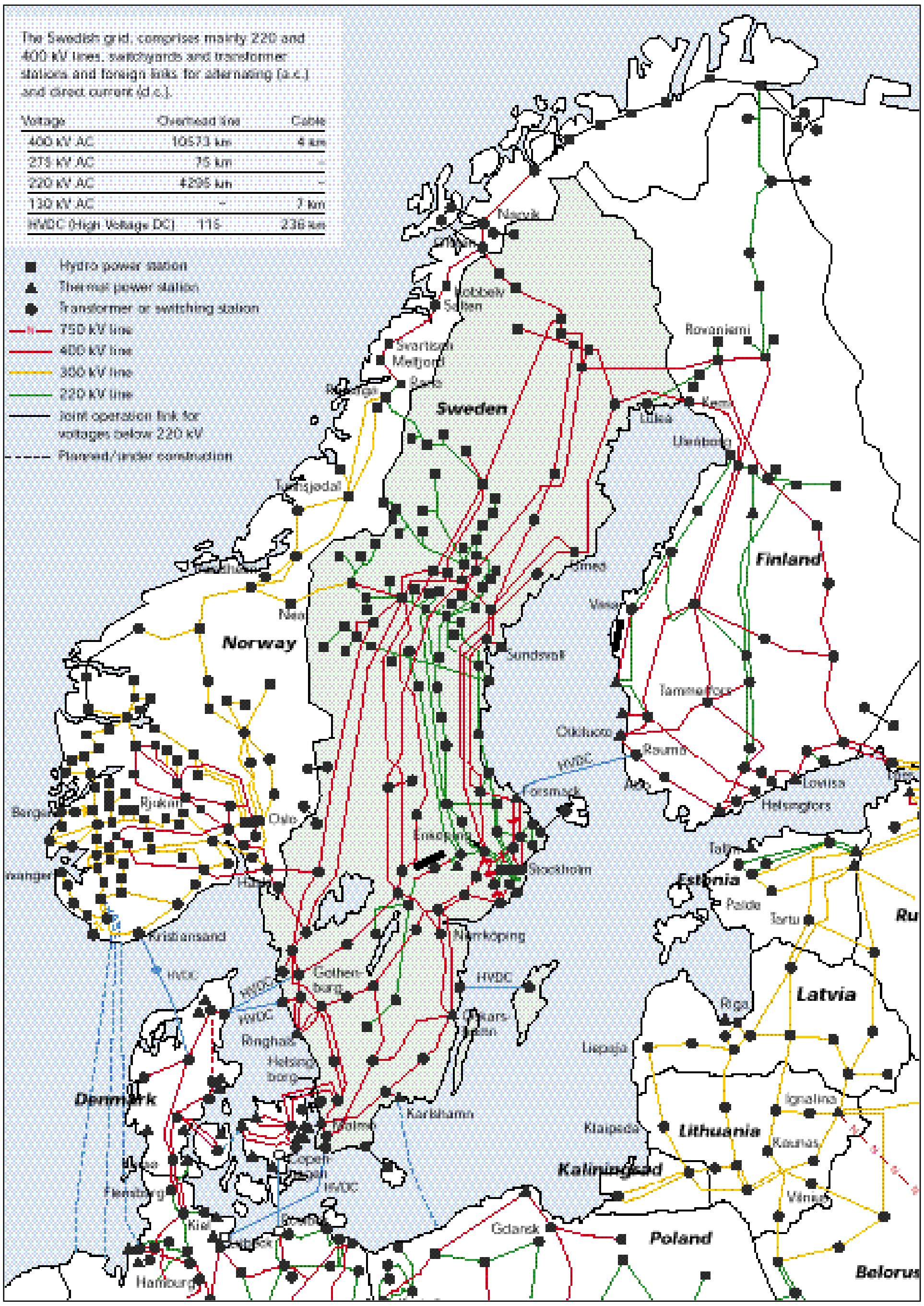


Figure 1. The Nordel Power System

– Step 1: 48.8 Hz; time delay: 0.15 s
– Step 2: 48.6 Hz; time delay: 0.15 s
– Step 3: 48.4 Hz; time delay: 0.15 s
– Step 4: 48.2 Hz; time delay: 0.15 s or 48.6 Hz for 15 s
– Step 5: 48.0 Hz; time delay: 0.15 s or 48.4 Hz for 20 s

The Western Electricity Coordinating Council (WECC), located on the west US cost is shown in the following figure:

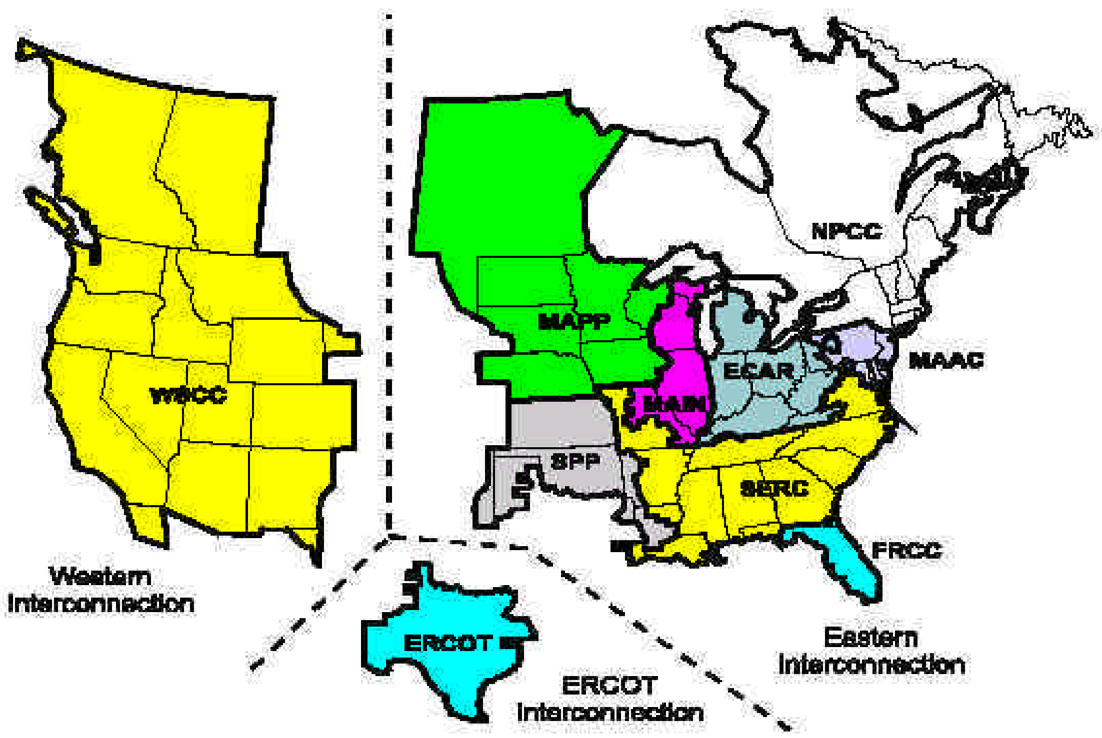


Figure 2. North American interconnected systems

WECC has adopted the so-called 59.1 Hz load shedding plan as a minimum standard for all interconnected utilities. The operation of this scheme is shown in the following table:

Load Shedding Step	% of customer load dropped	pickup [Hz]	tripping time
1	5.3	59.1	no intentional delay*
2	5.9	58.9	no intentional delay*
3	6.5	58.7	no intentional delay*
4	6.7	58.5	no intentional delay*
5	6.7	58.3	no intentional delay*

* The system average total tripping time (relay & breaker) should be no more than 14 cycles (i.e. 14/60=0.233 ms) at the indicated frequency set points.

2.1.10 Potential Problems with Load Shedding Applications

Underfrequency triggered load shedding might cause problems in the remaining part of the system, if not properly designed. One such example is high voltages in areas exposed to load shedding. This phenomenon is similar to the high voltage levels often occurring in power system restoration processes. Other situations that require some attention are discussed below.

2.1.10.1 Motor Loads

A substation, which has an extreme amount of motor loads, may present a problem of time coordination in the application of underfrequency relays for load shedding. If the transmission sources to such a substation were tripped out for any reason, the motor loads would tend to maintain the voltage while the frequency decreased as the motors were slowing down. This would especially be true if the line capacitance kept the motors excited. This slow decay of voltage may last longer than the usual three to six cycle trip delay used with a high-speed underfrequency relay, and the relay may trip and lock out breakers undesirably. In an unattended installation, restoration of the load would not then be accomplished by simply reenergizing the transmission line. One solution that has been applied is to further delay the operation of the underfrequency relay to about 20 cycles. This has apparently been adequate for most applications. Some attempts have also been made to use an undervoltage cutoff to help correct this problem. While this could be successful, care must be exercised in choosing the setting for the undervoltage device since a normal underfrequency condition on the system is usually accompanied by a lower than normal voltage. Too high an undervoltage setting would possibly block the underfrequency relay from doing a load shedding function when needed.

2.1.10.2 High-speed Reclosing

Many large industrial plants have adopted some form of load shedding program. One such application is a case where an industrial plant is tapped on to a power company through a transmission circuit that utilizes high-speed automatic reclosing. For faults on the transmission circuit the power company will usually trip both ends of the line, and then initiate high-speed reclosure of at least one end of the line. Since this reclosing is not synchronized with anything else, it is important that the industrial load be disconnected prior to the reclosure to prevent damage to heavy motors and local generators, if present. The motors and/or generators will likely have slowed down during the line interruption and their voltages would be out of synchronism with the power company voltage when the line is reenergized.

2.1.10.3 Overvoltage protection

When loads are shed suddenly during an underfrequency event, shunt capacitors remaining in service and possible additional reactive power generation of the distributed capacitance of overhead lines and cables may cause sustained overvoltages in the power system. Overvoltages can be high enough to cause power transformer overexcitation and consequent transformer magnetic core saturation. If this condition persist the power transformers magnetic core can be overheated and damaged. Because of this, shunt capacitors on the transmission system should either have automatic overvoltage protection or be tripped by underfrequency relays. In a similar way shunt reactors can be automatically switched on in order to reduce the excessive power system voltages. If it is evident by computer simulations that the overvoltages will be severe after under frequency load shedding operation, automatic switching of the shunt devices can be included as an integral part of the load shedding program.

2.1.10.4 Direct Load Tripping

There may be specific disturbances for which load needs to be tripped faster than afforded by an under frequency load shedding program to adequately arrest frequency and avoid cascading of other power system elements. This may be required either for regional or local needs. The program should allow such actions as long as it enhances and does not compromise the overall uniform load shedding program. Direct load tripping can be accomplished by sending trip signals to shed load based on preprogrammed logic or by using under frequency load shedding relays with frequency set points above the agreed operation level of the first load shedding step.

2.1.10.5 Underfrequency Protection of Generators

A major concern in the operation of steam turbine generators is the possibility of damage due to prolonged operation at reduced frequency during a system overload condition. Such a condition would result from an under-shedding of load during a system disturbance. Recognizing this possibility, many utilities have used or are considering the application of underfrequency relays and timers to protect steam turbine generators from damage. Therefore the generators connected to the grid that shall be protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames. Typical operation limits for steam turbine generators in 60 Hz system are shown in the table below:

Under Frequency	Over Frequency	Time Limit
60.0-59.5 Hz	60.0-60.5 Hz	N/A (continuous operating range)
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

2.2 Undervoltage Controlled Load Shedding

A voltage collapse of part of the electrical system is an indication that for the existing conditions and contingencies, some portion of the combined generation and transmission system has been operated beyond its capability. Voltage collapse can also be a symptom of a much larger problem, and when the system starts to collapse, there is a real danger that the localized problem will cascade into wider areas. The purpose of proper system planning and operating philosophies is for the system to function reliably, and failing that, to contain the impacts of disturbances to localized areas.

Voltage collapse, or uncontrolled loss of load or cascading may occur, for example, when sending sources are far enough removed from an area that the voltage at its loads experience a significant drop, especially during outage contingencies. System studies are needed to determine which systems are the potential candidates for a suitable UVLS scheme. It is most useful in a slow-decaying voltage system with the under-voltage relay time delay settings typically between 3 to 10 seconds. When overloads occur on long transmission lines in conjunction with a significant local voltage dip, then the effect of UVLS action would also be to alleviate such overloads.

Among all the potential uses of UVLS, it is usually not helpful for mitigating transient instability. The relay time delay to trip is normally set long enough to avoid false tripping and, hence load tripping will not occur fast enough to mitigate a transient stability event. UVLS is usually not helpful for mitigating local network facility overloading. The under-voltage trip threshold must be set low enough (again to avoid false tripping) that the UVLS relays would not pick up for most system conditions under which the typical facility would overload.

In today’s stressed transmission systems coupled with declining reactive power reserves, UVLS can be a low cost alternative to constructing new transmission lines or new generation to maintain system security. While new transmission lines and new generation projects are needed to meet the system load and provide long-term stability, such projects typically take about 3-10 years to complete. UVLS can be used as an interim measure until these projects are completed.

2.2.1 Basic Principles for Undervoltage Controlled Load Shedding

Transmission system voltage is needed to transfer electric power from the generation stations to the load centers, and is somewhat similar in function to water-pressure in a public water supply system. Reactive power is the component of total power that assists in maintaining proper voltages across the power system. Sufficient voltage is maintained by supplying the transmission system with reactive power from generating stations and static devices called shunt capacitors. Lightly loaded transmission lines also provide reactive power and help sustain power system voltages. In the contrary, heavily loaded transmission lines consume the reactive power. Therefore during heavy load condition more than normal amount of reactive power is required by the transmission system in order to transport the increased amount of active power. Unfortunately, the reactive power cannot travel long distances because it meets considerable resistance over the transmission lines. Therefore, reactive power sources need to be close to the point of reactive power demand — for example, near the load centers.

When heavily loaded transmission lines disconnect, the parallel lines that remain in service automatically pick up portions of flow from the disconnected line, which increases the reactive power consumed by these lines. When reactive supply is limited, the increased loading will cause a voltage drop along these lines. If reactive supply is not provided at the end of the lines, the voltage could fall precipitously. At that point, the transmission system can no longer transfer electric power from distant generation to energy users in load centers.

In some instances, the reactive power demand within an area is too great for the local generating units to supply. In those cases, the units can trip off line (automatic separation or shut-down), either from reactive power overload, or because the system voltage has become too low to provide power to the generators' own auxiliary equipment, such as fans, coal pulverizes, and pumps.

The power system is designed to ensure that if conditions on the grid (excessive or inadequate voltage, apparent impedance or frequency) threaten the safe operation of the transmission lines or power plants, the threatened equipment automatically separates from the network to protect itself from physical damage. Physical damage, if allowed to occur, would make restoration more difficult and much more expensive.

Power systems throughout the world have been experiencing voltage stability problems. That type of system-wide disturbance is manifested by several distinguishing features: low system voltage profiles, heavy reactive line flows, inadequate reactive support, heavily loaded power systems. The voltage collapse typically occurs abruptly, after a symptomatic period that may last in the time frames of a few seconds to several minutes, sometimes hours. The onset of voltage collapse is often precipitated by low-probability single or multiple contingencies. The consequences of collapse often require long system restoration, while large groups of customers are left without supply for extended periods of time. Schemes that mitigate against collapse need to use the symptoms to diagnose the approach of the collapse in time to initiate corrective action.

2.2.2 Reactive Power Reserves

Secondary voltage control is mainly used for controlling the overall system voltage profile in a region in such a way that maximum robustness against voltage collapse is achieved. The secondary voltage control system derives voltage set-point values for a number of pre-defined so called pilot nodes, chosen to be well representative of voltage in the region. The primary voltage control systems (tap-changer controllers and AVRs of generators, synchronous condensers and SVCs) then keep the voltage at these pilot-nodes at the desired value. By distributing the reactive power generation in a suitable way, reactive power margins in the synchronized units can be optimized. Reactive power support in the emergency condition can be achieved by:

- shunt capacitor bank connection and shunt reactor disconnection;
- shunt capacitor ”boosting” by temporarily decreasing the number of series groups in a shunt capacitor bank;
- increased Mvar output from reactive power controlled machines;
- temporary reactive power overload of synchronous machines;
- decrease of real power generation to enable increased reactive power generation for generators in the emergency area, can be efficient under certain circumstances
- OLTC actions

2.2.3 Actions of OLTC Transformers

The action of the on-load tap-changers (OLTCs) operating on the power transformers at various voltage levels has the main goal to supply the load at a voltage kept within a given range, as close as possible to the rated value. For a voltage collapse scenario the bulk system voltages are slowly decreasing while the OLTCs are restoring the distribution system voltages. By this action the active power demand on the transmission system is kept more or less constant, which further contributes to transmission voltage depression.

The simplest method to eliminate the OLTC action as a contributor to voltage collapse is to block the automatic raise operation during any period where voltage collapse appears to be a concern. The decision to temporarily block the tap-changer can be made using locally derived information or can be made at a central location and the supervisory system can then send a blocking signal to the unit. A co-ordinated blocking scheme can be utilised to block operation of OLTCs in an area where voltage instability is imminent. The co-ordinated scheme can be accomplished with undervoltage schemes acting independently in a co-ordinated fashion at various stations within a region, or it can be a centralised scheme that recognises a pattern of low voltages at key locations.

A more sophisticated use of the OLTCs, than just blocking them, could be to reduce the voltage set point. A larger load relief can be achieved in this way. As for the blocking of OLTCs the effectiveness is largely dependant on the characteristics of the supplied system, such as type of load, degree of shunt compensation, number of OLTCs on lower levels, etc.

2.2.4 Power System Characteristics

All important power system events are typically characterized by low or very low voltages occurring in the power system. The speed at which voltages change affects the types of measures that will be effective to prevent or contain the events. This speed is influenced by time and voltage varying characteristics of the power system elements like the loads, automatic tap changing transformers, generator excitation controls, governor and turbine response, protective relays, and other automatic or manual control actions. Typically the following three phenomena can cause voltage depression in the power system:

2.2.4.1 Long-term (slow) voltage collapse.

There have been some examples where voltage collapse has occurred after load build up over a period ranging from 5 minutes up to an hour. In this condition, increasing active loads are supplied from remote generation resources. The loads may be both voltage sensitive, and thermostatically increasing to meet constant cooling or heating demands. If under such conditions the power system cannot simultaneously supply additionally needed reactive power slow voltage collapse may be the final outcome.

Locations that have experienced long-term voltage collapse are Sweden 1983-12-27; Japan 1970-08-22 and 1987-07-23; France 1978-12-19, US/CA 2003-08-14, Sweden 2003-09-23, and Italy 2003-09-28.

2.2.4.2 Short-term (fast) voltage collapse.

The classical voltage instability is the result of low voltage in a load center following a disturbance of the power system structure. The initiating disturbance may involve equipment outages, or faults followed by equipment outages. When such outage occurs the power system cannot provide sufficient reactive power reserves to stabilize the system voltage within the first approximately 10 seconds after the initial disturbance.

2.2.4.3 Transient Instability

A fast voltage decay occurring on an interconnection is not a voltage collapse. It is characterized by voltage reduction in the 0 to 10 percent range in the load centers followed by a very fast collapse occurring over only a few seconds on an interconnection away from the load centers. The rapid voltage decay is the result of increasing angles between the interconnected systems as they pull out of step. The difficulty in applying UVLS for such a disturbance is that the voltage within the major load areas may not be depressed enough, and for a long enough time for UVLS relays to operate.

In order to study the voltage collapse phenomenon in a large electric power system, it is prudent to define local areas or “pockets” from voltage perspective. These are the areas that will sail or sink together for any major voltage related disturbance. For small electric systems, more than one system can be combined electrically to form one local area.

Boundaries of local areas are based on “electrical closeness” of system components, not their physical distances. It is possible to have two electrical substations in the same vicinity but owned by different utilities, and not connected electrically to each other. These substations, even though close geographically, may not be part of the same local area.

After a local area is established from an electrical perspective, the under voltage load shedding studies will now be focused on each individual area. Typically the generic load shedding schemes will not be suitable for every local area within the interconnection. Some local areas may find remedy by dropping only a nominal amount of load in one step, whereas others may need more extensive schemes using two or more levels of load dropping with corresponding multiple voltage pick-up points and time delays. Some areas may find it more efficient to use centralized schemes versus local schemes. It is also possible that some areas, particularly heavy exporting areas, may not even need any under voltage load shedding scheme.

In order to properly design and implement UVLS it is of outmost importance to perform all necessary studies in order to understand the power system response to such event.

2.2.5 Load Modeling

Load models and their parameters are probably the most difficult and important representation data to obtain. Loads are sensitive to voltage, frequency, and time. For the voltage collapse time period, frequency sensitivity is not usually a concern, but load sensitivity to voltage and time is always very important.

Voltage collapse can be studied in steady state simulations using constant MVA loads having no voltage sensitivity, however, system response and actual performance of an UVLS scheme may remain unknown by such simulations. Modeling with all constant MVA loads will produce the most pessimistic results, but there can be disadvantages to conclusions based on inaccurate analysis. The design may be less than optimal.

Voltage sensitivity may be modeled with loads at each bus represented as functions of the bus voltage. A common version of this is to model loads as part constant MVA, part constant current, and part constant impedance.

To determine the accuracy of the modeling results, field tests of voltage, MW, and Mvar versus time, can be conducted during the load conditions that are to be modeled. Load sensitivity to voltage step changes caused by opening lines and switching a reactor on can be measured. The time sensitivity of loads to address voltage collapse concerns is from the effects of thermostats on loads. Load models that include these effects are typically used in midterm dynamics programs, and not transient dynamics programs.

2.2.6 Steady State Simulations

Voltage collapse can be studied using power flow V-Q or P-V analysis, using voltage sensitive load modeling, and control action steps in sequences of power flow simulations. The reactive margins at critical buses can be tested for different load-shedding amounts and locations. The initial voltage drop following events can be determined for loads that would not have substantial amounts of motor stalling.

Insight into the speed of collapse can be obtained by changing the system load model in the power flow from constant MVA to constant impedance to represent the range from no response to an immediate load response to voltage. If the voltage collapse is going to be fast, the V-Q calculation will result in similar reactive margin between constant MVA loads and constant impedance loads. This method may help a utility determine if UVLS and automatic voltage controlled capacitors and reactors can respond fast enough to arrest the declining voltage. Dynamic simulation is, however, the best method for determining the speed of collapse.

2.2.7 Dynamic Simulations

Under-voltage load shedding can be studied simulating under-voltage relays tripping loads. Proposed settings for relay time delays and voltage trip thresholds can be modeled with existing dynamic models. The important control actions again are:

1. Generator VAR controls like field current relays, reactive power limits, and line-drop compensation.
2. Transformer automatic OLTC actions and blocking.
3. Automatic capacitor and reactor switching, and SVCs.
4. Remedial actions like direct load tripping.
5. Other local protection systems, and relay actions like impedance relays.

Since dynamic simulations are more time consuming, much of the work can be done with steady state, and then confirmed with dynamic analysis.

2.2.8 Undervoltage Load Shedding

Undervoltage load shedding is a final measure used to avoid a wide area voltage collapse when all other effective means are exhausted. The action of shedding load is no different from other load shedding schemes including underfrequency load shedding and overload load shedding. The initiation by low voltage, possibly in combination with other parameters provides the unique characteristic of this type of scheme.

Detection of low voltages on the transmission system may indicate the lack of sufficient reactive power to maintain system stability. If other emergency control actions such as reactive switching are not effective in restoring system voltages, it may be necessary to shed load in order to maintain system voltage stability. Undervoltage load shedding operates when there is a system disturbance and the voltage drops to a certain pre-selected level for a certain pre-selected time period. It is expected that the voltage will then stabilize or recover to normal levels. Loads with high absorption of reactive power are especially suitable for shedding to prevent voltage collapse.

A complicating factor in undervoltage load shedding schemes is that voltages may be very close to normal at the onset of voltage collapse. It is the inability of available reactive support to maintain the voltages that lead to the imminent wide area voltage collapse and blackout. Because voltage levels may be so close to normal levels at the onset of collapse, the low voltage parameter may be supplemented by other parameters, such as transmission circuit status, and/or availability of reactive power reserve. The need to measure parameters and initiate load shedding in diverse locations may require a true wide area protection system.

2.2.9 Manual or Automatic

Electric systems that experience heavy loadings on transmission facilities with limited reactive power control can be vulnerable to voltage instability. Such instability can cause tripping of generators and transmission facilities resulting in loss of customer demand as well as system collapse. Since voltage collapse can occur suddenly, there may not be sufficient time for operator actions to stabilize the systems. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse. Manual load shedding cannot be relied upon to provide the necessary action to stabilize the interconnected systems and mitigate the effects of a voltage collapse. Automatic load shedding is preferred solution. However, manual load shedding can supplement automatic load shedding schemes.

Manual load shedding can be used in small radial or self-contained systems where there is no danger of cascading collapses.

2.2.10 Scheme Design Information

When designing an automatic UVLS plan to protect against long-term and classical voltage collapse, the effect on the transmission system of lower voltage distributed transformer load tap changing action and generator over-excitation-limiters must be simulated and addressed. If UVLS relays sense voltage at the low voltage side of load tap changing transformers, they may not trip loads before excessively low transmission voltages are reached.

The challenges in designing a UVLS scheme are to ensure operation only for intended conditions, and to prevent operation during other conditions including momentary low voltage conditions caused by system faults, load pickup, etc.

For security purposes, two relays can be used to monitor voltage on the same bus, tripping load only if both relays operate. Some utilities have applied UVLS relays to both ends of high voltage lines that have distribution substations tapped off of them. The lines must not be critical to the network, yet have generation supply at either end. Unless both relays operate, the substation loads are not dropped.

UVLS are more effective by monitoring higher voltage buses with under-voltage relays, and shedding loads at lower voltage substations using direct trip signals. Centralized load shedding has the advantage of greater sensitivity, with faster tripping. The amount of load shed is predetermined, although several levels of load shedding are possible. Other control actions (capacitor bank switching, HVDC fast power change, generator voltage increase, generator tripping) are possible using the same remote measurements. Cost may be high, especially if redundant sensors, computers, and communication circuits are needed.

The following points should be kept in mind while designing the UVLS schemes:

1. Load shedding scheme should be designed to coordinate with protective devices and control schemes for momentary voltage dips, sustained faults, low voltages caused by stalled air conditioners, etc.

2. Time delay to initiate load dropping should be in seconds, not in cycles. A typical time delay varies between 3 to 10 seconds.
3. UVLS relays must be on VTs that are connected above automatic OLTCs.
4. Voltage pick-up points for the tripping signal should be set reasonably higher than the "nose point" of the critical P-V or Q-V curve.
5. Voltage pick-up points and the time delays of the local neighboring systems should be checked and coordinated.
6. Redundancy and enough intelligence should be built into the scheme to ensure reliable operation and to prevent false tripping.
7. Enough load should be shed to bring voltages to minimum operating voltage levels or higher.

2.2.11 Single Step or Multi-Step Design

UVLS is inherently "multi-step" in the sense that buses will experience differing voltages and voltage drops. This is unlike under-frequency sensing where all the buses in a local area have the same frequency. Having all UVLS relays set at 92% of nominal, for example, will work like groups of relays set at 91%, 92%, and 93% if the voltage drops to below 91%, and the relays have the same trip delays. Reasons to have different voltage settings and trip delays are to avoid over-tripping, and to attempt selectivity between loads. As well if over-voltage, or over-frequency is likely to follow after a single large load shedding stage, the amount of automatic load shed should be reduced, and multi-stage load shedding shall be adopted. Dynamic studies should verify the UVLS voltage trip settings and trip time delays.

2.2.12 Relay Settings

The UVLS relay trip voltages and time delays to trip must be appropriate for the system they are being applied to. The appropriateness depends on the structure of the transmission and generation network, the contingencies being planned for, the actual load response, and control actions of other devices like transformer OLTCs, generators, switched capacitors, SVCs, other relays, etc. These settings must be tested and confirmed by dynamic simulations.

The nature of possible voltage collapse may render local under-voltage load shedding relays ineffective. For example, fast voltage decay may occur across a system because of high transfers and wide power angles, rather than from high loads in the area of collapse. A transient stability simulation may be needed to verify angle stability. Undervoltage relay tripping could be too slow or may exacerbate transfer loading, resulting in higher reactive flows and lower voltage. Analysis may show that an angular instability condition could be reached at voltages that are higher than the settings that could reasonably be applied to local substation or distribution under-voltage load shedding relays. Direct load tripping would become necessary.

2.2.13 Practical example of under voltage relay settings

In the Puget Sound area within The Western Electricity Coordinating Council (WECC), located on the west US cost the UVLS voltage trip thresholds were determined from the results of steady state simulations of worst contingencies using voltage sensitive load models. These were then confirmed by the dynamic simulations. The time delay to trip addressed control actions like automatic capacitor switching, generator limits, transformer LTC action, system security and load reliability. The steps selected are:

1) Trip 5% of load when monitored bus voltages fall to 90% or lower of normal for a minimum of 3.5 seconds.
2) Trip 5% additional load when bus voltages fall to 92% or lower for 5.0 seconds.

3) Trip 5% additional load when bus voltages fall to 92% or lower for 8.0 seconds.

3 Expectation on intelligent load shedding

3.1 General principle

As introduced the intelligent load shedding may be composed of the ultimate distributed load shedding, the systems for critical preventing action and the system for a smooth load relief.

Additional strategies of load control may be implemented for energy management purpose (smoothing a local demand for one day period for instance) but this one-day schedule strategy for demand management is not the object of this document. The system for a smooth load relief described later and proposed in this document is targeting short term dynamical variation at a defined local scale.

The distributed load shedding is still an ultimate action when smooth load relief and critical preventing action are not sufficient enough. The constraints on the EPS lead to switch off some loads which need to be supplied at the moment. This kind of action needs a fast and accurate evaluation of the electrical parameters in different nodes of the network. A time scale for this ultimate action may be from a few seconds to a few minutes.

The critical preventing action may avoid real load shedding: the local power exchanges between a distribution EPS and the transmission EPS are handled in the direction required by the transmission system. A main known action is blocking or controlling adequately the transformation ration in HV/HV substations and in HV/MV substations. Another future action would be controlling some specific loads (cycled loads or loads having large process inertia or loads not sensitive to interruptions) in order to have fast reactive response to system demand. A time scale for this action may be from a few minutes to a few hours.

The smooth load relief is a solution taking into account loads behaviour in order to coordinate global small variations of the power exchanges in the system. Smoothing the power variations is initiated at the distribution level, contributing at the transmission level to a net reduction of stresses on the existing voltage control (frequency and magnitude). The existing scaling effect (summation of dispersed loads variations) is reinforced by this dispersed smooth load relief. The great difference with the two previous chapters (appropriate load shedding and fast critical preventing action) is that this coordination tries to combine local existing and controlled loads and production in order to smooth the equivalent local power injection without taking account the type of situation (normal, critical or emergency). The time scale for this strategy may be from several minutes to several hours. The strategy used for peak shaving is quite similar for making a smooth load relief. The aim is different, the peak shaving tries to reduce the daily peak power while the smooth load relief tries to avoid high slope of power variation along the day. The principle of action is similar by delaying or anticipating controlled loads on a given area.

The market and prices associated to these three kinds of services (the combination of these services is the structure of the intelligent load shedding) may be quite different. The price associated to load shedding may be close to the price used by the DNO for evaluating the cost of non energy supplied. The other prices are expected to vary between this price and the price expected on the normal market. The loads contributing on fast controlled load shedding (emergency situation) are able to contribute on critical preventing action (during first critical sequence) or to contribute on smooth load relief (during normal situation). The loads contributing on preventing action (during critical situation) are able to contribute on smooth load relief (during normal situation). Various other types of controlled loads are possible: for instance a simple load controlled just in case of load shedding need.

The critical preventing action and distributed loads shedding are used in order to avoid voltage instability (short term or long term), frequency instability, or cascading outages in case of overloaded system components. The critical preventing action may be used also to contribute to mitigate large oscillations at low frequency in the power system by appropriate and synchronized loads oscillations. Some kinds of loads are available for this anti-oscillation system but not all: the local agent dealing with the ILS has to have the updated sub-list of loads contracted for critical preventing action and able to contribute to this large oscillations mitigation system.

A main issue is to update correctly the electrical state on the EPS, including stability criterion, enabling to initiate and to process all the sequences of the ILS. The agent involved in the ILS must trip and control the right loads, but also must recover a normal reconnection as soon as possible when emergency or critical states have been passed correctly. Some time delay and stability criterion have to be defined in these scopes.

The information system may be structured with intermediate layers in order to parallelize the exchanges of information, simplifying and concatenating the needed contents from a layer to a superior layer, and sharing or distributing the needed contents from a layer to an inferior layer.

A two-ways signal seems necessary to exchange enough information with the system: to send messages about power available (amount and time schedule) from the load (or aggregated loads) to the system and also to receive the action orders from the system to the loads (or aggregated loads).

Dealing with the market mechanism for ILS, a solution may include two parts strongly different: a real time market for non critical action (the smooth load relief is achieved by update price indication leading the targeted loads to follow expected variation slopes calculated from the DNO objectives) and a specific prepared and scheduled prices system for the critical action (the distributed load shedding and the critical preventing action). This last point is necessary to reduce the short term dependency of the system security on a not certain response (in amount and in time) from the local market mechanism: during the critical state, the response of the targeted loads may be expected in a few seconds. Nevertheless the structure and the preparation of the critical response by local means need to be defined through a specific market, as for instance x-days-ahead market for y-days duration. In this case the DNO has a view on the possible reaction on its local system: the data need to be checked and updated during the operation regularly.

Different types of communication can be set,for instance real time binary signals such as [switch off | switch on] or [increase | decrease], or for instance sending load relief schemes.

An adaptive, sequentially updated distributed load shedding system requires methods to keep track on the actual load available to shed in the short term. This evaluation is needed by the local agent that distributes orders in order to reach a local target of fast shedding.

Intelligent load shedding can be made either on a contractual base, with respect to the statements in the contract, between the power supplier (or grid operator) and the customer, or as an emergency non-discriminative action to save the system. Load shedding can be caused by long term problems, such as energy shortage or generation capacity shortage (peak-shaving), or by short term problems, such as imbalance between generation and load (frequency problems), power oscillations or voltage instability (network problems).

The problem of identifying the load to shed for a certain disturbance is related to a number of parameters, such as:

1) the power system problem area,
2) the severity of the problem,
3) the time available to take proper actions,
4) the load shedding infrastructure and preparation, and
5) the cost for the load shedding

3.1.1 The power system problem area

For energy shortage as well as generation capacity problems the time available to take actions is normally long and will most probably be taken care of on a contractual basis within the Energy Management System (EMS) of the dispatcher.

To handle disturbances, such as trip of generation and network outages, the general rule of thumb is that *the load shedding should take place within the area of the largest power deficit, with respect to the power transmission capacity into this area*. Note that this rule is valid both for generation shortage and for transmission capacity shortage. For each characteristic disturbance, the corresponding area for load shedding has to be identified. The disturbances planned for in this way can be general (such as loss of generation in the north) or specific (such as loss of a certain tie-line). To specify which load to shed within a specified area is more a matter of type of load in the area, communication infrastructure, and preparation for load shedding (arming, routines, contracts, etc.).

3.1.2 The severity of the problem

As the general rule of thumb, we can easily conclude that the more severe disturbance the more powerful (in terms of amount and speed) load shedding is needed. Suppose that the area of interest has a list of load to be able to shed, organised in order of priority. Then there are a number of principles on how to act:

1) Estimate the "severity" of the disturbance from power system events and measured and derived power system quantities. Calculate the amount of load necessary to shed, pick this amount from the list, and order load shedding. This approach can also be sequential; load is shed until the system recovers.
2) Each load available for load shedding, has its own load shedding algorithm, which is triggered by local or remote power system events and measured and derived power system quantities. The order and total amount of load to shed is prepared in advance by the settings of the trigger quantities for each load.
3) In some applications also the time delay can be used to shed the right amount of load. The loads to shed have the same fundamental settings, but different time delays. In this way load will be shed until the system recovers.

Different implementations and solutions will have different impact on the security and the dependability of the load shedding system.

3.1.3 Time available to take proper actions

To save a power system in transition towards instability by load shedding, the time to action is crucial, and also very different for different types of disturbances. It might be a very good idea to design a load shedding system to counteract rather frequent events, where the speed requirements on the load relief are moderate, and not solve very rare stability problems with high requirements on load shedding speed. (That is, prepare for long term voltage instability, but not for short-term voltage instability.) It has to be remembered that there is always a risk for misoperation, and the consequences have to be compared to the benefit of successful operations. Some figures of time available to counteract different disturbances are given below (these figures are very much dependant on the size of the power system – larger systems generally give more time for remedial actions):

	Disturbance:	Time to action:
1)	First swing instability (out-of-step):	fractions of a second
2)	Power oscillations:	fractions of a second, up to a few seconds
3)	Short term voltage instability:	a few seconds

4) Long term voltage instability: 10 seconds to about one minute

5) Frequency instability: a few seconds

3.1.4 Load shedding infrastructure and preparation

Today load shedding is achieved by manually or automatically opening a circuit-breaker on 10/20 kV level. A first step towards "more intelligent load shedding" has been to equip larger loads with underfrequency and undervoltage relays, that automatically switches off the load on certain threshold levels. Such equipment is very distributed and does not require any communication, but the dispatcher does normally not know what help he will get from these systems in case of a disturbance, since he does not know which units are in operation. A few broadcasting systems that inform customers about tariff changes are also in use. The customer can then choose to connect such a signal directly to a load object that is selected for load shedding purposes.

The communication infrastructure performance influences the load shedding structure possibilities in terms of: selectivity, speed, one-way or two-ways, binary signals or complex messages, etc. as well as the possibility of "agent based negotiations" between the grid operator and the customer. Another aspect is the amount of preparations that can be made on beforehand –in different time scales – both concerning load connected available to be shed, and power system stress. (The load shedding system might be armed or disarmed with respect to the present power system operational situation; power flows, lines and generators in service, etc.)

3.1.5 Cost for the load shedding

There is always a cost related to load shedding, and different load objects have different costs. Three categories of costs can basically be calculated:

1) The costs for the power company (and/or grid operator) for not delivered energy (in combination with change in time for energy delivery) – this cost is normally very low if there are no specific fees for not delivered energy (such as the Kile system in Norway).
2) The direct costs for the customer that is exposed to the load shedding. These costs vary considerably, from almost nothing to very high costs and production interruptions in certain types of industry.
3) The third type of cost is the costs for the society, which also includes costs for insurance companies, delay in communications, etc. that are not regarded as customer costs. The costs for the society, due to electricity supply interruptions, are always higher or equal to the costs for the customers.

To be able to identify suitable load objects to shed the cost for a certain load shedding must always be compared to the alternative load objects to shed and to the benefit of the load shedding.

3.2 Need of detection of current instability situation

Detection of imminent instability operational conditions is crucial for the success of "intelligent load shedding". The instabilities to detect are

- transient angle instability (first swing or out-of-step),
- insufficiently damped power oscillations (dynamic instability),
- short term voltage instability (no load flow equilibrium point after the clearance of a sever fault), and

- long term voltage instability (slow dynamics after a disturbance, or load increase).

Very often also the risk of cascaded outages – that will lead to instability – is a vulnerable situation that is important to detect and counteract.

3.2.1 Transient angle instability

Transient angle instability is the phenomenon that appears when the voltage phasors in different parts of an interconnected power system, after the clearance of a fault, continue to separate and the angle between them passes 180 degrees. Theoretically transient angle instability can also be achieved by increasing the load level too much, so the phase angle over a certain interconnection exceeds 90 degrees, and starts to accelerate. To mitigate this type of disturbance is very hard, mainly due to the short time available for protective actions. In the large interconnected power systems worldwide transient angle instability has not been the initial cause of any recent major blackout. This type of instability is also called “first swing instability”.

Phasor measurement units or out-of-step functionality in modern distance protection can be used to detect imminent transient angle instability.

3.2.2 Insufficiently damped power oscillations

The damping of power oscillations after an incident in a power system is very important. If the damping is not sufficient, small power oscillations might grow to larger and larger oscillations and finally the critical angle between two voltage phasors passes 180 degrees and the synchronism is lost.

Insufficient damping is best detected by phasor measurement units, frequency or power measurements. In this case the time available for remedial actions is normally a little bit longer than for transient angle instability. This type of instability is also more frequent in modern, large interconnected systems, especially when a serious fault has decreased the power transfer capability considerably between two areas.

3.2.3 Short term voltage instability

Short term voltage instability is quite rare, and only a few disturbances of this type have been experienced. The typical example is a bush fire across a number of parallel heavily loaded overhead lines. The lines are tripped due to short circuits caused by the ionised air. When the high number of lines is tripped, the conditions to keep up the supply to the load area through the remaining connections are not fulfilled. It can be interpreted as that there is no solution to the load-flow equations, even if voltage sensitive load models are used, that restrains the distance and undervoltage protection from tripping. The time from fault clearance to collapse is just a few seconds. It is a hard assignment to design systems to mitigate short term instability.

3.2.4 Long term voltage instability

Long term voltage instability is the most common type of initial instability in today’s large interconnected power systems. the disturbance is usually started with a stressed system operational condition, a severe fault, and fault clearance. The power system survives this initial disturbance but voltage levels are low, power flows are high and the reactive power generation is high too. The load is initially decreased due to the voltage reduction, and frequency can therefore increase. After a while, tens of seconds to minutes, the load starts to recover and tap-changers on distribution transformers start to increase the distribution system voltage. This decreases the transmission system voltage and increases the transmission system current flow, and finally the most sensitive zone of a line distance protection trips the first transmission line. The remaining lines then become even more overloaded and trip quite quickly.

The time available to take remedial actions is long for automatic systems, that can be based on voltage levels, power transmission generator reactive power output, etc.

3.2.5 Thermal overload and cascaded outages

Thermal overload is a quite slow phenomenon, even if the heating current in an overhead line is considerably step-wise increased. The limiting factor for overhead line heating is either unrecoverable changed material structure of the conductor or a too short distance to ground of the energized conductor. The first action, if a branch element in an electric power grid is thermally overloaded, is to take the overloaded equipment out of service. It is quite surprising that most grid operators still choose to trip a network branch, when it is evidently most needed! It seems to be a better idea to reduce the load of the branch, by other means, such as load shedding, to a level that can be maintained in continuity. Such an action also prevents other branches from becoming overloaded. This strategy must also be classified as intelligent load shedding. But so far the main concern by grid operators and owners has been to save overloaded equipment by simply tripping it – not considering the immediately following consequences.

Cascaded outages are mainly a concern for lines and generators, and must be mitigated at an early stage. Cascaded outages normally origin from some kind of overload, that is transferred and increased to the remaining equipment when one is tripped. The time available to take proper prepared automatic actions is in general quite long.

3.3 Illustration of ILS for MV cell level 1 and 2

The two following figures illustrate the MV cell level 1 and level 2. The concept of these cells is already described in the documents [D1.4] and [D1.7].

At the level 1, actions are taken for smooth load relief and distributed load shedding. The agent knows the current volume and state of local controlled load and the associated availability. Sensing the voltage magnitude at the sending-end feeders, it knows if the agent of MV level 2 is making critical preventing action: blocking on-load tap-changers maintaining a low voltage level at secondary side of the HV/MV transformers. A specific exchange of messages between these agents may validate this information and may help the agent level 1 to be prepared to the right response to support the system.

The agent of the MV cell level 1 knows what power is exchanged at its boundaries, and knows partially what could be internally changed in various time responses (power measurements at the boundaries, internal demand and production expectations for the following hours, distributed resources production monitored or controlled, monitored loads, controlled loads).

The volume of possible distributed load shedding for the following hour may be sent (every hour) to the agent level 2 in order to allow him to coordinate the actions (distributing the expected contributions from the different level 1 cells).

During critical situation requiring distributed load shedding, the agent level 1 is informed by the agent level 2 of the expected volume of power to shed. The agent level 1 takes then the appropriate local decision and informed back the agent level 2 of the current state (updating the evaluation of available local fast power reserves) and results of the launched actions.

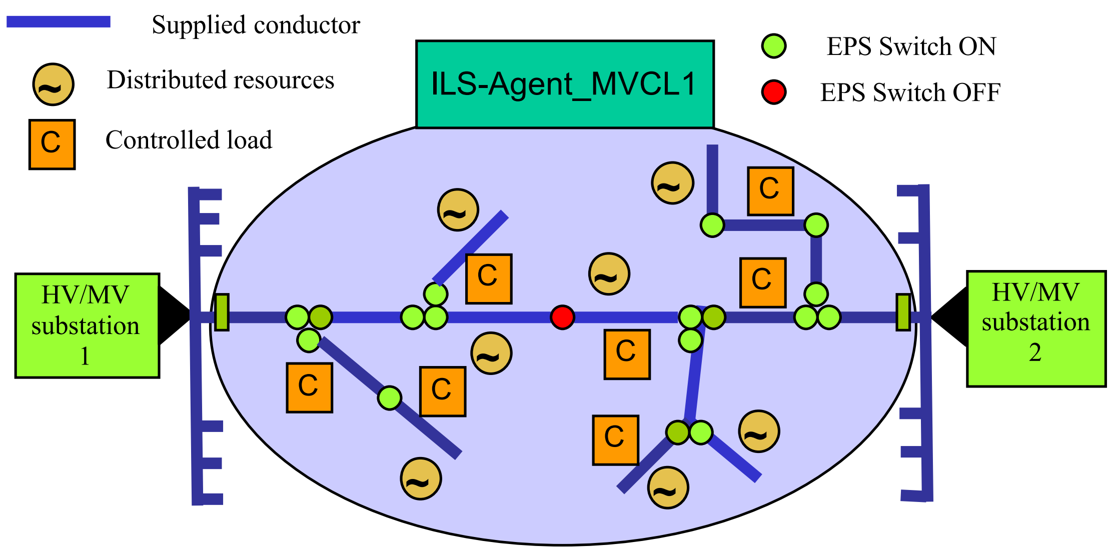


Figure 3: MV level 1 illustration with associated agent for ILS

The MV level 2 cell is assumed simple in this illustration with only 2 substations interlinked by the MV conductors. The associated agent may act on the transformers tap-changers controls in order to block or move them to a desired secondary voltage magnitude (during critical situation sensed locally or informed from the HV control room).

In the case of a very simple network with limited information nodes, the concept of level 1 and level 2 cells may be simplified in a unique agent at level 2 exchanging information with all the local nodes.

The concept of these two levels of cell is kept for general purpose of distribution automation: The agent of cell level 1 may be involved in various local functions (energy optimization, reconfiguration, specific protection systems) including the additional function of distributed load shedding or local smooth relief actions.

In France the MV level 2 cells may be composed of several tens of HV/MV substations, depending mainly on the development strategy of the utility involved. So the power exchanged between a MV level 2 and the surrounding HV network may vary from a few tens of MVA to several hundred of MVA. The agent responsible for the level 2 cell communicates with HV agent controlling the surrounding network: the information about the local power reserve capacity (for action of the ILS) is regularly updated and orders with defined amount of power required during critical situation is transmitted from the HV agent to the MV level 2 cell agent.

In case of failure of the communication system, the agent of the MV level 2 cell may take some actions in order to limit voltage or frequency deviations observed on its boundaries.

The ILS targets at the same events occurring inside the cell or outside the cell, the main goal being system support.

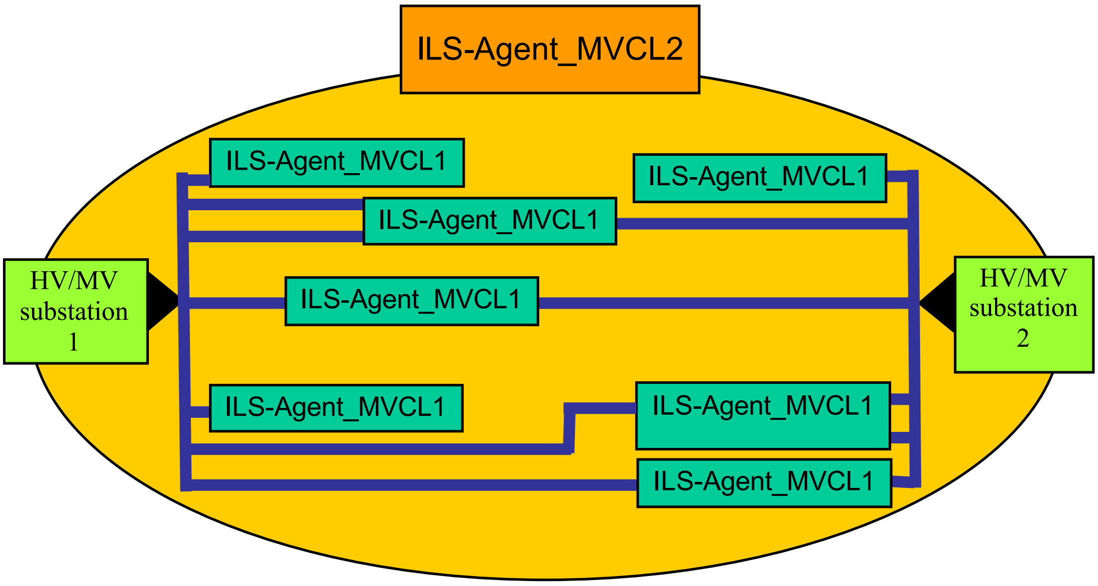


Figure 4: MV level 2 illustration with associated agent for ILS

The main advantage of the distributed ILS compared with the existing system (based on feeder shedding with no information on the real power variation involved) is to take into account real time power variations required (measurements and analyses) and involved (tuned action on local loads and local productions inside the feeders).

4 Tools for Intelligent Load Shedding

This chapter describes methods, strategies and algorithms to identify, allocate and prioritize the load objects most suitable to contribute to a smooth load relief or to an intelligent load shedding to avoid a partial or complete system breakdown, in an imminent instability situation. The actions, available to be taken to reduce the load, active and/or reactive part, seen from a specific node in the power system, vary very much depending on the installed facilities. In a planning stage it is of utmost importance to also include issues like load relief in critical situations, to be able to utilize the network investments. Such issues could be divided into active support devices in the area under consideration, e.g. emergency power generation, reactive power support, and HVDC tie-line support from neighbouring areas, and passive load reduction within the area, e.g. load object shut down, load object power reduction, general power consumption reduction due to change in voltage, and reduced export to neighbouring areas via HVDC tie-lines. It is also a matter of response time requirements, which are closely related to the speed of the disturbance propagation.

In this chapter, methods are presented, to prioritize, update and keep track on actions available to execute, **if** the operational situation should require load control to keep the system stable. In Chapter 6, we discuss algorithms to **activate** the actions prepared.

In a meshed power system, usually at transmission or subtransmission level, we normally use the term “power flow” to describe the situation, except when we describe the conditions for a certain line or transformer, e.g. line load or transformer load. Load is in general associated with a point in the network where the supply is radial, and in that sense additive. For the design of smooth load relief, we will use this radial view of the load characterization.

4.1 Local generation support capacity

Support means that some sort of active or reactive power contribution is injected into the load area under study. Different methods are discussed and evaluated. Some of the methods are based on a change in the relation between active and reactive power, you increase the active power generation by reducing the reactive power generation, or vice versa.

4.1.1 Start-up of generation

Start-up of local generation is of course a straightforward action to reduce the load supplied from the network. In the beginning of an instability situation, especially for voltage instability, it is hard to estimate the time to collapse, which has to be compared to the start-up time for the device. In such situations, it will normally be decided to make any effort to start all possible generators in the affected area. Even if the collapse comes quickly, at least a trail should have been made and it would be very embarrassing if the collapse will take place after a time longer than the start-up time, and no effort was made to try to start the generation. Such generators are normally diesel or gas turbines. Time to synchronization can be around 30 seconds, and time to full load a few minutes.

4.1.2 Increased generation in running units

Especially hydro units have a maximum efficiency point of operation slightly below the maximum power output. In an emergency situation this marginal could be utilized within a few to ten seconds. Many thermal units are designed for both heat and electricity generation, and in an emergency situation the electricity could be prioritized and increased. Some thermal units, especially gas turbines, have different ratings for continuous load and for short time overload. To avoid a system breakdown, it could be a very good idea to use a little of the gas turbine life time. Here we enter a contractual issue, since the owner of the gas turbine is primarily paid for kWh, and has no direct incentive to use machine life time to save the power system, which normally is the responsibility of the TSO (Transmission System Operator). Such support therefore has to be secured, either as a mandatory requirement in the grid code for generation or as an additional service to be paid for, preferably on market like conditions.

4.1.3 AVR and Governor boosting or re-scheduling

In case of an approaching voltage instability, the AVR (Automatic Voltage Regulator) could be boosted, e.g. by temporarily raising the voltage set-point. In a power deficit situation, especially concerning voltage instability, the active power generation can be reduced to increase the reactive power generation, and thereby increase the transmission capacity of the stressed network. This change of operational conditions for units inside the affected area is however more tricky and needs a special analysis for each situation [1].

4.1.4 Support from neighbouring areas

If the load area is connected to neighbouring areas via HVDC or HVDC-light, emergency power can be supplied within seconds. Typical EPC-functions (Emergency Power Control) automatically change the set-point value for the transfer rate over the connection. The change of set-point can be triggered by high/low frequency, high/low voltage magnitude or by manual actions. Normally the set-point is changed in steps of a preset active power value (ΔP is typically in the range of 10% of the rated power for the connection). Handling such support issues is more a contractual problem than a technical problem.

4.1.5 Static reactive power support

In case of voltage problems reactive power support is always welcome. At first it must be ensured that all shunt reactors are switched out and all shunt capacitors are switched in. SVCs might be boosted with a higher set-point value, to support a larger area, similarly to the AVR boosting in Section 4.1.3. Some utilities also use a shunt capacitor short time boosting method, characterized by temporarily short-circuit some of the series connected capacitor elements in a shunt capacitor [2].

4.2 Local load control capacity

This section describes load relief by actual load reduction, which basically can be performed in two ways: 1) reduction of the supply voltage, which normally gives, at least a temporary load relief; and 2) disconnection of load objects, groups of load objects or parts of load objects, such disconnection can also be achieved indirectly by the change of set-point, price level, or priority.

4.2.1 Load reduction by voltage reduction

Generally a load reduction will be achieved, at least temporarily, by reducing the supplying voltage. In load areas the most common way to reduce voltage is to use the on-load tap-changers of step-down transformers. The reduction can be achieved by reducing the set-point to a specific level, reducing the set-point a certain amount, or by frankly taking the automatic tap-changer control out of service and reduce the tap position. Normally a number of cascaded power transformers are used from the transmission level down to the customer supply level, and most of them are equipped with automatic individual, non-correlated, tap-changer controllers. In every application aiming at load reduction it is of utmost importance that the controlled tap-changer closest to the load is reached, and included in the scheme, or at least blocked, otherwise this tap-changer will re-establish the load voltage [3]. From a network operation point of view it is also advisable to keep the voltage level in the distribution system as high as possible, to reduce losses and make maximum benefit of line charging and shunt capacitors.

In Ireland a specific scheme is used to reduce the active power consumption in case of loss of production, shunt reactors are automatically switched in, controlled by the frequency level, to reduce voltage, and thereby reduce the load.

The effect of reducing load by voltage reduction is very much a matter of load characteristics, and control. Induction motors for example reduce their active power consumption very little with reduced voltage; electric heating is good for short time reduction, after a while, however, the voltage dependence of the controller will dominate, and the consumption might even increase [4], incandescent lamps are efficient for load reduction, as long as the customer not switch on another lamp.

4.2.2 Addressable load object control

The dominating method to select load for disconnection in critical situations in power systems of today is simply to select a feeder on typical distribution system levels of 10/20/30 kV. The only intelligence applied in many systems is to try to avoid areas with elevators, sometimes hospitals and special apartments for elderly people are also excluded.

The main idea with addressable load objects is to be able to reduce the electric power consumption in a specific area, a certain amount, with a minimum of customer inconvenience. The most typical example is electric hot water heaters, which could be switched off, for a limited time, practically at anytime with very small influence on the customer comfort. Electric space heating and air conditioners are other similar examples.

Many utilities around the world, such as ENEL in Italy and Sydkraft in Sweden, have very ambitious programs for including all customers in remote meter reading systems. Such systems require some sort of communication between the customer and the utility. Depending on the capability of the communication system different levels of complexity and performance of the load shedding system can be achieved. Some examples are given below.

1) The meter sends data regularly to the system – one-way communication.
   - Such a system does not help very much. The minimum requirement to be able to take part in a load shedding program is a communication link directed from the system to the load.
2) The meter sends data on request to the system.
   - The communication channel from the utility could in this case also be used to order load reduction. Depending on the speed and capacity of the channel and the receiving meter, either binary signals to execute prepared load object disconnection or more advanced load reduction, specified in MW/Mvar, could be requested.
3) High performance dual communication.
   - In this case full two-part negotiations can be performed to find suitable reduction levels for each node in the system. It is also a matter of speed; too much of “discussion” might take too long time with respect to the phenomena to counteract.

4.2.3 Price based load reduction

Price based load reduction is discussed in further details in Chapter 7. The most simple approach is the so called “price ladder”; where the consumer gives a table, where the desired MW-level is given for a number of price steps. Basically, if the electricity is cheap, we buy more; we use electricity for heating instead of oil or gas. If the electricity on the other hand is extremely expensive, we shut down our most energy consuming processes; to save money. With such a prepared price-ladder at the customer end, the utility just sends a signal corresponding to the present price, and the power consumption is rapidly adjusted to the corresponding load level.

5 Algorithms for Smooth Load Relief

Taking the concept of MV cell, two kinds of actions may be defined:

- Local-oriented action done in order to avoid large and fast variation of power at the boundary of the cell. This function repeated in the whole system without specific general coordination may help the system in its dynamical needed responses. In a normal situation, these variations in a higher or lower power are generally compensated at a large scale and absorbed by the large power plants. Nevertheless during critical situation, the variations may become synchronized because of controls and protections and may entail aggravating consequences.
- External-oriented action with coordination. A signal from superior agent may demand for a temporary power response from the local area caused by an event in another cell controlled by this agent.

For instance, the MV cell level 1 may answer to a local event. Depending on the volume of power involved, the local action may be sufficient to follow a given slope of power variation per minute. If it is not sufficient, this cell may require for a specific action from the cell level 2 (sending to it the missing local power in a given time). Then the cell level 2 may send quantified expected contributions to its other cell level 1 to deal with the local problem.

In fact the smooth load relief targeted the whole controlled load and distributed resources (considered there as apparent negative load). In the future a better name for these kinds of action would be a smooth power exchange relief, the exchange being relative to the given cell or EPS area.

Limiting the time variation of power exchange gives many improvements in the local power quality additionally to the benefits for dynamical stability on the system. The limited slope depends on the characteristics of the system and on the choice of the DNO. A default value as 0.5 MW/minute/MW_installed_in_cell may be taken at the scale of MV network for MV cell level 1 and MV cell level 2 (it means a slope of 5MW/min or 80kW/s for a cell involving 10MW of possible power exchange). Of course this limitation is intended for normal exchanges of power in normal or in critical situation in the system, and should not be applied for specific fast exchanges involved by system support (fast responses facing large frequency deviation or distributed load shedding): it is the reason why the dedicated agent has to be informed correctly of the real time state and has an important role of coordination between the chosen and associated control systems.

The measurements and calculations of power exchanges may be executed every second at the boundaries of the cell for making decision and begin distributed actions in less than 5s. Regularly (period of 10min for instance) the agent updates the available amount of controlled power on its area dedicated to SLR actions.

The action of remote controlled loads and remote controlled DR is typically temporary: Less than a few minutes in order to limit the extra power variation and the final steady state value is not influenced. While the limits for the power exchanges are not exceeded, the power controlled for smooth load relief is not used: exchange of power on boundaries within the normal range of power variation versus time. The following figure illustrated this range of action and no action expected from the SLR.

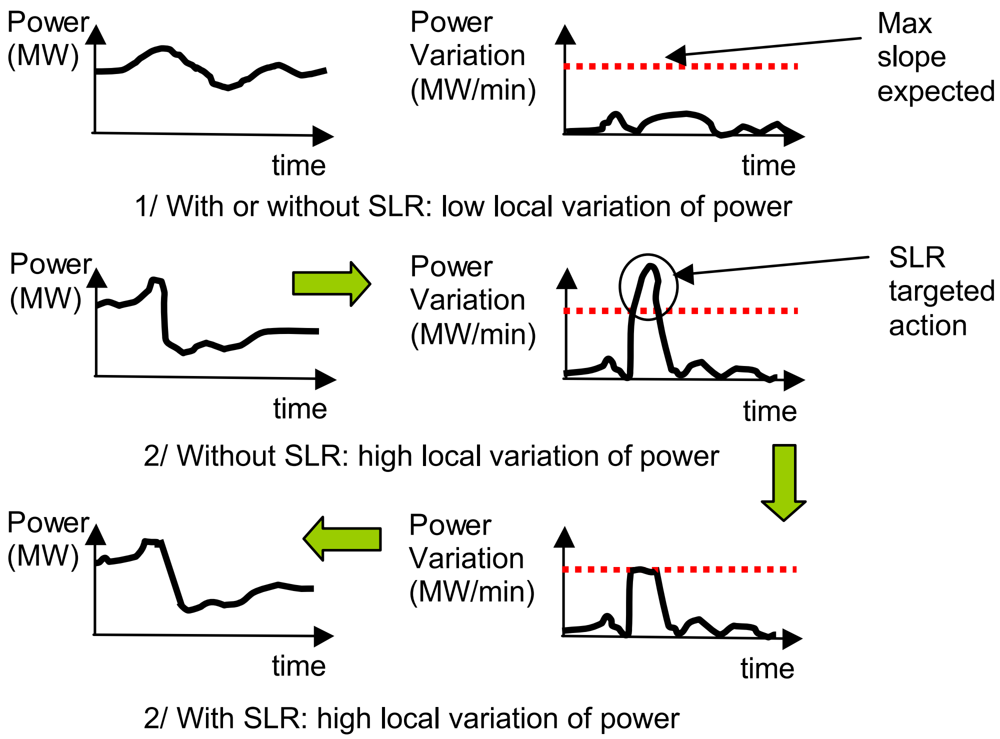


Figure 5: cell external exchange of power and SLR

The principle of an algorithm is presented on the following figure for a MV cell level 1

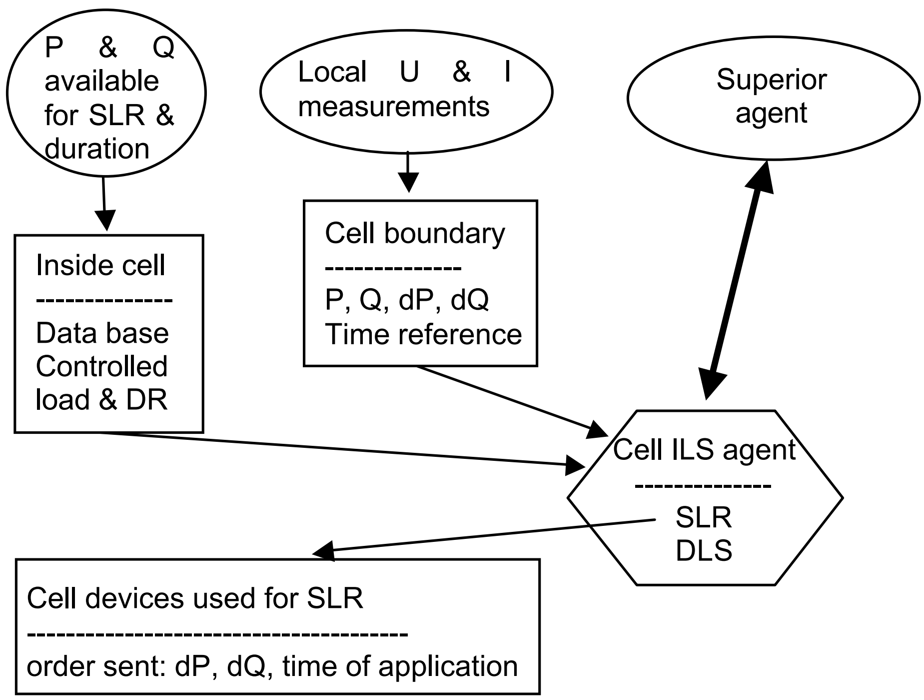


Figure 6: principle of algorithm for SLR

A superior agent may use a part of the SLR available power in order to counter-act and to mitigate large power oscillations occurring on the system as described in chapter 7. In general these large oscillations are observed at low frequency range around the hertz or a few hertz. This superior agent should belong to the HV information system.

The action induced by SLR in a single cell is small at the scale of the large interconnected

EPS, but the accumulation of the actions in each cell creates the great change in the total robustness of the system. Since the SLR is a typical cell function activated at any time, normal situation as critical situation, the stability effect (needed in critical situation with massive DR insertion) is naturally reinforced for the total system.

6 Algorithms for Distributed Load Shedding

In Chapter 5 we penetrated the concept of smooth load relief, i.e. different ways, methods and algorithms to achieve a smooth load relief, whenever needed from a power system point of view. In this chapter we will discuss power system criteria to activate the distributed load shedding. We will focus on voltage and frequency based schemes, since oscillations are very deeply studied in Chapter 7 and event based schemes start with the trigger criterion; an example of an event based system is also given in Chapter 6. Initially more resources have been put to find better ways to detect critical power system operational situations, than to make the load relief smooth or distributed load shedding. The reason is probably that the infrastructure, concerning transducers, communication, etc., is already present in the transmission system, but on the load side, very few load objects are still automatically controllable and we have to stay with substation circuit-breakers to activate the load relief. It is also a mater of driving forces; on the transmission level driving forces are to be found among relay manufacturers and control equipment suppliers; on the load control side, however, the utilities have to drive the process, since no new equipment or technology development is needed.

Many studies on how to save power systems that have entered critical situations have been performed. Concerning actions to counteract the propagation of the instability it is always a matter of **where** to take the action(s), **when** to activate the actions, and **how much** are the minimum amount of actions needed to be sure that the prolongation of the critical conditions are halted, and that the system is retrieved to a secure state [5].

Most nation wide blackouts during the last decades have been related to voltage instability. The three large system blackouts in 2003, North America, Italy and Sweden [6], [7], [8], were all classified as voltage instability disturbances. Rather early in the electrification era, underfrequency controlled load shedding was established, and with few updates and improvements, this technology has been working pretty well. On the other hand, even today, quite few systems aimed at protect against voltage instability are in operation.

6.1 Algorithms to counteract voltage instability

Large efforts have been made within international electro technical organisations, universities, and research centres to further understand the phenomena of voltage instability and to provide guides to design mitigation schemes [9]. However, not so much of these results have yet been implemented. There seems to be a gap in the mutual understanding and acceptance of prerequisites and conditions between academics and grid operators.

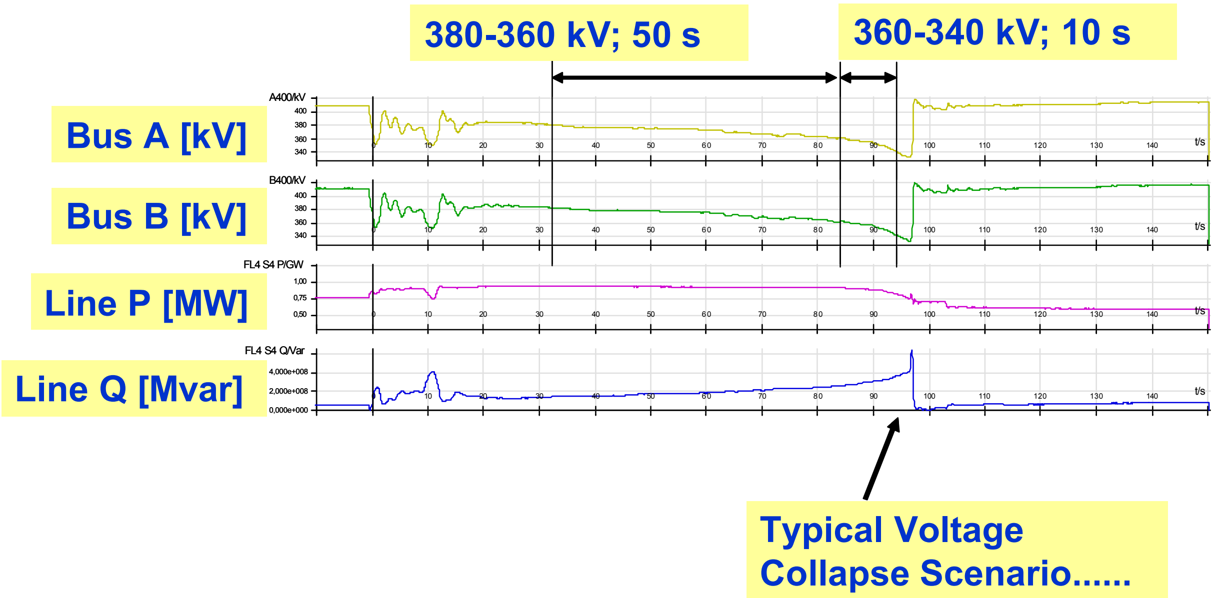
6.1.1 Voltage instability detection

A voltage instability situation in a certain area can be detected by low power system voltage, high reactive power output from nearby generators, and, closer to the system breakdown, generator field or armature current limiter activation. These indicators must then be combined, via voting systems or some sort of ANN, to form a robust detection system, with extremely high requirements both on dependability and on security. Since the voltage instability detection is called upon very seldom, but when called upon its duty is to avoid an extremely costly blackout, it must have a very high probability to do what it is intended to do. On the other hand, the actions taken by such a protection system are very powerful, and an unwanted action should be very costly, and must have a very low probability.

6.1.1.1 Undervoltage

The most simple, and straightforward, way to detect a near voltage instability is by undervoltage relays. From the academic and research level you might hear that the voltage level is not a generally reliable criterion, since a voltage collapse might occur at a rather high voltage level. The voltage level at the point of maximum loading for a transmission system is also very much dependent on the degree of reactive power shunt compensation in the load end. However, such an undervoltage based protection scheme has to be individually designed for each power system and the critical levels can easily be found in load flow studies and dynamic simulations. So the conclusion is that the voltage level is a good criterion, but settings have to be adjusted to each individual system. Since all power systems are exposed to “normal faults” cleared by the primary, and in some cases, the backup protection – without being in a “close-to-voltage-collapse-situation”, the time delay for these undervoltage protection relays have to be longer than the time delay for the backup clearance of shunt faults. The transmission system voltage some 100 km north of the affected area during the Swedish collapse scenario in 2003, is shown in Figure 7.

Figure 7: Recordings from mid Sweden during the blackout 2003-09-23



From Figure 7 we clearly see that the transmission system voltage is slowly decaying after the initial disturbance, and for about 50 seconds it is in the interval 380-360 kV, and for 10 seconds it is in the interval of 360-340 kV. The voltage levels in the affected area were even lower. These curves clearly indicate that there is plenty of time for an undervoltage based scheme to take actions. We also see that the active power flow to the affected area is decreasing, while the reactive power flow is increasing, which is typical for a voltage instability scenario.

It is important to measure the voltage on the transmission system level, since transformer tap-changers will keep up the voltage on lower levels during the voltage collapse event prolongation. The actions for a tap-changer on a 400/130 kV transformer, within the affected area, during the Swedish blackout, are shown in Figure 8. This tap-changer moved nine steps within 80 seconds, trying to keep up the downstream voltage, while the transmission system voltage was decaying.

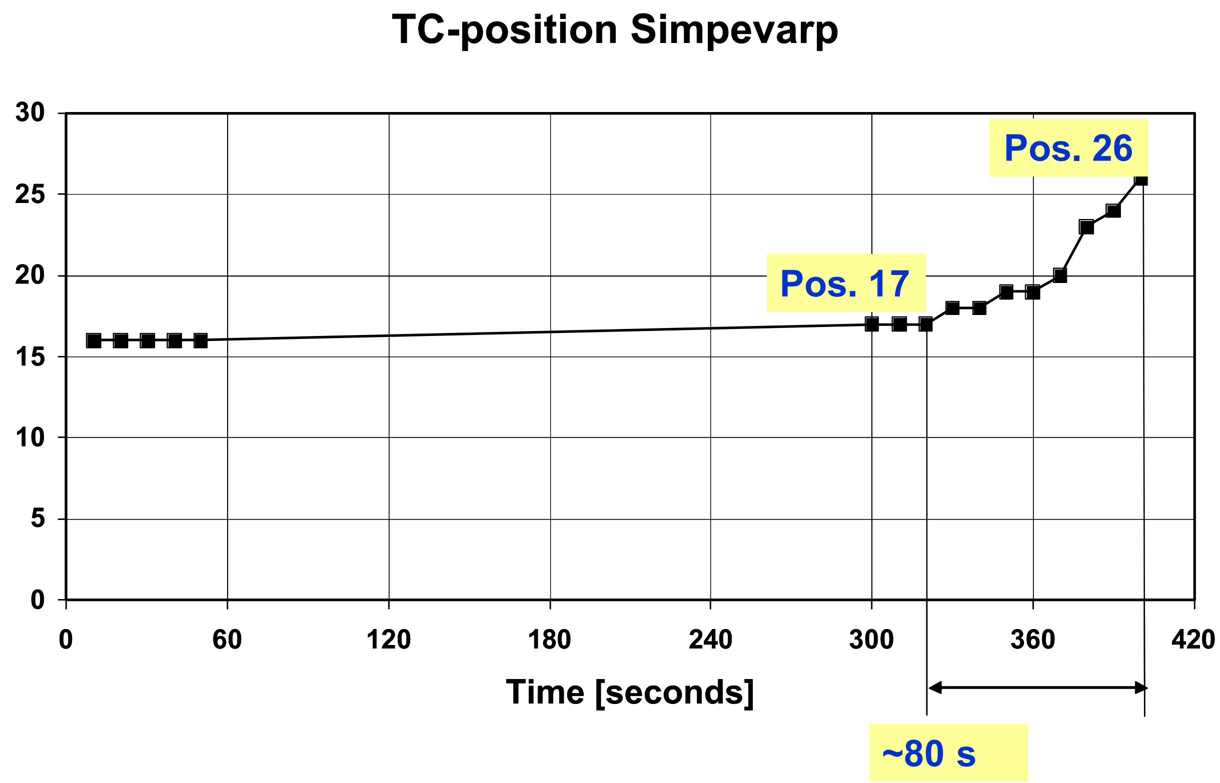


Figure 8: Tap-changer actions during a voltage instability

The single criterion “low voltage” in a certain substation has to be robust. This criterion must not be fulfilled if a certain device is taken out of service, and de-energized, a shunt fault occur in the neighbourhood, etc. On the other hand this signal must not be blocked by a single faulty device. A common and robust way to derive the low voltage criterion is to measure all the three phases, in different bays, and require that 2 out of 3 are low.

The undervoltage criteria can of course appear at different levels, we can for example have “low voltage”, “very low voltage” and “extremely low voltage”, resulting in different actions by the scheme.

Most systems installed to counteract voltage instability today are based on undervoltage relays. Some systems are totally built on a number of undervoltage relays, measuring the local voltage, without any communication, each of them aimed at activate a local load shedding. This design is very similar to most present underfrequency protection schemes. However the local frequency is a much better indicator of an imbalance between load and generation, than a local undervoltage is to detect a voltage instability. Therefore it is more important to have a distributed system to detect voltage instability.

6.1.1.2 High reactive power output

Transmission system buses close to large power stations, have a tendency to keep up the voltage, due to the voltage controller and the reactive support of the power units. Here, the reactive power output from the generators is a better criterion, which is also easily identified, and related to voltage problems further out in the transmission system.

6.1.1.3 Generator current limiter activated

Most large generators are equipped with field current limiters, which influence the AVR to limit the excitation to a level corresponding to the limiter setting. When the field current limiter is activated, the voltage at the generator bus is no longer kept at a constant value. The point of constant voltage has been moved to a fictive point behind the generator synchronous reactance, making the system weaker and reducing the reactive power support. Some generators are also equipped with armature current limiters, which also influence the AVR to keep the armature current below a limited level. If the armature current limiter is activated the power system has a severe problem, and preventive actions have to be quick and powerful. “Field current limiter activated” and “armature current limiter activated” are also good criteria that a voltage collapse situation is close.

The impact on the so called nose curve, used for voltage stability illustrations, of these limiters is very clearly shown in Figure 6.3. If no limiter is activated the load admittance increase follows the characteristic of the transmission system. When the field current limit is hit, (there is a small overshoot, due to a time delay in the limiter), the load characteristic follows another characteristic. This field current limited characteristic curve is similar to the original one, but with different parameters. The point of sending end constant voltage has been moved for the generator terminal to a point behind the synchronous reactance of the generator. When the armature current limit is hit, there is a similar overshoot, but the shape of the characteristic for increased load admittance is significantly different. A constant load current is maintained, and when the load admittance is increased the load voltage, as well as the load power, is decreased.

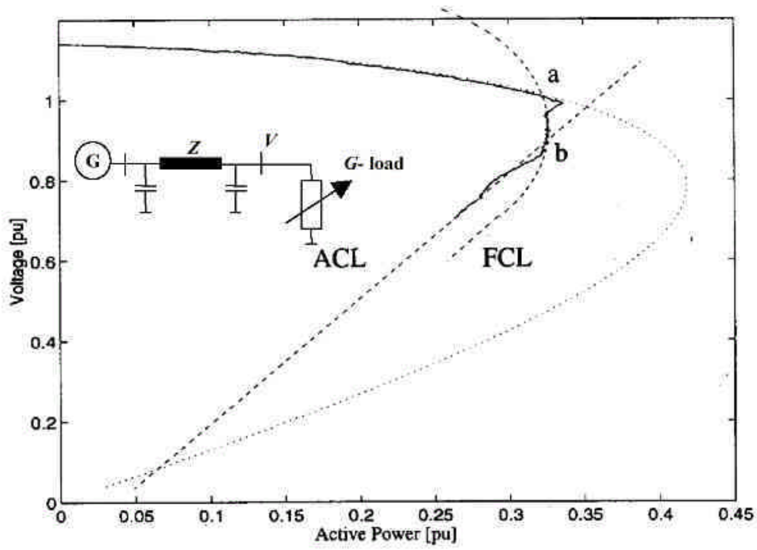


Figure 9: Effects of the armature (ACL) and field (FCL) current limiters on the nose-curve, from [10]

6.1.1.4 Forming the voltage instability detection criterion

Based on the individual criteria, low voltage, high reactive power output and generator current limiter activated, measured all over the area under consideration, one single, robust criterion to activate each mitigation action has to be derived. For the sake of robustness each action has its own full algorithm, preferably implemented in the substation where the action is going to take place. Since the individual criteria described in Subsections 6.1.1.1-3 are all binary, the most straightforward way to design the action criterion is normally by a voting system, sometimes in combination with criteria, like the protection scheme should be in service, the breaker to trip must be closed, etc., and sometimes also a local criterion is added at the end. Such a system, to counteract voltage instability in the southern part of Sweden, was designed, installed and commissioned in the 90:s [11]. The algorithms for switch-out of a shunt reactor and load shedding are given as block diagrams in Figure 10 and Figure 11, respectively. The logic solver and the communication part of the system shown in Figure 10 and 11 were implemented in the Sydkraft SCADA system, which later turned out to be too slow and unreliable.

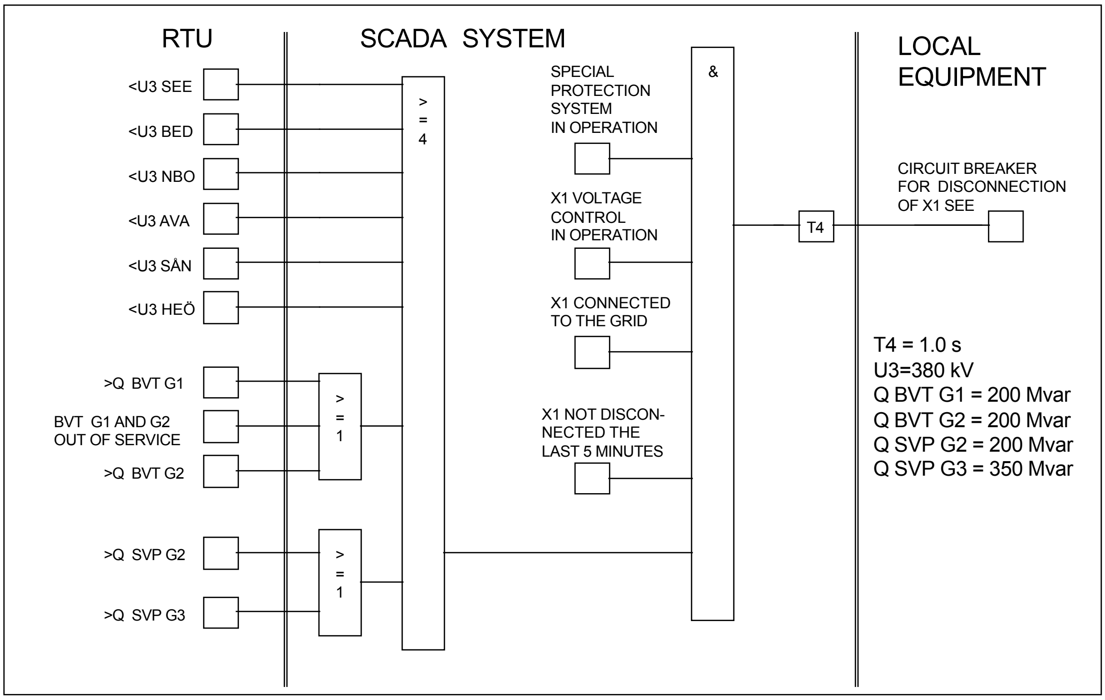


Figure 10: Algorithm to disconnect a shunt reactor

To trip the shunt reactor, we need 4 out of 8 input criteria to be fulfilled. Six of these criteria are low voltage in different substations all over the area, and two are related to reactive power output from two plants in the area. If at least one of G1 and G2 in BVT has a high reactive power output, or both the generators are out of service, this criterion is regarded as fulfilled. If at least one of G2 and G3 in the SVP power station shows a high reactive power output the corresponding criterion is regarded as fulfilled.

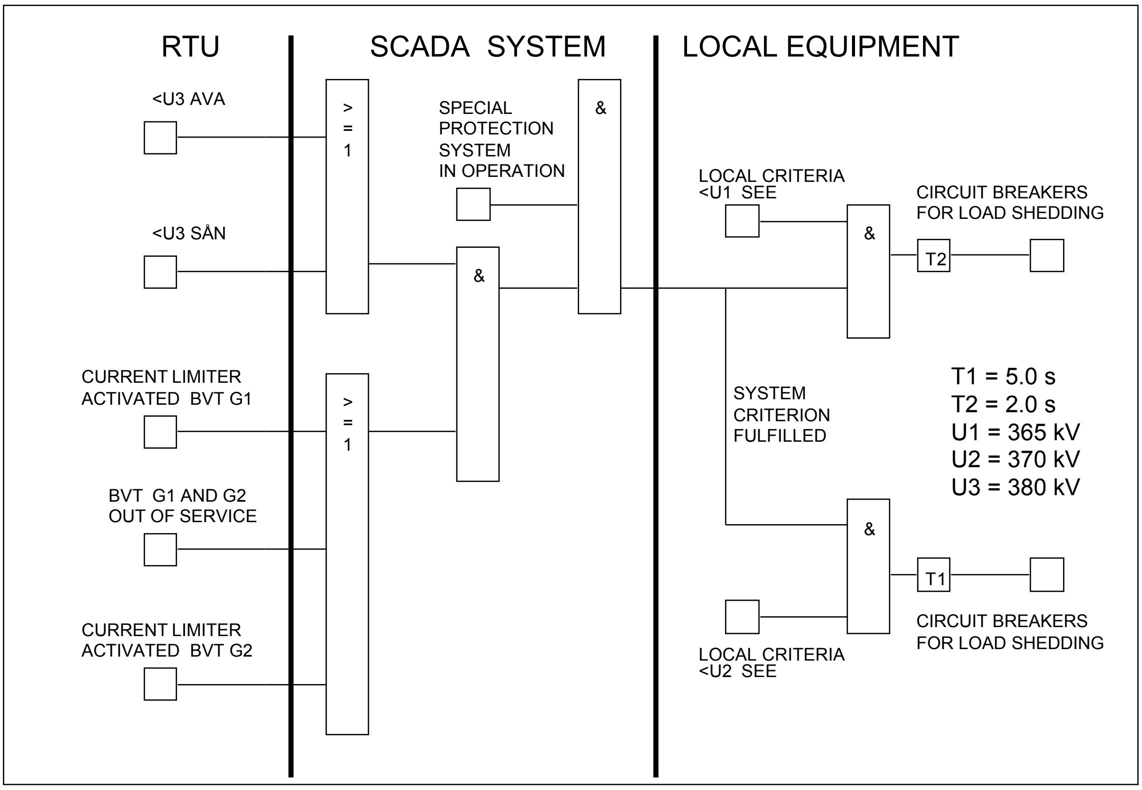


Figure 11: Algorithm to activate load shedding

To activate primary load shedding one out of two voltages in different parts of the system should be low and the most nearby generator site should have at least one generator with current limiter (field OR armature) activated, or both of the units out of service. Since load shedding is a powerful action, which must not happen unwantedly, a local low voltage criterion is added on the output. The voltage level settings in the 400 kV system as well as the time delays are shown in the figures.

6.1.2 Where, when and how much load to shed

For a voltage instability situation it is rather easy to show that it is most efficient to shed load in areas with the lowest transmission system voltage, since this is the location for the load causing the larges voltage drops and losses in the power system. When coming to details it can also be investigated, what type of load that is most favourable to shed. The basic rules for such decisions are that the less the voltage dependence of the load, the more favourable it is to shed, e.g. compensated induction motor load consume basically the same amount of active power, independently of the supply voltage level, and the reactive power consumption of the motor is reduced an amount that roughly corresponds to the reactive power supplied by the compensation capacitor. Lighting and heating load on the other hand have a strong voltage dependence, which means that their power consumption is reduced when the voltage is reduced. If there is a choice in this sense, it is more preferable to

shed motor load than heating load. Figure 12 shows the voltage and frequency behaviour by the end of the Swedish disturbance 2003-09-23. When the voltage is reduced the active power consumption is also reduced, resulting in an increased frequency of the system.

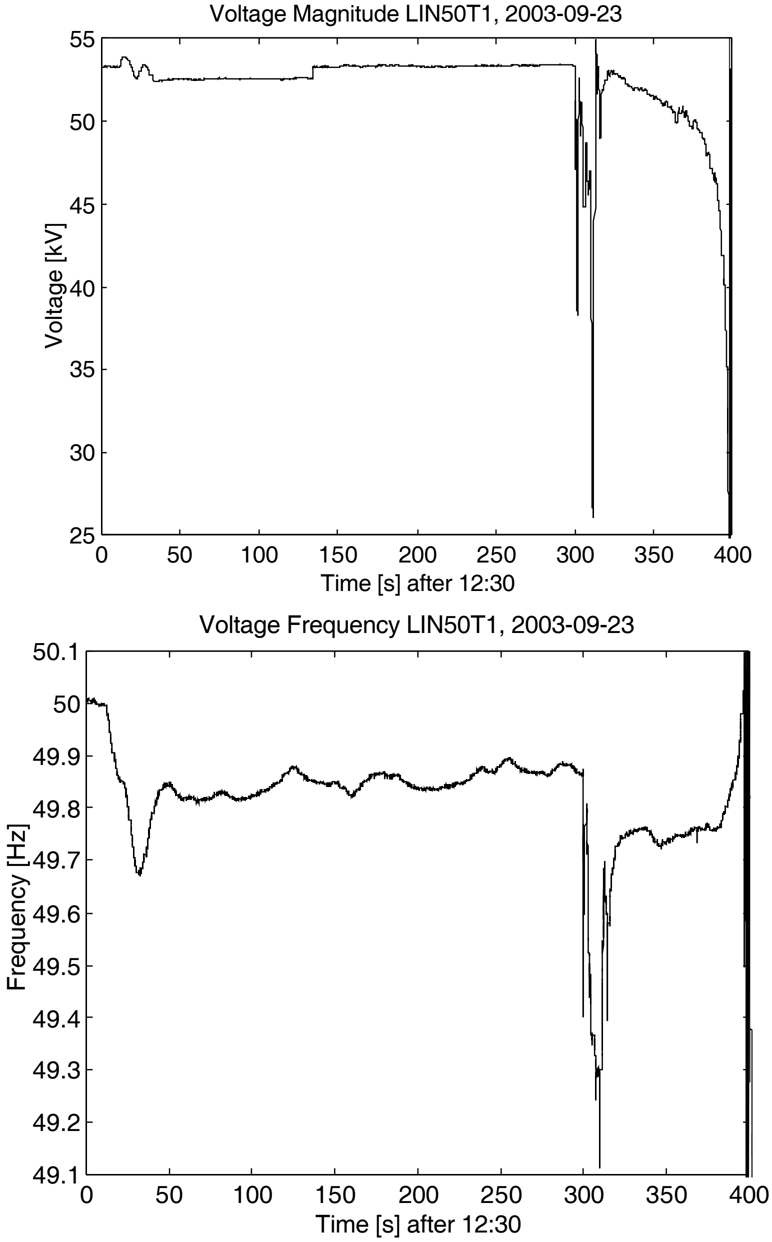


Figure 12: Voltage decrease and frequency increase by the end of the instability 2003-09-23

Load shedding actions have to have a longer time delay than backup clearance of shunt faults, 2-5 seconds should be sufficient margin depending on the system. The action must also be so early that it has an effective contribution to the collapse mitigation. Very seldom a long term voltage collapse occurs less than 30 seconds after the triggering event, which of course has to be checked carefully for each application. With these limitations a time delay of about 10 seconds, should leave enough margins in both directions. Actions should also be taken in an order of priority, i.e. low cost actions not affecting customers first, and costly actions affecting customers later. If time is critical, also the power of the action has to be considered, i.e. do not wait to long with the powerful actions.

For triggering load shedding to prevent a voltage instability, there are at least two parameters to set, the voltage trigger level and the time delay. Since a voltage collapse is a fairly slow event, load can be shed in steps until the voltage decay is interrupted and a reasonable voltage level is re-established. This procedure must leave enough space between the steps to let the protection scheme recognize the system response to the latest performed action. How to combine time delay and voltage trigger level is to some extension a matter of taste and tradition. Even though time is shorter at lower voltage, it might be a little risky to have a shorter time delay at lower voltage trigger levels, since several steps can go to action at the same time.

A Swedish patent application [12] has been submitted late 2003, claiming a method to shed an amount of load corresponding to a desired voltage recovery, which is a function of the present voltage level and the minimum acceptable operational voltage after the load shedding. Based on a measured, calculated or estimated value of the actual short circuit impedance of the supplying system, the desired amount of load to shed is easily calculated using basic electric circuit theory. When the amount of load has been calculated the load to shed is picked from a dynamic look-up table, as illustrated in Section 5.3.1.1.

6.2 Algorithms to counteract frequency instability

The steady state power system frequency deviation from its nominal value is a direct measure of the imbalance between the actual generation and the power demand, including losses. Normally the frequency control of the generators in the system are designed with droop, which means that active power output deviation from the set-point is a linear function of the frequency deviation; at lower frequencies the output is increased, and at higher frequencies the output is decreased. The droop ensures that contribution from each generator is limited to a certain amount, at off-nominal frequencies. The relation between the total composite regulating characteristic and the size of a change in load or generation, gives the frequency deviation due to the disturbance. In large interconnected systems each individual generator is small with respect to the total composite regulating capacity, and trip of even a large unit affects the system frequency very little. In smaller systems, however, even trip of a moderate sized generator will create a large frequency deviation. Load shedding based on the frequency deviation is installed in all major power systems. This is a simple and straightforward way to re-establish the balance between load and generation. Details on underfrequency controlled load shedding schemes throughout the world are given in chapter 2.1 of this document.

The power system frequency variation during a disturbance is probably best shown with an example. There was a disturbance in the Nordic system, January 13, 1979, when one out of three quite heavily loaded transmission lines from the North of Sweden to the South was lost, due to a broken fuse in the power supply to the distance protection for the line. The power oscillations, when the line was lost, were so large that the two remaining lines were also tripped. The Nordic system was then split into two parts, with a large power deficit in the South. The frequency in the South system is shown in Figure 13. Two steps of the underfrequency load shedding system (UFLS) were activated and disconnected totally 1 600 MW of load in the South system. Emergency power from the UCPTE system through HVDC connections were not enough to stop the frequency decay.

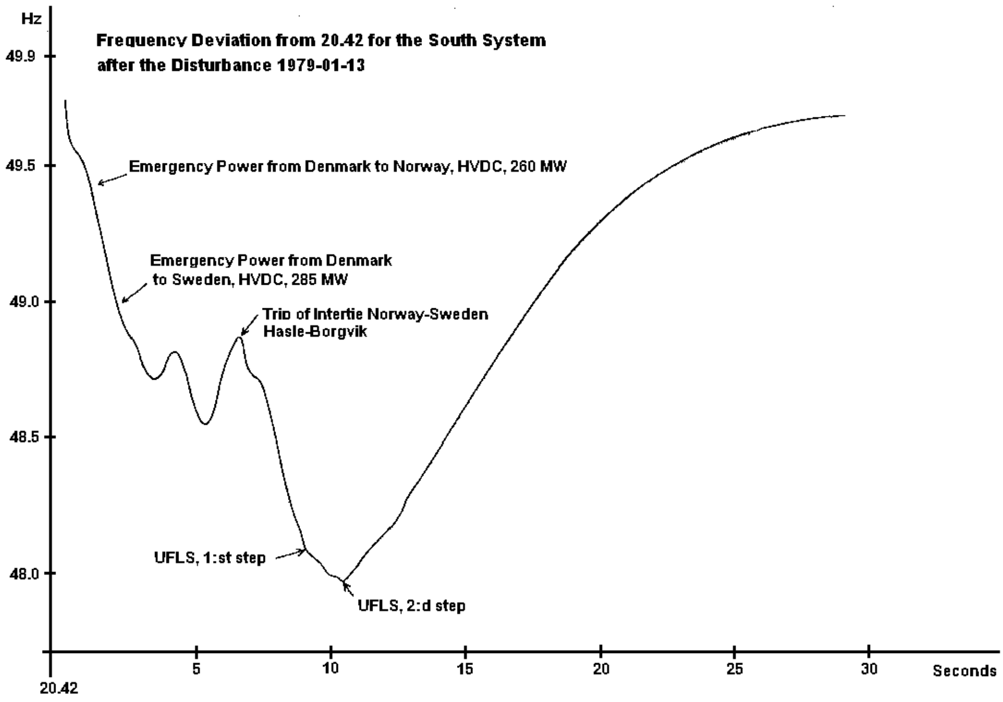


Figure 13: Frequency disturbance in the Nordic system January 13, 1979

6.2.1 Frequency instability detection

Almost every power system is equipped with underfrequency relays, set in a number of steps. Often the same time delay is used for each step. The design could also be such that each frequency step has two time delays; one short (about 0.2 s) to stop the frequency decay, and a longer one to bring the frequency back to an acceptable level. The settings vary with the size of the power system, or actually with the total composite regulating capacity. In smaller systems the normal frequency variations are larger and the settings have to deviate more from the nominal value. In the Nordic 50 Hz system, the five load shedding steps are activated between 48 and 49 Hz.

In some systems, especially small systems, where the size of the largest unit is big compared to the size of the system, also rate-of-change of frequency is used as a criterion to detect an imminent frequency instability, e.g. in Ireland. The rate-of-change of frequency criterion is normally used in combination with the frequency criterion, to speed up the load shedding. Combining the underfrequency trigger, with a high negative rate-of-change of frequency, makes it possible to shed load at a fairly high frequency level, without risking to shed load under normal operation conditions at quite low frequency. It also has to be emphasised that the rate-of-change of frequency is a rather nervous signal.

The frequency instability detection can also be event based, in such a way that when a large unit, or an important HVDC-connection, trips, at an active power level higher than a certain value, load shedding is automatically executed, without waiting for the frequency or rate-of-change of frequency to drop. Another such event based criterion could be islanded conditions. This is also a technique mainly used in smaller systems. An example of an event based load shedding system is described in Section 5.3.

The resolution of the load shedding scheme has to be high enough, in order not to overshed. Overshedding might cause high voltages, and damage to components and customer equipment. There is also a risk for overfrequency, resulting in trip of generation.

6.2.2 Where, when and how much load to shed

The stationary frequency in an AC system is a common variable that is the same all over the system. Although the local frequency is a great variable to indicate an imbalance between load and generation, and to some extent also the size of the imbalance, it does not say anything about where the generation has been lost or where to find the optimal location to shed load. In some power systems it is rather easy to identify typical load areas and typical generation areas. Load shedding is in such cases installed in typical load areas. Most such systems have the load shedding equally (or proportionally) spread within the load areas. However, suppose that we have a heavily loaded load area, with a big generator, and power import on tie-lines up to the capacity of the tie-lines. If the big generator is tripped and the load shedding is split among many load areas, the tie-line capacity will be exceeded, perhaps with a line trip due to overload and a voltage collapse as a consequence. Therefore, to keep the system power flow, as unchanged as possible, load should be shed as close as possible to the problem area, i.e. close to the lost power input (generator or HVDC-connection).

A Swedish patent [13] has been issued in 2004, claiming a method to combine a conventional underfrequency criterion with a time delay that has an inverse time characteristic, resulting in a shorter time delay in areas with low voltage. In this way load is shed in areas, which gives the most relief to the power system in terms of voltage drop and losses.

The load shedding can be performed as soon as possible. There is no reason, from the power system point of view, to delay the load shedding more than what is required to clearly ascertain the frequency drop. Load shedding and other actions to re-establish the power system frequency have to be taken in a prioritized order, e.g. 1) drop HVDC-export, 2) request HVDC-import, 3) drop low priority load, and 4) shed high priority load. A dynamic loo-up table similar to the one presented in Section 5.3.1.1 can be used and such a table could also include other actions than load shedding.

By tradition underfrequency controlled load shedding schemes have comprised a rather large amount of steps, at different frequency levels with the same time delay, where each step shed a fairly small amount of load. When the frequency is decaying, the load shedding steps are activated, one after the other, until the frequency decay is halted. Before the activation of the next step in the sequence there must be enough time for the underfrequency relays to recognize the power system response to the latest activated step. On the other hand, the load shedding must be fast enough to stop the frequency reduction, which puts a lower limit on the amount of load to be shed in each step. The rules give here are general and relative, for each system under consideration, thorough studies have to be performed to design the underfrequency controlled load shedding system.

6.3 Example: Event-based Adaptive Load-Shedding

This section describes a conceptual solution for load level adjustment in case of power system separation. The power system example chosen here is the SESCo system in Malaysia. This system is rather small and easy to overview, the incidents discussed are event based, but the concepts are general and any other triggering function could easily be converted to an “event” – corresponding to the trigger level.

In the SESCo system the 275 kV power flow is from Bintulu towards the Kuching area, see Figure 14. The connection is a double circuit 275 kV line, divided into 3 sections; Bintulu-Oya, Oya-Enkilili, and Enkilili- Mambong. In case of a double circuit fault, anywhere along the 275 kV line, there will be a system separation. To achieve balance between load and generation in the Sibu and Kuching areas load shedding is needed. The rate-of-change of frequency can be as much as -1.5 Hz/s, and frequency triggered load shedding might not be enough in all cases. And the possibilities of prioritization are limited.

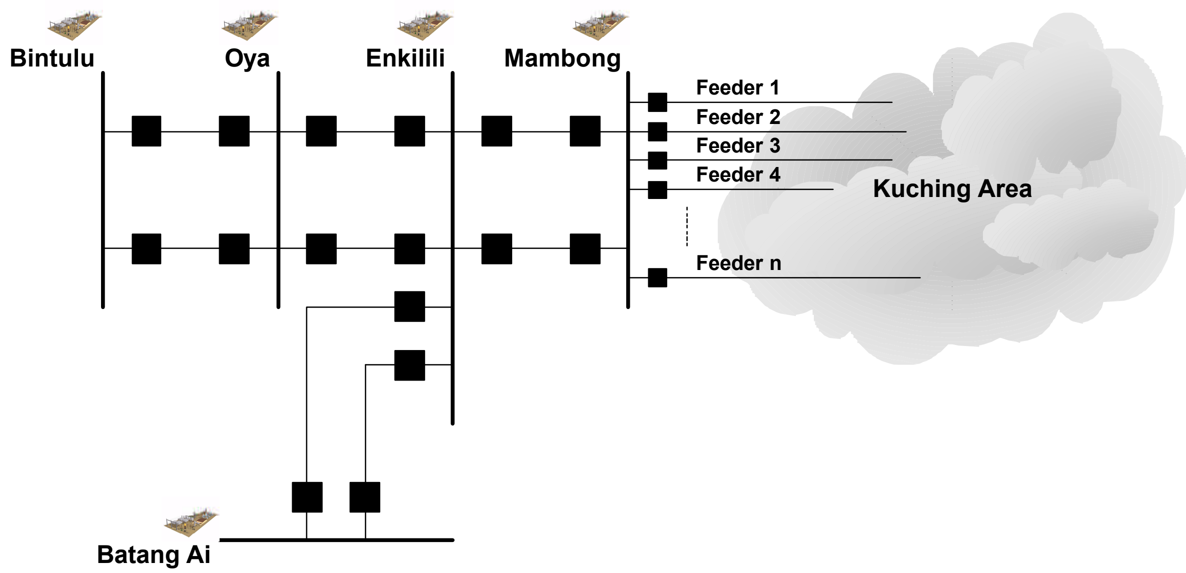


Figure 14: SESCo 275 kV system

6.3.1 Dynamic Look-up Table and Load Shedding Triggering

To shed load two conditions should be fulfilled:
1) The “arming” condition, for a certain feeder, should be fulfilled [Yes].

2) The “triggering” condition is fulfilled when both the lines in a corridor have been tripped. There are a number of ways to achieve this condition, in a secure and dependable way. The triggering signal is very critic, since it is so powerful (a false signal will trip a large amount of load). Therefore a scheme with 2 out of 3 is proposed for the triggering signal, see Figure 15.

- Then the load shedding is activated

6.3.1.1 Dynamic look-up table

The dynamic look-up table comprises all the feeders included in the load shedding scheme. The feeders are listed in the order of priority (so that Feeder 1 has a higher priority to be shed that Feeder 2, and so on). The actual feeder power [Px and Qx] is updated regularly, e.g. once every minute. The imported power [Pline, Qline], on the two 275 kV lines, is also updated at the same regularity. k (see Table 1) is identified according to:

∑[P(1)....P(k-1)] ≤ Pline ≤ ∑[P(1)....P(k)]

Feeders up to and including k will be shed instantaneously, when the “release”-signal comes, i.e. both the circuit-breakers open.

The expression:

Qline-∑[Q(1)....Q(k)],

can be used to estimate the reactive power unbalance after the load shedding. This information is used to decide if shunt reactors should be switched in (and how many...).

P-armed	Feeder Name	Active Power [P]	Reactive Power [Q]

Yes	Feeder 1	P1	Q1
Yes	Feeder 2	P2	Q2
Yes	Feeder 3	P3	Q3
Yes	Feeder 4	P4	Q4
Yes	......	.....	.....
Yes	Feeder (k-1)	P(k-1)	Q(k-1)
Yes	Feeder k	Pk	Qk
No	Feeder (k+1)	P(k+1)	Q(k+1)
No	.....	.....	.....
No	Feeder n	Pn	Qn

The actual feeder power values are picked from separate transducers and communicated to the central arming system via separate RTUs and communication channels (the communication channels are provided by SESCo). These are not time critical, since the load changes are normally rather slow. The dynamic look-up table could preferably be implemented in an industrial PC, in the substations Oya (for the section Bintulu-Oya), Enkilili (for the section Oya-Enkilili) and in Mambong (for the section Enkilili-Mambong). The number of Arming PCs depends on to what extent remote signals can be used, and if separate hardware is required for each scheme.

6.3.1.2 Triggering of the Load Shedding

Each of the feeders in the look-up table is then tripped by a logical AND-combination of “armed by the look-up table”, and “both circuit-breakers open”. These trip signals have to be sent from the 275 kV substation (Oya, Enkilili, and Mambong, respectively) to the feeder circuit breakers. These transfer trips are time critical.

There are a number of alternative trigger conditions, such as relay trip signals, or disconnector positions – suppose that one of the 275 kV lines is out of service, the disconnector is open, but the CB is closed, and we get a trip on the remaining line – then we should go to load shedding........., etc.

6.3.2 RES521 for on-line monitoring

The solution described above is simple and robust for the present transmission system. In a few years, when the 275 kV grid is extended, a more complex scheme will be required. Therefore it is a very good idea to install two phasor measurement units, e.g in Oya and Mambong. A suitable version of a PC -based on-line monitoring tool should be used. Such an installation for monitoring could later on be extended to a wide area control scheme.

6.3.3 Conceptual Solution

A conceptual solution is shown in Figure 15.

- Bay level: A P/Q transducer is connected to the CTs and VTs in each bay that is included in the SPS (System Protection Scheme). The transducer output is preferably a mA-signal reflecting the active and reactive power output on the feeder. These signals, two from each bay in a substation are sent to an RTU.

- Substation level: One RTU for each substation in the SPS collects the P/Q measurements from the transducers, and sends this data, via a communication network, to the “arming PC”. The RTU also receives the arming signals, one for each bay, and put this arming signal on a binary output. The trip signal is then derived by a logical AND-condition – preferably implemented in relay technology – with the “triggering signal”. On the substation level also a fast communication interface must be included to receive the “trig signals” from the condition “both 275 kV lines in a corridor have tripped”. A 2 out of 3 logic is recommended to send the trig signal to activate the load shedding.

-Arming PC: The arming PC is responsible for keeping the dynamic look-up table updated, by receiving the P/Q signals from the substations and sending arming signals back to the substations. A lot of security can be built into the arming PC, e.g. a connection to the existing SCADA provides a possibility to compare the SPS P/Q-data with the SCADA data, and if there is a big difference an alarm is given. One scheme is designed for each 275 kV corridor. Depending on the reliability requirements, more than one scheme could be implemented in the same arming PC.

- Triggering: A trig signal evaluator is responsible for submitting the condition “both the lines in the 275 kV corridor have tripped”. It is recommended to derive and send, preferably in different ways, 3 different trig signals, and in the receiving substation derive the 2 out of 3 condition. Each trig signal evaluator must be able to read analog and binary inputs as well as remote binary inputs. Depending on the level of reliability the same or different hardware have to be used to evaluate trig signals for the different schemes.

6.3.3.1 Selection of Equipment

Please refer to Figure 15.

- Bay Level P/Q measuring: Tillquist Measuring transducer, PQ 400, combined transducer for active and reactive power could be used. One transducer for each bay included in the SPS is required.

- Bay Level Trip: Two auxiliary relays and perhaps a trip relay is needed for each bay.

- Substation Level: The RTU for P/Q sending and arming signal receiving could be ABB RTU560 or ABB RTU211. The fast communication interface and the 2 out of 3 voting, could be implemented in conventional relay technology.

Arming PC: The arming PC could preferably be an ABB PCU400.

Triggering: The trig signal evaluator could be implemented in an ABB REC561.

6.3.3.2 Amount of Equipment

Please refer to Figure 15.

- Transducer: 1 P/Q transducer is needed for each bay that is included in the SPS.

- Trip: 2 auxiliary relays + 1 trip relay for each feeder in the SPS.

- RTU: 1 RTU for each substation in the scheme. The configuration of the RTU, and the amount of I/O-units depends on the number of feeders in each substation.

- Fast communication & 2 out of 3: One set for each substation.

- Arming PC: For redundancy 2 units are needed. 2 or 3 schemes (one for each section of the 275 kV double circuit line) could be implemented in the same arming PC.

- Triggering: To achieve the 2 out of 3 criterion, 3 REC561 are needed. It is not clear at this stage if, the same trig signal evaluator hardware can be used for different schemes.

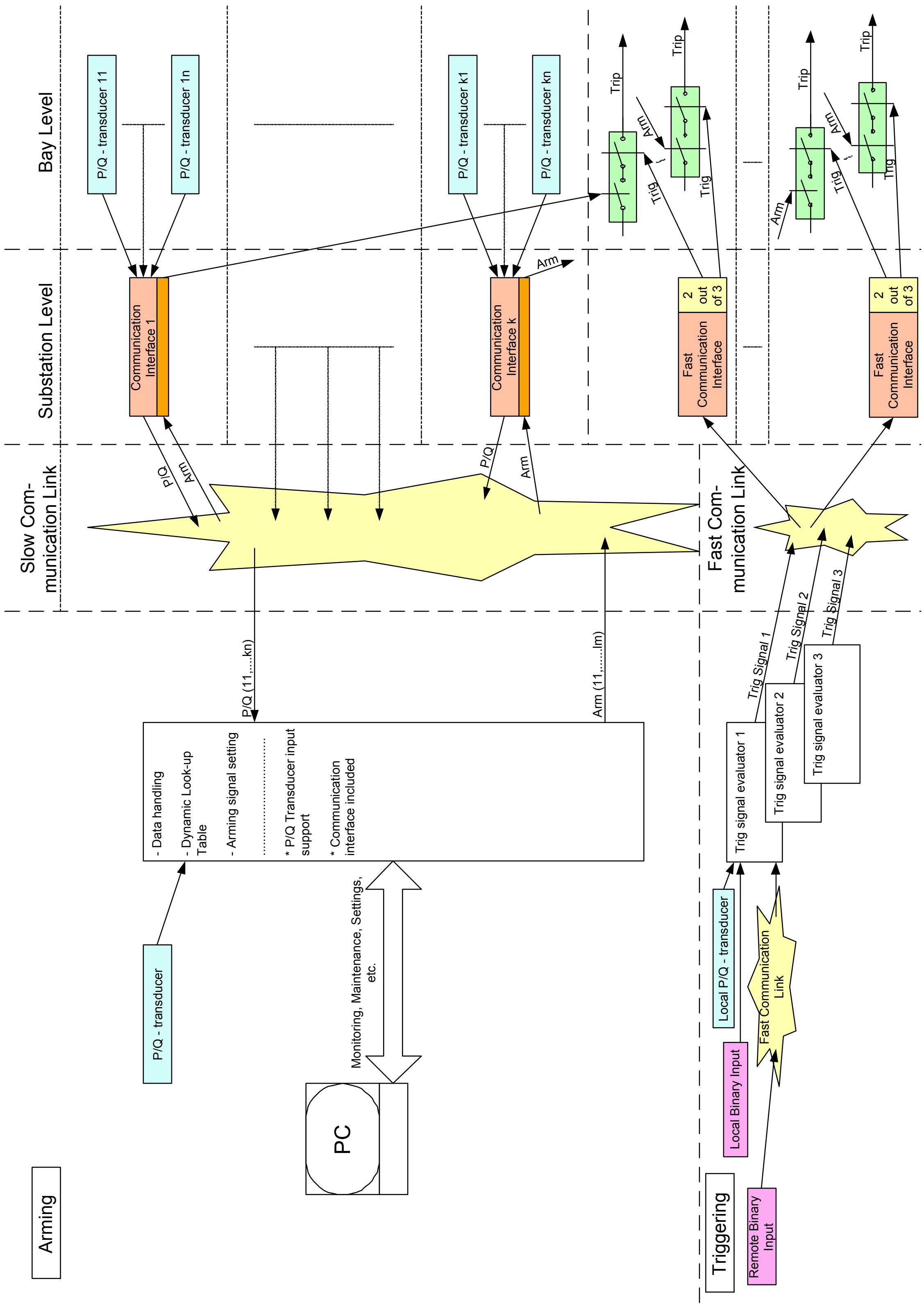


Figure 15: Conceptual solution for an event based adaptive load shedding system

7 EPS large oscillation mitigation

Since it is very hard to study controlled power oscillations in real networks, a laboratory project was performed to study algorithms to detect, characterize and damp power oscillations in electric power systems, in the area of 0.1 – 10 Hz. The algorithms were based on local measurements of voltage and current only as well as on both local measurements and phase angle differences between voltage vectors in different parts of the power system. A synchronized Phasor Measurement Unit (PMU) of ABB, was used to obtain the phase angle difference between two buses, and in this way, power oscillations could be detected.

To create power oscillations, three-phase faults were applied. In addition, measurements on a 400 V-power system model, available at the department were carried out.

In order to damp power oscillations, load switching i.e. breaking resistors were used. Time domain simulations were done in SIMPOW to verify the algorithms. The power system model of the department was modeled in SIMPOW as a 400 kV system and simulations were carried out on it. Three phase faults were applied to obtain transient instabilities. These instabilities were characterized and were damped out. These studies were done offline.

It was found that the angle difference signal derived from PMU proved to be a reliable indicator of power swing. Moreover, a result was that resistive load switching with appropriate value improves both transient stability margin and damping of the power swing.

The laboratory equipment at Chalmers comprises a DC motor drive, connected to a 400 V AC generator, six power line elements that can be freely connected in different structures, and a number of load models and objects. The total length of the line model is 900 km. The model can also be connected to the Nordel network. Two transformer models with tap-changers are also available. The model is shown in the Figure16.

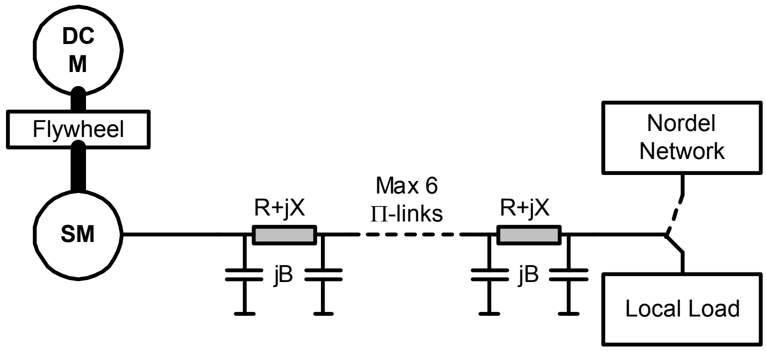


Figure 16: 400 V, 70 kVA laboratory system set up at Chalmers

This diploma work was conducted in co-operation with Solvina, in Gothenburg.

7.1 Laboratory Model

The purpose of this section is to describe the laboratory power system model available at the Department of Electric Power Engineering, CTH that has been used in this thesis work to study power oscillations.

7.1.1 The Power System Model

The power system model that is used in this thesis is a 3-phase model of a 400kV transmission system, inspired by the Swedish 400kV system and consists of:

- The power plant model
- The transmission line model
- One transformer with on load tap changer

The entire model operates at 400 V and the rated generator power is 75 kVA which gives a voltage scale of 1:1000 and a power scale of 1:18800 due to the impedance scale of the line model [14]. The model will be connected to the Swedish grid, which will serve as the infinite bus. By this, we achieve a one-machine infinite bus model. Figure 17 shows the one line diagram of the model.

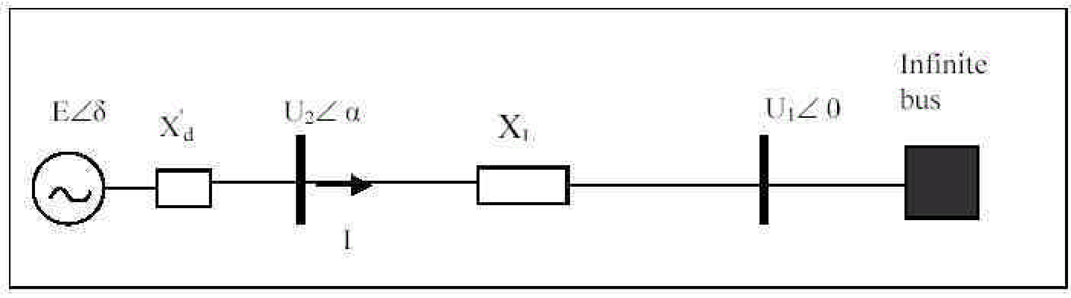


Figure 17: Laboratory model

7.1.2 The Power Plant Model

The power plant model is an accurate model based on the large Harsprånget hydro power plant situated by the Lule River in northern Sweden and it corresponds to a 1400 MVA plant [15].

The Turbine Part:
The generator is driven by an 85 kW DC motor.
DC motor data:
1000 rpm, 220 V
I = 420 A
Ra = 0,0118 Ω (at 15˚C)
La = 182 H
Rm = 66,5 Ω
J = 7,3 kgm²

The Flywheel:
A flywheel is mounted on the shaft between the generator and DC motor to give the lab model the same mechanical behaviour as the real power plant. Flywheel data:
1100 rpm
Diameter = 900 mm
Weight = 900 kg
J = 50 kgm²

The Generator:

The armature windings of the generator are Y-connected and the terminals are connected to the line model by a circuit breaker. The field winding is fed from a static exciter.

General generator data:
3-phase, 50 Hz, 6 poles, 1000 rpm
J = 18,8 kgm² -moment of inertia

Armature winding data
Sn = 75 kVA
Vn = 400 V

In = 108,3 A
X = 2,93 Ω
Xd' = 0,437 Ω
Xd'' = 0,332 Ω
Rs = 0,081 Ω

Field winding data
Vfd = 110 V
Ifd = 4,7 A

Dynamic data of generator:
The dynamic data was measured by two master students (Susanne and Maria) in their master thesis work.

Direct axis	Quadrature axis
Ra = 0,0295Ω (stator resistance)	Xa = 0,0295Ω (stator leakage reactance)
Xd = 2,3982Ω (synchronous reactance)	Xq = 1,2653Ω (synchronous reactance)
Xd' = 0,2951Ω (transient reactance)	Xq' = 0,2434Ω (transient reactance)
Xd'' = 0,1831Ω (sub-transient reactance)	Xq'' = 0,1309Ω (sub-transient reactance)
Td' = 1,5189s (transient open circuit time constant)	Tq' = 0,3406s (transient open circuit time constant)
Td'' = 0,0170s (sub-transient open circuit time constant)	Tq'' = 0,00032729s (sub-transient open circuit time constant)

Zbase = 2,133Ω

Dynamic data of generator (calculated)

Inertia constant in [MWs/MVA]:

$$H = \frac{\frac{1}{2} J\omega^2}{\mathrm{Smach}} \tag{3.1}$$

Where:
J - moment of inertia in kgm²
S_{mach} – 3-phase rating of machine in VA
ω - synchronous speed of machine in mechanical radians per second
Total moment of inertia for power plant is:

$$\frac{0{,}5 \times (18{,}8 + 50 + 7{,}3) \times \left(2\pi \times \frac{1000}{60}\right)}{75000} = 5{,}56s$$

Voltage Regulator:
The generator is equipped with a modern microprocessor-based voltage regulator. The regulator can control the terminal voltage, field current, reactive power or power factor. The voltage regulator is equipped with both delayed and instantaneous current limiters.
The delayed current limiters protect the exciter, armature and field windings against thermal overload under stressed operating conditions while the instantaneous field current limiter protects the semiconductors in the static exciter.
A power system stabiliser (PSS) is included in the control loop of the generator in order to enhance the angular stability.

7.1.3 The line Model

The line model consists of 6 identical π-sections, each corresponding to 150km of a 400kV line. These sections can either be connected in series or parallel. In this work a line of length 450 km i.e. 3 sections connected in series will be used.

Data for a π-section:
$X = 50,4\ \Omega$
$R = 4,17\ \Omega$
$C = 0,065767\ \mu F$ (i.e. $b = 2,06613e\text{-}5\ \Omega^{-1}$)

Comparing model data with real data gives an impedance scale of 1:53,2.

7.1.4 Power Transformers

One on-load tap-changer (OLTC) transformer is used in the model. The nominal transformer ratio is 1:1, since the voltage level is the same for the whole model. The regulation span is ±13.5% in ±9 steps of 1.5%. The power and voltage ratings were given the same values as the generator: 75kVA and 400V respectively.

7.1.5 Loads

This laboratory model will be run without dynamic loads. Power will only be produced into the infinite network.

7.1.6 Data Acquisition System

A phasor measurement unit (PMU) RES 521*1.0 from ABB will be used to collect data from the power system model. Figure 18 shows the picture of a PMU. The PMU is capable of recording long duration electrical disturbances in phasor format and is providing continuous phasor measurements in support of real time applications.

Figure 18: ABB's Phasor Measurement Unit RES 521

The reference for the phase angle is the NavStar Global Positioning System (GPS) that also supplies highly accurate time and date. The GPS is not used in this work since one PMU will be used to measure at two different buses. Voltage and current inputs to the PMU are derived from resistive voltage dividers and current transducers (LEM modules) respectively.

Phasor representations i.e. real and imaginary parts of voltages at the infinite bus and generator bus and currents through the line and the frequency and change in frequency are provided by the PMU. The angle difference between the two buses, the active and reactive powers are then calculated using the following relations:

$\angle U2$ – voltage angle of generator bus (α)

$\angle U1$ – voltage angle of infinite bus (0), this bus has been taken as reference bus.

$\angle I$ – current angle of the line (β)

$\alpha = \angle U2 - \angle U1$ - voltage angle difference between infinite bus and generator bus

$pf = \cos(\angle U2 - \angle I)$ - power factor $(\alpha - \beta)$

$P = U2\ I * \cos(\angle U2 - \angle I)$ - generator real power

$Q = U2\ I * \sin(\angle U2 - \angle I)$ - generator reactive power

$S = P + jQ$ - generator apparent power

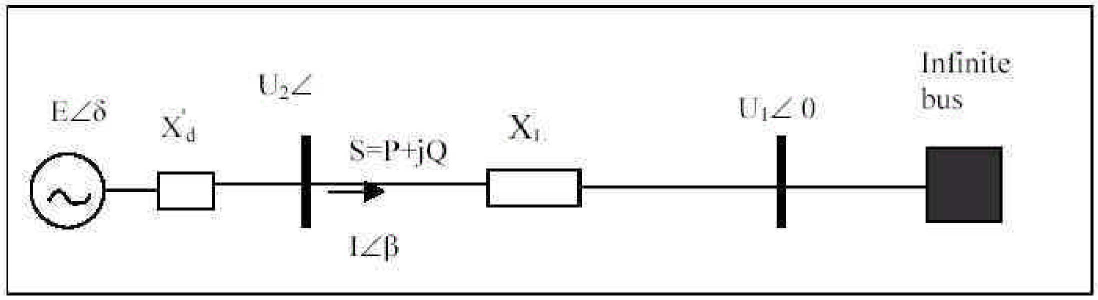


Figure 19: One line diagram of the lab model

Based on these quantities, oscillations in the power can be detected and damped.

7.2 Some Lab Measurements

The purpose of the laboratory measurements is to obtain some power oscillations. Measurements from the laboratory are presented in this chapter. These measurements are compared with the results obtained from theoretical analysis and simulations done in SIMPOW. The power oscillations recorded in the lab by the PMU, are characterized later in this section.

A three phase to earth fault was applied at different load conditions. The length of the transmission line was also varied. ABB's Phasor Measurement Unit RES 521 was used to take the readings. The PMU makes it possible to obtain the voltage phasors of different buses. The voltages of the generator and the grid and the current through the line were measured. The data from the PMU was stored in the computer in EXCEL format. This data file was loaded into MATLAB and then recreated.

Simulation of the lab model in SIMPOW was also carried out and a theoretical analysis was made to determine the system stability.

7.2.1 Power System Model

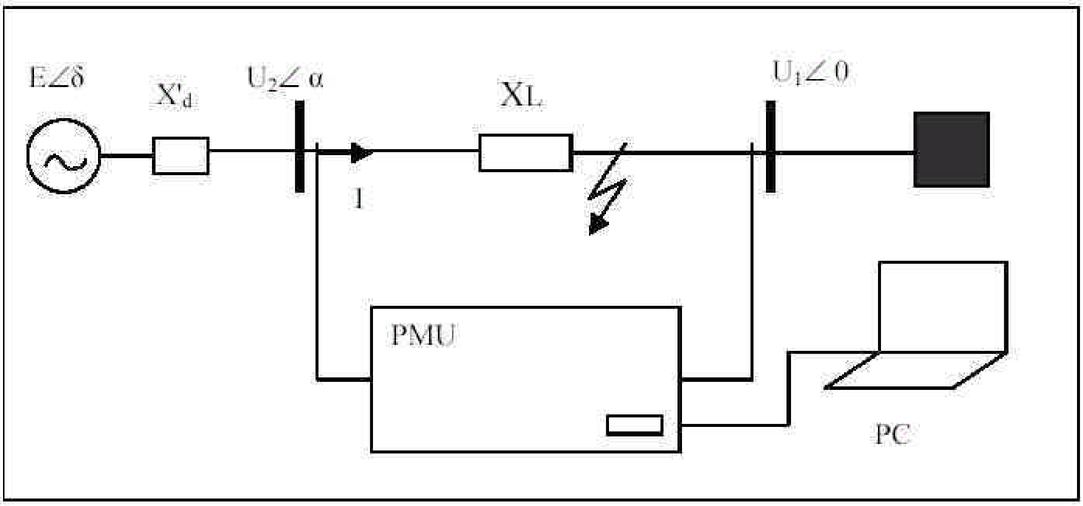


Figure 20: System for studying power oscillation

A three-phase fault was applied for a few hundreds of milliseconds to achieve some oscillations in the power. During the fault, no power is delivered to the infinite bus and after the fault, the system returns to the pre-fault state. Figure 20 shows the lay out of the lab set up.

7.2.2 Results of Theoretical Analysis of Laboratory Model

Power oscillations are due to unbalance between mechanical power input and electrical output. The unbalance could be caused by short circuits as the case is for this analysis. The purpose of this theoretical analysis is to determine:

If or not the system will be stable after the short circuit
The maximum angle for stability
The critical clearing time i.e. maximum duration of short circuit.
Power oscillations are analysed by:

The swing equation, which governs the rotational dynamics of synchronous machines in stability studies [16]. A graph of the solution is called the swing curve (δ as a function of time) of the machine and it shows whether the machine will remain in synchronism or not after a disturbance. The power angle equation is derived from the load flow equations. Its graph (power as a function of δ) is called the power angle curve.

Equal area criterion- Accelerating area must be less than the maximum decelerating area for system stability.

Swing equation: $$\frac{2H}{\omega s}\frac{d^2\delta}{dt^2} = Pm - Pe \quad \text{(p.u.)} \qquad (4.1)$$

Where:
H- Inertia constant
t- time in seconds
ωs- synchronous speed in electrical degrees
Pm- mechanical input power
Pe- electrical output power
δ- machine rotor angle with respect to infinite bus

Power-angle equation:

$$Pe = \frac{|U1||E|}{X}\sin\delta \tag{4.2}$$

Where:

U1- infinite bus voltage

E- transient internal voltage of generator

X- total series reactance (line reactance, generator transient reactance, transformer reactance)

Equal area criterion:

$$P\circ m(\delta t - \delta\circ) = \int_{\delta t}^{\delta u} Pe(\delta) - Pmd\delta \tag{4.3}$$

P°m – initial output mechanical power

δT – rotor angle after fault is cleared

δo - pre-fault rotor angle

δu - maximum available rotor angle

The generator in the lab model is delivering power of about 33kW and the terminal voltage and infinite–bus voltages are 381V and 377V respectively (line to line). The power-angle equation for the system applicable to operating conditions can be determined using the system parameters, i.e. reactances and solving the following equations.

$$I = \frac{U2 - U1}{jXL} \tag{4.4}$$

$$E = U2 + X'd \times I \tag{4.5}$$

$$\delta crit = \frac{\pi f P\circ m}{2H} T^2\mathrm{crit} + \delta\circ$$ (critical clearing angle) (4.6)

The frequency of oscillations is given by:

$$f = \frac{1}{2\pi}\sqrt{\frac{\omega s S p}{2H}} Hz \tag{4.7}$$

Where:

Sp – synchronising power coefficient $\frac{dPe}{d\delta}$ (4.8)

The power angle diagram before, during and after the 3-phase fault is plotted below in Figure 21.

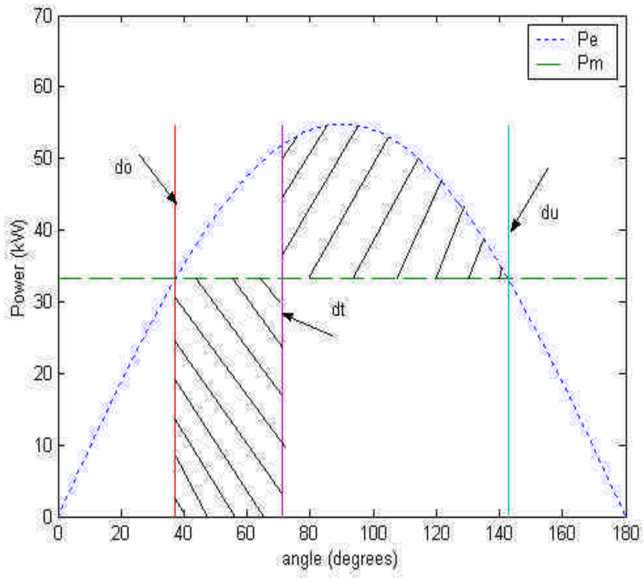


Figure 21: Power-angle curve (theoretical analysis)

From Figure 21, the following are the obtained results:

P_e = 54 sin δ (power angle equation)
δ_o = 37^0 degrees (operating angle)
Pe(δ_o) = 33 kW (also Pm initial input mechanical power)
δ_T = 70.1 degrees (critical clearing angle)
Critical clearing time = 308 ms
δ_u = 143 degrees(maximum available rotor angle)

The theoretical analysis shows that for the laboratory power system to remain stable after a fault, the fault should be cleared no later than after 308ms.

7.2.3 Results of Simulations of Laboratory Model In SIMPOW

The laboratory power system was modelled in SIMPOW as a 400kV-power system. The power-angle diagram is shown in Figure 22. The results obtained are as follows:

δo = 43.771 degrees
Pe(δo) = 621 MW (also Pm initial input mechanical power)
Critical clearing time = 274 ms
δmax = 136.23 degrees(maximum available rotor angle)

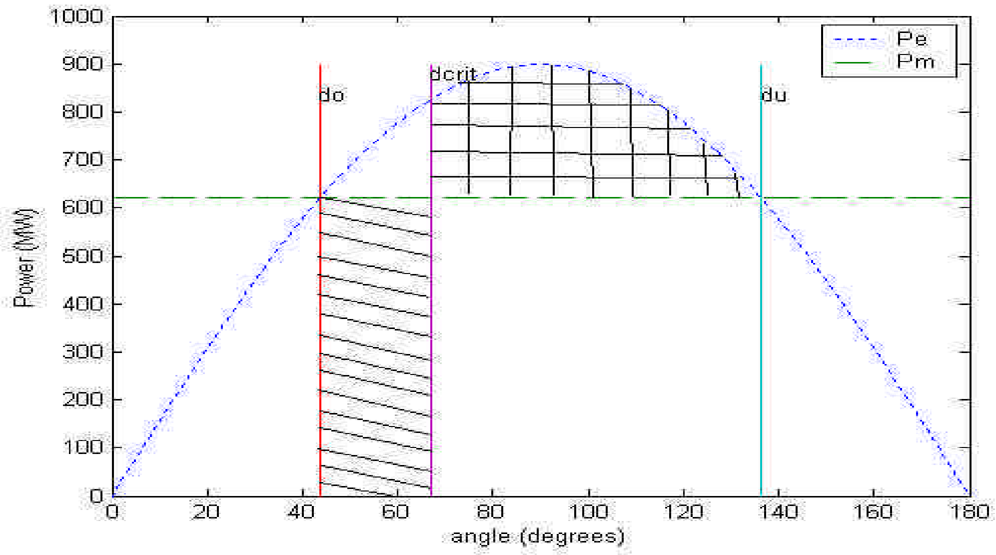


Figure 22: Power Tap-angle curve (Simulations). Steady state power 621 MW

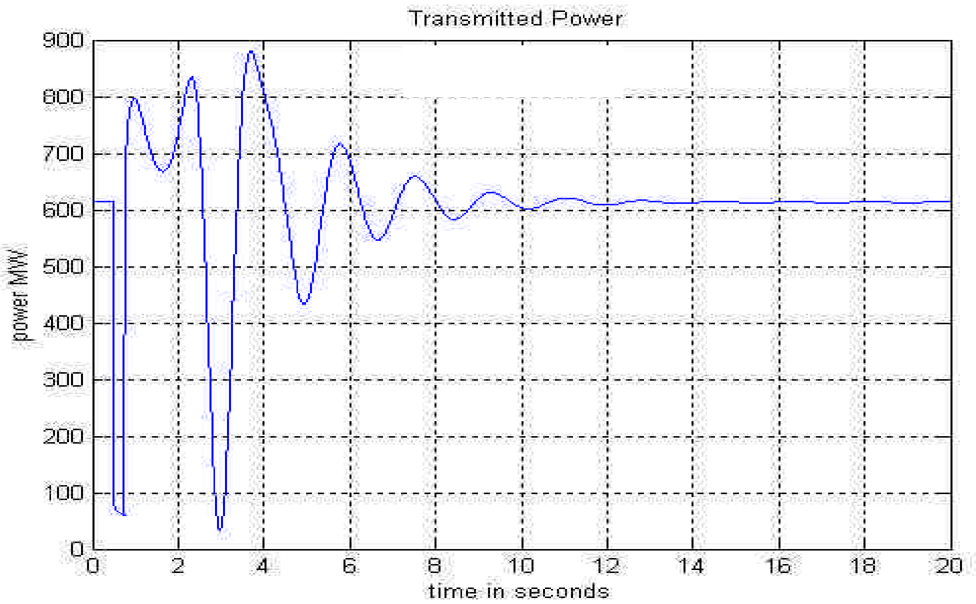


Figure 23: Transmitted power

Figure 23 shows the transmitted power from the generator bus to the infinite bus. Before the 3-phase fault was applied, power transmitted was 621 MW. The generator oscillates against the infinite bus by an angle of 80^0 as shown in Figure 24.

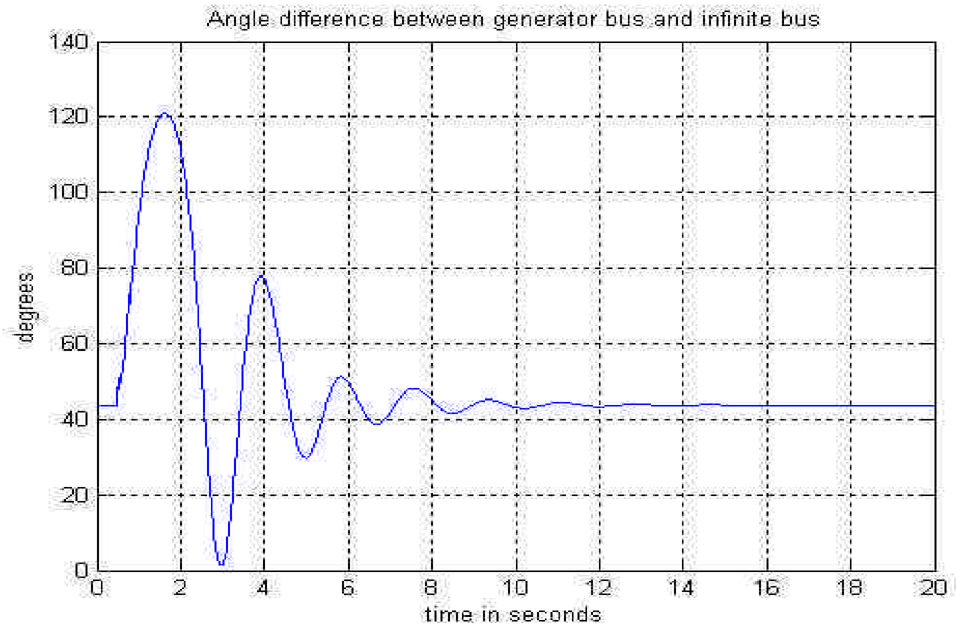


Figure 24: Angle difference between generator bus and infinite bus

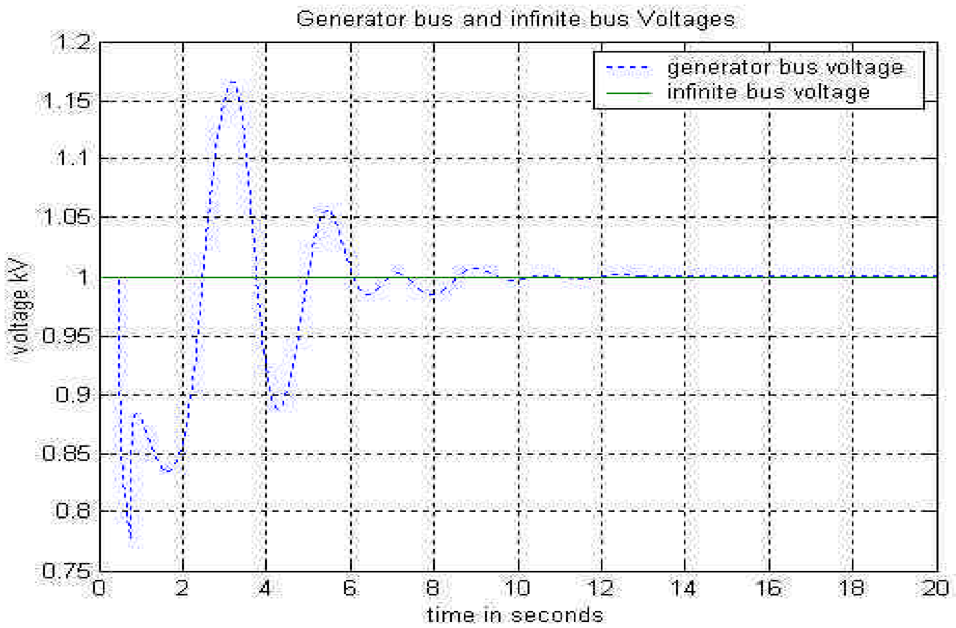


Figure 25: Generator bus and infinite bus voltages

Figure 25 shows the generator and infinite bus voltages. As seen above, the infinite bus voltage remains constant. The generator is swinging against the infinite bus.

7.2.4 Results of laboratory Tests

In the lab we recorded several readings. The generator was delivering 33 kW and faults with different time duration were applied, to find the critical clearing time. It was found from the lab that for this operating point (33 kW), critical clearing time is 370 ms. Figure 12 shows the power angle diagram.

δo = 37 degrees
$Pe(\delta o)$ = 33.3 kW (also Pm initial input mechanical power)

Critical clearing time = 370 ms
δmax = 143 degrees(maximum available rotor angle)

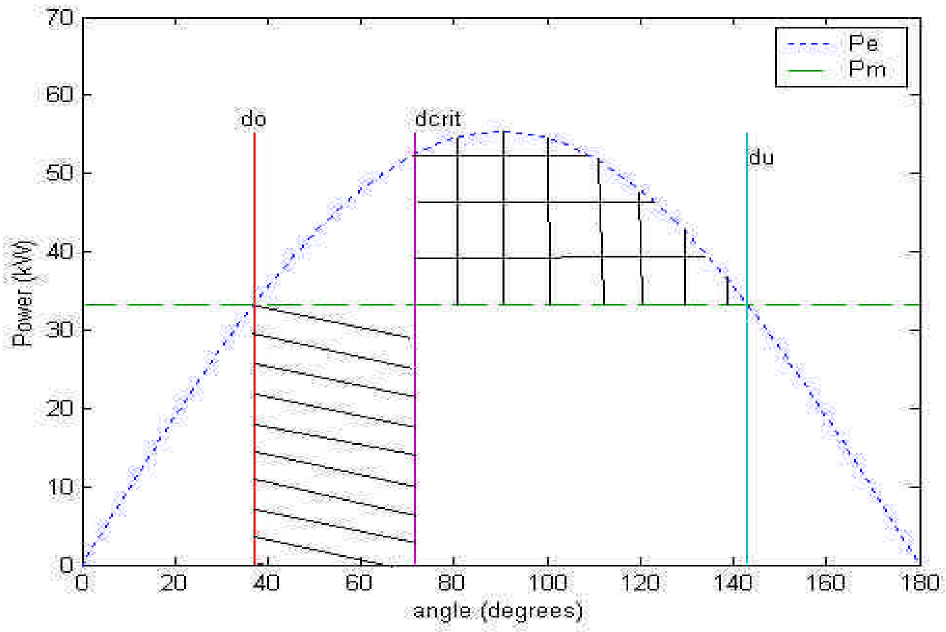


Figure 26: Power-angle curve (lab measurements)

7.2.5 Some Measurement Data

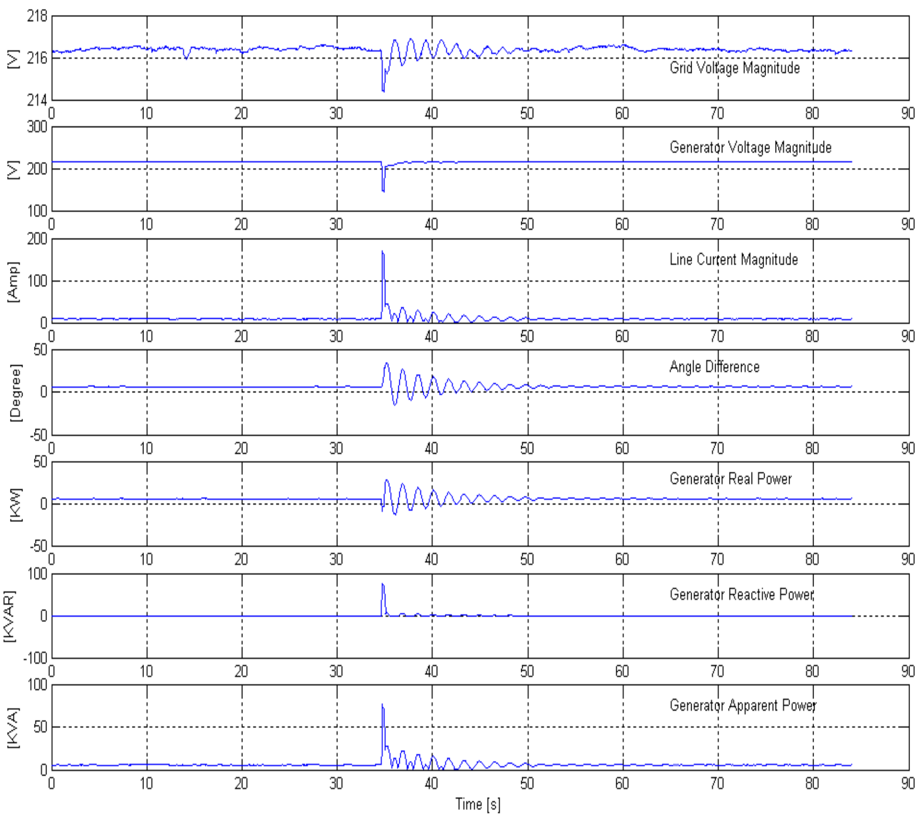


Figure 27: Measurements from a lightly loaded (7.5%) generator
Fault clearing time 300ms

Figure 27 shows grid voltage magnitude, generator voltage magnitude, line current magnitude, angle difference, generator real power, generator reactive power and generator apparent power. The generator rated power is 75 kVA. From the figure it is seen that the generator was running in no load condition. The duration of the fault was 300 ms. It is also seen that it is a well-damped oscillation. Figure 28 shows the power-angle diagram. When the fault was cleared at 27.4^0(δ1), the angle swings up to 33.6^0(δ2). As can be seen from Figure 28 there is enough area for the machine to decelerate.

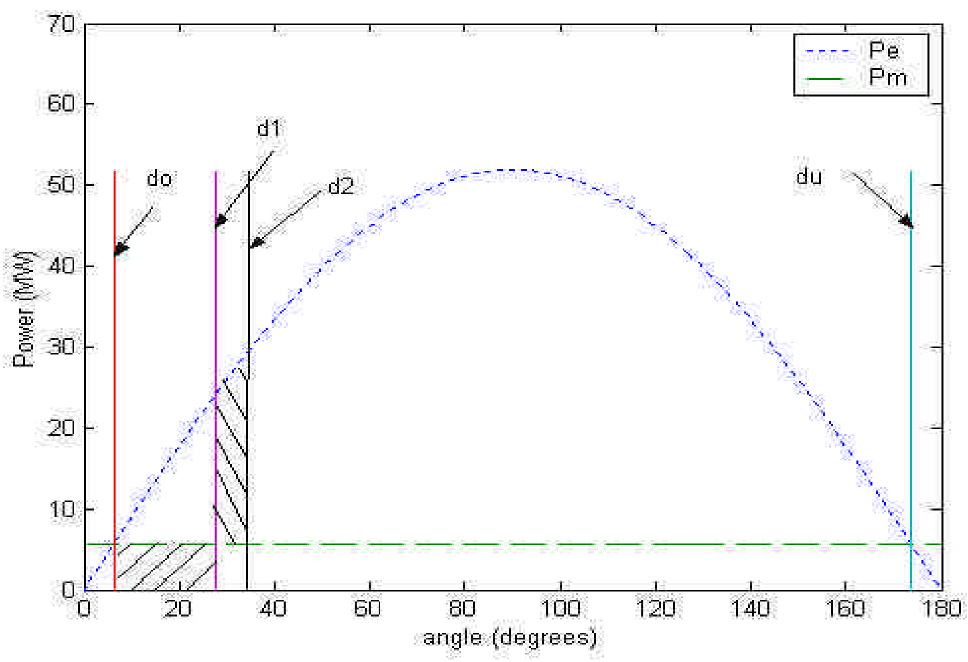


Figure 28: Power angle curve for lightly loaded (7.5%) generator

Fault clearing time 300ms

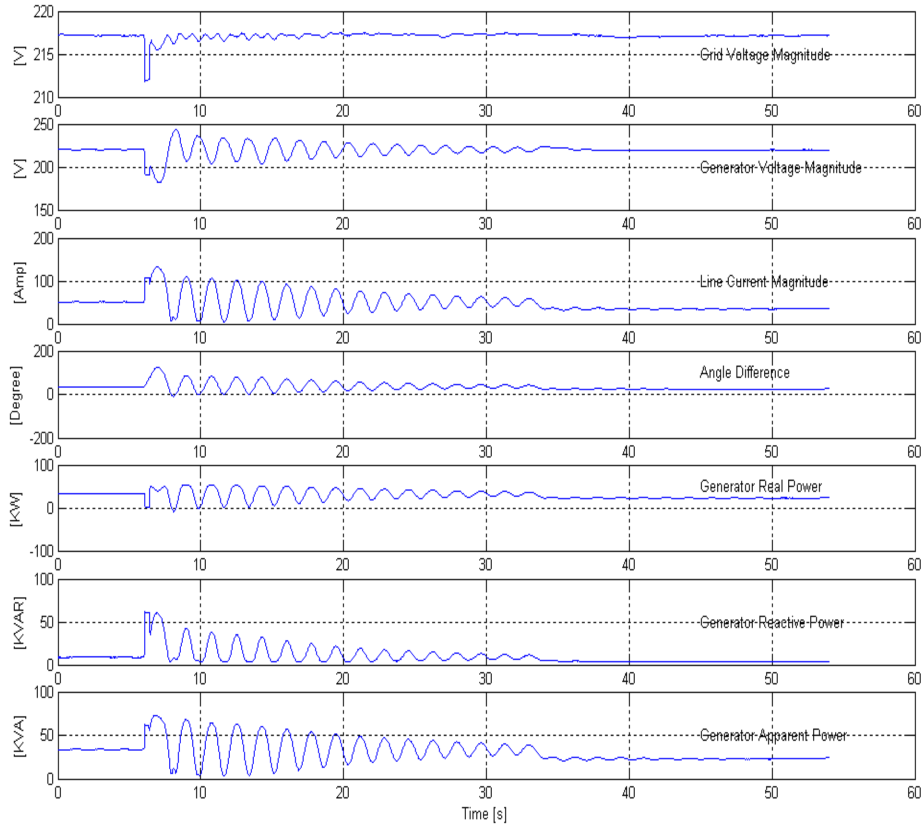


Figure 29: Measurement from a loaded (45%) generator

Fault clearing time 370ms

Figure 29 shows the measurements from the loaded (45%) generator. The generator was supplying 33 kW real power to the external net and supplying 9 kvar reactive power – as seen in the figure. After the fault is cleared, the angle swings up to 1230. For this operating point, the maximum allowed angle swing was 1440. For this set up both the generator power and the fault clearing time was higher than the previous set up. The angle swing was more in this case. The power angle curve is shown in Figure 30.

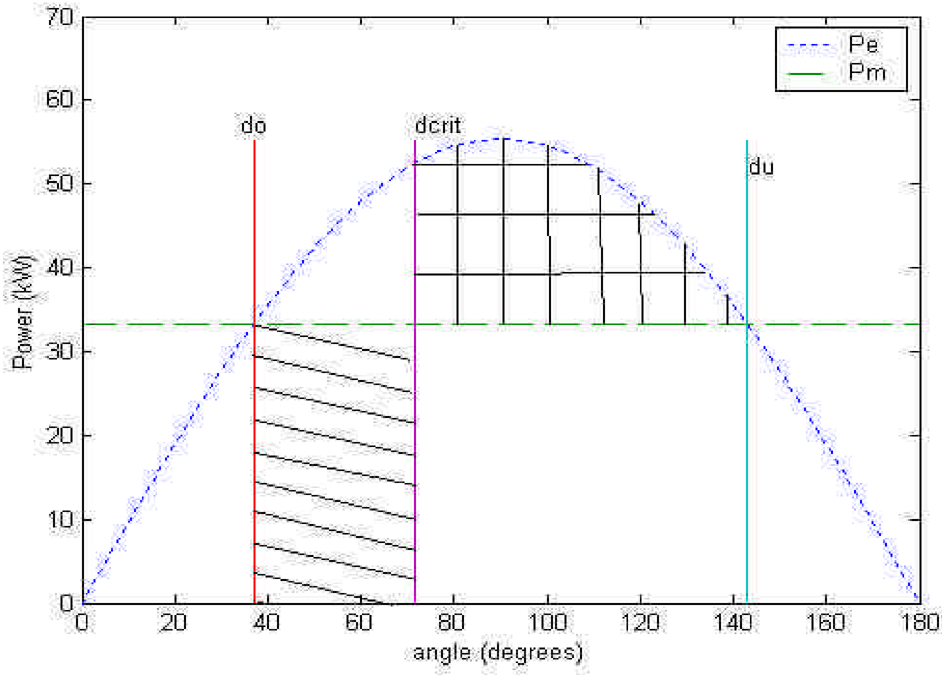


Figure 30: Power-angle curve with a loaded (45%) generator

Fault clearing time 370 ms

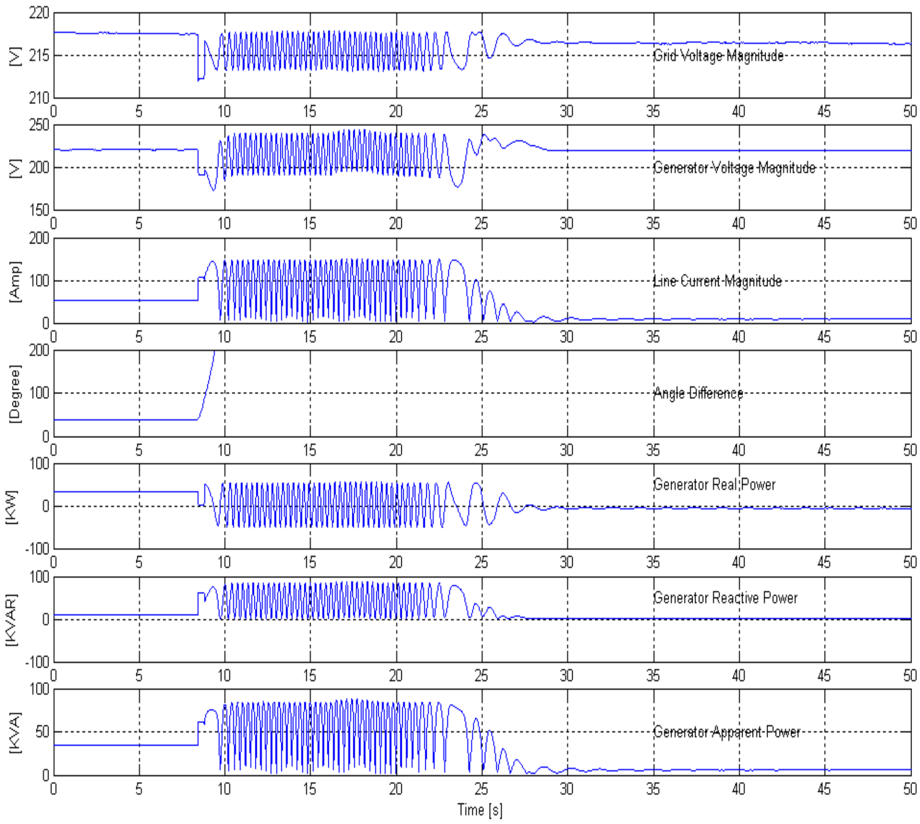


Figure 31: Measurement from a loaded (47%) generator

out of step oscillation

Finally, Figure 31 shows the reading from an out of step oscillation. In this set up the generator was loaded 47% of the rated load. To be able to get an out of step oscillation we applied a fault with long duration (400 ms). The fault clearing time was long enough to lose the synchronism (critical clearing time is 370 ms as mentioned earlier). As seen from the figure the machine was brought into stable condition after 15 seconds by adjusting the settings of the machine inertia limiter.

Figure 32 shows the power angle curve where the generator goes out of step. From the curve, one can see that the accelerating area (A1) is greater than the decelerating area (A2). So the generator looses synchronism. It is an example of first swing instability.

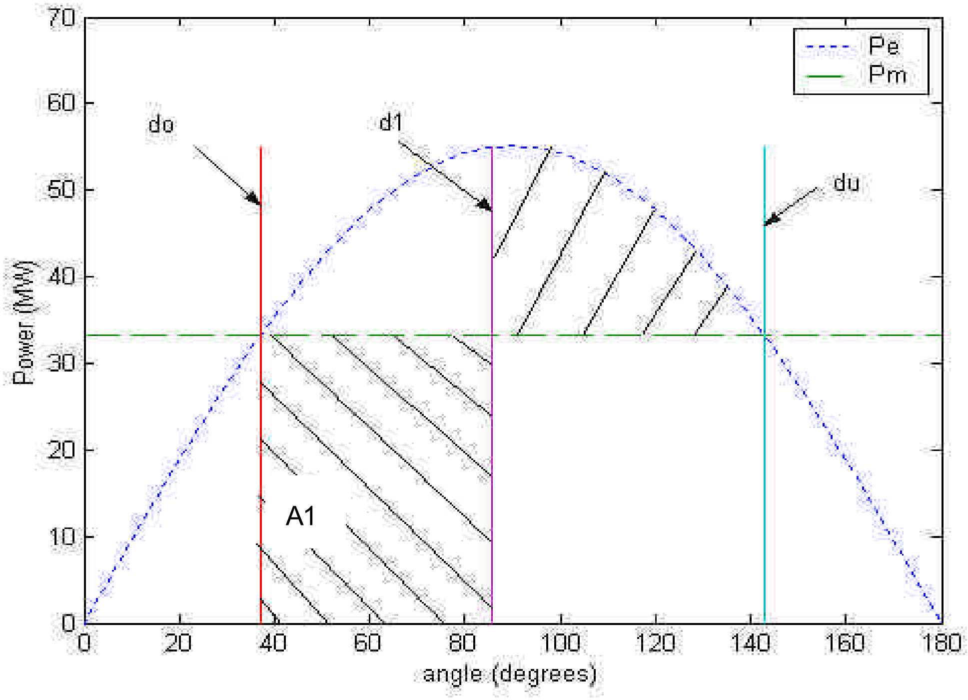


Figure 32: Power angle curve with a loaded (47%) generator

Out of step oscillation

7.2.6 Conclusions

From the lab measurements it has been found that the critical clearing angle is 370 ms. The generator was transferring 33.3 kW of real power. From the theoretical analysis of the lab model the critical clearing time has been found to be 308 ms. From the SIMPOW simulation the critical clearing time has been found to be 274 ms. There are differences among the results.

The reason for differences between the results from the theoretical analysis (critical clearing time 307ms) and those obtained from measurements (critical clearing time 370ms) could be because the power system model used for the theoretical analysis is an idealised one and it does not put into consideration all the impedances in the power system. And the model that has been built in SIMPOW was not the exact model of the lab.

7.3 Algorithms To Detect Power Oscillations

In this section different indicators to detect power oscillation have been considered. Among the indicators most suitable indicators have been investigated. Finally a comparison is drawn. In order to detect power oscillations in real time, indicators that can be obtained very quickly should be used and it is necessary to know what settings to use.

7.3.1 Indicators to Detect Power Oscillations:

The following indicators can be used to detect oscillations.

- Voltage phasors: angle difference between two nodes/buses compared to a threshold value.
- Angle difference signal fed into a low pass filter to see if there is any low frequency component (0.1 Hz to 10 Hz).
- Bus voltage angle compared with nominal value.
- Power oscillation: high and low thresholds penetrated by the active power within a predefined time period.
- Voltage oscillation: high and low thresholds penetrated by the voltage within a predefined time period.
- Power outside predefined threshold limit.
- Equal area criterion: Can be used to determine the maximum angle swing and maximum fault clearing time. It is suitable for a two-machine system or a one-machine-infinite bus system.

7.3.2 Tools to Accomplish Power Oscillation Detection:

Transient stability is characterized by a change in the phase angle between different systems. Phasor Measurement Units (PMU) make it possible to acquire wide area phasor data, so the voltage angle difference of buses will be used as indicator to detect low frequency power oscillations.

7.3.2.1 Comparing The Angle Difference With a Threshold Value (Algorithm 1):

When the angle difference exceeds a pre-defined threshold value instability is detected. In this work, ± 10% of the steady state voltage angle difference is taken as the threshold value. Figure 33 shows the block diagram of the method.

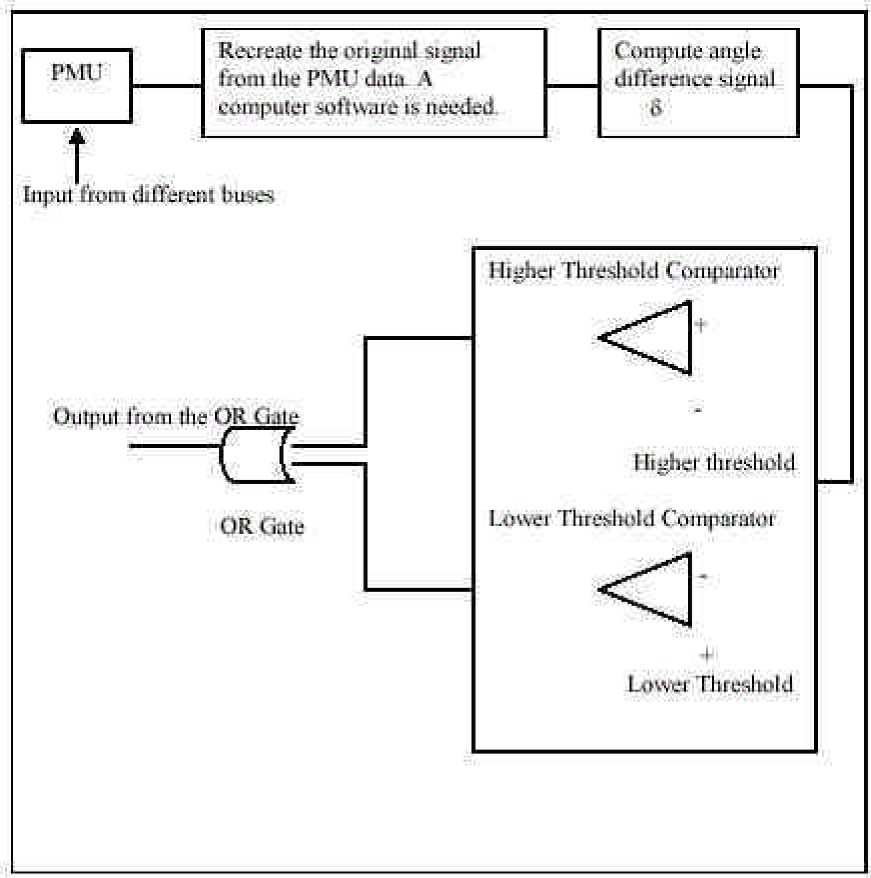


Figure 33: Block diagram of the detection algorithm 1

From the Figure 33 it is seen that the PMU signal should be processed before using it. From the PMU we are getting the voltage phasors of different buses. All these signals from different PMUs are precisely time synchronized. In our case, one PMU was used so we don't need to consider that. The data from the PMU was recorded in a PC. There should be a tool available (see "Future Work" chapter), which will calculate the phase angle and magnitude from the PMU data. When we have calculated the phasor angles of different buses we can get the angle difference between any two buses. The steady state value of the angle difference is dependent on the normal operating condition. We chose to set 10% of the nominal value as the dead zone. When the angle difference signal crosses the 110% or the 90% of the nominal value a detection signal is given. This comparison is done by two comparators comparing higher and lower threshold. If the output from any comparator is high, an oscillation is detected. The output of the two comparators is fed into an OR gate.

7.3.2.2 Filtering The Angle Difference Signal (Algorithm 2):

This algorithm is based on the filtering of the angle difference signal extracted from the PMU. This method is shown in Figure 34.

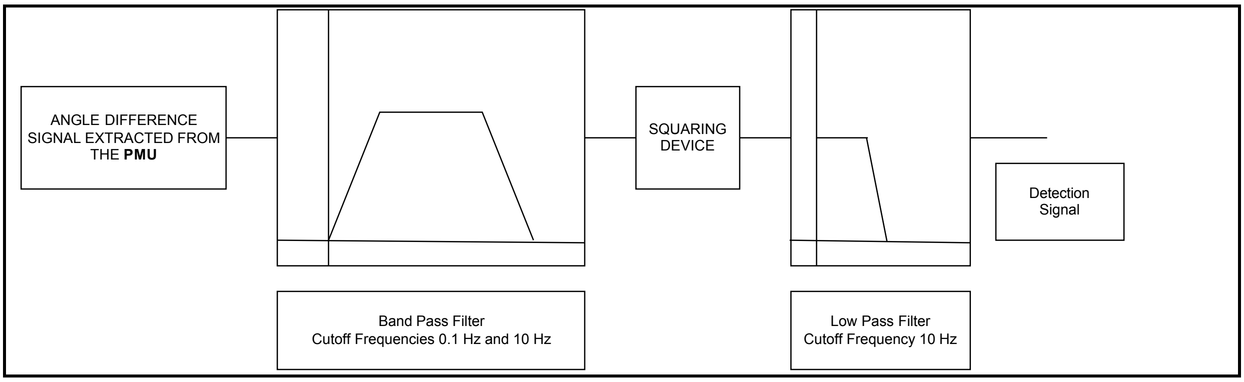


Figure 34: Block diagram of Algorithm 2

Here the angle difference signal is passed through a band pass filter whose cut off frequencies are 0.1 Hz and 10 Hz as we are interested in power oscillations in the range of 0.1 Hz to 10 Hz. The purpose of using the band pass filter is that if we want to divide the oscillation in different frequency group, then we can use different band pass filter in parallel. Another purpose is to get rid of very low frequency (less than 0.1 Hz) from the angle difference signal. The output from the band pass filter is squared to get rid of the zero crossing. This signal is then fed into a low pass filter whose cut off frequency is 10 Hz.

If any low frequency power oscillation is present, it will be indicated in the output of the low pass filter. We should set a threshold value for the low pass filter so when it exceeds the threshold value power oscillation is detected.

Now we will take one suitable power oscillation that we measured in the lab and investigate how well it works.

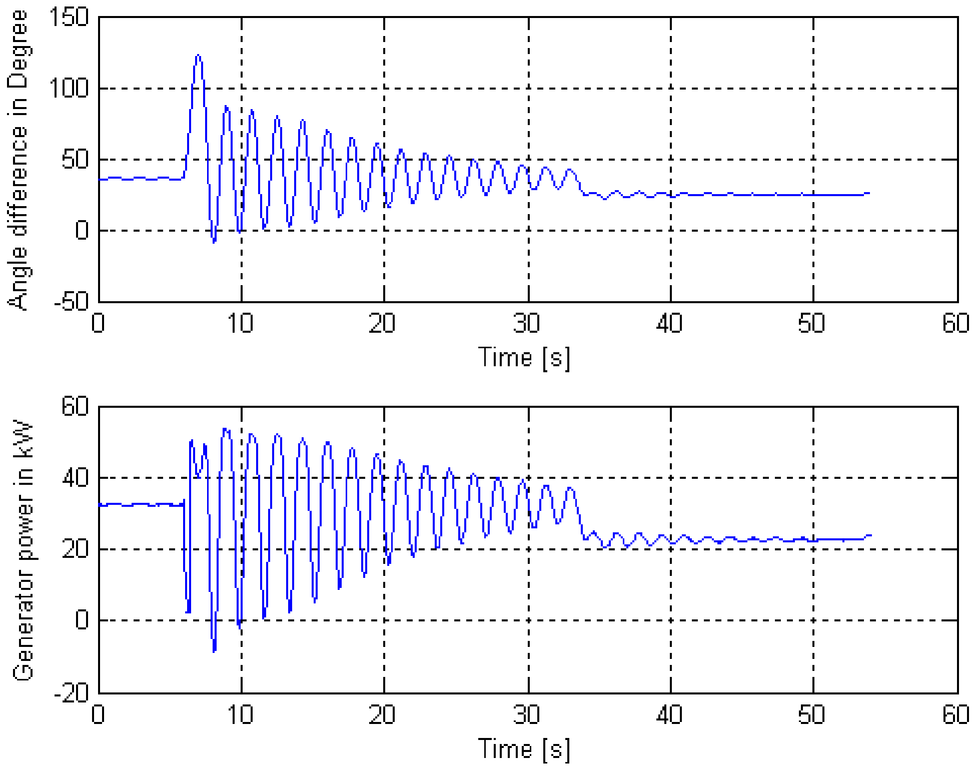


Figure 35: Angle difference and Generator power signal recorded in the lab.

Fault clearing time is 370 ms

Figure 35 shows a power oscillation that we recorded in the lab by a PMU. We initiated the dynamics of the machine by introducing a three phase to ground fault for 370ms. The generator was loaded 45% of its nominal power. This figure is presented in the previous section (Figure 29).

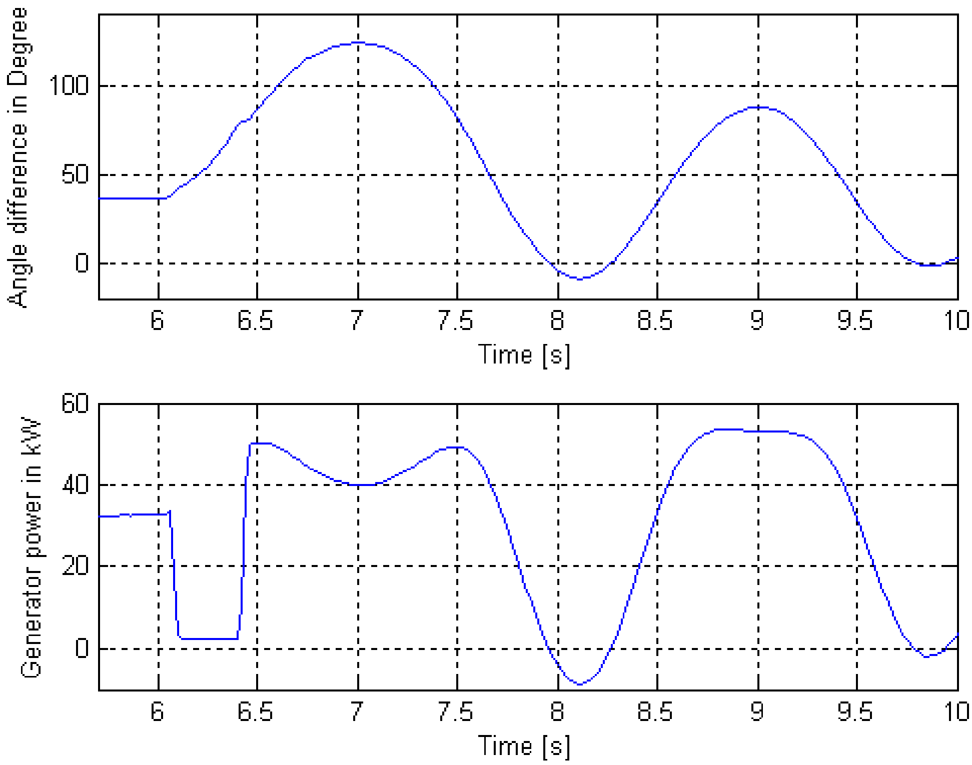


Figure 36: Zoomed version of Figure 35

Figure 36 shows the zoomed version of Figure 35. Here we can easily see the starting of the fault and the removal of the fault.

Now we will feed the angle difference signal into the band pass filter. The output is shown in Figure 37.

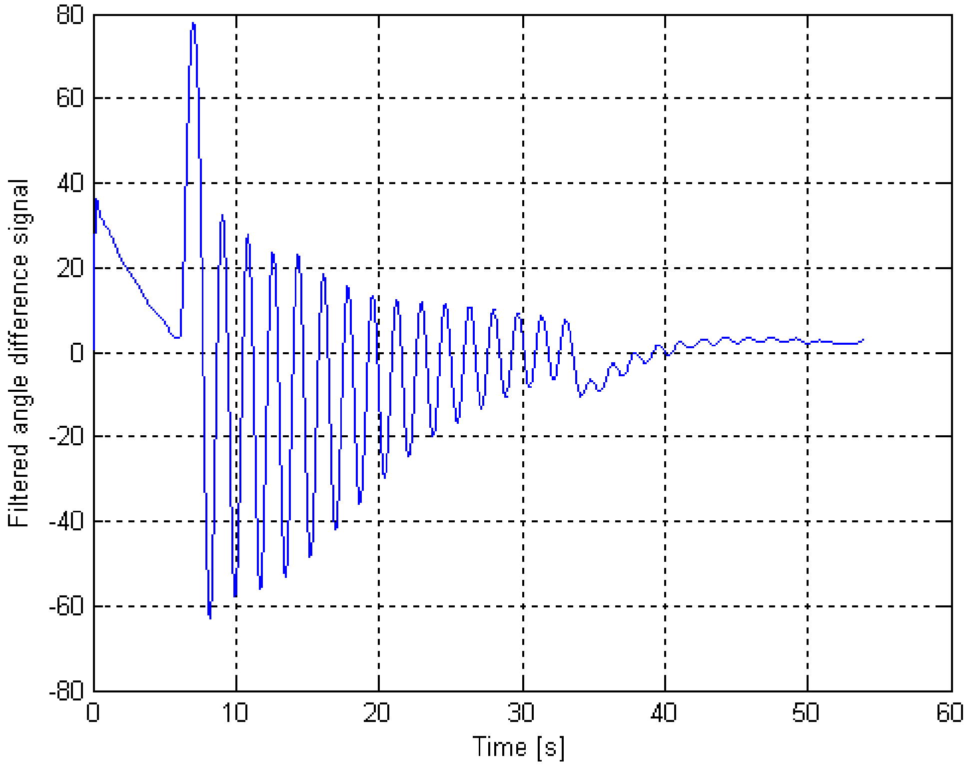


Figure 37: Output from the band pass filter

From Figure 37 we can easily see the transient at t=0 when the filter is connected. The DC value has been removed from the signal.

The output from this band pass filter is now squared to get rid of the negative part of the signal. It is shown in the next figure.

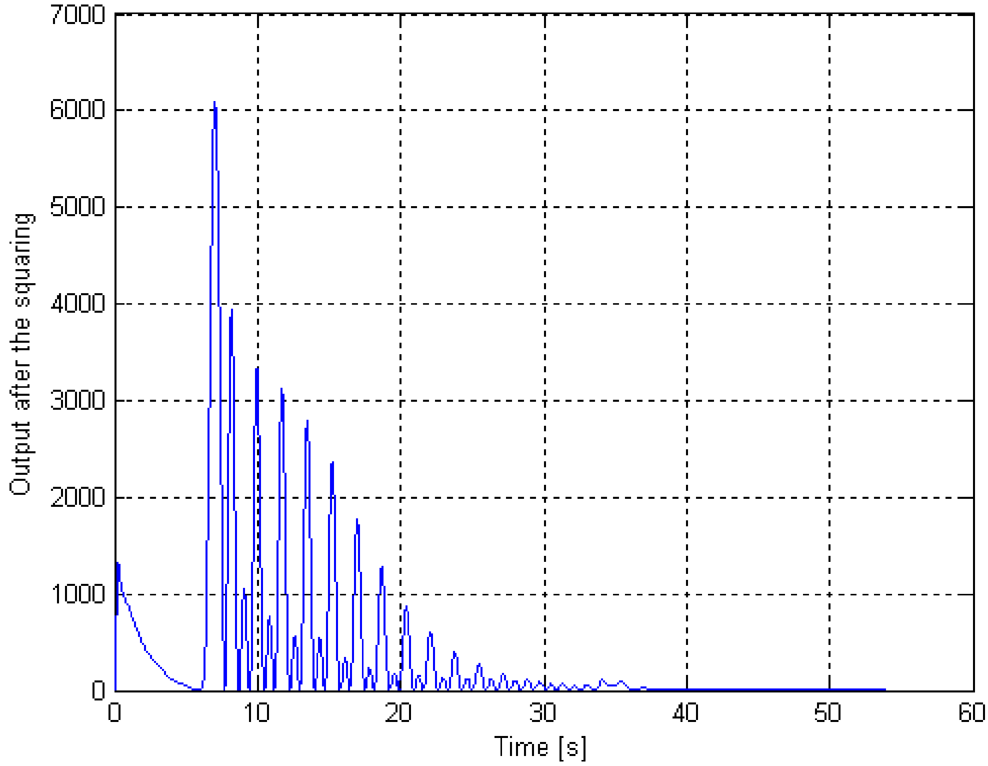


Figure 38: Output from the squaring block

From Figure 38 it is seen that negative part has been removed from the signal. Now this signal is passed through the low pass filter. The output is shown in Figure 39.

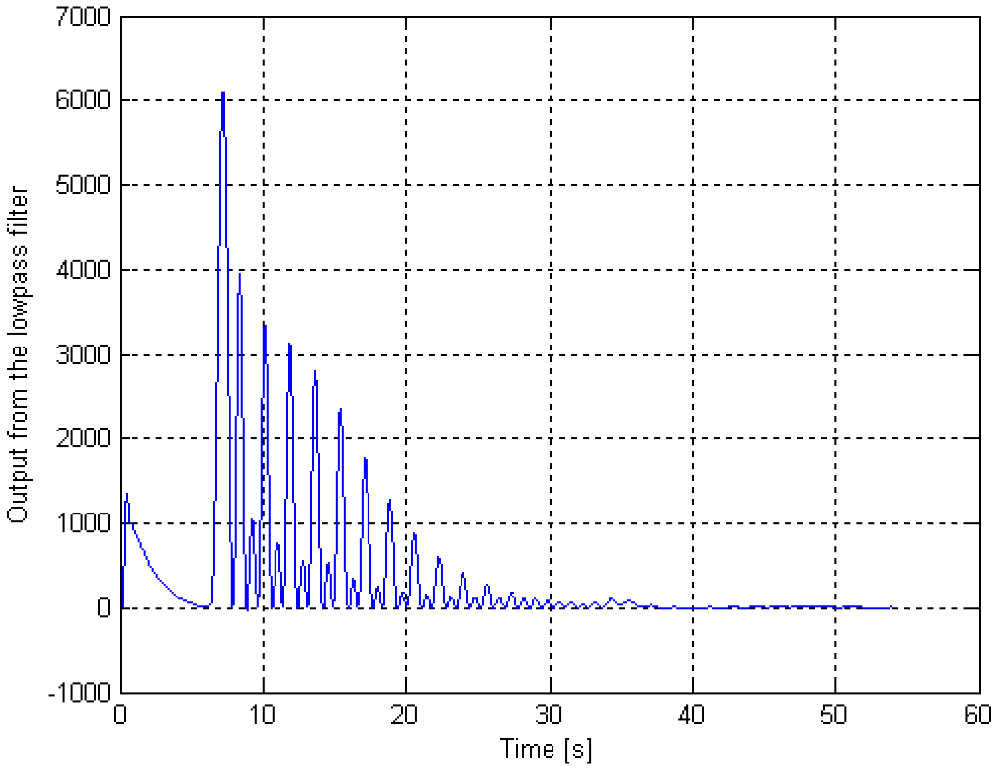


Figure 39: Output from the low pass filter

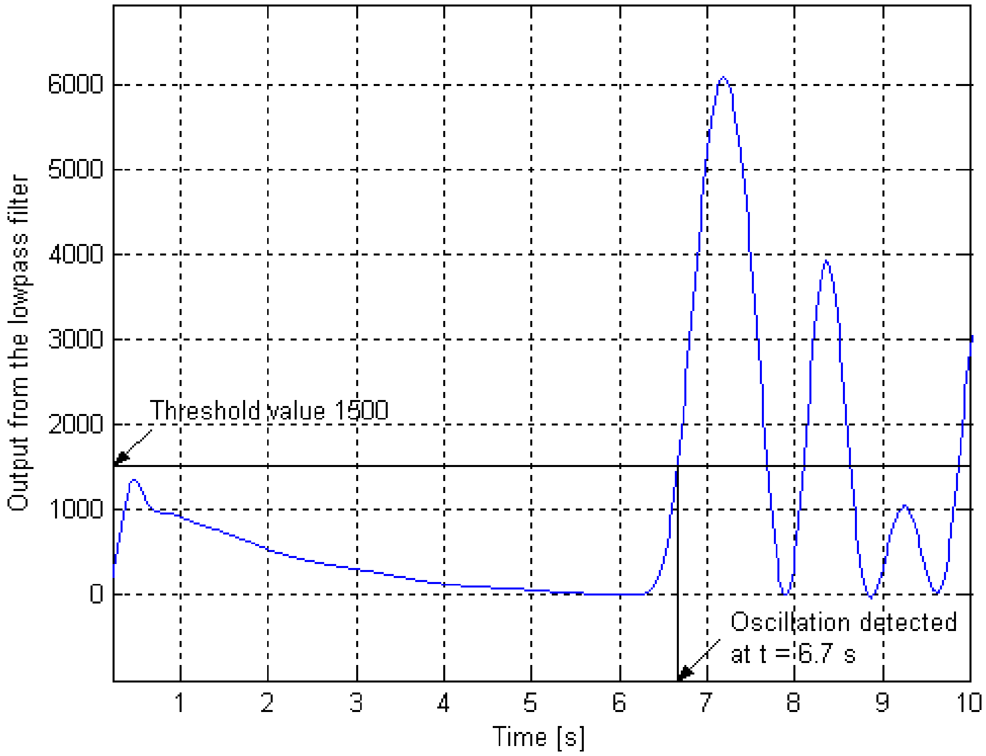


Figure 40: Plot of Figure 39 up to 10 s

Comparing this output signal with Figure 36 which was the original angle difference signal, we can see that for a threshold value of 1500, oscillation is detected at 6.7 s. From Figure 36 we can see that the fault is cleared at 6.42 s.

If we lower the threshold value of the filters the response will be even worse. Figure 41 shows the low pass filter output with cut off frequency of 5 Hz.

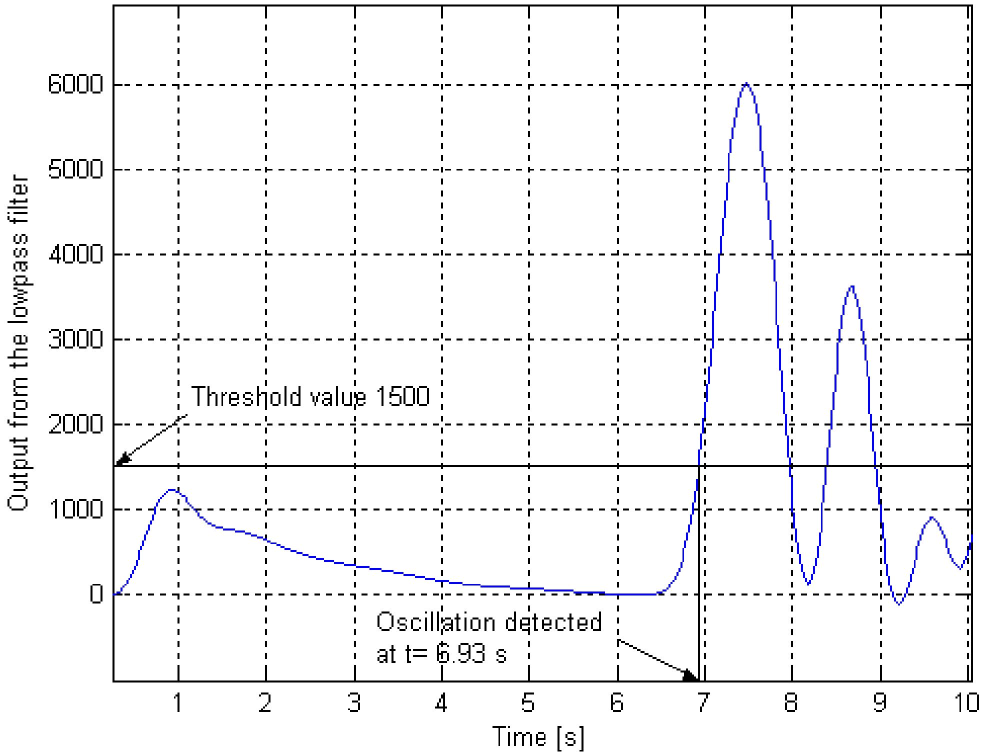


Figure 41: Output from the low pass filter with a lower cut off frequency (5 Hz)

From the figure it is seen that for the threshold of 1500, the oscillation is detected at 6.93 s.

So to make this method faster we have to increase the cut off frequencies of the filters. But then it will be sensitive to noise, which will make the detection erroneous.

7.3.3 Conclusion

The method of comparing the angle difference signal with a threshold value is faster. The method of filtering the angle difference signal is a slow process because of the filters. The drawback of this delay of the filter output could be solved by lag-lead compensation of the filter, which will make the scheme complicated. With the cut off frequency of 10 Hz the detection is acceptable though it is not instantaneous. When the oscillation is detected based on the algorithms presented above, an enable signal should be sent to the Thyristor-Controlled Braking Resistor (TCBR) unit. When the TCBR unit is enabled, then, based on the damping algorithm (described in Section 3.2.5) it will connect and disconnect the resistive load to damp out this oscillation.

7.4 Characterizing Power Oscillations

Following major disturbances such as transmission system faults, sudden load changes, loss of generating units or line switching, power oscillations may occur in a power system. These oscillations can be damped or un-damped. To characterize these oscillations we may consider their damped frequency of oscillation and time constant of the damped oscillation. When an oscillation is characterized by its frequency of oscillation, then one can have a rough idea about the cut off frequencies of the filters that has been used to detect the oscillation. Also the damping constant is needed to investigate different damping methods. In this thesis, the criterion of damping constant has been used to compare the damping with different load switching (see chapter-8). In this chapter the frequency of oscillation and the time constant of the power swing has been determined using ESPRIT algorithm [17]. Another algorithm called MUSIC has also been used to determine the frequency of oscillation to compare it with what we got by using ESPRIT method. For the characterization purpose all the data sequence has been used. Finally characterization is done by using varying data window to investigate the minimum length of the data window that is needed to characterize the oscillations for online purpose.

7.4.1 Tools Used to Determine Frequency and Time Constant

To determine the frequency and the damping constant we used the algorithms based on an eigen-decomposition of the correlation matrix of the time series signal such as MUSIC (MUltiple SIgnal Classification) and ESPRIT (Estimation of Signal Parameters via Rotational Invariance Techniques). From MUSIC method we can find the frequency spectrum of the signal and hence the frequency component that is present in the signal. From ESPRIT method we can get both the frequency of oscillation and the damping constant. More detailed theoretical analysis will be found in the reference [17].

7.4.1.1 MUSIC Algorithm

The multiple signal classification (MUSIC) method is a noise subspace frequency estimator [17]. The algorithm is briefly stated below:

Let us first consider the “weighted” spectral estimate

$$P(f) = \sum_{k=p+1}^{M} w_k \mid \boldsymbol{s}^H(f)\mathbf{v}_k \mid^2 \qquad (6.1)$$

where p is the number of sinusoidal components present in the signal, { $\mathbf{v}_k$, $k = p+1,\ldots\ldots\boldsymbol{M}$ } are the eigenvectors in the noise subspace, {w_k} are a set of positive weights, $\boldsymbol{H}$ denotes the conjugate transpose and $\mathbf{s}(f)$ is the complex sinusoidal vector

$$s(f) = [1, e^{j2\pi f}, e^{j4\pi f} \ldots\ldots\ldots e^{j2\pi(\boldsymbol{M}-1)f}] \qquad (6.2)$$

Note that at $f = f_i$, $\mathbf{s}(f_i) \equiv \mathbf{s}_i$, so that at any one of the p sinusoidal frequency components of the signal we have

$$P(f_i) = 0, \; i = 1,2\ldots,p \qquad (6.3)$$

Hence, the reciprocal of $P(f)$ is a sharply peaked function of frequency and provides a method for estimating the frequencies of the sinusoidal components.

Although theoretically $1/P(f)$ is infinite for $f = f_i$, in practice the estimation errors result in finite values for $1/P(f)$ at all frequencies.

7.4.1.2 ESPRIT Algorithm

ESPRIT (estimation of signal parameters via rotational invariance techniques) is another method for estimating frequencies of a sum of sinusoids by use of an eigen-decomposition approach [17]. ESPRIT exploits an underlying rotational invariance of signal subspaces spanned by two temporally displaced data vectors.

The steps for the methods are as follows:

2. From the data, compute the autocorrelation values $r_{yy}(m)$, m = 1,2,…..,M and from the matrices R_{yy} and R_{yz} corresponding to estimates of Γ_{yy} and Γ_{yz}.
3. Compute the eigenvalues of R_{yy}. For M>p, the minimum eigenvalue is an estimate of $\boldsymbol{\sigma}_w^2$.
4. Compute $C_{yy} = R_{yy} - \boldsymbol{\sigma}_w^2 I$ and $C_{yz} = R_{yz} - \boldsymbol{\sigma}_w^2 Q$, where Q is defined as

$$\Gamma_w = \sigma_w^2 \begin{bmatrix} 000......00 \\ 100......00 \\ 010......00 \\ .... \\ .... \\ 000......10 \end{bmatrix} \equiv \sigma_w^2 \mathbf{Q} \quad ....(6.4)$$

5. Compute the generalized eigenvalues of the matrix pair $\{C_{yy}, C_{yz}\}$. The *p* generalized eigenvalues of these matrices that lie on (or near) the unit circle determine the (estimate) elements of Φ and hence the sinusoide frequencies. The remaining M-*p* eigenvalues will lie at (or near) the origin. (Φ is a diagonal $p \times p$ matrix consisting of the relative phase between adjacent time samples of each of the complex sinusoids and is called a rotation operator).

7.4.2 Theoretically Constructed Signal:

In order to test the algorithms the following fictive signal was generated [20].

The equation of the signal is:

$$y(t) = \frac{1}{2}\cos(2\pi 4)e^{-0.4t} + \sin(2\pi 0.6)e^{-0.6t} + 2\sin(2\pi 0.8)e^{-0.3t} + 0.3\sin(2\pi 10)e^{-0.5t} \quad (6.5)$$

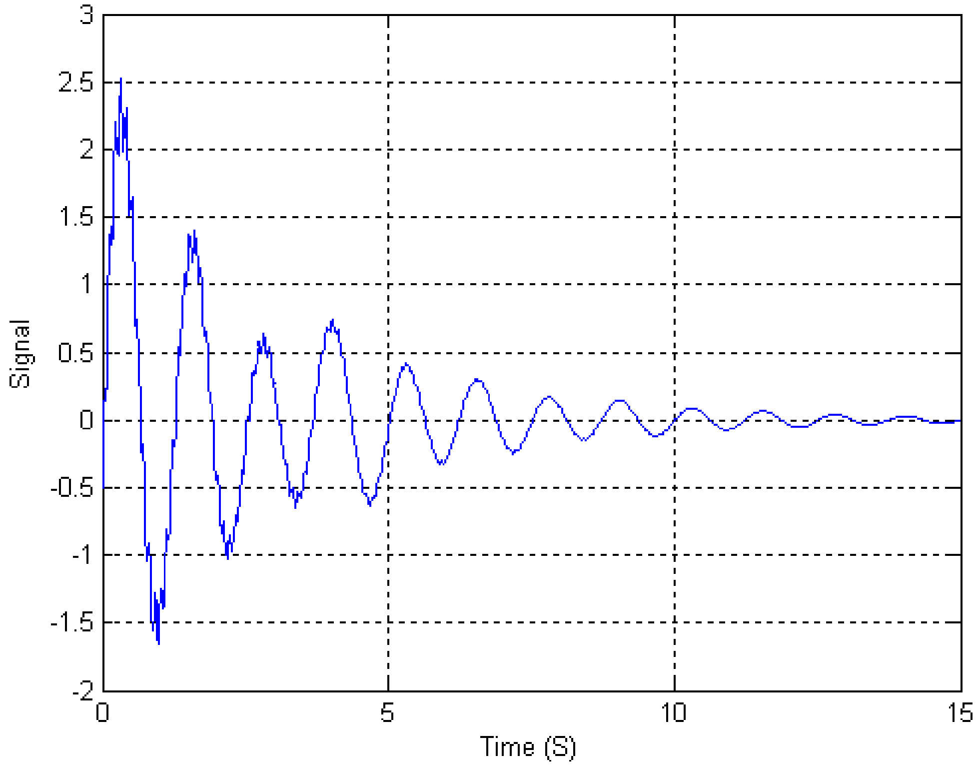


Figure 42: An example of a damped power oscillation

Figure 42 shows the graph of equation (6.5). In the figure we can now identify especially the 0.8 Hz component with a damping constant of 0.4.

We can test our tool on this signal to determine the frequencies and time constants.

When we applied the ESPRIT algorithm on this signal we get exactly the same frequencies and time constants.

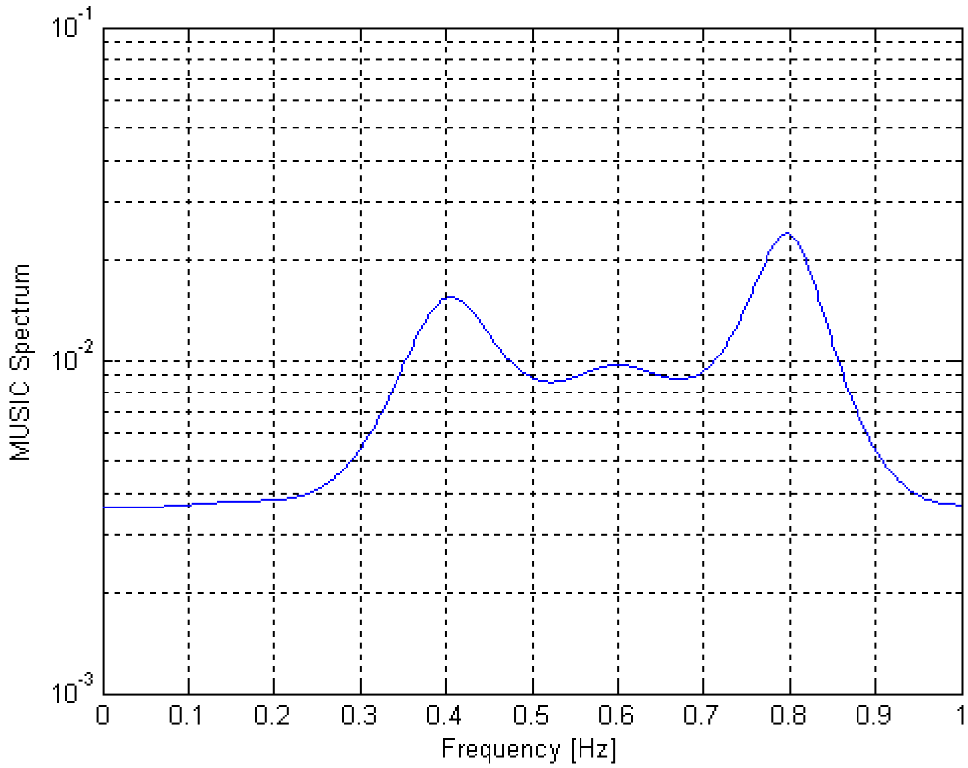


Figure 43: MUSIC spectrum of the signal

In Figure 43 the result found using the MUSIC algorithm is presented. Figure 43 clearly shows three frequencies within the frequency range of 0 to 1 Hz.

Now we can try to find the frequency and time constant of a real power oscillation by using this tool.

7.4.3 Experimental Results

In the power system lab of our department we carried out some short circuit tests. It included three-phase to ground faults with different fault duration. To record the data we use ABB's RES 521 Phasor Measurement Unit which stores the voltages of different nodes in complex form. In the model network of our lab we have a generator connected to the grid through a long transmission line. We measured the voltages of the two buses and the line current. We short circuited the line in the middle of it. These lab measurements have already been presented in Section 3.2.2.5.

Now we will take a few measurements and try to characterize them.

7.4.3.1 Experimentally Generated Oscillations

Measurement 1:

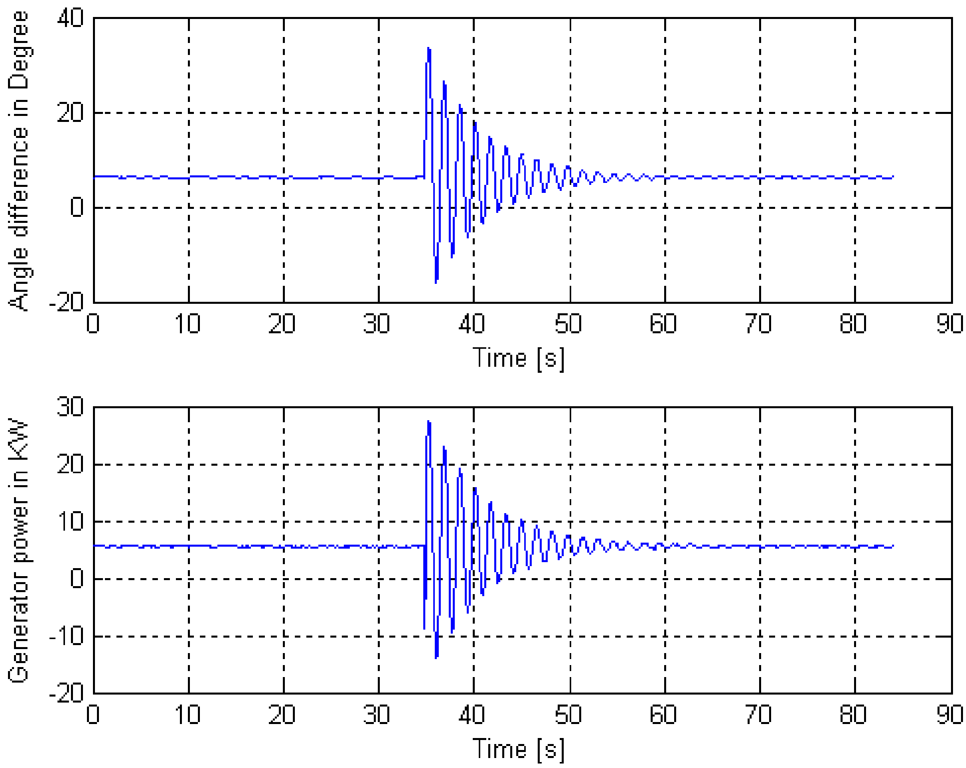


Figure 44: Angle difference and power measured

Figure 44 shows the angle difference of the two buses and the corresponding power swing. It is seen from the figure that it is a well-damped oscillation.

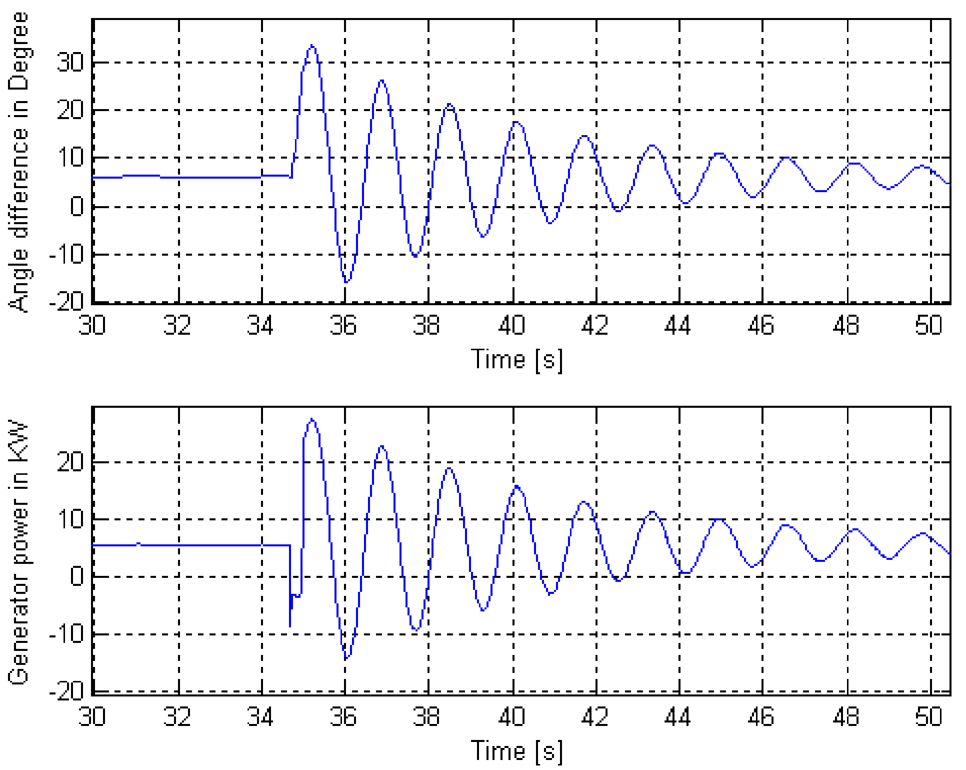


Figure 45: Zoomed version of Figure 44

Figure 45 shows a zoomed version of Figure 44. The fault clearing time was 300 ms. The generating unit in the lab was supplying a moderate amount of power. The angle swing is 27.45^0 from the operating point. It is interesting to note the power level during fault. The power-angle relation is also visible from the curves. The rotor angle increases linearly during the fault and after the fault has cleared it changes according to the power angle curve.

Measurement 2

Figure 46 shows another lab measurement. Here the fault clearing time was 500 ms. Here the angle swings to 44.6^0 from the operating point during the fault. Figure 47 shows the zoomed version of Figure 46 where we can clearly identify the fault removal.

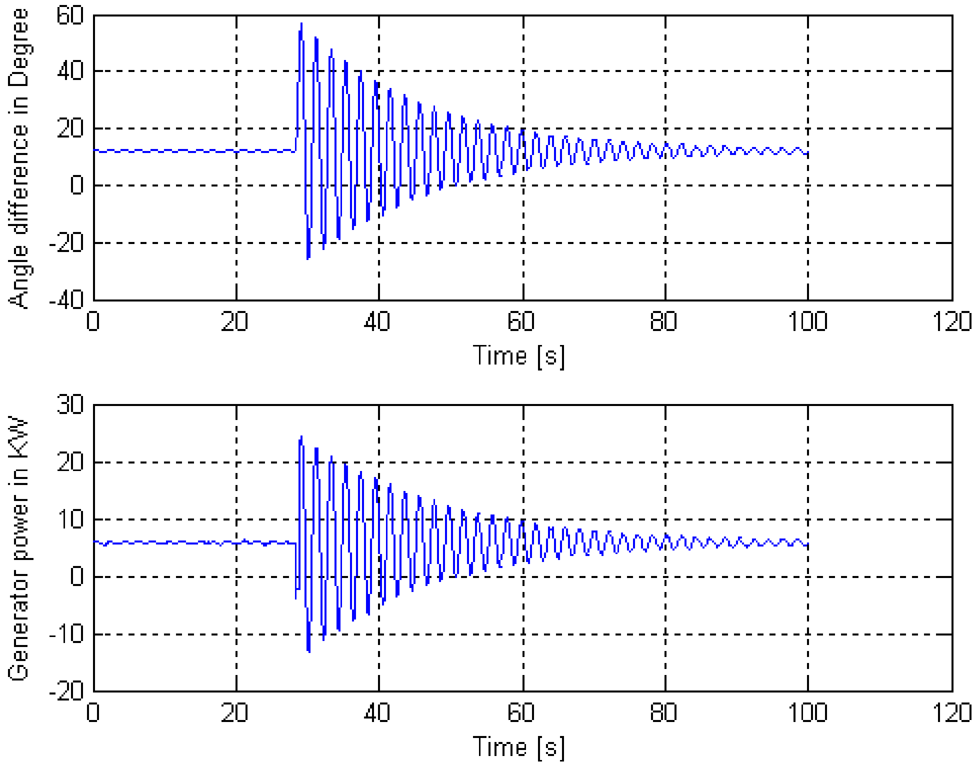


Figure 46: Angle difference and power measured

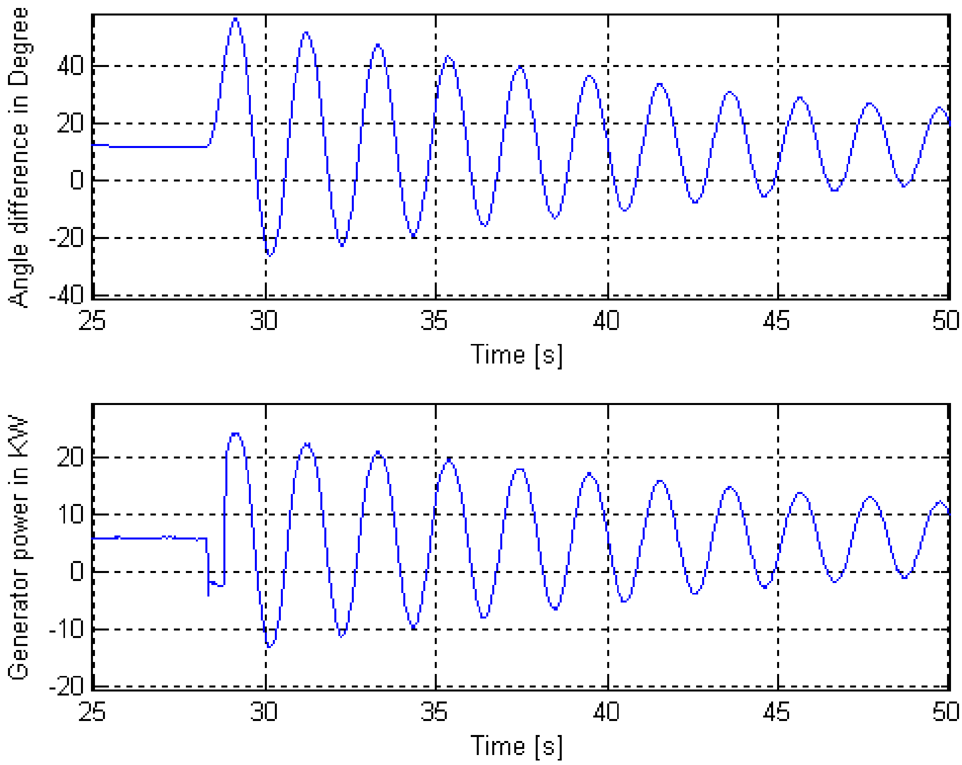


Figure 47: Zoom version of Figure 46

7.4.3.2 Characterizing the Measured Oscillations

Now we will try to characterize the oscillations presented above. In the characterization process we used the whole data sequence. First we will take Measurement 1. We will characterise both generator power signal and angle difference signal. We will use ESPRIT method in this case. Table 6.1 summarizes the results:

Table 6.1 Results from ESPRIT method.

Signal to be Characterized	**Frequency of Oscillation**	**Damping Constant**
Generator Power Swing	0.62 Hz	0.167
Angle Difference Signal	0.62 Hz	0.168

Now we will use the MUSIC algorithm. First we will find the frequency of the generator power swing and then the angle difference signal. Figure 48 shows the MUSIC spectrum of generator power swing and Figure 49 shows that of angle difference signal.

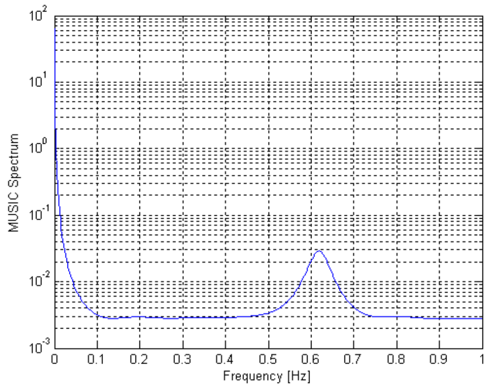


Figure 48: MUSIC spectrum of Power swing (Measurement 1)

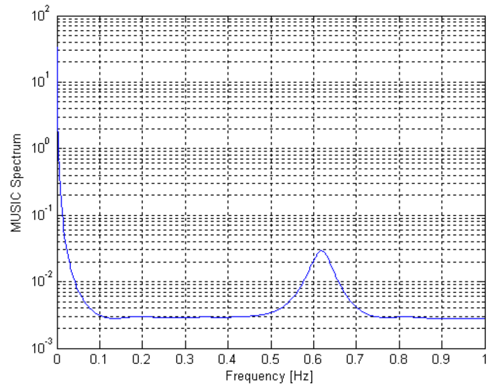


Figure 49: MUSIC spectrum of Angle difference signal (Measurement 1)

From both Figure 48 and Figure 49 the frequency is found to be 0.62 Hz.

Now we will take Measurement 2 and characterize in the same way. Table 6.2 summarizes the results from Measurement 2.

Table 6.2. Frequency and damping constant using the ESPRIT method.

Signal to be Characterized	**Frequency of Oscillation**	**Damping Constant**
Generator Power Swing	0.491Hz	0.05
Angle Difference Signal	0.491Hz	0.051

Now we will characterize the oscillation by MUSIC algorithm. Figure 50 shows the spectrum of power swing and Figure 51 shows that of angle difference.

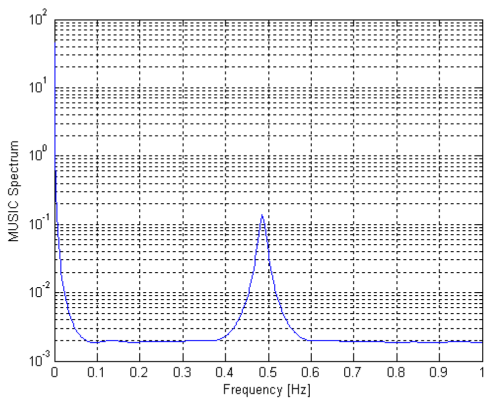


Figure 50: MUSIC spectrum of Power swing (Measurement 2)

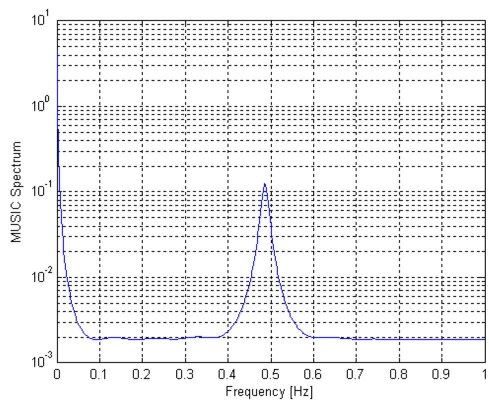


Figure 51: MUSIC spectrum of Angle difference signal (Measurement 2)

From Figure 50 the frequency is 0.49 Hz and from Figure 51 the frequency is 0.49 Hz.

From the above analysis we can say that we can characterize the power oscillation by angle difference signal as well.

7.4.3.3 Characterization of Power Oscillation With Varying Data Window

Our intention was to characterize the power oscillation based on online analysis. For this purpose we should use a data window of a certain length. Now we will perform the analysis with different data window length (0.5s, 1s, 2s, 4s, 6s, 8s, 10s) based on ESPRIT algorithm. First of all we will take “Measurement 1”.

Table 6.3. Frequency and damping constant of power oscillation with varying data window (Mesurement 1).

Using all the measured data	Length of data window	0.5 s	1 s	2 s	4 s	6 s	8 s	10 s
Freq: 0.62	Frequency	Freq: 0.49	Freq: 0.65	Freq: 0.62	Freq: 0.62	Freq: 0.62	Freq: 0.62	Freq: 0.62
Damp: 0.167	Damping constant	Damp: 0.357	Damp: 0.131	Damp: 0.187	Damp: 0.178	Damp: 0.172	Damp: 0.169	Damp: 0.167

From Table 6.3 it is clear that a 4 s data window length gives a value of frequency and damping constant quite close to the actual value. As the frequency is around 0.6 Hz we need at least 2 s data window to estimate the frequency properly. But to get a good estimate of damping constant we need two cycles of data i.e. 4 s data window. From the table above we see that we have a good estimate of frequency at 2 s data window and a good estimate of the damping constant at 4 s data window.

Now we will do the same thing with “Measurement 2” – an oscillation that we got with 500 ms fault clearing time. Table 6.4 summarizes the results.

Table 6.4. . Frequency and damping constant of power oscillation with varying data window (Measurement 2).

Using all the measured data	Length of data window	0.5 s	1 s	2 s
Freq: 0.49	Frequency	Freq: 0.62	Freq: 0.61	Freq: 0.35

Damp: 0.05	Damping constant	Damp: 0.346	Damp: -0.594	Damp: -0.331

4 s	6 s	8 s	10 s
Freq: 0.48	Freq: 0.48	Freq: 0.48	Freq: 0.48
Damp: 0.068	Damp: 0.051	Damp: 0.056	Damp: 0.05

Here also a data window length of 4 s gives good estimation of frequency. A data window length of 6 s gives exact value of frequency and damping constant.

7.4.4 Conclusion

From the above analysis it is seen that power oscillation can also be characterized by angle difference signal that we can get from the PMU. The ESPRIT method has been used successfully for characterizing power oscillations. As the frequency of oscillation is around 0.5 Hz, it is expected that we need at least 4 s data window (2 complete cycle) to characterize the signal. From the above analysis it is sees that data window length of 4 s is needed for an on line characterization of power oscillation.

7.5 Damping of Power Oscillation by Thyristor-Controlled Braking Resistor (TCBR)

In this chapter the role of braking resistor has been discussed with the help of power-angle-diagram [18]. The idea of connecting braking resistor based on speed deviation signal has also been discussed here [19], based on which the simulation has been done in Section 3.2.6.

7.5.1 Basic Concept

The Thyristor Controlled Braking Resistor (TCBR), Figure 52 is a shunt connected thyristor – switched resistor (usually linear resistor). Each leg of a three phase TCBR is controlled on or off, half-cycle by half-cycle to aid stabilization of power system transients and subsynchronous oscillations by reducing the net available energy for acceleration and hence lower speed deviation of the generating unit during a disturbance. TCBR is also referred to as Dynamic Brake [18].

TCBR can be utilized for variety of functions:

1. Prevent transient instability during the first power system swing cycle, by immediately taking away the power that would otherwise be used in accelerating the generator.
2. Enhance damping to prevent dynamic instability involving low frequency oscillations between interconnected ac systems.
3. Damp subsynchronous resonance (SSR) resulting from series capacitor

compensation, etc.

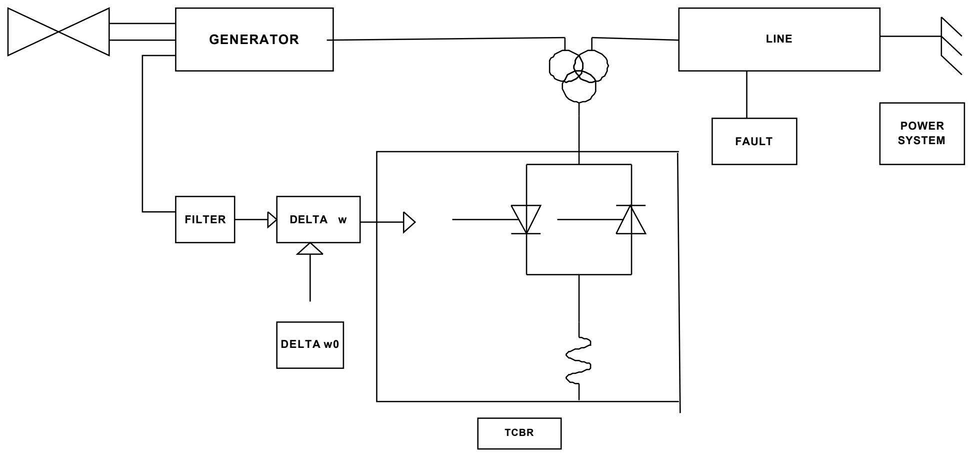


Figure 52: One-line diagram of Thyristor-Controlled Braking Registor

All these functions in turn enable maximizing the value of transmission and generation assets. Given appropriate rating and intelligent control it can be designed to simultaneously undertake multiple functions noted above. A TCBR can often be a relatively cheap and simple, highly reliable FACT controller. The best location for a TCBR is near a generator that would need braking during transient instability conditions. The three phase legs may be connected in wye or delta, although delta connection would be more convenient since the ground path would not be needed. A large bank may be divided into two or more banks to achieve partial redundancy.

7.5.2 Role of TCBR In Terms of Equal Area Criterion

Figure 53(a) shows a power angle diagram for a simple system of Figure 52, in order to explain the role of TCBR in terms of equal area criteria for transient stability [Ref 7.2]. Pe1 is the electric power from the generator requiring a rotor-stator angle (power angle) $\delta 1$. At steady state, the mechanical input power Pm is equal to the electrical power, neglecting losses. When a fault occurs on a line, the electrical output is greatly decreased during the fault and may even reach zero for a fault close to the generator. Assuming that the mechanical power remains constant during the first transient swing, the electric power during the fault drops to Pe2, and the excess mechanical power Pm – Pe2 (shaded area) begins to accelerate the turbine generator. As the machine speed increases, the rotor-stator angle also increases. The angle increases to $\delta 2$ at the instant of fault clearing. Following the fault clearing, including the removal of the faulted line, the electric power is restored through alternate transmission paths. The power angle follows a new lower curve of Pe3, determined by the new value of E1E2/X, which is lower because of increased impedance between the generator and the remote system.

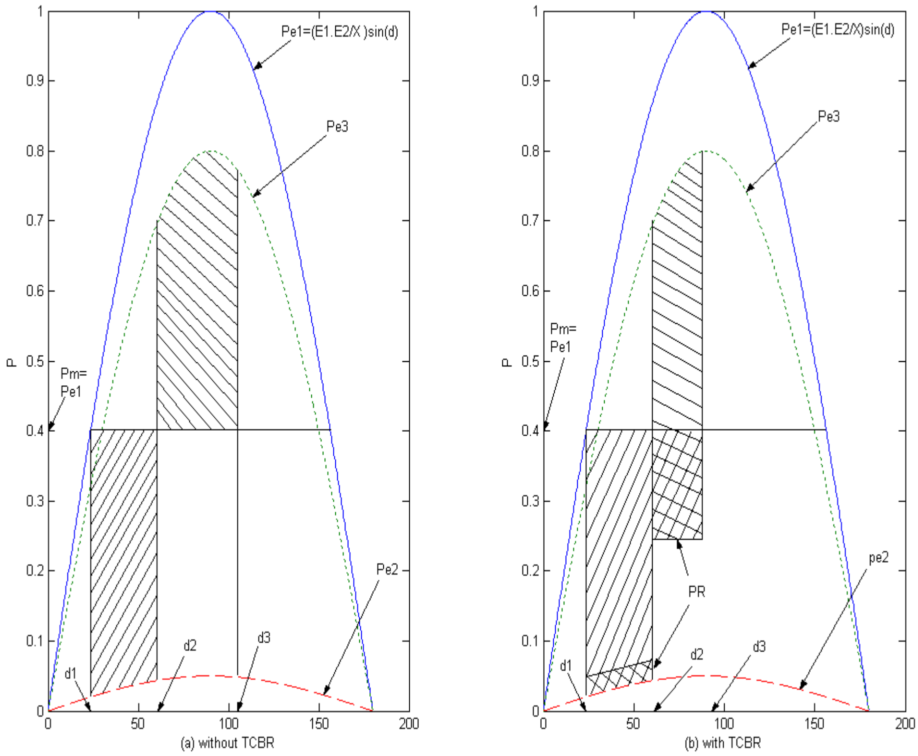


Figure 53: Power angle diagram

(a) without TCBR, (b) with TCBR

Following the fault clearing, the electrical power exceeds the mechanical power because of the increase in the power angle. As a consequence of the excess electrical power, the generator starts to decelerate. When the post fault shaded area of the excess electrical energy equals the pre-fault shaded area of excess mechanical energy, the mechanical angle reaches its transient maximum $\delta 3$ and its speed equals the synchronous speed. The rotor then starts to turn back, decelerate and the angle decreases. If the excess electrical energy following the fault did not equal the excess mechanical energy, it would be too late and the angle would take off (continue to increase). The generator connection to the system would be disconnected by the protective means in order to save the generator and the system from high overcurrent. This also means that an adequate margin has to be available for operation during the steady state operation, so that the generator does not fall out of step as a result of the most severe fault.

The TCBR can help to increase this margin, or conversely help in increasing the stability limit. Figure 53(b) shows the effect of the resistor in terms of the power angle curve. During the fault the resistor power, though small, helps to decrease the accelerating power and after the fault clearing it is much more effective in increasing the decelerating power. The maximum angle $\delta 3$ is now smaller than the case without the TCBR. Extra margin available depends on the power rating of the TCBR and it is not hard to imagine that this may be the most cost-effective and simplest way to enhance transient stability, if it happens to be the limiting criteria for the generated power.

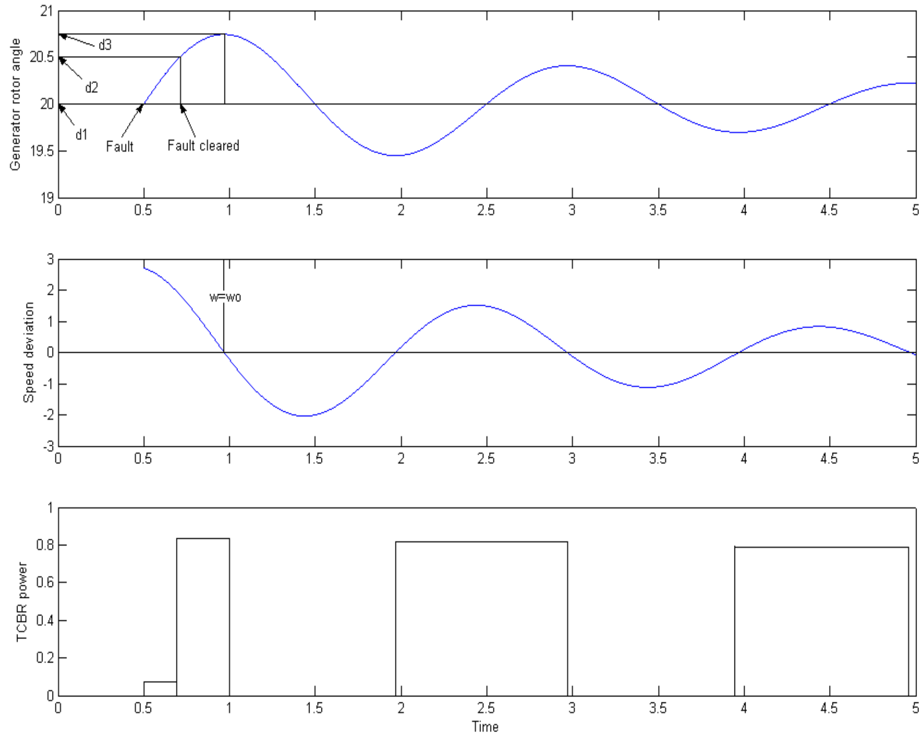


Figure 54: TCBR operation for damping
low frequency transients and dynamic instability

Figure 54 shows power swing waveforms in the time domain for a low frequency system swing, including power angle, speed deviation and resistor power. Speed deviation $\Delta\omega = \omega - \omega_0$, in which ω is the actual generator speed and ω_0 is the steady-state generator speed) is the basic control parameter, as shown in a simple one-line diagram of the TCBR. The resistor is switched on when the filtered speed deviation $\Delta\omega$ is positive i.e. when the rotor is accelerating, and the TCBR is switched off when the speed deviation is negative i.e. when the rotor is decelerating. During the fault the resistor power would be small or zero depending on the terminal voltage during the fault. Once the fault is removed the voltage will increase and so will the resistor power.

7.5.3 Conclusion

The main idea to damp power oscillation by load switching is to add a resistive load to counteract power oscillations. When the rotor starts accelerating we have to add the resistive load to take away the accelerating energy. At the same time we can improve the damping of the system. From the PMU unit we can measure the angle in different parts of the system. From this measured angle we can find the rotor speed deviation. When this deviation is positive i.e. the rotor is accelerating, we have to connect the load. And when the deviation is negative i.e. rotor is decelerating we have to disconnect the load. The next chapter of this thesis contains the simulation of this damping algorithm where a resistive load is connected and disconnected based on the derivative of the angle difference signal [18].

7.6 Simulation of Damping Algorithm

In this section damping of power oscillation by load switching has been simulated. Here transient stability enhancement and damping enhancement by load switching has been investigated with different switched load (5% & 10% of base load).

7.6.1 The SIMPOW Model

The SIMPOW model we used for these simulations is a one generator connected to an infinite bus system, see Figure 55. The model is a three-phase 400 kV power system. The model consists of one synchronous generator equipped with an AVR (Automatic Voltage Regulator), one transformer on the generator side and three lines connected in series. The rated generator power is 1400 MVA. Each line is 150 km and has a reactance of 50.4 ohm per phase and a resistance of 4.17 ohm per phase. No PSS (Power System Stabilizer) was included in the model in order to achieve a good power oscillation.

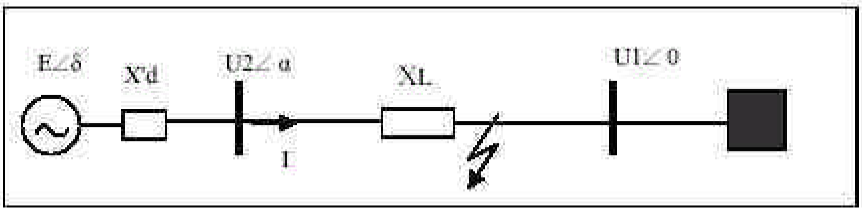


Figure 55: System for studying power oscillation

7.6.2 Simulation Results

To get a power oscillation we simulated a three phase to ground fault. We got a clear power oscillation. We can also see the angle swing which is in accordance with the power-angle relation. When the rotor of the generator accelerates – that happens when the mechanical power input to the turbine-generator is higher than the electrical power delivered which is the case when a fault is occurred – the rotor position starts to increase from its steady value. After the fault clearing, the rotor angle reaches to a new increased value. At this point the electrical power transferred is higher than the mechanical input power and the rotor speed is higher than the synchronous speed. As the electrical power exceeds the mechanical power because of the increase in the power angle, the generator starts to decelerate. When the post fault excess electrical energy equals the pre fault excess mechanical energy the mechanical angle reaches its transient maximum and its speed equals the synchronous speed. The rotor then starts to turn back, decelerates and the angle decreases. If the excess electrical energy following the fault did not equal the excess mechanical energy during fault, it would be too late, the angle would keep increasing and the machine would loose synchronism.

If we some how can manage to increase the delivered power during and immediately after the fault, then we can reduce the rotor angle swing and thereby can avoid out of step oscillation.

In the simulation we added a resistive load of 5% and 10% of the transferred power in first 1 swing and 2 swings. We connected the load as long as the change in angle difference is positive.

7.6.3 Transient Stability Enhancement by Load Switching

Load switching is a probably the most powerful tool to counteract imminent transient angle instability. Such load switching can either be realized by specific braking resistors or by – more or less – addressable resistive load in the power system. For the following study braking resistors have been used for the case of simplicity.

7.6.3.1 150 ms Fault Clearing Time

We simulated a three phase to ground fault to get a power swing. The fault clearing time was 150 ms. The generator delivered 621 MW of real power before the fault occurred.

5% Load Switching

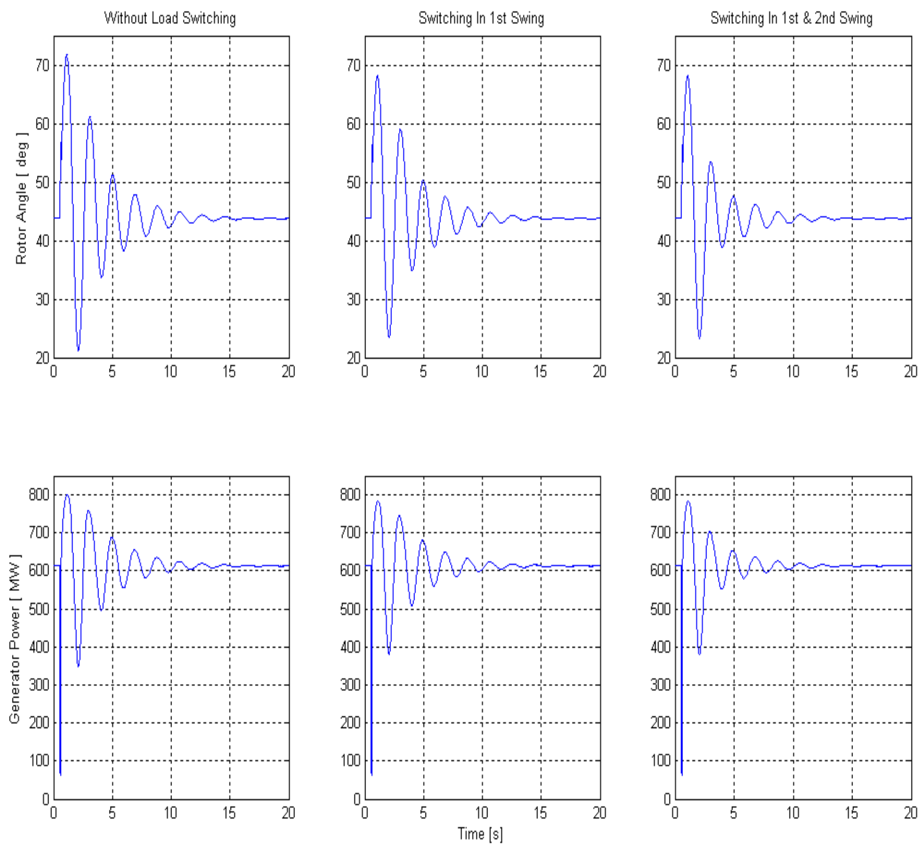


Figure 56: Increased transient stability margin (5% LS, 150ms)

by 5% load switching (switched load 30 MW). Fault clearing time 150 ms

Figure 56 shows the results of 5% load switching. It means that when the fault was cleared, we increased the power to 5% of the base load to absorb the accelerating energy. The braking resistor has been added in the generator end. Figure 57 shows the position of the braking resistor.

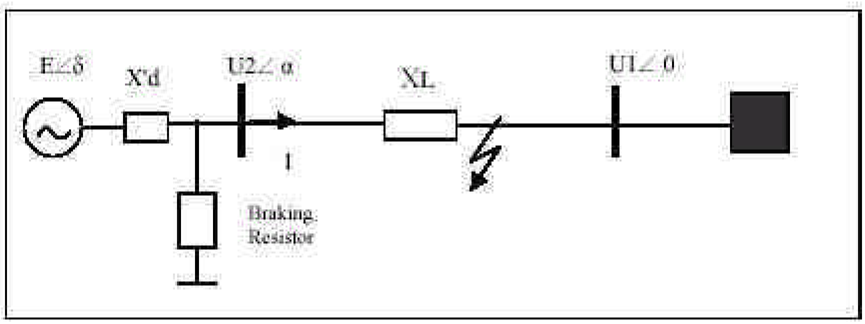


Figure 57: location of the braking resistor (SIMPOW model)

By doing this we changed the reactance to resistance ratio of the system. As a result the total damping of the system also changed. The frequency and the damping constant of the power oscillation are 0.53 Hz and 0.299 respectively. But when we used load switching in the first swing the frequency and damping became 0.52 Hz and 0.301. and when we used load switching in first two swings they became 0.52 Hz and 0.433 respectively. It is also seen that the stability margin was 64.5^0 but when we applied load switching in the first power swing it increases to 68^0 . Table 8.1 shows all these results.

Table 8.1 Simulation results showing Damping Constant, Frequency of Oscillation and Stability Margin for 5% load switching (150 ms fault clearing time).

	Without Load Switching	**Switching In 1st Swing**	**Switching In 1^{st} & 2^{nd} Swing**
Damping Constant	0.299	0.301	0.433
Oscillation Frequency	0.53 Hz	0.52 Hz	0.52 Hz
Stability Margin	64.5^0	68^0	68^0

10% Load Switching

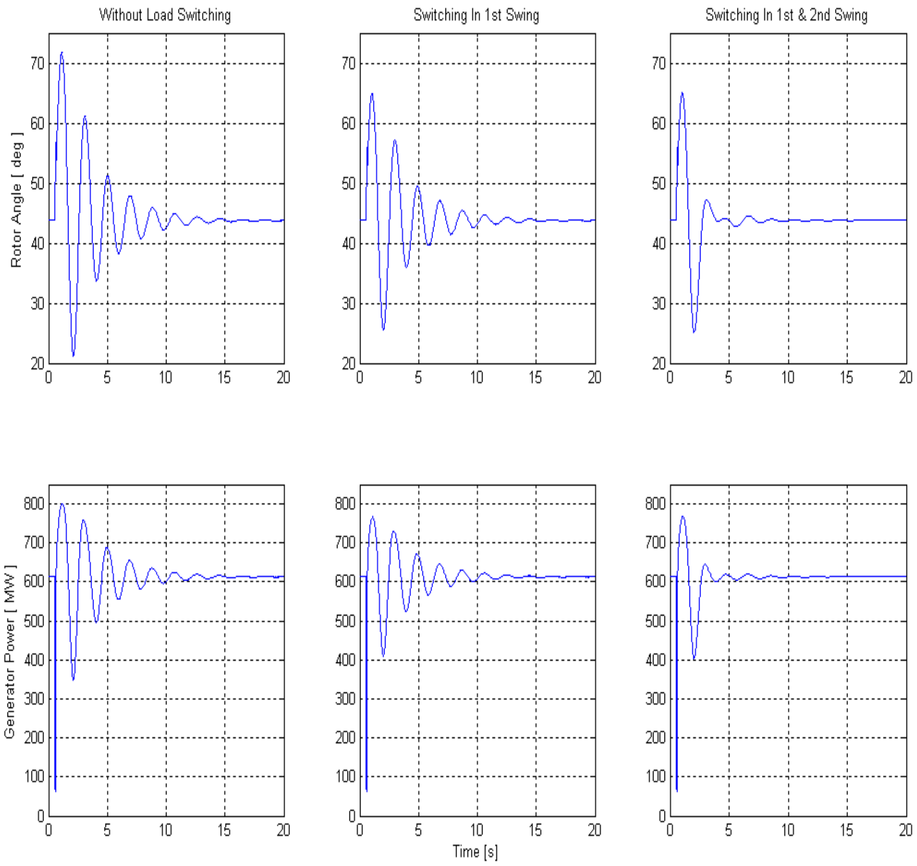


Figure 58: Increased transient stability margin (10% LS, 150ms)

by 10% load switching (switched load 60 MW). Fault clearing time 150 ms

When the amount of switched load is increased to 10% of the base load (621 MW) which is 60 MW, then both the damping constant and the stability margin increase. Figure 58 shows the simulation results. In case of switching in 1^{st} swing the frequency and damping constant of oscillation become 0.53 Hz and 0.314 respectively. When we used load switching in first 2 swings, then they become 0.5 Hz and 0.724. One important thing is that in this case the transient stability margin increases to 71.5^0 which is 3.5^0 more than the 5% load switching case. Table 8.2 summarizes the results.

Table 8.2 Simulation results showing Damping Constant, Frequency of Oscillation and Stability Margin for 10% load switching (150 ms fault clearing time).

	Without Load Switching	Switching In 1st Swing	Switching In 1^{st} & 2^{nd} Swing
Damping Constant	0.299	0.314	0.724
Frequency of Oscillation	0.53 Hz	0.53 Hz	0.5 Hz
Stability Margin	64.5^0	71.5^0	71.5^0

Comparison Between 5% & 10% Load Switching

For transient stability the first power swing after the fault clearing is the important one. If the generator does not lose synchronism in the first power swing, it will not happen later (in our case). By resistive load switching we can increase the transient stability margin.

In the above simulation initially the system transient stability limit was 64.5^0. With 5% load switching in the first swing the stability margin increases to 68^0 i.e. 3.5^0 increase. With 10% load switching the stability margin increases to 71.5^0 i.e. 7^0 increase.

We can use the load switching for transient stability enhancement. At the same time it can help increasing the damping coefficient as well. From the simulation we can see that a 5% load switching can increase the damping from 0.299 to 0.301 and a 10% load switching increases it to 0.314. Table 8.3 summarises the results.

Table 8.3 Comparison between 5% & 10% load switching. Fault clearing time 150 ms

	Transient Stability Margin	Damping Constant
Without Load Switching	64.5^0	0.299
5% Load Switching (1^{st} swing)	68^0	0.301
10% Load Switching (1^{st} swing)	71.5^0	0.314

7.6.3.2 272 ms Fault Clearing Time

To get a bigger power swing, we increased the fault clearing time to 272 ms in this simulation.

5% Load Switching

Figure 59 shows the simulation results. The frequency of oscillation and the damping constant is 0.49 Hz and 0.081. When 5% load is switched in the first power swing they become 0.52 Hz and 0.157. When switching is done in the first two swings they become 0.53 Hz and 0.176. The transient stability margin was 7^0 before load switching. After load switching in the first power swing it becomes 27.5^0. Table 8.4 summarizes the results.

Table 8.4 Simulation results showing Damping Constant, Frequency of Oscillation and Stability Margin for 5% load switching (272 ms fault clearing time).

	Without Load Switching	**Switching In 1^{st} Swing**	**Switching In 1^{st} & 2^{nd} Swing**
Damping Constant	0.081	0.157	0.176

Frequency of Oscillation	0.49 Hz	0.52 Hz	0.53 Hz
Stability Margin	7^0	27.5^0	27.5^0

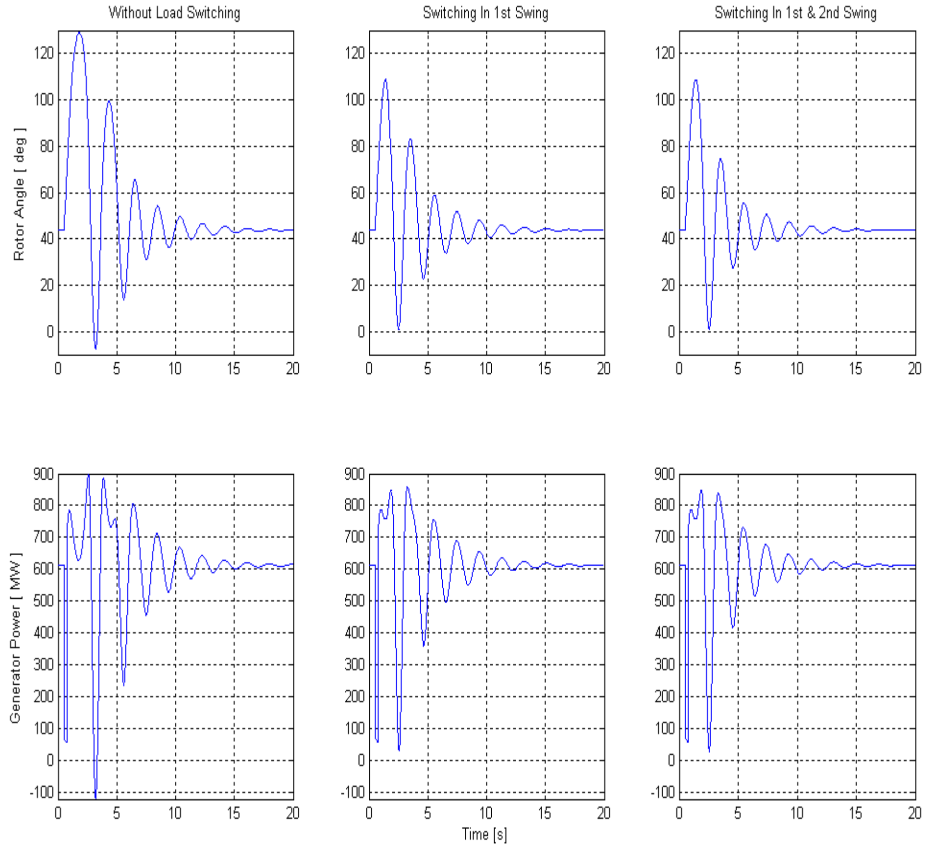


Figure 59: Increased transient stability margin (5% LS, 272ms)

by 5% load switching (switched load 30 MW). Fault clearing time 272 ms

10% Load Switching

Figure 60 shows the simulation results. The frequency of oscillation and the damping constant is 0.49 Hz and 0.081. When 10% load is switched in the first power swing they become 0.53 Hz and 0.182. When switching is done in the first two swings they become 0.54 Hz and 0.232. The transient stability margin was 7^0 before load switching. After load switching in the first power swing it becomes 37^0. Table 8.5 summarizes the results.

Table 8.5 Simulation results showing Damping Constant, Frequency of Oscillation and Stability Margin for 10% load switching (272 ms fault clearing time).

	Without Load Switching	**Switching In 1st Swing**	**Switching In 1^{st} & 2^{nd} Swing**
Damping Constant	0.081	0.182	0.232
Oscillation Frequency	0.49 Hz	0.53 Hz	0.54 Hz
Stability Margin	7^0	37^0	37^0

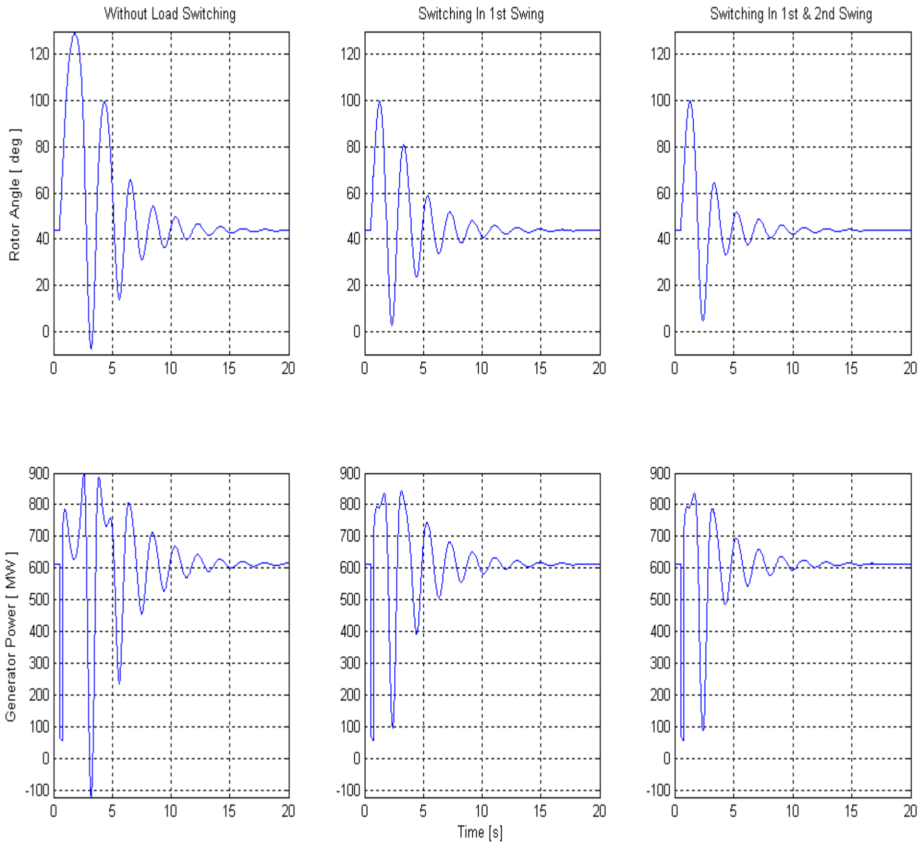


Figure 60: Increased transient stability margin (10% LS, 272ms)
by 10% load switching (switched load 60 MW). Fault clearing time 272 ms

7.6.4 Comparison Between 5% & 10% Load Switching

In the above simulation initially the system transient stability limit was 7^0. With 5% load switching in the first swing the stability margin increases to 27.5^0 i.e. 20.5^0 increase. With 10% load switching the stability margin increases to 37^0 i.e. 30^0 increase.

Here it shows that load switching of the right amount in the first power swing can increase the transient stability margin. At the same time it can help increasing the damping coefficient. From the simulation we can see that a 5% load switching can increase the system damping constant from 0.081 to 0.157 and a 10% load switching increases the damping by to 0.182. Table 8.6 summarises the results.

Table 8.6 Comparison between 5% & 10% load switching. Fault clearing time 272 ms

	Transient Stability Margin	Damping Constant
Without Load Switching	7^0	0.081
5% Load Switching (1^{st} swing)	27.5^0	0.157
10% Load Switching (1^{st} swing)	37^0	0.182

Switching a resistive load to increase the transient stability margin means to absorb accelerating energy from the generator. This accelerating energy should be absorbed in the resistive load which can be a district heating system. If we switch a higher amount of load to increasing the margin, we have to absorb a huge amount of energy which can be expensive or even it can be impossible with the existing resource available.

7.6.5 Damping Enhancement By Load Switching

Here we will investigate the effect of switching of a lower amount of load (1% of base load, 6 MW in this case) for a longer time on the damping coefficient.

7.6.5.1 150 ms Fault Clearing Time

The amount of switched load is 1% of base load and this time we will switch the load for 5 cycles and will see if it increases the damping. Figure 61 shows the simulation results. In this simulation we add a three phase to ground fault for 150 ms to get the power swing. The frequency of oscillation and the damping constant was 0.53 Hz and 0.299 respectively. After load switching they changed to 0.51 Hz and 0.344 respectively. In this case we managed to get 1^0 increase in the transient stability margin.

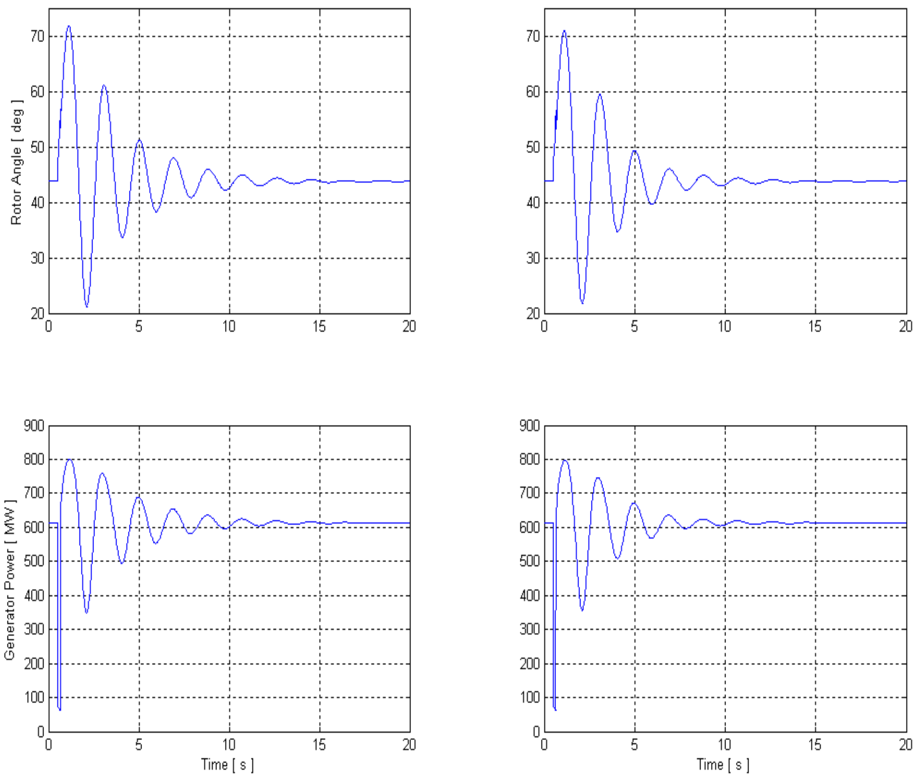


Figure 61: Damping enhancement by 1% load switching (150ms FCT)

(switched load 6 MW). Fault clearing time 150ms

In a simulation earlier (3.2.6.3.1) we showed that 5% load switching for one power swing can increase the damping from 0.299 to 0.301. In both the cases the amount of energy absorbed is almost the same. With the same absorbed energy we can get more damping when we absorb the energy evenly from each power swing. But it does not help that much to increase transient stability margin. Table 8.7 summarizes the results.

Table 8.7 Simulation results showing Damping Constant, Frequency of Oscillation and Stability Margin for 1% load switching (150 ms fault clearing time).

	Without Load Switching	**With 1% Load Switching**
7.6.5.2 Damping Constant	0.299	0.344
Frequency of Oscillation	0.53 Hz	0.51 Hz
Stability Margin	64.5^0	65.5^0

7.6.5.3 272 ms Fault Clearing Time:

In this simulation we took a bigger power swing that we got with 272 ms fault clearing time. The frequency of oscillation and the damping constant was 0.49 Hz and 0.081 respectively before applying load switching. These values change to 0.5 Hz and 0.115 respectively. These results are summarised in table 8.8. Figure 62 shows the simulation results. It is seen that the damping has not improved so effectively compared with the 5% load switching case with 272 ms fault clearing time. So in case of a severe oscillation this method of load switching is not an effective way of increasing damping.

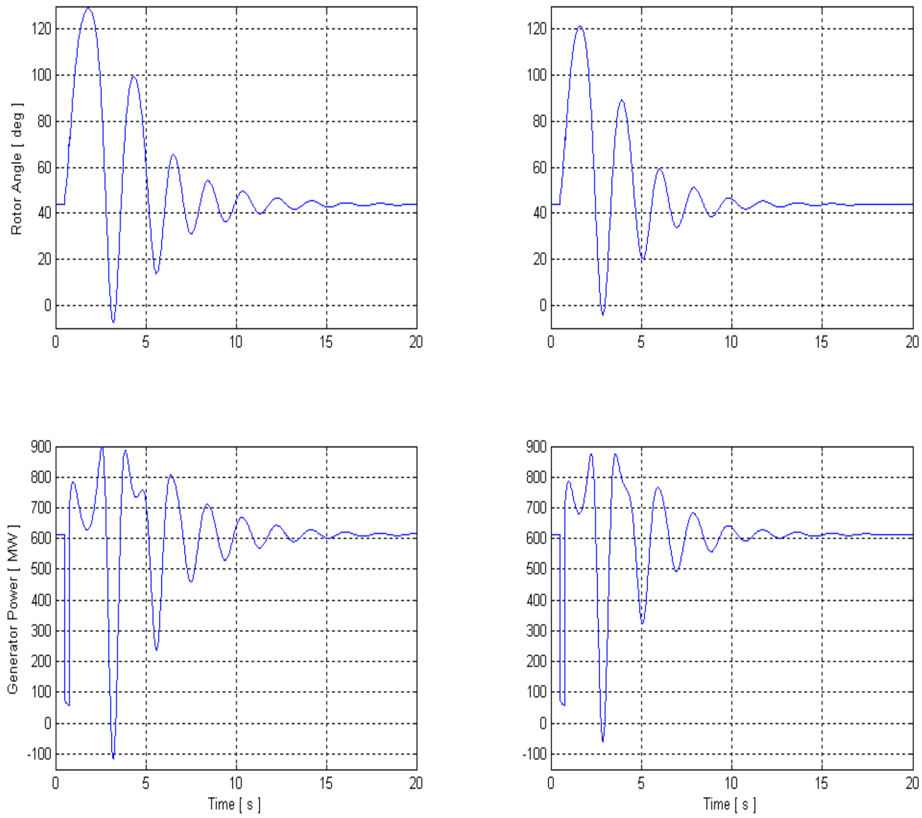


Figure 62: Damping enhancement by 1% load switching (272ms FCT) (switched load 6 MW). Fault clearing time 272ms

Table 8.8 Simulation results showing Damping Constant, Frequency of Oscillation and Stability Margin for 1% load switching (272 ms fault clearing time).

	Without Load Switching	**With 1% Load Switching**
7.6.5.4 Damping Constant	0.081	0.115
Frequency of Oscillation	0.49 Hz	0.5 Hz
Stability Margin	7^0	15^0

7.6.6 An Out of Step Oscillation:

Figure 63 shows an out of step oscillation. The fault clearing time exceeds the maximum allowable value. The machine loses its synchronism in the first power swing and is an example of first swing instability. With this system, if we add a load switching of 10% of base load (60 MW) in the first power swing, we can avoid the loss of synchronism. We can see it from Figure 60.

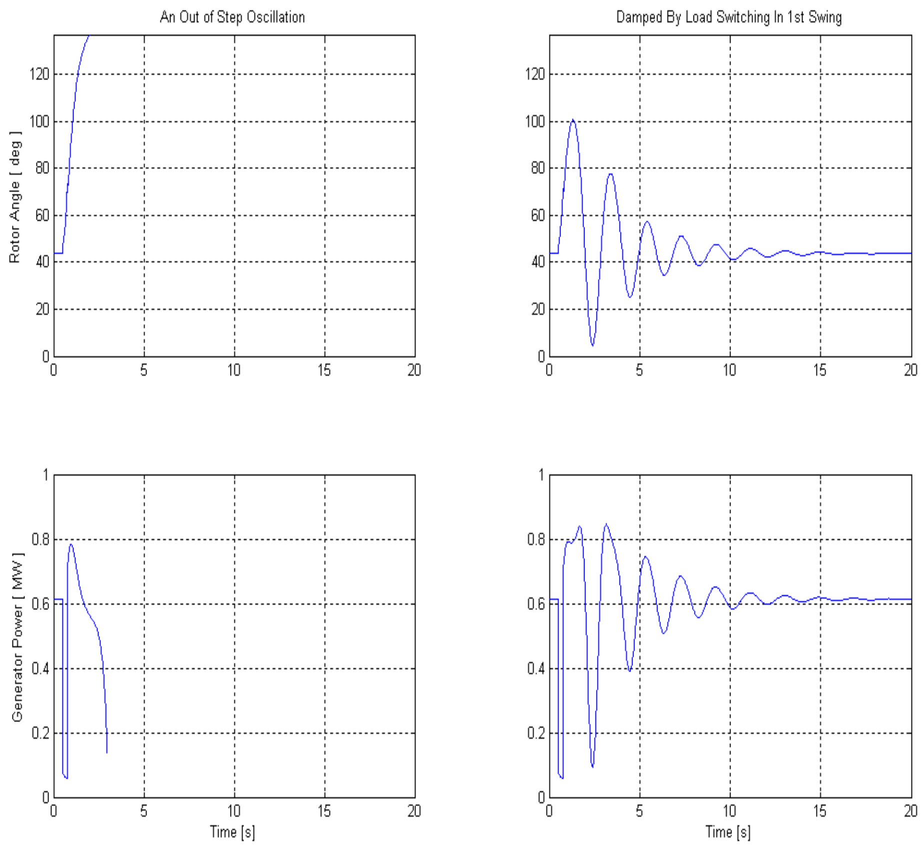


Figure 63: An out of step oscillation. Fault duration is 274 ms.

Lost of synchronism avoided by 10% load switching (60 MW) in the 1st power swing

7.6.7 Conclusion

From the above analysis it has been observed that switching of resistive load (5% or 10% of the base load) in the first power swing increases the transient stability margin. It improves the damping of the oscillation as well. On the other hand continuous switching of small amount of resistive load (1% of the base load) increases the damping when the fault is not so severe. In case of a severe fault this method of switching small amount of resistive load continuously is not enough for increasing the damping. In that case a larger amount of load (5% or 10% of the base load) can be switched in the first few swings which will improve both the damping and transient stability.

7.7 Conclusions

In this section, methods to detect power oscillations were investigated. For this, information about the voltage angles of different buses is needed. A Phasor Measurement Unit (PMU) from ABB was used for this purpose.

The phase angle difference between two bus voltages has proved to be a very good indicator of transient instability and it was used to detect power oscillations by comparing it to a pre-determined threshold value or to pass it through a low pass filter. The method of comparing the angle difference signal with a threshold, proved to be a better option.

For characterizing the power oscillation the ESPRIT algorithm has been used successfully. It has been proved to be a good tool for determining the damping constant and the frequency of oscillation. It has been found that power oscillation can also be characterized by the angle difference signal extracted from the PMU.

In addition, switching on and off loads was very effective in damping out oscillations and improving the transient stability margin. Continuous switching of a small amount of resistive load (1% of base load) improves the damping of the power swing when the fault was not too severe. In case of very severe faults, this continuous switching of a small amount of load is not enough.

Switching of a larger load (5% or 10% of base load) in the first swing improved the transient stability margin. It also increased the damping of the oscillation, which is an added advantage.

7.8 Future Work in the Area of Power System Damping

The detection and damping algorithm based on an angle difference signal derived from PMU should be tested on a larger network like NORDIC 32.

In this work we used PMU as a measuring unit, which was sampling data from the system and storing it in a computer hard disk. A computer application software is needed where it will not only store the data from the PMU but also process the raw data simultaneously and calculate the angle difference signal as we did it in our case with MATLAB. It should also contain the detection and damping algorithm so that when an oscillation is found it can generate an enable signal which will trigger the Thyristor Controlled Braking Resistor (TCBR).

Damping of power oscillation by resistive load switching should be simulated in a larger network. It should also be tested in the lab.

8 Market and ICT for Intelligent Load Shedding

8.1 Intelligent Load Shedding and Dynamic Pricing

As stated above, intelligent load shedding is about both detection of situations where the power system might go unstable and about how to deal with the critical situation. An obvious way to handle the situation in a smart way is to contract suitable (addressable) loads for fast short time switch-off (or reduction) of consumption. With fast and reliable enough communications this is an interesting solution.

A problem is how to be able to keep track on loads available to shed. Reliable information on this is a basis to be able to pick *(i)* the right amount and *(ii)* the right location of load to shed.

In work package WP1.2 different schemes of supply – demand matching based on dynamic pricing and the introduction of electronic markets are studied. The time frame of the market and pricing mechanisms is from day-ahead down to a few minutes ahead of runtime, i.e. the perspective of day-ahead (planning) markets down to balancing services. The big difference between these schemes and the mechanisms of today is that the schemes open up for utilisation of consumer side and DG dynamics.

An interesting extension of these perspectives is to introduce load shedding based on customer side price response and new market concepts. As in WP1.2 the concepts are means to utilise consumer side dynamics in an efficient way.

8.1.1 Concepts

Market based concepts that might be considered as means for intelligent load shedding range from sending of price signals to customer nodes where appropriate action is taken in predefined ways to full electronic markets where the availability for load shedding is dynamically traded. (With the result that a node in the system has instant access to information on loads available to shed.)

The communication capacity required ranges from one way (addressed or broadcast) communication to bi-directional communications. Furthermore, since it is desirable with a distributed structure where proper action can be taken at local levels, we see possibilities to reflect the structure of the physical grid in e.g. a market structure as advantageous. The demands on communications vary with the concept, the more sophisticated, the more it utilises the possibilities of modern ICT.

8.1.2 Starting Points

The basis for the concept of electronic power markets is modern communication technology and the availability of computational capacity, ICT. As stated above the communicational demands vary with the basic concept. A system that is based on price signals and estimations of customer response can rely on broadcasting or other one way communication systems. Full electronic market settings require bi-directional communications, on the other hand the outcome of the action taken may be computed in advance with high accuracy (variations in availability and in costs could be handled dynamically). When applying price based concepts to load shedding the speed and reliability of communications is of great interest.

8.1.3 Value

Price-based load shedding systems may be evaluated from a number of viewpoints.

The main concern is system stability, and a first question is whether price-based approaches to load shedding are useful to maintain (restore) system stability. This question is tightly related to technical issues such as available alternatives regarding communication, computations, etc, other critical issues are related to construction of system and algorithms.

When load shedding is needed to maintain (restore) system stability the aim is to do this in such a way that negative effects and costs are held as low as possible for all parties. From this viewpoint, the potentials of market-based approaches to load shedding might be of high interest, even though the demands on communications and on computational capacity are considerably higher than in other approaches. Hence, it is interesting to evaluate advantages and disadvantages relative more traditional approaches and approaches built on e.g. today's technology for peak shaving.

One feature of high interest in market based solutions is the possibility to use the price mechanism to achieve a smooth reestablishment of loads when returning to ordinary conditions, whether it is due to a successful load shedding operation or after a blackout.

8.1.4 Costs

To estimate costs for new technology is hard, but nevertheless of interest. The usage of electronic markets for supply – demand matching and for load shedding is such a novel approach, and it is hard to give more than rough estimates of parts of the costs for different participants.

Note: If the costs related to installations at the customer premises are high, a driving force for installation can be that the equipment is part of a package, e.g. a smart building concept. This gives opportunities to introduce a number of value-adding services that come in packages together with the ability to be part of dynamic power market systems involving a system for intelligent load shedding.

8.2 Electronic Markets for Intelligent Load Shedding

The development of early detection of upcoming system instability is an essential aspect of intelligent load shedding. The major part of this deliverable deals with technical aspects on the problem. Another problem is to define an optimal amount of load to shed, and an optimal location of this load (with respect to the disturbance). A third is to keep track on load available to shed in every instant, and to initiate the load shedding when action is triggered.

The earlier it is possible to detect an upcoming instability, the larger is the solution space and the more interesting it becomes to put effort into how to shed load in a way that minimises cost and other negative side effects.

Assume that we have a protection and detection system that is able to detect a critical situation at an early stage so that there might be time for other action than just to trigger a circuit breaker. Further assume that the system is equipped with hardware and software to compute volume and location of the load to shed. Then what is left of the load-shedding problem is how to shed load in a way that minimises the negative effects of the action.

In a traditional utility setting it is natural to think of schemes originating from techniques that originate in semi-automated peak load reduction. Concepts aimed for peak load reduction could be developed (with respect to automation and communication speed) to become a means for intelligent load shedding. The systems would probably involve loads from the large segment of thermal loads (loads that are not involved in production processes that might be disturbed or spoiled by short-term load shedding action). If the aim had been to develop a system for intelligent load shedding and nothing else, this would be the kind of system that would be of highest interest. It would probably be among the most cost efficient systems to install, and the loads have been shed that would have attractive properties in the limited damage caused by the action.

This would solve one half of the problem, how to initiate the load shedding: send a signal to a set of loads saying that they are to shut of or reduce their load according to a predefined scheme. The other half, how to keep track of load to shed is not solved. Traditional peak load reduction systems include no knowledge on the volumes that are affected by the action, since there is no knowledge on the current status of the loads (e.g. if they are on or off). This might be sufficient in a peak load reduction scenario, but the problem might be more severe in a load shedding scenario.

In Annex 1 problems related to the liberalised markets are pointed out, problems that stem from the loss of vertical integration of power utilities. These problems might look slightly different in different countries (due to legislation, etc.) but they have to be considered if the concept is.

Current development in the ICT sector opens up for new solutions to these parts of the load shedding problem, as well as for supply – demand matching. Dynamic power markets with participation from load side are within reach. These market concepts are highly interesting, first from a supply – demand matching perspective, and second, if electronic power markets are implemented with respect to dynamic demand – supply matching, capabilities biased towards intelligent load shedding are an option. In a natural way electronic markets give opportunities to handle both the problem of keeping track of loads (volumes) that are available for load shedding and the initiation of load shedding. Note that dynamic supply – demand matching markets give an imminent reduction of the risk for stability problems due to high peak load.

To introduce electronic markets solely for to handle load shedding is hardly an alternative. If electronic markets are introduced for supply – demand matching, utilising the dynamics of consumption and DG in the power grid, then intelligent load shedding could be another aspect of how to utilise them (and the investments).

If we assume an electronic market setting for supply – demand matching, the structure could be enhanced with trading of another good of interest; loads that are prepared to shut of/reduce consumption instantly when there is a need for this. Since electronic markets rely on bi-directional communications, it is obvious that we may assume that there is a possibility to keep the system updated on loads available to shed. Furthermore, the market setting provides an incitement to keep the system updated with information on what load is available to shed, and it supplies the grid operator with a price tag for the operation. This price tag might be related to the momentous action (limited to a maximum operational time, which is sufficient to transfer the problem from the load shedding arena to the load-balancing arena, i.e. a time frame of a few minutes).

Note that there still is, and should always be, a possibility for the grid operator to fall back to the traditional “red button” handling of the situation if the market isn’t able to handle it. In this way, it is always possible to take load-shedding action. When action is taken based on the market negative side effects of the load shedding is reduced, if the market fails to handle the situation, the traditional, rough schemes are still available. As a side effect, electronic markets for load shedding might provide possibilities to utilise the instrument at earlier stages than today.

To decide on scenarios for simulations on market based intelligent load shedding we need more information on the Öland grid and its customers. This information is to be used for construction of the scenarios and decisions on which customer categories to look closer into with respect to their potentials in a load shedding situation.

The information we want is on customer categories, their consumption (production), and consumption (production) patterns, including flexibility. From this data it is possible to construct realistic scenario descriptions and market simulations.

Available data from Öland is yearly consumption per substation and customer category, and fluctuations in maximum power. Data that is not available has to be derived from similar sources or estimated. Consumption patterns of different consumer categories are not available from the Öland material, but a study from 1991 0 that Sydkraft was highly involved in holds usable knowledge.

9 Application in the Öland System

Sydkraft operates the distribution network of the island of Öland in the south of Sweden. The CRISP experiment C is based on measurements achieved on this Island on three locations (north, middle and south). This grid is interesting to verify the ILS concept since future electrical constraints are expected on the island, due to projects of new wind farms installations..

9.1 Overview of the Öland power system

The Öland 50 kV distribution system is described in Figure 64. Existing and planned wind power farms are also marked, as well as the connection points for the recording equipment. From the supply point in LIN, the system is radially fed by two parallel 50 kV lines, feeding 50/10 kV transformers, connected to local distribution systems. In the south point of recording a rather large wind power farm is connected to the 50 kV grid via a 20/50 kV transformer. In the north point of recording a wind power farm is connected to one of the 10 kV feeders, that also feeds other load.

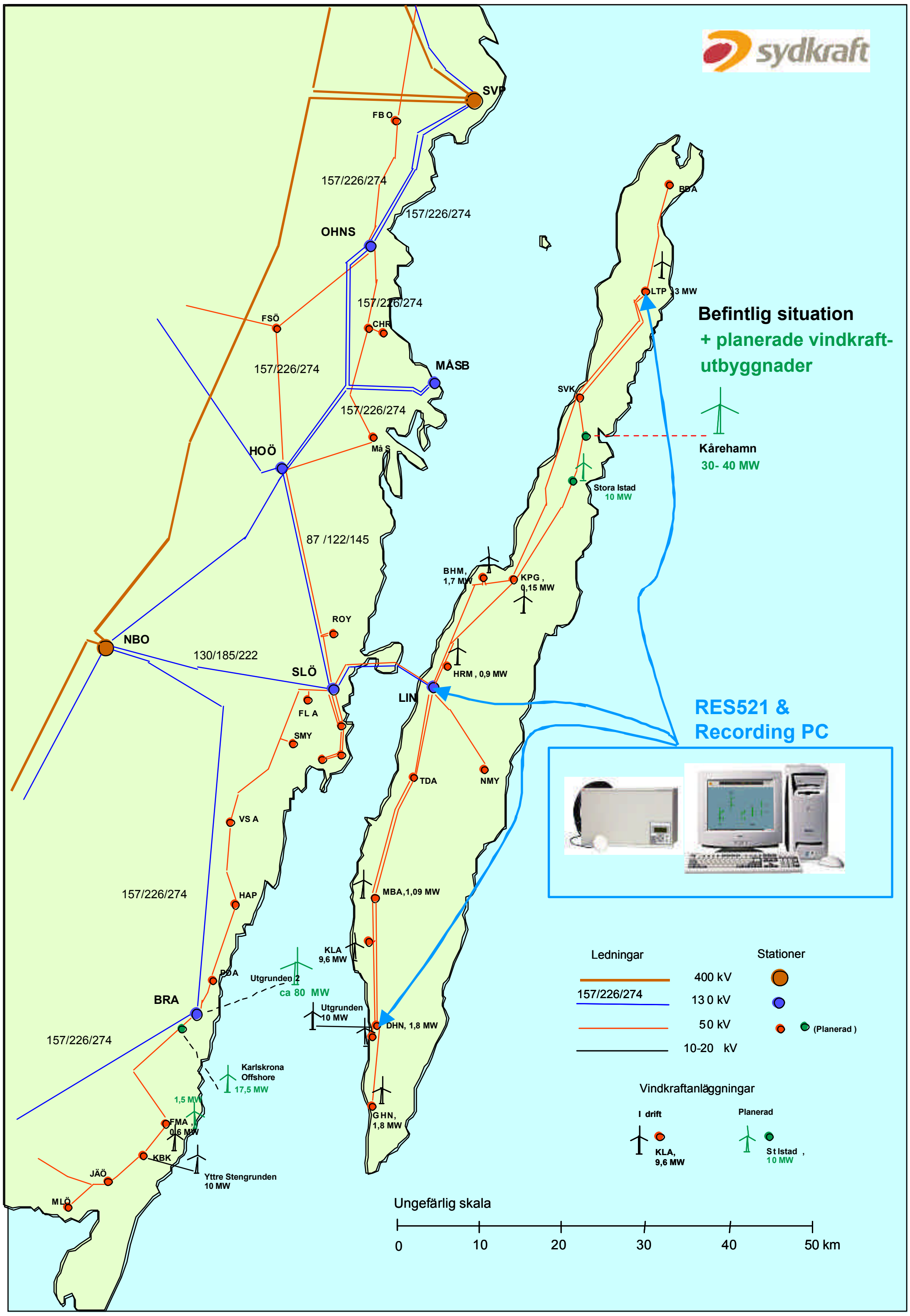


Figure 64. The grid of Öland, with wind power farms and recording nodes marked

In this section we give a description on the customer categories on an overall level and a per substation level. The description stops at the middle voltage level.

There are a dozen substations at Öland. One to two additional substations are planned in connection to planned wind power farms. Using the cell notation this gives a structure with Öland as a whole as a natural HV cell, with one MV cell for each substation. All of the current MV cells hold a number of LV cells (save one that is entirely devoted to a wind farm). One of the MV cells is not operated by Sydkraft, but by a local grid owner, Borgholm Energi.

The Öland simulations on utilisation of electronic market approaches to load shedding (and supply – demand matching) will take this cell structure as an organisational starting point. That is, we will assume that the distributed[1] market is structured in a way that reflects and utilises the physical structure of the grid.

In the following subsections we give an overview of load characteristics and composition on the level of HV/MV cell.

9.2 Description of the Öland HV Cell

As mentioned previously, Öland has a single connection to the mainland at Linsänkan, with a main 130 kV / 120MW connection and a spare 50 kV / 80 MW connection. Hence the island in it self may be viewed as a single node in the power system, or a high voltage cell in the main grid.

The main part of the Öland power grid is owned and operated by Sydkraft Nät. A local grid owner operates a smaller area, the Borgholm area.

9.2.1 Approximate Data on the Sydkraft Part of the Öland Grid

Area	1,300 km^2
No. of customers	20,000
50 kV grid length	250 km

[1] One reason to distribute the market calculations is to reduce communication volumes 0, another effect that is central from a load shedding perspective, is that local knowledge is increased (assuming that there is a matching between grid structure and market structure).

10/20 kV grid length	880 km
0.4 kV grid length	1,860 km
Max consumption (all of Öland)	85 MW
Short circuit power at connection point to mainland	500 MVA
Relative annual energy consumption:	
residential	25 %
summer cottages	14 %
agriculture	16 %
the 70 largest consumers	20 %
Local production relative total consumption:	21 %

9.2.2 Approximate Data Concerning the Other Part of the Grid

One part of the power grid of Öland belongs to a local utility, Borgholm Energi, some figures on their part of the grid:

No. of customers	4,000
Relative annual energy consumption:	
residential	27 %
summer cottages	5 %
the two largest industrial consumers	34 %
other industrial consumers	5 %

9.2.2.1 Current Situation

The maximum/minimum load of the Öland system is approximately 85 MW and 15 MW respectively.

The main customer categories are shown on a per substation level in following sections. They are given with annual energy consumption, number of customers, and their relative impact on the local situation (in terms of annual energy consumption).

9.2.2.2 Planned Wind Farms

There are plans to build two large wind farms (10 and 30-40 MW respectively) that will be integrated into the power grid of the northern part of Öland. If and when they are realised, they will be connected to the grid at new substations.

The relatively weak system gives that the impact of the planned wind farms will be large. New questions on local supply – demand matching rise from this. One is if flexibility in local consumption could match (parts of) the fluctuations in production of the wind farms.

9.2.2.3 Böda

The Öland system holds a dozen of middle voltage cells and the following gives a presentation of all of them from north to south, starting with Böda (c.f. Figure 64). In the presentation we have chosen a number of customer categories and give the number of customers and their yearly consumption (production). Furthermore, we give the category's percentage of the total consumption of the MV-cell (note, we relate the category to the total consumption, not the total volume including local production).

Due to the large impact of tourism and summer cottages, the load composition of Öland is a bit different from the average of Sweden. Apart from this, a large part of the permanent population is commuting to the mainland, and another substantial part is in agricultural businesses.

Böda is a MV cell that is dominated by tourism and summer cottages. No DG is present in the cell.

Customer category	**# customers**	**volume, kWh/year**	**% of total energy consumption**
Residential, electrical heating system	117	1213110	14.3
Residential, other/unspecified heating	86	736802	8.7
Industrial	15	192698	2.3
Agricultural	34	556909	6.6
Retail, electrical heating system	5	300431	3.6
Retail, other/unspecified	2	12707	0.2
Municipality related, electrical heating system	0	0	0
Municipality related, other/unspecified	4	141781	1.7
Summer cottages	631	2474625	29.3
Camping, rental cottages, etc.	5	1455804	17.2
Distributed generation (wind mills)	0	0	0

9.2.2.4 Löttorp

Residential customers and summer cottages dominate the Löttorp MV-cell. There is no DG present.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	446	4612490	22.8
Residential, other/unspecified heating	230	1903285	9.4
Industrial	40	960629	4.8
Agricultural	189	3464150	17.2
Retail, electrical heating system	11	354316	1.8
Retail, other/unspecified	12	282674	1.4
Municipality related, electrical heating system	4	238973	1.2
Municipality related, other/unspecified	1	5569	0
Summer cottages	1473	5270592	26.1
Camping, rental cottages, etc.	6	64349	0.3
Distributed generation (wind mills)	0	0	0

9.2.2.5 Sandvik

The dominating consumer categories of Sandvik are residential, agricultural, and summer cottages. There is no DG.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	263	3403203	19.0
Residential, other/unspecified heating	163	1564131	8.7
Industrial	16	1297376	7.2

Agricultural	206	4509406	25.2
Retail, electrical heating system	6	313527	1.8
Retail, other/unspecified	5	53271	0.3
Municipality related, electrical heating system	1	3546	0
Municipality related, other/unspecified	1	3456	0
Summer cottages	1327	5246331	29.3
Camping, rental cottages, etc.	0	0	0
Distributed generation (wind mills)	0	0	0

9.2.2.6 Borgholm

The Borgholm area, centred on the small town Borgholm, is the area with the largest permanent population on Öland.

As pointed out earlier the grid of the Borgholm area belongs to a local grid owner. Their customer categorisation differs from the one of Sydkraft.

Dominating categories are residential customers and industrial. There is no DG in the Borgholm area.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	796	14046000	17.17
Residential, other/unspecified heating	1779	8203000	10.03
Industrial	30	31658000	38.7
Agricultural	0	0	0
Retail, electrical heating system	0	0	0
Retail, other/unspecified	128	4573000	5.59
Municipality related, electrical heating system	0	0	0

Municipality related, other/unspecified	34	5886000	7.2
Summer cottages	919	3890000	4.76
Camping, rental cottages, etc.	0	0	0
Distributed generation (wind mills)	0	0	0

9.2.2.7 Köping

The consumer category with highest consumption in the Köping MV-cell is agricultural, followed by residential customers and summer cottages. The DG volume equals 29% of the consumption of the cell.

Customer category	**# customers**	**annual volume, kWh/year**	**% of total energy consumption**
Residential, electrical heating system	286	3753073	18.0
Residential, other/unspecified heating	173	1605064	7.7
Industrial	19	1051527	5.0
Agricultural	267	7561669	36.3
Retail, electrical heating system	3	115286	0.6
Retail, other/unspecified	4	116992	0.6
Municipality related, electrical heating system	2	737262	3.5
Municipality related, other/unspecified	1	9373	0
Summer cottages	812	3293722	15.8
Camping, rental cottages, etc.	4	757219	3.6
Distributed generation (wind mills)	1	6082161	29.2

9.2.2.8 Högsrum

Residential customers dominate the consumption of the cell, in size summer cottages and the agricultural sector follow. The DG equals 6% of the annual consumption of the cell.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	467	6722138	29.2
Residential, other/unspecified heating	224	2058141	9.0
Industrial	12	480647	2.1
Agricultural	182	3920021	17.0
Retail, electrical heating system	2	246686	1.1
Retail, other/unspecified	4	78507	0.3
Municipality related, electrical heating system	2	189154	0.8
Municipality related, other/unspecified	2	18503	0.1
Summer cottages	965	4904922	21.3
Camping, rental cottages, etc.	4	2604655	11.3
Distributed generation (wind mills)	1	1394818	6.1

9.2.2.9 Norra Möckleby

The dominating customer categories are residential and agricultural. There is no DG in the cell.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	311	4129164	28.2
Residential, other/unspecified heating	179	1568543	10.7
Industrial	8	286710	2.0

Agricultural	201	5573370	38.1
Retail, electrical heating system	6	236145	1.6
Retail, other/unspecified	1	22667	0.2
Municipality related, electrical heating system	1	46814	0.3
Municipality related, other/unspecified	2	10961	0.1
Summer cottages	366	1518612	10.4
Camping, rental cottages, etc.	0	0	0
Distributed generation (wind mills)	0	0	0

9.2.2.10 Torslunda

The Torslunda area is dominated by residential consumption, close to 50%, no DG.

Customer category	**# customers**	**annual volume, kWh/year**	**% of total energy consumption**
Residential, electrical heating system	1821	27299331	38.4
Residential, other/unspecified heating	1031	7543813	10.6
Industrial	61	4680706	6.6
Agricultural	184	4665416	6.6
Retail, electrical heating system	19	6213574	8.7
Retail, other/unspecified	19	534465	0.8
Municipality related, electrical heating system	11	3275014	4.6
Municipality related, other/unspecified	6	225716	0.3
Summer cottages	1594	6854500	9.6

Camping, rental cottages, etc.	8	1980142	2.8
Distributed generation (wind mills)	0	0	0

9.2.2.11 Mörbylånga

Industrial and residential customers dominate the consumption of Mörbylånga. The DG volume is close to 2% of the consumption.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	682	9315315	18.4
Residential, other/unspecified heating	631	4217534	8.3
Industrial	42	14853901	29.3
Agricultural	227	8246127	16.2
Retail, electrical heating system	6	1051600	2.1
Retail, other/unspecified	15	380729	0.8
Municipality related, electrical heating system	6	3170771	6.2
Municipality related, other/unspecified	8	884081	1.7
Summer cottages	613	3224238	6.4
Camping, rental cottages, etc.	3	356278	0.7
Distributed generation (wind mills)	1	903066	1.8

9.2.2.12 Kastlösa

Kastlösa substation handles a wind-farm and nothing else.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption

Distributed generation (wind mills)	9	16552144	

9.2.2.13 Degerhamn

Residential and agricultural customers dominate the consumption at Degerhamn. The DG equals 41% of the consumption – Utgrunden (DG) and Degerhamn C (industrial customer) excluded.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	202	2427068	22.0
Residential, other/unspecified heating	218	1534984	13.9
Industrial	5	45857	0.4
Agricultural	147	3293446	30.0
Retail, electrical heating system	3	222007	2.0
Retail, other/unspecified	1	10531	0.1
Municipality related, electrical heating system	1	172758	1.6
Municipality related, other/unspecified	1	2946	0
Summer cottages	353	1546065	14.0
Camping, rental cottages, etc.	1	26695	0.2
Distributed generation (wind mills)	5	4528425	41.0

9.2.2.14 Degerhamn Utgrunden

The Degerhamn Utgrunden MV cell is a pure production cell, holding a wind-farm.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Distributed generation (wind mills)	1	34619930	

9.2.2.15 Degerhamn C

Degerhamn C is a sole larger industrial unit with a consumption that is larger than the consumption of the rest of Degerhamn.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Industry	1	30983745	100

9.2.2.16 Grönhögen

The dominating customer category at Grönhögen is agricultural consumers, followed by residential ones. The DG volume equals 62% of the local consumption.

Customer category	# customers	annual volume, kWh/year	% of total energy consumption
Residential, electrical heating system	91	1203923	17.0
Residential, other/unspecified heating	101	679622	9.7
Industrial	8	478620	6.7
Agricultural	58	2399831	33.8
Retail, electrical heating system	1	110430	1.6
Retail, other/unspecified	0	0	0
Municipality related, electrical heating system	1	37632	0.5
Municipality related, other/unspecified	3	408886	5.6
Summer cottages	130	627876	8.8
Camping, rental cottages, etc.	4	63537	0.9
Distributed generation (wind mills)	8	4410478	62.0

9.3 Load Characteristics per Customer Class

A static evaluation of the load shedding potentials of different customer categories has to be based on available knowledge on the consumption patterns of the customer category. These patterns are not universal, i.e. the what is derived from a category in one country and region, during a certain season, might well not be applicable to a corresponding category in a different setting. On a top level, the overall consumption of the Nordic countries does not vary as much over the day as in continental Europe, on the other hand the seasonal variations between summer and winter are larger. This is mainly due to the large impact of electrical heating in the Nordic system.

In the second part of the '80s Svenska Elverksföreningen performed a study 0 on load curves of a large number of consumer categories. In this consumption patterns where defined for:

- winter, spring/autumn, and summer,
- weekdays and weekend,
- three characteristic daily average temperatures of each season.

Together with the figures on energy consumption this material can be used as input to the simulations, giving a good picture of the potentials of the customer categories that the study focuses on.

9.4 Local Extreme Load Situations

Öland is a popular summer vacation resort, and hence the load characteristics are different from many other areas in Sweden. The population of the island is much higher during the summer vacation period and e.g. Easter holidays than the basic year-around population. A large part of the year-around population commute to the mainland for work. All together this gives that the consumption pattern of the island differs considerably from average consumption patterns.

On a national level the impact of heating loads gives that peak load problems typically arise morning hours of cold winter weekday. On the island of Öland the local peak consumption comes with e.g. Easter holidays when the summer cottages are occupied and heated. Peak production in combination with low local consumption typically would come with windy autumn days.

9.5 Baselines

The most plausible and hence interesting scenarios are probably losses on transmission level where the Öland system is used to handle a "global" situation, i.e. a situation where the problem is external to Öland. In that case it is of minor interest what caused the load shedding, except for the time frame available for load shedding actions.

In this case the starting point is that the technical systems have triggered on a situation where the system is entering an unstable state, and there is still time to take other action than to break a circuit. In this situation one decision is on the load volume to shed, another is on the location of load. Both these decisions are more technical than market related, even though one could think of market related considerations here too, such as whether to shed load in a second best location due to economic considerations (but this is out of the scope of the project). The market part reduces to being able to shed the requested amount of load, and to do so sufficiently fast.

An obvious way to speed up the process is to always keep track of load to shed (and costs for taking market-based action) is to let the agents taking part in the market report changes in their status, continuously. In this way the critical decision can be based on precompiled market information and basically consist of sending of a price signal to the market participants. The price signal has to be accompanied by action identifying information for follow up, but this is tightly connected to technical solutions and more or less out of scope of the project.

For intelligent load shedding utilising electronic markets we identify the following baseline(s):

- The main focus is not on an action that is related to instability in the local grid of Öland, but a critical situation on the mainland. Öland is one of the nodes used to stabilise the situation.
- Local scenarios on Öland, where intelligent load shedding could save the situation, are related to loss of transmission capacity and/or loss of local generation. The most imminent disturbance to plan for is loss of the regular 130 kV cable from the main land during extreme high load conditions. Depending on the wind conditions and the local generation, the 50 kV back-up cable may or may not be able to supply the requested power. If not, smooth load relief, might be an economically attractive alternative to reinforcement of the back-up transmission capability.

  Of course a similar discussion can be applied also on lower levels out in the distribution system on Öland; 50 kV or 10 kV. If transmission/distribution capacity is reduced and local generation is available, intelligent load shedding might be the tool to establish a balanced system, either islanded or with a (fully loaded) connection to the rest of the system.

Since both wind-based production (the local DG) and consumption varies substantially with seasons, we focus on two periods of high interest on Öland as they are the two most extreme scenarios with respect to local production and consumption:

- **Spring (Easter time).** With the Easter holidays the consumption on the island reaches its highest levels. If there is no wind or low wind speed the local production is low, and the power flow from the mainland is high. With higher wind speed the local production is higher and our focus is on the internal flow within the Öland HV-cell. In the first case, the probability that Öland would be involved in solving an instability problem in the transmission grid on the mainland is relatively high. In the second case the loss of a power line on the island changes the topography and capacity of the local grid drastically.
- **Autumn (windy day).** A windy day in the autumn, well before the winter, the consumption on the island is low. The summer guests are gone, and the demand for power for heating is still low. On the other hand, as the DG of Öland is all wind based the production is high. In this situation the capacity to handle a load-shedding demand looks quite different from the spring scenario.

9.6 Customer Categories

To analyse the potentials of all customer categories is a huge assignment, to pick a small number of interesting categories and analyse them is more realistic. Categories that might be interesting to consider are for example different residential customers with electrical heating, office buildings and stores. Industrial customers are of a major interest in many ways, but the value of results in terms of to what extent it is possible to generalise them is limited (this is emphasised by the experiences from the peak load reduction projects of Sydkraft). If industrial loads are picked for evaluation, this has to be emphasised.

9.7 Impact of the intelligent load shedding system on the overall power supply

The total impact of the intelligent load shedding system on the overall power supply reliability and cost, has to be evaluated. The aim of the intelligent load shedding system is to save the system, by smooth load relief, in (very rare) situations, when the power system otherwise would go unstable. To evaluate such a system, a number of uncertain parameters have to be included, such as frequency of severe disturbances, cost of a severe disturbance, frequency and cost of unwanted operation of the protection system, maintenance, testing, upgrading, etc., of the protection system. There are two clear trends today that support the installation of system protection schemes. One is the need for increased utilization of the present power networks, due to difficulties in permissions for new lines. The other one is the increased costs for forced electricity outages, due to increased dependence of electric power in all sectors of the modern society. Numerical power system protection devices, with self-supervision have also significantly increased the reliability and reduced the need for maintenance and testing. In conclusion, increased power system capability by improved load control is becoming more and more attractive and more and more load shedding systems with different levels of intelligence are being installed and commissioned.

9.8 Conclusions

Three phasor measurement units have been installed at strategic nodes in the Öland system. These units will record highly accurate phasor data from April to September. The recordings together with simulations will form the base knowledge, concerning the interaction between the power transmission system, the local distribution system, the distributed generation and the load. Based on this knowledge intelligent load shedding systems can be designed. For the evaluation of the power system dynamics, a number of forced actions are planned, such as change of supply for the island of Öland from the regular 130 kV cable to the back-up cable, change of load and change of 50 kV network configuration. Beside these “forced” changes, thunderstorm related disturbances will provide interesting data during the summer period.

The phase angle difference between two bus voltages has proved to be a very good indicator of transient instability and it was used to detect power oscillations by comparing it to a pre-determined threshold value or to pass it through a low pass filter. The method of comparing the angle difference signal with a threshold, proved to be a better option. In addition, switching on and off loads was very effective in damping out oscillations and improving the transient stability margin. Continuous switching of a small amount of resistive load (1% of base load) improves the damping of the power swing when the fault was not too severe. In case of very severe faults, this continuous switching of a small amount of load is not enough. Switching of a larger load (5% or 10% of base load) in the first swing improved the transient stability margin. It also increased the damping of the oscillation, which is an added advantage.

The simulations aiming to investigate the potentials of price based and market based approaches will focus on a comparison between methods based on today’s technology for peak load reduction and a full electronic market setting. These are the two major concepts, price reactive consumption and DG is an interesting alternative that could be part of a transition towards electronic markets. The main drawback of the concept is that as the involved actors per definition do not take part in the equilibrium price establishment on the market, price reactive volumes other than marginal cause disturbances for this process.

The plan is to perform simulations based on

- a spring day scenario with high local consumption and low local production, and
- an autumn day scenario with low local consumption and high local production,

as this is the extremes in consumption patterns and local production patterns on Öland. The study will be based on yearly energy consumption as in the material underlying the presentation in this deliverable together with available material on load curves of different customer categories.

10 Conclusion

The document gives comprehensive information on the traditional load shedding based on voltage frequency criterion or on voltage magnitude criterion. Thorough information about large power oscillations is presented to underline the complexity of setting a proper solution for reaching a right level of stability in the system. The load shedding is a defence scheme used worldwide and its ideal objective during critical situation is to recover quickly the global balance between production and demand, with dynamical characteristics enabling a correct come back to stable steady-state.

The work on intelligent load shedding shows a future deep change in the associated distribution automation. The terminology used asks for some questions since the local intelligence leads rather to a distributed controlled system, the control being achieved on DG units and on controlled loads. The document takes into account three concepts of technical solution in order to deal with the stability of the system, which is the traditional goal of the existing load shedding: SLR (smooth load relief), CPA (critical preventing action) and DLS (distributed load shedding).

SLR is clearly a continuous control on the loads (real time setting of the power consumed) and of the DG units (real time setting of the power produced) in order to manage the real time exchange of power between a cell and the external network surrounding the cell. The agent managing the cell is as an automatic DNO (distribution network operator) trying to limit the exchanged power variation slope to a maximum given value. This function is really active on the devices (controlled local loads and DG units) when the exchanged power variation between all the components of the cell and the external side of the cell is higher than the given maximum value.

CPA is a set of traditional solutions already existing in order to limit the extension of a critical event. The typical solution is blocking the tap changer of the HV/MV transformers, fixing a minimum time limitation between several positions. This solution may be better controlled and used by the local agent informed by ICT of a global situation: more than a time based solution, a choice may be made knowing the real transmission situation and the real local voltage constraints. As indicated in the title of the function, it is not an energy management system dealing with steady-state local optimization, but an ultimate technical solution activated when critical situation is globally detected. The cause of the activation of this function is a trouble in the surrounding VHV (very high voltage) power system. The aim of this function is to avoid ‘active deterioration’ of the stability by actions in the distribution system, including of course the HV/MV transformers.

DLS is more similar to the traditional load shedding, except that the resulting action is not on the circuit breakers of the feeders, but on specific nodes inside the feeders. Since controlled production units and controlled loads will be dispersed in the feeders, this solution will be more flexible and effective to reach the objective of balancing global production and consumption. The real time management of power in distribution cells should enable to have a real tuned local action during critical situation: the local agent evaluates or is informed of the ‘apparent local load to shed’ (what is the more critical response expected by the network in case of falling frequency), it sends local orders (with quantified power variation expectation) to controlled loads or controlled DG units in order to meet the required local power variation.

As mentioned above the main goal is to act locally in a right level in order to support the system globally. Nevertheless these three technical solutions, involving a great control of various devices among the distribution, may be used for other purposes: the communication network with addressable devices (loads, DG units and electrical components of the network) designed for fast local measurements and control is operational also for other slower functions (EMS, automated voltage control). If the communication path is shared between different functions the priority must be clearly defined, the analysis and actions dedicated for critical condition prevailing.

Once market-based multi-agent systems are implemented for Supply-Demand matching, market-based approaches for ILS could have a great value, although there should always be a fall-back strategy in terms of immediate manual action.

The question ‘What kind of technology or strategy to take?’ also depends on the kind of problem and the response time needed. Different possible approaches how to determine the right response, including possible strategies and technologies, have been described. The document shows information about technical aspects (requirements and possible actions on the EPS) and about market aspects (how to build a specific market for load control or local production control in the purpose of intelligent load shedding). So not only most of the components of ILS systems have to be developed, tested and implemented, also the strategies combining these components in intelligent ways need to be further worked out, tested and implemented. Because the reliability and the availability of this power during critical situation is of prime importance, the market and price system should include ‘checking actions’ allowing to analyse and verify after critical periods what was the real actions by the different actors among the distribution.

Combining ICT, EPS devices and market devices is required for the future solutions proposed in the document. Another aspect is the dependence of each part of infrastructure from the others: a reliable system should take into account partial failure of one part, with a specific running mode. ICT as a central node of the information system must be carefully implemented in this way.