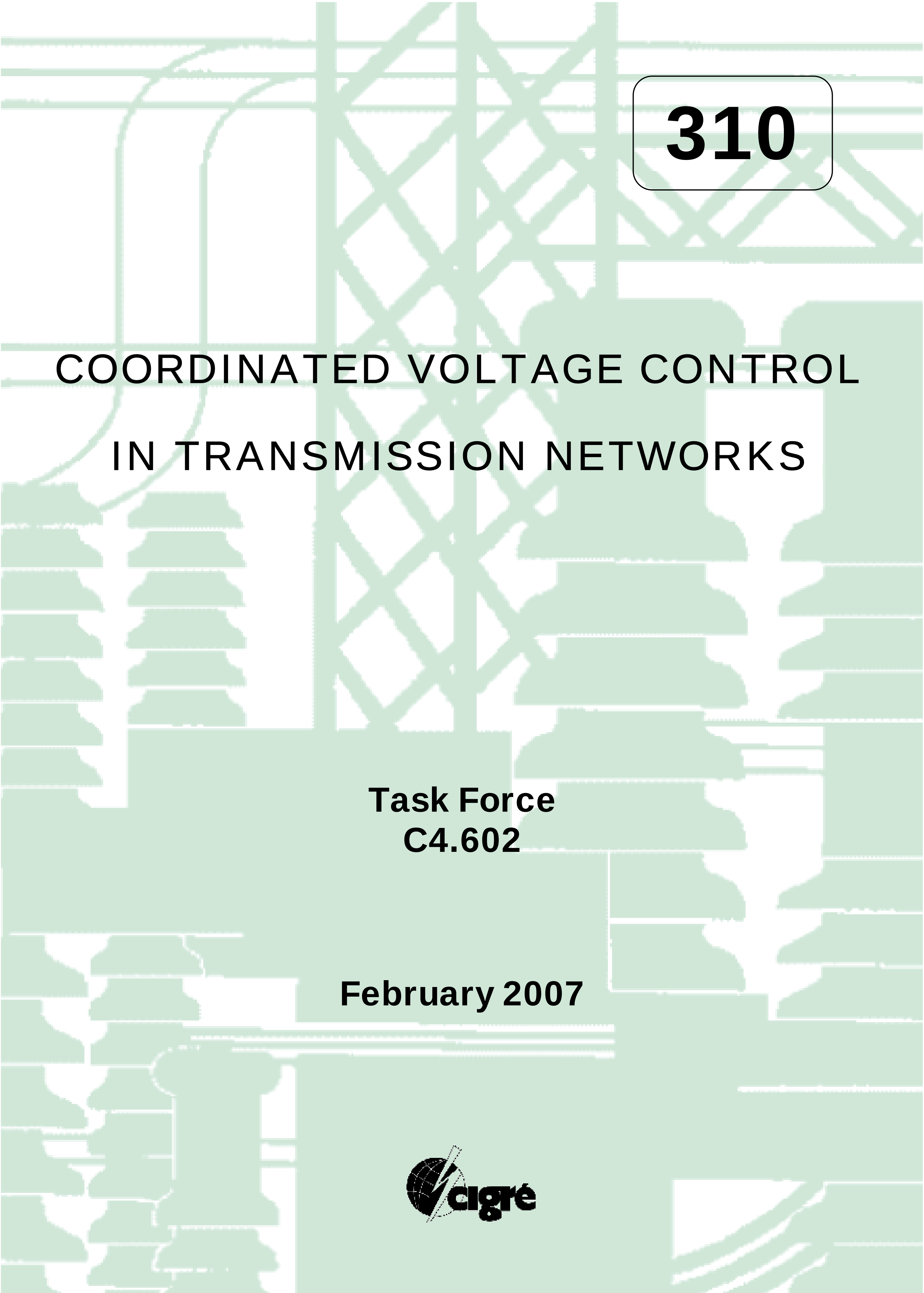

310

COORDINATED VOLTAGE CONTROL IN TRANSMISSION NETWORKS

Task Force
C4.602

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COORDINATED VOLTAGE CONTROL IN TRANSMISSION NETWORKS

Task Force
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CONTENTS

CHAPTER 5 CONTROL SYSTEM DESIGN CHARACTERISTICS 5-1

CHAPTER 6 VERIFIED PERFORMANCE INCLUDING FIELD TESTS 6-1

INDEX OF AUTHORS

CHAPTER 1 **INTRODUCTION**

N. Martins (Lead Editor), S. Corsi

CHAPTER 2 **MAJOR EXISTING CONFIGURATIONS OF HIERARCHICAL VOLTAGE CONTROL (THE BELGIUM, FRENCH AND ITALIAN SOLUTIONS)**

H. Lefebvre (Lead Editor), J. Van Hecke, N. Janssens, J. Deuse, G. F. Promel, G. Fabrice, D. Fragnier, J. Y. Boussion, P. Mallet, M. Bulot, S. Corsi

CHAPTER 3 **ADVANCED HIGH SIDE VOLTAGE REGULATORS**

J. Paserba (Lead Editor), C. Taylor, B. Davies, L. Midford, M. Shimomura, S. Tanaka, H. Kitamura, S. Murdoch, J. Sanches-Gasca, M. J. D'Antonio, R. A. Lawson, S. Corsi

CHAPTER 4 **COORDINATED CONTROL IN TRANSMISSION NETWORKS: CAPACITOR AND REACTOR BANKS, POWER ELECTRONIC DEVICES, AND LTC AUTOTRANSFORMERS**

C. Taylor (Lead Editor), S. Corsi, J. Paserba, S. Imai, K. Uhlen, M. C. Perdomo

CHAPTER 5 **CONTROL SYSTEM DESIGN CHARACTERISTICS**

S. Corsi (Lead Editor), M. Pozzi (Lead Editor), J. Van Hecke, G. Fabrice

CHAPTER 6 **VERIFIED PERFORMANCE INCLUDING FIELD TESTS**

S. Corsi (Lead Editor), M. Pozzi (Lead Editor), J. Van Hecke,

CHAPTER 7 **COMPUTER TOOLS FOR ANALYSIS AND DESIGN INCLUDING TYPICAL SIMULATION RESULTS**

J. Sanches-Gasca (Lead Editor), V. Ajjarapu, J. Van Hecke, N. Janssens, J. Deuse G. F. Promel, A. B. Marques, G. N. Taranto, D. M. Falcão, T. van Cutsem, H. Lefbvre, M. Pozzi

CHAPTER 8 **COORDINATED VOLTAGE CONTROL: COST-BENEFIT ANALYSIS OF ALTERNATIVES AND THE IMPACT OF SYSTEM RESTRUCTURING**

J. Van Hecke (Lead Editor), S. Corsi, G. Fabrice, Les Pereira

CHAPTER 9 **CONCLUSIONS**

N. Martins (Lead Editor), S. Corsi

APPENDICES J. C. R. Ferraz (Lead Editor)

APPENDIX A **EXAMPLE RESULTS ON SECONDARY VOLTAGE REGULATION**

N. Martins, J. C. R. Ferraz, V. Ajjarapu, G. N. Taranto, M. Pozzi

APPENDIX B **VOLTAGE REACTIVE POWER CONTROL STRATEGY IN THE COLOMBIAN TRANSMISSION SYSTEM CONTROL PHILOSOPHY, APPLICATION AND IMPLEMENTATION**

M. C. Perdomo, G. P. Arbeláez

APPENDIX C **IMPACT OF SVCS AND STATCOMS ON THE ITALIAN GRID IN THE PRESENCE OF SECONDARY VOLTAGE REGULATION**

M. Pozzi, C. Canizares

APPENDIX D **SIMULATION STUDY ON COORDINATED SECONDARY VOLTAGE REGULATION ON SVC UNITS IN THE NORDIC POWER SYSTEM**

K. Uhlen, B. Backen

APPENDIX E **POWER FLOW SOLUTIONS INCORPORATING DISCRETE SHUNT VOLTAGE CONTROLS FOR LOAD CURVE FOLLOWING**

N. Martins, J. A. Passos Filho, D. M. Falcão

APPENDIX F **EXAMPLES OF SECONDARY VOLTAGE-VAR CONTROLS APPLIED TO STATIC COMPENSATORS (STATCOMS) FOR FAST CAPACITOR CONTROL AND LONG TERM VAR MANAGEMENT**

J. Paserba

APPENDIX G **ADVANCED VOLTAGE AND REACTIVE POWER CONTROL OF WIND FARM-GENERATORS FOR IMPROVED SYSTEM DYNAMIC PERFORMANCE**

N. Miller

APPENDIX H **A FUZZY INFERENCE SYSTEM APPLICATION TO COORDINATED VOLTAGE CONTROL**

A. B. Marques, G. N. Taranto, D. M. Falcão

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C. Vournas

Executive Summary

This document provides an overview of the current analysis methods and practices on the coordinated transmission network voltage control, showing that its four hierarchical levels appear more or less explicitly in the different operational practices. The expected performances at the different levels are specified in terms of dynamics, operation quality and system security, emphasizing aspects that seem to be technically more advanced, or original. As the automation level varies among the various existing projects (in some cases also the manual control is included), the degree of system security, reliability and quality of operation will differ accordingly.

Several broad lines of research and advanced engineering projects, which have been fully commissioned, to improve the coordinated voltage control of transmission networks are described along with its related software/hardware requirements for: power system and equipment monitoring, operator support decision systems, implementation aspects of tertiary level control, link between coordinated voltage control and wide area protection, etc.

This document constitutes a useful addition to the rich set of references from past CIGRE and IEEE work. In particular this document contributes original material on the coordination of voltage controls, the current practices in various countries, the technological issues involved, and the existing methods of analysis and software tools.

The CIGRE C4.602 task force members and contributors add up to more than 30 individuals, representing 17 organizations in 10 countries. The following provides a brief summary of each of the major chapters.

Organization of this Report

Chapter 1 – Introduction

This chapter describes the transmission network voltage control problem, the voltage control hierarchical schemes adopted in various countries, the current practices and future trends, providing also a list of reports produced by CIGRE and IEEE as evidence of the relevance of the main topic of this report.

Chapter 2 – Major Existing Configurations of Hierarchical Voltage Control (The Belgian, French and Italian Solutions)

This chapter describes the coordinated voltage control schemes in current operation in Italy, France and Belgium. Secondary Voltage Control systems were first introduced in some European countries as a means to improve voltage quality, security and flexibility of operation. Secondary control involves splitting the network into theoretically non-interacting areas, with the voltages within each area being independently controlled. Secondary Voltage Control automatically adjusts the reactive power of certain generating units to control the voltage at a specific point (known as the pilot node) in the area, this being considered representative of the voltages at all points in the area. The similarities and differences among these schemes are described in this chapter.

Chapter 3 – Advanced High Side Voltage Regulators

Automatic regulation of power plant high-side voltage through AVR line drop compensation partially increases grid voltage support at the cost of possibly introducing destabilizing interactions between primary voltage regulators. Modern digital schemes achieve the intended objectives with minimum adverse interactions. Several existing schemes with modern designs are described in this chapter.

Chapter 4 – Coordinated Control in Transmission Networks: Capacitor and Reactor Banks, Power Electronic Devices, and LTC Autotransformers

For systems with very long transmission lines and remote generation, the possible areas without generation can have a conceptually equivalent SVR by coordinating the switching of reactive shunt banks as well as effectively changing the voltage set-points of either the static var compensators or the transformers load tap changers. This chapter, as well as others, is complemented with a few appendices that are listed along the text.

Chapter 5 – Control System Design Characteristics

The essential design characteristics of both the hierarchical voltage control systems considered in Chapter 2 and the advanced high side voltage control regulators described in Chapter 3 are provided in this Chapter. These characteristics comprise: control system architecture, functional organization, main hardware and software design choices for the various equipment, practical implementation aspects, and expected dynamic performance.

Chapter 6 – Verified Performance Including Field Tests

The main results of dynamic performance checking, during field commissioning tests and long-term operation monitoring, are described for the Italian and the Belgian hierarchical voltage control systems.

In the Italian case, the commissioning and monitoring activities were carried out at both power plant level and regional control center level. Information is also given on the future tests that will be carried out to assess the performance of the National Voltage Regulator (NVR) and Losses Minimization Control (LMC), which constitute the Tertiary Voltage Regulation level, to be commissioned in late 2007.

Regarding results on the Belgian hierarchical voltage regulation, only brief comments were provided.

Chapter 7 – Computer Tools for Analysis and Design Including Typical Simulation Results

Various computer tools developed or utilized by utilities, manufacturers, universities and research centers for the analysis and design of hierarchical voltage control schemes are described in this chapter. This chapter is also complemented with appendices describing simulation results obtained with real systems, as well as smaller systems for tutorial purposes. All information provided by active members of this task force on available software was included (albeit with necessary editorial changes) in this chapter.

Chapter 8 – Coordinated Voltage Control: Cost-Benefit Analysis of Alternatives and The Impact of System Restructuring

Use of FACTS controllers for network voltage support, mainly SVC and STATCOM, has been considered in recent years, even though the costs involved do not always justify this choice and, if extensively applied, they would require a coordinated control system similar to that described here for generators. These equipment are however important for dynamic voltage support, improving both angle and voltage stability. This chapter includes a cost-benefit analysis between an SVC based alternative for the regulation of the Italian transmission network voltage profile and the actual SVR and TVC schemes implemented in Italy. With the advent of restructuring and energy market deregulation, hierarchical voltage control systems are becoming increasingly more attractive. System operators recognize that SVR and TVR simplify the automatic control of the transmission network voltages, allow a more direct estimation of the system reactive power margins and also make possible the identification of the contributions of different participants to the voltage regulation ancillary service. Different ownership may present difficulties in building new coordinated voltage regulation schemes or upgrading existing ones, but such an important technical matter calls for specific regulatory rules.

Chapter 9 – Conclusions

This brief chapter attempts to make an overall assessment of the task force work and associated technical report, which were considered very positive. It also suggests topics for additional work in the area, which include: voltage emergency control and voltage wide-area protection in transmission networks.

Appendix A – Example Results on Secondary Voltage Regulation

Appendix B – Voltage Reactive Power Control Strategy in the Colombian Transmission System Control Philosophy, Application and Implementation

Appendix C – Impact of SVCs and STATCOMs on the Italian Grid in the Presence of Secondary Voltage Regulation

Appendix D – Simulation Study on Coordinated Secondary Voltage Regulation on SVC Units in the Nordic Power System

Appendix E – Power Flow Solutions Incorporating Discrete Shunt Voltage Controls for Tracking the Weekly Load Curve

Appendix F – Examples of Secondary Voltage-Var Controls Applied to Static Compensators (STATCOMs) for Fast Voltage Control and Long Term Var Management

Appendix G – Advanced Voltage and Reactive Power Control of Wind Farm-Generators for Improved System Dynamic Performance

Appendix H – A Fuzzy Inference System Application to Coordinated Voltage Control

Chapter 1

Introduction

1.1 The Voltage Control Problem

The control of grid voltage and reactive power in large networks has become even more critical in the last decade, due to the higher utilization of transmission assets. Many facts contribute to this, including: the increased distance between production sites and the load centers; delays in building new transmission projects; larger interconnections and increased meshing; power interchanges over long distances; connection of large capacity units to higher voltage levels, etc. Suitable voltage and var control solutions, capable of dealing with higher loads and associated transmission losses, for multiple scenarios and contingencies, are therefore needed. Nevertheless, the lack of real-time and closed-loop "automatic" coordination of reactive power resources, in common network voltage control practice, unjustifiably persists:

- “Manual” grid voltage control is still currently used by most system operators worldwide and typically involves: dispatching the generating units’ forecasted reactive powers, scheduling the power plants’ high side voltages, switching shunt capacitor or reactor banks for power factor correction and voltage regulation, and setting the voltage set-points of LTC and FACTS controllers. This conventional approach to solving the network voltage control problem is nowadays unsatisfactory because dispatching units’ reactive power and scheduling plants’ high side voltages are based on off-line forecasting and actual network operating conditions may be often quite different from their forecasted values;

- Voltage set-points coordination is often operated according to written operator instructions or requested by the system operator when strongly needed: untimely or inadequate control actions may occur during slow dynamic phenomena following unexpected events.

Automatic regulation of power plant high-side voltage through AVR line drop compensation partially increases grid voltage support at the risk of introducing destabilizing interactions between primary voltage regulators. Modern digital schemes achieve the intended objectives with minimum adverse interactions, as described in Chapter 3.

Use of FACTS controllers for regulating network voltage profile, mainly SVC and STATCOM, has been seriously considered in the last years, even though the costs involved do not always justify this choice and, if extensively applied, they would require a coordinated control system similar to that described here for generators. These equipment are however important for dynamic voltage support, improving both angle and short-term voltage stability.

The most effective solutions for reactive power and voltage control involve some form of coordination among reactive power resources and system controllers. Existing examples of coordinated voltage control solution consider the individual power plant level (plant high side voltage control) or collectively the power plant, regional and central dispatch levels (hierarchical voltage control system). The focus of this report is on coordinated voltage control in transmission networks, with emphasis on existing applications.

Several Coordinated Voltage Regulation (CVR) schemes are currently in continuous operation in practical systems, some of which encompass a whole country. With the advent of restructuring and energy market deregulation, hierarchical voltage control systems are becoming increasingly more attractive. System operators recognize that Secondary Voltage Regulation (SVR) and Tertiary Voltage Regulation (TVR) simplify the automatic control of the transmission network voltages and also make possible the identification of the contributions of different participants to the voltage ancillary service.

Network voltage control (or regulation) has usually been divided into three levels: primary control, secondary control and tertiary control. These levels are temporally and spatially independent by nature. Temporal independence means that the three control mechanisms do not significantly interact with each other, operating in three adjacent time-scales or frequency bands and maintaining robust performance and stability, when facing system changes; if the control laws were more complex there would always be the risk of oscillation and instability. These three levels, whose implementation and degree of automation vary among the various power systems, constitute the hierarchical structure of grid voltage control.

The primary voltage control principles are common to all power systems: keeping generator stator voltages close to their set-point values by means of excitation system controls fitted to all the generating units. Other primary control resources include: the units' reactive power dispatching; power plant high-side voltage regulation; mechanically switched capacitor banks and shunt reactors, and static var compensators.

Secondary Voltage Control or Regulation (SVR) systems were first introduced in some European countries as a means to improve voltage quality, security and flexibility of operation. Secondary control involves splitting the network into theoretically non-interacting areas, with the voltages within each area being independently controlled. An SVR automatically adjusts the reactive power of certain generating units to control the voltage at a specific point (known as the pilot node) in the area, this being considered representative of the voltages at all points in the area. For systems with very long transmission lines and remote generation, the possible areas without generation could have a conceptually similar SVR with a static var compensator coordinating the switching of reactive shunt banks as well as effectively changing the voltage set-points of LTC transformers.

The SVR ensures a more rational and efficient use of the available reactive power resources by automatically performing tasks that could not be performed as effectively by the system operator. This concept is also in line with the modern trend of higher automation, relieving the operator from performing repetitive tasks and keeping him focused on higher-level system monitoring. At the highest level, tertiary control is applied in some European countries to optimize the nationwide voltage map. This involves determining voltage set points for the pilot nodes in order to achieve safe and economic system operation. Tertiary control is currently performed in open loop, but when automated (according to Italian and French plans) will have a time response from 5 to 15 minutes.

1.2 Voltage Control Requirements

The adequate regulation of the transmission network voltage profile significantly contributes to the overall system security, operating economy and to the quality of supply. The control/ equipment requirements to achieve these benefits to system security are detailed below:

- Voltage quality: Voltage levels must be maintained in accordance with the planned schedule, the supplier's contract commitments and the technical constraints;

- Power system security:

  - The loss of one infeed or line must not endanger the network (i.e. a sufficient reactive power reserve should be made available);
  - Voltage values must remain within ranges compatible with equipment functional specifications (equipment overvoltage limits, minimum voltage for power station auxiliaries);
  - Voltage control efforts must be evenly distributed among available resources in order to avoid excessive currents in utility equipment;
  - Voltage control co-ordination contributes to network stability (for example, it increases the system voltage stability margin, or it may reduce the angle difference between generators).

- Operating economy: The cost of production including losses (static optimization problem) and the cost of generation operated according to security constraints (essentially a dynamic problem) should be minimized.

Voltage control is therefore a problem of dynamic optimization with security constraints. It involves a very wide range of time constants (from a few hundred milliseconds for the compensation of rapid fluctuations to several hours for load following and the associated problem of generator start-up and shutdown). Voltage control actions must therefore be structured over several time scales. Furthermore, voltage control requires various forecast studies (daily, weekly, monthly), whose aim is to define the best equipment arrangement for real-time control and the optimized voltage plan to be implemented.

Another major aspect is the local nature of the voltage/reactive power control, as opposed to frequency/active power control. Reactive power control action (generator excitation, capacitor/reactor switching, etc...) has therefore mainly a local impact, making possible to define many voltage control areas in an interconnected network. However, in the case of strongly interconnected networks, these areas may not be sufficiently decoupled and can develop significant adverse interaction.

Geographical and temporal coordination of control actions are thus needed to meet the various functional requirements (quality, security, economy).

1.3 The Voltage Control Hierarchy

The resources used for controlling the network voltage profile act according to pre-defined control strategies. The main resources include generators, synchronous compensators, capacitors and reactors, transformer taps, whereas controls include the voltage control system of generator, the reactive power control system of power plant, the voltage control system of area/region, the voltage control system of load tap changer, the centralized-remote voltage control system, etc. The operating practices of the various utilities reveal control resources and actions are organized in a hierarchical structure. The voltage control hierarchy comprises three levels, which we shall refer to as “Primary”, “Secondary” and “Tertiary” and a forecast level (referred to as “Forecast Studies"). The first two levels surely refer to real-time and closed-loop control, whereas the Tertiary control may be of automatic or manual type. The Forecast Studies involve only off-line studies.

1.3.1 Primary Voltage and Reactive Power Control

Primary control relates to automatic actions on individual equipment based on local measurements. The time scale ranges from 100 ms up to some seconds.

The devices that utilize primary voltage control are:

- Generators or synchronous compensators fitted with voltage regulators (AVR);
- Static var compensators;
- Capacitors and reactors when involved in automatic voltage control (mechanically switched, for example, on a voltage criterion);
- Automatic load tap changers;
- Automatic topology changers for stability improvement, (based on a local criterion).

The generator voltage control is mostly aimed to suitably maintain the stable interconnection to the grid during steady-state and dynamic conditions. The other controls are mostly aimed at improving the overall system performance (i.e. steady state stability, power flows, and voltage quality).

1.3.2 Secondary Voltage and Reactive Power Control

The terms Secondary Voltage Control and Secondary Voltage Regulation will be used interchangeably in this document, but only the acronym SVR will be used.

SVR performs the coordination of control resources within a voltage control area aiming at improving voltage quality in the transmission system and maintaining system security, the time scale being between one to a few minutes (when automatic).

Secondary voltage/var control (automatic or manual, depending on the utility) is essentially a centralized area control, even though it is decentralized with respect to the whole system or interconnection. It must minimize harmful interactions between the various primary elements, generally by using a non-interacting control law. Processing all the needed information requires monitoring a fairly wide and coherent geographical area. In addition, this type of control is designed to handle, within practical limits, any single contingency and still follow the load.

SVR performs the real time adjustment (manually or automatically) of the Primary Control reference points (voltage, reactive power) and handles control resources (by continuous controls as well as by switching on/off or up/down commands) as a function of system requirements.

Additional functions may be required: generator start-up and shut-down for voltage support, distribution voltage reductions, tap changer blocking and load-shedding. Finally, the required time decoupling between primary response and secondary response is implemented by proper selection of controller time constants: the secondary control response time should not be less than one minute and not higher than a few minutes in the presence of the Tertiary level.

1.3.3 Tertiary Voltage and Reactive Power Control

Tertiary voltage control is strongly related to economy and/or security optimization at the highest administrative authority level (utility, pool, or country). This is a relatively slow control (response time around 10 minutes when automatic), based on real-time measurements. TVR operates on the set-points of the Secondary Voltage level. In case the Tertiary level directly controls the Primary level, as in the Belgian system, the system voltage control is only based on the Tertiary level dynamics.

Clearly, tertiary control response time depends on dispatcher reaction time (manual control) or the time required to compute new reference values (computer assisted manual control or automatic). This response time must not be too long (to prevent the network from moving towards an insecure condition) or too short (to avoid any conflicting action with the primary and secondary controls). In case of an automatic closed-loop Tertiary Voltage Control, its response time should not be lower than 5 minutes in order to preserve temporal independence from Secondary Voltage Control.

Even in the absence of an automatic closed-loop Tertiary Voltage Control, some utilities have adopted an automatic secondary control (which does not attempt to reach the necessarily delayed optimum) aimed at providing satisfactory static and dynamic behavior during the time period between the primary control (very fast) and the tertiary control (relatively slow).

1.3.4 Voltage and Reactive Power Forecast Studies

This involves all the predictive studies and actions carried out to optimize voltage and reactive power controls, aiming at producing a satisfactory and coordinated behavior of its various components:

- The forecast studies are carried out for various time horizons (day-ahead, week-ahead, month-ahead);

- The forecast studies are used to optimize the system voltages and reactive powers by defining the settings of the available controls, also including the choice of non-automatic transformer taps. Network reliability is considered in these studies by checking the control margin for each forecasted scenario;

- The forecast studies attempt to establish a voltage profile, which is both economical and safe. Forecast studies have to be conservative in terms of reliability and therefore may not be optimum in terms of economy. Sufficient reactive reserve must be provided within each area to ensure the system will be capable of riding through "normal" operating incidents;

- Forecast studies aim at maintaining economy within reliability constraints for much longer time horizons than those dealt by Primary, Secondary and Tertiary Control, which are meant for online operation. According with the real time data needs, the Tertiary Voltage Level pursues the forecasted reference values as close as possible, while ensuring system security and reliability.

1.4 Previous CIGRE and IEEE Efforts and Focus of This Task Force

The combined efforts of the various CIGRE and IEEE task forces, convened to study transmission voltage control and stability issues, produced a vast amount of valuable material:

- CIGRE Task Force 38.02.03 – “Improvement of Voltage Control”, Electra, No. 135, pp. 114-127, 1991.

- CIGRE Task Force 38.02.10 – “Modeling of Voltage Collapse Including Dynamic Phenomena”, CIGRE Brochure No. 75, 1993; summary in Electra, pp. 71-77, April 1993

- CIGRE Task Force 38.02.11 – “Indices Predicting Voltage Collapse Including Dynamic Phenomena”, 1994.
- CIGRE Task Force 38.02.12 – “Criteria and Countermeasures for Voltage Collapse”, 1995.
- CIGRE Task Force 38.01.08 – “Modeling of Power Electronics Equipment (FACTS) in Load Flow and Stability Programs”, 1999.
- IEEE Tutorial Course – “Reactive Power: Basics, Problems and Solutions”, 87EH0262-6-PWR, 1987.
- IEEE Special Publication – “Voltage Stability of Power Systems: Concepts, Analytical Tools and Industry Experience”, 90TH0358-2-PWR, 1990.
- IEEE Special Publication – “Suggested Techniques for Voltage Stability Analysis”, 93TH0620-5-PWR, 1993.
- IEEE Special Tutorial Course – “Voltage Stability”, 1998.
- IEEE PES Special Publication – “Voltage Stability Assessment: Concepts, Practices and Tools”, SP101PSS, 2002.

This document constitutes a useful addition to this set of references. In particular this document contributes original material on the coordination of voltage controls, the current practices in various countries on coordinated control, the technological issues involved, and the existing methods of analysis and software tools.

1.5 Glossary or List of Acronyms

AGC	Automatic Generation Control
AVR	Automatic Voltage Regulator
CSVR	Coordinated Secondary Voltage Regulation
EHV	Extra-High Voltage
HSVC	High Side Voltage Control
HV	High Voltage
IPP	Independent Power Producer
ISO	Independent System Operator
JVC	Joint Var Control
LDC	Line Drop Compensation
LMC	Losses Minimization Controller
LTC	Load Tap Changer
LV	Low Voltage
MSVC	Master Station Voltage Control
MV	Medium Voltage
NVR	National Voltage Regulator
OEL	Over Excitation Limiter
PVR	Primary Voltage Regulation
RCC	Reactive Current Compensation
REPORT	Power Plant Voltage and Reactive Power Regulator
RTU	Remote Terminal Unit
RVR	Regional Voltage Regulator
SCADA	Supervisory Control and Data Acquisition
STATCOM	Static Compensator, based on Voltage Sourced Converter Technology

SVC	Static VAR compensator
SVR	Secondary Voltage Regulation
TVR	Tertiary Voltage Regulation

Chapter 2

Major Existing Configurations of Hierarchical Voltage Control (The Belgian, French and Italian Solutions)

2.1 Configuration of the Hierarchical Control System in Belgium

2.1.1 Primary Voltage Regulation

Coordinated Voltage Control in Belgium uses Primary and Tertiary Voltage Regulation, without the Secondary Voltage Regulation level [2-1].

This was made possible by an appropriate coordination of the Primary Voltage Regulation through the harmonization of the reactive droop of generator AVRs.

The reactive droop is defined using the approximate steady state AVR characteristic:

$$U = U_S - X_Q \cdot I_Q \qquad (2.1.1\text{-}1)$$

With:

U	Transmission voltage at the generator high-side bus:
U_S	Set point of the AVR;
X_Q	Reactive droop as seen from the grid;
I_Q	Reactive current injected by the generator into the grid.

A small reactive droop makes generators near a voltage disturbance react more vigorously and keeps the voltage more constant at their HV injection point. Consequently other generators will contribute less.

A larger reactive droop makes more generators contribute by changing reactive power production following a voltage disturbance, but ends up with less constant voltages.

In Belgium, an acceptable trade off value for the reactive droop for generators injecting in the HV grid was found to be about 10 % (base: rated reactive production). This means that a voltage drop of 10 % at a generator's HV injection point would increase its reactive production from zero to rated Mvar.

In Belgium generator AVRs were tuned over a 10-year (1985-1995) harmonization campaign. The outcome is, that following a disturbance the automatic reaction by the Primary Voltage Regulation results in a sufficiently acceptable voltage and in a sufficiently widespread reactive generation response as to avoid excitation limits. As a result, there is no urgent need for a fast acting reallocation of the reactive production over the generators, so that the installation of relatively expensive Secondary Voltage Control could be avoided (or postponed for many years).

2.1.2 Tertiary Voltage Regulation

The Belgian Tertiary Voltage Regulation (TVR) is operational since 1998 as an on-line grid operator support.

The TVR aims at a system-wide voltage regulation “optimum”, combining maximum voltages, minimum losses and best reactive power production spread, while limiting LTC transformer tap changes and shunt capacitor bank switching.

Based on State Estimator results, the TVR automatically recommends every 15 minutes, (or upon operators direct request) optimum generator AVR voltage setpoints, LTC transformer tap settings, and shunt capacitor switching. Comprehensive overviews are displayed to the operator, who has the final responsibility of applying the TVR results as a whole or partially, or disregard them.

TVR recommended actions can be implemented by the operator by pressing a single button with all the grouped commands.

2.2 Configuration of the French Hierarchical Control System

2.2.1 Voltage Control Mechanisms on the Transmission Network

The coordinated voltage control of the French EHV (extra-high voltage) network operates at three different levels, which are temporally and spatially independent. Temporal independence means that the three control mechanisms do not interact; if they did, we would risk oscillation or instability.

- Primary control involves keeping generator stator voltages at their set-point values, by means of controls fitted to all the generating units. This performs partial automatic correction, within a few seconds, to compensate against rapid random variation in the EHV voltage;
- In its present form, secondary regulation is chiefly effected through the secondary voltage regulation (SVR) system, which has a time constant of a few minutes and compensates against slower voltage variations. Secondary regulation involves splitting the network up into theoretically non-interacting zones, within which voltage is controlled individually. SVR automatically adjusts the reactive power of certain generating units to control the voltage at a specific point (known as the pilot node) in the zone, this being considered representative of the voltages at all points in the zone. However, a faster and more precise type of secondary regulation system – Coordinated Secondary Voltage Regulation, or CSVR – has been in use in western France over the last five years, and is eventually expected to take over from the existing SVR system;
- At the highest level, tertiary regulation is applied to optimize the nationwide voltage map. This involves determining voltage setpoints for the pilot nodes in order to achieve safe and economic system operation. Tertiary regulation is currently not automated, but if it were, it would have a time constant of around 20 minutes.

2.2.2 Secondary Voltage Regulation (SVR): Principles

Secondary Voltage Regulation began to be widely implemented in 1979. Much has already been written about the SVR system [2-2, 2-3, 2-4].

Figure 2-1 shows the SVR block diagram.

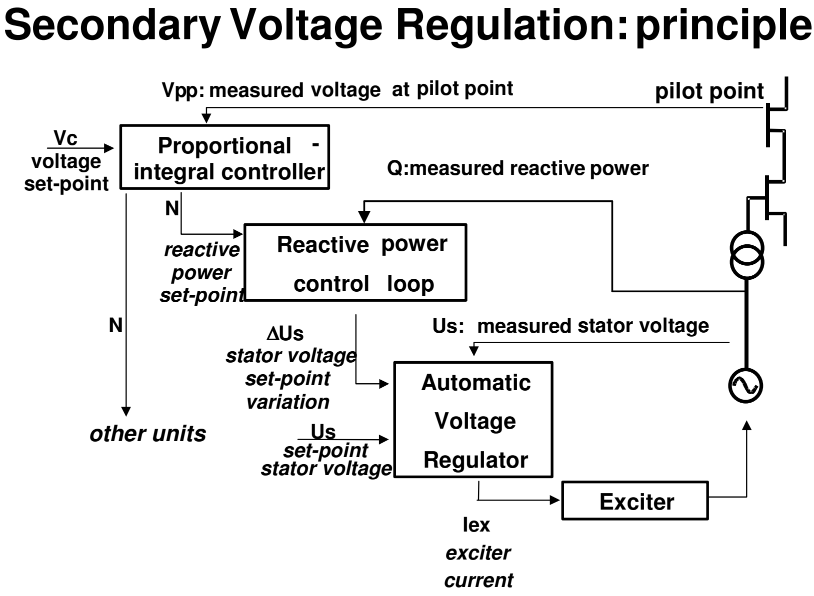


Figure 2-1 *SVR block diagram.*

The basic principle of the system in current use consists in dividing the EHV network into distinct control "zones". These zones need to be homogeneous from the point of view of voltage. Voltage is controlled in each zone by automatic regulation of the reactive power supplied by a set of generators belonging to the zone (called "regulating generators"). This regulating action is performed so as to control the voltage at a special point in the zone called "pilot node", this being considered representative of the voltages at all points in the zone. At present, France's transmission network comprises about 35 control zones including about 100 thermal generators (conventional fuel and nuclear) and 150 hydraulic generators. Total reactive power capacity available to perform voltage control is estimated at more than 30 000 Mvar.

The Secondary Voltage Regulation system regulates the voltage profile in each zone by distributing reactive power requirement among the various regulating generators. A control system comprising two distinct regulation loops is superimposed on the primary loop (AVR) of the regulating generators (Figure 2-1).

A proportional-integral law is used to calculate a control signal *N*, also termed the "level" of the zone, from the difference between the set-point value at the pilot node and the voltage effectively measured at the given instant. The level thus indicates the zone's reactive power requirement.

$$N = \alpha \int_0^t \frac{Vc - Vp}{Vn} dt + \beta \frac{Vc - Vp_{moy}}{Vn}$$

Where:

α, β	Integral and proportional gains;
V_P, V_C, V_n	Measured, set-point and nominal voltages;
V_{Pmoy}	Measured value at generating units

The level is calculated by a dedicated microcomputer located in the zone's regional dispatching center. The signal is then transmitted via a communication link to each regulating generator where it is used as setpoint for a second control loop governing reactive power generation. Each regulating generator participates in voltage control proportionally to its reactive power capacity.

The time constant established (3 min) lets the system perform its two main functions with sufficient speed. These two functions consist in automatically maintaining a satisfactory voltage profile when load varies and automatically restoring the voltage profile following a network incident so as to increase the operating safety margin.

2.2.3 HV Capacitor Control Integration

Automatic control of the HV capacitors becomes necessary when amount of Mvars required is high. Automatic control can be carried out at a local level (according to a voltage criterion for instance) or centrally. The local approach may result in inefficient use of all the reactive power sources available in case of incident, or even in functional incompatibilities. For this reason, action has been oriented towards integrating HV capacitor control into the secondary voltage regulation system. Integration is governed by the following principle: the capacitors are switched on a priority basis, as soon as the need to increase reactive power generation arises. In this way, a large reserve of reactive power can be maintained at generator level, which is immediately available in the event of an incident. Capacitors are progressively switched in, beginning with those at the lowest voltage level.

2.2.4 Limitations of SVR System

The SVR system has been in operation since the early eighties and has given satisfactory service despite some limitations, some of which are mitigated by extensive operating experience.

Some of these limitations of the SVR system are structural:

- In some regions, coupling between theoretically independent zones has increased as a result of grid development after the implementation of SVR. Therefore the number of zones should be updated or degradation in control dynamics has to be accepted;
- SVR requires reactive-power alignment of the generating units involved, but makes no allowance for excessive demand that might be made on certain units as a result of differences in physical proximity;

- The internal reactive-power control loop at generating-unit level is a destabilizing factor that can actually amplify the initial disturbance in the first few instants following certain incidents (generator drop-out for example).

Other limitations are design-related:

- The system makes only partial allowance for operating constraints. For example, it does not fully integrate monitoring of permissible voltage limits or generating unit operating limits;
- Control loop parameters are fixed, which precludes optimum tuning for operating conditions;
- The signal representing the required reactive power level varies at a rate that makes no allowance for generating unit response capabilities.

Structural limitations can only become more acute as the system grows, and there will come a time when renovation is required to address equipment ageing. For both of these reasons, it was decided to develop a more sophisticated secondary regulation system, known as CSVR, for "Coordinated Secondary Voltage Regulation”.

2.2.5 Coordinated Secondary Voltage Regulation (CSVR): Principles

This new system has been operating in western France since 1998. It is called Co-ordinated Secondary Voltage Regulation system (CSVR) because control signals for neighbouring zones are no longer calculated on an independent basis, as is the case in the SVR system. More details are available in [2-5, 2-6]

The design of the CSVR is based on a layout similar to that used in the SVR with the additional goal of eliminating the limitations described.

The basic principle governing the CSVR system continues to be that of regulating pilot node voltages at set-point values. However, the control signal is calculated for a “region” comprising several pilot nodes and the effects of individual generators on all pilot nodes are correctly taken into account.

In closed-loop mode, it computes fresh setpoint values for the generator unit primary controls. The undesirable effects of reactive power changes, due to SVR action, are therefore avoided.

These set-point values are obtained, by minimizing the following multi-variable quadratic function:

$$\min \left\{ \lambda_v \left\| \alpha (V_c - V_{pp}) - C_v \Delta U_c \right\|^2 + \lambda_q \left\| \alpha (Q_{ref} - Q) - C_q \Delta U_c \right\|^2 + \lambda_u \left\| \alpha (U_{ref} - U) - \Delta U_c \right\|^2 \right\}$$

Where:

α	Control gain;
V_{pp}, V_c	Measured and set-point voltage values at pilot nodes;
Q, Q_{ref}	Measured and set-point reactive power values at generating units;
U, U_{ref}	Measured and set-point stator voltage values;
ΔU_c	Vector of stator voltage variation;
$\lambda_v, \lambda_q, \lambda_u$	Weightings for terms in objective function: pilot point voltage, reactive

	power, and generator unit stator voltage;
C_v	Sensitivity matrices relating variations in pilot point voltage to variations in stator voltage (Network is modelled by sensitivity matrices for coordination between generating sites).
C_q	Sensitivity matrices relating variations in reactive power to variations in stator voltage.

Network and generator constraints are taken into account at each computation step using the following equations.

$$
\begin{aligned}
&\left\|\Delta U_c\right\| \le \Delta U_{\max} \\
&a\left(Q + C_q \Delta U_c\right) + b\Delta U_c \le c \\
&V_{pp_{\min}} \le V_{pp} + C_v \Delta U_c \le V_{pp_{\max}} \\
&V_{ps_{\min}} \le V_{ps} + C_{vs} \Delta U_c \le V_{ps_{\max}} \\
&V_{THT_{\min}} \le V_{THT} + C_v \Delta U_c \le V_{THT_{\max}}
\end{aligned}
$$

Where:

a, b, c	Coefficients of straight lines representing operating diagrams for generator units (P, Q, U). These diagrams depend on the active power output of the generator;
$V_{pp}, V_{pp_{\min}}, V_{pp}^{\max}$	Measured, minimum and maximum voltage at pilot points;
$V_{ps}, V_{ps_{\min}}, V_{ps}^{\max}$	Measured, minimum and maximum voltage at sensitive points;
V_{THT}	Voltages computed at generator unit EHV output.

The control system monitors the voltage at a limited number of network nodes, or “sensitive nodes”. Sensitive nodes are nodes at which the voltage must be kept between upper and lower limits, though it is not controlled to a set-point value like at a pilot point.

The weightings in the objective function may be adjusted to suit different control policies, giving priority to keeping pilot point voltages at reference values (high voltage values, for example), or to keeping reactive power generation close to the lower limit in order to gain reactive power margins. In practice, the weighting for EHV voltages is higher than that for the two other terms.

After five years under full-time operation in western France, CSVR has gained local operators confidence and showed its many advantages over the existing SVR system.

The experimental CSVR project reveals three major benefits:

- The voltage map is more stable, precise, and less demanding on the generating units reactive power;
- Coordination improves the utilisation of reactive reserves available at the generating units, by making higher demand on the units closest to the perturbation. This represents a decisive advantage over the SVR system, which simply aligns the reactive power demand from all generating units, regardless of physical proximity. In addition, static var compensation systems are under centralized control via the CSVR, whereas this capability was rarely used with the SVR system. And because CSVR evens out the control effort among generating units, it affords an overall increase in available reactive power reserves;

- The CSVR system has a better dynamic response (Figure 2-2) and this relieves operators from certain practices that were needed to mitigate problems associated with the imperfections in the SVR system (e.g. anticipation of high variations in consumption).

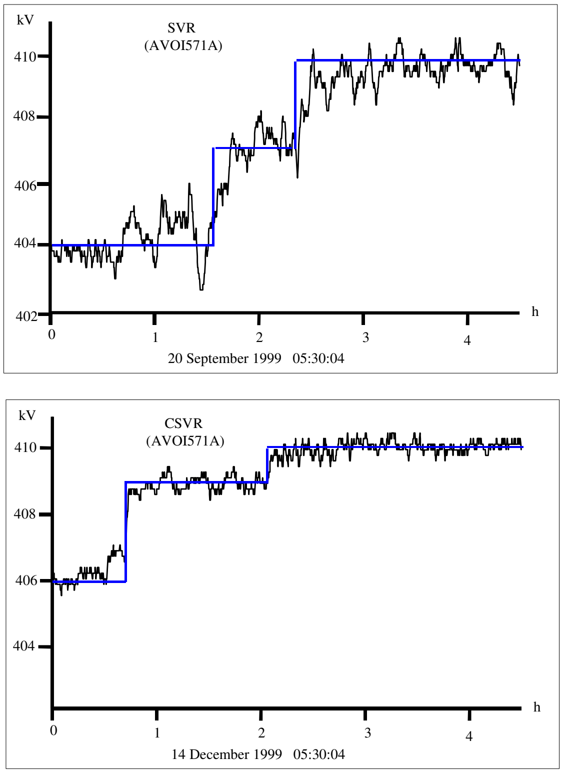
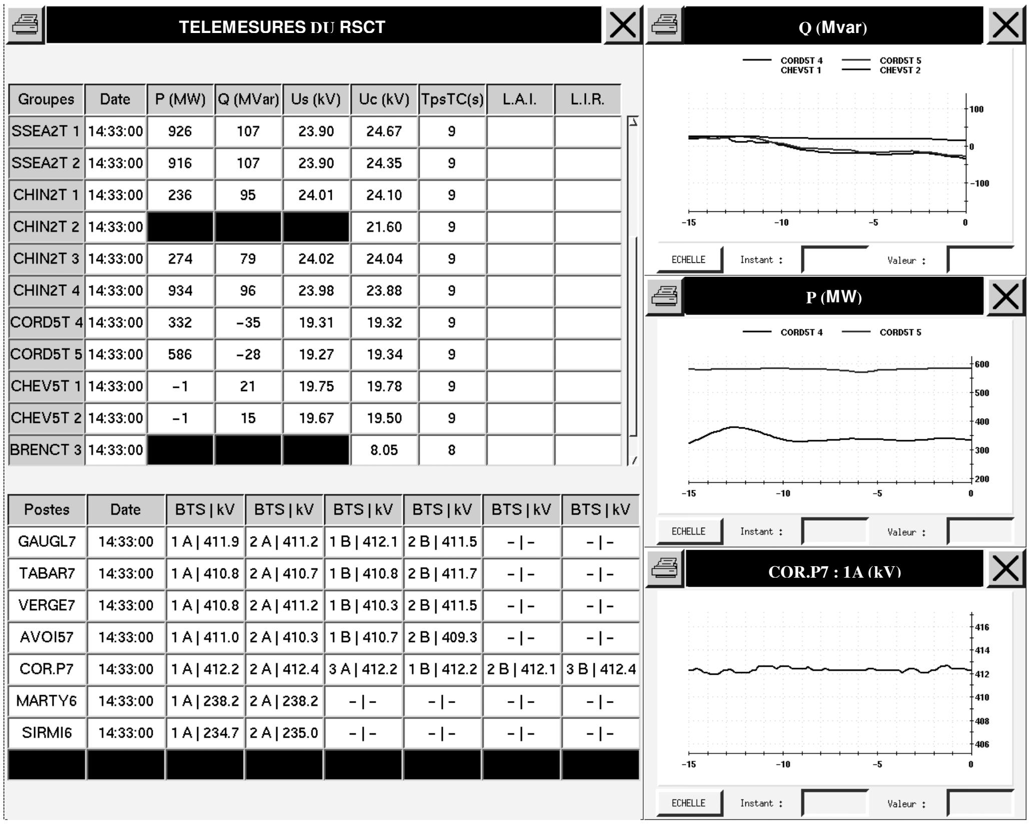


Figure 2-2 *Voltage set-point and voltage response with SVR and CSVR.*

We should also note three other improvements, which do not bring immediate cost savings, but greatly facilitate the operator's routine management tasks:

- Due to the voltage management priority, set-point values are determined naturally under the CSVR system, without producing abnormal transients. This contrasts with SVR, which requires prior initialization based on an evaluation of generator reactive power, followed by a standby period of five minutes (during which the set-point voltage must not be modified) in order to allow reactive power alignment among the generating units. And whereas CSVR control of a generating unit requires no special precautions, SVR control can require the operator to perform corrective action on the control level, because of the transient induced in the primary voltage control system;
- As CSVR offers higher measurement accuracy and valuable interface functions, operators continuously utilize it to monitor voltages over the whole western France network (Figure 2-3);



Groupes	Date	P (MW)	Q (MVar)	Us (kV)	Uc (kV)	TpsTC(s)	L.A.I.	L.I.R.
SSEA2T 1	14:33:00	926	107	23.90	24.67	9		
SSEA2T 2	14:33:00	916	107	23.90	24.35	9		
CHIN2T 1	14:33:00	236	95	24.01	24.10	9		
CHIN2T 2	14:33:00				21.60	9		
CHIN2T 3	14:33:00	274	79	24.02	24.04	9		
CHIN2T 4	14:33:00	934	96	23.98	23.88	9		
CORD5T 4	14:33:00	332	−35	19.31	19.32	9		
CORD5T 5	14:33:00	586	−28	19.27	19.34	9		
CHEV5T 1	14:33:00	−1	21	19.75	19.78	9		
CHEV5T 2	14:33:00	−1	15	19.67	19.50	9		
BRENCT 3	14:33:00				8.05	8		

Postes	Date	BTS | kV	BTS | kV	BTS | kV	BTS | kV	BTS | kV	BTS | kV
GAUGL7	14:33:00	1 A | 411.9	2 A | 411.2	1 B | 412.1	2 B | 411.5	– | –	– | –
TABAR7	14:33:00	1 A | 410.8	2 A | 410.7	1 B | 410.8	2 B | 411.7	– | –	– | –
VERGE7	14:33:00	1 A | 410.8	2 A | 411.2	1 B | 410.3	2 B | 411.5	– | –	– | –
AVOI57	14:33:00	1 A | 411.0	2 A | 410.3	1 B | 410.7	2 B | 409.3	– | –	– | –
COR.P7	14:33:00	1 A | 412.2	2 A | 412.4	3 A | 412.2	1 B | 412.2	2 B | 412.1	3 B | 412.4
MARTY6	14:33:00	1 A | 238.2	2 A | 238.2	– | –	– | –	– | –	– | –
SIRMI6	14:33:00	1 A | 234.7	2 A | 235.0	– | –	– | –	– | –	– | –

Figure 2-3 *Monitoring voltage MMI.*

- Reactive power management is improved because the operator can change the Q_{ref} value (reactive power reference value in optimization function) for one or more generating units in order to adapt operating points to a particular strategy.

These CSVR improvements enable the system to run closer to its actual operating limits, which is particularly pertinent under degraded network conditions following multiple incidents. Specifically, we note an increase in voltage collapse margin. By way of example, analysis shows that the CSVR system was instrumental in minimizing the impact of an incident in western Brittany in early 1998. Subsequent examination showed that in a similar situation the SVR system would have caused oscillations in voltage and reactive power among the generating units; this definitely would have disturbed operator monitoring and control functions, and would very possibly have introduced further complications.

2.2.6 Concluding Remarks on SVR and CSVR

Technical advantages of CSVR appear obvious. Taking into account local operating constraints, it has been decided to extend the Coordinated Voltage Regulation in the south-east of France. Nevertheless, to ensure a good compromise between cost and security for this different area of the French system, some small changes are required (in terms of accuracy or transmission delay) on the CSVR scheme implemented in the western part of France.

2.3 The Italian Hierarchical Voltage Control System

2.3.1 Basic Concepts of the Italian Secondary and Tertiary Voltage Regulations

The basic concepts of the Italian Secondary Voltage Regulation (SVR [2-7, 2-8, 2-9] are summarized here, focusing on the control system structure, expected performance and verified advantages:

- The idea to automatically control in real-time hundreds of transmission bus voltages is too complex and not reliable and therefore unrealistic and uneconomic;
- The generating units reactive power is, obviously, the main resource, at low cost, for network dynamic voltage support;
- A realistic simple voltage control system should be simple and consider a few dominant buses only, allowing a sub-optimal, but feasible and reliable control solution;
- Dominant bus ("pilot node") idea assumes as joint-buses those having high electrical coupling and voltages close to each other within a "regulation area";
- The control structure, depending on the grid subdivision into "regulated areas", automatically and (as much as possible) independently regulates each pilot node voltage;
- The reactive powers of the largest units in the area ("control plants") exert a major influence on the local pilot node voltage.

The Tertiary Voltage Regulation (TVR) is needed to increase the system operation security and efficiency, and involves the centralized coordination of the SVR decentralized structure:

- The pilot node voltage set-points are adequately updated and coordinated with dynamics slower than SVR, considering the operating condition of the overall grid and avoiding unnecessary and/or conflicting inter-area control efforts;
- The pilot node voltage set-points are computed and updated in real-time;
- The pilot nodes voltage set-points may be optimized to reduce grid losses, while preserving control margins.

Despite the goal of minimizing control system complexity, a considerable effort is required to achieve an effective voltage regulation in large transmission network. On one hand, a new power plant voltage and reactive power regulator is needed for controlling the reactive power production of generating units, as well as of synchronous compensators, according to the local bus or remote pilot node voltage regulator and taking into account the instantaneous available capability of the plant generators. On the other hand, a specific regional voltage regulator for the Regional Dispatcher is necessary for automatically maintaining pilot node voltages at their scheduled values, controlling by fast telecommunications the new power plant apparatus, switching reactors and shunt capacitor banks, ordering LTCs and FACTS controllers set-points. Lastly, a new voltage and reactive power optimizing regulator is required at the national/utility control level, for coordinating and updating, on-line and in real-time, all the pilot node voltage set-points (see Figure 2-4). All these special control apparatuses are not available on the market and until now they had to be specifically designed, developed and commissioned by the interested utilities or system operators.

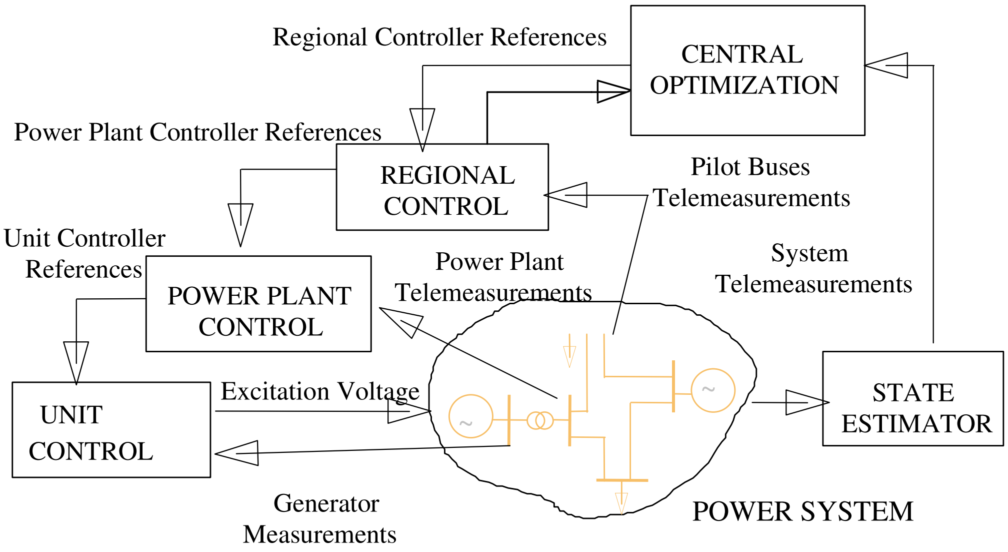


Figure 2-4 *The hierarchical voltage control structure for the Italian transmission network.*

2.3.2 The Control System Description

The Italian hierarchical voltage control system (see Figure 2-5) regulates in closed loop the voltages of the main EHV buses (pilot nodes), by driving in real-time the reactive resources that mostly influence these buses.

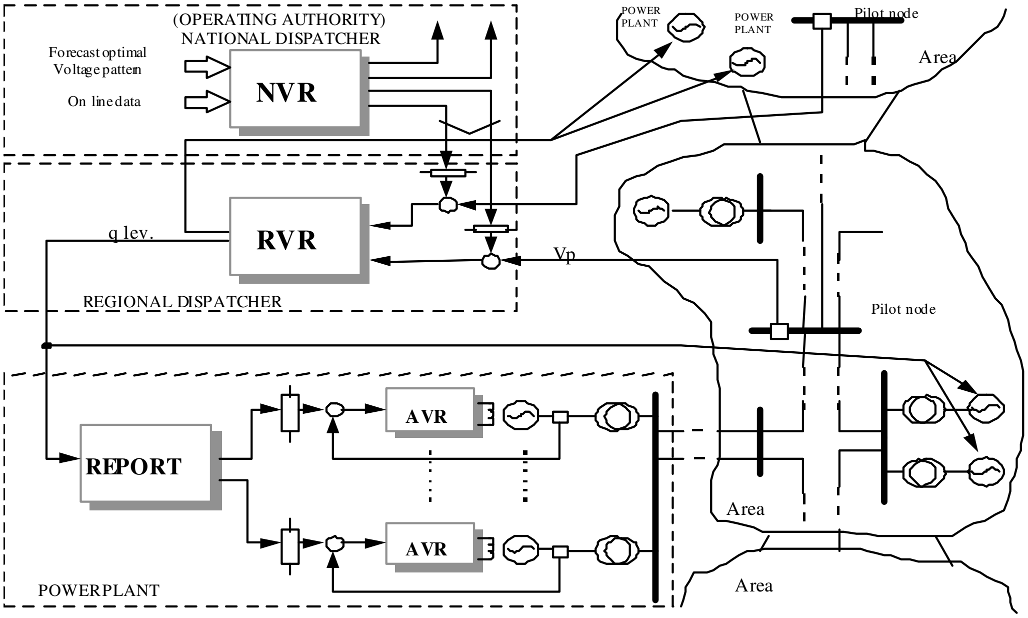


Figure 2-5 *Schematic diagram of Italian hierarchical Voltage Control System.*

The Regional Voltage Regulators (RVRs) close the control loops of the pilot node voltages, providing each area with a specific reactive power level, which drives the power plants Voltage and Reactive Power Regulators (REPORTs). In turn, REPORT closes the reactive power control loops of the plant units, directly operating on the set-points of the Automatic Voltage

Regulators (AVRs). RVR also operates the control of capacitor banks, shunt reactors, LTCs and SVCs for avoiding saturation of area generators. AVR fast control is called Primary Voltage Regulation (PVR). The combination of REPORT [2-10] and RVR [2-11] constitutes the SVR. At the highest hierarchical control level, a Tertiary Voltage Regulator (TVR) [2-12, 2-13, 2-14], co-ordinates in real-time, and in closed-loop the RVRs.

An Optimal Reactive Power Flow for Losses Minimization Control (LMC) [2-15, 2-16] computes, in short (day ahead) or very short (minutes ahead) terms, the forecasted optimal voltages and reactive levels, starting from the foreseen/current state estimation. Therefore TVR minimizes the differences between the actual field measurements and the optimal forecasted references. This computed "compromise" represents, at each instant, the "optimum" voltage plan.

The hierarchical voltage control system has different operation modes, according to its implementation level, maintenance interventions and transient or persistent failures:

- Without plant telecommunications, or when the RVR is not operating, REPORT automatically regulates the voltage of local EHV bus (high side voltage regulation), according to defined daily trends or plant operator voltage set-points, agreed by phone coordination with regional dispatcher;
- Without telecommunications or when TVR is not operating, the RVR autonomously regulates the pilot node voltages of its controlled areas, according to stored daily trends or regional dispatcher chosen voltage set-points, agreed by phone coordination with national control center;
- When the LMC is not in service, the TVR autonomously coordinates the RVRs assuming as reference for the optimization of pilot node voltages and reactive powers margins the available long term forecasted optimal plan, or the reference values in the national control center operator instructions.

The Italian ISO (GRTN) has completed the application of REPORT apparatus to all the main power plants, as well as of the RVR systems at the regional dispatcher control rooms, and is now defining voltage service rules for the operating SVR. The control system is working for many years without significant limitations.

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Chapter 3

Advanced High Side Voltage Regulators

3.1 Line Drop Compensation, High Side Voltage Control and Secondary Voltage Regulation

Generators typically regulate terminal voltage via automatic voltage regulator (AVR) and exciter equipment. The desired high side (transmission side) voltage schedule is usually maintained by the power plant operator or by slow SCADA-type process control computers. Power system dynamic performance, however, can be improved by faster regulation of the transmission voltage.

This section presents and debates various methods of transmission voltage control, with emphasis on voltage control by power plants. The controls are secondary to AVR automatic voltage regulators, which most commonly control generator terminal voltage (line drop compensation is also within the scope of this section). Secondary controls may be local to the power plant, providing an outer loop to regulate transmission-side voltage and equalize reactive power output of individual generators; this is by adjustment of individual generator AVR setpoints. For optimization, emergency boosting, and coordination of closely coupled power plants, the transmission-side voltage schedule or setpoint may come from a control-center-based tertiary loop. Control is generally hierarchical, with secondary voltage control being an order of magnitude slower than AVR, and tertiary control being an order of magnitude slower than secondary control. The primary and secondary loops may be combined for fast regulation of high side voltage similar to an SVC.

Digital technology and modern communications facilitate advances in voltage and stability control [3-1]. With regard to long-term voltage stability, many references describe prior work [3-2, 3-3].

3.1.1 Open Access and Industry Restructuring

Open access, and industry restructuring into generation, transmission, and distribution companies raises new questions on power plant voltage and reactive power control. The point of interconnection is usually at the transmission side of the generator step-up transformers. For both technical and commercial reasons, it’s logical to focus on the transmission side for network voltage control and reactive power interchange.

Restructuring requires industry interconnection standards and ancillary services mechanisms. NERC (North American Electric Reliability Council) is developing required standards, policies, and guides [3-4]. NERC Planning Standard III.C.S2 states: “Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.”

NERC Planning Standard III.C.S1 requires generators to operate in "automatic voltage control mode unless approved otherwise by the transmission system operator." With this mandatory requirement, ancillary service arrangements could reimburse generation companies for reactive power and reactive "energy" produced during heavy load conditions or absorbed during light load. Reimbursement could be for production or absorption outside a deadband, e.g. 0.98 power factor leading or lagging at the point of interconnection.

3.1.2 Power Plant Voltage Control

Bulk power system voltage control is primarily provided by excitation control of generators. Continuously acting AVRs have been standard for the past 50 years. From generator manufacturer and power plant viewpoints, regulation of terminal voltage is natural. Terminal voltage regulation ensures generator voltage is within ±5% of rated voltage, protects generator in the case of load rejection, and helps in regulation of power plant auxiliary voltage. Terminal voltage control is simpler than transmission side control, when multiple generators exist at a power plant (reactive droop compensation is used when generators are paralleled at their terminals). Digital AVRs and digital secondary control loops, however, facilitate more complex, higher performance control.

3.1.2.1 Line Drop Compensation

For tighter regulation of transmission voltage, line drop compensation may be used. Line drop compensation is a connection option of automatic voltage regulators. Regulation speed is the same as the terminal voltage regulation, resulting in improved transient (angle) and short-term voltage stability. Of course, long-term voltage stability is also improved. Reference [3-5] describes simulation results where 50% line drop compensation at nine power plants significantly improved long-term voltage stability in the Portland, Oregon load area. The improvement was similar to adding a 460 Mvar, 550-kV capacitor bank in the load area.

Difficulties with line drop compensation arise when two or more generators are paralleled at their terminals. Line drop compensation for this condition is discussed in this section and in References [3-6 to 3-10]. Again, digital AVRs facilitate more complicated control.

3.1.2.2 High Side Voltage Control

To meet transmission voltage schedules via AVR set point adjustment and to allocate reactive power output of units, power plants commonly use SCADA-type process control computers. The transmission voltage schedule is compared with transmission side voltage measurement. This control may be of the "shepherding" type involving sequential changes of AVR setpoints with subsequent control after waiting for response.

This section describes higher performance types of high side voltage control [3-6 to 3-11]. Other chapters describe "secondary" voltage control involving remote voltage measurements [3-12, 3-13].

3.1.2.3 Hydro Plant Control

Large hydro plants often include many relatively small units. The HV or EHV switchyard may be located several kilometers from the power plant. For example, the John Day plant on the Columbia River comprises sixteen 142 MVA units. There are four three-winding transformers, with two generators connected to each low voltage winding. Four 500-kV, 5.6 km power plant lines connect the power plant to the switchyard.

In such cases, line drop compensation is difficult because of multiple units per transformer winding.

High side voltage control is also difficult because telemetry is required from the switchyard voltage transformers to the power plant. An alternative is voltage transformer additions at the power plant, but this adds cost and there may not be space. Another possibility is transformer bushing potential devices, but accuracy is low.

Even when high side voltage measurements are readily available, the real-world accuracy of capacitive voltage transformers is around ±1% and averaging of several single-phase measurements is desirable.

The proposals in this section and in [3-6, 3-7, 3-8, 3-9] are especially attractive for hydro plants.

3.1.2.4 LTC Generator Step-up Transformers

On-load tap changer step-up transformers facilitate voltage control under different system conditions [3-3]. For cost and transformer reliability reasons, however, LTC step-up transformers are not common in most countries.

3.1.3 Transmission and Distribution Voltage Control

Power plant voltage control should be coordinated with transmission and distribution voltage control. This section provides perspective with respect to power plant voltage control.

3.1.3.1 Transmission Voltage Control

Transmission voltage control is largely done by mechanically switched reactor/capacitor banks; in special circumstances, static var compensators (SVC), STATCOMs, or synchronous condensers may be used. LTC auto-transformers are also used, most commonly with manual control through SCADA.

A strategy of many utilities is to apply shunt compensation to provide base reactive power, ensuring reactive power reserves at power plants for emergencies. This has allowed survival during a severe emergency [3-14].

Shunt compensation aids in optimal high (e.g. 1.08 per unit) and flat voltage profile for heavy load conditions. Control can be local, manual through SCADA, and automatic centralized.

Sophisticated local control of shunt compensation and LTC autotransformers is microprocessor based similar to thyristor switched compensation [3-2, 3-3, 3-15, 3-16].

Shunt capacitor banks are low cost and have virtually zero losses. Modern all-film fuseless capacitor banks increase cost-effectiveness [3-17, 3-18]. New techniques for multiple-step banks are developed [3-19, 3-20].

SVCs or STATCOMs can be used in special circumstances for fast continuous control. Contrasted to generators, SVCs or STATCOMs are designed specifically for transmission voltage regulation. Total SVC and MV component reactive power ratings are referred to the transmission side. All MV equipment is designed to support the transmission side reactive power and voltage regulation requirements.

The droop, or slope, setting is usually small compared to generators regulating terminal voltage (2–5%). Thus better voltage coordination between SVCs/STATCOMs and generators can be obtained by generator high side voltage control. With terminal voltage control, the effective high side droop of a generator is approximately equal to the per unit step-up transformer reactance.

3.1.3.2 Distribution Voltage Control

Distribution voltage control is performed by LTC bulk power delivery transformers, distribution voltage regulators, and shunt capacitor banks. Control of shunt capacitor banks tends to be based on current or reactive power at stations, and on voltage near end of feeders. Local microprocessors, centralized computers, and various communication technologies are available for capacitor control (distribution automation). An interesting approach that eliminates a major mechanism of voltage collapse (load restoration) is to use capacitor banks rather that LTC transformers for distribution voltage control.

The policy of many utilities is to compensate distribution to close to unity power factor [3-14]. With industry restructuring, unity power factor at the point of interconnection of transmission and distribution companies may be the target.

3.2 Wide-Area Stability and Voltage Control at BPA

BPA is developing wide-area stability and voltage control [3-21]. Figure 3-1 shows the concept. High accuracy positive sequence phasor measurements are used where available.

For high-speed transient stability control, fast generator tripping and 500-kV shunt/series compensation switching is proposed. For slow voltage control, 500-kV shunt compensation switching is proposed, plus power plant high-side voltage schedule changes.

Power plant voltage schedules are sent via the automatic generation control digital message. In a voltage emergency, power plants with reactive power reserves can be sent higher schedules to activate reserves to boost transmission voltages. This reduces reactive power losses, and increases line charging and shunt capacitor bank outputs. If power plant high-side voltage control does not provide droop, the control may also be used to equalize reactive power outputs of closely coupled plants.

Another goal is to automate autotransformer tap changing, preventing circulating reactive power/current between parallel transformers at different stations.

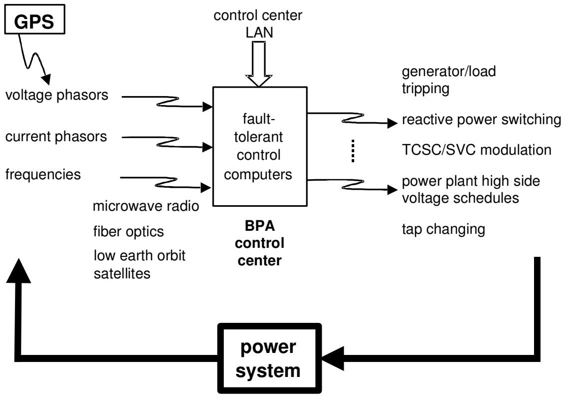


Figure 3-1 *Flexible platform for centralized control.*

Many of the components shown on Figure 3-1 exist, including phasor measurements, outgoing transfer trip signals for generator tripping and compensation switching, SCADA, control center LAN and digital AGC messages. Digital AGC messages include an emergency voltage control mode requesting power plant operators to bring all on-line and standby units to maximum reactive power capability. For the fast stability control, digital fiber optic communication is used for the phasor measurements. Fiber optic communication is more reliable and has smaller latency than alternatives.

With many input measurements and many outgoing signals, brute force redundancy is not planned. Failure of a single input signal or outgoing signal may degrade control, but will not cause failure.

Synergy with other control center functions such as BPA's reactive power monitor [3-22] and voltage security assessment development is expected.

One scheme to equalize reactive power outputs of closely coupled plants is being tested; the power plants are Grand Coulee (7,111 MW, 24 units) and Chief Joseph (2,614 MW, 27 units). Both plants have units connected at both 230-kV and 500-kV, with autotransformers connecting the 230-kV and 500-kV busses. The two plants, approximately 52 km apart, are connected by two 230-kV lines and one 500-kV line. The high side voltage schedules are adjusted to equalize the Mvar/MW ratio ($\tan\phi$) of the four generating groups. A BPA control center alarm is given for high autotransformer reactive power flow, leading to manual tap changing through SCADA.

3.3 High Side Voltage Control at Manitoba Hydro

Manitoba Hydro has twelve hydroelectric generating stations, and two thermal stations ranging in size from 5MVA to 1560MVA. The Manitoba Hydro system is characterized by the majority of its load being located in the southern part of the province in the city of Winnipeg. Approximately 70% of the generation originates from three hydroelectric stations on the Nelson River in northern Manitoba. These three hydroelectric plants, Kettle, Long Spruce, and

Limestone form an asynchronous ac network that supplies Winnipeg through two HVDC lines. In addition to the HVDC lines, there are also a number of radial 230 kV ac lines that transmit power to and from the south as conditions warrant. The Manitoba Hydro system contains tie lines to neighboring provinces and to the United States, the largest of which is a 500 kV ac line which passes through Duluth, Minnesota before terminating in Minneapolis (Figure 3-2).

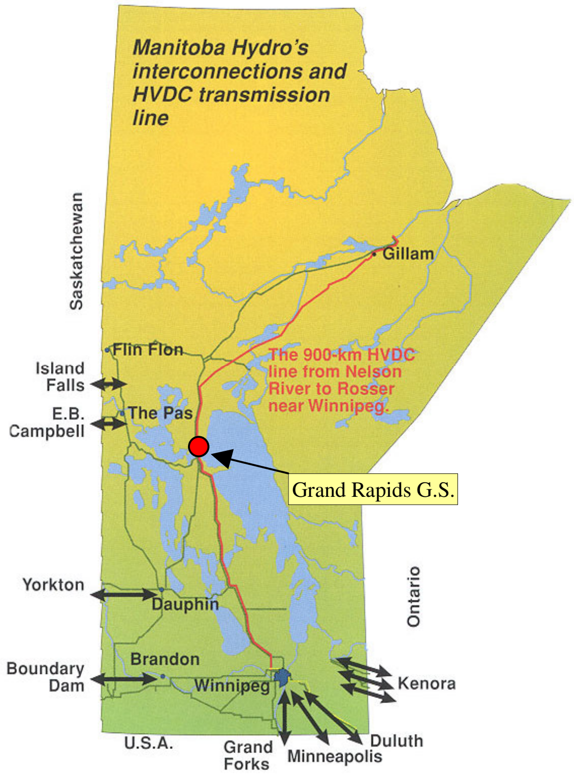


Figure 3-2 *System interconnection map.*

The focus for Manitoba Hydro over the years has revolved around two major considerations: stability of the ac network including interconnections, and stability of the AC/DC system including its isolated ac network. These two considerations show a strong inter-dependence. The stage upon which these stability questions exist is heavily influenced by high-side voltage levels. High-side voltage control has been important in enhancing the performance of the entire system.

High side voltage control at Manitoba Hydro primarily takes two forms. One form is directly through the excitation by either explicit control of a bus or by partial compensation from the generator terminals through to the high side bus. The second form, also through the excitation system, is joint operation of all units within a generating station to control a single high voltage bus, commonly referred to as Joint Var Control (JVC). Excitation systems, and hence JVC's, have two aspects to high side voltage control: speed of response and the ability to precisely set a high side voltage for the benefit of the system.

The first form can be relatively quick but because of the need to remain stable with other units, cannot be as precise in its control of high side voltage. The second form of control can be more precise but is usually slower. Manitoba Hydro often employs both forms of control within a generating station to provide maximum overall benefit to the system.

The benefit of the first form is in the speed at the expense of high side precision; the benefit of the second form is in the precision at the expense of speed. Until fairly recently, it was believed that the main benefit of a JVC is in placing units in the correct operating position to respond to disturbances. It was also believed that a JVC would be too slow in reacting to the actual transient. However, as knowledge of system dynamics increases, it is being realized that the response of slower devices, such as a JVC, can have a positive influence on stability [3-24].

3.3.1 Basic Elements

The functionality of the basic elements of high side voltage control within Manitoba Hydro will now be expanded upon.

3.3.1.1 Impedance Compensation

This element is generally applied to the control of voltage at some other point rather than the machine terminals, by so doing more strongly influencing the high side bus, which tends to be more intimately linked to system stability. Indirect voltage measurement is accomplished through stator current being scaled by the impedance through to the control point being added to the generator terminal voltage. In most instances, only a reactance is necessary and not a resistive component. At Manitoba Hydro, impedance compensation is limited to approximately 60% of the step-up transformer to avoid hunting problems with other units.

3.3.1.2 Generator Direct High Side Control

As an alternative to impedance compensation, and especially where there may be a more complex transformer arrangement than the standard step-up transformer, generator direct high side control can be used. In this arrangement, the exciter directly controls the high side bus voltage. Hunting would occur with multiple units attempting to control the same bus, so to avoid hunting, the high side bus voltage is drooped against the reactive output of the machine, either machine vars or the imaginary component of stator current. A minimum value of drooping would be around 3%. Therefore, similar to impedance compensation, closer, but not exact control of the high side bus is maintained.

3.3.1.3 Joint Var Control (JVC)

For a number of years, Manitoba Hydro has been working towards a standardized JVC design. The first application was for the control of nine synchronous compensators at an HVDC inverter bus [3-25, 3-26]. Essentially the machines would share control of the bus according to their relative var capabilities. This concept was extended further for generating stations, wherein the var capability at any particular point in time would be defined by the capability curve in conjunction with the actual operating condition. Further analysis and results will be presented in a later section. The JVC has been designed to operate with any droop from zero upwards. There was also flexibility to work with any speed of exciter response, from the slowest through to a fast response static exciter. It was also important to the design that reasonable self-diagnostics exist and that tripping of the JVC would be bumpless to the system.

3.3.2 Applications

As mentioned earlier, stability considerations related to high side voltage control have revolved around two major considerations in the Manitoba Hydro system, the HVDC network and the general HVAC network.

The general high side voltage control considerations for the HVDC network will be described first. In the northern collector system, a generating station exists close to each of the rectifier buses. Kettle is within two kilometers of the Radisson Bipole I rectifier bus and Limestone is within two kilometers of the Henday Bipole II rectifier bus. A third generating station, Long Spruce is approximately half way between Kettle and Limestone. Neither Kettle nor Limestone has a common generating station high side bus but rather brings power to the major busses at Radisson and Henday respectively along lines dedicated to pairs or individual units (Figure 3-3).

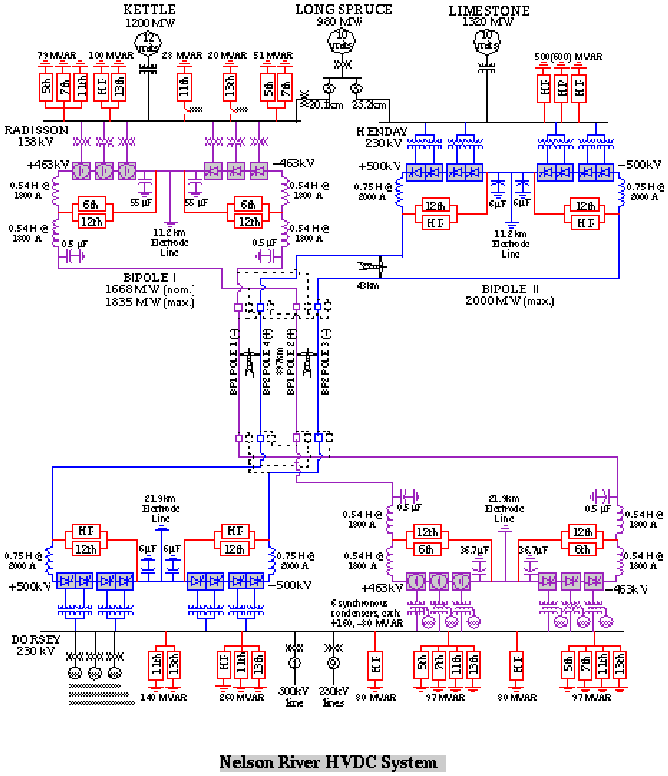


Figure 3-3 *Nelson River HVDC system.*

Through impedance compensation, both Kettle and Limestone exciters control the voltage half way through the generator step-up transformers. A rectifier station can be characterized by large quick changes in reactive power consumption and hence voltage, so fast, tight control through line drop compensation is important in helping to maintain orderly power transmission through the bipoles. Over the longer term, Kettle and Limestone JVCs provide direct control of their respective ac converter buses. These would be examples of a generating station JVC controlling a remote bus.

The third collector system generating station, Long Spruce, does not use line drop compensation but uses a JVC to control a nearby common ac bus.

Nine synchronous compensators control the inverter ac bus at Dorsey. This form of control could be important in general discussions of generator ac system high side voltage control.

The three largest synchronous compensators employ dedicated step-up transformers to connect to the 230 kV high side bus. The six smaller synchronous compensators are connected through the tertiaries of the Bipole I converter transformers. For fast exciter control, each of the units could control its respective unit terminals, but trying to apply simple line drop compensation to the tertiary connected units is too problematic. Therefore, to achieve the benefits of fast, tight control in this complex situation, generator direct high side control is employed. Each machine receives a measurement of the 230 kV ac bus voltage and this signal is drooped against the reactive output of each respective machine, in this case the stator current normalized over its range. The droop value used is 3%.

In the longer term, the Dorsey JVC reapportions var loadings while controlling bus voltage to an explicit value, which is zero JVC droop. As in the northern collector system, both short and long term voltage strategies are maximized for the overall benefit of the system.

It would be unusual to have this type of tertiary connected machine for a generator application but situations could exist, for example, where a number of smaller generators are stepped up through only one or two transformers. In this situation generator direct high side control would be attractive.

It should be emphasized that not only is the form and location of the machine control important, but also the exciter speed of response and exciter limits. This is true for the generating station units and synchronous compensators that optimize high side voltage control thereby allowing the dc to maximize its assistance to ac stability.

Another major consideration within the Manitoba Hydro system is related to the dominant operating mode of a given generating station. Most generating stations within Manitoba Hydro employ units that are only power producers. However two generating stations, Grand Rapids and Seven Sisters, are in critical voltage controlling positions and so to ensure that there is sufficient var ability regardless of river flows, units at these generating stations are convertible to synchronous compensators. Commissioning results for the Grand Rapids JVC will be presented later.

At Grand Rapids, Seven Sisters, and all other Manitoba Hydro ac network generating stations, the speed of response of the JVC is not critical to the stability of the system as a whole. The purpose of the JVC is to position units correctly so that normal exciter response can provide the best system benefit.

In addition to the JVC, Manitoba Hydro also tries to incorporate impedance compensation in the southern generating stations if the feature is available.

3.3.3 Manitoba Hydro JVC Design

Manitoba Hydro's JVC has been designed using standard programmable logic controller (PLC) hardware, with an intuitive computer operator interface. The design incorporates distributed I/O throughout the plant, with a TCP/IP Ethernet backbone for communication to the operator computer HMI (Human Machine Interface). One of the major considerations in the design of the system is to ensure that technicians can easily make changes to the software and settings as system requirements evolve. Program changes do not require an experienced computer programmer, and is easily understood by those familiar with PLC program logic. The design was also standardized to allow the controller to interface to a variety of excitation and unit configurations.

The JVC is one module of an overall Manitoba Hydro design concept known as the Unit Control and Monitoring System (UCMS). Other UCMS modules include a Joint Load Control (JLC), alarm annunciation, monitoring for reliability-centered maintenance, unit start/stop control, load/speed control, speed switches, and data logging. Each component communicates along a central redundant communication backbone, and any module can be installed at a plant at any time. A typical configuration is shown in Figure 3-4.

Remote operation is also accomplished by interfacing the PLC to a remote terminal unit (RTU) for control from the central control center in Winnipeg. Manitoba Hydro has successfully interfaced this new form of JVC to three generating facilities.

The JVC performs two functions: it controls the high side station bus voltage to a setpoint, and it ensures that the reactive loading on each machine is balanced based on the reactive capability of the machine (Figure 3-5). The voltage can normally be controlled to within ±0.5 percent of setpoint, and the reactive power to within 2% of rated without excessive wear to the rheostat motor. With an electronic reference setter, the JVC is capable of even tighter control.

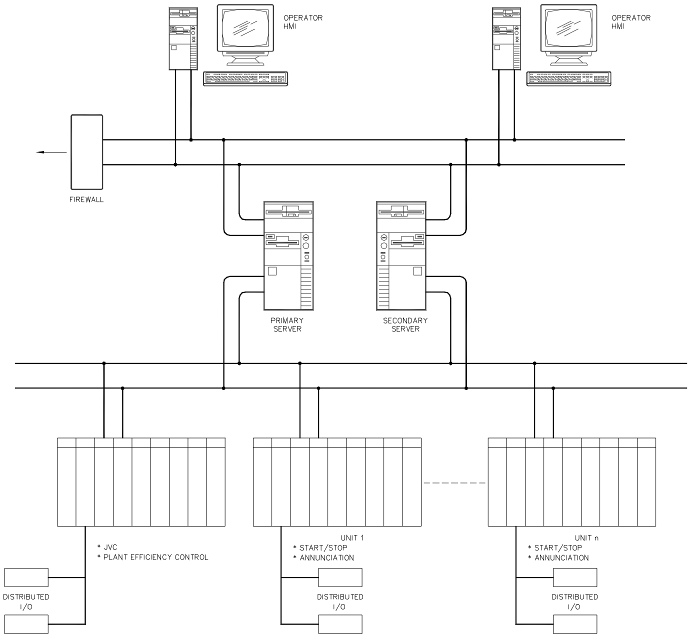


Figure 3-4 *Typical UCMS configuration for in-plant control.*

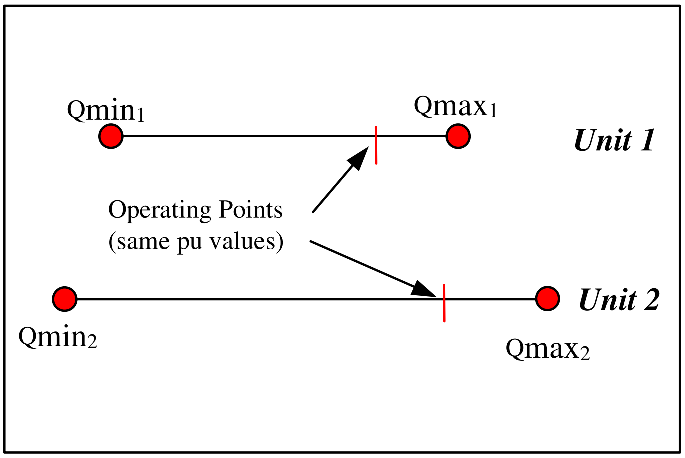
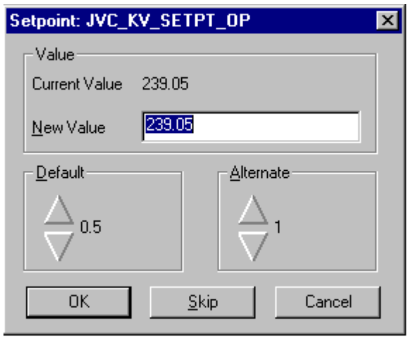


Figure 3-5 *Reactive power balancing based on reactive capability of the machines.*

3.3.3.1 Modes of Operation

The JVC has three modes of operation, AUTO, MANUAL, and OFF, with bumpless transfer between modes. Only the station operator or an abnormal condition can change the mode of operation.

In the AUTO mode, the JVC equipment performs bus voltage regulation by maintaining the high side bus voltage to the desired setpoint. The operator can specify the station kV setpoint within a specific range with 1kV raise/lowers, 0.5kV raise/lowers, or typing a setpoint. The operator is presently only allowed up to a 3kV setpoint change per operation. The standard pop-up window is shown in Figure 3-6.



Current Value 239.05

New Value 239.05

Figure 3-6 *Standard pop-up window for setpoint control.*

In AUTO mode the JVC system also regulates the reactive loading on each generator under its control so that all controlled generators carry their share of the reactive load based on their capability curve. Raise and lower pulses to the AVR are also inhibited if the machine operates beyond its capability. The operator has the ability to view the operating point within the capability curve at any time, as shown in Figure 3-7.

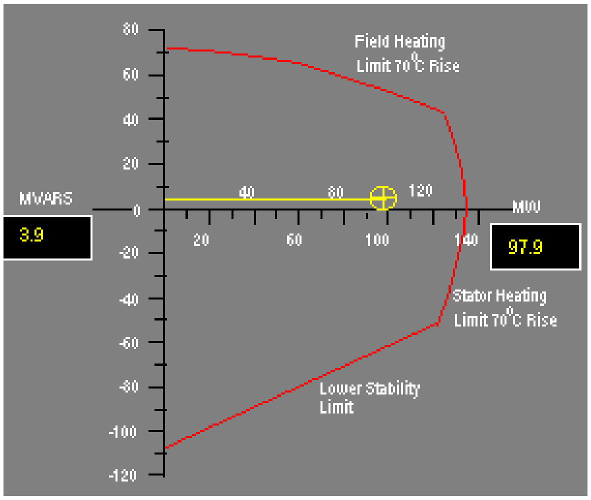


Figure 3-7 *Standard operator display showing the unit operating point within the capability curve.*

This mode of operation ensures the full reactive capability of every unit is available to the system, independent of varying unit sizes at a plant.

In MANUAL mode, the JVC equipment only regulates the reactive loading on each generator, and unlike AUTO operation, does not control the high side bus voltage. The JVC will trip to MANUAL if both bus indications fail to the PLC, the selected bus voltage limits are exceeded, the setpoint output current loop to the RTU fails, or the setpoint error is exceeded. This mode is not a normal state for the JVC and an alarm is issued. In this mode of operation, the operator is able to raise or lower the bus voltage by issuing a timed group of raise or lower pulses to all units on JVC.

In OFF mode, all units are removed from Joint Var Control, and the operator has manual control of each unit terminal voltage.

3.3.3.2 Bus Voltage and Selection

In some instances, there may be two high side buses at a station that can at times be operated in a split-bus arrangement. The operator can choose to use either bus as the feedback voltage for the JVC system. If the selected bus voltage signal fails, the control is automatically transferred to the healthy bus. If both buses fail, the JVC transfers to Manual mode.

In a split-bus arrangement, it is also important that the bus that is being controlled by the JVC is the same bus that the units are feeding. This is especially true when the two buses are not electrically close to one another, once split.

3.3.3.3 Voltage Droop

The JVC has been designed to regulate the reactive load of the entire station according to a drooped characteristic. The droop capability allows plants that are electrically close to one another to share the system reactive requirement.

3.3.3.4 Unit Field Temperature

With many JVC installations on older excitation systems, there is no over-excitation field current limit in the AVR. In these circumstances, the JVC is capable of calculating the field temperature from measuring Field Voltage and Field Current and provides indication and alarms to the operator if the temperature limits are exceeded. This feature also inhibits JVC raises to the AVR if the limit is exceeded.

3.3.4 JVC Field Results

Grand Rapids Generating Station, located on the Saskatchewan River about 400km north of Winnipeg (Figure 3-2), has a capacity of 472MW. Grand Rapids is a four-unit plant with two GE Silcomatic static exciters, and two GE rotating exciters. The first three units were running by 1965, and the final unit was commissioned in 1968. Grand Rapids provides Automatic Generation Control (AGC) for the system, and has recently been modified to operate as a synchronous condenser through the use of a compressed air blow-down scheme.

A JVC was recently commissioned at our Grand Rapids Hydroelectric Generating Station, and the following commissioning results demonstrate the controller response to several on-line system tests.

3.3.4.1 Mvar Balancing

Two units of equal rating, one with leading vars and the other with lagging vars, were placed on JVC to demonstrate the balancing algorithm. Figure 3-8 and Figure 3-9 show Unit Mvars, and Raise/Lower pulses to the rheostat respectively. The results indicate a very stable response. Because the active power (and therefore the reactive capability) from the machines are not the same at the time of the test, the final Mvar set point for the two units are not the same (refer back to Figure 3-5).

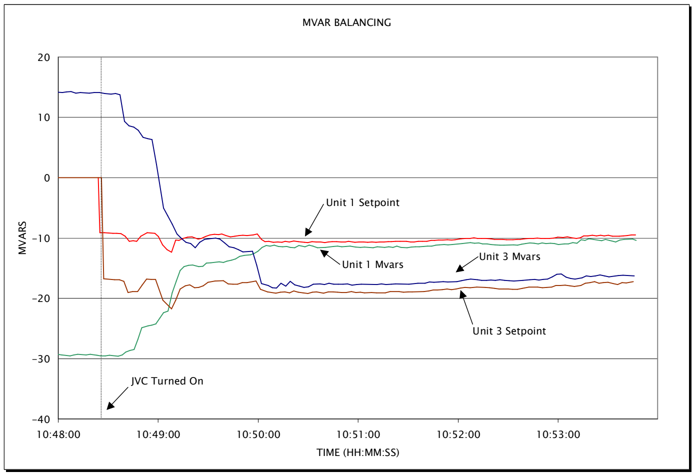


Figure 3-8 *Mvar balancing – unit Mvar response and set point.*

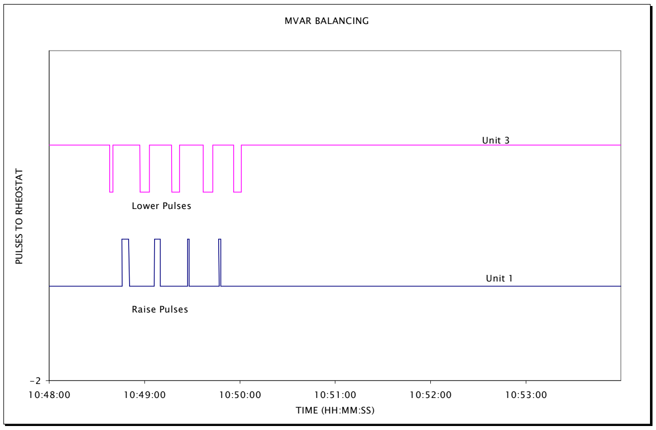


Figure 3-9 *Mvar balancing – raise/lower pulses to the exciter rheostat.*

3.3.4.2 Station Voltage Setpoint Change

A ± 2 kV step was performed on the station high side bus voltage with two units on JVC. Figure 3-10, Figure 3-11 and Figure 3-12 show station high side bus voltage, Unit Mvars, and raise/lower pulses to the rheostat respectively. The results show a very stable response, with a controlled voltage within ±0.5% of setpoint. Again, because the active power (and therefore the reactive capability) from the machines are not the same at the time of the test, the final MVAR setpoint for the two units are not the same.

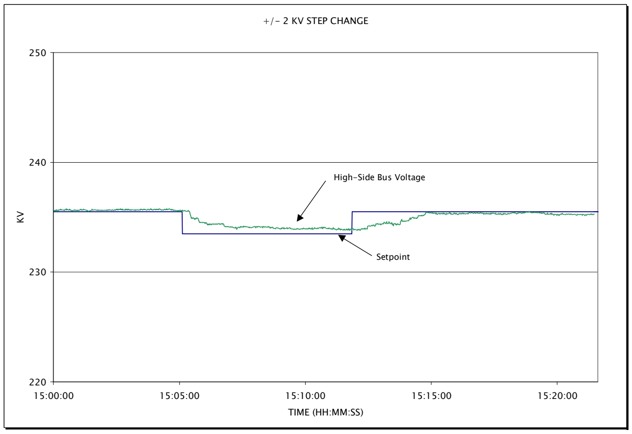


Figure 3-10 *±2 kV step – high side bus voltage response and setpoint.*

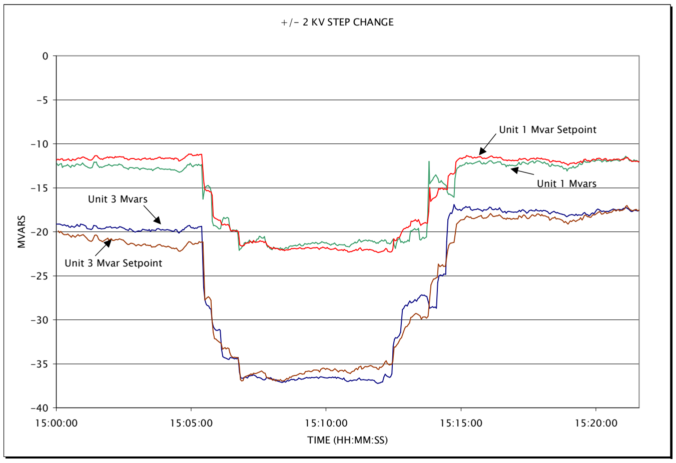


Figure 3-11 *±2 kV step – unit Mvar response and setpoint.*

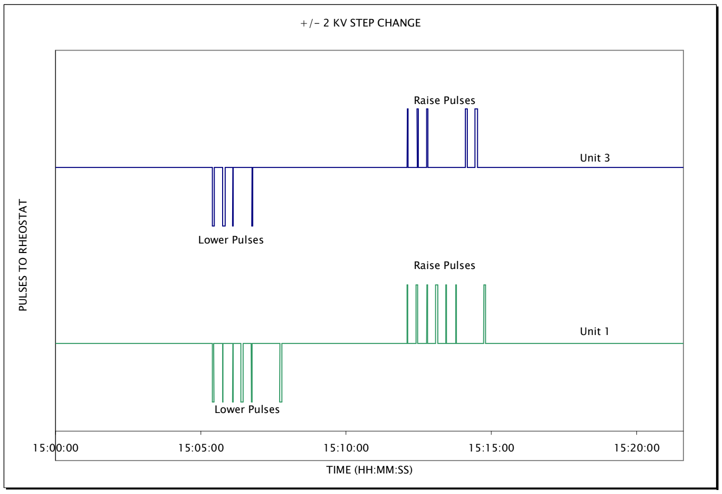


Figure 3-12 *±2 kV step – raise/lower pulses to the exciter rheostat.*

3.3.5 Conclusions

High side voltage control at Manitoba Hydro takes the form of impedance compensation, generator direct high side control, and plant Joint Var Control (JVC). Impedance compensation and direct high side control offer a fast response, but is not as precise as a JVC. Manitoba Hydro at times uses more than one form of high side control at a plant to provide maximum system benefit.

The JVC design has been standardized to allow the controller to interface to a variety of excitation and unit configurations. Commissioning results from Grand Rapids Generating Station show the response of the JVC for several on-line system tests.

3.4 Application of an Advanced Voltage and Reactive Power Regulator (REPORT) for High Side Voltage Control

3.4.1 REPORT Apparatus: Main Characteristics and Performances

The Research and Development Department of ENEL (now CESI) has designed and developed, since 1985, an innovative, microprocessor based, voltage and reactive power regulator, named REPORT, advanced as regards its rich and sophisticated functionality, friendly operator interface and monitoring.

REPORT allows two different control modes: reactive power level control mode or high side bus voltage control mode. In the first control mode, REPORT participates in the Secondary Voltage Regulation [3-24; 3-25]. In the second control mode, the power plant regulates, through REPORT, the local (power plant) high side bus voltage. In both these control modes each generator reactive power is regulated by REPORT through a closed-loop overlapping the primary Automatic Voltage Regulator (AVR). The set-point of each unit reactive power control loop is a percentage, given by a reactive power level signal, defined by the EHV bus voltage regulator, multiplied by the capability limit of the generator considered. The reactive limits in generation and absorption are computed, in real-time, as a function of the actual values of operating active power and voltage. Such capability limits take also into account the actual operating conditions of the generator cooling system.

REPORT regulates the EHV power plant bus voltage, according to suitable memorized voltage daily trends, otherwise the set-point is at disposal of the plant operator. Further functional details are described in Chapter 5.

3.4.2 REPORT Apparatus: General Application to the Italian Grid

A large number of REPORT regulators have been installed and are under continuous operation at the Italian power plants. Commissioning the REPORT apparatuses requires a certain amount of effort, costs and relevant organization to manage the plant modifications and the needed, even if short, putting out of service the generating units.

Nearly 50 power stations are equipped with the REPORT apparatuses. The stations are the largest hydraulic and thermal plants of the Italian system (having more than 150 generating units and totaling 39,195 MVA).

The REPORT application 2004 plan includes the last few remaining plants. As regards the REPORT application to the Italian IPP, it was decided their participation by the largest plants, which can give a significant contribution to the network voltage support.

Figure 3-13 shows the REPORT application, as installed at the thermal plant of Piacenza (Lombardia). The graphical monitor and functional keyboard installed at the plant control room are also in evidence.

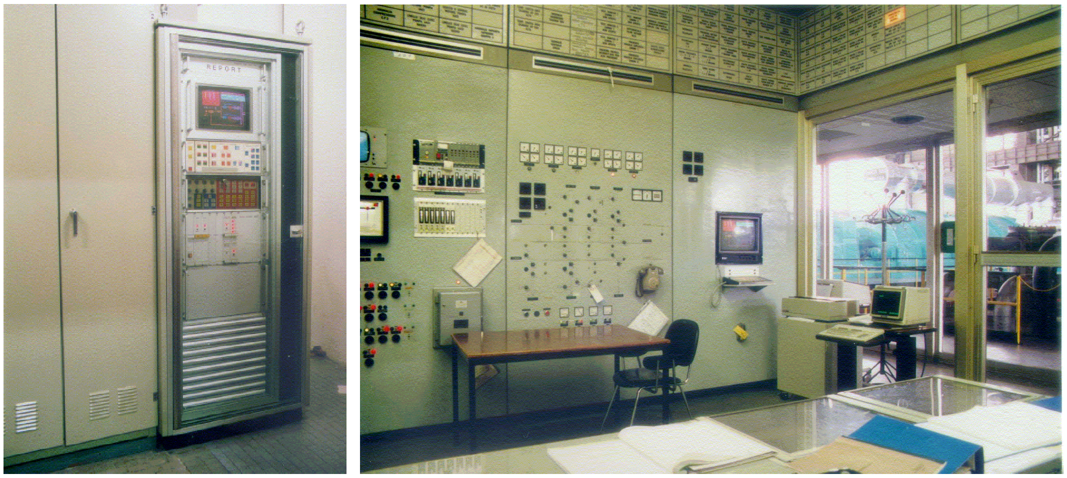


Figure 3-13 *Piacenza REPORT installation.*

3.4.3 REPORT Apparatus: Impact of the Application

The main promoter of the REPORT application is the ISO, not the power producers, because the largest amount of the reactive power resources for network control comes from the units, which apparently do not gain any local advantage. Therefore in Italy a recent ISO rule forces the power producers to provide their plants with REPORT apparatus.

Another aspect of the impact of the REPORT application is the different approach the Regional Dispatcher has to follow, as regards power system voltage and reactive power operation. While until now the Regional Dispatcher demands more or less reactive power according to network needs, by phone or by daily plans, with the REPORT control apparatus the dispatcher fixes the high-side voltage of the power plant and the reactive power will assume the value needed to obtain the desired voltage. REPORT therefore moves automatically the units to produce the reactive power, which is necessary to obtain the desired voltage in the local EHV bus, always maintaining the units inside their thermal limits.

Growing interest of the utilities and of the manufacturers on this topic, will create in the future a possible market for REPORT-like power plant control apparatus at competitive costs.

3.4.4 Conclusions

Under REPORT the plant reactive power is continuously controlled, in the amount (delivered or absorbed) that is necessary to regulate the voltage at the local high side bus. The availability and controllability of all the generating units, within their individual capability curves, is guaranteed by the REPORT apparatus which effectively performs the required continuous control. According to that, the single unit contribution to the network “voltage service” can be more correctly related to the fact that such a unit is or not directly controlled by REPORT [3-26] instead to simply measure the absolute value of the reactive power produced amount. In addition to the economical benefits for the network operation, the practical Italian experience of REPORT application has shown that also the plant operators, after an initial and natural hesitation, are growing in the appreciation of such a control system apparatus, which undoubtedly was proven to contribute to the quality and security improvement in power plant operation.

3.5 Improvement of Voltage Stability by the Advanced High Side Voltage Control Regulator

Voltage instability of power systems is becoming a more serious problem with the ever-increasing utilization and higher loading of existing transmission systems. Various countermeasures, i.e., synchronous condensers, shunt capacitors, static var compensators, etc., have been increasingly utilized.

Other effective alternatives, such as the line drop compensator that compensates the voltage drop by a reactive current, or the power system voltage regulator that uses a high side voltage as a feedback signal [3-27], have also been applied as control methods of the high side voltage of a step-up transformer via a generator excitation system.

The advanced High Side Voltage Control (HSVC) regulator [3-6 to 3-9] that controls the high side voltage of a step-up transformer has been developed with no requirement for any direct feedback signal (i.e., measurement) from the high voltage side of a step-up transformer. Though the control principle of the advanced HSVC is similar to that of the line drop compensator, the advanced HSVC is superior to the traditional methods with respect to control performance, reliability, and economy, as described in this section.

3.5.1 Principle & Characteristics of HSVC

The configuration of the advanced HSVC is shown in Figure 3-14. The basic principle of the advanced HSVC on a simple power system, shown in Figure 3-15, is as follows.

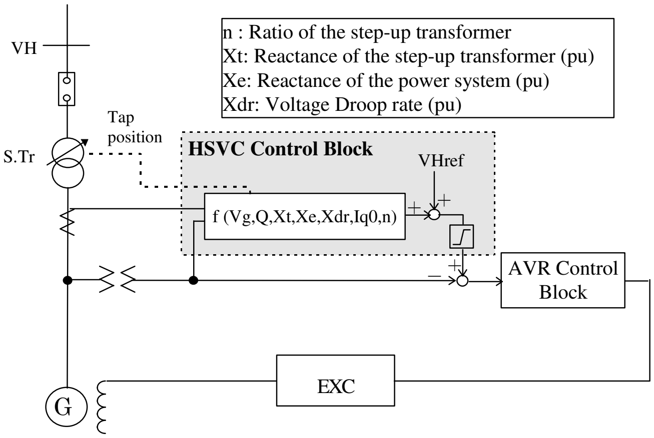


Figure 3-14 *Construction of HSVC control system.*

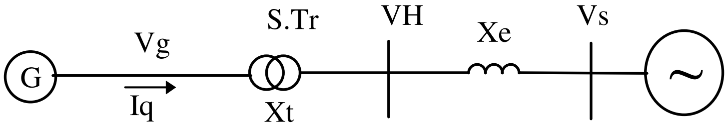


Figure 3-15 *Simple power system.*

3.5.1.1 Basic Function

With a target setting value of the high side voltage ($V_{H_{ref}}$), the generator terminal voltage (V_g), i.e., the low side voltage is controlled to be:

$$V_g = V_{H_{ref}} + (X_t - X_{dr}) \times I_q \qquad (3.5.1\text{-}1)$$

Where,

$$I_q = \frac{Q}{V_g}$$

on this condition, the resultant high side voltage (V_H) becomes,

$$V_H = V_{H_{ref}} - X_{dr} \times I_q \qquad (3.5.1\text{-}2)$$

This characteristic can be expressed as shown in Figure 3-16.

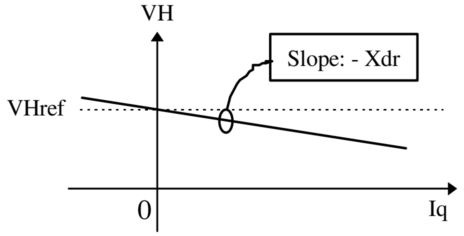


Figure 3-16 *Characteristics of HSVC.*

In words, for a target of $V_{H_{ref}}$, the V_H can be controlled to only drop for part of X_{dr}. This X_{dr} is necessary for stable parallel operation among multiple generators.

3.5.1.2 Reactive Current Compensation Function

To equal V_H with $V_{H_{ref}}$ at the specified reactive current (I_{q_0}), a supplementary control can be adopted by using I_{q_0}. The V_H at large reactive current can be kept to a higher value by this function. V_g is controlled to be:

$$V_g = V_{H_{ref}} + X_t \times I_q - X_{dr} \times (I_q - I_{q_0}) \qquad (3.5.1\text{-}3)$$

And V_H becomes,

$$V_H = V_{H_{ref}} - X_{dr} \times (I_q - I_{q_0}) \qquad (3.5.1\text{-}4)$$

These characteristics can be expressed as shown in Figure 3-17.

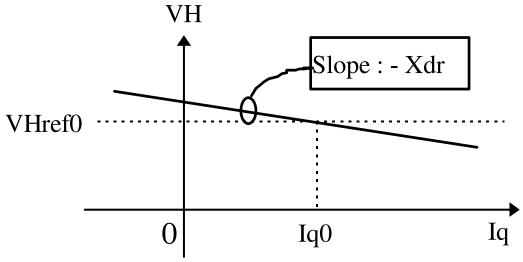


Figure 3-17 *Characteristics of reactive current compensation function.*

3.5.1.3 Reactive Current Compensation Function by X_e

This function is used to follow I_{q_0} automatically corresponding to $V_{H_{ref}}$ variation. For an original setting value $V_{H_{ref0}}$ and an external reactance, X_e a change of the reactive current (ΔI_{q_0}) by a new setting value $V_{H_{ref}}$ is approximately given as (3.5.1-5).

$$\Delta I_{q_0} = \frac{V_{H_{ref}} - V_{H_{ref0}}}{X_e} \qquad (3.5.1\text{-}5)$$

Therefore, this function can be realized by adding (3.5.1-5) to I_{q_0} of (3.5.1-3) and (3.5.1-4).

3.5.1.4 Compensation Function of the Droop Rate Corresponding to the Variation of the Tap Position of the Step-Up Transformer

When V_g is controlled by the advanced HSVC, the V_g may be generally maintained higher than its rated voltage in order to keep V_H to a constant value. On the other hand, the continuous allowable V_g is generally up to 5% of the rated voltage. If the V_g is near this maximum voltage in a steady state condition, the improving effect of the voltage stability by the advanced HSVC is reduced by this limitation. Therefore, in the case of a step-up transformer with LTC, the cooperative control between the advanced HSVC and the tap position control can increase the ability of the advanced HSVC by way of keeping the V_g to around the rated voltage in steady state condition. The following division of roles between the advanced HSVC and the tap position control is a suitable solution to improve the voltage stability.

Table 3-1

Control	Function
HSVC	Controls V_H to $V_{H_{ref}}$
Tap control	Controls V_g to approximately the rated voltage

However, the droop rate changes according to the variation of the voltage ratio and the reactance of step-up transformer (X_t) by controlling the tap position. As a result, the parallel operation among adjacent generators may become difficult due to an unbalance of reactive power on each generator, which is caused by discrepancy of tap position of each step-up transformer. For preventing this condition, the compensation function that keeps the droop rate constant corresponding to the tap position can be added to the HSVC. In the case that both a change of the voltage ratio and the reactance by a change of the tap position is the same value (n), the basic control function is changed from (3.5.1-1) to (3.5.1-6).

$$V_g = \frac{V_{H_{ref}}}{n} + \left(X_t - \frac{X_{dr}}{n} \right) \times I_q \qquad (3.5.1\text{-}6)$$

The resultant V_H becomes the same as (3.5.1-4).

The advanced HSVC has the following superior features.

- The $V_{H_{ref}}$ can be directly set to a desired value from local and/or remote location. Accordingly, the cooperating control of the power system voltage among multiple generators and/or substations is possible;
- A feedback signal (i.e., measurement) of a high side voltage is not required;
- The following optional functions can be added to the HSVC:
  - ➢ Reactive current compensation function;
  - ➢ Reactive current compensation function by X_e;
  - ➢ Compensation function of the droop rate corresponding to the variation of the tap position of the step-up transformer;
  - ➢ A phase compensation function can be added to further improve stability by modifying the response characteristics of the HSVC control loop;
  - ➢ The oscillatory stability of a power system can be improved by adding an adequate phase compensation function.

The performance of the HSVC described in the equations above was verified by simulation analysis of a step-change of $V_{H_{ref}}$ from 1.0 pu to 1.01 pu on a simple power system. These results are shown in Figure 3-18 and Figure 3-19.

Figure 3-18 shows each resultant characteristic that is plotted according to the simulation results before and after a step-change. The traced lines show the theoretical results.

The case A shows the droop characteristics of HSVC that is represented by (3.5.1-4). In this figure, theoretical and simulated results are obtained for variations in $V_{H_{ref}}$ and X_{dr}. These resultant points can be shown to fit each theoretical line very well.

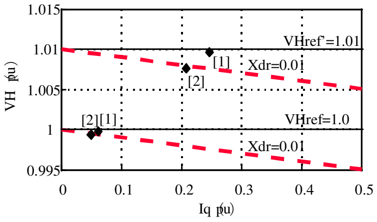
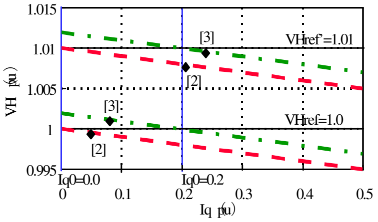
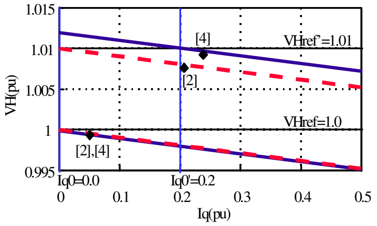
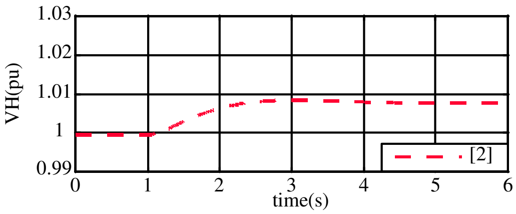
Case &Condition	Characteristics
[A] Study of effect of the droop rate X_{dr}	
Common Condition $I_{q_0} = 0.0$ pu	
Parameter : X_{dr} (pu) [1] $X_{dr} = 0.0$ [2] $X_{dr} = 0.1$	
[B] Study of effects of I_{q_0} function	
Common Condition $X_{dr} = 0.1$ pu	
Parameter : I_{q_0} (pu) [1] $I_{q_0} = 0.0$ [2] $I_{q_0} = 0.2$	
[C] Study of effects of I_{q_0} compensation function by X_e	
Common Condition $X_{dr} = 0.1$ pu	
Parameter: compensation function [2] off [4] on $X_e = 0.5$ pu	
Initial Condition: $P_1 = 0.9$ u, $Q_1 = 0.04$ pu, $V_{H_{ref}} = 1$ pu step: $\Delta V_{H_{ref}} = 0.01$ pu, base 100MVA	

Figure 3-18 *Verification result of HSVC function.*

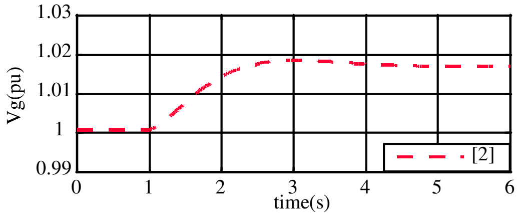
The case B shows the characteristic of I_{q_0} function that is represented by (3.5.1-3). In this figure, theoretical and simulated results are obtained for variations in $V_{H_{ref}}$ and I_{q_0}. In the case of $I_q = I_{q_0}$, the V_H is the $V_{H_{ref}}$ nearer value. Therefore, if the I_{q_0} is set to the actual value on the normal operation condition, the V_H can be controlled to $V_{H_{ref}}$.

The case C shows the characteristic of the I_{q_0} compensation function by X_e. In this figure, theoretical and simulated results are obtained for variations in $V_{H_{ref}}$ and without or with this function. These results show that V_H is controlled near the value of $V_{H_{ref}}$ both before and after the change of $V_{H_{ref}}$, according to the theory.

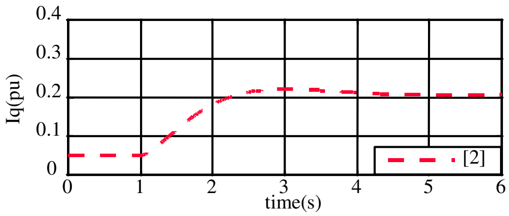
Figure 3-19 shows the response characteristics of the advanced HSVC in the case of equation (3.5.1-2). The V_H reaches $V_{H_{ref}}$ at about 1.5 sec. and is also controlled smoothly and stably.



(a) High Side Voltage



(b) Generator Terminal Voltage



(c) Generator Reactive Current

Figure 3-19 *Response characteristics of the HSVC.*

3.5.2 Improvement of Voltage Stability

The improving effect on the voltage stability of a power system by the advanced HSVC was estimated by P-V characteristics [3-2, 3-28]. Figure 3-20 shows a model of a simple power system. The resultant P-V characteristics by applying a static var compensator and the advanced HSVC are respectively shown as Figure 3-21 (a) and Figure 3-21 (b).

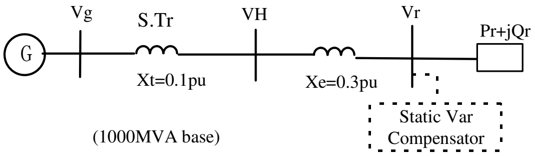
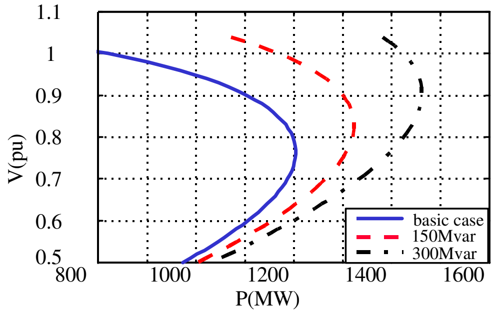
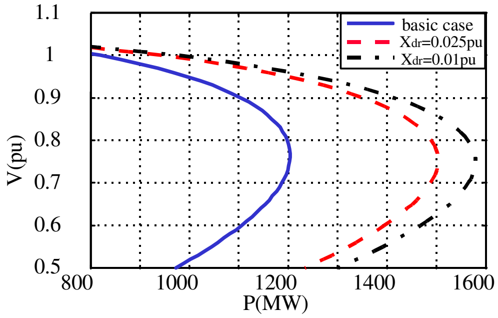


Figure 3-20 *Simple model of a single machine and one load.*



(a) P-V curve (static var compensator)



(b) P-V curve (HSVC)

Figure 3-21 *P-V characteristics.*

For the static var compensator, the allowable sending end power increases according to larger capacities of installed static var compensator, but the "nose" voltage tends to go up. On the other hand, for the advanced HSVC, the allowable sending end power increases according to a decrease in the droop rate and the nose voltage tend to go down. In other words, the advanced HSVC can also improve the system voltage characteristics by way of both pushing out the "nose" of the curve and not getting near the normal operating voltage of the power system. Moreover, since the advanced HSVC can be installed on all generators, including already installed facilities, the existing capability of power plants can effectively be put to practical use for voltage stability. Therefore, the advanced HSVC is also superior on economy.

3.5.3 Improving Effects of Oscillatory Stability

The improving effect on oscillatory stability by the advanced HSVC can be treated via the extended DeMello/Concordia model [3-29] shown in Figure 3-22. Parameters K7 and K8 can be respectively calculated by (3.5.3-1) and (3.5.3-2). The simplified model can be expressed as shown in Figure 3-23.

$$K_7 = \frac{-X'_d i_{do} + V_{qo}}{X'_d + X_e} V_b \sin\delta_o - \frac{X_q i_{qo} + V_{do}}{X_q + X_e} V_b \cos\delta_o \tag{3.5.3-1}$$

$$K_8 = \frac{X_e i_{do} + V_{qo}}{X'_d + X_e} \tag{3.5.3-2}$$

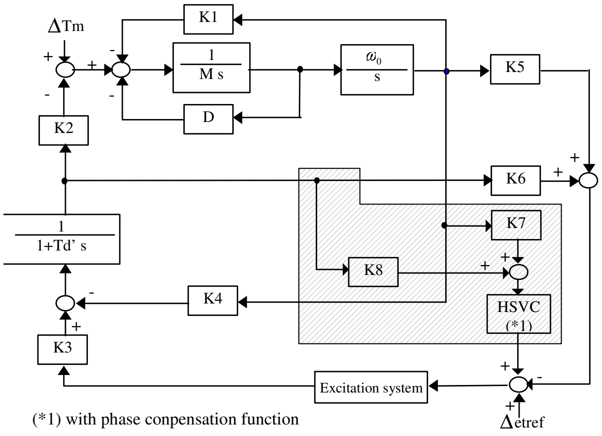


Figure 3-22 *Extended DeMello/Concordia model.*

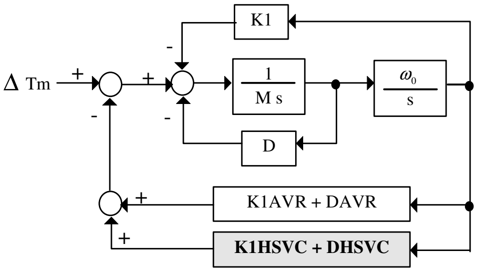
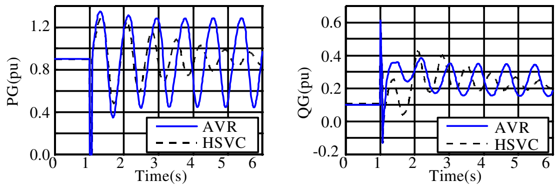
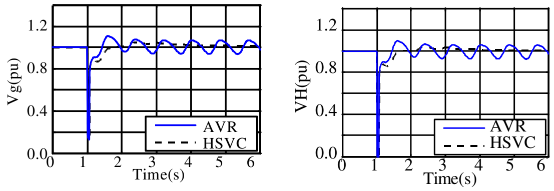


Figure 3-23 *Simplified model.*

K1AVR and DAVR are the factors of the synchronizing torque and the damping torque by the excitation system, respectively. Similarly, K1HSVC and DHSVC are the factors of the synchronizing torque and the damping torque by the HSVC, respectively. Accordingly, if a phase compensation function is added such that DHSVC becomes positive, then this means that damping, D, is added and thus the oscillatory stability of the power system can be improved. Figure 3-24 shows the simulation result in the case of a three-phase fault on the high voltage side of step-up transformer with the advanced HSVC equipped with a suitable phase compensation function. Where, in both cases of AVR and HSVC, a conventional PSS is not applied. This result shows a good mitigating effect of power system oscillations.



(a) Generator Power (b) Generator Reactive Power



(c) Generator Terminal Voltage (d) High Side Voltage

Condition : $X_t = 0.05$ pu, $X_e = 0.2$ pu, 100MVA base

Figure 3-24 *Suppressing effect of power oscillation.*

3.5.4 Performance on Parallel Operation

The performances for two cases of the parallel operation of two generators and four generators on the power system shown in Figure 3-25 were studied.

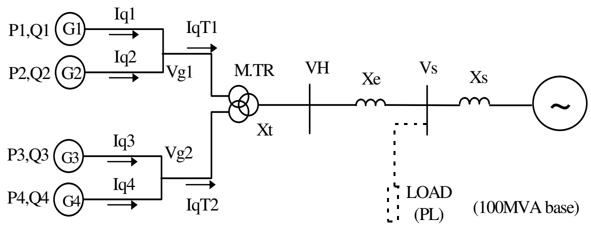


Figure 3-25 *Four machines model for studying the parallel operation.*

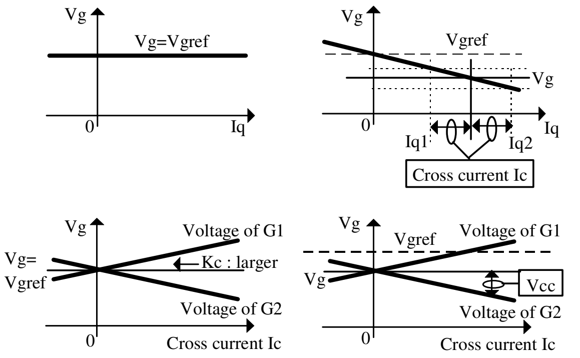
To this study, the advanced cross current suppression function is utilized to suppress the reactive cross current between the generators directly connected on the low voltage side of the step-up transformer. Here, it is between G1 and G2 and between G3 and G4. The conventional cross current compensating function that uses the load current of each generator may be detrimental to voltage stability, because V_g would decrease as reactive power increases. This compensating signal (V_{cc}) is:

$$V_{cc} = X_c \times I_q \qquad (3.5.4\text{-}1)$$

The advanced method that reduces the cross current by the deviation signal between generators, here adopted, has the compensating signal (V_{ac}) for G1 shown in (3.5.4-2).

$$V_{ac} = K_c \times (I_{q_2} - I_{q_1}) \qquad (3.5.4\text{-}2)$$

By increasing the suppression gain of cross current K_C, the cross current between generators can be reduced.. Accordingly, V_g is not affected by the reactive current of each generator and is kept constant. These characteristics of the conventional method and the advanced method are compared in Figure 3-26.



(a) Advanced method (b) Conventional method

Figure 3-26 *Characteristics of cross current suppression function.*

Figure 3-27 and Figure 3-28 show the time simulation results for a step disturbance of 0.01 pu in $V_{H_{ref}}$, on the parallel operation of two generators and four generators respectively. The results on two generators operation help verify the characteristics of the advanced cross current suppression function:

(a) V_H follows against a step of $V_{H_{ref}}$ within several seconds and is smoothly controlled without fluctuation. The resultant V_H fits the theoretical value;

(b) Even if the V_g detected by each AVR is different, V_H can be stably controlled according to $V_{H_{ref}}$;

(c) In spite of a discrepancy of each AVR gain, V_H can be controlled according to $V_{H_{ref}}$ except for a slower response of I_{q_2} by the lower AVR gain;

(d) In spite of a discrepancy of each AVR response characteristic, V_H can be controlled except for a slower response and increasing an overshoot of the G2;

(e) In spite of a discrepancy of operation mode, V_H can be stably controlled. As X_c becomes large, a deviation of I_q becomes small.

The results on four generators operation help verifying the characteristics between generator groups, G1/G2 and G3/G4. The same observations (a) to (e) above continue to apply. In addition

(f) Even if the step signal to G3/G4 AVR is delayed, V_H can be stably controlled according $V_{H_{ref}}$.

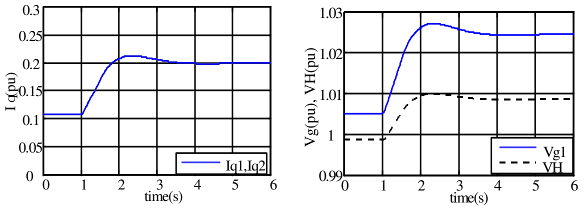
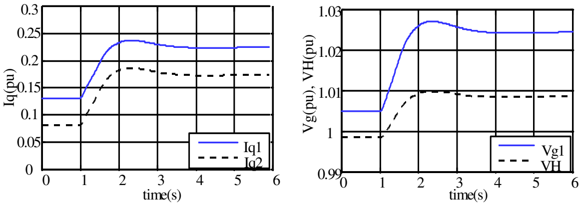
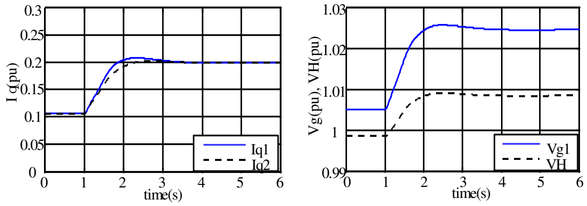
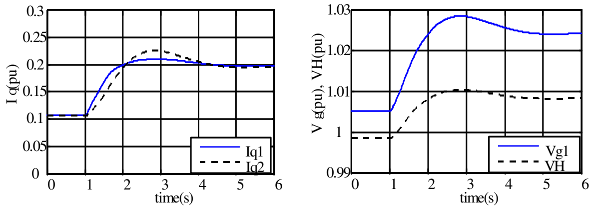
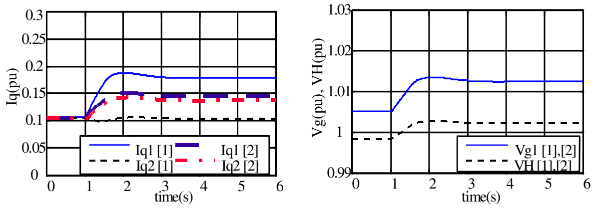
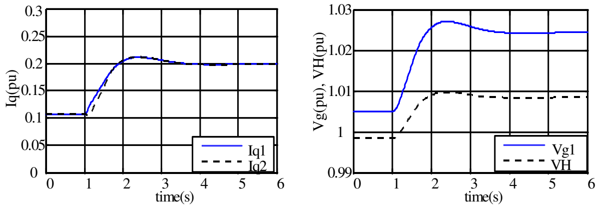
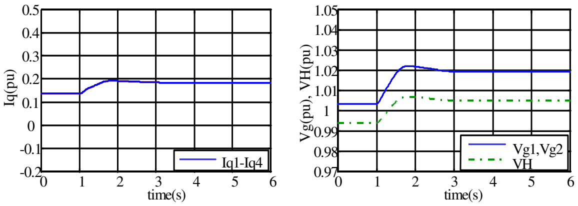
(a)Basic case	
[G1-V_g : G2-V_g = 0.995:1.005] (b)Discrepancy of AVR feedback voltage	
[G1-K: G2-K = 1:0.5] (c)Discrepancy of AVR gain	
[G1-$\omega \cdot C$: G2-$\omega \cdot C$ = 1:0.5($\omega \cdot C$: cross over frequency)] (d)Discrepancy of AVR response characteristics	
[G1: HSVC, G2:AVR X_c (pu):[1] X_c = 0.1 [2] X_c = 1.0] (e)Discrepancy of operation mode	
[Timing for change of $V_{H_{ref}}$ for G2 is 0.1s later than for G1.] (f)Discrepancy of timing for change of $V_{H_{ref}}$	

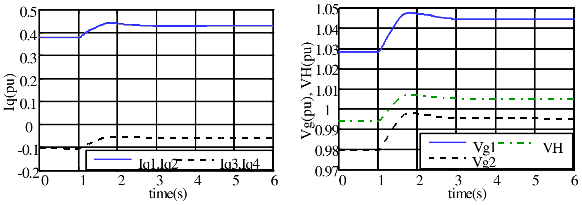
Figure 3-27 *Performance for two generators operation.*

(a)Basic case



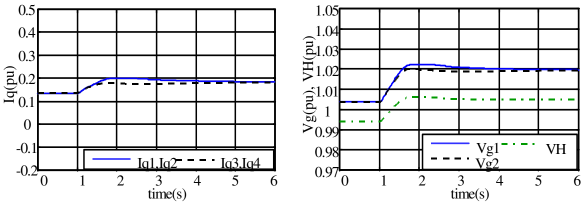
[G1/2-V_g :G3/4-V_g = 0.995:1.005]

(b)Discrepancy of AVR feedback voltage



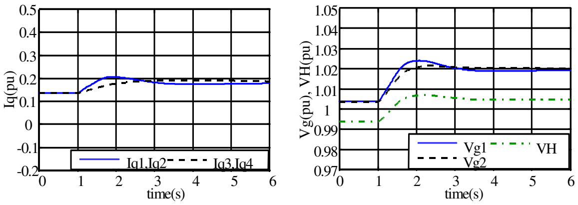
[G1/2-K:G3/4-K = 1:0.5]

(c)Discrepancy of AVR gain



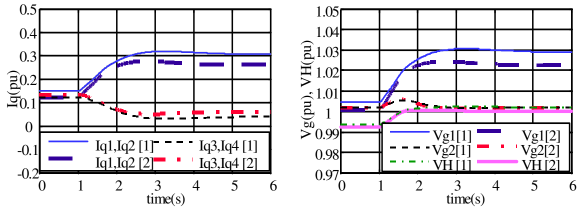
[G1/2- $\omega.C$:G3/4- ω c= 1:0.5 $\omega.C$: cross over frequency]

(d)Discrepancy of AVR response characteristics



[G1/2: HSVC, G3/4: AVR X_{dr} (pu):[1] X_{dr} = 0.01 [2] X_{dr} = 0.025]

(e)Discrepancy of operation mode



[Timing for change of $V_{H_{ref}}$ for G3/4 is 0.1s later than for G1/2.]

(f) Discrepancy of timing for change of $V_{H_{ref}}$

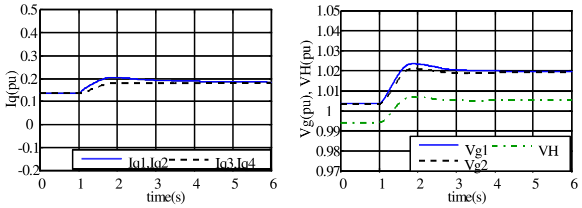


Figure 3-28 *Performance for four generators operation.*

3.5.5 Conclusions

- The performance of the various functions of the advanced HSVC was demonstrated for a simple power system. The simulation results were in complete agreement with theoretical expectation, confirming that the advanced HSVC could be put into practical use.

3.6 Excitation Control for High Side Voltage Regulation

The primary function of the excitation system is to regulate generator voltage and thereby help control system voltage. Most commonly, utility generation is operated on voltage control while in many instances industrial and co-generation plants could be operated on var/pf control. An available feature in most excitation systems, as discussed in previous sections, is the reactive current compensation (RCC). The RCC allows for regulation of voltage at a different point than at the generator terminals. This is done by measurement of the terminal voltage and addition (or subtraction) of a voltage proportional to the line current.

By utilizing proper settings, the RCC can be used to implement two different functions:

- Line Drop Compensation (LDC) that allows for regulating the voltage at a point part way into the step up transformer;
- Droop control that regulates a voltage internal to the machine, allowing units bused together to share var loading.

The simultaneous use of LDC and droop, RCC functions, in multi-unit plants with common connection is easily designed into modern digital–based excitation systems [3-7].

Proper use of RCC, including simultaneous use of LDC and droop where appropriate, offers an alternative to shunt capacitor compensation, with positive benefits of improved transient voltage support [3-30, 3-31]. Some case studies on a small power system model are presented to illustrate and quantify the effects. A brief discussion of other options such as master station voltage control, and coordinated system volt/var controls is also presented

3.6.1 Var Support for System Stability

The issue of var support on the heavily loaded system can be as critical as the traditional measure of MW reserve margin [3-31]. The system var losses that are required to be supplied are available from either rotating var's (generators, synchronous condensers), and/or various static var sources such as switched capacitors. The characteristics of these two types of var sources are different. Consider Figure 3-29 which shows a system bus to which is connected a mix of static and rotating var sources. To make the point, we consider the system bus voltage drops by 1% due to some external factor. Shunt connected capacitors will have their output reduced by 2% (of the bank nominal rating) since the output var's are proportional to the square of voltage. Inherently the static var source responds in the wrong way, reducing var output at a time when we would like to increase vars to support restoration of the system voltage. A rotating machine has an inherently beneficial characteristic to transiently supply vars during this same scenario. In the example shown the generator is connected to the grid through a step up transformer whose impedance is typically 10-20% on the generator MVA base. The same drop in system voltage of 1% results in an increase in vars from the generator of 5-10% of its rating. Further, the generator can increase var output through maintaining voltage control, up to the capability of the machine and transiently over and above the steady state capability within the over excitation limits in a well designed excitation system

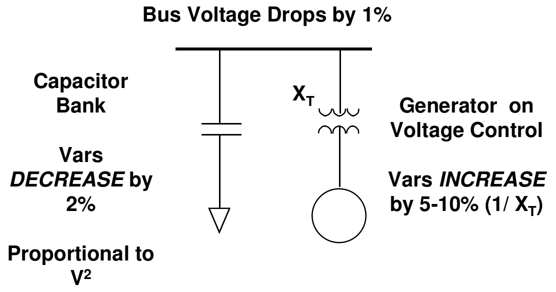


Figure 3-29 *Comparison of static and rotating var sources.*

3.6.2 Reactive Current Compensation

For units, which are in voltage control there is a function, normally a standard supplied feature, called Reactive Current Compensation (RCC) [3-32]. The RCC is a fast transient control that acts through the voltage regulator summing point. There is a slower acting control function that is discussed in the next section, called Master Station Voltage Control (MSVC). As discussed in previous sections, the RCC control provides for regulation of a voltage that is not the generator terminal voltage, but some other voltage synthesized using the terminal voltage, terminal current, and compensating impedance Z_c. The equation for the compensated voltage is defined in [3-] as:

$$V_c = V_T + (R_c + j.X_c)\times I_T \tag{3.6.2-1}$$

The voltage to be regulated is the compensated voltage, V_c, and it can be thought of as looking into the generator if the reactance X_c is positive (normally referred to as droop control) or looking outward into the network if X_c is negative (commonly referred to as line drop compensation). Normally, the resistive component, R_c is neglected since the R/X ratio is high.

The closer one regulates to the HV bus requires the unit to provide more vars to support the HV bus. If the generator is small relative to the system connection and the net impedance after compensation is too low, the unit var swings may be excessive in response to system voltage changes. For a situation with an isolated unit, the LDC may provide a good way of having better transient regulation of either a plant or HV bus voltage.

3.6.3 Stability Impacts of RCC

To illustrate some of the issues relative to the effect of the RCC on stability, consider a simple 2-machine model. Generator 1 is connected through a step up transformer and an equivalent transmission line. The second generator is a larger equivalent machine representing the remaining part of the system. The transmission line has a reactance of $X_e = 40\%$ while the step up transformer has a 10% reactance (on machine base). Figure 3-30 shows the response of the generator terminal voltage and reactive power output to a three phase fault three quarters of the way down a transmission line (remote fault). The excitation system is set up with RCC in LDC mode with compensation for 7.5% reactance looking into the system (75% compensation of the transformer impedance). The generator was loaded to 0.9 pu (rated) MW and 0.4 pu Mvar output and the fault clearing time close to critical clearing time. The difference between stable response with the LDC and unstable response without the LDC (terminal voltage regulation only) is evident. In order to obtain maximum benefit from the exciter during transient events, a properly designed and operating OEL (Over Excitation Limiter) must be an integral feature of the exciter. The use of shunt capacitor compensation can provide similar benefit, but at consequent greater risk for reduction of stability limits for larger voltage reductions. The use of LDC can make a difference in those cases where the unit var output and consequent transient stability limits are of concern.

The other way of using RCC is to allow for var sharing between two or more units connected together on a common bus [3-32]. This is illustrated in Figure 3-31, which shows two units connected together working through a step-up transformer. This configuration is common for either a cross compound (LP-HP) turbine generator combination, or hydro turbines sharing a split winding step up transformer connection. In this case it is required to have the RCC configured as droop control (positive value X_c – typically 5-6% on unit base) to regulate a voltage internal to the generator. This would provide an equivalent reactance to the common bus so that the units will share vars, as they would if there were a step-up transformer for each unit. In addition to droop, we can apply a simultaneous LDC control function to regulate into the step-up transformer (sometimes referred to as reactive differential compensation or cross-current compensation [3-36]). For each of the two units we can write an equation for the regulated voltage V_c which now depends on the current in both units.

$$V_{c_1} = V_T + j.X_{D_1} \times I_{T_1} - j.(X_{D_1} + X_{L_1}) \times (I_{T_1} + I_{T_2}) \qquad (3.6.3\text{-}1)$$

$$V_{c_2} = V_T + j.X_{D_2} \times I_{T_2} - j.(X_{D_2} + X_{L_1}) \times (I_{T_1} + I_{T_2}) \qquad (3.6.3\text{-}2)$$

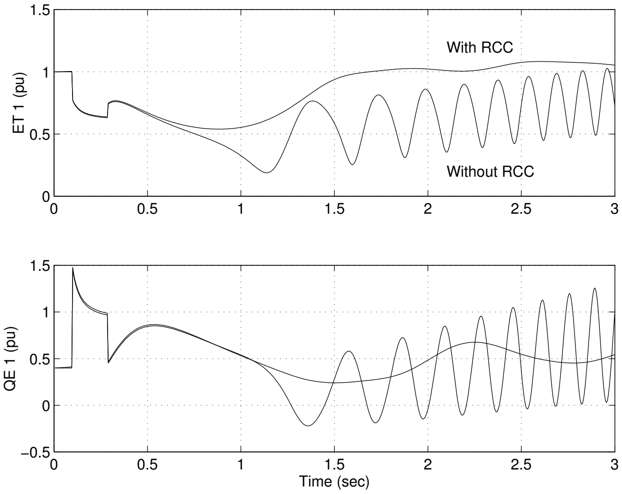


Figure 3-30 *Comparing the response to a three phase fault - with and without RCC (LDC).*

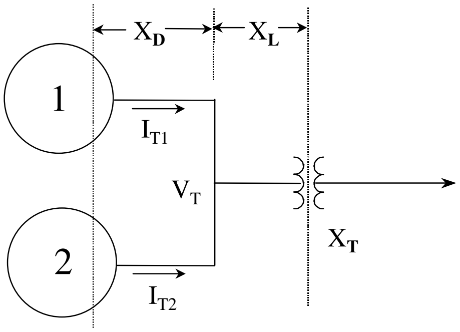


Figure 3-31 *Two-units bussed together, showing droop and LDC compensation.*

Where V_T and I_T are the terminal voltage and current, X_D is the droop impedance, and X_L is the line drop impedance. In theory the droop and line drop impedance's can be different on each unit so they are shown as subscript by unit number. It should be noted that each unit calculation requires the current from the adjacent unit(s). This concept can be extended to any number of units but typically the hydro turbine power blocks have 4 units, two one each side of a split winding connection. This is shown in Figure 3-32 as a one-line diagram. In the past, it was required to actually wire CT circuits of adjacent units together, which involved considerable accommodation in the design and effort in wiring. The digital based excitation control system architecture [3-34] may allow easy access and transfer of the required information using low bandwidth signal connections.

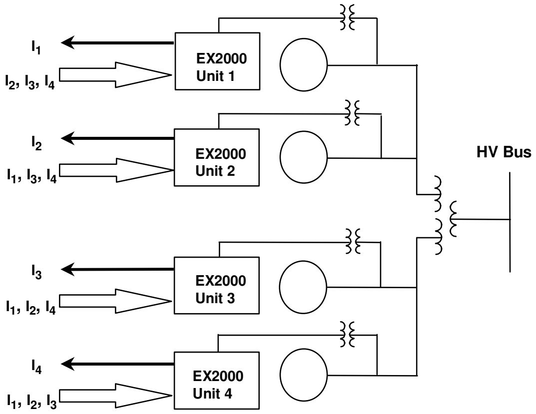


Figure 3-32 *Four unit hydro turbine power block, showing interconnection for HSVC.*

The GE EX2000 excitation system, for example, can have the option for input of three additional current signals from adjacent units. In practice, the calculation in EX2000 is based on the use of vector math in the high-speed transducer algorithms to calculate the reactive component of current, in addition to the previous assumption of only using the reactance to calculate the voltage change. The advantage of using the reactive current is that only scalar quantities (magnitudes) have to be included in the calculations reducing the bandwidth requirements for the current signals. The net effect of these assumptions amounts to less than one percent error for normal values of X_c in the 5-10% range. This facilitates constructing the required algorithm for reactive compensation on up to four units that share a common step-up transformer connection. Each unit's excitation system uses the computed reactive current from its own unit, and the input reactive currents from the other three excitation systems. The current signals are transferred using 4-20 mA current loops, and equations similar to those shown previously for the two-unit case are easily implemented in software functions using reactive current in place of actual current.

3.6.4 Plant and System Volt/Var Controls

The basic thrust of improving system stability margins is driving us towards ways of using volt/var control in a more coordinated fashion. The intent of these controls is to utilize the maximum range in var capability from the generators in a more automated fashion. The common factor of each of the systems reviewed here is that they require some input from adjacent units in a plant or in some cases all plants in the system. This kind of coordinated control requires a commitment and planning at system level and participation from all the units, much in the same way as PSS application is used in all of the Western US to achieve good damping for inertia modes.

The first level of var control is what is called Master Station Voltage/Var Control (MSVC) [3-35]. This is a control function that monitors all the units in a power plant and provides adjustment to the individual excitation systems to insure that the volt/var for each unit is balanced in respect to its capability. A block diagram of the MSVC control is given in Figure 3-33. The MSVC is slower outer loop (controller not regulator) acting through the raise lower commands, similar to an individual unit var/pf controller. The MSVC can be configured in a number of ways, one possible way would be to measure the var output of the plant and use the MSVC to trim each excitation system to insure that each unit is providing a var output in proportion to its individual capability. In a station with different sized units and different impedance's for the step transformers, there might otherwise be a tendency for some units to have var swings larger than their share in proportion to the other units. Balancing the var loading will maximize the dynamic range of system var support from the station. It is recognized that the plant operators could do this same function, but the MSVC automates this process.

An extension of the concept of MSVC is the REPORT system that is applied to the Italian gridand was discussed in section 3.4. This system has the same basic interface in each plant as the MSVC control. Taking the coordination to the next level, they apply a system level controller that is then tied to each of the plants in the system. In this case the control center will supply the appropriate set point to each plant. This type of control coordination requires a commitment from the utility and most likely an investment in a control interface for each unit.

A related type of coordinated control has been adopted by Tokyo Electric Power (TEPCO) in their PSVR (Power System Voltage Regulator) [3-37]. In this system the control is also applied to all units as a modification to the voltage regulator to include a high voltage bus setpoint control loop, in addition to the normal generator voltage regulation. This system differs from the setpoint control concept in that it supplies a regulation loop to the voltage regulator, which acts to insure that the HV grid voltage is regulated to a setpoint (with droop) to insure each unit is supplying its fair share of vars to support the HV bus voltage. In the TEPCO system all units have the PSVR control applied and the HV setpoint is varied with time during the day in patterns that are pre-selected and supplied by the system control center.

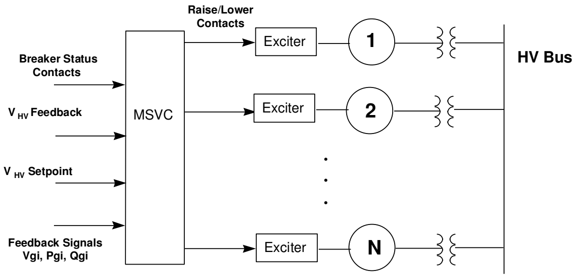


Figure 3-33 *Overall structure of MSVC controls.*

3.6.5 Summary and Conclusions

The use of reactive current compensation (RCC) for line drop compensation can provide stability improvements for a generator connected through a step up transformer. This type of control is often referred to as high side voltage control or secondary voltage control, as it offers tighter regulation of the high side voltage bus, by using more of the reactive capability of the units. In the case of multiple units bused together, the simultaneous use of both droop and line drop compensation can provide the same transient stability improvements. Studies of this control are recommended and may offer an alternative to other forms of reactive compensation for supporting system voltage.

The concept of Master Station Voltage Control (MSVC) and two notable system var controllers, the ENEL REPORT system and the TEPCO PSVR system, are mentioned to indicate what can be done by a utility which adopts a system wide voltage control philosophy.

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Chapter 4

Coordinated Control in Transmission Networks: Capacitor and Reactor Banks, Power Electronic Devices, and LTC Autotransformers

Generators typically regulate terminal voltage via automatic voltage regulators and exciter equipment. The desired high side (transmission side) voltage schedule is usually maintained by the power plant operator, or by slow SCADA-type process control computers. The previous chapters described advanced methods to regulate transmission voltage via generators. Either local (Chapter 3) or remote signals (Chapter 2) may be used.

Power plant voltage control should be coordinated with transmission and distribution voltage control. For heavy load conditions, transmission voltages should be high and flat. Active and reactive losses are thus minimized with line charging supported and reactive power flow across transmission lines and transformers minimized. Reduced active power losses result in less transmission line heating and conductor sagging—a contributing cause to some large-scale blackouts. Spinning reactive power reserve is maximized and potential for voltage collapse is minimized.

Especially in a restructured environment, an objective may be to minimize reactive power interchange between generating companies and transmission companies, and between transmission companies and distribution companies. This reduces losses and possible ancillary service payments, and ensures spinning reactive power reserves. Alternative procedures are to coordinate generator reactive power output for a reasonable voltage profile and sufficient reactive power reserves.

High and flat voltage profile requires—besides power plant high side voltage control—reactive power compensation at substations and feeders, and LTC transformers. Series compensation also helps maintain voltage profile. Usually, however, insufficient controllable compensation is available during peak load periods to perfectly maintain voltage profiles, and operation should be optimized (e.g., active loss minimization) using available devices.[1]

An effective strategy is to control power plant high side voltage by local measurement (Chapter 3), and to control substation devices using either local measurements or a combination of local and remote (wide-area) measurements. Many companies apply shunt compensation to provide base reactive power, ensuring reactive power reserves at power plants for emergencies. This helps prevent voltage collapse during severe emergencies [4-1].

This chapter emphasizes transmission substation voltage control using shunt compensation and automatic control of LTC autotransformers. Other relevant topics, however, include:

- LTC generator step-up transformers.

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[1] We also note that voltage measuring devices such as capacitive potential transformers have real-world accuracy of around ±1%, or ±5 kV for 500-kV transmission. Digital positive sequence (3 phase) measurement and averaging improves measurement accuracy.

- Series compensation;
- Distribution shunt and series compensation, and voltage regulation, and power quality devices.

4.1 Practice Using Local Measurements

Except for line-connected shunt reactors, transmission shunt compensation is usually switchable based on local voltage measurements. Control is usually by local voltage relays and/or system operators using SCADA. Special protection systems (remedial action schemes) are also used. Static var compensators and STATCOMs employ more sophisticated local control.

4.1.1 Shunt Reactor, Capacitor Banks, Line Switching, LTC Autotransformers

Shunt reactors may be necessary with long lines (especially EHV lines), as well as with submarine cables, and may be line or bus connected. Line-connected reactors may be either fixed or switchable. Bus-connected reactors are normally switchable. Shunt reactor disconnection during emergencies is an important voltage collapse countermeasure for some power companies.

Shunt capacitor banks are being increasingly applied at transmission voltages, including EHV voltages. For example, Bonneville Power Administration (BPA) has fourteen 500-kV banks (up to 460 Mvar at 550-kV), fifty-three 230-kV banks (up to 168 Mvar at 241-kV), and numerous 115-kV banks.

Shunt capacitor banks are low cost and have virtually zero losses. Modern all-film fuseless capacitor banks increase cost-effectiveness [4-2, 4-3]. New techniques for multiple-step banks are developed [4-4, 4-5]. Capacitor banks are in the same life-cycle cost range as power plant controls requiring remote signals as described in Chapter 2[2]. Reactive power transmission is largely avoided because of flatter voltage profile.

For large EHV capacitor or reactor banks, circuit breaker switching times are typically 2-cycle opening and 5-cycle closing. Current limiting reactors are the most robust means to limit switching transients, but precise control of switching instant may be used as a supplement to reactors. Although seldom used, several operations are possible within a few seconds [4-6]. Several switching per day is typical.

Shunt compensation control is mainly by SCADA. Under/overvoltage relays initiate switching for fast, severe voltage excursions. Voltage relays have definite time delay of seconds or tens of seconds, or may be of the inverse-time type. Control center reactive power monitoring aids preventive and corrective control by operators [4-14, 4-15, 4-16].

Fast capacitor/reactor bank switching is used for emergency stability control (special protection system, remedial action scheme). These are usually preplanned schemes that switch series and shunt compensation by transfer trip based on detection of outages [4-21].

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[2] Switchable capacitor banks minimize reactive power transfers and active power losses, have long lifetime, and are highly reliable.

A recent study suggested prices for fixed distribution, switched distribution, and relatively small switched transmission capacitor banks at US$5/$20/$10 per kvar respectively [4-7]. Capacitor bank prices in New South Wales, Australia are about A$7 per kvar for large banks.

For voltage control, power companies routinely de-energize long transmission lines during light load periods. A lightly loaded 160 km 500-kV line, for example, generates around 200 Mvar, contributing to high off-peak voltages.

System operators typically control LTC autotransformers via SCADA, possibly based on energy management system optimal power flow. In complex networks, minimization of circulating reactive current is an objective.

Shunt capacitor/reactor banks are typically switched several times per day over a weekly load curve. Appendix F describes advanced power flow program methodology to simulate switching to regulate voltage profile over a load curve.

4.1.2 Static Var Compensators, STATCOM, and Synchronous Condensers

In some circumstances, more expensive power electronic based shunt compensation may be justified. SVCs or STATCOMs are typically 4–6 times the cost of transmission-level mechanically switched compensation (US$30–$55/kvar). One application is a weak system where temporary overvoltage, as well as short-term voltage collapse, is a concern. SVCs or STATCOMs may be needed in power systems with substantial amount of wind generation (induction generators were commonly used for wind generation now largely being replaced by more sophisticated variable speed machines that have the ability to regulate reactive power).

Another application is where a high portion of load is induction motor so that fast voltage collapse occurs if motors don't reaccelerate following a fault. The SVC or STATCOM fast control is especially valuable with low inertia air conditioning load[3]; STATCOMs have performance advantages over SVCs [4-8].

SVCs and STATCOMs allow unrestricted switching or continuous control with minimal transients.

Primary SVC/STATCOM control in transmission applications is based on local high side voltage measurement. SVC current measurement is used to provide a droop effect for coordination with other devices, including generators. Power plants with high side voltage control should have similar droop settings [4-9, 4-10, 4-11].

For longer-term voltage stability problems (tens of seconds or minutes), SVCs or other power electronic devices typically are not justified [4-12]. Appendix D is an Italian network study that concludes that SVCs or STATCOMs are not required in the presence of secondary voltage regulation, and that manually or automatically switched shunt capacitor banks suffice. An exception where SVCs or STATCOMs may be justified is for operation near maximum power transfer capability, where small switching increments are required.

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[3] Stalled residential air conditioners typically trip after 5–10 seconds by thermal overload protection.

Static var compensators are mature technology. Various configurations are possible from building blocks of Thyristor Controlled Reactor (TCR), Thyristor Switched Capacitor (TSC), and Thyristor Switched Reactor (TSR). Several methods are used to reduce cost such as:

- Use of a smaller SVC or STATCOM that also controls local and, in some cases, remote mechanically switched compensation. A SVC with coordinated mechanical switching is termed a static var *system*;
- Connection to existing autotransformer tertiary, avoiding a dedicated coupling transformer;
- Use of short-time ratings [4-13];
- Modular, relocatable design.

Voltage-source converter based STATCOMs are becoming competitive with SVCs, at least for smaller Mvar ratings. There are several STATCOM designs, with high switching frequency pulse width modulation designs having higher losses. Comparison of SVCs versus STATCOMs includes performance, capital cost, losses, physical size, and modularity. Advantages of STATCOMs over SVCs include:

- Smaller footprint;
- Constant current rather than constant reactance characteristic outside control range. Compared to a SVC, a smaller STATCOM can provide equivalent dynamic performance;
- Higher bandwidth for control of voltage flicker and other fast transients;
- Improved performance on weak systems.

Synchronous condensers are generally not competitive with power electronic devices, but have the advantage of substantial time-overload capability. Some generators are convertible to synchronous condenser operation, and generators at decommissioned plants have been and can be converted to synchronous condensers.

As an alternative to large transmission-level SVCs or STATCOMs, multiple small distribution level devices may be attractive [4-32]. The reactive power support is then close to motors that have difficulty reaccelerating following faults. The reactive power losses in transmission-level SVC/STATCOM coupling transformers and bulk power delivery transformers are avoided.

4.2 Advanced Substation Voltage Control

Advanced automatic control of capacitor/reactor banks and LTC autotransformers is possible using microprocessors—such as used for thyristor-switched capacitor/reactor banks. Automatic control of network autotransformers generally improves voltage stability; the tap changing should be faster than tap changing at bulk power delivery transformers and distribution voltage regulators [4-19, 4-23].

Strategy is necessary to coordinate and prioritize shunt compensation switching and tap changing. Because of the consequence of a large transformer failure,[4] shunt compensation

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[4] The LTC mechanism is considered the most failure-prone part of a transformer.

switching is often more frequent than tap changing. Reducing tap changing is sometimes part of the justification for SVCs or STATCOMs.

Typically the LTC will control the secondary voltage within a deadband. If the capacitor banks try to control the same voltage, hunting between the two control devices will result. A viable alternative is to have the switched capacitor bank regulate the high-side voltage. Again a coordination of deadbands and time delays is necessary to avoid oscillatory behavior.

Remote signals improve the sensitivity of local voltage control. In particular, reactive power outputs of nearby power plants and static var compensators are sensitive indicators of voltage security, and of the need to switch shunt compensation. For load areas without substantial local generation, reactive power at the center of major support lines may be used (reactive power at center of lines is computed from substation measurements).

In addition to simple telemetering of remote signals, centralized, distributed and hierarchical control structures are possible.

For automatic LTC autotransformer control, remote signals or central logic may be needed to minimize circulating reactive current among parallel transformers at different stations.

4.2.1 Voltage Control in Belgium

Chapter 2 describes coordinated voltage control in Belgium [4-24]. Using OPF, a three-step process is used to recommend capacitor bank switching, tap changing, and generator reactive power production.

4.2.2 Substation Controller

Figure 4–1 shows a microprocessor-based scheme for substation control [4-17, 4-18[5], 4-19]. Remote (aux.) signals based on generator reactive power bias the local voltage measurements.

The microprocessor control may use inverse-time criteria for switching, i.e. accumulated volt-seconds outside dead zone. Other control such as fuzzy logic is possible.

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[5] In Colombia seven controls are in automatic operation (2 have the LTCs in manual waiting for a small modification) and two are waiting to go into auto operation.

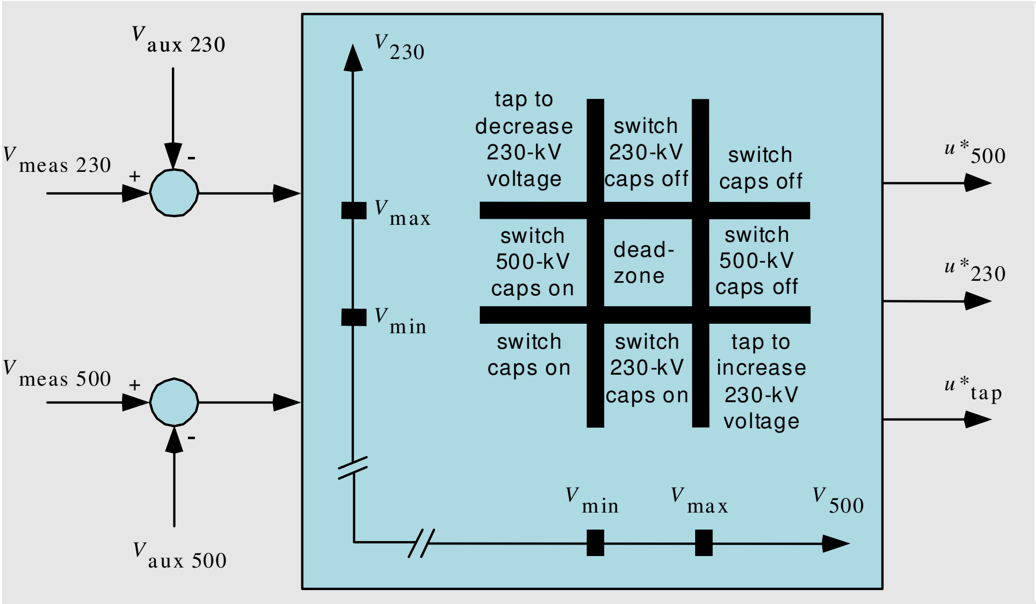

Figure 4–1 *500/230-kV substation controller for capacitor/reactor banks and LTC autotransformer.*

4.2.3 Coordinated Control of Capacitor/Reactor Banks in the Italian Grid by the Regional Voltage Regulator [4-16]

The basic principle of the SVR and TVR is the network subdivision into areas, a single area consisting of buses having a high electrical coupling. Therefore their voltages change in unison according to the trend of the area pilot node voltage.

The SVR reactive power level $q_i(t)$ of the j-area represents the control effort at the j-area and therefore the real-time reactive power load for the j-area control units. More precisely, $q_i(t)$ is the percentage of the j-area units reactive power with respect to their under or overexcitation limits; when $q_i(t)$ reaches +1 the j-area voltage regulation is saturated, because the operating points of all the j-area control units are fixed by their overexcitation limits.

The pilot node voltage of a grid area is therefore regulated through the SVR unless all the area control units reach their overexcitation limits—this extreme operating condition representing the area voltage regulation limit. Considering that voltage degradation takes some minutes, it appears reasonable, simple and effective to compute directly inside the SVR a real-time and on-line indicator of the j-area proximity to voltage regulation limits, mainly based on the actual value of the area reactive power level $q_i(t)$.

The RVR avoids operation at overexcitation limits by controlling all possible reactive power resources (capacitors banks, reactors, synchronous or static compensators, etc.) installed in the j-area, so as to reduce the $q_i(t)$ operating value and therefore the control effort of the generating units. The RVR acts automatically on the reactive power resources under its control and moreover sends signals to the regional operator requesting manual switching of the remaining resources. When all these control actions are accomplished and area control units do not allow additional overexcitation, then the difference 1- $q_i(t)$ clearly represents the distance of the j-area from its voltage regulation limit.

Design criteria for the RVR control of capacitor/reactor banks. The reactive power level $q_i(t)$ represents useful real-time, on-line information for the regional dispatcher. When given thresholds are exceeded and the area alarm is sounding, the operator must put into service the remaining reactive power resources of the j-area. In reaching the j-area high-risk conditions of voltage instability, the operator could manually block the j-area LTCs.

Because $q_i(t)$ is a real-time variable, it can be more effectively used for real-time automatic control actions. If $q_i(t)$ is greater than a threshold value representative of a j-area voltage control effort plus a small voltage control margin, the control logic will order the automatic switching of capacitors banks, reactors and SVCs of the concerned area.

If small reactive power control margins persist below a critical threshold, the RVR is allowed to automatically modify the voltage setpoints or the transformer ratio of the local LTCs to reduce load.

After these control actions, the control logic will automatically block the j-area LTCs. After this last control action the j-area RVR will have coordinated all the possible automatic control actions for supporting the pilot node voltage. When normal operating conditions return $q_i(t)$ will decrease and RVR will release the j-area LTCs and reduce the operating reactive power resources.

Implementation aspects of the RVR control of capacitor/reactor banks. The j-area $q_i(t)$ level is generally limited to the ±1 range. For generators equipped with devices allowing transient overloading and when the pilot node voltage regulator is enabled to manage the overloading, the reactive power level of the area can temporarily exceed the +1 value. When one area approaches reactive power saturation conditions, the corresponding pilot node voltage regulator has the possibility to telecontrol the reactive power resources of a configurable number of stations within the area, concerning:

- Blocking LTC action;
- Modification of LTCs transformation ratio;
- Updating of voltage references of SVCs;
- Capacitor banks on/off controls;
- Reactors on/off controls.

4.2.4 BPA Wide-Area stability and voltage Control System (WACS) Project

Bonneville Power Administration is developing wide-area stability and voltage control. The control provides a flexible platform for rapid implementation of generator or load tripping, and reactive power compensation for voltage support and stability. Features include phasor measurements, digital fiber optic communications, and fuzzy logic control. The control includes both fast and slow subsystems. The R&D demonstration is nearing completion, with on-line monitoring of real-time controller performance using wide-area measurement inputs [4-20]. A decision will be made on full-scale deployment with required redundancy and reliability including replacement of older phasor measurement units.

Potential benefits of the project are power transfer capability increase, and improved angle and voltage security. Contrasted to most special protection systems, WACS is a response-based (feedback) control system that responds to disturbances anywhere in the interconnection. Other potential benefits are capability to rapidly add new control functions based on the control platform and measurement base, and lower cost than special protection systems.

Synergy between the wide-area control and other control center applications is expected. For example, on-line security assessment can be used for controller tuning and adaptation. There will also be synergy between wide-area control and substation automation (e.g., intelligent electronic devices, digital control and protection).

Figure 4–2 shows the overall control. The project exploits "information age" technology in digital control and communications [4-21, 4-22]. Input signals are from positive sequence synchronized phasor measurements and from SCADA. Control action is centralized at the BPA control center and most of the control actions are discrete. *Flexibility* for rapid, low-cost implementation of new control requirements is a key attribute.

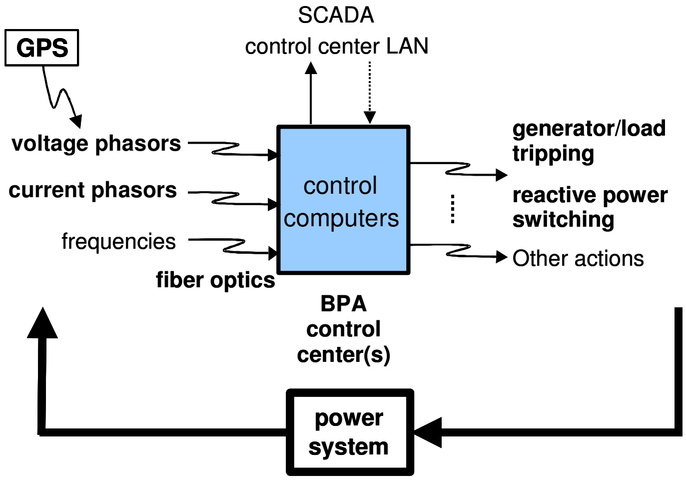

Figure 4–2 Flexible platform for centralized control. The initial demonstration includes only generator/load tripping and reactive power switching.

The project goals include:

- Provide fast response-based control (generator tripping and reactive power compensation switching) to maintain Pacific ac intertie stability for disturbances originating anywhere in the interconnection. Voltage magnitudes along the Pacific intertie are the primary input signals, but active and reactive power measurements, voltage phase angle, and bus frequencies are available. Eventually the control may replace special protection systems based on direct detection of certain outages;

- Initiate reactive compensation switching for voltage stability and voltage control. Control is based on voltage magnitudes and generator/static var compensator reactive power outputs using fuzzy logic. Fuzzy logic is a convenient means to combine reactive power and voltage magnitude measurements. For local areas without substantial generation, reactive power flow computed for the center of major support lines can replace generator reactive power. Reactive power is a much more sensitive indicator of voltage problems than voltage magnitude;

Many of the components shown on *Figure 4–2* exist, including synchronized phasor measurements, and outgoing transfer trip signals for generator tripping and 500-kV capacitor/reactor bank switching. With many input measurements and many outgoing signals, brute force redundancy is not planned. Failure of a single input signal or outgoing signal may degrade control, but not cause failure.

WACS uses phasor measurements from eight BPA stations. The phasors are transmitted at a 30-packet per second data rate over BPA's SONET fiber optic communications. Reference [4-20] provides comprehensive description.

4.2.5 BPA Automatic Voltage Control (AVC) Project

Based on research carried out by Washington State University [4-37,4-38], BPA and Ciber Inc. developed a prototype Automatic Voltage Control with on-line demonstration. AVC uses state estimator output for current power flow state, and performs fast, adaptive local-area power flow simulation to determine optimal switching of capacitor/reactor banks and LTC autotransformers. Control action time frame is in the order of several minutes depending on state estimation execution cycle, and at least initially would be "man-in-the-loop." An electrical distance method [4-33] is used to determine the local area of influence for each control device.

Compared to most other optimization programs, AVC is designed for discrete (discontinuous) switching rather than continuous control. Optimization of discrete switching is problematic in most other programs. This is especially true when there are many potential switching options, such as numerous substations with many capacitors/reactor banks of different sizes and different voltage levels, and with many LTC autotransformers between buses of voltage values such as 500-kV, 230-kV, and 115-kV.

The incremental computed effects of switching are added to the measured actual voltage values from SCADA to determine expected voltages after switching. The control minimizes the number of control actions while maintaining the voltage schedule, as well as meeting other objectives: avoiding circular reactive current flows, minimizing line losses and potentially automating operator actions.

The project was not continued beyond the prototype demonstration stage, but a detailed report is available [4-34].

4.2.6 Secondary Voltage-Var Controls Applied to Static Compensators (STATCOMs) for Fast Voltage Control and Long Term Var Management

Static Compensators (STATCOMs) apply advanced power electronic devices such as GTOs (Gate Turn Off Thyristors) or GCT/IGCTs (Gate Commutated Thyristors) and are able to exchange reactive current (inject or absorb) with the power system at a range of voltage levels, similar to a synchronous condenser. Thus, STATCOMs are able to provide voltage support to the power system in the vicinity of the bus to which it is connected. The reactive current injection capability of STATCOMs is illustrated in Figure 4-3.

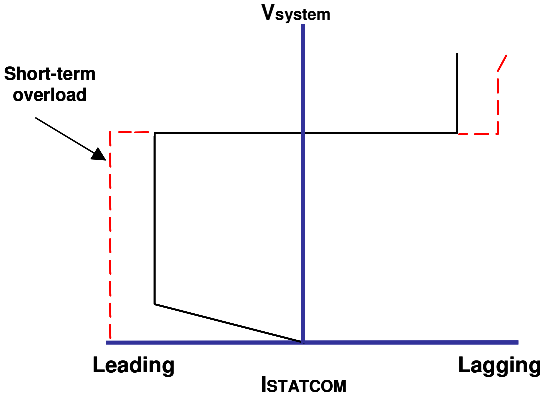

Figure 4-3. Reactive current capability of a STATCOM.

STATCOMs has been successfully applied in a number of projects over the past decade [4-25, 4-26] including several other recently completed STATCOMs in North America [4-27, 4-28, 4-29, 4-30].

Feedback controls in a STATCOM can mitigate voltage instability and improve system transient stability. Auxiliary controls, such as for power swing damping, can also be implemented in a STATCOM to help system oscillatory stability. Furthermore, secondary controls are often implemented in STATCOM installations to coordinate local and remote capacitor banks for fast voltage control and long term var management. The secondary control functions are the main focus of this subsection.

The primary control objective of a STATCOM is to support the bus voltage to which it is connected by injecting or absorbing reactive current. This is accomplished by a regulator using bus-measurement feedback, typically bus voltage. The typical step-response time of the STATCOM for this primary function of voltage control is in the order of 50 msec.

Figure 4-4 is an example of the primary control of STATCOM applied at two recent projects [4-27, 4-28]. The figure illustrates that the primary control has two main portions, namely, an automatic voltage regulator (AVR) with bus-voltage feedback, and an automatic reactive power regulator (AQR) with a STATCOM-reactive-power-output feedback, along with associated limiters.

Figure 4-4 shows that the AVR also has an available input for an auxiliary voltage signal, such as for a power swing damping control. Also shown in this figure is an auxiliary input for the AQR, which can be used for a coordination function for local and remote capacitor banks for fast voltage control and long term var management.

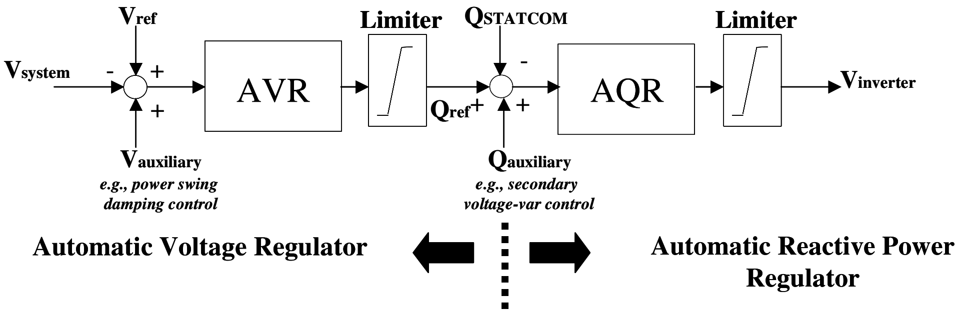

Figure 4-4. Functional block diagram of the primary control [4-27, 4-28].

The main purpose of secondary controls applied to a STATCOM is to ensure that it maintains an adequate range of dynamic capability for major system disturbances. The output of the secondary controls calls for the switching of capacitor banks to "reset" the reactive power output of the STATCOM to a pre-specified level after a system event (long term), or during the course of a daily load cycle (long term), or during an event for voltage control (fast). The concept of the primary and secondary control is illustrated in Figure 4-5.

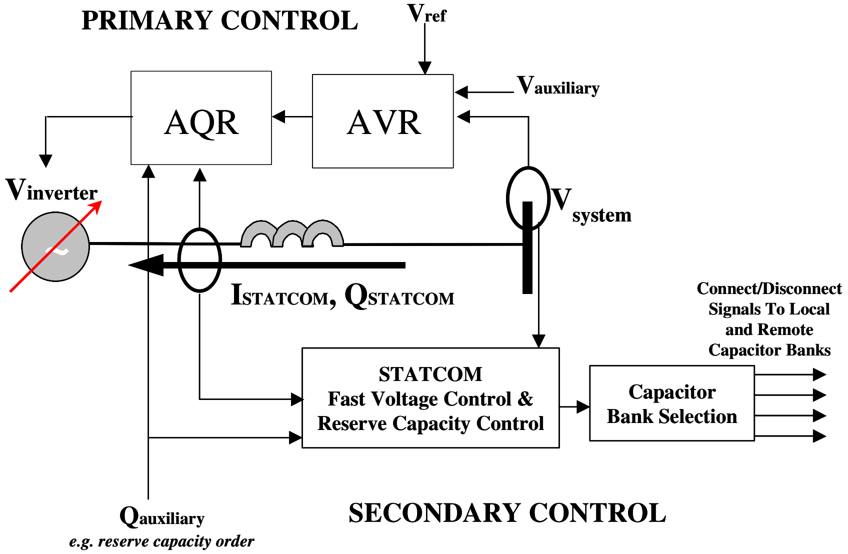

Figure 4-5. Functional diagram of the primary and secondary control of a STATCOM.

Reference [4-31], discusses the concept of coordinating a STATCOM with local voltage-var control devices such as load-tap changers (LTCs) and capacitor banks, for long-term voltage-var management. This reference introduced the concepts of long-term voltage-var management for any one of the following three objectives:

- Resetting a STATCOM by a simple reactive power runback function so that it would be available for the "next" dynamic event on the system.
- Improving the overall system voltage profile by coordinating the STATCOM with local LTCs and/or capacitor banks.
- Reducing LTC tap movements by coordinating the STATCOM with local LTCs and/or capacitor banks.

Reference [4-31] also discusses the advantages and disadvantages of applying secondary controls to STATCOMS for each of the above-listed objectives.

Although the concepts shown in this subsection were focused on STATCOM applications, the coordinated control concepts equally apply to Static Var Compensators (SVCs) as well.

Appendix G discusses two recent installations of STATCOM and the related application of secondary controls for fast voltage control and long-term var management. Other mentions of this concept can be found in [4-29, 4-30].

4.2.7 Advanced Substation Voltage Control in TEPCO

In Tokyo Electric Power Co. (TEPCO), high and flat voltage profile is maintained automatically by high side voltage control at generators, reactive power compensation at substations, and LTC transformers.

TEPCO applies shunt compensation to ensure reactive power reserves at power plants for severe contingencies during peak load periods as well as to correct load power factor. Over 5000 MVA of shunt reactors to compensate underground cable charging are disconnected during peak load periods to keep reactive power reserves at 500-kV substations. And, most of the shunt capacitor banks at 275-kV or lower substations are in service during peak load periods. Reactive power reserves are kept in bottom-up manner.

Shunt capacitor banks are applied at transmission voltages, including EHV voltages. TEPCO has 13000 Mvar at 500-kV substations, 7000 Mvar at 275-kV substations and 7000 Mvar at 154-kV substations. Most are connected to the tertiary side of transformers whose rated voltages are 22-kV or 66-kV. Some are connected to 154-kV buses.

In TEPCO, all transformers are equipped with LTC except for most of the main step-up transformers at power plants.

Both shunt compensation and LTCs are controlled by Voltage Reactive Power Controllers (VQC). VQCs play a role of simultaneous regulation of primary and secondary voltages for 500/275-kV or 500/154-kV substations, and primary side reactive power flow and secondary voltage for 275/154-kV, 275/66-kV, and 154/66-kV substations. VQCs use microprocessor technology. For example in 500/275-kV substations, both 500-kV and 275-kV bus voltages are used as input signals. The action to be taken is decided depending upon where the measured bus voltage is located on the operational plane shown in Figure 4-6. Although switched capacitor banks and LTCs regulate both high-side voltage and low-side voltages, one action is always selected, so that hunting between two controls is avoided. When both high-side and low-side voltages are below dead zone, switching on a capacitor bank is selected instead of tap-changing after accumulated voltage-seconds outside dead zone reaches the setting value for either high-side or low-side voltage.

Fast capacitor/reactor bank switching is also initiated by VQC with an inverse time delay of a few seconds against severe primary voltage excursions.

500-kV system voltage schedules are kept by high side voltage control with Power System Voltage Regulator (PSVR) at power plants and shunt-switching/LTC with VQC at substations as shown in Figure 4-6. Since major generation centers are located over hundred kilometers from load centers including Tokyo metropolitan area, and some 500-kV overhead transmission lines carry heavy flows exceeding surge impedance loading, net reactive power losses on power grid have to be compensated at both sending and receiving ends to keep voltage schedule.

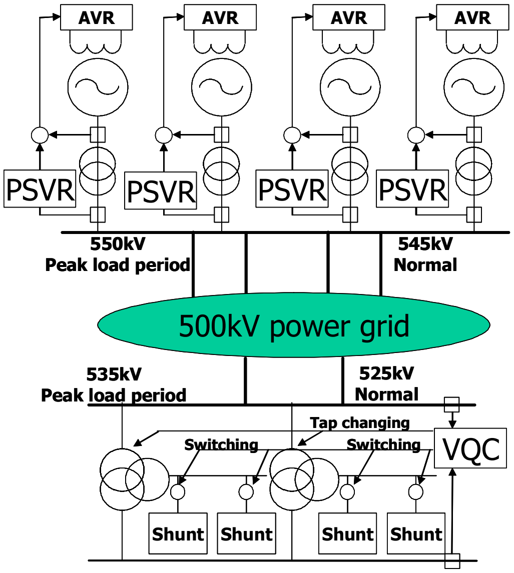

Figure 4-6 Voltage control for 500kV power grid

SVCs have been installed at three 500/275-kV substations. Primary SVC control is based on local high side voltage measurement with droop characteristics. Reactive power output of SVC is regulated by VQC supplementary signal of high-side voltage to keep dynamic reactive reserve at SVC, in a scheme which is similar to a Static var System.

Synchronous condensers whose rated capacity is 200 Mvar have been installed at three 500/275-kV substations. The control is same as SVC.

4.2.8 Study on Coordinated Secondary Voltage Regulation on SVC Units in the Nordic Power System

Statnett SF (the Norwegian Transmission System Operator) is making considerable efforts to increase transmission capabilities in the existing power transmission grid [4-35]. One of the focus areas is voltage stability and strategies for voltage control and reactive power. As part of these efforts a study has been performed to investigate if coordinated voltage control of SVC units can contribute to raise transmission limits in southern Norway. A prototype version of the control scheme has been implemented within Statnett's regional control center for southern Norway [4-36].

The southeast of Norway (Oslo region) is a high load area with little generation capacity. Thus, voltage control relies heavily on the use of capacitor banks, synchronous compensators and SVCs. The aim of the study has been to assess whether the present operating procedures could be automated in a simple way that provides additional benefits in term of:

- Improved voltage regulation;
- Increased reactive reserves;
- Simplification of the daily control routines for the operators.

If successful, this will enable Statnett's national control center to increase transfer capacity limits on transmission corridors that frequently constitute bottlenecks.

Three SVC units in the Oslo area are considered as part of the scheme, and the location and capacity of the SVC units are illustrated below (Figure 4.7).

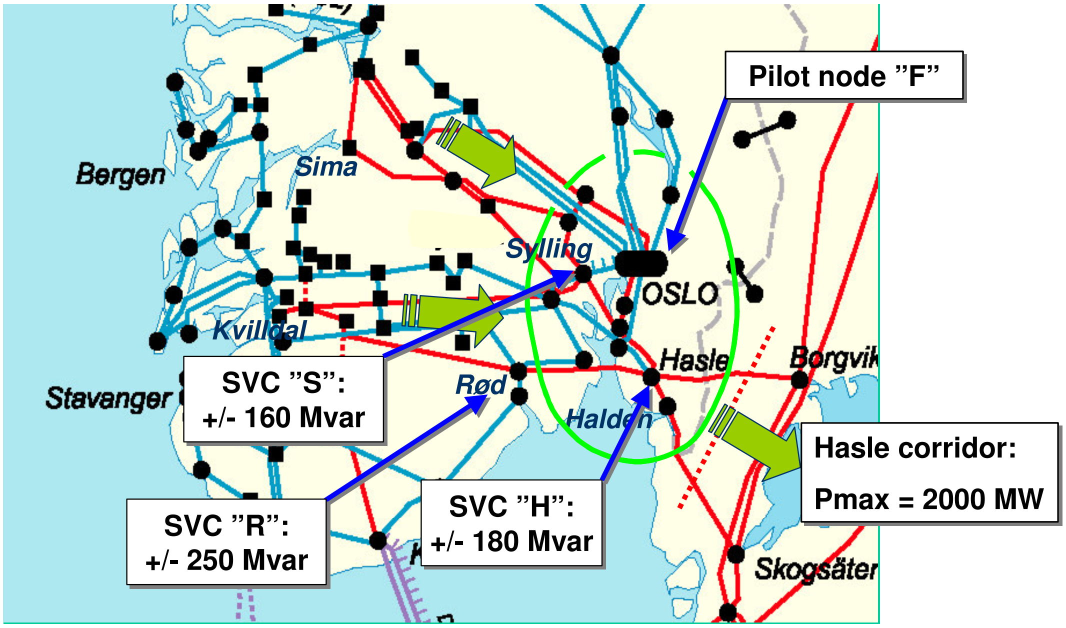

Figure 4.7. Hasle corridor (interface) and SVC units in Southern Norway.

In order to assess the proposed SVR scheme, dynamic simulations were carried out using a recently updated and validated Nordel transmission system model. The purpose of the analysis was to simulate the worst possible single contingency regarding voltage control, and to demonstrate improvements with use of the SVR scheme.

Sample results from the simulation study are shown in Appendix E. It is shown that acceptable voltage control can be maintained at a higher transfer level than the present limits by optimal use of reactive power sources. This indicates that the SVR scheme is promising with respect to simplifying operation of the SVC units and improving voltage stability limits.

A prototype version of the proposed control scheme has been implemented at Statnett's regional control center for southern Norway. This is a software implementation within the existing SCADA system, which utilizes the available functions for remote (setpoint) control of the different units. The general structure of the implementation is similar to the structure that was used in the simulation study, except that in addition to the three SVCs two synchronous condensers are also included in the prototype implementation.

From a dedicated control center display, the secondary voltage regulator can be activated, tuned and monitored. The operators can choose if they want the SVR to run continuously to automatically keep a certain voltage profile (and thereby relieve themselves from trivial tasks), or they can activate the SVR only at detection of voltage problems at certain nodes (pilot nodes) as an extra safety precaution.

4.3 Chapter Summary

With the availability of relatively low-cost shunt capacitor banks, and with the availability of digital controls and fiber optic communications, substation voltage control can be improved. For heavy load conditions, high and flat voltage profile can be achieved, resulting in low losses and in good voltage security (i.e., high spinning reactive power reserve). In restructured power systems, an objective of small reactive power interchange between generation, transmission, and distribution companies is facilitated by reactive power compensation.

A strategy of local power plant control and extensive use of capacitor banks with advanced controls may be more robust and cost-effective than a strategy primarily based on power plant controls using remote signals. This may be especially true where power plants are some distance (few hundred kilometers) from load centers. In any case, shunt compensation complements generating plant controls.

SVCs or STATCOMs are generally not needed for slow voltage control and longer-term voltage stability. When they provide needed fast control, coordinated control of mechanically switched capacitor/reactor banks is often required.

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Chapter 5

Control System Design Characteristics

5.1 Introduction

The essential design characteristics of both the hierarchical voltage control systems considered in Chapter 2 and the advanced high side voltage control regulators described in Chapter 3 are provided in this Chapter. These characteristics comprise: control system architecture, functional organization, main hardware and software design choices for the various equipment, practical implementation aspects, and expected dynamic performance.

The “high side voltage control regulators” are autonomous controllers that regulate the high-side bus of the power plants while maintaining balanced VAR generation on the individual units. Their main design characteristics are, generally, given through block-diagrams of main control loops, description of the interfaces with the generators and their faster primary regulators. The adopted control methodology, the dynamic performance of the added control loops for different operating conditions, and the dynamic interaction among the generator units under control are also considered.

Regarding the “hierarchical voltage control systems”, the design aspects are more numerous: in one hand the architecture of the multi-level control system has to be justified, as well as the basic criteria to subdivide the control functions among regulators at the same level, or between levels, and their coordination. Furthermore, the coordination in space and time of the different control loops is a crucial design aspect for a correct and stable dynamic performance of the overall system even during contingencies.

In general, a new regulator is required at each control level:

- At the power plant level the new regulator design characteristics are essentially those already mentioned for the “high side voltage control regulators”. In most cases the high side voltage control regulator is also able to operate inside a hierarchical voltage control system, following in real-time the higher level control signals and participating in the coordinated wide area voltage regulation;

- The criteria to manage the control functions at a given level and their subdivision among regulators at the same level, as well as the coordination between regulators of different levels, coupling /stabilization/dynamics must be defined. The telecommunications requirements must be taken into account in this hierarchical system.

The number of variables involved in the monitoring and control of voltages and reactive powers in a large power system is immense. The mass of data to be processed and the complexity of computations and decisions that lead to manual or automatic actions, keeping in view the large number of constraints involved, calls for a coordinated voltage control system, at the regional and central dispatchers (ISO) control rooms, of a computer-based instrumentation to be operated in a closed-loop and real-time mode. This closed-loop computer control must therefore have advanced design, utilize state-of-art hardware and software, in order to be properly integrated in the modern control rooms currently used at ISOs and to allow the full exploitation of the following computer technology advantages:

- Efficient operation of a large power system through effective, fast and reliable network monitoring and fast-response control actions;
- Optimal monitoring and control;
- Increased reliability and protection;
- Adaptation of equipment features supplied by EMS vendors to operator needs;
- Improved performance over the entire range.

The currently advanced level of the control technology, the growing automation required by modern electrical utilities and the effective and user-friendly interfaces demanded by control room operators impose high requirements of functionality and reliability to the coordinated regulation of transmission networks. These aspects are discussed below for the Italian and French SVR control schemes.

5.2 The Italian Control System Design Characteristics

The Italian coordinated voltage control system, described in Chapter 2, is characterized by a hierarchical control structure (Figure 5–1), where each level generates the reference setpoints for the next lower control level [5-2]:

- The Primary level includes the classical AVR units already operating in the power plants;
- The Secondary level includes the Power Plant Voltage and Reactive Power Regulators (REPORT, in the figure called PQR) able to operate autonomously as “advanced high side voltage regulators” or in a coordinate way under the control of the Regional Voltage Regulator (RVR) to achieve the SVR;
- The Tertiary level includes the centralized Tertiary Voltage Regulator (TVR), which updates in real-time all the pilot nodes voltage setpoints (SVR set-points) defined by the solution of an optimization problem with an objective function that represents a compromise between security and economy.

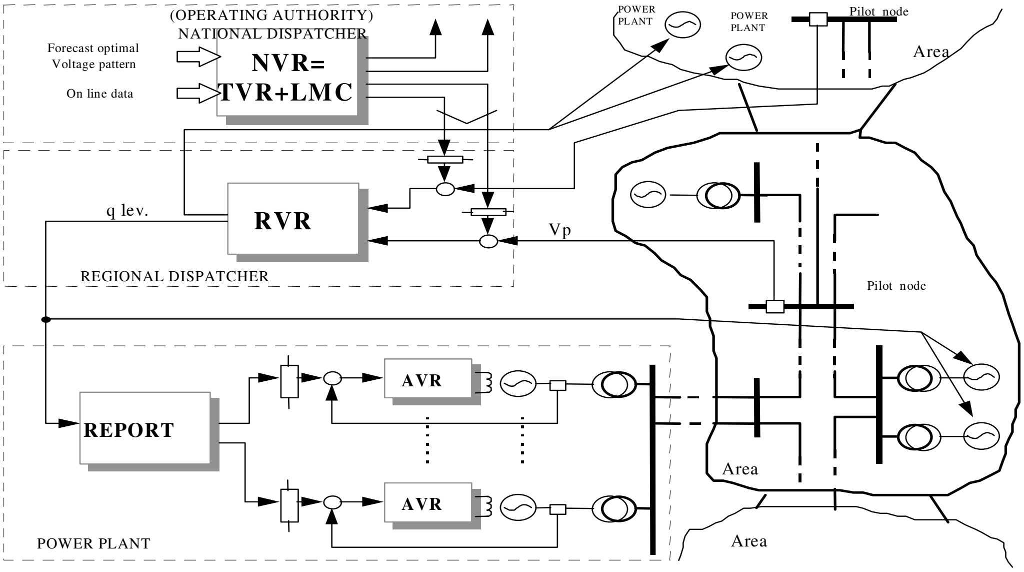

Figure 5–1 *The Italian coordinated voltage control of transmission network.*

The mentioned three hierarchical levels are real-time, overlapping closed control loops, which require a well-defined design and investigation of their dynamics and stability. On the contrary, the outermost level (see Chapter 2), where the optimal forecasting controller (LMC) operates, is decoupled in time from the previous levels. For such a hierarchical control system it is necessary to subdivide the network into electrical areas around the so-called pilot nodes.

5.2.1 Pilot Nodes and Control Generators Design Criteria

Simple and effective criteria are required for selecting the pilot node, the associated voltage area, and the area power plants participating in the pilot node voltage control.

5.2.1.1 Pilot Node and Area Design Criteria

The pilot node selection is based on the intuitive assumption that such nodes must be chosen amongst the strongest, that is, the nodes, which impose their voltages to the load nodes electrically close to them.

There is a constraint on the electrical coupling between pilot nodes: such coupling must be below a pre-established limit. In this way, potential problems of dynamic interaction between neighbor secondary voltage control loops are minimized as well as excessive reactive power exchanges among adjacent pilot nodes.

The analytical procedure utilized is based on the sensitivity matrix of node voltages to reactive power injected into the nodes, when operating with primary voltage regulation only. The method assumes as the pilot node “1” the strongest node (having the largest MVA level) in the whole network, without distinguishing between load or generation buses and excludes, from subsequent choices, all nodes with a coupling coefficient with the pilot node “1” greater than a pre-established limit (these nodes determine the network Area-1 under the pilot node “1” voltage control). The subsequent pilot node “2” is the strongest of the remaining nodes excluding from this choice those nodes with coupling coefficients to pilot node "1" exceeding the pre-established limit.

By proceeding in this way, pilot nodes that are gradually less and less strong are identified. The procedure is stopped when the choice of the next pilot node falls onto a node that is not sufficiently strong. Usually, a sufficient number of pilot nodes is defined in this way.

This method is simple, does not require a heavy computational load and gives satisfactory results after refining the coupling threshold values, which are dependent on the network characteristics. Highly decoupled secondary voltage control loops are achieved by using excessively low threshold values, but the number of the pilot nodes could be very small and the quality of the network voltages low. Selecting the right threshold values for the coupling coefficients is important, to ensure a well dimensioned number of pilot nodes for the system.

5.2.1.2 Control Generators Design Criterion

The SVR Areas are controlled by "reactive power level" signals, sent to each Area by the Regional Voltage Regulators (RVR). The reactive powers of those generators that most influence the pilot node voltages are controlled in real-time by the RVR.

The analytical procedure adopted to associate the control generators with the pilot node makes use of the sensitivity matrix S, relating the node voltages to the reactive power injected by the generators:

- The procedure consists in the reorganization of the sub-matrix obtained by the columns corresponding to the generator nodes and the rows of the pilot nodes;

- The procedure continues in finding the highest coefficient of each column of the sub-matrix and in reordering the columns in such a way that the first set comprises all columns having their highest coefficient placed in the first row, the second set with the columns having their highest coefficient placed in the second row, and so on up to the last set having their highest coefficient placed in the last row;

- Each set of columns identifies the generation nodes associated with the corresponding pilot node, through which the control generators are selected;

- The power plants selected to support the voltage at a given pilot node are those for which the product of their sensitivity coefficient times their rated reactive power is greater than a threshold for that given Area.

5.2.1.3 General Remarks

The subdivision of the transmission network into Areas must be robust with respect to small changes in the network, so as to avoid frequent and unnecessary changes in the control system configuration. On the other hand, structural changes in the network may impact the pilot node selection and call for an adequate design of the control system, which must be flexible and adaptive to face those possible, but not so frequent, changes.

The most recent studies for the choice of pilot nodes and associated control power plants in the Italian power system have provided the subdivision of the power network into 18 areas. The overall system involves all the major power plants connected to the 400 kV and 220 kV network, having a total reactive power capacity of about 20,000 MVAR. Figure 5-2 shows the subdivision into areas of the Italian network, pointing out the pilot nodes and the corresponding control power plants according to the SVR application plan.

Figure 5–2 *Application plan of the hierarchical SVR in the Italian grid.*

5.2.2 Control System Dynamics Performance

The space and time decoupling of the coordinated voltage control system is achieved with the following general specifications:

- The voltage regulator (AVR) determines the generating unit fast voltage control loop dynamics, characterized by a dominant time constant of about 0.5 s;

- The power plant joint voltage and reactive power regulator (REPORT) requires an outer loop around every unit in the plant which overlaps all their corresponding AVRs. The generator reactive power control loop is of integral type, and has a dominant time constant of about 5 s. The AVR fast dynamic performance, meant to support terminal voltage during electromechanical disturbances, are not significantly affected by this outer and slower reactive power control loop;

- REPORT may alternatively operate in "high side voltage regulator" mode, which is a local EHV bus voltage control characterized by a PI control law and a dominant time constant of about 50 s;

- Under RVR control, the Area REPORTs participate in the Secondary Voltage Regulation, with the pilot node voltage control loop characterized by a PI control law and a dominant time constant of 50 s;

- Under Tertiary Voltage Regulation (TVR), the involved RVRs impose the SVR voltage set-points determined by optimization tools according to economy and security objectives. The pilot nodes voltage set-points optimization has a control loop characterized by a dominant time constant of about 5 minutes;

- The off-line Losses Minimization Controller (LMC) computes the day-ahead voltage-reactive power optimal forecasted plan for the overall network, which is the input to the TVR. When the TVR recognizes this long-term forecasted plan to be very far from the real network operating conditions, the LMC is required to operate on-line with a delay determined by the system state estimation: 5 minutes or more. Even in this case the LMC loop is very slow and can be considered fully decoupled from the above mentioned inner loops.

5.2.2.1 General Comments

On the control system stability:

- The adopted design methodology includes the "time-decomposition" criterion among the control loops of different hierarchical levels and the "non-interactive" control law among the control loops at the same hierarchical level, achieving a highly stable behavior for the overall control system. As a consequence, the dynamic performance of each control loop is comparable to a "first order" system characterized by a dominant time constant.

- The adaptation of some control parameters is also employed, increasing the robustness of the control system with respect to network parameters changes, and maintaining its dynamic performance practically unchanged.

On the dynamic interaction among the power plant generators:

- The use of REPORT ensures adequate loop dynamics for the different operating conditions of the power plant, even in the event of network perturbations. In order to avoid reactive power oscillations among the power plant generators, REPORT makes use of a suitable decoupling control matrix, which compensates for the electrical interaction among generators.

On the dynamic interaction among the pilot node voltage control loops:

- RVR ensures adequate dynamics of pilot node voltage loops for all the power system operating conditions, even in the event of network perturbations. This is achieved through the complete dynamic decoupling among different pilot nodes voltage control loops controlled by the same RVR. The interactions between neighboring areas, whose electrical coupling is not negligible, are minimized through a suitable multi-input multi-output control algorithm.

On the adaptive control law:

- The RVR voltage control law is of proportional-integral type, where the dominant time constant is kept at about 50 s through adaptive control. This algorithm considers the number of groups taking part in the pilot node voltage regulation, the actual values of their capability curves and the on-line computed value of the equivalent reactance seen by the pilot node, network side. The selection of such a dominant time constant satisfies the need to keep decoupled in time this loop from those it overlaps and therefore makes the dynamic behavior of the pilot node voltage control loop very similar to that of a first order system.

- The proportional coefficient of the control law is dimensioned in order to achieve a “minimum phase” dynamics, so reducing to the minimum the undesired back swing of the unit reactive powers following a step change in network voltage. This short duration spike, opposite to the desired steady state change, is determined by the unit reactive power control loop and does not affect system stability.

On the telecommunication requirements:

- The dynamics of the pilot node voltage control loops is affected by the telecommunication delays between the RVR and the pilot node substations, as well as on the reactive power control level signals transmitted by RVR to the control power plants. Since the dominant time constant of this control loop is about 50 s and the RVR and REPORT apparatuses require 0.5 s to update their outputs, a correct reconstruction of the RVR dynamics would require the delay for each telecommunication channel to be no greater than 2 s. A telecommunication delay of 2 s is therefore used as an upper limit specification.

5.2.3 The REPORT Apparatus Functionality and Technology Design

The REPORT apparatus (see Figure 5-3 and Chapter 3) has as main task either the generator high-side bus voltage regulation, or the power plant participation in the pilot node voltage regulation by controlling the power plant reactive power generated, which is properly shared among all the units [5-1, 5-3].

Figure 5–3 *REPORT microprocessor-based apparatus.*

5.2.3.1 Other Functional Requirements

REPORT makes use of intelligent algorithms to recognize, in real-time and through local information, specific network contingencies (power plant islanding, bus isolation, etc.), and chooses accordingly the most suitable control mode and adapts the regulation parameters. At steady state operating condition, the reactive level signal is limited between –100% and +100%. Nevertheless, during transients, this level can exceed the normal limits, according to the overload capabilities of the generators. This allows the highest possible support to the network voltages in the event of severe but transient perturbations.

All the transitions between the REPORT working states (shutdown, turn-on, EHV Local Bus Voltage Regulation, Reactive Power Level Tele-regulation, etc.), either ordered by the operator or by the apparatus internal logic, are carried out through automatic procedures and tracking functions, ensuring bumpless commutations in every situation.

In order to avoid the operation of the units outside their voltage and capability limits, suitable limitations and protections have been implemented in REPORT: if a given unit hits a limit, the action of the corresponding reactive regulator is stopped from going over that limit. REPORT is also provided with rich supervisory and auto-diagnostic functions, ensuring the correct functioning of the apparatus and its field interface effectiveness.

The powerful performance of REPORT comes from the integration, within its software, of a detailed real-time simulation model of the plant-network system. This dynamic model allows closing the regulator control loops on the simulated power system, rather than on the real power plant. The REPORT simulation operating mode, available also during normal operation, is very useful during apparatus testing, functional checks and settings, as well as for training operators and maintenance personnel.

5.2.3.2 Graphical User Interface Requirements

REPORT has a user-friendly interface with rich monitoring features (see Figure 5-4). The operator has access to sophisticated graphic-based screen pages refreshed in real-time (animated pictures, signals and alarms, control parameters, memorized EHV bus voltage daily trends, etc.) and synthetic commands through a dedicated functional keyboard. During normal operation, all the control parameters and the EHV voltage daily trends can be modified via the REPORT friendly editor.

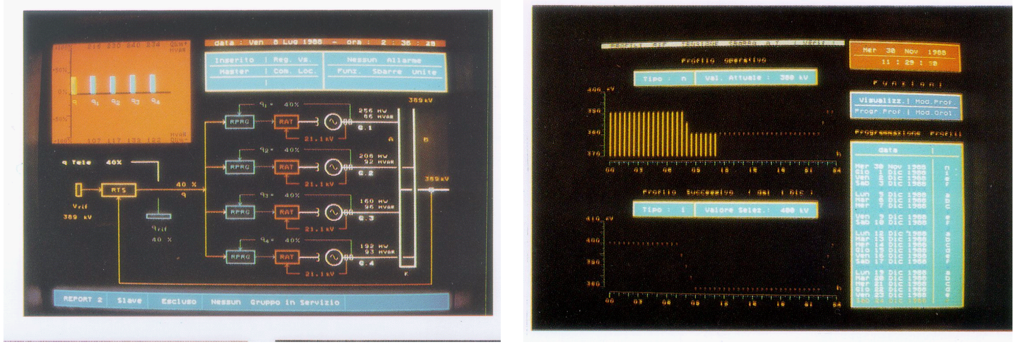

Figure 5–4 *REPORT example of graphical user interfaces.*

5.2.3.3 Installation Requirements

REPORT is lab tested in closed-loop mode with the use of the turbine-generator-network real-time simulator. Detailed functional tests are also carried out during commissioning. All the REPORT applications, which have been operated in the field for many years, have shown high reliability and growing acceptance by the plant operators.

Putting in service the REPORT apparatuses requires the largest effort, among those activities related to the practical application of the multilevel control solution. In fact, the number of power plants, in which the REPORT installation is required is considerably large. This requires considerable effort, costs and consistent organization of the utility technicians, mainly of those in the power plant modifications, some of which require the unit to be taken out of service. The preliminary activities for the REPORT installation in a power plant refer to wiring and interfaces between the excitation control system and the operating room, where the REPORT commands and monitored data must be made available. The telecommunication equipment for the exchange of measurements and commands between the local station and the regional dispatcher, have to be commissioned. The modifications needed in the AVR for its correct interfacing with REPORT mainly concern the AVR static calibrator with high precision (at least 12 bits D/A converters) and the adoption of static relays with optical insulated Up/Down commands, to be repeated with a maximum intervention time of 10ms. With REPORT into operation, the automatic exclusion of the Control Room AVR Up/Down manual commands as well as the opening of the compound additional feedback and the signaling of rotor overload-ability at the AVR level, are also requested.

5.2.4 The RVR Equipment Functionality and Technology Design

The regional voltage regulator RVR [5-4] automatically controls the pilot node voltages, through the local REPORTs. The success of the RVR project is based on the adequate knowledge of the power system needs and phenomena and related control solutions. The system has an open architecture, being therefore in line with modern control centers.

RVR requires considerable data exchange among the several voltage areas into which the electrical region is subdivided (measurements, signals and alarms coming from the network and from the power plants, control signals and commands sent to controlled plants and received from the National Voltage Regulator – NVR, etc.).

5.2.4.1 Hardware Architecture Requirements

The RVRs installed at the regional control centers of the Italian Independent System Operator (GRTN) are integrated with the local EMS, to achieve the required communication with the plants. The RVR consists of a Digital Alpha workstation to be connected with the EMS through a LAN Ethernet with TCP/IP communication protocol, as shown in Figure 5-5. The RVR workstation is equipped with: 64 MB RAM, 2 GB hard disk, Ethernet interface, color monitor 19”, mouse and keyboard, tape streamer. The software environment available on the RVR workstation consists of OPEN-VMS operating system, Ethernet communication software (TCP/IP protocol), graphical user interface X-Window Motif based. All the RVR control functions are implemented into the RVR workstation. Therefore the local EMS simply performs the RVR data exchange with the controlled plants and communications via LAN Ethernet with the workstation itself. The operator may request the starting of an additional MMI on the EMS main computer through an X-Terminal connection to the RVR session.

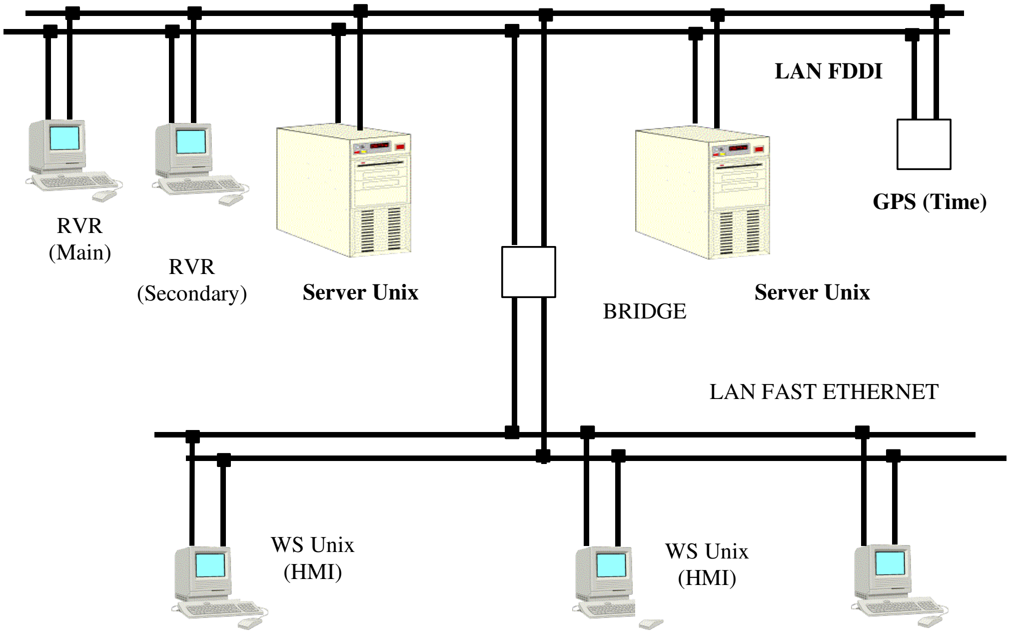

Figure 5–5 *RVR integration at regional control centers.*

5.2.4.2 Software Architecture Requirements

The RVR software architecture consists of a real-time system, which executes a pre-defined sequence of calculations every 500 ms time interval. During this time interval other less critical activities such as updating the MMI, are performed.

The RVR activities and requirements are summarized below:

- Acquisition and addressing of data required by the RVR processes at every cycle time or sampling time (regulation parameter);

- Acquisition and storage of data on the network topology for the region under control as well as other information that do not require a cyclic update (parameters, profile);

- Update of regulation and control outputs by computing the coordinated control actions through properly selected algorithms while taking into account all planed equipment disconnections in the regional grid, as well as the critical contingencies;

- Man machine interface with good graphic displays of system information and possible actions, to aid the system operators.

RVR requires databases covering different requirements concerning either the type and the structure of data stored (measurements, signals, profiles, etc.), the data access time and the capability for shared data access. In particular it is necessary to have:

- Real time, memory resident databases, to which the RVR has cyclical access for acquisition and data-loading operations. These databases are equipped with lock mechanisms for data protection against competitive accesses by other processes;

- Database on disk to store configuration data, parameters, files and other general data to which the RVR has no cyclic access but requires permanent storage.

The regions where the RVR is installed can be very different from each other regarding both the number and the type of controlled plants. Furthermore the topology/configuration of the controlled region can evolve with time. This requires the RVR software reconfiguration at every change or at each new installation. The RVR software has been designed for easy adaptability and expandability.

The RVR is modular regarding the number of elements to be controlled and automatically suits the structure of a single plant once a given number of configuration parameters is known. In practice, the RVR reconfiguration may be carried out based on the following elements: configuration file of the electrical region under control, MMI configuration file, maps of area and region topographies. Appropriate tools enable to easily perform the RVR reconfiguration operations.

5.2.4.3 Control and Protection Requirements

RVR simultaneously regulates, with independent and parallel actions, the voltages of its pilot nodes (max. 12) by remotely changing the reactive powers of the power plants under control. To accomplish this task, RVR employs a dedicated voltage regulator for each pilot node in the controlled region. The main functionalities of the pilot node voltage regulator are described below:

- The control law is of the proportional-integral type, with the dominant time constant of the voltage control loop kept at about 50 s by using an adaptive control algorithm. This algorithm considers the number of generating units taking part in the pilot node voltage regulation, their actual capability curves and the on-line computed value of the equivalent reactance seen from the pilot node. The selection of such a value for the dominant time constant ensures the time decoupling of this loop from those it overlaps. Therefore, the dynamic behavior of the pilot node voltage control loop is similar, in practice, to that of a first order system;

- The proportional gain of the PI control law is dimensioned in order to avoid undesired transients of the unit reactive powers. The RVR design also achieves the complete dynamic decoupling minimizing the interaction among the pilot node voltage control loops controlled by the same RVR and therefore avoiding oscillating transients of reactive power between neighboring areas, mainly when their electrical coupling is not negligible. It is also possible to select a positive, negative or null static droop for the pilot node voltage regulation, depending on the network conditions and on electrical couplings with the adjacent pilot nodes;

- The starting of each pilot node voltage regulator, once the RVR is under operation, can be ordered by the operator with no need for preliminary manual alignment of control generator voltages and pilot node set point values. The pilot node voltage regulation defines and updates in real time the values of the area reactive power level on the basis of a pilot node voltage setpoint which can be defined locally by the manual calibrator (manual local reference) or comes from the voltage profiles locally stored (automatic local reference) or is sent by NVR. Three types of stored profiles are therefore available: profiles sent by the National Control Center (NCC, today called GRTN), profiles defined by local operator and pre-set profiles associated with the calendar;

- Tracking functions among pilot node voltage calibrators and corresponding controlled magnitudes enable at any moment the switching between different operation modes without introducing undesired noise into the controlled magnitudes;

- One or two vicarious pilot nodes are foreseen for each area, in order to face possible failures of the main pilot node telecommunication equipment. In case of changes in the network configuration, the availability of vicarious nodes enables the operator to select that pilot node, which better performs the area pilot role. The selection of a particular pilot node is made by the RVR operator on the basis of local assessment of the network configuration and/or upon request from the NVR.

RVR allows the operator to perform on-line modifications of the area control system configuration, in order to better suit network, or power plant changes. In particular, it is possible to select the most adequate control and sensitivity matrices for the operating configuration of the regional network. Furthermore, for each controlled area it is possible to select the power plants under SVR and the peripheral ones performing high side voltage regulation, substations assigned to the SVR and their components enabled to the RVR automatic control. Under particular network configurations, some control power plants, due to their peculiar location can gravitate on an area close to that they generally belong to. These boundary plants, can participate in the telecontrol of the pilot node they belong to, under normal conditions, but during contingencies may participate in the control of another pilot node.

5.2.4.4 Graphical User Interface Requirements

All the graphic interfaces have been implemented in X-Window Motif environment. Depending on their functionalities, the MMI pages can be shared among different applications. The main application is related to the real-time operation including graphic pages organized according to a multi-level structure, which allows easy navigation, starting from a main page.

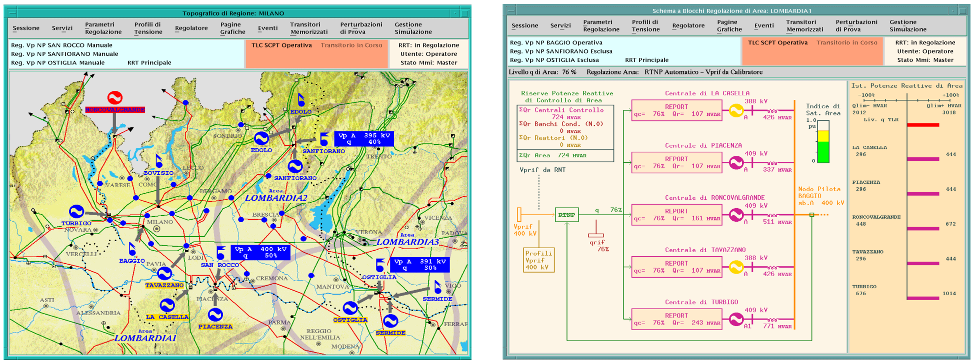

Figure 5–6 *Lombardy region topographical scheme and area regulation block diagram.*

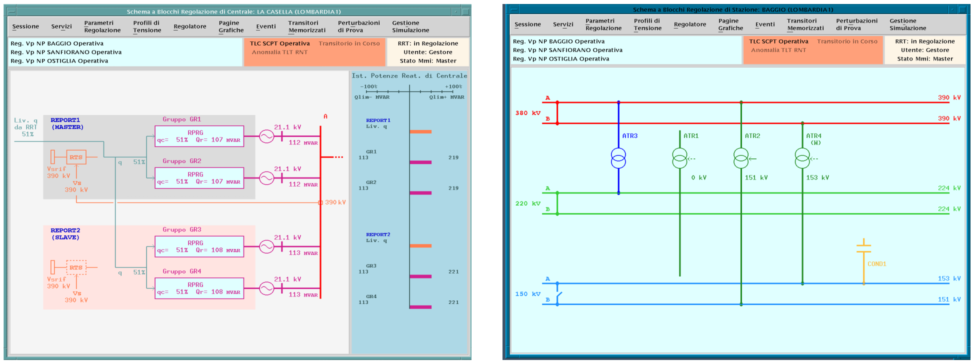

Figure 5–7 *Lombardy power plant regulation block diagram and station control scheme.*

Pages with inner levels of the controlled region show more detailed information: area topographies, area and power plant functional block diagrams and tables. Each page accepts RVR commands required for the control of the displayed environment and shows the relevant alarms and signals. According to Motif standards, all operations can be made through mouse. The main pages are described in the following:

- The region topography (Figure 5-6) is the basic page of the RVR, including the regional network divided into areas with the corresponding pilot nodes and control generators. Other data displayed: measure pilot nodes voltages, on/off SVR participation status of control power plants, important alarms and signals;

- The area topography is at the next inner level, and shows additional details relevant to the SVR operation on the selected area;

- The area block diagram (Figure 5-6) is at the same level of the area topography and shows the area regulation functionality, with the measurements coming from the relevant power plants. A histogram provides a real-time index of the area proximity to the reactive resources saturation rather than to the voltage instability limit when TVR is operating;

- The power plant block diagram (Figure 5-7) shows the plant functionality (telecontrol or local bus high side voltage regulation) and the operating point of each unit obtained from measurements and signals coming from the plant;
- The station control diagram (Figure 5-7) shows the shunt reactors and capacitors, SVCs and LTCs under RVR;
- The area signals and alarms provide details on the regulators and plants involved in the area voltage control.

Other MMI displays and facilities include:

- The control configuration, where the parameters defining the control system structure and dynamic performance can be displayed, modified and stored;
- The voltage profiles, where the daily trends of pilot node reference voltages are managed;
- The stored recordings on previous transients, which can be displayed upon request;
- The chronological data showing the sequence of events (alarms, signals, etc.) from previous disturbances;
- The step disturbance tests that can be applied to monitor real system dynamics;
- The simulation, where specific commands allow to define the power-plants operating condition and to reconstruct different failures in the measurements and signals received by RVR;
- The history file, where disk files (regulation parameters, control configurations, stored voltage profiles, transient records, etc.) can be displayed, analyzed, and maintained;
- The auxiliary services environment, with commands to make hardcopies of data stored or being displayed on a screen.

5.2.4.5 Other Requirements

The RVR enables the modification of its control parameters: time constants, relevant data from power-plants and network under control, sensitivity matrix of pilot nodes, etc. This allows quick calibrations of the RVR apparatus both during its commissioning and when modifications to the power plants or network occur. The parameter settings menu is enabled through appropriate access keys (password), to be reached only by authorized personnel.

The automatic, local reference operation mode allows the automatic updating of the reference value for each pilot node voltage according to a voltage profile associated with the current day and stored in the RVR. For each pilot node in the region, the RVR has three different sets of daily voltage profiles stored on disk and associated with the 365 calendar days after the current day. Each of these sets differs from the others according to their origin and the profile setting and programming methods utilized.

A generic daily voltage profile consists of 96 values corresponding to the set-point values to be implemented every quarter of an hour. During each quarter of an hour, the automatic updating of the pilot node reference voltage takes place every minute, according to a ramp trend, connecting the current reference value to that foreseen for the next quarter of an hour.

The built-in simulation function allows reproducing the RVR operation without the need to activate its interface with the plants. The simulation function is therefore very useful during the RVR functional tests, commissioning phase and also for operator training. The electrical network of the simulated region is described with sufficient detail to allow the reconstruction of voltage regulation phenomena that actually occurred. Specific commands are available for setting the simulation parameters and to compute the initial state of the simulated equivalent network. Specific commands allow the simulation of load variations, network perturbations, failure in signals coming from the plants or from telemetering equipment, incorrect values of tele-measurements, etc. The interface with the NVR is also simulated.

The RVR has available two frameworks for the automatic acquisition and storage of data on transient phenomena in the network voltage regulation:

- The first framework relates to transient trends under normal operation and consists in recording, every 5 min, all measurements adequately filtered, signals and alarms related to the RVR operation. These acquisitions are always active and do not require any type of trigger;

- The second framework concerns fast transients and allows a high density recording (one sample every 500 ms) for several minutes. This recording and storage is oriented towards the analysis of perturbations significantly affecting the RVR dynamics. This type of acquisition is enabled by appropriate triggers, recognizes large disturbances in the network and also allows the recording of the system conditions and minor transients before triggering.

The RVR has auto-diagnostic functions to detect and signal possible failures in the RVR apparatus, or in its interface with the regional EMS:

- RVR watchdog functions: checks the observance of time intervals duration designed for all the control system processes. To this purpose, at the end of every 500ms interval, which is the main sampling time of the system, all the RVR processes are checked (active or suspended) in order to exclude any unforeseen break (abort) that has taken place inside the time frame, as well as other real-time processes that have been completed or were terminated (absence of breaking of the time frame);

- Communication check with the local EMS and the National Control Center (where the NVR is located), promptly signaling the possible cut offs in data exchange;

- Detection of misalignment between local EMS and RVR databases, such as the presence of data related to unknown elements in the exchanged messages.

The RVR also includes diagnostics to acknowledge and signal the main failures attributed to the systems interconnected by the RVR (anomalous input signals, not executed RVR commands, etc.). These functions perform tests on RVR I/O magnitudes consistency; detect particular operation conditions in the controlled region (area in island operating condition, area close to voltage instability limit); check the effects of the control actions undertaken, thus allowing the diagnosis of possible failures in devices interfacing RVR.

5.2.5 The NVR Apparatus Functionality and Technology Design

At the highest level the NVR system consists of the Tertiary Voltage Regulator (TVR) and the Losses Minimization Controller (LMC). TVR coordinates in closed loop, for a secure and economic operation, the RVRs at the national/utility level, establishing the “pilot node voltage” pattern for the current network operating state and the forecasted optimal voltages and reactive powers. The TVR also performs slow corrections to achieve a better balance of reactive power generation levels and control margins among the areas [5-5].

The increase in the load margin of the transmission network, for operating conditions considered critical from the voltage instability point of view, is basically achieved by proper coordination [5-6] between the TVR and the RVRs, in order to prevent the units from operating at the over-excitation limits. If the reactive power control margins available for SVR are strongly reduced as a consequence of severe perturbations or abnormal load patterns, the TVR implements a network voltage reduction, progressively departing from the optimal planned short-term voltage profile, but always maintaining the maximum feasible voltages. Therefore, the TVR only allows the power plants controlled by the SVR to reach their capability limits if the transmission network voltages are very low. In this way, there is reduction in the risk of voltage collapse related to the over-excitation limits, as well as an increase of the overall transmission system loadability. In conclusion, the coordination between TVR and SVR allows the grid operators to achieve the full exploitation of the power transfer capabilities of the transmission network. This requirement is becoming more and more important in the restructured electric energy markets.

The main task of NVR is the processing and the real-time comparison of the control measurements issued from all the RVRs and areas, as well as the controlling of the pilot node voltage setpoints according to the optimal voltage pattern dispatch and the TVR objective function minimization. The NVR has an open architecture, according to the requirements imposed by modern power system control centers.

The NVR activities and control functions imply the execution of a predefined sequence of operations within a specified time interval and the definition of a scheduling procedure to perform the less critical activities. The NVR real-time application software runs in a Digital Alpha workstation with Unix operating system, and its fully graphical and user-friendly MMI is based on a set of multiple Motif windows.

5.2.5.1 Hardware Architecture Requirements

The NVR central computer has a dedicated platform, which is properly interfaced with the communication subsystems for the information exchange with the field data acquisition subsystem. The NVR integration with the existing SCADA system is being investigated.

The main hardware configuration consists of a Digital Alpha workstation, with Digital Unix operating system, with minimum memory requirement of 256 MB and 16 GB of hard disk storage. There is also the possibility to use one or two (for redundancy) Ethernet/serial communication boards. In addition, conventional backup devices (CDROM, TAPE or DAT) and advanced graphical features (19”color monitor with mouse and keyboard) are required.

The NVR central computer prototype is comprised of two equivalent workstations, one of them to be operated as a slave unit. In this case it will be necessary to select, at any operating time, one master computer (NVR master), where the NVR application commands and the navigation facilities are active. In the slave computer (NVR slave), which only allows navigation facilities, all the data are continuously updated and aligned with the master computer, allowing a multiple MMI feature in the control room. It is quite simple and economical to use the same computer as reserve unit and slave terminal.

5.2.5.2 Software Architecture Requirements

The NVR development requires the design and development of the software code related to the monitoring and control functions, the centralized services, the real-time database and the man machine interface.

The NVR real-time monitoring and control system performs many activities and has important characteristics:

- Data Acquisition and Communication: activation and control of TCP-IP connections with peripheral units (RVRs and LMC); activation and control of TCP-IP connections with central units (SCADA and EMS); data communication between NVR subsystems and their storage at the database; storage of dynamic and static data in the real-time and application databases respectively;

- Regulation and Control Functions (RCF): data acquisition/writing by the real-time database; validation of received measurements; auto-diagnostics and coherence tests; configuration of the initialization and the regulation parameters; request of additional information from the state estimation; request of simulation session for training and tests; transient recording of significant perturbations; commands and operating status management; alarm and signals activation;

- Database Administrator: definition of the data generation environment; definition of the conceptual, logical and physical scheme of the real-time and application databases; generation, maintenance and loading of the real-time and application databases;

- Centralized Services Library: real-time and application database access; inter-task communication; system time management; real-time task priority selection; identification and presentation of system errors;

- Man Machine Interface (MMI): operation in the X-Window Motif environment; graphical pages set with related coordinated commands; alarms and signals synthetic visualization; real-time operation environments; maps, alarms and signals; daily behavior of pilot nodes voltage profiles; area configuration, topography, alarms and signals; regulation and control system configuration; recorded transients visualization and analysis; chronological events visualization and analysis; simulation management; historical archives and printout management.

5.2.5.3 DataBase Requirements

The regulation and control system database has to meet different requirements, depending on the stored data type (static data or dynamic data), the required refreshing rate and the access violation problems (due to the need to preserve integrity and coherence of data accessed by different and concurrent processes).

These needs are due to the fact that a real-time process (RCF, for instance) has to exchange data through the database with processes having lower time requirements (MMI). In the case of the MMI process, it is sufficient that the refreshing rate be tuned to operator needs, while for the RCF process it is necessary that the acquired filed data be rapidly processed, in order to not destroy information and to allow a fast-response action for closed loop control. To cater for these different needs, the NVR control system uses different database environments:

- Master Database (real-time data): this section stores all the data that are cyclically accessed by the control system, taking into account data acquisition and communication performances and needs. Within a single cycle time the RCF process has to acquire from this database all the necessary real-time data, to make all the computations and to write the results to the same database, to be timely sent to the plants or substations for closed-loop control or regulation. It is therefore necessary that the access time of such a database, both in acquisition and writing phases, be sufficiently small. Furthermore, since this real-time activity cannot be stopped or delayed, the RCF process must be given the highest priority with respect to other processes in the competitive access to same database;

- Application Database: this section stores all the configuration data of the control system, together with all the limited access data (installation, platform, parameters, etc.) that do not require high priority in acquisition activity. This data type may be stored on disk and must be available at any system restart;

- Graphical Database: it should be emphasized that the MMI process utilizes all the visualization information contained in the master data and application databases (MMI commands, measurements, alarms, signals, messages from the real-time database, parameters, recorded transients, historical trends). This section contains all the MMI specific information like page layouts, system passwords, event loggers, etc.

5.2.6 The Losses Minimization Controller (LMC)

The LMC is at the highest level of the hierarchical voltage control. It performs the on-line upgrades of the overall network optimal forecasted voltage and reactive power plan, based on the most recent system “state estimation”. The main objective of the LMC is to achieve the minimum losses in the grid, by optimizing the values of the voltages. The LMC is based on an OPF program that computes the appropriate voltages and reactive powers to be used by TVR as a reference plan.

The LMC may bring a significant real-time improvement when the TVR recognizes the adopted (computed the day ahead by and off-line version of LMC) optimal forecast plan to be very far from the current network situation. In that case, LMC establishes on-line the new pilot node voltage pattern, depending on the actual values of pilot node voltages and area reactive power levels. LMC also compares the new voltage pattern with the day ahead forecasted optimal voltage plan, monitoring the verified differences.

The LMC runs on a Digital Alpha workstation and its user-friendly MMI allows the operator to configure the application according to the structure of the multilevel control solution (choice of pilot nodes and related controlled power plants), as well as based on the results of the previous off-line optimizations (day ahead forecast). A set of multiple Motif windows display the daily trend for each pilot node (measured voltage), the profile of the forecasted values estimated off-line, as well as of the best profiles computed on-line through the optimization procedure. Similar windows display the daily trends and the profiles of the area reactive power levels, which are updated in real-time, or obtained through computation requested automatically by TVR or manually by the operator.

The LMC output can be also used, via TCP/IP connection with the RVRs, to update the RVRs voltage setpoints, in case of TVR maintenance. This simplified open-loop control is obviously less effective than the closed-loop TVR.

Figure 5-8 shows an example of the LMC window representing the voltage values of the S.Rocco pilot node (North Italy), before and after the execution of the OPF procedure. The figure shows the day ahead forecast profile (in steps), the measured profile due to TVR and the optimal short–term profile. The optimal short-term profile (in red), characterized by higher values and flat trend, is computed according to the actual measurements coming from the system state estimation.

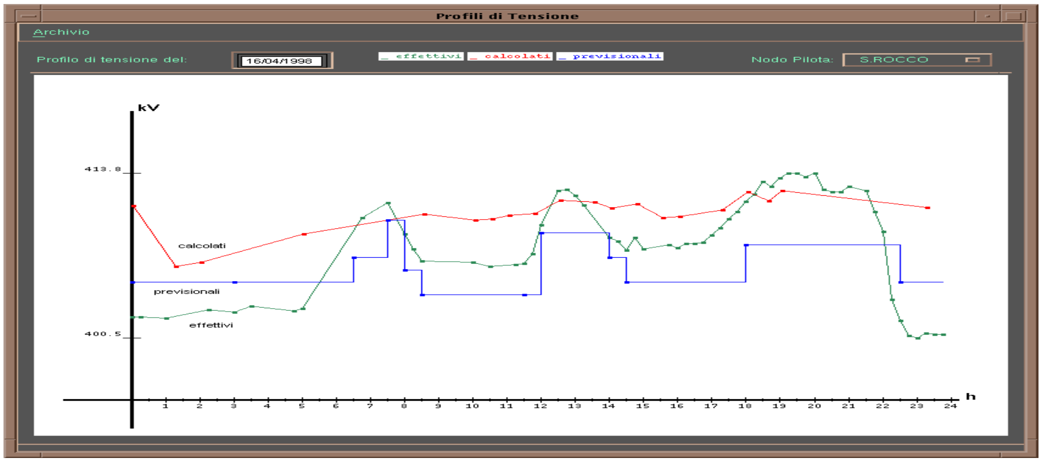

Figure 5–8 *Computed, measured and forecasted values of S. Rocco pilot node voltage.*

5.2.7 Control System Development State and Evolution Perspectives

The described multilevel control solution for the coordination of the reactive power resources is being applied to the whole Italian transmission network within the SVR and TVR projects.

The activities related to the practical application in Italy of the Secondary and Tertiary voltage control systems were concluded at the end of 2005. These activities include the field commissioning of about 50 REPORTs and 3 RVRs apparatuses [5-7, 5-8].]. The power stations equipped with the REPORT apparatuses are the largest hydraulic, thermal and combined-cycle plants in Italy. The number of the Italian plants involved is nearly 50 (having in total more than 150 generating units).

The global hierarchical control system, including the Tertiary Voltage Regulation was practically ready by the end of 2004. Its full operation delayed due to the commissioning of a new “Control System” at GRTN.

The coordinated voltage control system, in large part already in to operation, is undoubtedly contributing to enhance the quality and security of the power plant and grid operation.

5.3 The French Control System Design Characteristics

5.3.1 Introduction

This section presents a summary of the French Secondary Voltage Regulator (SVR) and Coordinated Secondary Voltage Regulator (CSVR) system architectures. The functionalities of these two systems have been previously described in Chapter 2.

5.3.2 Secondary Voltage Regulator System Architecture

Due to equipment ageing, SVR is being renovated. Here is described the present architecture.

SVR includes two control loops over the primary voltage regulation:

- A zone regulator (computer):
    - Receives the voltage measurements of the pilot node (one pilot node only for each zone),
    - Calculates and sends a control signal to the generators of the zone. This signal (also called the "level") is calculated from the difference between the setpoint value at the pilot point and the voltage effectively measured.
- A reactive power control device:
    - Receives the level (equivalent to a reactive power setpoint) from the Regional Dispatching Center,
    - Adjusts the reactive power generation according to the reactive power setpoint received.

Each generator´s participation in voltage control isproportional to its reactive power capacity (alignment principle).

SVR comprises equipment installed at substations, generating units and Regional Dispatching Center:

- Equipment in about 35 substations for the collection of the pilot node voltages. Pilot nodes are usually equipped with two voltage transducer sensors (in case of failure of one sensor or in case of two electric nodes operating);
- Reactive power measurement and control equipment in more than 100 thermal units and 150 hydro units, for the collection of remote signal (state of excitation limitations, etc.). These equipment are the interface between the level (calculated at the Regional Dispatching Center) and the primary voltage controller at the various plants;
- Regulators in the 7 Regional Dispatching Centers, which calculate the different levels (one level for each zone).

The level is transmitted through a specific link (which is also used for the power/frequency control – AGC data transmission). The classical network is used for conveying data from substations and generators to the regulators of the dispatching.

5.3.3 Coordinated Secondary Voltage Regulator System Architecture

Figure 5-9 shows the CSVR system architecture [5.9], which is made up as follows:

- Workstation (RSCT-D) located at control centre, responsible for real-time computation of setpoint voltage variations (ΔUc) to be sent to generating units;
- Digital transducer sensors (TN) fitted on generating units and substations;
- Interface module (MI) for inputting computed ΔUc values to primary voltage control set-point signal for each generating unit;
- Substation communication interfaces (RSCT-P), carrying signals from local digital transducers to RSCT-D;
- Power plant communication interfaces (RSCT-C), carrying signals from local digital transducers and interface modules up to RSCT-D;
- X25 communication network, conveying data (TM,TS) from substation and power plant interfaces to RSCT-D using ftp protocol;
- RSCT-D connection to SCADA at computerized regional control centre (SIRC), for inputting data on transmission network topology and status;
- Timekeeper at each site, for synchronization.

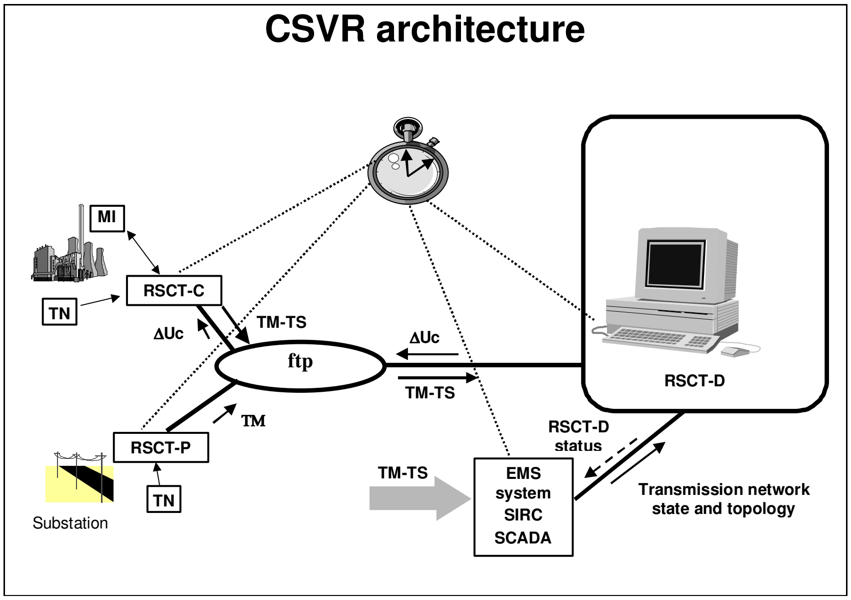

Figure 5–9 *CSVR architecture.*

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Chapter 6

Verified Performance Including Field Tests

6.1 Introduction

The criteria followed for characterizing, evaluating and comparing control system performances, based on the different control configuration characteristics and expected behavior, measured during factory and commissioning tests and monitoring activities carried out for the application of coordinated voltage control, take into account the following issues:

1. The two possible control system testing approaches:

- The "detailed checking" approach, which tries to reduce to a minimum the maintenance and fine tuning effort and costs after the system commissioning, through a detailed test plan at the factory and on the field, according to the idea that it is cheaper and more effective to deeply test and correct mistakes during factory and commissioning tests (because of the available instrumentation, the under test system operating condition and the generally large presence of technicians and experts) instead of during system operation because of the difficulty and risk of partial success;
- The "delayed checking" approach, which tries to reduce to a minimum the test factory and commissioning phases for being considered expensive, time consuming and less effective as compared to the long duration field tests during the actual system operation phase in the real field. This second approach considers less expensive and more effective the correction of possible mistakes in the field, during the system operation.

2. In case of detailed tests, the use of real-time simulators for closing system control loops with the objective to deeply check and tune their dynamics and related control logic, is considered a good option for system testing under heavy, perturbed operating conditions, which are usually not available during system field operation;

3. The dynamic performance tests of a hierarchical control system with several overlapping control loops generally requires different phases for checking and fine tuning. They start from the inner and faster control loop(s) and gradually move to the next outer and slower control loop(s), until they reach the slowest but more complex external loop that works together with all the others closed and overlapping regulating loops, previously checked and tuned; each control loop is individually tested, after the adequate setting of the inner loops;

4. In general, the preliminary tests are those performed in open loop operating condition, having the objective to check the correct operation of the new interface between two hierarchical contiguous levels, including the related telecommunications and their response time;

5. A dedicated test is organized for each control functionality to verify the real performance and the consistency with the expected performances. The considered functionalities are those related to the control system auto-diagnosis, protection logic, control logic, regulating functions;

6. The dynamics of each control loop is field tested and documented through step changes to its setpoint, with the objective to analyze the related transients and retune the loop (or loops) if necessary;
7. All the field tests are performed with the power plant generators in operation, around the dispatched operating points. The installation of the control system does not require the unit to be out of service except for the activities related to the new AVR interface.

6.2 The Italian Control System Field Test Results

The main results of dynamic performance checking, during field commissioning tests and long-term operation monitoring, are here described for the following subsystems:

- Unit Automatic Voltage Regulator (AVR);
- Plant Reactive Power Regulator (REPORT);
- Pilot Node Regional Voltage Regulator (RVR).

The commissioning and monitoring activities were carried out at both power plant level and regional control center level. Information is also given on the evolution perspectives, mainly regarding the National Voltage Regulator (NVR) and Losses Minimization Control (LMC) that constitute the Italian project for Tertiary Voltage Regulation.

6.2.1 Checking the Dynamic Performance during Commissioning Field Tests

6.2.1.1 Commissioning of AVR Modification at Power Plant Level

The AVR modification required for interfacing REPORT, the related wiring connections and tuning are checked according to the following test sequence list:

- Board customization jumpers setting and AVR main control signals verification;
- Checking of terminal voltage measurement and setpoint and related diagnostics;
- Grid voltage measurement tuning with related follow-up and signaling logic;
- Up/Down commands checking from both local and remote operators;
- Calibrator excursion field verification with related local and remote bounding indications;
- Calibrator excursion time verification, between both the bounding positions;
- Calibrator follow-up logic during both the manual and the automatic operation;
- Closed-loop final testing of AVR main control and regulation facilities ($I.\sin(\varphi)$ and $I.\cos(\varphi)$ measurement transducers, over-excitation and under-excitation limits).

6.2.1.2 Commissioning of REPORT at Power Plant Level

The commissioning of REPORT involves checking the wiring, measurement and control parameter values stored in REPORT, as well as the functional performances in the most significant operating conditions of the generating units. A complete verification of the over- and under-excitation limits working conditions is carried out, as well as the voltage limits protection, so as to make sure there is coherency between the AVR and the REPORT limit settings.

Control parameters, like the equivalent external reactance seen by REPORT, as well as time constants on the different regulation loops, are identified and validated. Step perturbations are applied to the setpoints of the generating unit reactive power and EHV bus voltage regulators.

REPORT commissioning activities typically require:

- REPORT apparatus cubicle installation;
- Wiring connections from the excitation systems;
- Wiring connections from the remote operation equipment (communication devices);
- Availability of all the measurement and instrumentation necessary to test the dynamic performance of the REPORT equipment.

The results shown below belong to a typical REPORT "detailed" commissioning activity. The results refer to the Italian pump-storage hydro power plant of Edolo, which is equipped with eight generating/pumping units, four of them controlled by a REPORT Master apparatus and the other four by a REPORT Slave cubicle. These tests have been subdivided into different basic groups:

- Single unit tests under REPORT manual control of the reactive power level;
- Multiple unit tests under REPORT manual control of the reactive power level;
- Multiple unit tests under REPORT automatic control of the local bus voltage level;
- Multiple unit tests under REPORT automatic control of the remote pilot node voltage level.

Single Unit Tests under REPORT Manual Control of the Reactive Power Level

During these commissioning tests, which are repeated for each individual unit, a suitable REPORT internal reactive power level setpoint is manually adjusted. The test sequence list, regarding both the generating and pumping modes of the reversible hydro plant, is arranged as follows:

- TEST A: unit insertion under REPORT control and over-excitation excursion;
- TEST B: unit insertion under REPORT control and under-excitation excursion.

The above tests are to verify the stable behavior of the overall system, the correct operation of the AVR interface (compound feedback excursion, Up/Down commands) and the precise correspondence between the reactive powers required and produced by each unit.

- TEST C1: step disturbance to generating unit voltage reference with REPORT control in over-excitation (see Figure 6–1);
- TEST D1: step disturbance to generating unit voltage reference with REPORT control in under-excitation (see Figure 6–2);
- TEST C2: step disturbance to pumping unit voltage reference with REPORT control in over-excitation;
- TEST D2: step disturbance to pumping unit voltage reference with REPORT control in under-excitation.

The above tests are to verify the control system transient behavior, and regulation accuracy, in different operating conditions, with the unit operating in both the generating and pumping modes.

- TEST E1: generating unit capability curve control by REPORT in over-excitation conditions;
- TEST F1: generating unit capability curve control by REPORT in under-excitation conditions;
- TEST E2: pumping unit capability curve control by REPORT in over-excitation conditions;
- TEST F2: pumping unit capability curve control by REPORT in under-excitation conditions.

The above tests are to verify the coherence between the capability curves defined at the REPORT controller and those realized by the AVR, in both the over-excitation and under-excitation operating conditions, with the unit operating in both the generating and pumping modes. The proper coordination with the maximum terminal voltage limitation, internal to the REPORT apparatus, is simultaneously checked. Additionally, tests on Master/Slave cubicles coordination are also carried out.

Multiple Unit Tests under REPORT Manual Control of the Reactive Power Level

During these commissioning tests, which are carried out for all the units at the same time, a suitable REPORT internal reactive power setpoint is manually adjusted. The test sequence list, regarding only the generating mode of the reversible hydro plant and including tests about the Master/Slave cubicles coordination, is arranged as follows:

- TEST G1: units insertion under REPORT control and over-excitation excursion;
- TEST G2: units insertion under REPORT control and under-excitation excursion.

The above tests are to verify the overall system stability and balanced operating behavior, a properly independent primary voltage control AVR and a precise identification of the parameter corresponding to the power plant external reactance.

- TEST H: generating units coherent response to a step applied to the REPORT controller, in over-excitation conditions (see Figure 6–3);

- TEST I: generating units coherent response to a step applied to the REPORT controller, in under-excitation conditions (see Figure 6–4).

The above tests are to verify the control system transient behavior and the regulation accuracy, in both the over-excitation and under-excitation operating conditions, with all the units operated together in the generating mode.

Multiple Unit Tests under REPORT Automatic Control of the Local Bus Voltage Level

During these commissioning tests, where a disturbance is simultaneously applied to all the units, a suitable REPORT internal bus voltage setpoint is manually adjusted. The test sequence list, regarding only the generating mode of the power plant, is arranged as follows and includes also tests about the Master/Slave cubicles coordination:

- TEST J: units insertion under REPORT control and bus voltage excursion;

- TEST K: generating units step response of REPORT in bus voltage control (see Figure 6–5).

The above tests are to verify the static and dynamic behavior of the control system, as well as the accuracies of both the reactive power control and bus voltage regulation loops, with all the units operating together in the generating mode.

- TEST L: forcing a REPORT measurement error in the bus voltage acquisition;

- TEST M: simulation of the REPORT operation with power plants that are electrically near;

- TEST N: units step response of REPORT in bus voltage control with compound.

The above tests are to verify the proper functioning of REPORT dedicated logic and the exhibition of specific dynamics, with all the units operating together in the generating mode.

- TEST O: units step response of AVR with REPORT in over-excitation and voltage control;

- TEST P: units step response of AVR with REPORT in under-excitation and voltage control.

The above tests are to verify the dynamic control system transient behavior, according to the expected requirements under disturbances of both the reactive power control and bus voltage regulation loops, with all the units operating together in the generating mode.

- TEST Q: starting of a single unit alone (only for hydro power plants);

- TEST R: stopping of a single unit alone (only for hydro power plants).

The above tests aim to verify the stable behavior of the overall system, the proper regulating action of the REPORT controller and a correct managing of a single unit starting and stopping, with all the other units operating together in the generating mode.

- TEST S: checking of REPORT control operation under local bus voltage profiles.

The above tests is to verify the system stable behavior, the proper regulating action of the REPORT controller, maintaining the bus voltage profiles defined by the operator, with all the units operating together in the generating mode.

Multiple Unit Tests under REPORT Automatic Control of the Remote Pilot Node Voltage Level

During these commissioning tests, conceived also for the remote joint operation of all the units, a suitable REPORT internal reactive power setpoint is manually adjusted. The test sequence list, regarding only the generating mode of the reversible hydro plant, also includes tests about the Master/Slave cubicles coordination and is arranged as follows:

- TEST T: units insertion under REPORT control and remote reactive level excursion (Figure 6–6).

This test is to verify the system stable behavior, the proper regulating action of the REPORT controller and a precise correspondence between the reactive power level required and that produced by all the units operating together in the generating mode.

- TEST U: forcing of a REPORT signal error on the remote reactive level acquisition.

These tests are to verify the proper behavior of the REPORT controller in specific operating conditions, which is expected to intervene through dedicated logics and exhibit appropriate dynamic performance, with all the units operating together in the generating mode.

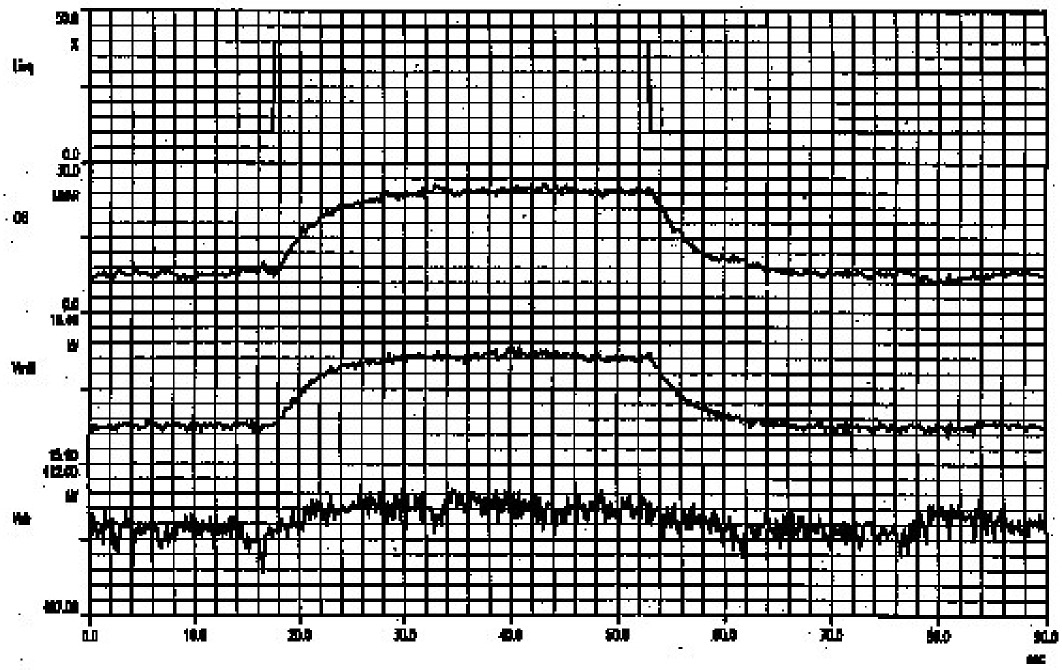


Figure 6–1 *TEST C1: generating unit step response of REPORT control in over-excitation.*

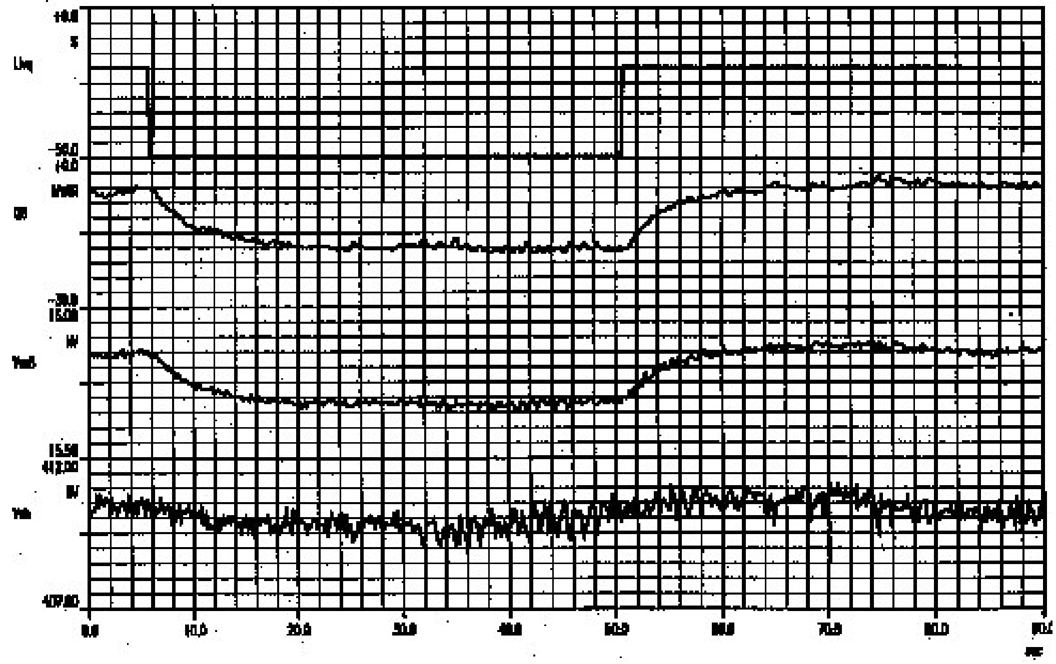


Figure 6–2 *TEST D1: generating unit step response of REPORT control in under-excitation.*

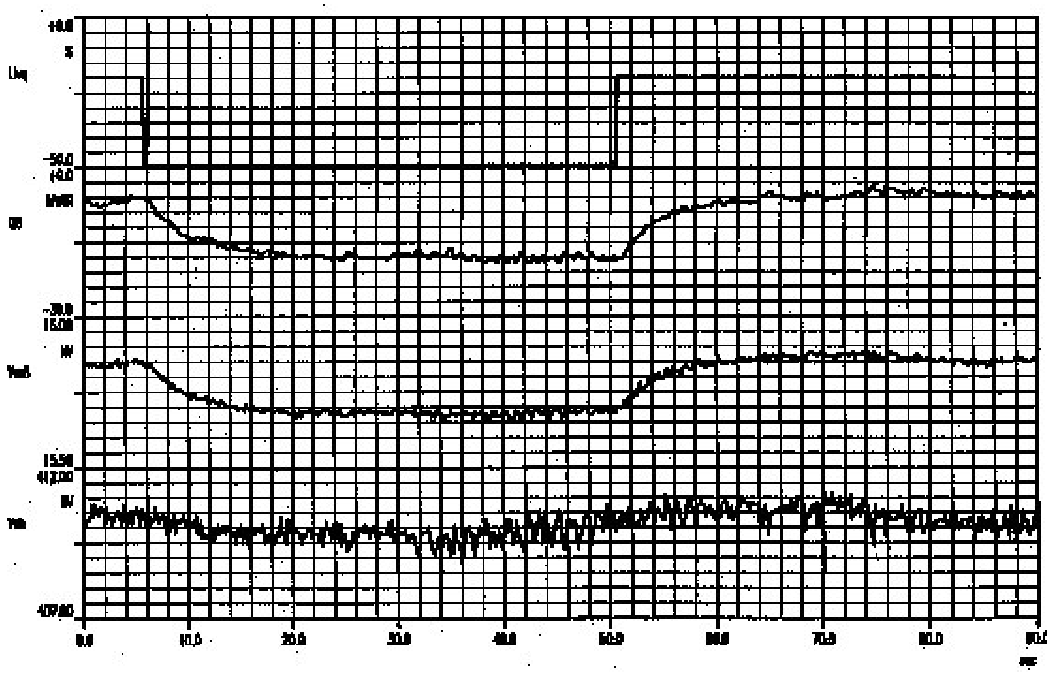


Figure 6–3 *TEST H: generating units step response of REPORT control in over-excitation.*

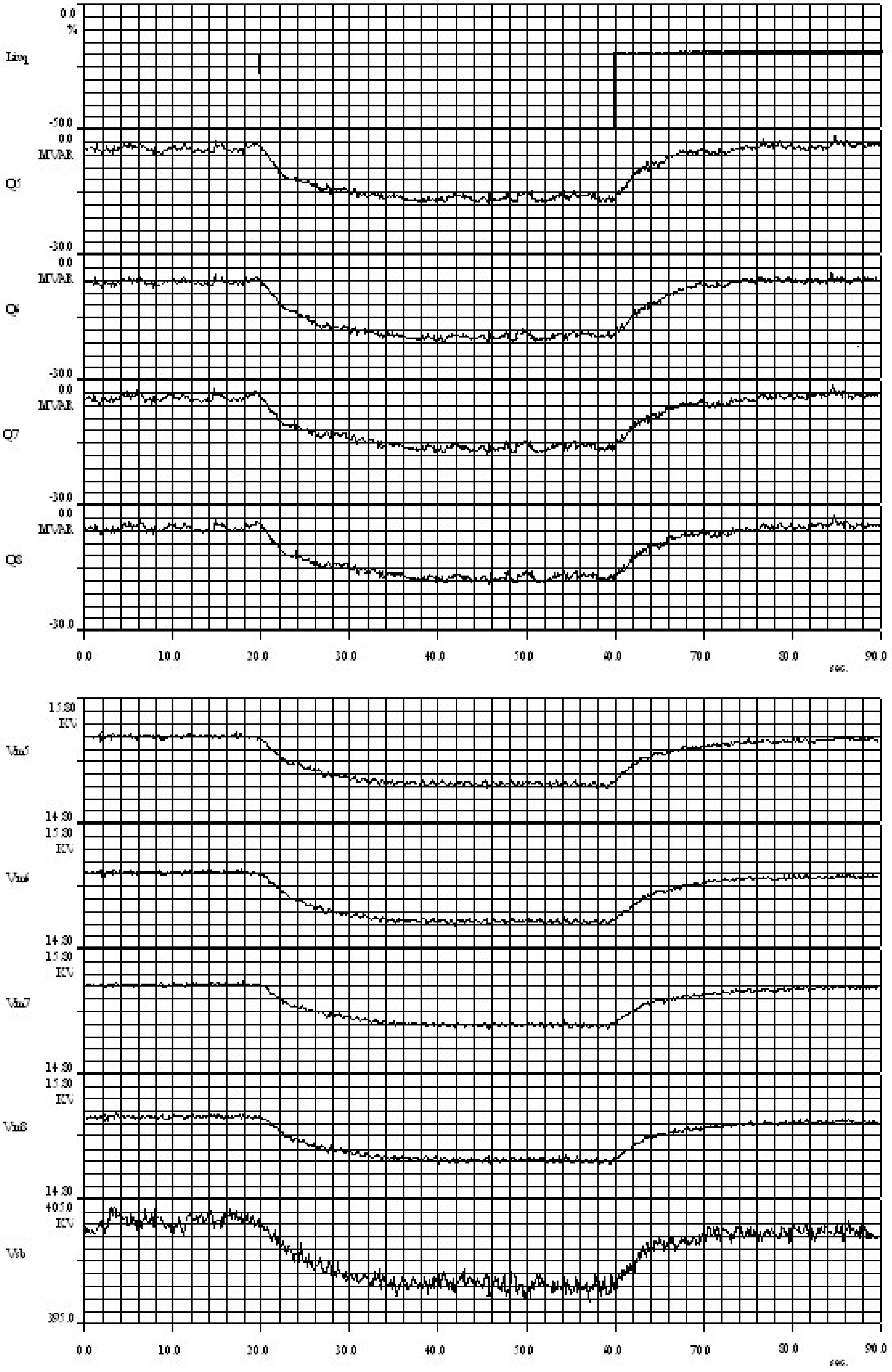


Figure 6–4 *TEST I: generating units step response of REPORT control in under-excitation.*

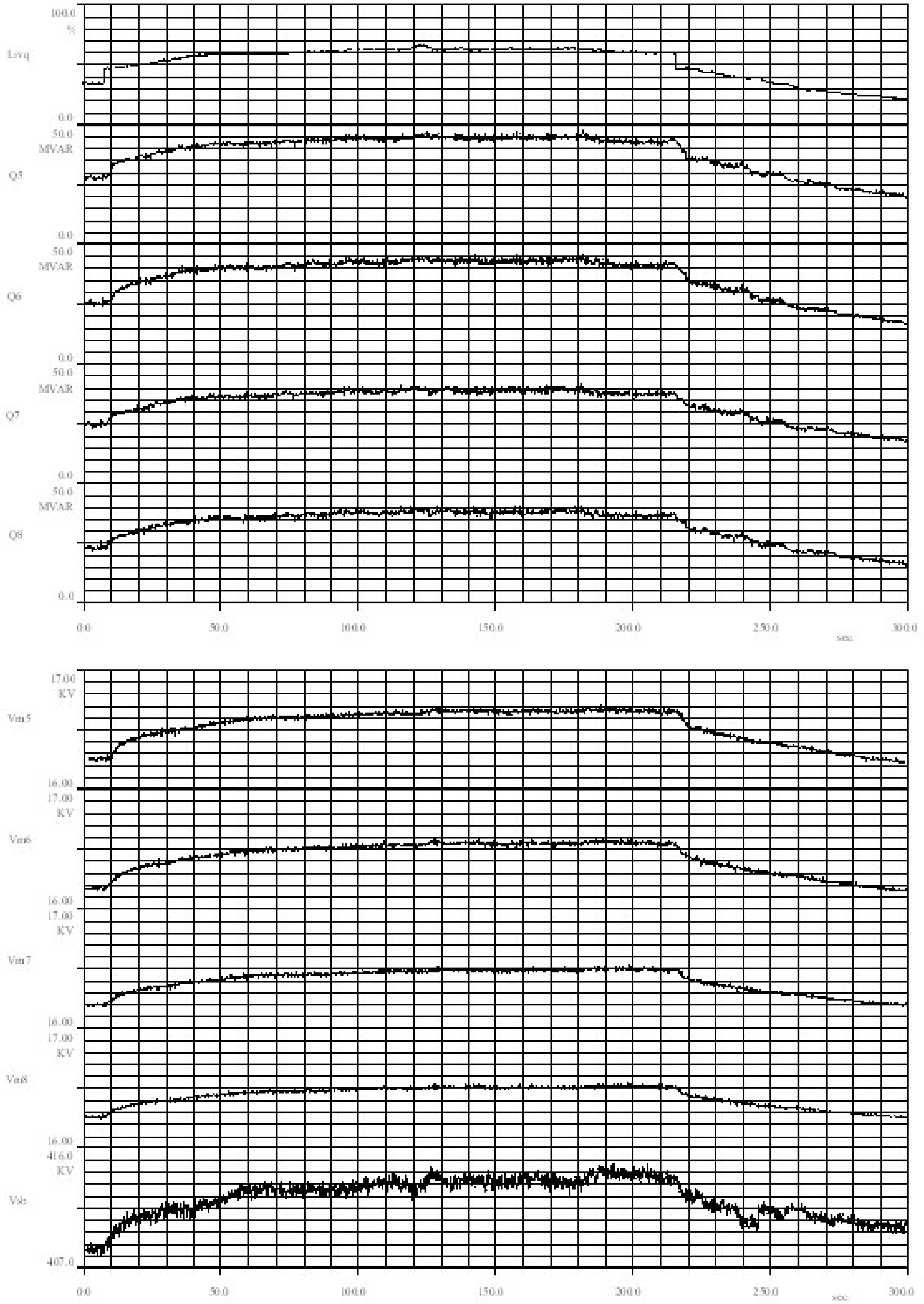


Figure 6–5 *TEST K: generating unit step response of REPORT in bus voltage control.*

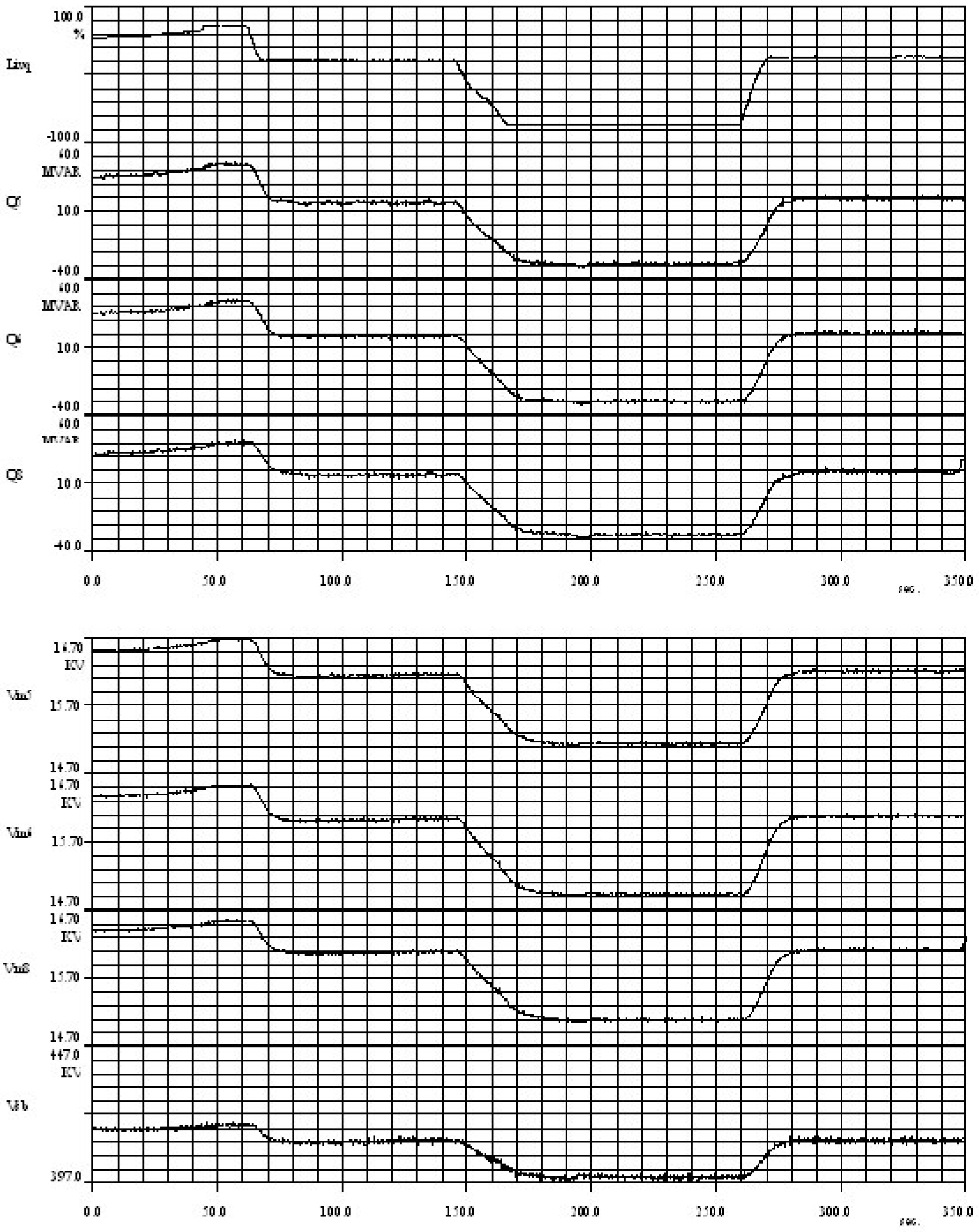


Figure 6–6 *TEST T: units insertion under REPORT control and remote reactive level excursion.*

6.2.1.3 Commissioning of RVR at Regional Control Center Level

RVR commissioning activities require the following configuration related tasks:

- Modifications in both the SCADA system and telecommunication equipment: all the incoming signals to the RVR (tele-measurements TM and tele-signals TS) and outgoing signals (tele-regulations TR and tele-controls TC), have to be carried through the SCADA system and the telecommunication equipment already in service. In order to allow such an exchange it is necessary to perform the following hardware/software interventions:

  - Implementation on the SCADA system of all the necessary interface routines allowing the network connection with RVR;
  - Generation in the SCADA database of all the necessary variables to be provided or received by RVR (REPORT information like TMs, TSs, TRs and TCs);
  - Development in the SCADA software of all the necessary logic to properly manage communication errors, system outages, peripheral devices maintenance;
  - Intervention on the telecommunication equipment for all the necessary modifications to properly assure suitable TMs and TRs refreshing times no greater than 2 s (for both the control loop measurements, like the TM of the pilot node voltage level, and regulation signals, like the TR related to the area reactive power level). For the other variables not directly acting on closed loops a higher refreshing time of 4 s may prove sufficient;
  - Activation of the telecommunication channels for the transmission of the necessary variables to be provided or received by RVR (REPORT information like TMs, TSs, TRs and TCs): this activity could require suitable hardware modifications (new tele-transmission equipment, new measurement transducers, etc.). In a preliminary phase it is sufficient to activate the telecommunication channels related to the pilot node voltage measurement (acquired with the appositely installed high precision converters) and to the variables relevant to the controlled power plants.

- RVR workstation installation in a suitable environment (for instance the Regional Dispatcher Control Room), with availability and proper configuration of the files relevant to the description of the controlled electrical region. These files describe with suitable syntax all the elements in the region controlled by the RVR (number of power plants, main characteristics and rated data, substations structure, etc.). These files contain all the IDs of the variables (TMs, TSs, TRs and TCs) that RVR will coherently exchange with the SCADA system. The following activities have to be completed before proceeding to the subsequent communication and functional checks:
  - Configuration data specification on all the controlled equipment in the electrical region;
  - Workstation platform customization (regulation parameters specification, sensitivity matrices computation, synoptic images definition and configuration);
  - Preliminary verification of all the modifications introduced at the telecommunication equipment and SCADA system levels (checking the correct RVR reception of the TMs and TSs from the controlled power plants and sub-stations, verification of the proper RVR transmission of the TRs and TCs to the controlled power plants);
  - Independent activation under the RVR control of single power plants (communication test between the RVR and the power plant, functional test of the plant under RVR control).
- RVR functional tests, after completing the telecommunication checks and verifying the availability of the power plant units under the local reactive power control by REPORT. It is also necessary that reactive power changes may be carried out, irrespectively of the active power generation, in response to grid voltage needs. The functional checks consist in verifying the proper dynamic behavior of each pilot node voltage regulator for all the foreseen operating modes (manual mode, automatic mode with voltage setpoint coming from a suitable calibrator, automatic mode with voltage setpoint coming from the suitable profiles defined by the operator or by the dispatching at the tertiary voltage regulation level), as well as the correct execution of procedures necessary for normal operation

(insertion/exclusion of power plants under the RVR tele-control, recovery from communication errors between the RVR and the power plants).

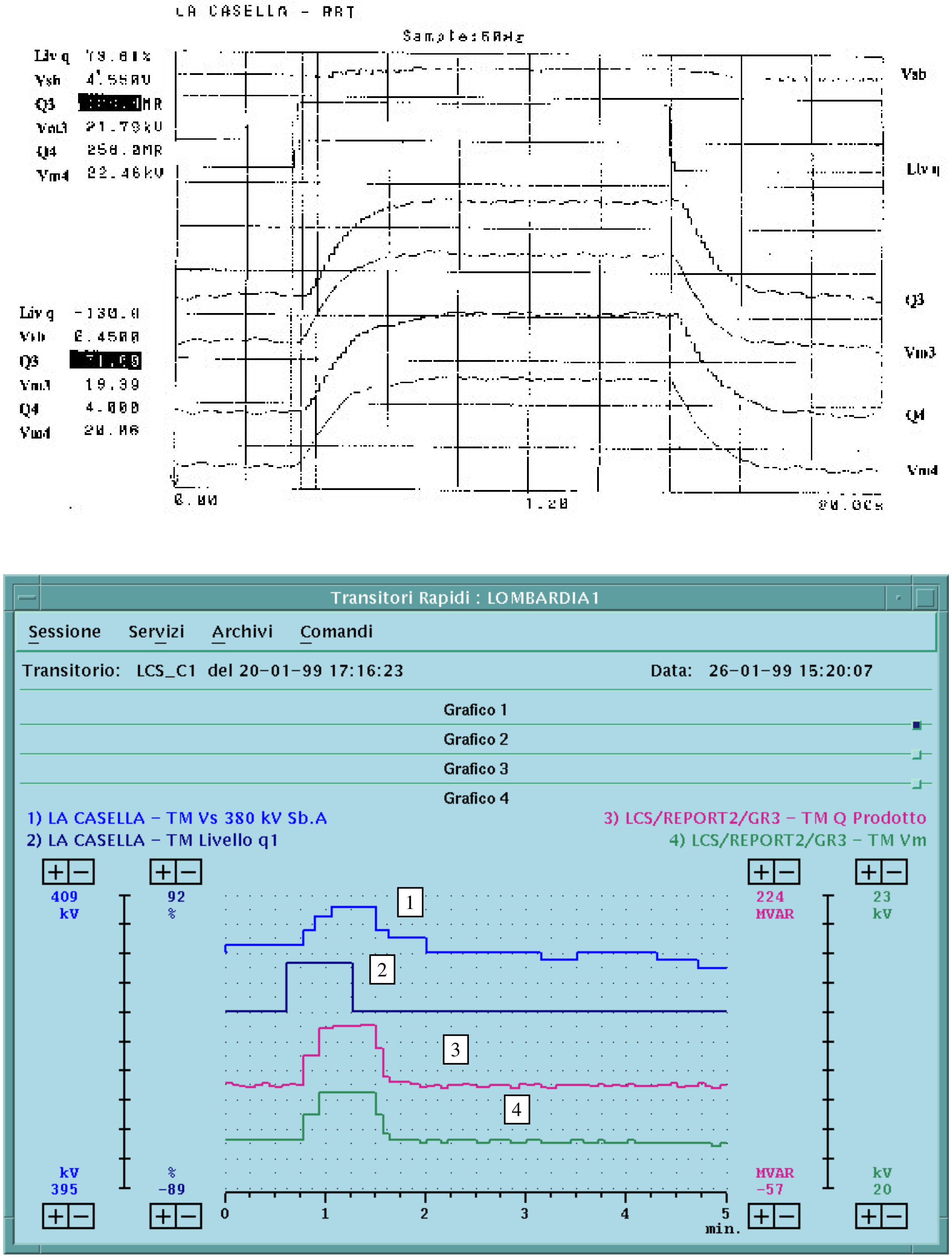
- Operation of the RVR in manual control: in this operating mode a suitable reactive power level calibrator, internal to the RVR, allows the operator to define the fixed reference value of the area reactive level, sent to all the controlled power plants. The following tests and protection logic verifications are carried out:
    - TEST A: insertion/exclusion of power plants under the RVR tele-control;
    - TEST B: calibrator excursion of the reactive power level for the area;
    - TEST C: step change in the area reactive power level (Figure 6–7).
- Operation of the RVR in automatic control: in this operating mode a suitable pilot node voltage level calibrator, internal to the RVR, allows the operator to define the fixed reference value of pilot node voltage, from which the area reactive level is computed and sent to all the controlled power plants. The following tests and protection logic verifications are carried out:
    - TEST E: verification of the correct switching between manual and automatic mode;
    - TEST F: calibrator excursion of the main pilot node voltage level;
    - TEST G: step change in the main pilot node voltage reference (Figure 6–8);
    - TEST H: operation under main pilot node voltage profiles chosen by the operator;
    - TEST I: testing of main pilot node compound feedback activation and effects;
    - TEST L: verification of the correct switching between main and reserve pilot nodes;
    - TEST M: testing of reserve pilot node feedback activation and effects;
    - TEST N (final verification of the automatic voltage regulation with all the controlled power plants under the RVR tele-regulation): step change in the main pilot node voltage level with the various controlled power plants (Figure 6–9).

The following results refer to the RVR commissioning activities carried out at the Lombardy regional dispatcher of Milan, during the activation of the thermal power plant of La Casella, which is equipped with two generating units controlled by a REPORT apparatus. At the moment of this activation, the thermal power plants of Piacenza, Tavazzano and Turbigo were already operating under the RVR control.

The dynamic tests carried out for the RVR commissioning at the Milan regional dispatch center have been recorded at both the power plant and control center levels, using suitable data acquisition system at the plant and the RVR internal data recording feature at the dispatcher. The letter labels given to each of the following recordings, made at both the power plant and control center, refer to the above mentioned tests identified by the same letter.

The transients in Figure 6–7, Figure 6–8 and Figure 6–9 show delays between the area reactive level and the power plant unit voltage and reactive power. This is due to the telecommunication channels delays inherent to sending/receiving signals for measurement and control.

Concerning the data resolution and the sampling rate, there is an evident difference between the variables involved in closed-loop control and those simply acquired for SCADA purpose.



Transitorio: LCS_C1 del 20-01-99 17:16:23 Data: 26-01-99 15:20:07

1) LA CASELLA – TM Vs 380 kV Sb.A
2) LA CASELLA – TM Livello q1
3) LCS/REPORT2/GR3 – TM Q Prodotto
4) LCS/REPORT2/GR3 – TM Vm

Figure 6–7 *TEST C: step change to the area reactive power level.*

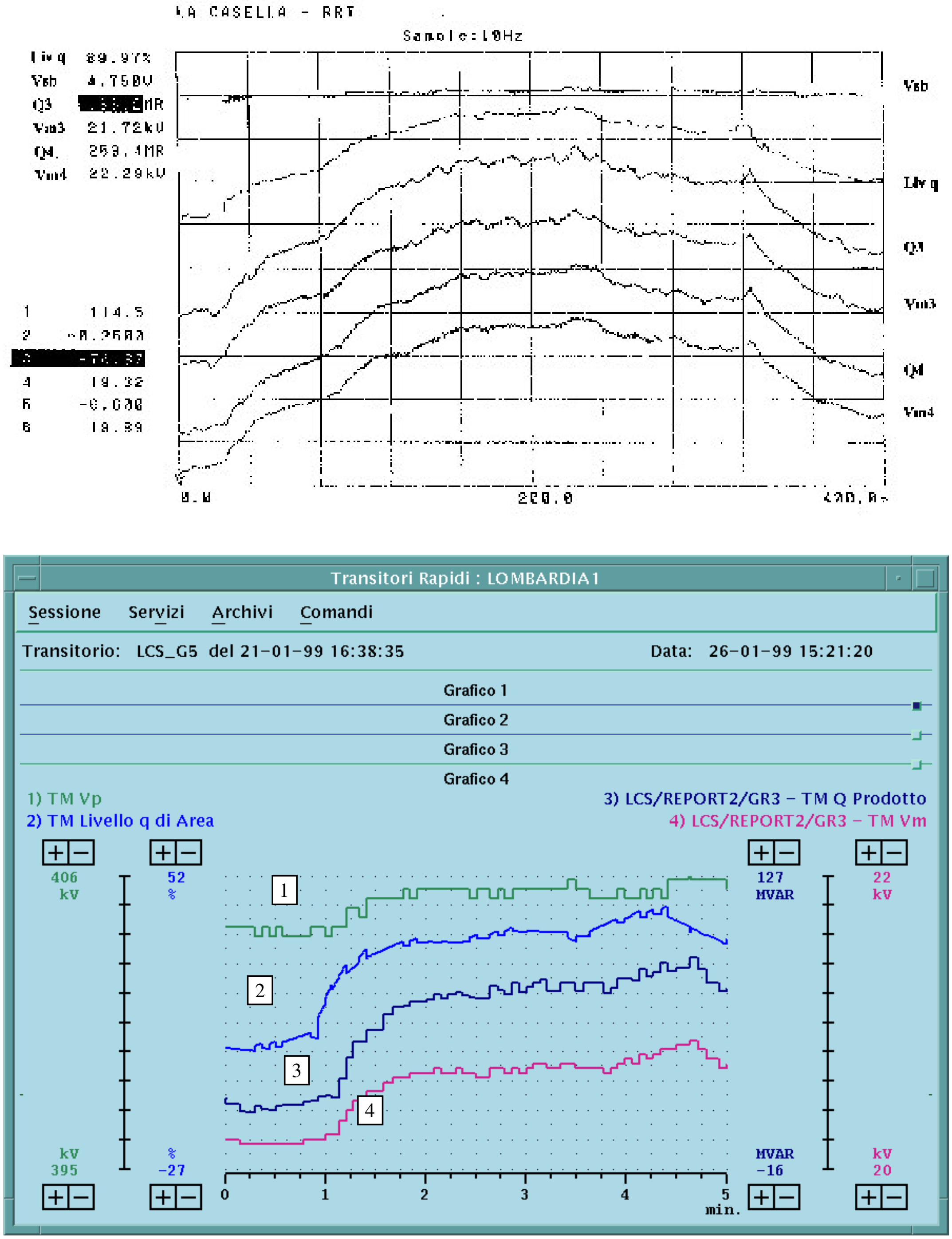


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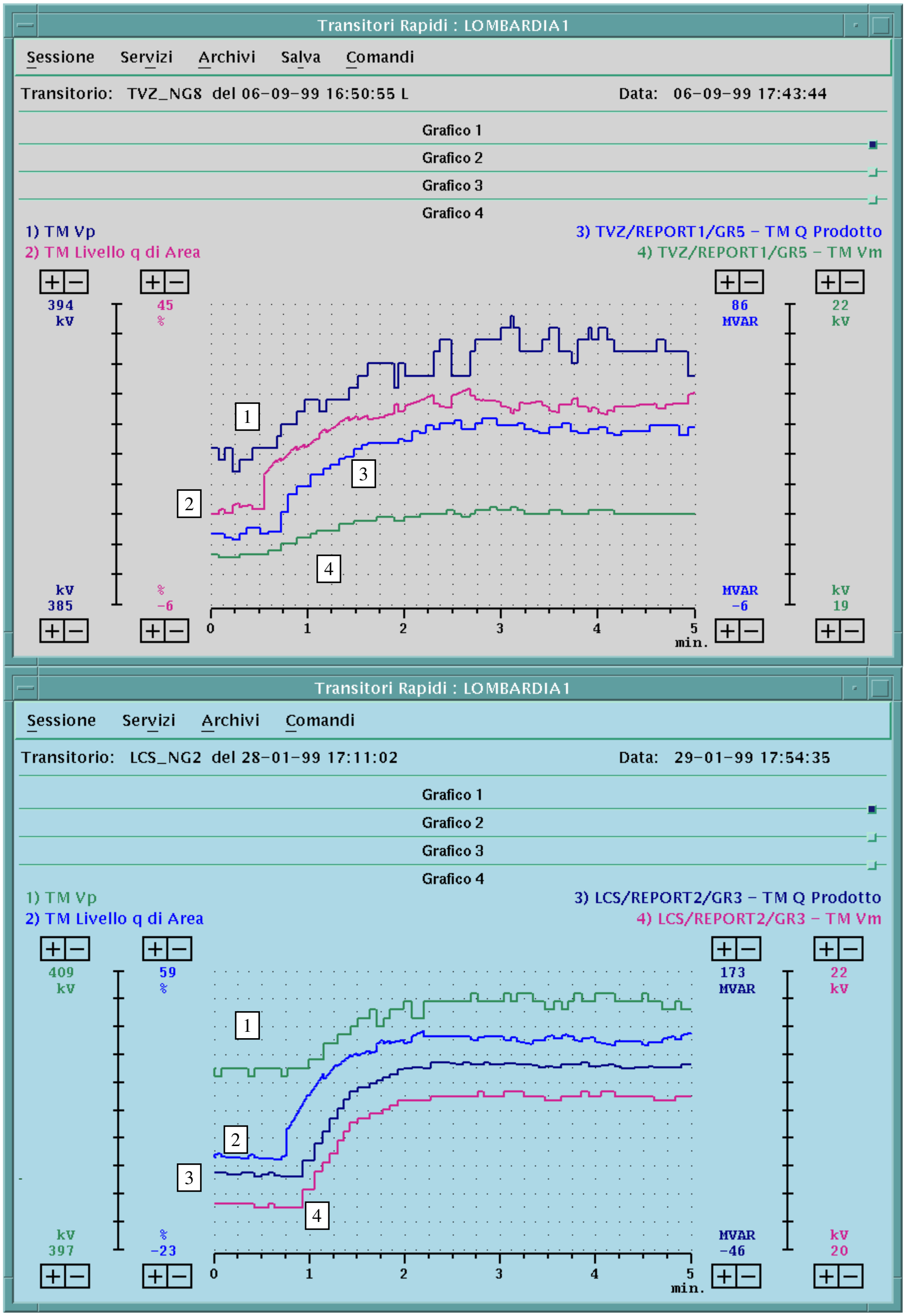
Figure 6–8 *TEST G: step change to the main pilot node voltage level.*



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Transitorio: LCS_NG2 del 28-01-99 17:11:02

Data: 29-01-99 17:54:35

Figure 6–9 *TEST N: step change to the main pilot node voltage level when having other power plants participating in the control.*

6.2.2 Monitoring the Long-Term Dynamic Performance

6.2.2.1 Monitoring of REPORT at Power Plant Level

The main goals for monitoring the power plant long-term dynamic performance can be summarized as follows:

- To check the proper functional design and the correct code implementation of REPORT with respect to the general control and regulation requirements;

- To verify the adequacy of the hardware and software control system architecture of REPORT, in terms of performance;

- To monitor the REPORT short-term performance (for the fine-tuning during the commissioning phase) and the long-term performance (for the effectiveness assessment during operational phase);

- To assess the REPORT control system performance in the light of power plant operational practice, and collect suggestions for improvements from system operators.

A lot of operational data have been collected, including the long-term recordings of the Lombardy power plants: Edolo, Sermide, Piacenza and Tavazzano. Description on theses recordings, for each power plant, obtained during both local bus voltage regulation and remote tele-operation, together with the main technical conclusions, are given below.

Local Bus Voltage Regulation at Edolo Power Plant

The recordings in Figure 6–10 have five-hour duration and refer to the REPORT local bus voltage regulation at the Edolo hydro power plant, for the daily voltage profiles defined by the operator, with the units operating in both the generating and pumping modes:

- The upper left of Figure 6–10 refers to a test recording carried in the morning and with the power plant operating in generating mode. The reactive power level is seen to be kept at zero when the REPORT bus voltage regulation is disabled (the voltage setpoint value follows the bus voltage actual fluctuations) and assume the actual control effort value when the REPORT bus voltage regulation is enabled. The bus voltage fluctuations are practically leveled at the specified voltage setpoint value. This bus voltage regulation capability occurred because the power plant units were modulated within their over-excitation limits;

- The lower half of Figure 6–10 refers to a test recording carried out during the night and with the plant operating in pumping mode. The reactive power level is kept at zero when the REPORT bus voltage regulation is disabled (the voltage set-point value follows the bus voltage actual fluctuations) and the actual control effort value when the REPORT bus voltage regulation is enabled. The bus voltage fluctuations are practically leveled at the specified voltage setpoint value. This bus voltage regulation capability occurred because the power plant units were modulated within their under-excitation limits.

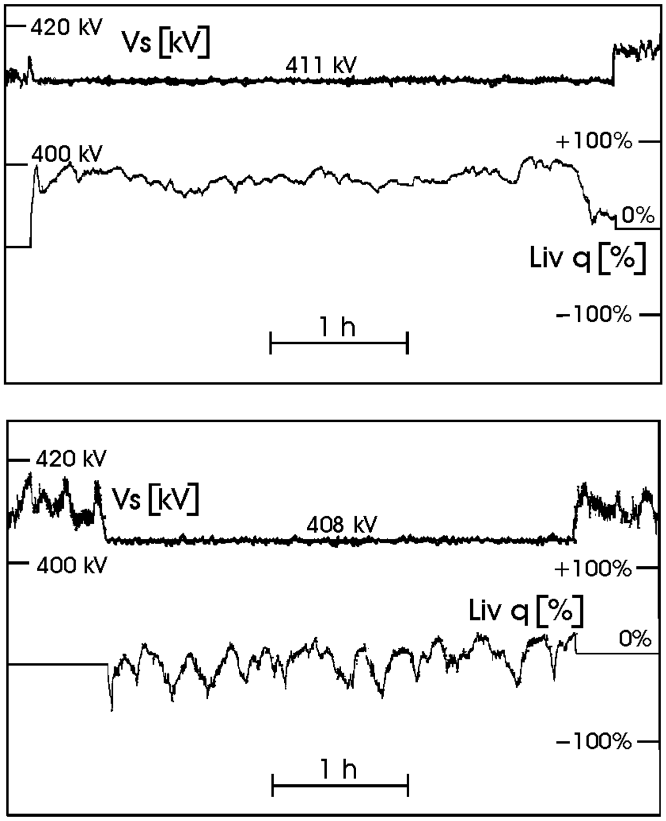

Figure 6–10 *Edolo power plant: checking of REPORT operation under local bus voltage profiles, for generating (upper half) and pumping (lower half) modes.*

Local Bus Voltage Regulation at Sermide Power Plant

Figure 6–11 and Figure 6–12 contain recordings of the REPORT local bus voltage regulation at the Sermide thermal power plant, under the daily voltage profiles defined by the operator, with the units operating in generating mode:

- The four plots in Figure 6–11 refer to the generating units 1-2 and correspond to a 70-minute recording made during the morning operation of the power plant. These recordings indicate the correct behavior of the REPORT control apparatus in the local bus voltage regulation: they show the actual reactive powers delivered by the units (aligned with the corresponding terminal voltages) and the resulting level of the power plant bus voltage. When facing external grid operating conditions involving a load reduction greater than expected, the bus voltage profile regulation by REPORT, despite the memorized profile calling for a higher bus voltage setpoint, requests a reduction in the reactive power delivered by the units for achieving the desired values of the bus voltage level;

- The four plots in Figure 6–12 refer to the generating units 3-4 and correspond to a 150-minute recording made during the night operation of the power plant. These recordings the correct performance of the REPORT controller in the local bus voltage regulation is still evident: they show the reactive power control (variable ranging in both the over-excitation and under-excitation zones with respect to the reactive power capability of the regulating units), the actual reactive powers delivered by the units (aligned with the corresponding terminal voltages) and the resulting level of the power plant bus voltage. As can be seen, in front of external grid operating conditions characterized by high levels of voltage, the bus bar voltage profile regulation by REPORT, despite the memorized profile asking for high bus voltage set-points, requires a reduction in the reactive power delivered by the units, with corresponding decrease of the terminal voltages, for keeping the bus voltage level at the desired value.

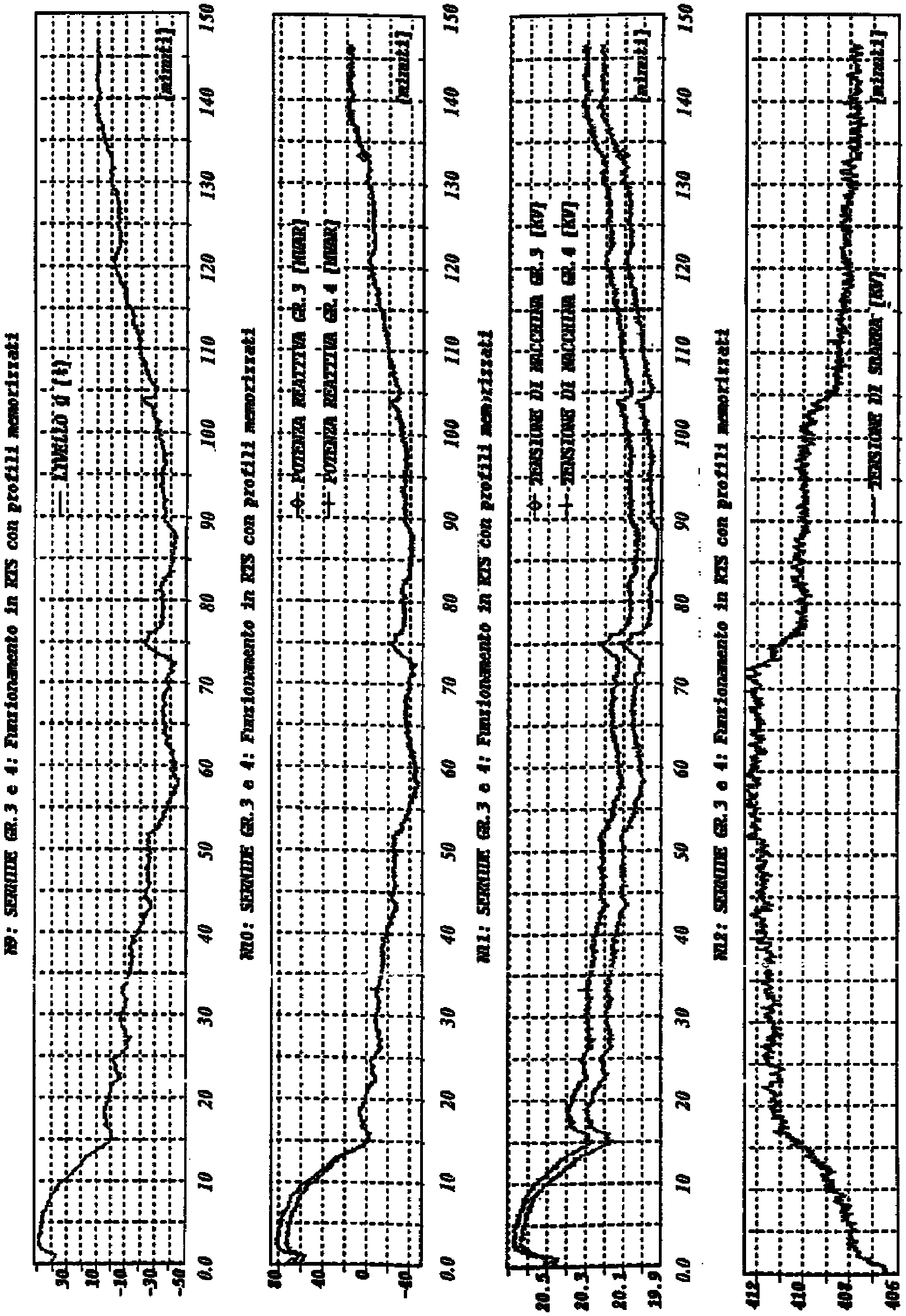

Figure 6–11 *Sermide power plant: checking of REPORT operation under local bus voltage profiles (150-minute recordings).*

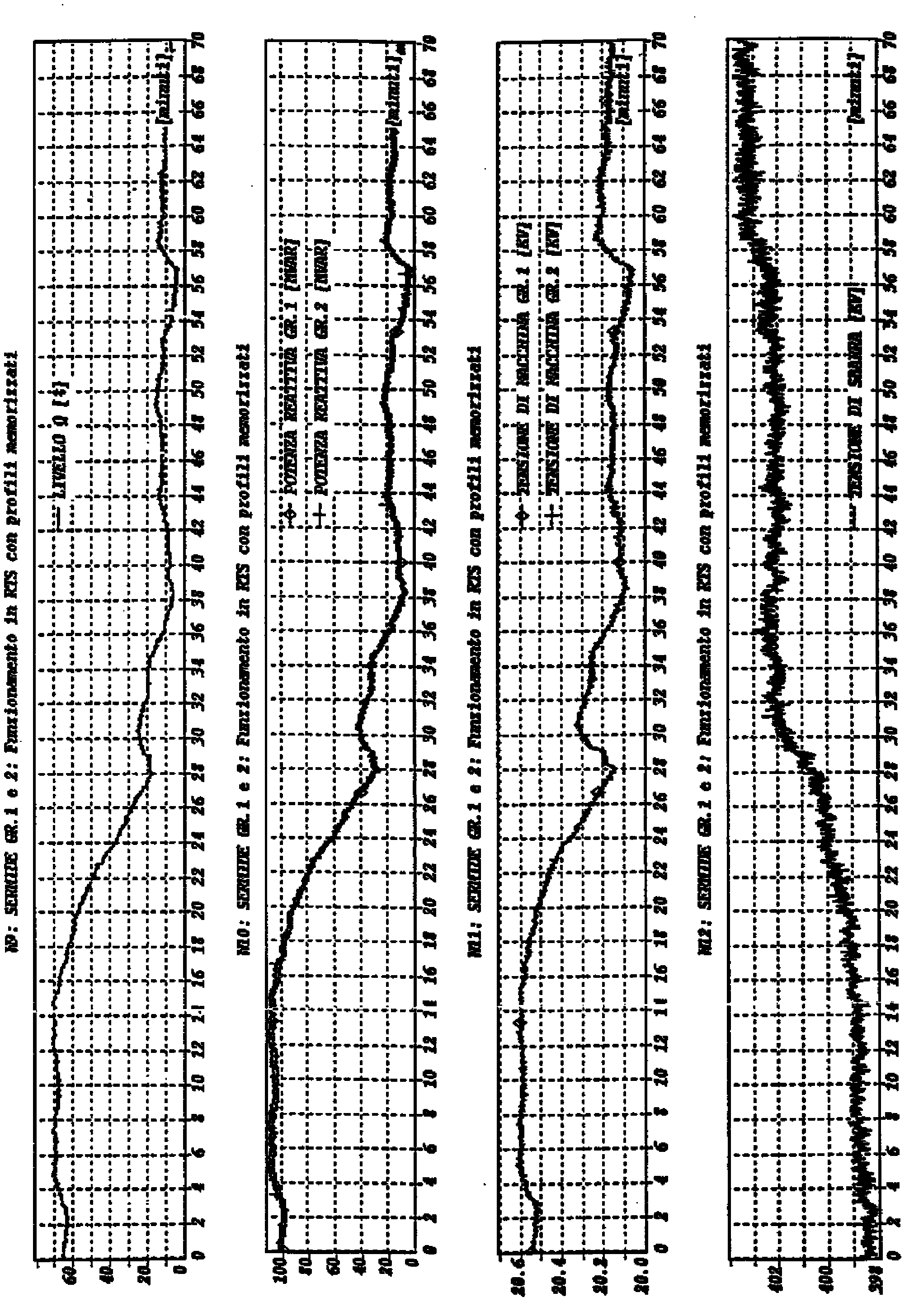

Figure 6–12 *Sermide power plant: checking of REPORT operation under local bus voltage profiles (70-minute recording).*

6.2.2.2 Monitoring of RVR at Regional Control Center Level

The monitoring of the regional control center dynamic performance has as main objectives:

- To check the proper functional design and the correct code implementation of RVR with respect to the general control and regulation requirements;
- To verify the adequacy of the hardware and software control system architecture of RVR, in terms of performance, reliability and expandability;
- To monitor the RVR short-term performance (for the fine-tuning during the commissioning phase) and the long-term performance (for the assessment during operational phase);
- To assess the RVR control system performance in the light of the regional dispatcher operational practice, and obtain from system operators suggestions for improvements.

A lot of operational data have been collected, including the long-term recordings of the Lombardy power plants: Piacenza, Tavazzano and Turbigo controlling the pilot node of Baggio and coordinated by RVR of Milan. Descriptions on these recordings, for each power plant, obtained during the local bus voltage regulation and the remote pilot node voltage tele-regulation, are given below together with the related technical conclusions.

Baggio Pilot Node Daily Voltage Profile with RVR and Area REPORTs Out of Service

Figure 6–13 refers to the daily voltage profile of the Baggio pilot node, recorded by the RVR at the Milan regional dispatcher, with the regulator itself and the area REPORTs disabled, that is without the Secondary Voltage Regulation.

- The first plot of Figure 6–13, with a recording duration of 24 hours (RVR recording feature of normal operation behavior), shows in the daily voltage profile of the Baggio pilot node the pair of under-voltage intervals, corresponding to the load peaks of middle morning and middle afternoon, as well as the over-voltage period, related to the lunch break. The RVR action should mitigate these variations through the proper coordination of the production/absorption levels of the tele-controlled power plants;
- The second plot of Figure 6–13, with a recording duration of 24 hours, shows the daily reactive power profile at the Tavazzano and Turbigo power plants corresponding to the voltage recording in the same figure. These voltage and reactive power recordings, which show large voltage variations and a lack of coordination between the two area power plants in supporting the Baggio voltage, are to be compared with Figure 6–14 and Figure 6–15, results related to the same pilot node and power plants when the SVR is in operation.

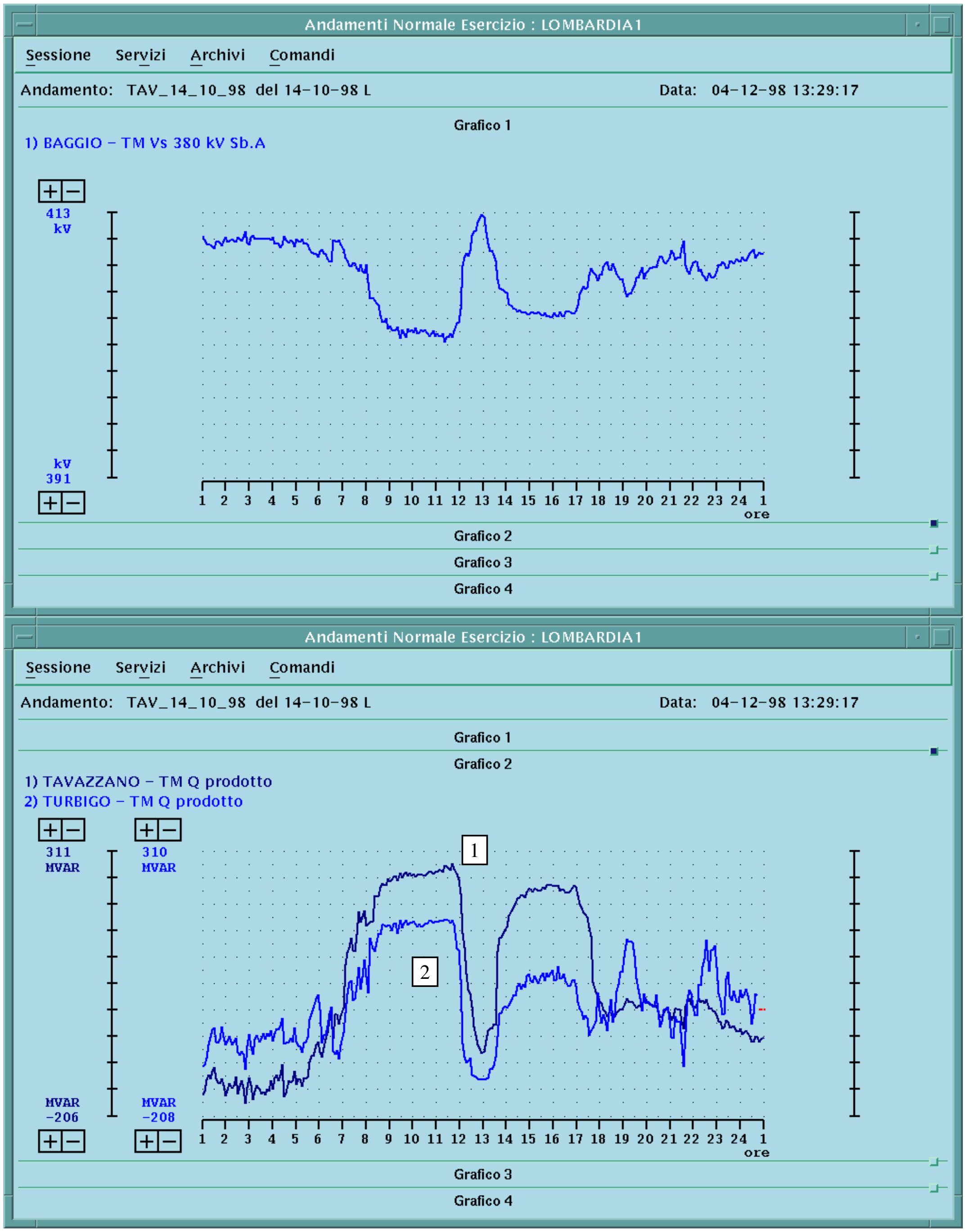

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Figure 6–13 *Baggio pilot node daily voltage profile without remote control of the Milan RVR.*

Baggio Pilot Node Daily Voltage Profile with Remote Pilot Node Voltage Regulation at Piacenza, Tavazzano and Turbigo Power Plants

Figure 6–14 and Figure 6–15 refer to the daily voltage profile (24-hour recordings) of the Baggio pilot node, recorded by the RVR at the Milan regional dispatcher, with the RVR itself enabled and the REPORT remote pilot node voltage control enabled at the Piacenza, Tavazzano and Turbigo thermal power plants, under the daily voltage profiles defined by the RVR operator:

- The first plot in Figure 6–14 clearly shows the better regulation of the daily voltage profile of the Baggio pilot node (recordings made on November 19th, 1999). A suitable under-voltage interval has been chosen in correspondence of the load peaks of middle morning and middle afternoon, in order to not saturate the over-excitation capabilities of the regulating units. It is still evident the over-voltage period, related to the lunch break, with the corresponding reactive power level under-excitation excursion. The RVR action therefore mitigates the variations induced by the external grid, through the proper coordination of the production/absorption levels of the tele-controlled power plants;

- The second plot in Figure 6–14 displays the daily reactive power profile at the Piacenza, Tavazzano and Turbigo power plants;

- The first plot in Figure 6–15 shows a quite flat daily voltage profile for the Baggio pilot node (recordings made on November 20th, 1999);

- The second plot in Figure 6–15 (stored by the same RVR recording feature), shows the pair of over-excitation intervals in the reactive power daily profile at the Piacenza, Tavazzano and Turbigo power plants, corresponding to the load peaks of middle morning and middle afternoon, as well as the under-excitation period, related to the lunch break. The RVR action again mitigates the variations induced by the external grid, with the goal of keeping the daily voltage profile defined by the RVR operator. At the same time, the reactive power production/absorption levels of the tele-controlled power plants appear properly coordinated and balanced.

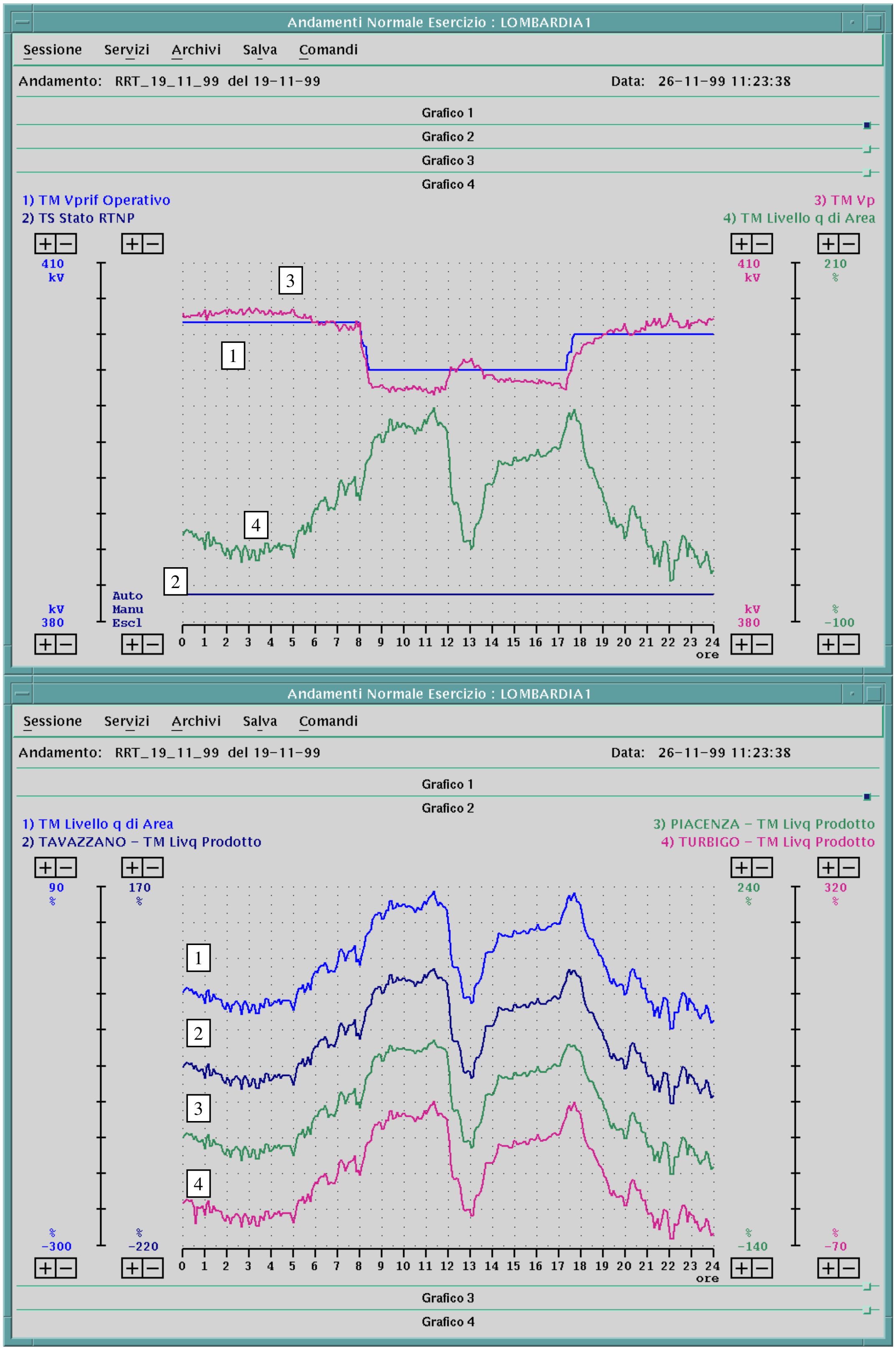
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Figure 6–14 *Baggio pilot node daily voltage profile with remote control of the Milan RVR (24-hour recordings).*

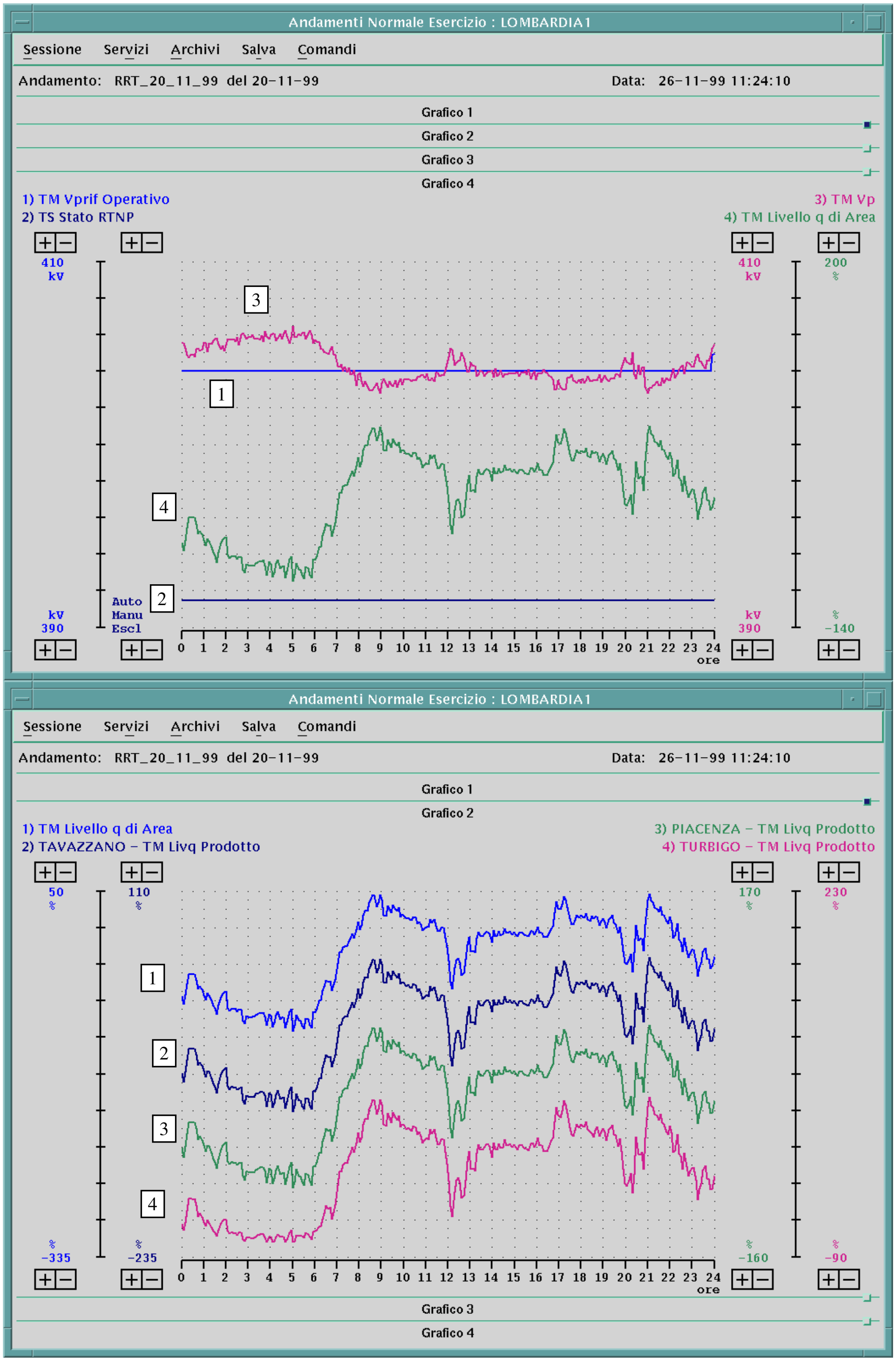

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Figure 6–15 *Baggio pilot node daily voltage profile with remote control of the Milan RVR (24-hour recordings).*

6.2.3 State of the Art Design and Evolution Perspectives

The commissioning and operating experience of both the REPORT apparatus (at the main Italian power plants) and the RVR workstations (at the regional dispatcher control centers) has demonstrated along the operation years all the positive aspects related to this solution, as well as provided possible functional and technological improvements. The main technical aspects assessed during the commissioning and monitoring activities are here shortly summarized, together with some general guidelines for the widespread application of the SVR solution together with some considerations on possible additional needs to face market uncertainties.

6.2.3.1 Technical Aspects Assessed During the Commissioning and Monitoring Activities

The REPORT local bus voltage regulation, achieved through the coordinated control of the reactive power of generating units, represents an effective functional characteristic, which is also useful for the power plant operators. Similarly, the control center operators recognize the advantages of having the same performance automatically achieved by the RVR at dispatcher level. Such features avoid unnecessary reactive power misalignments between the generating units of the same power plant as well as between power plants belonging to the same regulating area. Furthermore, the same feature provides a lot of diagnostic information on the power plant voltage regulation and area regulation systems, which may be usefully integrated with those already present within the control and supervision system of the power plants, or within the SCADA system at the control center level.

The REPORT apparatus relies on standard, high quality microprocessor and data acquisition boards, while the RVR system, running on a standard workstation, also allows high level of reliability. The operating experience has not revealed up to now significant problems due to transducers, boards or computer failures. Equipment updates towards more advanced microprocessors represents a relatively easy option and opportunity, which could enhance the capabilities of the overall coordinated voltage control application.

The functional design of both the REPORT and RVR systems, is based on quite conventional linear MIMO control algorithms with a certain degree of self-tuning functionality (capable, for instance, to adapt the regulation parameters according to the present control configuration of both the power plants and the regulation areas). They also use a lot of MMI facilities to manage the configuration, operation and supervision of the various apparatus, in a fast and relatively easy way, allowing the fast training of the power plant and control center personnel.

6.2.3.2 General Remarks about the Impact of the Global System Application

The largest amount of the reactive power resources for network control has been observed to come from generating units, which apparently do not gain any local advantage. Therefore the REPORT installation impact should not be considered marginal just because the power plant owners initially declare to be not interested in its application.

Another aspect of the closed-loop coordinated voltage control, attained with RVR, is the different philosophy that the Regional Dispatcher must adopt, as regards power system voltage and reactive power operation. Under the old, manual voltage control, the Regional Dispatcher demands more or less reactive power from the power plants by phone or by daily plans. With the RVR apparatus, the dispatcher fixes the voltage of the area pilot node and the generated reactive powers will assume the values that are needed to obtain the desired voltage.

This improved form of network voltage control can be achieved thanks to the RVR and REPORT control actions. In fact, RVR sends orders to REPORT that automatically drives the units to produce the reactive power needed to obtain the desired voltage in the HV network, while maintaining the units inside their over-excitation and under-excitation limits.

The application of a coordinated voltage control solution calls for a REPORT-like power plant control apparatus and a RVR-like control center regulation system, which are currently not available in the market. As a consequence, the coordinated voltage control application has up to now been proposed only by utilities, which have taken charge of the entire control system project and for certain aspects of the practical development and implementation of the control apparatus. External manufacturers are used but must build equipment on hardware following detailed project specification.

Not all the utilities have the internal resources and/or technical competence, or are able to manage efficiently external resources, involved in designing and development of control apparatus. The growing interest of the utilities and of the manufacturers on this topic will possibly establish a new market, in which the manufacturers could obtain the know-how from the utilities with more advanced technology.

6.2.3.3 Simple Guidelines for Promoting the Global System Application

When the production and network operation are jointly managed by the same utility this facilitates the successful implementation of a new hierarchical control system: the Network Operation Department, with the collaboration of internal or external research groups, can elaborate the coordinated voltage control proposal and specify the detailed control system, its architecture and the functional needs of its components at the various levels.

Regarding the power plant applications, the Production Department typically follows the REPORT provisioning and involves the internal resources for research, control apparatus design, specification and software code development. In this way REPORT can be designed with the necessary detail, also taking into account the ability of the potential manufacturers further improve the hardware and software components. The subdivision of the roles between operation and production allows pursuing the application, and also gives to the production people the opportunity to play an important role in the project. The success of the REPORT application is not however completely guaranteed, for it depends on the acceptance this new control apparatus will receive from the power plant personnel, based on its performance and reliability. In fact, power plant operators are in a position to switch off whatever control apparatus does not perform well in their opinion.

A simple guideline for promoting inside a utility the multilevel control solution is to start an experimental application of REPORT to a given power plant. This will certainly be able to show significant benefits due to the voltage support of the local HV network, when the RVR is not available, and in a larger extent, when the RVR will take the control of the power plant. This progressive spreading, area by area, of the RVR and REPORT applications with the consequent recognition of the growing benefits to the network voltage quality, is one of the suitable ways for reaching the general application of the multilevel control solution up to the installation of NVR and LMC at the national/utility control center. The organization needed for the REPORT and RVR application project usually involves the power plant and control center technical groups, the designers of the apparatus, and also special teams for telecommunication, measurements and tests. Furthermore, the installation of the REPORT and the related AVR modifications must be coordinated with the planned maintenance stops of the power plant units. The RVR installation and commissioning does not require stopping any of the units in the power plant.

Regarding the REPORT and RVR maintenance, an adequate training of power plant and control center personnel is needed. The higher the autonomy of the maintenance personnel, the lesser the need for external manufacturers. After the power plant and control center commissioning and the training for operation, the plant and dispatcher operators will increasingly recognize REPORT and RVR as very valuable instruments for maintaining both the pilot node voltage profile and the regulating units inside their thermal limits.

The improved system performance will eventually persuade operators to leave the excitation control function under the REPORT and RVR automatic regulation without any worries. After the power plant and regional dispatcher application, it will appear obvious to the properly trained network operators that REPORT and RVR, optimally coordinated by NVR and LMC, really allow an effective control of pilot nodes voltages, through the full and uniform exploitation of the power plant units, which share the same percentage effort with respect to their own thermal limits, without any dynamic exchange of reactive power among the units themselves. These described improvements to voltage control and reactive power coordination will also bring economical benefits to network operation.

6.2.3.4 Possible Additional Needs to Face Market Uncertainties

The coordinated voltage control aims at improving the security margins and obtaining a better system voltage profile, with an adequate distribution of the reactive resources in the different areas. This renders the system more robust to face possible perturbations caused by contingencies or by significant deviations of the loads from the expected values. This control structure exploits the possibility of achieving the above mentioned goals by means of a low number of signals and controls, requiring therefore a reduced amount of investments.

The on-going liberalization of the Italian electricity market puts in discussion the need of a coordinated voltage control. In reality it is easy to demonstrate that the adoption of such a control, originally designed for the management of the previously vertically integrated Italian system, is compatible with the new structure of the electric industry and market. Moreover, the superior performances of power system operation, achieved with the adoption of secondary and tertiary voltage regulation as compared to the simple local control by the primary voltage regulation, may be also demonstrated in the new environment.

The above comments are a result of some Italian on-going research projects, which are presently making use of some performance indicators to take into account the real losses in the transmission system, the global margin of reactive power available from the generation units, the distribution of the reactive power in the different areas, the attainment of operational constraints. Once suitable metrics are defined, a suitable procedure will compare the performance of the system with the coordinated voltage control in full operation, under partial operation or with only the primary control.

The first considered scenario may be derived with the methodology which GRTN, the Italian ISO, is planning to employ for scheduling the AVR setpoints, fixed by one-day-ahead OPF runs. This procedure resulted in an operating point that can be sub-optimal, due to the difference between the forecasted and the actual load. Moreover, the system operator often does not completely adopt the result of the OPF, preferring to set some voltages or some reactive power levels based more on his practical experience than on a mathematical optimization procedure. Based on the same day-ahead load forecast, the evolution of the system in such a scenario has been simulated with the coordinated voltage control in operation. Using the voltage set points for AVRs and pilot buses, determined by the day-ahead OPF run, the real system operating point was simulated by merging the above setpoints and the actual values of real and reactive loads, different from those forecasted.

The results of these more recent investigations show that the presence of the coordinated voltage control provides an operating point that is more robust against perturbations, such as load forecast errors, or grid contingencies. The operation robustness given by the coordinated voltage control is very important in the presence of an electricity market where, due to economic strategies that can be very different from technical strategies, it is more and more difficult to forecast which generators will produce according to the merit order. Having a higher level of robustness increases the overall reliability of the electric system in the presence of market uncertainties and therefore represents a strong incentive towards a centralized and coordinated form of network voltage control.

6.3 The Belgium Control System Field Test Results

Belgian Tertiary Voltage Control (TVC) has been operational since 1998 as described in [6-1]. The Belgium accumulated experience on TVC is summarized below:

- Robust State Estimation (SE) is absolutely essential for optimized coordinated voltage control;
- Excellent TVC convergence robustness (> 95 %) when State Estimation is reliable;
- Stable voltage profile: 24 hours a day, 7 days a week, within 2 % voltage margin all over the transmission grid;
- Stable transmission voltage ensures a good subtransmission voltage with less voltage controlling actions: less tap changes on LTC injectors to subtransmission grid, less switching of capacitor banks in subtransmission grid;
- As long as traditional practices suffice to maintain acceptable voltages, acceptance by grid operators of a new tool for optimization beyond strict technical requirements depends on their individual motivation;
- TVC minimization of the sum of the squares of generator reactive productions implicitly implies in keeping the transmission voltages as high as possible. Consequently, resulting active losses are only slightly higher than obtained with an active loss minimizing objective function. The difference is typically of the order of the computational accuracy and far smaller than available measurement accuracy. This means a very small extra operating cost in order to achieve a much better generator reactive reserve spread and increased voltage stability margins.

References

[6-1] J. Van Hecke, N. Janssens, J. Deuse, GF. Promel, “Coordinated Voltage Control Experience in Belgium”, CIGRE Session 2000, paper 38-111.

Chapter 7

Computer Tools for Analysis and Design Including Typical Simulation Results

7.1 Introduction

This Chapter provides an overview of existing programs and analysis methods for studying technical aspects associated with the coordinated voltage control in transmission networks.

Sections 7.2 and 7.3 describe the representation of secondary voltage control in power flow and dynamic studies using the software package ASTRE, developed at the University of Liège, Belgium.

Section 7.4 describes the application of four software tools for the study of issues related to the structure and to the static and dynamic performance of controllers.

Section 7.5 describes a set of software simulation tools for voltage stability analysis developed at Iowa State University.

Section 7.6 describes the dynamic performance of a Secondary Voltage Regulator and a Coordinated Secondary Voltage Regulator implemented in France.

No commercially available program was intentionally excluded from this Chapter. The program descriptions provided here are based on the availability of information and do not constitute an endorsement.

7.2 Secondary Voltage Control Representation in Power Flow Studies

7.2.1 Introduction

This and the following section describe how secondary voltage control can be represented in power flow and dynamic studies. The examples are taken from ASTRE, the voltage stability and security analysis software developed at the University of Liège, Belgium. This software is presently used by transmission system operators in France, Canada, Belgium and Greece.

The application of ASTRE to the French system requires the ability to model the various secondary voltage controllers in operation in this system [7-1]. This includes a representation of the "standard" proportional-integral (PI) controllers as well as the more recent (sensitivity matrix-based) controller [7-2, 7-3] in operation in the Western regional control center of RTE, the French transmission system operator. ASTRE is now incorporated to GAMME, the real-time security analysis software used in RTE control centers.

7.2.2 "Standard" Secondary Voltage Control

7.2.2.1 Principle

Simply stated, the effect of secondary voltage regulation is to keep the voltage of each pilot bus at its specified setpoint value, while sharing the total reactive power generation of the corresponding zone over the various participating generators according to participation factors. Typically, each participation factor is proportional to the reactive power capability of the corresponding generator.

A simple way to account for this regulation in power flow computations consists of adding a fictitious synchronous condenser at each pilot bus and switching all the (real) generators in the zone to the PQ type, as explained hereafter. The procedure is sketched in Figure 7-1.

The fictitious synchronous condenser produces no active power and holds its terminal voltage to the voltage setpoint of the pilot bus. Initially, all the reactive powers of the participating generators are set to zero.

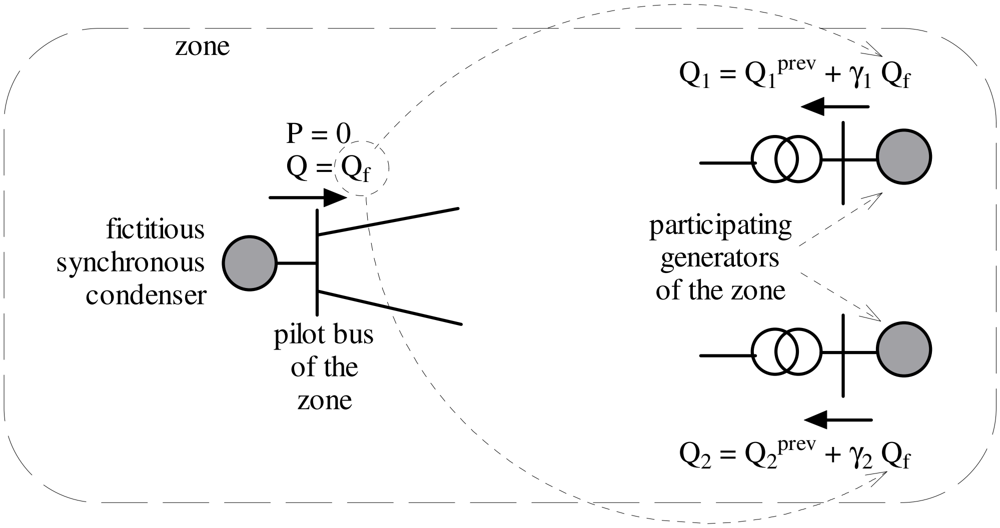

Figure 7-1 *Handling of secondary voltage control in power flow computations.*

Once the power flow iterations have converged (mismatches below some tolerance), the reactive power produced by the synchronous condenser is computed and distributed among the generators involved in the pilot bus voltage control, according to the specified participation factors. Thus, the new reactive power Q_i specified for the i-th participating generator is taken as:

$$Q_i = Q_i^{prev} + \gamma_i \; Q_f \qquad (7.1)$$

where Q_i^{prev} is the previously specified value (initially zero), Q_f is the reactive production that has appeared on the fictitious synchronous condenser and γ_i is the participation factor of the *i*-th generator.

Once the reactive productions of the PQ generators have been adjusted according to (7.1), new power flow iterations are performed. Ideally, the resulting power flow solution should be such that $Q_f = 0$, i.e. the fictitious synchronous condenser should produce no reactive power any longer. In practice, however, due to nonlinearities, it still produces some power, but significantly less than at the previous step. The new reactive production is thus redistributed according to (7.1) and the procedure is repeated until Q_f becomes negligible. Once this holds true, the fictitious synchronous condenser can be disconnected without changing the system state.

The convergence of the above iterative procedure has been found quite satisfactory. In fact, the handling of the pilot node as a PV bus helps convergence and compensates for the absence of voltage control by the participating generators.

In ASTRE, the fictitious synchronous condensers are attached automatically to the pilot buses when reading the secondary voltage control data, and are not shown in the final power flow results. The procedure is thus totally transparent to the user.

7.2.2.2 Handling of Limits

While adjusting the generator reactive productions, the following limits are checked and enforced:

- Lower and upper reactive power limits: if a limit is violated, the reactive production is set at this limit and the generator does no longer participate in secondary voltage control;
- Lower and upper voltage limits: if a limit is violated, the generator is switched from PQ to PV type, with V equal to the limit. This generator does no longer participate in secondary voltage control;
- If a zone has no participating generator any longer, the fictitious synchronous condenser is removed (the pilot bus voltage is no longer controlled).

7.2.2.3 Example

As an example, the trace of a power flow run on the French system is given in Figure 7-2. The figure shows the maximum active and reactive power mismatch at each iteration, in MW and Mvar, respectively.

```
  iter    max mismatches :  MW       Mvar

   1                   39220.0   182292.0
   2                    6441.8    32875.4
   3                     119.1      745.5
   4                       0.8        2.9
    secondary volt ctrl
   4                       0.8      118.0
   5                       0.4        2.5
    gener C.RHOH 1             upper V limited
    gener C.RHOH 2             upper V limited
    gener C.RHOH 3             upper V limited
    secondary volt ctrl
   5                      15.8      142.0
   6                       0.2        1.9
    no gener left to hold voltage at pil pt SISTES61
    no gener left to hold voltage at pil pt ROUGES71
    secondary volt ctrl
   6                       0.2      126.5
   7                       0.1        1.0
    gener BOLLEH 2             upper Q limited
    gener BOLLEH 3             upper Q limited
    gener BOLLEH 4             upper Q limited
    secondary volt ctrl
   7                       0.1       23.5
   8                       0.0        0.1
    gener BOLLEH 1             upper Q limited
    secondary volt ctrl
   8                       0.0        4.1
   9                       0.0        0.0
    secondary volt ctrl
   9                       0.0        1.2
  10                       0.0        0.0
    secondary volt ctrl
  10                       0.0        0.3
  11                       0.0        0.0
```

Figure 7-2 *Trace of a power flow run with secondary voltage iterations.*

After adding the fictitious synchronous condensers and setting the participating generators to the PQ type with Q=0, standard Newton-Raphson iterations are performed. After 4 iterations, the reactive power equations are solved within the specified tolerance. At this point, the productions of the fictitious synchronous condensers are distributed among the participating units, which creates new reactive power mismatches. Starting from the previous solution, 2 Newton-Raphson iterations are enough to reach the specified tolerance again. The procedure is repeated in the same way until the production of all fictitious synchronous generators are negligible. Seven secondary voltage control adjustments are needed, for a total of 11 Newton-Raphson iterations.

In the example shown in Figure 7-2, three generators become upper voltage limited, four become upper reactive power limited and two zones are removed from secondary voltage control because all their participating generators are limited.

7.2.3 Coordinated Secondary Voltage Control

The coordinated secondary voltage control is implemented in power flow calculations as follows:

- A standard power flow computation is first performed until convergence is reached;
- At the obtained solution, the C_v, C_q and C_{vs} sensitivity matrices are computed. A general sensitivity formula based on the transposed inverse Jacobian is used to this purpose [7-4]. Each column of the above matrices is obtained successively, by solving a sparse system;
- A quadratic programming problem is then solved to obtain the generator voltage corrections, while obeying constraints on:
  - The generator reactive powers;
  - The generator terminal voltages;
  - The pilot bus voltages;
  - The sensitive bus voltages;
  - As the steady state corresponding to completed secondary voltage regulation is sought, the control gain α of this regulator (see Eq. (7.2) in Section 7.3.2) is set to 1, i.e. the whole voltage correction is applied.
- The generator voltages are then updated and a new power flow computation is performed;
- The procedure is repeated until no change in generator voltages occur any longer. However, in these successive loops the sensitivity matrices are not updated, unless some generators reach their reactive power limits.
  - If the above optimization problem is found infeasible (in very stressed operating conditions), an attempt is made to solve it without the pilot and sensitive bus constraints. If this optimization also fails, secondary voltage control is ignored.

Since the standard and coordinated secondary voltage controls coexist in the RTE system, both are handled in the same power flow computation.

7.3 Secondary Voltage Control Representation in Dynamic Simulations

7.3.1 Introduction

There is, in principle, no obstacle to the incorporation of secondary voltage control models in dynamic simulation software. The only limitation may relate to the fact that this controller involves several generators (as secondary frequency control also does). Also, its discrete-time nature may prevent variable step size algorithms from increasing the steps when the fast transients have died out.

Secondary voltage control reacts in the long-term time scale (i.e. over several minutes after a disturbance). Besides, it is not required to act in very degraded system conditions. This makes the so-called *Quasi Steady-State* (QSS) simulation attractive for the simulation of situations involving secondary voltage control.

QSS simulation is a fast time-domain method well suited to the analysis of long-term voltage stability phenomena [7-1, 7-6, 7-7, 7-8, 7-11]. The QSS approximation relies on time-scale decomposition. The essence of this method is that faster phenomena are represented by their equilibrium conditions instead of their full dynamics. This greatly reduces the complexity of the resulting model and hence provides the computational efficiency required to meet the constraints of on-line or interactive applications. In addition, the amount of additional data required by the QSS model is moderate, so that data collection, validation and maintenance is not a big issue.

This method, which has been previously validated with respect to detailed time simulation [7-7], offers better accuracy and richer interpretations than simple methods based on power flow equations. For instance, in unstable cases, the area in trouble is automatically spotted, while complementary diagnosis tools can be run on the unstable system trajectory in order to identify appropriate remedial actions.

Thus, the method offers an interesting compromise between the computational efficiency of static methods and the above advantages of time-domain based approaches.

Under the QSS approximation, the short-term dynamics of a synchronous generator, its governor and its Automatic Voltage Regulator (AVR), are replaced by three nonlinear algebraic equations [7-11]. The latter account for the generation saturation, the AVR steady-state gain and the speed droop. These nonlinear equations are solved at each time step, together with the network equations. Loads, on the other hand, are typically represented as voltage dependent active and reactive powers at the Medium Voltage (MV) buses behind HV-MV distribution transformers. Load power restoration comes from the Load Tap Changers (LTCs) operating in such transformers, or from the load dynamic behaviour (for instance, in thermostatically controlled loads).

QSS simulation focuses on the long-term dynamics of LTCs, field current limiters, automatically switched shunt compensation, secondary voltage control, protecting devices, etc. This simulation takes into account the (initial and subsequent) delays between transformer tap changes, the delays before a synchronous machine is switched under constant field current, etc.

7.3.2 Standard Secondary Voltage Control in QSS Simulation

The standard secondary voltage control is implemented in ASTRE as follows:

- A Proportional-Integral (PI) controller produces the so-called *level* signal:

$$N = \alpha\left[\int_{-\infty}^{0} (V_p^o - V_p)dt + \int_{0}^{t} (V_p^o - V_p)dt\right] + \beta(V_p^o - V_p) \qquad (7.2)$$

  where V_p is the pilot bus voltage, V_p^o the corresponding setpoint and α (resp. β) is the proportional (resp. integral) gain. N is dimensionless and bounded by *–1* and *+1;*

- The i-th generator of the zone receives a reactive power production setpoint equal to $N\, Q_i^{nom}$ where Q_i^{nom} is the nominal reactive power capability of the generator;

- In the i-th generator, a local controller acts on the AVR voltage setpoint in order for the reactive production to track the above setpoint. This control is discrete by nature and based on the error signal $\varepsilon = N\, Q_i^{nom} - Q_i$ with the following logic:
  - ➢ If ε becomes larger than a threshold $\varepsilon_{APR}\, Q_i^{nom}$ for some time τ_{APR} , the AVR voltage setpoint is increased by ΔV_{APR};
  - ➢ If ε becomes smaller than a threshold $-\varepsilon_{APR}\, Q_i^{nom}$ for some time τ_{APR} , the AVR voltage setpoint is decreased by ΔV_{APR};
  - ➢ If required, several successive voltage corrections are made. However, to avoid stressing the machine, the τ_{APR} delay is obeyed in between two successive corrections.

Thus, once the system has reached equilibrium, ε is zero (in practice, negligible) and one has: $Q_i = N\, Q_i^{nom}$. By summing over the generators, one easily checks that the participation factor γ_i of §7.1.2.1 is $Q_i^{nom} / (\Sigma_j\, Q_j^{nom})$ while $N = (\Sigma_i\, Q_i) / (\Sigma_j\, Q_j^{nom})$.

In addition, generator voltage increases (decreases) stop as soon as the terminal voltage exceeds some threshold V^{max} (falls below some threshold V^{min}), or the field current is limited.

Optionally, the level N can be computed taking into account the error introduced by the coding of the pilot bus voltage over a limited number of bits and smoothing the error signal $V_p^o - V_p$ over three time samples in the proportional term of (2).

Secondary voltage control also aims at controlling shunt compensation within each zone. The objective is to keep the generator reactive power productions within some limits, in particular to maintain dynamic reactive power reserves to face contingencies. To this purpose:

- A monitored bus is attached to each controlled shunt element. The voltage at this bus is used to decide whether the compensation should be switched in or out. Typically, compensation is connected to HV sub-transmission buses and the monitored bus is at the EHV transmission level;

- When the level N exceeds some threshold N_c^{max}, compensation is increased (by adding capacitors or removing inductors) so as to relieve generators. A single step of compensation is changed at a time, with a delay τ_{comp} in between two changes, until the level goes back below N_c^{max};

- Within the zone, the modified shunt is the one with the lowest monitored voltage;

- A similar procedure applies to the case where N becomes lower than a threshold N_c^{min};

- Provision is made for the case where no generator participates in the secondary voltage control (because they are all tripped, or field current limited).

7.3.3 Illustrative Examples

The illustrative examples hereafter are taken from the RTE system.

Figure 7-3 shows the time response of a generator terminal voltage, as obtained by QSS simulation, following a disturbance applied at t= 10 s. The two curves relate to two different values of the proportional gain α. The figure shows that an appropriate choice of α can minimize the initial voltage variation, which is opposite to the final one, due to the reactive power control loop present on each generator.

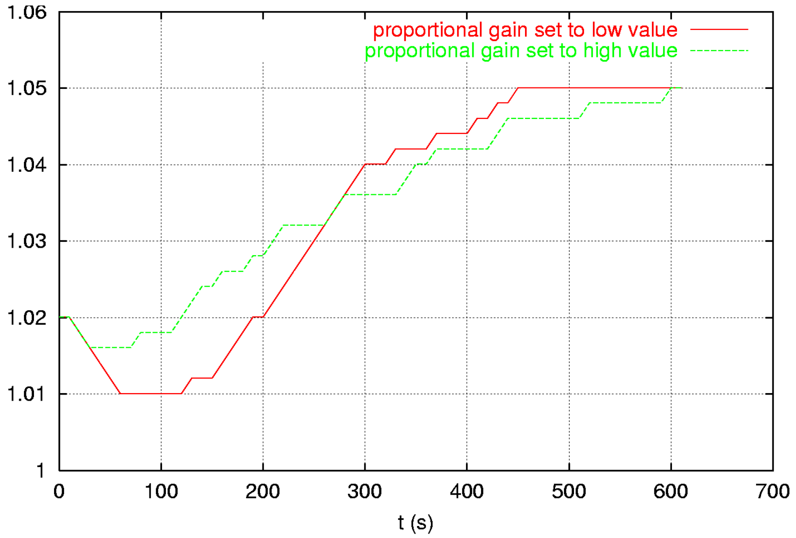

Figure 7-3 *Time evolution of a generator voltage (in pu) to a disturbance.*

Figure 7-4 illustrates the determination of a secure operation limit for voltage security analysis purposes [7-7, 7-8, 7-11]. The various curves show the system response to the same contingency (applied at t= 10 s) but for different levels of "system stress". The four loading scenarios were obtained by increasing the system load and rescheduling generation accordingly. The objective is to compute the maximum pre-contingency loading for which the system can withstand the contingency. The pre-contingency stressed states are computed by means of a power flow, taking into account the (static) effects of secondary voltage control, as described in the previous section. The system responses to the contingency are computed through QSS simulation. The four curves relate to: a) the base case situation (no stress), b) the system stressed at the maximum level (a value beyond which limits need not be computed), c) the marginally unstable case and d) the marginally stable case, which is the desired solution.

The curves show the voltage at a pilot bus. In the base case, the pilot bus voltage recovers to its pre-contingency value owing to secondary voltage control. In the other three cases, the reactive reserves of the generators are already exhausted in the pre-contingency situation, as can be seen from the lower initial voltage.

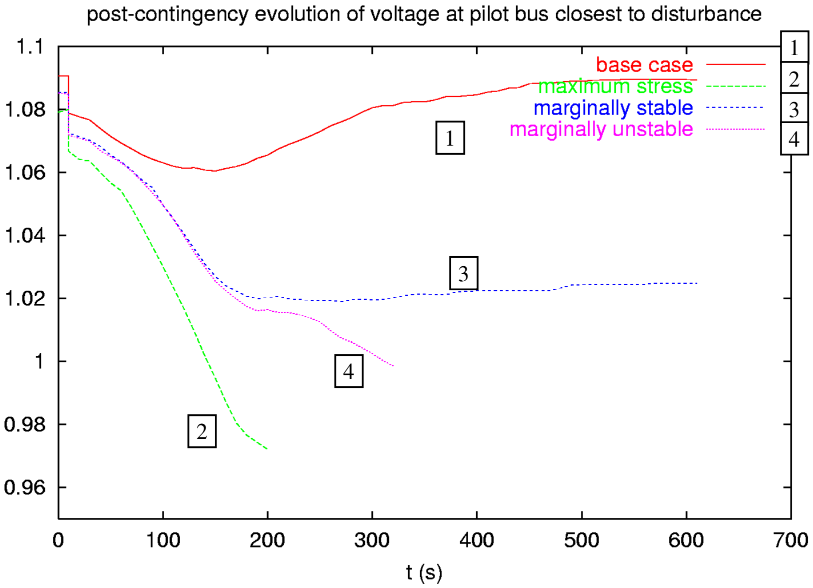

Figure 7-4 *Time evolution of a pilot bus voltage (in pu) following a disturbance, for 4 levels of pre-contingency stress.*

Such computations are performed in real-time [7-8, 7-9].

7.3.4 Coordinated Secondary Voltage Control in QSS Simulation

The coordinated secondary voltage control is also implemented in ASTRE. The following aspects are noteworthy:

- The C_v, C_q and C_{vs} sensitivity matrices are computed from the Jacobian of the long-term equilibrium equations, also used to diagnose voltage instability [7-8, 7-11];
- These matrices are computed when initializing the QSS simulation and are updated when a generator is tripped or is field current limited or when a network branch is tripped;
- The controller acts at regular time intervals τ on the AVR voltage setpoints of the participating generators. The AVR voltage droops are taken into account in QSS simulation;
- The reactive power capability of each generator is computed from the overexcitation limiter and the synchronous generator data;
- The quadratic-programming optimization problem involves the constraints enumerated in Section 7.1.3 as well as constraints on the variations of generator terminal voltages;
- The dynamics is improved by using predicted values of pilot bus voltages, generator voltages and reactive powers;
- The controller can also act on shunt compensation; the logic is similar to the one described in Section 7.2.2.

7.4 Integration of Software Tools for Coordinated Voltage Control

The studies performed by CESI (Centro Electtrotecnico Sperimentale Italiano) on the coordinated voltage control on transmission networks have been carried out using state-of-art computer tools for: a) performing short-circuit analysis and sensitivity computation (SENSIT); b) design and validation of power system controls (EASY5x); c) computing steady-state power-flow for reactive power dispatching and optimization (CRESO); d) dynamic analysis and simulation of the overall network (SICRE).

These tools have proven to be well suited to the required analyses and the good agreement between their results has increased the overall reliability of the performed studies.

7.4.1 Software Tools Used by CESI

7.4.1.1 SENSIT

SENSIT (*SENSITivity analysis* from CESI) computes the sensitivity coefficients needed for the determination of pilot nodes and control generators to be used in coordinated voltage control studies.

The pilot nodes selection is based on the *short circuit level matrix* and on its suitable reordering: the short circuit level of each pilot node has to be sufficiently high, so that its voltage magnitude is representative of the voltages in all the other busses in the area. To this aim all the grid nodes with a short circuit power higher than a certain user-defined level are first selected. It is also necessary to perform another selection based on the *electrical coupling between areas*, which has to result in a value lower than another user-defined threshold.

For the determination of control generators, the *sensitivity matrix* is used instead, because it contains information about the reciprocal coupling between the generators and the grid nodes (in particular the pilot nodes) and allows the selection, among the candidate control generators, of those mostly capable of producing the strongest voltage variation at the pilot node for a given reactive power variation.

Table 7-1 *An example of areas, pilot nodes and control generators determination by SENSIT.*

Pilot Node			Control Generators
1	CASANOVA	Piemonte	Chivasso, Entraque, Vado T., Venaus, Trino
2	S.FIORANO	Lombardia	Edolo, S.Fiorano
3	S.MASSENZA	Trentino	Cimego, Gargnano, Lana, S.Massenza, Torbole
4	REDIPUGLIA	Friuli	Monfalcone
5	BAGGIO	Lombardia	La Casella, Piacenza, Tavazzano, Roncovalgrande, Turbigo
6	OSTIGLIA	Lombardia	Ostiglia, Sermide
7	PORTOTOLLE	Veneto	Portotolle, Fusina, Portocorsini
8	POGGIO A C.	Toscana	Bargi, Piombino, S.Barbara, La Spezia
9	S.LUCIA	Lazio	Montalto, T.Valdaliga N, T.Valdaliga S
10	VILLANOVA	Abruzzo	Montorio, Provvidenza, S.Giacomo
11	S.SOFIA	Campania	Presenzano
12	BRINDISI	Puglia	Brindisi N, Brindisi S.
13	ROSSANO	Calabria	Rossano, Mercure
14	SORGENTE	Sicilia	S.F. Mela
15	BELLOLAMPO	Sicilia	Termini
16	MELILLI	Sicilia	Anapo, Priolo G.

7.4.1.2 EASY5x

EASY5x (*Engineering and Analysis System* from Boeing Computer System) software is used to *model and simulate dynamic systems* containing hydraulic, pneumatic, mechanical, thermal, electrical and digital sub-systems; a complete set of control system modeling, analysis and design features is included. Systems are quickly modeled with functional blocks (summers, dividers, signal generators, integrators, etc.) and/or with pre-defined components representing physical elements (pumps, gears, engines, etc.), as well as user-defined FORTRAN or C.

EAS5Yx is mainly suited for dynamic system modeling, nonlinear simulation, design and validation of control systems. It is an integrated computation environment, characterized by powerful computing and advanced graphical user interface, which allows:

- *To build the system model* by using standard blocks in predefined libraries, or user blocks defined by Fortran language programming, or built in macro-components libraries;
- *To check the modeling coherency* verifying the correct definition and observance of the interconnection rules between the system variables: such variables can be divided into input variables (or system parameter), state variables (characterized by ordinary differential or finite differences equations) and output variables (computed through algebraic equations);
- *To achieve an ordered and explicit formulation of the equations* describing the mathematical model. An executable model is then created, consisting of a Fortran routine with the equations of the overall system. This operation may reveal the presence of possible implicit or algebraic loops, which have to be necessarily removed, for instance, by introducing high speed filters;

- *To produce the object code and to control the execution flow*, by using the Fortran 77 compiler and the source level debugging features, directly executable within the Easy5x session;

- *To make the Fortran routines* for the execution of the following analysis procedures:
  - ➢ Steady-state: search of an equilibrium condition of the system, characterized by a state derivative vector with predefined minimum norm;
  - ➢ Simulation: computation of the transient responses of state and output variables of the system following perturbations in some input variable of the system. Different type and order numerical integration methods are available, either of the explicit or implicit type, whose evolution can be controlled through interactive graphical primitives (slider, button, strip-chart);
  - ➢ Linear model generation: determination of the linearized system model, around a steady-state condition, and evaluation of transition, input and output matrices, as well as of the eigenvalues and eigenvectors of the linearized system, which determine the dynamic modes present in the system transient responses following small perturbations;
  - ➢ Transfer function and frequency response: computation of the linearized system matrices which define an input-output transfer function (from a certain input to a determined output) and plotting of the frequency response curves;
  - ➢ Root locus: plotting of the locus in the complex plane of the linearized system eigenvalues, while changing the values of a particular system parameters;
  - ➢ Eigenvalues sensitivity: computes the sensitivity of linearized system eigenvalues, to changes in the values of specified system parameters;
  - ➢ Small-signal stability margins: determination of the maximum changes that can be applied to a particular system variable without causing the destabilization of the linearized system, which is equivalent to placing a system eigenvalue (real eigenvalue or complex-conjugate pairs) over the imaginary axis.

CESI developed a *macro-components library*, oriented towards the *simulation of electric power systems* (*Power System Library*). The library contains the dynamic models commonly used both within Enel and in the literature. The models allow for *the dynamic analysis of generation and transmission systems* with particular emphasis on the *design review and performance validation of control and regulation systems* (for instance AVR, speed-governor controls, secondary voltage regulation, automatic generation controls, etc). Such models have been used both for *short-term dynamics analysis* and *long-term dynamic network studies***.** The short-term analyses concern electromechanical rather than torsional stability problems, *design review and performance validation* of excitation control systems and of conventional or combined-cycle turbines governors. The long-term studies are mostly devoted to voltage instability and collapse phenomena or secondary and tertiary grid voltage regulation problems.

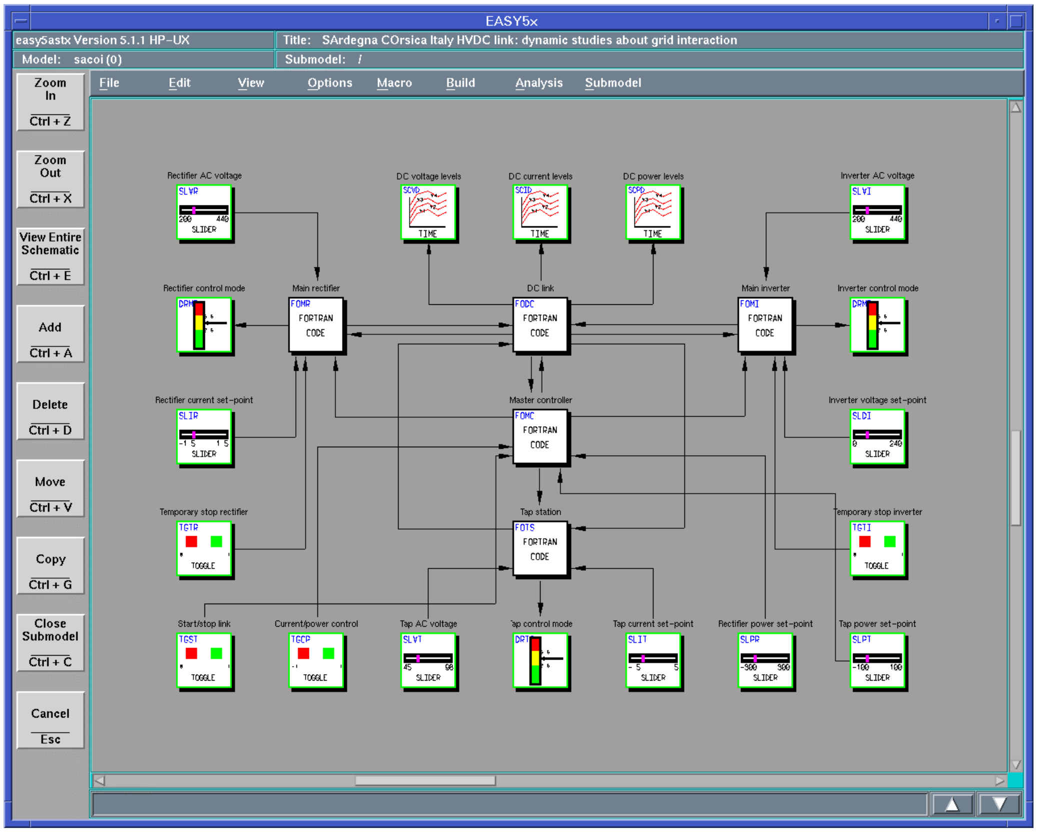

Figure 7–5 *The schematic diagram of an HVDC model in EASY5x.*

7.4.1.3 CRESO

CRESO (Network Calculation for Security Operation and Optimization from CESI) is an integrated software system that allows the simulation and analysis of a power network under steady-state conditions, as well as the optimization of the active and reactive power generation; Conventional power flow calculation and advanced functions for network studies are also available.

The main functions of the CRESO software are listed below:

- Power flow calculation (for complete network or study system plus external equivalents);
- Static security analysis;
- N-1 contingency analysis;
- Monitoring of thermal limits;
- State estimation;
- Active power redispatch;
- Reactive power redispatch;

- Voltage collapse margins;
- Computation of pilot node voltage references.

7.4.1.4 SICRE

SICRE (Interactive Dynamic Simulations of Electrical Networks from CESI) is a power system simulator covering different time-scale phenomena and modeling levels (grids, units, control systems and protections).

SICRE employs state-of-the-art models and algorithms and has a user-friendly interface, being a powerful tool to investigate the dynamic behavior of large power systems. SICRE *may perform the simultaneous simulation of electromechanical and long-term dynamics*: an automatic adjustment of the models, jointly with larger integration step, allows speeding up the simulation when the electromechanical phenomena and fast control loop dynamics have reached their new steady-state conditions.

The user may introduce perturbations or emulate actions either through the GUI facilities or in a pre-established scenario. The SICRE *highly interactive and user friendly GUI* allows the user to create and manipulate displays of the network diagrams, as well as send commands to the simulator engine. The reduced computation times, modularity, GUI effectiveness and user-friendliness make SICRE a very up-to-date simulator tool for the time domain analysis of power systems.

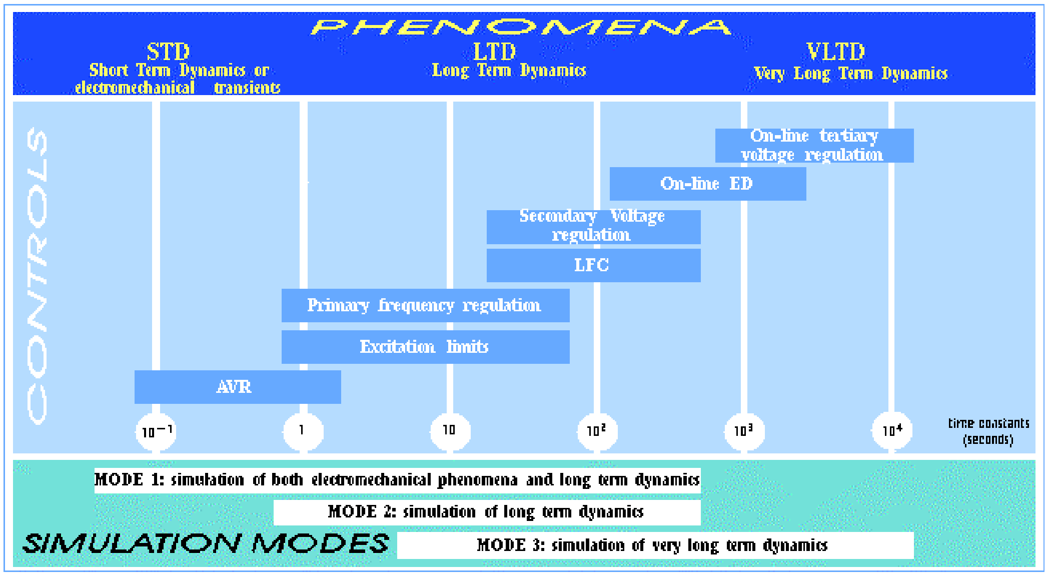

Figure 7–7 *The different time scale phenomena and models covered by SICRE.*

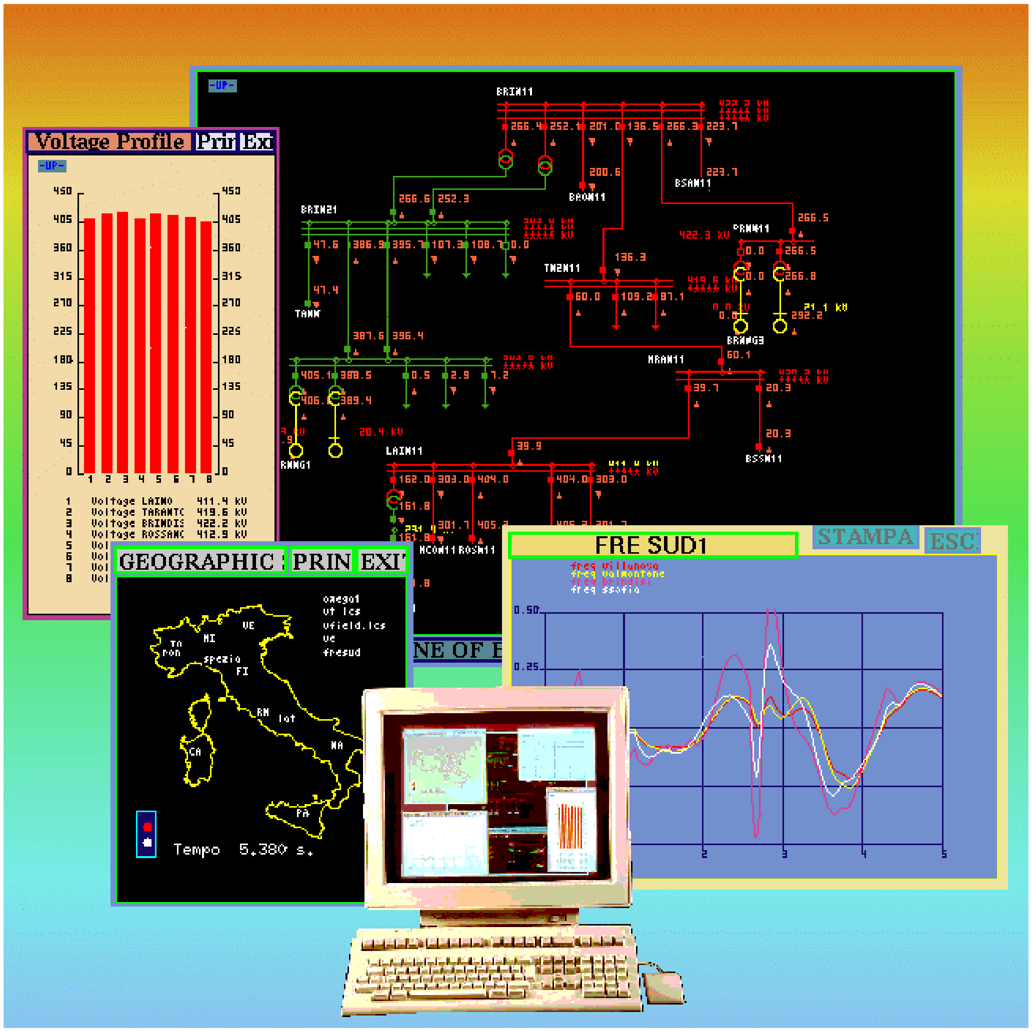

Figure 7–8 *The highly interactive and user friendly GUI of SICRE.*

7.5 Quasi-Steady State Simulator for the Design of a Knowledge-Based System for Supervision and Control of Regional Voltage Profile

A QSS simulator [7-10] was developed in Federal University of Rio de Janeiro (COPPE/UFRJ) following the ideas described in [7-11]. In a fast simulator, the electromechanical transients are assumed to be stable and neglected. Slow-acting voltage instability mechanisms, such as, LTC actuation and overexcitation limiters are thoroughly modeled.

This simulator was equipped with fuzzy logic routines to allow studying of a supervisory knowledge-based system for monitoring and control of regional voltage profile using Fuzzy Logic. Control strategies are defined by the system operators based on their experience and on off-line studies, which are translated into rules of a Fuzzy Inference System (FIS). The work focuses on long-term regional voltage control by power plants and synchronous condensers. The study system analyzed is the Rio de Janeiro (Rio) Area, an energy importing area constrained by voltage-related problems.

An introduction to a fuzzy inference system is given in Section I.1.1, but the results of the Rio Area study are described in Appendix I.

7.5.1 Fuzzy Inference System

Fuzzy Inference Systems (FIS) are methods for information processing dealing with uncertainty and vagueness based on the theory of fuzzy sets and fuzzy logic [7-5]. A FIS is based on set of rules of the form:

If *x* is *A*,	**Then *y* is *B***
Antecedent	Consequent

Where x and y are numerical variables and, A and B are linguistic variables, i. e., variables that assume linguistic values such as, HIGH, LOW, NOT TOO LOW, etc., which are defined by fuzzy sets and their membership functions.

Figure 7-9 shows the main elements of a FIS that is used in fuzzy logic controllers and signal processing applications. The FIS maps crisp inputs into crisp outputs. The four main elements are the rules, the inference engine, the fuzzyfier, and defuzzyfier. Description of the main elements is the following:

- *Rules*: is a set of rules as defined before;
- *Fuzzyfier*: determines the degree of membership of each input in the rule antecedent. If the antecedent has more than one component (proposition), the fuzzy operators AND (min) and OR (max) are used to combine the effects;
- *Inference Engine*: determines the degree of validity of the rule consequent and combines the results into the output fuzzy set. The principle assumes that "rules with a low membership degree in the antecedent must have small validity in the consequent";
- *Defuzzyfier*: determines a crisp output from a fuzzy set produced by the inference engine.

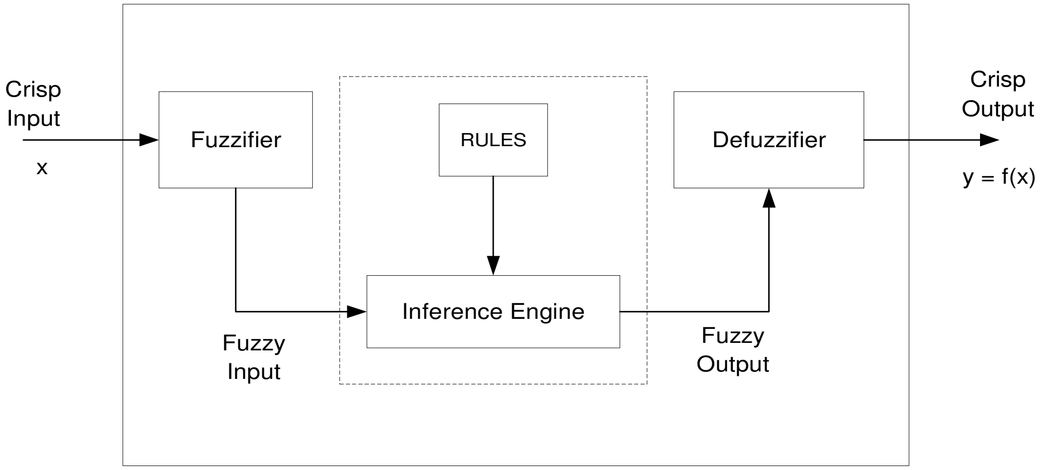

Figure 7–9 *Fuzzy Inference System.*

Once the rules have been established, a FIS can be viewed as a nonlinear mapping from a crisp input vector to a crisp output vector $y = f(x)$.

7.6 Iowa State University Based Simulation Tools

7.6.1 Overview

This section describes the simulation tools developed at Iowa State University that were modified to assess the beneficial impact of secondary voltage regulation schemes into voltage stability margins. The application of these tools on SVR assessment is also described. Part III of Appendix A of this report presents the simulation results on a 5 bus tutorial system introduced in this Appendix [7-12]. Direct Equilibrium Tracing Program (EQTP) is used to get the simulation results. The results presented verified the loadability margin improvement by the use of the SVR.

7.6.2 A Brief Review on Simulation Tools for SVR

There are three main aspects of Secondary Voltage Regulation: pilot bus selection, the control law and the decentralization problem. Different computer tools are needed to analyze these three aspects as described below.

7.6.3 Pilot Bus Selection

The pilot bus and generator selection is a large scale, nonlinear and combinatorial problem. No exact solution technique exists to address such a problem.

Pilot bus selection procedures reported in the literature are based either on simple rules [7-13, 7-14, 7-15] or on a linearized formulation [7-16, 7-17, 7-18] of the power flow equations. However, the interest of the secondary voltage regulation is most apparent when the system is working not far away from its transmission capacity limit. In such a situation a linearized model of the system is not appropriate, and the set of pilot buses that is selected using this linearized model may be far from optimal. It is therefore imperative to take into account the system non-linearity, so that full power flow equations are used [7-19]. The computation time is much increased by using this method, but it is still acceptable since pilot bus selection can be done offline.

The search procedure to select the best set of pilot buses is made up of two steps: a Greedy Algorithm to generate an initial set of pilot buses, and a comprehensive Global Search to improve the greedy selection. For any proposed set of pilot buses, we should solve the power flow for several different scenarios and consider different load models.

The Greedy Algorithm is a widely used optimal selection algorithm. It selects the pilot bus one at a time in a myopic fashion, i.e. given a subset of selected pilot buses, the next pilot bus to be selected is the load bus which produces the largest immediate improvement in the objective function, provided that such a load bus exist. The code for greedy algorithm and global search can be found in some mathematics tools [7-19]. It can be also included in the above power system software to achieve a comprehensive solution for pilot bus selection problem.

There are several search algorithms for the pilot bus selection [7-20], but they all rely on the information provided by the power flow software. Since the reactive power plays an important role in pilot bus selection, a full ac power flow is needed.

The power flow software and other search algorithm software can also be combined to generate new software that is useful for the pilot buses selection in Secondary Voltage Regulation. When using such kind of software, we should consider the computation time and accuracy requirements carefully.

In some European countries, the pilot bus selection part has been integrated into the Tertiary Voltage Control Scheme. The main target of the Tertiary Voltage Control is to achieve safe and economic system operation and optimize the nationwide voltage map. The computer tools for such kind of optimization (including the pilot buses selection) still need to be further developed.

7.6.4 The Control Law

The control law that is being proposed in the recent literature [7-3, 7-12, 7-18, 7-19] basically solves a quadratic programming problem at every control step. The objective of this quadratic programming problem is not only to keep voltage magnitude of pilot buses at their respective reference values, but also to achieve a balanced reactive power loading of the control generators. There are several sensitivity matrices involved in the objective function. One can either get such sensitivity information from power flow software or some other way.

The major goal of the computer tools used here is to solve a quadratic programming problem. The sensitivity information is very important for the efficiency of the control action. How to get the correct sensitivity information is still in the developing stage.

Simulations on practical systems are greatly needed to determine the weighing factors for generator reactive power output and pilot bus voltage. Also how to realize the optimal control law is a big problem. Different control modules can be adopted here. In order to decide which kind of control schemes to choose, simulations on the practical system are necessary.

7.6.5 The Decentralization Problem

It is not practical to implement the Secondary Voltage Regulation in a centralized manner. As a consequence, the division of the system into decentralized control areas has to be made minimizing the adverse effects of the generators of each area on the pilot bus voltages of the others. The procedure developed for this purpose is still based on the analysis of the sensitivity matrix that relates the changes of the voltages of control generators to the changes in the pilot bus voltages [7-18]. Again we can see the utilization of the power flow software in this field.

7.6.6 The Simulation Issues

Each of the above problems can be studied separately or combined together as a comprehensive problem to achieve certain objective. We can either do simulation on them separately or combine them into a comprehensive problem. There is some interdependency among these three parts, especially the first two aspects. The combination of pilot buses selection and control law is very important to make the control action more efficient.

7.6.7 Simulation Tools

The Iowa State University (ISU) simulation tools include:

- Direct Equilibrium Tracing Program (EQTP);
- Unified Margin Boundary Tracing (UMBT);
- Optimal Margin Boundary Tracing (OMBT);
- Local Parameterization Based Time Domain Simulation.

7.6.7.1 Direct Equilibrium Tracing Program (EQTP)

EQTP can trace the load margin without rebuilding system dynamic Jacobian and check its singularity [7-21]. It also eliminates all the unrealistic assumptions for the slack bus and PV bus. The program produces enhanced system stability information and accurately implements the system limits. The Secondary Voltage Regulation model has been included in this program to simulate the effects of SVR on system load margin. Using this program, margin sensitivity information for each control parameter can easily be obtained. Simulation results are presented in Part III of Appendix A to verify the results in [7-12].

7.6.7.2 Unified Margin Boundary Tracing (UMBT)

UMBT can check either Saddle Node Bifurcation or Hopf bifurcation condition along the equilibrium tracing and trace any related margin boundary, without calculating any eigenvalues [7-22]. The program can also check both bifurcation conditions and always switch to and continue the tracing on the most conservative margin boundary. For a given base case, the saddle node or Hopf bifurcation is first identified. Then, for any given control change scenario, the change in Saddle node or Hopf bifurcation margins can be traced. In Secondary Voltage Regulation, the control actions correspond to changes in the voltage references of the generator exciters, V_{ref}.

Once the scenario of V_{ref} change is defined under a certain Secondary Voltage Regulation scheme, the margin boundary can be traced directly by UMBT. This will provide margin change due to any large variation in V_{ref} without retracing the PV curve.

7.6.7.3 Optimal Margin Boundary Tracing (OMBT)

OMBT means optimal margin boundary tracing on an implicitly defined margin boundary surface in a multi-control parameter space [7-22]. It presents a practical methodology to solve for the cost sense optimal control configurations corresponding to a variety of voltage stability margin levels to satisfy the margin demand, either from energy transaction or system security. Optimal margin boundary manifold could be traced by augmenting the original equilibrium equations with optimality conditions. The proposed method considers all the system limits.

7.6.7.4 Local Parameterization Based Time Domain Simulation

This program proposes a numerically well-conditioned manifold-continuation based time domain simulation to solve power system Differential-Algebraic Equations DAE's [7-22]. Local parameterization is constructed to adjust the integration step size according to the variation of derivative of dynamic variable $\dot{X}$ or network variable Y ; numerical ill conditioning due to G_Y^{-1} could also be avoided. It can also approximate the quasi-steady state simulation. With these tools the dynamics of the SVR scheme can be simulated more accurately and conveniently.

7.7 Simulation Results for the French System

7.7.1 Performances of SVC and CSVR

In France, Secondary Voltage Regulators (SVR) began to be widely implemented in 1979. At present, France's transmission network comprises about 35 control zones including more than 100 thermal generators and 150 hydraulic generators. Total reactive power subjected to voltage control is estimated at more than 30000 Mvar [7-23].

The following conclusions can be drawn from the analyses of the system's operation behaviour:

- In both normal operation and under contingencies, voltage in each zone remains close to the setpoint specified by the dispatching center.
- It is easier for operators to control the voltage profile. High voltage operation is thus facilitated, and losses are reduced.
- To use the system to its full capacity, the operator can anticipate major variations in load by making preventive adjustments to voltage setpoints at pilot nodes in order to correctly accomodate load peaks and transfers.

But in some parts of the network (West and Southeast of France), it is very difficult to divide the network into independent control zones. In these parts of the network, SVR is reaching its limits (theses limits are described in chapter 2). However, the limitations can only become more acute as the system grows, and there will come a time when renovation is required, to address equipment ageing. For these reasons, it was decided to develop a more sophisticated secondary control system, known as CSVR, for "Coordinated Secondary Voltage Regulator". This CSVR has been in operation at the Western France Control Center for several years [7-4].

Various simulations were carried out on EUROSTAG [7-25] to study the performances of CSVR on the French EHV network [7-26]. Hereafter, the attention is focused on results achieved for the southeastern region of France. This region involves 180 EHV nodes, 30 of which belong to the 400 kV grid, 100 generating units and a high degree of meshing (Figure 7-19).

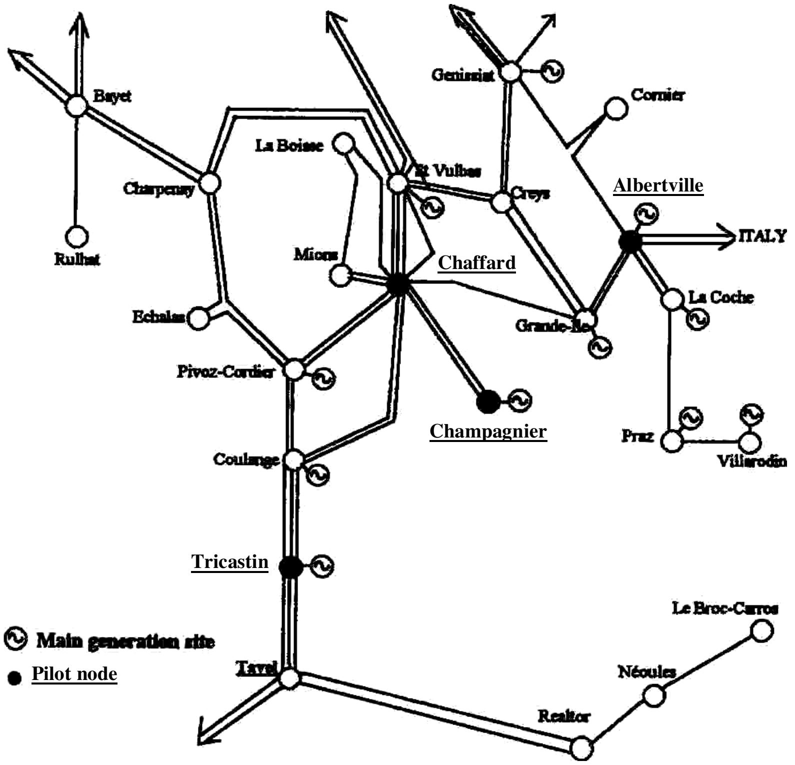

Figure 7–19 *Structure of the Southeastern French 400 kV Network.*

7.7.2 Control of Voltages in a Highly Meshed Network

The CSVR system must control the voltages at pilot points around the setpoint values, while separating the evolution of those voltages. This is justified as operators generally want to only make local modification that can be performed easily by adjusting the setpoint voltage of a pilot node. This can be difficult to achieve when the network is highly meshed.

Results of simulation on the selected region confirm the performance of the CSVR on this point. Figure 7-20 shows the modification of the Chaffard pilot point voltage with a 10 kV drop in its setpoint, whereas the voltages at the Albertville and Champagnier pilot points remain at their initial values. This result can be compared with the one obtained by a conventional SVR system (Figure 7-21) where a voltage drop of 6 kV can be observed on the neighbouring pilot points.

The applied setpoint step disturbance is quite large. The good performance obtained is due to the existence of the network's structure modelled in the control law. Owing to the presence of sensitivity factors Cv and Cq in the quadratic form (see Chapter 2), each controlling generator contributes, as a matter of priority, to the control of the pilot point that is the closest to it. However, if one of the pilot points can no longer be controlled by the nearest generators, due to a generator failure or to reactive power limits, the other generators in the region, electrically more distant, will contribute to control the voltage at that point.

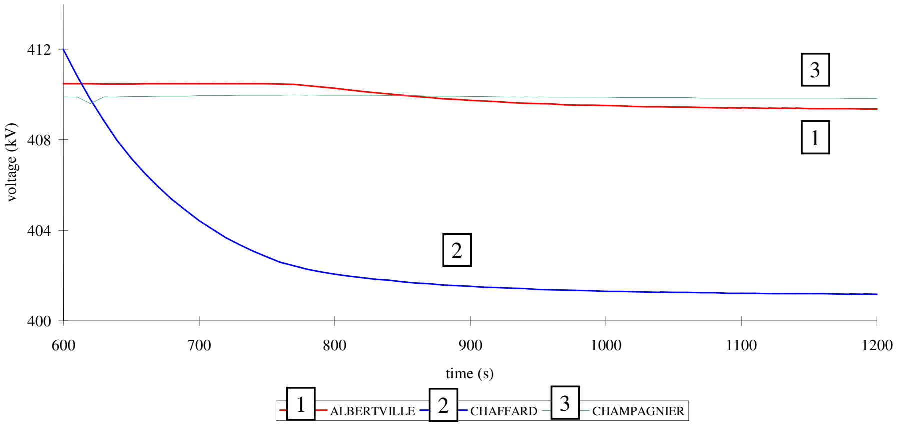

Figure 7–20 *Pilot Points Voltage with CSVR.*

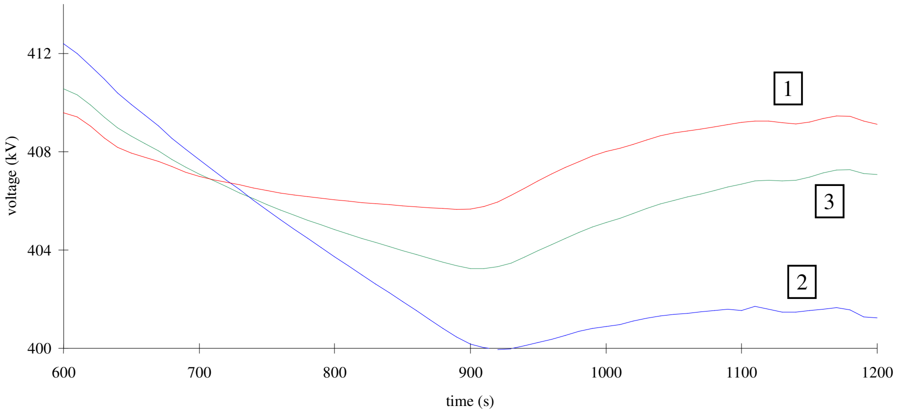

Figure 7–21 *Pilot Points Voltage with Conventional SVR.*

7.7.3 Use of Reactive Power Reserve

In Chapter 2, it was shown that with CSVR, each group has a "reference value" for reactive power generation that it strives to reach, but the control of pilot points is still the priority.

The reactive reference Qref can be set to zero in order to promote the building up of important reactive power reserves, which can be engaged in the event of load increase or failure. For some units, it can be seen that the reactive power produced is not as high with CSVR as it is with conventional SVR.

The control dynamics of the CSVR is less penalized than in other SVR, which enforce a strict alignment of reactive generations. In Figures 7-20 and 7-21, it can be seen that after 100 s, the voltage at Chaffard is only 2 kV from set-point value with CSVR, whereas the gap is 6 kV with SVR.

7.7.4 Voltage Control in Case of Failures and Load Variation

In case of failures (unit or line tripping), Primary Voltage Regulators (AVRs) contribute to enhance voltage regulation but sometimes this is not effective nor sufficient. Consequently, the network remains weakened. After the AVR actions, the CSVR allows to maintain and restore the voltage profile by mobilizing and co-ordinating reactive generations. It is therefore possible to prevent voltage collapse on the CSVR control area.

Figure 7-22 shows the rapid restoration of the pilot node's voltage by the CSVR after a drop of 5 kV caused by the tripping of generating units: the voltage recovery took less than three minutes.

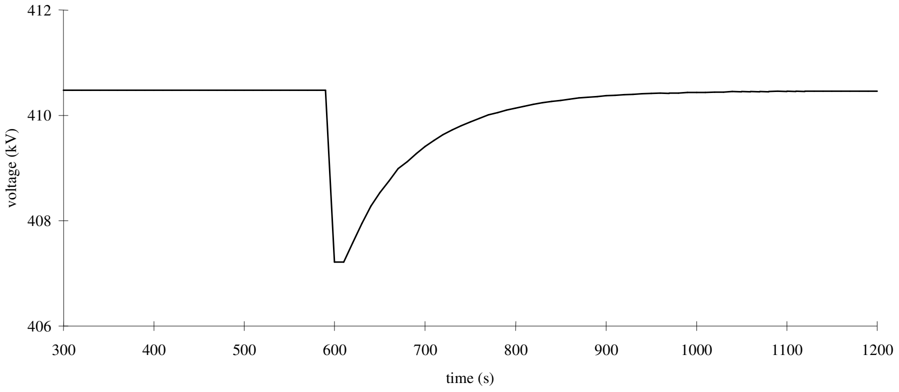

Figure 7–22 *Tripping of Units, Pilot Point Voltage.*

By maintaining voltage at some representative nodes of the network while making optimum use of reactive power generation, CSVR helps to improve network security. In some critical situations, which may lead to voltage collapse, CSVR can stave off the fatal moment of voltage collapse for several minutes. Those precious minutes give the operator time to take emergency measures such as blocking LTC, and perform remote load-shedding among others.

Figure 7-23 compares the network voltage performance with primary control only and with CSVR for a very severe load increase situation (30% per hour, 60000 MW of initial load), without modifying the generator operating schedules. This example shows that the network controlled with CSVR can be loaded 3000 MW more when compared with the control option of relying only on AVRs.

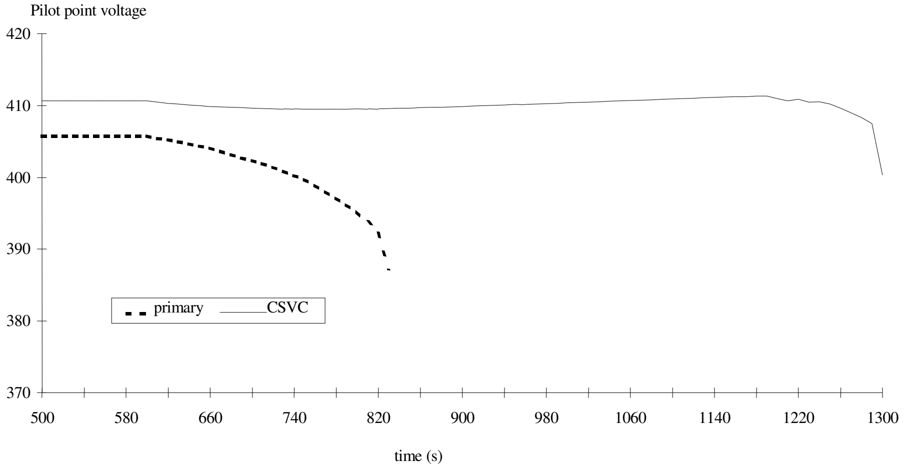

Figure 7–23 *Pilot Point Voltage.*

7.7.5 CSVR Deployment

7.7.5.1 Reduced Optimization Time for Problems with Many Variables

CSVR operating time is compatible with real-time requirements on large-scale problems.

The CSVR function is divided into three main parts: data acquisition and filtering, formalising and solving of the optimization problem, preparing and sending commands. A major part of the CPU time taken by the algorithm is dedicated to solving the optimization problem.

The computation times for the optimization software developed by EDF were measured on a UNIX workstation (made in year 1995). In this way, it was observed that the time achieved fits with the requirements of real time use. It was obtained thanks to the use of the active constraint method [7-27], which is one of the most efficient and reliable methods for solving quadratic optimization problems with linear constraints. There are two main reasons for this:

- Each stage of the algorithm deals only with inequality constraints, referred to as "active constraints" which is how the method got its name.

- Linear algebraic techniques are used in the algorithm. These techniques are comparable with base change operations in the simplex method and ensure convergence in a finite number of iterations.

Compared with the reduced gradient method, for example, the active constraint method is more reliable and faster, and performs particularly well for ill-conditioned problems.

7.7.5.2 Reliability and Robustness

Some other important features of CSVR, like its reliability and robustness, have also been extensively verified:

- The closed loop implementation allows for some deviation in sensitivity factors. So, in normal circumstances, or with a small load increase, the sensitivity matrices are revised at a relatively low frequency. But calculation of these matrices is also triggered in asynchronous mode by an event or an incident (change of topology, unit tripping, major load change).

- The reliability of methods implemented in the algorithm (filtering, mobile limits) to attenuate the effects of delays or measurements errors occurring in data transmission [7-28]. For example, the mobile limit method consists in reducing control dynamics when some variables approach their limits, by modifying those limits for the following command steps.

7.7.6 Future Developments

The Secondary Voltage Regulator system has been in operation since the early eighties and has given satisfactory service. SVR will remain in service in most regions in France. Required equipment maintenance and renovation are being provided.

The Coordinated Secondary Voltage Control has been implemented only in the Western part of France, known to be very sensitive to voltage problems. It features a more precise and stable voltage map, and a better dynamic response, thanks to the generator coordination. The Coordinated Secondary Voltage Control is expected to remain in operation in this region.

For some regions where SVR tends to reach limits more frequently, an extension to the CSVR was considered, but the simulated dynamic behaviour has not been as good as the one in the Western region of the French system.

The final objective is to select the best trade off between cost and efficiency.

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Chapter 8

Coordinated Voltage Control: Cost-Benefit Analysis of Alternatives and The impact of System Restructuring

8.1 Cost-Benefits of the Italian "Voltage Control Service"

Network voltage regulation, through the reactive power control of the main generators and the existing compensating equipment, maintains the network voltage profile close to optimum values despite the continuous changing of loads and mild network perturbations, enhancing the quality, security and economy of power system operation.

Network voltage support may be treated as power system ancillary service. A correct cost-benefit analysis of this service is a complex matter, requiring deep knowledge of the involved different machinery and control systems functionality and limits, their impact on the electrical network as well as the correct assessment of the multiple advantages and related economy [8-1].

8.1.1 Costs

The innovating voltage control system developed by ENEL (see Sections 2.3, 3.4, 5.2 of this brochure) is applied in the following cost/benefit analysis to a reference Utility having 50 large power plants and 50 network substations under control. At the higher levels the control system structure involves 5 Regional control centres and the national Dispatcher. The costs for the considered application are subdivided in capital and operation costs:

8.1.1.1 Capital Costs

- REPORTs and RVRs for the Secondary Voltage Regulation;
- NVR for the Tertiary Voltage Regulation;
- Optimal Voltage and Reactive Power Forecasting and Dispatching.

The estimated capital costs, which amount to 18,000 k€, are shown in Table 8-1:

Table 8-1 *Estimated Costs*

Studies, design and SW development	5,600 k€
Control apparatus manufacturing	6,200 k€
Installation + AVR interface modifications + field tests	6,200 k€
Total	18,000 k€

Considering an equipment life of 25 years:

- The yearly cost with a discount rate inflation removed of 8%, is equal to: 1,800 k€/year,

- The yearly cost with a discount rate inflation changed to 12%, is equal to: 2,580 k€/year.

8.1.1.2 Operation Costs

The operation costs are shown in Tables 8-2 and 8-3. The total yearly cost is thus estimated to be between 3600 - 4400 k€/year.

Table 8-2 *Costs for the maintenance and upgrade of control /apparatus and telecommunication apparatus, related to voltage-var control*

Optimal voltage and reactive power forecast and dispatching	155 k€/year
Tertiary voltage regulation	155 k€/year
Secondary voltage regulation (REPORTs and RVRs)	310 k€/year
Telecommunication system: (percentage of the maintenance related to voltage or var control)	155 k€/year

Table 8-3 *Costs for voltage/var operation (costs of the operators in the regional and central dispatching centres).*

Optimal voltage and reactive power forecasting and dispatching	517 k€/year
Tertiary and secondary voltage control	517 k€/year
Total Yearly Cost	**3600 - 4400 k€/year**

8.1.2 Benefits

8.1.2.1 Voltage Var Control Benefits

The application of Secondary Voltage Regulation may yield the following benefits:

- Reduction of up to 5% in the power system losses by reducing reactive power flows through a better coordination of the reactive power resources. The benefit in Italy of such a reduction in losses is estimated at 1,550 k€/year;

- Increase power transfer capability under security constraints, with estimated savings of 1,860 k€/year;

- Increase of spinning reactive reserves, which may prove essential during transients following large disturbances. To these increased reserves there corresponds a estimated reduction of about 3 to 5% in the non-supplied loads as a consequence of partial blackouts. The corresponding savings are roughly about 620 k€/year;

- Reduction of about 20% in the total time duration of voltage limit violations at the costumer end. The corresponding savings are estimated to be 930 k€/year;

- There is a significant reduction in the risk of power system blackouts due to voltage collapse, which corresponds at minimum to a yearly benefit of 9,300 k€/year.

  Total yearly benefit: 14,250 k€/year

This preliminary estimate of the benefits must be further perfected before being utilized to establish the voltage service contribution to the energy tariff.

8.1.2.2 Cost-Benefit Analysis

The cost-benefit analysis results, based on the above mentioned estimates are summarized in Table 8-4.

Table 8-4 *Cost-Benefit Analysis.*

Duration of the project	$X = 5$ *years*
Life of the results	$Z = 20$ *years*
Duration of the overall project	$N = 25$ *years*
Appreciation rate	$R = 8\,\%$
Failure Risk	$R_p = 5\,\%$
Appreciation rate with risk	$R' = R + R_p = 13\,\%$
Net Present Value	$NPV = 22{,}105$ kECU
Internal Rate of Return	$IRR = 64\,\%$
Pay-back Period	$PBP = 4.5$ years

Comments:

The SVR project pay-back period for a large application is shorter than the duration of the project itself since each partial realization operates autonomously, regulating its local voltage as soon as it is put into operation.

8.1.3 Comparison with Alternative Network Voltage Control Services

The conventional dispatching of voltage and reactive power is, in general, operated "manually" by telephone calls and according to written instructions based on network studies and optimal forecasting plans.

The reactive power dispatching is adequately managed by operators during normal network operating conditions. However, during unusual load demands and contingencies the outcome is dependent on the ability of the operators, the delay for the execution in the field of the Dispatcher's orders, the availability of reactive power reserves, the effectiveness of the process monitoring at the Dispatch centers, the delay in computing the updated state estimation and load flow.

In the conventional operating condition, it is very hard to assign values to the quality, security and economy of the corresponding “conventional voltage service” because its performance may range from unacceptable, to barely acceptable, up to a high quality level. Even considering the best level, the achievable benefits are, in general, low in comparison with those attained by an automatic network voltage control system.

Focusing attention on advanced network voltage control solutions, it is worth considering the *theoretical* (ideal) approach where all the generators operate producing active power only (power factor equal to 1), while all the load reactive powers are locally and dynamically compensated by SVCs regulating the voltages of the load HV and MV buses at the optimal value required by the local dispatcher. Obviously the amount of the Gvars, produced/absorbed by the SVCs is that needed by the loads, netted of the network contribution. This network operating condition is an ideal-optimal reference because the network losses are reduced to the minimum (reduced reactive power flows), while the quality of the voltage service reaches a top level, i.e. the voltages of the HV and MV load buses are maintained constant at the optimal values.

Comparing this ideal (reference) operating procedure and voltage control scheme with the Italian system with secondary and tertiary voltage controls, the following conclusions appear:

- The dynamic performance of the network voltage control, when facing small and large disturbances, are very similar for both control solutions;
- The network losses reduction is in favor of the ideal operating condition, but the differences are very small;
- The SVCs investments for the Italian network (about 17 Gvar required) correspond to the following yearly rates (the application lasting for 25 years):
- Discount rate 8%: 41,300 k€/year
- Discount rate 12%: 56,800 k€/year
- The O&M of the SVCs is roughly estimated at 2,580 k€/year;
- The transmission costs (studies, SW development, telecommunications and dispatching) for coordinating the SVC voltage setpoints is roughly estimated at: 2,580 k€/year.

The yearly rate cost comparison between the ideal SVC solution and the Italian coordinated voltage control system is given, on a preliminary basis, in Table 8-5.

Table 8-5 *Estimated yearly rate costs for network voltage control systems*

Network voltage control system	Discount rate 8%	Discount rate 12%
Ideal SVCs	63,000 k€/year	86,000 k€/year
Italian-Automatic Voltage Control	46,500 k€/year	56,800 k€/year

8.1.4 The Pricing Criteria for Voltage Control

The Italian Electricity Supply Industry has started unbundling the present tariff in a price for generation, and tariffs for transmission and a distribution, with separate prices for the “system services” (reserve margin, frequency regulation and voltage control).

The pricing of the “Voltage control Service” (VS) requires finding an adequate methodology to quantify the increase in voltage quality, power system security and operating economy that can be ascribed to this service.

Such duties are generally obtained with a mix of:

- Primarily production/absorption of reactive power by generators;
- Production/ absorption of reactive power by network capacitors/reactors;

- Voltage control at load buses by on load tap changers (LTCs) and by synchronous condensers, static var compensators/generators (SVCs, STATCOMs, etc.), if any.

The VS, in order to be effective, requires a suitable coordination of these reactive power resources. The Italian ISO is the world's first to nearly complete the activation of a technologically advanced network voltage control system (described in the previous Chapters), able to coordinate automatically all the reactive power reserves so as to reduce to a minimum both the control effort and the network losses, while maintaining voltage quality.

This hierarchical control system can be directly managed by the Italian ISO, which will be able to properly control and supervise the network voltage service (network security, reliability and voltage monitoring and VS accounting).

8.1.4.1 On the Generation Side

The Italian generators under Secondary Voltage Regulation (SVR) contribute to the VS in a more recognizable and consistent way than the remaining units in primary voltage control: they respond in the right time and without restriction on their nominal capability (monitored in real-time), in accordance with the real needs. For this reason the capital costs (reduced by the depreciation allowance) and operation costs of the units under SVR have to be considered in the pricing evaluation of the VS.

Because of their automatic and coordinated contribution to the network voltage support, these units/power plants stand as candidates for an additional economic remuneration, according to their participation level in the SVR and associated benefits for the network customers, in terms of voltage quality, system security and operating economy greater than given standards. The units, which exclusively operate under primary voltage regulation, cannot develop comparable and coherent control efforts for voltage support.

Therefore, the simple computation of the reactive power integral in not in general representative of the real contribution to support the voltage service. In addition, the lost contributions due to reactive power counterbalancing normally result in a greater control effort from the other power plants with consequent higher costs; in some cases uncoordinated actions could reduce the power system reliability up to the collapse risk.

The Italian ISO has recently proposed a new control criterion for the VS, strongly based on the short terms perspective of having all the main power plants operating under an automatic transmission network voltage control system. Currently, all the generators larger than 10 MVA are asked to contribute to support the transmission network voltages being controlled by PQR (REPORT). The operation under PQR becomes mandatory for the generators larger than 100 MVA.

A survey of generator performance based on the available measurements will allow assessing their individual participation in the transmission network voltage support and to assign correct economic values to their contribution, as well as to the penalties attributed to each of them.

The remuneration of each generator's contribution to VS must obviously take into account the sustained costs involved in achieving the recognized benefits.

8.1.4.2 Generation Costs

All the possible generator costs related to the VS are considered in this section, so that a cost-benefit analysis may be correctly carried out taking into account the different power system characteristics and country laws/rules.

The capital costs to be considered are:

(a) Oversize of the generator for reactive power production/absorption;

(b) Oversize of generator transformer taking into account the generator capability curve;

(c) Oversize of the unit exciter in agreement with the generator capability curve;

(d) Exciter controller, including unit voltage regulator, over- and under-excitation limits, REPORT interface, etc;

(e) REPORT apparatus.

Regarding item (a) ENEL's thermal generators have an estimated oversize cost to which correspond additional costs ranging from 5.1% to 6.5%, in accordance with the unit size and cooling. In the case of hydraulic generators, their sizes vary a great deal and the percentage of the related oversize therefore changes a lot from one unit to another.

Regarding item (b), the average of the transformer oversize is estimated at about 5.4%.

Considering together items (c) and (d), the estimated percentage of the exciter and controls capital costs related to voltage and vars is of about 65%.

Regarding item (e), the REPORT apparatus capital cost has to be related to voltage and var control. Therefore REPORT apparatus costs will be fully added to those of the overall network voltage control system.

The “yearly rate” of the generation capital costs (including a, b, c, d costs), is generally estimated referring to the yearly nominal production/absorption of reactive power and evaluating the unitary costs for chosen discount rates. A first computing attempt at ENEL on the subject gave costs ranging from 1.0 to 1.5 millions liras (ML, about € 517 to € 775) for each Mvar for year, considering the total generation capacity of 31525 Mvar. The yearly cost of a 370 MVA thermal unit would be of the value of 0.15 billion liras for year (GL/year, about 77.5 k€); the same cost is required by a 90 MVA hydraulic unit.

Only a part of the capital costs related to the generator, transformer and exciter oversize should be charged by the VS; no charge at all in cases where the full plant capital cost has been already amortized.

The generator operation costs include Losses and Operation & Maintenance (O&M) costs. The increased losses are related to the increased rating, such as fan losses and core losses, but also to the increase in stator copper losses when reactive power is produced or absorbed. Rotor copper losses, as well as exciter losses, are increased during over-excitation or reduced for under-excitation conditions.

The increased losses considered are:

- In the iron of generator unit and transformer;
- In the copper of generator unit and transformer;
- Mechanical (for the synchronous compensators only);
- In the exciter;
- In the auxiliary services for the egnerators and transformer cooling;
- For the starting up of the synchronous compensators.

For the thermal units, the iron and mechanical losses are each estimated equal to 0.2 % of the oversize (6000 MVA for the ENEL thermal generators); therefore the overall losses rate is equal to 13.2 GL/year (about 6,800 k€/year). For the ENEL hydraulic units, having an oversize of 2000 MVA in total, the overall losses rate is 5.3 GL/year (about 2,750 k€/year).

In conclusion the yearly losses rate for the ENEL's units is estimated between 15 and 25 GL/year (about 7,785 to 12,955 k€/year) corresponding to 350 – 400 GWh/year of energy lost.

The O&M fixed and variable costs also include the hardware and software maintenance and the operators training.

8.1.4.3 Transmission Costs

The pricing criteria for the VS should consider the capital costs of the ISO's hierarchical and automatic voltage control system, including the daily forecasting of the optimal voltage plan for the Italian transmission network. The other capital costs to be considered are those related to the installation of static condensers and reactors and their switching equipment and those for the LTC installed on both transmission and distribution transformers. The equipment amortizing allowances should be deducted from these capital costs. The operating costs for the network voltage support, which also include the additional network device losses and maintenance and the control equipment maintenance, should be considered in case of a network voltage service exceeding a given performance standard. The reactive power resources available at the Italian power plants are abundant during normal operating conditions with the existing power factor correction. In the Italian transmission network the average power factor (PF) is usually greater than 0.95 while in the MV and LV network the PF evolved from 0.9 to 0.93, between 1985 and 1994. Under compensated condition the PF varies at the yearly peak between 0.96 and 0.98. The expansion of the 380 kV network together with the reduction of the energy transfer from north to south due to the new generation plants built in the centre-south of Italy, have in fact determined different operating conditions of the Italian network with an increase in the need of unit underexcitation.

As already presented in Section 8.1, the capital costs to be considered are:

(a) Reactors and capacitor banks and associated switching equipment;

(b) LTCs in the transmission and distribution;

(c) SVCs, STATCOMs;

(d) REPORTs and RVRs for the Secondary Voltage Regulation;

(e) NVR for the for the Tertiary Voltage Regulation;

(f) Optimal Voltage and Reactive Power Forecasting and Dispatching.

The capital costs for the practical implementation of the Secondary and Tertiary voltage control system – points (d) and (e) above – include the installation of the REPORT apparatus at the major power plants, the RVR apparatus at each Regional Dispatcher and the NVR at the ISO National Control Centre.

The transmission network operation costs include:

(1) Losses in the network compensating equipment (At ENEL these losses amount to 4,840 MWh/year with a cost of about 103 k€/year);

(2) Losses in the electric lines. These losses in the Italian transmission network range from 250 MW up to 500 MW depending on the system operating conditions. An average yearly cost for these transmission losses amounts to: 129,000 – 155,000 k€/year. This cost includes the losses contributed by the reactive power flows, which are estimated to be slightly larger than 10%. Similar considerations can be done for the distribution losses.

(3) Costs for the maintenance and upgrade of control tools/apparatus and telecommunication apparatus, related to voltage-var control: the same as in Section 8.1

  - ✓ Optimal voltage and reactive power forecast and dispatching;
  - ✓ Tertiary voltage regulation;
  - ✓ Secondary voltage regulation (REPORTs and RVRs);
  - ✓ Telecommunication system: (percentage of the maintenance related to voltage or var control);

(4) Costs for voltage/var operation (the same costs of the operators in the regional and central dispatching centres as in Section 8.1) for:

  - ✓ Optimal voltage and reactive power forecasting and dispatching;
  - ✓ Tertiary and secondary voltage regulation.

The dominant part of the losses at points 1 and 2 are independent of the network voltage control being performed but strictly linked with the process physical characteristics.

The "loss of load" costs if VS is not available, i.e. the lack of reactive capability under contingency conditions leading to disconnection of customers to avoid voltage collapse, cannot be ignored and has to be evaluated in probabilistic terms by taking into account the so called Loss of Load Value.

Other losses to be considered, having a value equation very similar to the previous one, are those related to unavoidable network voltage instability and consequent voltage collapse. This is a very low probability event but the related costs are very high (tens of millions €s), and proportional to the size of the area hit by the blackout.

As a final point, the time period during which the contractual quality of the voltage at the customer's supply end is not guaranteed, causes a loss of income for the system operator.

8.1.4.4 Pricing Attempt

The described Generation and Transmission capital and O&M costs associated with VS stimulate the following questions:

- Should these costs be fully considered in the pricing criteria for the voltage service? Knowing the capital and O&M costs are necessary but not sufficient conditions to achieve a high level VS: the results also depend on the system operator skills;

- Which VS performance level should be assured by ISO and at which cost?

- In which way the pricing criteria should recognize and measure improvements in the voltage service?

During the Italian energy market restructuring process, new proposals for VS pricing, taking into account the presence of the new voltage control system (SVR), have been submitted to the Italian Energy Authority.

A pricing approach to quantify in a simple way the value of the "voltage duty" rendered by the generation and transmission system should take into account the following aspects:

- A VS benchmarking criterion to allow comparing the performance and costs with an “ideal” or optimal voltage control solution and also determines a maximum reference cost for any possible transmission network voltage control system.

- A pricing criterion based on VS market competition finds a strong simplification when supported by an automatic voltage control system.

The elements of those non-conflicting considerations could be combined in cascade to define an effective VS pricing methodology.

Benchmarking against the Ideal VS Reference

The criterion requires the following steps:

(i) Definition of a “theoretical (ideal) reference situation” in which the modern technique of load buses compensation (i.e. by the use of SVCs) is largely applied to all major load buses, since this is in principle able to offer the best standards. The cost of such unrealistic but useful reference control solution (see Section 8.1.3), which allows the most advanced and flexible network voltage control, corresponds to the upper limit value of any possible “voltage duty”;

(ii) Calculation of the cost of the “Automatic voltage control system (in Italy: SVR + TVR)” which best exploits the existing resources (see Section 8.1.1).

The criterion is based on the concept of "same value to the same voltage quality standard" and on the benchmarking of the chosen control system with respect to the ideal one.

Considering the Italian control solution with the automatic secondary and tertiary voltage regulations and the optimization of the reactive production of capacitor banks and shunt reactors, as well as of the LTCs, it is noted that the voltage quality standards are kept quite close (both in steady and transient state) to the theoretical (ideal) values.

The difference between the cost of the ideal control solution and the real cost of the Italian voltage control system, produces therefore the economic advantage of the latter control system. Moreover the ideal control system cost can be chosen as the upper limit of the VS cost.

The benchmarking criterion can be applied in practice according with the following proposal:

(i) Compute the generator reactive productions for various network scenarios, with voltage quality standard properly proposed;

(ii) Then, a "theoretical reference situation" is created in which such reactive productions are set equal to zero (PF of the generators equal to 1) and replaced – with the same voltage quality standard - by modern Static Var Compensators (SVCs) installed near the loads and regulating the voltage at the value deemed "optimum" by the Dispatching Center. Naturally, the total MVAR of the SVCs corresponds to the total needs of the loads, netted of the contribution of the network (Mvar production by the lines, absorption by the transformers). Such theoretical situation is "optimal" in respect to the reactive losses since:

  - ✓ On the power plant side the generators produce active power only, therefore the losses due to reactive flows are minimized;
  - ✓ On the load side, the reactive power is produced just in the needed amount by suitably tuned SVCs.

The above mentioned "theoretically optimal" situation is compared with the real optimized situation, where the reactive power produced by the generators and the losses are minimized through an optimum reactive power and voltage dispatch determined by an OPF program and implemented by the existing Secondary Voltage Regulation.

Competition in the VS Market

Moving to a VS market competition criterion, the ISO ability and the economic remuneration of its performance should be based on comparison with given VS performance standards fixed by the Energy Authority. Similarly, the generation companies' ability and their economic remuneration should be linked to their VS contractual agreements with ISO on each generator performance under PQR control and on the differences with the contractually due.

The new power plant “high voltage side regulator” (PQR) required by SVR is in fact the true, concrete possibility to achieve the objective of an effective voltage service for the following reasons:

- The objective to automatically coordinated, in real-time, the generators available reactive power resources, can be achieved;
- The generator reactive capability can be continuously monitored and therefore contractually defined in detail;
- The AVR stability, dynamics and coordination with the generator protections are implicitly guaranteed by PQR, which continuously monitors them as necessary conditions for its correct performance;
- A simple but effective monitoring of the verified contribution of each generator to network voltage support can be carried out by the PQR facilities for eventual comparison with the contractually expected performance and the correct computing of the generator economic remuneration.

An adequate metering of the generators performances under PQR and of the differences with respect to the contractually due, allows a correct management of each generator economic remuneration for its contribution to VS [8-2].

In agreement with the proposed VS market criterion, the Energy Authority monitors the ISO’s performances on VS meanwhile ISO, on its turn, performs his task of contracting generation companies according to power system voltage control needs. All the parties involved follow the market rules.

In practice the considered criterion requires the correct metering of the transmission network voltages and of the RVRs and TVR regulators performance, which can be simply defined on the basis of the available data at the Dispatchers control rooms. More complex is the metering system for the generator performances, but a strong simplification is possible due to the role played by the PQR.

The PQR objective is the automatic, coordinated and real-time participation of the power plant units in the transmission network voltage support. PQR controls the reactive powers of the power plant generators, in proportion to their capacities and the actual over and under-excitation limits of each generator. These dynamic limits, which can be computed by PQR according with the generator manufacturer voltage and thermal limits are continuously monitored and can be fully or partially assigned to the voltage service by PQR, according to the defined contractual agreement between the power plant and ISO.

Another constraint on the generator support to the network voltages is the maximum allowed voltage range at the generator terminal bus, which could limit the exploitation of the generator reactive power reserves. Also the generator field voltage can be modulated by PQR, according to the commercial agreement between the power plant and ISO.

The generator participation may be enlarged or reduced through PQR setting and remunerated accordingly after being confirmed by a precise and independent on-line special meter. PQR needs to be continuously checked also for its possible alternative control functionality:

(a) Power plant under SVR (tele-controlled by RVR);

(b) Power plant regulating the local HV bus voltage.

The two alternative performances, both linked to network voltage support, require a differentiated accounting to identufy the most valuable.

The power plant performance reference under PQR control defines the “voltage service contract” and comprises:

(1) PQR continuous control of all the power plant operating units;

(2) Unit reactive power availability up to its contractually agreed over- and under-excitation limits;

(3) Generator terminal voltage availability range up to the contractually agreed limits around the nominal value;

(4) Generator operation under PQR control, complying with the limits and range previously mentioned at points (2) and (3), with an availability not lower than the minimum, contractually agreed, value;

Obviously, the stricter is the contractually agreed performance, the larger will be the power plant risk and the related economic remuneration, if confirmed by field measurements.

From the commercial point of view, the actual generator contribution to the network voltage support must therefore be correctly monitored and compared with the contractually agreed performance for an impartial economic remuneration or the application/pursuance of penalty clauses. This objective can be achieved by a new meter of the power plant generator contribution to network voltage regulation, which collects the PQR available data related to the generators operating states and the main PQR control signal measurements. This meter would also be able to recognize and inform remote terminals about each generator performance and also verify whether it is in agreement with the contractual tie, as well as the amount of the eventual differences.

Conclusions on Pricing

In synthesis, the benchmarking criterion involves:

- The maximum cost to be attributed to VS;
- The VS recognized cost for the overall power system as a percentage of the maximum cost, corresponding to the adopted control system benchmark and to the actual VS performance with respect to the ideal one or those fixed by the Energy Authority;

The VS market competition criterion involves:

- The rules which fix the link on VS between the Energy Authority and the ISO, based on reliable cost and performance references;
- The contractual links between ISO and Power Plants based on simple and competitive market rules;

- The correctness of VS contractual links when strongly supported by the PQR controller, which allow a simple and reliable metering of each generator contribution to VS as well as the possible deviations with respect to the contractual due to ISO.

8.2 Cost-Benefits of the Belgian Tertiary Voltage Control

Considering the rather long effort of harmonising the voltage droop of the generator AVRs as being part of normal grid operators' job, the only cost was the development of the Tertiary Voltage Control software. The total investment comprising analysis, programming, debugging and operator training was less than 1 M€. The annual maintenance cost is less than 0.1 M€. This makes the Belgian solution a rather low budget one. One single MW (mean value over the year) lowering of grid losses is sufficient to ensure a positive cost-benefit balance.

8.3 Voltage Stability in Deregulated Markets

In the regulated electrical industry, the vertically integrated utilities are in full control of generation, transmission together with the obligation to serve load. This means that sufficient generating plants are constructed to meet load growth, and transmission systems are reinforced as needed to meet minimum reliability standards and criteria. Sufficient generating resources are maintained, including spinning reserves to regulate frequency, and sufficient reactive reserves are maintained to regulate voltage and prevent voltage instability. While future planning and operation of the system has its uncertainties (mainly in the occurrence of unknown contingencies of generation and line tripping that could happen in unknown combinations (above planning criteria) and in different operating load conditions of the system), the ability of the system owner to provide generation and transmission to serve load and reduce load shedding to a minimum is certainly easier because the owner is in full control.

In the new paradigm of the unregulated electricity market, generators and transmission system are owned by independent entities. The transmission owners may or may not have the obligation to serve load in their area. Generators are bid into the system on a day ahead and hour-ahead market. Generation reserves including spinning reserves will be controlled entirely in the future by ancillary market bids. There is no certainty that a specific generator providing voltage support (and included in 'planning' studies) will actually be operating in a particular area. The operation of specific generators together with the existing higher levels of spinning reserves that provide MW generation reserves and also voltage support reactive reserves would need to be (1) more accurately determined and (2) economically justified. The proportion of dynamic (generator, SC, SVC, STATCOM) reserves to static (fixed or switched reactive shunt banks) reactive reserves, which is a difficult quantity to be determined, will become even more difficult to be established, as economic justification will be required in addition to technical justification.

While overall responsibility of operating the system is in the hands of the Independent System Operator (ISO), the provision of adequate dynamic and static reactive reserves to voltage support, transmission adequacy and reinforcement, and generator dispatch satisfying market conditions, will clearly be a more challenging task. Existing challenges in the design and installation of secondary (or primary) voltage controls across the system in planning, design and operation will most certainly be more difficult. Even if technically desirable, they have to have economic justification for installation and operation between different control areas or ISOs. These issues should be recognized and factored into the concepts, analysis, design and operation processes as we move forward. Reserves deficiencies and market conditions in 2001 have already resulted in load shedding (e.g. in California) due to voltage conditions. As unregulated markets today are still in their formulation stages, we should get the best information possible from the existing ISOs including frank discussions on limitations of their operating models and practical difficulties that they face. Schemes put forward should thus recognize and factor in the impact of unregulated markets.

8.4 The Impact of System Restructuring Process on the Voltage Service in the Italian Network

The Italian electrical system moving from one strongly integrated national company (ENEL) to an economic/administrative unbundling among Production, Transmission, Distribution Divisions and national Independent System Operator (ISO), had to face the obvious problems linked with the reorganization transient. In particular, the changes affecting system operation aspects which have required and will always require high interaction among the separate "future companies" are also those strongly related with voltage service even if this service will be managed as unbundled. The new organization of the voltage service is surely different from the past one, but not necessarily less expensive, with the initiatives for additional improvements now depending on the market competition and the economical remuneration of the contribution to the network voltage support.

8.4.1 Sharing the Investments among Independent Competitive Entities

The automatic voltage control system developed and applied in Italy requires investments for defining and designing the solutions for the realization of the control . A larger part of the investments have already been made by the past ENEL organization. The remaining investments still needed, depend on the agreement between the ISO and the ENEL companies already structured as independent entities having autonomous budgets and pressed, particularly in this transient phase, to minimize costs and maximize the income.

In this muddled context, one of the main criticisms comes from the not yet quantified recognition in the energy tariff of the voltage service.

The project of the new voltage service at ENEL was in a palsy state at the beginning of the restructuring process. Soon after, due to the strong support from the Italian ISO in conjunction with the Transmission community all the relevant activities progressed.

At the independent producer side, those connected to the Transmission network are already moving towards autonomous financing of the REPORT apparatus for their power plants.

This fact strongly indicates that there is a common understanding on the importance to operation of the voltage network service, to be pursued by an automatic and nation-wide control system.

8.4.2 Different Rules of ENEL's Independent Entities on the Voltage Service

As network voltage/var control is of interest of all players, it promotes a strong interaction among ENEL's Production, Transmission and Distribution Divisions.

Due to unbundling, these separate Divisions have to define, also for the voltage service, the role they have to play, the operation link with the other Divisions as well as the related administrative procedures. Because the Italian new network voltage control system is automatic, to the managerial/administrative unbundling there corresponds an operational bundling: the unit reactive powers are telecontrolled by the Regional Dispatchers while the Distribution customers enjoy the many achieved benefits.

These unavoidable interactions link the decision of the independent entities on the voltage service. They are therefore forced to reach agreement, despite their different short-term interests and objectives. From this point of view, an automatic voltage control system already into operation, even if partially, fixes de facto the operational links among the independent entities, thus simplifying the operation modes, which must be coherent with the designed control solutions. The generating units will therefore continue to operate up to their capability limits, all together contributing with the same percentage of the control effort; the Regional Dispatchers Regulators (RVRs) will require the plants to produce the amount of reactive power strictly necessary to maintain the optimal voltage profile in the network; the automatic control of the optimal voltage plan will allow to reduce the network losses and to increase the network reliability with benefits to all customers.

The independent entities shall comply with the rules of the agreed convention, which will define the modes, frequency and duration of the maintenance interventions and the service restoration, as well as the penalties associated with non-compliance. In order to achieve this mutual effective cooperation, it is very important to establish to clear rules for the new Italian electricity market.

8.4.3 Sharing the Returns

The economic returns from the network voltage service to the Italian energy market operators will be defined by the Italian Energy Authority although taking into consideration the ISO proposals.

The economic interests related to the sharing of the voltage service returns will surely push towards improvements in the performance monitoring of those generating units controlled by REPORT, as well as those under primary voltage control only.

The monitoring of the voltage service improvements in terms of the quality, security and economy of the network operation will be surely activated. The future interests on the related economic returns will also push towards better monitoring and checking of the conformity of the other players' returns.

The voltage service economic returns will also push for improvements on the current rules on the subject, whether of technical, economical, or social nature.

8.4.4 Impact Evaluation

The complexity of the voltage service and the difficulty in correctly allocating it to the transmission tariff were described, focusing on the opportunities provided by the advanced automatic voltage control system under application in Italy. In the near future the voltage service will grow in role and importance inside the restructured energy market. Therefore many novelties on the subject will probably appear round the world related to improvements of its performances in terms of quality and accounting. The income from the necessary sharing of the voltage service returns will certainly improve the monitoring of the voltage service performance in a competitive framework. The impact of the Italian restructuring was not detrimental, since both the philosophy of the automatic voltage control at ENEL, and all the developments under way can be rather easily utilized also in the new unbundled structure of the future system allowing a simple operation and accounting of the service to the future ISO. Problems may arise at the organization level, since the high integration among Generation, Transmission and Distribution, all contributing to the voltage duty value, will be no more present. The new rules aimed to keep the network voltage control as prestigious service are to be set up. This is a challenge that must be coped with.

References

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Chapter 9

Conclusions

This report dealt with the coordinated voltage control in transmission networks, which represents a significant improvement on the classical reactive power dispatching in power systems. The coordinated control solutions currently implemented in different systems and countries were described by the experts that contributed to this document. Some systems, like the Italian and French, employ hierarchical real-time and closed-loop voltage control schemes having primary, secondary and tertiary levels, with the last level encompassing the entire country. Having the tertiary level in an automatic, real-time, feedback control mode is still an open issue, with the Italians being the largest supporters of this concept. In this hierarchical solution, the coordination is achieved at each level and also in between levels. This solution represents the most comprehensive example of hierarchical voltage control. Other existing voltage control solutions are decentralized, with autonomous local controls and limited coordination among the local reactive power resources.

The relevance of coordinated voltage control is evident from the large and continuous flow of technical publications and the high interest in panel sessions dealing with this subject. This task force gathered experts from 12 countries and held 10 meetings, during the 2000-2004 period, which were quite well attended and had numerous interesting presentations, most of which were submitted as contributions to this report.

The task force helped disseminating valuable knowledge among the international technical community, increasing interest and engineering activities in coordinated voltage control of whole transmission network regions, or just of EHV substations and generation sites. Publications on these topics, as well as actual engineering projects, have increased at international level.

Coordinated voltage control being a relatively recent topic, the existing realizations vary a lot and strongly reflect:

- the operator’s trust on the placement of automatic feedback controls at higher levels of the control hierarchy;
- the push for increasing levels of power system security and availability; technology and capital expenditure possibilities;
- equipment vintage;
- expected reliability;
- dominant dynamic phenomena in the system;
- experience and prevalent school of thought of system designers.

The secondary voltage controls commissioned in the whole of Italy and large parts of France, are based on the concept that generator reactive power is the main voltage control resource, for fast and slow changes. They can be fast and continuously controlled, and being already available in the field, might also be the cheapest. The secondary voltage control solution also sends switching commands to capacitor/reactor banks, in a slower time frame, but always in coordination with generators and LTC transformers.

In contrast, there is the transmission-based voltage control philosophy, operating mostly through capacitor banks and shunt reactors coordination without resorting to generators. This is based on the concept that generators should provide only active power (unity power factor operation) because of:

a) The difficulty of generation companies in accepting the automatic Var modulation of their generators being determined by a control system owned by the transmission company;

b) The generation dynamic reserves should rather be left for use during contingencies.

Local and regional intelligence is used for voltage and Var control. Keeping enough discontinuous and continuous controlled reactive reserves, spread throughout the transmission network is vital to system security.

Availability of advanced Generation, Transmission and Distribution equipment and communication technology have led to more automated power systems, increasing reliability and security. Coordinated voltage control continues to be developed in either centralized or decentralized modes, both of which are intended to enhance voltage quality, system availability and security and operation economy. Obviously, the performance is different when comparing the continuous with the discontinuous controls, the manually operated with the automatic controls, or the faster with the slower controls.

A clear distinction should be made between the “Local high-side voltage control” and the “Regional (wide-area) transmission network voltage control”:

- The first regulates the voltage of a given bus, while coordinating the reactive power resources connected to neighboring buses;

- The second requires a regional control structure to regulate the voltages at the main buses in the region through coordination of the regional Var resources, also achieving the objective of increasing transfer capacity and reducing losses within the region.

Therefore, the “Local” control can be considered as being a part of the “Regional”.

It is also proper to emphasize the differences between:

- The voltage control solution under normal or slightly perturbed operating conditions, having the objective to improve voltage quality, system security and operation economy;

- The voltage control solution under emergency conditions, which is required to operate like a protection scheme to help recover the system from a dangerous state, following a severe disturbance.

These two controls are complementary and meant to solve different tasks: the first improving the system stability and performance through its optimization; the second operating when the first has reached its limits, or whenever dangerous thresholds are reached and drastic measures are needed to ensure the survival of the power system. This report is devoted to the first kind of voltage control system, though it also discusses some solutions related to emergency control.

Computer tools for voltage-Var operational planning and online voltage-Var operation and control are also evolving. Flexibility in modeling complex coordinated controls is an important feature for modern power system software, user-defined representation of controls being desirable in dynamic, static and optimization tools. Quasi-steady-state simulations have become more widely used since they better reproduce power flow controls, by properly considering their different response times.

Newton power flow programs, the most pervasive power system analysis software, most probably will continue to be used, despite their difficulties: the multiplicity of existing solutions in the presence of many power flow controls of different nature. The price for representing essentially dynamic controls through static models includes unrealistic conflicts among power system controls, which would not exist if the dynamic nature of the controls were properly represented. Noting that power flow is quite an ill-posed problem, reference [9-1] describes a new solution algorithm that shows remarkable convergence properties in the presence of the usual discrete and continuous power flow controls. Even if not competitive with Newton power flow for easy problems, the initial results obtained indicate that this algorithm may prove valuable for poorly convergent or divergent cases.

Modern power system state estimators, provided there is good online data availability, are quite powerful and able to correctly capture the system state, considering the presence of all major power flow controls. These estimators, together with powerful optimal power flows, are essential for computing the optimal forecasted plan of voltages and reactive powers that must be used as references to the tertiary voltage regulation. The more the computed forecasting plan is related to a recent operating condition, the less will be the effort of the Tertiary control in optimizing, in real-time, the verified deviations from the optimal forecasted plan. Even the fastest state estimation cycles in current EMS installations are however still too slow for use in Tertiary and Secondary voltage regulation. Therefore, the closed-loop voltage control results that could be based on state estimation “measurements” would necessarily be very slow.

The wide-area coordination of discrete and continuous voltage control devices is often a very difficult problem, less from the technical and more from the political point of view, only roughly solved by good engineering practice and robust designs aided by numerous simulation studies. Most utilities need to invest in the modeling, simulation and performance optimization of voltage control schemes incorporating both continuous and discrete devices. Recent publications [CT_1, CT_2] report that a major North-American utility is investing in advanced technologies for wide-area voltage control coordination and emergency control, in an approach that bears some similarities (despite the control philosophy differences) with the secondary voltage control systems implemented in Italy and France.

This document described the current status of the coordinated voltage control around the world and also included other aspects related with voltage/reactive power dispatching, local generators coordination and voltage emergency control. The amount of described systems and the solutions adopted by their developers and operators did not come as balanced as desirable, reflecting the fact that a major part of the material on hierarchical voltage control was produced by the Italian members of this task force. Equal opportunity was however given to knowledgeable contributors from all systems and countries.

The multitude of existing voltage control solutions is somewhat confusing, for both the expert and layman. Fortunately, there is clear evidence of a general trend towards greater automation and regional coordination of the local Var resources, so as to achieve the most cost-effective transmission network voltage control.

The notation adopted in this document was kept as coherent as possible, but the text in the various sections reflects the styles of the individual contributors to this document. Much could be improved with more extensive editorial work, but this would further delay publication of this timely document with no significant benefit to the reader.

There is much room for additional work in this area: actually, enough to justify the creation of specific task forces in topics such as:

- Voltage emergency control on transmission networks;
- Voltage wide-area protection.

These topics are already under investigation by members of this task force.

References

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Appendix A

Example Results on Secondary Voltage Regulation

Part I – Transient, Mid-Term Dynamic Simulations on a Five-Bus SVR Example System

A.1 Introduction

As explained in Chapter 2 of this report Secondary Voltage Regulation (SVR) is a closed-loop regional control system involving the participation of generating plants, static compensators, synchronous condensers, LTC transformers, etc. These reactive power sources are coordinated to properly regulate the voltage of certain buses (pilot buses) in transmission networks. . The SVR acts in the time frame of a few minutes.

Results showing the benefits of a SVR scheme on a 5-bus illustrative system are presented in a tutorial manner. Only generating plants were considered as SVR actuators in the tutorial example. A transient, mid-term stability program was utilized in the dynamic performance assessment of the SVR scheme. The stability program allows the simulation of the mid-term voltage dynamics and the parameter tuning of the SVR control scheme.

A.2 Test System Description

A.2.1 System Data

The test system is outlined in Figure A-1 and comprises 5 buses, 5 lines, 2 generators and 1 load. The system data are described in this section and also in Section A.5.

The two generators have the same parameters but different sizes (MVA bases equal to 50 and 150 MVA for the generators connected to buses 1 and 2 respectively). The stator resistances and mechanical damping constants are zero for both machines. All five lines are purely inductive for simplicity.

The excitation control system model used in both machines is shown in Figure A-14 (see Section A.5). Speed-governors are represented in both machines by first-order models (see Section A.5, Figure A-15). The load at bus #30 has a static, constant-power (MW) model.

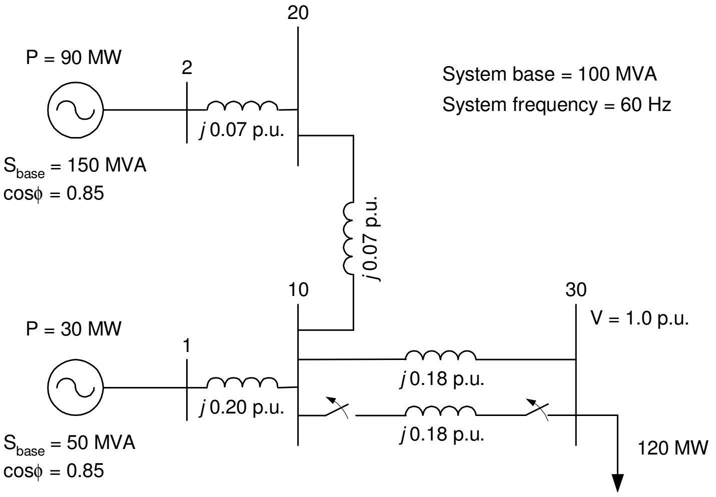

Figure A-1 Test system.

A.2.2 Structure of the SVR Scheme

The control structure of the SVR scheme utilized in this work is depicted in Figure A-2. This SVR scheme involves:

- A central controller that should preferably be placed in a regional control center. It has one PI controller for pilot node voltage regulation and a summer of the instantaneous reactive powers of the participating power plants. The controller inputs are the instantaneous reactive powers for all participating power plants and the pilot node bus voltage magnitude. The two central controller outputs, which are sent to all participating power plants, are the total reactive power generation (Q_{Total}) and the output from the pilot node voltage regulator;

- Distributed PI controllers, one per participating power plant, which regulate the reactive power outputs of these plants. Each power plant controller receives the two signals sent by the central controller and sends back the instantaneous reactive power output of the power plant.

The values of the SVR parameters utilized in this work are described in Section A.5 (Table A-3). The notation adopted in Figure A-2 is mostly self-explanatory. The gains α_1 and α_2 are participation factors which define the adopted Mvar generation ratio (Q_{G_1}, Q_{G_2}) at steady state. These participation factors may be fixed, manually varied by operators, or automatically set by the Tertiary Voltage Control to implement some desired voltage control strategy. The SVR control structure shown in Figure A-2 is rather simplified, but conceptually similar to SVR schemes previously utilized by European utilities. The SVR scheme is here assumed to be of the continuous type and to only involve the participation of synchronous generators.

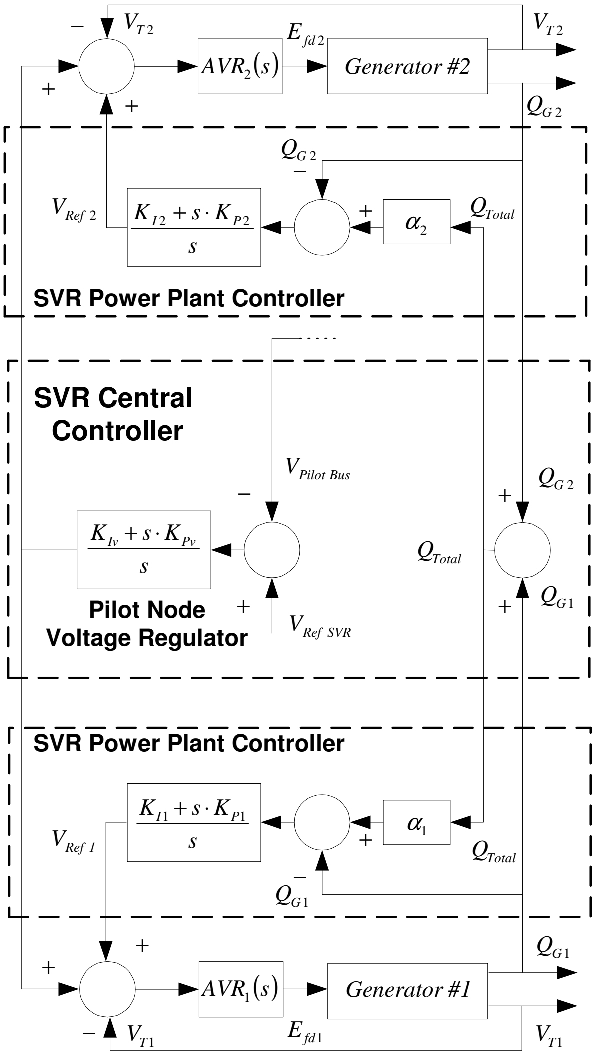

Figure A-2 *SVR control scheme for the illustrative test system.*

There exists an equivalent realization for the SVR scheme depicted in Figure A-2 that requires less communication. This alternative implementation involves placing all the $np+1$ PI controllers, np being the number of power plants, at the SVR Central Controller. The control block diagram for this alternative scheme is depicted in Figure A-3.

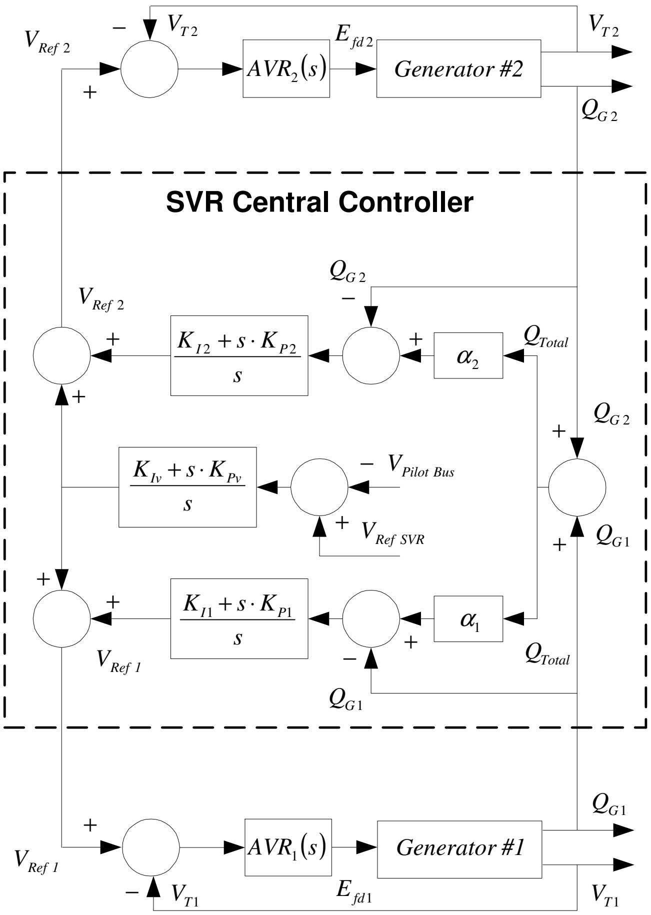

Figure A-3 *Equivalent SVR scheme.*

A.3 Dynamic Simulation Results

A.3.1 Dynamic Performance of Described SVR Scheme

The results presented in this section show the ability of the SVR scheme in regulating the pilot node voltage while adjusting the reactive powers of the two power plants in the test system according to their MVA capacities (50 MVA and 150 MVA). The factors α_1 and α_2 must therefore be made equal to ¼ and ¾, respectively.

The contingency studied consists in the outage of one circuit between buses #10 and #30 at 25s (the two open switches in Figure A-1 help identify the outaged line). Figure A-4 shows the voltage magnitude plots for all buses in the absence of SVR action. Note the permanent voltage depression in the load bus (bus #30).

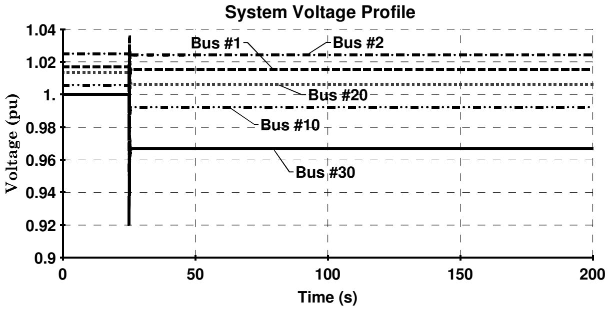

Figure A-4 *Bus voltages for system without SVR scheme.*

Figure A-5 shows the same voltage plots when considering the SVR action. The pilot bus voltage (bus #30 in this case) is seen to smoothly return to the scheduled value through the SVR action, ensuring a better quality of supply.

Note in Figure A-5 that the voltage at bus #2 reaches 1.055 pu following SVR action. This could be above maximum voltage operating limits, and would then require some other action like the switching of shunt compensation devices.

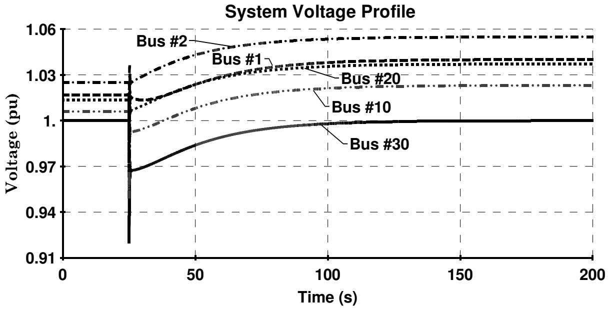

Figure A-5 *Bus voltages for system with SVR scheme.*

Figure A-6 compares the pilot bus voltage behavior in the presence (solid line) and absence (dashed line) of SVR action. Figure A-7 presents an enlarged view of Figure A-6, focusing on the short-term response. Note that the SVR action starts after the faster oscillatory dynamics has died down.

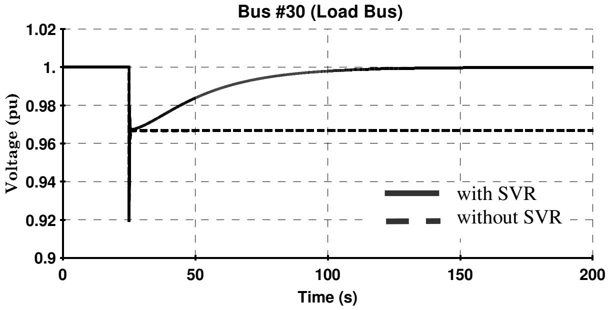

Figure A-6 *Pilot bus voltage in the presence and absence of the SVR scheme.*

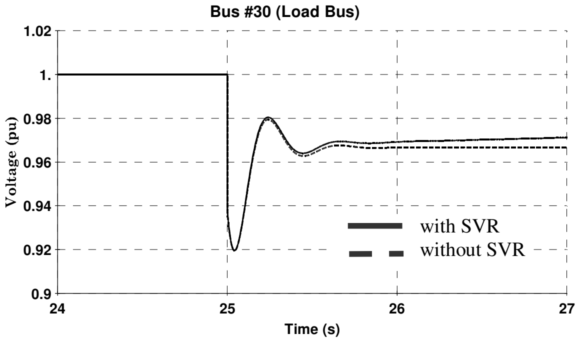

Figure A-7 *Enlarged view of Figure A-6 (short-term response).*

Figure A-8 shows the rotor frequency of generator #1 indicating that after a few electromechanical oscillations of very small amplitude, it returns to synchronous speed. The rotor frequency for generator #2 (not shown here) has an equivalent behavior. The impact of the SVR scheme on the transient behavior of rotor frequency and other relevant system variables was verified to be marginal in all cases analyzed.

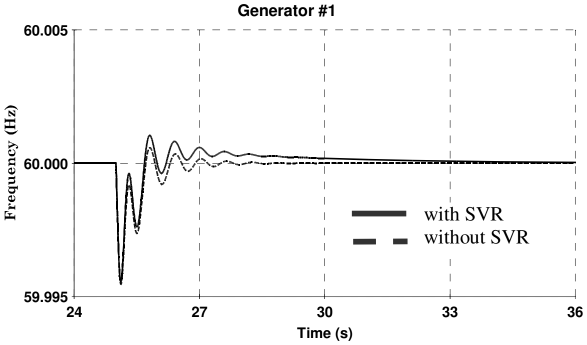

Figure A-8 *Rotor frequency of generator #1.*

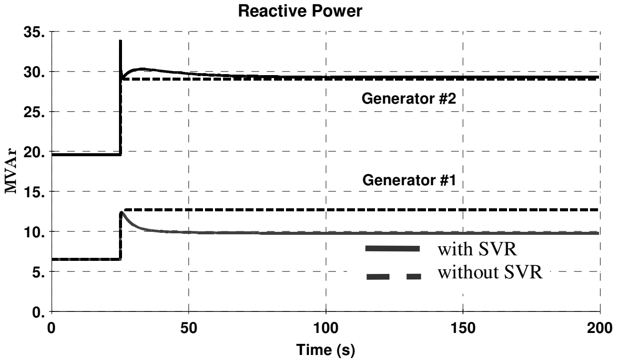

Figure A-9 *Reactive power at generators #1 and #2.*

The reactive powers for both generators are depicted in Figure A-9. In the presence of SVR action (solid line), the post-disturbance reactive power of generator #1 is smaller than it would be otherwise (no SVR action shown in dashed line). The post-disturbance value of the reactive power of generator #2 is not much affected by the SVR action for this specific disturbance.

Note that the SVR scheme ensures that the steady-state reactive power generations of the two power plants are kept at the scheduled 1:3 ratio.

The second test performed involved the application of a negative 10% step change to the reference voltage of the pilot bus (bus #30). Figure A-10 presents the voltage behavior of the pilot bus. Figure A-11 displays the reactive powers of both generators, which are seen to respond coherently to this disturbance.

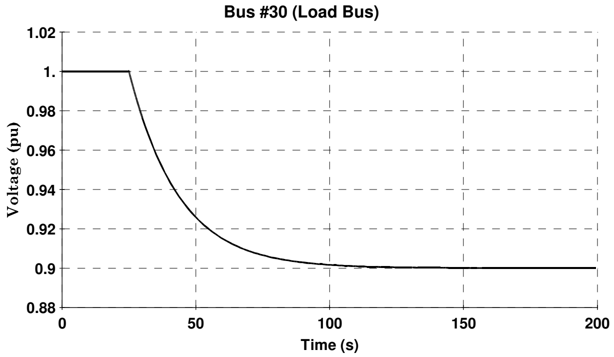

Figure A-10 *Pilot bus voltage for a step disturbance to the SVR voltage reference.*

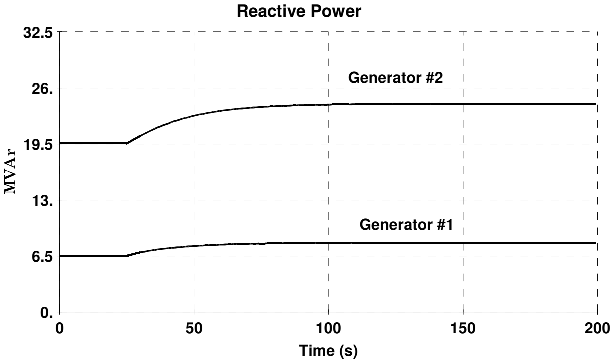

Figure A-11 *Generator reactive powers for a step disturbance to the SVR voltage reference.*

The gains of the PI controllers in the SVR scheme determine the performance and stability of the SVR scheme. The ratio K_I / K_P was varied for the three PI controllers over a fair range without much impact to the results. The SVR scheme was therefore found to be considerably robust to changes in the values of K_I and K_P for the three PI controllers. Note that the results of this section were produced for $K_P = 0.005$ and $K_I = 0.05$ in all three controllers (see Section A.5). SVR scheme with pure integral action is also realizable.

A.3.2 Performance of the SVR Scheme under a Control Loop Failure

System integrity is defined in multivariable control terminology as the capability of the control system to behave stably and remain functioning properly following the loss of a control loop. The same contingency (loss of one circuit between buses #10 and #30) is now simulated with the SVR controller at generator #1 disabled. The only data that is still transmitted to the SVR Central Controller is the instantaneous reactive power Q_{G_1}.

Figure A-12 and Figure A-13 compare the system performances in the absence or presence of SVR control loop failure at generator #1. Note that the SVR scheme, even with the control loop failure at generator #1, continues to perform its intended function. Note there is some degradation in performance, but this should not be critical in practical SVR schemes involving many participating power plants.

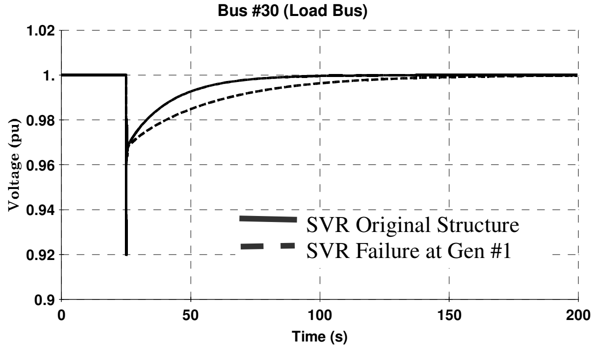

Figure A-12 *Pilot bus voltage with original SVR and with SVR failure at gen #1.*

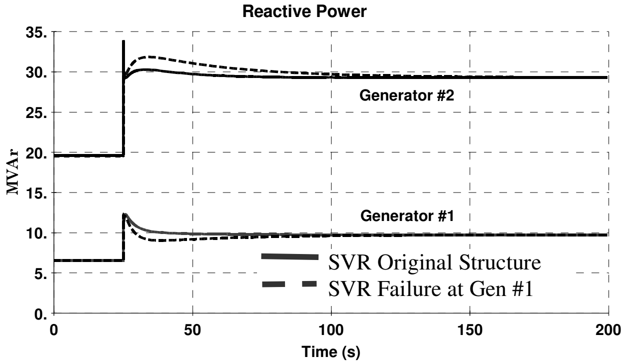

Figure A-13 *Reactive powers at generators #1 and #2.*

A.4 Conclusions

Results on a 5-bus demonstration example were used to help explain the concepts involved in secondary voltage regulation (SVR). There are several advantages in using an SVR scheme: 1) much better voltage regulation in the neighborhood of the pilot nodes; 2) better utilization of the system reactive reserves; 3) proper Var-sharing among closely-coupled power plants; 4) increase of the loading margin.

The control structure and parameters of the SVR scheme together with the full system data are given in this appendix. The SVR control scheme was seen to be intrinsically robust to the control loop failure in one of the participating generators. The participation factors α_1 and α_2 of the SVR scheme determine the steady-state Mvar-sharing ratio and may assume different values according to the voltage control strategy adopted and the system operating condition.

The SVR control structure depicted in Figure A-2 is conceptually similar to those employed in the first generation of European SVR schemes. Analysis and design studies of SVR schemes are expedited with the use of fast simulators of mid-term voltage dynamics.

A.5 System Data

Table A-1 *Power flow data (base case).*

Generation Data					
Bus Number	Voltage		Generation		
	Magnitude	Angle	MW	MVAr	Q_{Max}
1	1.017 pu	0.00°	30	6.52	26
2	1.025 pu	3.66°	90	19.56	78

Load Data				
Bus Number	Voltage		Load	
	Magnitude	Angle	MW	MVAr
30	1.000 pu	-9.50°	120	0

Line Data			
Bus From	Bus To	Circuit Number	Impedance
1	10	1	j 0.20 pu
2	20	1	j 0.07 pu
10	20	1	j 0.07 pu
10	30	1	j 0.18 pu
10	30	2	j 0.18 pu

Table A-2 *Synchronous Machine Data.*

X_d (pu)	X_q (pu)	$X_d^{'}$ (pu)	$X_d^{''}$ (pu)	X_l (pu)
1.4	0.75	0.4	0.25	0.15
$T_{d_0}^{'}$ (s)	$T_{d_0}^{''}$ (s)	$T_{q_0}^{''}$ (s)	H (s)	$cos\phi$
9.	0.025	0.08	3.	0.85

Table A-3 *Gain values for the SVR scheme.*

K_{I_1}	K_{P_1}	K_{I_2}	K_{P_2}	K_{I_v}	K_{P_v}
0.05	0.005	0.05	0.005	0.05	0.005

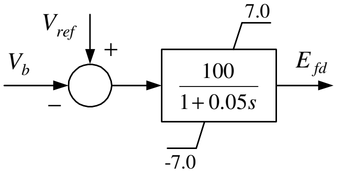

Figure A-14 *Excitation control system.*

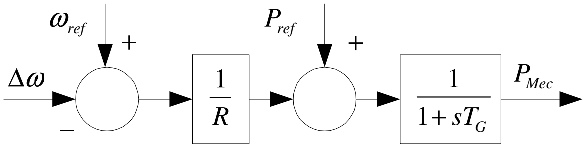

Figure A-15 *Speed-governor model (R = 4% and TG = 0.5s.).*

Part II – Iowa State University EQTP Simulation Results

A.6 Basic Description of EQTP Formulation

The simulation results presented in this Appendix were obtained from a fast simulation tool, based on the work presented in [A-1]. In our simulation, we consider only the pilot bus selection and the control law of the SVR. The dynamics of the SVR scheme are implicitly included by adopting different stepsizes in predictor-corrector method. The final equilibrium point associated with SVR scheme is represented by a set of algebraic equations.

The power system DAE model used in our simulation can be denoted as:

$$\begin{cases} \dot{X} = F^0(X,Y,Z,U) \\ X(t_0) = X_0 \\ 0 = G^0(X,Y,Z,U) \end{cases} \tag{A-1}$$

The algebraic equations for SVR schemes are given below:

$$z_c(k+1) = h_c(X,Y,Z,U,z_c(k)) \tag{A-2}$$

Where:

X	Contains all the system state variables
Y	Includes the algebraic variables
U	Is the control vector
Z	Consists of all uncontrolled disturbances (e.g. load variation at each bus)
Z_c	Represents the SVR scheme state variables (AVR's set points, which describe the SVR dynamics)

A.7 Description of the SVR Scheme

We use the same SVR parameters as in [A-2]. The gains α_1 and α_2 are participation factors that define the adopted Mvar generation ratio at steady state. These participation factors may be fixed, manually varied by operators or automatically set by the Tertiary Voltage Control to implement some desired voltage control strategy. The maximum reactive powers of the two generators are assumed fixed for simplicity. We include a steady state SVR scheme in our EQTP. We ignore the dynamics of the SVR and assume the scheme reaches the steady state at each step. This assumption is compatible with the discrete nature of the SVR scheme and better reflects the effect of the SVR scheme on the practical system.

For each generator involved in the SVR scheme:

$$V_i^{ref}(k+1) = V_i^{ref}(k) + [c_v(V_p^{set} - V_p) + c_q(\alpha_i Q_{g,tot} - Q_{g,i})] \tag{A-3}$$

Where:

$V_i^{ref}(k)$	The generator AVR voltage set point at k^{th} step;
V_p, V_p^{set}	Pilot bus voltage and set point respectively;
$Q_{g,i}, Q_{g,tot}$	Generator i reactive power output and system total reactive power output respectively;
c_v, c_q	The sensitivity factors.

A.8 Numerical Results

Ref. [A-2] simulated different SVR schemes on this simple system and presented some simulation results on margin improvement of SVR. Here we use the Direct Equilibrium Tracing Program (EQTP) to verify the simulation results in ref. [A-2]. Different implementation of SVR scheme is adopted here. In addition, we added another scenario with no SVR scheme to make the comparison. We simulated the steady-state performances of the following voltage control alternatives:

- SVR with bus #30 as pilot node;
- SVR with bus #20 as pilot node;
- SVR with bus #10 as pilot node;
- Without any SVR scheme;

These voltage control alternatives were compared for two system conditions: base case configuration and the contingency configuration (single-line outage between buses #10 and #30). The load was modeled as constant power. The extra active power needed to supply the increasing load was shared between the two generators according to their ratings.

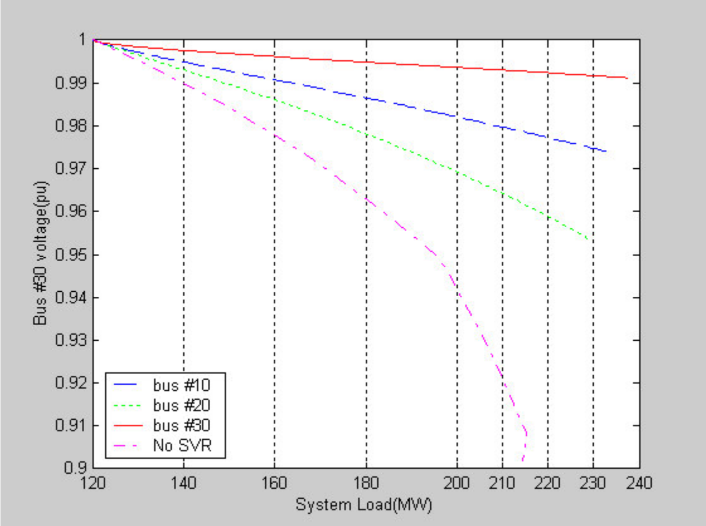

Figure A-16 *Voltage at the load bus (#30) for the base case configuration.*

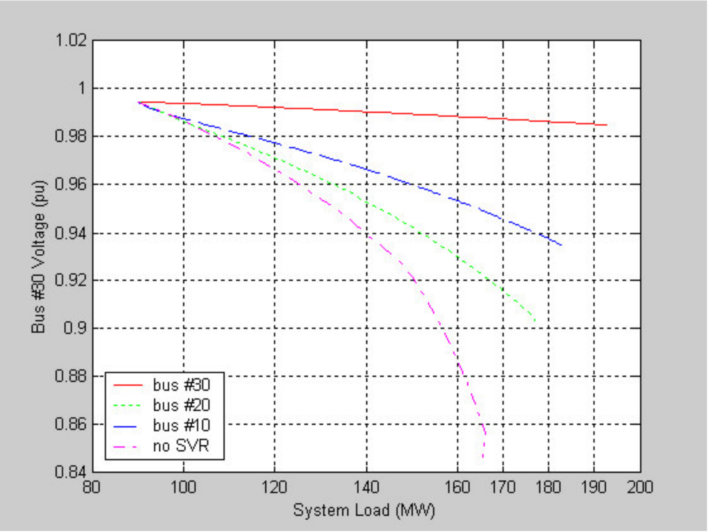

Figure A-17 *Voltage at the load bus (#30) for the contingency.*

Figure A-16 and Figure A-17 show that system loading margins change when adopting different voltage control alternatives. Figure A-16 corresponds to the base case, while Figure A-17 corresponds to the contingency case. In both cases, larger margins are achieved when adopting SVR schemes. At the same time, the generator terminal voltages will be higher than normal (without SVR scheme). Under certain configurations, the terminal voltage will be unacceptably high. This problem can be solved either by installing a switchable shunt capacitor or carefully adjusting the SVR scheme. These are similar to the results in [A-2].

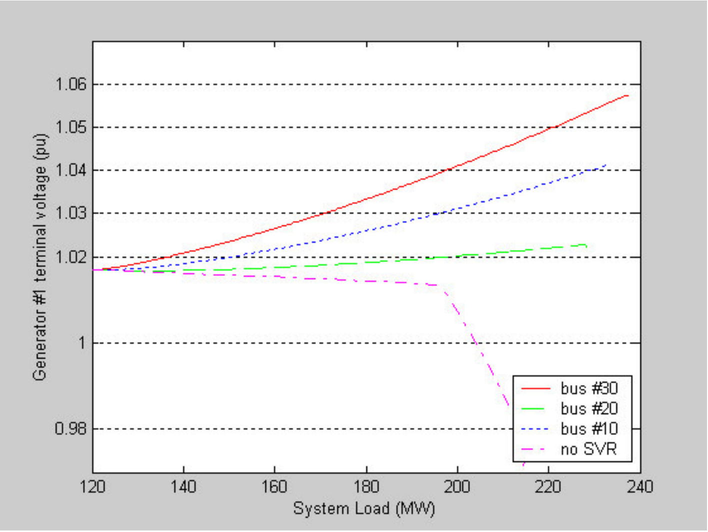

Figure A-18 *Generator #1 terminal voltage for the base case configuration.*

Figure A-18 and Figure A-19 show the generator terminal voltage change when adopting different voltage control alternatives under the base case configuration. Figure A-16 shows that the largest loading margin is obtained when choosing the load bus #30 as the pilot node of the SVR scheme. But from Figure A-19, if we choose such SVR scheme, the terminal voltage will reach 1.09 pu, exceeding the maximum operating voltage. By the combination of the two factors, the choice of bus #30 as the pilot node will be no longer the best. Instead, bus #20 as the pilot bus is a compromise solution.

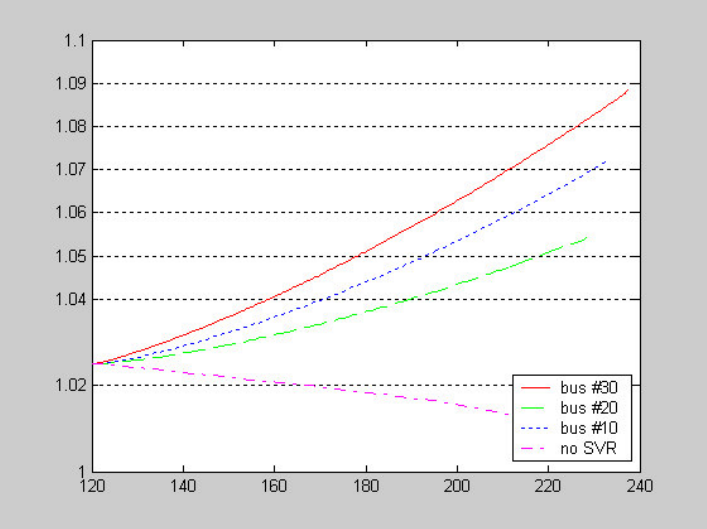

Figure A-19 *Generator #2 terminal voltage for the base case configuration.*

In this report we also adopt different Var-sharing ratios to see the effect of the generator reactive power reserve on SVR scheme. Figure A-20 shows the load margin change under different var-sharing ratios. Under the ratio 1:3 (equal to the ratio of the reactive power reserve between the two generators), we get the largest load margin. In general, the margin sensitivity analysis of V_{ref} of each generator can provide the information related to the appropriate var-sharing ratio. Margin sensitivity information can be easily calculated by EQTP. By ranking the sensitivity of V_{ref} to the load margin of each generator, we can recognize the most effective generator and then try to adjust the var-sharing ratio to achieve better results.

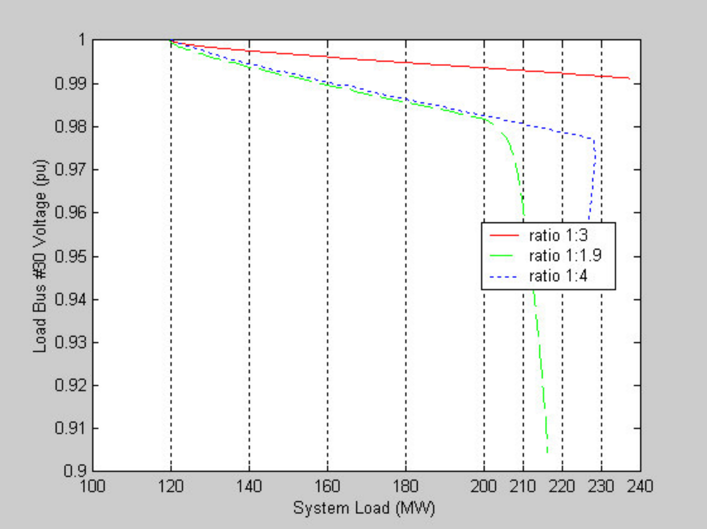

Figure A-20 *System load margin change under different var-sharing scheme.*

Part III – Tutorial System Results by ENEL

A.9 Introduction

A detailed performance analysis of the coordinated voltage control application of a large power system requires a quite complex mathematical modeling, depending on the grid extension, the variety of the relevant electrical components and the involved control and protection equipment. The modeling detail should be sufficient to capture the main system requirements and features, as actually implemented in the coordinated voltage control solution.

In the past, such analysis was mainly carried out from a "static" point of view. More recently, an in-depth evaluation of the dynamic performance of power systems, modeled with suitable detail, is capable of capturing all relevant dynamic interactions between system sub-components and related regulation, and protection loops as well as limiters.

A.10 STUDY CASE: Single Area Grid with two Equivalent Power Plants

This study case is shown in Figure A-21, where the power generation subsystem is formed by two equivalent units (G1 and G2 with different rated powers An1 and An2), connected in parallel (through step-up transformers Xt1, Xt2 and interconnection lines Xl1, Xl2) to the main supply bus of the grid, elsewhere named pilot node (node 3 = node 4 = node 7). Such a pilot node is connected through interconnection line Xe to an infinite bus (node 8), which represents the large capacity neighboring networks. Moreover the transmission and distribution subsystem is also present (by an interconnection line Xlc) between the power supply bus and the electrical loads of the system (final user area with nodes 5 and 6).

The final user area can be further subdivided in loads with a low voltage power supply (node 6), powered through an equivalent transformer (with reactances Xtcp, Xtcs) equipped with LTC (with variable transformer ratio Ntc), and loads directly coupled to the high voltage transmission line (node 5). The low voltage level at node 6 allows a quite detailed representation, consisting of both static (linear and non-linear with respect to the voltage supply V6) and dynamic loads (with fast responses as induction motors and low dynamics as thermo-controlled loads). At the node 5 voltage level, a simpler impedance load representation may result adequate.

The overall grid voltage regulation system is formed by the secondary voltage regulation loop to control the high voltage at the pilot node bus (node 4), by the local static compensation resource (SVC) to balance the reactive power absorbed at the station (node 5) and by the local LTC to regulate voltage at the final user load (node 6).

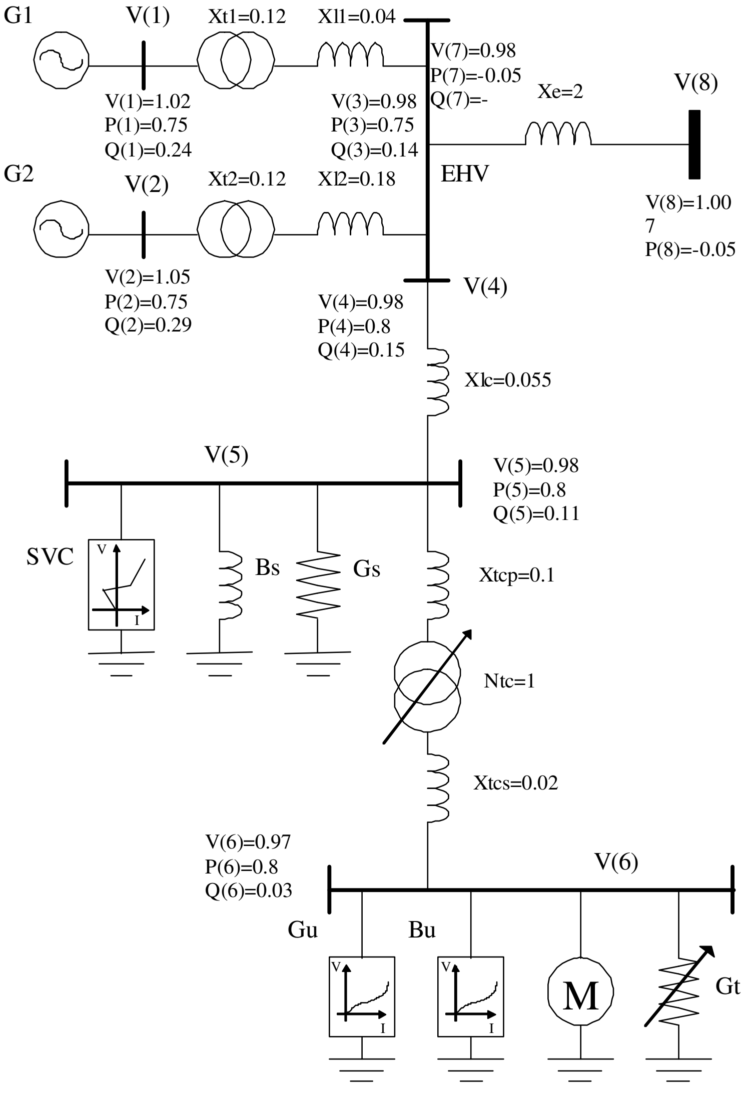

Figure A-21 *Simplified diagram for study case.*

A.10.1 Model of the Generating Units

The generating units are controlled by primary voltage regulation loops, with over-excitation limits and power system stabilizers, primary speed control governors and power plant program load units.

The time constants T_d', T_d'', T_{d0}', T_{d0}'', T_q', T_q'', T_{q0}', T_{q0}'', the synchronous reactances X_d, X_q and the sub-transient reactances X_d'' and X_q'' are assumed equal to the following values:

$X_d = 2.29\ pu$	$X_q = 2.21\ pu$
$X''_d = 0.2653\ pu$	$X''_q = 0.2653\ pu$
$T'_d = 1\ s$	$T'_q = 0.14\ s$
$T''_d = 0.014\ s$	$T''_q = 0.013\ s$
$T'_{d_0} = 6.36\ s$	$T'_{q_0} = 0.55\ s$
$T''_{d_0} = 0.019\ s$	$T''_{q_0} = 0.028\ s$

The step-up transformers are modeled by their leakage reactances (X_{t_1}, X_{t_2}), and the interconnection lines by the equivalent reactances (Xl1, Xl2). The voltage levels (V1, V2), power levels (P1 and Q1, P2 and Q2) and unit reactances (Xt1 and Xl1, Xt2 and Xl2) are referred respectively to the same nominal voltage (Vn1 = Vn2 = 20 kV), to a couple of different nominal powers (An1 = 3000 MVA e An2 = 750 MVA) and to a pair of different nominal impedances (Zn1 = Vn^2/An1, Zn2 = Vn^2/An2).

A.10.2 Primary Voltage Regulation (PVR)

The Automatic Voltage Regulator (AVR) loop (Figure A-22) allows the primary control of the terminal voltages V_1 and V_2 of the equivalent generating units through the excitation voltages V_{f1} and V_{f2}.

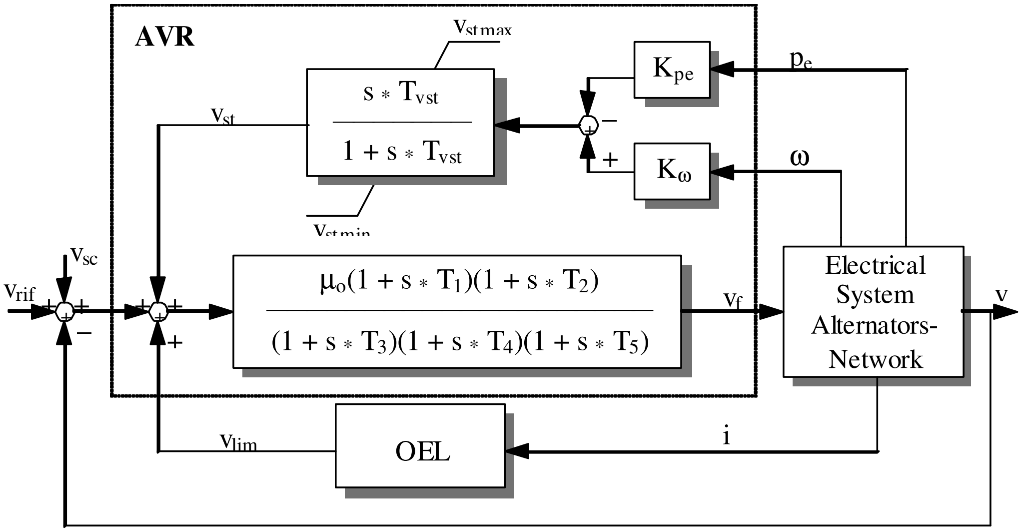

Figure A-22 Block diagram of the Primary Voltage Regulation (PVR).

The different signals in the Primary Voltage Regulation (PVR) are identified below:

The primary voltage set-point V_{rif}, indicating the terminal voltage required for the generator;

The measured terminal voltage V, used for feedback comparison with the related set-point;

The secondary voltage reference V_{sc}, coming from the reactive power regulation loop and representing the contribution of the primary voltage control to the reactive power regulation of the equivalent unit);

The limitation signal $V_{\lim}$ for the operation in over-excitation limit;

The additional feedback signal V_{st} for damping the electromechanical oscillations.

The machine excitation system is assumed for simplicity static with independent supply. The regulator has a 3rd order transfer function, with poles and zeros at high frequencies that allow achieving a wide band regulation while the low frequency high value gain μ_0 assures a quasi-null steady-state error.

The AVR parameters are the following:

μ_o = 500 p.u./p.u. *Tvst* = 3 s

T_1 = 2 s *Kpe* = 0,15 p.u./p.u.

T_2 = 0.05 s $K\omega$ = 15 p.u./p.u.

T_3 = 20 s *Vstmin*= -0.05 p.u.

T_4 = 0.02 s *Vstmax* = 0.05 p.u.

T_5 = 0.01 s

The operation of the synchronous machine in over-excitation is achieved at the primary voltage control level through the injection of the signal $V_{\lim}$ at the set-point node. Such a signal comes from an integral regulator, with only positive saturation, whose input continuously compares the actual excitation current If and the corresponding maximum value $If_{\lim}$.

In normal working conditions, If is lower than $If_{\lim}$ and the integrator, saturated with null $V_{\lim}$, does not participate in the primary voltage regulation. When If exceeds $If_{\lim}$, the integrator comes out of saturation and provides a negative $V_{\lim}$ signal, in such a way as to de-excite the machine and impose the limit condition $If = If_{\lim}$.

It is also possible to allow a certain degree of transient overload in the excitation windings, through the adoption of suitable non-linear blocks inserted in the field current limitation loop. The excitation current If can then reach levels higher than those previously imposed, nevertheless abiding to the limitations imposed by the machine time-thermal characteristics (rotor and winding heating, components endurance and aging).

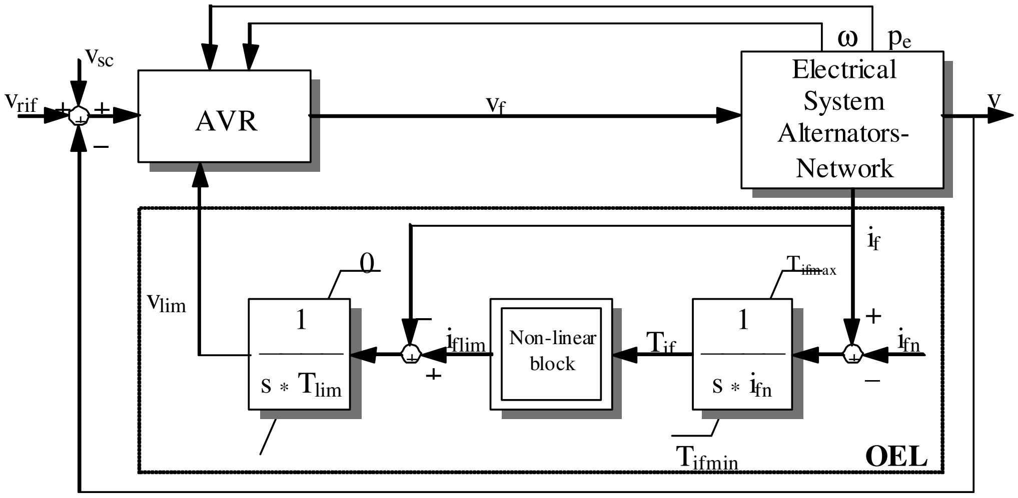

Figure A-23 *Block diagram of the over-excitation limit.*

The time interval available for transient extra-loads is typically within the range 5-15 s and the maximum allowed value for such a field windings operation is defined according to an integral equation based on the percent variation of excitation current If with respect to its nominal value Ifn.

The non-linear block defines, according to the instantaneous Tif value (lower or higher than the maximum allowed value) and the excitation system operating conditions (if a minimum recovery time has passed since the last overload operation), which is the proper value of Iflim, allowing only if possible the field windings extra-excitation.

Typical values for the over-excitation limit parameters are the following:

Tlim = 10 s *Tifmin* = 0 s

Vlimmax = 0 Tifmax = 5 s

A.10.3 Secondary Voltage Regulation (SVR)

In the tutorial system considered, the secondary voltage regulation is achieved only through the equivalent unit G1, with higher rated power (An1), controlling the bus voltage V3=V4=V7 (pilot node). The equivalent unit G2, with lower rated power (An2), is assumed operating only in primary voltage regulation.

The secondary voltage regulation is achieved through two hierarchically structured loops: the inner loop, of integral type, regulates the reactive power delivered by the equivalent unit, through the control variable Vsc acting on the voltage reference summing junction of the related AVR; the outer loop, of proportional-integral type, regulates more slowly the voltage level at the pilot node Vs, according to its set-point Vsrif and through the control variable Qrif acting on the reactive regulator [A-3, A-4].

The plant reactive power regulator (PQR) follows the request coming from the slow acting pilot node regional voltage regulator (RVR), shown in the outer loop of Figure A-24.

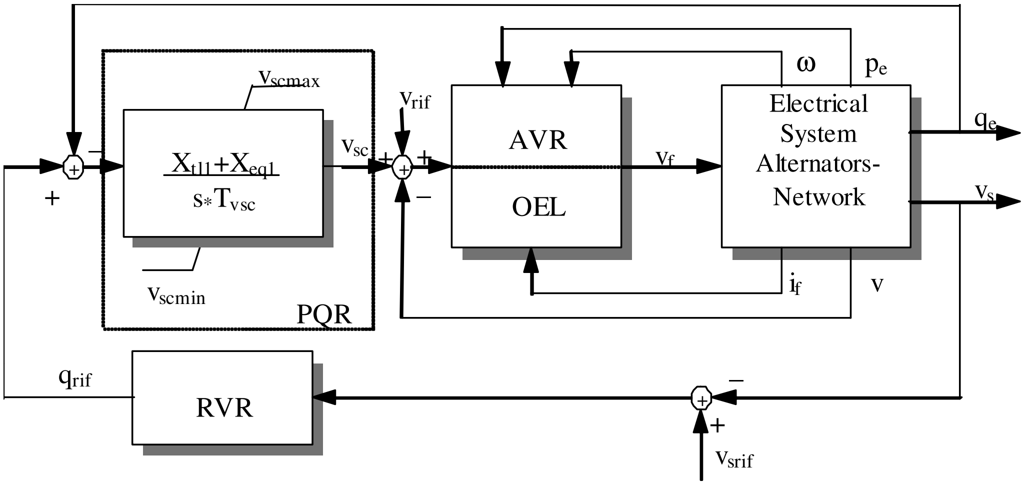

Figure A-24 *Block diagram of the plant reactive power regulator (PQR).*

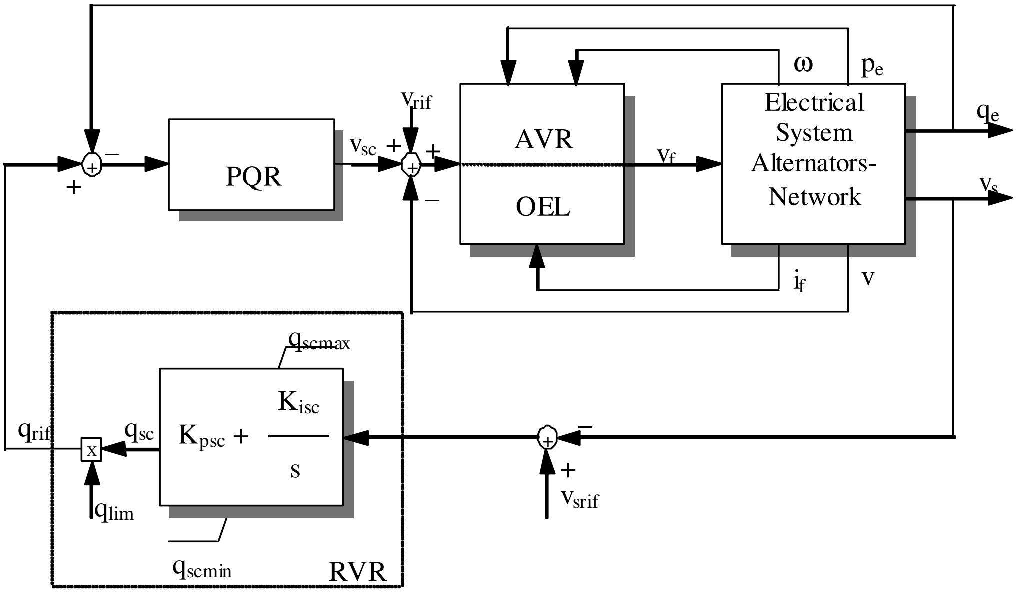

Figure A-25 *Block diagram of the regional pilot node voltage regulator (RVR).*

The determination of the PQR and RVR parameters is based on the requirement of a dynamic decoupling between hierarchical levels (inner levels are faster than outer levels), with an equivalent time constant Tvsc and Tqsc respectively equal to 5 s and 50 s. The time delay introduced in the PQR loop by the AVR (time constant equivalent to about 0.2-0.5 s), is negligible. Similarly, the PQR regulator introduces negligible delay in the RVR loop dynamics.

The reactive power level signal Qsc is kept within Qscmin and Qscmax (-1 and +1) and represents the ratio between the reactive power delivered by the generator and its maximum allowed value (Qlimp or Qlimn). In fact such a level is multiplied by Qlimp or Qlimn and the result is the reactive power request to be generated or absorbed depending on the unit over or under-excitation. The maximum allowed values Qlimp and Qlimn depend on the generator operating point and therefore are generally both time and load dependent.

The values for the PQR and RVR parameters are the following:

Xtl1 = 0.16 p.u. *Tvsc* = 5 s
Vscmin = -0.2 p.u. *Vscmax* = 0.15 p.u.
Qscmin = -1 *Qscmax* = 1

A more concise block diagram of the primary and secondary voltage regulation loops is shown in Figure A-26.

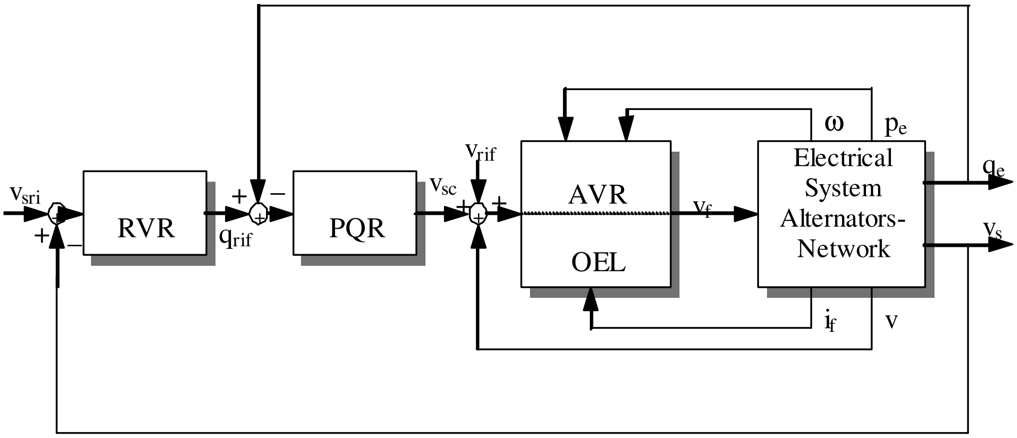

Figure A-26 *Block diagram of the primary and secondary voltage regulation loops.*

A.10.4 Simulation Results

A sample of the simulation results obtained for this tutorial system is presented in this Section for a load change applied to the pilot node bus, considering different configurations of the grid voltage regulation loops:

PT refers to the presence of the tap-changer control and primary voltage regulation at the generators;

PLT is similar to PT except for the addition of the over-excitation limits on units primary voltage regulation;

PLST is similar to PLT except for the addition of the secondary voltage regulation by the high rated size units;

PLSRT is similar to PLST except for the addition of the power flow regulation at the infinite bus node;

PLSRBT is similar to PLSRT except for the addition of the local voltage control by the static var compensator.

Figure A-27 to Figure A-31 display various results related ot this test system, which are summarized in the remaining text of this appendix.

As can be seen, growing the load ramp variation it becomes more difficult the regulation of the low voltage level of the load power supply (V6) at the related set-point (V6rif), due to the possible saturation or reverse action of the tap-changer control, moving the transformer ratio (NTC) with respect to its nominal value (NTCnom). Specific remarks are made on the differences among the five voltage control configurations as regards their ability to protect against voltage instability and collapse.

It is well known that the transients leading to voltage instability and collapse are strongly dependent on the behavior and the dynamic interaction between the unit over-excitation limits and the LTC regulation loop. With reference to the simplified grid model considered in this study case, the control loop of the LTC transformation ratio NTC affects both the load voltage profile V6 (the LV bus) and the pilot node voltage V4 (the HV bus) and therefore modifies the operating conditions of the equivalent units, as well as their exchanges with the infinite bus. The unit over-excitation limits operation considerably modifies the controllability of the load voltage V6 and entails, growing the load ramp variation and for low values of the transformer ratio NTC, the LTC control loop instability risk. Such instability causes a network voltage V4 and load voltage V6 degradation which only stops when the LTC reaches tap limits.

The coordinated secondary voltage regulation improves the controllability of the load voltage V6 and reduce the variations of NTC as long as the unit over-excitation limits are not reached. Secondary voltage regulation, when the controlled units are in over-excitation limit conditions, is in open loop and therefore does not help to arrest voltage degradation. Nevertheless, it should be pointed out that, within moderate load variation edges, the secondary voltage regulation keeps stable the LTC control loop, which otherwise becomes unstable without such regulation. With the secondary voltage regulation in operation, the unit over-excitation intervention is reached with a slight lead, with consequent LTC control loop instability, the transient evolution after the perturbation, and in particular the load voltage abatement, proceed more slowly. Moderate improvements to the LTC control loop stability are also obtained, only in the presence of the secondary voltage regulation, considering a time delay in the transformation ratio NTC control law: the LTC control loop intervention follows the load change with a time delay.

The performance of local voltage support by means of reactive power resources is inferior to that achieved through coordinated voltage control, due to their different rated size and control philosophy. Nevertheless their effects are quite similar concerning the interactions with tap-changer control, putting in evidence a reduced risk of over-excitation forcing of the generating units, due to the increased self support of the pilot node bus voltage.

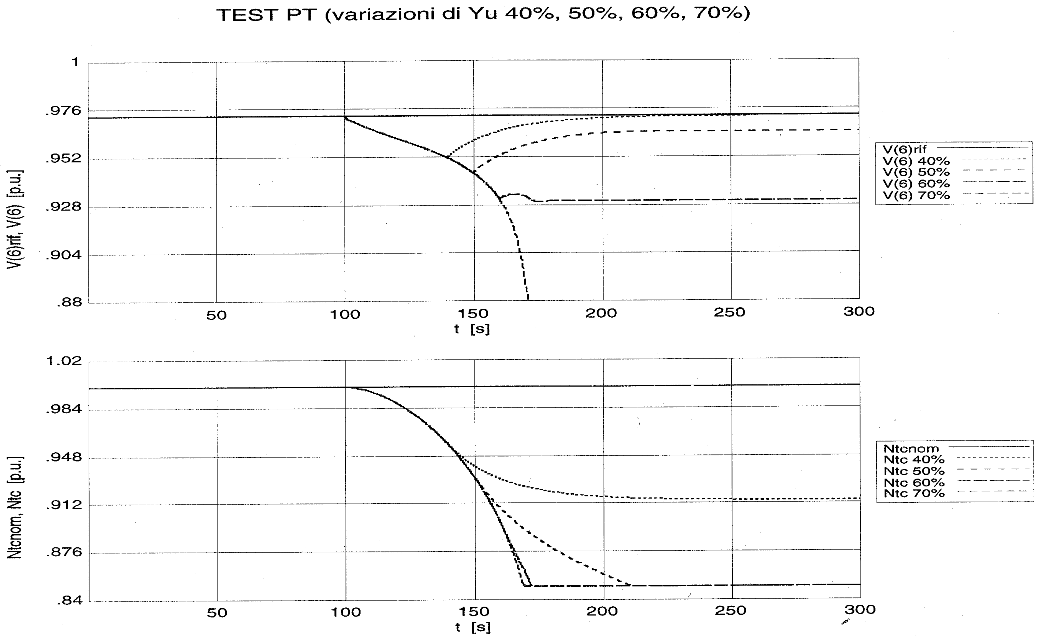
TEST PT (variazioni di Yu 40%, 50%, 60%, 70%)

Figure A-27 *Dynamic transients following pilot node load ramp in the presence of tap-changer control and units primary regulation (Configuration PT).*

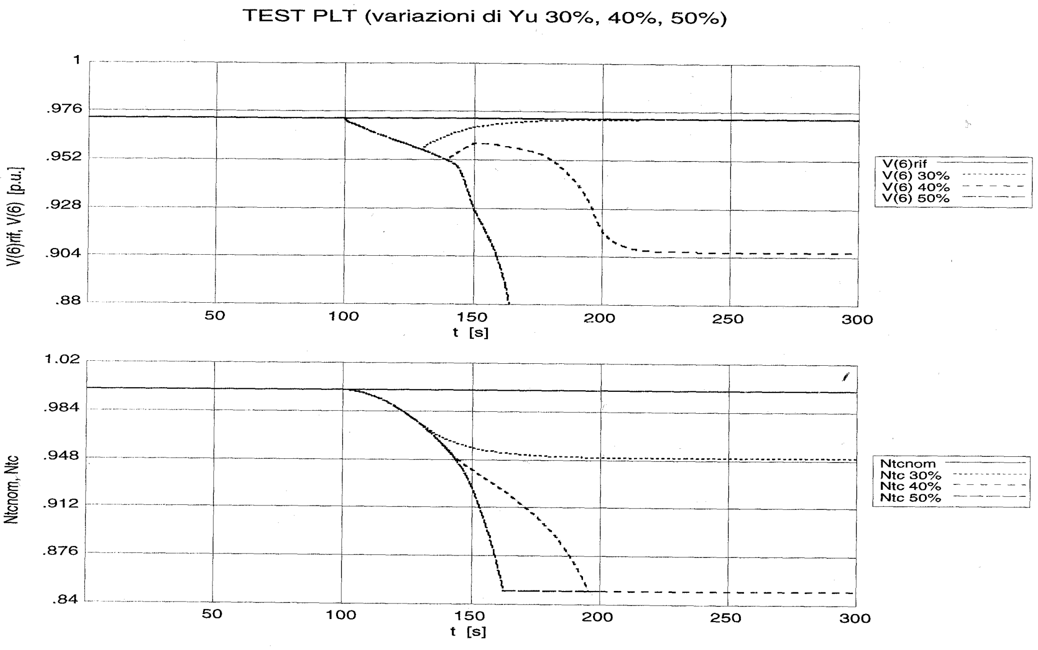
TEST PLT (variazioni di Yu 30%, 40%, 50%)

Figure A-28 *Dynamic transients following pilot node load ramp: the over-excitation limits on units primary regulation (Configuration PLT).*

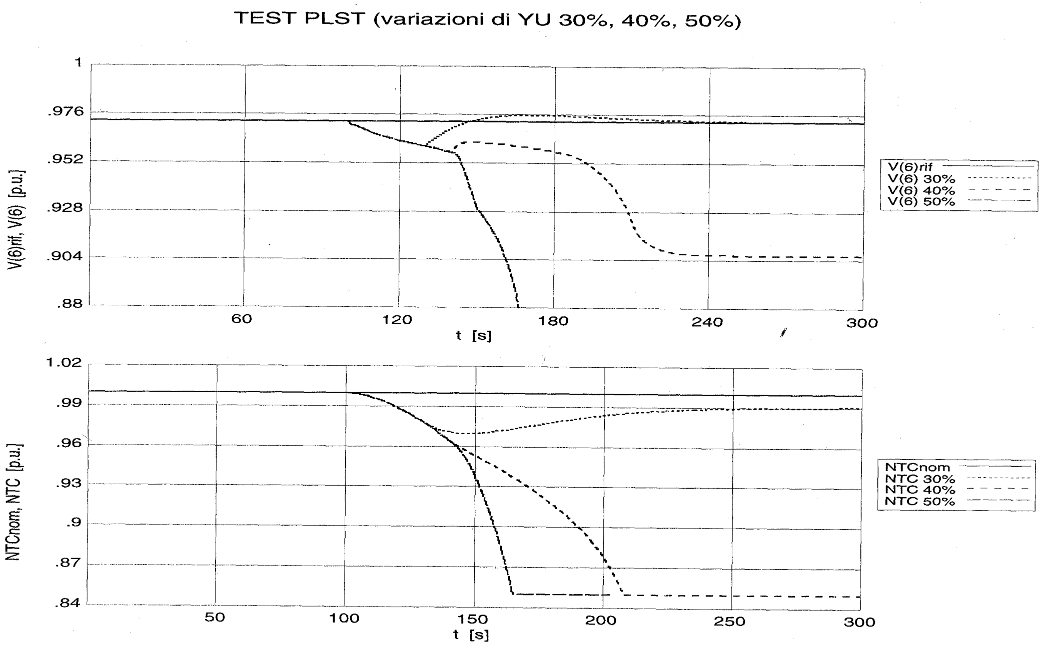

Figure A-29 *Dynamic transients following pilot node load ramp: same as previous case, with addition of the secondary voltage regulation at the high sized units (Configuration PLST).*

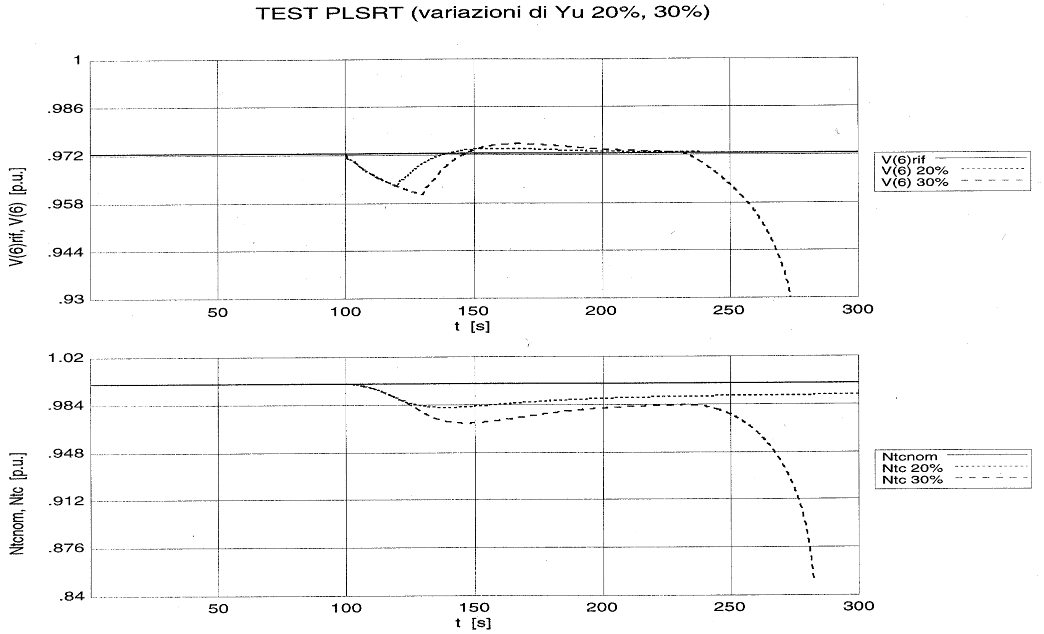

Figure A-30 *Dynamic transients following pilot node load ramp: same as previous case, with addition of power flow regulation at the infinite bus (Configuration PLSRT).*

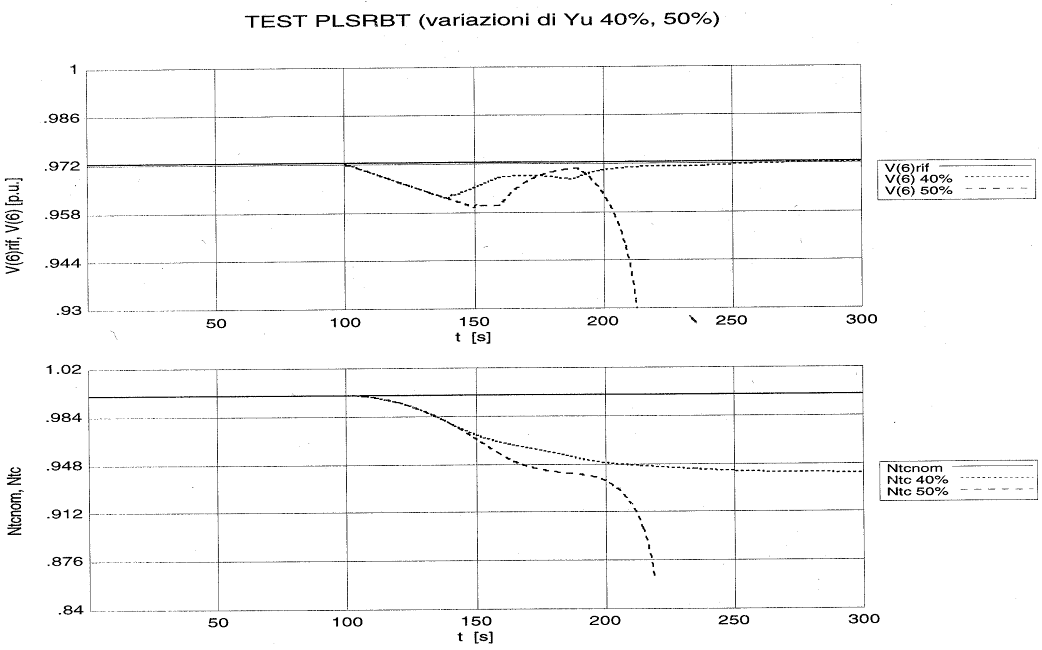

Figure A-31 *Dynamic transients following pilot node load ramp: same as previous case, with addition of the local voltage control by the static var compensator (Configuration PLSRBT).*

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[A-2] Nelson Martins; J C R Ferraz; Sergio Gomes Jr.; P E M Quintão; J A Passos Filho, “A Demonstration Example of Secondary Voltage Regulation: Detailed Dynamic Simulation and Continuation Power Flow Results”, *Panel Session on Secondary Voltage Control, IEEE/PES Winter Meeting*, Columbus, OH, January 2001.

[A-3] S. Corsi, M. Pozzi, Milan, M. Sforna, G. Dell’Olio, “ The Coordinated Automatic Voltage Control of the Italian Transmission Grid, Part I : Reasons of the Choice and Overview of the Consolidated Hierarchical System”- IEEE Transactions on Power Systems, vol. 19, n. 4, pp. 1723-1732, 2004.

[A-4] S. Corsi, M. Pozzi, Milan, M. Sforna, G. Dell’Olio, “ The Coordinated Automatic Voltage Control of the Italian Transmission Grid, Part II : Control Apparatuses and Field Performance of the Consolidated Hierarchical System”- IEEE Transactions on Power Systems, vol. 19, n. 4, pp. 1733-1741, 2004.

Appendix B

Voltage Reactive Power Control Strategy in the Colombian Transmission System: Control Philosophy, Application and Implementation

B.1 Introduction

The expansion of the Colombian Transmission System, with a new 500 kV line connecting the central and south western regions, demanded certain amount of fixed inductive compensation, some switched inductive compensation and some switched capacitive compensation, due to the 5 to 1 and 3 to 1 ratios, between the maximum and minimum demands found in the system. A decision on how to operate and control the connection and disconnection of all the switched elements had to be made bearing in mind that the new scheme of competition demands a more flexible and robust system with the least possible constraints. The so called Transmission System Constraints or Transmission Congestion, refer to the practical operating limits that require defining the minimum number of units and associated active generation that have to be dispatched in certain parts of the system, and the imports-exports limits between the different areas. When the offered price of a generating unit defined as minimum security generation, is above the marginal cost of the ideal dispatch, or the dispatch of strict merit order, then this out of merit generation constitutes an extra cost for the dispatch of the system.

The detailed system studies carried out for the design of The Expansion Plan, revealed that an overall control strategy was desirable for many reasons, among which are: (a) The need to ensure a secure way to handle the reactive power throughout the system (b) The need for a more flexible and controllable system (c) The need to reduce or eliminate transmission constraints and (d) The advantages gained by standardizing control equipment for the many projects in the expansion plan.

B.2 The Control Strategy

As the reactive power sources and sinks are distributed throughout the system, and since the dependence on communications could not be afforded to ensure system security, a decision was made towards a distributed control strategy.

Based on the observability of the system there are three levels of control and/or coordination:

- The local control: autonomous and restricted to the local substation;
- The area control or pilot control: locally autonomous as well as in its area of influence;
- Central coordination from the National Control Center “CND”: Defines the optimum voltage profiles for the system and in consequence sets the target voltages in real time for the pilot controls, as well as for the local controls.

The main objectives of the control strategy are:

- Maintain the voltages of all the nodes in the system at 220 kV level and above within the permitted range of operation, in accordance with the criteria of the Colombian Grid Code;
- Improve and extend the stability in order to maximize the utilization of the transmission system;
- Reduce the reactive power flow in the system to lower the I^2R and I^2X losses to a practical minimum and ensure an efficient operation;

B.2.1 Local Controls

Each individual control at a substation, called a Local Control, is responsible for the decisions for the connection and disconnection of the shunt elements, as well as for the tap movements of the LTC, when the local controlled variables go out of a predetermined range of operation. Remote variables can also be brought to the local controls to improve their performance under foreseen situations, but system security should not depend on the availability of these remote variables.

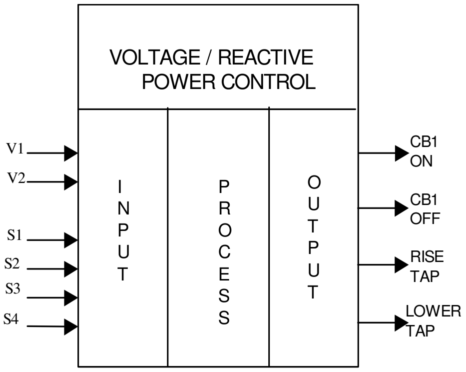


Figure B-1 *Local control.*

B.2.2 Pilot Controls

Some local controls are programmed to make area decisions, in which case they are called Pilot Controls or Area Controls. The need for these Pilot Controls arises when coordination between local controls within an electrical area is required, or when the control actions of faster continuous devices, such as Static Var Compensators or Voltage Regulators of nearby generators, do not allow the local control to observe big enough changes in the local controlled variables to initiate an action, but due to their strong electrical coupling, require some coordination in order to maintain adequate reactive reserves in the faster devices of the system.

B.2.3 Central Coordination

Having autonomous distributed controls that take care of the operation of shunt devices at critical times, allows non critical decisions to be made remotely, taking advantage of the wider observability of the system to determine and maintain optimum voltage profiles by changing in real time the setpoints of the pilot and local controls. This also assures optimum performance of the controls during the 24 hours of the day. A control strategy like this can be categorized as Distributed and Centrally Coordinated. The definition of the required setpoints for each individual control can be based on real time system analysis, such as optimal power flows, optimum reactive dispatch etc.

B.3 The Basic Control

The local controls as well as the pilot controls are based on the operation principle known as Voltage Reactive Power Control or VQC. The VQ control is a discrete control that makes decisions for the connection or disconnection of shunt elements, whenever the controlled variable leaves a deadband. In substations having two voltage levels coupled through transformers, the typical controlled variables are the two voltage levels. By assigning a deadband to each voltage level and putting them as the axis of a plane, nine distinct zones are obtained, reflecting the different operating states of the system, making possible to assign the most effective and secure actions for the different zones as well as their priority order. Figure C-2 shows such a plane for a typical substation, where the central region formed by the two dead bands is the zone of normal operation, and within this zone no decisions are made, but when the operating point moves outside this area, different actions are taken. The zones located at the four corners have the most critical need for control actions: zones 5 and 6 indicating low voltages and high voltages respectively, while zones 7 and 8 indicate that one voltage is high while the other is low. The best actions for zones 1, 2, 3 and 4 depend on the location of the shunt elements, the short circuit levels of the two voltage levels and the direction of power flow, but in any case simulations should prove their effectiveness.

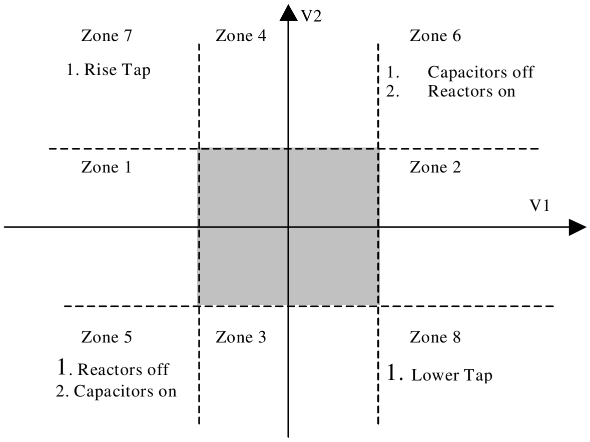


Figure B-2 *Principle of operation.*

This operation principle has been successfully used in Colombia for more than 5 years for the control of Mechanically Switched Capacitors, taking actions whenever the voltage goes outside the dead band, using a fixed programmable delay of about 10 to 15 seconds, with the help of a Programmable Logical Controller (PLC). Figure B-3 shows that this type of control has a hysteresis between the on and off actions, as a function of the width of the dead band and the short circuit level of the node. Hysteresis is always desirable with discrete controls; and this type of control is good enough for maintaining good voltage regulation during normal quasi-static conditions, but is not suitable for the dynamic state or under contingency conditions where faster actions are required.

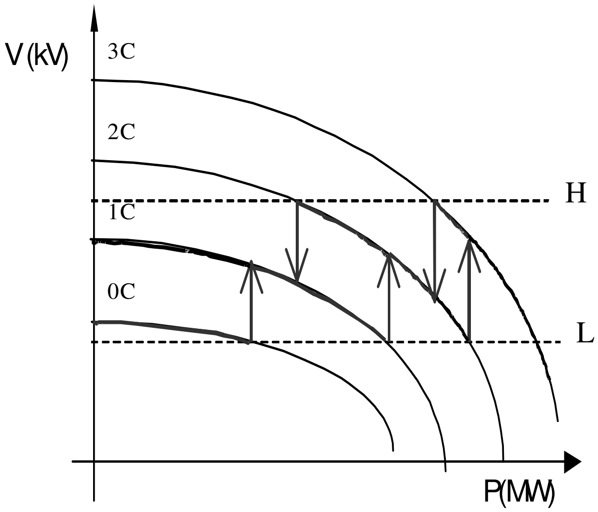


Figure B-3 *P-V characteristic.*

B.3.1 Integral of the Error Algorithm

The integral of the error outside the dead band provides an adaptive decision algorithm that reacts in accordance with the faced system condition, based on an area error:

$$A = \int \Delta V . dt \quad \text{(B-1)}$$

Where voltage is given in kV and time (t) in seconds. An improved performance of the control algorithm can be achieved by correcting the measured voltage by the effect of the injection or absorption of reactive power of nearby SVCs or generations.

$$Vcorrected = Vmeasured + Q[-\Delta \mathrm{V}/\Delta \mathrm{Q}] \quad \text{(B-2)}$$

The corrected voltage reflects the voltage obtained if the reactive sources or sinks were not present, thus anticipating the need for actions before they became saturated. This voltage correction algorithm improves voltage security since it allows maintaining adequate on-line reactive reserves in the faster devices of the system, at all times.

The change in voltage in a node due to reactive power injection or absorption is characterized by the system Load Line and (ΔV/ΔQ) is the slope of the Load Line. When the reactive power injections or absorptions are not in the same bus but in other busses of the system, then this factor has to be obtained by appropriate sensitivity analysis.

Keeping the history of past integrations of the errors for some time is desirable since by doing so, decisions are made faster for on-going phenomena. The integration history should not be kept for too long, however, otherwise the adaptive capability of the algorithm would be lost.

B.4 Control Algorithms for Different System Conditions

The microprocessor-based controller allows the operation of various parallel algorithms to optimize the performance of the controller over a wide number of credible system conditions.

B.4.1 Limit of Integration Time

For those cases where the error outside the deadband is very small and the integration algorithm could take very long, a supervision of the time outside the dead band can limit the time in which a decision is made. This time is usually programmed into the PLC to be in the range of 10 to 15 s, ensuring that in these cases, control actions are taken in times no longer than the programmed time.

B.4.2 Fast Decision Algorithm

A wider deadband can be used to identify highly critical system conditions that require faster decisions in order to maintain stability. For example, abnormally low voltages, in the absence of a fault (0.85 pu to 0.5 pu) could initiate fast actions to connect capacitors or disconnect reactors.

B.4.3 Reactive Limit Algorithm

In applications where the Voltage Reactive Power Control is to be coordinated with a continuous reactive source and/or sink (SVS or Synchronous Machine), the reactive output of this source should be monitored, and decisions be made whenever the reactive power exceeds a predefined limit. This algorithm serves as a back up to the one based on the measurement of the voltage, and also contributes to maintain adequate reactive reserves in the system.

B.5 Basic Monitoring Functions

The local and pilot controls also perform monitoring and alarm functions, to identify system conditions that are different to control automatically, indicating that the system would be better off in the hands of the operator.

B.5.1 Weak System Detection

This condition is detected by measuring the voltage change incurred by the connection or disconnection and comparing this with a programmable value, usually the width of the deadband. When this condition is detected, the control switches to manual operation and an alarm informs the operator of the situation. Operator intervention is required to restore the control to automatic mode.

B.5.2 Unstable Operation

Whenever the control makes three opposite operations within a programmable time window, unstable operation is detected and the control is switched to manual, while an alarm informs the operator of the situation. Once again operator intervention is required to restore the control back to automatic.

B.5.3 Actuation Failure

Every time a command is sent to an element, supervision is initiated to confirm the state change of the element. If this confirmation is not received within a programmed time, an actuation failure is detected, and an alarm comes off to alert the operator.

B.5.4 Invalid States Detection

This function detects invalid or inconsistent states of the monitored elements. For example, a circuit breaker can be either closed or open but not both. This is usually helpful to detect problems with signal acquisition.

B.5.5 Unavailable Resources

This condition is detected if the controlled variable goes out of the deadband and there aren't available resources to eliminate this violation. An alarm comes off informing the operator on this critical situation.

B.6 Interlock Functions

The controls must have the corresponding interlock functions to avoid non-permitted operations, and to prevent misoperation of the controlled elements. This is done by evaluating a permit signal for each control command (i.e. a capacitor or reactor connection command) based on the monitoring of the states or positions of the disconnectors, earthing connectors and circuit breakers.

B.7 Algorithm Design Methodology

The design and validation of the control algorithms is carried out in four steps:

- Choice of definition of the control strategy;
- Control hypothesis design;
- Functionality verification of the hypothetical control;

- Validation of the control strategy and control algorithms.

B.7.1 Control Strategy

From the substation layout, the position of the elements to maneuver and the bus voltages to control, a basic and logical control strategy is proposed. Figure B-4 shows the one line diagram of a substation with two voltage levels, 500 kV and 230 kV, an autotransformer with tap changer under load, two tertiary reactors and four capacitor banks connected to the 230 kV bus bar.

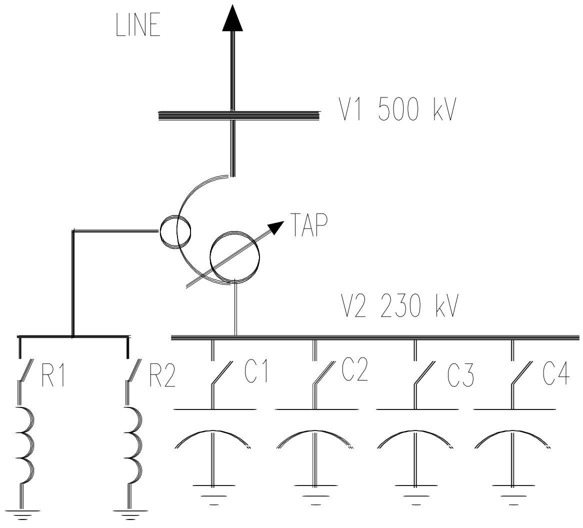


Figure B-4 *One line substation layout.*

B.7.2 Control Hypothesis Design

Having defined the basic control strategy, the hypothetical control algorithms need be designed. These hypothetical algorithms, which are merely based on the designer's perception of the system behavior should prove their functionality, or be modified until they do.

B.7.3 Functionality Verification

Using a stability program with user defined control models, the control is programmed in accordance with the control strategy and control hypothesis defined in the two previous steps; then dynamic simulations, especially suited to test each control function, are performed.

The integral of the error algorithm in combination with the fast decision algorithm, give the system a good transient and dynamic response to contingency situations, increasing the transmission loading capability of the system, as shown in Figure B-5.

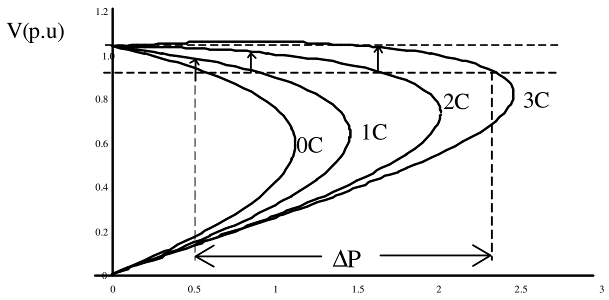


Figure B-5 *Increase in transmission loading capability.*

Figure B-6 shows a typical dynamic run to test the functionality of the basic integral of the error algorithm, in which the controlled voltage, integral of the error, and number of capacitor banks connected are shown.

B.7.4 Validation of Algorithms

By performing dynamic simulations of all credible system contingencies, the performance of control algorithms may be assessed. Every time the algorithms are changed to improve their performance for a specific situation, the complete set of dynamic simulations must be repeated to check whether this change does not degrade the performance for remaining conditions.

Figure B-7 shows a dynamic simulation to test the performance of a set of controls in the 500 kV system having a Static Var Compensator and a pilot control.

B.8 Implementation

It is advisable that the implementation of the VQ controls be done taking into account the following aspects:

- The microprocessor control;
- The voltage measurement;
- The short circuit detection;
- Synchronized switching.

B.8.1 The Microprocessor Control

The microprocessor control should be able to handle logical, as well as analog inputs and outputs with programmable capabilities for:

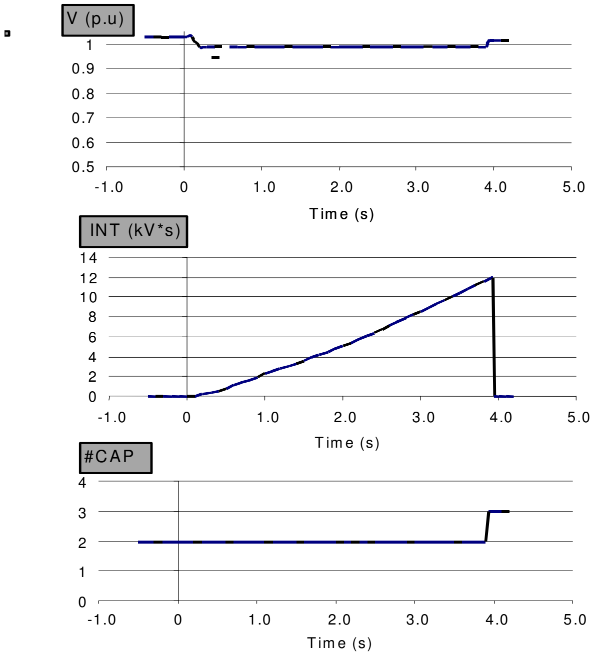


Figure B-6 *Functionality simulation test.*

- Logical functions;
- Control blocks as functions of Laplace operator;
- Mathematical and algebraic functions.

The communication requirements should be defined in accordance with the system communication standards and the specific needs.

B.8.2 Voltage Measurement

For a good performance of the described controls, the voltage measurement must be three-phase, not affected by harmonics or ambient temperature, and with a maximum error of ± 0.2 %, specially when the control requires certain coordination with SVCs and generators.

B.8.3 Short Circuit Detection

Short circuit conditions must be differentiated from abnormally low voltage conditions, so that while the short circuit is present no integration of the error is carried out. Short circuits are typically cleared in about 100 ms, so during this time the control waits for a proper identification of the system event being faced, which can in some cases be a high voltage condition due to load rejection associated with the fault clearing. Not having this algorithm, would introduce erroneous actions that could further deteriorate the system condition rather than improving it.

For this algorithm to operate adequately short circuit identification must be carried out on each phase (one phase short circuit detection).

B.8.4 Synchronized Switching

Having reactors or capacitors switched on and off by automatic control, substantially increases the number of daily operations imposed on the circuit breakers. Synchronized switching is therefore desirable to reduce both the transients in the system, as well as to increase the life of the contacts of the circuit breaker. In general, controlled switching can be applied to the connection and disconnection of both reactors and capacitors.

B.9 Conclusions

- Adopting an overall Voltage and Reactive Control strategy for a Transmission System, constitutes an intelligent way to tackle the voltage and reactive control problem, when there are many shunt elements to be controlled, and specially when a certain degree of coordination is required;
- Distributed intelligent controls with algorithms specially designed for their locations, show many advantages over a centralized control scheme, and have been shown to improve system security, even under the most stringent conditions;
- Choosing adequately the location of pilot controls to perform additional area tasks, show to improve the performance of local controls and adequately coordinate local controls with synchronous generators and Static Var Compensators;
- The possibility of changing the settings in real time allows the optimization of the performance of the controls and the system, since this can be done having the state of the complete system;
- The installation of VQ controls to operate shunt capacitors and reactors, can reduce or even eliminate Transmission Constraints, especially when their installation was originated from voltage support or voltage stability requirements.

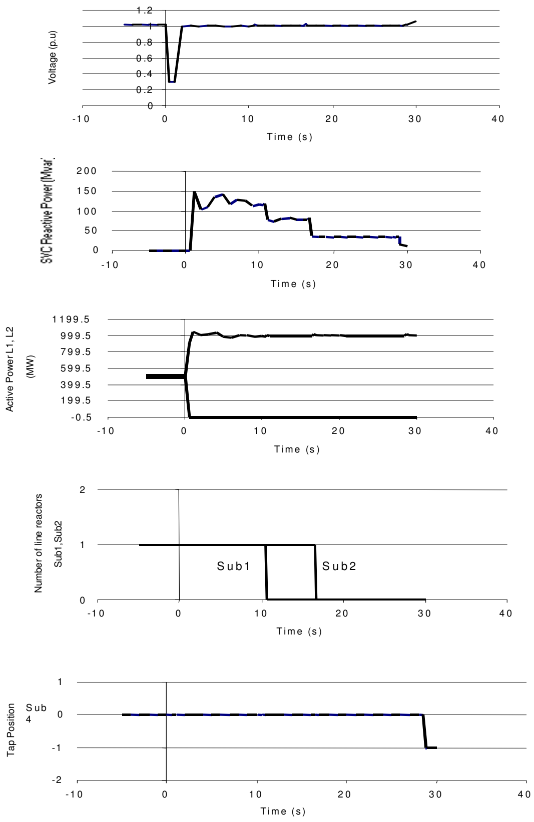


Figure B-7 *Validation simulation.*

- The installation of VQ controls, makes possible the operation of the system under very stringent conditions by augmenting the reactive reserves in the fast devices (SVCs and generators) as well as in the transmission system, since fast connection or disconnection of elements can be obtained in less than one second;

- It may be said that VQ controls make a system more flexible and adaptable to face most conditions, since the system controllability is substantially improved in both static and dynamic conditions.

Appendix C

Impact of SVCs and STATCOMs on the Italian grid in the Presence of Secondary Voltage Regulation

C.1 Introduction

The technological maturity and potential advantages of using power electronic controllers in transmission networks has made electrical utilities to search for cost-effective applications. This appendix studies the possible use of SVCs and STATCOMs in the Italian system. Attention is given to the use, interaction and coordination of these FACTS controllers with the Secondary Voltage Regulation (SVR) currently in operation in the Italian grid.

“Classical” voltage stability theory and different tools were used in this study:

- Methodologies used are mainly based on steady-state studies and tools providing some initial conclusions.

- Dynamic models, developed and implemented during the study, generally validated the steady-state analyses.

Advanced series compensators such as the Thyristor Controlled Series Capacitor (TCSC) or Static Series Synchronous Compensator (SSSC) are not considered, even though they may significantly impact system loadability. However, these are mainly intended to control power line flows rather than bus voltages, and hence cannot be easily coordinated with other voltage control systems such as the SVR.

Switched shunt capacitor banks are also considered in the study because for slow voltage control they present significant cost advantages as compared to SVCs and STATCOMs.

The steady-state voltage stability analysis has been carried out with the UWPFLOW tool considering distributed load ramp variations, with power imports fixed at their initial MVA values, power exports increasing to their maximum MVA values, transmission network operating with and without SVR, and reactive control with and without shunt compensation.

C.2 The Complete Italian Power System

The system model is based on a 243 bus representation of the 380-kV Italian transmission network, which has been previously validated. The main generators connected to the 380-kV network (71 generators), as well as the 380-kV interconnections with other countries are properly represented; one interconnection with the French network is chosen as the reference bus. The network below 220-kV and 150-kV, including loads and generators, are represented as equivalent PQ injections at the corresponding 380-kV connecting buses.

The network loading conditions correspond to those on July 17, 1999 at 11:00 AM, with a total load of about 22 GW. This is light compared to typical peak loading conditions, which are around 40 GW. The maximum loading levels verified on the Italian system have been of the order of 46 GW, with ENEL and IPPs supplying about 41.5 GW and with power imports of approximately 4.5 GW.

The Italian system has an installed capacity of about 73 GW, of which 20 GW come from hydro plants and 53 GW come from thermal units. The generation connected to the 380-kV system corresponds to an installed capacity of about 35 GW. The generation connected to the 220-kV and below network injects approximately 3.5 GW into the system; this value was kept roughly fixed. The 380-kV power exports on this system are approximately 3 GW; these were allowed to change up to their maximum MVA levels.

- The basic SVR structure of the Italian network Has been described in Chapter 2.

C.3 The Reduced Italian Power System

The original 243 bus 380-kV system was reduced to a 113 bus system with 29 generators. All buses in the original system having less than three 380-kV transmission lines connected to it were replaced by an equivalent interconnection. The 113-bus system is used for the steady-state analysis reported here. A further reduction was carried out by eliminating radial connections between generators and the 380-kV system, which yielded a 65 bus, 25 generator system model, used for dynamic simulations.

All these reductions were carried out at the base load conditions using steady-state equivalents. To validate this system, at least for steady-state analyses, PV curves were computed for both systems using a realistic scenario of load increase. All loads were modeled as constant power in this validation.

The voltage stability studies on the reduced Italian 380-kV system assume that only the largest loads in the various regions are modeled as constant power loads and are changed according to predefined regional patterns. The remaining system loads, including those representing power injections from the 220-kV or 150-kV network and below, which add to 9 GW of demand and 3.5 GW of injections, were modeled as impedance loads and remain fixed throughout the study. These loads and injections do not increase as the system is loaded; rather, these powers tend to decrease with decreasing system voltages.

Throughout all the studies on the reduced system, however, we observed that the power at these loads tend to remain somewhat constant, as the voltages on the corresponding buses do not change significantly with system loading. As some loads are modeled as impedance loads, the maximum loading or power transfer point of the reduced system does not necessarily coincide with the corresponding collapse or bifurcation point (singularity of the power flow Jacobian). In all cases, nevertheless, these two values were so close that for practical purposes they can be considered to be the same, which somewhat validates the selection of PQ loads.

C.4 Analysis with Power Exports Fixed at Their Initial MVA Values

Nose curves, and thus maximum loading conditions, were obtained for the reduced system assuming that generator power changed with the difference between the initial loading conditions and their maximum power; the power exports were kept fixed at their initial values. In this case, the maximum loading condition corresponds to about 36.5 MW of load due to generators reaching their maximum P or S limits. Hence, the system runs out of active power before reaching the collapse point.

Clearly, this is not an adequate system for studying the effect of shunt compensation and SVR on voltage stability, as the system does not collapse due to lack of reactive power but rather due to lack of active power. The only solution would be to increase available generation. Reaching this condition in voltage stability studies of the Italian network is not unusual, even for more complete system models, due to the known strength of the transmission network.

These maximum loading results are not near those reached in real life; the reasons for this are twofold:

- All exports and generation not connected directly to the 380-kV network were kept fixed at relatively low levels, corresponding to a lightly loaded system, and hence were not able to contribute enough active or reactive power to help support the load demands;

- The load models and the chosen "direction" of load growth, which are known to have significant impact on the PV curves and corresponding maximum loading points, are forcing the system to collapse at lower loading conditions..

When comparing the effects of shunt controllers and SVR, however, the exact value of the loading conditions at collapse should not cause a major impact on the final conclusions, as long as the chosen generation and loading patterns and models can be considered realistic.

C.5 Analysis with Power Imports Changing up to Their Maximum MVA Values

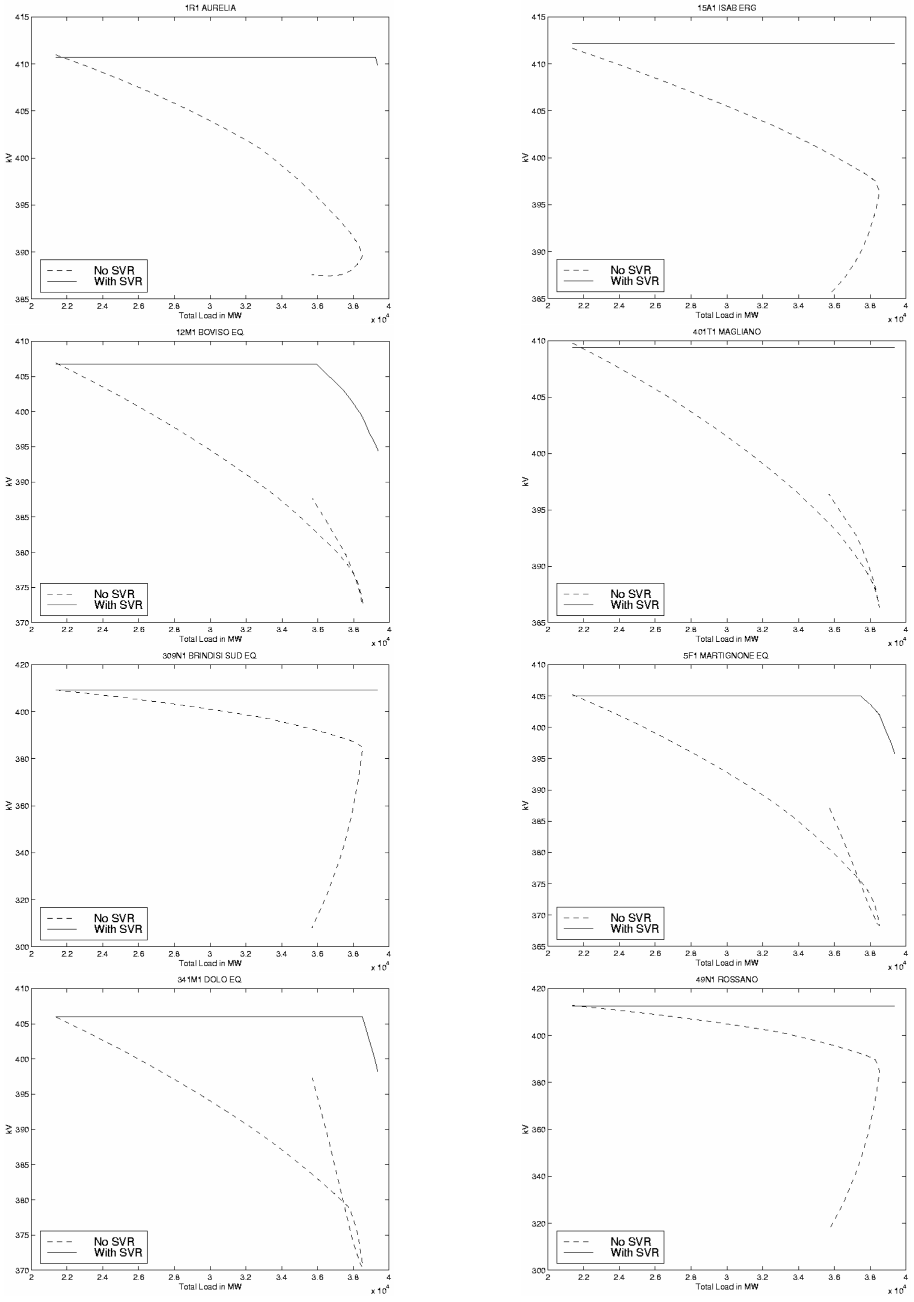
To attain the desired objectives of the present study power exports were allowed to change based on the difference between their initial MVA level and their maximum MVA limits. More active and reactive power was made available, particularly in the northern region, which has the largest power demands.

For this system model, the PV curves depicted on Figure D-1 were obtained, for cases with and without SVR. These figures represent the voltage profiles at 9 pilot buses, which basically span the whole Italian network, plus the bus that experiences the largest voltage variations for the chosen direction of load growth and considering the system without SVR; this bus is Villanova in the central Adriatic region, which is the candidate for shunt compensation.

The voltages at all system buses, with the exception of Villanova, remain within the acceptable voltage range of 360–430 kV for the 380-kV network. Observe that the system reaches a maximum loading condition of about 38.5 GW, which is still below the maximum 46 GW reached in real life.

Note that this value is only 2.5 GW above the maximum loading conditions of the system without exports, indicating that the maximum loading and maximum available generation points are rather close. In this case, various generators have reached their maximum P, S or Q limits, and the system collapses due to the loss of voltage control at the Brindisi generation, one of the largest Italian power stations and located in the south.

Hence, this system collapses due to a Limit-Induced Bifurcation (LIB). It is important to highlight the fact that the system Jacobian is near a singularity, a Saddle-Node Bifurcation (SNB), as it is typically the case in large systems, i.e. LIBs and SNBs tend to be rather close.



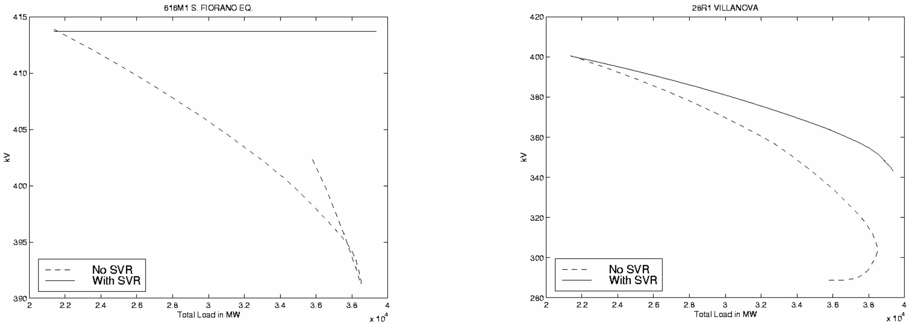


Figure C-1 *PV curves for the uncompensated system with and without SVR.*

C.6 Comparison between SVR and Shunt Compensation by SC, SVC and STATCOM

Given the collapse characteristics of the reduced system when exports are considered, we can analyze the effect of shunt compensation. The techniques to identify the “optimal” location and size of different shunt compensators are:

- A critical area, and thus the optimal location for a shunt compensator, is determined from the maximum voltage entries on the tangent vector for a LIB, or the zero right eigenvector for a SNB, depending on the type of collapse (for a SNB, these two vectors are basically the same). The bus Villanova was identified as the best location for a shunt compensator. This bus is in the central Adriatic region, an area already identified by ENEL during system operation and planning studies to be in need of reactive power support. Given the agreement with operational experience, the reduced model, including the loading and generation patterns chosen, is a valid model for the voltage stability studies, even though the maximum loading margins do not fully agree with the values observed in the field;

- The improvement in the MW loading margin with respect to the compensator size in Mvar located at the optimal bus defines the “best” Mvar compensation level. In this case, the maximum compensation size is 1300 Mvar with a corresponding maximum loading margin of about 39.5 GW. Choosing a shunt compensator of 1300 Mvar would be unrealistic. Therefore, 500 Mvar, which would certainly be considered large, is chosen as an adequate rating; for this value, the maximum loading of the system is about 39 GW, i.e. an increment close to 0.5 GW of the maximum loading margin of the system.

Based on this analysis, the use of a 500 Mvar shunt capacitor bank, SVC, or STATCOM were studied as possible compensator solutions. The reasons for looking at such diverse compensation options are as follows:

- Switched capacitor banks to slowly and discretely control bus voltages are always the first compensation option for improving longer-term voltage stability characteristics, given their relatively low cost and adequate time response when dealing with long-term dynamic phenomena;

- SVC, considered because of its widespread use and advantages such as reduced switching transients and fast time response, can be used to improve the overall stability of a power network;

- STATCOM is also considered given its advantages over a SVC in terms of installation size and dynamic response.

The following are the models and parameters used for each controller:

- A 380-kV, 500 Mvar capacitor bank is simply modeled as a continuously variable capacitive susceptance that controls the voltage at bus Villanova at its given initial voltage, within reactive power limits of 500 Mvar. In practice, the actual rating, limits and control steps would depend on diverse control techniques for discrete switching of capacitor banks. However, slight modeling differences should not have a major effect on the final conclusions of this study;

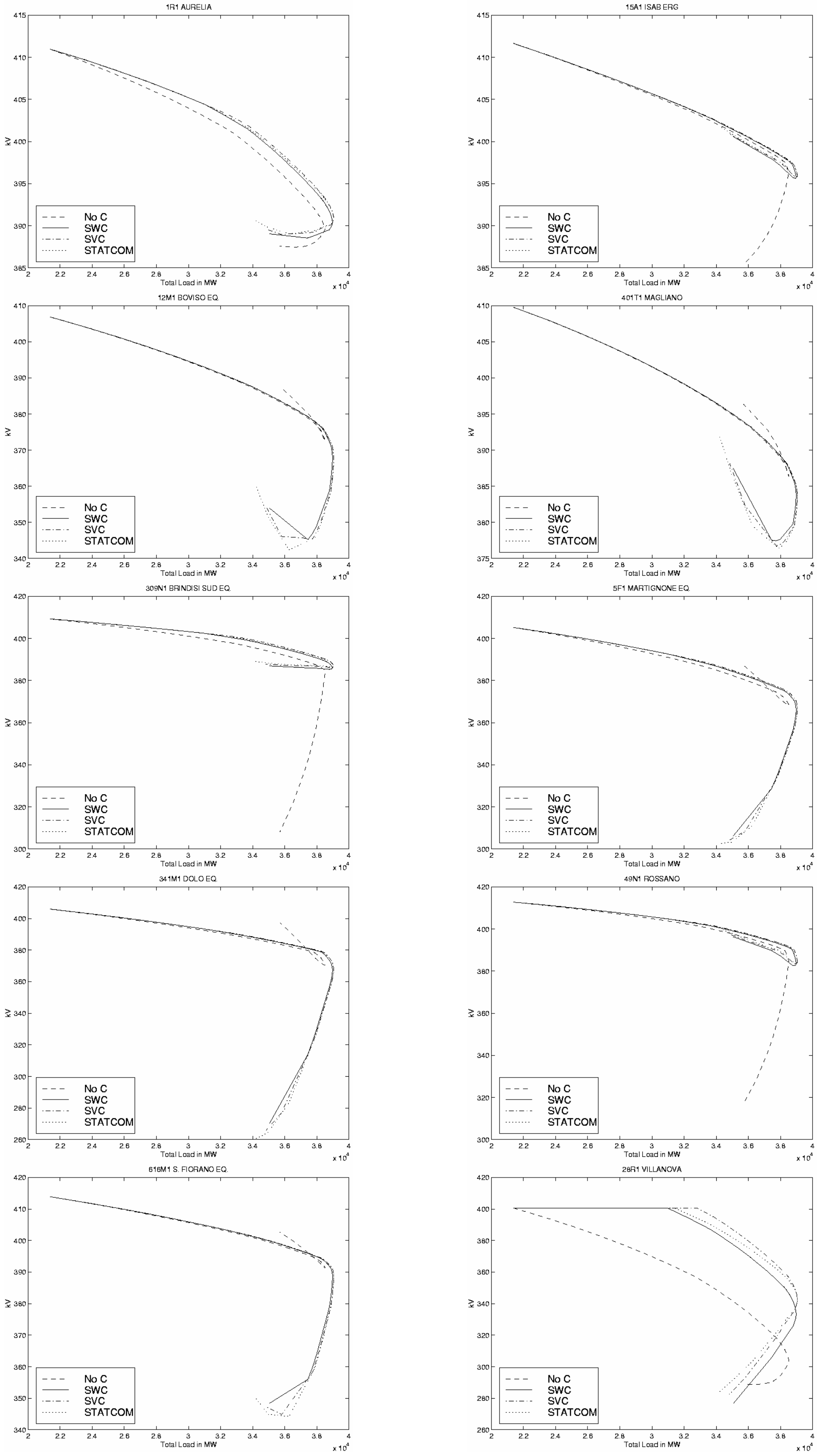
- A 380-kV, ±500 Mvar SVC is represented in detail, with transformer characteristics as well as inductive and capacitive reactances, control slope, limits, and voltage set points. Since a 1 per unit voltage magnitude and a zero control droop were used, the controller should be able to deliver reactive power above 500 Mvar, if the controlled voltage set point is chosen to be over 1 per unit, as is the case in the present studies (1.054 per unit). This could present an advantage over other controllers in terms of maximum system loadability;

- A 380 kV, ±500 Mvar STATCOM was modeled as a lossless 12-pulse controller operating under phase control, with a typical 10% AC equivalent reactance; the controller current limits are defined by the nominal current, i.e. 1 per unit.

The PV curves for the reduced system considering these three different shunt compensation options are shown in Figure D-2. The different compensation options basically produced the same results, with the SVC producing the best voltage profiles at the compensated bus Villanova due to its increase reactive power output, as previously explained. In all cases, the maximum loading point was approximately 39 GW, with the STATCOM producing the largest improvement in loading margin (+526 MW). It should be noted that, under shunt compensation, the voltages in the Central Adriatic region are almost within the acceptable voltage range of 360–430 kV over the whole range of load variation.

Figure D-3 shows the effect of SVR. Voltage profiles at the pilot nodes, as well as voltage at the critical bus Villanova stay almost within the desired 360–430 kV range, without the need for local compensation, for practically all loading levels.

Furthermore, the maximum loading of the system increases to about 39.4 GW, which is about 0.5 GW higher than with shunt compensation. The system now collapses due to lack of generator active power, rather than due to the typical SNB or LIB, as P or S limits are reached in all modeled generators and external links. If the same shunt compensation is introduced at the critical bus Villanova, the system is able to deliver over 200 MW more before it collapses due to lack of generated active power. The effect of the different compensators on the pilot nodes and critical bus is that the voltage at the critical bus remains within the desired voltage limits for all loading conditions.

 1R1 AURELIA

15A1 ISAB ERG

12M1 BOVISO EQ.

401T1 MAGLIANO

309N1 BRINDISI SUD EQ.

5F1 MARTIGNONE EQ.

341M1 DOLO EQ.

49N1 ROSSANO

616M1 S. FIORANO EQ.

28R1 VILLANOVA

Figure C-2 *PV curves for the shunt compensated Italian system without SVR.*

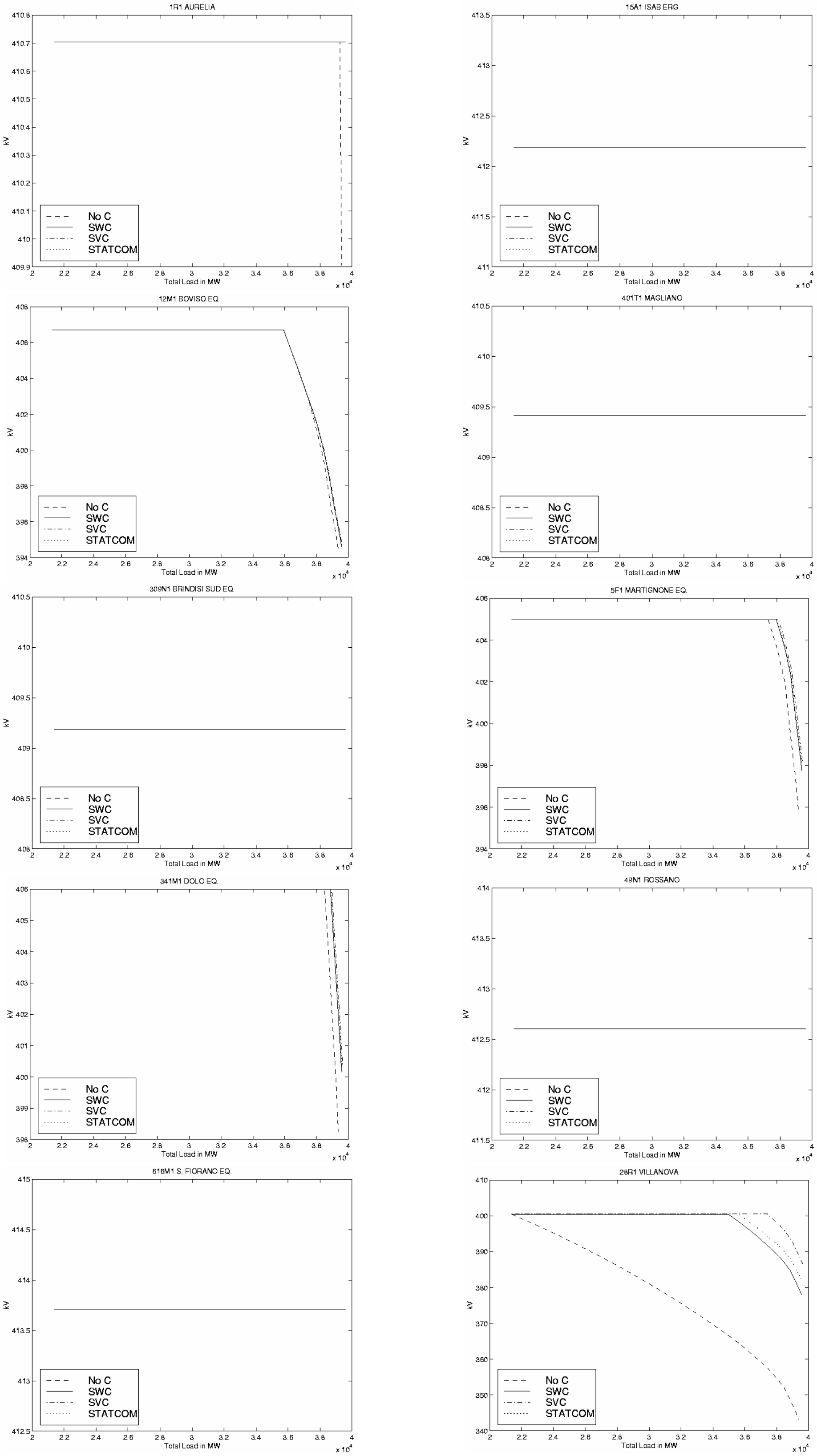


Figure C-3 *PV curves for the shunt compensated Italian system with SVR.*

C.7 Conclusions

This Appendix dealt with the steady-state voltage stability analysis of a reduced model of the Italian 380-kV network, analyzing the combined effects of SVR and shunt compensation on the transmission grid. The conclusions of this analysis are summarized below:

- The reduced system, with its associated generation and loading patterns and models, is based on some gross assumptions that might influence the final results. However, the need to carry out dynamic studies with the available simulation tools did not allow use of a more complete model. Nevertheless, the obtained results agree with those obtained for larger models and also agree with known behavior of the Italian system;

- In most study cases the reduced system runs out of available capacity before reaching a classical collapse condition, indicating that the model used is short of generation. However, previous studies on the full model of the Italian grid have also resulted in similar results. The fact that the system voltages remain within limits, with the exception of the central Adriatic region, indicate that the transmission network and its reactive power sources are rather strong, and hence there is no need for SVCs nor STATCOMs, especially if SVR is considered. Low voltage problems in the central Adriatic region can be mitigated by using manually or automatically switched capacitor banks, which is a much cheaper solution;

- It is clear that SVR improves voltage stability, as the voltage profiles become rather flat throughout the whole system, almost bringing within limits the voltages at full loading conditions in the critical area. The system loadability gains, brought by the SVR, are about 1 GW by just using more intelligently the available reactive power sources. This also results in reduced system losses, as one would expect, given the better system voltage profiles.

Appendix D

Simulation Study on Coordinated Secondary Voltage Regulation on SVC Units in the Nordic Power System

D.1 Introduction

Statnett SF (the Norwegian Transmission System Operator) is making considerable efforts to increase transmission capacity in the existing power transmission grid. One of the focus areas is voltage stability and strategies for voltage control and reactive power.

Voltage control of the main transmission grid in Southern Norway is the responsibility of Statnett's regional control center in Oslo. The southeast of Norway (Oslo region) is a high load area with little generation capacity. Thus, voltage control relies heavily on the use of capacitor banks, synchronous compensators and SVC units.

Today, there is no formal coordination or automation regarding priority or setpoint control of the reactive equipment. As a general rule, the SVC units should be run at limited output under normal operating conditions, so as to provide on-line and fast-acting reactive support.

The aim of this study is to assess whether the present operating procedures could be automated in a simple way in order to provide:

- Improved voltage regulation;
- Increased on-line reactive reserves;
- Simpler daily control routines for the operators.

If successful, this study will enable Statnett's national control center to increase transfer capacity limits on transmission corridors that frequently constitute bottlenecks.

D.2 Scope of the study

Various studies are being carried out to increase utilization of the main Nordic transmission grid [D-1]. One of the objectives is to develop methods for optimal utilization of components that are owned and controlled by the TSOs (Statnett in this case). As part of these efforts a simulation study is performed to investigate if coordinated voltage control of SVC units can contribute to raise transmission limits in southern Norway. A prototype version of the control scheme has been implemented within Statnett's regional control center for southern Norway [D-2].

A main focus in this area is the "Hasle corridor". This is the main transmission corridor for power exchange between Sweden and southern Norway, and consists of two 420 kV transmission lines, as shown in Figure D-1. There is a strong demand from the power market and a major economic motivation to increase transfer capacity on this corridor. A main objective is thus to raise the power transfer limits in order to relieve congestions and to reduce congestion costs.

The operating transfer limit on the Hasle corridor can be constrained by thermal capacity limits as well as angle and voltage stability. In this study, a secondary voltage regulation (SVR) scheme for coordinated control of SVC units is proposed as a means to reduce voltage stability constraints. Three SVC units in the Oslo area are considered as part of the scheme, and the location and capacity of the SVC units are illustrated in Figure D-1.

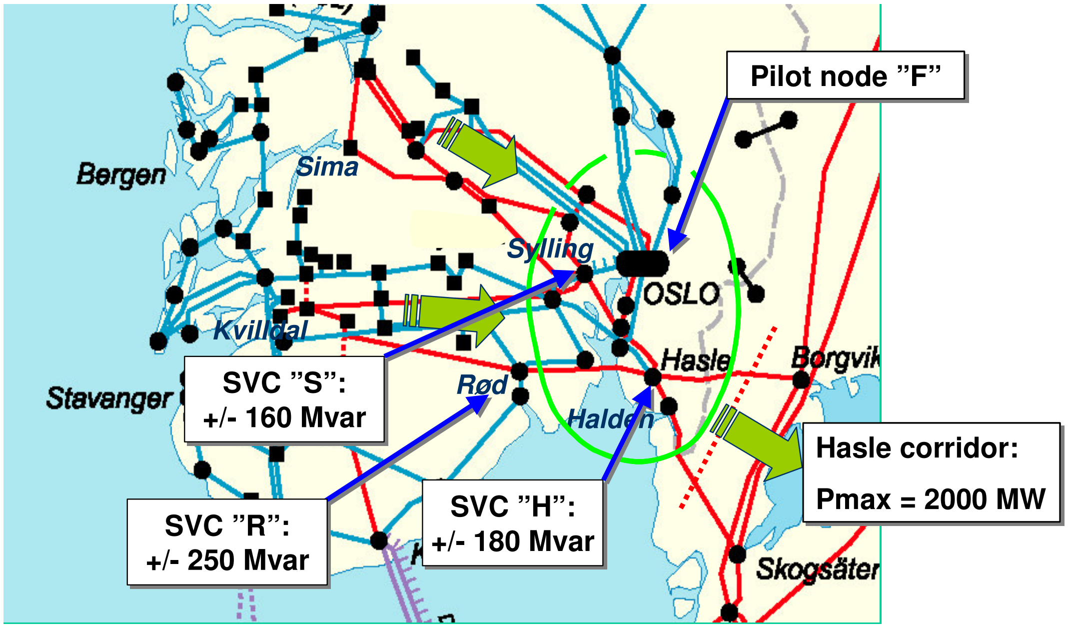


Figure D-1 *Hasle corridor (interface) and SVC units in Southern Norway.*

D.3 SVR scheme

A secondary voltage regulation (SVR) scheme is designed, and a simulation model is implemented in PSS/E. The control structure of the SVR is illustrated in Figure D-2. The scheme uses measured voltage as input and produces set points to coordinate the reactive power output on the three SVC units. The aim is to control the voltage at a pilot node that is representative for the control area, and at the same time to optimize the reactive reserves in the Oslo area.

The overall control objective of the proposed SVR scheme can be therefore formulated as:

- To maintain a sufficient and balanced reactive reserve in the SVC units during normal operation;
- To keep the pilot node voltage within specified limits.

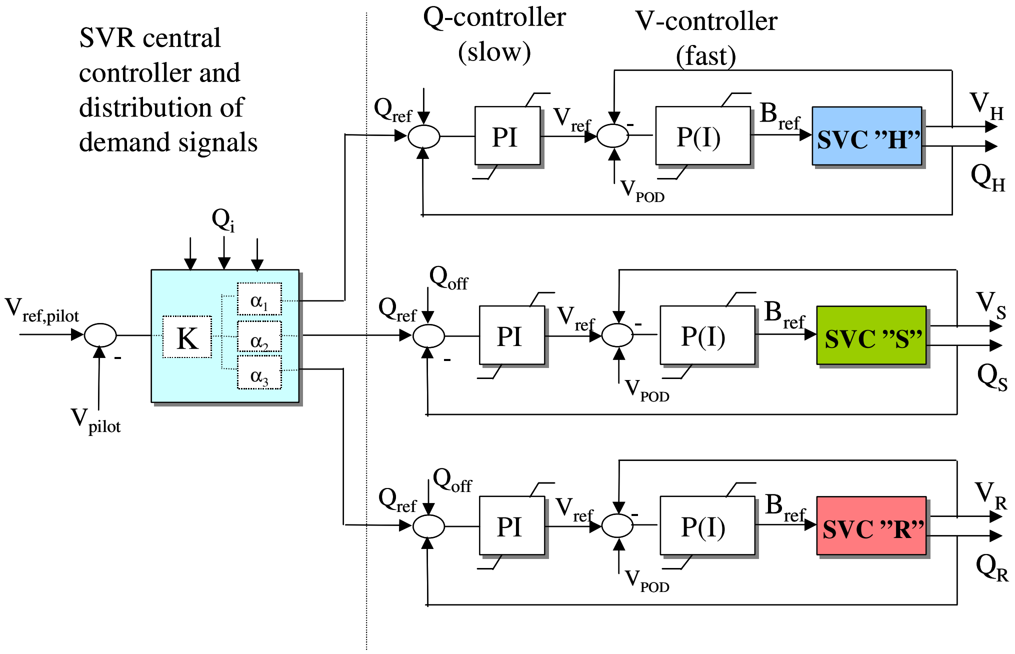


Figure D-2 *Control structure for a coordinated secondary voltage controller.*

The SVC units are presently equipped with primary (V-) controllers and secondary (Q-) controllers. A simplest possible implementation of an SVR central unit is a proportional controller, as illustrated in Figure D-2, where the gain and offset of each SVC unit can be tuned individually. Thus, if the distribution factors α_i add up to one, the gain K of the SVR represents the total Mvar/kV response of the installation.

As stated above, there are three main potential benefits that can be gained through an automatic SVR scheme:

- regulation and voltage profiles in the main 420 kV grid are handled automatically and are determined from the gain and setpoint of the SVR controller;
- Increased reactive reserves: Transfer limits are normally determined from the "N–1" criterion. This means that limits must be set so that voltage stability and voltage levels are acceptable after a critical contingency has occurred. Sufficient on-line reactive reserves are important in order to reduce the consequences of critical contingencies.
- Simplification of daily control routines: By having automatic and coordinated control of the SVCs, the operators can concentrate on monitoring the total reactive reserves. Sufficient reserves are maintained by switching of capacitor banks or other equipment with discrete control.

D.4 Case Studies and Simulation Results

In order to assess the proposed SVR scheme, dynamic simulations are carried out using a recent updated and validated Nordel transmission system model. The SVC models include detailed representation of controls and limit handling according to Figure D-2.

The purpose of the analysis is to simulate the worst possible single contingency regarding voltage stability, and to demonstrate improvements in voltage control with use of the SVR scheme.

To illustrate the potential of raising the power transfer limit of the Hasle corridor, a simple criterion is adopted from operating experience: The steady state (post contingency) pilot node voltage must be above 380 kV (base voltage is 440 kV). A base case operating condition is chosen where the system is operating at the maximum power transfer limit (2000 MW). The present operating limits are defined as a function of the total load in the greater Oslo area. This is illustrated in the nomogram of Figure D-3, where the base case loading is also indicated.

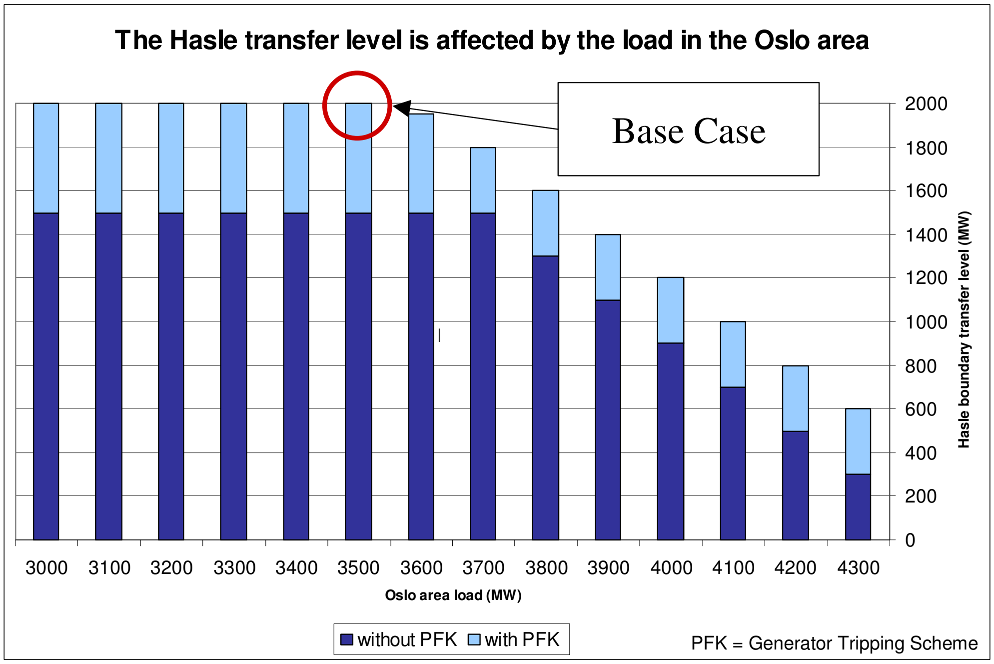
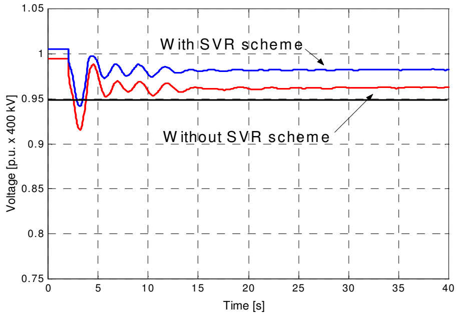


Figure D-3 *Present transfer limits on the Hasle corridor as a function of the Oslo area load (Source: Statnett SF).*

The applied contingency is outage of a 420 kV submarine cable across the Oslo Fjord. System. Responses with and without the SVR scheme are simulated. Since the base case represents a high load operating condition, it is assumed that the SVCs will operate close to their maximum power limits without the SVR scheme.

Sample results from the base case simulations are shown in Figure D-4 and Figure D-5. The same study is repeated at a load flow situation with 2400 MW transfer to demonstrate the benefit of SVR scheme. The corresponding results are shown in Figure D-6 and Figure D-7.



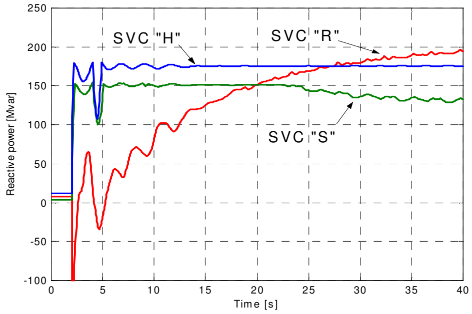
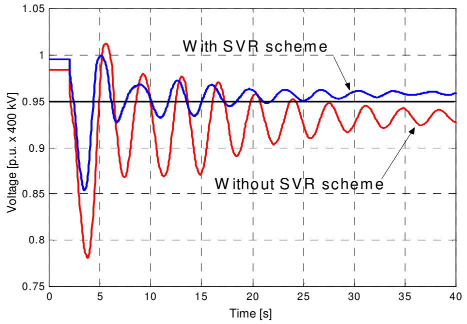


Figure D-4 *Case study: Present 2000 MW transfer limits on the Hasle corridor. Pilot node voltage response to line outage with and without SVR scheme.*

Figure D-5 *Case study: Present 2000 MW transfer limits on the Hasle corridor with SVR control. Response to line outage in reactive power output from the SVCs units is shown.*

Figure D-4 shows the response of the pilot node voltage after the contingency. It is seen that the system remains stable, and the steady state voltage remain above the minimum limit both with and without the SVR scheme. Figure D-5 shows the response of the SVR scheme. It is seen that two of the SVC units immediately reach their maximum limit as a response of the primary control action. The third SVC "R", however, does not sense the contingency locally, but contributes through the slower secondary control.



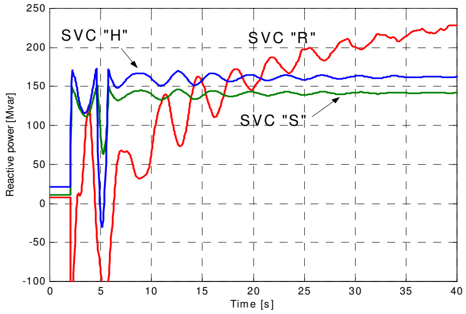


Figure D-6 *Case study: 2400 MW transfer limits on the Hasle corridor. Pilot node voltage response to line outage with and without SVR scheme.*

Figure D-7 *Case study: 2400 MW transfer limits on the Hasle corridor with SVR control. Response to line outage in reactive power output from the SVCs units is shown.*

It is seen from Figure D-6 that for increased transfer (2400 MW) the system remains stable but with low damping. However, the steady state voltage is unacceptably low without the SVR scheme. Figure D-7 shows the response of the SVR scheme. It is seen that all three SVC units eventually reach their maximum limit as a response of the primary and secondary control actions.

The results show that acceptable voltage control can be maintained at a higher transfer level than the present operating limits by optimal use of reactive sources. This indicates that the SVR scheme is promising with respect to simplify operation of the SVC units and to increase voltage stability limits.

D.5 Prototype Control Center Implementation

A prototype version of the proposed control scheme has been implemented at Statnett's regional control center for southern Norway. This is a software implementation within the existing SCADA system, which utilizes the available functions for remote (setpoint) control of the different units. The basic configuration of the prototype implementation and some results from initial testing of the control scheme is described here.

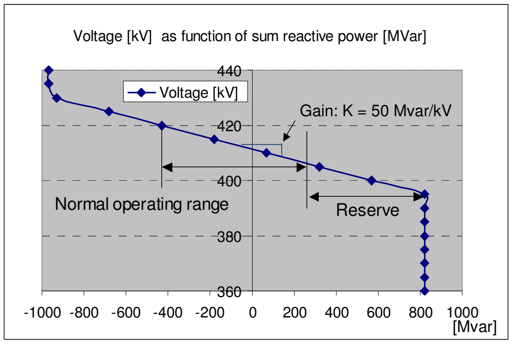
The general structure of the implementation is similar to the structure that is modeled and simulated above (Figure D-2). In addition to the three SVC units two synchronous condensers were also included in the prototype implementation. The names, types and nominal capacities of the participating units are summarized in Table D-1.

Table D-1 *Units participating in the SVR scheme.*

NAME	TYPE	Capacity, inductive	Capacity, capacitive	Comments
Sylling F1	Rotating condenser	-90 Mvar	+160 Mvar	Controllable in steps of 20 Mvar
Sylling SVC	SVC	-160 Mvar	+160 Mvar	Controllable in steps of 40 Mvar
Frogner F1	Rotating condenser	-90 Mvar	+250 Mvar	Controllable in steps of 10 Mvar
Rød SVC	SVC	-250 Mvar	+250 Mvar	Controllable in steps of 15 Mvar
Hasle TCR 1&2	TCR	-360 Mvar	0 Mvar	Controllable in steps of 50 Mvar

The control logic is similar to that shown in Figure D-2, except that the secondary (Q) controllers are implemented using the existing functionality for remote control of the units. Through remote signals from the control center this enables step changes in the individual voltage regulator set points. The resulting performance equals that of a slow PI-controller, but with discrete changes in the set points. The controllable step sizes of each unit are listed in Table D-1.

The operating philosophy of the SVR scheme is illustrated in Figure D-8. By selecting a proper gain, the secondary voltage control will automatically keep the pilot node voltage within desired limits during normal operation. When the reactive power output exceeds specified limits as indicated, this is a signaled to the operators to switch in (or out) capacitor banks in order to restore sufficient on-line reactive reserves. In a contingency situation, the primary voltage controllers will act independently to a local voltage drop and thereby activate reserve capacity. In addition, the SVR scheme may provide additional reserves by (slower) activation of units that do not sense a local problem.



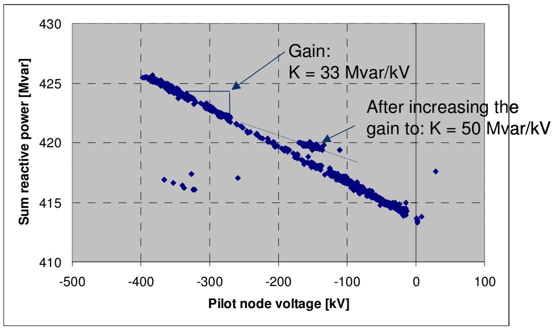


Figure D-8 *Normal operating characteristic of the SVR scheme. The figure illustrates how the pilot node voltage ideally becomes a linear function of the total reactive power activated.*

Figure D-9 *Scatter plot of measured voltage versus reactive power illustrating the actual operating characteristic of the SVR scheme during the 14 hour test period.*

From a dedicated control center display, the secondary voltage regulator can be activated, tuned and monitored. The operators can choose whether they want the SVR to run continuously to automatically keep a certain voltage profile (and thereby relieving them from trivial tasks), or only activate the SVR upon detection of voltage problems at certain nodes (pilot nodes) as an extra safety precaution.

Sample results from the first test period of operation (14 hours) are shown below. From the trend curves in Figure D-10 it is clearly seen how the SVR scheme responds to the characteristic load increase in the morning hours. For security reasons a rather low gain of 33 Mvar/kV was used during the first 13 hours. After that the gain was raised to 50 Mvar/kV. The effect of this can also be seen in Figure D-9, showing a scatter plot of voltage versus total reactive power.

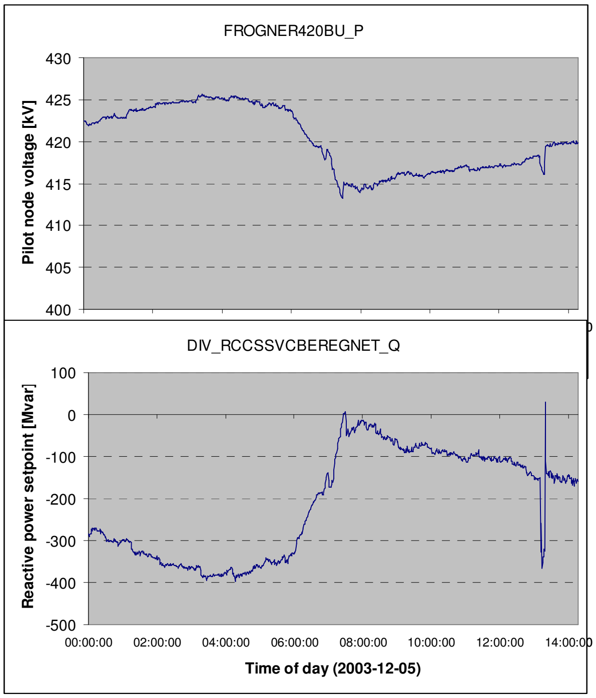


Figure D-10 *Trend curves from the 14-hour test period. The upper curve shows the pilot node voltage, and the lower curve shows the total reactive power that is activated by the SVR scheme.*

It is of crucial importance that automatic control schemes be robust and reliable, and that they do not adversely affect system stability. Figure D-11 shows results from a simple test to assess the stability and response time of the system. A step change in voltage set point from 415 kV to 420 kV is performed, and the responses in system voltage and reactive power were recorded. The SCADA measurements in Figure D-11 indicate that the setting time for the pilot node voltage is about 1-2 minutes, and that the system remains stable.

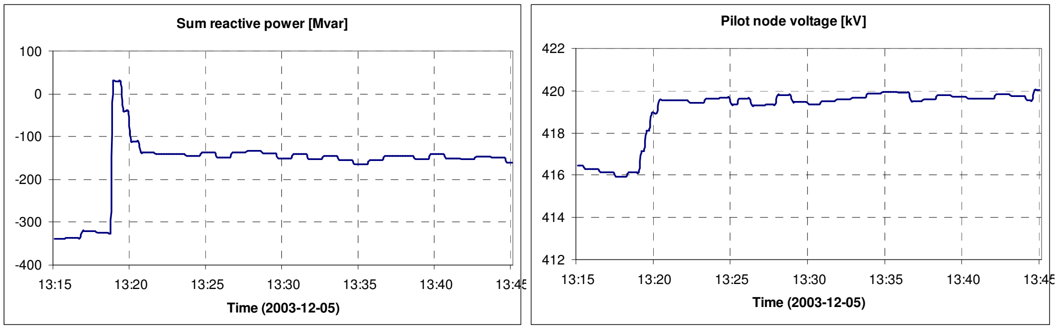


Figure D-11 *SCADA measurements from dynamic testing of the SVR scheme. The response to a step change in voltage set point is shown. The lower curve shows the measured pilot node voltage and the upper curve shows the reactive power output that was activated.*

D.6 Conclusions and further work

Power transfer on the “Hasle” corridor is important to the Nordic power market, but is presently limited by both thermal and stability problems. Thermal limits can and are already being raised by use of system protection (generator tripping) schemes. It is important also to raise the angle stability (damping) and voltage stability limits in order to improve security of operation.

The SVR scheme can contribute to improve voltage control and to raise the voltage stability limit.

Further work will concentrate on simulation studies in order to optimize the control structure, together with additional tuning and improvements of the practical implementation of the SVR scheme. The following activities are planned:

- Assess and define appropriate control objectives and input (measurement) signals. The control objective should reflect the desired trade off between voltage regulation and requirements for reactive reserves;
- Assess possible benefits of including other available components in the SVR scheme. Possible components in addition to synchronous condensers are capacitor banks (on-off control) and LTC transformers;
- Further testing to gain operators’ acceptance.

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[D-2] K. Uhlen, L. Warland, J.O. Gjerde, Khoi Vu, Ø. Kirkeluten: “Concepts for intelligent monitoring and control of power grids by use of new measurement technologies” *Paper B5-109, Cigre 2004 Session*, Paris 2004.

Appendix E

Power Flow Solutions Incorporating Discrete Shunt Voltage Controls for Load Curve Following

E.1 Introduction

This appendix describes the implementation of a power flow function that automatically solves the weekly load curve, which is sampled at every half-hour or ten-minute intervals. The automatic switching of shunt banks to regulate the system voltage profile along the weekly load is represented, extending the practical value of the obtained results [E-1].

Continuous and discrete reactive power compensation devices are distributed throughout the transmission and sub-transmission system in order to keep voltages within operating bounds and enhance system security and loading margins. The development of computer tools that properly model the continuous and discrete actions of the various voltage and Mvar control devices, along the weekly load curve is highly desirable for use in week-ahead operational planning studies.

The methodology represents discrete shunt devices for voltage control, at each loading level, initially as continuously acting controls that are incorporated into an augmented power flow Jacobian. After obtaining the continuous power flow solution for each sampling point of the load curve, these shunt devices are discretized to the nearest values, and a second power flow solution is then carried out.

The results so far obtained showed robust convergence along the whole weekly load curve, and also indicated that the reactive resources of the practical system being studied are able to keep voltages within operating range. Only base case conditions are investigated in this appendix. Maintaining adequate dynamic Mvar reserves during base case conditions is the adopted strategy to ensure (*N-1*) voltage security along the weekly load curve. Contingency analysis along the weekly load curve together with scheduled outage studies are not dealt with here.

E.2 Modeling Control Devices

Two common approaches for modeling power flow controls are: (*i*) Incorporation, in between iterations of the power flow solution process, of adjustments in relevant control parameters and/or variables [E-2, E-3, E-4]; (*ii*) Modeling each control device directly into the Jacobian matrix [E-5, E-6, E-7]. The latter approach is here adopted, since the full Newton method has a more robust convergence. The full set of equations, describing each device, is included into the power flow Jacobian matrix having the active and reactive power mismatches expressed in polar coordinates and generating a system of equations of order ($2nb + nc$), nb being the number of system buses and nc the total number of power flow controls.

A flexible representation of continuous control devices is obtained by augmenting the original power flow Jacobian with additional equations describing each control device and the associated controlled variable. This augmented set of equations leads to the following expanded Jacobian matrix equations:

$$\left[\begin{array}{c}\Delta\underline{P}\\ \\ \Delta\underline{Q}\\ \hline \Delta\underline{y}\end{array}\right] = \left[\begin{array}{cc|c}\dfrac{\partial\underline{P}}{\partial\underline{\theta}} & \dfrac{\partial\underline{P}}{\partial\underline{V}} & \dfrac{\partial\underline{P}}{\partial\underline{x}}\\ \dfrac{\partial\underline{Q}}{\partial\underline{\theta}} & \dfrac{\partial\underline{Q}}{\partial\underline{V}} & \dfrac{\partial\underline{Q}}{\partial\underline{x}}\\ \hline \dfrac{\partial\underline{y}}{\partial\underline{\theta}} & \dfrac{\partial\underline{y}}{\partial\underline{V}} & \dfrac{\partial\underline{y}}{\partial\underline{x}}\end{array}\right] \cdot \left[\begin{array}{c}\Delta\underline{\theta}\\ \\ \Delta\underline{V}\\ \hline \Delta\underline{x}\end{array}\right] \tag{E-1}$$

Where:

$$\Delta\underline{P} = \underline{P}^{sch} - \underline{P}^{cal} \tag{E-2}$$

$$\Delta\underline{Q} = \underline{Q}^{sch} - \underline{Q}^{cal} \tag{E-3}$$

$$P_k^{cal} = V_k \sum_{m\in\Omega_k} V_m (G_{km} \cos\theta_{km} + B_{km}\, sen\,\theta_{km}) \tag{E-4}$$

$$Q_k^{cal} = V_k \sum_{m\in\Omega_k} V_m (G_{km}\, sen\,\theta_{km} - B_{km} \cos\theta_{km}) \tag{E-5}$$

$$\underline{y} = f(\underline{\theta}, \underline{V}, \underline{x}) \tag{E-6}$$

$$\Delta\underline{y} = \underline{y}^{sch} - \underline{y}^{cal} \tag{E-7}$$

The symbol $\underline{x}$ is the vector of control variables, $\Delta\underline{y}$ is the mismatch vector of the controlled variables while $(\Delta\underline{\theta}, \Delta\underline{V}, \Delta\underline{x})$ is the state vector.

Each control equation defined in (E-6) ensures the controlled variable is at the specified value at convergence. It is worth noting the original Jacobian matrix structure is kept unchanged in this formulation [E-8]. References [E-9, E-10] describe this representation of control adjustments into a Newton power flow.

The control variables are updated at all iterations:

$$\underline{x}^{(h+1)} = \underline{x}^{(h)} + \Delta\underline{x}^{(h)} \tag{I-8}$$

h being the iteration number.

In the Newton method, the maximum active and reactive power mismatches are used to detect convergence. With the incorporation of control devices, an additional convergence criterion must be considered, that is, the value of $\left\|\Delta\underline{y}\right\|_\infty$ must be smaller than a given convergence tolerance.

The equations for the control devices are incorporated into the convergence process after a partial solution of the problem, i.e., when the active and reactive power mismatches of the system buses become smaller than a given tolerance.

Flexible coding and well-tested heuristics allow incorporating and removing control devices during the iterative solution process, usually providing adequate performance even for high loading conditions.

The additional lines/columns of the Jacobian matrix with their associated nonzero elements are represented as fictitious buses and fictitious transmission lines of the electrical network. This allowed the use of the same sparsity routines [E-11]. The adopted ordering for sparsity factorization of the Jacobian matrix is not as pictured in (E-1) but should be according to a modified Tinney-2 scheme, where the voltage control equation for a given device or scheme should be ordered last, with the other buses associated with the given scheme ordered first.

Power flow programs are under continuous improvement, in order to accommodate new devices, control strategies and system operating requirements. The program utilized for obtaining the results of this appendix has the features:

- Representation of LTC transformer tap control;
- Generator high side voltage control;
- Secondary voltage control;
- HVDC link controls;
- TCSC (Thyristor Controlled Series Capacitor) controlling either active power flow or line current;
- SVC (Static Var Compensation) to provide reactive power support for voltage control;
- Representation of induction motor loads and induction generators;
- Generator reactive capability curve;
- Area interchange control.

Cascaded LTC transformers exist in practical systems, where they do not cause control conflicts due to their different response speeds in the dynamic control of system voltage [E-12]. This is correctly simulated in dynamic stability programs, but their straight modeling into power flow programs may cause control conflicts or high sensitivities. Such power flow control conflicts should be circumvented through heuristics, designed to ensure that the action of LTC transformers in the higher voltage side of the cascade has precedence over the other transformers down the cascade.

The control redundancy associated with two or more shunt and/or series devices regulating the same bus voltage do not cause control conflict, as long as these devices use exactly the same control equations. Q-limits of PV buses are treated as described in [E-13].

E.3 Discrete Shunt Devices

Voltage regulation is performed to provide a better system voltage profile under different loading conditions [E-1, E-14]. Shunt capacitor and reactor banks are switched on/off, either manually or automatically, maintaining controlled bus voltages within a specified deadband. The desired voltage deadbands (or ranges) are usually determined based on operator's experience and standard practices.

The switching of large shunt banks may cause significant voltage changes at a local bus and adversely impact the performance of other nearby discrete devices.

The discrete nature of these devices makes their simulation in power flow programs become a complex task. The presence of multiple discrete devices in a given voltage area, is a permanent challenge to researchers and program developers. Local voltage may present high sensitivity to neighbor shunt devices, complicating algorithm performance in these cases.

This section describes the adopted method for simulating, in a Newton power flow, the automatic switching of discrete shunt devices for voltage control.

E.3.1 Mathematical Modeling

Consider a bus *m*, whose voltage is controlled by switched shunt devices located at bus *k*. The following voltage control equation therefore applies:

$$V_m - V_m^{sch} = 0 \tag{E-9}$$

A practical aspect that needs adequate modeling is that bus voltage should be maintained within a specified deadband and not at a fixed value. Therefore, the voltage control equation remains within the solution process only while the controlled voltage lies outside the desired range. The specified value for the controlled voltage is usually the mean value of the specified deadband (operating range). A strategy that is less demanding on Mvar, may be adopted by specifying the controlled voltage to be equal the deadband limit value that has been violated.

The control variable is the shunt susceptance of bus *k*:

$$x = b_k^{sh} \tag{E-10}$$

The mismatch of (E-9) is given by:

$$\Delta y = V_m^{sch} - V_m \tag{E-11}$$

Whenever the controlled voltage lies within the specified deadband, the above control equation is removed from the solution process by zeroing the associated row/column or adding a sufficiently large diagonal term. This voltage should be monitored at every iteration, and the corresponding Jacobian matrix changes carried out accordingly.

The modeling and treatment of discrete variables introduces a problem of combinatorial nature to the power flow solution method. After convergence of the continuous power flow, the obtained solution is adjusted to the nearest discrete value of the practical shunt banks.

This adjusted solution involves some heuristics, including a simplified sensitivity analysis to help discretizing the continuous solution, followed by power flow solutions considering the discrete banks switched on/off, as indicated by the sensitivity analysis.

This heuristics may cause slight violations of the specified voltage deadband, but the obtained results are still quite satisfactory, as shown in the results of this appendix.

The coordination among the discrete shunt controls of the transmission system, belonging to different voltage levels, is mostly achieved with the careful specification of realistic operating ranges for the several voltages levels. The discrete voltage control devices located at higher voltage levels have faster operating times: this is approximately modeled in the power flow process by adopting a higher operating voltage range for the switched shunt banks at this voltage level. This simple strategy has eliminated conflict of controls in the majority of cases, for the large interconnected Brazilian system. Other conflicts among nearby discrete control devices having roughly the same control objectives have been eliminated by engineering judgment, such as assigning to some of the discrete devices the responsibility for regulating the Mvar generation in dynamic voltage control devices.

E.3.2 Illustrative Example

Figure E-1 depicts a system comprising an infinite bus supplying an active load through a purely inductive transmission line. Six shunt capacitor modules, 20 Mvar each, are located at the load bus to regulate the load voltage [E-15].

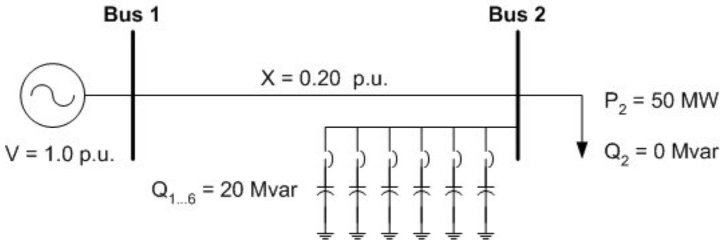

Figure E-1 *One-line diagram for 2-bus test system.*

A continuation power flow [E-16] was utilized to study the impact on system loadability and voltage control of the six automatically switched capacitor banks. The simulations described in this appendix relate to the following cases:

- System with no shunt compensation;
- System with a fixed capacitor of 120 Mvar;
- System with six automatically switched capacitor banks, 20 Mvar each.

The results obtained for these three cases are shown in Figure E-2, and have tutorial value. The results indicate that the system loadability obtained with the set of six automatically switched banks is equal to that obtained with a fixed 120 Mvar bank, with the advantage that the load voltage is always kept within the specified deadband (0.95-1.05 p.u., in this example).

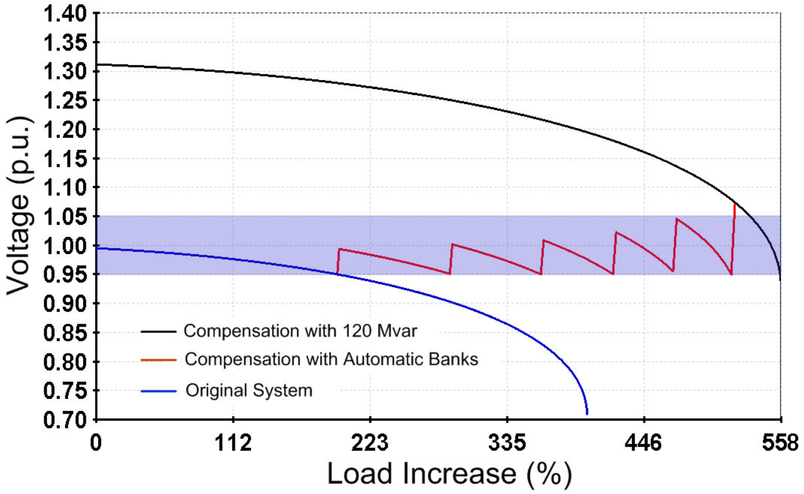

Figure E-2 *PV curves for three types of compensation.*

There are six voltage peaks, each related to the switching of one 20 Mvar capacitor module. One should note that the load bus voltage slightly violates the maximum voltage limit as the sixth capacitor module is switched in. This so happens because the load voltage sensitivity to capacitor switching increases as the system becomes more heavily compensated [E-15]. Table E-1 shows a summary of the results for the three study cases.

Table E-1 *System maximum loadbility.*

Case Identification	*Load Bus Voltage (p.u.)*		*Max. Loadbility*
	Min.	*Max.*	
Original System	0.709	0.995	250 MW
Compensation with 120 Mvar	0.938	1.312	329 MW
Compensation with Six Automatic Banks	0.938	1.074	329 MW

It is worth emphasizing that the continuation power flow algorithm obtains the plot in Figure E-2 in a single run, and has performed quite well in large system studies [E-17].

E.4 Ensuring Power Flow Convergence along the Load Curve

The automatic solution of the weekly load curve involves computing power flows at fixed load sampling intervals. The results of this appendix relate to load sampling intervals of one-half hour. The convergence of the Newton method is highly dependent on the initial system conditions: voltage magnitudes and angles at all buses, specified values or deadbands for regulated variables, etc. Therefore, prior to considering that a case has no solution, different initialization strategies are attempted. Another option involves splitting the load step into substeps. The reactive power limits at PV buses are treated using the back-off strategy described in [E-13].

In case all initialization options fail to yield power flow convergence for a given loading condition, the unsolved case is stored for future analysis and excluded from the load curve study, which then proceeds from the next load sampling interval.

Future work will incorporate an interior point OPF with an objective function of return to solvability through minimum loading curtailment [E-18]. This OPF function will then shed load at critical feeders, simulating therefore their automatic disconnection by under-voltage relays during system contingencies above planning criteria. All these functions are however only available for the continuous power flow problem.

E.5 Study of the Rio de Janeiro Area

The proposed method was utilized to study the voltage control performance of the Rio Area, considering the full model of the Brazilian North-South interconnection. The study case refers to the heavy load condition for April 2003, made available by the Brazilian System Operator (ONS).

The Rio de Janeiro Area, a heavy energy importing area with associated voltage stability weaknesses, was the chosen study area. The basic transmission topology of the Rio Area is pictured in Figure E-3, where the two letter acronyms inside circles indicate the major substations. Table E-2 shows some system statistics.

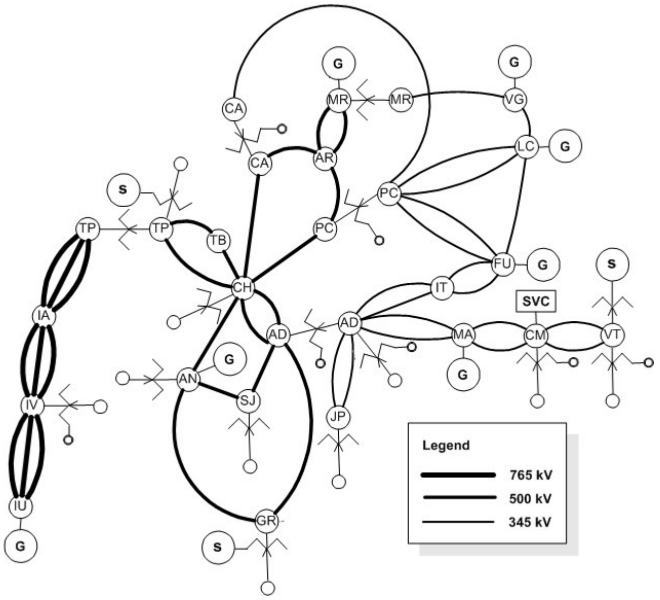

Figure E-3 *Major transmission diagram of the Rio area.*

Table E-2 *System statistics.*

System Statistics	*Elements or MW*
Buses	2485
Circuits	3563
Generators	242
Generators High Side Voltage Control	10
SVC’s	5
Transformers / LTC´s	1064 / 544
Active Load – System	42 923 MW
Active Load – Rio Area	7 100 MW

The load-generation balance is achieved by assigning participation factors to the major power plants supplying the Rio Area.

The voltage control strategies adopted in the study model somehow reflected the system operator experience: specific voltage deadbands are utilized at different voltage levels, and the voltage-controlled buses are key transmission system buses. Operating limits for critical equipment are included in the power flow data, together with known system security limits.

Table E-3 reproduces the general voltage limits for the major transmission voltage levels. Buses associated with bulk loads or important interconnections have more restrictive deadbands, as shown in Table E-4.

Table E-3 *Voltage criteria adopted in electric studies.*

Voltage Level	*Voltage Limits*	
	Min.	*Max.*
138 kV	0.950 p.u.	1.050 p.u.
230 kV	0.950 p.u.	1.050 p.u.
345 kV	0.950 p.u.	1.050 p.u.
500 kV	0.950 p.u.	1.100 p.u.
765 kV	0.960 p.u.	1.046 p.u.

Table E-4 *Voltage Criteria at specific load and interconnection buses.*

Voltage Level	*Voltage Limits*	
	Min.	*Max.*
São José 138 kV (SJ)	0.974 p.u.	1.030 p.u.
Adriano 138 kV (AD)	1.020 p.u.	1.050 p.u.
Campos 138 kV (CM)	1.014 p.u.	1.050 p.u.
Vitória 138 kV (VT)	1.007 p.u.	1.043 p.u.
Jacaré 138 kV (JP)	0.990 p.u.	1.010 p.u.
Angra 138 kV (AN)	1.007 p.u.	1.043 p.u.
C. Paulista 138 kV (CH)	1.029 p.u.	1.050 p.u.
Other bus loads	0.980 p.u.	1.050 p.u.

The data on the major switched shunt devices that impact the voltage profile of the Rio Area are displayed in Table E-5 (positive values denote capacitors while negative values denote reactors). The study described in this appendix simultaneously considered 136 modules of automatically switched capacitors and reactors, located at 68 system buses.

Table E-5 *Main shunt devices in transmission system.*

Bus Name	*Shunt Devices*	
	Number of Modules	*Size of Module (Mvar)*
IVAIPOR-R540 (IV)	3	-180.0
IVAIPOR-R540 (IV)	3	-180.0
T.PRETO—345 (TP)	8	200.0
TPRE-69-R360 (TP)	2	-180.0
C.PAULIS-500 (CH)	1	-136.0
ADRIANO—500 (AD)	1	-136.0
ITUTINGA-345 (IT)	1	200.0
ADRIANO—345 (AD)	2	162.5
S.JOSE---138 (SJ)	2	250.0
JACAREP—138 (JP)	2	100.0

The action of the continuous voltage control elements, listed in Table E-2, occurs simultaneously with that of the discrete shunt devices. The control conflicts that appear in the power flow problem, like cascaded tap-changers among others, are dealt with by heuristics.

Figure E-4 displays the weekly load curve, which is an input data to the program and comprises 336 points representing average values for 30-minute load sampling intervals. This was the typical weekly load curve for April 2003 in the Rio Area, as defined by the Brazilian System Operator (ONS). Note that the minimum and maximum system loads occur in the early hours of Sunday and Wednesday night, respectively. The minimum load in the Rio Area is 40% (4 170 MW) of the maximum load (7 100 MW), as shown in Table E-2.

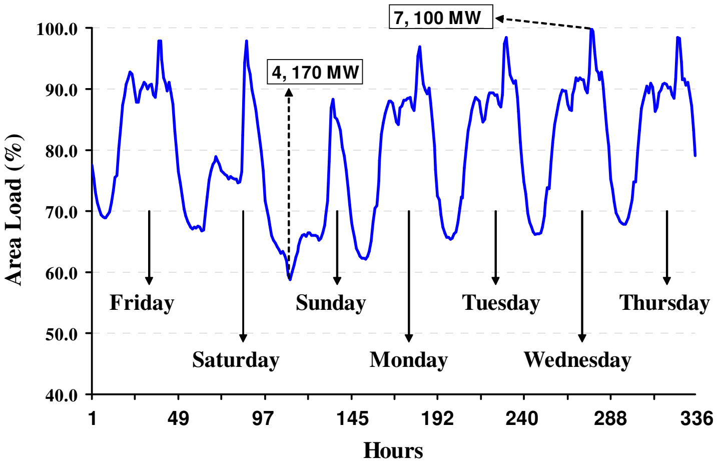

Figure E-4 *Weekly load curve for Rio Area during April 2003.*

Adequate power flow solutions were obtained for all the 336 cases of the weekly load curve, with tolerances of 1 MW/Mvar. for active and reactive power mismatches and of 0.005 pu for voltage magnitudes at controlled buses.

Figures E-5 to E-8 display the voltage profiles at relevant buses of the Rio Area and adjacent transmission systems. It is seen from these plots that the adopted voltage control strategy and the existing continuous and discrete reactive power resources are adequate to maintain the Rio Area voltage profile within the specified operating limits (see Tables E-3 and E-4).

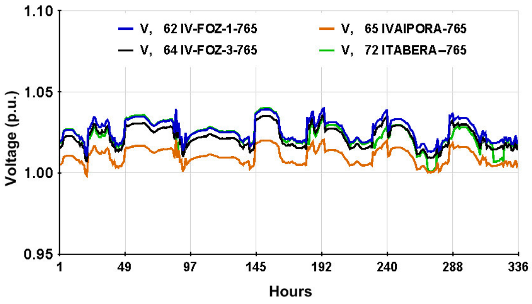

Figure E-5 *Voltage profile for major 765 kV buses.*

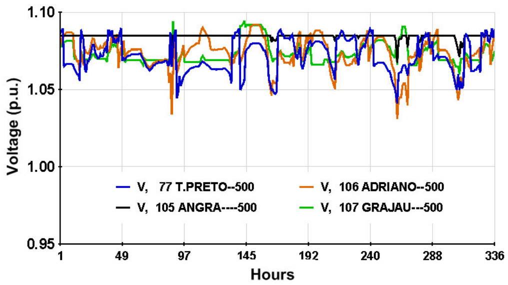

Figure E-6 *Voltage profile for major 500 kV buses.*

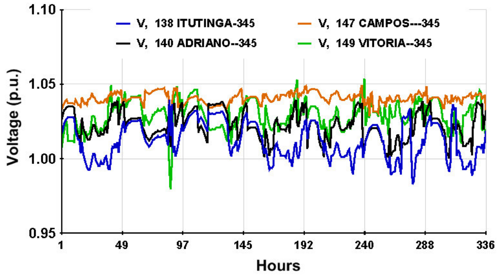

Figure E-7 *Voltage profile for major 345 kV buses.*

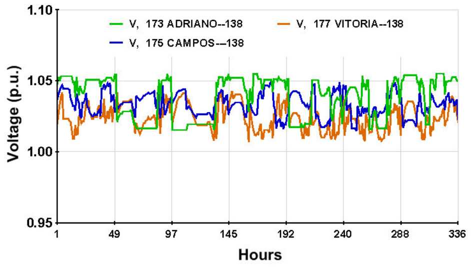

Figure E-8 *Voltage profile for major 138 kV buses.*

Figures E-9 to E-11 show the switchings of the capacitor/reactor modules that helped control the Rio Area voltage profile, along the weekly load curve. These switchings appear to be in agreement with the system voltage control needs, over the entire week.

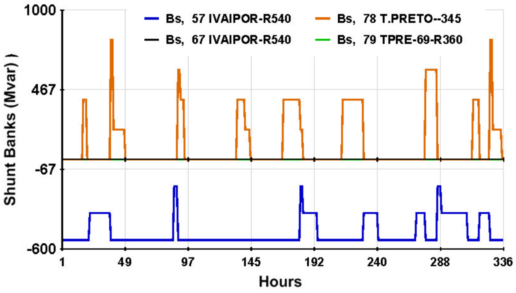

Figure E-9 *Shunt switchings – 765 kV transmission system.*

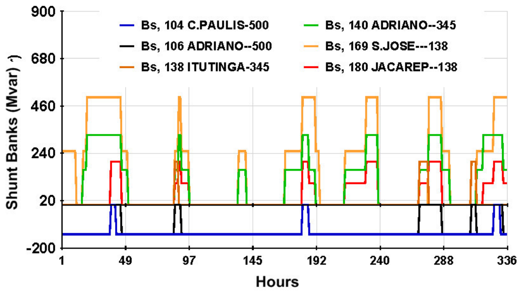

Figure E-10 *Shunt switchings – Rio de Janeiro Area.*

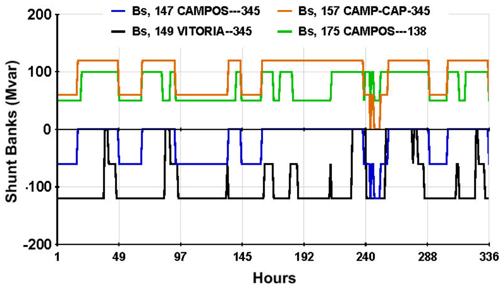

Figure I-11 *Shunt switchings – Rio de Janeiro Area.*

The CPU time required to perform these weekly load curve study is of roughly 2 minutes, when utilizing a PC with a 2.0 GHz processor. Preparing the data file for the discrete shunt devices for voltage control is a laborious task in large systems, which should be carried out by experienced engineers to avoid inputting data that will lead to voltage control conflicts.

E.6 Conclusions

This appendix described a power flow function developed to analyze the voltage control performance of large power systems along weekly load curves, incorporating both discrete and continuous voltage control devices. The discrete devices regulate local voltages to within a deadband: the same modeling is used for both manually and automatically switched shunt devices. Results are presented for a load curve having widely different maximum and minimum loadings. They indicate the method is numerically robust and apparently useful for week-ahead operational planning studies dealing with the allocation of switched reactive power reserves as well as the coordination of these voltage control resources.

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Appendix F

Examples of Secondary Voltage-Var Controls Applied to Static Compensators (STATCOMs) for Fast Capacitor Control and Long Term var Management

F.1. Introduction

This Appendix provides two examples for the concepts of secondary voltage-var controls applied to static compensators (STATCOMs) for fast capacitor control and long-term Var management presented in Chapter 4 of this document. Further concepts are contained in [F-1].

F.2 The Vermont Electric STATCOM at the Essex Substation [F-2]

F.2.1 Description of the STATCOM System

The STATCOM in the Vermont Electric (VELCO) system at the Essex 115-kV substation in Northeastern USA was installed to provide compensation for heavy increases in summertime electric usage, which have rendered the existing system increasingly vulnerable to events on the system. The requirements (i.e., the purpose of the STATCOM) can be categorized as dynamic reactive compensation needed for fast voltage support during critical contingencies.

As shown in Figure F-1, the STATCOM system consists of two groups of voltage-sourced converters (37.5 MVA each) and two sets of shunt capacitors (24.75 Mvar each). Each 37.5 MVA converter group consists of three sets of 12.5 MVA modules plus a 5 Mvar harmonic filter, with a nominal phase-to-phase ac voltage of 3.2 kV and a DC link voltage of 6,000 V. The two STATCOM groups are connected to the 115-kV system via two three-phase inverter transformers rated at 43 MVA, 3.2-kV/115-kV.

In addition to the primary control requirements described above, there were secondary power system control issues associated with this STATCOM application. The secondary control issues concerned both reserve capacity control and fast capacitor control. Therefore, the STATCOM control is coordinated with several local and remote capacitor banks to perform these secondary control functions. The STATCOM control monitors and switches (in or out) seven other capacitor banks: four local 24.75 Mvar banks at Essex, and three remote 24.75 Mvar banks at the Sandbar, Williston, and Georgia substations. There are also provisions built into the controller for two future banks at Essex. A one-line diagram of the 115-kV system in the vicinity of the Essex STATCOM is shown in Figure F-2.

The secondary control functions are illustrated in Figure F-3 and described in the following subsections.

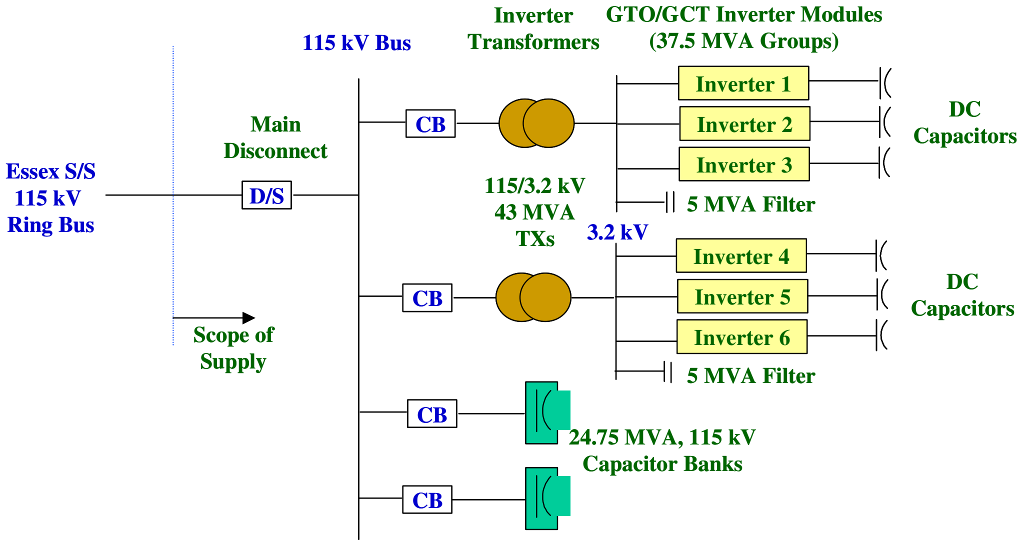


Figure F-1. Essex STATCOM system one-line diagram (CB=circuit breaker, D/S=disconnect switch).

F.2.2 Fast Capacitor Control

As illustrated in Figure F-3, the secondary control function for fast capacitor control monitors the voltage error of the STATCOM from the primary control (AVR), and if the error exceeds a threshold for a specified time, then a connect (for low voltage conditions) or disconnect (for high voltage conditions) signal is given. The panel of the STATCOM controller for the fast capacitor control is shown in Figure F-4. This figure shows that the available settings are for the voltage error (typically +/- 2%), a time for how long the voltage error must be exceeded (typically a few seconds), and a time interval before a subsequent switch signals can be given (typically tens of seconds or a few minutes). There are separate timer settings for connect and disconnect control actions.

Since the monitored voltage error is based on the Essex substation, to which the STATCOM is connected, this fast capacitor control is primarily for severe system conditions when the STATCOM is pushed into its limits. Thus an action of capacitor bank switching can move the STATCOM back into its controllable range.

F.2.3 Reserve Capacity Control

The reserve capacity control is designed to enable the operating point of the STATCOM inverters to be offset into the inductive region so that a desired "net capacitive range" or "reserve capacity" can be achieved. Reserve capacity is defined as the available net change in STATCOM inverter output towards the capacitive region from a given operating point. For example, if the STATCOM inverters are operating with zero net output, the reserve capacity will be equal to the maximum output rating of the inverters (75 Mvar). If the operating point is biased into the inductive region, for example to 24 Mvar or 48 Mvar inductive, then the reserve capacity will be 99 Mvar or 123 Mvar, respectively. The reserve capacity of the STATCOM can be selected by the operator to one of three positions; high, medium, and low, which add inductive offsets of 48, 24 and 0 Mvar respectively to the operating setpoint of the STATCOM. This is illustrated in Figure F-3.

The desired reserve capacity is a function of the system loading conditions with generally higher reserve capacity (i.e., more biasing into the inductive region) being required under heavy load conditions. Under light load conditions the system requirements for reserve capacity are lower and it is advantageous to operate the STATCOM at the low or medium reserve capacity settings to reduce the losses. The reserve capacity requirement is achieved by automatically connecting or disconnecting shunt capacitors at the Essex, Sandbar, Williston, and Georgia substations.

The panel for the STATCOM controller for the reserve capacity control is shown in Figure F-4. The capacitor banks selection logic is discussed in the next subsection.

F.2.4 Capacitor Bank Selection

The STATCOM secondary controls (fast capacitor control or the reserve capacity control) sends a signal when a capacitor bank switching event (connect or disconnect) is being requested. The algorithm adopted for the STATCOM first switches all capacitor banks at Essex with the "first-on/last-off" logic. For the remote capacitor banks at Williston, Sandbar, and Georgia, they are switched on or off based on their bus voltage (e.g., lowest voltage on first, highest voltage off first). If a selected capacitor bank is already on-line at the specified substation or is disabled, the selection controller searches for the next one in the hierarchy. The capacitor banks status panel of the STATCOM control is shown in Figure F-5.

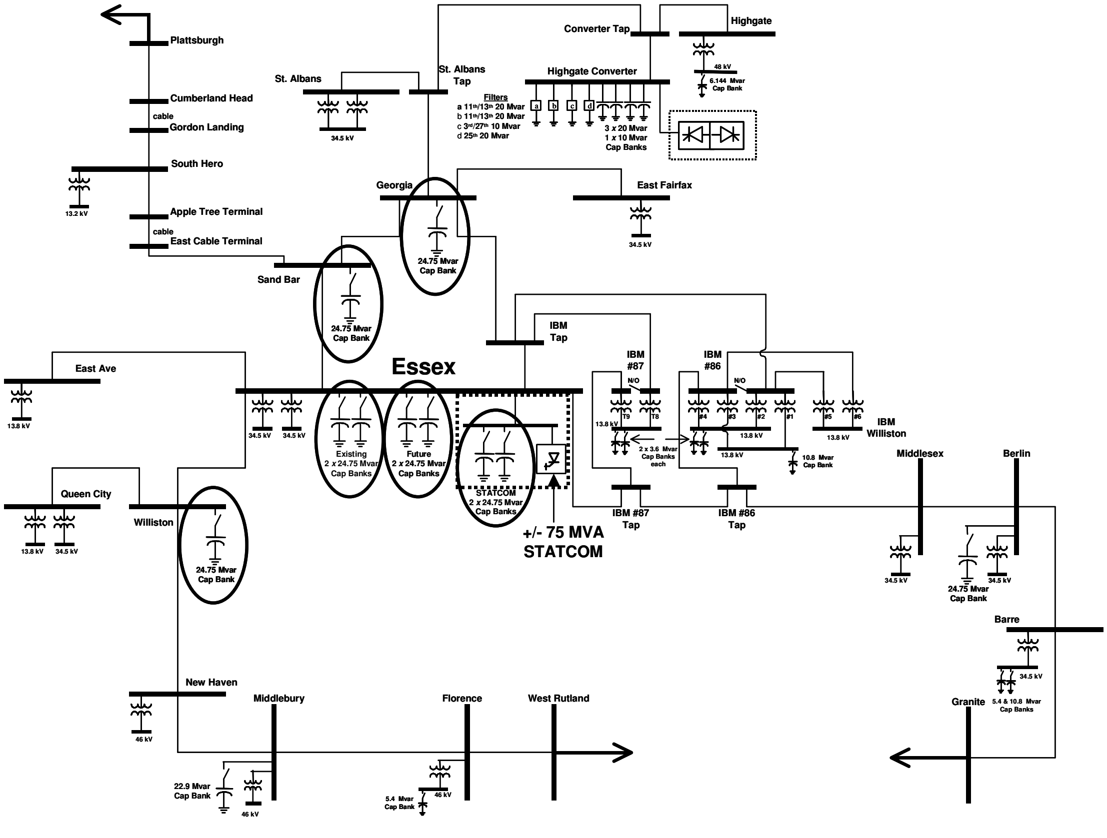


Figure F-2. One-line diagram of the 115-kV system in the vicinity of the Essex STATCOM. The highlighted capacitor banks are coordinated with the STATCOM for fast capacitor control and reserve capacity control [F-2].

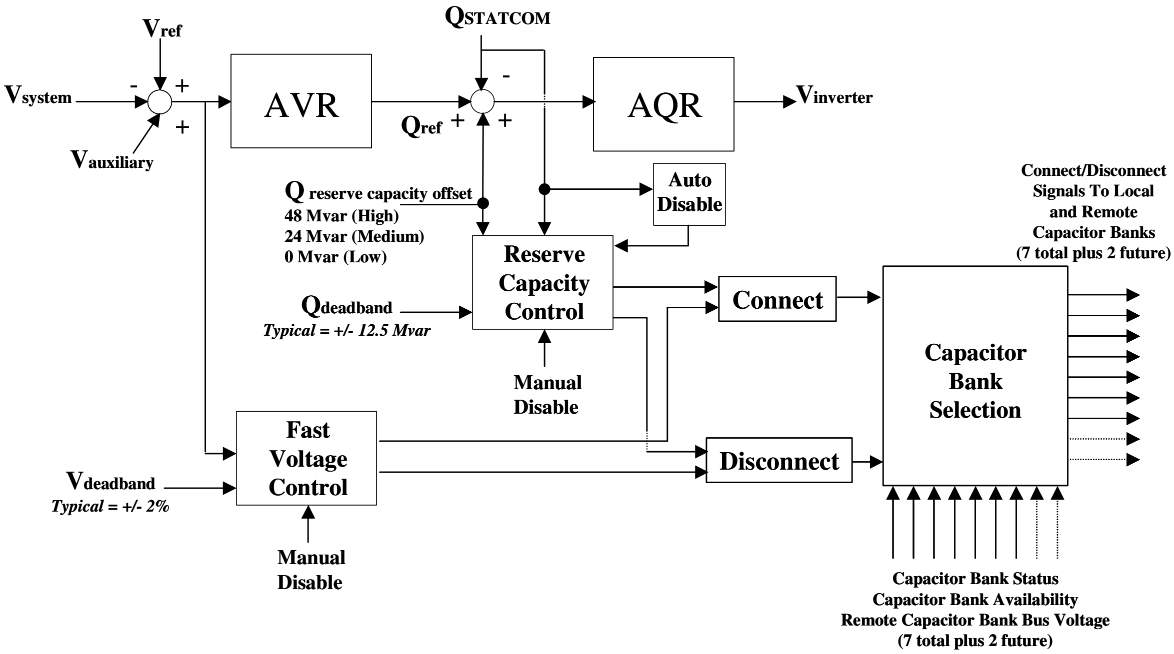
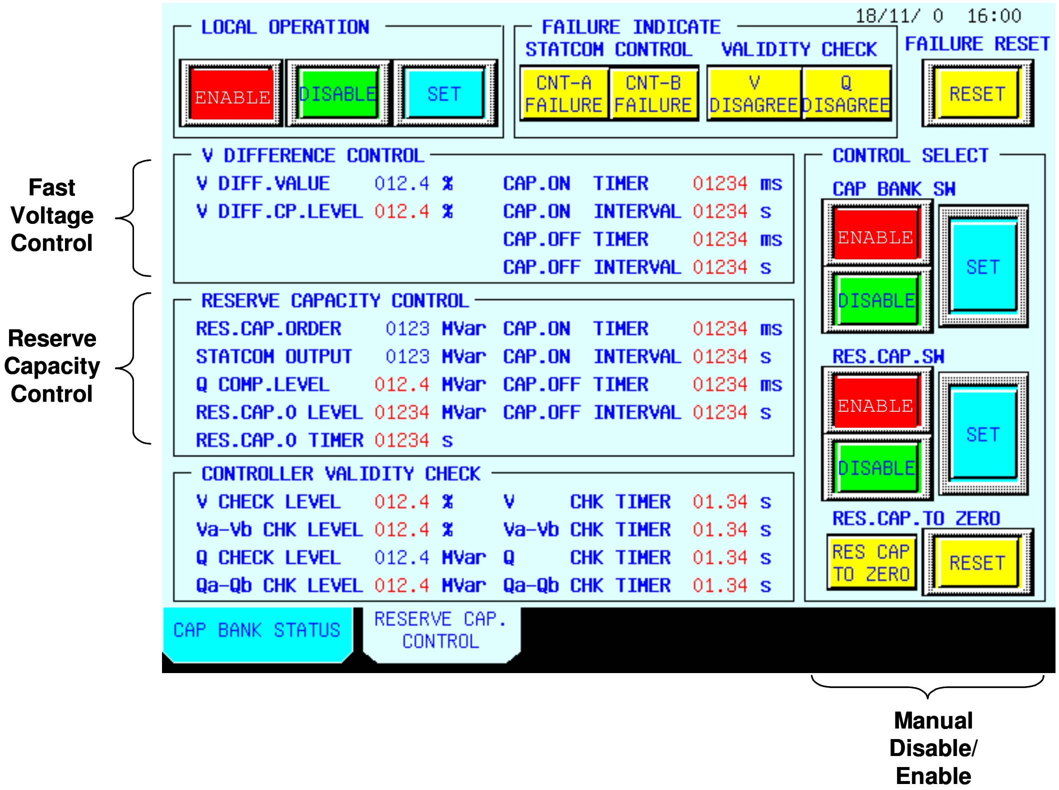


Figure F-3. Functional block diagram of the overall voltage-var control for the Essex STATCOM.



18/11/ 0 16:00

LOCAL OPERATION

FAILURE INDICATE

STATCOM CONTROL VALIDITY CHECK

FAILURE RESET

V DIFFERENCE CONTROL

V DIFF.VALUE 012.4 %
V DIFF.CP.LEVEL 012.4 %
CAP.ON TIMER 01234 ms
CAP.ON INTERVAL 01234 s
CAP.OFF TIMER 01234 ms
CAP.OFF INTERVAL 01234 s

RESERVE CAPACITY CONTROL

RES.CAP.ORDER 0123 MVar
STATCOM OUTPUT 0123 MVar
Q COMP.LEVEL 012.4 MVar
RES.CAP.0 LEVEL 01234 MVar
RES.CAP.0 TIMER 01234 s
CAP.ON TIMER 01234 ms
CAP.ON INTERVAL 01234 s
CAP.OFF TIMER 01234 ms
CAP.OFF INTERVAL 01234 s

CONTROLLER VALIDITY CHECK

V CHECK LEVEL 012.4 %
Va-Vb CHK LEVEL 012.4 %
Q CHECK LEVEL 012.4 MVar
Qa-Qb CHK LEVEL 012.4 MVar
V CHK TIMER 01.34 s
Va-Vb CHK TIMER 01.34 s
Q CHK TIMER 01.34 s
Qa-Qb CHK TIMER 01.34 s

CONTROL SELECT

CAP BANK SW

RES.CAP.SW

RES.CAP.TO ZERO

Figure F-4. Secondary control panel (fast capacitor control and reserve capacity control) of the Essex STATCOM controller (Note all input values are shown here as "01234….." before factory settings were in-place. Values shown in this panel for the STATCOM secondary control are settable).

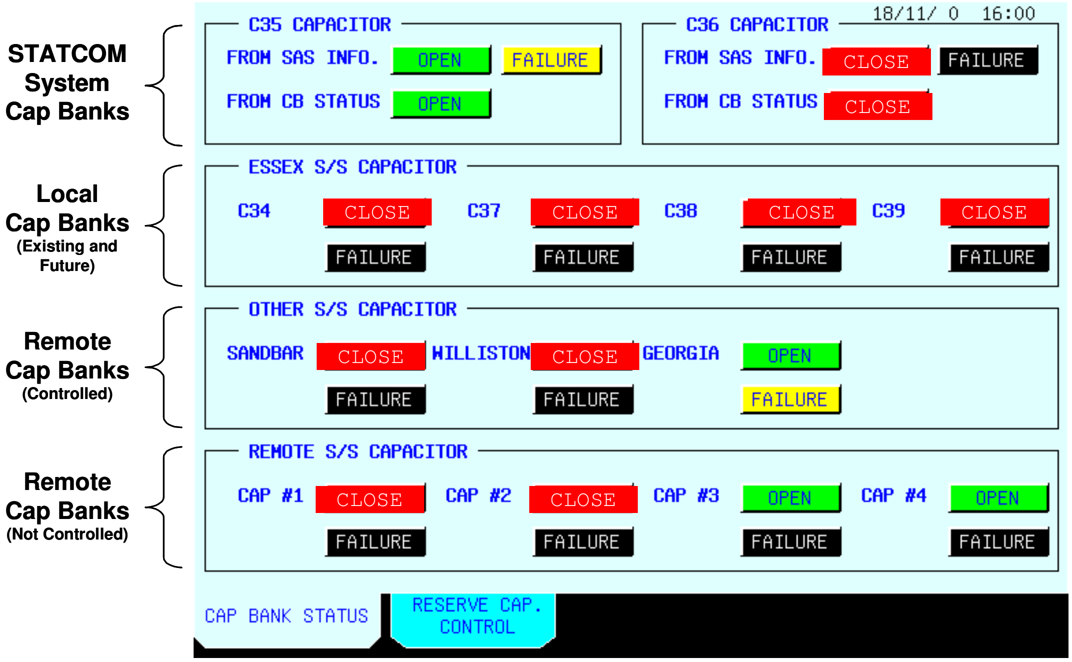


Figure F-5. Capacitor bank status panel of the Essex STATCOM controller.

There are provisions for control of four capacitor banks currently at Essex (two of which are associated with the STATCOM installation) plus two future banks at Essex, plus for the three remote banks. The information transmitted from the local and remote capacitor bank substations into the selection logic of the STATCOM secondary control, illustrated in Figure F-3, is as follows:

- Capacitor bank status
- Capacitor bank availability
- Remote capacitor bank bus voltage

To avoid frequent switching of the capacitor banks for the fast capacitor control, the capacitor bank selection logic has voltage deadbands, settable on the STATCOM control panels, as illustrated in Figure F-4.

F.3 The San Diego Gas and Electric STATCOM at the Talega Substation [F-3]

F.3.1 Description of the STATCOM System

The STATCOM in the San Diego Gas and Electric (SDG&E) system at the Talega 138-kV substation in Southern California USA is being applied for dynamic var control during peak load conditions, which have rendered the existing system increasingly vulnerable to system events on the transmission system.

As shown in Figure F-6, the STATCOM system has a rated capacity of +/- 100 MVA. The STATCOM system consists of two groups of voltage-sourced converters (50 MVA each). Each 50 MVA converter group consists of four sets of 12.5 MVA modules plus a 5 Mvar harmonic filter (plus one spare filter switchable to either group), with a nominal phase-to-phase ac voltage of 3.2 kV and a DC link voltage of 6,000 V. The two 50 MVA STATCOM groups are connected to the 138-kV system via three three-phase inverter transformers each rated at 55 MVA, 3.2-kV/138-kV (includes one "hot" spare). Either 50 MVA STATCOM group or both can be connected to each of the 138-kV buses via the various automatically controlled motor operated disconnects.

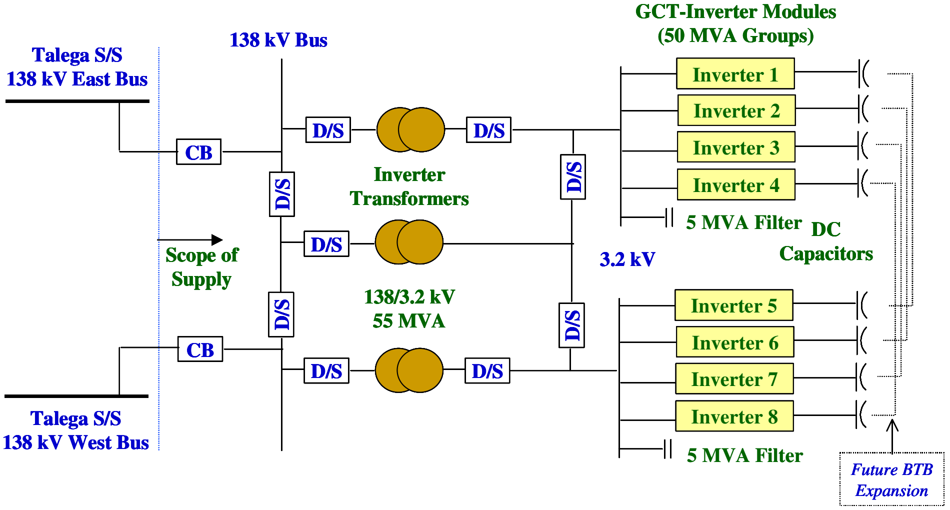


Figure F-6. Talega STATCOM one-line diagram (CB=circuit breaker, D/S=disconnect switch).

As part of the overall reactive compensation scheme at the Talega substation, there are also three 69 Mvar shunt capacitors that are connected to the Talega 230 kV system. Figure F-7 shows a one-line diagram of the 230/138-kV system in the vicinity of the Talega STATCOM installation.

The secondary control functions are illustrated in Figure F-8 and described in the following subsections.

F.3.2 Fast Capacitor Control

The fast capacitor control of the Talega STATCOM is similar to that of the Essex STATCOM. As illustrated in Figure F-8, the secondary control function for fast capacitor control monitors the Talega 138-kV bus voltage and if the voltage is outside a settable deadband for a specified time, then a connect (for low voltage conditions) or disconnect (for high voltage conditions) signal is given.

As noted, since the monitored voltage is at the Talega substation, to which the STATCOM is connected, this fast capacitor control is primarily for severe system conditions when the STATCOM is pushed to its limits. Thus an action of capacitor bank switching can move the STATCOM back into its controllable range. There is an added function to the fast capacitor control that will call for the connection of all available capacitor banks at the Talega 230-kV bus simultaneously for a rapid severe voltage drop.

Figure F-9 is a time-chart illustrating the Talega STATCOM fast capacitor control logic.

F.3.3 Reserve Capacity Control

The reserve capacity control of the Talega STATCOM has the function of keeping the output of the STATCOM to a minimum value, so as to minimize losses. If the reactive power output of the STATCOM is outside a settable deadband for a specified time, then a connect (for large capacitive Mvar output) or disconnect (for large inductive Mvar output) signal is given by the control. The deadband is rather large due to the fact that the capacitor banks being switched are rated at 69 Mvar.

Figure F-10 is a time-chart illustrating the Talega STATCOM reserve capacity control logic.

F.3.4 Capacitor Bank Selection

The capacitor banks selection logic will select one of the three capacitors at the Talega 230-kV substation (69 Mvar each) according to the status and availability/failure information. The selection logic includes cycling of the three banks.

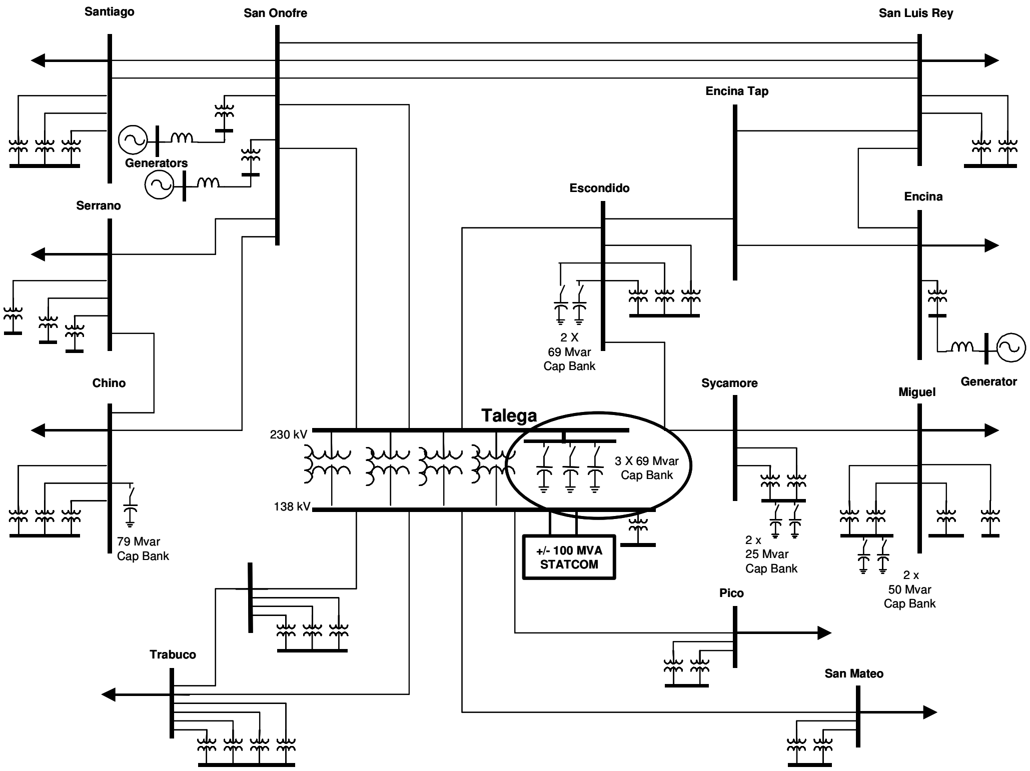


Figure F-7. One-line diagram of the 138 and 230-kV system in the vicinity of the Talega STATCOM. The highlighted capacitor banks are coordinated with the STATCOM for fast capacitor control and reserve capacity control [F-3].

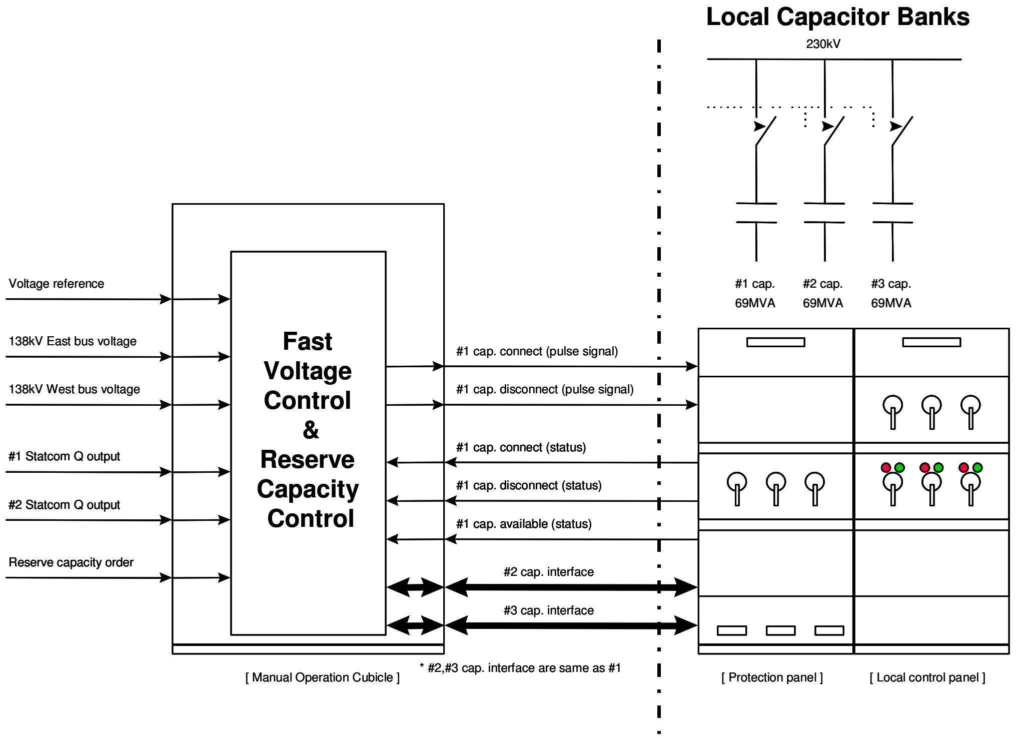


Figure F-8. Functional block diagram of the secondary control for the Talega STATCOM.

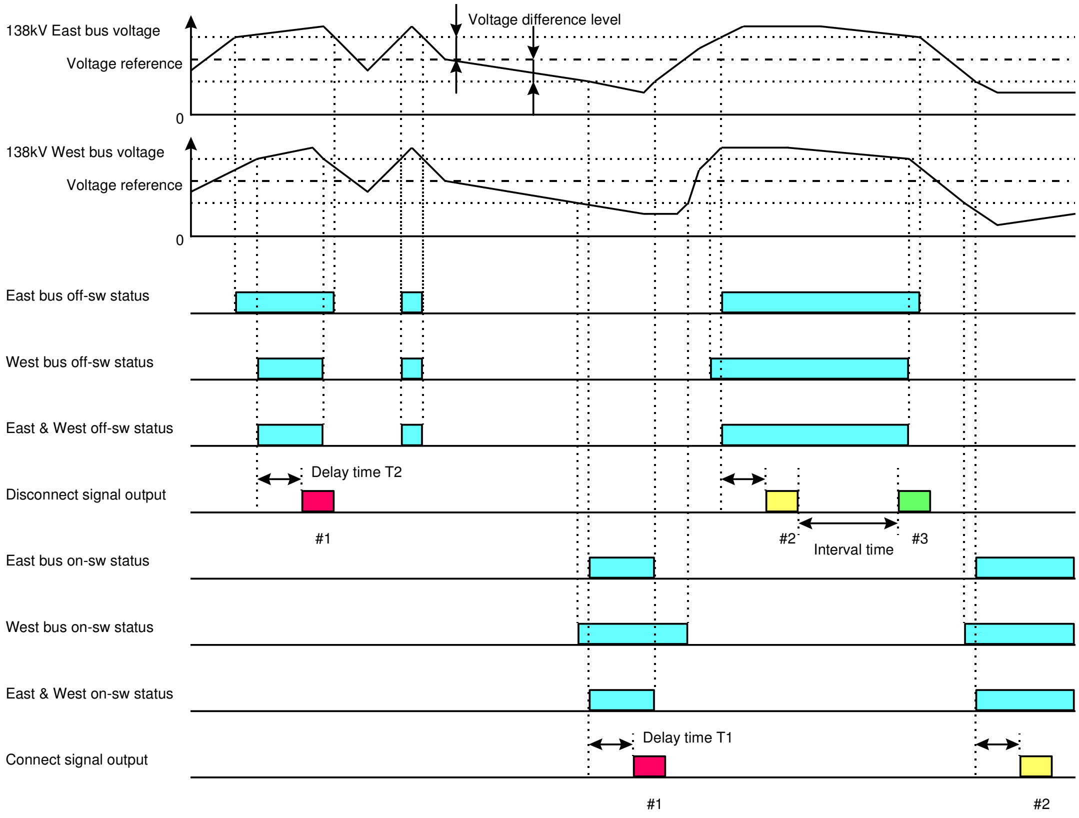


Figure F-9. Illustration of the logic for the Talega STATCOM <u>fast capacitor control</u> (Note: Timers, delays, and thresholds are settable on the STATCOM controller panels).

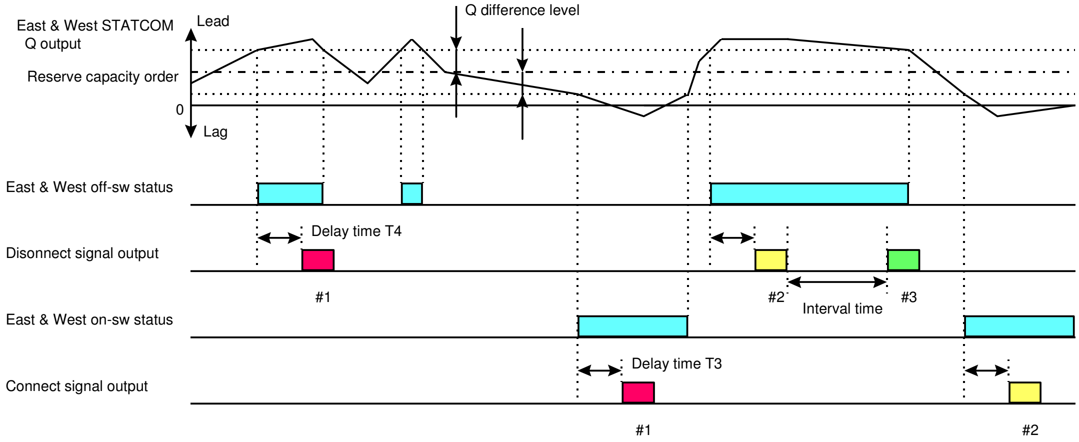


Figure F-10. Illustration of the logic for the Talega STATCOM reserve capacity control (Note: Timers, delays, and thresholds are settable on the STATCOM controller panels).

F.4 Summary

This appendix presented the concept and applications of secondary voltage-var controls applied to Static Compensators (STATCOMs) for fast capacitor control and long term var management. The primary purpose of the secondary controls is to ensure that an adequate range of the STATCOM dynamic capability is available for major system disturbances. The output of the secondary controls presented here call for the switching of capacitor banks to "reset" the reactive power output of the STATCOM to a pre-specified level after a system event (long term), or during the course of a daily load cycle (long term), or for voltage control (fast). Two recent applications of STATCOMs coordinated with local and remote capacitor banks for the purpose of fast capacitor control and long term var management were presented, namely the Vermont Electric +/- 75 MVA STATCOM at the Essex 115-kV substation, and the San Diego Gas & Electric +/- 100 MVA STATCOM at the Talega 138-kV substation.

References

[F-1] J. Paserba, D.J. Leonard, N.W. Miller, S.T. Naumann, M.G. Lauby, F.P. Sener, "Coordination of a Distribution Level Continuously Controlled Compensation Device With Existing Substation Equipment for Long Term Var Management," *IEEE Transactions on Power Delivery*, Vol. 9, No. 2, April 1994, pp. 1034-1040.

[F-2] G. Reed, J. Paserba, T. Croasdaile, M. Takeda, N. Morishima, Y. Hamasaki, L. Thomas, W. Allard, "STATCOM Application at VELCO Essex Substation," Panel Session on FACTS Applications To Improve Power System Dynamic Performance, *Proceedings of the IEEE PES T&D Conference and Exposition*, Atlanta, Georgia, October/November 2001.

[F-3] G. Reed, J. Paserba, T. Croasdaile, R. Westover, S. Jochi, N. Morishima, M. Takeda, T. Sugiyama, Y. Hamazaki, T. Snow, A. Abed, "SDG&E Talega STATCOM Project - System Analysis, Design, and Configuration," Panel Session on FACTS Technologies: Experiences of the Past Decade and Developments for the 21st Century in Asia and the World, *Proceedings of the IEEE PES T&D-Asia Conference and Exposition*, Yokahama, Japan, October 2002.

Appendix G

Advanced Voltage and Reactive Power Control of Wind Farm-Generators for Improved System Dynamic Performance

G.1 Introduction

Integration of large wind farms into bulk power systems presents multiple challenges to system operation and security. Vulnerability to common-mode tripping due to transmission system faults is a major concern throughout the world. In many systems, including proposed large off-shore projects, the wind farms are geographically remote and have relatively weak transmission systems.

The presence of wind farms raises serious concerns about system stability, especially stability issues related to bulk system disturbances. The latest generation of low-voltage ride-through technologies combined with new reactive and active power controls for wind turbine-generators can provide much improved system performance compared to more conventional systems.

This section describes the new voltage and reactive power control system, WindVAR, developed by GE for improved wind farm dynamic performance in weak transmission systems.

G.2 Fundamentals of Double Fed Generators

A simple schematic of an individual Wind Turbine-Generator (WTG) with a double fed asynchronous generator is shown in Figure G-1. Physically, the machine is similar to a conventional wound rotor induction (WRI) machine. However, the key distinction is that this machine is equipped with a solid-state voltage-sourced converter AC excitation system. The AC excitation is supplied through an ac-dc-ac converter. Machines of this structure are termed ‘double fed’, and have significantly different dynamic behavior than either conventional synchronous or induction machines. Modeling of these machines with conventional dynamic models for either synchronous or induction machines is, at best, highly approximate and should be avoided.

The fundamental frequency electrical dynamic performance of a double-fed WTG is completely dominated by the field converter. Conventional aspects of generator performance related to internal angle, excitation voltage, and synchronism are largely irrelevant. In practice, the electrical behavior of the generator and converter is that of a current-regulated voltage-source inverter. Like other voltage-source inverters (e.g. a BESS or a STATCOM), the WTG converter synthesizes an internal voltage behind a transformer reactance, which results in the desired active and reactive current being delivered to the device terminals. In the case of the WTG, the machine rotor and stator windings are primary and secondary windings of the transformer.

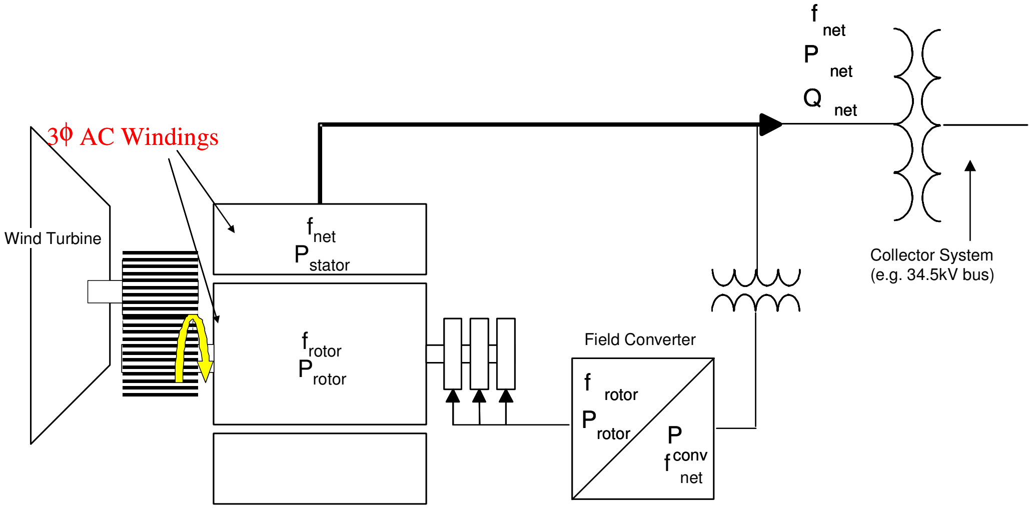


Figure G-1 *WTG Major Components.*

The variable rotational speed of the machine means that the ac frequency on the rotor winding corresponds to the difference between the stator frequency (50 or 60Hz) and the rotor speed. This is the slip frequency of the machine. In the vicinity of rated power, GE WTGs will normally operate at 120% speed, or -20% slip. Control of the excitation frequency allows the rotor speed to be controlled over a wide range, ±30%. The variable speed also means that the active power is divided between the stator and rotor circuits, roughly in proportion to the slip frequency. For rotor speeds above synchronous, the rotor active power is injected into the network through the converter. The active power on the rotor is converted to terminal frequency (50 or 60Hz). The variation in excitation frequency and the division of active power between the rotor and stator are handled by fast, high bandwidth regulators within the converter controls. The time response of the converter regulators are sub-cycle, and as such can be greatly simplified for understanding of bulk power system dynamic performance.

Broadly stated the objectives of the turbine control are to maximize power production while maintaining the desired rotor speed and avoiding equipment overloads. There are two controls (actuators) available to achieve these objectives: blade pitch control and torque order to the electrical controls (the converter).

This brief description captures the important characteristics of a single GE WTG. However, from a system perspective, the performance of groups of WTGs and how they interact with the bulk power system is of primary interest. Successful design of wind farms to achieve the best system dynamic behavior requires an understanding of both individual WTG behavior and overall wind farm behavior. In the following sections, advanced hardware and control features related to WindVAR, the new voltage and reactive power controller for WTGs is presented. WindVAR significantly improves the security and dynamic behavior of the host utility grid, and have been implemented on recently commissioned commercial projects with GE Wind Energy equipment.

G.3 Voltage and Reactive Power Control: WindVAR

For many wind farms, especially large remote and off-shore projects, traditional approaches to managing reactive power are no longer acceptable. Historically, most wind farms have been operated on power factor control – usually reactive power neutral. In systems with relatively low short circuit ratios, i.e. where the wind farm is large compared to the electrical stiffness of the host grid, such control strategies can result in unacceptable voltage performance, including flicker.

While the voltage and reactive power requirements of a wind farm are similar to that of conventional generation connected to weak AC systems, the physical structure of a wind farm imposes a different set of design constraints. In a large wind farm there can be a hundred or more individual WTGs, separated by tens or even hundreds of kilometers of electrical collector system. Each individual WTG has local, autonomous controls, as described above. For new wind farms with GE WTGs, these local controls include closed-loop regulators that take advantage of the STATCOM-like response capabilities. However, the power system needs are dictated at the point of interconnection with the host grid. To achieve improved voltage/VAR control, GE Wind Energy wind projects are equipped with a farm level supervisory control: GE's Wind Voltage-Ampere Reactive (WindVAR). This supervisory control senses AC system conditions and instructs the individual WTGs within a farm to adjust their local control objectives to meet system needs. WindVAR provides tight closed loop control of utility system voltages. This hierarchical control minimizes voltage flicker, improves system stability, reduces the risk of voltage collapse, and minimizes the impact of system disruptions. This provides two major benefits: First, the impact of active power fluctuations from wind variation on the grid voltages are minimized; second, the fast and precise voltage control effectively strengthens the grid, improving the overall power system's resilience to large disruptions.

WindVAR control structure is in principle similar to the secondary voltage control (SVR) scheme described in Chapter 2, but has faster dynamics to suit the application needs, and fully exploits the speed and other capabilities of the solid-state voltage source converter AC excitation system.

Figure G-2 shows the simulated response of a wind farm of 108 GE 1.5 MW wind turbine generators (WTGs) to ten minutes of highly variable wind near rated wind speed. The red traces show the system response with WindVAR, and the black traces show the system response with conventional fixed power factor control. The fixed power factor control is local to each individual WTG. At the utility bus (the point of interconnection), the system voltage with conventional power factor (pf) control exhibits unacceptably high variation. By comparison, the WindVAR controlled system voltage exhibits very small variations. The voltage flicker index, P_{st}, is less than 0.02 for this high stress condition – well within industry expectations. The variables plotted are:

1. Utility voltage. This is the p.u. voltage at the point-of-common-coupling (PCC) in p.u. For this system, the PCC is approximately 75 km from the wind farm;
2. Wind farm power. This is the total power delivered to the PCC, accounting for collector system and transmission losses;

3. Wind farm reactive power. This is the total reactive power deliver to the PCC, also accounting for the reactive losses of the collector and transmission system, which are quite significant;

4. Wind speed. This is the wind profile for this simulation.

The individual machines are subjected to the same profile in this case, which is very conservative. The behavior of one of the WTGs for this wind profile is shown in Figure G-3. The machine reactive power and terminal voltage are actively maneuvered by commands from WindVAR to produce the desired performance at the utility bus. Variables plotted include:

1. WTG terminal voltage, V_t. This is the p.u. voltage at the terminals of one of the individual wind turbine generators;
2. WTG speed, SPD. This is individual WTG speed variation due to wind speed variation and subject to the GE turbine control, which optimizes energy capture;
3. WTG reactive power, Q_g. This is the individual reactive power produced by the machine;
4. WTG active power, P_g. This is the individual WTG active power output. Notice that it is not significantly affected by the reactive power control between the two cases.

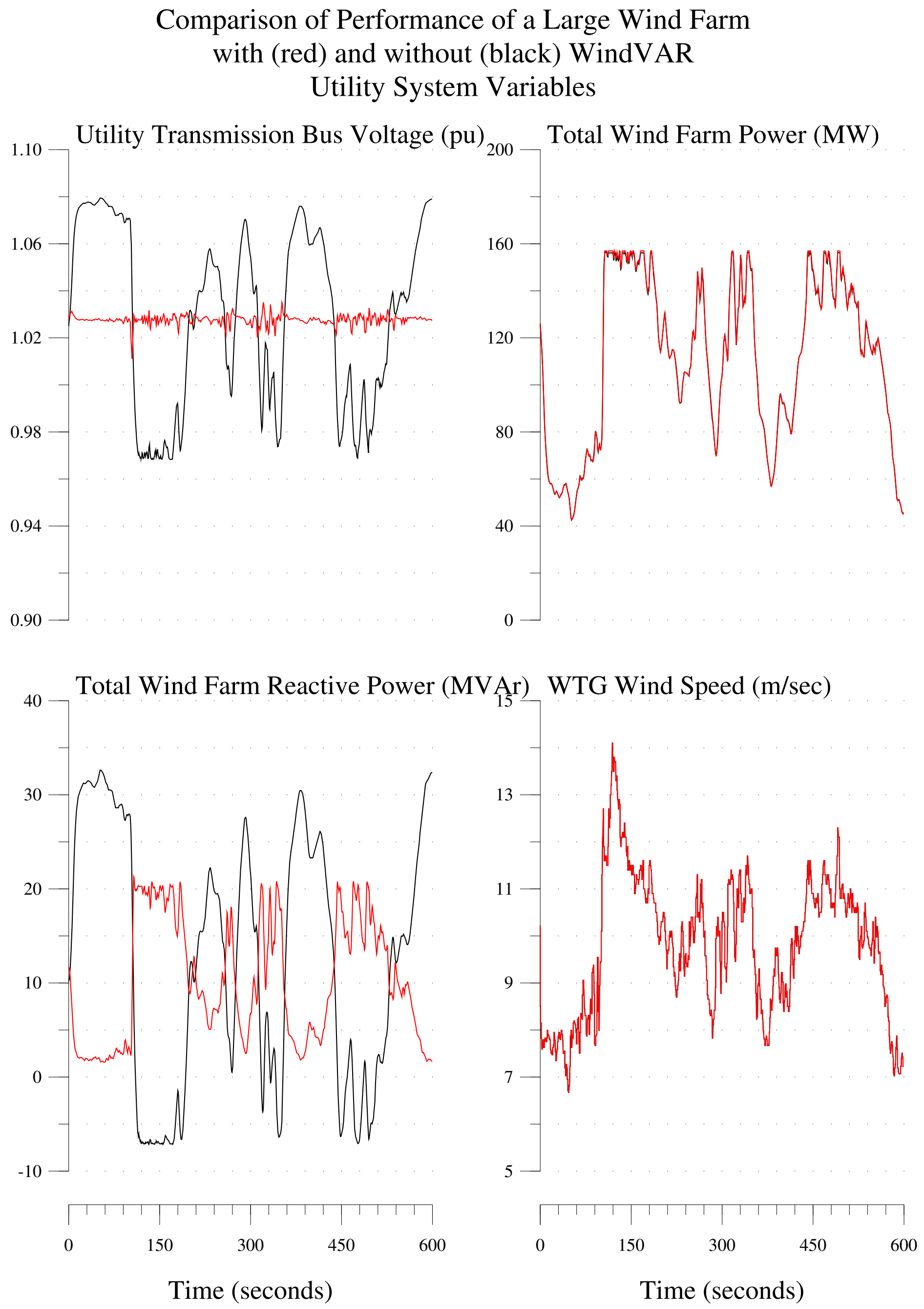


Figure G-2 *Simulated Utility Response with (red) and without (black) WindVAR.*

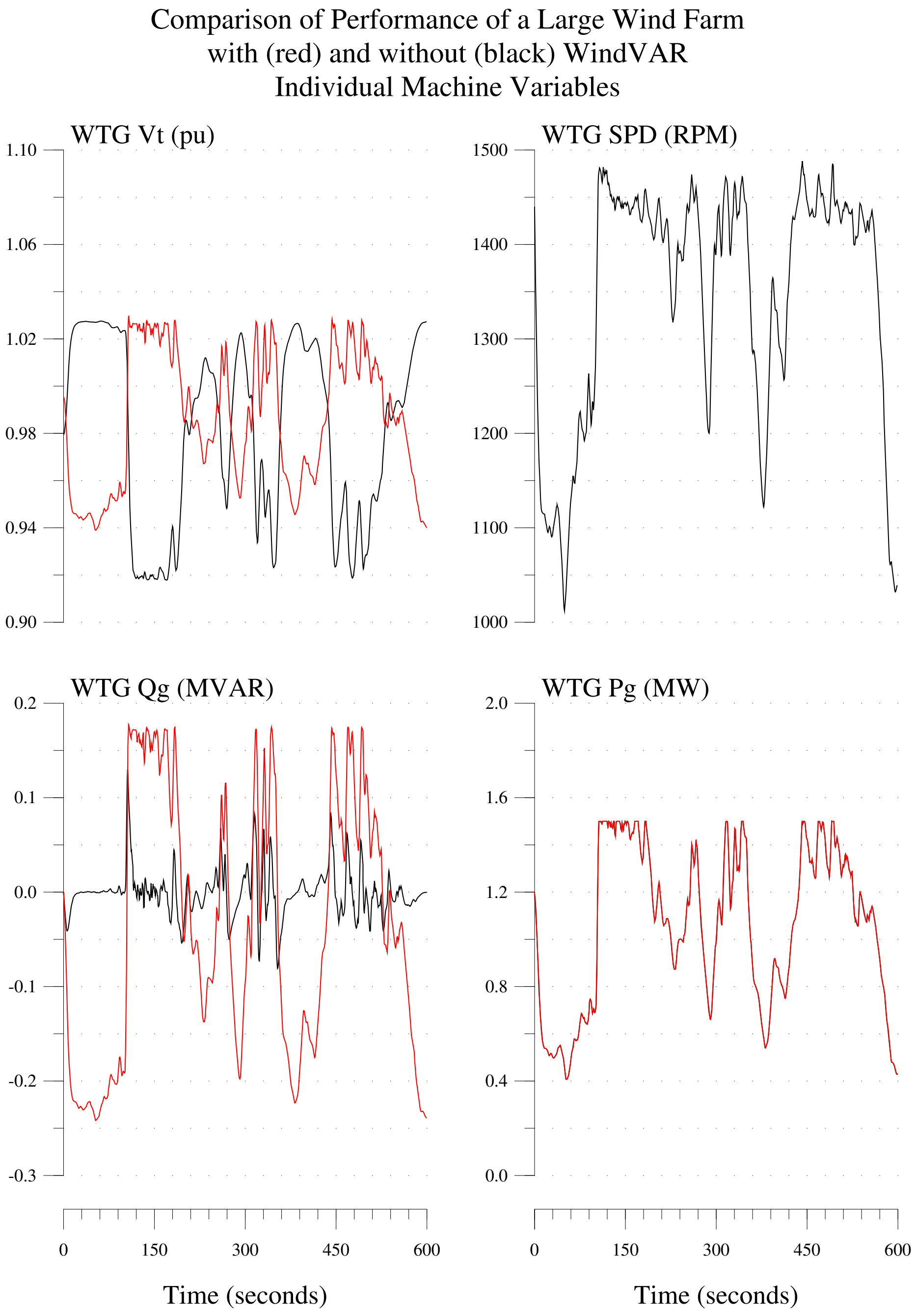


Figure G-3 *Simulated WTG Response with (red) and without (black) WindVAR.*

G.4 Conclusions

Maintaining operation through and immediately following system disturbances is a critical system security concern. LVRT, the low-voltage-ride-through GE technology, which is described in [G-1], can prevent cascading grid failures due to system faults;

The variability of wind power and the tendency for wind farms to be located in relatively weak electrical systems makes tight voltage regulation critical;

Combinations of advanced controls at individual WTGS and wind farm level supervisory controls, allow for secure operation even in systems with low short-circuit ratios;

The hierarchical control structure, including the ability of the WindVAR to account for the complexities introduced by long radial feeders or large amounts of AC cable inherent to off-shore wind farms is a key component of the controller.

References

[G-1] N. Miller, “Advanced Power Control of Wind Turbine Generators for Improved Power system Dynamic Performance”, invited paper to the IX SEPOPE, Rio de Janeiro, May 2004.

Appendix H

A Fuzzy Inference System Application to Coordinated Voltage Control

H.1 Introduction

The system studied is an equivalent of the Brazilian South/Southeast system modeled with 730 buses, 1146 branches and 104 generators. The region of interest for the studies is called Rio Area, which consists of the utilities LIGHT, CERJ, ESCELSA and part of Furnas system. It mainly represents the Rio de Janeiro metropolitan area, with a peak load of approximately 6000 MW in summer time (from January to March).

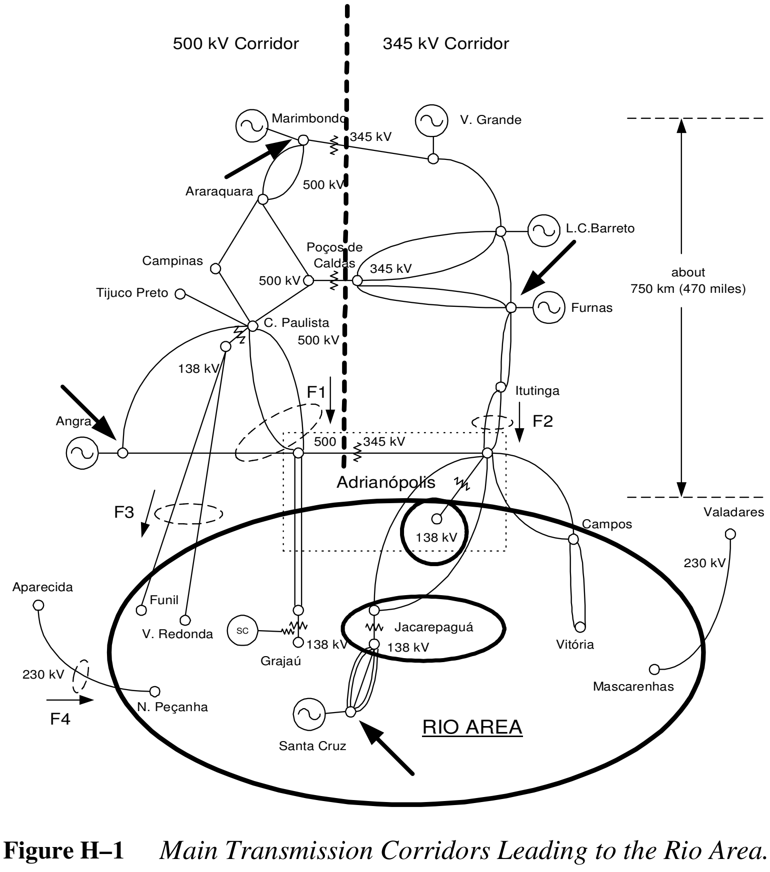


Figure H–1 *Main Transmission Corridors Leading to the Rio Area.*

Figure H-1 depicts the bulk power transfer corridors that lead to the Rio Area and the main reactive power resources for voltage control in the area. In the 500 kV corridors, Marimbondo hydro power plant and Angra nuclear power plant are the main reactive spinning sources for voltage control, whereas in the 345 kV corridors, Furnas hydro power plant is the main reactive source. The main sources of spinning reactive support within the Rio Area are two +200, –150

Mvar Synchronous Condensers (SC) at Grajaú station, and Santa Cruz thermal power plant. The application of a FIS to the coordinated voltage control of the Rio Area is accomplished by a set of rules, which are based on the experience of system operators and on off-line studies.

The voltages at the Adrianópolis 138 kV bus and at the Jacarepaguá 138 kV bus, together with the reactive power output of the Grajaú SC are the input variables (regulated variables) for the FIS. On the other hand, the high-side voltages at the Marimbondo, Furnas, Santa Cruz and Angra power plants are the output variables (control variables) for the FIS. Figure H-2 shows the integration of the FIS with the power system. The FIS could be viewed as a multivariable feedback fuzzy controller, if operated in closed-loop form.

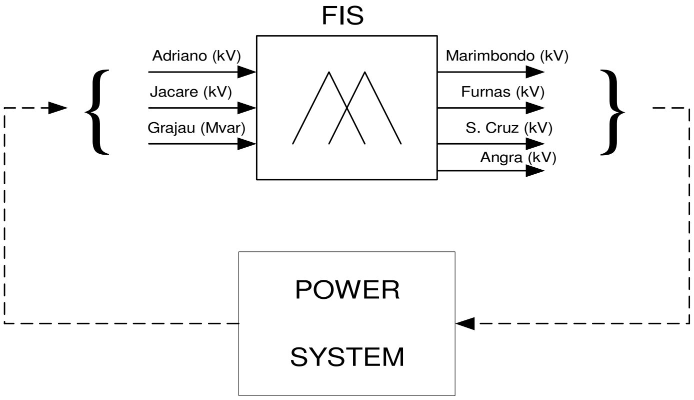


Figure H–2 *Closed-loop System.*

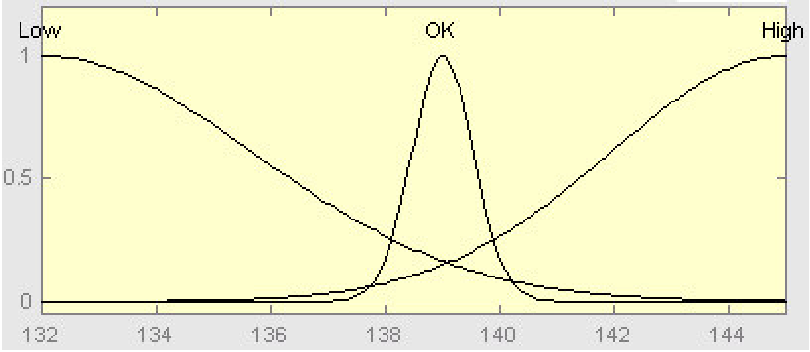


Figure H–3 *Membership Functions for the Linguistic Variable Jacarepaguá_138kV_Voltage.*

Depending on the values of the monitored variables, some of the rules will be activated and weighted automatically by the fuzzy system. Control actions like, increase/decrease the high-side voltage at power plants will be displayed to the system operators, who then decide whether to execute or not the action. Two objectives were kept in mind in the process of building the rules:

Keep the voltages of Jacarepaguá and Adrianópolis load buses, around the desired values established by the utilities of the Rio Area. This means to assume high degree (close to 1) of membership of these voltages to the fuzzy set represented by the term OK. Figure H-3 shows the set of membership functions of the linguistic variable Jacarepagua_138kV_Voltage.

Keep the Grajaú SC reactive power output between zero and −100 Mvar. This corresponds to assuming high values for the membership function of the term OK of the linguistic variable Grajau_Reactive_Output.

Based on the experience in controlling transmission network voltage in the Rio Area from Furnas EMS staff, and on the knowledge of off-line studies for voltage control in the Rio Area, 29 operating rules were built. Table H-1 describes 7 of these rules. Taking Rule 1 as an example, it defines the following control law: If Jacarepaguá 138 kV voltage is OK (see Figure H-3 for definition), Adrianópolis 138 kV is OK and Grajaú SC reactive power output is OK, Then the high-side voltages at Marimbondo, Furnas, Santa Cruz and Angra power plants must remain unchanged.

Table H-1 *Knowledge-Based Rules.*

	INPUTS			OUTPUTS			
Rule	Adria	Jacar	Graj	Mar	Fur	SCrz	Ang
1	OK	OK	OK	RE	RE	RE	RE
2	Low	Low	Cap	Up	Up	Up	Up
3	OK	High	LC	RE	SD	Down	RE
4	OK	High	Ind	RE	RE	Down	SD
5	NTL	Low	LC	Up	Up	Up	SU
6	NTL	OK	OK	SU	RE	RE	SU
7	NTL	OK	LI	RE	SU	RE	SU

Table H-2 *Table of Acronyms.*

OK	DESIRED
NTL	NOT TOO LOW
Cap	CAPACITIVE
LC	LOW CAPACITIVE
Ind	INDUCTIVE
LI	LOW INDUCTIVE
RE	REMAIN
SU	SMALL UP
SD	SMALL DOWN

The long bulk transmission corridors suffer voltage limit violations at intermediate buses during high load conditions. To solve this problemthe algorithm, shown in Figure H-4 was implemented, which checks the voltage at all buses along the transmission corridors against operating limits. If any limit violation occurs, an alarm will sound to call the operators' attention. In this way, a control hierarchy is accomplished, where priority is given to the control actions that eliminate limit violations, even if those are opposed to the control action inferred by the FIS.

In a practical open loop implementation of this control room FIS, the computer screen could be refreshed every 5 minutes or so, guiding the system operator on the best available options to be taken. In closed-loop operation, the FIS could be setup to read information from a real-time state estimator and send control signals every 20 seconds using a communication system similar to the one used for the Automatic Generation Control (AGC).

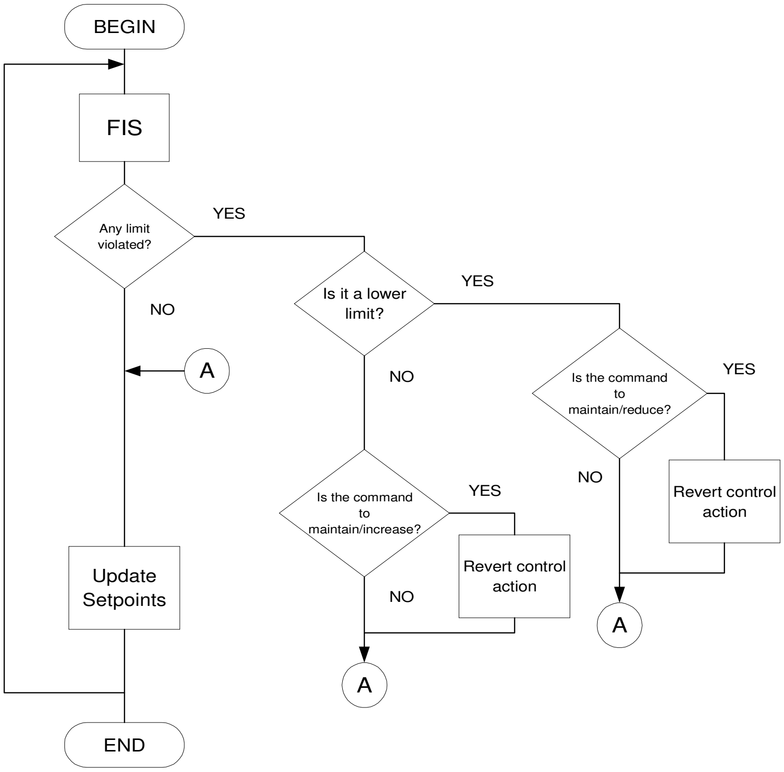


Figure H–4 *Flowchart for Limit Violation.*

H.1.1 Simulation Results

The results shown in this section are from a fast dynamic long-term simulation program presented in [H-1], and based on the ideas described in [H-2]. In the simulations the FIS was considered as a discrete-time feedback automatic control with a sampling-period and actuation cycle of 20 seconds.

The initial operating point for the simulation is a heavy load condition further stressed to induce a critical voltage condition in the Rio Area. The low voltage magnitudes of Jacarepaguá and Adrianópolis buses together with the +270 Mvar reactive power output of the Grajaú SC indicate an insecure operating scenario. To worsen the situation the Santa Cruz thermal power plant is not in operation. The unavailability of this power plant does not alter the rules of the FIS, since there is no operational flexibility in this case.

Table H-3 shows a sequence of events considered during the simulation. A decreasing constant-power-factor load ramp of 10% in the CERJ and ESCELSA subsystems was also applied throughout the 1000-second simulation.

Table H-3 *Sequence of Events.*

Time (sec)	Event
20	Manual shunt capacitor bank insertion: ✓ 160 Mvar at Adrianópolis 345 kV ✓ 100 Mvar at Jacarepaguá 138 kV ✓ 40 Mvar at Adrianópolis 138 kV
50	Manual shunt capacitor bank insertion: ✓ 200 Mvar in the LIGHT subsystem ✓ 300 Mvar in the CERJ and ESCELSA subsystems
300	Trip in one circuit of the 500 kV Adrianópolis/Cachoeira Paulista TL

Figures 7-5 - 7-7 show the simulation results. The figures also bring the upper and lower operating limits for the monitored variables, with wider ranges for the generating buses (Figure H-5) than for the load buses (Figure H-6).

Based on the simulation results the following observations can be made:

- Marimbondo 500 kV (Figure H-5): At the beginning of the simulation, the voltage is above the maximum limit of 550 kV (1.05 pu at the 525 kV base voltage). At the same instant, the voltages within the Rio Area are below the lower limit (Figure H-6). This bad voltage profile scenario forces the FIS to increase the voltage at the Marimbondo plant. However the hierarchy between the protection and the FIS reverses the control action in order to eliminate the voltage limit violation at Marimbondo. After the events at 20 and 50 seconds, all monitored voltages are too high, and the FIS starts reducing the plant voltage. At 300 sec the third event causes a small voltage rise, which is reduced again by the FIS afterwards;

- Jacarepaguá 138 kV (Figure H-6): At the beginning of the simulation, the voltage is very low. However, after the first and second events, the voltage reaches a value above the desirable operating range (from 138 to 140 kV), which is then reduced by the FIS. The voltage reaches a value below the operating range with the TL trip at 300 sec, but is again corrected by the FIS;

- Grajaú SCs (Figure H-7): At the beginning of the simulation, the SCs are generating 270 Mvar, well above the recommended value set by the operating instructions, which state that the SCs must operate within the range [−100 Mvar, zero Mvar], in order to keep sufficient spinning reactive reserves for voltage security. After the events at 20 and 50 seconds, the SCs start absorbing too much reactive power from the system. The FIS acts in order to increase the reactive reserves of the SCs. Once the TL is tripped at 300 ms, the SCs go off the operating range again, but they are brought back to the operating range by the FIS, and remain within this range for the rest of the simulation.

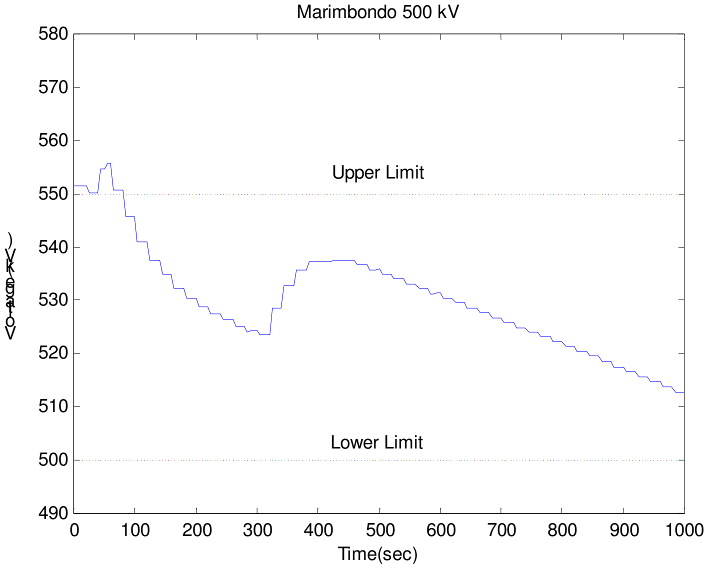


Figure H–5 *Marimbondo 500 kV Voltage.*

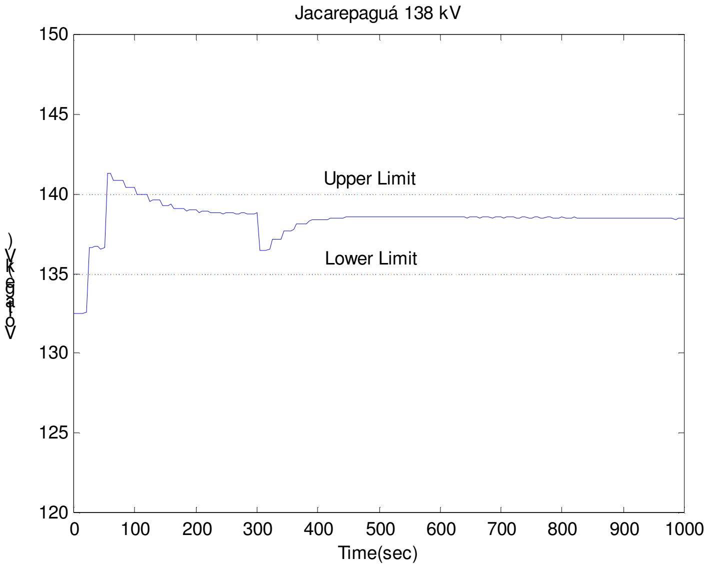


Figure H–6 *Jacarepaguá 138 kV Voltage.*

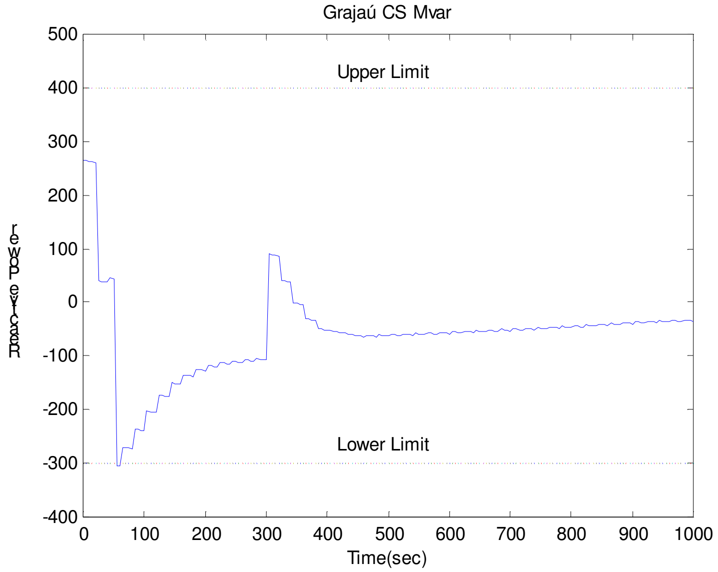


Figure H–7 *Grajaú SC Reactive Power Output.*

H.1.2 Conclusions

This Appendix proposes a support-decision tool based on fuzzy logic, to help the system operator in the coordinated voltage control of transmission networks.

The simulation results performed in the Rio Area showed a satisfactory performance from the proposed rule-based coordinated voltage control. The adopted rules reflect the experience of system operators aided by off-line studies.

If the FIS is used in the future as an automatic closed-loop controller, system operators will be relieved from doing repetitive daily tasks and dedicate their time to other tasks.

Current developments are focused on the conception of a FIS for capacitor and reactor bank switching. This will require a hierarchical structure involving two FIS, one dealing with the continuous reactive sources and other controlling the discrete reactive control sources.

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