UNIVERSIDAD PONTIFICIA COMILLAS DE MADRID

ESCUELA TÉCNICA SUPERIOR DE INGENIERÍA (ICAI)

(Instituto de Investigación Tecnológica)

MODELO REGULATORIO DEL CONTROL DE TENSIONES EN LOS SISTEMAS ELÉCTRICOS DE POTENCIA

Tesis para la obtención del grado de Doctor

Directores: Prof. Dr. D. Tomás Gómez San Román

Prof. Dr. D. David Soler Soneira

Autor: Ing. D. Pablo Frías Marín

Madrid 2008

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A REGULATORY MODEL PROPOSAL FOR VOLTAGE CONTROL IN ELECTRIC POWER SYSTEMS

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NOTIFICACIÓN AL INTERESADO DE LA CALIFICACIÓN DE LA LECTURA Y DEFENSA DE LA TESIS (OPCIONAL)

Se hace constar que **D. Pablo Frías Marín**

ha leído y defendido en el día de la fecha su tesis titulada "Modelo regulatorio del control de tensiones en los sistemas eléctricos de potencia" ante el Tribunal constituido por los siguientes Profesores:

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Resumen

Esta tesis propone un nuevo modelo regulatorio para el servicio complementario de control de tensiones y gestión de la potencia reactiva.

Inicialmente se identifican los principales productos del servicio, que son la capacidad de potencia reactiva y el uso de la misma. A continuación, se propone un mecanismo competitivo original para la prestación del servicio, basado en subastas anuales de capacidad de potencia reactiva, donde se firman contratos para proveer dicha capacidad en un período igual o superior a un año. Los agentes que pueden ofertar en la subasta son los generadores, condensadores, reactancias, SVCs y STATCOMs. La demanda del servicio queda definida por en la operación segura del sistema eléctrico tanto en condiciones normales como ante contingencias. El modelo propuesto limita eficientemente el poder de mercado.

La selección óptima de los recursos de reactiva en el mercado propuesto se realiza mediante un problema de optimización. Este problema optimiza simultáneamente la operación del sistema en los escenarios más representativos: demanda de horas punta y valle en condiciones normales y ante contingencias. La función objetivo del problema es la minimización de costes de compra de ofertas de capacidad de potencia reactiva, y otros costes de operación, como penalizaciones por baja calidad de suministro o el redespacho de generación. Las restricciones del problema son las ecuaciones del flujo de cargas, los límites de operación de los equipos, y el modelado de las contingencias.

Finalmente, la tesis presenta un diseño original de los flujos económicos. Una vez se ha cerrado el mercado de capacidad, aquellas ofertas seleccionadas serán remuneradas mediante precios marginales de largo plazo. Por su parte, el reparto de los costes del servicio está basado en precios marginales de largo plazo calculados usando Teoría de Juegos. Estos costes se distribuyen eficientemente entre las cargas y los equipos causantes de las contingencias. Por último, se usa un caso ejemplo realista que valida la propuesta regulatoria realizada en la tesis.

Abstract

This thesis proposes an original framework for the voltage control and reactive power management ancillary service.

First, the main products in the service are identified, which are the reactive power capacity and its use. Under this competitive framework, an original market structure is designed for the reactive power capacity, based on an annual auction. In addition, the use of the capacity will be remunerated with a regulated price. The agents that can participate in the service are generators, capacitor banks, shunt reactors, SVCs and STATCOM devices. The demand of the service is defined by the secure operation of the power system both under normal and contingency situations. The resulting scheme efficiently limits market power for those sources localized in privileged positions.

An optimization formulation is used to efficiently select the reactive power capacity bids. The resulting problem optimizes simultaneously the most representative operating conditions: peak and valley load conditions for normal and contingency scenarios. An original objective function minimizes the costs associated with the purchase of reactive power capacity, and with other expected operation costs, such as redispatching of generation units, or quality of service penalties. The constraints of the optimization problem are the power flow equations, the operating limits of the equipment, and the modeling of system contingencies.

An original design for the economic flows is also presented in this thesis. Once the market is cleared, selected bids will be remunerated based using long-term marginal pricing. On the other hand, the costs of the service are distributed using long-term marginal pricing based on Cooperative Game Theory. These costs are efficiently shared among the loads and the agents responsible for system contingencies. Finally, a realistic case study is used to verify the applicability of the regulatory approach.

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NOMENCLATURE

Set and Indices

Symbol	Interpretation
G	Set of generator units
N	Set of buses
L	Set of transmission lines
RT	Set of transformers
C	Set of capacitor banks
R	Set of shunt reactors
S	Set of scenarios (base case plus contingencies)
K	Set of subintervals in the Aumann-Shapley pricing calculation
J	Set of voltage control areas in which the power system has been divided
g	Generation unit ($g \in G$)
l	Transmission line ($l \in L$ or $l \in RT$)
n, m	Bus ($n, m \in N$)
c	Capacitor bank ($c \in C$)
r	Shunt reactor ($r \in R$)
s	Scenario ($s \in S$)

s_b,s_g,s_l	Base case, contingency of generator g, contingency of line l ($s_b, s_g, s_l \in S$)
k	Iteration in the Aumann-Shapley pricing calculation ($k \in K$)
j	Voltage control area ($j \in J$)

Parameters

Symbol	Interpretation
PD_n, QD_n	Active and reactive power demand at bus n (MW,Mvar)
P_g^0	Active power dispatched for generator g in the energy market (MW)
QA_g^{A0}	Reactive power absorption capacity assigned to generator g in previous auctions (Mvar)
QA_g^{G0}	Reactive power generation capacity assigned to generator g in previous auctions (Mvar)
QA_c^0	Reactive power capacity assigned to capacitor bank c in previous auctions (Mvar)
QA_r^0	Reactive power capacity assigned to shunt reactor r in previous auctions (Mvar)
H_s	Duration of a scenario s (hours)
$\Delta P_g^u, \Delta P_g^d$	Maximum active power change upwards/downwards that generator g can provide in case of contingencies (MW)
$\Delta Q_g^u, \Delta Q_g^d$	Maximum reactive power change upwards/downwards that generator g can provide in case of contingencies (Mvar)
$\Delta Q_c^u, \Delta Q_c^d$	Maximum reactive power change upwards/downwards that the capacitor bank c can provide in case of contingencies (Mvar)
$\Delta Q_r^u, \Delta Q_r^d$	Maximum reactive power change upwards/downwards that the shunt reactor r can provide in case of contingencies (Mvar)
$A_{V,s}^U, A_{V,s}^O$	Penalty for under and over voltage deviations for the scenario s (€/MWh/kV^2)
A_D	Penalty for the non-supplied energy (€/MWh)
A_c^C, B_c^C	Price coefficients of the annual bid of capacitor bank c for reactive power capacity (€/Mvar-year,€/Mvar^2-year)
A_r^R, B_r^R	Price coefficients of the annual bid of shunt reactor r for reactive power capacity (€/Mvar-year,€/Mvar^2-year)

A_g^P	Variable production cost of generator g (€/MWh)
A_L	Average price of energy losses purchase (€/MWh)
A_g^A, B_g^A	Price coefficients of the annual bid of generator g for reactive power absorption capacity (€/Mvar-year,€/Mvar^2-year)
A_g^G, B_g^G	Price coefficients of the annual bid of generator g for reactive power generation capacity (€/Mvar-year,€/Mvar^2-year)
A_g^{EA}, A_g^{EG}	Regulated compensation of the VAR capacity use for generator g, for VAR absorption and VAR generation (€/Mvar^2-h)
$SL_l^{\max}$	Transmission capacity of line l (MVA)
$V_{n,s}^{\min}, V_{n,s}^{\max}$	Minimum and maximum voltage limits at bus n in the scenario s (kV)
V^{min}, V^{max}	Minimum and maximum voltage security limits (kV)
$P_g^{\min}, P_g^{\max}$	Minimum and maximum active power generation of generator g (MW)
Q_g^{Gmax}, Q_g^{Amax}	Maximum reactive power generation and absorption of generator g (Mvar)
Q_g^{GPmax}, Q_g^{APmax}	Maximum reactive power generation and absorption of generator g operating at its maximum real power output (Mvar)
Q_g^{GPmin}, Q_g^{APmin}	Maximum reactive power generation and absorption of generator g operating at its minimum real power output (Mvar)
$Q_c^{\max}, Q_r^{\max}$	Maximum reactive power capacity of capacitor bank c and shunt reactor r respectively (Mvar)
RT_l^{min}, RT_l^{max}	Minimum and maximum rating values of the transformer tap ratio (p.u.)
Y_{nm}^c, Y_{nm}^s	Real and imaginary terms of the admittance between buses n and m
σ	Margin of the VAR capacity reserve

Variables

Symbol	Interpretation
$p_{g,s}$	Active power generation from generator g in scenario s (MW)
$q_{g,s}^A$	Reactive power absorption from generator g in scenario$s$ (Mvar)
$q_{g,s}^G$	Reactive power generation from generator g in scenario$s$ (Mvar)
qa_g^A	Assigned reactive power absorption capacity to generator g (Mvar)

qa_g^G Assigned reactive power generation capacity to generator g (Mvar)

$q_{c,s}$ Reactive power switched on by a capacitor bank c in scenario s (Mvar)

$q_{r,s}$ Reactive power switched on by a shunt reactor r in scenario s (Mvar)

qa_c Reactive power capacity assigned to capacitor bank c (Mvar)

qa_r Reactive power capacity assigned to shunt reactor r (Mvar)

$b_{c,s}$ Susceptance of capacitor banks c in scenario s

$b_{r,s}$ Susceptance of shunt reactor r in scenario s

$v_{n,s}$ Voltage at bus n in scenario s (kV)

$\Delta v_{n,s}^{\min}, \Delta v_{n,s}^{\max}$ Undervoltage and overvoltage deviations in bus n and scenario s(kV)

$\theta_{n,s}$ Voltage angle at bus n in scenario s (rad)

$d_{n,s}$ Continuous variable [0-1] that represents the portion of energy not supplied at bus n in scenario s

u_g Binary variable {0,1} (1 if generator g is dispatched, 0 otherwise)

$w_{g,s}$ Continuous variable [0-1] that defines the limits for active and reactive power production of generator g in scenario s, used to distribute the charges due to contingency scenarios

$w_{l,s}$ Continuous variable [0-1] that defines the value of the impedance matrix coefficients of transmission line l in scenario s, used to distribute the charges due to contingency scenarios

$sl_{l,s}$ Apparent power flow in line l and scenario s

rt_{nm}, rt_l Tap ratio of transformer located in between buses n and m which define the line l

$g_{nm,s}, b_{nm,s}$ Real and imaginary part of the admittance matrix corresponding to buses n and m for scenario s ($\mho$)

r_j^G, r_j^A Generation/absorption VAR capacity reserve in the voltage control area j

Economic outputs

Symbol	Interpretation
C_T	Total costs of the VAR capacity market (€-year)
C_{QC}	Annual costs associated with the procurement of VAR capacity (€-year)
C_{QE}	Expected annual costs of the regulated payment for VAR capacity use (€-year)
C_V	Expected annual costs for voltage deviations (€-year)
C_D	Expected annual costs of non-supplied energy (€-year)
C_P	Expected annual costs of generation redispatch (€-year)
R_g	Annual remuneration for selected VAR capacity of generator g (€-year)
R_c	Annual remuneration for selected VAR capacity of capacitor bank c (€-year)
R_r	Annual remuneration for selected VAR capacity of shunt reactor r (€-year)
CH_s	Annual charge paid by the agent responsible for contingency s(€-year)
CH_n	Annual charge paid by the load located in bus n (€-year)
CH_l	Annual charge paid by transmission line l due to its failure rate (€-year)
CH_g	Annual charge paid by generation g due to its failure rate (€-year)
$\lambda^p_{n,s}$	Lagrange multiplier of the active power balance equation at bus n in scenario s
$\lambda^q_{n,s}$	Lagrange multiplier of the reactive power balance equation at bus n in scenario s
$\lambda^{p*}_{n,s}$	Curtailed Lagrange multiplier of the active power balance equation at bus n in scenario s
$\lambda^{q*}_{n,s}$	Curtailed Lagrange multiplier of the reactive power balance equation at bus n in scenario s
$\bar{\lambda}^p_n$	Aumann-Shapley value for the active power balance equation at bus n in scenario s
$\bar{\lambda}^q_n$	Aumann-Shapley value for the reactive power balance equation at bus n in scenario s
$\mu^A_{g,s}$	Lagrange multiplier of the equation of the selected capacity of VAR absorption to generator g in scenario s

$\mu_{g,s}^{G}$	Lagrange multiplier of the equation of the selected capacity of VAR generation to generator g in scenario s
$\mu_{c,s}$	Lagrange multiplier of the equation for the selected VAR capacity to capacitor bank c in scenario s
$\mu_{r,s}$	Lagrange multiplier of the equation for the selected VAR capacity to shunt r in scenario s
$\gamma_{g,s}^{k}$	Lagrange multiplier of the equation that defines the active and reactive power limits for generator g in scenario s, calculated for the iteration k in the Aumann-Shapley procedure
$\gamma_{l,s}^{k}$	Lagrange multiplier of the equation that redefines the impedance matrix coefficients for transmission line l in scenario s, calculated for the iteration k in the Aumann-Shapley procedure
α	Normalizing factor for the loads in order to settle the revenue reconciliation

Acronyms

SYMBOL	INTERPRETATION
AGC	Automatic Generation Control, for active power management
AVR	Automatic Voltage Regulator, installed in generation units
CAISO	California Independent System Operator (United States)
CAPEX	CAPital EXpenditures
DSO	Distribution System Operator
ELCOM	Electricity Commission of New South West (Unites States)
ENS	Energy Non-Supplied
ERCOT	Electric Reliability Council of Texas (United States)
FERC	Federal Energy Regulatory Commission (United States)
GRTN	Gestore della Rete di Trasmissione Nazionale (Italy)
LOC	Loss of Opportunity Costs
MIBEL	Mercado Ibérico de la Electricidad (Spain and Portugal), which can be translated as Iberian Electric Energy Market
NERSA	National Energy Regulator of South Africa

NGC	National Grid Company (United Kingdom)
NYISO	New York Independent System Operator (United States)
OFGEM	The Office of Gas and Electricity Markets (United Kingdom)
OPEX	OPerational EXpenditures
OPF	Optimal Power Flow
PJM	Energy market in Pennsylvania, New Jersey and Maryland
POD	Point Of Delivery, connection point to the transmission network
REE	Red Eléctrica de España (Spanish SO)
SO	System Operator
STATCOM	Static Compensator
SVC	Static VAR Compensator
TSO	Transmission System Operator
UCPTE	Union pour la Coordination de la Production et du Transport d'Électricité
VAR	Reactive Power
VQ	Voltage control and reactive power management service

CHAPTER 1

Introduction

THIS introductory chapter presents the general background that motivates this thesis: the need for an improved regulatory model for reactive power and voltage control service under restructuring and re-regulation of electric power systems. Current incidents concerning power system security, such as the one in April 2004 in the United States where 50 million people were affected, show the critical importance of reactive power management. Traditional regulation schemes consider this service to be mandatory with no associated compensation, so therefore there were no clear incentives for the correct procurement of this service. New competitive mechanisms are needed in order to send efficient signals to service providers and demand in order to guarantee system security together with a minimization of the operation costs.

1.1 Reactive power support and voltage control

The supply of reactive power (VAR) is essential in order to maintain system security in electric power systems. In the new unbundled organization of electricity markets, voltage control is usually integrated into the so-called ancillary services, which comprise those services needed to guarantee the efficient and economic delivery of active power. Under this scheme, the management of voltage control is provided by the System Operators (SOs) using the different VAR sources, which are mainly generators and other compensating devices such as capacitor banks, shunt reactors, SVCs and STATCOM devices.

In most of the system-wide disturbances, inadequate reactive power management has been one of the main causes for the system collapse. The final report of the Power System Outage in the United States and Canada in April 2004[1] stated that *insufficient reactive power was an issue in the blackout*. Indeed, during this blackout the dynamic reactive power sources were exhausted in some areas, as shown in Figure1.1[2]. VAR support has also been identified as a key issue in other important blackouts in European power systems: 1987 in France[3] [RTE, 2002], 2003 in Italy [Corsi et al., 2004a, Vournas, 2004], or the emergency situation in 2001 in Spain[4].

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[1]On August 14, 2003 there was an electric power blackout in the Midwest and Northeast of the United States and Ontario (Canada). Fifty million customers were affected by the outage, constituting a 61800MW load, with and an estimated cost of $4 to $10 billion. The blackout began with the trip of Eastlake 5 generation unit at 13:31 hours. Soon after the alarm and logging system in the System Operator control room failed. After 15:05 hours, five transmission lines in 345kV tripped out because of contacting overgrown trees within the lines' right-of-way areas. The 138kV lines began to fail and collapsed, with the loss of an important transmission line between the substations Sammis and Star. This line trip triggered the cascade blackout of the neighboring power systems, due to new unsustainable overloading in the lines, and generation tripping. The normal operation of the whole affected area was recovered 4 days later.

[2] This figure presents the reactive power reserve margins for five regions throughout Ohio, including the most representative power plants [PSOTF, 2004]. The VAR reserve is plotted for three situations, at 13 hours, 15 hours and 16 hours. It is clear that the reactive power reserves in the Cleveland area were completely exhausted at 16 hours. Although the neighboring regions had enough VAR reserves, due to the local characteristic of VAR, they could not help the Cleveland area to maintain voltages.

[3]On January 12, 1987 there was a cold wave throughout all of France. There was enough capacity to supply the West area load with 5900MW, resulting in a voltage level of 405kV. Between 10:55 hours and 11.42 hours, the generating groups #1, #2 and #3 of the Thermal Power Plant of Cordemais became unavailable for different reasons. Still, Group #4 was strong enough to support the voltage level in the area, but a failure in its voltage regulating system caused the trip of the group. The outage of all the groups in Cordemais Thermal plant lowered voltage levels to 380kV during 30 seconds. Then, the autotransformers in the area modified their taps in order to improve the voltage level. Notwithstanding, this automatic operation of the autotransformers increased the power flows into the area, and voltages fell down. Consequently, 9 groups tripped and there was a disconnection of 9000MW load. At 11:50 hours a manual load shedding of 1500MW load was needed to recover the voltage levels in the transmission network. Gradually the system was restored, recovering normal operation at midnight.

[4]The energy consumption during December 2001 in Spain was higher than usual due to a cold wave. In December 17, 2001 the active power reserve in the Spanish power system was very low because

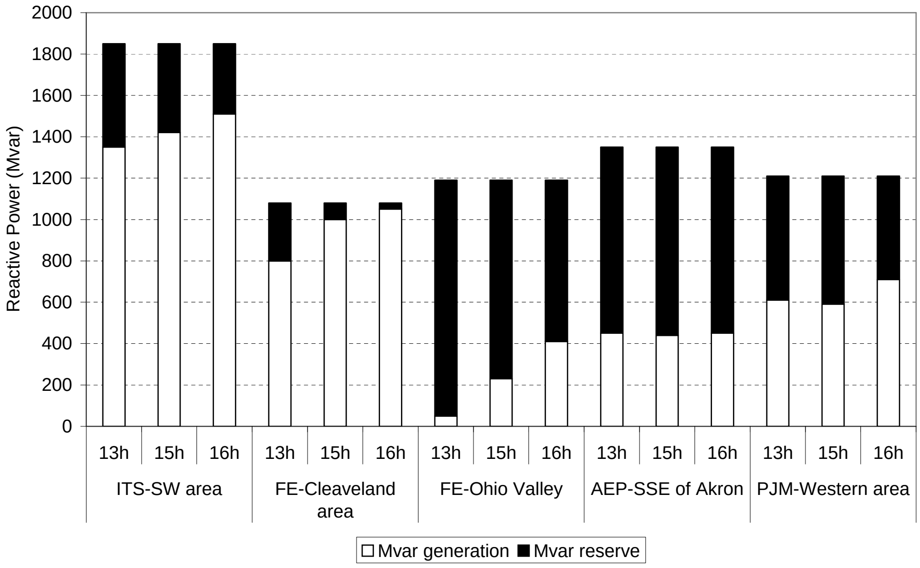

Figure 1.1: Reactive Reserves throughout the Ohio area on August 14, 2003 (Source: [PSOTF, 2004])

The previous situations could have been avoided, or at least neutralized with an adequate VAR management. However, reactive power policies are still not well deployed under the new paradigm of competitive electricity markets, mainly due to the complexity to understand voltage control and VAR support, and the difficulty to develop a competitive market for VAR procurement [Gross et al., 2006]. Several technical committees have studied the influence of VAR in grid blackouts [Andersson et al., 2005], among which stands the FERC report [FERC, 2005] for being the most extensive and detailed, this report found six main problems regarding current practices on VAR allocation and remuneration:

i) Discriminatory compensation for independent generators.

ii) Rigid, but imprecise interconnection standards that are insensitive to local needs.

iii) Lack of transparency and consistency in planning and procurement.

some important thermal units were unavailable, and the drought deeply reduced the hydraulic power generation. To cope with this critical situation, the System Operator took some preventive measures such as hydraulic pumping at night to increase the active power reserve, demand-side management actions, and the connection of static VAR compensation. Despite these measures, at 18 hours, voltages in the East area were very low, and Cofrentes Nuclear Plant had to reduce its output in 700MW in order to increase the VAR generation to maintain voltages in the area. Other nuclear power plants also reduced their output, but in a lower amount. The reduction of the generation in the east area increased the power flows from the North to the East. The transmission lines, which under normal operation generate 500Mvar, were under this new situation absorbing 1200Mvar. Consequently, voltages in the East area were reduced to 87% of their rated value, and to 86% in the Centre of Spain. Although there was no trip of any generator due to low voltages, some emergency actions were taken, such as a load shedding of 300MW in the Centre area and 200MW in the East.

iv) Poor financial incentives to provide or consume reactive power.

v) Poor incentives for some SOs to procure reactive power capability at the least cost.

vi) Failure of SOs to adjust VAR instructions so as to fully optimize the dispatch.

The tight relationship of voltage control and security of supply in power systems applies both to transmission networks and distribution networks. This thesis is focused on voltage control management in transmission networks, where the main problems on current practices have been previously highlighted. Voltage control in transmission networks is mainly procured by generators, and is generally complemented by other VAR compensation sources, such as capacitor banks, shunt reactors, SVCs, or STATCOM devices.

The voltage control actions performed to guarantee system security are typically based on three time-frames loops: (i) the primary control is achieved by fast VAR sources to compensate voltage variations, (ii) the secondary control actions coordinate the VAR support of different sources in an electric area, and (iii) the tertiary control includes dispatching and planning of VAR sources in order to guarantee short-term security of supply. The objective of this thesis dissertation is focused on the development of competitive mechanisms for the procurement of the long-term VAR support, assuming adequate primary and secondary control loops.

The products that have been identified with the voltage control service are the installed VAR capacity, and the use of that capacity. The cost analysis of both products carried out in this thesis determined that the main product is the installed capacity, which is proposed to be traded under competitive mechanisms. Under this scheme the different VAR sources can procure the service optionally, and will be paid accordingly. The use of the VAR capacity has a lower cost, and can be economically compensated using regulated mechanisms.

Under the competitive approach for VAR capacity procurement, the thesis explores the optimal selection of the VAR sources using a comprehensive optimization algorithm for the settlement of the proposed market structure. In order to send efficiency signals to all the market participants, the remuneration of the selected VAR sources is based on marginal pricing. On the other hand, revenue reconciliation and efficient signals are a primary objective for charging the demand of VAR capacity market. These signals are obtained using Cooperative Game Theory, based on Aumann-Shapley cost allocation.

1.2 Scope and objectives of this thesis

The aim of this thesis dissertation is to develop a unified framework for voltage control and reactive management service. This main objective requires the analysis and comprehension of the many specific characteristics of the voltage control mechanisms and their economic impact. At present, although there has been a great research effort made in this area, some key concepts are still misunderstood. Therefore, another key objective of this thesis is to clarify all the important concepts associated with the reactive power procurement.

In addition to the previous general objectives, the specific objectives tackled in the research study of this thesis can be summarized as follows:

i) Review the current regulatory mechanisms for the procurement of the reactive management and voltage control service. The analysis will include the agents participating in the service, the description of the costs of the service, and the allocation and remuneration mechanisms.

ii) From the previous analysis, propose a regulatory model for the VQ service. The design of the model should consider the possibility of being integrated into the current electricity trading mechanisms.

iii) Propose a mathematical formulation for the efficient selection of the best VAR resources, minimizing the purchase costs and the expected operation costs in the power system, which comprise the energy losses costs, voltage quality penalties, and non-supplied energy costs.

iv) Propose a remuneration mechanism for the procurement of the VQ service. First, the demand and procurement of the VQ service should be clearly identified. Then, the structure of payments and charges must send efficient economic and location signals to the market agents.

v) Apply the regulatory proposal for the VQ service to a case study in order to verify its applicability.

1.3 Outline of the document

In order to cover all the objectives this thesis dissertation is structured in seven chapters and four appendices. Each chapter covers a specific objective, including all developments and results for this purpose.

Chapter 2 analyzes the reactive power management and voltage control service in electric power systems and introduces the main proposals of this thesis dissertation. First, an introduction to reactive power control in power systems is presented. The main technical characteristics of the control are analyzed together with the system devices that can participate in its procurement. Then, the VQ service based on voltage control and reactive power management is defined, including the market participants, the VAR selection criteria and the economic flows. Finally, the economic theory is reviewed in order to provide a basis for the VQ service definition.

Chapter 3 constitutes the core of this thesis. This chapter presents a regulatory proposal to allocate and remunerate the VQ service. The proposal for this service is based on a reactive power capacity market. First, the framework in which the proposed market can be included is presented. Then, the VAR capacity is selected as the homogeneous product to be traded in the proposed market. This capacity market is then described, discussing the VAR capacity bids, and the structure of the market. The economic settlement of the VAR capacity market includes the payments to the selected VAR bids, and the charging mechanism for the demand of the service. Finally, monitoring and penalties are defined for the correct procurement of the service.

Chapter 4 presents an original VAR allocation method under the proposed market structure. The proposed formulation selects the best VAR capacity bids that minimize the cost of the VQ service procurement, meeting the security-operating conditions both in a base case and under selected system contingencies. First, a general description of the market auction and its theoretical basis are presented. Then, the mathematical formulation of the corresponding optimization problem is described in detail. Finally, some implementation details of the VAR capacity market settlement are analyzed. A simple illustrative case with two buses and three generators is used throughout this chapter to illustrate the theoretical discussion.

In Chapter 5 the principles for the settlement of the proposed VAR market are presented. First, the economic flows in the VAR market are described. On the one hand, the remuneration of the selected VAR sources are based on long-term marginal pricing. However on the other hand, the charging scheme is based on the Cooperative Game Theory, and will therefore differentiate the demand of VAR resources under normal operating conditions and the over costs associated with the contingencies.

Chapter 6 presents the results of a case study in order to verify the applicability of the proposed VAR capacity market. This case study, a power system with 39 buses and 10 generators, is presented first, with a brief description of the power system and the bids of the market agents. Then, the VAR capacity is assigned to the selected market agents. Finally, the economic flows in the market are obtained, remunerating VAR procurement, and charging VAR demand.

Chapter 7 summarizes the conclusions, developments, and results that have been achieved in the analysis carried out in this thesis. The main original contributions that this work has yielded are described, and finally new lines of research are suggested.

Appendix A presents an analysis of the innovative regulatory proposals for the VQ service in Spain and the United Kingdom. In addition, a comparative review of other regulatory frameworks in Europe, the United States and other countries is presented.

Appendix B presents an original approach to building the capacity bids for the proposed VAR capacity market. VAR bids comprise the definition of an available VAR capacity and a corresponding price. First, a new method to calculate VAR capacity at the connection point to the transmission network for the different VAR sources is presented. Then, the cost associated with the availability and use of the VAR capacity into the proposed market is described. The appendix is structured in two parts, analyzing the bids for generators, and then the bids of the other VAR compensation technologies participating in the market.

Appendix C includes an original economic analysis of the value for a distribution system operator of the voltage at the connection point to the transmission network. The cost evaluation considers the wear and tear of the voltage control equipment together with the energy losses costs and the expected penalties for the non-supplied energy.

The data of the case study analyzed in Chapter 6 is presented in Appendix D.

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CHAPTER 2

The VQ service in power systems

This chapter analyzes the reactive power management and voltage control service in electric power systems and introduces the main proposals of this thesis dissertation. The chapter is structured in three sections:

- First, an introduction to the reactive power control in power systems is presented. The main technical characteristics of the control are analyzed, together with the system devices that can participate in its procurement.
- Then, the VQ service based on voltage control and reactive power management is defined, trying to answer the following questions: who can provide the service? which criteria is used to select the VAR sources to participate in the service? what are the economic flows (remuneration to suppliers and charges to demand) in the VQ service?
- Finally, the economic theory is reviewed in order to provide a basis for the VQ service definition.

2.1 Voltage control and reactive power management

Back in 1882, Thomas A. Edison switched on the first generating station to supply electricity to 59 customers in lower Manhattan. The electric distribution was in 110 volts direct current. Edison realized that the voltage for the customers dropped as the consumption in lighting increased, and also if the customer was far away from the power station. He solved this problem by modifying the circuit of the direct current generator. This was the first voltage regulator, known as *compounding*. A few years later Nikola Tesla introduced the alternating current, which overcame the limitation of the direct current to transfer energy over long distances. This was done by changing the voltage levels with transformers, and therefore transmitting the energy with lower losses and lower voltage drops. However, the voltage regulation problem remained, and therefore was later solved by including in the alternating generator a voltage regulator that modified its excitation current. By modifying the excitation current, the voltage in the generator terminal is controlled, but also the reactive power[1] (VAR) generated by the alternator is modified. This double effect gives the name to *voltage control and reactive power management* (VQ control). Soon after, other static compensation devices were used to help generators to control voltages, such as capacitor banks and shunt reactors. Nowadays power electronics have developed improved VAR equipment, such as Static VAR Compensators (SVC), that can perform similar VAR compensation as that provided by generators. First studies on voltage control analyzed the VAR capability of generators [Adams and McClure, 1948], and during the eighties[2] and nineties a big effort was done in analyzing the optimal procurement of VAR support.

As it occurred in the very dawn of electricity, nowadays the main objective of the VQ control is to achieve an overall improvement of the system *security*, service *quality*, and economic *efficiency*. System security in power networks requires adequate voltage levels and reactive reserves in order to prevent voltage stability problems and to maintain system integrity when critical contingencies occur. On the other hand, service quality requires appropriate control of all voltages in the power system within tolerable limits. Finally, the economic efficiency implies reactive line flows control which results in minimal transmission losses.

Next, a description of the technical and economic characteristics of the VAR compensation equipment is presented, together with the detailed analysis of the voltage control in power systems.

[1]The formulation of reactive power is obtained from the general equation of the instantaneous power. The average value of reactive power is always zero, which means that the energy is flowing for half of the cycle in one direction and in the opposite direction for the second half of the cycle. Therefore, another quantity is needed to describe the back and forth flow of reactive power, which is the maximum instantaneous reactive power. Note that for the active power flow the average value is used, and the maximum instantaneous value is usually ignored as it is the same quantity as the average value. Finally, the *loss of reactive power* can be seen as a loss in the amplitude of the instantaneous reactive power [Fetea and Petroianu, 2000].

[2]A complete bibliography on reactive power and voltage control was developed in 1987 by the *IEEE VAR management Working Group* in [Smith et al., 1987].

2.1.1 VAR compensation equipment

Traditionally, there have been different voltage control procedures for transmission and distribution networks. Voltage control practices are the result of distinct operation and characteristics of transmission networks (a meshed network) and the distribution networks (radial operated networks, with low generation penetration).

The main objective of the *VQ control in transmission networks* is to provide security in the operation. In addition, the VQ control should watch the economic efficiency, and quality in the supply of energy. The providers of the VQ control are synchronous generators, power transformers, power lines, shunt reactors, and capacitors banks. The VQ control is usually considered as a *service* among the *ancillary services* for the transmission network, as it will be discussed in the following sections.

The aim of the *VQ control in distribution networks* is to maintain voltage amplitude in the demand within a range where loads can operate properly. Voltage problems are usually associated to long lines, together with the increase of load demand. The distribution system operators (DSOs) manage the voltage across the distribution network by adjusting the taps of transformers, and with the installation of voltage regulators and capacitor banks. Nowadays, the integration of large amounts of distributed generation in distribution networks poses a new challenge for the VQ control [Peças et al., 2005, Li et al., 2006].

This thesis dissertation is focused on the VQ control in transmission networks. The contribution of distribution networks will be aggregated as a single load connected to the transmission network. Figure 2.1 shows a general overview of the generation and consumption of VAR in a power system. VAR is demanded by loads and certain transmission equipment, such as transformers and power networks. Due to the local characteristic of the VQ control the electric power system is divided into different voltage control areas.

Most equipment in the power system can potentially participate in the VQ control by absorbing or generating VAR. A brief description of the characteristics of the equipment is presented below.

- Most *conventional and distributed power plants* use synchronous machines which are able to both generate and absorb reactive power. The limits for the VAR produced by a generator are defined by its *capability curve* which depends on the maximum rotor and stator currents[3]. Usually, generators at rated active

[3]The generator VAR limits due to the maximum current in the stator I_{max} depend on the operation point P_{op} and on the voltage level at the alternator terminals V, resulting in $Q_{max} = \sqrt{3V^2 I_{max}^2 - P_{op}^2}$. The formula for a synchronous compensator can be simplified as $Q_{max} = \sqrt{3} V I_{max}$.

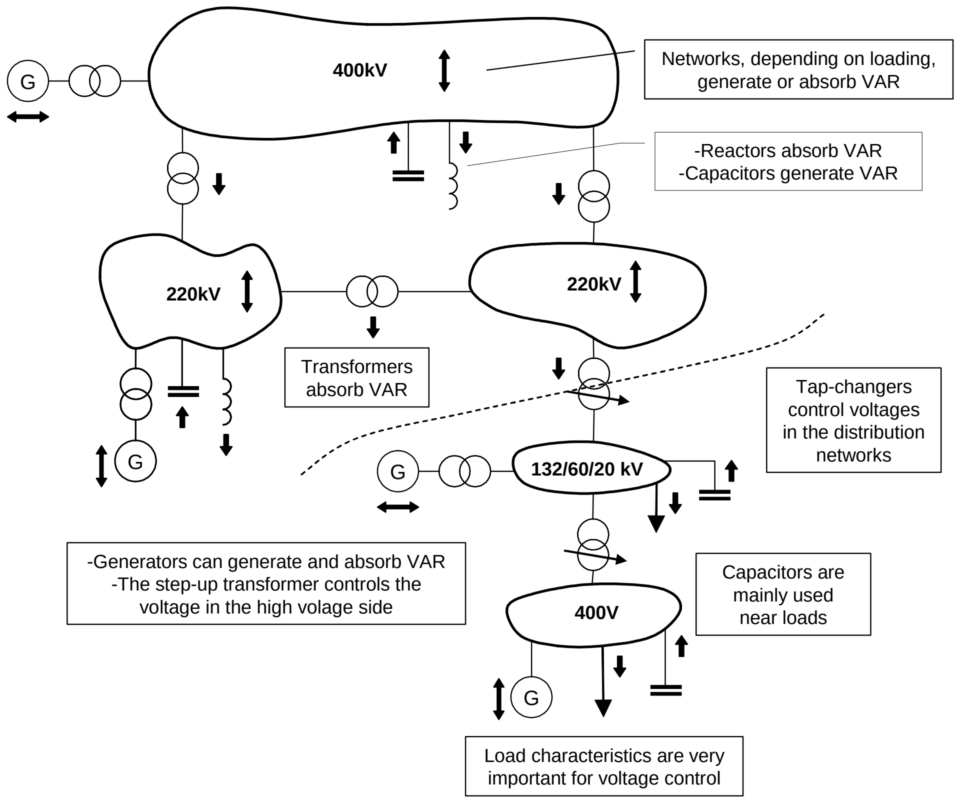

Figure 2.1: Reactive power flows in power systems
(Source: [RTE, 2002] and personal research)

power production can generate at their terminals 62% of their active power in reactive power (power factor 0.85 lag), and absorb 48% of its active power in reactive power (power factor 0.9 lead). The VAR limits in the high side of the step-up transformer include additional limits associated with the operation of the whole power plant [Adibi and Milanicz, 1994, Frías, 2004, Nilsson et al., 1994, Panvini and Yohn, 1995], as it will be analyzed in Appendix B. If the synchronous machine can be declutched from the associated turbine, then the generator can work as a synchronous compensator, with no active power production and its full VAR capacity available[4].

- Fixed or mechanically switched *capacitor banks and shunt reactors* have been traditionally used for VAR compensation. These devices provide an inexpensive compensation, and are widely used for power factor correction, both in low voltage and high voltage applications. Their main drawback is the quadratic dependence

[4]Converting a generator into a synchronous condenser requires the installation of a clutch, which has a cost of approximately 3% of the price of a new power plant (for example $700,000 in a 50MW generator). At present, there are several companies that manufactures clutches, such as Borg Warner `http://www.bwauto.com` and Marland `http://www.marland.com/literature/pdf/catalogs/cecon_disconnect_catalog.pdf`, which have already developed and installed clutches on turbine generators in the range of 1MW to 300MW [Li et al., 2006].

with voltage, which reduces their contribution to security under emergency situations. Moreover, mechanically switching devices may generate high inrush currents and require frequent maintenance [Frank, 1981]. Nowadays, more sophisticated VAR compensation devices have been developed, such as *static VAR compensators* (SVCs), which are based on thyristor switched capacitors and thyristor controlled reactors [Gyugyi et al., 1978]. SVCs provide a fast-acting VAR compensation, and are mainly used in high-voltage transmission networks and other applications such as electric arc-furnace[5]. Finally, devices based on *self-commutated converters*, such as *STATCOM* devices, can generate or absorb a reactive power current by pulse-width modulation. The time response of these devices is faster than the fundamental cycle, and similar to that provided by synchronous generators. These devices improve the VAR procurement under deteriorated voltage conditions, and require less space in the substation [Frank and Landstrom, 1971]. This technology has been used to develop new VAR compensation, from simple schemes of series compensation to other devices based on superconducting energy storage [Dixon et al., 2005].

- *Transmission lines* consume or generate VAR depending on loading. At the *natural load* there is no generation nor absorption of VAR at either end of the line. For loading above the natural load, the overhead line is a net VAR absorber, whilst it will become a net VAR generator if loading is below the natural load. *Underground cables* for the use at 275 to 400kV are usually net generators of reactive power.

- *Power transformers* always absorb reactive power. The VAR absorption is defined by a fixed amount and a variable value which depends on the square of the loading. Additionally, transformers can modify system voltages by changing their tap position. Most transmission and distribution transformers have on-load tap changers, while power plants usually install off-load tap changers that are less expensive and more reliable.

- *Consumer loads* can behave like resistors or reactors. Nearly all the industrial load is based on induction motors which absorb VAR with a typical power factor of 0.7 to 0.9. Incandescent lights and heaters act like resistors, while fluorescent lights usually have an average power factor of 0.95. Finally, the industrial loads with the higher VAR demand are arc furnaces (power factor 0.75-0.9) and arc welders (power factor 0.35-0.8). The electric supply to customer loads is provided by distribution overhead and underground cables which can generate or absorb VAR depending on their loading.

A summary of the characteristics of the different VAR compensation equipment is presented in Table 2.1, where VAR devices are classified into three main groups: (i) those devices based on synchronous alternators that provide a fast voltage control allowing overloading, (ii) static compensation devices with a stepped VAR procurement, and (iii) other network devices usually operated in different demand periods.

[5] An SVC is designed to instantaneously compensate the random variations of VAR due to the special characteristics of the arc-furnace load. Therefore, a stable and steady voltage supply is achieved.

Table 2.1: Technical characteristics of the VAR compensation devices

	Voltage control			VAR support	
VAR sources	**Normal operation**	**Speed**	**Voltage step**	**VAR procurement**	**Voltage dependence**
Conventional generation	Instantaneous	Fast	Continuous	Generation & absorption	Capability limits depend on V
Rotating synchronous condenser	Instantaneous	Fast	Continuous	Generation & absorption	Capability limits depend on V
Distributed generation	Instantaneous	Fast	Continuous	Generation & absorption	V
Capacitor bank	Hourly, seasonal	Slow	Stepped	Generation	V^2
Shunt reactor	Hourly, seasonal	Slow	On/off	Absorption	V^2
SVC	Instantaneous	Fast	Stepped	Generation & absorption	V^2
Self-commutated converters	Instantaneous	Fast	Continuous	Generation & absorption	V
Transmission line	Demand period	Slow	On/off	Generation or absorption	-
Transformer tap changer	Hourly, daily	Slow	Stepped	Voltage control	-
Loads	Hourly	Slow	Continuous	Absorption	Depends on load characteristics

(Source: [Kirby and Hirst, 1997] and personal research)

2.1.2 Voltage control

The previous VAR controllable devices require an adequate management in order to guarantee system security with the adequate voltage regulation. Voltage control in transmission systems can be structured into three control levels according to their response time (see Figure 2.2):

- The *primary control* is automatically managed by the Automatic Voltage Regulator (AVR), which is installed in all generation units. The AVR controls the generator output voltage at its terminals[6] by the variation of the excitation current of the alternator. A modification of the excitation current varies the reactive power production of the generator. This control is very fast, and can be considered as nearly instantaneous.
- The *secondary control* is also an automatic control, and it sends a voltage set point every few seconds to all generation units[7]. The voltage reference is set by the next control loop, although it can be updated for system security reasons.
- Finally, *tertiary control* comprises the calculation of the reference voltages for all the demand periods, involving some hours. Reference voltages are computed taking into account the economic and safe operation of the power system. This is an off-line control, usually managed by the System Operator (SO).

Most of the power systems operate under primary and tertiary voltage control, similar to an open-loop management. Secondary control has been implemented in some countries[8], such as Italy [Corsi et al., 1995, Corsi and CESI, 2000] and France [Lagonotte et al., 1989]. Practical approaches on the secondary voltage control usually decompose the power system into smaller regions called *voltage control areas*. This simplification reduces the number of VAR resources and buses to be controlled, so the time and effort needed for the secondary control is lower, compared to the situation where all the power system is simultaneously controlled.

According to the previous analysis, the VQ control can generally be simplified in two control actions: (i) a dynamic voltage regulation, and (ii) the voltage profile management and reactive power dispatch. This thesis dissertation is focused on long-term reactive power planning, where the SO decides the annual procurement mechanism for the VQ control. Decisions are taken assuming that the power system is operated under a certain voltage control scheme.

[6]In a power plant with two or more generators usually a Joint Voltage Control distributes the efforts of the generators to control the voltage in the high-side of the step-up transformers.

[7]Secondary voltage control is similar to the Automatic Generation Control (AGC) for active power and frequency control.

[8]The VAR management in the Spanish power system is currently carried out in open loop, with the help of expert systems [Sancha et al., 1992] that defines the set point and control actions of the static VAR devices in order to optimize the operation of the power system. Some studies have analyzed the advantages of implementing a secondary control [Sancha et al., 1996, de la Fuente, 1997].

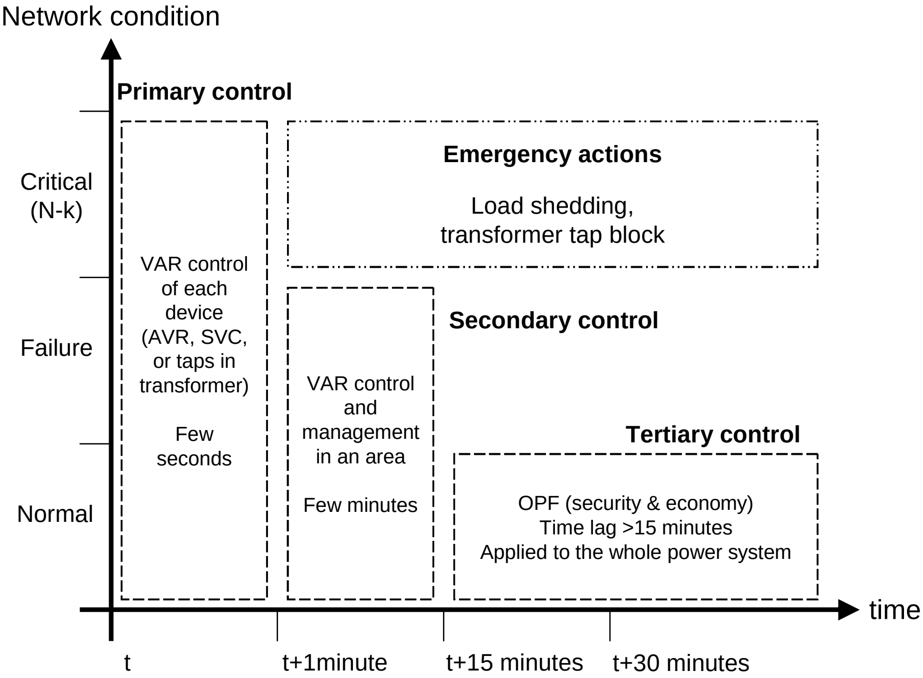

Figure 2.2: Voltage control levels
(Source: [UETP, 1997] and personal research)

2.1.2.1 Dynamic voltage control and VAR reserve management

Power system stability includes frequency and voltage stability. Frequency stability is a very fast process which is associated with generators swinging out of voltage. On the other hand, voltage stability problems are slower, from tens of seconds to minutes, and are caused by an imbalance between VAR generation and VAR demand. For this purpose, the VQ curves study the reactive power needed to maintain voltages in a certain bus for different power system operating conditions. These curves are divided into two areas, stable and unstable operation, which are delimited by the *critical voltage*. Under stable operation, an increment in voltages across the network requires more reactive power. For safe operation the working point should be well above the critical voltage [Kundur, 1994].

An example of stability analysis is shown in Figure 2.3. This figure represents four curves for different operating conditions, from normal operation to the failure of 3 elements in the power system. Under a normal operation scenario the operating point is #1; however, if a contingency occurs (N-1) the system moves to #2, reducing the voltage. Then, generators modify their VAR production to recover voltages, moving to the reference voltage #3. A new failure (N-2) may lead the system to #4 and #5; here, the system cannot recover its initial voltage since all the VAR sources are exhausted. If a new failure occurs (N-3), the system becomes unstable, as there is not enough VAR to maintain voltages.

To procure a safe preventive operation, the power system must have sufficient VAR

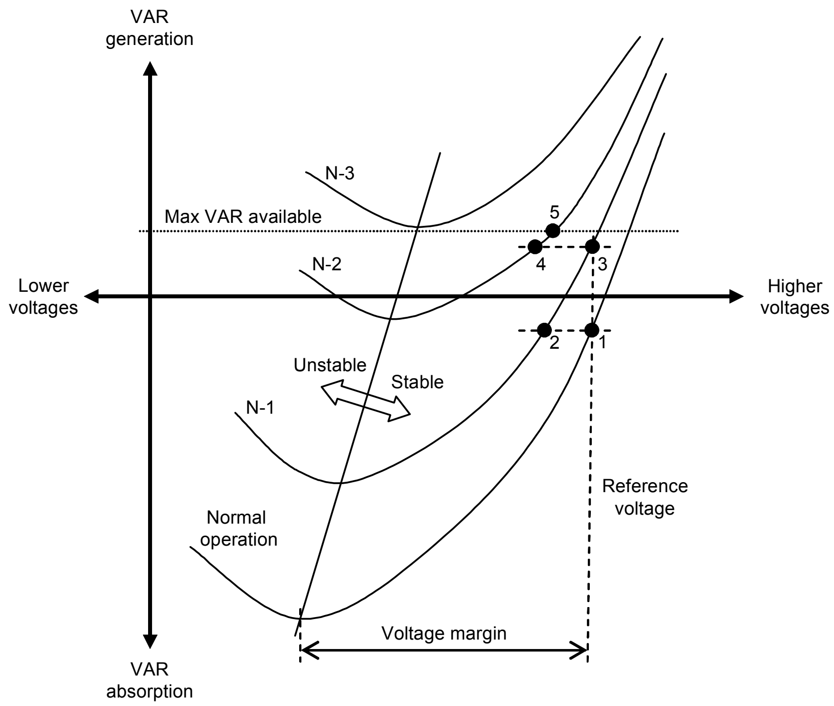

Figure 2.3: VQ curves for stability analysis
(Source: [PSOTF, 2004] and personal research)

reserve. The reactive power reserve must be procured fast enough to correct voltages in the case of system contingencies.

2.1.2.2 Voltage profile management and VAR dispatch

The second control action associated with the VQ control is in charge of the *voltage profile management* and *VAR dispatch*. This control action is provided by all VAR sources and managed by the SO, corresponding to the tertiary control loop, and its purpose is to minimize the transmission energy losses. Additionally, it guarantees the static security by keeping the voltage profile and the VAR reserve within specific margins. This service is similar to the economic dispatch in the energy markets were the SO dispatches the VAR control sources.

2.2 The VQ service

This section introduces the concept of the voltage control service, which is included among the so called *ancillary services* associated with the power delivery. First, a detailed analysis of the different theoretical procurement-alternatives is presented, together with a description of the main products associated with the voltage control service.

Then, the mechanisms to efficiently allocate the VAR resources are described. Finally, the economic flows (remuneration and charging) in this service are analyzed.

2.2.1 Definition of the VQ service

Currently, many countries have developed competitive mechanisms for electric energy trading. Most of these mechanisms are based on bilateral arrangements between generation companies and customers. However, some energy is still traded in spot markets.

Once the electric energy market has defined the corresponding energy transactions for the next period of time, the market agents rely on the SO in order to guarantee that these transactions take place under a secure, quality and economic efficiency standards. For this purpose, the SO defines a group of operating procedures based on engineering mandates in which all power system participants are involved. Among these operating procedures stand the voltage control and reactive power management (VQ control).

For the aim of economic efficiency, the SO can decide to create competitive mechanisms for the procurement of one of these operating procedures. This was why in the 90's the term *ancillary services* was first used in the United Kingdom, to designate the group of products and services needed to ensure the secure and efficient delivery of electric power according to certain quality standards [NGC, 1991]. The ancillary service associated with voltage and reactive management (VQ service) can be defined by the following characteristics:

- The generation units are the main service providers, although other VAR sources can also procure the service, such as capacitor banks, shunt reactors, SVCs, and other fast compensating devices.
- The SO is responsible for the definition of the volume of service, on behalf of all energy market participants. The volume of service must guarantee a reasonable security level which is settled by the load demand, the VAR requirements of the networks, and the set of probable contingencies.
- The service procurement will increase the costs of the ancillary services and reduce the expected costs for the operation costs in the period analyzed.

Traditionally, ancillary services have been integrated into the power generation business and they are non-separable with the active power production activity. Therefore, the purchase and remuneration of the VQ service have been integrated into the basic energy product, with a pass-through of its costs to all market participants. Nowadays, under the liberalization process in electricity markets, it is accepted that the ancillary services would have separate procurement and remuneration mechanisms in order to minimize the expected system costs, and send efficient economic signals to the participants. This thesis dissertation is focused on the development of a competitive market for the VQ service.

Economic analysis have demonstrated that voltage quality and system reliability have public good aspects [Joskow and Schmalensee, 1983]. The definition of a competitive market for the VQ service may have two difficulties, i) there may be a lack of VAR suppliers, and ii) the service demand is usually insensitive to the service value. Moreover, customers, regardless of their value of voltage quality, are going to receive the identical quality of service. Therefore, some regulatory authority should establish a cost-effective VQ service. On the other hand, real and reactive power are private goods, which are used to produce public goods, among which stand the VQ service. In this sense [Toomey et al., 2005] provides an engineering and economic model of voltage quality and reliability to determine its true value.

In conclusion, some type of central authority is needed to design, plan, and manage the VQ service. This entity, depending on the regulatory framework of each power system, could be an ISO or the Electricity Regulator. Regulation is needed because electric power does not lead itself to a degree of decentralized decision-making that is common in other markets [Thomas et al., 2006]. Therefore, the central authority should design a VAR market for the efficient procurement of private goods (active power and VAR) in order to optimally procure the public good service, that is to say the VQ service.

An analysis of the different options for the procurement, remuneration, and allocation of the VQ service is presented in this section.

2.2.2 Procurement of the VQ service

One of the objectives of this thesis dissertation is to develop a market mechanism for the VQ service. Therefore, the first topic of research is the analysis of the main products that can be defined for the VQ service. This section first discusses the main alternatives for the procurement of the VQ service, and then presents an international review of the current practices and definitions of the VQ service.

2.2.2.1 Procurement options of the VQ service

The liability to define the regulation for the procurement of the VQ service relies on the Energy Regulator. However, the public regulator usually passes on this responsibility to the SO, due to its experience in defining the operating criteria of power systems. The three questions that the SO should answer to define the VQ service procurement are: who can participate in the service? how is the VQ service provided? and, what mechanism regulates the participation in the service?

The international review presented in Appendix A shows that most SOs rely on generators as the main providers of the VQ service. Additionally, some of them define a minimum size for generators to participate in the service[9]. Other VAR compensation

[9] The Spanish SO defines a minimum capacity of 30MW per generation unit, or group of generators connected to the same point of the transmission network. Other countries have similar limits, 50MW in the United Kingdom and Wales, 100MW in Germany, 10MVA in Finland, and 25MVA in Belgium.

sources, such as capacitor banks and shunt reactors, have been traditionally considered as part of the transmission network assets and owned by the corresponding transmission companies. These devices are usually managed following the SO orders. Additionally, in order to guarantee system security the SO may install new VAR compensation equipment if the current VAR resources are exhausted. This thesis dissertation proposes advanced mechanisms for the procurement of the VQ service which incorporate the participation of private investors that install new VAR sources. Therefore, introducing competition in the available VAR sources will improve its procurement of the VQ service.

It is important to differentiate the role of the SO and the transmission network owner in the VQ service. The SO is responsible for the operation of the whole power system, to maintain the network within safe and secure operation limits, using the resources in the network from other owners, such as transmission or generation companies. Under an unbundled scheme[10] the SO is a regulated business that receives certain incentives to efficiently manage the total costs of system operation on behalf of customers. On the other hand, the new investments in the transmission network are recovered by the network companies usually through an annual investment program which is previously approved by the government. Therefore, it is very important to have *real unbundling between the SO and network owners*, because if not, the integrated company might benefit from its dominant position in the control of the transmission network, in terms of access to the network and economic benefits[11].

The SOs use the operating procedures for voltage control to define the needs of VAR support, and select the VAR sources that participate in the VQ service. The operating procedures are based on the control of the transmission voltages within certain security ranges. These voltage margins are usually defined according to engineering criteria for different load periods, voltage control areas in the power system, and voltage levels.

The procurement of VAR support by the different VAR sources can be defined by the SO as mandatory or optional participation in the VQ service:

- *Mandatory requirements*. All the agents have the obligation to provide a certain amount of VAR capacity to procure the VQ service. This requirement is usually specified for the installed VAR capacity in generators, with the definition of leading and lagging power factors. These power factor requirements can be defined for each generation unit in the machine terminals or in the connection point to the transmission network. The last alternative includes the consumption of

[10] In a liberalized electricity system, unbundling requires that the business that controls the network is separated from the commercial activities, generation and retail to final consumers.

[11] Two potential problems may arise if there is not sufficient unbundling between the SO and the transmission network owners. First, an integrated company owning the network and commercial activities might deny access to the network or apply unfair conditions to other generators or retailers that compete with those of the integrated company. Second, the integrated company might allocate costs more properly attributed to generation or retail to the network business. This would make the apparent costs of their generation or retail businesses artificially low and would give them an unfair advantage in these activities [Thomas, 2007].

reactive power of the transformer. Mandatory requirements are easy to define and implement, however, they should consider the different characteristics of the synchronous machines and power plants[12].

- *Mandatory but transferable requirements.* Under this option, VAR sources can be grouped into market agents to participate in the VQ service. Then, agents acquire an obligation to provide a certain level of VQ service and may decide to use their own resources to provide it, or purchase it from other agents. For example, a power plant can distribute the VAR procurement between different generators. Moreover, static VAR compensation can be installed in order to substitute the VAR procured by generators. This option improves service procurement from an economic point of view.

- *Optional requirements.* VAR sources acquire no obligation to provide VQ service, and can optionally participate in the VQ service. This option guarantees fair treatment for all market players. However, as the VQ service must be provided locally, the SO must develop specific mechanisms to guarantee that there is enough VAR capacity in each area.

An international review in Appendix A showed that most of the SOs define mandatory requirements for the installed VAR capacity of generators. The mandatory requirements for the available VAR capacity are usually defined in the alternator terminals in the range of power factors 0.85 lagging and 0.9 leading[13]. Other countries settled the power factor requirements in the connection point to the transmission network. Under this option the power plant assumes the VAR losses in the step-up transformer, and allows the operators the possibility to manage the VAR resources inside the power plant.

Most SOs relay on generators for the procurement of the VQ service, however, some countries such as Japan focus the effort of VQ service procurement on the VAR demand management. Under this alternative, a strong economic signal is sent to customers to improve their power factor[14], and this clearly reduces VAR needs in the transmission system.

According the operating procedures designed by the SOs, VAR resources participating in the VQ service (both under mandatory or optional requirements) must use their VAR capacity to maintain voltages within specific ranges. Due to the local characteristics of the VQ control, there is not a homogeneous use of the VAR capacity in all VAR sources because VAR needs in areas with high load are higher than other areas with less load and more generation.

[12]In Argentina, different power factor requirements are settled for hydro and thermal generators.

[13]The VAR generated or produced by a generator are also referred to as VAR lagging and capacitive VAR. On the other hand, the VAR absorbed or consumed are referred to as VAR leading and inductive VAR.

[14]The experience in Japan showed an improvement in the power factor, with average power factors of 0.99. Therefore, the VAR requirements in the transmission system are used to cover contingencies, and the VAR demanded by the own network.

Therefore, this thesis dissertation proposes that the participation in the service should be optional. Moreover, some specific mechanisms should be designed to encourage the participation of actual VAR sources and new investors in the VQ service.

2.2.2.2 The VQ service associated products and their cost

One of the objectives of this thesis dissertation is to propose a competitive mechanism for the VQ service. Within this line of research, and based on the international review of the service procurement, this section identifies the main products that can be traded in the VQ service. Then, the distribution of costs for each product is calculated in order to define a market based on the product of the highest cost.

As presented in the beginning of this chapter, there are two variables that define the VQ service, namely voltage and reactive power. A product based on the voltage value would clearly reflect the security level of the power system, however, its value depends on the transmission network configuration. Therefore, to maintain a selected voltage value, some VAR sources will exhaust all their capacity for a certain bus, while other sources will make no use of their capacity as the voltage in their bus is very stiff[15]. On the other hand, VAR capacity is a product similar to active power, which is easy to measure, and more or less homogeneous between all the VAR sources[16]. Then, two products can be identified in the VQ service from the cost point of view which can be found in any of the VAR sources participating in the service: (i) installed VAR capacity, and (ii) use of the VAR capacity [17].

- The *installed VAR capacity* is defined as the potential reactive power capacity that can be used in the VQ service. This product includes reactive power generation capacity and absorption capacity, both measured in Mvar. The costs associated with this product can be divided into (i) the investments needed for installing a determined VAR capacity in the power plant, and (ii) the control and communication equipment to provide the service, which includes the AVR and the communication system with the SO. All the associated costs can be considered as fixed costs. As presented in Table 2.2, the cost of the installed VAR capacity is the most important for all VAR sources.

[15]The *short circuit power* measures the strength of a bus in the power system. The higher the short circuit power, the more difficult it is to modify the voltage at the selected bus caused by a system contingency.

[16]Chapter 3 will analyze the details to define an homogeneous product for VAR capacity among all possible VAR providers.

[17]In [Soler, 2001] a proposal was introduced for the analysis of the cost structure of the ancillary service. In this scheme three cost components were identified: installed capacity, available capacity, and use of the corresponding capacity. This cost structure was successfully applied to the secondary reserve ancillary service of the Spanish Power System. Under this scheme, the cost associated with the availability of the VAR sources would be associated with the stand-by operation waiting for the instructions from the SO. This availability cost can be neglected.

- The *use of the VAR capacity* corresponds to the real-time use of the installed capacity. This product is measured in energy units both for reactive energy generation and absorption, in Mvarh. The cost of this product is associated with two issues:
  - If the VAR source operates within its normal capacity, costs of use will correspond to the change of active power losses in the generators. For generators, this cost is usually lower than that of VAR capacity, but is not negligible. In capacitor banks and shunt reactors this cost is associated with the wear of the mechanical switch. Finally, SVC and other fast control devices, have maintenance costs that are higher than those of capacitor banks.
  - If generators had to reduce the real power output in order to provide more VAR capacity, there would be a cost associated with the loss of revenues in the active power market, which is called Loss of Opportunity Costs (LOC). For instance, in the Spanish electricity market, the redispatch of generation units takes place after the active energy market is cleared, and takes into account not only voltage levels in the networks, but also congestions alleviation in the transmission lines. These costs have been analyzed in [Lamont and Fu, 1999].

A summary of the main cost components and cost distribution of the two products previously defined for the VQ service is presented in Table 2.2[18]. Additionally, a complete analysis of the costs for each VAR source when participating in the VQ service is presented in Appendix B. Note that the reactive power costs constitute nearly 1% of the total power generation industry cost [FERC, 2005, Kirby and Hirst, 1997].

From the above presented classification of service costs in Table 2.2, chronological decision making for agents participating in the VQ service agents can be defined. The installed VAR capacity corresponds to long-term decisions, usually annual, which are included in the planning period. On the other hand, the real-time operation of VAR resources determines the real use of the VAR capacity product, including a possible energy redispatch.

The cost distribution for the VAR capacity products presented in Table 2.2 shows that the main product, which is the one with the highest cost share, is the installed VAR capacity. This thesis dissertation proposes advanced mechanisms for the procurement of the VQ service, based on competitive markets. Therefore, the market approach will select the products to be traded. To avoid asymmetries in the remuneration and procurement of the service, only one product will be traded in the proposed market for the VQ service. The selected product is the one with the highest cost participation, which is the installed VAR capacity. Additionally, the SO will require the procurement of the VAR use product, as it is consubstantial to the selection of the installed VAR capacity.

[18]The cost sharing in other ancillary services [Soler, 2001] ordered as installed capacity cost share, available capacity cost share, and use cost share are, for primary reserve 95%, 5%, and 0%; for secondary reserve 5%, 75% and 20%; for tertiary reserve 0%, 10%, and 90%; for system recovery 90%, 10%, and 0%.

Table 2.2: Costs distribution of the VAR capacity products of the VAR compensation devices

	VAR costs			Costs distribution		
Equipment	**Installed capacity**	**VAR use, normal**	**VAR use, LOC**	**Installed capacity**	**VAR use, normal**	**VAR use, LOC**
Conventional generator	Difficult to separate	High	Yes	65%	30%	0-5%
Synchronous condenser	\$30-35/kvar	High	No	70%	30%	-
Distributed generation	Difficult to separate	High	Yes	65%	30%	0-5%
Capacitor banks	\$10-20/kvar	Very low	No	95%	5%	-
Shunt reactor	\$20-30/kvar	Very low	No	95%	5%	-
SVC	\$30-60/kvar	Moderate	No	90%	10%	-
STATCOM	\$55-70/kvar	Moderate	No	90%	10%	-

(LOC: loss of opportunity costs. Source: [Kirby and Hirst, 1997] and personal research)

2.2.3 Allocation of the VQ service

In this thesis dissertation, the allocation of the VQ service is defined as the strategy for using the available VAR resources in order to achieve the goal of procuring correctly the VQ service. The allocation strategy consists of the following three steps: (i) characterization of the volume of demand of the VQ service, (ii) selection of the VAR sources that can participate in the VQ service, (iii) definition of a mechanism to distribute the VAR demand between the VAR sources.

2.2.3.1 Volume of demand of VQ service

The volume of demand in the VQ service is defined by two topics, the VAR demand in the power system, and the security requirements that the SO defines in the operating procedures.

- VAR demand in the power system is constituted by the *active and reactive power energy* demanded by loads, and by the own VAR consumption of the transmission network. Moreover, contingencies in the power system constitute an additional demand of the VQ service, as they require a certain amount of VAR reserve to guarantee the system security.
- On the other hand, the SO, based on engineering experience, defined the operating procedures where the minimum and maximum voltages in the power system

under normal and emergency conditions are specified. Additionally, the operating procedures also define the *contingencies* that must be considered in the dispatching process of the energy market, for example the N-1 criteria. The N-1 security conditions are usually specified for preventive or corrective actions. Under the preventive N-1 security criteria, the system can face any credible contingency (loss of a single network element: generator, transmission line circuit, or transformer) whilst continuing to operate without any constraint violation for an indefinite time, provided that no further contingency occurs. In the corrective N-1 security criteria some constraint violations are permitted following an initial contingency, and the SO has to re-establish the normal operating conditions within a pre-determined time frame, usually 20 minutes.

According to the general characterization of the demand behavior, the VQ service demand can be (i) inelastic, if the SO can settle rigid requirements for the VQ service, or (ii) elastic if the system requirements are evaluated according to their economic impact on the operational costs.

- The *inelastic demand* of the VQ service corresponds to current practices of most SOs. Under this approach, the SO defines rigid requirements for the secure operation based on engineering practices. Requirements are based on fixed maximum and minimum voltages. In addition, only certain contingencies must be considered, for example following the N-1 criteria.
- In order to give some *elasticity to the demand* of the VQ service, all security criteria are relaxed. Then, deviations over the specific ranges are assimilated as new costs in the VQ service procurement. For instance, voltage deviations over the pre-defined range are penalized using a square function which measures the value of voltage to customers [Kim et al., 2004]. A detailed description of an elastic demand formulation for the VQ service is presented in Appendix C.

This thesis dissertation will focus on the approach of an elastic demand of the VQ service, trying to model the real value of the procurement of this service.

2.2.3.2 VAR sources participating in the VQ service

As described in the preceding section, most of the devices in the power system can potentially participate in the VQ service. In an initial approach, the VAR sources are classified into those which are controllable, that will be considered as the potential providers in the VQ service, and those with a low or null controllability, which will be part of the demand of the service. The first group includes most of the VAR sources described in the previous section, except loads. These sources can provide a certain amount of VAR to control the system voltages, and may receive a compensation for the procurement of the VQ service. On the other hand, the load power factor is considered in this thesis dissertation as a non-controllable variable. Therefore, loads may be charged proportionally to the required volume of VQ service; in addition, loads may be compensated if they contribute to the reduction of costs of the VQ service.

Traditionally, SOs have relied on generators to provide most of the VQ service requirements. Under this scheme, generators performed a real-time voltage control and provided a VAR capacity reserve to cover emergency situations. Other power system devices, such as capacitor banks, shunt reactors, SVCs, self-conmutated converters, transmission lines, and load tap changers were owned and operated by transmission companies, following the orders of the SO. Finally, special loads with a low power factor, such as arc furnaces, installed specific VAR compensation equipment as a requirement to be connected to the transmission network or to avoid penalties due to their high VAR demand.

The characterization of an homogeneous product for the VAR capacity require the definition of certain minimum requirements for the procurement of the corresponding VAR capacity. These requirements may refer to a minimum speed response of the VAR capacity, a minimum amount of VAR capacity, and a minimum number of VAR control actions performed per hour. The VAR sources that can fulfill these requirements are: generators, capacitor banks, shunt reactors, SVCs, and self-commutated converters. Other VQ control actions performed by the transmission companies, such as transmission line switching, and the adjustment of tap-changers in transformers cannot fulfill the previous criteria, and therefore are more difficult to fit into the definition of the homogeneous VAR capacity product. The VAR support provided by distributed generation units is integrated in the equivalent of the distribution networks connected to the transmission networks, and therefore are not considered in the VQ service. The definition of the homogeneous product installed in VAR capacity introduces competition in the VQ service. Moreover, new investors can install VAR equipment, not only to compensate low power factors, but also to participate in the VQ service as generators do.

2.2.3.3 Mechanism to assign the participation in the VQ service

Once the SO has defined the volume of demand of the VQ service, and the possible VAR sources that can participate in it, the SO has to develop a mechanism to distribute the VAR support between all participants. VAR allocation has been traditionally solved using planning tools, which are based on solution techniques of Optimal Power Flow (OPF) [Carpentier, 1979, Chamorel, 1987]. VAR planning usually assumes that all generators participate in the VQ service providing their full VAR capacity, so the problem to be solved only involves the optimal allocation and size of VAR compensation, mainly capacitor banks and shunt reactors. In addition, the VAR planning problem may also incorporate the minimization of other operational costs, such as energy losses reduction and voltage profile improvement.

The complete formulation of the OPF is a large-scale non-linear problem (2.1). The objective function consists of the minimization of the operational and investment costs associated with VAR procurement. The operating constraints include the power low balance equations in each node, which are equality and non-linear constraints. Additional inequality constraints include limits of VAR control equipment and voltage margins which settle the demand of the VQ service.

$$\begin{array}{ll} \min & C_{OP}+C_{INV} \\ s.t. & g\left(p_g,q_g,v_n,\theta_n\right)=0 \\ & h\left(p_g,q_g,v_n,\theta_n,qa_g,qa_c,qa_r\right)\leq 0 \end{array} \tag{2.1}$$

where:

C_{OP}, C_{INV}	Operation and investment costs, respectively
p_g, q_g	Active and reactive power generation
v_n, θ_n	Voltage value and voltage angle
qa_g, qa_c, qa_r	Available VAR capacity of generators, capacitor banks and shunt reactors

Due to the complexity of the VAR planning problem, many formulations have been proposed using different mathematical techniques to solve the optimization problem. The proposed techniques in the research literature can be grouped into two main categories [Zhang and Tolbert, 2005]: (i) *conventional optimization methods*, including linear, non-linear, and mixed-integer programming, and (ii) *artificial intelligent methods*, including simulated annealing, evolutionary algorithms, and artificial neuronal networks. Both groups have obtained similar performance levels on searching the optimal solutions. Practical experiences on VAR planning [Flatabo and Invernizzi, 1987, Vaahedi et al., 1998] show that the SO and other utilities usually decide new VAR investments in a deterministic manner, which is the result of actual needs of VAR compensation. Additionally, conventional optimization tools are still preferred for VAR planning rather than artificial intelligent methods, mainly because they are integrated into most of the power flow software used by SOs and utilities[19]. In this thesis dissertation, conventional optimization methods will be used, based on mixed-integer non-linear programming.

2.2.4 Economic flows in the VQ service

Once the VAR capacity sources have been allocated across the power system, a remuneration mechanism for its procurement should be established for both the VAR capacity and VAR use products. Moreover, the demand of the VQ service should be charged to cover the previous payments to suppliers. This section first presents a brief description of the remuneration alternatives, followed by a summary of the international practices. Then, the charging mechanisms for the demand of the service are analyzed.

[19] Examples of power flow software tools are PSS/E from PTI `http://pti-us.com`, NEPLAN `http://www.abb.com`, PowerWorld `http://www.powerworld.com`, and Matpower `http://www.pserc.cornell.edu/matpower`.

2.2.4.1 Remuneration to the VQ service suppliers

According to the economic theory, there are three basic remuneration alternatives, (i) no payment, (ii) payment at a regulated price determined by the corresponding regulator, and (iii) free price under a market based mechanism. The selected alternative is an input for the planning and allocation mechanisms, because the remuneration is usually part of the objective to be minimized in the VAR assignment methods.

- *No payment.* The first remuneration option does not compensate the selected VAR agents for the service procured. This alternative is clearly unfair as VAR agents incur in investment and operation costs due to its participation in the VQ service.
- *Regulated price.* Under the second option, the regulator determines a financial compensation for the agents, usually by using the average costs of the service. The total remuneration is obtained by multiplying the regulated price times the volume of VQ service allocated (capacity/use). One important drawback of this option is the difficulty to determine accurately the costs of the service. Notwithstanding, in the case that there is not enough competition in the service this scheme avoids market power exercise and high prices for the service.
- *Market price.* Finally, in the market price option, the supplying agents participating in the market decide the volume and price of service they want to achieve. This option potentially guarantees that all the agents recover their costs. If agents bid at their variable costs, and in case they are matched, they will recover their variable costs plus an additional revenue equal to the distance to the clearing price. This surplus is used to pay the capacity offered in the VQ service, which includes mainly control equipment. This mechanism provides incentives for VAR supplying agents to bid in accordance to their actual costs. Three main requirements are needed for the success of this scheme: (i) sufficient competition, and (ii) an homogeneous product which is (iii) interchangeable. Active power markets and some ancillary service markets, such as secondary reserve, can be managed using this remuneration alternative.

A summary of the remuneration options for the VAR capacity and VAR use products is presented in Table 2.3. The costs that selected VAR sources incur when procuring the VQ service are classified in capital expenditures (CAPEX) associated with the investments costs, and also operational expenditures (OPEX). As presented in the previous section, the VAR capacity is the main product in the VQ service, and the competitive market for the VQ service should be based on this product. Once the remuneration option for the VAR capacity is decided, then among the payment alternatives for the VAR use product, the one based on a competitive market is rejected because of a possible abuse. It is clear that two products associated with the same service cannot be traded under two independent markets based on marginal pricing. The main reason is that one agent could bid at a very low price in the VAR capacity market, and so this one would be selected; afterwards, the same agent could bid in the VAR use market at a very expensive price, and then this bid would be rejected. Therefore, the agent would receive remuneration for having a VAR capacity that cannot be used. Then, the VAR capacity product must be associated with certain mandatory requirements for the VAR use, such as a minimum number of hours procuring the service.

From the other two alternatives of remuneration for the VAR use product, the one without remuneration is also discarded. Under this approach the agent must include the expected use of the VAR in the corresponding VAR capacity bid. This scheme will put a high risk on the supplying agent in the estimation of the VAR use, as it may became a non-negligible amount of money.

Consequently, the best alternative for remunerating the VQ service is to trade the VAR capacity in a competitive market and to pay the VAR use at a regulated price fixed by the corresponding regulatory authority. This option minimizes the risk of the supplying agent, and also provides an incentive for the agent to use the allocated VAR capacity.

Table 2.3: Remuneration alternatives for the capacity and use products

	VAR CAPACITY		
VAR USE	*No remuneration*	*Regulated price*	*Market price*
No remuneration	⇑Easy to implement ⇓Clearly unfair for supplying agents	⇓Difficult to determine average CAPEX for all agents and technologies	⇓High risk for supplying agents on calculating expected OPEX
Regulated price	⇓Not fair, the main product is capacity	⇓Difficult to determine average CAPEX & OPEX for all agents and technologies	⇑Fair treatment ⇓Calculation of the regulated price
Market price	⇓Not fair, the main product is capacity	⇓Not consistent, CAPEX > OPEX ⇓Possible gaming	⇑Theoretically fair ⇓Not practical ⇓Possible gaming

(Source: personal research)

A detailed international review of the VQ service is included in Appendix A, and a summary of the remuneration approach is presented in Table 2.4. The most extended practice is the mandatory procurement of the VQ service without remuneration. This alternative is the more simplistic, and it is very common in those countries that still do not have competition in the wholesale energy market, or in the ancillary services. Other countries have had experience with the use of regulated prices for VAR capacity, and/or VAR use. This option is preferred for the VAR procurement over the mandatory requirements. Finally, some advanced regulations decided to provide the VQ service under a competitive market approach. The pioneer regulatory framework was developed in England and Wales, and its success spread to other countries such as Australia.

Table 2.4: International review of the VAR remuneration alternatives

	VAR CAPACITY		
VAR USE	*No remuneration*	*Regulated price*	*Market price*
No remuneration	Austria, Italy, Sweden, Argentina	France, New York ISO, California, PJM	n.a.
Regulated price	n.a.	Belgium, Czech Rep., Ireland, Netherlands, Spain, New England	Finland, Germany, Hungary, Norway, Poland
Market price	n.a.	n.a.	England & Wales, Australia (optional), New Zealand

(n.a.: not applicable. Source: personal research)

2.2.4.2 VQ service charging methodology

The definition of a fair and adequate method for allocating the costs may send efficient location and economic signals to the VAR demand agents, in order to control their VAR consumption. This section reviews the theoretical and practical schemes to allocate the costs of the VQ service, supplied by generators, capacitor banks, shunt reactors, SVCs and STATCOM devices.

Traditionally, the costs associated with the VQ service had been included in the general cost associated with the transmission business and then this cost was distributed between the demand agents according to the energy consumed.

Nowadays, a widespread methodology for charging VAR consumers is the one based on the power factor, as it is a measure of the VAR consumed by each user. Under this scheme if the VAR demand is within an allowed power factor range there is no charge. However, if the power factor is out of the range, then a charge based on (1-power factor) will be applied to the corresponding load[20]. The simplicity of the power factor approach makes it prevalent in regulated and open-access markets. However, this methodology lacks valuating the voltage control.

[20] The corresponding charges for VAR demand are usually applied to consumers connected to the transmission network, which are mainly distribution companies. Then, distribution utilities define specific cost recovery methodologies for the end-users of the network, in order to recover the VQ service charge. According to an international review [Alvarado et al., 1996, Dingley, 2002] there are several methods for VAR charging used by utilities: (i) charge according to VAR use as measured by the maximum VAR demand (kvar), or by the total energy (kvarh) during the billing period; (ii) charges based on the maximum apparent demand (kVA); (iii) charges based on the average power factor or the power factor at maximum load, including a threshold level; and (iv) no charges. Nowadays, the high integration of distributed generation in distribution networks should be considered when calculating the cost distribution of the VAR support [Chen et al., 2006, Peças et al., 2007].

In addition to the current experiences just reviewed, research literature has proposed other more sophisticated alternatives for allocating the costs of the VQ service. The first approach was derived from the marginal nodal VAR prices, as proposed in [El-Keib and Ma, 1997], but the formulation did not consider the investment and operational costs associated with the procurement of the VQ service. A new approach suggests that the customer could freely acquire the needed VAR capacity using the nodal prices within a local VAR market, using certain VAR adjustment factors [Hao and Papalexopoulos, 1997].

Another interesting approach is the methodology for VAR cost allocation based on tracing the power flows through the network. This method can deduce the real or reactive power from individual generators received by each load [Bialek, 1996, Bialek, 1998, Kirschen et al., 1997]. New developments on the graph theory [Wu et al., 2000] and the Ybus methodology [Chu et al., 2004] have improved the efficiency and fairness of this methodology.

Finally, nowadays new allocation mechanisms based on Cooperative Game Theory are introducing promising results for the distribution of the VAR costs among the demand agents [Lin et al., 2006]. This alternative will be explored in this thesis dissertation to define a cost distribution mechanism for the proposed competitive VAR capacity market.

2.3 Economic theory on VAR pricing

Once it is decided that agents participating in the VQ service should receive a compensation, the next question to be answered is how to compute these payments. In research literature, many approaches have been proposed. The aim of this thesis dissertation is to propose advanced criteria for the definition of efficient location and economic signals based on the economic theory. This section will first present the traditional scheme based on real time VAR marginal pricing and other research proposals for valuating the VAR capacity. Then, issues regarding the possible market power associated with the VQ service are discussed.

2.3.1 Real time VAR marginal pricing

The basic theory of spot pricing in power systems was first applied to active power markets [Schweppe and Caramanis, 1988]. According to this theory, independent generators would adjust their generation output using the spot prices, and this price would be the payment they would receive due to their power production. The marginal costs theory is based on the assumption that marginal costs can recover all costs involved to produce, transport, and deliver the active power.

The application of the marginal theory to reactive power was first presented in [Baughman and Siddiqi, 1991], where it was justified that VAR prices could not be neglected because they became relatively high under contingencies. This idea was confirmed by [Hogan, 1993], who argued that DC load models were not sufficient to determine active power prices under contingencies, requiring the complete formulation based on AC power flow models. Hogan stated that electricity markets need reactive power prices. In subsequent approaches, real-time prices of real and reactive power are obtained by modifying the OPF formulation [Li and David, 1993, Li and David, 1994, Baughman and Siddiqi, 1991]. This formulation was also used to compute the wheeling rates[21] to compensate the use of the transmission network.

The spot pricing formulation will be applied to design real time computation of the reactive power marginal pricing [Baughman et al., 1997a, Baughman et al., 1997b]. A decoupled modified OPF is used by [El-Keib and Ma, 1997] where the objective function of the sub-problem is to minimize the active power losses, obtaining reactive power prices. In these two approaches, the VAR production cost is not obtained, as noted in [Hao and Papalexopoulos, 1997] which details some alternatives for the computation of reactive power production costs.

The research was then focused on the role of the SO in planning the VAR needs. A first approach used an OPF to determine the optimal size and location of capacitor banks, minimizing the operation costs [Chattopadhyay et al., 1995]. Other proposals analyzed the role of the SO in the competitive market for VAR support [Dandachi, 1997]. Under these approaches, the operating costs included in the objective function were analyzed [Lamont and Fu, 1999], such as minimizing the movement of transmission devices, maximizing the social welfare [Choi et al., 1998], or including the maximization of the shipment of active power [Pirayesh et al., 2004a, Pirayesh et al., 2004b].

In conclusion, real-time VAR pricing is characterized by a high degree of volatility, with a value close to zero during normal operation, and high values under contingency situations. To eliminate this unstable signal for VAR support, long-term payments are needed [Barquín et al., 2000].

2.3.2 Valuating VAR capacity

The limitations of the real-time VAR pricing focused the new research on the analysis and valuation of the VAR capacity and the long-term contracts. In addition, the introduction of competition in electricity markets promoted the search for new proposal for competitive VAR markets.

An interesting valuation proposal for VAR support is based on the Equivalent Reactive Compensation method [Xu et al., 2000]. This approach values each VAR source for its actual contribution to the system security. This idea comes from the fact that if a VAR source changes its output, the network voltage profiles, and stability margins will change. Then, to measure the value of a VAR source, the calculation of all the new VAR compensation needed to maintain the same voltage profile and security margins is proposed. Therefore, the more VAR compensation needed, the more important the source is to the system. These new VAR sources are fictitious capacitor banks distributed across the system and are referred to as Equivalent Reactive Compensation.

[21] *Wheeling* is defined as the transmission of active and reactive power from a generator to a customer, using the transmission network that belongs to a third party.

The previous approach can be used to determine the minimum amount of VAR needed by a generator to procure its own active power [Wang and Xu, 2002]. Then, if the generator is producing more VAR than the minimum value, the generator will be supporting the power system and therefore can receive a compensation. On the other hand, if the generator is producing less VAR than the minimum value, the generator will be using the VAR procured by other sources and will therefore be charged according to its consumption.

In the aim of developing competitive markets for VAR support over the minimum requirements [Xu et al., 2000], first a characterization of the possible bids in this market were presented [Bhattacharya and Zhong, 2001, Zhong et al., 2004]. The proposed bid structure is based on a payment scheme consisting of four regions of VAR support from a generator (see Figure 2.4):

- A non-remunerated range where the generator is producing VAR to cover its own requirements (i).
- An operation payment for making available a certain capacity for VAR generation (ii) and VAR absorption (iii). Bids would include an availability price offer in (€), and a operating price for over and under excited VAR procurement in (€/Mvarh) respectively.
- An opportunity payment where the generator reduces its own real power generation to supply VAR capacity (iv). The opportunity price is a quadratic function of VAR (€/Mvarh^2).

The market structure is based on the SO as the single buyer that purchases the VAR support from different independent VAR suppliers. Under this market proposal, generator bids are then submitted to the SO in a uniform auction model [Zhong and Bhattacharya, 2002c]. Then, the SO calculates the VAR allocation and payment to each supplier. The proposed methodology for VAR allocation is similar to the one used for active power, and does not consider the local nature of the VAR support. Within this market proposal, a location dependent scheme can also be settled [Zhong et al., 2004]. For this purpose different voltage control areas are defined using the concept of the electrical distance between the buses in the power network. Then, for each voltage control area a uniform VAR price is calculated using a modified OPF model.

The above mentioned VAR market structure can be applied to any voltage control area. Similar approaches for VAR pricing in power systems based on electric areas were proposed [Corsi and CESI, 2000]. Its application in countries with a secondary voltage control structure[22] is analyzed in [Nobile and Bose, 2002], introducing the concept

[22] Under this control, power systems are divided into electric areas around the so-called pilot nodes. A pilot node is the most representative bus in an electric area for voltage control. The selection of the pilot buses is based on voltage/VAR sensitivity analysis and short circuit levels.

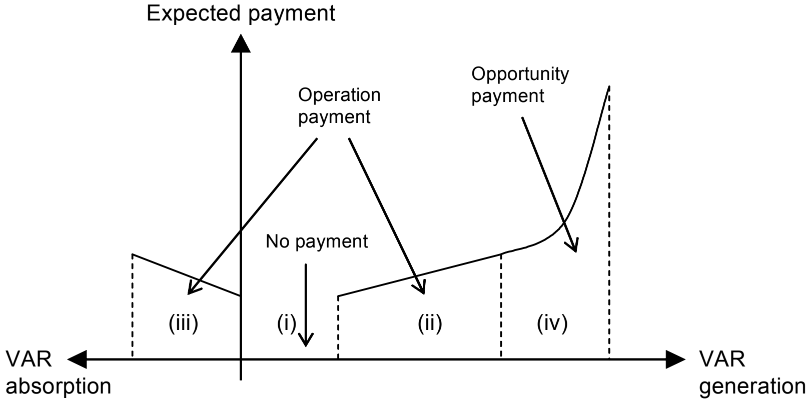

Figure 2.4: Structure of reactive power offers from VQ service providers

of regional VAR markets [Marannino et al., 2004]. These local markets are defined by generators whose reactive support are of similar value and therefore can be remunerated at the same price. The value of VAR produced by generators is calculated using an Optimal Reactive Power Flow (ORPF) [Corsi et al., 1995] with the objective of transmission losses minimization and the satisfaction of the security constraints of the power system.

In the previous approaches the demand of VAR support was based on deterministic values defined by engineering criteria or by the SO experience. However, the real value of the demand of VAR can significantly vary for different locations and load periods. The value of the VAR support has been analyzed in [Frías et al., 2005]. In this proposal, the demand of VAR for each voltage control area is obtained from the marginal utility function. The utility function is built by computing total expected operational costs for different reactive capacity levels available in the area. The system operation costs include four different system cost terms: security, voltage quality, energy losses, and redispatching costs. Finally, the marginal utility function is calculated as the variation of the expected operation costs when the reactive power capacity in the area is increased (see Figure 2.5).

In the same line of research, another option for defining the VAR support demand is to let market participants bid their voltage levels into the market [Kim et al., 2004]. Therefore, the OPF that allocates the VAR needs will consider the value for voltage, voltage regulation and VAR capacity. Moreover, including this value in the formulation improves the optimality of the solutions as the rigid voltage ranges are relaxed because they are included as decision variables.

To summarize, nowadays research is focused on VAR capacity arrangements in order to eliminate the volatility of real-time prices. Moreover, research is also working on competitive market approaches for the VAR support service which are based on different markets for each electrical region. The proposed market structures are based on a single

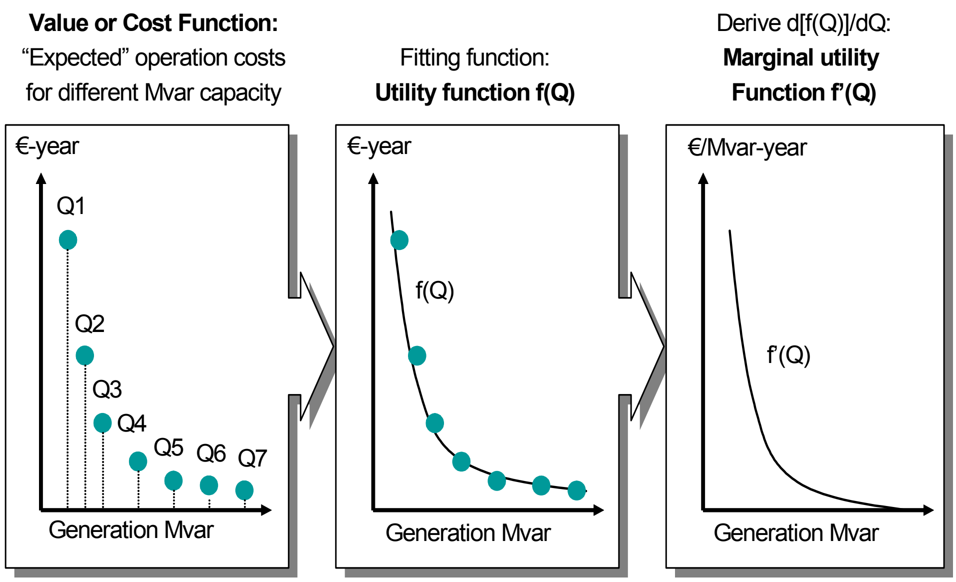

Figure 2.5: Building the market demand side curve for VAR generation capacity (Source: personal research)

buyer, which is the SO, that purchases the VAR support from several independent sellers.

2.3.3 VAR market power

Due to the local nature of VAR support and its limited ability to travel in the transmission network, market power is a main issue when studying the implementation of a competitive market for the VQ service. Market power can be defined as the ability to alter prices away from competitive levels from its own profit. Usually, only local VAR support can procure the VQ service in a certain area of the power system.

The traditional indicators to measure market power are based on supplier concentration using two simplistic indices [Stoft, 2002]:

- The Herfindahl-Hirschman index (HHI) is calculated as the sum of the squares of market shares[23] s_i for the N suppliers. In markets with low concentration $H < 1000$, and there is high concentration when $H > 1800$.

$$H = 10000 \sum_{i=1}^{N} s_i^2 \tag{2.2}$$

- The entropy coefficient takes the value $E = 0$ in a monopoly situation and $E = \ln(N)$ for market equilibrium.

[23] The market share is the output of a supplier divided by the total market output.

$$E = -\sum_{i=1}^{N} s_i \ln(s_i) \tag{2.3}$$

These indexes cannot be directly applied to measure the VAR market power, due to the specific characteristics of the voltage control. A first approach would be to analyze the actual ability of separately owned suppliers to control the voltage at that location for specific system conditions [Alvarado and Overbye, 1999], taking into account the load effect on the VAR demand [de Souza et al., 2001]. Under this approach, the market share considers both the relative available VAR from each generator, and the impact of that VAR on voltages. The market share is calculated as the change in the controlled bus voltage value ΔV_i divided by the sum of the controllable generators voltage changes ΔV_g:

$$s_i = 100 \frac{\Delta V_i}{\sum_g \Delta V_g} \tag{2.4}$$

The previous index is very simplistic and may be imprecise for measuring the VAR power market concentration as they do not consider specific characteristics of the VAR procurement. Therefore, more accurate alternatives to value VAR market power have been proposed using simulation and analysis. In [Chicco, 2004] an improved definition for the market share is presented. This new approach includes not only supplier concentration, but also the location of the VAR support, the network structure, and changing characteristics of the demand. The VAR share of a generator is obtained by analyzing the variation of loads and generation along a predefined direction until one of the generator reaches its VAR limit. The reactive support share is defined as the variation of the VAR generation from one selected initial condition to the limit condition referred to the sum of variations of all the VAR generations. The VAR support share measures the effectiveness of the VAR support procurement of a selected generator.

A practical implementation of the market power studies in England and Wales was analyzed in [Ahmed and Strbac, 2000]. The VAR market in England is based on combined VAR capacity and energy payments. The analysis uses a security constrained reactive OPF to value the VAR support of each generator in terms of both capability and utilization. The relative competitiveness of participating generators is also assessed for a spectrum of arrangements between a reactive capacity and a reactive utilization based market. One main conclusion of the analysis is that the VAR capability has a higher value than the utilization of VAR to the system operator.

2.4 Conclusions

The main responsibility of the SO is to maintain the system reliability and security to guarantee the correct fulfillment of the real power energy transactions. For this purpose, the SO defines certain procedures among which stand the reactive power and voltage control. In the VQ control the SO manages all the VAR resources in the network which are property of private owners.

In deregulated power systems, the VQ control was redefined as the VQ control service, included in the Ancillary Services of the energy supply. The new definition of the VQ service requires that its characteristics are correctly defined: the procurement of the service, the allocation of the different VAR sources, and the remuneration scheme.

The analysis of the cost structure of the possible VAR sources participating in the VQ service found two basic products: installed VAR capacity, and use of the VAR capacity. In addition, the use of VAR capacity may have high costs which are associated with the redispatch of generators to provide more VAR capacity. The demand in the VQ service is defined by the load from end-users and by the possible system contingencies.

To cover this demand, the SO can define different procurement alternatives, such as mandatory or optional participation in the VQ service. In most power systems, the procurement of the VAR support has remained as a mandatory and non-remunerated service, mainly because of the simplicity of the approach. However, the introduction of competition in ancillary services in some countries changed the requirements from mandatory to optional. The analysis carried out in this chapter concluded that real unbundling between the SO and the network owners is needed in order to develop competitive mechanism for the procurement of the VQ service. In addition, the best regulation scheme for the VQ service should be based on a free market for VAR capacity, and regulated payments for the VAR use.

The economic theory on VAR pricing gives some important information for remunerating the VQ service, and sends efficient and location price signals. According to the analysis, the VQ service allocation and remuneration should be based on long-term arrangements for the VAR capacity procurement, as the short-term VAR pricing has a high volatility due to the scenario with system contingencies. Moreover, due to the local characteristics of voltage support, different regional markets are preferred to a unique market for the whole power system. Additionally, any proposal to regional competitive markets should analyze the possible VAR market power in order to provide the corresponding mechanisms to minimize it.

2.5 References

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CHAPTER 3

A market proposal for the long-term VQ service

In the analysis presented in the previous chapter, some guidelines for the development of a regulatory framework for the VQ service procurement were discussed. Following these guidelines, this chapter presents a regulatory proposal to allocate and remunerate the VQ service. The proposal for this service is based on a reactive power capacity market.

First, the framework in which the proposed market can be included is presented. Then, the VAR capacity is selected as the homogeneous product to be traded in the proposed market. The capacity market is then described, discussing the VAR capacity bids, and the structure of the market. The economic settlement of the VAR capacity market includes the payments to the selected VAR bids, and the charging mechanism for the demand of the service. Finally, monitoring and penalties are defined for the correct procurement of the service.

3.1 Reference framework for the VAR market proposal

In the beginning of the 90's an international liberalization process in the energy sector converted the traditional centralized operation of electricity into a competitive market. In the beginning, only the energy market was cleared under competitive mechanisms. Soon after, some ancillary services were traded under market mechanisms. As presented in Chapter 2 and Appendix A, nowadays many countries are introducing a competitive mechanism in the procurement of the VQ service.

As it has been analyzed in the previous chapter, there are three decision levels associated with the VQ service procurement, (i) VAR planning, (ii) VAR dispatch and (iii) VAR use. The period of time for the construction and installation of new VAR sources or upgrading existing ones is usually less than one year. This period of time is short, compared with the time needed for the construction of new power plants which extends in several years. Therefore, the planning of VAR equipment covers usually a time frame of one or two years.

VAR dispatch is usually performed under the system constraint management mechanism, which normally takes place after the energy dispatch. Power system constraints include both congestions in the transmission network, and local voltage problems. System constraints are solved by changing the active power dispatch, increasing the generation of connected units and connecting off-line generation, and decreasing the generation of the most expensive units. Decisions are taken one day or, at least, one hour in advance of the real-time operation. Changes in the active power dispatch have specific economical compensations[1].

An adequate VAR control may reduce the transmission energy losses. This effect is the combined result of reducing currents with (i) the reduction of VAR flows through lines, and (ii) by increasing voltages. Each power system has its own mechanism to distribute and allocate the transmission losses[2].

The main requirements to create a competitive market for the VQ service are the following:

i) *Services unbundling.* The traditional operation of vertically-integrated power systems usually considered ancillary services as mandatory and non-remunerated. Nowadays, new electricity markets are developing competitive mechanisms not

[1] In the Spanish energy market system constraints are solved after the day-ahead energy market is cleared, and are regulated by the Operating Procedure P.O.-3.2 [REE, 1998]. Generation units submit specific bids for this market in quantity and price to solve constraints. These bids are different from those sent to the energy market. Selected generators are paid according to their bids. Those generators whose active power is reduced do not receive economic compensation.

[2] In Spain all the costs associated with transmission losses are allocated to customers using distribution factors [Conejo et al., 2002, González and Basagoiti, 1999]. There exist other alternatives for losses allocation, such as marginal pricing, incremental allocation, and transmission power flow decomposition among others [Unsihuay and Saavedra, 2003].

only for the energy supply but also for the ancillary services, among which stands the VQ service. These new competitive proposals for the procurement of the ancillary services increase the efficiency and fair treatment of the different suppliers.

ii) *Absence of market power.* Due to the local nature of VAR support, the existence of market power in the procurement of the service is quite usual. Therefore, specific mechanisms should be designed to limit or at least neutralize the potential exercise of market power.

iii) *Minimize the distortion with the energy market.* Most power systems with a market based mechanism for the energy dispatch perform a congestion management analysis after the energy market has been cleared. This analysis is usually carried out by the SO, that modifies the market scheduled output of generators, by increasing the generation of connected units and by connecting off-line generation, in order to fulfill the security criteria[3]. Under this scheme, the existence of previous long-term arrangements for the procurement of VAR capacity may potentially reduce the changes in the energy dispatch.

3.2 Product definition

The definition of a homogeneous product is a main requirement to establish a market for VAR. A product is considered to be homogeneous if the different bids for that product can be easily compared between each other. In Chapter 2 two products associated with the VQ service were identified: (i) installed VAR capacity, and (ii) use of the VAR capacity to control voltages. The economic analysis carried out in this thesis shows that a reasonable alternative for a market of the VQ service is to design a competitive mechanism for the product of the highest cost, which is the installed VAR capacity[4]. Additionally, the VAR use product will have an specific compensation mechanism, as it will be presented in the next section.

> The homogeneous product that will be traded in the proposed competitive VAR market is the *band of installed VAR capacity.* This basic product includes the VAR generation capacity and VAR absorption capacity.

The procurement of VAR capacity has two main characteristics, (i) the dynamic performance, and (ii) the dependence on voltage. The dynamic response of VAR sources is defined as the step in its VAR output that can be achieved within a determined

[3]Appendix A presents a brief description of the Spanish constraint management mechanism.

[4]In electric power markets the market is based on active power energy, as it is considered to be the main product. However, an additional compensation is also defined for the active power capacity, in order to send long-term signals for the security of energy supply.

time range[5]. In generators and synchronous condensers, the dynamic regulation is provided by the AVR, which performs a fast VAR control. A similar fast voltage control is provided by STATCOM devices and SVCs. Finally, capacitor banks have the slowest response, as their operation is based on voltage relays. The dynamic capacity is especially important for the response to a contingency. Therefore, it is proposed to characterize each VAR source by the maximum VAR change to be procured after a contingency. The VAR change will be defined independently for both directions over a working point, positive and negative VAR changes. Obviously, these changes in the VAR output are limited by the capability limits of each VAR source. The VAR variation should be procured with a certain dynamic criteria defined by (i) a maximum time[6] $t^{\max}$ for the procurement of all the VAR $Q^{\max}$, and (ii) a response lag or band for the VAR procurement. Figure 3.1 presents the correct procurement of the dynamic VAR support for positive changes. Two VAR responses are drawn, (i) the stepped response of a capacitor bank or SVC, and (ii) the continuous VAR regulation of the AVR of generators.

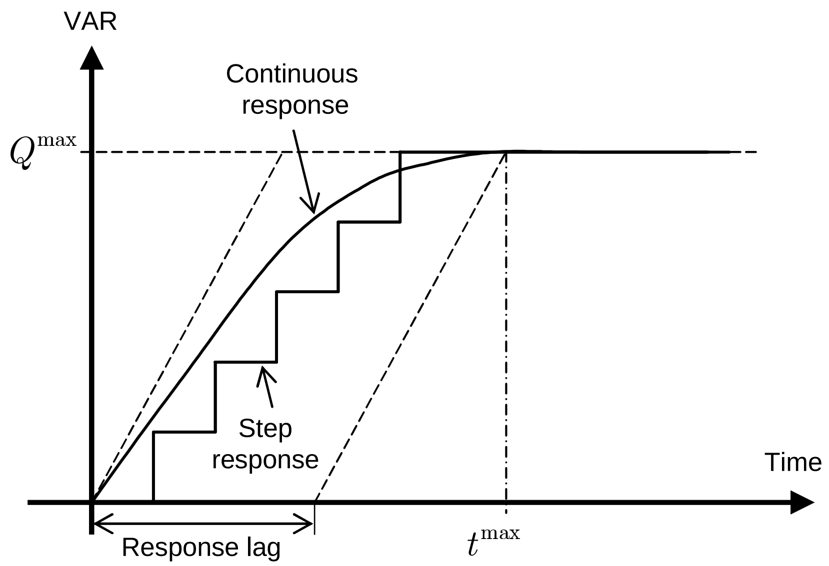

Figure 3.1: Dynamic response of VAR sources

A second characteristic of the VAR product provided by different sources is the influence of voltage in the VAR procured. VAR procurement of generators and synchronous compensators do not directly depend on the voltage in the transmission system. Notwithstanding, voltage must be considered when defining the available VAR capacity of these sources (see Appendix B). On the other hand, the VAR procured by static compensation devices such as capacitor banks, shunt reactors and SVCs depends on the voltage

[5]The secondary reserve ancillary service usually defines a reference step response that must be procured by all agents participating in this service. In the Spanish regulation, the step response must be equivalent to a linear system with a 100 seconds time constant.

[6]The maximum time lag is measured in tens of second.

squared. This issue is critical for low voltage operating situations, were VAR procurement is mostly needed. For low voltages the contribution of these VAR sources is highly reduced. The VAR procured by STATCOM devices can be assumed as proportional to the voltage value, which is a better response than that of static VAR sources. Therefore, the proposed market must consider the influence of voltage on the VAR procurement from the different devices.

3.3 The VAR capacity market

The SO must guarantee the system security associated with the VAR needs in the long-term. For this purpose, the SO selects certain VAR sources and, if needed, may require transmission owners to invest in new VAR sources in order to cover the expected VAR demand. The allocation of this VAR capacity results in costs that should be covered by all the agents participating in the energy market.

Under a real-time market for VAR paid at marginal prices, market agents would receive efficient incentives for optimal VAR investment. Marginal VAR prices are valuable under the contingency scenarios[7]. However, as these prices are very volatile, investment signals became quite unstable. In order to minimize the uncertainty of investments, long-term VAR markets should be designed. This market structure also improves competition, and therefore minimizes market power. Finally, long-term VAR markets in comparison with real-time markets are easier to implement and manage. Indeed, nowadays, current power flow software is still not able to manage large-scale real-time VAR pricing.

The proposed VAR market is based on long-term contracts between the SO and the selected supply agents. As the construction and installation time frame for new VAR sources is less than one year, markets for reactive power may cover a time frame of one year. Reactive generation and absorption capacity contracts are awarded in an annual auction for the whole power system. These contracts can be extended for more than one year in order to provide more stable economic signals for investments. Decisions are then taken one year in advance, allowing the entrance of new investments, as one year is enough time to install a new VAR device or to upgrade the existing ones.

The annual auction will cover the reactive power capacity needs of the power system that are not already covered by previous VAR capacity contracts. Hence, VAR needs will be determined by concluded VAR contracts, and by the natural load increase (see Figure 3.2).

This section describes in detail the proposed market for VAR capacity. First bids and demand for the market are presented. Then, the proposed mechanism to select the bids,

[7] In energy markets paid at marginal price peaking units recover their costs with high remuneration during peak hours.

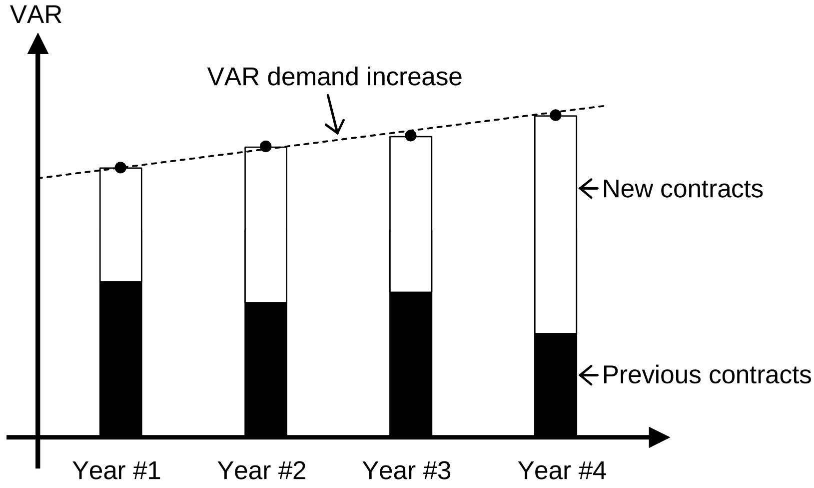

Figure 3.2: VAR capacity contracts

and the market arrangements between the selected VAR sources and the SO are defined. Finally issues regarding perfect and imperfect competition in the VAR capacity market are discussed.

3.3.1 Bids for the VAR capacity market

The VAR sources that can participate in the proposed VAR market are generators, synchronous condensers, capacitor banks, shunt reactors, SVCs and STATCOM devices. VAR sources must be connected to the transmission network. These sources can bid in the annual auction for both generation and absorption VAR capacity products, excluding the capacity that has already been assigned in previous auctions. *Bids represent the minimum revenue that the agent is willing to receive each year for the submitted quantities of VAR capacity.*

According to the definition of the VAR capacity product in the previous section, bids for the proposed market must contain the following information:

i) *VAR capacity for generation and absorption in the connection point to the transmission network.* The VAR installed capacity is a single value for capacitor banks and shunt reactors. Two values, generation and absorption installed VAR capacity, are required for SVCs and STATCOM devices. Finally, the calculation of VAR capacity for generators requires a thorough analysis of the operating conditions of the associated power plant (Appendix B includes a detailed analysis and examples for this calculation). The installed VAR capacity for generators is defined for the average voltage value in the connection to the transmission network. Additionally, four VAR values are required, associated with the operating point of maximum VAR generation and absorption corresponding to maximum and minimum active power generation (See Figure 3.3). For simplicity, it is assumed that the VAR capacity in a generator depends linearly on the active power generation[8].

ii) *Dynamic performance of the VAR capacity.* To determine the dynamic response of each VAR source according to Figure 3.1, annual tests should be performed. These tests have to be certified and sent to the SO or the Energy Regulator.

iii) *Dependence of the VAR procurement with voltage.* The default relationship of VAR procurement and voltage is linear to STATCOM devices, squared to other static VAR devices, and with no dependence to generators. If any source has a relationship different from that assigned by default, the VAR source has to justify the new voltage dependence based on certified tests.

iv) *Price for VAR capacity generation and VAR capacity absorption.* The bid price for the VAR sources can be easily calculated using economic analysis, taking into account the total investment, the expected life of the asset, and the maintenance costs. All VAR sources can bid into the annual auction submitting bid prices following a linear function $A+B{\cdot}VAR$. Bids presented by generators and STATCOM devices are formulated as: $A_g^G + B_g^G qa_g^G$ (€/Mvar-year) for maximum generation capacity $Q_g^{G,min}$, and $A_g^A + B_g^A qa_g^A$ (€/Mvar-year) for maximum absorption capacity $Q_g^{A,min}$. Capacitor banks, shunt reactors and SVCs submit bids using the same formulation: $A_c^C + B_c^C qa_c^C$ and $A_r^R + B_r^R qa_r^R$ respectively. A detailed analysis of the VAR bids of different agents is presented in Appendix B.

Market power is a main concern in a VAR capacity market [Alvarado and Overbye, 1999, de Mello Honorio et al., 2002]. Under the proposed approach, capacitor banks and shunt reactors may limit the exercise of market power from generators, as static VAR sources can be manufactured and installed in less than a year.

3.3.2 Determine the VAR demand for the VAR capacity market

The demand of VAR depends mainly on the load level. During peak hours, both loads and transmission networks consume VAR, so agents participating in the service should generate VAR to balance the flows. On the other hand, during light load periods agents may be required to absorb reactive power, as the transmission network generates VAR, which may not be compensated by load VAR consumption.

Therefore, the SO determines the demand of the VAR capacity market for the next year with the expected VAR demand in both peak hours and valley hours. Demand is defined by a typical generation dispatch, and by the loads of the distribution companies and large consumers.

Under system contingencies, the demand of VAR is modified, especially when that which is responsible for the contingency is a previously selected VAR source. Contingencies

[8]The real dependence of VAR with active power generation is by the square, as it is detailed in Appendix B.

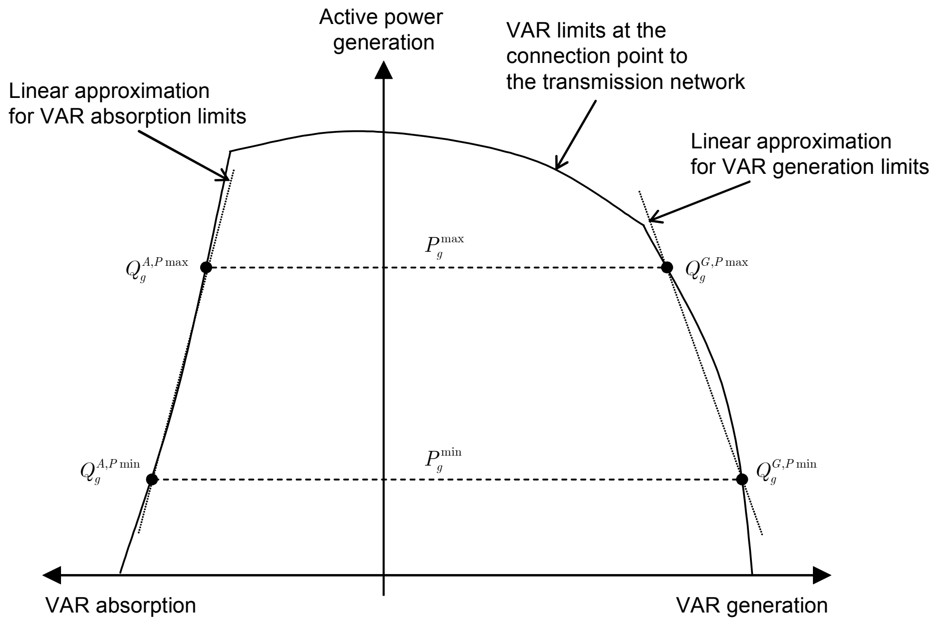

Figure 3.3: Characteristic points of the installed VAR capacity for generators

can occur due to a line trip, a generator outage, or a VAR source outage[9]. Therefore, the agents responsible for any probable contingency in the power system will be considered as a new demand of the VAR capacity market, and will be charged accordingly.

The SO must define the group of probable contingencies that impacts on the VAR needs, with their associated probability of occurrence. Historical data will be used to calculate the failure rates of the different devices to be considered in the contingencies.

3.3.3 VAR capacity market settlement

Before the annual auction takes place, the SO collects all the information needed for the VAR capacity market including:

i) *VAR bids* of different agents for VAR generation and absorption, including price, dynamic performance, and voltage dependence.

ii) *Expected demand* in peak and valley hours for the next year, and the associated average costs of energy production (A_g^P).

iii) The *probable contingencies* to be taken into account to analyze the VAR needs.

[9]A high change in the load is not considered a contingency for the VAR capacity market. Load contingencies are usually associated with a disconnection of customers, and this situation reduces the VAR needs in the system.

Some additional parameters are required to settle the VAR capacity market. These parameters are defined by the Energy Regulator and will be used to value certain externalities of the proposed market. Among these values stand:

i) Value of the non-supplied energy (A_D), measured in € per MWh non supplied.

ii) Value of the deviations of the voltage from its security range (A_V), measured in € per kV deviated.

Finally, the SO selects the bids to cover the VAR needs for the following year using an optimization algorithm. This algorithm considers all the economic and technical information and selects the optimal VAR sources. The mathematical formulation of the allocation mechanism will be presented in Chapter 4. Minimizing system costs is equivalent to maximizing net benefits of society, because the algorithm not only determines the optimal level of the VAR capacity to be installed, but also estimates the optimal level of voltage quality and system reliability.

3.3.4 VAR capacity market arrangements

All agents selected in the annual action acquire the obligation to participate in the VQ service using their assigned VAR capacity. On the one hand, selected SVCs, capacitor banks, and shunt reactors must provide their assigned capacity with no time discrimination, following the operation instructions given by the SO. On the other hand, generators selected in the auction must control voltages in defined reference buses of the network using their assigned VAR capacity. Generally the bus to be controlled is the connection point to the transmission network. However, some generators may be requested to control other important buses of the transmission network[10]. Then, two operating situations may happen:

i) If the generator is scheduled in the energy market, it will provide the VAR capacity.

ii) If the generator is not scheduled in the energy market and the SO calls it to solve local network problems, then the generator will be redispatched, and connected to the network.

The second situation will usually occurs during peak hours for selected generators to procure VAR generation capacity, and during valley hours for those selected for VAR absorption. The generator that has been redispatched will receive an economic compensation based on the *opportunity costs*. The opportunity cost of a generator is associated

[10]This especially applies to those power systems operated with an automatic secondary voltage control. This control criteria selects representative buses, known as *pilot buses*, whose voltage is representative of a wider electric area. Then, the control of the pilot buses guarantees the security operation of the whole power system.

with the reduction in the active power output to provide more VAR. Generally, generators can procure a certain amount of VAR support for the maximum active power output. Beyond that point, to get more VAR the generator must reduce its active power output. Therefore, there is a loss of profits or foregone sales, as the active power produced is reduced. The opportunity costs are then calculated for each hour as the difference between the clearing price and the variable cost of the generator, multiplied by the power that has been redispatched. The variable cost for active power production will be included as additional information in the VAR capacity bid, otherwise standard variable costs for each technology will be used.

The definition of an economic compensation for voltage constraints should be consistent with the constraint management mechanism in each power system. Although some constraints are easily identified as network congestions or voltage problems, most of the system constraints involve both aspects.

Under normal operating conditions, those generators that were not assigned in the VAR capacity market will tend to operate on a unitary power factor at the connection point. These units can procure VAR support to the power system, without remuneration, but must avoid operating against the needs of the VQ service, for instance absorbing VAR during peak hours in deteriorated voltage conditions.

3.3.5 Perfect and imperfect competition in the VAR capacity market

A perfect competitive VAR capacity market would be characterized by a high number of market participants. Then, the resulting market price will not depend on the sole behavior of a particular market agent. Under these circumstances, market agents have incentives to bid their real costs.

However, local VAR markets are usually characterized by a reduced number of market agents. This situation can lead agents with market power to bid over their real costs. This behavior can be minimized by using long-term contracts, leaving the possibility for new agents to install VAR compensation equipment. The SO can force transmission owners, which are a regulated business, to participate in the VAR capacity market with competitive bids for capacitor banks and shunt reactors. In addition, the SO can define cap prices for the VAR capacity bids.

3.4 Economic settlement of the VAR capacity market

This section presents the main characteristics of the mechanisms to remunerate the selected VAR sources and charge the demand of the VAR capacity in the proposed VAR capacity market. A detailed analysis of the economic flows is provided in Chapter 5. The economic settlement of the proposed VAR capacity market is based on the following criteria:

i) *Revenue reconciliation*, the sum of the charges to the demand of the service equals the sum of payments to the selected VAR sources.

ii) The costs for the procurement of the service for each agent should be *recovered with the payments*.

iii) The *net social benefit* should be maximized.

iv) All agents participating in the service should receive *efficient signals* in order to minimize the long-term costs associated with the VAR requirements.

3.4.1 Payments to the VAR procurement

All selected VAR agents will receive an annual payment in order to provide the assigned capacity the following year. Payments will recover the cost for the procurement of the service by the agents. The products in the VQ service are the installed VAR capacity, and the use of the selected capacity, which includes operational costs and LOC. The selected mechanism for remuneration should be transparent, fair, and easy to be implemented. Under these guidelines, two possible approaches are analyzed:

- *Remunerate only the installed VAR capacity using the market signals.* Under this scheme, the supplying agent must integrate in the bid both the installed VAR capacity and the expected use costs. The resulting bid is similar to the one proposed in [Zhong and Bhattacharya, 2002c] (see Figure 2.4), based on a single bid with different VAR ranges, each with an specific price. The calculation of the expected costs for the use product, especially due to redispatch or LOC, requires that the agent estimates the number of hours that might be redispatched, and the volume of the redispatched energy. It is clear that there is a high risk for the supplying agent, as small deviations in the estimation may result in quite different remunerations. However, under this remuneration approach the SO can use very simple tools to select the best alternatives for the VAR procurement.

- *Remunerate the installed VAR capacity with the market signals, and define regulated prices for the use of the service.* Under this approach, the supplying agent bids only for the VAR capacity, and also communicates its variable costs for active and reactive power production. Therefore, the risk for the supplying agent is very low as all the incurred costs in the VAR service are taken into account[11]. The allocation mechanism for the VAR capacity market designed by the SO is more complex than in the previous alternative.

[11]Suppose that a taxi-driver signs an annual contract with a person to provide transportation when required. If there is no additional payment for the mileage, the taxi-driver would have a high uncertainty of the real fuel costs. This risk will be included in the annual bid of the taxi-driver. To minimize the risk for the taxi driver, a practical approach is to include a regulated payment for the fuel cost, for example based on average prices.

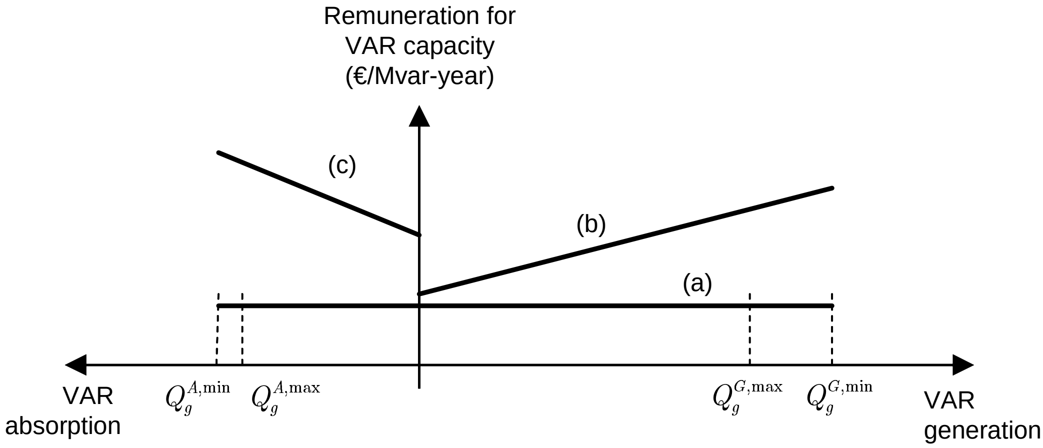

Figure 3.4: Bids for VAR capacity

Considering the practical implementation of the proposed VAR market approach, the second remuneration scheme is selected. Then, payments to the installed VAR capacity will be calculated using long-term marginal prices at each bus. The marginal prices are obtained from and optimization problem that minimizes the investment and operation costs associated with the VAR procurement (see Chapter 4). Therefore, agents participating in the market will receive efficient location and cost/value signals. Marginal pricing guarantees that all selected agents will recover their costs. Figure 3.4 shows an example of VAR capacity bids.

In addition, there is a regulated compensation for the use of the allocated VAR capacity (see Figure 3.5). The remuneration includes the sum of the VAR energy generated and the VAR energy absorbed. Payments differentiate VAR generation and absorption, due to its different costs. These regulated payments are easy to compute, taking into account the specific characteristics of each agent.

Finally, as commented in the previous section, a regulated compensation is defined for the use of the VAR capacity if the active power output is reduced. This payment will be computed for each hour, taking into account the variable cost of the generator and the clearing price for the energy market for that hour.

3.4.2 Charges to the VAR demand

A charging mechanism is designed to recover all the payments to the selected agents in the VAR capacity market. Charges are distributed among the demand of the VQ service using a methodology based on Cooperative Game Theory [Kreps, 1990]. The Cooperative Game Theory is applicable to cost allocation problems among participants that make use of the same service. Its objective is to obtain the fairest cost distribution. The approach in this thesis obtains the participation factors, also known as Aumann-Shapley values [Aumann and Shapley, 1975], on the costs of the VAR capacity market of the different agents that demand VAR support. These participation factors are obtained

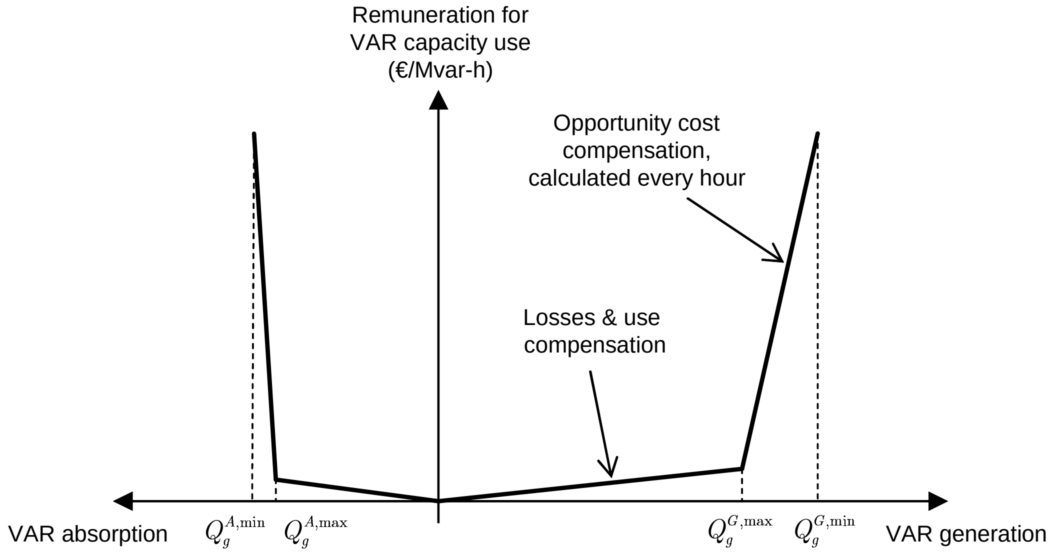

Figure 3.5: Remuneration for the use of the VAR capacity

using the marginal information that results from the equivalent optimization problem of the VAR capacity market settlement.

As described in the previous sections, the demand of the VQ service differentiates the load consumption, and system contingencies. On the one hand, loads will be charged according to their active and reactive power consumption, taking into account their influence on the VAR capacity costs. On the other hand, agents responsible for contingencies, mainly generators and transmission owners, will be charged for the additional VAR costs in the market. Charges to contingencies depend on the failure rate of the considered devices, and on the extra VAR required to guarantee system security conditions.

3.5 Monitoring and penalties

The procurement of the allocated VAR capacity is considered as correctly fulfilled when the corresponding VAR source follows the SO control actions using the allocated VAR capacity. Generators must maintain defined bus voltages within reference value, and other VAR devices must follow the SO instructions. However, the service could be correctly fulfilled with voltages out of the selected range, which is only possible when the VAR sources have already exhausted all their VAR capacity.

Once the selected VAR source has a certain purchased capacity, the SO cannot verify if that capacity really exists. Its existence will be demonstrated when the whole capacity is required under real operating conditions. As a large volume of VAR capacity is allocated to solve contingencies, it may occur that there are no contingencies for years, and so the SO will not know if the selected agent has that capacity available. Therefore, the

SO must design mechanisms for service monitoring and penalties in order to discourage market agents to declare VAR over-capacity. For example, periodic tests of selected VAR sources could be used. Under both test and real operation, if the selected agent cannot procure the allocated capacity, the agent should be penalized.

If a selected VAR source is called to solve voltage problems, and is not available, then this unavailability will be recorded and taken into account when calculating its failure rate (H_{s_g}) for the next VAR capacity auction. A failure rate increment will also increase the charges associated with contingencies to that VAR source.

The design of the penalties should discourage selected VAR sources to profit from bad practices. However, penalties should be limited to avoid discouraging VAR sources to participate in the VAR capacity market. A penalty of 1.5 times the difference of the allocated capacity and the real capacity is proposed in the case that the selected VAR source does not fulfill its obligations[12].

3.6 Conclusions

This Chapter has presented a regulatory proposal for the VQ service. The proposal is based on a VAR capacity market which can be applied to competitive energy markets.

The proposed market is based on a single product, VAR capacity. This product has the highest cost share compared with the use of the VAR capacity. The main product include a capacity range divided into VAR generation capacity and VAR absorption capacity. A homogeneous product is needed in order to compare all the VAR agents that are able to provide the service. Therefore, the VAR capacity has been characterized by its dynamic performance, and the dependence of the VAR procurement on the voltage in the transmission network. Then, annual tests are proposed to verify the main characteristics of each VAR source participating the proposed market.

Generators, capacitor banks, shunt reactors, SVCs and STATCOM devices, which are connected to the transmission network, can bid in the annual auction. Bids include VAR quantity and an associated price. The demand of the service is defined by the VAR needs during peak hours and valley hours. In addition, the over VAR requirements due to contingencies are included as a new demand agent.

An optimization algorithm is used to select the VAR sources that minimize the total system costs associated with the VAR management for the next year. The results of the optimization problem are also used to determine the payments for the selected VAR sources. Payments will be based on marginal pricing in order to receive efficient local and economic signals. Charges to demand and agents responsible for contingencies are distributed using the Cooperative Game Theory.

The correct procurement of the service needs monitoring and the definition of penalties in case of failing to provide the assigned VAR capacity. Penalty policy should discourage agents for bad practices, and encourage the correct procurement.

[12]This penalty factor was proposed in [Soler, 2001] for the secondary reserve ancillary service.

As a summary, Table 3.1 presents a comparison of different VAR capacity market proposals in the research literature which are characterized according to the model of the VQ service problem and the resulting economic flows. This thesis proposal presents a novel approach to the competitive procurement of the VQ service, based on an annual auction, which represents and advance over the traditional schemes based on centralized planning criteria. This novel competitive scheme improves the efficiency of the economic signals which are sent to the agents involved in the VQ service. In addition, this proposal attempts to improve on model limitations of previous works, taking into account the procurement of the VQ service from different VAR sources, and their dynamic voltage support in case of emergency operation. Moreover, the proposed scheme provides elasticity to the demand of the VQ service (Section 2.2.3.1) with the definition of a more complete objective function.

Table 3.1: Literature review of VAR valuation approaches

	Model of the VQ service allocation problem						Economic flows		
	Demand model	**VAR sources**	**Control area**	**VAR selection procedure**	**Objective function**	**Voltage control support**	**Procure-ment option**	**Remuneration scheme**	**Charging scheme**
Chattop95[a]	Inelastic	Generator, capacitor	Local	OPF	Losses	Static	Mandatory	ST marginal pricing	-
Rosehart00[b]	Inelastic	Generator	Global	OPF	Generation cost, distance to voltage collapse	Dynamic	-	-	-
Xu01[c]	Inelastic	Generator	Local	Value function	Security	Dynamic	-	-	-
Zhong02[d]	Inelastic	Generator	Global	OPF	VAR purchase, losses, bilateral contracts	Static	Optional	Global uniform price	-
Chattop02[e]	Inelastic	Generator	Area	OPF	VAR purchase, losses	Dynamic	Optional	ST+LT marginal pricing	ST+LT marginal pricing
Ribeiro04[f]	Inelastic	Generator	Area	OPF	VAR purchase, losses	Static	Mandatory	LT marginal pricing with A-S	-
Zhong04[g]	Inelastic	Generator	Area	OPF	VAR purchase	Static	Optional	Area uniform price	-
Frías05[h]	Elastic	Generator, capacitor	Region	Value function	Losses, Security, voltage quality	Static	Optional	Clearing price	Clearing price
Lin06[i]	Inelastic	Generator	Area	OPF	Cost of VAR from generators and capacitors	Static	Mandatory	-	ST marginal pricing with A-S
Thesis proposal	Elastic	Generator, capacitor, reactor, SVC, STATCOM	Area	OPF	VAR purchase, losses, voltage quality, security	Dynamic	Optional	LT marginal pricing with A-S	LT marginal pricing with A-S

([a][Chattopadhyay et al., 1995], [b][Rosehart et al., 2000, Rosehart et al., 2003], [c][Xu et al., 2001b], [d][Zhong and Bhattacharya, 2002c], [e][Chattopadhyay et al., 2001, Chattopadhyay and Chakrabarti, 2002], [f][Ribeiro et al., 2004], [g][Zhong et al., 2004], [h][Frías et al., 2005], [i][Lin et al., 2006], ST: short term, LT: long term, A-S: Aumann-Shapley)

3.7 References

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CHAPTER 4

VAR capacity market settlement

THIS chapter presents the formulation for the VAR capacity market settlement which is proposed in the thesis dissertation. The proposed formulation selects the best VAR capacity bids that minimize the cost of the VQ service procurement, meeting the security and operating conditions both in a normal operation scenario and under selected system contingencies. First, the VAR capacity bids of the supplier agents are analyzed. Then, a general description of the market auction and its theoretical basis are presented. The mathematical formulation of the corresponding optimization problem is then described in detail. Finally, some implementation details of the VAR capacity market settlement are analyzed. A simple illustrative case with two buses and three generators is used throughout this chapter to illustrate the theoretical discussion.

The formulation presented along the next sections includes variables in small letters and parameters in capital letters.

4.1 VAR capacity bids

The different VAR supplying agents can participate in the annual auction with bids including a volume of VAR capacity and an associated price. As described in the previous chapter, the remuneration of the service provides a compensation for the use of the purchased VAR capacity and for the loss of benefits due a reduction in the active power output in order to increase the VAR capacity. Therefore, bids should only consider those costs associated with the installed VAR capacity and those required for making the installed capacity available.

As will be presented in the next sections, the proposed market is based on long-term marginal pricing. Under this market structure only the variable costs of the VAR capacity are recognized. The adequate settlement of this market requires that the variable cost of the VAR capacity product are higher than the fixed cost ($A > I$ in (4.1)). According to economic theory, those markets where the capital costs are much higher than the variable costs ($I \gg A$ in (4.1)) are not competitive, as agents will be paid at their marginal cost (4.3), which is much lower than their average cost (4.2). Therefore, these agents will have economic losses and will quit the market [Rothwell and Gómez, 2003][1].

$$TC = I + A \cdot qa + \frac{1}{2} B \cdot qa^2 \tag{4.1}$$

$$AC = \frac{TC}{qa} = \frac{I}{qa} + A + \frac{1}{2} B \cdot qa \tag{4.2}$$

$$MC = \frac{d\,TC}{d\,qa} = A + B \cdot qa \tag{4.3}$$

where:

TC	Total cost associated with the VAR capacity (€)
AC, MC	Average and marginal cost associated with the VAR capacity (€/Mvar)
qa	Selected VAR capacity (Mvar)
A, B	Bid for VAR capacity (€/Mvar and €/Mvar^2)
I	Investment cost associated with VAR production (€)

This section first defines the structure of the VAR capacity bids of the different VAR sources. Then, the mechanism to integrate these bids in the proposed VAR capacity market settlement is described.

[1] If the average cost of single a agent offering VAR capacity falls with increases in the VAR capacity, and the marginal cost is below the average cost, then there exist *economies of scale*. In the electric industry there are some activities, such as networks, where the fixed cost is a high proportion of the total cost. This network activity is then a *natural monopoly*, and the design of a competitive market will fail to yield a market price equal to the marginal cost of production. In order to avoid market power in monopoly activities some regulation is required.

4.1.1 Bid definition

The proposed formulation for the bids includes a fixed term and a variable term which is proportional to the installed VAR capacity, as formulated in (4.4) (Appendix B presents a detailed analysis of how the bids for the different agents are calculated).

$$Bid = A + B \cdot qa \tag{4.4}$$

- The *fixed term A* is expressed in €/Mvar-year and represents the variable costs for manufacturing the VAR source. In addition, the costs for the new reinforcements in the substation and the connection to the main grid are also included in the fixed term, as they are also proportional to the VAR capacity. Finally, the expected penalties of the agent for the non-fulfillment of the service can also be incorporated in this term.
- On the other hand, the *variable term B* is expressed in €/Mvar^2-year, and comprises those costs which are proportional to the squared VAR capacity.

The application of the general bid structure for the VAR capacity market is discussed in the next subsections for generators and other compensation equipment.

4.1.1.1 Generators

The VAR capacity available in a generator has already been included in the installation cost of the power plant, according to the minimum technical requirements of the corresponding power system, and therefore is considered as a sunk cost[2]. The generator may have to undertake new investments to adapt the installation to procure the VQ service, making available the already installed VAR capacity, or to increase the VAR capacity. For instance, it can be necessary to change the transformer tap changer, to proceed with a rewind of the alternator, or to add addition static compensation. All these costs are dependent on the increase of VAR capacity and will be included in the fixed term A of the bid.

Moreover, the bid of the generator should include additional operating costs that are not included in the regulated compensation, especially those for making the VAR capacity available, and the possible penalties for non-supplying the selected capacity. These costs are more difficult to model and can be included in the bid using the variable term B.

Finally, the design of competitive bids for generators must take into account the variable costs of the competing VAR sources, especially those of capacitor banks and shunt reactors.

[2]It is important to observe that in order to procure VAR support, the generator and transformer have been over-dimensioned (compared with the size of the power plant if only active power is produced), resulting in an over cost.

4.1.1.2 Capacitor banks, shunt reactors, SVCs and STATCOM devices

These VAR sources are usually installed in an existing power substation. The investment cost comprises the engineering works to connect the VAR source to the existing substation, and the cost of the new equipment for control, measurement, monitoring and protection. On the other hand, the variable cost is proportional to the installed VAR capacity. Usually, in transmission networks the minimum installed VAR capacity is over 100 Mvar and below 500Mvar. For this capacity range it can be assumed that the capital costs are included in the variable costs, and therefore the bid can be approximated by the single parameter A (Section B.2 analyzes the VAR costs of these technologies in detail).

4.1.2 Integration of the bids in the VAR capacity market

The settlement of the VAR capacity market minimizes the purchases of VAR capacity considering certain quality and security criteria. Then, bids are included in an objective function as an additional cost term, which also includes voltage quality penalties, energy losses and redispatch costs, and non-supplied energy costs.

Generators, SVCs, and STATCOM devices can participate in the auction with two bids, corresponding to VAR capacity generation and absorption, respectively. Capacitor banks and shunt reactors can bid for their installed VAR capacity.

Due to a similar dynamic response of generators and STATCOM devices, the bids for both VAR technologies are formulated with the same equations, as presented in (4.5) and (4.6). For this purpose, the formulation considers that STATCOM devices do not produce active power.

$$A_g^G + B_g^G qa_g^G \tag{4.5}$$
$$A_g^A + B_g^A qa_g^A \tag{4.6}$$

where:

A_g^G, B_g^G	Price coefficients of the annual bid of generator g for reactive power generation capacity (€/Mvar-year,€/Mvar^2-year)
A_g^A, B_g^A	Price coefficients of the annual bid of generator g for reactive power absorption capacity (€/Mvar-year,€/Mvar^2-year)
qa_g^G, qa_g^A	Assigned reactive power generation/absorption capacity to generator g in the VAR capacity market settlement (Mvar)

On the other hand, the bids for shunt reactors and capacitor banks are formulated in (4.7) and (4.8) respectively. SVCs can be analyzed as a combination of a capacitor bank and shunt reactor with a better dynamic performance, and therefore their bids can be formulated as a combination of (4.7) and (4.8).

$$A_c^C + B_c^C qa_c \tag{4.7}$$
$$A_r^R + B_r^R qa_r \tag{4.8}$$

where:

A_c^C, B_c^C	Price coefficients of the annual bid of capacitor bank c for reactive power capacity (€/Mvar-year,€/Mvar^2-year)
A_r^R, B_r^R	Price coefficients of the annual bid of shunt reactor r for reactive power capacity (€/Mvar-year,€/Mvar^2-year)
qa_c, qa_r	Reactive power capacity assigned to capacitor bank c and shunt reactor r respectively in the VAR capacity market settlement (Mvar)

Illustrative case:

A simple power system will be used to clarify the main ideas of the VAR allocation problem under the proposed VAR capacity market. The results of the illustrative case will be presented after the theoretical discussion, below a horizontal line. A larger case study will be analyzed in Chapter 6.

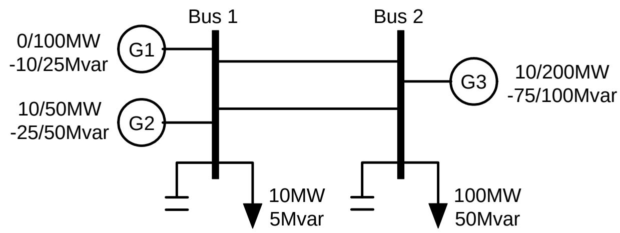

Figure 4.1: Two bus power system

The proposed illustrative case has 2 buses, 2 lines, and 3 generators. At peak hours, the load at bus #1 is 10MW and 5Mvar, and 100MW and 50Mvar at bus #2. Each circuit has an impedance of 0.03+j0.2 p.u. (base system of 100MVA and 400kV). The capacity of each circuit is 250MVA.

The capacity limits (for active and reactive power) of the VAR sources participating in the VAR market are presented in the next table. The VAR capability for generators are defined for the whole range of active power generation. The fourth column of the table includes the variable costs for active power production, which are used in the economic dispatch. Columns five to ten present the VAR capacity bids for all the VAR sources (a detailed analysis of the construction of VAR capacity bids is presented in Appendix B).

Table 4.1: Main characteristics of generators and VAR sources

	$P_g^{\min}$ (MW)	$P_g^{\max}$ (MW)	A_g^P (€/kWh)	$Q_g^{A,min}$ (Mvar)	A_g^A (€/kvar)	B_g^A (€/kvar^2)	$Q_g^{G,min}$ (Mvar)	A_g^G (€/kvar)	B_g^G (€/kvar^2)
G1	0	100	5	10	2	0	25	3	0
G2	10	50	2	25	1	0	50	2	0
G3	10	200	10	75	4	0	100	5	0
QC	-	-	-	0	-	-	500	10	0
QR	-	-	-	500	12	0	0	-	-

4.2 Market settlement

According to the analysis presented in the previous chapter, the security of a power system should be based on long-term decisions. This is the case of the VAR support service. In addition, the costs associated with the service procurement should be optimized. Therefore, decisions in the VAR capacity first market determine the best locations for the VAR sources, and secondly which are the characteristics of the selected VAR capacity. Then, the decision variables are the VAR capacity purchased to generators (qa_g^A absorption capacity, and qa_g^G generation capacity), shunt reactors (qa_r), and capacitor banks (qa_c). For simplicity, and based on their similar technical characteristics, the VAR capacity of SVCs will be considered as that provided by capacitor banks and shunt reactors; on the other hand, the VAR capacity provided by STATCOM devices is assimilated with the VAR provided by generators, with no active power output.

Most of the time the power system will be operated under steady-state conditions. However, system contingencies may occur which would require additional VAR resources to maintain system security. Therefore, decisions for the purchase of VAR capacity in the annual auction must evaluate the system security for all the possible operating situations in the following year.

The proposed VAR capacity market settlement problem is based on a single optimization problem which models the power system operation, both from the technical and economic point of view. A full AC power flow will be used to consider the effect of VAR flows, and also the common operational practices will be modeled. Decisions for VAR allocation will consider long-term or investment decisions for VAR capacity purchase, and short-term or operational costs derived from the operation of the selected sources. In addition, the single optimization problem simultaneously considers different operation scenarios. The scenarios are divided into operation under normal conditions, and operation under contingencies. Each scenario is characterized by its expected duration H_s, measured in hours per year (see Figure 4.2), and based on the failure rates of the equipment failed in each contingency.

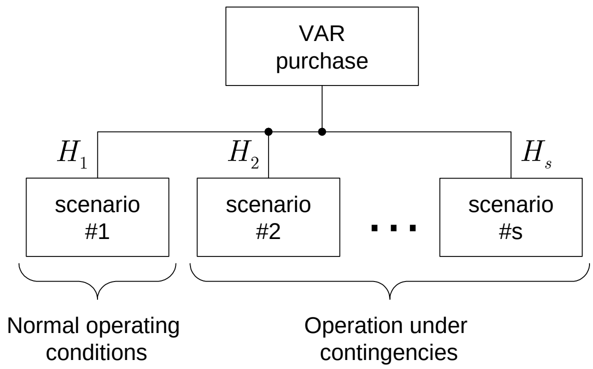

Figure 4.2: VAR capacity market settlement

This section first analyzes the VAR support under normal operating scenarios. Then, the mechanism to build and select the contingency scenarios is described. The decoupling of the resulting set of scenarios depending on the load consumption is then discussed. Finally, a general overview of the proposed VAR capacity market is presented.

4.2.1 Normal operation scenario

The analysis of the VAR needs in a power system which is operated under normal conditions is determined by the load consumption on different periods, mainly peak and low demand hours, and by the generation scheduling to cover that load, as it is described in this section.

4.2.1.1 VAR demand variation

VAR support in normal operation scenarios is mainly sized according to two operating situations, corresponding to peak demand and low demand hours. The operation under normal conditions is characterized, by the availability of all devices in the power system, including network devices, generators and other auxiliary equipment. The scheduled maintenance of the equipment will try to avoid unavailabilities during peak hours.

- During *peak demand hours*, loads consume their highest VAR. Then, the transmission system as a whole consumes reactive power and voltages tend to decrease. According to electricity laws, to keep the local energy balance of VAR certain, VAR must be generated from generators and other VAR sources. Therefore, this operating state settles the requirements for the VAR generation needs.
- On the other hand, during *low demand hours*, the reactive power consumed by loads is at their minimum. Under this situation, the transmission network usually behaves like a big capacitor, generating VAR and consequently rising voltages. To operate under secure conditions, additional VAR absorption is needed to compensate the transmission network VAR generation. Therefore, the needs of the power system for VAR absorption are mainly defined during low demand hours.

Moreover, the operation of the power system in-between these two extreme situations can be consequently managed with the VAR planned for the peak and low-demand scenarios.

Illustrative case:

A typical daily load curve has been analyzed in this illustrative case. We assume that the loads maintain their power factors for their full range of active power variation. Generators #1 and #2 will adjust the voltage in bus #1 at 1.03 p.u. providing the corresponding VAR. Therefore, the total VAR demand in the power system will equal the VAR procured by generators.

From the following figure it is clear that the demand of VAR in the illustrative case is correlated with the load curve. The difference between the VAR load and total demand is the VAR consumed by the transmission network, which varies with the system loading. Observe that this consumption is higher during peak hours than during low demand hours (due to the simplicity of the illustrative case, the network does not generate VAR).

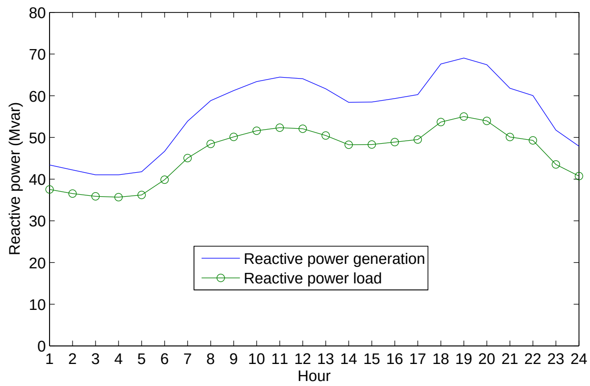

Figure 4.3: Daily evolution of VAR load and total VAR demand

4.2.1.2 Active power dispatch

The aim of the VAR capacity market settlement is to work with scenarios as close as possible to the real operating situations. For this purpose, an input to the VAR market settlement is the economic dispatch of generators, consisting of the scheduling of active power production for peak and low-demand hours. Since the economic dispatch usually does not consider the network, an estimation of the transmission energy losses is also provided.

As will be explained in the following sections, generator scheduling can be modified in the VAR capacity market, which includes the transmission network. The main causes for the output changes are the energy losses adjustment with the network, and possible constraints due to line congestion or low voltage problems which are solved by changing the output of generators. In order to guarantee that the output changes are achieved at minimum cost, the variable cost of generators are also an input to the VAR capacity market settlement.

Illustrative case:

In the illustrative case, a economic dispatch using generation variable costs A_g^P is carried out, and the output of generators in the base case is settled P_g^0 . Generator #1 is dispatched at 50MW, and 50MW for generator #2. As described in the next section, generator #3 is started-up at its minimum output in order to prevent non-supplied energy in the case of generator #2 unavailability. Therefore, the resulting economic dispatch is, 50MW, 50MW and 10MW for generators #1, #2 and #3 respectively. Since generator #1 is the marginal one, it will cover the energy losses.

4.2.2 Contingency scenarios

Contingency situations generally require additional VAR capacity with an adequate dynamic VAR support in order to guarantee system security. This section describes how contingency scenarios are built and characterized, and also presents a procedure to select the critical scenarios for the proposed VAR capacity market.

4.2.2.1 Main characteristics

The VAR capacity market settlement also considers certain probable contingencies in the power system. Contingencies can be the result of single or multiple changes in the normal operating conditions, such as generator outages, transmission equipment unavailability, or high changes in load. Each contingency is characterized by a set of states of the different power system devices and an associated probability of occurrence. For the proposed optimization problem, the failure probability will be calculated separately for peak and low demand hours.

We assume that under contingencies the power system reacts using the primary and secondary control mechanisms. Both active power-frequency control and reactive power-voltage control correct the deviations in the system variables. The speed governors and the AGC (Automatic Generation Control) modify the active power output of selected generators in order to cover the active power imbalance due to generation outage or load variation. The AVR (Automatic Voltage Regulator) and the secondary voltage control loop (if installed) adjust the position of VAR resources to maintain voltages within the security range.

The proposed formulation for the VAR capacity market will include a contingency in the optimization problem with additional constraints. The number of contingencies to be formulated is restricted by the characteristics of the solver and software tools used to solve the optimization problem. The number of possible operating scenarios resulting for the state of i devices with a non-zero failure rate will be 2^i.

For real power systems the number of possible scenarios would be very high, and moreover not all of these possible scenarios are worth analyzing, as their associated impact on the VAR investments is marginal. Therefore, in order to simplify the analysis, a preselection of the most important situations is required before including the contingency scenarios in the formulation.

The set of contingencies included in the VAR capacity market model are those with the highest impact on VAR requirements. A first approach to select the contingencies would be to rely on the intuition and experience of the SO, who can effectively rank the different contingencies in the power system. However, there are automatic contingency selection algorithms that can assist the SO to select the most critical contingencies, by providing an objective criterion for this assessment [Ejebe and Wollenberg, 1979]. These methods are known as *contingency screening and ranking* [Ekwue, 1991, Ejebe et al., 1995], and are usually based on the accurate and fast estimation of the voltage stability margin for all the possible contingencies. The approach used in this thesis dissertation is the Monte-Carlo simulation methodology [von Neumann, 1951]. Under this approach the proposed formulation for the VAR capacity market settlement is solved for different scenarios defined by the failure rates of the power system devices. This method is simple, and efficiently ranks the contingencies according to their effect on the total costs of the VAR capacity market.

4.2.2.2 Contingency selection

The Monte-Carlo simulation generates a set of random numbers that will define a possible operating situation [Law and Kelton, 1997]. To determine the availability of each power system device, a random variable with uniform distribution [0,1] is generated for each device. A mixed congruential generator is used to generate the set of random numbers x_n,

$$x_{n+1} = (a \cdot x_n + c)\,[mod(m)] \tag{4.9}$$

$$u_n = \frac{x_n}{m} \tag{4.10}$$

where:

a, c, m	Positive integer numbers, with $a < m, c < m$
$mod(m)$	A modulo operation finds the remainder of division of one number by another
x_n	Random number
u_n	Random number with a uniform distribution

Random numbers are obtained as a modulo operation involving the previous random number. The number of possible different random numbers to be generated is defined by m. Then, if the random value u_n is lower than the probability failure of the device

$f(i)$, that power system device will be unavailable. If the random value is higher than the probability failure, then the device will be available.

Once all the possible scenarios are generated, the settlement of the VAR capacity market and its cost are obtained for each single scenario using the formulation presented in the following sections. Then, the associated costs for each scenario are classified from the highest to the lowest, and those scenarios with the highest impact on the costs of the VAR market are selected. Finally, the settlement of the VAR capacity market is obtained simultaneously including all the selected scenarios.

Illustrative case:

For this illustrative case, the equipment that defines the possible operating scenarios consists of 2 generators and a circuit of the transmission line. The next table presents the total number of scenarios is $2^3 = 8$, corresponding to the device states (On) available, and (Off) unavailable.

Table 4.2: Scenario generation

Scenario #	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**
Single circuit	On	Off	On	On	Off	On	Off	Off
Generator 2	On	On	Off	On	Off	Off	On	Off
Generator 3	On	On	On	Off	On	Off	Off	Off

An example of the contingency selection for peak hours is presented with an estimated duration of 1000 hours-year. The probability failure of the different devices considered is presented in the next table.

Table 4.3: Failure rates in the illustrative case

	Failure rate
Single circuit	0.0094
Generator 2	0.0157
Generator 3	0.0315

A Monte Carlo simulation generated 10000 possible operating scenarios using a uniform distribution. A random number generator based on Coveyou & MacPherson [Carrasco and Fernández, 1996, Coveyou and Macpherson, 1967] is used, which is defined by $a = 5^6$, $c = 1$, $m = 2^{35}$. The equivalent hours of occurrence of each scenario are obtained by multiplying its probability times the total number of peak hours per year.

Table 4.4: Monte Carlo simulation failure results

Operating scenario	**Single circuit**	**Gen. 2**	**Gen. 3**	**Probability of occurrence**	**Hours in peak load**
1	On	On	On	0.9444	944.4
2	Off	On	On	0.0099	9.9
3	On	Off	On	0.0143	14.3
4	On	On	Off	0.0308	30.8
5	Off	Off	On	0.0002	0.2
6	On	Off	Off	0.0002	0.2
7	Off	On	Off	0.0002	0.2
8	Off	Off	Off	0	0

The optimization problem for VAR allocation is solved individually for each contingency scenario (the complete formulation is presented in the next sections). The following table presents the costs associated with each possible scenario. The contingencies that determine most of the VAR needs are #4 and #5.

Table 4.5: Costs associated with each scenario

Operating scenario	**Single circuit**	**Gen. 2**	**Gen. 3**	**Total VAR cost (k€-year)**
1	On	On	On	368
1+2	Off	On	On	470
1+3	On	Off	On	392
1+4	On	On	Off	449
1+5	Off	Off	On	388
1+6	On	Off	Off	444
1+7	Off	On	Off	442
1+8	Off	Off	Off	368

The differences between the costs of the VAR capacity market for the different operating scenarios are very small. For illustrative purposes, a comparison for the VAR capacity market settlement between the full set of scenarios, and the elimination of scenarios #3, #5 and #8 is presented in the next table. It is observed that the VAR purchases are quite similar under both approaches. The analysis based on the reduced number of scenarios is very efficient in a large scale power system; due to the simplicity of the illustrative case, in the following sections the VAR capacity market will consider the full set of scenarios.

Table 4.6: Comparison between complete and reduced problem formulation

	qa_1^G (Mvar)	qa_2^G (Mvar)	qa_3^G (Mvar)	qc_2 (Mvar)
Full set of scenarios	25	34	49	9
Scenarios 1+2+4+7	25	36	49	7

4.2.3 VAR allocation problem decoupling

For the sake of simplicity, it seems reasonable to divide the VAR capacity market settlement into two independent sub-problems, associated with peak and low demand hours. The reason for this decoupling is twofold:

- The total VAR demand in each power area clearly depends on the load consumption, as was presented in Section 4.2.1.1.
- The generation dispatch and the state of the different transmission devices also depend on the load period. This consideration is critical as it defines the VAR capacity available in each period, mostly determined by the generation units.

Then, a first sub-problem will model the operating situations associated with peak hours, including generation dispatch, VAR load, and the critical contingencies for that period. This first sub-problem will mainly determine the requirements for VAR generation allocation. On the other hand, a second sub-problem will model operating situations associated with low demand hours, defined by the generation dispatch and network devices states, together with the critical contingencies for that period. The second sub-problem will determine a VAR generation allocation (the capacity allocated will be usually lower than the requirements in peak hours) and, if necessary, the VAR absorption needs.

The impact of contingencies on VAR needs clearly depends on the load volume. For example, a line trip in peak load will usually need more VAR as the power flow in the neighboring lines will increase. However, a trip of the same line during low demand hours may improve voltages, as the network VAR generation is reduced.

Then, the calculation of the VAR needs for a whole year is based on the needs in two normal operating scenarios for peak and low demand hours. It is assumed that in other load situations, mostly plain hours, the VAR needs are covered by the two extreme scenarios. This simplification may lead to a sub-optimal VAR allocation, as the best decision should be taken in the formulation that includes all load periods. However, in practice, the difference in the optimum solution between both alternatives is very low compared with the simplicity in the formulation and the analysis of the results.

4.2.4 General overview of the market proposal

A summary of the methodology used for the settlement of the VAR capacity market is presented in Figure 4.4. First, the bids of the different VAR supplying agents are received by the SO, both for VAR capacity generation and absorption. Then, the SO defines the demand of the VAR, based on the operating conditions for peak and low-demand hours. Additionally, the failure rates of the power system devices settle the possible contingency scenarios, which are then filtered according to their single impact on the VAR market cost. Finally, the SO selects the optimal bids that minimize the short term and long term costs associated with the VQ service. For this purpose, the

VAR capacity market settlement is decoupled in different voltage control areas, and for peak and low-demand hours. The resulting market settlement selects the amount of VAR capacity to the supplying agents.

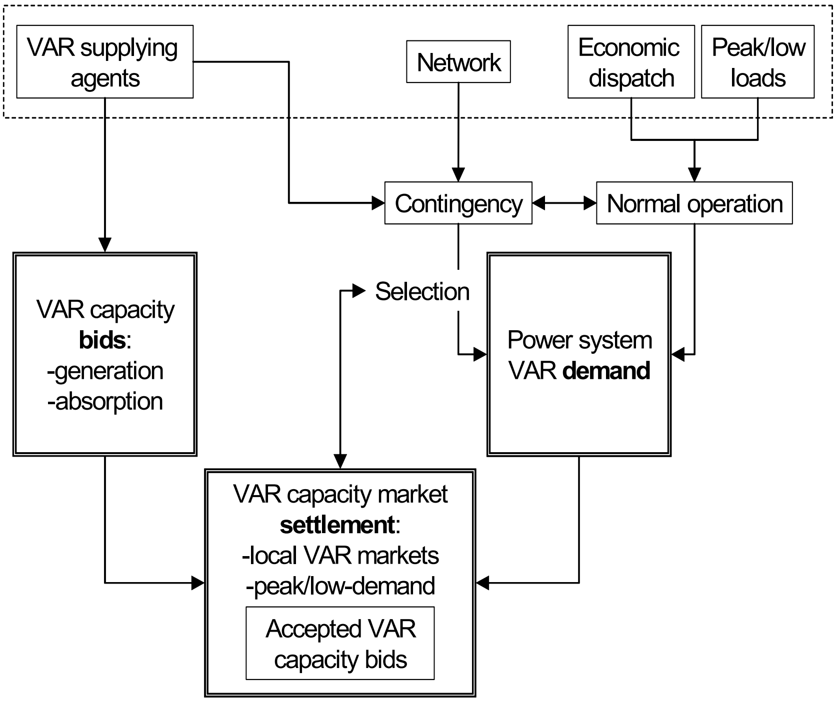

Figure 4.4: General overview of the VAR allocation problem

4.3 Optimization problem formulation

This section describes the mathematical approach to the VAR capacity market settlement, which is based on an optimization problem. First, the objective function of the resulting optimization problem is presented, and all its components are defined. Then, the constraints of the optimization problem approach are detailed and classified in different groups.

4.3.1 Objective function

The aim of the VAR capacity market settlement is to find the best security and quality levels at the minimum cost. This is a multi-objective optimization problem, based on the trade-off between the quality of the VQ service procurement and the cost for providing that level of quality (usually, the maximum security level is not at the minimum cost). For instance, the appropriate VAR management can reduce transmission energy losses by increasing the voltage level, which additionally results in a better voltage quality for distributors. Moreover, by acquiring a certain level of VAR capacity, above that used under normal operation, we can guarantee the security of the power system in the case of a contingency. Finally, some generator units can be redispatched, by connecting them or decreasing their output, in order to make more VAR capacity available to the power system, instead of acquiring static VAR compensation capacity.

Then, the objective function of the VAR capacity market settlement is formulated as the sum of the costs for purchasing VAR capacity, plus the expected payments for the VAR capacity use, the energy losses change, the generation redispatch costs, and penalties due to voltage quality, and non-supplied energy (4.11).

$$\min \{C_{QC} + C_{QE} + C_V + C_D + C_P\} \tag{4.11}$$

where:

C_{QC}	Annual costs associated with the procurement of VAR capacity (€-year)
C_{QE}	Expected annual costs of the regulated payment for VAR capacity use (€-year)
C_V	Expected annual costs for voltage deviations (€-year)
C_D	Expected annual costs of non-supplied energy (€-year)
C_P	Expected annual costs of generation redispatch (€-year)

The different cost terms in the objective function are described in the following subsections: (i) VAR capacity purchase, (ii) regulated VAR energy compensation, (iii) voltage deviation costs and non-supplied energy, and (iv) active power dispatch and energy losses.

4.3.1.1 VAR capacity purchase

The cost for the assignment of VAR capacity is given by equation (4.12). First, the cost for the purchase of VAR capacity to generators and STATCOM devices is defined for both VAR generation capacity and VAR absorption capacity. The cost is obtained as the allocated VAR capacity times the bid price for that selected capacity. On the other hand, the cost associated with the purchase of capacity to capacitor banks, shunt reactors and SVCs has been modeled as their bid price times their assigned capacity.

$$\begin{aligned} C_{QC} \;=\; & \sum_g qa_g^G \left(A_g^G + B_g^G qa_g^G\right) + \sum_g qa_g^A \left(A_g^A + B_g^A qa_g^A\right) \\ & \sum_c qa_c \left(A_c^C + B_c^C qa_c\right) + \sum_r qa_r \left(A_r^R + B_r^R qa_r\right) \end{aligned} \tag{4.12}$$

where:

qa_g^G, qa_g^A Generation/absorption VAR capacity purchased to generator g

qa_c VAR capacity purchased to capacitor bank c

qa_r VAR capacity purchased to shunt reactor r

4.3.1.2 Regulated VAR energy compensation

According to the market proposal, selected market participants can receive a regulated payment for the VAR energy. This cost is included in the objective function as C_{QE}, and is formulated in (4.13).

The general formulation of the VAR production cost differentiates VAR generation and VAR absorption for generators. A quadratic function is used to remunerate the VAR production costs, as discussed in Appendix B and [Barquin et al., 1998], which considers the incremental energy losses due to VAR production. VAR compensation by capacitor banks, shunt reactors, SVCs and STATCOM devices are not remunerated for the VAR capacity use, as the incremental costs can be neglected. The VAR energy compensation coefficients are regulated (A_g^{EA} and A_g^{EG}) and set by the SO.

$$C_{QE} = \sum_{s \in S} H_s \left\{ \sum_g \left[A_g^{EA} \left(q_{g,s}^A \right)^2 + A_g^{EG} \left(q_{g,s}^G \right)^2 \right] \right\} \tag{4.13}$$

where:

H_s Duration of a scenario s (hours)

A_g^{EA}, A_g^{EG} Regulated compensation of the VAR capacity use for generator g, for VAR absorption and VAR generation (€/Mvar^2-h)

$q_{g,s}^A, q_{g,s}^G$ Reactive power absorption/generation from generator g in scenarios s (Mvar)

Calculation example:

The incremental energy losses in a generator, due to the production and absorption of VAR, will consider the costs in the alternator (field and armature) and the transformer. The energy losses are formulated in (4.14), as the squared current times the resistance. Currents in the generator and transformer depend on the actual active and reactive power output and on the voltage at generator terminals. The field current is formulated as a linear function of the VAR output, based on the maximum field current $i_{fld,\max}$, and the field current for rated voltage $i_{fld,0}$.

$$Losses = i_{est}^2 r_{est} + i_{fld}^2 r_{fld} + i_{trf}^2 r_{trf} \tag{4.14}$$

The VAR energy actually measured by the SO is that which is on the high side of the transformer, which is q_{trf}. The VAR flowing in the armature q_{est} should consider the VAR consumed by the transformer, and that of the auxiliaries q_{aux}. A detailed model of a generic generator is presented in Appendix B.

$$q_{est} = q_{trf} + i_{trf}^2 x_{trf} + q_{aux} \tag{4.15}$$

An approximate value of losses in a generator is 0.5% of their rated output, and 0.3% for power transformers. The resulting losses for a power plant example are shown in the next figure. In order to obtain the energy losses variation in per unit of the rated power of the generator, an approximate squared function is used (4.16), including VAR generation and absorption. The proposed function (dashed line in the figure) clearly matches variation (solid line with circles) with the real losses, to obtain the energy remuneration, the previous functions are multiplied by the average price of active power in the corresponding year.

$$\Delta Losses = 0.0064 \cdot \left(q_{g,s}^G\right)^2 + 0.0008 \cdot \left(q_{g,s}^A\right)^2 \tag{4.16}$$

Energy losses in static VAR are very low, in the range of 0.1% of the actual VAR output (this value applies to both air-core reactors and capacitor banks), hence it is assumed that there is no compensation for the incremental losses.

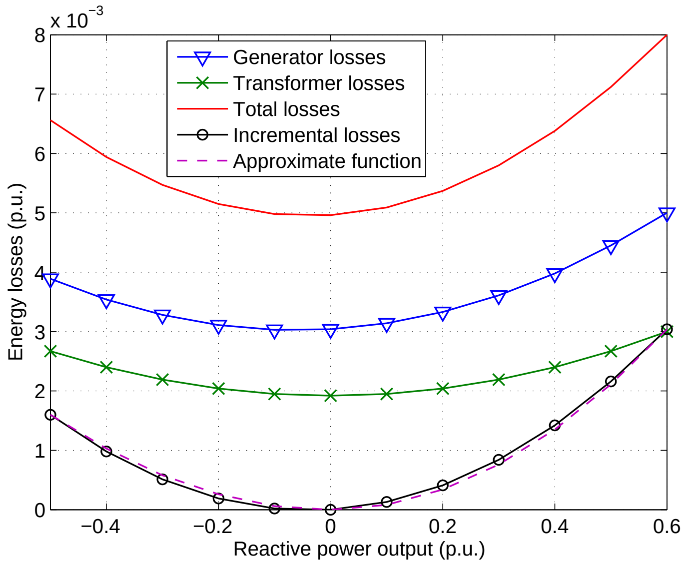

Figure 4.5: Energy losses variation in a generation power plant

4.3.1.3 Voltage deviation costs

The objective function of the VAR capacity market settlement also includes expected operation costs due to voltage deviations out of certain quality and security ranges. Real

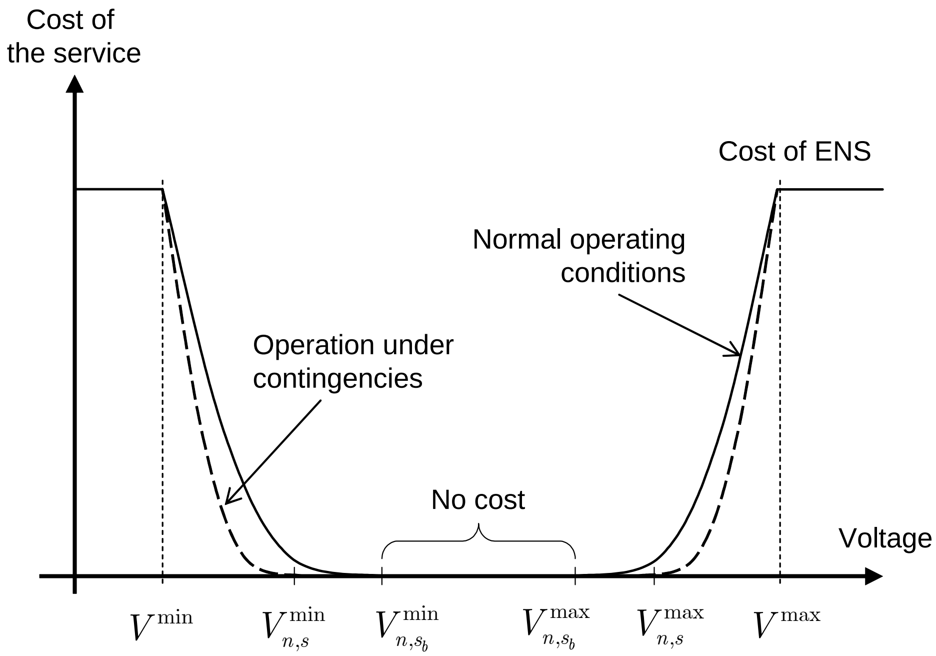

Figure 4.6: Voltage deviation costs

costs arise when low voltages require load shedding. Moreover, when voltages have *low quality*, control actions should be performed on the distribution side, and sensitive loads may suffer damages. These situations can be economically evaluated using approximate penalizations[3].

In order to valuate the voltage deviations at the buses, two voltage ranges have been defined (see Figure 4.6), a reference voltage range, and a security voltage range [Frías et al., 2005]:

- Generally, a *reference voltage range* $\left(V_{n,s_b}^{min}, V_{n,s_b}^{max}\right)$ is defined by the SO for each voltage control area of the power system, or to specific buses. This range takes into account the operation experience of the SO and, in some power systems a general optimization of the power system[4]. If voltage is within this reference range, then there is no penalization. Under contingency situations, the reference range is relaxed to a wider range $(V_{n,s}^{min}, V_{n,s}^{max})$.

[3] A similar, but more simplistic approach to include voltage quality in the optimization problems has been suggested in [Kim et al., 2004].

[4] Every year, the Spanish SO (Red Eléctrica) defines a set of reference voltage ranges for the five electric regions in Spain and for the three demand periods (peak, plain and low demand hours). Some strategically located generation buses receive specific voltage ranges. Reference ranges for 400kV during peak hours are usually 410-420kV, and 410-415kV for low demand hours. In 220kV transmission network the reference range for all demand periods is usually set at 230-235kV.

- For security reasons, and based on engineering practices, voltage in the transmission network should be within a certain *security range* (V^{min}, V^{max}). If voltage is out of this range, low voltage relays may disconnect load to avoid a local or general blackout of the power system. The load shedding cost is formulated in (4.17) using a penalty factor A_D. This coefficient is usually defined by the Energy Regulator[5], and is associated with the active non-supplied energy. Therefore, there is an efficient cost signal for voltages to be within the security range.

$$C_D = A_D \sum_s \left[H_s \sum_n (d_{n,s} PD_n) \right] \tag{4.17}$$

where:

A_D	Penalty for the non-supplied energy (€/MWh)
$d_{n,s}$	Continuous variable [0-1] that represents the portion of energy not supplied at bus n in scenario s
PD_n	Active power demand at bus n (MW)

- For voltages not in the reference range, but within the security band, a quadratic penalty is proposed. This cost represents the economic impact on the distributor business due to having one or another voltage in the supply point (a detailed analysis is presented in Appendix C) shows the importance that the distributor feels for a certain voltage value. The voltage value function is defined by the operation costs incurred by the distribution utilities to maintain voltages in the customers side within admissible ranges. If no control action were provided, then there would be a cost associated to the loss of voltage quality for the load connected downstream. Therefore, the penalty is proportional to the load connected to each bus, as formulated in (4.18). The penalty function considers different costs for under and over voltages. Moreover, two penalty curves will be designed for normal operating situations and operation under contingencies.

$$C_V = \sum_s H_s \sum_n PD_n \left[A^U_{V,s} \left(\Delta v^{\min}_{n,s}\right)^2 + A^O_{V,s} \left(\Delta v^{\max}_{n,s}\right)^2 \right] \tag{4.18}$$

where:

$A^U_{V,s}, A^O_{V,s}$	Penalty for under and over voltage deviations for the scenario s (€/MWh/kV^2)
$\Delta v^{min}_{n,s}, \Delta v^{max}_{n,s}$	Undervoltage and overvoltage deviations in bus n and scenario s(kV). The voltage deviation $\Delta v^{max}_{n,s}$ is defined for the range V^{max} and $V^{max}_{n,s}$, and $\Delta v^{min}_{n,s}$ is defined for the range V^{min} and $V^{min}_{n,s}$,.

[5]The Non-Supplied Energy penalty is usually in the range of 10 to 100 times the average energy price in €/kWh.

Illustrative case:

In Europe the price for non-supplied energy varies between 0.5€/kWh in Norway to 9€/kWh in France [Malaman et al., 2001, Billinton, 2002]. In this thesis dissertation, a compensation for the load shed A_D of 6 €/kWh is proposed. We also assume that the voltage security range is set to 0.8-1.2 p.u., and the reference voltage range is 0.98-1.03 p.u. Therefore, a quadratic penalty function is defined for voltages in the range 0.8-0.98 p.u. and 1.03-1.2 p.u., as shown in the next figure. Voltages below 0.8 p.u and above 1.2 p.u. will incur in non-supplied energy cost. The resulting coefficients for voltage deviations under normal operating conditions are A^U_{V,s_b}=185 €/kWh/pu^2, and A^O_{V,s_b}=208 €/kWh/pu^2, assuming that voltages are expressed in p.u.

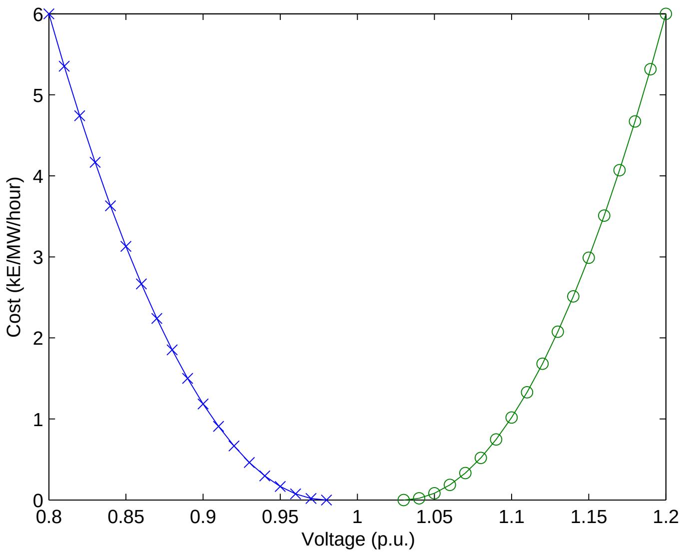

Figure 4.7: Voltage deviations cost

4.3.1.4 Active power redispatch and energy losses

An input to the VAR capacity market settlement is the generator dispatch P^0_g resulting from the energy market. As the energy dispatch usually does not consider the network, the volume of energy losses is estimated. The VAR capacity market settlement formulation includes the network, so the generator dispatch can be changed. The generator can be redispatched according to the following reasons:

i) The estimated energy losses differ from the calculated losses including the network.

ii) System constraints associated with congestion lines or voltage problems are solved by the redispatch of certain generators.

iii) The need of additional VAR capacity provided by a generator may require the reduction of that generator output.

The previous causes for generator redispatch are included in the objective function for the base scenario as an additional cost (4.19). The generator output under contingencies is not included in the formulation, as their output is settled by the corresponding emergency control loop, for instance the AGC (Automatic Generation Control), which distributes the active power production according to the generator active power ramps.

$$C_P = H_{s_b} \sum_g A_g^P \left(p_{g,s_b} - P_g^0\right) \tag{4.19}$$

where:

H_{s_b}	Duration of the base scenario (hours)
A_g^P	Variable production cost of generator g (€/MWh)
p_{g,s_b}	Active power generation from generator g in the base scenario s_b (MW)
P_g^0	Active power dispatched for generator g in the energy market (MW)

If the generator is called by the SO to reduce its original dispatch in order to increase its VAR capacity, then the generator will lose some revenues in the active power market. This loss of revenues is calculated as the difference between the clearing price and the variable costs of the generator, multiplied by the active power reduced. As commented in the previous chapter, this loss of revenues will be compensated to the generator, and therefore should be included as an additional cost in the objective function in the VAR capacity market settlement. This cost is known as *opportunity cost,* and it is already included in the formulation in (4.19), as (4.19) can be obtained as the simplification of (4.20) which includes the term for the incremental costs of redispatching generators, based on the difference of the clearing price in the active power market and the variable costs, and the term of the opportunity cost.

$$C_P = H_{s_b} \left[\sum_g \left(A_g^P - MP\right) \left(p_{g,s_b} - P_g^0\right) + \sum_g \left(MP - A_g^P\right) \left(p_{g,s_b} - P_g^0\right) \right] \tag{4.20}$$

where:

MP	Clearing price in the energy market (€/MWh)

4.3.2 Constraints

The constraints of the optimization problem approach for the VAR capacity market are detailed in the next subsections, which are classified in six different groups: (i) full AC power flow equations, (ii) operation limits, (iii) VAR capacity purchase constraints, (iv) dynamic VAR performance constraints, (v) contingency scenario modelling equations, and (vi) VAR capacity reserve constraints.

4.3.2.1 AC power flow

The power system behavior has been modeled with the full AC power flow equations (4.21)(4.22). Power flow equations are formulated for each considered scenario. A decision variable $d_{n,s}$ determine the amount of load to be disconnected, which affects both active and reactive power. Other decision variables identify the static compensation needed both for capacitor banks and shunt reactors based on their used capacity $q_{c,s}$ and $q_{r,s}$ respectively[6]. The procurement of static devices depends on the voltage magnitude at the connected bus.

$$\begin{aligned}&\sum_{g\in n} p_{g,s} - (1-d_{n,s})\,PD_n = \\ &v_{n,s}\sum_{m} v_{m,s}\left[g_{nm,s}\cos(\theta_{n,s}-\theta_{m,s}) + b_{nm,s}\sin(\theta_{n,s}-\theta_{m,s})\right] \\ &\forall n,m\in N, s\in S\end{aligned} \tag{4.21}$$

$$\begin{aligned}&\sum_{g\in n}\left(q^G_{g,s} - q^A_{g,s}\right) + \sum_{c\in n} q_{c,s}v^2_{n,s} - \sum_{r\in n} q_{r,s}v^2_{n,s} - (1-d_{n,s})\,QD_n = \\ &v_{n,s}\sum_{m} v_{m,s}\left[g_{nm,s}\sin(\theta_{n,s}-\theta_{m,s}) - b_{nm,s}\cos(\theta_{n,s}-\theta_{m,s})\right] \\ &\forall n,m\in N, s\in S\end{aligned} \tag{4.22}$$

where:

$q^G_{g,s}, q^A_{g,s}$	Reactive power generation/absorption from generator g in scenario s (Mvar)
$q_{c,s}, q_{r,s}$	Reactive power switched on by a capacitor bank c/shunt reactor r in scenario s (Mvar)
$d_{n,s}$	Continuous variable [0-1] that represents the portion of energy not supplied energy at bus n in scenario s
$v_{n,s}$	Voltage at bus n in scenario s (kV)
$\theta_{n,s}$	Voltage angle at bus n in scenario s (rad)
$g_{nm,s}, b_{nm,s}$	Real and imaginary part of the admittance matrix corresponding to buses n and m for scenario s (℧)

The transformers in the transmission network are included in the formulation by modifying the terms of the admittance matrix. The terms to be modified are those corresponding to the two buses where the transformer is connected, as formulated in (4.23) to (4.26).

[6] As the problem is formulated using per unit system, the susceptance of capacitor banks and shunt reactors equals their corresponding capacity $q_s = b_s$.

$$g_{nn,s_b} = \sum_{v \top n/m} Y^c_{nv} + \frac{Y^c_{nm}}{(rt_{nm})^2} \quad (4.23)$$

$$b_{nn,s_b} = \sum_{v \top n/m} Y^s_{nv} + \frac{Y^s_{nm}}{(rt_{nm})^2} \quad (4.24)$$

$$g_{nm,s_b} = \frac{Y^c_{nm}}{rt_{nm}} \quad (4.25)$$

$$b_{nm,s_b} = \frac{Y^s_{nm}}{rt_{nm}} \quad (4.26)$$

where:

rt_{nm} Tap ratio of transformer located in between buses n and m

Y^c_{nm}, Y^s_{nm} Real and imaginary terms of the admittance between buses n and m

$v \top n/m$ All buses v connected to n except m

4.3.2.2 Operation limits

According to the proposed mechanism for voltage deviation penalty, voltage deviations under and over the reference range are defined in (4.27) and (4.28), using the slack variables $\Delta v^{\min}_{n,s}$ and $\Delta v^{\max}_{n,s}$. The security voltage range is formulated in (4.29).

$$V^{\min}_{n,s} - \Delta v^{\min}_{n,s} \leq v_{n,s} \qquad \forall n \in N, s \in S \quad (4.27)$$

$$v_{n,s} \leq V^{\max}_{n,s} + \Delta v^{\max}_{n,s} \qquad \forall n \in N, s \in S \quad (4.28)$$

$$V^{\min} \leq \ v_{n,s} \leq V^{\max} \qquad \forall n \in N, s \in S \quad (4.29)$$

In addition, certain limits are defined for the voltage angle in order to obtain feasible operating points (4.30). The angle at the swing bus ns is set at zero (4.31).

$$-\pi \leq \theta_{n,s} \leq \pi \qquad \forall n \in N/\left\{ns\right\}, s \in S \quad (4.30)$$

$$\theta_{ns,s} = 0 \qquad \forall s \in S \quad (4.31)$$

Limits for the transmission line current are also considered (4.32). The selected limiting power will be the most restrictive, which corresponds to that of summer time.

$$sl_{l,s} \leq SL^{\max}_l \qquad \forall l \in L, s \in S \quad (4.32)$$

where:

$sl_{l,s}$	Apparent power flow in line l and scenario s
$SL_l^{\max}$	Transmission capacity of line l (MVA)

Maximum and minimum active power generation are required in order to limit the generation redispatch[7] (4.33). This constraint is only active if the generator is dispatched, $u_g = 1$.

$$u_g P_g^{\min} \leq p_{g,s} \leq u_g P_g^{\max} \qquad \forall g \in G, s \in S \tag{4.33}$$

where:

u_g	Binary variable [0,1] (1 if generator g is dispatched, 0 otherwise)
$P_g^{\min}, P_g^{\max}$	Minimum and maximum active power generation of generator g (MW)

Transformer tap ratio $rt_{l,s}$ must be within their maximum and minimum rating values (4.34). Step-up transformers in power plants and distribution transformers are not included in the formulation, as the VAR support is provided in the connection point to the transmission network. Therefore, this constraint applies to transformers in the transmission network, which connect different voltage transmission levels[8].

$$RT_l^{\min} \leq rt_{l,s} \leq RT_l^{\max} \tag{4.34}$$

where:

$rt_{l,s}$	Tap ratio of transformer located in between buses n and m which define the line l
$RT_l^{\min}, RT_l^{\max}$	Minimum and maximum rating values of the transformer tap ratio (p.u.)

4.3.2.3 VAR capacity purchases

Each selected VAR source can be required to produce reactive power within its assigned VAR capacity in the year of the auction, (4.35) to (4.38). Additionally, the VAR capacity purchases arranged in previous auctions are also considered.

[7] For simplicity, the start-up cost of generators is not included in the objective function. To include them in the formulation of the VAR capacity market, an additional variable is needed to represent that the generator has been started-up u_g^s. In addition, a parameter representing the state of the generator after the economic dispatch U_g^0 will inform on the start-up. Then $u_g^s = 1$ only if $U_g^0 = 0$ and $u_g = 1$. This condition can be formulated by including new constraints in the proposed formulation.

[8] These units are typically auto-transformers of 400/220kV, 400/132kV or 220/132kV.

$$0 \leq q^A_{g,s} \leq qa^A_g + QA^{A0}_g \qquad \forall g \in G \ , s \in S \tag{4.35}$$

$$0 \leq q^G_{g,s} \leq qa^G_g + QA^{G0}_g \qquad \forall g \in G \ , s \in S \tag{4.36}$$

$$0 \leq q_{c,s} \leq qa_c + QA^0_c \qquad \forall c \in C, s \in S \tag{4.37}$$

$$0 \leq q_{r,s} \leq qa_r + QA^0_r \qquad \forall r \in R, s \in S \tag{4.38}$$

where:

$q^A_{g,s}, q^G_{g,s}, q_{c,s}, q_{r,s}$	Output of the reactive power sources (Mvar)
$qa^A_g, qa^G_g, qa_c, qa_r$	Assigned reactive power capacity (Mvar)
$QA^{A0}_g, QA^{G0}_g, QA^0_c, QA^0_r$	Reactive power capacity assigned in previous auctions (Mvar)

The installation of compensating devices in a selected bus may be limited by physical restrictions, such as technical constraints in the substation, as formulated in (4.39) and (4.40).

$$qa_r + QA^0_r \leq Q^{\max}_r \qquad \forall r \in R \tag{4.39}$$

$$qa_c + QA^0_c \leq Q^{\max}_c \qquad \forall c \in R \tag{4.40}$$

where:

$Q^{\max}_c, Q^{\max}_r$	Maximum reactive power capacity of capacitor bank c and shunt reactor r respectively (Mvar)

On the other hand, the allocation of VAR capacity should take into account the capacity limits of generation units both for VAR generation and absorption, (4.41) and (4.42). As described in the previous sections, the VAR capacity limits depend on the active power output of the generator. According to the capacity curve shape, to increase the VAR capacity, the active power output should be reduced. The corresponding relationship between the active power output and the capacity limits is a non-linear function (see Figure 4.8). For simplicity, this relationship is approximated by a linear function. This simplification also guarantees that the calculated VAR limits, (4.43) and (4.44), will be always lower than the real VAR limits.

$$qa^G_g + QA^{G0}_g \leq u_g Q^{Gmax}_g \qquad \forall g \in G \tag{4.41}$$

$$qa_g^A + QA_g^{A0} \leq u_g Q_g^{Amax} \qquad \forall g \in G \tag{4.42}$$

$$Q_g^{Gmax} = Q_g^{GPmin} - \left(p_{g,s} - P_g^{min}\right) \frac{Q_g^{GPmin} - Q_g^{GPmax}}{P_g^{max} - P_g^{min}} \tag{4.43}$$

$$Q_g^{Amax} = Q_g^{APmin} - \left(p_{g,s} - P_g^{min}\right) \frac{Q_g^{APmin} - Q_g^{APmax}}{P_g^{max} - P_g^{min}} \tag{4.44}$$

where:

$Q_g^{G\max}, Q_g^{A\max}$	Maximum reactive power generation and absorption of generator g (Mvar)
P_g^{min}, P_g^{max}	Minimum and maximum active power generation of generator g (MW)
Q_g^{GPmin}, Q_g^{APmin}	Maximum reactive power generation and absorption of generator g operating at its minimum active power output (Mvar)
Q_g^{GPmax}, Q_g^{APmax}	Maximum reactive power generation and absorption of generator g operating at its maximum active power output (Mvar)

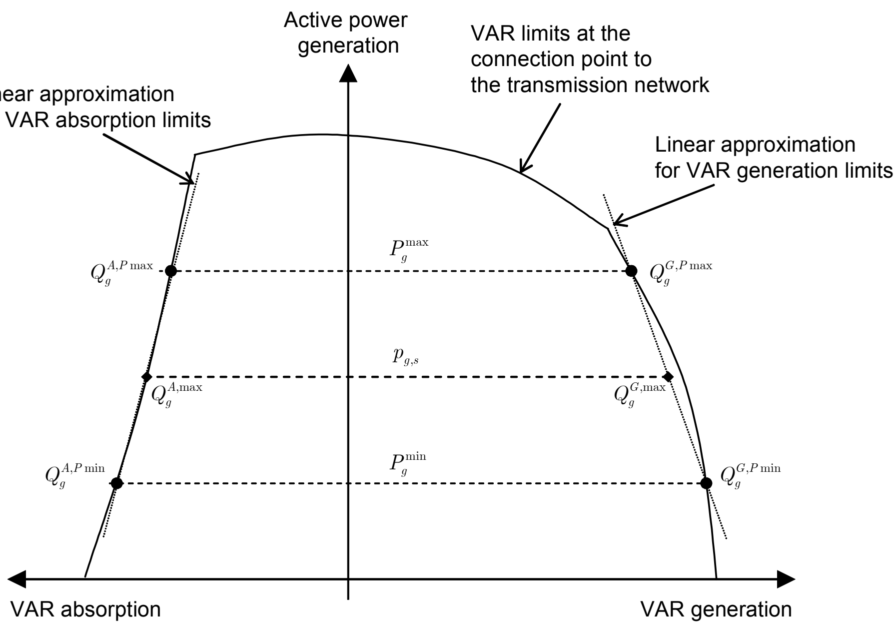

Figure 4.8: VAR limits for different operating points

4.3.2.4 Dynamic performance

In the selection of the VAR sources, it is important to consider their *dynamic performance* under contingencies. The dynamic performance is considered as the primary VAR response of a VAR source, without the change of the set point by the operator (power plant operator or SO). VAR regulation margin is formulated, for each VAR source, as the maximum variation of the VAR production in a scenario with contingency compared with the VAR production in the base case. These constraints join the operation under the base scenario and the contingencies, giving important information for the settlement of the VAR capacity market.

Generators, SVCs, and STATCOM devices can generally modify their VAR production very quickly, using their whole VAR capacity (4.45) (for very fast VAR regulating sources $\Delta Q_g^u = \Delta Q_g^u = \infty$, and therefore the constraint is not active). However, capacitor banks and shunt reactors have a slower dynamic performance, and their maximum VAR variation is more limited (4.46)(4.47) (for instance, $\Delta Q_c^d = \Delta Q_c^u = \Delta Q_r^d = \Delta Q_r^u = 0$).

$$-\Delta Q_g^d \leq q_{g,s}^A + q_{g,s}^G - q_{g,s_b}^A - q_{g,s_b}^G \leq \Delta Q_g^u \qquad \forall g \in G, s \neq s_b \tag{4.45}$$

$$-\Delta Q_c^d \leq q_{c,s} - q_{c,s_b} \leq \Delta Q_c^u \qquad \forall c \in C, s \neq s_b \tag{4.46}$$

$$-\Delta Q_r^d \leq q_{r,s} - q_{r,s_b} \leq \Delta Q_r^u \qquad \forall r \in R, s \neq s_b \tag{4.47}$$

where:

$\Delta Q_g^u, \Delta Q_g^d$	Maximum reactive power change upwards/downwards that generator g can provide in case of contingencies (Mvar)
$\Delta Q_c^u, \Delta Q_c^d$	Maximum reactive power change upwards/downwards that the capacitor bank c can provide in case of contingencies (Mvar)
$\Delta Q_r^u, \Delta Q_r^d$	Maximum reactive power change upwards/downwards that the shunt reactor r can provide in case of contingencies (Mvar)

The variation of the active power generation after a contingency clearly depends on the technology of the power plant (4.48). Hydraulic and combined cycle plants can modify their active power production faster than nuclear and other thermal plants.

$$-\Delta P_g^d \leq p_{g,s} - p_{g,s_b} \leq \Delta P_g^u \quad \forall g \in G, s \neq s_b \tag{4.48}$$

where:

$\Delta P_g^u, \Delta P_g^d$	Maximum active power change upwards/downwards that generator g can provide in case of contingencies (MW)

Illustrative case:

The following considerations were included in the illustrative case,

- In the capacity curve of generators $Q_g^{GPmin} = Q_g^{GPmax}$ and $Q_g^{APmin} = Q_g^{APmax}$.
- The dynamic performance of all generators is defined as $\Delta P_g^u = \Delta P_g^d = 20$MW, and $\Delta Q_g^u = \Delta Q_g^d = 50$Mvar.
- Capacitor banks and shunt reactors will not modify their operating capacity in the case of contingency, $\Delta Q_c^u = \Delta Q_c^d = 0$, and $\Delta Q_r^u = \Delta Q_r^d = 0$.
- There are no previous VAR capacity contracts with any of the market participants, therefore $QA_c^0 = QA_r^0 = 0$, and $QA_g^{G0} = QA_g^{A0} = 0$.

4.3.2.5 Modeling contingencies

The optimization formulation for VAR allocation also includes scenarios with contingencies. During contingencies, the control variables corresponding to the transformer tap position and voltage at the generator terminals are kept constant and equal to their value in the base scenario. Two possible contingencies are considered: generator unavailability and line trip.

4.3.2.5.1 Generator unavailability. The unavailability of a generator g_f in a scenario s_{g_f} is modeled with three additional constraints that set to zero its active and reactive power production (4.50)(4.51). Additionally, the active power lost is compensated by a set of generators in the active power regulating area. The contribution of each selected generator is in proportion to the difference between their maximum active power and their output in the base scenario (4.49). This criteria is similar to the one used in the Spanish power system [Martínez-Crespo et al., 2006].

$$p_{g,s_{g_f}} = p_{g,s_b} + p_{g_f,s_b} \frac{P_g^{\max} - p_{g,s_b}}{\sum_{g \neq g_f} \left(P_g^{\max} - p_{g,s_b} \right)} \qquad \forall s \in S/s_b, g \in G/g_f \tag{4.49}$$

$$p_{g_f,s_{g_f}} = 0 \tag{4.50}$$

$$q_{g_f,s_{g_f}} = 0 \tag{4.51}$$

where:

s_{g_f} The scenario where generator g becomes unavailable

4.3.2.5.2 Line trip. The trip of a transmission line is included in the model by modifying the impedance matrix of the power system. For line l between buses n and m, and the considered scenario s_l, eight parameters should be modified. These data correspond to the real (4.52) and imaginary part (4.53) of the impedance matrix, in rows n and m .

$$\begin{aligned} g_{nm,s_l} &= g_{mn,s_l} = 0 \\ g_{nn,s_l} &= g_{nn,s_b} - g_{nm,s_b} \\ g_{mm,s_l} &= g_{mm,s_b} - g_{nm,s_b} \end{aligned} \tag{4.52}$$

$$\begin{aligned} b_{nm,s_l} &= b_{mn,s_l} = 0 \\ b_{nn,s_l} &= b_{nn,s_b} - b_{nm,s_b} \\ b_{mm,s_l} &= b_{mm,s_b} - b_{nm,s_b} \end{aligned} \tag{4.53}$$

where:

g_{nm,s_l}, b_{nm,s_l}	Real and imaginary part of the admittance matrix corresponding to buses n and m for scenario s_l where transmission line l has failed (℧)

4.3.2.6 VAR reserve management

A good practice in the operation of power systems is to distribute the VAR capacity reserve homogeneously between the fast VAR sources, mainly generators. This criterion clearly improves the power system response in the case of a system contingency, as it minimizes the possibility that a VAR source exhausts its VAR capacity while other VAR sources are lightly loaded on VARs. The reserve margin is a result from the settlement of the VAR capacity market. The reserve margin is defined under normal operation conditions for each single voltage control area j, and for VAR capacity generation (4.54) and absorption (4.55). For better performance of the optimization formulation, a slack parameter σ for the VAR reserve margin in generators is included.

$$r_j^G - \sigma \leq 1 - \frac{q_{g,s_b}^G}{qa_g^G} \leq r_j^G + \sigma \qquad \forall g \in G \tag{4.54}$$

$$r_j^A - \sigma \leq 1 - \frac{q_{g,s_b}^A}{qa_g^A} \leq r_j^A + \sigma \qquad \forall g \in G \tag{4.55}$$

where:

r_j^G, r_j^A	Generation/absorption VAR capacity reserve in the voltage control area j
σ	Margin of the VAR capacity reserve

Illustrative case:

An adequate reserve margin variation of $\sigma = 0.2$ will be settled for the illustrative case. This gap allows a 20% deviation of reserve margins between generators.

4.4 Analysis of the results of the VAR capacity market settlement

The output of the optimization problem that formulates the settlement of the VAR capacity market contains both technical and economic information. This section first presents the main outputs of the market settlement, which are the selection of the VAR capacity bids for the next year and the estimated costs corresponding selected VAR supplying agents. Then, the information obtained from the Lagrange multipliers associated with the constraints of the optimization problem, which represents the VAR capacity market settlement, is analyzed. Finally, it is discussed the need of splitting the Lagrange multipliers in order to obtain clear economic signals.

4.4.1 Main outputs

The main output of the VAR market formulation is the selected VAR capacity for each source and the cost for the purchase of that VAR capacity. In addition an estimation of the operation costs included in the VAR capacity market are obtained, comprising the VAR energy regulated cost, energy losses and active power redispatch cost, voltage quality penalties, and cost for non-supplied energy.

The previous information was obtained from the power flow results of each scenario, including active and reactive power balance at each bus, and the corresponding voltage value. Additional estimations were also obtained, such as voltage deviations per bus, the non-supplied energy, the generation redispatch, and the use of the selected VAR capacity sources.

Illustrative case:

The selected VAR capacity in the illustrative case is *25Mvar to generator #1*, *34Mvar to generator #2*, *49Mvar to generator #3*, and a *capacitor bank of 9Mvar at bus 2*. The operating conditions for the scenarios are shown in the following table. Note that generator 3 was not initially dispatched ($P_3^0 = 0$), but it is started-up at its minimum power output, to avoid ENS in case of unavailability of generator 2. The active power output of generators during contingencies is defined by the automatic response as defined in (4.49), and voltages in the generator buses remain constant.

Table 4.7: Power flow results

Scenario	**#1** Base	**#2** Circuit out	**#3** G2 out	**#4** G3 out	**#5** Circuit & G2 out	**#6** G2 & G3 out	**#7** Circuit & G3 out	**#8** Circuit, G2, G3 out
v_1 (p.u.)	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03
v_2 (p.u.)	1.00	1.00	1.00	0.97	1.00	1.00	0.91	1.04
p_1 (MW)	52.2	53.4	77.9	62.9	78.5	63.2	47.8	19.6
p_2 (MW)	50.0	50.0	0.0	50.0	0.0	0.0	50.0	0.0
p_3 (MW)	10.0	10.0	33.8	0.0	33.8	0.0	0.0	0.0
q_1 (Mvar)	11.6	6.6	25.0	25.0	13.2	25.0	25.0	0.0
q_2 (Mvar)	11.6	6.6	0.0	34.4	0.0	0.0	34.4	0.0
q_3 (Mvar)	31.2	49.1	25.8	0.0	41.7	0.0	0.0	0.0

The annual costs associated with the VAR capacity market are summarized in next table. Observe that the costs with the highest weight are those associated with the purchase of VAR capacity and that of the active power redispatch.

Table 4.8: Cost sharing of the VAR capacity market

Cost	**(k€-year)**	**%**
Generator VAR purchase	389.47	58.2
Capacitor bank VAR purchase	87.8	13.1
VAR energy regulated cost	4.06	0.6
Voltage quality penalties	5.35	0.8
Non-supplied Energy penalties	77.27	11.6
Energy losses and redispatch	104.95	15.7
Total cost	668.9	100.0

4.4.2 Lagrange multipliers information

In the proposed optimization problem for the VAR capacity market settlement, the relevant marginal price information is obtained from the power flow equations and the VAR production limit constraints. The Lagrange multipliers for power flow equations (4.21) and (4.22) are $\lambda^p_{n,s}$ and $\lambda^q_{n,s}$ respectively. These values show the impact of a change in the active and reactive power load in the scenario s on the annual costs of the VAR capacity market, respectively. This information can be aggregated in a single multiplier taking into account all the scenarios together, as formulated in (4.56) and (4.57).

$$\lambda_n^p = \sum_s \lambda_{n,s}^p \qquad (4.56)$$

$$\lambda_n^q = \sum_s \lambda_{n,s}^q \qquad (4.57)$$

The Lagrange multipliers associated with VAR production limit constraints, (4.35) to (4.38), indicate how the total costs would be modified if the assigned VAR capacity is increased for generators in the scenario s ($\mu_{g,s}^G$ for generation and $\mu_{g,s}^A$ for absorption), capacitor banks ($\mu_{c,s}$), or shunt reactors ($\mu_{r,s}$). Similarly, the sum of the Lagrange multipliers for the whole set of scenarios S provides the information on the impact of the objective function if constraints are modified simultaneously for all the scenarios.

Illustrative case:

The marginal costs for active and reactive power load are presented in the next table. All Lagrange multipliers are positive values since an increase in the load, both for active and reactive power, increases the total costs of the VAR capacity market. The base scenario #1 determines the active power requirements in the illustrative case, as its Lagrange multipliers are the highest. On the other hand, the impact on costs of the VAR demand is distributed among the different scenarios, where scenarios #2 and #3 have the highest impact.

Table 4.9: Lagrange multipliers in the load buses (€/kvar-year)

Scenario	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**	**#8**	**Sum**
Outage	None	Circuit	G2	G3	Circuit, G2	G2, G3	Circuit, G3	Circuit, G2,G3	
λ_1^p	4.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.72
λ_2^p	4.89	1.70	-0.21	0.33	0.00	0.20	0.48	0.00	7.39
λ_1^q	0.07	0.00	2.41	1.48	0.00	1.88	0.53	0.00	6.37
λ_2^q	0.19	5.00	0.00	1.68	0.00	1.99	1.44	0.00	10.31

Dual variables for generation VAR capacity, presented in the next table, are negative values since an increase in assigned VAR capacity decreases the cost of the VAR capacity market. The Lagrange multipliers are not zero, if for that scenario the current VAR generation equals the VAR capacity purchased. Then, most of the purchased capacity is used at its maximum in scenarios #2, #5 and #6.

Table 4.10: Lagrange multipliers for generation (€/kvar-year)

Scenario	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**	**#8**	**Sum**
Outage	None	Circuit	G2	G3	Circuit, G2	G2, G3	Circuit, G3	Circuit, G2,G3	
μ_1^G	0.00	-2.41	-1.47	0.00	-1.88	-0.53	0.00	0.00	-6.3
μ_2^G	0.00	-2.41	-1.47	0.00	-1.88	-0.53	0.00	0.00	-6.3
μ_3^G	-5.00	0.00	-1.68	0.00	-1.99	-1.44	0.00	0.00	-10.1

4.4.3 Splitting the Lagrange multipliers

The Lagrange multipliers defined in the previous section include the information sensitivity of both the costs associated with the VAR capacity purchase, and the different estimated operational costs. As will be shown in the next chapter, the economic flows in the VAR capacity market require the information of the specific sensitivities for each cost-component in the objective function (4.11). This section presents a general approach for partitioning the Lagrange multipliers.

The formulation of the VAR capacity market settlement can be generalized in an optimization problem (4.58). This general formulation includes a set of variables associated with the VAR capacity purchases x, and a set of variables related with the operation of the power system y. Therefore, the objective function can be simplified as the sum of VAR capacity purchase $f_1(x)$ and operational costs $f_2(y)$. The formulation includes a set of equality constraints associated with the operation conditions $g(y)$. Finally, there is a block of constraints which depends on both operation and investment variables $h(x, y)$.

$$\begin{array}{lll} \min & f_1(x) + f_2(y) & \\ s.t. & g(y) = 0 & : \lambda \\ & h(x,y) \leq 0 & : \mu \end{array} \tag{4.58}$$

The Lagrange function of the previous formulation is,

$$L = f_1(x) + f_2(y) - \lambda \cdot g(y) - \mu \cdot h(x, y) \tag{4.59}$$

Then, the Karush-Kuhn-Tucker optimal conditions are,

$$\begin{array}{rcl} \dfrac{\partial L}{\partial x} = & \frac{\partial f_1(x)}{\partial x} - \mu \frac{\partial h(x,y)}{\partial x} & = 0 \\ \dfrac{\partial L}{\partial y} = & \frac{\partial f_2(y)}{\partial y} - \lambda \frac{\partial g(y)}{\partial y} - \mu \frac{\partial h(x,y)}{\partial y} & = 0 \end{array} \tag{4.60}$$

If the right-hand-side of the equality constraint $g(y)$ is modified in ε, then,

$$\frac{\partial g(y)}{\partial y} \Delta y = \varepsilon \tag{4.61}$$

The active constraints $h(x, y)$ will be also modified,

$$\frac{\partial h(x,y)}{\partial x} \Delta x + \frac{\partial h(x,y)}{\partial y} \Delta y = 0 \tag{4.62}$$

Additionally, in the optimum, it is verified that

$$\frac{\partial f_1(x)}{\partial x}\Delta x + \frac{\partial f_2(y)}{\partial y}\Delta y = \lambda \cdot \varepsilon \tag{4.63}$$

First, Δy is solved from (4.61). Then, Δy is substituted in (4.62), and Δx is solved from the same equation. Finally both Δx and Δy are substituted in (4.63), resulting that λ can be decomposed in two terms,

$$\lambda = \lambda_1 + \lambda_2 = -\frac{\partial f_1}{\partial x} \cdot \left(\frac{\partial h}{\partial x}\right)^{-1} \cdot \frac{\partial h}{\partial y} \cdot \left(\frac{\partial g}{\partial y}\right)^{-1} + \frac{\partial f_2}{\partial y} \cdot \left(\frac{\partial g}{\partial y}\right)^{-1} \tag{4.64}$$

The analytical expression of the division of the Lagrange multipliers can be obtained by substituting in (4.64) the optimization problem functions, (4.11) to (4.55).

The complexity of the analytical formulation of the Lagrange multipliers can be solved by obtaining a numerical approach. The following process is used to obtain the partition of the sensitivities,

i) Solve the optimization problem (4.58), storing the Lagrange multipliers λ^0, and the value of the objective functions $f_1(x^0)$ and $f_2(y^0)$.

ii) Select the constrain whose Lagrange multiplier is analyzed, and increase the constraint in ε.

iii) Solve the optimization problem (4.58), storing the Lagrange multipliers λ^*, and the value of the objective functions $f_1(x^*)$ and $f_2(y^*)$.

iv) The Lagrange multipliers can be then split as follows,

$$\lambda_1 = \frac{f_1(x^*) - f_1(x^0)}{\varepsilon} \tag{4.65}$$

$$\lambda_2 = \frac{f_2(y^*) - f_2(y^0)}{\varepsilon} \tag{4.66}$$

$$\lambda^0 = \lambda_1 + \lambda_2 \tag{4.67}$$

Illustrative case:

The next table presents the splitting of the Lagrange multipliers associated with the active and reactive power balance equations. These values were obtained using the numerical approach.

Table 4.11: Splitting of Lagrange multipliers

	VAR capacity C_{QC}	VAR energy C_{QE}	Losses and redispatch C_P	Voltage quality C_V	Energy non supplied C_D	Total cost C_T
λ_1^p(€/kW)	0	0	4.72	0	0	4.7
λ_2^p(€/kW)	3.29	-0.06	4.85	-0.16	0.06	7.4
λ_1^q(€/kvar)	6.35	0.05	-0.03	-0.41	0.41	6.3
λ_2^q(€/kvar)	8.25	0.14	0	0.44	0.3	10.3

Observe that the sensitivities of an increase in the active power load are directly related with the increase of generator output costs C_P (the sensitivity can be calculated as the variable costs of the clearing generator, generator #1 in the illustrative case, times the duration of the base scenario $A_g^P \cdot H_{s_b}$), and with the non-supplied energy. The sensitivities of the VAR load on the cost function of the VAR capacity market are based on the acquisition of new VAR capacity, and its influence on the non-supplied energy.

4.5 Other issues

This section presents the optimization characteristics of the optimization problem that represents the VAR capacity market settlement. In addition, some considerations for the implementation of the optimization problem in real power systems are described.

4.5.1 Optimization characteristics

The resulting optimization problem for the VAR capacity market has non-linear equations and includes both real and binary variables. Non-linear equations appear in the objective function and in the constraints, such as trigonometric functions and product of variables. The size of the proposed optimization problem is presented in Table 4.12.

The optimization problem has been coded in GAMS (General Algebraic Modeling System) [Brooke et al., 1988], using the specific solver for mixed-integer non-linear programming SBB [Bussieck and Drud, 2001]. The SBB solver uses the branch and bound algorithm[9] to solve the relaxed non-linear problem. In the branch and bound process, each of the possible candidates is a non-linear problem, which is solved using particular solvers, such as CONOPT [Stolbjerg-Drud, 1993].

[9] Branch and bound is an optimization technique designed to find optimal solutions, especially in discrete and combinatorial optimization. This technique consists of (i) the systematic enumeration of all candidate solutions (branching process, as it defines a tree of possible candidates); (ii) the calculation of the upper and lower estimated bounds of the quantity being optimized (bounding process); (iii) and finally some candidates are discarded by using the previous bounds (pruning process).

Table 4.12: Model characteristics

Variables	Binary	G
	Real	$1 + J + 3G + C + R + S\left(3L + 3G + C + R + 5N + 2N^2\right)$
Equations	Linear	$S\left(11G + 5N + L + 4C + 4R\right) - 2G - C - R + 2RT$
	Non-linear	$1 + S\left(2N + 3L\right)$

where:

G Set of generator units
C, R Set of capacitor banks and shunt reactors respectively
S Set of scenarios (base case plus contingencies)
L Set of transmission lines
RT Set of transformers
N Set of buses
J Set of voltage control areas in the power system

Illustrative case:

The optimization model used for the illustrative case is characterized by: *G=3, C=2, R=2, S=8, L=2, N=2, J=1,* and *RT=0*. Then, the resulting optimization problem size is defined by *3* binary variables, and a total of *308* real variables. The total number of equations is *554*, from which *81* are non-linear. The run-time for solving the proposed formulation in the proposed illustrative case was *3* seconds on a 1.86GHz Pentium machine.

4.5.2 Alternative formulations

The optimization problem for the VAR capacity market settlement has been tested with a 2 bus and a 39 buses case studies (see Chapter 6). *Decomposition techniques* can be used to obtain a better efficiency in the optimization process. This section presents two simple approaches, based on voltage control areas, and using the Benders decomposition methodology. In the research literature many other approaches can be found using more sophisticated methodologies [Zhang and Tolbert, 2005].

4.5.2.1 Voltage control areas

Voltage control, unlike frequency/active power control, is a local problem. Therefore, the global voltage control problem can be simplified in a set of local voltage control sub-problems, which are associated with smaller regions of the power system. This simplification has been widely used for the Secondary Voltage Control approaches [Lagonotte et al., 1989, Arcidiacono et al., 1993].

Under this assumption, the optimization problem for the VAR capacity market can be decomposed into a set of sub-problems. Each sub-problem will cover a smaller electric area, reducing the number of market participants, and the number of contingency scenarios. It is important to note that the optimum solution achieved in each sub-problem may slightly differ from the optimum solution in the global problem.

4.5.2.2 Benders decomposition

If the resulting optimization problem cannot be efficiently solved by the software, for instance if many scenarios are included in the formulation, or the voltage control area is very wide, then other optimization techniques such as Benders decomposition can be used. A two level Benders decomposition procedure is proposed to solve the complex optimization problem [Benders, 1962, Geoffrion, 1972]. This approach has already been used for the VAR equipment planning problem [Gómez, 1989, Gómez et al., 1991].

The Benders decomposition divides the global problem into a VAR allocation problem, and a set of S operational problems for each scenario. To solve the proposed optimization problem an iterative process between the VAR allocation problem and the operation sub-problems is established (see Figure 4.9).

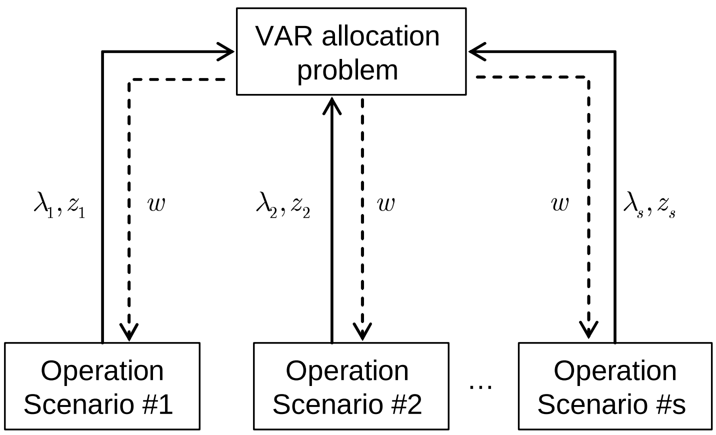

Figure 4.9: Benders decomposition

Each operation sub-problem optimizes the operation of the power system given a certain VAR allocation (w). Then, to the VAR allocation problem, the subproblems return their objective function values (z_s), and their sensitivities of this value to the VAR allocation (λ_s). This information is included in the main VAR allocation problem as new constraints (called Benders cuts), and a new VAR assignment is obtained. The optimal solution is achieved when the improvement in the global objective function in the next iteration is under a selected tolerance.

4.6 Conclusions

This chapter has presented the VAR capacity market settlement, which is based on an optimization problem. The proposed formulation selects the best VAR capacity bids that minimize the annual cost of the VQ service procurement, meeting certain security and operational constraints, which are defined both for normal and contingency scenarios.

The bids for the different VAR supplying agents that participate in the annual auction include VAR capacity and price. The bid structure should only consider those costs associated with the installed VAR capacity and those required for making the installed capacity available. Additionally, selected bids will receive a compensation for the use of the purchased VAR capacity, and for the loss of benefits due to a reduction in the active power output in order to increase the VAR capacity. Then, the resulting bid function for VAR capacity includes fixed and variable costs.

The detailed formulation of the annual VAR capacity market must take into account every single hour in the year with their corresponding operating situations. It has been found that a practical approach to solve the VAR market problem is to analyze two base scenarios representing the maximum requirements for VAR generation and VAR absorption in the power system. These scenarios correspond to the operating situations associated to peak demand and low demand hours.

The analysis also found that the operation under contingency scenarios may require additional VAR capacity than that calculated in the two previous base scenarios. These operating situations comprise a single or multiple unavailability of a power system device. For simplicity, it is recommended that not all the possible contingencies are taken into account, and a pre-selection is carried out of those contingencies with the highest impact on VAR market costs.

This chapter proposes to model the VAR capacity market settlement in an optimization problem. The objective function of the optimization problem includes the costs derived from the purchase contracts of VAR capacity, and other operational costs such as the regulated payment for VAR capacity use, voltage quality penalties, transmission losses, and generation redispatch. The optimization problem also considers the constraints that define the power flow equations, security limits of the power system operation, and the dynamic performance of the different VAR sources.

The resulting optimization problem is non-linear, and includes real and binary variables. The problem has been coded in GAMS and solved using specific mixed-integer non-linear programming tools. The application of the proposed formulation to large VAR capacity markets may require decomposition techniques to be run in a commercial optimization software.

The resulting information obtained from the output of the optimization problem for the VAR capacity market settlement is twofold, i) the selection of the best VAR capacity bids, ii) and the sensitivities of the VAR constraints with the overall VAR costs. These sensitivities are based on the Lagrange multipliers, and will be used in the next chapter to remunerate the VAR supplying agents and to charge the VAR demand.

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CHAPTER 5

Remuneration and charging criteria in the VAR capacity market

THIS chapter presents a remuneration mechanism for the procurement of VAR capacity and a charging scheme for the demand in the proposed VAR capacity market. First, the economic flows in the VAR market are described. On the one hand, the remuneration of the selected VAR sources is based on long-term marginal pricing. On the other hand, the charging scheme is based on the Cooperative Game Theory, and will differentiate the demand of VAR resources under normal operating conditions, and the over costs associated with the contingencies.

5.1 Economic settlement

In the previous chapter, the methodology for the VAR capacity market auction was presented. This section introduces the economic settlement in the VAR capacity market, comprising the economic flows between all the market participants. The main principles that have been considered for the design of the economic settlement are:

- Reward the providers of VAR capacity, and charge those agents who benefit from the VAR procurement [FERC, 2005].
- It should guarantee that all agents recover their incurred costs.
- It should send efficient signals to the VAR demand and procurement of the VAR capacity, in order to minimize long-term costs.
- It should maximize net social benefit.
- It should guarantee the revenue reconciliation: the sum of the charges to the demand of the VAR capacity should equal the sum of the remuneration to the selected VAR sources and the other operating costs.

Market agents in the VAR capacity market can be classified into VAR suppliers and VAR demand. As stated in the previous chapters, the VAR is procured by generators, capacitor banks, shunt reactors, SVCs and STATCOM devices, who will receive an economic compensation for the procurement. On the other hand, the VAR capacity is demanded by the system loads, and by the contingency situations due to the unavailability of the power system devices (see Figure 5.1). In some operating conditions, loads can reduce the needs of VAR capacity, and therefore can receive remuneration, as it will be discussed in the next sections. This thesis dissertation proposes that the costs for the purchase of VAR capacity and other operational costs considered in the market settlement should be charged to those agents that demand VAR.

For the economic flow definition, it is important to distinguish between the economic signal that the participating agents receive, and the desired economic volume to be recovered through the VAR capacity market. The marginal prices, which are obtained from the optimization problem used for the VAR capacity market clearing, include the complete information on the impact on the total costs associated with the VAR market. As will be discussed later, these marginal prices are divided into different terms for the appropriate remuneration and payment.

On the other hand, the costs included in the objective function of the VAR capacity market comprise the VAR capacity purchase and other estimated operational costs. This thesis dissertation proposes that only those costs directly associated with the VAR management are recovered through the VAR capacity market, as there are other mechanisms for recovering some of the costs included in the objective function, such as the energy losses.

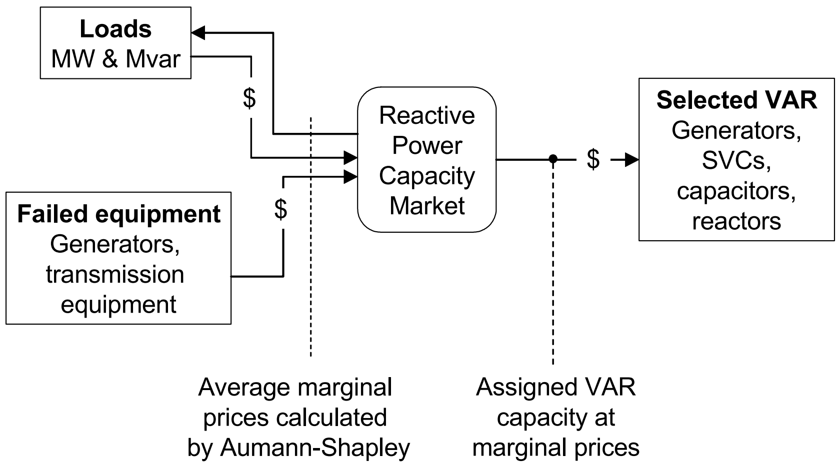

Figure 5.1: Economic flows in the VAR capacity market

5.2 Remuneration mechanisms in the VAR capacity market

This section presents the mechanism to remunerate the selected VAR capacity, which is based on the long-term marginal pricing. First the spot pricing framework is described, and then the implementation issues are discussed.

5.2.1 Spot pricing

According to the analysis carried out in Chapter 2, there are different remuneration schemes for the selected VAR capacity. A first approach would be to pay at their bid price, as formulated in the objective function of the optimization problem (for instance, $qa_g^G\left(A_g^G + B_g^G qa_g^G\right)$ for VAR capacity generation). However, this mechanism does not send the economic signal of the real/opportunity value of the allocated VAR capacity.

In order to promote VAR allocation efficiency, selected VAR suppliers will be paid using long-term marginal prices. Then, VAR agents will have incentives to invest in VAR capacity as the marginal prices can provide some fixed cost recovery for the investments. The long-term marginal prices are obtained, for each VAR supplying agent and scenario, as the Lagrange multiplier associated with the constraint of the VAR capacity limit. Therefore, the long-term marginal prices measure the change in the total costs associated with VAR procurement (comprising VAR capacity purchase, VAR energy regulated cost, penalties for voltage quality and non-supplied energy, energy losses and redispatch cost) if one more Mvar is selected from the bid of the corresponding VAR supplying agent.

The proposed pricing mechanism sends efficient location signals to the VAR supplying agents. There will be higher VAR prices in electric areas with a deficit of VAR capacity, which may attract new investments. Moreover, marginal pricing encourages market agents to bid at their marginal costs. If agents bid over their costs, they may be not selected in the auction. Finally generators procuring VAR capacity have a clear incentive to reduce their failure-rates. The failure-rate affects the selection of VAR capacity bids, the higher the failure-rate the less VAR capacity will be selected.

The proposed formulation for the costs in the VAR capacity market (4.11) considered that selected agents are paid at their bid. If agents are paid at their marginal price, then the total costs will increase when marginal prices are higher than bids. Notwithstanding, the optimal selection of VAR capacity does not change.

Next, a simplified formulation of the VAR capacity market settlement is presented in order to justify the remuneration of the selected VAR capacity.

5.2.1.1 Mathematical formulation

The simplified formulation of the objective function (5.1) only considers the cost of VAR generation capacity purchase and the regulated payment of VAR energy. Additionally, all the scenarios are considered to have the same duration. The formulation considers the reactive power balance equation (5.2), where the VAR generation must be positive (5.4) and below the selected VAR capacity (5.3). Finally, the selected VAR capacity must be lower than the installed VAR (5.5).

$$\min_{qa_g, q_{g,s}} \quad \sum_g \left(B_g \cdot qa_g + \sum_s A^E \cdot q_{g,s} \right) \tag{5.1}$$

$$s.t. \quad \sum_g q_{g,s} = QD_s \qquad \forall s \quad : \lambda^q_{g,s} \tag{5.2}$$

$$q_{g,s} \leq qa_g \qquad \forall g, \forall s \quad : \mu^{q+}_{g,s} \tag{5.3}$$

$$q_{g,s} \geq 0 \qquad \forall g, \forall s \quad : \mu^{q-}_{g,s} \tag{5.4}$$

$$qa_g \leq Q^{\max}_g \qquad \forall g \quad : \gamma_g \tag{5.5}$$

where:

B_g	Bid of generation g (€/Mvar)
qa_g	Selected reactive power generation capacity to generator g (Mvar)
A^E	Regulated compensation for VAR generation energy (€/Mvarh)
$q_{g,s}$	Reactive power generation from generator g in scenario$s$ (Mvar)
QD_s	Reactive power demand in the scenario s (Mvar)
$Q^{\max}_g$	Maximum reactive power generation of generator g (Mvar)
$\lambda^q_{g,s}, \mu^{q+}_{g,s}, \mu^{q-}_{g,s}, \gamma_g$	Lagrange multipliers of the corresponding constraints

The Lagrange function of the simplified formulation for the VAR capacity market is obtained in (5.6).

$$\begin{aligned} L &= \sum_g \left(B_g \cdot qa_g + \sum_s A^E \cdot q_{g,s} \right) \\ &+ \sum_s \lambda^q_{g,s} \left(QD_s - \sum_g q_{g,s} \right) \\ &+ \sum_s \sum_g \mu^{q+}_{g,s} \left(q_{g,s} - qa_g \right) \\ &- \sum_s \sum_g \mu^{q-}_{g,s} \cdot q_{g,s} \\ &+ \sum_g \gamma_g \left(qa_g - Q^{\max}_g \right) \end{aligned} \tag{5.6}$$

The optimality condition corresponding to the selection of the VAR capacity of agent g is formulated in (5.7). If the remuneration to VAR agent g is based on the sum of Lagrange multipliers associated with the (5.3) constraint, then agent g will cover its variable costs B_g. In addition, if the selected capacity reached its maximum, then agent g would receive a higher remuneration than its variable costs.

$$\begin{aligned} \frac{\partial L}{\partial qa_g} &= 0 \rightarrow \\ B_g - \sum_s \mu^{q+}_{g,s} + \gamma_g &= 0 \rightarrow \\ \boldsymbol{\sum_s \mu^{q+}_{g,s}} &= \boldsymbol{B_g + \gamma_g} \end{aligned} \tag{5.7}$$

On the other hand, the optimal condition for the use of the VAR capacity from agent g in scenario s is obtained in (5.8). Then, the marginal price of VAR use is obtained as the sum of the regulated payment A^E, an extra payment if the agent g in the scenario s is at its maximum selected capacity $\mu^{q+}_{g,s}$, and the positive difference between the VAR price in scenario s and the regulated VAR price if the agent g is not selected $\mu^{q-}_{g,s}$.

$$\begin{aligned} \frac{\partial L}{\partial q_{g,s}} &= 0 \rightarrow \\ A^E - \lambda^q_{g,s} + \mu^{q+}_{g,s} - \mu^{q-}_{g,s} &= 0 \rightarrow \\ \boldsymbol{\lambda^q_{g,s}} &= \boldsymbol{A^E + \mu^{q+}_{g,s} - \mu^{q-}_{g,s}} \end{aligned} \tag{5.8}$$

The previous result is obtained from the optimally complementary conditions, as formulated in (5.9).

$$\begin{aligned} \lambda^q_{g,s} &= A^E + \mu^{q+}_{g,s} - \mu^{q-}_{g,s} \\ \mu^{q+}_{g,s}\left(q_{g,s} - qa_g\right) &= 0 \\ \mu^{q-}_{g,s} \cdot q_{g,s} &= 0 \end{aligned} \tag{5.9}$$

$$\begin{cases} q_{g,s} = 0 & \begin{cases} \lambda^q_{g,s} = A^E - \mu^{q-}_{g,s} \\ \mu^{q+}_{g,s} = 0 \end{cases} \\ 0 < q_{g,s} < qa_g & \begin{cases} \lambda^q_{g,s} = A^E \\ \mu^{q+}_{g,s} = 0 \\ \mu^{q-}_{g,s} = 0 \end{cases} \\ q_{g,s} = qa_g & \begin{cases} \lambda^q_{g,s} = A^E + \mu^{q+}_{g,s} \\ \mu^{q-}_{g,s} = 0 \end{cases} \end{cases} \tag{5.10}$$

Observe, that when the agent g is unavailable ($q_{g,s} = 0$), its corresponding $\mu^{q+}_{g,s} = 0$, and therefore it will not receive any remuneration in that scenario, as formulated in (5.7). The remuneration for the use of the VAR capacity will be defined in the following sections.

5.2.2 Implementation mechanism

The long-term marginal prices for the selected sources are obtained from the VAR capacity constraints. Generator VAR capacity constraints are formulated in (4.35) and (4.36). Capacity constraints for capacitor banks are formulated in (4.37), and in (4.38) for shunt reactors.

The remuneration that each selected VAR source will receive is obtained as the product of the VAR capacity selected times the corresponding long-term marginal price. The long-term marginal price will be calculated as the sum of the marginal prices for each scenario, except for those scenarios where the selected VAR source failed. The proposed remuneration mechanism includes payments for the selected VAR generation and absorption capacity, and is formulated in (5.11) for generators and STATCOM devices, (5.12) for capacitor banks, and (5.13) for shunt reactors. The payments to SVCs are obtained as a combination of (5.12) and (5.13).

$$R_g = qa^G_g \sum_{s \neq s_g} \mu^G_{g,s} + qa^A_g \sum_{s \neq s_g} \mu^A_{g,s} \tag{5.11}$$

$$R_c = qa_c \sum_{s} \mu_{c,s} \tag{5.12}$$

$$R_r = qa_r \sum_s \mu_{r,s} \tag{5.13}$$

where:

R_g	Annual remuneration for the selected VAR capacity of generator g (€-year)
R_c	Annual remuneration for the selected VAR capacity of capacitor bank g (€-year)
R_r	Annual remuneration for the selected VAR capacity of shunt reactor g (€-year)
qa_g^G, qa_g^A	Assigned reactive power generation/absorption capacity to generator g (Mvar)
qa_c, qa_r	Reactive power capacity assigned to capacitor bank c/shunt reactor r, respectively (Mvar)
$\mu_{g,s}^G, \mu_{g,s}^A$	Lagrange multiplier of the equation of the selected VAR capacity generation/absorption to generator g in scenario s
$\mu_{c,s}, \mu_{r,s}$	Lagrange multiplier of the equation of the selected VAR capacity of capacitor bank c/shunt reactor r in scenario s

Illustrative case:

The remuneration of the selected VAR sources is presented in the next table. Observe that all VAR agents are paid at their bids, except Generator #1 and the capacitor bank that are paid over their bids. The over-recovery can be used by the agent to pay the capital costs. Moreover, these high VAR prices are a clear incentive for new VAR agents to participate in the capacity market.

Table 5.1: Remuneration of selected VAR sources

Market agent	**Selected capacity** (Mvar)	**Bid price** (€/kvar)	**Marginal price** (€/kvar)	**Total remuneration** (k€-year)
Generator 1	25	3	6.3	157
Generator 2	34	2	2	68
Generator 3	49	5	5	245
Capacitor bank 2	9	10	10.3	93

5.3 Charging mechanisms in the VAR capacity market

The aim of the charging mechanism is to send efficient signals to the demand of the VQ service and also to cover the operation costs and payments described in the previous section. The principle of cost causality is applied to distribute the charges to pay the selected VAR suppliers. For this purpose, two types of payment mechanisms are differentiated. First, load demands will be charged for the VAR capacity costs associated with the normal operation of the power system. Second, generators and transmission lines, because of their failure rates, impose extra requirements on VAR capacity. This additional VAR purchase will be charged to the devices responsible for contingencies. The distribution of the charges is obtained using marginal pricing together with the Cooperative Game theory.

This section is structured in two parts: first, charges for VAR capacity requirements under normal operation are presented, and then the charges for contingency scenarios are described.

5.3.1 Allocating VAR capacity costs under normal operating conditions

First, a proposal for charging the agents responsible for VAR capacity needs under normal conditions is presented. Then the implementation issues of the approach to the VAR capacity market are discussed.

5.3.1.1 Proposed charging mechanism

This subsection justifies the use of a curtailed marginal price based on the Cooperative Game theory to distribute the charges of the VAR capacity between the active and reactive power consumption of the loads. First, the different alternatives for pricing the VAR capacity demand are analyzed. Then the influence of active and reactive power load in the VAR capacity needs is discussed. And finally, this section defines a curtailed marginal signal to charge loads.

Selection of the pricing mechanism There are many alternatives to distribute the costs between the agents that demand the service. The simplest methodology is based on a *fixed price* for the volume of load consumed. However, this mechanism would not send location signals to the demand.

More sophisticated approaches are those that are based on marginal pricing. Charging agents in proportion to their *marginal cost,* induce agents into economic efficiency. However, marginal charging may recover more than the incurred costs in the VAR capacity market. This over-recovery can be eliminated by proportionally adjusting the resulting charges. This simplification may lead to situations were the charge is smaller than the service cost, which is the result of a cross-subsidy between other agents participating in the market [PSR, 2005].

Another interesting approach is one which is based on *incremental cost allocation.* Under this scheme, charges are calculated as the increase in the service costs when a new load participates in the VAR capacity market. This mechanism recovers all the costs of the service, and eliminates any possible cross-subsidy. However, charges are very dependent on the entrance order of the loads when calculating the incremental cost. This limitation is eliminated if all the possible permutations of entrance orders of loads are considered, which is called the *Shapley allocation* [Aumann and Shapley, 1975]. The main drawback of this alternative is the high computational effort needed to calculate all the possible load-entrance combinations. Moreover, the size of each agent influences in the charging. If two agents existed with the same sensitivity with the total costs, they would have different per-unit charges depending on their relative size.

The *Aumann-Shapley cost allocation* [Young, 1994] takes into account all the possible combinations of the agent entrance in the service, and also splits the agents size in many sub-agents in order to avoid the size influence on charging. The mathematical justification of its main characteristics can be found in [Barbosa, 1998, PSR, 2005, Ribeiro, 2005]. Additionally, the economical interpretation of the axioms of the Aumann-Shapley pricing [Billera and Heath, 1982, Lin et al., 2006] give out the most important characteristics of this allocation method:

- *Cost-sharing*, the generated revenue exactly recovers the total costs.
- *Additivity*, the price based on the total cost function is equal to the sum of prices computed with respect to the additive components of the cost function.
- *Positivity*, the demand of the consumer actually contributes to total costs and should have a non-negative price.
- *Rescaling*, a linear change in the units of measurement of the demand results in a simultaneous change in the price.
- *Consistency*, two consumers that have the same effect on the cost function should be charged the same price.

To summarize, the Aumann-Shapley methodology induces economic efficiency and fair distribution of the charges. Moreover, all the service costs are recovered with the collected charges, and the resulting distribution does not depend on the shape of the objective cost function.

Active and reactive power influence on VAR capacity needs Both the active power and reactive power consumption of loads defines the VAR needs in the power system. For instance, if all loads had a unit power factor, the power system would still need some VAR support to maintain voltages and guarantee the active power transactions.

The influence of active and reactive power loads in the objective function of the VAR capacity market is analyzed in this thesis dissertation using the Aumann-Shapley allocation methodology which obtains the participation factors for each load. These factors are calculated by integrating the long-term marginal costs of active and reactive power load over an specified interval for load variation [Young, 1994], as formulated in (5.14) and (5.15).

$$\bar{\lambda}_n^p = \int_0^K \frac{\partial \left(C_{QC} + C_{QE} + C_V + C_D + C_P\right)}{\partial PD_n} dk \tag{5.14}$$

$$\bar{\lambda}_n^q = \int_0^K \frac{\partial \left(C_{QC} + C_{QE} + C_V + C_D + C_P\right)}{\partial QD_n} dk \tag{5.15}$$

where:

$\bar{\lambda}_n^p, \bar{\lambda}_n^q$	Aumann-Shapley values for active and reactive power load at bus n
PD_n, QD_n	Active and reactive power demand at bus n (MW,Mvar)
K	Set of subintervals in the Aumann-Shapley pricing calculation

Definition of the curtailed marginal signal The Lagrange multipliers, which are used to obtain the Aumann-Shapley values, include the effect of all cost terms in the objective function, among which stand the economic dispatch of active power C_P. That is, if the active power load in a bus is increased, then generators will increase their output, and the VAR needs in the system may change. Generally, the variable costs of active power are much higher than those of VAR procurement, so the Lagrange multipliers will hide the sensitivity of the load over the VAR costs. Therefore, a curtailed Lagrange multiplier is used for VAR capacity charging which eliminates the effect of the generator output variable costs.

The sensitivity of the transmission losses is not eliminated from the curtailed Lagrange multiplier, since this sensitivity is comparable with that of VAR procurement. Moreover, although energy losses are charged using other mechanisms it is important to incorporate their sensitivity in the charging signals sent to the demand of VAR capacity.

5.3.1.2 Implementation mechanism

This thesis proposes to charge loads in order to cover the VAR capacity needs under normal operating conditions. These charges will be defined according to their location and influence on VAR costs, which are obtained from the Lagrange multipliers of the active and reactive power balance equations (4.21) and (4.22), respectively. The efficient distribution of charging is based on the Aumann-Shapley methodology, which will be based on the curtailed Lagrange multipliers that eliminate the effect of the generation variable costs. Charges will be computed separately for the active and reactive power loads, as both require a certain procurement of the VAR service.

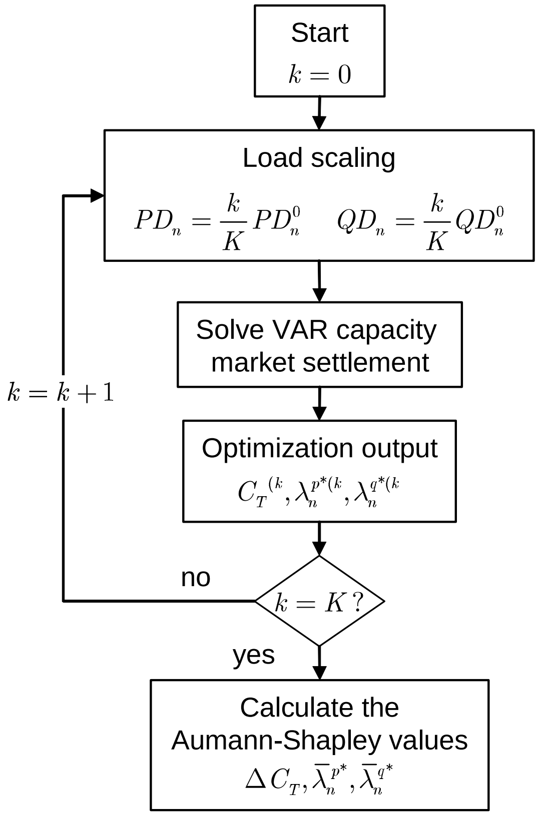

Figure 5.2: Calculation of the VAR cost allocation in the base case

In order to apply the Aumann-Shapley methodology to the proposed VAR capacity market, an iterative process will solve the VAR capacity market settlement for different volumes of load demand, as presented in Figure 5.2 [Ribeiro et al., 2004]. Initially, loads are divided in K intervals, and for each interval k the active and reactive power demand in all buses $n \in N$ are scaled, with a fixed power factor. Then, the optimization problem for VAR capacity market settlement is solved. The curtailed Lagrange multipliers of equations (4.21) and (4.22) are stored $\lambda_{n,s}^{p*(k}$, $\lambda_{n,s}^{q*(k}$ together with the value of the objective function $C_T^{(k}$. Once all the intervals have been solved, the average marginal costs are obtained, as formulated in (5.16) and (5.17).

$$\bar{\lambda}_{n,s}^{p*} = \frac{\sum_t \lambda_{n,s}^{p*(k}}{K} \tag{5.16}$$

$$\bar{\lambda}^{q*}_{n,s} = \frac{\sum_t \lambda^{q*(k}_{n,s}}{K} \tag{5.17}$$

where:

$\lambda^{p*(k}_{n,s}, \lambda^{q*(k}_{n,s}$	Curtailed Lagrange multipliers for active/reactive power load at bus n and scenario s, in the Aumann-Shapley iteration k
$\bar{\lambda}^{p*}_n, \bar{\lambda}^{q*}_n$	Aumann-Shapley values for active and reactive power load at bus n
K	Set of subintervals in the Aumann-Shapley pricing calculation

Finally, the load charges to be paid by loads located at bus n are computed using the Aumann-Shapley values,

$$CH_n = PD_n \sum_s \bar{\lambda}^{p*}_{n,s} + QD_n \sum_s \bar{\lambda}^{q*}_{n,s} \tag{5.18}$$

where:

CH_n	Annual charge paid by the load located in bus n (€-year)

The initial volume of charges collected from the loads is $\sum_n CH_n$. Considering that the Lagrange multipliers used for charging are obtained from the VAR capacity problem formulation, which includes both the normal conditions and contingency scenarios, consequently loads charged using these multipliers will receive a signal that takes into account their influence in each contingency. According to the proposed charging mechanism, the final volume of charges will only recover the costs under normal operating conditions; therefore, the final charges to loads will be scaled, as presented in the next sections.

The sum of all charges to the loads equals the total cost of the VAR capacity market under normal conditions (5.21). This can be easily justified using the Lagrange multiplier definition together with the load variation, where $\Delta PD_n = \frac{PD_n}{K}$ and $\Delta QD_n = \frac{QD_n}{K}$.

$$C^{(1}_T - C^{(0}_T = \sum_n \left(\lambda^{p(0}_n \cdot \Delta PD_n + \lambda^{q(0}_n \cdot \Delta QD_n\right) \tag{5.19}$$

$$\cdots \quad \vdots \quad \cdots$$

$$C^{(K}_T - C^{(K-1}_T = \sum_n \left(\lambda^{p*(K-1}_n \cdot \Delta PD_n + \lambda^{q*(K-1}_n \cdot \Delta QD_n\right) \tag{5.20}$$

$$C^{(K}_T - C^{(0}_T = \sum_n \left(\Delta PD_n \sum_t \lambda^{p*(k}_n + \Delta QD_n \sum_t \lambda^{q*(k}_n\right) \tag{5.21}$$

where:

$C_T^{(k}$	Total costs of the VAR capacity market in the Aumann-Shapley iteration k (€-year)
$\Delta PD_n, \Delta QD_n$	Increments of active and reactive power load per each Aumann-Shapley iteration at bus n

Illustrative case:

The distribution of costs between the loads in the illustrative case was obtained using the Aumann-Shapley methodology with 10 subintervals. The curtailed Lagrange multipliers are presented in the next table.

Table 5.2: Charges to loads using the Aumann-Shapley methodology

Aumann-Shapley iteration (k)	$\sum_s \lambda_{1,s}^{p*}$ (€/MW)	$\sum_s \lambda_{1,s}^{q*}$ (€/Mvar)	$\sum_s \lambda_{2,s}^{p*}$ (€/Mvar)	$\sum_s \lambda_{2,s}^{q*}$ (€/MW)
1	0.00	2.30	1.05	5.93
2	0.00	2.65	1.05	6.01
3	0.00	3.00	1.05	6.09
4	0.00	3.31	1.11	6.18
5	0.00	6.29	1.58	9.22
6	0.00	6.44	1.81	9.42
7	0.00	6.49	2.06	9.71
8	0.00	6.54	2.32	10.05
9	0.00	6.53	2.70	10.32
10	0.00	6.36	2.81	10.33
Average (k€/MW,Mvar)	0.00	4.99	1.75	8.33
Volume (MW,Mvar)	10.00	5.00	100.00	50.00
Charge (k€-year)	0.00	24.96	175.44	416.36

The load located at bus #2 is responsible for most of the VAR needs in the power system. In addition, the active power load at the same bus will be charged for its influence on the VAR capacity costs (especially on energy losses and voltage quality). However, the active power load at bus #1 is not charged as the marginal generator is located in this bus.

The sensitivity of the active power load located at bus #1 is null as the marginal generator is at the same bus, and therefore transmission losses do not increase for an increment of the active power demand. On the other hand, the sensitivity at bus #2 reflects the effect on energy losses. The Aumann-Shapley values associated with the reactive power load are similar in both buses.

5.3.2 Allocating VAR capacity costs due to equipment unavailability

This section first presents a proposal for charging the agents responsible for system contingencies. Then implementation issues of the approach to the VAR capacity market are discussed.

5.3.2.1 Proposed charging mechanism

The unavailability of generators or transmission equipment may require more investments in VAR sources to maintain the same reliability and quality levels of service. Then, market participants responsible for a contingency will be charged for the extra cost imposed on VAR supply requirements corresponding with that system contingency.

As described in Chapter 4, contingencies are incorporated in the VAR capacity market defined by including additional constraints in the corresponding scenario. The duration time of each scenario is calculated ex-ante using failure data which is updated every year. The efficiency signal that has to be sent to the agents is to reduce their failure rate.

The thesis dissertation has analyzed different cost allocation alternatives for distributing the over cost due to contingencies. Three approaches have been considered, (i) single contingency analysis cost allocation, (ii) cost allocation based on the use of the service, and (iii) Aumann-Shapley cost allocation. A detailed review of each approach is carried out in this section including results on the illustrative case.

Alternative 1: cost allocation considering the influence of each single contingency on the total costs Under this approach, the VAR capacity market clearing is solved S times, where each settlement eliminates a single selected contingency. The results obtained from the proposed formulation do not depend on the order of the selection of contingencies. The methodology consists of the following four steps:

i) Calculate the total costs for the optimization problem including all considered contingencies C_T, and the cost without contingencies C_{T,s_b}.

ii) Solve the optimization problem including all contingencies except the one to be evaluated and store the resulting total cost $C_{T,s}$.

iii) Go back to (ii) until all contingencies are analyzed.

iv) The charge for each contingency will calculated as,

$$CH_s = \frac{H_s\left(C_T - C_{T,s}\right)}{\sum\limits_{x\in S} H_x\left(C_T - C_{T,x}\right)}\left(C_T - C_{T,s_b}\right) \tag{5.22}$$

where:

H_s	Duration of a scenario s (hours)
C_T	Total costs of the VAR capacity market including all contingencies (€-year)
$C_{T,s}$	Total costs of the VAR capacity market if contingency s is not considered (€-year)
CH_s	Annual charge paid by the agent responsible for contingency s(€-year)

The charges to each single contingency are proportional to the ratio of the duration of that contingency times the cost change, and with inverse proportion to the sum of the products of duration times cost change for all contingencies. The charge for a single contingency is assigned to the specific VAR source. On the other hand, the charge for a multiple contingency can be divided into different charges to each device which is unavailable. The total charge is then assigned to each device in proportion to its single cost impact. Therefore, a line outage having a small cost impact compared with a generator outage will also be charged less than the generator in a multiple contingency including both devices.

This methodology is simple and requires low computational efforts. However, the distribution of charges for multiple contingencies is not completely fair.

Alternative 2: cost allocation associated with the use of the selected VAR resources A second approach to distribute the over cost due to contingencies is based on how much each contingency uses each selected VAR source during emergency operation. The use calculation comprises both the capacity used and in duration of the selected contingency. Therefore, each contingency will cover a corresponding part of the investment of each selected VAR source. The main advantage of this approach is that it is fair in the distribution of investment costs. However, the calculation procedure does not guarantee revenue reconciliation.

The distribution of the VAR costs due to contingencies is calculated according to the following steps:

i) For each assigned VAR capacity, the optimization algorithm provides the use of it in each contingency. For instance, qa_g^G is the assigned VAR capacity for selected generator g. In contingency s, the use of this capacity is represented by the value of the variable $q_{g,s}$.

ii) For each assigned VAR capacity, put in order the capacity use of it in each contingency, from the lowest to the highest use.

iii) Calculate the incremental cost of the contingency responsible for the highest use of the considered VAR capacity. This cost is calculated as the difference between the VAR remuneration corresponding to the highest use $C_{QC}\left(q_{g,s,\max}\right)$ minus the remuneration corresponding to the second highest use $C_{QC}\left(q_{g,s,\max-1}\right)$.

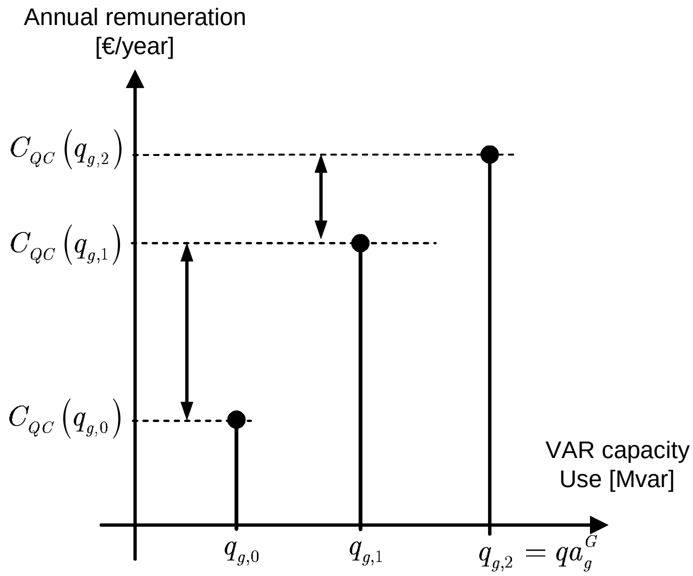

Figure 5.3: Incremental cost allocation

iv) Calculate the incremental costs for the rest of the contingencies in a similar way.

v) Finally, each incremental cost is shared by all the contingencies responsible for the use of the corresponding VAR capacity, according to their duration.

A charging calculation example for a selected generator g, whose assigned capacity was qa_g^G, in the case of two contingencies, is presented in Figure 5.3. The use of this VAR capacity in contingency #1 is defined by $q_{g,1}$, and $q_{g,2}$ for contingency #2. It is verified that $q_{g,2} = qa_g > q_{g,1}$. Contingency #2 is responsible for the incremental cost $C_{QC}(q_{g,2}) - C_{QC}(q_{g,1})$, while both contingencies #1 and #2 are responsible for the incremental cost $C_{QC}(q_{g,1}) - C_{QC}(q_{g,0})$, where $q_{g,0}$ means the use of this VAR capacity made at the base case. Therefore, the payments CH_s to be made by the agents responsible for both contingencies are calculated as follows:

$$CH_1 = [C_{QC}(q_{g,1}) - C_{QC}(q_{g,0})]\frac{H_1}{H_1 + H_2} \tag{5.23}$$

$$CH_2 = [C_{QC}(q_{g,1}) - C_{QC}(q_{g,0})]\frac{H_2}{H_1 + H_2} + [C_{QC}(q_{g,2}) - C_{QC}(q_{g,1})] \tag{5.24}$$

where:

H_s	Duration of a scenario s (hours)
C_{QC}	Annual costs associated with the procurement of VAR capacity (€-year)
CH_s	Annual charge paid by the agent responsible for contingency s (€-year)

The sum of both payments equals the remuneration of the selected VAR generator g minus the remuneration.

This methodology requires less computational effort than the previous approach since it only solves the optimization problem once. However, it lacks fair distribution of charges in multiple contingencies, and does not guarantee revenue reconciliation.

Alternative 3: Aumann-Shapley cost allocation The analysis presented in the section 5.3.1 to allocate costs to the loads using the Aumann-Shapley cost allocation can be easily applied to analyze the influence of each contingency in the total VAR costs. Contingencies can be considered as new agents entering into the VAR capacity market and demanding new VAR resources. Since the aim of all agents is to obtain the needed VAR at minimum cost, it can be analyzed using the Cooperative Game Theory.

The Aumann-Shapley methodology eliminates the influence of the order of agent entrance and the impact of the agent size. Moreover, it guarantees charging fairness and revenue reconciliation. Therefore, the total cost of the VAR capacity market minus the charges to loads equals the charges to contingencies. In addition, the distribution of charges in multiple contingencies can be easily achieved using the sensitivity indices.

Although this alternative requires a higher computational effort, because of the multiple VAR capacity market clearings, it is the selected alternative due to its characteristics of fairness in charging distribution for single and multiple contingencies.

5.3.2.2 Implementation of the proposed charging mechanism

This thesis proposes to charge devices responsible for contingencies in order to cover the extra VAR needs under these operating conditions. For instance, the additional VAR capacity needed to meet the security limits in the case of generator unavailability will be paid by that generator owner. Similarly, the corresponding transmission owner will pay the additional costs due to line unavailability. *These charges will be settled according to the location and influence on VAR costs of each device outage, which is obtained from long-term marginal signals based on the Lagrange multipliers using the Aumann-Shapley methodology.*

The procedure to calculate the Aumann-Shapley values is presented in Figure 5.4. The generator and line states are scaled for each of the iterations in the iterative process. Then, for each iteration the VAR capacity market problem is solved. The resulting Lagrange multipliers are stored in order to obtain their average values that will settle the distribution of the charges.

The implementation of the proposed approach requires some considerations on how to model the generator unavailability and transmission line trip, which are discussed in the next paragraphs.

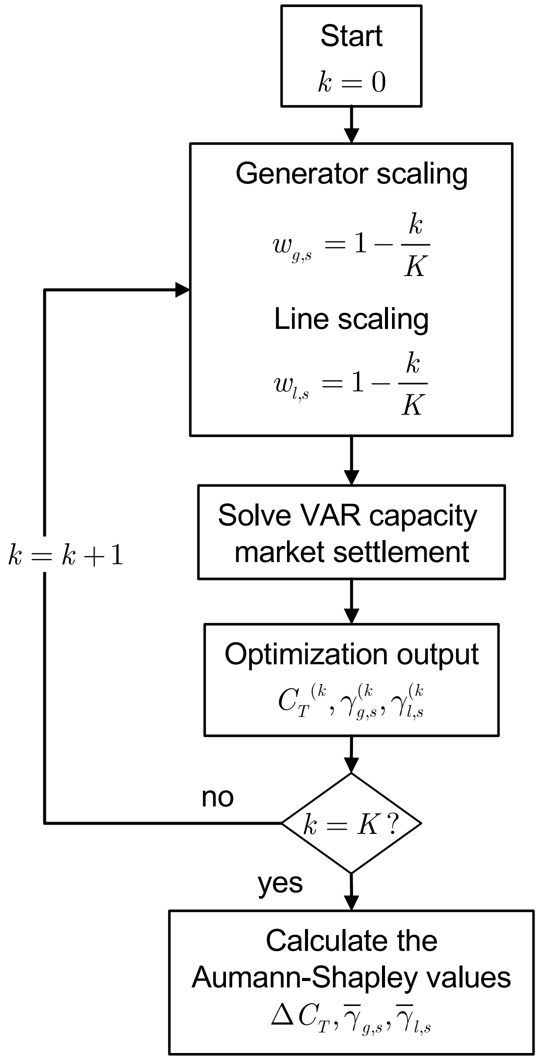

Figure 5.4: Calculation of the VAR cost allocation for contingencies

Generator unavailability To model the generator unavailability under the Aumann-Shapley methodology, the generator active and reactive power limits are modified for the scenario where it is unavailable. For this purpose a new variable $w_{g,s}$ is introduced, which indicates the available active and reactive power capacity for generator g in scenario s in per unit. Then, if the generator is available $w_{g,s} = 1$, and $w_{g,s} = 0$ in case on unavailability. In each iteration of the Aumann-Shapley procedure $w_{g,s}$ will be adjusted to a value in the range of 0 to 1. This variable is included in some of the equations of the VAR capacity market formulation: VAR generation limits (5.26)(5.27), generator output limits (5.28), and the active power dynamic response (5.29)(5.30). This variable is only modified in order to calculate the distribution of the charges, and equals 1 or 0 for the VAR capacity market settlement (5.25).

$$w_{g,s} = 1 \quad \forall g \forall s \qquad : \gamma_{g,s} \tag{5.25}$$

$$0 \leq q_{g,s}^{A} \leq w_{g,s} \cdot qa_{g}^{A} \qquad \forall g \in G \ , s \in S \tag{5.26}$$

$$0 \leq q_{g,s}^{G} \leq w_{g,s} \cdot qa_{g}^{G} \qquad \forall g \in G \ , s \in S \tag{5.27}$$

$$w_{g,s} \cdot u_g \cdot P_g^{\min} \leq p_{g,s} \leq w_{g,s} \cdot u_g \cdot P_g^{\max} \qquad \forall g \in G, s \in S \tag{5.28}$$

$$-w_{g,s} \cdot \Delta P_g^{d} \leq p_{g,s} - p_{g,s_b} \leq w_{g,s} \cdot \Delta P_g^{u} \quad \forall g \in G, s \neq s_b \tag{5.29}$$

$$p_{g,s_{g_f}} = p_{g,s_b} + p_{g_f,s_b} \frac{w_{g,s} \cdot P_g^{\max} - p_{g,s_b}}{\sum_{g \neq g_f} \left(w_{g,s} \cdot P_g^{\max} - p_{g,s_b} \right)} \qquad \forall s \in S/s_b, g \in G/g_f \tag{5.30}$$

The charges to be paid by the generator unavailability in the scenario s_{gf} are obtained as the average value of the Lagrange multipliers associated with the $w_{g,s_{gf}}$ equation, where s_{gf} is the scenario where generator g is unavailable. As the Lagrange multipliers are expressed in k€ per unit, and the variation of $w_{g,s}$ is from 1 to 0, then the charges are directly obtained as the average Lagrange multiplier (5.31).

$$CH_{s_{gf}} = \frac{1}{K} \sum_{k} \gamma_{g,s_{gf}}^{(k} \tag{5.31}$$

where:

$CH_{s_{gf}}$	Charges to generator g that is unavailable in scenario s_{gf} (€-year)
$\gamma_{g,s_{gf}}^{(k}$	Lagrange multiplier in the Aumann-Shapley iteration k of the state variable $w_{g,s_{gf}}$
K	Number of iterations in the Aumann-Shapley procedure

If generator g participates in more than one single scenario, then the total charge to that generator will be calculated as the sum of the single charges for each contingency (5.32).

$$CH_g = \sum_{s/g=off} CH_s = \sum_{s/g=off} \frac{1}{K} \sum_{k} \gamma_{g,s_{gf}}^{(k} \tag{5.32}$$

Transmission line unavailability The unavailability of a transmission line is modeled as a variation in the parameters of the system impedance matrix conductance (5.34) and susceptance (5.35). The variation depends on a binary variable $w_{l,s}$, which defines the state of the transmission lines, $w_{l,s} = 1$ if the transmission line l is available, and $w_{l,s} = 0$ if it is unavailable. Additionally, there is a new constraint associated with the line state variable whose Lagrange multiplier is $\gamma_{l,s}$ (5.33).

$$w_{l,s} = 1 \quad \forall l, \forall s/s_l \quad : \gamma_{l,s} \tag{5.33}$$

$$\begin{aligned} g_{n,m,s_l} &= g_{n,m,s_b} \cdot w_{l,s_l} \\ g_{m,n,s_l} &= g_{m,n,s_b} \cdot w_{l,s_l} \\ g_{n,n,s_l} &= g_{n,n,s_b} + g_{n,m,s_b} \cdot (1 - w_{l,s_l}) \\ g_{m,m,s_l} &= g_{m,m,s_b} + g_{n,m,s_b} \cdot (1 - w_{l,s_l}) \end{aligned} \tag{5.34}$$

$$\begin{aligned} b_{n,m,s_l} &= b_{n,m,s_b} \cdot w_{l,s_l} \\ b_{m,n,s_l} &= b_{m,n,s_b} \cdot w_{l,s_l} \\ b_{n,n,s_l} &= b_{n,n,s_b} + b_{n,m,s_b} \cdot (1 - w_{l,s_l}) \\ b_{m,m,s_l} &= b_{m,m,s_b} + b_{n,m,s_b} \cdot (1 - w_{l,s_l}) \end{aligned} \tag{5.35}$$

where:

g_{n,m,s_l}, b_{n,m,s_l}	Real and imaginary part of the admittance matrix corresponding to buses n and m for scenario s_l where line l is unavailable (℧)
g_{n,m,s_b}, b_{n,m,s_b}	Real and imaginary part of the admittance matrix corresponding to buses n and m for normal operation scenario s_b (℧)
w_{l,s_l}	Variable that defines the state of the transmission line l (0: opened, 1: closed)

For the Aumann-Shapley allocation, the line state variable is fixed within a value from 0 to 1 in different steps k (5.36).

$$w_{l,s} = 1 - \frac{k}{K} \tag{5.36}$$

Finally, the costs allocated to the unavailability of a line are calculated as the average value of the Lagrange multipliers associated with the constraint (5.37). If the line outage is included in different scenarios, then the total charge for that transmission line owner will consider its contribution to each contingency.

$$CH_l = \sum_{s/l=off} CH_{s_l} = \sum_{s/l=off} \frac{1}{K} \sum_k \gamma_{l,s_l}^{(k} \tag{5.37}$$

where:

CH_l Charges to transmission line l (€-year)

$\gamma_{l,s_l}^{(k}$ Lagrange multiplier associated with the constraint of the transmission line state

Illustrative case:

The Aumann-Shapley methodology divided the state variables $w_{l,s}$ and $w_{g,s}$ of the circuit 1-2 and generators #2 and #3 into 10 subintervals. The next table presents the average Lagrange multipliers that equal the annual charge for each agent responsible of a contingency.

Table 5.3: Application of Aumann-Shapley methodology to equipment failure

	Circuit unavailability	**G2 unavailability**	**G3 unavailability**
Average value (k€/p.u.)	$\sum_{s=2,5,7,8} \gamma_{l,s}$ 134.3	$\sum_{s=3,5,6,8} \gamma_{2,s}$ 142.7	$\sum_{s=4,6,7,8} \gamma_{3,s}$ 89.2
Annual charge (k€-year)	134.3	142.7	89.2

The three agents have a similar impact on the total costs in the VAR capacity market. Finally, the money collected from the charges under contingency situations is 366k€-year.

5.4 Final economic settlement

According to the proposed remuneration scheme, the charges collected to the VAR demand will pay the remuneration of the selected VAR capacity bids, as formulated in (5.38), excluding the other costs which are included in the objective function. The Aumann-Shapley procedure has already settled the efficient charges for the contingency scenarios. Then, in order to achieve a full revenue reconciliation in the VAR capacity market, a normalization process is performed to the load charges, as the current charging scheme usually results in an over recovery.

$$\sum_g R_g + \sum_c R_c + \sum_r R_r = \alpha \sum_n CH_n + \sum_{g\,\text{failed}} CH_g + \sum_{l\,\text{failed}} CH_l \tag{5.38}$$

where:

CH_g, CH_l, CH_n Charges to agents responsible for VAR demand (€-year)

R_g, R_c, R_r Remuneration for the selected VAR capacity bid(€-year)

α Normalizing factor

Illustrative case:

Table 5.4: Final economic settlement

	Remuneration (k€-year)	**Charge** (k€-year)	**Total** (k€-year)
Generator #1	157	-	157
Generator #2	68	143	-75
Generator #3	245	89	156
Capacitor bank #2	93	-	93
Line circuit	-	134	-134
Load at bus #1	-	15.5	-15.5
Load at bus #2	-	181.5	-181.5

Generators #1 and #3 and the capacitor bank located at bus #2 will get benefits in the final settlement of the VAR capacity market. On the other hand, loads will be charged for most of the costs according to their load volume. The agents responsible for contingencies, which are the transmission line and generator #2, will be charged for the rest of the costs. Observe that charges to generator #2 are higher than the VAR capacity payments, which is not the case of generator #3. Finally, the sum of the economic flows equals zero, which confirms the revenue reconciliation.

5.5 Other economic flows

As presented in the previous sections, the economic flows in the proposed VAR capacity market are associated with the remuneration of the selected VAR capacity bids, and the corresponding distribution of charges to cover these payments. The other costs terms included in the objective function are necessary for the efficient selection of the VAR capacity bids, and are associated with the expected operation costs resulting from the use of the selected VAR capacity. Some of these cost terms already have specific economic flows associated with their charging and remuneration. This thesis dissertation proposes that the real costs for the VAR operation costs should be charged using real-time signals, for instance marginal pricing or other methods.

- The effect of *energy losses* in the operational VAR costs is currently integrated into the general transmission loss allocation mechanism in force in each power system. There are different theoretical and practical loss allocation methodologies, such as the pro-rata procedures, the allocation based on marginal prices, and the proportional sharing [Conejo et al., 2002, Unsihuay and Saavedra, 2003]. Therefore, the VAR capacity market will not recover or be compensated by the energy losses costs.

- Similarly, the compensation to customers for *load shedding* has its own mechanisms. The responsible agents for the non-supplied energy are usually penalized according to their contribution to the emergency situation. In addition, power systems currently do not include *voltage quality penalties* as proposed in (4.18). In order to efficiently distribute the responsibilities under contingency situations (for instance, measuring the impact on energy non-supplied and voltage value of active and reactive power unavailability) economic signals can be obtained from specific OPF formulations that model the corresponding operating conditions. For example, a charging scheme is formulated in (5.39) based on marginal pricing.

$$CH_n^V = \frac{\partial C_V}{\partial PD_n} PD_n + \frac{\partial C_V}{\partial QD_n} QD_n \tag{5.39}$$

where:

CH_n^V	Charge for voltage deviations to load located at bus n (€)
C_V	Real costs for voltage deviations (€)
PD_n, QD_n	Active and reactive power demand at bus n (MW,Mvar)

- The charges to cover the *regulated payments of the VAR energy* can be based on schemes similar to those used for energy losses distribution, among which stands the real-time VAR marginal pricing. Since the duration of the normal operation situations is much higher than that of contingencies, loads will be charged for most of the VAR capacity use during normal operation, as formulated in (5.40). These charges will be distributed among the corresponding generators in proportion to their real VAR energy production.

$$CH_n^{QE} = \frac{\partial C_{QE}}{\partial PD_n} PD_n + \frac{\partial C_{QE}}{\partial QD_n} QD_n \tag{5.40}$$

where:

CH_n^{QE}	Charge for VAR energy to load located at bus n (€)
C_{QE}	Real costs for VAR energy (€)

- Finally, those generators whose output is redispatched in order to increase the VAR procurement will receive a compensation for the *opportunity costs*. Similar mechanisms as those proposed for the previous cost terms can be used to distribute these charges among the responsible agents.

5.6 Summary of the VAR capacity market procedure

A general overview of the procedures designed to settle, remunerate and charge in the VAR capacity market are presented in Figure 5.5. First, three independent modules are considered, i) data management, ii) VAR capacity market for peak hours and iii) VAR

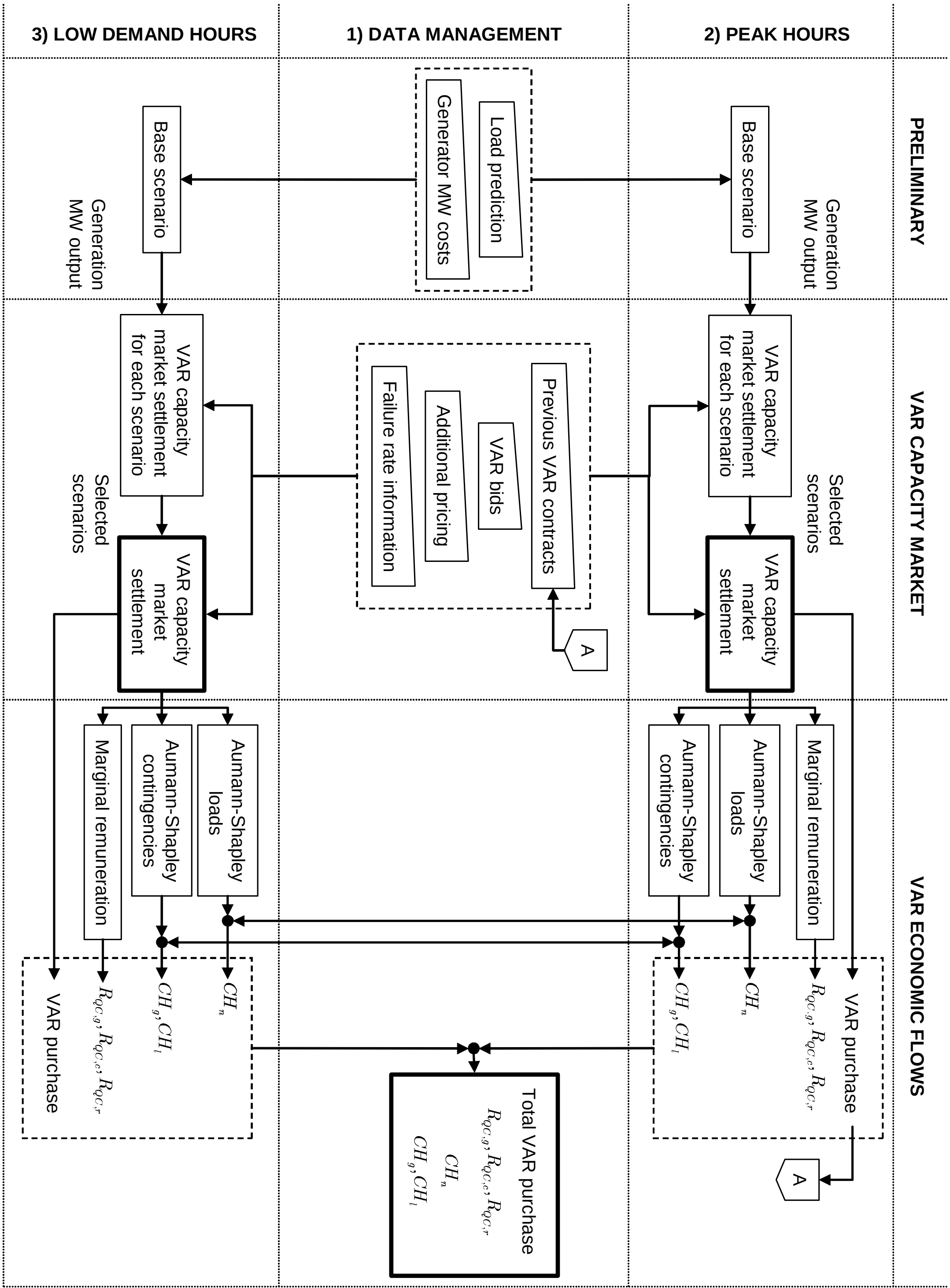

Figure 5.5: Detailed framework of the VAR capacity market

capacity market for low demand hours. In the data management module, the SO collects all the necessary information for the correct characterization and valuation of the VAR sources. Historical data on the generation costs, load demand, and VAR contracts and VAR energy will define the needs for VAR in the following year. On the other hand, the inputs in the VAR capacity auction are the characteristics of each market agent, including VAR bids, failure rates and operating limits. Additionally, parameters for energy quality valuation in the corresponding power system are needed.

The VAR capacity market for peak and low demand hours is divided into three parts, i) preliminary data management, ii) VAR capacity market settlement, and iii) VAR capacity economic flows. Firstly, variable costs of generators, load and network data will define the base case scenarios. The information of the failure rates of power system devices will identify the main contingency scenarios to be analyzed. For simplicity, only those scenarios with the highest impact on VAR needs will be considered. Then, all the information for the VAR capacity market is included in the optimization problem, for the base scenario and all the selected contingencies, and the then finally VAR capacity market is settled. The selected VAR capacity will be an input for the VAR capacity market in low demand hours.

The sensitivity coefficients obtained from the optimization problem are the basis for the remuneration and charging of the market agents. The remuneration of the VAR procurement is based on marginal pricing. An additional analysis with the Aumann-Shapley methodology is needed to distribute the charges between the VAR demand agents.

A similar procedure is used for the VAR capacity market in low demand hours. VAR needs are determined considering specific base scenarios, together with the results of the previously solved VAR market for peak hours. Finally, the resulting selected VAR capacity, payments to the VAR procurement, and charges to VAR demand are obtained as the sum of the outcomes of both VAR capacity markets.

5.7 Conclusions

This chapter has presented the remuneration mechanism for the selected VAR sources and a charging methodology for the demand in the VAR capacity market (see Figure 5.6). The main objective in the design of the mechanism for remuneration and charging is to send efficient cost and location signals to the participating agents in the VAR capacity market. For this aim, it has been found that the remuneration and charging schemes should be based on marginal pricing which differentiates short term and long term price signals.

On the one hand, the selected bids for VAR capacity will be remunerated using long-term marginal prices which are obtained from the VAR capacity market formulation.

On the other hand, charges will distinguish loads, which will pay for the VAR capacity installed in the base case, and agents responsible for contingencies that will assume the over cost resulting from their unavailability. From the analysis carried out in this chapter it has been concluded that these charges should be distributed using curtailed marginal prices that exclude the sensitivity with the variable costs of generators for procuring active power. In addition, the appropriate distribution of charges should be formulated using the Aumann-Shapley methodology, as it provides fair treatment and revenue reconciliation. These economic flows are made ex-ante, once the VAR capacity market is cleared.

There are other costs terms included in the objective function that are necessary for the efficient selection of the VAR capacity bids and which are associated with the operation costs resulting from the use of the selected VAR capacity. Some of these cost terms already have specific economic flows associated with their charging and remuneration, for instance energy losses. The other operating costs usually arise under contingency situations, such as voltage deviations and non-supplied energy. This chapter concluded that specific short-term economic signals should be sent to the responsible agents, for example based on marginal pricing. Similarly, the use of the VAR capacity and opportunity costs should be compensated to generators using similar short-term signals.

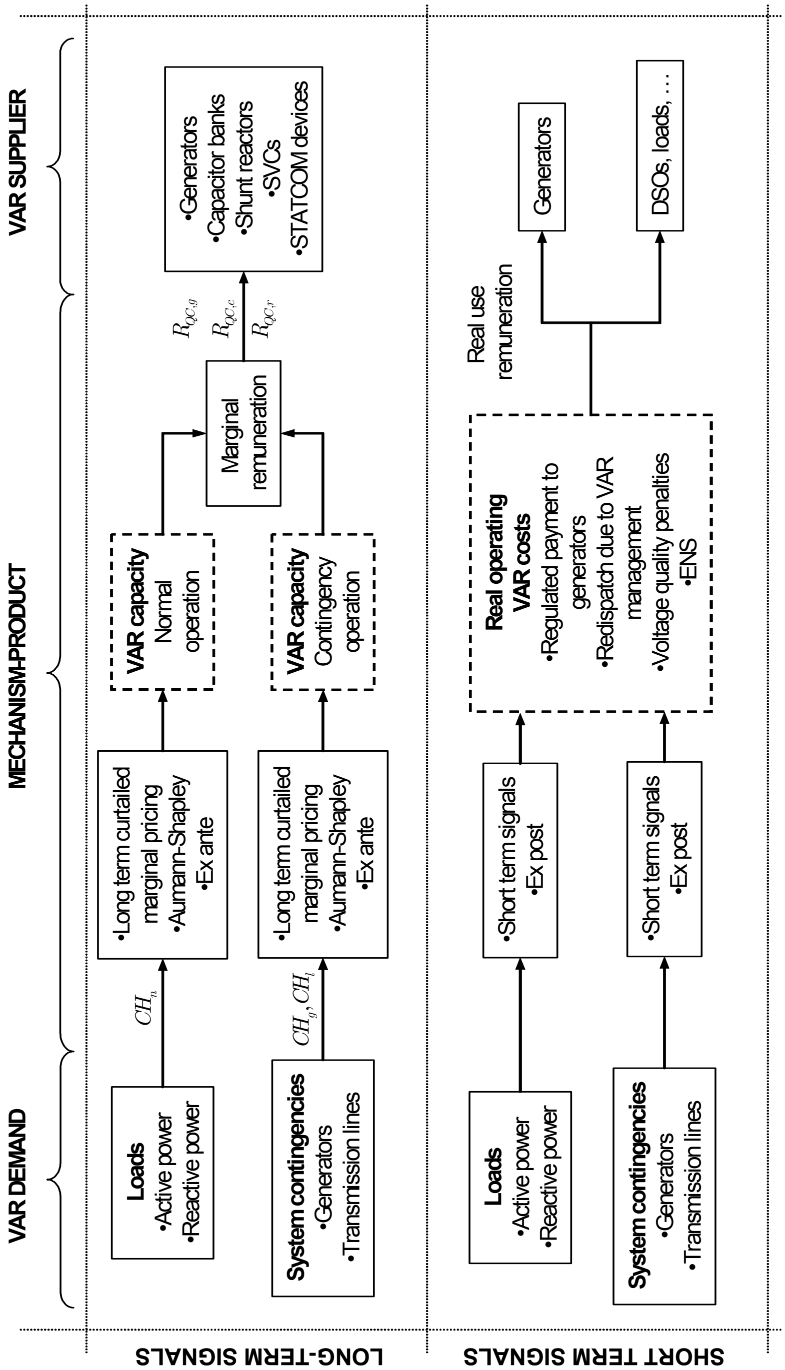

Figure 5.6: Resume of the economic flows in the VAR capacity market

5.8 References

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CHAPTER 6

Case Study

In the previous chapters, a proposal for the regulation of the VQ service was presented. A simple illustrative case was used throughout the description of the VAR capacity market to illustrate the main concepts of the proposal. This chapter includes a larger case study, with 39 buses, and 10 generation units, emulating a voltage control area in a real power system.

First, the case study is presented, including a brief description of the power system and the bids for the VAR capacity market. Then, the annual auction is cleared using the formulation proposed in the previous chapters. The results are first analyzed from a technical point of view, identifying the main voltage control actions. Finally, the economic flows for the VAR capacity market are settled, comprising the remuneration of the VAR procurement, and the charges to the VAR demand.

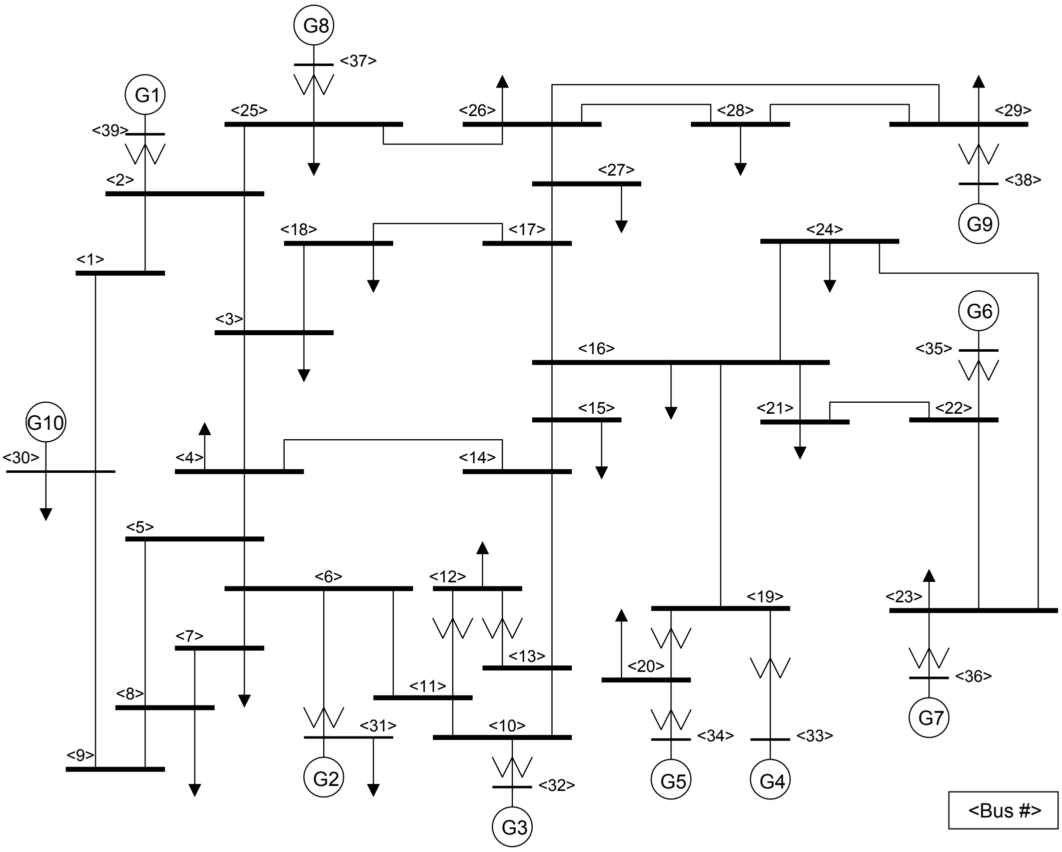

Figure 6.1: One-line diagram of the New England 39 bus test system

6.1 Description of the case study

This section first presents the main characteristic of the test system. Then, the VAR capacity bids of the agents participating in the annual VAR capacity auction are described. The demand for the capacity is defined taking into account the load in peak and low demand hours and the failure rates of the power system devices. Finally, the additional cost terms involved in the optimal purchase of VAR capacity are characterized.

6.1.1 Test system

The one-line diagram of the case study is shown in Figure 6.1. The 39 bus system is a simplified representation of the 345kV transmission system in the New England region of the United States [GEC, 1971, Athay et al., 1979, Pai, 1989]. This test system is well known in research literature for reliability and voltage studies. The power system is well-meshed, and has 10 generators, which are located at buses #30 to #39. All other buses are load buses, and can be selected to place new VAR compensation devices. A detailed description of this case study can be found in Appendix D.

Table 6.1: Bids for the VAR capacity market

Market agent	$Q^{G,Pmax}$ (Mvar)	A_g^G (€/kvar-year)	B_g^G (€/kvar^2-year)	$Q^{A,Pmax}$ (Mvar)	A_g^A (€/kvar-year)	B_g^A (€/kvar^2-year)
G1	620	1.1	0.01	-485	1	0
G2	500	1.5	0	-400	1.69	0
G3	800	1.35	0	-315	1.2	0
G4	400	1.5	0.01	-315	1.1	0
G5	315	1.85	0	-250	1.19	0
G6	150	0.9	0	-115	1.3	0
G7	350	1.56	0	-250	1.2	0
G8	550	1.07	0	-250	1.39	0
G9	550	20.5*	0	-400	20*	0
G10	900	1.69	0.02	-500	1	0
Capacitor bank	500	10	0	n.a.	n.a..	n.a.
Shunt reactor	n.a.	n.a.	n.a.	-500	16	0
SVC	500	18	0	-500	18	0
STATCOM	500	40	0	-500	40	0

(* The bid price of generator 9 is much higher than the other VAR compensation technologies in order to analyze the exercise of market power in the proposed VAR capacity auction)

The adequate voltage control in the case study is procured by 10 generation units and, if needed, by other VAR sources such as capacitor banks, SVCs or STATCOM devices. The research literature provides an initial overview of the voltage control problem in the New England case study, for example based on a secondary voltage control loop which is based on a set of reference or pilot buses. According to the selected buses, the power system can be divided into three or four voltage control areas, based for instance on the sets #18, #20, #22 and #26 [Conejo et al., 1993, de la Fuente, 1997].

6.1.2 Description of the VAR capacity bids

The capacity bids of the different agents are presented in Table 6.1 with separate bids for VAR generation capacity and VAR absorption capacity. As proposed in Chapter 3, capacity bids correspond to the connection point to the transmission network, which is the high voltage side of the step-up transformer. Therefore, the initial power system with 39 buses can be reduced to a network of 30 buses. Next, the capacity bids in the case study are analyzed, comprising the definition of the offered VAR capacity and the corresponding price.

To obtain the maximum capacity at the connection point, the operating constraints of the generation power plant must be considered. An example of the calculation of the VAR bid capacity is presented in Table 6.2 for Generator #6, including the different positions of the step-up transformer tap. The capacity limits were obtained for the

Table 6.2: Example of the VAR capacity bid for generator #6

Tap ratio position	$Q_g^{G,P\max}$ (Mvar)	$Q_g^{G,P\max}$ Operation limit	$Q_g^{A,P\max}$ (Mvar)	$Q_g^{A,P\max}$ Operation limit
1	0	Max rotor current	0	Min generator voltage
2	0	Max rotor current	0	Min generator voltage
3	150.1	Max rotor current	-12	Min generator voltage
4	133.6	Max generator voltage	-60.7	Min generator voltage
5	79.7	Max generator voltage	-115.3	Min generator voltage

rated active power generation (275 MW), and a typical voltage at the connection point of 1.03 p.u. (a complete description of these calculations can be found in Appendix B). The available VAR capacity for the generator is mainly limited by voltage constraints on the generation side. The proposed offered capacity will be 115 Mvar of generation capacity and -115 VAR of absorption capacity, and if the proposed bid is selected, then the generator will have to adjust the corresponding tap of the step-up transformer.

The bid prices of generators takes into account different costs, as described in Chapter 5 and Appendix B. In this case study, all generators participate in the annual auction for both VAR generation and absorption capacity with bid prices in the range of 0.9 to 1.85€/kvar-year. The proposed bid prices are similar to the regulated compensations established for VAR capacity in different power systems which vary from \$1/kvar-year in New England to nearly \$8/kvar-year in the United Kingdom (a complete review of these prices is presented in Appendix A)[1].

In order to observe how the proposed approach deals with market power, the bid price of generator #9 is settled well above the cost of other compensation technologies. This generator is selected as it is the only dynamic VAR source in the area comprised of buses #17 and #26 to #29.

Other VAR compensation technologies, such as capacitor banks, shunt reactors, SVCs and STATCOM devices, can be located at any bus of the network. The new installed capacity is limited for each technology to 500Mvar in each bus, which is associated to possible physical constraints in the substation. The bid prices for the VAR capacity of these compensation technologies correspond to typical variable costs, as was reviewed in Appendix B. The bid prices are presented in Table 6.1, and are in the range of 10€/kvar for capacitor banks to 40€/kvar-year for STATCOM devices.

Finally, for a better understanding of the results, it is assumed that no previous auctions

[1] Taking into account that an average value for the capacity payment is approximately \$10/kVA-year, the average price for VAR capacity represents 10% of this payment.

Table 6.3: Energy dispatch for peak and valley scenarios

Generator #	**Peak** (MW)	**Valley** (MW)
G1	1000	1000
G2	523.4	523.4
G3	650	150
G4	122.54	0
G5	631.64	631.64
G6	274.2	0
G7	560	130
G8	540	540
G9	830	210
G10	1018.55	505
Sum	6150.33	3690.20

of the VAR capacity market have taken place.

6.1.3 Description of the VAR capacity demand

The optimal selection of the best VAR capacity bids considers different operation scenarios. These scenarios are built taking into account the load consumption for peak and low-demand periods, and the different probable contingencies due to the unavailability of certain network devices.

The load in the power system is 6097 MW for peak hours, which is distributed as presented in Appendix D. Most of the loads in this case study have a power factor over 0.94, with the exception of the load located at bus #12 that has a power factor of 0.08[2]. Finally, the load located at bus #24 generates reactive power, due to an excess of VAR compensation. On the other hand, the load in low-demand hours corresponds to 60% of the peak load, with the same power factor, resulting in 3658 MW active power load.

The generation dispatch for both base scenarios is shown in Table 6.3. During peak hours all generation units are connected, while during low-demand hours generators, #4 and #9 are not dispatched.

The contingency scenarios in the proposed case study consider the failure rates of 9 generation units and the outage of five critical transmission lines. Their equivalent duration is presented in Table 6.4. Generator #10 represents the neighboring networks, and its associated failure rate can be neglected compared with the other system devices. The considered failure rates for forced outages are based on typical values:

[2]A reduced power factor can be associated to electric arc furnaces with active power supply and no VAR compensation.

Table 6.4: Failure rates of the power system devices in the New England 39 test system

Technology	**Description**	**Peak demand** (hours)	**Low demand** (hours)
Nuclear	G1	98	196
Hydro	G2	46	92
Thermal	G3	82	164
Thermal	G4	53	106
Hydro	G5	48	96
Thermal	G6	79	158
Thermal	G7	88	176
Hydro	G8	44	88
Thermal	G9	81	162
Hydro	G10	0	0
Trans. line	B8-B9	1.1	2.2
Trans. line	B13-B14	1.7	3.4
Trans. line	B16-B17	2	4
Trans. line	B21-B22	2	4
Trans. line	B28-B29	1.3	2.6

- A typical outage time of *power plants* over 500MW is 250 hours-year for hydraulic units, 400 hours-year for fossil-fuel units, and 500 hours-year for nuclear units [Billinton and Li, 1994].

- The failure rates for *transmission lines* comprise both failures associated with the lines, and those of the circuit breakers at both ends. For the 345kV network in the case study, a typical outage time is 0.56 hours-year for the transmission lines plus 8.7 hours-year for the circuit breakers, which results in 9 hours-year.

- Finally, the failure rates for the other *VAR compensation technologies*, such as capacitor banks and shunt reactors, are neglected compared to those for generation units.

6.1.4 Additional data for the VAR capacity market

As described throughout this thesis dissertation, the optimal selection of the VAR capacity bids is a trade-off between the VAR capacity purchase and other expected operation costs. These additional cost terms are valuated as follows:

- The regulated payment to generators *VAR energy* production is set at A_g^{EG}=0.32€/Mvarh for VAR generation, and A_g^{EA}=0.256€/Mvarh for VAR absorption, as formulated in (4.13).

Table 6.5: Run-time of the optimization model for the VAR capacity market in the case study

	Peak demand scenario (seconds)	**Low-demand scenario** (seconds)
VAR capacity market settlement	370	383
Charging to loads calculation	2235	832
Charging to contingencies calculation	1266	6874
Total run-time	3871	8089

- The voltage reference range for peak and low demand hours is set at 0.95-1.05p.u. In the case of contingencies, voltages can be in the range of 0.85-1.1p.u. Voltages out of this range are penalized according to the coefficients A^{U}_{V,s_b}=185€/kWh/V^2, and A^{O}_{V,s_b}=208€/kWh/V^2 (voltage V in per unit system) for under and over voltages as formulated in (4.18). Under certain emergency situations some loads can be disconnected in order to maintain voltages within the security range of 0.8-1.2 p.u. The non-supplied energy under these circumstances is paid at A_D=6€/kWh, as formulated in (4.17).

6.2 VAR capacity market settlement

This section presents the results of the VAR capacity market clearing algorithm which comprises the optimal selection of VAR capacity bids for peak hours and low-demand hours. The size of the optimization problem for this case study is determined by: 10 generators, 30 possible locations for capacitor banks, shunt reactors, SVCs and STATCOM devices, 15 operating scenarios, 37 transmission lines, 30 buses, 1 voltage control area and no transformer tap adjustment. The resulting optimization problem size is defined by 10 binary variables, and a total of 32,359 real variables. The total number of equations is 10,541, from which 2,566 are non-linear equations. The run-times for solving the proposed formulation are presented in Table 6.5, using a 1.86GHz Pentium machine with the SBB and CONOPT solvers [Stolbjerg-Drud, 1993, Bussieck and Drud, 2001] running under GAMS [Brooke et al., 1988].

6.2.1 VAR capacity purchase for peak hours

The purchase of VAR generation and absorption capacity for peak hours is shown in Figure 6.2. All bids for VAR generation capacity are selected, except that of generator #9. The VAR capacity of this generator is substituted by an SVC located at bus #29. Four bids for capacitor banks are also selected at buses #3, #8, #21 and #29. No bid for VAR absorption capacity is selected.

The VAR capacity bid of generator #9 is not selected due to its high price. To provide the VAR support to buses #26, #28, and #29, the bid of a SVC is selected, comprising

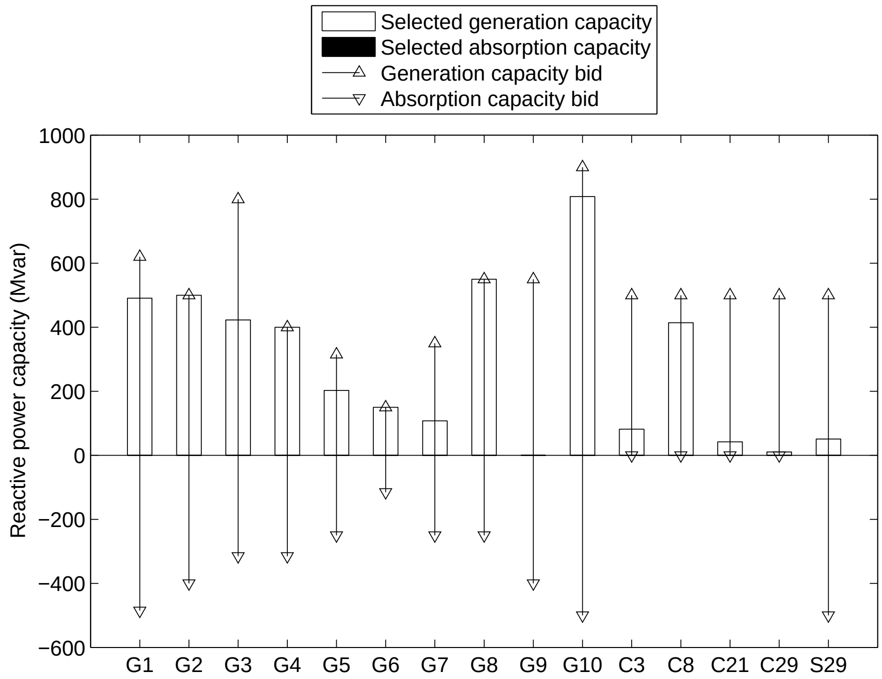

Figure 6.2: Selected VAR capacity bids for generation and absorption during peak hours

(G#: generator number; C#: capacitor bank located at bus #; S#: SVC located at bus #)

both generation and absorption capacity (as will be described in the next section). Therefore, although generator #9 has market power in the area for providing VAR, the installation of new VAR sources prevents the exercise of its predominant position.

The locations of the purchased VAR capacity to capacitor banks and SVC according to the proposed objective function are similar to the results of other technical studies reported in research literature. For instance, [Wang et al., 2003] analyzed the weakest locations in the New England 39 test system as far as system voltage profile is concerned, and identified buses #4 and #13 for the installation of SVCs, and buses #8 and #14 for the installation of STATCOM devices. Both analyses agree in the choice of buses #4 and #8 (the proposed VAR capacity auction selects bus#3 which is next to bus #4). Buses #29 and #21 do not coincide with the analysis in [Wang et al., 2003] as the proposed VAR capacity market considers additional economic and technical information such as failure rates of system devices.

The VAR generation provided by the selected VAR sources in the base case compensates the VAR demand from both the loads and the net absorbed VAR from the network (the loading levels of most transmission lines are over their natural load[3], and therefore the

[3]The natural loading of a power transmission line (see section 2.1.1), also known as the surge impedance loading (SIL), is the active power loading when reactive power is neither produced nor absorbed. It is calculated as $SIL=\frac{V^2}{Z_0}$, where V is the voltage level, and Z_0 is the characteristic or surge impedance of the transmission line which is obtained as $Z_0=\sqrt{\frac{R+j\omega L}{G+j\omega C}}$.

network behaves like a shunt reactor).

Half of the selected bids include the whole VAR capacity bid. Once the generator capacity is exhausted, some buses require additional VAR which is provided by capacitor banks. For instance, the area defined by the buses #3, #4, #5, #7, and #8 is weak in getting VAR support and is likely to have low voltages especially under contingent operation. Therefore, the installation of capacitor banks at buses #3 and #8 will help to maintain voltages.

SVCs are modeled as a mix of a capacitor bank and a shunt reactor, procuring a better dynamic VAR performance. On the other hand, the dynamic VAR support provided by STATCOM devices is similar to that provided by generators. The dependence of the actual VAR capacity on the voltage value of SVCs is by the squared; however STATCOM devices are characterized by a proportional dependence on voltage. Due to the specific characteristics of this case study, no bids of STATCOM devices are selected, because there are enough inexpensive and reliable dynamic VAR capacity bids provided by generators. Moreover, capacitor banks and SVCs are preferred since they are cheaper compensation alternatives. STATCOM devices will become an interesting option in areas with deteriorated voltages, where the available VAR capacity of other technologies is reduced by the squared voltage.

All the units are dispatched during peak hours, hence no generator start-up is required. Moreover, the initial dispatch is not modified because there are no network constraints. Finally, the possible redispatch associated with the output reduction to increase the VAR capacity[4] is not profitable as the resulting opportunity costs are much higher than the benefits obtained from increasing the VAR capacity provided by generators. The opportunity costs, which are more expensive than the purchase of VAR capacity even from capacitor banks, should be paid for the whole peak demand period.

The contingency scenarios considered in the case study require additional VAR production, as presented in Figure 6.3 and Figure 6.4. For those scenarios with the trip of a generation unit, the other generators modify their output according to the AGC signals, and compensate the loss of VAR capacity by increasing their VAR output. In the case of a line outage, the power flows change, increasing the loading levels of the rest of the lines, hence the VAR consumed by the network becomes higher. According to the dynamic performance of the capacitor banks and shunt reactors (as described in Appendix D), their VAR capacity is not modified under contingencies, and therefore equals the selected capacity in the auction. Then, the dynamic VAR support to the system is provided by generators and the SVC.

6.2.2 VAR capacity purchase for low-demand hours

The VAR capacity bids selected for peak hours are considered as already acquired and available when the VAR capacity needs for low-demand hours are analyzed. The bids

[4] The simplified capability curves of the generators are provided in Table D.2 in Appendix D.

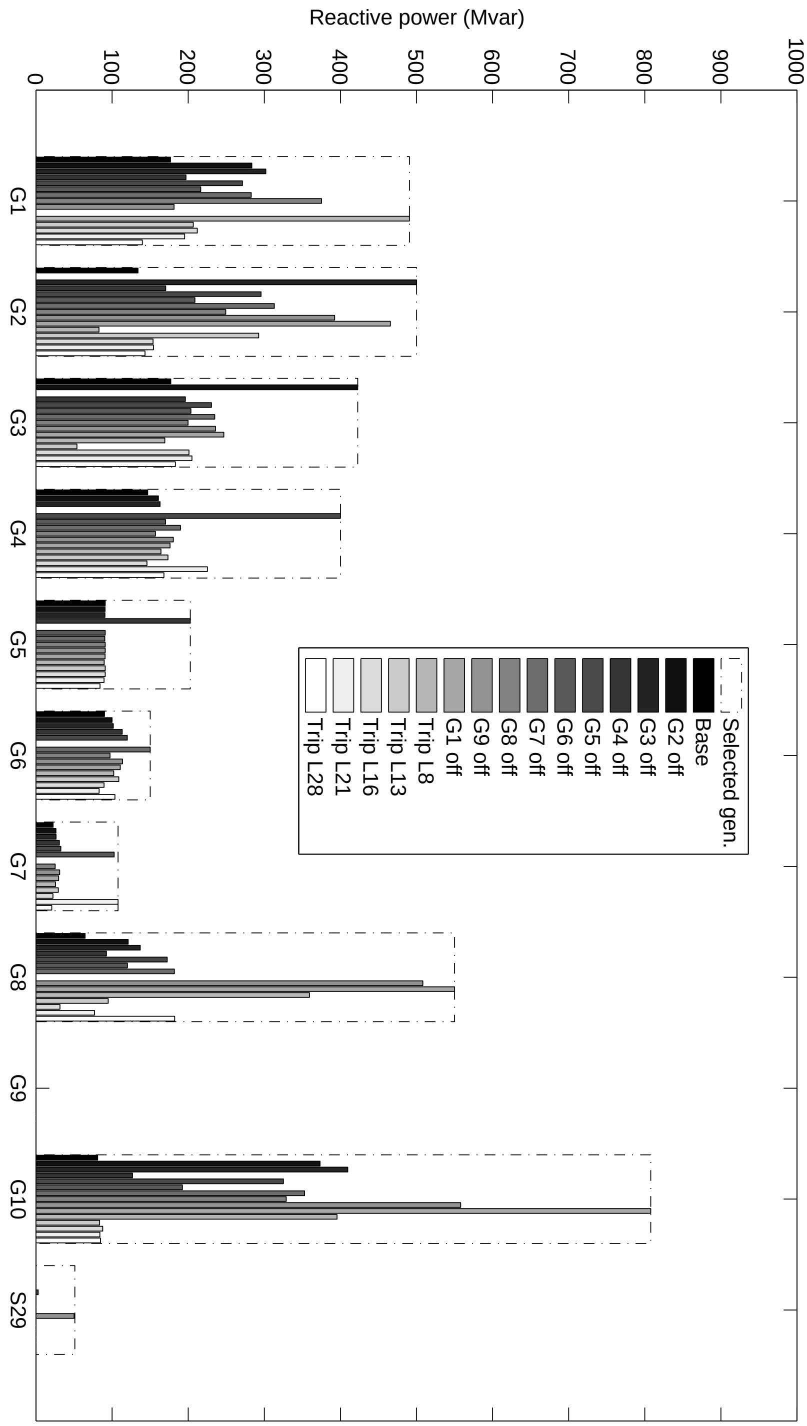

Figure 6.3: VAR output of selected VAR sources for the different contingencies during peak hours

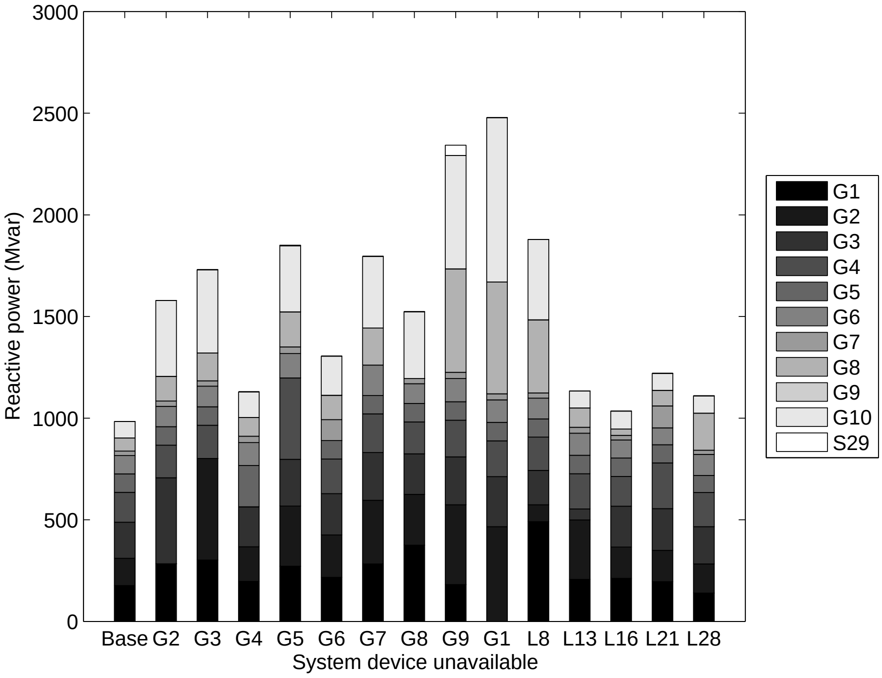

Figure 6.4: Aggregated VAR output of selected VAR sources for the different contingencies during peak hours

selected for this period are presented in Figure 6.5, comprising VAR capacity absorption of two generators and the already installed SVC.

During low-demand hours the loads reduce their VAR consumption, and the network is light loaded and behaves as a capacitor bank. The VAR provided by generators is reduced compared with that used during peak hours, and therefore there is no need to purchase additional VAR generation capacity. The VAR needs during low demand hours do not require additional compensation from shunt reactors, as there is enough inexpensive VAR support provided by generators. Finally, there is no redispatch of generation during this period.

The purchased absorption VAR capacity together with the generation capacity previously assigned must be procured by the agents for the whole year. These maximum VAR capacity purchases have simultaneously taken into account all the possible operating scenarios, both normal operation and contingencies, where the purchased capacity is used. In addition, a VAR reserve is needed in order to cover the possible contingencies during low-demand hours as shown in Figure 6.6 and Figure 6.7. The outage of a generation unit requires that other generators compensate the lost VAR capacity, which is critical in the case of the unavailability of generators #1 and #9. The trip of a transmission line during low-demand hours modifies the voltage profile at both ends of the line, and additional VAR support is needed to maintain an adequate voltage level. For instance, the trip of the line 16-17 requires that generator #8 and the SVC increase their VAR absorption to reduce the resulting voltages in the area.

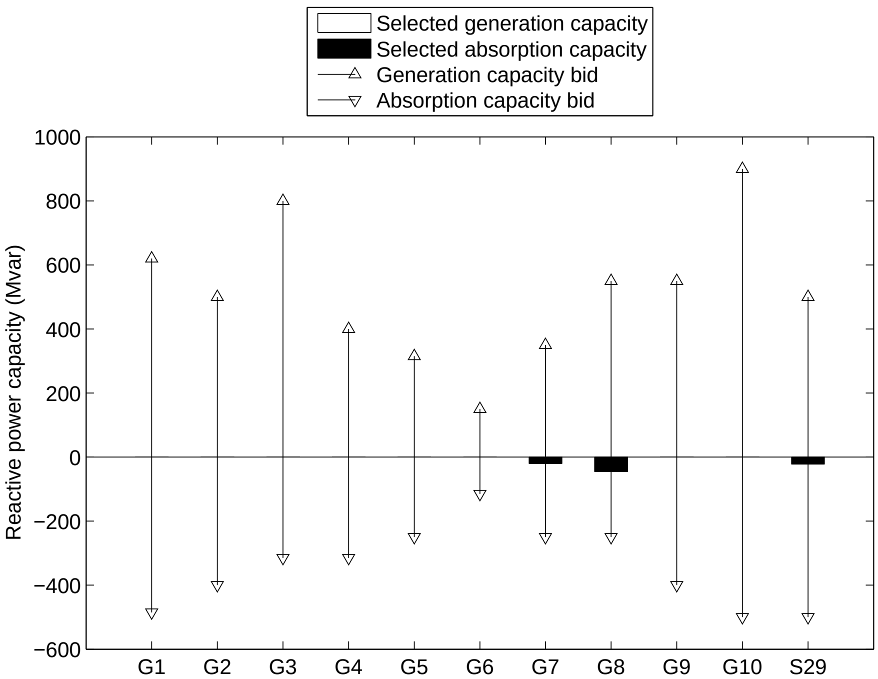

Figure 6.5: Selected VAR capacity bids for generation and absorption during low-demand hours

(G: generator number #; C: capacitor bank located at bus #; S: SVC located at bus #)

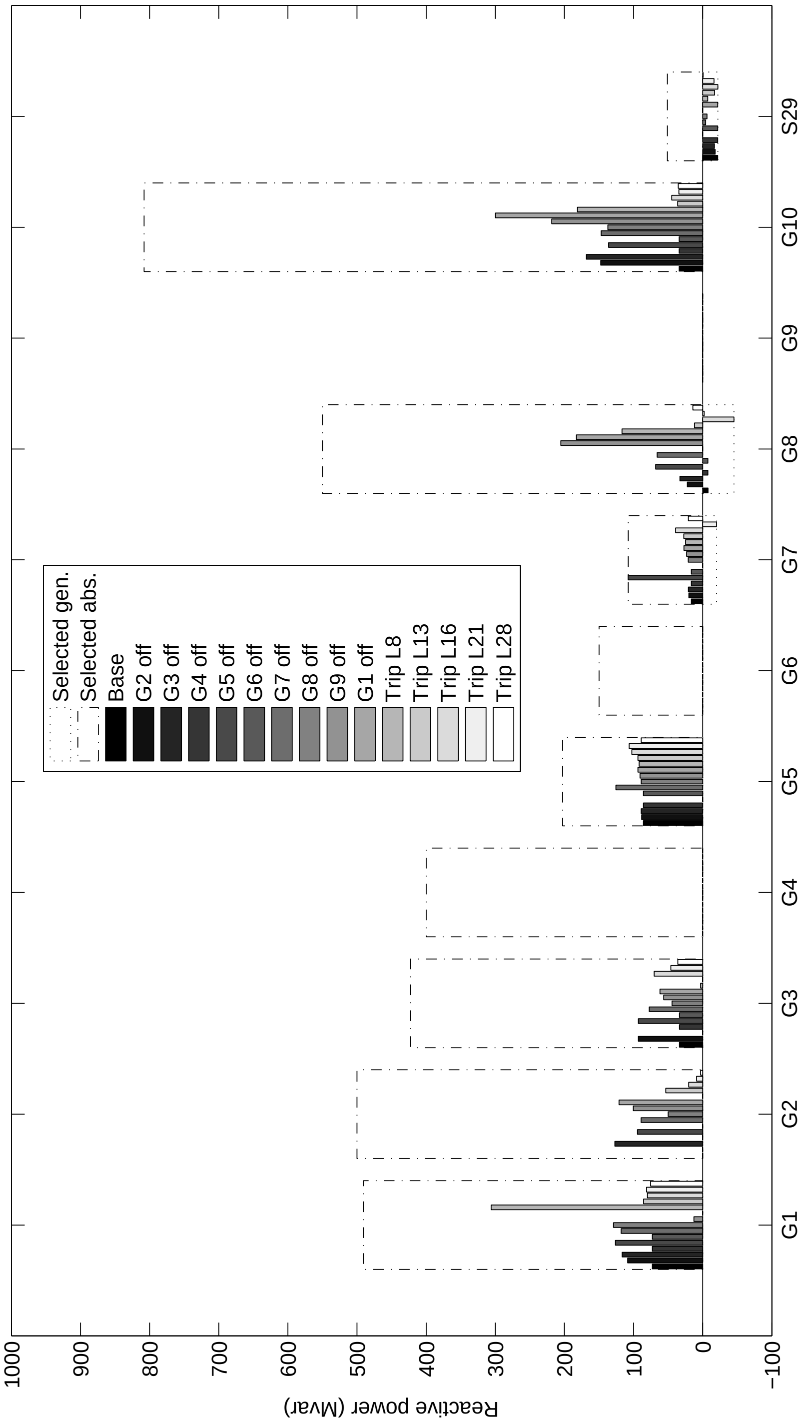

Figure 6.6: VAR output of selected VAR sources for the different contingencies during low-demand hours

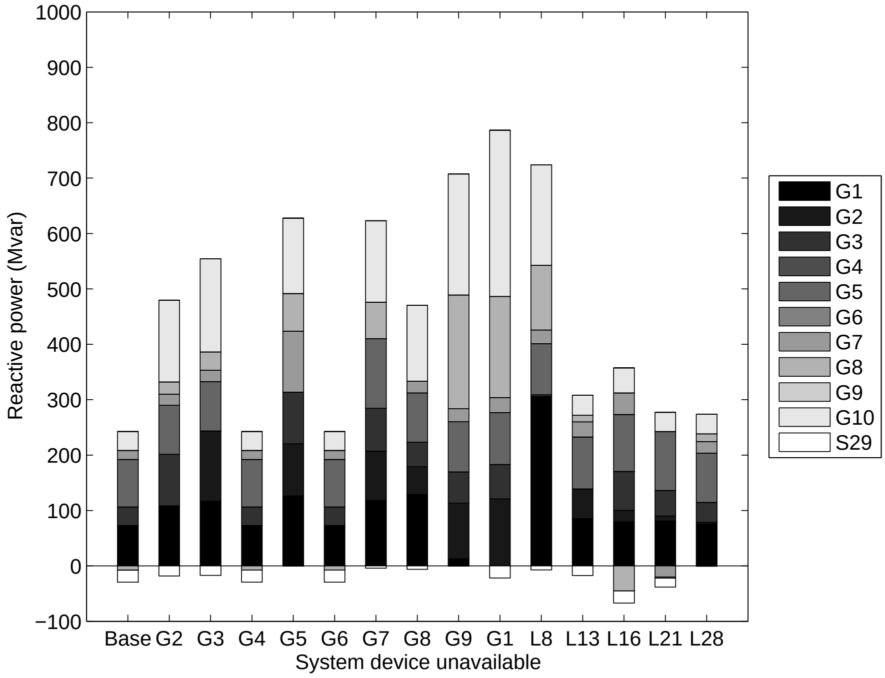

Figure 6.7: Aggregated VAR output of selected VAR sources for the different contingencies during low-demand hours

6.3 Economic settlement

Once the VAR capacity market is cleared, the associated economic flows should be defined. This section first presents the remuneration of the selected VAR capacity bids in the case study. Then, the charges to the VAR demand are detailed, including the charges to loads and to agents responsible for system contingencies. Finally, the final economic settlement summarizes the economic flows in the case study.

6.3.1 Remuneration of the selected VAR capacity bids

The payments to the selected VAR capacity bids are calculated using the long term marginal prices for VAR generation and absorption capacity as formulated in (5.11), and presented in Figure 6.8.

The marginal price for generators with a purchased capacity below their full capacity bid equals their corresponding bid price. However, if all the VAR capacity bid is purchased, which is the case of generators #2, #4, #6 and #8, then the marginal price will be over the bid. This is a clear signal for new VAR sources to connect to that bus. The marginal price for capacitor banks and the SVC equals their submitted bid price, as the selected capacity is below the maximum limit.

The distribution of the remuneration during peak hours is presented in Figure 6.9. As stated before, those generators with the full VAR capacity selected will receive the higher payment, which is the case of generators #2, #4, #6 and #8. The payments to the selected VAR capacity bids are obtained using the total cost sensitivities which are obtained from the optimization problem.

Finally, the expected payments for VAR capacity use and other estimated costs are presented in the next sections.

6.3.2 Charges to the VAR demand

The charging mechanism recovers the payments to the selected VAR capacity, and it is distributed among the system loads and the agents responsible for contingencies, as it is detailed in the next paragraphs.

6.3.2.1 Charges to loads

The distribution of the charges is proportional to the sensitivities of the power balance equations and the active and reactive power load, as formulated in (5.18), and presented in Figure 6.10.

All loads have a similar impact on the VAR requirements in the system, where it can be observed that sensitivities of the active power load are higher than VAR sensitivities, mainly due to the higher impact of the energy losses. On the other hand the negative

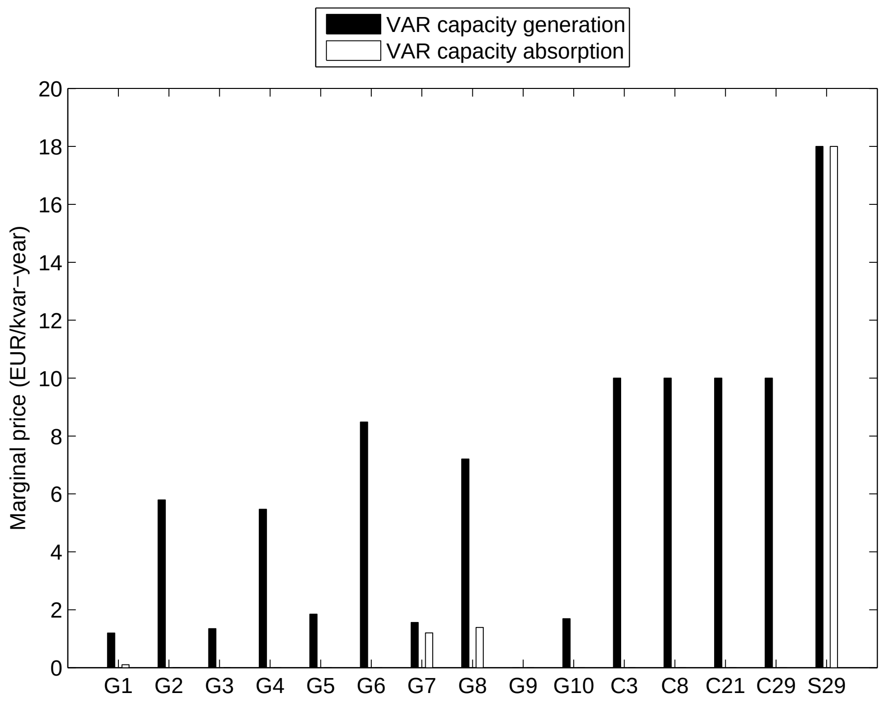

Figure 6.8: Marginal prices for VAR capacity generation and absorption

sensitivities for VAR load in buses #26 to #29 indicate that an increase in the VAR load reduces the total costs of the auction for VAR absorption. During low-demand hours these buses are located in an area with high voltages, where for certain contingencies VAR absorption capacity is required. An SVC located at bus #29 is selected to provide this capacity.

The contribution of each load to the VAR capacity needs in the power system is presented in Figure 6.11. In the economic settlement these charges are normalized in order to fit the payments to the selected VAR agents together with the charges to contingencies. The buses with negative sensitivities have payments for their VAR consumption, however the charges for active power consumption are higher, and hence the net economic result is a charge for the load. Loads located at buses #2 and #20 pay the highest charge as both have the highest consumption in this case study.

6.3.2.2 Charging due to equipment unavailability

The over cost associated with the different contingencies is charged to the agents responsible for the emergency situations. These charges are obtained from the sensitivities of the state variables representing the availability of each device, as presented in Figure 6.12. The distribution of these charges among the unavailabilities is presented in Figure 6.13, and is calculated using the duration of each system contingency.

During both demand periods, most of the charges are allocated to the unavailability of generators, due to the higher duration of their unavailability. This distribution is

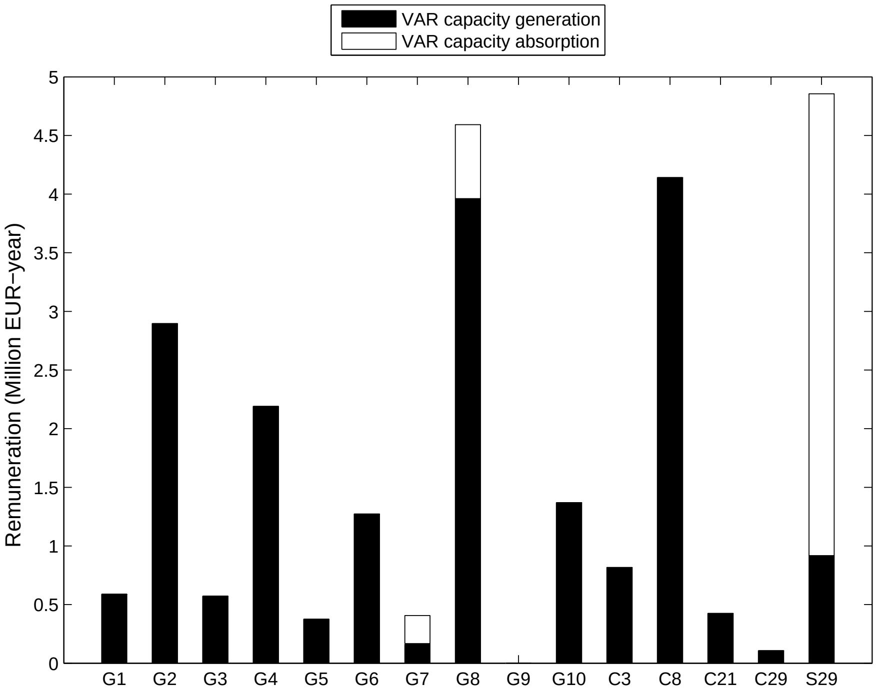

Figure 6.9: Remuneration for VAR capacity generation and absorption

reasonable since the outage of a selected generator in the VAR auction requires the purchase of additional VAR capacity to cover this loss. For this case study, generators #1 and #3 are responsible for most of the VAR needs during peak and low-demand periods respectively.

On the other hand, the unavailability of a transmission line generally has a higher impact on the VAR capacity needs as shown in Figure 6.12. For the selected transmission line contingencies, their outage always increases the VAR needs. In other networks the opening of a transmission line during light-load periods may potentially help the power system, since this reduces the generation of VAR from the network.

In this case study, the trip of transmission line 28-29 during peak hours reduces the voltages in the area defined by buses #17 and #27 to #29. Low voltages are due to a higher loading of transmission line 26-29 that supplies active power to the load at buses #25 to #28. In order to support voltages, additional VAR compensation is needed, which is provided by a capacitor bank and the SVC is located at bus #29. The trip of line 8-9 is also critical from the point of view of the VAR support, as the supply of the load at bus #8 is now carried out through line 5-8, increasing the voltage drops across the network. Finally during low-demand hours, the trip of the transmission lines 16-17 is critical since it requires the purchase of additional VAR absorption capacity from the SVC and the generators in order to maintain the voltage profile.

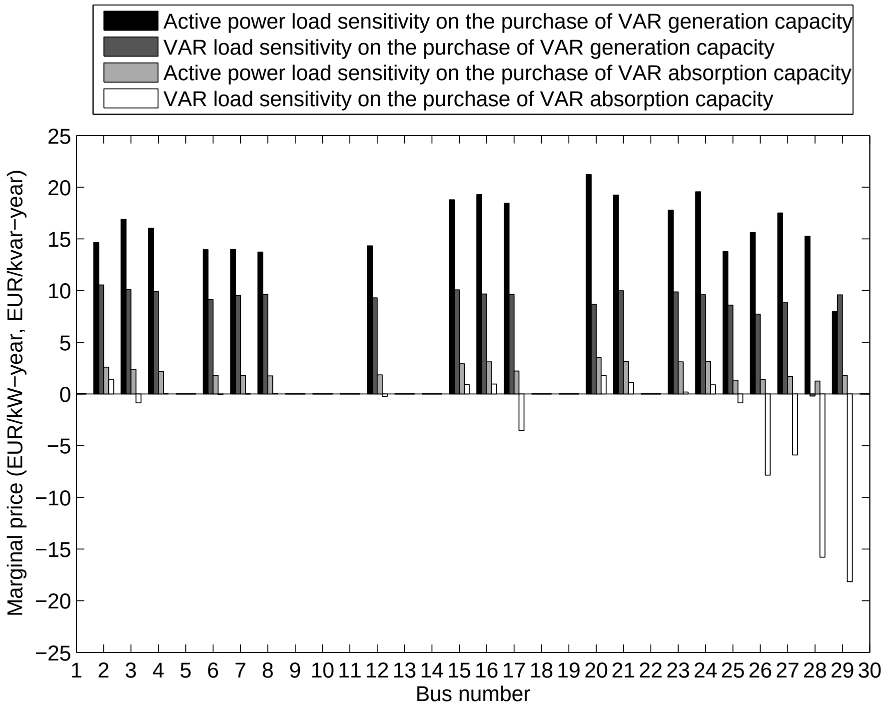

Figure 6.10: Marginal price at each bus

6.3.3 Final economic settlement

The final settlement of the VAR capacity market is presented in Table 6.6. The benefits are collected mostly by the generators, and also by capacitor banks and the SVC. On the other hand, loads are the main responsible factor for the VAR capacity requirements. System contingencies are charged for 30% of the purchased VAR capacity, distributed between generator outages with 25% of the charges, and transmission line trip with 5%.

The expected operation costs associated with the VAR capacity market are: 1.82 million € per year for the regulated payment for the use of the purchased VAR capacity, and 0.5 million € related with low voltage quality. In the resulting market clearing there were no costs associated with non-supplied energy nor opportunity costs for generation redispatch.

The money is collected and distributed among all the participants once the market is cleared. The economic volume of the VAR capacity market corresponds to similar values used in research studies that estimate the market value as 1% of the total energy market. For instance, the charge to the load at bus #2 in the VAR capacity auction is 3 million €-year for its maximum annual consumption of 1104MW and 350.5Mvar. This charge represents approximately 1% of the total costs for this load on active power purchases in the energy market, assuming that the average market price is 40€/MW, at an average consumption of 800 MW and 8760 hours per year. Similarly, generator 2 will be paid 3 million € for the purchase of VAR capacity and it will also be charged for 0.5 million € due to its failure rate. The resulting benefits in the VAR capacity market are

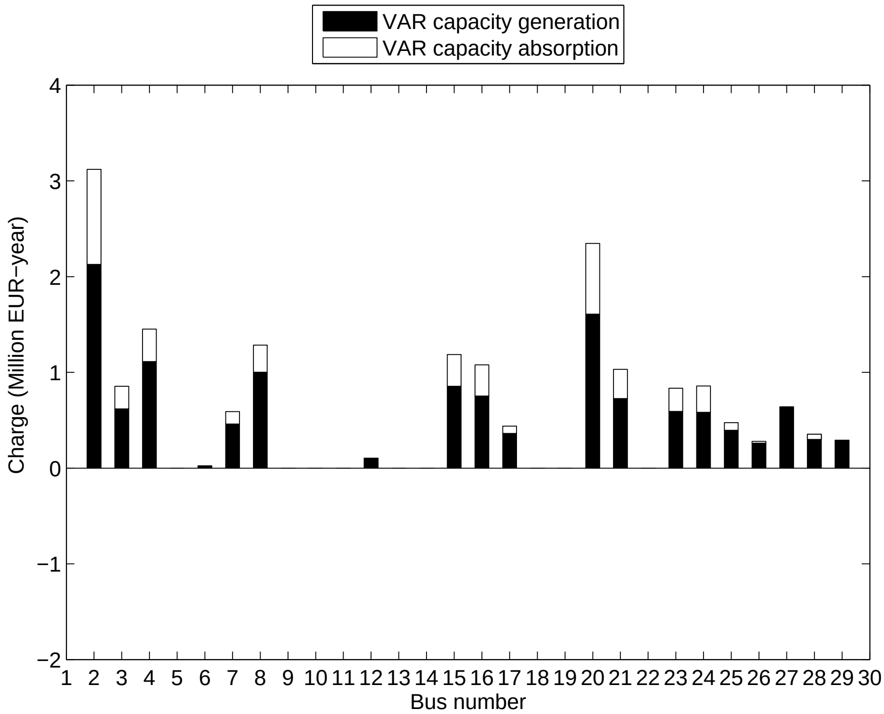

Figure 6.11: Charges to loads

2.5 million €, which represent roughly 1.5% of the total annual income, if we assume that the generator is dispatched at 500MW during 7000 hours per year and the average marginal price is 40€/MWh.

The agents will also receive their corresponding sensitivity on the VAR capacity purchase costs in order to take appropriate decisions related to the VAR. For instance, loads can reduce their maximum demand or install VAR compensation equipment. On the other hand, generators and transmission lines receive a clear incentive to reduce their failure rates.

Table 6.6: Economic settlement in this case study

	Remuneration (Million €-year)	**Charge** (Million€-year)	**Total** (Million€-year)
Generators	14.257	6.293	7.964
Capacitor banks	5.485	-	5.485
SVC	4.855	-	4.855
Loads	-	17.19	-17.19
Transmission line	-	1.117	-1.117

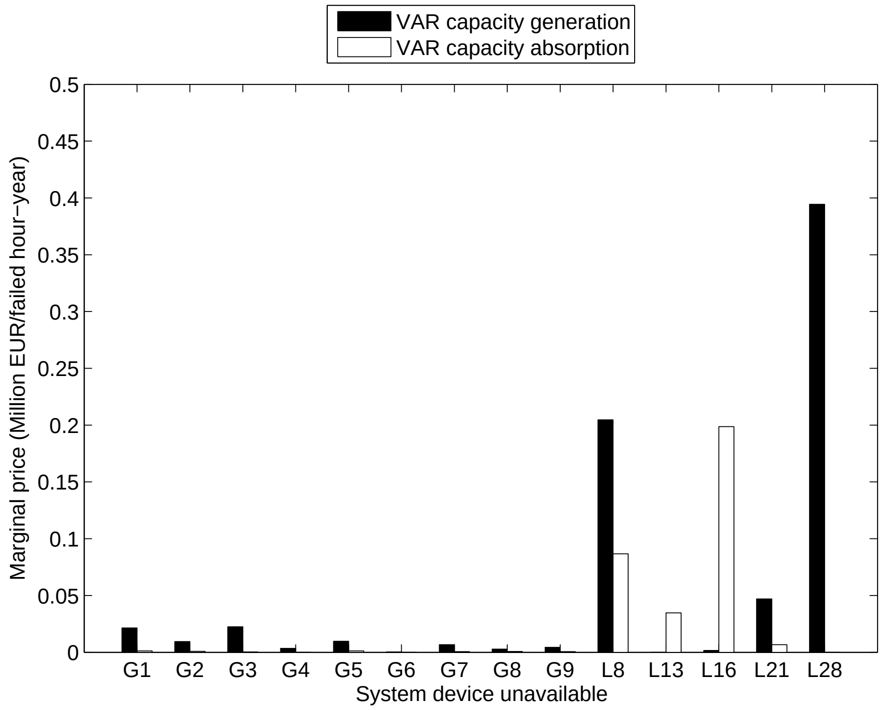

Figure 6.12: Marginal price for system outages

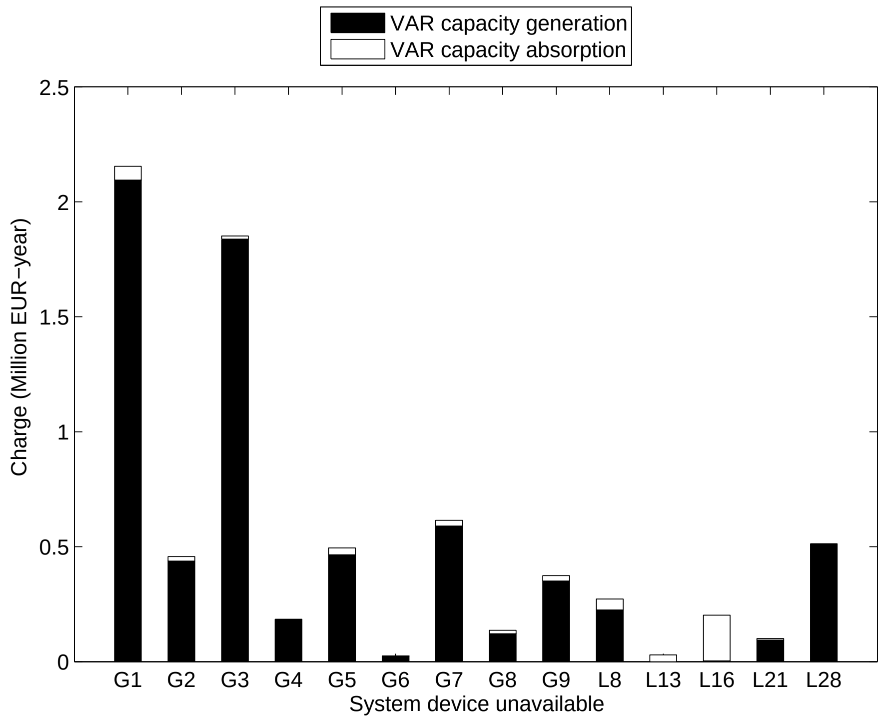

Figure 6.13: Charges to the agents responsible for system contingencies

6.4 Conclusions

This chapter has demonstrated the applicability of the proposed VAR capacity market to real power systems. For this purpose, the case study corresponds to a voltage control area in a real power system.

The optimal selection of the VAR capacity bids depends greatly on the specific characteristics of the power system. Therefore, the demand of VAR should be carefully analyzed, comprising the expected VAR load for peak and low-demand hours, and the historical failure rates of the different power system devices. In addition, the dynamic characteristic of the VAR capacity bids will define the selected VAR technologies. SVCs and STATCOM devices will be used if there is not enough dynamic VAR support provided by generators, or if the generator VAR capacity bids are expensive. Generally, generators will provide the dynamic VAR capacity, and shunt reactors and capacitor banks the fixed VAR compensation.

The remuneration for the procurement of the VAR capacity will cover the bids of the selected agents, and in real-time will also pay the incremental costs due to the VAR capacity use. If a generator is redispatched to provide additional VAR capacity, then that generator will receive compensation for the lost opportunity costs due to the reduction of its output. The results in the case study showed that, due to the high difference between the variable costs of active power production and the prices of the VAR capacity bids, it is unusual to reduce VAR capacity in the long-term scope. However, during real-time operation, generation redispatch to increase its available VAR capacity may take place under certain emergency situations.

The charges to the loads distribute the costs of VAR capacity purchases among the different buses in the transmission system. Therefore loads will be charged proportionally to their active and reactive power load; however, it may occur that loads are remunerated for their consumption, for example during low-demand hours when voltages rise and the VAR load helps the power system maintain acceptable voltage profiles.

Finally, the charges to the agents responsible for the contingencies will recover the over costs due to the extra VAR capacity needed to cope with the emergency situations. For simplicity, only those contingencies with the highest impact on VAR capacity costs are considered. These VAR charges due to emergency situations clearly motivate agents to reduce their failure rates.

6.5 References

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CHAPTER 7

Conclusions, contributions and future research

THIS last chapter is dedicated to present the main conclusions that resulted from the research carried out in this thesis dissertation. First, the conclusions of this work are presented. Then this chapter describes the original contributions that resulted while pursuing the general objective of this thesis. Finally, some future lines of research stemming from the developments of this thesis are identified.

7.1 Conclusions

The analysis of recent power system blackouts has found that current regulatory mechanisms for voltage control and reactive power management do not send efficient location and economic signals, in order to provide incentives for VAR sources to guarantee system security. Therefore, there is a need to develop competitive schemes for the procurement of the VQ service, with the objective of economic efficiency, quality of service, and guarantees of the security of supply.

A detailed study of the voltage control service showed that nowadays the most important agents who participate in the service are generators, capacitor banks, shunt reactors, SVCs and STATCOM devices. The different demand agents of the VQ service: loads (including both active and reactive power consumption), and system contingencies comprising the failure of generators or other power system devices have also been identified.

The definition of a competitive scheme for the procurement of the VQ service requires the unbundling of the different activities that integrate the electricity market. In the VQ service a main product is identified: the VAR capacity. The trading of this product requires certain homogeneity, which is provided by characterizing agents with their dynamic performance. As the time-frame for the installation of new VAR sources or the upgrading of the existing ones is generally less than one year, an annual periodicity for the proposed auction guarantees competition between already installed devices and new ones. This thesis dissertation therefore proposes a regulatory scheme for the VQ service based on an annual auction for the VAR capacity.

The proposed VAR capacity market is modeled and cleared using an optimization formulation. The resulting model is relatively complex, as it includes non-linear equations and binary variables. Notwithstanding current commercial solvers can manage this problem efficiently and in a reasonable amount of time (the VAR market clearing in a real voltage control area, including 10 generators and 30 buses, can be solved in 3 hours using a domestic computer). The objective function of the proposed formulation must take into account all the costs related with the procurement of VAR capacity, which comprises the purchase of capacity and other expected costs, such as energy losses costs, voltage quality penalties, and costs for non-supplied energy. The formulation should also consider the technical constraints of the operation in a real power system together with the economic arrangements in the proposed market.

The design scheme for the economic flows in the proposed market should focus on sending efficient economic and location signals to the agents involved in the VQ service. The remuneration mechanism based on long-term marginal prices guarantees that agents recover their bid. In addition, if the bid capacity is exhausted, an additional compensation will encourage new VAR agents to participate in the market.

The charges for the agents demanding the VQ service must measure their impact on the costs associated with the VAR capacity market. The calculation of the charges to the loads should consider the compound effect of active power and reactive power consumption. The analysis has shown that the costs sensitivities of reactive power are higher than those of active power; however, the effect of the active power should not be neglected, as it clearly impacts on losses and on the voltage profile.

The unavailability of generators and transmission lines increases the costs of the purchase of VAR capacity because additional fast VAR resources are needed to guarantee the system security under these emergency scenarios. The cost sharing among the contingencies can be calculated using sensitivity analysis of the state variables for the outage devices. Hence the resulting charges send efficient signals that encourage them to reduce their failure rates. According to the analysis and results of the case study, the impact on the purchase of VAR capacity of generator unavailability is higher than the trip of transmission lines. The main reason for this is that a failed generator with already purchased VAR capacity requires the purchase of additional fast VAR to cover the lost capacity. The application of the Cooperative Game Theory to the distribution of the charges guarantees the incurred cost recovery and the fair distribution among the responsible agents, both for loads and contingencies.

The applicability of the proposed competitive approach for the VAR capacity market has been verified with a case study that emulates a voltage area in a real power system. The results have shown that market power of generators is mitigated by the installation of other VAR sources, such as capacitor banks and SVCs. In addition, the installation of VAR compensation devices is a more economic alternative to redispatching of generators. The VAR support provided by SVCs is preferred to capacitor banks and shunt reactors in those locations where contingencies require a fast VAR support. Moreover, STATCOM devices become an interesting alternative to SVCs in locations with scarce VAR capacity and with very low voltage profiles.

7.2 Original contributions

The development of this thesis has yielded a number of original contributions that can be categorized into regulatory and modeling contributions.

7.2.1 Regulatory contributions

A first contribution of this thesis is the definition of the main products associated with voltage control and reactive power management service, included in chapters 2 and 3, which are VAR capacity and VAR use. In addition, the VAR capacity product has been characterized in order to settle a homogeneous product which can be traded freely in competitive markets.

A second contribution of this thesis is the design of an original regulatory framework for the procurement of the VQ service, which has been traditionally based on mandatory mechanism or under bilateral contracts. The original proposal, included in Chapter 3, presents a transparent market based on an annual auction where the product VAR capacity is priced and traded. The market clearing takes into account the economic and technical characteristics of the supplying agents and provides fair treatment for all the market participants.

Finally, a third contribution is the design of a scheme for remuneration and payment in the proposed VAR capacity market which sends efficient economic and location signals to all participants.

7.2.2 Modeling contributions

This thesis dissertation has presented a novel algorithm for the selection of the VAR capacity bids under the current market proposal. The original contributions in the formulation for the VAR market settlement are provided in Chapter 4:

i) The objective function in the proposed market includes penalties associated with voltage quality (Section 4.3.1.3). These penalties are based on a valuation that measures the economical impact on the distributor costs of the voltage deviations, as described in Appendix D.

ii) The objective function also takes into account the costs associated with the re-dispatch of generator units to provide additional VAR capacity (Section 4.3.1.4). Hence, the output of generators can be reduced, or even generators can be started up in order to increase the procurement of VAR capacity.

iii) The formulation for VAR purchase considers a set of possible contingency scenarios (Section 4.3.2.5), and the dynamic performance of the VAR sources to cope with these emergency situations (Section 4.3.2.4).

Furthermore, in Chapter 5, this thesis also includes original contributions to settle the economic flows in the proposed VAR capacity market, among which stand:

i) The payments to the selected VAR agents are based on long-term marginal prices for reactive power (Section 5.2).

ii) The charges to the loads in the proposed market take into account both the effect of the active and reactive power load in the total costs of the market (Section 5.3.1).

iii) The economic flows also consider charges to the responsible agents of the system contingencies. These charges are computed using the information provided by the Lagrange multipliers that define the state of the failed devices (Section 5.3.2).

iv) In order to send efficient economic signals, the effect of the variable costs of active power production is eliminated when calculating the previous Lagrange multipliers (Section 4.4.3).

7.3 Future research

The development of this thesis has lead to a number of future lines of research whose exploration is likely to yield interesting results. This section tries to summarize them and justify their relevance.

i) A natural continuation of this work is the implementation of the proposed VAR capacity market in a real power system, such as the Spanish network. During the implementation process, the mathematical formulation could be improved including additional specific characteristics of the Spanish power system.

ii) The regulatory and the modeling proposals presented in this thesis for the voltage control service can be applied to introduce competition in other ancillary services. For instance, the purchase of supplemental active power reserve (used to restore the spinning and the non-spinning active power reserves that are used during a contingency situation), or the selection of the black-start units (generators that are able to start themselves up without support from the grid, and have sufficient real and reactive capability to be useful in energizing pieces of the transmission system and starting additional generators). The optimal procurement of the previous ancillary services is a trade-off between the costs of purchasing a volume of service and the costs associated with the security of supply.

iii) The increasing penetration of distributed generation in sub-transmission systems poses a new challenge and an opportunity for voltage control in these networks. The distributed generation should receive similar efficient signals as the ones proposed in this thesis, in order to help the power system security and economic efficiency. For this purpose the basis of the proposed VAR capacity market can be applied to sub-transmission networks, taking into account the specific characteristics of these power systems.

APPENDIX A

International review of the VQ service

In Chapter 2 a summary of the regulatory models for the VQ service was presented. For a better understanding of the distinctive features of each power system, a detailed analysis is carried out in this appendix. The analysis is focused on the innovative proposals for the VQ service in Spain and the United Kingdom. In addition, a comparative review of other regulatory frameworks in Europe, the United States and other countries is presented.

A.1 The VQ service in Spain

This section presents a review of the reactive power support and voltage control management in the Spanish transmission network. First, a general description of the Spanish electricity market is presented. Then, the two market mechanisms for reactive power and voltage control are described, and the SO tools and the generator controls for voltage and VAR management are detailed. Finally, an analysis of the current situation is carried out and recommendations for future developments are proposed.

A.1.1 Description of the Spanish electricity market

The Spanish electricity market which started on January 1, 1998 is managed by two separate entities: The Market Operator (OMEL) and the System Operator (REE). OMEL runs the day-ahead energy market, based on an hourly matching of generation and demand bids. On the other hand, REE is responsible for the secure operation of the power system and manages the ancillary services markets.

In December 2006 the Spanish Power System had a total generation capacity of 78754MW, to cover the peak demand of 42153MW [REE, 2006]. REE is the owner of the transmission system, which has a total length of 33.197 km (including 400kV and 220kV voltage levels), and the sum of the transformer capacity is 51.872MVA.

The technical operation of the Spanish power system is regulated by different *Operating Procedures* [REE, 1998]. The ones related with voltage control are:

- P.O.-1.1 Operation and security principles.
- P.O.-1.3 Admissible voltages in the transmission network.
- P.O.-3.2 System constraint management.
- P.O.-7.4 Voltage control ancillary service.
- P.O.-8.3 Voltage control definition.

A.1.2 Voltage control and VAR management

The Spanish voltage control and reactive power management is based on two market mechanisms for its procurement:

i) *The voltage control ancillary service* which is provided by a a set of VAR resources, whose regulation capacity is assigned through an annual auction, and the real-time operation is managed by REE.

ii) *The constraint management* that is a mechanism used to solve congestion and low-voltage problems in the transmission network after the day-ahead market is cleared. To solve these constraints, REE ask generators to modify their outputs according to their submitted bids.

These two mechanisms for voltage control management are presented in detail in the following subsections.

A.1.2.1 Voltage control Ancillary Service

This service is defined in the Operating Procedure P.O.-7.4 (March 2000) [REE, 2000]. Regarding regulation capacity that should be provided annually by VAR sources there are two different requirements. First, a mandatory regulation capacity and VAR obligations have been set for all market participants. There is no remuneration for this part of the service. Additionally, market participants may offer an additional regulation capacity or VAR provision, submitting quantities at a regulated price in the annual auction. On the other hand, VAR sources are scheduled and controlled by REE on a daily basis.

At present, the market for the additional capacity has not yet been implemented. Under the current situation, only the mandatory capacity requirements must be fulfilled by generators and the reference voltage ranges must also be followed. These ranges are published every year by REE, for every power system area and for specific buses, and are obtained by off-line optimization studies. REE actually follows the voltage control service and publishes the measures for the service. If a generation plant does not fulfill the mandatory requirements no penalty is applied, however the anomalous situation is communicated to the Energy Regulatory Institutions.

The structure of the voltage control service comprises different issues, which are detailed in the next paragraphs: voltage control suppliers, service procurement and monitoring, economic flows, and an illustrative example.

A.1.2.1.1 Service suppliers Only market participants connected to the transmission network can provide this service:

- *Generators.* The service is provided by generation units connected to the same transmission bus, with installed capacity equal to or exceeding 30 MW.
- *Transmission companies.* This includes REE and other companies who own part of the 220 kV grid.
- *Qualified non-regulated consumers,* with a contracted demand of above 15 MW.
- *Distribution companies.*

A.1.2.1.2 Service procurement The mandatory regulation capacity requirements and additional procurement are differentiated:

- **Mandatory** VAR generation and absorption regulation capacity ranges are defined as follows:
  - *Generators:* the mandatory VAR output expressed as a percentage of the maximum MW output is a function of the transmission voltage (solid lines in Figure A.1 and Figure A.2). Both magnitudes, VAR outputs and voltages, are specified for the transmission High Voltage busbar of the generation substation. If the generation unit cannot reach the mandatory VAR requirements, it must carry out the needed investments.
  - *Transmission companies:* all the installed VAR resources should be available to provide the service.
  - *Qualified consumers and distribution companies:* power factor ranges are defined in three time frames, peak hours ($\cos\phi \geq 0.95$ inductive), flat hours ($\cos\phi \leq 1$ inductive) and valley hours ($0.95 \leq \cos\phi \leq 1$ both inductive).
- **Additional** VAR generation and absorption regulation capacity ranges are defined as follows:
  - *Generators* can bid quantity, but not price, of exceeding reactive power regulation capacity, both for generation and absorption. Different bids can be submitted for each month and main transformer tap ratios. Each bid includes two tables, one for reactive power generation capacity, and one for reactive power absorption capacity, as presented in Table A.1. To verify the submitted values, detailed technical data from the generation plant is required by REE.
  - *Qualified consumers and distribution companies* can offer their exceeding VAR capacity, structured in bids for each month and demand period (peak, flat, and valley hours).

  In an annual auction REE assigns the additional VAR regulation capacity to each service provider, trying to minimize additional payments.

A.1.2.1.3 Service monitoring REE supervises the performance of the voltage control service using measures received at the CECOEL (which in Spanish stands for *Centro de Control Eléctrico*). Active and reactive power flows and voltages in the transmission buses are registered every 5 minutes for generators and every 10 minutes for consumers. In the case of measurement errors, the values coming from the state-estimator software are used instead.

After the day-ahead market REE will compute daily the hour-reference-voltages for every controlled transmission bus. Currently REE only provides voltage reference ranges for some system areas and specific buses.

The service is correctly fulfilled when at least 75% of the measured voltage values in each hour comply with:

- *Generators*: (i) Voltage is within the permissible range $V_{ref}\pm 2.5$kV, (ii) if not, the unit has reached its assigned maximum VAR regulation capacity.
- *Qualified consumers and distributors*: the power factor values meet the mandatory requirements.
- *Transmission companies*: follow REE instructions regarding VAR sources dispatch in less than 10 minutes.

A.1.2.1.4 Service payments and penalties Additional *regulation VAR capacity* will be computed throughout four hourly terms.

- *Available additional generation regulation capacity*, measured in Mvar. The same for absorption capacity.
- *Reactive energy produced* using the additional VAR generation regulation capacity, measured in Mvarh. The same for absorbed reactive energy.

To compute the remuneration, each one of the previous terms would be multiplied by a regulated price (€/Mvar-year, €/Mvarh).

In the case that service providers do not comply with the agreed provision requirements they will be penalized. Penalties are established through a penalty cost times the reactive energy generated or absorbed under the default situation. Penalty costs are different in the case of violation of mandatory requirements, or in the case of violation of the additional VAR provision[1].

A.1.2.1.5 Generator voltage control example A generation plant producing 100 MW should keep voltages in the high voltage side substation busbar (HV) in the range of 405±2.5kV. Table A.1 and Table A.2 shows the assigned additional VAR regulation capacity for generation and absorption respectively. Figures A.1 and A.2 represent both mandatory requirements and assigned additional VAR capacity.

Two different operation situations are analyzed as follows:

[1] At present, neither prices nor penalty coefficients have been published yet.

Table A.1: Reactive power generation capacity bid for the example generation plant

Output	Voltage (kV)										
(MW)	380	384	388	392	396	400	404	408	412	416	420
100	38.0	37.2	36.4	35.6	34.8	34.0	33.2	32.4	31.6	30.8	30.0
90	39.9	39.1	38.2	37.4	36.5	35.7	34.9	34.0	33.2	32.3	31.5
80	41.0	40.2	39.3	38.4	37.6	36.7	35.9	35.0	34.1	33.3	32.4
70	42.2	41.3	40.4	39.5	38.6	37.7	36.9	36.0	35.1	34.2	33.3
60	43.3	42.4	41.5	40.6	39.7	38.8	37.8	36.9	36.0	35.1	34.2

(Second row: voltages in kV; First column: MW output; Cells: reactive power regulation capacity (Mvar); All values are specified for the HV side busbar of the power plant)

Table A.2: Reactive power absorption capacity bid for the example generation plant (Mvar)

Output	Voltage (kV)										
(MW)	380	384	388	392	396	400	404	408	412	416	420
100	12	14	16	18	20	22	24	26	28	30	32
90	12.2	14.3	16.3	18.4	20.4	22.4	24.5	26.5	28.6	30.6	32.6
80	12.5	14.6	16.6	18.7	20.8	22.9	25.0	27.0	29.1	31.2	33.3
70	12.7	14.8	17.0	19.1	21.2	23.3	25.4	27.6	29.7	31.8	33.9
60	13.0	15.1	17.3	19.4	21.6	23.8	25.9	28.1	30.2	32.4	34.6

(Second row: voltages in kV; First column: MW output; Cells: reactive power regulation capacity (Mvar); All values are specified for the HV side busbar of the power plant)

- Under the first situation, the generation unit is able to set the voltage at 406 kV, injecting 20 Mvar. The unit is providing the service correctly. It would obtain a remuneration for additional reactive energy production, and also for additional generation and absorption regulation capacity, as shown in Figure A.1.

- Under the second situation, the generation unit cannot maintain the voltage within the reference bandwidth. In this case the unit is not fulfilling with the service, as the reactive power generated is less than the assigned value. Independent of the regulation capacity remuneration, the unit would receive a double penalty: (i) a penalty for not reaching the mandatory requirement (18 Mvar), and (ii) a penalty for not reaching the additional assigned regulation capacity (35 Mvar), see Figure A.2.

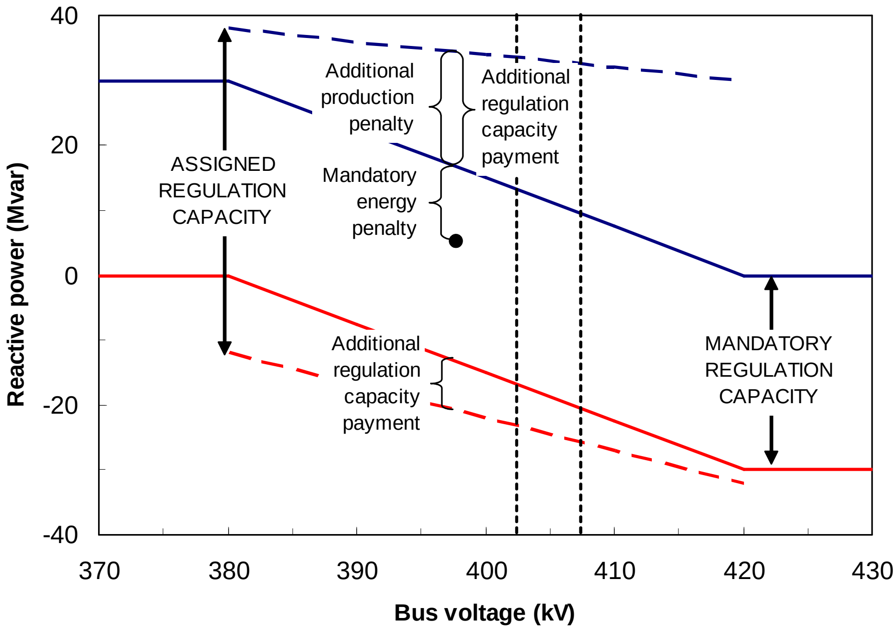

Figure A.1: Voltage service correct fulfillment
(Source: personal research)

A.1.2.2 System constraints management

The operating procedure P.O.-3.2 [REE, 2007] regulates the system constraint mechanism managed by REE. Network constraints may appear when the generation dispatch coming from the day-ahead energy market is implemented. To solve congestion and voltage problems, generation redispatch is performed by REE. In the Spanish power grid low-voltage problems are the most frequent and relevant constraints, and they are usually located in eastern and southern Spain, as shown in Figure A.3. This figure also shows the percentage of energy programmed to solved system constraints in the corresponding areas.

In the case of network constraints, generation units submit bids to solve them. Bids contain pairs of quantity and price, and they are independent of the ones submitted to the day-ahead energy market. REE calculates the generation redispatch that minimizes system cost and variation of initial market positions, fulfilling security criteria [REE, 1998, Lobato et al., 2000]. This redispatch can also include the start-up of some needed units. Generation redispatch increments and started-up units are paid at their bid price. On the other hand, generation redispatch decrements are paid at their bid price only if they are not responsible for the alleviated constraint.

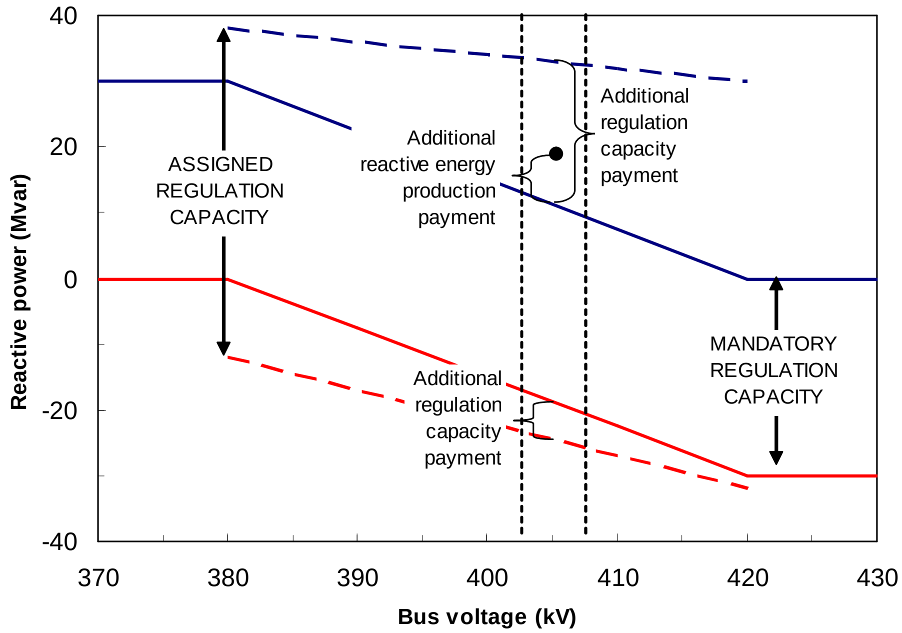

Figure A.2: Voltage service wrong fulfillment
(Source: personal research)

A.1.3 System Operator tools and generator control

Voltage control in the Spanish transmission network is performed in three time control loops:

i) Primary or Automatic Voltage Regulator (AVR) control, installed in each generator.

ii) Secondary or power plant control, reactive power management in each generation power plant.

iii) Tertiary or SO control, where REE optimizes the system operation every hour, providing the reference voltages for each controlled bus, and control actions for transmission VAR sources, according to the management market mechanisms described in the previous subsections, as shown in Figure A.4.

In addition, the Spanish Regulatory Authority analyzes the long-term needs of the power system and publishes a general planning of the electric sector [MITC, 2006]. Two actions are defined for the allocation of reactive power requirements: i) in the distribution level by installing capacitor banks and therefore compensating locally the demand of VAR, and ii) in the transmission level by connecting shunt reactors in low demand periods. According to the analysis carried out in [MITC, 2006] for the period 2005-2011 the future

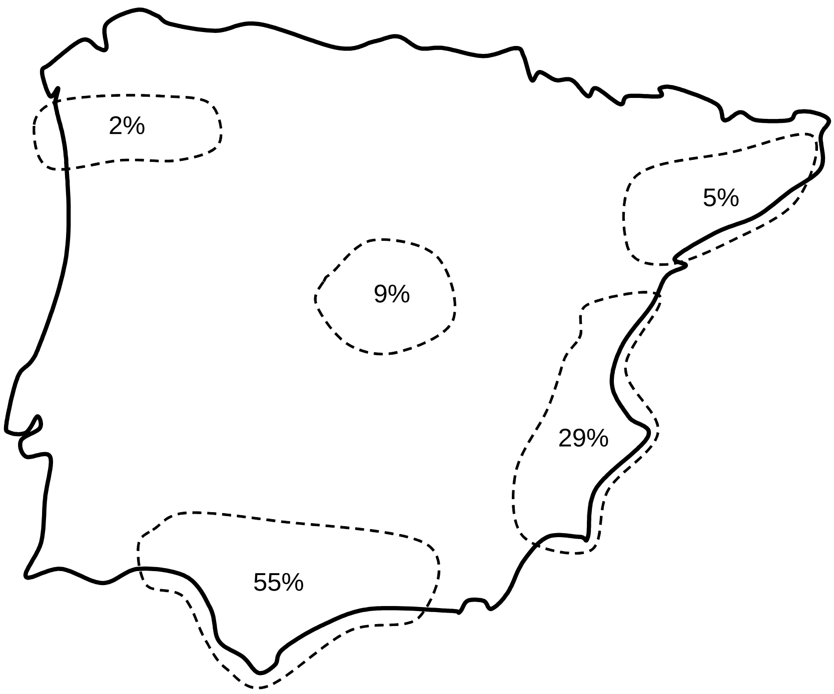

Figure A.3: Main technical constraints in the Spanish peninsular transmission network (Source: [Lobato, 2002] and personal research)

requirements of VAR will be covered with the installation of 2400Mvar of capacitor banks in the distribution level, and 11 shunt reactors of 150Mvar in the transmission network.

The SO tools and the generator controls for voltage and VAR management are detailed in the next subsections.

A.1.3.1 System Operator tools

REE manages the operation and planning of VAR sources in the Spanish transmission grid. VAR real-time operation consists of:

- *Connecting/disconnecting VAR compensating devices*, such as reactors and some capacitor banks. Most of the shunt reactors are connected to the 400k V network, and the rest to the tertiary winding of 400/220 kV transformers, as presented in Table A.3.
- *Switching lines*, mainly once a day, and during the night.
- Adjusting 400/220 kV transmission transformer taps. Most of them have on-load tap changers with 17 intermediate positions.
- Defining reference voltages at generation controlled buses.

Table A.3: Transmission System reactive power resources available in August 2005

	400kV		**220kV**	
	Number	MVA	Number	MVA
Transformers	101	52.409	1	63
Shunt reactors	29	4.050	37	2.514
Capacitor banks	-	-	13	1.083

(Source: [REE, 2006] and personal research)

Over a longer term with a horizon of one year, the coordination of the different VAR resources is achieved through the so-called *voltage plan*. This plan is obtained for different voltage control areas in which the Spanish transmission system is divided. This plan provides the voltage reference values at the generation buses, the transformer tap positions and shunt reactors scheduling. To develop the corresponding studies, optimal VAR dispatch algorithms are used.

A.1.3.2 Generator control

The most important reactive power resources are generators[2]. The VAR regulation capacity of a generation power plant depends on different technical aspects: (i) generator VAR capacity curve, (ii) generator terminal voltage ranges, and (iii) auxiliary services voltage ranges.

The available reactive power capacity greatly depends on the taps of the main and auxiliary services transformers. Therefore, load tap changers control can increase the capability of the power plant to provide VAR regulation capacity at the transmission network.

Additionally, a secondary loop control is installed in each power plant. The objective of this control is to distribute the reactive power output proportionally among the different units in the plant, as shown in Figure A.4.

A.1.4 Lessons learned and recommendations

The experience gained over the past years regarding the implementation of the rules for the voltage control ancillary service has been very positive for the Spanish electricity market. The operation procedures have provided transparency and fair treatment for the different market participants, and have facilitated REE to ensure a secure operation under the new deregulated structure. However, these first steps should be improved in order to cope with some drawbacks that have been identified during this initial implementation period.

[2]At present, in the Spanish power system, there is no generation unit operating as a synchronous compensator.

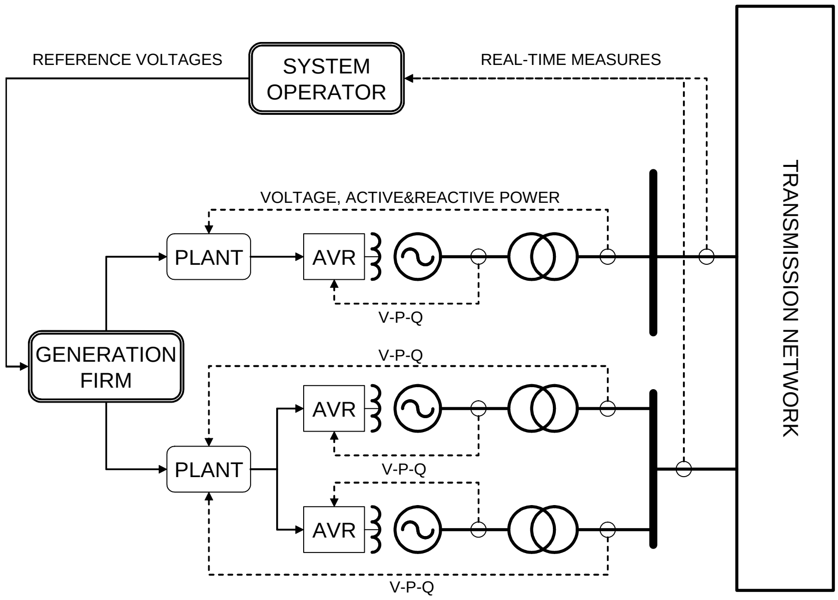

Figure A.4: Voltage control diagram
(Source: personal research)

A separation between a mandatory non-remunerated regulation capacity and a voluntary remunerated one is not a good practice. Studies on reactive power valuation have shown that reactive power regulation provision has been associated with extra energy losses costs and equipment investment. Therefore, the whole provision of the service should be remunerated. This would avoid market discrimination and economic inefficiency. For instance, a firm owning two nearby generating units would prefer to use only one of them to provide reactive power, instead of using both, in order to earn a higher remuneration due to being in the additional regulation capacity. The optimal solution for system security would be that both generators provide the same amount of reactive power, so that the available regulation capacity could be greater.

In order to achieve a correct service procurement, all the measures used by REE to remunerate the service (both the real-time and the state-estimator ones) should be shared on-line with generation units and distribution companies. Otherwise, VAR providers would be blind to efficiently control voltages within the required ranges.

Currently, the two mechanisms used to manage reactive power (constraint management and voltage control ancillary services) are not coordinated. A generation unit can be paid for the same service (reactive power capacity) twice, if the unit is needed both in the short and long term.

Some changes in the present normative should be made to coordinate operation procedures for voltage control in both transmission and distribution networks. Current regulation has technical and remuneration differences which can result in discriminatory and inefficient practices. For instance, generators based on renewable sources and connected to distribution networks receive a compensation for controlling their power factor within specific ranges, without responsibility for voltage control. That is not the case for generators connected to transmission networks. Furthermore, distribution operators currently cannot manage all the reactive power resources in their networks, such as distributed generation, to contribute to voltage control in the transmission network.

Finally, under the new common electric market between Spain and Portugal (MIBEL) a harmonization of the different operating proceedings should be achieved. Currently, Portugal defines the VQ service regulation in *Condiçoes técnicas de ligaçao à rede nacional de transporte* in [DDR, 2000], where generators are required to work within a power factor 0.85 producing VAR to 0.9 absorbing VAR.

A.2 The VQ service in the United Kingdom

This section presents a review of the reactive power management in the United Kingdom. First, a general description of the electricity market is presented. Then, the reactive power balancing service is described, and the SO tools and the generator controls for voltage and VAR management detailed. Finally, an analysis of the current experience is presented.

A.2.1 The electricity market in the United Kingdom

The electricity market in the United Kingdom began in 1991, and was reviewed in 2001 with the name of NETA. The electricity trading arrangements under NETA consist of three elements: a physical contracts market, a balancing mechanism, and the ancillary services markets. The National Grid Company (NGC) is the Transmission System Operator, and it is also responsible for the ancillary services management, consisting of: frequency control, reserve management and energy balance, reactive power and voltage control, and black start. All these services are provided predominantly by generators under contracts by NGC. Contracts are obtained via a tendering process or bilateral negotiations. Like other power systems, the costs associated with the ancillary services are passed through the load, with an uplift in the transmission tariff.

The cost for the purchase of ancillary services in the period 2007/08 is distributed as follows: 64 £ million for reactive power service, 106 £ million for frequency response, 39 £ million for fast active power reserve, and 65 £ million for standing reserve [OFGEM, 2007].

The peak demand in 2002 was 54.6GWh, and the annual consumption was 309.2TWh. The capacity mix is based mainly on coal fired power plants (45%), gas turbines (31%), and nuclear units (16%).

A.2.2 The reactive power balancing service

The next paragraphs describe the main issues of the VAR balancing service, comprising voltage control service procurement and monitoring, economic flows, and an illustrative example.

A.2.2.1 Service procurement

The reactive power balancing service is required for generation units connected to the transmission system, with a capacity of over 30MW. NGC establishes two ranges for the VAR service procurement, a mandatory VAR service procurement and an enhanced reactive power service.

- The *mandatory VAR service* is the provision of regulating reactive power output. At any given active power generation point, generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection. According to the Grid Code CC 6.3.2. [NGC, 2007a], all synchronous generating units must be capable of supplying rated MW at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the generating unit terminals. Generally, non-synchronous generators must be capable of supplying their rated MW output at any point between the limits 0.95 power factor lagging and 0.95 power factor leading at the connecting point to the transmission network.

- The *enhanced VAR service* is the provision of (i) voltage support which exceeds the minimum technical requirement of the mandatory VAR service (including Synchronous Compensation), and/or (ii) the VAR capability from any other plant or apparatus which can generate or absorb reactive power (including Static Compensation equipment) that is not required to provide the obligatory reactive power service.

The enhanced VAR service is procured with tenders, which are held every six months, starting on April 1 and October 1 respectively. Before the VAR tender is called, in order to participate in the tender, generators must submit a bid for VAR. Bids include three terms, (i) utilization prices (£/Mvarh), available capability prices (£/Mvar/h), and synchronized capability prices (£/Mvar/h). Prices are associated to four VAR capacity ranges, defined by three points of VAR absorption capacity, and three points for VAR generation capacity (see Figure A.5). All tenders are submitted in periods corresponding to whole calendar months, in order to be no less than twelve consecutive months and in multiples of six months.

If the generator bid is selected in the tender, in accordance with the evaluation criteria specified in the Grid Code [NGC, 2007a], then the generator will be granted with a market agreement with the SO. On the other hand, if a tender is not successful and the generator is required to provide the mandatory VAR service, then the generator will continue on the default arrangements for the mandatory requirements.

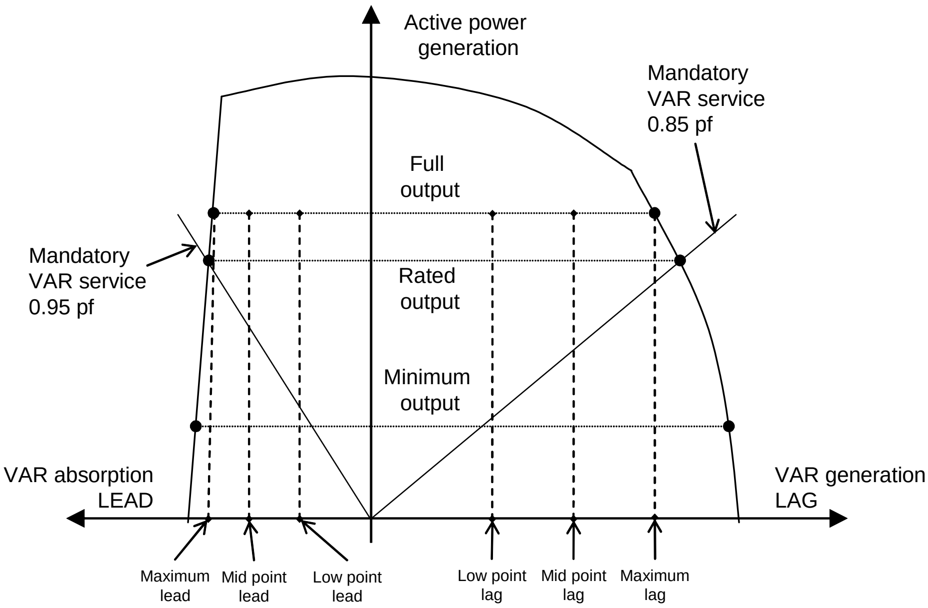

Figure A.5: VAR capacity breakpoints for the VAR tenders in England and Wales (Source: [NGC, 2007b])

A.2.2.2 Service monitoring

According to Grid Code [NGC, 2007a], the VAR output of generating units under steady state conditions should be made fully available in order to maintain voltages within the voltage range ±5%. This voltage range is applicable to 400kV, 275kV, 132kV networks. Therefore, generation units must have a continuously acting automatic excitation control system to provide constant terminal voltage control of the reactive service. For this purpose, NGC monitors the reactive service at each generation unit, and publishes the resulting measurement every year. These measurements are also used to remunerate the service.

A.2.2.3 Service payments and penalties

From a total of 180 agents that are able to participate in the tender, usually around 50 bids are received every tender, and normally not all received bids are accepted. Market arrangements for generation units cover 20-30% of the VAR lagging needs of the power system [NGC, 2006].

The reactive power service is remunerated using the formula presented in Appendix 2 of Schedule 3 *Balancing Services Market Mechanisms - Reactive Power* of the Connection and Use of System Code (CUSC) Contracts[3]. Under the default payment arrangements, expected prices for 2007 are £2.3198/Mvarh (winter Tender) and £2.1225/Mvarh (summer tender). Average prices in tenders in 2007 for VAR capacity (both availability and

[3]Complete information can be found in `http://www.nationalgrid.com/uk/Electricity/Codes/systemcode/contracts/`

synchronizing) are in the range of 0£ to £1/Mvar/h. Average prices for the utilization of the VAR capacity are approximately £3/Mvarh [NGC, 2006].

A.2.2.4 Example

An example of a successful tender of a generation unit of 490MW is presented in Table A.4. Observe that the structure of the bids for the three products is based on steeper incremental prices for higher Mvar outputs.

Table A.4: Tender matrix example for the VAR market in the United Kingdom for VAR generation

Nominated capacity:	**Leading capability**			**Lagging capability**		
490MW	Maximum	Mid Point	Low Point	Low Point	Mid Point	Maximum
Capability (Mvar)	155	100	50	75	150	201
Available capability prices (£/Mvar/h)	0.085	0.060	0.058	0.058	0.060	0.085
Synchronized capability prices (£/Mvar/h)	0.035	0.032	0.030	0.030	0.032	0.035
Utilization prices (£/Mvarh)	3.200	1.520	1.510	1.510	1.520	3.200

(Source: [NGC, 2006])

After a tender is held, NGC publishes a report describing the prices and VAR capacity data of the successful tenders, and also the metered Mvarh utilization from the eligible VAR service providers in the previous 6 month period. For example, the evaluation of the 18th Tender Round held on May 19, 2006 [NGC, 2006], noticed that:

- On the VAR market day, 21 tenders were received.
- With respect to the 21 tenders received, 20 were for the mandatory VAR service, and 1 tender was for the enhanced VAR service.
- All tenders were for a duration of 12 months.
- Of the 21 tenders evaluated, NGC offered VAR market agreements to 7, of which 6 proceeded with the contract.
- As of October 1, 2006 there were a total of 22 generators from a possible 180 with VAR Market Agreements (6 from this tender round and 16 from earlier

tender rounds). Any generator on a Reactive Power Market Agreement that commenced on October 1, 2006 cannot be tendered again until Tender Round 20 (for agreements commencing on October 1, 2007) at the earliest, due to the 12-month minimum agreement duration.

A.2.3 System Operator tools for voltage control

The NGC has economic incentives to reduce congestion across the network. In this sense, NGC has highly increased the number of VAR sources from the 90's to nowadays, from 3000Mvars to 19000Mvars of mechanically switched capacitors, 9000Mvars of SVCs, and 4000Mvars of Quadrature boosters[4] [FERC, 2005]. Most of these devices can be moved between substations in order to cover local voltage problems.

A.2.4 Lessons learned and recommendations

Current experience regarding VAR management in the United Kingdom shows that 20% of the VAR support is provided by generators, and the rest by other VAR sources. The successful VAR management by NGC has achieved a reduction by 90% of the network congestion costs since 1993 [Oren et al., 2002]. This objective is the result of a combination of operational improvements, enhanced forecasting, investments in the transmission network, and an efficient VAR market management.

A.3 The VQ service in Europe

This section presents a complete review of the VQ service in 18 European countries[5]. The review includes a comparison of the different technical requirements for the VQ control, and the economic analysis of the VQ service procurement.

A.3.1 Technical issues of the VQ control

First, a comparative analysis of the technical features in the VQ service is presented in Table A.5 and Table A.6. In all power systems throughout Europe the VQ service is included among the Ancillary Services of the electric power supply. In addition, this service is managed by the corresponding SO.

[4]Devices similar to phase shifters.

[5]The countries analyzed in the tables are: **AU** Austria (VERBUND `http://www.verbund.at`), **BE** Belgium, **CZ** Czech Republic (CEPS `http://www.ceps.cz`), **DN** Denmark (Energinet `http://www.energinet.dk`), **FI** Finland, **FR** France (RTE `http://www.rte-france.com`), **DE** Germany (DVG), **HU** Hungary, **IT** Italy, **IC** Iceland, **IR** Ireland (EIRGRID `http://www.eirgrid.ie`), **NE** The Netherlands, **NO** Norway, **PL** Poland (PSE `http://www.pse-operator.pl`), **PO** Portugal (REN `http://www.ren.pt`), **ES** Spain (REE `http://www.ree.es`), **SW** Sweden, **SL** Slovakia (SEPSAS `http://www.sepsas.sk`), and the **UK** United Kingdom (NGC `http://www.nationalgrid.com/uk/`).

From the review, most SOs require the VQ service to be provided in real-time voltage control which is achieved mainly by generators. The requirements for the VQ service usually lay on generators. Some countries also include specific requirements for the VAR sources owned by the transmission network owners. The size of generators that are entitled to participate in the VQ service is sometimes limited with a minimum MVA or MW requirement. Some examples are Spain, Germany or the United Kingdom, with a minimum installed capacity of 30MW. The monitorization of the procurement in the VQ service is based on the metering of voltage in certain buses of the transmission network, together with the actual VAR procurement of each VAR source.

In France all generators connected to networks over 225kV should have the ability to participate in the secondary voltage control. The dynamic response of the participating generators is monitored on-line, and should be compliant with a specific V/Q capability diagram and a response time (usually less than 60 seconds) [Margotin et al., 2006, RTE, 2006].

The definition of the volume of VAR service is usually settled using historical data on annual plans, and updated in some countries before the energy market is cleared.

The mandatory requirements for generators in the VQ service are defined using a power factor range or a tangent range[6]. The point where the procurement is measured can be the generator terminals, or the connection point to the transmission network (also called Point of Delivery POD). In order to compare the VAR requirements of the different countries, all values have been calculated at the POD[7]. The VAR requirements in the POD are normally in the range of 40% P_n of VAR absorption, and 50% of P_n for VAR generation[8]. The Spanish mandatory VAR capacity is the least restrictive, with a range of 15% for both VAR generation and absorption, compared with the requirements in the Netherlands of 75% of P_n. The less restrictive the power factor requirements, the more additional VAR support from other VAR sources is required.

A.3.2 Economic issues of the VQ service

Table A.7 and Table A.8 present a comparative review of the economical issues associated with the VQ service. According to the review, in most of the countries analyzed,

[6]The power factor is calculated as $cos\phi = \frac{P}{\sqrt{P^2+Q^2}}$,and the tangent as $tan\phi = \frac{Q}{P}$, where P is the active power and Q the reactive power produced by the generator, and ϕ the phase angle between the voltage and current signals.

[7]In this calculation it has been assumed that the step-up transformer of each generator has the same rated power as the generator, and a 12% short-circuit impedance.

[8]The VAR generated or produced by a generator are also referred to as VAR lagging and capacitive VAR. On the other hand, the VAR absorbed or consumed are referred to as VAR leading and inductive VAR.

Country	**Service provider**	**Service monitoring**	**Volume of service calculation**	$\cos\phi$ **mandatory requirements**	$\tan\phi$ **at POD**
AU	Generators and network devices	Allowed voltage range	n.a.	n.a.	n.a.
BE	Generators and network devices	Allowed voltage range	n.a.	At POD, -0.1 to 0.45 $\tan\phi$	-0.10 to 0.45
CZ	Generators	Allowed voltage range	n.a.	At generator terminals, 0.85 lag, 0.95 lead	-0.45 to 0.5
DN	Generators	Allowed voltage range	n.a.	n.a.	n.a.
FI	Generators (Pn>10MVA) and TSOs	Allowed voltage range	n.a.	At generator terminals, 0.95 lead, 0.9 lag	-0.45 to 0.36
FR	Generators	V/Q diagram and time response	When the generator is connected	At POD, -0.35 to 0.32 $\tan\phi$	-0.35 to 0.32
DE	Generators (Pn>100MW) and TSOs	Allowed voltage range	n.a.	At POD, 0.95 or 0.975 lag, 0.925 or 0.9 lead	-0.33/-0.23 to 0.41/0.48
HU	Generators	Yes	n.a.	n.a.	n.a.
IT	Generators (no minimum size limit)	Allowed voltage range	n.a.	Not defined	Not defined

Table A.5: Comparison of the technical features of the VQ service in Europe I
(n.a.: not available. Source: [Frías, 2004, Rebours et al., 2007a] and personal research)

Country	**Service provider**	**Service monitoring**	**Volume of service**	$\cos\phi$ **mandatory requirements**	$\tan\phi$ **at POD**
IR	Generators and network devices	Allowed voltage range	n.a.	At generator terminals, at P_n 0.93 lead, 0.85 lag, at $0.35P_n$ 0.7 lead, 0.4 lag	-0.4 to 0.5
NE	Generators	Allowed voltage range	n.a.	At POD, 0.8 lag, 0.8 lead	-0.75 to 0.75
NO	Generators (no minimum size limit)	Allowed voltage range	n.a.	At POD, 0.93 lag, 0.98 lead	-0.2 to 0.39
PL	Generators and network devices	Allowed voltage range	n.a.	n.a.	n.a.
PO	Generators and network devices	Allowed voltage range	n.a.	At generator terminals, 0.85 lag, 0.95 lead	-0.45 to 0.5
ES	Generators (P>30MW) and network devices	Voltage ranges defined in annual plans, and hourly	Updated every day	At POD, 0.989 lead, 0.989 lag	-0.15 to 0.15
SW	Generators (no minimum size limit)	Allowed voltage range	n.a.	At POD, 0.948 lag, 0.986 lead	-0.17 to 0.34
SL	Generators	Allowed voltage range	n.a.	n.a.	n.a.
UK	Generators (P>30MW)	Voltage range in 400kV, 275kV and 132kV must be within $V_n \pm 5\%$	Based on historical levels. Updated hourly	At generator terminals, 0.85 lag 0.95 lead	-0.45 to 0.5

Table A.6: Comparison of the technical features of the VQ service in Europe II
(n.a.: not available. Source: [Frías, 2004, Rebours et al., 2007a] and personal research)

the VQ service is procured via mandatory mechanisms. In Sweden, Italy and Iceland the procurement of the service is not yet remunerated. On the other hand, the VQ service is provided with bilateral and negotiated contracts between the supplying agents and the SO in the majority of European countries. Under these contracts the price can be regulated, which is the most common option, or agreed between the SO and the agents. Finally, only some advanced regulation has provided competition to the VQ service in the United Kingdom. The frequency of the markets or bilateral tenders for VAR support varies from 6 months in the United Kingdom, to one year in Spain or two years in France. The procedure to select the best VAR sources to supply the VQ service is mainly based on technical issues regarding the security of the operation of the power system. Additionally, in those power systems with competitive mechanisms for VAR procurement, the bids of the supplying agents are also considered. The remuneration of the selected agents (both under mandatory procurement or competitive mechanisms) is based on the investments and use in the VAR sources in most of the countries. Some regulations also design specific compensation for the opportunity costs due to active power reduction to increase the VAR support, such as in Germany.

The remuneration for VAR support in France differentiates "sensitive areas" and "non-sensitive areas" for voltage support which are defined by the SO. Generators located in "sensitive areas" are paid a fixed annual payment for participating in the voltage support. In addition, a variable payment is paid to all generators over the maximum VAR generation and absorption capacity, only for the hours where the generator is connected to the network. The variable payment can be increased by 50% in case the generator participates in the secondary voltage control [RTE, 2006, Bertolini, 2007].

The resulting VAR regulated/market prices vary from €0.07/MVA/hour in France and €0.11/Mvar/hour in Spain to €1.5/Mvar/hour in the United Kingdom for the available VAR capacity. The variable payment for VAR energy in Europe varies from €0.057/Mvarh in France and €0.5/Mvarh in Spain, to €4.5/Mvarh in the United Kingdom.

Finally, the cost of the VQ service is usually recovered through the transmission system tariffs. These tariffs differentiate end-users charges by voltage-level, average power-factor, among others.

In conclusion, the successful experience concerning the VQ service in the United Kingdom can help to improve the regulations in other countries. As the regulatory proposals for the service in most countries are very recent, there is currently not enough experience. However, regulators should be encouraged to introduce competitive mechanisms for the procurement of the VQ service, so that economic and technical efficiency will be improved.

Country	Remuneration mechanism	Market creation	Frequency of markets	Criteria for selecting VAR agents	Payments to supplying VAR agents	VAR prices	Charges to VAR demand
AU	Compulsory and open market	-	n.a.	Technical	Only for enhanced VAR: investment + use	n.a.	Customers through system tariffs
BE	n.a.	-	n.a.	Technical	n.a.	n.a.	Customers through system tariffs
CZ	Bilateral contracts	-	n.a.	Technical	Investment + use	n.a.	Customers through system tariffs
DN	Bilateral contracts	-	n.a.	Minimum dispatch cost	n.a.	n.a.	Generators & customers, through system tariffs
FI	Bilateral contracts	-	n.a.	Contract price, and technical	Investment + use + LOC	n.a.	Customers through system tariffs
FR	Compulsory and bilateral contracts	2000	Two or three years	Minimum dispatch cost	Regulated remuneration. Fixed value (€/month)+ availability (€/Mvar/h) + LOC	629€/MVA/year, 0.057 €/Mvar/hour +50%	Customers through system tariffs
DE	Compulsory, bilateral contracts, and open market	-	n.a.	Technical	LOC	n.a.	Customers
HU	Bilateral contracts	-	n.a.	Contract price	LOC	n.a.	Customers through system tariffs
IT	Compulsory	-	n.a.	Technical	No remuneration	n.a.	Customers through system tariffs
IC	Compulsory	-	n.a.	Technical	No remuneration	n.a.	Customers through system tariffs

Table A.7: Comparison of the economical features of the VQ service in Europe I
(n.a.: not available. Source: [EURELECTRIC, 2004, Rebours et al., 2007b] and personal research)

Country	Remuneration mechanism	Market creation	Frequency of markets	Criteria for selecting VAR agents	Payments to supplying VAR agents	VAR prices	Charges to VAR demand
IR	Compulsory	-	n.a.	Minimum dispatch cost	Regulated remuneration, for Availability + use	Availability €0.238/Mvarh + use €1.16/Mvarh	Customers through system tariffs
NE	Compulsory, and negotiated contracts	-	n.a.	Minimum dispatch cost, and technical	Open market	n.a.	Generators and customers, with an uplift
NO	Negotiated contracts	-	Annual	n.a.	Remuneration on enhanced VAR. Only use. No penalties.	n.a.	System tariffs
PL	Negotiated contracts	-	n.a.	Contract price	Contract price	n.a.	Customers through system tariffs
PO	Compulsory and bilateral contracts	-	n.a.	Technical	LOC + use (wear and tear)	n.a.	Network users, with system tariffs
ES	Compulsory and tendering process	2001, but still not in force	Annual	Technical	Regulated price on enhanced VAR. Capacity (€/Mvar/year) + use (€/Mvarh). Penalties	Approximate values, capacity €1000/Mvar/ year, use €0.5/Mvarh	Customers, with an uplift included in the transmission tariff
SW	Compulsory	-	n.a.	n.a.	No payment	n.a.	n.a.
SL	Compulsory	-	n.a.	n.a.	Regulated remuneration	n.a.	Customers share the price in accordance to consumption
UK	Compulsory and tendering process	April 1998	Semester: April, October	Minimum dispatch cost, and technical	Fixed (€/Mvar/h) + availability (€/Mvar/h) + use (€/Mvarh)	Capacity tenders €0-1.5/Mvar/h, use €4.5/Mvarh. Default use €0.6-2.8/Mvarh	Generators and customers, with system tariffs

Table A.8: Comparison of the economical features of the VQ service in Europe II
(n.a.: not available. Source: [EURELECTRIC, 2004, Rebours et al., 2007b] and personal research)

A.4 The VQ service in the United States and other countries

This section presents a comparative review of the VQ service in different power systems in the United States [Alvarado et al., 2003], and other representative countries around the world, such as Australia [NEMMCO, 2005], New Zealand [ELCOM, 2004], Argentina [ENRE, 2002], and Brazil [Frías, 2004]. This section first analyzes the technical issues of the voltage control, and then compares the economic characteristics of the VAR procurement schemes.

A.4.1 Technical issues of the VQ control

In the United States each power system can determine its own electricity policy for VAR procurement and compensation. In addition, the FERC[9] proposes some guidelines for the development of efficient regulatory mechanisms for the energy supply. Among others, the FERC published the Order No. 888 [FERC, 1996] where six ancillary services are defined, including the *reactive supply and voltage control from generation sources*. In this Order it was concluded that these services should be included in the transmission access tariff. The FERC considered that the VQ service should be unbundled for generation facilities from the basic transmission services. Currently, there is a wide range of experiences concerning the practical implementation of these rules within the different states.

Additionally, according to Order No.2003 [FERC, 2003] the Commission emphasized that generators connected to the transmission network should not be compensated if they operate within a power factor at the connection point of 0.95 leading and 0.95 lagging. Moreover, if they work over this minimum requirement, then generators should be compensated. Within the FERC proposal, CAISO and PJM [PJM, 2003, PJM, 2005] have defined more severe power factor requirements for VAR absorption, based on 0.9 lagging and 0.95 leading. Other power systems, such as New York ISO and New England ISO, defined specific power factor requirements based on annual testing of the VAR capability of generators. These tests vary from an annual periodicity in New York ISO to every two years in Texas, and to a period test every five years in New England and PJM [Kueck et al., 2006]. There are some additional requirements for generators to participate in the VQ control, for instance in PJM generators have to be under the control of a voltage control area operator.

The requirements concerning the power factor ranges for generators are similar in the other countries analyzed, which define a gap of 0.9 lagging and 0.93 leading (see Table A.9). In Argentina [ENRE, 2002], generators have to provide their full VAR capability curve in order to help TSOs to maintain voltages within certain operation ranges. Under

[9] The Federal Energy Regulatory Commission is an independent regulatory agency within the United States Department of Energy. The responsibility of the FERC is to regulate the interstate transmission of electricity, natural gas, and oil. `http://www.ferc.gov`

normal conditions 90% VAR capacity should be permanently available. In addition, under special situations 100% of VAR capacity can be required during 20 minutes, every 40 minutes. In Brazil [ELECTROBRAS, 1998, ONS, 2003] generators must send their capability curves to the SO in order to be integrated in the energy dispatch. Finally, Australia and New Zealand have similar power factor requirements, and the volume of VAR needs is adjusted for every energy market period, which is half an hour. For every period, and after static compensation and VAR capacity for generators are used, synchronous compensators and active power curtailment to increase VAR may be called.

A.4.2 Economic issues of the VQ service

In most of the power systems the VQ service is compulsory (see Table A.10). However, there are other alternatives, such as bilateral trading in California, New Zealand and Brazil, or using a tendering process in Australia. In California, if more VAR than the mandatory requirements is needed, the SO uses reliability must-run contracts with generators that are remunerated only in the case of active power reduction. Finally, some regulators such as NYISO and Argentina settle penalties in the case of non-fulfillment of the VQ service to the extent that in Argentina [ENRE, 2002] generators can be denied access to the energy market.

For most power systems, the VAR requirements are based on technical requirements, and their allocation is updated on an annual basis, with the exception of Argentina where it is updated with a monthly analysis.

The remuneration for the selected VAR supplying agents recognize the costs for investments and the opportunity costs, with the corresponding VAR capacity and LOC remuneration. New England, Brazil and New Zealand also remunerate for the use of VAR sources cost, which are only recognized for synchronous compensators in Australia. In Brazil [ELECTROBRAS, 1998, ONS, 2003] generators are paid ex-post on an annual basis, once the real costs of the VQ service are computed. The scarce data on VAR prices show that remuneration in New York for VAR capacity $0.2/Mvar/h, is in the range of the prices in Europe. Finally, the cost derived from the VQ service is integrated into the transmission system tariff which is charged to the end-customers.

Country / State	**Service provider**	**Service monitoring**	**Volume of service**	$\cos\phi$ **mandatory requirements**	$\tan\phi$ **at POD**
New York	Generators & synchronous condensers	Capability test every year	n.a.	At POD, 0.9 lag, 0.95 lead	-0.48 to 0.33
New England	Generators	Capability test every 5 years	n.a.	At POD, 0.9 lag, 0.95 lead	-0.48 to 0.33
California	Generators, transmission & distribution companies	No tests expect if problems are detected	Determined by the SO according to VAR needs	At POD, 0.9 lag, 0.95 lead	-0.48 to 0.33
PJM	Generators (no min size limit)	Capability test every 5 years	n.a.	At POD, 0.9 lag, 0.95 lead	-0.48 to 0.33
Texas	Generators	Capability test every 2 years	n.a.	At POD, 0.95 lag, 0.95 lead	-0.33 to 0.33
Argentina	All transmission network users	In 500kV $V_n \pm 3\%$, 230&132kV $V_n \pm 5\%$	n.a.	Full capability curve	-
Brazil	Generators	n.a.	0% permanently, 100% special	Full capability curve	-
Australia	Generators & synchronous condensers	Permanent monitoring of service participants	According to demand, every half-hour	At POD, 0.9 lag, 0.93 lead	-0.48 to 0.4
New Zealand	Generators	n.a.	Every half-hour	At POD, 0.928 lag, 0.928 lead	-0.4 to 0.4
South Africa	Generators	n.a.	n.a.	At generator terminals, 0.85 lag, 0.95 lead	-0.45 to 0.5

Table A.9: Comparison of the technical features of the VQ service in the United States and other countries (n.a.: not available. Source: [Frías, 2004, Raineri et al., 2006, Rebours et al., 2007a] and personal research)

Country / State	Remuneration mechanism	Market creation	Frequency of markets	Criteria for selecting VAR agents	Payments to supplying VAR agents	Approximate VAR prices	Charges to VAR demand
New York	Compulsory	-	Annual	Technical	Capacity, LOC. Penalties	Capacity $3919/Mvar/year	Transmission customers, with monthly charges
New England	Compulsory	-	5 years	Technical	Capacity, LOC, use. No penalties	Capacity $1050/Mvar/year	Transmission customers, with monthly charges
California	Bilateral contracts	-	Annual	Technical	Capacity only over mandatory limits, LOC, use (maintenance and wear)	n.a.	According to CAISO projected demand for reliability Must-Run contracts
PJM	Compulsory	1999	Annual	Technical	Fixed ($/Mvar/h), LOC ($/MWh)	Capacity $2430/Mvar/year	Transmission customers, with monthly charges
Texas	Compulsory	-	-	Technical	LOC & avoided costs	n.a.	n.a.
Argentina	Fixed monthly charges	-	Month	Technical	According to generator and TransCons declarations. Penalties	n.a.	According to declared VAR demand
Brazil	Bilateral contracts	-	-	Technical	Capacity ($/Mvar), use, LOC	n.a.	n.a.
Australia	Tendering process	2001	2 years	Technical and VAR bids	Availability (lead&lag) ($/Mvar/h), LOC ($/MWh), use only synchronous ($/MWh)	$0.2/MWh	Payments by customers according to the energy consumption
New Zealand	Compulsory and bilateral contracts	2004	-	Technical	Fixed ($/Mvar/h) availability ($/Mvar/h) use ($/Mvarh)	n.a.	n.a.
South Africa	Compulsory	-	-	Technical	No payment	n.a.	Transmission system charges

Table A.10: Comparison of the economical features of the VQ service in the United States and other countries (n.a.: not available. Source: [Raineri et al., 2006, Rebours et al., 2007b] and personal research)

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APPENDIX B

Bid definition for VAR capacity market participants

THIS appendix presents an approach to build the capacity bids for the proposed VAR capacity market. VAR bids are defined by an available VAR capacity and a corresponding price. First capacity bids for generators are analyzed, where the calculation of the available VAR capacity is performed with an original approach. Then, the cost associated with the availability and use of the VAR capacity into the proposed market is described. Finally, the bids of other VAR compensation devices are analyzed from the technical an cost point of view.

B.1 Generator VAR bids

This section describes how to build the generator VAR capacity bids for the proposed market. First, the available VAR capacity of a power plant is characterized, which is mainly limited by the capability diagram of the alternator and the operating limits inside the power plant. Then, the costs associated with the available VAR capacity are detailed. Finally, the previous cost characterization is used to propose a bid structure for the VAR capacity market presented in this thesis dissertation.

B.1.1 VAR capacity

The calculation of the available VAR capacity of a power plant comprises the following steps: (i) calculation of the capability diagram of the alternator, (ii) description of the operating constraints in the power plant, and (iii) definition of an algorithm to calculate the resulting VAR capacity. These three issues are described in the next subsections, and an illustrative example is also included.

B.1.1.1 Capability diagram of an alternator

The capability diagram of an alternator (see an example in Figure B.1) is a graph which shows the active power and reactive power capability limits within which the alternator is expected to operate under steady state conditions, as defined by the manufacturer. Different capability curves are defined for specific voltage values at the generator terminals, and also for conditions of the coolant used to refrigerate the generator. These diagrams are obtained from theoretical models of the alternator [Adibi and Milanicz, 1994], and then evaluated using empirical testing [Nilsson et al., 1994, Panvini and Yohn, 1995].

The reactive capability diagram of any alternator has three distinct limiting curves. The curve that is parallel to the active power axis for VAR generation represents the limit of the ability to cool the generator rotor when over-excited to produce VAR[1]. The curve that is parallel to the VAR axis for active power generation represents the limit of the ability to cool the armature windings[2]. Finally, the curve that is parallel to the active power axis, on the VAR absorption side, represents the limit of the ability to cool the end-turns/end iron, when reactive current is flowing and there is no reduced magnetic field from the rotor. The inability to cool the end-turns/end iron is the major reason why most alternators would not be operating with a large leading VAR power factor, absorbing VAR.

[1]Under this operating condition, the direct current injected in the rotor windings is at its rated value.

[2]The current flowing in the stator armature is at its rated value, increasing the heat of the armature.

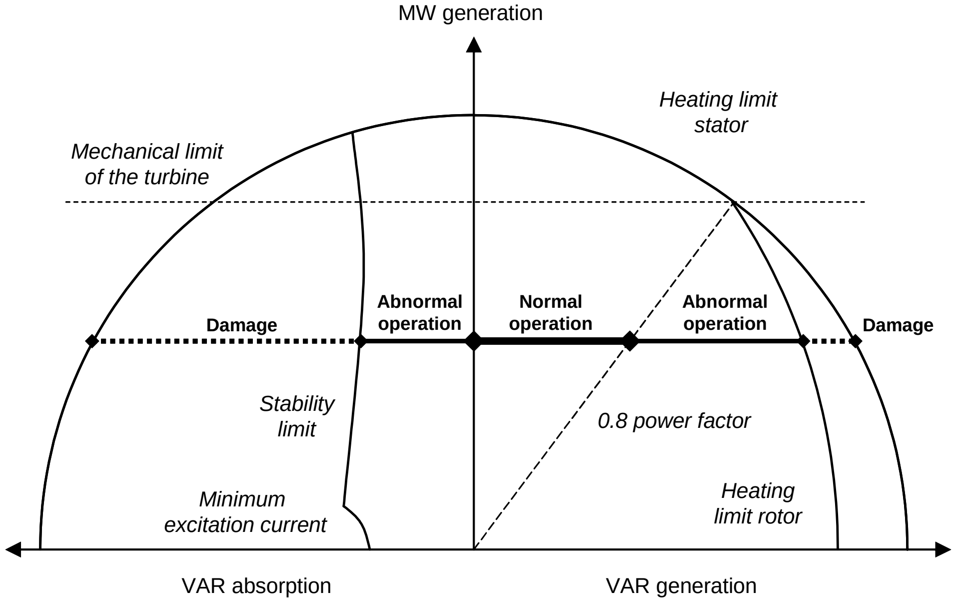

Figure B.1: Typical capability curve of an alternator and its limits
(Source: [Olson, 2006] and own search)

According to these limits, three operating areas can be defined in the capability curve, as indicated in Figure B.1: (i) the green area is the normal operating range of a typical synchronous machine; (ii) the yellow area is abnormal but not damaging operation; and finally (iii) operating in the red region during long periods will cause damage or misoperation.

B.1.1.2 Operation constraints

If the available VAR capacity is defined at the connection point to the transmission network, then additional operating constraints to the capability curve of the alternator should be considered. Among these additional limitations stand: (i) minimum and maximum voltage value at alternator terminals, and (ii) maximum charging of the step-up transformer.

The voltage value at generator terminals can become a limiting factor, as it supplies the auxiliary loads of the power plant. For instance, large amounts of VAR absorption will reduce voltages at generator terminals, and therefore the transformer that feeds the auxiliaries must be able to modify its tap ratio to compensate this voltage decrement. If the transformer tap-ratio range is low and there is no on-load tap changer, then the maximum VAR capacity will be limited. In addition, in the case of power plant re-powering (comprising an increase in the output of the turbine), the maximum current of the step-up transformer may limit the VAR production of the generator when operating at the new rated generator output.

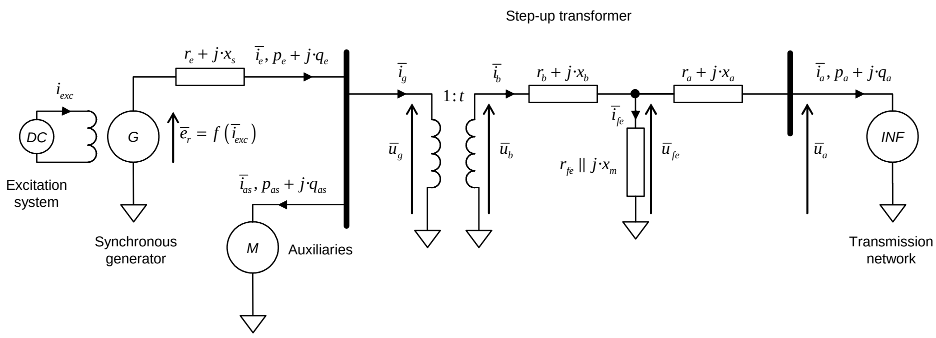

Figure B.2: Equivalent schematic of a power plant

B.1.1.3 Calculation of the available VAR capacity

In order to determine the real VAR capacity of the power plant, which includes the alternator capability curve and the other operating limits, this thesis dissertation proposes a simple calculation methodology based on electric circuit analysis. Under this approach, a generic circuit of a power plant is used, as presented in Figure B.2. This generic model can be directly adapted to the specific configurations of each power plant, for instance two generators sharing a three winding step-up transformer. The aim of the proposed methodology is to obtain the maximum VAR exported to the network q_a, for different values of generator output p_e, voltage value in the transmission network u_a, and tap-ratio of the step-up transformer t. The inputs of the model are the operating limits of the power plant, maximum rotor current, maximum stator current, minimum and maximum voltage at generator terminals, the auxiliaries load, and the characteristics of the step-up transformer and transformer for auxiliaries.

The power flow equations that describe the relationship between the variables in Figure B.2 are formulated in (B.1).

$$
\begin{aligned}
\vec{s}_a &= p_a + jq_a = \vec{u}_a \cdot \vec{i}_a^* \\
\vec{u}_{fe} &= \vec{u}_a + \vec{i}_a \cdot \vec{z}_a = \vec{i}_{fe} \cdot \vec{z}_{fe} \\
\vec{i}_b &= \vec{i}_{fe} + \vec{i}_a \\
\vec{u}_b &= \vec{u}_{fe} + \vec{i}_b \cdot \vec{z}_b \\
\vec{i}_g &= t \cdot \vec{i}_b \\
\vec{u}_g &= \vec{u}_b / t \\
\vec{s}_g &= \vec{u}_g \cdot \vec{i}_g^* \\
p_e &= \frac{p_g + b_b}{1 - a_p} \\
p_{as} &= a_p \cdot p_e + b_p \\
q_{as} &= a_q \cdot q_e + b_q \\
\vec{s}_{as} &= p_{as} + jq_{as} \\
\vec{s}_e &= \vec{s}_g + \vec{s}_{sa} \\
\vec{i}_e &= \left(\frac{\vec{s}_e}{\vec{u}_g} \right)^*
\end{aligned}
\tag{B.1}
$$

The demand of the auxiliary services in the power plant is formulated in (B.2) and is assumed to be linearly proportional with the generator output.

$$
\begin{aligned}
a_p &= \frac{p_{as}^{\max} - p_{as}^{\min}}{p_e^{\max} - p_e^{\min}} & b_p &= p_{as}^{\min} - a_p p_e^{\min} \\
a_q &= \frac{q_{as}^{\max} - q_{as}^{\min}}{p_e^{\max} - p_e^{\min}} & b_q &= q_{as}^{\min} - a_q p_e^{\min}
\end{aligned}
\tag{B.2}
$$

The tap ratio in per unit for the current tap position of the step-up transformer is formulated in (B.3), where U_{n1}/U_{n2} is the current voltage ratio on the high side/low voltage side in kV, and U_{B1}/U_{B2} is the off-nominal voltage ratio.

$$
t = \frac{U_{n1}/U_{n2}}{U_{B1}/U_{B2}}
\tag{B.3}
$$

Changes in the tap position modify the value of the impedances of the transformer which are obtained from open circuit and short circuit tests (B.4). A coefficient k_{dist} represents the variation of the disperse field for tap changes [Sáiz, 1985].

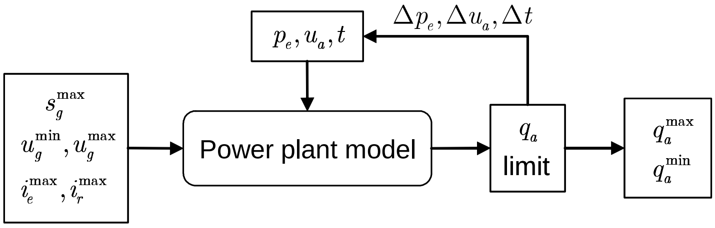

Figure B.3: Calculation of VAR limits for a power plant

$$
\begin{aligned}
p_{sc}^{'} &= \frac{p_{sc} \cdot t \cdot (1+t)}{2} \\
x_{sc}^{'} &= (1+k_{dist}) \cdot t^2 \cdot \sqrt{u_{sc}^2 - p_{sc}^2} \\
p_o^{'} &= \frac{p_o}{t^2} \\
i_o^{'} &= i_o
\end{aligned}
\tag{B.4}
$$

The calculation of the available VAR capacity is based on an iterative algorithm (see Figure B.3) where the power plant circuit in Figure B.2 is solved for different operation points which are defined by: (i) the generator output, (ii) the voltage at the transmission side, and (iii) the step-up transformer tap ratio. For each operation point, the VAR output of the generator is modified (first upwards and then downwards, in order to obtain the generation and absorption VAR capacity respectively). During the incremental/decremental process, the alternator VAR capacity and operation limits are checked. If a limit is reached then the maximum VAR capacity for that operation point is settled and the values of the different variables are stored.

Two infeasibilities may occur during the calculation of the VAR capacity limits, which are associated with inadequate voltage levels. Voltage infeasibility occurs when, for a specific operation point, voltages at generator terminals for any VAR production cannot be within the admissible limits.

B.1.1.4 Power plant example

A simple case study is used to illustrate the calculation of the VAR capacity of a power plant. Data is presented in Table B.1.

For the example power plant, the results of the VAR limits for generation (Table B.2) and absorption (Table B.3) are calculated, for five values of active power generation and thirteen voltage values in the transmission network[3]. The available VAR capacity

[3]These data for VAR capacity is required for generators participating in the Spanish Voltage Control Ancillary Service [REE, 2000].

Table B.1: Example generator data

Generator	*Rated power/voltage*	240 MVA, 17kV
	Max/Min MW	214/105 MW
	Max VAR generation at Max/Min MW	105/170 Mvar
	Stator resistance	0.0011Ω
	Rotor resistance	0.1640Ω
	Max/Rated excitation current	1.783/0.607kA
Transformer	*Rated power*	240MVA
	Rated voltage	16.15/230kV±2x2.5%
	Short-circuit voltage	11.52%
	Short-circuit power	0.091%
Auxiliaries	*Max/Min MW load*	7.1/4.52 MW
	Max/Min Mvar load	5.33/3.39 Mvar
	Max/Min voltage	17/16.5kV

is obtained at generator terminals and at the connection point to the transmission network. In addition, the voltage value at the connection point for each operating point is calculated. The limit of the VAR generation/absorption capacity can be: (i) **V+** and **V-** if limited by the generation maximum and minimum voltage limits, (ii) **Ir** if limited by the maximum rotor current, and (iii) **Inf** means that the operating point is infeasible for the selected voltage value at the connection point.

From the tables, it is observed that the VAR generation capacity in the example power plant is limited by the maximum voltage at auxiliaries, and the operation becomes dangerous when the voltage at the point of delivery is below 220kV. Similar results are obtained for the VAR absorption capacity, which is mainly limited by the minimum voltage level at the auxiliaries, and for voltages below 220kV the operation becomes unsafe. It is clear that the limiting factor is the restrictive voltage range at the auxiliaries that can be solved by the installation of a new transformer with a wider tap ratio range.

Figure B.4 presents the capability diagrams (active vs. reactive power at the connection point) for the example power plant considering that the average voltage at the connection point is 233kV, and all the possible tap ratios of the step-up transformer. Observe that for the tap position 247.25/16.15kV, the generator cannot operate properly, since the resulting voltages in the auxiliaries are very low, so a high VAR generation is needed to increase voltages. As the tap position increases, the generation VAR capacity is reduced, while the absorption VAR capacity is increased.

The selection of the optimal tap position will depend on the VAR needs of the voltage control area where the power plant is located. Additionally, the operation point of the power plant, defined by the average voltage in the transmission network and average generator output, should also be considered when selecting the tap position.

Table B.2: VAR generation limits components for tap ratio 230/16kV

VAR limit at the connection point													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	-0.5	27.4	54.6	76.3	75.7	75.1	0	0	0	0	0	0	0
180.1	2.0	29.9	57.1	83.6	101.3	100.8	100.3	0	0	0	0	0	0
153.5	4.1	32.1	59.3	85.8	111.6	121.2	120.8	0	0	0	0	0	0
126.9	6.0	33.9	61.2	87.7	113.5	137.5	137.1	136.7	0	0	0	0	0
100.3	7.5	35.5	62.7	89.3	115.1	140.3	149.8	149.4	0	0	0	0	0
VAR limit at generator terminals													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	23.6	52.3	81.0	104.5	104.5	104.6	0	0	0	0	0	0	0
180.1	21.1	49.7	78.4	107.1	126.8	126.9	126.9	0	0	0	0	0	0
153.5	18.9	47.5	76.2	104.8	133.5	144.7	144.7	0	0	0	0	0	0
126.9	16.9	45.6	74.2	102.9	131.5	158.8	158.8	158.8	0	0	0	0	0
100.3	15.3	44.0	72.6	101.2	129.8	158.5	169.8	169.9	0	0	0	0	0
Voltage limit at the transmission side													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	1.05	1.05	1.05	1.05	1.03	1.02	0	0	0	0	0	0	0
180.1	1.05	1.05	1.05	1.05	1.04	1.03	1.02	0	0	0	0	0	0
153.5	1.05	1.05	1.05	1.05	1.05	1.04	1.03	0	0	0	0	0	0
126.9	1.05	1.05	1.05	1.05	1.05	1.05	1.04	1.02	0	0	0	0	0
100.3	1.05	1.05	1.05	1.05	1.05	1.05	1.04	1.03	0	0	0	0	0
Active VAR constraint													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	V+	V+	V+	Ir	Ir	Ir	Inf	Inf	Inf	Inf	Inf	Inf	Inf
180.1	V+	V+	V+	V+	Ir	Ir	Ir	Inf	Inf	Inf	Inf	Inf	Inf
153.5	V+	V+	V+	V+	V+	Ir	Ir	Inf	Inf	Inf	Inf	Inf	Inf
126.9	V+	V+	V+	V+	V+	Ir	Ir	Ir	Inf	Inf	Inf	Inf	Inf
100.3	V+	V+	V+	V+	V+	V+	Ir	Ir	Inf	Inf	Inf	Inf	Inf

(**V**: voltage at the connection point to the transmission network, in kV. **P**: active power generation at the connection point, in MW)

Table B.3: VAR absorption limits components for tap ratio 230/16kV

VAR limit at the connection point													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	-68.4	-39.7	-11.6	15.7	42.3	68.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
180.1	-65.9	-37.1	-9.0	18.3	44.9	70.8	96.0	0.0	0.0	0.0	0.0	0.0	0.0
153.5	-63.6	-34.9	-6.8	20.6	47.2	73.2	98.4	0.0	0.0	0.0	0.0	0.0	0.0
126.9	-61.7	-32.9	-4.9	22.5	49.2	75.1	100.4	124.9	0.0	0.0	0.0	0.0	0.0
100.3	-60.2	-31.4	-3.3	24.1	50.8	76.8	102.1	126.6	0.0	0.0	0.0	0.0	0.0

VAR limit at generator terminals													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	-42.3	-14.4	13.5	41.3	69.2	97.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
180.1	-44.9	-17.0	10.8	38.6	66.5	94.3	122.2	0.0	0.0	0.0	0.0	0.0	0.0
153.5	-47.2	-19.4	8.5	36.3	64.1	91.9	119.8	0.0	0.0	0.0	0.0	0.0	0.0
126.9	-49.1	-21.3	6.5	34.3	62.1	89.9	117.7	145.5	0.0	0.0	0.0	0.0	0.0
100.3	-50.8	-23.0	4.8	32.6	60.4	88.1	115.9	143.7	0.0	0.0	0.0	0.0	0.0

Voltage limit at the transmission side													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	1.02	1.02	1.02	1.02	1.02	1.02	0	0	0	0	0	0	0
180.1	1.02	1.02	1.02	1.02	1.02	1.02	1.02	0	0	0	0	0	0
153.5	1.02	1.02	1.02	1.02	1.02	1.02	1.02	0	0	0	0	0	0
126.9	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	0	0	0	0	0
100.3	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	0	0	0	0	0

Active VAR constraint													
P\V	**241**	**238**	**235**	**232**	**229**	**226**	**223**	**220**	**217**	**214**	**211**	**208**	**205**
206.7	V-	V-	V-	V-	V-	V-	Inf	Inf	Inf	Inf	Inf	Inf	Inf
180.1	V-	V-	V-	V-	V-	V-	V-	Inf	Inf	Inf	Inf	Inf	Inf
153.5	V-	V-	V-	V-	V-	V-	V-	Inf	Inf	Inf	Inf	Inf	Inf
126.9	V-	V-	V-	V-	V-	V-	V-	V-	Inf	Inf	Inf	Inf	Inf
100.3	V-	V-	V-	V-	V-	V-	V-	V-	Inf	Inf	Inf	Inf	Inf

(**V**: voltage at the connection point to the transmission network, in kV. **P**: active power generation at the connection point, in MW)

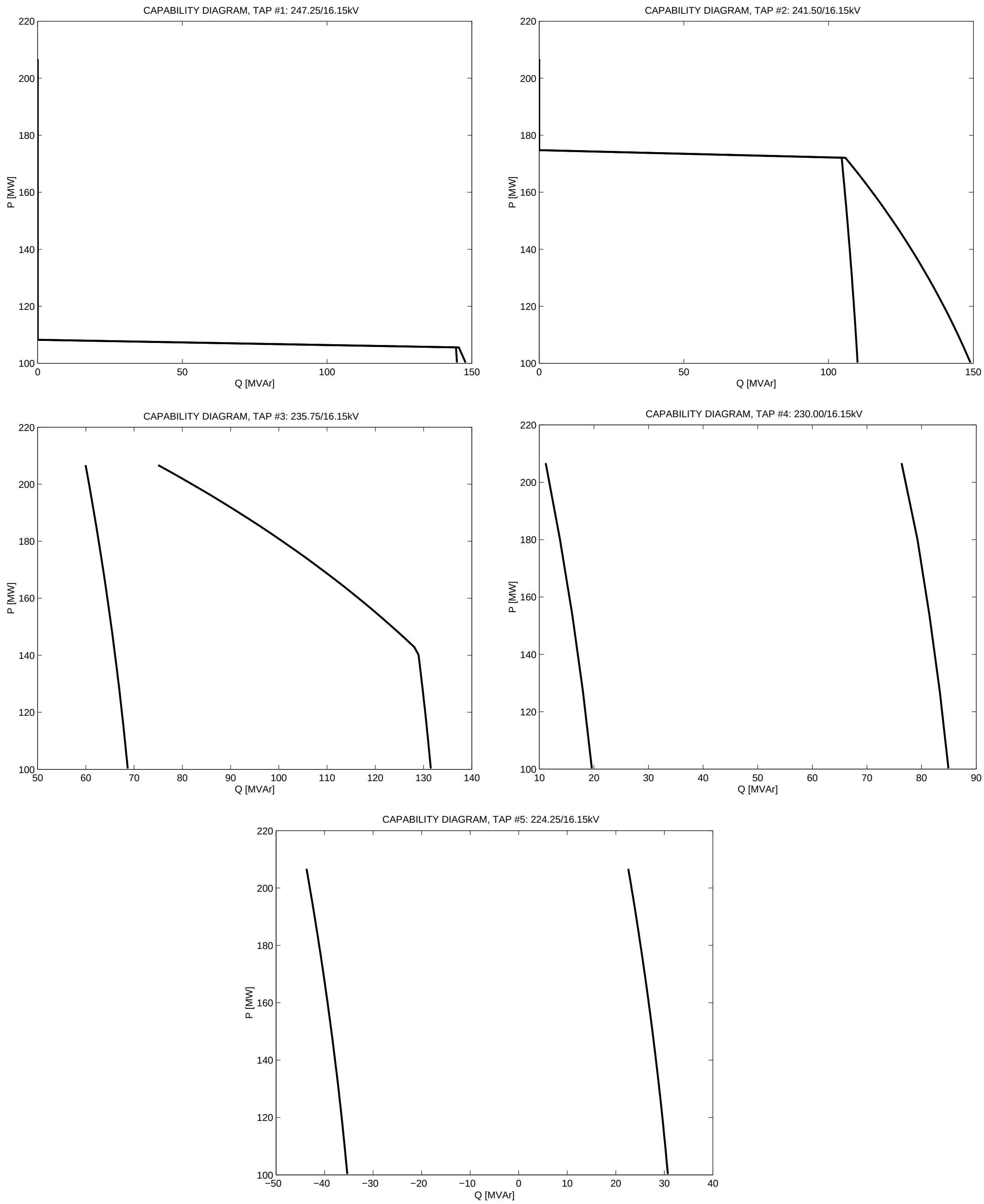

Figure B.4: Capability curves on the transmission side for different tap ratios of the step-up transformer

B.1.2 VAR capacity costs

This section presents the analysis of the costs associated with the VAR capacity available from the different VAR technologies. The analysis is illustrated with a power plant example.

B.1.2.1 Cost analysis

As presented in Chapter 2, the generator costs for the procurement of the VQ service can be divided into (i) fixed costs associated with the investments in VAR capacity, and (ii) variable costs resulting from the use of the VAR capacity.

B.1.2.1.1 Costs associated with the installed VAR capacity These costs correspond with the investments that a generator incurs in order to participate in the VQ service. The investments are associated with the over dimension of the power plant, the installation of control equipment, and other additional costs. The main fixed cost incurred in the VQ service is the over dimension of the whole power plant in order to provide VAR support. For this aim, the rating current of the different devices in the power plant is increased, such as the alternator, the step-up transformer, power cables and switch-breakers.

In order to value the effect of VAR capacity on the total costs of a power plant, we can assume that the total costs C are proportional to the apparent power installed S_n, including all the power devices, as formulated in (B.5) [Soler, 2001]. Under this formulation, the cost of the power plant without VAR capacity is $k \cdot P_n$, and the incremental investments for a selected VAR capacity Q_n are calculated as (B.6).

$$C = k \cdot S_n = k \cdot \sqrt{P_n^2 + Q_n^2} \tag{B.5}$$

$$C_{VAR} = k \cdot P_n \left(\sqrt{1 + \left(\frac{Q_n}{P_n} \right)^2} - 1 \right) \tag{B.6}$$

Power plant example:

In the example power plant, the ratio $\frac{Q_n}{P_n} = \frac{170}{214}$, so the total cost increase in installation costs is 28%[4]. For a capacity cost of $k = 300$k€/MVA, the increment in costs is 18000k€. Dividing the total investment due to VAR capacity in the 25 years of expected life of the power plant, results in 720k€/year.

There exist other investment costs associated with the installed VAR capacity and its availability to participate in the proposed VAR capacity market:

- The *voltage control equipment* of generators may be upgraded in order to properly participate in the proposed market.

- The *measurement equipment* should be accurate enough to guarantee that the voltage control is performed correctly. Reactive power and voltage value measures should be accurately taken both on the transmission side (for remuneration) and on the generation side (for operation security)[5].

- There is also an additional cost associated with *person/hours* dedicated to bidding to the VAR capacity market and to controlling the procurement of the VQ service with an adequate management of the resources.

Finally, existing power plants can explore the possibility to increase their VAR capacity resources in order to get additional benefits from their participation in the annual VAR capacity auction [Frías, 2004]:

- The transformer of the auxiliaries is sometimes the main constraint for the VAR capacity in the power plant due to its reduced or null voltage control (this is the case observed in the power plant example). To increase the VAR capacity the transformer should be replaced or rewinded with the installation of automatic on-load tap changers.

- A typical option to reduce the VAR consumption of the auxiliaries is the installation of capacitor banks downstream the transformer of auxiliaries. Similarly, an interesting alternative to increase the VAR capacity provided by the generator is the installation of capacitor banks and shunt reactors at the generator voltage level. Hence, the power plant can achieve a stepped control with the static VAR sources and a dynamic control performed by the generator. This is an economic option because these VAR sources are widely used for the generator voltage levels in the distribution networks.

- The re-powering of the turbine in old power plants is nowadays becoming more frequent. If alternators are not modified accordingly, then the VAR capacity production at rated power will be reduced, due to the shape of the capability curve [Johnson et al., 1999]. For a significant increase in the power output, some design changes are required in order to guarantee safe operation, among which stands rotor and stator rewind [Zawoysky and Tornroos, 2001]. These two options increase the VAR capacity of the generator, however this can be an expensive solution depending on the manufacturer.

[5] The precision of the voltage transformers must be lower than the admissible voltage variation. For example, in the Spanish power system the admissible voltage variation over the reference voltage is ± 2.5kV in 400kV networks which results in an accuracy lower than 1.25%.

B.1.2.1.2 Cost associated with the use of the selected VAR capacity Three separate costs terms are identified associated with the use of the VAR capacity, (i) active power redispatch cost, (ii) active power energy losses variation, and (iii) the increase of the maintenance costs due to equipment aging. As proposed in this thesis dissertation, all the VAR use costs are covered for agents participating in the VAR capacity market. The complete description of the costs will help the SO to define an appropriate regulated compensation for the VAR use. Extra costs due to redispatch and energy losses variation are easily computed, however the expected effect on the wear of the power plant is much more difficult to estimate.

Redispatch Generators may be *redispatched* in order to solve local voltage problems. A change in the dispatch of a generator can happen after the energy market is settled, or during real time operation. The active power dispatch modifications can consist of: (i) reducing the active power output to increase its VAR production, or (ii) starting up a generation unit.

Energy losses On the other hand, the main sources of energy losses in a power plant are[Mora, 2004]:

- *Alternator*. Losses considered in the stator are those associated with the Joule effect in the windings, Foucault and hysteresis losses in the iron core, and stray losses. Losses in the rotor are mainly due to the Joule effect in the windings, and losses associated with the efficiency of the exciter.

- *Step-up transformer*. Losses are mainly associated with the Joule effect in the windings, Foucault and hysteresis losses in the iron core, and other additional losses[6].

Energy losses in the stator, rotor and transformer depend on the squared current. The influence of VAR production in the stator current is symmetric for VAR generation and absorption. On the other hand, the full VAR capacity range (maximum VAR absorption to maximum VAR generation) is obtained by modifying the excitation current of the alternator from a minimum value to its maximum value. Finally, it is important to note that the variation of energy losses is highly non-linear with the VAR production, as formulated in [Barquin et al., 1998] and [Frías, 2004].

Equipment aging The production of active power out of the unitary power factor increases rotor and stator currents, which clearly affects the life and operation of the alternator. The main effects on the alternator operation are:

[6] A fair approach for the additional losses is 10% of the losses due to the Joule effect.

- *Mechanical damages.* Electromagnetic forces between conductors depend on the squared current, so increasing the current will also increase the vibrations in winding conductors and end-winding rings. In addition, higher currents increase temperatures, which lead to higher expansion/contraction and a relative movement of the mechanical parts. Finally, an increase in temperature also reduces the expected life of the insulation. Practical results of the effect of VAR production in vibrations and temperature variation are presented in Figures B.5 and B.6 respectively.

- *Maintenance costs.* Mechanical damages due to VAR production result in extra costs associated with the repair or replacement of equipment. Experience shows that a power plant regulating VAR needs more maintenance operations than others which constantly operate at unitary power factor.

- *Aging equipment.* The mechanical damages are also responsible for the acceleration in the aging of equipment. This specially applies to the rotor of the alternators, with a higher probability of inter-turn faults, increased vibration, or occasional earth faults [Turner, 1996].

- *The unavailability of the power plant* will also increase, in part due to maintenance and repair work. Therefore, a part of the costs associated with these periods should also be assigned to the VAR production.

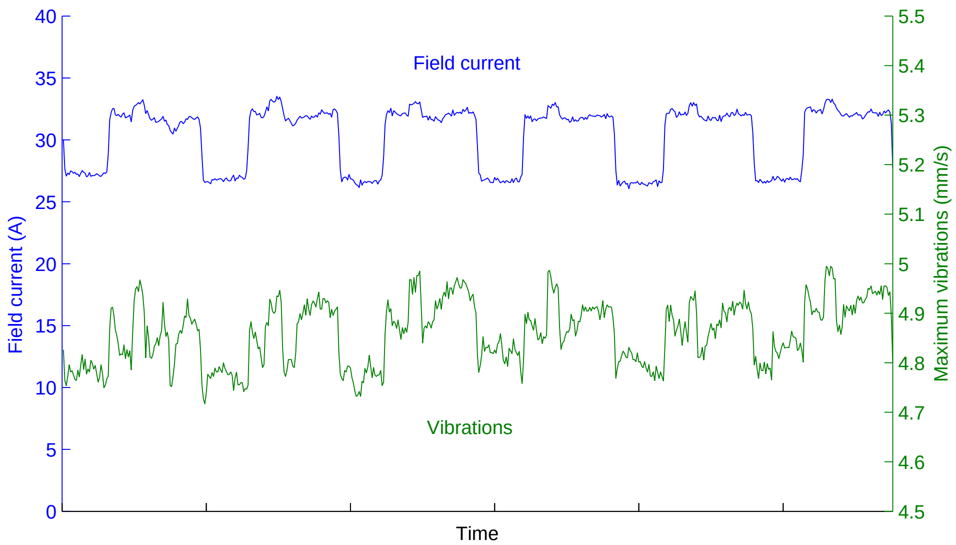

Figure B.5: Influence of VAR generation on vibrations
(Source: [Frías, 2005] and personal research)

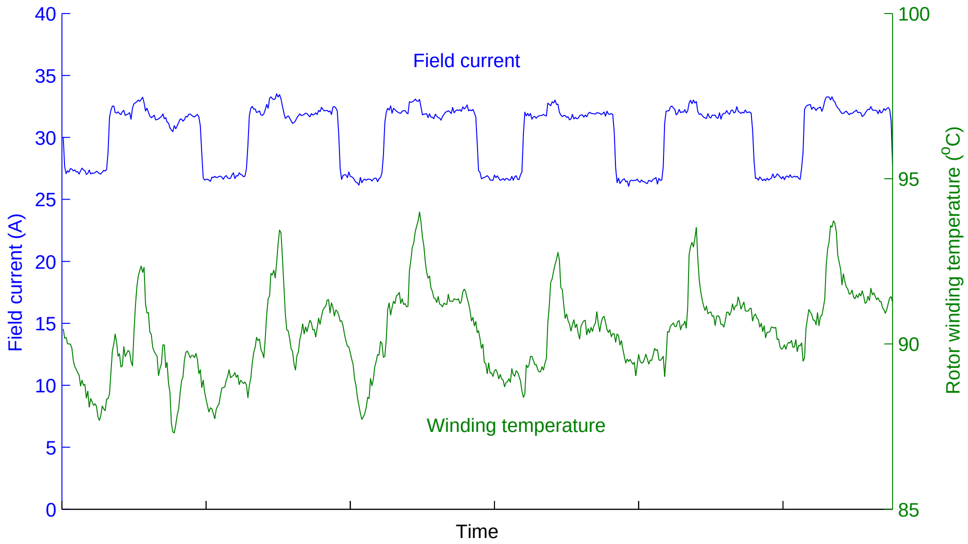

Figure B.6: Influence of VAR generation on winding temperature
(Source: [Frías, 2005] and personal research)

B.1.2.2 Power plant example

The energy losses define the costs of use of the available VAR capacity. Let us suppose that the generator is dispatched at 200MW during 6000 hours/year, which can be divided into 3000 plain hours, 1500 peak demand hours, and 1500 low demand hours. The average energy price is 40€/MWh. Another assumption is that during peak hours the generator is producing its max. VAR capacity, 0 Mvar in low demand hours, and a unitary power factor in the high side of the transformer during plain hours.

Table B.4: Cost analysis in the power station example

Demand period	VAR generator (Mvar)	VAR high-side (Mvar)	Stator current (kA)	Rotor current (kA)	Losses (MW)	Losses variation (MW)	Cost variation (€/year)
Low	0	-19.2	6.79	0.60	0.485	-0.155	-9341
Plain	19.38	0	6.82	0.82	0.641	0	0
Peak	105	80.5	7.67	1.78	1.952	1.311	78665

For these operating conditions it is expected that energy losses costs will increase in 69k€/year (see Table B.4 for the detailed calculation) with an average 40€/MWh.

B.1.3 Proposed bid structure

The design of competitive VAR capacity bids for generators should above all consider the remuneration scheme, which is based on long-term marginal pricing. The proposed bid structure should recover the incurred cost for providing the VAR capacity, and also include those operating costs presented in the previous section that are not compensated in the regulated remuneration.

It is clear that for most generators the VAR capacity has already been included in the total capital costs of the power plant, and hence can be considered as a sunk cost. Then, if a generator bid is based on a very low A and $B = 0$, then the SO will usually select the whole VAR capacity and remunerate it at the marginal, which is close to zero (See $Bid^{(1}$ in Figure B.7). Although the generator will recover the operation costs, it may prefer to get some additional benefit to cover the capital costs and the possible penalties that may arise in case of unavailability. Then, a new bid alternative is to increase the fixed term A (see $Bid^{(2}$ in Figure B.7). The value of the fixed term A can be obtained from the average costs for VAR capacity (B.8), which results from dividing the total cost (B.7) by the VAR capacity, as presented in Figure B.7.

$$TC = I + A \cdot qa + \frac{1}{2} B \cdot qa^2 \tag{B.7}$$

$$AC = \frac{I}{qa} + A + \frac{1}{2} B \cdot qa \tag{B.8}$$

where:

qa	Selected VAR capacity (Mvar)
A, B	Bid for VAR capacity (€/Mvar and €/Mvar^2)
I	Investment cost associated with VAR production (€)

Moreover, the generator can include part of the capital costs in the bid, by increasing the bid value A (see $Bid^{(3}$ in Figure B.7). Then, if the selected VAR capacity is below Q^* the generator will lose money, as the average costs will be higher than the benefits, and will get positive results for VAR capacity over Q^*. In order to maintain a competitive bid, the value of the term A should take into account the bids of the other agents and specially those of capacitor banks and shunt reactors.

Finally, the generator can formulate more complex bids, for instance by including a cost term which is proportional to the VAR capacity (see $Bid^{(4}$ in Figure B.7). The additional variable term can include the availability of the VAR capacity and other externalities.

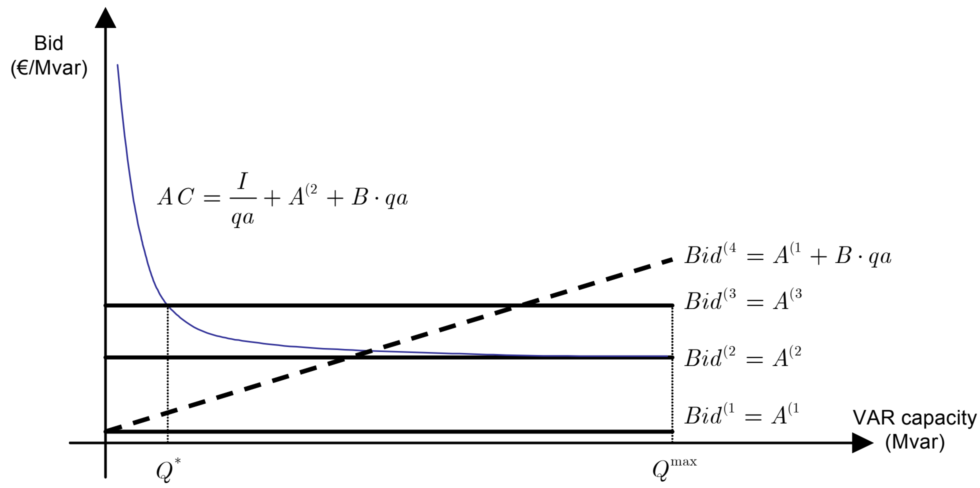

Figure B.7: Generator bid alternatives

B.2 Bid definition for other VAR compensation technologies

The available VAR capacity for capacitor banks, shunt reactors, SVCs and STATCOM devices correspond to their installed capacity, and there are no additional constraints as it happened with the VAR capacity provided by generators. However, the effective use of the VAR capacity depends on the voltage value at the connection point to the transmission network, as described in Chapter 2 the lower the voltage value the lower the VAR support. This relationship is by the squared voltage in capacitor banks, shunt reactors and SVCs, and proportional for STATCOM devices.

An estimation of the capital VAR capacity cost for the different VAR compensation technologies is presented in Figure B.8. The costs associated with the use of the VAR capacity can be neglected compared with the fixed costs. There are also other costs associated with the number of switching maneuvers, which result in a higher wear of the switching mechanism.

From Figure B.8 it is clear that the costs of VAR sources with an installed capacity over 100Mvar (which is the case in transmission networks) can be approximated by a variable cost that depends on the installed VAR capacity. Then, the capital costs for VAR sources installation are assumed to be taken in the variable cost, as presented in Figure B.9[7]. The fixed term in bid A (€/Mvar) equals the variable cost, which depends on the VAR compensation technology and on the voltage level. The variable term in bid function B can then be neglected.

[7]The Dynamic VAR (D-VAR) system is an advanced STATCOM technology that has been developed by American Superconductor `http://www.amsuper.com`.

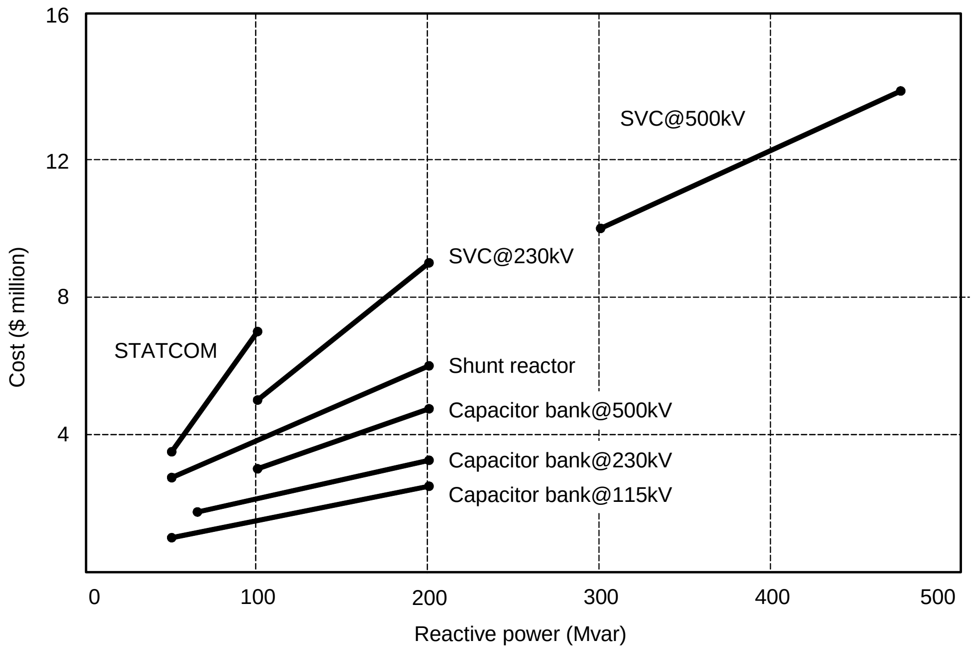

Figure B.8: Estimated fixed costs of different VAR compensation technologies (Source: [FERC, 2005, Acharya, 2004] and personal research)

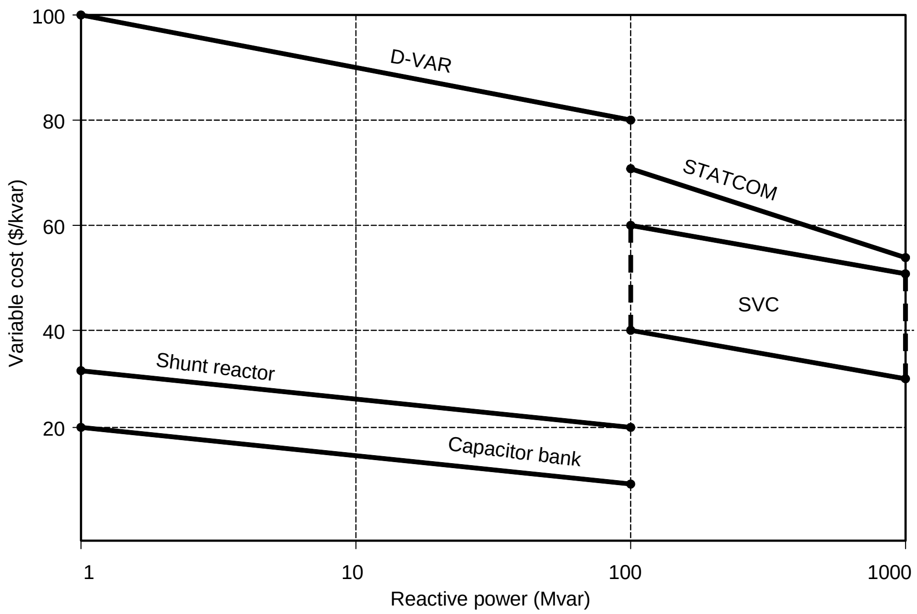

Figure B.9: Estimated variable costs of different VAR compensation technologies (Source: [Li et al., 2006] and personal research)

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APPENDIX C

Voltage value

The aim of this appendix is to estimate the value to the distributor of the voltage at the connection point to the transmission network. First, the different cost components of the voltage quality are identified. Then, an original quantitative analysis estimates the real costs using a power flow simulation for a small case study.

C.1 Cost components of voltage quality

Distribution System Operators (DSOs) are responsible for the supply of energy to the end-users within specific quality standards. The voltage value is a measure of the quality of supply. DSOs manage the voltage value across their networks with the help of certain control equipment such as transformers with on-load tap changers, capacitor banks, voltage regulators, and in recent years distributed generation[Peças et al., 2005]. The optimal management of these voltage control sources has been traditionally a productive research area [Lu and Hsu, 1997, Nerves and Savet, 2006]. Nowadays, distributed generation is not fully integrated into the distribution network management, and therefore, although its potential is very high, the real contribution to voltage control management can be neglected.

An adequate voltage control guarantees voltage quality, and additionally can reduce the energy losses. Distribution networks are characterized by a higher ratio of resistance/reactance than that of the transmission networks, therefore energy losses become quite economically important, as nearly 50% of the total losses in the power system are consumed in the distribution networks.

Current regulatory practices on VAR management in transmission networks charge the DSOs if they consume energy with a power factor out of a pre-specified range[1]. This charging mechanism valuates the needs of VAR support in the transmission network due to the VAR load supplied to the DSOs. In this thesis dissertation, an advanced methodology to value the Voltage Control service in the distribution networks is proposed in order to incorporate it on the transmission-side of the VQ service.

For this purpose, the costs of voltage support from the DSO point of view can be divided into three components, (i) energy losses of the distribution network, (ii) equipment operation cost, and (iii) non-supplied energy.

- Each power system has its own mechanism for charging energy losses. Most of these mechanisms agree that the DSO must receive a signal to minimize energy losses. Therefore by using adequate voltage control the DSO can benefit from energy losses reduction.

- The equipment operation cost is mainly focused on the wear and tear of the tap changers installed in the power transformers. The cost of an on-load tap changer represents approximately 5 to 10% of the total investment cost in a distribution transformer [Spence and Hall, 1995]. Yet the tap-changer is a critical device of the transformer that determines its reliability, as experience has shown that on-load tap changers cause the majority of transformer system failures [Bossi et al., 1983]. A failure in the tap-changer will require the replacement of the transformer unit,

[1] In Spain, according to the P.O.-7.4 [REE, 2000], during peak hours the DSO should not consume more than 33% of the active power load (power factor 0.95 inductive), during valley hours the DSO should not generate VAR (power factor 1), and during plain hours the VAR consumed by the DSO should be in the range of 0-33% of the active power load.

and an energy curtailment may be required if there is not a bypass transformer. The cost associated with a single tap change can be obtained by dividing the total investment cost per MVA of the transformer by the maximum number of tap changes. Nowadays, the investment cost is approximately €15000/MVA [Handley et al., 2001], and a usual maximum number of daily maneuvers in a power transformer is 11 changes/day [Lamont and Fu, 1999].

- When voltage in the distribution network falls below a minimum value, then protection equipment will selectively disconnect load. Each power system has its own criteria for load shedding. The compensation to the loads that have been shed also depends on the country, and domestic and industrial customers may be differentiated. In Europe, the price that regulators set for non-supplied energy varies between €0.5/kWh in Norway to 9€/kWh in France [Malaman et al., 2001, Billinton, 2002].

C.2 Quantitative analysis

The qualitative analysis performed in the previous section showed that voltage at the connection point to the transmission network can be valued according to the influence on energy losses, VAR equipment operating cost, and expected non-supplied energy. This section presents a numerical approach to the voltage value using a case study representing a distribution feeder. First, the distribution network case study data is presented. Then, an original formulation to calculate the power flows and the corresponding costs is presented. Finally, the costs associated with the voltage control in distribution networks are analyzed.

C.2.1 Distribution network example

The distribution network presented in Figure C.1 is connected to the transmission network in 400kV with a transformer, and then distributes the energy reducing the voltage level to 132kV, 20kV and 400V. For simplicity, all loads are connected in 400V, and their value is 100kW with a power factor of 0.8 each. The main characteristics of the network are shown in Table C.1 and Table C.2. Figure C.1 shows one single feeder per voltage level and assumes that the other feeders have identical structures.

For the quantitative analysis, it is assumed that the cost of non-supplied energy is 350€/MWh, and energy losses are paid at 60€/MWh. The expected life of the power

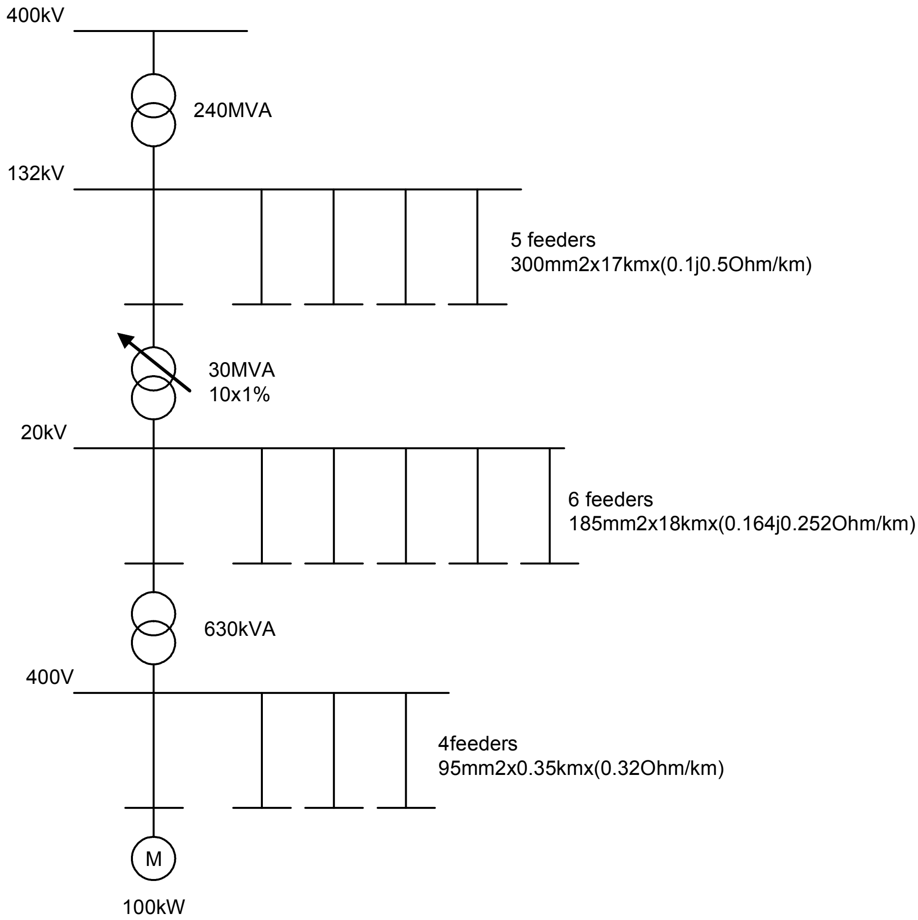

Figure C.1: Case study network

Table C.1: Distribution network example characteristics

Voltage level (kV)	**Number of circuits**	**Length** (km)	**Size** (mm^2)	**Impedance** (Ω/km)
132	5	17	300	0.1+j0.5
20	6	18	185	0.164+j0.252
0.4	4	0.35	95	0.32

Table C.2: Distribution network transformers characteristics

Rated power (MVA)	**Tap changer**	**Short circuit impedance** (%)	**Ratio X/R**
240	No	10	45
30	±5x1%	6	25
0.63	No	4	5

transformers is 40 years, with an investment cost of 15000€/MVA, and a maximum 11 tap changes per day.

The analysis studied the costs incurred by the DSO for different voltage values at the connection point to the transmission networks in 400kV. The voltage in the transmission network is modified in the range of 90% to 130% of the rated value.

In the proposed analysis the DSO voltage control equipments are the on-load tap changers in the transformers 132/20kV. These transformers will adjust their tap ratio in order to maintain voltages in 400V within 95% to 105% of the rated voltage value. If the voltage is out of this gap, a load shedding scheme will disconnect feeders connection to the 20kV level.

C.2.2 Proposed formulations for the powerflow and cost analysis

To solve the voltage control problem for the proposed case study, a radial power flow algorithm was designed. The proposed algorithm first calculates the line currents from the low voltage to the connection point to the transmission network. Then, the voltages across the network are calculated downstream. Once the power flow has successfully converged, it is verified that the voltages of the end-users are in the admissible range. If not, the position of the tap of the transformer is changed. If the tap positions are exhausted, then some load will be shed.

$\overline{v}_n = \overline{v}_1$
for $iter = 1$ to $ITER$
    for $n = N$ to 1
        $\bar{i}_n = \sum_{m \in (n,m)} \bar{i}_m + \frac{\bar{s}_n}{\bar{v}_n}$
    endfor
    for $n = 2$ to N
        $\overline{v}_n = t_n \left(\overline{v}_m - \bar{i}_n \overline{z}_n \right)$
    endfor
    if $\sum_n \left| v_n^{(i} - v_n^{(i-1} \right| < \varepsilon$ then END
    endif
endfor
if $v_n > V^{max}$ then
    if $t_n = t^{min}$ then $d_n = d_n + \Delta D$; $\overline{s}_n = \overline{s}_n \cdot d_n$
        else $t_n = t_n - \Delta t$; $T = T + 1$
    endif
elsif $v_n < V^{min}$ then
    if $t_n = t^{max}$ then $d_n = d_n + \Delta D$

```
        else $t_n = t_n + \Delta t$; $T_n = T_n + 1$
    endif
endif
```

where:

$\overline{v}_n$ Voltage at bus n

V^{max} , V^{min} Maximum and minimum admissible voltage values

$\overline{s}_n$ Load connected at bus n

$\overline{i}_n$ Current flowing upwards the bus n

t_n Tap ratio of the transformer at bus n, which is modified in steps of Δt

T_n Number of movements in the on-load tap changer

$\overline{z}_n$ Impedance of the line upwards the bus n

d_n Load disconnected expressed in per unit, in steps of ΔD

The calculation of the costs associated with voltage control assumes that the voltage at the transmission network is maintained during one hour. Therefore, the costs can be easily computed as the sum of the energy losses cost change, transformer wearing cost, and expected non-supplied energy cost (C.1).

$$C_V = A_P \left(\sum_n r_n i_n^2 - PL_o \right) + A_T \sum_n T_n + A_{ENS} \sum_n d_n s_n cos\phi_n \tag{C.1}$$

where:

A_P	Cost of the active power purchased by the distributor (€/MWh)
r_n	Resistance of the line upwards from the bus n (Ω)
i_n	Current flowing upwards from the bus n (Amp)
PL_o	Calculated losses for voltage at the connection point 1 p.u. (MW)
A_T	Cost for the wear of the transformer tap-changer (€/tap-change)
T_n	Number of movements in the on-load tap changer
A_{ENS}	Impedance of the line upwards from the bus n (€/MWh)
d_n	Load disconnected expressed in per unit, in steps of ΔD (MW)
s_n, ϕ_n	Load connected at bus n (MVA) with power factor $\cos \phi_n$

C.2.3 Technical and economic analysis

An example of the voltage control for voltage on the transmission side of 0.9 p.u. is shown in Figure C.2. The transformers of 30MVA move four taps upwards to correct the low voltages. However, the voltage value at the end-users is still below the reference range, so load shedding will be required.

The costs associated with the operation of the transformers of 30MVA are shown in Figure C.3. The cost increases as voltage falls or rises out of a dead voltage band. If voltage in the end consumer is not in the admissible range, then load will be shed to raise voltages, producing additional costs (see Figure C.4). Finally, energy losses clearly decrease for high voltages, as shown in Figure C.5.

The total costs associated with voltage magnitude on the transmission side are obtained as the sum of the previous costs terms (C.1). According to Figure C.6 three different cost regions can be identified:

i) For voltages within 1.025p.u. and 1.125p.u., costs associated with voltage control can be neglected.

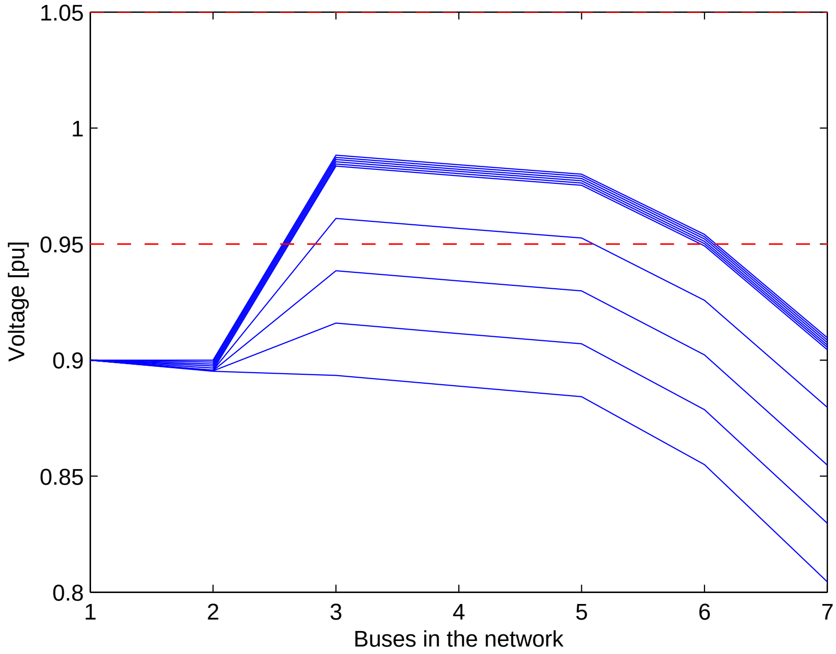

Figure C.2: Tap changes for a voltage of 0.9 p.u. on the transmission side

ii) Voltages above 1.25p.u. and below 0.94p.u. require load shedding management.

iii) Voltages in between i) and ii) incur additional costs which can be approximated by a quadratic function.

C.3 Conclusion

This appendix has presented a methodology to valuate voltage from the point of view of the Distribution Network Operator. The expected costs are associated with the variation of energy losses in the distribution network, the wear and tear of voltage control equipment, and the possible non-supplied energy. Results have been presented for a simple feeder, and can be applied to different configurations based on radial operation. Moreover, the resulting value curve has been obtained for a single hour. A more complete curve would be achieved if different load conditions, and voltage control equipment, such as capacitor banks, were included in the valuation.

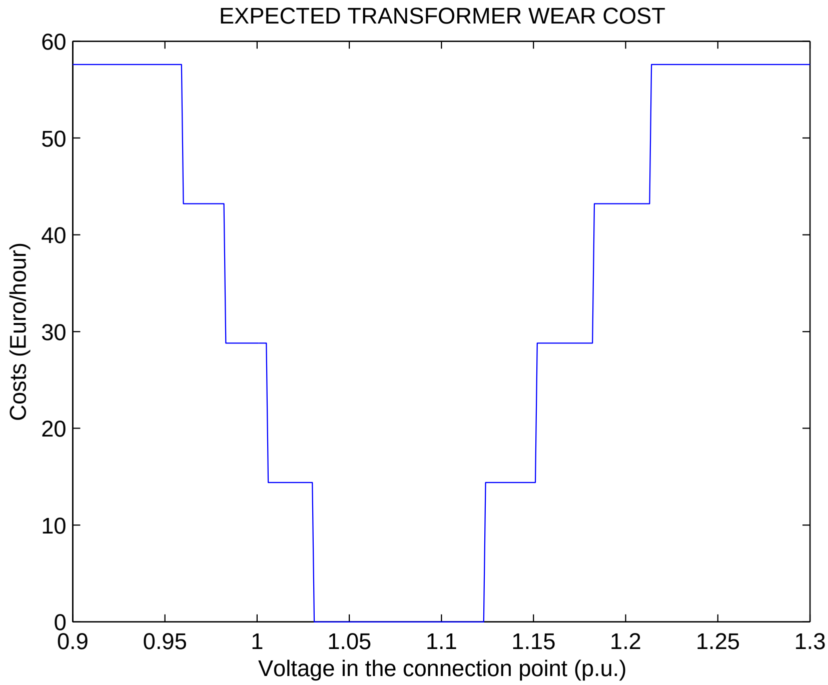

Figure C.3: Cost of tap changing

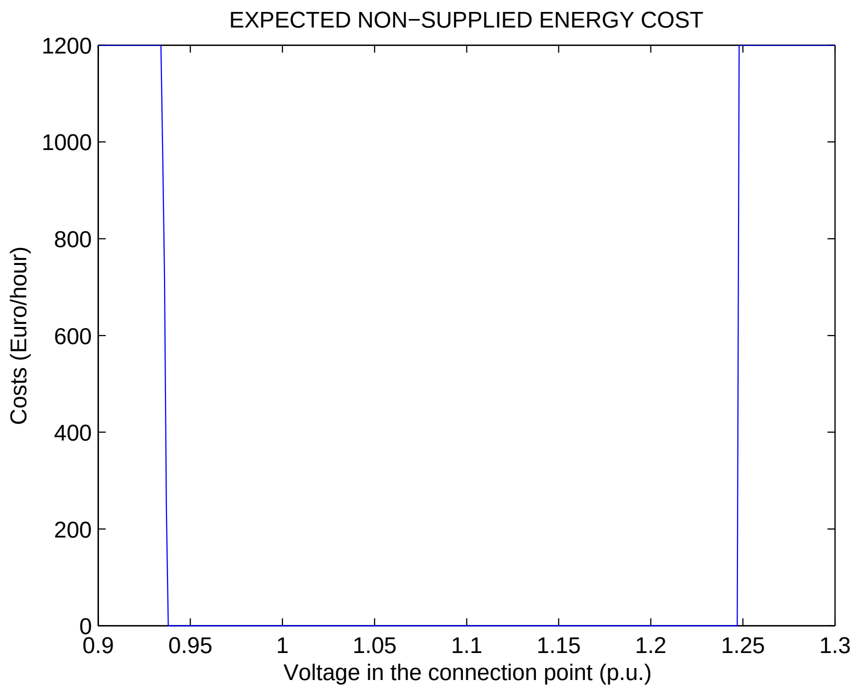

Figure C.4: Cost of energy-non supplied

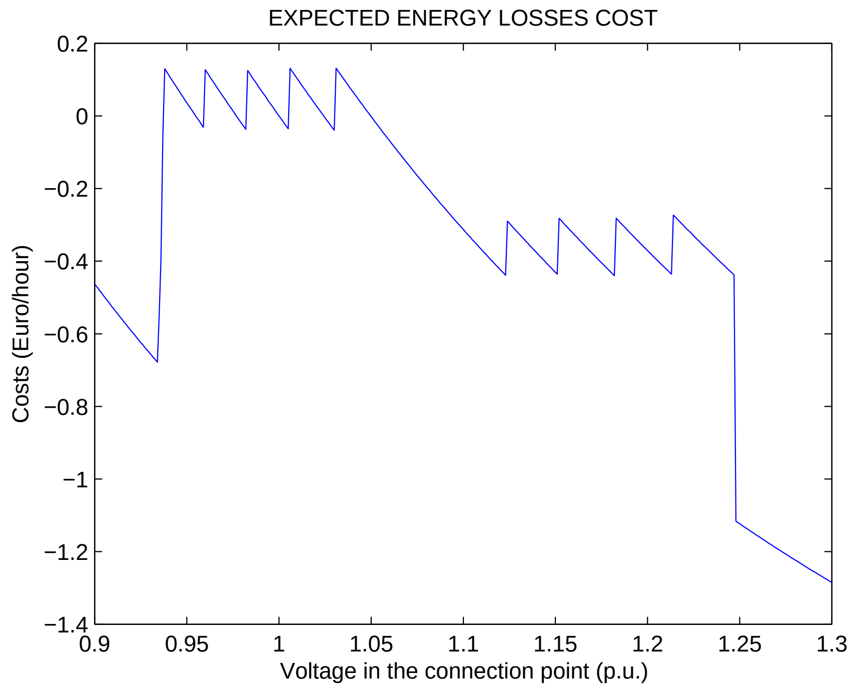

Figure C.5: Cost of energy losses

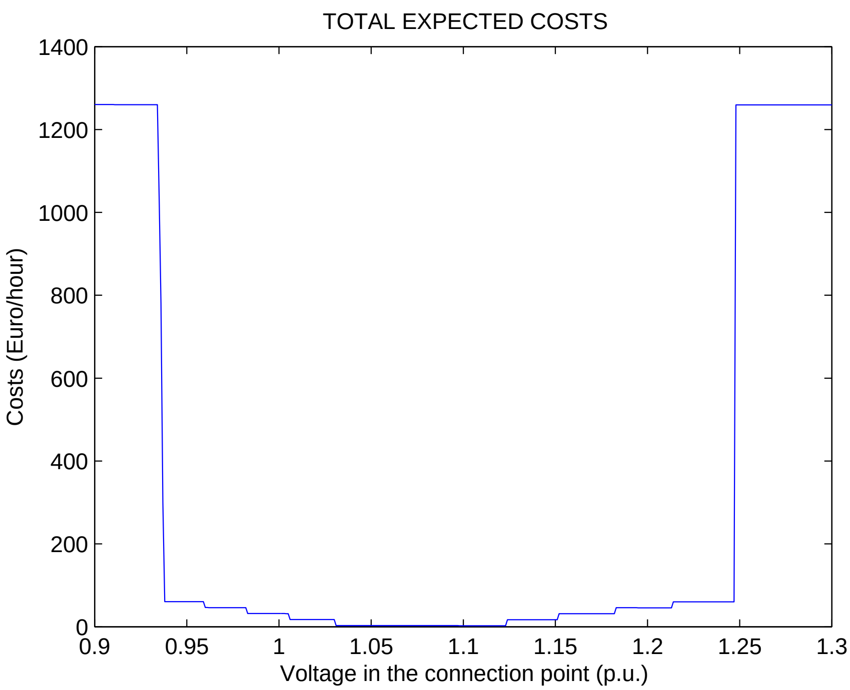

Figure C.6: Total voltage costs

C.4 References

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APPENDIX D

Case study data

THIS appendix includes the detailed technical and economic data used in Chapter 6 for the case study.

D.1 Technical data of the New England 39 case study

The 39 bus system is a simplified representation of the 345kV transmission system in the New England region in the United States, presented in Figure D.1. The network used in this thesis dissertation is a modified version of the system presented in [GEC, 1971, Athay et al., 1979, Pai, 1989], where buses #30 and #39 are renamed to buses #39 and #30, respectively.

The initial economic dispatch of generators is presented in Table D.1, and Table D.5 includes the value of the voltage variables in the resulting power flow. Generation units are characterized by their active and reactive power capability, which are presented in Table D.2, and their corresponding dynamic performance, shown in Table D.3. The data of the transmission lines and transformers in the network are included in Table D.6. Finally the failure rates of the considered power system devices are presented in Table D.4.

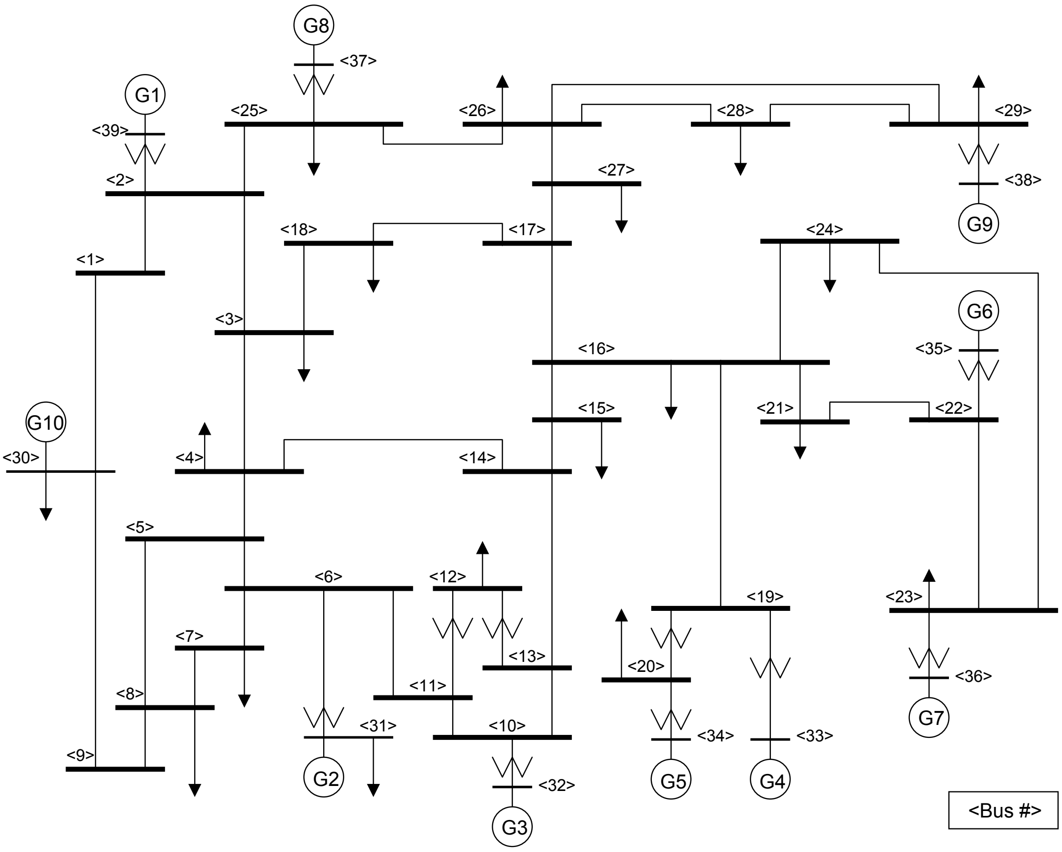

Figure D.1: One-line diagram of New England 39 test system

Table D.1: Generator initial dispatch data in the New England 39 case study

Generator #	P_g^0 (MW)	Q_g^0 (Mvar)	V_g^0 (p.u.)	A^P (€/MWh)
G1	1000	416.83	1.03	20
G2	523.4	248.02	1.03	30
G3	650	300	1.03	40
G4	122.54	74.71	1.03	65
G5	508	110.01	1.03	26
G6	274.2	101.4	1.03	70
G7	560	66.5	1.03	42
G8	540	-10.31	1.03	22
G9	830	-50.43	1.03	35
G10	1145.96	75.2	1.03	12

(Source: personal research)

Table D.2: Generator capability data in the New England 39 case study

Generator #	P^{min} (MW)	P^{max} (MW)	$Q^{G,Pmin}$ (Mvar)	$Q^{G,Pmax}$ (Mvar)	$Q^{A,Pmin}$ (Mvar)	$Q^{A,Pmax}$ (Mvar)
G1	500	1000	630	620	-480	-485
G2	0	600	520	500	-400	-400
G3	150	650	850	800	-315	-315
G4	120	500	432	400	-315	-315
G5	0	1000	325	315	-250	-250
G6	80	275	170	150	-115	-115
G7	130	600	360	350	-250	-250
G8	0	600	550	550	-250	-250
G9	210	850	550	550	-400	-400
G10	0	2500	905	900	-500	-500

(Source: personal research)

Table D.3: Generator dynamic data in the New England 39 case study

Generator #	ΔP^u (MW)	ΔP^d (MW)	ΔQ^u (Mvar)	ΔQ^d (Mvar)
G1	50	100	600	600
G2	20	200	400	400
G3	75	110	600	600
G4	55	155	300	300
G5	300	300	255	255
G6	25	100	100	100
G7	100	150	300	300
G8	125	125	450	450
G9	80	175	450	450
G10	1500	1500	800	800

(Source: personal research)

Table D.4: Failure rates of the power system devices in the New England 39 test system

Technology	**Description**	**Peak demand** (hours)	**Low demand** (hours)
Nuclear	G1	98	196
Hydro	G2	46	92
Thermal	G3	82	164
Thermal	G4	53	106
Hydro	G5	48	96
Thermal	G6	79	158
Thermal	G7	88	176
Hydro	G8	44	88
Thermal	G9	81	162
Hydro	G10	0	0
Trans. line	B8-B9	1.1	2.2
Trans. line	B13-B14	1.7	3.4
Trans. line	B16-B17	2	4
Trans. line	B21-B22	2	4
Trans. line	B28-B29	1.3	2.6

(Source: personal research)

Table D.5: Data for the simplified New England 39 case study

Bus	Voltage		Angle	Load		Generator	
	(p.u.)	(kV)	(Deg)	(MW)	(Mvar)	(MW)	(Mvar)
B1	1.040	358.844	-7.73	-	-	-	-
B2	1.040	358.8	-20.43	1104	250.5	1000	416.83
B3	1.018	351.486	-27.38	322	2.4	-	-
B4	1.002	345.649	-25.91	500	184	-	-
B5	1.021	352.458	-19.16	-	-	-	-
B6	1.030	355.3	-17.88	9.2	4.6	523.4	248.02
B7	1.014	349.7	-18.97	233.8	84	-	-
B8	1.010	348.3	-18.94	522	176	-	-
B9	1.0228	352.8	-7.6	-	-	-	-
B10	1.062	366.5	-13.86	-	-	650	300
B11	1.050	362.2	-15.17	-	-	-	-
B12	1.043	359.7	-14.59	7.5	88	-	-
B13	1.0602	365.7	-13.92	-	-	-	-
B14	1.004	346.5	-28.31	-	-	-	-
B15	1.006	347.0	-32.32	320	153	-	-
B16	1.022	352.5	-32.41	329	32.3	-	-
B17	1.020	351.8	-30.81	158	30	-	-
B18	1.020	351.9	-29.51	0	0	-	-
B19	1.040	358.8	-32.47	-	-	122.54	74.71
B20	1.040	358.8	-33.35	628	103	508	110.01
B21	1.023	352.9	-31.24	274	115	-	-
B22	1.040	358.8	-28.02	-	-	274.2	101.4
B23	1.040	358.8	-27.21	247.5	84.6	560	66.5
B24	1.028	354.7	-32.93	308.6	-92.2	-	-
B25	1.040	358.8	-20.2	224	47.2	540	-10.31
B26	1.034	356.8	-25.13	139	17	-	-
B27	1.020	352	-28.92	281	75.5	-	-
B28	1.038	358.1	-21.48	206	27.6	-	-
B29	1.040	358.8	-18.65	283.5	26.9	830	-50.43
B30	1.0	358.8	0	-	-	1145.96	75.2

(Source: personal research)

Table D.6: Line and transformer data in the simplified New England 39 case study

From bus	To bus	Circuit	Trans-former	R (p.u.)	X (p.u.)	C (p.u.)	Limit (MVA)	Tap Ratio
B9	B30	1	No	0.0001	0.025	0.12	1000	1
B8	B9	1	No	0.0023	0.0363	0.3804	1000	1
B7	B8	1	No	0.0004	0.0046	0.078	1000	1
B6	B7	1	No	0.0006	0.0092	0.113	1000	1
B6	B11	1	No	0.0007	0.0082	0.1389	1000	1
B5	B8	1	No	0.0008	0.0112	0.1476	1000	1
B5	B6	1	No	0.0002	0.0026	0.0434	1000	1
B4	B14	1	No	0.0008	0.0129	0.1382	1000	1
B4	B5	1	No	0.0008	0.0128	0.1342	1000	1
B3	B18	1	No	0.0011	0.0133	0.2138	1000	1
B3	B4	1	No	0.0013	0.0213	0.2214	1000	1
B28	B29	1	No	0.0014	0.0151	0.249	1000	1
B26	B28	1	No	0.0043	0.0474	0.7802	1000	1
B26	B27	1	No	0.0014	0.0147	0.2396	1000	1
B26	B29	1	No	0.0057	0.0625	1.029	1000	1
B25	B26	1	No	0.0032	0.0323	0.513	1000	1
B23	B24	1	No	0.0022	0.07	0.361	1000	1
B22	B23	1	No	0.0006	0.0096	0.1846	1000	1
B21	B22	1	No	0.0008	0.014	0.2565	1000	1
B2	B3	1	No	0.0013	0.0262	0.2572	1000	1
B2	B25	1	No	0.007	0.0086	0.146	1000	1
B19	B20	1	Yes	0.0007	0.0138	0	1000	1
B17	B27	1	No	0.0013	0.0173	0.3216	1000	1
B17	B18	1	No	0.0007	0.0082	0.1319	1000	1
B16	B24	1	No	0.0003	0.0059	0.068	1000	1
B16	B21	1	No	0.0008	0.0135	0.2548	1000	1
B16	B19	1	No	0.0016	0.0195	0.304	1000	1
B16	B17	1	No	0.0007	0.0089	0.1342	1000	1
B15	B16	1	No	0.0009	0.0094	0.171	1000	1
B14	B15	1	No	0.0018	0.0217	0.366	1000	1
B13	B14	1	No	0.0009	0.0101	0.1723	1000	1
B12	B13	1	Yes	0.0016	0.0435	0	1000	1.006
B12	B11	1	Yes	0.0016	0.0435	0	1000	1.006
B10	B13	1	No	0.0004	0.0043	0.0729	1000	1
B10	B11	1	No	0.0004	0.0043	0.0729	1000	1
B1	B30	1	No	0.001	0.025	0.75	1000	1
B1	B2	1	No	0.0035	0.0411	0.6987	1000	1

(Source: [GEC, 1971] and personal research)

D.2 References

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