Secure Provision of Reactive Power Ancillary Services in Competitive Electricity Markets

by

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I hereby declare that I am the sole author of this thesis. This is a true copy of the thesis, including any required final revisions, as accepted by my examiners.

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Abstract

The research work presented in this thesis discusses various complex issues associated with reactive power management and pricing in the context of new operating paradigms in deregulated power systems, proposing appropriate policy solutions. An integrated two-level framework for reactive power management is set forth, which is both suitable for a competitive market and ensures a secure and reliable operation of the associated power system. The framework is generic in nature and can be adopted for any electricity market structure. The proposed hierarchical reactive power market structure comprises two stages: procurement of reactive power resources on a seasonal basis, and real-time reactive power dispatch. The main objective of the proposed framework is to provide appropriate reactive power support from service providers at least cost, while ensuring a secure operation of the power system.

The proposed procurement procedure is based on a two-step optimization model. First, the marginal benefits of reactive power supply from each provider, with respect to system security, are obtained by solving a loadability-maximization problem subject to transmission security constraints imposed by voltage and thermal limits. Second, the selected set of generators is determined by solving an optimal power flow (OPF)-based auction. This auction maximizes a societal advantage function comprising generators' offers and their corresponding marginal benefits with respect to system security, and considering all transmission system constraints. The proposed procedure yields the selected set of generators and zonal price components, which would form the basis for seasonal contracts between the the system operator and the selected reactive power service providers.

The main objective of the proposed reactive power dispatch model is to minimize the total payment burden on the Independent System Operator (ISO), which is associated with reactive power dispatch. The real power generation is decoupled and assumed to be fixed during the reactive power dispatch procedures; however, the effect of reactive power on real power is considered in the model by calculating the required reduction in real power output of a generator due to an increase in its reactive power supply. In this case, real power generation is allowed to be rescheduled, within given limits, from the already dispatched levels obtained from the energy market clearing process. The proposed dispatch model achieves the main objective of an ISO in a competitive electricity market, which is to provide the required reactive power support from generators at least cost while ensuring a secure operation of the power system.

The proposed reactive power procurement and dispatch models capture both the technical and economic aspects of power system operation in competitive electricity markets; however, from an optimization point of view, these models represent non-convex mixed integer non-linear programming (MINLP) problems due to the presence of binary variables associated with the different regions of reactive power operation in a synchronous generator. Such MINLP optimization problems are difficult to solve, especially for an actual power system. A novel Generator Reactive Power Classification (GRPC) algorithm is proposed in this thesis to address this issue, with the advantage of iteratively solving the optimization models as a series of non-linear programming (NLP) sub-problems.

The proposed reactive power procurement and dispatch models are implemented and tested on the CIGRE 32-bus system, with several case studies that represent different practical operating scenarios. The developed models are also compared with other approaches for reactive power provision, and the results demonstrate the robustness and effectiveness of the proposed model. The results clearly reveal the main features of the proposed models for optimal provision of reactive power ancillary service, in order to suit the requirements of an ISO under today's stressed system conditions in a competitive market environment.

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Acronyms

AC-PF	AC Power Flow
AGC	Automatic Generation Control
ATC	Available Transfer Capability
ATSOI	Association of Transmission System Operators in Ireland
CAISO	California Independent System Operator
CBM	Capacity Benefit Margin
CPF	Continuation Power Flow
ELD	Economical Load Dispatch
EPACT	Energy Policy Act
ESA	Electrical Safety Authority
ETC	Existing Transmission Commitments
ETSO	European Transmission System Operators
FCAS	Frequency Control Ancillary Services
FERC	Federal Energy Regulatory Commission
GRPC	Generator Reactive Power Classification
HHI	Herfindahl-Hirshman Index
HOEP	Hourly Ontario Energy Price
IESO	Independent Electric System Operator
IMO	Independent Market Operator

IOS	Interconnected Operations Services
ISO	Independent System Operator
LF	Loading Factor
LMP	Locational Marginal Price
MCP	Market Clearing Price
MINLP	Mixed Integer Non-Linear Programming
NCAS	Network Control Ancillary Services
NEMMCO	National Electricity Market Management Company
NERC	North American Electric Reliability Council
NGET	National Grid Electricity Transmission
NLP	Non-Linear Programming
NYISO	New York Independent System Operator
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation
OPA	Ontario Power Authority
OPF	Optimal Power Flow
OPG	Ontario Power Generation
PURPA	Public Utilities Regulatory Policy Act
QPF	Reactive Power (Q) Payment Function
RSI	Residual Supply Index
RTO	Regional Transmission Organizations

SAF Societal Advantage Function

SRAS System Restart Ancillary Services

TEP Total Expected Payment

TMB Total Marginal Benefit

TRM Transmission Reliability Margin

TSO Transmission System Operator

TTC Total Transfer Capability

UCTE Union for Coordination of Transmission of Electricity

UKTSOA United Kingdom Transmission System Operators' Association

Chapter 1
Introduction

1.1 Research Motivation

Traditionally, electric utilities have been vertically integrated monopolies that have built generation, transmission, and distribution facilities to serve the needs of the customers in their service territories. For the past decade, the electric power industry has been going through a process of transition and restructuring by moving away from these vertically integrated monopolies and towards competitive markets. This has been achieved through a clear separation between transmission and generation activities, as well as by creating competition in the generation sector. This restructuring process has created certain class of services such as frequency regulation, energy imbalance, voltage and reactive power control, and generation and transmission reserves, which are essential to the power system in addition to the basic energy and power delivery services. This other class of services is referred to as *ancillary services*, and they are needed to ensure system security, reliability and efficiency.

Ancillary services are no longer an integral part of the electricity supply, as they used to be in the vertically integrated power industry structure, since they are now unbundled and priced separately. The Independent System Operator (ISO) is the entity entrusted to provide ancillary services through commercial transactions with ancillary services providers. In a competitive environment, the provision of these services must be carefully managed so that the power system requirements and market objectives are adequately met.

The Federal Energy Regulatory Commission (FERC) concluded in its Order No.888, April 1996, that reactive power supply and voltage control from generators is one of the six ancillary services that transmission providers must include in an open access transmission tariff. It also stated that reactive power from capacitors and FACTS controllers, installed as a part of the transmission system, is *not* a separate ancillary service [1]. However, there are recent recommendations for considering reactive power provision from these sources and to recognize them as ancillary services that are eligible for financial compensation [2]. FERC Order 2003 further states that a reactive power provider should not be financially compensated when operating within a power factor range of 0.95 lagging and 0.95 leading, but an ISO may change this range at its discretion [3].

Adequate provision of reactive power is essential in power systems in order to ensure their secure and reliable operation. Reactive power is tightly related to bus voltages throughout a power network, and hence reactive power services have a significant effect on system security. Insufficient reactive power supply can result in voltage collapse, which has been one of the reasons for some major blackouts worldwide [2]. The US-Canada Power System Outage Task Force states in its report that insufficient reactive power was an issue in the August 2003 blackout, and it recommended strengthening the reactive power and voltage control practices in all North American Electric Reliability Council (NERC) Regions [4].

In the erstwhile vertically integrated power system structure, provision of reactive power by utilities was embedded within the electricity supply to customers. However, in the deregulated power system structure, reactive power is managed and priced separately as an ancillary service. Competition in generation makes it important to consider the development of a reactive power market that complements the existing energy market. In spite of the fact that the cost of reactive power production is much less than that of real power, reactive power is critical to system reliability since its sufficient provision is necessary to avoid an extremely costly system collapse. Moreover, under stressed system conditions, reactive power requirements from some generators are only met at the expense of reducing their real power output, and hence they significantly increase the cost associated with reactive power production.

Currently, most power system operators procure reactive power services from available providers based on operational experience and expected voltage problems in the system. In real-time, most system operators use power flow programs to dispatch reactive power from the already contracted generators. However, there are several issues and concerns associated with the current procurement practices and pricing policies for reactive power which call for further systematic procedures to arrive at more efficient service management and sufficient reactive power support for a more reliable power system [2]. Some of these issues are technical limitations associated with power system operation, whereas others are policy issues related to the rules under which the electricity market operates in a certain jurisdiction. Technical issues include the following:

1. The high losses associated with transferring reactive power require that it should be provided locally. This localized nature of reactive power results in fewer suppliers generally available to provide the reactive power needed at any individual location. These suppliers are likely to have significant market power.
2. The worth of 1 Mvar of reactive power support with respect to voltage control and system security varies across the system. The benefits of reactive power from generators, with respect to system security, have to be considered in the procurement of reactive power where the contracted

suppliers are determined. Currently, most system operators rely on their experience to determine these contracted generators.

3. It is necessary to consider the effect of reactive power production of a synchronous generator on its active power generation, *i.e.* the effect of reactive power dispatch on active power dispatch, and hence on system security. There are certain situations where reactive power requirements from a generator can only be met at the cost of reducing its active power output. Such rescheduling in active power dispatch might result in an insecure operating condition.
4. Spot energy market prices are volatile, and they affect reactive power prices. This will be a significant issue if reactive power is to be managed in the same time frame of active power, since reactive power prices will be highly affected by the energy market prices in this case.
5. There are two ways reactive power ancillary services are provided: short-term dispatch versus long-term procurement. If reactive power is provided based on a short-term dispatch, then several issues such as energy market price volatility and the effect of reactive power on active power and system security will arise. On the other hand, long-term procurement can solve most of these issues, but it does not consider real-time operating conditions.

Policy issues, on the other hand, include the following:

1. Optimal procurement of reactive power is not always achieved, *i.e.* ISOs do not purchase reactive power at least-cost. In a competitive market environment, reactive power services should be efficiently provided from the most reliable and lowest-cost sources.

2. Reactive power ancillary services are not provided by considering all available sources; only reactive power from generators is considered as an ancillary service and is eligible for financial compensation. This decreases competition due to a lower number of market participants, and allows for market power to be exercised by certain service providers.

3. Poor financial incentive and discriminatory payments resulting in generators not being equally compensated. Unless reactive power suppliers are encouraged to participate in fair agreements, they will not be willing to provide these services. This impedes adequate and sufficient provision of reactive power support, and it may result in limited number of service providers, leading to an inefficient market operation.

4. There is a lack of transparency and consistency in planning and procurement process for reactive power services. This may result in an inefficient supply of reactive power support, since reactive power needs and reserves are not clearly defined by existing standards.

5. Interconnecting standards are assumed to be insensitive to local needs, *i.e.* without considering that reactive power needs may vary from one location to another.

For a competitive reactive power market to be developed, the above issues have to be carefully examined. New policy solutions and market structures need to be proposed that fit into the new shift of paradigm of operation of the power system. In a competitive electricity market, the objective of the ISO should be to provide reactive power ancillary services from possible service providers at the least cost, while ensuring a secure operation of the power system. Appropriate pricing structures and payment mechanisms, which effectively reflect the cost components associated with reactive power production, are then needed by the ISO in order to achieve such an objective.

1.2 Review

1.2.1 Reactive Power Management in Different Deregulated Markets

Reactive power management and payment mechanisms differ from one electricity market to another, and no uniform structure or design has yet evolved. In most cases, the ISO enters into contracts with the reactive power providers for procurement of their services. These contracts are usually bilateral agreements based on ISO experience, rather than on well formulated optimal procedures.

Currently in North America, according to NERC's Operating Policy 10 [5], only synchronous generators are compensated for reactive power provision. The New York ISO (NYISO) uses an embedded cost based pricing to compensate generators for their reactive power services, and it also imposes a penalty for failing to provide reactive power [6]. Generators are also compensated for their lost opportunity costs if they are required to produce reactive power by backing down their real power output. Such opportunity cost payments also exist in PJM Interconnection [7] and California ISO (CAISO) [8]. Provision of reactive power services in the California system is based on long-term contracts between CAISO and reliable must-run generators; generators are mandated to provide reactive power within a power factor range 0.9 lagging to 0.95 leading. Beyond these limits, the generators are paid for their reactive power including a lost opportunity cost payment.

The Independent Electric System Operator (IESO) in Ontario, Canada, requires generators to operate within a power factor range of 0.9 lagging to 0.95 leading and within a +/-5% range of its rated terminal voltage. The IESO signs contracts with generators for reactive power support and voltage control, and generators are paid for the incremental cost of energy loss in the windings due to the increased reactive power generation. The generators are also paid if they are required to generate reactive power levels that affect their real power dispatch, receiving an opportunity cost payment at the energy market clearing price for any power not generated [9].

Among other international practices, in Australia, synchronous condensers also receive payments for providing reactive power apart from generators [10]. On the other hand, Sweden follows a policy wherein reactive power is supplied by generators on a mandatory basis and without any financial compensation. In the Netherlands, individual network companies have to provide for their own reactive power, usually through bilateral contracts with local generators, who are only paid for the reactive capacity but not for reactive energy [11].

In the United Kingdom, the Transmission System Operator (TSO)-National Grid Electricity Transmission (NGET) invites half-yearly tenders for both "obligatory reactive power services" which correspond to the base reactive power each generator is required to provide, and "enhanced reactive power services" for generators with excess reactive power capabilities. There are two payment mechanisms: a default payment agreement, where both the generator and NGET enter into an agreement for service provision and payments; and a market-based agreement, where generators submit their reactive power bids to the NGET [12].

From the brief review of utility practices above, it is clear that there is no fully developed structure for competition or pricing of reactive power services in any system. Moreover there is no unified framework, universally acceptable, for reactive power management practices that have developed post-deregulation. In some cases the pricing is based on fixed contractual payments, and in other cases based on gross system usage (embedded cost), while in other markets there is no mechanism for payments. Even the classification of the obligatory reactive power band is quite an *ad hoc* process that varies across ISOs without following any well-defined criterion, apart from the operator's experience. Moreover, the ISOs do not have any well defined reactive power management system in their operational portfolio that could create an optimal provision of reactive power service considering all the issues arising from competition.

1.2.2 Review on Reactive Power Pricing and Management

Traditionally, reactive power dispatch has always been viewed by researchers as a loss minimization problem, subject to various system constraints such as nodal active and reactive power balance, bus voltage limits, and power generation limits [13]-[16]. Another approach has been to dispatch reactive power with the objective of maximizing the system loadability in order to minimize the risk of voltage collapse [17], [18]. Furthermore, multi-objective optimization models have also been proposed for the reactive power dispatch problem. In these models, reactive power is dispatched to achieve other objectives, in addition to the traditional loss minimization, such as maximizing voltage stability margin [19], or minimizing the voltage and transformer taps deviation [20].

The "traditional" dispatch approaches do not consider the cost incurred by the system operator to provide reactive power. One of the reasons for this is that, in a vertically integrated system, all generators were under the direct ownership and control of the central operator, and hence reactive power payments were bundled in the energy price. However, after the liberalization of electricity markets, reactive power has been recognized as an ancillary service to be purchased separately by the ISO [1], [3].

Researchers have been working at grasping various issues in reactive power pricing and management in the context of the new operating paradigms in competitive electricity markets. Technical and economic issues associated with pricing of reactive power, along with its optimal provision, have received significant attention. Appropriate pricing structures should be developed in a way that effectively reflect the different cost components associated with reactive power production from synchronous generators, which are the service providers in this case. Accordingly, several approaches have been reported in the literature for identifying and analyzing these cost components [21]-[24], which are mainly due to additional losses incurred by a generator when providing the required reactive power support.

Lamont and Fu have provided in [22] a comprehensive analysis of the various economic costs of reactive support from both generation and transmission sources. The reactive power cost from generation sources is divided into explicit and opportunity costs; explicit costs mainly comprise the capital cost for reactive power production, while opportunity costs account for the reduction in real power generation as a result of increased reactive power production. The authors have then proposed a cost-based reactive power dispatch that minimizes the total reactive power costs from generation and transmission sources, while maintaining all bus voltages within specified limits.

Luiz da Silva *et al* have discussed in [23] the practical issues related to establishing a suitable cost structure for reactive power production, as well as developing appropriate payment mechanisms for reactive power providers. Costs of reactive power production are divided into fixed capital costs and variable costs. A detailed analysis was carried out for different variable costs associated with reactive power production from various sources, including generators, synchronous compensators, static compensators, and shunts capacitors. The authors have proposed that payments for generators operating as synchronous compensators should be determined based on the operating time and real power consumption, rather than on reactive power production or absorption. Certain reactive power sources (*e.g.* capacitors and on-load tap changers), they argue, should be considered as part of the transmission network and not as ancillary services providers.

Gross *et al* have examined in [24] the variable costs of reactive power production/absorption by a generator, identifying the most dominant cost component. The authors have ignored the losses associated with reactive power generation within the generator capability curves, and referred instead to opportunity costs, which occur when the generator reaches its capability curve and is required to reduce its real power generation in order to meet the reactive power requirements, as the dominant component of the reactive power cost structure. The authors have also argued that generators should only be compensated by the ISO for this dominant cost component as an incentive to meet reactive power support requirements.

Based on these analyses, the cost of reactive power production from a synchronous generator can be divided into two main types: fixed cost and variable operating cost. Figure 1.1 shows a typical generator reactive power cost characteristic in which the two types of costs are shown [21]. The fixed cost typically denotes a part of the generator's capital cost that goes toward providing reactive power; hence, it is difficult to separate this cost component from the total plant capital cost. The variable cost includes two main components: a first component arising from the increased losses in the armature and field windings of the generator because of an increase in its reactive power output, and a second component associated with the cost of opportunity lost if the generator is required to reduce its real power generation in order to meet the reactive power requirements assigned by the ISO.

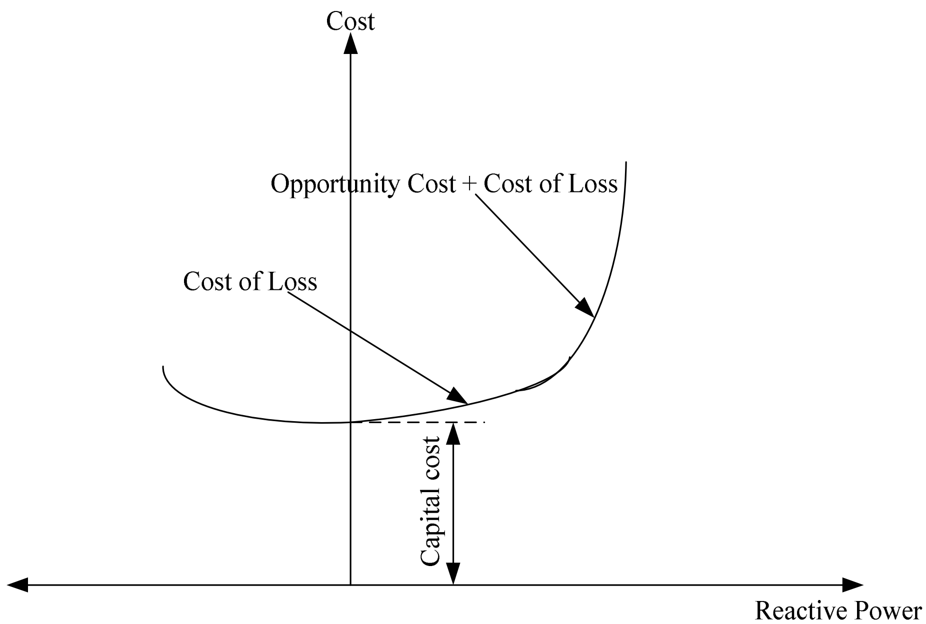

Figure 1.1 Cost of reactive power production from a synchronous generator.

Reactive power pricing policies have been typically based on power factor penalties. However, with the development of real-time or spot pricing theory [25], there has been significant interest in their application in the context of competitive electricity markets. Baughman and Siddiqi have introduced real-time pricing for reactive power in [26], based on the hourly marginal costs of providing real and reactive power at a given bus. These marginal costs, which correspond to the added operating expense incurred by the utility to serve an incremental demand, are obtained by solving an optimal power flow (OPF) that minimizes the total generation cost subject to operation constraints that include load flow equations, active and reactive generation limits, bus voltage limits, and transmission system limits.

The physical and economic principles for reactive power pricing are discussed in [27], where the authors have argued that marginal costs, rather than embedded costs, are the appropriate basis for efficient pricing of reactive power services in a competitive electricity market. The authors also recommend the use of capital costs for reactive power pricing, since these are significant components of reactive power costs and are more suitable for long-term contracts.

Hao and Papalexopoulos have presented in [28] two pricing methods based on reactive power unit cost measure. In the first structure, reactive power production limits are determined by performance requirements and standards; for example, power factor can be used as one of these standards where a certain range can be defined by the ISO, inside which reactive power providers are not compensated for their services. In this structure, penalties are proposed for service providers that violate these performance standards, and credits are given for providing extra reactive power generation beyond the specified standards. The second structure is based on a local reactive power concept, where the ISO procures reactive power services from the generators based on the cost of their reactive power capacity, and then recovers these payments from load customers according to their demand.

Hao has further proposed a method for reactive power management in [29], in which a mandated amount of reactive power is required from a generator beyond which this generator should be compensated for further reactive power production including the lost opportunity cost. Reactive power cost curves have been computed using a piece-wise linear representation of the capability curve of each generator. Reactive power schedules are then obtained by solving an OPF model that minimizes the reactive power cost which is formulated as a function of the reactive power output.

1.2.3 Review on Reactive Power Provision

Currently, most power system operators use power flow studies to arrive at reactive power dispatches, primarily relying on operational experience. However, there are several complex issues involved in reactive power management in deregulated electricity markets which call for further systematic procedures to arrive at better solutions. In a competitive electricity market, the ISO should provide reactive power support from service providers at the least cost while ensuring a secure operation of the power system. Thus, reactive power provision from generators can be achieved either by short-term dispatch based on real-time operating conditions, or long-term procurement based on seasonal agreements between the ISO and the generators, as service providers.

In the context of competitive electricity markets, reactive power *dispatch* essentially refers to short-term allocation of reactive power required from suppliers (*e.g.* generators) based on current system operating conditions. The ISO's problem is to determine the optimal reactive power schedule for all providers based on a given objective that depends on system operating criteria. Different objective functions can be used by the ISO, beside the traditional transmission loss minimization, such as minimization of reactive power cost [22], [29], [30]. Any objective can be adopted, but since some of them might be of a conflicting nature, the ISO needs to choose a criterion that best suits the market structure. For example, if the ISO only seeks to minimize losses to determine the required reactive power support, it might end up with an expensive set of reactive power providers, something not desirable in a market-based environment.

Several technical issues may arise if reactive power is to be dispatched in real-time. These issues include market power being exercised by some reactive power service providers, considering the localized nature of reactive power support; the effect of reactive power on active power generation and on system security; and the possibility of reactive power price volatility when it is dispatched in the same time-frame as the spot energy market. In general, many of these issues can be resolved if reactive power services are optimally procured through long-term agreements between the ISO and the service providers [27]-[29], [31]-[33]. These long-term contracts would likely reduce the possibility of generators' exercising market power, and at the same time could solve the problem of price volatility that arises when reactive power services are priced on a real-time basis. This argument is supported by economic theories and empirical evidence [34].

Bhattacharya *et al* have proposed a two-step approach to procure reactive power in [31]. In the first step, the marginal benefit of each reactive power bid with respect to total system losses is determined, and in the second step, an OPF-based model maximizing a social welfare function is solved to determine the optimal reactive power procurement. This work was extended in [32], where a uniform price auction model was proposed to competitively determine the prices for different components of reactive power services. Market settlement was achieved by simultaneously considering minimization of payment, total system losses, and deviations from contracted transactions. Using the same framework, a localized reactive power market for individual voltage control areas was proposed in [33] to address market power problems.

It can be seen from the above review of reactive power ancillary service pricing and management that most of the reported works focus either on developing suitable pricing methods that can effectively reflect the cost of reactive power production, or on proposing appropriate models for optimal reactive power procurement and/or dispatch. These models usually aim to achieve the extremum of a certain objective function (*e.g.* reactive power production cost minimization or social welfare maximization) using OPF models. An important requirement that has not been addressed in most of the existing or proposed models is the inclusion of system security in the reactive power procurement/dispatch process. The ISO typically seeks a reactive power solution that does not violate transmission security constraints, which are usually represented by voltage, thermal, and stability limits [35]. There is a need, then, for developing appropriate mechanisms for reactive power ancillary service management which aim at achieving optimal and secure reactive power provision and ensure a reliable and efficient network operation, while taking into account various market related issues.

1.3 The Present Research

In this thesis, an integrated framework for reactive power ancillary services management in competitive electricity markets is presented using a two-settlement model approach. The proposed model works at two hierarchical levels and in different time horizons; the first level is the procurement model which works in a seasonal time horizon, while the second level is the dispatch model which works in a one-hour to 30-minute window. The developed framework addresses the main issues associated with reactive power ancillary service management post-deregulation, proposing appropriate policy solutions that suit the requirements of the ISO in such a competitive market environment. The framework is generic in nature and designed to be adopted by system operators in any electricity market structure, be it a bilateral contract market or a pool market.

The "big picture" of the proposed framework for optimal provision of reactive power ancillary service is illustrated in Figure 1.2. The reactive power procurement stage takes place a few months ahead of real-time, in which the ISO would call for reactive power offers from all available generators (service providers in this case). The structure of these offers should ideally reflect their cost of providing reactive power. Based on the offers received and the forecasted real power information from the energy market, the ISO would solve an optimization model to maximize a societal advantage function (*SAF*) subject to system constraints, including system security. The solution of the optimization model yields a set of contracted generators, as well as the price components of reactive power. The contracted providers will have a seasonal obligation for reactive power provision and receive an availability payment.

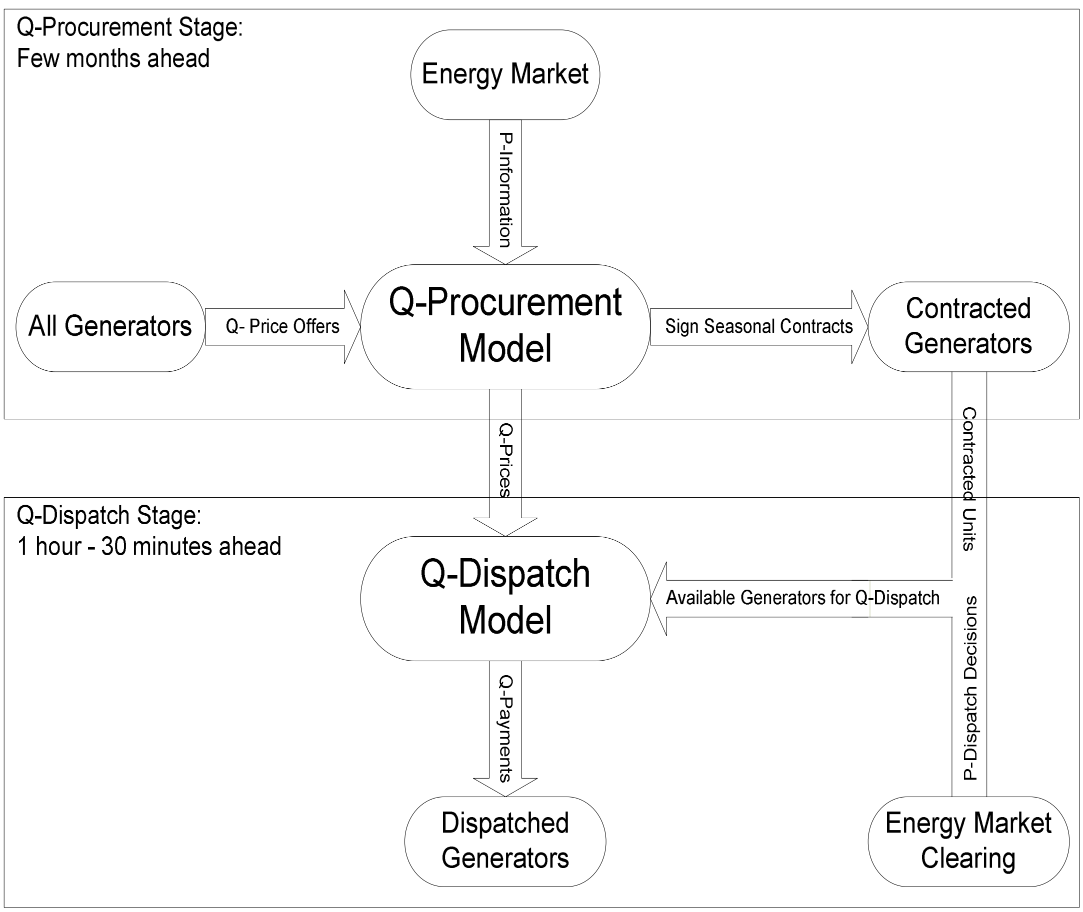

Figure 1.2 The “big picture” of the proposed reactive power framework.

The reactive power dispatch stage, on the other hand, takes place one hour to 30 minutes ahead of real-time, in which the ISO would determine the available units for reactive power dispatch based on the set of procured/contracted generators and the generating units available from short-term energy market clearing. The ISO then dispatches the units using an OPF-based model that minimizes total payments associated with reactive power dispatch, subject to appropriate system security constraints. Finally, the payments would be made for the service providers after real-time operation, based on the actual usage and dispatch requested by the ISO.

1.3.1 Research Objectives

In view of the above discussions, the main objective of this research work is to develop competitive mechanisms for reactive power procurement and dispatch, in the context of the new operating paradigms of deregulated power systems. The following are the main research goals:

- Study in detail the existing utilities' practices for reactive power management and pricing, aiming to develop appropriate mechanisms for reactive power provision that would fit the needs of system operators.
- Examine the main complex issues associated with reactive power ancillary service management in the context of the new operating paradigms in deregulated power systems, and propose appropriate policy solutions for these issues. The proposed solutions should suit the requirements of an ISO in a competitive electricity market and, at the same time, be in line with the current practices and market rules.
- Design a unified framework for reactive power management that is appropriate for a competitive market, and that ensures a secure and reliable operation of the associated power system.

- Develop suitable reactive power procurement procedures that take into consideration system security aspects, in order to determine an optimal set of generators and zonal price components, which would form the basis for seasonal contracts between the ISO and the selected reactive power service providers.
- Redefine the reactive power dispatch problem to take into account both the technical and economical aspects of operation in a market-based environment, while considering the effect of the reactive power dispatch on real power and system security.
- Develop computationally efficient algorithms for handling large-scale non-linear mixed integer programming (MINLP) models that are associated with reactive power procurement and dispatch problems, taking into consideration all relevant power system constraints, and that can be practically implemented on real-size power systems.

1.4 Thesis Outline

The rest of the thesis is organized as follows:

- Chapter 2 provides a detailed background review of reactive power as an ancillary service, within the context of power systems operation in a deregulated electricity market environment. Accordingly, ancillary services, including reactive power support, are defined stating their different types and how these services are managed in various electricity markets. Previous relevant reactive power provision models are also presented, pointing out their main advantages and limitations.
- Chapter 3 discusses in detail the main issues associated with reactive power

management post-deregulation, proposing several policy solutions based on the current practices of different utilities world-wide. Subsequently, a unified framework for reactive power ancillary service management is proposed.

- Chapter 4 presents the main procedures for long-term reactive power service procurement. The proposed OPF-based procurement model is then tested with the 32-bus CIGRE benchmark system and several case studies.
- Chapter 5 presents a redefined formulation for the reactive power dispatch procedures in the context of the new operating paradigms in competitive electricity markets. The payment minimization dispatch model is first proposed, and then tested with the CIGRE 32-bus system, considering several power system operating scenarios.
- Finally, Chapter 6 summarizes the work presented, pointing out the main contribution of the proposed research work, and suggesting possible directions for future work.

Chapter 2
Reactive Power as an Ancillary Service

2.1 Liberalization of the Power Industry

Electric utilities have been vertically integrated monopolies that have built generation, transmission, and distribution facilities to serve the needs of the customers in their service territories. Significant capital commitments were required to construct large power stations and to coordinate generation, transmission and distribution. The price of electricity was traditionally set by a regulatory process, rather than by market forces, which were designed to recover the cost of producing and delivering electricity to customers, as well as the capital costs. Under this monopolistic service regime, customers had no choice of supplier; and suppliers were not free to pursue customers outside their designated service territories.

Since the nineties, most of the electric power industry has been going through a process of transition and restructuring by moving away from vertically integrated monopolies and towards more competitive market models. This has been achieved through a clear separation between transmission and generation activities, as well as creating competition in the generation activities. Different countries are implementing industry restructuring in a variety of ways, depending on the characteristics of each market area which include: demand/supply balances, the extent of transmission capacity to facilitate energy imports to meet market demand, and the diversity of generation by fuel types. In designing and planning the market structure and rules for competition in their jurisdictions, governments, regulators and other industry participants are influenced by local market characteristics and the practices in other jurisdictions.

Although various countries are implementing industry restructuring in a variety of ways, there are a number of elements common to all of them. First, the generation of electricity and the provision of energy services to consumers are not natural monopolies. The generation sector is open to competition and end-users should have the opportunity to choose their source of supply. Generation companies can sell energy either through bilateral (long-term) contracts with customers, or by bidding for short-term energy supply in the spot markets. Second, the price of energy and the addition of new capacity should be driven by market forces rather than by some regulatory policies. Third, transmission and distribution are considered natural monopolies and are best managed through an independent regulator. Access to transmission and distribution networks is open on a non-discriminatory basis to all electricity market participants. Fourth, an Independent System Operator (ISO) is created to maintain system reliability and security and to ensure non-discriminatory access to transmission systems. Fifth, an Independent Market Operator (IMO) is usually present to facilitate market-driven commercial power transactions. The roles of the ISO and the IMO could be carried out separately or by a single entity.

Commercial power transactions in deregulated markets often take place through a central power exchange, or “pool”, administered by the IMO. Offers for energy supply at specified prices are made or “offered” into the power pool, and sufficient generation capacity is dispatched to meet demand. Purchasers can “bid” to buy power in this “spot market” or, alternatively, they can enter into bilateral contracts with service providers or retailers. Energy prices, in this case, are negotiable, and the IMO has to make sure that the resulting transactions will not violate any transmission security limits.

Deregulation has been implemented in different ways, and for various reasons among different countries [36]. In developed countries, the main reason has been to provide electricity to customers at lower prices, and to open the market for competition by allowing smaller players to have access to the electricity market by reducing the share of large state-owned utilities. On the other hand, high growth in demand and irrational tariff policies have been the driving forces for deregulation in developing countries. Technical and managerial inefficiencies in these countries have made it difficult to sustain generation and transmission expansions, and hence many utilities were forced by international funding agencies to restructure their power industries.

2.1.1 International Experience

Deregulation in Europe started with unbundling of utilities when the European Union Directive on the Internal Electricity Market was applied on February 1999 [37], introducing full competition among generators in the European market. The European Transmission System Operators (ETSO) came into existence in July 1999 to regulate the transmission of power between countries with effective price arrangements. Four transmission system operators formed the ETSO, namely Nordel in Nordic countries (Norway, Sweden, Finland, Denmark and Iceland); the Association of Transmission System Operators in Ireland (ATSOI); the Union for Coordination of Transmission of Electricity (UCTE); and the United Kingdom Transmission System Operators' Association (UKTSOA). The EU Directive did not restrict a specific market structure for all the countries; however, it defined regulations that can guarantee a fair and non-discriminatory competition between market participants, where large and medium-sized customers are allowed to choose their electricity suppliers. The Directive has also required all transmission and distribution owners to open their lines to other parties.

The process of restructuring of the electricity industry in Australia was initiated in 1991, and by 1998 a National Electricity Market was developed, where the National Electricity Market Management Company (NEMMCO) acted as both the ISO and IMO [38]. Generators could sell energy either by bidding in the spot market, or through formal (bilateral) contracts.

The New Zealand market, on the other hand, was opened in 1996. The Electricity Commission, which was established in September 2003, regulates the operation of the electricity industry and markets. New Zealand has a spot market, where each trading day is divided into half-hour trading periods. Energy trading is managed by Transpower, as the system operator, based on day-ahead bids submitted to the ISO by the generators and purchasers [39].

Since the US situation was different, with most of the electric utilities already owned by investors, it required a different form of restructuring. The Public Utilities Regulatory Policy Act (PURPA) of 1978 started the whole deregulation process in the US by allowing non-utility generators to enter the electricity market [40]. The US Energy Policy Act of 1992 (EPACT) then officially required the electric utility industry to deregulate, and assigned the process of transition and restructuring to FERC. Accordingly, FECR issued Orders 888 and 889 on Open Transmission Access in April 1996, requiring transmission companies to open their transmission system to other market participants, aiming to eliminate transmission monopolies [1], [41]. Furthermore, FERC issued Order 2000 in December 1999, requiring the development of different Regional Transmission Organizations (RTO) to handle transmission issues and ensure a reliable operation within effective tariff arrangements [42].

2.1.2 Ontario Electricity Market

Historically, Ontario Hydro had been a vertically integrated electricity utility and the only supplier of electricity for most of Ontario's customers. In November 1997, the Province released a White Paper entitled "Direction for Change" which set out a restructuring plan for the electricity industry in Ontario, aiming to create a competitive market. In April 1999, Ontario Hydro was restructured based on the Ontario Electricity Act of 1998. Finally, in May 1st, 2002, and two years after the initial deadline, the market was opened for competition [9].

Ontario Hydro was unbundled into five entities: Ontario Power Generation (OPG) Inc., which owns 75% of the total capacity and provides wholesale energy and ancillary services [43]; Hydro One Inc., which owns and controls the transmission, distribution and retail energy services; the Electrical Safety Authority (ESA), which carries out electrical equipment and wiring installation and inspection functions; the Ontario Electricity Financial Corporation (OEFC), responsible for managing Ontario Hydro's outstanding debt; and finally, the IMO, now known as the IESO, to act both as the ISO and IMO for Ontario's market. The IESO is responsible for the dispatch of generation to meet demand, the control of the Ontario transmission grid and the operation of energy and ancillary services markets. It is also responsible for maintaining a secure and reliable operation of the electrical system in Ontario, ensuring that all the standards and regulations of the market are being efficiently applied, and authorizing the market participants in the IESO administered market [9].

Generators, both from within and outside Ontario, compete to sell energy through the IESO-administered spot market. The IESO dispatches generators based on their offers to sell energy and operating reserve. The Market Clearing Price (MCP) is determined every five minutes, in addition to an Hourly Ontario Energy

Price (HOEP) which is the hourly average of the five-minute MCP [43], [44]. Transmission has remained a monopoly; however, it is regulated by the Ontario Energy Board (OEB) which decides the transmission and distribution tariffs. At the retail level, end-users have the option of contracting with any licensed energy retailer or continuing with their current distributor under a regulated supply. Market participants can also sell or purchase energy through physical bilateral contracts, provided that these contracts do not affect the real-time market administered by the IESO. These bilateral contracts, which represent a small part in energy trading of Ontario, need not be reported to the IESO and are not subject to Ontario market rules [9].

In 2005, another not for profit organization, The Ontario Power Authority (OPA), was established by The Electricity Restructuring Act [45] to ensure an adequate long-term supply of electricity in Ontario. The main objectives of the OPA are demand forecasting and management, as well as generation and transmission planning. In addition, the OPA is involved in various activities that ensure a reliable and secure operation of the Ontario power system, as well as promoting cleaner sources of energy and efficient use of electricity; the OPA also helps the OEB in developing retail price smoothing mechanisms.

2.2 Ancillary Services

As mentioned earlier in Section 1.1, the main feature of deregulation is the separation of generation and transmission activities, which has resulted in the emergence of ancillary services. These services include frequency regulation, energy imbalance, voltage and reactive power control, and generation and transmission reserves; these are required to ensure a reliable and secure operation of the power system. Ancillary services are now unbundled and priced separately, and they are no longer part of the electricity supply, as it used to be in vertically integrated electricity markets. The ISO is responsible for providing ancillary services, often through commercial transactions with services providers. In a competitive environment, the provision of these services must be carefully deployed and managed in order to meet system and market requirements.

2.2.1 Definitions

FERC defines ancillary services in Order 888 as “those services that are necessary to support the transmission energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with good utility practices” [1]. FERC Order 888 requires transmission providers to include six ancillary services in an open access transmission tariff to maintain reliability within and among the control areas affected by the transmission service. These six services are divided into the following two categories:

1. Services FERC requires transmission providers to offer and customers to accept from the transmission provider, and these include:

    - *Scheduling, System Control and Dispatch*: This service is required to schedule the movement of power through, out of, within, or into a control area in order to maintain supply-demand balance.

    - *Reactive Supply and Voltage Control from Generation Sources*: The system operator requires generators to provide (or absorb) reactive power in order to maintain the system bus voltages within some desired limits.

2. Services FERC requires transmission providers to offer but which customers can accept from the transmission provider, third parties, or by self-supply, and these include:

- *Regulation and Frequency Response*: The use of generation equipped with governors and automatic generation control (AGC) to follow the instantaneous change in the load in order to maintain continuous generation-load balance within the control area, and a scheduled interconnection frequency at 60 Hz.
- *Energy Imbalance*: The use of generation to correct for hourly mismatches between actual and scheduled delivery of energy between suppliers and their customers.
- *Operating Reserve - Spinning*: Spinning reserve service is provided by unloaded generating units that can respond immediately to correct for generation-load imbalance in the event of a system contingency.
- *Operating Reserve – Supplemental*: Supplemental reserve service is provided by unloaded generating units, by quick-start generation, or by interruptible load to correct for generation-load imbalance in the event of a system contingency; however the response does not have to be immediate, as in case of spinning reserve, but rather within a short period of time.

NERC refers to ancillary services as Interconnected Operations Services (IOS) which include services that are required to support the reliable operation of interconnected bulk electricity systems [5]. NERC has defined, in its IOS Working Group Technical Report [46], twelve IOS that are necessary to support the transmission of power at an adequate level of reliability and security; some of these services are similar to the six ancillary services required by FERC. The twelve services states by the IOS Working Group are:

- *Regulation*: Using generation or load in order to maintain a minute-to-minute generation-load balance within the control area.
- *Load Following*: The provision of the generation and interchange capability required to maintain the hour-to-hour and daily load variations not covered by regulation service.
- *Energy Imbalance*
- *Operating Reserve – Spinning*
- *Operating Reserve – Supplemental*
- *Backup Supply*: Electric generating capacity used to replace a generation outage or the failure to deliver generation due to an outage of transmission sources, and to serve a customer's load that exceeds its generation.
- *System Control*: Activities that are required to ensure the reliability of the North American interconnections, to minimize transmission constraints, and to guarantee the recovery of the system after a contingency or disturbance.
- *Reactive Power and Voltage Control from Generation Sources*
- *Network Stability Services from Generation Sources*: Using special equipment, or devices, such as power system stabilizers and dynamic braking resistors at the generating plants to meet NERC reliability requirements and maintain a secure transmission system.
- *System Black Start Capability*: The availability of generating units that can start without an outside electrical supply to take part in the restoration plan after a system blackout.
- *Real Power Transmission Losses*: The provision of capacity to replace energy losses on a transmission system.

- *Dynamic Schedule*: The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, and administration that are needed to electronically move real energy services associated with generation or load out of its Host Control Area and into a different Electronic Control Area.

2.2.2 Management in Different Markets

Ancillary services are defined, managed, and priced in different manners across various deregulated electricity markets all over the world. In New York, for instance, the NYISO is entrusted to manage the provision of all ancillary services, both those provided by the NYISO and the self-supplied ones. The NYISO uses two types of pricing mechanisms for ancillary services procurement: embedded-cost based pricing method for scheduling, system control and dispatch services, voltage support, and black start capability services; and market-based pricing methods for energy balance, regulation and frequency response, and operating reserve services [6], where the last two services can be self-supplied by transmission customers and suppliers by entering through a bidding process in the ancillary services market, with the NYISO choosing suitable providers for each service according to the bidding prices.

In the United Kingdom, The NGET is the system operator responsible for coordinating and managing the following two main categories of ancillary services defined by the Grid Code in the UK [47]:

1. *System Ancillary Services:* These services are essential for adequate system operation, and they must be provided by all the generating units connected to either the NGET transmission system or a supplier's distribution system

in England and Wales. System ancillary services are further divided into two categories:

- Services which must be provided by all generators, including *reactive energy* from other means than synchronous condensers or static voltage compensators, and *frequency control* using frequency sensitive generation by including a fast acting proportional frequency control device (or turbine speed governor) and unit load controller, or an equivalent control device, to provide frequency response under normal operational conditions.
- Services which generators will provide only if an agreement is reached with NGET, including *frequency control* involving the capability of a gas turbine or pumped storage unit to fast start, *black start capability*, and system to generator operational intertripping.

2. *Commercial Ancillary Services:* These services are not necessarily provided by generators, but rather through ancillary services or bilateral agreements. These services include *reactive energy* provided by synchronous condensers or static voltage compensators, and *operating margin* from pumped storage units or stand-by generation.

In Australia, NEMMCO is responsible for the provision of ancillary services. Ancillary services defined by NEMMCO fall under one of the following three main categories [10]:

1. *Frequency Control Ancillary Services (FCAS):* These are services that are required to maintain the frequency on the electrical system at any point in time, within limits set by the NEM frequency standards. FCAS are divided

into two types, namely regulation frequency control services provided by generators on AGC, for the adjustment of the generation-demand balance after minor deviations in load or generation; and contingency frequency control services, for the adjustment of the generation-demand balance after a major contingency such as the loss of a generating unit, which include generator governor response, load shedding, rapid generation, and rapid unit unloading.

2. *Network Control Ancillary Services (NCAS):* These are services that involve voltage control services, by means of reactive power support from generators or synchronous compensators and network loading control, to control the power flow on interconnections in the transmission network by means of AGC or load shedding.
3. *System Restart Ancillary Services (SRAS):* These are reserves for contingency conditions to enable the system to restart after a whole or partial system blackout.

Both NCAS and SRAS are provided to the market under long term ancillary service contracts between NEMMCO and the service providers. These services are paid for through a mixture of Enabling Payments that are made only when the service is specifically enabled, and Availability Payments that are made for every trading interval in which the service is available.

2.2.3 Ontario Electricity Market

According to the Market Rules of the Ontario Electricity Market, the IESO procures ancillary services in sufficient quantities and at the appropriate locations through contracts with ancillary service providers that are registered market participants to ensure reliable and secure system operation [9]. The IESO recognizes three operating reserve classes, namely 10 Minute Synchronized Operating Reserve (10S); 10 Minute Non-Synchronized Operating Reserve (10N); and 30 Minute Non-Synchronized Operating Reserve (30R) [43]. Only dispatchable generators can offer the 10S reserve, while dispatchable generators and loads, and boundary entities can offer the 10N and 30R reserves.

In addition to the above operating reserves, which are determined within the energy market, the following five ancillary services are recognized in the Ontario Market, and hence procured by the IESO:

1. *Regulation*: The use of generation equipped with governors and AGC to follow the minute-by-minute change in the load in order to maintain continuous generation-load balance within the control area, and a scheduled interconnection frequency at sixty cycles per second.

2. *Voltage Control and Reactive Support*: The control and maintenance of system voltages at specific locations, using reactive power support provided by generation units, as well as by synchronous condensers, capacitors, and other electrostatic equipment. However, only reactive power from generators and synchronous condensers can be remunerated, while the rest of the resources are not eligible for any payments.

3. *Black Start Capability*: The provision of generating resources, which can start without any external energy supply following a system blackout. They can then be used to restore the system by supplying other generating stations and critical loads.

4. *Emergency Demand Response Load*: Includes load facilities that are willing to reduce their load consumption, on short notice, to enable the IESO to maintain the reliability of the grid.

5. *Reliability Must-Run Resources*: The IESO may need to call registered facilities, excluding non-dispatchable loads, to maintain the reliability of the grid, whenever there are insufficient resources to provide physical services in a reliable way.

Ancillary service contracts between the IESO and ancillary service providers are limited to a term of no more than 36 months, where the services providers are compensated for their services in a non-discriminatory manner. In doing so, the IESO uses one or a combination of two ways according to the Market Rules of Ontario; if several providers exist for a certain ancillary service, the IESO determines the suitable providers and price for each service based on a competitive process. Alternatively, the IESO may have an agreement with only one ancillary service provider based on reasonable price offers.

2.3 Reactive Power as an Ancillary Service

According to FERC Order 888 [1], and NERC White Paper on Proposed Standards for Interconnection Services [48], only reactive power support from generation sources is considered as an ancillary service and is eligible for financial compensation. However, this may change in the near future to recognize other reactive power support sources, particularly FACTS controllers (*e.g.* static VAR compensators or SVC), as per the recent recommendations of FERC [2]. In view of the existing FERC guidelines, only reactive power support from synchronous generators is considered as an ancillary service throughout this thesis. Thus, it is useful to present a brief discussion on the main characteristics of a synchronous generator as a reactive power service provider and then attempt to examine its reactive power generation capability.

2.3.1 Reactive Power from Synchronous Generator

The real power output from a synchronous generator is usually limited by the capability of its prime mover. When real power and terminal voltage are fixed, the armature and field winding heating limits determine the reactive power capability of a generator [49]. Thus, in Figure 2.1, the armature heating limit is a circle with a radius ($V_t I_a$), centered at the origin, and expressed by the following equation:

$$P_G^2 + Q_G^2 \leq (V_t I_a)^2 \tag{2.1}$$

The field limit, on the other hand, is a circle with radius ($V_t E_f / X_s$) at (0, $-V_t^2/X_s$) and expressed by the following equation:

$$P_G^2 + \left(Q_G + \frac{V_t^2}{X_s} \right)^2 \leq \left(\frac{V_t E_f}{X_s} \right)^2 \tag{2.2}$$

Where,

P_G: Active power generation of the synchronous generator.

Q_G: Reactive power generation of the synchronous generator.

V_t: Terminal voltage of the synchronous generator at which its capability curves are calculated.

I_a: Rated armature current of the synchronous generator at which its capability curves are calculated.

E_f: Excitation voltage of the synchronous generator.

X_s: Synchronous reactance of the synchronous generator.

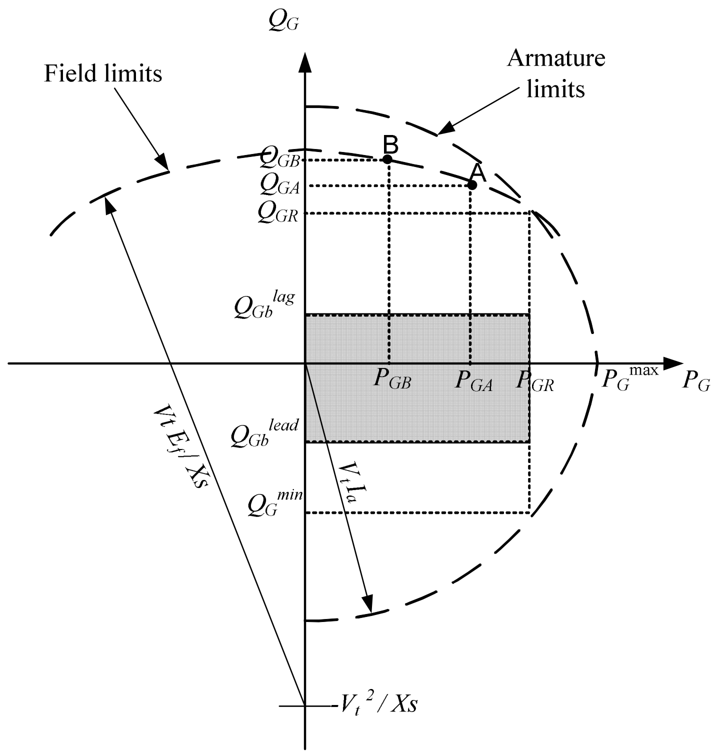

Figure 2.1 Synchronous generator capability curve.

The generator's MVA rating is the point of intersection of the two curves, given by (2.1) and (2.2), and therefore its corresponding real power rating is given by P_{GR}. At an operating point A, with real power output P_{GA} such that $P_{GA}<P_{GR}$, the limit on Q_G is imposed by the generator's field winding heating limit, whereas, when $P_{GA}>P_{GR}$, the limit on Q_G is imposed by the generator's armature winding heating limit.

There is a mandatory amount of reactive power that each generator has to provide, which is shown by the shaded area in Figure 2.1. If the generator is called upon by the ISO for additional reactive power provision beyond this area, it is then eligible for payment to compensate for the increased costs associated with losses in the windings. Such mandatory and ancillary classifications of reactive power capability is in line with what most system operators currently have in place for reactive power management.

According to the capability curve in Figure 2.1, the generator can provide reactive power until it reaches its heating limits (point A in Figure 2.1); any further increase in reactive power provision from the generator will be at the expense of a reduction in its real power generation. Hence, the generator is expected to receive an *opportunity cost payment* for providing reactive power beyond Q_{GA}, which accounts for the lost opportunity to sell its real power in the energy market and the associated revenue loss. Thus, the following three regions for reactive power generation can be identified in Figure 2.1 [31]:

- Region I ($Q_G^{min} \leq Q_G = Q_{G1} \leq 0$) refers to the under-excitation region, in which the generator is required to absorb reactive power.

- Region II ($0 \leq Q_G = Q_{G2} \leq Q_{GA}$) refers to the over-excitation region, in which the generator is required to supply reactive power within its reactive power capability limits.

- Region III ($Q_{GA} \leq Q_G = Q_{G3} \leq Q_{GB}$) refers to the lost opportunity region, in which the generator is asked to reduce its active power production in order to meet the system reactive power requirements. It is assumed here that P_{GB} would be the minimum amount of real power that the generator is able/willing to produce.

2.3.2 Reactive Power Service Provision

Traditionally, reactive power support and voltage control have been viewed by researchers as a loss minimization problem, in which reactive power is provided from different sources, including capacitor banks, FACTS controllers, and synchronous generators, subject to various system constraints such as nodal active and reactive power balance, bus voltage limits, and power generation limits. Thus, reactive power is dispatched by solving the following loss minimization problem:

$$\textit{Min.} \quad Loss = 0.5\sum_{i,j}\left(G_{ij}\left(V_i^2 + V_j^2 - 2V_iV_j\cos\left(\delta_j - \delta_i\right)\right)\right) \tag{2.3}$$

$$\textit{s.t.} \quad P_{Gi} - P_{Di} = \sum_j V_iV_jY_{ij}\cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{2.4}$$

$$Q_{Gi} - Q_{Di} + Q_{Ci} = -\sum_j V_iV_jY_{ij}\sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{2.5}$$

$$P_{Gi}^{\min} \leq P_{Gi} \leq P_{Gi}^{\max} \tag{2.6}$$

$$Q_{Gi}^{\min} \leq Q_{Gi} \leq Q_{Gi}^{\max} \tag{2.7}$$

$$Q_{Ci}^{\min} \leq Q_{Ci} \leq Q_{Ci}^{\max} \tag{2.8}$$

$$V_i^{\min} \leq V_i \leq V_i^{\max} \tag{2.9}$$

$$\left|P_{ij}\left(V, \delta\right)\right| \leq P_{ij}^{\max} \tag{2.10}$$

Where,

V_i: Voltage magnitude at bus *i*, in p.u.

δ_i: Voltage angle at bus *i*, in radians.

G_{ij}: Conductance of the line connecting buses *i* and *j*, in p.u.

Y_{ij}: Magnitude of the *ij* entry of the admittance (Y) matrix, in p.u.

θ_{ij}: Angle of the *ij* entry of the admittance (Y) matrix, in radians.

P_{Di}: Active power demand at bus *i*, in p.u.

Q_{Di}: Reactive power demand at bus *i*, in p.u.

P_{Gi}^{min}: Minimum active power limit of a generator at bus *i*, in p.u.

P_{Gi}^{max}: Maximum active power limit of a generator at bus *i*, in p.u.

Q_{Gi}^{min}: Minimum reactive power limit of a generator at bus *i*, in p.u.

Q_{Gi}^{max}: Maximum reactive power limit of a generator at bus *i*, in p.u.

Q_{Ci}: Reactive power output from a capacitor at bus *i*, in p.u.

Q_{Ci}^{min}: Minimum reactive power limit of a capacitor at bus *i*, in p.u.

Q_{Ci}^{max}: Maximum reactive power limit of a capacitor at bus *i*, in p.u.

V_i^{min}: Minimum allowable voltage at bus *i*, in p.u.

V_i^{max}: Maximum allowable voltage at bus *i*, in p.u.

P_{ij}: Power flow from bus *i* to bus *j*, in p.u.

P_{ij}^{max}: Maximum allowable power flow from bus *i* to bus *j*, in p.u.

The above OPF-based model is basically a non-linear optimization problem, with a loss minimization objective function (2.3). Equations (2.4) and (2.5) represent the nodal active and reactive power balance equations. Active power generation is kept within upper and lower limits using (2.6); whereas, constraints (2.7) and (2.8) limit the reactive power from generators and capacitors, respectively. Bus voltage limits are maintained using (2.9). Finally, line flow limits are imposed by (2.10).

In the context of vertically integrated utilities, the cost of reactive power support was bundled within the single electricity tariff, and service providers were not paid separately for this service. Accordingly, the “traditional” dispatch approaches did not consider the cost incurred by the system operator to provide the required reactive power support.

In competitive electricity markets, reactive power support from generators is provided as an ancillary service either through long-term procurement based on seasonal contracts between the ISO and the service providers, or through short-term dispatch based on real-time system operating conditions. Currently, most system operators procure reactive power by signing long-term agreements with the service providers; such agreements are mainly based on the operator’s experience and the expected system conditions rather than on optimization models. Subsequently, in real-time, the ISO typically uses power flow analysis to arrive at a feasible reactive power dispatch from the procured generators. Such dispatch mechanisms only ensure a secure reactive power dispatch, however, they do not take into consideration the payments associated with such a dispatch, *i.e.* the ISO does not dispatch reactive power at least cost.

Bhattacharya *et al* have looked at the problem of optimal procurement of reactive power ancillary services, in various papers [31]-[33]. A two-step reactive power procurement model was proposed in [31], which considered total system losses as a decision criterion in the procurement process. First, the marginal benefits of reactive power supply from each provider with respect to system losses, represented by Lagrange multipliers associated with the reactive power balance constraints, were obtained by solving the OPF model (2.3)-(2.9); line flow limits (2.10) were not considered in this model. Second, these Lagrange multipliers, together with the reactive power price offers from the generators, were used to solve the following procurement model that maximizes a societal advantage function (*SAF*), and hence determine the required reactive power support:

$$\begin{aligned} Max.\quad SAF &= \sum_{g}\left(C_L \cdot \lambda_g - m_{2g}\right)\cdot Q_{G2g} + \\ &\sum_{g}\left(\left(C_L \cdot \gamma_g - m_{2g}\right)\cdot Q_{G3g} - 0.5 m_{3g}\cdot\left(Q_{G3g} - Q_{GA}\right)^2\right) \end{aligned} \tag{2.11}$$

$$s.t.\quad P_{Gi} - P_{Di} = \sum_{j} V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{2.12}$$

$$Q_{Gi} - Q_{Di} = -\sum_{j} V_i V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \tag{2.13}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \tag{2.14}$$

$$\begin{aligned} W_{1g}\cdot Q_{Gg}^{\min} &\le Q_{G1g} \le W_{1g}\cdot Q_{Gbg}^{lead} \\ W_{2g}\cdot Q_{Gbg}^{lag} &\le Q_{G2g} \le W_{2g}\cdot Q_{GAg} \\ W_{3g}\cdot Q_{GAg} &\le Q_{G3g} \le W_{3g}\cdot Q_{GBg} \end{aligned} \tag{2.15}$$

$$W_{1g} + W_{2g} + W_{3g} = 1 \tag{2.16}$$

$$Q_{Gg} = Q_{G1g} + Q_{G2g} + Q_{G3g} \tag{2.17}$$

Where,

m_{2g}: Cost of loss price offer for generator *g* for operating in the over-excitation region, in \$/Mvarh.

m_{3g}: Opportunity price offer for generator *g* for operating in the opportunity region, in \$/Mvar^{2}h.

λ_g: Lagrange multiplier associated with the nodal reactive power balance equation denoting the sensitivity of the system loss to a change in reactive power injection at generator bus g, in MW/Mvar.

γ_g: Lagrange multiplier associated with the reactive power limit indicating by how much the system loss will change for a unit change in reactive power capability for generator g, in MW/Mvar.

C_L: A cost parameter denoting the economical worth of reducing losses in \$/MWh.

Q_{G1g}: Under-excitation reactive power of generator g, in p.u.

Q_{G2g}: Over-excitation reactive power of generator g, in p.u.

Q_{G3g}: Reactive power of generator g operating in the opportunity region, in p.u.

Q_{Gbg}^{lead}: Base leading reactive power of generator g, in p.u.

Q_{Gbg}^{lag}: Base lagging reactive power of generator g, in p.u.

Q_{GAg}: Maximum reactive power limit of generator g without reduction in real power generation, in p.u.

Q_{GBg}: Maximum allowable reactive power limit of generator g with reduction in real power generation, in p.u.

W_{1g}, W_{2g}, W_{3g}: Binary variables associated with the three regions of reactive power operation for generator g.

The above procurement model (2.11)-(2.17) is a mixed-integer non-linear programming (MINLP) problem, where the real power output from generators (P_G) is assumed to be known *a priori* because of the nature of the market structure considered therein. The limits for the three regions of reactive power operation for each generator are given in (2.15). Constraints (2.16) and (2.17) guarantee that only one out of the three regions, discussed earlier and illustrated in Figure 2.1, is selected. Accordingly, W_1, W_2 and W_3 in (2.15) and (2.16) are binary variables associated with these three regions, for each generator.

It can be seen that the reactive power procurement procedures proposed in [31] do not properly account for system security in either of the two steps, since the model (2.11)-(2.17) does not include line flow limits, which are of great importance to represent system security. In addition, the model neglects the effect of reactive power on the pre-determined active power, as generators operating in the opportunity region are required to reduce their active power generation; it is then important to check whether or not the model yields a reasonable solution. Moreover, from the optimization point of view, the procurement model (2.11)-(2.17) represents a difficult optimization problem, since it is a non-convex MINLP problem; the solution of this type of problem is very challenging due to the presence of both the integer variables and the non-convexities of the model itself.

It has been widely recognized by system operators that system security and particularly the impact of inadequate reactive power support on security is an important issue to be considered in system operation. In this context, security aspects need to be incorporated in the reactive power provision procedures. The impact of reactive power from each generator on system security has to be examined and represented in the procurement model. In real-time, transmission security limits have to be properly included in the reactive power dispatch model. Moreover, the effect of reactive power dispatch on real power dispatch has to be considered in real-time, to ensure a secure operating point after the rescheduling of real power from the already dispatched values obtained from the market clearing process, due to high reactive power requirements.

2.4 Reactive Power and System Security

Reactive power is directly associated with voltage, and hence voltage control is achieved in electric power systems by absorbing/delivering reactive power. Voltage control implies maintaining the voltage at each bus in the system within defined limits in order to prevent damage to electric power equipment and prevent voltage collapse in the case of large disturbances such as system faults, loss of generation, or transmission line outage. Voltage collapse occurs when the system tries to serve more load than what it can support.

If the power system is subjected to a large disturbance, the voltage will drop, resulting in an increase in the current to maintain the power supplied to the loads, and hence causing the lines to consume more reactive power, leading to a further drop in the voltage. Moreover, if the current increases beyond the current carrying capabilities of the transmission lines, these lines will trip, overloading other lines and eventually causing cascading failure. Also, if voltage drops too low, some generators will automatically disconnect to protect themselves. If the power system is unable to provide the necessary reactive power required to supply the reactive power demand, voltage drop may result in a complete voltage collapse. Sufficient reactive power is then an essential requirement for a secure and reliable operation of the electric power system, since inadequate reactive power supply might result in voltage stability problems.

In order to ensure a secure operation of the power system, the ISO needs to check the technical feasibility of potential transactions after energy market settlement; only those transactions that are within the transfer capabilities of the network are allowed. This is particularly important when dealing with reactive power, since it has a direct bearing on system security, and hence the power transfer capabilities of the transmission system [50].

Typically, the transfer capabilities of the system in the main transmission corridors are defined using the concept of Available Transfer Capability *(ATC)*, which is in turn defined as the remaining transfer capability of the transmission system for further commercial activity over and above its already committed uses [51], and is commonly expressed as:

$$ATC = TTC - TRM - ETC - CBM \tag{2.17}$$

Where, *TTC* is the Total Transfer Capability; *TRM* is the Transmission Reliability Margin, which is typically assumed to be a fixed value (*e.g.* 5% of *TTC* under normal operating conditions in the Western Electricity Coordinating Council *WECC* [52]); *ETC* is the Existing Transmission Commitments; and *CBM* is the Capacity Benefit Margin and is usually included in the *ETC*.

The *TTC* is typically defined as follows:

$$TTC = Min\left\{P_{Max_{I\,\lim}}, P_{Max_{V\,\lim}}, P_{Max_{S\,\lim}}\right\} \tag{2.18}$$

Where, $P_{Max_{I\,\lim}}$, $P_{Max_{V\,\lim}}$ and $P_{Max_{S\,\lim}}$ are the maximum powers the system can securely transmit considering thermal limits, voltage limits, and stability limits, respectively, based on at least an N-1 (worst single) contingency criterion.

Currently, electricity markets are usually operated under stressed loading conditions due to the increased demand and power transfers, thereby increasing the probability of the system experiencing stability problems. Under such conditions, system stability limits can be approximated through voltage stability limits [53]. In this context, the *TTC* can be evaluated using the system Loading Factor (*LF*), which is defined as the amount of additional loading of a given transmission corridor for a given dispatch pattern that does not violate thermal limits, bus voltages limits or voltage stability limits [54], and can be expressed as:

$$LF = LF_c - LF_0 \tag{2.19}$$

Where, LF_0 is the existing loading (the *ETC*), while LF_c is the system loading at the maximum loading point. Hence, using a *TRM* = 0.05**TTC*, the *ATC* can be approximately expressed in terms of *LF* as follows:

$$ATC \approx 0.95LF_c - LF_0 \tag{2.20}$$

It is worth mentioning here that the concept of a “system-wide” ATC, as proposed in [53], has been adopted in this thesis. This approach, however, does not preclude using (2.20) to determine the ATC values of particular transfer corridors, since this can be readily accomplished by properly defining power “sources” and “sinks” in the computation of LF_c.

Typically, an N-1 contingency criterion is used in the TTC calculation, which consists of studying single contingency cases one by one. For each contingency, LF_c is calculated, and the minimum LF_c defines the “worst” contingency.

The LF_c can be readily obtained from the system PV curves, as this represents the change in load between the operating point and the nose of the curve, which corresponds to how much the system may be loaded before reaching its thermal, voltage magnitude, or voltage stability limits. A typical PV curve is illustrated in Figure 2.2, showing the relation between the aforementioned ATC definitions and its relation with the system *LF*. This PV curve can be obtained using Continuation Power Flow (CPF) methods [54], which allow calculating complete voltage profiles, and hence determining the value of LF_c for a given "direction" of generation and loading increase considering different contingencies. On the other hand, the LF_c can also be computed by reformulating the conventional OPF with the objective function of maximizing *LF* [55], [56]. OPF-based models not only yield the value of LF_c, but also provide Lagrange multipliers that can be used as sensitivities equivalent to those computed by solving a CPF [57].

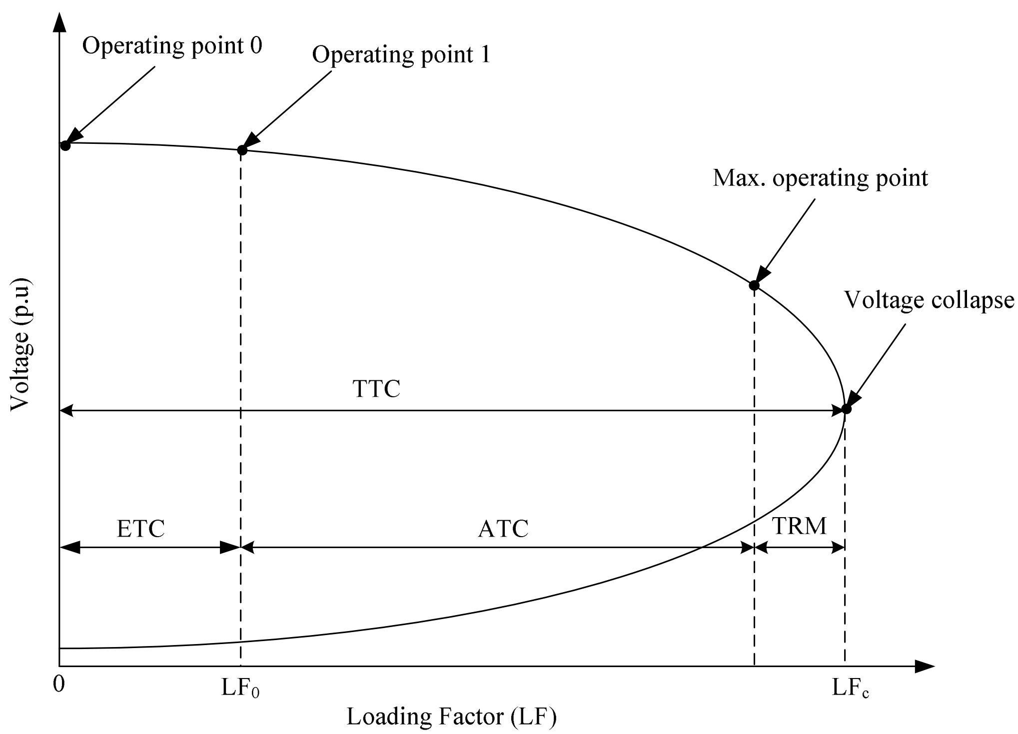

Figure 2.2 A Typical PV curve.

Based on the above discussions, and the idea of calculating marginal benefits of reactive power from each generator presented in [31], system security can be incorporated in the reactive power procurement process by calculating the marginal benefits of reactive power from generators with respect to system security. These marginal benefits can be represented by the Lagrange multipliers associated with an OPF-based model that maximizes *LF*, subject to transmission security constraints. Incorporating system security in the reactive power procurement process is one of the main novel contributions of this thesis; more details on how this is achieved will be presented in Chapter 4, where the proposed reactive power procurement model is discussed.

2.5 Summary

This chapter provides an overview of the process of “liberalization” of the power industry, with a detailed discussion on ancillary services including definitions, types, and the way they are managed in different jurisdictions worldwide. A background discussion on reactive power from synchronous generators is then presented, explaining the different regions of reactive power production and the associated cost components. Finally, the effect of reactive power on active power and system security is discussed, pointing out the importance of incorporating system security within the procedures of reactive power provision.

Chapter 3
A Unified Framework for Reactive Power Ancillary Service Management[1]

3.1 Introduction

In Chapter 2, the main aspects of reactive power ancillary services are presented, pointing out the clear shift in the way these services are managed and priced post-deregulation. Reactive power management and payment mechanisms differ from one electricity market to another, and no uniform structure or design has yet evolved. It is clear from the brief review for utilities' practices given earlier in Section 1.2.1 that there has been a move towards creating competitive reactive power markets in different countries and regions. However, there are several issues concerning the existing provision policies and payment mechanisms for reactive power services that impede the full development of a competitive market. Thus, this chapter first discusses the main issues associated with reactive power management and pricing in the context of the new operating paradigms in deregulated power systems. Subsequently, appropriate policy solutions, which are in line with the existing market rules and regulations, are proposed. Finally, a unified framework for reactive power management that is appropriate for a competitive market and that ensures a secure and reliable operation of the associated power system, is proposed and developed.

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[1]The work presented in this chapter has been published in the *proceedings of the 2006 IEEE-PES PSCE* in Atlanta, Georgia [58].

3.2 Issues Associated with Reactive Power Management

3.2.1 Optimal Provision for Reactive Power Services

In a competitive electricity market, reactive power provision by the ISO should be achieved in an optimal manner. The question that arises here is this: What is the best optimization criterion to be adopted by the ISO? In other words, what is the optimization objective that the ISO should be seeking to determine the system reactive power schedules? Should it be system loss minimization, as has been the usual practice, or should it be maximization of system security or minimization of reactive power costs?

Any of the aforementioned objectives can be adopted; however, since some of these objectives are of a conflicting nature, the ISO needs to choose a criterion that best suits a competitive market structure. For example, if the ISO seeks to minimize losses to determine its reactive power provision, it could end up with an expensive set of providers located close to the reactive load centers, without guaranteeing that the optimal solution would improve system security. Similarly, if the ISO seeks only to minimize its reactive power costs, it might end up with a set of low-priced offers from far-off generators, thus increasing the system losses and certainly negatively affecting system security. Hence, the choice of an appropriate optimization criterion is essential for the development of competitive reactive power provision mechanisms.

3.2.2 Reactive Power Payment Mechanisms

In a competitive market environment, if reactive power service providers are not properly compensated for their service, they will not have enough incentive to provide the required reactive power support, which will definitely affect the power system operation and security. An important issue that arises with regard to reactive power markets is then the choice of an appropriate payment mechanism. Should it be a market-based auction mechanism where the suppliers provide their reactive power bids to the ISO, which in turn determines the best reactive power price using an appropriate objective function? If so, should it then be a uniform price market for reactive power with a single reactive power price for the whole system, or a zonal level reactive power auction market where the system is divided into zones, and separate reactive power prices are determined for each zone? Should a Locational Marginal Price (LMP) market, in which reactive power price varies across each bus, be used?

If there is no auction market, then reactive power payments could be set on a contractual basis, with the ISO entering into bilateral agreements with the service providers and signing long-term contracts for the required reactive power services. For example, the IESO in Ontario signs 36-month contracts with generators, recognizing additional energy losses and opportunity costs associated with reactive power generation, and the cost of running the generating units as synchronous condensers if requested by the IESO [9]. The ISO-New England, on the other hand, pays a capacity component for qualified generators for the capability to provide reactive power services, in addition to the energy and lost opportunity components [59].

The reactive power payment mechanism could also take the form of a tender market structure as in the UK [12], where the selected generators are contracted for six months and are paid based on their initial tender price offers, similar to a pay-as-bid (first price) auction market.

3.2.3 The Effect of Reactive Power on Active Power and System Security

It is well accepted that the principal function of a synchronous generator is to generate real power to meet the demand of the system. Under certain circumstances, usually arising from critical system conditions, the ISO may request or instruct a generator to increase its reactive power output, which may require a reduction in its active power output, thereby affecting market and system operating conditions. The reactive power capacity of a synchronous generator is determined by its capability curve, shown in Figure 2.1, which demonstrates the relationship between its real and reactive power generation. Three regions of reactive power operation were identified earlier in Section 2.3.1: under-excitation, over-excitation, and opportunity regions. If the generator is operating in any of the first two regions, no change in its real power generation is required. Conversely, any reactive power generation requested by the ISO in the opportunity region will require a decrease in the real power generation from the already dispatched levels. Therefore, such an effect on real power dispatch has to be considered when modeling the reactive power dispatch problem.

The rescheduling in real power generation associated with an increase in the reactive power requirements may result in an insecure operation of the power system. Hence, the ISO needs to check the technical feasibility of the resulting solution after reactive power dispatch procedures are completed. Only those transactions that are within the transfer capabilities of the network are allowed. Therefore, in order to ensure a reliable and secure operation of the power system, it is important to incorporate system security in the reactive power provision procedures by including appropriate transmission security constraints, and to consider the effect of reactive power dispatch on real power dispatch and hence system security. Transmission security constraints are typically represented by voltage limits, thermal limits, and stability limits.

3.2.4 Energy Price Volatility

It has been the general experience of market operators and ISOs that energy prices can be highly volatile under certain system conditions, such as demand spikes or outages. In a short-term operational time-frame, volatile energy market conditions would certainly have an impact on reactive power procurement and dispatch procedures.

3.2.5 Reactive Power Market Power

One of the primary barriers to the implementation of a competitive market for reactive power is the possibility of market power arising because of the limited number of reactive power service providers at a given location in such a market. Furthermore, reactive power is a “local” service, *i.e.* it must be procured and provided as close to the demand buses as possible because of the technical issues associated with transporting reactive power over long distances. Hence, in a reactive power market, it is certainly plausible that some “well-located” suppliers may try to exercise market power by submitting excessively high price offers or by withholding reactive power supply in an attempt to increase the reactive power market price to their own advantage.

FERC Order 2000 mentions that market monitoring is an essential tool for ensuring non-discriminatory market operation and avoiding any opportunity for exercise of market power [42]. Several indices for measuring/quantifying market power (or market concentration) in real power auctions have been proposed in the literature, such as the traditional Herfindahl-Hirshman Index (HHI) [60], or the Residual Supply Index (RSI) [61]. In the context of reactive power markets, it would be important to consider these or other indices to analyze and thus address market power issues.

3.2.6 Reactive Power Management Time Line

In the context of deregulation, reactive power provision can possibly be managed as a short-term provision in which it is dispatched from available generators based on real-time system operating conditions. It may be also managed as a seasonal provision in which it is procured based on long-term agreements between the ISO and the service providers. If reactive power is managed concurrently with the energy market clearing process, some problems may arise such as price volatility and the effect of reactive power on real power and system security.

Currently, most system operators sign long-term contracts with reactive power service providers, based on operational experience and knowledge of the system and the expected voltage problems. In real-time, most system operators run power flow programs to determine the required reactive power dispatch levels from contracted providers. The ISO has to check if the solution of the power flow is not violating any of the security limits. In the case when generators are operating in the opportunity region, where they are required to back-up their real power generation to meet the reactive power requirements, the ISO needs to check if the resulting operating point after rescheduling of real power is secure or not.

3.3 Proposed Policy Solutions

3.3.1 Decoupling of Active and Reactive Power

Based on the above discussions regarding market inefficiencies and the associated problems that arise when both active and reactive power are simultaneously managed and priced by the ISO, a possible solution is to *decouple* these two markets from each other. Decoupling of active and reactive power markets is possible by placing them in two entirely different operating time frames. This minimizes the possibility of adverse effects on reactive power prices that might arise from the price volatility of real power.

The decoupling of active and reactive power has also been suggested in [30] and [62]. Such a decoupling implies that the OPF problem can be separated into sub-problems of active and reactive power. The active power sub-problem essentially provides the active power dispatch and prices in real-time based on a cost minimization (or social welfare maximization) market settlement model. The reactive power sub-problem, operating on different time frames, provides reactive power contracts, prices, and dispatch levels based on appropriate optimization criteria.

It is important to mention that the solution obtained from a “coupled” OPF model, simultaneously dispatching active and reactive power, is theoretically closer to the optimal. However, in addition to the price volatility issue that arises when handling active and reactive power simultaneously, the computational burden is also an important issue for large-size power systems, since it would require solving a rather complex and large-scale MINLP model. Decoupling the OPF problem provides the required flexibility for market development in reactive power services and avoids having to deal with the coupled model complexity, while retaining an acceptable level of accuracy.

3.3.2 Zonal Reactive Power Management

Different pricing mechanisms for reactive power ancillary services were mentioned in Section 3.2.2, raising the question of which one is more suitable in the context of deregulation. Given the localized nature of reactive power and the common practices amongst most electric utilities in regards to splitting the whole system into zones or voltage control areas, zonal reactive power management and pricing might be an appropriate approach. In the case of a system-wide uniform price, market inefficiencies resulting from market power being exercised by some reactive power service providers, anywhere in the system, will affect all other providers in the system. Zonal reactive power pricing, on the other hand, helps isolate and confine any existing market inefficiencies within the zone. These market inefficiencies may arise from some service providers trying to exercise market power by increasing their reactive power price offers. Examining and pricing reactive power support in a zonal context rather than as a whole system could also reduce the computational burden on the ISO [33].

In terms of service provision, zonal reactive power management allows for having additional reactive power reserves for each zone; this reserve can be called upon by the ISO in emergency cases associated with severe contingencies in the system. In general, zonal reactive power management can be achieved by splitting the system into different voltage control areas [63].

3.3.3 Alternative Sources of Reactive Power Supply

One of the main challenges associated with reactive power provision is that, so far, only reactive power support from synchronous generators has been considered as an ancillary service and eligible for financial compensation in North America, as per FERC Order 888 [1], and NERC White Paper on Proposed Standards for Interconnection Services [48]. However, these restrictive policies are currently under review, since it can be readily argued that with a more liberal reactive power ancillary service provision structure, there would be more competition due to an increased number of providers. This will lead to a reduction in reactive power prices, and improved system reliability and security.

Motivated by these discussions at various forums, FERC has recommended in its latest report on reactive power and voltage control in competitive electricity markets that system operators should fully consider other sources of reactive power supply [2]. In view of these discussions, it is important to examine how other reactive power providers, such as capacitor banks and FACTS controllers, could participate in the reactive power ancillary service markets to help develop a fully competitive reactive power market. This particular issue is not studied in this thesis, since the characteristics of these reactive power resources make them essentially different from generators; hence, appropriate policies will be required to determine how these resources can be properly compensated for providing reactive power as an ancillary service. Therefore, in the work presented in this thesis, only reactive power from synchronous generators is considered as an ancillary service, as per the existing FERC and NERC regulations.

3.3.4 Accounting for System Security

Given the impact of reactive power on active power and system security, as discussed in Section 3.2.3, system security should then be incorporated in the reactive power provision procedures. Accounting for system security can be achieved in two ways. The first way is by including appropriate transmission security limits, represented by voltage limits, thermal limits, and line flow limits, in the reactive power procurement and dispatch models. The second way is by having system security as a main criterion in the reactive power procurement procedures, where a set of contracted generators is selected and reactive power prices are determined.

Under stressed operating conditions, some generators might be required to increase their reactive power generation level beyond their capability limits determined by the field or armature heating limits, and hence the generator will be operating in the opportunity region (between Q_{GA} and Q_{GB} in Figure 2.1). Accordingly, this generator will have to reduce its active power generation, resulting in a rescheduling of active power from the already dispatched levels obtained from the energy market clearing process. Hence, the ISO has to check whether this new operating point is secure or not, *i.e.* whether or not any of the transmission security limits are violated. Thus, it is important not only to appropriately include security limits in the reactive power procurement and dispatch models, but also to take into consideration the effect of reactive power on active power.

3.4 A Proposed Framework for Reactive Power Management

Based on the discussions on the issues associated with reactive power management in Section 3.2, and the proposed policy solutions in Section 3.3, an integrated framework for reactive power management is proposed here. The proposed framework comprises two hierarchical levels of reactive power management, namely *reactive power procurement* and *reactive power dispatch*. Reactive power procurement is essentially a long-term issue, *i.e.* a seasonal problem, wherein the ISO seeks optimal reactive power contracts with possible suppliers that would be best suited to its needs and constraints in a given season. This optimal set of contracts should be determined taking into account forecasts of the demand and system conditions expected over the planning horizon. The criteria for such procurement could be many, but they should essentially take into consideration the cost/price offers of reactive power provision, and system security.

Reactive power dispatch, on the other hand, corresponds to the short-term, "real-time" allocation of reactive power to suppliers based on current operating conditions. The ISO determines the optimal reactive power schedule for all providers based on a certain objective that depends on system operating criteria, such as minimization of total system losses, minimization of deviations from contracted transactions, or maximization of system loadability to minimize the risk of voltage collapse.

Figure 3.1 explains the two hierarchical levels of the proposed reactive power management scheme on a time-scale. The procurement level is assumed to take place 180 days ahead of real-time, where the set of contracted generators and reactive power prices are determined, and an availability component is paid to the contracted service providers. Based on hourly energy market clearing, the reactive power dispatch procedure is assumed to take place one hour to 30 minutes ahead of real-time. Finally, reactive power settlements take place post-dispatch, and payments are made to the service providers based on real-time support levels.

The following sub-sections provide an overview of the proposed two levels of reactive power management.

3.4.1 Long-Term Management

This is the higher of the two levels in the hierarchy of the proposed reactive power management scheme. The objective of the ISO in this case is to procure "adequate" long-term reactive power supply for the system. The proposed procurement process would work as follows: The ISO first calls for reactive power offers from available service providers (only synchronous generators, according to FERC regulations), and based on the received offers, it solves an optimization model that maximizes a societal advantage function subject to system constraints, properly representing system security. Appropriate security indices, represented by marginal benefits of reactive power from each generator with respect to system security, are incorporated in the procurement procedures. The solution of procurement model yields the required set of generators to be contracted for reactive power service provision, as well as reactive power price components. The selected providers will have a long-term obligation for reactive power provision and will receive an availability payment for such a commitment. The schematic representation of the long-term reactive power procurement procedure is depicted in Figure 3.2.

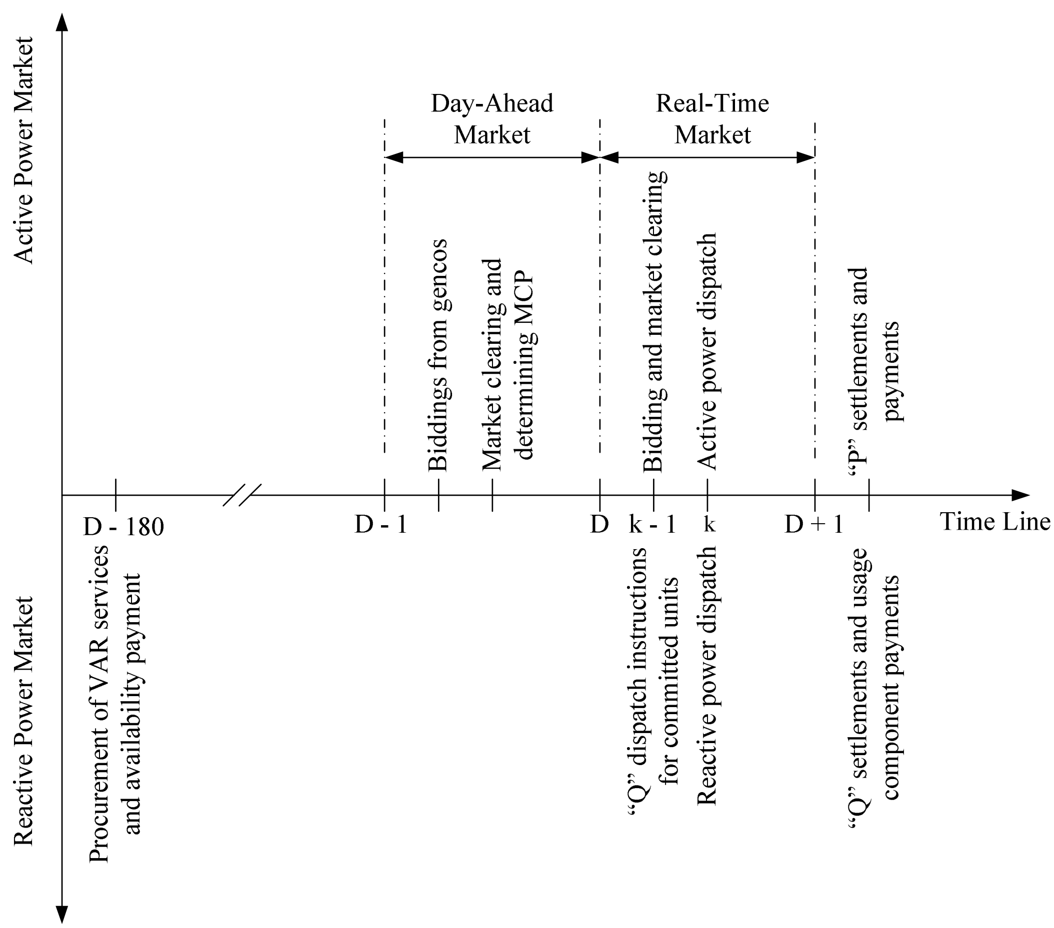

Figure 3.1 Active and reactive market clearing and dispatch at day D and hour k.

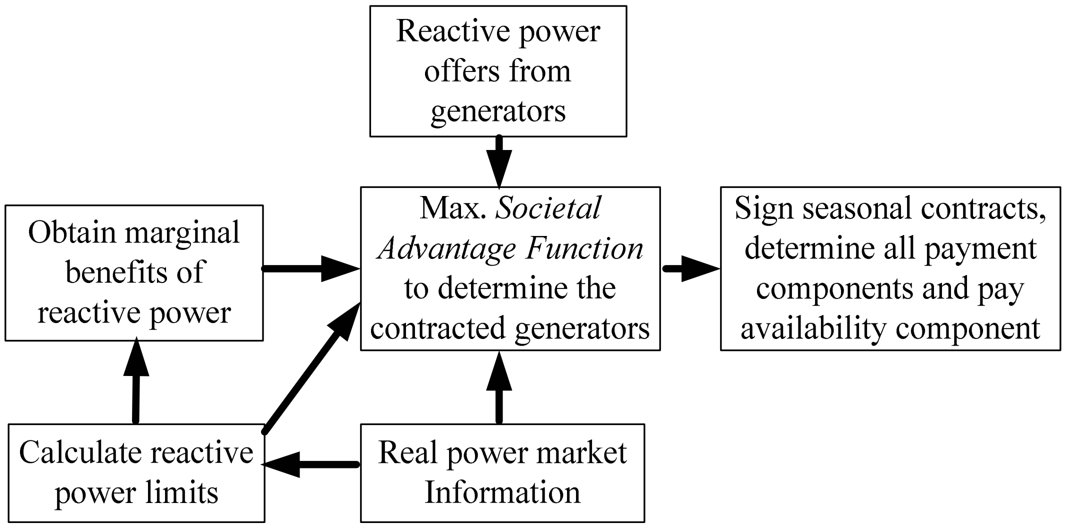

Figure 3.2 Long-term management (procurement) of reactive power services.

It is proposed that the reactive power price offers to be submitted by generators comprise three parts, as per the discussion on reactive power cost components (Figure 1.1) and the classification of reactive power output based on the generator's capability curve (Figure 2.1). Thus, the following represent the different components of a reactive power price offer from a generator:

- Availability price offer (m_o, \$/h): A fixed component to account for that portion of a supplier's capital cost that can be attributed to reactive power production.
- Cost of loss offer (m_1 and m_2 \$/Mvarh): A linearly varying component to account for the increased winding losses as reactive power output increases in the over- and under-excitation regions, respectively.
- Opportunity offer (m_3, \$/Mvar^{2}h): A nonlinearly varying component to account for the lost opportunity cost when a generator is constrained from

producing its scheduled real power in order to increase its reactive power production.

3.4.2 Short-Term Management

The lower level in the proposed hierarchical approach to reactive power management is the short-term management function, namely reactive power dispatch. In practice, active power and reactive power have been handled separately by most power system operators. Typically, active power dispatch is carried out using a linear programming model associated with an Economical Load Dispatch (ELD) calculation that maximizes social welfare, while guaranteeing that system security constraints are met [64]. Reactive power, on the other hand, is dispatched based on power flow studies and operational experience. However, as discussed earlier in Section 3.2, there are several complex issues involved in reactive power service provision in deregulated electricity markets that require further study and appropriate procedures to arrive at better solutions. Ideally, reactive power should be dispatched from generators in an economical manner that minimizes the ISO's payment burden, while also considering system security constraints.

Figure 3.3 illustrates the proposed schematic procedure for short-term dispatch of reactive power. The scheme is based on the assumption that a pre-determined set of contracted (or procured) generators with corresponding reactive power price components is available. This set of contracted generators should ideally be obtained within a long-term framework, for example, from the procurement process discussed earlier, to avoid the adverse impact of energy price volatility on reactive power prices. In line with current reactive power dispatch approaches, the ISO would carry out the dispatch procedure one hour to 30 minutes ahead of real-time. Based on the set of procured/contracted generators and the generating units available from the short-term energy market clearing, the ISO would determine the available units for reactive power dispatch. It would then dispatch the units using the proposed OPF-based model that minimizes total payments associated with reactive power dispatch, subject to appropriate system security constraints. Finally, payments would be calculated after real-time operation, based on the actual usage and the dispatch requested by the ISO.

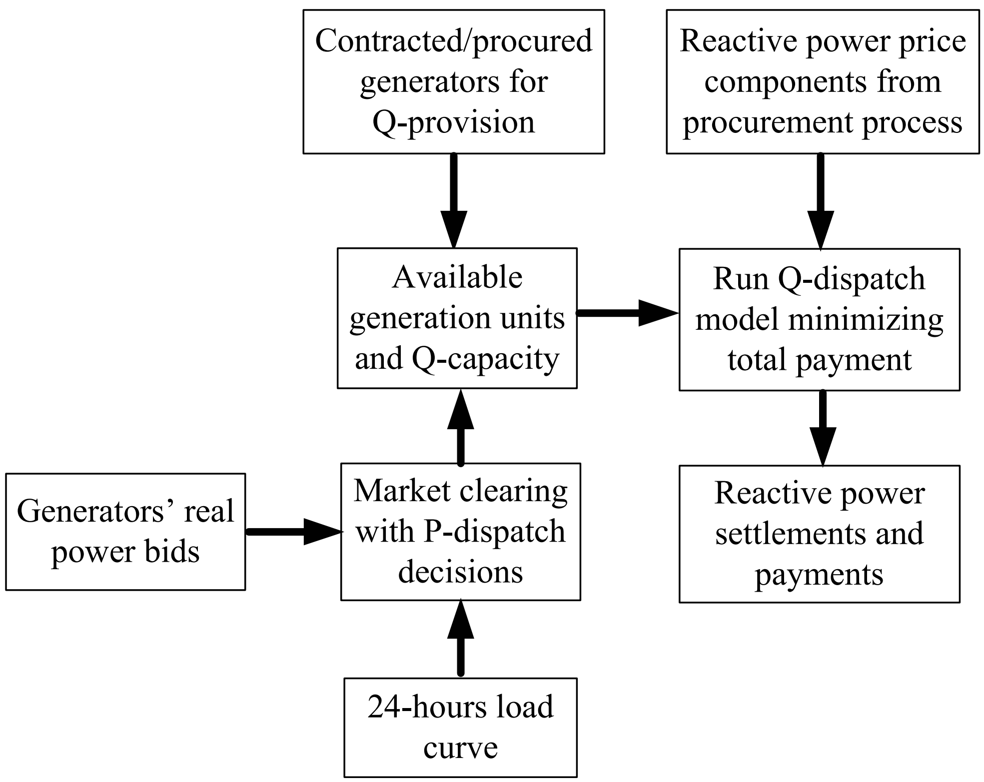

Figure 3.3 Short-term management (dispatch) of reactive power services.

Most system operators use dc-OPF models for real power market clearing and dispatch, with iterative mechanisms to guarantee system security. In this thesis, because of its emphasis on reactive power dispatch, it is assumed that the information from the energy market clearing process, *i.e.* energy prices and associated real power dispatches, are available prior to the execution of the reactive power dispatch procedures. It should be noted that an ac-OPF can also be used in lieu of the dc-OPF to arrive at the real power market clearing and dispatch. However, the computational burden of such an OPF is large for actual power systems, since it requires solving a rather complex and large-scale NLP model every few minutes (*e.g.* every 5 minutes in Ontario).

An important input to the proposed reactive power dispatch model is the set of available generators for real-time reactive power dispatch. Letting X be the set of contracted/procured generators for reactive power obtained at the procurement stage, and Y be the set of available generators from energy market clearing, then the available set of generators for reactive power dispatch will be given by $\xi = X \cap Y$.

The reactive power capacity of the available generating units is predetermined, based on the capability curves of these generators (Figure 2.1). Accordingly, for each generator, the upper and lower limits of the three reactive power operating regions are assumed to be known.

3.4.3 Reactive Power Pricing

Based on the three regions of reactive power operation and the associated costs identified earlier in Section 2.3, a reactive power payment function (*QPF*) is formulated, as shown in Figure 3.4, comprising the following payment components: an availability payment component (with a price ρ_0), which is a fixed component to account for the portion of a supplier's capital cost that can be attributed to reactive power production; two loss payment components (with prices ρ_1 and ρ_2), which are assumed as linearly varying components to account for the increased winding losses as reactive power output increases, in the under- and over-excitation regions, respectively; and an opportunity payment component (with a price ρ_3) to account for the lost opportunity cost associated with the operation in Region III. This opportunity component appears as a quadratic term because of the assumption that active power costs are parabolic functions of output power, which may be considered to approximately change linearly with reactive power in Region III (from point A to B in Figure 2.1). Accordingly, *QPF* for each generator *g* in the system can be mathematically represented by the following equation:

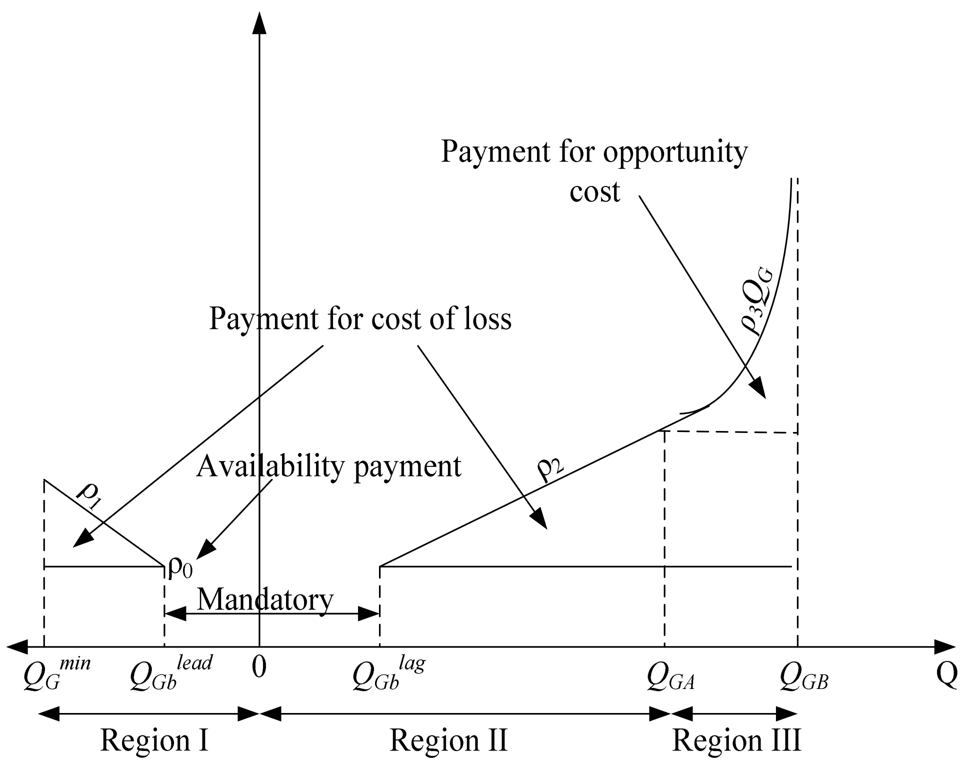

Figure 3.4 Reactive power payment function.

$$
\begin{aligned}
QPF_g = {} & \rho_{0g} + W_{2g}\rho_{2g}\left(Q_{G2g} - Q_{Gbg}^{lag}\right)S_b - W_{1g}\rho_{1g}\left(Q_{G1g} - Q_{Gbg}^{lead}\right)S_b \\
& + \rho_{2g}\left(W_{3fg} + W_{3rg}\right)\left(Q_{G3g} - Q_{Gbg}^{lag}\right)S_b \\
& + 0.5\rho_{3g}\left(W_{3fg} + W_{3rg}\right)\left(Q_{G3g} - Q_{GA}\right)^2 S_b^2
\end{aligned}
$$

$$
\begin{aligned}
W_{1g} &= \begin{cases} 1 & \text{if } Q_{Gg}^{\min} \le Q_{Gg} = Q_{G1g} \le Q_{Gbg}^{lead} \\ 0 & \text{otherwise} \end{cases} \\
W_{mg} &= \begin{cases} 1 & \text{if } Q_{Gbg}^{lead} \le Q_{Gg} = Q_{Gmg} \le Q_{Gbg}^{lag} \\ 0 & \text{otherwise} \end{cases} \\
W_{2g} &= \begin{cases} 1 & \text{if } Q_{Gbg}^{lag} \le Q_{Gg} = Q_{G2g} \le Q_{GAg} \\ 0 & \text{otherwise} \end{cases} \\
W_{3fg} &= \begin{cases} 1 & \text{if } Q_{GAg} \le Q_{Gg} = Q_{G3g} \le Q_{GBg} \,\&\, P_{Gog} < P_{GRg} \\ 0 & \text{otherwise} \end{cases} \\
W_{3rg} &= \begin{cases} 1 & \text{if } Q_{GAg} \le Q_{Gg} = Q_{G3g} \le Q_{GBg} \,\&\, P_{Gog} > P_{GRg} \\ 0 & \text{otherwise} \end{cases}
\end{aligned}
\tag{3.1}
$$

Where,

Q_{G1g}: Under-excitation reactive power of generator *g*, in p.u.

Q_{G2g}: Over-excitation reactive power of generator *g*, in p.u.

Q_{G3g}: Reactive power of generator *g* operating in the opportunity region, in p.u.

Q_{Gmg}: Mandatory reactive power of generator *g*, in p.u.

S_b: Base MVA power (assumed here to be 100 MVA).

ρ_{0g}: Availability price component of reactive power for generator *g*, in \$/h.

ρ_{1g}: Under-excitation price component of reactive power for generator *g*, in \$/Mvarh.

ρ_{2g}: Over-excitation price component of reactive power for generator g, in \$/Mvarh.

ρ_{3g}: Lost opportunity price component of reactive power for generator g, in \$/Mvar^{2}h.

Q_{Gbg}^{lead}: Base leading reactive power of generator g, in p.u.

Q_{Gbg}^{lag}: Base lagging reactive power of generator g, in p.u.

Q_{Gg}^{min}: Minimum reactive power limit of generator g, in p.u.

Q_{GAg}: Maximum reactive power limit of generator g without reduction in real power generation, in p.u.

Q_{GBg}: Maximum allowable reactive power limit of generator g with reduction in real power generation, in p.u.

P_{GRg}: Rated active power of generation g, in p.u.

P_{Gog}: Market clearing pre-determined active power dispatch for generator g, in p.u.

W_{mg}: Binary variable associated with mandatory reactive power production for generator g.

W_{1g}, W_{2g}: Binary variables associated with Regions I and II of reactive power operation for generator g, respectively.

W_{3rg}, W_{3fg}: Binary variables associated with armature and field limits of reactive power generation for generator g, respectively.

In this equation, the binary variables are needed to reflect the fact that the generator operates in only one of the three reactive power operating regions defined in Figure

2.1. Observe that *QPF* does not include the mandatory component of reactive power generation (Q_{Gmg}), since generators are not financially compensated for such obligatory amount of reactive power.

The four reactive power price components should be determined from the procurement stage, where the ISO signs long-term contracts with reactive power service providers in which both parties agree on the prices and the payment mechanism. For example, in Ontario, the IESO signs 36-month contracts with generators that are willing to provide reactive power services. Prices are based on costs of providing reactive power, which include additional costs from energy losses incurred by operating at a non-unity power factor and the cost of running the generating units as synchronous condensers if requested by the IESO [9]. Generators that are asked to reduce their real power output in order to meet the reactive power requirements are paid an additional lost opportunity component at the market clearing price. The New England ISO, on the other hand, pays a capacity component for qualified generators for the capability to provide reactive power services, in addition to the energy and lost opportunity components [59]; a "base VAR rate" of 2.32 $/Kvar-yr has been newly incorporated for qualified generators available for reactive power provision below 0.95 leading or 0.95 lagging power factors.

3.5 Summary

This chapter discusses the different issues associated with the existing provision policies and payment mechanisms for reactive power ancillary services. These issues include: determining the best optimization objective to be adopted by an ISO while providing reactive power services; determining the best payment mechanism for reactive power services; the effect of reactive power from a synchronous generator on its real power output and system security; energy price volatility and its effect on reactive power prices; and the possibility of market power because of the small number of reactive power service providers in a certain location. Accordingly, appropriate policy solutions are proposed to address some of these issues. Among the proposed solutions are: decoupling of active and reactive provisions in order to reduce the effect of energy price volatility on reactive power prices; procurement of reactive power support on a zonal basis in order to reduce the payment burden on the ISO and help reduce and confine the effects of market power; proper incorporation of system security in the reactive power procurement procedures; and considering other sources for reactive power support such as capacitor banks and FACTS devices.

Based on the current practices for reactive power provision by various ISOs in competitive electricity markets, this chapter proposes a hierarchical reactive power market structure that addresses the various issues associated with the existing policies and practices for reactive power management and payment mechanisms. The proposed framework is based on the separation of reactive power management into two distinct time-frames, *i.e.* a reactive power procurement stage carried out on a seasonal basis, and a reactive power dispatch stage that determines the reactive power levels in "real-time".

The proposed framework assumes a general offer structure for reactive power services based on the generators' reactive power costs and capability curves. It is argued that a zonal pricing procedure would be the most appropriate mechanism for payment of reactive power services, so that the local nature of reactive power supply can be used to address market power issues associated with players indulging in gaming strategies. The need to include reactive power providers other than generators to improve market competition and thus reduce reactive power prices is also discussed. Finally, arguments are presented for the need to properly represent system security in the proposed reactive power procurement and dispatch OPF-based procedures, proposing a specific methodology for including system security in the procurement stage.

Chapter 4

A Procurement Scheme for Reactive Power Ancillary Services Considering System Security[1]

4.1 Introduction

In Chapter 3, a two-level framework for the operation of a competitive market for reactive power ancillary services is presented. It is argued that the first-level, *i.e.* reactive power procurement, should take place on a seasonal basis, while the second-level, *i.e.* reactive power dispatch, should take place close to real-time operation. To this effect, a reactive power procurement scheme is proposed in this chapter.

A two-step reactive power procurement scheme is presented and discussed in this chapter. The proposed novel scheme incorporates, for the first time, system security as a selection criterion for the desired set of contracted generators. Given the competitive nature of electricity markets, the procurement model takes into consideration offers of reactive power from generators. The proposed procedure yields the selected set of generators and reactive power price components which would form the basis for seasonal contracts between the ISO and the selected reactive power service providers.

4.2 The Proposed Reactive Power Procurement Scheme

The objective of the ISO is essentially to define and procure adequate long-term

[1]The work presented in this chapter has been published in the *IEEE Transactions on Power Systems* [65].

reactive power supplies for the system. The proposed procurement scheme would work as follows (see Figure 3.2):

- The ISO calls for reactive power offers from the reactive power providers. The structure of these offers should ideally reflect their cost of providing reactive power. This issue was discussed in detail in Section 3.4.1.
- Based on the received offers, the ISO carries out an auction settlement, *i.e.* solves an optimization model to maximize a societal advantage function (*SAF*) subject to system constraints that include system security.
- This procurement market settlement, *i.e.* the solution of the optimization model, yields a set of contracted generators, as well as the price components of reactive power. The contracted providers will have a seasonal obligation for reactive power provision, and may receive an availability payment.

4.2.1 Reactive Power Offers from Generators

Based on the offer structure defined in Section 3.4.1, the long-term nature of the proposed procurement market model, and the local characteristics of reactive power, reactive power prices can be determined for each of the components of the reactive power offers. In case of traditional offer-based commodity markets, the two pricing approaches usually adopted are: *pay as bid* (first price auction), where selected participants are paid as per their respective bid; or *uniform price market* (second price auction), where all selected participants are paid a uniform price, which is the highest accepted offer. It has been argued by economists that uniform price markets provide an incentive to participants to bid their true costs and hence such auctions promote competition.

Applying the uniform price to reactive power markets would be a natural extension to the already existing real power auction mechanisms. However, given the localized nature of reactive power control, and the issues of market power associated with the limited number of providers at a given location, it would be more pertinent to disaggregate the uniform price of reactive power into zonal components. This has been argued in [33], where the power system is split into different voltage control areas or zones based on electrical distances or sensitivity analyses. Such a *zonal uniform price* mechanism for reactive power markets would reduce the impact of market power exercised by certain gaming generators, and should hence restrict them only to their given zones.

4.2.2 Marginal Benefits of Reactive Power Supply with Respect to System Security

The idea of examining the marginal benefits of reactive power injection at a bus has been proposed in [31], where the Lagrange multipliers associated with a loss-minimization OPF model were used to represent these marginal benefits. However, it has been widely recognized by ISOs that system security, and particularly the impact of inadequate reactive power support on security, are important issues to be considered in system operation. In this context, a reactive power procurement model based on the marginal contributions of reactive power injection to system security is proposed in this chapter.

As explained earlier in Section 2.4, system security can be incorporated in the reactive power procurement procedures by calculating the marginal benefits of reactive power from generators with respect to system security. These marginal benefits are represented by Lagrange multipliers associated with a loadability (or *LF*) maximization problem, subject to system security constraints. Thus, system security can be introduced in the reactive power procurement market model by solving the following OPF model based on [66]:

$$\max.\ \ LF \tag{4.1}$$

$$\text{s.t.}\quad P_{Gi}(1+LF+K_G)-P_{Di}(1+LF)=\sum_j V_iV_jY_{ij}\cos\left(\theta_{ij}+\delta_j-\delta_i\right)\quad \forall i \tag{4.2}$$

$$Q_{Gi}-Q_{Di}(1+LF)=-\sum_j V_iV_jY_{ij}\sin\left(\theta_{ij}+\delta_j-\delta_i\right)\ :\lambda_i\quad \forall i \tag{4.3}$$

$$\left.\begin{array}{l} Q_{Gg}\le Q_{Gg}^{\max}\quad :\gamma_g \qquad \forall g \\ Q_{Gg}^{\max}=\begin{cases}\sqrt{\left(\dfrac{V_{tg}E_{fg}}{X_{sg}}\right)^2-\left(P_{Gg}\right)^2}-\dfrac{V_{tg}^2}{X_{sg}} & for\ P_{Gg}<P_{GRg} \\ \sqrt{\left(V_{tg}I_{ag}\right)^2-\left(P_{Gg}\right)^2} & for\ P_{Gg}>P_{GRg}\end{cases}\end{array}\right\} \tag{4.4}$$

$$Q_{Gg}\ge Q_{Gg}^{\min}\ :\mu_g \qquad \forall g \tag{4.5}$$

$$V_i^{\min}\le V_i\le V_i^{\max} \qquad \forall i \tag{4.6}$$

$$\left|P_{ij}\left(V,\delta\right)\right|\le P_{ij}^{\max} \qquad \forall ij \tag{4.7}$$

$$P_{Gi}(1+LF+K_G)\le P_{Gi}^{\max} \qquad \forall i \tag{4.8}$$

$$(Q_{Gg}-Q_{Gg}^{\min})\cdot v_{ga}=0 \quad \forall g \tag{4.9}$$

$$(Q_{Gg}^{\max}-Q_{Gg})\cdot v_{gb}=0 \quad \forall g \tag{4.10}$$

$$V_g=V_{g0}+v_{ga}-v_{gb} \qquad \forall g \tag{4.11}$$

$$v_{ga},v_{gb}\ge 0 \qquad \forall g \tag{4.12}$$

Where, g denotes a generator bus. The following are the model variables to be determined by the solution of the *LF* maximization problem:

LF: Loading factor.

K_G: Variable to model a distributed slack bus.

Q_{Gi}: Reactive power generation at bus i, in p.u.

V_i: Voltage magnitude at bus i, in p.u.

δ_i: Voltage angle at bus i, in radians.

P_{ij}: Power flow from bus i to bus j, in p.u.

v_{ga}, v_{gb} : Two auxiliary variables representing the changes in generator g bus voltage due to reactive power limits.

The following are the model parameters which are input into the optimization model:

P_{Gi}: Active power generation at bus i, in p.u.

P_{Di}: Active power demand at bus i, in p.u.

Y_{ij}: Magnitude of the ij entry of the admittance (Y) matrix, in p.u.

θ_{ij}: Angle of the ij entry of the admittance (Y) matrix, in radians.

Q_{Di}: Reactive power demand at bus i, in p.u.

V_{tg}: Terminal voltage of generator g at which its capability curves are calculated, in p.u. (assumed here to be 1.05 p.u.)

I_{ag}: Rated armature current of generator g at which its capability curves are calculated, in p.u.

E_{fg}: Excitation voltage of generator g, in p.u.

X_{sg}: Synchronous reactance of generator g, in p.u.

P_{GRg}: Rated active power of generation g, in p.u.

Q_{Gg}^{min}: Minimum reactive power limit of generator g, in p.u.

V_i^{max}: Maximum allowable voltage at bus i, in p.u.

V_i^{min}: Minimum allowable voltage at bus i, in p.u.

P_{ij}^{max}: Maximum allowable power flow from bus i to bus j, in p.u.

P_{Gi}^{max}: Maximum active power generation at bus i, in p.u.

V_{g0}: Generator g terminal voltage corresponding to operating point 1 in Figure 2.2, in p.u.

In the above OPF model, (4.2) and (4.3) are the nodal active and reactive power flow equations, where the variable K_G is used to model a distributed slack bus to be able to better represent the distribution of system losses. The field and armature winding heating limits are imposed by (4.4). Equation (4.6) constrains all bus voltage to be within appropriate limits, while (4.7) imposes transmission line thermal limits, with P_{ij} representing the power flowing from bus i to bus j. Finally, (4.8) guarantees that generator active power dispatch levels will not be exceeded.

In order to account for the effect of reactive power limits on generator voltage settings and properly model the generators' voltage regulators, constraints (4.9)-(4.12) are added to the model. These constraints ensure that all the generators will be operating at their terminal voltage settings, defined by operating point 1 in Figure 2.2, as long as the reactive power is within its limits; in this case, the two variables v_{ga} and v_{gb} will be equal to zero to satisfy (4.9) and (4.10). If the reactive power output of any of the generators hits its maximum limit, set by (4.4), constraints (4.10) and (4.12) will force v_{gb} to have a positive value, therefore reducing the voltage at this generator bus according to (4.11). Similarly, if the lower limit of reactive power output for any generator is reached, v_{ga} will have a positive value, hence increasing the voltage at this generator bus. Note that v_{ga} and v_{gb} may still have a zero value even if reactive power limits are reached; these variables are used to simulate the loss of voltage control due to limits.

The Lagrange multipliers that represent the marginal benefit/contribution of each reactive power source with respect to system security for the above model are λ_g, γ_g and μ_g. The Lagrange multiplier λ_g is the dual of the nodal reactive power balance constraint (4.3), denoting the sensitivity of the system security (*LF*) to a change in reactive power demand at a generator bus *g*; γ_g is the dual of reactive power constraint (4.4) of generator *g*, indicating by how much *LF* will change for a unit change in reactive power capability of this generator; and μ_g is the dual of the under-excitation constraint (4.5). Accordingly, all of the three Lagrange multipliers will have a zero value for any generator as long as its Q_G lies within the limits given by (4.4) and (4.5); whereas, either γ_g or μ_g will have a non-zero value for any generator if its Q_G reaches the upper or lower limits, respectively, and the corresponding λ_g in this case will be equal in magnitude, but with the opposite sign. If Q_G for any generator is within its limits, it will be capable of compensating for any increase in reactive power demand at this generator bus without affecting *LF*, and hence λ_g will be zero in this case. Notice that the sign of these multipliers depends on the nature of the optimization problem and the way the associated constraints are treated in the solution process.

The optimization model (4.1)-(4.12) is solved considering single line outage contingency cases, wherein relevant system elements are tripped one at a time to determine the Lagrange multipliers associated with the worst contingency, as per the N-1 contingency criterion. The worst contingency is the one that yields the minimum value of *LF* amongst all contingencies. It is important to highlight the fact that other contingencies might exist, other than the worst one, where some generators' reactive power outputs may have a more significant effect on system loadability, *i.e.* higher values of λ_g, γ_g and μ_g; however, according to NERC's security criterion, operators are not required to act unless the worst contingency conditions are violated. Hence, a contingency that does not violate security limits, regardless of the positive effect that Q_G of a particular generator may have on improving system security for that given operating condition, is not relevant for the purpose of improving system security from the N-1 contingency criterion point of view. It should also be highlighted, as explained further below, that this proposed procurement model is solved for multiple operating conditions that are representative of the given season of interest, and hence a variety of worst contingencies and associated sensitivities are taken into account in the proposed procurement process.

4.2.3 Maximization of Societal Advantage Function

Once the reactive power limits and the marginal benefits (represented by λ, γ and μ) of each provider with respect to system security are determined, and reactive power offers are received, the ISO is in a position to carry out a procurement market settlement where its sole objective is to maximize a Societal Advantage Function or *SAF*. The classical concept of social welfare from economic theory is extended here to formulate a novel reactive power *SAF* which is based on the determination of aggregate system benefits accrued from reactive power services minus the expected payment by the ISO. The proposed *SAF* is formulated on a zonal basis and can be expressed as follows:

$$
\begin{aligned}
SAF_z = & -\sum_{g\in Z}\rho_{oz} - \sum_{g\in Z} W_{1g}\left(C_L\left|\mu_g\right| - \rho_{1z}\right)\left(Q_{G1g} - Q_{Gbg}^{lead}\right)S_b \\
& + \sum_{g\in Z} W_{2g}\left(C_L\left|\lambda_g\right| - \rho_{2z}\right)\left(Q_{G2g} - Q_{Gbg}^{lag}\right)S_b \\
& + \sum_{g\in Z}\left(W_{3fg} + W_{3rg}\right)\left(\left(C_L\left|\gamma_g\right| - \rho_{2z}\right)\left(Q_{G3g} - Q_{Gbg}^{lag}\right)S_b - 0.5\rho_{3z}\left(Q_{G3g} - Q_{GAg}\right)^2 S_b^2\right)
\end{aligned}
\tag{4.13}
$$

Where,

Q_{G1g}: Under-excitation reactive power of a generator g, in p.u.

Q_{G2g}: Over-excitation reactive power of a generator g, in p.u.

Q_{G3g}: Reactive power of a generator g operating in the opportunity region, in p.u.

S_b: Base MVA power (assumed here to be 100 MVA).

ρ_{0z}: Availability price component for reactive power in zone z, in \$/h.

ρ_{1z}: Under-excitation price component for reactive power in zone z, in \$/Mvarh.

ρ_{2z}: Over-excitation price component for reactive power in zone z, in \$/Mvarh.

ρ_{3z}: Lost opportunity price component for reactive power in zone z, in \$/Mvar^{2}h.

C_L: A cost parameter denoting the economical worth of increasing the system loadability, in \$/MWh.

λ_g: Lagrange multiplier associated with the nodal reactive power balance equation (4.3) at bus g, in MW/Mvar.

γ_g: Lagrange multiplier associated with the reactive power capability (4.4) of generator g, in MW/Mvar.

μ_g: Lagrange multiplier associated with the lower reactive power limit (4.5) of generator g, in MW/Mvar.

$Q_{Gbg}{}^{lead}$: Base leading reactive power of generator g, in p.u.

$Q_{Gbg}{}^{lag}$: Base lagging reactive power of generator g, in p.u.

Q_{GAg}: Maximum reactive power limit of generator g without reduction in real power generation, in p.u.

W_{1g}, W_{2g}: Binary variables associated with Regions I and II of reactive power operation for generator g, respectively.

W_{3rg}, W_{3fg}: Binary variables associated with armature and field limits of reactive power generation for generator g, respectively.

In (4.13), the subscript g denotes a generator in the system, while Z refers to the set of generators in zone z, considering that the system is divided into voltage control zones. The three reactive power generation components Q_{G1}, Q_{G2}, and Q_{G3} for a generator g correspond to the three regions of operations defined earlier in Section 2.3.1 and shown in Figure 2.1. Observe that, in (4.13), only reactive power generation beyond the mandatory region, *i.e.* between $Q_{Gb}{}^{lead}$ and $Q_{Gb}{}^{lag}$, is considered for financial compensation for the generators, as per the payment structure shown in Figure 3.4.

The constant C_L in (4.13) is a "loadability" cost parameter (in \$/MWh) denoting the economic worth of increasing the system loadability which represents, in this model, the expected worth of active power for the season of interest, and hence can be defined by the ISO using historical data and appropriate forecasting methods. In this thesis, C_L is assumed to be equal to 100 \$/MWh, which is a typical "high" price figure in the Ontario electricity market.

Observe that *SAF* (4.13) is based on the notion of a "marginal security benefit", *i.e.* the economic worth of reactive power support with respect to system security. For example, λ_g denotes the change in *LF* per Mvar change in reactive power demand at a bus g in zone z; since *LF* is dimensionless, λ_g is scaled by the total system MW demand, resulting in MW/Mvar units. Hence, the term $C_L|\lambda_g|$ represents the hourly marginal benefit to the ISO in \$/Mvarh, with respect to system security, from a change in reactive power demand at generation bus g in zone z. Similarly, the marginal benefit with respect to system security from a generator operating at its armature or field current limit or at the limit of its under-excitation mode are given by $C_L|\gamma_g|$ and $C_L|\mu_g|$ respectively. On the other hand, the four price components ρ_o, ρ_1, ρ_2, and ρ_3 represent the cost burden (total expected payment or TEP) of the ISO to provide reactive power support. Therefore, the proposed procurement algorithm is based on the following OPF model:

$$\text{max.} \quad SAF = \sum_z SAF_z \tag{4.14}$$

$$\text{s.t.} \quad P_{Gi} - P_{Di} = \sum_j V_i V_j Y_{ij} \cos(\theta_{ij} + \delta_j - \delta_i) \quad \forall i \tag{4.15}$$

$$Q_{Gi} - Q_{Di} = -\sum_j V_i V_j Y_{ij} \sin(\theta_{ij} + \delta_j - \delta_i) \quad \forall i \tag{4.16}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \qquad \forall i \tag{4.17}$$

$$\left|P_{ij}(V, \delta)\right| \le P_{ij}^{\max} \qquad \forall ij \tag{4.18}$$

$$\left.\begin{array}{l} W_{1g} Q_{Gg}^{\min} \le Q_{G1g} \le W_{1g} Q_{Gbg}^{lead} \\ W_{mg} Q_{Gbg}^{lead} \le Q_{Gmg} \le W_{mg} Q_{Gbg}^{lag} \\ W_{2g} Q_{Gbg}^{lag} \le Q_{G2g} \le W_{2g} Q_{GAg} \\ \left(W_{3fg} + W_{3rg}\right) Q_{GAg} \le Q_{G3g} \le \left(W_{3fg} + W_{3rg}\right) Q_{GBg} \end{array}\right\} \quad \forall g \tag{4.19}$$

$$W_{1g} + W_{mg} + W_{2g} + W_{3fg} + W_{3rg} = 1 \qquad \forall g \tag{4.20}$$

$$Q_{Gg} = Q_{G1g} + Q_{G2g} + Q_{G3g} + Q_{Gmg} \qquad \forall g \tag{4.21}$$

$$W_{1g} m_{1g} \le \rho_{1z} \qquad \forall\, g \in Z;\ \forall z \tag{4.22}$$

$$W_{2g} m_{2g} \le \rho_{2z} \qquad \forall\, g \in Z;\ \forall z \tag{4.23}$$

$$\left(W_{3fg} + W_{3rg}\right) m_{3g} \le \rho_{3z} \qquad \forall\, g \in Z;\ \forall z \tag{4.24}$$

$$\left(W_{1g} + W_{2g} + W_{3fg} + W_{3rg}\right) m_{og} \le \rho_{oz} \quad \forall\, g \in Z;\ \forall z \tag{4.25}$$

Where,

Q_{GBg}: Maximum allowable reactive power limit of generator g with reduction in real power generation, in p.u.

Q_{Gmg}: Mandatory reactive power of generator g, in p.u.

W_{mg}: Binary variable associated with mandatory reactive power production for generator g.

m_{og}: Availability price offer for generator g for operating in the over-excitation region, in \$/h.

m_{1g}: Cost of loss price offer for generator g for operating in the under-excitation region, in \$/Mvarh.

m_{2g}: Cost of loss price offer for generator g for operating in the over-excitation region, in \$/Mvarh.

m_{3g}: Opportunity price offer for generator g for operating in the opportunity region, in \$/Mvar^{2}h.

In this model, the three regions of reactive power production (including mandatory reactive power) identified from the generator's capability characteristic, shown in Figure 2.1, are introduced in (4.19)-(4.21), which guarantee that only one of these three regions will be selected at a time, for each generator. Therefore, the above model (4.14)-(4.25) is a non-convex MINLP problem because of the presence of binary variables associated with the reactive power regions of operation; this type of optimization problem requires special solvers and/or solution techniques. The approach used in this thesis for solving this optimization problem is discussed in detail in the following sub-section.

The constraints (4.22)-(4.25) ensure that the highest offered price for each of the four components of reactive power determines the four reactive power price components in each zone. According to (4.22)-(4.24), only the offers from contracted generators for each region of reactive power operation are considered when determining the corresponding price component. On the other hand, (4.25) ensures that the zonal availability price component (ρ_{oz}) will have a non-zero value if there is any contracted generator in that zone.

The solution of the above procurement model (4.14)-(4.25) yields the set of contracted generators as well as the four zonal uniform price components. This procurement procedure needs to be carried out for different cases (*e.g.* light load, heavy load, contingencies, etc.), in order to properly represent the various expected system operating conditions for the season of interest.

After the zonal uniform price components are determined for a variety of system operating conditions, the ISO signs contracts with the selected generators in which they receive an availability payment component. The generator will also receive a "usage" component, applicable in the real-time dispatch stage based on the actual reactive power supplied.

4.2.4 Generator Reactive Power Classification Algorithm

The proposed procurement model (4.14)-(4.25) captures both the technical, *i.e.* transmission security constraints, and economical, *i.e.* marginal benefits and payments, aspects of reactive power procurement. However, from the optimization point of view, this model represents a difficult optimization problem. The proposed model (4.14)-(4.25) would ideally require the presence of binary variables to select only one out of the three reactive power operating regions, and the corresponding price components, as per (4.22)-(4.25). One approach to solve the proposed model (4.14)-(4.25), then, is to formulate the problem as an explicit non-convex MINLP problem. However, the solution for this type of problem is very challenging because of the presence of both the binary variables and the non-convexities of the model itself [67], [68]. Solution techniques for this type of problem may get trapped at suboptimal solutions or even fail to yield a feasible point [69]. The number of available solvers for MINLP problems is still rather small, and according to [68], most of these solvers require a substantial amount of computational time for a small case study and might not yield an optimal solution for a large case study within many CPU hours. Moreover, most of the available MINLP solvers (such as DICOPT) have not been able to handle transmission capacity constraints, which are of great importance to represent system security. Hence, solving (4.14)-(4.25) using non-convex MINLP techniques is not the most appropriate choice, especially when realistic sized power systems are considered.

An iterative *Generator Reactive Power Classification (GRPC)* algorithm is proposed in this thesis to solve the proposed procurement model (4.14)-(4.25). The idea of the proposed GRPC is to re-formulate the problem so that it becomes a series of "standard" NLP sub-problems. The main objective is to choose only one region of reactive power operation to satisfy the conditions associated with the objective function *SAF* in (4.13) and the constraints (4.22)-(4.25). The proposed GRPC algorithm is depicted in Figure 4.1 and Figure 4.2.

The algorithm begins with initial allocations of reactive power to generators (Q_{Gg}) obtained from an initial feasibility analysis of the system (*e.g.* power flow solutions from given dispatch schemes). The initial region of reactive power operation of each generator can be identified according to the values of γ_g and the initial values of Q_{Gg}, as depicted in Figure 4.1. If Q_{Gg} is less than zero, the generator is operating in Region I; hence, Q_{G2} and Q_{G3} for this generator will be zero, and Q_{G1} will be a variable within its lower and upper limits. On the other hand, if Q_{Gg} is greater than zero and the value of γ_g is equal to zero, this implies that the generator is operating in Region II; hence, Q_{G1} and Q_{G3} for this generator will be zero, and Q_{G2} will be a variable within its lower and upper limits. Finally, Region III is selected if a generator has a value of γ_g not equal to zero.

Once the new set of Q_{Gg} is obtained, an update of the solution is required for each generator if Q_{Gg} hits the limits in any region, as shown in Figure 4.2. For example, if the reactive power of a generator *g* in Region II hits its lower limit, the problem is re-solved with this generator operating in Region I, and the new optimal value of *SAF* is calculated. If this value is higher than the old one, this generator is now in Region I; otherwise, the generator remains in Region II. Similarly, if a generator hits the upper limit of Region II, then the problem is re-solved with this generator operating in Region III. Note that the updating process is applied to only one generator at a time. The updating process is repeated for a certain number of iterations as shown in Figure 4.2. Observe that the updating process stops if no change in *SAF* is achieved after a complete iteration.

The proposed *GRPC* algorithm avoids the need for binary variables, thus keeping the optimization problem as an NLP; hence it can easily be applied to realistic power systems while incorporating all transmission system security constraints. The only issue is its dependence on the choice of the initial set of Q_G values and the order of the generators. This is also an issue with other non-convex MINLP solution approaches which are not concerned with finding a global

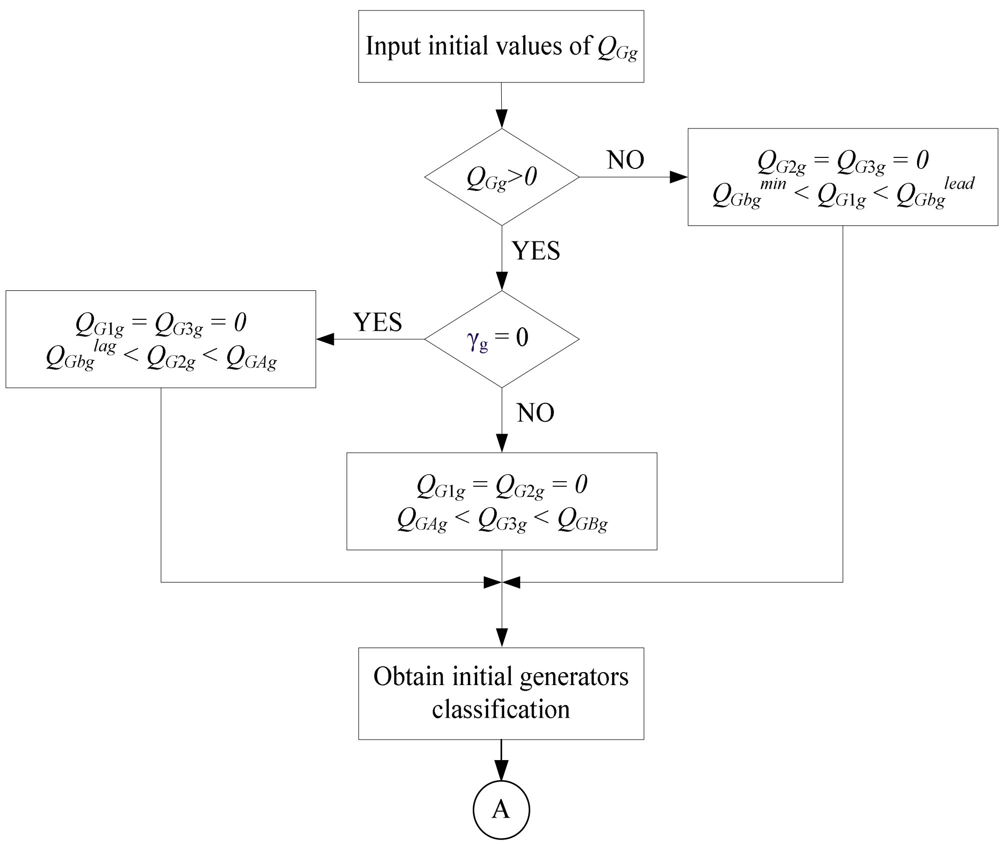

Figure 4.1 Identifying the region of Q_{Gg}.

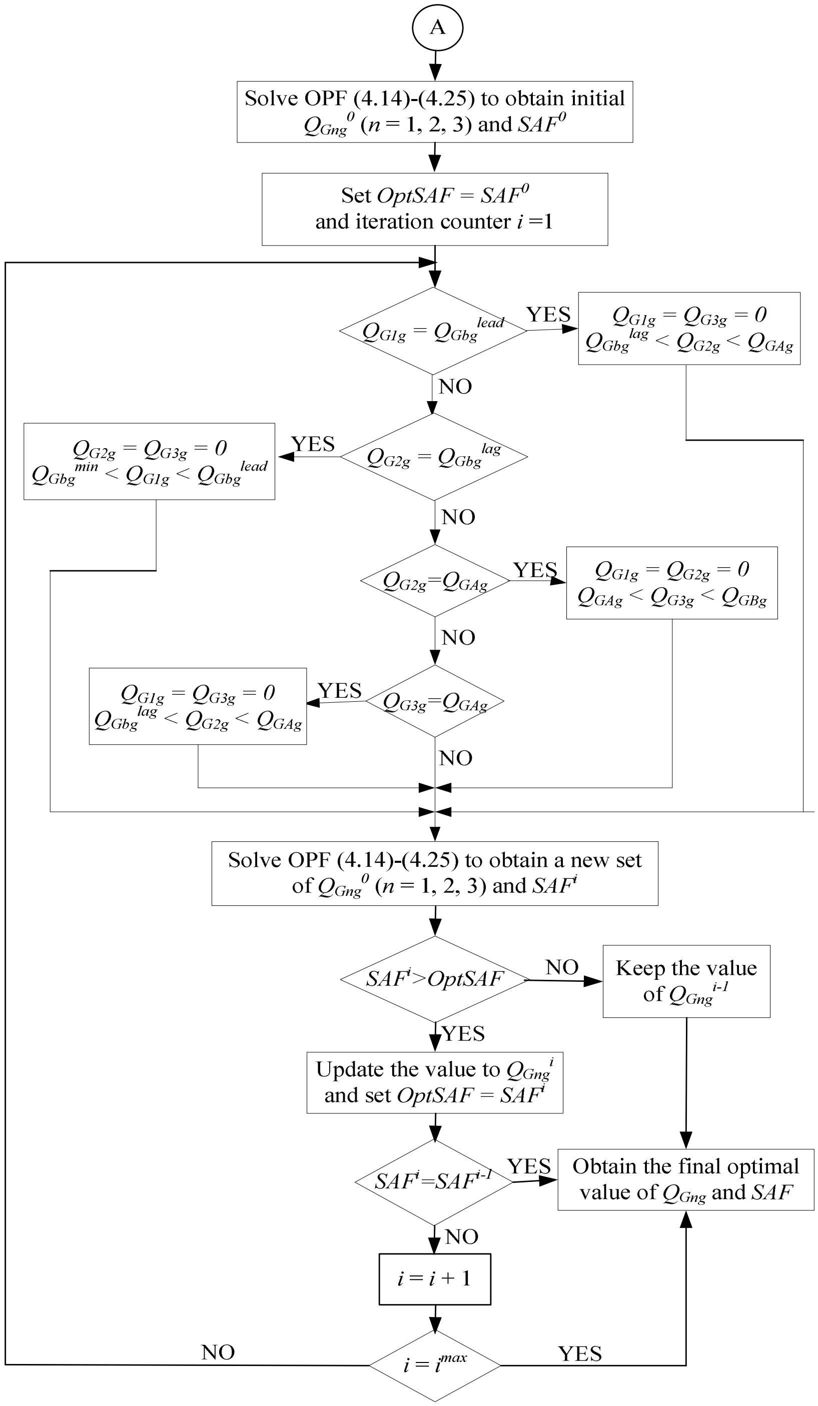

Figure 4.2 Updating the solution to (4.14)–(4.25).

optimum but with obtaining a practical feasible solution that meets typical ISO requirements. With regard to the choice of initial conditions, in this work, the ISO's "best practice" approach has been used as the initial solution point, wherein the initial values of Q_G are readily obtained from a power flow solution associated with the values of P_G obtained from the active power dispatch process. This initial solution point significantly improves the convergence and speed of the algorithm.

With regard to the order of generators, it is expected that the updating process will be affected by this order, and hence a random order of generators was adopted in this thesis. Almost the same set of contracted generators and zonal reactive power prices were obtained in each case, but a different number of iterations were required for convergence. However, this cannot be generalized, as the order in which the generators are updated might affect the final solution for other test systems. This is to be expected, as the optimization problem is non-convex, and thus only local optimal solutions can be guaranteed [70]. Note that the issue of obtaining local optima when solving non-convex NLP optimization problems applies to most practical optimization models in power systems (*e.g.* the ac-OPF problem); the same argument applies to the optimization model (4.1)-(4.12). Finally, it is important to highlight the fact that the proposed reactive power procurement model is to be carried out off-line and much ahead of real-time operation, and hence the computational burden is not a major issue in this case, regardless of the system size.

4.3 Implementation and Test Results

In this section the complete reactive power procurement model described in Section 4.2 is implemented and the details of the solution procedure are also discussed. The simulations are carried out using the CIGRE 32-bus test system (Figure 4.3) [71], since this allows for direct comparisons with the results available in the literature. The test system has 20 generators and a total demand of 10,940 MW. The system is split into three zones or voltage control areas as reported in [33]. Without any loss of generality, the power flow limits are considered to be dependent on the transmission voltage levels; thus, limits of 2000 MW for the 400 kV lines, 350 MW for 220 kV lines, and 250 MW for 130 kV lines are assumed. Generators are assumed to be eligible for financial compensation in all of the three regions of operations defined in Section 2.3.1, *i.e.* Q_{Gb}^{lead} and Q_{Gb}^{lag} in Figure 2.1 are assumed to be equal to zero for all generators without any loss of generality; this is in line with the IESO's approach for compensating reactive power service providers. The proposed optimization models, which are essentially NLP problems, are modeled in GAMS and solved using the MINOS solver [72].

4.3.1 Determining the Marginal Benefits of Reactive Power Services

As explained in Section 4.2.2, the marginal benefits of reactive power from each generator with respect to system security are represented by the three Lagrange multipliers λ, γ, and μ obtained by solving the *LF*-maximization model (4.1)-(4.12). A feasible solution, representing operating point 1 on the PV-curve, shown in Figure 2.2, is an input to the model; this initial point can be determined by the ISO based on classical economic dispatch procedures using seasonal demand forecast. The solution of the *LF*-maximization model yields the operating condition at the nose of the PV-curve, *i.e.* the point of voltage collapse. The model is first solved at normal operating conditions without considering any contingencies. Table 4.1 shows the initial operating point and the final solution, as well as the associated values of the three Lagrange multipliers λ, γ, and μ. The value of the loading factor (*LF*) in this case is 0.12 p.u., indicating a possible increase of 12% in the system loadability.

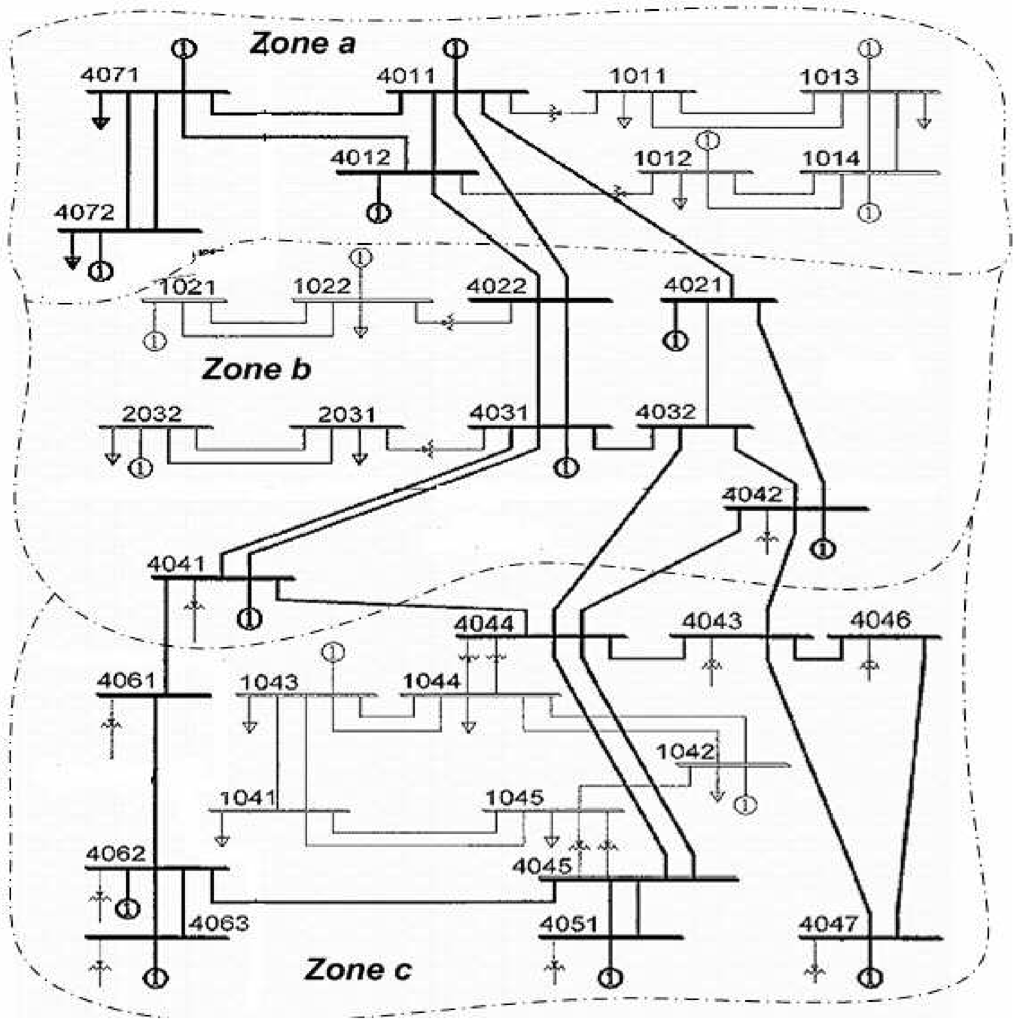

Figure 4.3 CIGRE 32-bus system split into three zones.

In Table 4.1, the values of λ, γ, and μ are zero for any generator when its Q_G lays within the limits (4.4) and (4.5). On the other hand, γ has a non-zero value for seven generators whose reactive power reach its upper limit; none of these generators are located in Zone *a*.

Table 4.1 Solution of the *LF*-maximization model (4.1)-(4.12) without contingency.

Zone	Bus	Input: operating point 1 in Figure 2.2		Solution: voltage collapse point in Figure 2.2				
		P_G (MW)	V (p.u.)	Q_G (MW)	V (p.u.)	Lagrange multipliers		
						λ	γ	μ
a	4072	1391.6	1.025	453	1.025	0	0	0
	4071	470	1.03	68.9	1.03	0	0	0
	4011	461	1.05	29.6	1.05	0	0	0
	4012	626.4	1.044	-103.5	1.044	0	0	0
	1013	492	0.931	-33.9	0.931	0	0	0
	1012	752	0.926	73.8	0.926	0	0	0
	1014	400	0.957	112.8	0.957	0	0	0
b	4021	282	1.1	102.4	1.094	-0.853	0.853	0
	4031	329	0.996	119.4	0.984	-0.737	0.737	0
	4042	658	0.983	238.8	0.959	-1.076	1.076	0
	4041	282	0.956	102.4	0.956	-0.431	0.431	0
	2032	799	0.912	100.4	0.912	0	0	0
	1022	235	0.952	85.3	0.926	-0.729	0. 729	0
	1021	478.8	1.017	144.7	1.017	0	0	0
c	4062	564	0.954	131.6	0.954	0	0	0
	4063	1128	0.943	202.6	0.943	0	0	0
	4051	658	0.922	238.8	0.872	-1.811	1.811	0
	4047	800	0.947	287.4	0.947	0	0	0
	1043	188	0.937	68.2	0.816	-2.503	2.503	0
	1042	376	0.9	33.2	0.9	0	0	0

Observe that γ for all of the seven generators has a positive sign, indicating an increase in *LF* for any increase in the reactive power capability of the generator. The corresponding value of λ in this case will be equal in magnitude but with the opposite sign, indicating a decrease in *LF* with any increase in reactive power demand at this generator bus. Since none of the generators is operating at its lower limit of reactive power, the value of μ is zero for all of the 20 generators. It can also be seen that there is no longer any control over bus voltages when a generator reaches its reactive power limits, *i.e.* these voltages are lower than their corresponding initial values.

The *LF*-maximization model (4.1)-(4.12) is solved for different contingencies following the N-1 contingency criterion, with one transmission line being taken out at a time and the model is solved to find the corresponding *LF* value. The values of *LF* for the five most critical contingencies are illustrated in Figure 4.4. The minimal value of *LF* results when the transmission line connecting Buses 4031 and 4032 is taken out. Hence, this contingency is referred to as the "worst contingency", and the associated Lagrange multipliers in this case represent the marginal benefits of reactive power from each generator with respect to the system security at the worst contingency.

The solution of the *LF*-maximization model (4.1)-(4.12) without the transmission line connecting Buses 4031 and 4032, *i.e.* at the worst contingency, is given in Table 4.2. The initial operating point is the same as that for the no-contingency case; however, the solution and hence the associated Lagrange multipliers are different in this case, since the power flow in the system changes as a result of the contingency. Generators at Buses 4021, 4031, 4041, 1022, and 1043 are still operating at the upper limits of their reactive power but with a different impact on system security, represented by the values of γ and λ at the corresponding bus, compared to that associated with normal operating condition without contingencies (Table 4.1). Two generators, 4042 and 4047, are now required to produce zero reactive power, which is their lower limit; hence, μ has a non-zero value at these two buses, denoting the sensitivity of *LF* to the change in the lower limit of reactive power for these generators.

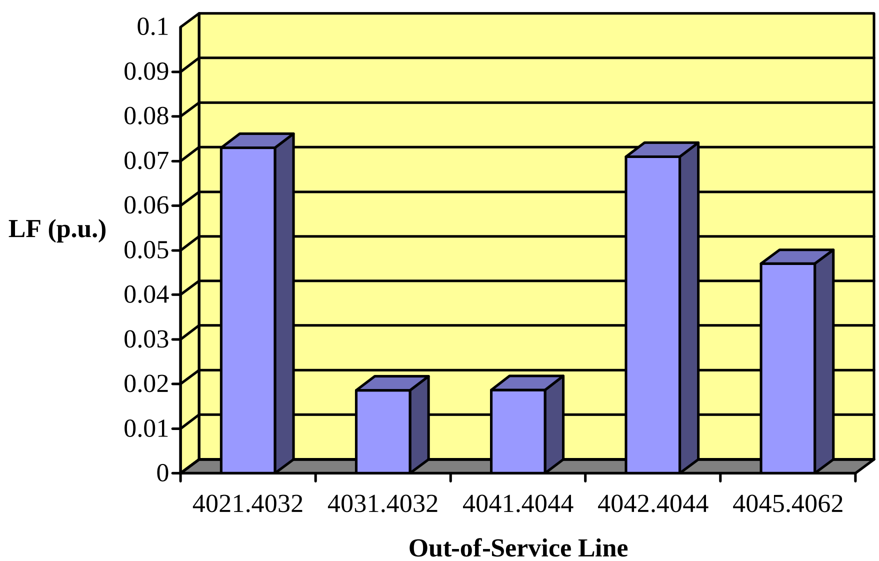

Figure 4.4 *LF* values for the most critical contingencies.

A comparison between the magnitudes of λ associated with the *LF*-maximization model without contingencies and at the worst contingency is illustrated in Figure 4.5. It can be seen from the chart that the magnitude of λ has increased at Generator buses 4031 and 4041as a result of the voltage drop at these buses following the contingency. This is because the impact of reactive power from these generators on system loadability is now higher with this drop in the voltage

Table 4.2 Solution of the *LF*-maximization model (4.1)-(4.12) at the worst contingency.

Zone	Bus	Input: operating point 1 in Figure 2.2		Solution: voltage collapse point in Figure 2.2				
		P_G (MW)	V (p.u.)	Q_G (MW)	V (p.u.)	Lagrange multipliers		
						λ	γ	μ
a	4072	1391.6	1.025	407.1	1.025	0	0	0
	4071	470	1.03	54.5	1.03	0	0	0
	4011	461	1.05	239	1.05	0	0	0
	4012	626.4	1.044	-117.7	1.044	0	0	0
	1013	492	0.931	-41	0.931	0	0	0
	1012	752	0.926	52.6	0.926	0	0	0
	1014	400	0.957	112.6	0.957	0	0	0
b	4021	282	1.1	102.4	1.1	-0.033	0.033	0
	4031	329	0.996	119.4	0.929	-0.903	0. 903	0
	4042	658	0.983	0	1.004	-1.404	0	1. 404
	4041	282	0.956	102.4	0.894	-1.310	1.310	0
	2032	799	0.912	168.9	0.912	0	0	0
	1022	235	0.952	85.3	0.926	-0.558	0. 558	0
	1021	478.8	1.017	130.8	1.017	0	0	0
c	4062	564	0.954	167.6	0.954	0	0	0
	4063	1128	0.943	175.9	0.943	0	0	0
	4051	658	0.922	167.9	0.922	0	0	0
	4047	800	0.947	0	0.953	-1.774	0	1. 774
	1043	188	0.937	68.2	0.911	-1.862	1.862	0
	1042	376	0.9	-23.3	0.9	0	0	0

levels. On the other hand, the impact of reactive power from the generators at buses 4021, 1022, and 1043, represented by the magnitude of λ at these buses, has decreased due to the increase in the voltage levels at these buses following the contingency. The value of λ for the generator at Bus 4051 has been reduced to zero, since it is no longer required to operate at its full reactive power capacity under the new conditions associated with the contingency. As a result of the contingency and the associated changes in the power flow throughout the system, the two generators at Buses 4042 and 4047 have reached their minimum reactive power limits following the increase in the voltage levels at these two buses; hence, λ in this case will be accompanied by μ, and not γ, and its magnitude represents the impact of reactive power from these two generators on the system loadability.

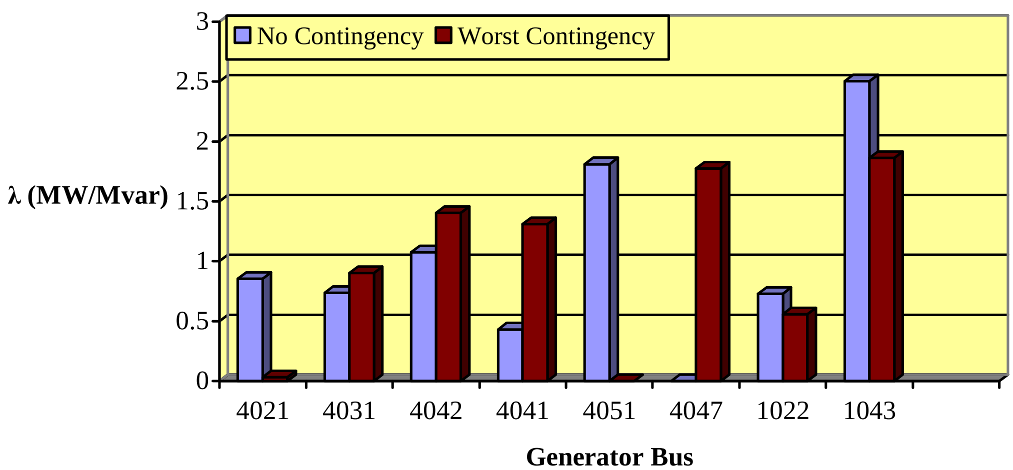

Figure 4.5 Comparison between the value of λ at no contingency and at the worst contingency.

4.3.2 Determining the Optimal Set of Contracted Generator

Once the reactive power marginal benefits have been determined, the next step is to obtain the optimal set of reactive power providers using the *GRPC* algorithm proposed in Section 4.2.4 to maximize *SAF*. The initial regions of reactive power operation are first identified using initial values of Q_{Gg} together with the value of γ_g, as depicted in the flow chart given in Figure 4.1. This initial classification of the generators into three operating regions is then used to solve the OPF model (4.14)-(4.25) to obtain the first solution set, which is then updated following the algorithm depicted in Figure 4.2. The updating process yields the final solution that includes the required set of generators to be contracted for reactive power service provision and the zonal uniform reactive power price components.

The reactive power procurement market model is examined considering the following two cases:

- Case I: Unstressed condition, with seasonal "low" load and no contingencies. The Lagrange multipliers λ_g, γ_g, and μ_g shown in Table 4.1 are used here.
- Case II: Stressed condition, with increased load with respect to Case I and considering contingencies. The Lagrange multipliers λ_g, γ_g, and μ_g are calculated for the worst contingency, as explained in Section 4.2.2, in this case.

For brevity of presentation, only two "extreme" loading cases are considered here to demonstrate the different procurement plans obtained from the proposed optimization model. However, in practice, *multiple* unstressed and stressed conditions should be studied by the ISO to arrive at its own set (or sets) of contracted generators. The ISO should then decide, based on its policies, directives, and market structure whether to contract the universal set of generators determined from all scenarios, only those associated with the worst contingencies, or only those associated with peak load conditions.

Case I

A typical low demand scenario is considered in this case, providing the ISO with a condition where generators are expected to be operating in under-excited mode. Applying the reactive power procurement procedures explained in Section 4.2, the initial value obtained for *SAF* was 1,766 \$/h. The solution was then improved using the GRPC algorithm depicted in Figure 4.2, where two updates were required in the first iteration, increasing the value of *SAF* to 1,969 \$/h. This value remained the same for several iterations, indicating that this is the best local solution that could be reached.

The final solution depicted in Table 4.3 provides the list of generators contracted by the ISO, and the zone-wise uniform reactive power price components for this case of low demand. As it can be observed, fifteen generators are required for reactive power service provisions in this case. Generators with the negative values of Q_G are operating in Region I (eight of the fifteen in this case), which represents the under-excited mode of operation. None of the generators are contracted to operate in Region III, and hence none will be contracted to receive the opportunity payment component. For the other three price components, the highest reactive power offer from contracted generators within a zone is selected as the zonal uniform price. For example, in Zone *a* only two generators, 4012 and 1012, are contracted to operate in Region I; and hence the under-excitation price (ρ_1) is 0.59 \$/Mvarh, which is the higher of the two generators' offered prices for this component, as shown in Table 4.3.

Table 4.3 Final solution for unstressed condition (Case I).

Zone	Bus	Price offers from each generator				Q_G	Zonal uniform prices			
		m_0	m_1	m_2	m_3		ρ_o	ρ_1	ρ_2	ρ_3
a	4072	0.58	0.57	0.57	0.21	238.3	0.78	0.59	0.74	NC
	4071	0.70	0.84	0.84	0.33	NC				
	4011	0.78	0.74	0.74	0.29	310.6				
	4012	0.61	0.57	0.57	0.21	-160				
	1013	0.40	0.40	0.40	0.18	89.3				
	1012	0.59	0.59	0.59	0.35	-80				
	1014	0.86	0.88	0.88	0.50	NC				
b	4021	0.80	0.91	0.91	0.31	-30	0.92	0.91	0.86	NC
	4031	0.92	0.90	0.90	0.36	-40				
	4042	0.68	0.69	0.69	0.23	NC				
	4041	0.51	0.56	0.56	0.24	-200				
	2032	0.87	0.86	0.86	0.29	168.9				
	1022	0.75	0.68	0.68	0.23	-25				
	1021	0.54	0.55	0.55	0.20	135.1				
c	4062	0.85	0.93	0.93	0.33	NC	0.85	0.53	0.81	NC
	4063	0.73	0.66	0.66	0.39	54.4				
	4051	0.85	0.81	0.81	0.26	24				
	4047	0.62	0.60	0.60	0.23	NC				
	1043	0.48	0.49	0.49	0.20	-20				
	1042	0.58	0.53	0.53	0.24	-40				
Total Marginal Benefit with respect to system security (TMB)							4,914 $/h			
Total Expected Payment by the ISO (TEP)							2,945 $/h			
Objective Function, *SAF* (*SAF* = TMB – TEP)							1,969 $/h			

NC = Not Contracted

Case II

There will be instances when the power system is heavily stressed due to contingencies and/or high demand conditions. In order to ensure a secure operation of the system in this case, reactive power provisions should be determined considering worst case scenarios, such as the case presented and discussed here.

In Section 4.3.1, the values of the three Lagrange multipliers λ_g, γ_g, and μ_g obtained by solving the OPF (4.1)-(4.12) for the worst contingency were reported (Table 4.2). These values are then used to solve the OPF model (4.14)-(4.25), obtaining an initial value of *SAF* of 23,486 \$/h. The solution was then updated using the GRPC algorithm, with four updates in the first iteration increasing the value of *SAF* to 39,984 \$/h. In the second iteration, three more updates for the solution took place improving the value of *SAF* to 55,403 \$/h. This value remained the same for several iterations indicating that no further improvements were possible and the best local solution was reached.

The final solution for Case II is given in Table 4.4, where twelve generators are contracted for reactive power service provision; four of these (generators shown in bold) are expected to operate in Region III. However, as none of these four generators are located in Zone *a*, no generators in this zone are contracted to receive an opportunity payment component. Observe also that three of these four generators are located in Zone *b*, where the worst contingency took place.

Comparing the results of Case I and Case II, the following can be observed:

- As the system is stressed, the reactive power requirements from generators also increase resulting in more generators operating in Region III (4 generators in Case II versus none in Case I).
- The final value of the objective function *SAF* in the stressed case is much

Table 4.4 Final solution for stressed condition (Case II).

Zone	Bus	Price offers from each generator				Q_G	Zonal uniform prices			
		m_0	m_1	m_2	m_3		ρ_o	ρ_1	ρ_2	ρ_3
a	4072	0.58	0.57	0.57	0.21	233.9	0.78	0.74	0.57	NC
	4071	0.70	0.84	0.84	0.33	NC				
	4011	0.78	0.74	0.74	0.29	-77.3				
	4012	0.61	0.57	0.57	0.21	NC				
	1013	0.40	0.40	0.40	0.18	NC				
	1012	0.59	0.59	0.59	0.35	NC				
	1014	0.86	0.88	0.88	0.50	NC				
b	4021	0.80	0.91	0.91	0.31	-30	0.92	0.91	0.90	0.36
	4031	**0.92**	**0.90**	**0.90**	**0.36**	**191.1**				
	4042	0.68	0.69	0.69	0.23	NC				
	4041	**0.51**	**0.56**	**0.56**	**0.24**	**163.8**				
	2032	0.87	0.86	0.86	0.29	104.5				
	1022	**0.75**	**0.68**	**0.68**	**0.23**	**136.5**				
	1021	0.54	0.55	0.55	0.20	151.5				
c	4062	0.85	0.93	0.93	0.33	NC	0.85	0.53	0.81	0.20
	4063	0.73	0.66	0.66	0.39	211.2				
	4051	0.85	0.81	0.81	0.26	182.4				
	4047	0.62	0.60	0.60	0.23	NC				
	1043	**0.48**	**0.49**	**0.49**	**0.20**	**109.2**				
	1042	0.58	0.53	0.53	0.24	-0.1				
Total Marginal Benefit with respect to system security (TMB)							58,709 \$/h			
Total Expected Payment by the ISO (TEP)							3,306 \$/h			
Objective Function, *SAF* (*SAF* = TMB – TEP)							55,403 \$/h			

NC = Not Contracted

higher than the unstressed case. To explain this, notice that *SAF* has two components, namely the Total Marginal Benefit (TMB) with respect to system security, and the Total Expected Payment (TEP) by the ISO. It can be seen from Tables 4.3 and 4.4 that the TEP only increased by 361 \$/h, while the TMB increased significantly from 4,914 \$/h to 58,709 \$/h. The TMB "jump" is due to the fact that the benefit to the system from reactive power support is much more significant when the system is heavily stressed. The more the system is stressed, the higher is its need for reactive power support to maintain system security.

- For the two cases considered, no generator located in Zone *a* is expected to receive an opportunity payment, since none of the generators from this zone is contracted to operate in Region III. This was expected, since the values of the Lagrange multipliers λ_g, γ_g, and μ_g obtained from the *LF* maximization analysis for both Cases I and II are all zeros for all generators in this zone (Tables 4.1 and 4.2). This indicates that the reactive power from generators in this zone does not have any effect on system security, and hence the procurement model does not seek much reactive power from these units.

- From an optimization point of view, both models have the same number of variables and equations, as indicated by the computational statistics depicted in Table 4.5. Observe that Case II requires about two and a half times the CPU time of Case I to arrive at the solution, since the *SAF*-maximization model (4.14)-(4.25) is solved sixteen times for the latter compared to only eight times for the former. This is to be expected, as more generators are pushed to operate in Regions II and III in Case II due to the higher loading conditions, as illustrated on Tables 4.3 and 4.4; hence more solution updates are required in this case.

Table 4.5 *SAF*-maximization model (4.14)-(4.25) statistics.

	Case I Unstressed condition	Case II Stressed condition
No. of variables	10,323	10,323
No. of equations	11,950	11,950
No. of *SAF-maximization* models solved	8	16
Total solution (CPU) time (sec)	14.35	35.56

4.3.3 Comparison of Zonal Uniform Pricing with System-Wide Uniform Pricing

In order to emphasize the advantages of the zonal uniform pricing scheme over a system-wide uniform price, the two cases discussed earlier are solved considering a uniform price for the four reactive price components, *i.e.* the whole system is treated as a single zone. The resulting prices for the two case studies are shown in Table 4.6.

Comparing the results in Table 4.6 with those obtained earlier in Tables 4.3 and 4.4, it can be observed that there is a reduction in the value of the *SAF* for both cases when a system-wide uniform reactive power pricing scheme is adopted (*e.g.* the *SAF* with zonal uniform pricing is 1,969 $/h in Case I, while it is 1,649 $/h with system-wide uniform pricing). In Case II, this reduction is not very significant, as the value of Q_G in both pricing approaches remains the same, and hence the marginal benefit component in *SAF*, which is high in Case II, does not change. However, the expected payments, which are functions of price components, are affected; thus, the TEP for the uniform price approach compared to the zonal price approach increases 11% for the unstressed case and 17% for the stressed case. This shows that using a zonal pricing mechanism not only reduces the risk of market power, but it also reduces the payment burden on the ISO.

Table 4.6 Results for a system-wide uniform pricing mechanism.

Price component	Case I	Case II
Availability Price	0.92	0.92
Under-excitation Price	0.91	0.91
Over-excitation Price	0.86	0.90
Opportunity Price	0	0.36
SAF	1,649 $/h	54,849 $/h
TEP	3,265 $/h	3,860 $/h

4.4 Summary

In this chapter, a novel seasonal procurement scheme for reactive power ancillary services is proposed and discussed. The procurement scheme is based on a two-step optimization process. The first step consists of determining the marginal benefits of reactive power with respect to system security, which are then used in the second step to maximize a reactive power societal advantage function, considering offers from service providers. Reactive power is procured from generators on a zonal basis. The solution of the proposed procurement model yields the optimal set of contracted generators in each zone and the corresponding zonal reactive power price components that would form the basis of contractual agreements for seasonal reactive power provision.

A computationally efficient *GRPC* algorithm is developed to solve the proposed reactive power procurement model. The proposed algorithm avoids the need for binary variables, thus keeping the optimization problem as an NLP; hence, it can easily be applied to realistic power systems while incorporating all transmission system security constraints.

The CIGRE 32-bus system is used as a sample system to demonstrate the feasibility of the proposed procurement scheme and the proposed solution technique. Two extreme case studies, representing unstressed and stressed operating conditions, are considered. The results show how reactive power requirements from generators increase under stressed operating conditions, resulting in four generators operating in the opportunity region compared to none in the unstressed condition. The results also demonstrate that the benefit of reactive power support is much more significant to the system when it is heavily stressed, illustrating the importance of reactive power in maintaining a secure operation of the power system. A comparison between a zonal reactive power pricing approach and a system-wide uniform pricing approach is carried out; the results of this comparison show how zonal pricing can reduce the payment burden on the ISO.

The next chapter discusses the development of reactive power dispatch procedures, based on the reactive power market framework proposed in Chapter 3 and the optimally procured set of reactive power contracts, and their corresponding price components, obtained from the proposed procurement model presented in this chapter.

Chapter 5
Redefining the Reactive Power Dispatch Problem[1]

5.1 Introduction

In Chapter 4, an optimal reactive power service procurement scheme is presented, which represents the first level of the two-settlement framework for reactive power ancillary service provision proposed earlier in Chapter 3. The solution of the long-term procurement model yields a set of contracted generators and four reactive power price components, namely the availability, under- and over-excitation, and opportunity components. The second level of the proposed framework, which determines the reactive power dispatch levels in "real-time", is the main focus of the research work presented in this chapter.

A novel reactive power dispatch framework is proposed in this chapter, which redefines the problem to suit the ISO requirements in the context of competitive electricity markets. The proposed model seeks to minimize the total payments associated with reactive power dispatched from service providers. To adhere to existing FERC regulations [1], only reactive power support from generators is considered as an ancillary service eligible for financial compensation in the work presented in this thesis.

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[1]Preliminarily findings of this chapter have been published in the *proceedings of the 2007 IEEE-PES General Meeting* in Tampa, Florida [73], and the complete work presented has been submitted to the *IEEE Transactions on Power Systems* [74].

5.2 The Proposed Reactive Power Dispatch Model

Based on the proposed reactive power dispatch scheme depicted in Figure 3.3, the ISO should be able to execute an optimal dispatch program to arrive at the required amount of reactive power in the real-time operation stage. A reactive power dispatch model is proposed here, taking into account both the economic and technical issues associated with service provisions in a competitive electricity market.

The proposed model seeks to minimize the following objective function *J*, which represents the total payments associated with reactive power dispatch:

$$
\begin{aligned}
J &= J_1 + J_2 + J_3 \\
J_1 &= \sum_g \begin{pmatrix} \rho_{0g} + W_{2g}\rho_{2g}\left(Q_{G2g} - Q_{Gbg}^{lag}\right)S_b - W_{1g}\rho_{1g}\left(Q_{G1g} - Q_{Gbg}^{lead}\right)S_b \\ + \rho_{2g}\left(W_{3fg} + W_{3rg}\right)\left(Q_{G3g} - Q_{Gbg}^{lag}\right)S_b \\ + 0.5\rho_{3g}\left(W_{3fg} + W_{3rg}\right)\left(Q_{G3g} - Q_{GA}\right)^2 S_b^2 \end{pmatrix} \\
J_2 &= \sum_i \left(\rho_{B1}P_{B1i}S_b + \rho_{B2}P_{B2i}S_b\right) \\
J_3 &= \rho_{MC}\left(P_L - P_{Lo}\right)S_b
\end{aligned}
\tag{5.1}
$$

Where,

Q_{G1g}: Under-excitation reactive power of generator *g*, in p.u.

Q_{G2g}: Over-excitation reactive power of generator *g*, in p.u.

Q_{G3g}: Reactive power of generator *g* operating in the opportunity region, in p.u.

S_b: Base MVA power (assumed here to be 100 MVA).

ρ_{0g}: Availability price component for reactive power for generator *g*, in $/h.

ρ_{1g}: Under-excitation price component for reactive power for generator *g*, in $/Mvarh.

ρ_{2g}: Over-excitation price component for reactive power for generator *g*, in $/Mvarh.

ρ_{3g}: Lost opportunity price component for reactive power for generator *g*, in $/Mvar^{2}h.

ρ_{B1}: Price of upward balance services P_B, in $/MWh.

ρ_{B2}: Price of downward balance services P_B, in $/MWh.

P_{B1i}: Upward balance service at bus *i*, in p.u.

P_{B2i}: Downward balance service at bus *i*, in p.u.

ρ_{MC}: Energy market clearing price, in $/MWh.

P_L: Total system losses, in p.u.

P_{Lo}: Pre-determined total system losses from energy market clearing, in p.u.

Q_{Gbg}^{lead}: Base leading reactive power of generator *g*, in p.u.

Q_{Gbg}^{lag}: Base lagging reactive power of generator *g*, in p.u.

Q_{GAg}: Maximum reactive power limit of generator *g* without reduction in real power generation, in p.u.

W_{1g}, W_{2g}: Binary variables associated with Regions I and II of reactive power operation for generator *g*, respectively.

W_{3rg}, W_{3fg}: Binary variables associated with armature and field limits on reactive power generation for generator g, respectively.

These payments can be divided into the following three main categories:

- Payment J_1 is associated with reactive power provided from generators. This component is a function of the predetermined price components associated with each region of operation (ρ_0, ρ_1, ρ_2, and ρ_3), as explained in Section 3.4.3. Accordingly, payment components are determined for Q_{G1}, Q_{G2}, and Q_{G3} corresponding to the operation of the generator in Region I, II, or III, respectively, plus an availability payment.
- Payment J_2 is associated with the energy balance service that is required to compensate for rescheduling of real power, *i.e.* the effect of reactive power dispatch on real power dispatch. This component will appear only when some generators are required to supply reactive power in Region III, where they need to reduce their real power generation in order to meet the system reactive power requirement. Consequently, there is a need to reschedule their real power (ΔP_G), and a balance service (P_B) is required at certain buses to compensate for real power deviations from already dispatched values (P_{Go}). The energy balance services from available providers might be an upward or downward service, *i.e.* P_{B1} and P_{B2}, respectively; the corresponding prices ρ_{B1} and ρ_{B2} are assumed to be known in advance from an energy balance market [75].
- Payment/credit J_3 is associated with the change in the total system losses due to reactive power dispatch and the rescheduling of real power generation. This component is positive (payment) when the total losses

calculated from the proposed reactive power dispatch solution (P_L) are higher than the losses from real power market clearing dispatch (P_{Lo}). If the proposed reactive power dispatch model yields lower losses than P_{Lo}, a loss credit (negative value) is in effect. The value of the payment or credit can be calculated by multiplying this difference (P_L - P_{Lo}) by the market clearing price (ρ_{MC}).

The proposed reactive power dispatch model is then formulated as follows:

$$\max.\ J \tag{5.2}$$

$$s.t.\quad P_{Goi} - \Delta P_{Gi} + P_{B1i} - P_{B2i} - P_{Di} = \sum_j V_i V_j Y_{ij} \cos\left(\theta_{ij} + \delta_j - \delta_i\right) \quad \forall i \tag{5.3}$$

$$Q_{Gi} - Q_{Di} = -\sum_j V_i V_j Y_{ij} \sin\left(\theta_{ij} + \delta_j - \delta_i\right) \quad \forall i \tag{5.4}$$

$$V_i^{\min} \le V_i \le V_i^{\max} \qquad \forall i \tag{5.5}$$

$$\left|P_{ij}(V,\delta)\right| \le P_{ij}^{\max} \qquad \forall i, j \tag{5.6}$$

$$\left.\begin{array}{l} W_{1g} Q_{Gg}^{\min} \le Q_{G1g} \le W_{1g} Q_{Gbg}^{lead} \\ W_{mg} Q_{Gbg}^{lead} \le Q_{Gmg} \le W_{mg} Q_{Gbg}^{lag} \\ W_{2g} Q_{Gbg}^{lag} \le Q_{G2g} \le W_{2g} Q_{GAg} \\ \left(W_{3fg} + W_{3rg}\right) Q_{GAg} \le Q_{G3g} \le \left(W_{3fg} + W_{3rg}\right) Q_{GBg} \end{array}\right\} \quad \forall g \tag{5.7}$$

$$W_{1g} + W_{mg} + W_{2g} + W_{3fg} + W_{3rg} = 1 \qquad \forall g \tag{5.8}$$

$$Q_{Gg} = Q_{G1g} + Q_{G2g} + Q_{G3g} + Q_{Gmg} \qquad \forall g \tag{5.9}$$

$$P_{Gxg} = W_{3fg}\sqrt{\left(\frac{V_{tg}E_{fg}}{X_{sg}}\right)^2 - \left(Q_{Gg} + \frac{V_{tg}^2}{X_{sg}}\right)^2} + W_{3rg}\sqrt{(V_{tg}I_{ag})^2 - Q_{Gg}^2} + \left(W_{1g} + W_{2g}\right)P_{Gog} \tag{5.10}$$

$$P_{Gog} - P_{Gxg} = \Delta P_{Gg} \tag{5.11}$$

$$\Delta P_{Gg} \leq c_g P_{Gog} \tag{5.12}$$

$$P_{B1i} \leq P_{B1i}^{\max} \tag{5.13}$$

$$P_{B2i} \leq P_{B2i}^{\max} \tag{5.14}$$

$$\sum_g Q_{Gg} \leq K_z \sum_g Q_{GAg} \qquad \forall g \in Z, \forall z \tag{5.15}$$

$$P_L = 0.5\sum_{i,j}\left(G_{ij}\left(V_i^2 + V_j^2 - 2V_iV_j\cos\left(\delta_j - \delta_i\right)\right)\right) \tag{5.16}$$

Where,

J: Total payment associated with the reactive power dispatch in \$/h.

P_{Goi}: Market clearing pre-determined active power dispatch at bus *i*, in p.u.

ΔP_{Gi}: Reduction in active power at bus *i* due to increase in reactive power beyond heating limits, in p.u.

P_{Di}: Active power demand at bus *i*, in p.u.

V_i: Voltage magnitude at bus *i*, in p.u.

δ_i: Voltage angle at bus *i*, in radians.

Y_{ij}: Magnitude of the *ij* entry of the admittance (Y) matrix, in p.u.

θ_{ij}: Angle of the *ij* entry of the admittance (Y) matrix, in radians.

Q_{Gi}: Reactive power generation at bus *i*, in p.u.

Q_{Di}: Reactive power demand at bus *i*, in p.u.

V_i^{min}: Minimum allowable voltage at bus *i*, in p.u.

V_i^{max}: Maximum allowable voltage at bus *i*, in p.u.

P_{ij}: Power flow from bus *i* to bus *j*, in p.u.

P_{ij}^{max}: Maximum allowable power flow from bus *i* to bus *j*, in p.u.

Q_{Gg}^{min}: Minimum reactive power limit of generator *g*, in p.u.

Q_{GBg}: Maximum allowable reactive power limit of generator *g* with reduction in real power generation, in p.u.

Q_{Gmg}: Mandatory reactive power of generator *g*, in p.u.

W_{mg}: Binary variable associated with mandatory reactive power production for generator *g*.

V_{tg}: Terminal voltage of generator *g* at which its capability curves are calculated, in p.u. (assumed here to be 1.05 p.u.)

I_{ag}: Rated armature current of generator *g* at which its capability curves are calculated, in p.u.

E_{fg}: Excitation voltage of generator *g*, in p.u.

X_{sg}: Synchronous reactance of generator *g*, in p.u.

P_{Gxg}: New active power dispatch for generator *g*, in p.u.

c_i: Maximum allowed level of active power reduction at bus *i*.

P_{B1i}^{max}: Maximum upward balance service at bus i, in p.u.

P_{B2i}^{max}: Maximum downward balance service at bus i, in p.u.

Z: The set of generators in zone z.

K_z: A fractional cap on reactive power usage in zone z.

G_{ij}: Conductance of the line connecting buses i and j, in p.u.

In the above model, equations (5.3) and (5.4) are the active and reactive power balance equations; observe that the nodal active power equation (5.3) is appropriately modified to include ΔP_G, P_{B1} and P_{B2}. System security limits, including bus voltage limits and line flow limits, are given by (5.5) and (5.6), respectively. The three regions of reactive power production identified from the generator's capability curves (Figure 2.1) are given by the constraints in (5.7). It is to be noted that the constraints (5.7)-(5.9) guarantee that of the three regions Q_{G1}, Q_{G2}, and Q_{G3}, only one is selected at a time for each generator.

The effect of reactive power dispatch on real power dispatch is included in the model by calculating the required reduction in real power dispatch (ΔP_G) using (5.10)-(5.12). Observe that ΔP_G will have a non-zero value only if the generator is operating in Region III, *i.e.* if the generator reaches its field limit ($P_{GA} < P_{GR}$) or armature limit ($P_{GA} > P_{GR}$); otherwise, P_{Gx} in (5.10) will be equal to P_{Go} and hence, according to (5.11), ΔP_G will be zero. In order to minimize the effect on real power dispatch, a "cap" on the reduction in real power is imposed, *e.g.* between 5 to 15%, as per constraint (5.12).

The ISO will require some balancing mechanism to compensate for the reschedule in real power and for changes in system losses as a result of the reactive power dispatch. In this work, it is assumed that such a market mechanism, *i.e.*

upward and downward balance services, is already in place as an ancillary service. This is typically the case in most markets, and thus can be used by the ISO within the proposed reactive power dispatch framework. A limit on the maximum upward and downward balance service available at each system bus is imposed by the constraints (5.13) and (5.14), respectively.

Based on typical voltage control approaches, constraints (5.15) are included to ensure sufficient reactive power reserves within a voltage control zone. The amount of reactive power reserves in zone z is given by $(1 - K_z)$; for example, $K_z = 0.9$ corresponds to a 90% cap on utilization and dispatch of available reactive power capacity, implying a 10% reactive power reserve in the zone. Observe that the value of Q_{GA} instead of Q_{GB} was used to define the zonal reactive power reserve in order to be more conservative, since the extra reactive power coming from a possible real power re-dispatch is unknown at the start of the dispatch process. Finally, the total system losses P_L in (5.1) are calculated using (5.16).

It is important to highlight the fact that the proposed payment function J given in (5.1) is of a generic nature, and it can be modified to fit other payment schemes adopted by system operators. For example, it was mentioned earlier that both the IESO in Ontario and the ISO New England compensate the generators operating at the opportunity region by directly paying them a lost opportunity component at the market clearing price. To consider such cases, the objective function can be readily modified as follows to represent such a payment mechanism:

$$\begin{aligned} J^* = &\sum_g \begin{pmatrix} \rho_{0g} + W_{2g}\rho_{2g}\left(Q_{G2g} - Q_{Gbg}^{lag}\right)S_b - W_{1g}\rho_{1g}\left(Q_{G1g} - Q_{Gbg}^{lead}\right)S_b \\ + \rho_{2g}\left(W_{3fg} + W_{3rg}\right)\left(Q_{G3g} - Q_{Gbg}^{lag}\right)S_b \end{pmatrix} \\ &+ \sum_g \rho_{MC}\Delta P_{Gg}S_b + \sum_i \left(\rho_{B1}P_{B1i}S_b + \rho_{B2}P_{B2i}S_b\right) \end{aligned} \tag{5.17}$$

Observe that the quadratic opportunity cost term in (5.1) has been replaced by a direct payment for rescheduled power $\rho_{MC}\Delta P_G$ in (5.17). Furthermore, loss payments/credits are not included, since this is not currently a common practice in “standard” reactive power dispatch approaches.

The proposed dispatch model (5.2)-(5.16) captures both the technical and economic aspects of reactive power dispatch. However, from the optimization point of view, this model represents a difficult problem, since it is essentially an MINLP problem, due to the presence of binary variables required to properly select only one out of the three regions of reactive power operation in the model. To address this issue, the proposed GRPC algorithm discussed earlier in Section 4.2.4 is also used here to solve this optimization problem.

The solution of the proposed dispatch model yields the following:

- The required reactive power support from each generator.
- The amount of real power to be rescheduled in order to meet the system reactive power requirements.
- The amount of energy balance services needed to compensate for the change in real power resulting from the reactive power dispatch.
- The total payment of the ISO to the service providers.

5.3 Implementation and Results

The proposed reactive power dispatch model (5.2)-(5.16) is tested on the CIGRE 32-bus system (Figure 4.3), and the associated results are presented and discussed in this section. The optimization models, which are transformed into NLP problems as previously discussed in Section 4.2.4, are modeled in GAMS and solved using the MINOS solver. The same power flow limits used in Section 4.3, are also used here. To simplify the analysis, all generators are again assumed to be eligible for payments in all of the three regions of operation, which implies that Q_{Gb}^{lead} and Q_{Gb}^{lag} in Figure 2.1 are equal to zero for all generators. Finally, a 30% reactive power reserve is assumed for each zone, *i.e.* K_z = 0.7 for all three zones.

For brevity of presentation, only two different operating scenarios are presented and discussed here to illustrate the performance, validity, and robustness of the proposed reactive power dispatch model. The first scenario is a base loading condition, whereas the second is a "stressed" operating condition in which the system loading level is increased by 10% with respect to base load and with one generating unit out of service. For each of these scenarios, the following cases are studied:

- *Case I ("standard" reactive power dispatch):* In this case, common ISO-practices are applied, where the real power dispatch from energy market clearing is used to solve an ac-power flow to determine the required reactive power dispatch. In most cases, operators use their own experience to "tune" the ac-power flow until a feasible and secure solution is achieved that does not violate voltage and line flow limits. Hence, this approach is simulated here to obtain a "standard" reactive power dispatch, and the associated payments are then calculated based on the proposed payment function J_1 in (5.1).

- *Case II (proposed reactive power dispatch):* In this case, the real power dispatch from energy market clearing, together with the set of contracted generators and the four reactive power price components from a procurement stage, are used to solve the proposed reactive power dispatch model (5.2)-(5.16). The solution of this model simultaneously yields the required reactive power dispatch and the associated payment components. In order to demonstrate the generality of the proposed dispatch model, the results are compared for two objectives, one with the function J given in (5.1), denoted here by Case II.a, and the second with the more "realistic" objective J^* given in (5.17), denoted here by Case II.b.

- *Case III ("ideal" reactive power dispatch):* This case simulates an ideal scenario in which a security constrained ac-OPF, minimizing the total real power cost, is used to simultaneously dispatch P and Q. This would be an ideal solution because it achieves the least-cost solution; however, such an approach is not currently used by ISOs in practice, because of the complexity associated with solving a coupled, large-scale, non-convex NLP model every few minutes. Furthermore, possible adverse effects on market prices associated with the simultaneous dispatch of real and reactive power within a competitive market environment could be a significant problem [28]. Once the reactive power dispatch is obtained for this ideal scenario, the associated reactive power payment is calculated based on the proposed J_1 in (2).

In the above cases, the four reactive power price components, defined earlier in Section 3.4.3, are assumed to be available from the procurement stage. These price components, as well as the set of contracted generators, are obtained here by solving the proposed reactive power procurement model (4.14)-(4.25) at high loading conditions and ignoring contingencies. These values are different from the ones shown in Tables 4.3 and 4.4; however, the way the contracted generators and the associated price components are obtained have no bearing on the proposed dispatch procedures, and they could actually come from any appropriate procurement process. The set of contracted generators and the four reactive power price components are given in Table 5.1, and are assumed to remain unchanged for all test cases. A market clearing price ρ_{MC} = 100 \$/MWh is assumed, which is a typical "high" price figure in the Ontario electricity market. The prices of energy balance services ρ_{B1} = 110 \$/MWh and ρ_{B2} = 90 \$/MWh are assumed to be pre-determined from a given energy balance auction, which can be assumed to be typical values, since these are usually around the value of ρ_{MC} [76].

Table 5.1 Contracted generators and the associated reactive power prices.

Zone	Contracted Generators	Zonal Reactive Power Prices			
		ρ_o	ρ_1	ρ_2	ρ_3
a	4072	0.78	0.74	0.57	NC
	4011				
	1013				
	1012				
b	4021	0.92	0.91	0.90	0.36
	4031				
	2032				
	1022				
	1021				
c	4063	0.85	0.53	0.81	0.26
	4051				
	1043				
	1042				

NC = Not Contracted

It should be noted that reactive power limits for the “standard” reactive power dispatch Case I and the “ideal” reactive power dispatch Case III do not include the opportunity region of operation. This is due to the fact that in the “traditional” reactive power dispatch approaches, which both of these cases represent, generators are typically modeled using fixed reactive power limits (Q_{GR} in Figure 2.1). The redefined reactive power dispatch proposed herein (Case II), on the other hand, is based on the concept of operating a generator in the opportunity region in return for adequate financial compensation. This allows for extended reactive power support from generators, which is important for power systems today, since they are operating closer to their limits in more stressed conditions.

5.3.1 Base Loading Condition

The solution of the three case studies under base loading conditions is given in Table 5.2. A set of 13 generators out of 20 are assumed to be contracted for reactive power provision (Table 5.1). Generators with negative Q_G values are operating in the under-excitation region (Region I); no generators are operating in Region III. For the purpose of the simulations presented here, the real power market clearing and dispatch, which is required to initiate the proposed reactive power dispatch procedure, is obtained using a “standard” dc-OPF model. This model minimizes the cost of energy production, subject to system security constraints. Transmission losses are modeled as a function of generator shift factors and real power injections [77].

It can be seen from the results in Table 5.2 that in Case I, when reactive power is dispatched using an ac-power flow (AC-PF), a 5.7 MW reduction in the real power of the slack bus (4011) takes place to adjust for the lower losses. Note also that the same P_G dispatch (obtained from dc-OPF) applies to both Case II.a and Case II.b. None of the generators are operating in Region III for these sub-cases, and hence ΔP_G is zero for all the generators. However, due to the fact that real power generation levels are kept constant and there is no slack bus in Case II, a downward balance service of 7.1 MW is required at generator Bus 1021 for Case II.a to account for the reduction in the total system losses. The difference in Q_G between these two sub-cases is due to the difference in payment structure of the two objective functions. Finally, observe the significantly different P_G and Q_G values obtained from the security constrained ac-OPF approach in Case III, which minimizes the total real power generation costs.

Table 5.2 Solution of the three cases under base loading condition.

BUS	Case I AC-PF		Case II Proposed dispatch model				Case III AC-OPF	
			II.a		II.b			
	P_G (MW)	Q_G (Mvar)	P_G (MW)	Q_G (Mvar)	P_G (MW)	Q_G (Mvar)	P_G (MW)	Q_G (Mvar)
4072	1380.6	484	1380.6	179.3	1380.6	179.6	1590.6	394.5
4011	900 - 5.7	-100	900	-89.2	900	-77.5	539.8	-100
4021	270	-2.4	270	-30	270	-30	270	-30
4031	315	-23.1	315	-40	315	-40	315	-40
4063	1035.4	103.4	1035.4	92.4	1035.4	97.1	1080	106.2
4051	630	97.4	630	83.6	630	90.7	630	92.9
2032	760	168.9	760	10.9	760	15	765	23.3
1013	275.5	-50	275.5	0	275.5	-50	383.9	-50
1012	720	57.4	720	0	720	275.8	720	70
1022	225	-25	225	0	225	0	225	-25
1021	350	51.7	350-7.1	0	350	0	430.2	84.4
1043	180	69.2	180	55	180	63.9	180	65.1
1042	360	-37.4	360	-40	360	-38.9	360	-38.8

Observe in Table 5.2 that there are significant differences in reactive power dispatch using the proposed approach (Case II) with respect to more "traditional" techniques (Cases I and III). This is a notable change arising from the proposed philosophy of reactive power dispatch, which is a basic paradigm shift.

The reactive power payment, the balance payment, and the total system losses for all cases are given in Table 5.3. Observe that the reactive power payment resulting from the proposed dispatch model (Case II) is the lowest, since the objective function is to minimize reactive power payments. It is also to be noted that this base-load scenario does not induce any reactive power dispatch of generators in the opportunity region, and therefore the difference in opportunity payment components between Cases II.a and II.b is not clearly brought out. A stressed operating condition is considered in the next section to demonstrate this issue.

Table 5.3 Losses and payment components for the three cases under base loading condition.

	Case I AC-PF	Case II: Proposed dispatch model		Case III AC-OPF
		II.a	II.b	
Losses (MW)	433.5	432.2	439.2	424.4
Q-Payment ($/h)	1,900	1,570	1,780	1,920
Balance-Payment ($/h)	515	640	0	0

The balance payment shown in Table 5.3 and associated with Case II.a is due to the downward balance service required at generator Bus 1021, illustrated in Table 5.2, which arises from the need to account for the change in system losses associated with the corresponding reactive power dispatch. This balance-payment is lower in Case I, where a 5.7 MW reduction in the losses is accounted for by Generator 4011 (slack bus). Note that Case III yields the lowest value of the system losses, since both P_G and Q_G are simultaneously dispatched using an ac-OPF. On the other hand, the system losses in Case II.a are lower than those in Case II.b, since for the former the objective function J explicitly includes a loss-payment component.

5.3.2 Stressed Operating Condition

Table 5.4 depicts the dispatch results obtained for the stressed system conditions. Observe in this case that the reactive power requirements have significantly increased for all the studied cases. In Case I, a rescheduling in real power generation of three generators is needed to achieve a feasible power flow solution; in this case the 9 MW (1.25%) reduction in P_G from Generator 1022 is picked up by Generator 4072, and an additional 9.7 MW is supplied by the slack bus 4011 to account for the increase in system losses associated with the reactive power dispatch.

In Cases II.a and II.b, Generator 1012 is dispatched in the opportunity region (shown in bold), and consequently a 11.7 MW (1.63%) reduction in its real power output is necessary to maintain reactive power generation within its field limits. This rescheduling in real power is compensated by an upward balance service of 11.4 MW in Case II.a and 12.1 MW in Case II.b, both at load Bus 1041. The difference between the MW reduction and the balance service is accounted for by the change in the total system losses. In Case III, there is no rescheduling of real power generation, since P_G and Q_G are simultaneously dispatched.

Table 5.4 Solution for the three cases under stressed condition.

BUS	Case I AC-PF		Case II Proposed dispatch model				Case III AC-OPF	
			II.a		II.b			
	P_G (MW)	Q_G (Mvar)	P_G (MW)	Q_G (Mvar)	P_G (MW)	Q_G (Mvar)	P_G (MW)	Q_G (Mvar)
4072	2310.3+9	303.5	2310.3	319.3	2310.3	297.4	2279.3	422.3
4011	900+9.7	-100	900	-100	900	-32.5	804.1	-100
4021	270	-30	270	-30	270	-30	270	-30
4031	315	-40	315	0	315	0	315	128.8
4063	1080	152.7	1080	156.8	1080	159.1	1080	163.6
4051	630	247.9	630	98.5	630	95.6	630	122.8
2032	765	175.6	765	201.1	765	179.9	765	212.5
1013	350.1	236.7	350.1	76.9	350.1	45.7	481.9	-50
1012	720-9	349	720-11.7	**367**	720-11.7	**367**	720	348.7
1022	0	0	0	0	0	0	0	0
1021	391.4	88	391.4	156.5	391.4	157.8	540	213.6
1043	180	87.2	180	87.2	180	87.2	180	87.2
1042	360	16.3	360	0	360	0	360	-7.8
1041 load	*0*	*0*	*11.4*	*0*	*12.1*	*0*	*0*	*0*

The reactive power and balance payments, as well as the total system losses for all cases, are given in Table 5.5. Observe that the lowest reactive power payment is achieved in Case II.a, with the payment being significantly different from that in Case II.b because of the difference in the opportunity payment component in the respective objective functions. Note that the balance payment component is present in Cases I and II due to the required rescheduling in real power generation. The difference in the balance-payment for Cases II.a and II.b can be attributed to the slight difference in the total system losses associated with the reactive power dispatch.

It is interesting to note that for the stressed system conditions, the proposed dispatch of Case II.a reduces system losses with respect to the ac-OPF dispatch of Case III. This is attributed here to the fact that the proposed dispatch model has the possibility to extend the reactive power limits to a generator's opportunity region, while an ac-OPF based reactive power dispatch constrains these to fixed rated limits.

Table 5.5 Losses and payment components for the three cases under stressed condition.

	Case I AC-PF	Case II: Proposed dispatch model		Case III AC-OPF
		a	b	
Losses (MW)	567.5	557.4	558.2	575
Q-Payment ($/h)	2,420	2,190	3,340	2,510
Balance-Payment ($/h)	2,060	1,250	1,330	0

Comparing the reactive power dispatch results of Case II.a for the two system conditions, it is observed that for base load (Table 5.2), 4 generators are operating in the under-excitation region and 4 are not dispatched for reactive power support, while none are required to operate in Region III. On the other hand, from

Table 5.4, a significant increase is observed in reactive power output from generators under a stressed operating condition, as expected, since only two generators are operating in the under-excitation region, while Generator 1012 is operating in Region III. The total amount of reactive power injected into the system has increased from 220 Mvar at base loading condition to 1333 Mvar under stressed operating condition.

5.4 Summary

In this chapter, a novel paradigm for reactive power dispatch in the context of deregulation is proposed. The classical reactive power dispatch problem is *redefined* from the perspective of an ISO's operating in competitive electricity markets. The new reactive power dispatch model incorporates the ISO's composite payment burden associated with the provision of reactive power support, while considering all operating aspects pertinent to a competitive environment. The model seeks to minimize the total payment by the ISO to reactive power providers, while ensuring a secure and reliable operation of the power system.

One important contribution of the model is that it considers the effect of reactive power on real power by "internalizing" the calculation of the reduction in real power output of a generator due to an increase in its reactive power supply. Furthermore, in order to ensure that rescheduling of real power because of reactive power supply requirements from generators is kept at a minimum, a payment component for balance services is included in the objective function.

Simulation studies are carried out considering two different loading scenarios. Furthermore, three cases are considered representing different approaches for reactive power dispatch. Thus, in addition to the proposed reactive power dispatch model, two other approaches are studied: First, a standard approach adopted by most system operators for dispatching reactive power support from generators is used; this approach is based on solving an ac-power flow using real power dispatch from energy market clearing. The second approach is an ideal scenario in which both real and reactive power are simultaneously dispatched by solving a security constrained ac-OPF that minimizes the total real power cost.

From the analysis of results obtained from the three case studies, it is shown that the proposed reactive power dispatch yields the lowest reactive power payments among all cases considered. It is also observed that the proposed reactive power dispatch approach yields better overall results than current dispatch practices.

Chapter 6
Conclusions

6.1 Summary and Conclusions

This thesis focuses on the management and pricing of reactive power ancillary services in the context of liberalized electricity markets. In Chapter 1, a comprehensive review of reactive power management and pricing is carried out. The review includes some of the existing utility practices worldwide as well as various approaches reported in the technical literature for reactive power cost allocation, pricing, and provision. Subsequently, the research work proposed in this thesis is presented, highlighting its main objectives.

In Chapter 2, the different types of ancillary services according to FERC and NERC definitions are presented and elaborated. An overview of reactive power management in different electric utilities around the world is discussed thereafter. This chapter also introduces the different regions of reactive power operation determined from the capability curve of a synchronous generator, and introduces the different cost components associated with each region. The impact of reactive power on system security is also discussed, and the chapter concludes by emphasizing on the importance of incorporating system security within the reactive power provision procedures.

In Chapter 3, the various issues associated with the existing utility practices for reactive power management and payment mechanisms are discussed. Appropriate policy solutions are then proposed in order to achieve an efficient service provision for reactive power ensuring a secure and reliable operation of the power system. The proposed policy solutions include the following:

- Decoupling of active and reactive power provisions in order to isolate the effect of price volatility of energy market on reactive power prices.
- Examining reactive power management on a zonal basis, to reduce the effect of some generators' trying to exercise market power by confining any possible market inefficiencies within a specific zone, and thus protect other market participants in the system.
- The development of an appropriate reactive power payment function that comprises four price components, corresponding to the three regions of reactive power operating (under-excitation, over-excitation, and opportunity regions), in addition to an availability component.
- Proper consideration and representation of the effect of reactive power dispatch on real power dispatch, and hence system security.

Based on these policy solutions, a novel hierarchical reactive power management framework is proposed and discussed in this chapter. The proposed framework is based on the separation of reactive power management into two distinct time-frames, *i.e.* a reactive power procurement stage carried out on a seasonal basis, and a reactive power dispatch stage that determines the actual reactive power generation levels close to real-time.

In Chapter 4, a novel reactive power procurement scheme is proposed representing the first level of the integrated framework. The scheme incorporates, for the first time, power system security as a selection criterion in the procurement of reactive power services. This is achieved by using the concept of marginal benefits of reactive power from a generator with respect to system security, represented by Lagrange multipliers associated with a loadability maximization model. These marginal benefits are then used to maximize a reactive power *societal advantage function*, considering offers from service providers, *i.e.* generators. Reactive power is procured from generators on a zonal basis, with the system being split into zones or voltage control areas using the concept of electrical distances. The optimal reactive power procurement model is solved using a novel GRPC algorithm, which alleviates the need for binary variables. The GRPC algorithm solves the procurement problem using an iterative updating procedure, in which a sequence of NLP sub-problems is solved until the best possible solution is achieved. The proposed GRPC algorithm, from the computational viewpoint, makes it possible to apply the proposed reactive power procurement model to realistic power systems, while incorporating all transmission security constraints. The proposed reactive power procurement model is implemented and tested on the CIGRE 32-bus system, and two case studies are considered, representing stressed and unstressed operating conditions. The solution of the proposed procurement model yields the optimal set of contracted generators in each zone and the corresponding zonal reactive power prices for all the four price components introduced in Chapter 3; these would form the basis of contractual agreements for seasonal reactive power provision.

In Chapter 5, the classical reactive power dispatch problem is redefined from the perspective of an ISO operating in competitive electricity markets. A novel reactive power dispatch scheme is proposed, which seeks to minimize the total payments by the ISO to reactive power providers while ensuring a secure and reliable operation of the power system. The proposed reactive power dispatch scheme considers the effect of reactive power on real power by calculating, within the optimization model, the required reduction in real power output of a generator due to an increase in its reactive power supply. This reduction in real power generation is compensated by using upwards and downwards balance services. A payment component for these balance services is included in the proposed objective function, in order to ensure that rescheduling of real power is kept at a minimum. Two different operating scenarios are considered in the CIGRE 32-bus system, and three cases are studied for each scenario, representing different approaches to reactive power dispatch. In addition to the proposed reactive power dispatch model, a "standard" approach adopted by most system operators for dispatching reactive power support from generators is used, as well as using an ideal scenario in which both real and reactive power are simultaneously dispatched by solving a security constrained ac-OPF that minimizes the total real power cost. The findings of this chapter demonstrate the effectiveness of the proposed reactive power dispatch, which yields the lowest reactive power payments and better overall results among all cases considered.

6.2 Main Contributions of the Research

The following are the main contributions of the research work presented in this thesis:

1. A comprehensive overview for reactive power ancillary services management and pricing is presented, discussing different mechanisms adopted by several utilities around the world, as well as proposed approaches reported in the technical literature.
2. This thesis presents a detailed analysis of the issues associated with reactive power service provision in competitive electricity markets, and prescribes corresponding policy solutions for them, which are in line with the common operating practices of electric utilities in North America. The analysis yields

a comprehensive and general framework for reactive power management and pricing in these markets.

3. Based on current practices for reactive power provision by various system operators in competitive electricity markets, a novel integrated framework based on a two-settlement model approach is proposed for reactive power ancillary service management. The proposed framework works at two hierarchical levels and in different time horizons; the first level is the procurement model which works in a seasonal time horizon, while the second level is the dispatch model which works in a 30 minutes to 1 hour window. The framework is generic in nature and is designed to fit into any electricity market structure, be it a bilateral contract market or a pool market.

4. System security is incorporated in reactive power procurement procedures, based on indices representing the marginal benefit of reactive power from each generator with respect to system security. Furthermore, appropriate transmission security constraints are represented in the model to ensure a secure procurement of reactive power support.

5. A novel reactive power dispatch model is proposed to suit the requirements of system operators in deregulated market. The main objective of this model is to dispatch reactive power from already contracted providers at least cost, while satisfying transmission security constraints and considering zonal reactive power reserves.

6. An important aspect of the new dispatch model is that it considers the effect of reactive power on real power by internalizing the calculation of the reduction in real power output of a generator due to an increase in its reactive power supply. Furthermore, in order to ensure that this rescheduling

of real power is kept at a minimum, a payment component for balance services is included in the objective function.

7. A novel *Generator Reactive Power Classification (GRPC) algorithm* is proposed in this thesis to solve the MINLP models associated with the optimal reactive power procurement and dispatch problems. The *GRPC* algorithm treats the optimization problem as iterative NLP sub-problems, alleviating the need for binary variables associated with the different possible regions of reactive power operation for each generator. This is a significant improvement from previously inefficient mathematical models and methods that treat the reactive power procurement problem as an MINLP problem.

6.3 Scope for Future Research

Based on the research work reported in this thesis, future research may be pursued in the following directions:

1. Apply the proposed reactive power procurement and dispatch models to actual power systems.
2. Examine the possibility of expanding the definition of reactive power ancillary service providers to include other resources such as capacitor banks and FACTS devices. This is in line with FERC recent recommendations to consider and recognize reactive power from these sources as ancillary services that are eligible for financial compensation.

3. Improve the performance of the proposed GRPC algorithm by looking at the optimal order of generators and starting point (initial value of reactive power), in order to arrive at the best possible solution.
4. Study the issue of reactive power providers' trying to exercise market power and indulging in gaming.
5. Investigate the contribution of DG resources to reactive power ancillary service provision, their optimal pricing, grid connection agreements, and technical requirements.
6. Examine reactive power provision and pricing problems from the generators' viewpoint, as service providers. In other words, build optimal bidding strategies for the competitive generators to participate in reactive power markets.

Appendix A
CIGRE 32-Bus System

The CIGRE 32-bus test system [71], shown in Figure A.1, has been used in this thesis to implement and test both the proposed reactive power procurement and dispatch models. The system encompasses a total demand of 10,940 MW and has 20 generators, 9 shunt capacitors, and 2 inductors. Bus 4011 is selected as the slack bus. The data for generator buses is provided in Table A.1, including the generators' limits, and the demand and voltage level at each of the 20 generator buses. The demand at load buses, together with the installed shunt capacitors and voltage levels, are given in Table A.2. The data for the transmission lines connecting system buses is given in Table A.3.

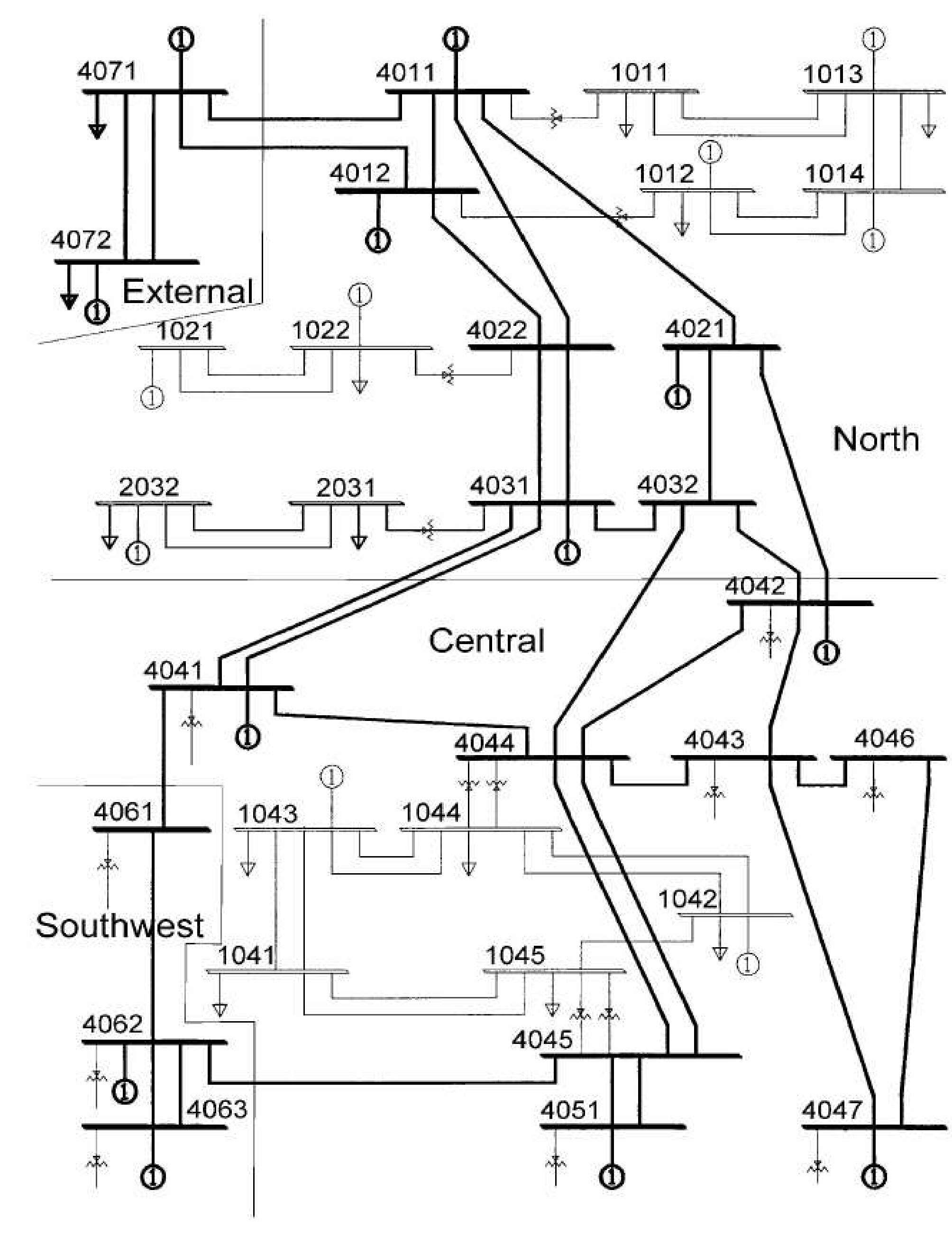

Figure A.1 CIGRE 32-bus system.

Table A.1 Generator buses.

Bus	P^{max} (MW)	P^{min} (MW)	Q^{min} (Mvar)	P_D (MW)	Q_D (Mvar)	Q_{Sh} (Mvar)	V_{Level} (KV)	X_S (p.u.)
4072	4500	0	-300	2000	500	0	400	1.5
4071	500	0	-50	300	100	-400	400	0.8
4011	1000	0	-100	0	0	0	400	1.2
4012	800	0	-160	0	0	-100	400	1.1
4021	300	0	-30	0	0	0	400	0.7
4031	350	0	-40	0	0	0	400	0.7
4042	700	0	0	0	0	0	400	1
4041	300	0	-200	0	0	200	400	0.7
4062	600	0	0	0	0	0	400	0.9
4063	1200	0	0	0	0	0	400	1.2
4051	700	0	0	0	0	100	400	1
4047	1200	0	0	0	0	0	400	1.2
2032	850	0	-80	200	50	0	220	1.1
1013	600	0	-50	100	40	0	130	0.9
1012	800	0	-80	300	100	0	130	1.1
1014	700	0	-100	0	0	0	130	1
1022	250	0	-25	280	95	50	130	0.7
1021	600	0	-160	0	0	0	130	0.9
1043	200	0	-20	230	100	150	130	0.6
1042	400	0	-40	300	80	0	130	0.8

Table A.2 Load buses.

Bus	P_D (MW)	Q_D (Mvar)	Q_{Sh} (Mvar)	V_{Level} (KV)
4022	0	0	0	400
4032	0	0	0	400
4043	0	0	200	400
4044	0	0	0	400
4045	0	0	0	400
4046	0	0	100	400
4061	0	0	0	400
2031	100	30	0	220
1011	200	80	0	130
1041	600	200	200	130
1044	800	300	200	130
1045	700	250	200	130
42	400	125.67	0	130
41	540	128.8	0	130
62	300	80.02	0	130
63	590	256.19	0	130
51	800	253.22	0	130
47	100	45.19	0	130
43	900	238.83	0	130
46	700	193.72	0	130
61	500	112.31	0	130

Table A.3 Transmission lines.

Line	Resistance (Ω)	Reactance (Ω)	Charging (p.u.)
4011.4012	1.6	12.8	0.4
4011.4021	9.6	96	3.58
4011.4022	6.4	64	2.39
4011.4071	8	72	2.79
4012.4022	6.4	56	2.09
4012.4071	8	80	2.98
4021.4032	6.4	64	2.39
4021.4042	16	96	5.97
4031.4022	3.2	32	1.2
4031.4032	1.6	16	0.6
4031.4041	4.8	32	2.39
4042.4032	16	64	3.98
4032.4044	9.6	80	4.77
4041.4044	4.8	48	1.79
4041.4061	9.6	72	2.59
4042.4043	3.2	24	0.99
4042.4044	3.2	32	1.19
4043.4044	1.6	16	0.6
4043.4046	1.6	16	0.6
4043.4047	3.2	32	1.19
4044.4045	1.6	16	0.6
4045.4051	3.2	32	1.2
4045.4062	17.6	128	4.77

Table A.3 – Continued from previous page.

Line	Resistance (Ω)	Reactance (Ω)	Charging (p.u.)
4046.4047	1.6	24	0.99
4061.4062	2.4	24	0.9
4062.4063	2.4	24	0.9
4071.4072	2.4	24	3
2031.2032	2.9	21.78	0.05
1011.1013	0.85	5.9	0.13
1012.1014	1.2	7.6	0.17
1013.1014	0.59	4.23	0.1
1021.1022	2.54	16.9	0.29
1041.1043	0.85	5.07	0.12
1041.1045	1.27	10.14	0.24
1042.1044	3.21	23.66	0.57
1042.1045	8.45	50.7	1.13
1043.1044	0.85	6.76	0.15

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