A MARKET APPROACH TO BALANCE SERVICES PRICING

by

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SUMMARY

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Keywords: Ancillary services, balancing services, reserves, energy, optimal power flow, co-optimization, simultaneous auction, Lagrange multiplier

The co-optimization of energy and reserves has become a standard requirement in integrated markets. This is due to the inverse relationship that exists between energy and reserves. The provision of reserves generally reduces the amount of primary energy a generating unit can produce and vice versa. This suggests that these products should be procured through a simultaneous auction to ensure optimal procurement and pricing. Furthermore, forward markets dictate that this co-optimization of energy and reserves be done over a multi-period planning horizon. This dissertation addresses the problem of optimal scheduling and pricing of energy and reserves over a multi-period planning horizon using an optimal power flow formulation.

The extension of the problem from a static optimization problem to a dynamic optimization problem is presented. Price definitions for energy and reserves in terms of shadow prices emanating from the optimization algorithm are provided. It is shown that the proposed formulation of prices leads to the cascading of reserve prices and eliminates the problem of "price reversal" where lower quality reserves are priced higher than higher quality reserves. Pricing conditions are also established for the downward substitution of higher quality reserves for lower quality reserves.

The proposed pricing formulations are tested on the IEEE 24 Bus Reliability Test System and on the South African power network. The simulated results show that cascading of reserve prices does occur and that prices of different types of reserves are equal when downward substitution of reserves occurs. Zonal reserve requirements result in higher energy and reserve prices, which in term result in higher procurement costs to the system operator and higher profits to market participants. Congestion on the network also results in higher procurement costs to the system operator and higher profits to market participants in the case of zonal pricing of reserves.

OPSOMMING

’N MARKBENADERING TOT DIE BALANSERING VAN DIENSTEPRYSVASSTELLING

deur

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Die ko-optimering van energie en reserwes het ’n standaardvereiste in geïntegreerde markte geword. Dit is as gevolg van die omgekeerde verhouding wat tussen energie en reserwes bestaan. Die voorsiening van reserwes verminder gewoonlik die hoeveelheid primêre energie wat ’n opwekkingseenheid kan produseer en omgekeerd. Dit dui daarop dat hierdie produkte deur ’n gelyktydige veiling verkry kan word om optimale verkryging en die beste prys te verseker. Daarbenewens dui termynmarkte daarop dat hierdie ko-optimering van energie en reserwes vir beplanning oor ’n uitgebreide periode gedoen moet word. Hierdie verhandeling gaan oor die probleem van optimale skedulering en prysvasstelling van energie en reserwes oor ’n uitgebreide periode deur gebruik te maak van ’n optimale kragvloeiformulering.

Die uitbreiding van die probleem van ’n statiese optimeringprobleem na ’n dinamiese optimeringprobleem word aangedui. Prysdefinisies vir energie en reserwes volgens skadupryse wat uit die optimeringalgoritme spruit, word verskaf. Daar word aangetoon dat die voorgestelde formulering van pryse lei na trapsgewyse aanpassing van reserwepryse

en die probleem van “prysomkering” uitskakel, waar pryse vir reserwes van laer kwaliteit hoër is as dié vir reserwes van hoër kwaliteit.

Die voorgestelde prysformulerings word getoets op die IEEE 24 Bus Betroubaarheidtoetsstelsel en op die Suid-Afrikaanse kragnetwerk. Die gesimuleerde resultate toon dat die trapsgewyse aanpassing van reserwepryse wel plaasvind en dat die pryse van verskillende tipes reserwes eenders is as afwaartse vervanging van reserwes plaasvind. Sone-reserwevereistes het hoër energie- en reserwepryse tot gevolg, wat oor ’n tydperk lei tot hoër verkrygingskoste vir die stelseloperateur en hoër winste vir markdeelnemers. Oorlading van die netwerk lei ook tot hoër verkrygingskoste vir die stelseloperateur en hoër wins vir markdeelnemers in die geval van sone-prysvasstelling vir reserwes.

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LIST OF ABBREVIATIONS

AC	Alternating current
DC	Direct current
ED	Economic dispatch
IR	Instantaneous reserves
ISO	Independent System Operator
MS	Market settlement
OPF	Optimal power flow
PSI	Partition separation index
RR	Regulation reserves
RTS	Reliability test system
TMNSR	10-minute non-spinning reserves
TMOR	30-minute operating reserves
TMSR	10-minute spinning reserves
SCUC	Security constrained unit commitment
SPD	Scheduling, pricing and dispatch
UC	Unit commitment

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CHAPTER 1 INTRODUCTION

1.1 ANCILLARY SERVICES

The security and stability of a power system is achieved by balancing supply and demand for real and reactive power. Such a balance results in the system frequency and voltage being maintained at predefined levels. These security requirements are achieved through the provision of services that are distinct from primary energy and are called ancillary services. Based on the specific service requirements, ancillary services can be grouped into balancing services, network services and system restoration services.

Balancing services comprise those services that are required for the balancing of supply and demand and are often referred to as reserves. An imbalance between supply and demand results in frequency deviations. These services are further categorised, based on speed of response, into primary frequency control, secondary frequency control and tertiary frequency control. The speed of response determines the quality of the service, with faster responding services being of a higher quality than slower ones [1] – [2].

Network services comprise those services that are required for network related stability and security issues. These services include voltage control services, which are used to maintain the voltage at predefined levels. Because of the close link between voltage and reactive power, these services are also called reactive power services [3]. Also included in this category are network congestion services, which are used to overcome energy imbalances resulting from constrained networks.

In the event of a power system collapse, restoration services are required to restore the system to its normal state. These services are provided by generators that can either start manually or by using energy stored in batteries. These services are also referred to as black start capability services [4].

1.2 MARKET DEREGULATION

Many utilities around the world have embarked on reforms to enhance competition for services and thus improve social welfare. The reforms include a clear separation between the production and sale of electricity, and network operations. As a result the vertically integrated operations of generation, transmission and distribution have been separated into independent entities. This transformation does not however eradicate the need for ancillary services but requires a new approach in the costing, procurement and delivery of these services.

Not all ancillary services lend themselves to trading in a market environment. Voltage control services are location dependent and thus could lead to market power issues when traded in a market. Black start capability services can only be provided by a limited number of generators and therefore could exercise market power when traded in a market. Balancing services are amenable to trading in an open market environment. Proper product definition and market design are the primary determinants of efficiency and liquidity in these markets, which in turn influence system reliability [5].

1.3 BALANCING SERVICES

The definition of products within balancing services is based on three levels of control that are generally used to balance supply and demand. These are primary frequency control, secondary frequency control and tertiary frequency control. Primary frequency control reserves are used to arrest the frequency following a large generator or load outage. In some markets this type of reserve is referred to as instantaneous reserves (IR) owing to the quick response required of these reserves. Secondary frequency control is centralised automatic control that adjusts the output power of generators to restore frequency and tie-line interchanges following an imbalance. Secondary frequency control is called automatic generation control in some markets and the reserves providing this service are called regulation reserves (RR). Tertiary frequency control refers to the manual dispatching of generating units to restore primary and secondary frequency control reserves. These reserves are sometimes referred to as replacement reserves [2].

1.4 PROBLEM STATEMENT

The trading of energy is generally achieved using forward markets and real-time markets. The forward market is usually a day-ahead market in which resources are scheduled for each hour of the following day. The day-ahead market is supplemented with a real-time market in which deviations from the day-ahead market are adjusted and corrected. In the real-time market, supply and demand are balanced in real-time. Primary energy is usually traded in the forward market while balancing services, also called reserves, are traded in both markets. In both these markets, the trading mechanism is in the form of an auction where suppliers submit bids to be entered into the auction. The structure of the bids is designed to ensure market efficiency.

The primary energy and the balancing services markets are intricately intertwined owing to the inverse relationship that exists between a generating unit's capacity to provide primary energy and reserves. The provision of reserves generally reduces the amount of primary energy the unit can produce and vice versa. This suggests that the co-optimization of both these markets using a simultaneous auction is required to ensure optimal procurement and pricing of these products. Various options exist within the framework of a simultaneous auction, depending on the objective of the auction and the market rules used in the auction. The objective of the market auction could be to minimize procurement cost or to minimize social cost.

In the co-optimization of the energy and balancing services markets, the procurement and pricing of services are achieved using an optimization algorithm in which the pricing is based on Lagrangian values or shadow prices. In this situation the requirements for reserves are incorporated either into the broader security constrained unit commitment (SCUC) problem or into the optimal power flow (OPF) problem. The optimal commitment and dispatch of resources, as well as the prices for energy and reserves, are then determined from these optimization algorithms.

An essential requirement for electricity pricing in competitive markets is that prices should accurately reflect costs. It is therefore important that correct prices for energy and reserves be determined and used in electricity tariff design. The complexity of this price determination is exacerbated by the fact that reserves of various types are involved in the co-optimization process and this co-optimization has to be performed over a multi-period planning horizon. The study in this dissertation proposes and presents an OPF formulation for the co-optimization of energy and reserves of various types over a multi-period planning horizon.

1.5 RESEARCH OBJECTIVE AND QUESTIONS

The primary objective of this dissertation is the development of a scheduling, pricing and dispatch (SPD) tool for integrated energy and reserve markets. The functionality and capability of the SPD tool should include:

- Co-optimization of energy and reserves of various types
- Co-optimization over a multi-period planning horizon
- Costing and pricing of energy and reserves

In achieving this primary objective, the following research questions are addressed:

- What formulation of the optimal power flow (OPF) problem will lead to price discovery of generation reserves of various types?
- What is the effect of such a formulation on uniform, zonal and nodal pricing of energy and reserves?
- What is the effect of network congestion on different pricing strategies when implemented under such a formulation?
- What open source market applications can be extended to include such a formulation?

1.6 HYPOTHESIS AND APPROACH

Cost-reflective pricing of energy and generation reserves of various types can be determined using an optimization algorithm such as an alternating current (AC) OPF, in which prices are based on Lagrangian values or shadow prices. In such a formulation the objective function is augmented to include reserve costs and the reserve requirements are incorporated as constraints into the problem.

This dissertation focuses on the development of an SPD tool for integrated markets. The development of this tool is achieved by extending the capabilities of an open source market application to include co-optimization of reserves of more than one type over a multi-period planning horizon. This is achieved in two stages. Initially the model is extended to enable the co-optimization of energy and reserves of various types over a single time period. The model is then validated for single-period co-optimization. The second stage involves extending the model for multi-period co-optimization and testing the model.

1.7 RESEARCH GOALS

The proposed research is the development of a Matlab-based market settlement (MS) tool for energy and generation reserves. Functionality will include the generation of energy and reserve market prices, and market settlements for these products. The main components will comprise an SPD engine and an MS engine with data flows, as shown in Figure 1.1.

Inputs to the SPD engine comprise energy and reserve requirements. Outputs of the SPD engine are generator energy and reserve schedules, as well as shadow prices for energy and reserves. Inputs into the MS engine include energy and reserve schedules and shadow prices. Outputs of the MS engine are energy and reserve prices, as well as settlements costs and payments. The optimization algorithm in the SPD engine will be based on a Lagrangian relaxation OPF formulation and prices for energy and reserves will be defined in terms of these shadow prices.

The design will be validated and tested using test data found in the literature. After validation, the model will be used to determine market prices and settlements for energy and reserves for a test system. Application of the model to a real system will then be demonstrated by determining energy and reserve prices for the Eskom network based on actual loads and generator characteristics.

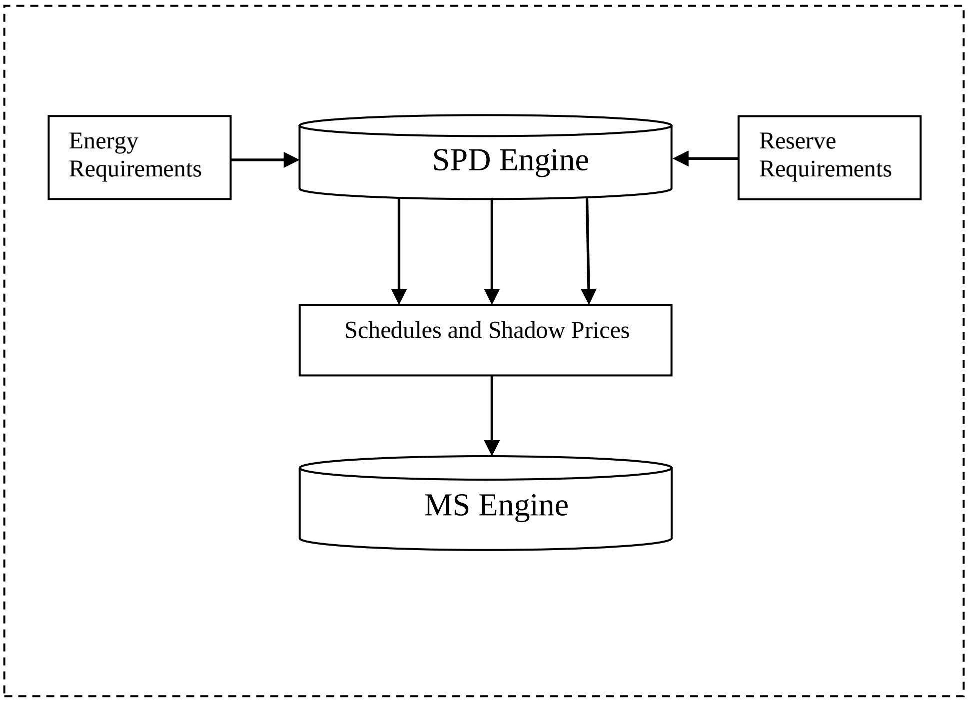

Figure 1.1 Market simulator

1.8 RESEARCH CONTRIBUTION

Guidelines for the creation of ancillary services markets is evolving based on experience of current markets. In such an environment, market simulation is an invaluable tool for market design and market monitoring. Different market structures can be tested and evaluated before implementation. Given the monetary value of energy markets, any simulation tool that provides the slightest gain in economic efficiency is a good investment.

The issue of market power in competitive markets is gaining much attention in the literature. The use of a market simulation tool for market monitoring purposes helps identify the existence of market power and helps analyse the strategic bidding patterns of market participants.

1.9 OVERVIEW OF STUDY

This chapter provides a brief introduction into ancillary services and ancillary services markets. The research problem, together with the research approach and research goals, is outlined.

Chapter 2 provides a critical analysis of the current body of knowledge on ancillary markets and energy pricing methods. Technical and economic aspects of ancillary service markets are researched and problems associated with the different types of auctions are highlighted.

Chapter 3 discusses the OPF problem and its extension from a static optimization problem to a multi-period optimization problem. Price definitions for energy and reserves in terms of Lagrangian values are presented and analyzed for suitability in terms of overcoming the problems highlighted in Chapter 2.

The co-optimization formulation for energy and reserves as presented in Chapter 3 is tested on the IEEE 24 bus reliability test system (RTS) in Chapter 4. Energy prices are analyzed at a nodal level while reserve prices are analyzed at a system and zonal level. The effect of congestion on the price of energy and reserves is also analyzed.

Chapter 5 discusses the application of the proposed pricing model to the South African power network. Energy and reserve prices are calculated for each of the power corridors in the Eskom network. Seasonal effects on prices are also investigated by simulating prices for a typical day in winter and summer.

Chapter 6 consists of a summary of findings and conclusions drawn from this research. Recommendations for future research emanating from this study are also made.

CHAPTER 2 LITERATURE STUDY

2.1 CHAPTER OBJECTIVES

The current body of knowledge on ancillary services markets is reviewed in this chapter. Technical and economic aspects are discussed and various design options for ancillary services markets are highlighted. The documented problems associated with sequential auctions are reviewed and a detailed analysis on the current state of research on simultaneous auctions is presented. Static and dynamic simultaneous auctions are discussed and gaps in the current body of knowledge are identified. The final part of the chapter reviews energy pricing methods. The advantages and disadvantages of each pricing method are highlighted.

2.2 ANCILLARY SERVICES MARKETS

The introduction of deregulation in the power industry in the 1990s gave impetus to research into ancillary services markets. The focus of the research was on extending the body of knowledge on market development in an attempt to create an enabling environment for deregulation. Technical and economic aspects of ancillary services were also researched so that markets could be created with full consideration of these aspects. Price discovery mechanisms of ancillary services have received ongoing attention, with new techniques being introduced to solve the SCUC problem and the OPF problem.

2.2.1 Technical and Economic Aspects

A general description of the most common ancillary services is presented by Raineri et al. [4]. Ancillary services pertaining to frequency control, power system co-ordination and operation, and system restoration are discussed. Key cost aspects of these services are also presented and the ancillary services markets of England and Wales, the Nordic countries, California, Argentina, Australia and Spain are analyzed. One of the conclusions drawn is that all markets rely on an independent system operator (ISO) to administer ancillary services.

The technical features of frequency and voltage control ancillary services are discussed by Rebours et al. [2]. Detailed discussions on the three levels of frequency control are presented. These are primary frequency control, secondary frequency control and tertiary frequency control. Different types of reserves are associated with each type of frequency control. Important technical parameters for primary frequency control include the droop characteristic of generators, deployment times of reserves and accuracy of measurements. Important parameters for secondary frequency control include the area control error and the deployment times of reserves. The technical specifications for these ancillary services in 11 different power systems are also reviewed.

The economic features for trading frequency and voltage control ancillary services are discussed by Rebours et al. [6]. Four methods for the procurement of ancillary services are discussed. These are compulsory provision, bilateral contracts, tendering, and spot market. Consequences of each method are discussed. The three methods for the remuneration of service providers are also discussed. These include payments based on a regulated price, a pay as bid price and a common market clearing price. The remuneration of service providers may combine several components that are intended to reflect the various costs a provider may incur. These include a fixed allowance, an availability price, a utilization payment, a utilization frequency price and opportunity cost payments. Other economic features for ancillary services markets include duration of contracts, frequency of review of ancillary services needs, price caps, market concentration and co-optimization of products. Compulsory provision of ancillary services and ancillary services markets are indicated as the methods to procure ancillary services in [7].

2.2.2 Design Options

Papalexopoulos and Singh [8] explore design options for ancillary services markets. Four design options are discussed. These options include sequential auctions, simultaneous auctions with downward substitution of reserves, pay as bid auctions and simultaneous optimization based ancillary services auctions. Potential problems and possible solutions for the various options are discussed. The definitions, operational requirements and other salient features of ancillary services products are also discussed. Oren [5] analyses the implications of various design alternatives within the framework of a simultaneous multiproduct framework. Market design alternatives are analyzed with respect to efficiency, distribution of gains between buyers and sellers and incentive compatibility. The design alternatives include simultaneous auctions with uniform pricing and social cost minimization, simultaneous auctions with uniform pricing and procurement cost minimization, and simultaneous auctions with pay as bid settlements. The study in [5] is extended by Kamat and Oren [9], who examine efficiency properties and incentive compatibility in the various design options.

Isemonger [10] presents an emerging set of core design parameters that are required for the optimal design of ancillary markets. This set of design parameters represents a rough consensus based on ancillary services markets utilized by various North American system operators. The design parameters include cascading procurement of ancillary services, pricing of ancillary services, number of markets, number of bid submissions, intertie provision of ancillary services, procurement cost allocation, regulation market differences, reserve market differences, scarcity pricing of reserves and reserves from loads.

Abbasy and Hakvoort [11] propose a generic framework for the design of balancing services markets. The design variables include the definition of balancing services, capacity and energy markets, reserve requirements, timing of markets, method of procurement and pricing mechanism. The high-level performance criteria include operational security and incentive compatibility.

2.2.3 Sequential Auctions

In the early stages of reform in the power industry, the auction for reserves was sequential. Separate auctions were held for each category of reserves, starting with reserves of the highest quality. Singh and Papalexopoulos [12] propose a separate auction for each category of reserves using capacity and energy bids, and a weighted probability of reserves for use in real-time. A similar design is proposed in [13]. A general discussion on sequential auctions can be found in [7], [10], [12]. Sequential auctions are susceptible to the phenomenon of "price reversal" where lower quality reserves are priced higher than higher quality reserves [5], [7], [8], [10], [12], [14], [15]. This is due to the market clearing price of each auction being independent of the prices of the subsequent auctions. ISOs, such as the California ISO, which opted for sequential auctions soon after deregulation, have embarked on various reforms in response to flaws in sequential markets [12], [14], [16], [17].

2.2.4 Simultaneous Auctions

Simultaneous auctions involving the co-optimization of energy and reserves have been extensively discussed in the literature [12], [14], [15], [17] – [30]. These studies can be grouped into multi-period (dynamic) studies [15], [18] – [25] and single-period (static) studies [14], [17], [26] – [30]. Furthermore, some studies are based on reserves of only one type [19] – [22], while other studies are based on reserves of more than one type [14], [15], [17], [18], [23] – [30]. In the co-optimization of energy and reserves, the scheduling and pricing of services is achieved using an optimization algorithm such as the unit commitment (UC) algorithm or the OPF algorithm. Co-optimization of energy and reserves based on the simultaneous solution of the UC and OPF problems is discussed [19]. UC formulations for the simultaneous co-optimization of energy and reserves can be found in [15], [18], [21], [25], [26], [28]. Decomposition techniques are employed in [15] and [18] to decompose the SCUC problem into a UC master problem and hourly network checking sub-problems. The problem is solved as a mixed integer problem in [21]. Lagrange relaxation-based procedures are used in [25] and [26]. The problem is solved as a mixed integer non-linear programming problem in [28].

OPF-based formulations for the co-optimization of energy and reserves can be found in [14], [20], [22], [27]. In [14], a formulation for the procurement of reserve services on a regional basis is presented. Regional reserve prices are defined in terms of Lagrange multipliers using a direct current (DC)-OPF-based formulation. In [20], the problem is solved over a multi-period planning horizon but inter-temporal constraints are not incorporated into the problem formulation. A dynamic OPF formulation for the co-optimization of energy and spinning reserves is presented in [22]. The problem is solved using a primal-dual interior point method. The formulation is however limited in that only spinning reserves are considered. A detailed AC-OPF-based formulation for the dispatch and pricing of energy in simultaneous markets is presented in [27]. The problem is solved using Lagrange relaxation. The locational marginal prices for energy and reserves of various types are defined in terms of Lagrange multipliers. The problem is formulated as a static problem and inter-temporal constraints are not considered.

A review of the literature does however indicate lack of research on multi-period simultaneous co-optimization of energy and reserves of more than one type.

2.2.5 Cascading of Reserves

Reserves are characterised according to their response time, with quicker responding reserves being of a higher quality than slower responding reserves. This hierarchical nature of reserves allows for higher quality reserves to be substituted for lower quality reserves. Efficient ancillary services markets must allow for such a substitution. Substitution of higher quality reserves for lower quality reserves is also referred to as downward substitution [5], [8], [10], [15], [18]. The substitutability of reserves leads to lower procurement costs, as shown in [10], and could also avoid the problem of price reversal among reserves.

2.3 ENERGY PRICING METHODS

The price of electricity is an important signal of the prevailing conditions in the power network to all market participants. In the absence of congestion and losses in the network, a uniform price is applicable throughout the system. In the case of congestion and losses, prices vary spatially throughout the network. Electricity pricing methods comprise uniform pricing methods and discriminatory pricing methods.

2.3.1 Uniform Pricing

Uniform pricing assumes that the impact of congestion on prices is insignificant and hence prices can be deemed uniform throughout the network. Uniform pricing is biased towards achieving market liquidity, which facilitates bilateral trading [31]. Under uniform pricing, the price of electricity is an approximation of the true underlying prices that result from the dispatch process. The uniform price is found by either averaging nodal prices or by simulating a dispatch in which some or all of the losses and congestion are ignored [32]. Advantages of uniform pricing include easy implementation and lower transaction costs. In cases where congestion is an issue, uniform pricing gives the wrong pricing signals to market participants and often requires manual intervention from the system operators for congestion alleviation [31].

2.3.2 Zonal Pricing

In the zonal pricing model, it is assumed that there are few transmission constraints and the network can be delineated into several zones that are separated by interface constraints. The zonal representation assumes that power can flow freely within the zone and therefore the price is uniform within each zone. Advantages of the zonal model include reduced complexity of the market [33]. Disadvantages include ineffective congestion management [33], [34].

2.3.3 Nodal Pricing

Nodal pricing involves calculating the market clearing price at each node of the power system. This pricing scheme is also termed 'Locational Marginal Pricing'. The price at each node represents the locational value of energy, including the cost of energy and the cost of delivery, which comprises losses and congestion. Advantages of nodal pricing include the promotion of efficient trading and the reflection of opportunity costs associated with the use of the transmission network. The nodal pricing method has proved its effectiveness in achieving congestion relief and market efficiency [31]. This is achieved using detailed modeling of power flows on the network. Disadvantages include the complexity of the method and its implementation [33].

2.4 CONCLUSION

The current state of ancillary services markets is discussed in this chapter. Technical and economic aspects of ancillary services are key considerations in designing ancillary services markets. Technical aspects of ancillary services include three levels of frequency control. These are primary frequency control, secondary frequency control and tertiary frequency control. Different types of reserves are associated with each type of frequency control. Economic aspects of ancillary services markets include methods for procurement of ancillary services and settlements for ancillary services.

Sequential and simultaneous auctions are two design options for ancillary services markets. A key flaw of sequential auctions is the phenomenon of ‘price reversal’, where lower quality reserves are priced higher than higher quality reserves. A key feature of simultaneous auctions is the co-optimization of energy and reserves, and the scheduling and pricing of services can be achieved using an optimization algorithm such as the OPF algorithm.

The hierarchical nature of reserves allows for the downward substitution of higher quality reserves for lower quality reserves. Such a substitution leads to lower procurement costs and could also avoid the problem of “price reversal” among reserves.

An OPF formulation for the co-optimization of energy and reserves of various types is presented in the next chapter. Prices for energy and reserves are defined in terms of Lagrange multipliers to enable price cascading of reserves and the elimination of the problem of ‘price reversal’ among reserves.

CHAPTER 3 OPTIMAL POWER FLOW

3.1 CHAPTER OBJECTIVES

An OPF based formulation for the simultaneous auction of energy and reserves over a multi-period planning horizon is presented. Energy and reserve prices are defined in terms of Lagrange multipliers to enable price cascading of reserves. Pricing requirements under conditions of downward substitution of reserves are established. The OPF based market application used in this study for the scheduling and pricing of resources is introduced and the mathematics behind the primal-dual interior point OPF solver used in the market application is discussed.

3.2 OPF FORMULATION

The ongoing restructuring of the electric power industry has imposed both economic and technical challenges. Economic problems related to electricity pricing and transaction mechanisms plague restructured markets. Technical challenges in market-oriented systems relate mainly to security and reliability issues [35]. Both these challenges are a result of the increased power system size and complex interconnections brought about by the deregulated market environment.

Economic dispatch (ED) and power flow are key applications in power systems operations. ED addresses the issues pertaining to the economics of power systems operation, while system security and reliability issues are addressed by the power flow application. The OPF application, which combines the ED and power flow, integrates the economics and security of the power system. Electricity pricing and reserves pricing are key issues in power system economics. Power system security and reliability involves ensuring that the power system operates within its limits and a key aspect of this is transmission management. Issues of transmission access and auxiliary costing are dealt with by using an OPF in an attempt to determine fair pricing and purchases [36].

The OPF problem is a nonlinear optimization problem that is used to determine the optimal values of control variables used to evaluate some objective function subject to certain system constraints. The standard form of the OPF problem is as follows:

$$\min f(x) \tag{3.1}$$

$$\text{subject to } g(x) = 0$$

$$h(x) \leq 0$$

$$x_{min} \leq x_{max}$$

where

x: Control variables vector. Typical control variables include bus voltage magnitudes and phase angles, generator power outputs, transformer tap settings and phase shifter angles.

f: Objective function to be optimized and generally represents generator costs.

g: Equality constraints consisting of the load flow equations.

h: Inequality constraints, typically consisting of generator capacity and transmission line flow constraints.

Two distinct formulations can be used in (3.1). The first uses a formulation in which the equality constraint in (3.1) comprises the power balance equations for real and reactive power and the inequality constraint comprises branch flow limits as non-linear functions of bus voltage magnitudes and angles. This formulation is referred to as the AC OPF problem. In the second formulation voltage magnitudes and reactive power are eliminated from the problem under certain assumptions [37], [38] and power flows are modeled as linear functions of the voltage angles. This formulation is referred to as the DC OPF problem.

3.3 OPF ALGORITHMS

Progress in the development of the OPF has closely tracked progress in numerical optimization techniques and advances in computer technology [36]. This has led to the development of commercial OPF programs that are able to solve very large and complex problems in a relatively short period of time. Any proposed solution to the OPF problem must meet the following requirements [39]:

1. Reliability

OPF calculations must be reliable for application in real-time. Solutions must converge to realistic answers to give credence to the OPF as a planning tool.

2. Speed

The OPF problem is a non-linear problem involving thousands of variables. It is therefore necessary to use solution techniques with fast convergence.

3. Flexibility

OPF solution methods simulate real-life power system operation and control. New requirements are therefore continually being defined for OPF solutions. This consequently requires robust and flexible OPF algorithms that must accommodate a wide range of objectives and constraints.

4. Maintainability

An OPF algorithm must include easy-to-maintain features for real-time applications because of new developments in system models.

Many different solution techniques exist to solve the OPF problem. The earliest OPF algorithms stem from classical mathematical programming methods. These include linear programming, quadratic programming, nonlinear programming, and interior point methods. Artificial intelligence methods such as genetic algorithms, evolutionary programming, and particle swarm optimization have also been used to overcome some of the drawbacks of conventional techniques. A review of OPF solution methods can be found in [39], [40].

The OPF problem in the context of deregulated electricity markets is discussed in [39], [41] – [43]. Application of OPF in electricity markets covers many areas. These include among others locational real-time pricing, network congestion management, available transfer capability estimation and transmission fee determination. OPF based tools in electricity market applications must provide the following [41], [42]:

1. Deterministic convergence.
2. Accurate computation of nodal prices.
3. Capability to handle both convex and non-convex cost functions.
4. Full modelling of active and reactive power flows for large-scale systems.
5. Satisfactory worst case performance that meets the requirements of real-time dispatching.

3.4 MULTI-PERIOD CO-OPTIMIZATION PROBLEM FORMULATION

The extension of the standard OPF problem into a multi-period co-optimization problem involving energy and reserves is illustrated below. Four types of reserves are considered in the formulation. These are RR, 10-minute spinning reserves (TMSR), 10-minute non-spinning reserves (TMNSR) and 30-minute operating reserves (TMOR). C_i is the cost associated with generator i. P_{Gi}^t is the active power output from generator i at time t. RR_{Gi}^t is the RR supplied by generator i at time t, $TMSR_{Gi}^t$ is the TMSR supplied by generator i at time t, $TMNSR_{Gi}^t$ is the TMNSR supplied by generator i at time t and $TMOR_{Gi}^t$ is the TMOR supplied by generator i at time t. T is the planning horizon in hours and N is the number of generators.

$$\min \sum_{t=1}^{T} \sum_{i=1}^{N} [C_i\,(P_{Gi}^t) + C_i(RR_{Gi}^t) + C_i(TMSR_{Gi}^t) + C_i(TMNSR_{Gi}^t) + C_i(TMOR_{Gi}^t)] \quad (3.2)$$

subject to

Power – balance constraints:

$P_j^t(V,\theta) = P_{Gj}^t - P_{Dj}^t$ $\qquad j = 1, 2, ..., J; \quad t = 1, 2, ..., T$

$Q_j^t(V,\theta) = Q_{Gj}^t - Q_{Dj}^t$ $\qquad j = 1, 2, ..., J; \quad t = 1, 2, ..., T$

where

J: The number of buses in the network.

P_j^t: The active power injection at bus j at time t.

Q_j^t: The reactive power injection at bus j at time t.

P_{Gj}^t: The total active power output of the generators connected to bus j at time t.

Q_{Gj}^t: The total reactive power output of the generators connected to bus j at time t.

P_{Dj}^{t}: The total active power load connected to bus j at time t.

Q_{Dj}^{t}: The total reactive power load connected to bus j at time t.

Reserve requirement constraints:

$\sum_{i=1}^{N} RR_{Gi}^{t} \geq RR^{t}$ $\quad t = 1, 2, ..., T$

$\sum_{i=1}^{N} RR_{Gi}^{t} + \sum_{i=1}^{N} TMSR_{Gi}^{t} \geq RR^{t} + TMSR^{t}$ $\quad t = 1, 2, ..., T$

$\sum_{i=1}^{N} RR_{Gi}^{t} + \sum_{i=1}^{N} TMSR_{Gi}^{t} + \sum_{i=1}^{N} TMNSR_{Gi}^{t} \geq RR^{t} + TMSR^{t} + TMNSR^{t}$ $\quad t = 1, 2, ..., T$

$\sum_{i=1}^{N} RR_{Gi}^{t} + \sum_{i=1}^{N} TMSR_{Gi}^{t} + \sum_{i=1}^{N} TMNSR_{Gi}^{t} + \sum_{i=1}^{N} TMOR_{Gi}^{t} \geq RR^{t} + TMSR^{t} + TMNSR^{t} + TMOR^{t}$ $\quad t = 1, 2, ..., T$

where

RR^{t}: The RR requirement at time t.

$TMSR^{t}$: The TMSR requirement at time t.

$TMNSR^{t}$: The TMNSR requirement at time t.

$TMOR^{t}$: The TMOR requirement at time t.

Capacity constraints:

$P_{Gi}^{t} + RR_{Gi}^{t} + TMSR_{Gi}^{t} + TMNSR_{Gi}^{t} + TMOR_{Gi}^{t} \leq P_{Gi}^{max}$ $\quad i = 1, 2, ..., N; \quad t = 1, 2, ..., T$

$P_{Gi}^{t} + RR_{Gi}^{t} + TMSR_{Gi}^{t} + TMNSR_{Gi}^{t} + TMOR_{Gi}^{t} \geq P_{Gi}^{min}$ $\quad i = 1, 2, ..., N; \quad t = 1, 2, ..., T$

$RR_{Gi}^{t} \leq RR_{Gi}^{max}$ $\quad i = 1, 2, ..., N; \quad t = 1, 2, ..., T$

$TMSR_{Gi}^{t} \leq TMSR_{Gi}^{max}$ $\quad i = 1, 2, ..., N; \quad t = 1, 2, ..., T$

$TMNSR_{Gi}^{t} \leq TMNSR_{Gi}^{max}$ $\quad i = 1, 2, ..., N; \quad t = 1, 2, ..., T$

$TMOR_{Gi}^{t} \leq TMOR_{Gi}^{max}$ $\quad i = 1, 2, ..., N; \quad t = 1, 2, ..., T$

where

P_{Gi}^{max}: The maximum active power output from generator i.

P_{Gi}^{min}: The minimum active power output from generator i.

RR_{Gi}^{max}: The maximum regulation reserves available from generator i.

$TMSR_{Gi}^{max}$: The maximum TMSR available from generator i.

$TMNSR_{Gi}^{max}$: The maximum TMNSR available from generator i.

$TMOR_{Gi}^{max}$: The maximum TMOR available from generator i.

Ramp rate constraints:

$-DR_{Gi} \leq P_{Gi}^{t+1} - P_{Gi}^{t} \leq UR_{Gi}$ $\quad$ i = 1, 2, ..., N; t = 1, 2, ..., T

where

DR_{Gi}: The active power ramp down limit of generator i.

UR_{Gi}: The active power ramp up limit of generator i.

Branch flow constraints:

$-F_b^{max} \leq F_b^t \leq F_b^{max}$ $\quad$ b = 1, 2, ..., B; t = 1, 2, ..., T

where

F_b^t: The active power flow in branch b at time t.

B: The number of branches in the network.

F_b^{max}: The maximum active power flow limit in branch b.

3.5 DEFINITION OF PRICES FOR ENERGY AND RESERVES

The price of energy and that of each type of reserve, over each time period t, is derived from the Lagrangian function for the optimization problem in (3.2). The Lagrange multipliers and the associated constraints are as follows:

λ: Power balance constraints.

μ: Reserve requirements constraints.

ν: Capacity constraints.

ρ: Ramp rate constraints.

σ: Branch flow constraints.

The Lagrangian function L, for each time period t, for the optimization problem in (3.2) is given on the next page.

$$L = \sum_{i=1}^{N}[C_i\,(P_{Gi}^t) + C_i(RR_{Gi}^t) + C_i(TMSR_{Gi}^t) + C_i(TMNSR_{Gi}^t) + C_i(TMOR_{Gi}^t)]$$
$$+ \lambda_{Pj}^t[P_j^t - P_{Gj}^t + P_{Dj}^t] + \lambda_{Qj}^t[Q_j^t - Q_{Gj}^t + Q_{Dj}^t]$$
$$+ \mu_{RR}^t[RR^t - \sum_{i=1}^{N} RR_{Gi}^t] + \mu_{TMSR}^t[RR^t + TMSR^t - \sum_{i=1}^{N} RR_{Gi}^t - \sum_{i=1}^{N} TMSR_{Gi}^t]$$
$$+ \mu_{TMNSR}^t[RR^t + TMSR^t + TMNSR^t - \sum_{i=1}^{N} RR_{Gi}^t - \sum_{i=1}^{N} TMSR_{Gi}^t - \sum_{i=1}^{N} TMNSR_{Gi}^t]$$
$$+\mu_{TMOR}^t[RR^t + TMSR^t + TMNSR^t + TMOR^t - \sum_{i=1}^{N} RR_{Gi}^t - \sum_{i=1}^{N} TMSR_{Gi}^t - \sum_{i=1}^{N} TMNSR_{Gi}^t - \sum_{i=1}^{N} TMOR_{Gi}^t]$$
$$+ \nu_{Pmax}^t[P_{Gi}^t + RR_{Gi}^t + TMSR_{Gi}^t + TMNSR_{Gi}^t + TMOR_{Gi}^t - P_{Gi}^{max}]$$
$$+ \nu_{Pmin}^t[P_{Gi}^{min} - P_{Gi}^t - RR_{Gi}^t - TMSR_{Gi}^t - TMNSR_{Gi}^t - TMOR_{Gi}^t]$$
$$+ \nu_{RRmax}^t[RR_{Gi}^t - RR_{Gi}^{max}] + \nu_{TMSRmax}^t[TMSR_{Gi}^t - TMSR_{Gi}^{max}]$$
$$+ \nu_{TMNSRmax}^t[TMNSR_{Gi}^t - TMNSR_{Gi}^{max}] + \nu_{TMORmax}^t[TMOR_{Gi}^t - TMOR_{Gi}^{max}]$$
$$+ \rho_{UR}^t[P_{Gi}^{t+1} - P_{Gi}^t - UR_{Gi}] + \rho_{DR}^t\,[-UR_{Gi} - P_{Gi}^t + P_{Gi}^{t+1}]$$
$$+ \sigma_{Fb\,max}^t[F_b^t - F_b^{max}] \quad (3.3)$$

3.5.1 Energy Price

The price of energy at each node J is defined as the incremental cost of supplying an additional megawatt of power at node J. An additional megawatt of power at node J will cause a change in the power flow at node J. This will result in a change in the power flow equation at node J. The incremental cost of energy at node J is therefore the incremental change in the Lagrangian due to an incremental change in the power flow at node J. Using (3.3), the incremental cost of energy for any time period t is given by

$$\frac{\partial L}{\partial[P_j^t - P_{Gi}^t - D_{Gi}^t]} = \lambda_{Pj}^t \quad (3.4)$$

3.5.2 Reserve Prices

The price of each type of reserve is defined as the incremental cost of supplying an additional megawatt of the type of reserve. The incremental cost is therefore the incremental change in the Lagrangian due to an incremental change in the system reserves requirement. Using (3.3), the incremental cost of RR, TMSR, TMNSR and TMOR at any time period t is given by

$$\frac{\partial L}{\partial[RRt]} = \mu_{RR}^t + \mu_{TMSR}^t + \mu_{TMNSR}^t + \mu_{TMOR}^t \quad (3.5)$$

$$\frac{\partial L}{\partial [TMSR^t]} = \mu_{TMSR}^t + \mu_{TMNSR}^t + \mu_{TMOR}^t \tag{3.6}$$

$$\frac{\partial L}{\partial [TMNSR^t]} = \mu_{TMNSR}^t + \mu_{TMOR}^t \tag{3.7}$$

$$\frac{\partial L}{\partial [TMOR^t]} = \mu_{TMOR}^t \tag{3.8}$$

3.6 PRICE REVERSAL ISSUES

The pricing formulation for the different types of reserves as outlined in (3.5) – (3.8) eradicates the phenomenon of "price reversal", where lower quality services are priced higher than higher quality services. The following relationships are derived from (3.5) – (3.8) and are based on the non-negativity of the Lagrange multipliers:

$$\mu_{RR}^t + \mu_{TMSR}^t + \mu_{TMNSR}^t + \mu_{TMOR}^t \geq \mu_{TMSR}^t + \mu_{TMNSR}^t + \mu_{TMOR}^t \geq \mu_{TMNSR}^t + \mu_{TMOR}^t \geq \mu_{TMOR}^t \tag{3.9}$$

$$\frac{\partial L}{\partial [RR^t]} \geq \frac{\partial L}{\partial [TMSR^t]} \geq \frac{\partial L}{\partial [TMNSR^t]} \geq \frac{\partial L}{\partial [TMOR^t]} \tag{3.10}$$

Relationships (3.9) and (3.10) show that the prices of reserves are cascaded and the prices are reflective of the quality of the reserves. RR, which is of the highest quality in the current analysis, is priced higher than the other three reserve types.

3.6.1 Downward Substitution

An essential requirement of the reserves market is that higher quality reserves may be substituted for lower quality reserves. The effect of such a requirement on the price of reserves is investigated for the case where RR is procured to meet some of the TMSR requirement. Under such conditions the RR procured will exceed the system requirement for RR. For any time period t,

$$\sum_{i=1}^{N} RR_{Gi}^t > RR^t$$

By the Karush Kuhn Tucker conditions

$$\mu_{RR}^t \, [RR^t - \sum_{i=1}^{N} RR_{Gi}^t] = 0$$

Therefore

$$\mu_{RR}^t = 0$$

From (3.5)

$$\frac{\partial L}{\partial [RRt]} = \mu_{TMSR}^{t} + \mu_{TMNSR}^{t} + \mu_{TMOR}^{t}$$

From (3.6)

$$\frac{\partial L}{\partial [TMSRt]} = \mu_{TMSR}^{t} + \mu_{TMNSR}^{t} + \mu_{TMOR}^{t}$$

Therefore

$$\frac{\partial L}{\partial [RRt]} = \frac{\partial L}{\partial [TMSRt]} \tag{3.11}$$

Equation (3.11) shows that the prices of the two types of reserves are equal under conditions of downward substitution.

3.7 MATPOWER

Matpower is an open-source Matlab based power systems simulation package, which is widely used in research and education for power flow and OPF studies. It is often used as an end user tool for running one-shot single period simulations defined via an input file. Matpower also includes tools for running OPF-based simultaneous auctions involving energy and reserves [38]. At the lower level, Matpower provides easy-to-use functions for power system analysis, while at the higher level, the structure of the OPF implementation is explicitly designed to be extensible, thus allowing for the addition of user-defined variables, costs and linear constraints [44].

The default OPF solver in Matpower is a primal-dual interior point solver. The solver is implemented in Matlab code and is based on Newton's method, using a polar form and a full Jacobian updated at each iteration. Each Newton step involves computing the real and reactive power bus mismatches, forming the Jacobian based on the sensitivities of these mismatches to changes in the optimization vector x, and solving for an updated value of x by factoring this Jacobian [38].

3.7.1 Primal-Dual Interior Point Algorithm

The default OPF solver in MATPOWER is a primal-dual interior point solver. Details of the algorithm used are taken from [45] and are outlined below. The standard optimization problem is:

$$\min \mathrm{f(x)} \tag{3.12}$$

$$\text{subject to } \mathrm{g(x)} = 0 \tag{3.13}$$

$$\mathrm{h(x)} \leq 0 \tag{3.14}$$

where the linear constraints and variable bounds have been incorporated into g(x) and h(x). The approach involves converting the inequality constraints (3.14) into equality constraints using a barrier function and a vector Z consisting of positive slack variables. The optimization problem then translates to:

$$\min\,[f(x) - \gamma \textstyle\sum_1^{ni} \ln(Z_m)] \tag{3.15}$$

$$\text{subject to } \mathrm{g(x)} = 0 \tag{3.16}$$

$$\mathrm{h(x)} + \mathrm{Z} = 0 \tag{3.17}$$

$$\mathrm{Z} > 0 \tag{3.18}$$

For a given value of γ, the Lagrangian for equality constrained problem in (3.15) is

$$L^\gamma(x, Z, \lambda, \mu) = f(x) + \lambda^T g(x) + \mu^T (h(x) + Z) - \gamma \sum_1^{ni} \ln(Z_m) \tag{3.19}$$

Taking partial derivatives with respect to each of the variables gives

$$\frac{\partial L^\gamma}{\partial x} = \frac{\partial f}{\partial x} + \lambda^T \frac{\partial g}{\partial x} + \mu^T \frac{\partial h}{\partial x} \tag{3.20}$$

$$\frac{\partial L^\gamma}{\partial z} = \mu^T - \gamma e^T [Z]^{-1} \tag{3.21}$$

$$\frac{\partial L^\gamma}{\partial \lambda} = g^T(x) \tag{3.22}$$

$$\frac{\partial L^\gamma}{\partial \mu} = h^T(x) + z^T \tag{3.23}$$

The Hessian of the Lagrangian with respect to x is given by

$$\frac{\partial^2 L^\gamma}{\partial x^2} = \frac{\partial^2 f}{\partial x^2} + \lambda^T \frac{\partial^2 g}{\partial x^2} + \mu^T \frac{\partial^2 h}{\partial x^2} \tag{3.24}$$

By the Karush Kuhn Tucker conditions

$$F(x, Z, \lambda, \mu) = \begin{bmatrix} \frac{\partial f^T}{\partial x} + \frac{\partial g^T \lambda}{\partial x} + \frac{\partial h^T \mu}{\partial x} \\ \mu Z - \gamma e \\ g(x) \\ h(x) + z \end{bmatrix} = \begin{bmatrix} 0 \\ 0 \\ 0 \\ 0 \end{bmatrix} \quad (3.25)$$

Equation (3.25) is solved using Newton's method. The Newton update step is obtained as follows:

$$\begin{bmatrix} \frac{\partial^2 L^\gamma}{\partial x^2} & 0 & \frac{\partial g^T}{\partial x} & \frac{\partial h^T}{\partial x} \\ 0 & \mu & 0 & Z \\ \frac{\partial g}{\partial x} & 0 & 0 & 0 \\ \frac{\partial h}{\partial x} & I & 0 & 0 \end{bmatrix} \begin{bmatrix} \Delta x \\ \Delta Z \\ \Delta \lambda \\ \Delta \mu \end{bmatrix} = - \begin{bmatrix} \frac{\partial L^\gamma}{\partial x} \\ \mu Z - \gamma e \\ g(x) \\ h(x) + z \end{bmatrix} \quad (3.26)$$

From the second row of (3.26)

$$\Delta \mu = -\mu + Z^{-1}(\gamma e - \mu \Delta Z) \quad (3.27)$$

From the fourth row of (3.26)

$$\Delta Z = -h(x) - Z - \frac{\partial h}{\partial x} \Delta x \quad (3.28)$$

Substituting (3.27) and (3.28) into the first row of (3.26) results in

$$\frac{\partial^2 L^\gamma}{\partial x^2} \Delta x + \frac{\partial g^T}{\partial x} \Delta \lambda + \frac{\partial h^T}{\partial x} \left\{ -\mu + Z^{-1} \left[\gamma e - \mu \left(-h(x) - Z - \frac{\partial h}{\partial x} \Delta x \right) \right] \right\} = - \frac{\partial L^\gamma}{\partial x} \quad (3.29)$$

Equation (3.29) simplifies to

$$\left(\frac{\partial^2 L^\gamma}{\partial x^2} + \frac{\partial h^T}{\partial x} Z^{-1} \mu \frac{\partial h}{\partial x}\right) \Delta x + \frac{\partial g^T}{\partial x} \Delta \lambda + \frac{\partial h^T}{\partial x} Z^{-1} \left(\gamma e + \mu h(x)\right) = - \frac{\partial L^\gamma}{\partial x} \quad (3.30)$$

From (3.30)

$$\left(\frac{\partial^2 L^\gamma}{\partial x^2} + \frac{\partial h^T}{\partial x} Z^{-1} \mu \frac{\partial h}{\partial x}\right) \Delta x + \frac{\partial g^T}{\partial x} \Delta \lambda = - \frac{\partial L^\gamma}{\partial x} - \frac{\partial h^T}{\partial x} Z^{-1} \left(\gamma e + \mu h(x)\right) \quad (3.31)$$

If M = $\frac{\partial^2 L^\gamma}{\partial x^2} + \frac{\partial h^T}{\partial x} Z^{-1} \mu \frac{\partial h}{\partial x}$ and N = $\frac{\partial L^\gamma}{\partial x} + \frac{\partial h^T}{\partial x} Z^{-1} \left(\gamma e + \mu h(x)\right)$, equation (3.31) can be written as

$$\mathrm{M} \Delta x + \frac{\partial g^T}{\partial x} \Delta \lambda = -N \quad (3.32)$$

Combining (3.32) and the third row of (3.26) results in a system of equations of reduced size:

$$\begin{bmatrix} M & \frac{\partial g^T}{\partial x} \\ \frac{\partial g}{\partial x} & 0 \end{bmatrix} \begin{bmatrix} \Delta x \\ \Delta \lambda \end{bmatrix} = \begin{bmatrix} -N \\ -g(x) \end{bmatrix} \tag{3.33}$$

The Newton update can be calculated as follows:

1. Compute Δx and $\Delta \lambda$ from (3.33).

2. Compute ΔZ from (3.28).

3. Compute $\Delta \mu$ from (3.27).

Strict feasibility of the trial solution is maintained by truncating the Newton step. This is achieved by scaling the primal and dual variables by α_p and α_d respectively.

$$\alpha_p = \min(\xi min_{\Delta\mu_m<0}\left(-\frac{Z_m}{\Delta\mu_m}\right), 1) \tag{3.34}$$

$$\alpha_d = \min(\xi min_{\Delta\mu_m<0}\left(-\frac{\mu_m}{\Delta\mu_m}\right), 1) \tag{3.35}$$

Using (3.34) and (3.35) the Newton updates are

$$x = x + \alpha_p \Delta x \tag{3.36}$$

$$Z = Z + \alpha_p \Delta Z \tag{3.37}$$

$$\lambda = \lambda + \alpha_d \Delta \lambda \tag{3.38}$$

$$\mu = \mu + \alpha_d \Delta \mu \tag{3.39}$$

The parameter ξ is a constant scalar that is slightly less than 1 and in MATPOWER ξ is set to 0.99995.

3.8 CONCLUSION

An OPF formulation for the co-optimization of energy and reserves over a multi-period planning horizon is discussed in this chapter. Four types of reserves are considered in the formulation. Prices for energy and each type of reserve are defined in terms of Lagrange multipliers. The proposed pricing of reserves leads to the cascading of prices, with higher quality reserves being priced higher than lower quality reserves. Furthermore, the proposed pricing formulation facilitates the downward substitution of reserves and in such cases the prices of the different types of reserves are equal.

The proposed OPF formulation for integrated markets is incorporated into MATPOWER and is tested on the IEEE 24 bus RTS in the next chapter.

CHAPTER 4 IEEE 24 BUS RELIABILITY TEST SYSTEM SIMULATION RESULTS

4.1 CHAPTER OBJECTIVES

In this chapter, the multi-period co-optimization of energy and reserves as proposed in the previous chapter is tested on an IEEE test system. The proposed price definitions for energy and reserves are implemented on the test system and it is demonstrated that these price definitions lead to cascading of prices, with higher quality reserves being more expensive than lower quality reserves. It is also shown that when higher quality reserves are substituted for lower quality reserves, the prices of the reserve types are equal.

The proposed pricing strategy is investigated for two fundamental cases of specifying reserve requirements. The price of energy and reserves is determined when reserve requirements are set at a system level. This is followed by the case where energy and reserve prices are determined when the reserve requirements are set at zonal level. The settlement amounts to suppliers of these services are also determined for each of the scenarios mentioned. This economic analysis of the simultaneous auction of energy and reserves is undertaken for the cases were the test system is operated under uncongested and under congested conditions.

4.2 IEEE 24 BUS RELIABILITY TEST SYSTEM

A simultaneous auction involving the co-optimization of energy and reserves of more than one type is performed on the IEEE 24 bus RTS using the MATPOWER simulation package [38], [44], [45]. The test system is illustrated in Figure 4.1 and consists of 24 buses, 32 generators and 17 constant power loads [46]. Additional data for the RTS including generator cost coefficients, generator active power operating limits, generator reserve bids and reserve capacity can be found in Table A.1 and Table A.2 in Appendix A. It should be noted that the six generators at bus 22 of the RTS are hydro-generators and do not participate in the market. Their output is fixed at a maximum capacity of 50 MW at all hours. The reserves are disaggregated into RR, TMSR, TMNSR and TMOR. The energy cost function for generator i is defined as:

$$C(P_{Gi}) = a_i P_{Gi}^2 + b_i P_{Gi} + c_i \tag{4.1}$$

where

P_{Gi} : The active power output of the generator i.

a_i , b_i and c_i are constant coefficients.

The simultaneous auction of energy and reserves is performed over a 24-hour period. The hourly load demand used in the simulations corresponds to Tuesday of Week 51 of the RTS system [46]. The hourly load and reserve requirements used to clear the markets are given in Table A.3 in the appendix. The hourly reserve requirements were kept constant over 24 hours.

The three standard pricing methods, comprising uniform pricing, zonal pricing and nodal pricing, are investigated. Hourly energy and reserve prices, as well as the generator settlements, are determined for each of these methods. In each of the cases considered, the price of energy is determined at a nodal level. Under uniform pricing, the test system is considered as a single zone and a uniform price per hour is determined for each class of reserve. Under zonal pricing, the optimal number of zones is first determined using fuzzy clustering. The reserves prices are then determined for each of the identified zones. The effect of transmission congestion on prices is also investigated. A critical branch between the congestion zones of the network is identified and removed from service, and the effect on energy and reserves prices is investigated.

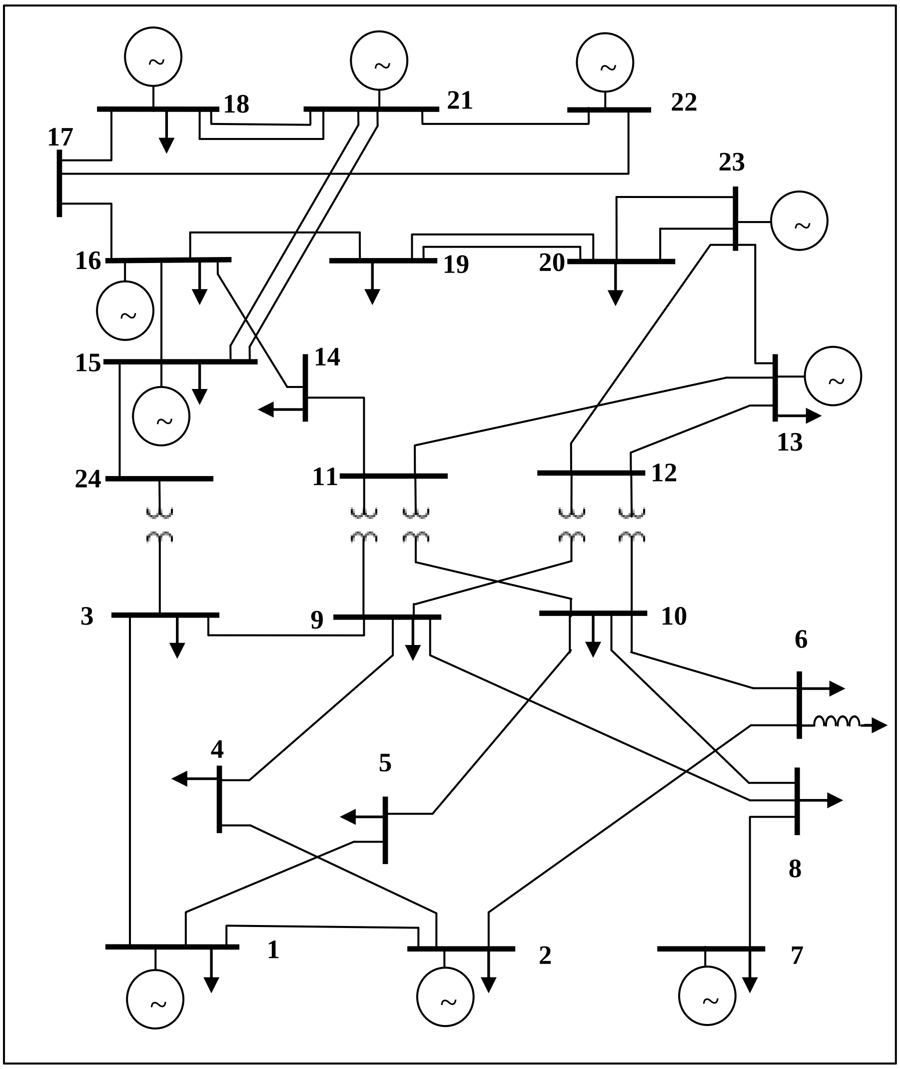

Figure 4.1 IEEE 24 bus reliability test system

4.3 SINGLE-PERIOD CO-OPTIMIZATION

The formulation for the co-optimization of energy and reserves is verified by performing a single-period co-optimization on the IEEE 24 bus RTS. The single period under consideration corresponds to hour 18 or hour 19, which are the periods of maximum demand on the system. The hourly load and reserve requirements are given in Table A.3 in the appendix. The hourly load requirement is 2850 MW. The RR and TMSR requirements for the hour are set to 130 MW, while the TMNSR and TMOR requirements are set to 100

MW. These values are the same as those used in [28], where the same test system is used for the joint clearing of energy and reserves.

The energy and reserves dispatch, together with the minimum and maximum capacities, for the 32 generators is given in Table 4.1. Table 4.1 shows that the total dispatch of all generators lie within their minimum and maximum output limits. The reserves dispatched at each generator are within the maximum reserve limits as given in Table A.2 in the appendix. The total energy dispatched for the hour is 2891.5 MW. This is higher than the load requirement of 2850 MW because of losses in the network. The total RR dispatched during the hour is 156.4 MW. This is higher than the RR requirement of 130 MW. There is therefore an oversupply of 26.4 MW of RR. The total TMSR dispatched during the hour is 103.6 MW. This is less than the TMSR requirement of 130 MW. There is therefore an undersupply of 26.4 MW of TMSR. The oversupply of RR is used to compensate for the undersupply of TMSR, thus confirming the downward substitution of higher quality reserves for lower quality reserves. The dispatch of TMSR and TMOR is equal to their requirements of 100 MW.

The nodal energy prices for the 24 buses are shown in Table 4.2. These prices correspond to the Lagrange multipliers for the power balance equations at each node, as shown in (3.4). The maximum energy price is \$38.25 per MWh at Bus 6 and the minimum energy price is \$33.38 per MWh at Bus 22. The Lagrange multipliers for the reserve requirement constraints, together with the price for each type of reserves, are shown in Table 4.3. The reserve prices are calculated based on (3.5) – (3.8). Table 4.3 shows that higher quality reserves are priced higher than lower quality reserves, thus confirming no price reversal of products. The price of RR and that of TMSR is the same, thus confirming that prices are equal under downward substitution. The prices of RR, TMSR and TMNSR are greater than the average energy price of \$36.14, thereby incentivising suppliers to participate in the reserve markets.

Table 4.1

Generator dispatch for single-period co-optimization

Generator Number	Energy (MW)	RR (MW)	TMSR (MW)	TMNSR (MW)	TMOR (MW)	Total (MW)	P_{MIN} (MW)	P_{MAX} (MW)
1	16.0	0.0	4.0	0.0	0.0	20.0	16.0	20.0
2	16.0	0.0	4.0	0.0	0.0	20.0	16.0	20.0
3	46.0	0.0	15.0	15.0	0.0	76.0	15.0	76.0
4	44.0	0.0	15.0	17.0	0.0	76.0	15.0	76.0
5	16.0	0.0	4.0	0.0	0.0	20.0	16.0	20.0
6	16.0	0.0	4.0	0.0	0.0	20.0	16.0	20.0
7	43.0	0.0	15.0	18.0	0.0	76.0	15.0	76.0
8	43.0	0.0	15.0	18.0	0.0	76.0	15.0	76.0
9	79.6	0.0	2.6	0.0	0.0	82.2	25.0	100.0
10	79.6	0.0	2.6	0.0	0.0	82.2	25.0	100.0
11	79.6	0.0	2.6	0.0	0.0	82.2	25.0	100.0
12	163.7	0.0	0.0	0.0	33.3	163.7	69.0	197.0
13	163.7	0.0	0.0	0.0	33.3	163.7	69.0	197.0
14	163.7	0.0	0.0	0.0	33.3	163.7	69.0	197.0
15	2.4	9.6	0.0	0.0	0.0	12.0	2.0	12.0
16	2.4	9.6	0.0	0.0	0.0	12.0	2.0	12.0
17	2.4	9.6	0.0	0.0	0.0	12.0	2.0	12.0
18	2.4	9.6	0.0	0.0	0.0	12.0	2.0	12.0
19	2.4	9.6	0.0	0.0	0.0	12.0	2.0	12.0
20	140.6	7.4	6.9	0.0	0.0	155.0	54.0	155.0
21	143.1	11.9	0.0	0.0	0.0	155.0	54.0	155.0
22	362.0	38.0	0.0	0.0	0.0	400.0	100.0	400.0
23	362.0	38.0	0.0	0.0	0.0	400.0	100.0	400.0
24	50.0	0.0	0.0	0.0	0.0	50.0	100.0	50.0
25	50.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0
26	50.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0
27	50.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0
28	50.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0
29	50.0	0.0	0.0	0.0	0.0	50.0	50.0	50.0
30	150.0	0.0	0.0	5.0	0.0	155.0	54.0	155.0
31	150.0	0.0	0.0	5.0	0.0	155.0	54.0	155.0
32	302.0	13.0	13.0	22.0	0.0	350.0	140.0	350.0
Total	2891.5	156.4	103.6	100.0	100.0			

The total cost and total payment to suppliers is given in Table 4.4. The proposed pricing strategy, as discussed in Chapter 3, results in a profit for all products. The total payment to suppliers is lower than that presented in [28] for the same test case. The payment to suppliers is the procurement cost incurred by the ISO and one of the goals of restructured electricity markets is to reduce procurement costs.

Table 4.2
Nodal energy prices for single-period co-optimization

Bus Number	1	2	3	4	5	6	7	8	9	10	11	12
Price ($/MWh)	37.55	37.58	36.73	37.95	37.86	38.25	36.55	37.83	36.76	37.04	36.65	36.52
Bus Number	13	14	15	16	17	18	19	20	21	22	23	24
Price ($/MWh)	35.81	36.24	35.11	35.16	34.55	34.38	35.26	35.04	34.26	33.38	34.80	36.15

Table 4.3
Lagrange multipliers and reserve prices for single-period co-optimization

μ_{RR} ($/MWh)	μ_{TMSR} ($/MWh)	μ_{TMNSR} ($/MWh)	μ_{TMOR} ($/MWh)	$Price_{RR}$ ($/MWh)	$Price_{TMSR}$ ($/MWh)	$Price_{TMNSR}$ ($/MWh)	$Price_{TMOR}$ ($/MWh)
0	7.50	16.73	20.77	45.00	45.00	37.50	20.77

Table 4.4
Total costs and payments for single-period co-optimization

Product	Cost ($)	Payment ($)
Energy	58609	101532
RR	3449	7037
TMSR	2136	4663
TMNSR	1136	3750
TMOR	2000	2077
TOTAL	**67330**	**119059**

4.4 MULTI-PERIOD CO-OPTIMIZATION

A simultaneous auction involving the co-optimization of energy and reserves over a 24-hour period is performed on the IEEE 24 bus RTS using MATPOWER. The hourly load and reserve requirements used to clear the markets are shown in Table A.3 in the appendix. The hourly load corresponds to Tuesday of week 51 of the RTS and the percentage load at each bus is based on values found in [46]. The reserve requirements are assumed to remain constant across the planning horizon.

4.4.1 System Level Reserve Requirements

In this case the reserve requirements are set at system level. The hourly energy dispatch and the hourly load demand are shown in Figure 4.2. For each hour the energy dispatched is greater than the required demand. This is due to system losses. Figure 4.2 also shows that the system losses are higher during the periods of high demand. The hourly RR dispatch and TMSR dispatch are shown in Figure 4.3. The hourly requirement for each type of reserve is 130 MW. Figure 4.3 shows that the sum of RR and TMSR dispatched during each hour is 260 MW. The hourly RR reserves dispatched during each hour is more than the requirement, while the hourly TMSR dispatched is less than the requirement, thus implying that RR will be substituted for TMSR during the hour. The hourly TMNSR and TMOR dispatched during each hour are 100 MW and are equal to the hourly requirement. The hourly dispatch over the 24-hour period is shown in Table A.4 in Appendix A.

The maximum hourly scheduled dispatch for each of the 32 generators over the 24-hour planning horizon is shown in Figure 4.4. The maximum dispatch includes energy and reserves. No capacity violations exist when the maximum hourly dispatch of each generator over the 24-hour period is compared to the generator's maximum capacity limit as given in Table A.1 in the appendix. All generators except generators 9, 10 and 11 are dispatched at maximum capacity during some hour in the planning horizon. The maximum dispatch for generators 9, 10 and 11 is 82.5 MW, which is lower than their maximum capacity of 100 MW.

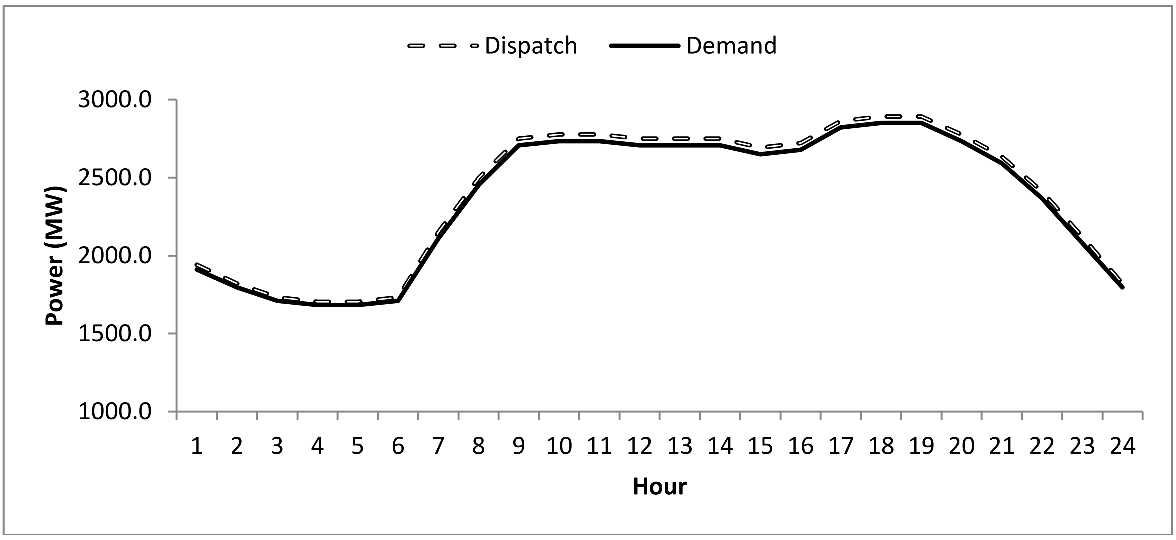

Figure 4.2 Hourly energy dispatch for system level reserve requirements

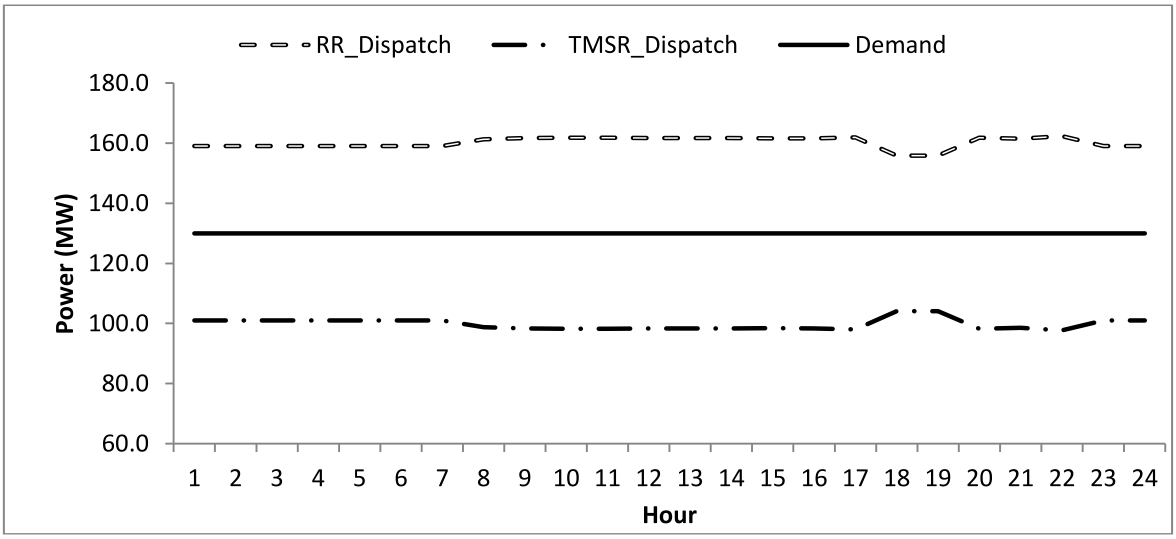

Figure 4.3 Hourly RR and TMSR dispatch for system level reserve requirements

The hourly maximum and minimum nodal energy prices are given in Figure 4.5. This is based on the maximum and minimum energy prices at each of the 24 buses. Figure 4.5 shows that the energy price reflects the load demand, with the energy price being highest during the period of maximum demand (hours 18 and 19) and lowest during the period of least demand (hours 4 and 5). The hourly energy price is given in Table A.5 in Appendix A.

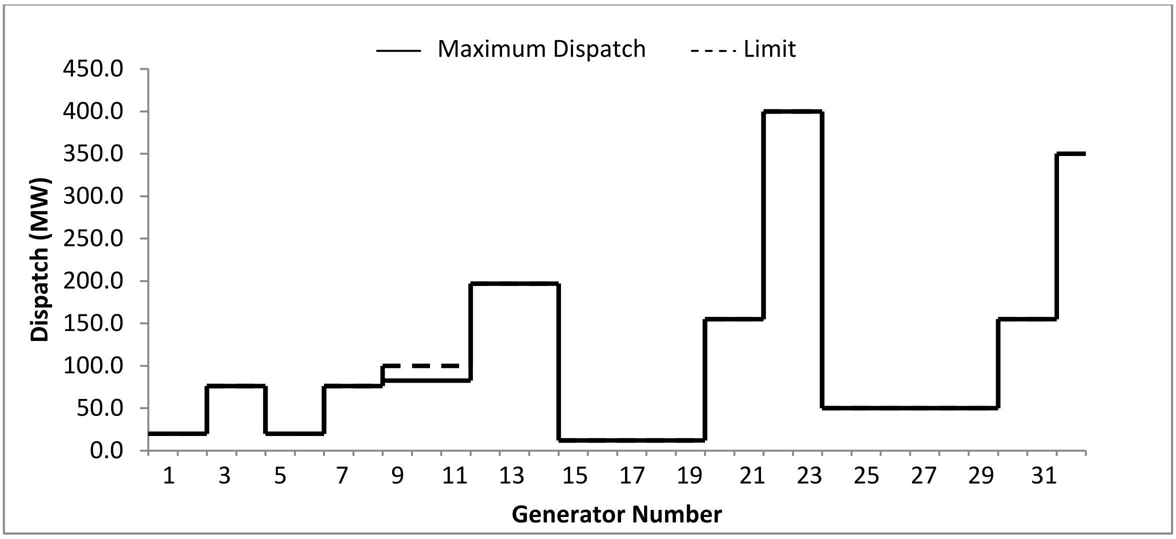

Figure 4.4 Maximum hourly dispatch for system level reserve requirements

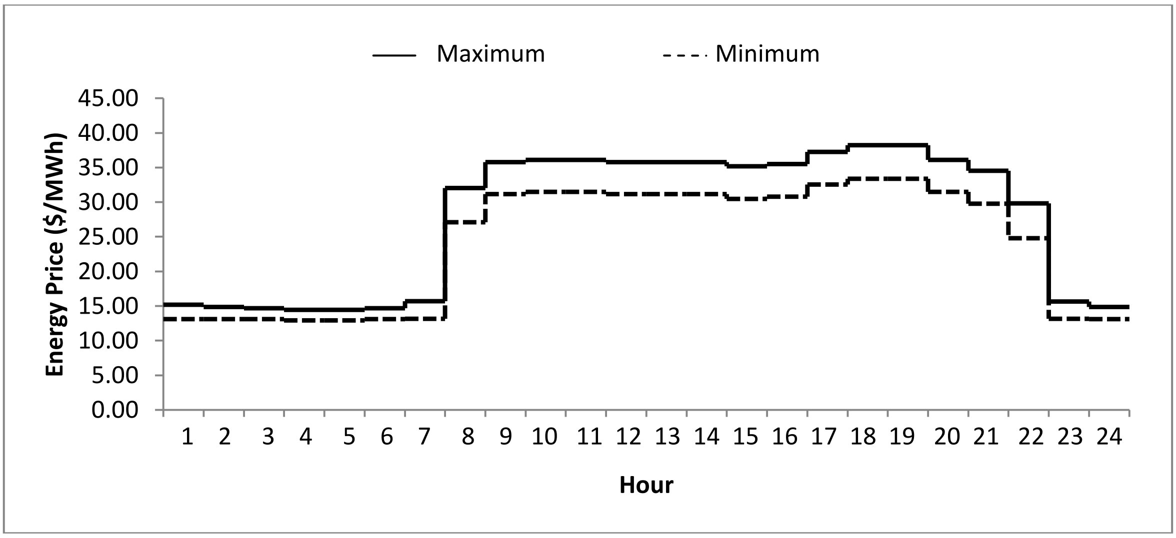

Figure 4.5 Hourly nodal energy price for system level reserve requirements

The hourly price for each type of reserve is shown in Figure 4.6. The price of RR and TMSR is the same over the 24-hour period, which indicates that RR, which is the higher quality product, is being dispatched to meet some of the TMSR requirement. Figure 4.6 also shows that the prices are cascaded, with higher quality products being more expensive than lower quality products. RR is the most expensive, while TMOR is the least expensive. The prices are also reflective of the load demand over the planning horizon, with higher prices during the periods of higher demand. The hourly reserves price is given in Table A.5 in Appendix A.

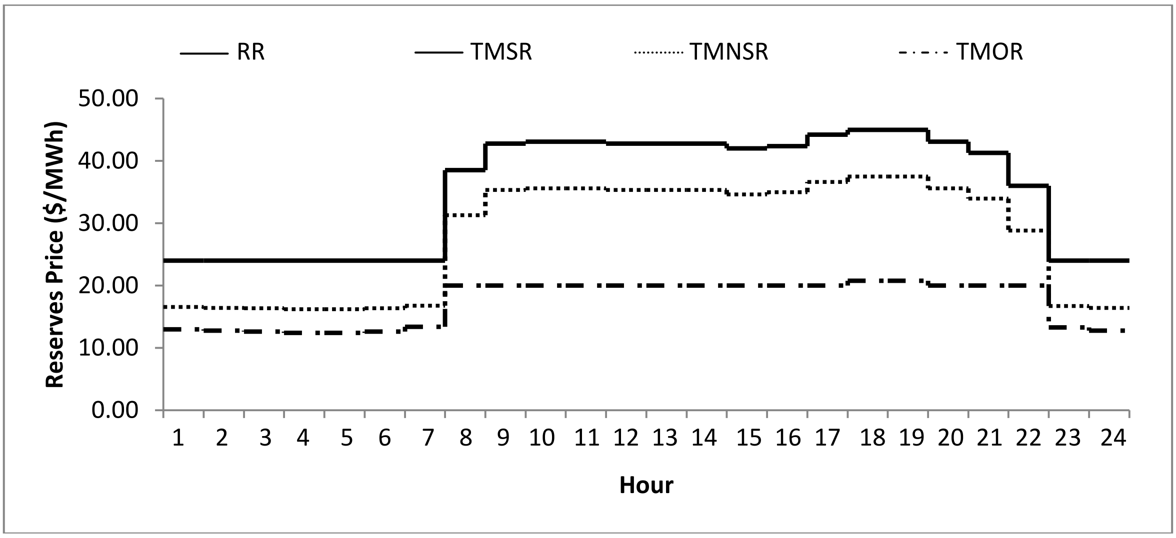

Figure 4.6 Hourly reserve prices for system level reserve requirements

The hourly combined costs and payments to suppliers are shown in Figure 4.7. The costs and payments are reflective of the hourly load demand and are at their maximum during the hours of peak demand. During periods of low demand, the cost to suppliers exceeds the payments due to suppliers. These losses in revenue are however recovered during the periods of high demand, as shown in Figure 4.8. The net profit to suppliers over the 24-hour period is $573 285.90. The hourly costs and payments to the generators are shown in Table A.6 in Appendix A.

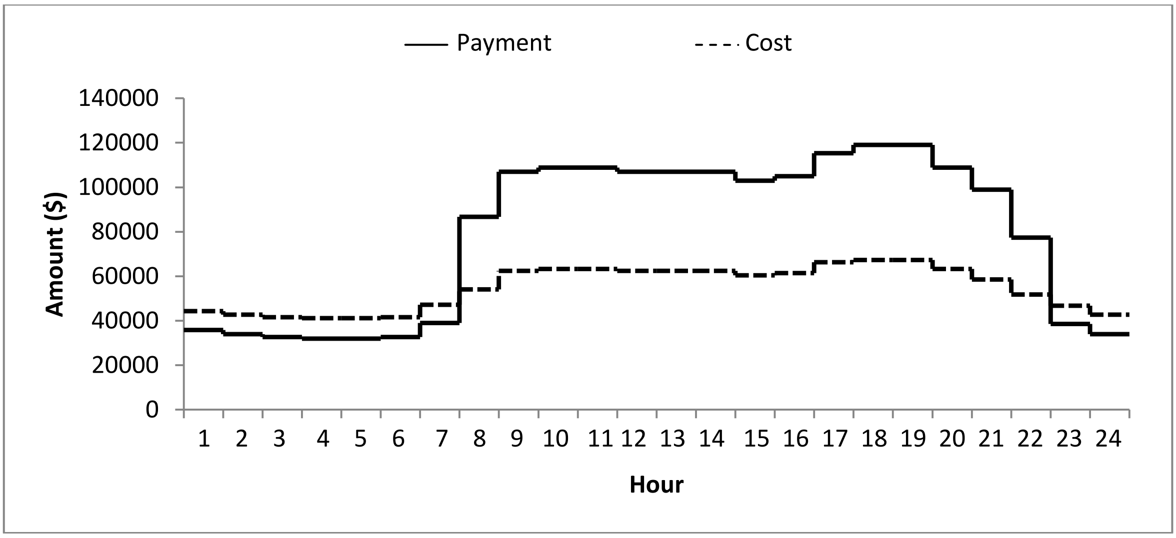

Figure 4.7 Hourly total costs and payments for system level reserve requirements

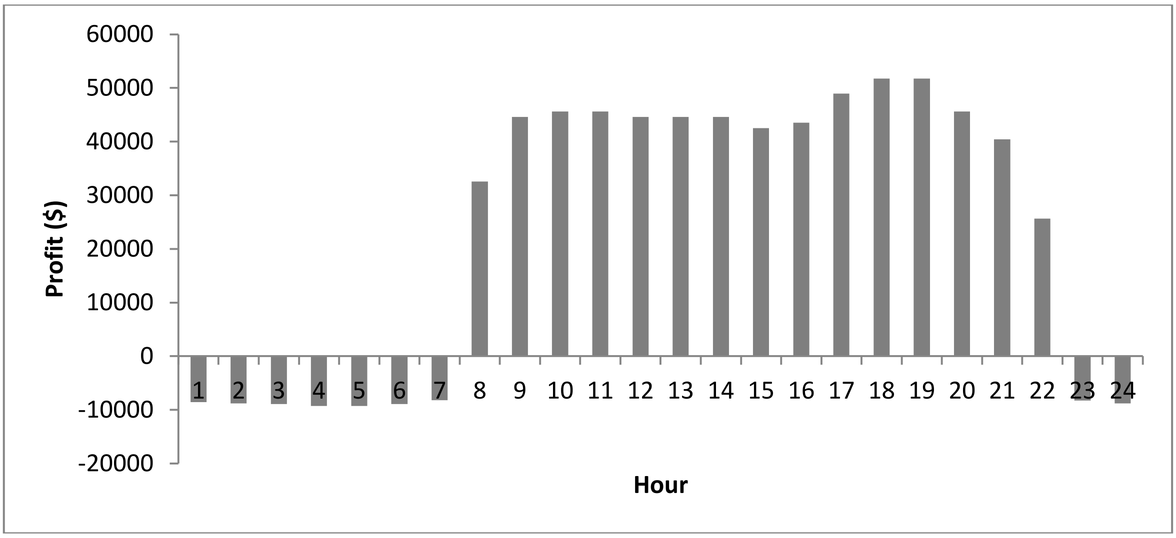

Figure 4.8 Hourly generator profit for system level reserve requirements

The maximum ramp rate of each generator over the 24-hour period is given in Table 4.5. The ramp rate limits are obtained from [47] and it is assumed that the ramp-up limit and the ramp-down limit are equal for each generator. The limits specified in [47] are in MW per minute and these have been converted to MW per hour in Table 4.5. Generators 24 to

29 are hydro units, which are inflexible. These generators therefore have maximum ramp rates of 0 MW per hour and are not considered.

Table 4.5
Maximum generator ramp rates

Generator Number	1	2	3	4	5	6	7	8	9	10	11	12	13
Maximum Ramp Rate (MW/hr)	6	6	52	52	6	6	52	52	55	55	55	62	62
Limit (MW/hr)	180	180	120	120	180	180	120	120	420	420	420	180	180
Generator Number	14	15	16	17	18	19	20	21	22	23	30	31	32
Maximum Ramp Rate (MW/hr)	62	10	10	10	10	10	24	34	262	300	16	16	99
Limit (MW/hr)	180	60	60	60	60	60	180	180	1200	1200	180	180	240

4.4.2 Zonal Level Reserve Requirements

Partitioning of the IEEE 24 bus test system into the optimal number of zones was based on the method proposed by Hong et al. [48]. The optimal number of zones for any N bus system is an integer between 2 and$\sqrt{N}$. For the IEEE test system with 24 buses, the optimal number of zones could be two, three or four. Starting with an initial assumption of two zones and using the nodal energy prices as inputs into the Fuzzy-c-means algorithm, the membership values of each bus in each zone, as well as the centre of each zone, were determined. These membership values and the centre of each zone were then used to determine a partition separation index (PSI) corresponding to the assumed number of zones. The optimum number of zones then corresponds to the number of zones with the maximum PSI value. For the current system, the optimum number of zones was found to be two. The partitioning of the system into two non-overlapping zones is shown in Figure 4.9.

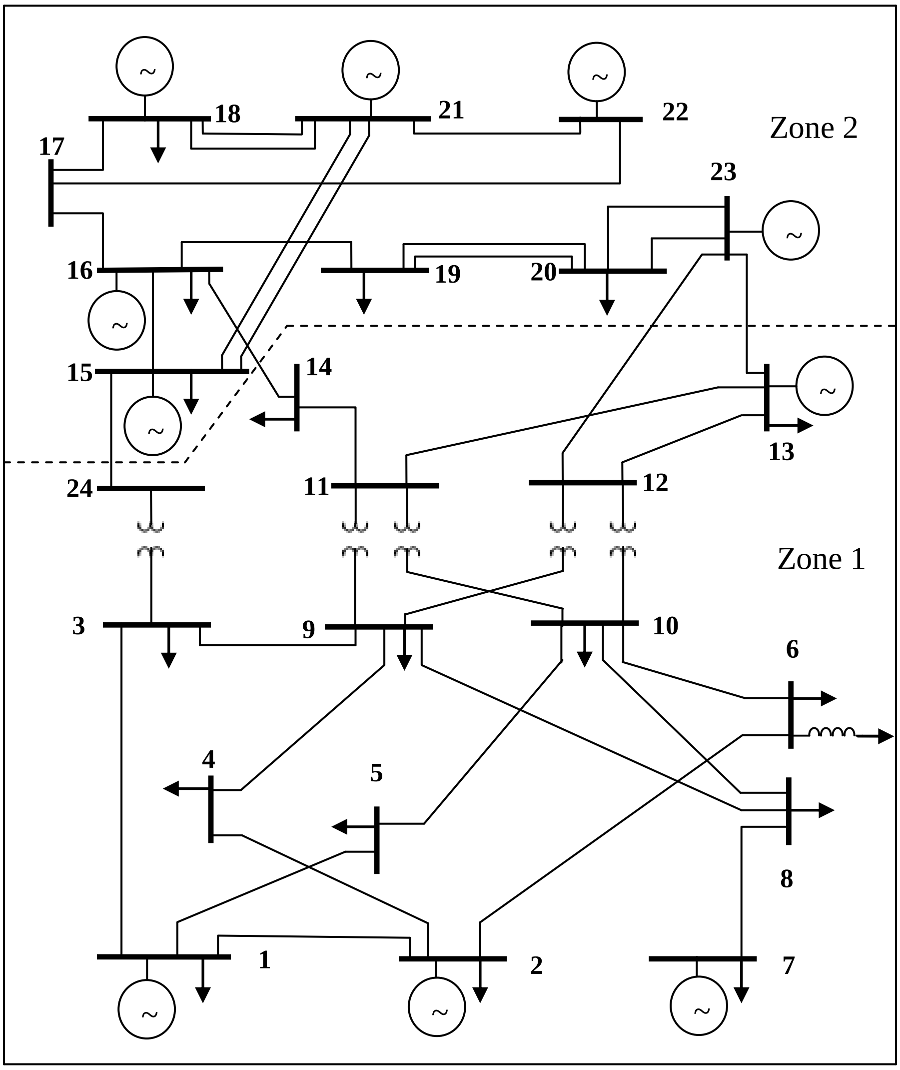

Figure 4.9 IEEE 24 bus reliability test system zones

The percentage load at each bus and the generator bus data for the IEEE 24 bus system are given in [46]. The percentage load requirement for each zone was determined from the percentage load at each bus located in that zone. The generation capacity in each zone was obtained from the generation buses in each zone. The reserve requirements for each zone were then determined in proportion to the percentage load in the zone. The percentage load requirement and the generation capacity in each zone are shown in Table 4.6. The hourly load and reserve requirements are given in Table A.7 in Appendix A.

Table 4.6
Zonal load requirements and generation capacity

	Load Requirement (MW)	Generation Capacity (MW)
Zone 1	62.8 %	1275
Zone 2	37.2%	2130

The hourly energy dispatch and the hourly load demand are shown in Figure 4.10. For each hour the energy dispatched is greater than the demand. This is due to system losses. Figure 4.10 also shows that the system losses are higher during the periods of higher demand. The hourly zonal RR dispatch, together with the zonal requirement, is shown in Figure 4.11. The total RR dispatched in zone 1 is lower than the 82 MW requirement of zone 1, while the total RR dispatched in zone 2 is more than the 48 MW requirement of zone 2. The generators in zone 2 are therefore used to meet some of the RR demand in zone 1. Figure 4.11 also shows that the total RR dispatched in both zones is more than the total RR requirement of 130 MW, thus indicating that RR will be used to meet the demand for other lower quality reserves.

The hourly zonal TMSR dispatch, together with the zonal requirement, is shown in Figure 4.12. In each zone the total TMSR dispatched is less than the zonal requirement. The TMSR requirement in zone 1 is 82 MW, while the requirement in zone 2 is 48 MW. Figure 4.12 also shows that the total TMSR dispatched in both zones is lower than the total TMSR requirement of 130 MW, thus indicating that the shortfall will need to be met using higher quality RR.

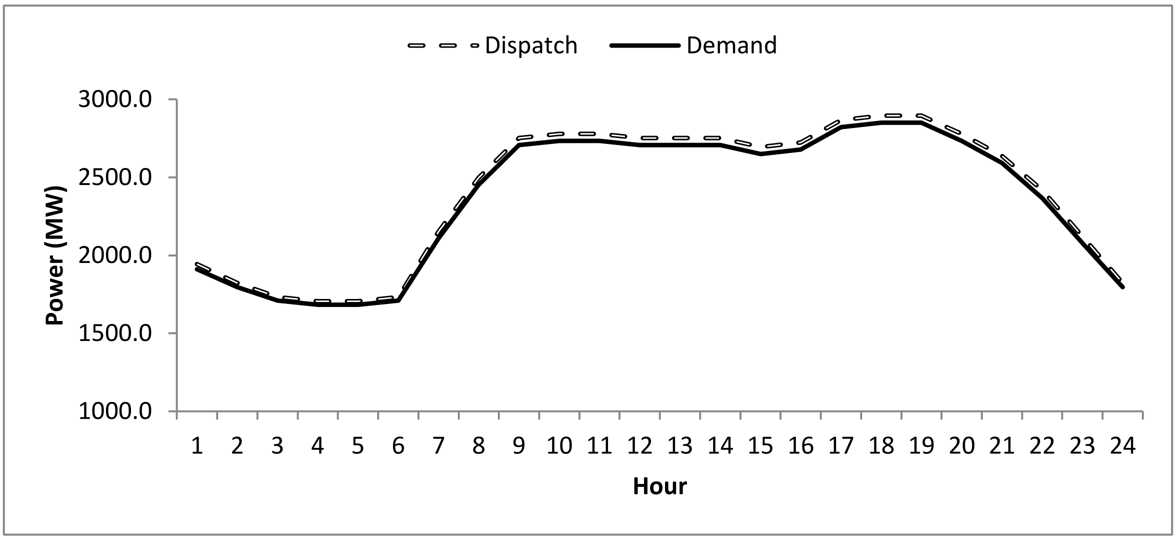

Figure 4.10 Hourly energy dispatch for zonal level reserve requirements

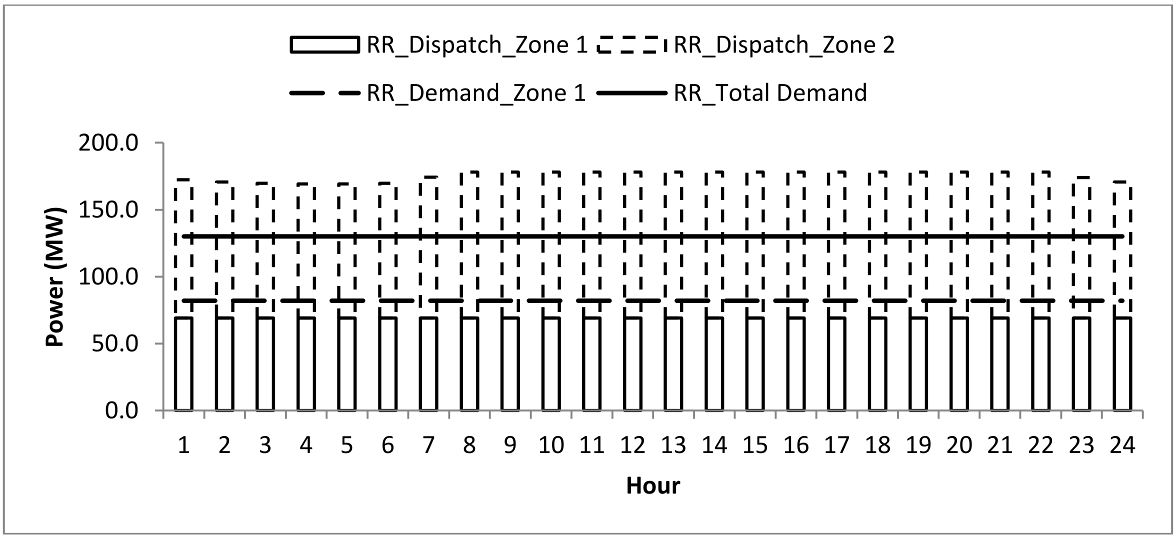

Figure 4.11 Hourly RR dispatch for zonal level reserve requirements

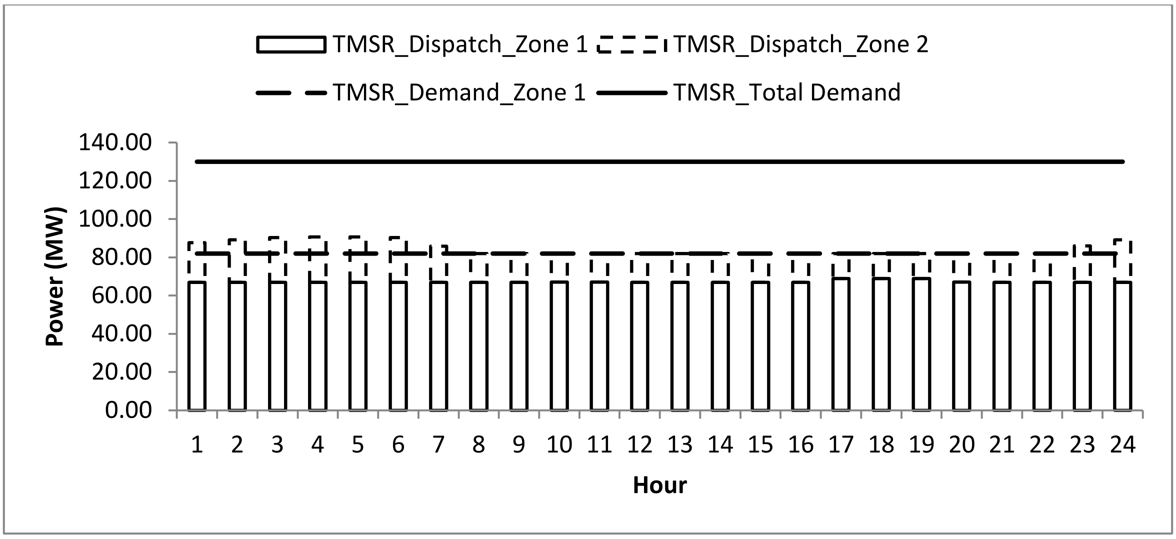

Figure 4.12 Hourly TMSR dispatch for zonal level reserve requirements

Figure 4.13 shows that the sum of the total RR and TMSR dispatched during each hour is 260 MW. The total hourly RR dispatched is more than the system requirement of 130 MW while the total hourly TMSR dispatched is less than the system requirement, thus indicating that RR is being substituted for TMSR at all hours.

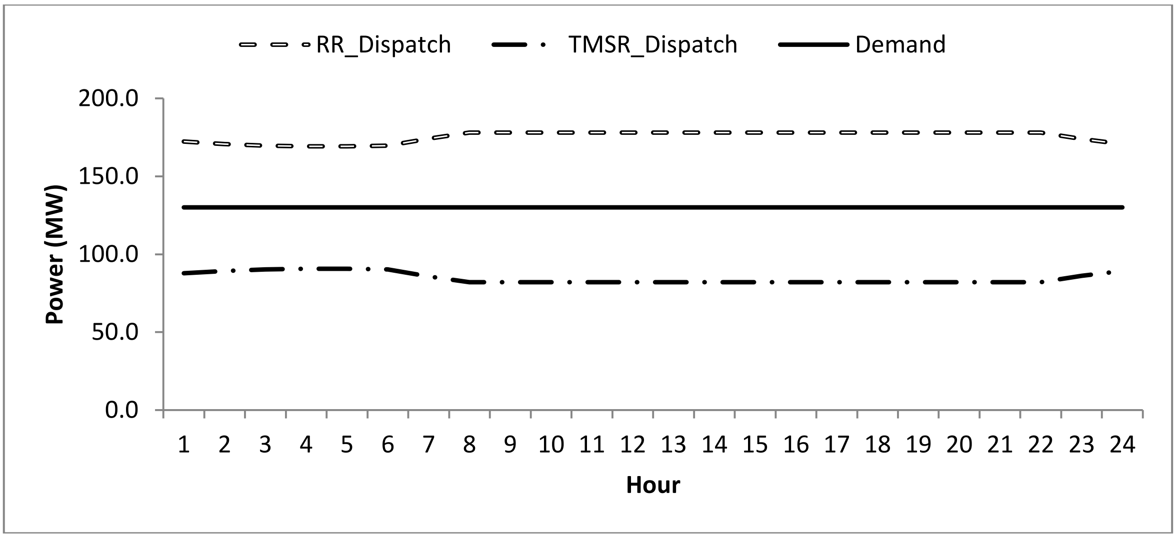

Figure 4.13 Hourly RR and TMSR dispatch for zonal level reserve requirements

The hourly zonal TMNSR dispatch, together with the zonal requirement, is shown in Figure 4.14. During hours 1 to 7 and during hours 23 and 24, the total TMNSR dispatched in zone 1 is more than the 63 MW requirement of zone 1. During the rest of the hours the TMNSR dispatched in zone 1 is equal to the requirement of zone 1. The TMNSR dispatched during all hours in zone 2 is equal to the 37 MW requirement of zone 2. Figure 4.14 also shows that during hours 1 to 7 and hours 23 and 24, the total TMNSR dispatched in both zones is more than the total TMNSR requirement of 100 MW.

The hourly zonal TMOR dispatch, together with the zonal requirement, is shown in Figure 4.15. During hours 1 to 7 and during hours 23 and 24, the total TMOR dispatched in zone 1 is less than the 63 MW requirement of zone 1. During the rest of the hours the TMOR dispatched in zone 1 is equal to the zonal requirement. During hours 1 to 7 and during hours 23 and 24, the total TMOR dispatched in zone 2 is more than the 37 MW requirement of zone 2. During the rest of the hours the TMOR dispatched in zone 2 is equal to the zonal requirement. Figure 4.15 also shows that the total TMSR dispatched in both zones is less than the total TMNSR requirement of 100 MW during hours 1 to 7 and hours 23 and 24, thus indicating the need for the use of higher quality reserves to meet this shortfall.

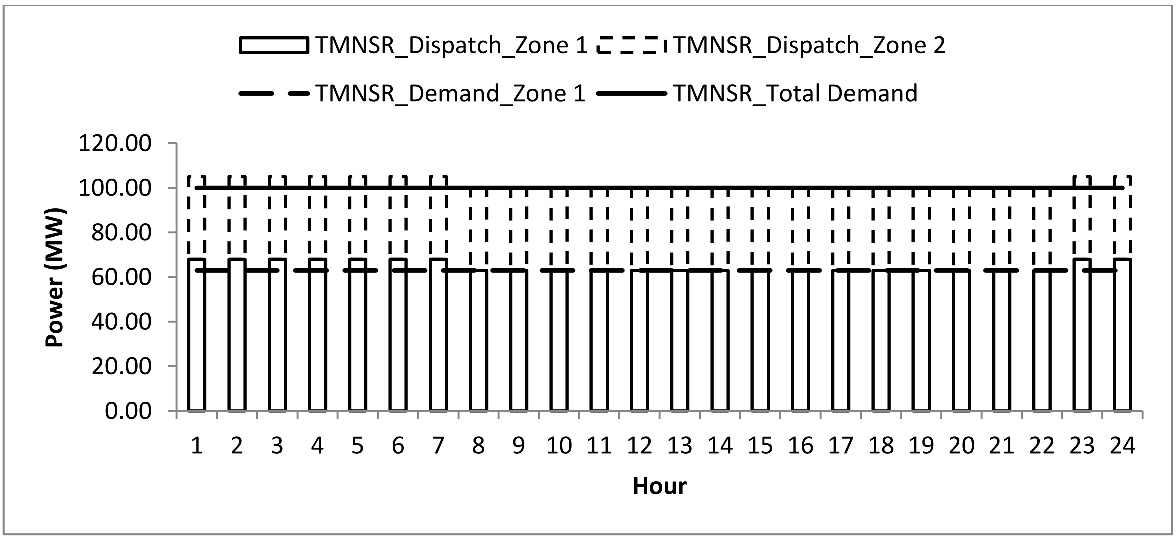

Figure 4.14 Hourly TMNSR dispatch for zonal level reserve requirements

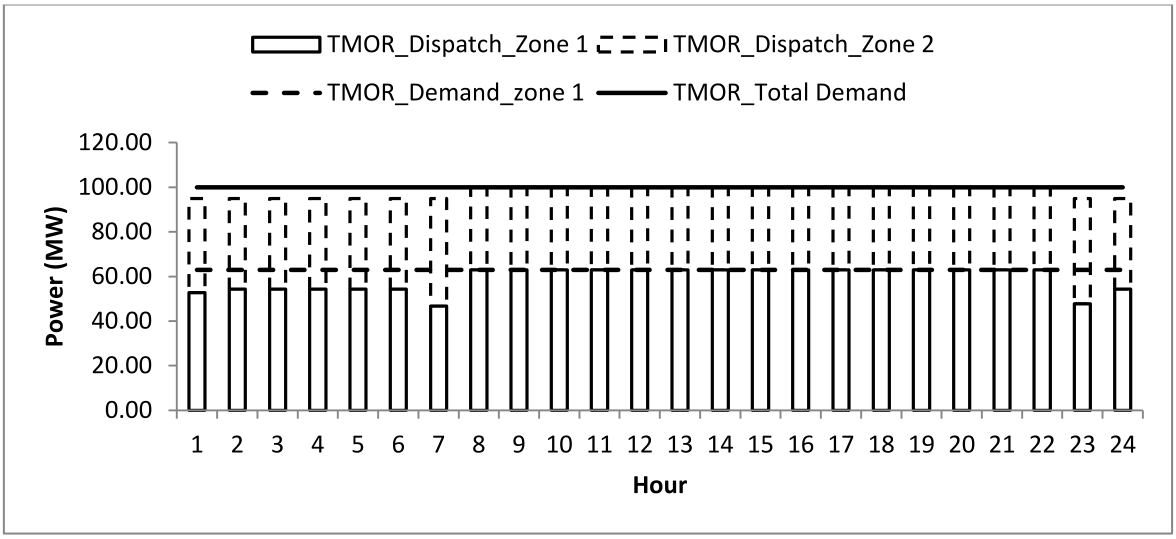

Figure 4.15 Hourly TMOR dispatch for zonal level reserve requirements

Figure 4.16 shows that the sum of the total TMNSR and TMOR dispatched during each hour is 200 MW. The total hourly TMNSR dispatched is more than the system requirement of 100 MW during hours 1 to 7 and during hours 23 and 24, while the total hourly TMOR dispatched is less than the system requirement during these hours, thus indicating that higher quality TMNSR is being substituted for TMOR during these hours.

The maximum scheduled dispatch for each of the 32 generators over the 24-hour planning horizon is shown in Figure 4.17. The maximum dispatch includes energy and reserves of all types. Figure 4.17 shows that there are no capacity violations for each of the generators. All generators except generators 9, 10, 11, 12, 13 and 14 are dispatched at maximum capacity during some hour in the 24-hour period. The maximum dispatch for generators 9, 10 and 11 is 84.1 MW, which is lower than their maximum capacity of 100 MW, while the maximum dispatch for generators 12, 13 and 14 is 196.3 MW, which is also lower than their maximum capacity of 197 MW.

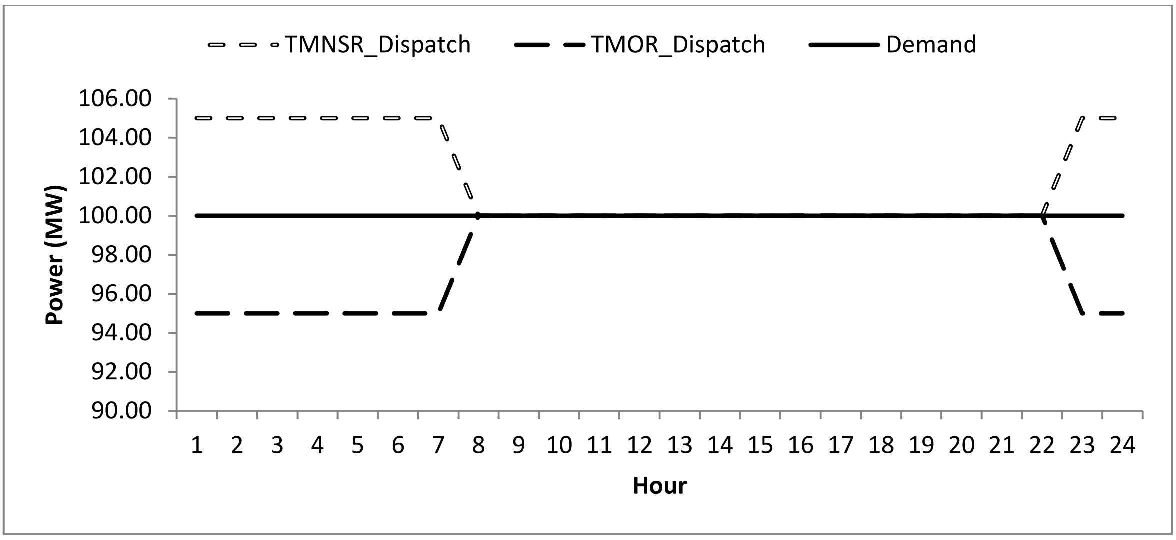

Figure 4.16 Hourly TMNSR and TMOR dispatch for zonal level reserve requirements

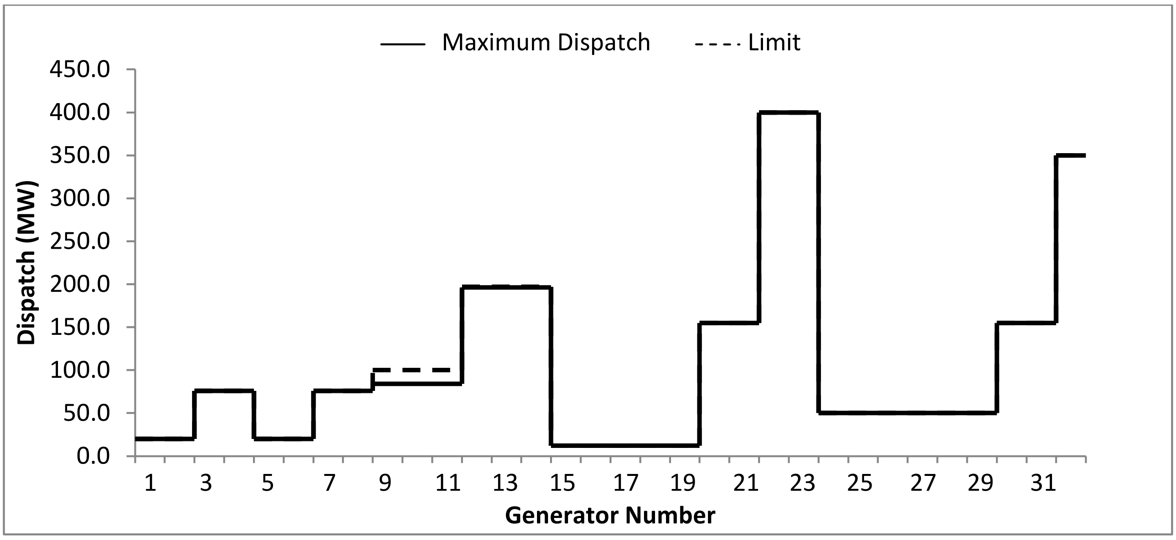

Figure 4.17 Maximum hourly dispatch for zonal level reserve requirements

The hourly maximum and minimum nodal energy price is given in Figure 4.18. This is based on the nodal energy prices at each of the 24 buses. Figure 4.18 shows that the energy price is reflective of the load demand, with the energy price being highest during the period of maximum demand (hours 18 and 19) and lowest during the period of least demand (hours 4 and 5). The hourly energy price data is given in Table A.8 in Appendix A.

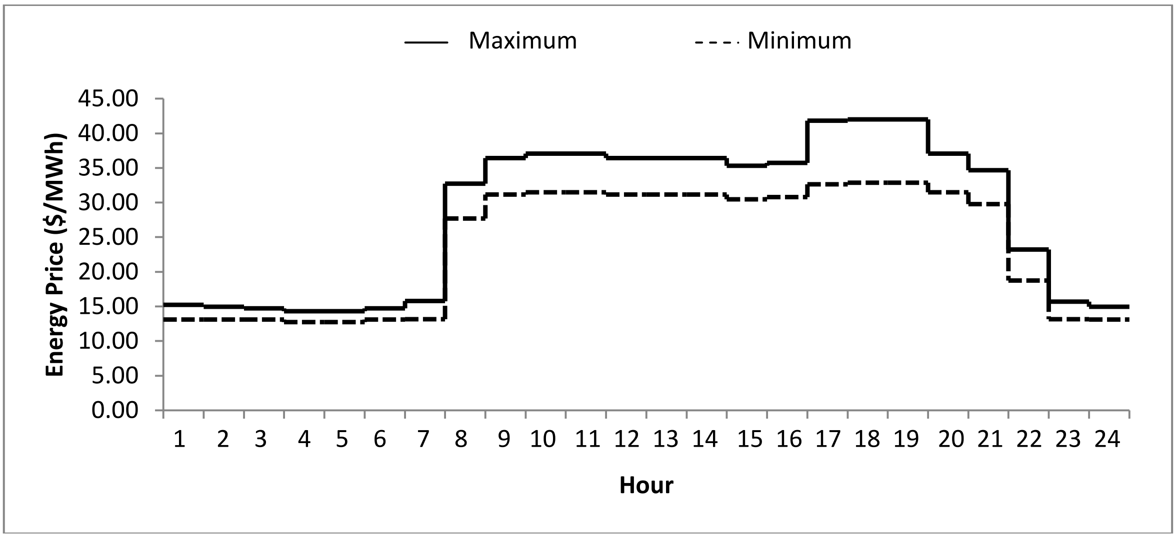

Figure 4.18 Hourly nodal energy price for zonal level reserve requirements

The hourly price of RR for each zone is shown in Figure 4.19. The price in zone 1 remains constant at $47 per MWh over the 24-hour period. The price in zone 2 varies over time with the highest price of $44.23 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $23.07 per MWh occurs during hours 4 and 5, which are the hours of least energy demand. The hourly RR prices are given in Table A.8 in Appendix A.

The hourly price of TMSR for each zone is shown in Figure 4.20. The price in zone 1 remains constant at $45 per MWh over the 24-hour period. The price in zone 2 varies over time with the highest price of $44.23 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $23.07 per MWh occurs during hours 4 and 5, which are the hours of least energy demand. The hourly TMSR prices are given in Table A.8 in Appendix A. The price of RR and TMSR in zone 2 is the same over the 24-hour period. This implies that RR is being substituted for TMSR, as is shown in Figure 4.13.

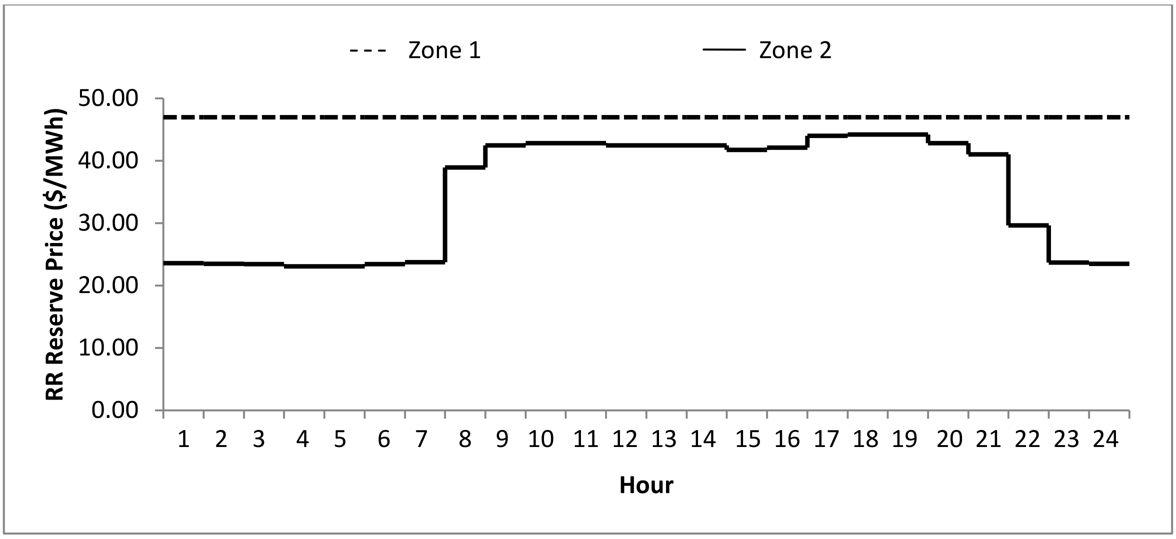

Figure 4.19 Hourly RR price for zonal level reserve requirements

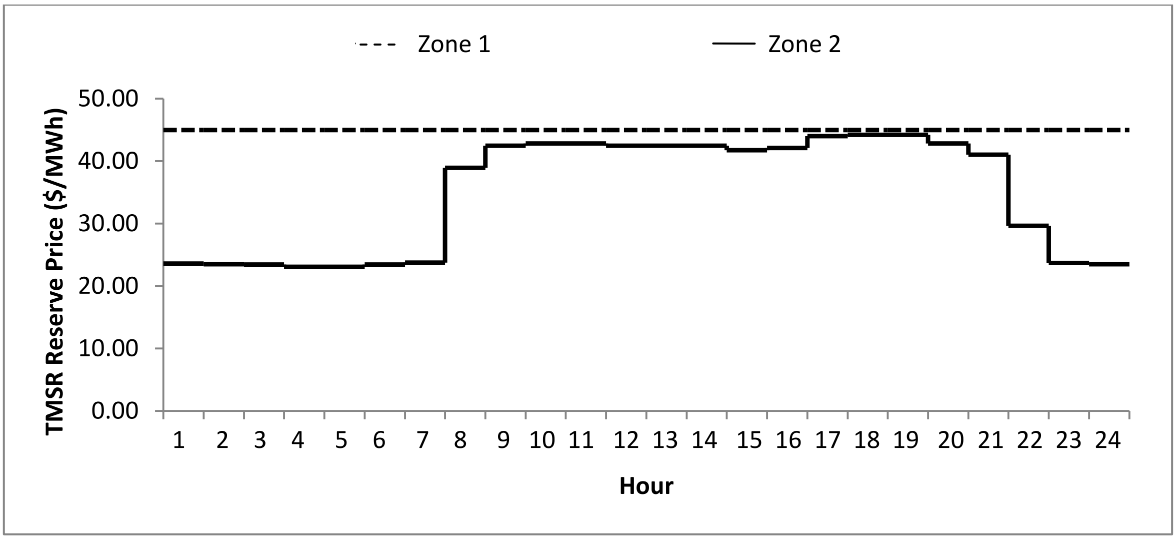

Figure 4.20 Hourly TMSR price for zonal level reserve requirements

The hourly price of TMNSR for each zone is shown in Figure 4.21. The price in zone 1 varies over time with the highest price of $36 per MWh occurring during hours 17, 18 and 19. The lowest price of $20 per MWh occurs during hours 1 to 7 and also during hours 22 to 24. The price in zone 2 varies over time with the highest price of $37.05 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of

$16.07 per MWh is during hours 4 and 5, which are the hours of least energy demand. The hourly TMNSR prices are given in Table A.8 in Appendix A.

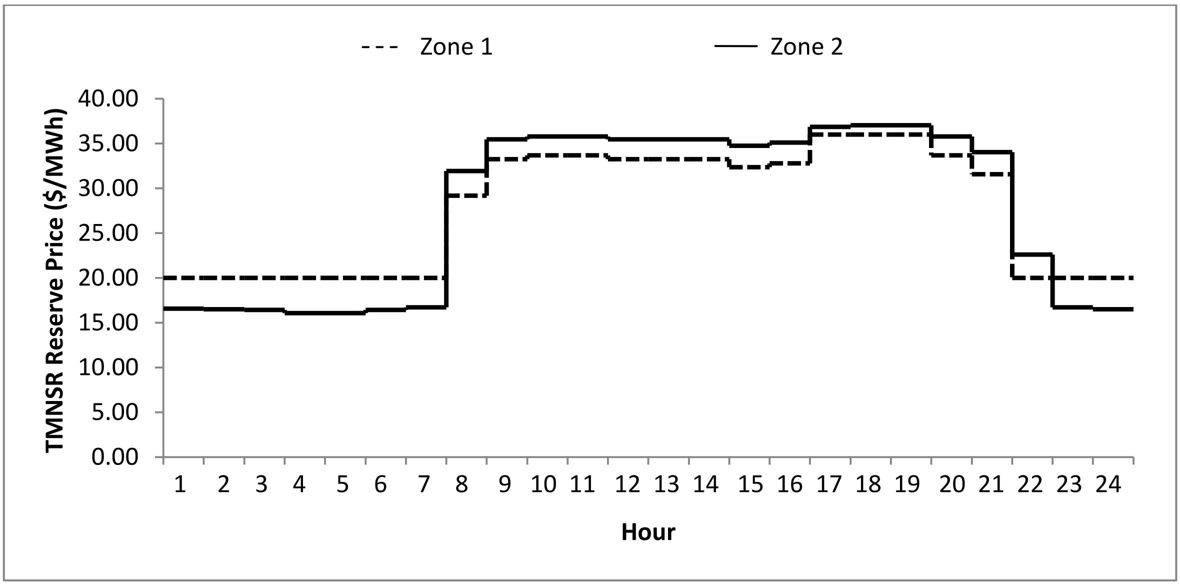

Figure 4.21 Hourly TMNSR price for zonal level reserve requirements

The hourly price of TMOR for each zone is shown in Figure 4.22. The price in zone 1 remains constant at $20 per MWh over the 24-hour period. The price in zone 2 varies over time with the highest price of $28.33 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $8.00 per MWh occurs during hours 1 to 7 and also during hours 23 and 24, which correspond to periods of low energy demand. The hourly TMOR prices are given in Table A.8 in Appendix A.

The hourly price for each type of reserve in zone 1 is shown in Figure 4.23. The figure shows that prices are cascaded, with higher quality reserves being more expensive than the lower quality reserves. RR is the most expensive, while TMOR is the least expensive. The price of all types of reserves except TMNSR remains constant during the 24 hour period. The price of TMNSR and TMOR is the same during hours 1 to 7 and also during hours 22 to 24, which implies that TMNSR is being substituted for TMOR during these hours. The hourly reserve prices are shown in Table A.8 in Appendix A.

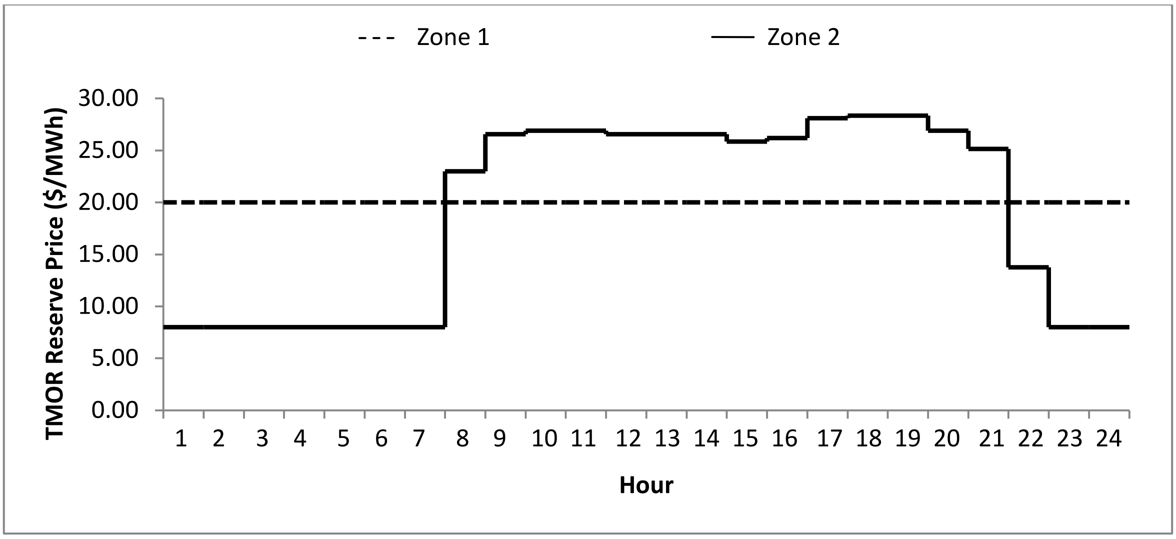

Figure 4.22 Hourly TMOR price for zonal level reserve requirements

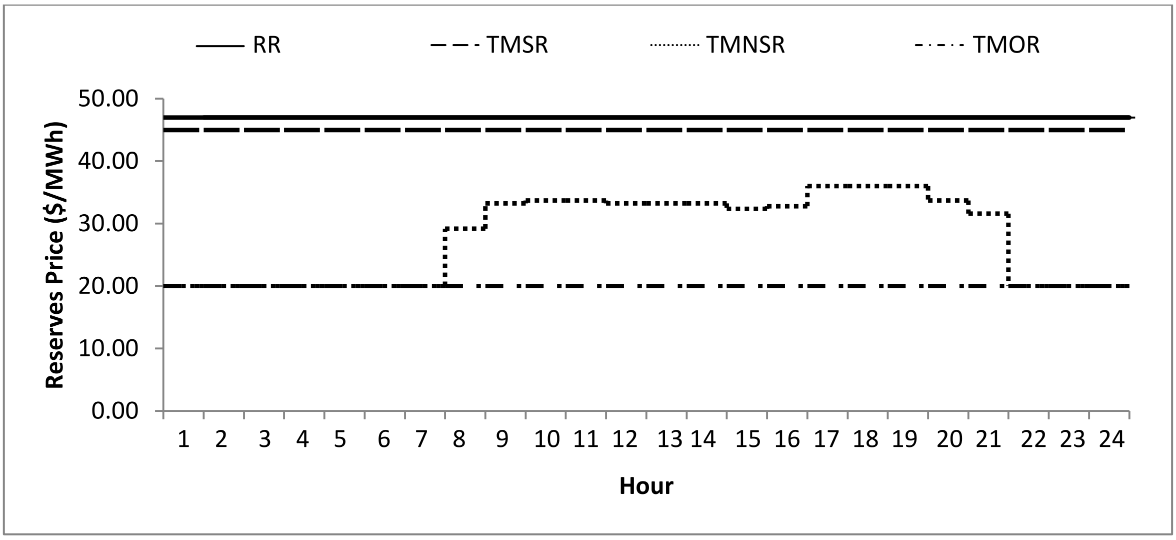

Figure 4.23 Zone 1 reserve prices for zonal level reserve requirements

The hourly price for each type of reserve in zone 2 is shown in Figure 4.24. The price of RR and TMSR is the same over the 24-hour period, which implies that RR is being substituted for TMSR over the 24-hour period. RR is the most expensive, while TMOR is the least expensive. The prices are also reflective of the load demand over the 24-hour period, with higher prices during the periods of higher demand. The hourly reserves price data are given in Table A.8 in Appendix A.

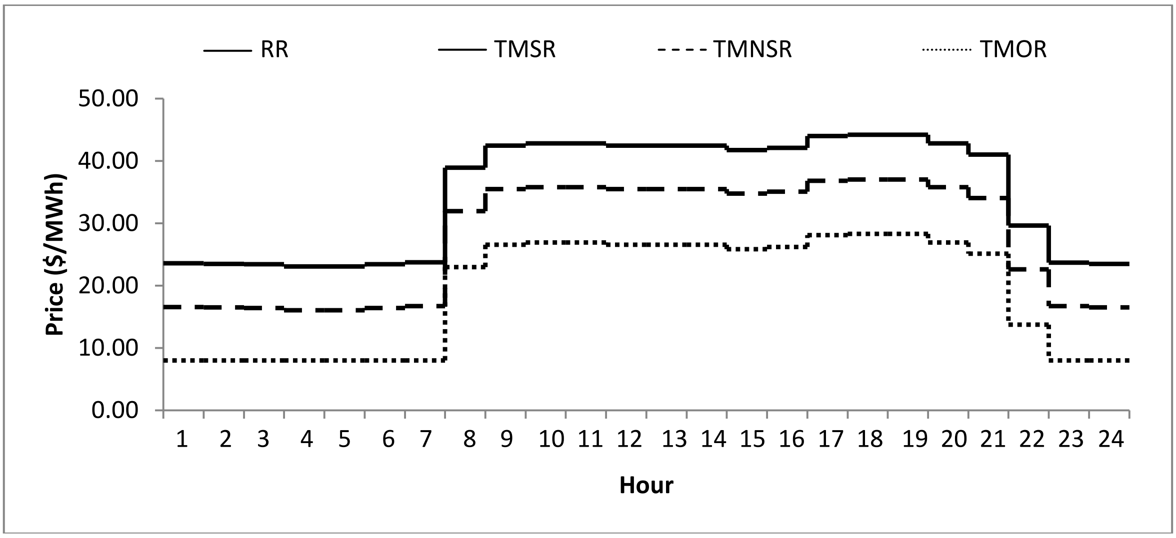

Figure 4.24 Zone 2 reserve prices for zonal level reserve requirements

The hourly combined costs and payments to suppliers are shown in Figure 4.25. The costs and payments are reflective of the hourly load demand and are at their maximum during the hours of peak demand. During periods of low demand, the cost to suppliers exceeds the payments due to suppliers. These losses in revenue are however recovered during periods of high demand, with suppliers making a net profit over the 24-hour planning horizon. The net profit to suppliers is $585 057.30.

The total quantity of each type of reserve procured in each zone over the 24-hour period, together with the associated cost and payment, are given in Table 4.7. The corresponding profit per zone is shown in Figure 4.26. More reserves are procured from suppliers in zone 1. The associated costs and payments are higher in zone 1 than in zone 2. The total quantity of reserves of all types procured in zone 1 is 6 246 MW, yielding a profit of $90 635.02 to suppliers, while the total amount of reserves procured in zone 2 is 4 794 MW, with a profit of $76 446.74 to suppliers.

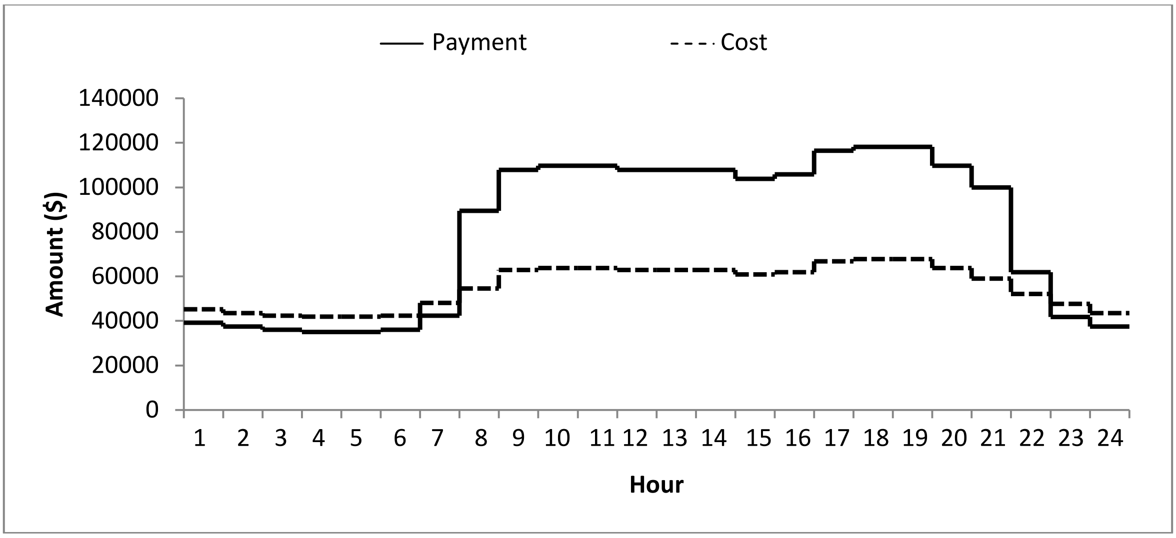

Figure 4.25 Hourly total costs and payments for zonal level reserve requirements

Table 4.7
Zonal reserve costs and payments

	Quantity Zone 1	Quantity Zone 2	Cost ($) Zone 1	Cost ($) Zone 2	Payment ($) Zone 1	Payment ($) Zone 2
RR	1656	2554	42778.89	39445.91	77831.99	89593.43
TMSR	1614	416	50008.24	8318.38	72631.29	13713.64
TMNSR	1557	888	14058.00	13980.00	42984.98	24664.96
TMOR	1419	936	24340.60	7104.00	28372.49	17323.00
Total	6246	4794	131185.73	68848.29	221820.75	145295.03

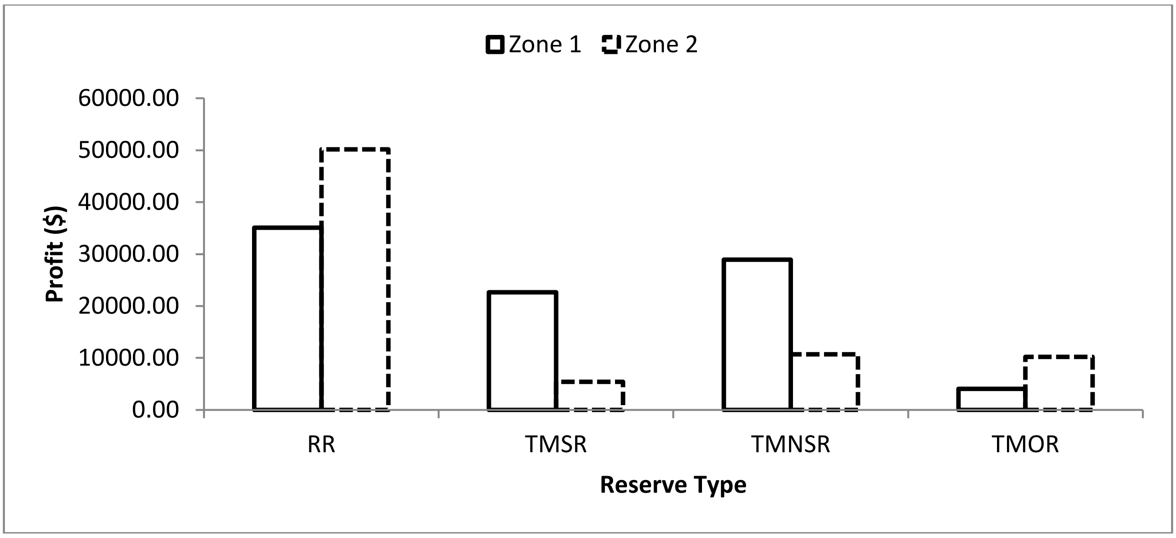

Figure 4.26 Zonal reserve profits

4.4.3 Effect of Congestion on Prices

The effect of transmission congestion on prices was investigated. A critical branch between the two congestion zones of the network was identified and removed from service, and the effect on energy and reserves prices was investigated. The branch connecting generator bus 13 in zone 1 and generator bus 23 in zone 2 was selected as the critical branch. The total generation connected to bus 13 was 300 MW and that connected to bus 23 was 660 MW. The effect on prices was investigated for the case where reserve requirements were set at system level and for the case where reserve requirements were set at zonal level.

4.4.3.1 System Level Reserve Requirements

The hourly energy dispatch and the hourly load demand for the congested case are shown in Figure 4.27. For each hour, the energy dispatched is greater than the required demand. This is due to system losses. Figure 4.27 also shows that the system losses are higher during the periods of higher demand.

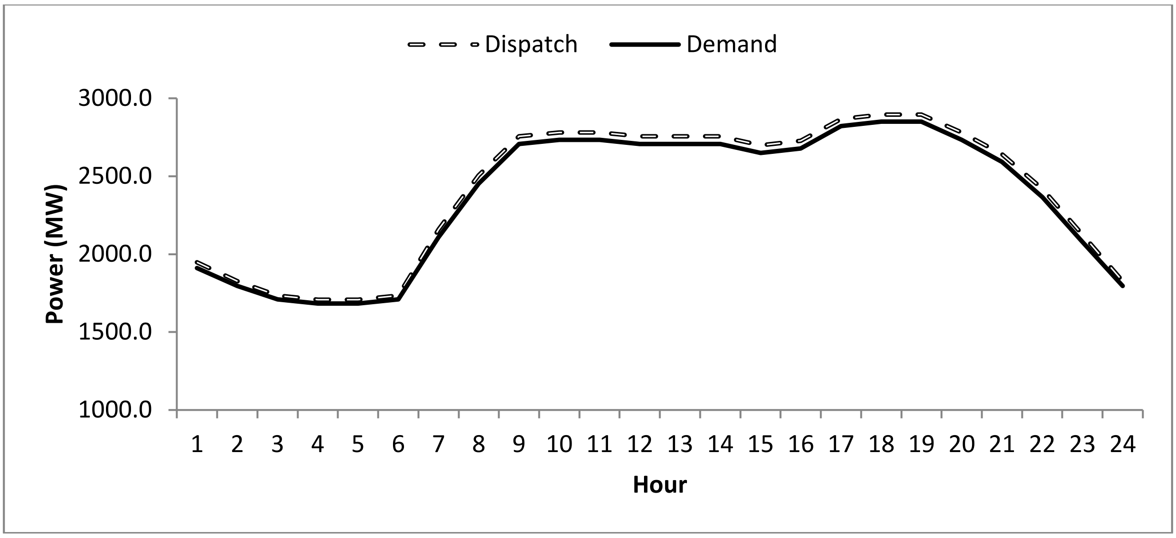

Figure 4.27 Hourly energy dispatch for system level reserve requirements with congestion

The maximum hourly scheduled dispatch for each of the 32 generators over the 24-hour period is shown in Figure 4.28. The maximum hourly dispatch includes energy and reserves. Comparing the maximum hourly dispatch of each generator to its maximum capacity limit, as given in Table A.1 in Appendix A, shows no capacity violations. All generators except generators 9, 10 and 11 are dispatched at maximum capacity during some hour in the planning horizon. The maximum dispatch for generators 9, 10 and 11 is 83.7 MW, which is lower than their maximum capacity of 100 MW.

The maximum and minimum hourly nodal energy prices are given in Figure 4.29. This is based on the nodal energy prices at each of the 24 buses. Figure 4.29 shows that the energy price reflects the load demand with the highest energy price of $38.64 per MWh being during the period of maximum demand (hours 18 and 19) and the lowest energy price of $13.03 being during the period of least demand (hours 4 and 5). The hourly energy price data is given in Table A.9 in the appendix. These energy prices are marginally higher than the corresponding energy prices for the uncongested case, as discussed in 4.4.1. The maximum and minimum energy prices for the uncongested case are $38.23 per MWh and $13.03 per MWh respectively.

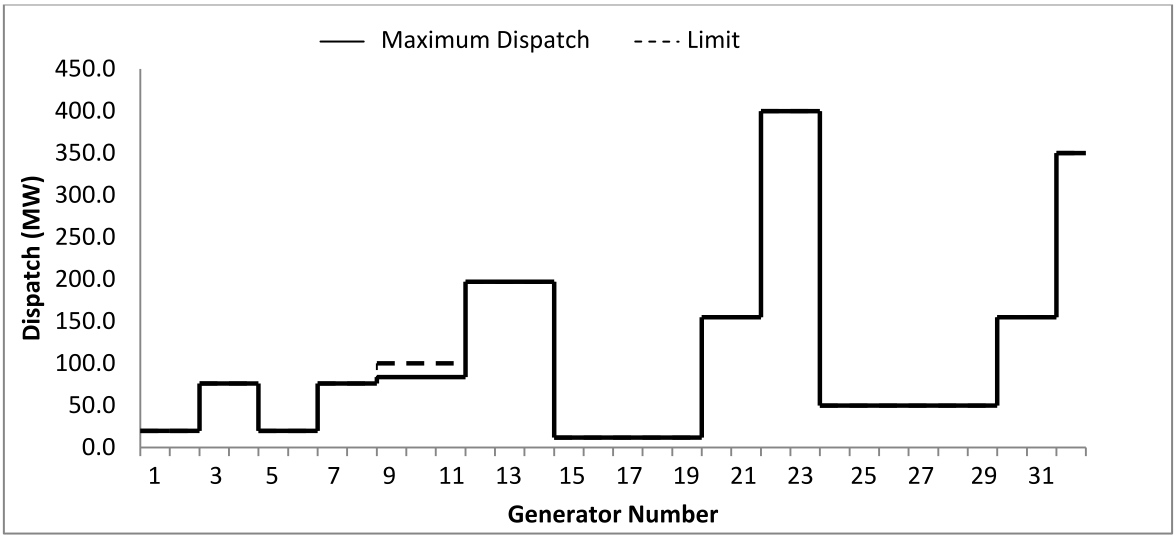

Figure 4.28 Maximum hourly dispatch for system level reserve requirements with congestion

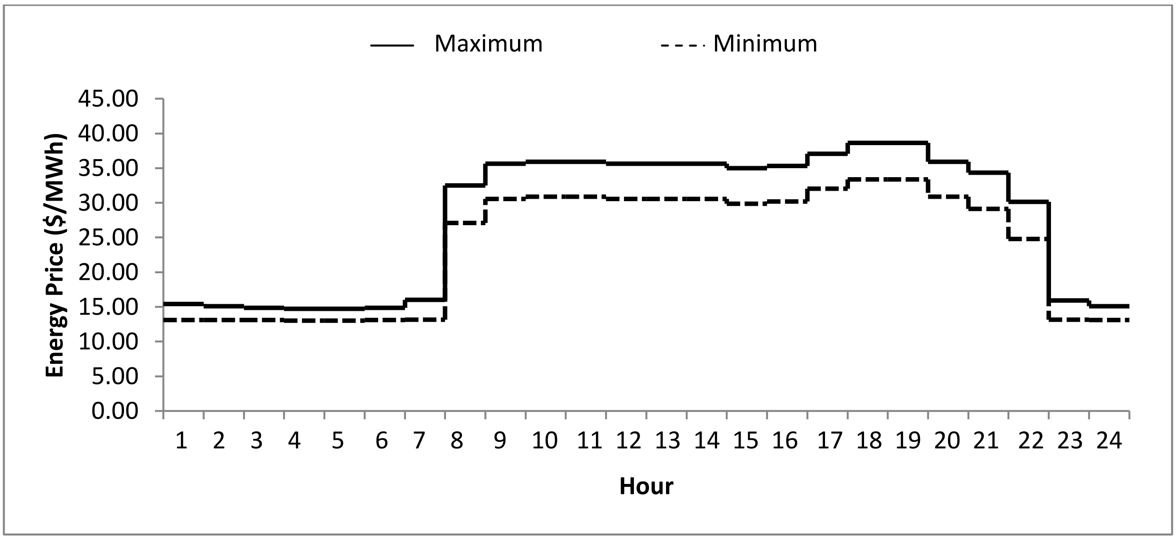

Figure 4.29 Hourly nodal energy price for system level reserve requirements with congestion

The hourly price for each type of reserve is shown in Figure 4.30. The price of RR and TMSR is the same over the 24-hour period, which indicates that RR, which is the higher quality product, is being dispatched to meet some of the TMSR requirement. Figure 4.30

also shows that the higher quality products are more expensive than the lower quality products. The prices also reflect the load demand over the planning horizon, with higher prices during the periods of higher demand.

The maximum and minimum prices of RR remain the same as in the uncongested case, as discussed in 4.4.1. The maximum and minimum RR prices are $45 per MWh and $24 per MWh respectively. The RR and TMSR prices are equal, as in the uncongested case. The maximum and minimum TMNSR prices are marginally lower than in the uncongested case and are set at $37.18 per MWh and $16.17 per MWh respectively. The maximum and minimum TMOR prices are marginally higher than in the uncongested case and are set at $21.44 per MWh and $12.65 per MWh respectively. The hourly reserve prices are given in Table A.9 in Appendix A.

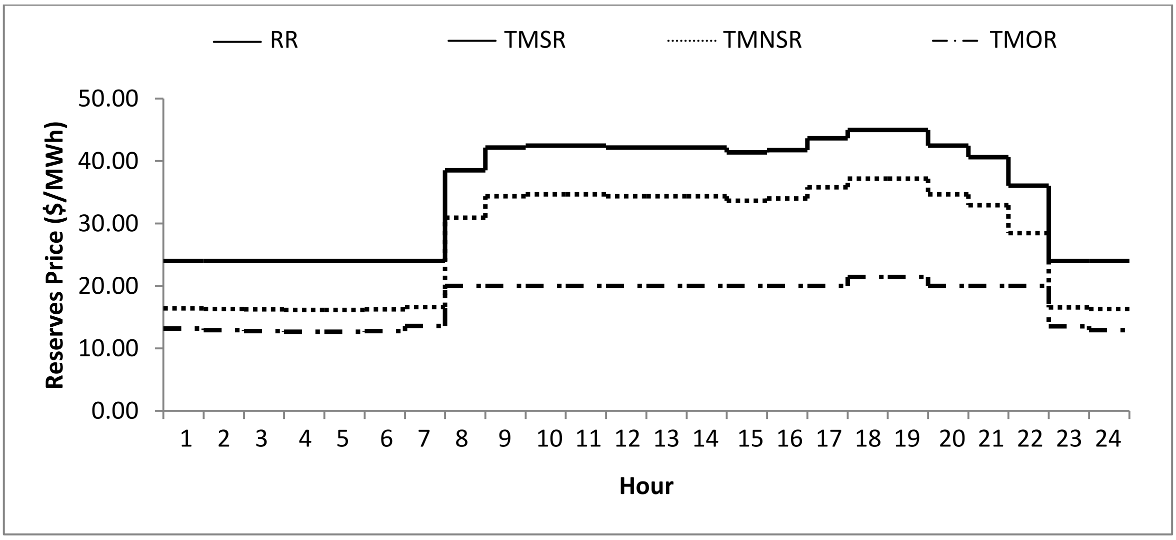

Figure 4.30 Hourly reserve prices for system level reserve requirements with congestion

The hourly combined costs and payments to suppliers are shown in Figure 4.31. The costs and payments are reflective of the hourly load demand and are at their maximum during the hours of peak demand. During periods of low demand, the cost to suppliers exceeds the payments due to suppliers. These losses in revenue are however recovered during periods of high demand, with suppliers making a net profit over the 24-hour planning horizon. The net profit to suppliers is $556 667.21 which lower than the profit of $573 285.90 for the uncongested case. This is due to lower income and higher costs to generators. The hourly costs and payments to the generators are shown in Table A.10 in Appendix A.

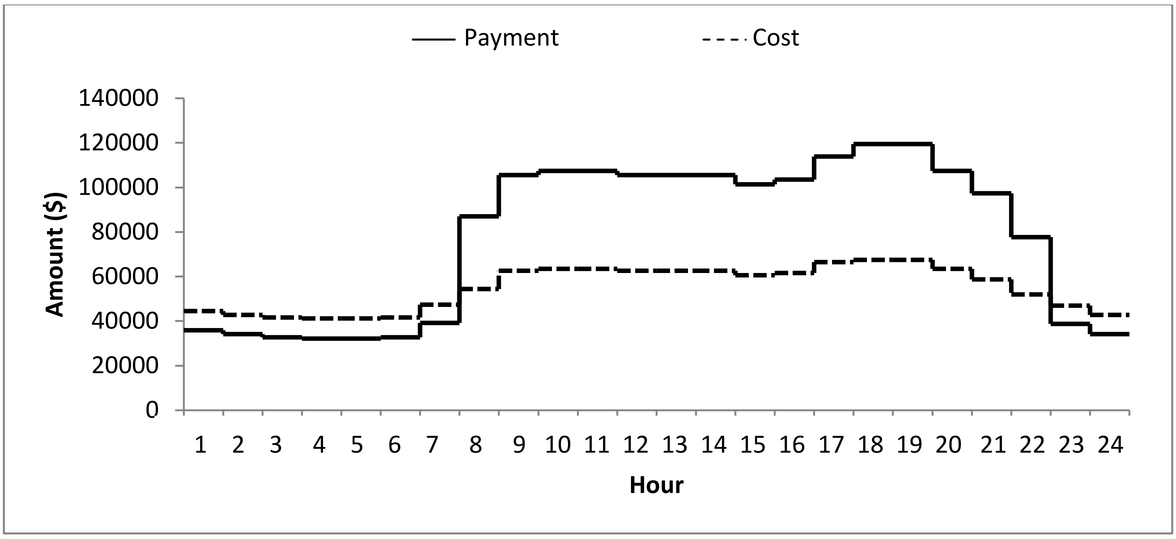

Figure 4.31 Hourly total costs and payments for system level reserve requirements with congestion

4.4.3.2 Reserve Requirements at Zonal Level

The hourly energy dispatch and the hourly load for the congested case are shown in Figure 4.32. For each hour the energy dispatched is greater than the required demand. This is due to system losses. Figure 4.32 also shows that the system losses are higher during periods of higher demand. Figure 4.33 shows the system losses for both the congested and uncongested case when reserve requirements are set at zonal level. The system losses are higher for the congested cases. The minimum difference in system losses between the two cases over the 24-hour period is 3.4 MW and the maximum difference in losses between the two cases is 14.4 MW.

The maximum hourly scheduled dispatch for each of the 32 generators over the 24-hour planning horizon is shown in Figure 4.34. The maximum hourly dispatch includes energy and reserves of all types. Figure 4.34 shows that there are no capacity violations for each of the generators. All generators except generators 9, 10, 11, 12, 13 and 14 are dispatched at maximum capacity during some hour in the 24-hour period. The maximum dispatch for generators 9, 10 and 11 is 85.5 MW, which is lower than their maximum capacity of 100 MW, while the maximum dispatch for generators 12, 13 and 14 is 196.9 MW, which is lower than their maximum capacity of 197 MW.

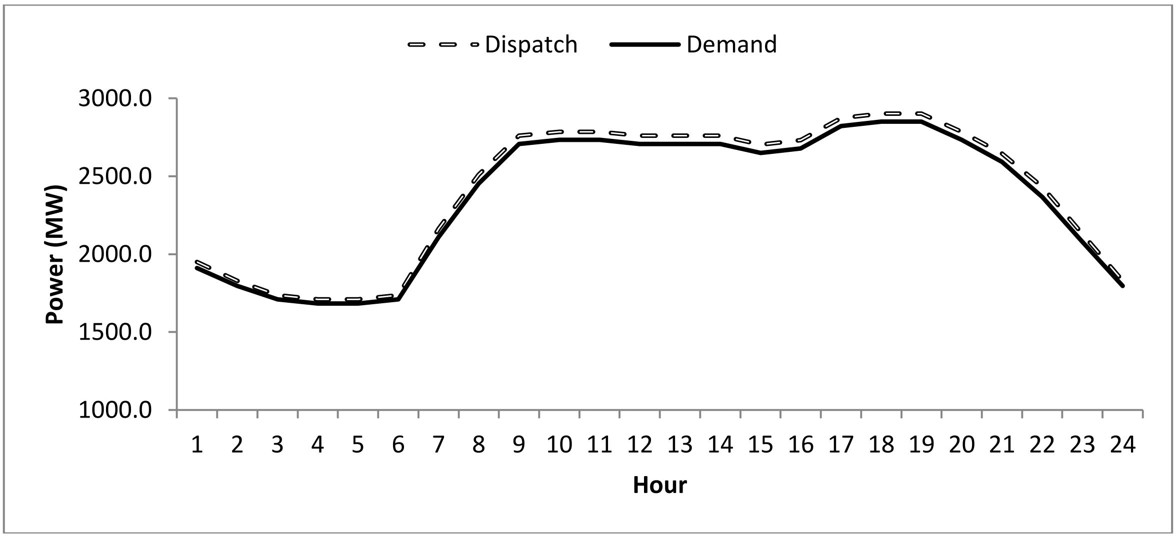

Figure 4.32 Hourly energy dispatch for zonal level reserve requirements with congestion

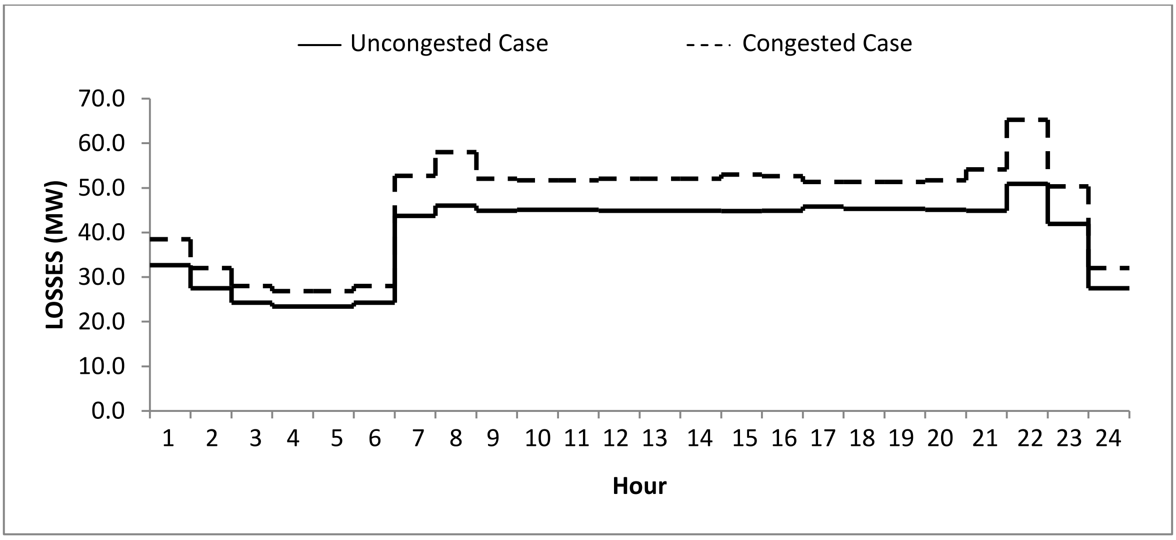

Figure 4.33 System losses for zonal level reserve requirements with congestion

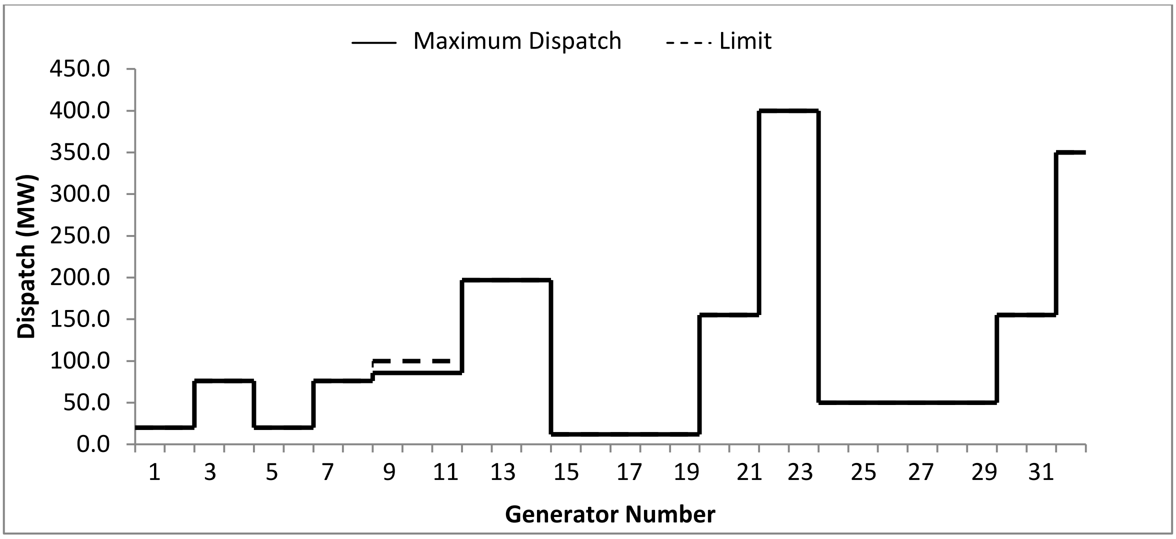

Figure 4.34 Maximum hourly dispatch for zonal level reserve requirements with congestion

The hourly maximum and minimum nodal energy prices are given in Figure 4.35. This is based on the nodal energy prices at each of the 24 buses. Figure 4.35 shows that the energy price reflects the load demand with the highest energy price of $41.65 per MWh being during the period of maximum demand (hours 18 and 19) and the lowest energy price of $12.94 per MWh during the period of least demand (hours 4 and 5). The hourly energy price is given in Table A.11 in Appendix A.

The hourly price of RR for each zone is shown in Figure 4.36. The price in zone 1 remains constant at $47 per MWh over the 24-hour period. The price in zone 2 varies over time with the highest price of $43.77 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $23.26 per MWh is during hours 4 and 5, which are the hours of least energy demand. The hourly RR prices are given in Table A.11 in Appendix A.

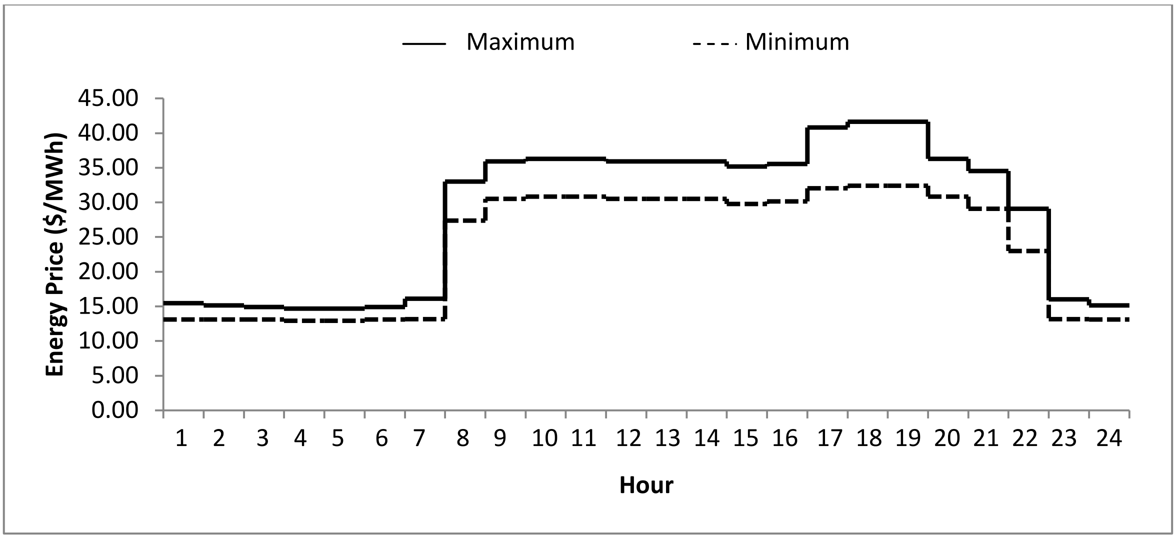

Figure 4.35 Hourly nodal energy price for zonal level reserve requirements with congestion

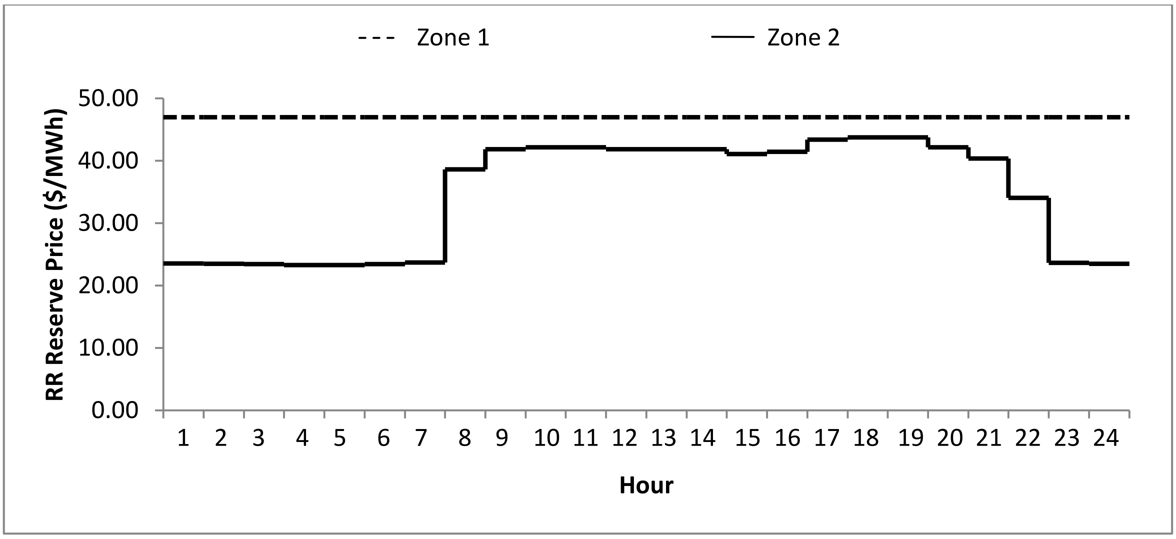

Figure 4.36 Hourly RR price for zonal level reserve requirements with congestion

The hourly price of TMSR for each zone is shown in Figure 4.37. The price in zone 1 remains constant at $45 per MWh over the 24-hour period. The price in zone 2 varies over time with the highest price of $43.77 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $23.26 per MWh is during hours 4 and 5, which are the hours of least energy demand. The price of RR and TMSR in zone 2 is the same, which implies that RR is being substituted for TMSR in zone 2. The hourly TMSR prices are given in Table A.11 in Appendix A.

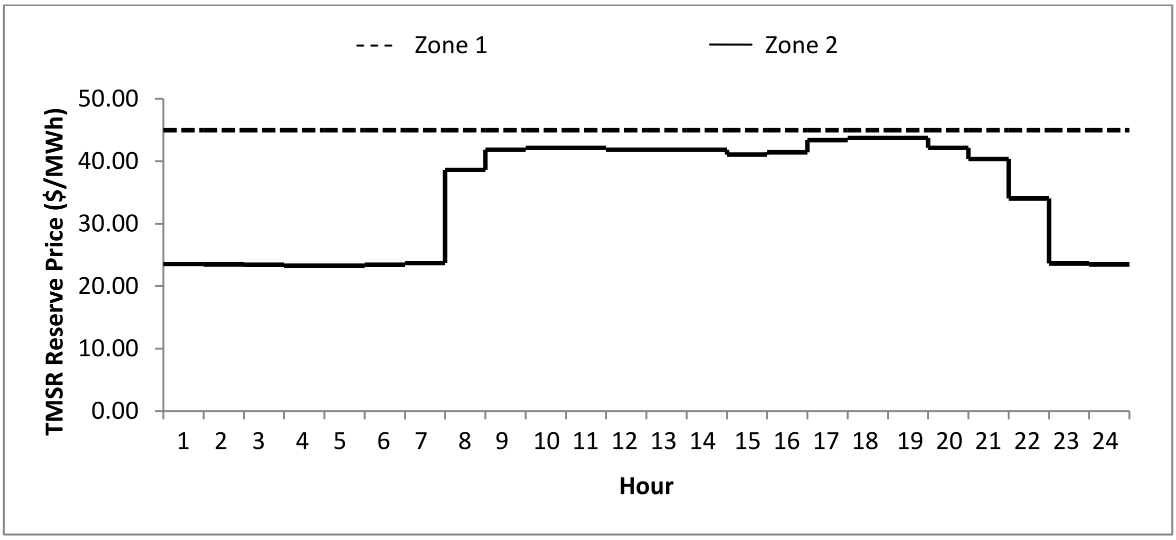

Figure 4.37 Hourly TMSR price for zonal level reserve requirements with congestion

The hourly price of TMNSR for each zone is shown in Figure 4.38. The price in zone 1 varies over time, with the highest price of $36 per MWh occurring during hours 18 and 19. The lowest price of $20 per MWh occurs during hours 1 to 7 and also during hours 23 and 24. The price in zone 2 also varies over time, with the highest price of $36.30 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $16.15 per MWh is during hours 4 and 5, which are the hours of least energy demand. The hourly TMNSR prices are given in Table A.11 in Appendix A.

The hourly price of TMOR for each zone is shown in Figure 4.39. The price in zone 1 remains constant at $20 per MWh over the 24-hour period. The price in zone 2 varies over time, with the highest price of $27.87 per MWh during hours 18 and 19, which are the hours of peak energy demand. The lowest price of $8.00 per MWh occurs during hours 1 to 7 and also during hours 23 and 24, which correspond to periods of low energy demand. The hourly TMOR prices are given in Table A.11 in Appendix A.

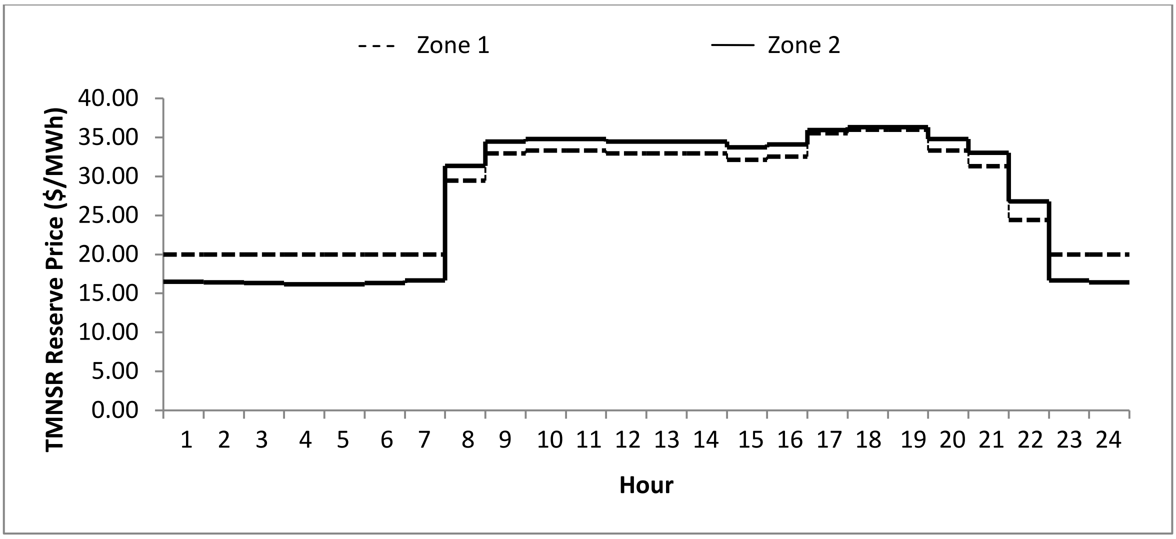

Figure 4.38 Hourly TMNSR price for zonal level reserve requirements with congestion

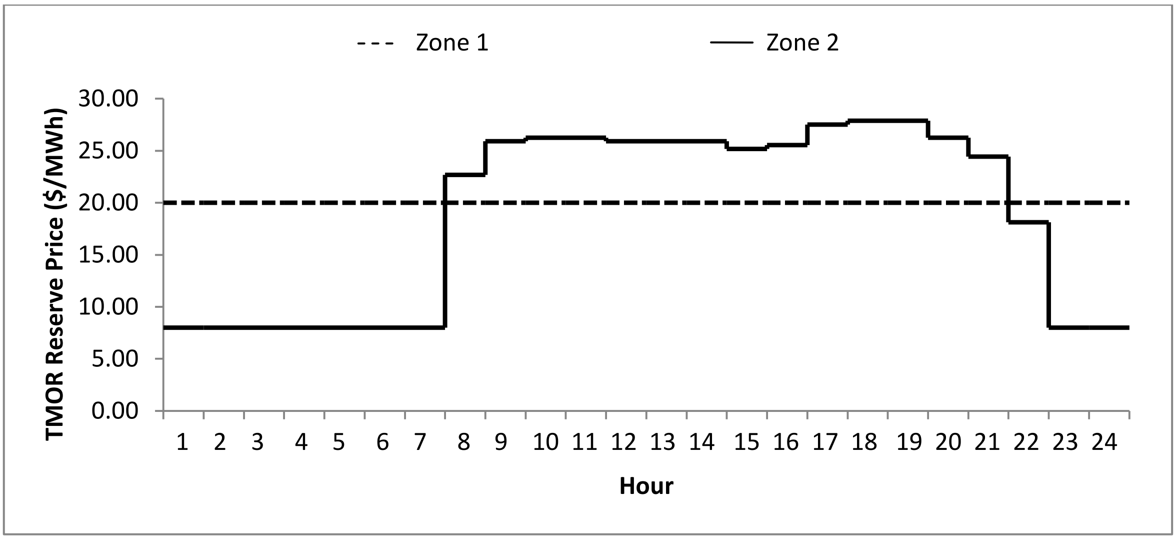

Figure 4.39 Hourly TMOR price for zonal level reserve requirements with congestion

The hourly price for each type of reserve in zone 1 is shown in Figure 4.40. The figure shows that prices are cascaded, with higher quality reserves being more expensive than lower quality reserves. RR is the most expensive, while TMOR is the least expensive. The price of all types of reserves except TMNSR remains constant during the 24 hour period.

The price of TMNSR and TMOR is the same during hours 1 to 7 and also during hours 22 to 24. The hourly reserve price data is given in Table A.11 in Appendix A.

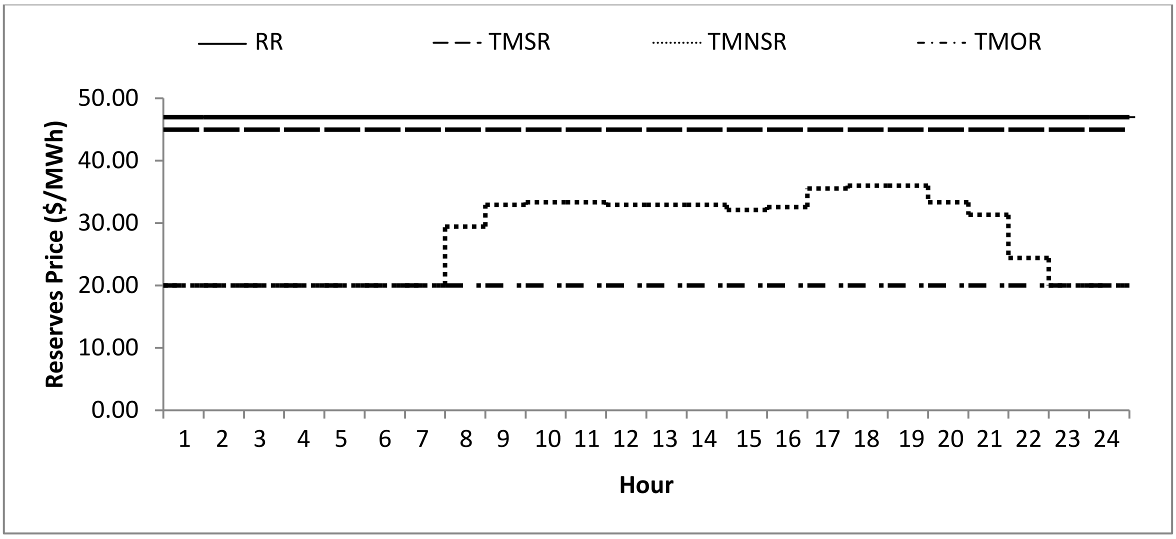

Figure 4.40 Zone 1 reserve prices for zonal level reserve requirements with congestion

The hourly price for each type of reserve in zone 2 is shown in Figure 4.41. The price of RR and TMSR is the same over the 24-hour period. The figure shows that prices are cascaded, with higher quality reserves being more expensive than lower quality reserves. RR is the most expensive, while TMOR is the least expensive. The prices also reflect the load demand over the 24-hour period, with higher prices during the periods of higher demand. The hourly reserve price data is given in Table A.11 in Appendix A.

The hourly combined costs and payments to suppliers are shown in Figure 4.42. The costs and payments are reflective of the hourly load demand and are at their maximum during the hours of peak demand. During hours 4 and 5, which are the hours of minimum demand, the cost to suppliers marginally exceeds the payments due to suppliers by an amount of $57.96. These losses in revenue are however recovered over the 24-hour period. The net profit to suppliers is $681 795.60, which is higher than the profit of $585 057.30 for the uncongested case. This is due to a higher income to generators. The hourly costs and payments to the generators are shown in Table A.12 in Appendix A.

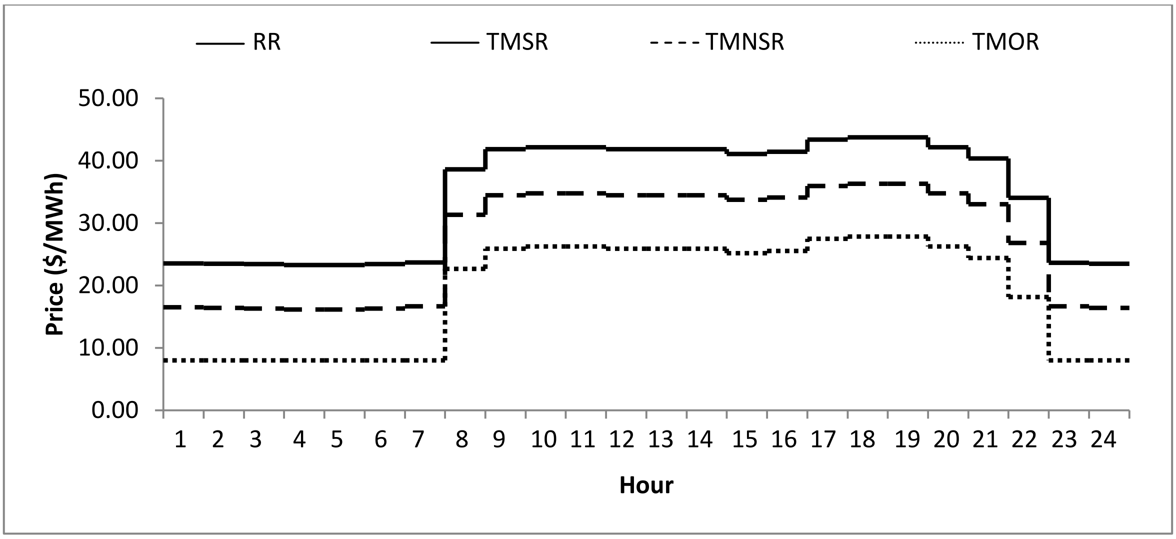

Figure 4.41 Zone 2 reserve prices for zonal level reserve requirements with congestion

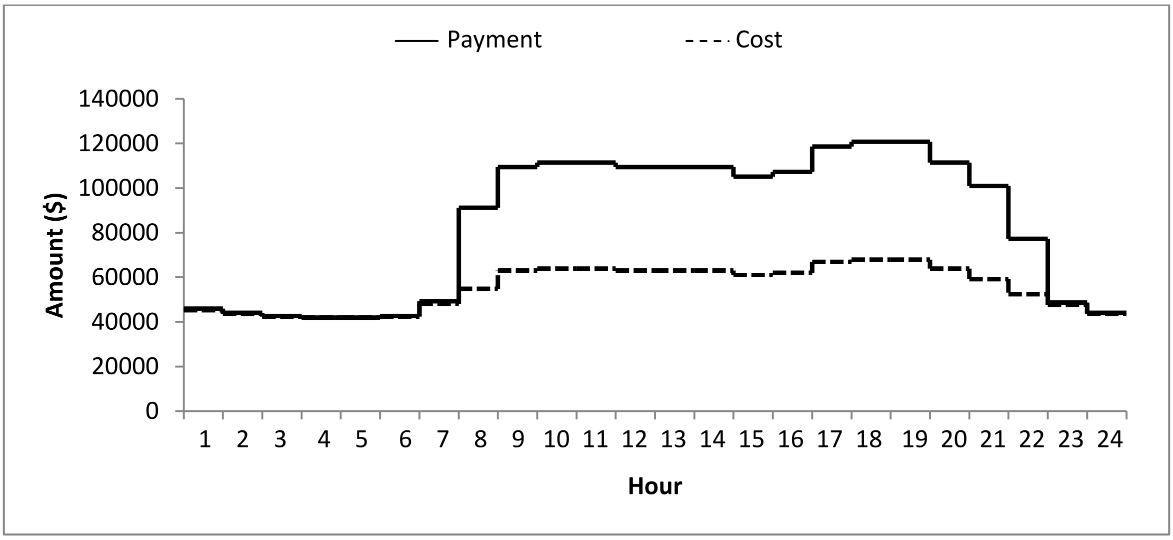

Figure 4.42 Hourly total costs and payments for zonal level reserve requirements with congestion

4.5 CONCLUSION

The proposed OPF formulation for integrated markets, as discussed in Chapter 3, is tested on the IEEE 24 bus RTS. The proposed pricing strategy is investigated for two fundamental cases of specifying reserve requirements. These cases involve specifying reserves at system level and at zonal level. Specifying reserve requirements at zonal level results in higher energy and reserve prices. In such cases, the costs incurred by the system operator are higher and the profit made by market participants is also higher.

Increased congestion on the network results in higher settlement costs to the system operator. Under zonal pricing of reserves, profits to market participants increase as congestion on the network increases.

A market approach to the pricing of energy and reserves in the South African power network is discussed in the next chapter. The proposed pricing formulations are used to determine energy and reserve prices for each of the power corridors in the South African network.

CHAPTER 5 CASE STUDY – ESKOM NETWORK

5.1 CHAPTER OBJECTIVES

In order to demonstrate the effectiveness of the proposed pricing formulation as outlined in Chapter 3, a case study is undertaken. A market approach for the pricing of energy and reserves in the South African power utility is investigated. The South African power network is modeled at a high level in terms of its current power corridors and generation mix. The energy and reserve requirements are based on actual values used on the network. Two scenarios are investigated to determine the seasonal effects on prices.

5.2 ESKOM GENERATION MIX

Eskom is the electricity utility in South Africa and supplies approximately 95% of South Africa's power needs. As of August 2012, Eskom's total installed capacity was 44 084 MW [49]. Coal, nuclear, conventional hydro, pumped storage, gas-fired and wind make up the Eskom generation mix. Coal-fired base load stations make up the largest portion of the generation mix at 85%. Wind-powered stations make up the smallest portion of the generation mix at less than 1%. The installed capacity of each type of technology and the percentage of the total generation mix are given in Table 5.1.

5.3 ESKOM NETWORK

The Eskom power network comprises seven power corridors. These power corridors are based on geographical location, as shown in Figure 5.1. The generation mix and installed capacity in each corridor are shown in Table 5.2. Most of Eskom's installed capacity is located in the North East Grid because of large coal reserves in the area. The Southern and Western Grids have a total installed capacity of 5 336 MW, which is approximately 12% of the total installed capacity. The only significant power station to the south of the country is the nuclear power station, with an installed capacity of 1 910 MW. The operation of the conventional hydro stations in the Southern Grid is regulated because of water restrictions.

The pumped storage station in the Western Grid is only used during peak hours because of water storage and pumping constraints. The gas-fired stations in the Southern and Western grid use kerosene diesel as their primary source of fuel and are therefore very expensive to run. These constraints result in a shortage of generation capacity in the Southern and Western Grids. Further information on the definition of the seven power corridors can be found in [50].

Table 5.1
Eskom plant mix (Source [49])

Technology	Number of Power Stations	Installed Capacity (MW)	Percentage of Mix (%)
Coal	13	37745	85.6
Nuclear	1	1910	4.3
Conventional Hydro	2	600	1.4
Pumped Storage	2	1400	3.2
Gas	4	2426	5.5
Wind	1	3	0.0
Total	23	44084	100

5.4 ESKOM ENERGY AND RESERVE REQUIREMENTS

Three types of reserves are used in the Eskom system. These are instantaneous reserves (IR), RR and TMSR. The reserve requirements for each type of reserve are specified at system level. Further information on the characteristics and the requirements for each type of reserves can be found in [52]. In this study, prices for energy and reserves are determined over a 24-hour period for a typical day in winter and in summer. The hourly load demand for the winter analysis corresponds to the actual load recorded on the network on Friday, 31 July 2009, and hourly load demand for the summer analysis corresponds to the actual load recorded on the network on Friday, 4 December 2009. The load and reserve requirements are given in Table B.1 in Appendix B. The generation mix in 2009 in each of the power corridors is given in Table B.2 in Appendix B. It should be noted that in 2009 only 12 coal-powered stations were operational as part of Eskom's generation mix.

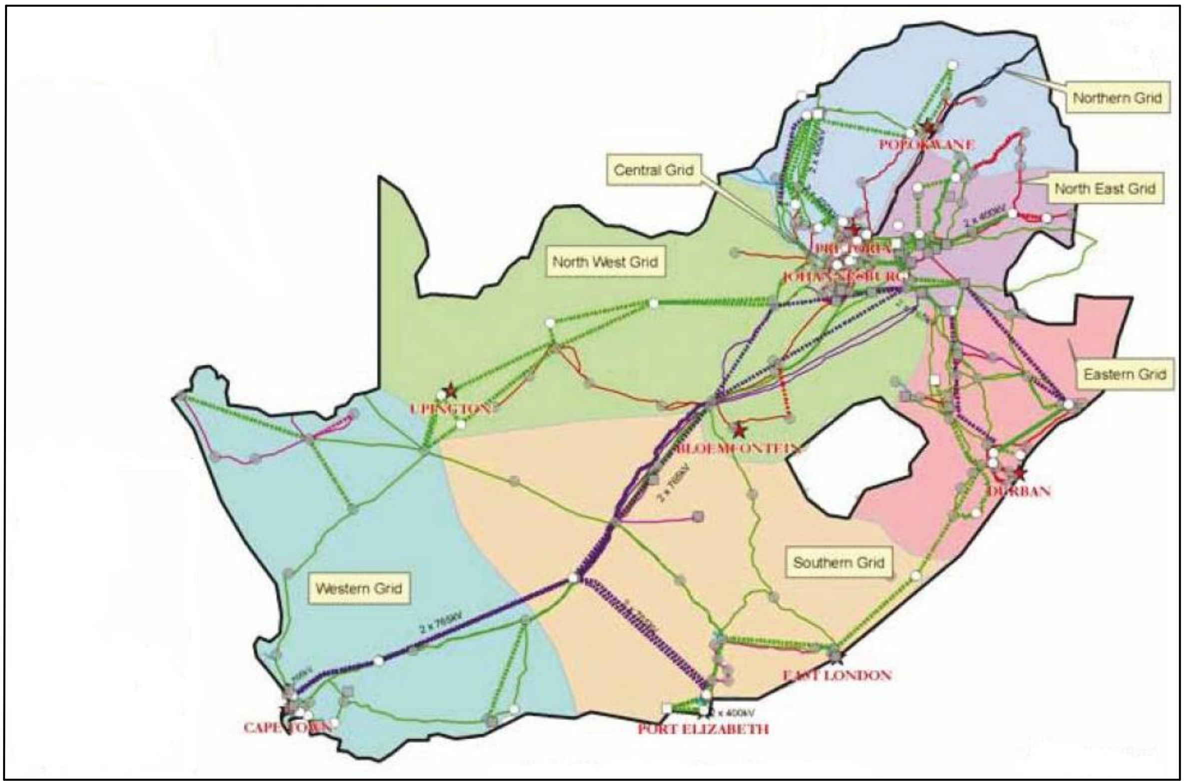

Figure 5.1 Eskom power corridors (Source [51])

5.5 ESKOM MARKET DATA

The availability of reliable and accurate market data for the Eskom network is a challenge because of confidentiality constraints imposed by the utility. Generator energy costs used in the simulations are based on fuel and water costs as used by the Ancillary Services department for constrained generation payment calculations. The fuel and water costs and the estimated cost of provision of reserves of each power station are shown in Figure B.3 in Appendix B. It should be noted that these costs are in South African Rands (R).

Table 5.2

Eskom power corridor plant mix (Source [49])

Corridor	Coal (MW)	Nuclear (MW)	Conventional Hydro (MW)	Pumped Storage (MW)	Gas (MW)	Wind (MW)
Northern	3990	0	0	0	0	0
North East	30047	0	0	0	0	0
North West	0	0	0	0	0	0
Central	3708	0	0	0	0	0
Eastern	0	0	0	1000	0	0
Southern	0	0	600	0	342	0
Western	0	1910	0	400	2084	3

5.6 WINTER ANALYSIS

5.6.1 Energy Dispatch

The hourly energy dispatch and the hourly demand for the Eskom system during winter are shown in Figure 5.2. Peak periods on the Eskom system are from 7:00 to 12:00 and from 18:00 to 21:00. The peak demand of 33 105 MW occurs at 19:00. For each hour of the planning horizon, the energy dispatched is greater than the demand because of system losses.

5.6.2 Energy Price

The hourly energy price for each of the Eskom power corridors during winter is shown in Figure 5.3. The price of energy is reflective of the load demand, with higher prices during periods of higher demand. The Western Grid has the highest energy price, with a price of R1 460 per MWh from hour 7 to hour 22. This is significantly higher than prices in the other corridors. This high price is due to expensive gas-fired stations being used to meet the load demand in the Western Grid. The hourly energy price in the remaining six power corridors, except the Western corridor, is shown in Figure 5.4. The price of energy in these corridors ranges from a minimum of R80.57 per MWh to a maximum of R200.87 per MWh over the 24-hour period. The North West and Southern Grids exhibit significantly higher energy prices between hour 6 and hour 21 because of generation supply shortages. The hourly energy price is given in Table B.4 in Appendix B.

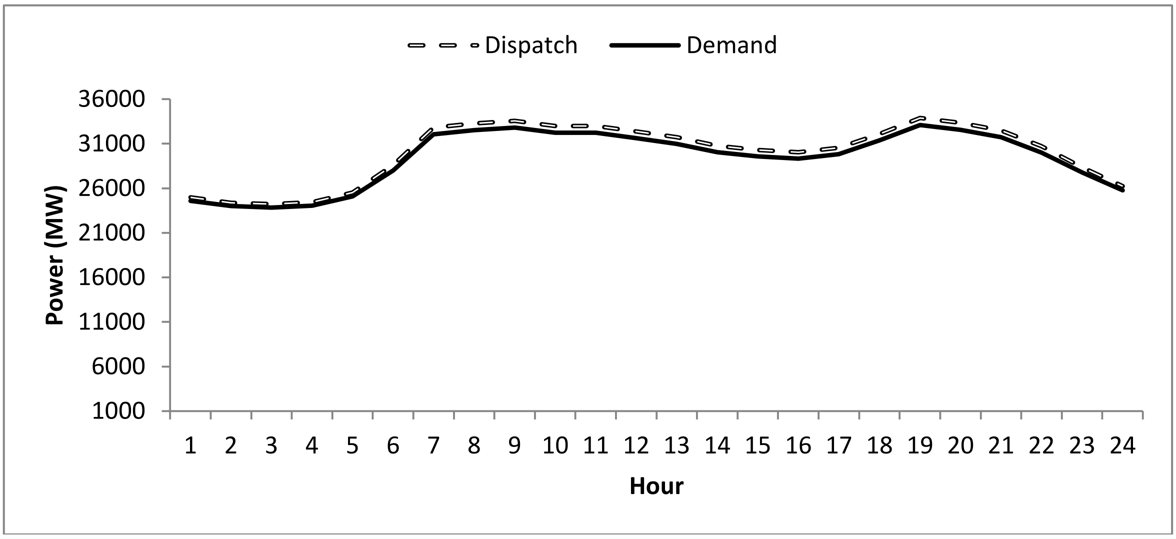

Figure 5.2 Eskom hourly energy dispatch for winter

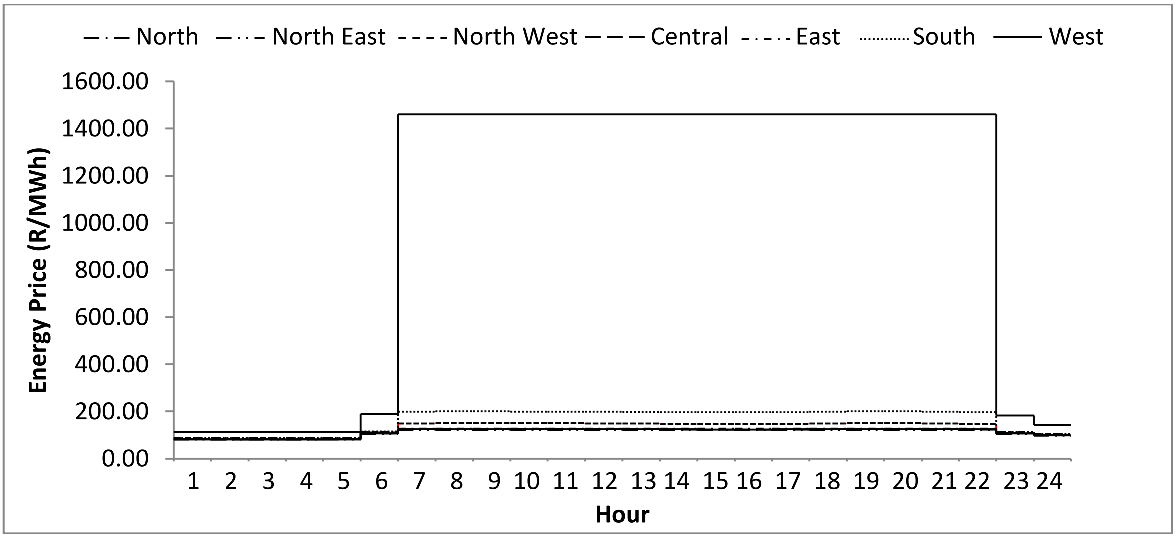

Figure 5.3 Eskom hourly energy prices for winter

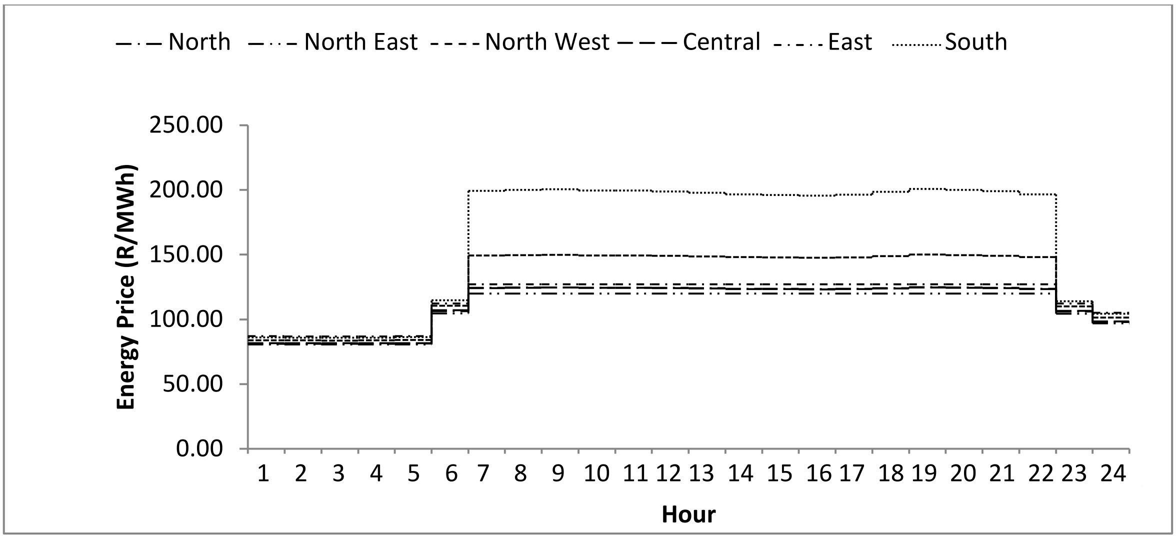

Figure 5.4 Eskom hourly energy prices for winter excluding Western Grid

5.6.3 Reserve Prices

The hourly price of each type of reserves is shown in Figure 5.5. The price of reserves is reflective of the load demand, with prices being higher during periods of higher demand. The prices are also cascaded, with higher quality reserves being more expensive than lower quality reserves. IR, which is the highest quality reserve type, is the most expensive over the 24-hour period. From hour 6 the price of IR and RR is the same, which indicates that some of the IR is being dispatched to meet some of the RR requirements. Since the reserve requirements were set at system level, the reserve prices remain uniform in each of the power corridors. The hourly reserves price data is given in Table B.5 in Appendix B.

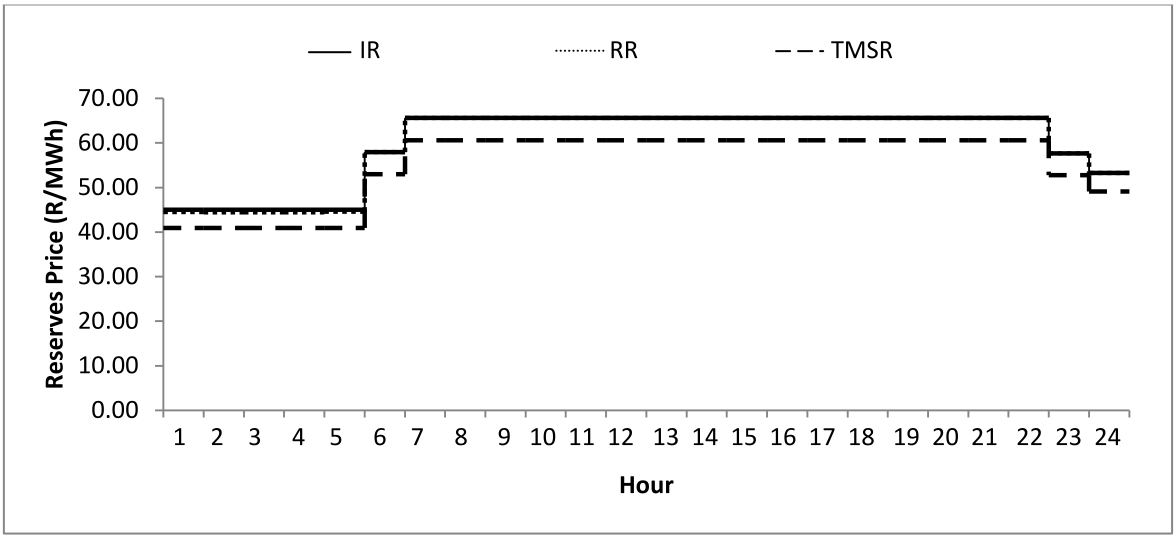

Figure 5.5 Eskom hourly reserve prices for winter

5.6.4 Energy and Reserves Settlements

The hourly combined costs and payments to generators supplying the Eskom network are shown in Figure 5.6. The total cost incurred by generators supplying energy and reserves over the 24-hour period is R55 944 705. The total payment to generators for the provision of energy and reserves is R138 688 674. The payment to generators exceeds the costs incurred by generators at all hours of the study horizon. The profits earned by generators are reflective of the hourly load demand, with higher profits during the periods of high load demand. The maximum hourly profit earned by generators is R4 721 288 during hour 19 and the total profit over the 24-hour period is R82 743 972. The hourly costs and payments to the generators are shown in Table B.6 in Appendix B.

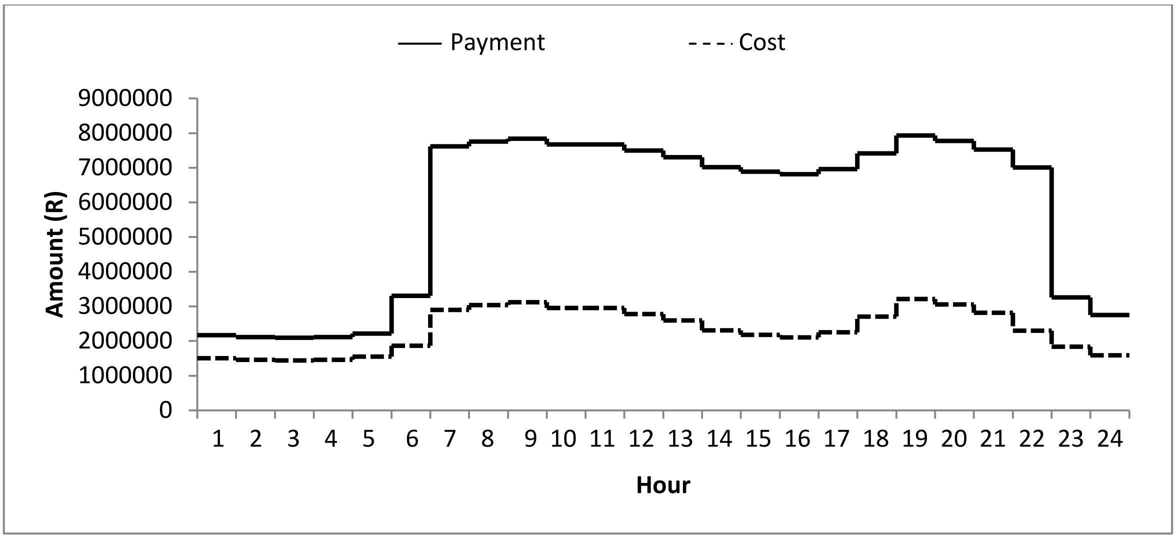

Figure 5.6 Eskom hourly total costs and payments for winter

5.7 SUMMER ANALYSIS

5.7.1 Energy Dispatch

The hourly energy dispatch and the hourly demand for the Eskom system during summer are shown in Figure 5.7. The load peaks at 7:00 and remains between 29 005 MW and 30 034 MW until 21:00. The peak demand of 31704 MW occurs at 11:00. For each hour of the planning horizon, the energy dispatched is greater than the demand because of system losses.

5.7.2 Energy Price

The hourly energy price for each of the Eskom power corridors during summer is shown in Figure 5.8. The price of energy is reflective of the load demand, with higher prices during periods of higher demand. The Western Grid has the highest energy price, with a price of R1 460 per MWh from hour 7 to hour 21. This price is significantly higher than prices in the other power corridors and is a result of expensive gas-fired stations being used to meet the load demand in the Western Grid. The hourly energy price in the remaining six power corridors, except the Western corridor, is shown in Figure 5.9. The price of energy in these corridors ranges between a minimum of R80.57 per MWh and a maximum of R198.90 per MWh over the 24-hour period. The North West and Southern Grids exhibit significantly higher energy prices between hour 7 and hour 21 because of generation supply shortages. The hourly energy price data is given in Table B.7 in Appendix B.

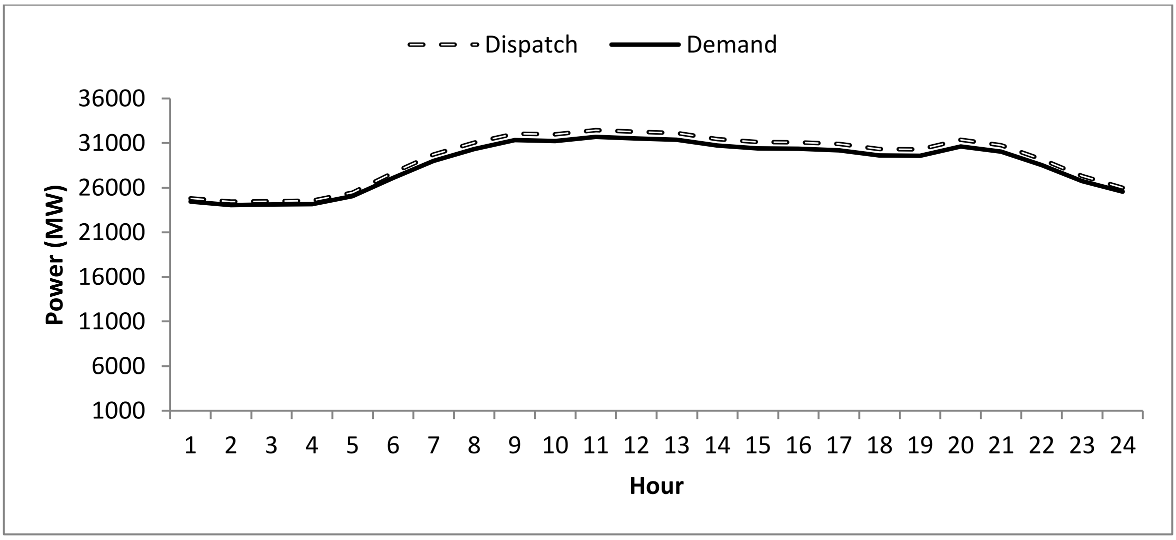

Figure 5.7 Eskom hourly energy dispatch for summer

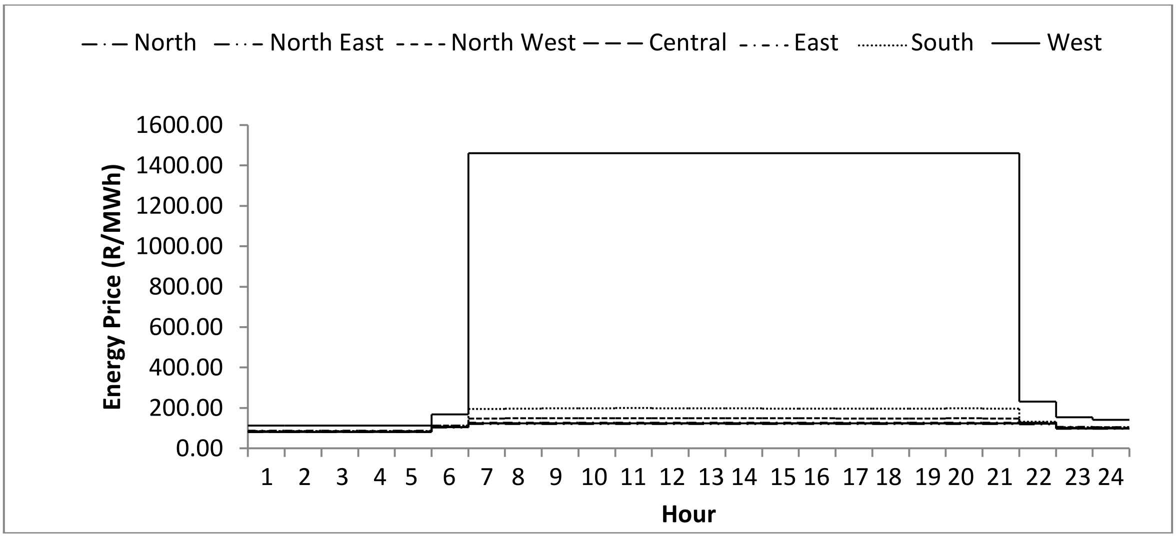

Figure 5.8 Eskom hourly energy prices for summer

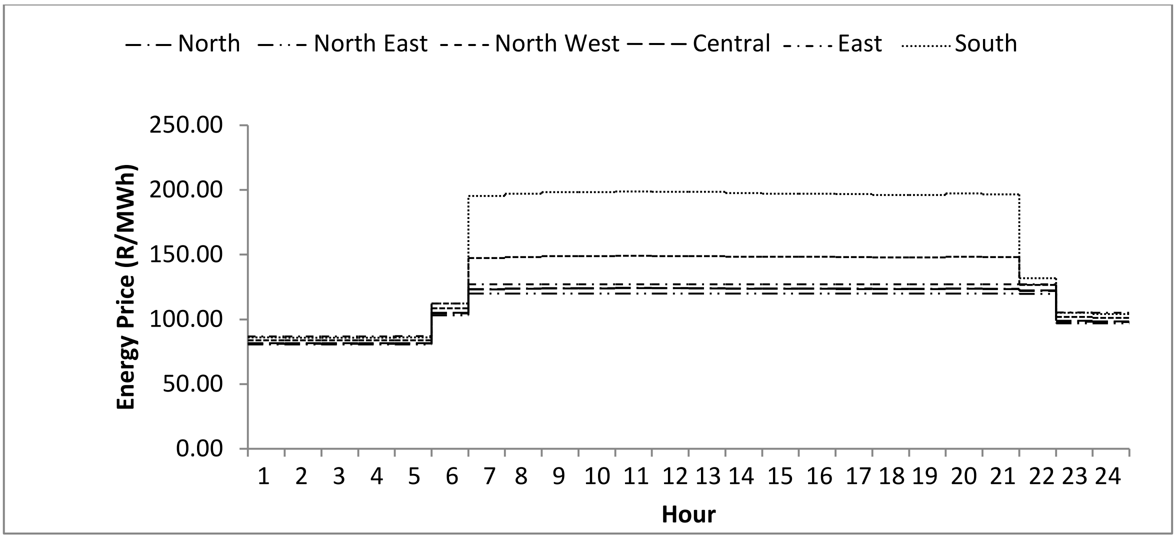

Figure 5.9 Eskom hourly prices for summer excluding Western Grid

5.7.3 Reserve Prices

The hourly price for each type of reserves is shown in Figure 5.10. The price of reserves is reflective of the load demand, with prices being higher during the periods of higher demand. The prices are also cascaded, with higher quality reserves being more expensive than lower quality reserves. IR, which is the highest quality reserve type, is the most expensive over the 24-hour period. From hour 6 to hour 23 the price of IR and RR is the same, which indicates that some of the IR is being dispatched to meet some of the RR requirement. Since the reserve requirements are set at system level, the reserve prices remain uniform in each of the power corridors. The hourly reserve price is given in Table B.8 in Appendix B.

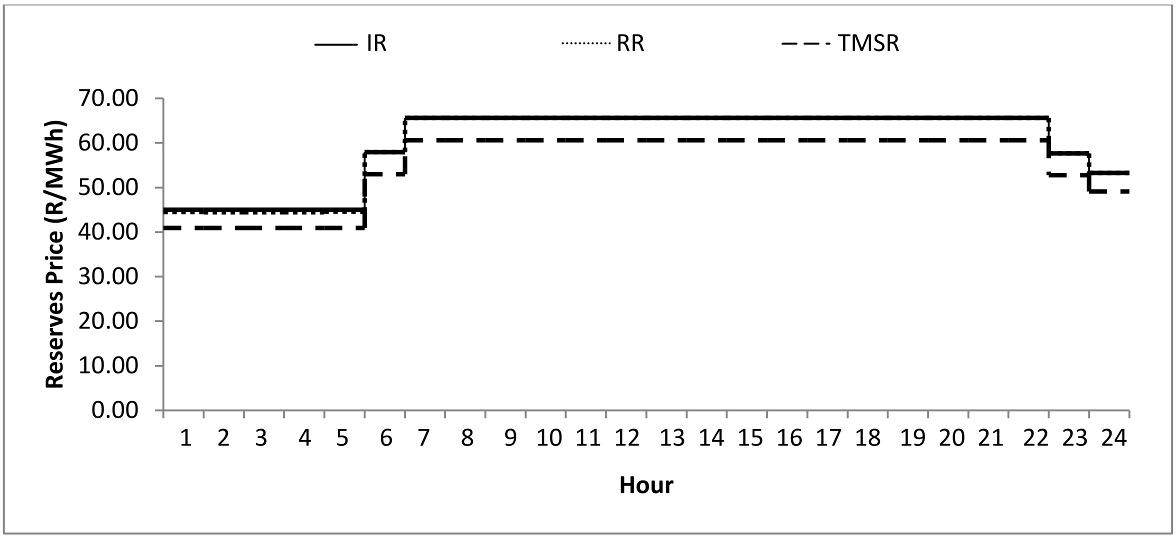

Figure 5.10 Eskom hourly reserve prices for summer

5.7.4 Energy and Reserves Settlements

The hourly combined costs and payments to generators supplying the Eskom network are shown in Figure 5.11. The total cost incurred by generators supplying energy and reserves over the 24-hour period is R51 252 464. The total payment to generators for the provision of energy and reserves is R130 824 102. The payment to generators exceeds the costs incurred by generators during all hours of the study horizon. The profits earned by generators are reflective of the hourly load demand, with higher profits during the periods of high load demand. The maximum hourly profit earned by generators is R4 715 354 during hour 11 and the total profit over the 24-hour period is R79 571 638. The hourly costs and payments to the generators are shown in Table B.9 in Appendix B.

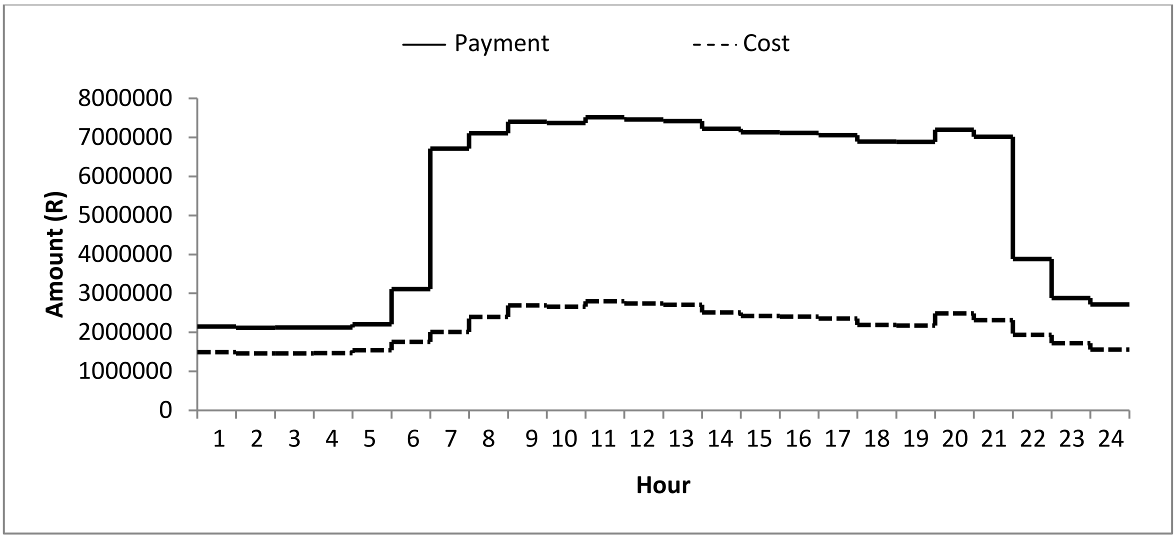

Figure 5.11 Eskom hourly total costs and payments for summer

5.8 SEASONAL COMPARISON

The energy requirement in winter is higher than the summer requirement because of the higher load demand. In the current study it was found that the energy requirement in winter exceeds the summer requirement by 2360 MWh. Tables B4, B5, B7 and B8 show that there is no significant variation in the price of energy and reserves during winter and summer. The total payment to generators is the procurement cost incurred by the ISO. This procurement cost is R7 864 572 higher during winter. The profit earned by generators is also R3 172 154 higher during winter. This is due to increased sales of energy.

5.9 CONCLUSION

The proposed pricing formulation for energy and reserves is applied to the South African network. The price of energy is highest in the Western Grid because of the use of gas-fired stations to meet the load. Excluding the Western grid, the price of energy is significantly higher in the North West and Southern Grids than in the remaining four power grids because of generation supply shortages.

Reserve prices on the Eskom network are cascaded, with IR being the most expensive and TMSR being the least expensive. Downward substitution of reserves does occur on the Eskom network, with IR being dispatched to meet some of the RR requirement during the day.

The settlement costs incurred by the system operator and the profit earned by market participants are higher during a typical day in winter than in summer. Energy prices are slightly higher in winter than in summer and reserve prices remain constant in summer and winter.

CHAPTER 6 CONCLUSION

6.1 SUMMARY OF FINDINGS

Many utilities around the world have embarked on reforms to enhance competition for the provision of electrical energy and related ancillary services. These reforms require a new approach to the costing and procurement of these services. The primary objective of this dissertation was the development of an SPD tool for integrated energy and reserve markets. This was achieved by extending the capabilities of an open source OPF market application to include reserves of more than one type and to include multi-period co-optimization capability. The shadow prices resulting from the optimization process were then used to define prices for energy and reserves.

From an evaluation of the simulated results, the following findings on integrated energy and reserve markets can be noted:

- The hourly price of energy and reserves are reflective of the hourly load demand. The prices are higher during periods of high demand and lower when the demand is low.
- The prices of different types of reserves are cascaded. Higher quality reserves are more expensive than lower quality reserves.
- Higher quality reserves may be substituted for lower quality reserves. In such a situation the prices of the different types of reserves involved are equal.
- Setting reserve requirements at zonal level results in higher nodal energy prices and reserve prices. In such a case, the costs incurred by the system operator are also higher. Zonal reserve requirements also result in higher profits to market participants.
- Increased congestion on the network results in higher costs to the system operator in the form of settlement costs to market participants. Under zonal pricing of reserves, profits to market participants increase as congestion on the network increases.

6.2 CONCLUSIONS

This dissertation has presented the study of an OPF-based simultaneous auction for energy and reserves of more than one type. The extension of the problem from a single-period problem to a multi-period problem with coupling constraints has been presented and discussed. Based on this study, the following conclusions can be stated:

- The AC OPF is an effective pricing tool in integrated energy market applications. The Lagrangian multipliers derived from such an application can be used for pricing energy and reserves to ensure economic efficiency in these markets.
- An efficient pricing strategy for reserves ensures the cascading of prices, with higher quality reserves being priced higher than lower quality reserves. Efficient pricing of reserves ensures that the “price reversal” phenomenon experienced in reserve markets is eliminated.
- An efficient pricing strategy for reserves allows for the downward substitution of reserves where higher quality reserves may be substituted for lower quality reserves. Such a substitution should not lead to price conflicts and “price reversal” issues.
- An effective pricing strategy for energy and reserves must incentivise market participants by ensuring that it is profitable to participate in such markets. In so doing, such a pricing strategy must strive to minimize the procurement costs incurred by the system operator.
- The economic effectiveness of an integrated electricity market is dependent on market participants bidding in their true costs for supplying energy and ancillary services. Failure to do so results in flawed pricing signals that are contrary to the reasons for implemented reforms in the industry.

6.3 SUGGESTIONS FOR FURTHER RESEARCH

The proposed pricing formulation for the simultaneous auction of energy and reserves has explored various topics on market development and optimization. Suggestions for further research emanating from the current study include:

- The proposed formulation is currently implemented as part of the OPF problem of which the UC problem serves as an input. It is suggested that the proposed integrated market be formulated as part of the UC problem and the results obtained be compared to those of the OPF formulation.
- The default OPF solver used in the market application is a primal-dual interior point solver. It is suggested that other solvers be investigated for effectiveness in minimizing the cost objective functions.
- The study horizon in the current study is over a 24-hour period. For practical applications, it is suggested that the study horizon be extended to include monthly and yearly studies.
- In the current study, the effect of congestion was investigated by removing one line from service. It is recommended that more lines be removed to increase congestion and to investigate pricing signals in terms of congestion management.
- For the case study, the South African power network was modeled at a high level in terms of seven power corridors. It is suggested that a full network model be implemented to improve the accuracy of the resulting energy and reserve prices. It is also suggested that the true cost of supplying energy and reserves for this system be investigated.

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APPENDIX A: 24 BUS RELIABILITY TEST SYSTEM

Table A.1
Data for generating units

Bus Number	Unit Number	Active Power Cost Coefficients and Limits				
		a	b	c	Min	Max
1,2	1,2	0.44	48.4	633	16	20
1,2	3,4	0.01	11.0	145	15	76
7	1-3	0.07	25.4	615	25	100
13	1-3	0.02	28.5	739	69	197
15	1-5	0.08	38.9	56	2	12
15	6	0.01	9.3	220	54	155
16	1	0.01	9.3	220	54	155
18,21	1	0.00	13.5	621	100	400
23	1,2	0.01	9.3	220	54	155
23	3	0.01	8.6	440	140	350

Table A.2
Data for generating units – reserve bids and capacity

Bus Number	Unit Number	Regulation Reserve		10-minute Spinning Reserve		10-minute Non-spinning Reserve		30-minute Operating Reserve	
		Bid	Max	Bid	Max	Bid	Max	Bid	Max
1,2	1,2	18	50	17	50	10	50	9	50
1,2	3,4	20	15	18	15	9	15	10	15
7	1-3	50	30	45	30	38	30	45	30
13	1-3	47	37	53	37	47	37	20	37
15	1-5	19	40	25	40	20	40	17	40
15	6	22	12	22	12	15	12	202	12
16	1	22	12	22	12	15	12	20	12
18,21	1	24	38	27	38	41	38	8	38
23	1,2	27	22	24	22	15	22	12	23
23	3	22	13	22	13	17	13	20	13

Table A.3
Hourly load and reserve requirements

Hour	Hourly Demand				
	Load Demand (MW)	Regulating Reserves (MW)	10-minute Spinning (MW)	10-minute Non-spinning (MW)	30-minute Operating Reserve (MW)
1	1911	130	130	100	100
2	1796	130	130	100	100
3	1709	130	130	100	100
4	1683	130	130	100	100
5	1683	130	130	100	100
6	1709	130	130	100	100
7	2110	130	130	100	100
8	2452	130	130	100	100
9	2708	130	130	100	100
10	2734	130	130	100	100
11	2734	130	130	100	100
12	2708	130	130	100	100
13	2708	130	130	100	100
14	2708	130	130	100	100
15	2650	130	130	100	100
16	2679	130	130	100	100
17	2821	130	130	100	100
18	2850	130	130	100	100
19	2850	130	130	100	100
20	2734	130	130	100	100
21	2592	130	130	100	100
22	2366	130	130	100	100
23	2080	130	130	100	100
24	1796	130	130	100	100

Table A.4
Hourly dispatch – uncongested case

Hour	Energy (MW)	Regulating Reserves (MW)	10-minute Spinning (MW)	10-Minute Non-spinning (MW)	30-minute Operating Reserve (MW)
1	1941	159.0	101.0	100.0	100.0
2	1821	159.0	101.0	100.0	100.0
3	1731	159.0	101.0	100.0	100.0
4	1704	159.0	101.0	100.0	100.0
5	1704	159.0	101.0	100.0	100.0
6	1731	159.0	101.0	100.0	100.0
7	2151	159.0	101.0	100.0	100.0
8	2497	161.2	98.8	100.0	100.0
9	2750	161.7	98.3	100.0	100.0
10	2776	161.8	98.2	100.0	100.0
11	2776	161.8	98.2	100.0	100.0
12	2750	161.7	98.3	100.0	100.0
13	2750	161.7	98.3	100.0	100.0
14	2750	161.7	98.3	100.0	100.0
15	2692	161.6	98.4	100.0	100.0
16	2721	161.6	98.4	100.0	100.0
17	2863	162.0	98.0	100.0	100.0
18	2892	155.9	104.1	100.0	100.0
19	2892	155.9	104.1	100.0	100.0
20	2776	161.8	98.2	100.0	100.0
21	2635	161.5	98.5	100.0	100.0
22	2412	162.4	97.6	100.0	100.0
23	2119	159.0	101.0	100.0	100.0
24	1821	159.0	101.0	100.0	100.0

Table A.5
Hourly energy and reserve prices – uncongested case

Hour	Minimum Energy Price ($/MWh)	Maximum Energy Price ($/MWh)	RR Price ($/MWh)	TMSR Price ($/MWh)	TMNSR Price ($/MWh)	TMOR Price ($/MWh)
1	13.12	15.17	24.00	24.00	16.55	12.98
2	13.10	14.87	24.00	24.00	16.43	12.76
3	13.09	14.66	24.00	24.00	16.35	12.61
4	12.94	14.45	24.00	24.00	16.19	12.42
5	12.94	14.45	24.00	24.00	16.19	12.42
6	13.09	14.66	24.00	24.00	16.35	12.61
7	13.14	15.71	24.00	24.00	16.75	13.36
8	27.10	32.04	38.51	38.51	31.30	20.00
9	31.16	35.79	42.76	42.76	35.32	20.00
10	31.48	36.08	43.09	43.09	35.62	20.00
11	31.48	36.08	43.09	43.09	35.62	20.00
12	31.16	35.79	42.76	42.76	35.32	20.00
13	31.16	35.79	42.76	42.76	35.32	20.00
14	31.16	35.79	42.76	42.76	35.32	20.00
15	30.46	35.16	42.03	42.03	34.64	20.00
16	30.81	35.48	42.39	42.39	34.98	20.00
17	32.55	37.25	44.21	44.21	36.64	20.00
18	33.39	38.23	45.00	45.00	37.51	20.78
19	33.39	38.23	45.00	45.00	37.51	20.78
20	31.48	36.08	43.09	43.09	35.62	20.00
21	29.77	34.52	41.31	41.31	33.98	20.00
22	24.77	29.82	36.00	36.00	28.80	20.00
23	13.14	15.62	24.00	24.00	16.72	13.30
24	13.10	14.87	24.00	24.00	16.43	12.76

Table A.6
Hourly costs and payments to generators – uncongested case

Hour	Cost ($)	Payment ($)	Profit ($)
1	44395.07	35812.92	-8582.16
2	42775.3	33985.36	-8789.93
3	41560.54	32622.2	-8938.35
4	41200.15	31939.32	-9260.84
5	41200.15	31939.32	-9260.84
6	41560.54	32622.2	-8938.35
7	47233.68	39013.15	-8220.52
8	54139.64	86709.52	32569.88
9	62412.81	107035.7	44622.91
10	63298.88	108890.5	45591.59
11	63298.88	108890.5	45591.59
12	62412.81	107035.7	44622.91
13	62412.81	107035.7	44622.91
14	62412.81	107035.7	44622.91
15	60468.14	102958	42489.83
16	61439.06	104983.3	43544.23
17	66325.43	115250.2	48924.73
18	67364.52	119117.8	51753.25
19	67364.52	119117.8	51753.25
20	63298.88	108890.5	45591.59
21	58561.18	98979.76	40418.58
22	51739.61	77365.54	25625.93
23	46802.76	38523.44	-8279.32
24	42775.3	33985.36	-8789.93

Table A.7
Hourly zonal load and reserve requirements

Hour	Hourly Demand								
	Load Demand (MW)	RR (MW)		TMSR (MW)		TMNSR (MW)		TMOR (MW)	
		Zone1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2
1	1911	82	48	82	48	63	37	63	37
2	1796	82	48	82	48	63	37	63	37
3	1709	82	48	82	48	63	37	63	37
4	1683	82	48	82	48	63	37	63	37
5	1683	82	48	82	48	63	37	63	37
6	1709	82	48	82	48	63	37	63	37
7	2110	82	48	82	48	63	37	63	37
8	2452	82	48	82	48	63	37	63	37
9	2708	82	48	82	48	63	37	63	37
10	2734	82	48	82	48	63	37	63	37
11	2734	82	48	82	48	63	37	63	37
12	2708	82	48	82	48	63	37	63	37
13	2708	82	48	82	48	63	37	63	37
14	2708	82	48	82	48	63	37	63	37
15	2650	82	48	82	48	63	37	63	37
16	2679	82	48	82	48	63	37	63	37
17	2821	82	48	82	48	63	37	63	37
18	2850	82	48	82	48	63	37	63	37
19	2850	82	48	82	48	63	37	63	37
20	2734	82	48	82	48	63	37	63	37
21	2592	82	48	82	48	63	37	63	37
22	2366	82	48	82	48	63	37	63	37
23	2080	82	48	82	48	63	37	63	37
24	1796	82	48	82	48	63	37	63	37

Table A.8
Energy and zonal reserve prices – uncongested case

Hour	Min Energy Price ($/MWh)	Max Energy Price ($/MWh)	RR Price ($/MWh)		TMSR Price ($/MWh)		TMNSR Price ($/MWh)		TMOR Price ($/MWh)	
			Zone1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2
1	13.12	15.23	47.00	23.58	45.00	23.58	20.00	16.58	20.00	8.00
2	13.10	14.93	47.00	23.49	45.00	23.49	20.00	16.49	20.00	8.00
3	13.09	14.72	47.00	23.42	45.00	23.42	20.00	16.42	20.00	8.00
4	12.74	14.29	47.00	23.07	45.00	23.07	20.00	16.07	20.00	8.00
5	12.74	14.29	47.00	23.07	45.00	23.07	20.00	16.07	20.00	8.00
6	13.09	14.72	47.00	23.42	45.00	23.42	20.00	16.42	20.00	8.00
7	13.14	15.78	47.00	23.73	45.00	23.73	20.00	16.73	20.00	8.01
8	27.69	32.74	47.00	38.92	45.00	38.92	29.20	31.95	20.00	22.99
9	31.16	36.43	47.00	42.48	45.00	42.48	33.26	35.47	20.00	26.57
10	31.48	37.05	47.00	42.81	45.00	42.81	33.69	35.78	20.00	26.91
11	31.48	37.05	47.00	42.81	45.00	42.81	33.69	35.78	20.00	26.91
12	31.16	36.43	47.00	42.48	45.00	42.48	33.26	35.47	20.00	26.57
13	31.16	36.43	47.00	42.48	45.00	42.48	33.26	35.47	20.00	26.57
14	31.16	36.43	47.00	42.48	45.00	42.48	33.26	35.47	20.00	26.57
15	30.45	35.33	47.00	41.75	45.00	41.75	32.37	34.75	20.00	25.84
16	30.79	35.71	47.00	42.11	45.00	42.11	32.78	35.11	20.00	26.20
17	32.64	41.84	47.00	44.00	45.00	44.00	36.00	36.85	20.00	28.10
18	32.86	42.00	47.00	44.23	45.00	44.23	36.00	37.05	20.00	28.33
19	32.86	42.00	47.00	44.23	45.00	44.23	36.00	37.05	20.00	28.33
20	31.48	37.05	47.00	42.81	45.00	42.81	33.69	35.78	20.00	26.91
21	29.77	34.69	47.00	41.05	45.00	41.05	31.58	34.06	20.00	25.14
22	18.73	23.24	47.00	29.62	45.00	29.62	20.00	22.62	20.00	13.77
23	13.14	15.69	47.00	23.71	45.00	23.71	20.00	16.71	20.00	8.00
24	13.10	14.93	47.00	23.49	45.00	23.49	20.00	16.49	20.00	8.00

Table A.9
Hourly energy and reserve prices – congested case

Hour	Minimum Energy Price ($/MWh)	Maximum Energy Price ($/MWh)	RR Price ($/MWh)	TMSR Price ($/MWh)	TMNSR Price ($/MWh)	TMOR Price ($/MWh)
1	13.13	15.40	24.00	24.00	16.43	13.17
2	13.11	15.07	24.00	24.00	16.32	12.93
3	13.09	14.84	24.00	24.00	16.24	12.76
4	13.03	14.71	24.00	24.00	16.17	12.65
5	13.03	14.71	24.00	24.00	16.17	12.65
6	13.09	14.84	24.00	24.00	16.24	12.76
7	13.14	16.00	24.00	24.00	16.61	13.60
8	27.09	32.51	38.52	38.52	30.91	20.00
9	30.57	35.64	42.15	42.15	34.37	20.00
10	30.90	35.93	42.49	42.49	34.70	20.00
11	30.90	35.93	42.49	42.49	34.70	20.00
12	30.57	35.64	42.15	42.15	34.37	20.00
13	30.57	35.64	42.15	42.15	34.37	20.00
14	30.57	35.64	42.15	42.15	34.37	20.00
15	29.84	35.01	41.39	41.39	33.65	20.00
16	30.20	35.33	41.77	41.77	34.01	20.00
17	32.02	37.07	43.65	43.65	35.79	20.00
18	33.37	38.64	45.00	45.00	37.18	21.44
19	33.37	38.64	45.00	45.00	37.18	21.44
20	30.90	35.93	42.49	42.49	34.70	20.00
21	29.13	34.37	40.65	40.65	32.95	20.00
22	24.77	30.17	36.04	36.04	28.44	20.00
23	13.14	15.91	24.00	24.00	16.58	13.53
24	13.11	15.07	24.00	24.00	16.32	12.93

Table A.10
Hourly costs and payments to generators – congested case

Hour	Cost ($)	Payment ($)	Profit ($)
1	44471.05	35953.4	-8517.65
2	42837.64	34100.75	-8736.89
3	41613.97	32719.18	-8894.79
4	41250.05	32199.5	-9050.54
5	41250.05	32199.5	-9050.54
6	41613.97	32719.18	-8894.79
7	47337.28	39204.22	-8133.06
8	54408.51	87072.24	32663.73
9	62590.38	105560.6	42970.23
10	63466.79	107441.7	43974.95
11	63466.79	107441.7	43974.95
12	62590.38	105560.6	42970.23
13	62590.38	105560.6	42970.23
14	62590.38	105560.6	42970.23
15	60667.67	101429	40761.36
16	61627.88	103479.2	41851.33
17	66462.84	113895.3	47432.48
18	67503.99	119537.1	52033.08
19	67503.99	119537.1	52033.08
20	63466.79	107441.7	43974.95
21	58783.1	97402.81	38619.71
22	51983.45	77661.6	25678.15
23	46901.61	38705.28	-8196.33
24	42837.64	34100.75	-8736.89

Table A.11
Energy and zonal reserve prices – congested case

Hour	Min Energy Price ($/MWh)	Max Energy Price ($/MWh)	RR Price ($/MWh)		TMSR Price ($/MWh)		TMNSR Price ($/MWh)		TMOR Price ($/MWh)	
			Zone1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2	Zone 1	Zone 2
1	13.13	15.48	47.00	23.55	45.00	23.55	20.00	16.50	20.00	8.00
2	13.11	15.14	47.00	23.48	45.00	23.48	20.00	16.40	20.00	8.00
3	13.09	14.90	47.00	23.43	45.00	23.43	20.00	16.32	20.00	8.00
4	12.94	14.68	47.00	23.26	45.00	23.26	20.00	16.15	20.00	8.00
5	12.94	14.68	47.00	23.26	45.00	23.26	20.00	16.15	20.00	8.00
6	13.09	14.90	47.00	23.43	45.00	23.43	20.00	16.32	20.00	8.00
7	13.14	16.10	47.00	23.67	45.00	23.67	20.00	16.67	20.00	8.01
8	27.38	32.99	47.00	38.60	45.00	38.60	29.44	31.36	20.00	22.68
9	30.52	35.93	47.00	41.83	45.00	41.83	32.95	34.47	20.00	25.92
10	30.85	36.29	47.00	42.17	45.00	42.17	33.33	34.79	20.00	26.26
11	30.85	36.29	47.00	42.17	45.00	42.17	33.33	34.79	20.00	26.26
12	30.52	35.93	47.00	41.83	45.00	41.83	32.95	34.47	20.00	25.92
13	30.52	35.93	47.00	41.83	45.00	41.83	32.95	34.47	20.00	25.92
14	30.52	35.93	47.00	41.83	45.00	41.83	32.95	34.47	20.00	25.92
15	29.79	35.18	47.00	41.08	45.00	41.08	32.13	33.75	20.00	25.17
16	30.15	35.54	47.00	41.45	45.00	41.45	32.54	34.10	20.00	25.54
17	32.06	40.81	47.00	43.41	45.00	43.41	35.54	35.96	20.00	27.51
18	32.41	41.65	47.00	43.77	45.00	43.77	36.00	36.30	20.00	27.87
19	32.41	41.65	47.00	43.77	45.00	43.77	36.00	36.30	20.00	27.87
20	30.85	36.29	47.00	42.17	45.00	42.17	33.33	34.79	20.00	26.26
21	29.08	34.54	47.00	40.35	45.00	40.35	31.32	33.04	20.00	24.43
22	22.97	29.10	47.00	34.07	45.00	34.07	24.43	26.80	20.00	18.13
23	13.14	16.00	47.00	23.65	45.00	23.65	20.00	16.65	20.00	8.01
24	13.11	15.14	47.00	23.48	45.00	23.48	20.00	16.40	20.00	8.00

Table A.12
Hourly costs and payments to generators – congested case

Hour	Cost ($)	Payment ($)	Profit ($)
1	45263.789	45944.39	680.60
2	43623.543	44079.812	456.27
3	42395.271	42688.955	293.68
4	42030.396	41972.437	-57.96
5	42030.396	41972.437	-57.96
6	42395.271	42688.955	293.68
7	48142.993	49198.608	1055.61
8	54797.338	91198.806	36401.47
9	63019.7	109415.98	46396.28
10	63900.372	111377.68	47477.31
11	63900.372	111377.68	47477.31
12	63019.7	109415.98	46396.28
13	63019.7	109415.98	46396.28
14	63019.7	109415.98	46396.28
15	61087.741	105107.26	44019.52
16	62052.978	107244.67	45191.69
17	66925.004	118586.84	51661.84
18	67962.884	120818.12	52855.23
19	67962.884	120818.12	52855.23
20	63900.372	111377.68	47477.31
21	59194.263	100914.7	41720.44
22	52359.697	77317.212	24957.51
23	47705.231	48700.647	995.42
24	43623.543	44079.812	456.27

APPENDIX B: ESKOM STUDY

Table B.1
Eskom hourly load and reserve requirements

Hour	Hourly Demand				
	Winter Load Demand (MW)	Summer Load Demand (MW)	IR (MW)	RR (MW)	TMSR (MW)
1	24598	24433	397	550	750
2	24003	24060	397	550	750
3	23849	24107	397	550	750
4	24059	24169	397	550	750
5	25104	25039	397	550	750
6	27997	27094	397	550	750
7	32041	29005	397	550	750
8	32511	30329	397	550	750
9	32798	31329	397	550	750
10	32224	31230	397	550	750
11	32232	31704	397	550	750
12	31634	31512	397	550	750
13	30990	31382	397	550	750
14	30031	30718	397	550	750
15	29581	30412	397	550	750
16	29340	30363	397	550	750
17	29842	30175	397	550	750
18	31364	29617	397	550	750
19	33105	29575	397	550	750
20	32569	30626	397	550	750
21	31745	30034	397	550	750
22	29994	28537	397	550	750
23	27775	26755	397	550	750
24	25778	25546	397	550	750

Table B.2
Eskom power corridor plant mix (Source [53])

Corridor	Coal (MW)	Nuclear (MW)	Conventional Hydro (MW)	Pumped Storage (MW)	Gas (MW)
Northern	3990	0	0	0	0
North East	28107	0	0	0	0
North West	0	0	0	0	0
Central	3708	0	0	0	0
Eastern	0	0	0	1000	0
Southern	0	0	600	0	342
Western	0	1910	0	400	1044

Table B.3
Eskom market data

Station	Energy (R/MWh)	IR (R/MWh)	RR (R/MWh)	TMSR (R/MWh)	Corridor
Coal 1	96.96	104.14	103.33	102.50	North East
Coal 2	130.57	N/A	N/A	130.57	North East
Coal 3	55.77	60.41	59.93	58.99	North East
Coal 4	128.16	N/A	N/A	128.16	North East
Coal 5	60.25	N/A	N/A	61.59	North East
Coal 6	79.25	86.56	85.74	78.94	North East
Coal 7	80.57	86.01	85.38	84.42	North East
Coal 8	59.18	63.84	63.04	61.83	Central
Coal 9	127.14	133.00	130.51	128.99	North East
Coal 10	53.84	55.02	N/A	54.85	Northern
Coal 11	55.02	57.53	57.52	56.46	North East
Coal 12	119.92	133.30	132.00	128.67	North East
Gas 1	1460	N/A	N/A	N/A	Western
Gas 2	1460	N/A	N/A	N/A	Western
Gas 3	2379	N/A	N/A	N/A	Southern
Gas 4	2379	N/A	N/A	N/A	Southern
Hydro 1	3.95	N/A	N/A	N/A	Southern
Hydro 2	3.95	N/A	N/A	N/A	Southern
Nuclear 1	33.93	N/A	N/A	N/A	Western
Pumped Storage 1	112.20	550	549	548	Eastern
Pumped Storage 2	112.20	400	399	398	Western

Table B.4
Hourly corridor energy price - winter

Hour	North (R)	North East (R)	North West (R)	Central (R)	East (R)	South (R)	West (R)
1	81.10	80.57	83.75	81.52	86.79	85.87	112.20
2	81.08	80.57	83.72	81.52	86.74	85.84	112.20
3	81.11	80.57	83.76	81.52	86.80	85.89	112.20
4	81.29	80.57	83.97	81.71	87.11	86.22	113.40
5	106.45	104.63	110.53	107.05	112.20	114.77	187.66
6	124.44	119.92	149.32	124.25	127.14	199.37	1460.00
7	124.61	119.92	149.63	124.44	127.14	200.02	1460.00
8	124.71	119.92	149.82	124.56	127.14	200.43	1460.00
9	124.51	119.92	149.44	124.33	127.14	199.63	1460.00
10	124.51	119.92	149.45	124.33	127.14	199.63	1460.00
11	124.30	119.92	149.06	124.09	127.14	198.81	1460.00
12	124.07	119.92	148.65	123.84	127.14	197.92	1460.00
13	123.73	119.92	148.04	123.46	127.14	196.62	1460.00
14	123.58	119.92	147.76	123.28	127.14	196.03	1460.00
15	123.50	119.92	147.61	123.19	127.14	195.69	1460.00
16	123.67	119.92	147.93	123.38	127.14	196.37	1460.00
17	124.20	119.92	148.89	123.99	127.14	198.43	1460.00
18	124.82	119.92	150.02	124.68	127.14	200.87	1460.00
19	124.63	119.92	149.67	124.47	127.14	200.11	1460.00
20	124.34	119.92	149.14	124.14	127.14	198.96	1460.00
21	123.72	119.92	148.02	123.44	127.14	196.57	1460.00
22	106.01	104.26	110.02	106.60	112.20	114.13	182.19
23	98.01	96.96	101.36	98.54	105.07	104.32	142.46
24	81.10	80.57	83.75	81.52	86.79	85.87	112.20

Table B.5
Hourly reserve prices - winter

Hour	IR (R)	RR (R)	TMSR (R)
1	45.06	44.49	40.95
2	45.06	44.43	40.95
3	45.06	44.42	40.95
4	45.06	44.43	40.95
5	45.06	44.62	40.95
6	57.92	57.92	52.98
7	65.66	65.66	60.63
8	65.66	65.66	60.63
9	65.66	65.66	60.63
10	65.66	65.66	60.63
11	65.66	65.66	60.63
12	65.66	65.66	60.63
13	65.66	65.66	60.63
14	65.66	65.66	60.63
15	65.66	65.66	60.63
16	65.66	65.66	60.63
17	65.66	65.66	60.63
18	65.66	65.66	60.63
19	65.66	65.66	60.63
20	65.66	65.66	60.63
21	65.66	65.66	60.63
22	65.66	65.66	60.63
23	57.66	57.66	52.80
24	53.25	53.25	49.15

Table B.6
Hourly costs and payments to generators – winter

Hour	Cost (R)	Payment (R)	Profit (R)
1	1504886.34	2164736.97	659850.63
2	1453361.74	2112403.27	659041.53
3	1440136.06	2099071.31	658935.25
4	1458125.12	2117206.32	659081.21
5	1548519.23	2212198.39	663679.16
6	1863743.82	3303137.02	1439393.20
7	2897341.72	7614113.94	4716772.23
8	3035911.84	7754670.00	4718758.16
9	3120239.42	7840224.21	4719984.79
10	2952202.84	7669758.95	4717556.10
11	2954432.52	7672019.11	4717586.59
12	2779648.66	7494727.52	4715078.86
13	2590311.49	7302677.68	4712366.19
14	2310164.48	7018565.35	4708400.86
15	2178744.67	6885299.85	4706555.18
16	2107409.76	6812971.64	4705561.88
17	2255166.53	6962793.28	4707626.75
18	2700188.00	7414122.52	4713934.52
19	3209324.70	7930612.78	4721288.08
20	3052962.09	7771973.15	4719011.05
21	2811142.22	7526679.29	4715537.07
22	2298818.93	7007069.64	4708250.70
23	1837451.83	3254218.88	1416767.05
24	1584468.08	2747422.93	1162954.85

Table B.7
Hourly corridor energy prices - summer

Hour	North (R)	North East (R)	North West (R)	Central (R)	East (R)	South (R)	West (R)
1	81.17	80.57	83.82	81.55	86.91	85.98	112.20
2	81.11	80.57	83.76	81.52	86.80	85.89	112.20
3	81.12	80.57	83.76	81.52	86.82	85.90	112.20
4	81.13	80.57	83.77	81.52	86.83	85.92	112.20
5	81.28	80.57	83.95	81.70	87.09	86.17	112.97
6	104.63	103.11	108.45	105.20	112.20	112.18	168.14
7	123.38	119.92	147.40	123.06	127.14	195.25	1460.00
8	123.84	119.92	148.23	123.57	127.14	197.02	1460.00
9	124.19	119.92	148.86	123.97	127.14	198.38	1460.00
10	124.15	119.92	148.81	123.93	127.14	198.26	1460.00
11	124.32	119.92	149.11	124.12	127.14	198.90	1460.00
12	124.25	119.92	148.98	124.04	127.14	198.64	1460.00
13	124.21	119.92	148.90	123.99	127.14	198.46	1460.00
14	123.97	119.92	148.48	123.73	127.14	197.54	1460.00
15	123.87	119.92	148.28	123.61	127.14	197.14	1460.00
16	123.85	119.92	148.25	123.59	127.14	197.08	1460.00
17	123.79	119.92	148.14	123.51	127.14	196.82	1460.00
18	123.59	119.92	147.78	123.30	127.14	196.06	1460.00
19	123.58	119.92	147.76	123.28	127.14	196.00	1460.00
20	123.94	119.92	148.42	123.69	127.14	197.42	1460.00
21	123.73	119.92	148.04	123.46	127.14	196.62	1460.00
22	121.86	119.57	126.68	122.52	127.14	131.85	231.01
23	98.29	96.96	101.81	98.81	105.46	105.18	153.50
24	97.95	96.96	101.25	98.47	104.98	104.12	140.27

Table B.8
Hourly reserve prices - summer

Hour	IR (R)	RR (R)	TMSR (R)
1	45.06	44.45	40.95
2	45.06	44.43	40.95
3	45.06	44.43	40.95
4	45.06	44.43	40.95
5	45.06	44.60	40.95
6	56.83	56.83	52.23
7	65.66	65.66	60.63
8	65.66	65.66	60.63
9	65.66	65.66	60.63
10	65.66	65.66	60.63
11	65.66	65.66	60.63
12	65.66	65.66	60.63
13	65.66	65.66	60.63
14	65.66	65.66	60.63
15	65.66	65.66	60.63
16	65.66	65.66	60.63
17	65.66	65.66	60.63
18	65.66	65.66	60.63
19	65.66	65.66	60.63
20	65.66	65.66	60.63
21	65.66	65.66	60.63
22	65.49	65.49	60.46
23	53.52	53.52	49.15
24	53.25	53.18	49.15

Table B.9
Hourly costs and payments to generators – summer

Hour	Cost (R)	Payment (R)	Profit (R)
1	1490625.64	2150117.23	659491.59
2	1458292.49	2117373.69	659081.21
3	1462275.95	2121388.53	659112.58
4	1467615.82	2126773.74	659157.92
5	1543047.05	2205598.11	662551.05
6	1758938.24	3111746.70	1352808.46
7	2009438.22	6713628.79	4704190.57
8	2396631.82	7106259.85	4709628.03
9	2688949.62	7402731.82	4713782.19
10	2660294.09	7373678.85	4713384.76
11	2799011.49	7514365.26	4715353.78
12	2743404.73	7457956.65	4714551.93
13	2705336.83	7419346.36	4714009.53
14	2511021.17	7222258.70	4711237.53
15	2420717.69	7130693.23	4709975.54
16	2406520.54	7116299.29	4709778.76
17	2351626.36	7060628.29	4709001.93
18	2188680.65	6895379.40	4706698.75
19	2176446.96	6882966.42	4706519.46
20	2484698.72	7195565.53	4710866.82
21	2310415.08	7018824.06	4708408.97
22	1936260.28	3884479.28	1948219.00
23	1722246.72	2878540.60	1156293.88
24	1559967.52	2717501.91	1157534.39