MARKET INTEGRATION OF WIND POWER: IMPACTS AND PARTICIPATION STRATEGIES

BY

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Dedication

This thesis is dedicated to my beloved parents.

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LIST OF ABBREVIATIONS

ARMA	Auto Regressive Moving Average
CC	Capital Cost
CF	Capacity Factor
CRF	Capital Recovery Factor
DA	Day-Ahead (Electricity Market)
DSM	Demand Side Management
DR	Demand Response
FCR	Fixed Cost Recovery
FP	Fuel Price
GT	Gas Turbine
HFO	Heavy Fuel Oil
HR	Heat Rate
I/C	Interruptible/Curtailable
LDC	Load Duration Curve
LF	Levelizing Factor
MC	Marginal Cost
MCP	Market Clearing Price
NG	Natural Gas
PC	Price Cap
RT	Real-Time Market
ST	Steam Turbine

ABSTRACT

Full Name : Shaik Abdur Rehman Imran

Thesis Title : Market Integration of Wind Power: Impacts and Participating Strategies

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Wind energy is a renewable resource that is rapidly gaining popularity. Low operating costs and negligible carbon emissions are attracting investors all over the world. However, hesitancy arises owing to the unreliable nature of the source. Forecasting of wind power is difficult and probabilities of errors are high. In this scenario, one needs to provide a solution to this problem of uncertainty in such a way that the benefits of wind power are not wasted and at the same time their disadvantages are significantly reduced.

Over the course of the thesis, wind energy integration into the electricity market will be studied and several techniques to reduce the problems associated with the integration will be investigated. Impacts of wind power penetration on the electricity market prices and conventional generation mix will also be dealt with. The results obtained will help in suggesting optimal participation strategies in the electricity market for the wind power generating company.

الملخص

الاسم الكامل: شيخ عبد الرحمن عمران

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طاقة الرياح هي مورد متجدد و تكتسب شعبية بسرعة. انخفاض تكاليف التشغيل وقلة انبعاثات الكربون تجتذب المستثمرين في جميع أنحاء العالم. ومع ذلك، ينشأ التردد حول أنها مصدر طبيعي لا يمكن الاعتماد عليه. من الصعوبة التنبؤ في طاقة الرياح واحتمالات الأخطاء مرتفعة. في هذا السيناريو، سنحتاج لتقييم الوضع وتوفير حل لهذه المشكلة مثل طريقه تجعل فوائد طاقة الرياح لا تضيع، وفي الوقت نفسه يتم تخفيض عيوبها.

على مدار الأطروحة، سيتم دراسة مختلف جوانب دمج طاقة الرياح في سوق الكهرباء وسيتم التحقيق في عدة تقنيات للحد من المشاكل المرتبطة بها. سيتم دراسة آثار دمج طاقة الرياح مع المصادر التقليدية على أسعار سوق الكهرباء. النتائج التي تم الحصول عليها تساعد في الجزء التالي من الأطروحة الذي يشير إلى استراتيجيات المشاركة المثلى في سوق الكهرباء لشركة توليد طاقة الرياح.

CHAPTER I

INTRODUCTION

Balancing the equilibrium between supply and demand is not straightforward for the system operator since demand is never fixed. Integrating renewable energy resources into the power system will alleviate the problem by causing uncertainty on the supply side as well. However, concerns are being raised over the existing technologies put to use for producing electric power. The conventional generators are operated on fossil fuels such as coal, natural gas, heavy fuel oil [1] etc. This type of generation ensures an available, reliable and controllable power supply. However, due to fossil fuel reserves being tapped and diminished constantly, their prices are increasing. In addition, there are concerns over global warming and pollution. Coal fired thermal power plants, for example are among the principal stationary polluters of the world [2] with a carbon footprint of 2.117 lb/kWh [1].

All these issues have led the energy industry to look for an alternative source of energy; one that beats the problem of cost as well as environmental damage. This has led to the study of several naturally abundant energy resources such as the solar, wind, geothermal etc. Collectively these are known as renewable energy resources since they are renewed by nature after use. Each resource has a unique technology associated with it to convert 'raw' energy into the required form. The resources have been successfully used to obtain electrical energy by using complex tools and technology that are out of the scope of this thesis. However, renewable energy resources have faced a few major setbacks.

The main disadvantage of renewable resources is they cannot be fully relied upon. Though they are free of cost when available, which results in negligible fuel costs for power generation, their

availability is not constant and cannot be controlled or predicted accurately. Due to this reason, renewables have been unable to gain and exercise power in the electric power industry. Another disadvantage is the high capital/fixed costs for renewable energy plants due to their relatively new technology and few manufacturers of equipment.

The integration of renewables in the existing electricity industry is a widely studied topic. This thesis deals with wind energy and its integration into the electricity market. Wind has a very high degree of randomness which results in its low participation in the electricity market. Electricity is a commodity and is traded within a fully formed market structure [3]. In this thesis, the contribution of wind energy in the electricity market is investigated and attempts will be made to overcome the problem of wind uncertainty.

1.1 Thesis Motivation

Wind generated power is clean, green, plentiful and with almost zero operating costs. Wind plants require little land and have less maintenance compared to other generators. A few objections have been made about wind plants affecting scenic beauty, generating noise etc. But considering its minimal impact on the environment compared to other technologies, the advantages of wind plants outweigh the disadvantages easily. However, reliability of supply is still a concern.

Wind, is consistent over the year in all parts of the world. However, there are short term fluctuations. This makes it difficult to tap wind energy. Offshore and onshore areas are assessed for wind power potential before installing the plant and wind turbines are equipped with tools to cope with changing directions and changing speeds of wind. Unfortunately this does not fully combat the problem of fluctuations in output power. A variable power output is inevitable. It is the responsibility of the producers to trade wind power skillfully in the electricity market so that they can make profits and at the same time not affect system reliability.

Participation in the electricity market is where wind power producers or wind GenCos (generating companies) face many problems. Market rules require GenCos to commit the delivery ahead of time to allow smooth system operation [3]. Delivering power as promised will lead to payment of contracted amount to the GenCo. However, failing to deliver will not only result in the loss of revenue, but additional payment by the GenCo as a penalty. Owing to the unpredictable nature of wind, a wind GenCo cannot decide ahead of time how much to participate in and what to expect of the outcome of the market. This problem of uncertainty for the wind GenCo is precisely what this thesis tries to overcome.

Attempts will be made to model the uncertainty in the output of wind farms. Knowing what to expect of the wind plant will take the producer a long way in decision making and will reduce risks involved. Strategies have been studied and developed for the wind power producer to implement while participating in the electricity market. The thesis seeks to serve as a guideline for new wind power GenCos to help decide how much capacity of wind power to install and how to participate in the electricity market so that the benefits can be fully capitalized upon.

1.2 Thesis Objectives

The main aims of this thesis are to analyze the potential impacts wind energy integration could have on the electricity market and investigate strategies to allow efficient wind power penetration in the electricity market. The following are the objectives of this thesis.

1. Analyzing the effects of large scale wind power integration on electricity prices, and conventional dispatch. Behavior of the dominant supplier (conventional) is studied to maximize its profits.
2. Developing an optimization model to allow participation of wind generator in the day-ahead electricity market to minimize cost-revenue ratio.

3. Estimating the profits and minimizing the cost-revenue ratio of a wind generator when it participates in the real-time/balancing/regulation electricity market.
4. Developing an integrated Real Time Pricing/Interruptible-Curtailable load demand response strategy that will benefit the wind GenCo in trading.

1.3 Layout of the Thesis

The organization and layout of the thesis is as follows. The next chapter will discuss in detail the published literature and the research work performed on the issue of integrating wind energy into the electricity market. For the sake of convenience the chapter is further divided into sections that make the topics easier to refer.

Following the chapter on literature survey, chapter 3 contains the initial work done which will serve as a base for the subsequent chapters. The chapter will deal with modeling wind speed, explain basic architecture of the electricity market, and will also contain all the data required.

Chapter 4 is devoted to the first objective, an analysis of the impacts of wind power intermittency on the existing structure of market prices and conventional dispatch. Hidden costs involved behind wind power penetration will be uncovered and the installed wind capacity which will minimize the market clearing will be determined. The behavior of a ‘dominant’ supplier; which is a conventional GenCo that withholds its capacity to trade in the real time market (when wind power falls short) will also be studied.

In chapter 5, an optimization model is developed to minimize the losses of the wind GenCo and thus minimize cost-revenue ratio when a wind GenCo participates in the day-ahead electricity market. Subsequently, the profit making capability of a wind GenCo in the real time market is studied. A comparison of revenuess is made between the two strategies while operating at an installed capacity that gives a minimum cost-revenue ratio.

Chapter 6 will develop a demand response strategy that will aid wind power GenCos in their day-ahead participation. An introduction to Demand Side Management will be presented in the chapter following which the proposed strategy for demand response will be discussed and formulated. Simulation results will be followed by a conclusion of the chapter.

Chapter 7 will contain the closing remarks of the thesis and will suggest future developments.

CHAPTER II

LITERATURE REVIEW

2.1 Wind Energy Integration

Wind power producers, though clean and green, face a difficult time competing in the electricity market. The main reason is the random intermittency of the outputs of wind turbines. This calls for an intricate mechanism that accommodates wind power producers into the wholesale electricity market as a reliable producer, even though intermittent. This trade-off is necessary as wind is a sustainable and renewable source of energy with very low operating costs [4] and almost zero carbon emissions.

To accommodate wind power in the existing electricity market structure, several proposals have been put forth. Modifying market structures, incentivizing renewable energy producers and devising new energy policies are some of several ways to help wind power GenCos integrate into the market. The literature on this issue is briefly summarized below.

The paper [5] serves as a guideline for potential wind power producers by providing an economic analysis on their investments. The work incorporates the uncertainties faced by producers over fuel costs, market prices, wind speed etc. Such an analysis will lead to a less risky endeavor on the part of the producer. Another paper that can serve as guide for new wind power producers, policy makers and market operators looking to integrate wind energy is [6]which discusses the various options wind power producers have at their disposal for trading in an electricity market.

Energy policies are seen playing a large role in integration of wind power producers into the market as seen in [7] where the authors compare electricity market designs and energy policies of

Europe, Australia and the USA. Feed-in-tariffs, bilateral contracts, wholesale pool trading, vertically integrated utilities etc. are considered for accommodating wind producers. The challenges faced by the countries and their subsequent responses are studied. Another paper on the Australian national electricity market [8] states that the NEM in Australia has taken several steps to accommodate wind energy and other renewables by providing temporal and locational price signals for generation. The study shows that returns on investments depend heavily on the location of the wind farm and seasonal uncertainty. The European Commission has also facilitated the integration of renewable energy sources and has provided a new regulatory framework as discussed in [9]. Furthermore in the same paper, cost analysis and market forecasts have been performed for an offshore wind GenCo in Spain. Another paper based on the European Union is [10] which gives a summary of wind energy policies and proposes a few electricity market designs to facilitate wind energy integration. Simulations have been performed on the Central European Power Market (CEPM) to analyze the effects of exceeded wind capacities by 2020 and estimate the market value of wind power in the near future [11].

Several papers suggest electricity market models that are better suited to accommodate wind power. One of them [12] discusses integration of wind power in the German electricity market. It presents a stochastic market model to minimize cost of a system that is generally adapting to more and more wind power penetration. The marginal value of wind power in such a system is estimated as well. Two electricity market structures are suggested by the authors of [13]; one that couples real-time prices with cost internalization may reduce costs but is difficult to implement. The second structure is a parallel market that supplies flexible loads through renewable resources when the system is not congested, and runs along with the conventional market. An electricity market model based on supply function equilibrium approach is discussed in [14] where the authors study the behavior of the conventional generator based on its risk preferences in face of intermittent wind power. Another paper that deals with the behavior of conventional generators is

[15] which tries to determine the conventional generation requirement to keep the system adequacy in check. The hidden costs accompanying wind generators are also dealt with in this paper. Meanwhile a model has been developed in [16] to include wind farms in the economic dispatch problem. Results show that reserve and penalty cost factors influence participation of wind farms heavily.

A case study in Denmark [17] analyses the participation of wind power in the real-time/balancing market and not in the day-ahead wholesale market as in the above papers. It concludes that active participation of wind farms in the balancing markets will result in a profit for wind GenCos since they will be avoiding imbalance penalties.

A paper based on the British power market [18] encourages wind GenCos to be more active in trading, avoid spilling and improve liquidity of the market and proposes an energy reallocation mechanism similar to that being adopted by Brazilian hydro generators. This can help small wind farm owners to play a deeper role in the market. In New Zealand [19] it has been observed till date that integration of wind generation at this stage will not cause much of a difference in operations and market prices. Small but negligible effects may be observed in the area of ancillary services. Also large scale integration will require accurate forecasting.

In contrast to the above studies, [20] assumes the wind GenCo as a price maker and a provider in the ancillary services market. This study based in Ireland indicated a closer alignment in market schedules and wind GenCos dispatch when considered as a price maker, and also identifies wind GenCos as an efficient contributor to the spinning reserves.

Modification of system load has been suggested in [21] via a unique Load Reduction Demand Response (LRDR) program. Simulation results on an IEEE test system show that using load reduction to accommodate wind GenCos will benefit the system economically and technically.

The concept of wind energy integration in coordination with a more conventional unit is also gaining popularity steadily since the dispatchable conventional unit can cover for the uncertainty in wind power. In paper [22], the wind GenCo operates in coordination with high capacity Na-S storage devices. The simulation results have indicated that this leads to better production planning and system operation.

2.2 Impacts of Wind Power Integration

Overall, the general consensus is that wind power integration into the electricity market would result in a decrease in electricity prices, fossil fuel consumption and CO_2 emissions. Issues may arise over power system stability, sensitivity and reliability [23]. To combat these, ancillary services are required which will gradually gain more prominence with increasing wind penetration. The literature survey presented gives a picture of how wind energy is affecting the existing electricity structure. Regional effects of wind energy penetration, observed from practical data collected around the world, can be known by referring to papers [24]–[32].

It is observed in [33] that if wind GenCos decided to operate as strategic units instead of price takers, it will lead to reduced market clearing prices. However, most investors refrain from investing in wind farms of that high capacity and so wind support tariff schemes by the government were suggested to encourage more participation. In the situation of demand participation in system operation, it is observed in [34] that acceptance of renewable sources by customers can result in a positive impact at nodal price behavior of conventional generators. Expected nodal prices and deviations decrease by accommodating low operating cost renewable resources like wind. In paper[35], the authors developed a stochastic Uniform Market Price model to assess impacts of wind power integration. The simulations showed increased social welfare and an increase in system reserves during off peak hours.

Integration of wind energy also results in an impact on the conventional generation mix. Mid-load serving and peak-load serving units are most affected due to uncertainty of wind [36]. It was seen in [37] that if wind GenCo acts as price taker and conventional generators bid their marginal cost, then changes in the capacity mix are more pronounced than change in prices. Change in thermal capacity is slight and a shift is observed towards units with higher operating and lesser fixed costs. This was observed in a study based in Great Britain. This is also corroborated by a study based on the Dutch electricity market [38] which shows similar behavior of thermal units. Impact of wind power GenCos on unit commitment and operating reserves have been discussed in [39]. Slow starting units committed in the day-ahead market can face high operational costs in face of uncertainty, while intraday unit commitment would have to be extremely active.

Integrating wind farms into the electricity market without prior analysis can result in several critical issues. The authors in [40] have argued that unless the existing market structure is rethought and redesigned, wind resource penetration will induce high levels of variability in the load served by existing conventional generators and may even lead to a higher number of loss of load situations. Another negative impact can be that of forecast errors [41]. Paper [42] devises a methodology to understand impact of forecast errors on offshore wind farms. Inaccurate forecasts could result in erratic overestimation and underestimation of market prices that may lead to cheap electricity for consumers or additional profits to producers[43]. As seen in [44], errors in prediction may lead to costlier up and down regulation of thermal plants. Intraday market trading is suggested for wind farms to evade forecast errors. Similar results are observed in [45] which state that wind impacts coal fired thermal units negatively if accommodated due to high startup costs and high minimum output limits. Based on the results the authors suggested that using wind power as a control option would be more beneficial as its leads to better system dynamics.

When impacts of wind power integration strictly on profits of units involved are considered, it is found that even though uncertainty may cause some producers to lose generation revenue, it can be beneficial for other producers in the reserve business [46]. Also higher wind power volatility will lead to higher spillage and hence, more loss of revenue.

The paper [47] shows that impacts of large scale penetration of intermittent sources in the electricity market may be difficult to estimate at this stage since growing volatility may mean that the system achieves equilibrium with difficulty. Apart from that, non-strategic behavior of generators also has unexpected effects. Nevertheless, a study based on the European electricity market [48] has shown that higher penetration for wind power GenCos will result in an early investment return. Simulations show that value of wind power drops from 110% of average power price to 50-80% of average power price as penetration level increases form 0-30% of consumption. Real time pricing can also be used to reduce fixed demand dispatch costs of wind generators [49]. A study [50] based in USA on the Pennsylvania-New Jersey-Maryland interconnection; popularly known as the PJM market has shown that for wholesale market participants the benefits cover the costs easily and quickly when wind energy is integrated into the grid.

Impacts of wind farm control strategies and location and location have been dealt with in [51]. Lowest market prices are obtained when the generator is controlled with a VR (voltage regulation) control strategy. Installation close to transmission system requires more reactive power to maintain bus voltage at unity and will hence increase prices.

2.3 Optimal Participation of Wind Generators in the Electricity Market

As asserted before, owing to the stochastic nature of wind, bidding by wind GenCos in the electricity market is not as straightforward as for a conventional GenCo. Several papers have

been published in this area, suggesting quite a few techniques to tackle this problem of uncertainty. The paper [52] discusses the bidding of wind power GenCos in the Spanish electricity market, and states that it is safer to submit bids in an intra-day market on a short term basis. The program SIPREOLICO is used for short term prediction of wind power. A stochastic optimization problem is formulated for obtaining maximum revenue for the wind generator keeping in mind the uncertainty involved. Three cases are studied and compared i.e. the optimal bidding case, bidding based on best prediction and one bid per day case. It is found that the optimal bid gives maximum revenue. The same authors, in paper [53] used short term bids again, but this time integrated hydro generation with wind generation in order to reduce imbalance penalties. Similarly, authors in [54] suggested a coordinated bidding strategy between wind and hydro pumped storage systems and formulated models to study both joint and disjoint operations. Risk assessment was performed by quantifying conditional value at risk (CVaR). Wind and gas-thermal unit coordination is analyzed and tested to positive results in [55].

Another paper [56] based on the Spanish system formulates a 2-stage stochastic problem using Linear Programming (LP) and Mixed Integer Linear Programming (MILP) for a coordinated wind and hydro pumped storage system. It concludes that the coordinated model achieves higher profits than in the scenario in which wind and hydro contribute individually. The MILP method is deemed as the better of the two in this case. Similar work is done in paper [57] in which the authors have used an energy storage device to store and release wind energy as the market demands. The Expected Energy Not Served (EENS) gives a measure of the risk associated. A MILP formulation is converted to a fuzzy-optimization problem and then solved. A different optimization technique has been discussed in [58], in which the authors have suggested a chance-constrained 2 stage optimization for coordinated wind and hydro pumped storage bidding.

Paper [59] takes into regard the optimal bidding and profit maximization of the wind power producer and at the same time attempts to alleviate the problems faced by the system operator. Like in the previous papers, this multi objective strategy makes use of MILP for formulation of the problem and fuzzy optimization techniques for solving.

In the year 2002, a study was performed on the integration of wind generators in the Dutch electricity market [60]. A probabilistic choice strategy (to minimize the imbalance costs) and a risk analysis strategy (to reduce losses in the worst case scenario) are employed in [61]. To define the deviation cost function, the imbalance costs have been estimated using annual and seasonal estimates. New, more advanced tools are used for wind power prediction.

In order to utilize the wind power GENCO as a multi-time dispatch-able source, the paper [62] couples the wind generator with an energy storage system and uses robust optimization to formulate the uncertainty. The robust optimization is different in the way that it defines the objective function for the worst case scenario, hence ensuring safety at all times. The bidding strategy is formulated as an LP problem. Case studies are performed for the day-ahead as well as the intra-day market.

The paper [63] uses a risk management approach to set the optimal bid level for a wind power supplier with the main objective being minimization of penalties imposed due to imbalances. It focuses on the volatile nature of imbalance prices and tries to forecast imbalance prices based on historical data. Depending on how close to the market clearing price the imbalance prices are expected to be, the output level to be contracted is decided by the supplier. Likewise, the paper [64], focuses on imbalance penalties and proposes an electricity market model in which a limited deviation from the bid level is tolerated by the system operator. The paper [65] also signifies the importance of risk assessment of the system in the face of wind farm participation and uses ‘utility theory’ to obtain maximum benefits and avert risk at the same time.

A study based on the Nordic electricity market [66] suggests that while performing optimization to select a proper bid level, the wind forecast error must also be considered. This will lead to lesser imbalance costs and as a result, higher profit for the wind power supplier. Another paper [67] corroborates the results of the previous one and claims that modeling the uncertainty of the forecast as a predictive distribution will help wind farms in achieving higher revenues and provide competition to other conventional dispatch-able generators. Simulations are performed on a wind farm in the Dutch market to validate the theory. Another paper [68] based on the Nordic pool investigates two models for the balancing markets to accommodate wind farm bids.

The paper [69] puts forth the possibility of a wind generator strategically withholding its production once the day-ahead contract has been signed. It works on three assumptions and concludes by stating that as long as the imbalance penalty is priced higher than the MCP, a GENCO will try to produce as much power as possible. However, it has also been observed [70] that if the wind power penetration increases due to the increase in MCP, the producer will face a hindrance in the form of its reserve capacity, as the reserve costs increase with higher penetration.

The paper [71] formulates an optimal bid level for wind power producer as a mathematical program with equilibrium constraints (MPEC) and further assesses the correlation between the wind power produced and the residual system imbalance. It is determined that optimal offer in the day ahead market increases with the level of penetration but decreases with correlation.

In [72], the authors have discussed a payment cost minimization (PCM) model. The effects of wind energy on the market are considered from a probabilistic point of view. The authors forecast wind speed and power using an ARMA model and then obtain its probability distribution. For each future sample, genetic algorithm is applied to solve for the PCM. The results obtained give the consumers an idea in the probabilistic sense of how much they should pay.

A study based in Denmark, which belongs to the Nordpool electricity market, revealed that if time between delivery and contract is shortened, the gains of the producer can increase by as much as 8%. The paper also takes into account the location factor of the wind producers and shows that a reduction in prediction error can be achieved if the forecast covers a large area. The paper [73] suggests that wind producers should not only bid in an energy market, but also in a regulation reserve market. This alleviates the effects of prediction errors and also provides a fast reserve option that will lead to better system security. Game theory has also been put to use to integrate wind energy in the energy and regulation reserve market [74].

A unique market clearing approach is proposed in [75]. In this paper, the authors combine the spinning reserve market and the energy market clearing mechanisms. The reserve is considered for two different cases; from the generating side as well as the load/consumer side. Hence, uncertainties from both wind forecasting as well as load forecasting are modeled. The objective remains minimization of cost for the wind power producer. Simulations are performed on an IEEE 30 bus system.

The paper [76] investigates the maximum wind capacity that could be profitably committed in a deregulated market. Simulations have been performed using data from the German electricity market. The study shows that large scale integration affects investments on conventional generation. Also for the wind GenCo to exercise considerable market power, there has to be a drastic increase in fossil fuel prices.

Increasing penetration of wind power requires ancillary services in large amounts as well as compliance with the Renewable Portfolio Standards as demonstrated [77]. Also, profit maximization for the wind GenCo has been examined in a scenario where the GenCo serves to the load when MCP is low and sells to the pool when high.

It was noted in the extensive literature survey performed that the main objective of all studies was to maximize profit. This is acceptable since a majority of the studies are based in northern Europe and North America, in regions which witness considerably good wind speed. However, not all areas witness a wind speed high and consistent enough to validate dependability on wind farms, such as the eastern province of Saudi Arabia (where this study is based). It automatically implies that in such a scenario, the goal should not be solely to maximize profit, but also to compare it against the cost that was incurred due to the wind farm. This thesis will try to fill up that void by attempting quantify the cost-revenue ratio for wind farms during their participation in the electricity market.

CHAPTER III

PRELIMINARY STUDY AND ANALYSIS TO INTEGRATE WIND POWER INTO THE ELECTRICITY MARKET

3.1 Introduction

For a wind power GenCo to participate in the electricity market, it needs to follow a set of market rules. For one, power delivery is required to be committed ahead of time if the wind GenCo intends to sign a forward contract. For this reason, a wind GenCo needs to forecast its output power for the coming day to make accurate bids into the market.

This chapter contains the preliminary work done that serves as a base for fulfilling the objectives of the thesis. Wind speed will be modeled based on historical data. The market rules that the wind GenCo needs to follow are also explained.

The next section of this chapter gives a brief description of the electricity market rules and architecture. Section 3.3 will guide the reader on wind power energy conversion, costs and modeling. A standard way of forecasting wind speed is by using an Auto Regressive Moving Average (ARMA) model and thus wind speed is modeled as an ARMA time series. In the same section, another method of modeling wind speed is proposed which uses a conditional probability approach to obtain the probability distribution of wind speed. Comparisons will be drawn between the two modeling techniques based on how they assist the wind GenCo. The last section includes details of other important data being used.

3.2 Electricity Market Architecture and Design

The idea of deregulating the electricity market has gained popularity in recent years [3]. In a deregulated scenario, the different components of the otherwise vertically integrated utility are unbundled. Generating companies, transmission companies, distribution companies and retail companies stand up and come forward offer their specialized services to the utility. Deregulation is beneficial in the way that it improves competition among participants willing to provide their services and encouraged more efficient and cost competitive generation among the sellers.

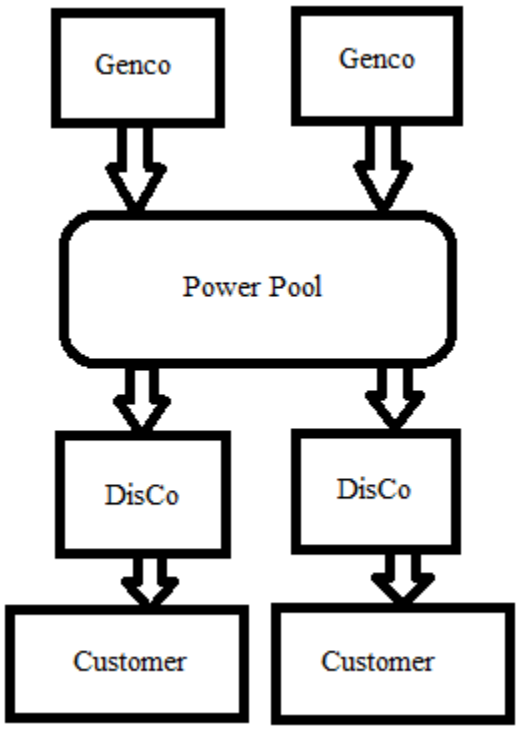

Fig 3.1 Deregulated Electricity Market Structure

In a deregulated trade, electricity is regarded as a commodity and is traded between entities. As with any other commodity, there exists a market which facilitates trades of electrical power and energy between parties. However, several major differences are observed between an ordinary goods market and an electricity market. Electricity is one commodity in which the supply has to

meet the demand almost instantly. Unlike other goods, large amounts of electrical power cannot be stored and reserved for later so as to be used during shortages.

Trading for power delivery may begin well in advance over a period of years and continue till the point of time the power is to be delivered. The earliest trades are done in a 'forward market'[3]. The forward market deals with contracts made on future delivery of power. Mostly all forward trading stops at the day-ahead market and the market operator holds these contracted values. The forward markets ensure smooth operation of the system. Since demand has a high correlation with season and time of the day, it can be forecasted to a good accuracy based on historical data. Hence a prior understanding between producers and customers on trading huge amounts of power can be reached well in advance before the power is delivered.

Any deviations that occur in the demand at the time of delivery are relatively lesser in magnitude and can be tended to by another type of market, the 'spot market'. The spot market deals with all the fluctuations that occur from the forward contracts. Any deviations in the contract, whether positive or negative, are transacted in the spot market. The market prices are not the same in a spot market and a forward market.

All markets except the real time market are financial in nature, meaning power delivery is optional for the supplier and it does not need to be a ready-to-produce generator to commit to a contract. Deviations from the contract at the time of delivery will be penalized financially. A customer who buys power in the forward market will either be delivered the power he was promised or else will be compensated financially. In contrast, a supplier in the real-time market has to have units that are ready to supply power at the instant.

3.3 The Day-Ahead Electricity Market

The day-ahead market, as mentioned earlier is a type of a forward market. The bids and offers are submitted a day ahead of delivery, usually around noon of the previous and the market is cleared via centralized auction. The last unit to sell typically sets the MCP. The demand is often found to be inelastic, which means that the quantity of energy demanded by the consumer remains fixed even as the price soars higher. This implies that the demand curve is vertical and in such a case, the intersection of the supply and demand curve gives the marginal cost price.

A wind generator has a high amount of uncertainty in its power output. This makes it difficult to commit to a value of energy one day ahead in time. If the wind power forecast proves to be wrong, the GenCo may end up losing money. A well thought, optimized approach is required to participate in the day-ahead market.

3.4 The Real-Time Market

The real-time/managed-spot/regulation market is expected to serve the shortcomings of the forward market contracts at the time of delivery. The power sold in a real time market is not under contract and does not use bids. It shows up when needed and accepts the spot price. Real-time markets are single-period markets as they take place just minutes before actual energy delivery. A real time market requires a centralized pool managed by the market operator since fast action is required. The real-time price for electricity fully depends upon the type of deviation from the forward contract. In this thesis the primary concern is the participation of a wind power GenCo in the market. Therefore the deviations that occur from the side of the supplier are considered.

There are two deviations that can occur when a GenCo commits to a forward market contract. The GenCo may, at the time of delivery, either produce more power than contracted, which is

termed as overproduction/positive imbalance or less power than contracted, which is called underproduction/negative imbalance.

Depending on the type of deviation, and the state of the system, the real time prices might change. The system is said to be in down regulation if the pool has more power being generated than being consumed. Similarly, the system is in an up-regulation if the pool has more power being consumed than being generated at the moment. Generally, the balancing market price is higher than the day-ahead price if the system is in up-regulation. Conversely, in the down-regulation case the balancing price is lower than the day-ahead price.

The participation at the balancing market opens opportunities for arbitrage for GenCos. When the GenCo's real-time imbalance with respect to the system is in the opposite direction compared to the overall system imbalance, GenCos receive a more favorable price at the balancing market. They can sell excess energy (positive imbalance) compared to their day-ahead position at a higher price than the day-ahead price when the system is in up-regulation, and repurchase their production deficit (negative imbalance) at a lower price in the down-regulation case. On the other hand, the balancing price is less favorable when the GenCo's imbalance and the system imbalance are in the same direction.

Denoting the up-regulation and down-regulation prices with C_{UP} and C_{DW}, respectively, while the clearing price at the balancing market is C_B. The pricing can be represented mathematically as follows:

$$C_{UP} = \begin{cases} C_B \; if \; C_B \geq MCP \\ \\ MCP \; if \; C_B < MCP \end{cases}$$

$$C_{DW} = \begin{cases} C_B \; if \; C_B < MCP \\ \\ MCP \; if \; C_B \geq MCP \end{cases}$$

Utilizing the wind generator in the real-time market is an interesting prospect. Since the real-time market requires GenCos to sell their current power production without any obligations, the wind GenCo is not liable to penalties. However, revenue is not guaranteed at all times since the system needs to be in up-regulation for the wind GenCo to start selling in the first place. Though system deviations occur, they are very low in magnitude compared to the power that can be traded in forward contracts. It will be studied in the upcoming chapters if trading in the real-time market only will help the wind GenCo recover its investment costs.

3.5 Wind Energy Conversion

The mechanical energy in wind is converted to electrical energy through elaborate wind turbine generator setups [78]. More number of wind turbines covering a large area increases the aggregate wind power and level of penetration. Low to medium scale penetration (<30%) of wind power does not require a redesign of the existing approaches of the power system and its operations. The same cannot be said though for high scale penetration (>30%) where the issues arising become more economical than technical.

To measure the amount of power that moving wind speed can offer, the following mathematical formulation is used [1].

$$Power\ in\ wind = \frac{1}{2} * \rho * A * v^3 * C_{Betz} \quad Watts \qquad 3.1$$

Where ‘A’ is the area swept by the blades, ‘ρ’ is air density and ‘v’ is wind velocity. The value of the Betz constant is 0.593, which means that if no other losses occur, only a maximum of 59% of the power of the wind speed can be extracted.

The wind energy conversion systems (WECS) are well equipped to deal with variability in wind speeds[1]. A typical wind turbine characteristic plot is shown below.

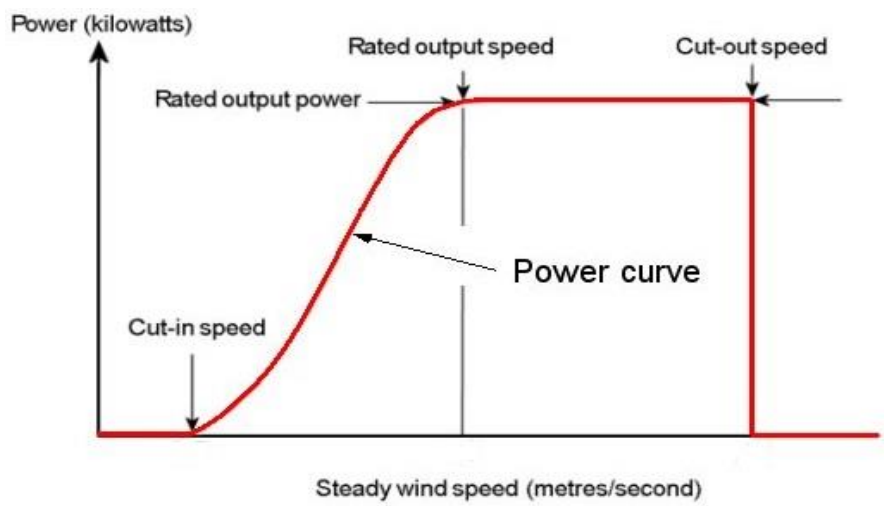

Fig 3.2 Wind Turbine Characteristics [1]

As observed from the plot, the Wind Turbine Generator (WTG) produces no power for wind speeds lower than the cut in speeds (3-5 m/s). For wind speeds higher than the cut in speed the WTG power produced increases exponentially till the wind speed reaches the value of rated speed of the WTG. From this rated speed (8-12 m/s) till the cut-out speed, the WTG produces rated power. When wind speeds are higher than cut-out (20-30m/s) speed (during severe weather conditions), the turbine blades are locked in place and prevented from rotating to maintain stability of the tower.

When provided with the rated power of the wind turbine, the wind speed can be converted to wind power by using the following relation[78].

$$WTG\ Output\ Power = \begin{cases} 0 & 0 < v \leq v_{ci},\ v_{co} < v \\ Rated\ power * \dfrac{v^3 - v_{ci}^3}{v_r^3 - v_{ci}^3} & v_{ci} < v < v_r \\ Rated\ power & v_r \leq v \leq v_{co} \end{cases} \quad 3.2$$

Here 'v' represents the measured wind speed. 'v_{ci}' represents the cut-in speed of the wind turbine, 'v_r' represents the rated speed and 'v_{co}' is the cut-out speed of the WTG.

3.6 Wind Speed Modeling

Since wind depends heavily on the weather, there is no way to predict wind speed and power with 100% accuracy. As mentioned earlier, this intermittency discourages system operators and power producers. Intelligent tools need to be used to try and determine a pattern in the wind based on either statistical data or multivariable weather models.

Before forecasting, it is important to determine the forecast horizon. Producers usually find short term forecasts from an hour to 36 hours ahead to be more reliable[78]. Therfore, day-ahead predictions will be the focus when the forecast is developed.

Numerical Weather Prediction (NWP) models are used by Meteorological and Weather Research and Development Centers [79]. These models make use of detailed 3-dimensional weather models over specific areas to predict wind direction and speed. Apart from NWP models, statistical modeling is another way to predict wind behavior. This type of modeling mainly relies on historical data collection. Some examples are Artificial Neural Networks (ANN's), fuzzy logic, regression models etc [79].

The forthcoming sections developed an ARMA model of wind speed which is a common tool for forecasting wind speed [79]–[82]. A new conditional probability based probability distribution model of wind speed will be developed. The bidding strategies discussed in later sections will take into consideration both the models and comparisons are made between them based on how they benefit the wind GenCo.

3.7 Auto Regressive Moving Average (ARMA) Model

The basic mathematical formulation for the model is provided below. An nth order auto-regressive model also denoted as AR(n) is a linear combination of the previous 'n' values of a quantity (as shown in the equation below) which may or may not be equal to the actual value [83].

$$\dot{y}_k = \sum_{i=0}^{n} a_i \, y_{k-i} \tag{3.3}$$

The error between this predicted value ($\dot{y}_k$) and actual value (y_k) is determined and is used to improve future predictions.

$$e_k = \dot{y}_k - y_k \tag{3.4}$$

This term is also known as 'white noise' and has a mean of zero. This term will also constitute the moving average value of the model. By using appropriate coefficients, a time series can be modeled as:

$$\dot{y}_k = C + \sum_{i=1}^{n} a_i y_{k-i} + \sum_{j=1}^{m} b_j e_{k-j} \tag{3.5}$$

This is called an nth order auto-regressive, mth order moving average, ARMA (n,m) model. The C term is a constant associated with the model while *a*, *b* are respective coefficients.

After modeling the wind speed, errors between actual values and the modeled series are calculated. These errors quantify the accuracy of the model. Since errors may either be in the positive or negative direction, calculating simply the mean will not give a proper depiction of accuracy. The Mean Absolute Error (MAE) and the Root Mean Square Error (RMSE) [78] use the absolute values of errors and hence are more reliable errors.

$$MAE = \frac{\sum_{i=1}^{n} |Error|}{n} \tag{3.6}$$

$$RMSE = \sqrt{\frac{\sum_{i=1}^{n} (Error)^2}{n}} \tag{3.7}$$

3.8 Simulation Results of ARMA model

In order to develop an ARMA model of the wind speed, wind speed data from Dhahran, Eastern Province, K.S.A was obtained for the year 2013. It is found that the area possesses an average wind speed of 4.7 m/s. However, this speed was measured at a height of 12m above ground. Wind speed is proportional to the height of measurement and since the WTG hub is situated at a height of 90m [84], the wind speeds need to be recalculated using the following relation.

$$\frac{v}{v_r} = \left(\frac{h}{h_r}\right)^{\alpha} \tag{3.8}$$

In the above equation 'v_r' is the measured reference velocity at height 'h_r'. 'v' and 'h' are the escalated velocities and height respectively. The value of 'α' is 1/7[1]. The new mean wind speed is found to be 6.2 m/s.

The partial autocorrelation function was plotted as shown below to determine lags of the wind speed. These lags are used to identify the best order of the ARMA time series by using the Akaike Information Criterion (AIC) [85].

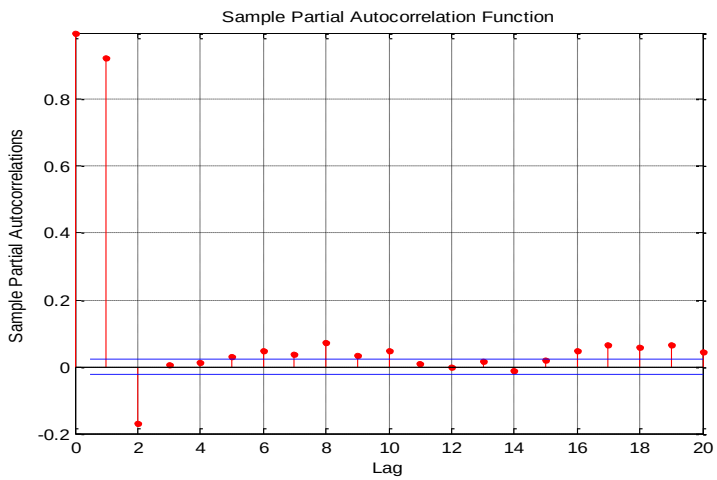

Fig 3.3 Sample Partial Autocorrelation Function of Wind Speed

From sample partial auto-correlation (Fig 3.3), it is evident that wind speed at any instant has a high correlation to up to 2 previous values. This gives us a possible 4 combinations of the order of the ARMA series (order = 1 or 2 for the auto-regressive component, order = 1 or 2 for the moving average component). The (1, 2) ARMA model is determined to be the best fit by AIC.

After selecting the order as the one having minimum value of AIC (Table 3.1), the parameters of the model are estimated based on historical wind speed data. Using the wind speed data of 2013, the estimated coefficients of the ARMA time series are:

Table 3.1 Comparison of AIC

Order	**AIC**
1,1	$2.64*10^4$
1,2	$2.608*10^4$
2,1	$2.61*10^4$
2,2	$2.63*10^4$

Table 3.2 ARMA model coefficients

Order	(1,2)
'AR_1' coefficient	0.892462
'MA_1' coefficient	0.189701
'MA_2' coefficient	0.0298948
Constant 'C'	0.505559
Variance	0.667293

The time series simulated for a period of 1 year (8760 samples) is shown in figure 3.4.

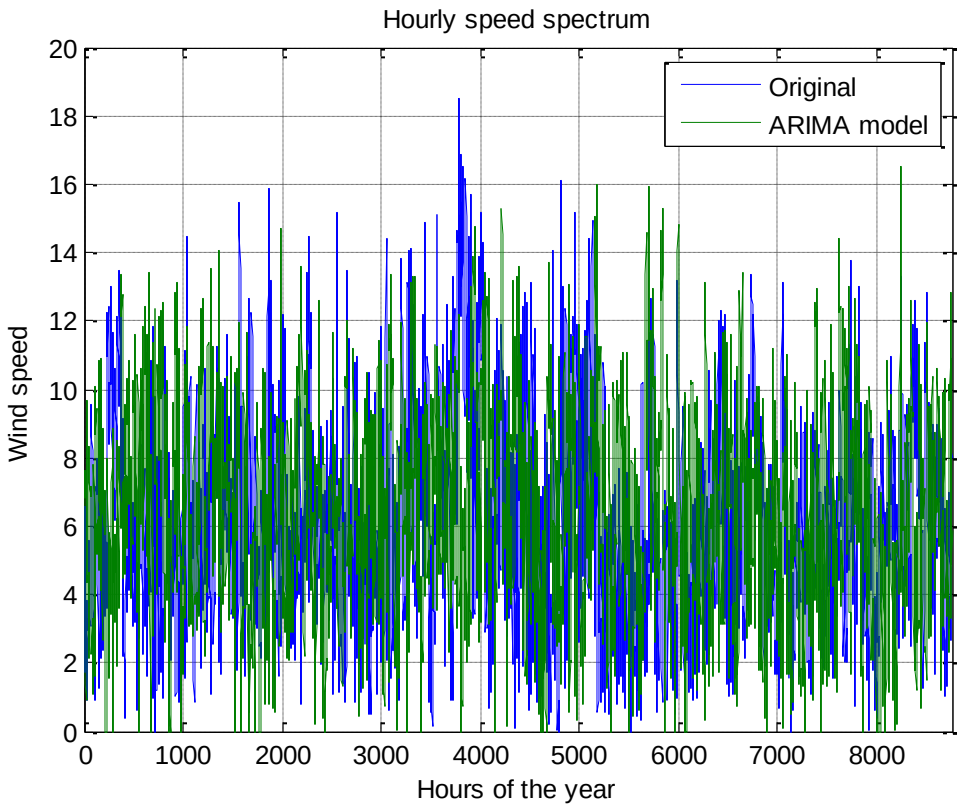

Fig 3.4 Comparison of Original Wind Speed and ARMA model

The mean absolute deviation and root mean square errors obtained when forecasted model is compared to the original wind speed are given below:

Table 3.3 Error values of ARMA model

MAE	3.1846 m/s	**RMSE**	3.95 m/s

The actual and modeled wind speeds were converted to their respective power values. Based on the wind speed dynamics it is decided that a low cut in and rated speed and high capacity wind turbine generator has to be selected. The following (Table 3.3) wind turbine generators were shortlisted as possible options and Alstom ECO 122/2700 was selected.

Table 3.4 Shortlisted Wind Turbine Generators

WTG Model	Capacity	Cut in Speed	Rated Speed	Cutout Speed
General Electric 1.7/100 [86]	1.7 MW	3 m/s	10 m/s	23 m/s
Alstom ECO 122/2700 [84]	2.7 MW	3 m/s	10 m/s	34 m/s
Alstom ECO 122/3000 [87]	3 MW	3 m/s	10.5 m/s	25 m/s

3.9 Modeling Probability Distribution of Wind Power

Wind producers are required to submit their bids for the next day in the afternoon of the ongoing day. At that moment of time a certain wind power production will be ongoing. Based on this current production of wind power and the forecast horizon of the bid, a probability distribution will be obtained for wind power based on historical data. This can also be called a conditional probability based probability distribution of wind power. The basic mathematical formulation is given below.

$$p_k\left(\frac{i}{j}\right) = \frac{f_{i,j,k}}{\sum f_{j,k}} \qquad 3.9$$

Where '$p_k(i/j)$' is the probability of occurrence of wind power scenario 'i' at hour 'k' given that current scenario of wind power is 'j'. '$f_{i,j,k}$' is the number of instances of scenario 'i' occurring at 'k' hours when current scenario is 'j'. This number of instances is obtained from historical data. It is observed that more historical data will result in a smoother probability distribution. The denominator denotes sum of all instances of all scenarios occurring at 'k' given that current scenario is 'j'. Historical wind speed data of Dhahran pertaining to years 1998-2003 was used to

obtain this probability distribution. The probability distribution will be used in the optimization problem in the next chapter.

3.10 Simulation Results of Proposed Probability Distribution

Using the concept and formulation explained in section 3.9, a 3D matrix was obtained to determine probabilities of scenarios of the 24 hours of the next day. The following plots show the probability distribution for selected hours.

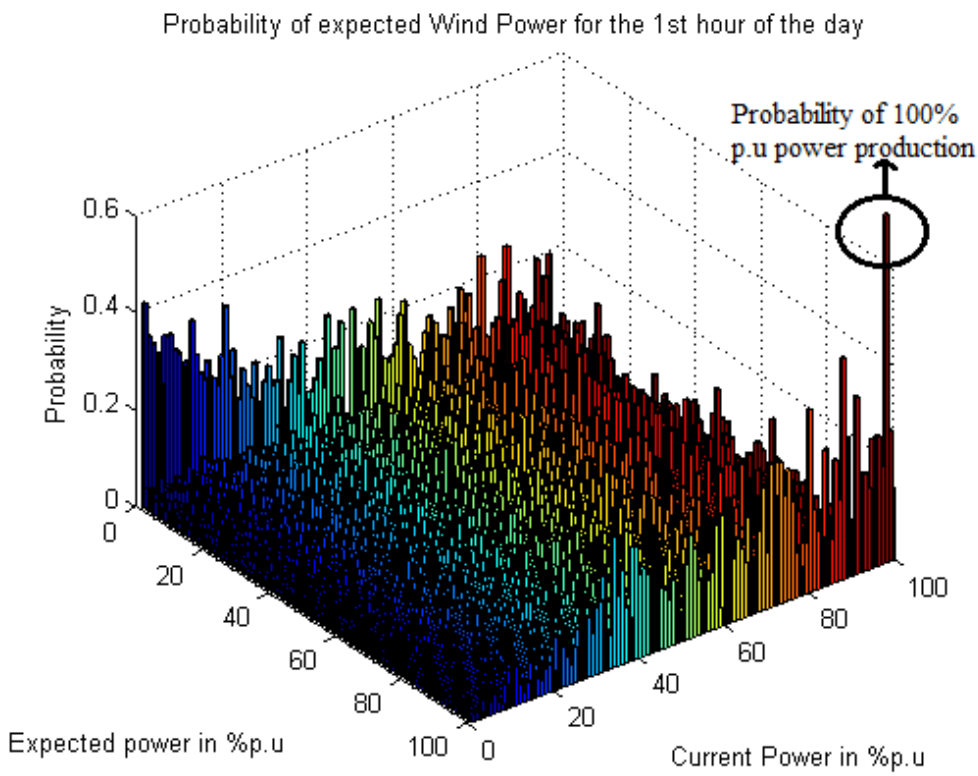

Fig 3.5 Probability Distribution of Wind Power for 1st hour of the next day

Fig 3.7 plots the probabilities of occurrence of wind power scenarios for all current power scenarios during the first bid hour. For example, the probability of occurrence (in the 1st hour) of wind power level equal to 100% of the installed capacity is 0.63 for a current power available equal to 100% p.u and 0.26 for current power available equal to 38% p.u.

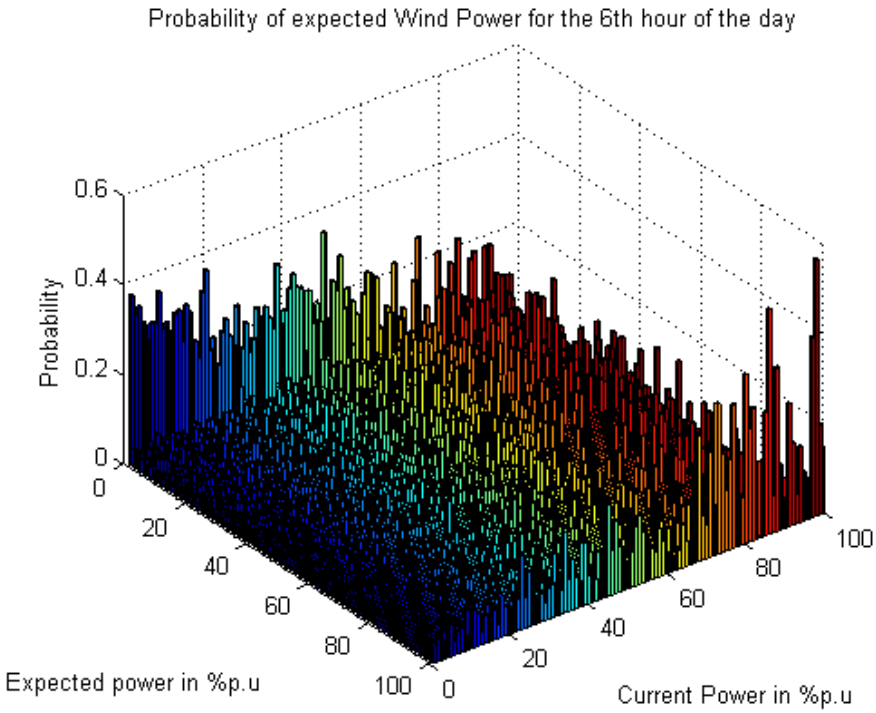

Fig 3.6 Probability Distribution of Wind Power for 6th hour of the next day

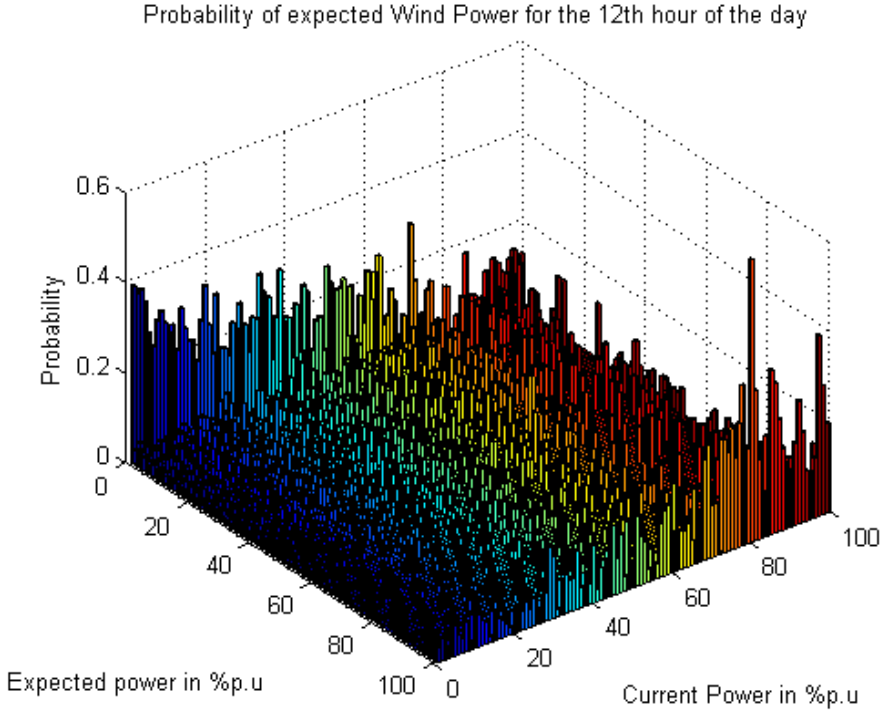

Fig 3.7 Probability Distribution of Wind Power for 12th hour of the next day

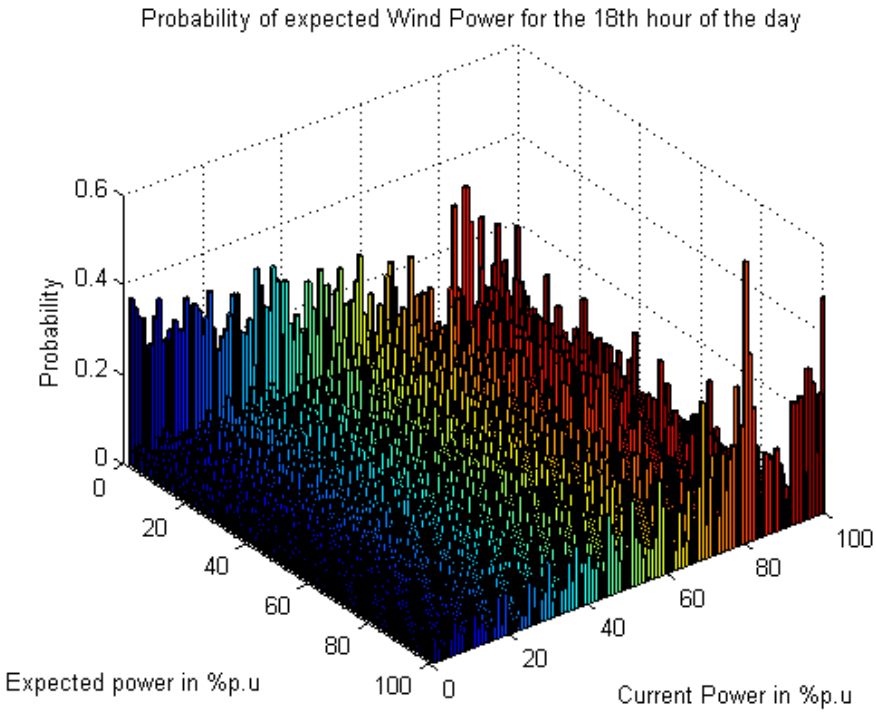

Fig 3.8 Probability Distribution of Wind Power for 18th hour of the next day

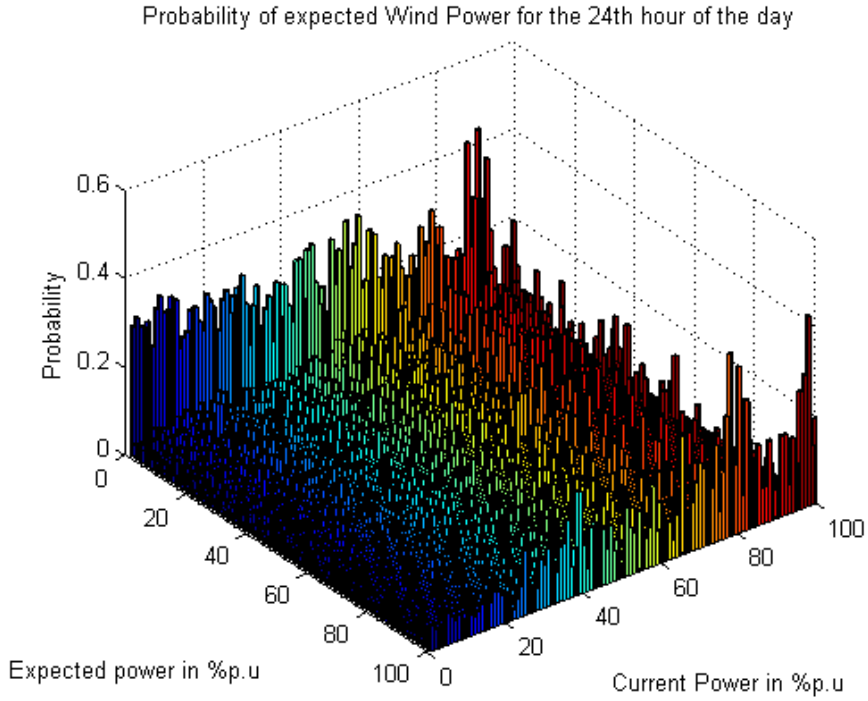

Fig 3.9 Probability Distribution of Wind Power for 24th hour of the next day

3.11 Cost of Wind Generation

The cost of wind power generation is needed to develop revenue and loss models. Wind turbine generators have high capital cost since the complex hardware is very expensive to purchase and integrate. However, WTG's require less land when compared to other renewable sources such as solar and hydro and as such, one aspect of installing wind power is cheap.

Since generators require no fuel, the fuel costs for a generator are almost negligible. However, the operation and maintenance costs of a WTG are higher than other renewable energy sources [78]. This is because wind farms, especially offshore, require skilled labor and maintenance of WTG components is costly.

A wind turbine is expected to have a life of about 25 years. Therefore, the capital and investment costs are levelized over the period before analysis. Literature survey yielded that purchase and installation of wind turbine generators may cost anything between a 3600 SAR/kW to 7200 SAR/kW[88]. It has been observed over the past years that costs of WTG have dropped and the median cost falls closer to the lower limit. In this thesis, the purchase and installation cost is assumed to be 4000 SAR/kW. To levelize this cost, it is divided by its lifespan, i.e. 25 years.

To cover the O&M costs of the WTG, cost is measured not over a unit of power, but over a unit of energy. This is because time of operation is an important aspect in deciding operation costs. A report by the British Wind Energy Association gave an average generation cost of onshore wind power equal to 18 KSA halalas/kWh. However, the costs dropped over the years and the O&M costs of the WTG once installed and functional are usually under 4 KSA halalas/kWh [89]. Therefore, the O&M costs or the marginal cost of wind energy production assumed in this thesis is 30 SAR/MWh.

3.12 SEC Eastern Province Load Data

Apart from wind speed, another set of raw data used is the load profile data for the SEC Eastern Operating Area of the year 2013. The load data is important because penetration of wind power in the market and/or installed capacity of wind farms will be measured as a percentage of peak load over the year.

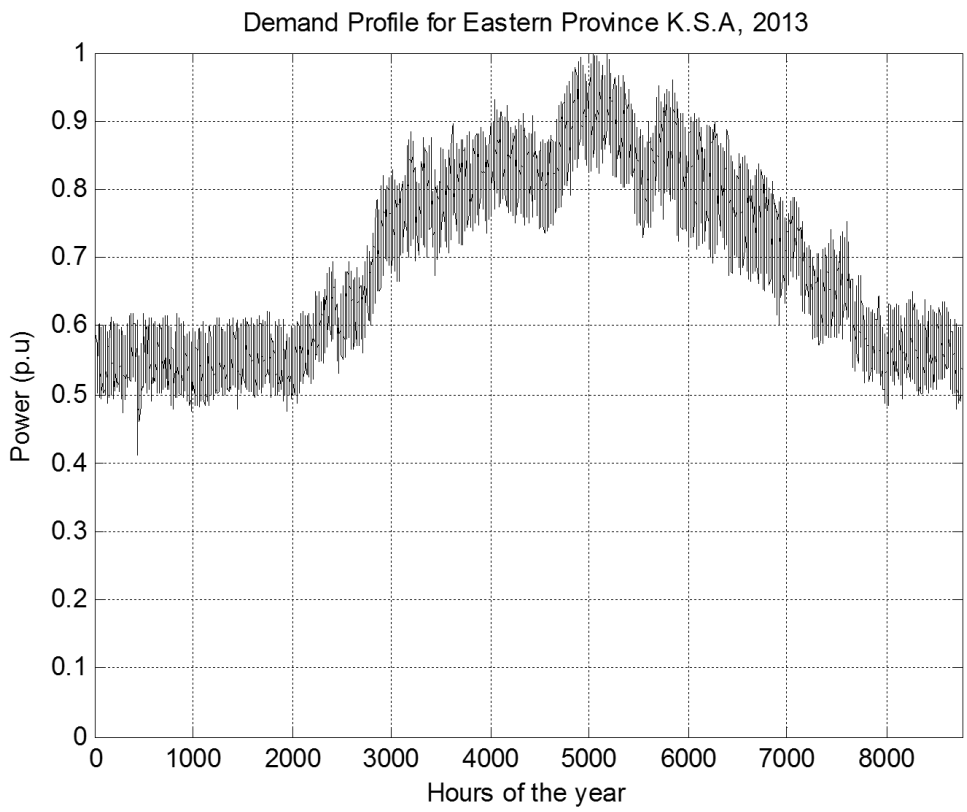

Fig 3.10 Demand Profile for SEC EOA, 2013

The other purposes that the load/demand profile will serve are:

- It will be arranged in descending order to form a Load Duration Curve (LDC) which is essential to perform a screening curve analysis.
- It will be used to determine market clearing prices.

- The load profile will be used to determine whether the system is in up regulation or down regulation based on the difference between the forecasted load profile and the actual load profile.
- The last chapter on demand response will modify this load profile to create energy savings and benefit the wind GenCo.

CHAPTER IV

IMPACTS OF WIND POWER PENETRATION ON MARKET PRICES AND CONVENTIONAL DISPATCH

4.1 Introduction

Depending on the percentage of installed capacity of wind power with respect to maximum demand, penetration of wind power is divided into small scale, medium scale and large scale [78]. Usually wind energy production in the range of 0-10% of the total energy consumed by the load is regarded as small scale, while 10-30% production is regarded as medium scale. Energy production above 30% of the required consumption is considered to be large scale penetration of wind GenCos. However, producing a certain percentage of energy does not mean that it displaces an equal amount of conventional generation. Since wind is erratic and production is uncontrolled, correlation of wind power produced and demand profile is poor. Thus, as penetration of wind power increases, a lot of wind power produced tends to be spilled.

To avoid such a scenario, a prior analysis is needed to decide the quantity of installed wind capacity that will present the owner of the GenCo with maximum returns and at the same time benefit the system. Such an analysis should focus on the impacts of varying levels of wind energy integration on the conventional dispatch, since conventional generation is the main proponent of wholesale market prices. The next section will discuss conventional generation costs and modeling. Screening curve analysis on the original load profile will be performed and market clearing prices will be determined in section 4.3. The section after will evaluate the impact of wind penetration on market clearing prices and conventional dispatch. In the last section, the

behavior of a conventional GenCo which decides to withhold its capacity for real-time trading will be studied. Section 4.6 will contain the conclusions and remarks.

4.2 Conventional Dispatch Model and Cost of Generation

Conventional generators run on various fuels and technologies resulting in different operating costs and fixed costs. The costs of generation have a direct effect on the prices of electricity which makes it absolutely essential for the dispatcher to opt for a cost minimized, optimal mix of conventional generators to supply the demand.

To obtain a cost minimized mix of generation over a period of time, prior 'screening curve' analysis and 'economic dispatch' by the system operator are the methods used. In the screening curve analysis, the costs of generators levelized over its supposed life are used in tandem with the load duration curve to obtain the level of power and duration that each type of generator will supply. The method is explained in detail below. The costs associated with generation, are also discussed.

All generators require a fixed capital cost that includes cost of buying machinery, land etc. Apart from fixed costs, there are marginal or operating costs associated with generators that come into the picture when the generator starts operating. Typically, the costs of generation are broken down as:

- Investment costs
- Fixed Operation and Maintenance costs
- Variable Operation and Maintenance costs
- Fuel costs (negligible for wind turbine generators)

Since generation planning is performed over a time period spanning decades, inflation also has to be taken into account. A solution exists for this problem which known as cost levelization of generators. Levelization gives us a single, constant and present worth equivalent value of generation cost [90].

A levelizing factor is a per unit multiplier that converts the annual varying cost to a fixed levelizing cost. It is given as:

$$L.F = \frac{1 - \left[\frac{1+a}{1+i}\right]^N * CRF}{(i-a)} \qquad 4.1$$

Using the levelizing factor, the respective levelized costs are calculated using equations 4.2-4.6.

$$Fuel\ Cost\ (\$/Yr) = Cap * C.F * 8760 * H.R * F.P * L.F \qquad 4.2$$

$$Fixed\ O\&M\ Cost\ (\$/Yr) = Cap * F.\ O\&M * L.F \qquad 4.3$$

$$Variable\ O\&M\ Cost\ (\$/Yr) = Cap * 8760 * C.F * V.\ O\&M * L.F \qquad 4.4$$

$$Investment\ Cost\ (\$/Yr) = Cap * C.C * F.C.R \qquad 4.5$$

$$Total\ cost = N_u * (Fuel\ Cost + Fixed\ O\&M\ Cost + Variable\ O\&M\ Cost + Inv.\ Cost) \qquad 4.6$$

Here ‘C.F’ is the capacity factor of the generator. ‘Cap’ denotes the installed capacity while ‘H.R’ and ‘F.P’ denote heat rate and fuel price respectively. ‘C.C’ is the capital cost and ‘F.C.R’ is fixed cost recovery. ‘N’ denotes the life of the generator and is assumed to be 30 years. ‘N_u’ is number of units. The values of inflation ‘a’ and interest rate ‘i’ are 3% and 8% respectively. The costs of generation are summarized in the table 4.1 and will be used for screening curve analysis.

Table 4.1 Generator Costs [91]

	Steam Turbine Generator	**Combined Cycle Generator**	**Gas Turbine Generator**
Type of fuel	HFO-380	NG	LCR
Cost of fuel	3.09 SAR/mmbtu	11.26 SAR/mmbtu	12.89 SAR/mmbtu
Capacity of unit	600 MW	450 MW	60 MW
Fixed O&M cost	42 SAR/kw-yr	46.5 SAR/kw-yr	45 SAR/kw-yr
Variable O&M cost	6.15 SAR/MWh	12.45 SAR/MWh	16.5 SAR/MWh

The variable costs, yearly O&M costs and fuel costs combine to give the marginal cost of the generator.

Table 4.2 Marginal Costs of Generators

Type of Unit	**Marginal cost in SAR/MWh**
Steam Turbine	53.9938
Combined Cycle	118.05
Gas Turbine	232.4685

Levelized cost over different capacity factors is calculated for different types of generators and plotted. These plots are known as screening curves. The points of intersection of the curves, when

corresponded with the load duration curve, give an optimal least cost mix of generation as seen below. This process is known as screening curve analysis.

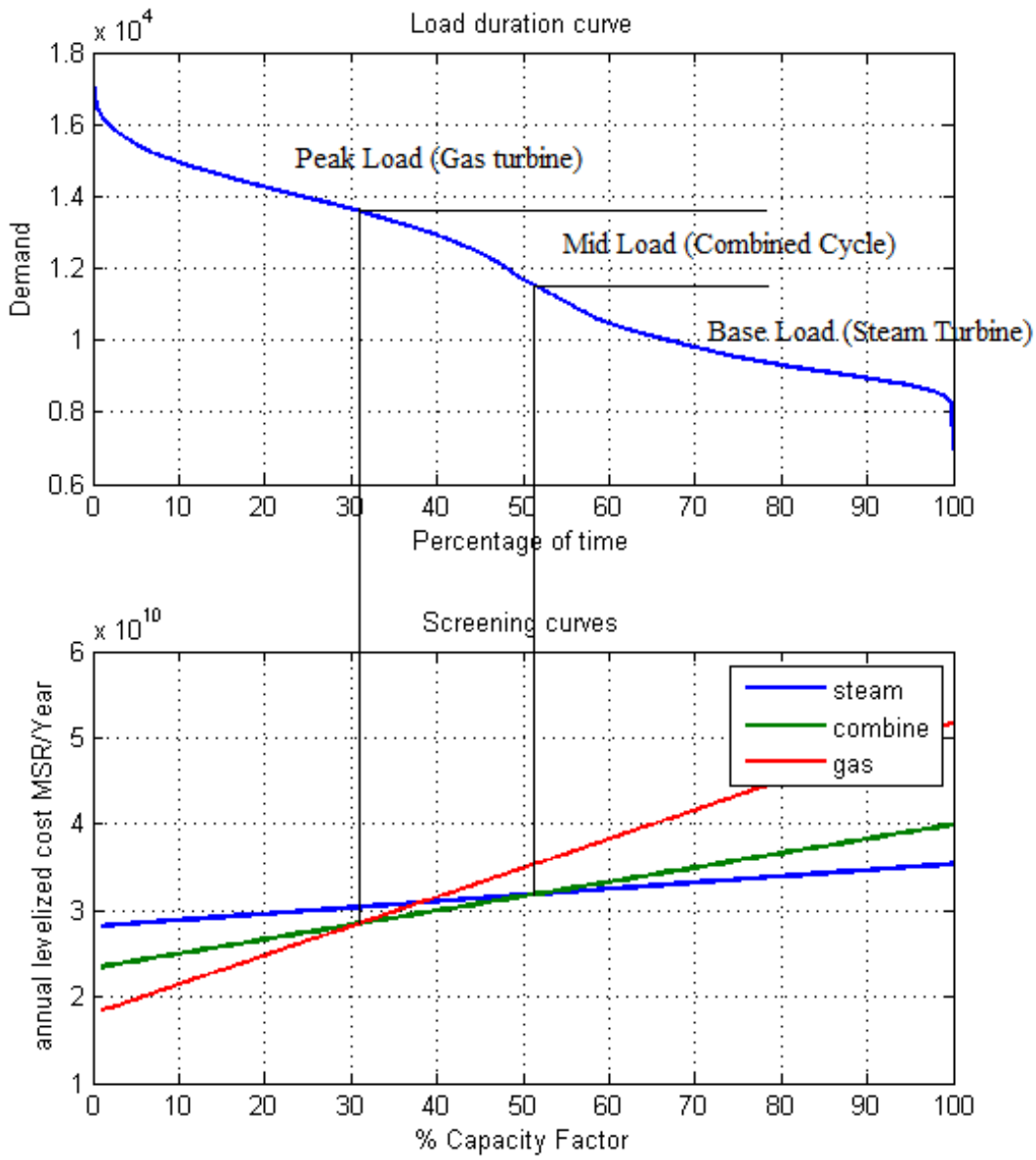

Fig 4.1 Screening Curve Analysis on Original Load Profile

As seen in the figure 4.1, the points of intersection of the curves are dropped on to the load duration curve so as to decide for what period of time and capacity output, which generator will

prove to be the cheapest. The load is divided into categories of base, mid and peak and amount of load to be served by each generator is decided. Based on the capacity of each generator unit and the optimal capacity factor, the number of units required for each type of generator is obtained. Capacity factors assumed are standard i.e. 0.7 for steam turbine and combined cycle and 0.5 for gas turbine.

Table 4.3 Mix of Generator Units from Screening Curve Analysis for 0% Wind Penetration

Type of Unit	**Number of units**	**Energy Produced**
Steam Turbine	29	40.95 GWh
Combined Cycle	8	23.2 GWh
Gas Turbine	116	39.4 GWh

4.3 Market Clearing Prices

To determine the market clearing prices for the year, a different approach was adopted as the data on bids and offers from suppliers and consumers was not present. To simulate the MCPs, the results of the screening curve analysis performed previously and the marginal costs of generators are used.

The screening curve analysis commits the generators in such that the production cost is minimized. The base load is served by the generator with the cheapest operating cost and as the load increases, the more expensive generators come into use. Hence, this analysis provides us the information as to which generator is used at what instant. The MCP at each hour is equal to the marginal cost of the most expensive generator active at that hour plus an assumed 15% profit.

Figure 4.2 shows the simulated MCP for the full year. In all the formulations used, the MCP is assumed to be deterministic and known to the wind power GenCo at all times.

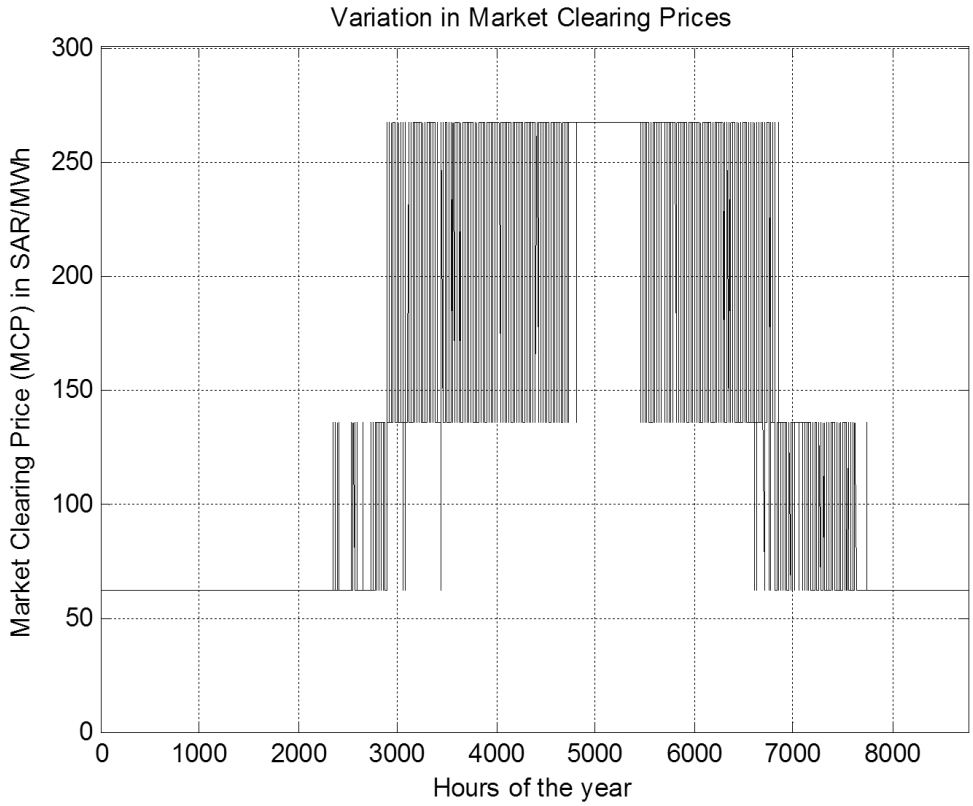

Fig 4.2 Market Clearing Prices for the year

4.4 Impact of Wind Penetration on Electricity Prices and Conventional Dispatch

To quantify the effect of wind power generation on conventional dispatch mix, the wind power production is subtracted from the load profile to obtain residual demand. The residual demand is obtained for varying levels of wind power penetration (installed wind capacity over varying levels of percentage of peak load.) The screening curve analysis is performed using the respective load duration curves obtained to obtain a capacity mix of conventional generation for varying levels of wind penetration. The procedure is summarized in the form of a flowchart as shown in figure 4.3.

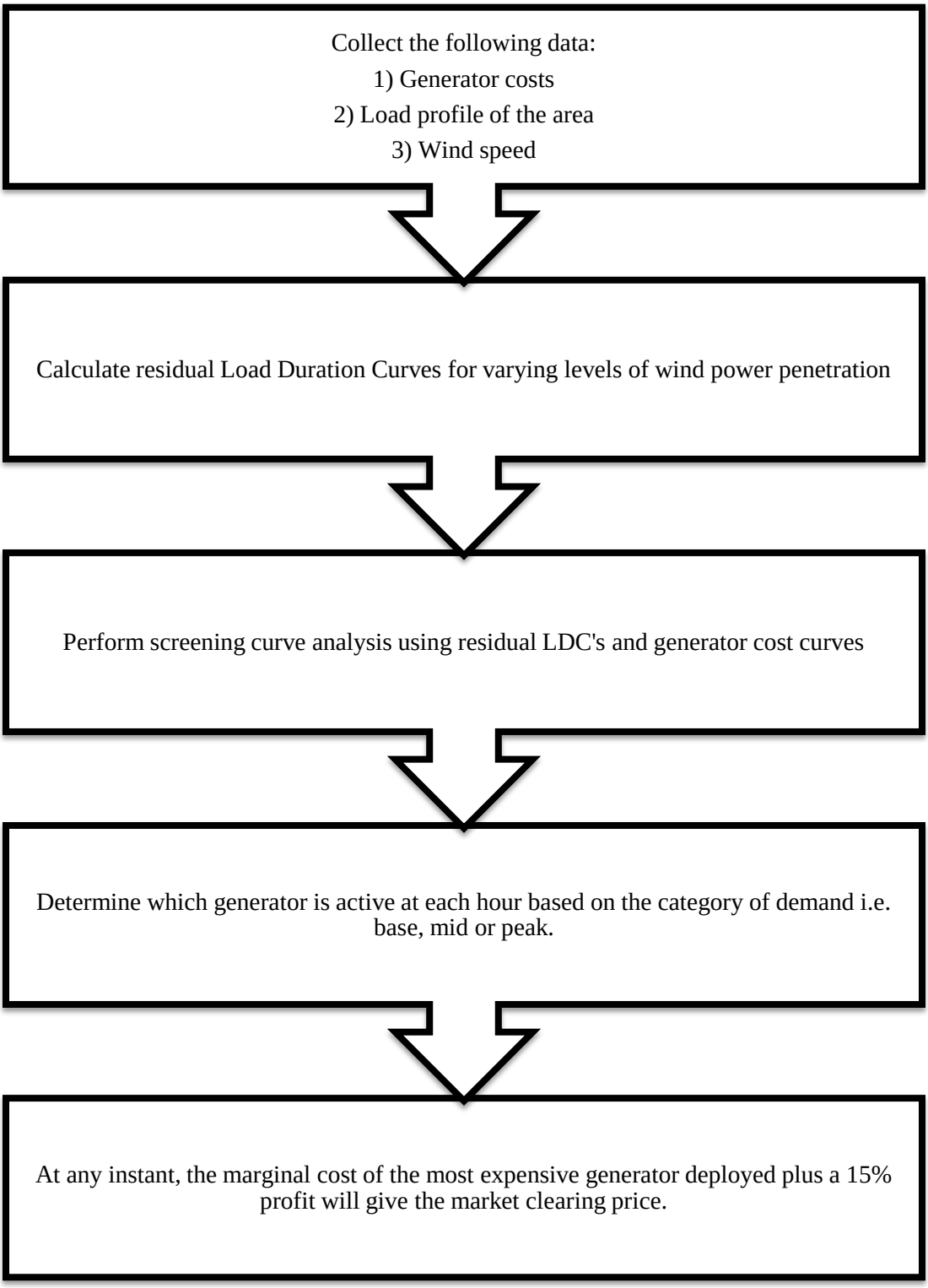

Fig 4.3 Procedure to Determine Wind Power Impact on MCP's.

4.5 Simulation Results

The residual LDC's obtained for varying levels of penetration are shown in the figure 4.4.

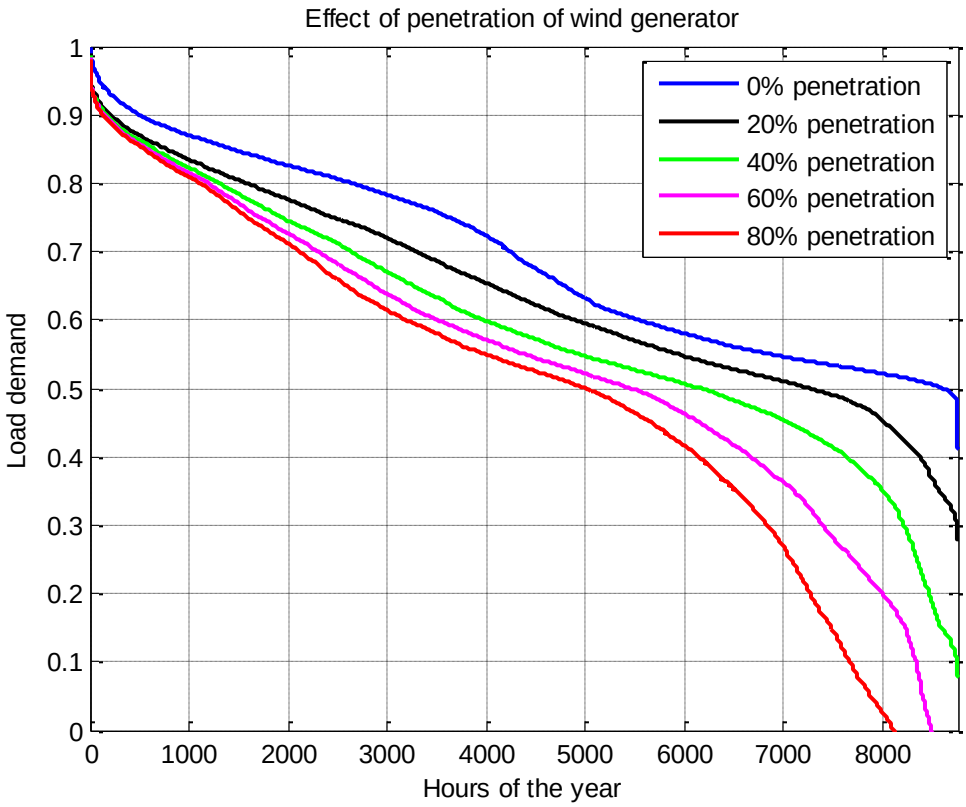

Fig 4.4 Residual Load Duration Curves after Wind Power Penetration

The curves are represented for selected percentages of penetration. After performing screening curve analyses on them, the impact on number of conventional generators involved is observed and displayed in table 4.4.

Figure 4.5 displays the variation in MCP with respect to penetration of wind power. The horizontal portions of the plot exist because MCP is assumed to depend only on the marginal cost of generators involved at any instant and not the number of generators or the energy supplied by them. **It is observed from the plot that MCP is least for a penetration of 10-17%. Therefore, the cost-revenue ratio will be minimized over this range of installed capacity.**

Table 4.4 Impact on Conventional Generation Unit Mix

	0% Penetration	**20% Penetration**	**40% Penetration**	**60% Penetration**	**80% Penetration**
Steam TurbineUnits	28	28	24	22	21
Combined Cycle Units	7	3	6	6	6
Gas Turbine Units	115	152	169	190	207

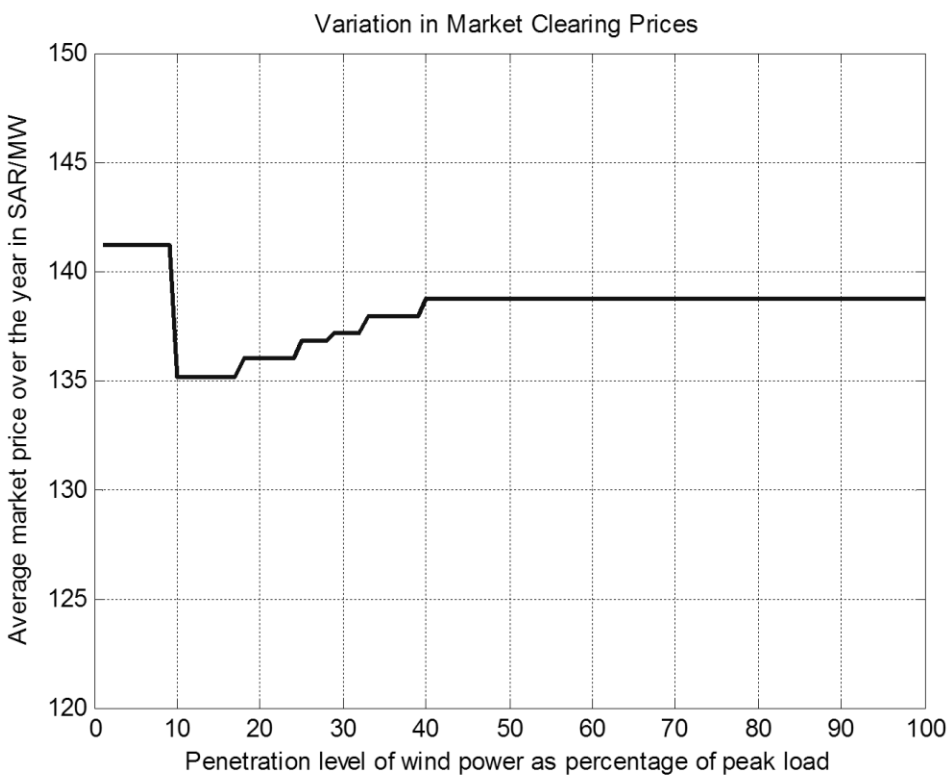

Fig 4.5 Effect of Wind Power Penetration on MCP

4.6 Generator Profits and Dominant Supplier Concept

The profit made by a generator for a single period can be given as:

$$Profit = (MCP * Ec) - (Imbalance\ costs) - MC \qquad 4.7$$

Where 'E_C' is the day-ahead bid contract and 'MC' denotes marginal cost. The imbalance costs are related to the difference between the delivered power and the contracted power. As explained in chapter 3, the imbalance costs change depending on whether the system is in up-regulation or down-regulation.

Consider a dispatch-able supplier to be a 'dominant' supplier when wind generators have been integrated in the system. This dominant supplier will seek to maximize its profits by withholding its capacity so as to trade it later when the wind generator falls short and the system operator offers higher prices. A single generator unit is being considered as a dominant supplier and the capacity of wind farm is considered equal to that of that the dominant supplier. This is because the dominant supplier should be able to cover for the deficiency of power caused by the wind generator in case the forecasts turn out to be incorrect.

The profit function for this dominant supplier maximized:

$$Profit_d = \sum_{i=1}^{T} [MCP_i * C_{cim} - MC_d] * [P_{fi} - P_{ai}] + \sum_{i=1}^{T} [MCP_i - MC_d] * P_d \qquad 4.8$$

$$Max\ \{Profit_d \mid 0 < P_d \leq P_{max}\} \qquad 4.9$$

$$0 < P_{fi} - P_{ai} < [P_{max} - P_d] \qquad 4.10$$

$$MC \leq MCP < PC \qquad 4.11$$

Here 'C_{cim}' denotes the imbalance cost coefficient, assumed to be equal to 1.314 [92]. 'P_f' and 'P_a' represent forecasted and actual powers. 'MC_d' denotes marginal cost of the dominant supplier which has an installed capacity 'P_{max}' and produces 'P_d'. The aim of the function is to optimize the quantity to be reserved for day-ahead and real-time market so as to maximize generator profit. The first component of the function is the profit due to withheld capacity of the generator for trading in the real time market. The second component is the profit due to day-ahead trading. Incentives for withholding are most for a base load supplier since it can utilize the increased market clearing prices during high load situations to boost its profits. For a mid-load and peak-load generator however, since their marginal costs are high, they don't have as much as profit boosting capacity as a base load generator.

4.7 Simulations and Results

The profit function of the dominant supplier was simulated and results were obtained using equations above. The penalty factor to be used was assumed as 0.314[92]. Therefore the up regulation price was (1+0.314) times the MCP at that instant and the down regulation price was (1-0.314) times the MCP. These penalties are adopted throughout the thesis.

First the dominant supplier was assumed to be a steam turbine and simulations were performed. During withholding, the capacity of wind farm is assumed equal to the dominant unit i.e. 600MW (Table 4.1).

It was observed that the base load can boost its profit by a narrow margin and among all possible levels of withholding for the unit over its capacity; maximum profits are obtained in the areas of full withholding or full day ahead trading. As shown in the figures 4.5 and 4.6, in the 600 MW steam turbine unit considered, maximum profit was obtained for 2 MW out of 600 traded in the day-ahead market and the remaining 598 MW withheld for the real time market.

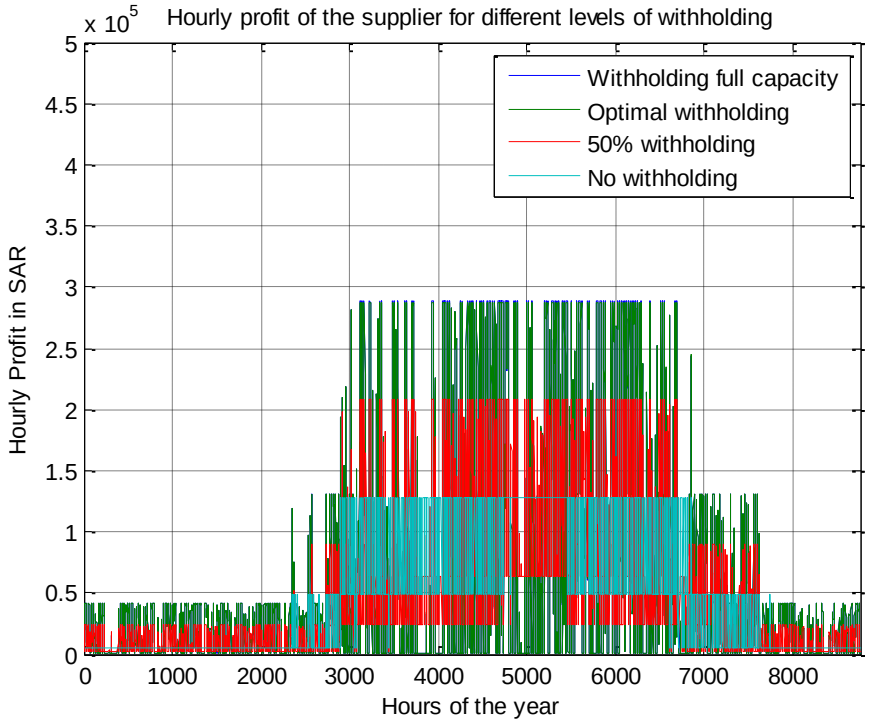

Fig 4.6 Hourly Profits for 600 MW Steam Turbine Withholding

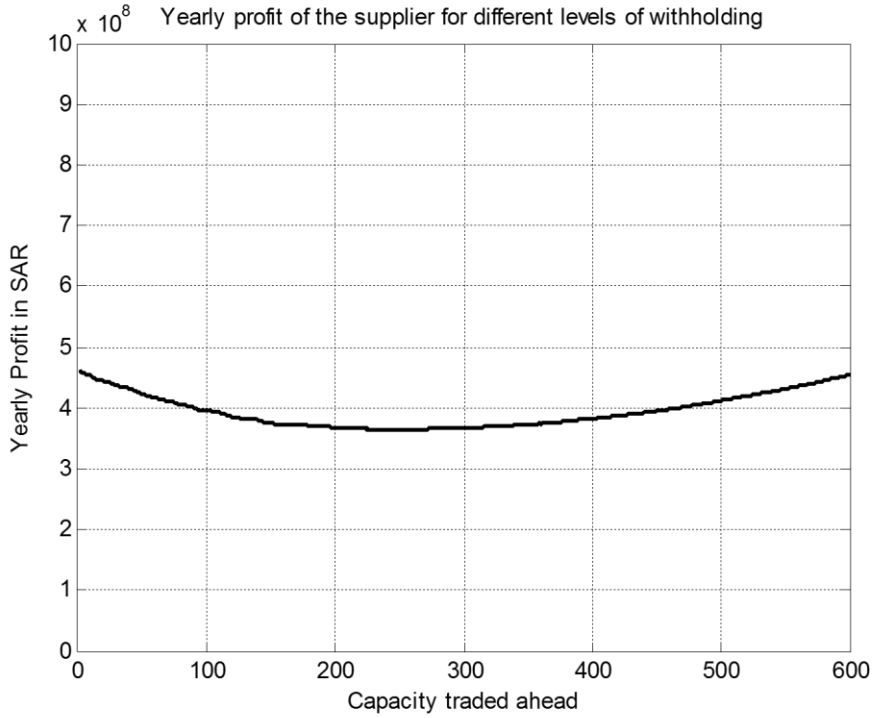

Fig 4.7 Profit Variation over Different Levels of Withholding for ST

On the other hand, for a combined cycle unit (mid load), the profit from full day ahead trading is higher than the profit withholding may provide (Fig 4.7). The reason being that since the marginal cost of CC unit is high, its profit boosting capacity is reduced substantially compared to base load generators.

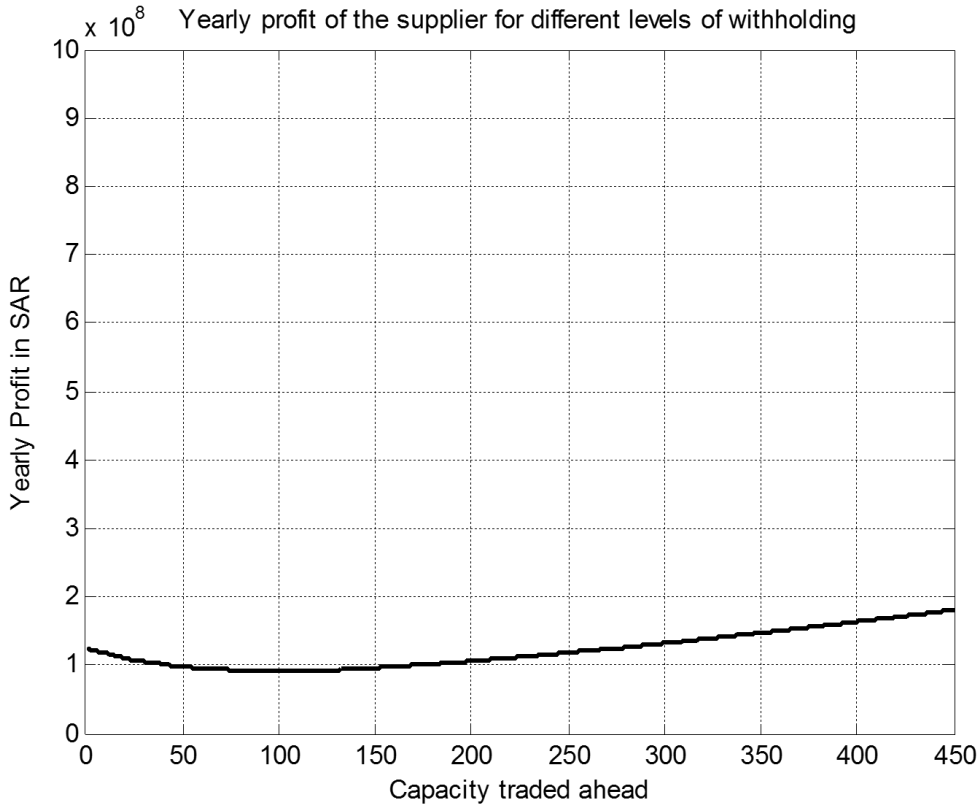

Fig 4.8 Profit Variation over Different Levels of Withholding for CC

4.8 Conclusions

It can be concluded, from the results and figures shown that integrating wind power is not a straightforward process and is observed to have higher investment costs than initially expected due to its negative impact on conventional generation.

Integration of wind power on a large scale will tend to replace the base load generators. However, the peak demand remains almost the same and this leads to an increase in peak load units and mid load units which have capital costs.

The impact on market clearing prices due to wind power penetration is also not as profound as expected and it can be concluded based on all the results and wind power costs that a medium scale penetration of 10-20% (installed capacity of wind power is equal to 10-20% of the peak demand of the year) will prove to be best for the system as well as the wind GenCo. The next chapter will develop a bidding strategy over this range of capacities and the capacity that yields minimum cost-revenue ratio will be chosen to be installed.

The dominant supplier concept was tested and determined not to hold much promise. More accurate wind power forecasts in the future will result in lesser profits for the supplier in real-time market and thus the strategy is discouraged.

CHAPTER V

OPTIMAL PARTICIPATION OF WIND POWER GENERATOR IN THE DAY-AHEAD MARKET AND REAL-TIME MARKET

5.1 Introduction

This chapter will deal with the participation of a wind power producer in the day-ahead (forward) market and the real-time (spot) market. Since wind generation has a very high investment cost and the area under consideration has a low average wind speed, simply seeking to maximize profits of the wind generator is not advisable. A cost-revenue ratio approach is required to decide the level of participation a wind power GenCo should go for.

Forward market penalties are imposed on the generators that deviate from their contract. To evade these penalties, participation in the real-time time market will also be considered. Comparison of profits and cost-revenue ratios will be made between the two participating strategies.

5.2 Participation in the Day-Ahead Electricity Market

This section discusses in detail the various aspects of participation of a wind power GenCo in the day-ahead market. The following assumptions are made:

- The market prices are deterministic and known in advance. However, the production level is stochastic.
- The wind power GenCo is a price-taker. This means that its participation does not affect the market clearing price and it will sell energy at the MCP available.

- Nodal or zonal pricing is disregarded since the wind farm is assumed to operate from a single bus.

The wind power GenCo will submit 24 hour bids in the day-ahead electricity market. Typically, all bids for the next day are submitted, accepted and cleared by noon of the previous day. The same protocol will be followed in this case.

5.3 Profit Function Formulation

In a perfect scenario, the revenue generated by the wind power GenCo will be:

$$\rho = MCP * E_C \tag{5.1}$$

Where $E_C = \hat{E}$

Here 'ρ' represents the revenue of the generator, 'E_C' represents the day-ahead energy bid by the GenCo and '$\hat{E}$' stands for the actual stochastic power production. Maximum revenue is achieved when the forecasted wind power tends to be equal to the bid. However, that is seldom the case. More often than not, there is a difference between forecasted power and the bid power.

$$E_{im} = \hat{E} - E_C \tag{5.2}$$

Where 'E_{im}' denotes the imbalance in energy, the difference between contracted energy and generated energy.

Depending on the imbalance, the wind GenCo is penalized by the clearing price of the real-time/balancing market. The GenCo has to settle for financial transaction for both over produced and under produced energy. The up-regulation and down-regulation prices are denoted by C_{UP} and C_{DW}, respectively, while the clearing price at the balancing market is C_B. The pricing can be represented mathematically as follows:

$$C_{UP} = \begin{cases} C_B & if \quad C_B \geq MCP \\ MCP & if \quad C_B < MCP \end{cases} \tag{5.3}$$

$$C_{DW} = \begin{cases} C_B & if \quad C_B < MCP \\ MCP & if \quad C_B \geq MCP \end{cases} \tag{5.4}$$

The next step will be to determine if the wind GenCo is in up regulation or down regulation. If the actual production is more than the energy bid, then the GenCo is said to be in down regulation. Similarly, if the actual production is less than the energy bid, then the GenCo is said to be in down regulation.

$$E_{UP} = \begin{cases} \hat{E} - E_C & if \quad \hat{E} - E_C \leq 0 \\ 0 & if \quad \hat{E} - E_C > 0 \end{cases} \tag{5.5}$$

$$E_{DW} = \begin{cases} 0 & if \quad \hat{E} - E_C \leq 0 \\ \hat{E} - E_C & if \quad \hat{E} - E_C > 0 \end{cases} \tag{5.6}$$

The relation between the regulation energy can also be expressed by the equality given below.

$$\hat{E} - E_C = E_{UP} + E_{DW} \tag{5.7}$$

The revenue function can thus be expresses as:

$$\rho = (MCP * E_C) - (C_{UP} * E_{UP}) + (C_{DW} * E_{DW}) \quad 5.8$$

The formula for profit can be rewritten as:

$$\rho = \left(MCP * \hat{E}\right) - [(C_{UP} - MCP) * E_{UP} + (MCP - C_{DW}) * E_{DW}] \quad 5.9$$

Here the first term denotes the maximum possible revenue, and the term enclosed in the second parenthesis is the possible revenue loss by the GenCo. The difference between the day-ahead price and the real-time price are the two non-negative penalties (shown below) by which the imbalance energy is transacted.

$$\phi_{UP} = C_{UP} - MCP \quad 5.10$$

$$\phi_{DW} = MCP - C_{DW} \quad 5.11$$

Therefore the profit function is now:

$$\rho = \left(MCP * \hat{E}\right) - [-\phi_{UP} * E_{UP} + \phi_{DW} * E_{DW}] \quad 5.12$$

5.4 Linear Stochastic Optimization Problem

The main objective is to maximize the function shown above. Since the first term is a constant calculated at the time of production and not a variable, it does not play a role in maximizing the function. Therefore, minimizing the second component is the goal. The mathematical representation of the linear stochastic optimization problem is given below:

$$\min_{E_C} \sum_{i=1}^{N} p_i * (-\phi_{UP} * E_i^{UP} + \phi_{DW} * E_i^{DW}) \quad 5.13$$

Subject to: $$0 \leq E_c \leq \bar{E} \quad 5.14$$

$$E_i - E_C = E_i^{UP} + E_i^{DW} \; \forall \, i \quad 5.15$$

$$E_i^{UP} \leq 0 \; \forall \, i \quad 5.16$$

$$E_i^{DW} \geq 0 \; \forall \, i \quad 5.17$$

By minimizing the above function, the value of the contracted energy 'E_C' that will result in a minimum value of the loss function is obtained. '$\bar{E}$' denotes the installed capacity.

The term 'p_i' used in the objective function indicates the probabilities of occurrences of a total of 'N' scenarios of power production as explained in section 3.9.

5.5 The Cost-Revenue Ratio

The cost–revenue ratio is the one of the most important aspect of this thesis, since it is a clear indicator to wind GenCos on how much to invest and what to expect in return. As it was observed in the previous section, installed wind capacities of 10-17% of the peak load gave the lowest market clearing prices. Hence the cost revenue ratio will be minimized over that range of installed capacities. The formulation is given below:

$$Min \sum_{k=1}^{365} \frac{(\sum_{n=1}^{24} C_w * \hat{E}_{n,k}) + (C_I * \bar{E}) - Subsidy}{\sum_{n=1}^{24}\left[\left(MCP_{n,k} * \hat{E}_{n,k}\right) - \sum_{i=1}^{N} p_{i,n,k} * \left(-\phi_{UP} * E_{i,n,k}^{UP} + \phi_{DW} * E_{i,n,k}^{DW}\right)\right]} \quad 5.18$$

Subject to: $$0.10 * D_M \leq \bar{E} \leq 0.17 * D_M \quad 5.19$$

$$MCP \leq PC \quad 5.20$$

The marginal cost per MWh (C_w) and purchase and installation cost (C_I) per MW are provided in section 3.11. The operators 'n', 'k' are used to denote time periods. Based on current trends, a

fixed subsidy is included, independent of installed capacity. This completes the mathematical formulation for day-ahead participation of wind GenCos.

5.6 Simulation Results

Upon simulating equation 5.18 for varying levels of wind power penetration, the following result is obtained.

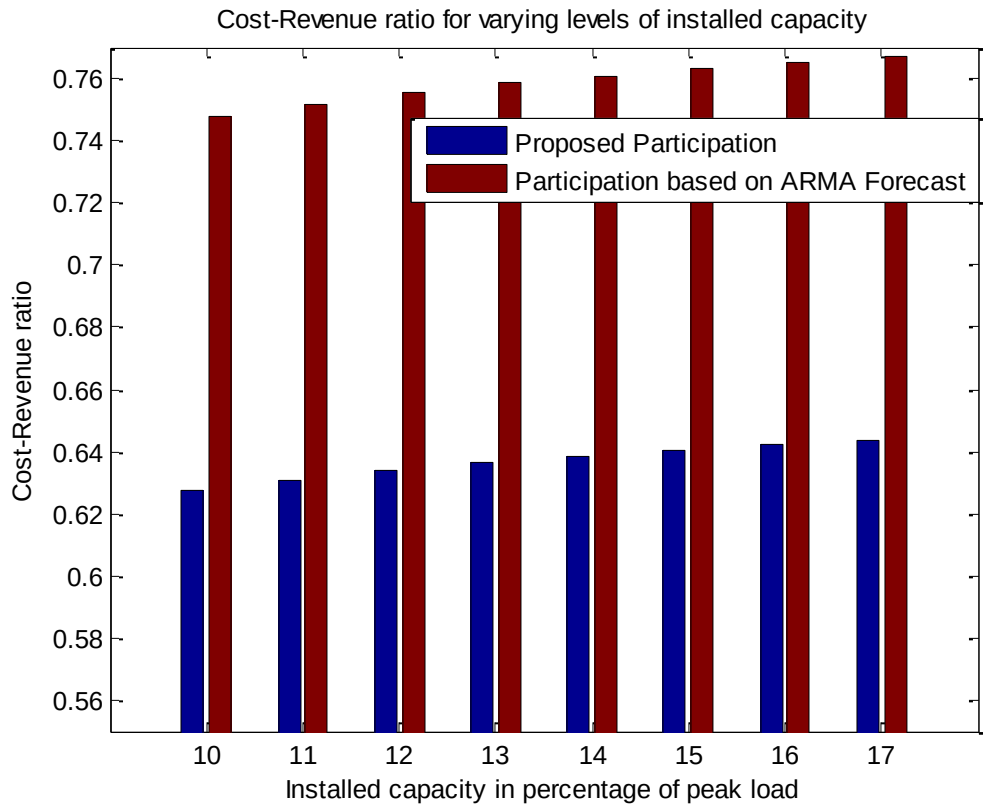

Fig 5.1 Cost-Revenue Ratio for varying Installed Capacity

Figure 5.1 plots the cost-revenue ratios for wind GenCo participation in the day-ahead market. Comparison is made between bidding based on ARMA forecast and bidding based on proposed method of probability distribution. It is observed from figure 5.1 that cost-revenue ratio is minimum for an installed capacity of wind power that is 10% of the peak load.

For this integration, the total revenue, estimated loss and estimated profit generated when participating in the day-ahead market based on ARMA forecast, and when participating based on the proposed conditional probability distribution based methodology are determined. The results obtained are compared.

The figures below show the bids and the expected losses for 3 randomly selected days.

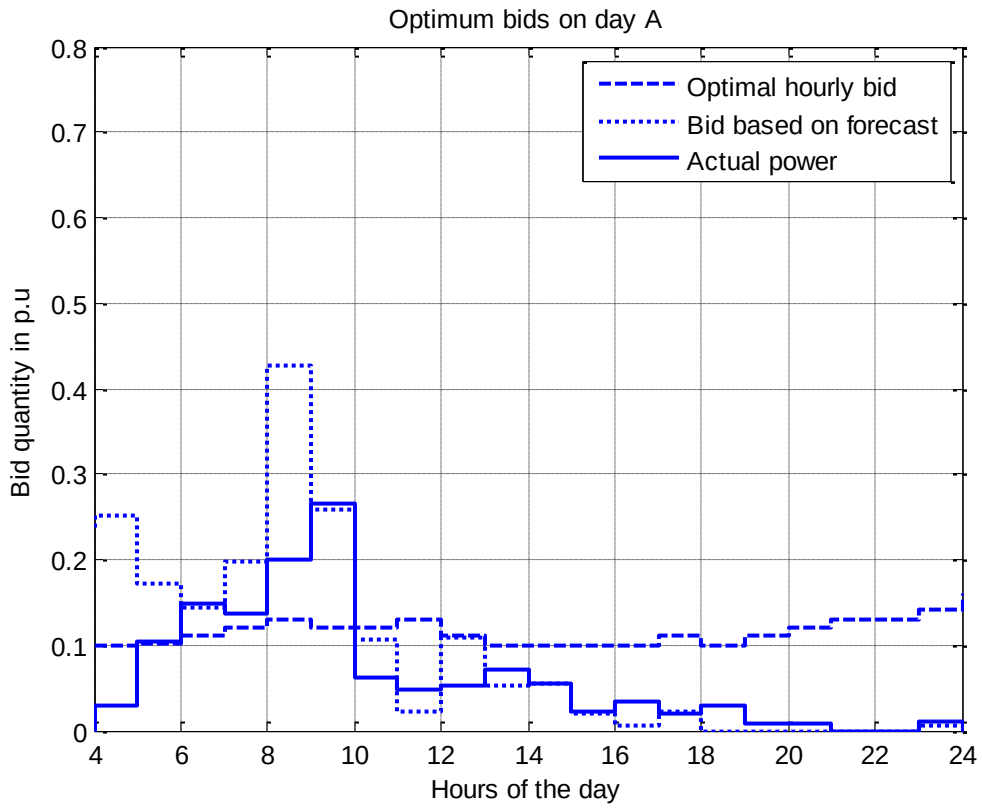

Fig 5.2 Bidding Comparisons on Day A

It is observed on day A and day C (figure 5.2 and 5.3) that the forecast is almost consistent with actual values. The optimal strategy proposed may cause more losses than bidding based on ARMA forecast. The figures 5.4 and 5.5 show the expected opportunity losses due to both types of bidding strategies.

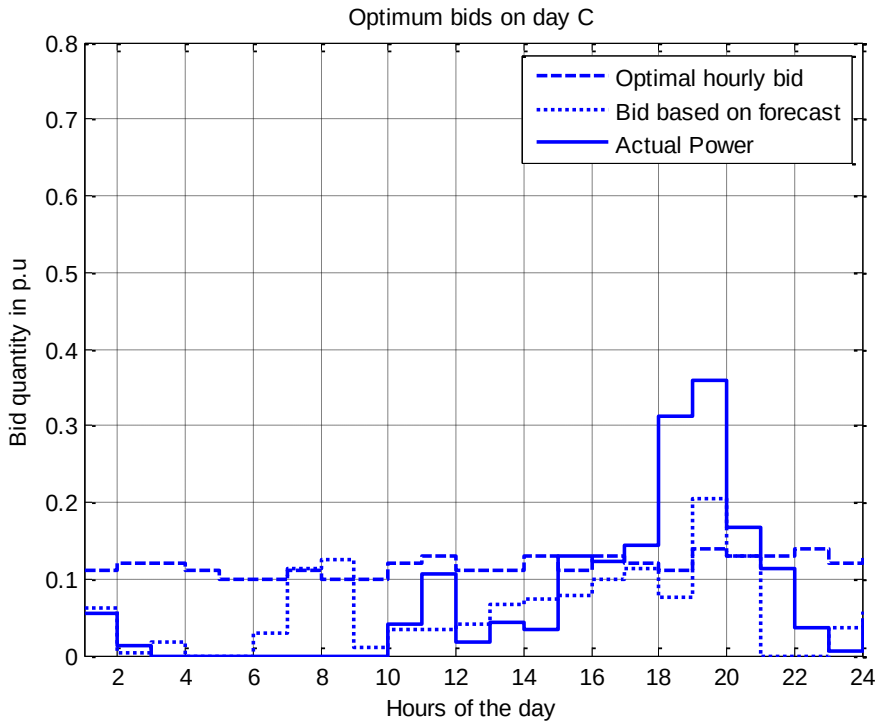

Fig 5.3 Bidding Comparisons on Day C

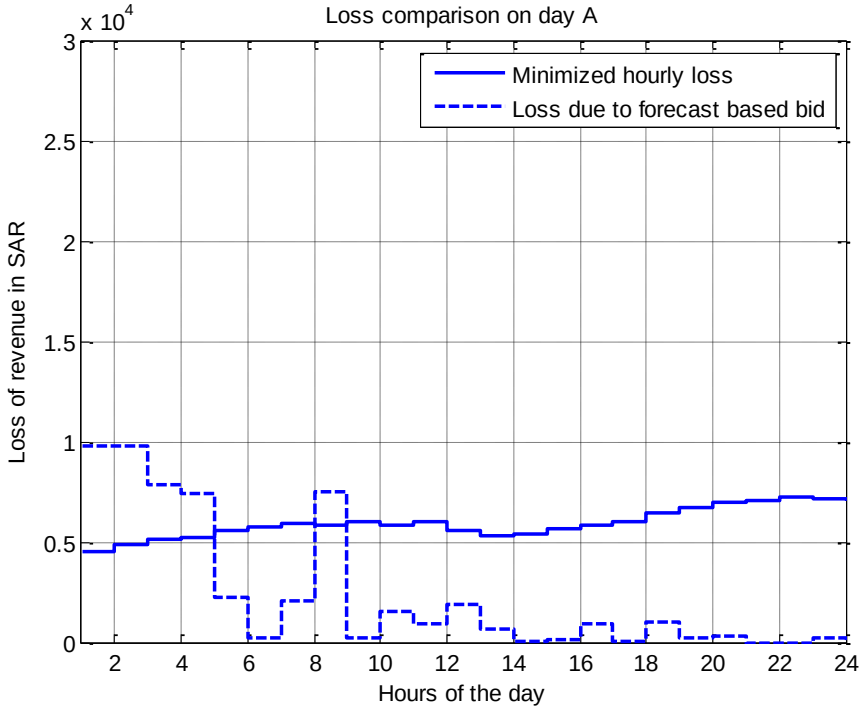

Fig 5.4 Loss Comparison between Strategies on Day A

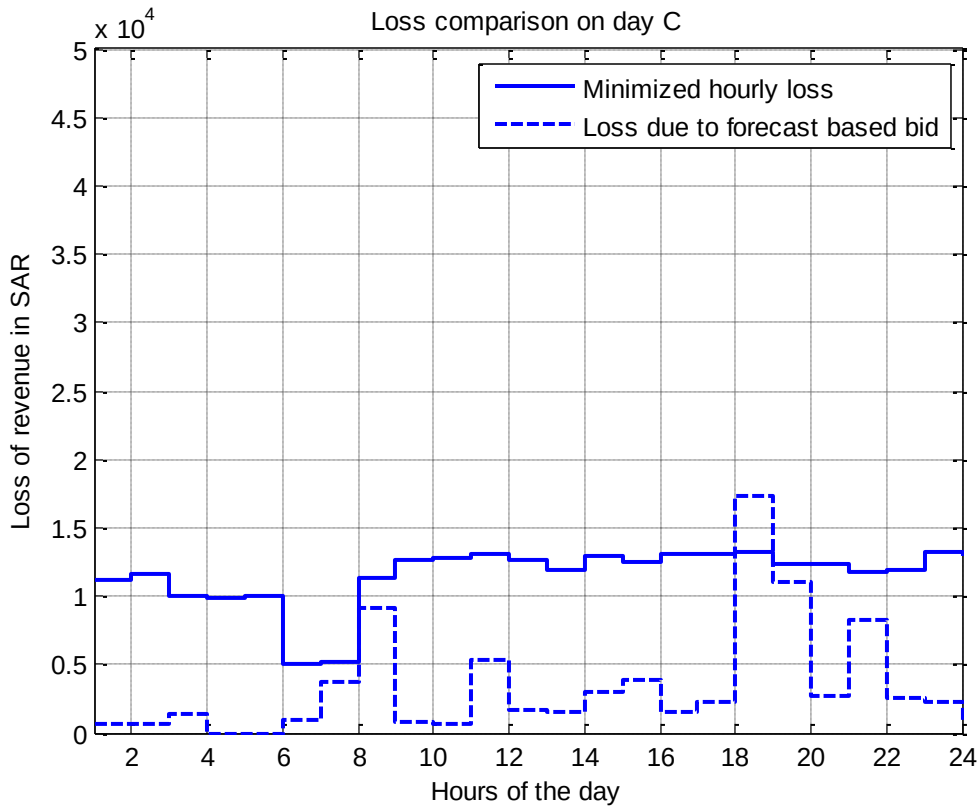

Fig 5.5 Loss Comparison between Strategies on Day C

As seen in the figure 5.5, losses are lesser for the ARMA forecast based bidding strategy. However, it is proven that over the year, when comparison of profits and losses are made, the bidding strategy proposed in this thesis will yield better results than the one based on ARMA forecast.

An example of a day when forecast is extremely erratic and the proposed strategy is inline with the actual power is shown below.

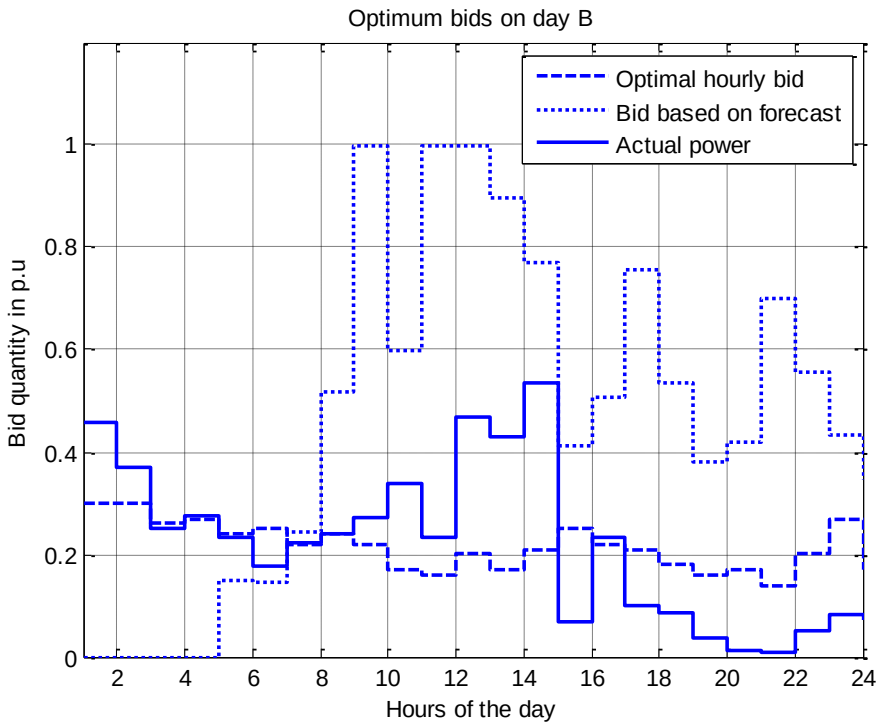

Fig 5.6 Bidding Comparisons on day B

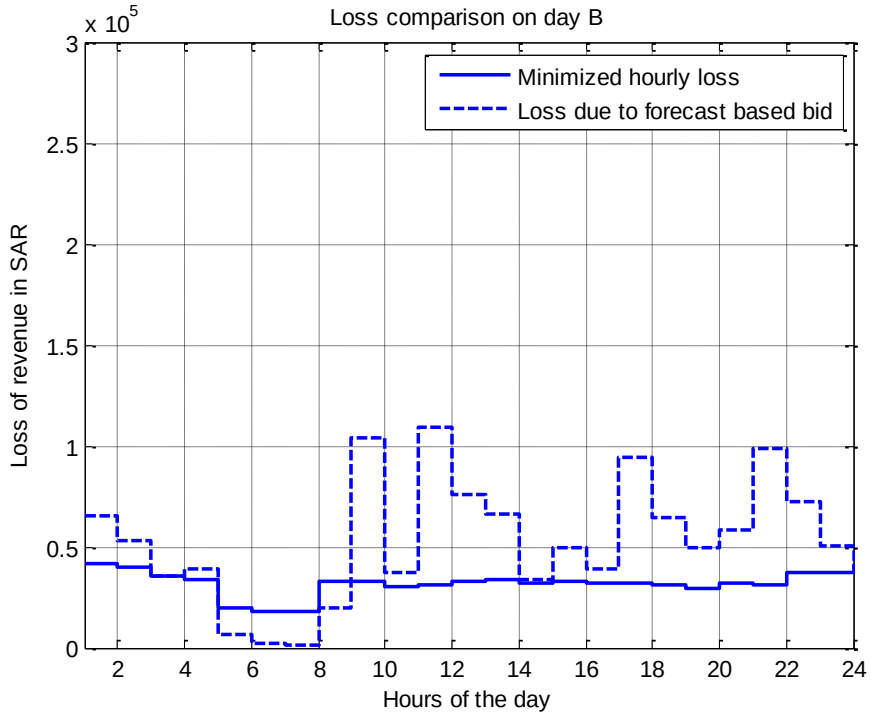

Fig 5.7 Loss Comparison between Strategies on Day B

When the sum of yearly profit, loss and revenue is calculated, the following result is obtained.

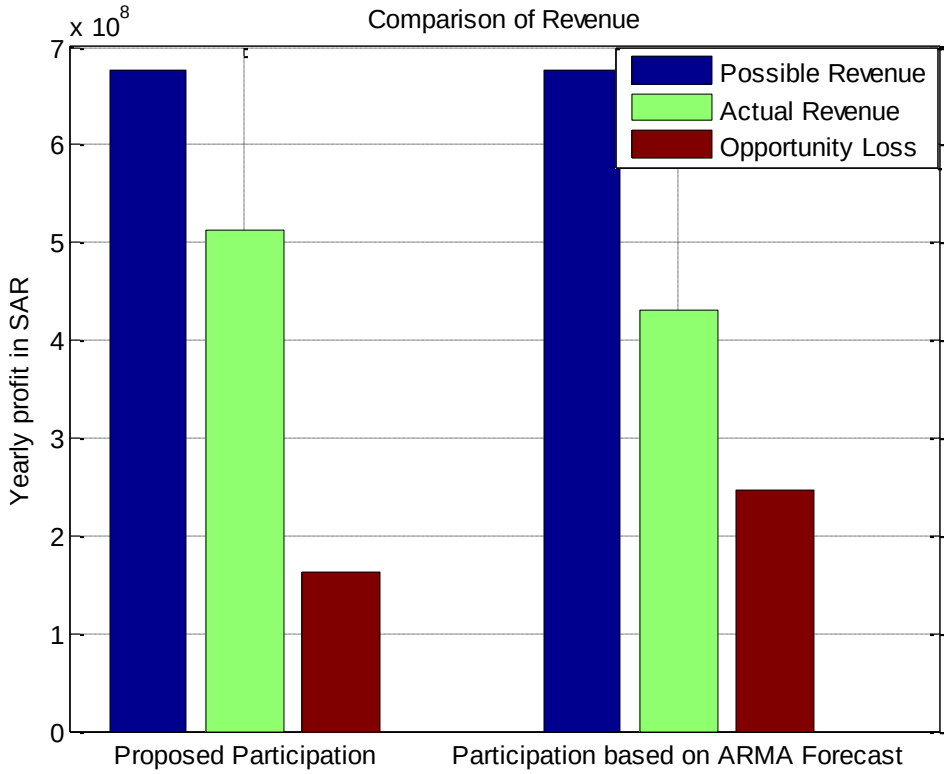

Fig 5.8 Comparison of Sum of Income Parameters over the Year

5.7 Participation in the Real-Time Electricity Market

In the real-time electricity market, the wind GenCo is assumed to sell its power instantaneously as it produces it. No prior commitments are required and as such no penalties are imposed. However, if the wind GenCo chooses to participate in the balancing market, it becomes fully dependent on the system imbalance. Power produced can be sold only when the system is in up regulation. When the system is in down regulation, the wind GenCo cannot sell tis power.

The formulation for the cost revenue ratio when the wind generator participates in the real-time market is given below.

$$Min \sum_{k=1}^{365} \frac{(\sum_{n=1}^{24} C_w * \hat{E}_{n,k}) + (C_I * \bar{E})}{\sum_{n=1}^{24} (MCP * \hat{E}_{n,k})} \qquad 5.21$$

Since the installed capacities for real-time participation are much lesser than day-ahead participation, they are not considered for subsidies.

5.8 Simulation and Results

For the real time participation, a moving average filter of span 5 was applied to the existing load profile to simulate a forecast of the daily load. Any deviations between the smoothed curve and actual curve were regarded as imbalances. Figure 5.9 represents the actual load profile and the smoothed demand load curve.

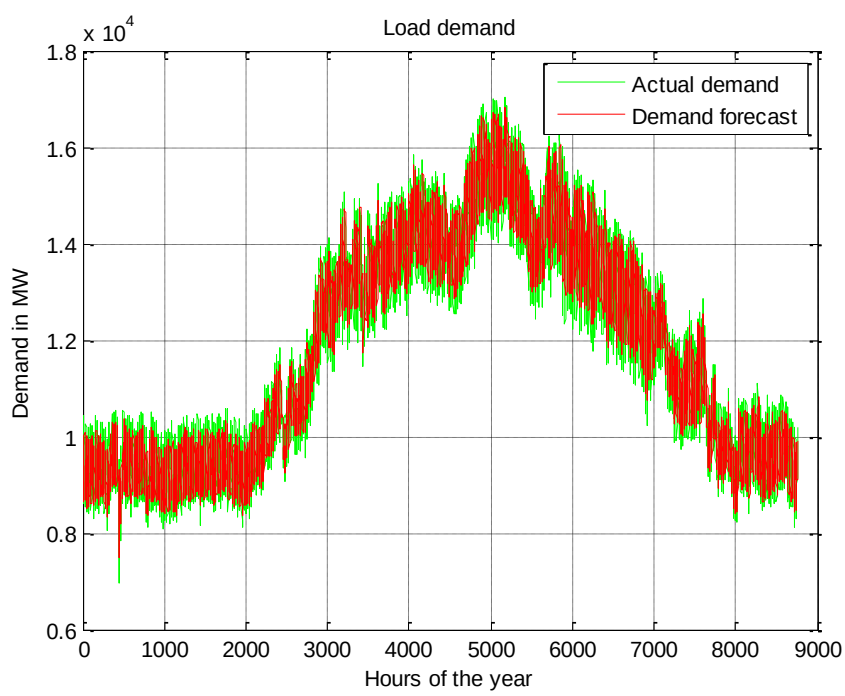

Fig 5.9 Simulation of Up and Down Regulation of the System

Any points on the actual load curve above the smoothed curve were regarded as up regulation on the consumer side, i.e. the system pool is short of energy. In this case, the wind generator would enter the balancing market and sell power at a price higher than the market clearing price.

Based on the value of the maximum deviation that occurred, it is observed that an installed wind energy capacity of 9% of the peak load will be enough to cater the system imbalances. The following figures show the revenue generated and the cost-revenue ratios obtained for the different levels of penetration.

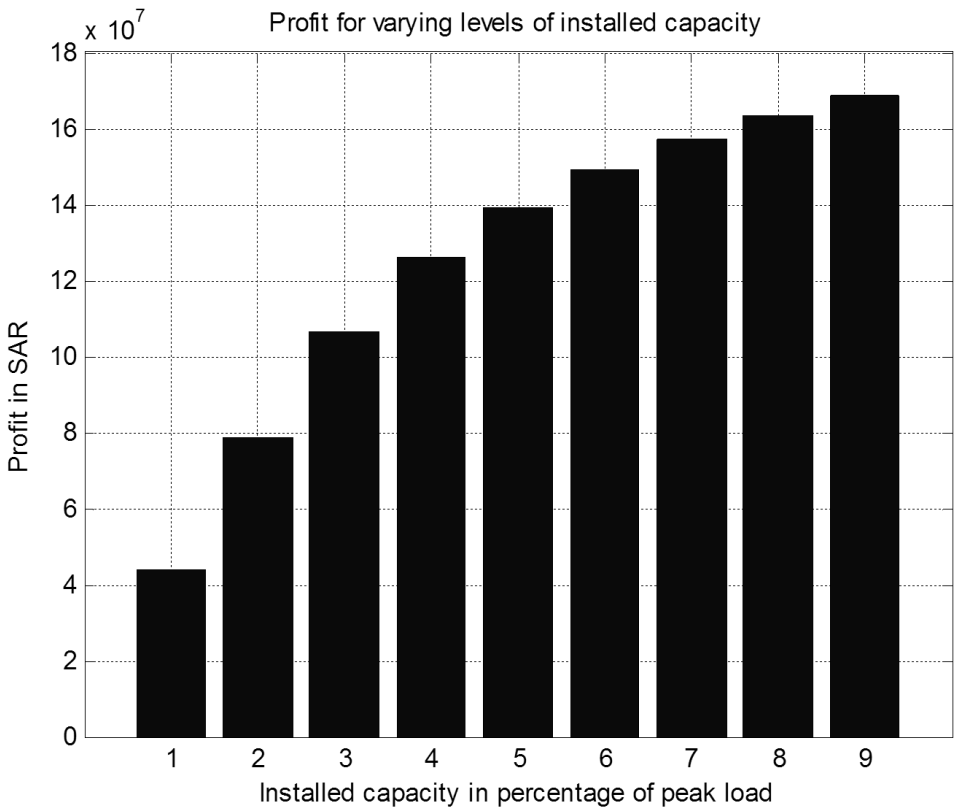

Fig 5.10 Revenue in RT Participation for varying Installed Capacity

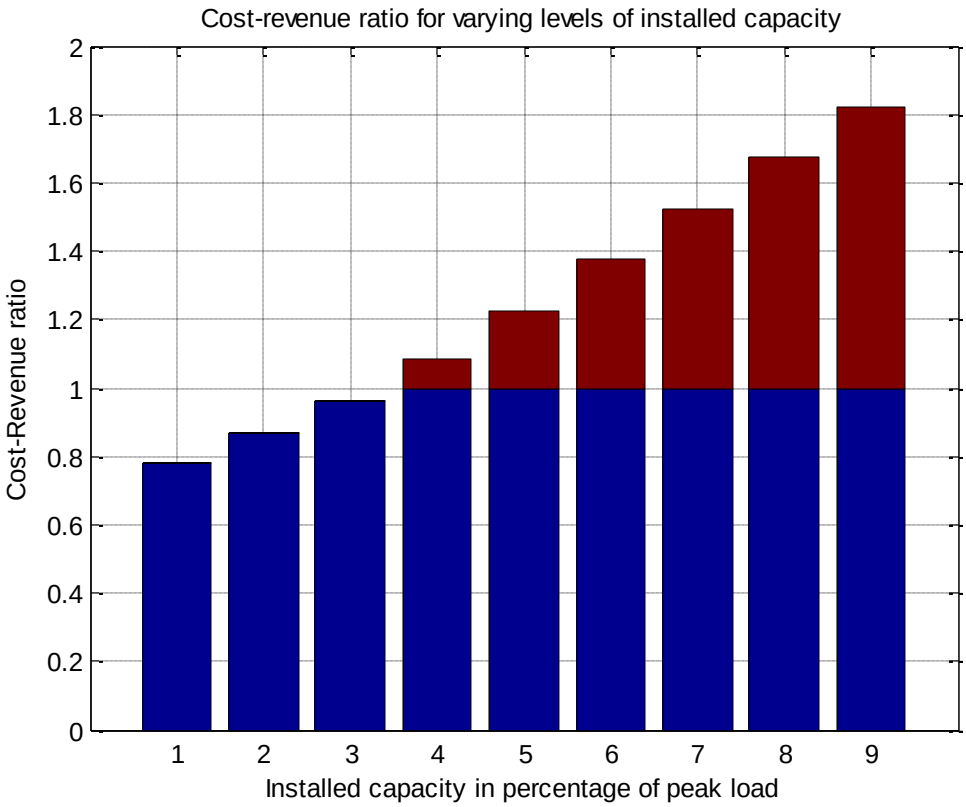

Fig 5.11 Cost-Revenue Ratios for varying Installed Capacity

It is observed that though the profit making capacity of the wind generator increases as installed capacity increases, after around 4%, the cost-revenue ratio starts going above 1, which means that the generator operation will result in a loss. The minimum cost-revenue ratio is obtained for an installed capacity of wind power equal to 1% of the peak load.

Figure 5.12 shows the possible revenue due to imbalances and the revenue generated by the wind generator due to an installed capacity of 1% of peak load (which gives minimum cost-revenue ratio).

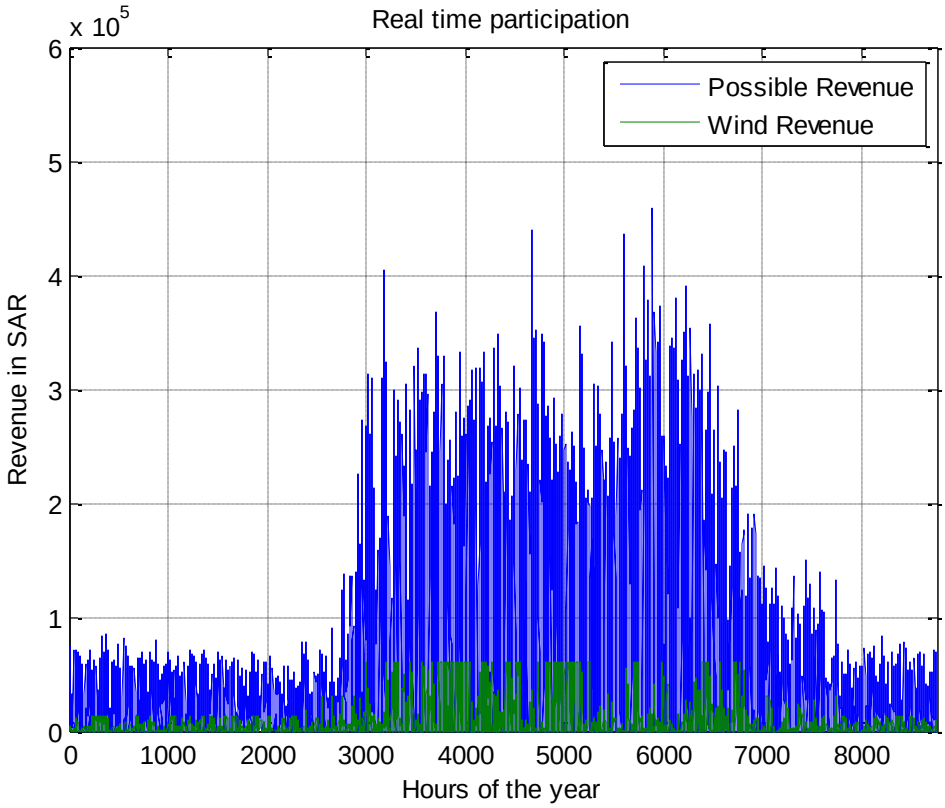

Fig 5.12 Revenue for Installed Capacity equal to 1% of Peak Load

5.9 Comparison between Day-Ahead and Real-Time Market Participation

The bar graph 5.13 compares the cost-revenue ratios between two strategies for their respective C-R ratio minimized operations. It is observed that since day-ahead market participation has a lower C-R ratio, it will tend to give better returns against the money invested.

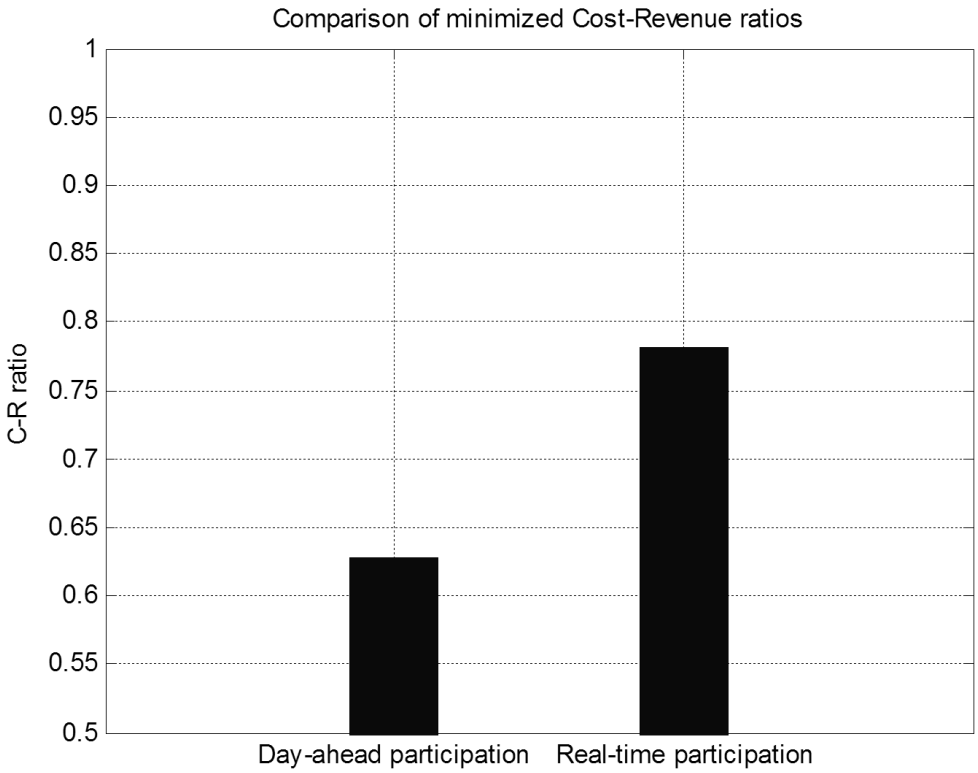

Fig 5.13 Comparison of C/R Ratios of two Strategies

The bar graph 5.14 compares the yearly profits made by the two different participating strategies, for their respective cost-revenue ratio minimized operations. In this case, day-ahead participation is observed to have an upper hand. Yearly operation in the day-ahead market can generate profits more than 5 times greater than those possible in the real-time market. Therefore, which market the producer decides to trade in will depend heavily on the budget, yearly targets and profit expectation.

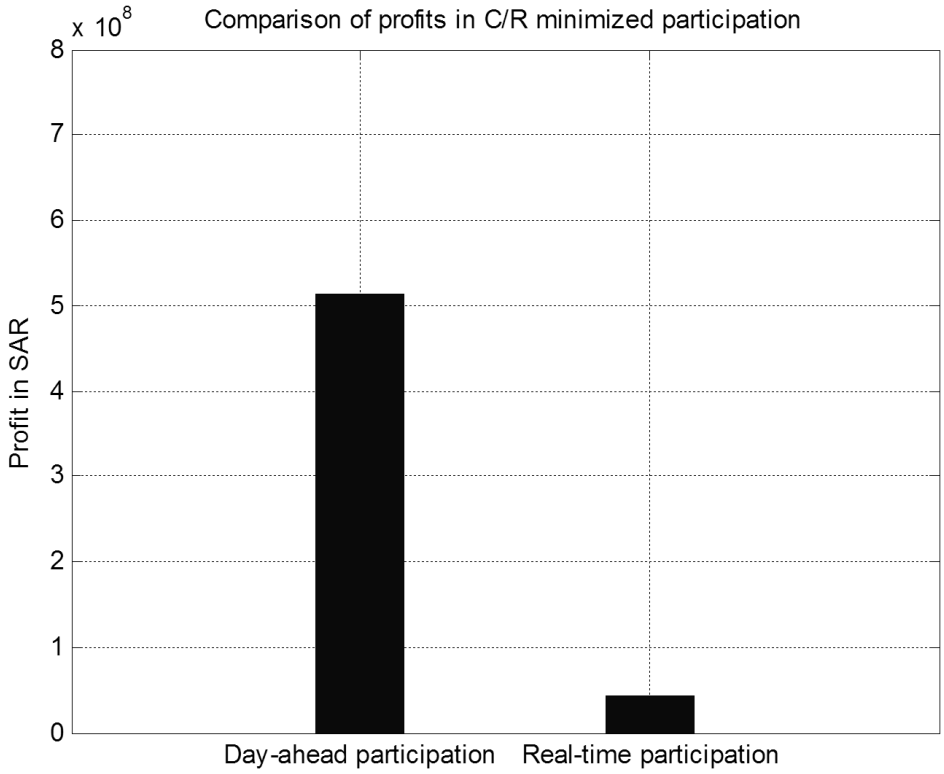

Fig 5.14 Comparison of Revenues between DA and RT Participation for C/R Ratio Minimized Operation

Based on the data from table 3.3, Alstom ECO 122/2700 was selected and the numbers of wind turbine generators required were calculated for C/R minimized day-ahead and real-time market participation.

Table 5.1 Number of Wind Turbine Generators Required

Type of Participation	**Number of Wind Turbine Generators**
Day-Ahead Market	631
Real-Time Market	64

5.10 Conclusions

In conclusion, participation strategies were developed for day-ahead and real-time market participation of wind power GenCo. The aim was not to simply maximize profits for the wind GenCo but suggest an optimal scenario in which costs of wind generation and hidden costs involving conventional generation are minimized and thus the grid is benefited.

Among the two strategies, day-ahead market participation is observed to be better for the wind GenCo. However, in absence of capital investment, low capacity participation in the real-time market is also advisable and is less of a hassle.

CHAPTER VI

DEMAND RESPONSE STRATEGY TO INTEGRATE WIND POWER INTO THE ELECTRICITY MARKET

6.1 Introduction

In the previous chapters, various aspects of wind power integration were analyzed and participation strategies were suggested that would provide maximum benefit to the wind power GenCo and to some extent the market operator. All those strategies focused on balancing the equilibrium by controlling the generation of power. However, control over consumption and demand is also possible by Demand Side Management (DSM) and would provide greater flexibility to the system. According to the DSM strategic plan of International Energy Agency (IEA), "demand side activities should be active elements and the first choice in all energy policy decisions designed to create more reliable and more sustainable energy systems".

In this chapter, demand response (DR) will be investigated as a tool to ease the participation of wind power GenCo into the electricity market. The main aim of the chapter is to formulate a DR strategy that will result in a benefit for the wind GenCo as well as the customer. The next section will give a brief introduction to DSM and its various categories. Section 6.3 will explain in detail the DR techniques adopted, the mathematical formulation of the strategy, and will compare the strategy to existing similar literature thereby highlighting the contribution made by the thesis. The last section will deal with simulation results and comparison between results of previous chapters and with other literature.

6.2 Demand Side Management

The term DSM includes all that can be done on the customer's side of an energy system, with options ranging from interchanging compact fluorescent lights (CFLs) with old incandescent bulbs to up to establishing a real-time dynamic demand management system. DSM was primarily performed by the utility in the past but in recent times it has moved towards a customer driven approach.

Depending on the impact and the timing of applied measures on the customer process, DSM can be divided into the following categories[93]:

- Energy Efficiency
- Time of Use
- Demand Response (DR)
- Spinning Reserve

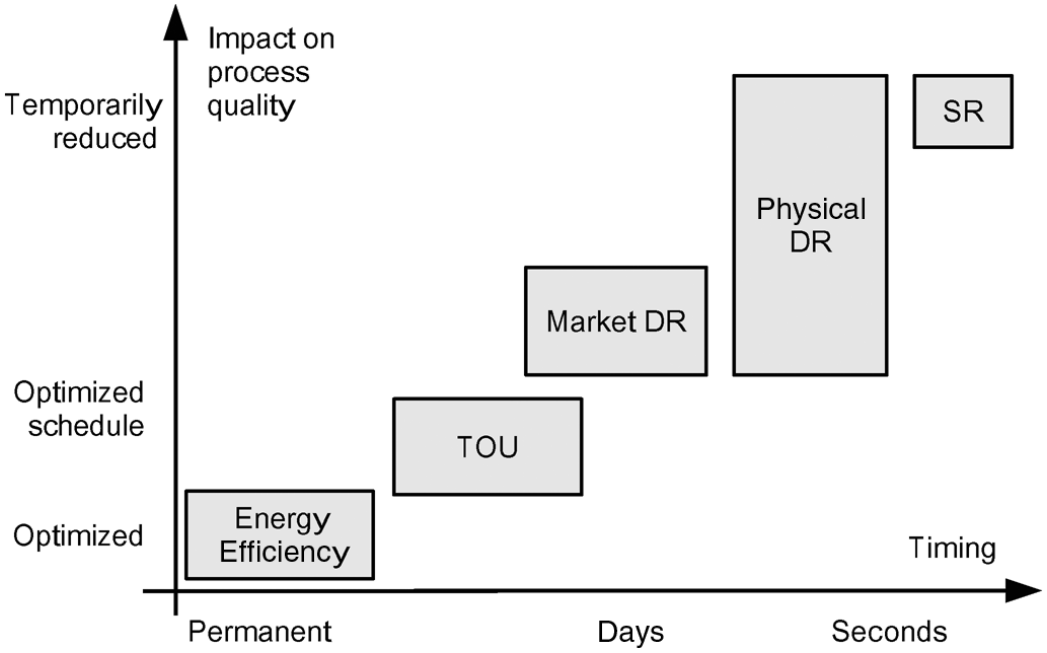

Fig 6.1 Representation of DSM

On a plot of timing versus impact as shown in the figure above, lower edge of the DSM spectrum corresponds to energy efficiency measures. They include permanent changes on equipment, e.g. replacing outdated and inefficient ventilation systems or improvements on the physical properties of the system such as adding additional insulation to building structures. Such methods cause immediate and long-lasting energy and emission savings and are therefore given high preference.

Time of use tariffs impose penalties on electricity usage at certain periods of time so that customers preplan their processes to minimize costs. A change in the TOU tariff does not happen on a frequent basis since a change in the price-schedule means a change in a supply contract. [94] states that combining DSM and TOU tariffs significantly increases security and lowers costs and emissions of energy systems with a high share of wind power.

Demand response covers a wide range of tools that may be adopted to alter consumer behavior. They are summarized below:

1) Incentive-Based DR
    a) **Direct-load control**: In this strategy, utility operators get free access and control on customer processes so that they may influence it accordingly.
    b) **Interruptible/curtailable rates**: In I/C rates, customers sign contracts that fix a certain amount of shedding level for the customer. Customers adhering to the contract will be awarded with incentives.
    c) **Emergency demand response programs**: The customers respond voluntarily to emergency signals broadcasted by the operator.
    d) **Capacity market programs**: The capacity market program is an integration of I/C rates and emergency demand response programs. In this program, customers guarantee to pitch in whenever the grid is in need.

e) **Demand bidding programs**: Customers are given the liberty to submit their offers for energy as generators submit their bids for supply.

2) Time-Based Rates DR

a) **Time-of-use rates**: In this technique, a static price schedule is fixed depending on the time of the day.

b) **Critical peak pricing**: CPP rates are a pre-specified higher electricity usage price based on peak demands that are superimposed on TOU rates.

c) **Real-time pricing (RTP)**: In RTP, wholesale market prices are forwarded to customers either simultaneously or around an hour in advance.

In addition to these options, ancillary services, extreme day CPP and extreme day pricing are a few other techniques used in demand response. Methods involving direct-from-grid management and emergency declarations etc. are considered as physical DR whereas pricing, RTP and other incentive based programs are grouped under market DR.

Demand side management via spinning reserves focuses more on improving power quality rather than load curtailment. The spinning reserves are responsible for the active and reactive power requirements of the grid as well as frequency control.

Out of the various DSM strategies mentioned, DR will be used in this thesis. DR is easier said than done since switching to a 'demand follows supply' requires a drastic rethinking of the existing infrastructure. Most of the DR techniques are based on ideas yet to be implemented such as intelligent bi-directional communication systems, intelligent appliances, smart metering etc. However, DR offers increased flexibility to the operator and eases restrictions on renewable energy GenCos.

6.3 Proposed Demand Response Strategy

The demand response strategy proposed in this thesis will develop the general strategy demonstrated in [95] and improve it in a manner that will benefit the wind power GenCo. A mixed strategy of Interruptible/Curtailable (I/C) load and RTP will be developed.

In the I/C component of the strategy, customers sign a contract with the demand aggregator where they agree to cut down their consumption by a certain measure. Adhering to the contract will result in incentives awarded to the customer by the demand aggregator. On the other hand, failing to uphold the contract will result in penalties to the customer.

The RTP component will provide a spot market price that is dependent on the current wind power production. This real time price is inversely proportional to wind power production and its hoped that incorporating it will result in better performance by the wind GenCo.

The DR services are assumed to be managed and regulated by a demand aggregator owned by the utility. The demand aggregator will charge the GenCo for DR. However, these charges are lesser than the penalties imposed by the market operator and thus will result in reduced losses. It is assumed that the incentive offered to the customer per MWh, penalty imposed per MWh and costs of DR services sold to the GenCo per MWh are all equal.

6.4 Problem Formulation

Elasticity of demand is the slope of a plot between quantity and price of demand [96]. It is a dimensionless measure of the sensitivity of demand with respect to price.

$$\varepsilon = \frac{\frac{\Delta q}{q}}{\frac{\Delta \pi}{\pi}} = \frac{\pi}{q} * \frac{\Delta q}{\Delta \pi} \qquad 6.1$$

Where ‘q’ is the electricity demand and ‘π’ is the electricity price.

It is often found that a change in price of one commodity will result in a change in the demand for another commodity. Even in a power system, it is assumed that higher peak prices will result in consumers shifting their loads to low price regions. A negative 'self-elasticity' can be used to represent the period in which loads are unable to shift to another time. A positive 'cross-elasticity' is used to represent the periods in which consumption can be transferred to low load periods[97].

$$\varepsilon(i,j) = \begin{cases} < 0 \; if \; i = j \\ > 0 \; if \; i \neq j \end{cases} \qquad 6.2$$

Where 'i', represents the current hour and 'j' represents all the 24 hours. To model the self and cross elasticity matrix, the load profile was divided into 3 regions of peak load period, medium load period and low load period as shown in the figure below. Based on literature survey [97][95], the elasticity matrix displayed in the table below was used.

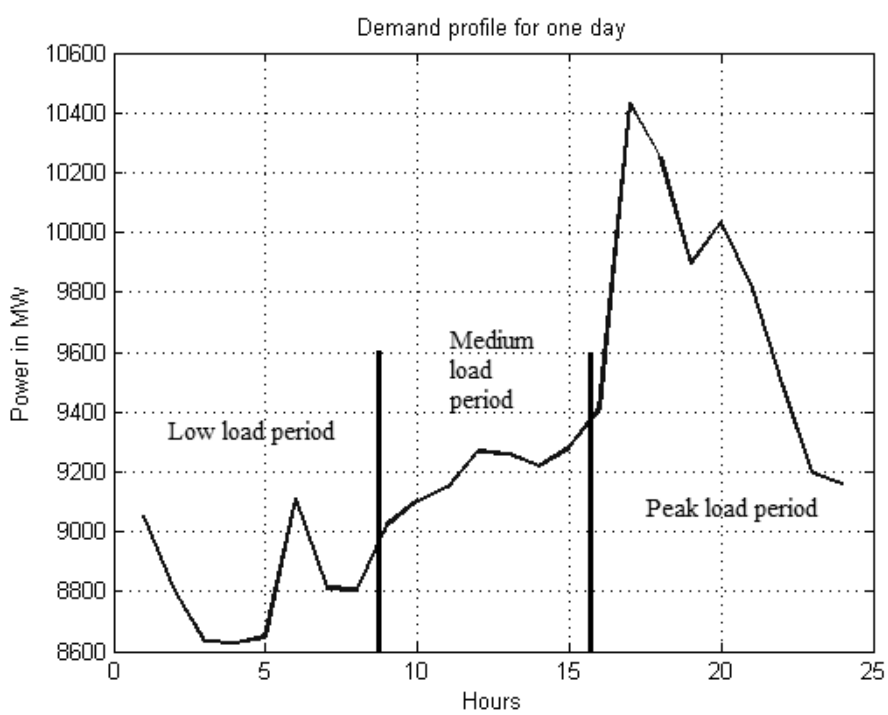

Fig 6.2 Demand Profile of a Random Day

Table 6.1 Elasticity Matrix

	Peak load period	Medium load period	Low load period
Peak load period	-0.2	0.016	0.012
Medium load period	0.016	-0.2	0.01
Low load period	0.012	0.01	-0.5

As explained in [97], the diagonal elements of this matrix represent the self elasticities while the off-diagonal elements correspond to the cross elasticities. The matrix indicates how a change in price during a single period affects the demand during all the periods. If the nonzero elements in a column are above the diagonal, the customers react to a high spot-price by bringing forward their consumption. If the non-zero elements are below the diagonal, the customers postpone their consumption until the high price period ends. If customers have the ability to reschedule their production over a long period, the nonzero elements will be spread over the column. If the flexibility of customers is limited, the nonzero elements will be seen clustered around the diagonal.

The next step is to model the I/C and RTP strategies. Denoting the new demand to be 'q_{new}' and the old original demand as 'q_{ori}':

$$\Delta q = q_{new} - q_{ori} \tag{6.3}$$

Supposing 'I' SAR/MWh is paid as an incentive to the customer for adhering to the I/C contract,

$$Incentive = I * (q_{new} - q_{ori}) \tag{6.4}$$

Considering a penalty of 'P' SAR/MWh imposed when customers fail to follow their IC contract,

$$Penalty = P * [IC - (q_{new} - q_{ori})] \tag{6.5}$$

Where ‘IC’ is the demand curtailment quantity signed between the customer and the demand aggregator.

To determine the customers benefit, the following equation is used.

$$B = b(q_{new}) - (q_{new} * \pi) + Incentive - Penalty \tag{6.6}$$

To maximize the customer benefit, the above expression is differentiated partially over ‘q_{new}’ and equated to zero.

$$\frac{\partial B}{\partial q_{new}} = \frac{\partial b(q_{new})}{\partial q_{new}} - \pi + \frac{\partial (Incentive)}{\partial q_{new}} - \frac{\partial (Penalty)}{\partial q_{new}} = 0 \tag{6.7}$$

$$\frac{\partial b(q_{new})}{\partial q_{new}} = \pi + I + P \tag{6.8}$$

Here ‘b’ is the quadratic benefit function [98] which is expressed below. ‘π’ represents the real-time price of electricity and ‘π_0’ will represent the original price without DR.

$$b(q_{new}) = b_0 + \pi_0 * (q_{new} - q_{ori}) * \left\{1 + \frac{q_{new} - q_{ori}}{2 * \varepsilon * q_{ori}}\right\} \tag{6.9}$$

Differentiate the above equation with respect to π and substituting the result in the previous equation,

$$\pi_0 * \left\{1 + \frac{q_{new} - q_{ori}}{\varepsilon * q_{ori}}\right\} = \pi + I + P \tag{6.10}$$

Rearranging the above equation, the new DR demand is calculated as shown in 6.11. This model is for a single period.

$$q_{new} = q_{ori} * \left\{1 + \varepsilon * \frac{(\pi - \pi_0 + I + P)}{\pi_0}\right\} \tag{6.11}$$

For multiple periods (24 hours) and keeping in mind the RTP based on wind power, the adjustment made is expressed below.

$$q_{new}(i) = q_{ori}(i) * \left\{ \begin{array}{c} 1 + \varepsilon(i,i) * \dfrac{\left(\pi(i) - \pi_0(i) + I(i) + P(i)\right)}{\pi_0(i)} + \\ \displaystyle\sum_{j=1, j\neq i}^{24} \varepsilon(i,j) * \dfrac{\left(\pi_0(j) + I(j) + P(j)\right)}{\pi_0(j)} \end{array} \right\} \qquad 6.12$$

To determine the real time price 'π', a linear model is proposed in which the power generated by the wind 'P_w' is inversely proportional to the price.

$$\pi \; \alpha \; \frac{1}{P_w} \qquad 6.13$$

Assuming an upper bound and lower bound on the price pertaining to wind power production, the function can be expressed as,

$$\pi = \left\{ \begin{array}{c} (1 + ub) * \pi_0;\; P_w = 0 \\ \\ \left(lb + \dfrac{\mathrm{m} * (1 + ub - lb)}{P_w} \right) * \pi_0; 0 < P_w \leq P_R \\ \\ (1 - lb) * \pi_0; P_w = P_R \end{array} \right. \qquad 6.14$$

Here 'lb' and 'ub' correspond to lower and upper bounds of prices. They are represented in percentages and divided by 100 when used in the function. P_W represents the output power of the wind while 'P_R' is the maximum rated output. 'm' represents the minimum value of 'P_w' not equal to 0 (obtained from historical data) and is therefore a constant.

6.5 Simulation Results

To perform simulations, electricity prices for consumers were obtained from Saudi Electricity Company and are displayed below.

Table 6.2 Electricity Tariffs

Slab in kWh	Industrial Tariff in Halala/kWh	Other Tariff in Halala/kWh
1-1000	12	5
1001-2000	12	5
2001-3000	12	10
3001-4000	12	10
4001-5000	12	12
5001-6000	12	12
6001-7000	12	15
7001-8000	12	20
8001-9000	12	22
9001-10000	12	24
>10001	12	26

The prices are applied to the load profile used earlier. Meanwhile, periods ranging from 12:00 am to 6:59am are chosen as low load periods, 7:00 am to 3:59 pm are chosen as medium load periods and 4:00 pm to 11:59 pm is chosen as peak load period. The trend is followed throughout the year irrespective of seasonal changes. The values of lower and upper bound are assumed to be equal to ±15% of the original price respectively. The demand aggregator is assumed to levy a penalty of,

award an incentive of and charge the wind GenCo for buying its services a price of 50 SAR/MWh. The data was substituted in the equations given and simulated.

The figure 6.3 shows the variation in real time pricing with respect to wind power generation.

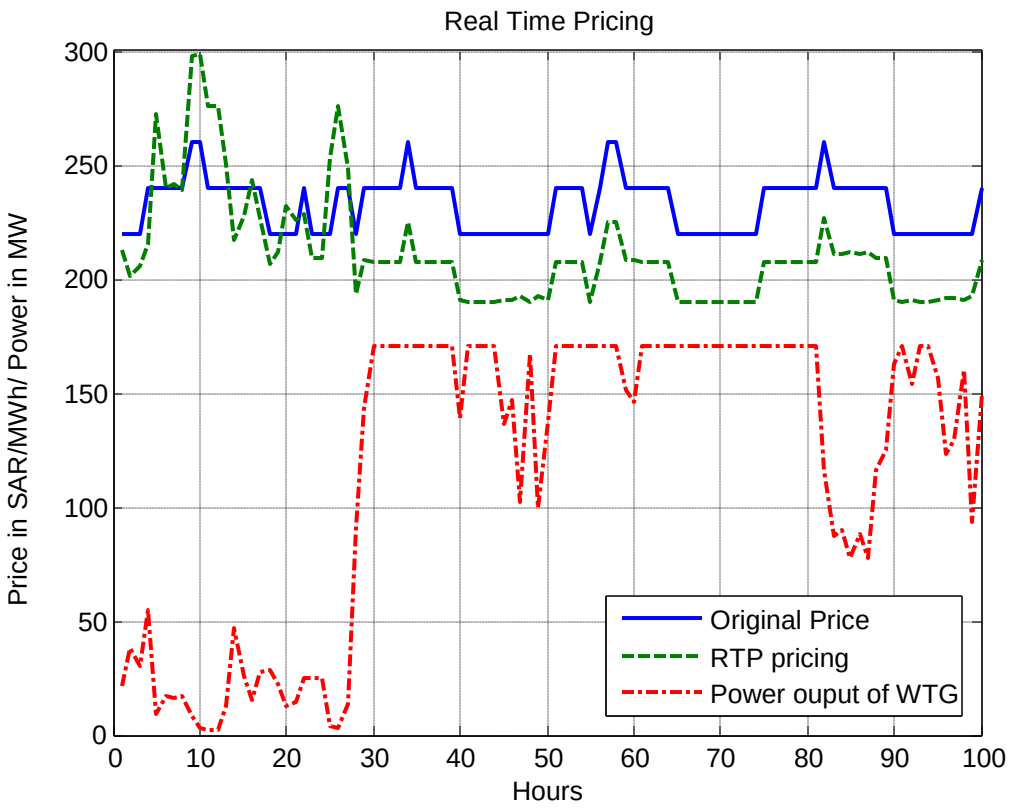

Fig 6.3 Real Time Pricing

The prices are observed to be following the production of wind power. They are lower for a higher production of wind power and vice versa.

Using the real-time prices and substituting in the equation to obtain new demand the following results are obtained.

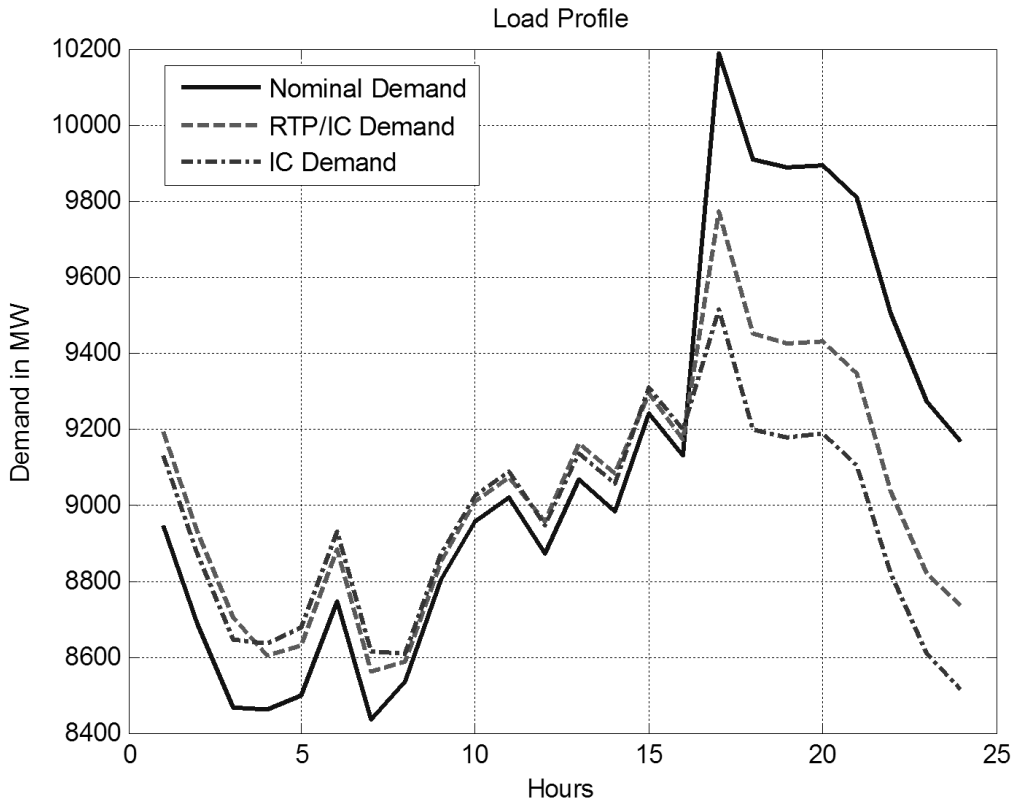

Fig 6.4 Demand Profile Comparisons

Figure 6.4 shows a comparison between the original demand profile, demand profile after applying only I/C technique of [95] and the proposed strategy of an integrated I/C and RTP technique.

It is observed as shown in figures 6.5 and 6.6 that energy savings are higher when the technique of [85] is used. This is because the I/C concentrates solely on peak load containment. On the other hand, the real time pricing induced by the wind power production will encourage customers to use more power when wind power production is higher thereby causing a conflict between the two techniques.

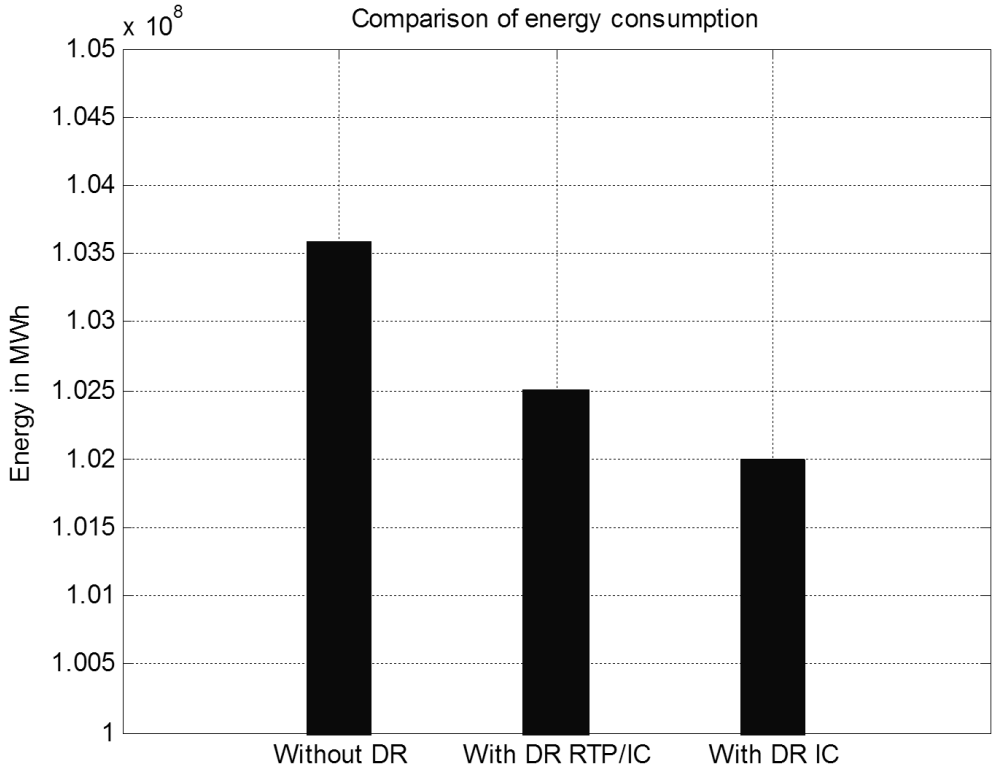

Fig 6.5 Comparison of Energy Consumption

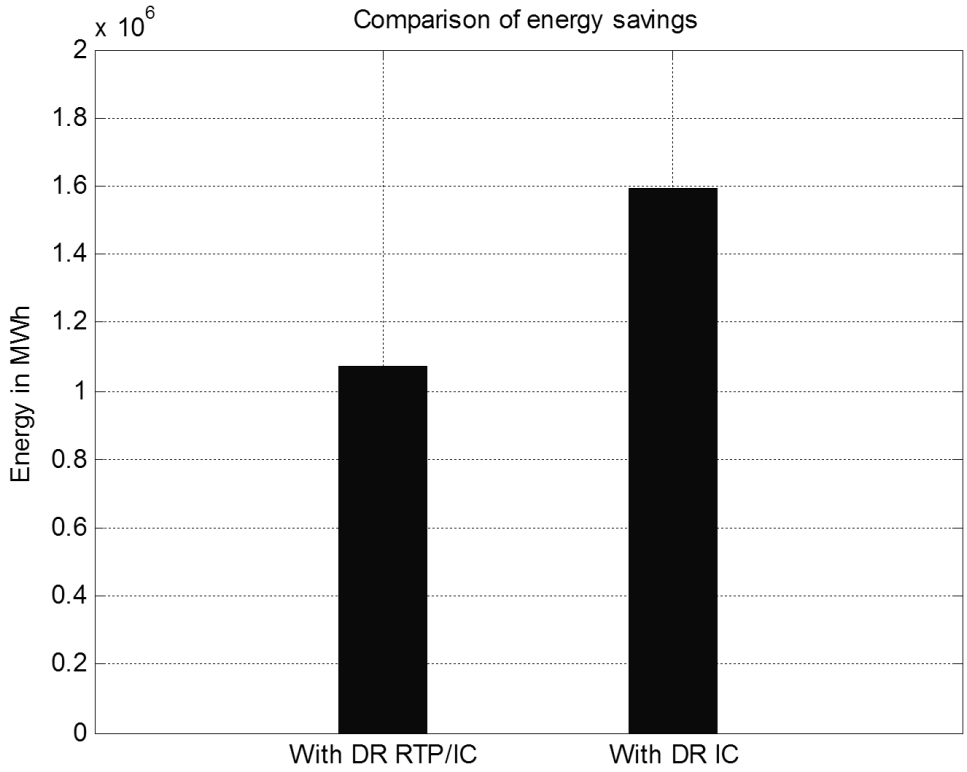

Fig 6.6 Comparison of Energy Savings

The advantage of the RTP/IC technique however, is that it serves to increase wind GenCo profits. The wind GenCo will buy DR services from the aggregator whenever it falls short in its day-ahead contract. The DR costs are much lesser than the penalties imposed by the operator. The figure below compares the differences that arise in profit and loss of the wind GenCo due to DR.

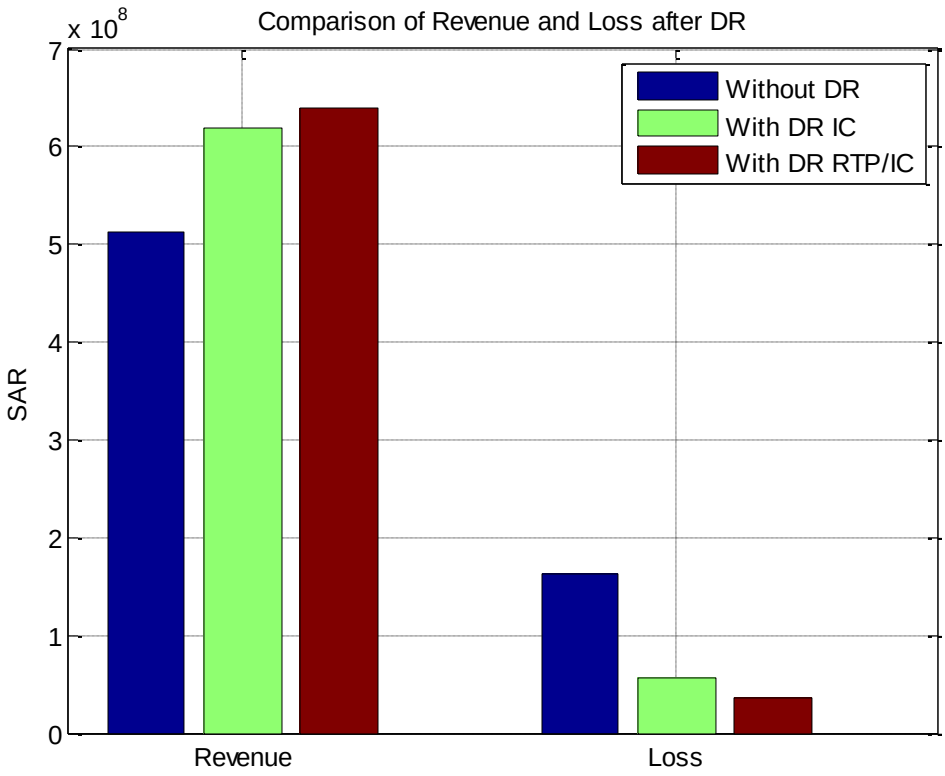

Fig 6.7 Comparison of Revenue and Losses for Wind GenCo

6.6 Conclusions

Out of the various DSM techniques present, DR is used in this chapter. DR is observed to be a useful tool for reducing costs for GenCos, reducing consumer prices and at the same time reducing emissions.

The DR strategy from [95] which was based on Interruptible/Curtailable contracts was built upon and extended to incorporate wind power generation via Real-Time Pricing. Though the energy savings are reduced in the proposed strategy when compared to the original, the wind GenCo profits are found to improve and overall, the results obtained suggest positive behavior of the system.

CHAPTER VII

CONCLUSIONS

7.1 Remarks

The thesis aimed at optimizing the integration of wind power into the electricity market to benefit the system as well as the wind GenCo. The location of study was the SEC Eastern Operating Area and Dhahran region was considered as the wind farm location.

The area in question has a low average wind speed and high intermittency. Hence, the change in residual peak load is unchanged even after increasing wind generation installed capacity levels to a value equal to peak demand. This results in installation of additional peak load and mid load serving conventional generation units. Due to this, the decrease in market clearing prices is little and minimum MCP's are observed for a low to medium scale (10%-17%) penetration. The cost-revenue ratios evaluated after the wind GenCo participates in the day-ahead electricity market indicate that a 10% of peak load installed capacity will give maximum return of investment to the GenCo and at the same time will lead to minimum MCP.

Having selected the capacity to be installed, two bidding strategies were compared for the wind GenCo to participate in the day-ahead electricity market i.e. bidding based on ARMA model forecast and bidding based on the proposed conditional probability based probability distribution of wind power. The latter was found to be more beneficial to the GenCo. Investigating the participation of the wind GenCo in the real-time market yielded that profits are much lesser than in day-ahead participation and cost-revenue ratio is higher. However, installed capacity required is much lower (around 1-5% of peak load) and hence provides an option for investors with low capital.

Demand response was investigated to integrate wind power. A joint strategy incorporating Interruptible/Curtailable loads and Real Time Pricing was proposed. The results obtained were compared with base literature and it was determined that though energy savings are lesser in the new strategy, it benefits the wind GenCo more and utilizing DR will encourage more wind GenCo to participate.

7.2 Future Works

Several developments can be made on the work done in this thesis. They are listed below:

- Aggregation of wind farms over multiple locations can be considered. Wake effect can also be included in the formulation. Also, Dhahran being a coastal area, an offshore location of the wind farm can also be considered. Wind generators at different locations would mean nodal pricing has to be taken into account.
- Market prices are assumed to be deterministic and known to the GenCo. This is not always the case and therefore a stochastic model can be developed for market prices as well.
- Another development would be to consider a bidding strategy that would integrate day-ahead and real-time market participation.

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